



National Electricity Market wholesale market settings review

Draft Report

August 2025

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Preface

Energy underpins every aspect of our modern economy and way of life. While many sectors claim to be essential, very few are as foundational as electricity. But the generation of electricity is responsible for around 33% of Australia's greenhouse gas emissions and as we work to meet our legislated emissions targets, the entire sector – from governments and regulators to retailers and consumers – needs to work together to deliver a net zero system that is affordable, reliable and fair.

At the heart of the electricity system is the National Electricity Market (NEM), a complex, interconnected marketplace that facilitates the supply of electricity to millions of consumers. The challenges facing the NEM are real, but not insurmountable.

This review takes a clear and comprehensive look at the NEM and seeks to chart a course that is ambitious but achievable, pragmatic but not short-sighted. In many ways, the Panel is recommending that we re-embrace many of the foundational principles of microeconomic reform that led to the establishment of the NEM in the 1990s.

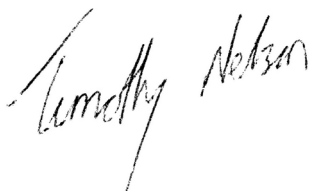
Millions of consumers are now electricity producers through small-scale solar, batteries and energy management systems. The opportunities for improving efficiency, reducing unit costs and improving outcomes for consumers are significant.

The Panel has not taken this task lightly or in isolation. We have built upon the significant body of work done in industry and academia, and the significant policy reforms and processes that have occurred already, including by the Finkel Review, the Energy Security Board and various governments. We are seeking to align with and not duplicate the processes being done in parallel by entities such as the Australian Energy Market Commission, the Australian Energy Regulator, the Australian Energy Market Operator and the Australian Consumer and Competition Commission.

Producing this draft report was the result of a large body of work. As Panel Chair, I take this opportunity to thank my fellow Panel members Ms Paula Conboy, Ms Ava Hancock and Mr Phil Hirschhorn, and the talented members of the secretariat. I also extend my sincere thanks to all those who have engaged with us, in good faith, in open and collaborative discussions across every region of the NEM. This includes representatives from the relevant state and territory governments, market bodies, generators, retailers, network providers, investors and electricity consumers across the NEM and beyond.

This draft report provides a clear and actionable path forward for the development and implementation of reforms that will support Australia's clean energy transition and ensure the long-term reliability and affordability of electricity services. We welcome your engagement on this draft report as we work towards delivery of a final report by the end of 2025.

Thank you



Tim Nelson
Panel Chair



Background to the report

Scope

The scope of this review was determined by the Terms of Reference issued by the Australian Government on behalf of the Energy and Climate Change Ministerial Council (ECMC) (**Appendix A**). Per the Terms of Reference, the Panel is to recommend future market settings to promote investment in firmed, renewable generation and storage capacity in the NEM following the conclusion of Capacity Investment Scheme tenders in 2027. The Panel is to make actionable recommendations to support the development and staged implementation of reforms to the NEM wholesale market that support the achievement of the National Electricity Objectives.

In undertaking the review, the Panel is considering interactions with the NEM reliability framework, governments' renewable energy targets and policies, and the importance of decarbonising Australia's electricity system, to achieve the Australian Government's legislated commitment to a 43% reduction in emissions on 2005 levels by 2030 and net zero emissions by 2050. Implementation of reforms is also considered, including the requirement for agreement at ECMC before amendments to the National Electricity Law and National Electricity Rules can be progressed.

Explicitly excluded from the scope of the review are options that involve implementation of carbon trading schemes and/or carbon markets and options that entail government support for new fossil fuel generation. For the avoidance of doubt, the Panel has determined that the following matters are out of scope of this review: fuel markets, carbon markets, and planning assessment reform. Retail pricing, network tariffs and exclusively behind-the-meter resources only to the extent that they are relevant for how electricity users interact with the NEM.

Process

The first phase of this review that informed this draft report involved broad engagement with stakeholders across the industry. To date, the Panel has received more than 100 formal submissions (see **Appendix B**), held more than 200 formal stakeholder meetings, engaged in more than 40 hours of co-design workshops with jurisdictions, market bodies and other stakeholders, issued more than 30 targeted surveys and structured interviews and held lunch-and-learn sessions connecting Australia's internationally renowned academic expertise with senior officials. The Panel has also spoken with key international stakeholders, including the International Energy Agency, market operators and regulators in the United States and the United Kingdom, and a wide range of market participants in New Zealand. The Panel has also had access to detailed commercial-in-confidence data and has commissioned or undertaken dedicated modelling to inform advice.

Following publication of this draft report the Panel will seek further engagement from stakeholders and will develop a final report, including an implementation roadmap, by the end of 2025.

Note to readers: This report is a draft and the views presented are preliminary. The Panel is continuing to develop and refine its analysis and recommendations, particularly in relation to implementation pathways. The Panel welcomes feedback, further evidence and engagement from stakeholders to inform the next phase of our work, particularly in response to specific questions flagged throughout the draft report.

Executive summary

The Panel has been tasked with reviewing the National Electricity Market (NEM) wholesale market settings to support investment in firm renewable generation and storage capacity following the conclusion of Capacity Investment Scheme (CIS) in 2027. This review builds on the legacy of earlier reviews that have grappled with similar challenges, including the Energy Security Board's Post-2025 Market Design (2021), the Independent Review into the Future Security of the National Electricity Market (2017) and the Australian Competition and Consumer Commission's Retail Electricity Pricing Enquiry (2018). Many of the core challenges identified in these reviews persist and have, in many cases, become more pressing as the penetration of variable renewable energy (VRE) in the system reaches record highs and the scheduled closure of ageing thermal generation draws nearer.

The Panel's focus is specifically on the spot wholesale market, related derivatives markets and long-term investment markets, with regard to the needs of both sellers and buyers. This complements earlier review efforts, which tended to concentrate more heavily on the seller side. Put simply, the Panel has considered how to better link these markets and ensure they work together for the end consumer – with the spot market facilitating efficient dispatch, the derivatives market managing risks arising from the spot market and a new Electricity Services Entry Mechanism (ESEM) extending the forward signals from the derivatives market to support longer-term investment.

Fuel markets, carbon markets and planning assessment reform are specifically excluded from the scope of this review, while other matters such as retail pricing, network tariffs and exclusively behind-the-meter resources are considered only as they relate to participation in the NEM.

Figure 1 – NEM Review Scope



Throughout our engagement with stakeholders across the energy sector, we have heard a consistent message: while the NEM continues to function reasonably efficiently for dispatch, the cumulative pressures across short-, medium- and long-term horizons demand coordinated, forward-looking reform.

The NEM is facing mounting pressures. Due to changes to the way we generate and consume electricity, the NEM is becoming a system that is more weather dependent, more energy constrained, less scheduled and less dispatchable. The Panel is of the view that these issues can be resolved, and the risks of operating in an increasingly weather-dependent system can be managed.

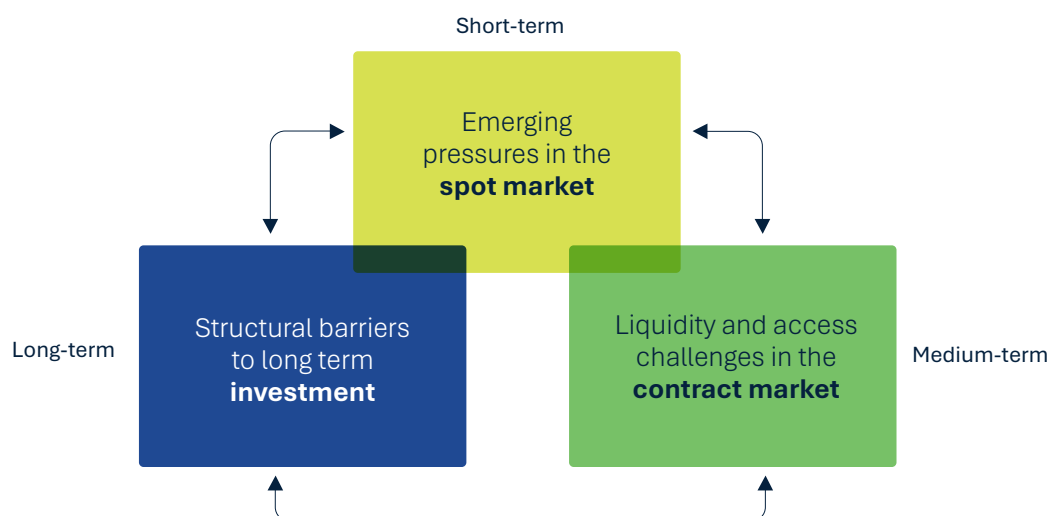
Weather dependent and energy constrained: VRE generators are central to decarbonising Australia's electricity supply. While VRE generators produce no greenhouse gas emissions, they are inherently weather dependent, introducing greater day-to-day and seasonal variability in supply. This growing reliance on weather-dependent resources increases the risk of periods where the market is energy constrained.

Less scheduled and less dispatchable: The market is also being shaped by the expanded participation of distributed energy resources (DER). Millions of new, small-scale, price-responsive generators (i.e. batteries) are expected to enter the market. Without reform to make these resources more 'scheduled' and observable to the market operator and market participants, the market may not be able to function without significant over-investment.

Building on the NEM's original blueprint to link the short-, medium- and long-term markets of the NEM

The Panel has presented draft recommendations that will, in our view, provide a means for seamlessly integrating medium-term risk management with efficient spot market operation, while for the first time, explicitly linking these with a long-term investment signal embedded within the National Electricity Law. It effectively builds on the NEM's original framework to link the short-, medium- and long-term markets for the first time.

Figure 2 – Emerging trends in the short-, medium- and long-term markets



Emerging operational pressures in the evolving spot market

At an operational level the spot market remains functional and broadly effective. Its core mechanisms continue to provide efficient dispatch and price discovery, even as the underlying sources of generation in the system change.

But the nature of price formation in spot market is changing, as the system shifts from one where demand and supply-side fuel costs were the principal drivers of price to one where supply-side variability, driven by the weather-dependent nature of VRE, is increasingly important. This marks a structural change in the dynamics of the market. Prices are increasingly characterised by longer periods of very low prices when solar and wind output is strong, punctuated by sharp, often very high, price spikes during periods of low renewable generation or unexpected outages. This evolving pattern reflects a steepening and hollowing out of the traditional merit order. This pattern is expected to change further as storage becomes more ubiquitous.

Prices are likely to become predictably more variable and unpredictably more volatile. Variability, such as the predictable daily rise and fall of solar output, or seasonal wind patterns, can be forecast and managed. But volatility, such as the sudden, unplanned withdrawal of capacity during generator and network outages, or extended and unforeseen periods of low wind and solar output ('dunkelflaute'), poses more significant challenges. These shocks can be difficult to anticipate and manage, particularly as coal-fired power stations approach the end of their technical and economic lives in a 'lumpy', non-linear fashion.

While sharpening price signals introduce some challenges, they are not inherently problematic if tools exist to respond to those signals or to manage risks. Sharp price signals are a necessary feature of a market responding to changing resource characteristics and supply-demand balance. They should be seen not as a flaw but as a sign of a market at work. The Panel notes the market will continue to respond to these signals, provided the right financial tools are available to allocate and manage risk effectively.

An energy-only, uniform clearing price market can continue to function effectively even as wind and solar, both with near-zero short-run marginal costs, become dominant sources of generation. In such a system, prices will increasingly be set not by traditional fuel costs but by the opportunity cost of storage technologies, such as batteries and pumped hydro, which shift energy from periods of low demand (or high supply) to periods of high demand. Additionally, flexible demand, such as industrial processes, electric vehicles and smart appliances, will play a critical role, with prices reflecting the value that consumers place on using electricity at different times. These dynamics ensure that even in a system dominated by variable renewables, the energy-only market can still produce efficient price signals to guide investment, dispatch and consumption.

One of the most pressing concerns in the operation of the spot market is the emergence of a growing class of non-scheduled resources that are responding to wholesale prices ('hidden participants') whose behaviour and impact on the system are not directly visible to the Australian Energy Market Operator (AEMO) and market participants in real time. This includes unscheduled consumer energy resources, such as rooftop solar PV, battery storage, electric vehicles and flexible demand. Traditional assumptions of inelastic demand are no longer valid. Consumers are now not only responsive but also producers of electricity, introducing a layer of complexity to system operation that challenges established tools and frameworks. The rise of these hidden participants risks undermining the operational integrity of the system if not properly integrated. The presence of hidden, flexible resources

creates a risk of uncoordinated withdrawal or injection of power during critical periods, making it more difficult for AEMO to maintain frequency, system strength and other essential system services.

The operational issues relating to hidden participants are likely to become critical if unaddressed. While the Panel recommends the existing wholesale spot market be retained as the core market for efficient dispatch and rewarding the provision of physical energy services (**Recommendation 1**), governments should consider measures to enhance the visibility and participation of ‘hidden’ dynamically price-responsive resources in the market (**Recommendation 2** and **Recommendation 3**), and pursue targeted reforms to ensure the spot market can continue to operate securely and reliably (**Recommendation 4** and **Recommendation 5**). Enhancing integration of new forms of participation, while preserving the efficient price formation at the heart of the market, is central to meeting the operational challenges of the next decade.

Liquidity and access challenges in medium-term financial markets

While the spot market governs the operation of the power system, it is the derivatives market that provides the scaffolding necessary to manage financial risk. Effective derivatives markets allow participants to transfer risk to those best equipped to manage it, enabling retailers to offer predictable prices to consumers and generators to manage the risk of uncertain prices. These markets perform a crucial function in maintaining confidence, enabling competition and supporting the long-term health of the NEM.

But this scaffolding is under growing strain. As noted earlier in this chapter, price signals are expected to continue to sharpen in the spot market as it becomes more weather dependent and energy constrained. These trends introduce new financial risks that need to be managed and a derivatives market is key.

Without reform some traditional hedging instruments are likely to become less available as thermal generators exit the market. These generators have historically underpinned supply of baseload swaps and played a key role in energy-related financial markets. This structural shift is already evident in regions at the leading edge of the transition. In South Australia, declining contract liquidity and increased market concentration have raised concerns around vertical foreclosure and the erosion of competition. The ability of new or smaller retailers to access affordable hedge products is diminishing, exposing them to unacceptable financial risk and reinforcing a trend towards vertical integration. If left unaddressed, this could result in a less dynamic and more concentrated retail sector with opaque prices, reducing choice for consumers and undermining the competitive pressures that help keep prices efficient.

While direct government interventions, such as the CIS, have provided revenue certainty for new investments, they typically do not contribute to derivatives market liquidity. Instead, they operate in parallel to the market, potentially crowding out private hedging activity and limiting the development of deeper, more transparent financial markets.

The Panel has observed encouraging signs of innovation in derivatives markets. In particular there is growing interest in new contract structures tailored to the characteristics of renewable generation. However, most of this activity is in over-the-counter markets, where deals are bilateral, bespoke and often inaccessible to smaller participants. Innovation in exchange-traded products has been slower and the tools available to manage new forms of risk have not kept pace with the underlying transformation of the generation fleet.

A well-functioning derivatives market is a precondition for a resilient and investable market-based electricity system. Rather than waiting for these issues to escalate, requiring more disruptive interventions as further coal closures occur, the Panel recommends the creation of an always-on market marking obligation (**Recommendation 6A**). This market marking obligation would be underpinned by a structured innovation process involving a wide range of market participants to ensure the contracts available in the market reflect the needs of buyers and sellers (**Recommendation 6B**). This would be complemented by the extension of the Medium-Term Projected Assessment of System Adequacy's (MT PASA) generation availability projections to ensure sufficient market information is available to support longer term liquidity and price discovery (**Recommendation 7**). Together, these measures should shield the NEM against future liquidity and access challenges.

Structural barriers to long-term investment

The long-term success of the NEM depends not only on operational resilience and financial risk management but on sustained, timely investment in the infrastructure needed to power Australia's future. This includes not only VRE but the firming, storage and essential system services that enable a secure and reliable grid. Without credible and durable investment signals, the energy transition cannot proceed in an orderly, efficient and affordable manner.

Historically, significant investment in electricity infrastructure has rarely occurred without some form of government support. The most prominent example of this government support has been the Renewable Energy Target (RET) which has historically delivered the vast majority of investment in small-scale and large-scale renewable resources. However, policies such as the RET have substituted coal-based energy with renewable-based energy, without any additional requirements to provide the other services consumers need, namely:

- **Shaping:** Moving electricity to the time of day it is needed
- **Firming:** Long-duration dispatchable capacity to deliver extra energy as needed
- **Essential system services:** Securing and stabilising the grid with a range of services, including frequency control, voltage regulation, system strength and inertia.

The CIS and state-based interventions such as the New South Wales Electricity Infrastructure Roadmap are the current policy instruments for de-risking private investment. But these policies sit adjacent to, rather than within, the market's structure which is articulated through the NEL and NER. In the absence of a nationally consistent replacement for the CIS, investment will be driven by state-based schemes, resulting in a more complicated and fractured investment landscape, which may fall short of what the system needs.

The first and most persistent of the barriers to new investment is the 'tenor gap': a mismatch between the long-term contracts needed by sellers to finance capital-intensive assets (often 10 to 30 years) and the short-term contracting of buyers (typically three to seven years). This tenor gap is driven by a broad suite of uncertainties – technological, regulatory and demand-related. Buyers and sellers must grapple with questions around the future cost of existing and emerging technologies, the trajectory of coal closures and emissions policies and future demand. These price and volume risks mean that on one hand investors in capital-intensive new projects need long-term revenue certainty to secure financing, but on the other the buyers of that generation are unwilling to make those long-term

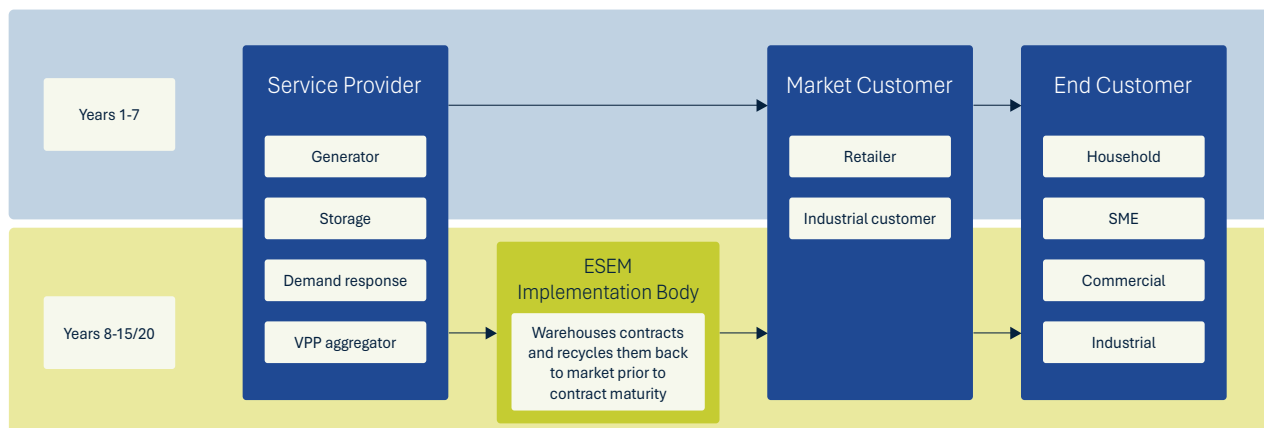
commitments. While some uncertainty is unavoidable in any major transition, policy frameworks must strive to provide as much stability and predictability as possible.

The second barrier to new investment is uncertainties driven by policies to achieve entry before exit. Consumers expect a seamless, uninterrupted transition with new generation capacity and the requisite system services in place before legacy plants retire. Unless policies achieve timely delivery of bulk energy, shaping, firming and the requisite system services are implemented through a clear, transparent and predictable framework, they risk creating a vicious cycle: uncertainty discourages investment, delays new entry and triggers further ad hoc interventions, exacerbating the very problem they aim to solve. The question is not whether governments should continue to play a role but how they can do so in a way that supports investment, preserves competition and strengthens the long-term interests of consumers.

The Panel recommends the creation of a new Electricity Services Entry Mechanism (ESEM) (**Recommendation 8**) that addresses these structural barriers that investors currently face and that the market, in its current form, is not well placed to resolve. The ESEM would represent an evolution on existing schemes. The ESEM retains the core features of other recent schemes such as the CIS (i.e. reverse auctions for competitive investments, with targets determined by reliability requirements and jurisdictional emissions goals) but with tweaks to ensure it is:

- **Enduring:** A permanent feature of the NEM, embedded in the NEL
- **Efficient:** Focused support for the later years of a project's financed life, targeting only those risks the market cannot manage
- **Market-linked:** Utilising financial derivatives (defined through the process articulated in **Recommendation 6B**) for contracting new investment and then progressively returning contracts to market to minimise costs to consumers, keep risks in-market and improve derivative market liquidity and access.

The Panel has also recommended a range of adjacent reforms to ensure regulatory settings, the innovation ecosystem and existing policies and programs align with the ESEM (**Recommendation 9**).

Figure 3 – Contract flows in the Electricity Services Entry Mechanism¹

Untapped potential and unstable prices for consumers

If the challenges facing the NEM are left unaddressed, there is a growing risk that consumers will view electricity markets as a system that no longer serves their interests. As the generation mix becomes more weather dependent and energy constrained, households and businesses may face greater price variability and reduced predictability in their electricity bills if wholesale prices are simply passed through to consumers. The Panel has heard clearly from stakeholders that all consumers want affordable energy, and many also place a premium on price certainty through simple retail offers and stable bills, but today's retail market's interaction with NEM outcomes is not well placed to provide this. Without reform, consumers will remain exposed to the full force of future fluctuations.

At the same time, more than three million households and small businesses have taken steps to manage their energy costs by investing in rooftop solar. The uptake of home batteries is also set to accelerate in response to new incentives and falling costs. This period of rapid growth presents a window of opportunity to ensure that these investments deliver benefits to not only individual consumers but to the electricity system.

¹ Time frames identified in this diagram are provided as an example for illustrative purposes only.

The Panel's vision for the NEM

Without timely and targeted reform the challenges outlined above are likely to intensify and become entrenched. The Panel's vision is to manage risks so that the NEM has:

- **sufficient investment in critical assets and services**, managing reliability risks
- **the most efficient and stable electricity prices for consumers**, as risk premiums reduce and competition thrives
- **reduced reliance on ad hoc government interventions**, by increasing policy predictability and investor confidence
- **a more unified and orderly transition**, aligned with the pace and scale needed to replace ageing coal-fired power stations and achieve emissions reduction objectives in an orderly and efficient way.

In considering how to achieve this vision, the Panel has been guided by a clear set of principles. These principles reflect the importance of aligning market reforms with the federated structure of the NEM, preserving the strengths of competitive markets and ensuring that public interventions deliver real and enduring benefits for consumers. Importantly, the Panel believes reforms across the short-, medium- and long-term time frames must be mutually reinforcing and considered holistically.

Figure 4 – Principles for interventions in the NEM

Align within the federated structure of the National Electricity Market

The NEM operates across multiple jurisdictions – Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania – each of which has constitutional responsibility for energy policy. Throughout the history of the NEM these jurisdictions have agreed to nationally harmonise most of the laws that govern the energy market, recognising that a coordinated national framework is essential to avoid fragmentation, duplication or inefficient outcomes. In this respect, wholesale energy market reform should continue to be consistent and harmonised across the NEM, while respecting the sovereignty of jurisdictions to pursue individual policy objectives within that shared framework.

Complement the existing wholesale market

Market interventions should be designed to strengthen, not supplant, the core mechanisms of the NEM. This includes preserving efficient price signals that guide operational decisions and ensuring that new investment mechanisms are integrated with spot and derivatives markets. A well-functioning wholesale market remains central to achieving reliability and affordability, and any additional measures should aim to enhance liquidity and transparency in forward contracting.

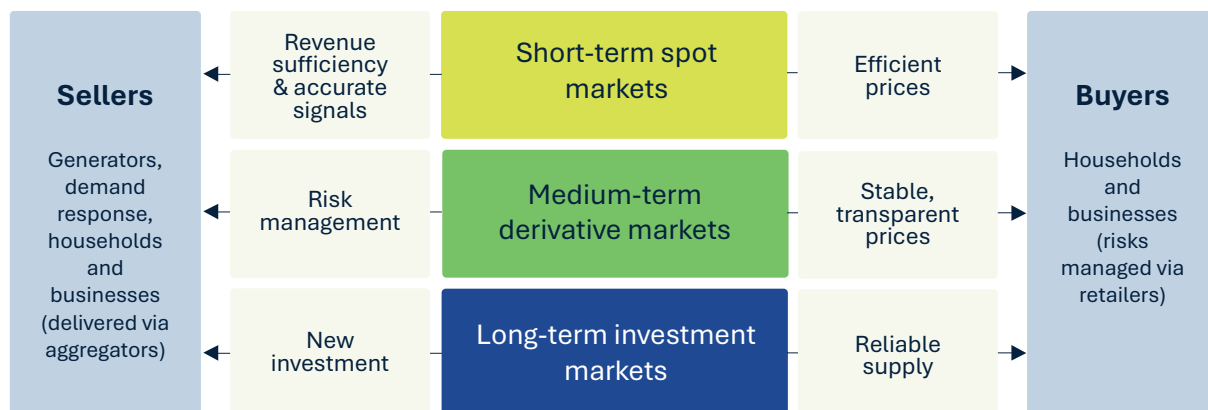
Target economic efficiency

Public interventions should be proportionate and deliver allocative efficient outcomes. Intervention should only address investment barriers that the market cannot resolve on its own, such as long-term risk allocation, coordination failures, or insufficient price signals, without crowding out private initiative.

Translate into benefits for electricity users

Electricity is an essential service for households and a critical input for industry. All reform efforts should ultimately be judged by their impact on electricity users. This includes supporting a competitive retail market that enables innovation and choice, while ensuring that consumers and businesses alike can access secure, reliable and affordable electricity. Where government action is required it should be clearly linked to delivering long-term value for the public, with transparent governance and accountability.

The Panel's recommendations seek to work together across the short-, medium- and long-term horizons work to uphold the foundational features of a well-functioning electricity market: efficient pricing, effective risk management and reliable supply (**Figure 5**).

Figure 5 – Features of a successful electricity market for buyers and sellers

The Panel's vision is ambitious but pragmatic. With targeted but consequential reforms, the NEM can operate closer to the original design intent – preserving the benefits of competition while delivering the investment and operational outcomes needed to support a secure, affordable, low-emissions energy future.

Recommendation summary

Drawing on extensive stakeholder consultation and detailed analysis, the Panel has developed a series of recommendations and observations. The Panel has focused on reforms that reinforce the NEM's effectiveness, put the consumer at the centre and uphold the jurisdictional roles of the states (**Figure 4**).

For **sellers** including generators, demand response providers and households and businesses participating via aggregators – the reforms aim to provide accurate price signals, improve access to risk management tools and increase investment certainty.

For **buyers** including retailers and commercial and industrial users – the reforms aim to deliver efficient spot prices, stable and transparent contract prices in the derivatives market, and long-term supply reliability.

Most importantly, for all **consumers** both with and without consumer energy resources – the reforms aim to ensure access to reliable electricity at fair, simple and stable prices, and fair rewards for providing services to the system.

Taken together, the Panel's proposed reforms provide a clear and practical pathway toward a more sustainable and efficient energy market – one that preserves the benefits of competition while addressing gaps that have emerged over time.

By improving short-term operational visibility, strengthening the derivatives market, providing long-term investment signals that utilise the derivatives market and engaging the targeted procurement of essential services that the market is not well placed to provide, the Panel's recommendations will enable the NEM to meet the needs of Australians for decades to come.

Figure 6 – Major recommendation themes



1 Maintain the real-time regional energy-only spot market as the core market for efficient dispatch and rewarding the provision of physical energy services

- A. Retain the real-time regional energy-only spot market with necessary rule changes to ensure its continued efficient and competitive operation, recognising that increasing spot market variability and volatility can be managed.
- B. Do not create additional mandatory centralised short-term (operational time frame) markets, such as capacity markets or physical ahead markets.
- C. Do not implement locational marginal pricing or variants considered previously.
- D. Do not create distribution-level wholesale energy markets. Instead, facilitate distribution-level energy resources to participate in regional markets and use dynamic operating envelopes and dynamic network tariffs to manage local constraints.

2 Energy ministers should require a broader range of price-responsive resources to be visible or dispatchable to participate in price formation

- A. Leverage the voluntarily scheduled resource (VSR) participant categories established under the Integrating Price Responsive Resources (IPRR) dispatch mode framework to give effect to **Recommendation 2B**. This includes the use of ‘active mode’, which facilitates dispatch of these resources within the merit order, and ‘inactive mode’, which facilitates visibility and predictability of these resources to the market and market operator.
- B. Energy ministers should propose a rule change to the Australian Energy Market Commission (AEMC) requiring that, by 2030, various forms of price-responsive resources should be visible or dispatchable in a relevant participant category, with this obligation falling on the relevant participant.

A working position, to be refined in the review’s next phase, is that each resource should be able to choose the most suitable pathway given its characteristics; with suitable pathways, at a minimum, including the following:

- Portfolios of small batteries or generation units (below 5 MW) participating as bidirectional units or VSRs in central dispatch, once their aggregated size grows above a pre-defined threshold.
 - Consumer energy resource (CER) aggregations, including virtual power plants, above a certain threshold participating in central dispatch through the VSR.
 - Retailers providing price pass-through contracts or with price-contingent dispatch contracts to the customer using the dispatch mode framework in active mode, or inactive mode.
 - Large loads above a certain threshold, including all market customers, participating through the dispatch mode framework (in active or inactive mode), WDRM or scheduled load frameworks.
- C. Energy ministers should establish a structured support framework to encourage price-responsive resources to participate in the IPRR framework, WDRM or as scheduled loads.

3 Governments should focus reforms and support for CER on facilitating market participation to enable consumers to benefit from being price-responsive

- A. Energy ministers should focus the National CER Roadmap on – and ensure sufficient resources are allocated to – delivering the critical roadmap elements that enable market participation (e.g. technical standards) and provide consumer protections.
 - B. Government incentives for investment in CER, such as for batteries, should support resources that are enabled to participate in the market through aggregators and are ready for dynamic network connections.
-

4 Market bodies should use the rule change process to ensure the efficient and competitive functioning of the real-time energy-only spot market

- A. Market bodies and the Australian Competition and Consumer Commission (ACCC) should work together to develop regulatory responses, including rule changes if needed, that address risks created by excessive rebidding and algorithmic bidding.
 - B. Market bodies should analyse whether publishing battery state of charge information from July 2025 adequately mitigates reliability risks or whether further reforms are needed.
 - C. Market bodies should work to minimise the impact of transmission network outages on the energy-only spot market. The Australian Energy Regulator (AER) should work with the AEMC and Australian Energy Market Operator (AEMO) to replace the suspended market impact component of the regulatory framework. The AER should also continue to review whether network constraints affect competition and drive high spot prices, and progress rule changes to the AEMC if required.
-

5 The Reliability Panel should consider adjusting the form of the market price settings

The market price settings, including the market price cap (MPC), market price floor (MPF), cumulative price threshold (CPT) and administered price cap (APC), should remain linked to the value of customer reliability (VCR) and to revenue adequacy for bulk energy, shaping and firming services.

However, given the significant changes expected in the market and the intention of recommendations in other chapters to extend price discovery, the Reliability Panel should consider whether to adjust the form of the market price settings and provide a longer-term outlook (up to 15 years) on their intended form to support long-term contracting.

6 Energy ministers should establish an always-on market making obligation (MMO) in the National Electricity Law/National Electricity Rules (NEL/NER) for a small number of key derivative contracts in each NEM region, with contract types determined through a co-design process with the AER and industry

- A. The MMO should apply to all participants above a pre-defined size and prescribe volumes that must be made available for trading and a limit on the bid–ask spread, with contract types determined through a co-design process with AER and industry.
- B. The AER should regularly convene (e.g. every two years) with industry (financial market bodies, generators, retailers and electricity users) to define a small set of core derivative contracts that sit at the heart of the electricity market. These:
 - should be able to be traded on an exchange platform
 - should be the subject of the market-making obligations
 - should be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW)
 - should be utilised to underwrite projects in the ESEM; and
 - could be used in retail price benchmarking

The Panel will work with stakeholders to further demonstrate how this would work in practice during the second half of 2025.

- C. During the second half of 2025, the Panel will work with stakeholders to explore approaches to improve the accessibility of derivative markets, with a focus on NEM prudential requirements, financial market margining requirements and the interaction between the two. This will allow for recommendations to be made in the final report to improve market access.

7 Ensure sufficient market information is available to support longer-term derivatives market liquidity and price discovery

Energy ministers should propose a rule change to the Australian Energy Market Commission (AEMC) that extends the medium-term projected assessment of system adequacy generation availability projections from three to five years and make them public.

8 Energy ministers should establish an Electricity Services Entry Mechanism (ESEM) within the National Electricity Law (NEL) to facilitate investment in the NEM

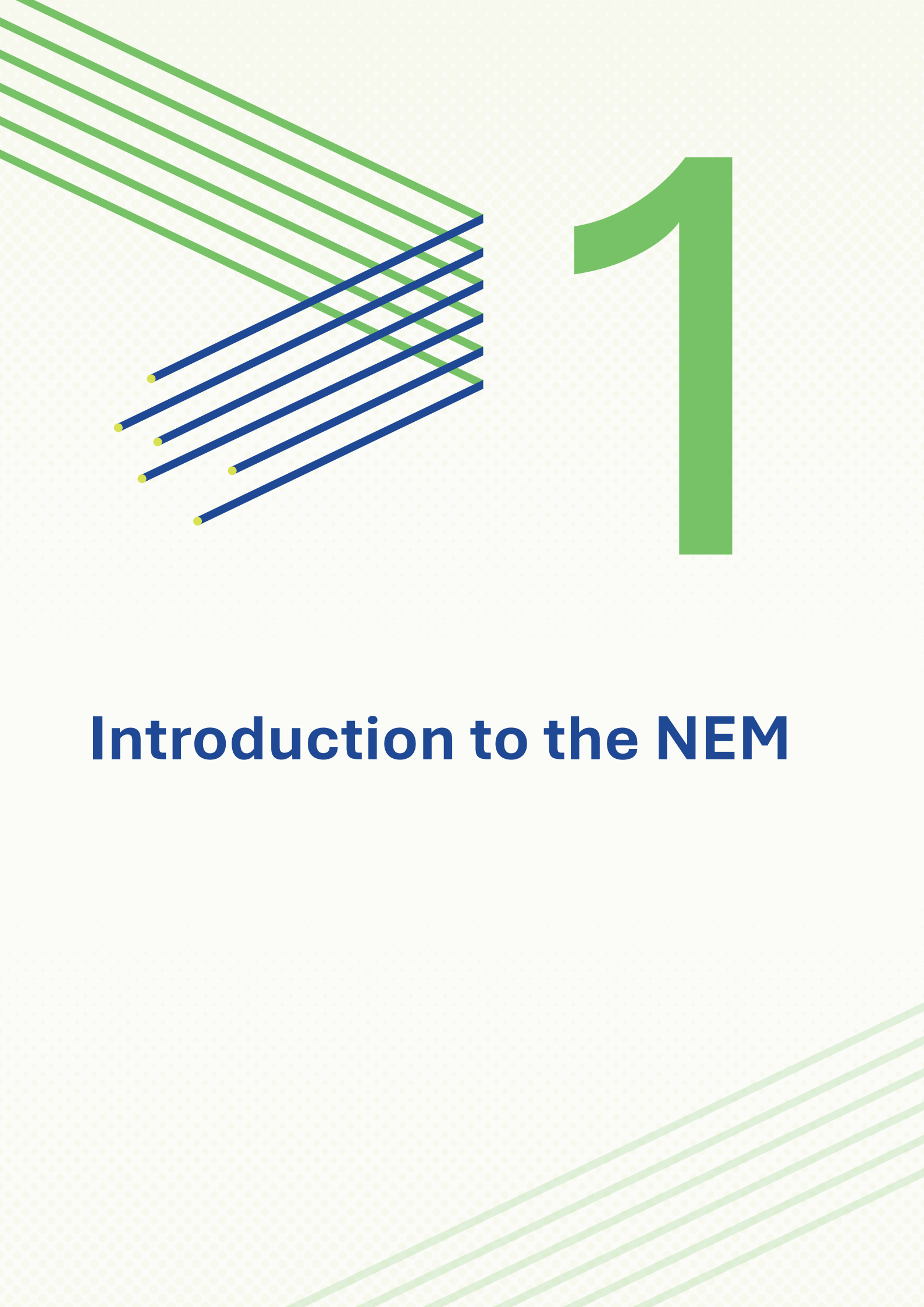
- A. Establish in the NEL an ESEM with the following key features:
 - The services initially procured by the ESEM should be bulk zero emissions energy, shaping and firming.
 - The ESEM should allow prospective new electricity service providers to compete for standardised, fungible contracts, developed through the co-design process outlined under **Recommendation 6B**, that offer a stable income stream upon the provision of a defined electricity service, facilitating the financing of new projects.

- The ESEM should not issue contracts for the years a project is able to secure them in-market. Rather, the ESEM should issue contracts for the later years of a project's life, allowing electricity service providers to sell their output to retailers or C&I users for the period of time that the market can manage risks effectively.
 - The ESEM should sell the standardised, fungible contracts back into the market at the point in time that allows retailers and C&I users to manage energy market risk, supporting retail competition.
 - The ESEM should be open to all providers of a given service, including aggregators of consumer energy resources (CER) and distributed energy resources (DER), and demand response providers, provided these resources are able to be scheduled for dispatch by the Australian Energy Market Operator (AEMO).
 - The ESEM should seek to procure quantities of each service that achieve the National Electricity Objective (NEO). This includes any specific requirements of government policies referenced in the Australian Energy Market Commission (AEMC) Targets Statement.
 - Where specific technologies are required to be procured by government policy and these technologies face greater barriers than just the tenor gap (e.g. offshore wind, pumped hydro) the ESEM should use an amended approach to facilitate their procurement.
- B. Where cost-effective, projects facilitated through the ESEM should also be able to provide Essential System Services. The ESEM administrator should coordinate with transmission network service providers (TNSPs). This should take the form of secondary contracting for the specific elements of the project that relate to providing ESS.
- C. A framework should be established to ensure the ESEM is able to consider market concentration when running tenders.
- D. A new longer-term out-of-market reserves service should be established to cover high-impact, low-likelihood events, with quantities to be procured at the discretion of jurisdictions, on advice from the Reliability Panel.
-

9 Governments and market bodies in the NEM should pursue a coordinated suite of reforms to ensure regulatory settings, the innovation ecosystem and existing policies and programs are aligned with the ESEM

- A. Governments should clarify how their emissions targets apply to projects procured to provide firming services, to provide certainty for investors.
- B. The Australian Government should task the Australian Renewable Energy Agency to accelerate the development and deployment of zero emissions technologies that provide firming at scale.
- C. Governments overseeing existing generation underwriting schemes to support long-term investment should consider options to improve derivative market liquidity.
- D. The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the time frame for inter-regional settlement residue units beyond three years.

- E. Once energy ministers are satisfied the ESEM and the Panel's proposed market making obligation are working effectively, they should look to phase out the Retail Reliability Obligation.
- F. Once the ESEM framework is established, energy ministers should consider opportunities to rationalise NEM forecasting and planning documents to avoid inconsistencies and duplication.
- G. Energy ministers should pursue reforms to improve consistency in the treatment of load, storage and generators connected at distribution and transmission level, to ensure a level playing field.



Introduction to the NEM

Chapter summary

In the 1990s Australian governments embarked on a series of energy market reforms designed to enhance competition, improve efficiency and drive innovation. In 1998 these reforms culminated in the establishment of the National Electricity Market (NEM), creating a wholesale spot market across participating eastern and southern states.

Privatisation of state-owned generation and retail businesses occurred in some jurisdictions, supported in part by vesting contracts to provide transitional revenue certainty. A voluntary derivatives market developed alongside the spot market, enabling participants to manage price risk and promoting investment certainty.

A core feature of the NEM's design is the link between the spot market, which provides short term price signals for dispatch, and the derivatives market, which is intended to support risk management and long-term investment via price discovery. While the system has functioned well in dispatching electricity efficiently, it has not consistently delivered clear and timely signals for new investment. Rather, new investment has largely been driven by adjacent or complementary government policies.

Retailers play a critical role in this framework, acting as financial intermediaries and managing wholesale price volatility on behalf of consumers. This dual-market architecture remains central to the NEM's operation, though it continues to evolve in response to emerging challenges and the energy transition.

History of the NEM

Defining the NEM: The term ‘NEM’ is used in different contexts to refer to different sets of activities – be it activities covered by the National Electricity Rules (NER) and Law (NEL), activities covered by the National Energy Retail Rules and National Energy Retail Law, or complementary activities relating to the derivatives market (including both exchange-traded and over-the-counter (OTC) contracts). For the purposes of this report, the Panel takes a broad definition, with ‘NEM’ referring to all of the above, including both the spot market (including Frequency Control Ancillary Services (FCAS)) and associated derivatives markets.

The NEM is a wholesale electricity market serving Victoria, New South Wales, the Australian Capital Territory, Queensland, South Australia and Tasmania that facilitates the buying and selling of electricity in real time. It is a complex ecosystem that brings together a diverse range of participants to contribute to the production, delivery and use of electricity.

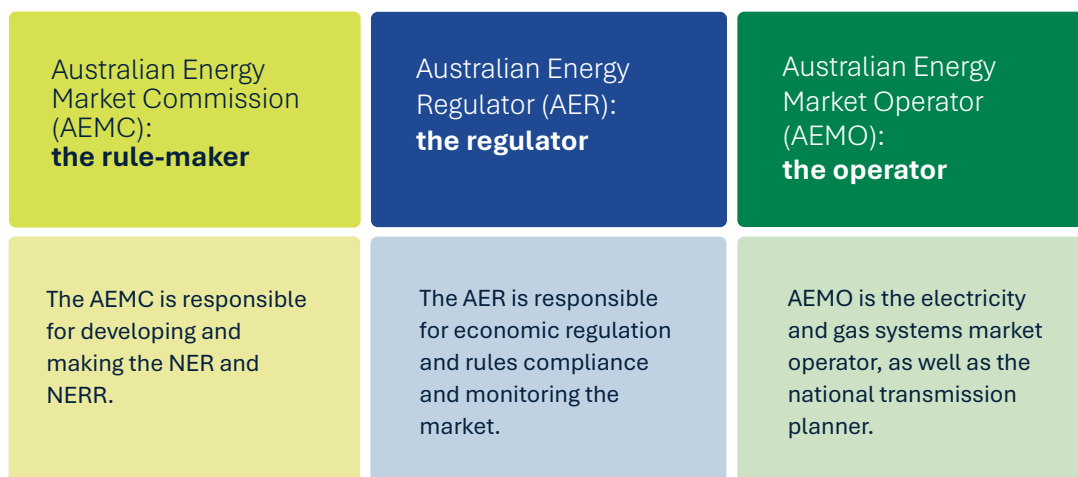
The NEM’s ‘stringy’ network of ~40,000 kilometres of high voltage transmission lines, lower voltage distribution lines and transformers deliver ~180–200 TWh of electricity each year to serve a population of more than 23 million. There are more than 600 registered participants in the NEM, including generators, transmission and distribution network service providers, and market customers (including retailers and large C&I users).

Electricity is a commodity that is produced, dispatched and consumed as a vital service for the end consumer. Consumers (residential and commercial and industrial users) are at the heart of the Panel’s efforts, considered both as beneficiaries and increasingly as participants of the market’s operation, through their choices in retail contracts, engagement in demand response, investment in distributed energy resources and adoption of evolving technology platforms.

Responsibility for electricity policy and regulation constitutionally resides with the states but in practice is exercised in a harmonised way. Through a cooperative legislative framework, the NEM is governed by national laws, particularly the NEL, which is enacted in South Australia and applied in all participating jurisdictions. The NER govern the operation of the NEM and specify everything from the responsibilities of participants to the dispatch of generation and the settlement of the market.

Three statutory market bodies govern the NEM (see **Figure 7**).

Figure 7 – Statutory market bodies in the NEM



The NEM was established with competition, transparency and efficiency at its core. The formal process to develop the NEM began in 1991 and culminated in the formal establishment of the NEM in 1998. Among other factors, the design of the NEM was influenced by the findings of the National Competition Policy Review chaired by Professor Frederick Hilmer (the Hilmer Review, 1993), which highlighted the inefficiencies of vertically integrated, state-owned electricity businesses and recommended separating monopoly networks from competitive activities like generation and retail. The NEM replaced state-based dispatch processes with a nationally consistent (excluding the Northern Territory and Western Australia), market-based framework for the efficient dispatch and trade of electricity.

The NEM was always intended to work as an integrated system of spot and derivatives markets². This structure was intended to ensure efficient allocation of generation and interstate trade in electricity, with high prices incentivising new generation as needed and sustained low prices encouraging the exit of excess or inefficient capacity. The derivatives market developed organically alongside the spot market and remains essential to its functioning.

The spot and derivatives market work together to meet demand, manage risk and – at least in theory – provide price signals to support longer-term investment. By design, the NEM's spot market creates sharp price signals for the dispatch of least marginal-cost plant to meet required demand and encourage generators to be available during times of scarcity. In turn, anticipation of future spot prices forms the basis of forward derivative contracts, which should provide price signals for future entry or exit of generating plant into or out of the system. In a well-functioning wholesale market, the spot and derivatives markets work in tandem to provide signals for efficient dispatch and timely investment – and ultimately, affordable and reliable electricity for consumers.

² Council of Australian Governments (2002), Towards a truly national and efficient energy market: Final report of the Council of Australian Governments Energy Market Review, p 23

Figure 8 – Timeline of development of spot and derivatives markets in the NEM

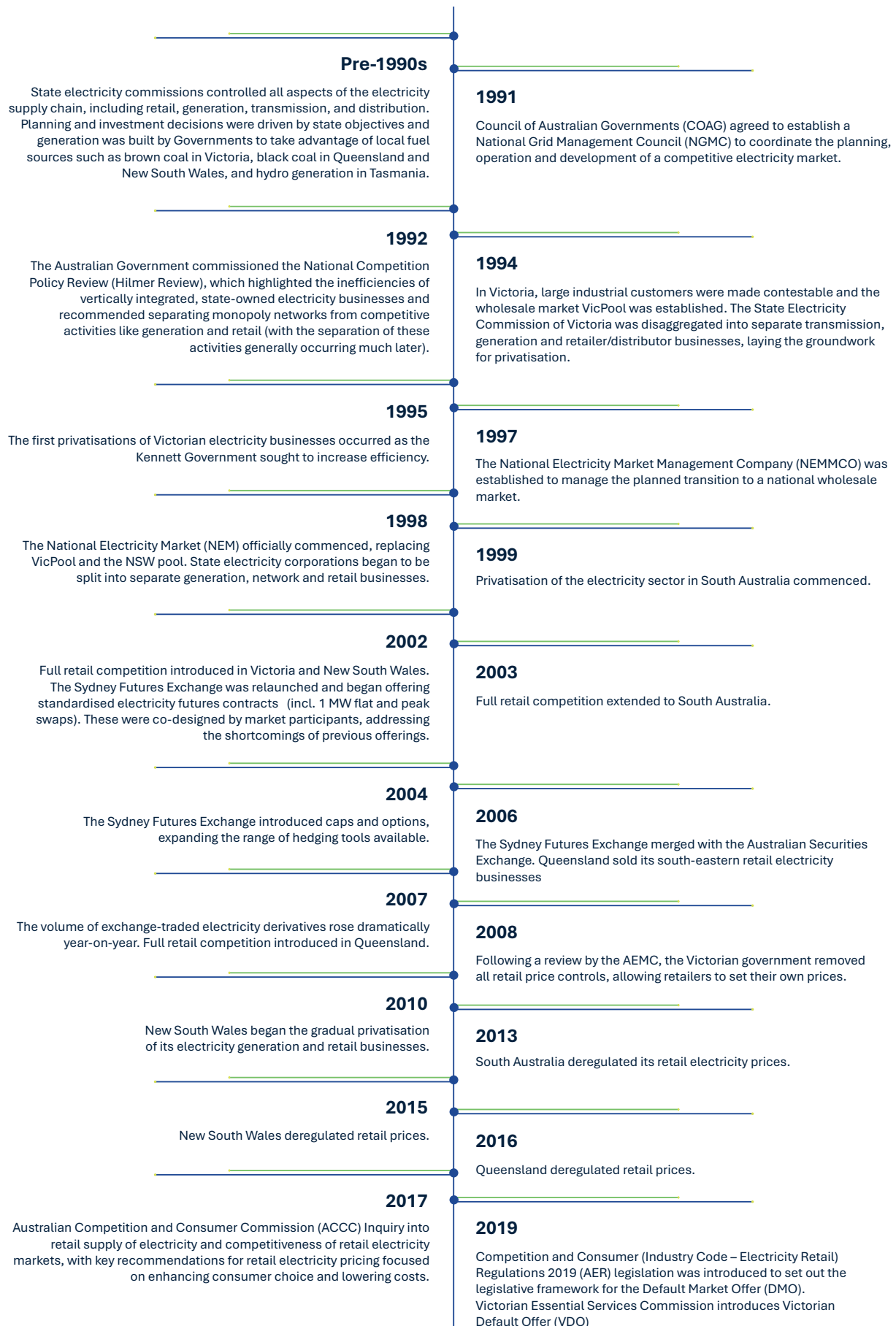
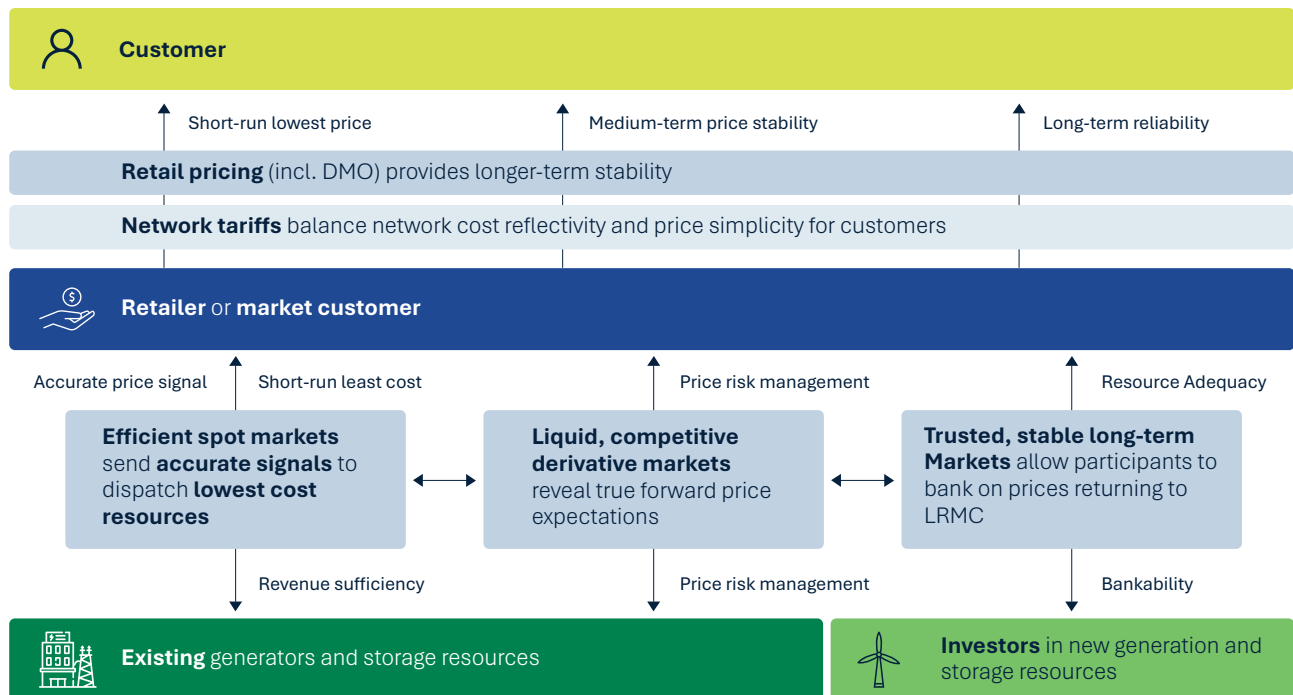


Figure 9 – How the NEM was intended to work

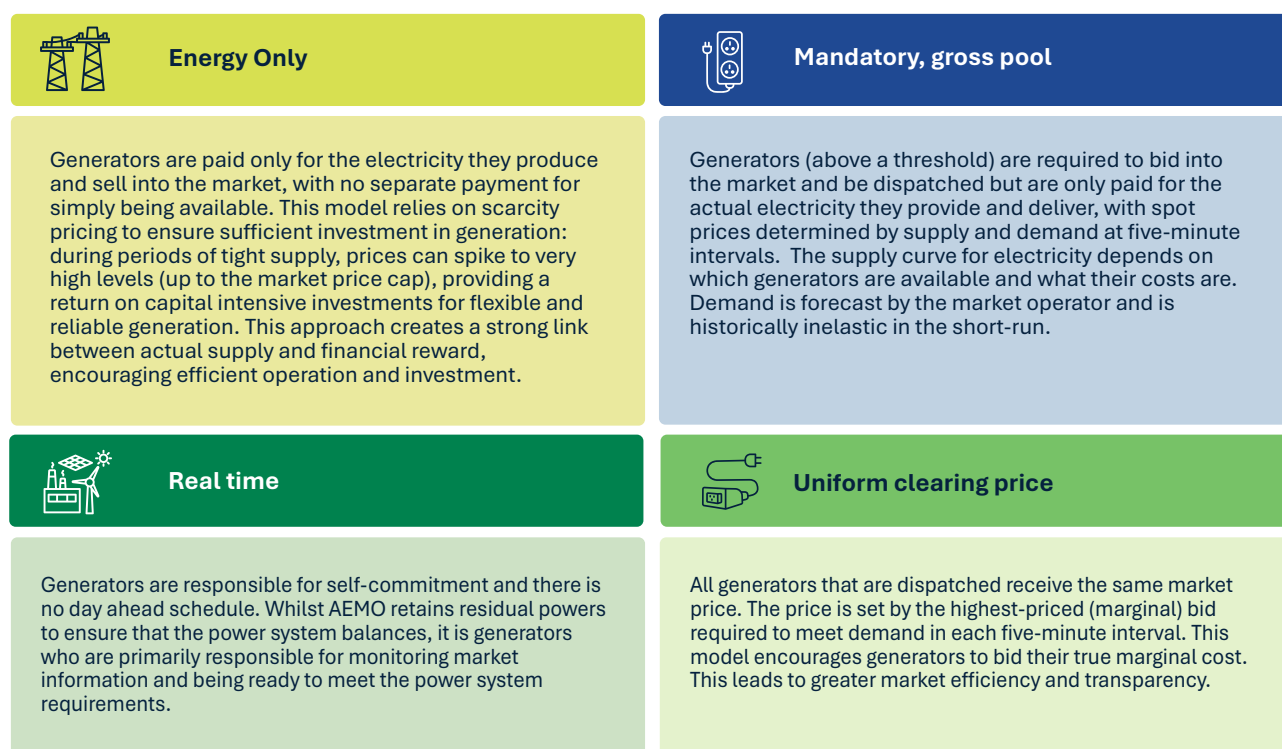


The role of the wholesale spot market, derivatives market and ancillary markets

The spot market provides transparent price signals for real-time dispatch and system balancing.

The NEM Dispatch Engine (NEMDE) runs the complex dispatch process, selecting the lowest cost combination of generator and load offers to meet demand across the NEM subject to the technical constraints of the power system. The output from NEMDE is a set of regional electricity ‘pool’ prices and dispatch instructions for generators and loads. Generators are paid the regional pool price for the energy they produce and retailers and other market customers must pay the regional pool price for the energy they consume in that region. AEMO manages the settlement of the market to ensure the financial integrity of the system.

Figure 10 – Key features of the wholesale spot market

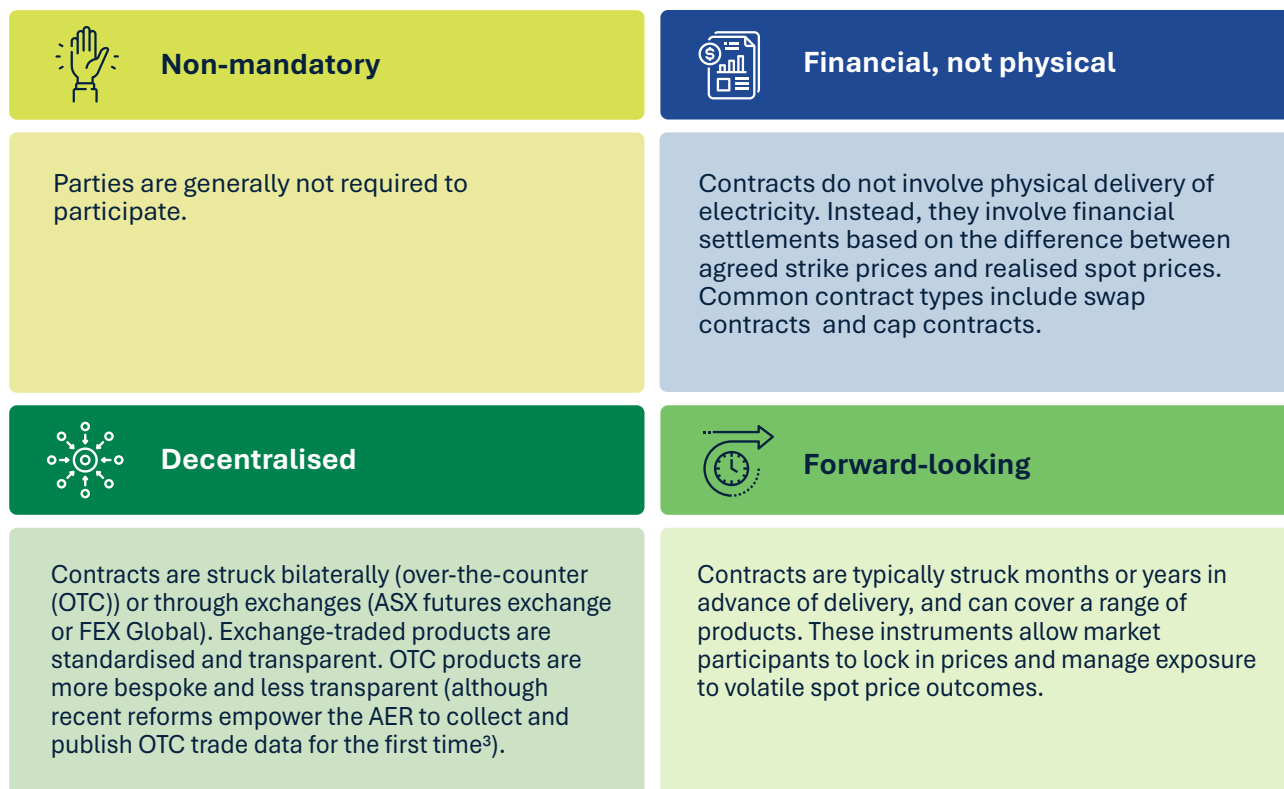


The spot market is supported by a suite of mechanisms to manage system security and market volatility, including price caps and floors and AEMO’s intervention powers.

The derivatives market provides generators and retailers with the ability to manage spot price risk.

While price volatility in the spot market sends important scarcity signals to support dispatch, it creates significant financial risks for retailers, who cannot pass on high prices to customers in real time, and generators, whose revenues are vulnerable to low spot prices. The derivatives market operates alongside the wholesale spot market and enables participants to manage the financial risks arising from volatility in the spot market. Importantly, the derivatives market allows the value of firm capacity to be effectively priced. In this way, derivatives markets facilitate a decentralised capacity market within the NEM.

Figure 11 – Key features of the NEM derivatives market



To be effective, the derivatives market must facilitate price discoverability, with transparent price signals that reflect market conditions and future expectations. It must also have enough competition and liquidity so that contracts can be bought and sold easily at reasonable prices. Derivatives markets should also provide for anonymous trading to avoid potential market discrimination.

Well-functioning derivatives markets can also provide forward price signals to support new investment. Rising contract prices signal expected scarcity and can incentivise investment; falling prices may lead to plant retiring or mothballing. However, the derivatives market's ability to inform efficient investment and retirement decisions is limited when it does not function as intended. This is important given the tenor gap the Panel has identified in relation to supplier and buyer misalignment around contracting appetite for future periods (see **Trends and challenges in the NEM**).

Retailers

Retailers buy energy from the spot market to meet their contracted customers' demand. The risks retailers face include volume risk, price differential risk, credit risk and prudential risks. Retailers have typically managed these risks by either buying hedging contracts (to shift wholesale price risk to another party) or investing in generation to balance earnings across the generation and retail arms of their business.

While vertically integrated retailers are less reliant on external contracts, they still participate in the derivatives market to manage residual risk. Some large commercial and industrial (C&I) users also hedge directly, either via financial intermediaries or by entering into long-term power purchase agreements (PPAs) with renewable energy developers as part of their broader decarbonisation and cost management strategies.

³ DCCCEW (2024), '[Amending the Australian Energy Regulatory Wholesale Market Monitoring and Reporting Framework](#)'.

Generators

Generators supply energy into the market to meet regional electricity demand. Generators face several risks, including price risk, fuel price risk, congestion risk, marginal loss factors (MLFs) and technical and regulatory risks. Variable renewable generators face specific risks relating to resource availability and certificate price risk, and storage operators face risks around price spread and arbitrage risks, degradation and operational risks and ancillary services market risks.

Like retailers, generators and storage operators have managed these risks with several strategies, including through the careful design and operation of plant, vertical integration, selling contracts to intermediaries, retailers or C&I users, or participation in government underwriting or revenue-sharing schemes (such as the Capacity Investment Scheme and New South Wales Long Term Energy Service Agreements (LTESAs)).

Figure 12 – Types of risks faced by retailers and generators in the NEM

Retailer risks

- **Volume risk:** Customer demand is higher or lower than forecast, leaving the retailer ‘short’ or ‘long’ relative to their contracted position.
- **Price differential risk:** Spot prices exceed the retailer’s contracted price but they cannot pass through the higher cost to customers.
- **Credit and prudential risk:** Retailers must post collateral with AEMO and may face losses if customers default on bill payments.

Generator and storage risks

- **Spot price risk:** Generators may not recover costs if spot prices are low and they are ‘long’ relative to contracted volumes.
- **Fuel price risk (thermal):** Exposure to volatile prices in coal, gas, or diesel fuel markets.
- **Congestion risk:** Output may be curtailed if located in a congested part of the network.
- **MLF risk:** Generators located far from demand centres may earn less due to energy losses on the transmission network.
- **Technology and regulatory risk:** Changes in policy or technology may erode the competitiveness or viability of existing assets.

Variable Renewable Energy-specific risks

- **Resource availability risk:** Output is dependent on the availability of wind, sunlight or water.
- **Certificate price risk:** Exposure to changes in the price of renewable energy certificates if not contracted under a PPA.

Storage-specific risks

- **Arbitrage and price spread risk:** Profitability depends on capturing sufficient price differentials between charging and discharging, accounting for round-trip losses.
- **Degradation and operational risk:** Frequent cycling and deep discharge can shorten battery life, requiring careful optimisation.
- **Ancillary services market risk:** Revenues from services like frequency control can be uncertain and variable.

Figure 13 – How the spot and derivatives (contract) markets work together

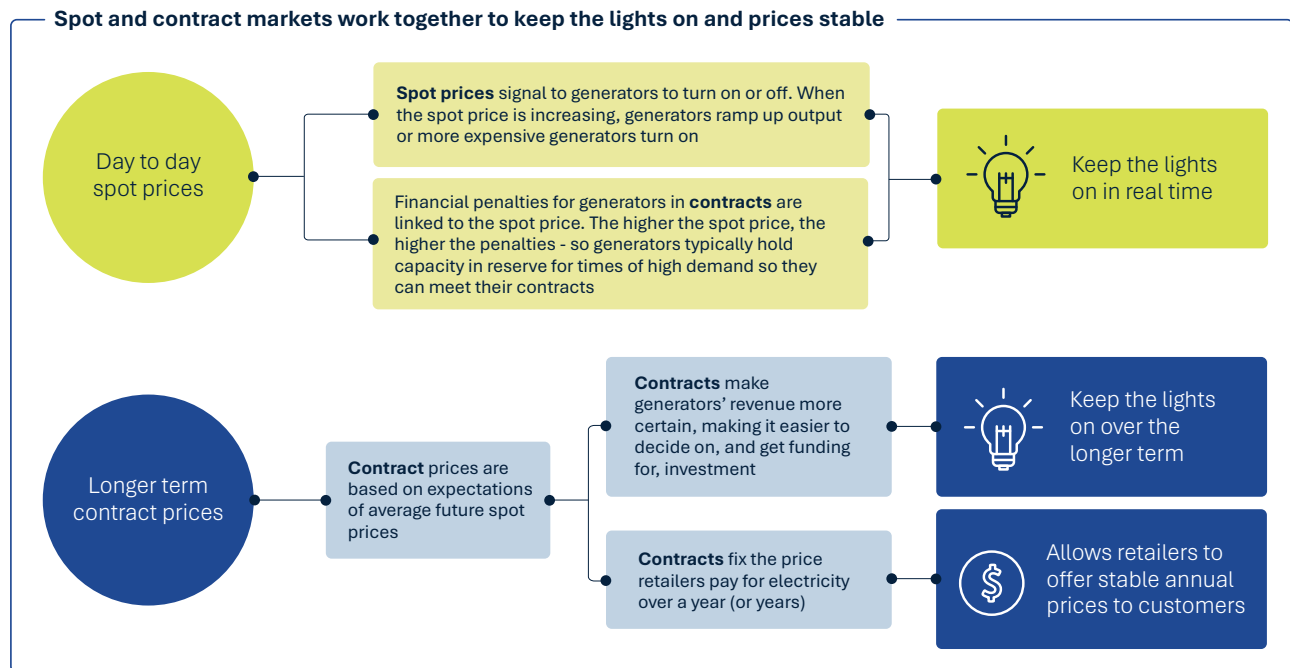
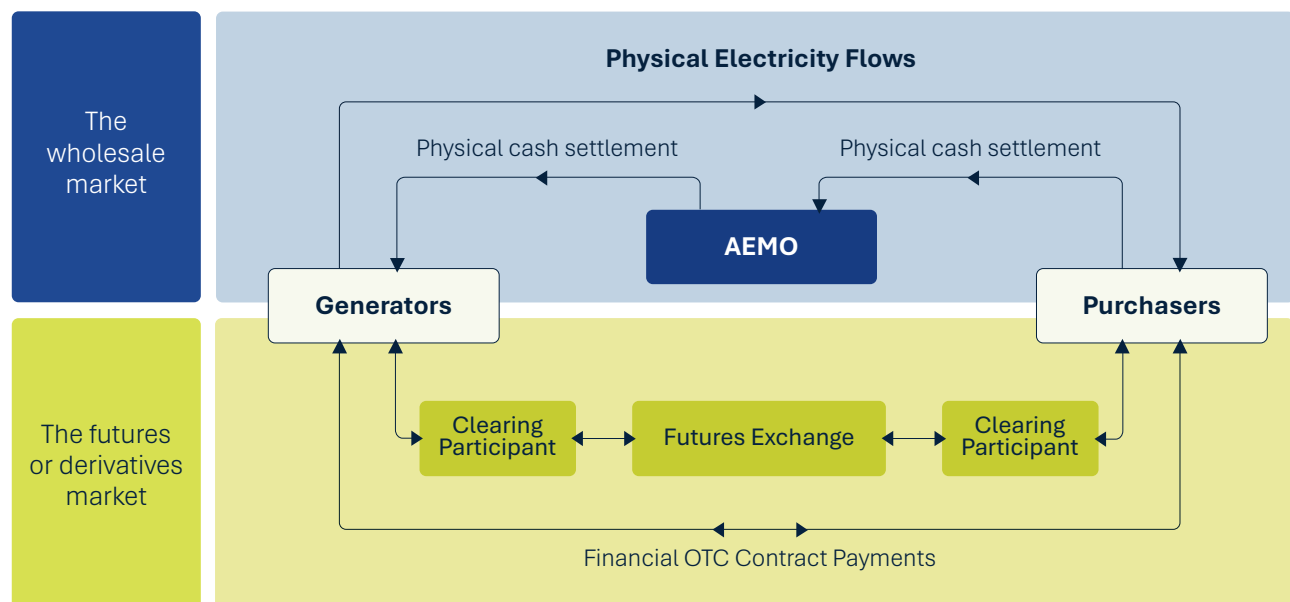


Figure 14 – Physical and financial flows in the NEM and associated derivatives markets

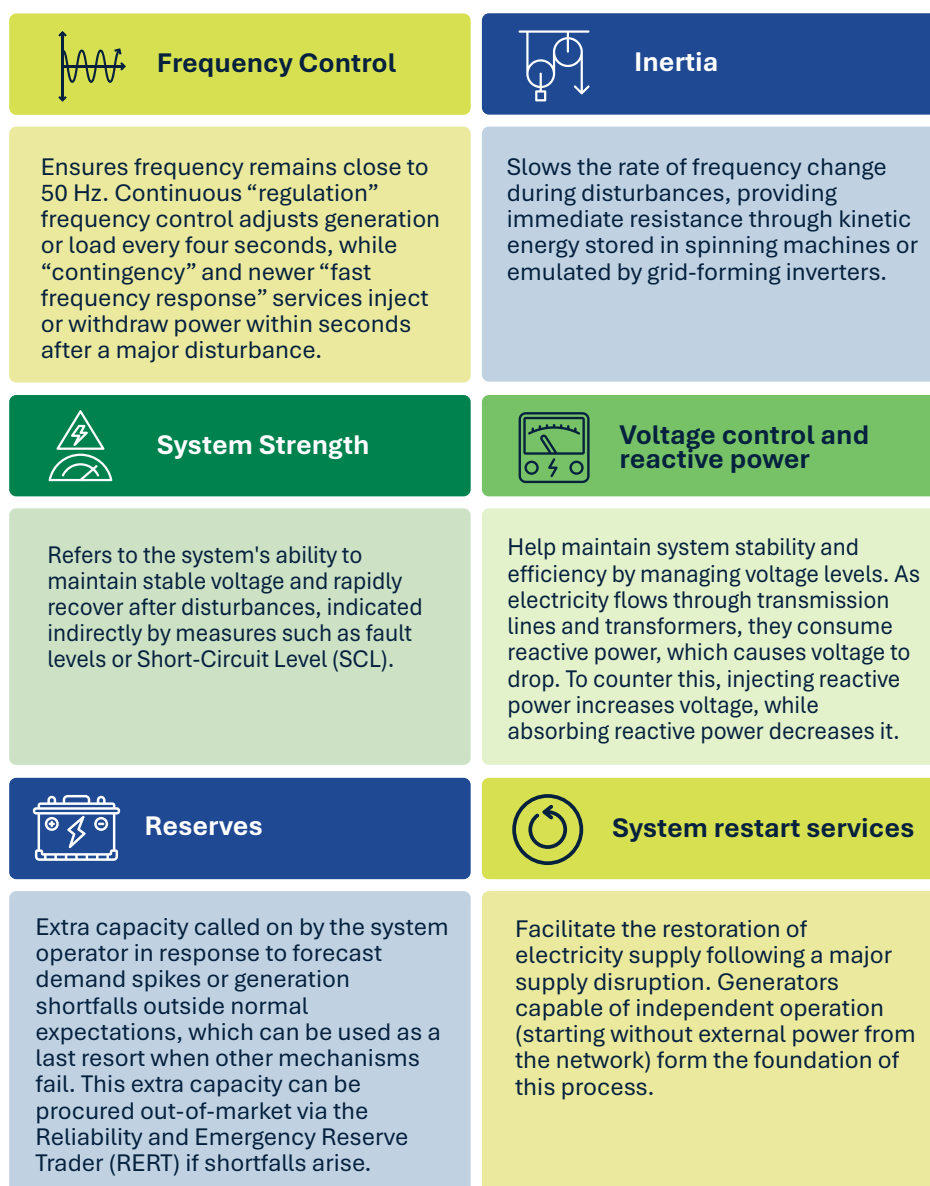


⁴ Adapted from AEMC spot and contract markets [webpage](#)

Essential System Services are fundamental to maintaining real-time system stability

Ancillary markets in the NEM primarily serve as mechanisms to procure certain essential system services (ESS). The secure and reliable real-time operation of the NEM depends not only on having sufficient generation (managed through the wholesale spot market) and financial tools for participants to manage risk (through the derivatives market) but also on a suite of technical capabilities known as ESS.

Figure 15 – Key ESS in a high inverter-based resources environment



Under the NEL, AEMO is responsible for maintaining power system security and ensuring the availability of ESS. AEMO directly contracts some services, such as network support and control ancillary services (NSCAS) and system restart ancillary services (SRAS), while markets have been developed within the NEM dispatch architecture for others, such as FCAS. Services including inertia and system strength have only recently begun to attract attention as traditional sources (such as

coal-fired plant) retire. Historically, these services were effectively provided as byproducts of large synchronous generators, like coal, gas and hydro, and did not require explicit procurement or pricing.

There are dedicated markets for FCAS, with all other services procured through bilateral contract. Ancillary service costs are recovered from market participants through a regulated cost allocation framework. These markets and contracts operate alongside the spot market, forming a complementary set of mechanisms to ensure that electricity is delivered securely and reliably.

Figure 16 below illustrates the different roles that AEMO and Transmission Network Service Providers (TNSPs) hold in providing ESS in the NEM.

- **Frequency Control Markets:** There are 10 FCAS markets, covering regulation and contingency services, designed to correct deviations in system frequency. Participants bid to provide these services and are paid both for being available and for delivering a service when called upon. As with the spot market for energy, bids are co-optimised within the NEMDE, which selects the least-cost combination of services subject to system constraints. This ensures frequency stability at lowest cost to the system.
- **Contracted Services:** For other essential services not suited to market-based procurement, AEMO enters into agreements with providers. These include NSCAS, used to maintain power flows and voltage within limits, and SRAS, which enable the re-energisation of the grid following a blackout.

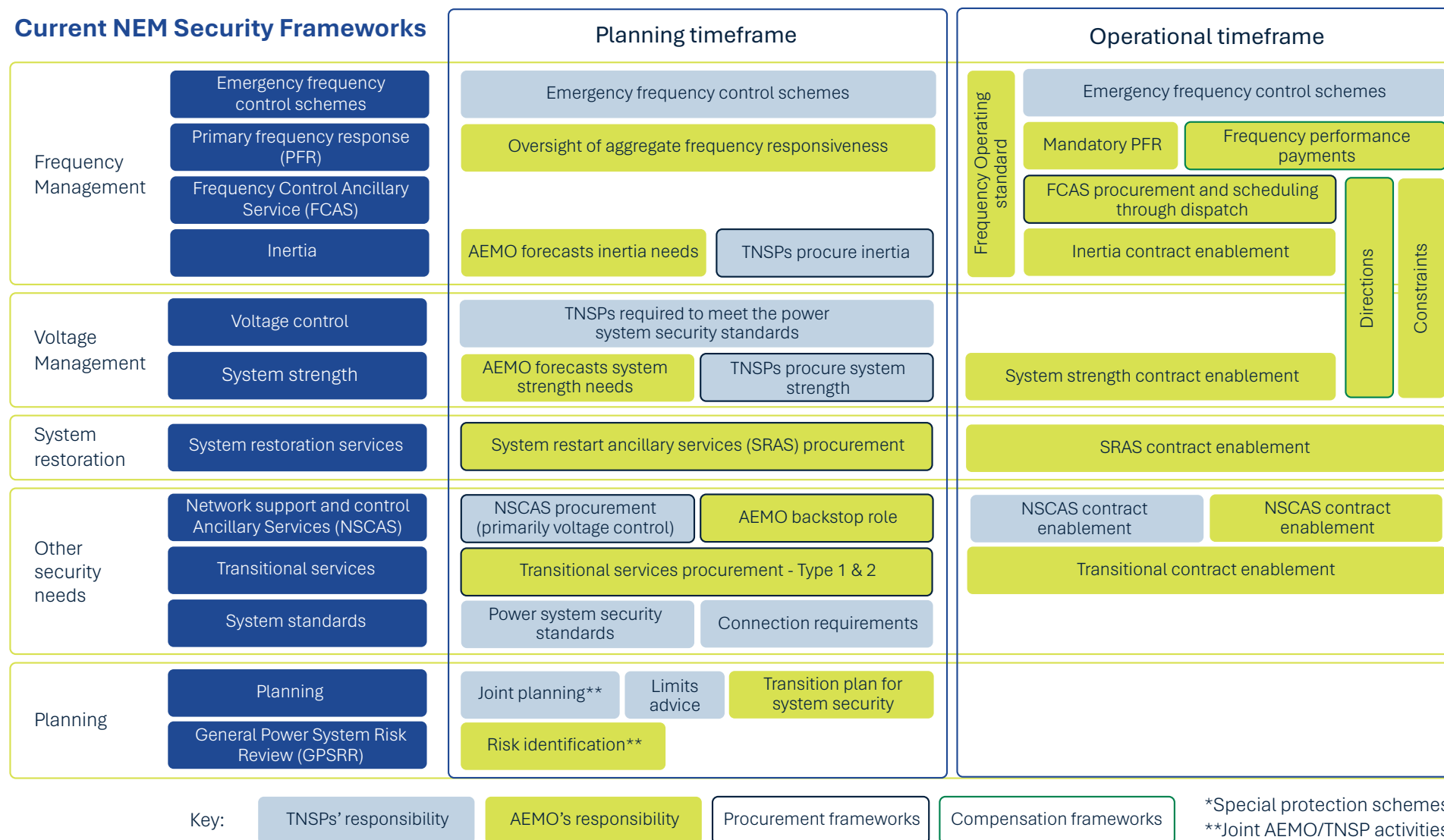
These markets and contracts operate alongside the spot market, forming a complementary set of mechanisms to ensure that electricity is delivered securely and reliably.

TNSPs assist AEMO by procuring and providing system strength services under contractual arrangements consistent with AEMO's requirements. The AER then determines appropriate cost recovery. Specifically, TNSPs have two key obligations:

- When AEMO identifies a gap in system strength or inertia through a declared NSCAS need, the TNSP must address that gap. If the required works must be delivered within 18 months, the associated expenditure is exempt from the Regulatory Investment Test for Transmission (RIT-T)⁵
- From 2 December 2025, TNSPs that are also designated as 'system strength service providers' must deliver an efficient level of system strength and ensure that AEMO's required three-phase fault levels are maintained at each declared system strength node.⁶

⁵ NER, cl. 5.16.3(a)(10).

⁶ AEMC (2021), [Rule determination: National electricity amendment \(efficient management of system strength on the power system\) Rule 2021](#), p 15. AER (2024), [The Efficient Management of System Strength Framework: AER Guidance Note](#), p 7

Figure 16 – Roles and responsibilities of AEMO and TNSPs in ESS planning and procurement⁷⁷ Adapted from AEMC presentation [Update on AEMC reform work program ESS & system security in March 2025](#).

Transmission in the NEM

While transmission planning and investment frameworks are specifically out of scope for this review, the transmission network remains fundamental to the efficient functioning of the NEM. The NEM's 40,000 kilometres of transmission lines connect generators to major load centres and enable electricity to flow between states through interconnectors. Key features of the transmission network include:

- **Open access and cost allocation:** Under the NEM's open access regime, generators may connect to the network provided they meet technical standards and fund their connection infrastructure. They do not pay for ongoing use of the shared transmission system. Instead, those costs are recovered from consumers. This arrangement encourages investment in generation but does not guarantee generators receive unconstrained access to the market. It is worth noting, New South Wales's Access Scheme diverges from this principle by allocating access rights in Renewable Energy Zones (REZs).
- **Interconnection and regional pricing:** The NEM is divided into five regions, each with a designated Regional Reference Node. Spot prices are calculated at these nodes and reflect local supply-demand conditions. Interconnectors link the regions, allowing electricity to flow from lower- to higher-priced regions, helping to moderate prices and improve reliability. However, when interconnectors reach capacity, regional prices separate, potentially leading to sharp price differences and revenue uncertainty for market participants operating across regional boundaries.
- **Losses and congestion:** Electricity is lost as it travels long distances. These losses are captured through marginal loss factors (MLFs) which adjust a generator's market revenue to reflect the actual value their electricity delivers to the system. MLFs are updated annually and can vary depending upon anticipated power flows from new loads and generators. In addition, transmission congestion can occur when physical limits on the network prevent the lowest-cost generation from being dispatched. When this happens, some generators are 'constrained off' and higher-cost local generators may set the market price.

Investment in new transmission

Centralised, long-term planning is essential to ensure transmission investment occurs in the right places, at the right scale and with sufficient lead time. The shift to a zero-marginal-cost system increases the need for some level of coordinated planning and policy direction to overcome persistent network constraints and ensure system reliability and efficiency. While market-based mechanisms like locational marginal pricing (LMP) and financial transmission rights (FTRs) have been previously considered as a potential solution, they have not been implemented as they cannot, on their own, deliver the long-term, capital-intensive transmission investments required to support a renewable-dominated system. FTRs are not issued over investment timeframes and are instead only provided for one to three years into the future.

State governments within the NEM have increasingly stepped in to coordinate transmission investment through mechanisms such as REZs. These zones bundle generation and transmission planning into a single framework, allowing governments to strategically identify areas with high renewable resource potential and then coordinate the necessary network upgrades to unlock that capacity. By doing so, states are effectively bypassing the uncertainty and delays associated with market-led transmission development. The REZ approach acknowledges the central planning imperative in

a zero-marginal-cost system and reflects a broader trend toward reasserting public control over network development to accelerate the clean energy transition and ensure system-wide efficiency and reliability.

Role of retailers

Retailers play an important role as matchmakers and risk managers. Retailers serve as the interface between wholesale markets and electricity users, managing price risk and tailoring products to customer needs. Since the market's inception, the regulatory framework for retailers has evolved, moving from highly regulated structures to widespread deregulation in the 2000s aimed at promoting competition and consumer choice, and more recently back towards stronger oversight. Growing concerns about affordability and market complexity led to the introduction of the Default Market Offer in 2019, to provide clearer reference pricing and protections for consumers. Ongoing reviews by the ACCC reflect a continued focus on ensuring the retail market remains competitive, transparent and responsive to consumer outcomes.

Vertical integration has led to the rise of 'gentailers' like AGL, Origin and EnergyAustralia. A second tier of gentailers has more recently emerged, including Alinta, Engie, Snowy/Red-Lumo and Hydro Tasmania/Momentum. Today these combined gentailers serve more than 80% of electricity users in the NEM.

The retail landscape has evolved as competition has increased. According to the AER, the retail landscape, previously dominated by the three Tier 1 retailers (AGL, Origin Energy and EnergyAustralia) now has over 52 active electricity retailers servicing over 6.8 million electricity users. Since 2019–20, Tier 1 retailers have lost 2.9% of their market share to Tier 2 retailers. Tier 2 retailers have been observed to provide a wider range of extremely high- and low-priced offers and their participation has been attributed to an increase in consumers on market offers.

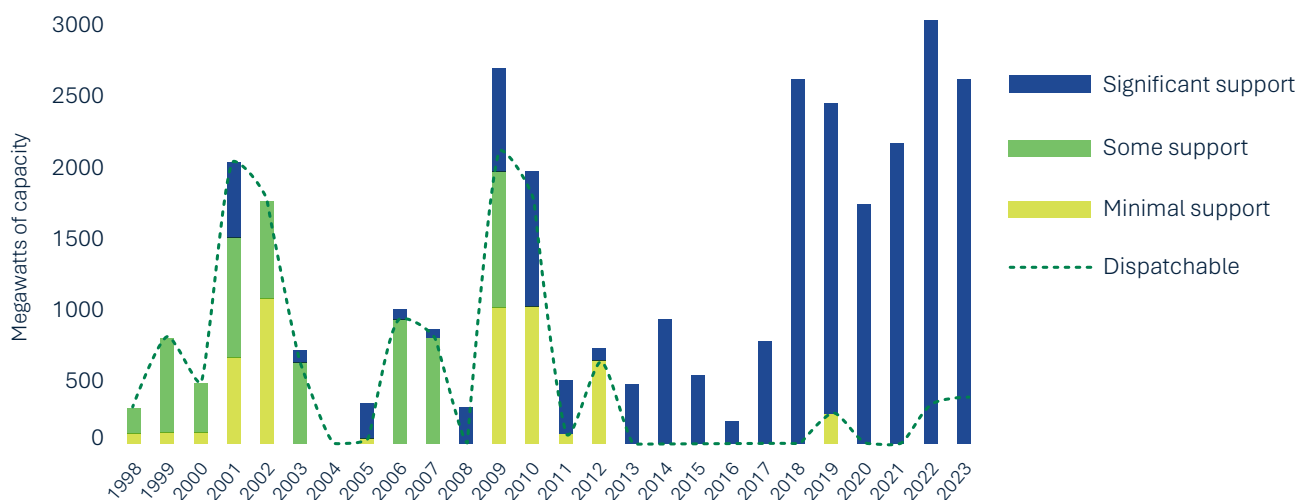
Investment trends

Investment in new generation in the NEM has been uneven – and in large part driven by specific policy measures. Investment in new generation in the NEM has fluctuated significantly over time, both in scale and by technology type. These shifts can be broadly grouped into three distinct periods since the market’s inception: a phase of growth driven primarily by rising peak demand (1998–2011); a period of oversupply and limited new investment outside of renewables mandated by the expanded Renewable Energy Target (2011–15); and the current phase of transition towards a low-emissions system (2015-present) (see **Figure 17**).

Although the design of the NEM aimed to let market forces drive investment decisions, government policy support has been a significant driver of investment in new generation since its inception. The Panel notes that this has been a feature of most deregulated electricity markets, irrespective of the market design adopted. Almost all investment in new generation capacity in the NEM has received some form of government support, and there are very few examples of pure, market-only investments that were made entirely on the basis of expectations about future spot market revenues and forward derivatives markets. Emerging research suggests NEM spot prices and derivative markets on their own have not driven recent investment decisions in the NEM, in contrast to the strong role of policy support⁸.

⁸ Csereklyei & Say (2025), *Quantifying the effect of energy policies on electricity generation investments in Australia’s National Electricity Market*, presentation at NEM Review ‘Lunch and Learn’, 6 June 2025.

Figure 17 – Generation build by non-market support, 1998–2023



Sources: NEM review analysis drawing on AEMO Generation Information, Bloomberg New Energy Finance, and the work and expertise of a range of experts. Includes utility scale generation from coal, gas, solar, wind, hydro. Excludes batteries, pumped hydro, rooftop solar or other small-scale resources, and demand side participation.

Periods of investment in the NEM

1998 to 2011: Growth

The NEM's early years saw strong growth in peak electricity demand, especially in Queensland. This drove significant investment in new generation capacity, particularly black coal in Queensland (Callide C, Milmerran, Tarong North, Kogan Creek) and gas generators (Oakey, Swanbank E, Braemar, Darling Downs).

Several factors supported this growth, including rising peak demand from air conditioning and economic growth, availability of long-term, low-cost coal or gas contracts, public investment via GBEs, and vertical integration by gentailers. National and state-based schemes also supported this growth, including the introduction of the Mandatory Renewable Energy Target in 2001, the NSW Greenhouse Gas Abatement Scheme (GGAS) in 2003 and Queensland's Gas Scheme in 2005.

2011 to 2014: Oversupply

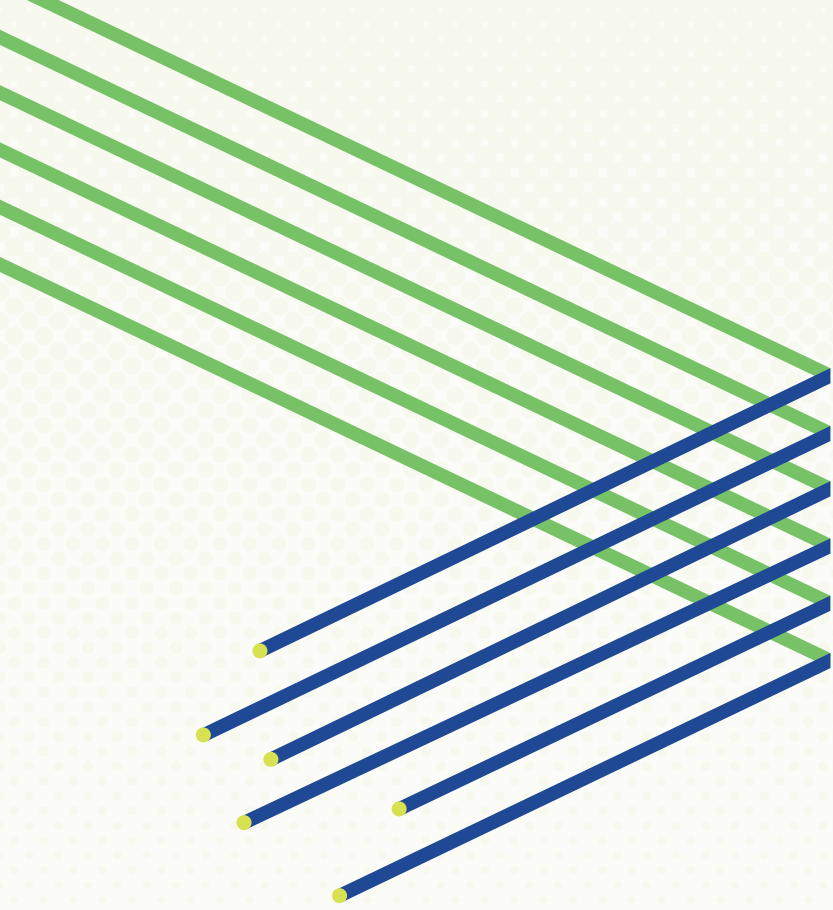
This period saw falling demand driven by significant changes in industrial load with the closure of smelters (Kurri Kurri and Point Henry), as well as energy efficiency measures and the growth of distributed solar PV. Simultaneously, industrial demand shifted with LNG developments in Queensland. The result was market oversupply, and AEMO's 2014 Electricity Statement of Opportunities (ESOO) forecast no new generation needed in any region.

Policy uncertainty further dampened investment: the Carbon Pollution Reduction Scheme was introduced in 2012 and then repealed in 2014, the RET was split into LRET and SRES, and the GGAS and Queensland Gas Scheme were wound down. Although some renewables were built, investor confidence was weak.

2015 to present: Transition

From 2016 NEM demand remained flat due to rooftop solar despite industrial load increases. This period saw the onset of a renewable investment boom driven by the Renewable Energy Target. Major thermal closures included Northern (2016), Hazelwood (2017) and Liddell (2023), tightening supply and pushing prices higher, exacerbated by rising domestic gas prices linked to global LNG markets.

Government investment increased (e.g. Snowy 2.0, Hunter Power Project) and new state-based mechanisms emerged. The NSW Electricity Infrastructure Roadmap (2020) and Commonwealth Capacity Investment Scheme (2022) introduced new investment models involving tenders and long-term contracts.



2

Trends and challenges in the NEM



Chapter summary

Any review of electricity market design must consider emerging trends and challenges. This chapter does not attempt to predict the precise shape of the future National Electricity Market (NEM) – other planning and forecasting documents are better placed to do this. Instead, it outlines the most important drivers of change and considers the implications for how the market functions.

Put simply, the key trend shaping the NEM is technological change. When the NEM was established, Australia's electricity system was powered predominantly by coal, gas and hydro. That foundation is now shifting in response to the need to decarbonise and modernise the electricity system. Variable renewable energy, particularly wind and solar, is likely to provide the bulk of Australia's electricity. This is likely to be firmed by batteries, pumped hydro and gas, with energy shifted to the times it is needed most. Consumers are likely to play a more complex role: millions of households and businesses are likely to not only consume energy but also increasingly produce, store and manage it, contributing actively to the system's supply and flexibility.

This shift brings challenges. Electricity supply is becoming more weather-dependent, more energy-constrained, less visible to the Australian Energy Market Operator (AEMO) and less able to deliver essential system services (ESS) in the way that large synchronous generators once did. At the same time, consumer behaviour is evolving in ways that introduce new uncertainties for forecasting demand and market operation.

These changes will test the NEM's existing structures across three key horizons:

- In the **spot market** increasing variability and volatility in supply and demand impede price formation without resources being visible. Forecasting and efficiency will improve if more market resources become visible and dispatchable.
- Price variability and volatility increases the importance of **derivatives markets**, which allow market participants to manage risk. If liquidity in these markets increases investor confidence and retail competition will improve.
- The current market design provides incomplete incentives to support **long-term investment** in the resources the future system requires, particularly assets that: shape and match supply and demand; provide longer-term firming of generation during periods of scarcity; and provide ESS after older generators are retired. Addressing the tenor gap between the short-term nature of derivatives markets and the long-term financing needs of capital-intensive projects, will be central to achieving investment at the pace and scale required.

The NEM has never been a set-and-forget system. Instead, it has evolved steadily to meet new challenges and will continue to do so. By identifying the most influential trends and designing reforms that can accommodate a wide range of technological changes, the Panel seeks to position the NEM for long-term success.

Technological changes

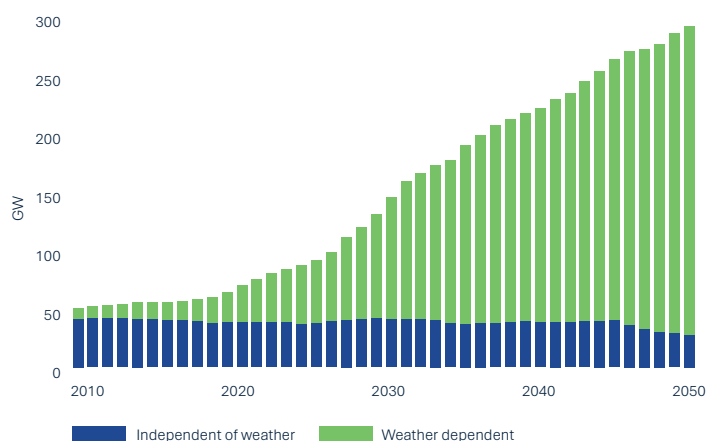
Generation technology in the NEM is changing, driven by the need to decarbonise the economy and modernise electricity systems as existing plant reaches the end of its useful life. This change is fundamentally reshaping the market. The step change scenario of AEMO's 2024 Integrated System Plan (ISP) reflects most of these anticipated changes – a shift towards supply that is less scheduled, more dependent on weather and more energy-limited.

The figures below use the ISP's capacity projections to show how these changes will affect the NEM under current policy settings⁹.

Figure 18 – Changing characteristics of generation in the NEM¹⁰

Increasingly weather dependent

The growth of variable renewable energy (VRE) will increase the electricity system's dependence on weather. This heightens supply and demand risks but also creates a market for shaping (storage, demand response) to spread demand across the day, and for firming resources. VRE variability will increasingly drive intraday, seasonal and annual price volatility. As a result, risk-management tools will become more important for generators, retailers and C&I users to manage the risks – physical and financial – of buying and selling electricity.

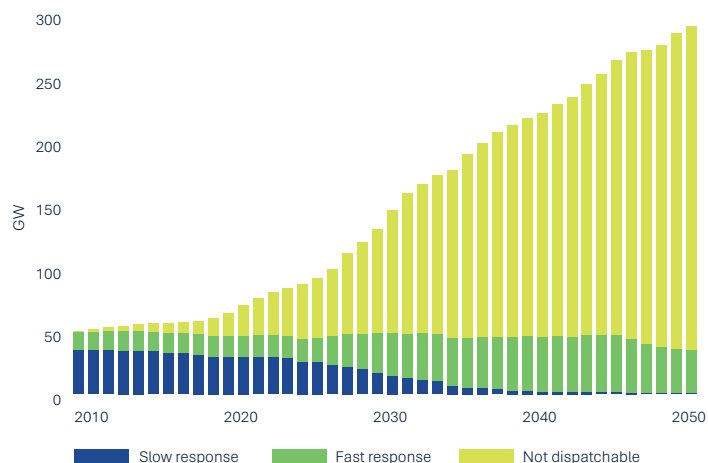


⁹ The capacity projections in **Figure 18** exclude demand-side participation and assume that projections of 'coordinated' CER storage will remain non-scheduled without reforms. The chapter 'Ensuring effective operation of the spot market' discusses the reforms needed to encourage CER coordination'. Sources: AEMO 2024 ISP data, NEM Review analysis.

¹⁰ NEM Review analysis based on AEMO 2024 ISP data.

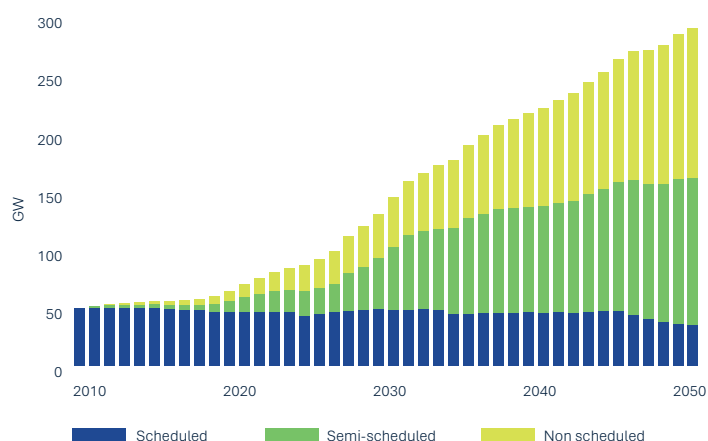
Less dispatchable capacity

New dispatchable generation will be required to provide shaping and firming services when VRE is scarce.



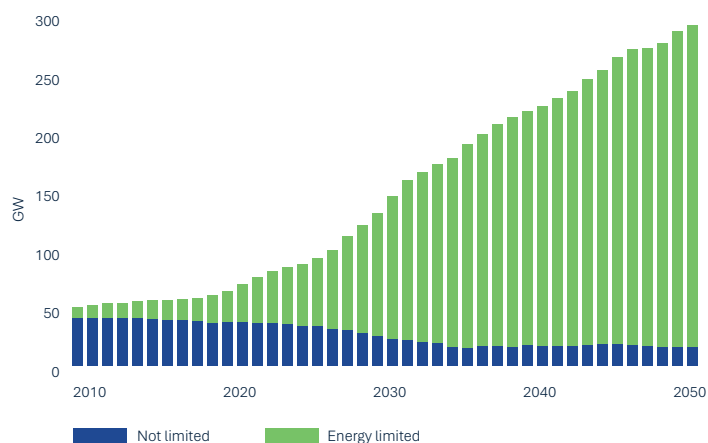
Less visible and less scheduled resources

Distributed consumer-owned resources, such as home solar and battery systems, will provide an increasing share of capacity. If virtual power plants (VPPs) are not participating in the market, AEMO's demand forecasts may become less accurate, reducing market efficiency and jeopardising grid stability. Without visibility of these resources, there is a significant risk of over-building large-scale resources. It is estimated this could result in \$1.4 billion to \$1.8 billion of extra unnecessary costs¹¹.



Energy limited

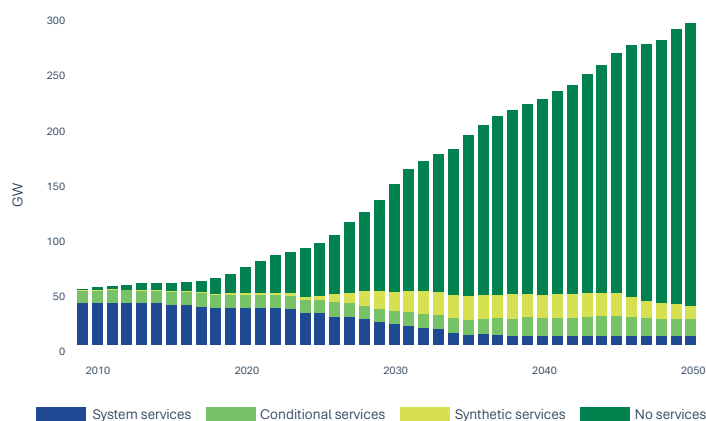
The growing reliance on 'energy-limited' plant – such as VRE (limited by weather dependence) and batteries, hydro and pumped hydro (limited by storage capacity) – highlights the need for long-duration firming capacity and reserves to support the NEM during prolonged periods of low wind and solar generation.



¹¹ IES (2024), [Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM](#), final report to AEMO, pp 7–9.

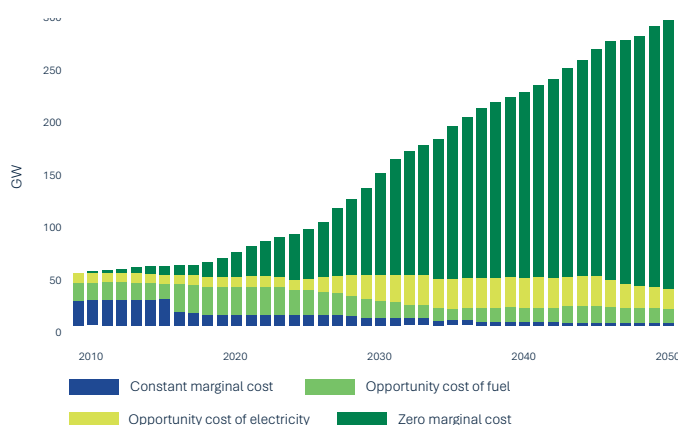
Less able to provide essential system services

Coal-fired power stations have provided many of the essential engineering services the grid needs to operate securely, such as system strength and inertia. To keep the grid running smoothly as we shift to other forms of bulk energy, shaping and firming, we need new technologies that do this. This includes machines that can operate as synchronous condensers, grid-forming inverters and other smart solutions. Encouraging investment in the most cost-efficient alternatives will help to secure the future energy system.



Changing nature of marginal costs

Price-setting in the spot market will continuously evolve as generation technologies change. Thermal power stations (black coal, gas and diesel, but not brown coal or mine-to-mouth coal) are exposed to international fuel markets, which affect their marginal costs. The opportunity costs of storage – electricity prices at other times of the day – may increasingly set spot prices during demand peaks and periods of low VRE generation. Today these opportunity costs are strongly influenced by global gas markets. VRE, with no effective opportunity cost, may set prices at other times.



Implications for the wholesale spot market

NEM prices rise and fall in line with supply availability and demand fluctuations – and always have. However, the physical changes to generation are changing these price dynamics. The barriers to efficient spot market operation and price formation are expected to become more acute, with the NEM characterised by a growing number of hidden resources, an increased need for AEMO to intervene in the market to maintain grid stability and persistent uncertainty around future demand. The Panel notes that many stakeholders expect to see spot price signals sharpening, operational price forecasts becoming less accurate and gas continuing to play a role in price formation at certain times of the day and year.

Prices will become predictably more variable and unpredictably more volatile

Price variability is a feature, not a flaw, of an energy-only spot market. Price variability allocates resources more efficiently when they are needed¹² and benefits a market that is designed for it. However, the nature of price formation will change, becoming more predictably variable on a day-to-day and seasonal basis, and more unpredictably volatile as a result of unplanned withdrawal of capacity during generator and network outages, or extended and unforeseen periods of low wind and solar output ('dunkelflautes').

Intraday price variability has increased as abundant solar generation lowers prices during the day, while higher-priced generation satisfies evening demand peaks. This price spread provides the economic basis for energy storage: charging amid low prices and discharging when prices are higher.¹³

Seasonal pricing has also changed. **Figure 19** depicts spot market pricing outcomes in South Australia, where coal power stations have been retired and there is significant VRE penetration. Fifteen years ago, pricing was relatively smooth across the day, with higher prices driven by air-conditioner use in the summer afternoon.¹⁴ Since then, intraday and seasonal price spreads have increased markedly, with prices at their highest during winter evenings. VRE generation is scarcer in winter, when gas prices tend to be higher due to the use of gas for space heating.¹⁵

¹² [Submissions to the initial NEM Review consultation](#) from AGL Energy, Snowy Hydro, ENGIE and ACEN Australia.

¹³ AER (2024), [Wholesale electricity market performance report 2024](#), p 90.

¹⁴ Strengers (2011), 'Air-conditioning Australian households: The impact of dynamic peak pricing', *Energy Policy*, volume 38, issue 11.

¹⁵ AER (2024), [State of the energy market 2024](#), p 152.

Figure 19 – Average seasonal and time-of-day 30-minute spot prices (2023 dollars) in South Australia, 2010 to 2011 and 2023 to 2024¹⁶

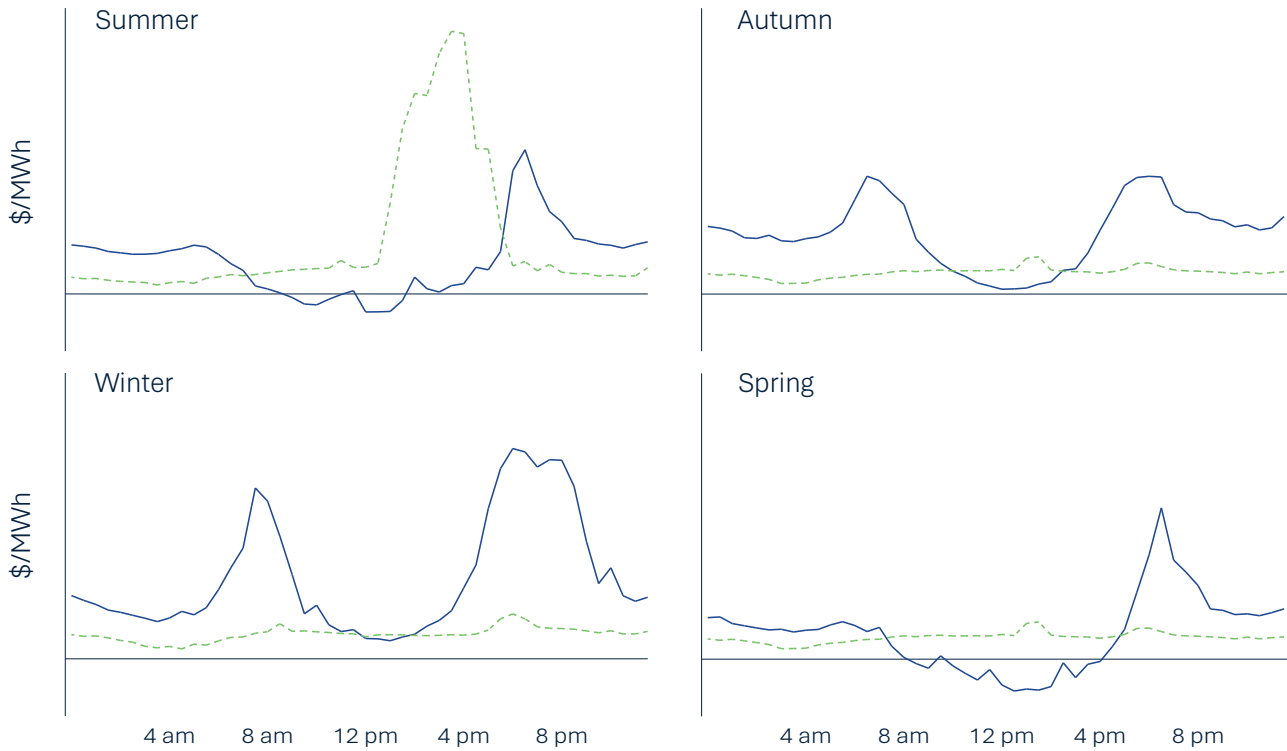
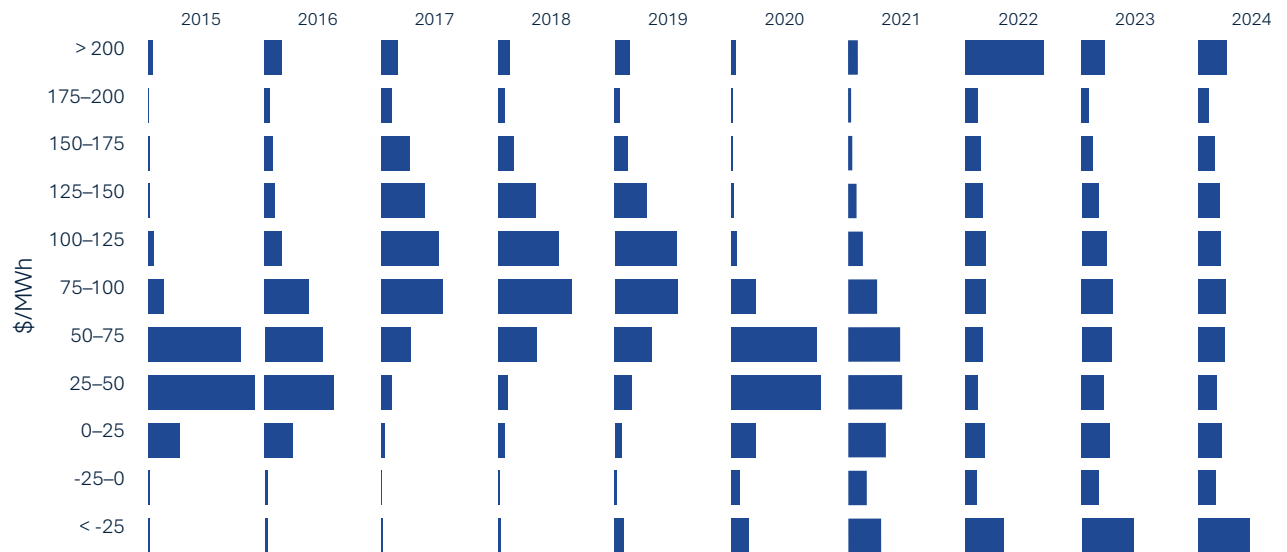


Figure 20 (below) shows the distribution of spot prices over the past decade in South Australia. As that market has become more reliant on VRE, periods of negative spot prices and higher peak prices, once rare, have become a feature of the price cycle.

Figure 20 – Distribution of 30-minute spot prices (2023 dollars) in South Australia, 2015 to 2024¹⁷

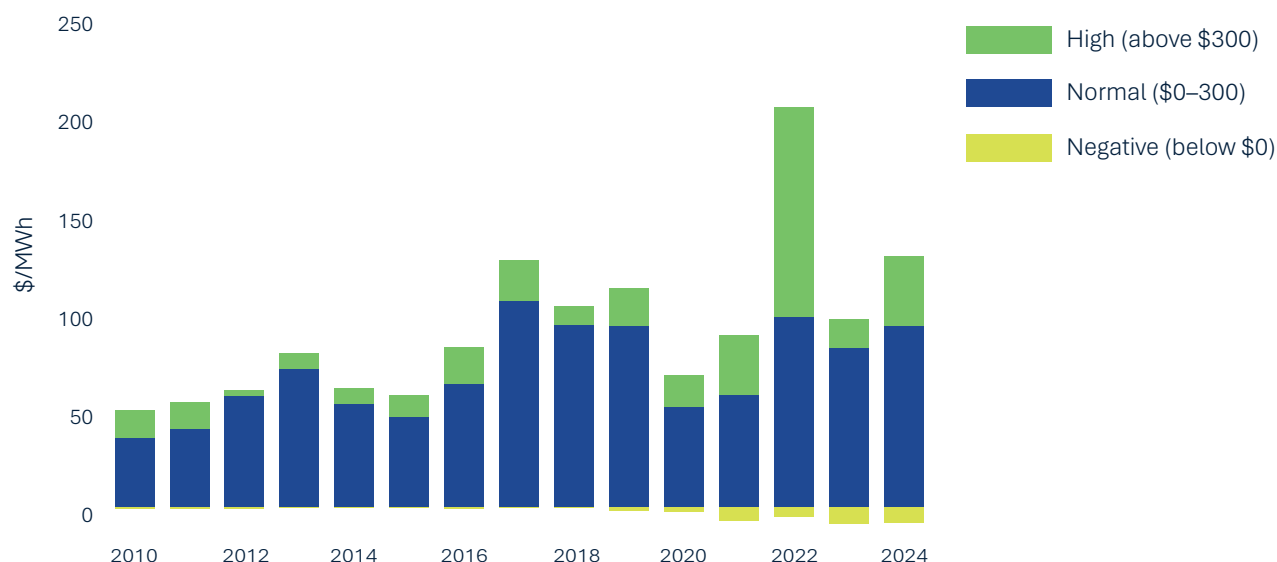


¹⁶ Sources: AEMO MMS data, ABS CPI data, NEM Review analysis.

¹⁷ Ibid.

Across the NEM, average real spot prices and price variability have increased over the past 15 years. **Figure 21** (below) shows high and negative prices playing a growing role in overall annual prices.

Figure 21 – Contribution of high, normal and negative prices to the annual NEM price (2023 dollars) weighted by native demand, 2010 to 2024¹⁸



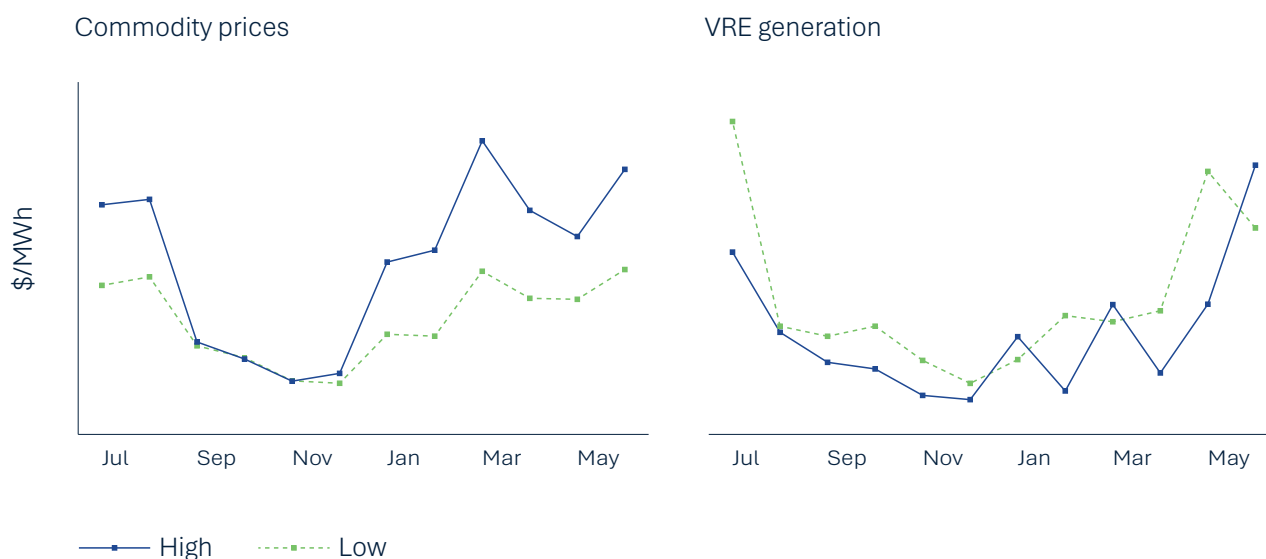
Since the 1990s, overall prices have risen as the NEM progressively absorbed an oversupply of legacy coal-fired, fully depreciated plant. Prices shifted to reflect the need for long-run investment rather than just recovery of short-run costs.

Weather and fuel costs increasingly drive price volatility. Modelling undertaken by Aurora Energy Research for the NEM Review considered the impacts of different gas prices and weather conditions (with renewable output derived from high and low-resource years from the past decade) on the spot market to 2040. The results are intuitively obvious: windy conditions with low gas prices produce very low prices. Wind droughts and higher gas prices produce much higher electricity prices.

The potential variation is shown in **Figure 22**, which depicts modelled prices in 2039–40 under different gas price scenarios, and under different weather scenarios that affect VRE generation.

¹⁸ Ibid.

Figure 22 – Forecast New South Wales time-weighted-average 30-minute spot price distribution (2023 dollars) in 2039–40 in different commodity and weather scenarios¹⁹



Operational prices are becoming less certain

AEMO's pre-dispatch process generates prices from five minutes to five days ahead of dispatch. These price forecasts are not predictions but are simply the result of market participants' current intentions to offer their supply based on AEMO's forecast future demand. As conditions change, participants can alter the quantities of supply in the price bid bands they set. This 'rebidding' allows the market to clear in real time. However, with more weather-driven generation and variable demand, it is becoming more difficult to anticipate market conditions the further into the future one observes.

The average difference between the actual price and the pre-dispatch price²⁰ across the NEM in 2010 was about \$7/MWh 5 minutes from real-time, and about \$17/MWh 30 minutes ahead of real time (2023 dollars).²¹ The corresponding differences in 2024 were about \$35/MWh for 5 minutes and about \$55/MWh for 30 minutes.

Several factors may explain why these differences are becoming more acute:

- Reliance on weather-dependent VRE generation, which is inherently difficult (but not impossible) to forecast.
- Growth in consumer energy resources (CER) such as solar PV and batteries, which are not visible to AEMO in the same way that other generators are.
- Increased utility battery bidding and the use of auto-bidding software, which research has associated with higher pre-dispatch price differences.²²

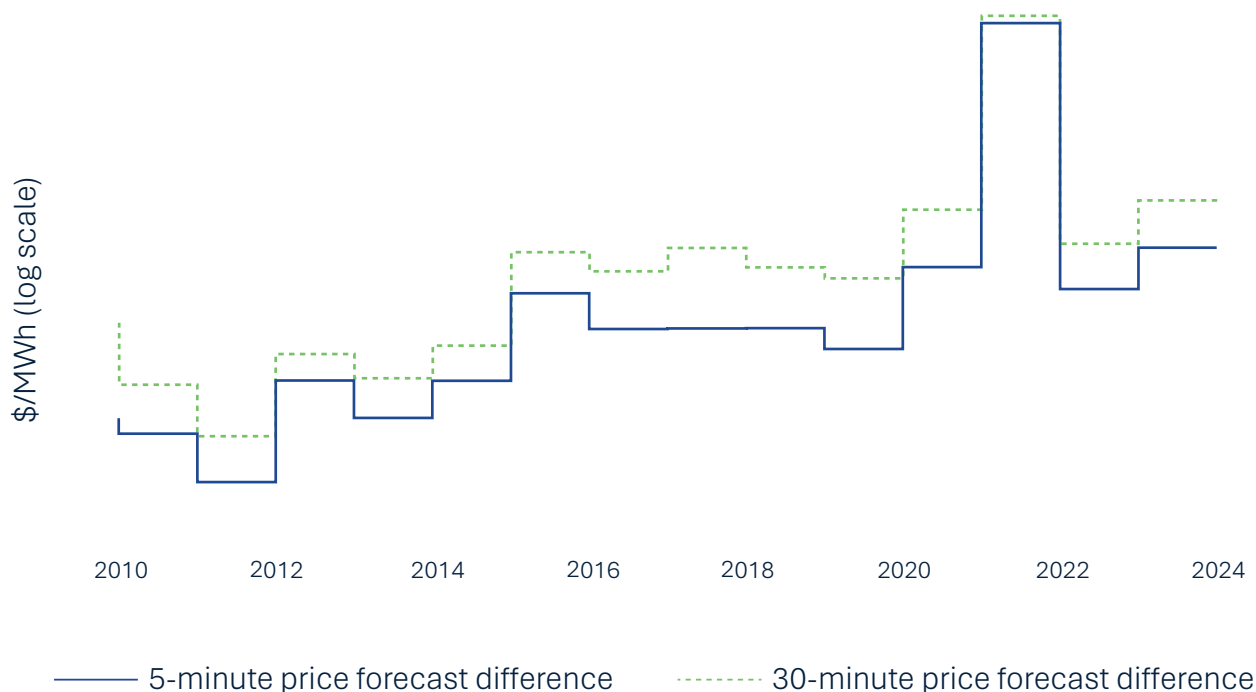
¹⁹ Source: Aurora Energy Services modelling for the NEM Review.

²⁰ Mean absolute error is used to indicate 'average difference' for this purpose.

²¹ Source: AEMO MMS data, ABS CPI data, NEM Review analysis.

²² Prakash et al. (2025), 'The scheduling role of future pricing information in electricity markets with rising deployments of energy storage: An Australian National Electricity Market case study', Energy Economics, volume 142.

Figure 23 – Annual NEM-wide mean absolute differences of pre-dispatch and actual price outcomes (2023 dollars), 2010 to 2024²³



Gas will continue to influence prices at certain times of the day and year

Gas prices remain highly correlated with electricity prices.²⁴ Global gas prices reflect the opportunity cost of the NEM's gas-fired generators. These generators will only generate if the value of their electricity exceeds the equivalent value they would receive from selling their gas to the gas market. Gas prices therefore influence electricity prices particularly acutely outside solar hours and during VRE droughts²⁵. Stakeholders have noted that the price of gas generation is often used as a benchmark for bids by batteries, hydro and pumped hydro, whose short-run marginal costs are the opportunity costs of dispatching at other times.²⁶

In this way, international gas prices sometimes set NEM spot prices even when another form of flexible generation is the nominal price-setter. For example, gas-fired generators contributed only 12% of dispatched energy from 2014 to 2021 but were estimated to have influenced the price of almost 75% of generation.²⁷ Gas generators are likely to continue to do this during times of scarce VRE supply. AEMO expects the NEM to rely on gas as a strategic reserve, particularly during VRE droughts and extreme weather events.²⁸ The chart in **Figure 18** which depicts the changing nature of marginal costs shows that gas is projected to continue to play a role as peaking generation during the transition.

²³ Sources: AEMO MMS data, ABS CPI data, NEM Review analysis.

²⁴ Nolan et al. (2022), 'The role of gas price in wholesale electricity price outcomes in the Australian National Electricity Market', Centre for Applied Energy Economics and Policy Research working paper.

²⁵ AEMO (2025), [Submission to the initial NEM review consultation](#), p 14.

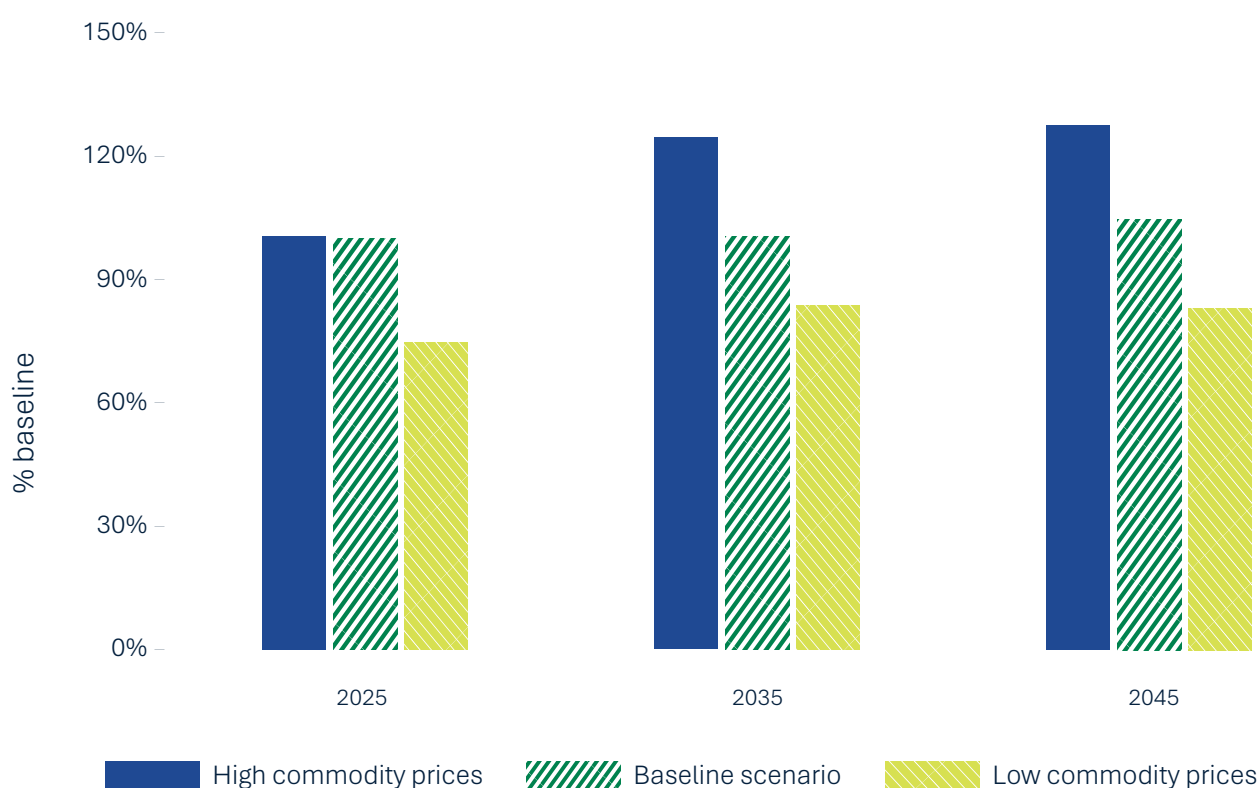
²⁶ [Submissions to the initial NEM Review consultation](#) from AEMO and the Energy Efficiency Council.

²⁷ Hirschhorn et al. (2022), [Is electricity pricing running out of gas?](#), Boston Consulting Group article.

²⁸ AEMO (2024), [2024 Integrated System Plan for the National Electricity Market](#), p 69.

Aurora Energy Research modelling suggests international gas markets may continue to have an ongoing influence on spot prices. **Figure 24** compares Aurora’s baseline forecasts, in which the long-term average gas price is assumed to be \$14.8/GJ, with alternative scenarios in which gas prices are significantly lower (\$10/GJ) and higher (\$20/GJ). The effect on NEM spot prices is observable: for example, the modelling suggests electricity prices in the higher gas price scenario would be around 20% more in 2045 than they would be in the baseline gas price scenario. The evolution of the role of CER, storage and demand response (DR) as participants in the wholesale market could impact on these outcomes.

Figure 24 – Forecast time-weighted-average New South Wales real prices (relative to the baseline in 2025) under three commodity price scenarios, 2025 to 2045²⁹



Hidden resources are impeding price formation

More resources are increasingly invisible to the market, including distributed energy resources (DER) and DR providers. These ‘hidden resources’ respond to price but do not participate in price formation. If this trend continues, it is likely to undermine efficient price formation and lead to over-building of grid-scale resources.

DER – including rooftop solar, household batteries and electric vehicles (EVs) – are transforming the NEM. Conservatively, it is estimated that consumers may spend between \$100–150 billion on CER/

²⁹ Aurora Energy Services modelling for the NEM Review.

DER in the next 25 years, excluding EVs.³⁰ These resources are not fully visible to AEMO or other market participants as they do not offer their generation into the market via the same systems and software used by larger resources (such as grid-scale batteries and generators). Their invisibility affects the dispatch process, complicating forecasting and undermining efficient price formation, at an extra cost to consumers.

AEMO's ISP assumes that, within four years, most small batteries and EVs will be well-coordinated or 'orchestrated'. However, it remains unclear whether this will occur. Consumer uptake of orchestration services remains low, estimated at about 14%.³¹ AEMO estimates about \$4.1 billion of extra grid-scale investment will be needed if the proportion of orchestration of consumer batteries does not grow.³² Furthermore, the benefits will be undermined to the extent the level of orchestration grows but remains invisible to the dispatch process. Consumers would pay for this over-spending – the result of building unnecessary generation and procuring of FCAS to correct frequency deviations caused by unanticipated responses by hidden DER – which could be avoided through greater participation and coordination.

Distributed solar and distributed storage

Distributed solar: Rooftop solar has become the fuel source with the highest registered capacity in the NEM.³³ In the past five years, consumers have installed distributed solar at about twice the rate of utility-scale solar. AEMO projects the overall capacity of distributed solar to double in the next decade, from more than 25 GW to 50 GW.³⁴ While rooftop solar has relatively predictable output, its integration into the market remains challenging because it does not participate directly in the dispatch process.

Distributed storage: Sales of distributed storage, such as home batteries and vehicle-to-grid EVs, are increasing. AEMO expects adoption to continue to grow strongly into the early 2030s, projecting capacity to increase from 1 GW to 7 GW in 2029–30, then to 34 GW in 2049–50.³⁵ This growth is more challenging than solar because it is difficult to forecast how batteries will be used. Batteries can be optimised for energy arbitrage, ESS, demand shifting or self-consumption. They can also join aggregated VPPs. However, VPPs are typically not visible to AEMO or the wider market.

DR involves consumers adjusting their electricity use in response to price signals or grid conditions. Changing wholesale market dynamics will increase the value and importance of DR in both reducing peak demand and potentially supporting minimum system load.

However, the integration of DR into the spot market, particularly through the Wholesale Demand Response Mechanism, has faced challenges. Only a few demand response service providers have

³⁰ A conservative estimate of total spending on small-scale battery (embedded and aggregated) and solar uptake (rooftop and PVNSG) alone, based on AEMO's 2024 ISP step change scenario and prices as per the 2024–25 CSIRO GenCost report's current policies pricing. See AEMO (2024), 2024 Integrated System Plan – Step Change Scenario, and CSIRO (2024), GenCost 2024–25: Current Policies Pricing.

³¹ Graham & Mediawatch (2024), Small-scale solar PV and battery projections 2024 Commissioned for AEMO's draft 2025 Input, Assumptions and Scenarios Report, p 36.

³² AEMO (2024), [2024 Integrated System Plan for the National Electricity Market](#), p 67.

³³ AER (2024), [State of the energy market 2024](#), p 293.

³⁴ AEMO (2024), 2024 ISP data (step change scenario).

³⁵ AEMO (2024), 2024 [Integrated System Plan for the National Electricity Market](#), p 50.

registered, and the total participative load has been relatively low. Financial and regulatory incentives may be insufficient to encourage wider participation. If these barriers above remain unaddressed, potential DR resources will remain invisible to AEMO and other market participants, and the potential benefits for grid stability and cost reduction will be unrealised.³⁶

Role of demand response in price formation

Intraday and annual dynamics: As generation becomes more weather-dependent and variable, demand flexibility can play a greater role in smoothing out intraday demand troughs and peaks. In the longer term, annual price variability will increase as weather outcomes drive wholesale market dynamics. DR's ability to support reliability will be of high value in low VRE weather years.

Seasonal shifts: Most market analysts expect seasonal demand peaks to shift from summer to winter in all states except Queensland, creating opportunities for seasonal demand flexibility. This shift may be prominent in cooler regions, which have higher costs in winter when energy use is high (due to spatial heaters) and wind and solar generation are low, requiring the dispatch of dispatchable generation to meet demand.

ESS-related interventions are increasing

ESS helps keep the electricity system within its technical operating envelope, during normal operation and following contingencies, so that it can securely deliver electricity. Traditionally, power stations such as those powered by coal, gas or hydro provided ESS such as system strength and inertia as a by-product of their operation. These generators use large spinning machines that help stabilise the grid by resisting sudden changes in frequency and supporting voltage levels. In contrast, VRE sources like wind and solar connect to the grid through power electronics called inverters. Standard inverters do not inherently provide the same stabilising effects as traditional generators. However, with advanced designs – such as in grid-forming inverters or advanced battery systems – these technologies can be engineered to deliver some system services and support grid stability.

The NEM needs ESS to maintain a stable and secure power system. Without these services, the grid can face outages, equipment damage, market disruptions and broader economic impacts. When there are insufficient alternative sources for these services, AEMO must dispatch older thermal plants through out-of-merit-order directions. This can lead to the use of more expensive or less efficient energy,³⁷ highlighting the financial and environmental costs of the lack of ESS from newer, more sustainable sources.

³⁶ AEMC (2025), [Review of the Wholesale Demand Response Mechanism](#).

³⁷ AER (2024), [State of the energy market 2024](#).

Increasing number of out-of-merit-order directions

AEMO directs market participants to ensure power system security, typically when the market fails to deliver enough system strength, inertia or voltage support through normal dispatch. These directions are currently most common in South Australia due to its high penetration of inverter-based resources and limited local synchronous generation.

Intended as a last resort to protect system security, these directions often involve keeping synchronous generators like gas or diesel plants online, or starting them, even when not economically optimal. This ensures stability but it is inefficient and undesirable in the long term.

In recent years, the number of these directions has been higher than expected for a last-resort mechanism. The costs associated with these directions can be high, ultimately borne by consumers, contributing to a growing proportion of the wholesale component of consumer bills.³⁸ Since these costs are determined outside the market, they do not reflect the market-determined value of the service and include a premium for involuntary participation. They also cannot be hedged or proactively managed by end users. Increased reliance on the use of directions is likely to have an inflationary impact on energy costs for consumers.

The transition to renewable generation coincides with a transformation of the nature of electricity demand. AEMO forecasts that electricity consumption will almost double by 2050,³⁹ driven by electrification, economic growth, industry changes and other factors. The interaction between dispatched generation and consumers will also become more complex: consumers, enabled by smart meters, smart appliances and CER, will be able to be more self-reliant and better able to respond to price signals by shifting their consumption.

³⁸ AER (2024), [Wholesale electricity market performance report 2024](#), p138.

³⁹ AEMO (2024), [2024 Integrated System Plan for the National Electricity Market](#), p 22.

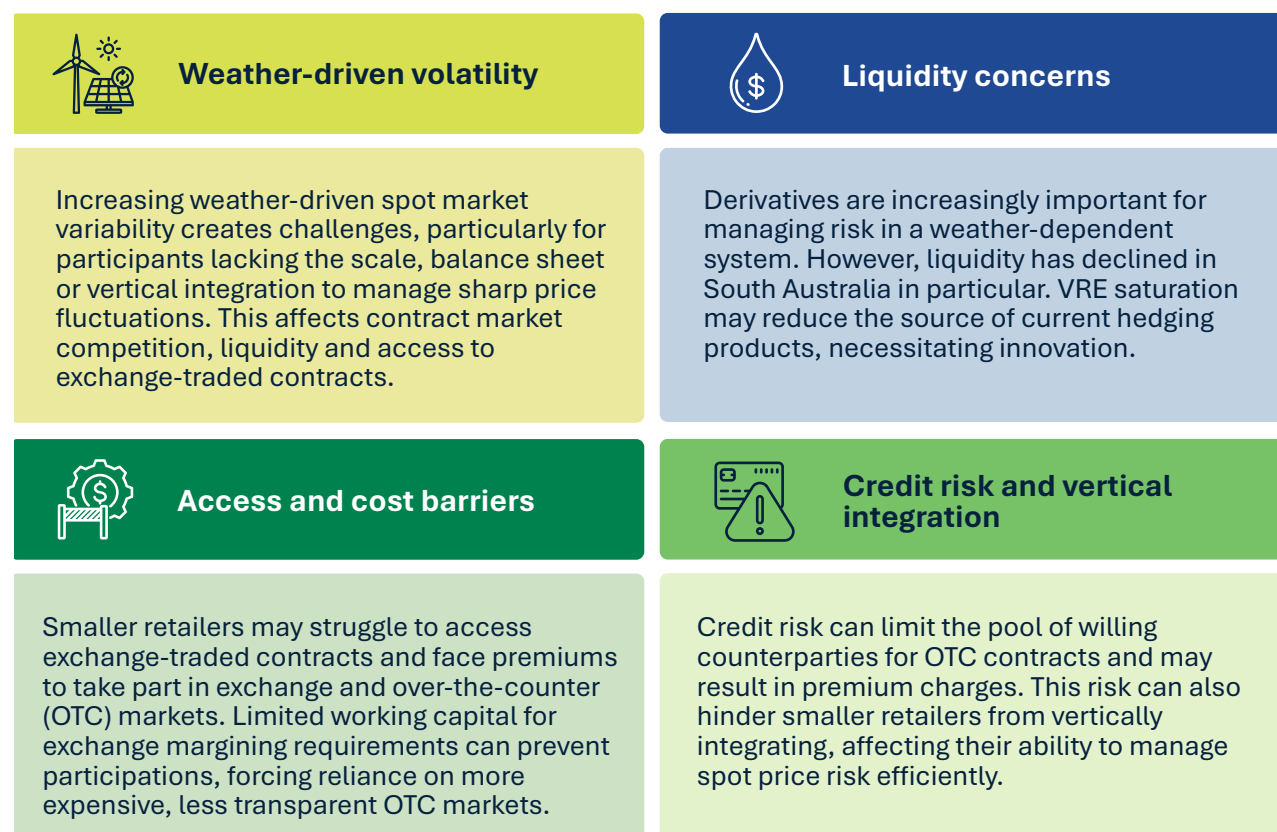
Implications for the derivatives market

Wholesale spot prices are likely to become more variable and volatile due to the growing dependency on weather. This variability and volatility can bring economic benefits but also increases the level of risk that market participants must manage. This risk will exist irrespective of the market's design, shifting from an energy-only to an energy-plus-capacity market would not alter the nature of physical risks in a weather-dependent system (alternatives to energy-only market designs are addressed further in **Ensuring effective operation of the spot market**).

Liquid and well-functioning derivatives markets are essential for managing this risk, maintaining competition and supporting the NEM's open-market approach.⁴⁰ These markets allow participants to transfer risk to those best able to manage it, enabling retailers to offer predictable prices to consumers and helping generators secure revenue certainty.

The transition to renewable energy presents specific challenges for derivatives markets, including weather-driven volatility, declining liquidity, rising access and cost barriers, and risks introduced by a trend towards vertical integration.

Figure 25 – Key challenges in the derivatives market

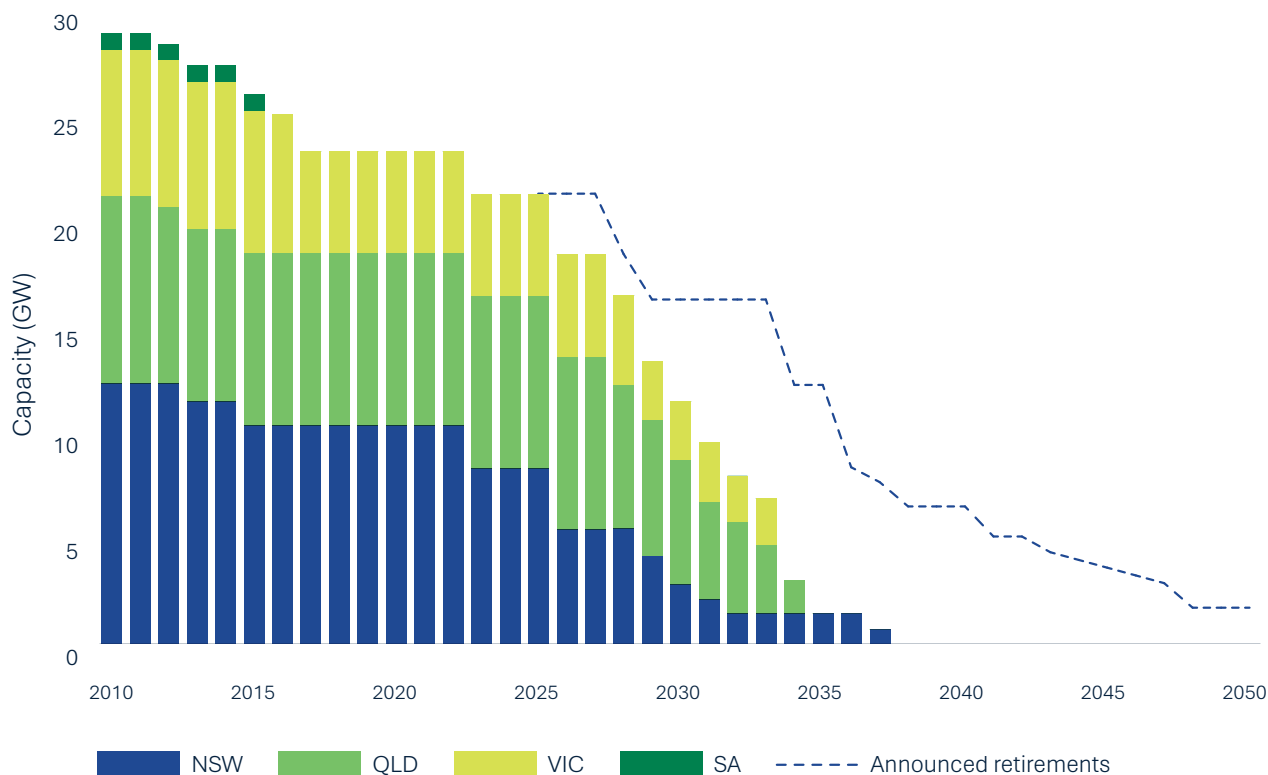


⁴⁰ Origin Energy, ACEN Australia, Clean Energy Council and CleanCo Queensland, [Submissions to the initial NEM Review consultation](#).

The derivatives market needs to evolve to continue to support price transparency and liquidity

The energy transition will change the way market participants manage forward risks, with thermal generators poised to retire in coming decades (**Figure 26**).

Figure 26 – Projected coal power station closures, 2009–10 to 2049–50⁴¹



Standard exchange-traded contracts developed in the 2000s allowed market participants to hedge forward risks. Supply-side participants at that time included thermal and hydro generators, while demand-side participants included retailers and C&I users with relatively stable, predictable electricity loads. Going forward, VRE generation like solar and wind (bulk energy) is expected to meet rising demand for electricity. However, the available supply from these plants depends on weather patterns. This means a VRE generator's ability to physically commit to supply electricity during a given period is influenced by the accuracy of weather forecasts. This contrasts with a coal, gas or hydro plant, which assesses whether it has access to coal, gas or water. As a result, VRE is less well placed to defend firm derivative contracts, such as baseload swaps or caps.

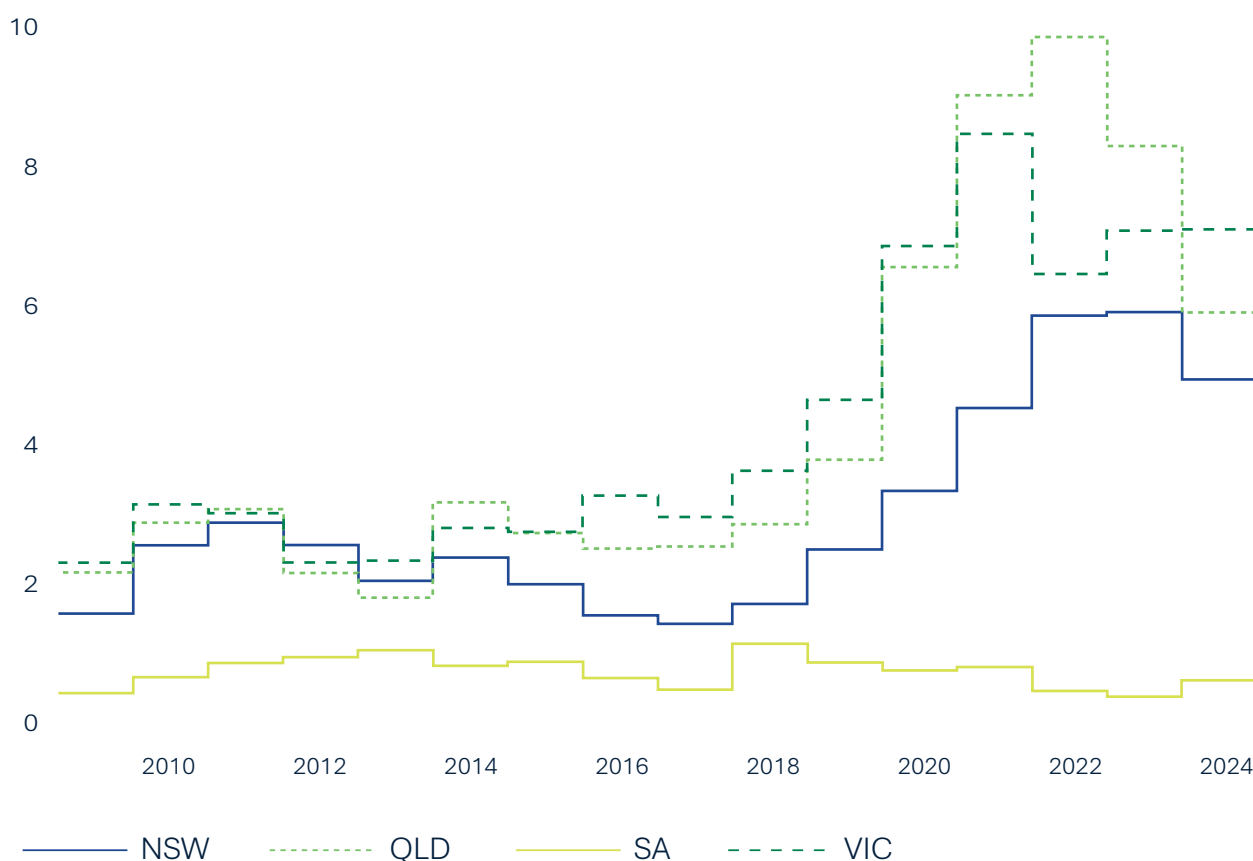
The products developed to hedge risks were designed for coal, gas and hydro generators as well as retailers and C&I users. As thermal units retire, liquidity and price transparency will be at risk unless derivatives markets evolve to allow energy to be traded from new technologies: providers of bulk energy, shaping and firming services. It is critical that derivatives markets evolve in a timely manner so new forms of contracts suitable for new technologies are available before coal plants retire.

⁴¹ Sources: AEMO 2024 ISP data (step change scenario); announced retirements are from AEMO's [Generating Unit Expected Closure Year April 2025](#). Note: The 2024 ISP projections were modelled before the NSW Government extended Eraring Power Station's operation.

The volume of energy traded on the ASX has increased considerably over the past five years. Swaptions, which, for a premium, can reduce buyers' exposure to price volatility, have overtaken base contracts to become the most widely traded energy products on the ASX.

The exception is South Australia, where liquidity is declining and has been low for many years (**Figure 27**). Trade volumes in the state's derivatives market have consistently been lower than in other NEM regions. The South Australian market is highly dependent on VRE bulk energy and peaking plants, and as a result has prolonged periods of negative prices and higher peak prices when VRE is scarce. Contract volumes and sizes (energy per trade) have fallen and, unlike other NEM markets, caps, used to hedge against price spikes, make up most of the state's ASX energy trade,⁴² which is dominated by a few large market participants.⁴³ The dynamics of South Australia's derivatives market provide potential insights into the challenges other state markets face as east-coast coal plants retire in the future.

Figure 27 – Volume of ASX-traded electricity contracts relative to native demand, 2010–24⁴⁴



Other factors limiting liquidity in SA include limited competition for long-duration dispatchable electricity generation. While the Panel notes that vertical integration may be a legitimate commercial response to managing risk, it cannot occur at the expense of transparent and liquid forward markets that provide end-users with confidence in their pricing outcomes.

⁴² AER (2024), [Wholesale electricity market performance report 2024](#), p 129

⁴³ *Op. cit.* p. 134.

⁴⁴ Source: ASX Energy data, NEM Review analysis. The liquidity ratio, a measure used by the AER, is the volume of all ASX-traded contracts divided by total native demand.

Suitable contracts need to be available before coal plant exits

As new weather-dependent technologies become the primary source of bulk energy (i.e. wind and solar) it will be important for derivatives markets to evolve beyond the products designed for the late 20th century (i.e. baseload swaps and caps). Stakeholders have demonstrated to the Panel that innovation is occurring; time-of-day and fixed shape products are being developed and traded.

However, while derivatives markets are adjusting to changes in the NEM, the pace of change has been too slow. Work is needed to bring innovative contracts to market more quickly. The transition to weather-dependent VRE, with battery, hydro and gas turbine firming, alongside the retirement of coal generation, is changing the nature of spot price risk. Market participants see a need for new contract types, such as time-of-day blocks, morning and evening peak caps, and battery tolling agreements. OTC markets are innovating, and morning and evening peak swaps were listed on the ASX from July 2025. But exchange contract innovation is slow and some stakeholders question whether innovation will be quick enough to meet evolving market needs. Regulatory and market dynamics also influence innovation in the derivatives market. The development of new contracts involves multiple steps, including market surveys, risk assessments and regulatory approvals, while factors such as business priorities and past demand experiences influence the timing and success of new products.

Implications for long-term investment

As NEM requirements and technologies evolve, potential investors in new generation and storage assets face novel and increasing risks. Concurrently, the markets for financial instruments are becoming increasingly thin. Historically, governments and system operators have supported investment through various interventions, as detailed in the **Introduction to the NEM**.

The Panel has identified that most historic policy interventions have been incomplete. For example, the Renewable Energy Target required investments in new renewables to displace the **bulk energy** from existing emissions-intensive generation. However, a more comprehensive policy suite would have also addressed critical services that these emissions-intensive generators provided, which are now absent unless supplied by other entities. These services include:

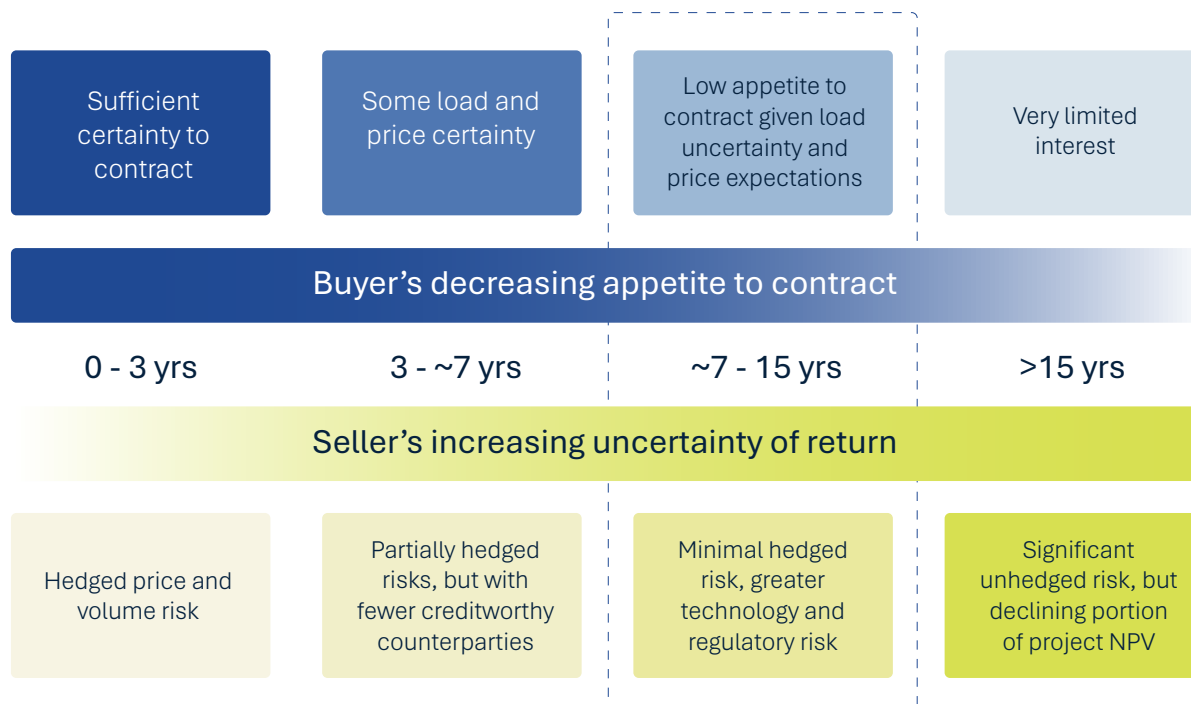
- **Shaping:** Matching the intraday and inter-day profiles of supply and demand to meet regular peaks
- **Firming:** Very long-duration and dispatchable resources that can be delivered as needed
- **Essential system services:** Services that maintain voltage, wave form and tolerance to faults
- **Usable hedging contracts:** Derivatives that allow market customers to manage risk and stabilise prices.

The tenor gap will persist

The Panel has identified the tenor gap as a reason the wholesale spot market and associated derivatives market are not driving efficient investment in the NEM. Derivative markets are typically short-dated, exchange-traded contracts generally traded three years out. However, many new projects require contracts of 15 years or longer. This mismatch is compounded by a range of overlapping risks – technological, regulatory, credit and demand related – that suppress the availability and affordability of long-term offtakes. The result is the tenor gap: a disconnect between the long-lived nature of generation and storage assets, and the short-term signals the market currently provides.⁴⁵

⁴⁵ [Submissions to the initial NEM Review consultation](#) from ACEN Australia (p 2) and ATCO Australia (p 1)

Figure 28 – The tenor gap



The NEM Review conducted a targeted survey of market participants to further investigate the tenor gap. While specific information from this survey is commercially sensitive, it confirmed that retailers continue to largely contract only a few years in advance. It also highlighted that the tenor gap is technology-specific, with notably larger gaps for peaking gas generation and pumped hydro, and notably smaller gaps for batteries and wind. Most retailers and other natural contract buyers (e.g. large commercial loads) can contract for 15 years or longer in the right circumstances, but in practice do so very rarely.

Coal exit uncertainties and entry before exit will need to be managed

Bringing new generation assets online before ageing coal plants exit may create a period of oversupply. This is necessary to avoid the risks of under-supply, including load shedding or blackouts. However, prolonged oversupply can drive prices down, deterring private investors from committing to new projects.⁴⁶

The uncertainty over when large, ageing coal generators might exit the market makes investment decisions difficult. As very large and 'lumpy' sources of generation, coal generator exits are material to new investment revenue expectations.

Governments are managing coal exits through policies like state-based structured transition agreements and the Orderly Exit Management Framework. Notwithstanding these policies, stakeholders continue to raise concerns about coal exit uncertainties in the medium to long term.⁴⁷

⁴⁶ [Submissions to the initial NEM Review consultation](#) from Iberdrola Australia (p 2) and Clean Energy Investor Group (p 4).

⁴⁷ [Submissions to the initial NEM Review consultation](#) from AEMO (p 4), Squadron (p 2), AEMC (p ii), Tesla (p 7), AFMA (p 2), Institute for Energy Economics and Financial Analysis (p 2), Clean Energy Council (p 6), Nexa Advisory (p 1), and Queensland Conservation Council (p. 3).

Investment challenges in other energy markets

Australia is not alone in facing challenges to incentivise new investment in energy services. Other markets are also struggling to attract investment. In seeking to address the NEM's investment challenges, the Panel has examined how other countries have tackled similar issues on their path to net zero.

Through its international consultation the Panel has observed evidence of the shift to 'hybrid' markets. For example, London Economics presented evidence that electricity systems in North America are "transitioning to electricity markets that are more regulated and have more government intervention". European energy experts at the International Energy Agency's 2025 Power Market Design Expert Workshop similarly emphasised the need for hybrid markets that allow long-term contracting to facilitate investment.

The Panel has considered a range of international mechanisms. These include:

Contracts-for-difference: Used in Britain to provide revenue certainty to new generators.

Centrally administered capacity markets: In the United States (e.g. New York and PJM Interconnection regional transmission organisation), these markets offer forward revenue streams to support system adequacy.

Reliability-based capacity mechanism: Ireland's mechanism provides indirect risk protection for retailers.

Market-driven approach: New Zealand's approach, centred on energy-only pricing and supported by scarcity pricing and demand response, highlights the trade-offs between market reliance and revenue certainty.

International experience highlights a range of mechanisms to support investment in energy systems, each tailored to local context, policy objectives and market design, with mixed success.

When assessed against the unique institutional and market characteristics of the NEM, it became clear that tailored solutions building on international ideas will be needed to meet the NEM's future investment needs.

Implications for electricity users

In considering the trends and challenges facing the NEM, the Panel focused on how these will impact on electricity users. Ultimately, the market only exists to serve electricity users.

Electricity users have diverse preferences in how they produce, use and manage their electricity. However, some outcomes are almost universally valued: reliable electricity at fair, stable and affordable prices. The Panel believes the market's success or failure must ultimately be judged by whether it delivers these outcomes.

The trends outlined in this chapter – the changing nature of generation in the spot market, liquidity pressures in derivatives markets and persistent structural challenges in providing the right signals for new investment – pose real risks to electricity users. Without reform this trajectory would leave consumers materially worse off, with higher bills, reduced choice and declining confidence in the energy transition.



3

Ensuring effective operation of the spot market



Chapter summary

The energy-only spot market design has proven effective at dispatching resources in real time and will continue to do so through the energy transition. The market provides sharp price signals that accurately reflect the balance of supply and demand in real time and over operational time frames. It is a powerful mechanism for ensuring efficient resource utilisation and addressing near-term reliability issues as they arise.

The Panel acknowledges the operation of the spot market is not always perfect, with inefficiencies that can impede the most efficient outcomes. On balance, the Panel considers that these ‘wrinkles’ are manageable within the current market design. Many of the more material challenges to the operation of the spot market are best addressed through incremental reforms in the spot market and complementary reforms on the investment side of the market, rather than an overhaul of the spot market design. The costs, risks and complexity of adopting alternatives are likely to outweigh the potential benefits (**Recommendation 1**).

Through the energy transition, the drivers of price formation in the energy-only market are fundamentally changing. Historically, the marginal price of electricity was strongly linked to generator fuel costs. In future, price formation will be driven by very low short-run marginal cost renewable energy, the opportunity cost of energy-constrained resources such as batteries, hydro power and pumped hydro, price sensitivities of responsive distributed energy resources (DER) and consumer energy resources (CER), demand flexibility and gas prices.

To maintain an energy-only market that is fit for the future, the Panel recommends the following reforms:

- Make price-responsive resources – including demand flexibility and DER that are currently hidden – visible to the market operator or require price responsive resources above certain thresholds to formally participate in price formation (**Recommendation 2**).
- Unlock the full benefits of consumers becoming price-responsive (**Recommendation 3**).
- Address emerging issues, including around bidding practices, visibility of battery state of charge information and the impact of transmission network outages on the spot market (**Recommendation 4**).
- Ensure market price settings adapt to the changing needs for energy, services, technologies and market dynamics (**Recommendation 5**).

Recommendations

1 Maintain the real-time regional energy-only spot market as the core market for efficient dispatch and rewarding the provision of physical energy services

- A. Retain the real-time regional energy-only spot market with necessary rule changes to ensure its continued efficient and competitive operation, recognising that increasing spot market variability and volatility can be managed.
 - B. Do not create additional mandatory centralised short-term (operational timeframe) markets, such as capacity markets or physical ahead markets.
 - C. Do not implement locational marginal pricing or variants considered previously.
 - D. Do not create distribution-level wholesale energy markets. Instead, facilitate distribution-level energy resources to participate in regional markets and use dynamic operating envelopes and dynamic network tariffs to manage local constraints.
-

2 Energy ministers should require a broader range of price-responsive resources to be visible or dispatchable to participate in price formation

- A. Leverage the voluntarily scheduled resource (VSR) participant categories established under the Integrating Price Responsive Resources (IPRR) dispatch mode framework to give effect to **Recommendation 2B**. This includes the use of ‘active mode’ which facilitates dispatch of these resources within the merit order, and ‘inactive mode’, which facilitates visibility and predictability of these resources to the market and market operator.
- B. Energy ministers should propose a rule change to the Australian Energy Market Commission (AEMC) requiring that, by 2030, various forms of price-responsive resources should be visible or dispatchable in a relevant participant category, with this obligation falling on the relevant participant.

A working position, to be refined in the review’s next phase, is that each resource should be able to choose the most suitable pathway given its characteristics; with suitable pathways, at a minimum, including the following:

- Portfolios of small batteries or generation units (below 5 MW) participating as bidirectional units or VSRs in central dispatch, once their aggregated size grows above a pre-defined threshold.
- Consumer energy resource (CER) aggregations, including virtual power plants, above a certain threshold participating in central dispatch through the VSR.
- Retailers providing price pass-through contracts or with price-contingent dispatch contracts to the customer using the dispatch mode framework in active mode, or inactive mode.
- Large loads above a certain threshold, including all market customers, participating through the dispatch mode framework (in active or inactive mode), WDRM or scheduled load frameworks. Energy ministers should establish a structured support framework to

encourage price-responsive resources to participate in the IPRR framework, WDRM, or as scheduled loads.

3 Governments should focus reforms and support for CER on facilitating market participation to enable consumers to benefit from being price-responsive

- A. Energy ministers should focus the National CER Roadmap on – and ensure sufficient resources are allocated to – delivering the critical roadmap elements that enable market participation (e.g. technical standards) and provide consumer protections.
 - B. Government incentives for investment in CER, such as for batteries, should support resources that are enabled to participate in the market through aggregators and are ready for dynamic network connections.
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4 Market bodies should use the rule change process to ensure the efficient and competitive functioning of the real-time energy-only spot market

- A. Market bodies and the Australian Competition and Consumer Commission (ACCC) should work together to develop regulatory responses, including rule changes if needed, that address risks created by excessive rebidding and algorithmic bidding.
 - B. Market bodies should analyse whether publishing battery state of charge information from July 2025 adequately mitigates reliability risks or whether further reforms are needed.
 - C. Market bodies should work to minimise the impact of transmission network outages on the energy-only spot market. The Australian Energy Regulator (AER) should work with the AEMC and Australian Energy Market Operator (AEMO) to replace the suspended market impact component of the regulatory framework. The AER should also continue to review whether network constraints affect competition and drive high spot prices, and progress rule changes to the AEMC if required.
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5 The Reliability Panel should consider adjusting the form of the market price settings

- A. The market price settings, including the market price cap (MPC), market price floor (MPF), cumulative price threshold (CPT) and administered price cap (APC), should remain linked to the value of customer reliability (VCR) and to revenue adequacy for bulk energy, shaping, and firming services. However, given the significant changes expected in the market and the intention of recommendations in other chapters to extend price discovery, the Reliability Panel should consider whether to adjust the form of the market price settings and provide a longer-term outlook (up to 15 years) on their intended form to support long-term contracting.

Recommendation 1: Maintain the real-time regional energy-only spot market as the core market for efficient dispatch and rewarding the provision of physical energy services

The energy-only spot market is a core strength of the NEM but the shape of supply and demand is changing

The NEM was designed as a mandatory gross pool with an energy-only market, to align with the Hilmer reforms' goals of competition and efficiency.⁴⁸ In this market, scheduled generators must offer their available capacity at prices ranging from the market price floor of negative \$1,000/MWh⁴⁹ to the MPC of \$20,300/MWh,⁵⁰ updating their offers every 5 minutes. The highest-priced offer needed to meet demand sets the spot price in real time (uniform-clearing price as opposed to pay-as-bid) every 5 minutes and in every region. All dispatched generators receive this single price at the regional reference node, reflecting a key feature of the NEM: the lack of price disaggregation across sub-regions or at the distributed level.

This energy-only, gross pool, real-time, regional pricing mechanism creates sharp, transparent price signals that seek to reflect supply–demand conditions. Price volatility is a fundamental feature of this market design, allowing prices to reflect the real-time supply–demand balance and the level of resource scarcity.⁵¹ These price signals play a role in driving investment over the long term, with higher prices during times of generation scarcity signalling the need for new capacity. Derivative markets capture expectations of spot prices over the medium term. For the market to remain sustainable, it must facilitate generators recovering efficient fixed and variable costs over the life of the asset. The NEM is designed to dispatch the cheapest generator bids first, followed by progressively more expensive offers, until enough electricity is produced to meet demand, subject to any network or technical constraints.⁵² Traditionally, this merit order consisted of generation to suit baseload, mid-merit and peaking demand, each with progressively higher short-run marginal costs (SRMC).

However, the physical characteristics of the system are undergoing significant transformation. A generation fleet composed primarily of near-zero SRMC variable renewable energy, opportunity-cost-based generation such as batteries and hydropower (with limited energy available compared to capacity) and higher-cost firming (such as gas-powered generation) creates a very different supply curve.

⁴⁸ A gross pool market requires generators to sell all electricity through the market pool. This is contrasted to a net pool market where generators can make bilateral contracts directly with market customers for delivery of electricity before they sell any remaining electricity in the market pool.

⁴⁹ AEMC (2023), [National Electricity Amendment \(Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap\) Rule](#), p 2.

⁵⁰ AEMC (2025), [AEMC updates market price cap for 2025–26](#), media statement, 27 February.

⁵¹ [Submissions to the initial NEM Review consultation](#) from CS Energy (p 2), the Superpower Institute (p 6).

⁵² AER (2024), [State of the energy market 2024](#), p 17.

Figure 29 – The NEM's past (left) and future (right) supply and demand curve

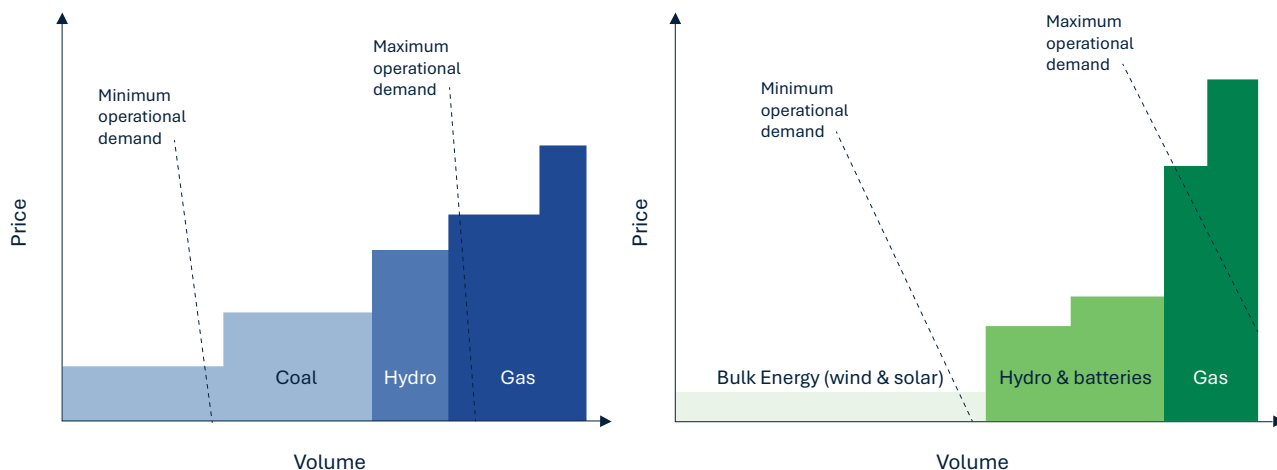
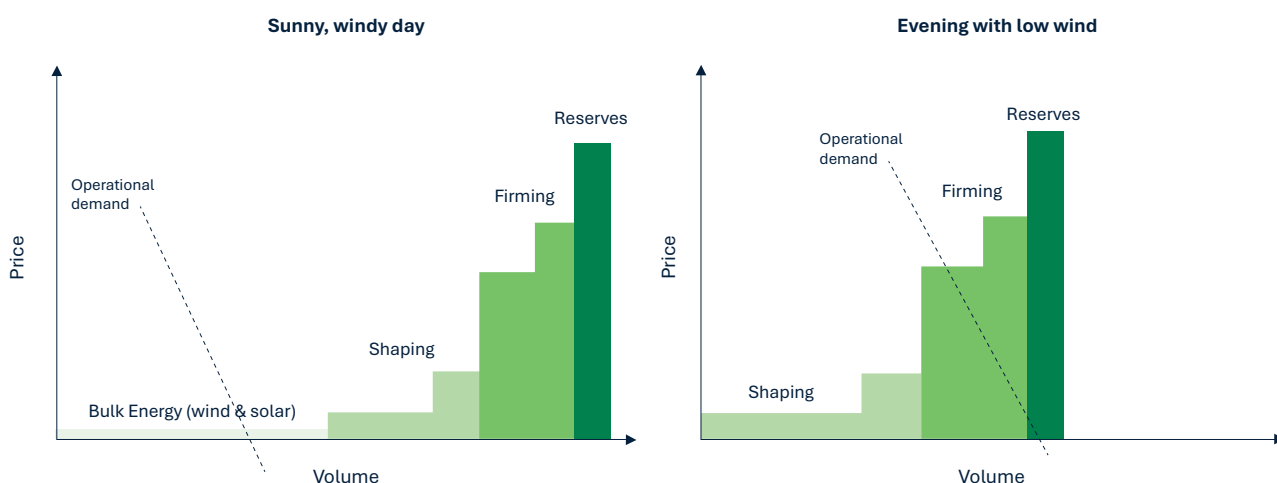


Figure 29 shows how the supply and demand curve changes as more renewable generation enters the NEM. Renewables, with near-zero SRMC, sit at the bottom of the generator bid stack and displace higher-cost generators such as coal. During periods of high renewable output, the supply curve flattens, particularly during periods of low operational demand. However, when renewable output drops, the curve steepens sharply as the market turns to more expensive, flexible generation to meet peak demand.

Figure 30 shows how the supply curve shifts with changing renewable output. When wind and solar energy are abundant, the supply curve flattens due to the availability of near-zero marginal-cost supply. When renewable generation is scarce, the curve steepens and contracts, leading to higher and potentially more volatile prices.

Figure 30 – High (left) and low (right) weather output affects the supply and demand curve



The NEM was designed in an era where grid-based demand was relatively inelastic in the short term, meaning consumers were largely unable or unwilling to shift their electricity use in response to price changes. However, the growing integration of CER, DER and both small and large-scale demand flexibility (all partial grid-substitutes) is leading to more elasticity of demand for grid electricity.⁵³ The

⁵³ While consumers may continue to use electricity, they can use less from the grid when it is expensive because they can produce and store their own electricity.

transition to greater VRE penetrations will increase spot price variability, presenting opportunities for some users to shift their demand in response to price changes, enabling more dynamic responses to changing supply conditions. The AER plays a key role in monitoring high-price events to ensure that prices reflect underlying supply and demand conditions, or factors such as network constraints or strategic rebidding.⁵⁴

Traditionally, the cost of coal and gas has played a significant role in setting electricity prices due to price inelasticity. However, the emergence of storage and energy management systems may result in the opportunity cost of storage and demand increasingly playing a role in establishing prices.

Electricity users with highly flexible demand are expected to play a significant role in setting electricity prices in the future, by adjusting their consumption in response to market signals, and helping to balance supply and demand.⁵⁵ For example, in New Zealand the Tiwai Point aluminium smelter, which uses about 20% of electricity in the North Island, has commercial agreements to provide large-scale demand response to the system.⁵⁶ During the winter of 2024 Tiwai Point progressively increased its demand response above the contracted maximum, to 205 MW, a 36% reduction in total consumption.⁵⁷ By actively adjusting industrial energy use, New Zealand can maintain balance in the power system and reduce reliance on more expensive generation during peak winter demand.⁵⁸

The energy-only market remains efficient in a highly renewable system

In a system dominated by near-zero marginal cost renewables, there are growing concerns that the market will experience frequent zero or negative prices during periods of surplus renewables and sharp price spikes during renewable output scarcity.^{59,60} A key question is: can the market continue to send clear, efficient price signals that reflect marginal costs in a system dominated by near-zero marginal cost renewable generation?

Most stakeholders agree that the energy-only market continues to deliver reasonably efficient operational dispatch.⁶¹

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The potential for price volatility is inherent to the energy-only market design as it enables a highly accurate reflection of the balance of supply and demand, and the level of resource scarcity. –

CS Energy

The ability of the energy-only market to reveal system dynamics and convey scarcity in real time is one of its strengths. –

Snowy Hydro

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⁵⁴ AER (2022), [Significant price reporting guidelines](#), p 3.

⁵⁵ Briggs et al. (2024), ‘Flexible Demand – the Current State of Play in Australia’, in *Institute for Sustainable Futures*.

⁵⁶ Electricity Authority Te Mana Hiko (2024), [The Tiwai Point smelter demand response in winter 2024](#) article, 28 November.

⁵⁷ Op cit.

⁵⁸ NZ Electricity Authority (2025), [Rewarding industrial demand flexibility: Issues and options paper](#), p 2.

⁵⁹ Antweiler, W. & Müsgens, F. (2024), ‘The new merit order: the viability of energy-only electricity markets with only intermittent renewable energy sources and grid-scale storage’, in *USAE Working Paper*.

⁶⁰ G Thomaßen et al. (2022), ‘Will the energy-only market collapse? On market dynamics in low-carbon electricity systems’, in *Renewable and Sustainable Energy Reviews*.

⁶¹ [Submissions to the initial NEM Review consultation](#) from CS Energy (p 2), Snowy Hydro (p 5), AFMA (p 2), Iberdrola (p 5), Hydro Tasmania (p 13), ENGIE (p. 2), AGL (p 3), and ACEN Renewables (p 2).

The reduced role of fuel costs in high-renewables systems does not necessarily undermine the fundamentals of energy-only markets, provided that storage operations, scarcity pricing and demand response are effectively integrated into market operations.⁶² The opportunity cost of storing electricity in batteries or pumped hydro is likely to be an important driver of prices, as there is always a trade-off for how long to store or discharge energy.⁶³ Even modest demand elasticity can enhance market performance by smoothing out extreme price spikes.⁶⁴ This underscores the importance of enabling greater visibility and participation of both large-scale and behind-the-meter demand-responsive resources to ensure efficient price formation (refer to **Recommendation 2**).⁶⁵

The spot market is sending incomplete signals for investment

The energy-only market has generally succeeded in delivering both revenue adequacy and efficiency over short-term operational timeframes, key strengths that should be preserved through the transition. However, as the NEM transitions, there is a growing need for durable, long-term investment signals.

The tenor gap, defined by the Panel as the mismatch between long-term contracts needed by sellers and the short-term contracting of buyers, is a significant factor. Uncertainty around the timing of coal plant retirements, rapid technological changes and shifting policy settings makes it difficult for investors to assess future market conditions and commit to financing capital intensive long-term projects.

To address this, the Panel has proposed targeted reforms, including the Electricity Services Entry Mechanism (ESEM), to provide durable, long-term signals while preserving the efficiency and integrity of the real-time wholesale spot market.

⁶² T Brown et al. (2025), '[Price formation without fuel costs: the interaction of demand elasticity with storage bidding](#)', in Energy Economics.

⁶³ Ibid.

⁶⁴ Ibid.

⁶⁵ Ibid.

1A: Retain the real-time regional energy-only spot market with necessary rule changes to ensure its continued efficient and competitive operation, recognising that increasing spot market prices variability and volatility can be managed.

Incremental reforms to the well-functioning spot market can manage factors impeding efficient operation

Most stakeholders agree that the spot market efficiently allocates existing resources and, in tandem with forward derivative markets, provides revenue sufficiency for an efficient level of investment, though there are alternative views.⁶⁶

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The sustainability of the current dispatch process is showing signs that evolution is required to ensure it remains fit for purpose – AEMO

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As the NEM undergoes fundamental changes to its generation fleet, factors impeding efficient operation and price discovery may become more prominent. However, these factors can be addressed with incremental reforms such as requiring the participation of aggregated small-scale, price-responsive resources (**Recommendation 2**). To preserve the efficiency and competitiveness of the spot market, the Panel recommends retaining its core design while making targeted rule changes as required (**Recommendation 4**). This includes addressing excessive and algorithmic bidding, assessing the adequacy of battery state of charge information and reducing transmission outage impacts on spot market efficiency.

Consumers must be supported to respond to or manage price risk

As the energy mix becomes more energy-constrained and weather-dependent, spot price signals are expected to sharpen. This increased price and earnings volatility for market participants will increase the importance of responding to or managing risk for consumers and generators.⁶⁷

As prices become more variable, demand flexibility can play a greater role in smoothing out demand troughs and peaks. The full benefits of price-responsive resources in meeting market needs will only be unlocked when these resources are visible to the market. This visibility enables efficient spot price formation, promoting grid stability, competition and investment. The Panel acknowledges both the significant opportunity and the potential cost of failing to effectively integrate responsive demand into the market and has recommended reforms to support consumer outcomes (**Recommendation 2**).

A well-functioning derivatives market, characterised by transparent pricing, robust competition and deep liquidity, is essential for translating volatile spot signals into investable, forward-looking price information.⁶⁸ Increased year-to-year variability as weather increasingly drives price outcomes, particularly over winter, will affect retail electricity prices, underscoring the importance of retailers engaging in longer-term risk management to smooth wholesale volatility for consumers. While derivatives markets are adjusting to changes in the NEM, the pace has been too slow. The Panel

⁶⁶ [Submissions to the initial NEM Review consultation](#) from AEMO (p 2), and T Ancev and S Qu (p 1).

⁶⁷ Hirschhorn et al. (2022), ‘[Is electricity pricing running out of gas?](#)’, Boston Consulting Group article.

⁶⁸ [Submissions to the initial NEM Review consultation](#) from CleanCo Queensland (p 3), Iberdrola (p 6), ENGIE (p 2).

acknowledges the need for market participants to manage price risk effectively and has recommended reforms to support consumers (see **Maintaining liquidity in the derivatives market**).

System security directions are increasing costs for consumers

The physical characteristics of the system are evolving as VRE replaces synchronous generators that traditionally provided essential system services to the grid. Without alternative sources of inertia, system strength and voltage support, AEMO must dispatch legacy thermal units, even when these are not the lowest-cost energy sources.⁶⁹ These out-of-merit-order directions have increased in frequency and cost over recent years with these costs ultimately borne by consumers. In South Australia, the cost of these directions is becoming a material and growing proportion of consumer bills.⁷⁰

As synchronous units have physical characteristics that support grid stability, shifting towards more asynchronous, inverter-based VRE means grid stability must be provided in other ways. Several reforms underway are designed to address these issues, and the ESEM presents a further opportunity to deliver ESS capabilities at lower cost (see **Unlocking long-term investment in new energy services**).

⁶⁹ AER (2024), [State of the energy market 2024](#).

⁷⁰ The Compensation Recovery Amount as a proportion of the DMO wholesale cost for residential and small business customers has increased from 3% in 2020–21 to 5% in 2022–23 in SA. AER 2024, [Wholesale electricity market performance report 2024](#), 20 December, p 138.

1B: Do not create additional mandatory centralised short-term (operational timeframe) markets, such as capacity markets or physical ahead markets

The existing energy-only market maintains reliability over operational timeframes

Some stakeholders argue that spot price signals are becoming less effective in providing revenue certainty for peaking generation. Concerns have been raised that the wholesale energy-only market is struggling to deliver sufficient long-term price signals to support timely and efficient investment, leading to suggestions for alternative models. Several stakeholders proposed introducing a capacity market or a certified capacity scheme, similar to the capacity mechanism proposed by the Energy Security Board in 2021.⁷¹ The intention behind introducing a capacity market is to provide a regulatory mechanism that ensures generation is available during peak times, supporting revenue sufficiency and consistency for dispatchable generation.

However, the existing energy-only market delivers strong, real-time scarcity signals through a high MPC aligned with the VCR. These sharp price signals incentivise availability when it is most needed and allow generators to recover costs during scarcity events. Conversely, participants are penalised for not delivering energy when it is most required by being exposed to high prices when they have forward-sold their capacity. Alternative market designs struggle to match these price signals for ensuring reliability, particularly as new, more flexible resources enter the system, such as batteries.

The NEM also features a well-established cap contract market that allows participants to manage risk and smooth revenue, supporting revenue consistency for market participants. This market is effectively a decentralised capacity market. Participants actively use these markets to hedge against price volatility.

These features of the energy-only market deliver the key outcome that capacity markets are designed to provide over the operational timeframe – reliable capacity that meets reliability standards. The Panel believes an energy-only market will continue to provide these outcomes in a renewable-dominated and high-opportunity-cost system. Neither energy-only markets nor short-term capacity markets alone are sufficient to incentivise the necessary investment during the transition, as neither overcome the tenor gap. International experience shows that once a market design is chosen, the most effective approach is to build on that foundation, addressing emerging challenges through targeted reforms rather than pursuing major market redesign (see discussion of international challenges in other energy markets in **Trends and challenges in the NEM**). Given this, the Panel has prioritised targeted reforms that support the existing system rather than fundamentally restructuring it.

⁷¹ For example: Australian Pipelines and Gas Association, Potentia Energy, Hydro Tasmania, Origin Energy, Shell Energy, Alinta, Energy Users Association of Australia, Centre for Independent Studies, Stanwell Corporation, CleanCo Queensland, and Delta (2025), [Submissions to the Initial NEM Review Consultation](#).

Why uniform clearing price rather than pay-as-bid?

The NEM operates using a uniform clearing price. Under this system, all generators receive the same transparent clearing price, set by the marginal cost of the last generator dispatched to meet demand. This is designed to encourage all generators to bid their true costs. The market then selects the lowest-cost combination to supply electricity, with the aim of delivering efficient, least-cost outcomes for consumers under conditions of effective competition.⁷²

By contrast, a pay-as-bid system forces participants to submit bids that reflect their best guess at what price will be for the most expensive needed resource, instead of bidding their actual costs.⁷³ This encourages gaming and strategic bidding. The most sophisticated players tend to win, while smaller or newer participants are disadvantaged. Prices under pay-as-bid reflect bidding strategies, not actual system costs, which undermines transparency and weakens investment signals. Bids in a pay-as-bid model tend to converge around the same level, making the total cost similar to the uniform clearing price.⁷⁴ Uniform clearing prices also support liquid derivatives markets (a key means by which participants can manage risk), clear price signals for investment, and efficient dispatch – all critical as we integrate more renewables, storage, and flexible demand into the grid.

A limited number of stakeholders raised the introduction of physical day-ahead markets to improve certainty and coordination in the NEM. Physical day-ahead markets are markets where market participants purchase and sell electric energy at financially binding day-ahead prices for the following day. A system operator uses this to create a schedule of commitments for the purchase and sale of energy for the following day according to bid and offer data from participants. Day-ahead markets are accompanied by a real time or balancing energy markets, to account for variations in supply and demand between the day-ahead schedule and actual market conditions at the time of dispatch.

Some stakeholders highlighted barriers for price-responsive consumers and dispatchable loads to optimise load with sufficient notice (see **Recommendation 2**). International examples, like the day ahead market in PJM Interconnection, aim to provide demand response providers with greater predictability and notice for participation. However, even markets with day ahead trading, such as CAISO or ERCOT, are relying on additional investment support by government through long-term contracts or state funding programs. While the Panel recognises the potential benefits of short-term ahead markets for some participants, these services can be provided through financial markets, where innovation is already occurring. Furthermore, resources requiring very significant notice to respond to conditions may not necessarily be as economic in an increasingly weather-dependent system where flexibility and fast response is most valuable.

⁷² Watkiss, J. et al. (2023), [Time to Double Down on Uniform Pricing in U.S. Energy Markets](#), in *Yale Journal on Regulation*

⁷³ ISO New England (2006), [The Benefits of Uniform Clearing-Price Auctions for Pricing Electricity](#), p 1.

⁷⁴ Ibid.

1C: Do not implement locational marginal pricing (LMP) or variants considered previously

The cost of implementing LMP, and other variants recently considered by the AEMC, would likely exceed the benefits and would not provide certainty to market participants over investment timeframes

The NEM was designed with zonal/regional pricing, where price formulation and market functions occur in relation to a designated reference node in each region.⁷⁵ The combination of open access, regional pricing and central dispatch can result in both operational and investment inefficiencies, particularly under constrained conditions. By applying a uniform price across each zone, the market can misprice generation when there are transmission constraints, leading to profits that diverge from the true economic value of participants' actions.⁷⁶ To partially address this, the NEM incorporates marginal loss factors (MLFs) as a core feature of the locational pricing framework. MLFs reflect marginal transmission losses between generation and regional reference nodes, which are applied in market settlement. MLFs provide a financial signal that helps guide efficient investment in generation and discourages development in locations that would increase system losses.

A limited number of stakeholders propose implementing LMP to address concerns that a lack of locational signals in the NEM could lead to over-investment in generation and network infrastructure beyond what consumers value.⁷⁷ LMP is a core feature of many international electricity markets, designed to reflect the true cost of supplying electricity at different points on the grid by incorporating both generation costs and network congestion. It is most effective in systems with varying marginal costs, such as those dominated by coal and gas. For example, where a constraint limits flows from a region with low-cost coal (e.g. \$50/MWh) to one relying on higher-cost gas (e.g. \$150/MWh), LMP results in higher prices on the constrained side, signalling scarcity and the value of local generation.

This dynamic changes dramatically in the context of a decarbonised grid dominated by wind and solar. With most renewable generators bidding at or near-zero SRMC, the system cannot distinguish economically between them during periods of constraints. While LMP still reflects scarcity on the constrained side, it no longer provides meaningful dispatch signals or guides efficient investment. LMP in this context becomes less useful as a tool for driving efficient short-run outcomes or long-term investment signals. However, evidence from the wholesale electricity market in ERCOT shows that LMP could provide greater operational efficiency benefits by incentivising more efficient bidding by storage in congested areas.⁷⁸

⁷⁵ Zonal pricing (also known as regional pricing) refers to setting of wholesale prices at the regional reference node of each NEM jurisdiction. Nodal pricing refers to setting of prices at each node on a network. There are typically hundreds of nodes on a transmission network. Further information is available at AEMC (2024), [Final report volume 3 of 3: Transmission access reform: Access and pricing in the NEM](#), p 1–3.

⁷⁶ M Katzen & G Leslie (2024), [Siting and operating incentives in electrical networks: a study of mispricing in Australia's zonal market](#) in *International Journal of Industrial Organization*.

⁷⁷ [Submissions to the initial NEM Review consultation](#) from Centre for Independent Studies (p 8), Greg Williams (p 4), Reposit Power (p 4), Energy Consumers Australia (p 5).

⁷⁸ Potomac Economics (2025) [2024 State of the Energy Market Report for the ERCOT Electricity Market](#), p 52.

The limitations of market mechanisms in transmission investment

LMP is a core feature of many electricity markets, designed to signal the true cost of delivering electricity at different locations by accounting for both generation costs and network congestion.

LMP works effectively when there is a diverse set of generators with varying marginal costs distributed across the network. Take, for example, the traditional grid dominated by coal and gas. Suppose there is a transmission constraint between two regions: Region A with low-cost coal generators (e.g. \$20/MWh) and Region B that relies on higher-cost gas generators (e.g. \$80/MWh). When the transmission line becomes constrained, Region B must meet its own demand using more expensive local generation. As a result, the LMP in Region B rises significantly, accurately reflecting the cost of local supply and the value of scarce transmission capacity. This price signal incentivises more efficient dispatch, demand-side response and potentially local investment to relieve the constraint.

However, this dynamic changes dramatically in the context of a decarbonised grid dominated by wind and solar. These renewable generators have effectively zero short-run marginal cost, meaning they all bid into the market at or near \$0/MWh. Imagine now that Region A and Region B are both rich in solar resources, and a constraint emerges between them. Behind the constraint, say in Region A, there may be 500 MW of solar generation but the transmission line can only carry 300 MW. With all solar generators bidding in at \$0, the system has no economic basis to prefer one over another; they are indistinguishable from a cost perspective. As a result, LMP still rises on the constrained side (Region B), reflecting scarcity, but it does little to guide efficient dispatch or signal which generator should be built or curtailed. There is no marginal cost variation to exploit. LMP in this context becomes less useful as a tool for driving efficient short-run outcomes or long-term investment signals.

Some argue that financial transmission rights (FTRs) – which pay out based on price differences between nodes – can address this problem by providing a hedging instrument for congestion risk. In theory, FTRs reward holders when there is a price difference between two locations, which could provide an incentive to build generation in congested areas or fund transmission upgrades. However, in practice, FTRs have limitations. First, they are typically auctioned or allocated for relatively short durations, one to three years at most. For example, market participants in New Zealand report that the two-year FTR auctions provide limited value for long-term investment decisions, with no generators citing them as enabling new generation. This timeframe is far too short to underpin the kind of long-lived capital investment required to build new transmission infrastructure or large-scale generation. Second, FTRs are purely financial instruments; they do not confer physical access to the grid or rights to dispatch.

The issue of zonal versus nodal pricing has been considered numerous times since the NEM's inception, but successive reviews have ultimately retained the zonal market design. Most recently, the AEMC completed its transmission access reform review in 2024, recommending against implementing the hybrid access reform model. The AEMC concluded that the benefits of priority access to improve investment efficiency and certainty over and above what can be achieved through jurisdictional schemes, if delivered effectively, would likely be marginal.⁷⁹

⁷⁹ AEMC (2024), [Final report: Volume 1 of 3, September. Transmission access reform.](#)

It was determined that the congestion relief market, which is complex and contains a number of design compromises, creates uncertainty about whether potential benefits would materialise and outweigh the costs of implementation.⁸⁰ The Panel will not pursue LMP as part of this review, as LMP and related transmission access reforms were recently ruled out by Energy and Climate Ministers in 2023.⁸¹

Under current market settings in the NEM, generators operating in congested areas can develop solutions for managing constraints through investment in flexible resources. By co-locating storage behind the congestion point, generators can smooth output during peak congestion periods, improve access to higher market prices, and reduce curtailment risks. These arrangements can create mutual benefits: generators increase their revenue certainty and asset utilisation, while the shared infrastructure spreads costs and improves the overall efficiency of grid utilisation. Virtual transmission can also increase the effective capacity of the existing transmission system by placing batteries near demand centres. Transmission network service providers (TNSPs) can contract these batteries to boost line ratings and safely move more energy through the network, deferring or avoiding the need for physical infrastructure upgrades. These strategies demonstrate responses to network congestion and how the market can work to respond to network congestion, finding effective solutions without the need for locational marginal pricing.

As noted above, the policy response to the mispriced signals for investment associated with the current zonal market design is the development of Renewable Energy Zones (REZs) by individual NEM jurisdictions. While implementation varies, REZs typically allocate defined network capacity to new renewable generation and storage projects based on expected generation and load profiles.⁸² In principle, this approach helps reduce the risk of inefficient or duplicative network investments by providing a framework for coordinated decentralised investment.⁸³

⁸⁰ Ibid.

⁸¹ Energy and Climate Change Ministerial Council, [Meeting Communiqué](#), 24 February 2023.

⁸² Ibid.

⁸³ P Simshauser (2025), '[Competition vs. coordination: optimising wind, solar and batteries in renewable energy zones](#)', in Energy Economics.

1D: Do not create distribution-level wholesale energy markets. Instead, facilitate distribution-level energy resources to participate in regional markets and use dynamic operating envelopes and dynamic network tariffs to manage local constraints

Integrating CER within the existing market is preferable to creating new distribution-level wholesale markets

Work is being undertaken through the National CER Roadmap to consult on the roles and responsibilities for integrating CER economically into the market and physically into the power system, including potential options for real-time energy markets at the distribution level.⁸⁴ The Panel notes that separate distribution-level wholesale markets would represent significant changes to the NEM as it currently stands. Such changes would require detailed and lengthy consultation with industry, market and consumer stakeholders on the costs and benefits.

The Panel does not see the creation of a separate distribution-level wholesale energy market as a necessary reform at this time. This approach would likely involve significant implementation costs and add complexity for participants engaging across multiple markets and regions, potentially having negative consequences for competition. The Panel considers that the NEM is already evolving to integrate CER within the existing market framework and that work on developing separate distribution-level wholesale markets would divert resources away from this. Rather than pursuing structural redesign, the Panel has focused on accelerating this evolution through targeted reforms that enable CER to participate more fully and efficiently. This includes integrating distribution-level resources into the existing regional market framework (see **Recommendation 2**). This would be supported by dynamic operating envelopes and network tariffs to manage local constraints efficiently. The Panel has considered other aspects of the roadmap at **Recommendation 3**.

⁸⁴ Consultation opened 9 July 2025 on CER Roadmap workstream [M3/P5 – Redefine roles for market and power systems operations](#) and closes 20 August 2025.



Recommendation 2: Energy ministers should require a broader range of price-responsive resources to be visible or dispatchable to participate in price formation

As explained in **Trends and challenges in the NEM**, the NEM is transforming rapidly into a system dominated by weather-dependent bulk VRE resources and an expanding fleet of CER, DER and demand response resources.

These decentralised and price-responsive resources will play an increasingly vital role in delivering bulk energy and shaping services in the NEM. As their scale and influence grow, so too does the need to ensure they operate in ways that support the efficient functioning of the NEM. While consumers and businesses that respond dynamically to price signals can benefit directly, broader market benefits will only be realised if these resources are visible to the market and able to participate effectively. If the market does not accommodate their participation in price formation, the market will become increasingly inefficient, unstable and costly.

As high-capacity factor thermal generation exits, accurate price signals from demand flexibility and distributed resources will become increasingly important for overall price formation in the wholesale market.

Increasing existing price-responsive participation creates value in the market for eligible and active resources. However, providing visibility of this to the market will be the contributing factor for market-wide benefit. There is a significant pool of untapped market efficiency, but unlocking it hinges on getting the market settings right to ensure benefit for both price-responsive resources and the wider market.

Hidden resources are distorting forecasts, raising system costs and weakening investment signals

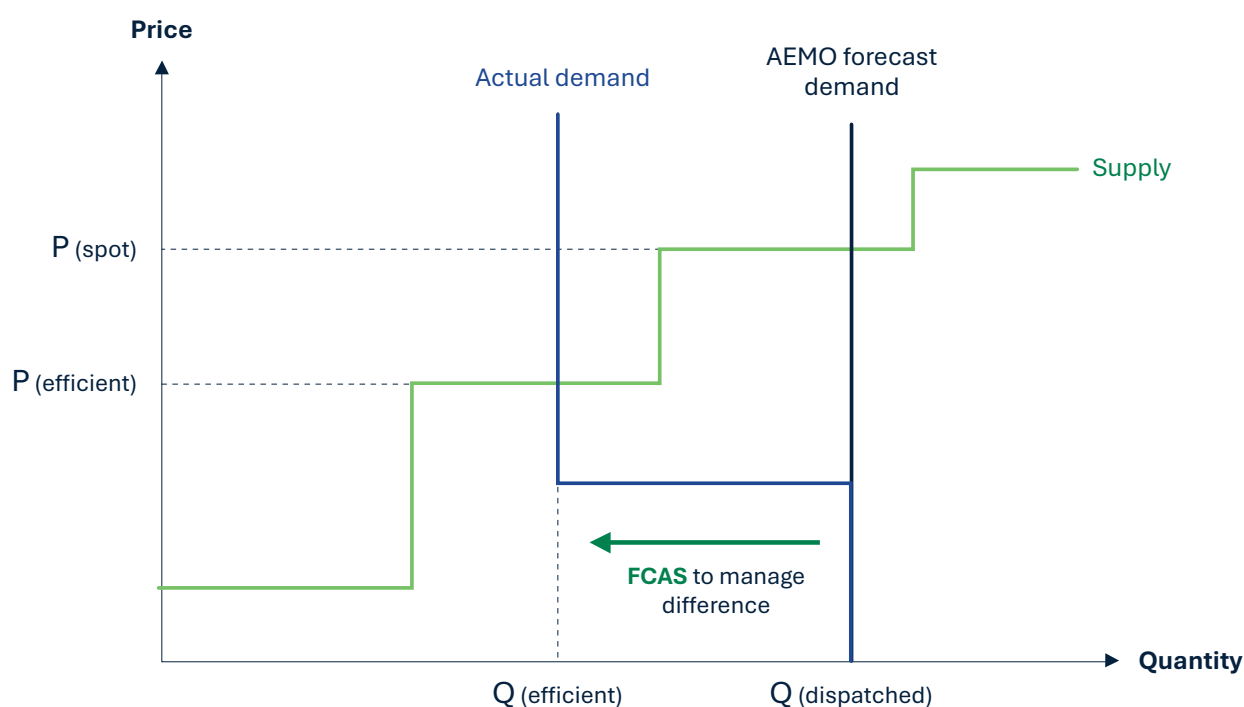
Drift away from the NEM's foundational gross pool model: The NEM was designed as a gross pool with energy derivative markets to manage risk. However, the current obligation to participate in the gross pool applies only to generation above 30 MW and batteries above 5 MW, with no participation obligation on the demand side or small resources. As large, centralised resources are replaced with smaller, decentralised resources (not obliged to participate in the gross pool), the market is shifting towards a net pool. In the absence of explicit policy decisions, this creates gaps in market participation and price formation.

Hidden participants result in mis-forecasting and mis-formation of price: Price-responsive resources that are not visible to the market operator and other participants create significant impediments to efficient market operation. This lack of visibility means AEMO and market participants cannot accurately forecast how distributed resources and large-scale demand will respond to price changes. As outlined in the AEMC's *Integrating Price Responsive Resources* final determination, the lack of visibility of price-responsive CER, DER and demand flexibility (price responsive resources)

leads to AEMO routinely over/under-forecasting demand and dispatching more/less supply than is necessary.⁸⁵ This results in higher-than-necessary dispatch prices in wholesale markets.

Increased FCAS costs: The lack of visibility and participation by price-responsive resources increases the need for frequency control ancillary services (FCAS) to balance mis-forecasting within a five-minute dispatch interval, creating inefficient excess FCAS costs (**Figure 31**).⁸⁶ These costs are an externality of price-responsive resources because FCAS costs related to hidden participants are recovered from all consumers. This is different to large generators, who are subject to individually calculated frequency performance payments.

Figure 31 – Inaccurate demand forecasts cause higher than efficient spot prices, and increase generation and FCAS costs⁸⁷



In the 2024 *Integrating Price Responsive Resources into the NEM* final determination, the AEMC identified that AEMO currently does not have visibility of unscheduled price-responsive resources' intentions because they are hidden participants, creating inefficient spot price formation. AEMO therefore produces an incomplete price inelastic demand forecast and dispatches generation to meet that forecast demand. **Figure 31** illustrates when resources unexpectedly reduce demand or increase supply in response to price, AEMO will typically over-forecast demand and over-dispatch generation. To balance supply with actual demand levels FCAS is required to address the short-term imbalance. As a result, spot prices are higher than needed, more generation is dispatched than needed and higher FCAS costs are required to redress the inefficiency in price formation and generation dispatch.⁸⁸

⁸⁵ AEMC (2024), [National Electricity Amendment \(Integrating price-responsive resources into the NEM\) Rule 2024](#), final determination, 19 December, p 22.

⁸⁶ Op cit., p 22.

⁸⁷ Ibid.

⁸⁸ AEMC (2024), [Integrating price-responsive resources into the NEM final determination](#), p iii.

Increasing uncertainty and risk: Market inefficiencies that cause less accurate short-term forecasts can, in turn, increase the risk of participation for demand-responsive loads and investment in distributed resources. Price-responsive loads and resources may be hesitant to participate due to uncertainty around demand (and therefore price) forecasts.

Poorer signals for long-term investment: The lack of visibility and participation of price-responsive resources results in less accurate long-term forecasting by AEMO and investors. This can lead to inefficient long-term investment in generation, storage and demand response, as poor integration of CER, DER and demand flexibility into the market may ultimately result in inefficient over-investment in centralised resources and peaking plants. By using resources that already exist to meet demand, rather than investing in peak capacity that is seldom used, demand flexibility and distributed resources can reduce the development cost of centralised generation assets that must be recovered from consumers over the long run.

Why is this an issue now when price-responsive resources have always existed?

Demand response has always been a feature of the NEM. Many C&I users have contracts in place that reduce demand by a prescribed amount when prices exceed a particular threshold (e.g. \$300/MWh). These static price responsive loads can display consistent demand response patterns that are observable in the market and in some cases can be used to predict their likely behaviour.

However, the landscape is changing with the rapid proliferation of distributed batteries and more dynamically price-responsive resources (see **Figure 18**). These dynamic resources operate differently from static ones. They constantly reassess the optimal time to inject power into or withdraw power from the grid as factors like the opportunity cost of storage vary. This behaviour makes them nearly impossible to forecast because their actions are constantly changing based on real-time conditions.

This unpredictability can lead to significant market inefficiencies and increased costs. To mitigate these challenges, it is necessary for these dynamic resources to inform the market of their intentions at different price points. Failing to address this issue would have a similar effect to allowing a large thermal power station to ignore AEMO's dispatch instructions and inject power regardless of whether the system needs it. This lack of coordination and visibility can lead to over-supply or under-supply situations, resulting in high costs and reduced market efficiency.

Enabling price-responsive resources to participate in price formation will unlock competition and deliver savings for consumers

Addressing these failures and increasing the visibility and participation of price-responsive resources can yield significant benefits to consumers. Enabling fair competition on an equal footing between supply-side and demand-side resources can help put downward pressure on wholesale prices in the short term (operational time horizon) and long term (investment time horizon).

To be clear, the Panel is not proposing that households with batteries be required to join a virtual power plant; and for those that do, they are not required to participate directly in the wholesale energy market. Instead, the focus is on aggregators, such as VPPs, which households can authorise to use their batteries to inject power into the market on their behalf. This approach is consistent with the VSR framework and ensures that households can benefit from market participation without the complexity of direct involvement.

AEMO and the AEMC have provided a number of estimates of the benefits from CER, DER and demand response:

- AEMO's 2024 ISP found that around \$4.1 billion of additional grid-scale investment will be needed to 2050 without effective coordination of consumer batteries, increasing the costs that are reflected in consumer bills.⁸⁹
- IES modelling commissioned by the AEMC for the *Integrating Price Responsive Resources* rule change found that the social benefit of visibility and dispatch of price responsive resources could be between \$1.4 and \$1.8 billion, against a base case with no visibility of these resources. This represents a reduction in costs from a decrease in regulation FCAS enablement volumes, reduced emissions, reductions in the cost of generation needed to meet demand and reduced RERT costs.⁹⁰
- IES modelling for the AEMC also found that the IPRR reform is expected to lower spot prices by between \$12 billion and \$13 billion (2023 dollars) and reduce FCAS prices between \$678 million and \$814 million.⁹¹

What are demand flexibility, CER, DER and VPPs?

Demand flexibility

Demand flexibility is the ability of businesses to adjust their electricity use in response to grid conditions or price signals, reducing strain on the network during peak times. Examples include shifting loads to off-peak hours, shedding non-essential loads, shaping load profiles, modulating usage dynamically, managing multisite loads, and providing fast, short-term responses to grid needs. To unlock value for consumers from this flexibility there is a range of spot-price pass-through retail offerings in the market.

⁸⁹ AEMO (2024), [2024 Integrated System Plan for the National Electricity Market](#), p 17.

⁹⁰ All figures in NPV 2023 dollars, IES 2024, [Benefit analysis of improved integration of unscheduled price responsive resources into the NEM \(ERC0352\) – Australian Energy Market Commission – Final Report, 24 June](#), p 7–9.

⁹¹ Figures in NPV 2023 dollars, AEMC [2024 Integrated System Plan for the National Electricity Market](#), p 15.

Distributed energy resources

DER include small-scale energy resources such as generators, battery storage and electric vehicle (EV) charging facilities. CER, a subset of DER, are located at consumer sites and include rooftop solar, batteries, EVs and controllable devices like smart appliances.

Virtual power plants

VPPs aggregate DERs to provide grid services traditionally handled by conventional power plants. They offer benefits like contingency services, energy market participation, cost reduction and network support, improving grid reliability and efficiency. Different VPPs benefit consumers in different ways, often through fixed payments, participation incentives or lower energy costs.

A range of barriers discourage participation in the market

Many large electricity users already respond to price signals but this demand response typically is invisible to the market. The Panel's focus is therefore not on the practical ability of large loads to respond to price signals but on addressing the barriers that prevent these resources from participating in the market, where their contribution can support significant system-wide benefits.

C&I demand flexibility

Extensive engagement by the Panel with C&I users, their retailers and aggregators demonstrates that a significant amount of demand response is already occurring. While some C&I loads face operational barriers to participating in demand flexibility, the major barriers ultimately come down to financial risk, set-up and ongoing operational costs, and revenue certainty. Submissions and structured interviews with C&I users undertaken by the Panel found that these barriers include the following:

- **Business focus:** C&I users expressed that energy trading and demand flexibility are secondary to their core business. Active participation in central dispatch would require building additional in-house capabilities, with the costs potentially outweighing the benefits.
- **Preferences for indirect engagement via retailers:** Some large, hidden industrial consumers already engaged in demand response through retailers. Stakeholders appreciate being able to negotiate how much control they have over their load, especially where there are production commitments or safety concerns. Some stakeholders, who in return access lower, long-term fixed electricity rates, are satisfied with the certainty the arrangement offers.
- **Costly to participate:** C&I users noted the significant costs involved in setting up systems to provide demand response and become compliant as a wholesale demand response or FCAS provider. These costs include automated system control technology, extra labour expenses, training of the existing workforce and costs associated with AEMO compliance requirements.
- **Financial risk:** Stakeholders are wary of the lack of reliability of revenue from variable spot prices, combined with the potential loss of production. In some cases, the financial risk alone is enough to deter participation. Some stakeholders noted the difficulty of relying on AEMO short-term, pre-dispatch forecasts due to their lack of accuracy.
- **Operational control and safety:** Some stakeholders' feedback indicated that their business was unable to participate directly in the market due to the need for total control over their load for safety reasons. Others expressed the difficulty in responding in real time, noting that more notice would be required to match their longer operational timeframes (e.g. various teams

in different locations would need to be notified to carry out multiple switches on different machines in sequence).

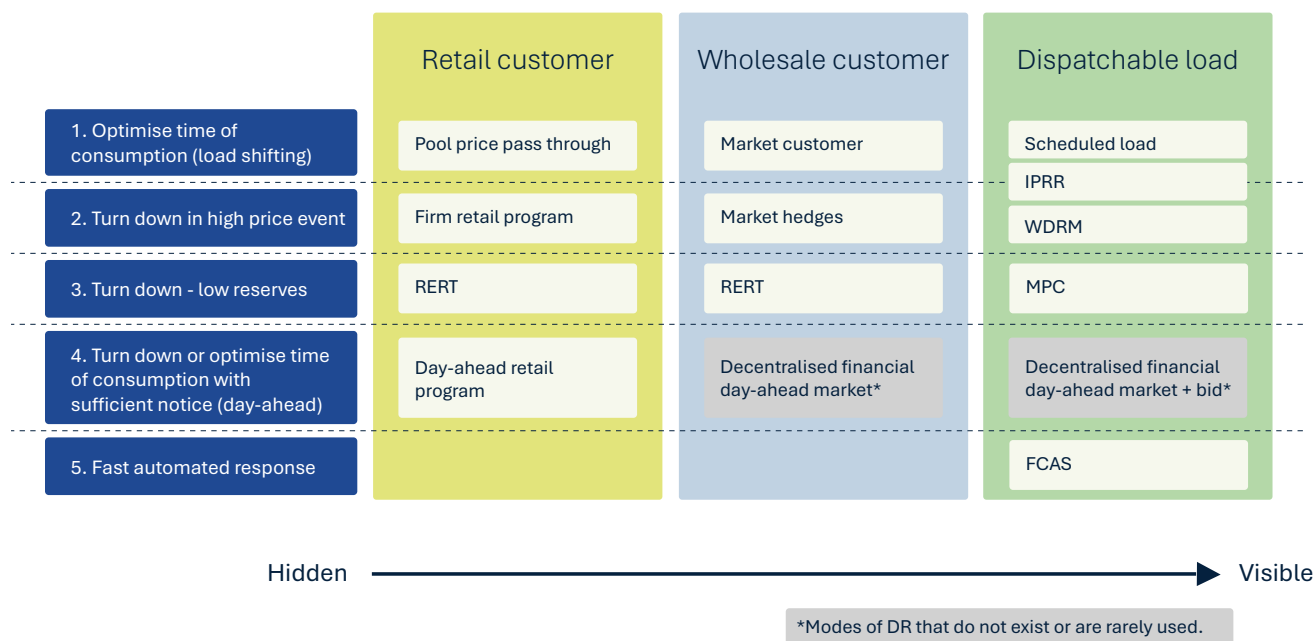
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More needs to be done to encourage consumers to participate in the market. The NEM does not readily support dual-sided engagement. There is an asymmetry of knowledge between electricity generators/retailers and consumers – including large, sophisticated users – that prevents consumers from playing a more active role in the market. – Bluescope⁹²

”

Figure 32 shows the processes that C&I loads employ in their demand response and the mechanisms or contracts available to return value. The Panel has identified there are mechanisms available to participate in demand response in various situations as either a consumer or C&I user or as a dispatchable load. However, one exception is the ability for a C&I user or dispatchable load to turn down or optimise time of consumption with sufficient notice. Decentralised financial ahead markets would fill this gap and meet the needs of some price-responsive consumers that need sufficient notice to be able to respond. Stakeholders have seen evidence in the market that innovation is occurring to develop this with week ahead contracts traded on time-of-day markets' screen broker. Derivatives market innovation is discussed more in **Maintaining liquidity in the derivatives market**.

Figure 32 – Visibility of price-responsive C&I resources across different modes of participation



⁹² Bluescope (2025), [Submission to the Initial NEM Review Consultation](#), p 4.

Most demand response occurs via mechanisms that are not participative

The NER provides mechanisms for C&I loads to offer visible and participative demand response through the WDRM and the scheduled load participant category.

Introduced in 2021 the WDRM allows large electricity consumers to engage in the wholesale market by reducing energy use during peak demand. However, the mechanism has seen limited uptake and only two participants are currently involved, comprising 151 MW of participative load.⁹³ The AEMC is reviewing the effectiveness of the WDRM, with its draft report recommending that the WDRM should continue operating with further reforms to expand eligibility to users that are served by multiple connection points.⁹⁴ Stakeholder feedback to the NEM Review has highlighted several barriers to participation, including complexity in establishing accurate baseline methodologies and ongoing compliance, lack of awareness from C&I users and a perceived lack of revenue opportunities compared to the costs and risks of participation.

Similarly, the scheduled load participant category has seen limited engagement. The only resources currently registered are storage assets. Stakeholders have confirmed that there is little incentive for any C&I loads to register due to the lack of perceived benefits and the complexity of compliance.

While some very large loads participate directly in the NEM as market customers, these participants are not required to provide demand forecasts or indicate the responsiveness of their load to the wholesale price.

⁹³ AEMO (2025), [NEM Registration and Exemption List](#).

⁹⁴ AEMC (2025), [Review of the Wholesale Demand Response Mechanism \(Draft Report\)](#), p i-iii.

CER and DER

Many consumers prefer straightforward arrangements and are not embracing visibility or participation due to a preference for simple, easy-to-understand retail offers. Aggregation services play a crucial role by translating the complex real-time drivers of cost savings into simple offers like bill discounts, lower prices or multi-year fixed-price contracts. Any new obligations for greater market participation should be placed on aggregators and retailers rather than on individual consumers.

Optimising the benefits of CER uptake by planning ahead

The rapid adoption of rooftop solar photovoltaic (PV) in Australia has helped cut emissions and electricity bills for more than 4 million households and small businesses.⁹⁵ This shift has reduced grid demand in the middle of the day. Unlike large-scale generation, small-scale solar PV is not required to participate in the market by offering energy at various price bands. Low levels of minimum demand can pose system security risks by displacing large synchronous generation and increasing the potential for power system issues.

AEMO's latest power system risk review continues to prioritise management of minimum system demand.⁹⁶ This is reflected in the use of 'backstop' mechanisms by state governments, including allowing distribution businesses to turn off solar PV as a last resort.⁹⁷

Rooftop PV exports are not visible or dispatchable to AEMO as system operator. Instead, rooftop PV owners are paid for exports per their retail contract. Consequently, the level of rooftop solar PV exported into the market does not correlate with its value in the wholesale market.

This oversupply of solar PV has contributed to significant increases in negative pricing periods in the NEM. In 2024 about 4.5 TWh of generation was curtailed – an increase from previous years. A large share of this was due to network constraints but more than 3.3 TWh was curtailed for economic reasons.⁹⁸ This is equivalent to over 1.3 GW of utility-scale solar sitting idle for a full year. If all additional CER continues to operate outside the gross pool, it will likely exacerbate these market inefficiencies, increasing costs.

Battery uptake is expected to rise significantly. The step change scenario in AEMO's 2024 Integrated System Plan (ISP) projects that the capacity of residential and commercial batteries, supported by policies such as the Commonwealth's Cheaper Home Batteries Program, will increase from today's 1 GW to 7 GW in 2029–30, and then 34 GW in 2049–50.

Effectively orchestrating household battery storage into the NEM wholesale market could significantly benefit consumers. However, if this is poorly managed significant amounts of small-scale storage interacting with the grid could create issues similar to those caused by rooftop solar. The market's efficient operation could be compromised and the costs of managing system security risks could increase. AEMO would face the challenge of managing a system in which the behaviour of a substantial volume of demand and supply is not operationally visible or predictable. The Panel's recommendations aim to get ahead of these issues so that the maximum benefit from these new resources can be delivered to consumers.

⁹⁵ CER (2024), [Australia reaches 4 million small-scale renewable energy installations](#).

⁹⁶ AEMO (2025), [Draft 2025 GPSRR Report](#), 10 June.

⁹⁷ AEMO (2024), [Operating electricity grids with rooftop solar installations fact sheet](#).

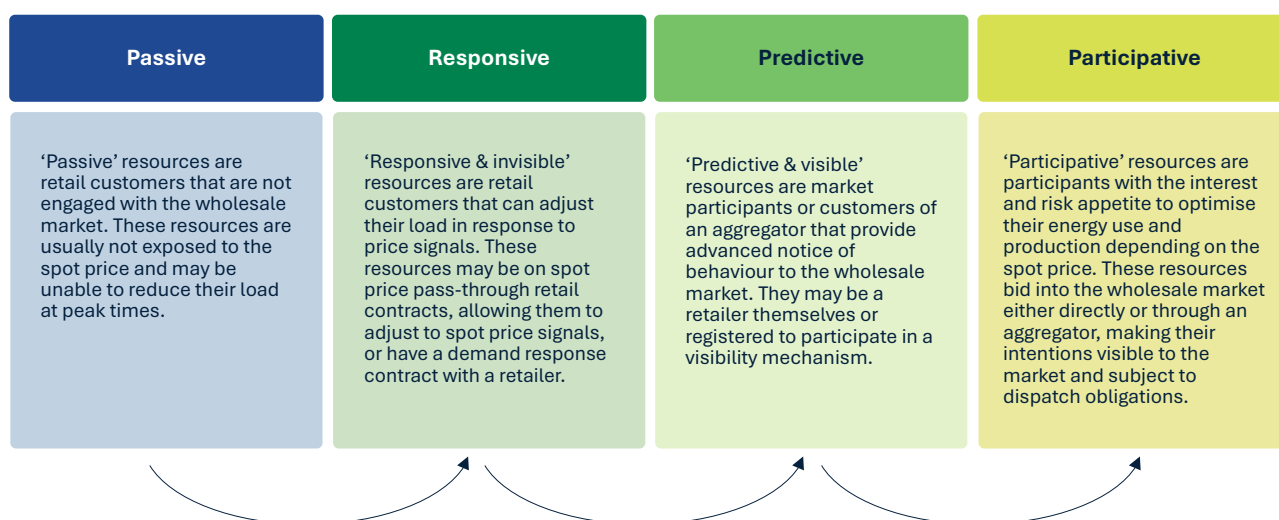
⁹⁸ Sources: AEMO Quarterly Energy Dynamics Q1 2025 workbook data, NEM Review analysis.

The market needs to encourage and reward participation

Demand flexibility and distributed resources encompass a wide range of participants, who behave differently. The Institute for Energy Economics and Financial Analysis estimates that demand response and VPP storage in the NEM already totals about 2.4 GW.⁹⁹ AEMO projects that this distributed storage capacity could reach 11 GW by 2030 – equivalent to five Snowy 2.0 projects. However, without reforms, as little as 1.5 to 4 GW may be price-responsive.¹⁰⁰

These resources can be broadly categorised into four conceptual groups, as shown in **Figure 33** below.

Figure 33 – Categories of CER, DER and demand response providers



The Panel’s consultation with C&I users confirmed a significant amount of price-responsive load and resources in the NEM, though most choose to operate in modes that are not visible to the market. Similarly, most CER operates passively and those that are price-responsive are not visible. However, an array of retail and automation products may support significant growth in price response over the coming decade.¹⁰¹

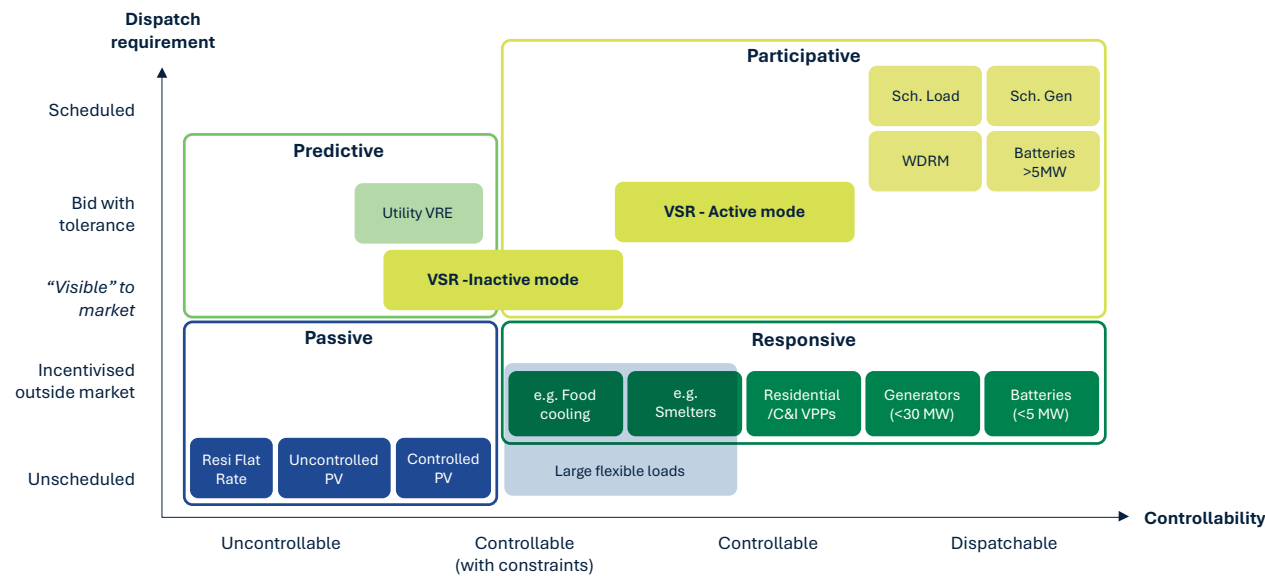
The Panel’s recommendations aim to transition responsive and hidden C&I and CER resources towards predictive or participative categories (**Figure 34**). This shift would allow these consumers to benefit from the market and improve the market’s overall efficiency.

⁹⁹ IEEFA (2025), [Submission to the Initial NEM Review Consultation](#), p 9, 11.

¹⁰⁰ AEMO (2025), [Draft 2025 inputs assumptions and scenarios report stage 2](#), 28 February.

¹⁰¹ Energy Consumers Australia (2023), [Submission to the AEMC on integrating price responsive resources into the NEM](#), p 1.

Figure 34 – Targeting the participative gap



This figure categorises resources by visibility and controllability in the market. Passive loads are unscheduled and uncontrollable, while participative loads are accurately controlled and visible, contributing to price formation. The market efficiency gap can be reduced by enabling responsive loads to become predictive or participative.

Table 1. Modes of participation in the NEM's wholesale and demand response markets

This table details the various modes of participation in the NEM's wholesale and demand response markets, illustrating how each mode offers different levels of visibility to AEMO and the broader market. It compares features such as market visibility, dispatch obligations, accuracy requirements and suitability for small consumers. The table presents a spectrum ranging from fully scheduled, highly visible market participation, typically limited to C&I users, to simpler, passive or retailer-managed options accessible to small consumers. This includes emerging models like VPPs, demand-response contracts and low-bill programs. The table shows how increasing digitalisation is enabling more flexible and responsive participation models while balancing complexity, risk and consumer accessibility.

Mode	Lead time to respond	Visibility in the market	Category	Obligation for consumption to be accurate	Why this mode is attractive	Availability to small-scale customers
Scheduled load	Real time	Fully visible	Participative	Must respond to dispatch instructions	Enabled to bid into the spot market like a generator	Not available
Demand response service provider (DRSP)	Real time	Fully visible	Participative	Must respond to dispatch instructions	Eligible loads that participate receive the spot price for reducing load	Not available
DRSP of ancillary services (FCAS)	Real time	Fully visible	Participative	Must respond to dispatch instructions	Eligible loads receive FCAS revenue, with only minor/short-term changes to load drawn from the grid	Available by settlement via a small resource aggregator (SRA) rather than direct participation
Voluntary scheduled resource (dispatch mode) – in development	Real time	Fully visible	Responsive/participative	Must respond to dispatch instructions in aggregate (expected to be more lenient)	Enabled to bid into the spot market like a generator. Incentive scheme for early years	In development, expected to be available for aggregated consumers via retailers
C&I user and consumer – pool price exposure	Real time	Hidden	Responsive	No obligation	Enabled to maintain full control of energy use and not subject to dispatch obligations. Can hedge their energy position	Not available

Mode		Lead time to respond	Visibility in the market	Category	Obligation for consumption to be accurate	Why this mode is attractive	Availability to small-scale customers
Through a retailer	Consumer on pool-price-pass-through contract	Real time	Hidden	Responsive	No obligation	Enabled to maintain full control of energy use, be dynamic and flex energy use in response to spot prices	Available, high potential benefit and risk
	Consumer with a demand response contract	As agreed in contract	Hidden	Responsive	Contractual obligation to be accurate within agreed limits	Simplicity and reliability of a fixed and steady energy cost. Boundaries around reducing load are negotiated in the contract. VPP rebates translate to shorter payback period on investment	Available, includes VPP participation with rebates
	Consumer participating in a retailer's day-ahead demand response program	24 hours	Hidden	Responsive	Contractual obligation to be accurate	Given notice time to reduce load. Consumer controls when they participate	Available via some retailers
	Consumer participating in a low or no-bill program	Real time	Hidden	Responsive (at retailer/ aggregator level)	No obligation	Household pays for CER; retailer manages and offers low or zero electricity bills. Simple for household, low financial risk	Available
	C&I user and consumer – pool price exposure	Real time	Hidden	Responsive	No obligation	Enabled to maintain full control of energy use and not subject to dispatch obligations. Can hedge their energy position	Not available

Mode		Lead time to respond	Visibility in the market	Category	Obligation for consumption to be accurate	Why this mode is attractive	Availability to small-scale customers
	Self-consumption or response to static prices (flat or time-varying)	Pre-programmed schedule or real-time optimisation of self-consumption	Hidden but should be forecastable	Passive	No obligation	Simple, low financial risk. Installer can calculate effects on payback period for CER	Available
	Through Reliability and Emergency Reserve Trader framework (RERT)	Real time	Semi-visible	Responsive	Must respond to agreed level	Long and short-notice contract payments available	Theoretically possible (subject to 10 MW block size) and demonstrated in trials

2A: Leverage the VSR participant categories established under the IPRR dispatch mode framework to give effect to Recommendation 2B

This includes the use of ‘active mode’ which facilitates dispatch of these resources within the merit order, and ‘inactive mode’, which facilitates visibility and predictability of these resources to the market and market operator.

The IPRR framework is a fit-for-purpose mechanism to encourage visibility and participation

The AEMC’s IPRR rule change establishes a mechanism to increase visibility and encourage participation of price-responsive resources in the wholesale market, contributing to efficient price formation.

The rule change introduces the dispatch mode framework into the NEM, which is set to commence in May 2027. This allows currently unscheduled price-responsive resources to become scheduled and dispatched. The VSR ‘active mode’ allows these resources to bid into the spot market, set prices, receive dispatch instructions and earn FCAS revenue. It also offers options for resources to enter ‘inactive mode’ and ‘hibernation mode’, providing flexibility as to whether and over what time period they participate in dispatch. Market access is facilitated through the creation of VSRs, leveraging existing registered participant categories in the NEM.

These arrangements aim to boost demand-side participation by:

- Increasing access: Allowing both smaller aggregated loads and large industrial loads to be scheduled and dispatchable, facilitating direct market participation for consumers of all sizes.
- Raising market awareness: Involving consultation and collaboration with stakeholders to highlight the benefits of demand response, crucial for broader participation.
- Enhancing economic viability: Introducing short-term incentive payments to make demand response more financially attractive, addressing concerns about economic viability.
- Streamlining integration: Integrating unscheduled price-responsive resources into the planning and operation of the NEM, reducing technical and operational challenges and aiding spot price formation to benefit consumers with lower wholesale costs.

Key features of the dispatch mode framework include the following:

- Allows resources to nominate as a VSR, either standalone or aggregated, permitting a wide range of load sizes to participate without changing their underlying connection point classification.
- The financially responsible market participant (usually a retailer) bids load intentions for its portfolio, reducing operational obligations on individual resources.
- Telemetry requirements for smaller loads are expected to be less onerous than those for scheduled loads.

- Inactive mode: participants will still be scheduled resources but with exemptions under certain rules. They are still required to provide bids but with no dispatch obligations.¹⁰²
- Hibernation mode: Participants can opt to hibernate for 30 days to 18 months, during which they are not required to participate in central dispatch.¹⁰³
- Active mode participants are excluded from cost recovery for RERT and directions.
- Participants can tender for incentive payments from a \$50 million fund to overcome setup costs for compliance with dispatch obligations.
- Participants can receive frequency performance payments if each VSR has appropriate aggregated telemetry, as specified by AEMO's guidelines.

The IPRR participant categories should be used to give effect to Recommendation 2B

The VSR framework will be used as the basis to give effect to **Recommendation 2B**. This approach builds on the existing work of the market bodies, which has been under development for a number of years, and provides a clear and practical foundation for expanding participation. The IPRR framework is designed to be less onerous for smaller or aggregations of distributed resources, enabling them to participate in ways that reflect their operational capabilities. At the same time, it delivers the visibility needed for the market operator to forecast, plan and operate the system efficiently. The Panel considers that the IPRR strikes an appropriate balance between operational visibility and participant flexibility.

¹⁰² AEMC (2024c), [National Electricity Amendment \(Integrating price-responsive resources into the NEM\) Rule 2024](#), rule determination, 19 December, clause 3.10A.2.

¹⁰³ Ibid.

2B: Energy ministers should propose a rule change to the AEMC requiring that, by 2030, various forms of price-responsive resources should be visible or dispatchable in a relevant participant category, with this obligation falling on the relevant participant

A working position, to be refined in the NEM Review's next phase, is that each resource should be able to choose the most suitable pathway given its characteristics; with suitable pathways, at a minimum, including the following:

- Portfolios of small batteries or generation units (below 5 MW) participating as bidirectional units or VSRs in central dispatch, once their aggregated size grows above a pre-defined threshold.
- Consumer energy resource (CER) aggregations, including virtual power plants, above a certain threshold participating in central dispatch through the VSR.
- Retailers providing price pass-through contracts or with price-contingent dispatch contracts to the customer using the dispatch mode framework in active mode, or inactive mode.
- Large loads above a certain threshold, including all market customers, participating through the dispatch mode framework (in active or inactive mode), WDRM or scheduled load frameworks.

The price-responsive resources listed above will increasingly influence market outcomes due to their size, either individually or in aggregate, or their highly price-responsive nature. Very large industrial loads, such as aluminium smelters, can materially impact demand at any given time. Similarly, large aggregations of CER can rival the size of centralised power plants and significantly affect demand forecasting and outcomes. These units or aggregations can shift supply and demand dynamics to the same extent as traditional large, centralised power stations.

Price-responsive large loads or aggregations are becoming increasingly difficult to predict, as technological advances allow them to respond in real time to price movements in ways that are not visible to AEMO and other market participants. Previously, simple demand-response behaviours from large loads could be observed over time. However, the increasing sophistication of VPPs and demand response is making price response more dynamic.

The growing size (individual or aggregated) and highly price-responsive nature of these resources make it crucial for them to be subject to an appropriate level of visibility and dispatchability requirements, comparable to those placed on centralised generation. The Panel considers evolving towards a set of requirements for both supply and demand sides aligned to their capability to be essential for a well-functioning energy-only market that operates in the long-term interests of consumers.

Evolving toward targeted participation requirements will support a fairer, more efficient market

While the AEMC designed the VSR as a voluntary framework for price-responsive resources significantly impacting system outcomes, dispatch mode (and potentially other existing mechanisms like the WDRM) should evolve to facilitate mandatory participation for some resource types over time. Voluntary VSR participation will be available from 2027; the Panel's recommended mandatory participation would come into effect by 2030.

This recommendation aims to:

- allow time before 2030 for the dispatch mode framework to become embedded in the market and for affected participants to prepare and build the necessary capabilities
- build on existing frameworks familiar to participants, such as the emerging dispatch mode framework (see **Recommendation 2A**) and the WDRM
- ensure flexibility to match participation modes appropriate to the operations and features of different types of resource
- spur innovation in the market for energy service providers, aggregators and retailers by providing a longer lead time of four to five years before participation obligations take effect, allowing the market to innovate to assist participants in meeting their obligations at lower cost and risk.

What this reform may look like for portfolios of medium-scale batteries

Portfolios of batteries, including those with individual units below 5 MW, could participate as VSRs or individual bi-directional units once their aggregated size exceeds a pre-defined threshold.

Individual batteries above 5 MW are required to participate in dispatch as bi-directional units, but batteries below this threshold are not, leading to potential aggregated portfolios of sub-5 MW hidden participant batteries. The Panel considers these portfolios could be scheduled by registering them as VSRs and requiring them to participate in active mode once the aggregate size surpasses a threshold, such as 5 MW. Similar requirements would apply to portfolios of small generation units.

What this reform may look like for aggregations of DER or CER

CER aggregations, including VPPs, of a pre-defined size could use the VSR framework in dispatch mode or the WDRM framework.

For clarity, the Panel's recommendation for visibility does not apply to 'passive' CER – for example solar and batteries that are operated to optimise a household's electricity bill in response to a simple retail price, or to maximise household consumption. Rather, if these resources are controlled in response to spot prices (such as through a VPP) then the aggregator (or VPP provider – generally a retailer) will be required to either forecast, or bid, the behaviour of the entire VPP at different price levels. This obligation would arise from 2030 and once the aggregated VPP reaches a specified threshold.

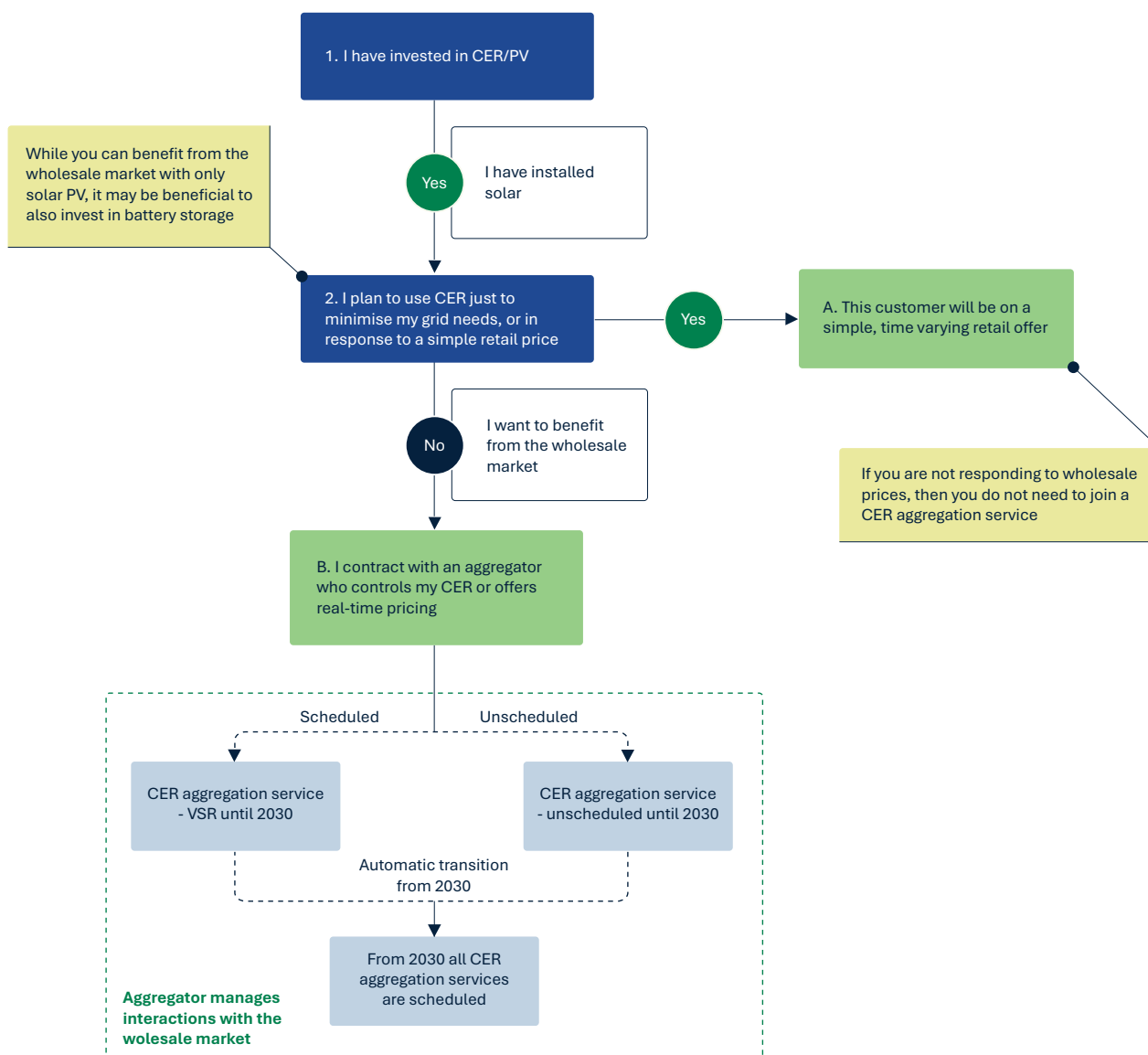
A threshold needs to be established to determine which aggregation services fall under the mandate's scope. Defining this within a band may be preferable given VPPs and aggregation services can change in size over time, influenced by customer enrolment and the level of orchestrated CER.

In the United States, the Federal Energy Regulatory Commission Order 2022 specifies that market operators must accommodate aggregations of 100 kW or more in dispatch. A potential approach for Australia could involve allowing aggregations to participate as VSRs at this level initially, with mandatory participation at a higher threshold, such as 30 MW (equivalent to the requirement for single generators to be scheduled) or 5 MW (equivalent to the requirement for single batteries to be scheduled).

Figure 35 demonstrates the flexibility individual consumers will have as a result of the IPRR reforms and the recommended reforms in this draft report.

Figure 35 – CER decision tree for households from May 2027

CER decision tree for a household from May 2027



What this reform may look like for price-responsive retail contracts

Retailers with price-pass-through contracts or price-contingent contracts could nominate as a VSR provider.

Customer loads on pool-price-pass-through contracts or with retailer contracts that include demand response at price points could be nominated as a VSR provider as part of a retailer's wider CER aggregation portfolio.

A lighter obligation would involve requiring retailers to provide visibility over these contracts and price responsiveness to AEMO. This could be achieved by requiring that retailers participate as a VSR in inactive mode at a minimum. Inactive mode includes a requirement for the financially responsible market participant to indicate the price at which their demand response or CER aggregations will respond. There are no compliance penalties for inaccurate information, as the information is indicative only. For this pathway to effectively address the issues with hidden resources leading to inaccurate forecasts and higher FCAS costs, it would likely need to be built on incentives or obligations to encourage best available estimates of price response.

Alternatively, retailers with price-pass-through contracts or price-contingent contracts with customers could be required to participate as a VSR provider in active mode. This would facilitate greater reliability of information for forecasting and allow better participation in price formation.

The Panel intends to further consider how greater visibility and participation of price-pass-through and price-contingent contracts can be achieved. In considering lighter-handed options for visibility only versus options to require participation in dispatch, the Panel will consider the extent to which heavier obligations could disincentivise retailers from offering price contingent demand response contracts to their customers.

An appropriate threshold would need to be defined for a retailers' portfolio of price-responsive demand, complemented with accepted methods of estimating the size of the price-responsive portfolio.

What this reform may look like for very large price-responsive loads

Large industrial loads and market customers should be required to participate in dispatch from 2030.

Large industrial loads play a significant role in maintaining system security. These large loads are, in many cases, already demand-responsive, and companies manage their exposure to volatile spot prices with firm operational guidelines and a relatively higher level of sophistication than smaller loads. However, without visibility of load intentions, there have been instances where AEMO has intervened to meet forecast demand and subsequently found it was unnecessary due to a significant drop in industrial load, increasing costs for consumers.

Visibility of these large loads would ensure efficient system operations and lower costs for consumers. The compliance pathway for large loads above a pre-defined threshold could require participation as a VSR in active dispatch mode, via WDRM or as a scheduled load.

In setting a threshold, the following will need to be considered:

- whether a set MW limit is an appropriate approach to determining a requirement to be visible and participate, or alternative criteria such as being a market customer is more suitable
- how significant loads above a certain size impact overall demand forecasting and market outcomes
- the capability of large industrial loads to participate via dispatch through the VSR -active mode or the WDRM.

Questions for stakeholders

- Is the dispatch mode framework a suitable mechanism to underpin visible and participative price response under a mandatory framework?
- How should we structure a mandate for these resources to be visible and dispatchable, given the resources' different features and the different options for participation that currently exist in the NEM?
- What thresholds should be set to require participation by medium-scale batteries, CER/DER aggregations and large loads?
- How should requirements for visibility of price responsiveness in retail contracts be established and does the VSR inactive mode provide sufficient information?

2C: Energy ministers should establish a structured support framework to encourage price-responsive resources to participate in the IPRR framework, WDRM or as scheduled loads

Targeted support is needed to unlock greater market participation of price-responsive resources

The Panel expects that support will be needed to transition price-responsive resources, including those currently behind retail contracts or in the wholesale pool market, to more visible and participative modes.

Stakeholder consultations, including structured interviews with C&I businesses, indicated that there are barriers to demand response resources becoming participative, including:

- cost of initial investments needed to meet dispatchability requirements, such as telemetry
- cost of building up capability to participate in the wholesale market
- risks associated with participating in the wholesale market
- potential loss of value as participative demand response reduces wholesale spot prices.

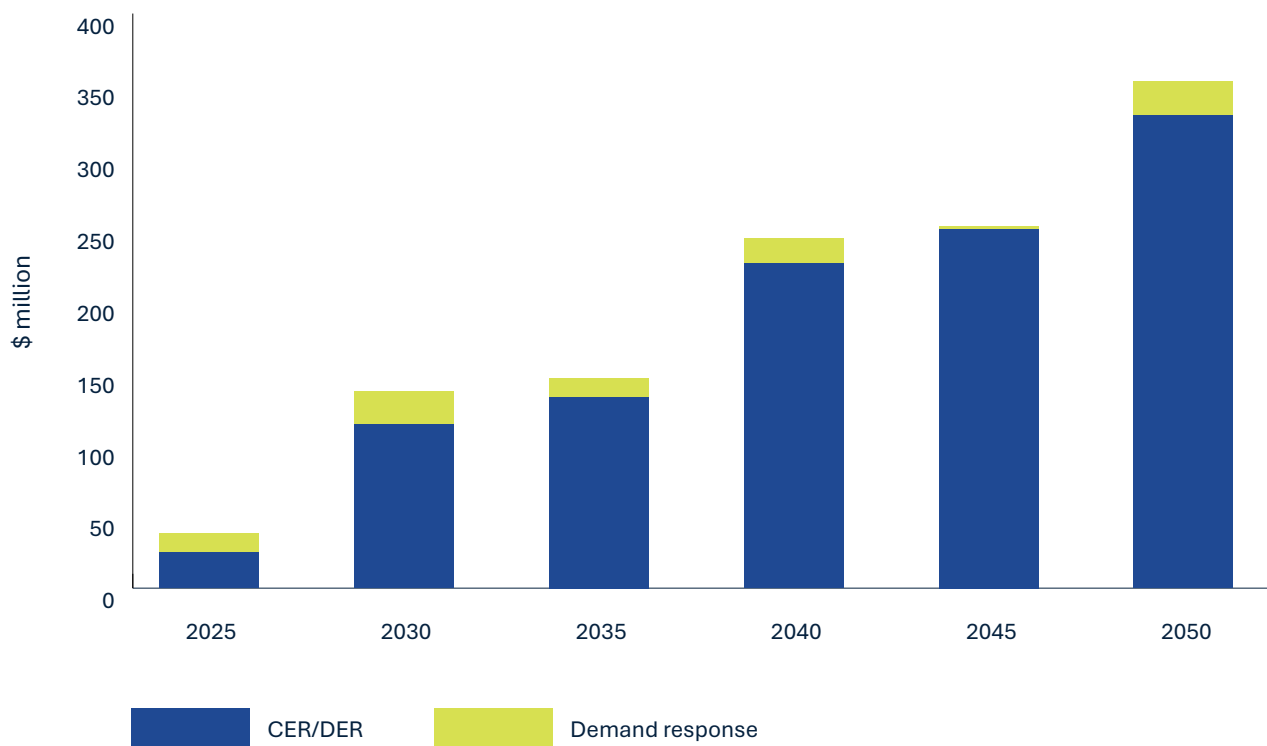
To increase participation in active dispatch mode, the support provided would need to outweigh the barriers faced by hidden responsive resources in becoming participative. On the other hand, to ensure net societal benefit, support should not exceed the system-wide benefit of marginal visibility or participation.

In its 2024 IPRR rule determination the AEMC concluded that an incentive mechanism is necessary to encourage participation in dispatch mode and that it would contribute to the National Electricity Objective (NEO) by lowering wholesale energy system costs for consumers. This mechanism drives participation by requiring AEMO to conduct tenders to pay participants to enter dispatch mode in the first five years of the mechanism.¹⁰⁴ The overall payments to VSR participants are capped at \$50 million and will be recovered by AEMO through market participants, primarily retailers, and ultimately, consumers.¹⁰⁵ **Figure 36** shows the estimated economic benefits over time from integrating dispatchable price-responsive resources.¹⁰⁶

¹⁰⁴ AEMC (2024), [National Electricity Amendment \(Integrating price-responsive resources into the NEM\) Rule 2024, final determination](#), p i.

¹⁰⁵ Ibid, p 41.

¹⁰⁶ IES (2024), [Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM](#), p 18.

Figure 36 – Estimated benefits of integrating price-responsive resources over time

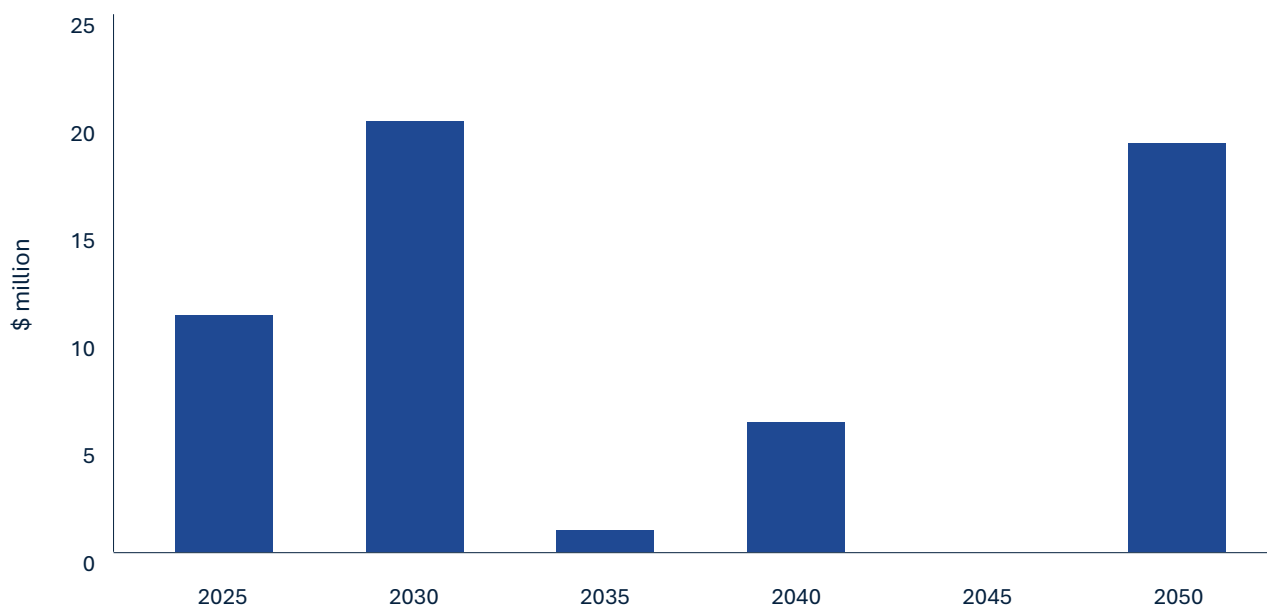
Longer-term structured support may also be needed to encourage participative demand as we move from a voluntary approach

Ongoing structured support might be needed to support electricity users to become participative in the context of moving from the voluntary IPRR framework.

There is a range of options to support the cost of initial investments needed to provide price-responsiveness in a visible and participative way. This could include increasing the total amount of incentives available under the IPRR incentive pool to better reflect the benefits provided and to create a longer-lasting mechanism to offer certainty for participants. Additionally, tender amounts could be tiered to reflect participation levels, with larger amounts available to those intending to participate in active dispatch mode.

A second option could be an ongoing grant scheme for such investments, analogous to the typical market development funding managed by the Australian Renewable Energy Agency (ARENA). Consideration could be given to an ARENA funding program to support investment costs needed to facilitate participation in the market through the VSR framework (or another appropriate framework), building on the extensive work ARENA has already done to support market development in this area.

A third option could see a demand response participation service conceived under the ESEM, whereby existing price-responsive resources receive support for participating in active dispatch model. Existing funds intended to be tendered through AEMO could be offered through the ESEM to streamline the demand response support process. The Panel anticipates that this service would reduce the reliance on RERT activation, thereby reducing associated costs for market participants. **Figure 37** shows RERT cost-reduction estimates for probabilistic uptake of dispatch mode.

Figure 37 – Estimated benefits of reducing RERT costs¹⁰⁷

Investment in new demand response resources will be eligible for shaping and firming services under the ESEM

The Panel recommends establishing an ESEM (further detailed in **Unlocking long-term investment in new energy services**) to address the mismatch in contracting tenors between buyers and sellers. Through detailed consultation with end users, the Panel found this tenor gap also applies to demand response and flexible load. Larger C&I users noted that longer-term revenue certainty is needed to justify investments in making their operations more flexible.

The proposed ESEM is designed to be technology-neutral and indifferent between large- and small-scale resources and supply and demand resources. New demand response resources would be therefore eligible to compete for financial contracts offered under the ESEM shaping and firming services. These resources would be required to participate in the wholesale market, either in VSR active mode, through the WDRM, or as scheduled load.

The design of the ESEM and services contracts are discussed in **Unlocking long-term investment in new energy services**.

Questions for stakeholders

What form and scale of support would deliver the best outcome for VSR participants, the wider market and customers?

¹⁰⁷ IES (2024), [Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM](#), p 13.

Recommendation 3: Governments should focus reforms and support for CER on facilitating market participation to enable consumers to benefit from being price-responsive

3A: Energy ministers should focus the National CER Roadmap on – and ensure sufficient resources are allocated to – delivering the critical roadmap elements that enable market participation (e.g. technical standards) and provide consumer protections

Progress on priority CER reforms is critical to protect consumers and enable efficient market participation

The Energy and Climate Ministerial Council endorsed the National CER Roadmap in 2024 to build national consistency and support a harmonised approach to unlocking the full potential of CER. The roadmap aims to ensure efficient and effective CER uptake, spreading benefits equitably, including in jurisdictions that choose to provide subsidies to accelerate investment.

The Panel notes the high priority Ministers have given to delivering reforms under the CER Roadmap; and the efforts to deliver a complex work program with multiple competing stakeholder demands. Stakeholders are strongly supportive of the work of CER reform and have noted delays in some CER national reform priorities.

The Panel recommends, if resources to concurrently deliver all elements of the roadmap cannot be found, some elements should be prioritised. The Panel endorses the following existing reform priorities as ones likely to create better outcomes in the wholesale market that benefit consumers.

- **Extending consumer protections for CER (due in 2026)**

This reform (CER Roadmap priority C1) extends consumer protections to new energy services, ensuring coverage for the full scope of CER products. Stakeholder consultations have highlighted concerns about risks to consumers associated with new energy service products and handing over control of their CER assets to retailers. Clear consumer protections will build trust and maximise consumer engagement. This is critically important to complement the Panel's recommendation that aggregations of price-responsive CER should be visible or scheduled (**Recommendation 2**). Consumer protections for CER are discussed further in **Ensuring consumers benefit**.

- **National regulatory framework for CER to set and enforce standards (due by end of 2026)**

This reform (CER Roadmap priority T2) focuses on creating regulations for standard setting and compliance for CER. A national framework will reduce regulatory costs, promote competition and enhance the integration of CER into the grid, improving system security and reliability. The Panel views this as a key enabler of CER uptake, as inconsistent technology and a lack of standards across CER products are barriers to consumer participation in CER.

- **Data sharing arrangements (due between 2025 and 2027)**

This reform (CER Roadmap priority M2) covers data access rights, metrics and processes for collecting CER data, including establishing a CER data exchange and improving data availability for consumers. Reliable data is crucial for forward planning, operating the power system and maximising CER value to all consumers through real-time energy trading. Industry and consumer-based stakeholders have highlighted the lack of reliable data on CER uptake and real-time energy trading as significant challenges for forward planning. This includes long-term forecasting through the ISP and the real-time challenges around generation dispatch. The key pilot projects, Project EDGE and Project Edith, have emphasised that efficient functioning of CER in the NEM is aided by interoperable communications between resources and organisations, and widespread availability of accessible data for consumers, their agents, system and network operators.¹⁰⁸

The Panel has commented on reform priority M3/P5 relating to roles and responsibilities (including the Distribution System Market Operator concept) as part of **Recommendation 1** not to create additional distribution-level wholesale energy markets.

In addition to triaging work if required, to allow strategic focus on the highest priorities and those that require minister-level agreement, the Consumer Energy Resources taskforce could separate out relevant elements of work to established governance arrangements, where possible.

¹⁰⁸ See, for example, [DEIP DER Market Integration Trials Summary Report 2](#), ARENA on behalf of Distributed Energy Integration Program 2023.

3B: Government incentives for investment in CER, such as for batteries, should support resources that are enabled to participate in the market through aggregators and are ready for dynamic network connections

Government programs now offer significant support for the adoption of CER. The Panel recommends that funding from these schemes be contingent on these resources being installed in a manner that allows for them to be aggregated.

Over time, the requirements of funding schemes could be adjusted to further simplify the activation pathway for consumers who choose to sign up with an aggregation service. This approach will support earlier recommendations by making it easier for CER to participate in the market through aggregators.

Further, it is important that new CER connections are not just ready for aggregation in the wholesale market, but also ready for dynamic network connections. This ensures that CER can dynamically operate within network limits including system security backstops. Aggregation helps coordinate CER to balance energy on the system through the wholesale market, whereas dynamic connections help coordinate CER to help operate networks within their technical limits and the energy system within its secure limits. The Panel notes the National CER Roadmap priorities for technical standards to underpin aggregation (T1) and dynamic network connections (P1), which will be supported by the proposed national regulatory framework for CER (T2). Once the relevant technical requirements are settled, the Panel's recommendation would incentivise voluntary adoption ahead of any general requirement that might apply to all new installations.

Recommendation 4: Market bodies should use the rule change process to ensure the efficient and competitive functioning of the real-time energy-only spot market

4A: Market bodies and the Australian Competition and Consumer Commission (ACCC) should work together to develop regulatory responses, including rule changes if needed, that address risks created by excessive rebidding and algorithmic bidding

Suppliers are rebidding energy at a rapidly increasing rate

Bidding energy supply at higher prices, even at short notice, is part of the market's design. Rebidding allows generators to respond to changing conditions and information, which is crucial for a spot market that reflects real-world conditions at the time of dispatch.¹⁰⁹ Bidding that increases prices is legitimate if it reflects scarcity, as short periods of high prices allow generators to earn a return on their investment and provide a signal for new resources to enter the market.¹¹⁰ As noted earlier in this chapter, it is important that the efficient mix of generation earns sufficient revenue to recover both short- and long-run costs.

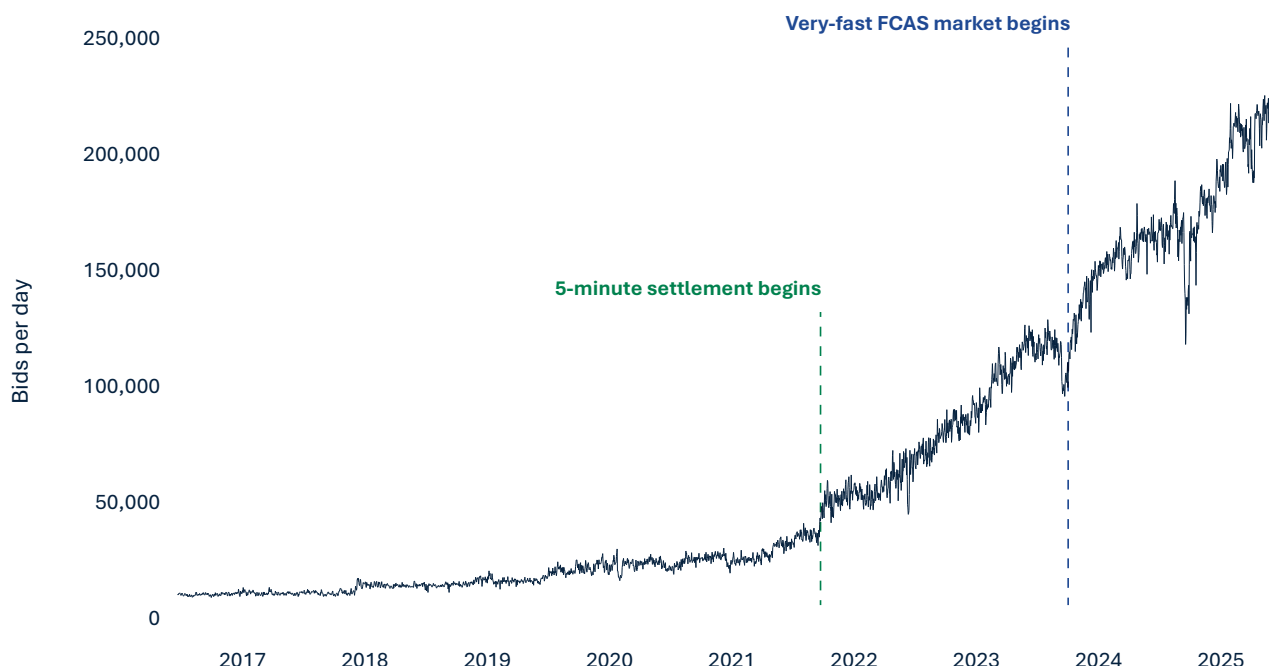
However, the significant increase in the volume of bids in recent years (see **Figure 38**) has raised regulatory and governance concerns.¹¹¹ The reliance on autobidding software further complicates these issues, as opaque algorithms can hinder regulators' ability to scrutinise market behaviour and ensure compliance.¹¹²

¹⁰⁹ AER (2024), [Wholesale energy market performance report 2024](#), p 158.

¹¹⁰ Ibid.

¹¹¹ AEMC (2025), [Supplementary submission to the NEM Review](#), p 21.

¹¹² Chan, J. (2021), [Algorithmic collusion and Australian competition law: trouble ahead for the National Electricity Market?](#), *UNSW Law Journal*, p 1368.

Figure 38 – Number of bids by NEM participants per day, July 2016 to June 2025¹¹³

Regulations outlaw misleading bids but they are difficult to detect

The National Electricity Rules (NER) oblige market participants not to make false or misleading bids, which are bids that participants have no genuine intention to honour or are made without a reasonable basis.¹¹⁴ The rules also require participants to always have appropriate staff (not machines) available to respond to instructions from AEMO.¹¹⁵ Additionally, the NER require the AER to monitor and report on factors that contribute to significant price outcomes,¹¹⁶ including rebidding specifically.¹¹⁷

The AER’s reports on high-price events during 2024 found that rebidding was a common driver of these events, while noting that all events had multiple drivers.¹¹⁸ The regulator’s wholesale market performance report for 2024 also discussed battery bidding behaviour, noting that batteries often make hundreds of rebids in a day, relying on auto-bidding software.¹¹⁹ However, the AER found it difficult to interpret whether this rebidding was excessive or simply responsive, noting: “It can be difficult to distinguish between battery rebids that reflect changing costs and those that reflect a lack of competitive constraint or exercise of market power to put upward pressure on prices.” Importantly, operators of larger-scale batteries informed the Panel that the constant rebidding is necessary for batteries to comply with their obligations under the NER. Even small changes to their state of charge require updates to all future periods, as their intentions have very slightly changed.

¹¹³ NEM Review analysis of AEMO MMS data (rows per day in the “BIDDAYOFFER” table).

¹¹⁴ AEMC (2025), [National Electricity Rules, version 227](#), clause 3.8.22A.

¹¹⁵ *Op. cit.*, clause 4.9.2(d).

¹¹⁶ Thirty-minute periods where the average spot price exceeds \$5,000/MWh. See AER 2022, [Significant price reporting guidelines](#), p 3.

¹¹⁷ AEMC (2025), AEMC (2025), [National Electricity Rules, version 227](#), clause 3.13.7(b)(2)(iii).

¹¹⁸ For example: AER (2024c), [Electricity prices above \\$5,000 per MWh, October to December 2024](#), p 2.

¹¹⁹ AER (2024), [Wholesale energy market performance report 2024](#), p 93.

Algorithmic bidding may facilitate non-competitive outcomes and price distortion

Regulators have held concerns that widespread use of algorithmic bidding could undermine competition and lead to non-competitive outcomes.^{120,121} Many machine-learning models used in autobidders are opaque, meaning the rationale behind their decisions cannot be scrutinised. Algorithms could collude even without the knowledge of the parties on whose behalf they bid,¹²² for example, by using pre-dispatch to send tacit signals to other bidders. The AEMC has documented how this kind of signalling, built into an algorithmic bidding strategy, can lead to much higher payoffs for generators despite them risking only a “very small percentage of their total offered quantity”.¹²³

The NEM’s characteristics — its size, five-minute energy intervals and 10 frequency markets, including at the one-second interval — make it potentially susceptible to algorithmic collusion.^{124,125} Many generators already use machine-learning models to bid. A recent University of New South Wales study suggested that the significant increase in the number of bids in the NEM at least partly explained a corresponding rise in pre-dispatch price uncertainty.¹²⁶

Despite these concerns, algorithmic tools can help participants use market information more effectively, improving market efficiency. Restricting their use completely is unlikely to benefit consumers.

The NEM needs updated oversight of these emerging risks

Market bodies and the ACCC should collaborate to develop rule changes and update regulatory responses to ensure that rebidding and algorithmic bidding contribute to efficient price formation and do not distort forecasting and price discovery. The scale of algorithmic bidding will continue to increase as more trading portfolios use algorithmic software to manage bidding. Appropriate governance, standards and regulatory oversight will be essential to ensure that these tools improve market efficiency. The Panel recommends that market bodies establish a program of work to:

- understand the scale and nature of the challenges that excessive and algorithmic bidding pose to the spot market and any resourcing requirements to ensure they can effectively address these challenges
- identify and implement rule changes and regulatory responses to these challenges.

Questions for stakeholders

How might the increased use of autobidding and algorithmic machine learning impact dispatch?

¹²⁰ Ezrachi, A. & Stucke, M. E. (2017), '[Artificial intelligence & collusion: when computers inhibit competition](#)', in University of Illinois Law Review, p 17–75.

¹²¹ AEMC (2025), [Supplementary submission to the NEM Review](#), p 12.

¹²² Ben-David, R. (2023), '[Rethinking markets, regulation and governance for the energy transition](#)', prepared for the ACCC/AER 2023 Regulatory Conference, p 22.

¹²³ AEMC (2025), [Supplementary submission to the NEM Review](#), p 15.

¹²⁴ Chan, J. (2021), '[Algorithmic collusion and Australian competition law: trouble ahead for the National Electricity Market?](#)', in *UNSW Law Journal*, p 13–68.

¹²⁵ AEMC (2025), [Supplementary submission to the NEM Review](#), p 14.

¹²⁶ Prakash et al. (2025). [The Scheduling Role of Future Pricing Information in Electricity Markets with Rising Deployments of Energy Storage: An Australian National Electricity Market Case Study](#), in *Energy Economics*, p 108-191.

4B: Market bodies should analyse whether publishing battery state of charge information from July 2025 adequately mitigates reliability risks or whether further reforms are needed

The recent Enhancing Reserve Information rule change has improved the market's visibility of forecast and actual state-of-charge information for batteries, and the energy limits of other assets.¹²⁷ As of 1 July 2025, AEMO began publishing, along with other data, the following:

- The previous trading day's five-minute data for individual utility-scale batteries.
- The aggregate state of charge of each region's battery fleet in real time during dispatch.
- The forecast aggregate state of charge of each region's battery fleet in the:
 - five-minute short-term projected assessment of system adequacy (ST PASA) up to 1 hour before dispatch
 - 30-minute ST PASA from 1 hour before dispatch to the end of the next trading day.

The AEMC determined that this information would help participants make more informed operational decisions.¹²⁸ An expected benefit is that storage assets will respond more effectively to risks such as lack of reserve events by retaining charge until the network needs it.¹²⁹

AEMO has noted it observes batteries, operating in a commercially rational way, discharge significant portions of their charge before peak demand. It agrees that publishing state-of-charge information should improve market operations and has implemented aspects of the rule change two years earlier than required. However, AEMO also argues that this intervention alone might not ensure that the battery fleet supports reliability when supply is tight.¹³⁰ As the NEM becomes more dependent on variable generation, AEMO expects to rely increasingly on energy-limited plant generally – not only batteries – to maintain reliability.

The Panel believes it is important to assess whether this recent rule change is adequate or whether further reforms will be needed. It recommends that market bodies analyse how the publication of state-of-charge information affects the operation of batteries and other energy-limited plant. Participants' use of algorithmic bidding based on enhanced publication of state-of-charge and energy-constraint information will also be an important consideration, highlighting the link between **Recommendation 4A** (above) and **Recommendation 4B**.

Questions for stakeholders

What other market information could be made public to help achieve the NEO?

¹²⁷ AEMO (2024), [Enhancing reserve information – high level implementation assessment](#), p 4.

¹²⁸ AEMC (2024), [National Electricity Amendment \(Enhancing reserve information final determination\) Rule 2024](#), rule determination, p 33.

¹²⁹ Ibid.

¹³⁰ AEMO (2023), [Submission to the AEMC on an operating reserve market](#), p 2.

4C: Market bodies should work to minimise the impact of transmission network outages on the energy-only spot market.

The AER should work with AEMO and the AEMC to replace the suspended Market Impact Component (MIC) of the regulatory framework, and the AER should continue to review whether network constraints affect competition and drive high spot prices, and progress rule changes to the AEMC if required

Network outages need to be balanced with market outcomes

TNSPs periodically take lines out of service for maintenance, vegetation management or to connect new generation. These activities can temporarily reduce network capacity and increase spot prices by limiting electricity flows, making careful planning essential. TNSPs must notify AEMO of all scheduled outages under the Congestion Information Resource guidelines.¹³¹ AEMO publishes this information via the Network Outage Scheduler and approves outages only if system security and reliability are maintained. Outside of notification, TNSPs have limited incentives to reduce the impact of their activities on wholesale prices.

Regulatory mechanisms play a crucial role in shaping TNSP behaviour. The Service Target Performance Incentive Scheme has been the primary tool, though it focuses broadly on network reliability. It has three components:¹³²

- **Service Component:** Incentivises fewer and shorter supply interruptions.
- **MIC:** Encourages TNSPs to schedule outages to minimise wholesale market disruption.
- **Network Capability Component (NCC):** Supports low-cost projects that improve market outcomes and benefit consumers.

In a recent review, the AER strengthened the NCC to make it more effective but suspended the MIC.¹³³ The suspension was driven by TNSPs often facing maximum penalties, regardless of their actions, due to a rise in MIC events linked to the energy transition. Specifically, the move from centrally located thermal generation to geographically dispersed and weather dependent generation has created new demands on the transmission network with implications for how TNSPs manage their assets. In practice, this has increased the number of binding constraints on the transmission network and more MIC penalty events, with most TNSPs incurring maximum penalties for circumstances that may be beyond their control. The AER has noted that if a TNSP knows it is likely to occur maximum penalties under the MIC irrespective of its actions, its incentive to manage outages is significantly diminished.

The Panel supports the AER's decision to strengthen the NCC due to its value in supporting high-value projects like dynamic line ratings, which can reduce generator curtailment by enabling greater energy transfer through transmission lines under favourable weather conditions.¹³⁴

¹³¹ AEMO (2021), [Congestion information resource guidelines](#), p 7–8.

¹³² AER (2025), [Service target performance incentive scheme version 6](#), Clause 2.2(a).

¹³³ AER (2025), [Service Target Performance Incentive Scheme – Final Amendments: Explanatory Statement](#), p 2, 11.

¹³⁴ Ibid.

Given the potential price impacts of outages, the Panel advocates for stronger incentives for TNSPs to consider wholesale market effects in their planning. A revised, price-based mechanism could deliver clear, market-aligned signals or, alternatively, a conduct obligation could address market impacts without imposing excessive penalties. A targeted mechanism is essential to protect consumers and market outcomes while enabling essential works.

Reduce opportunities to exploit market power during network outages

Temporary network constraints can temporarily increase market power for participants, allowing them to rebid in ways that elevate spot prices. For example, in New South Wales in May 2024, a planned outage on the Collector–Yass transmission line prevented up to 1,400 MW of low-cost generation from reaching major load centres, including Sydney.¹³⁵ During high-price intervals, unconstrained generators contributed to price spikes by rebidding capacity above \$5,000/MWh, behaviour facilitated by network limitations and unplanned coal unit outages.

There is a growing risk of such market dynamics intensifying due to delays in transmission expansion and the retirement or unexpected outages of the ageing coal fleet, leading to more frequent network constraints. These conditions create opportunities for strategic rebidding, further increasing price volatility. Therefore, the Panel recommends that the AER reviews how network constraints resulting from outages driving high spot prices affect competition and progress rule changes if required. This would be complementary to the existing work being done by the AER through its Wholesale Electricity Market Performance Report.¹³⁶

¹³⁵ AER (2024), [Wholesale electricity market performance report 2024](#), p 72.

¹³⁶ AER (2024), [Wholesale electricity market performance report 2024](#), section 4.3.

Recommendation 5: The Reliability Panel should consider adjusting the form of the market price settings over time

The market price settings, including the MPC, MPF, CPT and APC, should remain linked to the VCR and to revenue adequacy for efficient investment in bulk energy, shaping and firming services.

However, given the significant changes expected in the market and the intention of recommendations in other chapters to extend price discovery, the Reliability Panel should consider whether the form of the market price settings needs to change over time and provide a longer-term outlook (up to 15 years) on their intended form to support long-term contracting.

The reliability standard is a core element of the NEM framework for delivering reliability

The reliability standard defines the maximum expected amount of energy at risk of not being served in a region in a given financial year, currently set at 0.002% unserved energy (USE). Every four years the Reliability Panel reviews the reliability standard and settings to assess their appropriateness and effectiveness in meeting market, participant and consumer requirements.¹³⁷

The VCR is a central input into this process, reflecting how much consumers are willing to pay to avoid wholesale market-related outages. Determined by the AER through direct customer engagement, the VCR ensures the reliability standard balances reliability outcomes against the cost of achieving them.

The MPC is a lever to incentivise supply and investment to deliver the reliability standard

Previously referred to as the value of lost load, the MPC sets the maximum price that can be reached in the spot market during any dispatch or trading interval. It plays a critical balancing role – ensuring there is sufficient incentive for generators to invest, while protecting consumers from paying more than the value they place on reliable electricity supply (the value of customer reliability).¹³⁸

A high MPC provides strong incentives for generation and demand response to activate during peak system stress events.¹³⁹ Modelling undertaken by the Reliability Panel identifies the marginal new entrant required to meet the reliability standard and the price-duration combination that aligns with the level of reliability consumers value. Under the current framework, this marginal unit is often modelled as an open-cycle gas turbine or other fast-start peaking generator. The objective is to ensure

¹³⁷ AEMC [Reliability Panel: responsibilities and obligations](#), web page.

¹³⁸ AEMC (2022), [2022 Reliability standard and settings review](#), p 63.

¹³⁹ AEMC (2025), [Submission to the Initial NEM Review Consultation](#), p 12.

that this unit, operating during scarcity conditions for a small number of hours, can recover its fixed and variable costs through a plausible number of high-price events.

The MPF signals supply surpluses and limits participants' financial exposure

The MPF places a lower limit (currently -\$1,000/MWh) on dispatch prices in the wholesale market. It allows the market to clear during low demand periods while maintaining system stability and limiting participants' financial exposure.¹⁴⁰ The Reliability Panel may only recommend an MPF that allows the market to clear in most circumstances without posing significant risks to market integrity.¹⁴¹

The CPT and APC also limit participants' financial exposure

The CPT is the rolling total of seven days of trading prices in a region which, if breached, triggers an administered price period, during which the APC limits spot prices to \$600/MWh. The APC and CPT work together to limit market participant financial exposure to prolonged high prices, maintain pricing signals for new developments and support the achievement of reliability standards.¹⁴² The APC acts as a 'last-resort safety' tool, ensuring generators can recover short term costs and incentivise continued operation.¹⁴³

After the June 2022 market suspension, the AEMC raised the APC to a level sufficient for peaking generators to recover a higher SRMC and to encourage generators to continue participating in the normal dispatch process.¹⁴⁴ By allowing more cost-reflective bidding from generators during an administered price period, the market can find the least-cost solution to dispatch in real time, rather than relying on directions from AEMO to meet reliability requirements.¹⁴⁵

International comparisons

International wholesale electricity markets use various frameworks to balance the need to incentivise investment and ensure system reliability while protecting consumers from extreme price volatility. In energy-only markets such as the NEM the MPC tends to be set relatively high for generators to recover their fixed and variable costs solely through the spot market. The MPC needs to reflect the value electricity users place on uninterrupted supply. The NEM's MPC, currently set at \$20,300/MWh,¹⁴⁶ is among the highest globally. The high MPC ensures that during periods of scarcity, prices can provide revenue sufficiency for generation capacity that is only needed infrequently. Importantly, most electricity users are not exposed to these prices; rather, retailers manage the risks on their behalf through the procurement of cap contracts, which act as a form of decentralised capacity market. In contrast, centralised capacity markets provide generators with an additional revenue stream through capacity payments, which remunerate them for being available to supply electricity. Capacity markets generally set a lower MPC because capacity payments reduce the reliance on scarcity pricing to ensure revenue sufficiency.

¹⁴⁰ AEMC (2022), [2022 Reliability standard and settings review](#), p. 99

¹⁴¹ Op. cit., p 100.

¹⁴² AEMC (2022), [Amending the administered price cap](#).

¹⁴³ Ibid.

¹⁴⁴ AEMC (2022), [National Electricity Amendment \(Amending the administered price cap\) Rule 2022](#), p 2

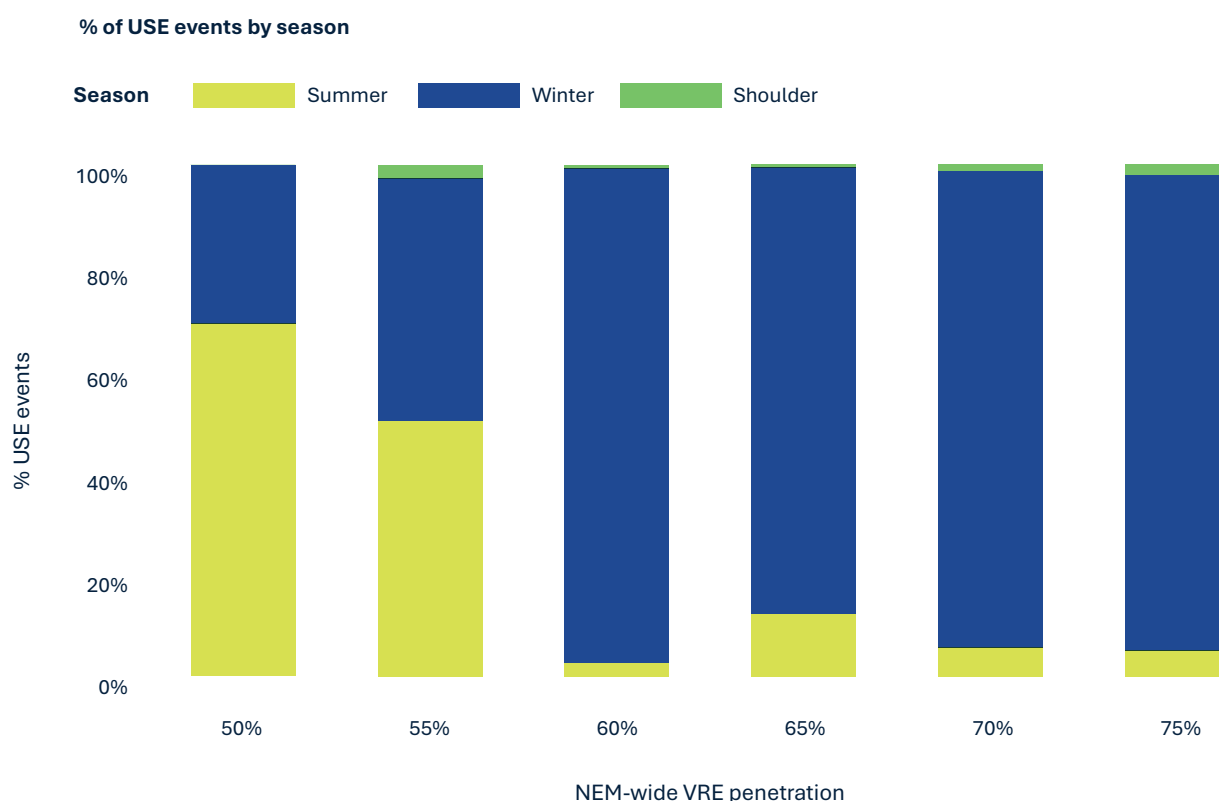
¹⁴⁵ Op. cit., p 5.

¹⁴⁶ The market price cap as of 1 July 2025.

The transition is challenging current market price settings

The NEM's increasing weather dependency and system volatility (discussed in **Trends and challenges in the NEM**) mean that the nature of extreme reliability and high-price events is changing. Historically, unserved energy events and the resulting high-price events were generally concentrated during short periods of high summer demand, often driven by thermal plant outages. However, these risks are increasingly shifting towards winter (see **Figure 39**), where lower solar output and prolonged low-wind conditions create risks to reliability. These events are projected to become more frequent and prolonged in a high penetration renewable system, creating new types of challenges for system reliability.

Figure 39 – Reliability risk is shifting from summer to winter¹⁴⁷



The Reliability Panel's 2024 review noted current market price settings alone could not incentivise the investment needed to manage the risk of severe, low-probability events without placing an excessive cost burden on consumers. The Panel recommends allowing jurisdictional ministers to procure out-of-market reserves to deal with these types of events (see **Recommendation 8D**).

In the absence of greater contracting activity (see **Maintaining liquidity in the derivatives market**), peaking generators may face growing revenue unpredictability due to the increasing unpredictability of high price events with rare weather conditions.

A higher MPC can improve investment viability for peaking and storage assets, as these assets are often financed using derivatives such as cap contracts. Market price settings strongly influence the structure and terms of these contracts and the level of risk that contracted parties are exposed to.

¹⁴⁷ AEMC (2023), [Directions Paper: Review of the form of the reliability standard and APC](#), p 26.

For example, a higher market price cap increases the potential amounts that a generator may need to pay to a contract counterparty under a \$300 cap contract when prices exceed \$300/MWh. Some stakeholders argue the existing MPC incentivises short-duration storage over longer-duration, firming assets.¹⁴⁸ AEMC modelling has found the MPC supports the entry of traditional peaking plants like open cycle gas turbines but is unlikely to support higher-cost or more capital-intensive technologies, such as pumped hydro.¹⁴⁹

Reliability settings may need to change over time to accommodate the transition

Stakeholders have proposed a range of reforms to the market price settings, including increasing the MPC to incentivise investment to reduce the need for parallel mechanisms.¹⁵⁰ Some suggested that a longer or higher CPT would incentivise technologies with greater capability to deliver sustained energy supply and allow for greater revenue capture for long-duration storage and firming generation.¹⁵¹ However, concerns were raised that any increases to the MPC could create extreme price volatility and additional risks for retailers and consumers.¹⁵² Other stakeholders recommended changing the way the MPF is conceptualised to accurately reflect oversupply costs, such as by setting different MPFs for scheduled and semi-scheduled assets.¹⁵³ These options reflect broader shifts in market risk profiles for generators and retailers, underscoring the market's need to deliver reliable outcomes in an economically efficient and resilient manner.

The Panel considers that greater demand flexibility can help smooth spot market price spikes and reduce the frequency of prices hitting the MPC or breaching the CPT.¹⁵⁴ In this context, the Panel believes that the Reliability Panel may need to adjust the form of the reliability settings over time. For example, a more granular approach could be required, with the MPC set at multiple levels for different time periods. A hypothetical example might be:

- Market settings could permit very high prices (e.g. current levels) for a very short period of time (e.g. two hours each day) to incentivise particular types of batteries and demand response.
- Moderate prices could be applied for a much longer period (e.g. 12 hours each day) to incentivise firming technologies that may be required to meet prolonged periods of very low renewable output.
- Lower prices could be set for the rest of the week to ensure reliability is achieved while maintaining cost-effectiveness for consumers.

This simple hypothetical example demonstrates an alternative construct of the market price settings. It is not the Panel's view of how the settings should evolve. However, the Panel believes the Reliability Panel should adopt a forward-looking view of these settings, which may require some evolution from the current approach. The Panel intends to work collaboratively with the Reliability Panel ahead of developing the final report to further progress how these settings may evolve.

¹⁴⁸ Dr Sarah Lawley (2025), [Submission to the Initial NEM Review Consultation](#), p 8.

¹⁴⁹ AEMC (2023), [National Electricity Amendment \(Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap\) Rule](#), p 20.

¹⁵⁰ [Submissions to the initial NEM Review consultation](#) from AFMA (p 3), Clean Energy Council (p 9), Akaysha (p 20).

¹⁵¹ [Submissions to the initial NEM Review consultation](#) from Clean Energy Council (p 9) and AGL (p 6).

¹⁵² Alinta Energy (2025), [Submission to the Initial NEM Review Consultation](#), p 6.

¹⁵³ [Submissions to the initial NEM Review consultation](#) from Reposit Power (p 3) and Snowy Hydro (p 2).

¹⁵⁴ D Biggar and M Hesamzadeh (2024), ['Crisis in Texas and Australia: failures of energy-only markets or unforeseen consequences of price caps?' in Energy Economics](#).

The Reliability Panel should provide a longer-term outlook for the form of the market price settings

Market price settings (particularly the MPC, CPT and APC) play a significant role in shaping expected future revenue opportunities and allocation of risk in the NEM and, in turn, prices in the derivatives market.¹⁵⁵ Currently, the Reliability Panel reviews and recommends changes to the reliability standard and settings (including the market price settings) every four years. This provides medium-term certainty but is limited in its ability to support longer-term planning and contracting.

Long-term investment and pricing of early- and mid-year contracts requires market participants to have a degree of confidence in the form of market price settings into the future. Furthermore, as the generation mix shifts from thermal generation to VRE and more flexible demand-side resources, the need for investment in technologies like batteries and demand response becomes increasingly important. These technologies have distinct revenue profiles: for example, long-duration batteries benefit from sustained high-price periods, while demand response may depend on sharp, short-duration peaks.¹⁵⁶ Supporting investment in these technologies will require greater confidence in how market price settings may evolve over time.

The Panel suggests that the Reliability Panel incorporate into its process a long-term outlook (15-years) that guides how the form of the market price settings may evolve in response to emerging technologies. Doing so would not fix future prices but would provide market participants visibility into how the settings could evolve in response to system needs and emerging technologies. This would facilitate participants entering into longer-term contracts with greater confidence in how market risks and revenues will be shaped over time.

The Reliability Panel should also consider the impact of the ESEM and align long-term signals with other market functions

The Panel recommends the Reliability Panel consider market price settings in light of the ESEM (see **Recommendation 8**). The ESEM creates a long-term investment signal in the NEM using derivative contracts, such as cap contracts. As the ESEM relies on long-term contracting to bridge the tenor gap and provide investment signals, any changes to the market price settings will affect risk allocation and contract values over time. A forward-looking view of these settings would help participants and the ESEM administrator to value ESEM contracts accurately.

Some stakeholders raised concerns that a new approach to incentivising capacity could result in consumers paying twice for new capacity.¹⁵⁷ In its 2023 review, the AEMC determined that the expanded CIS and jurisdictional programs are complementary to, rather than a substitute for, efficient market price settings.¹⁵⁸ The AEMC found these mechanisms are designed to work alongside MPC and CPT levels to support timely investment in flexible supply and ensure reliability during the system transition, without compromising the role of price signals in the energy-only market.¹⁵⁹

Aligning these long-term signals with other market functions, such as AEMO's medium-term projection and assessment of system adequacy (see **Recommendation 7**) and Electricity Statement

¹⁵⁵ AEMC (2022), [Final Report: Review of the Reliability Standard and Settings](#).

¹⁵⁶ Rangarajan et al. (2025), 'Revisiting the Crisis: An Empirical Analysis of the NEM Suspension', in *Energy Economics*.

¹⁵⁷ Energy Consumers Australia (2025), [Submission to the Initial NEM Review Consultation](#), p 8.

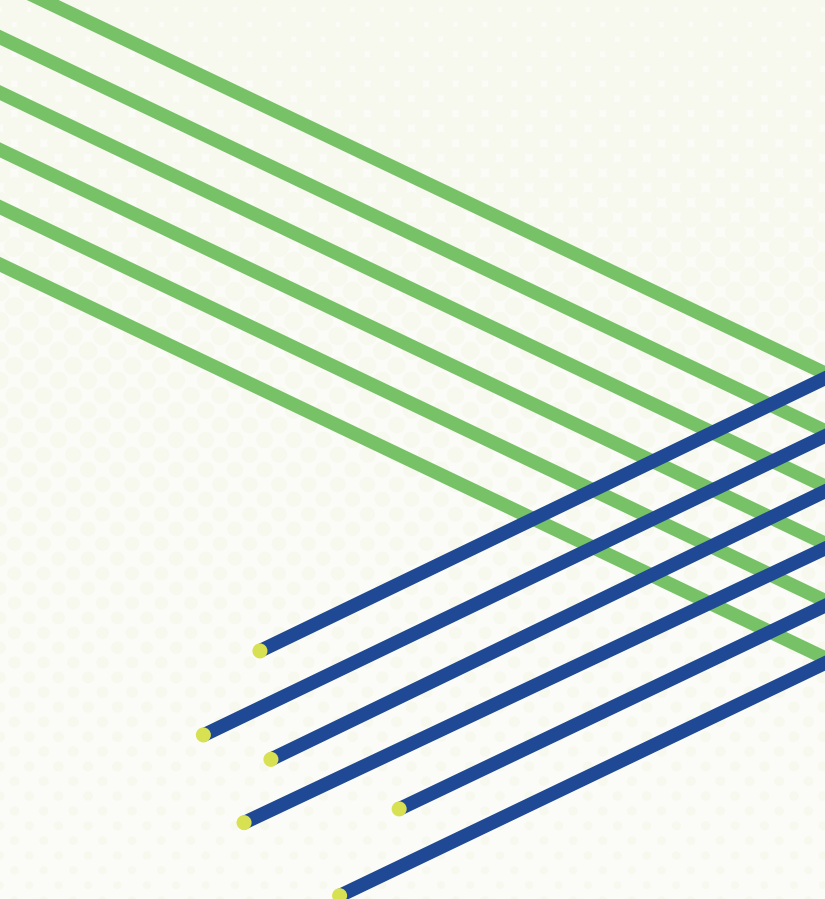
¹⁵⁸ AEMC (2023), [National Electricity Amendment \(Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap\) Rule](#), p 5.

¹⁵⁹ *Ibid.*, p ii.

of Opportunities, would help reduce the investment risk premium and provide greater confidence for underwriting medium and long-term contracts.

Questions for stakeholders

Would a forward-looking view of the form of market price settings provide greater certainty for buyers and sellers of electricity?



4

Maintaining liquidity in the derivatives market



Chapter summary

Derivatives markets are essential to the operation of energy-only markets like the NEM. They enable participants to hedge risk and send critical medium-term signals for pricing and investment. As the spot market becomes more predictably variable and unpredictably volatile through the transition, access to transparent and liquid derivatives markets will only become more important.

Transparency of retailers' risk management costs increases electricity users' confidence that retail prices are fair and reasonable. Transparent derivatives markets also enable the trading of contracts on fair terms and with transparent prices that reflect expected future market conditions. These are important conditions to facilitate generation and retail market competition and to help market participants establish fair value.

Effective derivatives markets must be liquid and accessible to willing participants. Currently, small and stand-alone retailers face barriers to accessing affordable hedging. Without improving accessibility, this could intensify and negatively affect competition in the NEM.

Effective and liquid derivatives markets can only exist if they transact the risk-management products that market participants need and value. As the energy transition is changing the nature of risks against which participants must hedge, market participants must have access to evolving financial energy derivatives capable of managing these risks. While innovation in energy-related financial markets is happening, it is not at the pace required to support an effective market, particularly for exchange-traded products. Unless participants utilise hybrid generation or a portfolio of variable and shaping assets, traditional hedging instruments, such as baseload swaps, are likely to become less available as thermal generators exit the market. Timely innovation is needed to mitigate the risk of declining liquidity in the NEM.

To improve accessibility, liquidity and innovation in derivatives markets, the Panel recommends reforms to:

- Establish an always-on market making obligation (MMO) to support liquidity through the transition and improve market transparency and access for small retailers (see **Recommendation 6A**)
- Institute a new co-design process – the Australian Energy Regulator (AER) should work with industry to define a core set of exchange-traded derivative products suitable for an increasingly weather-dependent system, with these products to apply to the MMO (see **Recommendation 6B**)
- Improve the availability of market information necessary to support hedging over a longer time horizon, including by improving the medium-term projected assessment of system adequacy (MT PASA) process to extend the generator information provided (see **Recommendation 7**)

Enabling participants to hedge risks over a longer forward period is needed. By adopting these reforms in the medium-term derivatives market, financial derivative contracts (rather than revenue underwriting) can then be integrated into the design of the long-term investment signal, the Electricity Services Entry Mechanism (ESEM) outlined in **Unlocking long-term investment in new energy services**.

Recommendations

6 Energy ministers should establish an always-on market making obligation (MMO) in the National Electricity Law/National Electricity Rules (NEL/NER) for a small number of key derivative contracts in each NEM region, with contract types determined through a co-design process with the AER and industry

- A. The MMO should apply to all participants above a pre-defined size and prescribe volumes that must be made available for trading and a limit on the bid-ask spread, with contract types determined through a co-design process with AER and industry.
- B. The AER should regularly convene (e.g. every two years) with industry (financial market bodies, generators, retailers and electricity users) to define a small set of core derivative contracts that sit at the heart of the electricity market. These:
- should be able to be traded on an exchange platform
 - should be the subject of the market making obligations
 - should be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW)
 - should be utilised to underwrite projects in the ESEM; and
 - could be used in retail price benchmarking

The Panel will work with stakeholders to further demonstrate how this would work in practice during the second half of 2025.

- C. During the second half of 2025, the Panel will work with stakeholders to explore approaches to improve the accessibility of derivative markets, with a focus on NEM prudential requirements, financial market margining requirements, and the interaction between the two. This will allow for recommendations to be made in the final report to improve market access.

7 Ensure sufficient market information is available to support longer-term derivatives market liquidity and price discovery

Energy ministers should propose a rule change to the Australian Energy Market Commission (AEMC) that extends the medium-term projected assessment of system adequacy generation availability projections from three to five years and make them public.



Recommendation 6: Energy ministers establish an always-on market making obligation in the NEL/NER for a small number of key derivative contracts in each NEM region, with contract types determined through a co-design process with AER and industry

A liquid, innovative and accessible energy derivatives market enables market participants to hedge risk and to send medium-term price and investment signals. The Panel's recommendations aim to support such a market through establishment of an always-on market making obligation (MMO) (**Recommendation 6A**), establishment of a co-design process to identify core derivative contracts that would be applied through the MMO (**Recommendation 6B**) and work to minimise the impact of prudential working capital (**Recommendation 6C**).

While current challenges around liquidity and access have not yet become critical in most regions of the NEM, there are concerning trends that, if left unaddressed, could erode competition and lead to poor outcomes for consumers. As set out in **Trends and challenges in the NEM**, liquidity is declining in South Australia, which is highly dependent on VRE bulk energy and peaking plants, and where standard contracts are increasingly less suitable. There is a risk that liquidity in other states' markets will experience the same decline unless contract markets evolve to keep pace with the transition.

Rather than waiting for these issues to escalate and require more disruptive intervention, the Panel recommends early, targeted reforms to strengthen the foundations of the derivatives markets. These measures are designed to pre-empt deterioration, promote confidence and ensure the market remains fit for purpose through the transition.

Innovation must keep pace with the changing market, particularly for exchange traded contracts

Derivatives markets that respond to the changing generation mix and spot market will be critical to ensuring retailers and generators can continue to manage short to medium-term spot price risk in an increasingly weather-dependent, volatile and variable system.

Innovation has been occurring in the over-the-counter (OTC) contracts market to meet participants' needs, although this does not provide the transparency that is valuable for price discovery. Exchange-traded contract innovation is happening too slowly and needs to keep pace with the changing wholesale market and the changing risk management needs of retailers and generators. An efficient and liquid exchange-traded contracts market is important for price transparency and accessibility. Without these characteristics, electricity users will be unable to determine whether their retail pricing is fair and trust in the overall electricity system and energy transition will be significantly undermined.

Innovation in financial products is not translating quickly enough to exchanges

As coal plant exits the market, new products that reflect an increasingly weather dependent system will need to be available. The Panel is aware of significant innovation that is occurring in the OTC market. However, this innovation has not translated across to exchange-based trading. Given the time it takes to develop new products, the Panel considers a structured process is needed to accelerate innovations critical for meeting emerging needs to become exchange-traded (see **Recommendation 6B**).

Some stakeholders consider that derivatives markets have worked well to date.¹⁶⁰ However, new exchange-traded products generally require a long lead time to become available. These new derivatives are also generally variants of existing products. For example, the most successful exchange-traded contract innovation in recent years is the ASX's base strip option ('swaption'), which is essentially an option to trade a strip of four quarterly baseload futures contracts for a calendar or financial year.¹⁶¹ Other examples include the ASX's new morning (6–9am) and evening (4–9pm) 'super peak' futures contracts, listed from late June 2025.¹⁶²

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While contract markets are evolving to meet new needs, this may not occur as quickly, or pre-emptively, as the system needs. Contracts are emerging to cover 4–6 hour daily diurnal spread but less so for overnight coverage. We are not aware of contracts emerging to cover dunkelflaute. – **Clean Energy Council**¹⁶³

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New energy derivatives are needed as the market changes. For example, solar generation is already changing market dynamics and the nature of risks. AFMA provided an example of the ASX's traditional 7am–10pm peak product becoming unviable with decreasing demand and very low average wholesale prices during the middle of the day.¹⁶⁴ As coal plant retires, the nature of market risks will change further as variable renewable energy (VRE) is unable to sell the same contracts that have been provided in the past.

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As renewables are unable to offer the same level of firm contracts, standard contracts in secondary markets may become harder to obtain. The role of contract markets and their preferred forms have not yet evolved to balance management of risks with exposing customers to an efficient level of price volatility over time. – **Australian Energy Council**¹⁶⁵

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¹⁶⁰ [Submissions to the initial NEM Review consultation](#) from AFMA (p 4), Clean Energy Council (p 11) and AGL (p 13).

¹⁶¹ Swaptions have been increasingly central over the last 7 years. See AER, [Wholesale Energy Market Performance Report 2024](#), Figure 3.1, p 41.

¹⁶² ASX (2025), [New Australian Peak Load Electricity Futures Trading Fees & Margins](#), Notice reference number: 0628.25.06.

¹⁶³ Clean Energy Council (2025), [Submission to the Initial NEM Review Consultation](#), p 11.

¹⁶⁴ AFMA (2025), [Submission to the Initial NEM Review Consultation](#), p 5.

¹⁶⁵ Australian Energy Council (2025), [Submission to the Initial NEM Review Consultation](#), p 2.

New and different contract types are needed to manage new and different risks

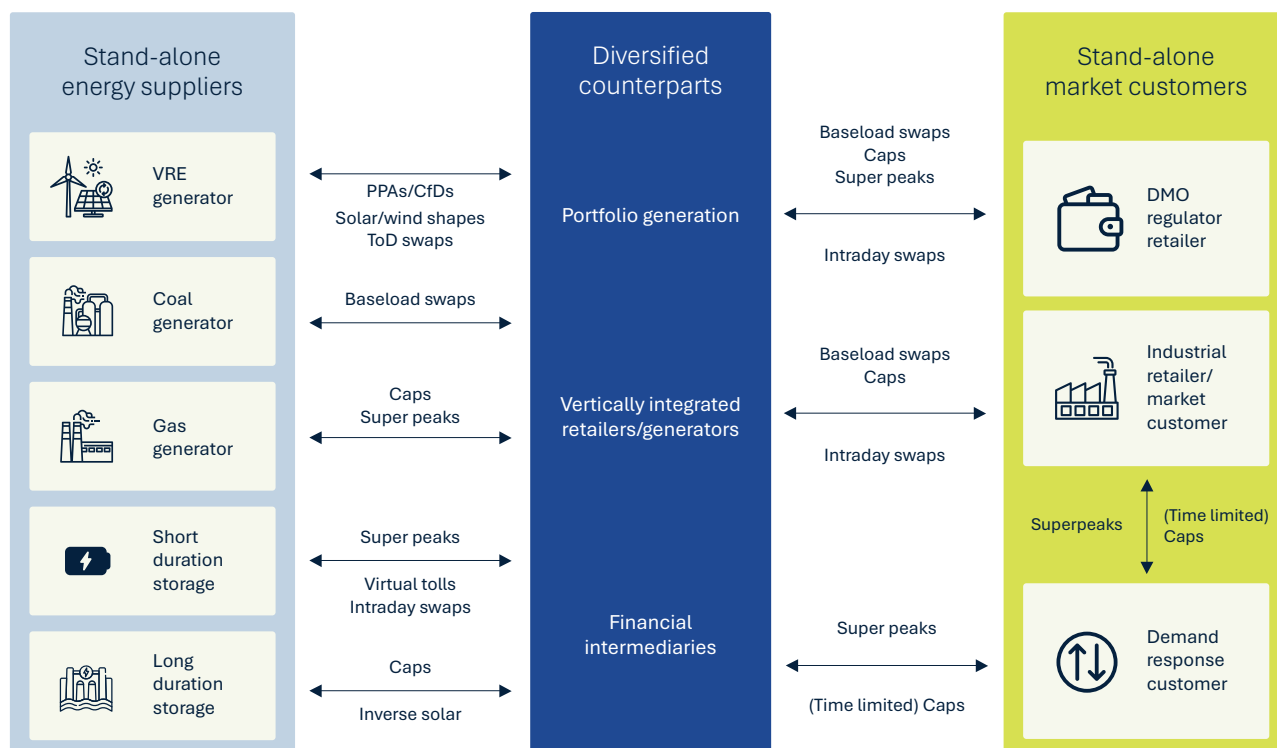
Derivatives markets need to respond to the changing generation mix and spot market. While coal generators are well suited to offering baseload swaps, VRE generators and storage are less naturally suited to being baseload sellers. Through Panel consultation, a representative of a generation business noted that baseload swaps would remain an attractive buy-side hedging option. However, the baseload seller would need to use a portfolio of bulk energy and firming services to be able to physically operate in a manner that meets the financial obligations of the contract. In contrast, a representative of a retail business noted baseload swaps are a function of the generation available when the NEM was formed. This stakeholder noted that products such as four-hour blocks and four-hour super peaks are a more natural product for retailer hedging with a generation fleet transitioning from thermal coal to renewables, storage and firming assets.

Discussions with retailers also highlighted the importance of accounting for changing load. One representative of a retailer noted that risk management will depend on a retailer's business model. A retailer's need to manage spot price risk is reduced with factors such as demand side response with contracts that expose customers to a degree of spot price variability. Another retail business noted the importance of accounting for changing load conditions. A shifting consumer load profile may see retailers focus on hedging morning and evening peak demand and the need to hedge other parts of the day may be a risk/value judgement for retailers.

Figure 40 shows some of the relationships between different types of contracts and market participants. This illustrates that a range of different products are needed to meet the hedging needs of different market participants. This is consistent with what the Panel has heard from stakeholders, who suggest a range of products and strategies will be needed. These include super peak swaps, solar shaped products, standardised renewable products, storage ownership and tolling.¹⁶⁶

¹⁶⁶ Flottmann et al. (2023), '[Derivatives and Hedging Practices in the Australian National Electricity Market](#)' in *Centre for Applied Energy Economics & Policy Research*.

Figure 40 – Examples of electricity derivative counterparty relationships



Note: Contracts above the arrows are exchange traded. Contracts below the arrows are over-the-counter contracts.

Innovation is occurring in the OTC market

Innovation in energy derivatives largely occurs in the OTC market. OTC contracts range from bespoke contracts to standard contracts listed on closed exchanges. Bespoke OTC contracts can be structured to meet a participant's requirements, allowing for much more flexibility than exchange-traded contracts, and are more responsive to changes in market conditions.¹⁶⁷

Stakeholders provided many examples of OTC contract innovation such as solar and inverse solar shapes, storage tolling and contracts based on temperature and plant indexes. The Australian Competition and Consumer Commission's (ACCC) 2023 NEM inquiry report identified that some newer OTC products had been used by retailers and generators, but noted trades in these products were rare.¹⁶⁸

¹⁶⁷ Australian Energy Council (2025), [Submission to the Initial NEM Review Consultation](#), p 9.

¹⁶⁸ ACCC (2023), [Inquiry into the National Electricity Market: December 2023 Report](#), p 76

Figure 41 – Examples of how bespoke contracts more extensively meet dimensions of innovation

Contract types	 OTC bespoke Written for individual customers	 OTC quoted Price can be readily quoted through a broker	 OTC screen brokered trading Limited transparency on closed trading platform	 Exchange-listed Traded transparently on public exchange (e.g. ASX)
Weather/production risk for VRE	VRE PPAs Wind shapes Wind/temperature index derivatives		Time-of-day blocks Solar shapes	
Changing demand profile for retailers	Sculpted profiles	Load following swaps	Time-of-day blocks Inverse solar shapes	Morning/evening peak swaps
Daily arbitrage risk for storage assets	Virtual tolls		Time-of-day blocks	
Nearer-term position adjustment			Week-ahead swaps	

Initial volumes for a new contract may be small to minimise risk as the counterparties test the contract. In the broker's case, the contract may have standardised terms to facilitate trading and reduce costs for participants.

Speed of implementation, ease of access and allowing time to develop liquidity for a possible later move to an exchange are reasons why New Zealand's super peak contract was launched in the OTC market and not on an exchange.

Case study: Using the OTC market for New Zealand's super peak contract

In 2023 the Electricity Authority (New Zealand's electricity regulator) published a report "Price discovery in a high renewables market", prepared by the Authority's Market Development Advisory Group. This report recommended the Authority work with industry to co-design new standardised flexibility products. The Standardised Flexibility Product Co-design Group was convened by the Authority with eight members selected from buyers, sellers and financial intermediaries. The Co-design group developed a new standardised super peak hedge contract covering morning and evening peaks.

The group decided to launch the contract on the OTC market rather than the ASX (New Zealand's primary electricity futures exchange) to do the following:

- Meet the three-month timeframe to develop and launch the contract.¹⁶⁹ Listing a new product on an exchange would have taken at least 18 months.
- Allow growth in trade volumes. Listing on an exchange would have been challenging to justify without significant trading volumes.
- Facilitate access for smaller participants. Several market participants noted that exchange transaction and carrying costs were prohibitive, combined with wholesale market prudential requirements.

The group said moving the contract to an exchange would eventually be considered, if it was agreed to be beneficial.¹⁷⁰ The Electricity Authority engaged a broker to manage an OTC market for the new contract and trading began 28 January 2025.

The Panel considers that while the derivatives market is innovating, this innovation is not available to all participants through the exchange. This could be a function of the process required for new products to be listed on exchange platforms.

Elements of this standard process help to ensure a liquid and trusted market and should be retained. It is also very much a 'chicken-and-egg' type problem whereby participants do not need new products until coal plants shut and new sources of energy are generating. In many ways, this is similar to the entry-before-exit problem for investors. As such, the Panel's recommendations relate to ensuring that innovative contract types become standardised and fungible before coal plants permanently close. Achieving this will require close collaboration with industry to choose fit-for-purpose contract types for the long-term ESEM (as discussed in **Unlocking long-term investment in new energy services**) and using market making to support liquidity for those contract types (medium term).

¹⁶⁹ Standardised Flexibility Co-Design Group (2024), [Standardised Flexibility Co-Design Group Recommendations](#).

¹⁷⁰ Ibid.

The challenges of developing standard exchange and OTC contracts

In submissions to the review, several market participants welcomed the ASX's morning and evening peak futures contracts (progressively listed for each NEM region except Tasmania from late June 2025 to late July 2025¹⁷¹) but noted the contracts had taken five years to develop.

In meetings with stakeholders (including ASX, brokers and retailers) regarding contract development, the Panel heard that many factors contribute to contract development time. These can include consulting the market, determining a contract's parameters, risk and financial assessments, business case development, board approval, contract and system testing, and financial regulatory approval.

Electricity is just one of many commodities in which exchanges, clearing participants and brokers trade. Factors such as resource prioritisation and an exchange operator's strategic priorities can therefore affect when new products are introduced.

A representative from a market broker stated that it can take several years to develop a novel, standardised OTC contract. This involves ongoing customer consultation, trialling and evolving products, managing changing customer needs, dealing with market events (e.g. COVID and the war in Ukraine) and competition from other brokers developing similar products.

With broad stakeholder support, there are opportunities to expedite contract development. As set out in **Recommendation 6B**, the AER could perform an important facilitation role in an industry co-designed contract development process. The objective of this process should be to ensure contract design can evolve with sufficient pace to allow for contracting to continue through the transition from thermal coal generation to firmed, shaped renewables. The Panel is interested in stakeholder views on derivatives market innovation.

Some exchange-traded market making schemes already aim to improve liquidity, but further reforms are needed

The existing Market Liquidity Obligation (MLO) and ASX voluntary market making scheme provide limited market making services that are likely to be insufficient to address looming liquidity issues.

Market making fundamentals

Market making refers to the practice of a **market maker** offering both bid (the highest price they will buy) and ask (the lowest price they will sell) quotes for standardised derivative contracts on a transparent platform, such as an exchange or through bilateral negotiations in OTC markets. They provide liquidity by ensuring buyers and sellers can transact in the market and promote price transparency through updating their prices to reflect underlying markets. A market maker benefits from the bid–ask spread (see below) and, if under a commercial arrangement, may also benefit from incentives provided by an exchange, such as reduced trading commissions.¹⁷² In electricity markets, market making mechanisms are often employed to ensure that financial hedging products are available to trade, especially in periods of low liquidity or high volatility.

¹⁷¹ ASX Energy (2025), [Launching morning and evening peak electricity futures contract](#).

¹⁷² ASX (2025), [Market maker arrangements webpage](#).

Market making mechanisms can be **mandatory** or **voluntary**, or **commercial**, with the Australian electricity derivative market currently using a voluntary scheme on the ASX.

Mandatory market making schemes require designated participants (often large generators, retailers and vertically integrated gentailers) to offer contracts during defined trading windows. These obligations are typically set in regulation and are designed to ensure enduring liquidity in critical contracts.

Voluntary market making involves participants choosing to provide liquidity due to commercial benefits rather than being compelled by regulation. These participants enter into arrangements with the exchange where they receive financial benefits from meeting market making targets to buy and sell within defined parameters. Depending on the arrangement, benefits might include a fee for service, incentive payments, lower trading fees and preferential market access.

Voluntary schemes can complement mandatory programs by increasing the diversity of market makers and enhancing liquidity during off-peak periods or in less-traded products.

Commercial market making involves contracting with a third party to provide market making services. This includes frameworks under which a regulator tenders for market making services and reimburses the provider the costs of providing these services (for example, the commercial market making approach adopted in New Zealand – see case study below). Under this approach the provider commits to quoting buy and sell prices within parameters defined by the regulator (such as maximum spreads and minimum volumes) to support liquidity in targeted products.

Bid-ask spread is the difference between the best (highest) price at which a market participant is willing to buy an asset (the bid) and the best (lowest) price at which a market participant is willing to sell the same asset (the ask). A narrower spread is indicative of a more liquid market and improves price transparency and price discovery for market participants. Markets that encourage price makers generally follow market practices that recommend a maximum bid-ask spread to ensure participants are quoting prices that facilitate efficient price discovery.

The MLO was established as part of the introduction of the Retailer Reliability Obligation (RRO) in June 2019, and the ASX established a voluntary market making service in July 2019. In 2019 the AEMC considered a rule change request to establish a market making service in the NEM. It cited the recent establishment of the MLO and ASX voluntary scheme as key factors in its decision not to introduce a new market making scheme.¹⁷³

While both changes in 2019 aimed to improve market liquidity, additional or different mechanisms are now needed to ensure derivatives market liquidity.

“

In our recent review of the RRO, we requested that the Commonwealth consider reviewing market liquidity as part of its work on the design of the future wholesale market. We would encourage the Panel to consider whether mechanisms, such as the CIS, have improved liquidity and if alternative arrangements could improve market liquidity and reduce costs. – AEMC¹⁷⁴

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¹⁷³ AEMC (2019), [Rule determination: National electricity amendment \(market making arrangements in the NEM\) Rule 2019](#), p i.

¹⁷⁴ AEMC (2025), [Submission to the Initial NEM Review Consultation](#), p 24.

The MLO established a foundation for mandatory market making in the NEM but should be replaced with a stronger obligation

The MLO is a market liquidity requirement that only operates when a T-3 instrument is triggered under the RRO in response to a reliability gap forecast by AEMO or an energy minister.¹⁷⁵ The MLO aims to provide a source of derivatives for liable entities to purchase to meet contracting requirements that are placed on retailers and other large users under the RRO. It therefore operates for discrete periods and is neither broad nor enduring. It also provides several exclusions. For example, MLO generators can miss 10 trading periods per month at their discretion – approximately a quarter of the available trading sessions.¹⁷⁶ The MLO is currently in effect in Victoria, South Australia and New South Wales, with market making requirements placed on EnergyAustralia, Origin, Snowy Hydro, AGL and Engie.¹⁷⁷ The MLO also has volume limits (over which the obligation is no longer required) based on net selling 1.25% of the generator's registered capacity over the quarter. This consideration of net position is atypical for a market making obligation.¹⁷⁸

Despite its limited nature, the MLO has been used and has had some positive impact. In its submission to the review, AFMA noted that market making has been successful in the NEM and in overseas markets and enjoys wide support from their membership.¹⁷⁹ AFMA further noted that its members generally consider the MLO has boosted liquidity and been positive for the NEM, with parties that have been obliged to act as market makers confident that they can manage the risks of being a market maker.¹⁸⁰ In its submissions to the AEMC's Review of the Operation of Retailer Reliability Obligation, the ASX also noted that the MLO plays a useful role in supporting price discovery in regions with low levels of liquidity.¹⁸¹

Several submissions to the review noted that the current MLO framework does not adequately address participants' emerging forward risk management needs.¹⁸² Stakeholders such as AFMA suggested the MLO should be replaced with an explicit market making framework developed in co-operation with market participants.¹⁸³ Iberdrola Australia suggested the MLO be made permanent and be expanded to include more participants, longer periods and more frequent bids with tighter spreads.¹⁸⁴ This view is also supported by the Australian Energy Council (AEC):

¹⁷⁵ A T-3 instrument under the RRO is triggered under an instrument made by the AER three years and three months from the commencement of a reliability gap identified by AEMO. Under the T-3 instrument, obligated entities under the MLO must provide qualifying contracts for liable entities to purchase to help meet their share of the forecast reliability gap. The MLO ceases to operate when a T-1 instrument is triggered, as the RRO requires liable entities to be fully contracted to cover their share of the reliability gap one year in advance of the forecast gap.

¹⁷⁶ AER (2024), [Interim market liquidity obligation guidelines](#).

¹⁷⁷ AER (2025), [MLO register February 2025](#).

¹⁷⁸ National Electricity Rules (2025), 4A.G.19(b), accessed 17 July 2025.

¹⁷⁹ AFMA (2025), [Submission to the Initial NEM Review Consultation](#), p 4.

¹⁸⁰ [Submissions to the initial NEM Review consultation](#) from Clean Energy Council (p 12), AGL (p 10) and Shell Energy (p 4).

¹⁸¹ AEMC (2025), [Review of the operation of the Retailer Reliability Obligation](#), p 34.

¹⁸² Clean Energy Council (2025), [Submission to the Initial NEM Review Consultation](#), p 12; AGL (2025), [Submission to the Initial NEM Review Consultation](#), p 10; Shell Energy (2025), [Submission to the Initial NEM Review Consultation](#), p 4.

¹⁸³ AFMA (2025), [Submission to the Initial NEM Review Consultation](#), p4.

¹⁸⁴ Iberdrola (2025), [Submission to the Initial NEM Review Consultation](#), p10.



The AEC believes that the RRO in its current form adds no value and should be repealed and that the market liquidity obligation (MLO) could be replaced by an ongoing market making framework to promote liquidity. Market participants have gained experience of both acting as a market maker in the NEM and the benefits of market making. It is generally accepted that the MLO has boosted liquidity and been a positive for the NEM, with parties who have been obliged to act as market makers confident that they can manage the risks of being a market maker. - AEC¹⁸⁵



The AEMC's review of the RRO found that liquidity in South Australia has declined since the introduction of the RRO, and remained steady in other regions.¹⁸⁶ However, in contrast to the MLO, which only delivers increased liquidity in response to occasional reliability gaps over a narrow time period, a permanent market making obligation would be designed to target liquidity and price transparency on an ongoing and consistent basis.

Voluntary market making schemes can struggle to deliver liquidity and price transparency during times of market stress. Voluntary market making schemes carry the risk that market makers can withdraw from providing services during periods of high price volatility.¹⁸⁷ They risk providing less certainty to the market that the intended liquidity and price-discovery benefits of market making will be available at times of market stress. This is likely to be especially true as electricity systems become more weather dependent.

Voluntary schemes also do not necessarily guarantee an adequate pool of market makers. As market making is riskier when there are fewer market makers, withdrawal of participants from market making schemes can create a negative feedback loop where a declining number of market makers increases the risk to remaining participants.

The ASX's voluntary market maker scheme applies to base load electricity futures markets in New South Wales, Victoria, Queensland and South Australia. The requirement under this scheme is similar to that required under the MLO, including exclusions that apply to about a quarter of the available trading sessions in a month.¹⁸⁸ Notably, the New Zealand Electricity Authority replaced a voluntary market making scheme in NZ with a scheme involving mandatory market making requirements on the four large gentailers. This followed widespread withdrawal of market making services during a period of market volatility in 2018 (see **Case study: New Zealand market making experience**).

International experience shows market making can improve liquidity and price discovery

Other jurisdictions have experienced similar liquidity challenges to those faced by the NEM, with literature outlining that electricity markets often lend themselves to settings that are highly concentrated, vertically integrated and subsequently result in low forward liquidity.¹⁸⁹ Market making schemes of various forms are an established design feature of electricity derivatives markets internationally. The Panel has considered the experience of the United Kingdom and New Zealand, in implementing market making schemes. The UK and New Zealand are comparable liberalised markets with relatively high price caps, and vertically integrated generator-retailer structures.

¹⁸⁵ AEC (2025), [Submission to the Initial NEM Review Consultation](#), p 8.

¹⁸⁶ AEMC (2025), [Review of the operation of the Retailer Reliability Obligation](#), p 34-36.

¹⁸⁷ IEA (2020), [Power systems in transition Challenges and opportunities ahead for electricity security](#).

¹⁸⁸ ASX (2025), [Market maker arrangements](#).

¹⁸⁹ T Kanamura and DW Bunn (2022), [Market making and electricity price formation in Japan](#), in Energy Economics; Cramton (2017), [Electricity market design](#), in Oxford Review of Economic Policy.

New Zealand's market making scheme (see **Case study: New Zealand market making experience**) provides a useful model for a potential market making obligation in the NEM and has been effective in improving market liquidity. The New Zealand Electricity Authority is expanding its market making scheme further, with a broad review to commence in late 2025.¹⁹⁰

Like New Zealand, the UK also introduced mandatory market making (see **Case study: UK market making experience**). Market making in the UK initially had a positive impact. It was repealed after several gentailers in the market became less vertically integrated. This reduced the need for a market making obligation, with enough trading between market participants for sufficient liquidity without it.

Case study: New Zealand market making experience

Market making has featured in the New Zealand electricity futures market since voluntary arrangements began in 2010 following a ministerial review. After a major gas outage in 2018 led to a widening in bid-ask spreads for key listed contracts and a temporary withdrawal of services, the New Zealand Electricity Authority (the Authority) worked with participants to enhance the voluntary market making arrangements. The regulated bid-ask spread was reduced, contract volumes increased and data provided to the Authority improved transparency.

In 2020 the Electricity Authority introduced a regulatory backstop. The backstop requires voluntary market makers (the four large gentailers in the NZ market) to provide compulsory market making services if their voluntary performance does not meet a regulated standard. The backstop began as a temporary measure and was made permanent in 2021.

The Authority further reformed the market making scheme with the introduction of a commercial market maker in 2022, which it contracted to provide commercial market making to meet the same service level parameters as regulated market makers (the four large gentailers). The introduction of a commercial market maker aims to enhance the performance and efficiency of the NZ electricity futures market while providing the opportunity to increase the diversity of participants. The Authority considers that access to a wider pool of market makers and introducing a potentially more efficient provider will contribute to greater confidence in the forward price curve. In addition, the commercial scheme will allow participants to give feedback on their desired service levels helping the authority to adapt the service in a way that strikes an appropriate balance between the costs and benefits. The arrangements should also make the price of market making more transparent and efficient.¹⁹¹ The costs of the commercial market maker are recovered via a levy on electricity generators and retailers (including existing market makers). The NZ Cabinet has provided the Authority with a maximum appropriation of \$14.4 million annually, informed by indicative prices for commercial market making obtained in 2021.¹⁹²

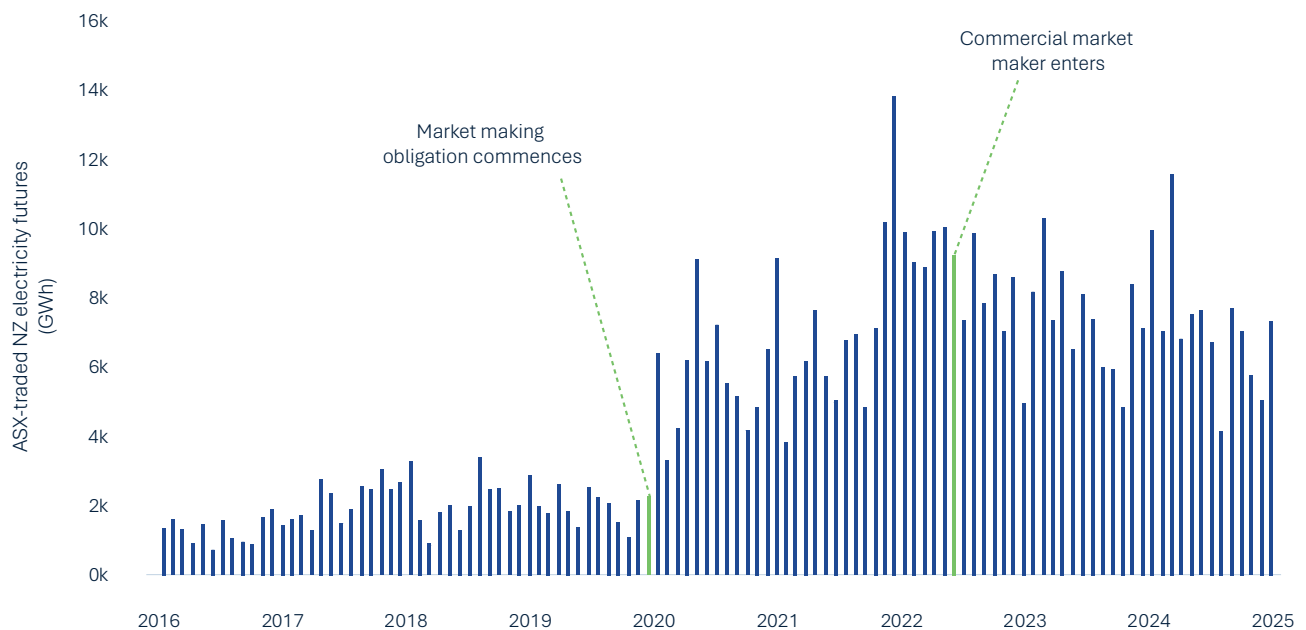
Figure 42 shows changes in base quarterly contract volumes traded up to the end of 2024. This is an alternative liquidity measure to open interest and reflects the number of contracts traded in a period.

¹⁹⁰ Electricity Authority (2025), [Decision paper: Market making under high stress conditions](#), p 15–17.

¹⁹¹ Electricity Authority (2021), [Levy consultation: Commercial market-making scheme – Consultation paper](#), p ii. Ministry of Business, Innovation, and Employment (2021), [Cabinet paper: Electricity Authority levy increase: funding the commercial market making scheme](#).

¹⁹² Ibid.

Figure 42 – Monthly electricity futures traded in New Zealand by volume (2016 to 2024)



Source: ASX data sourced from the New Zealand Electricity Authority (www.emi.ea.govt.nz/r/xihiy), NEM Review analysis.

Source: New Zealand Electricity Authority 2025, [Consultation paper: Expiry of urgent code regarding market making under high stress conditions](#).

Case study: UK market making experience

The Office of Gas and Electricity Markets (Ofgem), the UK energy regulator, introduced a market making obligation in 2014, focusing on the UK's six major gentailers. Ofgem introduced this obligation as part of its 'Secure and Promote' reforms, which also included minimum service standards for trading and day-ahead reporting requirements. Economic consultants NERA analysed how these reforms affected liquidity. It found that traded volumes increased 17% from 2013 to 2017, suppliers trebled from December 2013 to June 2019, bid-ask spreads narrowed as the market making obligation specified a maximum spread, and churn broadly remained unchanged.

In November 2019 Ofgem suspended the obligation. After divestments led to reduced vertical integration for four of the six major gentailers, Ofgem removed the market making requirement from their licence conditions.^{193,194} Ofgem considered a market making obligation falling only on two parties would result in costs being disproportionate to the benefits.

Ofgem also considered the obligation had become less effective in enabling robust reference prices relative to what the market would otherwise provide. However, this was likely due to there being fewer regulated market makers and the market becoming more naturally competitive following new entrants and unbundling by previously vertically integrated entities.

Several stakeholders argued against Ofgem suspending its market making obligation. They raised that while the design of the obligation had become obsolete, Ofgem should implement an alternative liquidity support instead of suspension.

Consulting on power market liquidity in 2023 to 2024 Ofgem decided not to introduce liquidity interventions in the short to medium term. Ofgem nevertheless committed to continue monitoring liquidity trends and to consider potential policy levers to improve liquidity.

"We are not ruling out the introduction of a market maker in the future and may consider this as a potential option if market conditions show there may be a clear benefit to introducing this." – Ofgem 2024¹⁹⁵

Source: NERA 2019, [GB wholesale power market liquidity: options assessment](#), Ofgem 2019, [Decision to suspend the Secure and Promote Market Making Obligation with effect on 18 November 2019](#); Ofgem 2024, [Summary of Responses: Power Market Liquidity Call for Input](#)

¹⁹³ Ofgem removed obligations for E.ON UK in November 2016, Centrica in August 2018, ScottishPower in January 2019 and RWE Npower in October 2019. EDF Energy and SSE remained.

¹⁹⁴ Ofgem (2014), [Liquidity in the wholesale electricity market \(special condition AA of the electricity generation licence\): Guidance](#), p 8–9.

¹⁹⁵ Ofgem (2024), [Summary of Responses: Power Market Liquidity Call for Input](#), p 5.

6A: The MMO should apply to all participants above a pre-defined size and prescribe volumes that must be made available for trading and a limit on the bid–ask spread, with contract types determined through a co-design process with AER and industry.

The Panel recommends energy ministers establish an energy derivatives MMO in the NEL/NER, building on lessons from the existing MLO and from international examples. This will become particularly important for managing the risks associated with a weather-dependent system where periods of abundance and scarcity will drive more volatile and variable spot pricing outcomes. To provide customers with stable pricing, retailers will need access to transparent, liquid wholesale derivatives markets which facilitate risk management of spot pricing outcomes.

The Panel recommends designing an MMO to meet the following key policy objectives:

- Facilitate trade in new standardised financial contracts that will sit at the heart of the electricity market through an AER-convened co-design process, that better address the needs of buyers and sellers as the system shifts from centralised thermal units to firmed VRE (see **Recommendation 6B**)
- Link the long-term investment signal with the medium-term derivatives market by basing this MMO on (a subset of) the same standardised, fungible contracts which will also be used for longer-term contracting through the ESEM (see **Recommendation 8**).
- Support short- to medium-term derivatives market liquidity (i.e. one-to-five years into the future).
- Support accessibility to derivatives markets so all market participants can access hedging products on competitive terms to manage the risks of an increasingly weather dependent electricity system. This is a pre-requisite for effective retail competition.
- Enhance and extend price discovery.

The MMO should address the structural issues poised to undermine NEM derivatives market liquidity over coming decades, and related barriers to access and limitations to innovation. In doing so, an MMO should enable derivative derivatives markets with transparent pricing, robust competition and deep liquidity. These features are essential for translating variable and volatile spot signals into investable, forward-looking price information.¹⁹⁶

The MMO should also aim to extend the forward period over which participants can hedge risks. By adopting these reforms in the medium-term derivatives market, financial derivative contracts (rather than revenue underwriting) can then be integrated into the design of the long-term investment signal, the ESEM (see **Recommendation 8**). Such an obligation would be designed to achieve the policy objectives set out in the section above. The Panel will continue to work with stakeholders during the second half of 2025 to define how this MMO could operate. A number of preliminary considerations on key design elements – participation, activation, coverage and products – are detailed below.

¹⁹⁶ [Submissions to the initial NEM Review consultation](#) from CleanCo Queensland (p 3), Iberdrola (p 6), Engie (p 2).

A set of core derivative contracts, co-designed with industry, will sit at the core of the MMO

As noted above, the shift to firmed renewables may require a distinctly different set of contracts from those traded in the past. As such, the Panel is of the view that the AER should regularly convene (e.g. every two years) with industry (including generators, retailers, financial participants, and electricity users) and its representative bodies (e.g., the Australian Financial Markets Association (AFMA), the Australian Energy Council (AEC), the Clean Energy Council (CEC), the Australian Securities Exchange (ASX)) to define a small set of core derivative contracts at the heart of the electricity market (see **Recommendation 6B**).

A MMO could take several forms but mandatory participation should be a feature

The Panel considers an MMO that includes an element of mandated participation preferable to a purely voluntary scheme.

Market making schemes range from compulsory participation for designated market participants (e.g. the MLO) to voluntary participation driven by financial incentives (e.g. ASX market making schemes). Participation models may also fall in between. For example, gentailers in New Zealand are voluntary market makers but are subject to performance reporting and have mandatory market making obligations placed on them if they underperform, creating the effect of an obligation. The New Zealand Electricity Authority has also tendered for market making under a commercial arrangement.

Evidence from international examples suggest that voluntary market making tends to be ineffective at times of market stress, which is also when it is most needed to sustain liquidity and a robust forward price curve. As the ASX already currently runs a voluntary market making scheme, it is not clear that an additional voluntary scheme would add value. Similarly, the MLO already provides for mandatory market making and several stakeholders have indicated that this could be improved and expanded.

The Panel is interested in stakeholder views about whether a mandatory MMO could be enhanced by other participation features. For example, there may be merit in designing an MMO that also features commercial market making, such as New Zealand. Such a model could spread the costs of market making whilst providing transparency around those costs.

The MMO should be always-on

The Panel considers an MMO should operate on a permanent / always-on basis. This feature would provide small retailers with an ongoing benchmark price and access to a reliable source of contract offerings. Furthermore, it would provide confidence for electricity users that the price they are paying is reasonable and fair. This design choice differs from schemes that are only active during specific periods temporarily or based on a trigger mechanism, such as when the market is experiencing times of stress or low liquidity, or to address specific reliability issues (such as the RRO/MLO). Since the MLO is only triggered under specific conditions, it does not directly bring forward supply to market under normal market conditions.

It is common practice for market making obligations to operate each trading day. There is a range of potential design options around trading requirements. For example:

- Under the voluntary ASX scheme and MLO, market making occurs in two half-hour periods (11:00–11:30am, 3:30–4pm).

- The MLO provides flexibility for market makers to also nominate two other half-hour trading periods for market making, although it is not clear if this has been useful or used in practice.¹⁹⁷
- In New Zealand, market making occurs for one half-hour trading window in the afternoon with a refresh that enables traders to split their bids in two.
- Market making schemes generally provide market makers with several trading exemptions. For instance, under the MLO and voluntary ASX scheme, market makers can miss 10 trading periods per month at their discretion without consequence. Some exemptions are sensible but could undermine the effectiveness of market making if used in excess.

Market making roles should reflect participant nature and size

Some schemes target participants based on market share and the extent to which they are vertically integrated. Other metrics, such as a participant's share of dispatchable capacity, could also be used to allocate market making functions.

For example, a potential approach could be to pursue an MMO on large buyers (retailers), large sellers (generators) and vertically integrated market participants above a certain market share threshold. If such a threshold was applied, the Panel would recommend reviewing the threshold periodically as part of the AER's regular convening of industry participants to facilitate contract innovation (e.g. every two years). The Panel is interested in stakeholder views on what types of market participants would be suitable market makers.

To be clear, requirements on participants would reflect the nature and size of their business. For example, a stand-alone renewable generator would not have a requirement to trade in cap contracts.

Market making in different NEM regions should take account of jurisdictional market and policy conditions

Designing a market making obligation in the NEM should take account of variations between NEM regions, such as differences in policy settings and the operational environment for hedging. The Panel notes that the South Australian Department of Energy and Mining (DEM) is currently consulting on proposed market making and reliability obligations that would accompany its Firm Energy Reliability Mechanism (FERM). This mechanism proposes to establish commercial and regulatory arrangements that would support investment in sufficient long duration firm capacity for the South Australian NEM region. The proposed mechanism includes a five-year Firm Energy Target set by the South Australian Minister and arrangements for contracts made between the Minister and long duration capacity providers for the purposes of meeting the target.

As part of the design, the scheme regulations provide for a market liquidity obligation applicable to existing and new providers of long duration capacity and a reliability obligation imposed on retailers and other large load customers. Under the market liquidity obligation generators will be required to post bids for a specified amount of nominated capacity in eligible contract markets or on a specified exchange.

The proposed obligations have a number of objectives which include providing predictable revenue streams to long duration capacity providers, minimising the need for underwriting support and ensuring retailers are able to meet consumer demand during periods of market stress.

¹⁹⁷ AER (2024), [Interim market liquidity obligation guidelines](#).

DEM has published draft regulations and a draft Minister's guideline which outline a possible design approach to the obligations. It is envisaged that the South Australian FERM regulations will commence operation in August 2025 with the first capacity tender to be launched in Q3 2025.

The Panel will work with DEM and South Australian stakeholders in the second half of 2025 to determine how a future NEM MMO would interact with the proposed design for the South Australian FERM.

The application of market making will also need to be considered carefully for Tasmania, which has a very different market structure and regulatory framework to the rest of the NEM, and where there is no ASX Energy exchange.

The potential role of an MMO in Tasmania

Over 90% of generation capacity in the Tasmanian region is provided by Hydro Tasmania. Hydro Tasmania controls approximately 2,174 MW of hydro generation capacity in the NEM producing around 9,000 GW hours of electricity each year given average inflows. Hydro Tasmania has a minority equity interest in approximately 300 MW of wind generation and nearly 400MW of gas-powered generation, although production from gas is typically limited, depending on hydrological conditions (and market opportunities).

At present, under the National Electricity Rules, the Market Liquidity Obligation that is included within the Retailer Reliability Obligation does not apply in Tasmania. Tasmanian region derivatives contracts are not available on the ASX, and the only party offering wholesale contracting options against the Tasmanian spot price is Hydro Tasmania.

Wholesale contract liquidity in Tasmania is a function of both regulatory arrangements and commercial activity by Hydro Tasmania.

To ensure that wholesale market contracts are made available to electricity retailers and users in Tasmania, the Electricity Supply Industry Act 1995 (Tas) sets out the framework for the Wholesale Contract Regulatory Instrument (WCRI), which is administered by the Tasmanian Economic Regulator. Under this instrument, Hydro Tasmania is required to make available specific forms and volumes of wholesale contract types with prescribed terms, with the prices of those contracts set through a detailed pricing framework. These requirements are intended to cover household and small business customer demand. The primary driver of those regulated contract prices is the ASX-listed Victorian forward price for the equivalent contract type (flat, peak cap etc). Currently, the volume obligation on Hydro Tasmania to make regulated contracts available is set based on the size of the small customer base in Tasmania (residential customers plus small business customers under 150MWh pa). In addition to those regulatory obligations, Hydro Tasmania publishes a weekly 'rate card' on a voluntary basis for three contract types and is free to set its own prices for such volumes. All transactions are OTC.

An issue for policy makers to consider is whether any new MMO could apply in Tasmania as a means to drive greater liquidity in the Tasmanian region. This could be in addition or as an alternative to the WCRI.

Whilst the operation of an MMO may be challenging, given Hydro Tasmania's significant position and a lack of competition in the Tasmanian wholesale region of the NEM, it is possible that the construction of the new Marinus Link interconnector (one, and potentially two, new 750 MW cables) between Victoria and Tasmania may create new opportunities to drive liquidity and competition. Combined with the 500 MW capacity of Basslink, the construction of Marinus Link should support greater inter-regional trading and closer alignment of the Victorian and Tasmanian spot prices.

For example, as renewable exports increase from Tasmania from different generation sources, it may be possible to apply a new MMO to a broader range of Tasmanian entities (subject to how any threshold is set) to support liquidity in both the Tasmanian region and in cross-border trading into Victoria. Similarly, the application of an MMO in Victoria may also help to facilitate inter-regional trading and exports into Tasmania. However, the ability of the MMO to support inter-regional trading would rely upon trading parties also being able to access inter-regional settlement residues (IRSR) to hedge inter-regional price differences through the IRSR auctions.

The Panel will work with stakeholders to consider how such arrangements could work in the second half of 2025 with a view to providing further guidance in the final report.

The Panel has considered alternative measures to address liquidity and price transparency

The Panel has also considered stronger measures to address liquidity and price transparency in the market, including stakeholder suggestions for accounting separation of vertically integrated gentailers. Stakeholders have suggested that gentailers can divert significant generation capacity within their portfolio away from the derivatives market and towards internal hedging. In its 2024 Wholesale Markets Performance Report the AER highlighted that gentailers have high market shares of firm capacity across the NEM, most notably in New South Wales, Victoria and South Australia.¹⁹⁸ Market concentration and an ability to allocate firm generation to a gentailer's retail arm through opaque internal accounting raises risks for liquidity and competition in the market.

Stakeholders have suggested accounting separation as a means of driving greater price transparency and suggested the Panel consider this option. Accounting separation requires maintenance of separate accounts between different arms of a business. It ensures costs and revenues can be clearly identified between parts of the business or a related body corporate. Typically, accounting separation includes obligations to report to a regulator, as well as a compliance and enforcement regime to ensure any misallocation of costs and revenues are detected and penalised.

Accounting separation for gentailers would require accounting separation between a business's generation and retail arms. Its objective would be to ensure transfer pricing – the internal price gentailers use to attribute generation to their retail business – is transparent. Obligations on gentailers to report internal transfer pricing to regulators already exist in other electricity markets, such as New Zealand.¹⁹⁹

¹⁹⁸ AER (2024), [Wholesale Electricity Market Performance Report 2024](#), p 59-61.

¹⁹⁹ Electricity Authority Te Mana Hiko (2021), [Wholesale Markets – Internal Transfer Prices and Segmented Profitability Reporting – Decision Paper](#).

The Panel is of the view that an MMO is likely to achieve the price transparency and liquidity required. However, active monitoring of the performance and impacts of its recommended MMO will be necessary to determine whether further measures are needed in the future.

Questions for stakeholders

- Which products should an MMO for the NEM encompass?
- What additional design elements should the Panel consider to ensure an MMO provides efficient outcomes for end users?

6B: The AER should regularly convene (e.g. every two years) with industry (financial market bodies, brokers, generators, retailers and electricity users) to define a small set of core derivative contracts that sit at the heart of the electricity market

These contracts:

- should be able to be traded on an exchange platform
- should be the subject of the market making obligations
- should be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW)
- should be utilised to underwrite projects in the ESEM
- could be used in retail price benchmarking.

The Panel will work with stakeholders to further demonstrate how this would work in practice during the second half of 2025.

It is important to facilitate continued contract innovation based on what the evolving market needs

Most existing market making schemes have focused on traditional forms of managing forward liquidity – broadly equivalent to baseload swaps and cap contracts in the NEM.

It could be beneficial to pursue an MMO that includes base load futures and cap contracts. However, to prepare for a firmed VRE future (without large centralised thermal units), it is critical that regular investigation into expanding the scheme's MMO's coverage should occur as innovative products come to market, including contract types developed in the OTC market. Importantly, market making could drive a competitive and liquid market for the standardised, fungible contract types that are utilised through the ESEM. The MMO would drive liquidity for these products over the medium term and the ESEM would utilise these contracts to support investment over the long term. As such, there will be an explicit link between the medium-term and long-term electricity market economics.

Market making could also be used to drive liquidity in contracts of smaller lot sizes (e.g. 100 kW instead of 1 MW) and potentially (with sufficient innovation) longer tenor (a five-year swap analogous to a five-year interest rate swap). By complementing potential efforts to reduce lot sizes, market making could reduce some of the barriers small retailers face to accessing exchange-traded contracts.

Product innovation should be driven by market participants to leverage their expertise

The Panel recommends the AER regularly convene with industry to define a small set of core derivative contracts that sit at the heart of the electricity market. This industry co-design process would develop

a set of derivative contract types that are suitable for managing current and emerging risks. The co-design process should include industry (generators, retailers, financial participants such as traders and brokers, and electricity users) and its representative bodies (e.g. the Australian Financial Markets Association (AFMA), the Australian Energy Council (AEC) and the Australian Securities Exchange (ASX)).

The recommended co-design process has been informed by stakeholder feedback that product innovation should be driven by market participants.²⁰⁰ A co-design process would ensure that expertise held by industry participants actively trading in derivatives markets is leveraged. This will assist in the development of contract types that are well suited to the risk management needs of different participants. It will also allow market sounding with industry participants, as part of the co-design process to gauge likely trading levels and liquidity after a product is launched. Building market sounding into the co-design process could help inform the pathway to market and implementation timeframe for contract types that are identified through the process.

A co-design process could also assist in identifying additional market benefits. For example, if parcel size is creating a barrier to access this AER-led process could drive the development of products to be traded in smaller parcels.

The AER leading this process would be consistent with its current roles of defining contracts that are eligible under the MLO, and assessing how derivative contracts feed into the calculation of the Default Market Offer (DMO). The AER is also implementing its expanded wholesale market monitoring role, under which it monitors the performance of electricity contract markets as well as the spot market. Such an AER-led process would provide a pathway for determining what energy derivatives would be subject to market making requirements. This would be valuable given the AER would be the regulator responsible for compliance with any new market making obligation.

This AER-led process would also have a vital role in defining what standardised, derivative contract types would be suitable for use in the ESEM. If this process successfully defines contracts that market participants readily use it could provide a powerful input for the AER in considering market participant costs in the context of the DMO.

The Panel will work with stakeholders during the second half of 2025 to further demonstrate how this process would work in practice. By undertaking a preliminary or pilot consultation process the Panel will provide the AER with an ability to quickly stand up the co-design process as part of the implementation of the Panel's recommendations.

In forming this recommendation, the Panel notes that a similar co-design process was successfully used in New Zealand (see **Case study: Using the OTC market for New Zealand's super peak contract**).

²⁰⁰ AFMA (2025), [Submission to the Initial NEM Review Consultation](#), p 4–5.

This recommendation also aligns with one of the ACCC's recommendations in its 2023 NEM Inquiry:

“

The government should investigate, in consultation with the ASX and market participants, whether there are ways to support new hedging products being listed on the ASX in a timelier manner.

This could involve coordinating collaboration between the ASX and market participants to identify, design and list suitable products. Other examples could include funding market making incentives within the exchange, or underwriting the risk of new hedging products to reduce margin obligations for retailers until the product becomes more liquid. Some of the types of products that may be needed on the exchange include super-peak products, inverse-solar products, or products that hedge the spread for storage charging and discharging.²⁰¹ – ACCC

”

Questions for stakeholders

- How can the proposed co-design process be designed to best accelerate contract market innovation, determine appropriate ESEM contract types and identify contract types that should be subject to the market making obligation?
- What should be the design and governance of an ongoing contract market co-design process in the NEM?
- What contract types should the Panel explore, in consultation with industry and market participants, over the next six months for the purposes of market making and the ESEM?

²⁰¹ ACCC (2023), [Inquiry into the National Electricity Market: December 2023 Report](#), p 11.

6C: During the second half of 2025 the Panel will work with stakeholders to explore approaches to improve the accessibility of derivatives markets, with a focus on NEM prudential requirements, financial market margining requirements and the interaction between the two.

This will allow for recommendations to be made in the final report to improve market access.

Small, stand-alone retailers are important for competition in the NEM

Through discounted pricing and innovative offers, small and stand-alone retailers provide competitive pressure on retail prices over the long term. Market analysis reflects that smaller retailers (including larger Tier 2 retailers) have a positive market impact by providing competitive offers,²⁰² using innovation and marketing to attract customers,²⁰³ and having more customers on market offers than their larger counterparts.²⁰⁴

Retail markets can only be competitive and efficient if these new, stand-alone retailers can enter and acquire risk management services on reasonable terms. To prudently manage risk, both for themselves and on behalf of their customers, electricity retailers need to access derivative markets. This especially holds for stand-alone retailers that do not benefit from owning generation assets.

To trade in the NEM electricity spot and ASX electricity derivative markets, participants must meet prudential (set by AEMO) and margining requirements (set by financial market exchanges, brokers, and intermediaries) respectively. These financial assurances are essential for managing credit risk and maintaining market integrity and stability, ensuring that retailers are financially sound when buying on behalf of customers.

While prudential management is essential to manage AEMO's risk exposure in settling the NEM wholesale market, the Panel has heard that the current requirements can demand substantial working capital and impose significant costs. The Panel has heard that these requirements disproportionately affect small retailers and do not always reflect the risks they are designed to manage.

²⁰² ACCC (2023), [Inquiry into the National Electricity Market: December 2023 Report](#), p 8.

²⁰³ AER (2025), [Quarterly retail performance report: October – December 2024](#), p 16.

²⁰⁴ AER (2024), [Annual retail markets report 2023–24](#), p 16.

Understanding AEMO prudential and ASX margining requirements

To participate in the NEM and trade electricity derivatives on the ASX, energy retailers must meet specific prudential and margining requirements designed to ensure they can meet their liabilities, thereby safeguarding market stability.

Maximum Credit Limit (MCL) for accessing the NEM: Retailers must provide AEMO with credit support (typically bank guarantees) to meet their MCL, which reflects their estimated liabilities over the settlement period. Retailers with higher credit risk can pay a premium for bank guarantees. AEMO calculates each retailer's MCL based on expected price volatility, expected peak load, trading volumes and several other factors such as reallocation of generation revenue and credit risk profile.²⁰⁵ Reallocation of generation revenue is when a retailer and generator agree to transfer settlement amounts directly between themselves, which reduces the retailer's MCL by shifting financial exposure away from AEMO.²⁰⁶

When the MCL increases, AEMO may issue call notices, requiring participants to provide additional capital, sometimes within hours. In the absence of generation revenue, a small, stand-alone retailer may hold aside capital to meet these calls.

Clearing and margin requirements for accessing the ASX: Participants must post an initial margin with their clearing participant, the size of which is based on market volatility and the size and nature of the participant's contract positions.²⁰⁷ When market movements result in losses, the ASX issues a margin call, requiring participants to post additional collateral, often within a single business day.

Prudential working capital can pose a barrier for small, stand-alone retailers

AEMO's prudential requirements for operating as a retailer in the NEM can absorb a significant proportion of a small retailer's working capital. While recent reforms to shorten the spot market settlement cycle and to allow AEMO to accept cash as credit support may mitigate some of this pressure, prudential requirements are likely to continue to affect small retailer positions.^{208,209}

Small, stand-alone retailers often face higher MCLs than vertically integrated retailers due to their lack of generation assets. While vertically integrated retailers must also meet prudential requirements, their MCLs are offset by a generator credit. For example, expected sustained higher spot prices will result in AEMO requiring the stand-alone retailers to provide additional working capital, for a vertically integrated retailer, the additional capital will be offset, at least in part, by an increased generator credit.

While the reallocation of energy and revenue in the NEM's settlement process can reduce a retailer's MCL, these arrangements are more straightforward for vertically integrated participants that can effectively enter reallocations with themselves. In contrast, establishing reallocation agreements between separate counterparties can be more complex, particularly for small retailers with lower credit ratings. When such agreements are reached, the Panel understands that small retailers may incur additional costs due to their credit risk. In practice the vast majority (more than 80%) of

²⁰⁵ AEMO (2024), [National Electricity Market credit limit procedures](#).

²⁰⁶ AEMO (2020), [Guide to Electricity Reallocations August 2020](#).

²⁰⁷ ASX (2020), [Overview of ASX Energy Initial Margins](#).

²⁰⁸ AEMC (2024), [National Electricity Amendment \(Shortening the settlement cycle\) Rule 2024](#).

²⁰⁹ AEMC (2025), [National Electricity Amendment \(Allowing AEMO to accept cash as credit support\) Rule 2025](#).

reallocations in the NEM are intra-company reallocations (within a vertically integrated gentailer).²¹⁰ The AEMC has noted a possibility that the use of reallocations may decline in the future with the increase in non-firm generators, who are less likely to enter into these types of contracts.²¹¹

Additionally, there is no connection between the prudential requirements for the AEMO position and ASX exchange-traded requirements. Retailers will commonly hold exchange-traded derivatives with a position opposite to their position in the spot market. While the risk of spot-price movements to each of those positions offset each other, the prudential requirements do not.

Margining requirements pose a barrier to accessing exchange-traded derivatives but do not take physical positions into account

Exchange traded markets, primarily the ASX's electricity derivatives, offer the simplest, most transparent and liquid contracts. The ACCC has noted that many small retailers are of the view they cannot effectively manage spot market risk without ASX contracts.²¹²

In discussions with the Panel, representatives from small retailers expressed that the substantial amount of working capital needed to fulfill exchange margining requirements hinders their access to exchange-traded markets. In fact, working capital impediments to accessing hedging contracts have been identified as a barrier to entry and further expansion, as far back as 2020.²¹³ ASX margin calls can be relatively expensive for small standalone retailers who are less able to draw on financial reserves and access low-cost credit to meet them. Several retailers also advised the ACCC that they were required to provide an additional margin compared to larger retailers due to their credit risk.²¹⁴

In 2023 the ACCC found that 90% of small retailers stated they were unable to access ASX contracts or faced challenges in executing their hedging strategies.²¹⁵ This creates an over-reliance on OTC contracts (see **Figure 43**), with the ACCC reporting that ASX trades accounted for less than 15% of small retailer-traded contract volumes in 2023.

²¹⁰ AEMC, (2024), [National Electricity Amendment \(Shortening the settlement cycle\) Rule 2024](#), p 14.

²¹¹ AEMC (2024), [National Electricity Amendment \(Shortening the settlement cycle\) Rule 2024](#), p 20.

²¹² ACCC (2023), [Inquiry into the National Electricity Market: December 2023 Report](#), p 7.

²¹³ AER (2024), [State of the Energy Market](#), p 271; AEMC (2020), [Retail Energy Competition Review](#), p 23.

²¹⁴ Based on compulsory-gathered market participant survey data. ACCC (2023), [Inquiry into the National Electricity Market: December 2023 Report](#), p 7, 95, 98.

²¹⁵ Ibid.

Figure 43 – Proportion of ASX and OTC contracts traded by large and smaller retailer



Source: ACCC, *Inquiry into the National Electricity Market, December 2023 Report*

Note: Excludes power purchase agreements, and load following and generation following shaped products

Additionally, the ASX's margining requirements assess a participant's ASX energy portfolio but do not account for their physical positions (for example, generation assets or retail contracts) with opposite exposure to the ASX-listed contract. This can result in margining obligations that do not accurately reflect the participant's actual risk exposure, unnecessarily tying up working capital (see below **Case study**).

Case study: Pressure on derivative market access during the 2022 energy crisis

High and volatile NEM prices in 2022 put pressure on the energy derivatives market, which limited retailer access to risk management products. Several connected events culminated in the 2022 energy crisis. Higher global energy prices following Russia's invasion of Ukraine drove up east coast gas market prices, which drove up NEM spot prices. A winter cold snap combined with key coal generator outages resulted in AEMO enforcing the \$300/MWh administered price cap. AEMO later suspended the NEM and temporarily directed generators to dispatch after some generators elected to not dispatch at the administered price cap.

High and volatile NEM prices during this period put pressure on the energy derivatives market by requiring parties to post more working capital to cover higher margining requirements. As margining requirements do not take physical positions into account, generators have less incentive to sell derivatives during these periods. Given this, not only did the financial burden of meeting margining requirements increase but the supply of contracts greatly diminished. This put pressure on small stand-alone retailers that needed to purchase energy derivatives. Barriers to access increased further as clearing services became restricted during this period.

Seven retailers failed during this period, resulting in the AER declaring seven Retailer of Last Resort events.²¹⁶ Several retailers cited that they were required to exit the market as they were unable to adequately hedge their forward positions. The AEMC also noted that both high wholesale prices and reduced derivatives market liquidity contributed to a record number of retailer failures.²¹⁷

There may be other considerations beyond prudential working capital that can improve access to derivatives markets

While the Panel intends to further enquire into AEMO prudential and margining requirements, it could also consider the other factors that may limit small retailer access to derivative markets.

While margining requirements for derivative contracts create a cost barrier to derivative market access, in 2023, the ACCC found the primary reason that most small retailers were unable to trade on the ASX was that they could not find a clearing participant prepared to work with them because they were considered riskier clients than larger participants.²¹⁸ This barrier is also highlighted in the above **Case study**.

The ACCC also identified another potential barrier to effective hedging was the minimum 1 MW trade size in the ASX.

“

Small and start-up retailers have very small loads, and may find it difficult to build a portfolio of hedges in 1 MW ‘blocks’. For example, a new retailer that has amassed 5000 customers might have an average load of around 3.5 MW. Trading on the ASX would require the retailer to hedge to 3 MW or 4 MW of coverage, which means the retailer will be around 15 per cent under- or over-covered. Being under-covered exposes the retailer to risk, while being over-covered is wasted cost. – ACCC (2018)²¹⁹

”

The Panel considered this potential barrier in recommending that contracts developed under **Recommendation 6B** be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW). The Panel recognises that this could have a positive impact on contract market access.

Questions for stakeholders

- What actions can be taken to improve the accessibility of derivative markets for small retailers?
- Would reforms to AEMO prudential working capital requirements assist in reducing barriers to participation for small retailers?

²¹⁶ AER (2024), [Determination of Origin Energy's Designated RoLR cost recovery applications](#).

²¹⁷ AEMC (2024), [Final report: Review into the arrangements for failed retailers' electricity and gas contracts](#), accessed 11 June 2025, p 2.

²¹⁸ Based on compulsory-gathered market participant survey data. ACCC (2023), [Inquiry into the National Electricity Market: December 2023 Report](#), p 7, 95, 98.

²¹⁹ ACCC (2018), [Retail electricity pricing inquiry – Final report](#), p 141.

Recommendation 7: Ensure sufficient market information is available to support longer-term derivatives market liquidity and price discovery

A well-functioning electricity market needs credible long-term signals that encourage investment. The Panel believes that providing relevant information to the market over a longer time horizon will improve liquidity and price discovery in contract markets.

The Panel has considered a range of options to improve the availability of market information to support more liquid hedging over a longer period. The Panel recommends extending the medium-term projected assessment of system adequacy (MT PASA) generation availability (see **Recommendation 7**) and requiring the Reliability Panel to provide a longer-term outlook, of up to 15 years, on the form of the market price settings to support improved confidence in the value and risks associated with long-term contracts.

Energy ministers should propose a rule change to the AEMC that extends the MT PASA's generation availability projections from three to five years and makes them public

Extended transparency of supply availability will increase market confidence

A well-functioning electricity market needs credible long-term signals to encourage investment. This could be done by extending generation availability projections in the MT PASA, AEMO's forecast of whether the NEM has enough supply to meet demand in the next few years.

In 2020 the AEMC made a rule change to improve transparency of the MT PASA by extending availability projections from two to three years and making them public.²²⁰ This change aimed to reduce information asymmetry, helping market participants make better-informed decisions about investing in new supply, entering contracts and scheduling maintenance. It also intended to increase visibility of reliability risks, giving participants earlier notice of forecast shortages and potentially reducing reliance on emergency reserves and lowering costs.²²¹

The quality of these projections is crucial for realising these benefits. The NEM Review has observed shortcomings in data provided by market participants. For example, participants include few planning outages beyond one year and tend to provide identical availability projections in years 2 and 3.

The Panel believes that extending the MT PASA's generation availability projections to five years should unlock further benefits, despite these early shortcomings, which should lessen as the market adapts. This requirement to provide availability projections would have the effect of extending notice of

²²⁰ AEMC (2020), [Rule determination Improving transparency and extending duration of MT PASA](#).

²²¹ Op. cit., p. 10.

closure from the existing 42 months to five years.²²² This would ensure that contracts are traded on the basis of the most accurate and up-to-date information. Although projections will always be subject to change, increased transparency is likely to improve market efficiency over time.²²³ Extending this information further would be likely to increase market participants' confidence over the projection horizon, potentially increasing liquidity in the derivatives market.

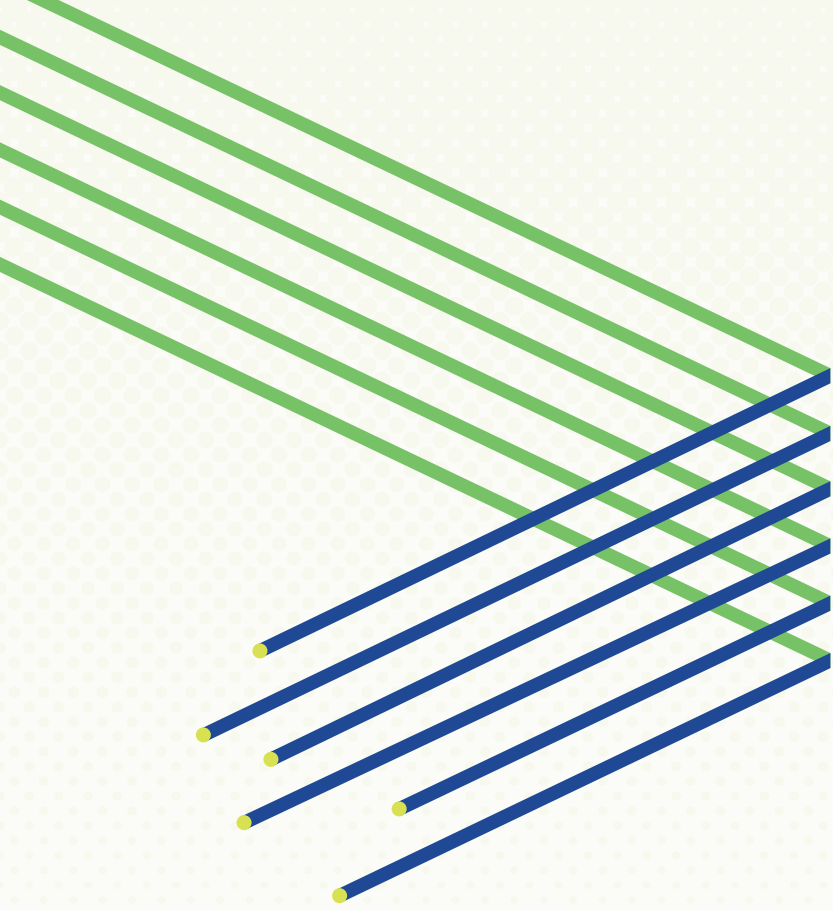
Longer-term forecasts of generator availability, and consequently generator closures, would complement the ESEM in enabling market participants to manage uncertainty. This recommendation in particular, in combination with the ESEM, will assist with the issue of entry before exit.

Questions for stakeholders

- What information do market participants need to ensure efficient price discovery, and over what time frames is this information needed?
- What could be done to facilitate more accurate information being provided?

²²² AEMC (2025), [National Electricity Rules, version 227](#), clause 2.10.1(c2).

²²³ Op. cit., p 16.



5

**Unlocking long-term
investment in new
energy services**



Chapter summary

The Panel has identified the most significant barrier to investment in new firm renewable generation in the NEM as the tenor gap – the mismatch between the long financing timeframes required by potential new sellers and the short contracting horizons of market buyers.

This mismatch is not new, and has previously been addressed through adjacent underwriting policies, such as the Capacity Investment Scheme (CIS) and New South Wales Electricity Infrastructure Roadmap. However, these long-term investment policies are not fully integrated into the NEM's market structures (spot and derivative markets). Without an enduring framework and clear price signals that align with the lifespan and risk profile of new assets, new projects are unlikely to proceed. This risks higher costs and a less reliable system for consumers.

To incentivise long-term investment in the full range of electricity services needed in the NEM, the Panel recommends the following:

- Establishing the Electricity Services Entry Mechanism (ESEM) as a long-term investment signal to address the tenor gap (**Recommendation 8A**). The ESEM should procure new bulk energy, shaping and firming projects by offering fungible, financial contracts for the 'later years'²²⁴ of a project's life, where buyers and sellers are less able to manage market risk (see **Recommendation 6B**). These contracts would be recycled back into the market at the point in time where buyers will naturally require them to manage the risk of participating in the spot market. The ESEM would allow for long-term investment while enhancing liquidity and connecting long-term investment signals to short- and medium-term markets.
- The ESEM should be used to coordinate procurement of Essential System Services (ESS), such as system strength and inertia, where cost-effective (**Recommendation 8B**). It should also include a framework to act on market concentration when running tenders (**Recommendation 8C**) and provide a framework for procuring out-of-market reserves to address low-probability, high-impact events (**Recommendation 8D**).

The Panel also recommends options to ensure regulatory settings, the innovation ecosystem, and existing policies and programs are aligned with the ESEM and continue to facilitate long-term investment effectively (**Recommendation 9**).

Taken together, these recommendations seek to solve the most material issue preventing efficient long-term investment and deliver the services consumers need. The recommendations are designed to address only those issues the market is unlikely to address on its own, complementing and enhancing the operation of the short-term spot and medium-term derivative markets.

²²⁴ 'Later years' in this context are defined as the years of a project's financed life where it cannot find reasonably priced contracts in-market. The Panel anticipates this to be from years 5–7 to up to 20 years after commissioning for conventional generation projects, depending on the technical lifespan of the asset. These timeframes will need to be flexible depending upon the service and will evolve over time.

Recommendations

8 Energy ministers should establish an Electricity Services Entry Mechanism (ESEM) within the National Electricity Law (NEL) to facilitate investment in the NEM

A. Establish in the NEL an ESEM with the following key features:

- The services initially procured by the ESEM should be bulk zero emissions energy, shaping and firming.
- The ESEM should allow prospective new electricity service providers to compete for standardised, fungible contracts, developed through the co-design process outlined under **Recommendation 6B**, that offer a stable income stream upon the provision of a defined electricity service, facilitating the financing of new projects.
- The ESEM should not issue contracts for the years a project is able to secure them in-market. Rather, the ESEM should issue contracts for the later years of a project's life, allowing electricity service providers to sell their output to retailers or C&I users for the period of time that the market can manage risks effectively.
- The ESEM should sell the standardised, fungible contracts back into the market at the point in time that allows retailers and C&I users to manage energy market risk, supporting retail competition.
- The ESEM should be open to all providers of a given service, including aggregators of consumer energy resources (CER) and distributed energy resources (DER), and demand response providers, provided these resources are able to be scheduled for dispatch by the Australian Energy Market Operator (AEMO).
- The ESEM should seek to procure quantities of each service that achieve the National Electricity Objective (NEO). This includes any specific requirements of government policies referenced in the Australian Energy Market Commission (AEMC) Targets Statement.
- Where specific technologies are required to be procured by government policy and these technologies face greater barriers than just the tenor gap (e.g. offshore wind, pumped hydro) the ESEM should use an amended approach to facilitate their procurement.

B. Where cost-effective, projects facilitated through the ESEM should also be able to provide Essential System Services. The ESEM administrator should coordinate with transmission network service providers (TNSPs). This should take the form of secondary contracting for the specific elements of the project that relate to providing ESS.

C. A framework should be established to ensure the ESEM is able to consider market concentration when running tenders.

D. A new longer-term out-of-market reserves service should be established to cover high-impact, low-likelihood events, with quantities to be procured at the discretion of jurisdictions, on advice from the Reliability Panel.

9 Governments and market bodies in the NEM should pursue a coordinated suite of reforms to ensure regulatory settings, the innovation ecosystem, and existing policies and programs are aligned with the ESEM

- A. Governments should clarify how their emissions targets apply to projects procured to provide firming services, to provide certainty for investors.
- B. The Australian Government should task the Australian Renewable Energy Agency to accelerate the development and deployment of zero emissions technologies that provide firming at scale.
- C. Governments overseeing existing generation underwriting schemes to support long-term investment should consider options to improve derivative market liquidity.
- D. The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter-regional settlement residue units beyond three years.
- E. Once energy ministers are satisfied the ESEM and the Panel's proposed market making obligation are working effectively, they should look to phase out the Retail Reliability Obligation.
- F. Once the ESEM framework is established, energy ministers should consider opportunities to rationalise NEM forecasting and planning documents to avoid inconsistencies and duplication.
- G. Energy ministers should pursue reforms to improve consistency in the treatment of load, storage and generators connected at distribution and transmission level, to ensure a level playing field.

Recommendation 8: Energy ministers should establish an ESEM within the NEL to facilitate investment in the NEM

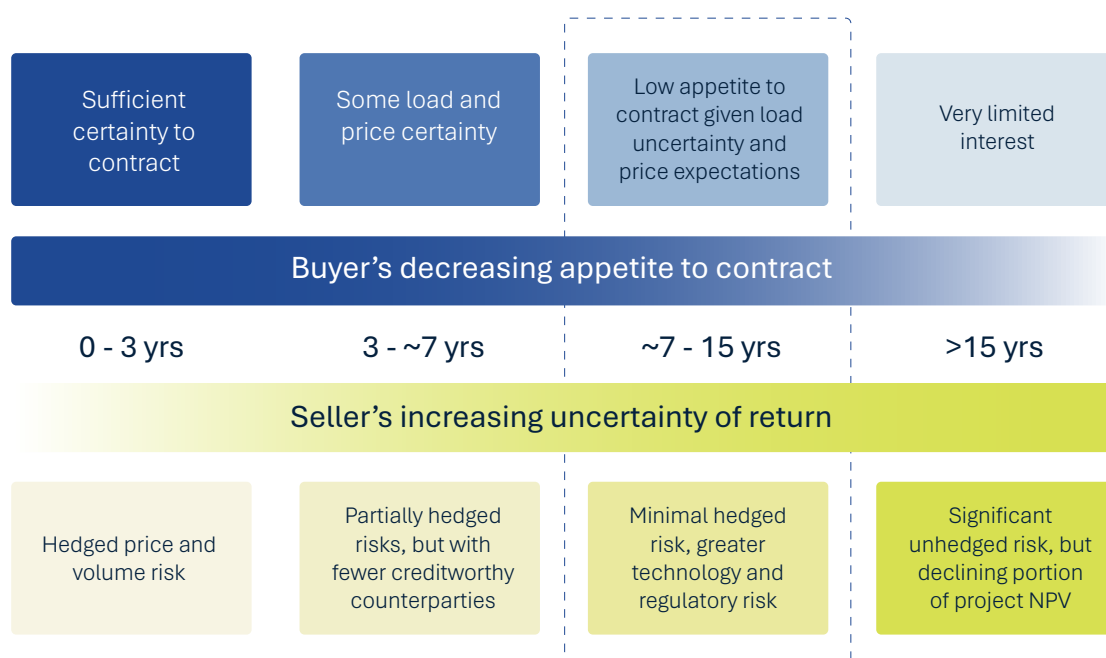
Long-term investment signals are missing in the NEM

Spot and derivatives markets do not deliver long-term signals to support investment in generation infrastructure and related energy services. Ideally, investors would deliver efficient investment in new supply in response to market prices, and forward prices in derivatives markets would serve as a window to the future, reflecting expectations of spot prices and giving investors the information they need to make informed decisions about building, upgrading or retiring assets.

However, as detailed in **Trends and challenges in the NEM**, this has rarely occurred in practice, particularly in recent years. Generation in the NEM at its commencement was largely legacy coal fired, fully depreciated plant. Since then, most new generation projects have entered the system thanks to significant support from policies adjacent to the NEM, such as the Renewable Energy Target among others. Similar challenges are observed internationally and across various market types, including capacity markets. A growing academic consensus agrees ‘hybrid’ market designs featuring strong short term operational and long-term investment signals are necessary to deliver the energy transition.²²⁵

Stakeholders and experts helped the Panel identify barriers to efficient investment. The tenor gap is the most critical of these issues, as detailed below. Put simply, the timeframe for investors, retailers and C&I users for managing risk does not match the timeframes over which heavy fixed cost generation infrastructure is financed.

Figure 44 – The tenor gap



²²⁵ For example, see ESIG (2025), [Electricity Market Visions to support a reliable and affordable grid under electricity decarbonisation](#), p 29.

8A: Establish in the NEL an ESEM with the following key features:

- The services initially procured by the ESEM should be bulk zero emissions energy, shaping and firming.
- The ESEM should allow prospective new electricity service providers to compete for standardised, fungible contracts, developed through the co-design process outlined under **Recommendation 6B**, that offer a stable income stream upon the provision of a defined electricity service, facilitating the financing of new projects.
- The ESEM should not issue contracts for the years a project is able to secure them in-market. Rather, the ESEM should issue contracts for the later years of a project's life, allowing electricity service providers to sell their output to retailers or C&I users for the period of time that the market can manage risks effectively.
- The ESEM should sell the standardised, fungible contracts back into the market at the point in time that allows retailers and C&I users to manage energy market risk, supporting retail competition.
- The ESEM should be open to all providers of a given service, including aggregators of CER and DER, and demand response providers, provided these resources are able to be scheduled for dispatch by AEMO.
- The ESEM should seek to procure quantities of each service that achieve the NEO. This includes any specific requirements of government policies referenced in the AEMC Targets Statement.
- Where specific technologies are required to be procured by government policy and these technologies face greater barriers than just the tenor gap (e.g. offshore wind, pumped hydro) the ESEM should use an amended approach to facilitate their procurement.

The Panel recommends establishing the ESEM to provide long-term investment signals for the new electricity investments future electricity consumers will require. Importantly, the ESEM will utilise the same forward market (medium-term) contracts (see **Recommendation 6**) that are used to manage real-time wholesale spot market risks (short term).

This recommendation solves the most material issue identified by the Panel preventing efficient long-term investment – the tenor gap. Put simply, the multi-decadal timeframes for investment are significantly longer than shorter contracting tenors used by retailers and C&I users for managing risk. The need for a new mechanism to support investment was clearly identified in the Panel's Terms of Reference and reinforced throughout the Panel's engagement with stakeholders (see **Appendix A**), including governments, generators, retailers, consumer groups, investors, financiers and market bodies.

The ESEM creates a long-term investment signal for the NEM

The ESEM is intended to provide long-term investment certainty. It achieves this by only addressing the risks the market is clearly incapable of managing. By addressing these risks using the same derivative

markets that are used to manage spot-price risks, it creates an internally consistent link between short-term, medium-term and long-term economic signals.

The ESEM would support new investment in the core services retailers and C&I users require by providing long-term contracting for new projects. The ESEM would be used to procure new bulk energy, shaping and firming services for only the timeframes of a project's operation where it is unable to find buyers in the market (i.e. the years after the period in which buyers and sellers can enter into market contracts).

The ESEM would address the risks of new investment in these later years of a project's life via standardised and fungible financial derivative contracts (see **Recommendation 6B**). These contracts would be progressively sold back into the forward derivatives market so that at the relevant time period in the future, retailers and C&I users will be able to manage the risks of operating in the spot market by procuring derivative contracts. In practical terms the ESEM is effectively a 'warehouse' that holds contracts temporarily until the market requires them. Voluntary participation in ESEM auctions will ensure that project developers that are able to achieve final investment decision with existing contracting options can continue to do so.

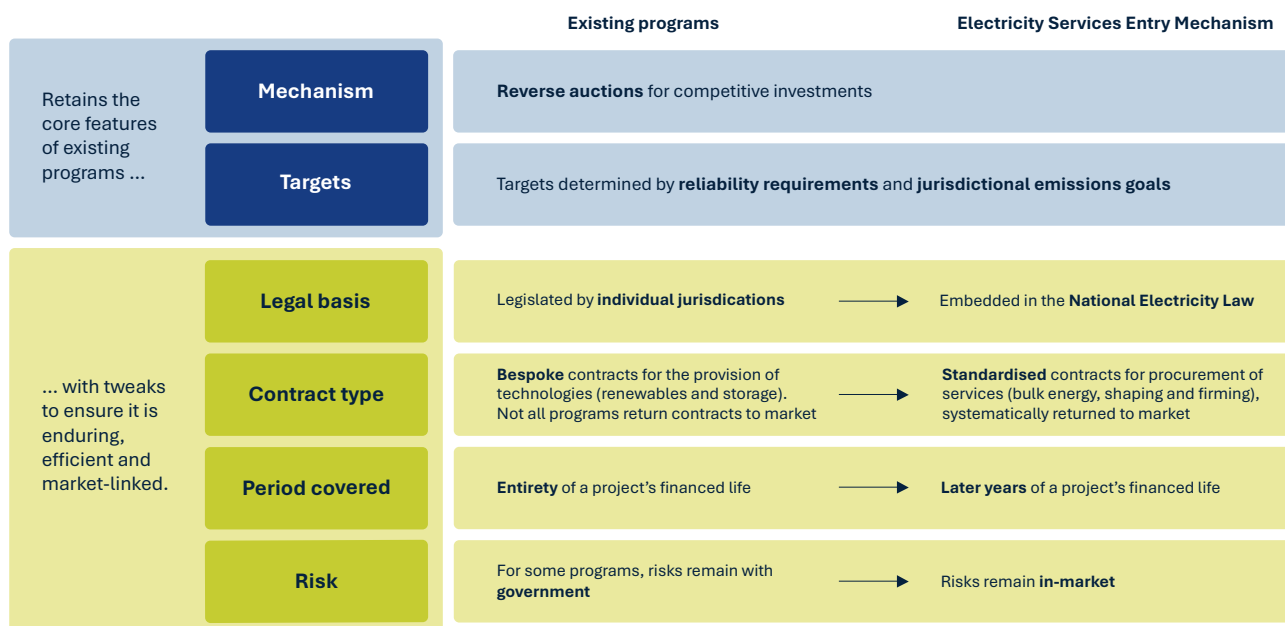
The ESEM design is intended to be self-limiting. If market participants move towards solving the tenor gap outside the ESEM architecture, the ESEM would eventually cease to operate.

The ESEM is an evolution of the existing approaches to creating long-term investment signals. It builds on the strengths of existing Australian support schemes by creating a hybrid approach of both decentralised and centralised procurement. This approach adopts the best parts of existing or forthcoming schemes such as the Renewable Energy Target, the New South Wales Electricity Infrastructure Roadmap (in particular, Long-Term Energy Service Agreements (LTESAs)), the Australian Government's Capacity Investment Scheme, Victorian Renewable Energy Target auctions, the Australian Capital Territory's renewables auctions and the South Australia Firm Energy Reliability Mechanism. These schemes are all able to be integrated into the ESEM over time to provide a consistent framework for investment signals across the NEM.

The ESEM is intended to create an observable long-term contracts market, providing all suppliers and market customers with the ability to manage risks over the long term. By focusing only on the later years of new investments, the scheme should deliver competitively neutral outcomes for all (existing and new) generators as the products utilised by market participants will be the same. Retail competition and innovation will be supported through the continued provision of derivative contracts that allow energy market price risk to be managed.

Importantly, the Panel has recommended a long-term investment signal that is effectively a pivot from existing schemes. It utilises the architecture already established (e.g. the skills within existing contracting bodies, such as AusEnergy Services, to conduct reverse auctions and enter into long-term contracts) by existing policies but has several points of pivot to make the ESEM more effective and consistent across the short-term, medium-term and long-term timeframes.

Figure 45 – The ESEM as evolution, not revolution



A simple example of how the ESEM would work

With a coal-fired power station scheduled to close,²²⁶ the market requires three new services (bulk energy, shaping and firming) to replace it.²²⁷ For the appropriate quantity of each service to ensure the NEO is met (competitively priced, reliable, secure and emissions free electricity),²²⁸ providers of these three services compete in an auction with the lowest cost options procured. New investment would be financed based upon the following:

- Revenue from the early years of the project (for example, years 1 to 7)²²⁹ being obtained from selling contracts to retailers or C&I users. For example, the firming generation would sell cap contracts or use the generation to hedge sales to a C&I user. Projects are free to contract as appropriate for these years, with no ESEM involvement.
- Revenue from the later years of the project (for example, years 8 to 15) being obtained from selling standardised financial derivative contracts to a central buyer (e.g. the central buyer for New South Wales LTESAs is the Scheme Financial Vehicle (SFV)).

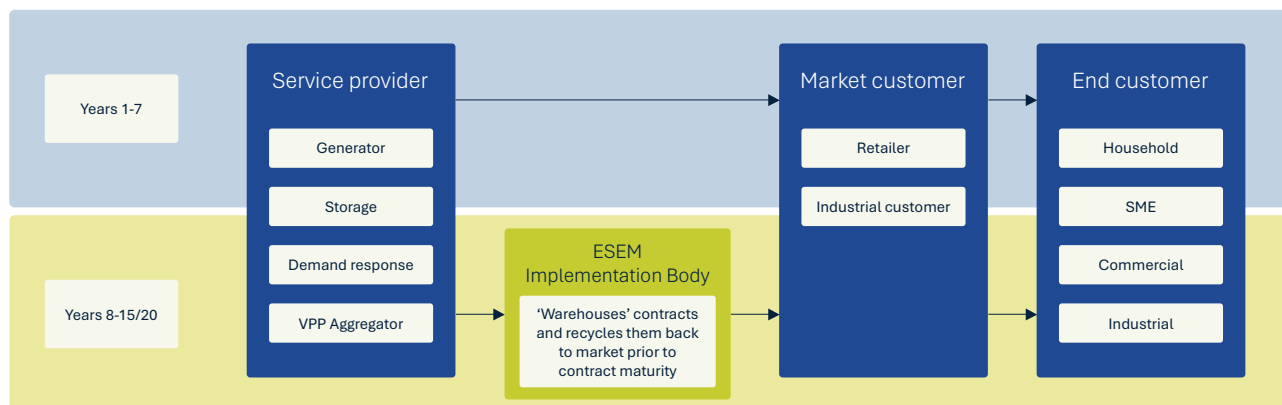
As time progresses, the central buyer sells back these contracts to the market (retailers and C&I users). This ensures that the bulk energy, shaping and firming is available to market participants to manage energy market risk. The long-term investment signal is effectively integrated into the market, rather than separate or adjacent to it. A diagrammatic representation is presented below.

²²⁶ Sufficient notice would have been provided given **Recommendation 7** to allow all services to be procured and available in time for the coal to close.

²²⁷ Essential system services are also required. These are discussed in **Recommendation 8B**.

²²⁸ The AEMC is required under the national energy laws to publish a list of the jurisdictional targets to be considered when applying the national energy objectives.

²²⁹ The use of seven years for the upper bound of project early years is informed by survey data received by the Panel from industry stakeholders. Subsequent stakeholder feedback has indicated that seven years may be too long for some project types. The ultimate timeframe definitions adopted will need to be flexible depending upon the service and will evolve over time.



Cap contracts as a form of capacity payment

In the NEM, cap contracts are commonly bought by retailers and large energy users to manage the risk of high spot prices, and sold by dispatchable generators to secure a stable revenue source. A standard cap contract is the proposed contract type to incentivise investment in new firming capacity through the ESEM, and as outlined below, can be seen as a form of decentralised capacity payment for dispatchable generators.

Definition

A cap contract gives the buyer the right to receive a payout whenever the spot price exceeds a certain threshold – historically \$300/MWh in the NEM – over a defined period (e.g. calendar quarter).

- The seller of the cap receives an upfront premium (like an insurance payment).
- In return, the seller must pay the difference between the spot price and \$300/MWh for each half-hour period when the spot price exceeds \$300.

Example:

A retailer buys a \$300 cap contract for 5 MW over Q1 2025

- If the spot price stays below \$300/MWh, the contract does nothing and the seller keeps the premium

- If spot prices jump to \$1,000/MWh in one 30-minute interval: the payout is: $(\$1,000 - \$300) \times 5\text{MW} \times 0.5\text{ hours} = \$1,750$ (compensating the buyer for the high price paid in the spot market).

ESEM cap vs capacity payment

The revenue and obligation structures of cap contracts and capacity payments are very similar. Both provide a fixed revenue stream paid over a standard period (i.e. quarterly, annually) and entail an obligation to generate in specific circumstances. A cap contract imposes a substantial, market-determined financial obligation to generate when spot prices rise above a pre-determined threshold (e.g. \$300/MWh), whereas a capacity payment obligates generation when reserves are tight. In the context of caps auctioned through the ESEM, an additional obligation to build the physical plant is imposed.

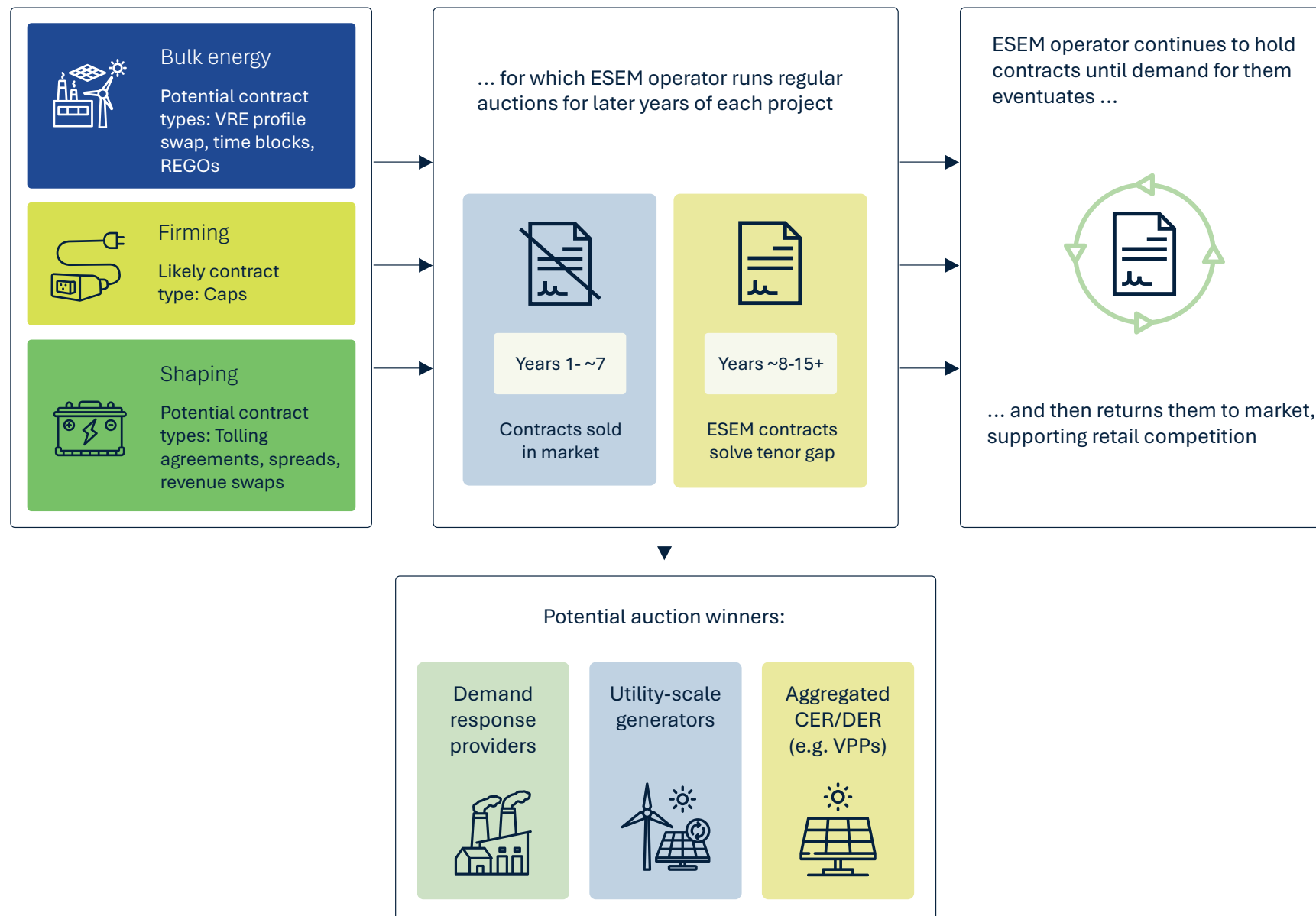


Figure 46 – Key features of the ESEM



²³⁰ AEMC (2025), [Emissions targets statement under the national energy laws](#), p i.

Why not extend the LRET or the CIS?

A number of stakeholder submissions to the NEM review discussed a potential extension of the large-scale renewable energy target (LRET), the creation of a certificated capacity scheme similar to the capacity mechanism proposed by the Energy Security Board, or an extension of the CIS.²³¹

While the Panel appreciates the many potential benefits of these schemes, it remains concerned they would not address the tenor gap, which the Panel has identified as the key issue impeding investment in the NEM. Retailers already have obligations – future electricity demand – that should encourage contracting. It is not clear that additional certificate obligations would meaningfully increase retailer willingness to extend the tenor of contracts, as retailers would face the same uncertainties discussed above and in previous chapters. Regulating retailers and large loads to require 15 years of contracting could theoretically address this issue. However, this may simply result in penalties being paid, as retailers could buy certificates in the short term but avoid purchases over a longer timeframe. This would result in a stalemate between buyers and sellers. Penalties would then potentially be paid in later years when the supply of certificates is insufficient. The policy would be ineffective unless the tenor gap is somehow addressed.

The Panel notes that Renewable Energy Guarantee of Origin certificates could be procured through the ESEM to support the bulk energy services (see Appendix C). This would be similar to a centrally procured LRET, providing long-term certainty to address the tenor gap. This is one of many different contracting structures that could be used to support the bulk energy service.

The Panel has not identified material issues suggesting existing market participants are failing to recover the costs of their investments. For this reason, the Panel has developed the ESEM to focus on new projects, not existing projects. Very importantly, the mechanism will be utilising (a subset of) the derivative contract structures determined through the proposed AER-led co-design process (see **Recommendation 6B**), and that will also be used by existing market participants. As such, it will deliver competitively neutral pricing for new investments and incumbent resources (to the extent that they both provide similar services to the market).

Underwriting schemes like the CIS may reduce the liquidity of the medium-term derivatives market (see **Maintaining liquidity in the derivatives market**). The CIS also addresses risks the Panel believe can be managed in-market – most notably, risks in a project's early years. In other respects, the ESEM builds on many other aspects of the CIS (see **Figure 45** above).

²³¹ [Submissions to the Initial NEM Review Consultation](#) advocating for extension of the LRET included AGL, RWE, EnergyAustralia, and ACEN Renewables. Submissions advocating for a capacity mechanism included Australian Pipelines and Gas Association, Potentia Energy, HydroTas, Origin Energy, Shell Energy, Alinta, Energy Users Association of Australia, the Centre for Independent Studies, Stanwell Corporation Limited, CleanCo QLD, and Delta. Submissions advocating for an extended CIS included the Climate Change Authority, HydroTas, Akaysha, SnowyHydro, ATCO, ACEN Australia and Advanced Materials and Battery Council. Other submissions argued against these mechanisms.

The ESEM will procure bulk energy, shaping and firming services

The services procured by the scheme need to reflect the changing needs of the system, as discussed in **Trends and challenges in the NEM** and **Ensuring effective operation of the spot market**. The Panel recommends the core in-market services to be procured at commencement of the ESEM should include bulk energy, shaping and firming services, as detailed in **Table 2** below. These services are well suited to a scheme in which a central, independent administrator provides long-tenor contracts that are subsequently on-sold to the market, creating both investment certainty and forward market liquidity. Services could be defined in the NEL or the NER. Each service will need a tailored contract structure to unlock the ESEM's benefits, as discussed below and in **Appendix C**.

Table 2. Proposed definitions of services

Name and units	Proposed definition	Examples of provider technologies (not exhaustive)
Bulk energy <i>Megawatt-hours</i>	Zero emissions electricity generation sent out from a generating unit or voluntarily scheduled resource.	Utility-scale and rooftop solar, offshore and onshore wind, run-of-river hydro, biomass, concentrated solar thermal.
Shaping <i>Megawatts of capacity and megawatt-hours of storage or availability</i>	The capability to consume or generate from a bidirectional unit or voluntarily scheduled resource, or to consume and cease to consume from a voluntarily scheduled resource.	Utility-scale and small-scale battery storage, pumped hydro, compressed air storage, industrial demand response.
Firming <i>Megawatts of capacity</i>	Capacity from a scheduled generating unit, bidirectional unit, voluntarily scheduled resource, that is capable of being dispatched continuously for the time it takes to reach the cumulative price threshold if prices are at the market price cap. ²³²	Pumped hydro, long-duration batteries, compressed air storage, open cycle gas turbines, gas reciprocating engines, hydrogen turbines or engines, industrial demand response, aggregated small-scale storage, concentrated solar thermal.

Ideally, new projects should be able to bid to provide more than one service, as this could be the most efficient outcome. For example, a pumped hydro project would be well placed to provide both shaping and firming services (and potentially reserves, see **Recommendation 8D**).

Questions for stakeholders

Are bulk energy, shaping and firming appropriately defined? How could single projects provide multiple services without undue scheme complexity?

²³² Currently this duration is around 7.5 hours. It will rise to 8.5 hours by 1 July 2027. For further information, see AEMC (2023), [Amendment of the Market Price Cap, Cumulative Price Threshold, and Administer Price Cap](#), p 2.

The ESEM will facilitate a level playing field to ensure least-cost outcomes

The ESEM should allow competition from any technology that can provide the service. While utility scale generation is likely to be a significant contributor to each service, other resources would be eligible, including the following:

Aggregated CER/DER	Demand side participation
Rooftop solar	Industrial load shifting
Home batteries	Commercial buildings
Community batteries	Aggregated consumer appliances

A level playing field is a key way of ensuring least-cost outcomes. The inclusion of all resources is important because maximising the types and numbers of resources that can compete to deliver services can drive innovation and lower costs to consumers.²³³ Studies suggest the whole energy system may benefit from a diverse combination of resources, particularly when it comes to reliability.²³⁴ The most efficient combinations of resources will be difficult to forecast, especially if technology costs continue to change.²³⁵ As such, a technology-neutral focus on services that is open to the maximum number of competitive resources increases the likelihood of the ESEM delivering the best outcome for consumers.

Many stakeholders supported the participation of a diverse suite of resources and put forward a range of design suggestions to accommodate them effectively.

“

We need to level the playing field and create discrete approaches to ensure we procure capacity from the demand side. – Energy Consumers Australia²³⁶

Markets must use the smallest reasonable minimum site and aggregation size requirements to support competition. – Solar Citizens²³⁷

A separate stream of investment for offshore wind will be required to reflect its complementarity to other forms of renewable energy generation. – ACTU²³⁸

”

The below principles will guide further design of the ESEM and how participation of diverse resources can be facilitated.

²³³ ESIG (2025), [Electricity Market Visions to support a reliable and affordable grid under electricity decarbonisation](#), p 27.

²³⁴ E.g. IHS Energy (2014), [The Value of US Power Supply Diversity](#), Billimoria et al. (2025), [Hedging and tail risk in electricity markets](#).

²³⁵ Ghadim et al. (2025), [‘Are we too pessimistic? Cost projections for solar photovoltaics, wind power, and batteries are over-estimating actual costs globally’](#), in *Applied Energy*.

²³⁶ Energy Consumers Australia (2025), [Submission to the Initial NEM Review Consultation](#), p 3.

²³⁷ Solar Citizens (2025), [Submission to the Initial NEM Review Consultation](#), p 4.

²³⁸ ACTU (2025), [Submission to the Initial NEM Review Consultation](#), p 3.

Table 3. Principles for facilitating the participation of diverse resources in the ESEM

Balance flexibility with comparability	Many parameters – such as years of contracted coverage – may be flexible to accommodate different technologies or business models. This flexibility will be balanced against the standardisation needed to compare the delivery of the underlying service at the lowest cost.
Recognise the value of participation	Meeting financial obligations under ESEM contracts will require those resources to be participative in the electricity spot market. As raised in Recommendation 2 in Ensuring effective operation of the spot market , encouraging more market participants to become visible will be important to secure the future system.

Question for stakeholders

How can the ESEM provide a technology neutral level playing field to encourage maximum competition to provide services?

Technologies that face barriers beyond the tenor gap

The ESEM would be required to procure the necessary resources to fulfill the NEO, including the emissions objective introduced by ministers in 2023.²³⁹ The AEMC Targets Statement lists the Australian government and state and territory government targets the ESEM would be required to meet.²⁴⁰

Specific technologies that form the basis of jurisdictional targets and face barriers greater than just the tenor gap could be supported by the ESEM. In particular, the deployment of offshore wind and long-duration storage (including pumped hydro resources) could be integrated within the ESEM architecture.²⁴¹ Other resources, such as innovative long duration storage, could also be included over time if jurisdictions mandated them.

Offshore wind offers several benefits to the energy system, including higher capacity factors and generation that may be non-correlated with other weather-dependent resources (higher value bulk energy). Similarly, pumped hydro can provide synchronous generation services to support grid security (ESS) and provide very-long-duration storage (firming, shaping and reserves).

However, investments in these projects may face higher costs or additional risks compared to other providers of the services to be procured through the ESEM. To the extent that technologies face these barriers beyond the tenor gap, the Panel notes that:

- projects would still be required to source the most competitive contracts for their service from the market
- additional costs beyond what the market is prepared to pay for the service could be recovered from consumers via the same cost recovery mechanism established for the ESEM, but for the life of the entire project (e.g. years 1 through 25).

²³⁹ DCCEE (2023), [Incorporating an emissions reduction objective into the national energy objectives](#).

²⁴⁰ AEMC (2025), [Targets statement for greenhouse gas emissions](#), p 1.

²⁴¹ For example, see [Victoria Offshore wind energy](#), [NSW Pumped Hydro Roadmap](#), [Hydro Tasmania](#), [Queensland Hydro](#)

The ESEM focuses on managing risk in the later years of a project's life

The focus on financial derivative contracting for the later years of a project's life is similar to that recommended by the Australian Competition and Consumer Commission (ACCC) in its 2018 Retail Electricity Price Inquiry, which suggested government-supported “energy offtake agreements for the later years (say 6-15)” to bolster NEM investment signals.²⁴²

“

*[Derivative] markets work in the short term but hard to strike long term contracts – tenor is a key issue. – Clean Energy Council*²⁴³

”

Questions for stakeholders

- How might an approach to support the later years of a project's life be tailored to address the varied dynamics across the three services (bulk energy, shaping and firming)?
- For each service, what is the appropriate indicative timeframe for support (e.g. year 8 to 15)?

The ESEM should procure quantities of each service guided by the NEO

A key consideration for the ESEM is the question of how the quantities of each service to be procured should be determined. The NEO should form the basis of these determinations.²⁴⁴ The NEO has several limbs, including:

Reliability and security: The ESEM would procure sufficient new electricity services to meet demand and keep the electricity system reliable, including coordination of ESS (see **Recommendation 8B**).

Efficiency and the long-term interests of consumers: The ESEM would procure new electricity services competitively, at the lowest possible cost to consumers.

Achievement of targets for reducing Australia's greenhouse gas emissions: The ESEM would procure new electricity services to meet the targets outlined in the AEMC Targets Statement, which lists governments' emissions reduction and renewable energy targets.²⁴⁵

A key design feature adopted by the Panel is the hybrid nature of the mechanism – it relies upon markets for the observable future and only intervenes for the later years of project lifespans. This creates an ‘automatic stabiliser’ effect for quantities to be procured. If far too much is procured, observable contract prices will be too low to support new investment and ESEM auctions will either be unnecessary or fail to attract economic projects. This approach helps prevent over-procurement based on future projections that may not align with market realities.

The central buyer's long-term contracting will be guided by the mix of technologies and pricing for the various services being put forward to solve observable market timeframes. In this way, market participants will have an implicit meeting of the minds with the central buyer about the appropriate

²⁴² ACCC (2018), [Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry – Final Report](#), p 100.

²⁴³ CEC (2025), [Submission to the Initial NEM Review Consultation](#), p 4.

²⁴⁴ SA Government (2025), [National Electricity \(South Australia\) Act 1996](#), p 48.

²⁴⁵ AEMC (2025), [Targets statement for greenhouse gas emissions](#).

mix of services to best deliver the least-cost outcome of keeping the system secure, reliable and zero emissions.

There are several existing planning exercises in the NEM and elsewhere that are important to consider for determining the mix of services required in the future.

Table 4. Existing planning exercises in the NEM

Planning exercise	Purpose and process	Frequency and horizon
Integrated System Plan (AEMO)	Develop an efficient whole-of-system plan that achieves power system needs and contributes to the NEO. Specify network projects as actionable to accelerate regulatory processes.	Published every two years, after consultation, technical inputs and modelling. 25+-year indicative pathway.
Electricity Statement of Opportunities (AEMO)	Reveal possible opportunities for new investment to fill gaps. Assess reliability to determine whether the Retailer Reliability Obligation should be triggered.	Published annually (or after material change to system). 10-year detailed outlook
New South Wales Infrastructure Investment Objectives Report (AusEnergy Services Ltd)	Identify the most cost-effective path to meet New South Wales Electricity Infrastructure Roadmap goals, including generation and long-duration storage targets, the Energy Security Target and NEM reliability standards. Informs LTESA tenders.	Published every two years, or as required if firming needed to avoid EST breach. 20-year indicative pathway. 10-year plan for tenders.
Small-scale technology percentage (CER)	Sets the target for the number of small-scale renewable energy certificates that need to be submitted by liable entities. Informed by multiple consultant forecasts of uptake of relevant technologies.	Published annually. 1-year ahead binding target. 2-year non-binding outlook.

Any forecasts used to determine quantities should be subject to rigorous reviews to improve forecast accuracy over time, akin to AEMO's existing processes.²⁴⁶

The final decision on how much of each service to procure, and the timing of this procurement, will be significant. Energy ministers may wish to nominate a suitable entity to decide, informed by the expert planning processes like those described above. The Panel has noted that a body with characteristics such as the Reliability Panel (which has representatives from market bodies, industry and consumers) would be worth considering for this role.

Questions for stakeholders

What governance and processes should be established to determine the quantity and timing of each service procured through the ESEM?

²⁴⁶ AEMO (2025), [Forecasting Accuracy Reporting](#).

The ESEM should assist with orderly exit

The orderly exit of large coal generators is a critical part of the transition and the source of material uncertainty for market participants, as discussed in **Trends and challenges in the NEM**. The ESEM would facilitate the orderly exit of these generators.

As noted earlier, the NEO (and therefore the AEMC Targets Statement)²⁴⁷ sets out the emissions reduction and renewable energy targets the ESEM would be required to deliver if established within the NEL.

Energy ministers determine their renewable energy and emissions targets. The AEMC Targets Statement is simply the means of embedding these so they are applicable under the NEO.²⁴⁸ The ESEM would procure sufficient new services to allow coal or other emissions-intensive generators to close on schedule. For example, Victoria's existing targets would require the ESEM to procure renewables equivalent to 95% of in-state generation, 6.3GW of storage and 4GW of offshore wind by 2035. Governments, rather than the ESEM, would determine their own 'pace of change' through the energy transition as it proceeds.

The ESEM should be used to ensure the purpose of the Orderly Exit Management Framework for coal and gas generation exits is achieved.²⁴⁹ When considering procurement targets, the ESEM could align new entry with retirement dates for large thermal generators²⁵⁰ to ensure sufficient replacement resources are procured and available prior to the large generation units ceasing operation. The ESEM could do this in a way which seeks to achieve some overlap (to ensure continuity of system reliability and security) but with the objective of minimising this overlap and any impact on wholesale prices. To give jurisdictions confidence that projects are delivered on time, it will be important for the ESEM to ensure commissioning timeframes are met.

²⁴⁷ AEMC (2025), [Emissions targets statement under the national energy laws](#).

²⁴⁸ SA Government (2025), [National Electricity \(South Australia\) Act 1996](#)

²⁴⁹ DCCEEW (2024), [Orderly Exit Management Framework](#).

²⁵⁰ The Panel is also proposing generators be required to provide MTPASA information out to five years, which would give the ESEM five years notice to procure replacement resources for closing thermal generators (see **Recommendation 7**).

ESEM contracts should be standardised and fungible

The Panel has noted through consultation that there is a range of derivative contracts currently used, and emerging, to match buyers and sellers of bulk energy, shaping and firming. As detailed in **Maintaining liquidity in the derivatives market**, these contracts will need to evolve to allow market participants to manage risks and stabilise prices as the energy transition continues. The contracts used by the ESEM could help to promote these innovation efforts. In this context, the Panel has recommended that the Australian Energy Regulator (AER) convene a regular contract co-design process (see **Recommendation 6B**). The Panel notes that ESEM contracts will likely evolve over time to reflect the ongoing evolution of technologies and consumer preferences.

The Panel recommends that responsibility for finalising contract structures should rest with the entity or entities charged with delivering the scheme. Important guiding principles should be established in the ESEM's regulatory architecture. These include the following:

- Contracts should be designed to manage medium- to long-term financial risks that the market is unable to address (i.e. tenor gap), and support investment under the ESEM.
- Contracts should be financial (i.e. not tied to physical plant operation), tradeable, structured to support price transparency, and be useful for retailers for managing exposure to spot prices across the three targeted services.
- Contracts should encourage generators to deliver services when they are most needed, aligning incentives with system value and reliability outcomes.

Contracts secured by project developers through ESEM auctions for the later years of a project will be financial in nature but dependent upon plant commissioning. This is necessary to ensure winning project bids result in the new project being built. After project commissioning, the buy-side of these contracts can be sold back into the market or 'recycled' by the independent ESEM administrator, as discussed below. As the contracted period approaches, the number of interested counterparties will rise, enabling contracts held by the ESEM administrator to be sold back into the market. **Appendix C** provides examples of some contract structures the Panel has noted are being used by stakeholders to manage medium term risks of operating in the NEM.

The option of options

Some of the contract structures detailed in **Appendix C** could be utilised as put options. For example, a new project could bid for the option to sell a time block contract. This would make the ESEM operate somewhat like LTESAs in New South Wales.²⁵¹ An option of this kind might allow new projects to bid for the minimum support they need to secure financing for a project, but leave projects free to operate within the market. Using options could complicate the recycling of contracts, as the ESEM administrator will not know in advance whether options will be put, but these risks could be managed through matching call options or requiring reasonable advance notice prior to the options being exercised.

²⁵¹ NSW Government (2025), [Long-Term Energy Service Agreements](#).

Questions for stakeholders

- As per **Recommendation 6B**, which set of contracts would be useful for supporting the entry of new providers of bulk energy, shaping and firming through the ESEM and useful to manage spot price risk through derivative markets?
- Should any contracts be structured as options?

The ESEM administrator should sell contracts back into the market

To ensure ongoing liquidity in electricity forward markets, the ESEM administrator would be required to recycle contracts purchased through auctions for the later years of each project. The Panel notes that the ESEM administrator would act to close out all positions in a structured way prior to contract maturity. Its operations would be bound within a strict risk management framework that is in the long-term interests of consumers. Forward market liquidity is critical to ensure retailers can adequately manage risk, a fact that was highlighted in several submissions to the review's initial public consultation.²⁵² This is especially important for small retailers, which have been highlighted by the ACCC as crucial in maintaining competitive pressure on retail prices.²⁵³

The continued exit over time of thermal generators, historically active participants in forward markets, has the potential (in the absence of innovation) to reduce forward market liquidity. Power purchase agreements, which have historically supported renewables investments, do not naturally provide the firm contracts needed by retailers to hedge their load.²⁵⁴ Additionally, recent projects entering the NEM have received government assistance, partly removing project risk and reducing the incentive to participate in hedging markets.²⁵⁵

For these reasons, contract recycling will be an important part of the ESEM. Contracts will be designed as standardised, fungible financial derivative products that can be resold to retailers and C&I users.

It is likely that contract sales would be operationalised through back-to-back arrangements, whereby the ESEM administrator remains counterparty to contracts with developers and enters into correspondingly opposite contracts with other parties.

²⁵² [Submissions to the initial NEM Review consultation](#) from AFMA (p 4), AGL (p 10) and EnergyAustralia (p 7).

²⁵³ ACCC (2023), [Inquiry into the National Electricity Market: December 2023 Report](#), p 8.

²⁵⁴ J Flottmann et al (2025), [‘The Forward Market Dilemma in Energy-Only Electricity Markets’](#), University of Cambridge Energy Policy Research Group.

²⁵⁵ Ibid.

Long-term price transparency, the ESEM and Snowy Hydro

Snowy Hydro is a 100% Australian Government-owned government business enterprise with over 5.5 GW of generation assets and over 1.1 million retail electricity customers.²⁵⁶

Snowy Hydro is the third-largest generator by capacity in the NEM and the leading owner of flexible generation, controlling nearly 60% of New South Wales's flexible capacity and nearly 40% of Victoria's.²⁵⁷ This capacity position is set to expand with the imminent commissioning of the 660 MW Hunter Power Project (HPP)²⁵⁸ and the 2.2 GW Snowy 2.0 pumped hydro project²⁵⁹ in 2029.

Snowy Hydro could play a leadership role in kickstarting ESEM contract recycling, as it is already a provider of long-term contracts. By selling contracts (backed by Snowy's existing and imminent projects) to market customers through the same platform used for ESEM contract recycling, Snowy could boost contract liquidity while familiarising the market with ESEM operations.

Questions for stakeholders

How could Snowy Hydro's capacity be used to kickstart the ESEM contract recycling platform and benefit the NEM overall? How could any risks be managed?

The Panel is considering governance arrangements for the ESEM

As noted earlier, the ESEM is effectively an evolution from the CIS and LTESA frameworks. All of the expertise within existing market bodies could be applied to implement the Panel's recommendations relatively quickly. This is a key design feature adopted by the Panel – utilise the existing policy and regulatory architecture rather than reinventing it from scratch.

That said, bringing the ESEM into existence would require some work in relation to legal amendments and governance. The Panel is considering appropriate legislative, regulatory and administrative arrangements to institute the mechanism. These will be explored over the second half of 2025, informed by stakeholder feedback on this draft report and through further engagement with the Australian, state and territory governments and relevant institutions.

A few principles will guide the Panel as it considers its recommendations on ESEM governance:

- **National consistency, jurisdictional sovereignty** – each NEM jurisdiction is constitutionally responsible for its energy system, and this sovereignty will be respected as the ESEM is implemented. Jurisdictions will retain control of the pace and nature of their electricity system transition. This is not at odds with the ESEM contributing a greater level of consistency, predictability, transparency and stability to the NEM, as many existing jurisdiction-specific interventions can be integrated into the systemwide framework the ESEM will provide.
- **Stable, transparent architecture** – the mechanism should maximise transparency (e.g. informing the market on ESEM contract prices), administrative roles should be independent from

²⁵⁶ [Snowy Hydro \(2025\)](#).

²⁵⁷ AER (2024), [Wholesale Electricity Market Performance Report – December 2024](#).

²⁵⁸ [Hunter Power Project - Snowy Hydro](#).

²⁵⁹ [About - Snowy Hydro](#).

government where appropriate (e.g. determining winning tenders), and clear rules should govern operations (e.g. framework for recycling of contracts).

- **Evolution, not revolution** – wherever possible, ESEM implementation will build on existing institutions and policy architecture. This will accelerate implementation timeframes, utilise existing skills and expertise, and limit market disruptions.

Questions for stakeholders

How should energy ministers allocate roles and responsibilities for ESEM implementation and administration?

The NEL and NER should house the ESEM

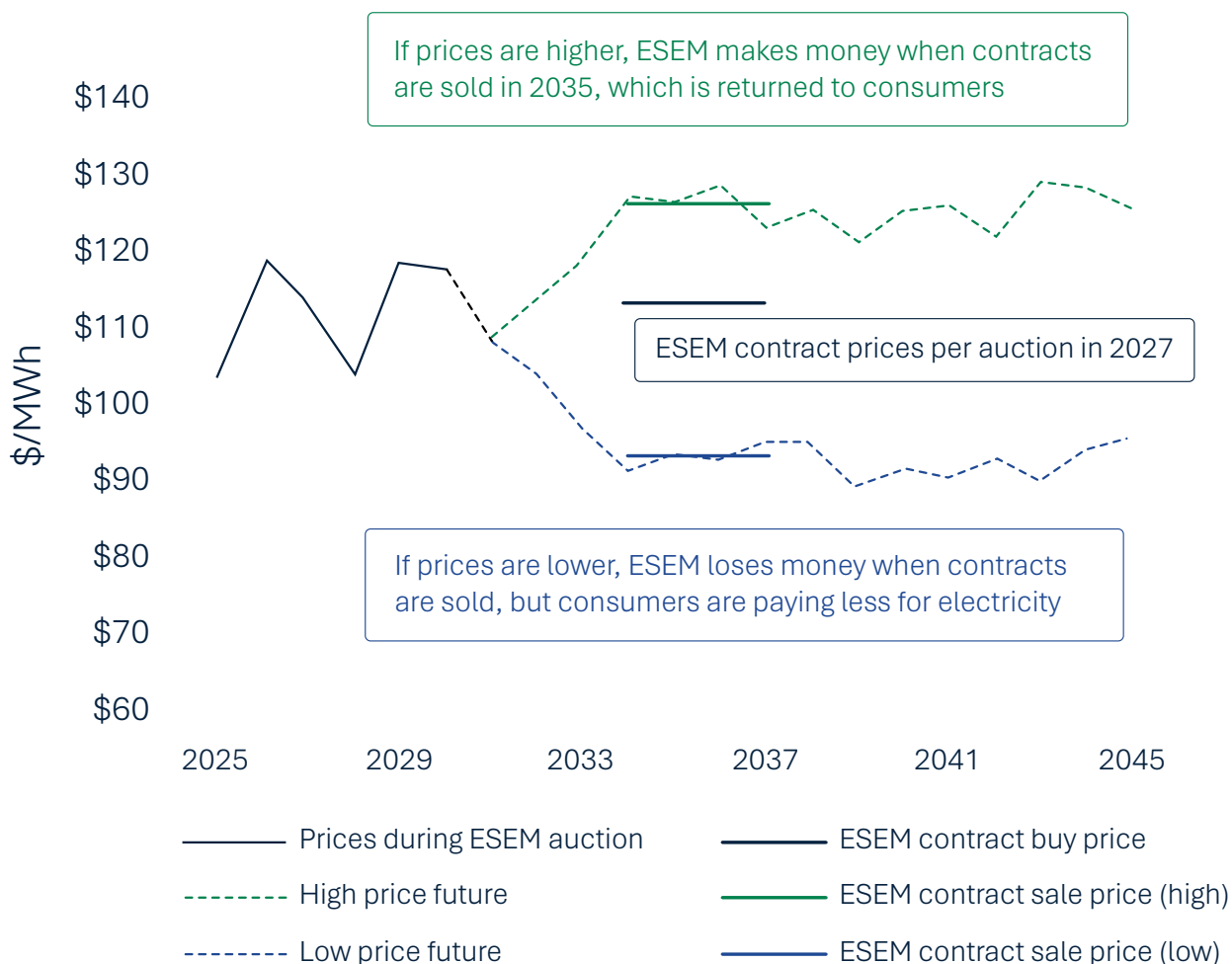
Establishing the ESEM will require a coordinated package of legislative and regulatory changes, including amendments to the NEL and NER, and potentially the establishment of new intergovernmental agreements, depending on the governance and funding model. Some legislation at a federal or state and territory level may also be required, pending detailed design decisions and legal advice.

Non-financial considerations associated with new electricity generation projects are best addressed through complementary policy frameworks, rather than through the merit criteria of the ESEM

This approach recognises that obligations related to matters such as community engagement, workforce development and local benefit sharing are more effectively governed through broader planning, regulatory or reputational mechanisms. Furthermore, broader economy-wide outcomes are likely to be optimised through coordination rather than competition between project proponents. The Panel is of the view that any non-financial criteria required by jurisdictions should be treated as preconditions for participating in the ESEM rather than as competitive criteria to be assessed by the administrator.

Residual costs or rebates should flow to electricity users

Under the ESEM, the administrator will bear some of the risks of investment in new bulk energy, shaping and firming infrastructure. Depending on the prices that the ESEM administrator pays for contracts at tender and the price it receives when it recycles the contracts into the market, this risk could be realised as a financial loss or gain, as shown in the hypothetical example below.

Figure 47 – Cost recovery²⁶⁰

The Panel's intention is that losses or gains from closing out positions will be recovered from or rebated to electricity users. There are various mechanisms that could be applied to recover and rebate the costs of the ESEM, including through NEM charges, network charges or retailer bills. The Panel will focus on the design of the cost recovery mechanism for the ESEM after the release of the draft report, in consultation with NEM jurisdiction governments.

As a starting point, the Panel has developed some principles for the cost recovery mechanism and is seeking feedback from stakeholders on how the costs of the scheme (if any) should be recovered.

Scheme operations should be governed by a principle of maximising benefits to electricity users and, thus, minimising costs. This includes minimising administrative and compliance costs.

1. **Any residual costs or rebates from the ESEM should remain inside the NEM** and thus ultimately be recovered from or paid to electricity users.
2. **Any costs or rebates from the ESEM should generally be settled in the region where they are incurred.** Some jurisdictions may wish to share the costs of mutually beneficial investments, akin to the recent interconnector cost sharing rule change.²⁶¹

²⁶⁰ This is a simplified, illustrative example; actual costs or rebates will be complex to determine and depend on a large range of factors.

²⁶¹ AEMC (2024), [Providing flexibility in the allocation of interconnector costs](#).

3. **The nature of any rebating or cost passthrough should be matched to the underlying service.** For example, the bulk energy service could be linked to a dollar-per-megawatt-hour rebate or charge, while the firming service could be linked to a fixed dollar-per-megawatt covering peak periods.
4. **Costs should only be recovered in the relevant year.** For example, if contracts for the year 2035 are closed out at a loss, the costs would not be recovered from electricity users until post-2035.
5. **Arrangements should seek to support stability in retail prices.** This will require costs or rebates to be known in advance so retailers can smooth their allocation onto bills.

The Panel welcomes views on appropriate, equitable approaches to cost recovery across customer classes and jurisdictions.

Questions for stakeholders

How should any residual ESEM costs or rebates from the closing out of contracts be allocated to consumers?

8B: Where cost-effective, projects facilitated through the ESEM should also be able to provide essential system services (ESS)

The ESEM administrator should coordinate with TNSPs. This should take the form of secondary contracting for the specific elements of the project that relate to providing ESS.

Work is underway but more is needed to deliver timely and sufficient investment in ESS

As outlined in **Introduction to the NEM**, Australia's decarbonisation efforts have primarily focused on replacing coal-fired generation with low-cost, inverter-based renewable energy. This transition has led to a decline in ESS traditionally supplied by synchronous coal-fired generators.

The recent underinvestment in ESS reflects a combination of absent price signals, fragmented and overlapping procurement processes and the non-excludable nature of these services. There is also the matter of forecast accuracy and remediation lag. These issues are further exacerbated by location-specific requirements and protracted regulatory processes, which delay delivery and increase the need for out-of-market interventions to maintain system security.

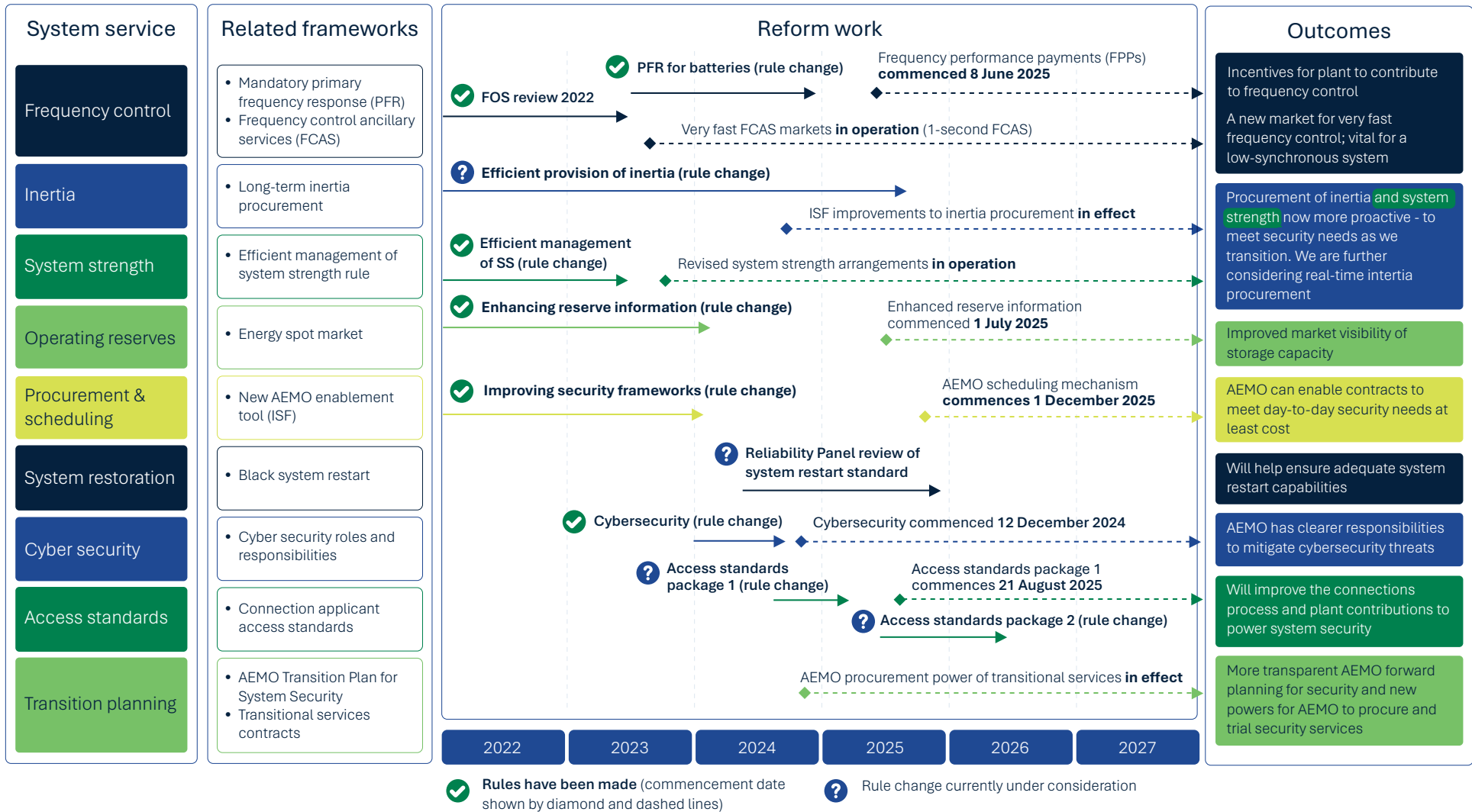
In short, risks around ESS are asymmetric. There are significantly greater implications of being too late than too early in the provision of ESS. As the pace of decarbonisation increases, substantial investment in new generation, storage and transmission infrastructure will be required. Embedding ESS into project design from the outset presents an opportunity to enhance overall system efficiency, reduce total costs and avoid the need for costly retrofits in the future.

Several reforms already underway are designed to address current issues:

- **AEMC's Improving Security Frameworks Rule** enables AEMO to procure transitional services and enhanced the inertia framework used by TNSPs to trigger procurement.
- **The Reliability Panel's review of the System Restart Standard** reassesses whether existing restart obligations and incentives remain appropriate as the energy system evolves.
- **AEMO's Application of Advanced Grid-Scale Inverters** in the NEM quantifies inverter capabilities and refines procurement approaches for services such as inertia and voltage control.
- **AEMC's access standards rule changes** strengthen technical requirements for new connections to ensure projects are capable of contributing ESS where feasible.

The ESEM presents a further opportunity to deliver ESS capabilities at lower cost and in a more timely way by coordinating investment decisions more effectively. Improved coordination can reduce the risk of timing error, underinvestment in the short run and overinvestment in the long run, and help capture co-benefits during project development, avoiding the need for costly retrofits or stand-alone infrastructure later.

Figure 48 – The AEMC’s system security work program, rule commencement and implementation timelines



Timing constraints, narrowly defined regulatory requirements and muted investment signals pose challenges to the provision of ESS

TNSPs and AEMO have specific responsibilities for providing ESS in the NEM. TNSPs²⁶² are responsible for procuring network support and control ancillary services (NSCAS), system strength and inertia services. Over the past five years, system strength and inertia have consistently been among the most frequently declared services in shortfall in the NEM, prompting multiple remediation programmes (see **Figure 48** overleaf).

As a monopoly provider of network services, the amount of revenue TNSPs are allowed to earn is regulated by the AER. This means if they spend money on something that is not planned or approved ahead of time, they may not get approval to recover that cost from consumers. This reduces the likelihood of pre-emptive or strategic co-investment when early action would be beneficial in dealing with the asymmetric risks of being too late.

“

The transmission revenue recovery process is not suited to the recovery of unpredictable and volatile costs, and these cash flow impacts can have flow on effects on financing costs and expenditure programs. – Energy Networks Australia²⁶³

”

The Regulatory Investment Test for Transmission (RIT-T) is a prescribed economic assessment process undertaken by TNSPs to evaluate proposed projects. It includes multiple consultation stages and may take more than 12 months, depending on complexity. Due to both its duration and the differing regulatory settings for networks and generators, the RIT-T often does not align with the investment timelines of new generation assets that may be capable of delivering ESS.

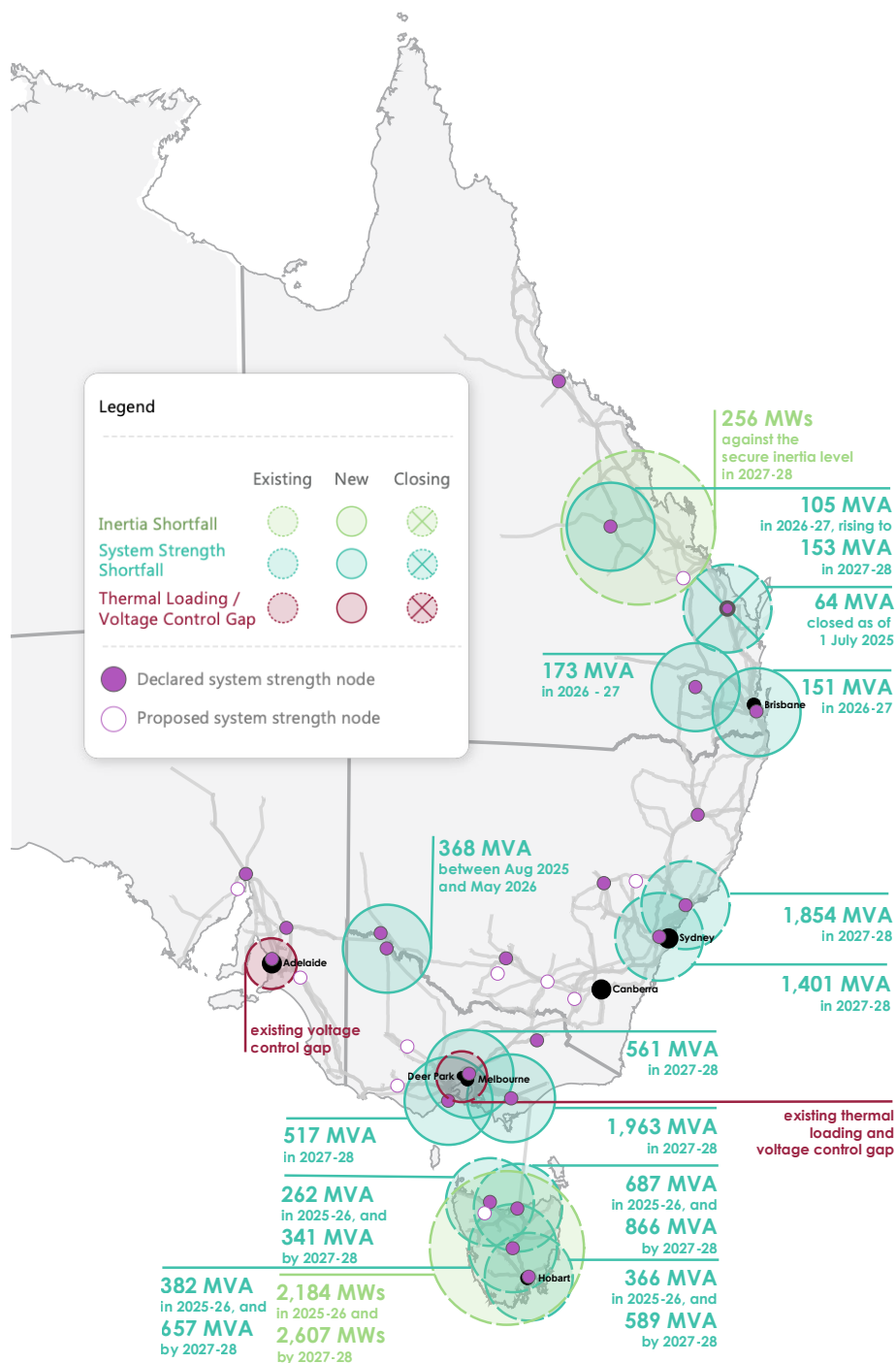
The RIT-T is structured around a clearly defined ‘identified need’, which limits flexibility for opportunity-driven investments (such as integrating ESS capability into new generation) unless the Integrated System Plan has already indicated a requirement for that enhancement.

Together, these timing constraints, narrowly defined regulatory requirements and muted investment signals contribute to a gap between when the system needs new services and when existing frameworks can respond.

²⁶² Except in Victoria where it is AEMO Victorian Planning.

²⁶³ Energy Networks Australia (2025), [The NEM wholesale market review](#).

Figure 49 – Map of system security needs across the NEM

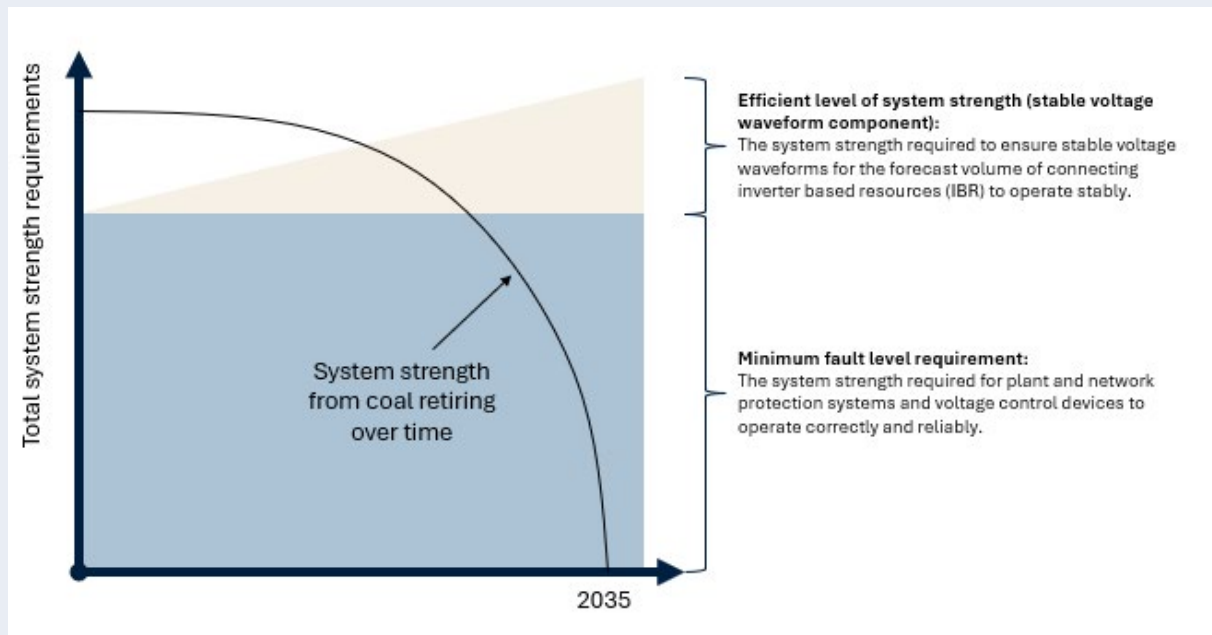


Source: AEMO 2024, [System strength, inertia and Network Support and Control Ancillary Services reports infographic](#).

As noted above, the market bodies are already undertaking substantial reforms to ESS provision (see **Figure 49** above). The Panel notes that additional coordination through the ESEM could support more efficient outcomes through reduced duplication of investment. By addressing this gap, the ESEM could enable timely, co-optimised deployment of assets that might otherwise be delayed or excluded under current frameworks. This would help reduce total system costs and support delivery of the services the future system will need.

Case study: Cost Effective Solutions - Enhancing System Strength with Townsville Power Station

In December 2021 AEMO declared an immediate system strength shortfall of 44 to 65 megavolt-amperes (MVA) at the Gin Gin system strength node in Central Queensland. This shortfall was due to the projected decline of synchronous machines online in the region. In May 2022 AEMO updated the shortfall to up to 64MVA for the period to 1 December 2025.



System strength is crucial for the stability of the power system, especially with the increasing penetration of inverter-based generation. The shortfall at Gin Gin was declared because the system strength services were projected to fall below the minimum requirements for more than 1% of the time under typical dispatch patterns. Powerlink needed to address this shortfall to ensure the stability and reliability of the power system in Queensland.

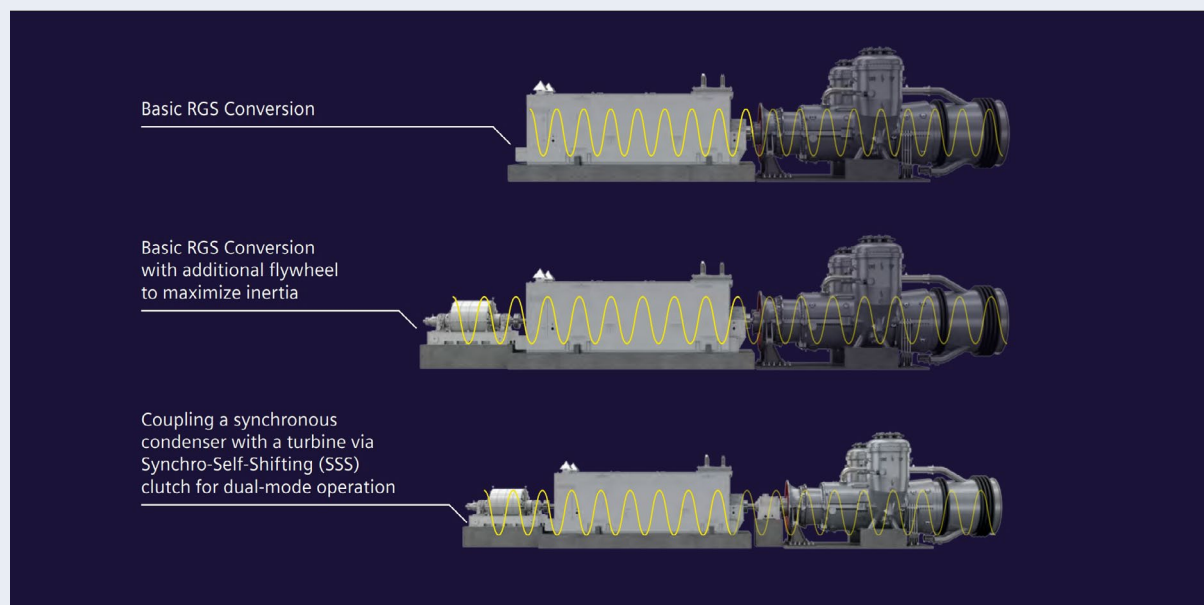
AEMO minimum three-phase fault level expected 99% of the time, December 2023

System Strength Node	Pre-contingent minimum fault level (MVA)	Post-contingent minimum fault level (MVA)	Minimum post contingent three phase fault current (MVA) expected 99% of the time, financial year ending					
			2024	2025	2026	2027	2028	2029
Gin Gin	2,800	2,250	2,192	2,201	2,201	2,195	2,083	2,093

Approach

Powerlink commenced an expression of interest process for short- and long-term non-network solutions to address the fault level shortfall at the Gin Gin node. After detailed analysis, Powerlink concluded that adding a clutch to the shaft between the gas turbine and the synchronous generator at the Townsville Power Station was the least-cost option to address the shortfall. This conversion allows Townsville Power Station to operate as a synchronous condenser providing system strength without moving the gas turbine or generator.

The project involves converting the gas turbine and generator to a hybrid rotating grid stabiliser. This conversion includes retrofitting an SSS Clutch, which allows the unit to operate as a synchronous condenser. This is expected to be delivered by mid-2025 at which point Townsville Power Station operating as either a generator or as a synchronous condenser will provide sufficient system strength for inverter-based generation facilities in North and Central Queensland to operate stably.



Benefits from the installation of a clutch at Townsville Power Station include:

- **Cost effective solution:** the conversion to a hybrid rotating grid stabiliser is up to 50 per cent less costly than installing a new synchronous condenser.
- **Timely implementation:** the project can be completed in 18 months, compared to over 36 months for a new synchronous condenser.
- **Revenue generation:** the plant owner, Ratch Australia, will gain a new revenue stream from providing grid services.
- **Flexibility:** Townsville Power Station will have the capability to switch flexibly between power generation and grid stabilisation modes.
- **Grid stability:** the electrical inertia provided by Townsville Power Station in grid stabilisation mode is calculated to be around 250 MWs and around 1,000 MWs in power generation mode.

The conversion of the Townsville Power Station to a HRG stabiliser represents a significant step in enhancing system strength and grid stability in Queensland.

By providing a cost-effective and timely solution to the system strength shortfall, Townsville Power Station plays a crucial role in supporting the transition to renewable energy sources and ensuring the stability of the power system.

This example shows what is possible when asset developers and owners work collaboratively with TNSPs to identify efficient solutions. The ESEM process, by incorporating ESS provision earlier in the investment process, rather than retrofitting at a later stage, should result in lower costs for ESS and therefore lower costs for consumers.

The ESEM should be used to complement other solutions to coordinate procurement of ESS

The Panel recommends that the body administering the ESEM allows for proponents of bulk energy, shaping and firming services to enter into secondary contracts for ESS where this is technically feasible and cost-effective. Coordinated planning and procurement can support the efficient integration of ESS as a co-benefit of new projects. The Panel acknowledges that the ESEM could help to coordinate investment over the longer term. The ESEM will not solve immediate shortfalls and should not be seen as replacing the obligations on AEMO and TNSPs to manage the provision of ESS.

Incorporating ESS capabilities during the design stage of new generation projects is generally more cost-effective than retrofitting or building stand-alone ESS infrastructure. While dedicated assets (such as synchronous condensers) may still be required in some areas, co-optimisation of ESS capabilities with other services where practicable can reduce overall service delivery costs. For example, grid-forming capabilities in batteries or clutches on gas turbines may provide lower-cost alternatives to stand-alone system security solutions.

A coordinated procurement process under the ESEM could identify and capture these capabilities from the outset. Aligning procurement signals would overcome fragmented incentives, reduce the risk of inefficient timing and support the concurrent delivery of generation and system services. It also allows for strategic siting of ESS assets to maximise network value and can help avoid duplicative infrastructure, as seen in the Townsville Power Station case.



Any recommended mechanism, including standalone government schemes, needs to encourage bundling of technologies with system service capabilities so it contributes to the cost efficient and timely delivery of the capabilities needed to manage a high [inverter based resource] system and better manage orderly exit of coal from the system. – AEMO²⁶⁴



TNSPs²⁶⁵ would remain responsible for delivering system strength and inertia under the existing regulatory framework. The coordination through the ESEM would support their role without undermining it.

Using the ESEM to coordinate ESS would require clearly defined needs and a transparent procurement processes

The recommended approach rests on two core principles:

1. **Clarity:** clearly defining ESS requirements.
2. **Transparency:** explaining how ESS considerations influence ESEM procurement outcomes.

Coordination between AEMO and the ESEM administrator will be essential to implementing this approach. AEMO's annual forecasts covering system strength, inertia and Network Support and Control Ancillary Services needs would continue to define ESS requirements at key locations.²⁶⁶ These forecasts would inform the design of documentation issued under the ESEM. To ensure operational readiness, proponents must also demonstrate compliance with the technical standards required for AEMO's enablement tool.²⁶⁷

To be clear, there would be no requirement on project providers to incorporate ESS into their projects seeking contracts for bulk energy, shaping and firming services. However, when conducting tenders, the ESEM could consider both of the following:

1. A core bid for bulk energy, shaping, or firming services only.
2. An optional 'ESS bid' that outlines the incremental cost of providing additional ESS capability beyond any connection obligations that may apply.

The core bid would be assessed through standard competitive auction processes. The ESS bid would be considered separately, with reference to the reasonableness of the proposed price and alignment with AEMO's identified system needs. To promote transparency, proponents must state the marginal cost of delivering ESS in their ESS bid. The ESEM administrator will publish the winning bids' marginal costs of delivering ESS.

Given the locational specificity of ESS and the smaller pool of eligible providers, competitive pressure on ESS bids may be more limited. This is particularly the case where the shortfall is large or urgent. To manage this, the ESEM administrator could compare costs with those paid by TNSPs for similar services, for example the annually published AER-approved unit prices for system strength in each TNSP region.

²⁶⁴ AEMO (2025), [Submission to the Initial NEM Review Consultation](#), p 13.

²⁶⁵ Except in Victoria where it is AEMO Victorian Planning.

²⁶⁶ It could be beneficial to bring these forecast horizons into alignment to enhance coordination and planning. These forecasts provide proponents with clear guidance on baseline ESS requirements.

²⁶⁷ AEMO (2025), [Improving Security Frameworks – High Level Implementation Assessment Final](#), p 17.

If a proponent's primary bid is successful, the ESEM administrator may choose to enter a secondary ESS contract where the ESS bid is assessed as reasonable and aligns with identified system needs. This secondary contract would provide a stable revenue stream to cover incremental equipment costs, such as clutches for gas turbines or grid-forming functionality in batteries.

Where an ESS contract aligns with a need that passes the RIT-T, the contract could be novated to the relevant TNSP, enabling integration into existing regulatory frameworks. Alternatively, if the ESEM does not directly contract for ESS it could share relevant tendering information with TNSPs to support price discovery and accelerate regulatory approval. The AER should continue its role in giving forward guidance and overseeing the cost-effectiveness of major non-network contracts.

Questions for stakeholders

- Will a model that procures ESS contracts alongside bulk zero-emissions energy, shaping and firming support additional ESS provision in a cost-efficient manner?
- Are there any other alternative approaches that would support cost efficient provision of ESS through the ESEM?

8C: A framework should be established to ensure the ESEM is able to consider market concentration when running tenders²⁶⁸

Competition in the NEM is vital for driving efficiency, innovation and affordability. The ESEM should prevent anti-competitive pressures, as discussed below.

Liquidity in derivative markets is essential for retail competition

Electricity derivative market liquidity underpins a competitive retail sector, as it enables retailers to hedge according to their specific needs.²⁶⁹ Limited trading volumes can lead to wider bid–ask spreads and higher risk premiums embedded in contract prices, while producing less reliable price signals for future investment decisions. If the tenor gap persists and the ESEM is required to underwrite energy, shaping and firming, the ESEM will be a large seller of contracts into the market, boosting liquidity.

Unnecessarily high credit barriers limit smaller players from participating

Independent retailers and smaller new entrant generators are unlikely to be viewed as investment-grade creditworthy by banks, limiting their ability to contract at low cost. Trading on exchanges like the Australian Securities Exchange (ASX) requires substantial capital for margins, again disadvantaging smaller entities with limited balance sheets²⁷⁰ (see discussion at **Recommendation 6C**). Similarly, favourable OTC contract terms often require strong credit ratings, or bank or parent company guarantees.

The ESEM could contract with smaller parties, with the scheme administrator absorbing some credit risks as appropriate. This approach requires careful consideration of trade-offs and administrative complexities.

Concentrated ownership of dispatchable assets limits competitive pressure

The AER has noted market concentration has reduced in recent years as the energy transition has brought new players into generation and retail markets.²⁷¹ Ownership of dispatchable generation remains relatively concentrated and a few large participants are often needed to meet demand when renewable production is low.²⁷²

²⁶⁸ This aspect of the ESEM is not intended to be utilised in Tasmania, which has a unique market structure due to the predominance of its state-owned hydro assets.

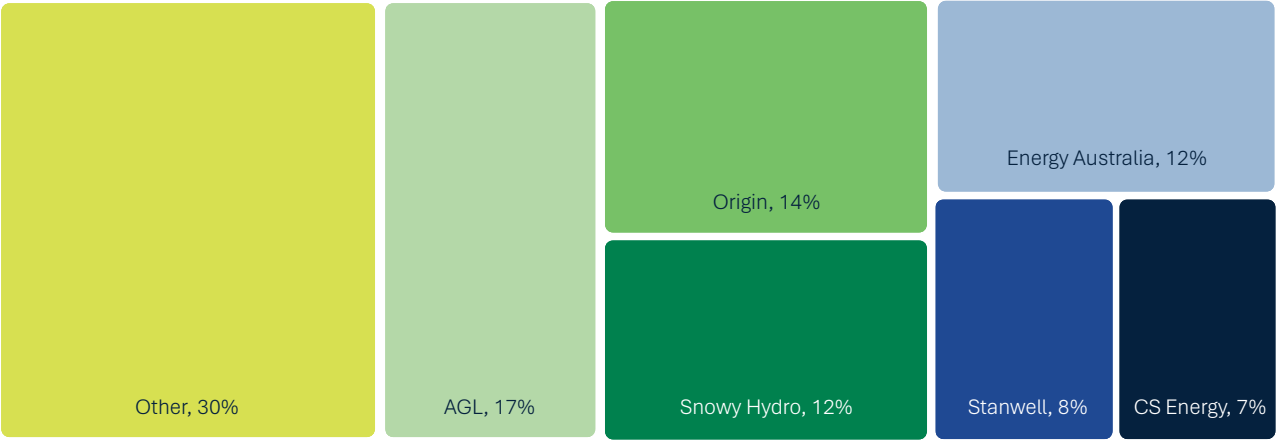
²⁶⁹ ACCC (2018), [Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry – Final Report](#), p 113.

²⁷⁰ AER (2022), [Wholesale Electricity Market Performance Report – December 2022](#), p 54.

²⁷¹ AER (2024), [Wholesale Electricity Market Performance Report – December 2024](#), p 2.

²⁷² Ibid., p 2.

Figure 50 – Share of dispatchable capacity, 2024



Source: AER. Data as of 31 December 2024. Dispatchable capacity includes gas, coal, batteries and hydro.

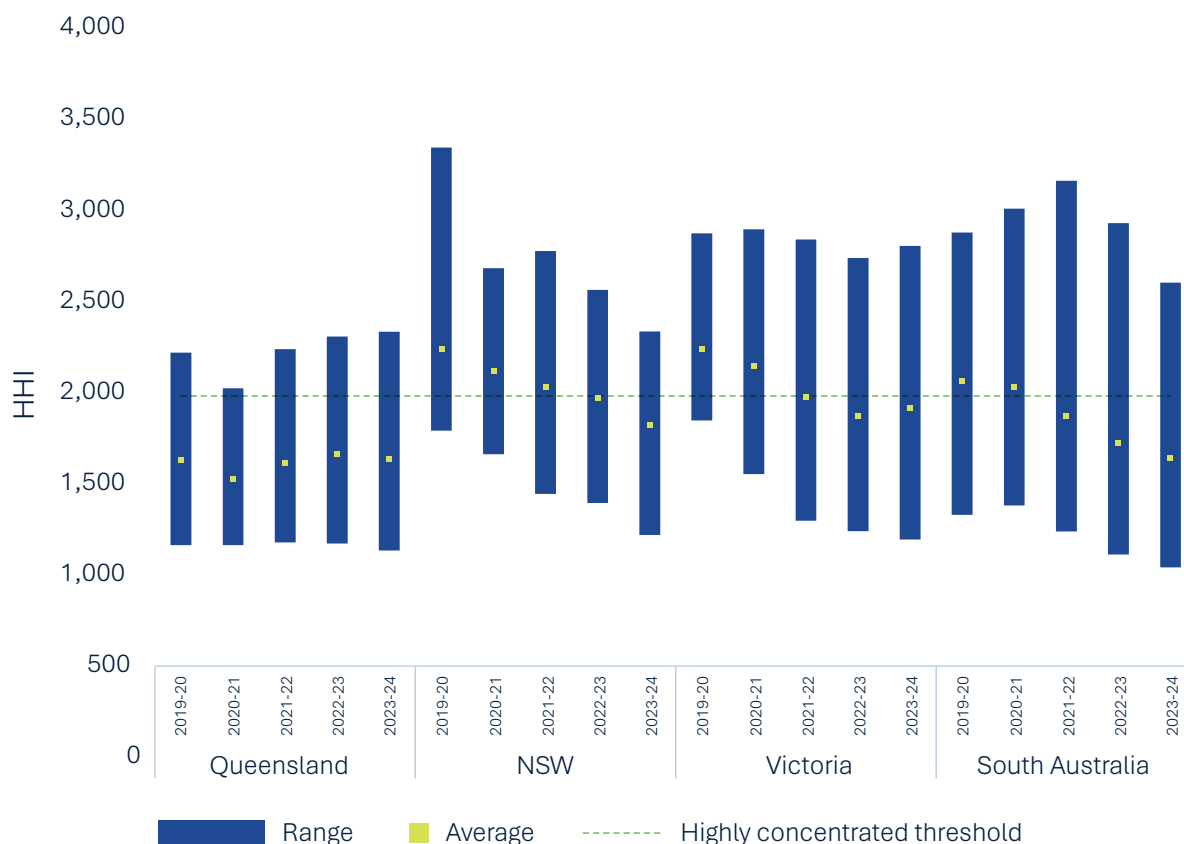
Figure 51 shows the Herfindahl Hirschman Index (HHI)²⁷³ for NEM mainland regions for each bid interval from 2019–20 to 2023–24. The AER considers a score of 2,000 to indicate a market that is highly concentrated, though notes some jurisdictions consider 1,800 or above as highly concentrated.²⁷⁴ While the median HHI score was under 2,000 in every region in 2023–24, during periods of low wind and solar output Victorian HHI scores reached as high as 2,800 and South Australian scores reached 2,600.²⁷⁵

²⁷³ The Herfindahl-Hirschman index is a measure of the competitiveness of an industry in terms of the market concentration of its participants.

²⁷⁴ Ibid., p. 51.

²⁷⁵ Ibid., p. 56.

Figure 51 – Herfindahl Hirschman Index by jurisdiction, 2019–24



Source: Adapted from AER Wholesale Electricity Market Performance Report 2024, Figure 4.5 and p.51

As the energy transition continues to unfold, competition will remain central to good consumer outcomes in the NEM

The ESEM could play a role in addressing market concentration concerns.²⁷⁶ For example:

- The AER could publish benchmarks on market concentration across the three ESEM services (bulk energy, shaping, firming) and retail markets.
- The ESEM administrator could limit its contracting with any participants with large market shares that would lead to the market shares that breach this concentration benchmark.

In its 2018 Inquiry the ACCC recommended a scheme with similar characteristics to some aspects of the ESEM and suggested contracts should “not involve any existing retail or wholesale market participant with a significant market share (say a share of 10 per cent or more in any NEM region)”.²⁷⁷

Questions for stakeholders

How could the ESEM help to keep the NEM competitive?

²⁷⁶ For avoidance of doubt, this role would not supersede the existing regulatory functions of the AER and ACCC.

²⁷⁷ ACCC (2018), [Restoring electricity affordability and Australia’s competitive advantage: Retail Electricity Pricing Inquiry – Final Report](#), p 100.

8D: A new longer-term out-of-market reserves service should be established to cover high-impact, low-likelihood events, with quantities to be procured at the discretion of jurisdictions, on advice from the Reliability Panel

In addition to in-market services procured by the ESEM, the Panel also propose an out-of-market reserves service to address specific challenges. Reserves service providers would:

- receive a flat annuity contract for all relevant periods, with associated availability obligations
- remain out-of-market unless specific conditions (established in clear and binding rules) are met
- be procured on the direction of jurisdictional energy ministers, informed by advice from the Reliability Panel.

Reserves have been suggested by a number of stakeholders as a useful addition to the NEM.

“

Strategic reserves could present an avenue to increase reliability, with limited impact on the market dynamics and prices. If, like the [Reliability and Emergency Reserve Trader], strategic reserves were explicitly (and only) out-of-market, and don't impact price formation within the market, it may present an option with limited distortion of the wholesale market dynamics.

– University of New South Wales Collaboration on Energy and Environmental Markets²⁷⁸

”

“

The current energy-only market design can provide enduring market signals and certainty ... when complemented by: ... a strategic reserve. – Nexa Advisory²⁷⁹

”

Existing reserves have been focused on the short term

Reserves in the NEM today are primarily procured through the RERT framework. The framework directs AEMO to take reasonable actions to contract for emergency reserves subject to guidelines in the NER developed by the Reliability Panel. RERT is triggered if a shortfall is projected against the Reliability Standard – that is, 0.002% of electricity demand is likely to be unserved over the course of a year. If a shortfall is projected, RERT allows AEMO to procure reserve services for a period of up to 12 months.²⁸⁰

Interim Reliability Reserves (IRR) were introduced as a temporary measure in 2020. They were originally set to expire in 2025 but the AEMC extended the application of the measure to 2028.^{281,282} They established an out-of-market reserve which was used to support the more stringent Interim

²⁷⁸ UNSW CEEM (2025), [Submission to the Initial NEM Review Consultation](#), p 9.

²⁷⁹ Nexa Advisory (2025), [Submission to the Initial NEM Review Consultation](#), p 2.

²⁸⁰ AEMO (2024), [Reliability and Emergency Reserve Trader \(RERT\)](#).

²⁸¹ AEMC (2023), [National Electricity Amendment \(Extending the application of the IRR to the RRO\) Rule 2023 No. 4](#).

²⁸² The cut-off date for entering into multi-year contracts under the IRR was 31 March 2025, meaning that AEMO can now only enter into reserve contracts in line with long-notice RERT.

Reliability Measure (IRM) (0.0006%). This provision allowed AEMO to procure reserve services for up to three years.²⁸³ In practice, the longest contract supported in the IRM has been four months.²⁸⁴

Jurisdictions have used temporary derogations to modify these rules when managing local circumstances. Victoria allowed AEMO to enter into reserve contracts for up to three years between 2019 and 2023. South Australia recently had a derogation allowing the use of recently mothballed gas to support RERT contracts.

A new, longer-term reserve could help jurisdictions manage emerging risks

As outlined in **Trends and challenges in the NEM** and **Ensuring effective operation of the spot market**, one of the changes facing the future electricity system is increasing weather-dependency of both supply and demand. Approaches to managing reliability will need to evolve in parallel with the transition of the electricity system. For example, future supply and demand imbalances are likely to change from short duration power peaks in summer to extended periods of energy deficit in winter.

The Reliability Panel considers long-term weather variability when reviewing the Reliability Standard and market price settings and recently conducted extensive modelling of a large number of possible outcomes to examine future weather variability in depth.²⁸⁵ The Panel recommends market price settings continue to be the primary signal of the value of meeting reliability standards. Procurement quantities for the ESEM will be based on sufficient bulk energy, shaping and firming to meet the reliability standard, including consideration of weather variability. The combined actions of the Reliability Panel and ESEM will support meeting the Reliability Standard across most future expected variations in weather.

However, as noted by the Reliability Panel, these mechanisms will not completely eliminate the risk of energy shortfalls, and it is possible that when events do occur they may be deeper or longer (but very rare). **Figure 52** shows a range of possible future events for 2035–40, as modelled by the Reliability Panel.²⁸⁶ Jurisdictions may want to procure additional insurance above and beyond the Reliability Standard to protect against such events.

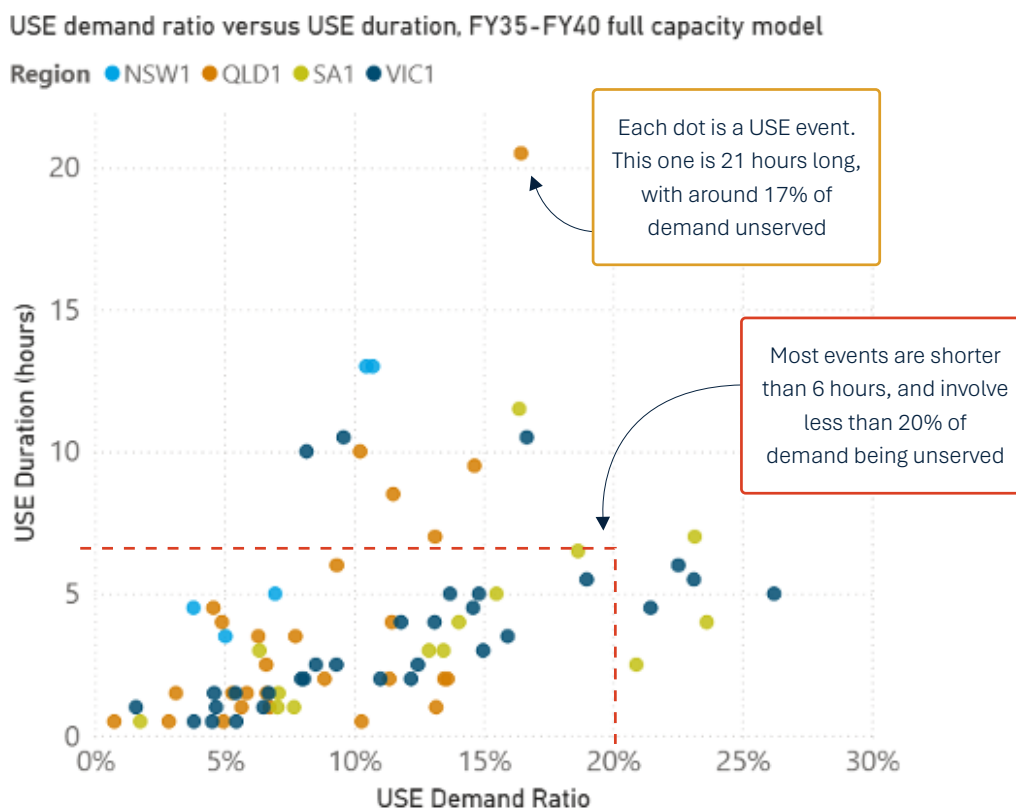
²⁸³ DCCEE (2020), [Interim Reliability Measures](#).

²⁸⁴ AEMO (2023, 2024, 2025), [RERT Reporting](#).

²⁸⁵ Reliability Panel AEMC (2024), [Review of the form of the reliability standard and administered price cap](#), p 20.

²⁸⁶ *Ibid*, p 30.

Figure 52 – Unserved energy events (USE) in a possible future NEM



Source: Figure 6.3 from Reliability Panel (2024), [Review of the form of the reliability standard and administered price cap](#), p. 30.

New resources required to address high-impact, low-probability events are unlikely to recover the costs of their investment in-market unless market price settings are set to extremely high levels. Put simply, if the cost of the resource needs to be recovered via a small number of hours every few years, the price would need to be very high. This is likely to be unacceptable to stakeholders and not in the long-term interests of consumers. As such, an out-of-market reserves service may be a more appropriate mechanism to encourage the establishment of the necessary resources to cover these rare weather-related events.

The ESEM should be used to source additional investment for out-of-market reserves where it is directed to do so. The Reliability Panel could provide advice on the costs and benefits of procuring additional out-of-market reserves. Such advice would also include the likelihood, duration and depth of any reliability issues highlighted. Jurisdictions, informed by this advice, could nominate the amount of services to be procured. Reserves contracts would be long-term in nature. The cost of these reserve contracts would be recovered from consumers in the jurisdiction that requested the reserves.

Projects that are contracted to provide reserve services would be expected to be available to mitigate potential shortfalls. Projects that are not available when contracted would be subject to penalties. Triggers to enter the market would form part of the reserves contract. This might include a severe weather event resulting in expected load shedding, exceedance of the Cumulative Price Threshold or other triggers defined clearly in the NER. It is important to note that strategic reserves may not protect against outages in the event of severe weather as other factors (such as trees falling on power lines)

are often the cause of disruptions. Jurisdictions could consider if locational diversity of reserves to support climate resilience should also be included within the framework.

Unlike standard ESEM procurements, reserve contracts would be bespoke, physically linked and thus not fungible. Integrating procurement with the ESEM could allow a new investment to be supported for periods beyond the reserve contracting period via standard ESEM contracts, if there was an identified need for that service after the reserve contracting period (for example, because of long-term expected demand growth or the retirement of existing generators).

The ESEM framework would allow proponents to provide both shaping, firming and reserves where it is cost effective to do so. For example, the storage duration of a pumped hydro project could be extended from eight hours to 24 hours with the additional storage capacity held in reserve. A reserve contract may also provide gas plant support to add additional on-site fuel storage or to contract for the option of additional gas above that required to meet the firming requirement. The marginal cost of adding an energy reserve is likely to be less than the cost of a standalone reserve.

Some jurisdictions have processes to assess jurisdictional specific reliability risks and deliver additional in-market resources, such as the Energy Security Target in New South Wales or the forthcoming Firm Energy Reliability Mechanism in South Australia.^{287,288} As these schemes procure service providers to operate in-market, they could be integrated into the ESEM firming service over time.

Questions for stakeholders

How could a new, longer term strategic reserves service be established in the NEM?

²⁸⁷ NSW Government (2022), [Energy Security Target Monitor](#).

²⁸⁸ SA Government (2025), [Firm Energy Reliability Mechanism](#).



Recommendation 9: Governments and market bodies in the NEM should pursue a coordinated suite of reforms to ensure regulatory settings, the innovation ecosystem and existing policies and programs are aligned with the ESEM

The Panel recognises that the success of the proposed ESEM will depend not only on its design but also on the broader regulatory, policy and institutional environment. A well-functioning long-term investment signal mechanism should be supported by consistent market signals, complementary policy frameworks and a clear pathway for integrating new technologies. Without alignment across these domains, the ESEM's ability to unlock timely and efficient investment in bulk energy, firming and shaping could be undermined.

To this end, the Panel has identified a coordinated set of supporting reforms that governments, energy ministers and market bodies should pursue. These reforms are designed to ensure that emissions targets are applied consistently, innovation is strategically directed, existing schemes contribute to market functioning and market settings allow participants to manage risk. They also highlight opportunities to streamline planning and improve regulatory clarity as new resources enter the system.

Together, these actions would reinforce investor confidence, lower emissions, improve competition and unlock the full potential of the ESEM.

9A: Governments should clarify how their greenhouse gas emissions targets apply to projects procured to provide firming services, to provide certainty for investors

Zero-emissions bulk energy and shaping providers supported by the ESEM will help to decarbonise the NEM, as the providers of these services will not produce emissions. However, peaking thermal generators that are successful in obtaining contracts for the firming service would produce scope 1 emissions if fuelled with conventional methane or diesel. As firming generators do not have high capacity factors, the Panel notes that even if firming is provided by conventional peaking gas generation in the short term, the total emissions will be relatively low.

Firming investment within the ESEM framework will be supported by electricity derivatives contracts, as described above. However, with a conventional cap contract or similar, an emissions-intensive firming project would be fully exposed to uncertain costs associated with changes in emissions policy. This risk has already impacted appetite for firming investment^{289,290} and will continue to do so in the absence of a clear framework for how emissions are considered for firming generation.

Several energy generation investors have indicated to the Panel that clarity in relation to emissions targets from firming generation would be a pre-requisite for future investment. The Panel notes that some governments have provided this clarity, and examples include:

- **Requiring offsets for scope 1 emissions:** New South Wales has provided a clear framework through regulation by the state's Environment Protection Authority. New gas generators must have annual emissions intensity lower than the state average prior to 2036. After that, projects must achieve net zero scope 1 emissions with emission offsets sourced from within the state.²⁹¹
- **Setting emissions intensity thresholds:** Western Australia is exploring options for setting an emissions intensity threshold for capacity credit eligibility²⁹² and Europe introduced a limit to the scope 1 emissions intensity of generators for its capacity scheme.²⁹³

²⁸⁹ Comincioli et al. (2024), '[Carbon Taxation and Electricity Price Dynamics: Empirical Evidence from the Australian Market](#)', in Environmental and Resource Economics.

²⁹⁰ Carbon policy uncertainty was also raised in many submissions to the NEM Review Initial Consultation.

²⁹¹ NSW EPA (2024), [Overseeing firming infrastructure's greenhouse gas emissions obligations](#).

²⁹² WA Government (2024), [Market Advisory Committee - March 2024 - Meeting papers](#).

²⁹³ European Union (2019), [Regulation - 2019/943 – on the internal market for electricity](#), Article 22-4.

9B: The Australian Government should task the Australian Renewable Energy Agency (ARENA) to accelerate the development and deployment of zero emissions technologies that provide firming at scale

Firming is a crucial service to ensure the reliability of the electricity system as it moves to an increasingly weather-dependent state. Zero-emissions technologies like long-duration lithium ion energy storage, compressed air storage, iron air or flow batteries, pumped hydro, hydrogen turbines and engines, small-scale aggregated demand response or industrial demand response can already provide this service. However, these technologies are often not yet as cost-competitive or available as fossil fuel alternatives, such as open-cycle gas turbines and gas-fuelled reciprocating engines.²⁹⁴

Considering current technology costs, AEMO's 2024 ISP suggests the NEM will need around 15 GW of low capacity factor peaking gas generation.²⁹⁵ The use of some gas generation will support rapid and substantial emissions reductions by allowing the closure of ageing, high-emissions coal plant, reducing NEM emissions from more than 100 million tonnes today to less than 10 million tonnes in future.²⁹⁶ Nonetheless, these remaining emissions are material. Stakeholders have also noted that an over-reliance on gas into the future could create risks if gas supplies are limited or unreliable.²⁹⁷

For these reasons among others, efforts to develop suitable replacement technologies should be prioritised. The benefits of zero-emissions firming technologies were noted in stakeholder submissions, as were the commercial challenges they face:

“

Adding [long duration energy storage] to the system can have a material positive impact on both emissions and system costs ... Challenges bringing LDES include revenue uncertainty, market design, large upfront capital investment and the early development stage of many LDES technologies. – Advanced Material and Battery Council²⁹⁸

”

“

The NEM Review Panel should recommend immediate government attention to fund the gap and develop programs that incentivise investment in LDES technologies that are scalable such as flow batteries and liquid air storage. – NEXA Advisory²⁹⁹

”

ARENA is well placed to support the accelerated development and deployment of zero emission technologies. ARENA's Large-scale Solar PV Competitive Round³⁰⁰ demonstrated that targeted support could further progress cost reduction in utility scale photovoltaics. ARENA has similarly supported pumped hydro³⁰¹ and compressed air storage projects³⁰², helping to bridge the gap to progress towards

²⁹⁴ E.g. CSIRO (2024), [GenCost 2024–25 Consultation Draft](#).

²⁹⁵ AEMO (2024), [2024 Integrated System Plan](#), p 69.

²⁹⁶ AEMO (2024), [Integrated System Plan Generation and Storage Outlook](#), Step Change Scenario.

²⁹⁷ Clean Energy Council (2024), [The future of long duration energy storage](#), p 9.

²⁹⁸ Advanced Material and Battery Council (2025), [Submission to the Initial NEM Review Consultation](#), p 4.

²⁹⁹ Nexa Advisory (2025), [Submission to the Initial NEM Review Consultation](#), p 6.

³⁰⁰ ARENA (2018), [Large-Scale Solar Round](#).

³⁰¹ ARENA (2021), [Kidston Pumped Hydro Energy Storage](#).

³⁰² ARENA (2022), [Hydrostor - Broken Hill Advanced Compressed Air Energy Storage Demonstration](#).

commercial operation in the NEM. Increased ARENA support for zero emissions firming technologies could further accelerate NEM decarbonisation and help to remove the last source of emissions from Australia's electricity system.

9C: Governments overseeing existing generation underwriting schemes to support long-term investment should consider options to improve derivative market liquidity

Federal, state and territory governments have introduced schemes to provide long-term revenue support for new capacity in the NEM, including:

- Australia Capital Territory Renewable Energy Reverse Auctions
- Victorian Renewable Energy Target (VRET)
- New South Wales Electricity Infrastructure Roadmap
- The Australian Government CIS.

A major focus of these schemes has been to manage generator investment uncertainty and they have been successful in incentivising the build of new renewable energy and firming capacity. However, stakeholders have identified that the design or implementation of these schemes may decrease derivatives market liquidity. It is important to note that some schemes, such as the VRET and LTESA, do include recycling provisions, but their use remains nascent.³⁰³

“

The contractual requirements of the CIS, and equivalent state schemes, have greatly limited the ability of new assets to participate in the financial market, which has reduced their ability to contribute to market liquidity. – Australian Financial Markets Association³⁰⁴

”

“

Both the Roadmap and CIS schemes are currently struggling with how to accommodate related party contracting. – RWE Renewables³⁰⁵

”

“

The CIS will also reduce the participation in the contracts market, which could cause liquidity problems. – Australian Energy Council³⁰⁶

”

Questions for stakeholders

How could government support schemes recycle bulk energy, shaping and firming from existing contracts to support market liquidity?

³⁰³ For example, SEC Victoria (2025), [SEC to power 5% of Victoria's electricity market, and provisions in the New South Wales Electricity Infrastructure Investment Act 2020, Section 52](#).

³⁰⁴ AFMA (2025), [Submission to the Initial NEM Review Consultation](#), p 6.

³⁰⁵ RWE Renewables (2025), [Submission to the Initial NEM Review Consultation](#), p 3.

³⁰⁶ Australian Energy Council (2025), [Submission to the Initial NEM Review Consultation](#), p 3.

9D: The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter-regional settlement residue units beyond three years

Stronger inter-regional hedging is likely to be needed to support investment in variable renewable energy (VRE)

The Panel supports the AEMC's commitment to review inter-regional settlement and hedging arrangements, which are essential in a system increasingly reliant on VRE, where sharper regional price differentials are expected.³⁰⁷ The AEMC's review will aim to strengthen inter-regional trade, ensure fair cost distribution and maintain confidence in the NEM's market mechanisms.

As part of its review, the Panel recommends the AEMC review hedging arrangements across interconnectors to provide longer-term certainty. In particular, the AEMC could consider options that would extend the contracting tenor of inter-regional settlement residue units beyond three years as part of its proposed review of settlement residue auction arrangements. This would improve the value of the settlement residue auction process as a financial risk management tool, particularly when used alongside contracts issued under the ESEM.

In making this recommendation the Panel recognises that several positive initiatives and reforms are already underway to support interconnection across the NEM. The recommendation is therefore intended to complement rather than replace this ongoing work.

Interconnectors

Interconnectors are critical to delivering the full benefits of the NEM, particularly as more weather-dependent generation connects. Their importance will continue to grow as interconnectors link regions with diverse weather patterns.

One barrier to interconnector investment has been the allocation of costs across interconnected regions. While the benefits of interconnection are often broad and diffuse, the construction costs typically fall on one or two jurisdictions, creating a misalignment of costs and benefits. Even where interconnector costs are shared equally between jurisdictions, there can still be disparities in the cost-benefit ratio for each, often reflecting differences in population size and how those costs are recovered from consumers.

This barrier should now be reduced following a recent NER change that allows jurisdictions to agree on cost allocation through ministerial agreement.³⁰⁸ Where further work is required on interconnector cost sharing, governments and the AEMC should continue to pursue it.

³⁰⁷ For this commitment, see AEMC (2024), [Draft rule determination: National electricity amendment \(Inter-regional settlements residue arrangements for transmission loops\)](#) Rule 2025, p 36–43.

³⁰⁸ AEMC (2024), [Providing flexibility in the allocation of interconnector costs](#).

Questions for stakeholders

How satisfied are market participants with settlement residue auctions as a financial risk management tool? Are other options for providing longer term contracting opportunities across interconnectors worth considering?

9E: Once energy ministers are satisfied the ESEM and the Panel’s proposed market making obligation are working effectively, they should look to phase out the Retail Reliability Obligation

The Panel has received substantial feedback from stakeholders raising concerns with the Retailer Reliability Obligation (RRO).

“

The requirement to contract through the RRO is cumbersome, expensive and does not achieve the RRO’s intended outcomes. – **Flow Power**³⁰⁹

”

“

The RRO does not incentivise investment and should be abolished. – **Shevy Moss Feiglin & Tom Geiser**³¹⁰

”

“

The RRO is unlikely to promote investment, given it is a reactive scheme that has rarely been triggered ... There is also a weak relationship between the typical cause of a forecast reliability gap (P10 demand coincident with outages) and the actions that retailers are required to take (temporarily entering financial contracts to a P50 level). – **AEMO**³¹¹

”

The RRO commenced on 1 July 2019 and requires retailers to establish firm contractual coverage when AEMO foresees a potential shortfall in energy supply, with the aim of incentivising investment in new capacity. While the Panel supports the rationale that led to the establishment of the RRO, a range of implementation issues have limited the scheme’s effectiveness and imposed costs or created uncertainty for a breadth of market participants.

As the RRO only requires retailers to contract for the near term, it does not address the tenor gap and is therefore not suited to driving new investment to ensure long-term reliability. Once established, the ESEM should fulfil the intended purpose of the RRO in this respect.

While market participants raised significant concerns with the RRO as a whole, many participants agreed a market making scheme similar to the Market Liquidity Obligation – a sub-component of the RRO – could be a valuable component of the future NEM.³¹² **Recommendation 6** includes the establishment of a permanent market making obligation in the NEM.

³⁰⁹ Flow Power (2025), [Submission to the Initial NEM Review Consultation](#), p 9.

³¹⁰ Shevy Moss Feiglin & Tom Geiser (2025), [Submission to the Initial NEM Review Consultation](#), p 3.

³¹¹ AEMO (2025), [Submission to the Initial NEM Review Consultation](#), p 7.

³¹² Examples from the [NEM Review Initial Consultation](#) include the Australian Energy Council, Australian Financial Markets Association, the Australian Energy Market Commission, and the Clean Energy Council.

9F: Once the ESEM framework is established, energy ministers should consider opportunities to rationalise NEM forecasting and planning documents to avoid inconsistencies and duplication

Once ESEM planning processes are established it will be important to clearly delineate the roles of existing planning and reporting exercises to minimise the risk of multiple conflicting planning pathways creating uncertainty for participants as to the direction of the future NEM. Existing planning exercises in the NEM details some of these existing exercises.

Pending broader questions around ESEM governance and implementation, there may be opportunities to reconcile ESEM planning and existing processes, including the Integrated System Plan and Electricity Statement of Opportunities. The goals and underpinnings of these exercises have changed and expanded significantly over time. As the ESEM is established, it is appropriate to consider whether some of the roles of these planning exercises could be dovetailed with those underpinning ESEM operations.

With existing work under the ECMC to reduce reporting duplication,³¹³ this recommendation could be incorporated into that ongoing workstream.

³¹³ ECMC (2025), [Communique 14 March 2025](#), p 2.

9G: Energy ministers should pursue reforms to improve consistency in the treatment of load, storage and generators connected at distribution and transmission level, to ensure a level playing field

The most efficient mix of resources is likely to include both transmission and distribution-connected generators and storage, including at sub-transmission and high-voltage levels. DNSPs have suggested that there is capacity to connect these resources at some locations on distribution networks with little requirement for network augmentation. Analysis by LEK for Energy Networks Australia, for example, suggested connection at these locations is cheaper (per MW) than connecting to transmission in a Renewable Energy Zone.³¹⁴

Storage providers have reported limited success in negotiating access to distribution networks on terms competitive with those available on the transmission network. Transmission network and distribution network connection and pricing are regulated under different parts of the NER. To the extent the rules and their implementation by network businesses result in different pricing and service levels that don't reflect different underlying cost drivers, there is an inefficient signal for investment.

This issue was identified and partly considered in the AEMC's Integrating Storage rule-change process in 2020 to 2021.³¹⁵ In its final determination, the AEMC retained the current framework to allow storage to connect under a:

- negotiated agreement at the transmission level
- direct control service tariff or storage tariff trial option, where offered, at the distribution level.

The AEMC made minor amendments to the NER to clarify how the negotiated framework applies in relation to grid-scale storage and hybrids; and to reduce barriers to the uptake of shared transmission services on a negotiated basis.

The AEMC noted "the rules were not designed for loads like storage that are price sensitive and can minimise impact on network congestion. It would be appropriate for a future rule change to address the broader issue of how network costs should be recovered".³¹⁶ The AEMC also noted that these issues are also relevant for other large flexible loads (e.g. hydrogen, data centres). At the time, the AEMC anticipated receiving a rule-change request covering this issue, but this request did not eventuate.³¹⁷ The AEMC's pricing review is an avenue to consider distribution network reforms in this area, but its current scope does not appear to allow for examining differences between transmission and distribution holistically.³¹⁸

While the Panel has not formed a view on the appropriate solution in this area, we note several types of solutions have come up in our initial investigation of the area:

³¹⁴ Energy Networks Australia and LEK (2024), [The Time is Now: Getting smarter with the grid](#), p 23.

³¹⁵ AEMC (2021), [Integrating energy storage systems into the NEM](#).

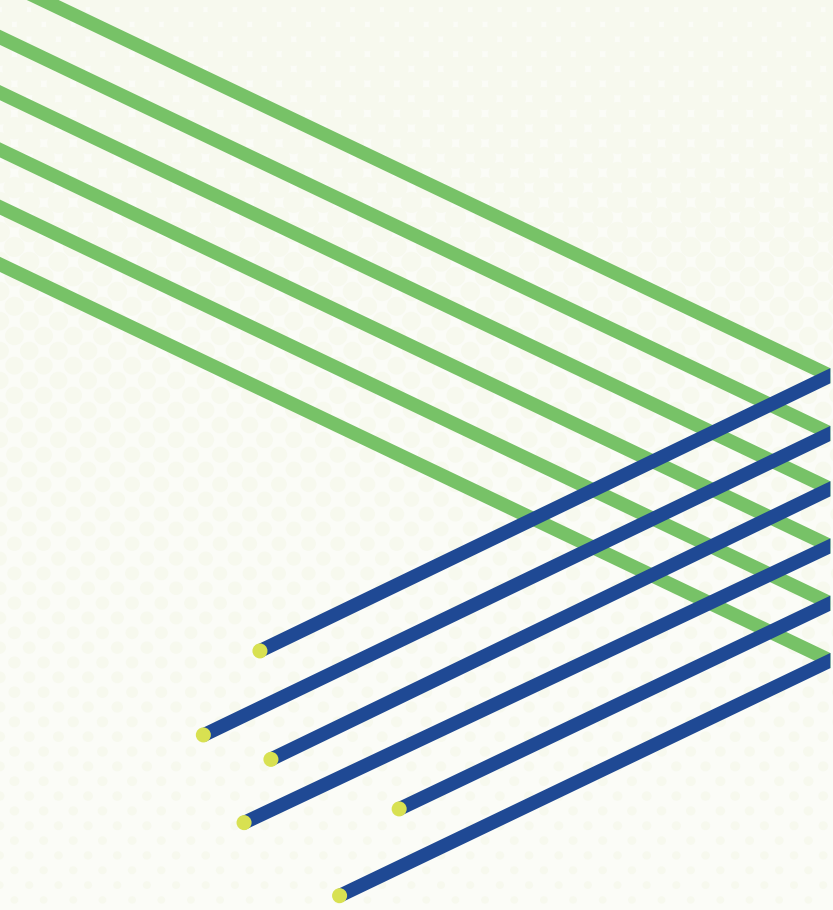
³¹⁶ Ibid., p xi.

³¹⁷ Ibid., p 53.

³¹⁸ AEMC (2025), [The pricing review: Electricity pricing for a consumer-driven future](#).

- Establish ‘local energy hub’ arrangements allowing distribution network service providers to make prospective investments to support future generation and storage connection (with appropriate regulatory oversight to ensure prospective expenditure is efficient).
- Allow negotiated arrangements at distribution level (noting this would need to come with appropriate incentives to balance the relative market power of distribution networks in such a negotiation).
- Reform tariff frameworks such that battery energy storage systems and utility-scale responsive loads received tariffs which better reflect their ability to reduce network costs over time, and remove the burden of individually negotiating each connection.
- Reform connection and charging arrangements, looking across transmission and distribution rules.

The Panel recommends energy ministers pursue solutions in one or more of these areas by tasking the AEMC with a review, or through a rule-change request, which could allow faster resolution within the AEMC’s decision-making powers.



6

**Ensuring consumers
benefit**



Chapter summary

The NEM only exists as a construct to serve the long-term interests of consumers. As such, consumer outcomes are a key driver of the Panel's draft recommendations.

In the previous three chapters, the Panel has put forward a series of draft recommendations that are intended to safeguard the efficient operation of the energy-only spot market, support transparency, accessibility and liquidity in the derivatives market, and underpin long-term investment in electricity services during the transition. The Panel is confident that these draft recommendations should facilitate outcomes that are in the long-term interests of consumers.

This chapter shifts focus from formal recommendations to draft observations. These observations highlight how the proposed reforms could unlock broader consumer benefits if complemented by action from governments and market bodies.

In particular, the Panel identifies areas where coordinated reforms could amplify the impact of its recommendations and better align the energy market framework with evolving consumer needs. This includes enabling consumers to access simpler, more predictable and stable electricity bills that can mitigate the impacts of price volatility; delivering more equitable network tariffs; and updating consumer protection frameworks for new energy services including aggregation and virtual power plants.

Specifically, the Panel identifies four opportunities for jurisdictions and market bodies that are facilitated by the Panel's recommendations:

- Support the development of simple, multi-year fixed price retail contracts by enabling benchmark price transparency and reviewing barriers such as early exit fee restrictions (**Observation 1**). This is facilitated by **Recommendation 6** and **Recommendation 8**.
- Reform network tariff structures to ensure they are more equitable and better aligned with wholesale market dynamics, particularly in the context of rising consumer energy resource (CER) uptake (**Observation 2**). This would unlock the benefits of **Recommendation 2**.
- Update the methodology for regulated retail price benchmarks to reflect the evolving nature of the derivatives market in the context of the market making obligations (**Observation 3**). This would unlock the benefits of **Recommendation 6**.
- Extend the National Energy Customer Framework to cover new energy services, including CER aggregation, and explore the introduction of an overarching consumer duty to protect customers engaging with more complex service offerings (**Observation 4**). This would ensure consumers can have confidence that **Recommendation 2** and **Recommendation 3** can be delivered in a way that maximises consumer benefits.

These observations are important directions for future reform. They are presented to inform the ongoing work of jurisdictions, regulators and policy makers, and ensure that the foundational market reforms proposed in this review are matched by complementary actions to support a simple, fair and consumer-focused energy system.



Observation 1: Consider supporting the development of simple, multi-year fixed price retail contracts

The Panel has recommended reforms which would improve long-term wholesale price transparency and enable retailers to purchase longer-term wholesale electricity services contracts in the NEM. Retailers would then be well placed to offer multi-year fixed retail offers to those electricity consumers who would value them. This would protect consumers from volatility and deliver more predictable bills.

While some consumers value flexibility, the Panel has heard from a range of stakeholders that many consumers highly value simplicity, predictability and affordability in their electricity bills. There may be value in, and appetite for, reforms that build on the recommendations put forward by the Panel to better support these consumer preferences for longer-term pricing.

To support these preferences, the Panel observes the following:

- The Australian Energy Regulator (AER) could publish benchmark cost stacks via the Energy Made Easy website, up to five years ahead. These would guide retail offers and help consumers make informed decisions about entering fixed-priced energy contracts that smooth intra- and inter-year volatility.
- Jurisdictions could consider removing regulatory barriers that prevent retailers charging reasonable and cost reflective early exit fees (that reflect the cost to the retailer of hedging risk on behalf of the customer) for consumers who enter into a multi-year contract at a fixed price and then seek to exit the contract before its expiration.

Taken together, these reforms could allow for stable, longer-term prices for consumers that reflect underlying costs, without the volatility and variability associated with an increasingly weather dependent system.

Retailers are facing new risks in managing customer load

Retailers play a crucial risk management role in the NEM, ensuring they have adequate bulk energy generation, shaping and firming resources to meet the demand of their customer portfolios over time. This is typically achieved by purchasing a mix of derivative contracts with electricity generators and, in some cases, use of their own generation resources (vertical integration).

Retail risk management in the NEM is becoming more complex due to rising volatility and variability in the wholesale spot market, driven by several factors including the following:

- Traditional sources of dispatchable generation are being replaced by weather dependent generation resources that can experience fluctuations. In some cases, these fluctuations can be prolonged, such as renewable energy droughts.
- Outages and unreliability associated with ageing coal plants are contributing to market instability as these plants gradually exit the market.

- International gas price variability and its impact on the costs of operating gas fired electricity generation.
- The growing adoption of behind-the-meter, weather dependent and energy limited resources.
- Increasing demand from electrification and the potential for renewable shortages to coincide with high system demand.
- The impact of extreme weather events straining the electricity system.

Without reform through the recommendations outlined in the previous chapters, the Panel is concerned that liquidity, price transparency and access to hedging contracts for retailers may decline.

Consumers should have access to multi-year fixed price contracts and pricing information

The recommendations in the previous chapters should facilitate the trading of risk management products for longer periods into the future. The market making obligation (**Recommendation 6**) and implementation of the ESEM (**Recommendation 8**) could extend price transparency over decadal timeframes. With wholesale price transparency in place and a liquid derivatives market facilitating access to longer-dated risk management products, retailers should be well positioned to offer multi-year fixed-price contracts to electricity consumers. Multi-year fixed-price contracts would help to deliver more predictable and stable electricity bills for electricity consumers.

The Panel notes that consumers should not be required to enter multi-year fixed-price contracts. Rather, consumers should be given the option to take up multi-year offers subject to their own personal circumstances. For the reasons outlined below, this would also require changes to early exit fee restrictions within existing consumer protection frameworks.

Most consumers want simple price offers and predictable bills

Consumers have diverse preferences about how they manage their electricity consumption and the products and behind-the-meter services that they wish to purchase from their retailer. This diversity is also influenced by new CER technologies and aggregation services that enable consumers to benefit from both self-consumption of electricity and exports to the grid. Electricity consumers are not homogenous:

“

Any conversation on activating consumer participation in energy markets must begin by recognising the immense variation in energy consumers. This is common to both households and commercial and industrial energy consumers. While there is a minority of ‘prosumers’ who are highly engaged and are willing and able to adjust their consumption to respond to spot prices, most energy users are more concerned with the services energy provides (a cool house, a hot meal, a productive factory, etc). – Energy Efficiency Council³¹⁹

”

The Panel has heard that most consumers want simple, reliable and affordable electricity services. The January 2025 Energy Consumers Australia Energy Report Card ‘Consumer knowledge of electricity pricing and responsiveness to price signals’ indicates that, based on a survey approach, 54% of consumers prefer a basic relationship with the energy system, seeking a simple and reliable electricity

³¹⁹ Energy Efficiency Council (2025), [Submission to the initial NEM Review consultation](#).

service at a reasonable price. The report card also indicates that many solar rooftop owners are passive, with 46% of those consumers seeking only basic engagement.³²⁰

Relatedly, the Australian Competition and Consumer Commission's (ACCC) December 2024 Inquiry into the NEM indicates that consumer switching activity remains low at around 20% each year and that 81% cent of consumers could be on a better offer at that point in time.³²¹ This suggests that many consumers are failing to switch even if there are better offers available.

Stakeholders have also indicated that most consumers want simple, actionable tariffs and predictable bills. For example, in its submission to this review AGL stated:

“

AGL's view is that retail and network tariffs should be simple, actionable and fair:

- *Simple so that customers can understand and engage with the tariff*
- *Actionable so that a customer (or their agent) can respond effectively to capture the benefits*
- *Fair so that the tariff is not punitive for a customer who can't respond.*³²²

”

Similarly, Energy Australia has indicated:

“

*Our customers expect a secure, reliable and affordable electricity supply as the power system undergoes the transition to cleaner energy. It is also clear that customers want predictable prices and energy bills which do not result in continuous bill shock.*³²³

”

By contrast, the Energy Consumers Australia report card indicates that approximately 46% of consumers want a more active relationship with the market, including access to choice of tariffs, being able to monitor and adjust their usage throughout the day to save money and the choice to store or export energy to the grid.³²⁴ Whilst these consumers may be more engaged it is also important that tariff offerings are easy to understand:

“

The signals that end-consumers face need to be sufficiently simple so they can meaningfully respond and invest in CER, and this will involve both price and non-price signals.

– Australian Energy Market Commission (AEMC)³²⁵

”

Access to benchmark price information over multi-year horizons will benefit consumers

Stakeholders have indicated that many consumers would prefer stable and predictable electricity bills. **Recommendation 6** will better facilitate longer-term risk management on behalf of consumers.

³²⁰ Energy Efficiency Council (2025), [Submission to the initial NEM Review consultation](#).

³²¹ ACCC (2024), [Inquiry into the National Electricity Market report](#).

³²² AGL (2025), [Submission to the initial NEM Review consultation](#), p 11-12.

³²³ EnergyAustralia (2025), [Submission to the initial NEM Review consultation](#), p 2.

³²⁴ Energy Efficiency Council (2025), [Consumer knowledge of electricity pricing and responsiveness to price signals – Consumer Energy Report Card January 2025](#).

³²⁵ AEMC (2025), [Submission to the initial NEM Review consultation](#), p 41.

To maximise the benefits of this recommendation, electricity consumers would stand to gain from having access to longer-term or multi-year contracts that mitigate the impacts of wholesale market volatility. Under the framework outlined below, these multi-year contracts could be offered on a simple fixed-price basis through a retailer service (or subscription) fee specifying a simple price amount expressed in dollars. However, at present, customer contracting for retail services largely occurs through short term retail contracts, with retail prices changing on an annual basis creating complexity and year-on-year volatility for consumers.

Under the existing framework the annual Default Market Offer (DMO) sets a maximum benchmark price that retailers can charge consumers on standing offer contracts. This price serves as a retail reference price against which retail market offers can be compared. As a result, consumers have limited information on future retail prices beyond the annual timeframe of the DMO. This lack of information hinders their ability to assess whether a longer-term fixed-price contract extending beyond one year could be suitable for their personal circumstances.

Default Market Offer (DMO)

The DMO was introduced in 2019 and is the maximum price that retailers can charge electricity consumers on default contracts known as standing offer contracts. It is an electricity price ‘safety net’ protecting consumers from unjustifiably high prices, while also allowing retailers to recover costs.

The DMO price determination applies to residential and small business consumers in New South Wales, south-east Queensland and South Australia.

The DMO prices for each region also act as a ‘reference price’ for residential and small business offers in that area. When advertising or promoting market offer pricing, retailers must show the price of their offer in comparison to the DMO/reference price. This assists consumers when comparing the price of different market offers.

The AER’s role is to determine DMO prices annually. The DMO for 2025–26 is the seventh time the AER has determined DMO prices and so is referred to as DMO7.

The DMO framework is currently being reviewed by the Australian Government. As part of this review, the Australian Government’s Department of Climate Change, Energy, the Environment and Water (DCCEEW) released a consultation paper on potential reforms to the objectives and methodology underpinning the DMO.³²⁶

Regulated retail electricity prices apply in regional Queensland, the Australian Capital Territory and Tasmania due to limited retail electricity competition.

Throughout the Panel’s consultation process, stakeholders have indicated that many consumers want simple and predictable billing arrangements. Without reforms that allow consumers to lock in wholesale prices over a longer period, consumers may be exposed to significant variability in their electricity bills caused by future wholesale market price volatility. To address this, the publication of transparent multi-year cost benchmarks may help electricity consumers contract for longer periods

³²⁶ DCCEEW (June 2025), [Consultation paper](#).

providing them with greater certainty over their future electricity bills. This would allow, but not compel, consumers to choose to enter into longer-term contracts.

Jurisdictions could consider establishing non-binding electricity cost benchmarks published for periods of up to five years. The benchmark wholesale costs could be developed by the AER utilising the trading data of the standardised contracts developed through the market making obligation process and published on the Energy Made Easy website. The published cost benchmarks would also incorporate forecasts of network costs in addition to the wholesale cost benchmark. Retailers would then compete on the additional service fee charged to deliver the wholesale and network outcomes published by the AER.

Consumers would be able to view the cost benchmarks and service fees over both a short-term to multi-year horizon on the Energy Made Easy website. This would enable consumers to compare different retailer service fee offerings. For example, the cost benchmarks and service fee prices could be available on a monthly, quarterly and yearly basis, with annual prices published for one to five years ahead. These prices would help inform consumer decisions on whether a short-term variable or multi-year fixed-term electricity contract is more suitable for their circumstances.

Price discovery through multi-year retail price benchmarks would complement, rather than replace, the DMO. The DMO would remain as the annually-updated cap on regulated standing offers and the reference price for market offers. Longer-term retail price benchmarks would help consumers assess multi-year contracts. Such a framework could be similar to how consumers in the banking sector access both long- and short-term interest rate information to decide whether to enter a fixed or variable interest rate home loan.

As illustrated below, consumer access to fixed interest rate loans in the financial services sector enables consumers to mitigate future interest rate variations and achieve more stable repayments they have budgeted for. In the case of electricity, consumers could also avoid significant electricity bill variability associated with wholesale market volatility by locking in a multi-year fixed-price deal with their retailer.

Fixed and variable rate home loans analogy

To better understand the advantages associated with longer-term electricity contracts, a comparison can be made to fixed and variable rate home loans.

Home loans

A fixed rate home loan maintains the same interest rate for the duration of the fixed term. A variable rate home loan interest rate fluctuates with a number of factors, including in part the official cash rate set by the Reserve Bank of Australia as well as higher or lower funding costs for the lender.

The main advantage of a fixed interest rate loan is certainty; a customer can lock in or 'fix' their interest rate for a set period (typically one to five years). In contrast, the main advantage of a variable rate home loan is flexibility. Customers can pay off their home loan sooner by maintaining their repayments if interest rates fall. However, if interest rates rise, the customer's lender may increase the cost of repayments.

Energy bills

Multi-year fixed-term energy contracts (e.g. three or five year) could provide additional choice for consumers that value certainty and predictability over flexibility. Consumers would weigh the pros and cons of both options, drawing on information from retailers and using Energy Made Easy.

There are international examples of price comparison sites that offer longer-term retail energy contracts. One example is the PA Power Switch website which is the official switching website of the Pennsylvania Public Utility Commission. This website includes retail offers with varying terms including short term (three to six months) and longer term (12, 24 and 36 months).³²⁷

Retail cost benchmarks would promote competition between retailers

Benchmark costs could be published by the AER as a 'cost stack' including network, wholesale and government scheme cost components, supplemented by a simple service (or subscription) fee expressed in dollar or percentage terms set by each retailer.

In practice, the benchmark wholesale costs for each NEM region would be informed by longer-term forward wholesale pricing achieved through the improvements to liquidity and price transparency delivered by the Panel's wholesale market recommendations.

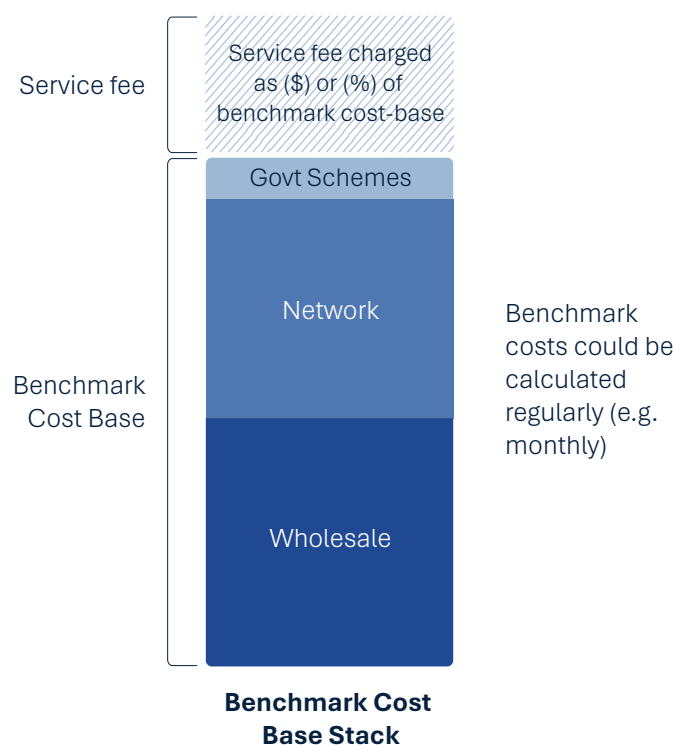
In terms of the network component, the transmission and distribution network costs could be informed by network Tariff Structure Statements which are approved by the AER every five years and aligned with network reset periods. However, network expenditure forecasts would be needed for benchmark periods that cross over five-year network revenue reset periods. Overall, the five-year regulatory reset period for networks, coupled with revenue smoothing across periods, could provide a basis for longer-term price transparency in networks costs, whilst also acknowledging that revenue adjustments occur between resets.

Retailers would have the flexibility to set their own service fees that could be published through the Energy Made Easy website. These fees would take the form of a simple price amount expressed in dollars or percentage terms, allowing consumers to compare different retailer service fees in choosing a retail offer. Service fees may vary across retailers as each will have different cost structures for delivering core retail services including risk management services and billing. Such an approach would ultimately help consumers identify those retailers who perform better in delivering their services as consumers are likely to choose a retailer with a lower service fee. This benchmarking approach could benefit consumers by simplifying choice between competing offers, thus fostering competition and promoting efficient provision of electricity services within the retail sector. This approach could apply in the jurisdictions with retail competition but would not be required in regions where electricity prices are regulated, such as regional Queensland, Tasmania and the Australian Capital Territory.

The benchmark and service fee approach is illustrated further in Benchmark and service fee approach (illustrative only).

³²⁷ www.papowerswitch.com

Figure 53 – Benchmark and service fee approach (illustrative only)



Benchmark costs and service fees would be simple to understand for those seeking minimal engagement

The Panel is conscious that most consumers prefer simple, easy to understand and predictable electricity prices and bills – a simple price for a simple service.

The energy sector is already highly complex and can sometimes be difficult for consumers to navigate effectively. These complexities have prompted recent reforms, including the AER's Better Bill Guidelines, which seek to simplify billing processes. The AEMC is also reviewing consumer pricing through its Electricity Pricing for a Consumer-Driven Future review. The AEMC's review is examining the critical role that electricity pricing, products and services will play in meeting the diverse needs of consumers, including enabling the use of CER that households and businesses are increasingly adopting as part of the energy transition.

The risks and challenges consumers face when navigating the market's complexities are also highlighted in Dr Ron Ben-David's proposal for the AEMC to consider an inner and outer market in his response to the AEMC's Pricing Review consultation paper.³²⁸ The concept of a benchmark cost and retailer service fee, combined with an obligation for retailers to offer multi-year fixed price contracts, aligns with the 'inner' or 'safe harbour' concept suggested by Dr Ben-David and provides consumers with a straightforward price offer.

³²⁸ R Ben-David (2024), [Submission to AEMC consultation paper: 'The pricing review – Electricity pricing for a consumer-driven future'](#), Monash Energy Institute.

An inner and outer market for electricity consumers

In his submissions to the AEMC's Electricity Pricing for a Consumer-Driven Future, Dr Ron Ben-David highlights that consumers possess varying levels of risk appetite and proficiency when it comes to participating in – particularly contracting within – the increasingly complex and risky electricity market. He urges the AEMC to adopt, as a key objective, the avoidance of exposing consumers to risks they are ill equipped to understand, manage or appropriately price.

In line with this objective, market and regulatory design should differentiate between an **'inner'** and **'outer'** consumer energy market:

- The inner market would act as a 'safe harbour', shielding consumers from risks and costs they are ill-equipped to understand, navigate or manage. Prices in this market would be governed by clear policy and regulatory principles.
- The outer market would be a space for consumers who choose to actively participate in the broader energy market by trading their consumption, production and/or storage. These consumers would accept greater risks and benefits, with minimal regulatory oversight.

Dr Ben-David also calls for a statutory consumer duty in the outer market such that energy service providers should be required to make reasonable endeavours to act in the best interests of consumers when offering or delivering contractual services.

The Panel considers that there is significant merit in Dr Ben-David's proposed approach. As the energy transition progresses, price signals are expected to increasingly become volatile and variable, fundamentally reshaping how market participants manage and hedge short-term wholesale price risks. Derivatives markets must evolve to meet the diverse hedging needs of generators – from bulk energy to shaping and firming services – as well as the varying demand profiles and risk exposures faced by retailers and consumers. To sustain public support for the transition, consumers must have access to contracts that align with their individual risk appetite and proficiency in navigating market complexity.

The simple transparent benchmark cost model described above could form the basis of the inner market envisioned by Dr Ben-David.

Source: Dr Ron Ben-David, Monash Energy Institute, Submission to AEMC Pricing Review Consultation paper, December 2024.

Simple transparent benchmark prices that include a retail service fee could provide a simple option for largely passive consumers that seek a basic electricity service. A simple benchmark pricing framework also avoids exposure to the risks around more complex retail products and services, which some consumers may not be able to understand, manage or price.

However, benchmark offer arrangements may not be suited to those consumers wanting more active engagement with the market including consumers who wish to enter into price responsive aggregation services or virtual power plant (VPP) arrangements – these involve more complex products and services, and control of CER devices. As such, these services are more likely to be suited to consumers with a higher risk appetite and proficiency in understanding the implications associated with third party control of devices. Consistent with Dr Ron Ben-David's observations, these consumers could be subject to less prescriptive regulation and covered by the overarching statutory duty originally

put forward by the AER that the energy service provider act in the best interests of the consumer. This is discussed further below in **Observation 4**.

There is a range of barriers to retailers offering longer-term contracts to electricity consumers, which in turn prevents consumers accessing the benefits of more stable pricing and predictable billing

Currently there are numerous restrictions on retailers applying early exit fees to consumers under the National Electricity Customer Framework (NECF).

Under clause 49A of the National Energy Retail Rules retailers can apply an early termination charge to a fixed-term retail contract provided that:

- the contract includes details of the amount or manner of calculation of the charge
- the charge is a reasonable estimate of the costs to the retailer resulting from the early termination – however, this cannot include costs based on “lost supply or lost profits”.

Similarly, several NEM jurisdictions have also imposed similar restrictions on the ability of retailers to charge cost reflective and reasonable exit fees which may prevent the ability of retailers to impose such fees where a consumer seeks to enter a multi-year contract at a fixed price.

The Panel observes that the restriction in clause 49A prevents a retailer from recovering the costs based on lost supply or lost profit. In practical terms, this means a retailer cannot recover a proportion of the costs associated with any derivative contract for wholesale electricity services that it may have entered on behalf of that departing consumer, as part of its risk management role.

Overall, the restrictions may therefore prevent retailers from being able to recover the costs of entering long-term contracts for bulk energy, shaping and firming services under the Panel’s proposed arrangements. This in turn creates an indirect barrier to retailers contracting to secure longer-term investment in generation and storage to support the energy transition and to consumers being able to enter multi-year fixed-price contracts.

Energy ministers could consider reviewing these arrangements to enable more flexibility. The objective of this review would be to ensure consumers could (should they wish) enter multi-year fixed-price contracts to protect themselves from future market volatility and variability in an increasingly weather dependent system.

Relatedly, energy ministers could consider whether existing consumer protection arrangements are preventing the offer of multi-year contracts, and effectively supporting consumers in deciding whether to enter into a multi-year fixed-price arrangement with their retailer. This includes ensuring that consumers are provided with the correct information to understand the risks and trade-offs associated with entering into these multi-year contracts and that contract outcomes align with a consumer’s interests.

For those regions where electricity retail prices are regulated (namely, the Australian Capital Territory, Tasmania and regional Queensland), jurisdictional regulators may wish to consider whether a form of regulation (including a regulated exit fee) is required that would enable the consumer to agree a multi-year fixed-price contract and which would ensure that any exit fee is cost reflective and efficient.

Observation 2: Consider reforming network tariff structures to ensure they are more equitable and better aligned with wholesale market dynamics

The Panel has noted the very significant benefits that accrue from the deployment of CER.

Recommendation 2 is designed to ensure that the maximum benefit can be obtained from this deployment for all consumers. The Panel notes that in the long term it will be important that economic signals from the wholesale market and network tariff design combine to maximise consumer benefits.

Continued use of volumetric network tariffs (including time-of-use volumetric tariffs) could result in some consumers avoiding contributing proportionately to network investment costs. This creates equity concerns, as consumers without CER, particularly those experiencing vulnerability, may bear a greater share of network costs. Such outcomes may intensify as the uptake of household battery storage grows.

To address this growing trend, the Panel observes that through its pricing review the AEMC could prioritise reforms that:

- Transition away from volumetric tariffs to other network tariffs with a higher fixed component. This would help ensure a fairer allocation of network costs across all consumer types and support the availability of simple multi-year fixed-price retail offers as outlined in **Observation 1**, leveraging **Recommendation 6** and **Recommendation 8**.
- Require distribution businesses to offer dynamic (cost reflective) network tariffs for price responsive and participative consumers (through their retailer), particularly those participating in CER aggregation. This would support more efficient market engagement for consumers capable and willing to respond to price signals.

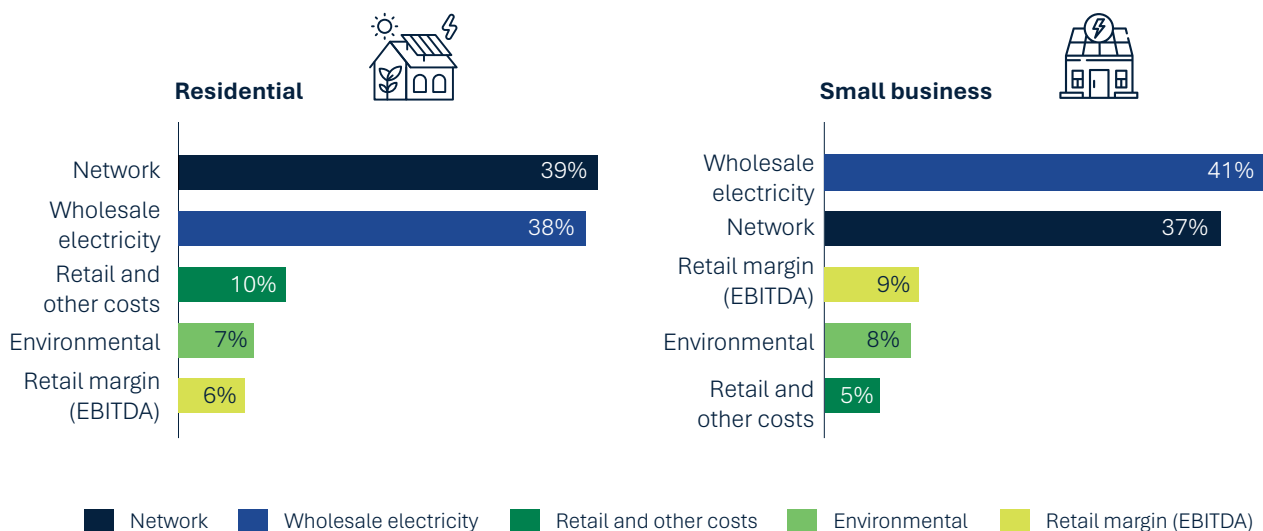
Network tariffs make up a large share of consumer bills

The cost of network services form a key component of consumer bills. These include the costs of building and operating electricity networks and providing a return on capital deployed. Across the NEM, distribution costs are the largest component of network costs, followed by transmission costs.³²⁹

Figure 54 provides an estimated cost breakdown of residential and small business electricity bills for 2023–24, showing that network costs comprise close to 40% of the bill for residential and small business consumers.

³²⁹ AER (2024), [State of the Energy Market Report](#), p 244.

Figure 54 – Cost breakdown of residential and small business electricity bills for 2023–24



Source: AEMC graphic (Discussion paper, *The pricing review*, AEMC, June 2025, p17) based on ACCC analysis and graphic set out in the ACCC, *Electricity Inquiry report* of December 2024.

Network businesses are monopolies regulated by the AER via a network reset process that establishes revenue caps for each network across a five year period. Under this process the AER also assesses and approves network pricing proposals from network businesses through Tariff Structure Statements, which also extend over a five-year period.

The AEMC has recently noted that 62% of consumers are on flat volumetric network tariffs with the same price applied to per unit of energy consumption (MWh) of electricity across the day, whilst 21% are on time-of-use network tariffs (where the volumetric rate changes over the day) and the remaining 17% on demand tariffs. Demand tariffs or charges are based on the maximum power used within a specified period.³³⁰

Network tariffs are designed to recover the costs of network infrastructure that has already been built, whilst also signalling to network users the costs associated with future investment. The Network Pricing Objective set out in clause 6.18.5(a) of the National Electricity Rules (NER) provides that the network tariff for a service should reflect the efficient costs of providing the service to a retailer. The NER also sets out the Network Pricing Principles, which include that each tariff must be based on the long-run marginal cost of providing the service to the retail consumers assigned to that tariff, and recover total efficient costs and expected revenue in a way that minimises distortions to price signals for efficient usage.³³¹

Retailers mediate tariff signals, shaping how consumers respond to network costs

The setting of distribution network tariffs can have important impacts on how consumers use their electricity, including how the owners of CER assets optimise these assets either through self-consumption or through access to aggregation services such as VPPs. Put simply, it is the combination of wholesale market signals and network tariffs that drive participant behaviour.

³³⁰ AEMC (2025), [Discussion Paper: The Pricing Review](#), p 54–55.

³³¹ Energy Efficiency Council (2025), [Consumer knowledge of electricity pricing and responsiveness to price signals – Consumer Energy Report Card January 2025](#)

The extent to which network tariff structures are reflected in retail prices is determined by a consumer's retailer. A retailer may choose to pass through these signals directly to the consumer via their retail offer or choose to adjust the signal or not pass it through.

In this sense both the setting of network tariffs and the extent to which they are reflected (in addition to wholesale costs) in retail prices for consumers, will impact consumer behaviour and particularly the use of CER assets including solar PV and battery storage. In turn, these behaviours and the way in which CER is deployed can impact on the dynamics of the wholesale market. Network tariffs, wholesale prices and wholesale market participation opportunities come together in retail price and service offers to shape consumers' overall demand (including their use of and investment in CER) over time.

As outlined in **Recommendation 2** in Ensuring effective operation of the spot market the Panel is recommending measures are taken to increase visibility of aggregated CER exports in the NEM, particularly as take up of household battery storage increases. The Panel however also has observations on how the structure of network tariffs can influence wholesale market outcomes and how more efficient outcomes could be achieved through increased alignment across networks and wholesale markets. These observations are set out further below.

Network tariffs have evolved towards greater time-of-use based differentiation

Australia's record uptake of household solar PV has resulted in very low grid demand in the middle of the day. However, households and businesses have much greater demands on the grid during morning and evening peak demand periods and overnight. Historical growth in evening peak demand has required networks to invest in expanding the capacity of the system. The costs of these investments are recovered through network charges.

The use of flat volumetric charges has obvious shortcomings given these market dynamics. Networks are therefore increasingly offering time-of-use tariffs including 'solar sponge' and export reward tariffs that encourage consumers to consume more electricity when overall demand on the system is low and consume less when overall demand on the system is high. Tariffs such as these can help smooth demand throughout the day, reducing the peaks which can drive investment costs.

The AER promotes collaboration between networks, retailers and consumers on trials of new and innovative network tariffs to develop ways to incentivise consumption when demand is low and disincentivise consumption when demand is high. An example of this type of trial is SA Power Networks residential 'electrify' trial with a targeted peak window and solar sponge designed to encourage consumers with flexible load and solar PV to shift electricity use to during the day or overnight.

Some distribution networks are also using demand tariffs to recover network costs. As noted above, these charges are based on the maximum power used by a consumer within a specified time period. The AER has recently issued a decision on the tariff structure statements for the Ergon and Energex distribution businesses in Queensland, which approved both its demand tariffs and time-of-use tariffs for household and small business customers but required these distributors to change the default network tariff assignment for those customers away from demand tariffs and onto time-of-use tariffs. In making these decisions the AER has indicated that many retail customers may be unable to respond to or mitigate the impact of demand tariffs because they do not understand them.

The AER has referred to ACCC Electricity Inquiry Report (December 2024) findings that approximately 51% of customers with demand retail offers were paying prices at or above the Default Market Offer (DMO), compared to 38% of customers on the flat rate and 27% on time-of-use tariffs.³³²

The AEMC's pricing review is considering network and retail tariffs, how these interact and how they can operate together to facilitate the design and offering of electricity products and services for consumers through the energy transition, including through enabling CER. The AEMC has recently published a discussion paper on the review (discussed further below) and is due to deliver a final report on the review in early 2026.

Network tariffs should drive efficient utilisation of network capacity

The Panel notes that there are significant interlinkages between wholesale prices and network tariffs and retail pricing. Network tariffs and retail pricing can play a key role in determining price signals for end consumers.

Overall, the Panel notes broad agreement amongst stakeholders that the combination of wholesale market settings and network tariffs should drive efficient utilisation of electricity infrastructure. Network tariffs should provide effective signals to retailers (and ultimately consumers) that can help drive network efficiency. Specifically, if designed correctly these tariffs and the way they are reflected in retail offers can shape consumer behaviour in a way that can reduce or avoid inefficient future network investment, the costs of which are borne by consumers. The ability of network tariffs to shape consumer behaviour is also critically dependent on the characteristics of the consumers who are facing these price signals including their ability and willingness to modify their electricity consumption patterns.

In addition, stakeholders have noted that network tariffs should encourage a fair and equitable sharing of the costs of the network among electricity consumers including both those who own and do not own CER assets.³³³

The Panel notes the recent position of the AEMC as set out in its March 2025 updated Final Guidelines on the National Energy Objectives that achieving equitable outcomes “is essential for building and maintaining the social licence that is necessary to enable a timely and least cost transition”.³³⁴

Today's network tariffs may conflict with wholesale market signals

Whilst progress has been made on tariff reform, the Panel notes that the generalised signals provided by volumetric long-run marginal cost-based time-of-use network tariffs (for example, with network-wide peak time periods) may be misaligned with the costs of building the network to meet peak demand. In particular, as greater uptake of behind the meter batteries occurs, many households will have a much lower overall consumption (including during many peak periods) but will still use the grid almost entirely on the largest peak demand days. Except for targeted investments to increase ‘hosting capacity’ for CER (which can now be funded through export charges), the majority of network augmentation is driven by meeting peak demand rather than supporting CER exports.

³³² ER (2025), [Final Decision Attachment 19 - Tariff structure statement - Ergon Energy and Energex - 2025-30 Distribution determination revenue proposal - April 2025](#), p 17-18.

³³³ The AEMC makes similar observations regarding network tariffs and equity in their ‘[Pricing Review Discussion paper](#)’, p 54.

³³⁴ AEMC (2025), [How the National Energy Objectives shape our decisions](#), p 10.

The combination of responsive CER technologies and aggregation services effectively enables these resources and services to inject or withdraw electricity into the grid in very short response times, and the Panel is concerned that generalised and broad long-run marginal cost volumetric tariffs may ultimately impede the integration of these resources into the NEM, at a cost to consumers. For example, a time-of-use tariff with a broad peak period could capture times of low wholesale prices without reflecting actual network constraints. If the high network tariff is passed through, it could constrain a household's ability to charge a battery or to consume electricity when this may otherwise help to increase demand on the electricity system at a time of negative wholesale prices.

An example of the problems associated with misaligned network tariffs is set out in the AEMC's recent June 2025 pricing review paper. In this paper the AEMC notes:

“

*Current network tariffs can conflict with the wholesale market signal. Where the network signal is accurate and effective, this is not necessarily problematic and consumers who choose to engage can respond to the more valuable signal. Consumers may currently, however, be receiving network signals that get in the way of wholesale market engagement without necessarily reducing network costs.*³³⁵

”

The Panel considers that the cost drivers of wholesale pricing and distribution networks are generally likely to align. Specifically, the Panel expects that at times of the day when electricity demand is high compared to available supply (reflected in higher wholesale prices), distribution networks are also likely to be constrained due to limited import capacity. This also means that the need for network augmentations is likely to align with periods of wholesale energy market scarcity and higher wholesale prices, which are more likely to occur during evening peak demand.

This does not mean that network tariffs signals must 'give way' to wholesale price signals. Where there are genuine local constraints on the distribution network (both import and export constraints) that restrict retailers and consumers from accessing the wholesale market, these could be signalled through dynamic network tariffs³³⁶ and dynamic operating envelopes. The Panel notes that several stakeholders commented that dynamic network signals that are more responsive to real time changes in the wholesale market can deliver important benefits by better enabling CER participation through aggregation services. In this context, Ausgrid is currently undertaking a trial, Project Edith, which involves the application of dynamic near-real-time price signals in relation to VPPs and their customers.³³⁷

Network tariffs may be preventing efficient utilisation of the network and creating inequitable outcomes for consumers

Recent AER analysis in its September 2024 Electricity and Gas Networks Performance Report, suggests that the capacity of the distribution networks is under-utilised (see **Figure 55**).

³³⁵ AEMC (2025), [Discussion Paper: The Pricing Review](#), p 59.

³³⁶ A dynamic network tariff provides for network prices to change across five minute periods (aligned with the NEM wholesale market) reflecting network conditions at these times in specific locations. These tariffs are currently being explored through Ausgrid's Project Edith trial.

³³⁷ Submissions that comment on the benefits of dynamic network tariffs and real time signals include: [Submissions to the initial NEM Review Consultation](#) from Origin (p 28), Reposit Power (p 6) and Ausgrid (p 6), and [Submission to the AEMC Consultation Paper on Improving the NEM Access Standards](#) (Package 2) from Ausgrid (p 6).

The Panel observes that network prices that do not reflect under-utilisation of network capacity at a distribution level may be impeding efficient wholesale electricity market outcomes for consumers: The AER has indicated that...

“

*Low utilisation (i.e., high spare capacity) means a network can service large increases in peak demand. However, low utilisation may also mean customers are paying for network assets they rarely use, questioning whether the capex investment was an efficient cost.*³³⁸

”

The AER’s Electricity and Gas Networks Performance Report also states that:

“

*Zone substation transformer capacity, maximum demand and utilisation have all been relatively flat since 2014, which coincides with a steep decrease in augmentation expenditure.*³³⁹

”

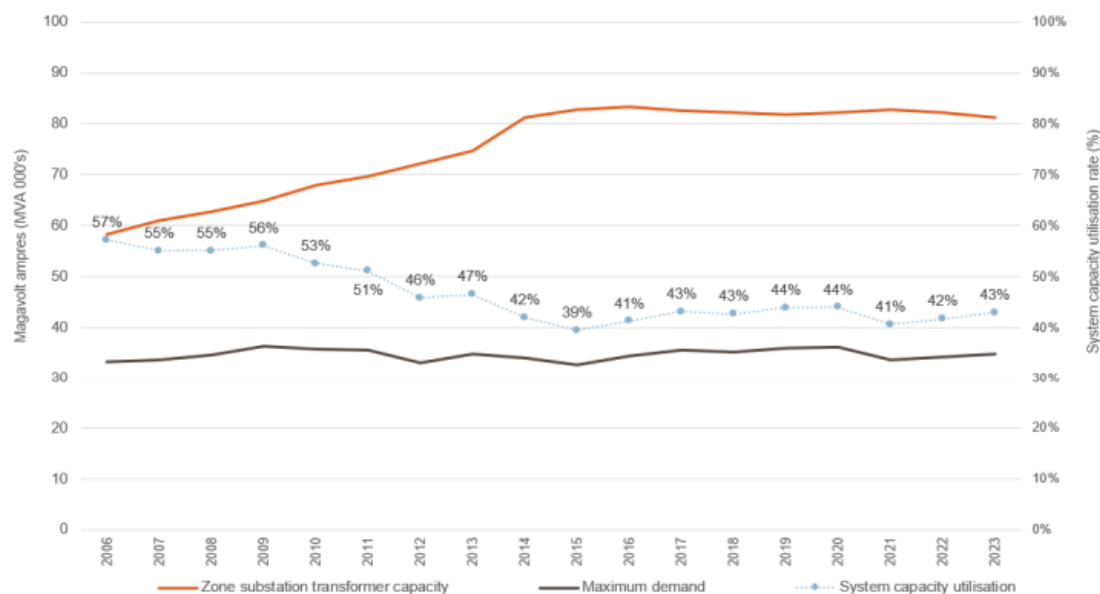
As a qualifier to the above observations, the Panel notes the AER’s September 2024 *Electricity and Gas Networks Performance Report* does not reflect localised constraints from exports from solar photovoltaic (PV) systems. These constraints are becoming more prevalent as more consumers install solar PV systems, requiring DNSPs to possibly limit CER being exported into the grid to protect network assets.³⁴⁰

³³⁸ AER (2024), [Electricity and Gas Networks Performance Report](#), p 41-42.

³³⁹ Ibid.

³⁴⁰ Ibid.

Figure 55 – Network utilisation by DNSPs



Source: Electricity and Gas Networks Performance report, September 2024, p42

Drawing upon AER and AEMC analysis and stakeholder feedback, the Panel notes that existing network tariff signals are blunt and not aligned with wholesale pricing signals to deliver least cost electricity outcomes for consumers. In particular, existing long-run marginal cost approaches to developing demand tariffs and time varying volumetric tariffs may not be sufficiently targeted or granular and may instead be dis-incentivising usage of electricity at times when network capacity is not congested or constrained. The Panel recognises that this depends on whether tariffs such as these are presented to consumers with options to adjust behaviour by their retailer (e.g. CER deployment).

Broadly the Panel notes three issues raised by stakeholders through the review in relation to volumetric long-run marginal cost tariffs:

- Generalised volumetric long-run marginal cost time varying tariffs may constrain the use of spare distribution network capacity at times when either more supply or consumption is needed in the wholesale market.** Without reform, this could exacerbate wholesale market volatility in an increasingly weather-based energy system. These effects are dependent on the extent to which these tariffs are accompanied by retail contracts and technology options (e.g. solar PV, BESS etc).
- Volumetric time varying tariffs based on long-run marginal cost are sending generalised and broad network investment signals to retailers and consumers that may not relate to those parts of the network where investment is required either now or in the future.** In practical terms, this means that network pricing signals are being used to modify behaviour when it is not necessary to do so as the network, or that part of the network is unconstrained. The use of CER with accompanying dynamic network tariffs and dynamic operating envelopes is seen as a key way of overcoming this.
- Volumetric tariffs enable self-consuming owners of CER to avoid paying for the use of the grid, whilst other non-CER owning consumers pay for the network.** Stakeholders have expressed concern that these effects will become greater as household battery storage ownership increases. Without reform of network tariff methodologies, the existing arrangements are likely to have significant fairness and equity implications. The Panel notes that similar

concerns have been raised in the AEMC's Discussion paper on the Pricing Review. The AEMC has indicated that *“current network tariffs allow consumers, particularly those with CER to pay less for network services without necessarily contributing to reducing future network costs. This shifts costs onto other consumers, including the most vulnerable.”*³⁴¹

The above issues relating to network tariff implications for investment and operation of consumer energy resources are on top of the issues for medium-scale distributed energy resources discussed under **Recommendation 9G**. Ideally, these issues would be considered together so that network tariffs (as a whole across transmission and distribution) are encouraging efficient investment and operating decisions for large and small-scale resources. This is a precondition for fully realising the Panel's intended level playing field for different resources in the ESEM.

Retailers are responsible for managing network tariff risks for consumers

Retailers are responsible for managing network tariffs on behalf of consumers. Risk management is the core function of retailers and providing consumers with products and services that allow them to best respond to wholesale and network tariffs is critical to their value proposition.

In some cases, retailers may choose to pass on time-varying tariffs, whilst in other cases retailers may choose to translate network tariffs into simple retail offers whilst managing the network tariff risk themselves. Ultimately, it is the Panel's view that retailers should be responding to network tariffs by providing products and services to end use consumers that allow them to more efficiently use the network.

The Panel notes the AEMC's recent final determination on the Accelerating Smart Meter Deployment rule change which introduced consumer safeguards around the pass-through of cost reflective network tariffs upon deployment of a smart meter.³⁴² These include a requirement (applicable for two years) on retailers to obtain a consumer's consent before varying their retail prices (i.e. placing the customer on a cost-reflective tariff) following the installation of a smart meter. The rule also introduced a requirement that designated retailers must make flat tariff standing offers to consumers with a smart meter, subject to implementation by jurisdictions.

In its final determination the AEMC noted in relation to these reforms that retailers could take a portfolio approach in managing these reforms, choosing how to spread any costs across their customer base. The AEMC also stated it did “not consider that retailers will be uniformly worse off facing a network tariff that they cannot directly pass on to consumers. Whilst we acknowledge that retailer costs may increase for some customers, cost-reflective network tariffs will result in lower costs for other customers”.³⁴³

The AEMC's determination affirms that retailers have a role in managing network tariff risk on behalf of consumers, and that the application of cost reflective tariffs should not mean in practice that they need to be automatically passed through.

This is particularly important given that (as noted above) many consumers seek a simple retail offer and may not have the capacity, interest or capability to navigate more complex tariffs.

³⁴¹ AEMC (2025), [Discussion Paper: The Pricing Review](#), p 55.

³⁴² AEMC (2024), [National Electricity Amendment \(Accelerating Smart Meter Deployment\) Rule](#), p 32.

³⁴³ AEMC (2024), [National Electricity Amendment \(Accelerating Smart Meter Deployment\) Rule](#), p 32.

Simpler network tariffs for consumers and targeting network congestion

Approaches to tariff methodologies and the application of these methodologies are matters for both the AEMC in determining pricing objectives and principles and the AER through its decisions on proposed tariff structure statements. The observations on future network tariff reform set out in this chapter, and the views received from stakeholders to this draft report, could form an input into the AEMC's pricing review currently underway.

The Panel considers that there is merit in the AEMC considering:

- Moving towards more fixed-price structures for network tariffs, which could be translated into simple retail offers for the majority of electricity consumers that seek a simple price for a simple service. The Panel notes that in considering any move towards fixed rate tariffs it is important that the equity and distributional impacts are considered by policy makers.
- Simple retail offers could also be accessed by those CER owners that self-consume and who do not want to purchase aggregation-based services from retailers.
- By contrast consumers that purchase aggregation services (and for whom there is a greater understanding of and appetite for risk) would be assigned more dynamic and responsive network tariffs; for example, to reflect the forward-looking cost of investment to address local congestion in their network area.

Overall, where there are limited or highly localised constraints on distribution networks, it is arguable that these are priced through dynamic and/or critical peak pricing mechanisms. In addition, residual network costs that are unrelated to future network requirements could be recovered through a fixed charge rather than generalised use of time-of-use volumetric charges.

As noted above, further analysis would be required in relation to these high-level observations to determine appropriate network tariff methodologies for the medium and long term.



Observation 3: Consider updating the methodology for regulated retail price benchmarks (such as the DMO) to reflect the evolving nature of the derivatives market in the context of new contract structures and market making obligations

The current methodologies used to calculate the wholesale cost component of the DMO influences retailer hedging strategies in the NEM. Currently the AER relies on a book-build approach to determine hedging costs. The DMO approach is based on contracts purchased two to three years in advance. The Panel's recommendations in relation to market making and derivative contract structures (**Recommendation 6**) provide an opportunity to ensure that retail pricing methodologies are based on the most efficient hedging strategies.

The Panel observes that the AER could consider revisiting the DMO book-build methodology to incorporate emerging and longer-dated hedging instruments to reflect improved medium-term wholesale price transparency delivered through the Panel's contract structure and market making recommendation (**Recommendation 6**). Given the Panel's finding that the DMO methodology is a material driver of market retailer hedging strategies, adjusting the methodologies to reflect long- and medium-term price signals will assist retailers in offering stable, longer-term pricing for consumers

The Panel's recommendation for the AER to work with industry to ensure that contracts available to trade for the purpose of market making are forward looking and potentially longer dated should allow for the DMO methodology and any new retail benchmarking to evolve to suit the needs of an increasingly weather dependent volatile and variable market (**Recommendation 6**).

The Panel's recommendation to establish a market making obligation is aimed at lengthening the period over which derivative markets operate and creating transparent price signals. The obligation would be built around a standardised and fungible set of exchange traded contracts that meet retailers' and generators' changing risk management needs in a more weather-dependent, variable and volatile environment.

Given the DMO's influence on retailer hedging strategies, the AER may wish to consider revising their wholesale electricity cost methodologies to factor in these new contracts. This will help promote uptake and liquidity and ensure retailers and their customers capture the full benefits of these reforms.



Observation 4: Consider extending the National Energy Customer Framework to cover new energy services, including CER aggregation, and explore the introduction of an overarching consumer duty to protect customers engaging with more complex service offerings

The uptake of new energy services, including aggregation services, has the potential to deliver meaningful benefits to both individual consumers and the broader energy system. However, these new services are inherently complex and introduce new risks that may affect consumers' access to electricity as an essential service. Currently, such services fall outside the scope of the existing energy consumer protection framework, exposing consumers to potential harm. Without appropriate protections, poor consumer outcomes could erode trust, reduce engagement and ultimately hinder the widespread adoption of these innovations, to the detriment of all consumers.

The Panel observes that jurisdictions could prioritise work through the National CER Roadmap to address this regulatory gap by extending the National Energy Customer Framework to cover new energy services. This work should include consideration of an overarching consumer duty, requiring retailers and service providers to act in the best interests of consumers when offering or delivering new energy services.

Current protections do not adequately cover CER aggregation services

In Ensuring effective operation of the spot market, the Panel has made recommendations that will increase visibility of CER. Given the broader benefits of participation in the wholesale market, the Panel notes that many stakeholders expect a significant growth in the uptake of CER aggregation services. At present CER aggregation services sit outside the existing energy consumer protection frameworks, namely the National Energy Customer Framework. Instead, these services are covered solely by the Australian Consumer Law.

Many new energy services including aggregation and VPP products are complex and are becoming increasingly intertwined with the provision of electricity as an essential service. New energy and aggregation services involve customers handing some control over their CER assets to a third-party aggregator to optimise. In some circumstances this can lead to customer detriment if risks are not adequately explained upfront or where a customer contracts for a service that is not suited to their personal circumstances and which impacts negatively on the provision of electricity as an essential service. For example, a poorly designed and implemented product to control air conditioning assets may reduce the customer's ability to heat or cool their house at certain times of the day.

The AER has identified consumer harm risks in aggregation services

In 2022 the AER completed a review of the consumer protection arrangements governing new energy services and noted risks of harm to consumers around contracts, information provision, performance of services, control of assets, payment difficulty, dispute resolution and service provider conduct.³⁴⁴ In its review the AER concluded that the National Energy Customer Framework's energy-specific consumer protections should be updated to include new energy services including aggregation services. Effective energy-specific consumer protections that extend beyond the ACL would support consumer trust and confidence. This would in turn encourage the wider take-up and effective use of new technologies and changes in consumer behaviour, driving further innovation and realising the significant benefits that new energy services bring to the energy transition.

The AER also put forward the concept of establishing an overarching consumer duty that would apply to sellers of new energy services and which would require the seller to act in the best interests of the consumer. The introduction of an overarching consumer duty would ensure a focus on achieving favourable consumer outcomes, recognising the growing role that consumers are playing in the energy market. Support for the reform of energy consumer protection arrangements, including an overarching duty has also recently come from Energy Consumers Australia through its report on opportunities for CER participation in wholesale markets and grid services.

This report notes:

“

*Fit for purpose consumer engagement and protections will improve social licence through a more engaged customer base.... Consumer protection frameworks should evolve with the flexibility to account for the range of range of energy services available to consumers.*³⁴⁵

”

The Panel supports prioritising consumer protection reform to build trust and CER uptake

Governments are currently considering consumer protection reform for new energy services, including an overarching consumer duty, as part of the CER Roadmap.³⁴⁶

In March 2025 energy ministers initiated the Better Energy Customer Experience workstream to review the energy consumer protection frameworks. This work is being led by DCCEE in conjunction with state and territory government officials and will build upon the work undertaken by the AER. The workstream will aim to identify existing, emerging and potential future challenges in consumer protection settings and to assess whether the National Energy Customer Framework remains fit for purpose.

The work will develop reforms where required to ensure a smooth energy transition that supports consumers and the realisation of the benefits of the transition. In April 2025 DCCEE published an initial stakeholder consultation paper with a Directions paper due in December 2025 and

³⁴⁴ AER (2022), [Review of consumer protections for future energy services](#).

³⁴⁵ Energy Consumers Australia and Rennie Advisory (2025), [Opportunities for CER participation in wholesale markets and grid services, Final Summary Report](#), p 10.

³⁴⁶ Work on consumer protections reform forms is being undertaken under initiative C.1 of the CER Roadmap ('[National Consumer Energy Resources Roadmap](#)', [Energy and Climate Change Ministerial Council](#), 2024, p 14).

recommendations to Ministers in early 2027.³⁴⁷ The consultation paper also seeks views on the merits of a principles-based regulation and more specifically, an overarching consumer duty in addressing future unforeseen consumer risks. The Panel considers that reforms to the National Energy Customer Framework are needed to incorporate new energy services and should be prioritised by governments. The current arrangements may lead to poor consumer outcomes that lower trust and which therefore undermine take-up of new energy services.

³⁴⁷ Energy and Climate Change Ministerial Council (2025), [Better Energy Customer Experiences Consultation Paper](#).

Appendix A – Terms of Reference

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TERMS OF REFERENCE

Review of Market Settings in the National Electricity Market to Follow the Capacity Investment Scheme

1. This terms of reference sets out an expert panel-led review supported by the Commonwealth Department of Climate Change, Energy, Environment and Water (DCCEEW), into market settings to promote investment in firmed, renewable generation and storage capacity in the National Electricity Market (NEM) following the conclusion of Capacity Investment Scheme (CIS) tenders in 2027.
2. The expert panel will consist of a full time Chair and three part time panel members with a diversity and depth of expertise, supported by robust governance arrangements to deliver independent policy recommendations that are in the long-term interests of energy consumers and Australia.

Background

3. The NEM, under the National Electricity Objective (NEO), was created to deliver reliable, competitively priced, safe and secure electricity services in the long-term interests of consumers. As a power system and wholesale market, it was designed to centralise and efficiently dispatch existing generation and to incentivise new infrastructure through its spot, contract, and retail markets in order to provide electricity at least cost to consumers.
4. It is essential that wholesale market settings in the NEM support Australia's clean energy transition by providing effective signals to incentivise investment in the optimal mix of energy resources to meet future electricity demand. These energy resources include firmed renewable generation, storage, bulk variable renewable energy (VRE) and Consumer Energy Resources (CER), which are forecast by AEMO to compose upwards of 60 GW of dispatchable capacity in 2050.
5. The Commonwealth Government responded to the need for an acceleration of investment in firmed renewable energy to replace ageing thermal coal generation capacity by introducing the CIS. The CIS will support an additional 32GW of firmed renewable energy generation and storage, underpinning around \$74 billion in new investment nation-wide.
6. The CIS was supported by states and territory Energy Ministers through the Energy and Climate Change Ministerial Council (ECMC) as the preferred instrument in the near term for supporting additional investment in clean, dispatchable generation and storage capacity. CIS tenders will be conducted until 2027 for projects that are generating electricity on-grid by 2030.
7. Beyond this, there is a need for wholesale market settings to provide effective signals to investors for the provision of the optimal mix of energy in the NEM, ensuring resource adequacy and supporting reliability in the NEM at lowest cost to consumers.
8. To address this, at the November 2023 ECMC meeting, Commonwealth, state and territory Energy Ministers agreed that the Commonwealth would commence work with NEM

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jurisdictions on a review of market settings to promote investment in firmed, renewable generation and storage capacity in the NEM following the conclusion of CIS tenders in 2027.

9. The review will produce recommendations for consideration by Energy Ministers through ECMC.

Scope of the inquiry

10. The expert panel will recommend future market settings to promote investment in firmed, renewable generation and storage capacity in the NEM following the conclusion of CIS tenders in 2027. The expert panel will make actionable recommendations to support the development and staged implementation of reforms to the NEM wholesale market that support the achievement of the National Electricity Objectives including affordability, reliability and emission reduction in the long-term interests of consumers and prosperity of Australia's economy.
11. The expert panel should consider:
 - Interactions with the NEM reliability framework, to ensure clear and transparent settings that align with the proposed reforms and best serve the long-term interest of consumers.
 - Interactions with governments' renewable energy targets and policies in promoting investment, including the role of enduring jurisdictional schemes such as the NSW Roadmap.
 - The importance of decarbonising Australia's electricity system for achieving the Australian Government's legislated commitments to achieving a 43 per cent reduction in emissions on 2005 levels by 2030 and net zero emissions by 2050.
 - The pathway for implementation of the reforms, including the requirement for agreement at ECMC before amendments to the National Electricity Law (NEL) and National Electricity Rules (NER) can be progressed.
12. The expert panel will not consider options that involve implementation of carbon trading schemes, carbon markets or that entail governments supporting new fossil fuel generation.
13. In forming its recommendations, the expert panel will consider the work of the former Energy Security Board on incentivizing firmed dispatchable generation and storage capacity in the NEM, as well as AEMO's Integrated System Plan as the most comprehensively outlined pathway for the NEM through the energy transformation.
14. The expert panel will prepare a roadmap detailing the timelines and responsible parties for implementation of the review's recommendations.

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Process

15. The expert panel will undertake an appropriate public consultation process including holding public forums, inviting submissions, and releasing a report with draft recommendations to the public before making its final recommendations.
16. The expert panel will consult with state and territory governments. The review will also consult with the Australian Energy Market Commission, the Australian Energy Market Operator, the Australian Energy Regulator, the Australian Competition and Consumer Commission, the Clean Energy Regulator and Clean Energy Finance Corporation, industry participants, unions, and consumer representatives on relevant matters.

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Appendix B – Stakeholder feedback

Stakeholder engagement has been a central feature of this review. From the outset, the Panel adopted an open and collaborative approach, recognising the value of drawing on the perspectives of a diverse range of stakeholders to inform its recommendations.

Extensive engagement was undertaken across industry, academia, market bodies and all levels of government, as well as with leading international experts. Stakeholder input played a critical role in shaping the direction of the review's recommendations and in providing practical insights into potential implementation pathways.

The Panel is grateful for the time, thought and effort that stakeholders contributed throughout the review. Their considered feedback has been instrumental in refining the Panel's thinking and translating ideas into concrete proposals.

How we engaged

A range of platforms were used to encourage broad and meaningful participation throughout the review. These included:

- **Hosting an online industry forum** to introduce the review and formally open the consultation process.
- **Inviting public written submissions** on the review's Terms of Reference, resulting in more than 100 responses from across the industry.
- **Conducting over 150 individual meetings** with 90 different stakeholders in the first four months of the review. These meetings were critical in building relationships, gaining in-depth insights into industry perspectives and testing early design assumptions.
- **Engaging extensively with NEM states and territories** and the Australian Government throughout the process, to ensure that jurisdictions likely to be impacted had the opportunity to contribute and shape the Panel's thinking.
- **Working closely with market bodies** through regular meetings and co-design workshops, in recognition of their central role in the operation and governance of electricity markets.
- **Undertaking targeted surveys, interviews and workshops** with specific stakeholder groups to better understand their operational contexts and day-to-day decision making. These engagements provided valuable insights into the commercially sensitive parameters that influence behaviour in the market.
- **Testing emerging ideas through engagement** with global experts and exposure to evolving practices in other electricity markets. This included discussions with international market bodies, grid operators, generators and aggregators.
- **Holding open forums** in each NEM capital city and online to discuss preliminary findings and directions and hear stakeholder views in a transparent setting. These forums also enabled stakeholders to hear directly from one another, reinforcing a 'no surprises' approach.
- **Running 'lunch and learn' sessions** with academic experts to share the latest research and inform the Panel's thinking, while also supporting stakeholder understanding.

Who we heard from

The consultation process saw input from a range of individuals representing a wide cross-section of the energy industry. Formal written submissions were received from the following entities and individuals, and can be accessed online at the Have Your Say website (listed overleaf).

What we heard

The Panel has taken a considered and balanced approach in preparing this report, drawing on the breadth and diversity of stakeholder views gathered throughout the review process. In areas where perspectives aligned, such as the importance of providing investment certainty and maintaining reliability through the transition, stakeholder input directly reinforced the Panel's findings and recommendations. In areas of divergence the Panel carefully weighed competing views, commissioned detailed modelling, and drew on international experience to test options.

This report acknowledges the complexity of these debates and seeks to chart a pragmatic and forward-looking path grounded in broad-based engagement and informed judgment. While stakeholder perspectives are reflected throughout the report, the Panel recognises that it cannot capture the full breadth and nuance of views shared during the process.

The Panel has gratefully received formal written submissions from the following entities:

ACEN Renewables	Australian Energy Regulator (AER)
ACTU	Australian Industry Greenhouse Network (AIGN)
Advanced Materials and Battery Council	Australian Pipelines and Gas Association
AEMO	Australian Sugar Milling Council
AFMA	BCA
AGL	Bluescope Steel
Akaysha Energy	Carbon Market Institute
Alan Pears	Cement Industry Federation
Alinta Energy	Central NSW Joint Organisation
APA	Changing Weather
ASTRI and AUSTELA	Chris Waring
ATCO Australia	Clean Energy Council
Ausgrid	Clean Energy Investor Group
Australian Aluminium Council	CleanCo Queensland
Australian Energy Council (AEC)	Climate Change Authority
Australian Energy Market Commission	Climateworks Centre
Australian Energy Producers (AEP)	

Committee for Sydney	Committee for Sydney
CS Energy Limited	CS Energy Limited
David Close	David Close
Delta	Delta
Dr Sarah Lawley	Dr Sarah Lawley
Dr. Vikki McLeod	Dr. Vikki McLeod
Electric Vehicle Council	Electric Vehicle Council
Electrical Trades Union	Electrical Trades Union
Enel X Australia Pty Ltd	Enel X Australia Pty Ltd
Energex and Ergon Energy	Energex and Ergon Energy
Energy Consumers Australia	Energy Consumers Australia
Energy Efficiency Council	Energy Efficiency Council
Energy Users Association of Australia	Energy Users Association of Australia
EnergyAustralia	EnergyAustralia
Engie	Engie
Engineers Australia	Engineers Australia
Erne Energy	Erne Energy
Flow Power	Flow Power
Green Energy Trading Pty Ltd	Green Energy Trading Pty Ltd
Greg Williams	Greg Williams
Hon Nick Duigan MLC Minister for Energy and Renewables	Hon Nick Duigan MLC Minister for Energy and Renewables
Hydro Tasmania	Hydro Tasmania
Hydrostor	Hydrostor
Iberdrola	Iberdrola
Institute for Energy Economics and Financial Analysis	Institute for Energy Economics and Financial Analysis
Jack Pead	Jack Pead
Justice and Equity Centre	Justice and Equity Centre
Kevin Cox	Kevin Cox
Minerals Council of Australia	Minerals Council of Australia

Nexa Advisory

Origin Energy

Paul Verschuer

Potentia Energy

Powering Australia

Productivity Commission

Queensland Conservation Council

Reposit Power

RWE Renewables

SA Power Networks

Shell Energy

Shevy Moss Feiglin & Tom Geiser

Smart Energy Council

Snowy Hydro

Solar Citizens

Squadron Energy

Stanwell Corporation Limited

SwitchDin

TasNetworks

Tesla

The Centre for Independent Studies

The Superpower Institute

Tiho Ancev and Songze Qu

Tilt Renewables

UNSW

**Warren Centre Energy Hub in the Faculty of
Engineering at the University of Sydney**

Yun Tian



Appendix C – Design considerations for the Electricity Services Entry Mechanism

This appendix includes some early thinking on the derivative contracts that could be used to underpin the ESEM. It is not exhaustive and should not be taken as indicating any firm policy positions.

The Panel is not the ongoing decision maker in relation to contract structures. Rather, its recommendations establish a process by which industry participants (generators, financial market participants, electricity users and consumer representatives) would regularly convene to agree on structures to be used in the proposed market making obligation, with a subset of these to be used within the ESEM (see **Recommendation 6B**). The Panel intends to work with stakeholders during H2 2025 to run a demonstration process that will develop prototype contract structures across the three services: bulk energy, shaping and firming. These could be utilised to underpin the first investments developed under the ESEM and transactions required by the MMO.

Importantly, derivative contracts utilised in the ESEM should reflect the following principles:

- **Promote derivatives market liquidity and reflect the service provided to electricity users in a tradeable contract:** financial (i.e. not tied to physical plant operation), tradeable, structured to support price transparency and be useful for retailers for managing exposure to spot prices across the three targeted services;
- **Allow new projects to be financed:** designed to manage medium- to long-term financial risks and to facilitate investment under the ESEM; and
- **Preserve investment and operational signals:** encourage generators to deliver services when they are most needed, aligning incentives with system value and reliability outcomes.

The ESEM's use of derivative contracts is a deliberate design choice: in exchange for an upfront fixed payment, the seller takes on a financial obligation to deliver or procure the specified services at required times – facing market-based financial consequences if they do not.

Service: Bulk energy

Generation-independent contracts-for-difference (CfD)

Detail

This product would be analogous to a baseload swap but instead of the product being based upon the time-weighted average, it would be based upon a specific bulk energy profile.

The bulk energy profile could be nearby, similar projects (e.g. the five nearest wind farms), or broader (e.g. all bulk variable energy production in New South Wales).

NB: there is a range of contract designs in the literature with overlapping features that are intended to be broadly captured here (e.g. index CfDs, financial CfDs, yardstick CfDs, capability CfDs). This also includes proxy revenue swaps, which have seen limited use in the NEM.

Seller gets: fixed contract profile revenue; market revenue when producing above the contract profile

Seller commits: financial equivalent of producing to the specified bulk energy profile

Buyer gets: fixed price for a bulk energy profile

Examples

A body of literature is emerging that outlines how GI CfDs could address some degree of volume risk while maintaining operational and investment signals.

(e.g. [Schlecht, I., Hirth, L., & Maurer, C. \(2022\), Financial Wind CfDs](#), [Newbery, D. \(2021\) Designing an Incentive-compatible Support Scheme](#))

Time blocks

Detail

Standardised swap contracts broken up into blocks (e.g. 1hr/4hr/8hr) covering all 24 hours of a day. New projects could bid in specific blocks depending on the profile they are likely to generate.

To reduce volume risk for sellers, blocks could be capped (for example, at \$300), though this would reduce their value for buyers. The viability of such a variant could be improved by pairing with a temporally overlapping cap product (see ‘time-limited cap’ below)

Seller gets: fixed contract profile revenue; market revenue when producing above the contract profile

Seller commits: financial equivalent of producing to the specified contract profile

Buyer gets: fixed price for the block profile

Examples	The new ASX peak product is a version of this product covering evening and morning hours. Variations of these products covering all hours also trade on OTC platforms such as ToD Markets and CORE Markets.
Renewable energy guarantee of origin (REGO)	
Detail	The ESEM could procure REGOs from new projects. This would give projects a secondary revenue stream. REGOs can be generated by small- and large-scale resources, and could also be differentiated to encourage optimal projects (for example, assigning different values to different times of day). REGOs could also be procured through the ESEM operator entering a contract for difference (CfD) based on REGO prices for new projects. Seller gets: fixed price for the REGOs procured Seller commits: surrendering REGOs / financial equivalent of buying REGOs in the market and selling at the fixed price Buyer gets: allocation of green product rights or the REGO spot price
Examples	See AEMC submission to the NEM Review Initial Consultation working paper appendix, p. 17

Service: Shaping

Price spreads

Detail	The difference between a given number of highest- and lowest-price trading intervals every day (e.g. 1/2/4/6 hrs). Seller gets: fixed revenue for daily charge/discharge cycle; market revenue sourced outside the energy market, for example in frequency markets Seller commits: financial equivalent of charging in lowest price hours and discharging in highest Buyer gets: fixed price for an arbitrage profile
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Examples	A similar contract type called a ‘Virtual Storage Contract’ was developed by Renewable Energy Hub (now CORE Markets) with the first trade completed in 2021 (ARENA, Renewable Energy Hub Lessons Learnt Report 2)
Virtual tolls	
Detail	The seller provides revenues for standardised time periods and asset use. The seller retains control over the asset, providing the option to use the asset as per the standardised time periods or engage in alternative market behaviour such as receiving FCAS revenue. This enhances the liquidity of the asset as it is divorced from physical plant obligations. Seller gets: fixed daily revenue Seller commits: financial equivalent of charging/discharging in the intervals nominated by the buyer Buyer gets: equivalent of moving electricity between the intervals they nominate
Examples	Virtual tolling agreements have evolved as a financialised version of physical tolling agreements that are currently used in the NEM to bank storage projects. A prominent recent example of the use of a virtual toll agreement in the NEM is the announced contract between EnergyAustralia and Akaysha Energy in 2024 . Further explanation of this contract type can be found at ‘ Modo Energy, Battery tolling agreements: How do they work? ’.
Time-limited caps or floors	
Detail	Covers specific time blocks within a day (e.g. peak hours, solar excess). Pays out prices above cap (e.g. \$300) or below floor (e.g. \$0) or both, during these hours. Different products may be more or less appropriate for different entities (e.g. demand response may sell floors, generators could sell caps, batteries may sell a combined inverse collar). Seller gets: fixed premium revenue; marginal profit between strike price and charging price (for caps) Seller commits: financial equivalent of generating when prices in the relevant interval are above strike prices and passing on revenue above strike price (for caps) Buyer gets: portion of spot price over/under strike prices for caps/floors respectively
Examples	CORE Markets have noted that there has been some recent interest in ‘super peak’ caps covering the hours of 5–9pm.

Service: Firming	
Caps	
Detail	For a given capacity, the buyer receives all spot market revenues above a strike price. ASX-traded caps have a strike price of \$300, though this may need to be adjusted in future as per the innovation that is occurring in OTC markets. Seller gets: cap premium revenue; marginal profit between strike price and fuel/charging price; gross margin at sub-cap prices Seller commits: financial equivalent of generating when prices are above strike prices and passing on revenue above strike price Buyer gets: portion of spot prices over strike price
Examples	Cap contracts are a liquid ASX-traded derivative commonly used for hedging in the NEM. A recent discussion of NEM hedging practices including the contemporary utilisation of cap contracts is included in <i>Flottmann, J., Wild, P., and Todorova, N. (2024) Derivatives and hedging practices in the Australian National Electricity Market</i>.



Glossary

ACCC

Australian Competition and Consumer Commission

AEC

Australian Energy Council

AEMC

Australian Energy Market Commission

AEMC Targets Statement

list of the jurisdictional emissions reduction targets, prepared by the AEMC as required under the national energy laws, to be considered when applying the national energy objectives

AEMO

Australian Energy Market Operator

AER

Australian Energy Regulator

AFMA

Australian Financial Markets Association

APC

Administered Price Cap

ARENA

Australian Renewable Energy Agency

ASX

Australian Securities Exchange

BESS

battery energy storage system

C&I user

commercial and industrial electricity user

CER

consumer energy resources

CfD

contract for difference

CFM

congestion relief market

Consumer

small electricity user (i.e. households and small businesses)

CPT

Cumulative Price Threshold

CRM

congestion relief market

Customer

electricity user purchasing electricity from a retailer (distinct from ‘market customer’ – see below)

DCCEEW

Department of Climate Change, Energy, Environment and Water (federal)

DER

Distributed Energy Resources

DMO

Default Market Offer

DNSP

distribution network service provider

DR

Demand Response

Dunkelflaute

periods of low wind and solar output

ECMC

Energy and Climate Ministerial Council

Electricity user

small- and large-scale entities purchasing electricity either through a retailer or on the wholesale market

ESC

Victorian Essential Services Commission

ESEM

Electricity Services Entry Mechanism

ESS

essential system services

EV

electric vehicle

FCAS

frequency control ancillary services

FTR

financial transmission rights

GJ

gigajoule

IPRR

Integrating Price Responsive Resources

IRM

Interim Reliability Measure

ISP

Integrated System Plan (AEMO)

kW

kilowatt

LMP

locational marginal pricing

LTESA

long-term energy service agreement

Market customer

registered participant in the wholesale electricity market who purchases electricity for their own consumption or for on-sale to electricity users (i.e. retailers or C&I users)

MCL

maximum credit limit

MIC

market impact component

MLF

marginal loss factor

MLO

Market Liquidity Obligation

MMO

market making obligation

MPC

Market Price Cap

MPF

Market Price Floor

MT PASA

medium-term projected assessment of system adequacy

MW

megawatt

MWh

megawatt-hour

NCC

network capability component

NEL

National Electricity Law

NEM

National Electricity Market

NEMDE

NEM Dispatch Engine

NEO

National Electricity Objective

NER

National Electricity Rules

NERL

National Electricity Retail Law

NERR

National Electricity Retail Rules

NSCAS

network support and control ancillary services

Ofgem

Office of Gas and Electricity Markets (UK)

OTC

over the counter

PJM

PJM Interconnection, a regional transmission organisation

PPA

power purchase agreement

PV

photovoltaic

REGO

renewable energy guarantee of origin

REZ

renewable energy zone

RIT-T

Regulatory Investment Test for Transmission

RRO

Retailer Reliability Obligation

SOC

state of charge

SRAS

System Restart Ancillary Services

SRMC

short-run marginal costs

ST PASA

short-term projected assessment of system adequacy

TNSP

Transmission Network Service Provider

USE

unserved energy

VCR

Value of Customer Reliability

VPP

virtual power plant

VRE

variable renewable energy

VSR

voluntarily scheduled resource

WDRM

Wholesale Demand Response Mechanism