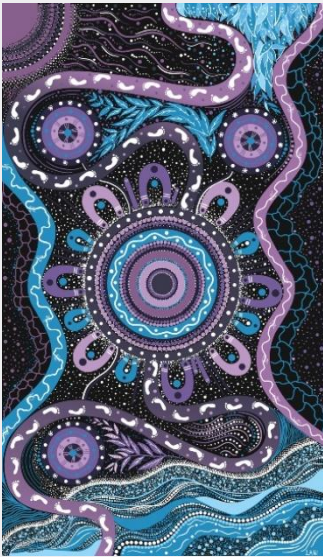


2025 GPSRR Approach Paper

December 2024

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 2025 General Power System Risk Review (2025 GPSRR) approach paper under clause 5.20A.2(c)(3) of the National Electricity Rules.

Disclaimer

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Abbreviations

Abbreviation	Term	Abbreviation	Term
1P	single phase	NEM	National Electricity Market
3P	three phase	NER	National Electricity Rules
AMP	AEMO Modelling Platform	NSP	network service provider
BESS	battery energy storage system/s	OFGS	over frequency generation shedding
CER	consumer energy resources	OPDMS	Operations and Planning Data Management System
CMLD	composite load model	PEC	Project EnergyConnect
DER	distributed energy resources	PFR	primary frequency response
DNSP	distribution network service provider	POE	probability of exceedance
DPV	distributed photovoltaics	PSCAD™	Power System Computer Aided Design
EFCS	emergency frequency control scheme	PSFRR	Power System Frequency Risk Review
FCAS	frequency control ancillary services	PSS@E	Power System Simulation for Engineering
FRT	fault ride-through	REZ	renewable energy zone
FY	financial year	RoCoF	rate of change of frequency
GPSRR	General Power System Risk Review	SPS	special protection scheme/s
IBR	inverter-based resources	TNSP	transmission network service provider
ISP	Integrated System Plan	UFLS	under frequency load shedding
IT	information technology	VCR	value of customer reliability
JSSC	Jurisdictional System Security Coordinator	VNI	Victoria – New South Wales Interconnector
kV	kilovolt/s	ZIP	impedance (Z), current (I) and power (P)
MW	megawatt/s		

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 report¹ was published on 25 July 2024.

AEMO has commenced the 2025 GPSRR and plans to publish the 2025 GPSRR report by 31 July 2025.

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.
- 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 final approach paper published by AEMO following consultation on:

- The prioritised set of risks that AEMO will review in the 2025 GPSRR (see Section 3).
- The approach, methodologies, information, and assumptions AEMO will use in assessing the priority risks (see Sections 2, 3, 4 and 5).
- AEMO's plans to consult with relevant parties throughout the review (see Section 6).

This approach paper has been prepared by AEMO 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.

In October 2024, AEMO published an initial version of the approach paper for consultation, in accordance with NER 5.20A.2(c)(3). Based on stakeholder feedback received and additional AEMO review, AEMO has modified

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



some aspects of this final approach paper. AEMO has also published a separate report² on relevant stakeholder feedback received, AEMO’s responses, and the reasons for changes made to this final approach paper.

1.2 Priority risks

AEMO has selected the following priority risks for review:

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

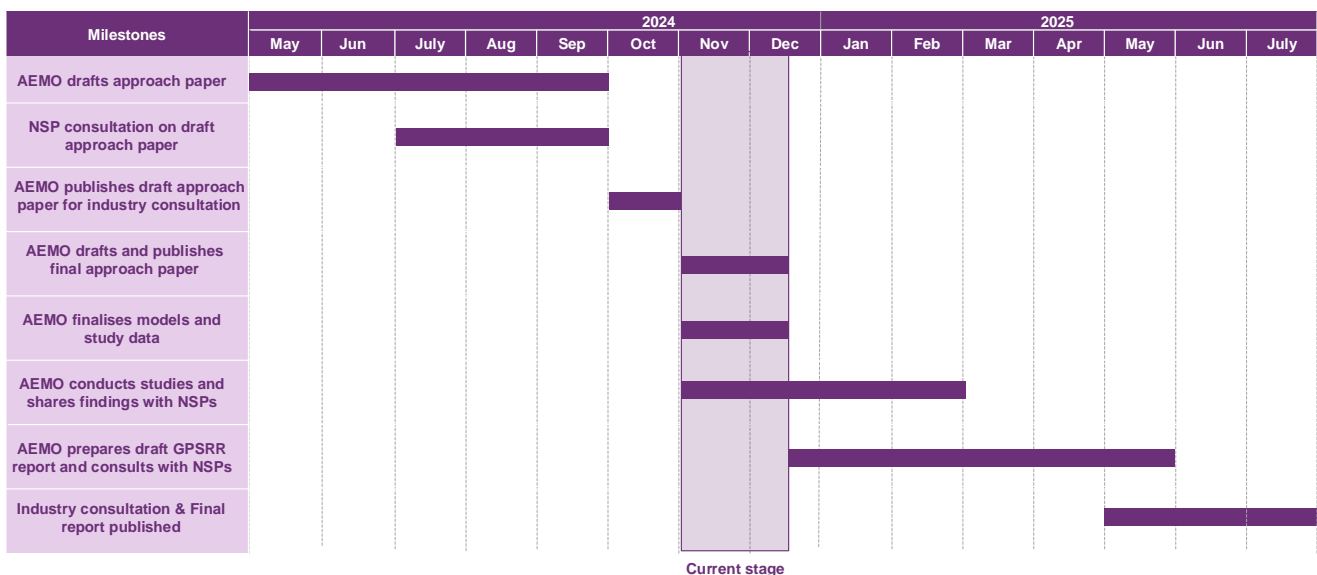
AEMO proposes to consider a range of other events and conditions in addition to the priority risks, but not to include detailed analysis. Further details on these priority risks and the methodology used to identify them are in Section 3.

1.3 2025 GPSRR delivery plan

1.3.1 Project schedule

Figure 1 shows a high-level project schedule for key activities, including the approach paper development and consultation.

Figure 1 High-level project schedule



² 2025 GPSRR approach consultation report, at <https://aemo.com.au/consultations/current-and-closed-consultations/2025-general-power-system-risk-review-approach-consultation>.

1.3.2 Project critical activities

The following activities are considered critical for successful delivery of the GPSRR report by July 2025:

Completed

- Collation of all preliminary models and input data for the study³ (October 2024).
- Submissions on approach paper close (November 2024).
- Publication of final GPSRR approach paper (December 2024).

Planned

- Completion of GPSRR studies (February 2025).
- Draft 2024 GPSRR report published for industry feedback (May 2025).
- Publication of final GPSRR report (by 31 July 2025).

³ Or application of appropriate and agreed modelling assumptions.

2 Study background

2.1 Evolving power system risks

As a part of the GPSRR, AEMO assesses the risks of the future power system. The GPSRR considers system changes including:

- Operational loads.
- Distributed photovoltaics (DPV) and IBR penetration.
- Changes in operation/retirement of existing synchronous generators.
- Addition, upgrade, or decommissioning of special protection schemes (SPS).
- Updates to EFCSSs.
- Major network augmentations including renewable energy zone (REZ) developments and other new committed generation.

2.2 Network development path

The 2024 *Integrated System Plan* (ISP) and its optimal development path support Australia's complex and rapid energy transformation towards net zero emissions. The 2024 ISP *Step Change* scenario has been identified as the most likely scenario to play out⁴, so AEMO will use forecasting data from the 2024 ISP *Step Change* scenario in the 2025 GPSRR for future projections.

Unless noted otherwise, Table 1 displays each of the major ISP committed, anticipated and actionable projects in the next five years and is consistent with the Transmission Augmentation Information workbook published in August 2024⁵.

The projects listed in Table 1 were considered to be major augmentations that may impact the contingencies proposed to be studied in the 2025 GPSRR. Significant network augmentations will have material impacts on the outcomes of power system studies and therefore were considered in the assessment of future network conditions. Announced potential closures of power stations such as Eraring Power Station (2027) and Yallourn Power Station (2028) will also be considered in future studies. AEMO does not intend to include augmentations that are determined to not have a significant impact on the proposed contingencies.

⁴ See Section 3.3 of the 2024 ISP, at <https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en>.

⁵ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

Table 1 Committed, anticipated and actionable major transmission projects to June 2030

Project	Capacity release date ^A	Status
Far North Queensland REZ	June 2024	Committed
Project EnergyConnect	Stage 1: December 2024 ⁶ Stage 2: July 2027	Commissioned Committed
Western Renewables Link (uprated) ^B	July 2027	Anticipated
Central West Orana REZ Network Infrastructure Project	August 2028	Anticipated
CopperString 2032	June 2029	Anticipated
HumeLink	Northern: July 2026 Southern: December 2026	ISP Actionable Project
Sydney Ring North (Hunter Transmission Project)	December 2028	New South Wales Actionable Project ^C
Victoria – New South Wales Interconnector West (VNI West)	December 2029	ISP Actionable Project
Hunter-Central Coast REZ Network Infrastructure project	July 2028 ⁷	New South Wales Actionable Project ^C
Sydney Ring South	September 2028	ISP Actionable Project
Gladstone Grid Reinforcement	March 2029	Queensland Actionable Project ^D
Mid North South Australia REZ Expansion	July 2029	ISP Actionable Project
Waddamana to Palmerston transfer capability upgrade	July 2029	ISP Actionable Project

A. The capacity release and timing is conditional on availability of suitable market conditions and good test results.

B. The scope of this project, which will unlock renewable energy resources, reduce network congestion, and improve utilisation of existing assets in western parts of Victoria, was updated as an outcome of the VNI West options analysis, resulting in a higher capacity and harnessing 1,460 megawatts (MW) of renewable capacity rather than the original design of 600 MW.

C. These projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.

D. This project will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (QLD) rather than the ISP framework.

⁶ December 2024 is the expected date as the Transmission Augmentation Information workbook published in June 2024. However, the capacity release date may be delayed depending on the outcomes of inter-network testing.

⁷ Timing has been updated to align with EnergyCo's advice that full capacity will be available in mid-2028.

3 Priority risks to be assessed

3.1 Priority risk identification factors

When identifying contingency events or other events or conditions for assessment as priority risks in the 2025 GPSRR, AEMO had regard to the following key factors and sources of information⁸:

- 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.
- 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 2025 GPSRR report (by 31 July 2025).

Other relevant factors and how they contribute to the categorisation of risks are outlined in Section 3.4.

3.2 NSP consultation

To identify potential risks for priority assessment, AEMO asked each transmission network service provider (TNSP) and distribution network service provider (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.
- Other events or conditions that would likely lead to cascading outages or supply disruptions.

To aid the collection and assessment of this information, AEMO requested NSPs to complete a risk assessment document, with the following information in relation to the nominated event or condition as applicable:

1. A high-level description of the risk or non-credible contingency event that could lead to cascading outages or major supply disruptions.
2. A primary risk category (see Table 2).
3. A description of which network elements would trip if the event occurred.
4. A description of which protection elements would be likely to operate if the event occurred.

⁸ As required by NER 5.20A.1(a1).

5. Details of any historical occurrences (or near misses).
6. Details of any existing control or risk management strategies.
7. Details of any planned augmentations that may affect the event or risk.
8. An outline of the likely consequences of the event.
9. Whether the event has the potential to cause cascading failures.
10. Details of any previous studies or assessments of the event.
11. The likelihood of the event occurring. Table 3 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.
12. Consequence. Table 4 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 of potential priority risks based on operational experience, recent power system events and anticipated power system changes (such as REZ developments).

Table 2 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.
SPS risks	Any incident which is caused by unexpected interactions or maloperation or non-operation of SPS systems.
Cyber security risks	Any incident which is caused by a malicious cyber attack.
IT risks	Any incident which is caused by an 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 3 Likelihood descriptions

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

Table 4 Consequence descriptions

Consequence	Market and system impact
Extreme	Loss of supply to a state(s) for any duration. Market suspension of multiple markets for a prolonged period.
Major	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	Localised/minimal loss of supply in a state. Market(s) in administered state or material scheduling error.
Minor	Intervention required to maintain supply. Immaterial scheduling error (below dispute threshold).
Immaterial	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 5.

Table 5 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

Section 3.4 provides information on categorisation of the information received on key contingencies and risks for the 2025 GPSRR.

3.3 Review of relevant system events since the 2024 GPSRR

AEMO will identify all relevant system events that occurred in the previous financial year (FY) 2023-24 in the 2025 GPSRR report. The findings and recommendations from these incidents will be considered in the 2025 GPSRR. In

particular, the trip of the Moorabool – Sydenham 500 kilovolts (kV) No. 1 and No. 2 lines on 13 February 2024⁹ contributed to the choice of priority risks proposed to be studied in the 2025 GPSRR¹⁰.

3.4 Initial risk categorisation

AEMO considered all the risks identified in the NSP consultation exercise and organised them into three broad categories:

- Contingencies and risks where AEMO concluded there are adequate controls in place or are considered to low priority. AEMO will not consider these risks as part of the 2025 GPSRR. For example, these contingencies or risks may have:
 - Reclassification procedures to identify and control risk.
 - Tools in place to monitor and alert control room operators, in addition to the necessary documented procedures.
 - Automatic protection or remedial action schemes that operate to limit the impact of the contingency.
 - Been analysed/managed as part of normal NSP processes.
- Contingencies or risks where the impact is difficult to define and study or that are outside the GPSRR scope. AEMO will discuss these 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 risks¹¹. Examples include:
 - Small signal stability.
 - Extreme weather conditions.
 - Cyber risks.
 - System strength and inertia management in real time.
 - Auto-bidding risks.
 - Limited visibility of participant systems.
 - Inverter limit violations due to inability of generator response.
 - Maximum allowable active power ramp rates.
 - System restart with a transitioning power system.
 - Communications risks.
 - Power system model accuracy.

⁹ 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.

¹⁰ Including only system incidents for which reports have been published at the time of publication of this approach paper.

¹¹ See details relating to AEMO's Operations Technology Roadmap at <https://aemo.com.au/en/initiatives/major-programs/operations-technology-program/operations-technology-roadmap>.

- Cumulative non-compliances.
- Inadequate system strength (for example, post Yallourn).
- Contingencies with a lower inherent risk rating (see Table 5).
- High consequence contingencies or events without adequate protection or an adequate process to manage the event. Risks in this category are candidates for review as part of the 2025 GPSRR. These were further assessed to select priority risks that should be prioritised for study in this year’s review. Where risks were not selected for study, AEMO may consider them in future reviews or refer to relevant work underway by NSPs and/or AEMO to assess/control the risk.

3.5 Proposed priority risks to be assessed

AEMO has reviewed the risks submitted under the 2025 GPSRR process and has selected key contingencies or other events or conditions as priority risks for assessment. The risks listed below were selected for the 2025 GPSRR based on:

- The likely power system impact and its estimated probability of occurrence.
- Details of any review/work previously completed to understand or manage the risk.
- Any changes to power system conditions or other factors which may have materially changed the risk profile.
- Whether the risk has been reviewed previously as part of AEMO’s risk review process (under a recent Power System Frequency Risk Review (PSFRR) or GPSRR).

Priority risks were selected for study against historical and future operating conditions (up to five years in the future in FY 2029-30).

Where risks are expected to be significantly impacted by projected future changes in the power system, these risks are selected to be studied under future operating conditions. The process to identify these priority risks for future studies also considered the timeframe required for the implementation of possible remedial actions and any planned network augmentations that may affect the risk likelihood or consequence.

The future studies will consider the 2024 ISP *Step Change* projected levels of demand, generation, and distributed energy resources (DER)/DPV. Updated under frequency load shedding (UFLS)/over frequency generator shedding (OFGS) settings, planned network augmentations/upgrades, and corresponding protection schemes will also be considered where relevant.

Priority Risk 1 – IBR response to remote frequency events

The rapid growth of new technology in the NEM can introduce operational challenges as it is integrated into the system. In particular, it has been identified that large quantities of new battery energy storage systems (BESS) in specific regions may present short-term challenges regarding the frequency droop response to large remote contingencies. If BESS connections are concentrated in one region, the rapid combined frequency response to remote contingencies may overload critical lines or cause instability in the network. BESS frequency droop settings may be as low as 1.7%, resulting in rapid active power response from remote plant that is quicker than active power response of plant much closer to the contingency. This is currently seen as a short-term risk that is

present for unequal distribution of BESS, which typically have more aggressive frequency droop settings than other plant. However, it is expected in the longer-term that BESS connections will be distributed more evenly, and concentrated frequency response will not be dominated by any one region.

Initial studies have already been completed assessing the impact of BESS frequency response in South Australia to credible contingencies and it was found that there are no issues currently identified. However, the impact of non-credible contingencies has not yet been assessed in detail and will be the focus of the studies in the 2025 GPSRR. In addition to the 2025 GPSRR South Australia BESS studies, AEMO is planning to undertake preliminary studies on other NEM regions and the BESS response to remote non-credible contingencies.

Table 6 Risk 1 overview

Contingency	IBR response to remote frequency events
Likelihood	<p>Unlikely (>5% - 20%)</p> <ul style="list-style-type: none"> • Rapid growth in BESS in South Australia and other regions. • Potential issue for a wide range of non-credible contingencies in the NEM. • No current agreed approach on BESS frequency droop settings in relation to non-credible contingencies. • Initial studies on credible contingencies show potential future issues, but further studies are required to understand impact of non-credible contingencies.
Impact	<p>Major (loss of supply to a large portion of a state, for any duration).</p> <ul style="list-style-type: none"> • Potential for instability/overloading of interconnectors/key transmission corridors. • Could lead to generation tripping and frequency risk that has potential cascading effects. • Could cause system security challenges.
Risk conditions	<p>Based on two future scenarios, pre-Project EnergyConnect (PEC) stage 2 (before 2027) and post-PEC stage 2 (after 2027), the following risk conditions will be assessed:</p> <ul style="list-style-type: none"> • High Heywood Interconnector South Australia export and import. • High PEC South Australia export and import (for post PEC S2 cases). • High and low NEM demand. • Low primary frequency response availability from other plant. • High IBR generation in South Australia. • High IBR generation in Victoria. • Low synchronous generation/inertia (South Australia). • High and low synchronous generation/inertia (rest of NEM).
Existing management strategies	<p>Potential to limit frequency droop settings of future BESS connections through existing connection processes.</p>
Potential solutions	<p>Mitigation measures for this issue are being considered through working groups, and results from these studies will contribute to the planned approach. Potential solutions may include:</p> <ul style="list-style-type: none"> • Frequency droop setting limitations. • Implementation of multiple frequency droop settings for BESS. • Regional frequency control ancillary services (FCAS) dispatch. • Remedial action scheme.
Study software	<p>PSS@E (full NEM model)</p>
Risk raised by	<p>ElectraNet</p>



Priority Risk 2 – Minimum system load conditions

Increasing levels of consumer energy resources (CER) are resulting in lower system minimum operational demands in regions across the NEM. This is an emerging problem particularly in Victoria and South Australia, where insufficient demand to support minimum load requirements can cause issues for system strength, voltage management and frequency control. This is also being experienced in other regions such as New South Wales and Queensland, and the risk is expected to increase further as uptake of CER continues.

Minimum system load conditions present several risks to the operation of the power system:

- Under minimum system load conditions, synchronous generation is typically displaced by inverter-based generation, resulting in a reduction of inertia and system strength in the system and potential difficulty in maintaining the minimum number of synchronous units online.
 - Reduced inertia in the power system may result in more severe rate of change of frequency (RoCoF) following power system events, increasing the risk of cascading failures.
 - Insufficient system strength can result in maloperation of protection systems following a disturbance in the power system. It also can result in an inability of the power system to maintain and control the voltage waveform to facilitate the secure operation of IBR.
- The operation of CER largely exists outside of AEMO control and is only visible in aggregate.
 - Without control of CER, reduced demand may fall to levels such that it is not possible to keep online sufficient generation to maintain essential system services. In the most extreme cases, line flows may be pushed above secure limits.
- CER are also displacing scheduled and semi-scheduled connected generators, which have a requirement to meet strict performance standards.
 - This includes the requirement for generators to remain online during credible power system contingency events. Contingency events during minimum load conditions may result in larger contingency sizes¹² and more severe system impacts due to CER fault ride-through (FRT) performance.

Table 7 Risk 2 overview

Contingency	Minimum system load conditions
Likelihood	Unlikely (>5% - 20%) <ul style="list-style-type: none"> • Increasing levels of CER are contributing to reducing minimum demand across the NEM. • Potential issues for a range of credible or non-credible contingencies in the NEM depending on operating conditions.
Impact	Major (loss of supply to a large portion of a state, for any duration). <ul style="list-style-type: none"> • Potential for violation of interconnector/key transmission corridor transfer limits. • Could result in large generation contingency sizes and frequency risk that has potential cascading effects. • Could cause system security challenges.

¹² Contingency size refers to the net level of generation or demand that is disconnected as a consequence of the contingency.

Contingency	Minimum system load conditions
Risk conditions	Risk conditions for violation of VNI transient stability export limits: <ul style="list-style-type: none"> • Negative or low South Australia regional demand. • Low Victorian regional demand. • High Victorian and South Australian DPV generation. • Low synchronous generation/inertia (South Australia and Victoria). • Heywood interconnector flow from South Australia to Victoria. • High VNI flow from Victoria to New South Wales.
Existing management strategies	Emerging risk, with new management strategies under development. Existing management strategies include MSL procedures, high voltage management strategies and system strength constraints.
Potential solutions	Potential solutions may include: <ul style="list-style-type: none"> • Development of procedures to increase regional demand to maintain power system security. • Dynamic voltage management systems. • Load coordination (e.g. shifting hot water load to times of high DPV output). • Other procedures or plans as agreed upon by NSPs and governments. • Improvement of CER disturbance ride-through capabilities.
Study software	Desktop evaluation.
Risk raised by	AEMO, AusNet, Engineers Australia

Priority Risk 3 – Unexpected operation and interaction of control schemes and protection systems

The correct operation of control schemes and protection systems is essential to manage a range of credible and non-credible contingency events that may occur. Protection systems provide safe isolation of faulted equipment reducing the impact and severity of power system events. The use of control schemes allows for improved asset utilisation, network access for generating systems and can aid with recovery from severe contingency events.

However, the implementation of control schemes and protection systems also introduces risks related to failure or unexpected operation that can lead to adverse system impacts such as cascading failure and supply disruptions. In the context of the energy transition, there are several factors that contribute to an increased risk likelihood:

- The proposed connection of REZs may introduce increased non-credible contingency sizes, relying on SPSs to manage any system impacts. The potential increase in number and complexity of protection schemes regarding this introduces risks that are difficult to quantify.
- Retirement of synchronous generation may result in lower fault levels in the NEM, increasing risk of power system protection maloperation. As fault levels decrease, the occurrence of unexpected operation of protection systems may become more common.
- Power system operating incident reports show events where protection systems did not operate as expected.
- To ensure a cost-effective energy transition, it is likely that existing infrastructure will be utilised more heavily, with remedial action schemes implemented to defer or replace the need for additional capital expenditure. As more schemes are implemented, the risk of interaction increases.
- It is difficult to conduct appropriate live testing of large, complex schemes without impacting the network. However, without extensive testing, the likelihood of correct operation of schemes is difficult to confirm as the power system evolves.

Table 8 Risk 3 overview

Contingency	Unexpected operation and interaction of control schemes and protection systems
Likelihood	<p>Unlikely (>5% - 20%)</p> <ul style="list-style-type: none"> Increasing non-credible contingency sizes as large generators are connecting via new REZs or to existing transmission corridors. As more control and protection schemes are introduced, the likelihood of interaction increases. Potential issues for a range of credible or non-credible contingencies in the NEM depending on operating conditions.
Impact	<p>Extreme (loss of supply to a state(s) for any duration. Market suspension of multiple markets for a prolonged period).</p> <ul style="list-style-type: none"> Interaction or maloperation of SPS could cause significant impacts to the power system, potentially leading to cascading failure and loss of supply to multiple states. Unexpected operation of protection systems can result in large generation contingency sizes, such as seen with the loss of Loy Yang A after the trip of the Moorabool – Sydenham 500 kV lines on 13 February 2024.
Risk conditions	<ul style="list-style-type: none"> Increasing non-credible contingency sizes. Proposed new control and protection schemes for generator connections. Decreasing inertia and system strength.
Existing management strategies	Emerging risk, with management strategies under development. Existing management strategies include the Remedial Action Scheme guidelines and other related RAS management strategies already in place.
Potential solutions	<p>Potential solutions may include:</p> <ul style="list-style-type: none"> Review of Remedial Action Scheme (RAS) guidelines. Working groups and consultation across industry to determine appropriate risk mitigation measures.
Study approach	Desktop evaluation.
Risk raised by	AEMO, ElectraNet

Priority Risk 4 – Increasing risks of non-credible contingencies

As the energy transition progresses, the risks of non-credible contingency events may increase due to a range of contributing factors affecting both the likelihood and consequence of occurrence. There are a number of mechanisms currently in place to manage non-credible contingencies, including:

- Emergency frequency control or remedial action schemes.
- Declaration of a protected event.
- Reclassification using the indistinct events framework.

These mechanisms may not be suitable in their current form if the likelihood or severity of non-credible contingencies increases significantly in the future.

One example of increased likelihood of non-credible contingencies is seen in the recent occurrences of tower failures in the NEM. There have been several recent occurrences of tower failures that had the potential to lead to significant non-credible contingency sizes and potential cascading failures or severe supply disruptions, including

- The trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024¹³.

¹³ 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.

- The trip of South East – Tailem Bend 275 kV lines on 12 November 2022¹⁴.
- The trip of Liapootah – Palmerston – Waddamana 220 kV No. 1 and No. 2 lines on 14 October 2022¹⁵.

In addition to a potential increase in likelihood of non-credible contingencies, there are also several factors that may result in increased severity of power system outcomes if a non-credible contingency were to occur. These include:

- New generation connections to existing transmission corridors, increasing the non-credible contingency size through loss of lines.
- Connection of new REZs introducing large non-credible contingency sizes and increasing loading on existing corridors.
- Increase in CER, resulting in DPV shake-off for contingency events, potentially resulting in further increases of non-credible contingency sizes.
- Retirement of synchronous generation in the NEM, resulting in reduced system strength and inertia.

Table 9 Risk 4 overview

Contingency	Increasing risks of non-credible contingencies
Likelihood	Possible (>20% to 50% annual probability) <ul style="list-style-type: none"> • Several recent historical occurrences across the NEM. • Changing weather conditions. • Aging infrastructure approaching end of service life.
Impact	Major (loss of supply to a large portion of a state, for any duration). <ul style="list-style-type: none"> • Increasing non-credible contingency sizes. • Potential for cascading failures if generation unexpectedly trips after tower failures. (Similar to the 13 February 2024 event in Victoria when Loy Yang Power Station A tripped).
Risk conditions	Various, including: <ul style="list-style-type: none"> • Aging infrastructure approaching end of service life. • Changing weather conditions. • Increased loading of existing transmission corridors. • New REZs introducing new large non-credible contingencies. • Increase in CER. • Retirement of synchronous generation.
Existing management strategies	Existing asset maintenance and replacement programs, reclassification framework, ECFS, RAS, protected event.
Potential solutions	Protected event.
Study approach	Desktop evaluation.
Risk raised by	ElectraNet, Engineers Australia, CitiPower, Powercor, United Energy, Essential Energy.

¹⁴ See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf?la=en.

¹⁵ See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-liapootah---palmerston---waddamana-no-1-and-no-2-220-kv-lines.pdf?la=en.

Additional assessments by NSPs

AEMO is also liaising with NSPs on studies planned by each NSP to assess non-credible risks (including system stability assessment and identification of required SPSs) as the part of augmentations required by NER S5.1.8.

3.6 Other review tasks

The following activities will also be included in the 2025 GPSRR scope:

- Summary of key emergency under frequency management initiatives underway in each NEM region.
- Consideration of potential requests for, and benefit of, declaration of new protected events.
- A status update for the recommendations from the 2024 GPSRR¹⁶ and previous risk reviews.

¹⁶ 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.

4 Models, input data and study cases

Power system network models and input data requirements for 2025 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.

The PSS®E full NEM network model will be used to assess the relevant priority risks where a need for power system studies has been identified for the 2025 GPSRR. Further information is provided in Section 4.4.

4.1 Monitored parameters

The 2025 GPSRR studies will consider the following system parameters when assessing the response of the power system for each priority risk:

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

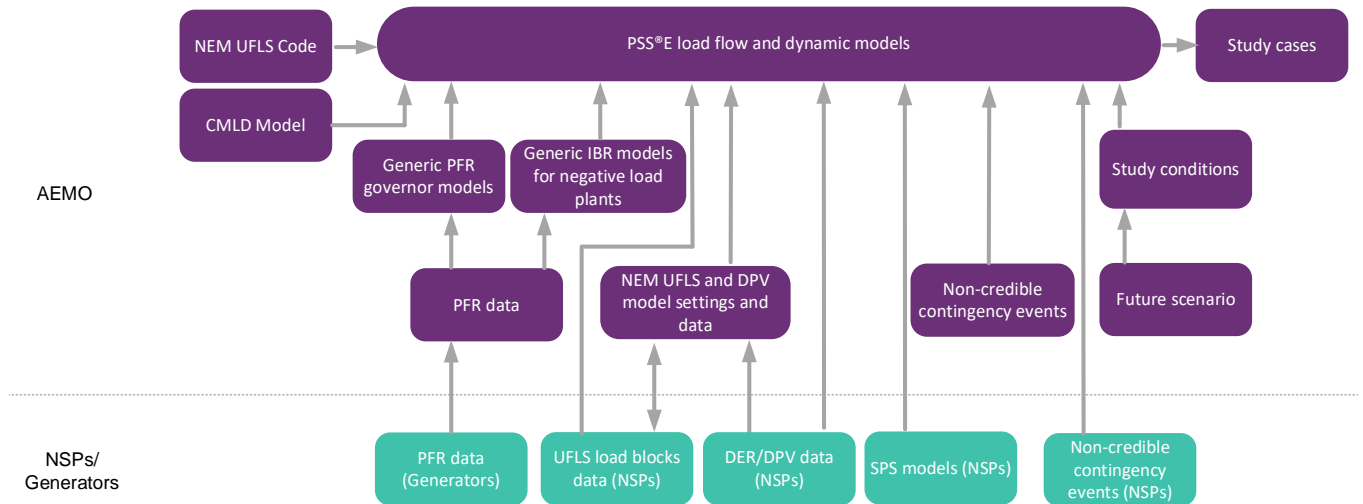
4.2 Study software

AEMO plans to use PSS®E v34.9 software to assess the relevant contingency events for the 2025 GPSRR. No risks were identified as requiring the use of Power System Computer Aided Design (PSCAD)[™].

4.3 2025 GPSRR model sources

2025 GPSRR model sources are shown in Figure 2.

Figure 2 2025 GPSRR model sources



PFR: primary frequency response.

4.4 Network model

4.4.1 IBR response to remote frequency events

Studies for the IBR response to remote frequency events will be carried out using a full NEM network model based on AEMO Modelling Platform¹⁷ (AMP) cases. This model will be modified to include the new interconnectors, generation and network augmentations that are planned for completion for the time of the study.

- For pre-PEC Stage 2 studies, augmentations up to the year of study will be included in the model.
- For post-PEC Stage 2 studies, augmentations up to 2027 will be included.

As detailed in Section 4.11, future dispatch conditions will be based on the five-year 2024 ISP *Step Change* projection data. The key system forecast parameters planned to be considered in setting up the study cases are included in Table 6 (in Section 3.5). All studies will assume a system normal network configuration¹⁸.

The capacities of the Heywood and PEC interconnectors are assumed to be as per the values listed in Table 100. It is assumed that successful inter-network testing for PEC Stage 1 will release Heywood capacity to 650 megawatts (MW) for import and export.

¹⁷ AEMO is currently transitioning from the existing Operations and Planning Data Management System (OPDMS) to the AEMO Modelling Platform (AMP). More details regarding this can be found at <https://opdms.prod.nemnet.net.au/>.

¹⁸ 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.

Table 10 South Australia AC interconnector capacities, post PEC commissioning and completion of inter-network testing

PEC Stage	Heywood capacity (MW)	PEC capacity (MW)	Combined capacity (MW)
1	650 SA import 650 SA export	150 SA import 150 SA export	750 SA import 700 SA export
2	650 SA import 650 SA export	800 SA import 800 SA export	1300 SA import 1450 SA export

4.5 Primary frequency response (PFR) governor models

4.5.1 PFR applied settings

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

4.5.2 Units without governor model in OPDMS

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 will be used for the 2025 GPSRR studies.

4.5.3 Units with governor models in OPDMS

Generators have an ongoing obligation to provide NSPs and AEMO with up-to-date modelling information which encompasses all control systems that respond to voltage or frequency disturbances on the power system. AEMO 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 updated site-specific information is not available, generic governor models with appropriate PFR settings will be used.

4.5.4 BESS models

For future committed projects, site-specific models will be used where they are available. If specific models of BESS are not available, suitable generic BESS models will be used with assumed frequency droop settings as advised by proponents. Frequency droops settings will be investigated as part of the 2025 GPSRR studies and may be set to a minimum value of 1.7%.

4.5.5 IBR models for large-scale wind and solar generation

The following approach will be used for modelling IBR in the GPSRR studies:

- For those IBR units that have completed PFR commissioning, where appropriate, the generator model in OPDMS 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 OPDMS 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

Unless stated otherwise, FCAS response of synchronous generators will not be considered in the studies apart from the frequency responses provided by PFR governors. The FCAS lower capabilities of IBR are planned to be considered according to PFR settings, if PFR commissioning is completed. The FCAS lower capability of IBR plants are 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 Special protection scheme (SPS) models

Typically, for most simulation studies that involve assessment of credible contingency events, SPS models are not included. Given the criticality of such models in the assessment of power system security in response to non-credible contingency events, system protection schemes that are relevant to key study contingencies will be modelled.

For the 2025 GPSRR studies, if any updated SPS model/relay models are not available, the latest SPS models available at the time of study or appropriate study assumptions will be used.

4.8 Emergency frequency control scheme models

4.8.1 UFLS models

If required, UFLS settings will be based on UFLS data presently available to AEMO.

At the time of study, if the UFLS OPDMS bus mapping information is available, the UFLS loads as identified by the mapping will be used to model the UFLS scheme. If bus mapping is not available, 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 will be used to estimate the amount of UFLS at each frequency band. Additionally, any planned future UFLS remediation measures in NEM regions will be modelled.

4.8.2 Over frequency generation shedding (OFGS) models

If required, 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.

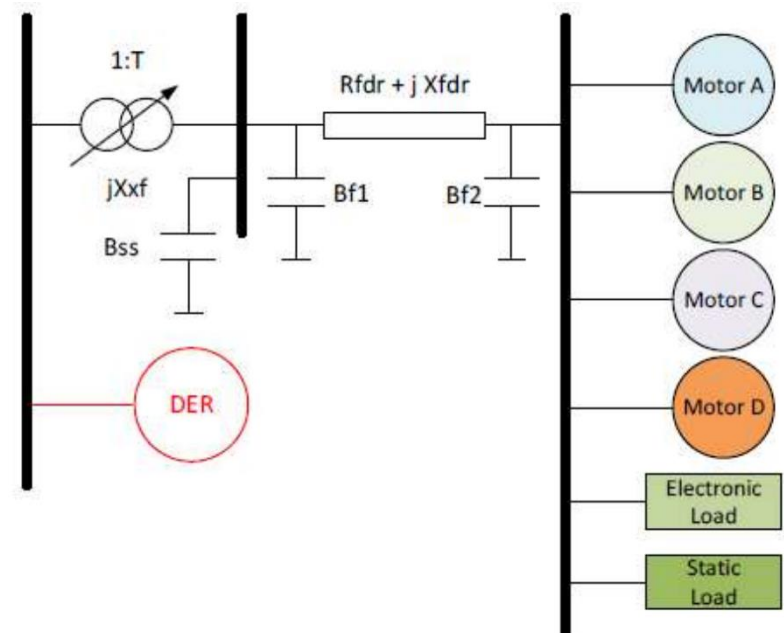
4.9 Distributed energy resources (DER)/distributed PV (DPV) models

DER/DPV models will be considered as per the process outlined in *PSS@E models for load and distributed PV in the NEM*¹⁹. DPV bus mapping data for all mainland NEM regions is available at the time of writing this report and will be used to model the DER/DPV in PSS@E at relevant buses. For future scenarios up to FY 2029-30, assumptions will be based on 2024 ISP forecasts to project future DPV generation in each region.

4.10 Load models

The composite load model (CMLD) will be used to model load response in the full NEM PSS@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)²⁰. The composite load model structure is shown in Figure 3.

Figure 3 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

¹⁹ Further details on AEMO PSS@E models for load and distributed PV in the NEM are at <https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en>.

²⁰ See <https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en>.

due to the response of motors are better captured¹⁹. Load shake-off is important to consider for the GPSRR studies so that the frequency and voltage response of the system is adequately modelled.

4.11 Forecasting assumptions

The 2024 ISP forecasting methodology, set out in the *ISP Methodology* published in June 2023²¹, will be applied to forecast future network dispatch conditions, noting that the conditions selected will be reviewed based on the latest ISP information available. The following parameters are proposed to be applied for future projections:

- Short-term schedule half hourly dispatches.
- Future dispatch years up to FY 2029-30.
- High and low demand traces (10% probability of exceedance (POE) and 90% POE).
- Five reference years²².
- Three 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.

²¹ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

²² 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 will be used in the 2025 GPSRR to estimate the risk cost for relevant risks. This risk cost methodology will 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)²³ and the estimated time to restore interrupted load following the event (T). The VCR for the NEM was published at \$40.99/kilowatt hour (kWh) by the Australian Energy Regulator (AER) for year 2019 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 loss of load in a specific region, an individual VCR value can be used rather than the overall NEM value referenced above.

The likelihood of a severe risk event has two components:

- Probability of the risk event (Pc), which can be determined using 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 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.

There is currently work underway by the AER to review and update the VCR by 18 December 2024²⁴. Once published, this will be reviewed by AEMO and considered in the risk cost assessments for the GPSRR.

²³ AER 2019, Values of Consumer Reliability – Final Decision, Table 5.22, at <https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf>.

²⁴ See <https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024>.

6 Consultation approach

Key consultation activities and tentative timelines planned for the 2025 GPSRR are below.

Completed consultation

1. Engagement with AEMO internal teams and NSPs to finalise the scope of 2025 GPSRR, including discussions with NSPs in finalising the list of contingencies to be included in the study (May 2024 to September 2024).
2. Seeking NSP feedback on the 2025 GPSRR draft approach paper (July 2024 to September 2024).
3. Industry consultation (including with JSSCs) on the 2025 GPSRR draft approach paper (October 2024 to November 2024).
4. GPSRR approach industry briefing session (October 2024).
5. Publication of the 2025 GPSRR final approach paper (December 2024).

Ongoing consultation

6. Regular monthly meetings with TNSPs to update on GPSRR progress and to discuss risk inputs for current and future GPSRRs (ongoing).

Planned consultation

7. On completion of the studies, AEMO to share the findings with NSPs (January 2025 to March 2025).
8. Seeking feedback from NSPs on the draft 2025 GPSRR report (mid-April 2025 to late-April 2025).
9. Draft 2025 GPSRR report published for industry feedback (May 2025).
10. Publication of the final 2025 GPSRR report (by 31 July 2025).