
Reliability Panel AEMC

Draft report

2026 Reliability Standard and Settings Review

27 November 2025

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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 draft report has been prepared for the Reliability Panel's (Panel) 2026 Reliability Standard and Settings Review (RSS review or RSSR). The purpose of this paper is to seek stakeholder feedback on the Panel's draft recommendations and modelling results. It is part of an extensive consultation approach that has been conducted throughout this review.
- 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 is considering whether the level of the standard and settings remain appropriate for expected market conditions from 1 July 2028 to 30 June 2032. We are required to complete the review by 30 April 2026.
- 3 After careful consideration and an assessment of the changing conditions in the market and changes to how consumers value reliability, we are making a number of **draft recommendations**:
 - Since the 2022 Review, the cost of open-cycle gas turbines (OCGTs) has increased, and the reported value consumers place on reliability has decreased. As such, our modelling results suggest a reliability standard from **0.002 to 0.004 per cent unserved energy (USE)** is consistent with the value of customer reliability (VCR). A reliability standard at the midpoint of 0.003 per cent USE is most aligned with maintaining consistent market price settings while also having minimal impact on how customers experience reliability. We are seeking your feedback on what you consider to be the most appropriate level of the standard within that range, and the associated market price cap and cumulative price threshold required to deliver that standard.
 - We propose to retain the **market floor price at -\$1,000/MWh** and set the market to automatically clear at the market floor price during Minimum System Load level 3 (MSL3) conditions.
 - We propose to retain the **administered price cap and administered floor price at \$600/MWh and -\$600/MWh**, respectively.

The Panel aims to balance the incremental cost of new capacity with the value customers place on reliability

- 4 A reliable power system has adequate capacity (generation, demand response, regional 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 balance between supply and demand in real-time. The focus of this review is ensuring the market can deliver the optimal level of generation, storage and demand response to meet customer expectations.
- 5 The national electricity market (NEM) provides high levels of wholesale market reliability with no actual USE events caused by resource inadequacy occurring in the last five years. When customers experience supply interruptions, they are predominantly due to network outages (95.2% to distribution network outages such as trees falling on distribution lines, 3.5% security such as under-frequency load-shedding, and 1.2% transmission outages such as extreme weather events damaging transmission towers), rather than issues with resource adequacy (0.1% of outages). This review is limited to the key parameters affecting reliability in the wholesale market (resource adequacy): the reliability standard and the four reliability settings. The vast majority of disruptions (network and system security) are managed through other standards and mechanisms.
- 6 The core objective of the reliability framework in the NEM is to deliver efficient reliability outcomes

through market mechanisms to the greatest extent possible. These mechanisms provide strong financial incentives for participants (generators, retailers, aggregators and customers) to make investment, retirement and operational decisions that support reliability in the long-term interests of consumers.

- 7 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** is expressed as the level of USE that represents an efficient economic trade-off between reliability and affordability based on what consumers value in being able to use electricity when they want it.
 - The **reliability settings** are set to achieve market outcomes consistent with the reliability 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:
 - market price cap (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
 - cumulative price threshold (CPT) – which acts to manage the risk of high prices over a sustained period by triggering an administrative price period (APP)
 - market floor price (MFP) – which sets a lower limit on wholesale market prices that can be reached in any trading interval to allow the market to clear in most circumstances
 - administered price cap and floor price (APC and AFP) – which place upper and lower limits on dispatch prices that apply during an APP after a period of sustained high prices causing the CPT to be breached.

We have seen increases in the capital cost of gas-fired generation and a reduction in the value customers place on reliability

- 8 While the characteristics of outages are different and there are no reliability events most years in most regions, the current reliability standard of 0.002 per cent USE is equivalent to 10 minutes of lost supply per year for all energy users in the NEM.
- 9 Setting the reliability standard and settings takes into account the lowest cost generation technology that is needed to procure the next incremental unit of capacity to deliver electricity. Since the Panel's last review of the standard and settings in 2022, we have seen two key changes in the technology mix that impacts the level of the standard and, therefore, the possible level of the MPC and CPT. These are:
1. While the costs of building batteries have reduced, the costs to build new gas-fired generation have gone up, which means it would cost more to meet the current standard. While our modelling shows that new gas-fired generation continues to be the lowest cost technology to resolve USE events during the next reliability period, we expect the market to deliver a mix of batteries, open-cycle gas turbines (OCGTs), and demand side participation to meet the reliability standard. This approach is consistent with the expectation that gas-fired generation, although operating less frequently, will continue to play an important role in providing backup generation when needed to meet the reliability standard during the next reliability period.

2. The VCR, determined by the Australian Energy Regulator (AER), has decreased in all regions, with an average decrease of about 18 per cent. This suggests that customers, on average, place less value on the same level of reliability.
- 10 The impact of these two changes is that, on balance, a different reliability standard could limit the cost impacts on consumers without significantly affecting the reliability they experience.

The long-term interests of customers are best promoted by a reliability standard from 0.002% to 0.004% USE

- 11 Based on extensive economic analysis and market modelling, and considering the changes in the market since 2022, the Reliability Panel's **draft recommendation** is that the reliability standard for 1 July 2028 to 30 June 2032 be set in the range of **0.002 to 0.004 per cent** expected USE per region per year. A standard within this range would result in minimal practical impacts on the reliability level that customers experience day-to-day (99 per cent of outages are due to network outages) while also reducing the cost impacts of achieving the reliability standard.
- 12 We note that a **reliability standard of 0.003** per cent USE is most aligned with maintaining consistent market price settings while also having minimal impact on how customers experience reliability. That is, it likely best balances the cost impacts of generation outages against the cost of building more generation or storage capacity to avoid them.
- 13 The Panel is seeking stakeholder feedback on setting the reliability standard within this range for the final recommendation to ensure that the recommended standard is at a level that:
 - balances delivering reliable electricity while minimising costs for customers
 - maintains regulatory stability and minimises uncertainty for market participants.
- 14 We are also seeking stakeholder feedback on the appropriate level of the standard, as it has significant implications for the market price settings required to deliver the necessary investment to meet that standard.
- 15 In determining the optimal level of reliability, the Panel considered the interaction with jurisdictional support schemes that could underwrite new entrant generation by reducing their investment risk. Given that jurisdictional schemes are designed to complement, rather than substitute for, the reliability framework investment signals, the Panel has assessed total system costs on a purely market basis, without explicitly modelling jurisdictional support schemes. However, we did carry out a modelling sensitivity to reflect a possible reduction in the cost of capital for technologies that are eligible for jurisdictional support. We found the impact to be largely immaterial.

The Panel is seeking feedback on MPC and CPT combinations to meet the range of reliability standards

- 16 The MPC and CPT work together to support investment outcomes consistent with the reliability standard while also limiting potential systemic financial risks. For this reason, the level of the MPC and CPT are considered together in this draft report.
- 17 Given the Panel has provided a range of reliability standards for stakeholders to consider, we are not making any specific recommendations on the level of the MPC and CPT in this draft report. However, we do include a range of modelling outcomes that identify possible candidate MPC and CPT combinations for stakeholder consideration.
- 18 The Panel notes that the modelling reveals significantly different outcomes in NEM regions

stemming from the size, shape and duration of USE events. We are aware that because a single set of market price settings apply throughout the NEM, there are implications for reliability outcomes in different regions. Ultimately, the market price settings must meet the reliability standard in all regions.

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

- 19 The Panel's draft 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.
- 20 The Panel also recommends that the market automatically clear at the MFP during Minimum System Load 3 (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.

The Panel recommends retaining the form of the CPT and retaining the administered price cap and floor price

- 21 As outlined in the Issues Paper, the Panel has considered whether an alternative form of the CPT is needed to reflect changing market conditions and the changing financial risks faced by market participants. After assessing the possible options and considering stakeholder feedback, we have concluded that the current form, which uses the cumulative sum of cleared prices, serves the interests of consumers. It does this by simply, effectively and transparently accumulating prices, balancing the need for a reactive, agile CPT with regulatory stability for market participants.
- 22 The Panel's draft view is to retain the APC at \$600/MWh for the review period. The APC was increased from \$300/MWh to \$600/MWh in 2022–2023 to ensure that it aligns with typical generator short-run costs and would continue to ensure supply availability during an APP. The Panel considers that retaining the APC and administered floor price at \$600/MWh and -\$600/MWh respectively, maintains the intended price signal while encouraging continued participation by thermal generation and storage during periods of extended high prices. This then reduces the need for AEMO interventions in the market.

We have collaborated with the NEM review Expert Panel

- 23 The Panel notes that the NEM Wholesale Market Settings Review Expert Panel (the Expert Panel) is due to make its recommendations to Energy Ministers in December 2025. We have engaged extensively with the Expert Panel to understand the potential implications of their recommendations for the Reliability Panel's work, including considering a future Panel review of the form of the market price settings.
- 24 While the implementation timeframe for NEM review recommendations is not yet known, the reliability standard and settings resulting from this RSSR are expected to commence before the NEM review's recommendations come into effect, should Energy Ministers agree to those recommendations.

We are seeking stakeholder views by 29 January 2026

- 25 The Panel is committed to seeking stakeholder feedback on its draft report and providing opportunities for engagement. The Panel invites submissions from interested parties in response to this draft report by Thursday, 29 January 2026.

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1 Introduction

Box 1: Key points in Chapter 1

- The Reliability Panel (Panel) is reviewing the reliability standard and settings (RSSR) in accordance with the National Electricity Rules (NER) and the 2021 reliability standard and settings (RSS) guidelines.
- As noted in the issues paper, the RSSR will consider emissions reduction as part of the revised national electricity objective (NEO).
- This draft report sets out the Panel's considerations 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 draft recommendations and seek stakeholder feedback.

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 is reviewing the reliability standard and settings to apply from 2028 to 2032

Under the NER, the Panel is required to conduct a review of the reliability standard and reliability settings every four years. This four-yearly 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 are conducting 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
- stakeholder input to date, including responses to the issues paper and ongoing discussions
- other relevant factors.

The Panel's work has focused on reliability outcomes in mainland NEM regions given the different market arrangements in Tasmania. Reliability risk is very low in Tasmania, which has a hydro-

dominated fleet and is expected to have improved interconnection capacity with the completion of Marinus Stage 1 in 2030/31.

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

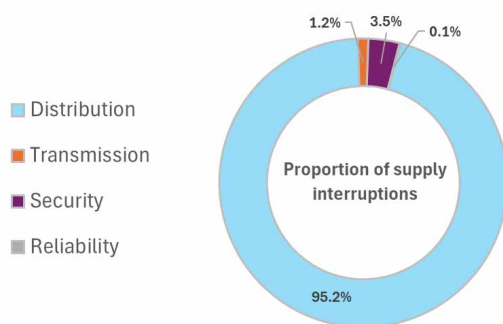
The reliability standard and settings are key components of the NEM's reliability framework. These elements aim to encourage sufficient investment in generation, storage and demand response capacity to meet customer demand for energy, while protecting market participants from potential substantial risks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

The reliability standard determines the optimal level of reliability that customers value

The reliability standard is an ex-ante standard used to indicate to the market the required level of supply to meet demand to the level of reliability 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. It is currently set at a maximum of 0.002 per cent of the total energy demanded in that region for a given financial year. In practical terms, this translates to, at most, roughly 10 minutes of reliability-derived outages per customer per year on average. 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.

Practically, the NEM provides high levels of wholesale reliability with no actual USE events occurring in the last five years. As noted in Figure 1.1 below, when customers experience supply interruptions, they are predominantly due to network outages (95.2 per cent, 3.5 per cent and 1.2 per cent attributed to distribution network outages, security, and transmission outages, respectively), rather than issues with resource adequacy (0.1 per cent of outages). This is important to understand because the reliability standard measures generation capacity adequacy, not network performance.

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



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

The Panel recently confirmed unserved energy as the form of the reliability standard

The Panel reviewed the form of the standard in 2024 to determine whether it needed to change as the market transitions to a power system dominated by variable renewable energy (VRE). We found that, based on the extensive modelling and stakeholder consultation, the existing form of the standard remains fit for purpose and can adequately capture the changing risk profile as the

¹ Clause 3.9.3C(a) of the NER.

NEM transitions. In the future, while the nature of reliability risk may change in several ways, including the small risk of infrequent but significant USE events, the expected value of USE remains an effective way to measure that risk and weigh it against the costs of increased reliability.² Therefore, for the 2026 RSSR, the Panel's focus has been on the level of the standard rather than redefining the metric itself.

Chapter 2 of this paper provides further detail on the purpose and function of the reliability standard.

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 1 July 2025 to 30 June 2026

	30 June 2026	1 July 2026	1 July 2027
Reliability Standard	0.002% USE	0.002% USE	0.002% USE
Market Price Cap	\$20,300/MWh	\$20,700/MWh	\$22,800/MWh
Cumulative Price Threshold	\$1,823,600/MWh	\$1,987,200/MWh	\$2,325,600/MWh
Administered Price Cap	\$600/MWh	\$600/MWh	\$600/MWh
Administered Floor Price	-\$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](#)

² Reliability Panel, [Review of the form of the reliability standard and administered price cap, Final report, 27 June 2024.](#)

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 is limited in focusing on the key parameters affecting reliability in the wholesale market: the reliability standard and the four reliability settings.

Critically, the reliability standard and settings are not all-encompassing. For instance, they do not address network 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 also make recommendations to improve the effectiveness of the NEM's reliability framework. In this review, the Panel has made a draft 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 will apply or take into account, these include:

- **Requirements in the NER³** - the NER stipulates that any change the Panel recommends must be likely to contribute to the achievement of the NEO.
- **Reliability Standard and Settings Guidelines (2021 guidelines)⁴** - these guidelines, developed by the Panel, outline the principles and assessment approach for RSS reviews.
- **Terms of reference provided by the AEMC.⁵**

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 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).⁶

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 draft recommendations, in accordance with the guidelines and in response to stakeholder feedback, the Panel has also 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 costs for customers over the long term.

Therefore, in accordance with the 2021 RSS guidelines, the Panel will only consider recommended changes to the reliability standard or settings where there is a material benefit to doing so. If the

3 Clause 3.9.3A of the NER.

4 Reliability Panel, [Review of the reliability standard and settings guidelines](#), Final guidelines, 1 July 2021.

5 2026 RSSR [AEMC terms of reference](#).

6 The Panel has published guidance on how it will consider the emissions reduction component of this work, which can be found [here](#).

review process finds a change in standard and settings that would result in only a minor benefit, the Panel may retain the current settings.⁷

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

After completing the review, the Panel must submit to the AEMC any rule change proposal that results from a review as soon as practicable after the review itself is completed.⁸ Any change to the standard or settings would then be made through an AEMC rule change process.

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 ageing thermal generation fleet with VRE
- 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.⁹

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 ageing thermal generation

The physical power system continues to undergo significant changes, with the ongoing exit of ageing 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 and are experiencing higher outages as utilisation falls. The market must now maintain adequate levels of reliability with a smaller pool of ageing 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 rising levels of 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:

⁷ Reliability Panel, [Review of the reliability standard and settings guidelines](#), 1 July 2021.

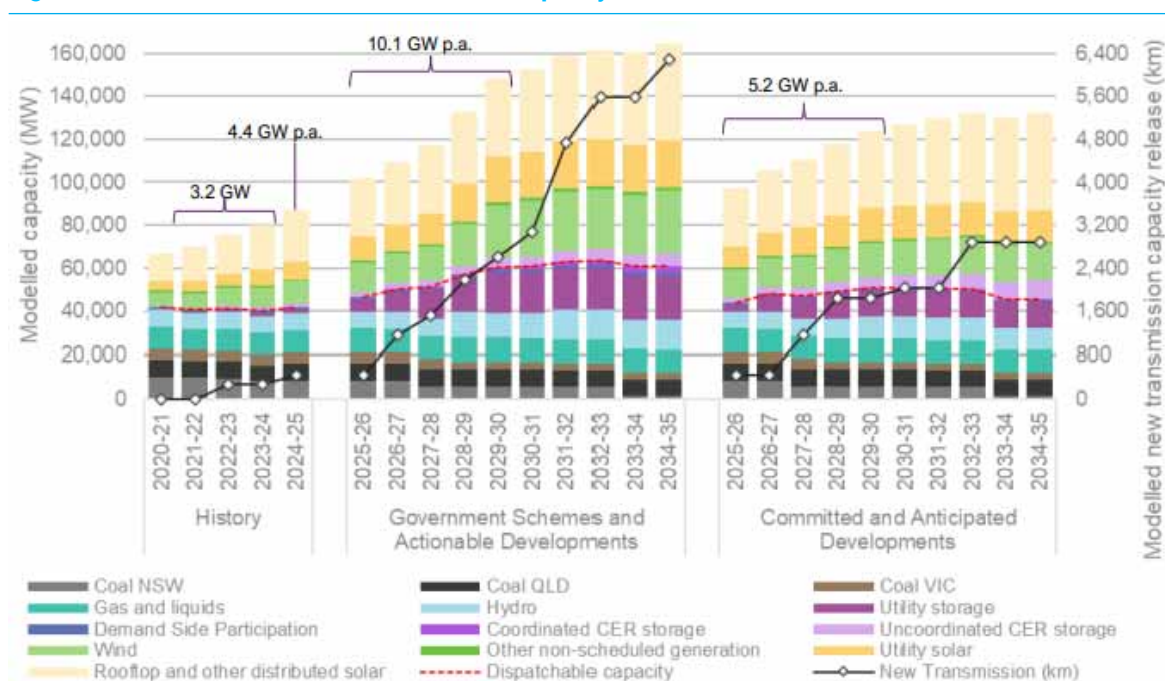
⁸ Clause 3.9.3A(i) of the NER.

⁹ For more details, see Chapter 2 of the Issues paper.

- around 10 GW of coal capacity is expected to withdraw, including Eraring (2027), Yallourn (2028) and Gladstone (2029)¹⁰
- 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.

Figure 1.2: ES00 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 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.¹¹

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.

¹⁰ The updated closure date of Gladstone is not reflected in the 2025 ES00.

¹¹ For more details, see section 2.1 of the issues paper.

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
- a continuing acceleration of rooftop PV deployment in the NEM¹²
- reducing operational demand, which has implications for the delivery of additional generation and system security¹³
- increases in the uptake 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 shows 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 draft position is to recommend settings that can stand on their own to meet

¹² AEMO's draft IASR projects rooftop PV capacity in the NEM to increase to nearly 29 GW, growing to more than 36 GW by 2031/32.

¹³ For example, AEMO 2025 ES00 projects minimum operational demand in NSW of 1,977 MW in 2027/28.

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. To ensure the market settings deliver on this goal, we are seeking stakeholder feedback on our approach to considering the effect of jurisdictional schemes.

The effect of jurisdictional schemes, a summary of stakeholder feedback and consultation questions are discussed in chapter 4.

1.4.1 The NEM review's draft 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 outcomes of this review may have significant implications for the reliability outlook for 2028/29 to 2031/32, and particularly for any future RSSR period. The Panel has engaged closely with the Expert Panel to determine the implications of their draft recommendations on the appropriateness of the reliability standard and market price settings.

A relevant draft recommendation 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 will consult with stakeholders by seeking feedback on this draft report. The Panel will also hold a number of stakeholder meetings, as required. The key dates are shown in Table 1.2.

Table 1.2: Indicative review timetable

Draft report published	27 November 2025
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Stakeholder submissions due	29 January 2026
Final report published	By 30 April 2026

1.5.1 Making a submission

Stakeholders can help shape the recommendations by participating in this review process. Engaging with stakeholders helps us understand the potential impacts of our recommendations and, in doing so, contributes to well-informed, high quality review recommendations.

1.5.2 How to make a written submission

Due date: Written submissions responding to this draft report must be lodged with AEMC by COB, 29 January 2026.

How to make a submission: From the AEMC’s website, www.aemc.gov.au, find the “lodge a submission” function under the “Contact Us” tab, and select the project reference code REL0094.

Tips for making submissions are available on the AEMC website.¹⁴

Publication: The AEMC publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example, offensive or defamatory content, or content that is likely to infringe intellectual property rights).

1.5.3 Contact us

To contact us, please use the form available on the project page.

1.6 Structure of this report

- Chapter 2 discusses how the draft reliability standard would promote the NEO.
- Chapter 3 discusses the draft market settings would promote the NEO.
- Chapter 4 discusses the modelling results.
- Appendix A discusses background and context.
- Appendix B discusses the assessment principles.
- Appendix C discusses the detailed modelling methodology.

¹⁴ See: <https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/submission-tips>

2 The optimal level of the reliability standard

Box 2: Key points in Chapter 2

- The reliability standard defines the maximum amount of USE that is at risk of being delivered 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.
- Since the last review of the standard and settings in 2022, increasing costs of gas-fired generation (the benchmark technology), combined with a reduction in the value customers place on reliability, have impacted the optimal level of the reliability standard and related market price settings.
- **Our draft modelling suggests that the optimal reliability standard is from 0.002 to 0.004 per cent USE.** We are seeking your feedback on what stakeholders consider to be the most appropriate level of the standard within that range, and the associated market price cap and cumulative price threshold required to deliver that standard.
- A reliability standard in the midpoint at **0.003 per cent USE** is most aligned with maintaining consistent price settings while also having minimal impact on how customers experience outages.
- The changing profile of reliability risk has been 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 may influence the choice of a national standard to best meet customer expectations in all regions of the NEM.
- The Panel's modelling has considered high and low VCR sensitivities to provide information on the trade-off with delivering higher or lower levels of reliability. It indicated that the efficient level of reliability does not shift materially from the base case level under both the low VCR and high VCR sensitivities. The Panel is seeking stakeholder feedback on the outcomes under the base, low, and high VCR cases.

Under the 2021 RSS guidelines for the 2026 review, the Panel can consider both the form and level of the reliability standard. However, as noted in chapter 1, the Panel is not considering the form of the standard, given that our recent comprehensive review concluded that it is still an appropriate measure as we continue to transition to a renewable-dominated generation fleet.¹⁵

This chapter outlines the Panel's draft considerations and position on the level of the reliability standard from 2028 to 2032, with the aim of seeking stakeholder feedback. It outlines:

- Section 2.1 — the purpose of the reliability standard is to represent the trade-off between costs and reliability for customers.

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

- Section 2.2 – the Panel’s draft recommendation of the optimal level of the reliability standard
- Section 2.3 – the reliability standard as a NEM-wide measure
- Section 2.4 – the reliability standard reflects the value customers place on a reliable supply of electricity
- Section 2.5 – the value of regulatory stability.

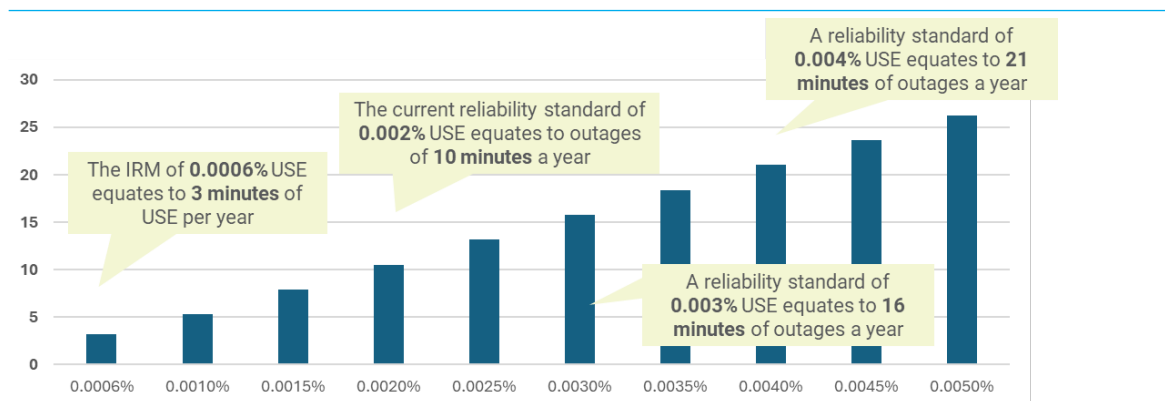
The NER and the 2021 guidelines set out specific requirements for what the Panel should consider and the assessment criteria that the Panel must take into account when reviewing the standard. The Panel has applied these assessment criteria to consider the standard’s level in this 2026 RSS review, alongside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

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 purpose is to define 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. 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 current standard is expressed as expected USE of no more than 0.002 per cent in each NEM region in a financial year.¹⁶ In practice, under the standard, the total energy disruption to customers would be equivalent to around 10 minutes of lost supply per customer per year. Figure 2.1 below translates different USE levels into the equivalent time customer supply would be disrupted.

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



¹⁶ 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 come to an end on 1 July 2028, the commencement of the period for which this RSS review applies.

The standard is based on an economic trade-off made based on 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 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 demand on a regional basis. It is not a regulatory or performance standard that is 'enforced'. Rather, it indicates the efficient level of reliability for the purposes of informing 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 up to real-time, through the various ES00 reports, and projected short and medium term assessment of system adequacy (ST-PASA and MT-PASA).

Source: AEMO, Reliability Standard Implementation Guidelines, 23 October 2025, pp7-8.

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 chapter 1, only exceedingly rare supply interruptions due to insufficient supply or interconnection capacity are considered. The vast majority of outages, over 99%, do not count towards the standard as they are due to local distribution network interruptions, force majeure or system security events. This distinction is crucial to ensure that the reliability standard remains focused on ensuring resource adequacy.

Stakeholders broadly acknowledge the standard's central role in the NEM's reliability framework. The AEC emphasised that the standard and settings collectively make a critical contribution to delivering the marginal plant needed to achieve the reliability that customers expect.¹⁷

Similarly, Energy Consumers Australia noted the tension between cost and customer reliability outcomes that the Panel is tasked with grappling with:¹⁸

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.

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

18 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 tolerate some outage in exchange for lower bills. It must be set nationally to reflect the level of reliability that is in the long-term interests of consumers.

2.1.1 How the Panel's draft recommendations for the reliability standard promote the NEO

In determining the optimal level, the Panel is guided by the need to act in the long-term term interests of consumers, the NEO and the general assessment principles set out in the guidelines. In making its draft 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.

2.2 The modelling suggests the optimal reliability standard should be set in the range of 0.002 to 0.004 per cent USE

Based on extensive economic and power system modelling and analysis, the Reliability Panel's **draft recommendation** is that the reliability standard for 1 July 2028 to 30 June 2032 be set in the range **0.002 to 0.004 per cent** expected USE per region per year. A reliability standard at the midpoint of **0.003 per cent USE** is most aligned with maintaining consistent market price settings, while also having minimal impact on how customers experience reliability.

We have observed increases in the capital cost of gas-fired generation and a reduction in the value customers place on reliability

As explained throughout this chapter, the Panel's findings align with observable market outcomes. Since the 2022 review, we have observed two key changes in market outcomes that affect the optimal reliability standard level and, consequently, the potential level of the MPC and CPT. These are:

1. While the costs of building batteries have reduced, the costs to build a new gas-fired generation have gone up, which means it will cost more to meet the current standard. While we are modelling the impact of delivering a new gas-fired generator, we expect a mix of batteries, OCGTs, and demand side participation will be the optimal capacity mix delivered by the market to meet the reliability standard.
2. The VCR has decreased in all regions, with an average decrease of roughly 18 per cent. This means that customers place less value on the same level of reliability.

The Panel is seeking stakeholder feedback on the precise level within this range, noting that total system costs are relatively insensitive across this band. However, different levels could have significant implications for the optimal market price settings in different regions.

In practice, this means the Panel is considering either retaining the existing standard or potentially relaxing it slightly if that is shown to still meet consumers' reliability expectations at a lower cost. We are not considering tightening the standard as the analysis did not demonstrate a net benefit

in doing so. A tighter standard would promote unjustified additional market-driven investment. It would raise costs for consumers for a level of reliability they likely do not value enough to justify those costs.

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. Likewise, moving to a tighter standard yields rapidly diminishing costs of avoided outages while costs disproportionately increase. This flat curve suggests that any point within the proposed range would result in similar outcomes for customers.

Presenting a band for the draft report acknowledges the future uncertainty, given the significant transformation currently underway on both the supply and demand sides of the electricity system. It also recognises the value of regulatory stability versus the benefits of flexibly adjusting the standard in response to changing circumstances. For the final recommendations, based on our analysis and stakeholder feedback, the Panel will recommend a single value.

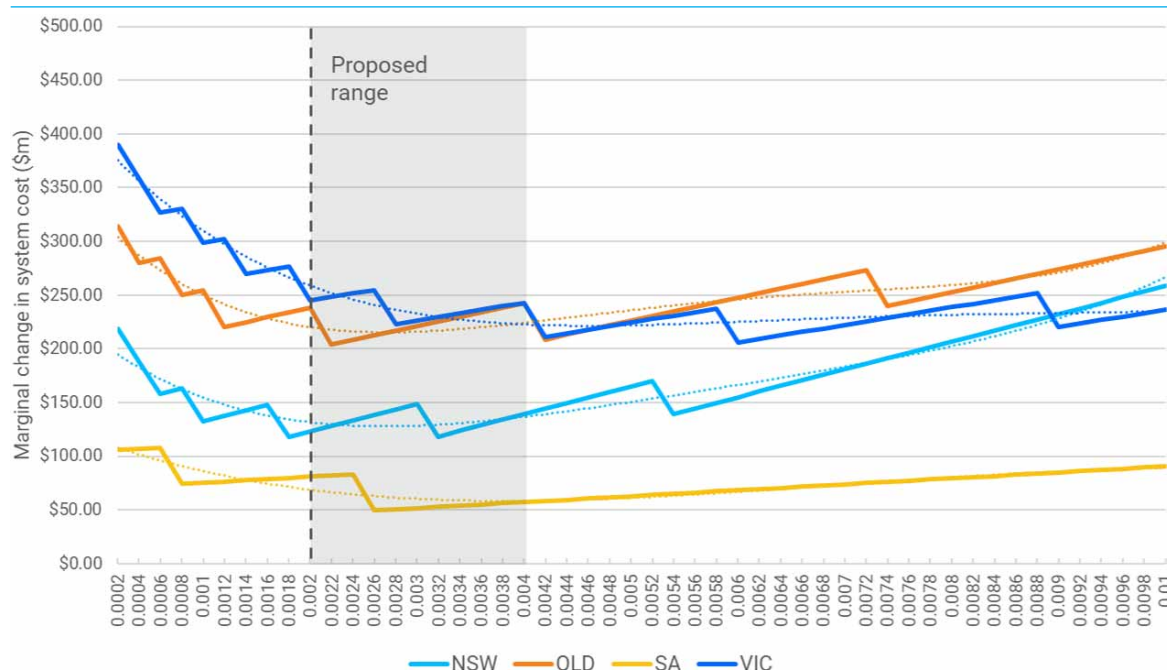
2.2.1 Consumer outcomes are maximised by a standard from 0.002% to 0.004% USE

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 chapter 4, our approach sequentially determined:

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

In determining the optimal level of reliability, the Panel considered the interaction with jurisdictional support schemes that could underwrite new entrant generation by reducing their investment risk. Given that jurisdictional schemes are designed to complement, rather than substitute for, the reliability framework investment signals, the Panel has assessed total system costs on a purely market basis, without explicitly modelling jurisdictional support schemes. However, we did carry out a modelling sensitivity to reflect a possible reduction in the cost of capital for technologies that are eligible for jurisdictional support, and found the impact to be largely immaterial.

Figure 2.2 identifies the total annualised system generating and USE cost associated with a range of different new entrant open cycle gas turbines (OCGTs), two-hour, and four-hour batteries evaluated using the base case VCR for all regions of the mainland NEM.

Figure 2.2: Total system cost curves are broadly similar between regions

The outcome of the stage 1 modelling indicates that:

- in the range of 0.002% to 0.004% USE total costs for customers are minimised, with total system costs remaining relatively flat within the band¹⁹
- 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.

We are seeking stakeholder feedback on the appropriate level of the reliability standard within the proposed band

The Panel has not made a specific recommendation on the level of the reliability standard for the period of 1 July 2028 to 30 June 2032 at this stage of the review. The Panel will make a final recommendation once it receives stakeholder feedback and finalises the economic modelling.

After we receive stakeholder feedback, the Panel's final recommendation will be a level of the reliability standard that:

- balances delivering reliable electricity while minimising costs for customers
- maintains regulatory stability and minimises uncertainty for market participants.

Recommending a standard closer to 0.002 per cent USE would mean prioritising regulatory stability in terms of customer reliability outcomes, but it would likely require increases in the market price settings. Prioritising stability of the market price settings, as recommended in most stakeholder submissions, would require a standard close to 0.003 per cent USE. A standard closer to 0.004 per cent USE would best reflect the current, albeit inherently uncertain and volatile, generator and unserved energy costs.

¹⁹ 0.002% USE and 0.004% USE translates to approximately 10 and 21 minutes of unserved energy per year.

We are seeking views from stakeholders on what the Panel should prioritise to best promote the long-term interests of consumers in accordance with our obligations under the Rules and guidelines.

Question 1: The Panel's draft reliability standard is from 0.002% to 0.004% USE

- What point from 0.002% USE to 0.004% USE would best serve the long-term interests of consumers, and why?
- How should the Panel determine the optimal point that promotes the long-term interests of consumers?

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 price 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 quickly respond and generate during rare peak demand and high price periods.

The Panel's modelling for this review has identified OCGT peaking plant as the single marginal entrant technology 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 price settings are capable of incentivising adequate investment in firm generation, with OCGTs setting the benchmark for the revenue required from the market during periods of scarcity. That being said, we understand that the market will deliver the optimal mix of batteries, gas firming, and demand-side participation to meet system needs within the operational timeframe. Especially in South Australia, where OCGTs and 4 hour batteries are close to equally effective at meeting system needs during USE events.

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 for extended shortfall events, during the 2028 to 2032 period, a gas peaker remains the lowest-cost and most efficient option to cover the types of reliability gaps that may occur.

This view was echoed by many stakeholders, for example, Origin Energy noted that:²⁰

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 2 and 4 hours of storage. While effective for daily peak shaping, the batteries were comparatively less efficient in meeting long-duration and scarce reliability shortfalls due to their comparably high capital cost.

²⁰ Submission to the issues paper, Origin Energy, pp 1-2.

- **USE distributions differed between different NEM regions** – the characteristics of USE events had significant implications for the relative competitiveness of OCGTs versus 4-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 price settings are sufficient to incentivise investment in gas firming, ensuring that consumer outcomes are met at the lowest cost.

As batteries could be the marginal new entrant for the next review, our understanding of how their market behaviour will evolve is critical

That being said, the Panel recognises that batteries are rapidly becoming more cost-competitive and their capabilities are increasing. It is quite plausible that for the next RSSR, battery storage could emerge as the marginal new entrant instead of an OCGT. The Panel’s draft recommendation in this review is based on current conditions (with OCGT as marginal), but we flag this impending shift in marginal technology so that stakeholders can help us anticipate future developments. In particular, the Panel is seeking input on how future reviews could account for a BESS’ revenue profile and market behaviour when determining the reliability settings.

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; however, we invite stakeholders’ feedback on how future Panels should approach estimating a battery’s revenue requirement.

Question 2: Assumptions of battery behaviour for the next RSSR

- How should we assume batteries participate in the market when determining the level of revenue recovered during USE events?

2.3 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, so that it adequately protects consumers in every state while not over-investing in any one area.

In practice, when determining the required level of capacity (and the market price settings to support it), the region with the greatest reliability shortfall risk tends to be the region on which the greatest focus is placed.²¹ If one region is forecast to experience more frequent, larger, or sooner USE events than others (relative to demand), meeting the standard in that region will generally ensure that all other regions meet it as well. However, this approach is complicated by the significant divergences in market needs and characteristics in different regions of the NEM.

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:²²

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 with implications for the optimal technology mix and market price settings. For example:

- 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 could cause a large deficit for an hour or two).
- Victoria's modelled reliability shortfalls occur in winter months, compared to other regions, whose unserved energy events continue to occur in summer months during the relevant period.

The regional analysis reinforces our draft decision that a single, nationally-applied reliability standard in the range of 0.002% to 0.004% USE is appropriate and can accommodate the differing reliability risk 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. The Panel invites stakeholders to comment on whether they agree that the draft standard adequately reflects regional needs and whether the balance between regional specificity and national consistency has been properly struck.

More details on the differences in regional USE outcomes are outlined in chapter 4.

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

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

Question 3: A national reliability standard to reflect regional differences

- What level of the Reliability Standard in the range of 0.002% to 0.004% USE would best reflect the needs across the NEM? Otherwise, how should the Panel consider regional differences?

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

The Panel has taken into account the AER's VCR in determining the efficient level of reliability as expressed in the standard.²³ In making its draft recommendation, the Panel also considered any marked or forecast changes in the way consumers use electricity, particularly through the use of new technology, that suggest many consumers may place a lower or higher value on a reliable supply of electricity from the NEM.

2.4.1 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 VCR describes consumers' willingness-to-pay for reliability and is, therefore, a critical parameter in the Panel's assessment. We utilise the VCR to determine a reliability standard that strikes a balance between having enough generation and demand response to meet customer demand in most circumstances and ensuring consumers are willing to pay the associated costs.

The NER requires the Panel to have regard to any VCR determined by the AER and may take into account any other matters specified in the RSS Review 2021 Guidelines or any other matters that the Panel considers relevant. This section sets out the Panel's use of VCR figures published by the AER in the context of the factors it considers relevant.

The Panel has used a jurisdictional customer load-weighted VCR as its base case, using the values in 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 level of the reliability standard.

As outlined in the issues paper and noted in stakeholder submissions the Panel acknowledges that there is no single VCR that accurately captures all consumer values placed on reliability.²⁴ Different VCR values exist for residential and business customers, as well as for different climate zones, which are linked to volumetric energy consumption. Even the AER's comprehensive assessment, which seeks to capture complex information and consumer preferences, cannot possibly capture all the variation in the value customers place on reliability, including differences between individuals, or the value consumers may place on reliability on a very hot day compared to a mild day.

2.4.2 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

²³ Clause 3.9.3A(e) of the NER.

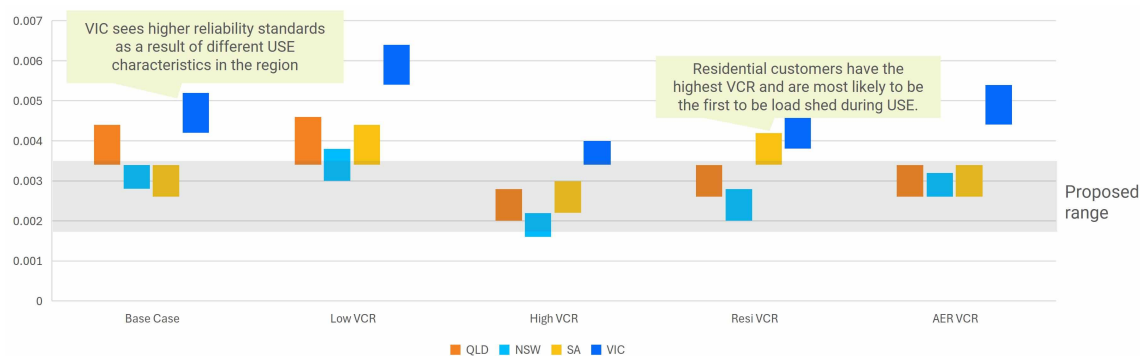
²⁴ Submissions to the issues paper: AEC, p.2.

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 only impacts 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.

As illustrated in Figure 2.3 below, the Panel found that the VCR sensitivities resulted in intuitively consistent outcomes. A higher VCR resulted in a tighter standard, and vice versa. Following the outcome of the analysis, the Panel proceeded with the base case VCR assumption; however, we are seeking stakeholder feedback on the appropriateness of the standard from 0.002% to 0.004% USE considering the implications for reliability outcomes in different regions.

Figure 2.3: Reliability standard sensitivities by scenario and region



Note: As noted in section 2.3, our preliminary modelling results indicate that reliability outcomes in different regions differ significantly due to the characteristics of unserved energy events. Although our modelling results are not yet final and will be refined for the final report, we understand that the results in Victoria are primarily driven by USE characteristics. Reliability risk occurs mainly in Winter, and is characterised by less frequent, shorter, but deeper events.

2.5 The Panel’s broader considerations and stakeholder feedback reinforce the value of regulatory stability

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 CIS and the renewable energy target (RET)) and the potential introduction of new support mechanisms (including the 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.
- **Regulatory stability** – stakeholders consistently emphasised the value of stability and predictability in reliability parameters. Frequent changes risk undermining investor confidence and increasing uncertainty for new projects.
- **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 with respect to gas turbines, have led to increased international competition. 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.

2.5.1 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:²⁵

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 price settings could increase risk premiums, inhibit investment, or even prompt the disorderly exit of existing capacity in response to inadequate market revenues. The Panel is acutely aware of this, and our draft 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. In this draft, we are considering a standard of up to 0.004% USE (a lower level of reliability), as the evidence suggests it might reduce costs in line with a reduction in consumers' reliability expectations, and resulting from increases in the cost of new generation.

Question 4: The importance of regulatory stability

- How should the Panel balance the value of regulatory stability versus the need to remain flexible to changing circumstances?
- What are the implications for the Panel determining the optimal reliability standard?

²⁵ 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.

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 and APC protect against sustained excessive prices.
- The Panel's draft recommendations on the market price 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.
- In line with the 2021 Guidelines, the Panel's draft recommendations propose changes to individual settings only where a material benefit is evident. If a setting's current value continues to effectively achieve its purpose, our draft recommendation is to retain it to ensure predictability.

Preliminary modelling results indicate a clear tradeoff between reliability and cost. Achieving the current or a tighter reliability standard requires higher market price settings and vice versa. We are seeking stakeholder feedback on the optimal level.

- The Panel considered a range of MPC/CPT combinations that could support the draft reliability standard (from 0.002% to 0.004 per cent USE). Preliminary modelling suggests that some increase in the MPC and CPT would be required to maintain reliability at the current level of 0.002% USE, largely due to cost inflation and the need to incentivise new forms of firming capacity as the system transitions.
- However, instead of specifying exact new values in this draft report, the Panel is presenting a range of feasible MPC and CPT combinations – representing efficient frontiers of market price settings – corresponding to different reliability levels. Any combination along this frontier would deliver sufficient capacity to meet the modelled reliability standard for its respective level, while minimising total system costs.
- By publishing these frontier curves for consultation, the Panel is highlighting the inherent trade-offs and seeking stakeholder input on the preferred balance between reliability and cost before making a final recommendation.

The draft 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, the draft recommendation is to retain the current form of CPT, as the Panel considers it continues to best serve the interests of consumers. It remains the most straightforward and effective mechanism to integrate the duration of high prices into risk management.

The draft recommendation is to retain the current MFP and recommend that the market automatically clear at the MFP during minimum system load (MSL) conditions

- The Panel's draft recommendation is to retain the MFP at -\$1,000/MWh. Analysis of price and dispatch patterns indicates that this level rarely binds, and when it does, it adequately allows

the market to clear excess supply. Changing the MFP (upwards or downwards) was found to have minimal benefit for consumers.

- The Panel also recommends that the market automatically clear at the MFP during Minimum System Load level 3 (MSL3) conditions. This is analogous to how, during load shedding events, prices are set at the MPC. Such a trigger would transparently reflect when the system has more supply than it can handle, avoiding AEMO from having to manually intervene while prices might not fully signal the severity of the situation.

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

- The Panel's draft view is to retain the positive APC at \$600/MWh and AFP at -\$600/MWh for the review period. The APC was increased from \$300 to \$600 in 2022–2023 in recognition that \$300 was insufficient to keep generators (especially fuel-constrained ones) willing to generate during an extended crisis. At \$600, the APC now better aligns with typical generator short-run costs (even under stress conditions like high gas prices) and thus should ensure supply availability during an APP.
- The Panel is also recommending that the administered floor price remain at -\$600/MWh.

The draft recommendation is to retain the current approach to indexing the market price settings

- The Panel confirms that, in accordance with the RSS guidelines, the current approach to indexation of the market price settings will be retained. This means the MPC and CPT values will continue to be indexed annually to inflation to preserve their real value, while the MFP and APC remain fixed at their nominal levels.

This chapter outlines the issues and criteria relevant to the Panel's draft recommendations of the market price settings to apply from 1 July 2028 to 30 June 2032. We are seeking stakeholder views on the Panel's draft recommendations, our analysis and modelling results. The settings are price mechanisms designed to incentivise investment in sufficient generation capacity and demand-side response 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.

This chapter sets out the Panel's draft recommendations with respect to:

- Section 3.1 — combinations of market price caps and the cumulative price thresholds at different reliability standards
- Section 3.2 — retaining the current market floor price and the proposed link to minimum system load
- Section 3.3 — the form of the cumulative price threshold
- Section 3.4 — administered price cap.

Consistent with the RSS guidelines, the Panel has only made draft recommendations to change individual market price settings where there is a material benefit in doing so. We are not recommending changes to settings where we have been unable to justify any revisions based on improved outcomes for consumers.

3.1 The market price cap and cumulative price threshold determine the price envelope with which the reliability standard is delivered

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.

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 has implications for 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 of retailers in managing that risk, the effective allocation of risk, and the investment signals sent to deliver the optimal capacity mix. Artificially reducing the market price cap could counter-productively worsen long-term consumer outcomes by weakening critical investment signals, thereby resulting in costly unreliability. Average electricity prices better reflect the cost exposure for customers. The Panel's overall intent remains to promote consumers' long-term interests by achieving the optimal level of reliability at lowest overall costs.

The Panel has not recommended specific MPC and CPT values in this draft report. Instead, the Panel seeks stakeholder feedback on optimal combinations of market price settings corresponding to the range of reliability standards explored in Chapter 2. All combinations on the modelled 'frontier' of MPC/CPT combinations would inherently be able to deliver capacity to meet the modelled reliability standards at lowest total cost, and the Panel will leverage stakeholder feedback in coming to a final recommendation.

Stakeholder submissions emphasised the importance of regulatory stability in this area, cautioning that frequent or drastic changes to the market price settings could undermine investment certainty.

This section:

- introduces the objectives of, and the relationship between, the CPT and MPC
- summarises stakeholder views on the CPT and MPC
- outlines the Panel's considerations informing its draft position
- presents modelling outcomes informing the Panel's assessment of possible options for the level of the MPC and CPT, and
- presents the Panel's draft position on possible ranges for the CPT and MPC for stakeholder feedback.

Consistent with the review's assessment principles, the Panel will only recommend changing the MPC or CPT if it is justified by a material improvement for consumers (such as more efficient investment signals or better management of price risk).

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

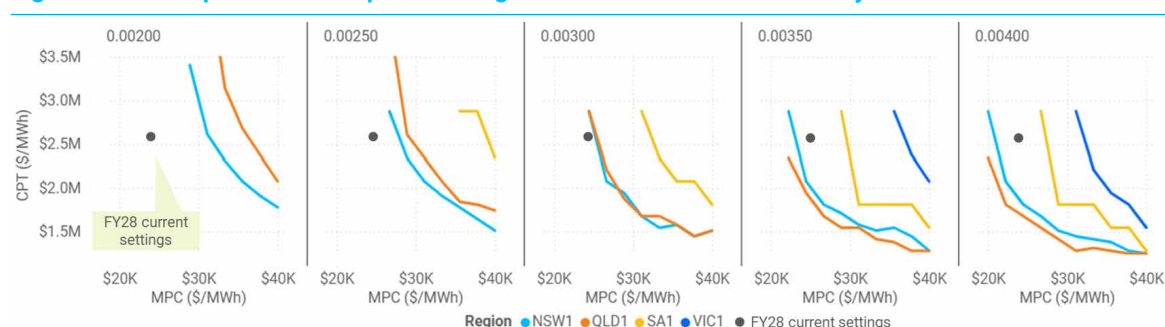
The Panel has examined a range of potential MPC and CPT values that correspond to different possible reliability standards under consideration (from 0.002% USE to 0.004% USE). This analysis has revealed an efficient frontier of MPC/CPT combinations, a set of pairings of the cap and threshold that can 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% to 0.004% 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%) 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% 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.
- These frontiers show that a higher market price cap than in the previous RSSR is required to achieve the same level of reliability. As discussed in Chapter 2, this reflects the higher build costs and WACC associated with new OCGT.

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 0.003% USE to 0.0035% USE. This means that maintaining a reliability standard somewhat tighter than this optimal point (for instance, at the current 0.002% USE standard) would come at a modest increase in system cost. Together, these findings illustrate the fundamental trade-off between reliability, cost and regulatory certainty.

The optimal combination of market price settings is sensitive to the characteristics of USE events

The modelling was concurrently conducted across all mainland NEM regions, as reliability outcomes and the characteristics of USE events can vary significantly by region. At tighter reliability levels, the required MPC/CPT combinations to attract investment were found to be considerably higher in regions like Victoria and South Australia (which experience peaky, tighter USE events) than in New South Wales or Queensland (which experience longer, shallower USE events).

Rather than base the market price settings on a single worst-case region, the Panel is aiming for a reliability standard (and associated price settings) that work for all regions. To this end, the Panel

has published the regional MPC/CPT frontier curves and is seeking stakeholder views on how to balance these differences in determining uniform NEM-wide settings.

Meeting the current 0.002% USE reliability standard would require an increase 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% USE is to be maintained into the future, reflecting the increase in the build cost and a higher WACC for new firm generation.²⁶ To achieve the same outcome, firm peaking capacity (such as 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%) unless the price envelope expanded to attract additional investment. In other words, to continue meeting a 0.002% USE standard, the market would likely require an MPC and CPT above the status quo to ensure revenue sufficiency for new entrants. In Victoria, no combinations of market price settings with an MPC below \$40,000/MWh and a CPT below \$3.5 million were found to deliver a standard below 0.0035% USE. Analysis shows that the current market settings would result in reliability outcomes of approximately 0.003% USE.

Slightly loosening the reliability standard would significantly reduce the level and cost of investment

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 due to lower levels of scarcely utilised capacity being required. As noted in Chapter 2, total system costs (the cost of new generation and unserved energy) are minimised at approximately 0.003% USE to 0.0035% USE. If the reliability standard were set at this level, the MPC and CPT required would be lower than those needed to meet the current standard, because the market would not need to attract as much peaking capacity to cover the last fraction of extreme demand.

Consumers would face a higher risk of occasional supply shortfalls (noting that more than 99 per cent of outages customers currently experience relate to distribution or transmission outages).²⁷ However, they would benefit from the lower overall system costs which more likely 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. However, the cost curve is relatively flat near its optimal point, which implies that choosing a standard somewhat above 0.002% USE could deliver most of the cost savings while only marginally reducing reliability.

Stakeholder submissions endorsed regulatory stability to allow the recent increases in the market price settings to deliver

Stakeholders broadly supported the Panel's view that regulatory stability is critical to deliver the investment needed to meet the reliability standard. For example, Hydro Tasmania and Snowy Hydro both noted that changing market conditions reemphasise the importance of stability, stating that the settings should only change when and if there is a material benefit in doing so as they are the key to delivering critical investment in new generation capacity.²⁸ AFMA similarly

26 Analysis shows that the required MPC to meet the IRM of 0.006% USE is in excess of \$50,000/MWh.

27 Ranging from 10 minutes of USE a year at 0.002% to 21 minutes of USE a year at 0.004%.

28 Submissions to the issues paper: Snowy Hydro pg 1 and Hydro Tasmania pg 1.

considered that the impact of recent increases to the market price settings should be allowed to take effect before significant changes are made to the level of these settings.²⁹ The Panel agrees with the importance of regulatory stability and notes that the RSSR guidelines require the Panel to be confident of a material benefit to consumers to recommend a change to the market price settings.

Stakeholder feedback is critical for the Panel to balance cost and reliability outcomes and determine settings that are in the best long-term interests of consumers

The Panel is seeking stakeholder feedback, which we will use, alongside updated modelling and the assessment criteria, to determine a final recommended reliability standard and associated market price settings. The modelling has been instrumental in quantifying the cost-reliability trade-off in light of the fundamental changes underway in the system as we transition to an energy-constrained world with increasing variability and uncertainty.

As with previous RSS reviews, the results have identified a range of solutions – rather than a single minimum solution – for achieving reliability in the 2028-32 period. The Panel will use its best judgement to balance the modelling outcome and the outcome of stakeholder consultation, informing where on the efficient frontier the NEM's reliability standard and price settings should be set, thereby balancing affordability, risk, and reliability in the long-term interests of consumers.

Question 5: Optimal level of the market price settings

- Which of the combination of market price setting frontiers and corresponding reliability standard do stakeholders think best balance the long term interests of consumers?
- How should the MPC be traded off with the CPT along these frontiers to best meet system needs?
- How should the Panel meet the varying needs of different regions through the MPC and CPT?

3.1.2 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.³⁰ The Panel's draft 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). The Panel remains open, however, to reconsidering the form of the CPT and other market price settings in future. 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:

²⁹ AFMA, submission to the issues paper, 17 July 2025, p. 2.

³⁰ 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.

- **Wholesale prices are becoming more bimodal due to 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.

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

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

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. Simple 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.

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.

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 more quickly 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.

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 draft 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 certain level

of agility 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 Issues Paper on the form of the CPT was limited. AEMO considered there was merit to considering alternative forms, particularly only accumulating prices above a threshold, but did not explicitly support any alternative form.³¹ AEC suggested that if the form of the CPT should change, the Panel should consider a staggered approach, whereby a progressively lower APC would apply as several CPTs are breached³² The Panel does not consider, however, that this approach represents any benefit in terms of the objectives of the CPT, namely to prevent cascading financial risk. Several stakeholders emphasised the need to focus on this role of the CPT, explicitly stating that it's role is not to prevent or replace the need for market participants to manage their own financial risk.³³

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.

Question 6: The Panel's draft recommendation to retain the current form of the cumulative price threshold

- Do stakeholders agree with the draft recommendation to retain the current form of the cumulative price threshold?

3.2 The market floor price seeks to ensure the market can clear without market intervention

The MFP prevents market instability by placing a lower limit on wholesale spot prices (currently set at -\$1,000/MWh). The purpose of the MFP is described in the RSSR guidelines and includes allowing 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.

In determining this, the Panel must consider 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 considered the MFP against these criteria and NEO, is making a draft recommendation to retain the current form and level of the MFP, namely -\$1,000/MWh. The Panel is also recommending an automatic trigger for setting the spot price at the MFP during MSL3 conditions, in much the same way the spot price is set to the MPC during unserved energy events. Our rationale for these recommendations is provided below.

31 AEMO, submission to the Issues Paper, 17 July 2025, p. 6.

32 AEC, submission to the Issues Paper, 17 July 2025, p. 8.

33 AFMA, Snowy Hydro, Shell Energy, submissions to the Issues Paper, 17 July 2025.

3.2.1 The MFP should not be treated as an investment signal for flexible load

In the Panel's view it is not appropriate to consider the MFP as an investment signal for flexible load in the same way that it treats the MPC and CPT as an investment signal for generation. There are three reasons for this:

- MFP and near-MFP events are rare and becoming less frequent
- negative prices are not well correlated with excess generation
- batteries respond to arbitrage opportunities (driven by price spreads) more than absolute negative prices.

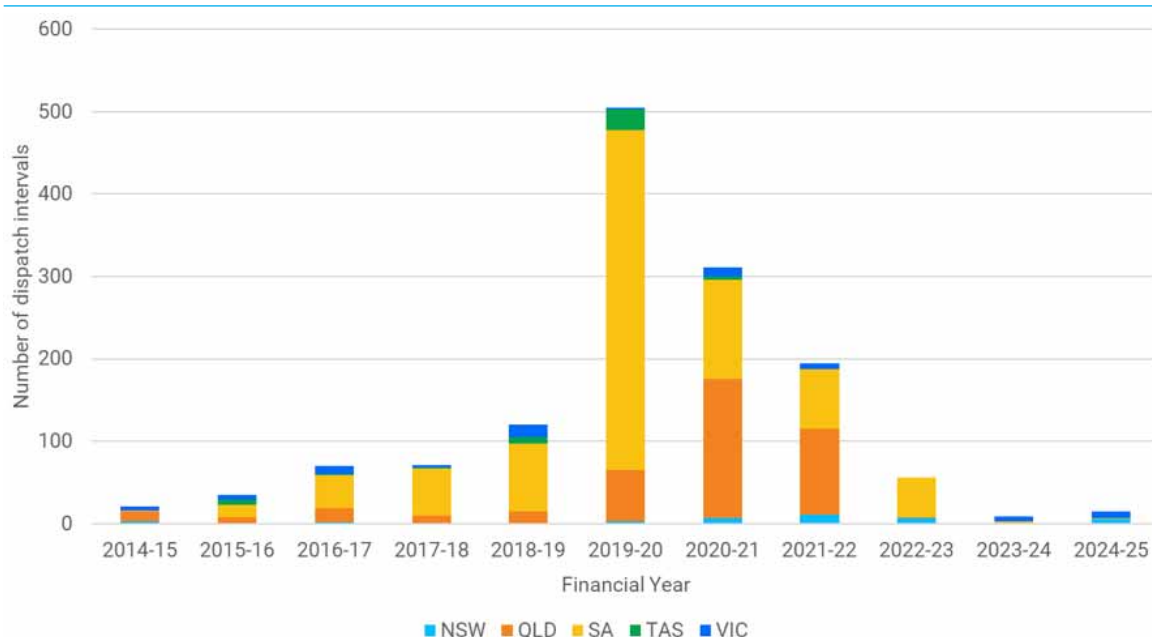
The incidence of MFP events has declined significantly due to the introduction of 5-minute settlement and negative price clauses in PPAs

As discussed in the issues paper and shown in Figure 3.2 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 reduced the incentives for disorderly bidding
- market in recent years has seen a shift in the way that power purchase agreements (PPAs) are structured, such that generators are more likely to be exposed to negative prices.

The outcome of these factors is that 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 consider that an investment case can be built around the particular level of the MFP. This is particularly true as there are currently no cap-style contracts for negative prices that could smooth the otherwise lumpy cash flows resulting from MFP events.

Figure 3.2: The number of MFP events (with \$1/MWh tolerance) has declined in recent years



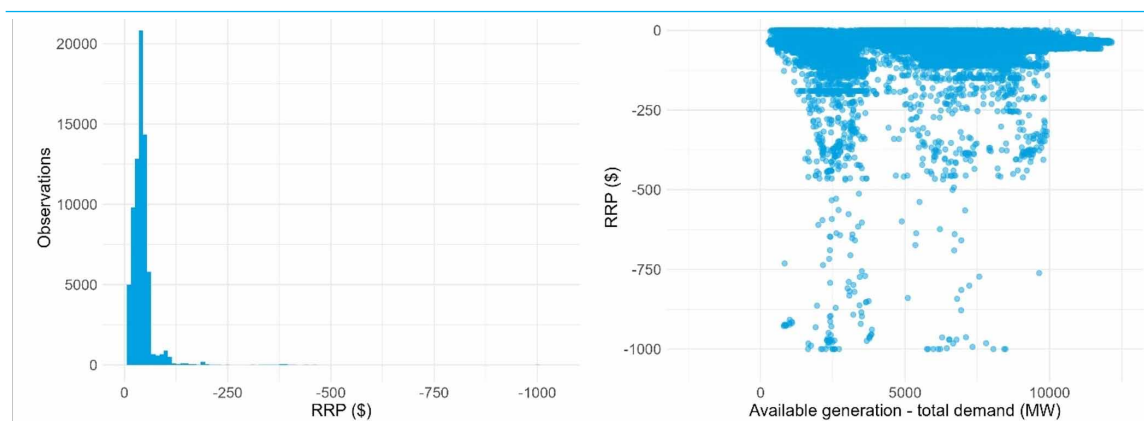
Source: Panel analysis of AEMO data

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

Floor and near-floor pricing often occurs as a result of race-to-the-floor bidding by generators seeking to avoid being curtailed. This results in a poor correlation between excess generation and extremely negative prices. Examination of negative prices reveals clusters in two price bands, as shown in Figure 3.3 below. They are:

- Firstly, representing the vast majority of negative price intervals, there is a cluster of dispatch intervals at approximately $-\$50/\text{MWh}$, 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 $-\$50/\text{MWh}$ and $\$0/\text{MWh}$.
- Secondly, a much smaller cluster appears between $-\$150/\text{MWh}$ and $-\$500/\text{MWh}$. This is likely driven by the fixed cost of thermal generation to perform a hot start.

Figure 3.3: 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 below 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.

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

Given the reasons outlined above, the Panel has not identified any material benefits that would materialise from revising the current level of the MFP. We examined the potential effects of either raising the MFP (making it a less negative number) or lowering it further into negative territory. Our finding is that neither direction offers a meaningful improvement for consumers or market efficiency.

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

While the MFP currently very rarely binds, if it is set too high, there is a risk that it could prevent an unloading signal for thermal generators. The MFP should be sufficiently low that thermal generators can reflect the fixed costs of a hot start in their bids. This provides an unloading signal for thermal generation when demand is low, thus allowing the market to clear efficiently. The Panel considers that the current level of the MFP satisfies this requirement.

The Panel is concerned that raising the MFP would prevent the market from clearing efficiently during low-demand periods, as generators might not get a strong enough price signal to withdraw. If the price signal is insufficient, AEMO may need to intervene more frequently to maintain system security. In short, a higher MFP could impair the market's self-balancing mechanism at low demand. We are satisfied that $-\$1,000/\text{MWh}$ remains low enough to avoid this problem.

A lower MFP would not convincingly deliver additional benefits for consumers

Further, the Panel considers that load is often not exposed to spot prices, and negative prices do not, therefore, necessarily represent a signal for load to ramp up or turn on. While this is a feature of the retail market that can not be addressed here, it represents a further requirement 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. Absent 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 think it is likely that there would be any material benefit to consumers or efficiency gains from lowering the MFP from its current level. A lower MFP could directionally strengthen the incentive for price-responsive load during periods of demand. However:

- 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 it 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 considers that 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, as the Panel would be required to do to recommend a change under the RSSR guidelines. Thus, the Panel's draft recommendation is to retain the current MFP of $-\$1,000/\text{MWh}$ for this RSSR period.

Most stakeholders considered the current floor functions well

AEMO, Shell Energy, Origin, Alinta, AFMA, and AEC all considered that the current floor price functions well. AEMO identified, however, that there may be a role for the MFP to address MSL risk, but identified that a lower floor could exacerbate issues caused by disorderly bidding. Shell Energy and Origin, however, considered that the risk of disorderly bidding is waning with market solutions taking effect. Only one individual supported a negative CPT, which most stakeholders thought would not provide any meaningful benefit to consumers, but would add complexity. The Panel has therefore not considered a negative CPT for this review period.

Some stakeholders, however, considered that the Panel should take an alternative approach to the MFP. Snowy Hydro and Hydro Tasmania considered implementing a lower floor price for

dispatchable generators to allow them to more easily defend their contracts. The Panel understands that the Commission is considering a rule change submitted by Snowy Hydro on the issue and does not see a consumer benefit in introducing multiple floor prices at this stage.

ECA suggested the MFP should be reduced to improve incentives for BESS and demand response, while an individual considered a lower floor is needed to mitigate the risk of disorderly bidding. As Shell Energy and Origin noted in their submission, the incidence of disorderly bidding is declining as the structure of contracts has evolved to increase generators' exposure to negative prices. Further, as discussed above, the Panel does not consider a lower MFP would provide meaningful benefits to consumers, including through improved signals for BESS and demand response. However, the Panel's recommendation discussed in section 3.2.3 below would sharpen the operational signal for BESS and dispatchable load, providing increased incentives for CER orchestration.

Question 7: The Panel's draft recommendation to retain the current market floor price

- Do stakeholders agree with the draft recommendation to retain the current market floor price of -\$1,000/MWh?

3.2.3 The Panel recommends a mechanism for automatically placing the spot price at the floor during MSL3 events

While the Panel is not proposing a change to the level of the MFP itself, we are recommending a related improvement to address emerging challenges during extreme low-demand conditions. The rise of unorchestrated consumer energy resources, particularly rooftop solar PV, has led to an increase in the frequency of minimum system load (MSL) events. MSL events are periods when total demand from the grid is very low (approaching the point where it threatens secure operation of the power system).

The Panel draft recommendation is to link the MSL to the MFP, akin to how the MPC is used during load shedding

The Panel is making a draft recommendation to implement an automatic price floor trigger when AEMO declares an MSL3 event (extremely low operational demand threatening security). In such a situation, the spot price would be automatically set to the MFP for the duration (akin to clearing at the MPC during periods of load shedding). This change would reinforce the market's ability to handle low-demand situations by strengthening price signals, aligning with the goal of the MFP to allow the market to clear.

We consider this reflects stakeholder feedback on the Issues Paper, including from AEMO, which identified a potential role for the MFP to address MSL risk but warned that a lower floor may exacerbate issues caused by disorderly bidding. Ergon Energy and Energex also considered the Panel should explore how the MFP could be used to address MSL events and prevent emergency backstops. This mechanism would sharpen price signals during MSL events without requiring a lower floor price.

We welcome further stakeholder feedback on this proposal, including any considerations around its implementation or impacts on participants.

Minimum system load concerns reflect the need to ensure sufficient security services remain online to

maintain the power system in its technical operating envelope

During MSL events, AEMO has to ensure enough synchronous generators remain online to provide essential services (voltage control, system strength, etc.). If demand drops below the combined minimum generation requirements of the relevant generators, AEMO may need to intervene by directing generators or curtailing distributed generation to maintain system security. Under the Improving Security Frameworks for the Energy Transition rule, AEMO has developed an enablement tool to schedule units online, ensuring that adequate system services are continuously available.³⁴

The Panel notes that there may be security implications if the market clears at $-\$1,000/\text{MWh}$ during an MSL3 event, as generators that remain online for system security reasons will be exposed to the minimum price. This could result in financial losses for generators who are providing a necessary service. In practice, however, many of these units are likely to be contracted or otherwise internally hedged against extreme prices at minimum generation levels. If not, they will likely be contracted with the relevant inertia or system strength service provider who is ultimately responsible for ensuring the right mix of security services is continuously available.

Moreover, the benefit of the proposal is that it potentially reduces the need for AEMO to intervene. If the price automatically drops to $-\$1,000/\text{MWh}$, some generators will preemptively withdraw (reducing supply), and demand may increase, possibly resolving the MSL condition. This would result in less manual intervention from AEMO. Fewer interventions mean fewer out-of-market actions and fewer compensation payments overall, which is a more efficient outcome for consumers.

In their submissions to the Issues Paper, AEC and Origin suggested that MSL is a system security issue, and that the market price settings are not the right mechanism for addressing it. The Panel agrees that currently correlations between insufficient load and very low prices are weak, and that therefore a lower MFP would not meaningfully address MSL risk. However, this mechanism would sharpen market signals by improving correlations between MSL risk and floor pricing, improving the incentives to deal with the underlying issues driving the need for intervention.

The market is failing to clear without AEMO intervention (one of the aims of the MFP)

Currently, the market price signal does not always adequately prevent or resolve MSL events. Prices can fall to low or negative levels when demand is low, but as noted above, they often bottom out around the $-\$0/\text{MWh}$ to $-\$50/\text{MWh}$ range due to factors such as LGC incentives or generators' bidding strategies. MSL conditions have primarily materialised with market prices greater than $-\$500/\text{MWh}$, instead of the absolute floor of $-\$1000/\text{MWh}$.

From the market design perspective, one of the MFP's aims is to allow the market to clear without intervention. If supply truly exceeds the minimum secure level of demand, prices should go low enough to force some suppliers out or encourage load to increase until balance is restored. If power system security issues related to minimum demand rely on AEMO issuing directions to curtail generation even when there is an oversupply, then the MFP is not operating effectively.

Greater orchestration of CER is critical to maintain system security

The Panel's rationale is that by forcing the price to $-\$1,000/\text{MWh}$ in an MSL3 event, we send the strongest possible market signal for participants to respond:

³⁴ See: <https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition>

- any flexible loads or storage that can increase consumption have the maximum incentive to do so, and
- any generators still online have the maximum disincentive to keep producing.

In particular, this could encourage rooftop PV systems to temporarily curtail their exports or shift to consuming energy on-site at rare times when system security would otherwise be compromised.

Many rooftop solar installations are not yet incentivised or equipped to respond to real-time prices (especially negative ones), but over the coming years, the capability for dynamic solar curtailment or orchestration is expected to grow as more rooftop solar is installed and participation in VPPs continues to increase. Implementing this change now would lay the groundwork for that future by ensuring the market properly reflects the severity of rare minimum system load events. Without greater CER integration and given the acceleration in its deployment, there is a risk of continuing exacerbation of the minimum operational demand risks.

Question 8: The Panel's draft recommendation to link the market floor price and minimum system load events

- Do stakeholders agree with the Panel's draft recommendation to require the market to clear at the MFP during MSL3 conditions?

3.3 The administrative price cap is the maximum price paid to market participants during an administered price period

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 long 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.³⁵ 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 and NEO, the Panel is making a **draft recommendation to retain the positive APC level at \$600/MWh and AFP at -\$600/MWh**. The rationale for this draft recommendation is provided below.

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

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

As noted in the Issues Paper, 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.³⁶ The AEMC stated that 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:

- lower APC to mitigate the risk of a systemic financial collapse of the electricity industry during an extreme market event
- higher APC to incentivise market participants to supply electricity during administered price events
- higher 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 the June 2022. This would reduce available generation and potentially require intervention by AEMO, potentially delaying the return to normal market operations.

If the APC is too low and a high-cost generator is dispatched nonetheless, it has the option to pursue a compensation claim to ensure it recovers all eligible costs.³⁷ 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 contributing to financial instability in the market in response to extreme market events. Accounting for these factors, the Panel considers that retaining the level of the APC is appropriate.

This is supported by Origin Energy and AFMA submissions to the issues paper, which voiced general support for the level of the APC remaining at \$600/MWh consistent with the Panel's view.³⁸ Some stakeholders, however considered that the Panel should further assess the APC level. JEC raised that the current level is unjustified whilst Shell and Origin noted the potential to reassess the form of the APC, including the possibility of establishing a link with the MPC or reviewing the form of the APC once ongoing regulatory reforms have been finalised. The Panel notes that the form of the APC was only recently confirmed to be effective. As such, it is not considered to be in scope for this RSS review. The draft NEM review Expert Panel has also made a draft 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.³⁹

36 AEMC, [Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap](#), Rule determination, 7 December 2023.

37 Clause 3.14.6 of the NER.

38 AEMC, [Review of the form of the reliability standard and administered price cap](#), Final report, 27 June 2024.

39 AEMC, [Review of the form of the reliability standard and administered price cap](#), Final report, 27 June 2024.

Question 9: The Panel's draft recommendations on the administered price cap and floor

- Do stakeholders agree with the draft recommendation to retain the current level of the APC at \$600/MWh?
- Do stakeholders agree with the draft recommendation to retain the current level of the AFP at -\$600/MWh?

4 Detailed market modelling informs each RSSR

Box 5: Key points in Chapter 4

- The Panel has carried out detailed modelling to provide evidence to inform the Panel's decision on the draft reliability standards and settings recommendations.
- We have engaged an external third party to provide quality assurance of the modelling methodology, results and insights.
- The modelling has comprised two broad stages:
 - Stage 1 - time-sequential market modelling to determine the optimal level of the reliability standard.
 - Stage 2 - optimisation and scenario modelling to determine the appropriate settings to achieve this standard.
- The high-level principles, inputs, assumptions and limitations to modelling are in line with the requirements in the NER and 2021 guidelines. We have included the assumption and details that underpin the modelling as part of this report.
- Given the very low utilisation rates of marginal generators, the emissions cost was found to be relatively minor.
- We have run several sensitivities to determine the derisking effects of jurisdictional schemes and the different values of customer reliability.

In accordance with our obligations under the NER and the RSS guidelines, the Panel has done comprehensive modelling to inform the draft optimal reliability standard range and corresponding market settings that would best promote the long-term interests of consumers. This chapter provides a high-level description of the modelling approach and results to seek stakeholder feedback. Specifically, it describes:

- Section 4.1 – the high-level modelling approach to determine the optimal reliability standard and corresponding market price settings
- Section 4.2 – the optimal range of reliability standards and marginal technology
- Section 4.3 – the effective market setting frontiers that deliver the range of reliability standards.

We are seeking stakeholder feedback on our modelling approach, assumptions, and results. We have engaged independent experts who will review the model prior to the publication of the final report and recommendations, as part of a comprehensive quality assurance process.

Appendix C provides further details on the methodology, including specific inputs and assumptions that drive the modelling, as well as a broader set of modelling outcomes. These outcomes include the characteristics of unserved energy in our base model and the results of all sensitivities.

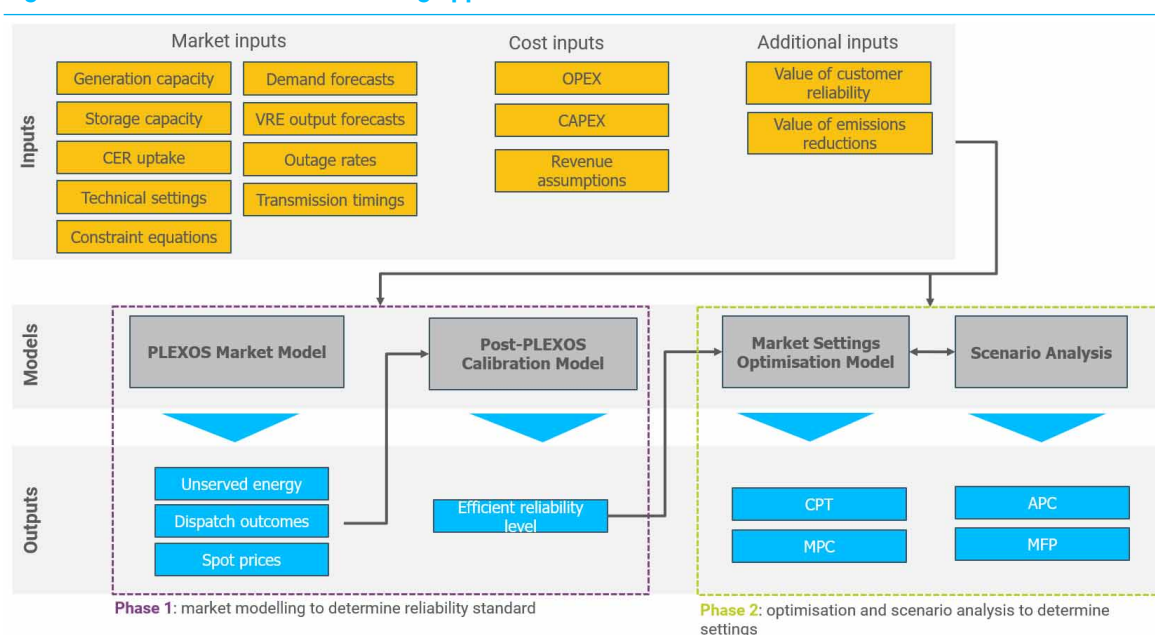
4.1 The modelling approach sought to determine the optimal standard and settings

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

1. The first stage determines an optimal reliability standard through a combination of time-sequential market modelling using PLEXOS (optimisation software), and through post-simulation calibration and scenario analysis.
2. Once the optimal reliability level has been derived, the second stage of modelling can begin. This stage utilises optimisation methods and further scenario analysis to determine the appropriate market settings, specifically the MPC and CPT, that will provide market signals to support the level of investment required for the optimal reliability level.

This modelling approach is illustrated in Figure 4.1 below.

Figure 4.1: Overview of modelling approach



Source: AEMC

Section 4.1.1 and section 4.1.2 describe the stage one and stage two methodology at a high level. More detail is included in the issues paper, and in Appendix x.

4.1.1 The optimal standard is a level that balances the cost of new generation and the level of reliability that customers value

An efficient reliability standard delivers a level of reliability consistent with the value customers place on it. As outlined in the issues paper, modelling informing this efficient level requires an assessment and comparison of costs:

- to consumers from USE arising from a range of different reliability events, and
- of procuring additional power system resources (both supply side generation, storage and demand response) to address this USE.

The modelling task in the first stage (stage 1) of work is to identify a level of reliability as a percentage of USE, which has the lowest total costs by balancing the delivery of a reliable electricity supply while maintaining reasonable costs for consumers. This efficient level occurs when the incremental cost of procuring additional power system resources to achieve a more reliable system exceeds the marginal value consumers place on that additional reliability.

High-level approach to modelling the level of the reliability standard

The modelling approach we will take to identify an efficient reliability standard is, at a conceptual level, the same as that developed by Intelligent Energy Systems and described in the 2022 RSSR. However, we have made changes to account for changing market conditions and improved modelling techniques developed for the Panel's review of the form of the reliability standard.⁴⁰ This high-level methodology is as follows:

- Set up a market model using the most up-to-date PLEXOS market model and generator information from AEMO and other referenced sources such as CSIRO, ACIL Allen and GHD.
- Iteratively examine the levels of additional generator capacity of different specific technology types to produce higher levels of reliability (this is done in a post-processing excel model, rather than through additional PLEXOS simulations).

We implemented several methodological improvements we identified compared to the 2022 RSSR, which include using:

- A larger set of weather reference years in the PLEXOS modelling to produce a greater sample of USE outcomes with greater variability, better reflecting the uncertainties inherent in a more weather-dependent power system.
- A post-processing Excel model to examine the change in USE and dispatch outcomes with additional capacity. This approach allowed the team to generate cost curves at a much higher granularity level by reducing the computing and model run-time requirements.
- Cost-curves generated by the post-processing model represented the sum of the total cost of capacity to meet incrementally higher levels of reliability and the cost incurred by consumers from unserved energy (priced at the VCR) for each level of reliability. The optimal economic value of reliability, where the marginal cost of increased capacity equals the marginal cost of unserved energy, is represented by the minimum point on the curve.

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.

4.1.2 The appropriate market settings must be capable of incentivising the marginal new entrant to meet the reliability standard

As introduced in chapter 3, the market price settings set incentives for investment in the most efficient mix of generation capacity, energy storage, and demand-side response to deliver the reliability standard, while also providing limits that protect market participants from temporary or sustained periods of very high prices.

A significant amount of modelling and scenario analysis informs these settings, and the interactions and trade-offs between them must also be considered. The MPC and CPT together form the price envelope critical to delivering the level of reliability that customers value, and are the focus of stage 2 of the modelling.

High level approach to modelling the settings

The modelling to determine the most appropriate price settings requires a set of inputs, including:

- the efficient level of reliability defined by the modelling in stage one
- a time-sequential profile of USE and dispatch outcomes from the modelling in stage 1 for scenarios of different reliability outcome
- the cost of procuring additional power system resources (both supply side generation, storage and demand response) to address this USE

⁴⁰ More information on the modelling approach for this review can be found [here](#).

A grid-search optimisation model is run with the inputs above to determine the optimal reliability settings, whose objective function 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.

As with the modelling to determine the most efficient level of reliability, the modelling in this stage also includes a number of assumptions, which are detailed in the appendix.

4.1.3 The Panel considered the effect of jurisdictional settings when determining the marginal new entrant, but not the reliability settings

As noted in Table 4.1, jurisdictional schemes other than the RET do not provide an additional revenue source; instead, they serve as an underwriting mechanism, providing a bespoke negotiated revenue ceiling and floor for contracted generators or some other form of de-risking. By guaranteeing a certain level of wholesale market revenue by topping up shortfalls and a form of revenue clawback, these schemes act as a mechanism for reducing the risk associated with new entrants' investments. Crucially, these jurisdictional schemes are not designed to replace but instead complement the signals provided by the wholesale market.

The Panel has considered the effect of jurisdictional schemes by running a low-WACC sensitivity for eligible technologies

Although underwriting does not provide an additional source of revenue, it can reduce the cost of capital (WACC) for contracted projects by mitigating downside risks for financiers through partially de-risking investments. As such, for the draft report and subject to seeking additional stakeholder feedback:

- For stage 1 of the modelling work (determining the optimal reliability standard), a low WACC sensitivity was run to simulate the de-risking benefits of jurisdictional schemes and reflect the risk reduction provided by these schemes for selected technologies.⁴¹
- For stage 2 (determining the optimal market settings), the Panel did not consider the effect of jurisdictional schemes for the reasons outlined below, but we are seeking stakeholder feedback on this assumption.

Table 4.1: Summary of current operational jurisdictional schemes

Jurisdictional scheme	De-risking / additional revenue	Eligible technologies	Relevant regions	Scheme termination
Renewable Energy Target (RET)	Additional revenue	Wind, solar, hydro (non-marginal)	All	2030
Victorian Renewable Energy Target (VRET)	De-risking	Wind, solar	VIC	Unclear (tenders run periodically in line with state targets)
NSW Roadmap (LTESA)	De-risking	Wind, solar, BESS, GPG, hydro	NSW	>2032
Capacity Investment Scheme (CIS)	De-risking	Wind, solar, renewable storage	All	2030

41 BESS systems are eligible for all jurisdictional schemes. GPGs are only eligible for underwriting in NSW and SA.

Jurisdictional scheme	De-risking / additional revenue	Eligible technologies	Relevant regions	Scheme termination
Firm Energy Reliability Mechanism (FERM)	De-risking	GPG, long duration storage (LDS)	SA	Unclear

Source: AEMC, 2025

Note: A more comprehensive list of jurisdictional and commonwealth energy policy targets and support schemes is outlined in section 2.4 of the issues paper⁴² and is included on the AEMC's website.⁴³

Jurisdictional schemes are designed to complement wholesale market price settings and avoid 'double-counting' of revenues

Jurisdictional underwriting schemes work in conjunction with the wholesale market signals and seek to minimise downside investment risks, thereby supporting investment in new generation. Most schemes leverage 'collar' contracting approaches where projects negotiate annual revenue floors and caps with the scheme administrator through a competitive, negotiated and bespoke tender process. If:

- Market revenues exceed the agreed-upon cap, then Governments or energy consumers would claw back all or part of the surplus.
- Market revenues are less than the agreed-upon floor, then Governments or energy consumers would top up the shortfall.

If the Panel reduced the market settings based on support provided by jurisdictional schemes, it would not decrease the system cost of reliability (other than potentially a minor reduction in the cost of capital) nor prevent 'double-counting' of costs. Instead, it would reallocate these costs to scheme cost recovery processes rather than the market customers, thereby potentially distorting spot market signals and resulting in a less efficient resource mix.

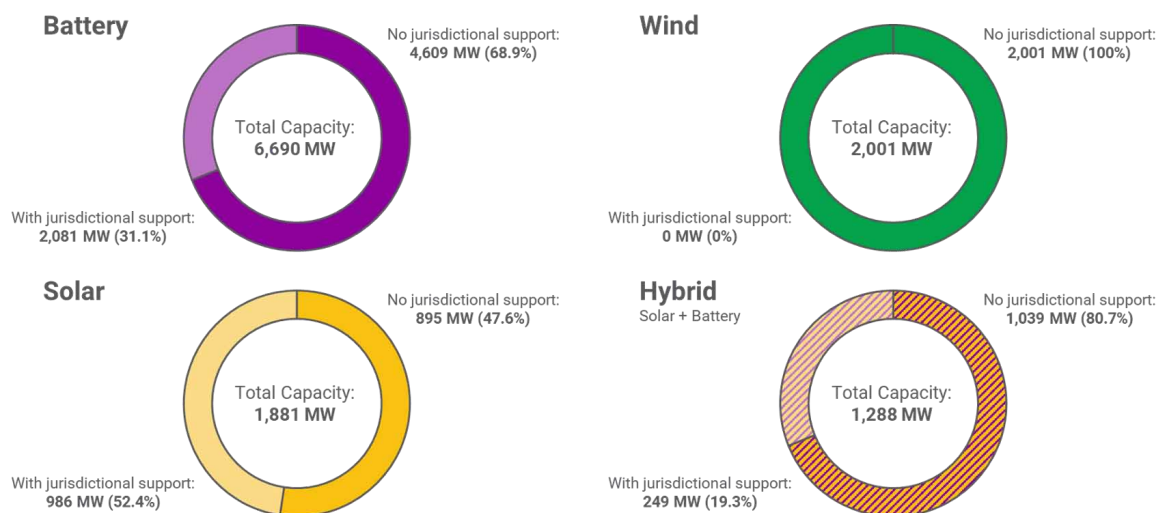
Other than the RET, most investments reaching financial close have not been underwritten by jurisdictional schemes

As noted in Figure 4.2, a minority of renewable generation and storage projects reaching financial investment decisions have had jurisdictional support. Most investments that have reached financial close since mid-2022 have not relied on jurisdictional support; instead, they have relied on the market revenues to deliver on the business case.

42 AEMC, [2026 Reliability Standard and Settings Review](#) Issues Paper, 19 June 2022

43 AEMC, [Targets statement for greenhouse gas](#)

Figure 4.2: Project Capacity Reaching FID since July 2022 - With versus without Jurisdictional Support (LTESA, VRET or CIS)



Source: WattClarity, Are CIS-ers doin' it for themselves? Part 4: Policy lessons highlighted by the Nelson Review, 14 October 2025.

Investment delivered by effective wholesale market signals is crucial to achieving the reliability outcomes that consumers value and expect. Softening those signals in response to jurisdictional support for a subset of generators, comprising a subset of available technologies, could result in cascading revenue insufficiency issues for both new and existing generators.

Lowering the market price settings to account for jurisdictional support could increase reliance on – and embed the need for – such schemes

As part of the 2022 rule change to increase the market price cap, HoustonKemp provided advice to the AEMC that lowering the market settings to match potential underwriting support from jurisdictional schemes would not adequately incentivise investment in the marginal unit.⁴⁴ In such circumstances, to meet the reliability standard, jurisdictional schemes would need to extend procurement to the entirety of firming required to meet the reliability standard, thereby inherently cementing an ongoing role in the market reliability framework.

Effective wholesale market price signals deliver reliability for customers at the lowest cost by incentivising the optimal resource mix

Market-based price signals ensure sufficient investment in the right mix of capacity to meet the reliability standard long-term, while providing effective signals for efficient consumption. These signals combine to minimise jurisdictional scheme costs and leverage market forces to ensure the final capacity mix is the most effective to meet long-term customer needs. Distorting these signals by increasing the need for government intervention could result in inefficient duplication.

Stakeholder submissions broadly supported our proposed approach, with consumer representatives advocating for solutions to avoid double-counting of revenues

In response to the issues paper, most stakeholders supported the ongoing role of market settings alongside jurisdictional schemes and regulatory reform. Shell Energy noted that the process and

⁴⁴ HoustonKemp, [Do jurisdictional schemes change the need for the Reliability Panel's proposed market price settings?](#), 24 August 2023.

framework for considering the reliability standard and settings remain appropriate in the context of jurisdictional schemes. Building on this, they stated that existing policy has already taken the settings into account and therefore investment has taken place under the assumption that the existing framework is enduring.⁴⁵ Hydro Tasmania and AGL supported this sentiment, highlighting that adjusting the settings to account for jurisdictional schemes could compromise the effectiveness of the schemes themselves by diminishing future investment signals and increasing reliance on government support.⁴⁶ AEMO similarly considered that the market settings should remain fit-for-purpose in providing financial incentives for investment in the NEM, despite the existence of jurisdictional underwriting schemes.⁴⁷

Consumer representatives, however, noted that jurisdictional schemes should be taken into account when determining the market price settings, to avoid the risk of duplicating investment signals.⁴⁸ These stakeholders considered that this approach would lead to increased costs to consumers whilst diluting the investment signals the schemes intend to provide.⁴⁹

The Panel is seeking stakeholder feedback on our approach to considering the effect of jurisdictional schemes

The Panel is united in seeking to deliver outcomes that meet the optimal reliability standard at the lowest cost for customers. To ensure that customers' exposure is minimised, the Panel is seeking stakeholder feedback on our treatment of jurisdictional schemes when determining the optimal market price settings. Such feedback will be critical for the Panel's deliberations when determining the final recommendations.

Question 10: Treatment of jurisdictional schemes

- Do stakeholders agree with the Panel's decision to run a low-WACC sensitivity to determine the effect of jurisdictional schemes when determining the optimal reliability standard?
- Do stakeholders agree or disagree that the effect of jurisdictional schemes should not be considered when determining the efficient market price settings? If disagree, how should we quantify the monetary value of jurisdictional support schemes in our modelling?

4.2 Our model develops the most cost-effective marginal new entrant and reliability levels

As outlined above, the first stage of modelling aims to develop a reliability cost curve for each region and for each potential marginal new entrant technology, enabling the most cost-effective reliability standard to be identified. To achieve these objectives, we first built a PLEXOS model to serve as our base case, where reliability outcomes in each region are low. This allows us to iteratively add capacity to determine the total cost at different reliability levels.

4.2.1 A base case market model was developed

Our base model was created by using AEMO's published ES00 PLEXOS model, where we took the published model as-is, and made some minor adjustments, including:

45 Shell Energy, submission to the issues paper, p. 1.

46 Submissions to the issues paper: Hydro Tasmania, pp. 3-4; AGL, p. 2.

47 AEMO, submission to the issues paper, p. 5.

48 Submissions to the issues paper: ECA, p. 2; SACOSS, p. 4; JEC, p. 4.

49 *ibid.*

- 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.

We also made adjustments to capacity 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. The changes to capacity by region is described in Table 4.2 below:

Table 4.2: Capacity changes in the base PLEXOS model

Region	Change to the 2025 ESOO model	Notes
New South Wales	One of two Vales Point coal units turned off	This is to increase USE in NSW to align more with other regions
Queensland	Five of six Gladstone coal units turned off	• In the October ESOO update, AEMO advised that Gladstone Power Station would be retiring in March 2029 • One Gladstone unit remained online to manage QLD USE levels
South Australia	No changes	• SA already has a high level of USE in the ESOO, so no changes are needed • The October ESOO update pushes back Torrens B retirement, however, this is before our horizon - no changes needed as we would have removed TIPS to get USE
Victoria	One of four Loy Yang units turned off	This is to increase USE in VIC to align more with other regions

Note: The Panel notes that Queensland has announced that it may potentially delay coal retirements. We have not included it 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 not have a material impact on the modelling results.

We ran this base case PLEXOS model using the 23 provided weather reference years (2003 to 2025 inclusive), with 15 stochastic outage samples per reference year, and employed PoE10 and PoE50 demand traces.

The resultant level of reliability in each region is described in Table 4.3 below:

Table 4.3: Reliability level by region in the base PLEXOS model

Region	Annual Consumption (TWh)	Reliability level (%)	Notes
New South Wales	73.05	0.0054	This is lower than other regions but still high enough for our modelling purposes
Queensland	57.71	0.0222	This is lower than in the updated ESOO, but still aligns with ESOO forecasts regarding reliability gaps in

Region	Annual Consumption (TWh)	Reliability level (%)	Notes
			QLD.
South Australia	16.35	0.0109	
Victoria	47.94	0.0199	

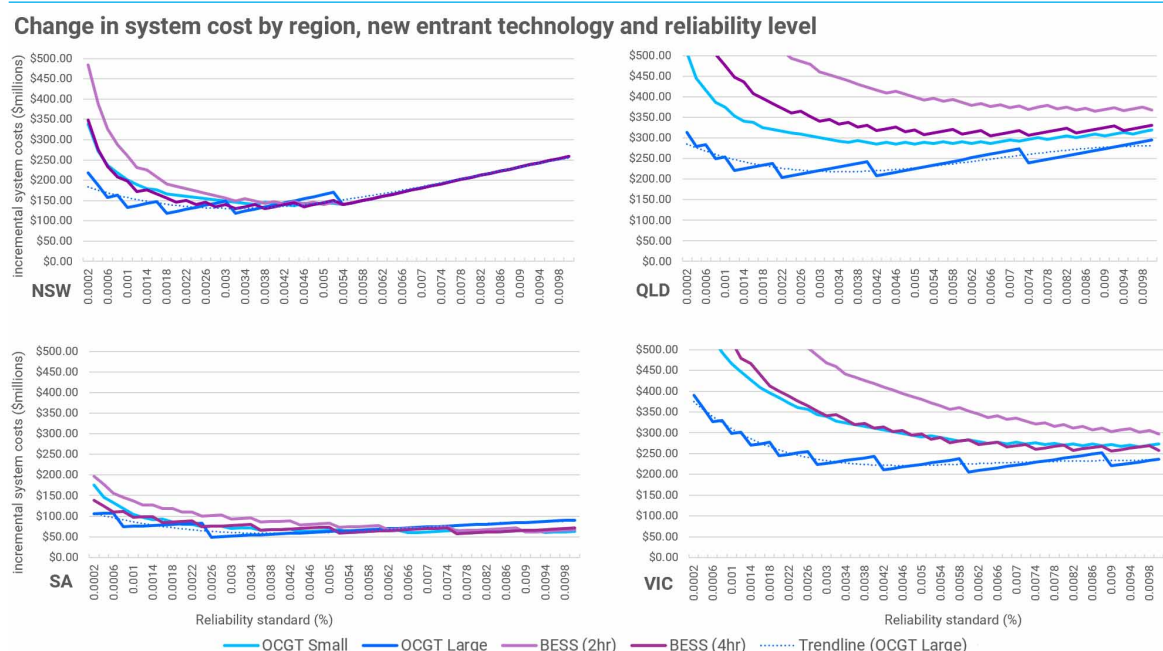
For more details on our base case, see Appendix A.

4.2.2 Large OCGT was found to be the most cost-effective marginal new entrant

Following the development of the base case model, we run a calibration process for each marginal new entrant technology candidate to determine the marginal change in system cost (including cost of unserved energy) for each additional new entrant. This process is described in more detail in the appendix.

The resultant cost curves are shown in Figure 4.3 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. South Australia's size and the unique unserved energy characteristics result in the 4-hour battery and the large OCGT being much closer together, but the large OCGT remains slightly more cost-effective.

Figure 4.3: 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, as the unit size is 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 the capacity increment from a single large OCGT is able to meet a level of reliability from 0.01% up to 0.0025%. To address this issue, we have added a dotted line, which is the polynomial best-fit

line for the large OCGT entrant. This shows a smoother curve and allows us to see the minimal range more clearly; however, we note that this is an approximation.

The large OCGT remains the most effective marginal new entrant on which to benchmark the reliability settings, despite rising capital and operational costs, and in an environment where battery costs are falling. 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 lowest cost. As regions continue to transition away from thermal generator-dominated fleets at different rates, we expect the diverging USE event characteristics to continue with implications for the suitability of universal market price settings across the NEM.

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 between different sources of energy as intended.

The distribution of unserved energy by region is discussed more in Appendix A.

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.

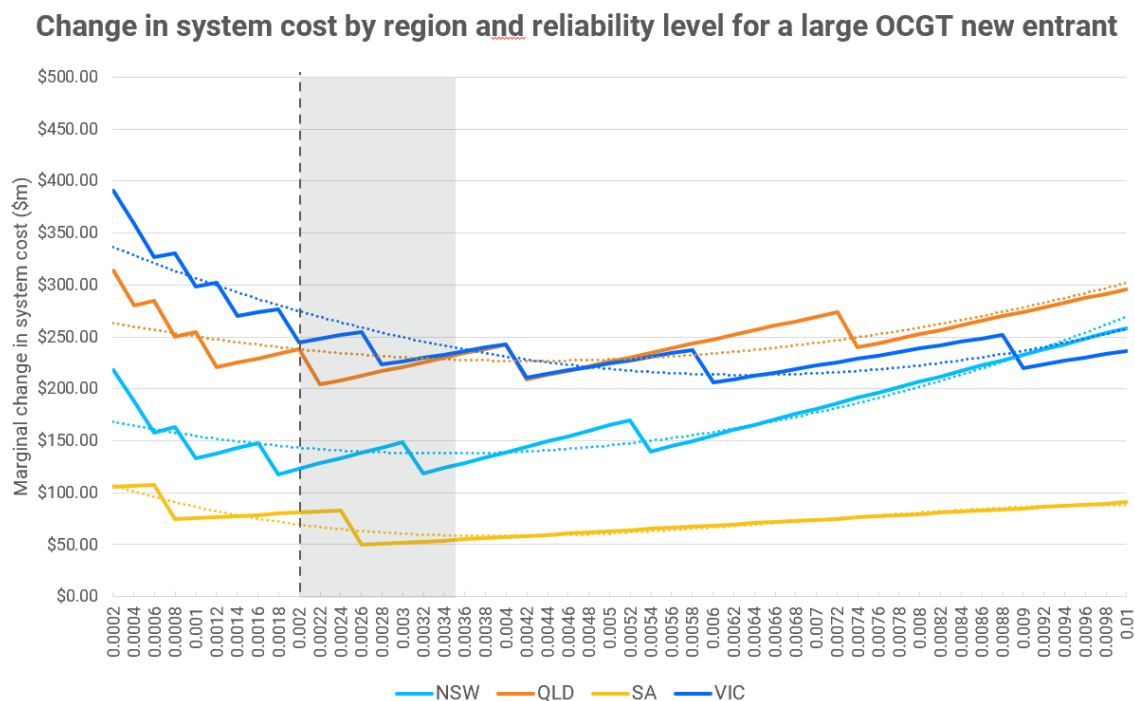
The impact of these sensitivities still broadly point to large OCGT as being the most cost-effective marginal new entrant. Sensitivity results are presented briefly in section 4.2.5, and in full in Appendix A.

As outlined in chapter 2 and 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.

4.2.3 We found that the most appropriate reliability level is between 0.002% and 0.0035%

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 range for the reliability standard.

Figure 4.4 below shows the resultant curve, with the proposed range of reliability levels highlighted by the grey box:

Figure 4.4: 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. For the relatively flat minimum range, the cost of providing incremental capacity is almost the same as the value that 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%. 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.

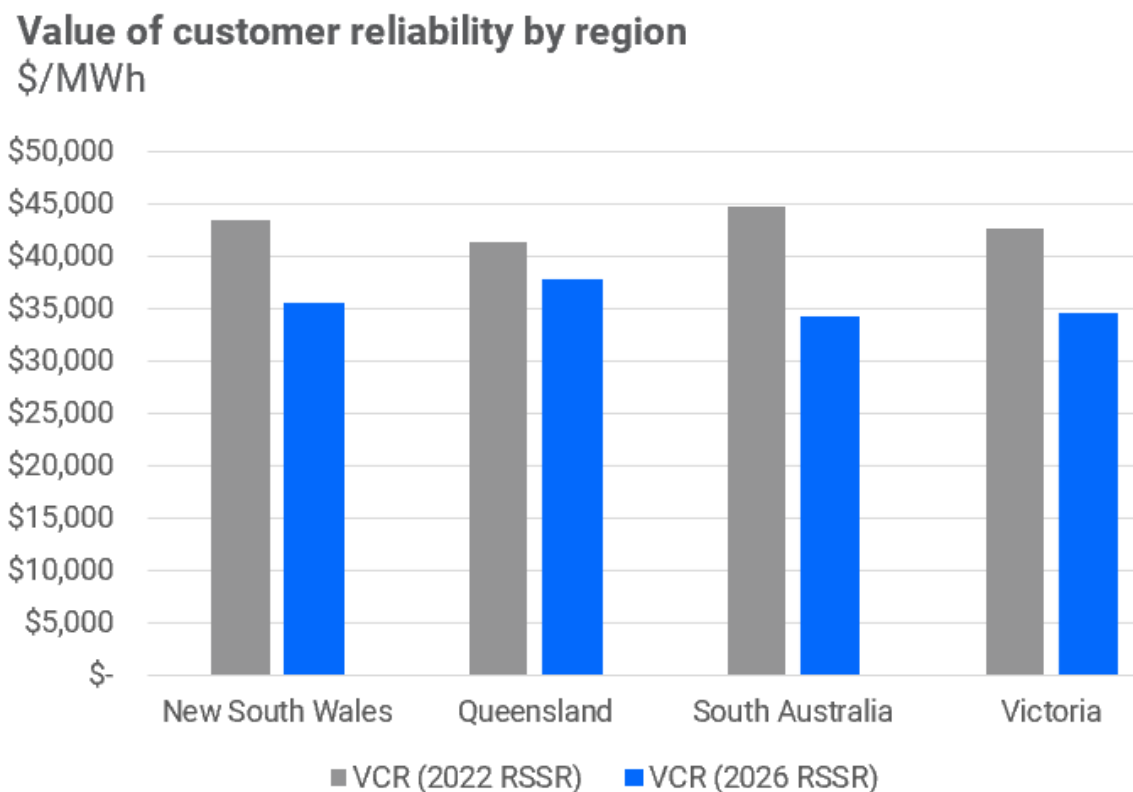
The efficient reliability level is a function of the cost of new generation and the value consumers place on reliability. Since the last RSSR, both of these parameters have moved in a direction that would drive the optimal reliability level to the right (that is less reliable).

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. This pushes the optimal reliability level to the right, all else being equal, as it means that customers place less value on the same level of reliability. Figure 4.5 below shows the change in VCR from

the previous RSSR to the current RSSR. Note that we apply a re-weighting of the VCR, which is discussed further in Chapter 2.

Figure 4.5: The VCR has decreased in all mainland NEM regions



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

On the other side of the equation, the costs to build new OCGT capacity has also gone up, which similarly pushes the optimal point to the right as it means that for a given level of reliability, it will cost more to meet that standard. The increasing costs of OCGTs is discussed in more detail in section 4.3.1.

Another important insight related to these curves is that they are all relatively flat. I.e, a large change in reliability standard produces a relatively small change in incremental system costs. The reason that these curves have become flatter compared to the previous RSSR is also a direct consequence of the changing underlying costs and value of customer reliability discussed above. In particular, this is because the cost of new generation and the value of customer reliability have converged. Because the VCR has gone down, and the cost of new OCGT entry have gone up, the two components potentially balance out at lower levels of reliability, such that the cost of addressing an additional MW of unserved energy is relatively balanced by additional value that customers place on that additional reliability. While this is true in the middle range of reliability, between 0.003% to 0.008%, at high levels of reliability below 0.003% the cost of new generation to address additional unserved energy becomes much higher as relatively more MWs are needed to address 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 that, for example, a reliability standard of 0.003% incurs only a negligible additional cost compared to a reliability standard of 0.0035%.

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

There are also significant differences in regions, both in terms of the incremental change in system cost against the base case (the height of the curve), and their overall shape. The former is driven largely by the size of the region and the level of reliability 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, as the base case reliability level is 0.0054%, the Y-axis value at this reliability 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, but the cost of new generation increases, as additional new entrants are required to meet the higher levels of reliability. South Australia has the lowest incremental cost curve because it is the region with the lowest peak demand and annual energy. 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.

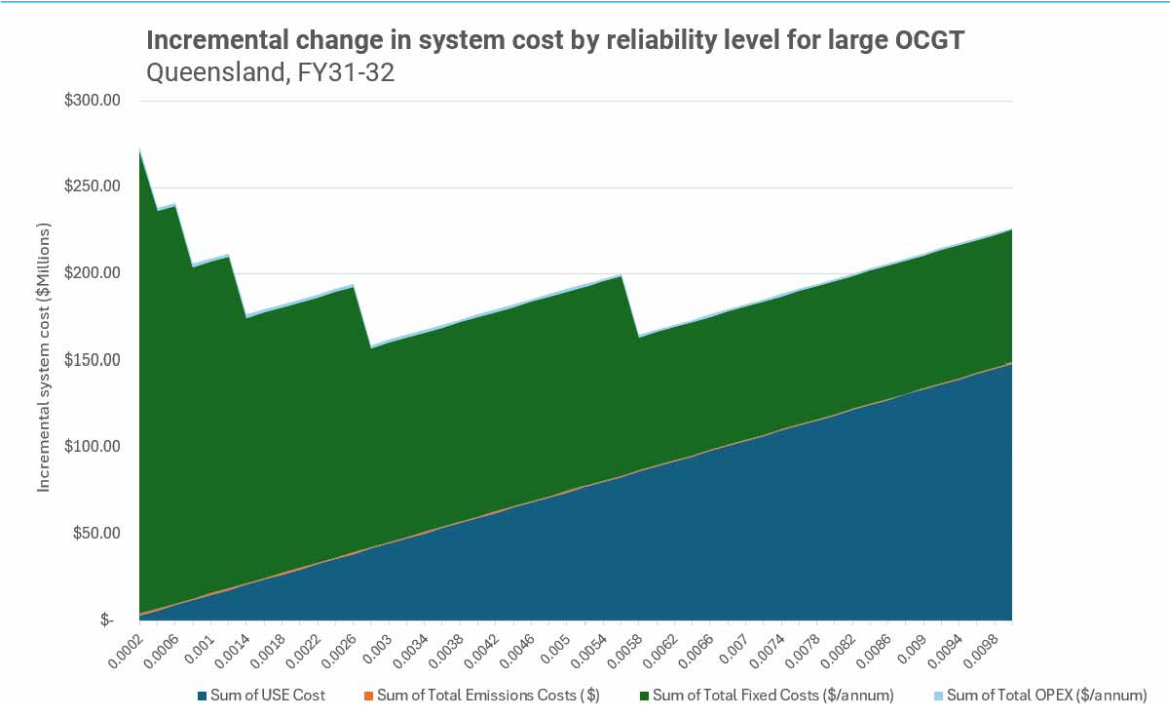
The differences in the shape of the curve, however, are a function of the regional new entrant costs, the regional VCR levels and the differences in the distribution of unserved energy between regions. All else being equal, regions with higher generation costs or lower VCRs will have an optimal reliability to the right, and regions with lower generation costs or higher VCRs will have an 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 has an outsized impact on the shape of the curve as these costs are higher in absolute terms. The primary driver of the differing shape of the curves, however, is the differences in characteristics of unserved energy between regions. This is discussed in more detail in section 4.4.

4.2.4 We considered the value of emissions reductions

As discussed in the issues paper, we have considered the cost of emissions reductions in stage one of the modelling by including the total emissions costs in the reliability curve. These costs are valued at the value of emissions reductions published by the AER, and multiplied by the total emissions resulting from the additional generation needed to meet the given reliability standard. Note that these costs are only included for the OCGT new entrant.

Figure 4.6 below shows the incremental change in system cost by reliability level and cost component for a large OCGT in Queensland for FY31/32. Given how infrequently this firming generation is operating, both operational costs and emissions costs are negligible compared to the fixed capital costs and cost of unserved energy.

Figure 4.6: Emissions costs make up a negligible proportion of new entrant costs



Source: AEMC

4.2.5 We considered a range of sensitivities

To ensure our analysis is robust and to understand the impact of different drivers, we conducted several sensitivity analyses related to the cost of capital for technologies eligible for jurisdictional schemes and customer reliability values. These sensitivities are listed in Table 4.4 below:

Table 4.4: A broad range of sensitivities were run in stage one

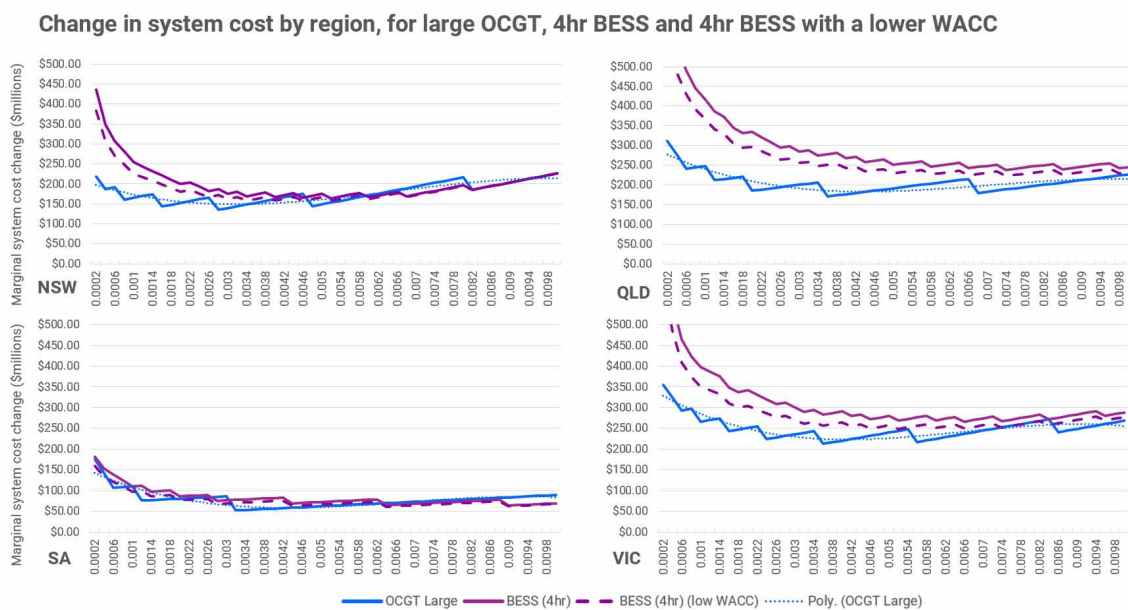
Area	Sensitivity	Description
VCR	AERs VCR	Using the VCRs as published by AEMO, without any re-weighting
	Low VCR	Re-weighting the AER's VCR based on the average of small and large business VCRs
	High VCR	Re-weighting the AER's VCR based on the highest region's residential VCR (Victoria)
	Residential VCR	The average residential VCR, as residential consumers are currently first to be load-shed
Generation costs	Low WACC	Using a WACC of 2 percentage points lower for batteries
	Battery behaviour outside of USE periods	We ran two sensitivities on different approaches to

Area	Sensitivity	Description
		calculating the reduction in system costs outside of USE periods as a result of a new marginal entrant battery cycling daily. This sensitivity did not lead to materially different outcomes and is presented in the Appendix.

Our low WACC sensitivity shows that large OCGTs are still the most cost-effective new entrant to address reliability

The results of the low WACC sensitivity are shown in Figure 4.7 below:

Figure 4.7: OCGTs remain most cost-effective even with a 2% WACC discount to account for any de-risking from jurisdictional schemes



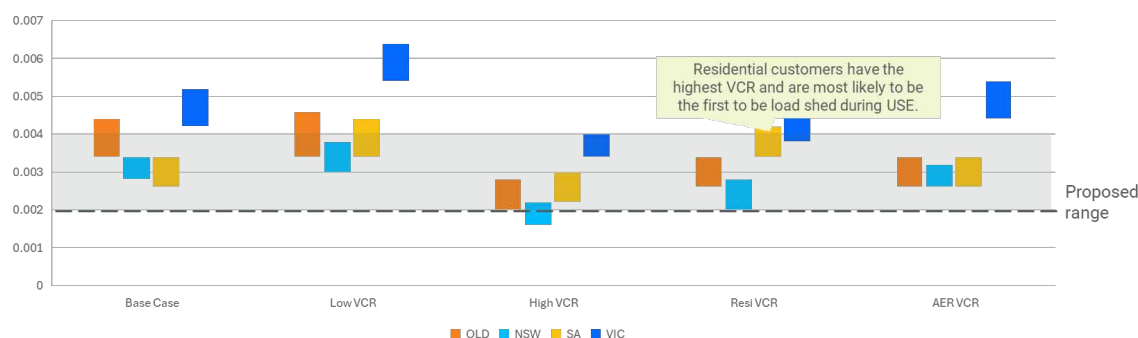
Jurisdictional schemes that apply to BESS provide revenue underwriting, thus de-risking investment in these technologies. We have considered this impact through modelling system costs with a reduced cost of capital for BESS entrants. These results show that even with a 2 per cent reduction in the cost of capital, OCGT remains the lowest cost single technology entrant.

Our sensitivities on the VCR all show the proposed range remains appropriate despite future VCR uncertainty and regional differences

We have used the 2024 VCR survey results as the basis for our consideration of the reliability standard. The Panel notes that VCR survey results may change drastically by the review period (the next survey is scheduled to be published in 2029). Therefore, we have considered alternative VCR figures to test the appropriateness of the proposed reliability standard range. These are derived from re-weighting actual survey results; for example, residential consumers have a higher VCR than commercial and industrial customers.

Our base case utilises a load-weighted average of the VCR survey results to reflect the nature of rotational load shedding during reliability events. This differs slightly from the AER's approach to aggregating survey results, which, since VCR figures are used more widely than just the context of reliability, weights the survey results by total outages.

Figure 4.8: The proposed range of reliability standards captures the lowest-cost reliability standard in most regions under most scenarios



The results illustrated in Figure 4.8 reflect the combination of both the costs associated with achieving reliability and the VCR results, leading to variance between regions that is not necessarily descriptive of the VCR results alone. The proposed reliability standard range captures the lowest-cost standard in most states in most sensitivities.

4.3 Modelling revealed the optimal market price settings

Once the marginal new entrant and the appropriate reliability levels had been identified, we commenced stage 2 of the modelling to determine the optimal MPC and CPT settings for each region and each reliability level within the range.

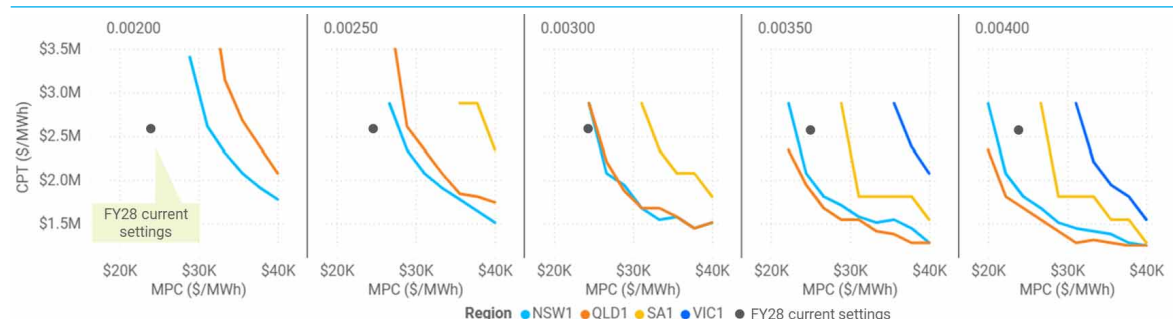
The assumptions, inputs and methodology for this stage of the modelling are described in more detail in Appendix A.

4.3.1 The optimal market settings differ by reliability level and region

This stage of the modelling is run using a grid-search optimisation approach to determine combinations of the 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 still be revenue sufficient. The optimisation produces a 'frontier' of MPC and CPT points that satisfy this condition, given an upper and lower bound for both the MPC and the 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).

Figure 4.9 below illustrates the frontier of minimal MPC and CPT settings for a marginal new entrant large OCGT in each region and at each level of reliability within the proposed range (in increments of 0.0005%). The current settings for FY27-28 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 4.9: The optimal MPC and CPT increase with an increasing reliability level



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 for a higher MPC/CPT frontier is the increasing costs of building an OCGT unit. Figure 4.10 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 4.10: OCGT costs have increased compared to the previous RSSR



Source: Inputs, assumptions and scenarios report 2025 (AEMO)

Note: Costs are based on the last year of the respective RSSR periods (2028 and 2032 respectively) and have not been adjusted for inflation

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

The second factor that primarily 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.

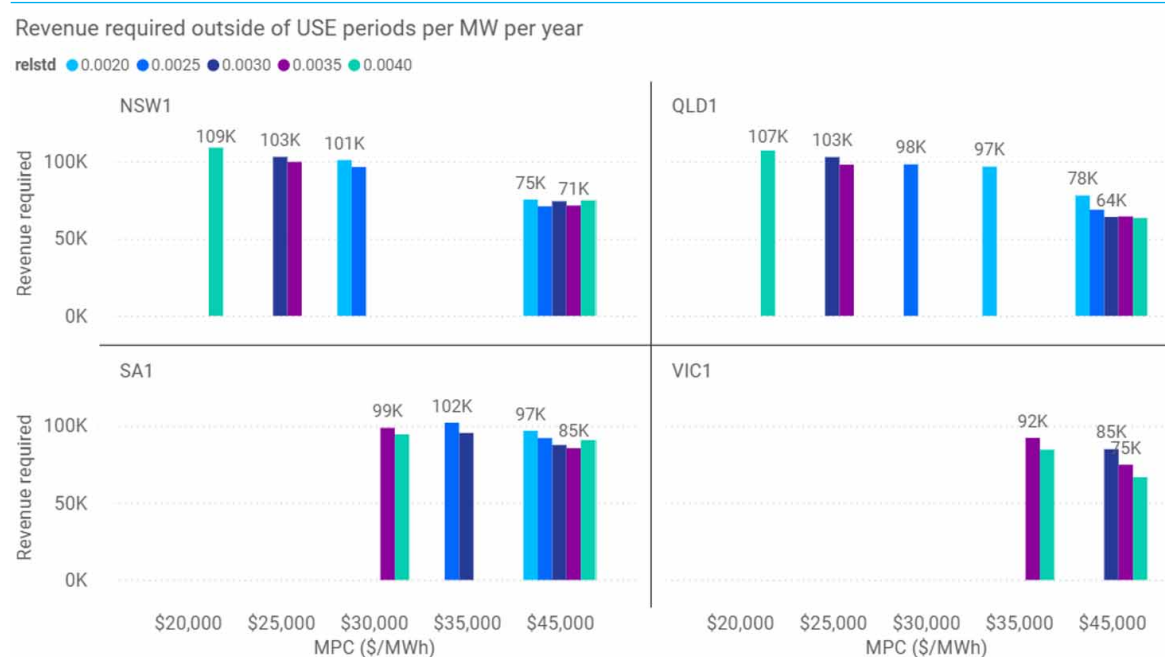
4.3.2 Batteries would need to earn up to 70% of their required revenue outside of reliability periods given these settings to be the marginal benchmark technology for avoiding USE

As our analysis revealed that the most cost-effective single technology new entrant to address unserved energy is a large OCGT. Therefore, we have determined the most appropriate market price settings incentivise entry benchmarked by this technology. However, the Panel considers that in reality, the entry of a combination of technologies to address reliability risk is likely to minimise system cost, including batteries. To understand whether these market price settings would be high enough to also incentivise entry of new batteries, we performed a back-solving exercise to calculate the revenue that a 4hr BESS would earn, specifically during unserved energy periods, given the market settings shown in Figure 4.9 above.

Batteries are significantly more complex to model than OCGT generators. This is due to their bidirectional nature, the perfect foresight of the model, and the fact that batteries often cycle daily, rather than responding to scarcity periods with low utilisation rates, as OCGT does. Modelling these characteristics, therefore, requires a significant number of input assumptions. The Panel therefore considers that this approach is more appropriate than modelling battery revenues from the bottom up to determine the market price settings.

Figure 4.11 below shows the results of this back-solving approach, where the total revenue that batteries would require outside unserved energy is plotted against the MPC and CPT combinations tested. This analysis indicates that batteries would need to earn between \$60k/MW at high MPCs and over \$100k/MW for low MPCs outside of USE events.

Figure 4.11: Batteries would need earn between \$60k/MW to over \$100k/MW outside of USE events to remain revenue sufficient



Source: AEMC analysis

As 4hr BESS fixed costs lie between \$15m to \$16m, this implies that a 100MW unit needs to earn roughly \$150,000/MW to \$160,000/MW to remain revenue sufficient. Therefore, we find that batteries would need to earn between 40 to 70 per cent of their revenue outside of USE periods, depending on the MPC and CPT settings.

Note that this analysis rests on a number of simplifying assumptions:

- The capacity of new entrant battery required is to address the last 0.0004% of reliability (e.g. to reduce the level of reliability from 0.0024% to 0.002%).
- The battery has perfect foresight of USE events.
- The battery starts at 80% state of charge before each USE event (to mitigate the impact of perfect foresight).
- The battery discharges until it gets to 0% state of charge, or until the end of the USE event, whichever comes first.
- We do not explicitly model charging costs, only revenues during USE events, therefore we implicitly assume an average charging cost of \$0.

These assumptions are necessary to perform the back-calculation, however in reality there is significant uncertainty regarding the way a marginal new entrant battery will operate during USE periods, and outside of USE events. As the assumptions we have made are relatively optimistic towards battery costs and revenues, we consider the estimate of their required revenue outside USE periods to be closer to an upper bound estimate.

Question 11: Battery revenue requirements

- Do stakeholders consider that the market settings benchmarked based on OCGTs are high enough to incentivise a new entrant 4hr BESS, given the results above?

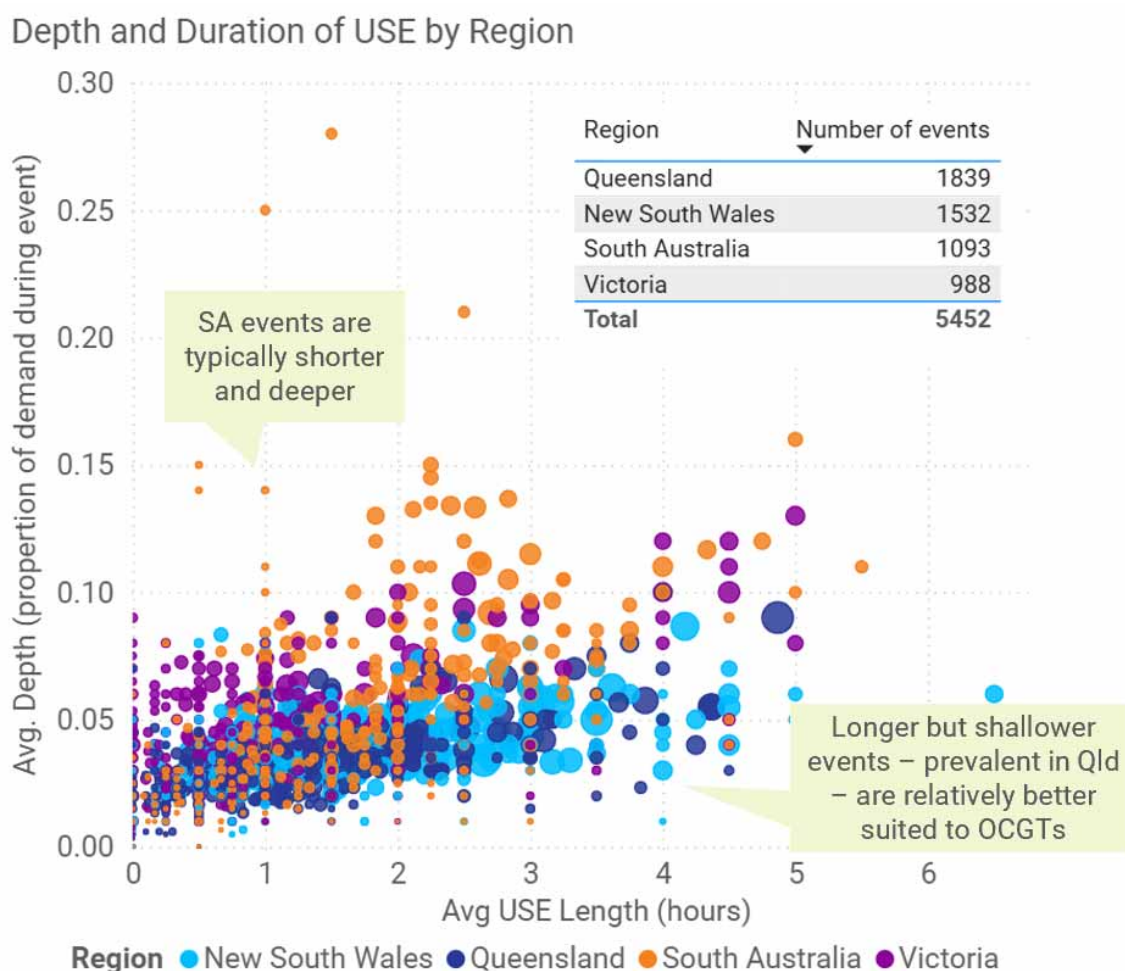
4.4 Differences in regional results are largely driven by the characteristics of their unserved energy distribution

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 (more reliable) than 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 outcome as the northern regions. These results can predominantly be explained by the underlying characteristics of unserved energy in the regions. These characteristics are explored in more detail in Appendix A, though a high level summary is provided here.

Figure 4.12 below aims to show the differing characteristics of unserved energy between regions, noting that:

- Each dot represents a single model run for financial year FY31/32 (out of the 23 reference years, 15 outage samples and 2 PoE levels).
- The Y-axis shows the average depth of USE events in that run, calculated as the proportion of demand that is unserved during the event.
- The X-axis shows the average length of USE events in that run in hours.
- The size of the dot represents the total MWh of unserved energy in that run.

Figure 4.12: South Australia and Victoria have different USE characteristics compared to QLD and NSW



Note: These results are from the calibrated model, set to a reliability level of 0.003% in each region

This chart highlights the primary differences between regions, in that for a given level of reliability, Queensland and New South Wales have a greater number of events, which are typically longer and shallower. In contrast, Victoria and South Australia have relatively fewer events, but they are typically shorter and deeper. These differences arise from the market characteristics of each region, including the percentage of renewable energy, the local weather conditions, and the profile of demand.

For example, the relatively higher share of wind capacity and lower share of thermal capacity in South Australia contribute to the unserved energy events being shorter and deeper. Unserved energy events increasingly correlate with low wind conditions after sunset. While, in most occasions, this only results in events relatively shallow and short events, if unserved energy or forced outages in other regions, or unusual dispatch patterns result in constraints forcing counter price flows, events in South Australia can be quite deep. This is compared to Queensland where unserved energy events are driven by forced outages during higher than usual summer demand and where network constraint are relatively less complex, resulting in shallower but longer events. In tFigure 4.12 above, the deeper outliers for South Australia and longer event in New South Wales are the result of the complex interplay of the variability of wind after sunset, forced outage for

thermal plant and network congestion. The actual performance of the network will be able to be more fully understood following the commissioning of new network elements. This RSSR analysis supports the conclusions of the 2024 Form of the Standard Review that unserved energy event characteristics are closely linked to the variability, and potentially predictability of renewable energy supply, network congestion resulting in complex interconnector flows.

This analysis supports the modelling that the Panel published as part of the review of the form of the reliability standard, which also found that as the NEM transitions to a higher proportion of VRE, unserved energy events may become fewer, but they may be deeper and longer.

The outcomes on stage one and stage two follow from these differing unserved energy characteristics; as South Australia has fewer events, but the events are deeper, which requires more capacity with less energy limits to be built but that capacity spends more time sitting idle. Conversely, frequent, shallower and longer events are less costly to address, especially by an OCGT unit, as less capacity is needed and that capacity utilised for a longer time period so they can earn more revenue.

These regional differences are discussed in more detail in the Appendix.

A Background and context

Box 6: Key points in Appendix B

- Power system reliability involves an adequate amount of capacity to meet customer needs, which the existing reliability framework aims to ensure.
- Power system reliability is distinct from power system security.
- 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 introduces and discusses:

- power system reliability in the NEM
- the current NEM framework for delivering reliability, of which the standard and settings are an important part, 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,⁵⁰ 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 any appropriate operational framework so that supply and demand are continuously balanced. 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,⁵¹ providing strong financial incentives for participants to make investment, retirement and operational decisions that support reliability.⁵²

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, even if there is an incident such as the loss of a major transmission line.

The Panel is required to focus on the reliability of the power system when conducting the RSS review. Specifically, the level of reliability provided by power generation and inter-regional transmission assets.⁵³

50 AEMC, 2026 [Reliability Standard and Settings Review, Issues Paper](#), 19 June 2025.

51 Reliability Panel, [Information Paper: The reliability standard, current considerations](#), 12 March 2020, Sydney.

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

53 Clause 3.9.3C of the NER.

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, and
- Delays to the construction or commissioning of new generating units or inter-regional transmission elements, including delays due to industrial action or force majeure (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, and
- Industrial action or force majeure at existing generating facilities or inter-regional transmission facilities.⁵⁴

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 level of the standard is based on the level of USE, which represents an efficient economic trade-off between reliability and affordability, taking into account 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 provide signals for the development and dispatch of generation and demand-side resources, as well as information about the balance of supply and demand across different locations 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 any potential reliability problems as they arise.

Spot market

The NEM utilises a gross pool (mandatory participation) energy-only market design. Generators sell all the electricity they produce through the wholesale market for electricity, which matches supply to demand on a five-minute basis.⁵⁵ From market participant bids and offers to consume or

⁵⁴ For more details see section A.1.2 of the issues paper.

⁵⁵ NEM market design includes 10 markets for frequency control ancillary services (FCAS) that regulate frequency by balancing supply and demand for electricity on sub five-minute timescales.

supply electricity at specific prices, the national electricity market dispatch engine (NEMDE) determines the lowest-cost combination of scheduled generation or demand to meet customer loads, given the physical limitations of the power system. AEMO then issues dispatch instructions and wholesale market prices are determined from the generator offers or demand bids to supply the last MW of customer load in the NEM.⁵⁶ The pricing framework for the NEM allows for price variability within an envelope established by the settings. The market price settings therefore act to limit the prices that generators receive for supplying electricity and the revenue potential from investment decisions. The level of the market price settings therefore need to carefully balance the reliability benefits of efficient wholesale market price signals with the financial risks faced by market participants

This trade-off, along with related considerations, is discussed in more detail in Chapter 6 of the issues paper.

Contract market

Reliability outcomes in the NEM are facilitated by financial contracting for risk management.⁵⁷ The contracts, or financial derivatives, market supports reliability in the NEM by providing a means for retailers and generators to manage their exposure to spot prices, by allowing participants to trade uncertain and variable spot market prices for fixed prices for a specific period (e.g., a month, quarter, year or longer). Contract markets create incentives for reliability, including on:

- **Operational timescales** - generators who have sold contracts are incentivised to be available when needed (i.e. when spot prices are high), in order to be dispatched to at least the volume of those contracts, so the revenues earned in the spot market fund payouts on their contract positions. This incentive to 'turn up' is heightened during periods of high prices and tight demand-supply, which is precisely when the system most values the generator's output.
- **Investment timescales** - forward contracting lowers the cost of financing investment in generation capacity, which lowers the cost of achieving and maintaining system reliability. Contracts provide generators with a steadier stream of revenue than the spot market. A steadier stream of revenue reduces the risks to parties providing funding to generators, such as debt and equity holders. This lowers the overall cost of capital required to finance the project and lowers the cost of the new generation capacity.

Prices in the contract market also reveal participant expectations regarding the value of, and risk associated with, additional resource investments. Price signals in the contract market therefore complement those in the spot market in signalling the value of new entrant investment to support reliability outcomes.

A.2.2 AEMO information and intervention processes

A key role for the reliability standard is to guide various decisions made by AEMO in its role as the system operator. AEMO is responsible for operationalising the reliability standard through its forecasting and operational processes. AEMO's Reliability Standard Implementation Guidelines set out how AEMO implements the reliability standard.⁵⁸ AEMO uses the reliability standard in several core ways including to:

⁵⁶ This framework is underpinned by the economic principle that the most efficient investment decisions are made if market participants can make their own decisions in response to marginal prices. As such, the market price provides the signals needed for investors to make informed investment and divestment decisions.

⁵⁷ While the financial markets this contracting occurs through are not part of the formal wholesale electricity market operated by AEMO, contract markets are still a critical element of the NEM reliability framework.

⁵⁸ AEMO, [Reliability Standard Implementation Guidelines](#), December 2020.

- 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,⁵⁹ and
- 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.

Information processes

AEMO is required by the NER to publish various materials which provide information to market participants – and any other interested parties – on matters pertaining to the reliability standard; that is, over and above the information contained in contract and spot market prices. This information is a crucial component of the existing reliability framework, helping to guide and inform market participants' expectations of the future, and enabling more efficient investment and operational decisions.

The purpose of this information is to inform the market of prevailing and forecast conditions, particularly when reserves may be running low, in order to elicit a market response. For example, the Electricity Statement of Opportunities (ESOO) identifies potential shortages of generation over a 10-year forecast time horizon, prompting the market to make new investments to alleviate any forecast reliability issues. AEMO also publishes relevant information through its Projected Assessment of System Adequacy (PASA) and pre-dispatch processes.⁶⁰

In operational timescales, AEMO issues lack of reserve (LOR) notices to inform the market when supply scarcity conditions apply. AEMO declares LOR conditions when it determines there is a non-remote probability of unserved energy due to a shortfall of available capacity reserves at a given time in the assessment horizon.⁶¹ LOR notices are either LOR1, LOR2, and LOR3 in order of increasing supply scarcity.⁶²

Intervention mechanisms

As effective as information processes can be in delivering the desired reliability outcomes through market incentives, they do not always elicit the outcomes needed. If the market fails to respond to the information AEMO publishes, AEMO may have no other choice but to intervene in the market more directly.

AEMO therefore has various 'last resort' intervention powers that enable it to deal with actual or potential shortages of varying degrees of severity. Under the NER, these intervention mechanisms include the following:

- AEMO has reliability and emergency reserve trader (RERT) obligations. These allow AEMO to contract for reserves ahead of a period where reserves are projected to be insufficient to meet the reliability standard. AEMO can dispatch/activate these reserves to manage power system reliability and, where practicable, security.⁶³
- In addition, if there is a risk to the secure or reliable operation of the power system, AEMO can use directions or instructions under NER clause 4.8.9 to:

59 AEMO, [Reliability Standard Implementation Guidelines](#), December 2020, pp. 8-22.

60 Clauses 3.7.2(f)(6) and 3.7.3(h)(5) of the NER.

61 In the NEM, reserves are made available by the market as part of usual operation of the power system and expectations of future price outcomes in the energy market. Reserves refer to the amount of spare capacity available given amount of generation, demand and demand response at any point in time, and can be 'In market' from generators that are available to run, but because available capacity is greater than demand, are not called on to run, and 'Out of market' from the emergency reserves that AEMO procures through the reliability and emergency reserve trader (RERT) mechanism to be in standby.

62 Clause 4.8.4 of the NER - additional information is available in AEMO's reserve level declaration guidelines, available [here](#).

63 Clause 3.20.3 of the NER.

- Direct a generator to increase its output, if this is possible and can be done safely.
- Direct a large energy user, such as an industrial plant, to temporarily disconnect its load or reduce demand.

If a shortfall in supply persists, even after these measures have been implemented, AEMO may require involuntary load shedding as a last resort to maintain the power system in a secure state. It does this by instructing a transmission network service provider to arrange for the interruption of customer load.

These intervention mechanisms provide an important ultimate safety net when there is insufficient generation capacity to maintain adequate reserves above demand, to minimise the adverse impacts on customers of involuntary load shedding. Although AEMO would be expected to do all that it can to avoid load shedding using the above intervention mechanisms, there will be times when involuntary load shedding will be unavoidable because the level of investment and operational decisions is being driven by a reliability standard that is non-zero.

A.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 seeing the power system supply and demand balance continue to become more sensitive to weather conditions than has historically been the case.⁶⁴

⁶⁴ 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 A

- The assessment framework that the Panel must apply to considerations 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 will only recommend 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.
- If the Panel recommends any changes, they will need to submit a rule change request to the AEMC so that the Commission can review and implement these changes.

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.⁶⁵The specific framework includes:⁶⁶

- 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 (**General Assessment Principles**).

The NEO is:⁶⁷

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.

⁶⁵ Reliability Panel, [Review of the reliability standard and settings guidelines](#), Final guidelines, 1 July 2021

⁶⁶ *ibid.*

⁶⁷ Section 7 of the NEL.

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

1. **Allowing efficient price signals while managing price risk:** The Reliability Panel will exercise its judgment 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, and
 - 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 informs 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.

B.1.1 The Panel will consider emissions reduction in making its recommendations

In September 2023, the NEO were amended to explicitly include an emissions reduction objective. This is the first time that an RSS Review has been required to consider emissions reductions.⁶⁸ To the extent that the Panel considers the level of the reliability standard or any of the market settings will meaningfully impact carbon emissions, we will consider this cost in our analysis based on the AER's value of emissions reduction.⁶⁹

Further details on how emissions are considered are provided in section 3.2.1 and chapter 6 of the issues paper.⁷⁰

B.2 The review will consider a range of other factors / Other considerations that the Panel may take into account

There are several other requirements in the Rules that relate to the assessment of the standard and each of the settings. These requirements and criteria are outlined in the guidelines and collectively inform the materiality assessment, enabling the Panel to evaluate the standard and each of the settings. This section outlines the Panel's approach to assessing the reliability standard and settings.

68 AEMC, [Reliability Panel Guide to applying emissions reduction component of the National Electricity Objective](#), Final guidelines, 4 April 2024.

69 AER, [Valuing emissions reduction - Final guidance](#), May 2024.

70 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 several requirements outlined 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 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 each of the reliability settings. These are outlined in the guidelines and are discussed in chapters 3 and 4 of the issues paper.⁷¹

B.3 The Panel will make recommendations to the AEMC

In addition to the General Assessment Principles and NER Assessment Criteria outlined above, several equally important steps must be taken for a change to the standard or settings to ensure that stakeholders have the opportunity to understand and respond to any such change. The Panel considers that this ensures the regulatory process remains predictable while balancing the need for the market to be flexible to changing market conditions

Futhermore, to improve predictability and flexibility in its review, and to best incorporate new information about how the NEM is changing, the Panel will only change the level or form of the reliability standard or settings where there would be a material benefit in doing so. The analysis undertaken in this review will determine the most efficient level of the reliability standard and corresponding market price settings. These will be compared to the status quo, as the Panel will only recommend changes that would result in a material benefit. This ensures that predictability in the reliability standard and settings, an important feature of the market for participants and new investors, is maintained. If the Panel recommends that a change to the reliability standard and settings would result in a material benefit, it will need to submit a rule change request to the AEMC to implement these changes. The Commission would then consider these proposed changes through the usual rule change process, allowing further opportunities for stakeholder input and consultation above those already incorporated into this review's process.

⁷¹ 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 in more detail. In terms of methodology it covers:

- the approach,
- the detailed inputs and assumptions,
- modelling limitations,
- the setup of the base case model, and
- the calibration approach.

Furthermore, this section also covers results in more detail including:

- sensitivities relating to the level of the standard,
- sensitivities relating to the MPC and CPT, and
- characteristics of unserved energy between regions.

C.1 Methodology

Detailed modelling of the electricity market informs each RSSR. Modelling provides a quantitative basis for the Panel to identify 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 approach to modelling to inform the 2026 RSSR.

Specifically, this chapter:

- Appendix C.1 – outlines the methodology and limitations of the modelling
- Appendix C.2 – describes the inputs, assumptions and treatment of key issues
- Appendix C.3 – details the market model setup and results
- Appendix C.4 – details the sensitivities and results.

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 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

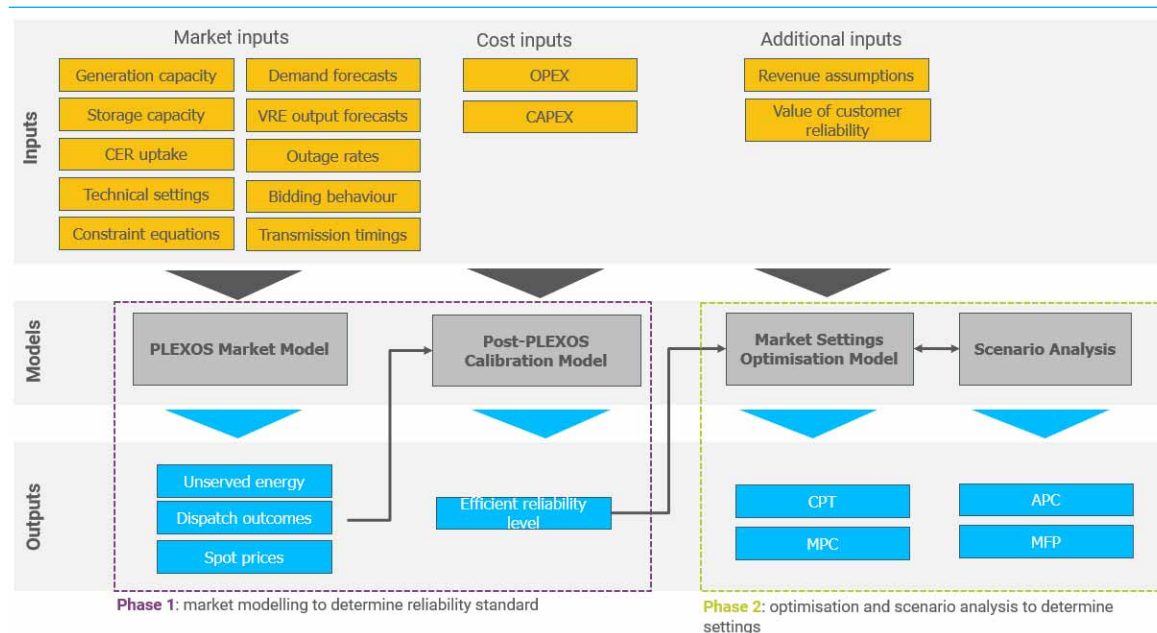
Previous RSSR modelling processes have all involved market simulations to test aspects such as an appropriate market price cap, such that peaking generators are revenue sufficient to promote the delivery of an optimal reliability standard. Prior to the Rules requirement to establish a formal value of customer reliability, earlier studies developed an implied VCR as a reasonability test. Modelling is not a perfect answer. 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 ES00 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 phases of modelling required for this review:

1. The first phase is to determine an efficient reliability standard through a combination of time-sequential market modelling using the optimisation software PLEXOS and through post-simulation scenario analysis.
2. Once an efficient reliability level has been derived, the second phase of modelling can begin. This phase 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 2025 Inputs Assumptions and Scenarios document. The following figure illustrates the categories of information used, and the additional information derived from the AER's Value of Customer Reliability (VCR).

Figure C.1: Block diagram of the modelling framework



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

The modelling task in the first phase 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

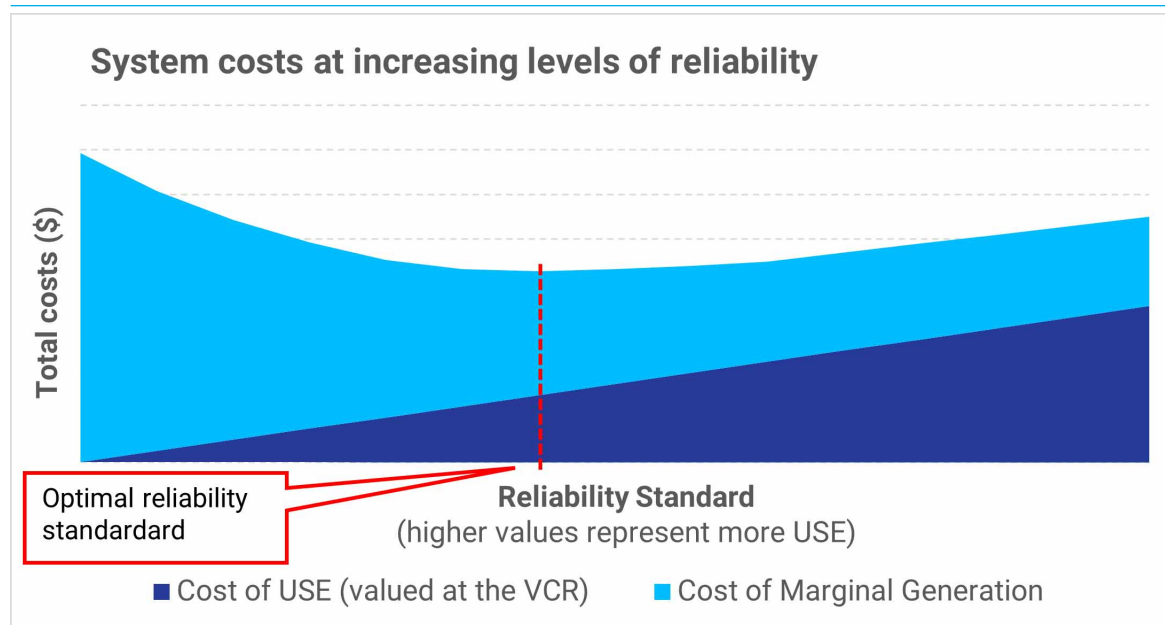
from various unit sizes and technologies, the optimisation model can incrementally consider the incremental change in cost from adding sufficient plant to deliver different levels of reliability.

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 ES00 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 is based on balancing the delivery of a reliable electricity supply while maintaining 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 the VCR and increases at a constant rate as the reliability standard increases (becomes less tight), and
- the cost of generation, which decreases sharply when moving away from a system that is 100% reliable and then tapers out, since a perfectly reliable system would require more generation assets than a less reliable system.

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 ⁷². However, we have made changes to account for changing market conditions and improved modelling

72 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 review⁷³. 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 (this may be done in a post-processing Excel model, rather than through additional PLEXOS simulations)

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

- A much larger set of weather reference years in the PLEXOS modelling to produce a greater sample of USE outcomes with greater variability.
- A post-processing excel 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 creates a benchmark and the incremental capacity added only operates during periods of USE. Furthermore, as these models assume all plant operates 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.1.2 and appendix C.2.

Modelling stage two informed the market price settings

As described in the issues paper and chapter 4, 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 perform a greater number model runs and reflect a greater 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, where these system costs were 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 (to address USE only, based on an assumed profile described in section x), 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 simply minimising the MPC and CPT, with the constraint ensuring revenue sufficiency for the marginal

⁷³ 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>

new entrant. This approach produces results that are reasonably aligned with the previous RSSR, but allows us to run many more iterations of the model. We are testing the most appropriate market price settings for each region and for various levels of reliability.

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
- determine the capacity needed to meet every reliability level, increasing at increments of 0.001% USE (e.g. for a given reliability level of 0.002%, find the capacity needed to move from 0.003% to 0.002%)

Once this data is retrieved, we then run an iterative grid-search of a range of MPC and CPT values based on a range of acceptable values. In the base case, we chose a range of acceptable MPC values from \$15,000/MWh to \$45,000/MWh and a range of 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 capacity 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 in appendix C.1.2 and appendix C.2.

C.1.2 Limitations of the approach

The modelling for this review has several broad limitations that stakeholders should be aware of. 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 the modelling were solely carried out through market modelling simulations, dispatch outcomes may be different, and spot prices would likely be lower, leading to a higher

combination of the MPC and/or CPT. 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 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% 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 as defined in AEMO's ES00 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, supply chain constraints, and planning approval delays).

C.2 Inputs and assumptions

This section describes the data assumptions and modelling inputs 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)⁷⁴
- 2024 Electricity Statement of Opportunities (ES00)⁷⁵
- 2025 ES00 (when it is released in August 2025)
- 2025 Inputs Assumptions and Scenarios Report (IASR)⁷⁶.

We also relied upon documents published by the AER, including the 2024 Values of Customer Reliability (VCR)⁷⁷ and the Value of Emissions Reductions (VER)⁷⁸

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 ES00	We have diverged in select regions from the ES00 to ensure that our base case has

⁷⁴ 2024 Integrated System Plan (ISP), available at: <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp>

⁷⁵ NEM Electricity Statement of Opportunities (ES00), available at: <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-es00>

⁷⁶ Draft 2025 Inputs Assumptions and Scenarios Consultation, available at: <https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>

⁷⁷ Values of Customer Reliability 2024, available at: <https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024>

⁷⁸ 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
		sufficient unserved energy. This process and resultant changes to capacity are described in section x.
Generation and storage retirement	From AEMO's 2025 ES00	See note above.
Transmission upgrade timings	From AEMO's 2025 ES00, which is in turn sourced from AEMO's 2025 IASR	
CER forecasts, including Virtual Power Plants (VPPs)	From AEMO's 2025 ES00, which is in turn sourced from AEMO's 2025 IASR	
Demand side participation (DSP)	From AEMO's 2025 ES00, 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 ES00, which is in turn sourced from AEMO's 2025 IASR	We have run 15 outage samples per reference year and demand level, sampling from the outage rates as set in the ES00/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 ES00 PLEXOS model	
Demand forecasts	From AEMO's 2025 ES00	We have used AEMO's PoE10 and PoE50 demand traces
VRE output forecasts	From AEMO's 2025 ES00	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, and so we have decided to use only the AEMO set of traces. We note that AEMO's inclusion of additional weather traces has increased the sample size of weather years considerably since the previous ES00.

Input	Description or source	Notes
Hydro inflows	From AEMO's 2025 ES00	
Generation and storage cost data	From AEMO's 2025 IASR	Originally taken from CSIRO's GenCost report
Value of customer reliability	From AER's VCR report	We have re-weighted these VCR values (see Chapter 2 for further details) and performed sensitivities which are outlined in appendix C.4.
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 ES00 and ISP.	Base case assumptions regarding demand, generation mix, demand-side participation, transmissions 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 potentially lead to very different reliability outcomes and hence reliability settings.
	Weather reference years are based on historical data and do not take into account 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 ES00 and gives us a much larger sample with which to produce results.	A greater number of weather reference years would make our results even 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. There is also no currently accepted method of modelling the impacts of climate change, as the changes to weather are very hard to predict, particularly at the

Area	Assumption / Limitation	Notes
		low levels of granularity that we would require for our modelling. Ultimately this is a limitation of the input data available to us, however a large set of weather years goes some way in ameliorating this issue as it gives us a larger sample size, in which outlier events may be present. The AEMC is preparing a longer series of weather reference years, however this was not used in this analysis as it is yet to be formally tested.
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 future markets dominated by variable renewable energy sources may experience very high ramp rates from weather based events.	A higher resolution (e.g. 5mins) would involve significantly higher run times and resource costs. Given the 30min interval is the same as used by AEMO 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, so 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 assume a flat price of \$150/MWh in the week	As the triggering of the CPT is driven primarily by periods of unserved energy where the spot price is at the MPC, these assumptions do not make a

Area	Assumption / Limitation	Notes
	preceding USE events in all regions, rather than model spot prices explicitly. This is because spot price forecasting is inherently uncertain, and may influence results unduly. By setting a flat consistent spot price in each region for the periods before and between unserved energy events we ensure that regions are treated equally, and so that we can explain differences in reference to 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 that have 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 having unserved energy, and prices are likely to be elevated compared to normal periods.	significant difference to results.
	We calculate revenues based on a marginal new unit meeting the last 0.001% of reliability, i.e. for a standard of 0.002%, we model the revenues for a unit to reduce the level of unserved energy from 0.003% to 0.0002%.	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 the differences between regions based on region sizes don't impact results unduly. For example, if we treated new entry in terms of whole units only, South Australia would have a much larger proportional cost, as the size of the OCGT unit makes up a much larger proportion of total demand in that State.	
	The marginal new entrant operates only during USE periods, and is based on assumed operating behaviour. For an OCGT unit, we assume it operates at its maximum capacity during all USE events for the entire duration of the event. For BESS, we assume a starting state of charge for USE events of 80% and discharge to either 0% SoC (the stored energy in the battery is exhausted) or	This assumption allows us to determine revenues without running an entire PLEXOS simulation.

Area	Assumption / Limitation	Notes
	the USE event has ended (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% SoC in preparation for the next USE event.	

C.2.3 Treatment of revenue outside USE periods

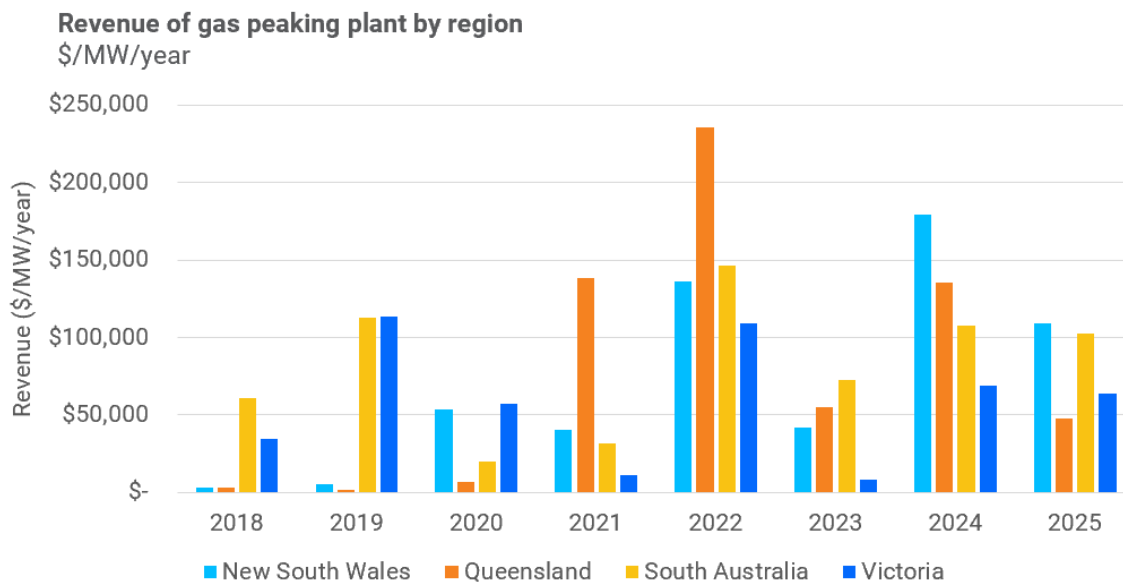
The revenue earned by generators outside of reliability events plays a crucial role in determining the required MPC/CPT combinations to ensure revenue adequacy for new entrants in reliability. As these revenues are used as a “top-up” additional to revenues earned from reliability events, an assumption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

There are a number of difficulties in determining what the non-reliability revenues for OCGT and BESS will be, 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 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 as being close to the average revenues taken from historical outcomes for gas peakers for various years and at different capacity factors. This analysis was repeated in this RSSR, with the results shown in Figure C.3 below. Higher revenues during 2022 relate predominantly from higher fuel prices over financial year ending 2023. The historical analysis shows that the operational role of peakers in regions with higher renewable penetration is different to that of peakers 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 compared to the already uncertain revenues for OCGT. This includes:

- ancillary service (FCAS) revenues are rapidly decreasing
- there has been a rapid uptake of these units in the market which has now largely satisfied the FCAS market requirement, and has resulted in batteries cannibalising each others revenues
- currently merchant battery revenues are predominantly based on arbitrage, and are therefore even more dependent on the daily spread in prices
- 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 did back-solve 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 Section X of Chapter 4.

C.2.4 Treatment of demand-side participation

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 DSP that would be available 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 Market modelling

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

C.3.1 Base case PLEXOS model

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, which is published as a PLEXOS model and is a representation of the NEM for the next 10 years based on current forecasts of supply and demand.

We use the ESOO central case for our demand outlook, and we incorporate all the 'committed and anticipated' capacity in our supply outlook. This model reflects the conditions that are most likely to occur given announced project start and end dates.

Number of model runs and weightings applied

To ensure we have a large enough sample size of future unserved energy events, we run hundreds of simulations using variations in input data. There is a necessary trade-off in this approach, as 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.3: Number of samples

Input	Description	Parameter value	Notes
Weather reference years	This represents historical weather outcomes, and affects both the availability of variable renewable resources but also the shape of demand	23	This is consistent with AEMOs ES00
Outage samples	This reflects a random sample from a distribution of thermal outage rates. For example, if a coal unit has a 15% forced outage rate, then it will be unavailable for 15% 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. Furthermore the seed for generating the random patterns was kept constant to ensure repeatability.	15	This is slightly less than the 25 outage samples that AEMO run in their ES00, however our analysis has found that weather reference years are a more impactful driver of USE outcomes so we are comfortable making this tradeoff to use less outage samples.
Peak demand levels	This represents different forecasts of peak demand, where the PoE10 trace represents a scenario in which peak demand is at the 10th percentile (i.e. on the higher end), and the PoE50 trace represents a median peak demand level.	2; PoE10 and PoE50	This is consistent with AEMOs ES00
Years in the revenue period	This is the financial years that are simulated	1 year; FY31/32	We have chosen to model this year only as it has the highest forecast of unserved energy across all regions. See section X for more discussion on this.
Total number of runs:		690	

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

Sample weights

The results from each run is 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% for PoE10 traces and weighting of 70% to PoE50 traces, consistent with the previous RSS reviews.

C.3.2 Calibration approach

A significant methodological change compared to 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 resultant dataset post-hoc 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 of new entrant technologies would be infeasible due to runtime and cost constraints; 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 according to appendix C.3.1) 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 (~5-10x) in each region.

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

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 during all USE events for the entire duration of the event. For BESS, assume a starting state of charge of 80% and then discharge until the unit has reached 0% SoC or the USE event has ended (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% 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, repeated 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, as for each increment of reliability we attribute fixed and operational costs to the number of additional units needed, and we apply the VCR to the remaining amount of 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 the level of reliability (e.g. to move from 0.003% to 0.002%).

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 of 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 under-state the impact of the additional capacity. On the other hand, PLEXOS is a perfect foresight optimisation which may over-state the impact of additional capacity. In reality, the true impact of additional capacity is likely somewhere between these two methods.

We also performed tests in which we compared 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 that are broadly similar to PLEXOS, but for OCGT, we found that the calibration approach reduced USE by 20% less than the equivalent reduction in capacity from 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% reduction in the number of MW calculated through the calibration approach in stage one of the modelling.

C.3.3 Characteristics of USE

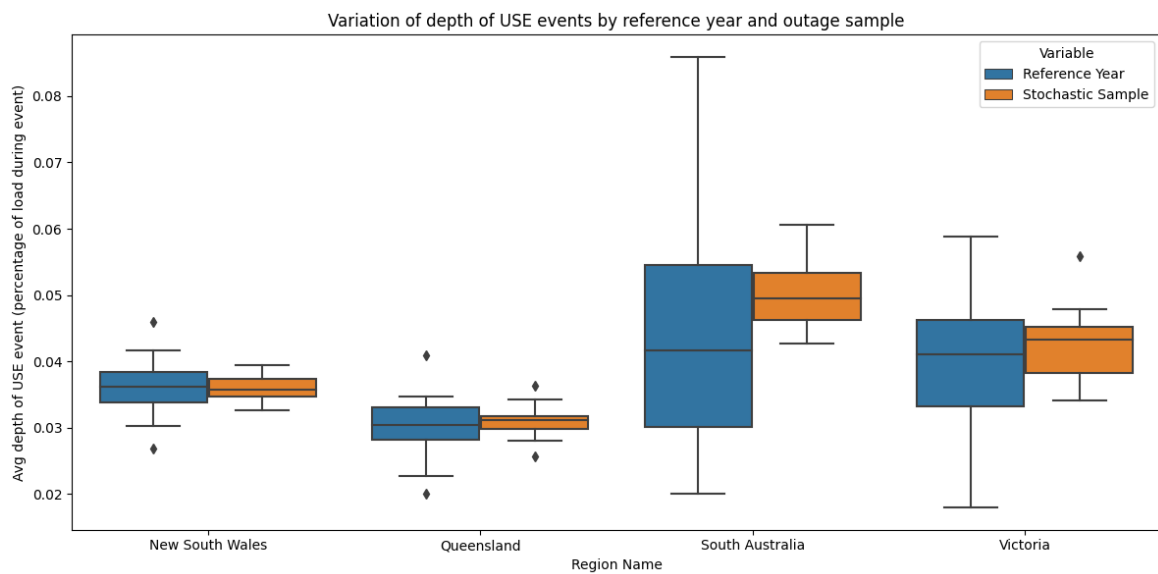
This section describes the characteristics of unserved energy revealed by our modelling. These characteristics are a significant driver of the overall results and are particularly explanatory in terms of regional differences.

Weather reference years provide greater variability of unserved energy outcomes than outage samples

The modelling undertaken by the Panel for the 2024 Review of the Form of the Reliability Standard highlighted that, as the NEM transitions to a system with higher penetration of renewable energy, unserved energy events may be increasingly driven by weather. Specifically, the Panel found that there is far more variability between weather reference years as a driver of reliability outcomes compared with the variability between 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.

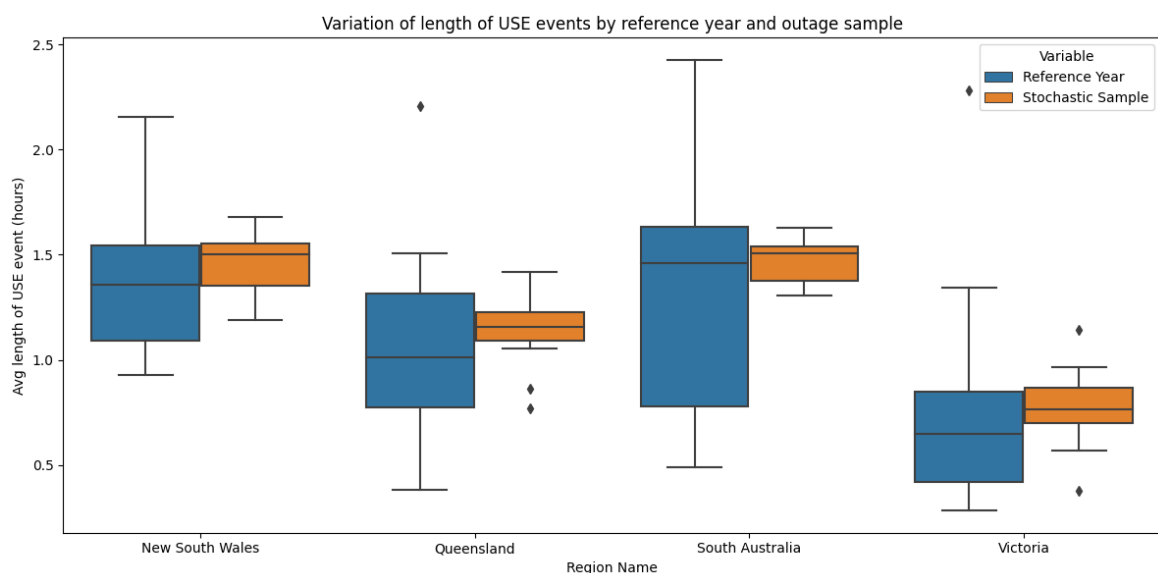
Figure C.4 below shows the variation in average depth of USE events by region between weather reference years and stochastic outage samples. In the figure below and the following figure, a USE event is defined as a continuous period of unserved energy. This result clearly shows that there is a greater variation both in terms of the interquartile range and the full range between average results by weather year as opposed to average results by stochastic outage sample. This is particularly clear in South Australia and Victoria.

Figure C.4: There is greater variability in USE depth between weather reference years than outage samples



Similarly, Figure C.5 below shows the variation in average length of USE events between weather reference years and stochastic outage samples.

Figure C.5: There is greater variability in USE length between weather reference years than outage samples



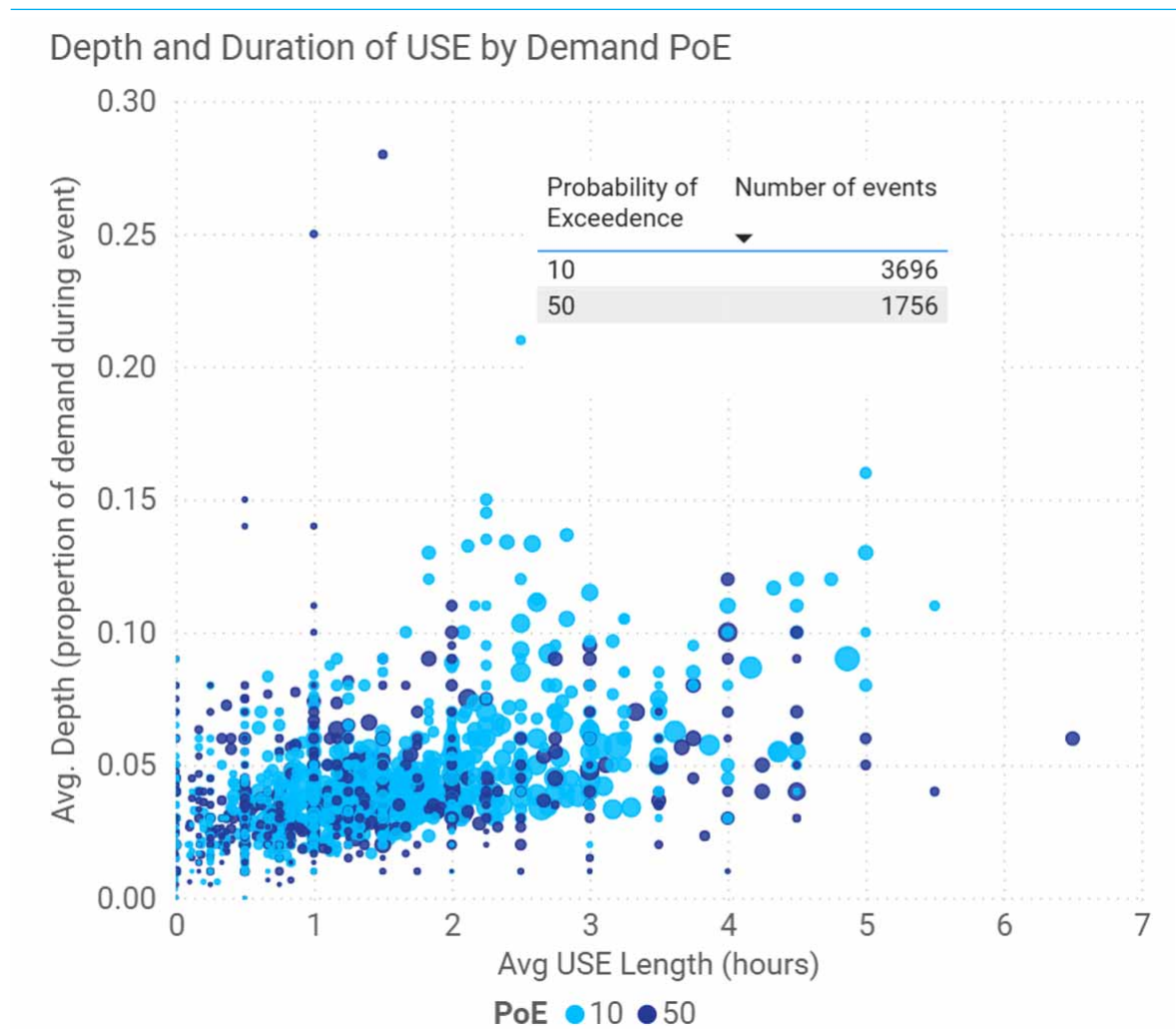
There are fewer USE events in the PoE10 demand level runs, but the depth and duration of the events are similar

As discussed in appendix C.3.1, we ran the PLEXOS simulation using PoE10 and PoE50 peak demand traces, and weighted results accordingly. Figure C.6 below shows the result of these run,

highlighting that PoE10 runs produced almost 2 times as many USE events, but the shape of these events in terms of depth and duration was similar to the PoE50 runs. Note that in this figure and the next figure, Figure C.7:

- Each dot represents a single model run for financial year FY31/32 (out of the 23 reference years, 15 outage samples and 2 PoE levels).
- The Y-axis shows the average depth of USE events in that run, calculated as the proportion of demand that is unserved during the event.
- The X-axis shows the average length of USE events in that run in hours.
- The size of the dot represents the total MWh of unserved energy in that run.

Figure C.6: Peak demand did not have a major impact on the depth and duration of USE events as a whole



Unserved energy 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 (more reliable) than 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 unserved energy in the regions, in particular they are due to these southern regions have relatively fewer, shorter, but deeper events.

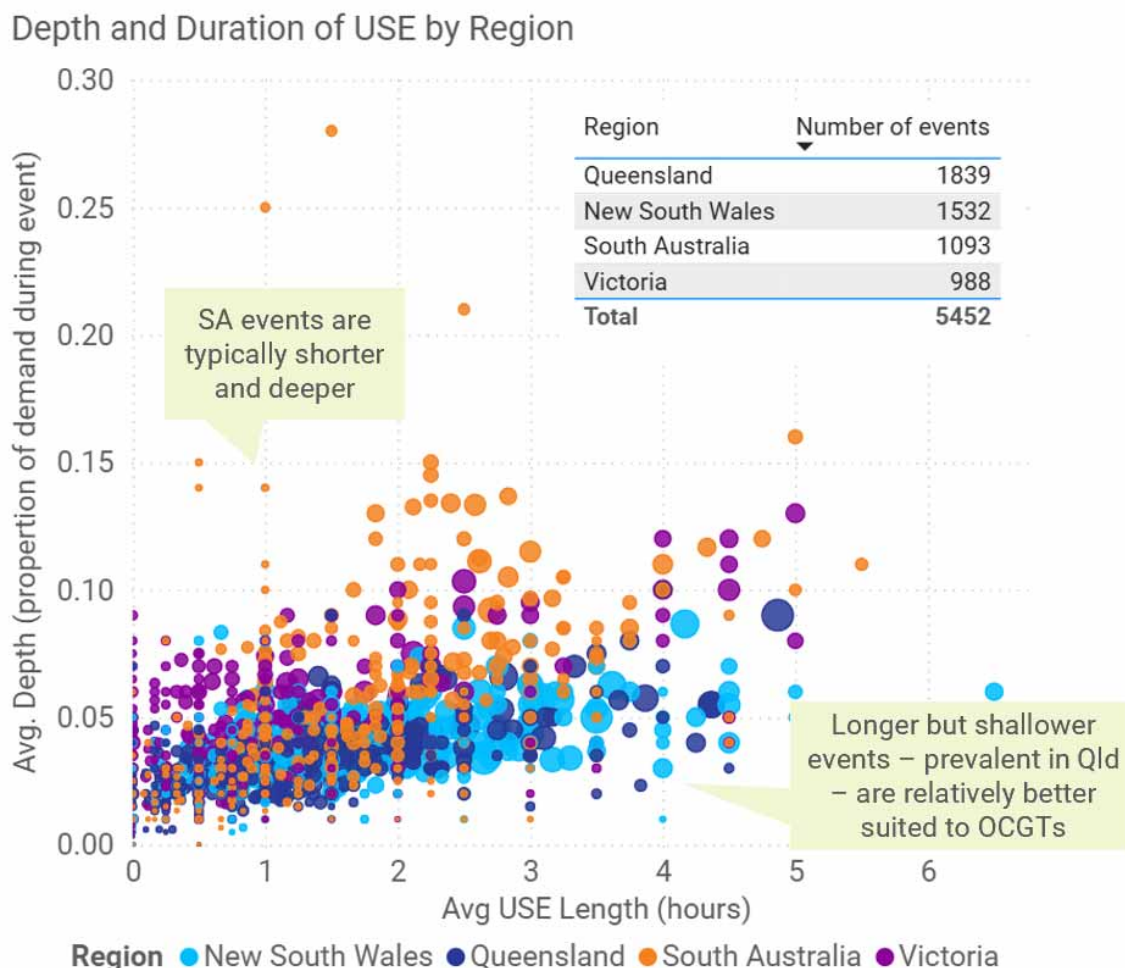
Regions with fewer, but deeper events naturally lead to an efficient reliability level that is relatively lower (more unserved energy), and equivalent market price settings that are relatively higher. In the case of the former, this is because fixed costs make up the majority of the new generation costs, and deeper events require a greater number of units to address; therefore, there are greater fixed costs that need to be recovered 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 (and in Section X of chapter 4) shows the average depth and duration of USE events by region for results calibrated to a reliability standard of 0.003%.

Figure C.7: 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

Though this chart shows thousands of events, and each of these USE events are 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 worst point there was 1.5GW unserved out of a total demand approaching 4.3GW, representing a depth of roughly 40%, representing a depth of roughly 40%. The situation was made worse during this event with output reductions for some OCGTs at Hallett, for the diesels at Lonsdale and Port Stanvac, and some reductions in the interconnector capacity from Victoria and New South Wales. As with most 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 huge drop-off on wind generation as the sun sets, dropping 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 simulation), 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

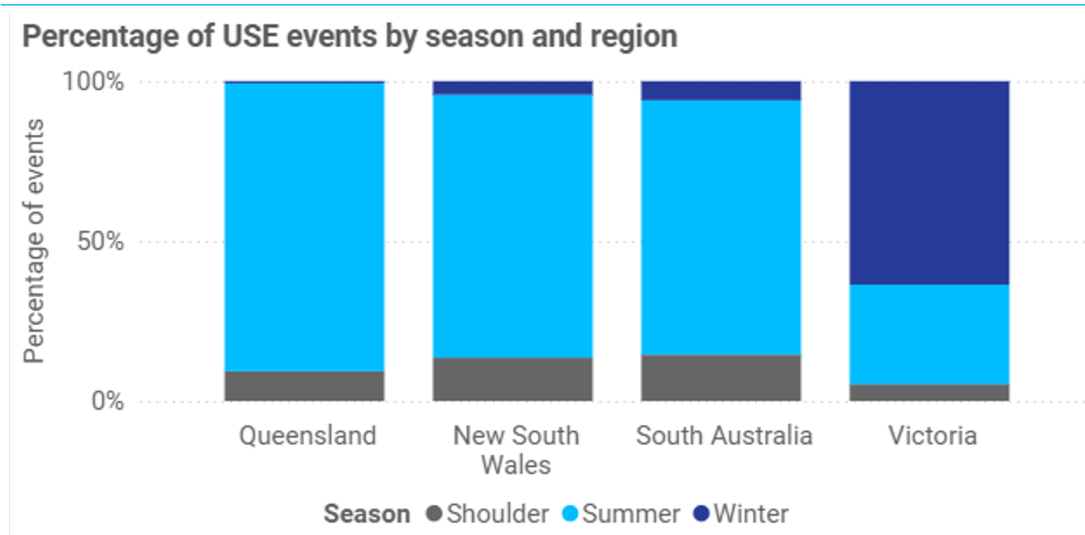
In the three days between the 28th Jan 2032 and the 31st of Jan 2032, Queensland experienced five distinct unserved energy events in reference year 2007, at the PoE50 level of demand, for a particular outage sample. Over these days in this sample, there was between 1.8GW to 2.3GW of black coal unavailable, 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% 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.

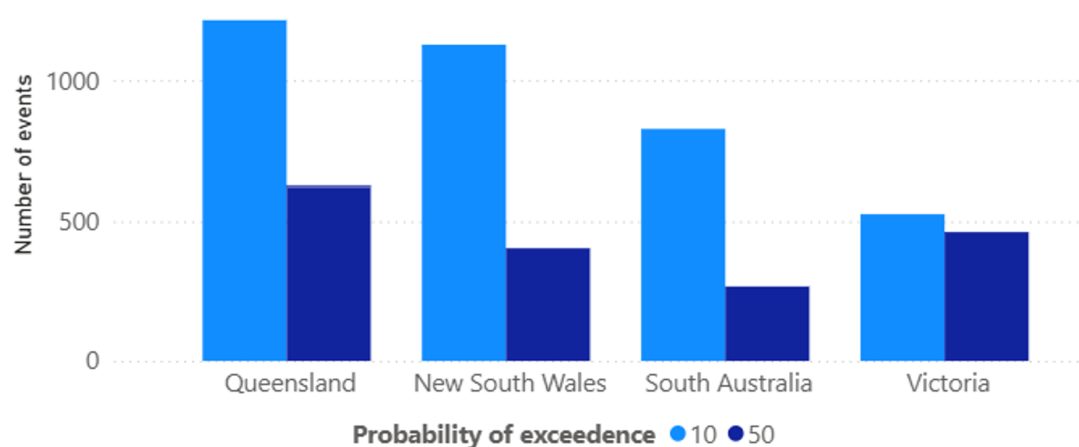
Victorian USE events are driven by a different demand profile with implications for the optimal reliability standard in the region

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.8 below:

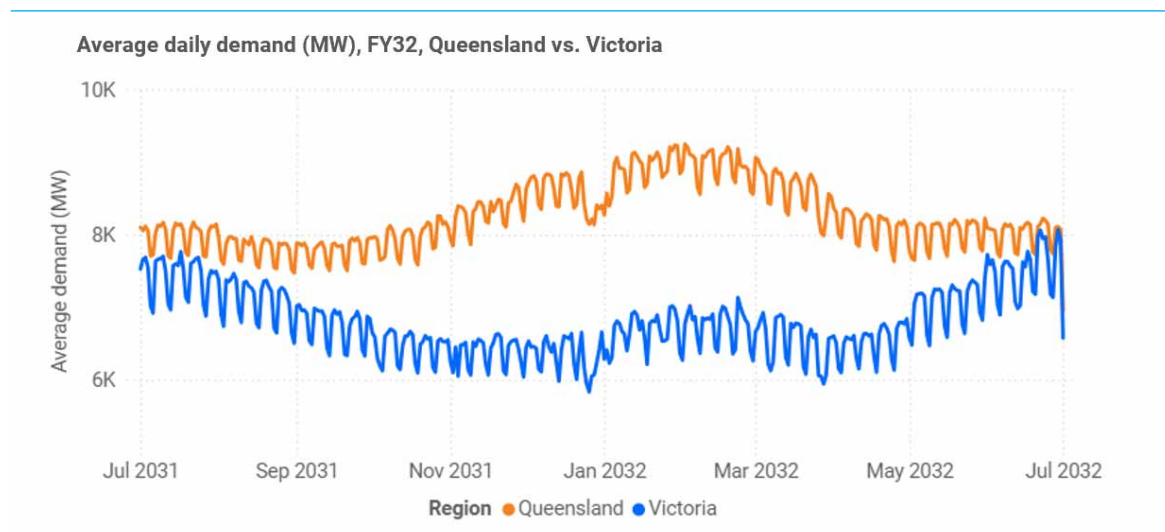
Figure C.8: Victorian USE events are predominantly in Winter



Number of events by Region and Probability of exceedence



This outcome is a result of the differing demand characteristics of Victoria compared to other regions. All regions in the NEM are expected to shift to a winter-peaking demand profile, rather than a summer-peaking demand profile, 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 due to a faster electrification trend than 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.9 below, which shows the average daily demand across all weather years for a PoE50 peak demand levels:

Figure C.9: 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.4 Sensitivities

This section describes the sensitivities that we ran for both Stage 1 and Stage 2, including the modelling outcomes and the implications for the standard and settings.

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 as a method for accounting for the impact of jurisdictional schemes that de-risk investment in certain technology types, where we applied a 2 percentage point reduction in the WACC for batteries. Results of this sensitivity are presented in Chapter 4.

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

As discussed in Chapter 4 and due to the underlying volatility in VCR values from the last survey, we conducted several sensitivity analyses examining different weightings of the VCR. The values for each of these sensitivities are shown in Table C.4 below:

Table C.4: We used a range of values of customer reliability in the sensitivities

Sensitivity	New South Wales VCR	Queensland VCR	South Australia VCR	Victoria VCR
Central case	\$35.38/kWh	\$37.68/kWh	\$34.16/kWh	\$34.54/kWh
Low VCR sensitivity	\$28.06/kWh	\$28.06/kWh	\$28.06/kWh	\$28.06/kWh
High VCR sensitivity	\$49.23/kWh	\$49.23/kWh	\$49.23/kWh	\$49.23/kWh

Sensitivity	New South Wales VCR	Queensland VCR	South Australia VCR	Victoria VCR
Residential VCR sensitivity	\$41.48/kWh	\$41.48/kWh	\$41.48/kWh	\$41.48/kWh
AER VCR weighting sensitivity	\$38.53/kWh	\$36.09/kWh	\$48.52/kWh	\$49.23/kWh

The results of these sensitivities are shown in the figures below:

Figure C.10: Results of the low VCR sensitivity

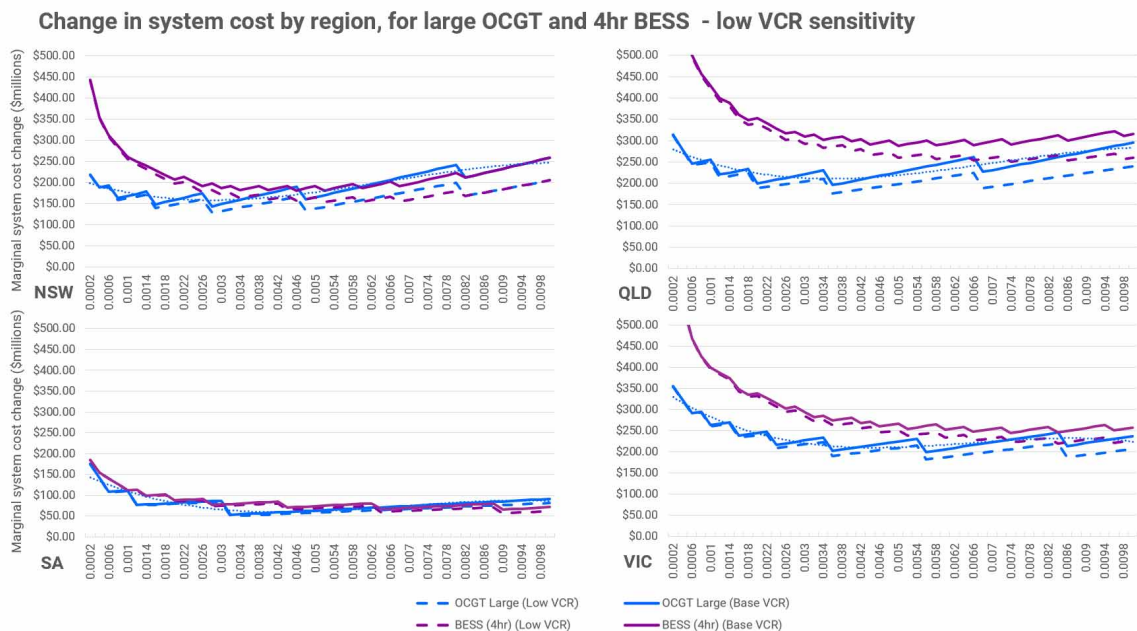


Figure C.11: Results of the high VCR sensitivity

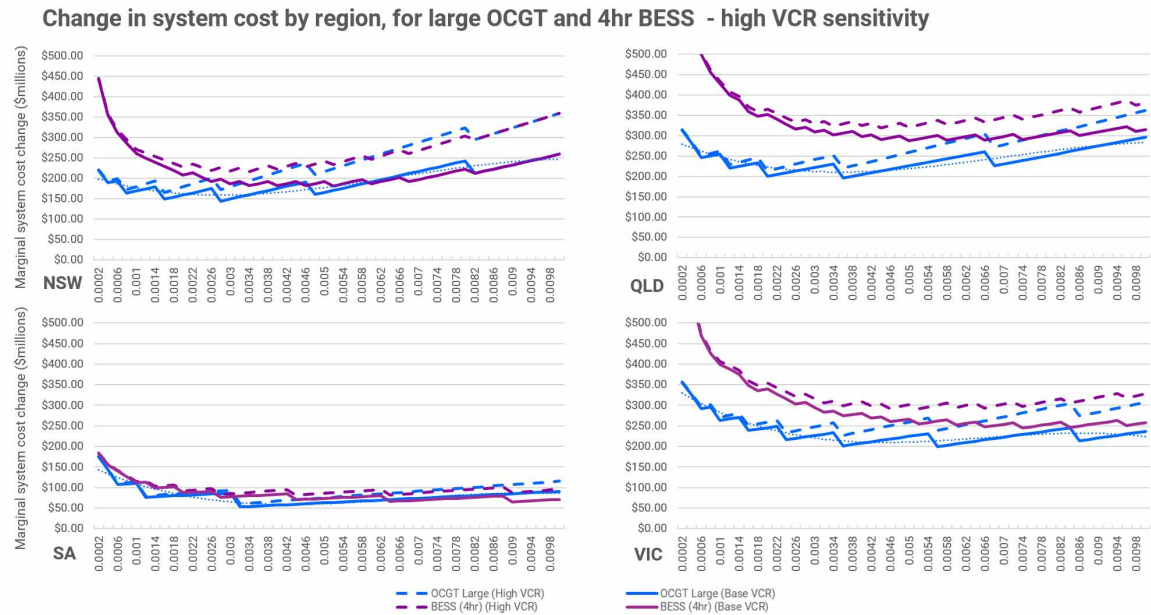


Figure C.12: Results of the residential VCR sensitivity

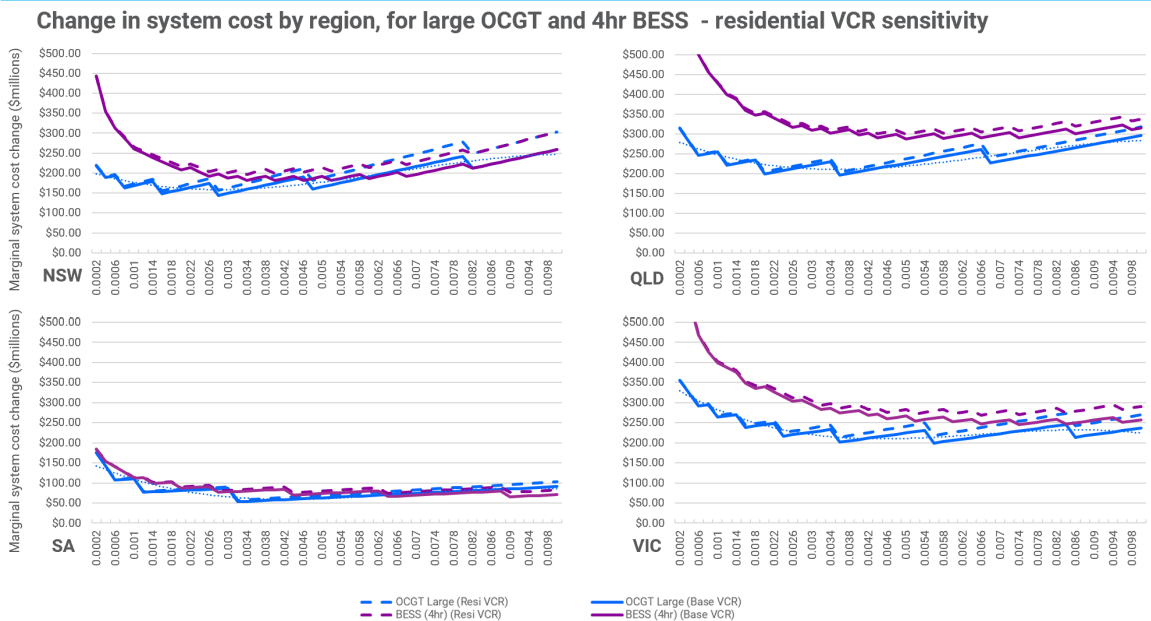
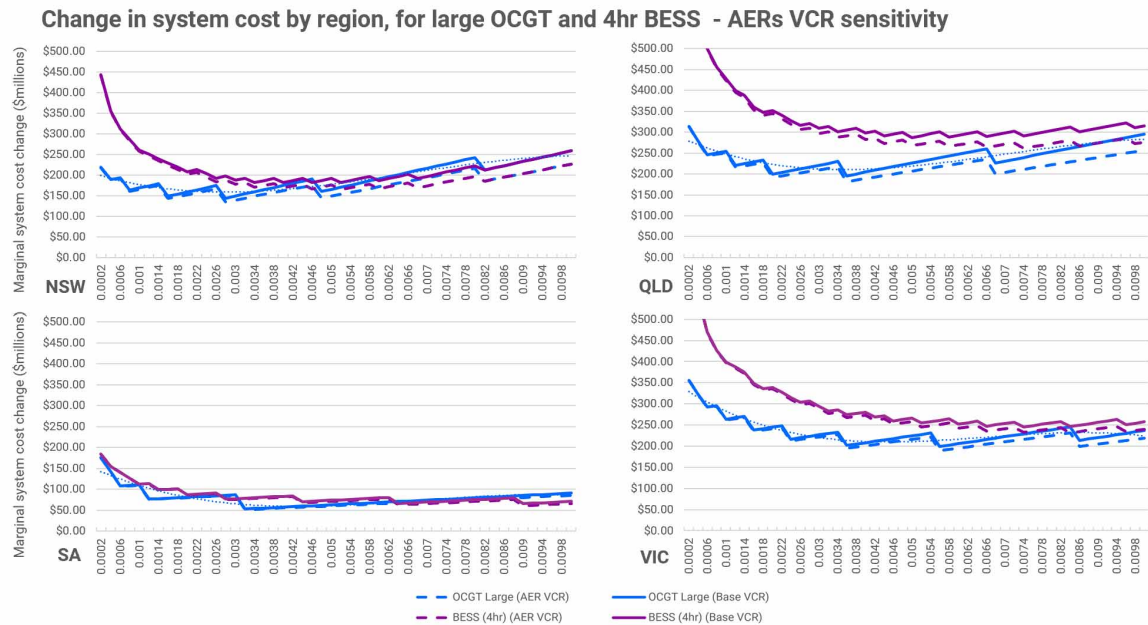


Figure C.13: Results of the AER-weighted VCR sensitivity



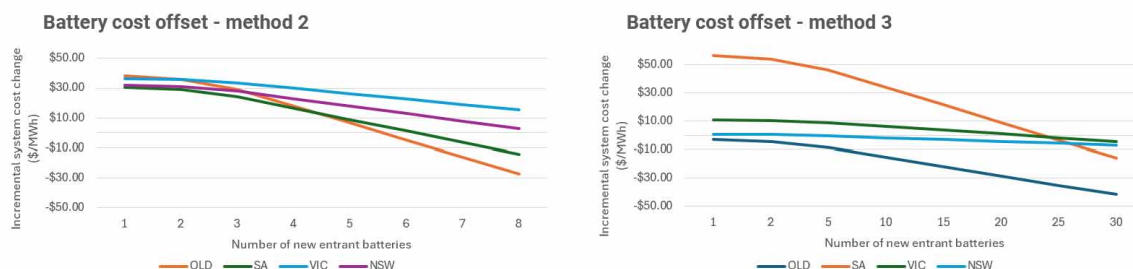
We relied on several approaches to simulate battery behaviour during and outside of USE events

Unlike OCGTs, marginal new entrant batteries may operate frequently across the year outside unserved energy periods. This behaviour may change system costs, for example, if a battery cycles by charging on excess VRE generation and discharging in a way that pushes out thermal generation from the bid stack, this would reduce total system cost. We have modelled this cost reduction in three ways:

1. Assume a net change in system cost of \$0, i.e. the marginal new entrant battery has a net neutral impact on costs
2. Run a number of PLEXOS market models with increasing numbers of batteries and calculate the change in overall system cost as more batteries are added, allowing PLEXOS to dispatch the batteries using perfect foresight
3. Run a number of PLEXOS market models with increasing numbers of batteries and determine the SRMC at each interval, then apply a “typical” battery charging profile on top of these SRMC data points to determine the likely battery cost displacement

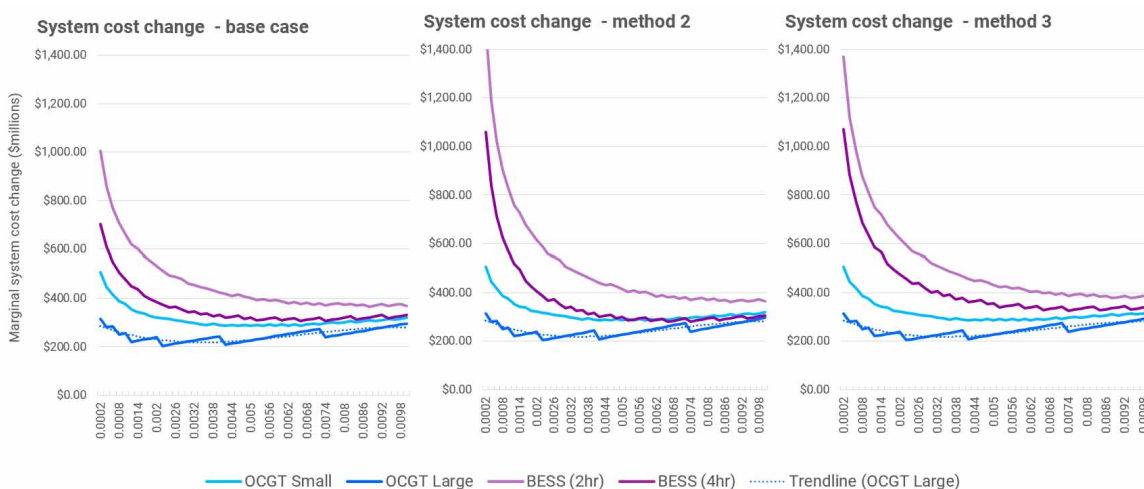
These methods result in different cost reduction curves, demonstrated in Figure C.14 below, where the X-axis shows the number of new entrant batteries and the Y-axis shows the incremental change in system cost as a result of batteries’ daily cycling in terms of \$/MWh.

Figure C.14: Depending on the assumptions and methodology, battery cycling typically reduce system costs outside of USE periods



For methods two and three, we assume that the additional batteries cycle once per day, then we apply the battery cost offset figure (based on the number of new batteries needed for the given reliability level) to determine a total cost offset. This is then netted off the total marginal system cost change in our reliability curves, and is presented in Figure C.15 below:

Figure C.15: Large OCGTs are still the most cost-effective technology to meet reliability



The overall effect of including this system cost reduction from battery cycling behaviour is small and also differs by method. In the second method, we can see that the net effect is that batteries are more cost-effective, though still less cost-effective than OCGT at delivering reliability in Queensland. In the third method, we observe that it actually increases total system costs. This is because this method assumes a typical charging profile (rather than a dispatch profile that is modelled in PLEXOS using perfect foresight), where the analysis shows that batteries often charge from higher cost technologies and so the net effect on system costs is negligible or negative (if their charging behaviour leads to more thermal generation being dispatched).

As battery behaviour in FY31/32 is very uncertain, and therefore the appropriate cost reduction is also uncertain, we use Method 1 for all our results. This is also because methods two and three produce results that either make batteries more cost-effective or less cost-effective, and method one falls between them.

Battery bidding behaviour and characteristics complicate RSSR modelling

As highlighted in Chapter 2, the Panel expects that, were current technology cost trends to continue, batteries could be the marginal new entrant in the next RSS review. Given the increased complexities and assumptions required to effectively model the contribution of batteries to USE events, we have sought stakeholder feedback on how the Panel should approach such modelling tasks going forward.