

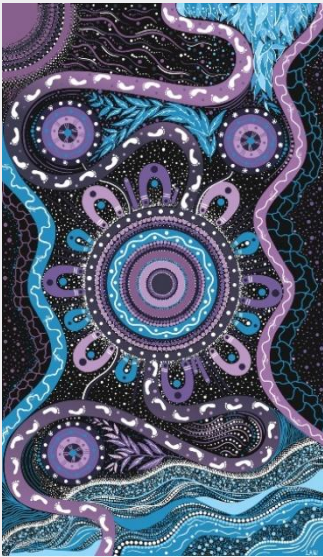
# 2026 GPSRR Approach Paper – Draft

October 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 the 2026 General Power System Risk Review (2026 GPSRR) approach paper under clause 5.20A.2(c)(3) of the National Electricity Rules.

### Disclaimer

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# 1 Introduction

## 1.1 Purpose and invitation for submissions

In accordance with rule 5.20A of the National Electricity Rules (NER), AEMO is required to undertake a General Power System Risk Review (GPSRR) and prepare a GPSRR report for the National Electricity Market (NEM) at least annually. The latest GPSRR report<sup>1</sup> was published on 31 July 2025.

AEMO has commenced the 2026 GPSRR and plans to publish the 2026 GPSRR report by 31 July 2026.

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

The purpose of the GPSRR is to review:

- a prioritised set of risks comprising of credible or non-credible contingency events and other events and conditions that could lead to cascading outages or major supply disruptions,
- the current arrangements for managing the identified priority risks and options for their future management,
- the arrangements for management of existing protected events and consideration of any changes or revocation, and
- the performance of existing emergency frequency control schemes (EFCS) and the need for any modifications.

In addition to the identified priority risks, the GPSRR will also summarise key activities related to other power system risks that AEMO is currently undertaking.

This document is the approach paper published by AEMO for consultation on:

- the prioritised set of risks that AEMO plans to review in the 2026 GPSRR (see Section 2),
- the approach, methodologies, information, and assumptions AEMO proposes to use in assessing the priority risks (see Sections 2, 3, 4 and 5), and
- AEMO's proposal to consult with relevant parties throughout the review (see Section 6).

AEMO has prepared this approach paper with inputs from network service providers (NSPs) and industry on potential priority risks, and their initial feedback on the assessment method. In addition to consultation with NSPs, AEMO undertook a review of potential risks based on operational experience, recent power system events and anticipated power system changes. The approach paper also includes a high-level description of the work planned to address the other core elements of the GPSRR.

Submissions are now invited on this approach paper from interested parties and may be made by email to [gpsrr@aemo.com.au](mailto:gpsrr@aemo.com.au) by **12 November 2025**.

AEMO is particularly seeking feedback on the proposed priority risks, and the assessment methodology, inputs and assumptions. Please note that relevant submissions will be published, except for material identified as confidential, and

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<sup>1</sup> See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review>.

should be consistent with AEMO's consultation submission guidelines<sup>2</sup>. AEMO may additionally or alternatively elect to summarise the substance of relevant issues raised that are common across multiple submissions.

Please identify any parts of your submission that you wish to remain confidential and explain why. AEMO may still publish that information if it does not consider it to be confidential but will consult with you before doing so. Material identified as confidential may be given less weight in the decision-making process than material that is published.

Submissions received after the closing date and time will not be valid, and AEMO is not obliged to consider them. Any late submissions should explain the reason for lateness and the detriment to you if AEMO does not consider your submission.

## 1.2 List of key consultation questions

Table 1 outlines key areas of this approach paper on which AEMO is seeking industry feedback. AEMO also welcomes feedback on any other aspect of the proposed approach described in this paper.

**Table 1 Key consultation questions**

Question	Section
1. What are stakeholder views on the proposed priority risks and the associated approach and methodology for assessment in the 2026 GPSRR?	Section 2.1
2. Are there any other current and emerging system operator risks that may lead to cascading failure or major supply disruptions that should be included for discussion in the 2026 GPSRR?	Section 2.2
3. Are there any suggested improvements regarding the risk assessment methodology?	Section 1
4. What are stakeholder views regarding the proposed modelling approach for the priority risks for assessment in the 2026 GPSRR?	Section 3
5. What are stakeholder views regarding the proposed risk cost assessment methodology to be applied in the 2026 GPSRR?	Section 5
6. Does the proposed consultation approach meet stakeholder expectations and do stakeholders have any suggestions on how AEMO could best engage with industry on the development of the 2026 GPSRR?	Section 6

<sup>2</sup> See [https://aemo.com.au/-/media/files/stakeholder\\_consultation/working\\_groups/industry\\_meeting\\_schedule/aemo-consultation-submission-guidelines---march-2023.pdf?la=en](https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/industry_meeting_schedule/aemo-consultation-submission-guidelines---march-2023.pdf?la=en).

## 2 Priority risks to be assessed

### 2.1 Proposed priority risks to be assessed

AEMO has reviewed the risks identified under the 2026 GPSRR risk assessment process and has proposed key events or conditions from the candidate list as priority risks that could lead to cascading outages or major supply disruptions for assessment in the 2026 GPSRR:

- **Emerging risks associated with increasing large load connections**
- **Non-credible system strength risks associated with unavailability of synchronous machines.**
- **Large non-credible generation contingency events.**
- **Voltage control risks.**

In identifying the risks listed above as priority risks, AEMO has had regard to:

- the likely power system impact and estimated probability of occurrence of the risks,
- details of any review/work previously completed to understand or manage the risks,
- any changes to power system conditions or other factors which may have materially changed the risk profile, and
- whether the risks have been reviewed previously as part of AEMO's risk review process (under a recent Power System Frequency Risk Review [PSFRR] or GPSRR).

The proposed priority risks are targeted for study against historical and future operating conditions, typically considering a timeframe up to five years in the future. For the 2026 GPSRR, this includes consideration up to 1 July 2030.

Further details on the proposed priority risks are provided in the sections below.

#### Priority Risk 1 – Emerging risks associated with increasing large load connections

**There is increasing interest in the connection of large loads, which may change how the power system is operated, but will also provide opportunities and benefits to the NEM.** There is an expectation that a growing number of new large loads will connect to the NEM in coming years, introducing potential differences in operational characteristics compared to current connections. While this will require focused efforts to achieve successful integration, there are significant power system benefits associated with these new large loads that must be considered. Some of the benefits include the potential to offer services such as demand response, frequency control ancillary services (FCAS), inertia and system strength. Large loads will also take on a portion of network costs that may otherwise be borne by other energy consumers.

**There are some emerging changes in power system characteristics associated with the rapid emergence of large loads in the NEM, particularly with inverter-based loads that are sensitive to voltage disturbances.**

To successfully integrate new large loads into the NEM, there are several considerations. One such consideration is that high concentration of voltage-sensitive large loads poses a risk that disturbances may lead to the simultaneous disconnection of multiple large loads, resulting in significant frequency and voltage excursions. If not accounted for, these events may exceed the capacity of existing FCAS, potentially triggering over-frequency generator shedding (OFGS) or other cascading failures under extreme scenarios.

**Other challenges to be considered include operational behaviours of large loads that may impact the operation of the power system, such as demand ramping or the introduction of forced oscillations.** Rapid demand ramping can limit the availability of FCAS or contribute to interconnectors exceeding their scheduled values, reducing system resilience and increasing the severity of contingency events in the NEM. Sub-synchronous oscillations may also be introduced as a result of periodic ramping up and down of demand from tasks such as batch processing or artificial intelligence (AI) model training. These oscillations can interact with nearby plant and potentially cause mechanical stress or reduced operational lifespan.

**There are a number of workstreams currently contributing to the shared understanding of the benefits and potential risks associated with increasing large load connections.**

Outside of the GPSRR, large load connections are being investigated through the following workstreams:

- The AEMC’s Improving the NEM Access Standards (Package 2) Review, with a draft determination targeted for publication in March 2026.
- AEMO’s development of an interim assessment approach for data centres, with a draft approach to be published in January 2026.
- AEMO’s targeted review of access standards for large loads, which will build on the AEMC’s review, with an approach paper targeted for publication in April 2026. Engagement with NSPs, OEMs, Developers and international System Operators has already begun to inform this review.

The 2026 GPSRR also intends to investigate the risks which may emerge if appropriate proactive or mitigation measures are not implemented. This is planned to be achieved by:

- **Investigating large load contingency sizes associated with typical protection settings.** Power System Simulation for Engineering (PSS®E) studies will be completed assessing the size of large load disconnection considering various fault locations, fault types and large load ride-through performance and protection settings.
- **Assessing the impact of large load reconnection.** After large loads disconnect for a fault, the post-fault reconnection may have similarly significant impacts. PSS®E studies are proposed to assess these impacts and investigate the effects of limiting the reconnection ramp rate.
- **Studying the potential for forced oscillations to impact the network.** Power System Computer Aided Design (PSCAD)™ is proposed to demonstrate issues that can arise for oscillations generated at various frequencies. This is intended to highlight potential interactions that could be considered in load access standards.
- **Desktop review of international experience including events relating to large loads.** Under the International System Operator Network (ISON), AEMO is actively collaborating with other system operators on large loads. The 2026 GPSRR proposes to cover an international review of major incidents related to large loads and commentary on mitigation approaches in other networks. Additionally, a comparison of proposed load access standards across different system operators will also be completed.
- **Discussing other operational and connections risks associated with large loads.** Other risks associated with large loads will be discussed qualitatively to describe the potential impacts and risks associated with large load connections.

**Table 2 Risk 1 overview**

Risk	Emerging risks associated with increasing large load connections
Likelihood	Possible (annual probability >20% - 50%)

Risk	Emerging risks associated with increasing large load connections
	<ul style="list-style-type: none"> <li>• Significant pipeline of large inverter-based loads projected to connect to the NEM within the next five years and beyond.</li> <li>• Ride-through requirements for loads are not specified in detail in the NEM.</li> <li>• Modelling for large loads is not advanced, resulting in uncertainty in analysis and expected performance.</li> <li>• Large loads connected in other networks are known to switch to uninterruptible power supplies (UPS) for voltage disturbances.</li> <li>• Loads may connect in similar areas, increasing the likelihood of a power system fault affecting multiple connections.</li> </ul>
Impact	<p><b>Extreme (loss of supply to a state(s), for any duration)</b></p> <ul style="list-style-type: none"> <li>• Projected connections of new large loads are expected to exceed the current largest load contingency size in the NEM.</li> <li>• Significant voltage disturbances have the potential to affect multiple loads simultaneously, causing shake-off of large loads and significant quantities of residential load.</li> <li>• Voltage control of the network will be more difficult, particularly when large inverter-based loads disconnect or reconnect suddenly.</li> <li>• Fast ramp rate of new inverter-based loads within a trading interval will impact availability of FCAS, interconnector drift or upstream constraints.</li> <li>• Forced oscillations from load cycling may propagate through the network.</li> </ul>
Risk conditions	<p>Based on future scenarios, the following risk conditions will be assessed:</p> <ul style="list-style-type: none"> <li>• Increasing projected large load connections, particularly high concentration of connections in New South Wales and Victoria.</li> <li>• High interconnector flows out of New South Wales for New South Wales load contingencies.</li> <li>• High interconnector flows out of Victoria for Victorian load contingencies.</li> <li>• High and low NEM demand.</li> <li>• Low primary frequency response availability from other plant.</li> <li>• Minimum system load conditions.</li> <li>• Low synchronous generation/inertia.</li> </ul>
Existing management strategies	Existing load connection processes.
Potential solutions	Mitigation measures for this issue are being considered through the <i>Improving the NEM access standards – Package 2</i> rule change. Studies undertaken through the 2026 GPSRR will inform certain technical requirements such as voltage ride through settings.
Study software	PSS®E (full NEM model)
Risk raised by	AEMO, AusNet, ElectraNet, Jemena, Transgrid

## Priority Risk 2 – Non-credible system strength risks associated with unavailability of synchronous machines

**System strength risks may be present due to unavailability of synchronous machines through retirement, decommitment or planned and unplanned outages.** As the energy transition progresses, the planned retirement or decommitment of major synchronous generators introduces the potential for system strength risks that may require additional remediation measures. The availability of synchronous machines plays a critical role in maintaining system strength and ensuring the resilience of the power system under both credible and non-credible contingency conditions. While these risks are currently managed through the existing system strength framework and the *Transition Plan for System Security*, system strength risks may be further compounded if multiple planned or unplanned outages were to occur. It has already been noted that several synchronous generators have concurrent planned outages in 2027 post synchronous generation retirement, which will impact system strength and operability.

**AEMO has considered credible system strength requirements post coal withdrawal and is now considering non-credible impacts.** AEMO has already completed significant work regarding the near-term operational requirements post withdrawal

of coal generation. However, AEMO has identified that there is a need to further understand the low probability, but high consequence, outcomes that could be associated with non-credible contingencies or further long-term outages of synchronous generation or synchronous condensers.

**Several factors contribute to the increased likelihood and consequence of this risk:**

- The retirement or unavailability of synchronous generation reduces average synchronous fault levels, which may increase the risk of instability following significant non-credible contingencies, or impact the operation of protection systems.
- In low system strength conditions, inverter-based resources (IBR) or synchronous machines may fail to stably ride through large disturbances, exacerbating the impact of non-credible contingencies and contributing to an increased likelihood of cascading failure.
- Any delays in the delivery of synchronous condensers, or further outages of synchronous generation, will increase operational complexity and increase potential system strength risks.

**Studies are proposed in the 2026 GPSRR to assess the impact of non-credible contingencies post coal retirement or decommitment under several scenarios.** It is planned to include:

- **Assessment of system response and fault ride-through performance of IBR under non-credible contingency events.** PSCAD™ studies are proposed to assess system impacts for non-credible contingencies in low synchronous unit dispatch scenarios post- retirement or decommitment of large synchronous generation in 2027 or 2028.
- **Investigation of the operational impacts arising from further outages or delayed delivery of infrastructure.** Various scenarios would be considered to further understand the resilience of the system and how sensitive it is to any further outages or delays in delivery of transmission infrastructure such as generation, transmission or synchronous condensers. Operational actions that are required to meet system security will be considered.
- **Discussion on the potential for unserved energy events.** In operating conditions where inadequate levels of synchronous generation are available, this increases the likelihood of being unable to dispatch available IBR generation. If this occurs during times of higher operational demand, there may be scenarios where significant non-credible contingencies may result in unserved energy.

**Table 3 Risk 2 overview**

Risk	Non-credible system strength risks associated with unavailability of synchronous machines
Likelihood	<p><b>Unlikely (annual probability &gt;5% - 20%)</b></p> <ul style="list-style-type: none"> <li>• Several large generators are expected to retire in the near future. Any further planned or unplanned outages will result in more frequent conditions where significant contingencies could lead to system strength issues.</li> <li>• Synchronous generation lifetime extensions may not mitigate this risk as the likelihood of failure or extended outages increases as operating time continues.</li> <li>• Any delays in the delivery of synchronous condensers, transmission infrastructure or other remedial measures due to supply chain issues, regulatory processes or other factors will increase the operating time at low system strength conditions.</li> </ul>

Risk	Non-credible system strength risks associated with unavailability of synchronous machines
Impact	<p><b>Extreme (loss of supply to a state(s), for any duration)</b></p> <ul style="list-style-type: none"> <li>• Non-credible contingencies may lead to significant system strength impacts with more severe consequences in a system with reduced resilience.</li> <li>• IBR plant may not ride through contingencies that reduce system strength, leading to unexpected behaviour or cascading failures.</li> <li>• Insufficient fault levels for reliable operation of protection systems, resulting in the need for directions or load shedding to restore system security.</li> <li>• Operability of the network will be constrained as synchronous machines retire or are unavailable due to outages.</li> <li>• Response of aging synchronous plants may be unreliable during significant contingency events, potentially leading to cascading failure.</li> <li>• Reduced system resilience and greater propagation of voltage depressions during faults, leading to more widespread impacts.</li> </ul>
Risk conditions	<ul style="list-style-type: none"> <li>• Large power station retirements.</li> <li>• Further planned or unplanned synchronous generator or network outages.</li> <li>• Delayed delivery of system strength remediation measures such as synchronous condensers.</li> <li>• High and low NEM demand.</li> <li>• Low synchronous generation/inertia.</li> <li>• High IBR generation.</li> </ul>
Existing management strategies	Synchronous condensers, synchronous generation lifetime extensions or staged retirement, curtailment of IBR or utilisation of BESS.
Potential solutions	<p>Solutions may be identified as a result of studies and analysis that will be undertaken via the 2026 GPSRR process. This will include assessment of the following:</p> <ul style="list-style-type: none"> <li>• Non-credible contingency and IBR risks associated with unavailability of synchronous generation.</li> <li>• Impact on delays to system strength remediation measures such as synchronous condensers.</li> <li>• Impacts of outages of synchronous generation on system strength and resilience.</li> <li>• Opportunities relating to the existing generation fleet, such as enabling operation in synchronous condenser mode.</li> </ul> <p>Solutions may include:</p> <ul style="list-style-type: none"> <li>• Increased list of generators in minimum generation combinations to allow greater operational flexibility</li> <li>• Protected events</li> <li>• Remedial action schemes (RASS) to manage unstable IBR response.</li> <li>• Assessment of suitability of grid forming IBR.</li> </ul>
Study software	PSCAD™ (four state model)
Risk raised by	AEMO, Transgrid

### Priority Risk 3 – Large non-credible generation contingency events

As the power system continues to evolve, the risks associated with large non-credible generation contingency events are requiring increased focus. The connection of large amounts of new generation is underway as the energy transition progresses, connecting through new renewable energy zones (REZs), existing transmission lines or via new transmission infrastructure. Non-credible contingency risks may increase if these large quantities of generation are located behind common assets that could fail under rare circumstances.

These non-credible contingencies could occur in a number of ways, including but not limited to:

- A double circuit tower failure event that results in the loss of two transmission lines.
- Loss of multiple towers within the same easement, resulting in the loss of two or more transmission lines.
- A circuit breaker failure event that results in loss of multiple generators at once.

- A busbar fault, resulting in multiple circuit breaker operations at a terminal station or substation.
- Shared asset risk such as a common coal mine shared by multiple coal generators.
- Type faults that may result in the widespread failure of a single type of inverter after firmware updates.
- Single point of failure risks associated with third parties that control large quantities of aggregated generation (e.g. bidding and central dispatch software or similar).
- Inadvertent operation of a power plant controller (PPC) managing multiple connection points.

**While there are currently some mitigation measures in place to manage significant non-credible contingencies, their effectiveness may reduce if non-credible contingency sizes or the complexity of impacts increase.** Typically, mitigation measures such as RASs, protected events and emergency frequency control schemes (including under frequency load shedding [UFLS]) are utilised to manage critical non-credible contingency risks that are assessed to have significant impacts. However, as non-credible contingency sizes increase, the complexity of the required RAS, the volume of load required to be tripped, the capacity of batteries that need to ramp up output in response, or the requirements for the protected event may introduce unacceptable risks or limitations.

**The 2026 GPSRR intends to undertake quantitative analysis to assess this risk in detail.** Large non-credible generation contingencies are proposed to be considered under the 2026 GPSRR as follows:

- **PSS<sup>®</sup>E studies undertaken to assess the impacts of increasing non-credible contingency sizes in each region for historical and future cases.** Non-credible contingency events will be assessed to determine power system outcomes for a range of dispatch scenarios. This is proposed to involve applying a range of high impact non-credible contingencies that could occur in the current or future system. This may involve the loss of multiple lines or towers, circuit breaker failure events, loss of multiple generating units or other similar non-credible contingencies. Additionally, sensitivities will be completed where an increasingly sized hypothetical generator will be disconnected to find the range of instability if it is not found prior.
- **PSS<sup>®</sup>E sensitivities will be completed on the effectiveness of mitigation measures such as increased FCAS, non-credible contingency size limits, RAS, protected events and EFCS.** Investigation of other potential risk mitigation measures and their effectiveness will be undertaken to determine potential risk mitigation options.

As a result of this analysis, it is intended to demonstrate the range of sizes of non-credible contingency event that may result in instability in each region and to comment on the effectiveness of potential mitigation options.

**Table 4 Risk 3 overview**

Risk	Large non-credible generation contingency events
Likelihood	<p><b>Unlikely (annual probability &gt;5% - 20%)</b></p> <ul style="list-style-type: none"> <li>• Several recent historical occurrences across the NEM, driven by changing weather conditions.</li> <li>• Addition of new generation to existing or new double circuit transmission lines.</li> <li>• Large new REZ connections to the NEM connected via double circuit lines.</li> <li>• Progressive withdrawal of synchronous generation, contributing to declining system strength and inertia.</li> <li>• Increasing penetration of distributed photovoltaics (DPV), contributing to increased contingency sizes due to the associated DPV shake-off that can occur during other large contingency events.</li> </ul>
Impact	<p><b>Extreme (loss of supply to a state(s) for any duration.)</b></p> <ul style="list-style-type: none"> <li>• Increasing contingency sizes may be too large or complex for remedial action schemes to mitigate, leading to cascading failure and system instability.</li> </ul>

Risk	Large non-credible generation contingency events
	<ul style="list-style-type: none"> <li>• Large changes in inter-regional flows leading to instability on interconnectors.</li> <li>• Significant non-credible contingencies may result in frequency instability that cannot be arrested by UFLS or OFGS.</li> <li>• Potential for cascading failures for significant system events, particularly related to system strength.</li> </ul>
Risk conditions	<ul style="list-style-type: none"> <li>• Retirement of synchronous generation.</li> <li>• High interconnector flows.</li> <li>• Low system strength and inertia.</li> <li>• High and low NEM demand.</li> <li>• Severe weather conditions.</li> <li>• Increased loading of existing transmission corridors.</li> <li>• High capacity transmission corridors or cutsets to centralised generation.</li> <li>• Increase in DPV.</li> <li>• Declining resilience.</li> </ul>
Existing management strategies	NER S5.1.8 requirements, RAS, reclassification framework, EFCS, protected event.
Potential solutions	<p>Potential solutions may include:</p> <ul style="list-style-type: none"> <li>• Changes to access standards to limit non-credible contingency sizes for certain higher likelihood non-credible contingencies.</li> <li>• Remedial action schemes.</li> <li>• Increased FCAS.</li> <li>• Protected events.</li> <li>• UFLS review.</li> <li>• Emergency under frequency response (EUFR).</li> <li>• Further consideration of high impact, low probability events under the planning framework.</li> <li>• Increased system resilience through STATCOMs, static Var compensators (SVCs) and synchronous condensers.</li> <li>• Addition of grid forming BESS.</li> </ul>
Study approach	PSS®E (full NEM model)
Risk raised by	AEMO, AEMO Victorian Planning, ElectraNet, Transgrid

## Priority Risk 4 – Voltage control risks

**Voltage control risks are emerging as a focus area in the evolving power system landscape.** As the NEM transitions toward higher penetrations of IBR and declining average system strength, the ability to manage voltages under all operating conditions may become increasingly challenging. Potential reductions in dynamic reactive support, increasing DPV generation in the daytime, or variable renewable energy flows may all impact voltage profiles. Continued monitoring of this risk is required to identify any challenges that may have the potential to lead to major supply disruptions.

**The potential for inadequate voltage control to result in cascading failure in the NEM will be reviewed.** Recent international incidents have demonstrated how inadequate voltage control can trigger cascading generator disconnections and widespread instability. While the NEM may not be as exposed to the particular mode of failure that was seen in other networks internationally, there may still be potential for voltage control risks to result in similar consequences, particularly during conditions where voltages approach the limits of normal operating ranges.

The 2026 GPSRR plans to:

- **Qualitatively examine voltage control risks across the NEM, with a focus on identifying current and emerging risks and assessing the adequacy of current processes.** This is not proposed to include detailed studies but instead will provide commentary on the risks present and the potential consequences that may occur. This may include:

- A review of changes in reactive power reserves in various regions to identify where risk may be increasing.
- Discussion of risks that occur on the boundaries of operational zones, such as between transmission NSPs (TNSPs) and distribution NSPs (DNSPs).
- **Review potential mitigation options and identify further work or detailed analysis required where relevant.** Potential mitigation options will be discussed and if required, further quantitative analysis may be identified for work in a future GPSRR or other workstream.

**Table 5 Risk 4 overview**

Risk	Voltage control risks
Likelihood	<p><b>Unlikely (annual probability &gt;5% - 20%)</b></p> <ul style="list-style-type: none"> <li>• Overvoltage protection settings that have not been coordinated appropriately may result in cascading failures if voltages exceed the normal operating bands.</li> <li>• Insufficient dynamic reactive power response if large amounts of IBR failed to ride through faults that reduce system strength.</li> <li>• Large variations in voltage profile due to changes in variable renewable energy flows or DPV output.</li> <li>• Reduction in dynamic reactive support with planned or unplanned unavailability of synchronous generation.</li> <li>• The occurrence of large load or export contingencies, or operation of UFLS during certain operating conditions, could raise voltages in the system, contributing to voltage control and cascading failure risks.</li> <li>• Voltages outside of the normal operating range could lead to voltage sensitive inverter-based loads tripping and causing unexpected frequency events or instability.</li> <li>• Steady state voltage control issues arising from operational differences between daytime and nighttime requirements.</li> <li>• SVCs, synchronous condensers, STATCOMs and IBRs being tuned for strong system strength conditions may cause voltage system issues when operating in a system with reduced system strength.</li> </ul>
Impact	<p><b>Major (loss of supply to a large portion of a state, for any duration).</b></p> <ul style="list-style-type: none"> <li>• Voltage-led cascading failures of generators, leading to system instability and blackouts.</li> <li>• Reduced voltage stability margins, leading to instability on interconnectors or voltage collapse.</li> <li>• Potential undamped oscillations from synchronous condensers or from control interactions between grid forming and grid following inverters.</li> <li>• Damage to primary insulation with the potential to delay restoration of supply.</li> </ul>
Risk conditions	<p>Various, including:</p> <ul style="list-style-type: none"> <li>• High and low NEM demand.</li> <li>• Low system strength and inertia.</li> <li>• High and low quantities of IBR online for dynamic reactive power support.</li> <li>• Lack of coordination of generator voltage protection settings.</li> <li>• High or rapidly changing demand from inverter-based loads.</li> </ul>
Existing management strategies	Existing voltage control responsibilities within operational zones, existing network support agreements (NSA) and Improving Security Frameworks (ISF) solutions.
Potential solutions	Reviews of overvoltage protection settings, EFCS, generator reactive power requirements, TNSP voltage planning standards, improved AEMO VAR dispatch effectiveness, oscillation detection tools, IBR fault ride-through (FRT) and SVC tuning, defined performance standards for SVCs and STATCOMs.
Study approach	Desktop evaluation.
Risk raised by	AEMO

### Consultation question 1

What are stakeholder views on the proposed priority risks and the associated approach and methodology for assessment in the 2026 GPSRR?

## 2.2 Current and emerging system operator risks

In addition to the priority risks, AEMO also considers other current and emerging risks that were identified throughout the GPSRR risk assessment process. Updates on these risks are proposed to be provided in the 2026 GPSRR, covering:

- an overview of each current or emerging system operator risk, outlining the consequence and likelihood factors contributing to the risk,
- details on any actions or mitigation measures that are planned or underway, and
- where necessary, recommendations including the consideration of particular risks for the following year's GPSRR.

AEMO intends to discuss these current and emerging system operator risks in the report but does not plan to carry out additional studies. AEMO may also include additional commentary regarding whether systems and tools are fit for purpose to manage these risks.

Examples of the risks that may be included are provided in the list below:

- Communications risks, such as those related to monitoring, protection and control, market system and dispatch.
- Complexity or inadvertent operation risks associated with remedial action schemes.
- Consumer energy resources (CER) related risks.
- Cyber security risks.
- Declining system resilience.
- EFCS.
- Extreme weather conditions (including solar eclipse).
- Frequency regulation.
- Increasing complexity of limits.
- International experience of system operator risks.
- Maximum allowable active power ramp rates.
- Minimum system load (MSL) risks.
- Operational demand swings due to transient distributed photovoltaic (DPV) response.
- Performance gaps in grid-connected battery energy storage systems (BESS).
- Plant compliance and performance.
- Power system model accuracy, management and capability.
- Short notice closure of large loads.

- Small signal stability.
- System restart with a transitioning power system.
- System strength and inertia management.
- System strength in distribution networks.
- Third party forecasting, auto-bidding or other service provider risks.

Where risks were not selected for study, AEMO may consider them in future reviews or refer to relevant work underway by NSPs or AEMO to assess the risk.

### Consultation question 2

Are there any other current and emerging system operator risks that may lead to cascading failure or major supply disruptions that should be included for discussion in the 2026 GPSRR?

## 2.3 Other review tasks

The following activities are also within the scope of the 2026 GPSRR where relevant:

- Summary of key emergency under frequency management initiatives underway in each NEM region.
- Consideration of potential requests for declaration of new protected events, including cost benefit analysis.
- A status update for the recommendations from the 2025 GPSRR<sup>3</sup> and previous risk reviews.

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<sup>3</sup> See [https://aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2024/draft-2024-general-power-system-risk-review-report-consultation/2024-gpsrr.pdf?la=en](https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/draft-2024-general-power-system-risk-review-report-consultation/2024-gpsrr.pdf?la=en).

## 3 Risk assessment methodology

### 3.1 Priority risk identification

**The GPSRR takes in a range of inputs to determine priority risks for assessment.** Each year, the GPSRR highlights a number of priority risks that may lead to cascading failure or major supply disruptions to assess in detail through the annual GPSRR. The identification of risks for the GPSRR is an iterative process that draws on a broad range of inputs across the power industry.

Risk inputs are sourced from:

- TNSPs and DNSPs,
- internal AEMO teams,
- wider industry through formal consultation periods and engagements, and
- insights and recommendations from previous GPSRRs.

Formal requests for risk inputs commence prior to the publication of the previous year's GPSRR and continue through to the finalisation of the 2026 GPSRR Approach Paper.

**Once risk inputs are received, individual risks are reviewed and grouped into common themes.** This analysis assists in identifying overarching risks that may affect the power system more widely. For each theme, existing mitigation measures are reviewed and assessed for their effectiveness.

**Risks are then evaluated and ranked to determine the priority risks.** Finally, risks are ranked in priority order based on their assessed likelihood and consequence ratings, taking into account the effectiveness of any mitigation measures already in place. The top-ranked risks are designated as priority risks and will be assessed in detail. Risks that are not selected as priority risks will be considered for inclusion as current and emerging system operator risks, or for assessment as priority risks in a future GPSRR.

### 3.2 Priority risk identification factors

**Multiple factors are considered when determining the priority risks for the GPSRR.** When identifying contingency events or other events or conditions for assessment as priority risks in the 2026 GPSRR, AEMO had regard to the following key factors and sources of information<sup>4</sup>:

- The severity of the likely power system security outcomes if the events or conditions occur.
- The likelihood of occurrence.
- Whether technically and (on preliminary assessment) economically feasible management options are likely to be available.

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<sup>4</sup> As required by NER 5.20A.1(a1).

- Any regulatory requirements or obligations that may make management options difficult to implement.
- Any information provided by NSPs and Jurisdictional System Security Coordinators (JSSCs).
- If applicable, any findings or analysis from previous event investigation or reporting.
- Whether there are any current risk mitigation measures or processes in place to manage the event.
- The scope of work that is achievable within the publication timeframe of the final 2026 GPSRR report (by 31 July 2026).

Other relevant factors and how they contribute to the categorisation of risks are outlined in the following sections.

### 3.3 NSP consultation

#### **NSPs were consulted on potential events or conditions that may lead to cascading outages or major supply disruptions.**

To identify potential risks for priority assessment, AEMO asked each TNSP and DNSP to share with AEMO any:

- priority credible or non-credible contingency events that may result in uncontrolled changes in frequency leading to cascading outages, or major supply disruptions, and
- other events or conditions that would likely lead to cascading outages or supply disruptions.

**Information was provided to AEMO through detailed risk assessment documents.** To aid the collection and assessment of this information, AEMO requested NSPs to complete a risk assessment document providing the following information in relation to the nominated event or condition as applicable:

- A high-level description of the risk or non-credible contingency event that could lead to cascading outages or major supply disruptions.
- A primary risk category (see Table 6).
- A description of which network elements would trip if the event occurred.
- A description of which protection elements would be likely to operate if the event occurred.
- Details of any historical occurrences (or near misses).
- Details of any existing control or risk management strategies.
- Details of any planned augmentations that may affect the event or risk.
- An outline of the likely consequences of the event.
- Whether the event has the potential to cause cascading failures.
- Details of any previous studies or assessments of the event.
- The likelihood of the event occurring. Table 7 below outlines how likelihood was categorised for this risk assessment. A likelihood rating from 1 to 5 was assigned based on the likelihood category specified, where 1 was the lowest likelihood and 5 was the highest likelihood.
- Consequence. Table 8 below outlines how consequence was categorised for this risk assessment. A consequence rating from 1 to 5 was assigned based on the consequence category specified, where 1 was the lowest consequence, and 5 was the highest consequence.

An inherent risk rating was then calculated based on the likelihood and consequence of the event.

In addition to consultation with NSPs, AEMO undertook a review to identify potential priority risks based on its operational experience, recent power system events and anticipated power system changes (such as major transmission augmentations).

**Table 6 Risk categories**

Risk category	Description
Frequency risk	Any incident caused by unacceptable frequency conditions on the power system.
Voltage risk	Any incident caused by unacceptable voltage conditions on the power system.
Inertia risk	Any incident caused by a lack of system inertia; this lack of inertia could lead to a rate of change of frequency (RoCoF) event.
System strength services risk	Any incident caused by a lack of system strength services. This lack of availability could lead to system instability and/or protection maloperations.
Distributed energy risks	Any incident which is caused by distributed energy resources (DER). This could be DER disconnecting during a fault and leading to an excessive frequency change, or it could be an incident directly caused by the DER in an area.
RAS risks	Any incident which is caused by unexpected interactions or maloperation or non-operation of RAS systems.
Cyber security risks	Any incident which is caused by a malicious cyber attack.
IT risks	Any incident which is caused by an information technology (IT) failure (not a cyber attack).
Weather-related risks	Any incident caused by weather impacts such as flooding, lightning and storms.
Other	Any incident not categorised above.

**Table 7 Likelihood descriptions**

Likelihood	Likelihood rating	Annual probability	Qualitative description
Almost certain	5	>90%	Will occur in most circumstances; statistical record of several occurrences.
Likely	4	>50% - 90%	Can be expected to occur in most circumstances; statistical record of at least two or more occurrences.
Possible	3	>20% - 50%	May occur but not expected in most circumstances; statistical record of at least one occurrence.
Unlikely	2	>5% - 20%	Conceivable but unlikely to occur in any given year; may or may not have statistical history of occurrence
Rare	1	≤5%	Will only occur in exceptional circumstances; no history of occurrence.

**Table 8 Consequence descriptions**

Consequence	Consequence rating	Market and system impact
Extreme	5	Loss of supply to a state(s) for any duration. Market suspension of multiple markets for a prolonged period.
Major	4	Loss of supply to a large portion of a state, for any duration. Market suspension in one jurisdiction or market for a short period.
Moderate	3	Localised/minimal loss of supply in a state. Market(s) in administered state or material scheduling error.
Minor	2	Intervention required to maintain supply. Immaterial scheduling error (below dispute threshold).
Immaterial	1	No restriction of supply. No disruption to markets.

To determine the rating of risks considered in the GPSRR, the inherent risk rating was calculated as the product of the likelihood rating (1 to 5) and the consequence rating (1 to 5). The outcomes of this calculation are shown in Table 9.

**Table 9 Inherent risk rating matrix**

	Almost certain	Likely	Possible	Unlikely	Rare
Extreme	25	20	15	10	5
Major	20	16	12	8	4
Moderate	15	12	9	6	3
Minor	10	8	6	4	2
Immaterial	5	4	3	2	1

### Consultation question 3

Are there any suggested improvements regarding the risk assessment methodology proposed for the 2026 GPSRR?

## 3.4 Review of relevant system events since the 2025 GPSRR

In addition to the risks mentioned previously, AEMO will also consider significant system incidents. AEMO will identify all relevant system events that occurred in the previous FY 2024-25 in the 2026 GPSRR report. The findings and recommendations from these incidents will be considered in the 2026 GPSRR.

## 4 Models, input data and assumptions

Power system network models and input data requirements which will be used in assessing each priority risk for the 2026 GPSRR are discussed in this section of the approach paper. Where the assessment of credible or non-credible risks requires power system studies as part of the GPSRR, it is important that updated models of relevant systems are included and appropriate assumptions are made where information is unavailable.

### 4.1 Monitored parameters

**In addition to the specific focus areas of the study, a subset of key system parameters will be monitored in assessing the results of the GPSRR studies.** It is proposed that, where studies are undertaken for the 2026 GPSRR, the following system parameters will be considered when assessing the response of the power system for each priority risk:

- Violation of voltage and frequency operating standards.
- Performance of generators, fault ride-through (FRT) of the IBR units and DPV disconnections.
- Response of EFCS and RASs relevant to the contingency.
- Voltage, frequency, and transmission line flow instabilities.
- Indications in the results towards insufficiencies in system strength or inertia.
- High rate of change of frequency (RoCoF) conditions.

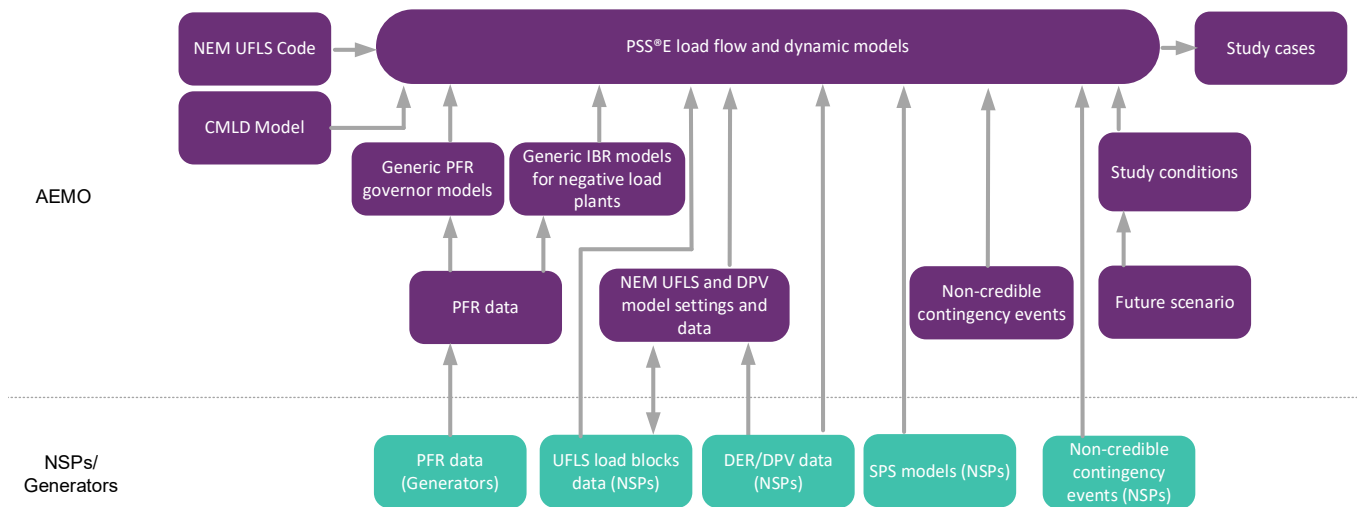
### 4.2 Study software

**Both PSCAD™ and PSS®E are proposed to be used for the 2026 GPSRR.** AEMO plans to use both the PSS®E full NEM network model and the NEM mainland Power System Computer Aided Design (PSCAD)™ model to assess relevant priority risks where a need for power system studies has been identified for the 2026 GPSRR. PSCAD™ will be used to assess contingency events where FRT behaviour of IBR may impact the assessment results. Events that are unlikely to be impacted will be studied in PSS®E. Further information is provided in Section 4.4.

### 4.3 2026 GPSRR model sources

2026 GPSRR model sources are shown in Figure 1.

Figure 1 2026 GPSRR model sources



PFR: primary frequency response.

## 4.4 Network models

### PSS®E full NEM network model

The full NEM network model will be used based on AEMO Modelling Platform (AMP) cases. This model is planned to be modified to include the new interconnectors, generation and network augmentations that are planned for completion for the time of the study.

Future dispatch conditions will be based on the 2024 *Integrated System Plan (ISP) Step Change* data but will review the latest information from the Draft 2026 ISP when available. As detailed in Section 4.11, future dispatch conditions are proposed to be based on the five-year 2024 ISP *Step Change* projection data. Key updates or changes that are outlined in the Draft 2026 ISP will also be taken into consideration. The key system forecast parameters planned to be considered in setting up the study cases are included in Table 2 to Table 5 (in Section 2.1). All studies are proposed to assume a system normal network configuration except where relevant to the study scenario<sup>5</sup>.

### NEM mainland PSCAD™ model

The four state NEM PSCAD™ model will be used to assess contingencies relating to system strength issues or IBR FRT. Consistent with the *System Strength Requirements Methodology*<sup>6</sup>, to assess contingencies relating to system strength issues or FRT behaviours of IBR, AEMO will conduct electromagnetic transient (EMT) analysis using the four state NEM PSCAD™ version 5 model. The key system parameters that will be considered in setting up the study cases are included in Table 2 to Table 5 (in Section 2.1). All studies will assume a system normal network configuration.

<sup>5</sup> System normal snapshots restore the nominal configuration of the network. Network outages (planned or unplanned) are restored to the nominal configuration while generation and load are retained as they were in the snapshot timestamp. In the future studies it is planned that the load and generation will be redispatched, and network projects will be added to match the forecast network conditions.

<sup>6</sup> See [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf).

## 4.5 Primary frequency response (PFR)

### 4.5.1 PFR applied settings

**PFR settings will be used where available to more accurately model generator performance.** PFR settings data applied to the generators are required to model generator frequency performance accurately. Where these settings are available to AEMO, they are proposed to be included in the model.

### 4.5.2 Units without governor models in AMP

**Generic governor models will be used for generating units where governor models are not available.** Many generating units have implemented new PFR settings, however updated governor models were not made available to AEMO in some instances. To address this issue, AEMO has developed three generic governor models corresponding to steam, hydro and gas turbines that represent governor response in line with new PFR settings during frequency events. These generic governor models are proposed to be used for the 2026 GPSRR studies.

### 4.5.3 Units with governor models in AMP

**Site-specific governor models will be used where available.** Generators have an ongoing obligation to provide NSPs and AEMO with up-to-date modelling information which encompasses all control systems that respond to voltage or frequency disturbances on the power system. AEMO has sent reminders to all large mainland NEM generators of their obligations to provide updated frequency control models, and the need for this information to support the GPSRR. Where this information is available, it will be used in the GPSRR studies. If updated site-specific information is not available, generic governor models with appropriate PFR settings are proposed to be used.

### 4.5.4 BESS models

**Site-specific BESS models will be used where available and generic BESS models will be used for plant with no site-specific model.** For future committed projects, site-specific models are planned to be used where they are available. If specific models of BESS are not available, suitable generic BESS models are proposed to be used with assumed frequency droop settings as advised by proponents.

### 4.5.5 IBR models for large-scale wind and solar generation

**Large-scale wind and solar generation will use site-specific models where available and will use generic models where site-specific models are unavailable.** The following approach is proposed for modelling IBR in the GPSRR studies:

- For those IBR units that have completed PFR commissioning, where appropriate, the generator model in AMP will be used.
- Generators have an ongoing obligation to ensure that the NSP and AEMO have accurate models that reflect the voltage and frequency performance of their plant, and it will be assumed that the provided models are representative of their actual performance.
- Legacy IBR plants represented in AMP as negative loads will be represented using generic PSS®E IBR models wherever possible.

- For future studies, if no site-specific model is available, committed plant will be modelled using generic models with minimum PFR settings.

## 4.6 Frequency control ancillary services (FCAS) response

**FCAS response from generators will be considered according to PFR settings.** Unless stated otherwise, it is proposed that FCAS response of synchronous generators will not be considered in the studies apart from the frequency responses provided by PFR governors. The FCAS capabilities of IBR are planned to be considered according to PFR settings, if PFR commissioning is completed. Where IBR plant are resource limited, such as solar or wind generation, only lower capability will be considered. The FCAS lower capability of IBR plants is not planned to be considered if confirmation of frequency control enablement from the generator is not available at the time of the study.

## 4.7 RAS models

**RAS models will be included in the GPSRR where relevant to system studies.** Typically, for most simulation studies that involve assessment of credible contingency events, RAS models are not included. Given the criticality of such models in the assessment of power system security in response to non-credible contingency events, it is proposed that key RAS models will be considered. Only remedial action schemes that are relevant to key study contingencies are planned to be modelled.

For the 2026 GPSRR studies, if any updated RAS model/relay models are not available, the latest RAS models available at the time of study or appropriate study assumptions are planned to be used.

## 4.8 Emergency frequency control scheme (EFCS) models

### 4.8.1 Under frequency load shedding (UFLS) models

**UFLS models will be considered for contingencies where UFLS is expected to operate.** If it is determined that UFLS is expected to operate in the contingencies studied, it is proposed that UFLS settings will be based on UFLS data presently available to AEMO. At the time of study, if the UFLS bus mapping information is available, the UFLS loads as identified by the mapping are planned to be used to model the UFLS scheme. If bus mapping is not available, it is proposed that UFLS loads will be allocated within relevant region(s), so the net UFLS loads in the region align with the net estimated regional UFLS for the given snapshot. For future scenarios, DPV and underlying demand growth levels based on the 2024 ISP forecasts are planned to be used to estimate the amount of UFLS at each frequency band. Additionally, any planned future UFLS remediation measures in NEM regions are planned to be modelled.

### 4.8.2 Over frequency generation shedding (OFGS) models

**OFGS will be considered for contingencies where OFGS is expected to operate.** If it is determined that OFGS is expected to operate in the contingencies studied, it is proposed that OFGS settings will be based on data presently available to AEMO. If required, it is proposed that existing South Australia and Western Victoria OFGS model settings will be used unless the scheme is reviewed and revised settings are available prior to the studies being undertaken.



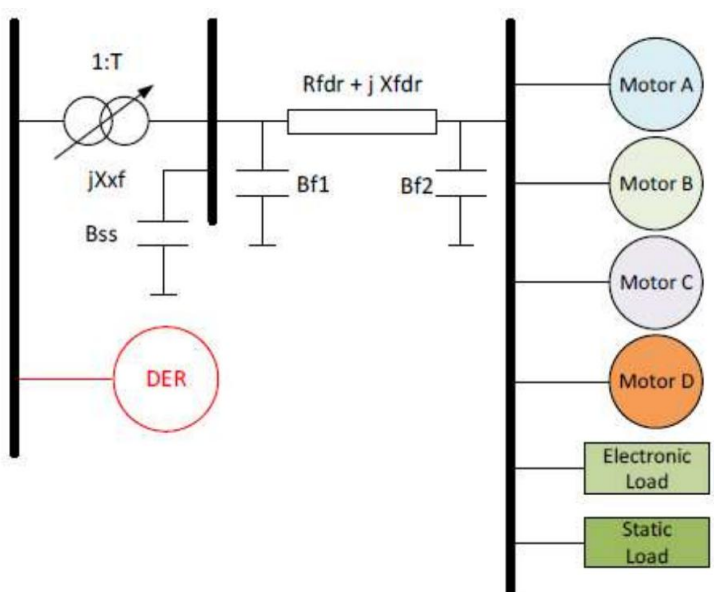
## 4.9 Distributed energy resources (DER)/distributed PV (DPV) models

DER/DPV models are proposed to be considered as per the process outlined in *PSS<sup>®</sup>E models for load and distributed PV in the NEM<sup>7</sup>*. DPV bus mapping data for all mainland NEM regions is available at the time of writing this report and is planned to be used to model the DER/DPV in PSS<sup>®</sup>E at relevant buses. For future scenarios up to FY 2030-31, assumptions are planned to be based on 2024 ISP forecasts to project future DPV generation in each region.

## 4.10 Load models

The composite load model (CMLD) is proposed to be used to model typical load response in the full NEM PSS<sup>®</sup>E GPSRR studies. It consists of six load components at the end of a feeder equivalent circuit, which is represented by a series impedance and shunt compensation. It is intended to emulate various load components' aggregate behaviour. It includes three three-phase (3P) induction motor models (motor A, B and C), a single-phase (1P) capacitor-start motor performance model (motor D), static load components (constant current and constant impedance), and a power electronic load model (constant active and reactive power)<sup>8</sup>. The composite load model structure is shown in Figure 2.

**Figure 2 The CMLD model structure and the implementation of the DERAEMO1 model**



The CMLD model captures load shake off in response to large disturbances, which is a significant improvement compared with the previous impedance (Z), current (I) and power (P) (ZIP) model, which does not represent load shake-off. Since the CMLD model comprises explicit representations of different motor types, the load dynamics due to the response of motors are better captured<sup>7</sup>. Load shake-off is important to consider for the GPSRR studies so that the frequency and voltage response of the system is adequately modelled.

<sup>7</sup> Further details on AEMO PSS<sup>®</sup>E models for load and distributed PV in the NEM are at <https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/power-system-model-development>.

<sup>8</sup> See <https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en>.

### 4.10.1 Modelling of large loads

**Large loads will be modelled as constant current and constant admittance loads, with a relay model used to implement protection settings.** Large loads will be modelled as constant current loads for active power and constant admittance loads for reactive power. The dynamic response of large loads is expected to be dominated by the protection settings, where loads will be tripped using a relay model when under voltage or under frequency occurs. The UVUFxxU1 model from the PSS®E model library is proposed to be used to investigate different under frequency and undervoltage load shedding responses.

## 4.11 Forecasting assumptions

**The 2024 ISP forecasting methodology is planned to be applied to forecast future network conditions for future studies, with consideration of updates from the draft 2026 ISP.** The 2024 ISP forecasting methodology, set out in the *ISP Methodology* published in June 2023<sup>9</sup>, is planned to be applied to forecast future network dispatch conditions, noting that the conditions selected will be reviewed based on the latest ISP information available. Where relevant, the future dispatch conditions will be used as a basis for developing sensitivities that may include further network changes to investigate the risk in question.

The following parameters are proposed to be applied for future projections:

- Short-term schedule half hourly dispatches.
- Future dispatch years up to FY 2030-31.
- High and low demand traces (10% probability of exceedance [POE] and 90% POE).
- Five reference years<sup>10</sup>.
- Two solution iterations, to capture different model probabilistic outcomes, such as generation outages.
- The generation build and retirements in the 2024 ISP *Step Change* scenario.
- Full network constraints representing the network augmentations assumed in the 2024 ISP *Step Change* scenario.

### Consultation question 4

What are stakeholder views regarding the proposed modelling approach for the priority risks for assessment in the 2026 GPSRR?

<sup>9</sup> At [https://aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology\\_june-2023.pdf?la=en](https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en).

<sup>10</sup> AEMO optimises expansion decisions across multiple historical weather years known as “reference years” to account for short- and medium-term weather diversity.

## 5 Risk cost assessment methodology

This section describes the methodology that is proposed to be used in the 2026 GPSRR to estimate the risk cost for relevant risks. This risk cost methodology can be used to quantify key risks in monetary terms. A simplified quantitative approach can be used considering each risk consequence and likelihood as shown below:

$$\text{Risk} = \text{consequence} \times \text{likelihood occurrence (or probability)}$$

The risk cost can be determined by calculating the cost of the risk consequence. The cost of a severe risk will be calculated as the total interruption of loads (measured in megawatt hours [MWh]) multiplied by the value of customer reliability (VCR)<sup>11</sup> and the estimated time to restore interrupted load following the event (T). The VCR for the NEM was published at \$41.48/kilowatt hour (kWh) by the Australian Energy Regulator (AER) for year 2024 and it is required to be adjusted to the relevant year where the risk cost is being calculated based on the Consumer Price Index (CPI). For assessment of the risk cost for outages expected to be greater than 12 hours, the work completed by the AER on the value of network resilience (VNR)<sup>12</sup> will be referenced. This approach applies multiples of the standard VCR depending on the duration of the outage.

The likelihood of a severe risk event has two components:

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

Therefore, the above formula can be expanded to:

$$\text{Risk cost} = L \times T \times \text{VCR} \times P_c \times P_e$$

where:

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

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

VCR is the value of the unserved energy during the interruption

Pc is the probability of a risk event

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

### Consultation question 5

What are stakeholder views regarding the proposed risk cost assessment methodology to be applied in 2026 GPSRR?

<sup>11</sup> AER 2024, Values of Customer Reliability - Final report on VCR values, Table 1, at [https://www.aer.gov.au/system/files/2024-12/2024-12-18%20AER%20-%20Final%20report%20-%202024%20VCR%20review\\_0.pdf](https://www.aer.gov.au/system/files/2024-12/2024-12-18%20AER%20-%20Final%20report%20-%202024%20VCR%20review_0.pdf).

<sup>12</sup> AER 2024, Final Decision – Value of Network Resilience 2024, Section 4.2.1, at <https://www.aer.gov.au/industry/registers/resources/reviews/value-network-resilience-2024>

## 6 Consultation approach and delivery timelines

### 6.1 2026 GPSRR consultation approach and timelines

Key consultation activities and tentative timelines planned for the 2026 GPSRR are detailed below.

#### Completed consultation

1. Engagement with AEMO internal teams and NSPs to finalise the scope of 2026 GPSRR (April 2025 to September 2025).
2. NSP consultation on the 2026 GPSRR draft approach paper (September 2025).

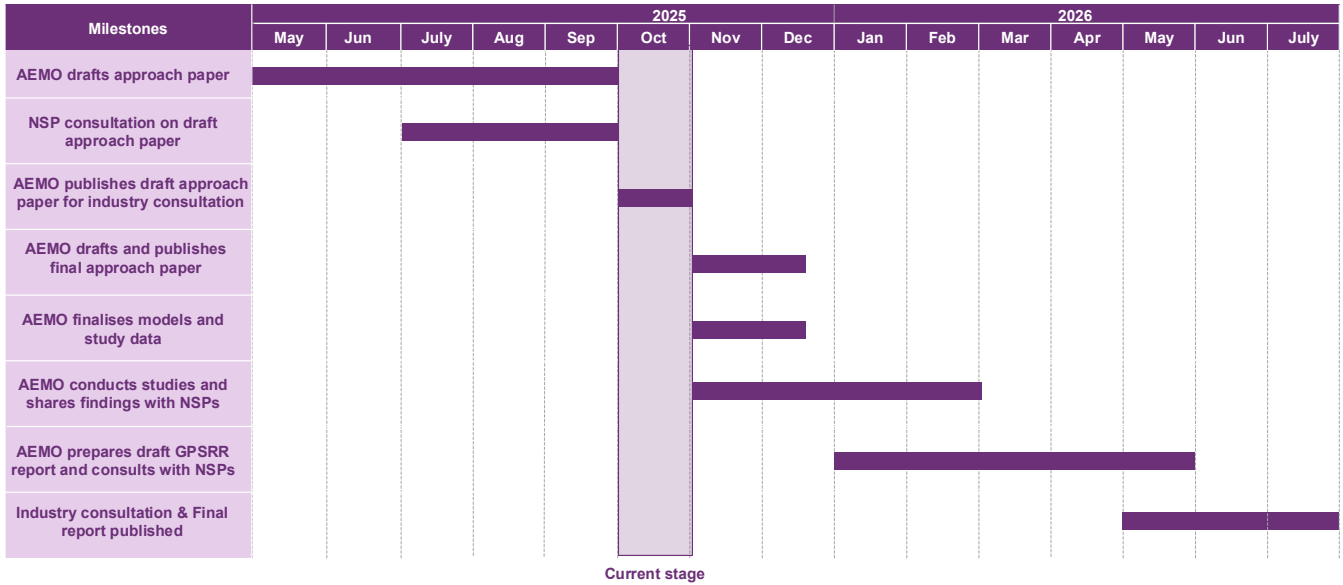
#### Planned consultation

3. Industry consultation on the 2026 GPSRR draft approach paper (October 2025 to November 2025).
4. GPSRR approach industry briefing session (October 2025).
5. Regular monthly meetings with TNSPs to update on GPSRR progress and to discuss risk inputs for current and future GPSRRs (November 2025 to March 2026).
6. Publication of the 2026 GPSRR final approach paper (December 2025).
7. On completion of the studies, AEMO to share the findings with NSPs (January 2026 to March 2026).
8. Seeking feedback from NSPs on the draft 2026 GPSRR report (mid-April 2026 to late-April 2026).
9. Draft 2026 GPSRR report published for industry feedback (May 2026).
10. Publication of the final 2026 GPSRR report (by 31 July 2026).

#### 2026 GPSRR delivery timelines

Figure 3 shows a high-level project schedule for key activities, including the approach paper development and consultation.

Figure 3 High-level project schedule



### Consultation question 6

Does the consultation approach meet stakeholder expectations, and do stakeholders have any suggestions on how AEMO could best engage with industry on the development of the 2026 GPSRR?

# Abbreviations

Abbreviation	Term	Abbreviation	Term
<b>1P</b>	single phase	<b>MSL</b>	minimum system load
<b>3P</b>	three phase	<b>MW</b>	megawatt/s
<b>AER</b>	Australian Energy Regulator	<b>MWh</b>	megawatt-hour/s
<b>AI</b>	artificial intelligence	<b>NEM</b>	National Electricity Market
<b>AMP</b>	AEMO modelling platform	<b>NER</b>	National Electricity Rules
<b>BESS</b>	battery energy storage system/s	<b>NSP</b>	network service provider
<b>CER</b>	consumer energy resources	<b>OFGS</b>	over frequency generation shedding
<b>CMLD</b>	composite load model	<b>PFR</b>	primary frequency response
<b>CPI</b>	consumer price index	<b>POE</b>	probability of exceedance
<b>DER</b>	distributed energy resources	<b>PPC</b>	power plant controller
<b>DNSP</b>	distribution network service provider	<b>PSCAD™</b>	Power System Computer Aided Design
<b>DPV</b>	distributed photovoltaics	<b>PSFRR</b>	Power System Frequency Risk Review
<b>EFCS</b>	emergency frequency control scheme	<b>PSS®E</b>	Power System Simulation for Engineering
<b>EMT</b>	electromagnetic transient	<b>RAS</b>	remedial action scheme
<b>EUFR</b>	emergency under frequency response	<b>REZ</b>	renewable energy zone
<b>FCAS</b>	frequency control ancillary services	<b>RoCoF</b>	rate of change of frequency
<b>FRT</b>	fault ride-through	<b>SPS</b>	special protection scheme/s
<b>FY</b>	financial year	<b>SVC</b>	static var compensator
<b>GPSRR</b>	General Power System Risk Review	<b>TNSP</b>	transmission network service provider
<b>IBR</b>	inverter-based resources	<b>UFLS</b>	under frequency load shedding
<b>ISON</b>	International System Operator Network	<b>UPS</b>	uninterruptible power supply
<b>ISP</b>	<i>Integrated System Plan</i>	<b>VCR</b>	value of customer reliability
<b>JSSC</b>	Jurisdictional System Security Coordinator	<b>ZIP</b>	impedance (Z), current (I) and power (P)
<b>kWh</b>	kilowatt-hour/s		