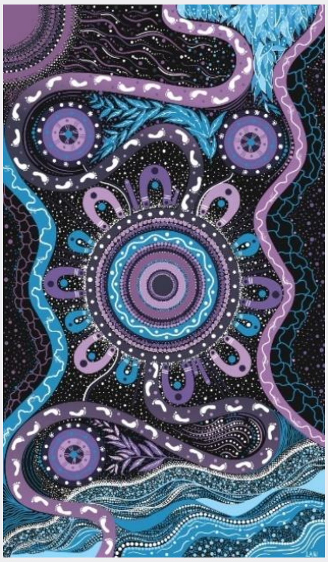
AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

2025 General Power System Risk Review Report – Draft

June 2025

Consultation Draft

A report for the National Electricity Market



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO has prepared this draft 2025 General Power System Risk Review report as an interim step in its review under clause 5.20A.3 of the National Electricity Rules. This draft report is published for consultation purposes only.

This publication is generally based on information available to AEMO as of 1 June 2025 unless otherwise indicated.

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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). 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.

The 2025 GPSRR consultation has highlighted some of the changes that the NEM is experiencing as it undergoes the energy transition. This transition is not unique to Australia, with many countries across the world transforming their energy systems to reduce carbon emissions and replace aging infrastructure. It is important that the transition is managed appropriately to ensure the continuing reliable and secure operation of the power system.

With a focus on this objective and to meet the requirements under NER 5.20A, AEMO has reviewed a prioritised set of risks to the power system through the 2025 GPSRR.

The recommendations made in this report aim to identify actions that will support the secure operation of the power system into the future. AEMO recognises the complexity of the energy transition and that it is not possible to predict or control all risks in a rapidly changing energy system.

The first four sections of this report detail the analysis on the following priority risks:

- **Inverter-based resources (IBR) response to remote frequency events.**
- **Minimum system load (MSL).**
- **Unexpected operation and interaction of protection systems and control schemes.**
- **Increasing risks of non-credible contingencies.**

These priority risks were selected with industry through the 2025 GPSRR approach consultation process[1]. This process considers inputs from NSPs and industry on potential priority risks, as well as AEMO's own operational experience, occurrence of recent power system events and any anticipated power system changes.

In addition to priority risks, the 2025 GSPRR report also contains assessment of other current and emerging risks in the NEM. Section 5 sets out some of these emerging risks which may evolve to operational risks if actions are not taken in investment timeframes. Systems, market design and regulatory frameworks are required to support timely investment to deliver reliability and system security capabilities. The effectiveness of new frameworks and investment will directly impact the progression of emerging risks and the scale of their impact.

Sections 6 and 7 provide details on the performance of existing emergency frequency control schemes and a review of relevant operating incidents, while Section 8 provides status updates on past GPSRR recommendations. A list of abbreviations and key terms is also provided at the end of the report for reference.

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[1] See https://aemo.com.au/consultations/current-and-closed-consultations/2025-general-power-system-risk-review-approach-consultation.

2025 GPSRR priority risks

AEMO's analysis for the 2025 GPSRR has led to the recommendations for the four priority risks summarised below.

IBR response to remote frequency events

Over 30 gigawatts (GW) of battery energy storage systems (BESS) is expected to connect through the energy transition by 2050[2]. BESS technology offers many operational and performance benefits to the power system, with their value as fast, dispatchable capacity primarily driving this rapid growth. However, if BESS or other fast-acting IBR facilities are concentrated in certain areas without appropriate settings, there is a potential risk of instability or thermal overload to interconnectors and other key transmission circuits during remote frequency events. AEMO identified that existing and planned BESS facilities in the NEM are sufficiently distributed to mitigate the risk of excessive BESS frequency response in the short and medium term. Continual monitoring of regional BESS capacity dispersion is necessary to ensure this risk remains low. For more details on IBR response to remote frequency events, refer to Section 1.

Recommendation 1

AEMO recommends that all network service providers (NSPs), as well as AEMO, commit to:

- Continue monitoring the location, control settings, and timelines of expected BESS or other fast-acting IBR connections in their respective networks or regions.
- Continue sharing any changes in concentration of IBR in regions or sub-regions that could affect power system stability.

Minimum system load (MSL)

The uptake of consumer energy resources (CER) in the NEM is significant, where one-third of detached homes in the NEM currently have rooftop solar installed. The total capacity of rooftop solar is expected to increase further as cost reductions support the connection of more homes and the installation of larger systems. The 2024 *Integrated System Plan* (ISP) Step Change scenario forecast rooftop solar capacity will reach 72 GW by 2050.

The cumulative increase in rooftop solar capacity is progressively impacting power system operations. During conditions of high rooftop solar output and low underlying demand, there may be an elevated system security risk. AEMO has previously released two reports on this matter – *Supporting secure operation with high levels of distributed resources*[3] and *Compliance of Distributed Energy Resources with Technical Settings: Update*[4]. There is a range of solutions to address MSL challenges, with many being actively considered. However, the implementation of regulatory mechanisms can take some time, while the need for action is already urgent. This requires consideration of both short-term operational measures and longer-term solutions.

Some of the major operational initiatives underway to address this risk include requiring compliance of distributed photovoltaic (PV) inverters with AS/NZS 4777.2:2020, implementing emergency backstop mechanisms, and

[2] See https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf.

[3] See https://aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/supporting-secure-operation-with-high-levels-of-distributed-resources-q4-2024.pdf?la=en.

[4] See https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en.

completing the 2025 Thermal Audit. These initiatives are highlighted in this report as high priority measures that will mitigate some of the short-term operational risks that the NEM is experiencing regarding MSL. These initiatives will need to be progressed in parallel with other longer-term regulatory and market solutions. These other measures are detailed further in the Engineering Roadmap, together with the CER Roadmap, identifying a range of reforms to better manage and integrate CER.

For completeness, the recommendations in AEMO's previous reports on emergency backstop and AS/NZS 4777.2:2020 compliance are presented below. AEMO recognises that these matters are being progressed but highlights that timelines must be met to mitigate potential system security impacts. For more details on MSL conditions, see Section 2.

Recommendation 2

The lack of emergency backstop mechanisms is contributing to operational risk during MSL conditions. To address this, the recommendations outlined in *Supporting secure operation with high levels of distributed resources*[5] should continue to be implemented with high priority. These include:

Governments and/or regulatory bodies to continue:

- Implementing suitable regulatory frameworks to require backstop capability in all regions.
- Ensuring emergency backstop coverage of all new distributed PV systems.
- Implementing regulatory frameworks to incentivise and enforce high backstop compliance.
- Allowing periodic aggregated remote testing of the emergency backstop mechanism.

Distribution network service providers (DNSPs) to continue:

- Implementing backstop capabilities, with periodic testing of the system at operational scale and the capability to estimate distributed PV generation available for curtailment.
- Implementing systems for monitoring, maintaining and enforcing high compliance to backstop.
- Developing DNSP operating procedures for efficient delivery of backstop.
- Implementing systems to minimise delay between AEMO instruction and delivery of backstop.

Transmission network service providers (TNSPs) to continue:

- Developing TNSP operating procedures for the use of backstop.
- Analysing transmission system needs in low demand periods.

AEMO to continue:

- Developing the models which assess and refine MSL profiles.
- Determining thresholds where backstop will be required.
- Developing AEMO procedures for use of backstop, ensuring all other available actions are considered prior.

[5] See https://aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/supporting-secure-operation-with-high-levels-of-distributed-resources-q4-2024.pdf?la=en.

Recommendation 3

The lack of compliance with the latest AS/NZS 4777.2:2020 inverter requirements standard is contributing to operational risks during MSL conditions. To address this, the recommendations outlined in *Compliance of Distributed Energy Resources with Technical Settings: Update*[6] should continue to be implemented with high priority. These include:

Governments and/or regulatory bodies to continue:

- Implementing suitable long-term governance frameworks to develop, introduce and implement CER technical standards and address the existing limitations in compliance regulatory frameworks.

Original equipment manufacturers (OEMs) to continue:

- Considering available actions to improve compliance and support installers in selecting the correct standard.
- Improving ability to extract and share comprehensive datasets on settings applied to devices in the field, both at the time of installation and on an ongoing basis.
- Maintaining accurate records of firmware updates.
- Supporting physical site inspections by improving access to information on inverter internal settings.

DNSPs to continue:

- Implementing programs to monitor compliance of distributed PV within their networks.
- Collaborating with AEMO to continue uplifting tools and capabilities for analysis of inverter performance.
- Improving compliance through investigation of commissioning processes, policies to allow remote changes to inverter settings and rectification processes that will rectify incorrect settings.

Unexpected operation and interaction of protection systems and control schemes

The NEM is seeing changing fault levels, new transmission topologies, and varying power flow paths as the energy transition progresses. As a result, many of the assumptions underpinning power system protection designs are subject to change. In addition, new generation projects are increasingly observed to propose remedial action schemes (RASs) to manage non-credible contingencies. While these schemes add complexity, they also bring benefits of minimising costs and deferring the need for further investment in primary plant that would otherwise be required. To manage this increase in complexity and changing system conditions, the risk of unexpected operation of protection systems and control schemes requires increased consideration. For more details on the unexpected operation and interaction of protection systems and control schemes, refer to Section 3.

Recommendation 4

It is recommended that AEMO leads a project with input from industry to investigate and implement explicit requirements related to RASs in the NEM.

The proposed work will include the following:

[6] See https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en.

- Detailed studies conducted by AEMO on RAS unexpected operation. This will include studies using power system simulation software to better understand the impact that operation of RASs may have on the system and understand the maximum operable RAS generation and load tripping sizes.
- Review of the NER clauses relevant to RASs. This may if required, lead to a rule change request to clarify RAS requirements in the NER.
- Investigation of RAS modelling requirements for RASs in the NEM and best practice across other network operators. This will inform RAS modelling requirements and work towards building models of RASs in the NEM that can be used to simulate maloperation and interaction risks.
- Expansion of the Remedial Action Scheme Guidelines into explicit requirements for RASs in consultation with industry. The full requirements should include consideration of the following:
  - Strategy for management of non-credible contingencies, including defining when a RAS is the preferred solution, and when it is not acceptable.
  - Definition of maximum RAS contingency size.
  - Stability criteria and post-thermal overload criteria for assessing non-credible contingencies to determine if a RAS is required.
  - Details on the limits to the number and complexity of schemes and any mitigation measures that must be taken if schemes are more complex than the standards allow.
  - Periodic reviews of RAS design to identify needs for updates following power system changes.
  - How to incorporate other existing and future RASs in the design and planning process.
  - Detailed model requirements, including aspects like communications delays, measurement times, circuit breaker opening times and measurement locations. In some instances, hardware in the loop tests may be required to capture hardware performance.
  - Detailed testing and verification requirements for RASs, such as regular audits of settings to ensure they align with design (for example, generator settings, control scheme settings).
  - Outputs from the recently created CIGRE working group *System Integrity Protection Schemes and the (N-1) criteria.* These outputs will support the development of other requirements based on international experience.
  - Other key topics identified through consultation with industry.

Increasing risks of non-credible contingencies

The changing topology of the power system may result in an increased risk for non-credible contingencies, as the number and size of potential non-credible contingencies increase. Continued assessment of non-credible contingencies will become increasingly important as the potential impacts become more significant, testing the resilience of the power system. AEMO recognises that new tools for managing non-credible contingency events may be required to adequately address this risk in the future. For more details on the increasing risks of non-credible contingencies, refer to Section 4.

Recommendation 5

It is recommended that AEMO leads further work considering how non-credible contingencies should be managed into the future.

This work would include input from industry and should include:

- Detailed studies conducted by AEMO on non-credible contingency sizes, both in the current and future network. This would include:
  - Studies using power system simulation software to better understand the size of non-credible contingencies that may result in cascading failure in the NEM for each region.
  - Analysis of existing non-credible contingencies in addition to proposed new connections.
  - Assessment of system strength and inertia impacts, as well as voltage and frequency response.
- AEMO would engage with industry on non-credible contingencies, to receive input and feedback. The proposed consultation will include:
  - Scope of studies and critical contingencies to be considered for each region.
  - Modelling approach, software and assumptions.
  - Results, outcomes and conclusions.
- AEMO would also investigate the process for managing non-credible contingencies that affect multiple jurisdictions. This may lead to the development of guidelines specifying requirements on roles and responsibilities related to multiple region contingencies.
- AEMO would lead a review of the NER clauses on non-credible contingencies, with input from industry. If determined to be necessary, this may lead to a rule change request regarding non-credible contingencies in the NEM.
- Consideration of additional tools or funding mechanisms that are effective to facilitate management of non-credible contingencies.

Further information and request for feedback

AEMO seeks to answer all participant questions and to receive feedback on this draft report. Please email gpsrr@aemo.com.au to:

- **receive a calendar invitation to the industry question and answer session**, planned to be held on 20 June 2025, and/or
- **submit written feedback on the draft report,** in particular regarding the findings and recommendations, and potential focus areas for the 2026 GPSRR (which will be consulted on separately under NER 5.20A.2(c)(3)).

Submissions received before 5.00 pm (AEST) 1 July 2025 will be considered for the final 2025 GPSRR report, due for publication by 31 July 2025. Relevant submissions will be published on AEMO's website, subject to AEMO's consultation submission guidelines[7], and AEMO may elect to summarise the substance of relevant issues raised that are common across multiple submissions. Please indicate if there are any parts of the submission that should be kept confidential, with reasons why.

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[7] See https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/industry_meeting_schedule/aemo-consultation-submission-guidelines---march-2023.pdf.

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1 IBR response to remote frequency events

BESS connections to the NEM continue to grow, with over 30 GW of BESS expected to connect by 2050. While this rapid growth is primarily driven by their value as fast, dispatchable capacity, BESS technology also offers many other operational and performance benefits to the power system. One aspect of note is that BESS in the NEM are required to provide primary frequency response (PFR)[8] when operating with non-zero dispatch targets[9].

In consultation for the 2025 GPSRR, ElectraNet identified a potential risk related to increasing transmission connected BESS capacity, where the concentrated active power response from BESS localised to South Australia during NEM frequency events could result in stability or thermal issues on interconnectors or other key transmission corridors. AEMO determined this to be a priority risk for the 2025 GPSRR due to its potential for cascading failure.

AEMO has evaluated the risk associated with increasing BESS capacity throughout the NEM, studying BESS performance in response to remote non-credible contingencies and their subsequent impact on the NEM's interconnectors.

AEMO found that the existing and planned grid-scale BESS facilities in the NEM are sufficiently distributed to mitigate the risk of aggregated BESS frequency response in the short and medium term. However, continual monitoring of BESS developments and capacity dispersion is necessary to ensure this risk remains low. If BESS or other IBR plant become concentrated in certain areas, there is potential for this risk to be present for interconnectors or other transmission lines.

This is supported by the following set of findings:

- **As BESS capacity increases in all NEM regions, post-contingent interconnector stability is improved due to distributed BESS frequency response.**
  - Increasing BESS capacity is forecast to be dispersed across all NEM regions. This provides balanced frequency support, reducing the risk that one region will dominate the response and overload interconnectors or critical transmission lines.
  - Higher aggregate BESS capacity in the NEM more effectively arrests frequency excursions. This results in reduced frequency deviations that individual BESS facilities are exposed to.
  - BESS developments will require ongoing monitoring to ensure future BESS projects do not result in disproportionately concentrated BESS in any single NEM region or sub-region.
- **New and planned interconnectors provide network stability improvements during contingencies.**
  - Studies show that when interconnector stability was challenged, the addition of PEC Stage 1 (PEC-S1) or PEC Stage 2 (PEC-S2) provided an alternate pathway that was critical to transfer power transiently following the contingency.

[8] See https://aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/primary-frequency-response.

[9] Schedule 2 of the National Electricity Amendment (Primary frequency response incentive arrangements) Rule 2022 No. 8 will commence operation on 8 June 2025.

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  - High-capacity interconnectors also provide low impedance connections to other regions, bringing inertia centres electrically closer across the NEM. This improves the frequency response of low-inertia regions.
- **Aggressive BESS frequency control settings are acceptable if adequately managed.**
  - Aggregated BESS response with aggressive frequency droop settings provides a benefit for overall frequency regulation. Moderating BESS frequency droop settings in all NEM regions has little impact on interconnector stability and worsens frequency excursions.
  - Consistent frequency droop settings should be considered for BESS in all regions. Varying frequency settings between regions may promote disproportionate BESS response for local or remote contingencies.

1.1 Integrated BESS capacity offers many benefits

Over 2 GW of BESS capacity is currently integrated in the NEM, and a further 9 GW is either committed or anticipated. By 2050, 34 GW of BESS projects are expected to connect, demonstrating a significant interest in the connection of new BESS to the NEM. The capacity of integrated grid-scale BESS facilities and the services they provide is expected to continue growing at a rapid rate as the energy transition progresses.

BESS capacity growth brings many benefits to the power system, such as:

- Fast active and reactive power response capability, providing rapid frequency and voltage support to power systems during contingency events.
- Short-duration energy storage that can absorb power at times of low system demand and operate as a generator when network demand is at peak levels.
- Improved utilisation of transmission assets and deferral of network upgrades.
- The emerging provision of new services and capability to assist with the secure operation of the network, such as virtual inertia, support to system restart pathways and grid forming inverter control.

1.2 Concentrated BESS presents potential risks

Concentrated BESS capacity in single regions in the NEM could bring challenges. While there are significant benefits to integrating BESS across the NEM, there are some challenges that must be considered.

Key factors that can have impacts on the system include:

- **Connection location.** The location of large-scale BESS greatly impacts power system stability due to the fast response of these facilities to remote frequency disturbances. If the response is concentrated over key transmission lines or interconnectors, this can have system stability repercussions.
- **Control settings**. Many existing large-scale BESS installations in the NEM have aggressive frequency droop settings (< 2%), meaning they discharge or charge significant quantities of power for small frequency disturbances.

These factors should be carefully analysed to ensure that no existing issues are exacerbated, or future problems are introduced.

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ElectraNet conducted initial studies on concentrated BESS response within South Australia, observing that aggressive droop settings resulted in this technology responding much faster to remote frequency events than other generators across the NEM. The following impacts were observed:

- **Higher transient power swings on interconnectors, and higher post-contingent flows through critical transmission cut sets when the system stabilises at a new operating point.**
  - These responses can result in system instability and increase the challenge of post-contingent power system security management.
- **BESS in South Australia can be exposed to higher frequency excursions than the other mainland NEM regions.**
  - Frequency excursions in the South Australian power system can be greater than the level observed for the other mainland NEM regions, because local inertia in South Australia is typically lower.
  - An increased frequency excursion results in an increased proportional frequency response from BESS.

ElectraNet's studies showed this is a potential risk, but only when BESS is concentrated in one region. ElectraNet's studies[10] focused on BESS integrated in South Australia – discounting BESS response from other regions – and did not include network augmentation such as Project EnergyConnect (PEC) at the time of these studies. This represents an onerous study scenario where there is a large discrepancy in the capacity of BESS connected in one region relative to the rest of the NEM, with the absence of adequate PFR or fast frequency response (FFR) capability integrated on the remote side of the interconnectors. AEMO completed studies in the 2025 GPSRR to understand the impact of BESS response in all regions, and to assess the impacts of planned network augmentations.

1.3 AEMO has assessed BESS performance using interconnector stability modelling

AEMO undertook studies to assess the impact of BESS on stability across the NEM's interconnectors, paying particular attention to South Australia. Remote non-credible contingencies were applied to observe the impacts of increasing interconnector power flows due to BESS frequency response. In these studies, the following were considered:

- Import and export scenarios over Heywood[11] and PEC[12] interconnectors.
- Pre and post PEC-S1 and PEC-S2.
- High and low system demands.

[10] Due to the timing of ElectraNet's studies, neither PEC Stage 1 nor PEC Stage 2 were included in its analysis. AEMO's studies in the 2025 GPSRR indicate that the addition of these augmentations further supports power system stability.

[11] The Heywood Interconnector is the 275 kilovolts (kV) alternating current (AC) interconnection between the South Australian and Victorian transmission networks, spanning from South East Switching Station to Heywood Terminal Station in the two regions respectively.

[12] PEC is a new 330 kV AC interconnection between South Australia and New South Wales, operating in parallel with the existing Heywood and Murraylink interconnectors. The project is delivered in two stages: Stage 1 connects Robertstown in South Australia through to Buronga in New South Wales to provide 150 megawatts (MW) of additional capacity, while Stage 2 extends this connection through to Wagga Wagga at full capacity of 800 MW.

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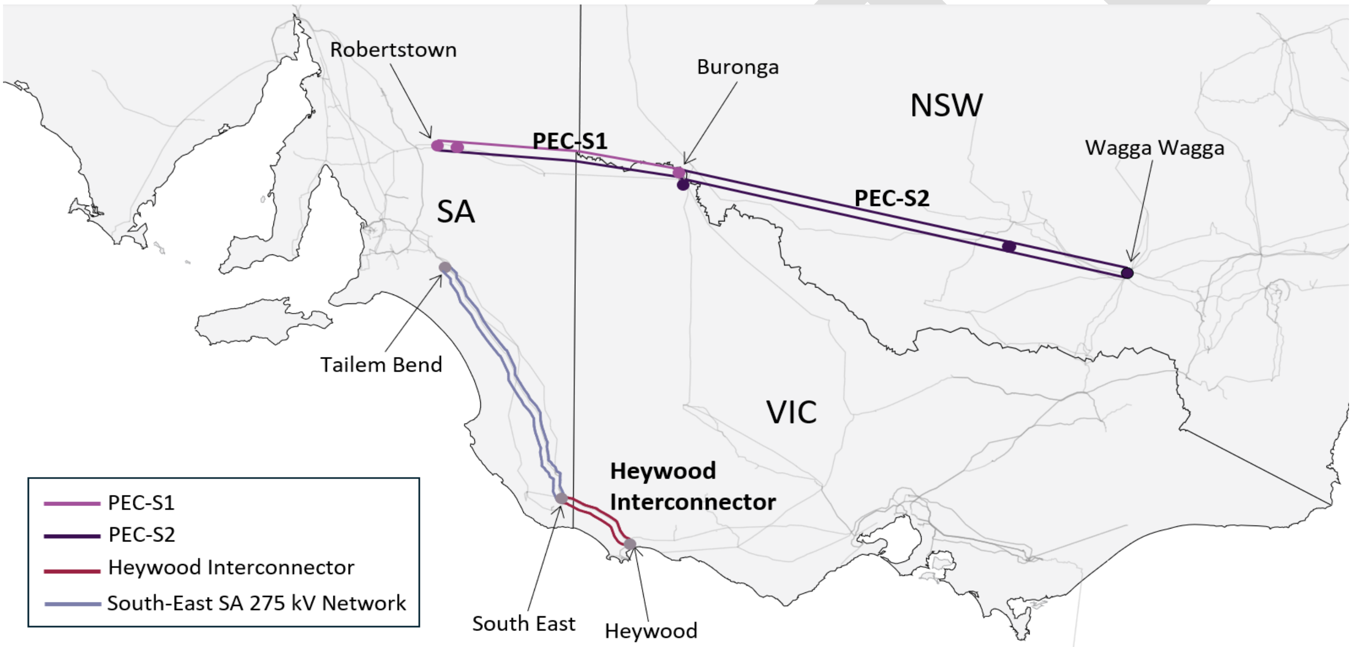
- Generation and load contingencies.
- Sensitivities with less aggressive droop settings for future BESS.

For studies prior to the PEC-S1 augmentation, AEMO assumed the maximum South Australian export limit across the Heywood Interconnector of 550 megawatts (MW) as the pre-contingent flow level. With PEC-S1 in service, the limit across the Heywood Interconnector is raised to 650 MW bidirectionally, and 750 MW bidirectionally with the eventual operation of PEC-S2. For the NEM's other alternating current (AC) interconnectors, the pre-contingent flow levels were set either on, or close to, their specified transfer limits[13]. For all studies South Australia's four synchronous condensers were assumed to be in service, offering inertia contribution for the region.

Figure 1 presents the transmission network topology across the south-eastern NEM regions, highlighting the interconnections into South Australia; Heywood Interconnector connecting through to Victoria, and PEC (Stages 1 and 2) through to New South Wales.

Figure 1 Transmission network overview showing Heywood and PEC interconnectors



From 2024 to 2027, the growth in BESS capacity is expected to surpass 9 GW[14], with the regional breakdown of this aggregate capacity presented in Table 1. These yearly metrics represent the BESS capacity levels modelled in these studies[15]. BESS were assumed to have grid following converter controls except for facilities with grid forming capability captured in dynamic models provided to AEMO. The committed transmission augmentations expected in service throughout the progression of this four-year horizon are also included in AEMO's modelling.

[13] For more information on the NEM's interconnector capabilities, see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/interconnector-capabilities.pdf.

[14] Taking into account advice from NSPs, as well as considering all committed and anticipated BESS. See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[15] BESS were considered dispatched at ~0 MW for all studies, allowing these facilities to both supply and absorb active power in response to generator and load contingencies respectively.

Table 1 Regional BESS capacities modelled each year from 2024 to 2027 (MW)

NEM region	Total 2024 BESS capacity	Total 2025 BESS capacity	Total 2026 BESS capacity	Total 2027 BESS capacity
South Australia	695	975	1,240	1,630
Queensland	450	1,355	1,605	2,105
Victoria	675	1,065	1,405	2,200
New South Wales	480	1,790	3,320	3,320
NEM total	**2,300**	**5,185**	**7,570**	**9,255**

This allowed AEMO to explore:

1. The AC interconnector stability concerns of concentrated BESS capacity in a single NEM region.
2. The trend in AC interconnector stability with increasing, geographically dispersed, BESS throughout all NEM regions.
3. The benefits of other BESS capabilities, such as reactive power control to provide fast dynamic voltage support.
4. The network stability improvements due to increasing transmission augmentations and regional interconnection.
5. The effect of moderating BESS frequency control settings on network stability.
6. The relative impact of load versus generation contingencies on the network stability owing to BESS PFR/FFR.

AEMO investigated these six key points in detail to understand how BESS will change the response of the power system for non-credible contingencies. The findings are detailed in Sections 1.4 to 1.9.

1.4 Concentrated BESS capacity reduces interconnector stability

The concentration of BESS in a single region reduces the stability threshold[16] of the NEM's interconnectors. When considering large quantities of BESS localised only in one region, it was found that this could reduce the stability threshold of interconnectors. This is due to the fast active power response from BESS facilities that surpasses other PFR and FFR providers in the NEM, resulting in large active power flow increases across AC interconnectors.

To investigate the impact of this on Heywood stability, AEMO evaluated three scenarios, considering the 2024 regional BESS capacities detailed in Table 1:

- Concentrated BESS localised in South Australia.
- No BESS in the NEM.
- BESS in all regions.

[16] This is the contingency size resulting in out-of-step conditions between sending and receiving ends of the AC interconnector. The mode of interconnector instability may be voltage or transient stability, and ultimately results in regional separation and expected transmission line tripping executed via installed loss-of-synchronism relays.

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After comparing the first two cases, AEMO found that cases with the absence of BESS in the NEM demonstrated a stability threshold significantly higher than when BESS are concentrated solely in South Australia.

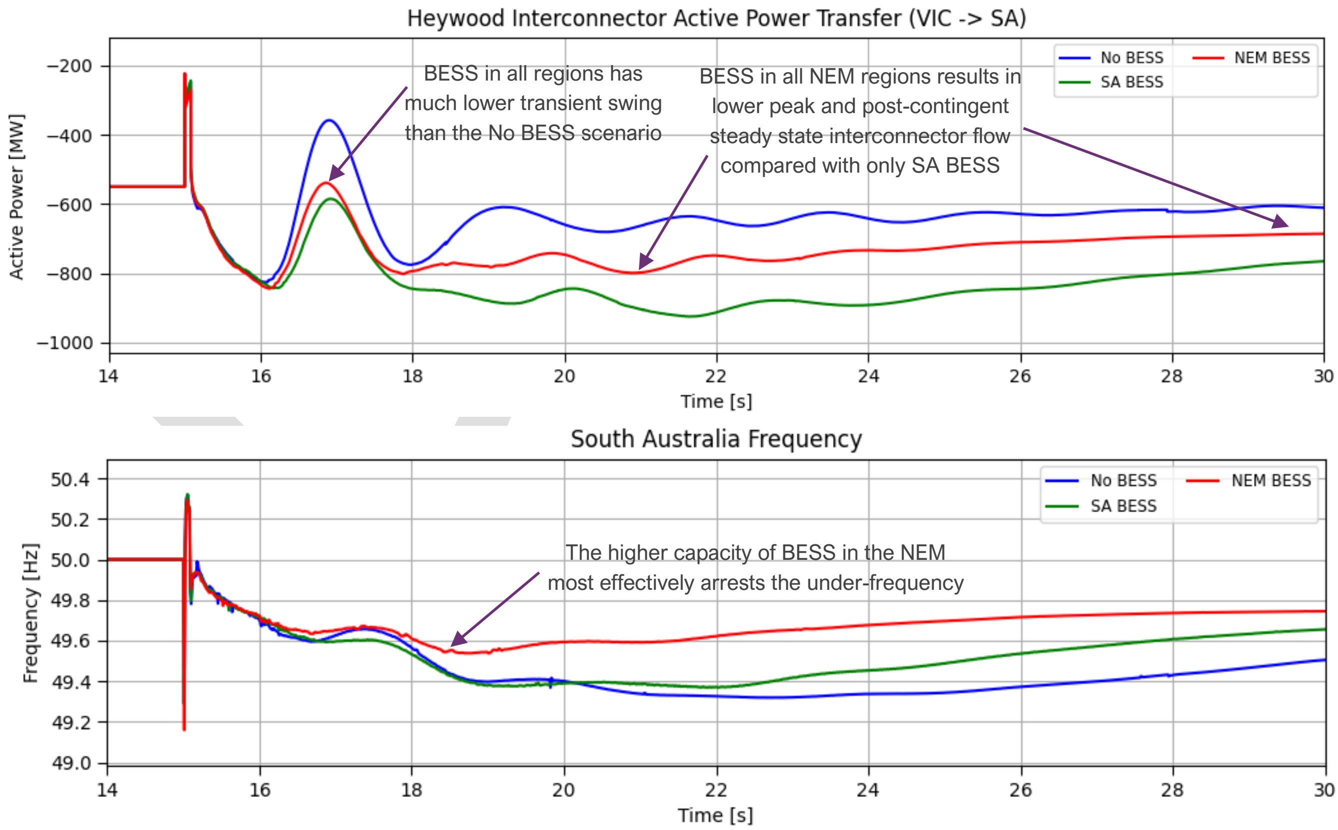
However, the ability of the NEM to arrest the resultant frequency deviation is largely degraded without the frequency response capability of these BESS. When BESS are integrated across all NEM regions, the stability threshold across the Heywood interconnector and the magnitude of the resulting frequency excursion are both improved.

The optimal case was with BESS integrated throughout all NEM regions. The results in Figure 2 show the power system response to a 2 GW non-credible generator contingency applied in Victoria during South Australia export conditions. These display active power transfer across the Heywood Interconnector (top) and the local South Australian frequency response (bottom), as measured at Para.

The three scenarios – South Australian BESS only, BESS in all regions, and no BESS – are shown via the *green*, *red*, and *blue* traces respectively. While the initial power swing (within the first 1 second of the contingency) on the Heywood Interconnector is similar between the three scenarios, the changing post-contingent steady state power flows between the three cases varies considerably.

It is clear in the figure that the case with BESS in all NEM regions resulted in the smallest frequency deviation, and also resulted in lower peak and post-contingent steady state interconnector flows compared with the South Australian BESS only case.

Figure 2 BESS localised to South Australia resulted in the highest post-contingent interconnector flows



Three key aspects contribute to this outcome:

- Active power support is provided from both sides of the Heywood Interconnector to arrest NEM frequency excursions.
- The additional BESS facilities connected in all regions can dynamically inject or absorb reactive power to offer support to network voltages. This improves the ability to increase power flows to the post-contingent generation or load deficit.
- An overall greater capacity of BESS in the NEM yields a less severe frequency nadir, exposing South Australian BESS to smaller frequency excursions. This reduces the proportional response from BESS integrated in the region.

1.5 Increasing dispersed BESS capacity improves stable network operation

Provided that transmission-connected BESS facilities are sufficiently distributed, the trending increase in BESS facilities throughout all regions does not appear to pose a significant risk in the NEM. AEMO's study results demonstrate that increased regional large-scale BESS capacity improves interconnector stability, which corresponds to an effective increase in the critical remote generator contingency size. For all interconnectors, this improvement was observed in each study year assessed, with some scenarios displaying tolerable contingency size increases up to 1 GW when comparing 2024 and 2027 studies.

AEMO studied the stability threshold across the Heywood Interconnector, Victoria – New South Wales Interconnector (VNI), and Queensland – New South Wales Interconnector (QNI) during high transfer conditions. These particular studies also considered PEC-S1 to be in service for study scenarios from 2024 to 2027.

The trending improvement in the NEM's interconnector stability is due to the increasing integration of BESS capacity evenly across all NEM regions. This increases the fast-acting PFR/FFR capacity on the remote side of interconnectors thereby reducing the magnitude of any NEM-wide frequency excursions. As a result, the response of BESS facilities localised in any single region is limited and therefore interconnector instability is less likely to occur.

Figure 3 illustrates this outcome, presenting an example from Torrens Island BESS, a 250 MW BESS located in South Australia. The figure demonstrates the trending reduction in the BESS frequency response for equal contingency sizes for scenarios from 2024 through 2027. Due to the reduced frequency excursions as more BESS is installed across the NEM, a smaller active power contribution from Torrens Island BESS is required. Note that the transition from the 2024 (*blue*) to 2025 (*green*) study scenarios halves the BESS's PFR provision.

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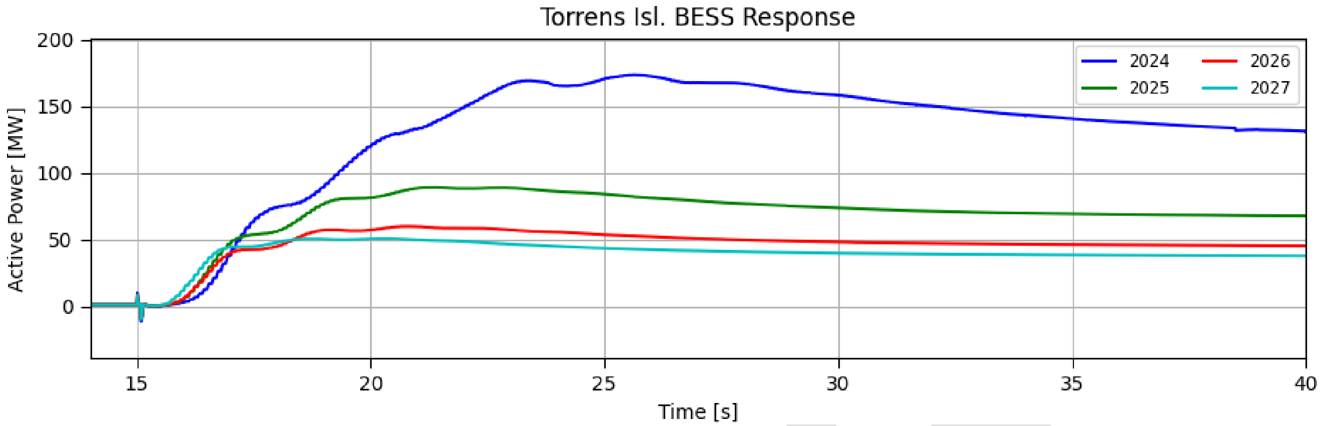
Figure 3 Reducing individual BESS contribution from 2024 to 2027



Select results present a reduction in the post-contingent power flow level on interconnectors from year to year. Again, this is attributed to the total BESS capacity connected across the NEM resulting in a considerable reduction in the frequency deviation following contingency events.

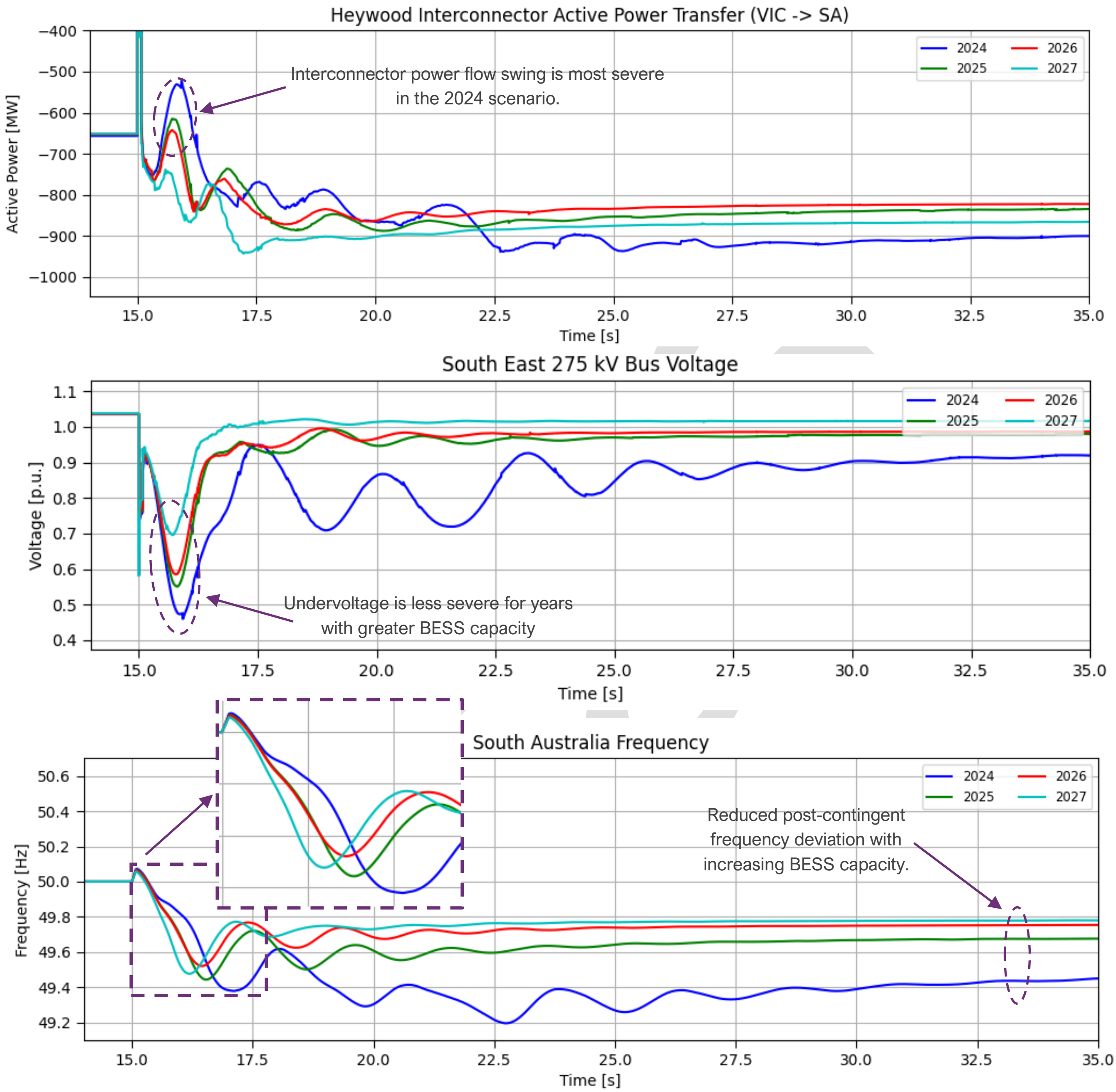
These trends are illustrated in Figure 4, which shows improved Heywood interconnector stability as more BESS are integrated into the NEM – the transient undervoltage at South East 275 kV Switching Station[17] is reduced for cases from 2024 to 2027. The figure shows Heywood interconnector power transfer (top), South East 275 kV bus voltage (middle), and the local South Australian frequency (bottom).

The responses observed for 2024 to 2027 scenarios are presented in each instance after a 3 GW Victorian generator contingency is applied during low South Australia demand conditions. Note that the improvement in the regional frequency excursion level and transient undervoltage at South East Switching Station are indicative of the improvement in Heywood interconnector stability for increasing BESS capacity represented by each study year. A reduced frequency excursion in South Australia results in a reduced contribution from South Australian BESS as per their frequency droop settings.

The location of BESS affects the performance of interconnectors, with BESS added close to the Heywood interconnector having a significant impact on voltage stability. As seen in Figure 4, a significant improvement in system performance is seen between 2024 and 2025 when BESS capacity in Victoria increases from 675 MW to 1,065 MW. Similarly, a step change in performance is seen between 2026 and 2027 when BESS capacity increases from 1,405 MW to 2,200 MW. It was found that the addition of BESS located close to Heywood provides transient reactive power support to assist in voltage stability post contingency, and subsequent active power flows over the interconnector. The reactive power benefits that BESS provide are discussed in more detail in Section 1.6. These benefits were demonstrated in the 2027 scenario where a 250 MW BESS was connected near the Heywood interconnector. The BESS provided significant voltage stability support for transient power flow increases from South Australia across Heywood, injecting more than 100 megavolt amperes reactive (MVAr) transiently in some instances.

[17] A rapid increase in exporting power flow across Heywood Interconnector can result in voltage instability/collapse in the south-east South Australia 275 kV transmission network.

Figure 4 Improving Heywood Interconnector stability with increasing NEM BESS capacity from 2024 to 2027



1.6 The reactive power capability of BESS benefits network stability

While one of the dominant performance characteristics of BESS is their fast and high proportional active power response to frequency events, they are also capable of providing significant voltage support through their dynamic reactive power capability. This additional fast-acting reactive power support helps improve overall power system stability.

Existing voltage support devices are challenged during large network contingencies. Under credible contingency conditions, voltage stability limits are typically well understood by NSPs, and reactive support mechanisms are implemented to alleviate network constraints where required. This is typically achieved via the installation of shunt capacitor banks for fixed support, or static volt-ampere reactive compensators (SVCs) where dynamic voltage support is required. However, these devices offer diminishing returns during severe undervoltage conditions[18], such as those that may occur during transient power swings. This challenge is exacerbated when the pre-contingent transfer level of an interconnector is elevated, as high transfer levels will push interconnectors closer to their secure transfer limit and require the absorption of more reactive power.

Voltage stability can limit interconnector transfer capability. AEMO observed that system voltages are stressed in response to remote non-credible contingency events where interconnector flows increase significantly due to BESS frequency response. This inherently imposes challenges on system voltages, particularly during the transient response period. A reduction in system voltages can also degrade the active power that an AC interconnector can transfer. This challenge increases further during higher system load conditions where the overall demand for reactive support is inherently elevated. In the Heywood Interconnector transfer and South East 275 kV plots presented in Figure 4 above, an example of Heywood Interconnector dynamic performance during South Australian export conditions demonstrates this impact:

- A rapid increase in active power provided by the region's BESS develops a severe undervoltage at South East 275 kilovolts (kV) Switching Station immediately following post-fault recovery from remote non-credible contingencies.
- Transient undervoltage temporarily reduces the active power flow across the interconnector prior to voltage recovery.

BESS can support voltage stability. Studies completed found that if BESS are connected in locations that are vulnerable to voltage stability challenges, this significantly improves the ability of the system to support voltages and more stably permit higher flows across the NEM's AC interconnectors[19]. This was particularly evident during severe transient undervoltage conditions and rapid power flows changes, where a rapid reactive power injection is necessary to arrest a fast-falling undervoltage. This capability could also offer benefit to other critical transmission cut sets. If implemented, this could improve stability limits without requiring investment via other dedicated fast dynamic voltage support mechanisms such as static synchronous compensators (STATCOMs).

1.7 New interconnectors further support increasing BESS capacity

Transmission augmentations improve network stability for BESS frequency response. This is evident for new interconnectors that provide alternate pathways for power flows between regions after contingency events and strengthen the electrical connection between regions. AEMO observed that with the addition of PEC-S1, there is a clear improvement to the power transfer stability across the Heywood Interconnector, and from South Australia overall. After applying remote contingencies, PEC-S1 provides the required additional capacity to support transient power increases due to BESS frequency response. The transient response of PEC-S1 can be upwards of 250 MW for short periods of time. For some of the larger non-credible contingencies assessed, the contribution

[18] Shunt capacitors provide a static reactive power contribution that is proportional to the square of their terminal voltage. SVCs, while capable of dynamically varying their reactive power delivered, also offer reactive power contribution that is proportional to the square of their terminal voltage when operating on a reactive limit.

[19] BESS offer a constant current limit, so their reactive power output operating on their reactive limit varies in direct proportion with voltage.

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from BESS in South Australia can exceed 500 MW, so the additional interconnector power flow sharing is considerable.

This benefit is also highly valuable due to the additional capacity that will be released on the Heywood Interconnector with the introduction of PEC and appropriate internetwork testing. This augmentation will eventually permit testing to increase bidirectional flows on Heywood of 650 MW with PEC-S1 in service, and up to 750 MW with the eventual operation of PEC-S2.

The geographical separation of Heywood and PEC interconnectors is favourable. Their largely different connection points in South Australia provides diversity. This means that for large contingencies where the voltage at the Heywood Interconnector is supressed, the voltage across PEC may still remain healthy, supporting the rapid response from BESS transiently across the other interconnector. This finding is supported by the following observations:

- Despite large transient undervoltages and subsequent power flow reduction across Heywood Interconnector, the response of South Australian BESS is adequately supported. This is achieved through flows momentarily directed across PEC-S1.
- Transient power flow redirection across PEC-S1 supports the recovery of the sending-end voltage of Heywood Interconnector. After recovery of voltages at Heywood, the interconnector can adequately support increasing flows to supply the remote energy deficit.
- Coincident with the recovery of Heywood Interconnector flows, power transfers across PEC-S1 rapidly reduce back to approximately the pre-contingent level.

This interconnector performance is presented in Figure 5, displaying Heywood and PEC-S1 Interconnector power flows. This figure demonstrates the impact of a 2.6 GW generator contingency in Victoria on the voltage at South East 275 kV switching station, with each trace representing the increasing BESS capacity from 2024 to 2027. Of particular interest is the transient contingency response period within 2.5 seconds post contingency. It can be seen that PEC-S1 supports flow increases exceeding 250 MW momentarily prior to voltage recovery at the South East 275 kV bus.

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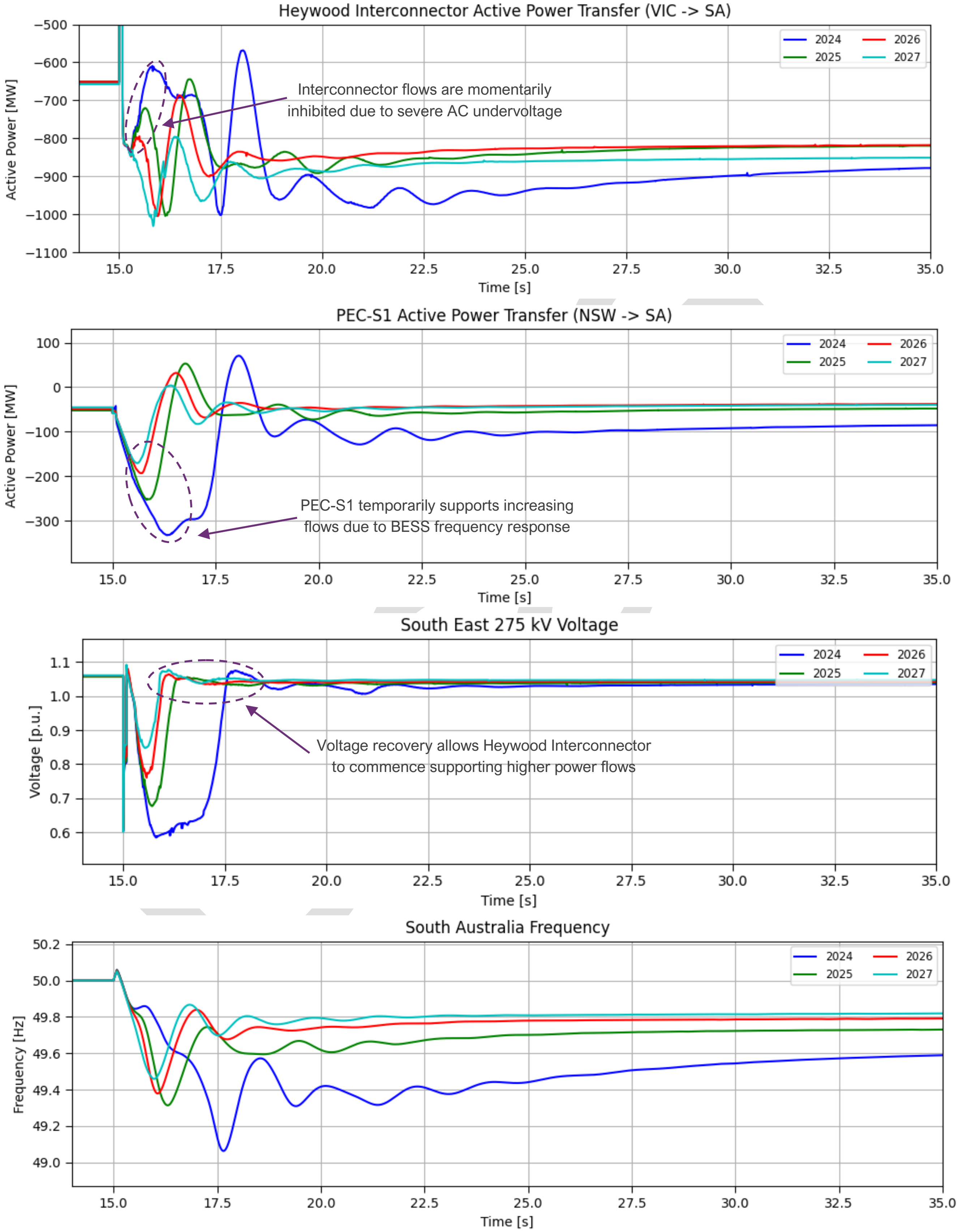
Figure 5 PEC-S1 supports Heywood Interconnector stability during the transient period



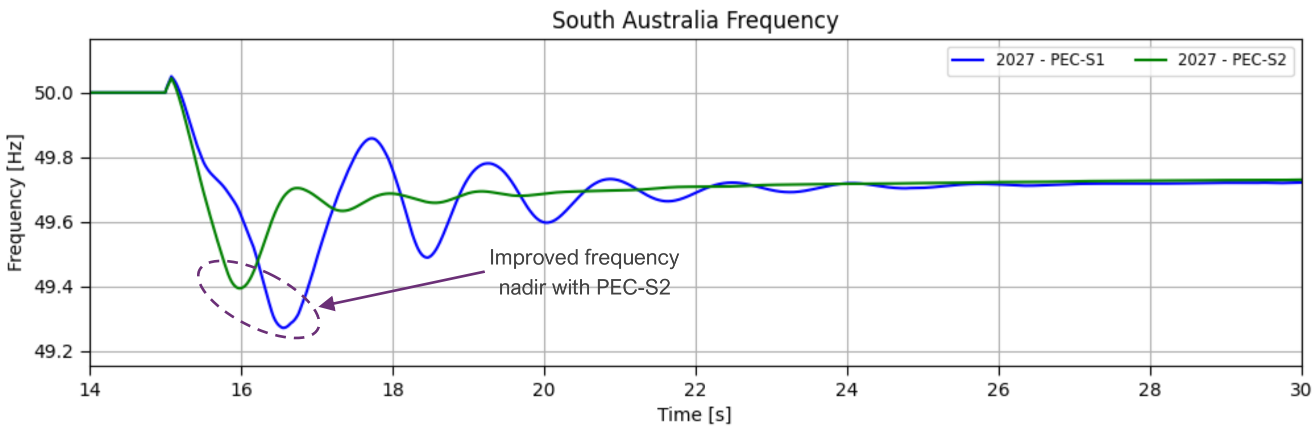
The integration of PEC-S2 further improves internetwork stability. This is demonstrated via an increase in remote contingency size required to cause instability across the Heywood Interconnector.

PEC-S2 provides a higher capacity transmission corridor from South Australia through to the core 500 kV southern backbone expected to be developed in New South Wales, and an additional connection into north-western Victoria. This high-capacity interconnection reduces the effective impedance between regions, bringing large inertia centres such as New South Wales electrically closer to South Australia. This results in more tightly coupled electrical frequencies in each region and damps the additional frequency swings experienced in South Australia for NEM contingencies.

A total of four synchronous condensers will also be integrated as a component of PEC's delivery, which further supports network stability due to their inertial and system strength contributions.

Figure 6 illustrates this performance improvement due to the integration of PEC-S2, relative to PEC-S1 for 2027 operating scenarios, shown via *green* and *blue* frequency traces respectively. Note the less severe frequency nadir and damping improvement due to the integration of PEC-S2. PEC and Heywood interconnector flows are preserved between case comparisons, applying 3.6 GW generator contingencies in Victoria.

Figure 6 PEC-S2 improves South Australia's frequency response to NEM events



1.8 Interconnector stability is not affected significantly by less aggressive BESS frequency droop settings

AEMO completed studies with future BESS with less aggressive frequency droop settings of 4%. AEMO used proponent-provided models, where available, to model the future committed or anticipated BESS facilities for the future operating scenarios. In the majority of cases, these connections implemented a frequency droop setting of 1.7% to maximise their registered capacity in frequency control ancillary services (FCAS) markets. To assess power system performance where the frequency droop of BESS is less aggressive, studies were re-run with frequency droop settings of all future BESS set to 4%[20] to understand the impact on the stability threshold of the Heywood Interconnector. The settings of BESS currently in service remained unchanged.

[20] This reduces the proportional frequency response of the BESS, requiring a 4% change in frequency to provide an active power delivery/absorption quantity equivalent to the rated active power capacity of the BESS.

AEMO found that internetwork stability is not sensitive to moderated frequency droop settings when applied equivalently to all BESS in the NEM. This remains due to the faster response time of BESS relative to other technologies. During South Australia export conditions, AEMO found that all scenarios resulted in reduced stability across Heywood Interconnector when BESS are configured with a 4% frequency droop. While this trend was consistent, it must be noted that the decline in stability was minor. The low impact of this stability reduction is especially evident for cases with higher demand conditions in South Australia. These cases are more onerous on voltage stability and subsequently see a reduction in interconnector stability threshold between 20-100 MW.

Aggressive frequency droop settings offer benefits. In the studies completed, it was found that implementing lower frequency droop settings for BESS results in a higher proportional active power response and offers the inherent benefit of arresting frequency excursions in the NEM more effectively. In contrast, if less aggressive BESS frequency droop settings are used, this results in more extreme frequency excursions. For large enough contingencies, existing emergency frequency control schemes (EFCS) may trigger before interconnector stability limits are surpassed. Other benefits of utilising more aggressive frequency droop control can be observed via the damping level of post-contingent voltage oscillations, which improves compared to the scenario assessing 4% frequency droop response.

These findings are presented in Figure 7, illustrating a comparison between 1.7% and 4% frequency droop on Heywood Interconnector flows (top), system voltage (middle), and system frequency (bottom) for 3 GW generator contingencies in Victoria for a 2025 study scenario.

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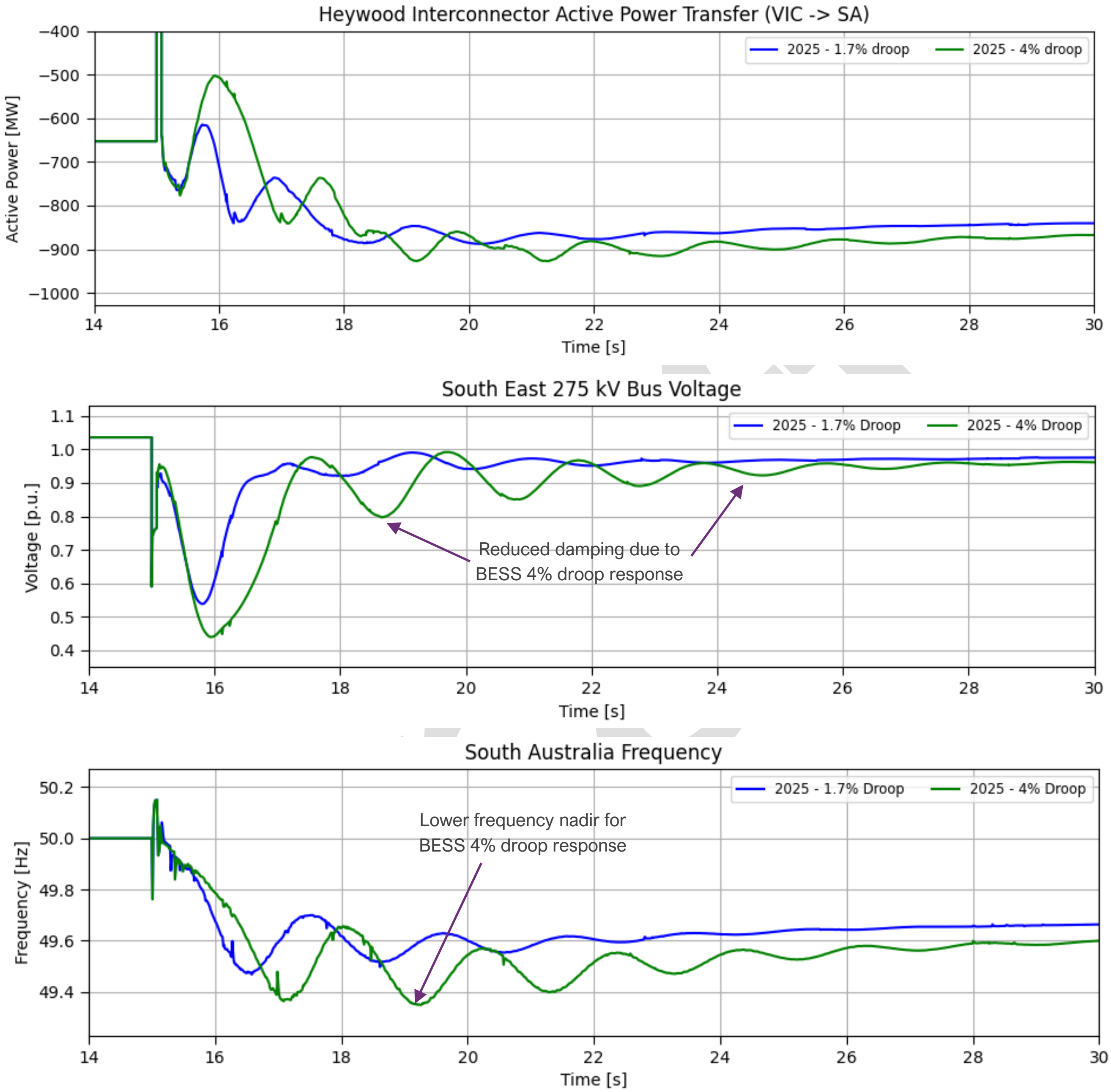
Figure 7 1.7% BESS frequency droop settings offer benefits compared to 4% frequency droop



Implementing less aggressive frequency droop settings for BESS results in performance trade-offs. While opting to use less aggressive frequency droop control for BESS in a single region may reduce interconnector stability concerns during remote contingency events, this poses other risks regarding frequency regulation. This reduces the proportional response offered by BESS for local contingencies within the affected region, further relying on frequency support provision from other regions. Increasing the frequency droop of BESS located in a single region will also degrade the technical ability of the region to support islanded operation, precisely when the frequency regulation from BESS facilities is most critical.

1.9 BESS response to generator contingencies is more onerous than load contingencies

AEMO assessed the impacts of both generator and load contingencies. Unlike other generation technologies, BESS can rapidly commence charging at high rates to absorb active power and arrest over-frequency excursions. They can even transition from a state of discharging to charging (or vice versa) seamlessly during dynamic system conditions. AEMO compared BESS response to load and generator contingencies, assessing the network impact in terms of Heywood Interconnector stability, considering South Australia import and export conditions. These studies were applied for future operating scenarios inclusively between 2024 and 2027.

Interconnector stability impacts vary considerably between load and generator contingencies. Remote generator contingencies were significantly more onerous than load contingencies on interconnector stability. This was attributed to several factors:

- **The contingent loss of bulk electrical load elevates voltages across the power system**, including those in the south-east 275 kV transmission network in South Australia. This improves the overall voltage stability across the Heywood Interconnector and through to Tailem Bend 275 kV Substation.
- **The contingent loss of synchronous generation degrades system inertia** and can result in higher rate of change of frequency (RoCoF) for generator contingencies compared to load events. This can subsequently develop increasing rates of proportional BESS response.
- **Loss of generation also reduces the ability to manage reactive power**. This results in remaining synchronous generators or other reactive support devices being pushed closer to reactive limits, reducing resilience of the system to manage another contingency. If insufficient reactive power is available, voltages will be reduced in the network leading to a reduction in overall voltage stability.
- **Generating plant across the NEM can typically reduce their active power output during over-frequency events**. This assists frequency stabilisation and can result in an overall reduced frequency deviation during load events. Generator contingencies are more onerous in this regard because the maximum active power limit for synchronous units and resource limits for IBR can prevent the provision of increasing active power.

Figure 8 illustrates a selection of these factors, presenting interconnector flows and the system frequency with incrementally more BESS in the NEM from 2024 to 2027. These results show the response when a remote 3 GW load or generator contingency is applied. Larger frequency deviations are seen for generator contingencies and the maximum Heywood Interconnector flows are also higher for generator contingencies. This is due to the power flow sharing between Heywood and PEC-S1 interconnectors, where for load contingencies the power transfer on PEC-S1 is only slightly perturbed relative to the generator contingency studies. Healthy voltages across Heywood Interconnector, particularly during the transient period, supports higher flows levels for load events.

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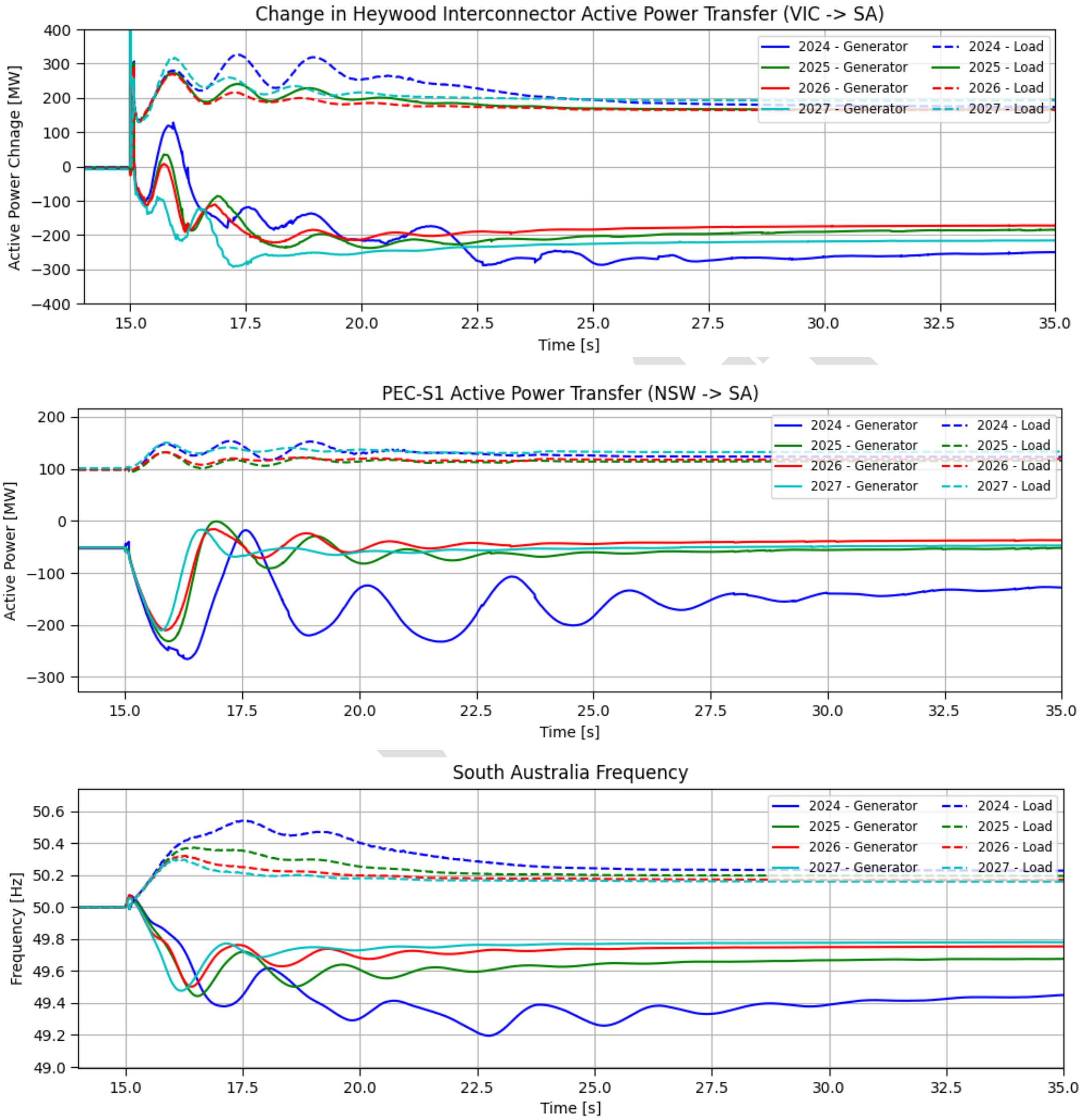
Figure 8 Comparing load and generator contingencies on Heywood Interconnector stability



1.10 Monitoring of BESS developments and capacity dispersion is necessary to ensure this risk remains low

While AEMO's findings indicate that the existing trajectory for BESS developments in the NEM does not introduce significant risk in the short and medium term, this outcome is contingent on the following factors:

- **Connection distribution** – BESS are geographically dispersed throughout all NEM regions, reducing the risk of concentrated BESS capacity to any one region.
- **Frequency control** – the frequency control action from BESS facilities remains consistent with existing frequency droop control designs, and the droop settings implemented by future BESS are consistent throughout all mainland NEM regions.
- **Operation** – the operation of the aggregate BESS capacity in a single region does not drastically vary from neighbouring regions.
- **NEM conditions** – changing operating conditions, such as a decline in system inertia, will vary the frequency response presented by each NEM region owing to contingency events.

Future work and monitoring are necessary to ensure that changes in these aspects can be adequately managed and this risk remains low. The following items require ongoing consideration:

- **Connection location, connection timelines, and frequency control settings of BESS developments**. These aspects should be monitored across all mainland NEM regions, with attention paid to circumstances where a trending increase in BESS capacity is apparent. The studied benefit of geographically dispersed BESS may be shared with power system design teams to support efficient planning of future connections of this technology. This includes understanding local challenges which may cause aggregate BESS response to impact critical transmission elements within a region, extending the consideration of BESS response impacts beyond just the NEM's interconnectors.
- **The use of BESS to support challenging operating conditions**. Conditions such as lack of reserve (LOR) or MSL in a specific region may impose market conditions or require directions from AEMO that result in BESS being operated differently to those in neighbouring regions. If one region has its collective BESS capacity operating close to an active power limit, this may considerably offset the balance of available BESS capacity throughout the NEM. This could result in higher than expected active power contribution from BESS in neighbouring regions.
- **Consideration of optimal frequency droop settings for BESS in the NEM.** This may be considered as possible future work completed by AEMO.
- **Future scenarios with lower system inertia**. This may introduce higher RoCoF conditions during contingencies and accelerated BESS response. These assessments may consider both overall lower inertia in the NEM, and also in specific regions, such as those that may arise with the future single or zero generating unit operation in South Australia.
  - Due to the NEM's transmission network topology and low inertia commonly experienced in South Australia, this exposes the local South Australian frequency to more severe excursions than other NEM regions. This can result in a higher proportional response from South Australian BESS, but this should largely improve with the commissioning of the PEC-S2 interconnector.
- **Synthetic (virtual) inertia capability**. Many of the future BESS connections will implement grid-forming converter controls, offering stability benefits to the power system. These grid-forming systems implement a virtual machine mode with the intention that their control system is capable of a dynamic response that emulates the stability benefits of synchronous machines, such as inertia provision during frequency events. BESS offering synthetic inertia will respond in proportion to RoCoF, in addition to the magnitude of a given

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frequency deviation as achieved with frequency droop control. For BESS enabled to provide synthetic inertia services, faster RoCoF during contingency conditions will afford a higher synthetic inertial response from BESS and may exacerbate transient power swings on interconnectors.

- **BESS participation in network control schemes**. Control schemes such as the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) intend to clamp or reduce the proportional response from select BESS facilities during significant continencies. This aims to limit the response from local BESS contributing to stability issues on interconnectors. As this control opposes frequency droop regulation, a balance between BESS armed for control schemes and the capacity available for frequency regulation requires careful consideration.

Other factors should also be considered:

- **BESS integration in Tasmania**. Although there is no BESS capacity currently integrated in the Tasmanian power system, the frequency settings of future BESS with proposed connections in Tasmania may require careful consideration and coordination with the frequency control response of the existing hydropower fleet, Basslink's frequency controller[21] and implications for the existing special protection schemes (SPSs) currently operating in Tasmania. The wider frequency operating bands in the Tasmanian power system may also require additional consideration regarding the subsequent tuning of BESS PFR compared to the mainland NEM regions.
- **Coordinating BESS locations for voltage support benefits.** This provides an opportunity to improve network stability in regions that are currently challenged in terms of voltage stability. These considerations may provide opportunities to unlock otherwise latent capacity on critical transmission cut sets constrained due to voltage stability limits.

Recommendation 1

AEMO recommends that all network service providers (NSPs), as well as AEMO, commit to:

- Continue monitoring the location, control settings, and timelines of expected BESS or other fast-acting IBR connections in their respective networks or regions.
- Continue sharing any changes in concentration of IBR in regions or sub-regions that could affect power system stability.

[21] The design of the frequency controller was made to be faster than hydro governors in order to implement the Network Control System Protection Scheme (NCSPS). This scheme is designed so that post contingent tripping of generation results in Basslink reducing flow, rather than on-island generation increasing output. Any fast acting BESS frequency response could have the unintended outcome of reducing the effectiveness of the NCSPS scheme.

2 Minimum system load

The uptake of CER in the NEM is growing, with one-third of detached homes in the NEM hosting rooftop solar. Cost reductions are expected to continue supporting the connection of more homes and larger systems. The 2024 ISP's Step Change scenario forecast that rooftop solar capacity will increase from just over 20 GW in 2025 to reach a capacity of 72 GW by 2050. While these levels of penetration of CER provides benefits to the NEM, it also presents unique challenges.

Rooftop solar contributes power when sunlight is available, with its maximum output typically occurring at midday. As the installed rooftop solar capacity increases in the NEM, this results in further reductions in operational demand in the middle of the day. Minimum levels of operational demand are decreasing across the NEM, at an average of 1.2 GW per year.

As minimum operational demand decreases, it may trigger minimum system load (MSL) conditions. MSL is initially more likely to occur on days when underlying demand is lowest, such as mild sunny days on weekends or public holidays in spring or autumn. MSL conditions may become more common in the system as minimum operational demand levels continues to decrease. MSL carries with it a number of risks to power system security and reliability.

This section considers how AEMO is working with industry, governments and regulators on strategies to manage the increasing occurrence and risks of MSL conditions driven by the rise in CER.

- MSL risks arise from rooftop solar displacing traditional synchronous generators that provide essential system services such as inertia, system strength and voltage support. Rooftop solar may drive operational demand to lower levels that are insufficient for synchronous generators to operate at or above their minimum stable operating levels. AEMO requires further commitments and capability from DNSPs, installers, governments and state regulators to enable satisfactory management of this risk.
- Currently, these risks are being managed through the MSL framework. Actions depend on the level of demand and range from providing advance notice to the market of projected MSL conditions, through to actively managing rooftop solar output to restore demand.
- To mitigate the increasing risk of MSL conditions, further action is needed in the long term. This includes the actions already recommended by the CER and Engineering Roadmaps, such as greater inverter compliance with AS/NZS4777.2:2020, and greater availability of emergency backstop mechanisms. It also includes enabling the operation of thermal generation at lower levels, and utilisation of BESS as load reserves. AEMO is continuing analysis to better understand the operating envelope for MSL conditions and how these actions can be implemented.

2.1 The operational risks of MSL conditions to the power system

MSL conditions introduce several power system risks that relate to the increased amount of rooftop solar generation displacing traditional synchronous generators. There are three general types of operational risks related to MSL that are discussed in this report:

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- The reduction of essential system services such as inertia, system strength and voltage support that are provided by traditional synchronous generators.
- Larger system contingency sizes due to non-compliance of distributed PV inverters with the latest fault ride-through standards.
- A lack of predictability and visibility of rooftop solar output resulting from the operation of CER outside of AEMO managed markets. This can manifest in reduced availability of under-frequency load shedding (UFLS), uncertainty of system restart ancillary services (SRAS) pathways, or the need to shed underlying native load to balance system needs.

These risks are currently being managed through short-term operational measures (see Section 2.2), with additional longer-term measures being developed (Section 2.3).

2.1.1 Reduced inertia

Reduced inertia in the power system results in more severe RoCoF following power system events, increasing the risk of cascading failures. Synchronous generators typically have large rotating masses that provide natural inertia to the system that opposes changes in frequency. When a loss of a generator or load occurs, the natural inertial response from the synchronous generators will assist in maintaining the frequency close to 50 hertz (Hz).

If synchronous generation is displaced by rooftop solar that cannot provide this inertia, the power system may see larger frequency deviations after power system incidents. Deviations that exceed design limits can result in unexpected operation of other plant and contribute to cascading failures.

2.1.2 Insufficient system strength

Synchronous generators also provide system strength, which is the ability of the power system to maintain and control the voltage waveform at a given location[22]. Rooftop solar does not inherently provide system strength, meaning there can be increased risk at times of MSL if there is insufficient system strength available from other sources.

Low system strength can result in the unexpected operation of devices that rely on a strong voltage waveform to operate. This includes inadvertent operation of protection systems following a disturbance in the power system, sub-synchronous oscillations, or the inability of IBR generators to ride through system disturbances.

2.1.3 System restart challenges

Sufficient stabilising demand is required for system restart, but higher distributed PV generation operating conditions are causing load variations and load erosion. If the existing distributed PV management processes are ineffective in restart scenarios, there may not be sufficient demand to restart the system until night-time or low distributed PV operating conditions, which may delay restart times significantly.

[22] See https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

2.1.4 Challenges in managing system voltages

Low system demand can result in higher system voltages, where lightly loaded transmission lines act as capacitors. This effect can drive system voltages higher, with potential damage to power system equipment if the voltages are not controlled within normal limits.

The ability to control these voltages is also reduced when grid-scale generation is displaced by rooftop solar. Both grid-scale synchronous and IBR generation can absorb or supply reactive power to maintain voltages within the required range. However, this may not be available if rooftop solar dominates the generation mix, as it cannot typically provide reactive power at the location or scale that the grid needs to manage voltages effectively.

Under low demand conditions, voltage control devices such as grid-scale generation, synchronous condensers, STATCOMs or SVCs must absorb a significant amount of reactive power to keep voltages low. This limits the amount of reactive power headroom available to maintain post-contingent voltages within acceptable limits. This is particularly an issue in the event of a trip of a major reactive power absorbing unit such as a generator or large reactor.

2.1.5 Large ramping events

Significant active power contribution from rooftop solar can reduce diversity in the source of generation. This can result in large ramping events when cloud cover unexpectedly reduces the output of rooftop solar, and demand suddenly increases.

This was observed recently in Western Australia's South West Integrated System (SWIS), where demand was at approximately 1,600 MW before cloud cover reduced the output of a large amount of rooftop solar. As shown in Figure 9, the operational demand increased from 1,600 MW to above 2,385 MW, resulting in a demand increase of 49% over 40 minutes.

To manage large increases in operational demand such as this requires sufficient headroom from online generating units or BESS, or the ability to bring on fast-acting generation quickly to maintain the energy balance of the system.

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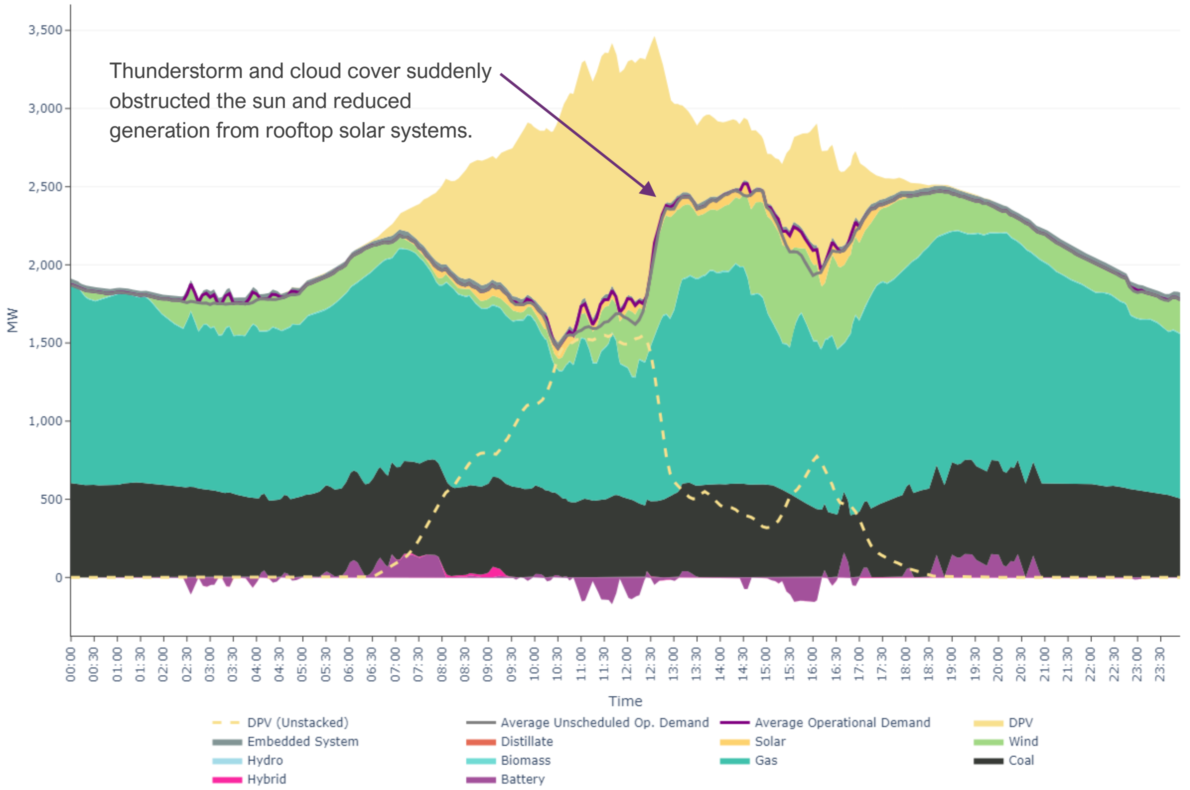
Figure 9 Rapid upswing in electricity demand in Western Australia's SWIS on 13 March 2025



2.1.6 Operation of CER exists largely outside of AEMO managed markets

There are currently only limited mechanisms in place for AEMO to manage the impacts associated with rooftop solar. There is currently inadequate visibility of aggregated CER, as well as limited forecasting ability to predict rooftop solar response. If this continues, reduced demand may fall to levels such that it is not possible to keep sufficient generation online to maintain essential system services. In some scenarios, transmission line flows may be pushed above secure limits.

Currently, regions with high levels of CER generation will export to other neighbouring regions to take advantage of inter-regional demand diversity. However, as rooftop solar connections increase further, there may be coincident MSL conditions across multiple regions.

2.1.7 Reduced efficacy of UFLS

Increasing levels of generation from distributed PV are reducing the load on UFLS circuits, reducing the effectiveness of UFLS. With very high levels of distributed PV 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, exacerbating the supply demand imbalance when they activate following an under frequency event.

2.1.8 Rooftop solar may trip during power system disturbances

In 2020, AS/NZS4777.2 was updated to ensure that inverters would remain connected following temporary grid disturbances and reduce the risk of sympathetic shake-off following power system incidents. Initial compliance with this standard was identified to be below satisfactory levels. Since then, AEMO has collaborated with industry, governments and regulators to uplift compliance of these systems largely through voluntary actions. However, if issues are not addressed to manage the compliance of CER to technical settings in the long-term, the risk of issues, such as rooftop solar tripping for power system disturbances, may persist.

An increased contingency size has the following impacts:

- Increased severity of power system incidents.
  - Larger contingency sizes will cause a larger disturbance to the network, impacting the frequency and voltage more severely. This can result in unexpected consequences and potential cascading effects, especially for non-credible contingencies where the outcomes are difficult to predict.
- Increased need for FCAS.
  - To manage larger credible contingency sizes, additional backup generation or BESS is required to provide active power or inertia to the system after a contingency event.
  - This is managed in the market by increasing the need for contingency FCAS, as well as inertia support services such as FFR, increasing costs to consumers.
- Reduced network stability limits.
  - An increase in credible contingency size pushes the network closer to its stability limits, particularly for transfers over interconnectors or major transmission lines.
  - To address this, constraints may be used under high solar conditions that will constrain interconnectors or other transmission lines to account for the increased contingency size. This increases market costs and reduces the effective utilisation of power system assets.

2.1.9 Outage planning difficulties

- Outages may reduce network stability limits, and this impact is exacerbated when attempting to undertake outages in combination with factors such as MSL conditions or a potential increase in rooftop solar contingency size.
- Network stability limits may reach levels where multi-day outages are not practical to proceed. If key maintenance works cannot be completed when planned, this increases the risk that unplanned outages will cause system incidents.

2.1.10 Outages of large loads create operational difficulties

Large industrial loads contribute significantly to power system demand and under MSL conditions, the impact of losing a large load will further reduce demand.

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This was seen in South Australia in October 2024, where Olympic Dam was disconnected from the grid for an extended period as a result of severe weather[23]. This reduced demand in South Australia and resulted in several days with negative operational demand when high solar conditions were experienced.

Outages of other large industrial loads, or interconnectors, could result in similar impacts to MSL conditions in various regions across the NEM.

Loss of a large load during MSL conditions can also result in system security issues:

- Operational actions to increase demand can take up to 90 minutes to implement, but the NER require AEMO to take reasonable actions to aim to resecure within 30 minutes.
- This creates issues if the loss of a large load occurs, and sufficient actions cannot be taken to restore load and meet security requirements.

Currently, the MSL framework considers the impacts of the largest credible loss of load, but if a non-credible load loss were to occur, this could result in worse power system outcomes.

2.2 Operational measures are in place to address the current risk

The risks associated with MSL are managed primarily through the MSL framework, which defines three tiers of market notices that are used to convey the risks and actions that are being taken.

There are a number of actions that can be taken to mitigate risks depending on the level of demand. These actions range from providing advance notice to the market of projected MSL conditions, up to actively managing rooftop solar output where possible to restore demand. Key actions that are taken for each level are described below.

MSL1: Issuing market notifications to prompt a market response

MSL1 is seen as advance notice and provides a notification to the market that a possible MSL event is forecast. This is generally provided at least one day in advance but can be issued for much shorter notice periods if system conditions change rapidly.

MSL2: Grid-scale actions will be taken to mitigate the risk

These actions include:

- Recalling planned transmission outages to restore export capacity to neighbouring regions if possible.
- Constraining any significant non-scheduled generation to 0 MW. By constraining these units, this allows larger synchronous generation to contribute more active power, operate above their minimum stable operating levels and provide the required essential system services.
- Constraining scheduled or semi-scheduled units to 0 MW if not required and if already not constrained off by normal dispatch processes.

[23] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/tower-failures-in-south-australia-and-new-south-wales-on-16-and-17-october-2024.pdf?la=en.

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- Increasing electricity demand by directing large consumers into service to absorb excess energy, such as pumped hydro or batteries if not already operating.

MSL3: AEMO will instruct TNSPs to maintain system demand above a specified level

This is achieved through a number of the following measures, depending on the region:

- Curtailment of non-scheduled and exempt embedded generation.
- Load shifting. Some DNSPs have some ability to temporarily shift a proportion of electric hot water load into the middle of the day.
- Active distributed PV management to curtail rooftop solar and restore demand.
- Voltage management systems to disconnect distributed PV in emergency scenarios. Increasing distribution voltages can be used as a method of last resort to disconnect distributed PV to maintain system security. This would only be used for emergency scenarios and is not recommended for regular use because it can risk damage to customer equipment. This may not be a possibility in all regions due to regulatory requirements.
- Shedding of reverse flowing feeders. If the above actions are not sufficient to clear the MSL3 condition, the final action that can be taken is shedding of reverse flowing feeders. This involves shedding whole distribution feeders where generation exceeds demand due to the outputs of rooftop solar or any other distributed generation, therefore increasing the overall operational demand. This approach has a high impact on customers, requiring shedding significant quantities of customer load to achieve a small increase in operational demand. At present, this is the only form of control available to increase operational demand in many areas of the NEM.

2.3 AEMO, industry, governments and regulators are acting to mitigate the increasing risk

The amount of distributed PV projected to connect to the system is increasing, which further intensifies the issues the power system is experiencing relating to rooftop solar. To address the increasing risk, a range of short-term and longer-term projects are underway.

The actions that are currently being progressed are detailed below. This report primarily focuses on the actions that are being taken to address the short-term operational risks associated with MSL conditions, but other longer-term actions are mentioned with references for further information. It is important to note that these actions must be implemented within the recommended timeframes to effectively reduce risks.

2.3.1 AS/NZS4777.2:2020 compliance

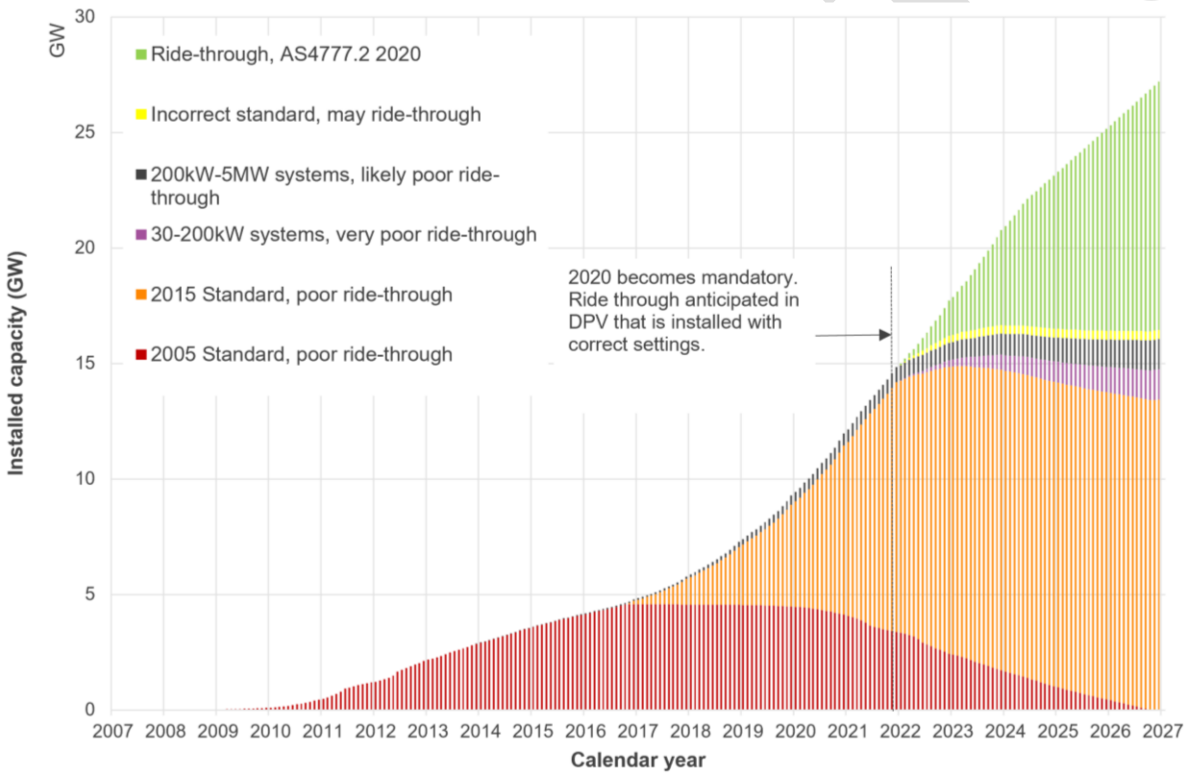
OEMs, installers and DNSPs should continue to ensure that new distributed PV inverters comply with AS/NZS4777.2:2020 to improve distributed PV fault ride through and reduce the risk of increasing contingency sizes.

AS/NZS4777.2:2020 compliance relates to the ability of distributed PV inverters to ride through system faults. By improving the compliance of inverters with this standard, the risk of an increased contingency size due to distributed PV shake off will be reduced. The 2020 version of the standard has significantly improved fault ride-through requirements, and inverters that comply with this standard will be much less likely to shake-off due to a power system disturbance.

Recent work has resulted in an uplift to 94% of new installs achieving compliance with this standard, largely through voluntary actions taken by OEMs. Figure 10 shows the total installed capacity of distributed PV in the NEM, and the proportion that is expected to successfully ride-through disturbances[24]. If this installation compliance rate is sustained, Figure 10 indicates a plateauing of the distributed PV shake-off risk. There remains a significant quantity of legacy inverters that do not comply with the 2020 standard and the risk of increased contingency sizes related to distributed PV shake-off must continue to be managed until these are replaced.

Regulatory frameworks for setting and enforcing CER technical standards are also being considered in the National CER Roadmap[25]. This is intended to support the long-term maintenance and continued improvement of compliance rates at the point installation and ongoing in the field.

Figure 10 Ride-through capabilities of the installed distributed PV fleet in the NEM



[24] See *Compliance of Distributed Energy Resources with Technical Settings: Update*, at https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

[25] Energy and Climate Change Ministerial Council, National CER Roadmap (2024), at https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

Analysis by AEMO consistently indicates that mid-sized PV inverters with capacities 30-200 kilowatts (kW) have poor ride-through rates even when compliant to the 2020 standard[26,27,28]. Recent investigation has also indicated that non-scheduled PV (PVNSG) systems with capacities 200 kW to 5 MW also exhibit poor ride-through. As shown above in Figure 10, this behaviour increases the contingency risk associated with distributed PV shake-off. The effect on the contingency size will continue to grow as more systems of this size are installed, until the cause is identified and addressed. AEMO is currently investigating causes and recommends that DNSPs in all regions investigate and address this problem[29,30,31].

2.3.2 Emergency backstop mechanisms

Emergency backstop mechanisms should be implemented in all regions to allow restoration of operational demand and enable scheduled generation to provide essential system services.

Implementation of emergency backstop mechanisms provides a pathway to restore operational demand for system security. By reducing the output of rooftop solar, operational demand will increase, ideally to allow more synchronous generators to operate at or above their stable minimum operating level.

However, the implementation of emergency backstop mechanisms can be difficult to achieve. The South Australian government, working closely with SA Power Networks, has been building curtailment capacity since 2020. Experience suggests that basic implementation in regions may take one to two years, while up to five years may be required to achieve compliance across the majority of new installations.

As more distributed PV connects, MSL decreases further. This must be offset by increasing the amount of emergency backstop that can be relied upon to restore operational demand when needed. Experience from other regions indicates that compliance rates may only be around 10% for the first year of implementation, although as high as 55% could be achieved with a significant amount of investment and uplift in compliance. Ideally, compliance rates above 90% should be targeted in the long term to ensure there is no shortfall in emergency backstop capability available.

Measures to support ongoing power system security are outlined in the CER Roadmap[32], particularly the requirement for "backstop mechanisms to be in place" by the end of 2025.

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[26] AEMO (October 2024) *Addendum on DPV and load behaviour: 275 kV current transformer failures in South Australia 14-27 March 2024*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/addendum-on-dpv-and-load-behaviour275-kv-current-transformer-failures-in-south-australia-1427-march.pdf?la=en&hash=92FFAF11AE92AE64C746EEC6EBD01EEE.

[27] AEMO (April 2024) *Loss of SCADA and line protection at Keilor Terminal Station on 29 June 2023*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/loss-of-scada-and-line-protection-at-keilor-terminal-station-on-29-june-2023.pdf?la=en&hash=B7C3B7DC25F97BAE68E1B9890F4763BE.

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

[29] AEMO (October 2024) *Addendum on DPV and load behaviour: 275 kV current transformer failures in South Australia 14-27 March 2024*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/addendum-on-dpv-and-load-behaviour275-kv-current-transformer-failures-in-south-australia-1427-march.pdf?la=en&hash=92FFAF11AE92AE64C746EEC6EBD01EEE.

[30] AEMO (April 2024) *Loss of SCADA and line protection at Keilor Terminal Station on 29 June 2023*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/loss-of-scada-and-line-protection-at-keilor-terminal-station-on-29-june-2023.pdf?la=en&hash=B7C3B7DC25F97BAE68E1B9890F4763BE.

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

[32] See https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

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While having backstop mechanisms in place is important, the quantity of emergency backstop compared to the MSL values must be considered. If low compliance rates are achieved, there may still be a shortfall by the end of 2025 with subsequent risk to the power system.

Therefore, it is important that DNSPs begin and continue implementing emergency backstop mechanisms in all regions to ensure adequate backstop capability is available, and to work towards compliance rates of 90% of all distributed PV inverters.

2.3.3 Provision of essential system services at lower levels of generation

Aims to enable scheduled generation to provide essential system services at lower levels of system demand.

Essential system services can be provided at lower levels of demand by reducing the minimum stable operating levels of essential units, or through investment in new assets that can provide system services in other ways (such as synchronous condensers, batteries, or reactive power management devices).

AEMO, assisted by engineering consultants, is currently undertaking a 2025 Thermal Audit to support efficient market operation and maintain power system security. This will include analysis of the capabilities of existing and new thermal plant to operate at lower demand levels.

The review is intended to focus on:

- Sharing information about recent NEM operational challenges (such as system strength, demand variability and minimum system load management) and future system needs.
- Exploring plans and opportunities for upgrades to existing thermal power plant.
- Discussing planned and potential capability for new thermal power plant.

The outcome of the review should enable an operational strategy for existing thermal fleet management and help inform operational transition planning across the NEM.

2.3.4 Increasing demand in daytime periods

Increases demand at times of high solar output.

Increasing demand in daytime periods can make more effective use of the abundant distributed PV generation available in these periods. This may include new industries which increase constant or flexible demand, and may also include electrification of appliances and transport, and increased demand response and coordination of CER. Practical options to increase responsive demand may evolve over time but are operationally limited at present.

2.3.5 Energy storage

Energy storage as a means to shift time of energy usage.

Storage can help move energy from daytime periods to other periods, increasing demand when required particularly during emergency conditions (and facilitating efficient use of the abundant energy available in low demand periods). This capability is limited at present but will likely increase due to increased investment in storage technologies, and through the coordination of CER storages.

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2.3.6 Minimum system strength and inertia requirements

Efficient provision of inertia and system strength to support adequate levels of essential system services in the NEM.

To assist in management of system strength and inertia requirements into the future, the AEMC has made or is progressing a number of rule changes. These include:

- ***Efficient management of system strength on the power system*, published in October 2021.** This rule was designed to deliver system strength to areas of need in the grid, relating to the supply, coordination and demand for system strength.
- **The *National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 (ISF Rule)*, published in March 2024[33].** This rule aligns inertia and system strength procurement timeframes, supports the procurement of essential system services via the network support and control ancillary services (NSCAS) framework, creates a new transitional non-market ancillary services framework to procure system security services ('transitional services'), and empowers AEMO to schedule system security services with a whole-of-NEM perspective. The final parts of this rule come into effect on 2 December 2025.
- ***Efficient provision of inertia*, initiated in March 2023. Draft determination is scheduled for June 2025.** This rule proposes an ancillary service spot market for inertia to support the secure and efficient operation of the power system.

These rule changes will support the provision of system strength and inertia in the system across the medium to long term. Technology options may include investment in new synchronous condensers, contracts with market participants, or the conversion of existing thermal units into synchronous condensers.

2.3.7 Resecuring reserves

Mitigates the risks associated with losing large loads during MSL conditions.

- BESS storage in Victoria and South Australia can be used as load reserve during MSL2 conditions. This is achieved by directing BESS to discharge over the morning peak to attain close to minimum state of charge.
- BESS is then constrained at minimum MW during the MSL2 period and is ready to begin charging if there is a load contingency event. The BESS will be automatically dispatched as loads to resecure within 30 minutes as required under the NER.
- BESS will be eligible for directions compensation, but further review of this approach will occur in 2025, including the potential for procurement as a contracted service. These potential Type 1 Transitional Services are described in more detail in the 2024 *Transition Plan for System Security*[34].

2.3.8 System studies and analysis

Studies are planned to better understand the operating envelope for MSL conditions.

[33] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[34] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transition-planning/aemo-2024-transition-plan-for-system-security.pdf.

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As detailed in the *Transition Plan for System Security*, the following studies are underway:

- Frequency control – system studies for frequency control are needed to assess adequacy of supply of frequency reserves during operation of low demand periods. These are planned to be completed prior to spring 2025.
- System strength – synchronous generator minimum unit combinations will be assessed to ensure sufficient system strength will be available during minimum operational demand periods. These combinations will be assessed under very low load conditions in preparation for the 2025 spring season.
- Transient and oscillatory stability – transient and oscillatory stability studies are planned to assess the system normal export[35] transient stability limit and calculate the limits of VNI during low demand conditions.
- Voltage control – work on uplift of voltage management modelling and limits advice is required in preparation for implementation of new MSL procedures for spring 2025. Updated Victorian voltage management advice has been prepared and implemented in advance of summer 2024-25, and this analysis will need to be repeated for lower demand projections for spring 2025.
- Variable renewable energy (VRE) – studies are required to assess the capacity to meet ramping events under Victorian and South Australian island conditions. These studies are planned to be undertaken for spring 2025 to increase confidence of operation during MSL conditions.

2.3.9 Engineering and CER Roadmap actions

Long-term actions are outlined in the Engineering Roadmap[36] and the CER Roadmap[37] that will mitigate risks related to AS/NZS4777.2 compliance and MSL.

Relevant actions proposed in the Engineering Roadmap and CER Roadmap include:

<u>Engineering Roadmap</u>

- Establishing effective emergency distributed PV shedding schemes, operational roles and procedures in each NEM region, before MSL challenges emerge.
- Specifying functional requirements and operational processes for robust and reliable emergency backstop mechanisms.
- Continuing to engage with jurisdictions and DNSPs on implementation, as well as market bodies towards nationally aligned approaches and associated roles and responsibilities.
- Collaboratively assessing and progressing actions necessary to meet functional requirements. This includes clarity on operational boundaries between the distribution network and bulk power system operation, as well as operational coordination, and data exchange between AEMO, NSPs and other parties (such as retailers and aggregators).

[35] Exporting from Victoria to New South Wales.

[36] AEMO (August 2024) Engineering Roadmap, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/nem-engineering-roadmap-fy2025-priority-actions.pdf.

[37] Energy and Climate Change Ministerial Council, National CER Roadmap (2024), at https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

- Collaborating with DNSPs to establish effective and consistent disturbance withstand performance standards for <5 MW connections in the distribution network
- Establishing strong governance frameworks for assessing and enforcing ongoing compliance of DER inverters to meet performance requirements.

CER Roadmap actions

- A national regulatory framework for CER to enforce standards, which will support governance and compliance for standards such as AS/NZS4777.2:2020, minimising further growth in risks associated with distributed PV contingencies.
- Mechanisms that incentivise customers to choose to have their CER coordinated by market actors in line with market signals and system needs. This may include enabling new market offers and tariff structures to support CER uptake and customers, increasing access to the market and incentivisation of CER to respond to market signals, including retail and network pricing, and pathways for aggregated CER to participate in the energy market.
- Mechanisms for coordinated CER to deliver automated and streamlined methods for the management of customer distributed PV systems within normal market dispatch systems.
- Redefining roles and responsibilities for market and power system operations, which will support access to and use of community batteries and EV chargers, and other distributed resources.
- Data sharing arrangements to inform planning, enable future markets, and support effective power system operation, with considerations for cyber security.
- Enabling consumers to export and import more power to and from the grid through initiatives such as fast tracking DNSP implementation of flexible exports (discussed further in Section 4.1).
- Improving voltage management across distribution networks.
- Incentivising distribution network investment in CER.
- Ensuring consumer protections and communication strategy to increase consumer trust and ensure CER benefits are understood by all consumers.

2.4 MSL recommendations on operational risks

AEMO has published two key reports that make recommendations on emergency backstop capability and the compliance of DER with AS/NZS 4777.2:2020. These are:

- *Supporting secure operation with high levels of distributed resources*[38].
- *Compliance of Distributed Energy Resources with Technical Settings: Update*[39].

The recommendations from these reports are summarised below. Progress is currently underway, and should continue with high priority to ensure timelines are met.

[38] See https://aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/supporting-secure-operation-with-high-levels-of-distributed-resources-q4-2024.pdf?la=en.

[39] See https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en.

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Recommendation 2

The lack of emergency backstop mechanisms is contributing to operational risk during MSL conditions. To address this, the recommendations outlined in *Supporting secure operation with high levels of distributed resources*[40] should continue to be implemented with high priority. These include:

Governments and/or regulatory bodies to continue:

- Implementing suitable regulatory frameworks to require backstop capability in all regions.
- Ensuring emergency backstop coverage of all new distributed PV systems.
- Implementing regulatory frameworks to incentivise and enforce high backstop compliance.
- Allowing periodic aggregated remote testing of the emergency backstop mechanism.

DNSPs to continue:

- Implementing backstop capabilities, with periodic testing of the system at operational scale and the capability to estimate distributed PV generation available for curtailment.
- Implementing systems for monitoring, maintaining and enforcing high compliance to backstop.
- Developing DNSP operating procedures for efficient delivery of backstop.
- Implementing systems to minimise delay between AEMO instruction and delivery of backstop.

TNSPs to continue:

- Developing TNSP operating procedures for the use of backstop.
- Analysing transmission system needs in low demand periods.

AEMO to continue:

- Developing the models which assess and refine MSL profiles.
- Determining thresholds where backstop will be required.
- Developing AEMO procedures for use of backstop, ensuring all other available actions are considered prior.

[40] See https://aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/supporting-secure-operation-with-high-levels-of-distributed-resources-q4-2024.pdf?la=en.

Recommendation 3

The lack of compliance with the latest AS/NZS 4777.2:2020 inverter requirements standard is contributing to operational risks during MSL conditions. To address this, the recommendations outlined in *Compliance of Distributed Energy Resources with Technical Settings: Update*[41] related to compliance with the AS/NZS 4777.2:2020 inverter requirements standard should continue to be implemented with high priority. These include:

Governments and/or regulatory bodies to continue:

- Implementing suitable long-term governance frameworks to develop, introduce and implement DER technical standards and address the existing limitations in compliance regulatory frameworks.

OEMs to continue:

- Considering available actions to improve compliance and support installers in selecting the correct standard.
- Improving ability to extract and share comprehensive datasets on settings applied to devices in the field, both at the time of installation and on an ongoing basis.
- Maintaining accurate records of firmware updates.
- Supporting physical site inspections by improving access to information on inverter internal settings.

DNSPs to continue:

- Implementing programs to monitor compliance of distributed PV within their networks.
- Collaborating with AEMO to continue uplifting tools and capabilities for analysis of inverter performance.
- Improving compliance through investigation of commissioning processes, policies to allow remote changes to inverter settings and rectification processes that will rectify incorrect settings.

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[41] See https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en.

3 Unexpected operation and interaction of protection systems and control schemes

As the energy transition progresses, many of the assumptions on which power system protection has been designed are subject to change. The NEM is seeing changing fault levels, new transmission topologies, and varying power flow paths. The complexity of the system is also increasing as new projects consider complex control schemes to minimise costs and defer the need for further investment in primary plant. Under these conditions, the risk of unexpected operation of power system protection is likely to increase.

The risk of interaction or inadvertent operation of schemes can occur due to a range of factors. Design errors, unexpected operating conditions or human interactions can result in schemes operating unexpectedly. The inadvertent operation of a single scheme can result in the loss of significant amounts of generation, exceeding the limits for credible contingency thresholds. Where multiple schemes operate in close proximity or share common inputs, schemes may interact and cause multiple operations, leading to cascading failure. This risk is difficult to quantify, as the unexpected operation can trip multiple transmission assets or generators. In addition to this, it can have particularly significant impacts where schemes are used to manage large contingency events.

Power system protection may also operate unexpectedly, leading to increased contingency sizes for power system incidents. Unexpected operation can also lead to cascading failure where multiple protection systems or schemes are impacted by conditions that were not planned for in the design of the system.

This section considers these risks, and recommends the additional work needed to mitigate them:

- **Protection maloperation and interaction risks are present.** This is indicated by past incidents and near misses, as well as contributing factors such as unclear requirements for the design and maintenance of RASs.
- **The frequency and severity of these incidents may significantly increase in the future if actions are not taken.** Many of the key assumptions that protection systems and control schemes have been designed on are changing through the energy transition. The number and complexity of schemes are also expected to increase, further increasing the likelihood and consequence of scheme interactions.
- **Therefore, actions are needed now to ensure that the increasing risks are appropriately mitigated.** Further work is required to review the NER clauses and outline comprehensive requirements for the design, maintenance, modelling and operation of RASs. These must be achieved to balance economical delivery of the energy transition, operability of the system and acceptable risks related to RASs.

3.1 Protection inadvertent operation and interaction risk factors are present

The unexpected operation of protection systems and control schemes is typically a low likelihood and high consequence event. Historical incidents have shown that these incidents are possible in the NEM, and while the occurrence is infrequent, the potential consequences are significant.

There are several factors that presently contribute to the growing focus on this risk and must be addressed to mitigate its impact and decrease the likelihood of occurrence over time:

- Legacy protection settings and grandfathered connection agreements could result in unexpected protection operation in a changing system. There is a need for regular reviews and audits of protection schemes, systems and generator settings, particularly after incidents and near misses.
- Requirements for the design of RASs are not well defined, creating inconsistency in approach and sub-optimal design outcomes. There is no obligation for designers to comply with the current RAS Guidelines, which could lead to varying approaches across different projects.
- Information management, maintenance and testing of RASs needs improvement to ensure ongoing management of schemes is sustainable, and that RASs can be modelled accurately. There is a need for accurate modelling of RASs that can be used to simulate interaction risks.

The risks associated with unexpected operation of protection systems and control schemes are discussed in more detail below.

3.1.1 Historical incidents and near misses show evidence of the potential consequences and current risk of protection maloperation

The potential consequences of the unexpected operation of protection systems are demonstrated by a number of historical incidents that have occurred in the NEM in recent years. While some of these events were only near misses, these highlight the consequences that could have occurred under certain operating conditions. If these operating conditions are expected to become more frequent in the future, the impact of this risk may increase.

Some significant historical incidents reported on by AEMO include:

- Trip of multiple generators and lines in Queensland on 25 May 2021[42]. This incident demonstrates the potential consequence of cascading failure, with over 3 GW of generation and 2 GW of load tripping due to cascading events.
- A South Australian black system event on 28 September 2016[43], resulting in 850,000 customers losing power. The incident began with the loss of three transmission lines but led to cascading failure after the protection settings of nine wind farms unexpectedly reduced power output by 456 MW.
- Loss of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024[44]. After the trip of these two transmission lines, an additional 2,690 MW of generation was lost including the runback and subsequent trip of all four Loy Yang A units due to protection operation.

A review of other incidents contributed by AEMO and NSPs highlighted many root causes for protection maloperation incidents, such as design errors, implementation errors, communications issues, temporary

[42] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/trip-of-multiple-generators-and-lines-in-qld-and-associated-under-frequency-load-shedding.pdf.

[43] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2017/integrated-final-report-sa-black-system-28-september-2016.pdf.

[44] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf?la=en.

operating arrangements and manufacturer errors. When incidents such as these occur, NSPs and AEMO investigate the root causes and implement solutions to prevent reoccurrence. However, there are still common failures that occur across different regions, as well as failures that are difficult to predict.

3.1.2 The requirements for RASs are not clearly defined

RAS interaction or maloperation risk can have significant consequences. Further contributing to this risk is that the requirements for RAS are not clearly defined. There are a number of documents that provide some guidance on principles when designing and implementing RASs, but further work is required to develop specific requirements that are agreed upon by industry. The current inputs are described below.

RAS Guidelines

The RAS Guidelines were not intended to provide comprehensive requirements for RASs. When AEMO developed the RAS Guidelines in 2022, these were intended to provide a reference of good electricity industry practice, as well as summarising relevant NER obligations relevant to the design, testing and maintenance of RASs. There is further scope to improve on these guidelines to provide guidance on what is explicitly acceptable for the design of a RAS. Currently there are many design decisions that are up to individual interpretation which is likely to lead to inconsistent approaches and risk appetites across projects.

NER obligations

Requirements for RASs are not covered in sufficient detail in the NER. There are several clauses located across NER chapters that provide base requirements related to identifying the need for a RAS, as well as clauses on maintenance, review, modelling and testing. This does not provide a comprehensive coverage of RAS requirements, but instead discusses RASs in the context of the other clauses.

The main clause specifying the need for a RAS for non-credible contingencies is not clear. Through consultation with industry, feedback was received that NER S5.1.8 was not clear in defining when a RAS is required and is open to varying interpretations. Inconsistent interpretations of the NER obligations will lead to varying implementations of RASs. Clarity is required across the design and implementation stages to reduce the likelihood that errors or unexpected operation may occur.

Project considerations

Non-credible contingencies are often considered late in project timelines, when other factors have already been decided. This can lead to a situation where there are no other feasible options to mitigate non-credible contingencies except for implementing a RAS. If the non-credible contingency size is too large, this can result in a situation where implementing a RAS will introduce significant maloperation risk. However, not implementing a RAS will result in significant non-credible contingency risk that could lead to cascading failure if it were to occur. Considering non-credible contingencies and RAS options earlier in the design process may alleviate some of these issues and result in improved outcomes.

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3.1.3 Design, information management, maintenance and testing of RASs needs improvement

The process of designing, documenting, modelling, maintaining and testing RASs is not well defined. There are opportunities to provide explicit instructions on RASs to prevent issues in the operation and maintenance stages.

RAS design

The current RAS Guidelines are a reference of good electricity industry practice, but do not provide binding requirements in the design of RASs. High level design principles are outlined in the RAS Guidelines, but there are no obligations to meet specific requirements. Without explicit requirements, it is likely that design of RASs will not be consistent across projects, and this will lead to sub-optimal design outcomes.

Design considerations that should be specified in detail include, but are not limited to:

- Suggested strategy for management of non-credible contingencies and when a RAS is the preferred solution, and when it is not acceptable.
- Actions that are considered appropriate for RAS to take under different conditions.
- Requirement to prevent the unexpected operation of a protection scheme, with built in redundancy or back up schemes.
- Limits on the maximum amount of generation or load tripping that can be controlled by a single device.
- Details on the allowable complexity of schemes, including any mitigation measures that must be taken if schemes are more complex than the standards allow.
- Consideration of how to incorporate other existing and future RASs in the design and planning process.
- Detailed model requirements, including aspects like communications delays, measurement times, circuit breaker opening times and measurement locations.

RAS documentation

RAS documentation is not standardised in the NEM, and the quality of documentation provided will influence the confidence with which the RAS can be operated and maintained into the future. AEMO's RAS Guidelines specify high-level expectations for RAS documentation, but further details would be beneficial to ensure consistency across projects. Without consistent and comprehensive documentation, there is a risk that engineering knowledge is not passed on sufficiently within the business, especially if there is turnover in the engineering teams that assisted with the design and commissioning. This creates risks that issues will arise in the operation and maintenance of RASs which often involve highly specialised knowledge.

RAS visibility

Having appropriate visibility of RAS when operating the system is important to prevent unwanted interactions or operations. RASs and their status are currently not reflected in some control room tools and systems, which introduces risks that decisions will be made without all the information being present. Adequate situational awareness of schemes is essential for those operating and planning around them.

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Modelling of RASs

Modelling of RASs can be limited, especially early in the process when projects are first proposed. The need for models of RASs is becoming more important as the number of schemes and their impact on the system grows. As outlined in the RAS Guidelines*,* models should be developed for any new or modified schemes, except where they are of low complexity and low impact on the system. The impact on the system should also consider whether any contingencies could trigger the RAS in combination with other RASs, leading to a material impact on the system.

Accurate and comprehensive models of RASs could support studies to better understand inadvertent operation and interaction risks. The importance of having accurate and complete RAS models increases with the number and complexity of RAS in the system. As RASs are added to the system, it is important that accurate models are provided and maintained so that RAS inadvertent operation and interaction risks can be studied in simulation software to better understand risks in the NEM.

Maintenance of RASs

RASs are often designed for specific operating conditions at the time of implementation, but the process for how these assumptions are reviewed and updated over time could benefit from further consideration. Over the lifetime of a RAS, design assumptions may be influenced by system changes such as network augmentations, generation retirements or reductions in system strength or inertia. As more significant changes are experienced in the NEM, these will have greater potential to influence the operation of RASs. It is important that these changes are reviewed regularly to minimise the introduction of maloperation or interaction risks. Change control methodology should also be standardised so that any updates or revisions to RASs can be tracked and managed over time.

Testing of RASs

Testing of RASs is critical to ensure stable and reliable operation under both normal and contingency conditions. As RAS design is typically implemented in simulation software, this makes testing and evaluating performance difficult, especially when the scheme is managing large-scale events with significant impacts on the power system. Conducting tests is difficult in these circumstances, and determining how schemes might interact or operate unexpectedly is also challenging. The use of real-world power system tests where practical, or power hardware in the loop testing should be undertaken to provide further confidence in operation.

Regular testing if a RAS has not operated for a period of time would also be beneficial and can be coordinated around outages if this will reduce the impact to the power system. For example, if a scheme trips a number of generators, the scheme can be tested when these generators are out of service to determine whether the appropriate circuit breakers open as expected. To ensure RASs function as intended, reviews should also be conducted following their operation. This evaluation should assess whether the scheme performed as designed, identifying any errors or potential updates required.

3.1.4 Reducing risks from past design and installation mistakes

Risk can be present in the system where design mistakes or grandfathered connection agreements have resulted in generators to connect with requirements that do not adhere to the current standards.

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This is evident from a number of historical incidents that involved protection maloperation:

- 13 February 2024 – older generators may not have had multiple fault ride-through requirements in their generator performance standards (GPS)[45], resulting in a larger contingency size and cascading failures.
- 13 February 2024 – lack of review of settings, or incorrect settings, has resulted in larger contingencies in the islanding of the Latrobe network due to switch on to fault settings.
- 28 September 2016 – incorrect fault ride-through settings of wind farms were common across multiple plants and resulted in cascading failure and eventual black system in South Australia.

Annual reviews on emergency controls, protection systems and control systems are required to be conducted by NSPs under NER 5.12 or 5.13. These reviews are included in NSP annual planning reports (APRs). However, as more schemes are introduced into the system, the review of potential interactions and the audit of existing settings become more important. It should be considered whether this process is currently sufficient, or if more focus is required to mitigate increasing risk. Reviews should also consider interregional impacts and how protection schemes may interact across regional boundaries.

3.2 This risk has the potential to increase in the near future

As a result of the changing resource mix, many of the key assumptions that protection systems and control schemes have been designed on are subject to change. There are many factors that are contributing to this such as changing fault levels, increasing rooftop solar, varying network topologies, and different power flow paths due to system augmentations. The number and complexity of schemes are also expected to increase, further increasing the likelihood and consequence of scheme interactions.

Changing operating conditions will impact the design assumptions of protection

In a period of rapid change for the power system, there are a number of factors that will affect the operation of protection systems and control schemes. Power system protection is typically designed for specific scenarios, with defined inputs and design assumptions that determine how the protection system makes the critical decision on whether to operate or not. If the design assumptions or inputs change significantly from the design, the power system protection may operate in unexpected ways. This is highly undesirable for critical infrastructure that the power system relies on to prevent cascading failures.

Examples of factors that may impact the operation of protection systems and control schemes include:

- **Reduced synchronous generation and subsequent system fault levels.** This can cause issues where power system protection cannot discriminate between faults that it should operate for within its zone, and faults where it should defer to closer protection devices.
- **Increased rooftop solar.** There is potential for the aggregated response of rooftop solar to trigger multiple control systems, particularly due to fault ride through issues. Increased rooftop solar will also reduce the efficacy of UFLS.

[45] See https://www.aer.gov.au/industry/registers/resources/guidelines/generator-performance-standards-information-booklet.

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- **Increasing number of schemes.** These may be introduced to manage non-credible contingencies and increase interaction risks as more schemes are implemented.
- **Increasing complexity of schemes.** There are limited explicit design requirements restricting complexity, which may result in complex schemes that can operate in unexpected ways.
- **Outsourcing of protection design and maintenance.** Due to the timeframes required to achieve commissioning of new projects, protection design and maintenance may be outsourced, leading to lack of expertise and future issues.
- **Incorrect assumptions.** RASs make assumptions about state of plant and other power system parameters to determine when operation is required. If these assumptions are no longer valid due to significant changes in operating conditions, the consequences can be significant.

New network augmentations and increasing non-credible contingency sizes is contributing to increased risk

Significant network augmentations and new generation connections can result in increasing non-credible contingency sizes. Coupled with the potential addition of rooftop solar shake-off, this could lead to more wide-ranging impacts from non-credible contingencies. As discussed in more detail in Section 4, there are several factors regarding non-credible contingencies that can result in increased risk:

- **New generation connections and transmission augmentations** introducing large contingency sizes that are likely to be addressed using a RAS under the current frameworks.
- **Rooftop solar shake-off** contributing to larger contingency sizes, further increasing the consequence of contingencies and the impact to the power system. These larger contingency sizes may not have been accounted for in historical protection design.
- **Circuit breaker fail contingency sizes** may increase where additional generation is added to existing substations configurations.
- **The contingency sizes associated with existing transmission lines and control schemes may be increasing** as the connection of more generation utilises existing assets. Larger schemes increase the inadvertent operation and interaction risk, with more severe consequences if they operate unexpectedly.

New and more complex schemes are being proposed

New schemes are being proposed for the connection of new generation or other system augmentations to address large non-credible contingency sizes. Loss of the transmission lines connecting new generation may result in significant contingency sizes, which requires rapid operation of protection schemes to maintain system stability. Implementation of a RAS is often the most economical solution and reduces the need for installation of additional infrastructure. However, schemes tripping large quantities of generation or load at very fast operating times introduce maloperation or non-operation risk if the design, maintenance or installation of the scheme is inadequate. This highlights the growing importance of scheme design, operation, modelling and maintenance as the number of schemes increases.

New proposed schemes include the following:

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- A large scheme was initially considered for the non-credible loss of HumeLink 500 kV lines to prevent instability, which would have required a complex scheme with very fast operation times. Further studies have identified that a smaller scheme, or other mitigation measures to reduce the likelihood or consequence of this contingency, may be required instead. While this particular instance may not require a large scheme for operation, the risk of other significant augmentations requiring complex and fast-acting schemes is a potential issue.
- Complex schemes are already being implemented into the system with the Waratah Super Battery (WSB) system integrity protection scheme (SIPS), an example of a complex control scheme.
  - The scheme allows the WSB to act as a virtual transmission line, preventing lines from exceeding their contingency ratings and increasing the transmission capacity of the existing network without needing to build new lines.
  - This scheme brings economic benefits, allowing better utilisation of existing assets to transfer power at times of high demand.
  - However, due to the complexity of the scheme, it requires a significant amount of design, planning and maintenance to ensure it operates as expected. The scheme is expected to have many inputs as it monitors multiple transmission lines, as well as sending signals to various generators and the WSB.
  - The implementation of a scheme such as this can be a prudent option to reduce network costs and better utilise existing assets provided that the necessary design, maintenance and rigorous testing procedures are followed to reduce the risks of maloperation. However, the risk increases as more of these schemes are introduced, and the risk is no longer limited to the maloperation on a single scheme, but also the many ways that the schemes can interact with each other unexpectedly.
- New schemes are also proposed in Victoria to mitigate the potential for PEC instability under certain operating conditions. There are a number of schemes in South-West Victoria, and the increasing complexity of additional schemes will require co-ordination, testing and modelling to understand the unexpected operation and interaction risks.

The introduction of large numbers of RASs into the system will add complexity in the planning and operation of the network that must be managed. Relying on RASs allows network infrastructure to be utilised more efficiently but may introduce complexities when managing outages and planned maintenance. RAS requirements should specify that outages or maintenance on any assets involved in the scheme must be planned for in the design stage.

As schemes become more complex, the reliance on data and communications for the operation of RASs may also increase. This highlights the need for accurate data processing, storage and management to ensure the quality of data is maintained. To ensure reliable communications, redundancy in design, and diversity in communications providers will be required. Consistent approaches to the requirements for managing data and communications should be achieved for all RASs to limit the risk of unexpected operation of protection systems and control schemes.

There are examples of RASs in the NEM that have operated successfully without significant issues that should be referenced in new designs. When designed, installed and maintained correctly, the use of RASs can achieve positive power system outcomes. Control schemes that are well designed can prevent expenditure that

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would otherwise be required to build additional transmission lines or other infrastructure. This can be seen in Tasmania as an example, where the Frequency Control System Protection Scheme (FCSPS) and the Network Control System Protection Scheme (NCSPS) have allowed more efficient operation of the Tasmanian system[46]:

- The FCSPS was developed to allow the Basslink interconnector to transfer power flows that significantly exceed the size of the next largest contingency in Tasmania. Through automatic arming of concentrated load blocks and generating units, this scheme is ready to trip load or generation within milliseconds to manage frequency on loss of the interconnector. This scheme has operated successfully many times during its years in service.
- The NCSPS allows dual circuit transmission corridors to run up to 95% of the thermal rating while still operating a secure system. In the event of a network contingency, the NCSPS will issue runback or trip commands to generators to prevent the overload of transmission lines. This has also operated successfully for many years.

These schemes demonstrate the successful implementation of RASs and could be referenced as examples of the required design, maintenance and installation that should be specified in standard RAS requirements.

3.3 To ensure ongoing power system security, a number of mitigation measures should be considered to address the increasing risk

Actions are required to address the increasing risk associated with the unexpected operation and interaction of control schemes and protection systems. The expected number and complexity of schemes is growing in the NEM, as is required to deliver the energy transition at low cost. However, the potential for protection inadvertent operation or interaction may increase if actions are not taken to standardise RAS requirements in the NEM, improve modelling capability and limit exposure to RAS related risks.

To support the ongoing use of RASs in the NEM, clear requirements for the design, operation, maintenance and modelling of RASs should be investigated and made mandatory. As RASs increase in complexity and number, it is important that industry agrees on set requirements that will find the balance between economical delivery of the energy transition, operability of the system and acceptable risks related to RASs.

Recommendation 4

It is recommended that AEMO leads a project with input from industry to investigate and implement explicit requirements related to RASs in the NEM.

The proposed work will include the following:

- Detailed studies conducted by AEMO on RAS unexpected operation. This will include studies using power system simulation software to better understand the impact that operation of RASs may have on the system and understand the maximum operable RAS generation and load tripping sizes.

[46] See *Managing a High Penetration of Renewables – A Tasmanian Case Study*, at https://www.aemo.com.au/Media-Centre/~/-/media/B47810C12E25473CB81968D5D4218F78.ashx.

- Review of the NER clauses relevant to RASs. This may if required, lead to a rule change request to clarify RAS requirements in the NER.
- Investigation of RAS modelling requirements for RASs in the NEM and best practice across other network operators. This will inform RAS modelling requirements and work towards building models of RASs in the NEM that can be used to simulate maloperation and interaction risks.
- Expansion of the Remedial Action Scheme Guidelines into explicit requirements for RASs in consultation with industry. The full requirements should include consideration of the following:
  - Strategy for management of non-credible contingencies, including defining when a RAS is the preferred solution, and when it is not acceptable.
  - Definition of maximum RAS contingency size.
  - Stability criteria and post-thermal overload criteria for assessing non-credible contingencies to determine if a RAS is required.
  - Details on the limits to the number and complexity of schemes and any mitigation measures that must be taken if schemes are more complex than the standards allow.
  - Periodic reviews of RAS design to identify needs for updates following power system changes.
  - How to incorporate other existing and future RASs in the design and planning process.
  - Detailed model requirements, including aspects like communications delays, measurement times, circuit breaker opening times and measurement locations. In some instances, hardware in the loop tests may be required to capture hardware performance.
  - Detailed testing and verification requirements for RASs, such as regular audits of settings to ensure they align with design (generator settings, control scheme settings, etc).
  - Outputs from the recently created CIGRE working group *System Integrity Protection Schemes and the (N-1) criteria.* These outputs will support the development of other requirements based on international experience.
  - Other key topics identified through consultation with industry.

4 Increasing risks of non-credible contingencies

The changing topology of the future grid may result in an increased risk for non-credible contingencies. The energy transition marks a shift in the operation of the network, with a greater focus on the connection of new generation either through new or existing transmission infrastructure. The increase in new generation, combined with a greater focus on transmission, may mean that non-credible contingencies have a larger impact in the future. This will require careful consideration of non-credible contingencies that may result in severe consequences to mitigate risks appropriately.

This section recommends that further work is undertaken to understand the requirements for non-credible contingencies in the future.

It discusses how:

- **The changing topology of the future grid may result in an increased risk related to non-credible contingencies.** The risks arise from the connection of large-scale generation through existing or new transmission lines or substations. It also manifests through increased contingency sizes due to rooftop solar shake off and the potential reduction in system strength and inertia as traditional synchronous generation retires. The impacts of destructive weather add further uncertainty to the management of non-credible contingencies in the midst of climate change and a system that is becoming increasingly weather dependent.
- **The historical approach to managing non-credible contingencies may not be suitable for the future grid.** Historically, the NEM was designed and planned for N-1 contingencies, and non-credible contingencies were managed in the operational timeframe. This approach has been suitable where non-credible contingencies are infrequent, and there is sufficient operating margin or emergency controls that can be used to reduce the likelihood or consequence of cascading failure. However, the historical methods of designing and operating the power system may not be optimal as the number and scale of non-credible contingencies increases.
- **A new approach for managing non-credible contingencies should be considered now.** The optimal time to consider updated methods of managing non-credible contingencies is now, when the design decisions for new generation and transmission infrastructure can still be influenced. Factors to be considered include increasing clarity in the NER regarding non-credible contingencies, consistency in RAS design and operation and limits on allowable non-credible contingency sizes.

4.1 Increasing risk factors for non-credible contingencies

The power system is undergoing a fundamental shift in how it is designed, requiring consideration of how it should be planned and operated into the future. The historical approach to operating the system may not be suitable for the future system due to a range of risk factors that are changing the non-credible contingency risk landscape. These risk factors are discussed in more detail below.

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4.1.1 Increasing contingency sizes

Connection of new generation may increase non-credible contingency sizes. To support the energy transition, large volumes of generation are proposed to be connected via high capacity double circuit transmission lines. These circuits are designed with redundancy to manage the credible loss of one of these lines, such that the largest credible contingency in the NEM does not increase. However, contingency sizes related to the loss of both circuits do not have a specified limit, potentially resulting in increasing non-credible contingency sizes into the future.

Larger connections to existing transmission lines or substations increase non-credible contingency sizes. New generation is also proposed for connection to existing transmission lines and substations, further utilising the existing network infrastructure for power transmission. Large amounts of new generation can push the infrastructure to its limits, increasing contingency sizes for the loss of transmission lines, increasing the size of RASs (such as in South-West Victoria), or resulting in more generation connected behind circuit breakers at substations, increasing circuit breaker failure risk.

Rooftop solar shake-off contributes further to contingency sizes. During periods of high rooftop solar penetration, the size of non-credible contingencies can significantly increase due to the higher likelihood of distributed PV shake-off, as described in Section 2 in the discussion on MSL conditions. When this is combined with other factors mentioned such as large generation connections and increased flow over transmission lines, the potential non-credible contingency size becomes significant.

4.1.2 System strength and inertia impacts

System strength and inertia impacts following non-credible contingencies are not currently planned for. A non-credible contingency that occurs in one part of the network may lead to reduced system strength or inertia in other parts of the network due to increased impedance between key generators or synchronous condensers. Non-credible contingencies are not currently considered in the dispatch of inertia or system strength, but this may become necessary if essential system services become concentrated in small areas of the network. This risk has been discussed in previous GPSRRs[47].

With more inverter-based generation and load connecting to the grid, system strength and inertia impacts may have greater consequence. Increasing connections of IBR will require greater consideration of system strength and inertia impacts from non-credible contingencies. Historically this has not been a significant problem due to the operating margin contributed from the numerous synchronous generators in the NEM. However, with more generation relying on system strength and inertia from other sources, any contingency that separates generation from essential system services may cause wider ranging impacts. Reduction in system strength or inertia could result in IBR generators failing to ride through disturbances, or more severe frequency impacts to the grid.

[47] 2024, 2023 GPSRR reports at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review.

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4.1.3 New generation connections

New generation connected through long, double circuit transmission lines requires further consideration of non-credible contingencies. To access locations with the best potential, generation is often located in remote areas that are far from major load centres. To connect these developments to the NEM requires long transmission lines designed to transfer large quantities of power. Long transmission lines present a larger geographical footprint that requires increased consideration of weather conditions such as storms, bushfires or lightning. This can be managed through the implementation of appropriate mitigation measures to prevent the non-credible loss of these lines resulting in cascading failure.

As more generation connects behind double circuit transmission lines, the consequences of loss of these lines increases. As more generation connects to existing or new double circuit transmission lines, the potential consequence of losing both circuits increases. These impacts can be frequency related based on the generation contingency size or can be power system stability related if the loss of lines results in significant changes in power flows. Significantly large contingency sizes may result in situations where RASs are not suitable to mitigate the risk due to the speed of operation that would be required. However, the non-credible contingency risk can be managed in other ways such as through the introduction of non-credible contingency size limits.

4.1.4 Impacts of severe weather events

The power system is becoming increasingly weather-dependent, and weather-related events are often a trigger for non-credible contingencies. Severe weather can initiate large non-credible contingency events, with environmental circumstances such as bushfires, cyclones and storms all able to cause significant damage. It is suspected that destructive winds and convective downbursts have contributed to many of the recent tower failure incidents that have occurred in the NEM. The ability of these transmission towers to withstand extreme weather events will become increasingly important in the future power system where large quantities of power will be transmitted over double circuit lines.

Several notable weather-related events have occurred in the NEM during the last year, including:

- Loss of the Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024, where six 500 kV towers (three on each of the to 500 kV circuits) failed during an extreme weather event. This event led to loss of over 2.5 GW of generation and shedding of over 300 MW of customer load.
- Loss of the Broken Hill – Buronga 220 kV No. X2 line on 16 October 2024, resulting in the disconnection of 34 MW of customer load and 140 MW of generation and the isolation of Broken Hill from the rest of the NEM. This was caused by the failure of seven transmission towers located approximately 50 km south of Broken Hill.
- Loss of the Davenport – Olympic Dam West 275 kV line on 17 October 2024, caused by the failure of two transmission towers 145 km north of Davenport. This resulted in the loss of 155 MW of load, and an extended outage of the Olympic Dam site, resulting in MSL conditions in South Australia during the outage.

This highlights the importance of higher visibility of weather-related trends and usage of these outcomes in transmission line design, operations and network planning. It also reinforces the potential for non-credible contingencies to occur due to uncontrollable circumstances. The power system is becoming increasingly weather-dependent, as discussed in more detail in Section 5.5.

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4.1.5 Connection of large loads

New loads are connecting that are larger than previously experienced. The energy transition is also facilitating the connection of large, concentrated loads in certain areas of the network. This presents a new risk profile for load-based contingencies that has not been as common previously. Loads proposed to connect to the system are significantly larger than historical loads, where new connections of data centre, battery and pumped hydro loads potentially reaching 800 MW. Typically, large industrial loads connected to the NEM may be in the range of 300 MW or less. When these potential large load contingencies are combined with MSL conditions, the risk increases further as discussed in Section 2.

These loads may be more sensitive to power system disturbances. In addition to the increased size, some of these loads, such as data centres, may also be highly sensitive to voltage disturbances[48]. In the event of power system disturbances, data centre loads will transfer to backup power supplies to avoid outages or to prevent damage to equipment. This can lead to significant changes in load experienced by the system, even for shallow faults. This means that not only are contingency sizes potentially larger, they also may be more common when loads switch to uninterruptible power supplies for system disturbances.

4.2 Current processes may not be suitable to operate the future power system

The current approach for managing non-credible contingencies is not suited to the future power system. The potential number of significant non-credible contingencies is increasing due to a combination of new connections and the changing topology of the network. This increased number of potential non-credible contingencies becomes difficult to manage under the existing framework, which manages non-credible contingencies as special cases.

4.2.1 Managing non-credible contingencies within the current framework is limited

The current framework for addressing non-credible contingencies is limited to the following main options:

- **Addressing non-credible contingencies in the planning stage**. In planning the network, NSPs are obliged under S5.1.8 to consider any non-credible contingencies that are likely to result in severe disruptions to the power system. Once a non-credible contingency is identified that meets these criteria, emergency controls should be installed, maintained or upgraded to minimise the disruption and significantly reduce the probability of cascading failure.
  - The common interpretation for emergency controls under this clause is to implement a RAS to mitigate risks for critical non-credible contingencies. To manage individual events, a RAS may be appropriate, but as discussed in Section 3, as more RASs are introduced into the system, protection interaction and inadvertent operation risks increase. To continue with the approach of using RASs to address non-credible contingency risks, it is important to uplift RAS design, modelling, operation and maintenance standards to ensure consistent and sustainable design principles are used across projects.

[48] See https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.

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  - In addition to this, as non-credible contingency sizes increase further, a RAS may not be able to operate quickly or reliably enough to be considered as appropriate mitigation. As non-credible contingency sizes grow, the speed of operation and the amount of generation or load that RASs need to arm and trip will also increase. Non-credible contingency sizes should be investigated, and limits determined to ensure that excessive risk is not introduced through the development of new schemes.
- **Assessing priority risks through the GPSRR.** The GPSRR is an annual report that reviews a prioritised list of non-credible contingencies, in addition to other events and conditions, that may lead to cascading outages or major supply disruptions. It focuses on a small subset of the highest priority risks to consider each year.
  - The GPSRR considers current and future risks, however future risks should ideally be already covered under the planning framework. The GPSRR provides a safety net to identify any risks that may result in cascading failure that have not been identified through other methods.
  - Through the GPSRR, recommendations can be made to consider RASs, invoke a protected event, or any number of other options. However, addressing individual non-credible contingency events through the GPSRR process involves mitigating the risk with operational measures after the risk has been identified as one of the highest priority risks in the NEM. Ideally, these risks should be mitigated before this stage through appropriate contingency size limits or well-designed RASs.
- **Accepting non-credible contingency risk.** The last approach for non-credible contingencies is to accept the risk and operate the system with partial or no mitigation measures in place for certain contingencies. This would be done for non-credible contingencies where the NSP may determine that it is not a critical non-credible contingency. On their assessment, the risk may be sufficiently low, or they have confidence that there will not be cascading failure as a result of this contingency. Under certain conditions, this may be a valid option, as not every non-credible contingency can be protected against. However, for contingencies that are of a sufficient size or importance to the network, it would be prudent to explain the justification for this decision-making. If the risk is sufficiently low, taking no action for certain non-credible contingencies may be a lower cost outcome for consumers, particularly if the event does not occur or the consequences are not as severe as anticipated.

4.2.2 Maximum non-credible contingency sizes are not specified

In planning the network, there are currently no specified limits for maximum non-credible contingency size. From an economical perspective, this incentivises maximising the amount of generation that can be connected behind multiple lines but ensuring that any credible contingency is limited below existing limits. This meets the project's requirements that the maximum credible contingency size of the system does not exceed the current limits, but it introduces more non-credible contingency risk if loss of multiple lines were to occur. This makes it increasingly difficult to operate the system, particularly if non-credible contingency sizes reach levels where RASs may not be able to operate sufficiently fast enough to limit cascading failure. If RASs are not a viable option due to complexity, NSPs may be limited to either accepting the risk, constraining the system, or retrospectively installing more infrastructure.

4.2.3 Requirements for non-credible contingency events that affect multiple jurisdictions are not specified

Non-credible contingencies that affect multiple jurisdictions require further consideration of the roles and responsibilities when mitigations are required. Non-credible contingencies have the potential to cause wider ranging impacts on the system that can span multiple jurisdictions. In these instances, it is not clear where the responsibility lies in implementing a solution, and whether this should be assigned to the jurisdiction where the contingency occurs, or where the instability first occurs. An example of this was studied in the 2023 GPSRR, where a range of non-credible contingencies across the NEM could result in instability on QNI. Currently these types of non-credible contingencies are considered through the GPSRR, but the process would benefit from the development of guidelines in consultation with industry to formally define roles and responsibilities.

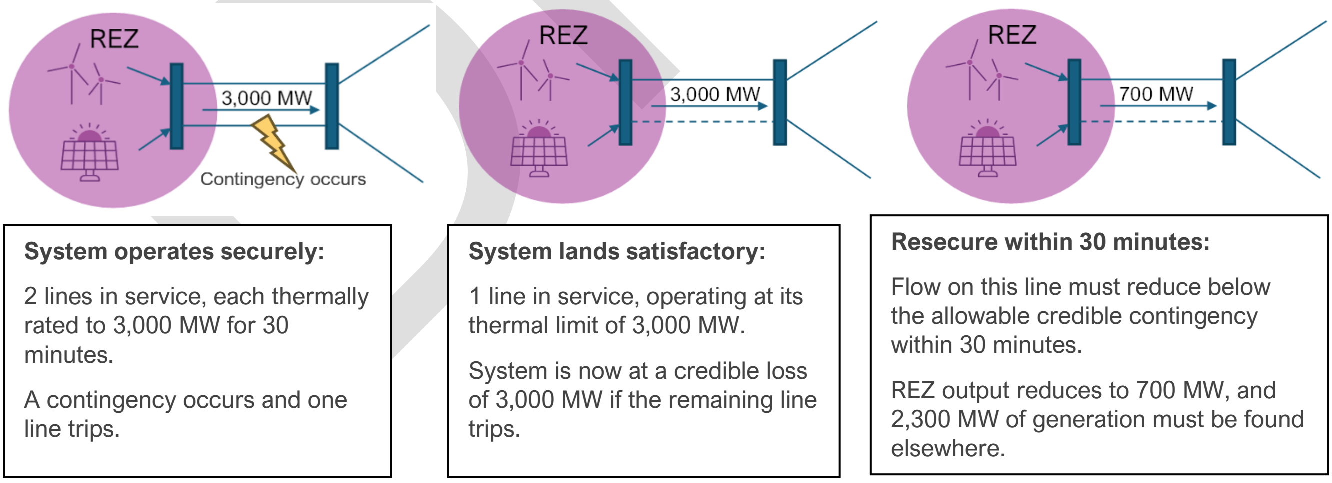
4.2.4 Operational issues with large generation connections behind double circuit lines

Resecuring the network after a credible contingency may not be possible within 30 minutes.

In addition to the non-credible contingency risk, there are operational difficulties that arise from large generation connections behind double circuit lines. The loss of one line can result in an insecure system, and unsatisfactory conditions if the loss of the other line were to occur.

Consider the hypothetical scenario shown in Figure 11 regarding a 3 GW REZ that is connected behind double circuit lines. While the system is rated to manage the credible loss of one of the lines, this presents an operational issue in how to resecure the system after the first credible contingency. To resecure, the REZ output must be reduced below the allowable credible contingency limits. This requires a large quantity of generation to be found from elsewhere, or enacting load shedding to maintain system security.

Figure 11 Hypothetical contingency scenario



In times of high demand, or LOR conditions, it may not be possible to find the additional generation required to secure the system. In these instances, load shedding may be the only option, which is not an ideal outcome for consumers if these conditions become more frequent in the future. If generation is available, there may be additional costs to make it available for system security purposes. Resecuring the network may require constraints or additional FCAS, resulting in increased market costs.

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Mitigation measures to address this issue should be considered. Potential options include:

- Contracting/procuring BESS for frequency control following the second contingency.
- Mitigation of load shedding risk by using real time available reserve data in constraints to ensure that REZs are only constrained when reserves are low.
- Increased procurement of FCAS.

4.3 Future work regarding non-credible contingencies

The 2025 GPSRR has identified that there are emerging risks related to non-credible contingencies. The work completed has highlighted that mitigation measures will be required in the long term and that actions should be taken now. Determining the appropriate methods to manage non-credible contingencies is a complex problem and will require further consultation with stakeholders and key industry bodies.

Recommendation 5

It is recommended that AEMO leads further work considering how non-credible contingencies should be managed into the future.

This work will include input from industry and should include:

- Detailed studies conducted by AEMO on non-credible contingency sizes, both in the current and future network. This will include:
  - Studies using power system simulation software to better understand the size of non-credible contingencies that may result in cascading failure in the NEM for each region.
  - Analysis of existing non-credible contingencies in addition to proposed new connections.
  - Assessment of system strength and inertia impacts, as well as voltage and frequency response.
- AEMO will engage with industry on non-credible contingencies, to receive input and feedback. The proposed consultation will include:
  - Scope of studies and critical contingencies to be considered for each region.
  - Modelling approach, software and assumptions.
  - Results, outcomes and conclusions.
- AEMO will also investigate the process for managing non-credible contingencies that affect multiple jurisdictions. This may lead to the development of guidelines specifying requirements on roles and responsibilities related to multiple region contingencies.
- AEMO will lead a review of the NER clauses on non-credible contingencies, with input from industry. If determined to be necessary, this may lead to:
  - A rule change request regarding the requirement for non-credible contingency size limits in the NEM.
  - Consideration of additional tools or funding mechanisms that are required to facilitate management of non-credible contingencies.

5 Current and emerging system operator risks

In addition to the priority risks considered in the GPSRR, a brief overview of other current and emerging risks is provided. This gives some background on some issues that are being experienced in the NEM and would be relevant to other power systems across the world. This section provides an overview of each risk, as well as any actions that are currently being progressed. These risks may be considered in more detail as priority risks in future GPSRRs if they are assessed to be high priority.

5.1 Retirement of synchronous generation and system strength impacts

Existing generator operators have advised AEMO of an expected closure schedule that includes approximately 11.2 GW of thermal generation capacity in the next 10 years[49]. This will result in retirement of approximately 34% of the currently registered thermal fleet. The retirement of this synchronous capacity imposes a considerable reduction in generating plant capable of offering system strength contribution in the NEM[50]. A trending decline in system strength after thermal plant retirement imposes a risk to the management of secure power system operation in the NEM.

5.1.1 Low system strength challenges

Insufficient system strength poses risks to the power system

Operating a system with reduced system strength presents a number of challenges, with some of the most prominent including:

- **Inability to operate inverter-based generation**.
  - Low system strength conditions can impact the commutation stability of IBR plant, affecting their dynamic performance during network contingencies. This is due to a change to the operating conditions their control systems were originally tuned for, which may have assumed higher system strength condition. Instability of one plant can also lead to instability in others, potentially leading to cascading impacts.
- **Insufficient fault levels to enable protection systems to operate correctly**.
  - This can lead to cascading events if protection systems do not operate to clear power system faults according to their designed level of discrimination, and within the required clearing times specified under the NER.

[49] AEMO (August 2024) 2024 Electricity Statement of Opportunities (ESOO) for the NEM, at aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf.

[50] System strength can be broadly described as the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance.

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- **Insufficient fault levels to enable stable operation of voltage control systems, such as capacitor banks, reactors, and dynamic voltage control equipment.**
  - This can lead to the following:
    - A reduction in reactive margins and subsequent voltage stability issues.
    - Limitations in the power transfer stability of network interconnectors and key transmission cut-sets.
    - Impacts on the stable operation of generating systems.
    - Voltage excursions beyond the permitted operating levels specified in the NER.
- **Reduction in operational flexibility.**
  - If remedial measures are not implemented, system strength shortfalls could be more likely following the expected thermal generation retirements. Shortfalls could also be further exacerbated under fuel shortage conditions or forced outages of remaining system strength units.
  - The retirement of critical thermal units considerably reduces the pool of units available to meet minimum synchronous unit combinations. Remaining generators may have to be run longer to meet minimum requirements, reducing availability to undergo routine maintenance and potentially increasing the likelihood of unplanned outages.

Challenges exist in the integration of system strength solutions

AEMO is engaging with System Strength Service Providers (SSSPs) on potential system strength solutions, but there are some challenges. These challenges include:

- Time requirements to complete the regulatory investment test for transmission (RIT-T) processes.
- Increasing asset costs and supply chain issues.
- Increased global demand for system strength solutions.
- Increased risk of forced outages relating to aging assets.
- The consequences of delayed delivery of system strength solutions will be significant.

Some SSSPs have published Project Assessment Draft Reports to indicate available options to meet system strength obligations. These involve both network and non-network options including:

- Development of synchronous condensers.
- Retrofitting of clutches to existing or future gas turbines.
- IBR facilities with grid-forming converter control capability.
- Contracts with the existing synchronous generation fleet.

Initiatives are underway to manage the impact of retiring generation capacity

With the impending retirement of Eraring and Yallourn power stations in 2027 and 2028 respectively, AEMO is progressing several initiatives to manage and understand the impacts in the short-term horizon. These initiatives include:

- An internal task force focusing on the retirement of Eraring and Yallourn, assessing key critical contingency events and the impact these would have on the system operability post-retirement.
- AEMO publications such as the Engineering Roadmap and *Transition Plan for System Security* provide analysis and information on the existing technical gaps and outline subsequent actions.
- Developing a new short term (ST) projected assessment of system adequacy (PASA) tool[51], with an expected delivery date in 2026. This system is designed to improve the accuracy of power system forecasting and provide visibility of system security issues to operations planning and real-time operations teams.

Due to the significant power system changes that thermal generation retirement presents in the NEM, the impact on power system constraints in the next five years should be considered in detail. Critical risks identified through studies may warrant consideration as a priority risk for assessment in a future GPSRR.

5.2 System strength and inertia management in real time

AEMO's control room currently manages system strength and inertia in real time as per the Power System Security Guidelines (PSSG)[52]. This is achieved through constraints and directions when necessary, and supplemented by regional system security procedures, contingency plans, schemes, and limits advice. The use of limits advice in particular is critical for AEMO to manage the power system, highlighting the importance of having accurate information to make real time decisions.

AEMO relies on limits advice to manage power system security

To manage system strength and inertia in real time, limits and operational advice are required to adjust the minimum synchronous unit combination requirements in accordance with operating conditions. If limits are not provided from TNSPs, this can unknowingly place the power system in an insecure operating state during outage conditions. AEMO's control room has visibility of minimum fault levels, but monitoring is not performed if limits have not been processed.

Increasing network monitoring capability is becoming available across the NEM, which provides benefits. This is being achieved via the rollout of wide area monitoring schemes (WAMS) and phasor measurement units (PMUs). While this does not improve system strength visibility directly, these systems provide a mechanism to assess other behaviours such as IBR commutation instabilities as a result of reducing system strength. It is still necessary that NSPs provide limits advice on the technical envelope for the magnitude of commutation instability experienced.

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

[52] See SO OP 3715, 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.

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Improving security frameworks (ISF) rule change provides better tools to manage secure network operation

The Australian Energy Market Commission (AEMC) published the National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 (ISF Rule) in March 2024[53]. The ISF Rule expands the system security procurement frameworks and provides AEMO with new tools to manage power system security in the NEM through the current energy transition, with the full ISF Rule taking effect from 2 December 2025.

The ISF rule addresses system security challenges by providing alternative options for procurement of critical services, to reduce reliance on directions and provide better incentives for participants to invest in providing system security in the longer term.

5.3 Small signal stability

Small signal stability is the ability of the power system to maintain synchronism after being subjected to a small perturbation without the application of a contingency event. This issue is gaining an increased focus in the NEM due to the growing presence of IBRs.

AEMO is currently considering the following issues regarding small signal stability in the NEM:

- **Changing generation mix from synchronous generation to IBR influences small signal stability.**
  - The displacement of synchronous generators is affecting many factors that impact small signal stability such as inertia, network topology, system strength and the damping and frequency of inter-area modes.
  - As coal-fired plant retires, the reduced inertia impacts the frequencies of inter-area modes. This results in reduced effectiveness of damping devices in the system.
- **IBR impact on inter-area modes.**
  - The installation of new IBR also affects the damping and frequency of inter-area modes. However, the impact is difficult to accurately predict, with no general principles that can be reliably applied.
  - Accurate simulations are difficult to conduct because there is a lack of IBR small signal models in the NEM. This results in inadequate small signal stability assessment for connection studies.
  - Existing IBR plants may be further contributing to small signal stability issues because they are not tuned for the lower system strength operating conditions that are emerging. It is likely they were tuned for higher short circuit ratios but this has not been updated as system conditions change.
- **Reduced effectiveness of existing power oscillation dampers (PODs).**
  - As a result of the changing power system, the performance of existing equipment is not as effective as when they were originally implemented. PODs at the Greenbank, South Pine and Blackwall SVCs were all tuned over 15 years ago for a grid that looked much different than today. Due to the changing topology,

[53] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

inertia, system strength and generation in the system, the effectiveness of the damping may be significantly reduced.

- **Synchronous condensers introduce negative damping of inter-area modes.**
  - While synchronous condensers bring many benefits to improve system strength and RoCoF, they introduce the potential to exacerbate inter-area modes. Synchronous condensers may provide negative damping due to the introduction of negative damping torques and the lack of any damping devices associated with the synchronous condenser.
  - Research into synchronous condenser damping devices should be a high priority to ensure the addition of synchronous condensers for system strength and inertia do not have unacceptable small signal stability outcomes.
- **Integration of IBR may lead to sub-synchronous or super-synchronous oscillations.**
  - The introduction of non-fundamental frequency oscillations due to the integration of IBR is an issue that is on the rise in many power systems, including the NEM. IBR can introduce sub- and super-synchronous frequencies, with the possibility that the induced frequencies will resonate with other power system equipment and cause damage.

Actions currently underway to address these issues include:

- As outlined in the Engineering Roadmap, AEMO is embarking on a project to establish small signal stability offsets between simulation results and the measurements[54].
- AEMO is progressing work on improving small signal stability tools and creating new ones where required. This work includes:
  - Building confidence in oscillatory stability monitoring tools.
  - Developing new short-duration damping tools.
  - Developing an online small signal dashboard to improve visibility of this issue.
- Through the internetwork testing process, AEMO reviews current models and results.
- To address sub-synchronous oscillations, these are being investigated as they appear in the network. This involves analysing high-speed data, such as measurements from PMUs, to identify the source of oscillations.

5.4 Power system model accuracy

AEMO uses modelling data and simulation models to assess technical performance standards and to determine power system operational limits. Power system models are used for purposes ranging from assessing the security of the system in real-time operations to developing constraints, limits and designing power system requirements in planning and connection studies.

Maintaining the accuracy of power system models is a key factor in achieving realistic outcomes and effective decision-making. Incorrect models will have repercussions that flow into many elements of the power system,

[54] At https://aemo.com.au/initiatives/major-programs/engineering-roadmap.

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potentially resulting in increased risk of unexpected system incidents, or overly conservative limits that may have adverse market outcomes for customers.

To ensure power system model accuracy is maintained, AEMO is progressing actions as outlined in the sections below.

5.4.1 Operations Technology Program

AEMO's modelling and scheduling capabilities are being uplifted under the Operations Technology Program. This program core purpose is to identify and deliver new and enhanced technologies, processes and tools as part of the Operations Technology Program. Under the modelling and scheduling workstream, AEMO is aiming to deliver technology to improve system monitoring and simulation capability, as well as increasing visibility of real-time and forecasted system operation. Some of the current projects in the planning or execution phases include:

- **Data Online Service,** introducing an online catalogue to purchase AEMO models.
- **Operations Simulator,** improving the speed and snapshot handling capability of PSCAD to enable fast electromagnetic transient (EMT) contingency analysis.
- **Network Outage Scheduler (NOS) Uplift,** uplifting the NOS system to enhance its capabilities, improve reliability and align it to current supported versions.
- **Wide area monitoring systems upgrade,** to provide the capability to handle, process and store increased PMU telemetry data.
- **High speed monitoring,** deploying PMUs at TNSP sites to detect small signal disturbances caused by IBR.

5.4.2 Regular updates to the power system models

In a continuously changing network, periodic model improvements are essential to ensure accuracy and performance. This includes validating and verifying that the network parameters are accurately represented in respective models. Additionally, new augmentations and plants connections should be integrated through regular updates to achieve closer alignment with the actual network.

As inaccuracies in power system models directly affect power system limits and can cause failed runs in real-time contingency analysis tools, maintaining model accuracy is vital for ensuring power system security. In planning studies, insufficient models can result in incorrect interpretations of future power system conditions, potentially influencing decision-making.

The following ongoing initiatives have been taken to address these risks:

- AEMO regularly updates base cases for both root mean squared (RMS) and EMT simulation models. Updates typically include integrating new plants models, updating existing plants with latest models, implementing network augmentations, and troubleshooting models.
- The initial releasable user guide (RUG) audit has been completed, and plans are underway to update the RUG database.

5.4.3 Modelling capability improvements

The operations simulator project is enabling fast EMT simulations of the power system with its snapshot handling capability. Significant work undertaken for this project allows Power System Computer Aided Design (PSCAD™) snapshots to be downloaded from the AEMO modelling platform (AMP) for any timestamp, similar to what is possible for Power System Simulation for Engineering (PSS®E) snapshots.

The simulation speed of the NEM PSCAD™ model has been significantly increased, enhancing the efficiency of EMT simulations. This allows for improved visibility into system strength-related limits, and more effective planning capabilities, especially considering the high penetration of IBR. The work completed also unlocks readily available EMT cases to perform frequent model validations, ensuring the power system operates securely.

5.4.4 Increasing need to accurately model CER response

The performance of CER, including both distributed PV and dynamic loads, has a significant impact on the power system following contingencies and must be modelled accurately. At times, aggregate distributed PV is the largest generator in the NEM, and CER shake-off can significantly affect the development of limits and constraints. If not modelled appropriately and validated regularly, this can result in large discrepancies in allowable limits and constraints.

AEMO is continuously validating and improving CER and composite load (CMLD)[55] models to reflect the true state of the network and investigate impacts on existing limits. These models are available for both RMS and EMT simulations. Additionally, the behaviour of distributed PV during power system incidents is being examined in incident reports to illustrate its overall impact on the system.

5.5 Weather-related risks

Extreme weather conditions are a major cause of non-credible contingencies, particularly related to the loss of transmission lines. Bushfires, cyclones, storms and lighting can all have significant impacts on the power system when major transmission lines are affected. Data available to AEMO's forecasting teams suggests that the extreme end of weather conditions being experienced today is similar to what was experienced five years ago. However, there are trends indicating an increase in the severity of some factors such as temperatures, winds speeds, humidity and the location of particular weather events. In addition to this, the power system is becoming increasingly dependent on weather due to more geographically dispersed network infrastructure, as well as generators that rely on wind, solar and hydro for power generation.

5.5.1 Changing weather patterns across the NEM

Weather conditions have been observed to be changing across the NEM. Higher wind speeds, such as tornados, convective downbursts and supercells, have recently been observed across all NEM regions. Tropical cyclones are also being observed further south due to warming oceans, which means southern states may be at

[55] See https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/power-system-model-development.

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increasing risk of severe weather events if this trend continues. This poses increased risk for regions that have not been subjected to high wind speeds previously, especially if older network infrastructure was not designed to withstand these conditions.

Typically, the majority of severe weather events are very localised conditions and are particularly difficult to forecast, with most modern tools only capable of flagging wider high-risk areas. Unpredictable and highly localised weather patterns can locally influence power system behaviour and provide operational challenges.

Historically, temperature has been the key driver of demand. There is a slight trend of increasing temperatures each year with each summer being hotter than the last. Winters have also generally increased in temperature, but significant cold spells are still present. Increased demand is seen across most regions during prolonged heat waves in summer. Increased temperatures also drive a higher likelihood of bushfires and subsequent risk to transmission operations.

5.5.2 The network is becoming more dependent on weather

The uptake in renewable energy sources is making the power system more dependent on weather conditions. This is experienced primarily through solar and wind, but there are a number of ways weather will impact the operation of the NEM, as outlined in the sections below.

Distributed PV

Any wide-scale changes that distributed PV encounters will have significant impacts on the power system. This can be seen when unexpected cloud cover shades a large portion of distributed PV in a region, leading to rapid changes in operational demand.

However, there are some factors that are reducing correlation with weather. While distributed PV capacity is increasing across the NEM, its impact is becoming less correlated with weather conditions as additional measures are implemented, for example:

- Emergency backstop capability implementation is underway and will provide a mechanism to reduce distributed PV output irrespective of weather conditions.
- Consumers are responding to price signals from the market, where distributed PV exports may be more closely linked to price rather than weather conditions specifically.
- Some NSPs are implementing dynamic export limits, which will restrict solar exports during MSL conditions.

Large-scale wind and solar

Increasing wind speed and temperatures are expected to have an impact on large-scale wind and solar farms. These types of plant typically have cut-out wind speeds and maximum operating temperatures to preserve the safety of the plant during extreme weather conditions. This creates an operational issue where large amounts of wind and solar farms can disconnect and lead to large contingency sizes and potentially cascading failures.

Other weather-based impacts

There are also a number of other weather based impacts on the power system, such as:

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- Solar eclipse – this will impact solar generation for no longer than a few hours and it is more predictable to prepare other forms of generation to support the grid during this period.
- Cyclones – ocean temperatures are rising, which is a key condition for sustaining tropical cyclones. As water temperatures rise, cyclones are more likely to survive further south than usually expected.
- Bushfires – rising temperatures increase the likelihood of bushfires, which may impact operation of transmission lines.
- High voltage direct current (HVDC) or other inverter thermal limits being reached, resulting in fast runback.
- Lower transmission line capacities where dynamic line ratings are used.
- Drought impacts on hydro generation and storage levels.

5.6 Communication-related risks

Communication systems are becoming more important as the size and complexity of the power system increases. There is a growing relationship between power system security and the reliability of communication systems, because so many of the functions required to operate a complex and modern power system rely heavily on communications infrastructure.

Specific communications-related risks that are being considered by AEMO include:

- **Communications related to CER.**
  - CER is of increasing importance in the NEM, and the ability to predict and forecast it will be crucial to ensure the operability of the system. Communications related to CER are still being rolled out, but it will introduce significant risk if this is not managed appropriately. Aggregation of CER in virtual power plants (VPPs) or through load response often uses communications using the mobile network or home internet connections like the National Broadband Network (NBN). The implementation of emergency backstop mechanisms is also internet based, which opens up further cyber risks. For such a large network, being able to control aggregated CER through cyber-attacks could have severe impacts on the power system.
- **Redundancy of communications provider.**
  - The loss of a major telecommunications provider can result in significant impacts to a power system that is heavily reliant on communications infrastructure. This can have wide-ranging impacts across CER, protection operation, markets, control rooms, generator dispatch and more. It is important to have redundancy of communications provider for critical infrastructure, to account for loss of service, such as the Optus outage that occurred in November 2023. Communications redundancy may not necessarily be present with two different providers if the same network is used for each. True communications redundancy with different networks is the best approach for critical infrastructure.
- **Reviewable operating incident reports on recent communications-related power system incidents:**
  - 17 March 2023 – market suspension in New South Wales[56].

[56] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2023/final-report---nsw-market-suspension-17-march-2023.pdf?la=en.

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- 22 April 2023 – market suspension in Victoria[57].
- 29 June 2023 – loss of supervisory control and data acquisition (SCADA) and line protection at Keilor Terminal Station[58].

5.7 Cyber-related risks

Cyber related risks in the NEM are increasingly related to communication of internet connected devices. As the power system moves towards incorporating internet-connected devices, this brings a range of benefits for NSPs and system operators, but also creates possibilities for interference. As the capabilities of NSPs and AEMO to interface with CER increase, so does the risk that cyber-attacks could be used to target the same capabilities.

5.7.1 Centralising the visibility and operation of CER introduces cyber risk to the power system

CER are becoming increasingly integral to power systems, and their reliance on internet-based communications for control and monitoring make them susceptible to cyber-attacks. Interference with these controls can result in changes to CER output and impact power system security. Similar risks are present for the following technologies:

- Smart loads such as air-conditioners with internet connections.
- Electric vehicles and charging stations.
- Smart meters.
- Home battery storage.

It is important that, as these devices are becoming increasingly connected to the internet and communications systems, cyber security is considered from the outset. Secure installations with appropriate standards, encryption and authentication are the best form of protection, rather than relying on secondary approaches such as monitoring, detecting, defending and recovering from cyber-attacks.

5.7.2 Ransomware and phishing risks for key industry bodies

The energy industry has many key industry bodies that could be targets for ransomware or phishing attacks. Wherever humans are involved in the operation of businesses, there is a risk that social engineering or phishing attacks can be used to gain access to key data and systems. These attacks used to focus on encryption of data but may also now include stealing sensitive information to release if they are not financially compensated. Any attacks on key industry bodies will reduce their ability to provide essential service to the power system, which may be critical if it coincides with times of high demand, low reserves or MSL conditions.

[57] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2023/preliminary-report-vic-market-suspension.pdf?la=en.

[58] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/loss-of-scada-and-line-protection-at-keilor-terminal-station-on-29-june-2023.pdf?la=en.

5.7.3 Physical supply chain issues

The supply chain of devices used in NEM will become increasingly important as complexity and number of devices connected to the internet increases. It will become difficult to ensure that there are no supply chain issues such as cyber compromised systems that can be activated via back door mechanisms. Even if such systems are identified and replaced, the same risk may still be present for any replacement products. To mitigate this risk, a focus on engineering out vulnerabilities, enhancing resilience and mitigating risks without wholesale replacement is recommended under the consequence driven cyber informed engineering methodology[59].

5.7.4 Cyber risk in the NEM

Cyber risk has significant focus in the power industry, and there is a significant amount of work underway to identify and address these risks. Work currently being progressed includes:

- The CER Roadmap from the Department of Climate Change, Energy, the Environment and Water (DCEEW) addresses CER cyber risks.
- Supply chain challenges are being discussed with key industry bodies with specific collaboration between AEMO and NSPs.
- At the international scale, isolated systems are used in the US to test cyber threats.
- AEMO is leading the work on Australian Energy Sector Cyber Security Framework (AESCSF).
- Department of Home Affairs is leading the work on the security of critical infrastructure (SOCI) framework.
- Distributed PV systems have now been included in the scope of the *Cyber Security Act 2024* (Cth).

5.8 System restart with the transitioning power system

SRAS are provided by generators with the ability to start, or remain online, without drawing electricity from the grid. SRAS providers restart the power system by providing energy to other generators following a major blackout.

SRAS has historically been provided by large synchronous generating units, since these units can output active power consistently and provide inertia to maintain stability. Due to the current reliance on large thermal units to provide SRAS services, the limited pool of existing system restoration units is decreasing with generation retirements.

5.8.1 Current and future SRAS-related risks in the NEM

- **There is a limited pool of SRAS providers in some NEM regions, and some are potentially less capable of effectively commencing the process of restoring the power system.** Overall, there is currently little competition for the provision of SRAS services, and limited incentives for the development/construction of new -restart capable plants.

[59] See https://inl.gov/national-security/cce/.

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- **Lack of system strength during restart prevents most IBR from participating in the early stages of restoration**, although some BESS may still be able to provide early voltage and frequency support. Despite this, there is currently no incentive for BESS to reserve headroom to provide SRAS.
- **The risk of distributed PV impacts on system restart continue to grow**, directly affecting the viability of restart paths at certain times of the day and year. Sufficient stabilising demand is required for system restart, but higher distributed PV generation operating conditions are causing load variations and load erosion. If the existing distributed PV management processes are ineffective in restart scenarios, there may not be sufficient demand to restart the system until night-time or low distributed PV operating conditions, which may delay restart times significantly.
- **Public behaviour during restart may drive atypical load characteristics.** In system black conditions, many people may leave commercial or industrial workplaces to return home, driving unpredictable demand. SRAS paths are developed assuming historical loads, but this may deviate from what is experienced in a system black event.
- **The system restart path across NEM regions is moving with the changing generation mix**, and restart sources are often a long distance from major load centres. Therefore, although system restart path testing is valuable, it has a significant market impact and there are limited testing opportunities.

5.8.2 Actions taken to mitigate SRAS risks

There are several actions currently underway to manage risks associated with SRAS in the NEM. These include:

- Working to revise regional system restart plans to ensure minimum switching is required, while also providing sufficient guidance on alternative switching paths where they exist.
- Conducting annual system restart training with NSPs.
- Seeking improved and accurate information from generators, TNSPs and DNSPs to input into restart plans.
- Working to encourage and enable extended network testing.
- Investigating the use of grid-forming inverters and the possibility of utilising BESS during early stages of system restoration.
- Investigation of emergency back-stop mechanisms which may be used to facilitate the availability of stable demand during system restart.
- A review of the system restart standard (set by the Reliability Panel) has commenced[60].

5.9 Auto-bidding systems risk

Auto-bidding is becoming more prevalent in the operation of the NEM, where NEM participant generators use software that carry out bids and rebids automatically in accordance with pre-set parameters. Auto-bidding tools typically use five-minute pre-dispatch (PD) and dispatch data for decision-making. This reliance on five-minute PD data means that auto-rebidding typically takes place less than one hour ahead of dispatch.

[60] See https://www.aemc.gov.au/market-reviews-advice/review-system-restart-standard-0.

5.9.1 The use of auto-bidding in the NEM enhances efficiency but poses unique risks to the system

The use of auto-bidding software by NEM participant generators is becoming increasingly common, as it allows for more efficient and responsive bidding strategies. By leveraging five-minute pre-dispatch and dispatch data, these tools can optimise bids based on real-time market conditions.

However, despite these benefits, these tools introduce a number of risks related to market competition, stability, and rebidding behaviour. To address these risks, regulatory measures may need to be considered to mitigate potential disruptions.

5.9.2 There is an increased risk with auto-bidding, particularly when it is dominated by only a few providers

- **Market structure assumption** – the current market design is based on the principle of multiple participants competing for energy and ancillary services. A concentration of auto-bidding providers undermines this assumption, potentially leading to less competitive behaviours and distorting pricing.
- **Vulnerability during intervention events** – common bidding platforms can expose the NEM to risk during intervention periods. AEMO may need to intervene to manage the power system, which can complicate the bidding landscape and impact overall market stability.
- **Rebidding behaviour** – when a generator in a region decides to cease generation, AEMO might direct it to remain online to maintain system strength. This situation can trigger ongoing rebidding behaviour, particularly exacerbated by auto-bidding platforms, which may lead to rapid and potentially destabilising changes in market offers.

To mitigate the risk of rebidding during intervention events, reform could be considered that allows rejection of rebidding during intervention periods. This would help maintain market integrity and support the system to operate smoothly during critical times, reducing the potential for adverse impacts on pricing and reliability.

5.10 Maximum allowable active power ramp rates

BESS, and other IBR in the NEM, have advanced dynamic active power response that allow them to very rapidly change active power setpoints in response to system events or price signals. This typically exceeds the ability of other synchronous generation technologies that are limited by mechanical constraints.

While this capability can result in system and market benefits, it also introduces risks, where the rapid or unintended changes in active power can have significant impacts on the power system.

5.10.1 BESS facilities with high active power ramp rates can affect interconnector stability

The energy delivery capability of BESS can generate large active power changes that may impact system stability. An example of the risk associated with this BESS capability is discussed in Section 1, where BESS are observed to deliver high proportional active power responses to frequency events in the NEM due to their aggressive frequency droop control settings. In circumstances where significant aggregate BESS capacity is localised to a single region, this presents challenges to interconnector stability during remote frequency events.

However, AEMO's findings from study of this risk indicates that geographically dispersed BESS capacity moderates this risk when frequency support contributions are provided equivalently from all mainland NEM regions.

5.10.2 Control settings can be adjusted to reduce the risk of rapid active power changes

With increasing integration of IBR technologies such as BESS, control settings can be designed to tune the response of new facilities according to changing power system needs. Functional tests will be required to ensure these control systems behave as designed. For new connections in the NEM, an assessment of impact to system capability is required under the NER. This ensures that under the automatic access standard, a new connection does not reduce any inter-regional or intra-regional power transfer capability below existing levels, which may occur if these facilities respond rapidly to network events or changes in market pricing signals.

5.10.3 Control system maloperation of large-scale BESS facilities can result in significant system impacts

Control system maloperation may result in BESS facilities negatively impacting the system by delivering unwanted and rapid active power changes. This change could be from maximum to minimum output levels within sub-cycle timeframes. If oscillatory behaviour occurs with repeated swinging between maximum and minimum active power limits, this will have particularly significant impacts on the power system. For large BESS systems capable of developing high-magnitude power oscillations, this could rapidly change transfers through critical transmission circuits or interconnectors. As the frequency of these oscillations may be significantly faster than typical power swings or oscillatory modes in the NEM, such oscillations may appear as out-of-step conditions to loss of synchronism (LOS) relays (or abnormal power swings to other distance protection relays) causing inadvertent protection operation, and a subsequent risk of cascading outages.

This accentuates the importance of performing rigorous testing at various hold points and limiting the released capacity of these systems until performance has been proven to reduce the risk of control maloperation occurring when the plant is cleared to operate at full capacity.

5.10.4 Actions being considered to mitigate active power ramp rates

This emerging risk is still developing, but the industry is considering high level solutions that may be implemented in future. AEMO and TNSPs are investigating solutions to mitigate risks associated with rapid active power ramp rates. Discussions are only high level at present, but include:

- Review of maximum allowable BESS connection sizes controlled by a single power plant controller.
- Introduction of additional control schemes designed to prevent the unintended operation of BESS active power ramping.

5.11 Limited visibility of participant systems

While the numbers of CER installations are increasing each year, the visibility and control of these systems by NSPs and system operators remains limited. Work has been completed to improve large-scale renewables

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integration, and a similar focus is needed to ensure CER are effectively integrated into the grid, maintaining system security and reliability as uptake grows.

- **Telemetry requirements for aggregated CER.**
  - The power system data communication standard[61] sets out the standard and protocols applicable to the recording, transmission or receipt of telemetered data for the purpose of monitoring and managing power system security and reliability. However, there is growing industry pressure to review this standard and the telemetry requirements for aggregated CER, which is essential for operational visibility and effective CER management in the NEM.
- **Poor data quality for CER.**
  - Data quality for CER poses a problem for system operators and NSPs to have confidence knowing how CER will respond. In the NEM, there is a significant lack of data for CER units under 30 kilovolt amperes (kVA), and any available data is also often unreliable.
- **Lack of SCADA or control hinders effective CER management in the NEM.**
  - CER also lack SCADA integration or direct control capabilities. The vast majority of distributed PV systems lack real-time monitoring, control, or active management, even during emergencies. This creates operational challenges for both distribution networks and the broader power system, particularly in areas where distributed PV adoption is high compared to local electricity demand.
- **Limited visibility of technical settings and behaviour during disturbances**
  - As identified in Section 2.3.1, visibility of the compliance of CER devices to technical settings, namely AS/NZS4777.2, is critical for understanding the risks to system security. Further, the conformance of these technical settings when in the field, is necessary for identifying any potential compliance issues and challenges where the inverter behaviour does not align with the needs of the grid.

Some of the operational challenges and system impact include:

- Voltage and frequency stability issues during periods of high level of distributed PV generation and low local demand.
- MSL challenges where AEMO might be forced to intervene by using emergency backstop mechanisms (see Section 2.3.2 for more information).
- Emergency response limitations during major system disturbances, where uncontrolled distributed PV shake off can exacerbate grid instability.
- Increased susceptibility to large generation ramping events.

To mitigate this increasing risk, several actions are being undertaken, including the following:

- Release of the CER Roadmap, which includes the establishment of backstop capabilities by spring 2025.
- In the process of establishing minimum CER device capability for coordination and aggregation or interoperability within AS/NZS 4777 and AS 4755.

[61] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/AEMO-Standard-for-Power-System-Data-Communications.pdf.

- The Engineering Roadmap highlights the requirement for establishing framework and incentives to encourage uptake of CER responding to market, network, and tariff signals.
- Through the Australian Solar Energy Forecasting System Phase 3 (ASEFS3), AEMO is developing a new five-minute distributed PV generation estimate value, which aims to increase granularity of the distributed PV generation estimated actuals and forecasts and reduce delays in accounting for changing grid and weather conditions.

5.12 Generator compliance

As the number of connections increases in the NEM, the issue of generator compliance becomes more significant. For a small number of non-compliances, these can be addressed simply on an individual basis, but as non-compliances accumulate across many generators in the NEM, it becomes increasingly difficult to manage.

5.12.1 Common OEM-related non-compliance issues pose risks to multiple generating plants

In Australia, a limited number of OEMs supply equipment for IBR projects, and any issue affecting one OEM can impact all plants using that technology. These new IBR connections involve complex control systems, which are not always correctly configured, posing significant risks when implemented across multiple IBR plants. For instance, a major OEM is currently facing challenges with its IBR plants not providing PFR.

Some OEMs have also exited the Australian market, leaving IBR plants without ongoing support. This requires significant effort to resolve ongoing control issues and ensure proper performance. Additionally, OEMs often releases software updates to fix problems, but these updates are difficult to model and can worsen existing issues.

5.12.2 Impending synchronous machine retirement reduces incentive for generators to address non-compliances

The retirement of synchronous machines reduces incentives to address non-compliance issues, as plants nearing closure have little financial incentive to invest in remediation. This increases the risk of unresolved issues persisting, potentially impacting system stability. This challenge is already unfolding in the current power system, highlighting the need for proactive management to ensure compliance and stability.

The most common non-compliance issues relate to the following NER clauses:

- Reactive power capability (S5.2.5.1).
- Reactive power control (S5.2.5.13).
- Active power control (S5.2.5.14).

Violations of these clauses can cause significant issues, particularly reactive power capability requirements and the impact on voltage management during periods of low demand. Notably, clause S5.2.5.1 is increasingly being breached by newer synchronous machines, when traditionally, synchronous machines provided generous reactive power capability beyond the mandated levels. Additionally, generators undergoing a S5.3.9 process on excitation system upgrade will often reduce their reactive power capability to meet only the minimum requirement

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for automatic access. While there is no obligation to exceed automatic access requirement, the sudden withdrawal of this capacity can be an operational shock, impacting grid stability and management.

5.12.3 Current commissioning processes can lead to unresolved non-compliances or unknown generator performance issues

Non-compliances that are not addressed at commissioning may never get resolved. If an OEM issue arises during commissioning of a plant, the connection process may continue with the understanding that the plant should return once the issue is resolved. However, this does not pressure the OEM to address the problem promptly and can result in ongoing generator non-compliances.

Not all controls are tested adequately in the commissioning process. Conflicts between generator runback control and PFR controls are not always detected, as these controls are typically not tested during commissioning. These issues often remain hidden until a real-world power system event occurs, potentially causing oscillations and non-compliance. While there is pressure to resolve some issues during commissioning, plants typically take a longer time to fix these issues.

5.12.4 Ensuring generators provide PFR remains a challenge

Some OEMs currently face challenges with PFR. Since PFR is not included in the GPS and it is not tested during commissioning, this makes compliance difficult to enforce. To address this, AEMO is actively engaging with participants to improve PFR implementation, particularly focusing on those plants that are not meeting requirements.

5.12.5 Oscillatory challenges and model benchmarking also present risk with cumulative non-compliances

The NEM is experiencing an increasing number of oscillations, particularly sub-synchronous oscillations, which are currently localised to groups of IBR. However, as more IBR interact, these oscillations could become more widespread, potentially leading to new inter-area oscillatory modes. There is no systematic benchmarking of non-compliances against plant models to verify if the issue exists within the models. As non-compliances increase across the power system, plant models may become less representative of actual performance, impacting system planning and stability.

5.13 Inverter limit violations due to inability of generator response

At times, it is necessary to disconnect or block inverters that are connected to the power system to maintain system security. Inverter limits are imposed on IBR plants in situations where system strength-related impacts are present in the power system or when parts of the network are at a credible risk of islanding.

Managing the number of connected inverters is currently a manual process, which can involve time-consuming communications with multiple parties to provide instructions for limiting inverters. This has contributed to several

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recent events[62] where the power system became insecure for periods exceeding 30 minutes where inverters were not limited as required.

As the uptake of IBR continues to increase, this could result in periods requiring inverter restrictions to occur more frequently. If processes continue to be manual, this may not be a sustainable approach for large numbers of IBR and may lead to periods where the power system is not secure.

AEMO has identified several contributing factors related to inverter limit violations and is working with the industry to implement both short-term and long-term solutions to mitigate these risks.

Risk regarding inverter limit violations is expected to increase:

- An increasing number of scenarios have been observed where inverter limits need to be imposed during operation of the power system.
- A higher share of IBR will impact system strength, resulting in adverse effects such as post-contingent voltage instability. This often results in limiting the number of connected inverters during planned outages, or after unplanned outages, to prevent instability and risks of islands being supplied by IBR.
- As the uptake of IBR increases, this trend is also expected to increase in future.

Challenges in managing inverter limits for secure power system operation:

- Some existing IBR plants are unable to disconnect inverters within the required timeframes due to inherent limitations of the plant design and unavailability of remote control facilities for plant operators. It has also been identified that backup facilities at the NSP connection point are inadequate. These backup facilities are intended to disconnect the entire plant as a measure of last resort to resecure the system.
- There is a lack of awareness and well-defined procedures of some IBR plants to limit connected inverters within allocated time to secure the power system.
- Current practice of manual intervention to limit inverters has proved to be a time-consuming task, with increasing complexity of limit advice and number of participants that need to be contacted.
- Inconsistent terminologies used across the NEM to indicate the connection status of the IBR inverters may lead to operational errors. For example, the following inverter limiting operations should be referred to by different terminologies:
  – Physical disconnection of the inverters from the system by means of circuit breakers or any other means.
  – Blocking of inverters restricting their active and reactive power output to zero and will not provide any response during disturbance (inverters may be physically connected).

AEMO has taken initiatives and is working with participants to mitigate issues:

- AEMO has shared the inverter limit issue with TNSPs at the Power System Security Working Group (PSSWG). Temporary operating advice (TOA) was issued to define AEMO's interpretation of various inverter disconnection terminologies and obtain TNSP alignment with these definitions.

[62] Inverter limit violation at Moree solar farm, see https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/exceedance-of-the-inverter-limit-at-moree-solar-farm.pdf?la=en, and Inverter limit violation at New England solar farm, see https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/exceedance-of-the-inverter-limit-at-new-england-solar-farm.pdf?la=en.

- AEMO and TNSPs are working towards implementing consistent terminologies in their process documents and limit advice. Additionally, effective plans to resecure the power system within 30 minutes will be implemented.
- The long-term goal is to implement a fully automated system to disconnect and dispatch inverters.

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6 Performance of existing emergency frequency control schemes

In addition to the evaluation of the selected priority risks, the GPSRR also provides an overview of risk mitigation measures encompassing existing EFCSs, operational capabilities and other emerging risks in the context of an evolving power system. EFCSs are emergency control schemes that are relied on to maintain power system frequency within the operating limits specified in the Frequency Operating Standard (FOS)[63] following the occurrence of a non-credible contingency event.

6.1 Over-frequency generation shedding (OFGS) review

OFGS schemes operate to trip generators for extreme or high consequence over-frequency events. At present, OFGS schemes are in operation in Tasmania, South Australia and Western Victoria. OFGS is also in the implementation phase in Queensland. The following improvements are being pursued or planned to improve OFGS operation in different regions:

- South Australian and Western Victoria OFGS – ElectraNet and AEMO Victorian Planning (AVP) have implemented updated settings with required participants in South Australia and are now working through commercial aspects of the OFGS implementation.
- Queensland OFGS – in the 2022 PSFRR[64], AEMO identified a requirement to implement an OFGS in Queensland to help mitigate for extreme over-frequency events, such as those due to trip of QNI and Queensland separation. The design of the Queensland OFGS scheme has been finalised in consultation with the relevant NSPs, and they are progressing with implementation.
- AEMO will continue to assess the effectiveness of existing NEM OFGS schemes and the need for any modifications.
- AEMO has finalised the development of an updated strategy for the overall co-ordination of generator over frequency protection settings.

6.2 Emergency under-frequency management

UFLS is a last resort "safety net", designed to prevent black system events when severe non-credible generation contingencies occur where a drop in frequency has not been arrested by PFR and FCAS. It involves the automatic disconnection of load circuits to rebalance supply and demand.

Increasing levels of generation from distributed PV are reducing the load on UFLS circuits, reducing the effectiveness of UFLS. With very high levels of distributed PV generation, UFLS circuits can operate in reverse

[63] Effective 9 October 2023, at https://www.aemc.gov.au/sites/default/files/2024-01/Frequency%20Operating%20Standard.pdf.

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

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flows, which means that in the absence of intervention, UFLS relays will act to disconnect circuits that are net generators, exacerbating the supply demand imbalance when they activate following an under frequency event.

Table 2 summarises key emergency under-frequency management initiatives underway to mitigate risks associated with increasing distributed PV and its impact on UFLS.

Table 2 Summary of mainland NEM regions UFLS remediation projects

Region	Project	Lead	Status
NEM	Determination of Emergency Under Frequency Response (EUFR) requirements for low demand periods	AEMO	• Developed and applied methodology to determine EUFR target for South Australia (see further detail below).
	Improved UFLS models	AEMO	• Improved integration of UFLS into AEMO's RMS models. AEMO created mappings of regional UFLS relays to individual transmission bus locations in the full NEM PSS®E model based on data compiled from NSPs for all mainland NEM regions. This approach most accurately reflects the physical distribution of this type of generation and UFLS in the system. • Improved modelling is necessary to facilitate ongoing work to design and update UFLS settings under emerging novel power system conditions.
	2025 NEM UFLS adequacy review	AEMO	• AEMO will also carry out NEM UFLS adequacy review in the second part of 2025.
	Updates to UFLS schedules and procedures used by AEMO	AEMO	• AEMO has completed the UFLS schedule and procedures update in Q4 2024.
South Australia	Dynamic arming[A] of UFLS relays (blocks UFLS activation if circuit is in reverse flow)	SA NSPs	• Australian Energy Regulator (AER) approved SA Power Networks cost pass-through application[B]. • SA Power Networks implementation thus far recovered 395 MW out of a target of 385 MW exceeding it by 10 MW. SA Power Networks will continue to monitor feeder flows, and maintain suitable coverage of dynamic arming over time, as more feeders pass reverse flow thresholds.
	Real time SCADA feed of UFLS load in each band	SA NSPs	• Real-time SCADA feed established for total SA UFLS load. • Real-time SCADA updated quarterly as increased visibility with Dynamic Arming functionality is being rolled out. • SA Power Networks is updating capability to provide visibility of load in individual UFLS bands (target completion: Q3 2025)
	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 has been finalised and the project has implemented its target of 120 MW of delayed UFLS.
Victoria	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to distributed PV, 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[E], identifying continuing trend in decline.
	Real time SCADA feed of UFLS load in each band	VIC NSPs	• AEMO has established a method for compiling Victorian UFLS data from transmission use of system charge (TUoS) metering (for post-hoc analysis). • Further NSP actions required to establish real-time visibility. To be completed by Q4 2025.
	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 developed a rectification proposal and received approval from AEMO, but the AER rejected the proposal. Hence, AusNet Transmission has proposed to remove reverse flowing feeders. A

Region	Project	Lead	Status
			Jurisdictional System Security Coordinator (JSSC) led review of respective load shedding procedures is in progress.
	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). To be completed by Q4 2025.
	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 endorsed by VEEC and VIC DNSPs. AusNet Transmission is working with Powercor with the endorsement. • AusNet Transmission has received approval from AEMO. However, AER has rejected the proposal. Hence, AusNet Transmission currently has proposed removing reverse flowing feeders. A JSSC led review of respective load shedding procedures is in progress.
	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 published a short report on the findings to inform further NSP investigation[G].
	Explore options to address the impacts of distributed PV on the UFLS scheme.	VIC NSPs	• AusNet Transmission is now looking to address the impacts of distributed PV on the UFLS scheme. • Expected to be carried out in the 2026-31 period, the preliminary design works to start in 2026, subject to AER funding.
New South Wales	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to distributed PV[H]. Recommended NSPs explore rectification options.
	NSP progress on UFLS remediation	NSW NSPs	• NSPs conducting an audit of New South Wales 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.
Queensland	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to distributed PV[I]. Recommended NSPs explore rectification options.
	NSP progress on UFLS remediation	QLD NSPs	• NSPs auditing UFLS scheme, identifying areas of improvement. • NSPs identify metering uplifts required, especially to identify UFLS circuits in reverse power flow. Energy Queensland has completed excluding certain reverse flowing feeders.

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 (PSFRR), 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 (October 2023) *Under frequency load shedding: Exploring dynamic arming options for adapting to distributed PV*, https://aemo.com.au/-/media/files/initiatives/der/2023/dynamic-arming-options-for-ufls.pdf?la=en&hash=F6B7A015C8EB872C83513BA9C95EFE5B.
H. 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.
I. 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.

6.3 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. These are summarised in Table 3.

AEMO is also currently working on the 2025 NEM UFLS adequacy review with support from NSPs. This review will involve a detailed evaluation of the regional UFLS bands and assess the performance and adequacy of the current UFLS schemes.

Table 3 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 (2020 studies suggest Victorian 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 Queensland 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. • 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.
Real time SCADA feed of UFLS load in each band	SA	• Real-time SCADA feed established for total South Australian UFLS load. Visibility increased with Dynamic Arming functionality is being rolled out. • SA Power Networks is updating capability to provide visibility of load in individual UFLS bands (target completion: Q3 2025)
	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 (for example, metering improvements to identify reverse flows accurately). • 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).

7 Review of incidents

AEMO reviews power system incidents of significance in accordance with NER 4.8.15, referred to as 'reviewable operating incidents'. AEMO identifies incidents as reviewable based on the criteria set out in NER 4.8.15 and the Reliability Panel's 'Guidelines for identifying reviewable operating incidents'[65].

For an incident to be reviewable, it must be a noteworthy or significant event on the power system and typically includes an impact to power system security, frequency, voltage or results in load disconnection or loss. Based on its experience reviewing power system incidents, AEMO has observed that unexpected power system responses often occur during such incidents. These can increase an event's severity through impacts such as:

- Protection maloperation.
- Unexpected load disconnection.
- Issues with distributed PV fault ride-through performance.
- Issues with generator fault ride-through performance.
- Issues with fault ride-through of large loads.

7.1 Summary of reviewable operating incidents in 2024-25

To date in financial year 2024-25:

- There have been 19 reviewable operating incidents including one major incident.
- There has been an increase in incidents attributed to environmental factors. This includes four incidents caused by lightning strikes and two incidents resulting from bushfires.

Details of these reviewable operating incidents can be found in published incident reports, which are available on AEMO's website[66].

Figure 12 shows the root causes of incidents in 2024-25 to date and compared to 2023-24.

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

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

Figure 12 Root cause of reviewable operating incidents, 2024-25 and 2023-24

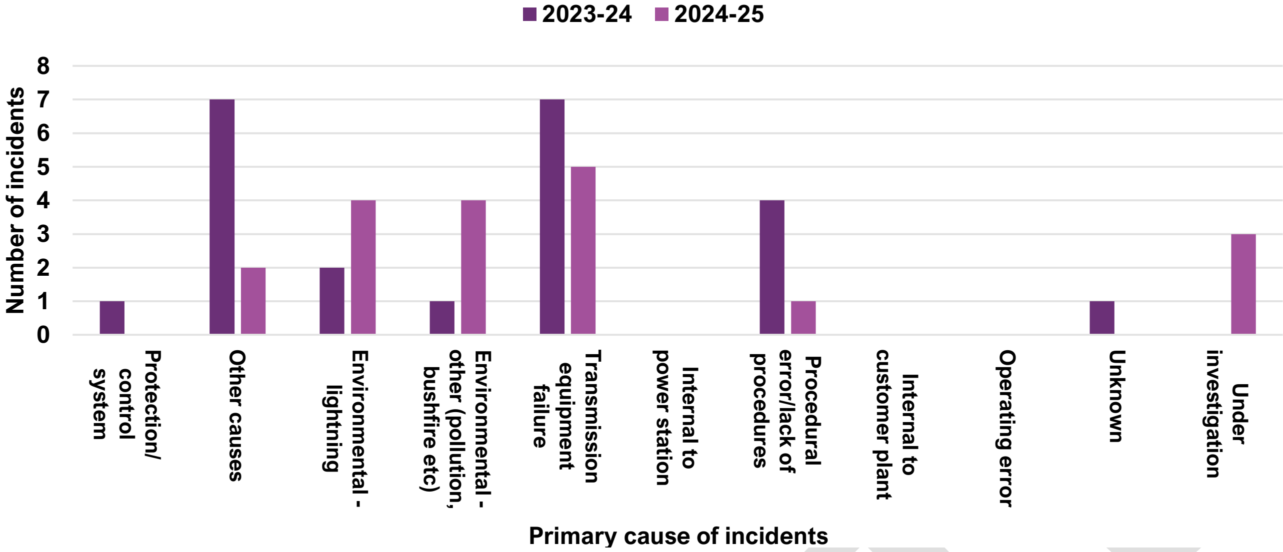
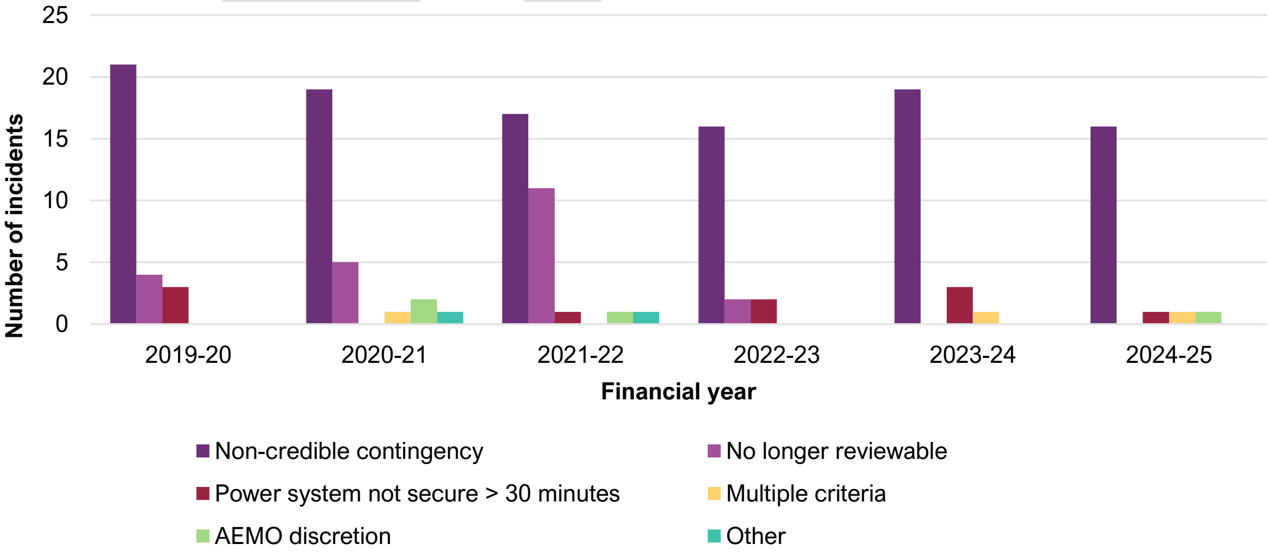


Figure 13 illustrates the number of incidents AEMO has reviewed over the past six financial years, to demonstrate trends over a longer time period. These have also been separated into categories based on the criteria that classifies them as reviewable. The most common criteria of reviewable incident are those that involve non-credible contingency events impacting critical transmission elements. However, some incidents met multiple criteria, meaning they qualified under more than one condition for being classified as reviewable. These are typically more significant incidents. AEMO has also undertaken reviews of other incidents considered to be of significance at its discretion, consistent with the Reliability Panel's Guidelines.

Figure 13 Reviewable incidents by criteria, 2019-20 to 2024-25 (to date)



Note: The "No longer reviewable" category reflects incidents that were previously classified as reviewable based on criteria that have now been excluded in the latest Reliability Panel's guidelines.

7.2 Relevant recent incidents

Some reviewable operating incidents have highlighted potential risks to the power system that could lead to cascading failures or major supply disruptions. Table 4 details recent incidents that are relevant to the GPSRR.

Table 4 Power system risks from recent reviewable operating incidents

Incident	Incident summary	Relevance to the GPSRR
Non-credible islanding of the Jeeralang to Morwell 220 kV network on 13 February 2024[A]	During this incident, an inadvertent protection function operation simultaneously tripped four 500/220 kV transformers at Hazelwood Terminal Station. This led to the formation of an electrical island consisting of approximately 200 MW of load.	**This incident underscores the significant potential consequences of unexpected protection operations (as discussed in Section 3.1),** particularly when multiple critical transmission elements trip simultaneously. It reinforces the necessity of thorough reviews and audits of protection schemes to ensure they are correctly configured and coordinated, preventing unintended operations that could lead to widespread disruptions in the power system.
Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024[B]	The Moorabool – Sydenham (SYTS) 500 kV No. 1 and No. 2 lines tripped following the failure of six 500 kV towers (three on each of the two 500 kV circuits). Approximately 3 seconds after each line tripped, auto-reclosure was attempted at the SYTS end. The auto-reclosure of each line applied a three-phase fault to the network.	**This incident demonstrates severe impacts of three-phase faults, which are considered non-credible by AEMO.** The voltage disturbance from the three-phase faults resulted in the shake-off[C] of 870 MW of net operational demand in Victoria, including approximately 1,294 MW of underlying load and 424 MW of distributed PV generation. The voltage disturbance also caused the runback of all four Loy Lang A units, leading to their tripping and an additional loss of 2,210 MW of generation in Victoria, adding to the contingency size.
Three-phase fault at Sheffield 220 kV A busbar and trip of load in Tasmania on 12 April 2024[D]	A three-phase fault occurred at the Sheffield 220 kV A busbar, resulting in the loss of approximately 542 MW of load in Tasmania.	**This event further highlights the significant impacts that three-phase faults can have on the power system.** In this incident, the three-phase fault triggered a deep voltage depression, resulting in the disconnection of approximately 487 MW of load in Tasmania – equivalent to around 43% of the Tasmanian operational demand at the time. **This also highlights the importance of carefully assessing the potential risks when reviewing and auditing SPSs to avoid unintentionally exacerbating system conditions under all possible scenarios.** The activation of the FCSPS during this incident led to an additional 55 MW of load loss when the Tasmanian network frequency was well above the nominal system frequency (frequency was at 51.2 Hz at this time), delaying the return of the network frequency back to 50 Hz. While this SPS operated as designed, its contribution to the incident was adverse.
NEM Market Suspension on 5 September 2024[E]	An information technology (IT) failure which resulted in the failure of the dispatch process led AEMO to declare a suspension of the spot market in all NEM regions from trading interval (TI) 1355[F] hrs to TI 1510 hrs on 5 September 2024.	**This incident illustrates the operational risks that could arise when IT failures disrupt dispatch systems and prevent timely market responses.** The IT failure impacted the entire dispatch process and prevented AEMO from using some critical systems. As a result, generators were also unable to receive dispatch targets from AEMO's electricity market management system. Following the suspension of the spot market, AEMO had to take significant actions by issuing a direction to a participant to operate the power system in a secure state.
Trip of Wagga 330 kV B busbar on 31 October 2024[G]	The Wagga 330 kV B busbar tripped due to a single blue phase-to-earth fault. Following this trip, several constraints related to secure inverter limits of multiple IBR plants were violated, lasting up to 70 minutes.	**Delays in existing manual inverter management process highlight the operational challenges and associated power system security risks (as further discussed in Section 5.13).** This event is one of several recent incidents where participants were requested to disconnect inverters for AEMO to maintain power system security or return the power system to a secure operating state. During this event, AEMO had to contact multiple participants to request inverter disconnection within a tight time frame. Given the manual nature of the existing process, some participants took up to 70 minutes to disconnect

Incident	Incident summary	Relevance to the GPSRR
		inverters during this event. Given the power system security implications of these delays, AEMO is working with the industry to implement both short term and long-term solutions to mitigate these risks, as further discussed in Section 5.13.

A. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/non-credible-islanding-of-the-jeeralang-to-morwell-220-kv-network-on-13-february-2024.pdf?la=en.
B. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf?la=en.
C. Load shake-off refers to generalised disconnection of load in response to unusual network conditions during a disturbance, such as a deep voltage dip or phase angle jump.
D. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/final-report--three-phase-fault-at-sheffield-and-trip-of-load-in-tasmania-on-12-april-2024.pdf.
E. Given the significance of this event, AEMO has prepared and published a preliminary report covering this event. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2024/preliminary-report---nem-market-suspension.pdf?la=en. The final report on this incident is expected to be published in Q3 2025.
F. This refers to the five-minute trading interval ending at 1355 hrs.
G. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/trip-of-wagga-b-busbar.pdf?la=en.

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8 GPSRR recommendations

Table 5 contains the status of open or recently closed GPSRR and power system frequency risk review (PSFRR) recommendations and a brief update on actions taken to progress each recommendation.

Table 5 Summary of previous GPSRR and PSFRR recommendation status

Report	Recommendation	Status	Update
2020 PSFRR (Section 2.5.1, page 25)	ElectraNet in collaboration with AEMO to enhance the reliability of the SIPS by implementing a wide area protection scheme (WAPS)	Closed	WAPS was commissioned in December 2023. The WAPS extension to include PEC-S1 has been implemented.
2020 PSFRR (Section 6.2.1, Table 37, page 73)	Various recommendations to address the identified South Australian UFLS issues	In progress	These are discussed extensively in Section 6.2 of the 2025 GPSRR.
2020 PSFRR (Executive summary, Page 6 and page 70)	AEMO, in consultation with ElectraNet, will review the effectiveness of the OFGS and modify it if required, to include additional generation in the scheme.	In progress	ElectraNet and AVP have updated all required settings in South Australia and Western Victoria. ElectraNet is working with commercial aspects of OFGS implementation with participants.
2022 PSFRR Recommendation 1	New OFGS scheme to manage Queensland over-frequency during Queensland separation: AEMO and Powerlink to implement OFGS in Queensland.	Ongoing	AEMO is currently working on the design of a Queensland OFGS in consultation with Powerlink. The design of the Queensland OFGS scheme has been finalised in consultation with the relevant NSPs, and they are progressing with implementation.
2022 PSFRR Recommendation 2	To manage the loss of both Dederang Terminal Station – South Morang Terminal Station 330 kV lines: AVP to review existing interconnector emergency control scheme (IECS) when Victoria is importing and develop a new SPS for when Victoria is exporting, jointly with Transgrid.	Closed	AVP review of the existing IECS scheme for Victoria import conditions concluded that no changes will be applied to the current IECS scheme for the importing condition. For Victoria export conditions, AVP has completed the study and has provided recommendations to manage the risk.
2022 PSFRR Recommendation 3	To manage loss of both Columboola – Western Downs 275 kV lines: Powerlink to implement a new SPS under NER S5.1.8.	Ongoing	Powerlink is working the scheme design and settings which are in the process of being finalised. Currently the commissioning target is February 2026.
2022 PSFRR Recommendation 4a	Management of Queensland UFLS: Powerlink and Energy Queensland to identify and implement measures to restore UFLS load, and to collaborate with AEMO on the design and implementation of remediation measures.	Ongoing	AEMO will assess UFLS load as part of the 2025 NEM UFLS adequacy review.
2022 PSFRR Recommendation 5	Review of wide area monitoring protection and control (WAMPAC) scheme to mitigate risks associated with non-credible loss of Calvale – Halys 275 kV lines: Powerlink to review the adequacy of WAMPAC to manage increased risks due to QNI transfers increases following QNI upgrade (tranche 2).	Ongoing	Powerlink is currently reassessing the non-credible contingencies for Central Queensland (CQ) and South Queensland (SQ) SPS settings, taking account of the revised composite and distributed energy resources load model.
2022 PSFRR Recommendation 6	Further work is required to mitigate risks associated with reduced effectiveness of UFLS schemes as reported in the 2020 PSFRR: To address the impact of distributed PV growth on UFLS. To restore EUFR to as close as possible to the level of 60% of underlying load at all times.	Ongoing	NSPs, in collaboration with AEMO, have extensive current and planned initiatives to improve the efficacy of UFLS. These are discussed extensively Sections 6.2 and 6.3 of the 2025 GPSRR.

Report	Recommendation	Status	Update
	NSPs to investigate measures to remediate the impacts of 'reverse' UFLS operation.		
2022 PSFRR Recommendation 9	Manage risks associated with large generation ramping events in South Australia.	Ongoing	The ramping event risk due to solar generation is being managed through the Reclassification Criteria in the PSSG. AEMO has also been engaging with weather forecast providers to create and enhance products to capture these ramping risks. Any further risks and developments to manage these potential abnormal events will be considered for inclusion in the PSSG.
2022 PSFRR Recommendation 10	Manage risks associated with non-credible loss of future North Ballarat – Sydenham 500 kV lines.	Closed	The preferred option has been updated to include a new 500 kV line between Bulgana and Sydenham, instead of North Ballarat and Sydenham. AVP's preliminary analysis concluded that there is no need for an SPS to manage system loading levels following a non-credible event on the Bulgana – Sydenham 500 kV lines.
2023 GPSRR Recommendation 2	Given the potentially significant impact QNI instability could have on the NEM, AEMO recommends that Powerlink and Transgrid investigate, design and implement an 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.	Ongoing	A working group comprising of AEMO, Powerlink, Transgrid, AVP and ElectraNet is set up to address this issue. Powerlink has completed initial studies and concluded that QNI stability can be preserved if sufficient load is tripped in the same region as the initiating generation contingency. The stability criteria and dispatch conditions for the study have been finalised and AEMO is progressing with developing base cases for studies and study scope document.
2023 GPSRR Recommendation 3	Given the potential for Moorabool contingency events to result in separation of the mainland NEM into four islanded areas, AEMO recommends that AEMO, 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.	Ongoing	For South Australian export: Work is underway to develop a new scheme to trip APD only under certain network conditions to fill the gap of the SAIT RAS design. This will also include a review and modification of the existing EAPT. For South Australian import: Work is underway to develop a new scheme to trip Non-Generator Fast Tripping scheme generation under certain network condition to fill the gaps of SAIT RAS design.
2023 GPSRR 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.	Ongoing	Refer to Section 5.1 for more information.
2023 GPSRR 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.	Ongoing	AEMO is currently following up with NSPs around initiatives taken to reduce the emerging capability gaps in operational capability.
2023 GPSRR 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.	Ongoing	AEMO is currently following up with NSPs around risks identified under NER S5.1.8 and the need for associated remedial actions.
2023 GPSRR 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	Ongoing	AEMO, EnergyCo and Transgrid are working on WSB SIPS to manage non- credible contingencies following potential Eraring Power Station closure.

Report	Recommendation	Status	Update
	share its investigation findings with AEMO for consideration in future GPSRRs.		
2023 GPSRR Recommendation 8	AEMO to finalise the development of an updated strategy for the overall co-ordination of generator over frequency protection settings.	Closed	AEMO has finalised the strategy document.
2023 GPSRR Recommendation 9	AEMO to review the protected event and reclassification frameworks by Q4 2023. As part of this review, AEMO will consider the submission of a rule change proposal to enhance the protected event framework.	Closed	AEMO has completed a review of the protected event and reclassification framework and concluded that rule change proposal submission is not required at this time.
2024 GPSRR Recommendation 1	Given the criticality of the site for system reliability as well as system strength and security, AEMO recommends that AVP design and implement a suitable solution to improve the overall resilience of the Loy Yang substation as a priority and share its findings with AEMO for consideration in future GPSRRs.	Ongoing	AVP is in the process of investigating options to address this risk.
2024 GPSRR Recommendation 2	Given the potentially significant impact of non-credible loss of HumeLink 500 kV circuits during times of high northerly flows, AEMO recommends implementing cost-effective measures to minimise the probability the risk. If a scheme is found viable, Transgrid to implement an emergency control scheme to mitigate risks associated with voltage collapse in the Bannaby area.	Ongoing	Transgrid has implemented design changes to reduce the likelihood of failure, however, the consequence of this risk remains significant. Transgrid is also undertaking ongoing study work and has determined that a much smaller SPS could be implemented to provide for network stability. Transgrid is also conducting studies which will investigate Snowy 2.0 in pumping mode.
2024 GPSRR Recommendation 3	AEMO recommends that NSPs outside South Australia, in conjunction with AEMO, investigate (and implement wherever possible) low-cost measures, such as dynamic arming, to restore UFLS availability in addition to the existing and planned projects/initiatives.	Ongoing	AEMO is currently following up with NSPs around the dynamic arming project, including costs, approvals, and SCADA points. AEMO will also carry out a NEM UFLS adequacy review in the second part of 2025. This review will shed more light on the urgency of dynamic arming implementation in regions.
2024 GPSRR Recommendation 4	AEMO anticipates significant operational challenges to emerge as thermal generating units retire and will develop operational procedures for scenarios where insufficient synchronous units are available for AEMO to direct to meet the minimum regional system strength requirements. This will include a BowTie risk assessment that incorporates the appropriate limit advice and contingency plans from NSPs.	Ongoing	Refer to Section 5.1 for more information.
2024 GPSRR Recommendation 5	Evaluating post PEC-S1 operational mitigations for non-credible loss of Heywood, there is currently a constraint which limits import into South Australia over the Heywood interconnector. Given PEC-S1 will be inter-tripped for the non-credible loss of the Heywood Interconnector, these constraints will remain in place following commissioning of PEC-S1.	Closed	This recommendation provided information to participants that the Heywood Interconnector import into South Australia constraint will remain in place following commissioning of PEC-S1.
2024 GPSRR Recommendation 6	UFLS data quality: AEMO strongly recommends real-time visibility of UFLS availability is established in all mainland NEM regions (similar to that which exists for South Australia). Given escalating operational risks, AEMO recommends this occur without delay.	Ongoing	AEMO is currently following up with NSPs around initiatives taken to establish real-time visibility of UFLS availability in all mainland NEM regions. The 2025 NEM UFLS adequacy review will also assess the risk.
2024 GPSRR Recommendation 7	Updates to UFLS schedules and procedures: AEMO recommends that NSPs work with AEMO to provide up-to-date and accurate UFLS availability	Ongoing	AEMO has completed the UFLS schedule and procedures update in Q4 2024. The regional schedules will be regularly updated with new

Report	Recommendation	Status	Update
	information to support AEMO's review of UFLS adequacy.		information. AEMO is currently working on creating a user-friendly dashboard.
2024 GPSRR Recommendation 8	UFLS scheme review: Consolidate the 121 UFLS bands in New South Wales to reduce (unnecessary) complexity. Review the QNI inhibit scheme to ensure it remains effective at preventing QNI instability for remote frequency disturbances south of Queensland.	Ongoing	Transgrid will consider the consolidation of bands in near future. AEMO will review the QNI Inhibit scheme as part of the NEM 2025 UFLS Adequacy Review.
2024 GPSRR Recommendation 9	RAS Guidelines review: Given the growing number and complexity of NEM RASs, AEMO recommends that, as part of the existing obligations under NER S5.1.8 and 5.14, NSPs in collaboration with AEMO engage in extensive and detailed joint planning to review the RAS Guidelines.	Ongoing	AEMO is working on the review of RAS Guidelines.
2024 GPSRR Recommendation 10	To reduce the number of transmission line trips due to lightning in South Australia, AEMO recommends that ElectraNet investigate South Australia transmission tower earthing and lightning protection based on recent contingency events to identify or rule out any existing design weaknesses. Additionally, AEMO recommends, in accordance with NER S5.1.8, that ElectraNet investigates the suitability of a RAS to prevent South Australia intra-regional separation.	Ongoing	ElectraNet has commenced system studies to look at the potential design for a control scheme to prevent South Australia intra-regional separation. In addition, ElectraNet is currently working on RIT-T for Mid North REZ, which may address the same risk.
2024 GPSRR Recommendation 11	Managing risks associated with localised aggregated BESS response to remote frequency disturbances. AEMO is working with ElectraNet to consider suitable remedial measures to address this risk, such as those detailed in Section 6.14.2.	Closed	AEMO has completed the assessment of this risk as a part of the 2025 GPSRR.

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Abbreviations and key terms

Abbreviation	Term	Abbreviation	Term
AC	alternating current	LOR	lack of reserve
AEMC	Australian Energy Market Commission	LOS	loss of synchronism
AER	Australian Energy Regulator	ms	millisecond/s
AESCSF	Australian Energy Sector Cyber Security Framework	MSL	minimum system load
AMI	advanced metering infrastructure	MW	megawatt/s
AMP	AEMO modelling platform	NBN	National Broadband Network
APR	annual planning report/s	NEM	National Electricity Market
ASEFS3	Australian Solar Energy Forecasting System Phase 3	NER	National Electricity Rules (NER followed by a number indicates that numbered rule or clause of the NER)
AVP	AEMO Victorian Planning	NSP	Network Service Provider
BESS	battery energy storage system/s	OEM	original equipment manufacturer/s
CER	consumer energy resources	OFGS	over-frequency generation shedding
CMLD	composite load model	PASA	projected assessment of system adequacy
CQ	Central Queensland	PD	pre-dispatch
DER	distributed energy resources	PEC	Project EnergyConnect
DNSP	Distribution Network Service Provider	PEC-S1	PEC Stage 1
EAPT	Emergency Alcoa-Portland Potline Tripping	PEC-S2	PEC Stage 2
EFCS	emergency frequency control scheme	PFR	primary frequency response
EMT	electromagnetic transient	PMU	phasor measurement unit
EUFR	emergency under frequency response	POD	power oscillation damper/s
FCAS	frequency control ancillary services	PSCAD™	Power System Computer Aided Design
FCSPS	frequency control system protection scheme	PSFRR	power system frequency risk review
FFR	fast frequency response	PSS®E	Power System Simulation for Engineering
FOS	frequency operating standard	PSSG	Power System Security Guidelines
GPSRR	general power system risk review	PSSWG	Power System Security Working Group
GPS	generator performance standard/s	PV	photovoltaic/s
GW	gigawatt/s	QNI	Queensland – New South Wales Interconnector
Hz	hertz	RAS	remedial action scheme
IBR	inverter-based resources	REZ	renewable energy zone
IECS	interconnector emergency control scheme	RIT-T	regulatory investment test for transmission
ISF	improving security frameworks	RMS	root mean squared
ISP	*Integrated System Plan*	RoCoF	rate of change of frequency
IT	information technology	RUG	releasable user guide
JSSC	Jurisdictional System Security Coordinator	SAIT RAS	South Australia Interconnector Trip Remedial Action Scheme
kV	kilovolt/s	SCADA	supervisory control and data acquisition
kVA	kilovolt ampere/s	SIPS	system integrity protection scheme

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Abbreviation	Term	Abbreviation	Term
SISC	System Integration Steering Committee	TOA	temporary operating advice
SOCI	security of critical infrastructure	TUoS	Transmission Use of System
SPS	special protection scheme/s	VEEC	Victorian Electricity Emergency Committee
SQ	South Queensland	VNI	Victoria – New South Wales Interconnector
SRAS	system restart ancillary services	VPP	virtual power plant/s
SSSP	System Strength Service Provider/s	VRE	variable renewable energy
ST	short term	WAMPAC	wide area monitoring protection and control
STATCOM	static synchronous compensator/s	WAMS	wide area monitoring scheme
SVC	static volt-ampere reactive compensator/s	WAPS	wide area protection scheme
SYTS	Sydenham Terminal Station	WEM	Wholesale Electricity Market
TI	trading interval	WSB	Waratah Super Battery
TNSP	Transmission Network Service Provider	TOA	temporary operating advice

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified. The table of simplified meanings below is for ease of reference and these are not exact transcriptions of the NER definitions.

Term	Definition
Satisfactory operating state	The power system is in a satisfactory operating state when all of the following apply: • 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 both: • 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 (for example, a 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.

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