AEMC

REVIEW

Reliability Panel AEMC

Final report

2026 Reliability Standard and Settings Review

23 April 2026

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About the Reliability Panel

The Panel forms part of the AEMC's institutional arrangements and is comprised of members who represent a range of participants in the National Electricity Market, including small and large consumers, generators, network businesses, retailers and AEMO. It is responsible for monitoring, reviewing and reporting on reliability, security and safety on the national electricity system, and advising the AEMC in respect of such matters. The Panel's key responsibilities are specified in section 38 of the National Electricity Law.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the Traditional Custodians of the many different lands across Australia on which we live and work. The AEMC office is located on the land of the Gadigal people of the Eora nation. We pay respect to all Elders past and present, and to the enduring connection of Aboriginal and Torres Strait Islander peoples to Country.

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Executive Summary

1 This final report has been prepared for the Reliability Panel's (Panel) 2026 Reliability Standard and Settings Review (RSS review or RSSR). Following an extensive period of analysis, modelling and consultation, the Panel has made recommendations regarding the reliability standard and market price settings to apply from 1 July 2028 to 30 June 2032.

2 The National Electricity Rules (NER) require the Panel to review the reliability standard (standard) and reliability settings (settings) every four years. The Panel's 2026 RSSR has considered whether the level of the standard and market price settings remain appropriate for expected market conditions from 1 July 2028 to 30 June 2032. The Panel includes representatives from across the National Electricity Market (NEM), including small and large consumers, generators, distributed energy resources (DER), networks, retailers and the Australian Energy Market Operator (AEMO).

3 The Panel's role is to recommend a reliability standard and associated market price settings that signal investment in an appropriate mix of generation, storage, interconnection and demand response that is balanced with the level of reliability consumers value. The reliability standard has direct implications for market price settings. Higher standards generally require stronger price signals, such as a higher market price cap, to incentivise additional investment to avoid rare outage events, whereas lower standards reduce system costs but are associated with higher expected outage costs.

4 In developing its recommendations, the Panel has undertaken detailed economic modelling, engaged extensively with stakeholders through multiple rounds of consultation, and sought independent quality assurance of the modelling from Intelligent Energy Systems (IES). IES concluded that the Panel's modelling is robust and reliable, and provides a sound basis for determining the efficient level of the reliability standard and the associated market price settings.

5 The reliability standard represents a targeted level of reliability over the investment timeframe. It does not imply that supply-related outages occur year by year. AEMO will continue to operate the power system in real time to meet all consumer demand and has a range of in-market and out-of-market tools available to do so.

6 In this final report, we are making a number of **recommendations**:

- We recommend the reliability standard be updated to **0.003 per cent expected unserved energy (USE)** for the review period (99.997 per cent reliability). We have concluded that the revised standard:
    - better serves the long-term interests of consumers, resulting in minimal day-to-day impacts on reliability outcomes consumers experience, while avoiding increases in costs that would be required to meet the current standard of 0.002 per cent USE (99.998 per cent reliability)
    - is generally consistent with the value customers place on a reliable supply of electricity
    - aligns with the underlying increases in the costs of new gas peaking generation.
- We recommend retaining:
    - the **market price cap (MPC) at $22,800** (2022 dollars) and **cumulative price threshold (CPT) at $2,325,600** (2022 dollars)
    - the **market floor price (MFP) at -$1,000/MWh** and recommend that the Commission consider revising the rules to require the market to automatically clear at the MFP during Minimum System Load level 3 (MSL3) conditions

- the **administered price cap (APC) and administered floor price (AFP) at $600/MWh and -$600/MWh, respectively**.

7 The Panel acknowledges recent geopolitical developments affecting global commodity markets. While the modelling was completed prior to the latest period of volatility, the Panel is confident that both the modelling methodology and results are robust for the relevant review period and not materially affected by current movements in international gas and fuel markets.

The Panel balances the expected impact of supply outages and the cost of avoiding them

8 A reliable power system has adequate capacity (generation, demand response, interconnection, and energy storage capacity) to meet consumer needs. As our system transitions, it requires sufficient investment to replace retiring thermal generators and meet increasing demand, as well as effective operational signals to maintain a real-time balance between supply and demand.

9 The core objective of the reliability framework in the national electricity market (NEM) is to use market mechanisms to deliver efficient reliability outcomes to the greatest extent possible. These mechanisms provide financial incentives for participants (generators, retailers, aggregators and customers) to make investment, retirement and operational decisions that support efficient levels of reliability in the long-term interests of consumers.

10 The reliability standard and settings are key components of the NEM's reliability framework. They aim to encourage sufficient investment in capacity to meet consumer demand for energy, while, in conjunction with derivatives markets, providing ways for market participants to manage financial risks that could otherwise threaten the overall stability and integrity of the market:

- The **reliability standard** defines an efficient level of reliability, expressed as the level of USE that represents an efficient economic trade-off between reliability and affordability based on what consumers value. In effect, balancing the impact of reliability shortfalls against the cost of avoiding them.
- The **reliability settings** are set to achieve market outcomes consistent with the standard by defining a price envelope that provides sufficient revenue to support investment while also limiting the potential for extreme high, low, and cumulative price impacts. They are the:
  - MPC – which places an upper limit on dispatch prices in the wholesale market, and is the primary investment signal to deliver critical investment and meet the reliability standard.
  - CPT – which acts to manage the risk of high prices over a sustained period by triggering an administrative price period (APP).
  - APC and AFP – which place upper and lower limits on dispatch prices that apply during an APP after a period of sustained high prices caused the CPT to be breached.

The long-term interests of customers are best promoted by a reliability standard of 0.003% USE

11 Based on extensive economic and power system modelling and analysis, and stakeholder engagement, the Reliability Panel's **final recommendation** is that the reliability standard for 1 July 2028 to 30 June 2032 be **0.003 per cent** expected USE per region per year (a reliability level of 99.997 per cent).

12 The review highlighted that the reliability standard has become less aligned with observed outcomes and consumer experience, which is a key reason why the Panel recommends evolving the reliability standard rather than further tightening the market price settings.

13 The change to the reliability level (from 99.998 per cent) is driven by:

- a reduction in the value of customer reliability (VCR)
- an increase in the costs of new generation capacity
- the size and duration of modelled unserved energy (USE) events.

14 The recommended standard will have **minimal day-to-day impacts on the reliability outcomes consumers experience**, increasing the planned long-term target from an average of 10 minutes to 16 minutes of unserved energy per year, while **avoiding increases in costs** required to meet the current 0.002 per cent standard. In the current cost-of-living environment, **the Panel considers it particularly important to avoid increases in market price settings that would raise consumer bills without delivering commensurate benefits**.

15 Importantly, in real time, the system will continue to operate at very high levels of reliability, supported by a range of out-of-market and jurisdictional tools. These measures are intended to complement, rather than replace, the market-based reliability framework.

16 As the Panel has previously acknowledged, consumers' experience of reliability is expected to remain high. However, **during rare and extreme events, when both market-based and out-of-market measures are fully utilised and exhausted**, a subset of consumers may experience reliability shortfalls.

17 The proposed revision to the reliability standard represents a modest relaxation of the long-term target, equivalent to moving from approximately three hours to five hours of rotational load shedding for around half the population once every ten years. This reflects a potential small increase in rare but controlled operational load shedding used to manage supply-demand imbalances during periods of resource inadequacy, noting that in practice, such load shedding is extremely infrequent with its impacts unevenly distributed across customer groups.

18 Moreover, given that more than 99 per cent of the outages customers experience are due to distribution network outages, not insufficient generation, we consider our final recommendation best promotes the long-term economic interests of consumers by aligning the standard with the value consumers place on reliability.

19 The Panel acknowledges that the underlying data and forecasts on which its recommendation has been made are subject to limitations and uncertainty, although they represent the best available evidence. As the market continues to evolve, future outcomes may vary from those anticipated. This is part of the reason why the Panel reviews the standard and settings every four years – so we can adjust them as needed in response to evolving market conditions.

20 The Panel will submit a rule change request to the Australian Energy Market Commission (AEMC or Commission) for consideration to give effect to the recommendations.

The Panel recommends no changes to the market price cap and cumulative price threshold over the review period

21 The MPC and CPT should together be sufficient to support investment outcomes consistent with the reliability standard while also limiting potential systemic financial risks. For this reason, the MPC and CPT levels have been considered together throughout this process.

22 Although customer bills are most sensitive to average wholesale prices rather than the level of the market price cap, our modelling indicates that to achieve the current reliability standard across all regions (0.002 per cent USE), the market price settings would need to be raised to levels exceeding the value customers place on reliability.

23 On balance, the Panel is not convinced that further increasing the market price settings at this time would improve long-term consumer outcomes. **The currently scheduled settings strike an appropriate balance between supporting critical investment and the reliability customers ultimately experience**. The Panel agrees with stakeholders that unwarranted revisions to the market settings over the review period could undermine investment certainty. As such, the Panel has decided to recommend a change in the reliability standard rather than further increasing the market price settings to deliver a higher required level of investment.

24 As noted in the previous 2022 RSSR, we recognise that market price settings will result in different reliability outcomes across regions of the NEM, depending on the underlying characteristics of unserved energy events. The Panel found that aligning the settings to deliver the optimal level of reliability across all regions is not currently possible, and this has been evident in the NEM since its inception.

The Panel recommends retaining the current MFP and linking it to MSL events

25 The Panel's final recommendation is to retain the MFP at -$1,000/MWh. Our analysis indicates that this level rarely binds, and when it does, it adequately allows the market to clear excess supply. We found that there are minimal benefits to consumers from changing the MFP.

26 However, the Panel recommends that the market automatically clear at the MFP during MSL3 conditions. This is analogous to how, during load shedding events, prices are set at the MPC. Such a trigger would transparently reflect system needs and may minimise the need for AEMO intervention to manage MSL events. The Panel will submit a separate rule change request to the AEMC on this proposal, to allow for a full consultation process and consideration of any potential unintended consequences. We will not be recommending this rule change be done on a fast-track basis, as further consultation is required.

The Panel recommends retaining the current administered price cap and floor

27 The Panel's final recommendation is to retain the APC and AFP at $600/MWh and -$600/MWh for the review period. The APC was increased from $300/MWh to $600/MWh in 2022–2023 to align with typical generator short-run costs, the cap on prices in the gas markets, and to continue to ensure supply availability during an APP.

28 The Panel considers that retaining the APC at $600/MWh maintains the intended price signal while encouraging continued participation by thermal generation and storage during periods of extended high prices.

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1 Introduction

Box 1: Key points in Chapter 1

- The Reliability Panel (Panel) has reviewed the reliability standard and settings (RSSR) in accordance with the National Electricity Rules (NER) and the 2021 reliability standard and settings (RSS) guidelines.
- This final report sets out the Panel's recommendations for the level of the reliability standard and corresponding market settings (the market price cap, the cumulative price threshold, the market floor price and the administered price cap) that will apply from 1 July 2028 to 30 June 2032.
- The purpose of this paper is to outline the Panel's final recommendations.
- As noted in the draft report, the RSSR has considered emissions reduction as part of the revised national electricity objective (NEO).

This chapter outlines the:

- Section 1.1 — purpose and scope of the 2026 RSSR
- Section 1.2 — the Panel requirements for the 2026 RSSR
- Section 1.3 — important considerations as the NEM transitions to a system dominated by variable renewable energy
- Section 1.4 — the implications of policy uncertainty on investment certainty
- Section 1.5 — stakeholder consultation and engagement
- Section 1.6 — structure of the report.

1.1 The Panel has reviewed the reliability standard and settings to apply from 2028 to 2032

Under the NER, the Panel is required to review the reliability standard and reliability settings every four years. This review enables the Panel to assess and consider whether the standard and each market setting remain suitable for the expected market conditions, or whether adjustments are necessary to ensure these mechanisms continue to deliver on their intended purpose.

We conducted this 2026 RSSR in accordance with the NER and the RSS review guidelines to consider the appropriateness of the level of the reliability standard and market price settings that will apply in the national electricity market (NEM) from 1 July 2028 to 30 June 2032.

In conducting the 2026 RSSR, the Panel has explicitly taken into account:

- the Australian Energy Market Commission's (AEMC) terms of reference, which direct attention to collaborating with the Commonwealth's NEM Wholesale Market Settings review
- the results from comprehensive economic modelling
- stakeholder input, including responses to the issues paper, draft report and meeting discussions
- other relevant factors.

1.1.1 The reliability standard and settings are core components of the NEM's reliability framework

The reliability standard and settings are the key components of the NEM's reliability framework. These elements aim to encourage sufficient investment in generation, storage and demand response capacity to meet customer energy demand, while protecting market participants from substantial risks that threaten the stability and integrity of the market.

The reliability standard determines the optimal level of reliability that customers value over the planning timeframe

The reliability standard is a long-term, ex-ante standard used to signal to the market the level of supply required to meet demand and achieve the reliability that customers value, on a regional basis. The form and level of the reliability standard are specified in the NER.[1] The reliability standard is expressed in terms of the expected unserved energy (USE) in a region.[2] It is currently set at a maximum of 0.002 per cent of the total energy demand in that region for a given financial year.

Or put another way, it is set to meet 99.998 per cent of total energy demanded. In practical terms, this translates to, at most, roughly 10 minutes of reliability-derived outages per customer per year on average.[3] It represents an economically optimal balance between reliability and cost — a level of supply shortfall that, when weighed against the cost of avoiding that shortfall, is considered acceptable and in the long-term interests of consumers. Critically, it is not an operational standard. In real time, reliability outcomes far exceed the reliability standard.

Practically, as noted in Figure 1.1 below, most of the outages experienced by customers have been due to issues on the distribution network. In the financial year 2011 to the financial year 2024, distribution-related interruptions accounted for over 96 per cent of total energy lost, with reliability issues accounting for only 0.1 per cent of outages. [4] Moreover, the reliability standard operates as a long-run planning benchmark and does not represent year-by-year or operational reliability outcomes, which are managed by AEMO in real time.

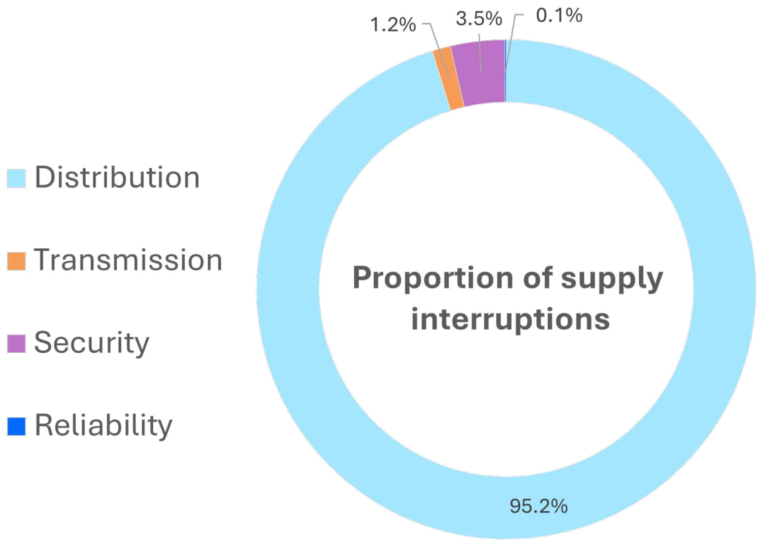
1 Clause 3.9.3C(a) of the NER.

2 The Panel recently confirmed USE as the form of the reliability standard. See Reliability Panel, Review of the form of the reliability standard and administered price cap, Final report, 27 June 2024 and Chapter 2 of the draft report for further detail on the purpose and function of the reliability standard.

3 This figure is illustrative and is calculated as a regional average based on average demand. In reality, the experience of individual customers will depend on the specific unserved energy events.

4 AEMC, NEM Reliability & Security Report FY2024, 26 June 2025.

Figure 1.1: Proportion of energy supply interruptions by cause (FY2011-FY2024)



Source: AEMC, NEM Reliability & Security Report FY2024, 26 June 2025.

The market price settings operationalise the reliability standard

The reliability settings (also known as the market price settings) are price mechanisms designed to encourage investment in sufficient generation capacity, storage and demand-side participation to deliver the reliability standard, while providing limits that protect market participants from periods of very high or very low prices, both temporary and on a sustained basis. The settings consist of the following:

- **Market Price Cap (MPC)**, which places an upper limit on dispatch prices in the wholesale market, and is a wholesale market investment signal to deliver critical investment to meet the reliability standard.
- **Market Floor Price (MFP)**, which places a lower limit on dispatch prices in the wholesale market during periods of oversupply, encourages demand-side participation and minimises the need for market intervention.
- **Cumulative Price Threshold (CPT)**, which represents a threshold of cumulative dispatch prices over a period of seven days (2,016 trading intervals) that, when surpassed, triggers an Administered Price Period (APP) to limit the financial exposure of market participants during extended volatility events.
- **Administered Price Cap (APC)**, which is the upper limit on dispatch prices that applies during an APP after a period of sustained high prices caused the CPT to be breached. It is high enough to keep generators supplying into the market, but low enough to protect market participants from excessive financial exposure over an extended period.

Chapter 4 of the issues paper provides further details on the purpose and functions of the market settings.

Table 1.1: The current reliability standard and settings 30 June 2026 to 1 July 2027 (2022 dollars)

	30 June 2026	1 July 2026	1 July 2027
Reliability Standard	0.002% USE	0.002% USE	0.002% USE
Market Price Cap	$18,600/MWh	$20,700/MWh	$22,800/MWh
Cumulative Price Threshold	$1,674,000/MWh	$1,987,200/MWh	$2,325,600/MWh
Administered Price Cap	$600/MWh	$600/MWh	$600/MWh
Market Floor Price	-$1,000/MWh	-$1,000/MWh	-$1,000/MWh

Source: AEMC, Schedule of Reliability Settings 2025-26, found here

1.1.2 The reliability standard and settings have a crucial, but fixed role

This review focuses on the reliability of the large-scale generation and transmission system, specifically the reliability provided by power generation, storage, demand response, and interconnectors, to meet customer demand. It does not address distribution-level outages, force majeure or system security events. Those aspects, which are responsible for most customer outages, are managed through other standards and mechanisms.

Within that narrow reliability domain, the Panel may make recommendations to improve the effectiveness of the NEM's reliability framework. In this review, the Panel has made a recommendation regarding the application of the MFP during minimum system load events. This measure falls within the Panel's remit as it pertains to the effective functioning of the market price settings.

See section 1.2.2 of the issues paper for more details on the additional factors that affect investment decisions and reliability in the NEM.

1.2 The Panel is required to consider the national electricity objective when making its recommendations

When conducting the review of the reliability standard and settings, there are several factors that the Panel takes into account. These include:

- **Requirements in the NER**[5] - the NER stipulates that any change the Panel recommends must be likely to contribute to the achievement of the National Electricity Objective (NEO).
- **Reliability Standard and Settings Guidelines (2021 guidelines)**[6] - these guidelines, developed by the Panel, outline the principles and assessment approach for RSS reviews.
- **Terms of reference provided by the AEMC.**[7]

A notable inclusion in this review is the consideration of achieving jurisdictional emissions reduction targets in accordance with the revised NEO. The Panel interprets this as the obligation to ensure that any recommended reliability standard or settings do not hinder - and ideally

5 Clause 3.9.3A of the NER.

6 Reliability Panel, Review of the reliability standard and settings guidelines, Final guidelines, 1 July 2021.

7 2026 RSSR AEMC terms of reference.

complement - the transition to a lower-emissions power system when balanced with the other limbs of the NEO (long-term interests of consumers, price, quality, safety, reliability, and security).[8]

1.2.1 The Panel must consider the materiality of any changes and only recommend changes when there is a material benefit for customers

In making its final recommendations, in accordance with the guidelines and in response to stakeholder feedback, the Panel has placed significant value on regulatory stability. The electricity sector is experiencing unprecedented change, and investors and market participants consistently emphasise the importance of a stable and predictable regulatory environment. Frequent revisions to the settings can increase uncertainty and risk premiums, potentially leading to higher long-term costs for consumers.

Therefore, in accordance with the 2021 RSS guidelines, the Panel has only considered recommended changes to the reliability standard or settings where there is a material benefit to do so. The analysis undertaken in this review has determined the most efficient level of the reliability standard and corresponding market price settings. These have been compared to the status quo, to ensure predictability in the reliability standard and settings are maintained. Where the review process found a change in standard and settings that would result in only a minor benefit, the Panel has retained the current settings.[9]

The AEMC will assess the Panel's final recommendations through a rule change request

After completing the review, the Panel must submit to the AEMC any rule change proposal resulting from the review as soon as practicable after the review is completed.[10] The Commission would then consider these proposed changes through a rule change process, providing additional opportunities for stakeholder input and consultation beyond those already incorporated into this review's process.

The NEM is transitioning to a system dominated by variable renewable energy

The 2026 RSSR is undertaken in the context of a power system undergoing a significant transition, including the withdrawal of thermal generation, the rapid growth of variable renewable energy, the increasing deployment of battery storage, and the rising penetration of consumer energy resources. These changes are increasing uncertainty in demand, price outcomes and investment conditions whilst broadening the range of circumstances under which reliability risks may arise.

Against this background, the Panel's final recommendations are intended to ensure the reliability standard and market price settings remain fit for purpose and continue to support reliable supply to meet the long-term interests of consumers. See appendix A for more details on the context and background of this review.

1.3 The NEM is transitioning to a system dominated by variable renewable energy

This section provides context on how key changes in the NEM's physical and policy environment have implications for the long-term reliable delivery of electricity to consumers. This includes:

- the replacement of coal-fired generation with variable renewable energy (VRE)

8 The Panel has published guidance on how it will consider the emissions reduction component of this work, which can be found here.

9 Reliability Panel, Review of the reliability standard and settings guidelines, 1 July 2021.

10 Clause 3.9.3A(i) of the NER.

- increased demand-side uncertainty driven by rooftop PV, electrification and changing customer behaviour
- increasing price volatility in the wholesale market as the generation mix changes.[11]

These trends directly affect how reliability is maintained at the level customers expect and how effectively the market settings drive the required level of investment. Further details on the transition of the NEM's generation fleet is available in the issues paper.

1.3.1 Large scale renewable energy is continuing to replace thermal generation

The physical power system continues to undergo significant changes, with the ongoing exit of thermal generators and the entry of large volumes of bulk renewable generation, batteries and firming. With thermal generators running less frequently, they need to operate more flexibly in response to signals provided by the wholesale market. The market must now maintain adequate reliability levels with a smaller pool of thermal units. The pace of replacement firm investment is, therefore, critical to meeting reliability needs.

This transition from a grid supplied primarily by thermal generation to one dominated by VRE capacity has several reliability implications, many of which we already observe in the NEM. In the past, shortfalls were almost exclusively tied to peak demand events on hot summer days combined with generator outages. In the future, while peak demand events (potentially also in winter) remain a cause, we must also consider energy-limited shortfalls (for example, a scenario where multiple cloudy days lead to a shortfall even during periods of moderate demand). The Panel is also mindful that different regions of the NEM are at different stages of the transition and, as such, may face different system needs and challenges. Although the reliability standard and settings are nationally consistent, we have considered any implications for individual regions.

On the consumer side, there is also an ongoing increase in the uptake of distributed consumer energy resources (CER) and in responsive demand. These shifts are changing market dynamics and price outcomes, with varying implications for the 2026 RSSR. The Panel has considered how these changes affect the optimal reliability standard and market price settings.

Between now and 2032:

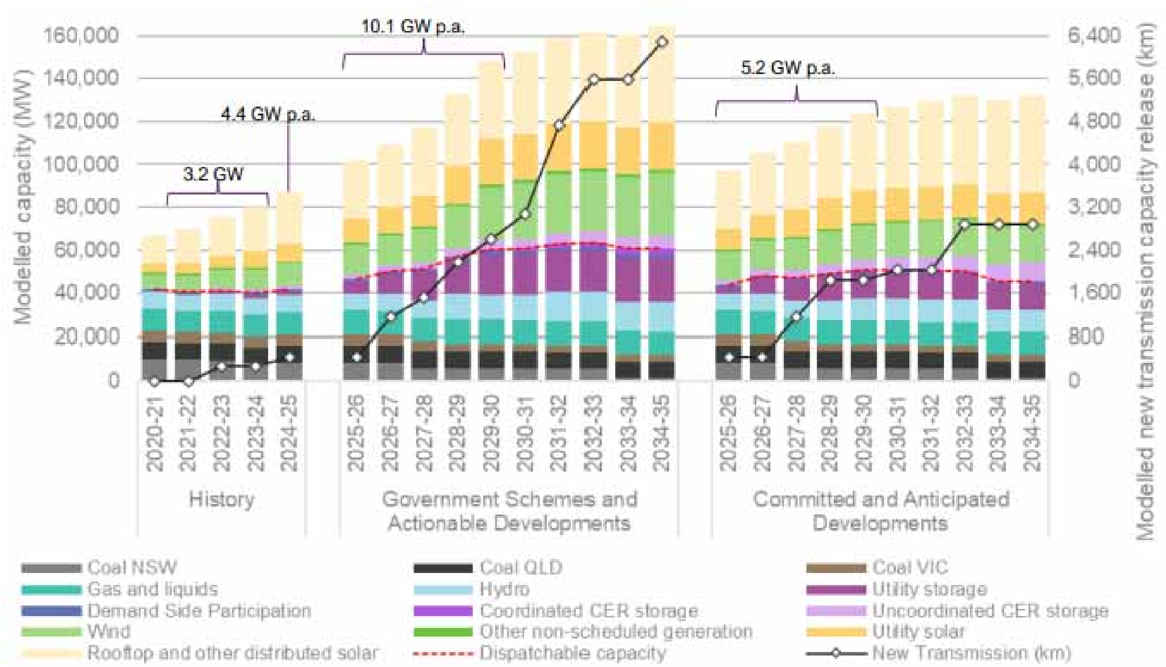
- around 10 GW of coal capacity is expected to withdraw, including Yallourn (2028), Eraring (2029) and Gladstone (2029)[12]
- over 30 GW of new utility-scale wind and solar capacity is expected to be commissioned
- committed and anticipated grid-scale battery capacity is forecast to exceed 12 GW
- demand is forecast to increase from 178 TWh to 207 TWh
- rooftop solar capacity is expected to reach more than 35 GW, reducing daytime operational demand.

The scale of the investment challenge that is critical to meeting customer outcomes is clearly illustrated in Figure 1.2 below.

11 For more details, see Chapter 2 of the Issues paper.

12 The updated closure date of Gladstone is not reflected in the 2025 ESOO.

Figure 1.2: ESOO historical and forecast capacity mix



Source: AEMO, 2025, Electricity Statement of Opportunities

Note: 10 year infrastructure development outlooks under typical summer availability assumptions with annual new utility-scale generation and storage commissioning quantities identified

The role of generators in the NEM is evolving as the thermal generation fleet continues to be replaced by VRE. Historically, generators either provided baseload, in the case of coal, or peaking energy, primarily in the case of Open Cycle Gas Turbine (OCGT) plants. However, as we transition, generators now provide at least one of three energy services: bulk VRE energy, intraday shaping, and firming services. Different technologies typically provide these services, and an efficient and reliable system requires a reliability framework that effectively facilitates the delivery of all three.[13]

As bulk renewables become the predominant source of electricity, prolonged periods of low solar and wind output (renewable droughts) can drive temporary shortfalls. As identified in the Panel's *form of the standard* work and albeit unlikely, these shortfalls could span longer durations and be larger in magnitude than historical experience suggests, reinforcing the need for long-duration storage and flexible gas firming.[14]

1.3.2 Rooftop PV and changing consumer behaviour are increasing uncertainty in long-term demand forecasting

The underlying modelling that seeks to optimise the reliability standard and settings is becoming more complex, reflecting the increased uncertainty in long-term assumptions and forecasting. As the generation fleet becomes increasingly weather-dependent, customers become increasingly self-reliant, and projected system load continues to evolve, the challenge persists. It is driven primarily by:

- inherently variable output from renewable energy sources

13 For more details, see section 2.1 of the issues paper.

14 AEMC, Review of the form of the reliability standard and administered price cap, Final report, 27 June 2024.

- a continuing acceleration of rooftop PV deployment in the NEM[15]
- reducing operational demand, which has implications for the delivery of additional generation and system security[16]
- increases in the update of electric vehicles and distributed storage
- uncertainty surrounding the future demand on the power system driven by electrification or data centres.

We expect such complexity, faced by regulators and market participants alike, to remain until the transition away from a thermal-dominated fleet to one relying on variable renewable energy is complete.

1.3.3 Increasing price volatility in the wholesale market

The transition is also clearly visible in wholesale market outcomes, with prices fluctuating from negative and near-zero prices when VRE generation is abundant to intervals of higher prices when VRE output is low, demand is high, or when transmission outages constrain generation.

Together, these changes are broadening the conditions under which reliability events may occur. Instead of a single summer peak, the NEM now faces multiple reliability stress points across seasons and times of day. Despite this, modelling and operational evidence show that the overall likelihood of USE remains low. The reliability standard is consistently met in almost all scenarios, demonstrating the resilience of the existing market design. However, the reliability settings must be resilient to volatility and ensure that market outcomes continue to incentivise the optimal and efficient capacity mix to best meet the long-term interests of consumers.

Chapter 2 of the issues paper provides further details on NEM's transition and its implications.

1.4 The Panel's approach to considering the effect of jurisdictional schemes

This Review is undertaken in the context of the introduction of a range of jurisdictional schemes, such as the Commonwealth's Capacity Investment Scheme (CIS), NSW's Long-term Energy Services Agreements (LTESAs) and SA's Firm Energy Reliability Mechanism (FERM). This not only impacts reliability modelling, but real-world reliability outcomes. These impacts are particularly salient as some of these schemes end in 2030, which falls in the middle of the RSSR period.

The market settings must continue to support delivering the optimal level of reliability that customers value at the lowest cost. As such, the Panel has assessed the implications of jurisdictional schemes on the appropriate level of the reliability standard and market price settings. The Panel's final position is to recommend settings that can stand on their own to meet the reliability standard, independent of jurisdictional schemes. This provides valuable assurance that reliability will be maintained, regardless of future market interventions. However, we have considered the effects of jurisdictional schemes on determining the marginal new entrant generator as part of the first stage of our modelling. We did this by running a low weighted average cost of capital (WACC) sensitivity.

The Panel is united in seeking to deliver final recommendations and market settings that meet the optimal reliability standard at the lowest long-term cost for consumers.

15 AEMO's draft IASR projects rooftop PV capacity in the NEM to increase to nearly 29 GW, growing to more than 36 GW by FY2032.

16 For example, AEMOs 2025 ESOO projects minimum operational demand in NSW of 1,977 MW in FY2028.

1.4.1 The NEM review's final recommendations complement the spot market and the market price settings

Announced in November 2024, the Commonwealth Department of Climate Change, Energy, the Environment and Water (DCCEEW) commissioned an independent expert panel (the Expert Panel) to perform a review of the NEM wholesale market settings in order to arrive at recommendations for supporting the investment needed (following the conclusion of CIS tenders in 2027).

The final recommendations of the NEM Review may have significant implications for the reliability outlook for FY2028 to FY2032, and particularly for any future RSSR period. The Panel has engaged closely with the Expert Panel to determine the implications of their final recommendations on the appropriateness of the reliability standard and market price settings.

A key recommendation of the NEM Review is the introduction of an Energy Services Entry Mechanism (ESEM), a centralised body that seeks to bridge the tenor gap (the misalignment between the contracting needs of generators and customers) and drive investment in bulk renewables, shaping and firming in line with jurisdictional targets. Under the ESEM, jurisdictions could also procure out-of-market reserves to deliver reliability outcomes that exceed the reliability standard, the delivery of which and its associated costs should not rely on wholesale market-driven investment.

Both the Reliability Panel and the Expert Panel agree that the proposed ESEM serves as a mechanism that complements rather than replaces the role of market price settings. Under the NEM Review's proposals, the market settings should continue to be capable of delivering the efficient level of investment critical to meeting power system needs, otherwise, there are risks of:

- significant market distortions with investments becoming dependent on out-of-market jurisdictional support
- existing generation experiencing revenue insufficiency
- inefficient distortions leading to a sub-optimal capacity mix, thereby increasing overall costs for consumers.

1.5 Stakeholder consultation and engagement

The Panel has conducted extensive stakeholder consultation throughout this review, including seeking feedback on the issues paper and draft report. The Panel also held a number of stakeholder meetings as required.

The Panel received 18 submissions in response to the draft report. The Panel has considered stakeholder feedback in finalising its conclusions. The feedback provided is reflected throughout this final paper.

Table 1.2 outlines the key stages of the review and the associated stakeholder consultation periods.

Table 1.2: 2026 Reliability Standard and Settings Review timeline

Issues paper published	19 June 2025
Close of stakeholder submissions	17 July 2025
Draft report published	27 November 2025
Close of stakeholder submissions	22 January 2026
Final report published	23 April 2026

1.6 Structure of this report

- Chapter 2 discusses how the final reliability standard would promote the NEO.
- Chapter 3 discusses the final recommended form and level of the market price cap and cumulative price threshold.
- Chapter 4 discusses the level of the market floor price and the administered price cap.
- Appendix A discusses background and context.
- Appendix B discusses the assessment principles.
- Appendix C discusses the detailed modelling methodology and results.

2 A reliability standard of 0.003 per cent USE

Box 2: Key points in Chapter 2

- The reliability standard is an ex-ante planning standard that defines the maximum amount of unserved energy (USE) that we expect to occur in a year. It forms the core of the NEM's reliability framework by expressing the optimal level of generation and transmission capacity that customers value at a point in time.
- Setting the level of the standard involves an inherent trade-off: a higher standard means fewer outages (lower USE), but higher costs, whereas a lower standard tolerates more outages (higher USE) with lower costs. The Panel's role is to balance these costs and benefits in line with what customers value.
- The reliability standard is the key input to determine the market settings (the MPC, MFP, CPT and APC) that define the price envelope that is applied to spot market outcomes.
- **The Panel's final recommendation is that a reliability standard of 0.003 per cent USE (99.997 per cent reliability) best serves the long-term interests of consumers** by balancing the incremental cost of new capacity and what customers ultimately value.
- We concluded that a slight relaxation of the reliability standard would have **minimal day-to-day impacts on the reliability outcomes consumers would actually experience**, increasing the planning timeframe target from an average of 10 minutes to 16 minutes of unserved energy per year, while **avoiding cost increases that would be required** to meet the current 0.002 per cent USE standard. In the current cost-of-living environment, **the Panel considers it particularly important to avoid increases in market price settings that would raise consumer bills without delivering commensurate benefits**.
- Importantly, in real time, the system will continue to operate at very high levels of reliability, supported by a range of out-of-market and jurisdictional tools. These measures are intended to complement, rather than replace, the market-based reliability framework.
- As the Panel has previously acknowledged, consumers' experience of reliability is expected to remain high. However, during rare and extreme events, when both market-based and out-of-market measures are insufficient, a subset of consumers may experience rotational load shedding.
- The proposed revision to the reliability standard represents a modest relaxation of the long-term target, equivalent to moving from approximately three hours to five hours of rotational load shedding for around half the population once every ten years. This reflects a potential small increase in rare but controlled operational load shedding used to manage supply-demand imbalances during periods of resource inadequacy, noting that in practice, such load shedding is extremely infrequent, with its impacts unevenly distributed across customer groups.
- Moreover, given that more than 99 per cent of the outages customers experience are due to network outages, we consider that our final recommendation best promotes the long-term economic interests of consumers, in the context of the evolving relationship of consumers with the wholesale electricity market.

- Stakeholder submissions to the draft report supported the Panel's focus on regulatory stability to support critical and capital-intensive investments in new generation capacity. Views diverged in terms of the optimal level of the reliability standard, with:
  - several stakeholders arguing that retaining both the current reliability standard and settings is critical to maintain regulatory stability and support investment certainty
  - some stakeholders supporting the Panel's draft position that a slight relaxation of the standard could be warranted, given the outcome of the Panel's economic modelling and the underlying trends we identified: an increase in the cost of gas generation and a reduction in the value customers place on reliability
  - a small number of stakeholders calling for the settings to be significantly reduced, the standard to be further lowered, or both.
- The Panel's final recommendation seeks to promote regulatory certainty, while aligning the reliability standard with what customers ultimately value, by retaining the current reliability settings that are critical to support investment. To ensure the outcome is reconcilable with the modelling outcome, we have decided to modestly relax the optimal reliability standard. Such a change would result in a minor difference in the reliability outcomes consumers experience, while ensuring that market price settings can realistically deliver the long-term target. Retaining the current standard would have decoupled the Panel's recommendation from the economic modelling and resulted in a planning timeframe standard that is unlikely to be achieved under the current market price settings.
- The changing profile of reliability risk was factored into determining the standard's level. The Panel considered how the transition to renewables, increasing decentralised generation, evolving demand patterns, the value of customer reliability (VCR), and the importance of regulatory stability influence the choice of a national standard to best meet customer expectations across all NEM regions.

This chapter outlines the Panel's final recommendation on the level of the reliability standard from 1 July 2028 to 30 June 2032. Specifically, this chapter outlines:

- Section 2.1 — the purpose of the reliability standard is to represent the trade-off between costs and reliability for customers.
- Section 2.2 — the Panel's final recommendation of the optimal level of the reliability standard
- Section 2.3 — the reliability standard reflects the value customers place on a reliable supply of electricity
- Section 2.4 — the value of regulatory stability
- Section 2.5 — the reliability standard as a NEM-wide measure.

The NER and the 2021 guidelines set out specific requirements for what the Panel should consider and the assessment criteria it must apply when reviewing the standard. The Panel has applied these assessment criteria to consider the standard's level in this 2026 RSS review, alongside the Panel's guidance on applying the emissions reduction component of the NEO. The Panel has also conducted a materiality assessment to ensure changes are recommended only when there is a material benefit, thereby supporting investment with stable, predictable outcomes for market participants.

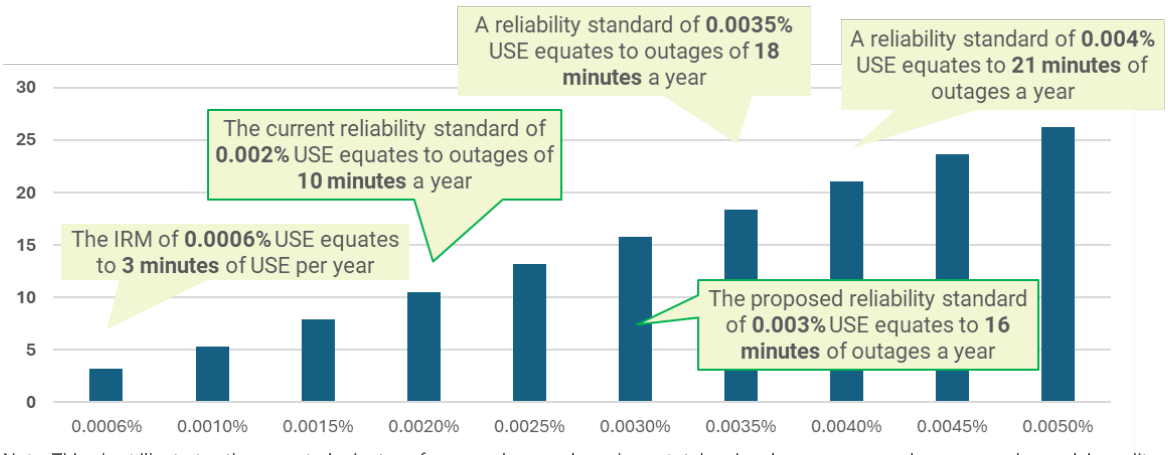
Under the 2021 RSS guidelines, the Panel can consider both the form and level of the reliability standard. However, as noted in the issues paper and the draft report, the Panel has not reconsidered the form of the standard, given that our recently completed and comprehensive review concluded that unserved energy is still an appropriate measure as we continue to transition to a renewable-dominated generation fleet.[17]

2.1 The reliability standard represents the trade-off between cost and reliability for customers

The reliability standard in the NEM serves as a benchmark for adequacy of supply. Its defines the maximum expected amount of energy that is at risk of not being served in a region in a given financial year, by providing a clear, actionable expression of the economically efficient level of generation and transmission capacity. The standard does not guarantee that supply shortfalls will never occur nor does it define the maximum in any event. It provides a probabilistic benchmark, guiding investment and operational decisions to achieve reliability efficiently across the long term. Shortfalls can still occur during rare combinations of extreme weather, plant outages or network events. What matters is that, over time, the expected level of USE aligns with what consumers are willing to pay to avoid — the efficient level of reliability.

The current standard, in force from 1 July 2025 to 30 June 2028, is expressed as expected USE of no more than 0.002 per cent in each NEM region in a financial year.[18] In practice, under the standard, the total energy disruption to customers would not exceed around 10 minutes of lost supply per customer per year.[19] [20]Figure 2.1 below translates different USE levels into the estimated equivalent time customer supply would be disrupted.

Figure 2.1: Customer outcomes at different USE levels (number of minutes per year)



Note: This chart illustrates the expected minutes of unserved energy based on a total regional average, assuming average demand. In reality, individual customer outcomes may differ from this depending on the nature of the unserved energy events.

The standard is based on an economic trade-off made on the basis of estimates of the value that consumers place on different levels of reliability. It is a key input to the various market settings, comprising the MPC, MFP, CPT, and APC, which define the price envelope that applies to spot

17 Reliability Panel, Review of the form of the reliability standard and administered price cap, Final Report, 27 June 2024.

18 In 2020, federal and state ministers, on the advice of the Energy Security Board (ESB), endorsed an Interim Reliability Measure (IRM) of 0.006% USE. This measure currently only applies for triggering the Retailer Reliability Obligation (RRO). The IRM trigger for the RRO will end on 1 July 2028, the commencement of the period for which this RSS review applies.

19 This figure is calculated based on a total regional average, assuming average demand, and taking into account load shedding processes.

20 Under the proposed revision, this represents a modest relaxation in the long-term planning target, from approximately three to five hours of rotational load shedding for around half the population once every ten years, noting that the impacts of load shedding are not evenly distributed across consumers.

market outcomes. Box 3 below provides more details on the role of the reliability standard in the NEM, and chapter 3 provides further discussion on the market price settings.

Box 3: The role of the reliability standard in the NEM

The standard provides a clear, actionable expression of the economically efficient level of generation and transmission capacity sought for the NEM. In the NEM, the standard is an ex-ante standard that indicates to the market the required level of supply to meet regional demand. It is not a regulatory or performance standard that is 'enforced'. Rather, it indicates the level of reliability required to inform the market under the NEM reliability frameworks.

In simple terms:

- a higher reliability standard represents less unserved energy and would require greater investment in generation capacity with higher consumer costs, and
- a lower reliability standard would represent more unserved energy and would require less investment in generation capacity with lower consumer costs.

It seeks an economic optimum in which the marginal cost of adding more reliability is equal to the marginal value of reliability to customers.

AEMO is responsible for operationalising the standard through its forecasting processes, modelling and projecting whether the market will deliver adequate levels of capacity to meet the standard. It does this across a number of time frames, from years ahead to real-time, through the various ESOO reports, in the projected short- and medium-term assessment of system adequacy (ST-PASA and MT-PASA) and through RERT procurement.

Source: AEMO, Reliability Standard Implementation Guidelines, 23 October 2025, pp. 7-8.

It is important to note the scope of the reliability standard. The NER strictly defines the types of outages that count as USE for the purpose of the standard. As outlined in appendix A.1, only supply interruptions due to insufficient supply or interconnection capacity are considered. Some types of outages are excluded from the standard as remedies or protections would not be efficient, this includes outages such as force majeure events from extreme weather or other system security events. Industrial action is also excluded. The vast majority of outages experienced by consumers are related to local distribution network interruptions and also do not count towards the standard. This distinction is crucial to ensure that the reliability standard remains focused on ensuring resource adequacy and that customers do not incur excessive costs.

Stakeholders broadly acknowledge the standard's central role in the NEM's reliability framework. The Australian Energy Council (AEC) emphasised that the standard and settings, together, make a critical contribution to delivering the marginal plant needed to achieve the reliability customers expect.[21]

Similarly, Energy Consumers Australia (ECA) noted the tension between cost and customer reliability outcomes that the Panel is tasked with grappling with:[22]

> Consumers tell [the ECA] that the most important features of an energy plan are keeping energy bills as low as possible and ensuring a stable, reliable electricity supply with minimal outages. This review is therefore critical to ensuring these outcomes are met efficiently and fairly for all consumers.

21 AEC, Submission to the issues paper, 17 July 2025, p.5.

22 Energy Consumers Australia, Submission to the issues paper, 17 July 2025, p.2.

In striking this balance, the Panel is mindful that the standard represents consumers' aggregate willingness to trade-off incrementally higher levels of reliability in exchange for lower bills. The Panel is also required to set a national standard and national market price settings to recognise the interconnected nature of the NEM.

2.1.1 Stakeholder submissions to the draft report strongly argued for regulatory stability, with diverging views on the optimal level of the reliability standard

Stakeholder submissions supported the Panel's focus on regulatory stability, given its importance in delivering large-scale, capital-intensive investments in the new generation. However, views diverged in terms of the optimal reliability level:

- Several stakeholders advocated for retaining the current reliability standard level of 0.002 per cent USE (99.998 per cent reliability) to support regulatory stability and due to the volatility of the underlying data.[23]
- Several stakeholders agreed with the Panel's draft recommendation to relax the reliability standard in line with the modelling results. EnergyAustralia, Akaysha, Alinta Energy, Tesla, and Origin Energy supported the Panel's initial view that 0.003 per cent USE (99.997 per cent reliability) may best serve consumers' long-term interests,[24] while Shell and consumer representatives noted that total system costs are minimised at a reliability standard between 0.004-0.0045 per cent USE.[25]

The Panel's overall view remains that clear and predictable investment signals are critical to support large-scale new generation capacity. However, we have concluded that prioritising regulatory stability in the market price settings, while allowing the reliability standard to evolve to align with the outcome of our analysis, best serves the long-term interests of consumers. Retaining both the current standard and settings would decouple the Panel's recommendations from the outcome of our economic modelling and the underlying trends: an increase in the cost of open cycle gas turbines (OCGT) firming and a lower value customers place on reliability. Such a decision could reduce the trust in, and the credibility of, the Panel's evidence-based approach to determining the optimal reliability level for consumers.

2.1.2 Unserved energy in the NEM has been rare since FY2019

The reliability standard represents the optimal level of unserved energy over the investment timeframe. It seeks to manage the costs ultimately borne by consumers as the cost of supplying an incrementally more reliable supply of electricity increases disproportionately as more units are required to serve increasingly unlikely levels of demand. Essentially, the higher the reliability level, the greater the investment in lower-capacity-factor generation required to support increasingly unlikely demand levels. Moreover, as the Panel noted in the review of the form of the standard and the APC, there may be certain high-impact, low-probability events for which the current reliability frameworks are ill-suited. To manage the risk of such low likelihood events, other tools, such as the NEM Review's strategic reserve proposal, could provide additional flexibility and insurance through out-of-market delivered investment.[26]

Over the investment timeframe, the optimal level of reliability guides the determination of market price settings to deliver the efficient level of investment; however, the NEM has experienced very

23 Submissions to the draft report: Snowy Hydro, p.3; CS Energy, p.2; AEMO, p.3; Hydro Tasmania, p.3; AGL, pp.1-2.

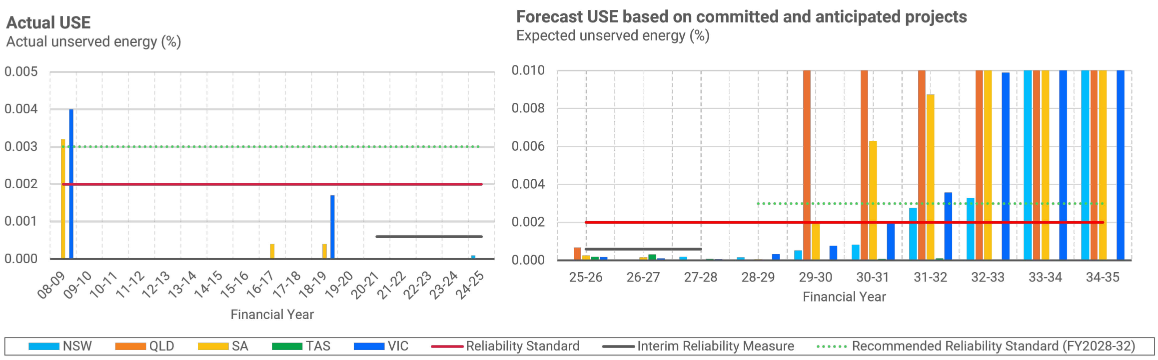
24 Submissions to the draft report: EnergyAustralia, p.2; Akaysha, p.1; Alinta Energy, p.1; Delta Electricity, p.1; Tesla, p.1; Origin Energy, p.1; ENGIE, p.1.

25 Submissions to the draft report: Shell Energy, p.2; EUAA, p.2; Justice and Equity Centre, p.2.

26 AEMC, Review of the form of the reliability standard and administered price cap, Final report, 27 June 2024, p.iv.

few unserved energy events during the operational timeframe. Figure 2.2 from the Panel's analysis highlights that there has been limited instances of unserved energy in the NEM since FY2019:

Figure 2.2: Actual and forecast unserved energy events in the NEM



Source: Panel analysis of AEMO data.

Essentially, the reliability standard accounts for a certain level of unserved energy within the planning timeframe, given that the cost of supplying 100 per cent reliability outweighs the benefits. However, within the operational timeframe, the NEM operates with very high reliability, with most supply disruptions caused by network or system security issues rather than supply inadequacy.

2.1.3 How the Panel's final recommendations for the reliability standard promote the NEO

In determining the optimal level, the Panel is guided by the long-term interests of consumers, the NEO and the general assessment principles set out in the guidelines. In making its final recommendations in this report, the Panel has focused specifically on the following two key principles:

- **Delivering a level of reliability consistent with the value placed on that reliability by customers** – the comprehensive modelling exercise undertaken by the Panel seeks to carefully balance the cost of additional generation and the cost of unserved energy to minimise costs and promote the long-term interests of customers.
- **Providing a predictable and flexible regulatory framework** – the Panel recognises the trade-off between regulatory stability and flexibility to changing circumstances. We are mindful that investment in the NEM depends on a level of predictability; as such, we have conducted a materiality assessment and will continue to account for it when determining the final standard and settings. Moreover, the Panel is aware of the volatility and uncertainty surrounding the underlying data and projections used in our economic modelling. As such, we have used our discretion to recommend a slight relaxation of the reliability standard.

The Panel considers the final recommendations best balance the modelling outcome, the need for stability, and stakeholder submissions to the draft report.

2.2 The modelling suggests the optimal reliability standard is 0.003 per cent USE

Based on extensive economic and power system modelling and analysis, the Reliability Panel's **final recommendation** is that the reliability standard for 1 July 2028 to 30 June 2032 be **0.003 per**

cent expected USE per region per year. This represents a long-term reliability target of 99.997 per cent.

In practice, this means the Panel is recommending a slight relaxation of the standard, as it will likely have minimal practical impact on consumers' day-to-day reliability outcomes, and avoid a significant increase in market price settings and the investment required to meet the current standard. Retaining the current standard would result in unjustified additional market-driven investment, as it would unjustifiably raise consumer costs beyond a level of reliability they likely value.

Moreover, as outlined in Chapter 1, the Panel recognises that consumer reliability outcomes are most sensitive to network performance. This change to the reliability standard will likely have a minor effect on what customers actually experience, especially in the context of a system in which customers' relationship with the grid is rapidly evolving as the penetration of distributed energy continues to accelerate.

The Panel's modelling, as outlined below, identified a broad flat minimum total cost curve around the current standard. Within this band, incremental changes in USE are roughly balanced by the increase in expected costs of unserved energy. Moving to a tighter (higher) standard yields rapidly diminishing costs of avoided outages, while costs increase disproportionately. Moving to a looser (lower) standard quickly results in the cost of outages exceeding the cost of firming generation. The role of the Panel is to recommend an optimal level that adequately manages the trade-offs on behalf of customers.

2.2.1 Consumer outcomes are maximised by a standard of 0.003 per cent USE

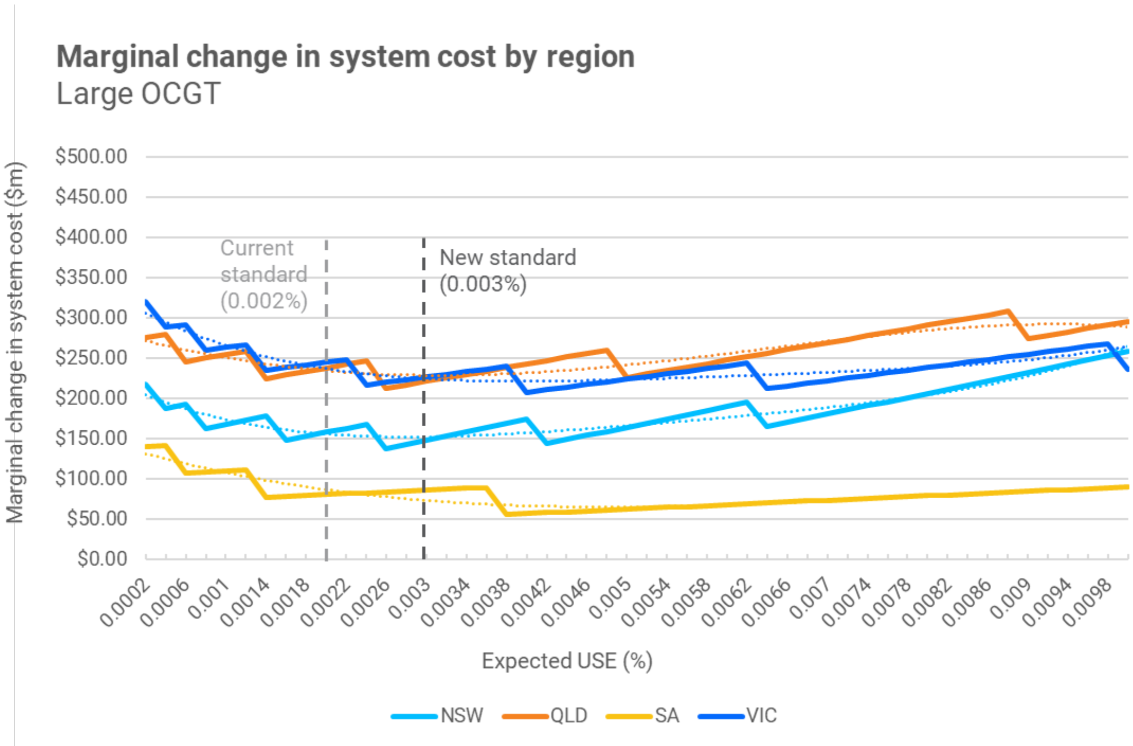
The Panel has undertaken a comprehensive modelling exercise to determine the optimal combination of reliability standard and settings that best meet consumer outcomes by balancing the cost of unserved energy with the cost of additional generation. As outlined in the appendix, our approach sequentially determined the:

- optimal level of reliability (stage 1 of the modelling)
- market price settings required to deliver the optimal level (stage 2 of the modelling).

In determining the optimal level of reliability, the Panel excluded the impact of jurisdictional support schemes that could underwrite new entrant generation by reducing their investment risk. Instead, the Panel sought to assess total system costs on a purely commercial basis, while performing a sensitivity analysis to reflect the potential reduction in the cost of capital for eligible technologies. Our conclusion remains that jurisdictional schemes complement the existing reliability framework and operate alongside it, enabling governments to deliver higher levels of reliability at their discretion.

Figure 2.3 identifies the total annualised system generating and USE cost associated with a range of different new entrant OCGTs, two-hour, and four-hour batteries evaluated using the base case VCR for all regions of the mainland NEM.

Figure 2.3: Total system cost curves are broadly similar between regions



The outcome of the stage 1 modelling indicates that:

- between 0.002 per cent and 0.0035 per cent USE total costs for customers are minimised,[27] with total system costs remaining relatively flat within the band
- 0.003 per cent USE best optimises consumer outcomes in all NEM regions
- the most cost-effective marginal new entrant generator remains an OCGT
- batteries are relatively more suited to being the marginal new entrant in states that have a greater share of variable renewable energy due to different USE event characteristics.

2.2.2 The evolving marginal new entrant to meet the reliability standard

A critical factor in determining the reliability standard (and the associated market settings) is identifying the marginal new entrant technology that is required to deliver reliability at the margin. Historically, in the NEM, this role has been fulfilled by gas OCGTs, given their relatively low capital costs and ability to respond quickly and generate during rare peak-demand and high-price periods.

The Panel's modelling for this review has identified OCGT peaking plant as the marginal entrant in all scenarios during the modelled period. This implies that maintaining the optimal level of reliability through 2028–32 is primarily a question of whether the market settings can incentivise adequate investment in firm generation, with OCGTs setting the benchmark for the revenue required from the market during periods of scarcity.

27 0.002 per cent USE and 0.0035 per cent USE translates to approximately 10 and 18 minutes of unserved energy per year.

However, the energy transition is evolving in response to continuous technological innovation. Rapid cost declines in battery storage, demand-side participation, and CER, as well as emerging long-duration storage options, all affect what the marginal reliability resource could be over the long term. The Panel has considered these trends based on the best currently available information. Our assessment is that, while batteries and demand-side participation will play a growing role in managing intraday reliability, especially during extended shortfall events, during the 2028 to 2032 period, a gas peaker remains the lowest-cost and most efficient option to address reliability gaps - particularly during extended periods of lower-than-expected renewable generation.

This view was echoed by many stakeholders, for example, Origin Energy noted that:[28]

> Ensuring reliability of supply at least cost as the market transitions will inherently still be contingent on ensuring sufficient investment in longer-duration firming capacity, including gas power generation (GPG).

The modelling identifies several key reasons for the role of OCGTs during the review period:

- **Duration and energy limits** – the modelled BESS had two and four hours of storage. While effective for daily peak shaping, the batteries were comparatively less efficient at addressing long-duration and reliability shortfalls due to their relatively high capital cost.
- **USE distributions differed between different NEM regions** – the characteristics of USE events had significant implications for the relative competitiveness of OCGTs versus four-hour batteries. Unserved energy events in regions with a greater share of renewables (for example, South Australia) tended to be shorter, deeper and more suited to battery storage, while states with greater reliance on thermal generation (such as Queensland) tended to have longer and shallower USE events more suited to gas firming.

In conclusion, for 2028–32 period, the Panel's analysis affirms that OCGTs remain the benchmark technology to deliver reliability at least cost. Undoubtedly, the market will deliver the optimal capacity mix, comprising OCGTs, batteries, and demand side participation, based on specific market needs as technology costs and constraints continue to evolve. However, it is crucial that the market settings are sufficient to incentivise investment in gas firming, ensuring that consumer outcomes are met at the lowest cost.

Batteries could be the marginal new entrant for the next review, with implications for the modelling approach

The Panel recognises that batteries are becoming increasingly cost-competitive and their capabilities are improving. It is quite plausible that, for the next RSSR, battery storage could emerge as the marginal new entrant rather than an OCGT. The Panel's final recommendation in this review is based on current conditions (with OCGT as the marginal technology), but we flag this impending shift in marginal technology so that stakeholders can help us anticipate future developments.

The main complicating factor is that a battery can earn significant revenue outside of USE events, by arbitraging energy and providing ancillary services (like frequency control). An OCGT, by contrast, typically earns most of its revenue in a small number of very high-priced periods. This means that if a battery becomes the marginal entrant, the way we calculate the required revenue for that entrant might need to evolve. This is a complex issue that the Panel is not directly addressing in this review, but will consider going forward.

28 Submission to the issues paper, Origin Energy, pp 1-2.

2.3 The reliability standard reflects the value customers place on a reliable supply of electricity

The Panel has taken into account the AER's most recent VCR in determining the efficient level of reliability as expressed in the standard.[29] In making its final recommendation, the Panel also considered any marked or forecast changes in the way consumers use electricity, particularly through new technology, that suggest many consumers may place a lower or higher value on a reliable supply of electricity from the NEM.

2.3.1 The VCR is used to assess the costs of unserved energy, but the Panel acknowledges that it does not perfectly capture consumers' complex preferences

The value of customer reliability (VCR) represents consumers' willingness to pay for reliability and is therefore a critical input to the Panel's assessment. The Panel uses the VCR to inform a reliability standard that balances having sufficient generation and demand response to meet customer demand in most circumstances, while ensuring that consumers are willing to pay the associated costs.

The NER requires the Panel to have regard to any VCR determined by the AER and allow the Panel to take into account other matters specified in the RSS Review 2021 Guidelines, as well as any additional factors it considers relevant. This section explains how the Panel has applied the VCR figures published by the AER in the context of those broader considerations.

The Panel has used a jurisdictional customer load-weighted VCR as its base case, based on the values from the AER's 2024 survey. These values reflect the customer composition of the network as per the guidance provided in the AER's final report. The Panel considers that, while the customer load-weighted VCRs are a single-point estimate, they still represent the best estimate of the VCR as a base case for assessing the reliability standard.

The Panel also recognises, as outlined in the issues paper and reflected in stakeholder submissions,[30] that no single VCR can fully capture the diversity of consumer values placed on reliability. VCRs differ between residential and business customers, across climate zones, and by energy consumption patterns. Even the AER's comprehensive assessment cannot fully capture the variation in individual preferences, nor differences in the value placed on reliability under specific conditions, such as extreme heat events compared with mild weather. Moreover, there remain different views on the societal impacts of USE versus its economic impacts.[31]

Stakeholders responding to the draft report further highlighted uncertainty in the VCR estimates.[32]CS Energy noted that:[33]

> The five years 2019-2024 were shaped by the highly unusual economic conditions caused by the policy responses to Covid-19. Bearing in mind the reliability standard is intended to contribute to long term investment certainty, an abundance of caution is warranted in considering these VCR results in recommending a change to the reliability standard.

The Panel's final recommendation reflects this uncertainty by adopting a gradual adjustment to the reliability standard, rather than targeting the absolute minimum level suggested by the modelling. The Panel remains of the view that the VCR should continue to be a key input in

29 Clause 3.9.3A(e) of the NER.

30 Submissions to the issues paper: AEC, p.2.

31 Submission to the draft report: AEMO, p.2.

32 Submission to the draft report, CS Energy, p.2, AGL, p.1., ENGIE, p.2.

33 Submission to the draft report, CS Energy, p.2

determining outcomes that promote consumers' long-term interests. This link was broadly supported by stakeholders.[34] However, even aside from the evolving relationship between consumers and wholesale market reliability, the clear increase in the cost of firming capacity independently supports reconsideration of the reliability level that best aligns with consumer value.

2.3.2 The Panel has conducted a sensitivity analysis to determine the materiality of different VCR outcomes

The Panel has conducted a sensitivity analysis using the following low and high case VCRs, to capture the impact of this uncertainty on the efficient level of reliability, accounting for different customer types and classes, rotational load shedding practices, and outage duration. In summary, the:

- **Low case VCR** – the Panel has re-weighted the AER's customer load weighted VCR to increase the proportion of large commercial and industrial loads. The low case reflects the Panel's uncertainty surrounding the reliability expectation as the power system transitions and customers continue to adopt distributed energy resources and other forms of backup generation.
- **High case VCR** – the Panel has re-weighted the one-hour duration VCR values for all customer segments. This approach addressed the general duration of rotational load shedding, which typically affects only individual customers for up to one hour.
- **Residential-only VCR** – given that the latest AER VCR results outline large divergences between the values that residential, commercial and industrial customers place on reliability, the Panel has also run a sensitivity analysis to determine the optimal reliability standard, taking only the residential VCR values into account to account for the fact that they are most likely to be affected by load shedding.

The Panel found that the VCR sensitivities resulted in intuitively consistent outcomes. A higher VCR resulted in a tighter standard, and vice versa. Based on the analysis, the Panel proceeded with the base-case VCR assumption.

2.4 The Panel's broader considerations and stakeholder feedback reinforce the value of stability and certainty for investments

The Panel has also considered broader market and policy factors relevant to the reliability standard:

- **Market evolution** – the end of existing jurisdictional schemes (such as the Capacity Investment Scheme (CIS) and the renewable energy target (RET)) and the potential introduction of new support mechanisms (including the Electricity Services Entry Mechanism (ESEM) result in regulatory uncertainty but could provide additional derisking to incentivise investment in new firming capacity.
- **Operational experience** – there is some evidence to suggest that reliability pressures are increasing and operational reliability is becoming more challenging for AEMO to manage.
- **Integration with emissions objectives** – the reliability framework now sits within an amended NEO that includes emissions reduction.
- **Investment stability and certainty** – stakeholders consistently emphasised the value of stability and predictability in investment parameters. Frequent changes risk undermining

34 Submissions to the draft report: HydroTasmania, p.1; EnergyAustralia, p.1, JEC, p.4, EUAA, p.1

investor confidence and increasing uncertainty for new projects. When seeking to support investment stability, the Panel has discretion to make gradual changes to the standard and settings to reflect underlying uncertainty and evolving conditions.

- **Supply chain constraints and permitting barriers** – the market price settings are not able to resolve some of the other underlying issues delaying the deployment of new firming generation. Supply chain constraints, particularly for gas turbines, transformers and synchronous condensers, have led to increased international competition and long lead times. Moreover, local, state and commonwealth permitting and environmental approvals can further delay the construction and operation of critically needed capacity that is essential to meeting customer needs as the power system transitions.

2.4.1 The Panel will only recommend changes to the standard or settings when convinced that it is in the long-term interests of consumers

A consistent theme in stakeholder submissions – and a key principle for the Panel – is the importance of stability in the reliability standard and settings. Regulatory stability supports investor confidence. Project developers and market participants make long-term investment and operational decisions based on expectations of the market framework. The need for stability was noted by broad groups of stakeholders, such as the AEC who stated that:[35]

> Given their importance, a well-functioning NEM depends on stable and predictable reliability settings. This is not to suggest that they should never materially change – recent important improvements include an increase in the APC following the market suspension event of 2022 – but that volatility in the settings is best avoided.

Frequent or unpredictable changes to the standard or pricing settings could increase risk premiums, inhibit investment, or even prompt the disorderly exit of existing capacity due to inadequate market revenues. The Panel is acutely aware of this, and our final recommendations are intended to evolve the settings only where clearly justified, in line with the RSS review guideline materiality threshold.

The Panel's approach to materiality is that any change should yield a meaningful improvement in reliability outcomes or market efficiency for consumers and outweigh any associated costs or disruptions. Our final recommendation is to relax the standard to 0.003 per cent USE, as the evidence suggests it best aligns the cost of providing a reliable supply of electricity with reduced consumer expectations of reliability and rising generation costs.

Most stakeholder submissions to the draft report supported the Panel's focus on regulatory stability to support critical generation investment in generation

The Panel notes that stakeholder submissions to the draft report strongly supported the need for regulatory stability to support long-term capital allocation decisions.[36] Given the nature and scale of energy investments:[37]

> Stable and predictable reliability settings are essential for a well-functioning NEM and that volatility in the settings does not help regulatory stability. Recent increases in market settings should be allowed to take effect before further significant changes are made.

35 Stakeholder submissions to the issues paper: AEC, p.1; Origin Energy, pp. 2-3; AFMA, p.1; Snowy Hydro, p.1; Hydro Tasmania, p.1.

36 Submissions to the draft report: Snowy Hydro, p.4, CS Energy, p.2, AEMO, p.3.

37 Snowy Hydro, submission to the draft report, 29.01.2026, p.4.

Our final recommendations strongly align with this view by prioritising stability in the market price settings. Although several stakeholder submissions recommended it, we do not consider it appropriate to maintain both the current reliability standard and market price settings, as our modelling and the clear trends underpinning it indicate that the current price settings would be insufficient to realistically meet the current 0.002% USE standard.

Were the standard and the settings to be clearly misaligned, as recommended in some submissions, a missing money problem would likely eventuate, resulting in a disconnect between what reliability outcomes we target and what is delivered. We do not consider that such an outcome would serve the best long-term interests of consumers.

Several consumer representatives advocated that consideration of regulatory stability should not impede the relaxation of the standard nor the settings

Consumer representatives, including the JEC, emphasised that the reliability standard and settings should reflect consumers' willingness to pay for reliability and adapt as preferences and market conditions evolve.[38] They expressed concern that placing too significant a weight on regulatory stability could unduly constrain the Panel's ability to adjust the standard in response to updated evidence, particularly where consumers face rising energy costs and where changes are characterised as incremental rather than structural. From this perspective, consumer representatives argue that regulatory stability should not, of itself, impede a relaxation of the reliability standard where doing so better aligns outcomes with contemporary consumer value.

The Panel agrees that regulatory stability should not be supported at all costs. Rather, gradual revisions to the reliability standard and settings allow the market to adjust over time to evolving circumstances, while also recognising the underlying uncertainty and volatility in the inputs that inform the Panel's analysis.

Stability is not treated as a barrier to change, but as a relevant consideration where decisions affect long-lived investments, risk allocation, and market confidence. Consistent with this approach, the Panel has evolved the standard and settings where the evidence clearly justifies doing so, including following the 2022 RSSR.

While JEC characterises a relaxation of the standard as a minor and incremental change, the Panel considers that changes to the reliability standard are inherently material, as they directly affect investment signals, expected reliability outcomes, and the alignment between the standard and market price settings. Even relatively small changes to the standard can have meaningful implications for capacity investment, risk premiums, and the timing of entry and exit decisions, particularly in a market undergoing significant structural change.

Importantly, regulatory stability does not imply preserving existing standard or settings where they are no longer fit for purpose. Instead, it requires that changes be well-justified, proportionate, and predictable. The Panel's recommended relaxation to 0.003% USE reflects this approach. It represents a measured adjustment that better aligns the standard with consumer value and prevailing conditions, while avoiding the risks associated with either maintaining a clearly misaligned standard or making a larger, more disruptive change.

In the Panel's view, this approach best promotes the long-term interests of consumers by balancing efficiency, affordability, and investment confidence, rather than prioritising any single consideration in isolation.

38 Submission to the draft report: JEC, p.3.

2.5 Although the reliability standard is a NEM-wide measure, reliability outcomes differ by region

The NEM's reliability standard is a national benchmark applied to each region, but the nature of reliability risk can differ markedly from one region to another, depending on the stage of the energy transition and the interconnection capacity. In setting the standard level, the Panel must ensure the outcome is fit-for-purpose across all regions, adequately protecting consumers in every state without over-investing in any one area.

In practice, when determining the required capacity level (and the market settings to support it), the region with the greatest reliability shortfall risk tends to be the one on which the greatest focus is placed.[39] If one region is forecast to experience more frequent, larger, or longer USE events than others (relative to demand), meeting the standard in that region will generally ensure that all other regions meet it too. The Panel's modelling and analysis for 2028–32 identified Queensland as the region most likely to drive the reliability outcome, because:

- Queensland has relatively limited interconnection with the southern states, meaning it cannot always lean on imports if local generation is scarce.
- Queensland still relies heavily on ageing coal generation, a large portion of which is slated for retirement in the 2040s. As these retirements approach, reliability risk can increase, especially if closures happen earlier than expected or if plant availability declines.
- Queensland experiences summer heatwaves that drive very high peak demand. These events can strain the supply-demand balance for days at a time, resulting in extended USE events.
- Continued and significant growth in rooftop PV in Queensland reduces midday operational demand but requires a steep ramp in demand in late afternoon when solar generation fades.

Different USE energy profiles have emerged in different states based on renewable energy penetration

It is essential to note that the nature of USE events can vary significantly regionally in terms of frequency, depth and duration. This has implications for the appropriateness of market price settings to drive the optimal technology mix. This was highlighted in AEMO's submission to the issues paper:[40]

> AEMO suggests that a practical way to incorporate this may be for the review is to consider the distribution of USE events in terms of depth, duration and frequency when setting the level of the standard. For example, 0.002% average annual USE could equate to forecast USE exceeding 10% of winter demand (depth) for 3 hours (duration), occurring every four to five years (frequency).

The outcome of our modelling confirmed that states could have similar average USE outcomes that materialise in significantly different ways:

- Queensland's risk might be characterised by longer-duration, shallower shortfalls (for example, a heatwave increasing maximum demand).
- South Australia might face shorter, deeper events (for instance, a wind lull coinciding with high demand after sunset could cause a large deficit for an hour or two).

In conclusion, the regional analysis reinforces our decision that a single, nationally-applied reliability standard of 0.003% USE is appropriate and can accommodate the differing reliability risk

39 The 2022 RSSR focused the analysis on reliability outcomes in NSW.

40 AEMO, submission to the issues paper, p.2.

profiles of regions. It will guide the market to invest in the optimal capacity mix in the right locations, at least cost, such that every region remains at or above the economically efficient reliability level. The standard, coupled with well-calibrated market price settings, provides a nationally consistent yet regionally informed approach.

More details on the differences in regional USE outcomes are outlined in the appendix.

3 The form and level of the market price settings

Box 4: Key points in chapter 3

- The market price settings (MPC, CPT, APC, MFP) define the price envelope that underpins investment in generation and demand response in the NEM. They are crucial for delivering the reliability standard. The MPC and CPT, in particular, set the incentive for new capacity by allowing prices to rise during scarcity, while the CPT protects against sustained high prices.
- The Panel's final recommendations on the market settings aim to maintain a balance: providing sufficient revenue opportunities for investments needed to meet reliability, while limiting financial risks for market participants to acceptable levels and preserving regulatory stability.
- In line with the 2021 guidelines, the Panel must only recommend changes to individual settings where a material benefit is evident. Thus, the Panel has not recommended any changes to the MPC or CPT.
- **The Panel's final recommendations are for an MPC of $22,800/MWh and a CPT of $2,325,600 in the base year 2022**.

Modelling results indicate a clear trade-off between reliability and cost. Achieving a tighter reliability standard requires higher market price settings and vice versa. The currently scheduled settings best manage that trade-off.

- In the draft report, the Panel considered a range of MPC/CPT combinations that could support a reliability standard in the range of 0.002–0.0035 per cent USE. The modelling results showed that delivering investment to meet:
  - The current reliability standard of 0.002 per cent USE (99.998 per cent reliability) would require significant increases in the market price settings above and beyond a level that customers are willing to pay for to deliver small increments of additional reliability.
  - A reliability standard of 0.003 per cent USE (99.997 per cent reliability) best balances the cost of new generation investment and the level of reliability customers value. It is also best aligned with the currently scheduled market price settings, thereby supporting regulatory stability.
- The current approach to determining the optimal standard and settings requires a uniform value across all NEM regions. However, the modelling has identified that regional needs differ depending on the size and shape of unserved energy events generation mix and interconnection capacity. As such, the market settings will likely deliver different effective long-term reliability levels. In practice, reliability outcomes remain high in all regions at all times, and we note that these regional differences have been part of the NEM since its inception.

The Panel's final recommendation seeks to strengthen regulatory stability and certainty to deliver the level of investment that is required to meet long-term reliability needs.

- Stakeholders emphasised the need for regulatory stability to foster investment and ensure the effective ongoing operation of the market. The Panel agrees and has preferred regulatory stability in accounting for the uncertainty and volatility of modelling inputs and results.
- In coming to its final recommendations, the Panel decided to prioritise maintaining regulatory stability in the market price settings, given the increases following the 2022 review and the need to support large-scale and capital-intensive investments in new generation. As such, the

reliability standard has been slightly relaxed to align with the modelling outcomes and the underlying trends currently underway: an increase in the cost of gas-firming generation and a reduction in the value customers place on reliability.

- Importantly, although the standard has been slightly relaxed, the changes are unlikely to have any significant effects on the day-to-day reliability outcomes customers experience while shielding them from the increase in the market price settings that would be required to meet the current standard.

The final recommendation is to retain the current form of the CPT

- The Panel considered a range of alternative forms of the CPT (such as counting only prices above a threshold like $300/MWh or counting only peak-period prices) to ensure it remains fit for purpose for the expected future market conditions. After assessment and stakeholder feedback, the Panel recommends retaining the current CPT form, as it continues to best serve consumers' interests. It remains the most straightforward and effective mechanism to integrate the duration of high prices into risk management.
- Moreover, the NEM Wholesale Market Settings review has recommended a broader review of the form of the market price settings. As such, the Panel considers that, subject to Ministerial endorsement, the form of the market price settings in an evolving system will be holistically reviewed and that no changes are warranted as part of the 2026 RSSR.

This chapter outlines the issues and criteria relevant to the Panel's final recommendations of the market price settings to apply from 1 July 2028 to 30 June 2032. The settings are price mechanisms designed to incentivise investment in sufficient generation capacity and demand-side response to deliver the reliability standard, while imposing limits that protect market participants from periods of very high or very low prices, both temporary and sustained.

This chapter sets out the Panel's final recommendations and reasoning, including:

- Section 3.1 — the currently scheduled MPC and CPT align with the new reliability standard
- Section 3.2 — the Panel agrees with stakeholders on the need for regulatory stability
- Section 3.3 — the current form of the CPT is preferable to alternative formulations

Consistent with the RSS guidelines, the Panel has only made recommendations to change individual market price settings where there is a material benefit in doing so. In this instance, the Panel has not recommended any change to the level or form of the MPC or CPT.

3.1 The currently scheduled MPC and CPT align with the new reliability standard

The MPC and CPT share a common purpose in the NEM's reliability framework. Together, these two settings create a price envelope within which the reliability standard is delivered. In simple terms, the MPC provides an incentive for investment in peaking generation, storage, and demand response by defining the maximum possible price signals during periods of scarcity. The CPT works in tandem with the MPC to protect the long-term integrity of the market by limiting participants' total exposure to sustained high prices and limiting the risk of cascading failures.

Because the MPC and CPT function together to balance investment incentives against risk management, the Panel has considered them jointly when assessing potential changes. The objective is to set these values high enough to drive efficient new investment (ensuring sufficient capacity to meet the reliability standard), but not so high that they threaten the financial stability of market participants or lead to excessive price risk. Any change to one of these settings typically affects the other, and the Panel must ensure the combination continues to meet reliability objectives without exposing consumers and retailers to untenable risk.

Critically, previous Panel analysis has found that customer cost outcomes are relatively insensitive to the explicit level of the market price settings, given the hedging strategies retailers employ to manage that risk, the effective allocation of risk, and the investment signals sent to deliver the optimal capacity mix. While setting the MPC too high results in excessive price volatility and risks overbuilding, artificially reducing the MPC could counter-productively worsen long-term consumer outcomes by weakening critical investment signals, thereby resulting in costly unreliability. Average electricity prices better reflect customers' cost exposure than the MPC and CPT levels. The Panel's overall intent remains to promote consumers' long-term interests by achieving the optimal level of reliability at the lowest overall costs.

The Panel has determined that retaining the market settings as they are currently scheduled to be at the start of this review period best balances the need for regulatory stability with delivering reliability outcomes that customers value. This means an MPC of $22,800/MWh and a CPT of $2,325,600 with a base year of 2022.[41]

3.1.1 The Panel's modelling highlights the trade-off between reliability and the market settings

The Panel has examined a range of potential MPC and CPT values corresponding to different reliability standards under consideration (from 0.002 per cent USE to 0.004 per cent USE). This analysis has revealed an efficient frontier of MPC/CPT combinations, a set of pairings of the cap and threshold that can deliver the required level of reliability at the lowest overall system cost.

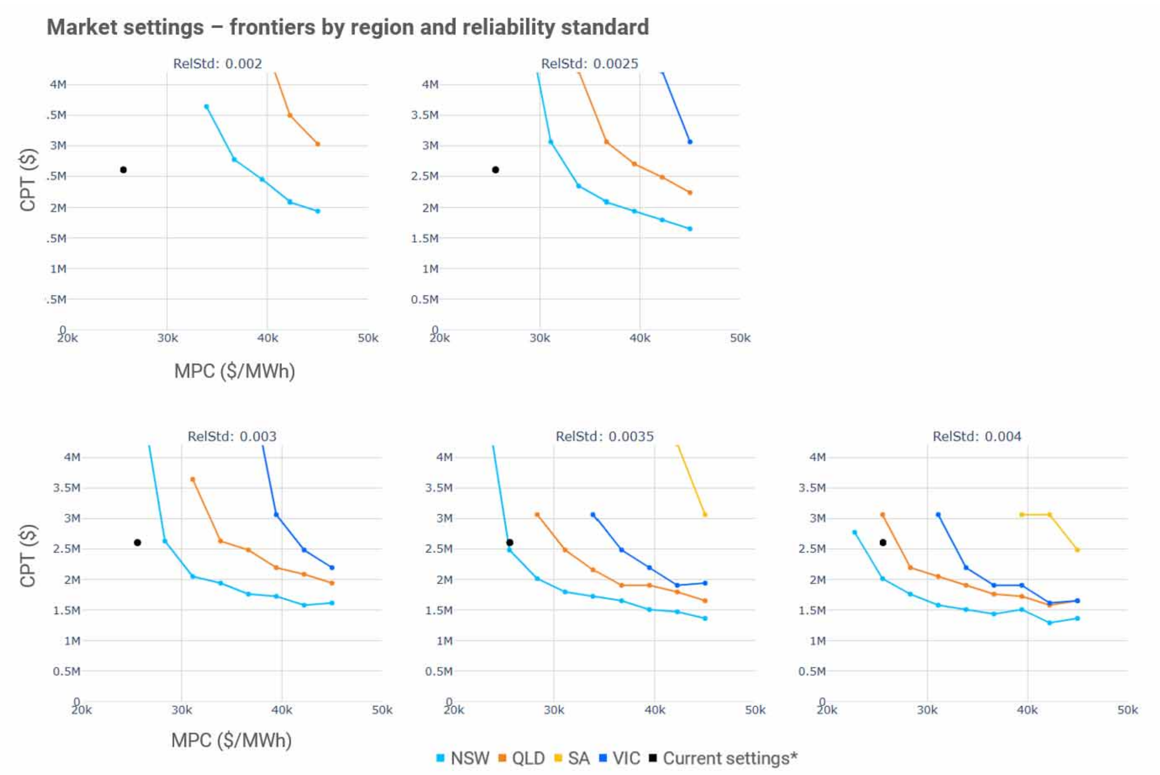
The Panel has published efficient frontiers of MPC/CPT combinations capable of delivering reliability from 0.002 per cent to 0.004 per cent USE

As shown in Figure 3.1 below, the modelling shows that:

- Tighter reliability standards (i.e. a lower allowed USE, such as 0.002 per cent) would necessitate higher price caps and a higher CPT to incentivise the additional investment needed for that level of reliability, which in turn could increase costs to consumers above what they value.
- A slightly more relaxed reliability standard (for example, 0.004 per cent USE) can be achieved with comparatively lower MPC and CPT settings, resulting in lower investment costs and lower total system costs. Albeit with a higher expected incidence of unserved energy.

41 This retains the existing base year of 2022 in the rules. This also reflects the scheduled increase in the market price settings due to take place from 1 July 2027 as per the 2023 *Amendment of the Market Price Cap, Cumulative Price Threshold, and Administered Price Cap rule change*. These figures will be indexed to CPI when they apply from 1 July 2028.

Figure 3.1: Optimal market price settings at different levels of reliability



As described in Chapter 2, the total system cost curve is relatively flat around its minimum, which our modelling indicates occurs at roughly 0.0035 per cent USE. This means that maintaining a reliability standard somewhat tighter than the optimal point (for instance, at the current 0.002 per cent USE standard) would entail increases in system cost, which customers are inherently required to pay for. Together, these findings illustrate the fundamental trade-off between reliability, cost and regulatory certainty.

Meeting the current 0.002 per cent USE reliability standard would require large increases in the market price settings

The Panel's modelling results support the view that some increase in the level of the MPC and CPT would be required if the NEM's current reliability standard of 0.002 per cent USE is to be maintained into the future, reflecting the increase in the cost of new firm generation. To achieve the same outcome, firm peaking capacity (such as open cycle gas turbines (OCGTs) or equivalent resources) would need sufficient revenue opportunities to cover their higher capital costs, which in turn may necessitate a higher MPC and CPT than those presently in place.

The modelling found that, under current settings and cost assumptions, the expected reliability would decrease (USE would increase above 0.002 per cent) unless the price envelope expanded to attract additional investment. In other words, to continue meeting a 0.002 per cent USE standard, the market would likely require an MPC and CPT above the status quo to ensure revenue sufficiency for new entrants. This increase would be approximately to $35,000/MWh for the MPC and $3m for the CPT to deliver this level of reliability in NSW. Greater increases still would be required in other regions. These are drastic increases and do not align with the view that stakeholders expressed in submissions to the draft report that regulatory stability is crucial for the effective function of the market.[42] Furthermore, the price volatility these settings would permit, and the level of investment they would facilitate, do not align with the value customers place on reliability. As discussed in chapter 2, changes to the VCR and input costs mean that 0.002 per cent USE is no longer the level of reliability that minimises overall system costs in line with the long-term interests of consumers.

The currently scheduled market settings deliver reliability that customers value

As illustrated in Figure 3.1 above, the model confirms that relaxing the reliability standard slightly can reduce the required level of market price settings, as lower levels of scarcely utilised firming capacity are required. As noted in Chapter 2, total system costs (the cost of new generation and unserved energy) are minimised at approximately 0.0035 per cent USE. Importantly, this represents a relaxation of long-term reliability targets from 99.998 per cent to 99.9965 per cent reliability (10 minutes to 18 minutes of unserved energy per year). This minor relaxation of the reliability standard for the average customer allows the Panel to deliver the optimal reliability level while retaining the currently scheduled market price settings. The counterfactual outcome, meeting the current reliability standard of 0.002 per cent USE, would require large increases in the MPC and CPT, because the market would need to attract more scarcely-utilised peaking capacity to meet the last fraction of extreme demand.

Consumers face a marginally higher risk of occasional supply shortfalls (noting that more than 99 per cent of outages customers currently experience relate to distribution or transmission outages).[43] However, we model that consumers benefit from the lower overall system costs, which better reflect the value they place on reliability. This includes deferred or avoided investment in peaking generation. The incremental cost of moving to a tighter standard grows rapidly, reflecting the diminishing returns of investment in new generation investment. The currently scheduled market price settings deliver reliability at the optimal reliability standard. Thus, the investment facilitated by these settings corresponds to the value customers place on the reliability that investment provides. In addition to aligning with the level of reliability customers value, the current market settings afford market participants and new entrants the regulatory stability required to deliver investment on the scale needed to meet long-term emissions-reduction and reliability goals. This is discussed further in section 3.2.

3.1.2 While regional disparities remain, the currently scheduled settings manage these best

Our modelling shows that the currently scheduled market settings will deliver approximately to the new reliability standard of 0.003 per cent USE in New South Wales and Queensland. However, the expected reliability outcomes in Victoria and South Australia under these settings have slightly higher levels of USE. This has been true in previous iterations of the RSSR, however those reviews focused on using New South Wales as the representative region for reliability as this was previously where reliability risk was most pertinent. The IES modelling report for the 2022 RSSR found that:[44]

> The corresponding MPC and CPT combinations in Victoria are significantly higher than that in New South Wales owing to the different underlying base USE volume corresponding to 0.002 per cent of its demand, and the associated USE distribution

42 submissions to the draft report: Origin Energy, p. 1; Snowy Hydro, p. 4; AFMA, p. 1.

43 Illustratively, this is equivalent to 16 minutes of USE a year at 0.003 per cent assuming average demand.

44 IES, 2022 RSSR Final modelling report, 31 August 2022, p. 10.

The disparities between regions are primarily due to the different USE characteristics we model in those regions. In South Australia, for example, similar USE levels to other regions are characterised by less frequent, but longer and deeper, reliability shortfalls. This places a higher burden on the market settings to deliver adequate revenue to firming capacity in fewer events, requiring higher settings.

The Panel considers that the currently scheduled market settings are appropriate for the NEM as a whole. This is:

- Firstly, because the market settings required to achieve the reliability standard as an upper bound on modelled USE outcomes in *all* regions would be significantly higher than the currently scheduled settings. This imposes regulatory instability on the market and permits significantly more price volatility than the currently scheduled market settings.
- Secondly, the Panel notes that the varying characteristics of USE in NEM regions mean that South Australia and Victoria have optimal reliability standards that have greater levels of USE than in New South Wales or Queensland. Thus, raising market settings to meet the reliability standard across all regions would not only lead to overinvestment and excess price volatility in those regions, but also deliver reliability above the level customers are willing to pay for in South Australia and Victoria.

Regional disparities are an inherent feature of a national market in transition, with differing needs and interconnection capacity. The Panel is confident that the currently scheduled market settings work best for the NEM as a whole in preserving regulatory stability while best providing customers with the level of reliability they value in all regions.

3.2 The Panel agrees with stakeholders on the need for regulatory stability

Stakeholder submissions to the Draft Report emphasised the importance of regulatory stability in the market. This is crucial to fostering the investment needed to meet reliability and emissions reduction objectives. On the desirability of regulatory stability, Origin Energy commented:[45]

> We consider it unlikely that any changes to the market price [settings]... could deliver benefits that would exceed the value of predictability and stability for the market at this stage.

This echoes Snowy Hydro's comment that:[46]

> Stable and predictable reliability settings are essential for a well-function NEM and that volatility in the settings does not help regulatory stability. Recent increases in market settings should be allowed to take effect before further significant changes are made.

AFMA expressed a similar view about allowing prior changes to take effect, submitting that:[47]

> Given that the market settings were recently demonstrated to be effective in a period of high stress and that the Panel's 2022 recommendations to increase MPC and CPT above the rate of inflation are yet to be fully implemented, we do not consider that there is a case for significant change to either the form or level of the market settings at this stage

45 Origin Energy, submission to the draft report, p. 1, 29 January 2026.

46 Snowy Hydro, submission to the draft report, p. 4, 29 January 2026.

47 AFMA, submission to the draft report, p. 1, 29 January 2026.

The Panel agrees with stakeholders that regulatory stability is a crucial characteristic of the market and is necessary to encourage investment and ensure the market's stable and effective functioning. The Panel further notes that the:

- **Last RSSR increased the levels of the MPC and CPT:** These increases are not yet fully implemented and should be allowed time to take full effect.[48]
- **Input assumptions that determine the standard and settings are volatile**. This is particularly salient for the VCR and OCGT build cost assumptions. It is likely that those underlying assumptions will continue to evolve as they have previously due to supply chain constraints, uncertain future demand, and continuing geopolitical pressures on commodity markets.
- **Market continues to evolve**, and many of the input assumptions will be out of date by the review period.

Only two stakeholders explicitly did not support retaining the currently scheduled levels of the MPC and CPT. Delta Electricity submitted that[49]

> the [MPC] and CPT should be increased from current levels. Higher MPC and CPT settings are necessary to:
>
> - reflect the cost of new firming capacity in a decarbonising system
> - send adequate signals to investors faced with rising financing and development costs.

Meanwhile, ECA considered the investment case for new entrants is not heavily contingent on the level of the MPC.[50]

> modelling of the MPC assumes that the "marginal" entrant unit recovers most of its cost during scarcity events when prices are close to or near the MPC... However, we do not consider this assumption to be realistic, since we observe that every existing gas generator and grid-scale battery in the NEM earns significant revenue at prices well below the MPC.

The Panel considers the increased build costs for firming capacity Delta cite are reflected in the recommended change to the reliability standard. The Panel's modelling exercise provides that the currently scheduled market price settings are commensurate with the recommended new reliability standard. Furthermore, the Panel has, in determining the necessary market price settings for firming capacity to recover investment costs, assumed additional revenue of $50k/MW that is generated from the market outside of contribution to reliability. Therefore, the Panel continues to consider that the currently scheduled market price settings are adequate to provide an expected level of reliability close to the recommended new reliability standard.

The 2021 RSS guidelines provide that movements in the price settings should be gradual. They further state that in recommending the market price settings, the Panel should give consideration to the effect on the financial burden faced by market participants, including from price volatility. While the primary consideration for the Panel is ensuring that the market settings deliver a level of reliability that customers value, this modelling exercise necessarily entails a degree of uncertainty and input assumptions are often volatile. The Panel therefore values regulatory stability in managing and accounting for this uncertainty to ensure the reliability framework is effective in the long run.

48 Submissions to the draft report; Snowy Hydro, p. 4; AFMA, p. 1.

49 Delta Electricity, submission to the draft report, p. 1, 13 January 2026.

50 ECA, submission to the draft report, p. 5, 29 January 2026

3.3 The current form of the CPT is preferable to alternative formulations

The Panel has consulted on and subsequently considered alternative forms that the CPT might take.[51] The Panel's final recommendation is that the current form of the CPT remains fit for purpose and most effectively manages excess financial risk in a manner that is sensitive to adverse conditions, while minimising unpredictable administrative pricing periods (APPs). In addition to the current form of the CPT, the Panel has considered:

- only cumulating prices above a certain threshold (for example, above $300/MWh)
- only cumulating prices in specific time blocks aligned with peak demand (e.g., 4 – 7pm)
- changing the accumulation period, either shortening or extending (e.g., 3-day, 2-week or longer CPT).

The Panel has considered the ongoing role of the CPT in relation to changing market conditions and reliability risks:

- **Wholesale prices are becoming more bimodal due to variable renewable energy (VRE) penetration** – resulting in more predictably volatile prices, changing the nature of financial risks for market participants. The CPT should continue to encourage generators to sell contracts while retaining the incentive for retailers to manage their own wholesale risk.
- **The system is becoming more weather dependent** – reliability risk and generation scarcity are slowly shifting to become more infrequent, but longer and deeper when they do occur. This increases the market demand for long-duration firming assets that can respond to these events. It is therefore essential that the CPT does not hinder the investment case for these assets in mitigating excessive financial risk.
- **CER and price-responsive load are growing** – the deployment of CER is providing retailers with opportunities to more effectively pass wholesale costs through to customers and manage their wholesale market risk through price-responsive load. This opportunity directionally reduces, but does not eradicate, the need for the CPT to manage risks for retailers. However, risks for generators who have sold contracts remain, and the CPT performs an important role in encouraging generators to sell contracts through managing that risk, which is necessary for healthy and liquid contracts markets.

Additional details on how market conditions are evolving are outlined in Chapter 1 and in the Issues Paper.

3.3.1 The Panel has concluded that retaining the current form of the CPT is in the best interest of consumers

The Panel notes that the current form of the CPT is susceptible to being triggered by sustained periods of moderately high prices, as was the case during the market suspension in June 2022. Further, the CPT could see improved agility if the accumulation period were shortened, as explored under option three.

After examining the alternative formulations, the Panel's final recommendation is that the current form of the CPT adequately manages financial risks, retaining the incentive for retailers and generators to enter into their own risk management contracts, while mitigating excess risks that could cascade through the market. Furthermore, the current form of the CPT retains a degree of

51 The AEMC currently has two rule change projects underway related to the calculation of the CPT: the CPT calculation during administered pricing and amending the CPT methodology changes proposed by Snowy Hydro and Delta Electricity, respectively. These proposals do not relate to the CPT form or value, but rather the way they are calculated in real-time.

flexibility while retaining effective price signals and not imposing unnecessary regulatory burden on market participants or damaging the effective operation of derivatives markets.

Stakeholder commentary in submissions to the Draft Report on the form of the CPT was limited. AEMO considered that the nature of reliability risk has not changed such that a new form of CPT has become more appropriate.[52] Snowy Hydro and Shell Energy similarly supported retaining the current form of the CPT.[53]

Absent tangible improvements for consumers presented by one of the alternative forms the CPT might take, the Panel recommends retaining the current form of the CPT. The RSSR guidelines require the Panel to be satisfied that a change to the current settings represents a meaningful benefit to consumers to recommend such a change. We do not consider that this condition has been met for the alternative CPT forms.

The Panel notes the recommendations of the NEM Review final report, which included that the Panel should conduct a dedicated and ongoing review of the form of the market settings. The Panel expects the first of these to be conducted before the next review, ensuring the form of the market settings remain fit for purpose.

3.3.2 The Panel has evaluated whether the form of the CPT could be improved

Under the current design, the CPT simply accumulates all dispatch prices (for energy and frequency control ancillary services) over a rolling seven-day window. If the cumulative total exceeds the threshold, an APP is triggered, capping prices at the APC until the period ends. This mechanism has been long-standing and familiar to market participants. However, the Panel explored several alternative formulations of the CPT to see if they might better achieve the CPT's twin objectives:

- capping total price risk to encourage contracting and prevent cascading retailer failures, while
- maintaining effective price signals for efficient operation and investment.

A summary of the alternative formulations is available in Table 3.1 below.

Table 3.1: We have assessed several different forms of the CPT to determine if alternative options could better serve customers

Assessment principles	Option 1: cumulate prices above a threshold	Option 2: cumulate prices in specific times of day	Option 3: change the accumulation period	Status Quo: cumulate all energy prices over a 7-day period
Allowing efficient price signals while managing risk	Yes, this can continue to allow efficient price signals while managing excess risk	No, this inappropriately addresses a particular type of risk that should be managed by participants and adds risk for generators	Changing the accumulation period may result in misalignment between price signals permitted under the CPT and adverse market conditions	Yes, this manages excess financial risk simply

52 AEMO, submission to the Draft Report, 29 January 2026, p. 3.

53 Submissions to the Draft Report; Snowy Hydro, p. 6; Shell Energy, p. 5, 29 January 2026.

Assessment principles	Option 1: cumulate prices above a threshold	Option 2: cumulate prices in specific times of day	Option 3: change the accumulation period	Status Quo: cumulate all energy prices over a 7-day period
Delivering the optimal reliability level	This depends on the level, not the form of the CPT	This depends on the level, not the form of the CPT	This depends on the level, not the form of the CPT	This depends on the level, not the form of the CPT
Predictable and flexible regulatory framework	Yes, this is similar to the function of cap contracts or negative price exclusions under PPAs, which are well understood in the market	No, this is a major shift in the function of the CPT and is a rigid mechanism in assigning a particular time block	Yes, this could be designed to minimise regulatory uncertainty and impact for participants	Yes, this is the status quo and a long-established mechanism

3.3.3 Assessment of option 1: The CPT to only cumulate prices above a threshold

This option involves cumulating only those prices that exceed a certain threshold (for example, $300/MWh to align with exchange-traded cap contracts). The accumulation of these prices will trigger an APP when they exceed the CPT, much like the existing mechanism. This would likely require a reduced level of the CPT, all things being equal, compared to the current form of the CPT. Analysis of historical prices indicates this would have similar outcomes to the current accumulation approach.

This approach potentially aligns more closely with the objective of the CPT, as it only moderates those prices that represent a financial risk to market participants. Further, as stated above, this could be structured to align with cap contract structures and thus the objective of mitigating excess risk for generators who sell caps. The Panel further considers this approach appropriately retains a requirement for retailers and market customers to manage their own wholesale risk while market conditions are muted, and they can reasonably predict their load, while providing a backstop for extended periods of high prices. Alignment with cap contract structures could also provide participants with greater clarity on the impact of the CPT on cap premiums. This alignment, however, also risks baking in cap contract structures, limiting the agility of derivatives markets to adapt to changing market conditions in the future.

The Panel considers, however, that this approach retains some financial risk from extended periods of prices below the threshold used for the CPT. This could further provide greater incentives for generators with market power to leverage this threshold to prevent triggering administered pricing. There is also a risk that this may encourage a shift in hedging strategy away from cap contracts and towards swaps as retailers and market customers seek to manage average price risk. This presents potential challenges for firming generation looking to smooth their cash flows.

3.3.4 Assessment of option 2: The CPT to only cumulate prices in specific peak times of day

This option involves cumulating only those prices in specific time blocks when demand is expected to be high. The accumulation of these prices will trigger an APP when they exceed the CPT. The specific time blocks should, under this approach, be tied to underlying demand and could be determined by the Panel through the RSSR process.

This provides protection to participants only during periods when demand is high, and therefore, risk is more difficult for retailers and market customers to manage. This approach targets the inherent uncertainty that exists in trying to forecast load at the tails. Therefore, it retains incentives for market customers to manage their own risk but recognises that uncertainty may cause cascading financial risk.

This approach, however, risks reducing the incentive for market customers to shift load away from peak periods due to increased wholesale risk during off-peak periods and more targeted protection afforded by the CPT during peak hours. Similarly, this offers greater incentives for gaming to generators with market power due to the lack of protection afforded during the off-peak period. Under this approach, sustained high prices in off-peak periods present a risk of cascading retail failures if there is significant spot-exposed load. This is an increasing risk as the NEM transitions, as reliability risk, when it does arise, is increasingly the result of sustained periods of low output from weather-dependent generators. This risk is also felt by generators who sell contracts, as they may be financially exposed outside those time block hours due to generating units failing.

3.3.5 Assessment of option 3: The CPT to cumulate prices over shorter or longer timeframes

The Panel considers that a shorter accumulation period could make the CPT mechanism more agile. It more quickly binds to respond to sustained high prices, and the market exits APP events faster when normal market conditions return. This likely results in an increased number of shorter APPs, which signal the market is not functioning as intended. APP events also have significant impacts on derivatives markets. More frequent APPs not only introduce additional uncertainty into contract markets, potentially hindering liquidity in these markets, but also increase regulatory burden for participants and reliance on compensation frameworks.

A longer accumulation period allows for more sustained periods of high prices before the CPT binds. This means that market signals are retained for longer, including responding to the underlying cause of high prices. A less reactive CPT may also encourage retailers and generators to proactively manage their risk, thereby improving liquidity in contract markets. However, a longer accumulation period is less reactive to adverse market conditions, which can result in potentially exacerbated financial risks for market participants. This also results in high prices taking longer to wash out of the CPT calculation, resulting in administered pricing that outlasts the underlying cause of market instability.

4 The level of the market floor price and administered price cap

Box 5: Key points in chapter 4

- The market floor price (MFP) and administered price cap (APC) aim to manage financial risk and maintain market operability by acting as the lower and upper bounds to limit price volatility.
- In line with the 2021 RSS Panel guidelines, the Panel recommends changes to the settings only in the instance there is a material benefit in doing so. Unless there is a clear benefit to revising the price settings, under the guidelines the Panel must recommend retaining the current settings in the interests of regulatory stability.

The final recommendation is to retain the current MFP and pursue a minimum system load (MSL) trigger through a standalone rule change request

- The Panel's final recommendation is to retain the MFP at -$1,000/MWh, as this level provides appropriate operational signals. The Panel notes that the MFP rarely binds; therefore, changing the level of the MFP would not meaningfully benefit consumers.
- Stakeholder submissions to the draft report showed broad support for retaining the current MFP, noting the level upholds the settings' intent to ensure the market continues to clear during low demand periods.
- The Panel also recommends pursuing the MSL trigger proposed in the draft report in a separate rule change request. In line with stakeholder feedback, this will allow for further consideration of and consultation on the impacts of this trigger and the overarching governance arrangements in the rules.

The final recommendation is to retain the current APC at $600/MWh and the administered floor price (AFP) at -$600/MWh

- The Panel's final recommendation is to retain the APC at $600/MWh and AFP at -$600/MWh for the review period. The APC was previously increased in 2022 from $300/MWh to $600/MWh to align with generator short-run costs (especially those of fuel-constrained ones) and encourage generation during an extended crisis. The Panel considers that the current levels remain sufficient to ensure supply is available during an administered pricing period (APP).
- In response to the draft report, stakeholders broadly supported retaining the current level of the APC, noting that the current APC is sufficient to cover the marginal source of generation under most conditions and the benefits of changing the value are outweighed by the value of stability.

The final recommendation is to retain the current approach of not indexing the MFP, APC and AFP to CPI

- The Panel considers that in accordance with the RSS guidelines, the current approach to indexation of the MFP, APC and AFP will be retained. This means the MFP and APC will remain fixed at their nominal levels and not be indexed to CPI.

- The Panel's recent review of the form of the standard and APC found that indexation was not necessary, provided the level of the APC is sufficiently high to cover short-run marginal costs of the marginal generator with minimum reliance on compensation.

4.1 The Panel recommends retaining the current form and level of the MFP at -$1,000/MWh

The MFP imposes a floor on wholesale spot prices and is currently set at -$1,000/MWh. The purpose of the MFP is to allow the market to clear during low-demand periods while preventing market instability by imposing a negative limit on the total potential volatility of market prices.[54]

In determining the appropriate level of the MFP, the Panel considered factors including but not limited to:

- the number and frequency of trading intervals where the market prices have been, or have approached, the level of the MFP
- whether there have been significant changes in the generation fleet, such that average generator cycling costs have changed significantly.

The Panel, having assessed the MFP against these criteria and the NEO, **recommends retaining the current form and level of the MFP at -$1,000/MWh.**

The rationale for this recommendation is largely consistent with the draft report. A brief overview of the Panel's rationale, with updates reflecting stakeholder feedback on the draft report, is provided below.

4.1.1 MFP shouldn't be treated as an investment signal for flexible load

The Panel does not consider it appropriate to treat the MFP as an investment signal for flexible load. This conclusion reflects three key factors:

- MFP and near-MFP events are rare and have become less frequent
- negative prices are not well correlated with excess generation
- batteries respond to arbitrage opportunities driven by price spread, more so than absolute negative prices.

The incidence of MFP and near-MFP events has declined significantly

As shown in Figure 4.1 below, the incidence of floor or near-floor price events has declined significantly in recent years. This is driven by factors including:

- the introduction of five-minute settlement in October 2021, which reduced the incentives for disorderly bidding
- a shift in the way that power purchase agreements (PPAs) are structured, such that generators are more likely to be exposed to negative prices.

As a result, there have been just six dispatch intervals in the NEM at the floor in the last three full financial years. Allowing for a $1/MWh tolerance, the number of near-floor dispatch intervals has also declined, from a peak of more than 500 NEM-wide in FY2020 to just 15 in FY2025. The rarity of these events makes it challenging to build an investment case that relies on the MFP. This is

54 Reliability Panel, Review of the reliability standard and settings guidelines, Final guidelines, 1July 2021.

emphasised by the lack of cap-style contracts for negative prices that could smooth the otherwise lumpy cash flows resulting from MFP events.

Figure 4.1: The number of MFP events (with $1/MWh tolerance) has declined in recent years

Source: Panel analysis of AEMO data

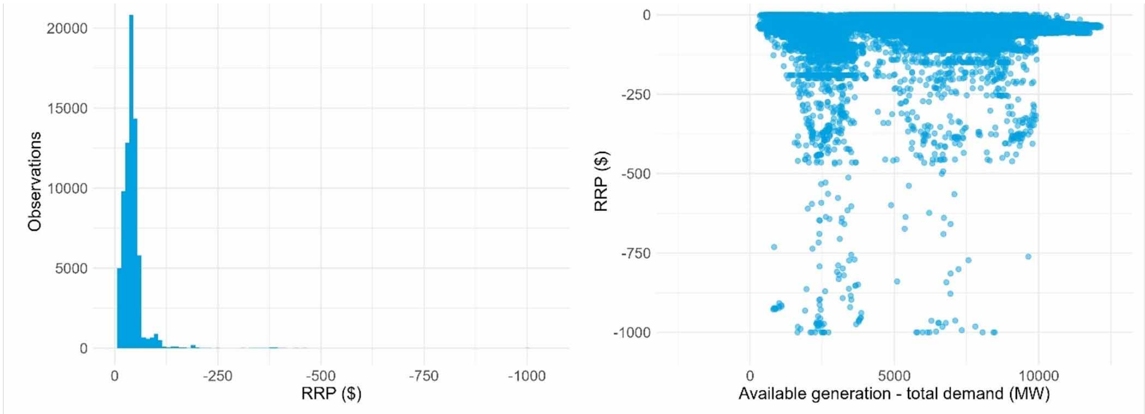
Negative prices are typically determined by LGC prices and hot start costs for thermal generation

Floor and near-floor pricing often results from race-to-the-floor bidding by generators seeking to avoid curtailment. This results in a poor correlation between excess generation and extremely negative prices. As shown in Figure 4.2 below, analysis of historic negative prices reveals two distinct clusters:

- First, representing the vast majority of negative price intervals, there is a cluster of dispatch intervals at approximately -$50/MWh, the negative of large-scale generation certificate (LGC) prices. LGCs provide additional revenue above the spot price and thus work to essentially shift an eligible generator's SRMC to a negative value. In 2024, 81 per cent of all negative intervals were between -$50/MWh and $0/MWh.[55]
- Second, a much smaller cluster appears between -$150/MWh and -$500/MWh. This is likely driven by the fixed cost of thermal generation to perform a hot start.

55 No new LGCs will be created following the end of the RET on 31 December 2030.

Figure 4.2: Negative prices are poorly correlated with excess available capacity



Source: Panel analysis of AEMO data

Rather than a strong correlation between excess available generation and very low negative prices, the graph above broadly shows two vertical funnels at approximately 2,500 MW and 6,000 MW of excess available generation. The absence of any apparent correlation between extremely negative prices and excess available generation suggests that very low prices are better attributed to network constraints and bidding behaviour, rather than excess supply. Therefore, the Panel considers it is not appropriate to treat the MFP as an investment signal for flexible load.

4.1.2 Changing the level of the MFP would not meaningfully benefit consumers

The Panel has not identified any material benefits to consumers or market efficiency from changing the current level of the market floor price. We assessed the potential effects of both raising the MFP (making it a less negative number) or lowering it further into negative territory. The Panel concludes that neither approach would deliver a meaningful improvement for consumers or market efficiency.

Raising the MFP could result in system instability by weakening operational signals provided by the spot market

While the MFP currently very rarely binds, setting it too high poses the risk that it could prevent an unloading signal for thermal generators. The MFP must be sufficiently low to allow thermal generators to reflect the fixed costs of a hot start in their bids. This provides an unloading signal for thermal generation when demand is low, enabling the market to clear efficiently. The Panel considers the current level of the MFP at -$1,000MW/h satisfies this requirement.

Raising the MFP would not give generators a strong price signal to withdraw, but may prevent the market from clearing efficiently during low-demand periods and increase the likelihood that AEMO would need to intervene to maintain system security. A higher MFP could therefore impair the market's self-balancing mechanism at low demand. The Panel considers that -$1,000/MWh remains low enough to avoid this problem.

Lowering the MFP would not convincingly deliver additional benefits for consumers

The Panel also considers that lowering the MFP further would not deliver meaningful benefits for consumers. The Panel notes that load is often not exposed to spot prices, and negative prices, therefore, do not necessarily represent a strong operational signal for load to ramp up or turn on. While this is a feature of the retail market that cannot be addressed through changes to the MFP alone, it represents a further need for the level of the MFP to facilitate sufficiently low prices that any cost pass-throughs to load exceed (negatively) the retail costs to serve that load. Without this operational signal, the MFP would exacerbate potential MSL risks by failing to allow the spot market to provide an operational signal to flexible loads.

As discussed above, MFP events are very rare and have become less frequent in recent years. The Panel therefore does not consider it likely that lowering the MFP would deliver any material benefit to consumers or efficiency gains. While a lower MFP in principle could directionally strengthen the incentive for price-responsive load during periods of demand:

- The rarity of MFP events and poor correlation between low prices and excess generation means this is not a suitable investment signal for flexible load.
- Many price-responsive consumers do not participate directly in the wholesale market and thus respond to price signals via an aggregator or retailer. This represents a coordination and technical challenge that a lower MFP does not solve.
- MFP events maximise the operational signal for load at any level.
- Though rare, a lower MFP directionally increases financial risk for generators that are incentivised to race to the floor in their bids.

Further lowering the MFP would add volatility and downside risk primarily to generators, which could have knock-on effects (for example, requiring more system security payments from networks when units operate at very negative prices for system security reasons).

The Panel therefore considers the current level of the MFP allows the market to clear when demand is low while adequately limiting excess financial risk from very low prices. The Panel has not identified a material benefit to consumers associated with either raising or lowering the level of the MFP. Consistent with the RSSR guidelines, the Panel recommends retaining the current MFP of -$1,000/MWh for this RSSR period.

Most stakeholders supported retaining the current MFP

Submissions to the draft report generally supported retaining the current level of the MFP. Support for maintaining the MFP at -$1,000/MWh was expressed by Delta, AFMA, Hydro Tasmania, EnergyAustralia, Origin, AGL, Alinta and EUAA.[56] These stakeholders considered the current MFP remains appropriate to uphold its intent and support price signals. Alinta echoed the Panel's analysis, highlighting that the MFP has not been reached frequently, and when it has, it has not indicated 'a bottleneck of generators' inability to reflect cycling costs in bids'.[57] Some stakeholders emphasised the importance of stability and considered this outweighed the value of any changes to the MFP at this time.[58]

A small number of stakeholders supported the level short term but suggested the MFP may warrant further consideration beyond this. In particular, Akaysha supported the recommendation short term, noting a reduction may be warranted if MSL trends increase, whereas Shell noted forecast changes may warrant further consideration of an increase.[59]

Snowy Hydro, however, raised concerns the MFP has not been thoroughly reviewed, noting its pending 2021 RCR that advocates for a lower MFP for dispatchable generation to address congestion risks, thereby allowing generators to defend contracts.[60] Snowy Hydro, considered that

56 Submissions to the draft report; Delta, p. 2; AFMA, p. 1; Hydro Tasmania, p. 2; EnergyAustralia, p. 4; Origin, p. 1; AGL, p. 1; Alinta, p. 2; EUAA, p. 3.

57 Alinta, submission to the draft report, p. 2, 29 January 2026.

58 Origin, submission to the draft report, p. 1, 29 January 2026.

59 Submissions to the draft report; Akaysha, p. 1; Shell, p. 6.

60 Snowy Hydro, submission to the draft report, pp. 6-7, 29 January 2026.

a lower MFP would address market access risks to some extent.[61]All other stakeholders supported retaining the MFP level at -$1,000/MWh for this review period.

4.2 The Panel recommends pursuing a mechanism to place the spot price at the MFP during MSL3 events in a standalone rule change request

The Panel recommends that its proposed mechanism to automatically place the spot price at the MFP during minimum system load (MSL) 3 events be progressed through a separate rule change process. In the draft report, the Panel recommended implementing an automatic price floor trigger when AEMO declares an MSL3 event, to address emerging challenges during extreme low-demand conditions.[62] This recommendation reflects the Panel's assessment that the frequency of MSL events are increasing, largely due to the rise of unorchestrated consumer energy resources, particularly rooftop solar PV. During an MSL event, total demand from the grid is very low, often falling to the point where it threatens the secure operation of the power system.

In the draft report, the Panel proposed linking MSL3 events to the market floor price for the duration of those events, akin to market clearing at the MPC during load shedding. The intent of this proposal was to strengthen operational price signals during low demand situations, improve alignment between market outcomes and system security needs, whilst reducing reliance on AEMO intervention. By automatically setting the spot price at the MFP during MSL3, the mechanism could encourage the withdrawal of excess supply and greater demand response, thereby supporting the market's ability to clear.[63]

Stakeholders raised that further consideration of the impacts of such a mechanism is required

Submissions to the draft report presented mixed views on the proposed mechanism to automatically place the spot price at the MFP during MSL3 events. Many stakeholders, including AGL, AEMO, Snowy Hydro, Hydro Tasmania, Akaysha and EnergyAustralia, acknowledged the growing challenges associated with MSL events and supported the MSL3 trigger to limit intervention and provide market signals.[64] Snowy Hydro considered the proposed mechanism to be sensible, provided it is a more transparent, efficient market signal than out of market invervention.[65] Similar sentiment was raised by EnergyAustralia, who noted the 'mechanism would reduce interventions when system load is extremely low and align dispatch with operational realities under two-sided market conditions'[66]. AEMO also supported the mechanism in principle, citing the need to provide strong pricing signals during MSL conditions. [67]This feedback aligns with the Panel's rationale for the consideration of an MSL mechanism. However, these stakeholders, and most others, considered that the impacts of such a mechanism must be further assessed to determine whether there would be any unintended consequences. Tesla, for instance, raised that many policy instruments are underway that aim to address MSL conditions, noting further consideration of how these mechanisms would interact may be needed.[68]

CS Energy, Shell, Origin, EUAA and Alinta did not support the MSL3 trigger, noting potential unintended impacts, such as disorderly bidding & storage incentives, should be assessed.[69] CS

61 .ibid.
62 For more details on the proposed mechanism, see section 3.2.3 of the draft report.
63 See section 3.2.3 of the draft report for more details on the Panels analysis.
64 Submissions to the draft report; AGL, p. 1; AEMO, p. 3; SnowyHydro, p. 7; Hydro Tasmania, p. 1; Akaysha, p. 1; EnergyAustralia, p. 4.
65 Snowy Hydro, submission to the draft report, 29 January 2026, p.7.
66 Energy Australia, submission to the draft report, 29 January 2026, p. 4.
67 AEMO, submission to the draft report, 29 January 2026, p. 4.
68 Tesla, submission to the draft report, p. 1, 29 January 2026.
69 Submissions to the draft report; CS Energy, p. 2; Shell, p. 5; Origin, p. 2; EUAA, p. 3; Alinta, p. 2.

Energy raised that MSL events are a direct result of high investment in rooftop PV systems, which are not spot-price reactive enough for the mechanism to be a sufficient solution. [70]These stakeholders also expressed different views on the fundamental causes of MSL events. Alinta, on the one hand, expressed that MSL is a system strength issue and that introducing a trigger may increase system security contract costs, whilst CS Energy considered it is a risk largely created by rooftop solar, and the mechanism would undermine the economic position of coal.[71]

The Panel agrees that MSL is a system security challenge and, currently, the correlation between insufficient load and very low prices is weak. We therefore do not consider that lowering the MFP itself would meaningfully address MSL risk. However, the Panel considers that a targeted mechanism could sharpen price signals during MSL3 events and improve alignment between market outcomes and system needs.

The Panel also recognises there are important design and implementation considerations associated with such a mechanism, including interactions with existing security frameworks, potential impacts on AEMO, market participants and the overarching governance arrangements surrounding the MSL framework. Stakeholder feedback also highlighted that these issues warrant further investigation.

For these reasons, the Panel recommends pursuing this mechanism through a separate rule change request to allow for a more detailed assessment of these impacts. Progressing the mechanism in this way would allow the impacts and key considerations to be appropriately consulted on and assessed.

4.3 The Panel recommends retaining the current administered price cap at $600/MWh

The APC is the maximum market price paid to participants, currently $600/MWh, that can be reached in any dispatch interval and any trading interval during an APP. Similarly, the administered floor price (AFP), currently -$600/MWh is the lowest price that can be reached during an APP. The combination of the CPT, APC and AFP contains extreme financial exposure in extraordinary circumstances: the CPT triggers the APP after a prolonged price spike, and then the APC limits any further price outcomes to a more moderate level until the stress conditions pass.

As the Panel recently confirmed the form of the APC, including that it should not be indexed to CPI, we have only considered if the level of the APC is fit for purpose for this review period.[72] Both the NER and the guidelines outline the assessment criteria that the Panel has taken into account when reviewing the level of the APC. The Panel has also considered factors, including, but not limited to, whether there have been:

- significant changes in the typical short-run marginal costs of generators in the NEM
- any compensation claims since the last review.

After assessing the APC against the assessment criteria, NEO and stakeholder feedback to the draft report, the Panel is making a **final recommendation to retain the APC level at $600/MWh and AFP at -$600/MWh**. The rationale for this recommendation is largely consistent with the reasoning in the draft report. The Panel's rationale, including the consideration of stakeholder feedback, is provided below.

70 CS Energy, submission to the draft report, 29 January 2026, p. 2.

71 Submissions to the draft report; Alinta, p. 2; CS Energy, p. 2.

72 Reliability Panel, Review of the Form of the Reliability Standard and APC, Final report, 2024.

4.3.1 The APC must balance the reliability risks from generator recommitment and financial risks for market participants

As noted in the draft report, in December 2023, following the completion of the 2022 RSSR, the AEMC made a more preferable rule to amend the level of the APC to $600/MWh.[73] The AEMC stated the $600/MWh level would maintain the intended price signal while accounting for the expected effects of inflation over the rule change period. It would also encourage continued participation by thermal generation and storage during periods of extended high prices, reducing the need for AEMO intervention and the risk of outages for customers over the period to 2028.

Given the role and purpose of the APC, it needs to be set at a sufficient level to encourage continued participation during times of extended high input costs, reducing the need for AEMO intervention and the risk of outages for consumers. This requires the Panel to make a trade-off that involves balancing a number of competing objectives, namely having a sufficiently:

- low APC to mitigate the risk of a systemic financial collapse of the electricity industry during an extreme market event
- high APC to incentivise market participants to supply electricity during administered price events
- high APC to minimise compensation claims by market participants following an application of the administered price cap.

An APP occurs following an extended period of high prices and is likely to occur under conditions of generation supply scarcity. Having an APC that is too low may discourage high-cost generators from bidding into the market during an APP, as seen in June 2022. This would reduce available generation and potentially require AEMO intervention, potentially delaying the return to normal market operations.

If the APC is too low and a high-cost generator is dispatched anyway, it can pursue a compensation claim to recover all eligible costs.[74] However, this is an expensive and time-consuming process. As such, the Panel considers it highly desirable to ensure that the APC is sufficiently high to minimise the likelihood of triggering a compensation claim.

Conversely, an APC that is too high may unnecessarily contribute to the financial distress of energy purchasers and risk exacerbating market instability in response to extreme market events. Accounting for these factors, the Panel considers that retaining the APC at $600/MWh and the AFP at -$600/MWh is appropriate.

Stakeholders largely supported retaining the current level of the APC

Delta, Hydro Tasmania, Akaysha, EnergyAustralia, Tesla, Snowy Hydro, AGL and Origin supported retaining the current APC at $600/MWh.[75] Snowy Hydro noted that the current APC is sufficient to cover the marginal source of generation under most conditions whilst Origin considered the benefits of changing the value would not exceed the value of stability.[76] Most stakeholders did not explicitly comment on the AFP. However, Hydro Tasmania stated the AFP is sufficient given draft modelling suggests there is no material benefits for change at this time.[77]

73 AEMC, Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap, Rule determination, 7 December 2023.

74 Clause 3.14.6 of the NER.

75 Submissions to the draft report; Delta, p. 2; Hydro Tasmania, p. 2; Akaysha, p. 2; EnergyAustralia, p. 5; Tesla, p. 1; Snowy Hydro, p. 7; AGL, p. 1; Origin, p. 1.

76 Submissions to the draft report; Snowy Hydro, p. 7; Origin, p. 1.

77 Hydro Tasmana, submission to the draft report, p. 2, 29 January 2026.

Some stakeholders did not support retaining the current APC level. Alinta raised that the Panel should lower the APC to $500/MWh to align with derivatives markets and reduce participants' risk exposure.[78] This was also supported by the Justice and Equity Centre, which noted there is no justification for the APC to be set above $500/MWh.[79] Shell, on the other hand, considered that the Panel did not assess if the current APC covers the cost of energy storage and efficiency losses and raised that consideration should be given to setting the APC and AFP values independently.[80]

AFMA and ENGIE noted that the APC should be indexed to CPI to remain commercially relevant.[81] The Panel notes that this was examined in detail in the recent review of the form of the standard and the APC. The review found that indexation was not necessary, provided the level of the APC is sufficiently high to cover short-run marginal costs of the marginal generator with minimum reliance on compensation.[82] Therefore, in accordance with the RSS guidelines, the current approach to indexation of the APC/AFP will be retained.

The NEM Review Expert Panel has also made a final recommendation that we undertake a broader review of the appropriateness of the form of the settings, which could provide another opportunity to investigate the form, were Energy Ministers to adopt the recommendation.[83]

The Panel is not convinced that revising the MFP, APC or AFP would materially improve customer outcomes at this time. As such, as required under the RSS guidelines, the Panel is recommending retaining the current settings for the relevant review period.

78 Alinta, submission to the draft report, p. 3, 29 January 2026.

79 Justice and Equity Centre, submission to the draft report, pp. 1-2.

80 Shell, submission to the draft report, pp. 8-9, 29 January 2026.

81 Submissions to the draft report; AFMA, p. 2; ENGIE, pp. 2-3.

82 AEMC, Review of the form of the reliability standard and administered price cap, Final report, 27 June 2024.

83 Department of Climate Change, Energy, the Environment and Water, National Electricity Market wholesale market settings review, Final Report, December 2025, p. 125.

A Background and context

Box 6: Key points in appendix A

- Power system reliability requires investment in an adequate amount of bulk energy, shaping and firming capacity to meet customer needs. The NEM's reliability framework aims to achieve this outcome while accounting for the costs ultimately borne by consumers.
- Power system reliability is distinct from power system security or network outages.
- The level of the reliability standard is based on the level of USE that represents an efficient economic trade-off between reliability and affordability, based on what customers value.
- The increase in variable renewable generation is seeing the power system supply and demand balance continue to become more sensitive to weather conditions than has historically been the case.

This appendix provides background and context for the 2026 RSS review and briefly discusses:

- power system reliability in the NEM
- the current NEM framework for delivering reliability, of which the standard and settings are a cornerstone, and
- reliability outcomes to date in the NEM.

A.1 What is power system reliability in the NEM?

As outlined in chapter 3 of the issues paper, [84]a reliable power system has an adequate amount of capacity (generation, demand response and interconnector capacity) to meet customer needs. This requires adequate investment in capacity, including sufficient investment to cover generator retirements, as well as an appropriate operational framework to maintain supply and demand balance at any given point in time. Hence, the core objective of the existing reliability in the NEM is to deliver efficient reliability outcomes through market mechanisms to the largest extent possible,[85]providing strong financial incentives for participants to make investment, retirement and operational decisions that support reliability.[86]

A.1.1 Power system reliability is distinct from power system security

While "security" relates to the stability of the power system in terms of its ability to withstand disturbances, "reliability" of the power system is about having sufficient resources to generate and transport electricity to meet customer demand. Overall, the power system needs to be:

- Reliable - having enough capacity (generation and networks) to supply customers.
- Secure - able to operate within defined technical limits and able to withstand a single credible contingency event, such as the loss of a transmission line or generator.

The Panel is required to focus on the reliability of the power system when conducting the RSS review, specifically the reliability provided by power generation and interregional transmission

84 AEMC, 2026 Reliability Standard and Settings Review, Issues Paper, 19 June 2025.

85 Reliability Panel, Information Paper: The reliability standard, current considerations, 12 March 2020, Sydney.

86 For more details see appendix A of the issues paper.

assets. [87] For more details on the distinction between power system reliability and security, see section A.1.1 of the issues paper.

A.1.2 Reliability events and the definition of unserved energy in the NEM

The NER defines the circumstances in which unserved energy (USE) is counted for the purposes of assessing reliability. Clause 3.9.3C of the NER specifies that USE for the purposes of the reliability standard includes energy demanded but not supplied due to power system reliability incidents resulting from:

- A single credible contingency event on a generating unit or an inter-regional transmission element that may occur concurrently with generating unit or inter-regional transmission element outages.
- Delays to the construction or commissioning of new generating units or inter-regional transmission elements, including delays due to industrial action or acts of God (such as extreme weather events).

USE excludes energy demanded but not supplied due to power system security incidents resulting from:

- Multiple contingency events, protected events or non-credible contingency events on a generating unit or an inter-regional transmission element, that may occur concurrently with generating unit or inter-regional transmission element outages.
- Outages of transmission network or distribution network elements that do not significantly impact the ability to transfer power into the region where the USE occurred.
- Industrial action or acts of God at existing generating facilities or inter-regional transmission facilities.[88]

A.2 Current framework for delivering reliability in the NEM

A reliability framework requires a trade-off between the prices paid for electricity and the cost of not having energy when it is needed. The standard's level is based on the USE level, which represents an efficient economic trade-off between reliability and affordability, aligned with what customers value.

A.2.1 Market incentives

Market incentives are the foundation of the current NEM reliability framework. Prices in the spot and contract markets signal when generation and demand-side resources should be built and dispatched, and provide information about the balance of supply and demand across different places and times. As the expected supply/demand balance tightens, spot and contract prices will rise within the price envelope defined by the market price settings. A rise in market prices affects operational decisions and provides an incentive for entry and increased production, addressing potential reliability problems as they arise.[89]

A.2.2 AEMO information and intervention processes

A key role of the reliability standard is to guide AEMO's decisions as the system operator. AEMO is responsible for operationalising the reliability standard through its forecasting and operational

87 Clause 3.9.3C of the NER.

88 For more details see section A.1.2 of the issues paper.

89 For more details on the spot market and contract market see section A.2.1 of the draft report.

processes. AEMO's Reliability Standard Implementation Guidelines set out how AEMO implements the reliability standard.[90] AEMO uses the reliability standard in several core ways, including to:

- Publish forecasts regarding reliability and its components to inform market participants, network service providers and potential investors, over ten-year, two-year, and six-day outlooks.[91]
- Monitor demand and generation capacity and, if necessary, initiate action in relation to a relevant AEMO intervention event to maintain the reliability of supply and power system security where practicable.[92]

A.2.3 NEM reliability to date

The NEM has historically enjoyed a very high level of reliability. However, reliability issues sometimes occur when the balance of supply and demand in a region is tight. The increase in variable renewable generation is making the power system supply and demand balance more sensitive to weather conditions than has historically been the case.[93]

90 AEMO, Reliability Standard Implementation Guidelines, December 2020.

91 AEMO, Reliability Standard Implementation Guidelines, December 2020, pp. 8-22.

92 For more details on AEMO information processes and intervention mechanisms see section A.2.2 of the draft report.

93 For more details on the NEM reliability performance see appendix A.3 of the issues paper.

B Assessment principles and approach

Box 7: Key points in appendix B

- The assessment framework that the Panel applied when considering the form and level of the reliability standard and market settings is provided in the NER.
- The Panel is also guided by the requirements in the 2021 reliability standard and settings guidelines.
- The Panel has only recommended changes if these represent a material benefit in achieving the NEO, including if the proposed changes promote the efficient, secure and reliable delivery of jurisdictional emissions reduction targets.
- For any recommended changes, the Panel will submit a rule change request to the AEMC.

The Panel's assessment principles and approach for the 2026 RSS review were outlined in the issues paper published 19 June 2025.

As noted in the issues paper, the Panel applies a specific framework when reviewing the reliability standard and settings. [94]The specific framework includes: [95]

- the general assessment principles in the guidelines to contribute to the achievement of the NEO, including the function of the standard and settings
- the overarching assessment criteria and considerations set out in the NER.

The Panel has applied this assessment framework when considering the reliability standard and settings, including both the form and the level.

B.1 The general assessment principles are set out in the RSSR guidelines

The 2021 guidelines state that when undertaking a review of the reliability standard and settings, the Panel will be guided by the NEO and the assessment principles set out below.

The NEO is:[96]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The General Assessment Principles set out in the 2021 guidelines are:

94 Reliability Panel, Review of the reliability standard and settings guidelines, Final guidelines, 1July 2021

95 ibid.

96 Section 7 of the NEL.

1. **Allowing efficient price signals while managing price risk:** The Reliability Panel will exercise its judgement to balance allowing for efficient price signals against managing wholesale price risk for participants. The settings should:
   a. allow sufficient scope for competition between buyers and sellers in the market to set efficient prices to achieve the standard, over the long run
   b. be designed to provide a sufficient range to promote this behaviour in the market
   c. also provide protection from uncapped prices in any given trading interval, and sustained high prices over a defined period, such that wholesale market outcomes do not result in inefficient over-investment, overly high financing costs or excessive price risk for all participants.
2. **Delivering a level of reliability consistent with the value placed on that reliability by customers:** The Reliability Panel will have regard to estimates of the value customers place on reliability when exercising its judgement as to the level of the standard. The settings should be sufficient to support the level of investment necessary to deliver the reliability standard over the long run.
3. **Providing a predictable and flexible regulatory framework:** The Reliability Panel will exercise its judgement to achieve predictable outcomes, recognising the importance of stability for market participants to invest, while taking into account changing market conditions, to support efficient investment and operational decisions by participants. The assessment principle, approach and supporting criteria inform the materiality assessment that the Panel will apply in its consideration of the form and level of reliability standard and settings.

For any recommended changes to the reliability standard and settings, the Panel would need to be satisfied that such changes will, or are likely to, contribute to achieving the NEO and meet the requirements in the 2021 guidelines and the NER. If the Panel recommended a change, this would need to be progressed through an AEMC rule change process (see chapter 1).

B.1.1 The Panel has considered emissions reduction in making its recommendations

In September 2023, the NEO was amended to explicitly include an emissions-reduction objective. This is the first time that an RSS Review has been required to consider emissions reductions.[97] To the extent the Panel considered the level of the reliability standard or any of the market settings would meaningfully impact carbon emissions, we have considered this cost in our analysis based on the AER's value of emissions reduction.[98] Further details on how emissions are considered are provided in section 3.2.1 and chapter 6 of the issues paper.[99]

B.2 Other considerations that the Panel has taken into account

There are a number of other requirements in the Rules that relate to the assessment of the standard and each of the settings. These requirements and criteria are included in the guidelines and, collectively, inform the Panel's materiality assessment of any changes to the standard and each of the settings. This section details the Panel's approach to assessing the reliability standard and settings.

97 AEMC, Reliability Panel Guide to applying emissions reduction component of the National Electricity Objective, Final guidelines, 4 April 2024.

98 AER, Valuing emissions reduction - Final guidance, May 2024.

99 AEMC, 2026 Reliability Standard and Settings Review, Issues Paper, 19 June 2025.

B.2.1 The rules outline other factors this review must consider

When undertaking each review, the Panel must follow a number of requirements in the NER. These include:

- complying with the reliability standard and settings guidelines
- having regard to any terms of reference provided by the AEMC
- having regard to the potential impact of any proposed change to a reliability setting on:
  - spot prices
  - investment in the National Electricity Market (NEM)
  - the reliability of the power system, and
  - market Participants.
- having regard to any value of customer reliability determined by the AER which the Panel considers relevant, and
- any other matters specified in the guidelines or which the Panel considers relevant

As noted, there is a range of NER-specific requirements that apply to the reliability standard and to each reliability setting. These are outlined in the guidelines and are discussed in chapters 3 and 4 of the issues paper. [100]

100 AEMC, 2026 Reliability Standard and Settings Review, Issues Paper, 19 June 2025.

C Detailed modelling methodology and results

This appendix describes the modelling methodology, inputs, assumptions and results. Specifically, this chapter:

- Appendix C.1 — outlines the methodology, limitations of the modelling, and changes since the draft report
- Appendix C.2 — describes the inputs, assumptions and treatment of key issues
- Appendix C.3 — outlines the quality assurance assessment and changes since the draft report
- Appendix C.4 — details the market model setup and calibration approach
- Appendix C.5 — details the results and sensitivities.

We have also published an external quality assurance report on the project page, which confirms the robustness of the modelling approach and the resulting analysis. The quality assurance process identified a few minor issues, all of which have since been addressed.

C.1 Methodology

Detailed modelling of the electricity market informs each RSSR. Modelling provides the Panel with a quantitative basis for identifying efficient levels for the standard and market price settings. This appendix expands on the high-level description and summary of results in the earlier chapters and outlines issues relevant to the Panel's modelling approach to inform the 2026 RSSR.

C.1.1 Approach

The modelling required to inform the Panel's determination of efficient levels for the standard and settings must meet the requirements of Clause 3.9.3A(e)(3) of the NER and the 2021 RSS Guidelines.

The Panel's analysis was based on a sophisticated market modelling process to determine settings that best promote the long-term interests of consumers

Previous RSSR modelling processes have involved market simulations to test aspects such as an appropriate market price cap, such that peaking generators are revenue sufficient to promote the delivery of an optimal reliability standard. Prior to the Rules requirement to establish a formal value of customer reliability (VCR), earlier studies included, amongst other approaches, the development of an implied VCR, as a reasonability test. Modelling is not perfect. However, it is an effective tool to consider a range of potential market outcomes for future periods based on a set of accepted assumptions. It is used extensively in the development of AEMO's Electricity Statement of Opportunities (ESOO) and in the development of forward market planning documents such as the Integrated System Plan (ISP). While not exactly the same as AEMO's ESOO or ISP, the RSSR uses market simulations to establish an economically balanced range of values for the reliability standard and, based on that range, to provide values for the market price cap and cumulative price threshold.

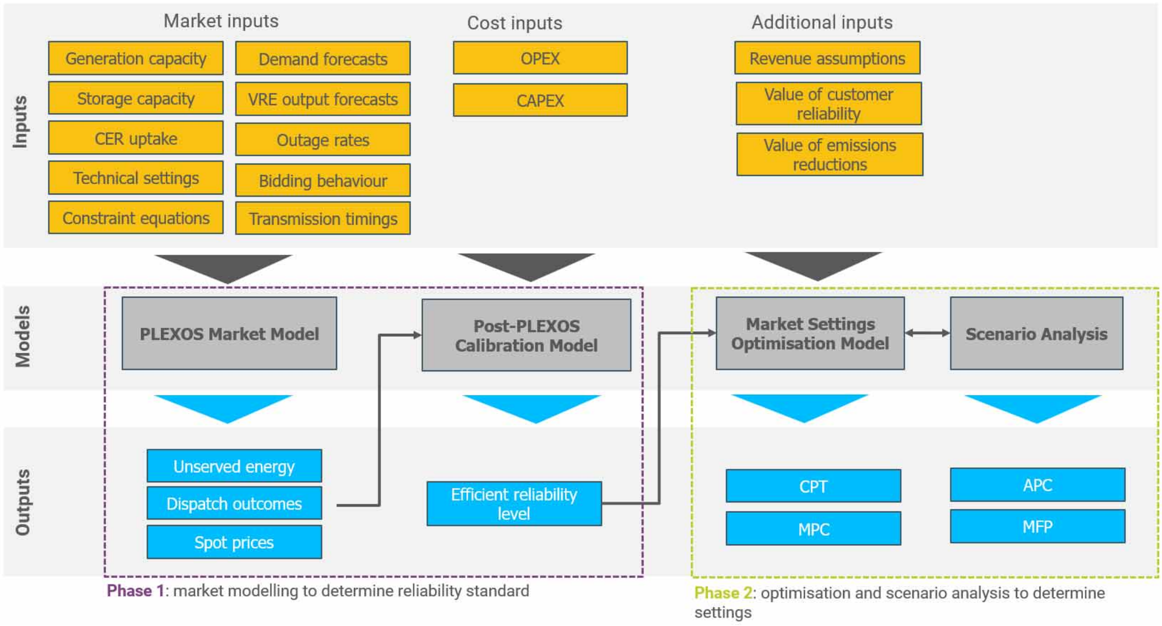
There are two broad stages of modelling required for this review:

1. The first stage is to determine an efficient reliability standard through a combination of time-sequential short run marginal cost market modelling using the optimisation software PLEXOS and through post-simulation scenario analysis.

2. Once an efficient reliability level has been derived, the second stage of modelling can begin. This stage uses optimisation methods and further scenario analysis to determine the optimal market price settings that deliver the reliability standard.

The majority of the information used in the PLEXOS modelling was sourced directly from AEMO's Draft 2026 Inputs Assumptions and Scenarios document, and AEMO's 2025 ESOO. The following figure illustrates the categories of information used.

Figure C.1: The modelling framework involves two phases and takes into account data from a range of sources



Modelling stage one determined the optimal level of reliability that customers value

The modelling task in the first stage of work is to identify a level of reliability under the current form of the reliability standard. Specifically, the modelling task supports the establishment of an optimal range of reliability standards, balancing the cost of operating the market at different levels of reliability against the cost borne by consumers based on the level of unserved energy at the VCR.

The assessment principles and scope of work require that the modelling be based on a base case which comprises a set of assumptions, including committed policies, that are most likely to represent the state of the NEM over the Review Period. The general modelling approach is consistent with previous reviews and includes simulations that cover variations in forced outage profiles, weather-sensitive peak demands, and demand shapes across a base case and several relevant scenarios and sensitivities.

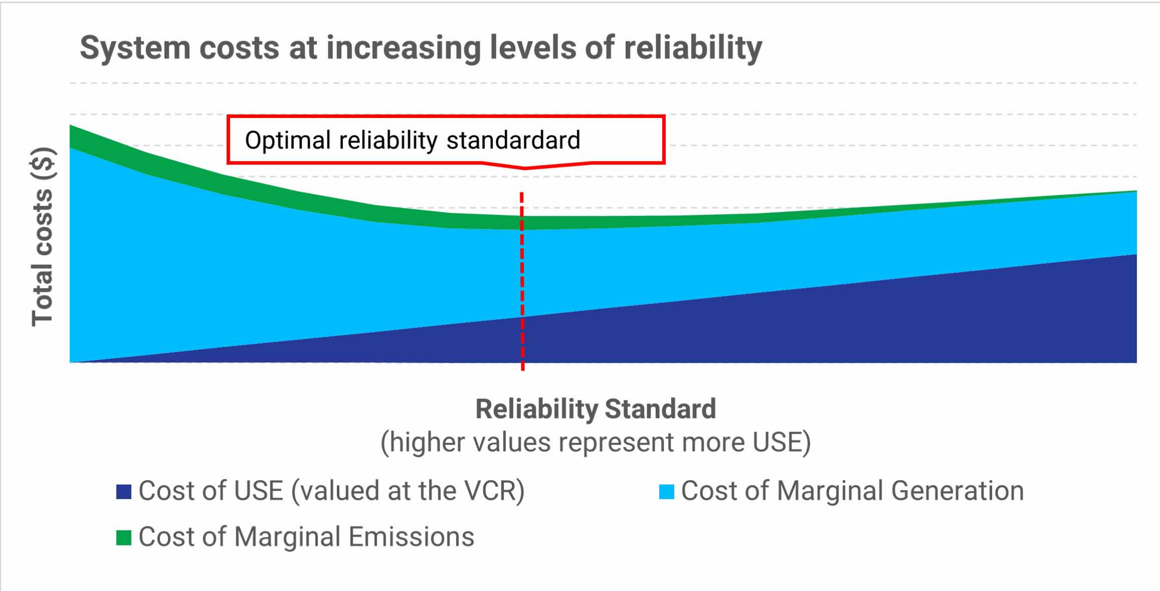
Most of the supply and demand modelling was completed in PLEXOS, a market simulation tool, targeting a level of USE above the reliability standard before decoupling and addressing the marginal new entrant and the optimal reliability settings in a separate optimisation model. In this way, rather than running a large number of simulations to consider different levels of new entry from various unit sizes and technologies, the optimisation model can incrementally consider the change in cost from adding sufficient plant to deliver different levels of reliability.

In the 2022 RSSR, PLEXOS modelling was used to determine the total cost of market operation in specific years. Some existing peaking capacity was removed from the ESOO model to increase levels of USE and allow for new capacity with known performance and cost to be added incrementally. While computationally expensive, this approach provided results regarding the change in USE events for a given capacity increment and the total system costs. The optimisation process balances the delivery of a reliable electricity supply with efficient costs for consumers. This optimal level occurs when the incremental cost of procuring additional power system resources to achieve a more reliable system exceeds the value consumers place on that additional reliability. This concept is illustrated in Figure C.2 below, which shows an increasing reliability standard on the X-axis (where a higher standard represents more USE, or less reliability) and the total system cost on the Y-axis.

The total system cost comprises:

- the cost of USE, which is valued using AER's VCR and increases at a constant rate as the reliability standard increases (becomes less tight),
- the cost of generation, including fixed and variable costs, which decreases sharply when moving away from a system that is 100 per cent reliable and then tapers out, since a perfectly reliable system would require more generation assets than a less reliable system, and
- the cost of emissions, valued using the AER's Value of Emissions Reduction (VER).

Figure C.2: Conceptual representation of the optimal level of the reliability standard



Source: AEMC, illustrative only

High level approach to modelling the level of the reliability standard

At a conceptual level, our modelling approach identifies an efficient reliability standard in a manner similar to that developed by Intelligent Energy Systems (IES) and described in the [101]. However, we have made changes to account for changing market conditions and improved modelling

101 2022 Reliability Standard and Settings Review, published 1st September 2022, available at https://www.aemc.gov.au/market-reviews-advice/2022-reliability-standard-and-settings-review

techniques developed for the Panel's 2024 Form of the Standard Review[102]. This high-level methodology is as follows:

- set up a market model using the most up-to-date market and generator information from AEMO and other sources, such as CSIRO
- modify this model by removing firm capacity such that it produces a level of USE that is below the reliability standard (that is, more USE than the existing standard)
- run this model over the review period (2028-29 to 2031-32) to generate a time-sequential profile of USE and dispatch outcomes for different weather reference years and outage samples
- iteratively add generator capacity of different technology types to produce higher levels of reliability.

We have evolved the methodology that IES developed for the 2022 RSSR by using:

- A larger set of weather reference years in the PLEXOS modelling to produce a greater sample of USE outcomes with greater variability.
- A post-processing python model alongside the market model to iteratively examine the incremental change in system cost for different levels of reliability/USE ; this reduces the computational burden compared to running hundreds of PLEXOS models and provides a greater number of cost points against which to set the level of the standard. This approach assumes that the base-case model serves as a benchmark, and that the incremental capacity added operates primarily during periods of USE. Furthermore, as these models assume all plant operate in accordance with their short-run marginal cost, the costs associated with the operation of that incremental capacity can be determined from their published cost parameters.

As with all modelling, there are many assumptions and limitations that we must be aware of. These are described in more detail in appendix C.2.

Modelling stage two informed the market price settings

As described in the issues paper and draft report, the second stage of the modelling focused on determining the optimal market price settings to deliver a chosen reliability standard, where the goal is to minimise the total system cost whilst still ensuring that new entrant power system resources can recover enough revenue to cover their whole-of-life capital and operating costs.

Compared to the 2022 RSSR, and as with our calibration approach in stage one of the modelling, we have made a few simplifying assumptions to allow us to run more model runs and reflect a broader range of possible conditions. In the previous RSSR, in this stage of the modelling, the objective function of the optimisation model was to minimise total system costs, defined as the sum of spot revenue and the cost of unserved energy measured at the VCR. As our calibration model assumes a simplified dispatch of marginal new entrants, we calculate a fixed cost of unserved energy for each modelled reliability level. We also assume that spot prices in periods outside unserved energy do not change, since the marginal new unit is assumed to only generate during USE periods.

These simplifying assumptions allow us to reduce the optimisation approach to minimising the MPC and CPT, subject to ensuring revenue sufficiency for the marginal new entrant. This approach produces results that are reasonably aligned with the previous RSSR, while allowing us to run

102 Review of the form of the reliability standard and APC, published 27th June 2024, available at https://www.aemc.gov.au/market-reviews-advice/review-form-reliability-standard-and-apc

many more model iterations. We are testing the most appropriate market price settings for each region and at various reliability levels.

At a high level, the process to determine the minimal MPC and CPT is as follows:

- from the calibration approach in stage one of the modelling, produce a time-series of USE events for a given reliability level, then
- determines the capacity needed to meet every reliability level, increasing at increments of 0.001 per cent USE (e.g. for a given reliability level of 0.002 per cent, find the capacity needed to move from 0.003 per cent to 0.002 per cent)

Once this data is retrieved, we run an iterative grid search over a range of MPC and CPT values, based on a range of acceptable values. In the base case, we chose acceptable MPC values of $15,000/MWh to $45,000/MWh and acceptable CPT values of $750,000 to $4,500,000. The grid search algorithm works as follows:

1. Start with the lowest MPC value in the range
2. Calculate the revenue for a marginal new entrant, based on the lowest CPT in the range, and given the assumption that the new entrant operates to its maximum rating (given the appropriate derating) during periods of USE
3. If the revenue is lower than the required annualised costs, then repeat step 2 above with the highest CPT in the range
4. If the revenue is still lower than the required annualised costs, then the solution is infeasible. And move on to the next MPC value
5. If the revenue is higher than required, then pick a CPT value halfway between the current level and the lowest level
6. Repeat step 5, continually reducing the range of CPT values and testing them until the calculated revenue is within tolerance of the requirement
7. Once the minimal CPT is picked, add this as a dot on the frontier curve and repeat steps 2 to 7 with the next MPC in the range.

In this way, we iterate through each reliability level, region and MPC/CPT combination until we produce a frontier of minimum market price settings corresponding to the associated reliability standard level. Additional assumptions and limitations are described below.

C.1.2 Limitations of the approach

The modelling for this review has several broad limitations. These are summarised below:

- The modelling framework only considers total system costs and revenues for the marginal new entrant. There are broader issues outside the modelling scope that need consideration, including regulatory stability, market integrity and financial risks, contract market implications, new entrant revenue predictability, and investment price signals (i.e. the results from the modelling cannot be interpreted on a standalone basis and should be considered alongside these other issues).
- The calibration approach assumes no change in dispatch outcomes outside of USE periods with the introduction of new entrant capacity to bring the system in line with the reliability standard. If modelling were solely carried out through market simulations, dispatch outcomes may differ, and spot prices would likely be lower, leading to a higher MPC and/or CPT combination. The constant price and dispatch assumption is required to allow for modelling flexibility.

- The optimal reliability settings are highly dependent on the USE distributions. There is a risk that the outcomes based on the limited number of samples run may not have reached convergence; however, given resource constraints and diminishing returns, it may be infeasible to run a market model that reaches true statistical convergence.
- The stage two model does not directly account for inter-regional and pain-sharing impacts. Analysis of the modelled USE outcomes in the 2022 RSSR found less than 0.2 per cent of all USE intervals where the interconnections into the region experiencing USE was not at the import limit. This is consistent with the definition of USE in AEMO's ESOO modelling methodology, implying that each region must build its own new-entrant capacity to address its own reliability gap. Pain sharing can potentially impact the USE distribution, but would also be limited by network constraints across two neighbouring regions.
- The modelling cannot account for non-market constraints that could compromise the delivery of new generation capacity (such as jurisdictional policies, plant and equipment supply chain constraints, and planning approval delays).

C.2 Inputs and assumptions

This section describes the data assumptions and modelling inputs that we have used in the modelling.

C.2.1 Data inputs

The base case modelling has directly leveraged AEMO's published documents and PLEXOS models including the:

- 2024 Integrated System Plan (ISP)[103]
- 2025 Electricity Statement of Opportunities (ESOO)[104]
- 2026 Draft ISP Inputs Assumptions and Scenarios Report (IASR)[105].

We also relied upon documents published by the AER, including the 2024 Values of Customer Reliability (VCR)[106] and the Value of Emissions Reductions (VER)[107]

The key inputs that come from these documents and other sources are summarised in Table C.1 below:

Table C.1: Modelling inputs

Input	Description or source	Notes
Generation and storage build	From AEMO's 2025 ESOO	We have diverged from the ESOO in select regions to ensure our base case has sufficient unserved energy. This process and resultant changes

103 2024 Integrated System Plan (ISP), available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp

104 NEM Electricity Statement of Opportunities (ESOO), available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo

105 Draft 2026 ISP Inputs Assumptions workbook, available at: https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-consultation

106 Values of Customer Reliability 2024, available at: https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024

107 Valuing emissions reduction - Final guidance and explanatory statement - May 2024, available at: https://www.aer.gov.au/documents/aer-valuing-emissions-reduction-final-guidance-and-explanatory-statement-may-2024

Input	Description or source	Notes
		to capacity are described in this report
Generation and storage retirement	From AEMO's 2025 ESOO	See note above.
Transmission upgrade timings	From AEMO's 2025 ESOO, which is in turn sourced from AEMO's 2025 IASR	
CER forecasts, including Virtual Power Plants (VPPs)	From AEMO's 2025 ESOO, which is in turn sourced from AEMO's 2025 IASR	
Demand side participation (DSP)	From AEMO's 2025 ESOO, which is in turn sourced from AEMO's 2025 IASR	
Technical settings including outage and maintenance rates for generation, storage and transmission	From AEMO's 2025 ESOO, which is in turn sourced from AEMO's 2025 IASR	We have run 15 and 25 outage samples per reference year and demand level, sampling from the outage rates as set in the ESOO/IASR
Seasonal de-ratings	From AEMO's 2026 Draft IASR	
Bidding behaviour	We have run the base PLEXOS model using SRMC based bidding	
Constraint equations	Constraint representation is taken directly from AEMO's 2025 ESOO PLEXOS model	
Demand forecasts	From AEMO's 2025 ESOO	We have used AEMO's PoE10 and PoE50 demand traces
VRE output forecasts	From AEMOs' 2025 ESOO	We have used AEMO's set of 23 weather reference years. In the issues paper we discussed potentially using an extended set of 85 weather reference years, however this would come at a significant resource cost in terms of both computational resources and time, so we used only the AEMO set of traces. We note that AEMO's inclusion of additional weather traces has increased the sample size of weather years since the previous ESOO.
Hydro inflows	From AEMO's 2025 ESOO	
Generation and storage cost	From AEMO's 2026 Draft IASR	Originally taken from CSIRO's

Input	Description or source	Notes
data		GenCost report
Value of customer reliability	From AER's VCR report	We have re-weighted these VCR values. See the draft report for further details.
Value of emissions reduction	From AER's VER report	

C.2.2 Modelling assumptions and limitations

The Panel is aware of the following limitations of the modelling in addressing the scope of work and broader objectives of the RSSR. These limitations and the assumptions used to address them are summarised in the table below.

Table C.2: Modelling assumptions and limitations

Area	Assumption / Limitation	Notes
Modelling inputs	The base case inputs are sourced from AEMO's Step Change scenario using the ESOO and ISP.	Base case assumptions regarding demand, generation mix, demand-side participation, transmission timing and other critical generator and market components are taken from AEMO's Step Change scenario. These assumptions may change in the future and could lead to very different reliability outcomes and, hence, reliability settings.
	Weather reference years are based on historical data and do not account for climate change. We have used AEMO's extended set of 23 weather reference years. This is a significant improvement over the 13 weather-reference years in the previous ESOO and provides us with a much larger sample with which to produce results.	A greater number of weather reference years would make our results more robust, however, we must balance modelling accuracy with feasibility, and it was decided that running an extended set of reference years would be too costly on balance, given that we would expect results not to change materially. There is currently no accepted method for modelling the impacts of climate change, as changes in weather are difficult to predict, particularly at the levels of granularity required for our modelling. Ultimately, this is a limitation of the input data available to us, a large set of

Area	Assumption / Limitation	Notes
		weather years goes some way in ameliorating this issue, as it gives us a larger sample size, in which outlier events may be present.
Phase one - determining the optimal standard	The modelling framework only considers total incremental system costs.	The modelling framework only considers total system costs and revenues for the marginal new entrant. Broader issues outside the modelling scope, including regulatory stability, market integrity and financial risks, contract market implications, new entrant revenue predictability, and investment price signals, are not fully captured in the modelling exercise.
	The market modelling is carried out at 30-minute resolution, which may not capture variability at more granular time scales.	A higher resolution (e.g. 5 mins) would entail significantly longer run times and higher resource costs. Given the 30 min interval is more granular than that used by AEMO (AEMO uses hourly intervals) we consider this appropriate for this review. The increasing capacity of batteries is likely to accommodate large ramp rates from VRE / weather events until other energy unlimited resources can be activated.
Phase two - determining the market price settings	Revenues outside unserved energy periods are very difficult to forecast considering the rapidly changing nature of the wholesale market, and especially in relation to the behaviour of a marginal new entrant. We use a default figure of $50k/MW/year for OCGT.	See appendix C.2.3 below.
	Spot prices around unserved energy events influence outcomes as they are included in the calculation of cumulative prices that affect when the CPT is triggered. We assure a flat price of $150/MWh in the week preceding USE events across all regions, rather than explicitly modelling spot prices. This is because spot price forecasting is inherently uncertain and may unduly influence results. By setting a flat, consistent	As the triggering of the CPT is primarily driven by periods of unserved energy when the spot price is at the MPC, these assumptions do not significantly affect the results. We tested sensitivities to the assumed flat spot prices to confirm this.

Area	Assumption / Limitation	Notes
	spot price in each region for the periods before and between unserved energy events, we ensure that regions are treated equally and that we can explain differences in terms of the unserved energy distribution rather than our forecast of spot prices. As our calibration approach adds capacity back into the model outside the simulation runs, we also need to modify spot prices for periods with unserved energy in the original simulation but not in the calibrated result. For these periods, we assume a flat spot price of $300. This reflects the fact that these periods are close to unserved energy levels, and prices are likely to be elevated compared to normal periods.	
	We calculate revenues based on a marginal new unit meeting the last 0.001 per cent of reliability; i.e., for a standard of 0.002 per cent, we model the revenues for a unit that reduces the level of unserved energy from 0.003 per cent to 0.002 per cent.	This assumption allows us to model continuous new entry in MW rather than needing to incentivise an entire new unit.
	New entry is based on continuous (non-integer) new entry, rather than being whole units only. This assumption ensures that differences in region sizes don't unduly affect results. For example, if we treated new entry as whole units only, South Australia would have a much higher proportional cost, as the size of the more economically efficient OCGT unit makes up a larger proportion of total demand in that region.	
	The marginal new entrant operates primarily during USE periods and is based on assumed operating behaviour. For an OCGT unit, we assume it operates to the extent required during all USE events for the duration of each event. For BESS, we assume a starting state of charge for USE events of 80 per cent and discharge to either 0 per cent state of charge ((SoC) the stored energy in the battery is exhausted) or the USE event has ended (whichever comes first). The Battery Energy Storage Systems (BESS) unit is assumed to	This assumption allows us to estimate revenues without running a full PLEXOS simulation. This is appropriate for an OCGT, but less accurate for a BESS. We are aware that in reality, the ability for BESS to charge is also dependent on there being enough spare capacity in the market during preceding periods. Our current assumptions can therefore be interpreted as close to an upper bound on how much USE battery units can address.

Area	Assumption / Limitation	Notes
	be able to charge at its technical capability for each interval between the end of one USE period and the start of the next period.	

C.2.3 Treatment of revenue outside USE periods

Revenue earned by generators outside reliability events plays a crucial role in determining the required MPC/CPT combinations to ensure revenue adequacy for new entrants into reliability. As these revenues are used as a 'top-up' additional to revenues earned from reliability events, an assumption of higher revenue would lead to lower market price settings, all else being equal.

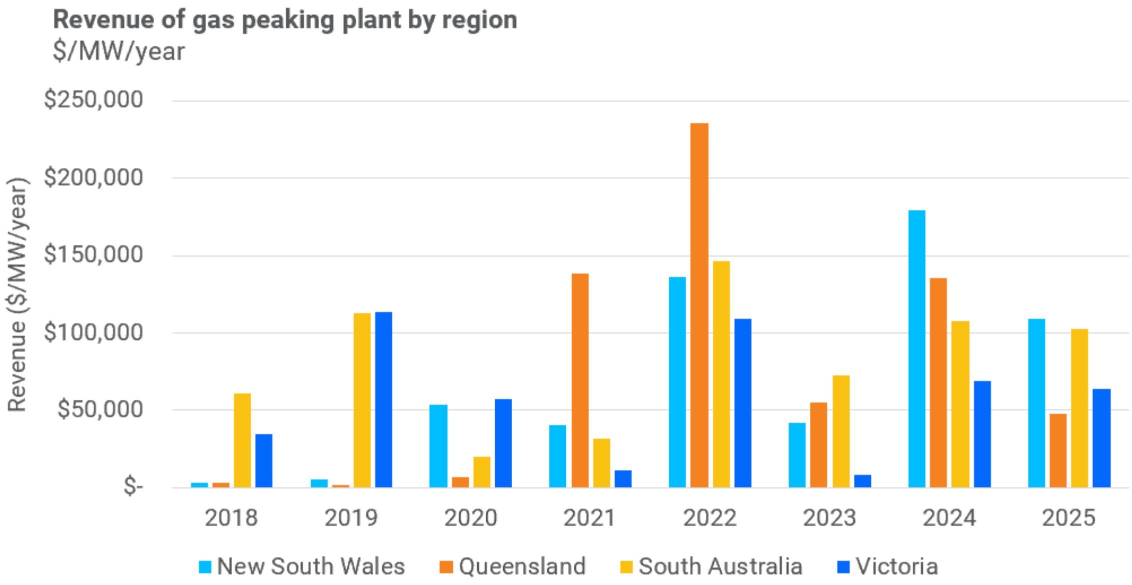
There are a number of difficulties in determining the non-reliability revenues for OCGT and BESS, particularly for the marginal new entrant. There are uncertainties in each of the following factors, which are all drivers of revenue:

- the overall level of spot prices
- the variability in spot prices, e.g. the daily price spread and the prices around times of unserved energy
- the duration of low and high prices suitable for arbitrage
- the operating behaviour of a marginal new entrant
- the additional revenue streams outside the wholesale market (e.g. ancillary services).

Non-reliability revenues for OCGT

In the 2022 RSSR, a figure of $46,250/MW/year was assumed for the marginal OCGT unit. This figure was chosen because it is close to the average revenue from historical outcomes for gas peakers across various years and capacity factors. This analysis was repeated in this RSSR, with the results shown in Figure C.3 below. Higher revenues in 2022 were predominantly due to higher fuel prices over the financial year ending 2023. This historical analysis shows that the operational role of peakers in regions with higher renewable penetration differs from that in regions with lower penetration. The 'firming' role played by these units is expected to continue to grow as the transition continues, which may warrant alternate treatment in future reviews.

Figure C.3: Gas peaker revenues vary significantly between regions and years



This analysis reveals a significant variability in revenues for gas peakers across regions and historical years. We would expect the revenues in future years to be similarly variable (if not, even more so). Given the variability and inherent uncertainties in estimating revenues, we have adopted a figure of $50,000/MW/year to maintain a relatively consistent revenue assumption with last year, with a slight increase to account for inflation.

Non-reliability revenues for BESS

Estimating non-reliability revenues for BESS is even more challenging than for OCGT, as it involves additional uncertainties and complexities beyond those already inherent in OCGT revenues. This includes:

- ancillary service (FCAS) revenues have been declining as increasing deployment of BESS has intensified competition, leading to revenue cannibalisation among batteries
- currently merchant battery revenues are predominantly derived from arbitrage or energy tolling, and are therefore even more dependent on the daily spread in prices and contractual opportunities
- it is unclear how frequently a marginal new entrant battery would operate outside of USE periods.

As stage one of the modelling identified the large OCGT as the most cost-efficient benchmark technology to address unserved energy, we did not explicitly model the price settings required for batteries, and therefore did not need to make an assumption regarding BESS revenues. However, we back-solved the required non-reliability revenue for batteries to ensure revenue sufficiency, given the market price settings required for OCGT units. These results are presented in Chapter 4 of the draft RSSR report.

C.2.4 Treatment of demand side response

The Panel has, for several reasons, not included demand side participation (DSP), in the sense of flexible demand or demand response, as a candidate marginal technology for determining the optimal reliability standard.

Firstly, while DSP is an important and established contributor to operational reliability, the modelling framework for determining a marginal new entrant requires consistent, system-wide input assumptions. For other technologies, these assumptions are drawn from AEMO's IASR and ESOO, but no equivalent dataset exists for DSP costs or the volume of available DSP at different levels of opportunity cost. Unlike technologies with relatively uniform engineering and capital characteristics, DSP costs are highly context-dependent, varying by load type, business process, retail arrangement, and opportunity cost. As a result, any DSP cost curve would rely on bespoke assumptions rather than independently developed inputs, and would not provide a defensible basis for determining the reliability standard.

Secondly, the marginal new entrant approach isolates technologies to understand their relative costs of meeting the reliability standard. DSP presents structural challenges in this framework. Its heterogeneity makes it difficult to represent with a single marginal entrant cost curve, and it is not realistic to expect DSP alone to meet the full incremental reliability requirement in the model, even though DSP clearly and critically contributes to reliability in the operational timeframe alongside many other technologies.

Reflecting these methodological and data availability constraints, rather than any assessment of DSP's importance or maturity, the Panel has determined that DSP should not be considered as a candidate marginal technology for this review period. The Panel anticipates that improvements in data availability and modelling capability may enable a more robust consideration of DSP as a marginal entrant in future reviews.

C.3 Quality assurance and changes since the draft report

We contracted an external consultant, Intelligent Energy Services (IES), to conduct a quality assurance review of the modelling methodology and results. IES completed the modelling for the RSSR in 2022 and, as such, are very well-placed to assess the validity and quality of the modelling that was conducted internally for this RSSR. This external audit ultimately concluded that the modelling is robust and reliable:

> Based on our review across all assessed areas, we conclude that the modelling is robust, reliable, and provides a sound basis for informing the efficient level of the reliability standard and the corresponding MPC/CPT. The methodology has been carefully applied, incorporating relevant technical and economic parameters, and aligns closely with the 2022 RSSR approach.

The full quality assurance report has been published alongside the final RSSR report for transparency.

We note that during the quality assurance process, several minor issues were identified. These issues, along with updates to market data and our own analysis on ways to improve the modelling, have led to several changes to the inputs and modelling process between the draft and final report. In summary, we have:

- created a new base case PLEXOS model for stage two of the modelling, which:

    - made adjustments to the capacity of firm plant in the model to bring reliability closer to the proposed standard
    - ran an additional 10 outage samples for each reference year and probability of exceedence (PoE) model
- updated cost information to reflect the Draft 2026 IASR
- included seasonal de-rating factors on OCGT plant for stage one and stage two of the modelling
- addressed several non-material issues in the modelling process, including:
    - attaching the PoE10 2010 reference year demand trace correctly
    - fixed processing issues for 24 PLEXOS runs
    - fixed minor coding bugs for the battery calibration script.

The changes to the new base case are detailed further below. Further details on the quality assurance process and findings can be found in the report.

C.4 Market modelling

This section describes the setup of the base case market model, the calibration methodology, and the characteristics of unserved energy that result from this process.

C.4.1 Two base case market models were developed

The basis of the modelling is a detailed time-sequential market model, which captures the dynamics of the NEM during the study period for each region. This market model was built using the simulation software PLEXOS, which is a linear optimisation program that is designed to replicate dispatch outcomes in energy markets. In particular, we use AEMO's published ESOO model, available as a PLEXOS model and representing the NEM over the next 10 years based on current forecasts of supply and demand. We use the ESOO central case for our demand outlook, and consistent with AEMO's approach to the ESOO, we incorporate all the appropriate 'committed and anticipated' capacity in our supply outlook. This model reflects the conditions most likely to occur given the announced project start and end dates.

For the modelling in the final report, we created two base case PLEXOS models. The first is the same as the base case in our draft report, with some small bug fixes following the identification of minor issues in the quality assurance process. The second base-case PLEXOS model is designed specifically for stage two of the modelling (determining the market settings) and, as such, some capacity was reactivated to achieve a level of reliability closer to the proposed standard. Furthermore, we ran an additional 10 outage scenarios for each reference year and PoE level. The purpose of these changes is to establish a base case that is less dependent on the post-PLEXOS calibration and to increase the sample size to increase confidence in the results. This is particularly important in the second stage of the modelling as the market settings are more sensitive to the shape of USE events than the efficient level of the standard.

Initial model setup

The base models were created by using AEMO's published ESOO PLEXOS model, where we took the published model as-is, and made some minor adjustments, including:

- increasing the granularity of the time-step from 1-hour intervals to 30-minute intervals,
- changing the representation of chronology in the medium-term schedule from partial to fitted, and

- changing the total capacity in each region to ensure that all regions have a similar level of reliability and that there is sufficient unserved energy to generate system cost curves across the entire spectrum of reliability levels.

We note that during the quality assurance process, a number of minor issues with the base case that we developed for the draft report were discovered. Specifically:

- the 2010 reference year PoE10 PLEXOS run was incorrectly attached to the 2009 reference year demand, and
- there were 24 PLEXOS runs that failed during the model run or data ingestion process.

We have since addressed these issues, although five PLEXOS runs still failed. Due to timing and expected lack of materiality, we excluded these five incomplete runs from the stage one base case.

Capacity changes

The changes to capacity from the 2025 ESOO model are described in Table C.3 below for each base case:

Table C.3: Capacity changes in the base PLEXOS model

Region	Capacity changes - stage one base case	Capacity changes - stage two base case
New South Wales	• One of the two Vales Point coal units turned off	• One of the two Vales Point coal units turned off • One of the four Colongra OCGT units turned off
Queensland	• Five of the six Gladstone coal units turned off	• Five of the six Gladstone coal units turned off • Added 500MW of generic OCGT
South Australia	No changes	• Added 200MW of generic OCGT
Victoria	• One of the four Loy Yang units turned off	• Laverton North OCGT turned off

Note: The Panel notes that Queensland has announced that it may delay coal retirements. We have not included this in the modelling due to uncertainty in the details of this proposal. Furthermore, our baseline model requires the removal of capacity to generate sufficient unserved energy for the study, so any changes to jurisdictional policy in this regard would likely not have a material impact on the modelling results.

Number of model runs and weightings applied

To ensure we have a large enough sample of future unserved energy events, we run hundreds of simulations with varying input data. There is a necessary trade-off in this approach: a greater number of runs provides a larger sample size and thus a more robust set of results; however, these model runs come at a significant resource cost, both in terms of time and computing power.

The table below shows the number of samples for each input variation that we ran:

Table C.4: Number of samples

Input	Description	Parameter value - stage one base case	Parameter value - stage two base case	Notes
Weather reference years	This represents historical weather outcomes which affects both the availability of variable renewable resources and the shape of demand	23	23	This is consistent with AEMO's ESOO
Outage samples	This reflects a random sample from a distribution of thermal outage rates. For example, if a coal unit has a 15 per cent forced outage rate, then it will be unavailable for 15 per cent of the year. Together with the mean time to repair (MTTR) parameter PLEXOS will assign a number of forced outages each the length of the MTTR sufficient that the Forced outage rate is satisfied. 15 samples allows PLEXOS to generate 15 potential outage patterns to be considered.	15	25	The number of samples in stage one is less than the 25 outage samples that AEMO run in their ESOO. However, our analysis found that weather reference years were a more impactful driver of USE outcomes, so we are comfortable making this tradeoff to use fewer outage samples. For Stage 2, given the greater sensitivity of the market settings, we considered it appropriate to trade off longer run times in order to achieve higher accuracy.
Peak demand levels	This shows different forecasts of peak demand, where the PoE10 trace represents a scenario with peak demand at the 10th percentile (i.e., on the higher end), and the PoE50 trace represents median peak demand.	2; PoE10 and PoE50	2; PoE10 and PoE50	This is consistent with AEMO's ESOO
Years in the revenue period	This is the financial years that are simulated	1 year; FY31/32	1 year; FY31/32	We have chosen to model this year only, as it has the highest forecast of unserved energy across all regions.
Total number of runs:		685	1150	We note that 5 PLEXOS runs failed due to computational issues in the stage one base case,

Input	Description	Parameter value - stage one base case	Parameter value - stage two base case	Notes
				resulting in 685 runs instead of the expected 690. As these runs represent less than 1 per cent, we expect this to have no material impact on results.

The Panel believes this strikes a good balance between sample size and feasibility.

Sample weights

The results from each run are weighted according to the PoE10 or PoE50 demand trace used. This weighting is necessary because the PoE10 traces assume a less likely future. If they were treated on the same footing as the PoE50 traces, this would result in an outcome that is potentially more unreliable than reality. We use a weighting of 30 per cent for PoE10 traces and a weighting of 70 per cent to PoE50 traces, consistent with the previous RSS reviews.

Reliability outcomes

The resultant level of reliability for each base case is described in Table C.5 below:

Table C.5: Reliability level by region in the base PLEXOS model

Region	Annual Consumption (TWh)	Reliability level (%) - stage one base case	Reliability level (%) - stage two base case
New South Wales	73.05	0.0062	0.0059
Queensland	57.71	0.0249	0.0075
South Australia	16.35	0.0122	0.0051
Victoria	47.94	0.0223	0.0099

Note: NSW reliability improved marginally, even though capacity was taken out. This is a result of relatively larger increases in capacity in interconnected regions, which improve the reliability outcome for NSW, and, in part, due to the randomness associated with the higher number of samples in the stage two base case.

C.4.2 Calibration approach

A significant methodological change from the previous RSSR is the introduction of the calibration approach. This approach uses results from a base PLEXOS model run and then adds firm capacity back into the resulting dataset ex-post to determine outcomes for different levels of reliability. The benefit of this methodology is that it enables us to generate outcomes for various reliability levels relatively quickly. Running thousands of PLEXOS models with different capacities for new-entrant technologies would be computationally infeasible; therefore, we find that the calibration approach is appropriate. The steps that we follow in this methodology are outlined below:

1. Run a base case PLEXOS model across a given number of samples (in our case, 23 reference years, 15 outage samples and 2 PoE demand levels).

2. Calculate the level of reliability by determining the weighted average total of unserved energy across all samples (weighted by PoE) and dividing by the expected annual average demand in each region.
3. Iteratively add or remove capacity and recalculate step 2 until the calculated reliability level is sufficiently higher than the current standard (around 5-10 times) in each region.

Once a baseline PLEXOS model is settled upon, the following steps are repeated for each candidate technology and reliability level between 0.0001per cent and 0.01 per cent USE in increments of 0.001 per cent:

1. Add in a unit of the candidate technology, and recalculate the total unserved energy in each sample using an assumed operating behaviour during USE events. For an OCGT unit, assume it operates at its maximum capacity throughout all USE events. For BESS, assume a starting state of charge of 80 per cent and discharge until the unit reaches 0 per cent SoC or the USE event ends (whichever comes first). Charge the unit using any spare capacity between USE events based on its technical parameters until it is back up to 80 per cent SoC in preparation for the next USE event.
2. Re-calculate the total level of reliability across all samples in terms of the reliability standard.
3. If the reliability level is below the targeted level, repeat steps 1-2.
4. If the reliability level is at or above the targeted level, end the process there and record the number of additional units required to achieve this level.

The result of this calibration process is an extended dataset of USE outcomes for a range of reliability levels, along with the number of additional units required above the baseline to achieve that reliability level for each candidate technology. This dataset is then used to produce the reliability curves in stage one of the modelling. For each increment in reliability, we attribute fixed and operational costs to the additional units required, and we apply the VCR to the remaining unserved energy. We also use this dataset for stage two of the modelling, as we calculate the revenue a unit earns based on the capacity required to achieve an additional 0.001 percentage-point increase in reliability (e.g., moving from 0.003 per cent to 0.002 per cent).

We performed detailed calibration of the modelling to address any limitations

The primary limitation of this approach is that the complexities of dispatch during periods of unserved energy and outside unserved energy are not captured when additional capacity is introduced - this is the simplifying assumption that allows us to run the calibration process quickly, but may understate the impact of the additional capacity. On the other hand, PLEXOS is a perfect foresight optimisation which may overstate the impact of additional capacity. In reality, the true impact of additional capacity is likely somewhere between these two methods.

We also performed tests comparing the results of our calibration with those of re-running a PLEXOS model with the additional capacity. For BESS, we found that the calibration approach produced results broadly similar to PLEXOS, but for OCGT, it reduced USE by 20 per cent less than the equivalent capacity reduction in the PLEXOS simulation. This was because, in the full model run, dispatch by the additional OCGT unit may be used to charge batteries before USE events, thereby reducing the USE by more than the capacity added. To alleviate this discrepancy, we apply a 20 per cent reduction in the number of MW calculated through the calibration approach in stage one of the modelling.

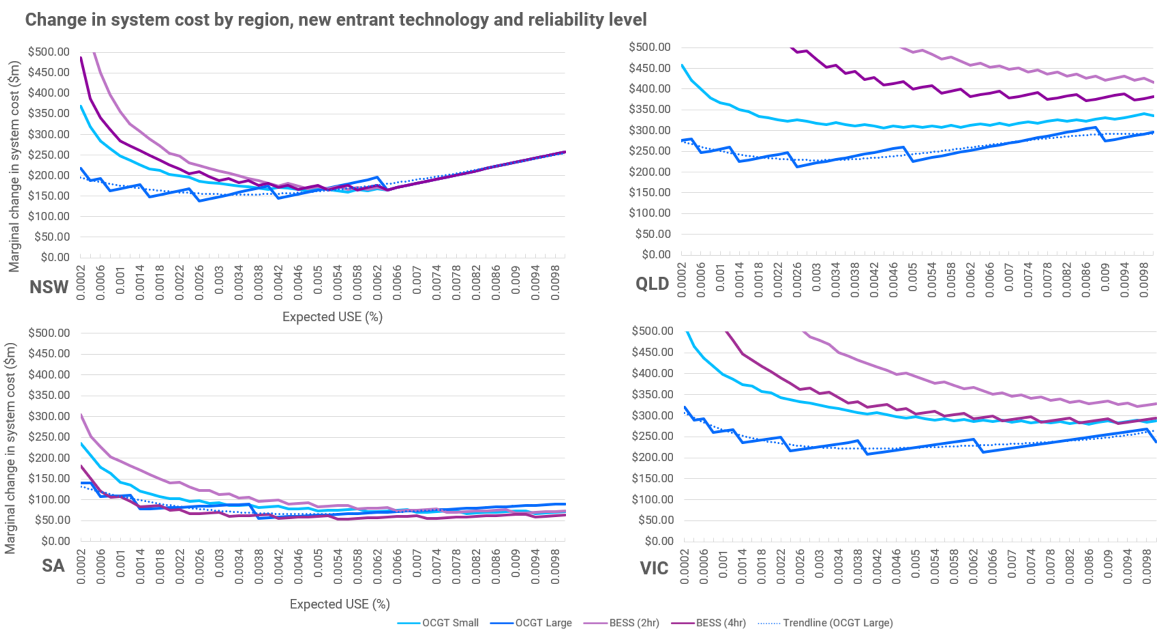
C.5 2026 RSSR modelling results

This section presents the modelling results for stages one and two, including the characteristics of unserved energy and regional differences.

C.5.1 The lowest cost marginal new entrant

The cost curves developed in stage one are shown in Figure C.4Figure C.4 below for each region, where the X-axis shows different reliability levels and the Y-axis shows the marginal change in total system cost compared to the base case for each region. The figure shows that the large OCGT is the most cost-effective marginal new entrant to address reliability in all regions except South Australia. South Australia's size and the unique unserved energy characteristics result in the 4-hour battery and the large OCGT being relatively equally cost-effective in addressing unserved energy.

Figure C.4: The large OCGT is the most cost-effective new entrant in all regions



Note that the 'jaggedness' of the curves is explained by the change in the incremental costs from an additional capacity unit needed to deliver the next level of reliability. This is particularly noticeable for the large OCGT, with a unit size of 265MW, allowing a single unit to address a wide range of reliability levels. This effect is more pronounced in regions such as South Australia, where a single large OCGT increment is able to meet a level of reliability from 0.01per cent to 0.0025 per cent. To address this issue, we have added a polynomial best-fit line for the large OCGT entrant (shown as the dotted line). This shows a smoother curve and allows us to see the minimal range more clearly, however we recognise that this is an approximation.

The large OCGT remains the most effective marginal new entrant on which to benchmark reliability settings, despite rising capital and operational costs and a falling battery cost environment. This is primarily due to the duration of unserved energy events, which, during longer events, may require more overall battery capacity and storage volume to prevent battery energy from being exhausted.

An example of this is South Australia, where unserved energy events are typically shorter but deeper. For these events, short-duration storage is more ideally suited, and as such, we see that the 4-hour battery and OCGTs are almost interchangeable. However, in Queensland, where unserved energy events are typically shallower but longer, an energy-unlimited gas peaker best meets reliability outcomes at the lowest cost. As regions transition away from thermal generator-dominated fleets at different rates, we expect diverging USE event characteristics to persist, with implications for the suitability of universal market price settings across the NEM. We expect that reliability characteristics will converge again once all NEM regions have transitioned to a low-cost and low-emissions future system.

Despite OCGTs remaining the lowest-cost technology on which the reliability standard is based for this review, the Panel expects the market to continue delivering the optimal mix of batteries, OCGTs, and demand response to meet the reliability standard within the operational timeframe. It is likely that batteries will continue to displace gas-fired generation in providing essential day-to-day shaping of supply and demand, while OCGTs refocus on generating during longer-term renewable energy droughts. This would represent the market optimising across different energy sources as intended.

The distribution of unserved energy by region is discussed more in appendix C.5.4.

The Panel's sensitivity analysis confirmed OCGTs as the marginal entrant to benchmark the market price settings

Our analysis also considered a number of sensitivities, including alternate values for:

- the value of customer reliability (VCR),
- the weighted average cost of capital (WACC), and
- battery revenue outside of USE events.

The impact of these sensitivities still broadly point to large OCGT as being the most cost-effective marginal new entrant. Sensitivity results are presented in the draft report.

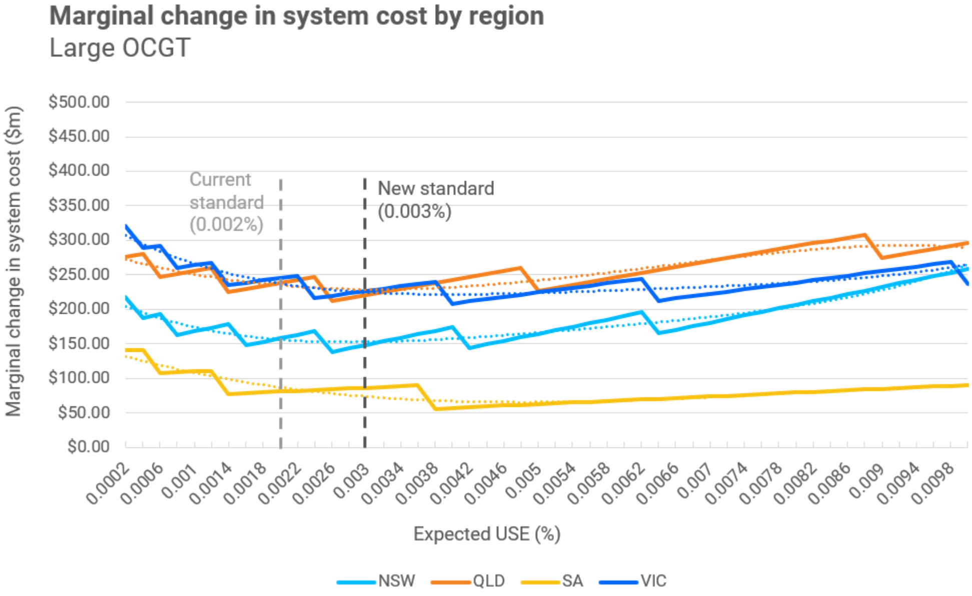
Assuming that BESS cost reductions continue to materialise, the Panel considers it relatively likely that batteries will emerge as the marginal new entrant in the next RSS review. Given the particular challenges in modelling battery behaviour, we have sought stakeholder feedback on how the Panel should approach this exercise in the next review.

C.5.2 Efficient level of the reliability standard

Once the large OCGT was identified as the most cost-effective benchmark technology, we compared the reliability cost curves for each region to determine the most appropriate reliability standard range.

Figure C.5 below shows the resultant curve, with the current and proposed reliability standard highlighted:

Figure C.5: The optimal reliability level is to the right of the current standard in all regions



These reliability curves reveal several insights that are explored in more detail below:

1. The optimal reliability level has shifted to the right compared to the previous RSSR.
2. The curves appear to have fairly 'flat' ranges around their minimums, indicating that a material change in reliability level does not correspond to a material change in cost. Given the relatively flat minimum range, the cost of providing incremental capacity is almost equal to the value customers place on reliability.
3. There are significant differences between regions, both in terms of change in system cost and in terms of optimal reliability level.

In all regions, the most cost-efficient level of reliability is higher (less reliable) than the current standard of 0.002 per cent. This outcome is driven by a confluence of factors, including:

- a reduction in the value of customer reliability compared with the previous RSSR,
- an increase in the cost of building and providing fuel to a new OCGT capacity, and
- a change in the underlying distribution and characteristics of regional USE events.

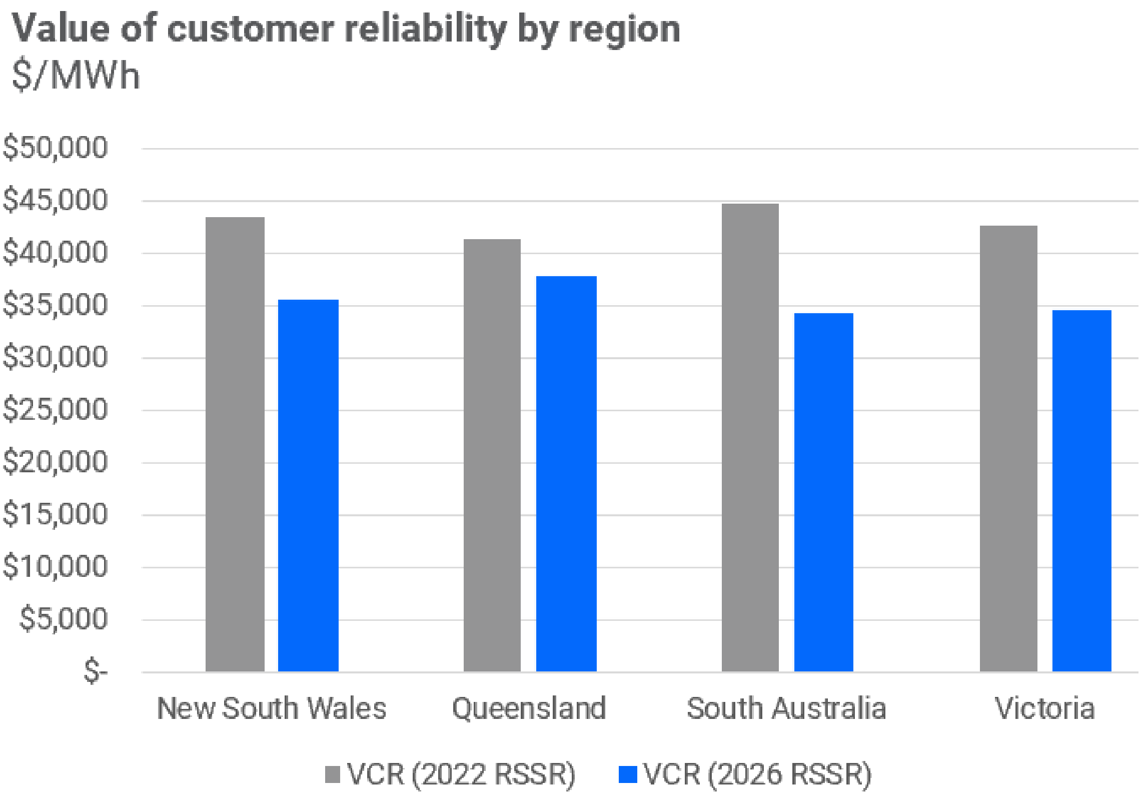
The efficient reliability level is a function of the cost of new generation and the value consumers place on reliability. Since the last RSSR, both of these parameters have moved in a direction that would drive the optimal reliability level to the right (that is less reliable).

A reduction in the value of customer reliability is partially responsible for a reduction in the optimal level of reliability

The VCR has decreased in all regions, with an average decrease of roughly 18 per cent.[108] This shifts the optimal reliability level to the right, all else equal, because customers place less value on the same level of reliability. Figure C.6 below shows the change in VCR from the previous RSSR to the current RSSR. Note that we reweighted the VCR, as discussed further in Chapter 2 and the draft report.

108 Australian Energy Regulator, Value of Customer Reliability - Final Report, December 2024, pp.5-6.

Figure C.6: The VCR has decreased in all mainland NEM regions



Increases in the cost of gas firming partially explain the increased cost to meet the current level of reliability

On the other side of the equation, the costs to build new OCGT capacity have also increased, meaning that, for a given level of reliability, it will cost more to meet that standard. The increasing costs of OCGTs are discussed in more detail in appendix C.2.

Another important insight about these curves is that they are all relatively flat: a large change in the reliability standard produces only a small change in incremental system costs. The reason these curves have become flatter than previous RSSRs is a direct consequence of the changing underlying costs and the value of customer reliability discussed above. In particular, this is because the cost contribution from the marginal new entrant generator and the value of customer reliability have somewhat converged. The lower VCR and increased cost of new OCGT entry balance at a lower level of reliability. While this is true in the middle range of reliability (0.003 per cent to 0.008 per cent), at high levels of reliability below 0.003 per cent, the cost of new generation to address additional unserved energy becomes much higher, as relatively more MWs are needed to close the gap.

The implications of this effect are that there is a range of efficient reliability levels, where the change in total system cost between the top and bottom of the range is very small. In practical terms, this means, for example, that a reliability standard of 0.003 per cent incurs only a negligible additional cost compared to 0.0035 per cent.

Differences in the characteristics of USE events have large implications for the optimal market settings

There are also significant differences across regions, both in the incremental change in system cost relative to the base case (the height of the curve) and in their overall shape. The former is largely driven by the region's size and the reliability level in our base case. The Y-axis represents the total incremental cost derived from the cost of unserved energy (valued at the VCR), plus the cost of any additional new entrant capacity for each reliability level. In NSW, with a base-case reliability level of 0.0054per cent, the Y-axis value at this level is simply the total unserved energy multiplied by the VCR. As we move to the right of the curve, the cost of unserved energy decreases, while the cost of new generation increases, as additional entrants are required to meet higher reliability levels. South Australia has the lowest incremental cost curve because it has the lowest peak demand and annual energy consumption. Consequently, the MW capacity needed to achieve different reliability levels is lower, and the cost of unserved energy is lower as there is less MWh of unserved energy.

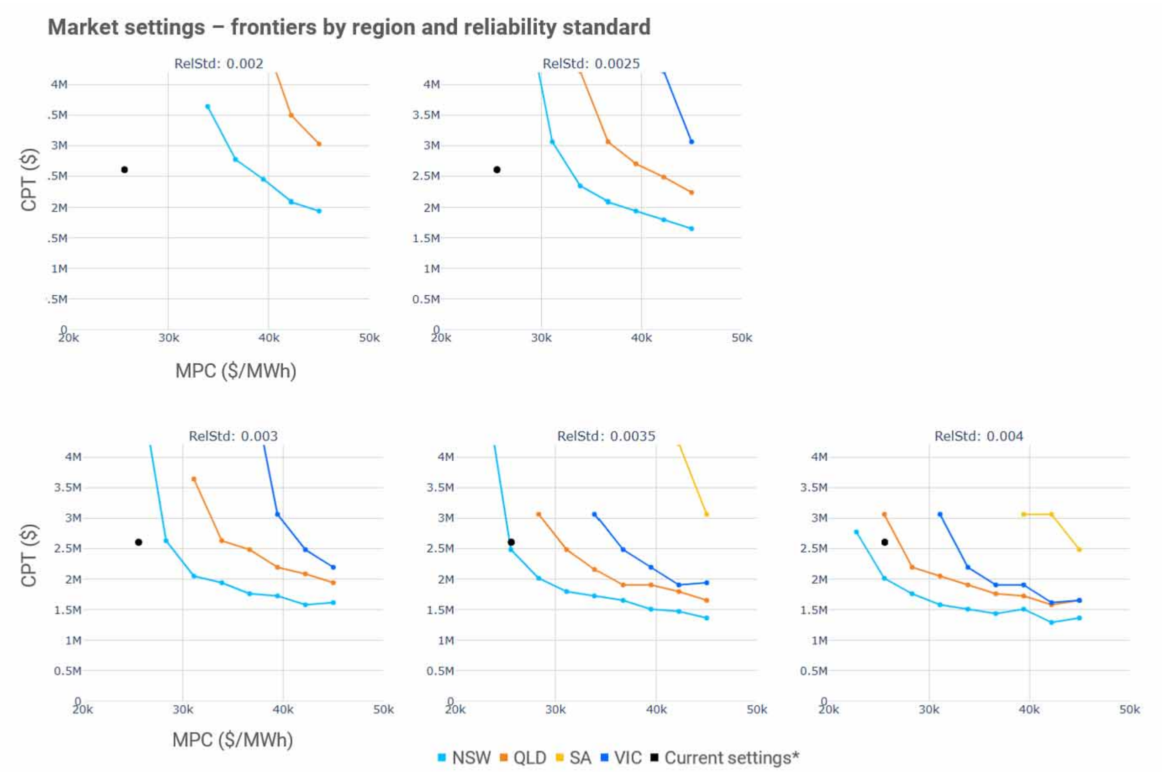
The differences in the shape of the curve, however, are a function of the regional new entrant costs, the regional VCR levels and the differences in the distribution of unserved energy between regions. All else being equal, regions with higher generation costs or lower VCRs will have optimal reliability to the right, and regions with lower generation costs or higher VCRs will have optimal reliability to the left. Interestingly, both Victoria and South Australia have VCRs that are roughly 8-9 per cent lower than those in Queensland (the region with the highest VCR), and generation costs that are also 8-9 per cent lower than those in Queensland (the region with the highest OCGT costs). While these effects roughly balance out on a per-unit basis, the impact of lower generation costs is larger in absolute terms, shaping the curve. The primary driver of the differing shapes of the curves, however, is the difference in the characteristics of unserved energy between regions.

C.5.3 Efficient market price settings

This stage of the modelling is run using a grid-search optimisation approach to determine combinations of MPC and CPT for a marginal new entrant in each region, such that system costs are minimised, subject to the constraint that the marginal new entrant must remain revenue sufficient. The optimisation produces a 'frontier' of MPC and CPT points that satisfy this condition, given upper and lower bounds for both MPC and CPT. The reason that this frontier exists is that the same revenue outcome may be achieved using a high MPC but low CPT (such that the generator earns lots of revenue quickly before administered pricing kicks in), or by a low MPC but high CPT (such that a generator earns lower revenue per interval, but is able to earn the market price cap for a longer time period).

The chart below illustrates the frontier of minimal MPC and CPT settings for a marginal new entrant large OCGT in each region and at each reliability level within the proposed range (incremental by 0.0005 per cent). The current FY27-28 settings in 2025 dollars are indicated by the black dot. Note that this optimisation was bounded by an MPC range of $20,000/MWh to $40,000/MWh, and a CPT range of $750,000 to $4,000,000.

Figure C.7: The optimal MPC and CPT increase with an increasing reliability level



Note: The 'current settings' reflect the settings from 1st July 2027, converted from a base year of 2022 into a base year of 2025.

There are a number of important outcomes of this modelling:

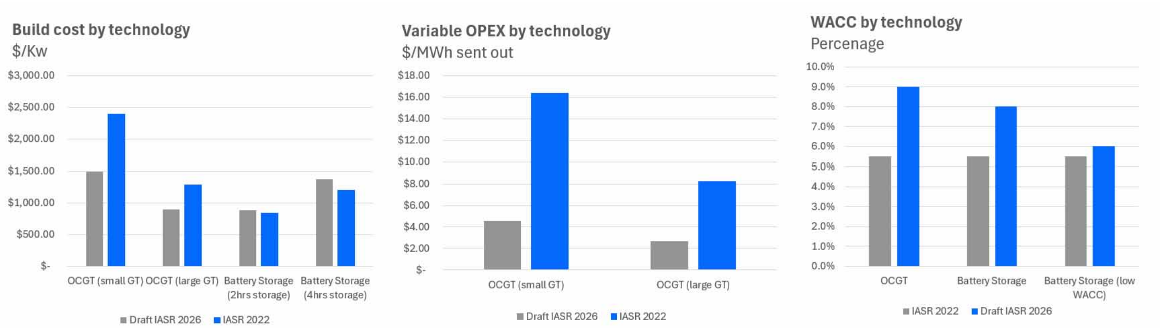
1. the MPC/CPT frontiers are significantly higher than in the 2022 RSSR
2. there are significant differences between outcomes at different reliability levels, and
3. there are significant differences between outcomes for each region.

These outcomes can be explained by reference to the changes in the inputs, in particular, the most important factors driving these outcomes are:

- the increasing cost of building an OCGT unit, and
- the underlying distribution, duration and depth of unserved energy in each region.

One of the primary drivers of a higher MPC/CPT frontier is the rising cost of building an OCGT unit. Figure C.8 below shows the changes in build cost, operational costs, and weighted average cost of capital between AEMO's 2022 IASR (used in the 2022 RSSR), and the 2025 IASR (used in this RSSR).

Figure C.8: OCGT costs have increased compared to the previous RSSR



Source: Inputs, assumptions and scenarios workbook 2021/22 and Draft 2026 ISP Inputs and Assumption workbook (AEMO)

Note: Costs are based on the last year of the respective RSSR periods (2027/28 and 2031/32, respectively) and have not been adjusted for inflation. Variable OPEX in the 2022 IASR is based on the 'NSW medium' forecast.

As costs have increased for large OCGTs, we should expect that, all else equal, market price settings must also increase to ensure they remain revenue sufficient for the same level of reliability.

The second factor that influences these results is the changing distribution of unserved energy as the NEM transitions to renewables, and the different characteristics of unserved energy between regions. This is described in the section below.

C.5.4 Characteristics of USE

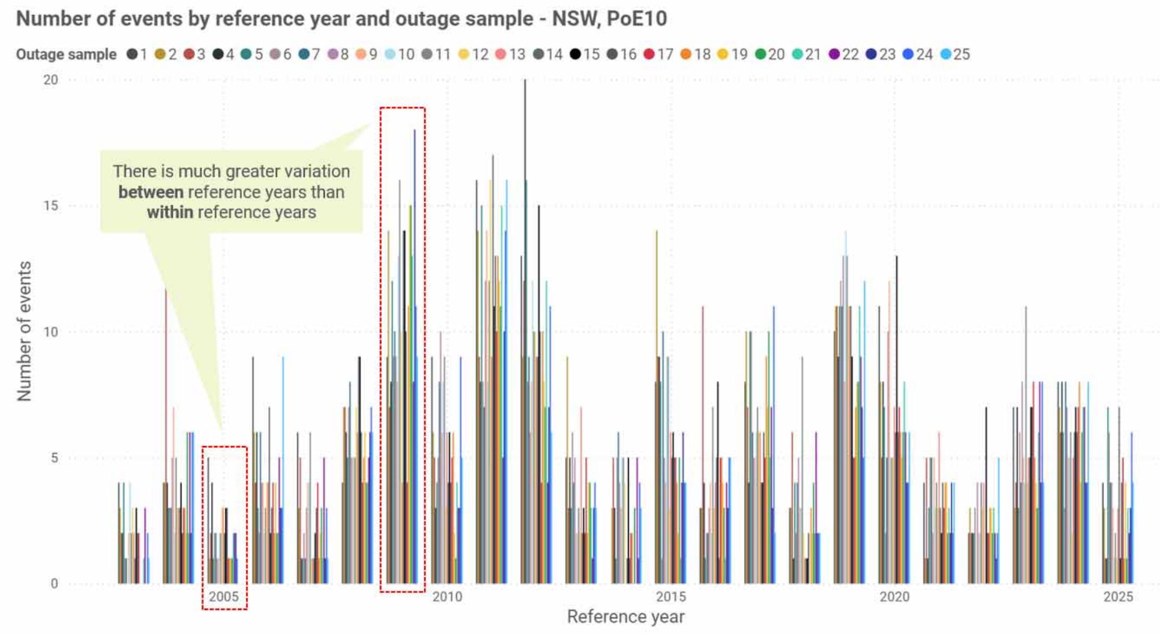
This section describes the characteristics of USE revealed by our modelling. These characteristics are a significant driver of overall results and are particularly explanatory of regional differences.

Weather reference years drive outcomes more so than outage samples

The modelling undertaken by the Panel for the Review of the Form of the Reliability Standard in 2024 highlighted that, as the NEM transitions to a system with higher penetration of renewable energy, unserved energy events may increasingly be driven by weather. Specifically, the Panel found that there is far greater variability in weather reference years as a driver of reliability outcomes than in stochastic thermal outage samples. Whilst the scope of work and modelling horizon for this RSS review differ from the Form of the Standard work, we have found similar results.

Figure C.9 below shows the number of USE events by reference year and stochastic outage sample for NSW at the PoE10 demand level. This distribution clearly highlights that there is far more variation in the number of USE events between reference years than within reference years. Similar analysis is presented in the draft report.

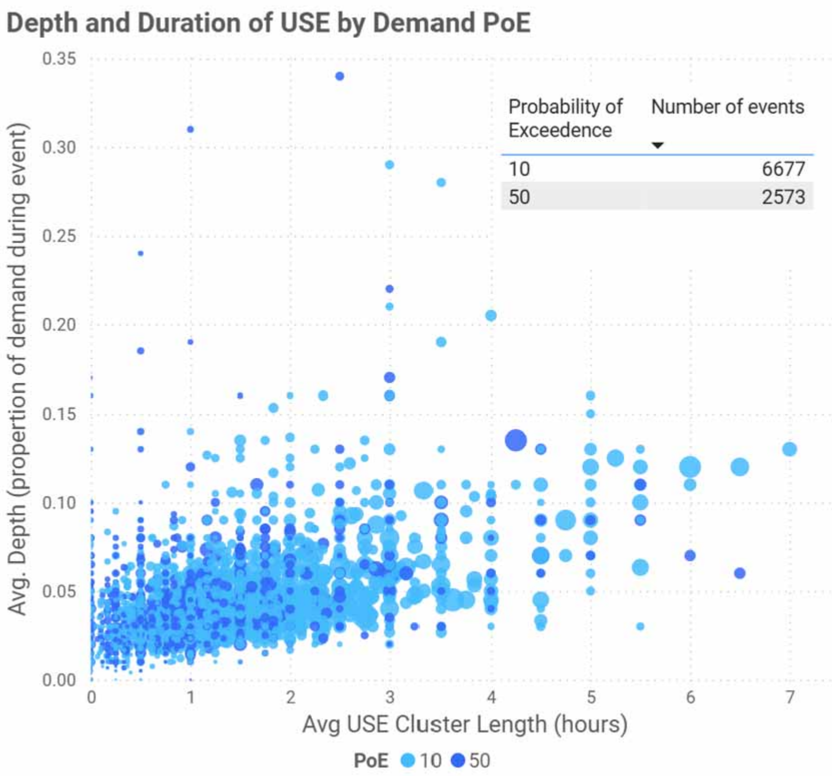
Figure C.9: There is greater variation between reference years than within reference years



There are fewer USE events in the PoE10 demand level runs, but the depth and duration of the events are similar

We ran the PLEXOS simulation using PoE10 and PoE50 peak-demand traces and weighted the results accordingly. Figure C.10 below shows the result of these runs, highlighting that PoE10 runs produced almost twice as many USE events, but the shape of these events in terms of depth and duration was similar to the PoE50 runs.

Figure C.10: Peak demand did not have a major impact on the depth and duration of USE events as a whole



USE characteristics differ significantly by region

In both stage one and stage two of the modelling, regional results differ significantly. In the first stage of the modelling, Victoria and South Australia both show optimal reliability levels that are lower (i.e., more reliable) than those of New South Wales and Queensland. Similarly, in stage two of the modelling, Victoria and South Australia both show a market price frontier that is to the right of New South Wales and Queensland, implying a higher MPC and CPT to achieve the same reliability outcomes as the regions. These results can predominantly be explained by the underlying characteristics of USE in the regions, particularly because southern regions have relatively fewer, shorter, but deeper events.

Regions with fewer, but deeper events naturally lead to an efficient reliability level that is relatively lower (more USE), and equivalent market price settings that are relatively higher. In the case of the former, this is because fixed costs make up the majority of new generation costs, and deeper events require a greater number of units to address; therefore, there are greater fixed costs to recover in fewer periods. Higher generation costs push the efficient reliability standard to the right.

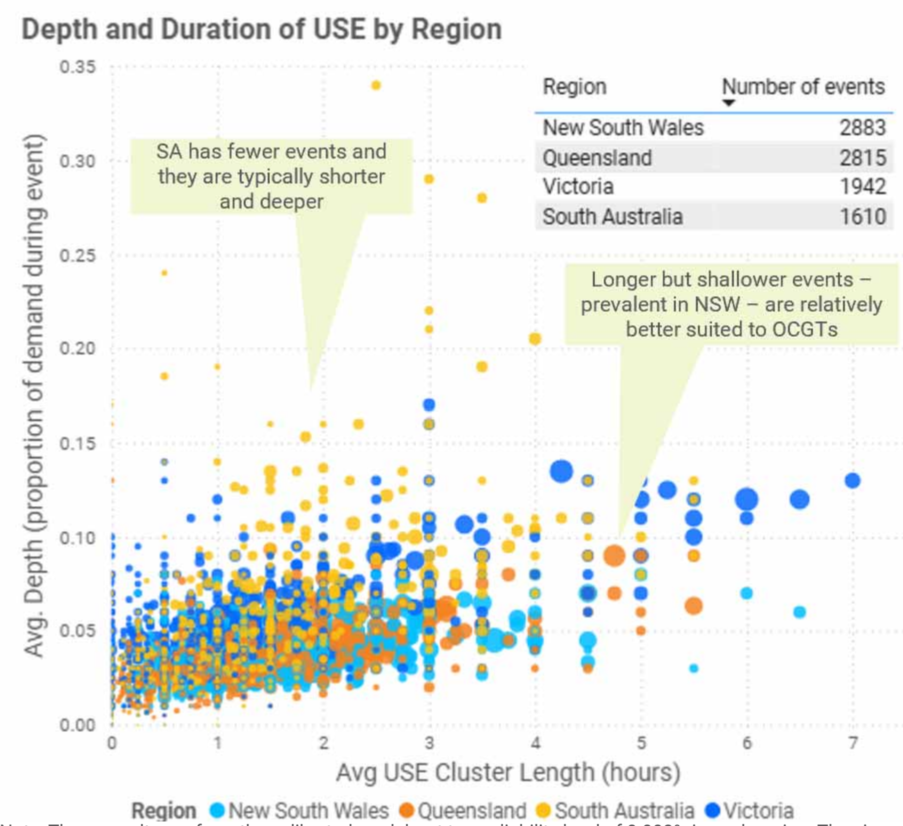
In terms of the market price settings, shorter, less frequent, and deeper events push the settings higher due to two factors:

- more capacity is required (as events are deeper), and
- that capacity will have fewer intervals in which to earn revenue (as there are fewer USE events).

Both these factors push the market price settings up, all else being equal.

The chart below shows the average depth and duration of USE events by region, calibrated to a reliability standard of 0.003 per cent.

Figure C.11: There are differences in USE depth, duration and frequency between regions



Note: These results are from the calibrated model, set to a reliability level of 0.003% in each region. The size of the dot represents the total MWh of USE during the simulation.

This chart shows thousands of events, and each event is driven by slightly different individual factors. We have summarised a few of the regional specific events below to demonstrate some of these differences. Note that these descriptions pertain to the uncalibrated PLEXOS results.

South Australian deep USE event in January 2032

On the 24th January 2032, the simulation for reference year 2019 and PoE10 produced a deep unserved energy event in most outage samples, which represents one of the worst USE events in all the simulations that we ran. This USE event lasted from 6pm until 11pm (both before and after calibration) and, at its deepest, had 1.5GW unserved out of a total demand approaching 4.3GW (representing a depth of roughly 40 per cent). The situation was made worse during this event with output reductions for some OCGTs at Hallett, diesels at Lonsdale and Port Stanvac, and some reductions in the interconnector capacity from Victoria and New South Wales. As with many unserved energy events in the model, it began when both rooftop and utility-scale solar drops away as the sun goes down, taking out almost 2.5GW of capacity. In this specific event, there is also a significant drop-off on wind generation as the sun sets from almost 2GW of available capacity down to less than 100MW by 6pm. This extreme drop in VRE output also corresponds to the highest demand period in the entirety of FY31/32, likely relating to a very high temperature day in South Australia where there is higher than usual demand, driven by air conditioning.

This case study in South Australia, while extreme (being the worst event in almost 700 simulations), still broadly captures the dynamics associated with South Australian USE events; periods after sunset with higher than usual demand but much lower than usual wind output. As VRE makes up a very large proportion of the region's available capacity in this time period, these events can become very deep.

Queensland shallow, long events in January 2032

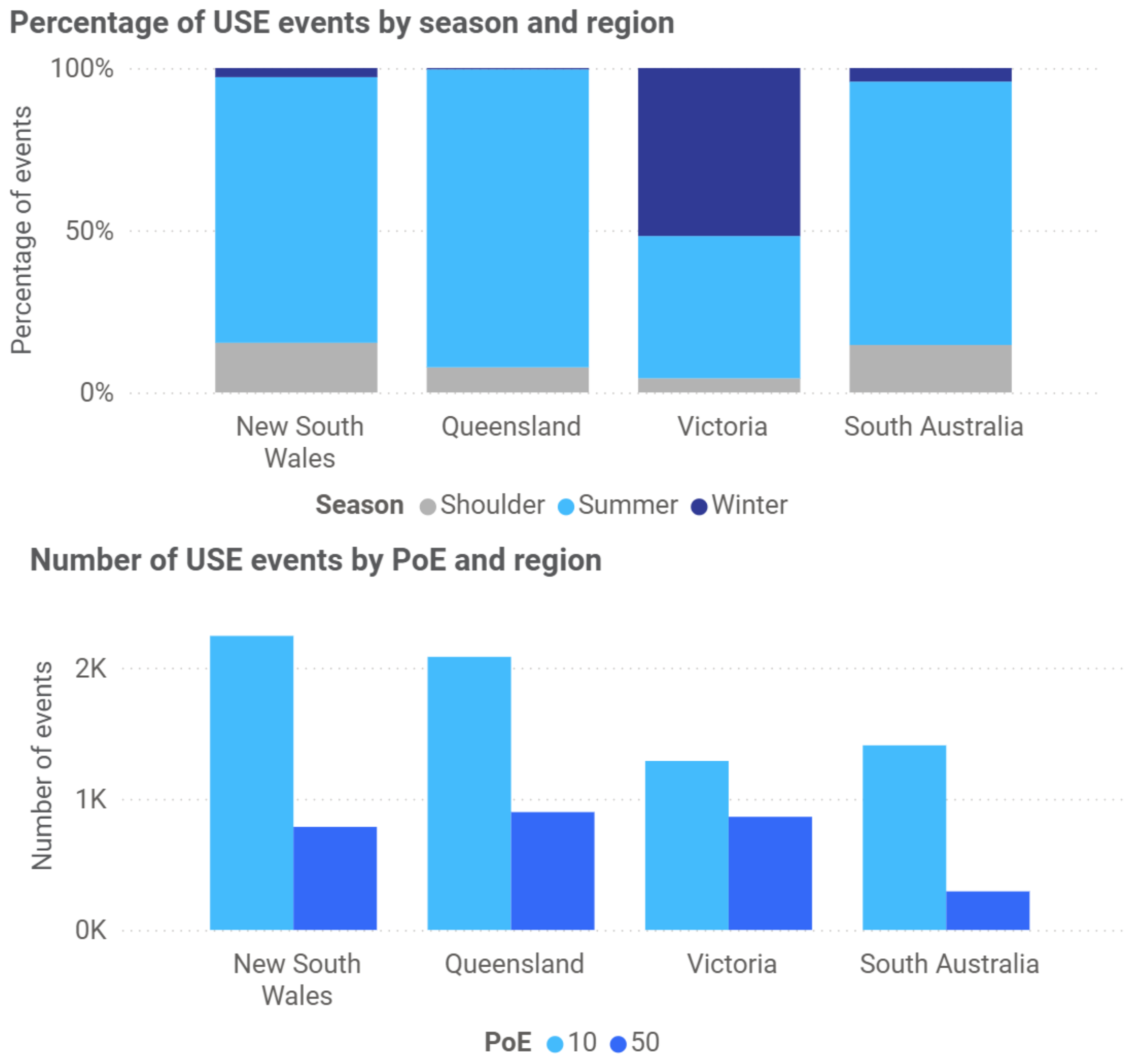
In the three days between the 28th Jan 2032 and the 31st of Jan 2032, Queensland experienced five distinct unserved energy events in reference year 2007, at the PoE50 level of demand, for a particular outage sample. Over these days in this sample, there was between 1.8GW to 2.3GW of black coal unavailable, 125MW from Kidstone Pumped Hydro unavailable, and a further 366MW of gas plant unavailable. These events occurred during the evening peaks (for example, between 6pm and 10pm on the 27th) but also overnight (between midnight and 6am on the 29th), typically lasting around 6 hours. Whilst these events were relatively long, they were also relatively shallow, typically only leading to roughly 5 per cent of demand being unserved in each interval.

This series of events highlights broadly the drivers of unserved energy in Queensland, which are more so driven by reductions in thermal capacity caused by outages, rather than large drops in available capacity due to low VRE availability.

Victorian USE events are driven by a different demand profile with implications for the optimal reliability standard in the region

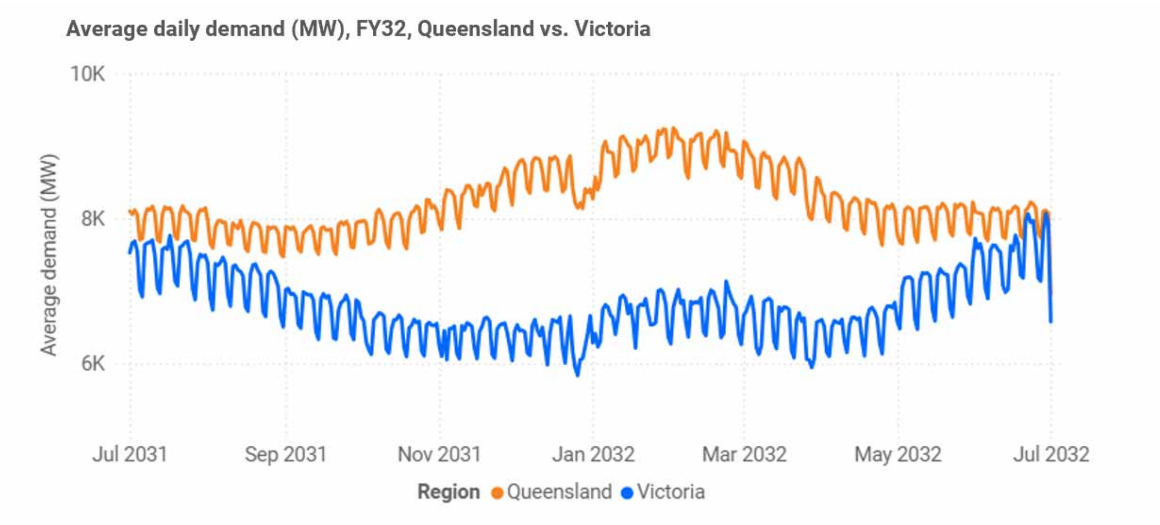
Victoria has an additional point of difference to other regions, in that the majority of its USE events occur during winter, and a higher proportion of these events occur in the PoE50 peak demand simulations. This result is shown in Figure C.12 below:

Figure C.12: Victorian USE events are predominantly in Winter



This outcome is a result of Victoria's differing demand characteristics compared to other regions. All regions in the NEM are expected to shift to a winter-peaking demand profile rather than a summer-peaking one, although this transition is anticipated to occur more quickly in Victoria. This is because Victoria already has higher winter demand due to colder temperatures and a faster electrification trend than in other regions, as Victorians move away from gas appliances. The differences in demand profile across the year between Victoria and Queensland (the most summer peaking region) are highlighted in Figure C.13 below, which shows the average daily demand across all weather years for a PoE50 peak demand levels:

Figure C.13: Demand in Victoria is winter peaking



The underlying seasonal demand differences stem from the ESOO data on which our modelling is based. It explains the significant divergence between the reliability outcomes and optimal market settings in Victoria compared to other states, reinforcing the difficulty of determining consistent market price settings across all NEM regions.

C.5.5 Sensitivities

We accounted for the effect of jurisdictional schemes by running a low WACC sensitivity to simulate the de-risking of investment

This sensitivity was developed to account for the impact of jurisdictional schemes that de-risk investment in certain technology types, and we applied a 2 percentage-point reduction in the WACC for batteries. The results of this sensitivity analysis are presented in Chapter 4 of the draft RSSR report.

The Panel investigated how sensitive the modelled outcomes are to different VCR levels

As the VCR is a critical input to the modelling, we ran a number of sensitivity analyses with higher and lower values. These are presented in Chapter 4 of the draft RSSR report.