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AUSTRALIAN ENERGY REGULATOR

State of the energy market

Wholesale electricity market performance report 2026

August 2026

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Executive summary

Introduction

The AER reviews the performance of the wholesale electricity market under the National Electricity Law. This annual review assesses whether the National Electricity Market (NEM) is competitive, efficient and reliable through the energy transition and also provides advice to energy ministers on reforms needed to address any significant risks.

This is our fifth review of wholesale electricity market performance. This report examines how market performance has changed over the past 5 years, with a particular focus on outcomes in 2025. The report identifies where market outcomes have improved, where risks are becoming more concentrated, and what this means for policymakers as the NEM transitions to a lower-emissions system. We used information collected from market participants about electricity contracting, using a Market Monitoring Information Order for the first time. This gives us better visibility of contract markets and incentives behind spot outcomes than previous wholesale electricity market performance reports (WEMPRs).

Our overarching finding is that the NEM is transforming from one market into many different markets within each region, defined often by the time of day and service type. Price outcomes increasingly depend on whether enough flexible capacity is available when it is needed. If flexible supply, storage, transmission and demand response do not scale to provide necessary capacity in the right places and at the right times, consumers may face higher prices and greater reliability risks, because the market will be more vulnerable to supply and demand shocks. The emergence of so many distinct markets is also increasing the complexity of our market monitoring task and will inform our future focus areas for surveillance of participant conduct.

Key findings from our analysis

Prices eased in 2025, but pressure remains outside the daytime

Prices and revenue in 2025 were lower than in 2024 across all periods of the day, but they remained materially above pre-2022 levels in the evening peak and overnight periods. This resulted in higher average prices and total revenue compared with 2021, except in Queensland where evening peak and average prices were lower in 2025.

The evening peak improved in 2025 in part due to the increase in the volume of mid-priced offers from new battery entry and fewer very high-price events. More low-priced offers from new wind and solar generation drove lower daytime prices, with battery load offers increasingly setting the price. However, higher coal fuel prices limited the improvement in overnight prices compared with 2021. The increase in capacity at peak times and higher renewable generation were contributing factors to lower base futures and cap prices.

Coal set the price less often overall, particularly during the day, but remains important overnight, especially in Queensland and New South Wales (NSW). Batteries are still a small share of total generation but are increasingly influential during the evening peak, when they are beginning to displace gas and hydro as the generators that most often determine price. These changes show that new flexible capacity is improving some outcomes, but not yet enough to remove price pressure when renewable output is lower and demand is higher.

Overall, 2025 showed signs of easing market pressure, but not a return to pre-2022 energy prices. Higher fuel costs, elevated evening and overnight prices, increased demand and continuing reliance on dispatchable capacity suggest that consumer outcomes will depend heavily on how quickly flexible supply, storage, transmission and demand-side responses can scale to meet the changing shape of demand.

Conditions for frequency control ancillary services (FCAS) were more favourable, with costs at their lowest level since 2016, although localised spikes in South Australia show that competition and system security risks can still produce regional cost pressures.

Competition has improved overall, but risks remain at specific times, locations and services

Competition in the NEM improved in 2025 as new generation and storage entered the market and ownership became more diverse. The largest participants accounted for a smaller share of generation output across mainland regions, and concentration was lower on average, particularly during the middle of the day when solar output is high. New battery capacity also reduced concentration during peak times, with new entry more than doubling since mid-2024 and a more diverse set of owners entering the market.

However, lower average concentration does not mean competition risks have been resolved. Risks are now more likely to emerge at particular times, services and places. Competition remains more limited during the evening peak and overnight, when solar output is low and the system relies more heavily on dispatchable generation. Large participants remain pivotal in some regions and periods, especially in Queensland and during evening peaks. Firming services also remain highly concentrated, with the largest providers controlling a substantial share of capacity across the NEM and very high shares in some regions.

These risks are also shaped by network conditions and system security needs. FCAS markets have become more competitive overall as batteries entered the market and costs decreased to their lowest level since 2016. However, local FCAS requirements can still create concentrated and high-priced markets when regions are separated or at risk of separation. Interconnectors also remain an important competitive constraint by allowing lower-cost supply to enter regions where local generation would otherwise set higher prices. However, that constraint weakens when interconnectors are constrained or unavailable, increasing the importance of local supply conditions.

Contract markets have stabilised since 2022, but access to risk management remains uneven

Electricity contract markets have broadly stabilised after the disruption of 2022. Australian Securities Exchange (ASX) traded volumes reached record levels, open interest rebounded from the lows recorded in early 2025, and volatility in base futures and caps prices returned to levels similar to pre-2022. This indicates the contracting environment is more stable, supported by improved access to clearing and stronger activity in exchange-traded products.

However, market depth and participation are uneven. Non-energy market participants provided much of the trading liquidity on the ASX, while energy market participants accounted for a larger share of open interest because they tend to hold positions longer to manage physical exposure to wholesale price risk. Reported trading by energy market participants was concentrated, with the top 5 participants accounting for most reported ASX and over-the-counter contract volume. Concentration is most evident further from expiry, when energy market participants are more active and in less liquid segments, such as South Australia.

Market participants also reported continuing barriers, including margining requirements, credit constraints, product suitability, liquidity and transparency. Where participants face barriers, their ability to manage wholesale risk and compete may be affected.

Participant conduct largely reflects market conditions

Participant conduct is changing as the generation mix changes, though most observed behaviour appears broadly consistent with market conditions. New renewable capacity is increasing the volume of low-priced offers during the day, and new battery capacity is increasing the volume of mid-priced offers at peak times. Higher fuel costs, plant availability and changing scarcity conditions are influencing how coal, gas and hydro capacity is offered.

Offer behaviour is increasingly shaped by the different roles technologies play across the day. Renewable generators are contributing more low-priced capacity during the day, while coal and gas offers remain more important outside the daytime. Some coal generators appear to be moving capacity to higher price bands to avoid uneconomic dispatch during low-price periods, while gas generators continue to offer a material share of capacity at higher prices in some tight conditions.

Analysis does not indicate sustained market power across the NEM, but it does show that automation, battery bidding and portfolio behaviour is making conduct more complex to assess. There has been a dramatic increase in re-bidding, driven by automated bidding technologies adopted by many market participants. This may produce more efficient price outcomes because it is responsive to market conditions. However, it also brings risks of market manipulation and collusion. Further, the data associated with, for example, the growth in rebids from 5.4 million per year in 2020 to 73 million in 2025, poses a significant market monitoring challenge. We are providing guidance to market participants and continuing to invest in our analytical capabilities to address this. For future reports we will also place a greater focus on portfolio bidding, assessed against market conditions. We will be monitoring the risk that portfolios or participants are able to push prices to inefficient levels on a sustained basis or in ways that don't align with underlying market conditions. The AER will also examine interactions with the contract market to monitor for cross-market manipulation.

Recent entry has supported market outcomes, but future delivery is less certain

The significant new entry between October 2024 and the end of 2025, primarily batteries, improved supply conditions and helped ease prices. The increase in capacity meant the market was less vulnerable to shocks, either from the supply side due to network and generation outages and low wind or the demand side due to weather conditions. But much of the forward pipeline remains at an early stage of development. Headline project volumes are dynamic and subject to project delays, and capacity may not enter the market as anticipated or when capacity is most needed.

Investment signals vary significantly by technology. Batteries currently appear to have the strongest commercial case, supported by revenue opportunities from price volatility and falling capital costs. The recent fall in price spreads will affect the investment outlook. Wind and solar face weaker investment signals, with wind affected by higher construction costs and solar revenues reduced by stronger daytime competition, including from rooftop PV. New gas entry is also difficult to justify commercially because of higher construction costs, turbine shortages and long lead times.

These delivery risks are becoming more material as coal exits approach. Around 15.7 gigawatts (GW) of thermal capacity are scheduled to close over the next decade, including 6.8 GW of withdrawals across 2028 and 2029. If replacement supply, storage, firming and transmission are delayed, the NEM will face greater risks of price volatility, reliability pressure and reduced competitive pressure. Therefore, the next phase of the transition will depend on how much capacity is proposed and whether credible projects can be delivered in the right locations and timeframes, alongside the system security and network capability needed to support this new capacity.

Rising network congestion costs indicate that, without incentives and price signals, new generation is not always located in areas of the grid that minimise system costs. This is an issue that may be partially addressed by increased transmission investment and some policy measures, such as renewable energy zones. However, as we have observed in our recently released information paper on the future of electricity network regulation,[1] we expect our future regulatory framework for energy is likely to require a more explicit consideration of how best to tackle coordination challenges across planning, market design and network boundaries rather than through siloed transmission, distribution and wholesale approaches.

Recent changes in coal generation and utility-scale batteries and their future outlook demonstrate the rapid and profound change underway in the NEM

An aging fleet of fuel-exposed dispatchable units is giving way to a new fleet of flexible and increasingly long-duration dispatchable units that are not fuel-exposed and respond differently to market dynamics.

Coal's role in the market has been impacted by a range of factors in recent years. Coal generator outages increased from 2017–18, peaking in 2021–22. This was due to a range of factors, including aging plant, delayed maintenance and the significant failure at Callide C power plant in Queensland. As part of WEMPR 2022, some participants told us that maintenance of coal plants was affected during this period by COVID-19, which impacted staff and contractor availability and delivery of parts, delaying maintenance and low wholesale prices, which impacted the cost and benefit assessment of maintenance against projected future revenue.[2] The level of outages has declined in recent years but remain higher than 2017–18 levels.

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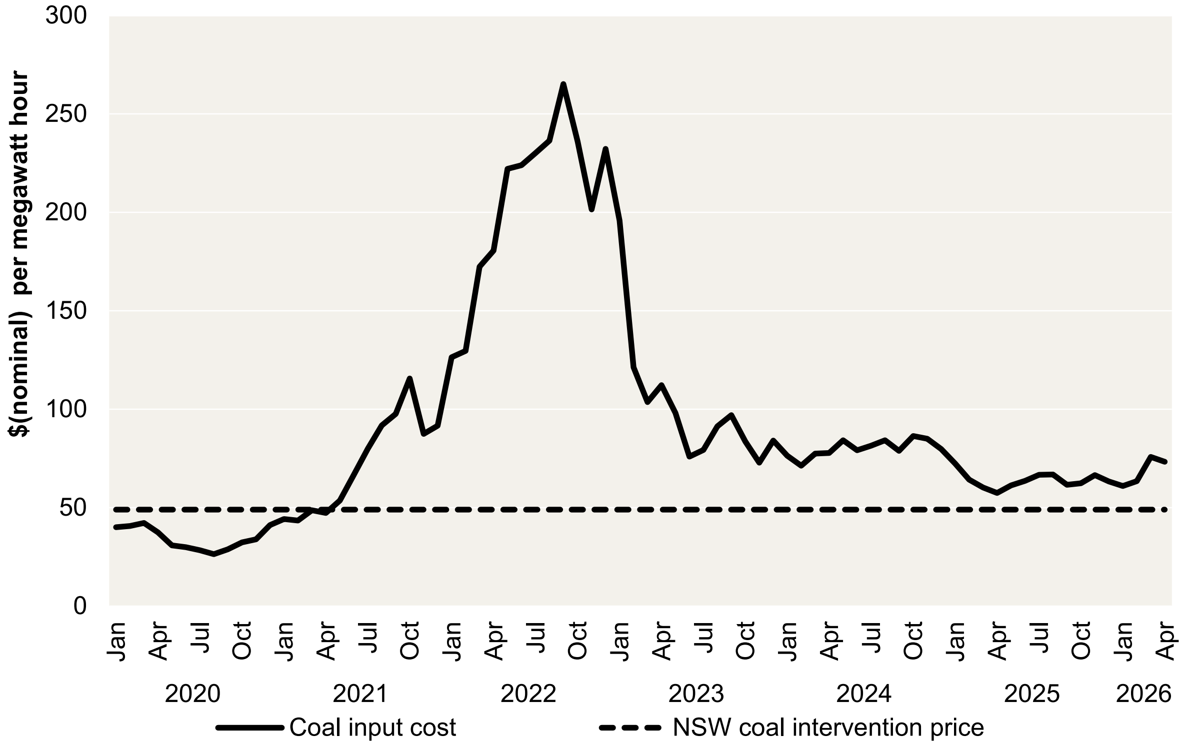
1 AER, *Information paper – Future of network regulation – 2026*, Australian Energy Regulator, 19 June 2026, pp. 16, 53, accessed 20 July 2026.

2 AER, Wholesale Electricity Market Performance Report 2022, Australian Energy Regulator, 15 December 2022, p. 68.

Proxy input cost of coal per MWh based on spot prices



Note: This chart is Figure 2.16 from Chapter 2: Market conditions and change drivers.

Coinciding with performance issues, there have been significant fuel price increases. This was initially triggered by the war in Ukraine. Coal prices have now fallen from record highs in 2022 but remain high compared with historical levels. Average coal input prices in 2025 were around $64 per MWh, around 31% higher than during the market intervention (around $49 per MWh) and 87% higher than the 2020 average (around $34 per MWh). The jump in coal fuel prices coincided with a large decline in low-priced coal offers. Some of the decline was reversed during the coal price intervention but low-priced offers declined again when the intervention ended.

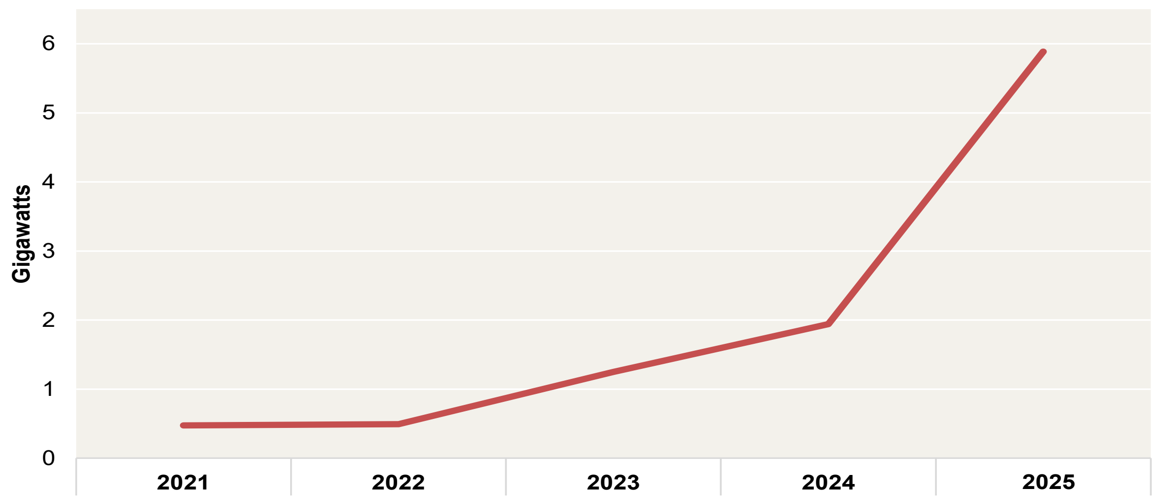
The reduction in low-priced offers led to coal setting the price less frequently, but at higher levels. Commercial rebidding has also contributed to coal setting high prices. From early May to early August 2024 commercial rebidding by coal plants drove high prices and resulted in the Cumulative Price Threshold being breached in NSW in early May 2024, triggering a period of administered pricing cap. The administered price period lasted from 8 May to 15 May. Subsequently, there have been fewer instances of commercial rebidding by coal plants causing high prices.

In 2022 market participants informed the AER that the combination of coal closures, concerns about reliability of baseload plant, concerns about coal supply and uncertainty around fuel costs has led them to reduce the number of hedge contracts sold off the back of this baseload plant compared with past years. The willingness of portfolio generators to offer base futures contracts in the future will be influenced by the performance of their coal plant.

Coal generation output has been declining and will continue to decline, but it remains the largest source of generation and still has a significant impact on market outcomes. Over the next 3 years, 6 GW of coal is scheduled to exit the market. Because these are large, concentrated withdrawals rather than gradual retirements, they increase the risk of market volatility and reliability pressure if replacement capacity is delayed or does not align with demand.

Batteries' role in the market has increased significantly in the past 5 years and will continue to grow. At the start of 2021 there were just 5 utility-scale batteries in the NEM, totalling 261 megawatts (MW). These ranged in duration from 15 minutes to 2 hours and most of their revenue was derived from FCAS markets. FCAS prices and costs had started rising in 2015. Over time, batteries and other new technologies have competed down FCAS prices, with FCAS revenue in 2025 the lowest since 2016.

Cumulative battery new entry since January 2021



Note: This chart uses the same data as Figure 6.1 in Chapter 6: Entry and Exit.

As the amount of battery capacity installed increased, so did the average duration. This contributed to more revenue being derived from energy markets because the batteries were less energy constrained. In 2025 energy markets made up around 80% of battery spot market revenue. The large increase in installed capacity in 2025, rising from 2.2 GW at the start of the year to 6.1 GW by the end, had a material impact on wholesale market outcomes. Batteries increased their volume of mid-priced offers, contributing to lower prices in the second half of 2025.

Nearly two-thirds of the batteries currently installed have a duration of at least 2 hours. Longer-duration batteries have started entering the market, including the first 8-hour battery that started operation in June 2026, supported by the NSW Energy Road Map. The entry of more long-duration batteries (8 hours plus) in the current investment pipeline will be primarily supported by the NSW Energy Road Map and the Firm Energy Reliability Mechanism (South Australia).

There will be significant battery new entry over the next 3 years. There is currently 6.5 GW of committed capacity – most of which has at least a 2-hour duration, with some longer durations. There is a further 11.3 GW of anticipated capacity, some of which will enter over the next 3 years.[3]

Recommendations

Our analysis highlights 2 priorities. First, policy should respond to the growing concentration of value and risk in the overnight period. Second, government-supported investment should focus on projects that are credible, deliverable and able to enter the market when needed.

Reduce overnight price pressure by improving competition and shifting discretionary demand

Overnight and evening prices remain a key pressure point in the NEM. Coal continues to play an important role in both overnight generation and price setting. Coinciding with higher fuel prices, black coal generators reduced their volume of low-priced offers, contributing to higher overnight prices.

The most advanced new projects are likely to help more during the evening peak than overnight. Batteries and hydro made up most committed capacity, and only a smaller volume of committed wind was available to support overnight supply. While batteries and hydro can generate at any time, the arbitrage opportunity is larger at peak times and batteries are energy constrained. Battery behaviour may change if peak prices are competed down and there is a greater share of long-duration storage (8 hours plus). Wind is more relevant to overnight competition, but new wind projects remain costly and harder to deliver, facing a range of approval and logistical challenges. Without a stronger focus on time-of-day outcomes, consumers may continue to face higher overnight prices even as total capacity increases.

Overnight price pressure can be reduced by increasing competition and shifting discretionary demand into the day. This should include removing any unnecessary regulatory requirements impeding the delivery of new wind projects and other overnight supply, and identifying how discretionary load, such as hot water systems, pool pumps and EV charging, can be shifted away from overnight periods and into solar hours. This would complement the new Solar Sharer Offer, which is designed to provide financial incentives to shift demand to the middle of the day. Increasing daytime demand would also assist with operational challenges for the system from very low demand.

Strengthen delivery requirements for government-supported projects

Significant new entry is required over the next decade. It is important that new generation and storage is delivered in a timely fashion, as coal exits are approaching.

Given the central role of government schemes to investment in the NEM, governments should strengthen delivery discipline in future capacity support schemes by increasing the emphasis on project maturity, setting clear delivery windows and enforcing milestones. For the Electricity Services Entry Mechanism (ESEM), governments should consider adopting a minimum project readiness standard before support is awarded, including planning status, connection progress, land access, financing and procurement readiness.

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[3] AEMO, NEM Generation information publication, Australian Energy Market Operator, April 2026.

Implementation

Maintain flexibility when setting competition thresholds

In this report, in addition to market share by dispatchable generation, we have included market share analysis by service type. Market share is the simplest measure of concentration. Our approach is not intended to prejudge potential approaches for a future competition threshold test for the ESEM. Rather, it is intended to provide information on the ownership structure of the fuel types covered by ESEM services and provide a starting point on the level of concentration for the future service types.

The NEM wholesale market settings review categorised the replacement capacity for outgoing coal generation according to 3 types – bulk energy, shaping and firming – depending on the service it provides to the market.

The categories in this report align with the NEM review, except that as a simplifying assumption we have not included run-of-river hydro in bulk energy and have only included pumped hydro in shaping (rather than in both shaping and firming).

Bulk energy – that is, energy provided by grid-scale wind and solar – is diversely owned, with each region having a low overall level of market concentration. Shaping – which is provided by battery and pumped hydro generators – remains more concentrated than bulk energy, but competition is improving rapidly due to new entry of diversely owned batteries. Firming – which is provided by gas, non-pumped hydro, diesel and other liquid fuel generation – remains the most concentrated service type and has shown little evidence of becoming less concentrated.

Competition risks are no longer captured well by broad market-wide concentration measures alone. As the NEM changes, risks are emerging in more specific ways: by time of day, service type, region, network condition and access to contract markets. Average concentration may fall while market power risks remain material in the periods and services where flexible capacity is scarce.

Building in scope for the AER to adjust competition metrics as the market develops will support the intent of the ESEM. The AER will continue to develop our metrics to provide advice on risks, including taking a forward-looking perspective on how trends in the NEM may shape competitive outcomes into the future.

1 Monitoring the National Electricity Market

The AER monitors the performance of the National Electricity Market (NEM). The NEM is a wholesale spot market into which generators in eastern and southern Australia trade electricity (Box 2.1). This chapter outlines why and how we monitor this market.

1.1 Our reports provide information on the performance of the NEM to support efficient and competitive markets

Our reports provide an independent, expert and long-term perspective on the performance of wholesale electricity markets.

We monitor and report on the performance of the NEM under the National Electricity Law (NEL). The NEL requires us to review the performance of the wholesale electricity markets, including analysing and identifying whether there is effective competition and whether there are market features that may be detrimental to effective competition or the efficient functioning of the market.

We must report on the market at least every 2 years. From this, we may also advise the Australian and state governments on market performance and identify whether legislative or regulatory reform is required.

This 2026 report is our fifth report presenting a comprehensive picture of competition in the NEM. In addition, we have other performance reporting obligations across our wholesale, retail and network areas.[4] For wholesale, many of our other functions focus on short-term market outcomes, compliance issues and individual price events.

Our monitoring roles support the National Electricity Objective in the NEL, which is to promote the efficient investment, operation and use of electricity services for the long-term interest of consumers. Through our monitoring and reporting, we assist consumers to understand the key drivers of outcomes in the wholesale electricity market and make more informed consumption decisions. Providing timely and relevant information to the market also supports efficient investment decisions and provides insights to policy makers to guide regulatory change.

1.2 We analyse competition and efficiency in the wholesale electricity market

Our assessment of market performance includes analysing whether there is effective competition and if the market is functioning efficiently.

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4 AER, Performance reporting, Australian Energy Regulator.

1.2.1 Effective competition in the NEM

The level of competition in any market can be assessed against a range of competitive outcomes. At one end of the range is a monopoly, where one firm effectively controls all output in the market and there is no competition. At the other end is a perfectly competitive market, where no firm holds market power at any time. Perfect competition rarely occurs in practice.

The NEL requires us to assess whether there is 'effective' competition, rather than perfect competition, and provides a non-exhaustive list of factors to which we must have regard:[5]

- whether there are active competitors in the market and whether those competitors hold a reasonably sustainable position in the market (or whether there is merely the threat of competition in the market)
- whether prices are determined on a long-term basis by underlying costs rather than the existence of market power, even though a particular competitor may hold a substantial degree of market power from time to time
- whether barriers to entry into the market are sufficiently low so that a substantial degree of market power may only be held by a particular competitor on a temporary basis
- whether there is independent rivalry in all dimensions of the price, product or service offered in the market
- any other matters the AER considers relevant.

The NEL suggests the wholesale electricity market may still be considered 'effectively' competitive over the long term even if participants hold a substantial degree of market power at times. In particular, the NEL refers to prices over the long term and market power held by a participant on a temporary basis. These factors suggest we should have regard to whether market power is sustained.

An energy-only market, such as the NEM, is characterised as being effectively competitive if it has many participants, with no one participant controlling a high proportion of capacity for a significant period. Participants should generally have an incentive to bid close to their fuel and operating costs; otherwise, they risk a cheaper competitor displacing their output.

Current market design is based on the assumption that periods of high spot and contract prices, driven by tightened supply and demand conditions, should provide a signal for new generators to enter the market. Conversely, if demand decreases relative to supply, there should be downward pressure on prices, which should prompt higher cost generators to exit the market.

Contract markets also act in conjunction with spot markets as a price risk management tool as well as a longer-term signal for investment. In an effectively competitive energy-only market, barriers to entry and exit are sufficiently low that investors can respond efficiently to price signals.

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5 National Electricity Law, Section 18B.

1.2.2 Efficiency in the NEM

The NEL does not provide a definition of efficiency, but it is a well understood concept in economic literature. Economic efficiency is concerned with maximising overall welfare in a market given the available resources. We have had regard to 3 dimensions of efficiency:

- Allocative efficiency – resources are allocated to their highest value uses. In electricity markets, this means the electricity that consumers demand is provided by the lowest cost supply-side and demand-side options.
- Productive efficiency – the value of resources used are minimised for a given level of outputs. This includes removing any inefficient costs in supplying electricity to consumers.
- Dynamic efficiency – resources are allocated efficiently over time. In energy markets, this means enabling innovation and having the right mix of demand-side and supply-side options to provide maximum output at minimum cost over time.

1.3 We relied on a range of information and analysis, including contract market information collected from participants

We used a range of information for our 2026 analysis, including from:

- the Australian Energy Market Operator (AEMO)
- the Australian Securities Exchange (ASX)
- the Commonwealth Scientific and Industrial Research Organisation (CSIRO)
- market participants.

1.3.1 Our approach included analysing the structure, conduct and performance of the markets

In 2026 we have applied the same approach as our past 2 reports, using a structure–conduct–performance framework to analyse the market and focusing on effective competition and efficiency. In broad terms:

- structure refers to the market structure and includes the number and size of buyers and sellers, the nature of the products and the height of barriers to entry
- conduct refers to firms' behaviour in the market, including production, and buying and selling decisions
- performance refers to market outcomes, usually by reference to concepts of efficiency.

Our Enhanced wholesale market monitoring guideline (2024) provides more detail on this framework. We also published the *Wholesale electricity market performance report 2026 – Methods and assumptions* to explain the approach we have taken and allow stakeholders to replicate the analysis.

1.3.2 We expanded our analysis to include confidential contract data

In 2025, for the first time, the AER used a Market Monitoring Information Order (MMIO) to compulsorily gather information on electricity contract markets. Under the MMIO we collected information on exchange-traded contracts (ASX), over-the-counter (OTC) standard contracts, historical information on power purchase agreements (PPAs) and qualitative information on factors affecting energy market participants' use of ASX and OTC markets. The information collected under the MMIO enabled us to undertake market structure analysis of the contract market, complementing the market structure analysis of the spot market.

1.3.3 How this document is structured

While we adopted the structure–conduct–performance framework to analyse the markets, this report is structured around our key findings and issues we identified.

This report covers:

- Chapter 2 – overview of market conditions and change drivers
- Chapter 3 – contract markets
- Chapter 4 – whether the current market structure supports efficient and competitive markets
- Chapter 5 – whether participants are exercising market power
- Chapter 6 – entry and exit.

2 Market conditions and change drivers

Outcomes in the National Electricity Market (NEM) are becoming more fragmented by time of day. Higher prices and more revenue are increasingly concentrated outside the daytime. Renewables are reshaping daytime supply and demand, but dispatchable generation – and increasingly batteries – still determine outcomes at critical times. Coal has maintained its price-setting role overnight.

Key findings

- Average annual wholesale electricity prices in 2025 were lower than in 2024 in all regions, due to fewer prices above $5,000 per megawatt hour (MWh), more low-priced and mid-priced offers at peak times from batteries, and an increase in the supply of wind and solar generation. Compared with 2021, prices were higher in all regions, except Queensland.
- Total revenue was lower in 2025 compared with 2024 in all periods, particularly in the evening peak. Total revenue was higher in 2025 compared with 2021, driven by higher prices during the evening peak and overnight periods, while daytime revenues were lower.
- Intermittent renewable generation continued to grow and accounted for 37% of total generation in 2025, up from 24% in 2021 and 32% in 2024. The influence of intermittent renewable generation was greatest during the day, when wind and solar made a larger contribution to supply and pricing outcomes.
- Electricity demand increased, with morning and evening demand the highest across the previous 5 years.
- Black coal availability was lower in 2025 compared with 2024 but higher than in 2021 (its lowest level), when a major failure occurred. Brown coal availability remained higher than black coal throughout the period.
- Fuel prices remained higher than pre-2022 levels. In 2025 average coal prices ($ per MWh) were around 31% higher than during the market intervention and 87% higher than the 2020 average.
- Batteries, solar and wind set the price more frequently in 2025, with the increase in battery price setting particularly pronounced as more battery capacity entered the market. Coal set the price less often overall, particularly during the day, but maintained its price-setting role overnight.
- Frequency control ancillary services (FCAS) costs in 2025 were the lowest since 2016, driven by lower prices due to increased competition, primarily due to batteries.

Electricity generated in eastern and southern Australia is traded through the NEM. The NEM is a wholesale spot market, where fluctuations in supply and demand determine wholesale electricity prices.

Assessing whether the NEM is effectively competitive and operating efficiently over the long term requires an understanding of prevailing market conditions and the key drivers of participant behaviour and price outcomes. This chapter outlines recent market outcomes and underlying drivers and considers whether these conditions are likely to persist.

Box 2.1 The NEM

The NEM is a wholesale spot market for trading electricity in eastern and southern Australia. The market covers 5 regions – Queensland, NSW (including the ACT), Victoria, South Australia and Tasmania – which are connected via high voltage transmission links called interconnectors.

Generators and storage providers participate in the NEM by submitting offers to the Australian Energy Market Operator (AEMO) to supply or use quantities of electricity at different prices for different periods of time. These include coal-fired, gas-powered, wind, hydro-electric and large-scale solar generators, as well as batteries and pumped hydro. Around 324 power stations (comprising around 420 units in total) can make offers to supply or use quantities of electricity in different price bands. Electricity generated by rooftop solar systems is not traded through the NEM, but it does reduce demand.

AEMO matches supply and demand in real time by issuing instructions to generators every 5 minutes (known as a dispatch interval). It selects the lowest-priced offers first and then progressively more expensive offers until enough electricity is dispatched to meet demand. The last generator needed to meet demand (known as the marginal generator) sets the spot price for the 5-minute dispatch interval.

Spot prices can range from the market floor of −$1,000 per megawatt hour (MWh) to the market price cap of $23,200 per MWh.[6] All dispatched generators are paid the spot price, regardless of how they bid.

To manage spot price risk, generators and retailers will often use hedge contracts, including those traded on the Australian Securities Exchange (ASX) and over-the-counter contracts, which lock in future electricity prices. Participants may also enter into long-term power purchase agreements and often have both generation and energy retailing businesses (referred to as vertical integration) to balance out the risks across the markets.

While the market is designed to meet electricity demand in a cost-efficient way, other factors such as network limitations can intervene. For example, if the network is congested near the lowest-cost generator, AEMO may need to dispatch higher-cost generators in other parts of the network. Market outcomes can also be affected by bidding behaviour. For example, a participant with market power may rebid capacity from low to high prices, pushing prices above efficient levels.

2.1 Annual wholesale prices fell in all regions in 2025 but remained above 2021 levels in most regions

Average annual wholesale electricity prices in 2025 were lower than in 2024 in all regions. This was primarily due to lower prices in the second half of 2025, driven by new battery, solar and wind entry, which increased the volume of low-priced to mid-priced offers. Batteries

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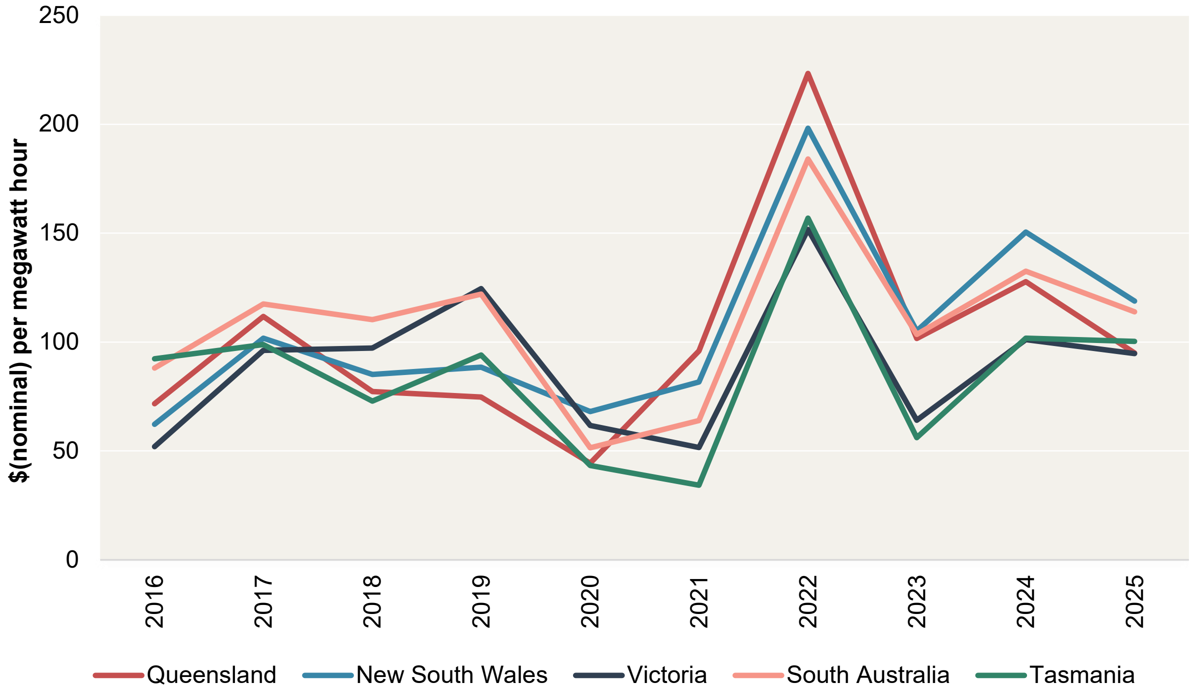
6 The wholesale electricity market price cap was set at $23,200/MWh on 1 July 2026.

increased their low-priced to mid-priced offers at peak times and there were fewer periods when prices exceeded $5,000 per MWh. However, compared with 2021, prices were higher in all regions, except Queensland. This was largely due to higher input prices, particularly coal (section 2.4.1), which reduced the volume of lower-priced offers (Figure 5.5, Figure 5.15).

Figure 2.1 Annual volume-weighted average prices in the NEM



Note: Volume-weighted average price is weighted against native demand in each region. The AER defines native demand as the sum of demand met by all local scheduled, semi-scheduled and non-scheduled generation, plus interconnector imports in a region. It does not include demand met by rooftop solar systems.
Source: AER analysis using NEM data.

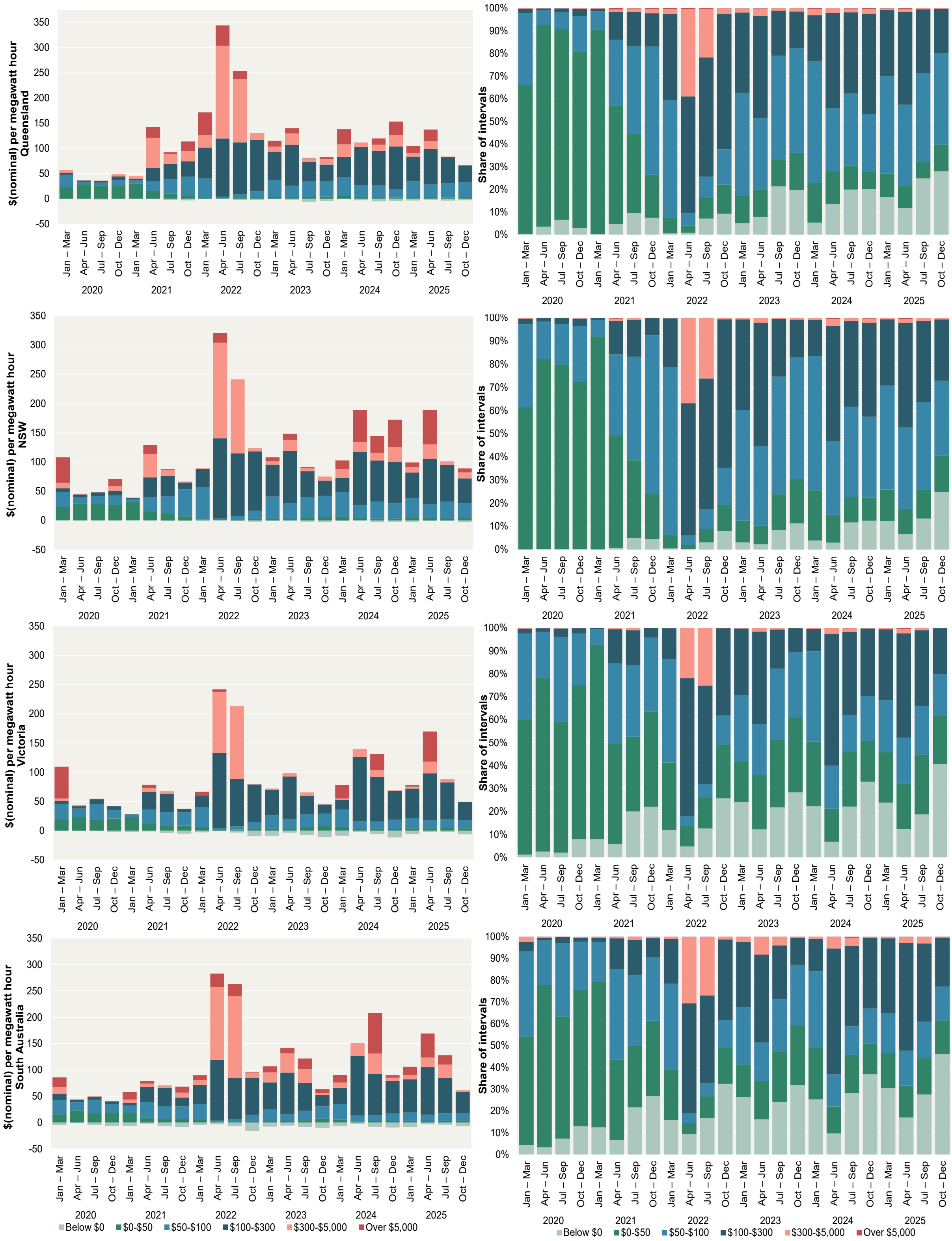
2.1.1 Higher price bands contributed less to mainland average prices in the past year

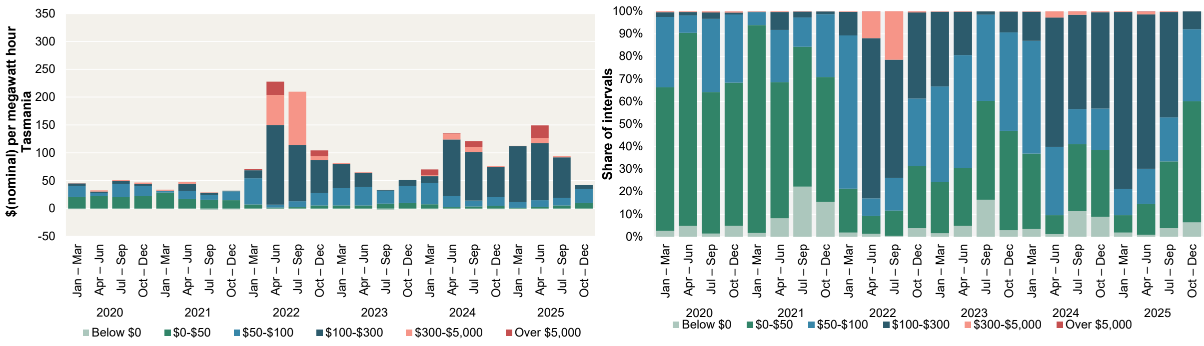
In the past year, prices above $100 per MWh contributed less to average wholesale prices across mainland regions. This reflected an increase in low-priced and mid-priced offers from batteries, solar and wind, and fewer prices over $5,000 per MWh. A higher volume of offers in the mid-priced bands help reduce market volatility. Greater volatility increases risk and costs for participants.

Since 2020, negative prices (below $0 per MWh) have become more frequent, mostly during the day, driven by new entry of solar and wind. However, negative prices have a smaller effect on average spot prices than high-price events. This is because negative prices are often only slightly below $0 per MWh, whereas high-price events tend to be more extreme and often occur when demand is higher, affecting a larger amount of dispatched electricity.

Before fuel prices started to increase in 2021, prices were often set between $0 per MWh and $50 per MWh. In 2020, this price band contributed around 40 to 60% of average wholesale prices. As fuel prices increased, particularly for coal (section 2.4.1), the volume of offers between $0 and $50 per MWh fell sharply.

Figure 2.2 Contribution and intervals of different price bands to quarterly wholesale prices



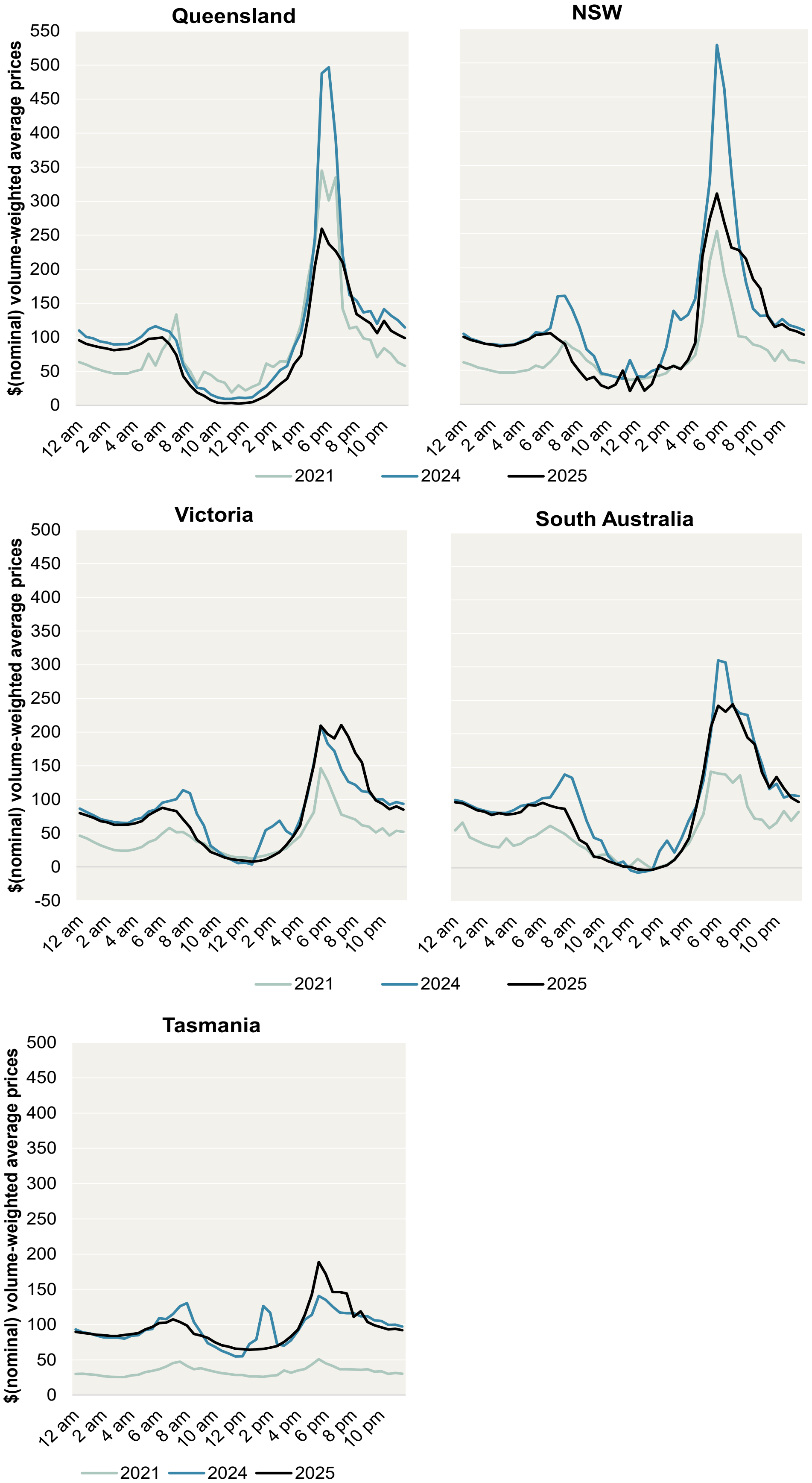


Note: Charts on the left show the extent to which different spot prices within defined bands contributed to the volume-weighted average wholesale prices in each region. Charts on the right show the percentage of intervals in each of the defined price bands.
Source: AER analysis using NEM data.

2.1.2 Prices remained above 2021 levels during the evening peak and overnight in all regions except Queensland

Price increases were concentrated at specific times of the day. Higher annual prices have been driven by price increases in the evening peak (4 pm to 9 pm) and overnight (9 pm to 6 am). In NSW, Victoria and South Australia, prices increased at these times due to a reduction in lower-priced offers. In Queensland, prices were higher overnight but were lower during the evening peak. Year-on-year changes in evening peak prices are heavily influenced by the number of events when prices are above $5,000 per MWh. In all mainland regions, prices were lower in 2025 compared with 2021 most of the day (9 am to 4 pm) and were generally higher in the morning peak (6 am to 9 am). In Tasmania, prices increased across all times of day compared with 2021.

Figure 2.3 Yearly average prices, by time of day



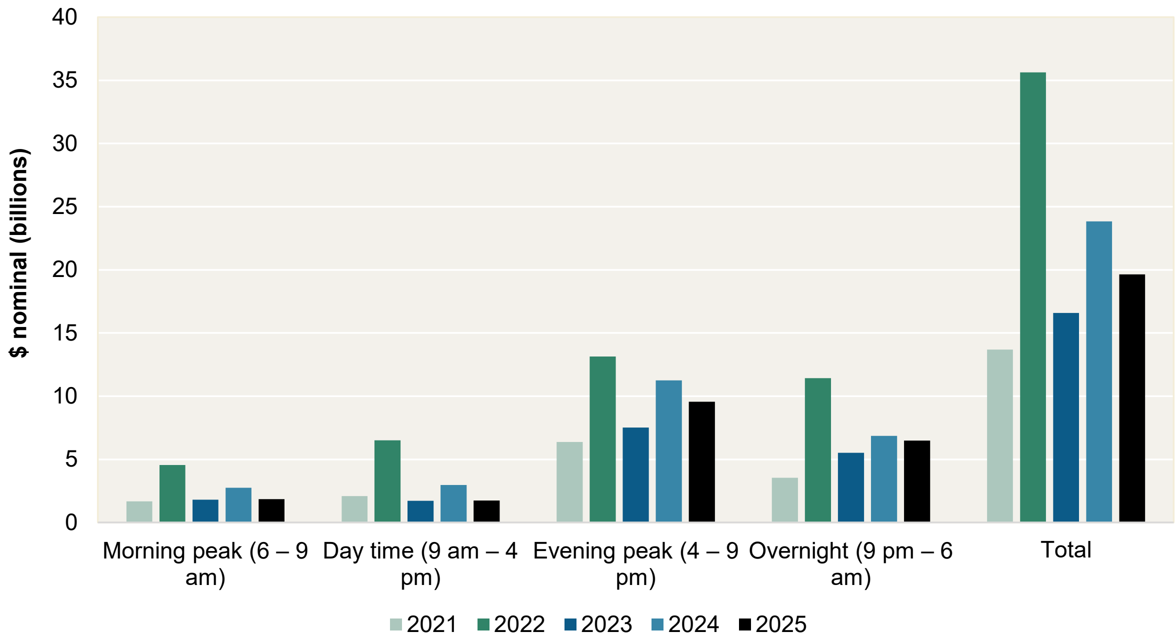
Note: Figure presents outcomes in NEM time (Australian Eastern Standard Time).
Source: AER analysis using NEM data.

2.1.3 Revenue remained above 2021 levels in 2025, driven by growth in the evening peak and overnight

In nominal terms, revenue remained above 2021 levels in 2025, driven by growth in the evening peak and overnight. Total NEM energy revenue decreased by around 18%, from $23.8 billion in 2024 to $19.6 billion in 2025. Revenue in 2025 was 43% higher than in 2021 ($13.7 billion).

Compared with 2021, total energy revenue in 2025 was higher across all times-of-day categories (Figure 2.4), except the daytime period (9 am to 4 pm). Evening peak (4 pm to 9 pm) revenue in 2025 was $3.2 billion higher, increasing from $6.4 billion to $9.6 billion, while overnight (9 pm to 6 am) revenue was $3 billion higher, increasing from $3.5 billion to $6.5 billion. Higher evening peak and overnight prices drove the increase in revenue during these times (Figure 2.4). In 2025, 49% of revenue was earned in the evening peak and 33% was earned overnight.

Figure 2.4 Total revenue, by time of day



Note: Figure presents outcomes in NEM time (Australian Eastern Standard Time).
Source: AER analysis using NEM data.

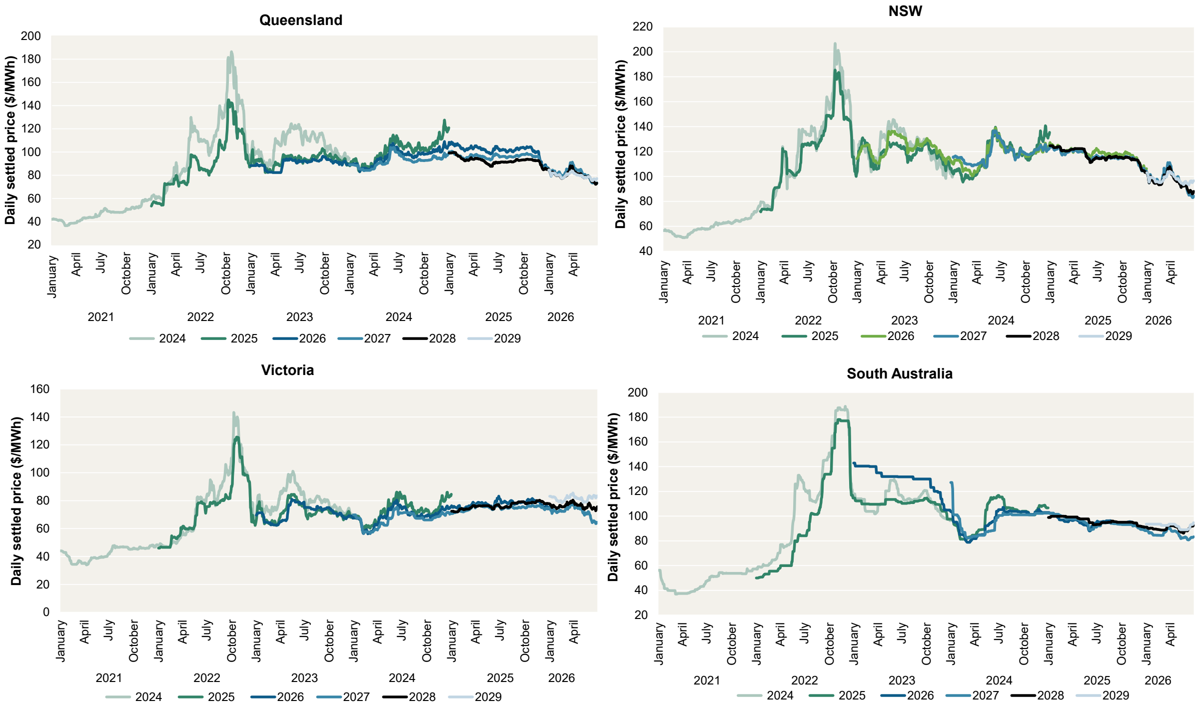
2.1.4 ASX base and cap futures prices fell in most regions

Contracts are used as a hedging tool by both generators and retailers to reduce their spot market risk. Base futures are one of the most traded contracts, allowing the buyer and seller to lock in a price for electricity in advance. The price of base futures gives an indication of where market participants expect spot prices to be in the future. Caps protect the buyer against very high electricity prices. For generators, selling caps provides upfront premium income that can help stabilise cash flow when spot prices are low or moderate. The level of the premium is driven by the expectation of the frequency and level of future high prices and high price volatility.

Base futures prices peaked during 2022 (Figure 2.5), as did spot prices (Figure 2.1). Since then, prices have stabilised but remain above pre-2022 levels. At the end of 2025, prices for base futures began to fall as additional capacity entered the market and spot prices declined.

From late 2025 to early 2026, base futures prices fell in all regions, except Victoria. Prices rose in March 2026 following the escalation of conflict in the Middle East, before declining in the April to June quarter of 2026.

Figure 2.5 Daily settled prices of calendar-year base futures

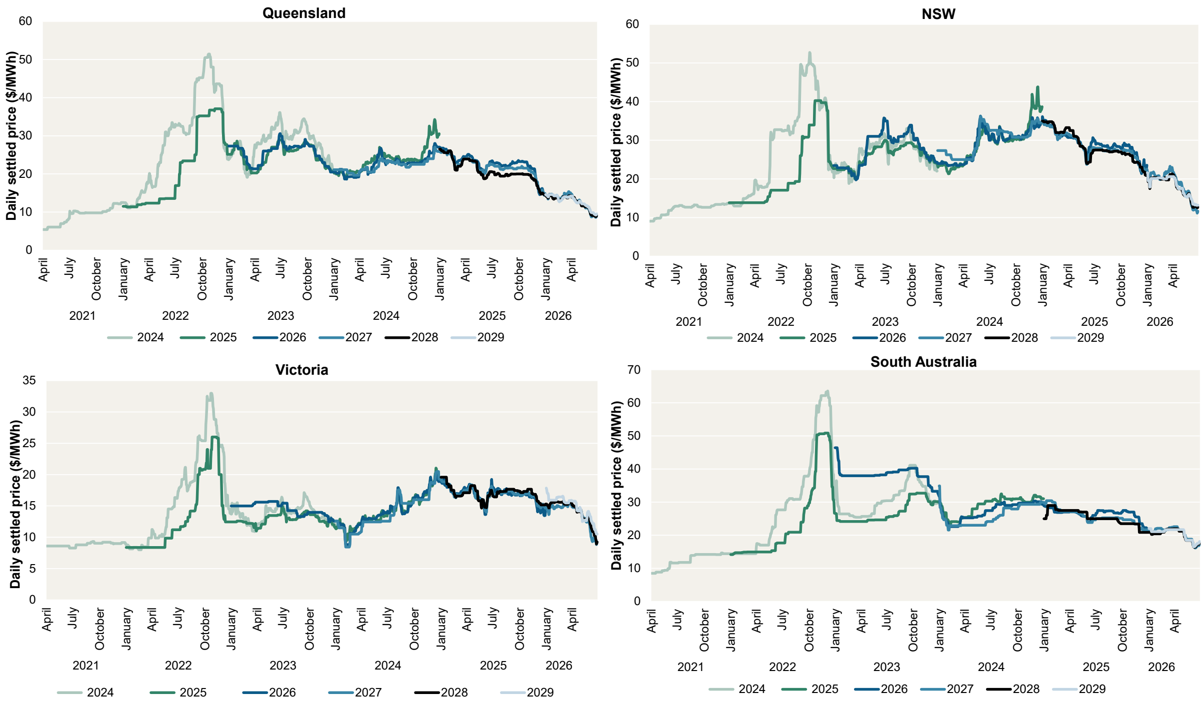


Note: Daily settlement prices ($ per MWh) for calendar-year base futures are shown separately for each NEM region. Within each chart, each curve represents a different delivery calendar year, which refers to the calendar year covered by the contract.
Source: AER analysis using ASX Energy data.

Cap prices followed a similar path to base futures, peaking in 2022 before stabilising above pre-2022 levels. In 2025 cap prices fell in all regions, with the largest declines in NSW and Queensland (more than 40%) and smaller falls in South Australia and Victoria.

Cap prices increased in March 2026 following the escalation of conflict in the Middle East, although by less than base futures. By June 2026, cap prices had fallen to new multi-year lows in Queensland and NSW.

Figure 2.6 Daily settled prices of calendar-year caps



Note: Daily settlement prices ($ per MWh) for calendar-year caps are shown separately for each NEM region. Within each chart, each curve represents a different delivery calendar year, which refers to the calendar year covered by the contract.
Source: AER analysis using ASX Energy data.

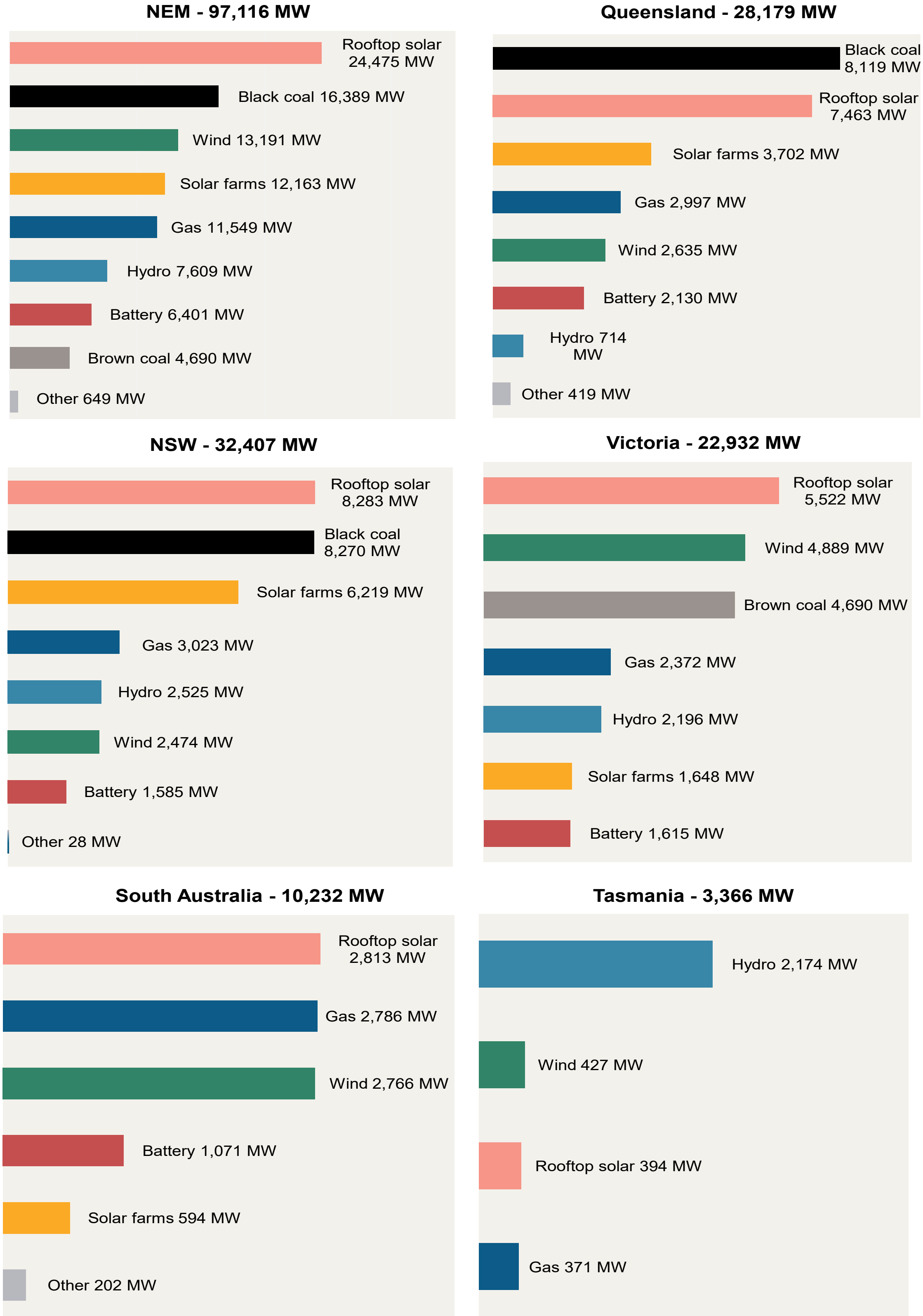
2.2 NEM generation mix continues to shift towards intermittent renewables and storage

The NEM generation mix continues to shift towards wind, solar and batteries. This shift can be described using either registered capacity[7] or generation output, which provide different perspectives on the composition of supply and how it is used.

Rooftop solar accounted for the largest share of registered capacity in 2025 (25%), followed by black coal (17%). Renewable technologies – rooftop solar, solar farms, wind farms and hydro – accounted for 59% of total registered capacity, similar to the 60% in 2024.

7 Registered capacity refers to the highest amount of electricity a generator has been registered to produce per hour. A typical generator will produce electricity at a rate lower than its registered capacity most of the time, with different generation technologies able to produce electricity at different rates relative to their capacity.

Figure 2.7 Registered capacity, by fuel type and region, 2025

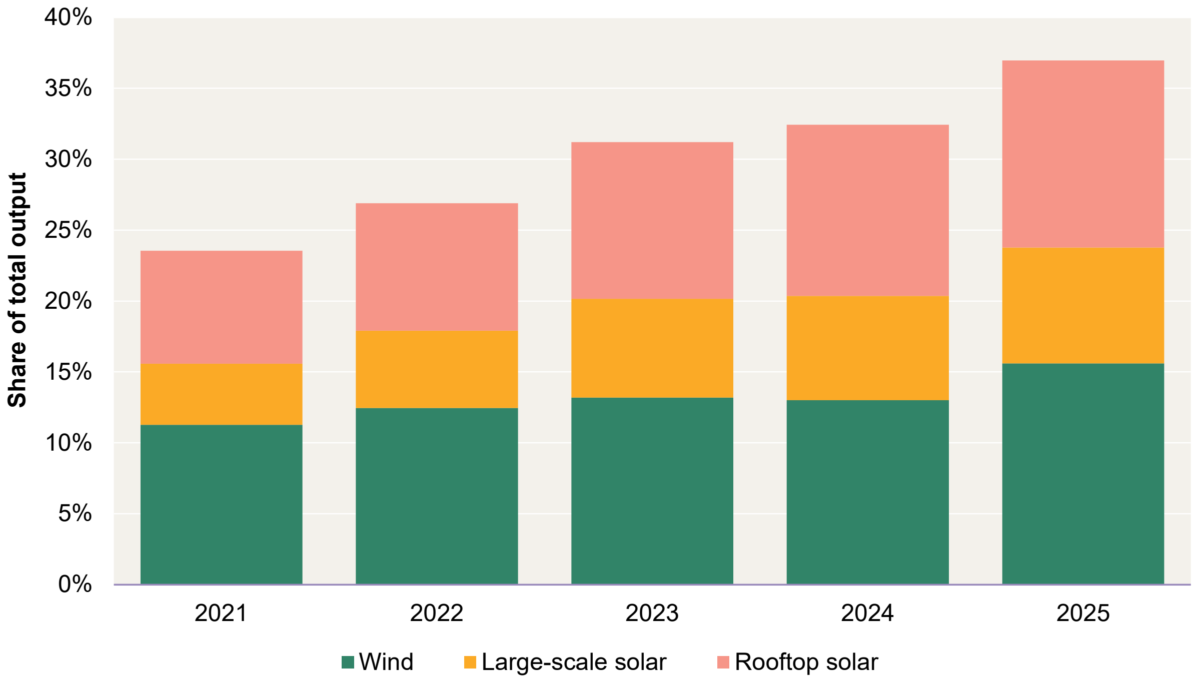


Note: Registered capacity at 31 December 2025. Other registered capacity includes biomass, waste gas, diesel and liquid fuels. Loads and non-scheduled generation have been excluded. For solar and battery units, we used the maximum capacity metric rather than registered capacity because inverter constraints may prevent these units from dispatching their full registered capacity. Rooftop solar is behind-the-meter rather than being NEM registered generation capacity but is included for context.
Source: AER; AEMO (grid capacity data); Clean Energy Regulator (rooftop solar capacity data).

Since 2021, the share of total generation from wind and solar has grown from 24% to almost 37%. In 2025, wind generation accounted for around 16% of total generation, rooftop solar for 13% and solar farms for 8%.

Wind generation can vary year to year due to changing weather conditions, including periods of low wind output. Across the NEM, wind output increased in absolute terms every year, but its share of total generation declined in 2024 from the previous year. Wind's share of generation remained lower in Queensland (6%) and NSW (11%) than in other regions, but it accounted for almost one-quarter of total generation in Victoria (24%) and Tasmania (21%), and almost half in South Australia (48%).[8]

Figure 2.8 NEM annual wind and solar generation, as a percentage of total generation

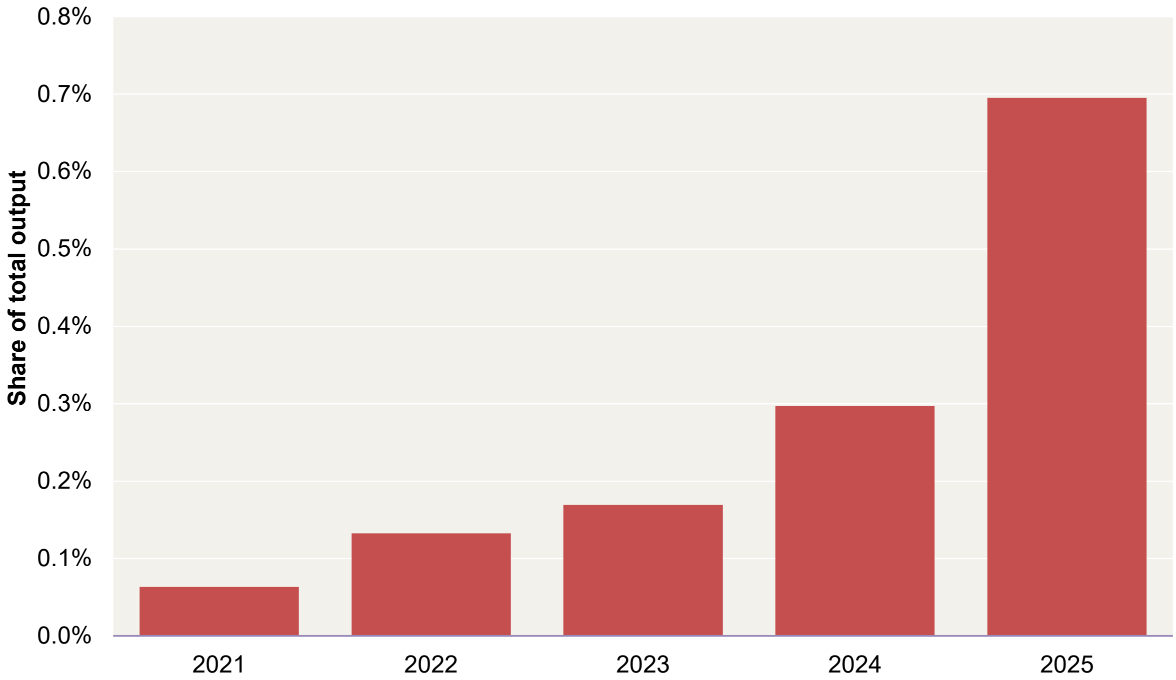


Note: Sum of generation as share of total generation by calendar year.
Source: AER analysis using NEM data.

Battery generation was a small share of total generation, but it is increasing quickly. Its share increased from 0.06% in 2021 to 0.7% in 2025, with most of the growth occurring in the past year.

8 Charts and data on regions are available in the Market conditions and change driver data book.

Figure 2.9 NEM annual battery generation, as a percentage of total generation

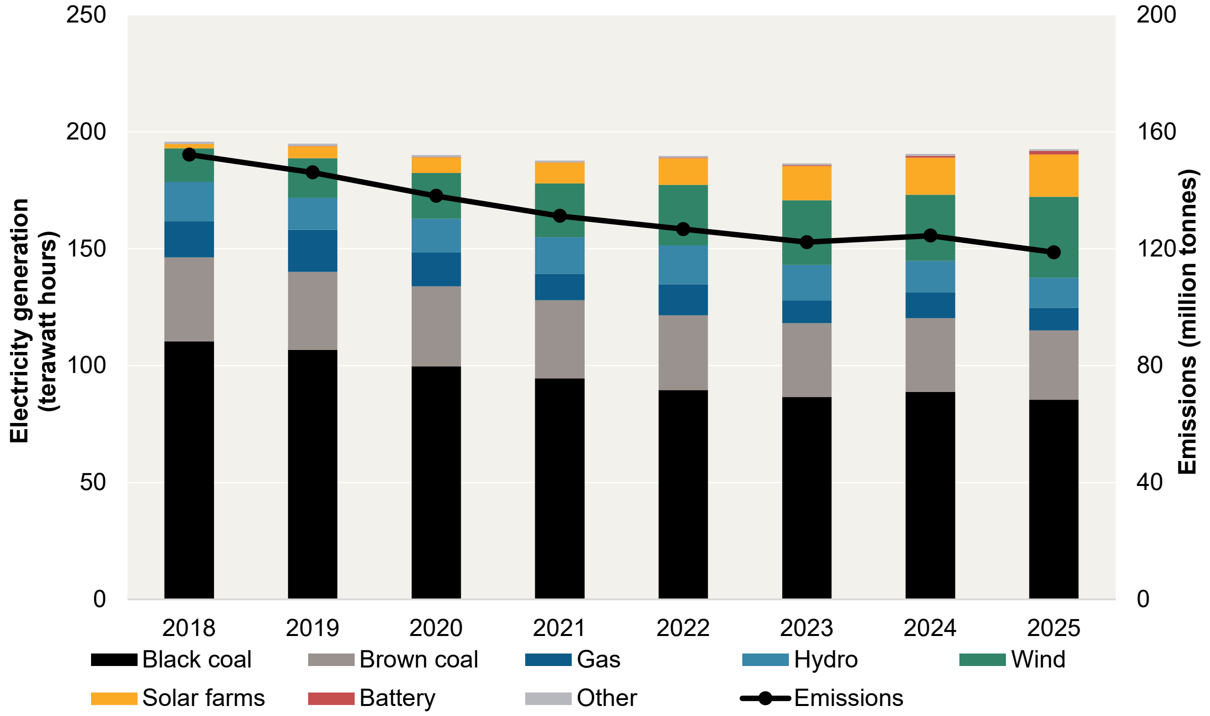


Note: Sum of generation as share of total generation by calendar year.
Source: AER analysis using NEM data.

As the NEM generation mix has shifted away from coal and towards intermittent renewable energy, total emissions declined from 2018 to 2023, before increasing slightly in 2024. The increase in 2024 reflected higher black coal generation and lower hydro generation. In 2025, black coal generation dropped below 2023 levels and total emissions continued to decrease.

Reducing emissions from the energy sector are also expected to support the decarbonisation of other high-emitting sectors, including transportation and industrial processes.

Figure 2.10 Annual generation, by fuel type and emissions[9]



Source: AER analysis using NEM and National Greenhouse Gas Inventory data (DCCEEW).

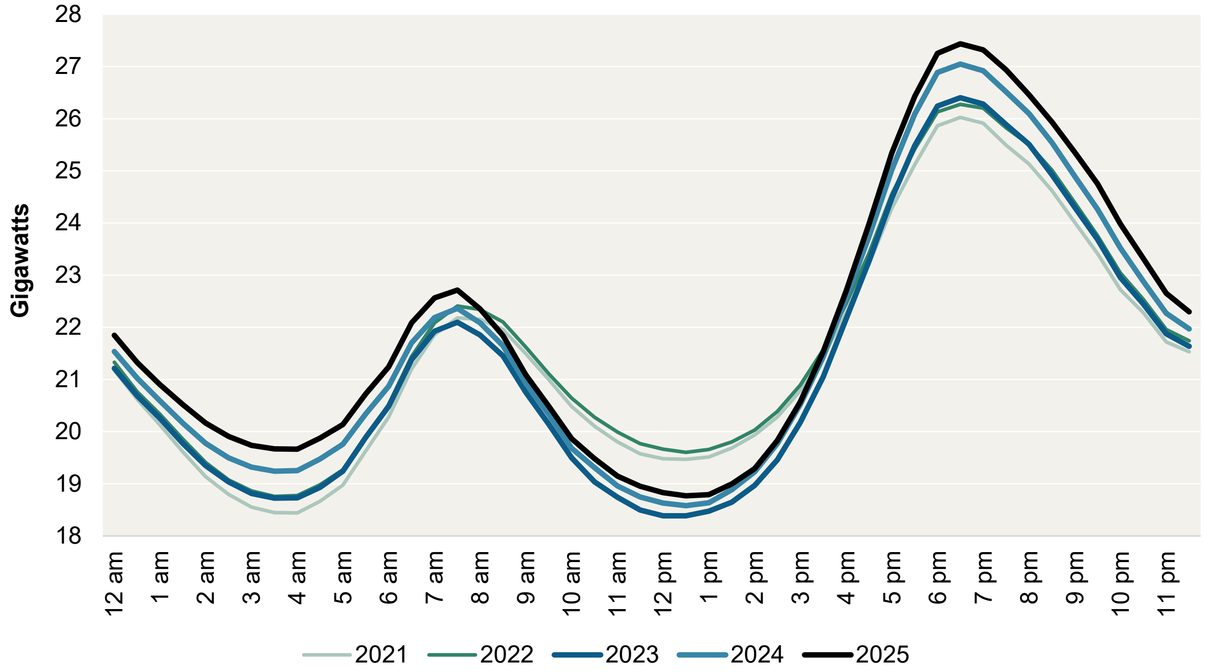
2.3 Demand increased at all times of the day, particularly outside the daytime

Changes in the generation mix and continued uptake of rooftop solar have reshaped demand. Rooftop solar reduces underlying demand during the day. In 2025, average native demand between 4:30 pm and 8 am was the highest across the previous 5 years. Daytime demand in 2025 was also the highest since 2022, despite continued rooftop solar uptake. This increase in demand during the day aligns with increased battery capacity entering the NEM. Population growth is also likely to play a part.

The AER defines native demand as demand met by all power stations within the region, including local scheduled, semi-scheduled, non-scheduled and exempt generation, plus bidirectional units when they are generating, plus interconnector imports. It does not include demand met by wholesale demand response and rooftop solar. Native demand is the most appropriate demand measure to report on historic demand because it captures actual metered demand as well as demand that was offset by exempted generation and non-scheduled units.

9 To generate 1 MWh of electricity, brown coal generators produce around 1.2 tonnes of carbon dioxide, black coal generators produce 0.9 tonnes and gas generators produce around 0.7 tonnes.

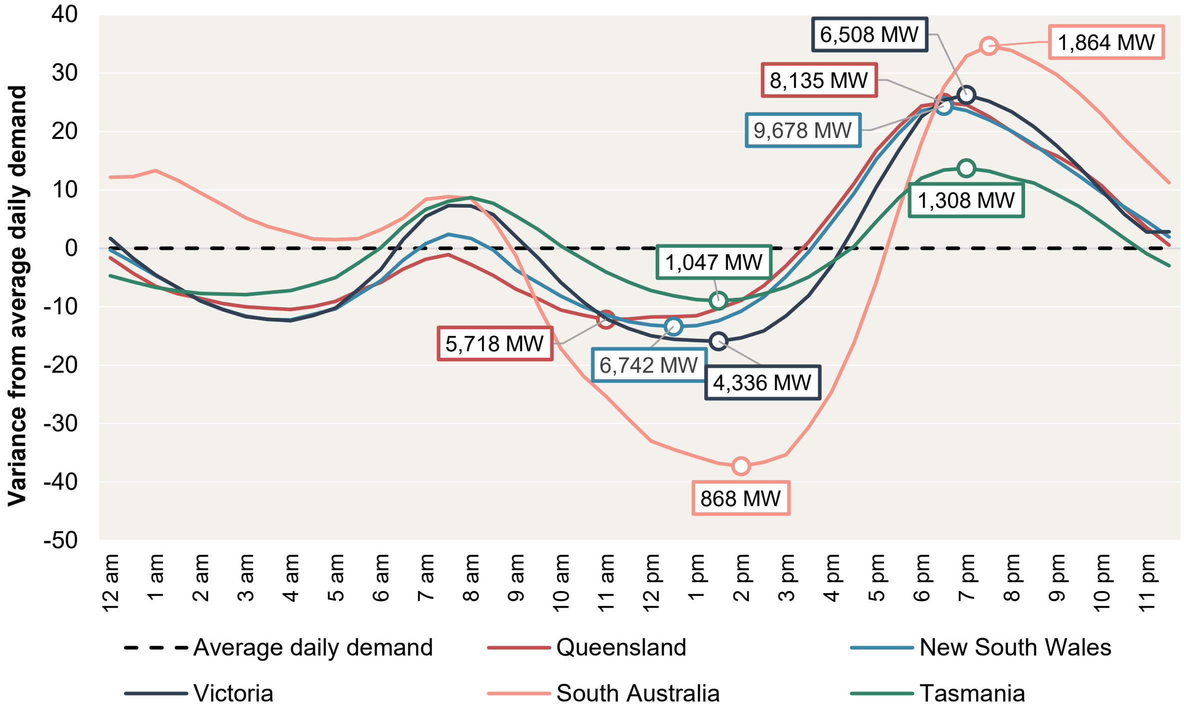
Figure 2.11 Average NEM native demand, by time of day



Note: This figure presents outcomes in NEM time (Australian Eastern Standard Time). Values of the y-axis do not start at zero to highlight the changes in demand.
Source: AER analysis using NEM data.

The gap between average minimum and maximum demand varies considerably across regions. South Australia had the largest gap in 2025 (approximately 72% difference between average minimum and average maximum demand). Victoria, NSW and Queensland had more moderate gaps (37%), while Tasmania had the flattest demand throughout the day (23%) (Figure 2.12). This variation is influenced by factors such as rooftop solar uptake, which tends to increase demand variability, and the proportion of electricity demand from heavy industry, which tends to reduce it.

Figure 2.12 Average native demand, by time of day, by region, 2025



Notes: This figure presents outcomes in NEM time (Australian Eastern Standard Time). Data labels show the average daily minimum and maximum demand in each region.
Source: AER analysis using NEM data.

This variation in average demand requires power supply that can respond flexibly to rapid changes across the day. This has increased reliance on dispatchable generation to ramp up from lower daytime output levels to meet the evening peak. These conditions also create opportunities for flexible resources that can shift energy between low-price daytime periods to higher-price peak periods.

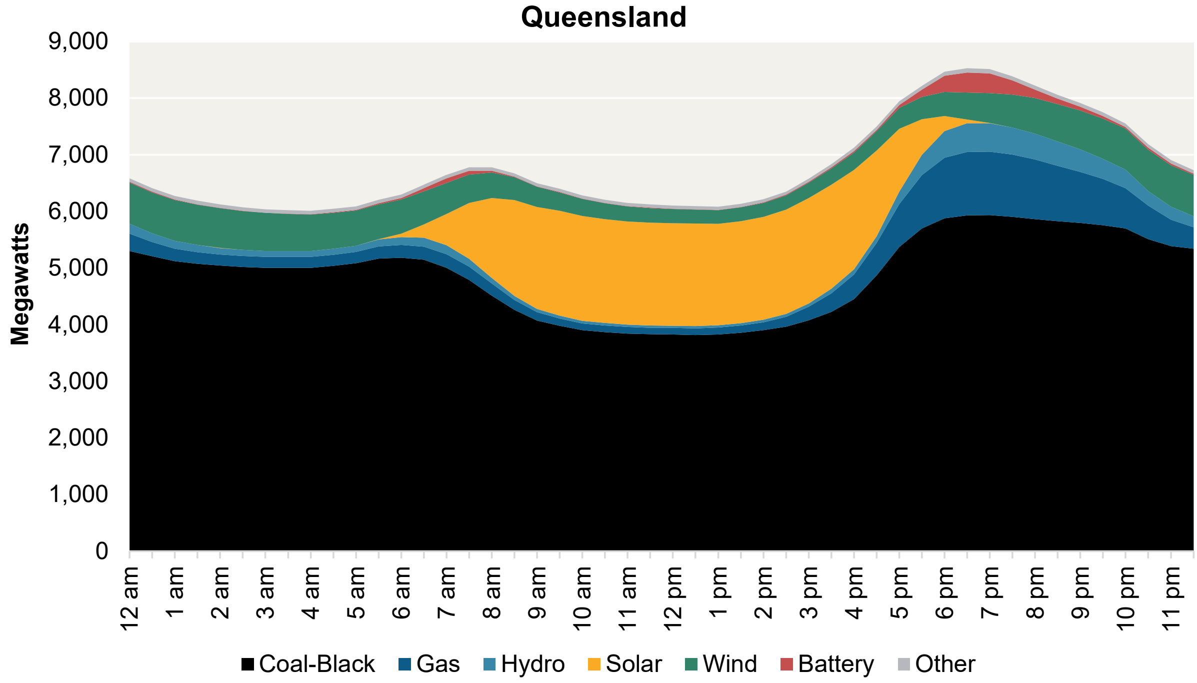
Low demand can require AEMO to intervene in the market to maintain grid stability. For example, AEMO may use directions to maintain system strength when the number of synchronous generators falls below required levels. Directions can be issued to manage minimum system load conditions (section 6.3.1).

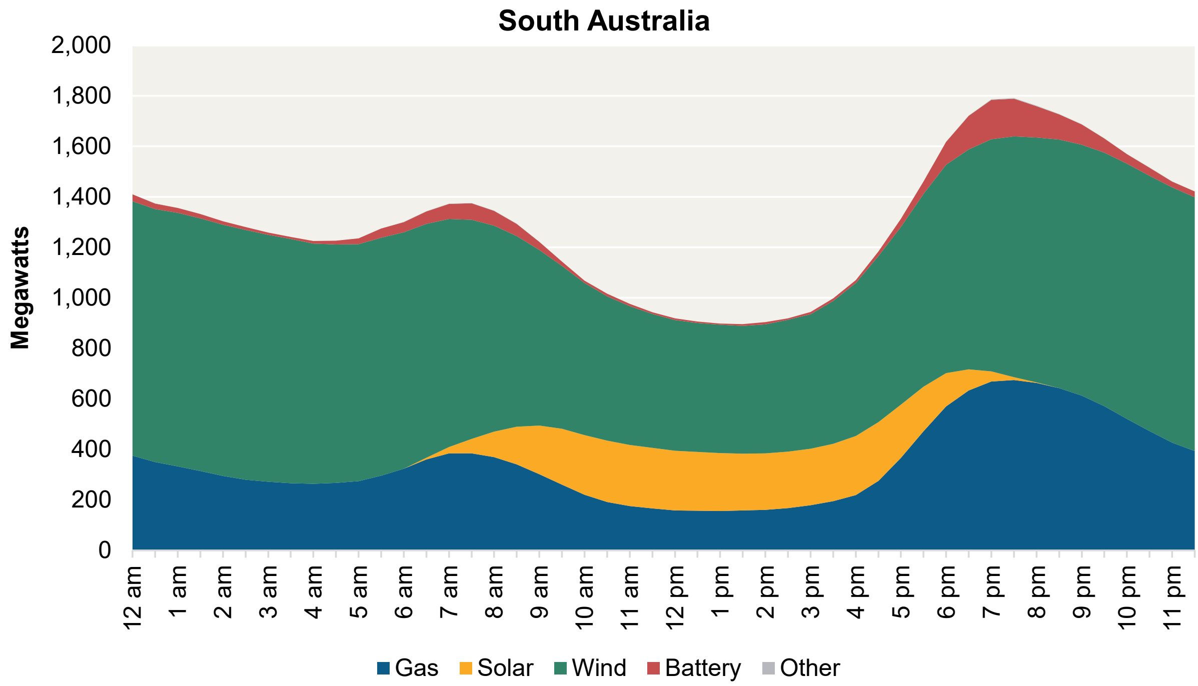
2.3.1 Intermittent renewables generation is highest during the day, while dispatchable generation remains dominant at other times

While rooftop solar reduces demand, large-scale solar supplies a growing share of grid generation during the day. Across mainland regions, large-scale solar provided between 13% and 37% of output in the middle of the day in 2025, displacing coal, gas and hydro generation. Wind generated power at all times of the day, but on average generated more power overnight. In most regions, dispatchable fuel types continue to provide most of the generation outside the daytime.

Coal remains the dominant fuel type in Queensland, Victoria and NSW. During peak periods, batteries provide additional supply by charging during low-priced or negative-priced periods in the middle of the day and discharging when demand and prices are higher. While battery generation accounted for 0.7% of total generation in 2025, further growth in battery capacity is expected to change the generation mix and dispatch outcomes over time.

Figure 2.13 Generation, by fuel type, by time of day, 2025[10]





Note: Other dispatch includes biomass, waste gas, diesel and liquid fuels.
Source: AER analysis using NEM data.

10 Charts and data for NSW, Victoria and Tasmania can be found in the Market conditions and change drivers data book.

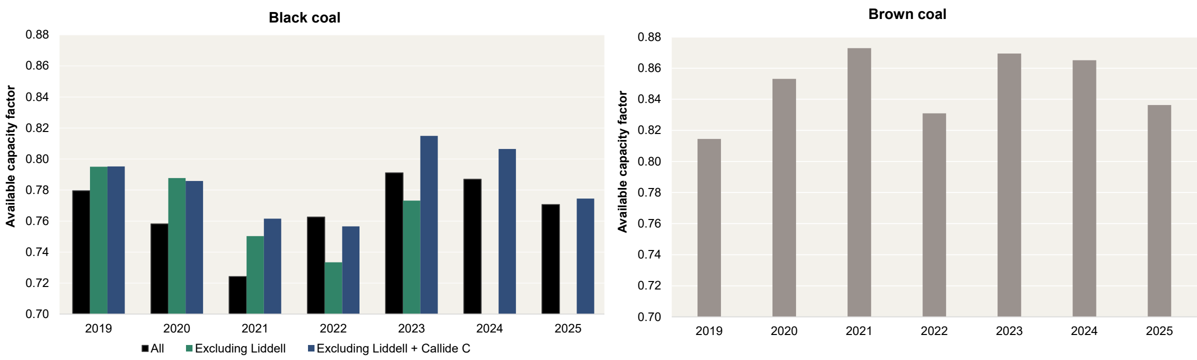
2.4 Supply conditions and price-setting trends

2.4.1 Coal availability in 2025 at similar levels to 2019

Black coal availability reached its lowest level in 2021, when a major failure occurred to Callide C. Availability peaked in 2023, before easing in 2025 to around pre-2021 levels.

The average availability capacity factor for brown coal remained higher than for black coal throughout the period, although it fluctuated with dips in 2019 and 2022. While the average availability capacity factor for brown coal was lower in 2025 than in previous years, it remained higher than 2019 and 2022 levels.

Figure 2.14 Average available capacity factor for black and brown coal



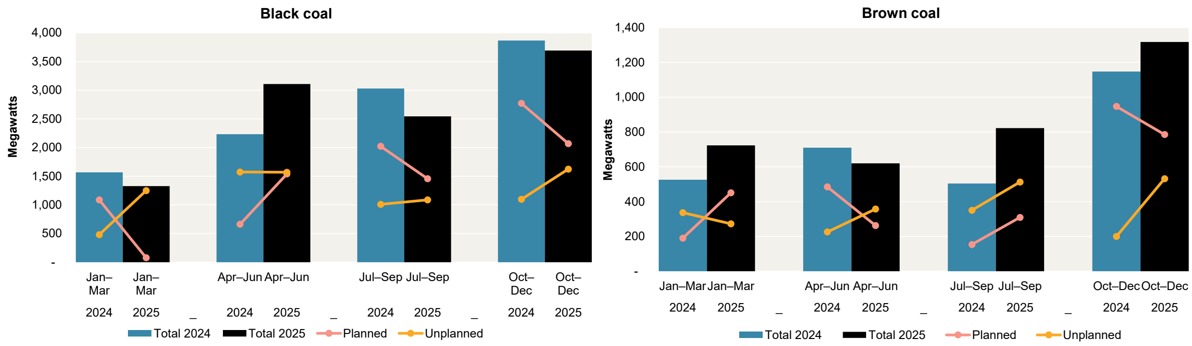
Note: The average available capacity factor is calculated by comparing generator availability to registered capacity. Liddell ceased operation in 2023 after operating for more than 52 years.
Source: AER analysis using NEM data.

2.4.2 Unplanned outages increased in most quarters in 2025

Outages refer to periods when a dispatchable generator is completely offline, either for planned maintenance or unplanned events. Planned outages allow other providers to adjust their offers, and potentially their generation, in response. Unplanned outages can increase market volatility, which can put upward pressure on future contract prices. A plant's reliability also affects the level of contracting the owner is willing to undertake.

Total coal outages showed mixed trends in 2025, but unplanned outages were generally higher than in 2024. For black coal, total outages were lower than in 2024 in the January to March, July to September and October to December quarters, but unplanned outages were higher in those quarters. For brown coal, total outages increased in the January to March, July to September and October to December quarters in 2025, while unplanned outages were higher in the April to June, July to September and October to December quarters.

Figure 2.15 Planned and unplanned coal outages



Note: Time-weighted MW maximum capacity average over the entire quarter, calculated at dispatch interval (5 minutes).
Source: AEMO.

2.4.3 Coal and gas input costs remain above pre-2022 levels

In 2025 coal and gas input costs were lower than their 2022 peaks but remained above earlier levels.

Coal input costs are a key determinant of coal generators' cost of producing electricity. Black coal generators source their fuel directly from an attached mine or through contracts with independent suppliers. NSW black coal generators typically acquire their fuel through contracts. Because domestic contract prices are often linked to international benchmark prices, generators can remain exposed to changes in export coal prices. This exposure can be greater when supply disruptions require additional purchases or when contracts are renegotiated during periods of volatility.

Coal generators in Victoria use brown coal rather than black coal. Brown coal is plentiful in the Gippsland region and relatively low cost. Because it is low quality and unsuitable for export, its cost is not influenced by export market coal prices.

In 2025 the international export price for black coal declined and averaged around $163 per tonne (around $64 per MWh) (Figure 2.16). Despite this decline, average coal prices in 2025 were still around 31% higher than during the market intervention (around $49 per MWh) and 87% higher than the 2020 average (around $34 per MWh) (Figure 2.16).

As part of the Energy Price Relief Plan[11] agreed to by National Cabinet, on 22 December 2022 the NSW Premier declared a coal market price emergency. The NSW Government capped the price of black coal sold to generators at $125 per tonne.[12] This is the equivalent of $49 per MWh. The Queensland Government moved simultaneously to direct its coal generators. During the market interventions, we observed an increase in low-priced and mid-priced offers from NSW and Queensland coal generators, indicating the intervention had a role in suppressing prices while it was in effect. The NSW intervention ended on 30 June 2024.

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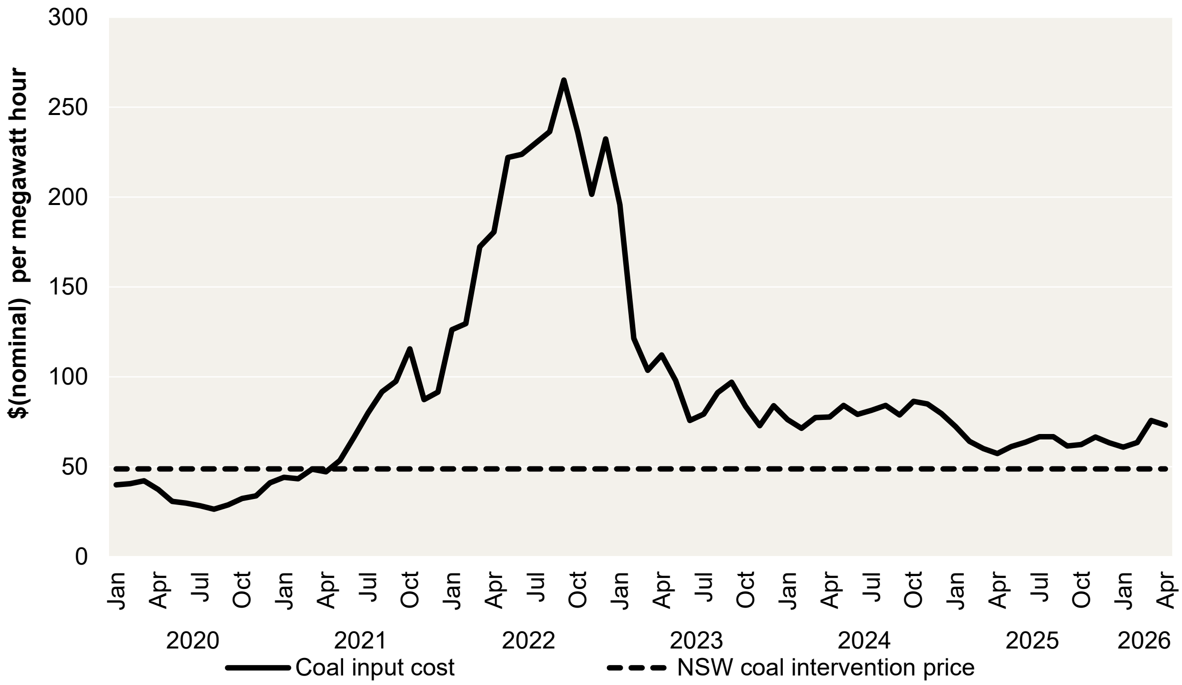
11 Australian Government, Energy Price Relief Plan, media release, accessed 10 August 2026.

12 The $125 per tonne coal cap price was based on 5,500 kilocalories per kilogram (kcal/kg). For coal with other calorific values, it was $0.02273 per kcal/kg.

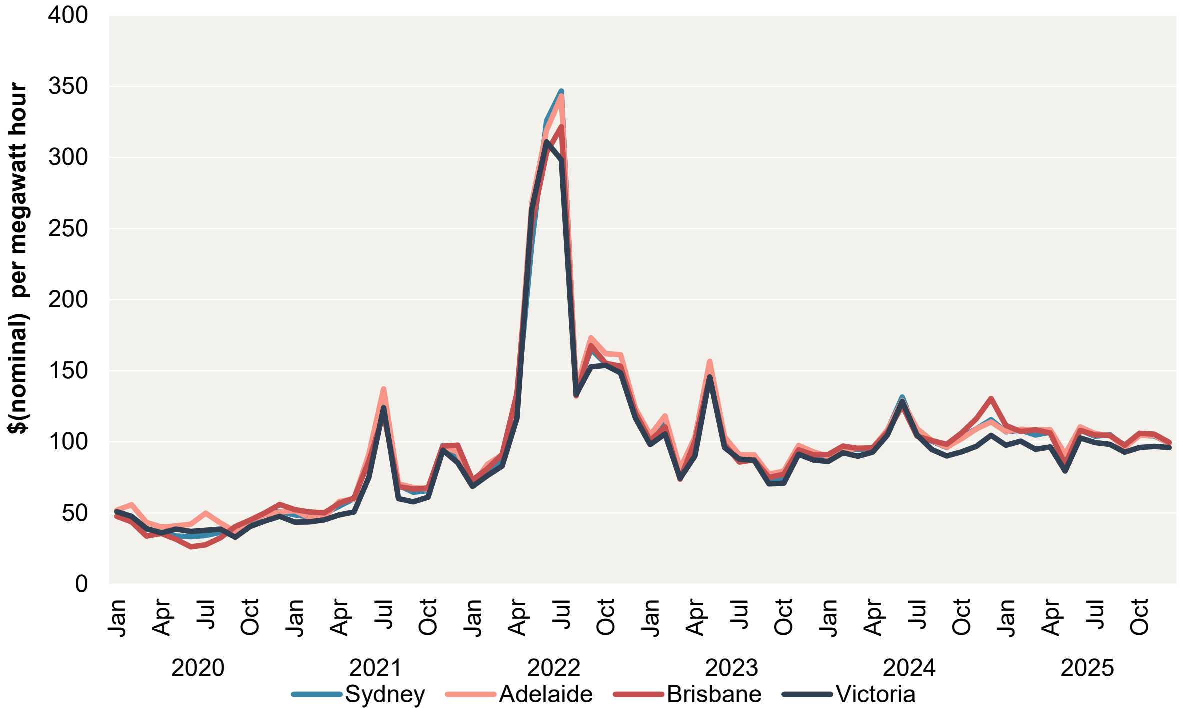
Figure 2.16 Proxy input cost of coal per MWh based on spot prices



Note: To convert coal prices from US$ per tonne to AUD$ per MWh, we use the formula: $ per MWh = coal cost (US$ per tonne) divided by the exchange rate (monthly average) x heat rate (GJ per MWh)/low heating value (GJ per tonne). For coal, we use a constant heat rate of 9 GJ per MWh and a low heating value of 23 GJ per tonne.
Source: AER analysis of the Newcastle thermal coal index using data from GlobalCOAL.

Like black coal generators, gas-powered generators source fuel from spot markets and both short-term and long-term contracts with suppliers. Gas input costs moved broadly together across regions until mid-2024. From July 2024 Victorian gas input costs fell below those in other regions, and that gap has persisted through to the end of 2025. Overall, gas input costs have been generally stable since 2024 but remained above 2023 levels.

Figure 2.17 Proxy input cost of gas per MWh based on spot prices



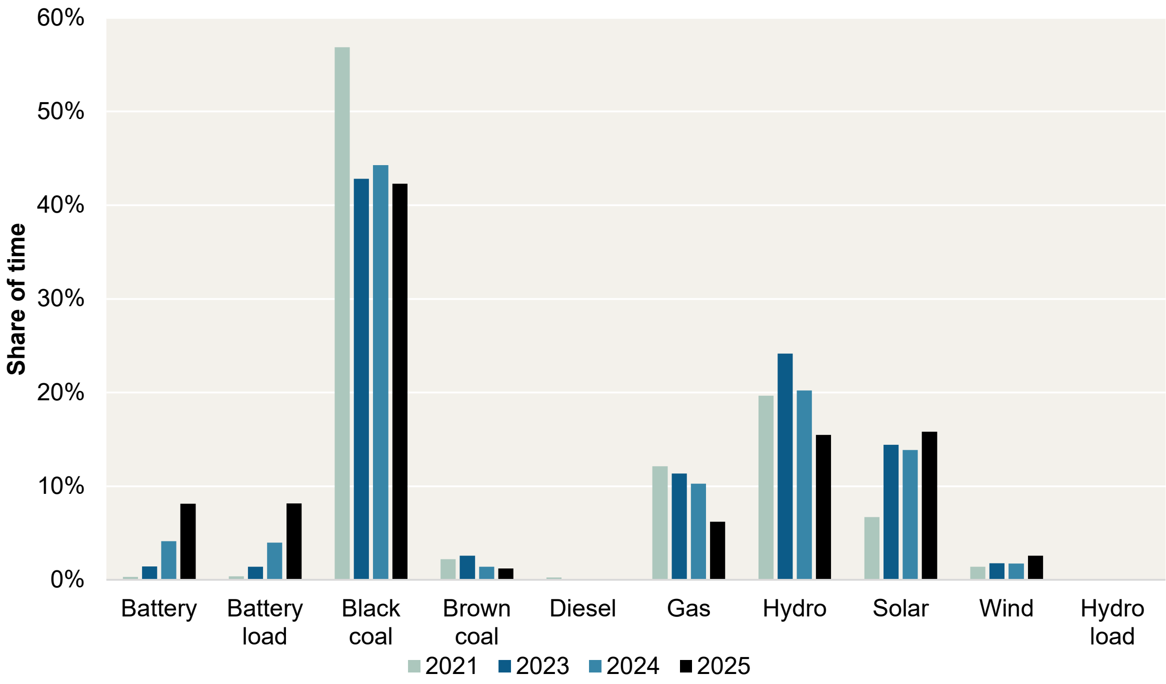
Note: Adelaide, Brisbane and Sydney Short Term Trading Market hub prices are average daily ex ante gas prices by month. Victorian Declared Wholesale Gas Market prices are average daily weighted prices by month. To convert the gas prices from per GJ to per MWh, we use the formula: $ per MWh = gas cost x heat rate (GJ per MWh). For gas, we use an average constant heat rate for combined cycle gas turbine (CCGT) units of 8 GJ per MWh. However, open cycle gas turbine (OCGT) units are more likely to set the price in periods of peak demand – because they operate less efficiently than CCGT, they have higher heat rates. As a result, the cost of gas in $ per MWh is higher.
Source: AER analysis using gas market data.

2.4.4 Batteries increasingly set the price as coal's role declined

Prices are set by different fuel types depending on the region and time of day. Prior to the 'energy squeeze' (pre-2022), prices were set more often across regions by coal, gas and hydro. Since then (2023 to 2025) those fuels have generally set the price less often, while batteries, solar and wind have set it more often. Queensland and NSW started with similar price-setting patterns and experienced similar changes in recent years, as did Victoria and South Australia.

Black coal remained the dominant price setter in Queensland and NSW, setting the price more than 40% of the time in 2025, although this was significantly lower than in 2021. The increase in solar setting the price was a key driver of the reduction. Battery generation and battery load (charging) have increasingly set the price, rising from around a combined 1% in 2021 to 16.3% in 2025, replacing gas and hydro.

Figure 2.18 Price setting, by fuel type, Queensland[13]

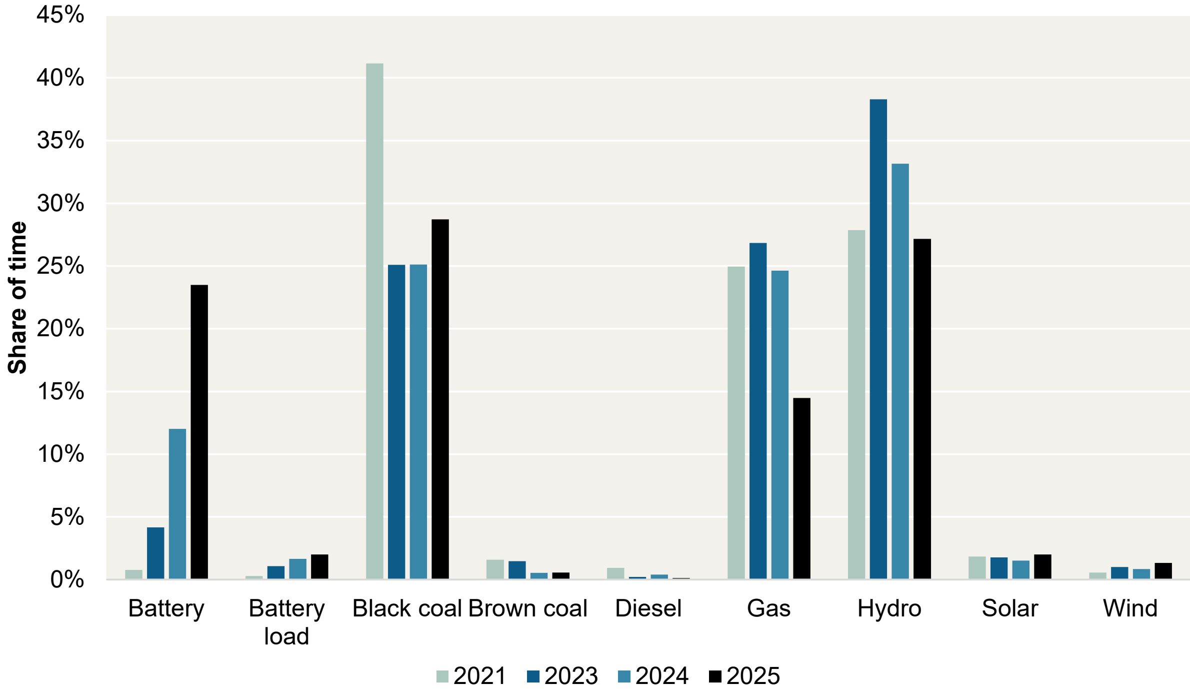


Source: AER analysis using NEM data.

During the evening peak (4 pm to 9 pm) in Queensland and NSW, black coal set the price less often than in 2021, coinciding with higher fuel prices and fewer low-priced offers. It was initially replaced by hydro (2023). Since peaking in 2023, gas and hydro have set the price less often in Queensland and NSW. By contrast, battery generation and load set the price 25.5% of the time during the evening peak in 2025, up from around 1% in 2021.

13 Charts and data for NSW, South Australia and Tasmania can be found in the Market conditions and change drivers data book.

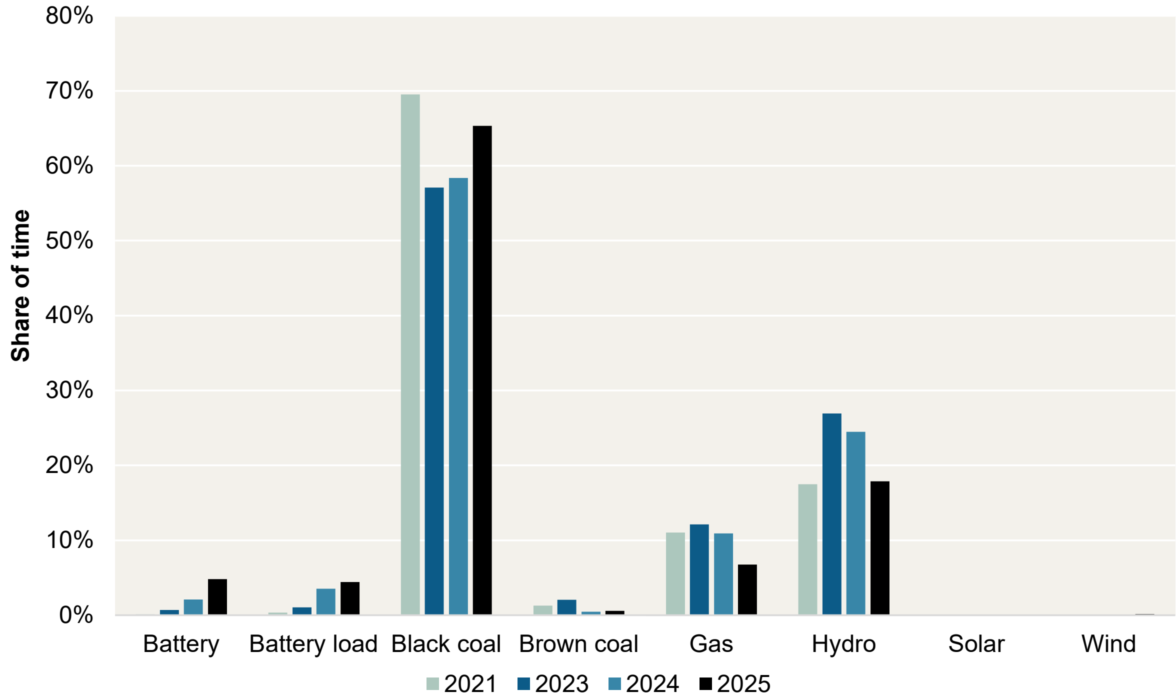
Figure 2.19 Price setting, by fuel type, evening peak (4 pm to 9 pm), Queensland



Source: AER analysis using NEM data.

Overnight (9 pm to 6 am) black coal remained the dominant price-setting fuel type in Queensland and NSW, setting the price 65% of the time in Queensland and declining only slightly since 2021. Gas and hydro showed a similar pattern to the evening peak, but with smaller declines. Battery price setting remains low overnight, with battery generation and load setting the price around 9% of the time in 2025.

Figure 2.20 Price setting, by fuel type, overnight (9 pm to 6 am), Queensland



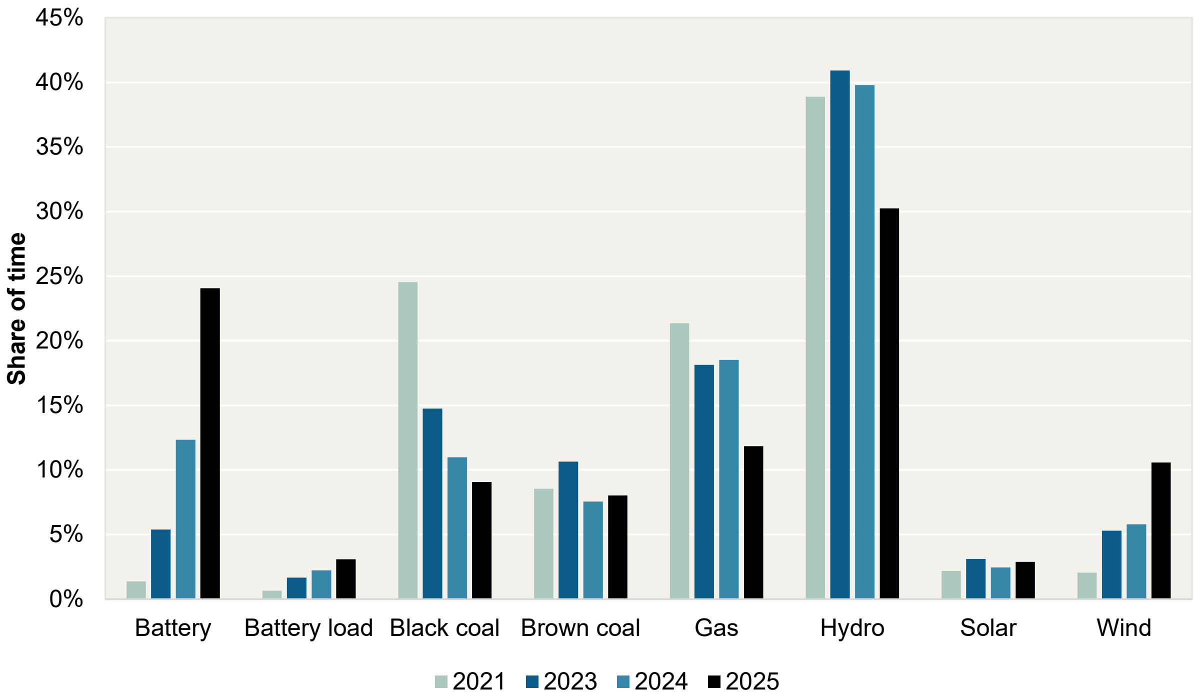
Source: AER analysis using NEM data.

In Victoria and South Australia, black coal also set the price less often, although from a lower base than in Queensland and NSW.[14] In Victoria, brown coal showed a similar decline overnight (9 pm to 6 am), but its evening peak (4 pm to 9 pm) price-setting frequency was broadly unchanged. The impact of brown coal on both overnight and evening peak prices declined in South Australia.

Gas and hydro both recorded significant declines in evening peak price-setting compared with 2024. Hydro set the price 30% of the time in 2025, down from 40% in 2024, while gas declined from 18% to 12%. Hydro also declined overnight.

Wind sets the price more often in Victoria in 2025, reaching 11% of the time during both the evening peak and overnight, up from 2.1% and 3.6% in 2021. Batteries also played a larger role, setting the price 27% of the time in the evening peak and 12% overnight in 2025, compared with 2% in both periods in 2021.

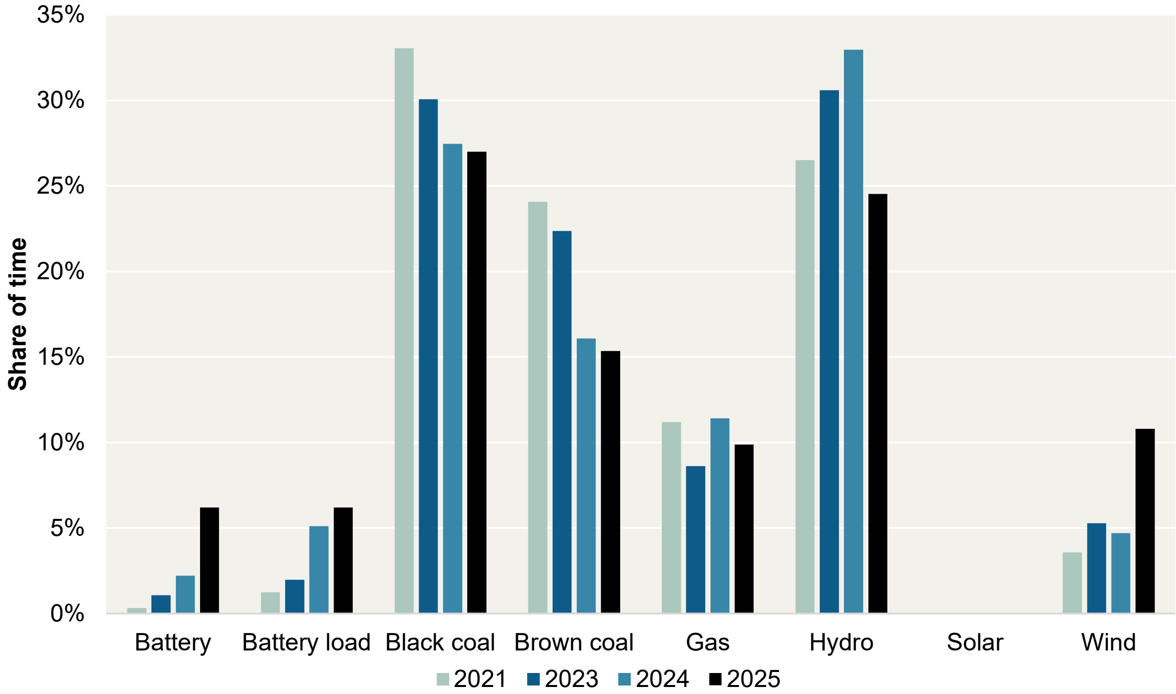
Figure 2.21 Price setting, by fuel type, evening peak (4 pm to 9 pm), Victoria



Source: AER analysis using NEM data.

14 A generator in one region can set the price in another region over unconstrained interconnection.

Figure 2.22 Price setting, by fuel type, overnight (9 pm to 6 am), Victoria



Source: AER analysis using NEM data.

2.5 Frequency control ancillary services costs remained low in 2025, with localised spikes in South Australia

Box 2.2 Frequency control ancillary services

Frequency variations occur when supply and demand are not perfectly balanced. AEMO uses FCAS to support system frequency by providing revenue for generators, batteries and other technologies that can help to stabilise the frequency when required. The cost of managing FCAS reflects both the availability of suppliers with the capability to respond to frequency variations and the level of competition. AEMO operates energy and FCAS markets through co-optimisation to minimise overall costs by jointly dispatching energy and FCAS requirements.

FCAS are divided into 2 main types:

- regulation services, which address small, continuous frequency changes
- contingency services, which handle large, infrequent shifts.

AEMO maintains system frequency near 50 Hertz through 10 FCAS markets, including various ‘raise’ and ‘lower’ services to maintain frequency at this level across different response times.

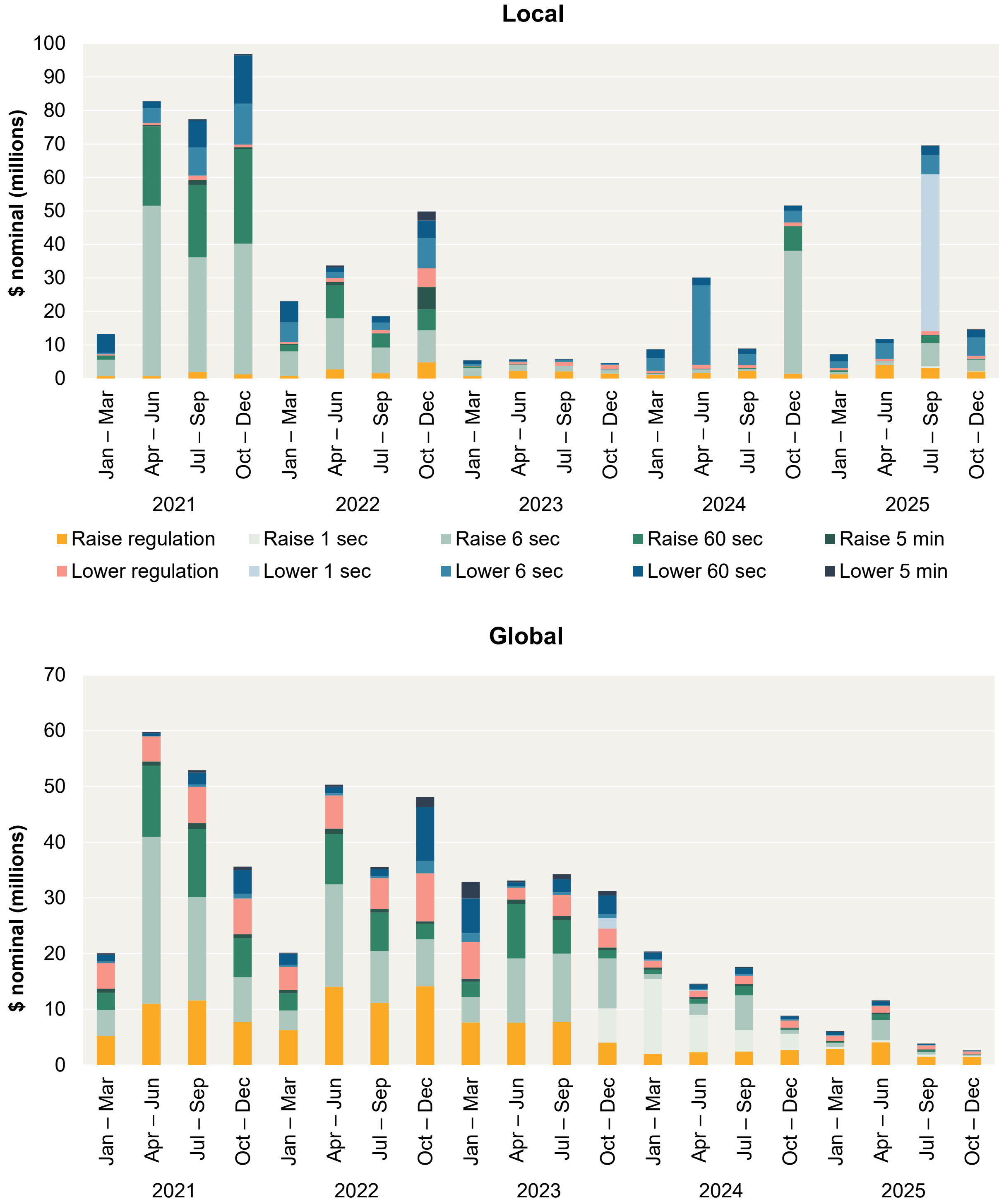
FCAS can be global (shared across regions) or local (restricted to certain regions during potential separation events). Most of the time, FCAS is procured in a global market, with services supplied across regions. Local requirements ensure system stability when there is credible risk of interconnectors failure, especially in Queensland, South Australia and Tasmania, which are each only connected to one other region.

AEMO procures each FCAS service as needed, depending on factors such as the size of the largest credible event for contingency services and ongoing system requirements for regulation services.

Global FCAS costs continued to decline in 2025, driven by increased competition as more battery service providers entered the market. Local FCAS costs also remained low, except for the July to September 2025 quarter, when South Australia experienced higher costs due to the lower 1-second service. Further details can be found in the *Prices above $5,000/MWh – July to September 2025* report.[15] When a region needs to rely on local services there can be a lack of competition, causing high prices. The market structure of the local FCAS markets for South Australia and Queensland are discussed in section 4.2.

15 AER, Prices above $5,000/MWh - July to September 2025 report, Australian Energy Regulator, 1 December 2025.

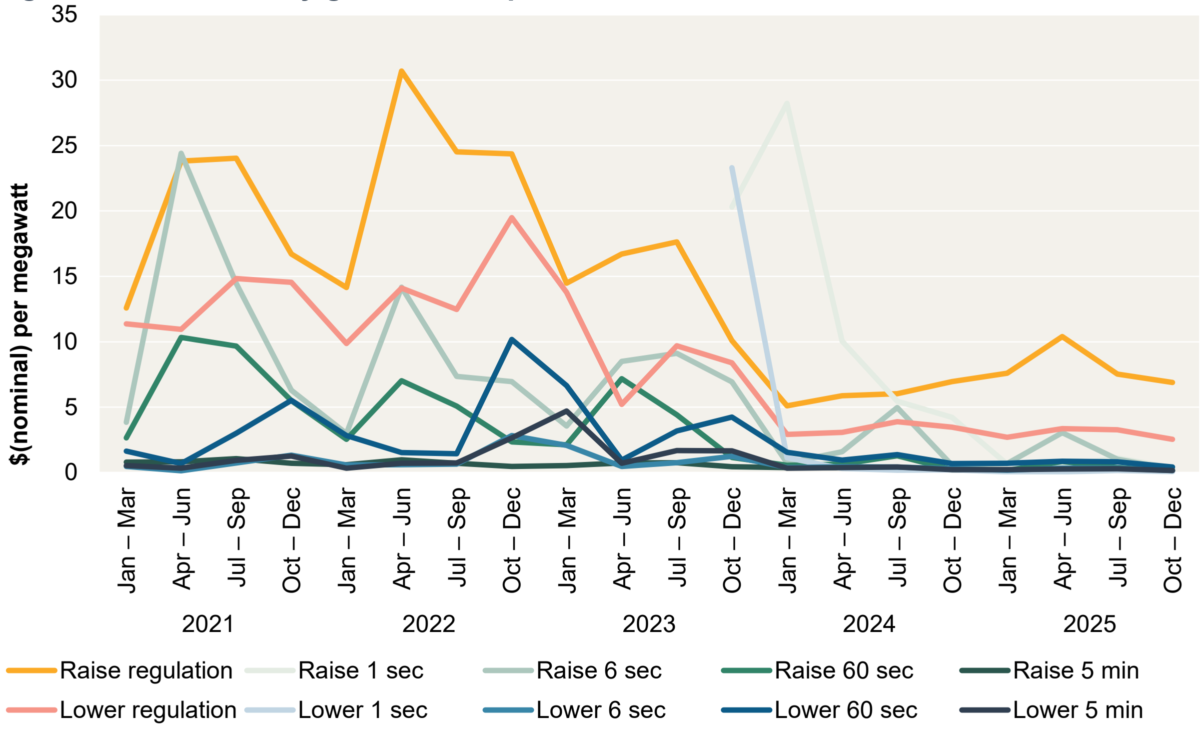
Figure 2.23 Global and local FCAS costs



Note: Global FCAS costs are the sum of total costs for each ancillary service for the NEM, calculated by multiplying the price with the enablement of each service for all regions. Local FCAS costs are the sum of total costs for each service in each region.
Source: AER analysis of NEM data.

Global FCAS prices fell across all contingency services during 2025, including the newer raise 1-second and lower 1-second services. Regulation services remained more expensive, particularly raise regulation, which averaged $8 per MW in 2025.

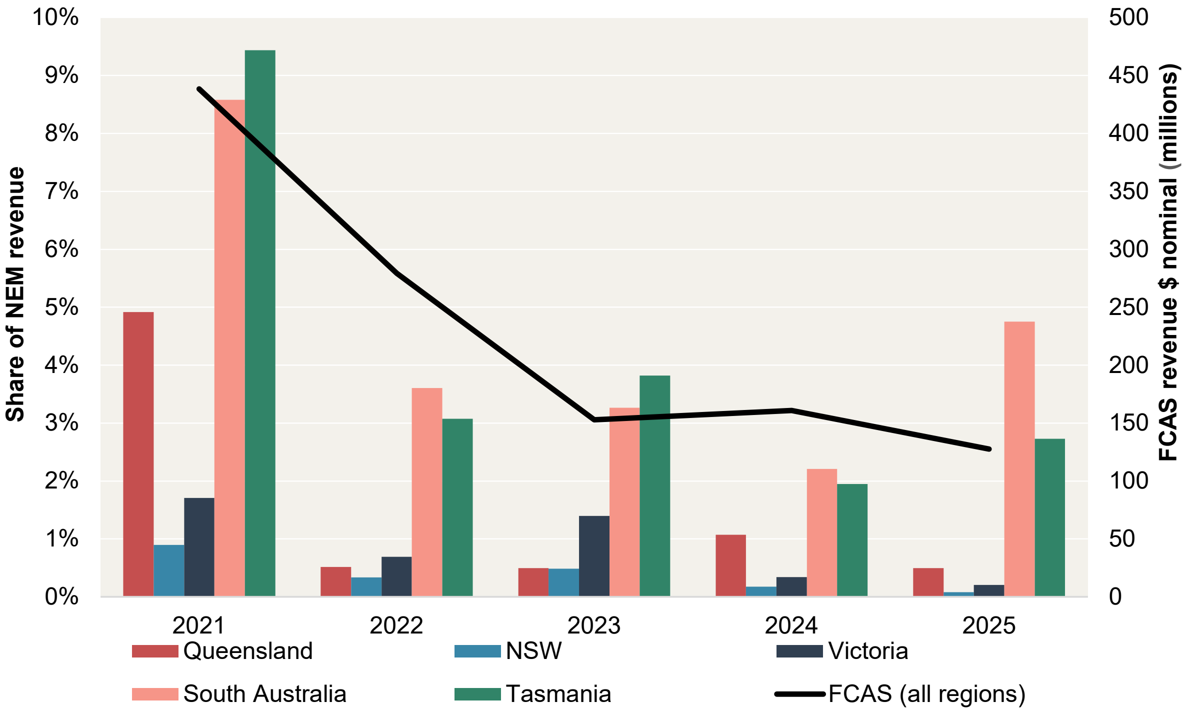
Figure 2.24 Quarterly global FCAS prices



Source: AER analysis of NEM data.

In 2025, FCAS revenue accounted for 0.1% of total market revenue in NSW, continuing the region's declining trend. In South Australia, FCAS revenue accounted for 4.8%, the highest share since 2021. This increase in South Australia is due to the spike in local costs in the July to September 2025 quarter.

Figure 2.25 FCAS revenue as a percentage of wholesale market revenue, by region



Source: AER analysis of NEM data.

3 Contract markets

Australian Securities Exchange (ASX) activity has recovered strongly and market conditions have normalised relative to 2022. Energy market participants trade earlier and hold contract positions longer to help smooth prices over time. Non-energy market participants provide much of the trading liquidity on the ASX. The exception is trading more than 24 months before expiry. It is at these times the market is concentrated, where the top 5 energy market participants have their largest share of the market.

Key findings

ASX market conditions

- ASX-traded contract volumes reached a record high on a 12-month rolling average basis.
- ASX open interest declined in 2024 and early 2025, before rebounding to its highest level since November 2023, largely driven by swaptions.
- Market volatility eased despite the Middle East conflict, with option premiums and price volatility in base futures and caps now broadly back to pre-2022 levels.

Participant position and concentration

- Between 2021 and 2025, energy market participants accounted for 43% of ASX purchase volume and 42% of ASX sale volume.
- Reported trading by energy market participants was highly concentrated, with the top 5 participants accounting for most reported ASX and over-the-counter (OTC) volume.
- Energy market participants accounted for a larger share of ASX open interest than traded volume, due to energy market participants generally having a more stable ASX positioning that they tend to roll over time.

Contract types and trading behaviour

- Swaptions remained the most traded ASX contract type. Energy market participants accounted for a larger share of traded volume and open interest in swaptions and caps than across ASX contracts overall.
- Average rate options grew strongly and were traded and held more heavily by non-energy market participants.

OTC market

- Between 2021 and 2025, reported OTC standard contract volumes were around one-fifth of the reported ASX volumes. This share varied across states, with OTC volumes exceeding ASX volumes in South Australia, but representing a much smaller share of total traded volume in NSW.
- Flat swaps accounted for most OTC standard contract volume.
- Evening and morning peak contracts traded far more in OTC markets than on the ASX.
- Higher strike cap contracts were traded in the OTC market, although the $300 per megawatt hour (MWh) strike remained the most common.

Power purchase agreements (PPAs)

- Reported PPA purchase volumes were equivalent to around one-fifth of underlying NEM demand between 2021 and 2025.
- Reported PPA volumes were concentrated in wind and solar, which together accounted for more than 90% of total volume.
- The volume-weighted average reported price was higher for wind PPAs than for solar PPAs. Reported prices for solar are in the range of levelised cost of energy estimated by the CSIRO for new entry. For wind, reported prices are below the estimated range, reflecting the increase in construction costs in recent years.

Access to contract markets

- Access to clearing has improved since 2022, helping participants trade on the ASX.
- Respondents to our survey questions listed margining requirements, the type of products available and liquidity as the top barriers to using the ASX. The type of products and market transparency were the main barriers for OTC contracts.

Wholesale electricity spot prices can be highly volatile, ranging from the market floor of −$1,000 per megawatt hour (MWh) to the market price cap of $23,200 per MWh.[16] This volatility creates a financial risk for market participants. Generators can earn less when settlement prices are low, while retailers can face high costs when spot prices are high and they cannot pass those costs through to customers. Contract markets help electricity market participants manage exposure to this spot price risk.

Most wholesale electricity market participants use contract markets to hedge at least part of this exposure. Contract markets operate alongside the wholesale spot market, and each megawatt hour of electricity can be traded multiple times in these secondary markets. Contract prices reflect market expectations of future wholesale prices and volatility. Non-energy market participants, which do not have direct exposure to spot market price risk, also participate in these markets.

The wholesale electricity market is supported by several financial and contracting markets:

- **Exchange-traded markets** – these are electricity derivatives that are primarily traded on the ASX. Electricity futures contracts are available for Queensland, NSW, Victoria and South Australia.
- **Over-the-counter (OTC) markets** – these contracts are negotiated directly between 2 parties, often through a broker. The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements. Common OTC products include swaps, caps and other customised hedge contracts.
- **Power purchase agreements (PPAs)** – these are usually longer-term bilateral contracts between a generator and an electricity buyer, such as a retailer or large energy user. PPAs provide greater long-term revenue certainty and are often used to support

16 The wholesale electricity market price cap was set at $23,200/MWh on 1 July 2026.

investment in renewable generation, although similar arrangements can also be used for other generation assets.

Box 3.1 Key contract types and terms used in the report

Contract types

Electricity contract markets include a range of products used to manage the risk of changes in wholesale electricity prices. Some products are standardised to support liquidity, while others are negotiated directly between parties.

The main products traded are futures, caps and options.

- **Futures contracts** allow buyers and sellers to lock in a fixed price (the strike price) for electricity to be bought or sold at a future date. These contracts can cover different times of the day, regions and contract prices, such as a quarter or a year. Each contract relates to a nominated time of day in a particular region. Available products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand). Futures contracts can also be traded monthly or as calendar or financial year 'strips' covering all 4 quarters of a year. Futures contracts are settled against the spot price in the relevant region – that is, if the spot price later differs from the contract price, one party pays the other the difference. In OTC markets, similar products are known as swaps or contracts for difference.
- **Caps** protect the buyer against very high electricity prices. The buyer pays a premium, and if the spot prices rise above the agreed strike price, the seller pays the difference between the strike price and the average spot price. On the ASX, cap contracts have a strike price of $300 per MWh, while OTC markets offer other strike prices.
- **Options** give the buyer the right, but not the obligation, to enter a contract later on agreed price and volume terms. The buyer pays a premium for this flexibility. A call option gives the right to buy, while a put option gives the right to sell.

Two types of standard options are available through the ASX.

- **Swaptions (also called base strip options)** are options over a set of quarterly base future contracts. They give the buyer the right to lock in a future price for those contracts, for a calendar or financial year. The buyer pays a premium and can exercise the option on any business day up to and including the expiry date (swaptions expire 6 weeks before the start of the calendar or financial year).
- **Average rate options (also called Asian options)** are quarterly contracts, the payout on which depends on the average spot price over the quarter. The buyer pays a premium. At the end of the quarter, the option pays out only if the average spot price makes the contract valuable to the buyer.

Key terms

- **Hedge trading** means using contracts to reduce the financial risk of changes in the spot prices.
- **Hedging horizons** means how far in advance a contract is traded before its last trading day.

- **Margin payments** are amounts paid as security to reduce the risk that a party cannot meet its payment obligations under contract. In exchange-traded markets, the ASX and clearing providers require these payments to manage risk. In OTC markets, counterparty risks are more often managed by assessing creditworthiness of the parties.

  There are 2 types of margins:

1) Initial margins are paid when a contract is entered into. It provides a buffer against possible price changes over a short period. It can be provided as cash, collateral or a guarantee.
2) Variation margins are paid daily and are based on the daily changes to the settled price for each contract. When a futures contract increases in price, the seller must pay the difference between yesterday's price and today's price in the form of a variation margin. The buyer of the contract will receive the variation margin. The opposite is true when the price of the contract falls. The variation margin must be paid in cash within a day of the price movement.

- **Open interest** is the number of contracts that are still active and have not yet been closed out or delivered.
- **Speculative trading** means buying and selling contracts to profit from price movements, rather than to manage an existing exposure to electricity prices. Speculators play a role in providing risk management products to the market that natural participants may not necessarily provide.
- **Energy market participants** are the retailers, generators, integrated resource providers and related trading companies that reported trade data to the AER under the Market Monitoring Information Order (MMIO).
- **Non-energy market participants** are other parties that trade electricity contracts but did not report trade data to the AER under the MMIO.
- **Top 5 energy market participants** are the 5 reporting energy market participants with the highest traded volumes or open interest in the relevant category. Therefore, the top 5 participants may differ across contract types, regions and other categories.
- **Other energy market participants** are all remaining reporting participants outside the top 5.

3.1 Overview

In 2025 the AER used a Market Monitoring Information Order[17] (MMIO) for the first time to compulsorily gather information on electricity contract markets. Under the MMIO we collected information on exchange-traded contracts (ASX), OTC standard contracts, historical information on PPAs and qualitative information on factors affecting energy market participants' use of ASX and OTC markets. The information collected enabled us to undertake market structure analysis of the contract market, complementing the market structure analysis of the spot market in chapter 4. In future reports, we will continue to

17 The Australian Energy Regulator published its first Electricity Market Monitoring Information Order (MMIO-ELEC-2025-02) and accompanying Explanatory Statement on 16 December 2025.

develop our analysis of contract and spot market outcomes using data collected under the MMIO.

This chapter provides a high-level view of the market using ASX public data. Using the information gathered under the MMIO, it then examines the role of non-energy participants, the top 5 energy market participants and the remaining energy market participants across a range of metrics including traded volumes, open interest and hedging horizon.

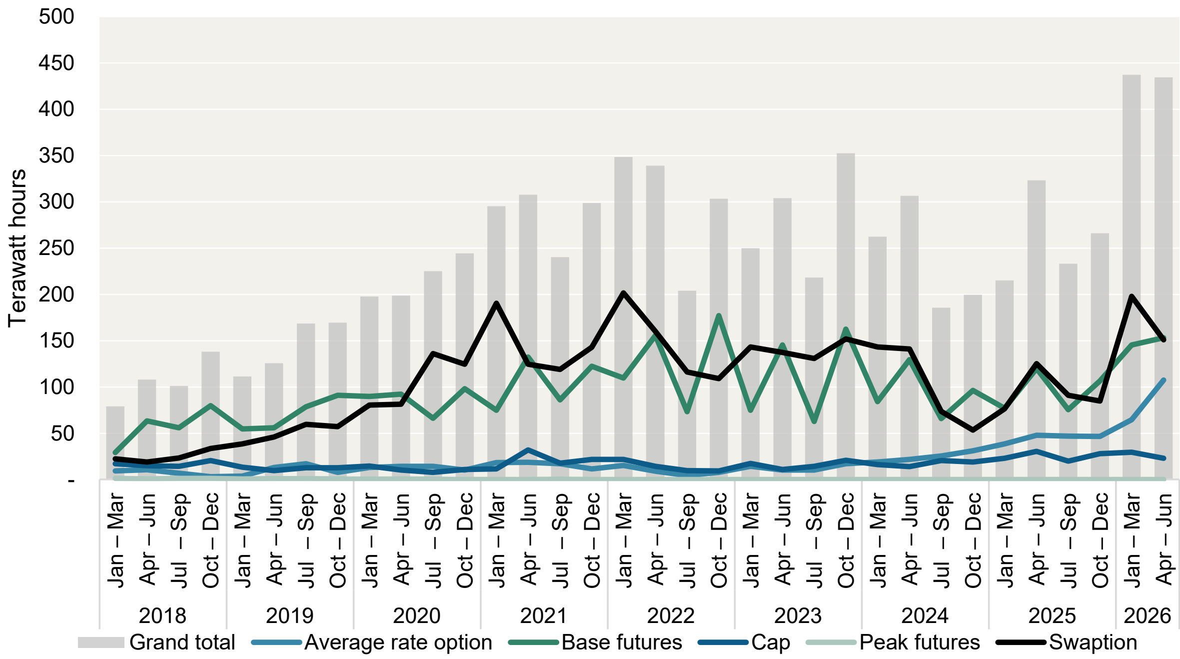
The top 5 energy market participants are identified separately for purchases and sales, and by contract type and region, so the participants may differ across categories. A mixture of business types are represented. Some are vertically integrated with roughly evenly matched generation and retail books. Some are vertically integrated but mismatched with either long generation or retail. Some are not vertically integrated, fundamentally generation or retail businesses. These different characteristics mean that while they are all trading a lot in various contract markets, they are doing so for different reasons, which are linked to their physical market positions.

3.2 ASX market conditions

3.2.1 ASX-traded contract volumes were at record levels for the first half of 2026

ASX-traded contract volumes set consecutive quarterly records in the January to March and April to June 2026 quarters (Figure 3.1). Annual traded volumes grew strongly from 2018 to 2022, reaching 1,194 terawatt hours (TWh) in 2022. Volumes then declined in 2023 and 2024 before rebounding in 2025. This recovery has continued into 2026. In the 12 months to June 2026, traded volumes reached 1,371 TWh, exceeding the previous peak of 1,226 TWh recorded in the 12 months to June 2022.

Figure 3.1 Traded volumes in ASX electricity contracts (NEM)



Note: Volume of trades that occurred during the quarter across ASX Energy futures. The x-axis represents the quarter in which the trades occurred.
Source: AER analysis using ASX data.

The decline in traded volumes in 2023 and 2024 occurred alongside a decline in open interest. This suggests participants were reducing their outstanding positions following the exceptional market volatility and record levels of open interest observed in 2022. The subsequent recovery in traded volumes was also accompanied by renewed growth in open interest, indicating that participants are rebuilding positions. These trends are discussed further in section 3.2.3.

The fall in ASX-traded volumes in 2023 and 2024, and the subsequent recovery, was mainly driven by swaptions and base futures. In the 12 months to June 2026, base futures traded volume had recovered to 480 TWh, compared with a peak of 516 TWh in the 12 months to December 2022.

Swaptions followed a similar pattern. Traded volume fell from a peak of 624 TWh in the 12 months to June 2022 to a low of 329 TWh in the 12 months to June 2025, before recovering to 525 TWh in the 12 months to June 2026.

In contrast, traded volume in average rate options increased steadily. It rose from 36 TWh in the 12 months to March 2023 to 265 TWh in the 12 months to June 2026. Average rate options are now the third most traded ASX contract type, after swaptions and base futures.

Caps also recovered after declining from earlier highs. Their traded volume reached 108 TWh in the 12 months to March 2026. This exceeded the previous peak of 93 TWh in the 12 months to March 2022. The volume remained elevated at 100 TWh in the 12 months to June 2026.

Although the average rate options and caps have grown faster in recent years, swaptions and base futures remain the largest ASX contract types. Together, they accounted for 73% of total ASX-traded volume in 2025 and 74% of traded volume in 2026 to 30 June.

Trading in South Australian contracts remained relatively limited despite broader growth across the NEM. Since 2021, South Australian contracts have accounted for 0.5% of total ASX-traded volume, compared with South Australia’s 6% share of NEM demand. Rolling annual traded volume recovered from a record low of 1.72 TWh in the 12 months to September 2023 to 6.52 TWh in the 12 months to March 2026.

Trading increased sharply in the April to June 2026 quarter, when a record 6.48 TWh of South Australian contracts was traded. 79% of this volume related to contracts with more than 18 months remaining to the last trading day. Open interest also rose sharply in June 2026, reaching a record 9.7 TWh on 30 June. This was 43% above the previous record of 6.8 TWh on 27 September 2018. Together, these developments suggest that some market participants are trading and holding larger volumes of South Australian contracts than previously.

Recent changes in trading activity and participant behaviour around the Middle East conflict are discussed in section 3.2.5.

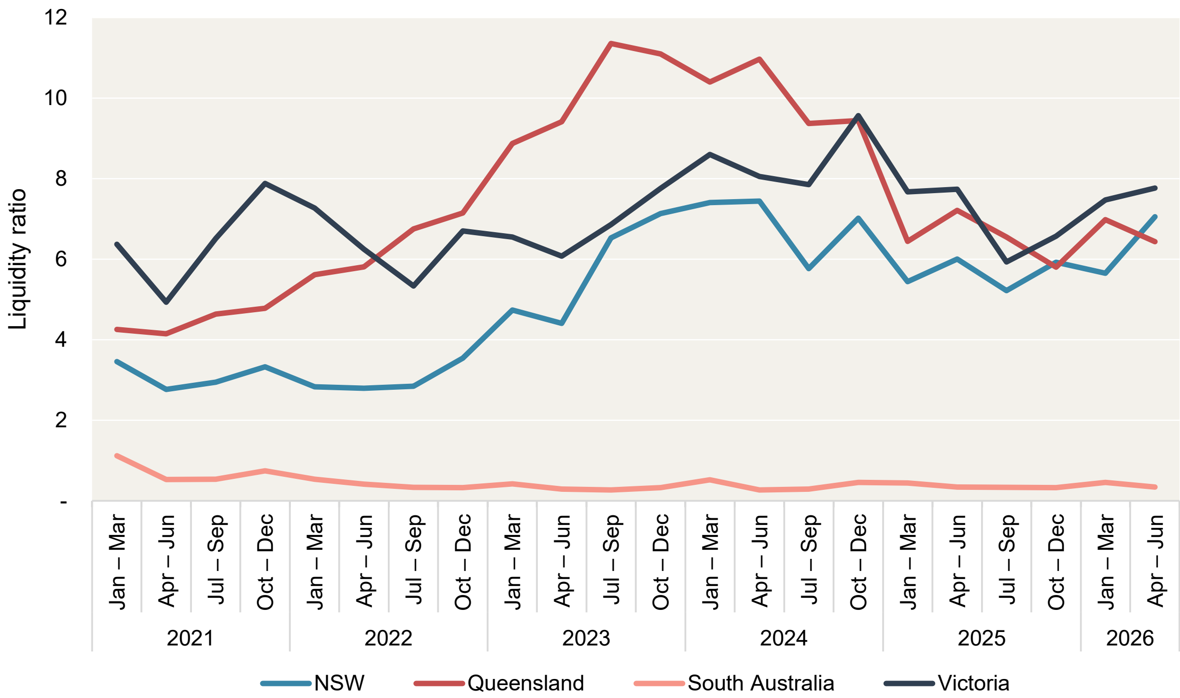
3.2.2 Liquidity ratio remains historically high, except in South Australia

The liquidity ratio is one measure of market liquidity, calculated as cumulative ASX-traded contract volume for delivery in a given quarter divided by native demand in the spot market for that quarter. Because contracts can be traded more than 3 years before delivery, recent-quarter ratios reflect trading activity over several years. The ratio does not capture all aspects of liquidity, such as bid-ask spreads, counterparty availability or the ease of executing large trades.

The ratio has not returned to its 2023 peaks because of lower traded volumes in 2024 and 2025. However, it remained historically high in Victoria, Queensland and NSW in the April to June 2026 quarter. This indicates that the accumulated volume of contracts traded for these delivery periods remained substantial relative to underlying demand.

South Australia remained the exception, consistent with the limited volume of South Australian contracts discussed in section 3.2.1. The relatively low ratio indicates that participants may have fewer opportunities to manage South Australian exposure through the ASX market. However, as discussed in section 3.5.1, OTC markets play a particularly important role in South Australia and may partly compensate for the state's limited ASX liquidity.

Figure 3.2 ASX liquidity ratio for all contract types



Note: Contract-traded volumes used to calculate the liquidity ratio are allocated to the delivery period specified in the contract, rather than the period in which the contract was traded. For contracts covering more than one quarter, traded volumes are pro-rated across the relevant quarters. Demand volumes are based on native demand.
Source: AER analysis using ASX data and AEMO data.

3.2.3 ASX open interest rebounded to its highest level since November 2023

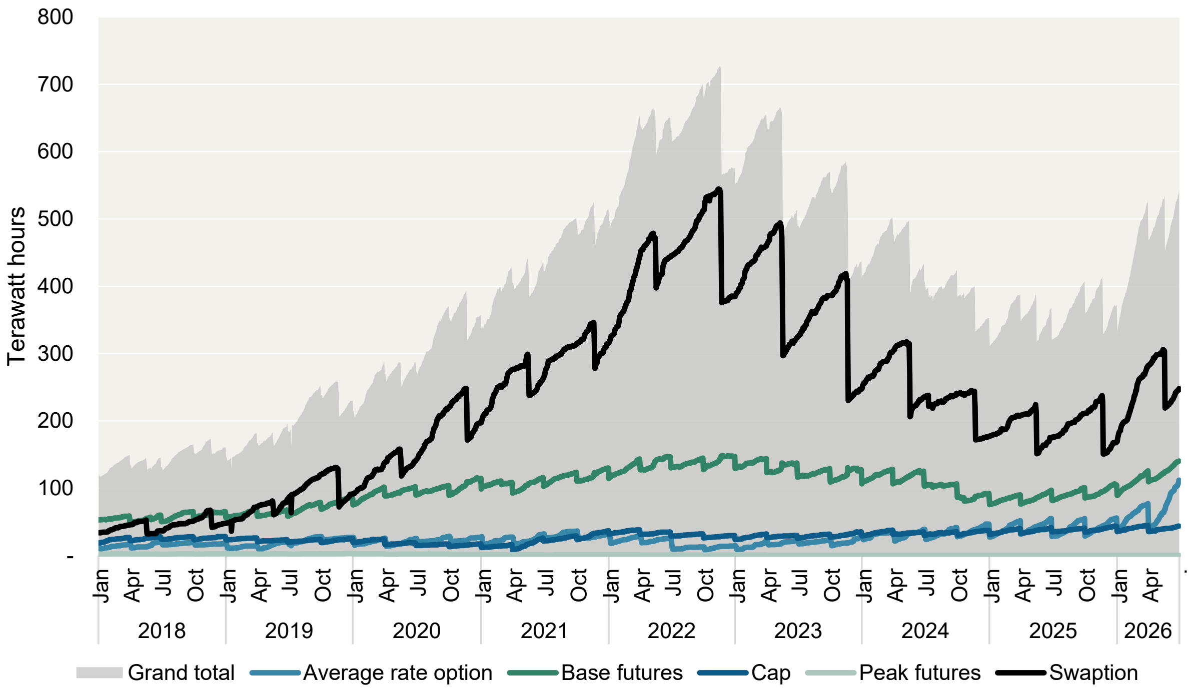
Another way to assess market liquidity is open interest. Open interest indicates how many open contracts are being held by market participants on the ASX at a given point in time. Higher levels of open interest indicate more contracts are available for trade (better liquidity) and are being held for longer periods of time. Higher liquidity makes it easier to enter and exit from positions and can result in lower bid-ask spreads. ASX open interest has recovered from early 2025 lows but remains below the record peak of 727 TWh on 16 November 2022. It reached 543 TWh on 30 June 2026, its highest level since November 2023.

The fall from the 2022 peak, and the subsequent rebound, were largely driven by swaptions and base futures. Swaption open interest peaked at 544 TWh on 14 November 2022, then declined until late 2025 before recovering to 304 TWh on 19 May 2026, immediately before the expiry of 2026–27 swaptions. This was its highest level since May 2024. Base futures followed a similar pattern, peaking at 148 TWh on 28 November 2022, falling until early 2025, and then recovering to 140 TWh on 30 June 2026, its highest level since June 2024.

By contrast, open interest in average rate options and caps increased more steadily. Both were at record levels on 30 June 2026, at 112 TWh and 44 TWh, respectively.

The increase in open interest during the January to March 2026 quarter, including the contributions of energy and non-energy market participants, is discussed in section 3.2.5.

Figure 3.3 Daily open interest

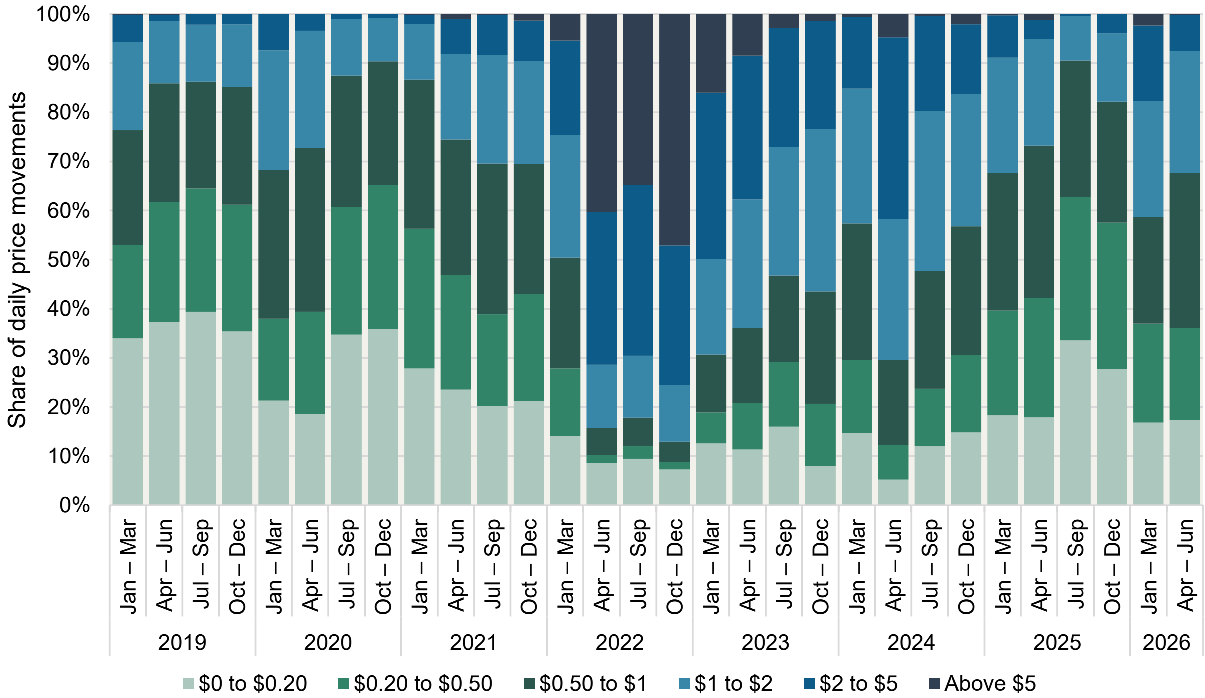


Note: Daily open interest is shown in terawatt hours (TWh) for all ASX Energy contracts.
Source: AER analysis using ASX data.

3.2.4 Overall market volatility and option premiums have declined

Volatility in calendar-year base futures and cap prices has decreased since our 2024 report and is now broadly back to pre-2022 levels. The share of daily price movements below $1 per MWh increased over the period leading into 2026, consistent with lower day-to-day price volatility. Price movements around the Middle East conflict are discussed further in section 3.2.5.

Figure 3.4 Distribution of absolute daily price movements for quarterly base futures



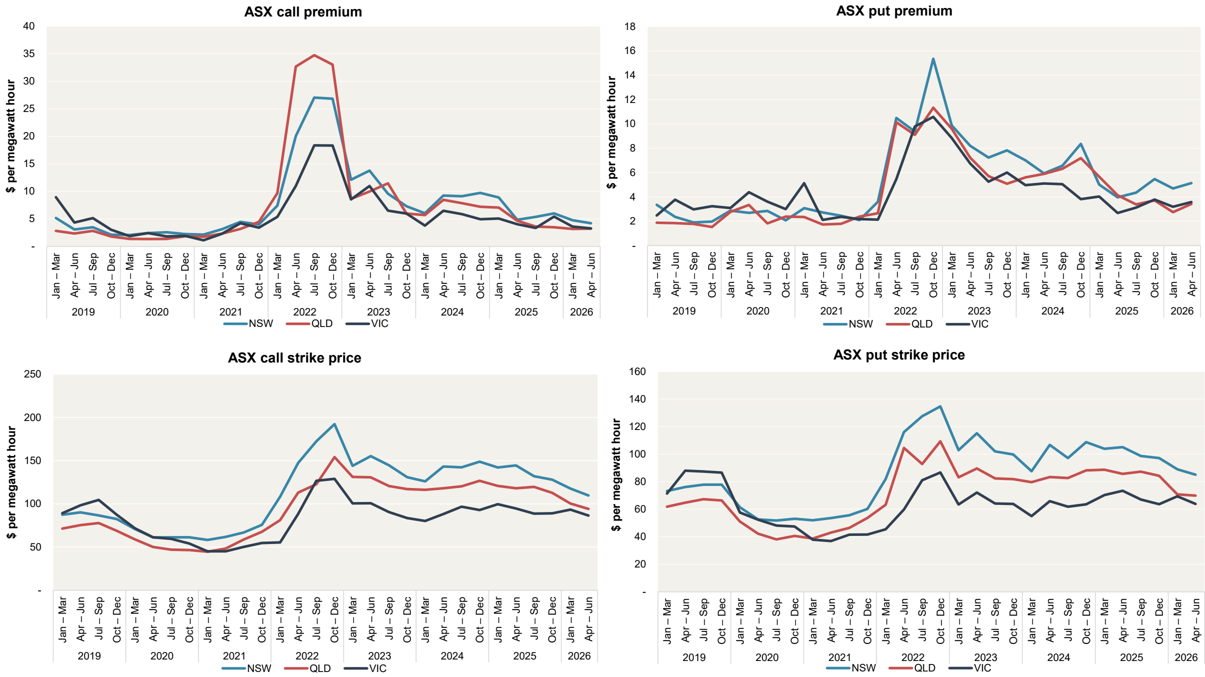
Note: Absolute daily price movements are shown as a percentage of observations within each quarter. Only quarterly base futures with delivery starting in the next 4 quarters are included, as these contracts are more liquid. Prices are included for Queensland, NSW and Victoria only. South Australia is excluded due to lower liquidity, which may make settlement prices less representative of the underlying contract value. Values are nominal.
Source: AER analysis using ASX data.

The decrease in daily price movements assists market participants through smaller margining payments. Each time the contract price moves, either the buyer or seller is required to make a variation margin payment, with smaller price movements reducing the need for variation margin payments. This helps cash flow because margins are paid daily on contracts for generation that won't be sold into the spot market for months or years in the future.

Improvements are evident in ASX options markets. Options allow buyers to hedge further in the future while reducing margining costs, with losses limited to the premium if the options expire out of the money. Swaptions remain one of the most traded products and average rate option volumes have been increasing (section 3.2.1).

Average call option premiums weighted by traded volume, have returned to around pre-2022 levels, suggesting that the cost of buying protection has normalised. However, strike prices have not returned to pre-2022 levels.

Figure 3.5 Volume-weighted average premium and strike price of ASX options



Note: The volume-weighted average premiums and strike prices are calculated using traded MWh as weights and include all ASX-traded options, including swaptions and average rate options. The x-axis represents the quarter in which trades occurred. Values are nominal.
Source: AER analysis using ASX data.

3.2.5 ASX market activity around the Middle East conflict

Trading activity had already increased before the escalation of the Middle East conflict at the end of February 2026. But the heightened geopolitical uncertainty and volatility in global energy markets may have contributed to elevated trading and adjustments to participants' risk-management positions during March. Trading volumes in December 2025 and January and February 2026 were the highest recorded for their respective calendar months, indicating that the broader increase in market activity preceded the conflict. Traded volume in March 2026 was more than double the level recorded in March 2025, although it remained 4% below the record set in March 2022 following Russia's invasion of Ukraine. Swaptions were the main contributor to the year-on-year increase, with traded volume more than 3 times the March 2025 level.

MMIO data show that energy market participants increased their reported trading during the January to March 2026 quarter. Reported monthly purchases increased from 34 TWh in December 2025 to between 53 TWh and 57 TWh per month during the quarter, while reported monthly sales increased from 29 TWh to between 54 TWh and 63 TWh. The increase was concentrated in base futures and swaptions. Compared with the October to December 2025 quarter, purchases of base futures increased from 47 TWh to 74 TWh and purchases of swaptions increased from 33 TWh to 63 TWh. Sales of base futures increased from 39 TWh to 75 TWh, while sales of swaptions increased from 35 TWh to 72 TWh.

Energy market participants' reported trading in average rate options was broadly unchanged. Purchases increased from 13 TWh in the October to December 2025 quarter to 14 TWh in the January to March 2026 quarter, while sales remained at 14 TWh. This suggests that the increase in total average rate option volumes was largely associated with trading by non-energy market participants, consistent with their larger share of activity in these contracts (section 3.4.1).

Contract prices had generally declined in the 3 months leading up to the conflict. Prices increased sharply in March as the conflict escalated, accompanied by elevated volatility. However, the magnitude of the price increase and the level of volatility were both substantially below those observed in 2022. Prices subsequently resumed their downward trend and volatility moderated, indicating that the effect to date of the conflict on Australian electricity contract prices was relatively short-lived (section 2.1.4). Unlike the events of 2022, there was very little underlying change in the spot market alongside the changes in ASX markets.

Higher trading activity was accompanied by a substantial increase in outstanding positions. Total ASX open interest increased from 329 TWh on 2 January 2026 to 529 TWh on 31 March 2026. Over the same period, energy market participants' reported long open interest increased from 162 TWh to 208 TWh, while their reported short open interest increased from 155 TWh to 209 TWh.[18] These increases were smaller than the overall growth in ASX open interest, indicating that non-energy market participants accounted for most of the increase in positions on both sides of the market. Open interest plateaued from late March but remained elevated as contract prices resumed their decline and volatility moderated. Together with the increase in trading before the conflict, this suggests that the growth in open interest reflected a broader and more sustained adjustment in market positions, rather than only a temporary response to geopolitical developments.

3.2.6 Energy market participants accounted for less than half of ASX-traded volume between 2021 and 2025

Between 2021 and 2025, energy market participants reported 2,358 TWh of ASX purchases and 2,314 TWh of ASX sales, representing 43% of total ASX purchase volume and 42% of total ASX sale volume. Their share was highest in 2021, when they accounted for 51% of purchase volume and 52% of sale volume, before falling to around 40% from 2022 to 2025. Non-energy market participants, which are not required to report to the AER, accounted for most ASX trading and were an important source of broader market liquidity.

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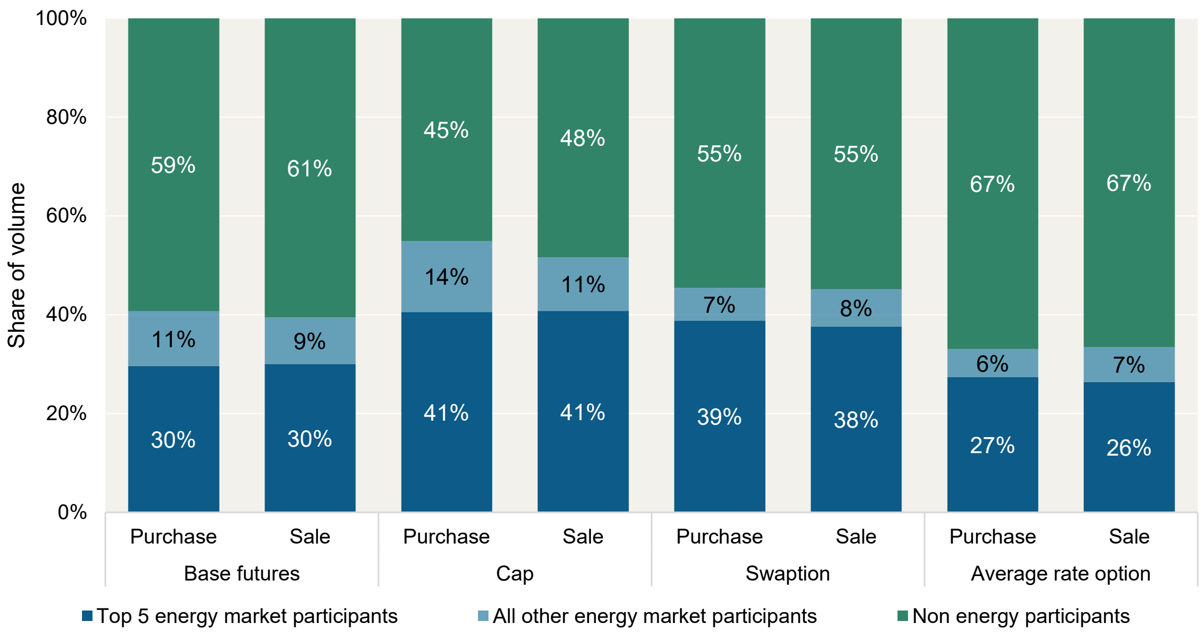
18 Long open interest refers to the total number of outstanding long contracts (i.e. those in which the buyer agrees to purchase the asset at a predetermined price in the future). Short open interest refers to the total number of outstanding short contracts (i.e. those in which the seller agrees to sell the asset at a predetermined price in the future).

Figure 3.6 Proportion of ASX-traded volume, by participant type



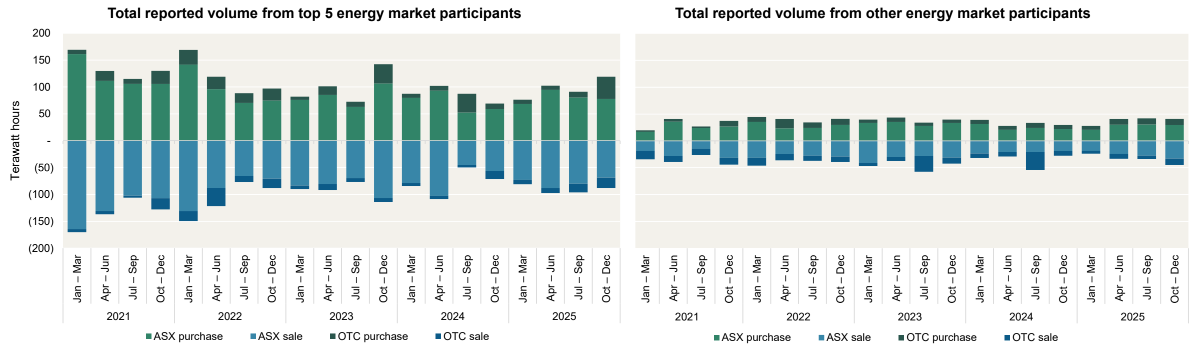
Note: Proportions of traded volume are calculated over 2021 to 2025 as reported traded volume from energy market participants, in MWh, divided by total ASX-traded volume in MWh. The top 5 energy market participants are selected separately by ASX purchase and sale and contract type and may therefore differ across categories.
Source: AER analysis using ASX and MMIO data.

3.2.7 Top 5 energy market participants accounted for most reported trading activity

ASX and OTC trading done by energy market participants was concentrated. In ASX markets, the top 5 energy market participants accounted for 77% of total ASX-traded volume between 2021 and 2025 reported to the AER. The top 8 participants accounted for 93%. This concentration remained high in 2025, with the same top 5 participants accounting for 75% of total reported ASX volume. Despite accounting for most of the reported volume, the top 5 energy market participants accounted for only around one-third of the total traded volume.

OTC was less concentrated than ASX trading but still dominated by a small number of participants. Between 2021 and 2025, the top 5 energy market participants accounted for 67% of total reported OTC traded volume, while the top 8 participants accounted for 80%. In 2025, the top 5 accounted for 70% of all reported OTC volume, with 4 of the top 5 unchanged from the earlier period.

Figure 3.7 Total reported traded volume by participant type and trade type



Note: Total reported quarterly traded volumes are presented separately for ASX purchases, ASX sales, OTC purchases and OTC sales. Purchases are shown as positive values and sales as negative values. One chart shows the top 5 energy market participants by traded volume, while the other shows all the other energy market participants.
Source: AER analysis using MMIO data.

We also assessed market concentration across contract categories, by purchase or sale, regions and contract types. Across these categories, the single largest energy market participant accounted for just over 20% to more than 40% of total reported market volume contributed by energy market participants. When total ASX volume, including trades by non-energy market participants, is used as the denominator, the largest energy participant's share falls to between high single digits and just under 20%.[19]

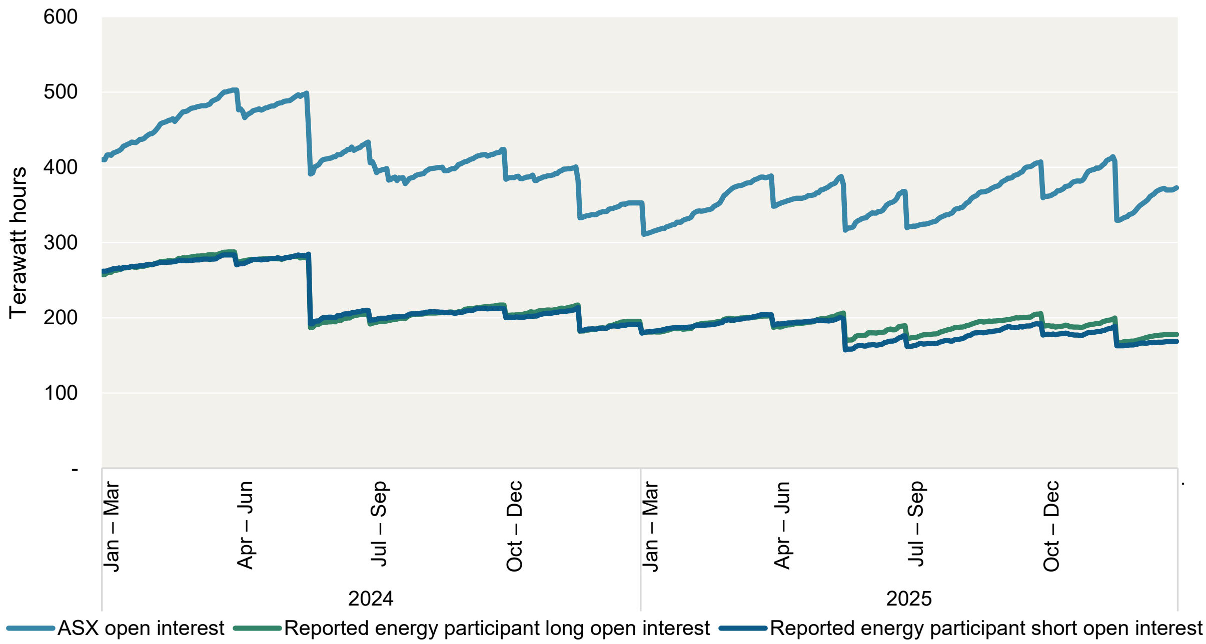
3.2.8 Energy market participants held a larger share of total ASX open interest than traded volume

On average over 2024 and 2025, energy market participants accounted for a larger share of ASX open interest than of traded volume. They were estimated to hold 55% of market long open interest and 54% of market short open interest, compared with 41% of total market purchase volume and 39% of total market sales volume.

This suggests energy market participants tend to have a more stable positioning than non-energy market participants on the exchange, consistent with a larger share of their trading being used for hedging rather than shorter-term trading. This reflects that energy market participants are primarily focused on hedging the risk of buying and selling electricity in the physical energy markets.

19 This is only for NSW, Queensland and Victoria. We have excluded South Australia due to the low volume traded.

Figure 3.8 Energy market participants and total market open interest



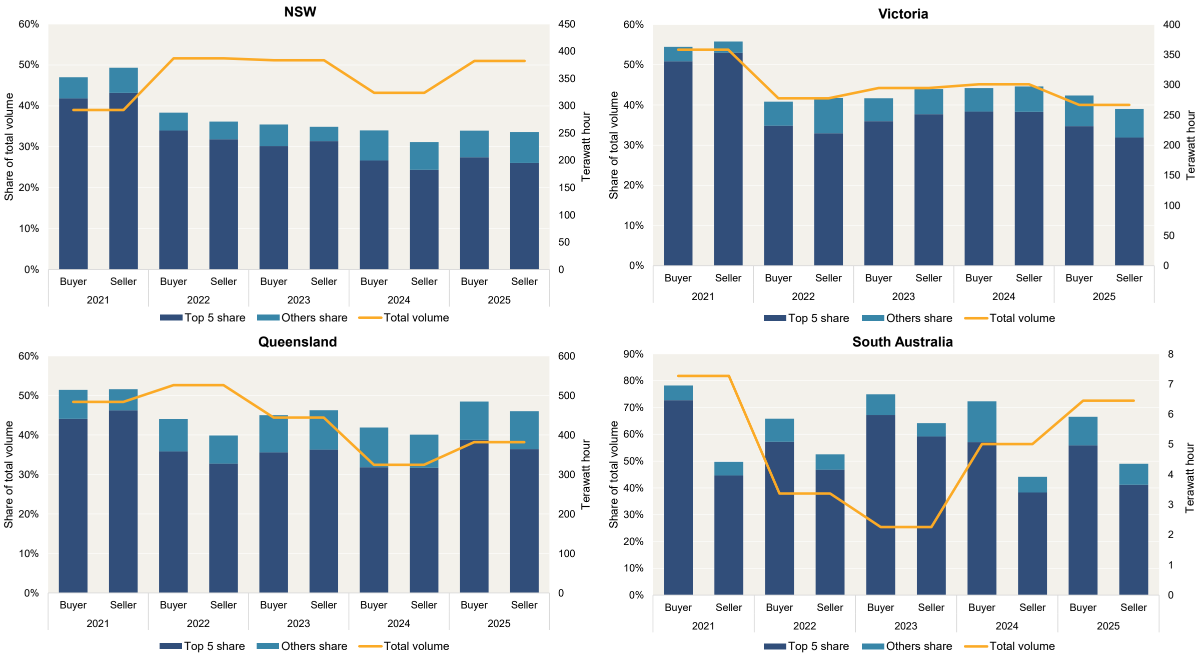
Note: Total market open interest is ASX-reported open interest. Reported energy market participant long and short open interest are estimated using MMIO-reported exchange trade data. Only 2024 and 2025 figures are presented because the reported trade data covers 2021 to 2025, and contracts can be traded up to 3 years ahead of delivery.
Source: AER analysis using ASX and MMIO data.

3.2.9 Energy market participants' share of ASX trading varied across states

Energy market participants' share of traded volume varied materially by state. Their share was highest in South Australia, where they accounted for 72% of total purchase volume and 50% of total sale volume between 2021 and 2025. This likely reflects the relatively low liquidity of South Australian contracts, which makes them less attractive to non-energy market participants.

By contrast, energy market participants' share was lowest in NSW, at 37% of purchase volume and 37% of sale volume. This suggests non-energy market participants were relatively more active in NSW contracts.

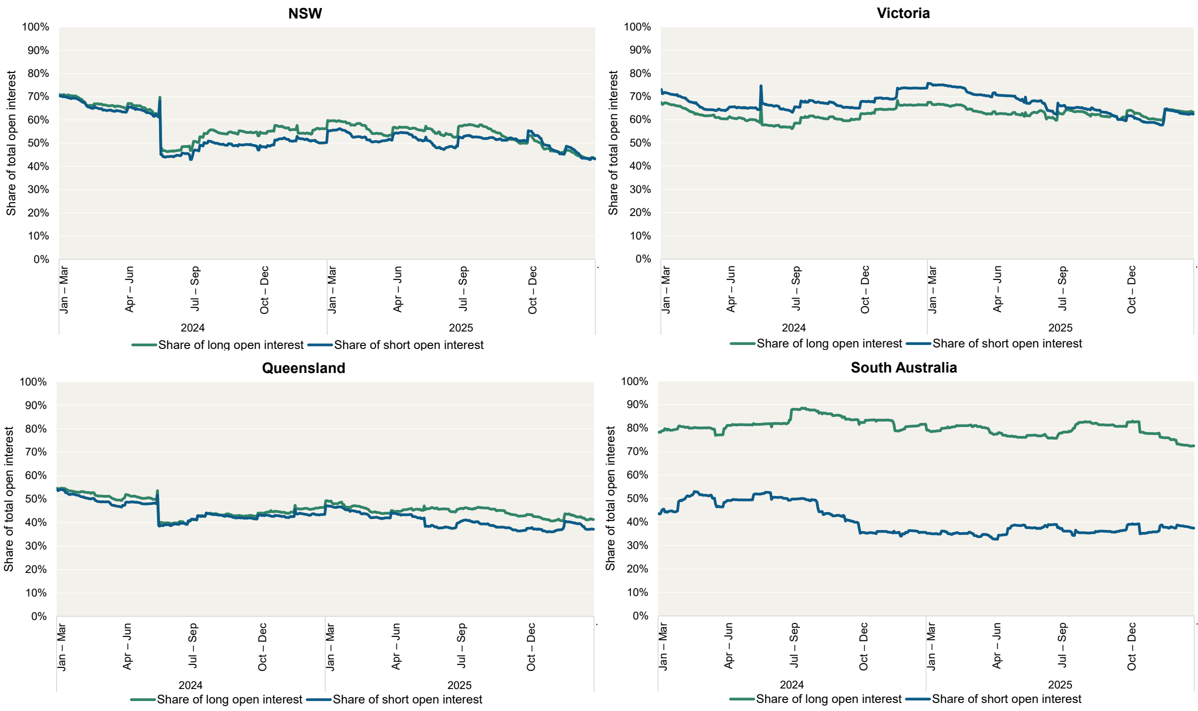
Figure 3.9 Energy market participants' share of total ASX-traded volume, by state



Note: Energy market participants' share of total traded volume is calculated by dividing their total reported purchase and sale volume, in MWh, by total ASX-traded volume in MWh. The top 5 energy market participants are identified separately for purchases and sales in each state and may therefore differ across categories. Non-energy market participants also trade ASX electricity derivatives but are excluded from the chart, so the percentages do not sum to 100%. The secondary line shows total annual ASX-traded volume by state, in TWh.
Source: AER analysis using ASX and MMIO data.

Energy market participants' share of open interest was higher than their share of traded volume in all states. For example, in NSW, they accounted for 58% of long open interest and 55% of short open interest on average over 2024 and 2025, materially higher than their approximately one-third share of total traded volume. The difference between the 3 large regions was driven by a higher level of open interest in swaptions in Victoria and a lower level of base futures open interest in Queensland. The higher level of open interest than traded volumes reflects that energy market participants are primarily focused on hedging the risk of exposure to the spot market. This results in them being more likely to trade and hold a contract until expiry compared with a participant that is entering into contracts solely for financial purposes.

Figure 3.10 Energy market participants' share of total ASX open interest, by state



Note: Open interest held by energy market participants was estimated using their reported exchange trades. A contract position was assumed to contribute to open interest where it had not been closed out or expired. Only 2024 and 2025 figures are presented because the reported trade data covers 2021 to 2025, and contracts can be traded up to 3 years ahead of delivery.
Source: AER analysis using ASX and MMIO data.

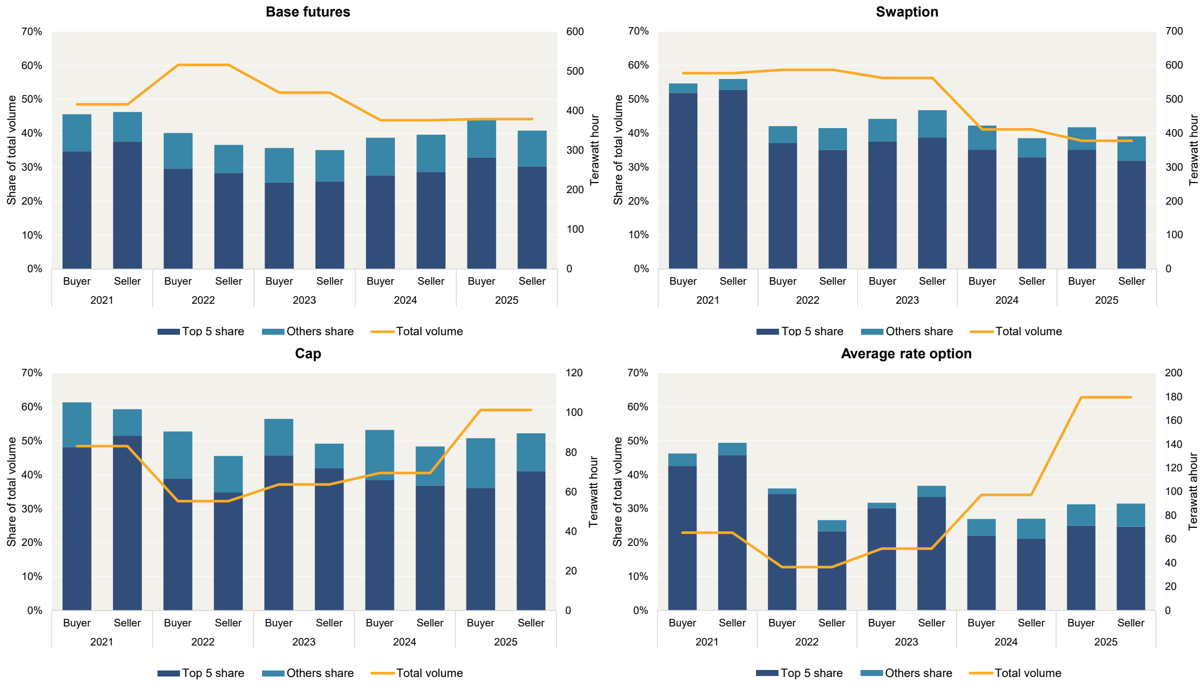
3.3 Contract types and trading behaviour

3.3.1 Energy market participants are more prominent in swaptions and caps

Swaptions were the most traded ASX energy contract between 2021 and 2025. Energy market participants accounted for a larger share of swaption traded volume than of the ASX trading overall, making up 45% of total purchase volume and 45% of total sale volume, compared with 43% and 42% across all contract types. Energy market participants also held a larger average share of market open interest in swaptions. Over 2024 and 2025, they were estimated to account for 64% of long open interest and 64% of short open interest in swaptions, compared with 55% and 54% of all contract types.

The higher level of open interest indicates that swaptions play a significant role in the hedging strategies of some energy market participants. They allow retailers and generators to lock in a fixed strike price for base futures, while still allowing for the flexibility if prices move in their favour.

Figure 3.11 Energy market participants' share of total ASX-traded volume by contract type



Note: Energy market participants' share of total traded volume is calculated by dividing their total reported purchase and sale volume, in MWh, by total ASX-traded volume in MWh. The top 5 energy market participants are identified separately for purchases and sales within each contract type and may therefore differ across categories. Non-energy market participants also trade ASX electricity derivatives but are excluded from the chart, so the percentages do not sum to 100%. The secondary line shows total annual ASX-traded volume by contract type, in TWh.
Source: AER analysis using ASX and MMIO data.

Caps reached their highest annual traded volume in 2025, at 101 TWh, above the previous peak of 83 TWh in 2021. Between 2021 and 2025, energy market participants accounted for a larger share of traded volume in caps than in ASX trading overall, making up 55% of purchases and 52% of sales volume. Their estimated share of cap open interest was also the highest of any ASX contract type, at 77% of long open interest and 67% of short open interest over 2024 and 2025.

Although caps are traded in volumes lower than other ASX contract types, they play a critical role in hedging price risk for retailers. ASX cap contracts have a strike price of $300/MWh, which protects retailers during periods of high spot prices. For generators, selling caps provides premium income that can help stabilise cash flow when spot prices are low or moderate.

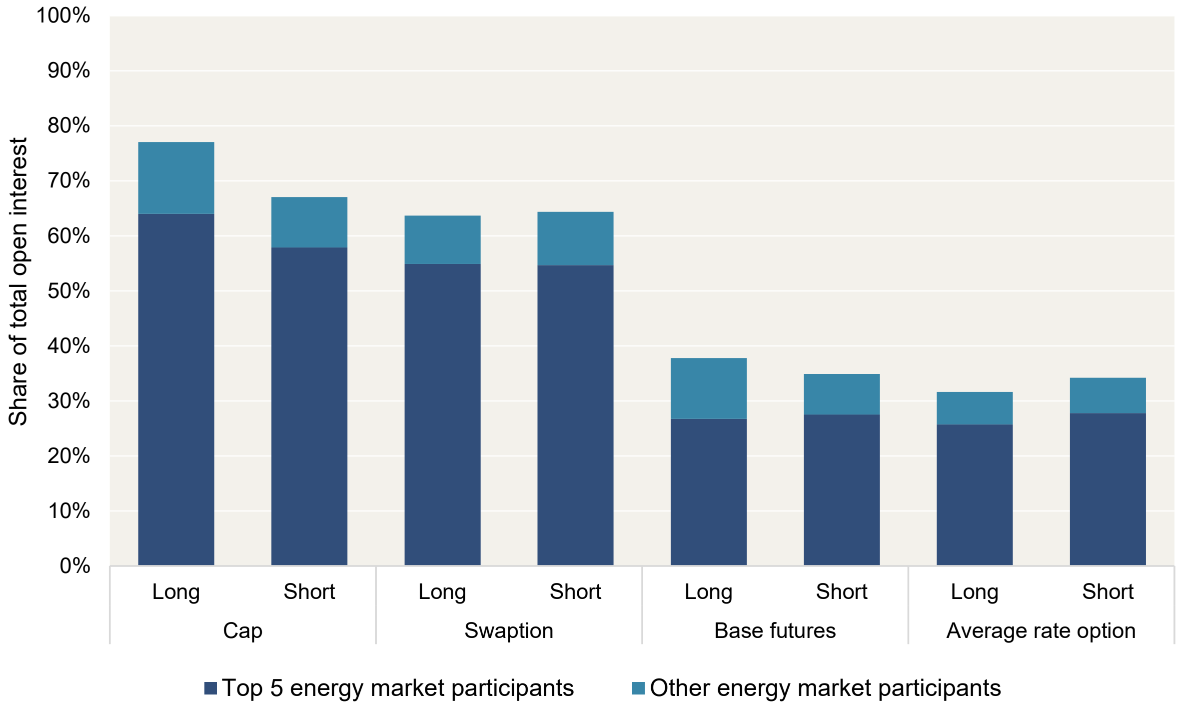
High cap trading volumes in 2025 coincided with a substantial decline in cap prices. Over the year, calendar year 2026 cap prices fell:

- by 35% in NSW, from $36.12/MWh to $23.52/MWh
- by 46% in Queensland, from $27.03/MWh to $14.52/MWh
- by 23% in Victoria, from $18.92/MWh to $14.58/MWh.

South Australia cap prices also fell by 24% from $28.85/MWh to $21.84/MWh, but traded volume declined.

Energy market participants increased both their purchases and sales compared with 2022 to 2024. The growth in total cap sales was driven by energy market participants, while purchases were driven by non-energy market participants. This indicates that more cap protection was traded even as the market assigned a lower value to peak-price risk. Noting there are many reasons for the increase, the rapid expansion of battery capacity may have contributed by increasing supply during high-price periods, reducing the expected frequency and severity of prices above $300/MWh and increasing participants' incentives to sell caps. Lower cap prices may also have encouraged retailers to purchase additional protection.

Figure 3.12 Energy market participants' share of total ASX open interest, by contract type, 2024 to 2025



Note: Proportions of open interest by contract type are calculated over the 2024 to 2025 period as estimated open interest held by energy market participants, in MWh, divided by total ASX open interest in MWh. Open interest held by energy market participants was estimated using their reported exchange trades. The top 5 energy market participants are selected separately by ASX long and short positions and contract type, so may differ across categories. Non-energy market participants also hold ASX electricity derivatives but are excluded from the chart, so the percentages do not sum to 100%.
Source: AER analysis using ASX and MMIO data.

Average rate options have been the fastest-growing contract type by traded volume since 2022. Annual traded volume overtook caps in 2024 and was 77% higher than caps in 2025. However, most of this activity was driven by non-energy market participants. Between 2021 and 2025, energy market participants accounted for only 33.0% of total purchase volume and 33.4% of total sale volume – the lowest share among all contract types. Their share of open interest was also the lowest, at 32% of long open interest and 34% of short open interest on average over 2024 and 2025.

Average rate option contracts are unique because they are typically traded closer to the contract expiry than other ASX contract types, with most trading occurring within 6 months of the contract's last trading day. Combined with the relatively high share of open interest held by non-energy market participants, this suggests these contracts are being used more for shorter-term trading or speculative activity linked to spot market outcomes. Energy market participants may also use average rate options to manage operational and spot price risks, including by buying calls to support additional futures sales or buying puts to protect against downside spot exposure.

Base futures sat between caps and average rate options in terms of energy market participant involvement. Between 2021 and 2025, energy market participants accounted for 41% of purchase volume and 39% of sale volume in base futures, slightly below their overall share across all contract types. Over 2024 and 2025, they were estimated to hold 38% of long open interest and 35% of short open interest in base futures, also below their overall share.

3.3.2 Energy market participants generally trade earlier than non-energy market participants, though patterns vary by contract type

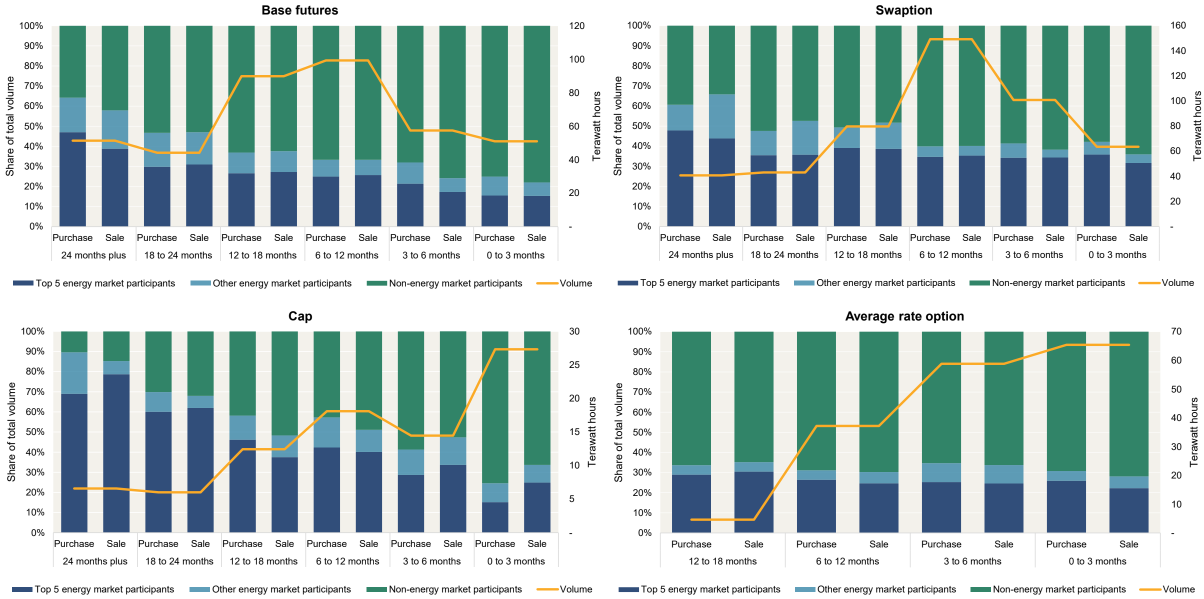
Energy market participants generally traded most ASX contract types significantly earlier than non-energy market participants. Their share of traded volume tended to decline as contracts approached their last trading day, suggesting they were more active earlier in the contract lifecycle.

Hedging horizon analysis provides insight into how different participant groups manage timing risk and liquidity needs. Energy market participants are more likely to use ASX contracts to manage physical generation or retail exposures over a longer period. Trading further ahead of expiry can help smooth cash flow, reduce exposure to short-term price movements, and allow positions to be gradually built or reduced rather than through large trades close to delivery. This can be especially important in less liquid contracts, where trading slowly may help reduce price impact.

The pattern was clear in 2025 caps. Energy market participants accounted for 90% of purchase volume traded more than 2 years ahead but only 25% of purchase volume traded within 3 months of the contract's last trading day. A similar pattern was seen on the sell side, where they accounted for 85% of sale volume traded more than 2 years in advance, compared with 34% traded within 3 months of expiry. Similar patterns were observed for 2025 base futures and swaptions. Overall, the top 5 energy market participants are only around one-third of the traded volume, but they make up a significant share of contracts traded more than 18 months from expiry for caps and 24 months from expiry for base futures and swaptions (Figure 3.13). Longer-dated trades represented only a small share of total activity. Most base futures, swaptions and caps were traded within 18 months of expiry, while most average rate options were traded within 12 months.

The same broad pattern was also observed for 2024 contracts. Energy market participants' share of traded volume declined as contract expiry approached for base futures, caps and swaptions.

Figure 3.13 ASX hedging horizons by contract type: energy vs non-energy participants, 2025 expiries

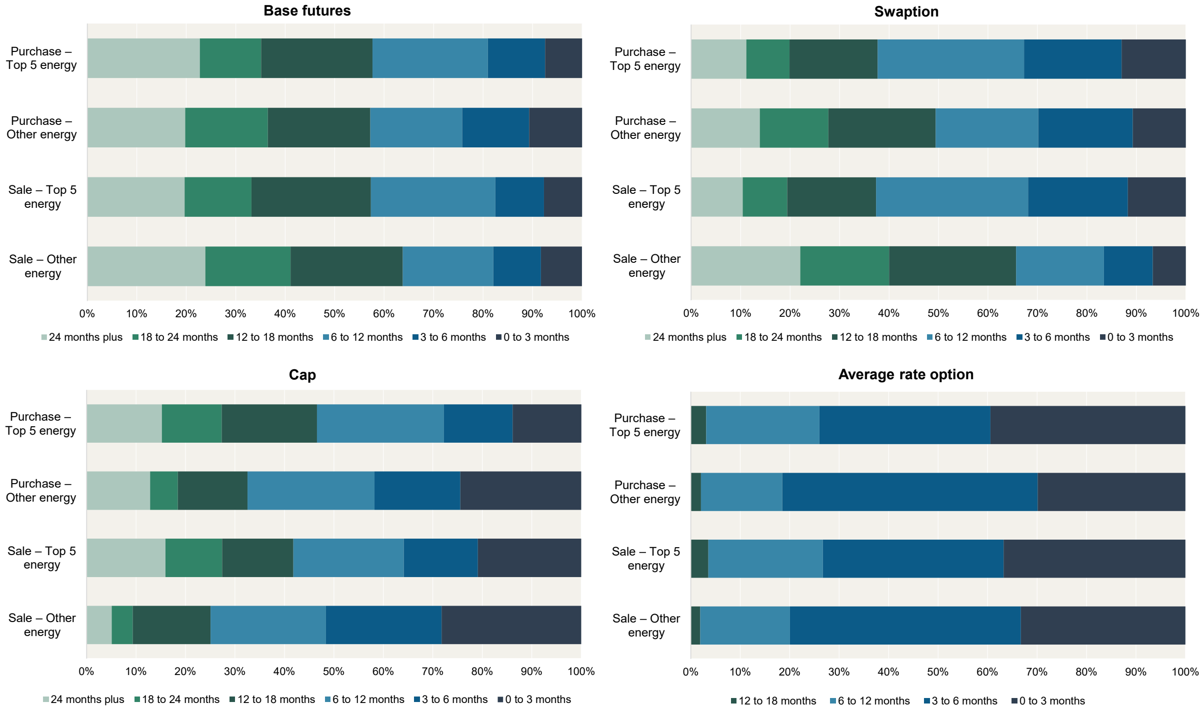


Note: This chart includes all trades for ASX Energy contracts with delivery in 2025. Proportions are calculated using traded volume in MWh from reported energy market participants and total ASX-traded volume across hedging horizon buckets, by ASX purchase or sale and contract type. The top 5 energy market participants are selected separately by ASX purchase or sale and contract type, so may differ across categories. The secondary line shows the total traded volume for each category in terawatt hours (TWh).
Source: AER analysis using ASX and MMIO data.

While non-energy market participants tend to account for a larger share of trades closer to the last trading day, the split between participant types varies across NSW, Queensland and Victoria. For example, for contracts expiring in 2025, the top 5 energy market participants accounted for a larger share of total ASX-traded volume more than 24 months ahead in Queensland and Victoria than in NSW. In Queensland, the top 5 accounted for 71% of purchases and 66% of sales in this category. In Victoria, they accounted for 58% of purchases and 62% of sales, compared with 53% of purchases and 55% of sales in NSW.

Hedging horizon patterns also varied within energy market participant groups. The top 5 energy market participants tended to trade caps and average rate options earlier than other energy market participants. For base futures, the top 5 tended to buy earlier, while other energy market participants tended to sell earlier. Swaptions were the exception, with the top 5 tending to trade later. These differences may reflect variation in participants' hedging needs and trading strategies, including how gradually they build or reduce positions. However, the top 5 were identified separately for each contract type and trade direction; therefore, they do not represent a fixed group across these comparisons.

Figure 3.14 ASX hedging horizons by contract type: top 5 vs other NEM energy participants, 2025 expiries



Note: This chart includes all reported trades by energy market participants for ASX Energy contracts with delivery in 2025. Proportions are calculated using traded volume in MWh across hedging horizon buckets, by participant group, ASX purchase or sale, and contract type. The top 5 energy market participants are selected separately by ASX purchase or sale and contract type, so may differ across categories.
Source: AER analysis using MMIO data.

There is variation across regions, with Queensland energy market participants generally trading further in advance. Queensland's different market structure, with less vertical integration, may contribute to this pattern. Some participants may trade earlier because of their internal risk-management practices or greater exposure to generation. This may support liquidity further out and encourage earlier trading by other participants.

3.4 OTC market

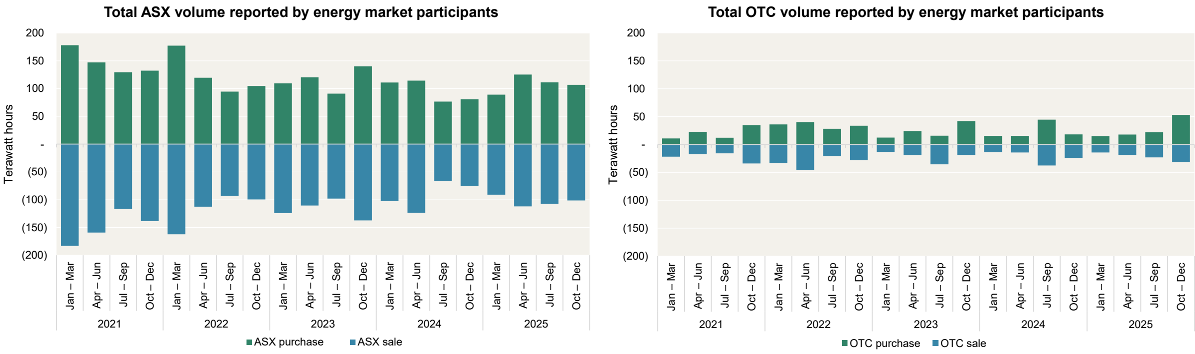
3.4.1 Reported OTC standard contract volumes were around one-fifth of ASX volumes

Between 2021 and 2025, energy market participants reported 515 TWh of OTC contracts purchased and 479 TWh of sales. This was equivalent to 22% of reported ASX purchase volume and 21% of ASX sale volume over the same period. The mismatch between reported purchase and sale volumes is because some of the trading was with non-energy market participants – as such, it was only reported by one side of the trade.

OTC volumes spiked in 2022 during the period of extremely high spot market prices and volatility. Traded volumes in 2022 were 57% higher than in 2021. One reason was the sharp increase in margin requirements for contracts held on the ASX, which made OTC trading more attractive for some participants. OTC volumes subsided in 2023 and grew slightly in each of the following 2 years.

Unlike ASX contracts, which are primarily traded for quarterly or annual durations, OTC contracts can be negotiated for a much wider range of durations. Most reported OTC traded volume (96% of MWh traded) was for contracts with a duration of 12 months or less. Longer-term contracts with durations of more than 3 years accounted for 4% of the traded volume, some of which exceeded 10 years.

Figure 3.15 Total ASX-traded and OTC-traded volume reported by energy market participants

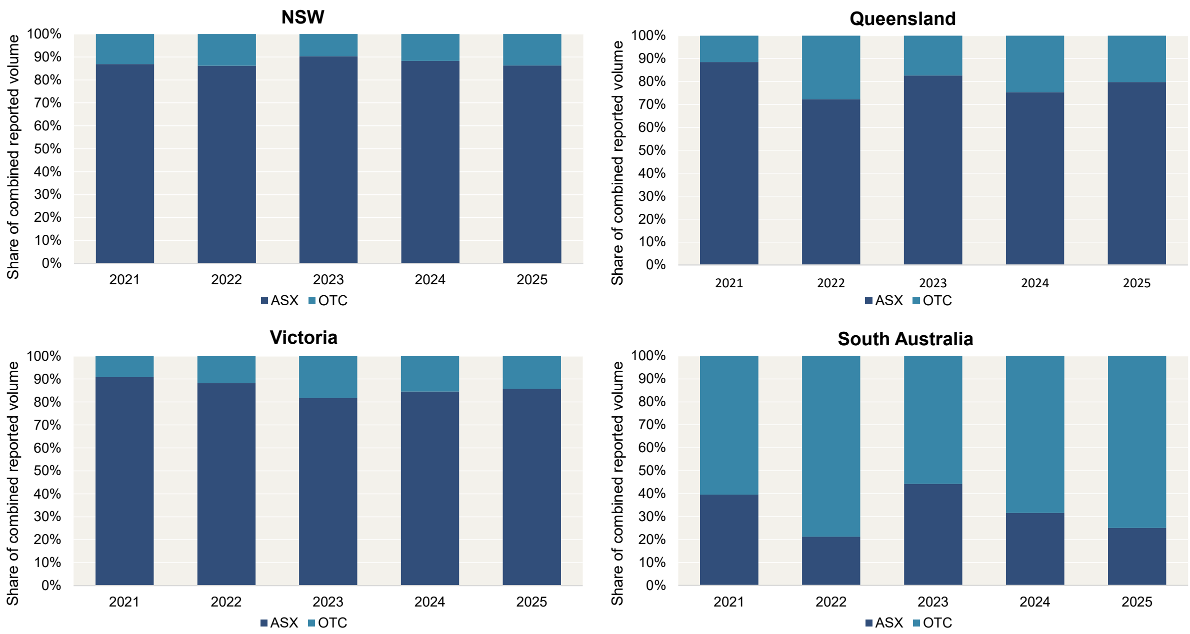


Note: Chart shows the volumes of the ASX and OTC markets for standard contracts, as reported to the AER by energy market participants. Purchases are shown as positive values and sales as negative values. It excludes any trades undertaken by non-energy market participants, such as banks or trading businesses, because they are not subject to the MMIO.
Source: AER analysis using MMIO data.

The relative shares of ASX and OTC volume varied significantly across states. In South Australia, reported OTC volume was more than double the reported ASX volume. By contrast, in Victoria and NSW, reported OTC volume was only around one-seventh of reported ASX volume. This indicates that OTC markets play a particularly important role in South Australia, where ASX market liquidity is limited. Despite this, previous AER analysis has found ASX and OTC prices in South Australia were very similar.[20]

20 AER, Default market offer prices 2025–26 issues paper, Australian Energy Regulator, October 2024, p. 22.

Figure 3.16 ASX and OTC shares of total reported volume, by state

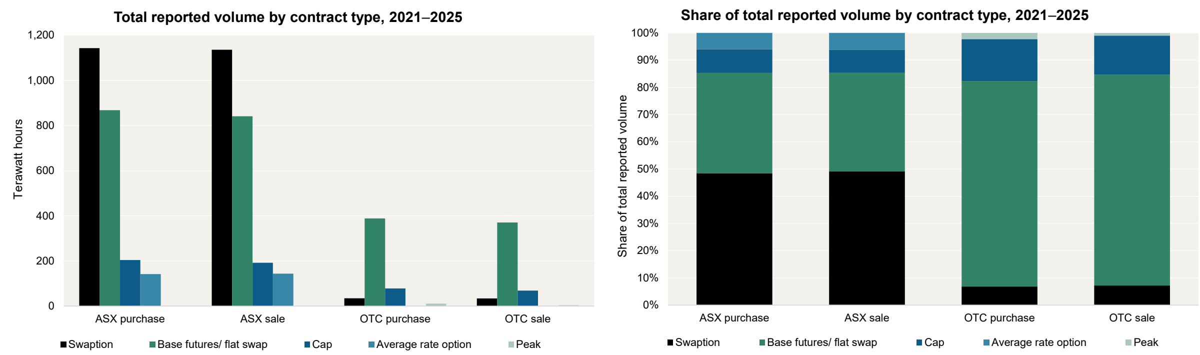


Note: Chart shows total reported ASX and OTC purchases and sales for standard contracts by state, as reported to the AER by energy market participants. It excludes trades by non-energy market participants, such as banks or trading businesses, because they are not subject to the MMIO.
Source: AER analysis using MMIO data.

3.4.2 Standard OTC trades are dominated by flat swaps

Flat swaps made up most reported OTC standard contract trading between 2021 and 2025. They accounted for 75% of total reported OTC purchase volume and 77% of sale volume. Caps were the next largest product, accounting for 15% of purchase volume and 14% of sales volume. This differs from the ASX market, where swaptions are the most traded contract type.

Figure 3.17 Volume comparison of reported ASX and OTC trades, by contract type



Note: Flat swaps are the OTC equivalent of base futures traded on the ASX. The term swap is used when a contract is traded and settled OTC, while future is used when a contract is traded on an exchange. Flat and base are equivalent terms, referring to contracts that cover all hours within the contract period.
Source: AER analysis using ASX and MMIO data.

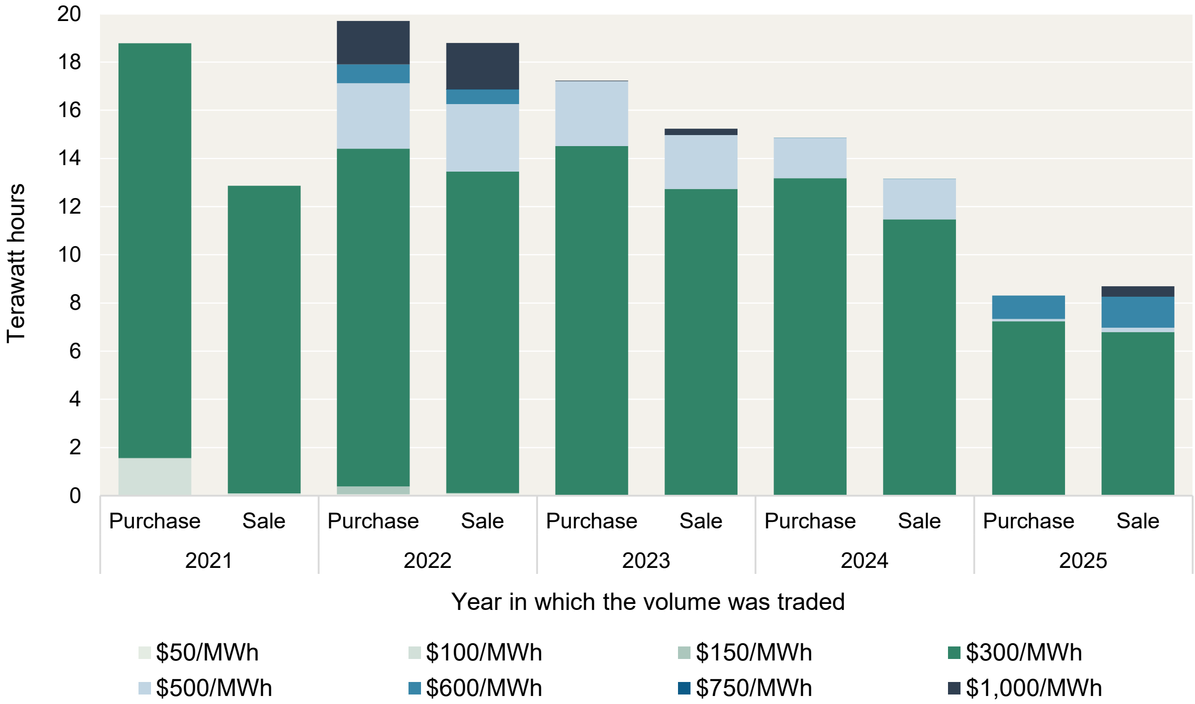
3.4.3 $300 per MWh remained the most common strike price for standard OTC caps

Cap contracts were traded primarily on the ASX, which accounted for 73% of combined reported cap volume. OTC cap trading briefly increased during the 2022 energy crisis, reaching 41% of combined volume, before falling back to 14% by 2025 as spot price pressures eased and participants returned to exchange markets. Trading on both sides of the OTC market is heavily concentrated, with large energy market participants accounting for over three-quarters of the volume.

Within OTC markets, $300 per MWh strike prices remained dominant, accounting for 83% of reported volume. After the sharp spot price spikes in 2022, some higher strike products gained traction. Because caps with these higher strike prices are not available on the ASX, the OTC market is innovating in the use of higher strikes to meet a different hedging need. $500 per MWh contracts accounted for over 10% of volume from 2022 to 2024, before being largely replaced by $600 per MWh contracts in 2025. Strike prices below $300 per MWh were uncommon, with none reported since 2022.

Quarterly contracts accounted for 64% of OTC volume, while annual contracts accounted for 32%, broadly mirroring the quarterly and annual structure seen in ASX caps. OTC caps were also traded further ahead of delivery than ASX caps. Between 2021 and 2025, 69% of OTC cap volume traded by energy market participants was contracted more than one year before contract expiry, compared with 50% for ASX-traded caps. By contrast, non-energy market participants accounted for most ASX cap trading in the final 3 months before expiry.

Figure 3.18 Reported volumes of OTC caps, by different strike price



Note: The MMIO only covered energy market participants. The mismatch between reported purchase and sale volumes is because non-energy market participants are not captured under the MMIO and not required to report their trades to the AER. Where one counterparty to a trade is a non-energy market participant, that trade will only be reported by one of the trade parties.
Source: AER analysis using MMIO data.

3.4.4 Peak contracts more commonly traded OTC than on the ASX

Morning and evening peak futures were introduced by the ASX in June 2025.[21] Trading activity in these contracts on the ASX has so far been very limited, with only 0.03 TWh of evening peak contracts traded between their launch in July 2025 and March 2026. By contrast, OTC trading in morning and evening peak contracts increased sharply in 2025. In 2025 alone, reported OTC trades accounted for more than half of all peak contract trades over 2021 to 2025. Reported OTC peak contract purchases and sales reached 4.6 TWh and 2.3 TWh, respectively, in 2025, materially exceeding ASX-traded volumes since launch.

One reason for this difference is that OTC peak contracts can be tailored to participants' needs, whereas ASX peak load contracts use uniform time profiles. In the OTC market, 62% of morning peak contracts use a 6 am to 9 am profile, matching the ASX profile. By contrast, 54% of evening peak contracts use a 4 pm to 10 pm profile, which differs from both the ASX profile of 4 pm to 9 pm and the TOD Markets[22] standard of 4 pm to 8 pm. In terms of contract length, 62% of reported OTC peak contracts covered one quarter to one year, while 27% covered one quarter or less.

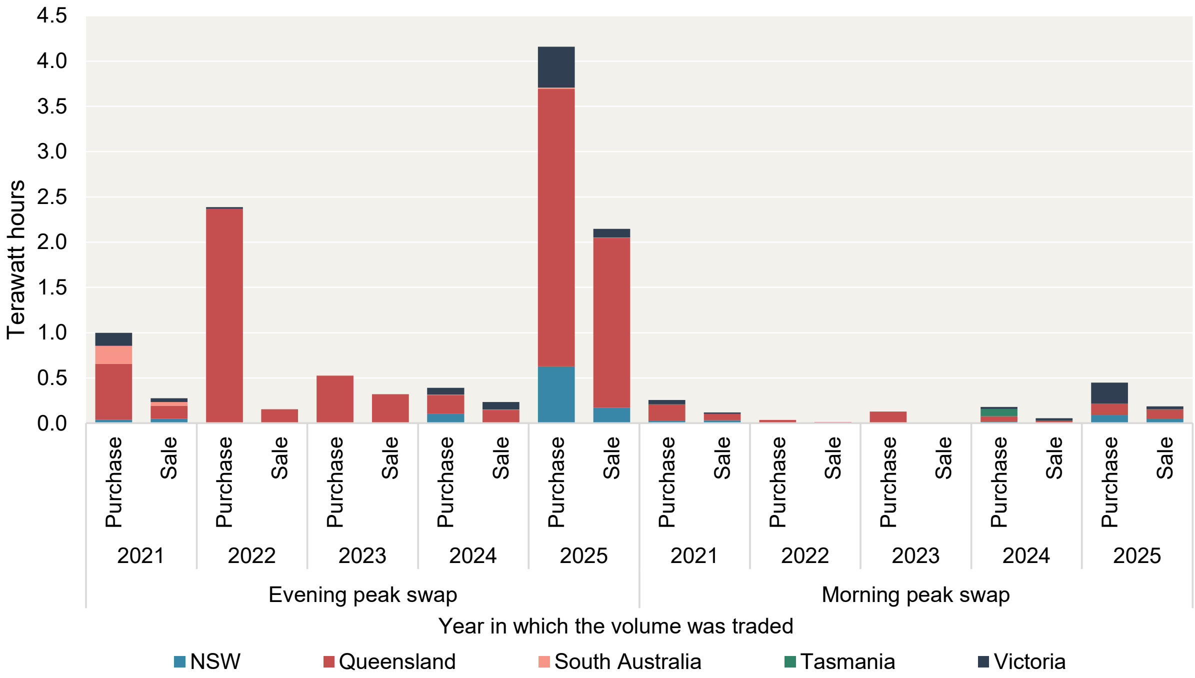
Trading was concentrated in Queensland, which accounted for 78% of total OTC peak contract volume. Evening peak contracts also dominated within the OTC market, accounting for 89% of trades, compared with 11% for morning peak contracts.

OTC morning and evening peak contracts appear to be primarily used for medium-term hedging, with 52% of trade volume covering delivery between 1 and 3 years from the trade date. Non-energy market participants were also active in this market, acting as the counterparty for around half of the OTC contract volume traded in 2025.

21 ASX expanded its electricity derivatives offering in 2025 with the launch of Morning and Evening Peak Load Electricity Quarterly Futures contracts. NSW contracts were launched on 30 June 2025, followed by Queensland on 7 July, Victoria on 21 July and South Australia on 28 July.

22 TOD Markets operates a digital OTC market platform offering standardised time-of-day electricity derivatives for the NEM. Their evening peak product is 4 pm to 8 pm.

Figure 3.19 Reported traded volumes of OTC peak contracts, by state



Note: The MMIO only covered energy market participants. The mismatch between reported purchase and sale volumes is because non-energy market participants are not captured under the MMIO and not required to report their trades to the AER. Where one counterparty to a trade is a non-energy market participant, that trade will only be reported by one of the trade parties.
Source: AER analysis using MMIO data.

3.5 Power purchase agreements

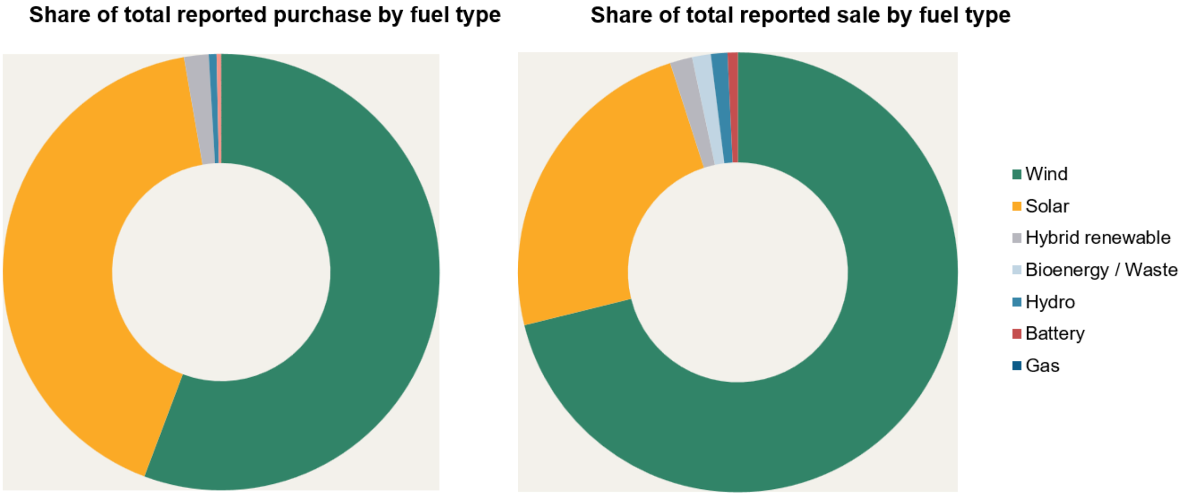
3.5.1 Reported PPA purchase volumes were around one-fifth of the NEM underlying demand

Between 2021 and 2025, energy market participants reported 179 TWh of PPA purchases and 110 TWh of PPA sales. These volumes were equivalent to 19% and 12%, respectively, of total underlying NEM demand over the same period.

3.5.2 Reported PPA volumes were concentrated in wind and solar

Wind and solar were the dominant fuel types in reported PPAs, together accounting for more than 95% of total volume. Between 2021 and 2025, wind and solar accounted for 56% and 42% of reported PPA purchase volumes, respectively. For reported PPA sale volumes, wind accounted for 71% and solar for 24%.

Figure 3.20 Share of reported PPA volumes, by fuel type



Note: Chart shows the share of PPA purchase and sale volumes by generation asset fuel type from 2021 to 2025, based on data reported to the AER by energy market participants. It excludes trades undertaken by non-energy market participants, such as banks or trading businesses, because they are not subject to the MMIO.
Source: AER analysis using MMIO data.

3.5.3 Reported PPA sale prices were lower for solar than wind

Reported solar PPA sale prices were lower than wind prices between 2021 and 2025. Across all reported PPA sales over the period, the volume-weighted average price was $54.49/MWh for solar, compared with $66.70/MWh for wind.[23] Over the period, the volume-weighted average sale price for wind ranged between $63.56/MWh and $72.40/MWh. Solar PPAs reported a lower volume-weighted average price overall, ranging between $53.35/MWh and $56.74/MWh. Prices varied by region. Reported prices for solar are in the range of levelised cost of energy estimated by the CSIRO for new entry solar ($52.48 to $88.38 per MWh).[24] The reported prices for wind are lower ($77.82 to $128.80 per MWh),[25] reflecting the increase in construction costs for wind farms in recent years (section 6.1.2.1).

3.6 Findings from qualitative questions

3.6.1 Access to clearing has improved since 2022

To transact on the ASX, market participants must engage an approved clearing participant to clear and settle transactions. As a central counterparty, the ASX facilitates trades between market participants and mitigates counterparty risk by becoming the buyer to every seller and the seller to every buyer. The ASX Clearing House manages this risk exposure by imposing margin requirements on clearing participants, who subsequently pass on these capital and margin requirements to energy retailers and generators.

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23 Some energy market participants reporting under the MMIO reported bundled PPA prices that included both energy and LGC components.

24 CSIRO, GenCost 2025-26: Final report, July 2026, Apx Tables B.9–B.10.

25 CSIRO, GenCost 2025-26: Final report, July 2026, Apx Tables B.9–B.10.

Access to clearing services emerged as a material constraint in 2022, coinciding with unprecedented contract price volatility and the exit of Bell Potter as an ASX clearing participant. Affected market participants subsequently reported to the AER varying degrees of success in securing alternative clearing arrangements over the following 2 years.

The clearing landscape saw some relief across 2023 and 2024 with the entry of 2 new approved clearing participants for ASX Energy products. Marex commenced operations in October 2023, followed by StoneX in April 2024. While Macquarie Bank remains the largest provider of clearing services, both Marex and StoneX have successfully onboarded clients since their market entry. Between 2021 and 2025, 41% of energy market participants that reported using a clearing service provider reported using either Marex or StoneX, a clear indication that the entry of the 2 new clearing participants has improved access to clearing services.

3.6.2 Market participant clearing arrangements

Using its compulsory information-gathering powers under the MMIO, the AER surveyed energy market participants about their access to clearing services and broader barriers to contract market entry.[26] Between 2021 and 2025, 83% of those energy market participants reported using ASX clearing providers. Key findings include:

- Most of the market is covered by 4 primary clearing participants: Macquarie Bank, Marex, BNP Paribas and StoneX. Jarden was also used as an execution broker, with transactions subsequently cleared via StoneX.
- Macquarie Bank and BNP Paribas serve as the primary clearing participants for large to mid-tier energy market participants. Newer entrants Marex and StoneX predominantly provide clearing services to smaller market participants.
- Most surveyed energy market participants rely on a single clearing provider. Only 20% of participants reported maintaining relationships with more than one clearing participant over the past 5 years.

3.6.3 Barriers to contract market participation

The AER evaluated barriers to entry across both exchange-traded (ASX) and broader OTC contract markets to understand impacts on market liquidity and risk management.

We surveyed over 40 market participants on whether the following potential issues were barriers to contracting on the ASX. More market participants responded than the number of active ASX clearing users, indicating deterred or aspirational market entrants.

Potential barrier	Proportion of participants that agreed
Margining requirements	53%
Standard contract types available on the ASX did not meet hedging needs	45%

26 The survey questions can be found in the Market Monitoring Information Order Electricity - MMIOELEC-2025-02, pp. 23–25. Responses were collected on 30 March 2026 and will be collected annually.

Potential barrier	Proportion of participants that agreed
Liquidity	43%, including both large and small participants
Costs and fees to access the ASX were too high	31%, including both large and small participants
Unable to access clearing services	19%, mostly smaller participants
Minimum lot sizes of 1 MW were too large	7%

71% of the respondents identified being impacted by at least one of the barriers above. Of the impacted participants, around 75% were able to trade on the ASX despite these barriers. Of those not trading on the ASX currently, the key barrier identified was that the contract types available on the ASX were not suitable to their hedging needs.

A broader cohort of market participants were asked whether the below potential structural barriers impacted their ability to secure OTC energy contracts effectively.

Potential barrier	Proportion of participants that agreed
Lack of appropriate products at an acceptable price	39%
Lack of market transparency	30%
Credit worthiness	28%
Regulatory or compliance burden	26%
Lack of products meeting their risk needs	20%
Lack of market relationships or industry connections	20%

Overall, these findings indicate that barriers to contract market participation arise from a combination of liquidity, product suitability, credit and access constraints. The introduction of a market making obligation (MMO) in South Australia as part of the Firm Energy Reliability Mechanism is intended to help with liquidity.[27] There are a number of other reforms that will help access to the ASX contract market, including AEMO's Shortening the settlement cycle (August–November 2026),[28] new Maximum Credit Limit methodology (from 1 December 2026)[29] and Cash as credit support (November 2026).[30]

27 South Australian Government, FERM Market Liquidity Obligation Consultation, 20 January 2026, accessed June 2026.

28 AEMO, Shortening the Settlement Cycle, Australian Energy Market Operator, 12 February 2025, accessed June 2026.

29 AEMO, Credit Limit Procedures – SSC and related changes, Australian Energy Market Operator, 10 December 2025, accessed June 2026.

30 AEMO, Cash security, Australian Energy Market Operator, 7 August 2025, accessed June 2026.

4 Market structure

Market concentration has declined overall, but significant risks remain in firming services, local frequency control ancillary services (FCAS) markets, and at key times of the day.

Key findings

- Since our last report, entry of new generation and storage capacity has reduced market concentration and lowered the market share for the largest participants across all mainland regions.
- Market concentration varies by time of day. It is lowest during the day, when output from diversely owned grid-scale solar is high. It is more concentrated during the evening peak and overnight and can still exceed our threshold for high concentration at times.
- Ownership of dispatchable capacity remains concentrated but has improved since our last report.
- Reliance on the largest 2 participants to meet demand declined in mainland NEM regions, but 1 or 2 large participants are still pivotal for a significant share of time in some regions and during evening peak periods.
- Local FCAS markets are highly concentrated in South Australia and Tasmania. This means that when these markets are separated or at risk of separation, prices can be high. In South Australia, this contributed to very high FCAS prices during an outage on the Heywood interconnector in July to September 2025.
- Interconnectors can provide competitive pressure from neighbouring regions, but this weakens when they are constrained. In 2025, interconnectors between South Australia and Victoria were frequently constrained, leading to reduced price alignment. The Victoria–NSW interconnector was also constrained frequently and at low levels of flow, particularly in summer.
- Settlement residue auctions remain primarily a hedging tool for regional price separation, but auction prices and growing financial participation also reveal market expectations about interconnector performance, regional divergence and the future value of interregional trade.

Competition is influenced by the structure of the market. A generator has more opportunity to exercise market power in a market with few participants, especially during periods of limited interconnector capacity, when demand is high or when supply is constrained. This chapter examines market structure using a range of indicators, including:

- concentration metrics, such as Herfindahl Hirschman Index (HHI) (section 4.1.1), market share by output (section 4.1.2) and market share by registered capacity (section 4.1.3)
- pivotal supplier analysis (section 4.1.4)
- interconnector performance (section 4.4) and hedging of interregional flows (section 4.5).

We also discuss concentration of FCAS markets in section 4.2.

The ability to exercise market power is distinct from incentives to exercise that power. A participant's incentives will be influenced by a range of factors, including the extent to which it has hedged against spot prices, the extent to which it is vertically integrated, and government direction or regulation. In chapter 5, we assess the extent to which participants exercise market power, particularly on a sustained basis.

4.1 Concentration of ownership

Despite new entry, a small number of large participants continue to control a significant share of generation capacity in the NEM, particularly in firming services. This means opportunities remain to exercise market power, especially during periods of supply stress and at certain times of the day when dispatchable generation is most needed.

Box 4.1 How we assess market concentration

Market concentration refers to the number and relative size of participants in a market. A concentrated wholesale electricity market has a high proportion of capacity controlled by a small number of participants and is more susceptible to outcomes that are not competitive. Market concentration can be measured using various metrics. A more detailed description of our metrics can be found in our methodology document.

Herfindahl Hirschman Index (HHI)

HHI provides an indication of market concentration and allows for comparisons across regions and over time.

Our HHI analysis looks at the market share across all participants in the market based on 5-minute bid availability. This accounts for outages, fuel availability and bidding behaviour. Looking at it on a 5-minute basis enables a dynamic assessment of concentration under changing market conditions.

We consider a HHI score above 2,000 to indicate a highly concentrated market. This is the same benchmark used by the ACCC in its merger assessments.[31]

Market share

Market share is the simplest measure of concentration. This report uses 2 measures of market share – market share by generation output and market share by registered capacity.

Market share by generation output

Market share by generation output measures a participant's share of annual energy delivery. It provides a good reflection of the nature of a market participant's generation fleet and contribution to market outcomes. However, it may under-represent market participants with flexible generation portfolios who tend to only use their units to respond to peak prices.

Market share by registered capacity

Market share by registered capacity measures a participant's share of total registered generation capacity at a point in time. It does not capture factors that may affect actual output, such as outages, network constraints, operating costs and plant availability.

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31 ACCC, Merger assessment guidelines, Australian Competition and Consumer Commission, 20 June 2025, p. 13, accessed 2 April 2026.

In this report, the primary category is dispatchable generation. Coal remains the largest source of dispatchable generation capacity, meaning the ownership of coal generation has a significant influence on market concentration.

We have also included market share by service type. The NEM wholesale market settings review (NEM Review) categorised the replacement capacity for outgoing coal generation according to 3 types – bulk energy, shaping and firming – depending on the service it provides to the market.[32]

- **Bulk energy** is defined in the NEM Review as zero emissions electricity generation sent out from a generating unit or voluntarily scheduled resource. In our analysis, we have limited the bulk energy category to large-scale wind and solar generating units. These are the generators providing most of the additional megawatt hours of energy to replace coal power stations as they retire.
- **Shaping** services are those that help balance variable renewable outputs like solar and wind through short-duration output, filling gaps during peak usage periods and preventing overloading or underutilisation of resources. We have categorised shaping services as energy provided by storage capacity – that is, battery and pumped hydro units.
- **Firming** services provide longer-duration dispatchable supply when bulk energy and shaping are insufficient. This includes gas, non-pumped hydro, diesel and other liquid fuel generation.

Our approach is not intended to prejudge potential approaches for a future competition threshold test for the Electricity Services Entry Mechanism (ESEM). Rather, it is intended to provide information on the ownership structure of the fuel types covered by ESEM services.

The categories in this report align with the NEM Review, except that as a simplifying assumption we have not included run-of-river hydro in bulk energy and have only included pumped hydro in shaping (rather than in both shaping and firming).[33]

Pivotal supplier test (PST)

The PST measures the extent to which one or more participants are 'pivotal' to clearing the market. A participant is pivotal if market demand exceeds the capacity of all other participants, including possible imports from other regions. In these circumstances, the participant must be dispatched (at least partly) to meet demand. The PST gives an indication of the likelihood a participant will have the opportunity to exercise market power.

4.1.1 Market concentration in the NEM has improved overall, but instances of high concentration remain

Market concentration in mainland NEM regions has continued to decline, reflecting improving competition on average. HHI scores have fallen in all mainland regions since our last report and remain below the threshold for a highly concentrated market (Figure 4.1). This improvement reflects ongoing entry of new generation and storage capacity owned by a

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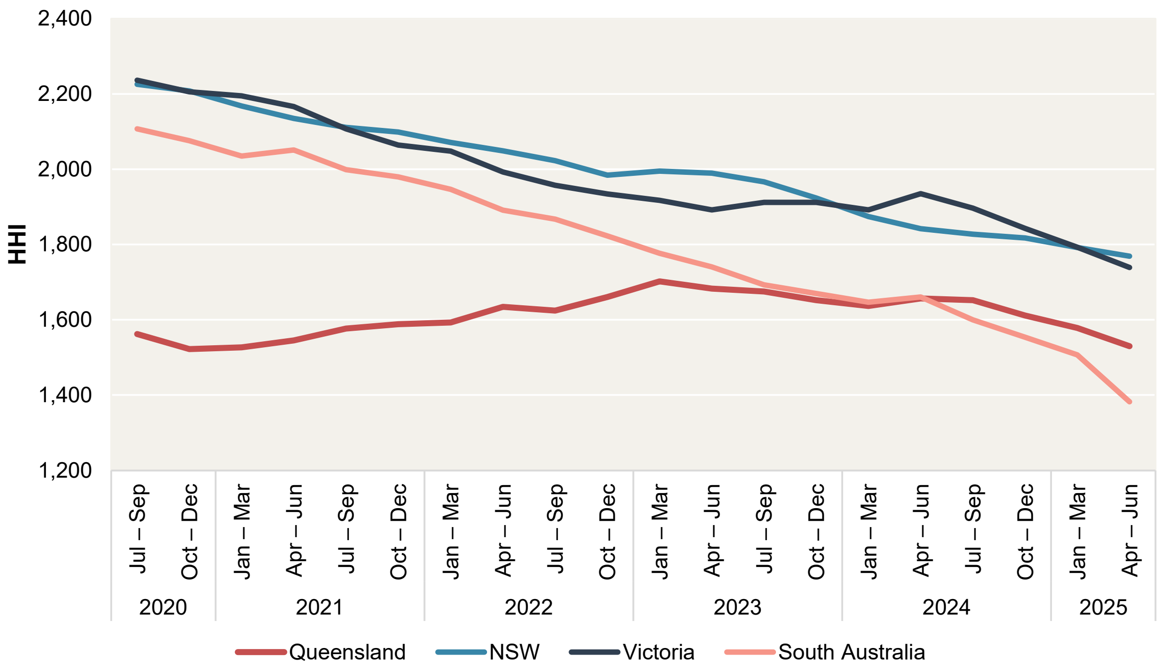
[32] Australian Government, National Electricity Market wholesale market settings review, p. 156, 16 December 2025, accessed 2 April 2026.

[33] Australian Government, National Electricity Market wholesale market settings review, p. 184, 16 December 2025, accessed 2 April 2026.

wider range of participants. However, competition risks remain in particular services, regions and trading intervals, and instances of high concentration still occur in some parts of the market.

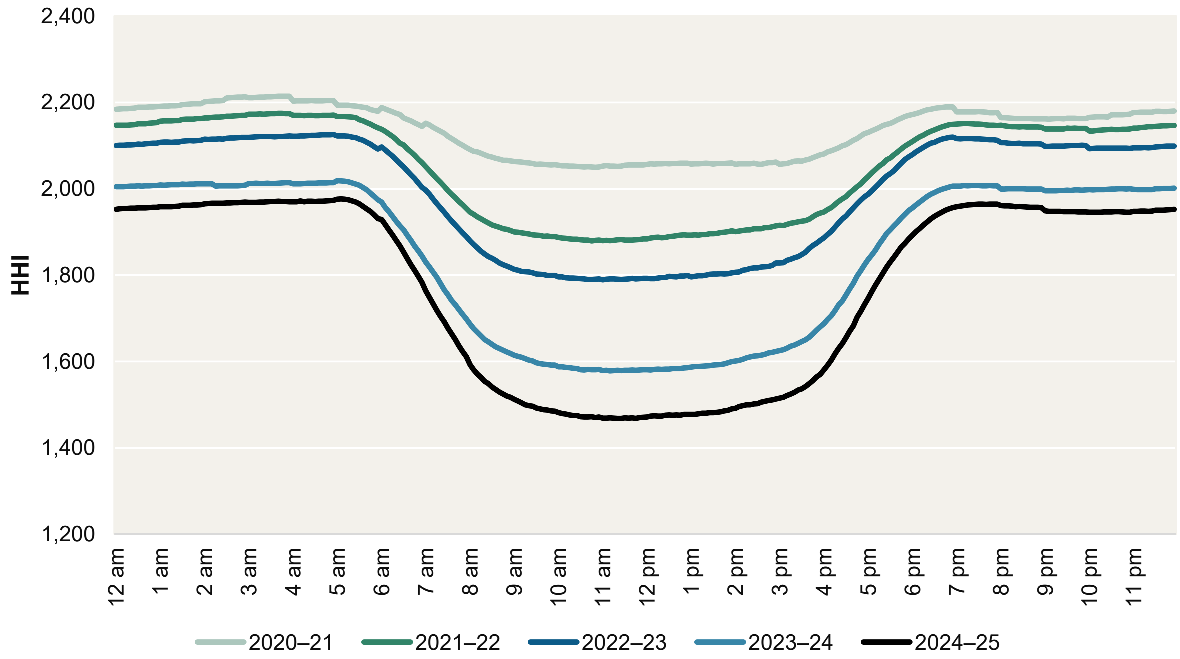
Figure 4.1 Quarterly rolling average HHI, by bid availability



Note: Calculations of HHI exclude market suspension periods as well as administered pricing intervals when prices would otherwise have been higher than the administered price cap. Quarterly rolling averages were calculated by averaging HHI values across 4 quarters. For example, the rolling average for Apr – Jun 2025 is calculated by summing the average HHI values for Jul – Sep 2024, Oct – Dec 2024, Jan – Mar 2025 and Apr – Jun 2025, and dividing by 4.
Source: AER analysis using NEM data and market research.

The largest improvement has occurred in the middle of the day, particularly in Queensland and NSW (Figure 4.2), where higher output from large-scale solar has reduced concentration. Concentration has also eased slightly during peak and overnight periods due to wind and batteries.

Figure 4.2 NSW financial year average HHI, by time of day[34]



Note: Calculations of HHI exclude market suspension periods as well as administered pricing intervals when prices would have otherwise been higher than the administered price cap. HHI for each time of day is averaged across all dispatch intervals for that time of day in that year. Figure presents outcomes in NEM time.
Source: AER analysis using NEM data and market research.

Despite these improvements, the market can still be highly concentrated in all regions at times (Figure 4.3), indicating ongoing vulnerability in specific intervals. Concentration levels above 2,000 occurred most frequently in NSW and Victoria. These regions have a higher concentration of dispatchable capacity than South Australia and, especially, Queensland.[35] This means that during periods of low renewable output, when the market depends more heavily on dispatchable generation, concentration can be higher.

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34 Charts and data for the other regions are available in the Market Structure data book.

35 This is due to all other participants in Queensland being relatively small, compared to the 2 largest. This is discussed further in section 4.1.4

Figure 4.3 Variability in bid HHI, by region

Note: Calculations of HHI exclude market suspension periods as well as administered pricing intervals when prices would have otherwise been higher than the administered price cap. The top of the range shows the dispatch interval with the highest HHI score, while the bottom shows the lowest HHI score.
Source: AER analysis using NEM data and market research.

Historically, peak concentration was highest in Victoria and South Australia, but it has declined in recent years. These regions continue to show the greatest variation between high and low concentration levels. This reflects the higher penetration of diversely owned intermittent renewable generation compared with regional demand. Periods of high renewable output generally coincide with lower concentration, whereas concentration increases when the system relies more heavily on dispatchable generation. South Australia now records the lowest 90th percentile concentration among all regions.

Peak concentration is lowest in Queensland. Stanwell and CS Energy together hold a large market share, but the remainder of generation capacity is relatively diversified. The lower penetration of renewables in Queensland also means there is less variation in concentration.

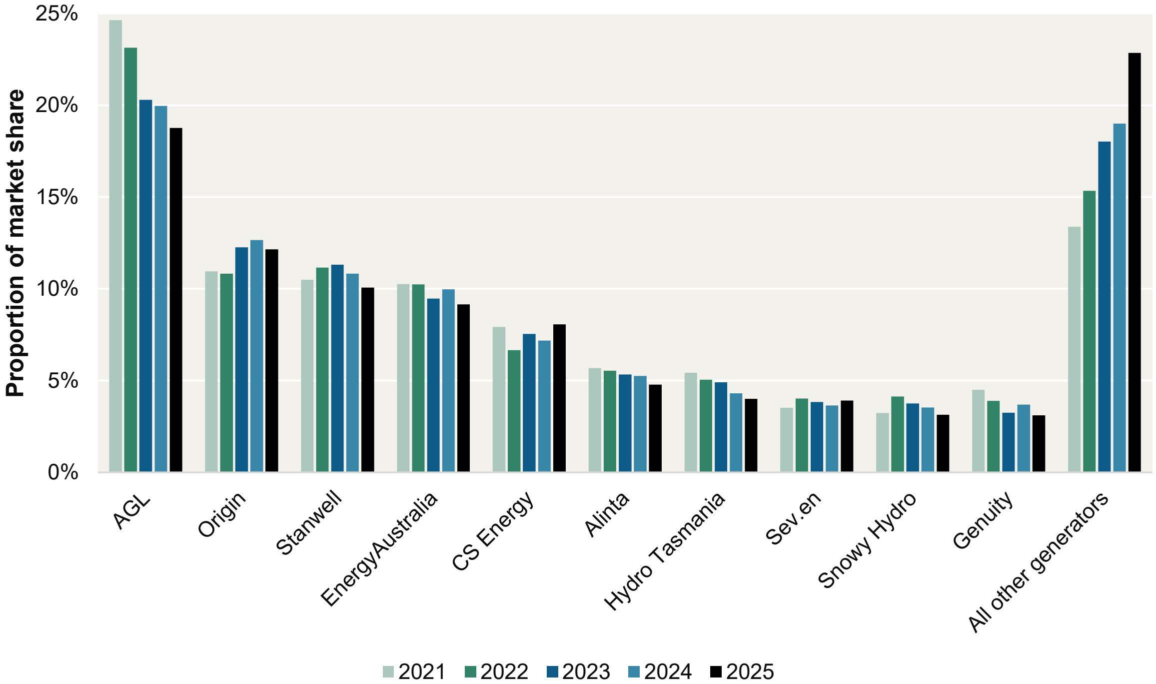
The 90th percentile provides a more reliable indicator of underlying trends of peak concentration than the annual maximum. HHI is calculated for each 5-minute interval, so a short period of exceptionally high concentration can produce an outlier maximum value. This might occur, for example, if low wind and solar output were to coincide with several plant outages, leaving one participant with an exceptionally large market share.

From 2024 to 2025, the 90th percentile HHI declined across all regions, including NSW where the highest level of concentration increased. This suggests that, although periods of high concentration persist, underlying concentration levels are improving even during peak times.

4.1.2 Share of generation output from the largest generators continues to decline

The NEM's generation output is becoming less concentrated, with the largest participants supplying a smaller share of output and smaller participants gaining market share (Figure 4.4). This suggests new entry and growth of smaller participants is reducing the dominance of incumbent generators in energy supply. Since 2021, market shares have declined for 7 of the 10 largest participants by output. AGL, the NEM's largest generator by output, recorded a decline in market share from 25% to 19%, while the combined share of generators outside the top 10 increased from 13% to 23%.

Figure 4.4 Market share by generation output, NEM

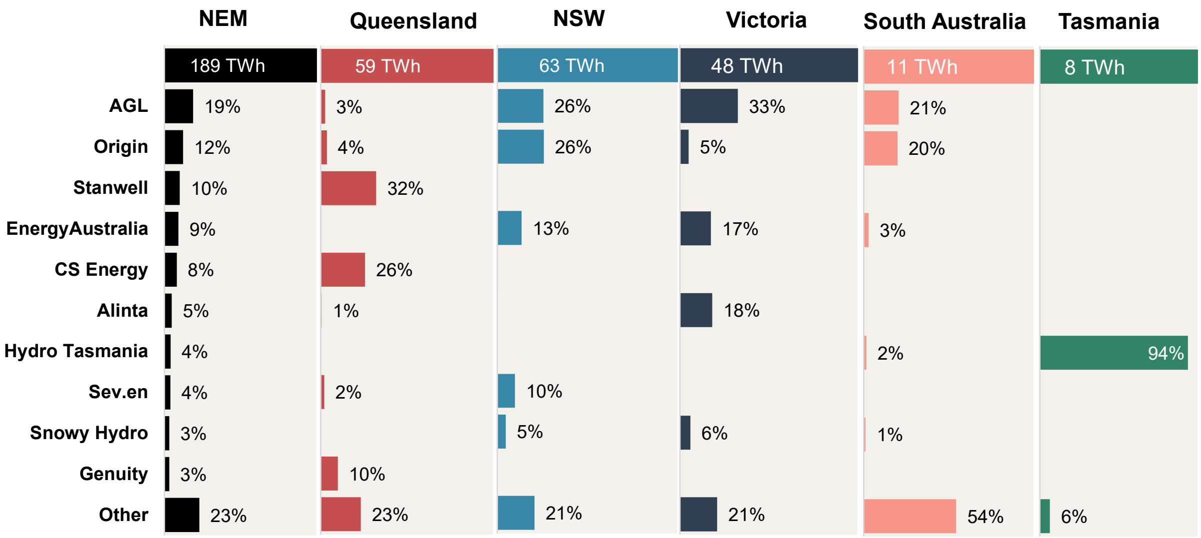


Note: Market shares of output over the past 5 years. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Output is split on a pro rata basis if ownership changed in 2025. Where multiple owners are invested in a generating unit, the output of that unit has been split proportionally between owners according to their percentage of total ownership. Output from rooftop solar systems, interconnectors, loads and non-scheduled generation are excluded from the data.
Source: AER analysis using NEM data and market research.

The decline was broad-based across all mainland regions, although the scale of change varied. Since 2021, the largest reduction in concentration was in South Australia (Figure 4.5):

- In Queensland, the share owned by Stanwell, CS Energy and Genuity fell from 75% to 68%.
- In NSW, the share owned by AGL, Origin and EnergyAustralia fell from 76% to 65%.
- In Victoria, the share owned by AGL, Alinta and EnergyAustralia fell from 79% to 68%.
- In South Australia, the share owned by AGL, Origin and Engie fell from 70% to 53%.

Figure 4.5 Market share by generation output, by region, 2025

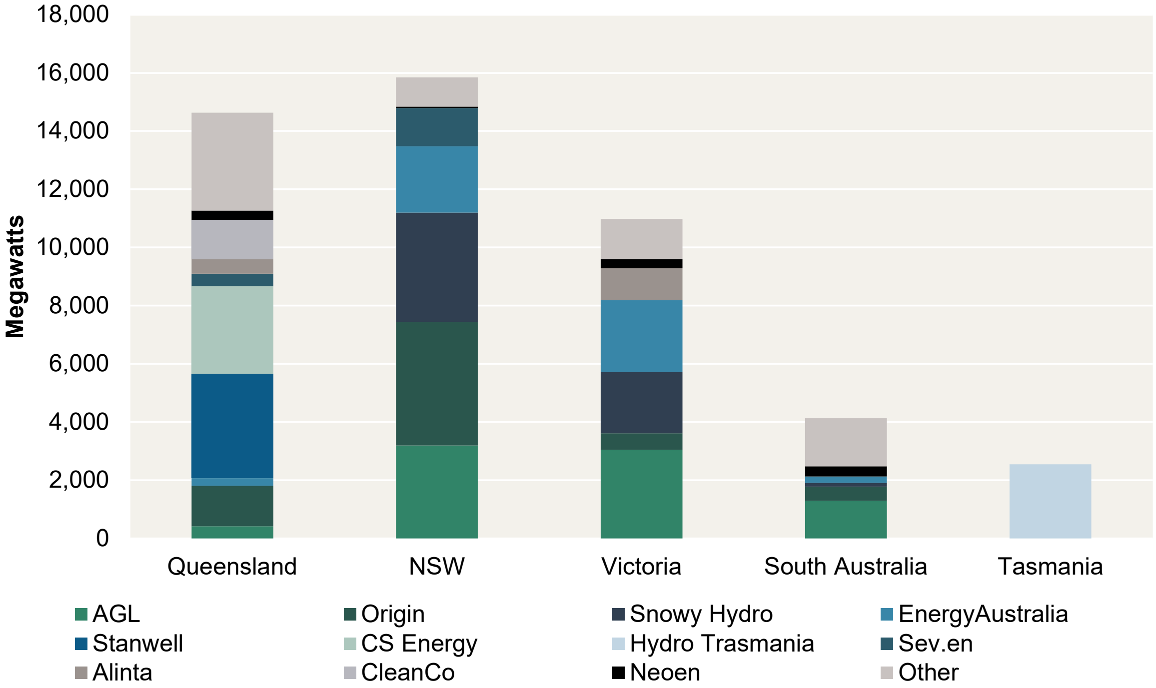


Note: Market shares of output in 2025. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Output is split on a pro rata basis if ownership changed in 2025. Where multiple owners are invested in a generating unit, the output of that unit has been split proportionally between owners according to their percentage of total ownership. Output from rooftop solar systems, interconnectors, loads and non-scheduled generation are excluded from the data.
Source: AER analysis using NEM data and market research.

4.1.3 Dispatchable generation remains concentrated but is improving

Dispatchable generation remains concentrated but has improved since our last report. AGL, Origin Energy and Snowy Hydro collectively control 43% of dispatchable generation capacity across the NEM. The largest 3 providers of dispatchable generation capacity in each region control 55% of capacity in Queensland, 71% in NSW, 69% in Victoria and 64% in South Australia. Apart from NSW, this represents an improvement compared with the concentration levels reported in the *Wholesale electricity market performance report 2024*.

Figure 4.6 Market share, by registered capacity, dispatchable generation



Note: Registered capacity share uses registered capacity of all market scheduled and semi-scheduled generation (excluding market loads) registered at 31 December 2025. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Dispatchable classification includes generation from coal, hydro, gas, liquid, diesel and battery (all scheduled generation).
Source: AER analysis using AEMO registration data and market research.

Concentration varied by service type

To provide information on ownership structure of the fuel types covered by the Electricity Services Entry Mechanism, we have also analysed registered capacity by service type. The NEM wholesale market settings review (NEM Review) categorised the replacement capacity for outgoing coal generation according to 3 types – bulk energy, shaping and firming – depending on the service it provides to the market (Box 4.1).[36] As these categories describe replacement capacity, the NEM Review did not place coal into any of them. The service definitions used in this report represent an indicative approach to classifying capacity by service type.

Bulk energy is diversely owned

Bulk energy – that is, energy provided by grid-scale wind and solar – is the least concentrated service type. The 3 largest providers of this service – AGL, Acciona Energy and Origin Energy – owned the output from just 20% of total registered bulk energy capacity in the market at 31 December 2025. This is compared with the 24% market share held by the largest 3 companies (then AGL, Origin Energy and Iberdrola) at 30 June 2024. While some individual providers have a larger market share in one region – for example, Acciona's 20%

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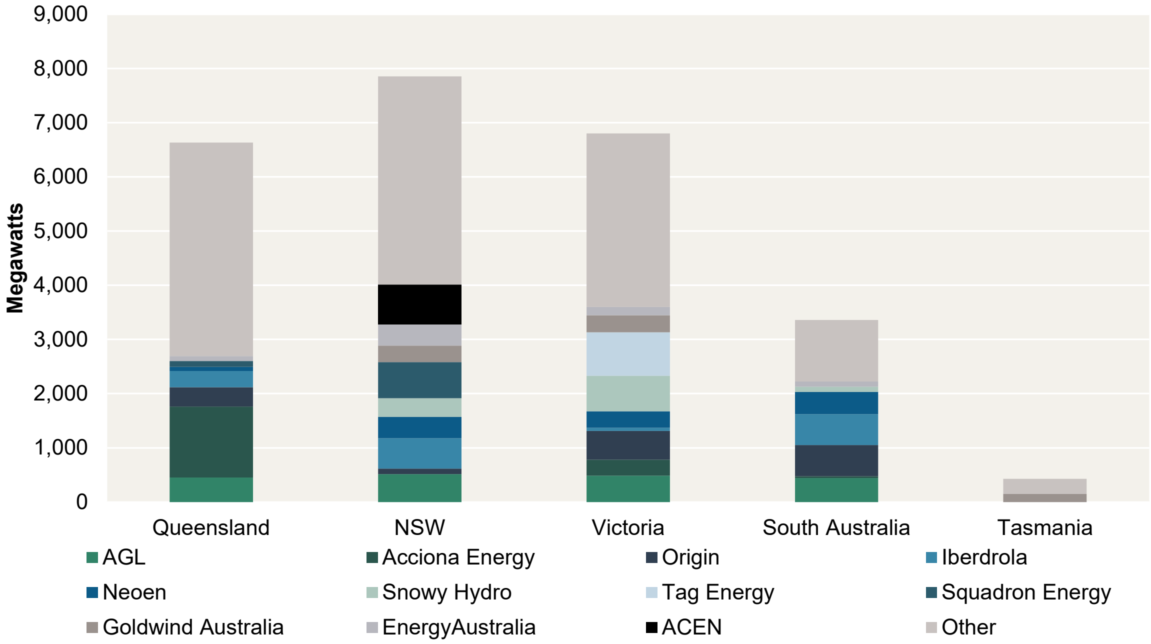
36 Australian Government, National Electricity Market wholesale market settings review, p. 179, 16 December 2025, accessed 2 April 2026.

market share in Queensland – each region has a low overall level of market concentration (Figure 4.7).[37]

Figure 4.7 Market share, by registered capacity, bulk energy service



Note: Registered capacity share uses registered capacity of all market scheduled and semi-scheduled generation (excluding market loads) registered at 31 December 2025. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Registered capacity is classified by service type broadly in line with the NEM Review framework. Our bulk energy category includes grid-scale wind and solar generation.
Source: AER analysis using AEMO registration data and market research.

Rapid new entry of diversely owned battery capacity has reduced concentration of shaping services

Shaping – which is provided by battery and pumped hydro generators – remains more concentrated than bulk energy, but competition is improving rapidly. The 3 largest providers – Snowy Hydro, AGL and Neoen – owned the output from 39% of capacity across the NEM at 31 December 2025 (Figure 4.8). This compares with a 66% share owned by the largest 3 companies (Snowy Hydro, Neoen and CleanCo) at 30 June 2024.

Shaping capacity over this period more than doubled from 4.4 gigawatts (GW) to 9.3 GW. The influx of new diversely owned battery capacity led to large declines in the share of the top 3 in Queensland (from 84% to 56%), South Australia (96% to 68%) and Victoria (90% to 64%). NSW had a more modest decrease (85% to 74%). Of the 13 GW of committed projects, 6.5 GW are battery projects.[38]

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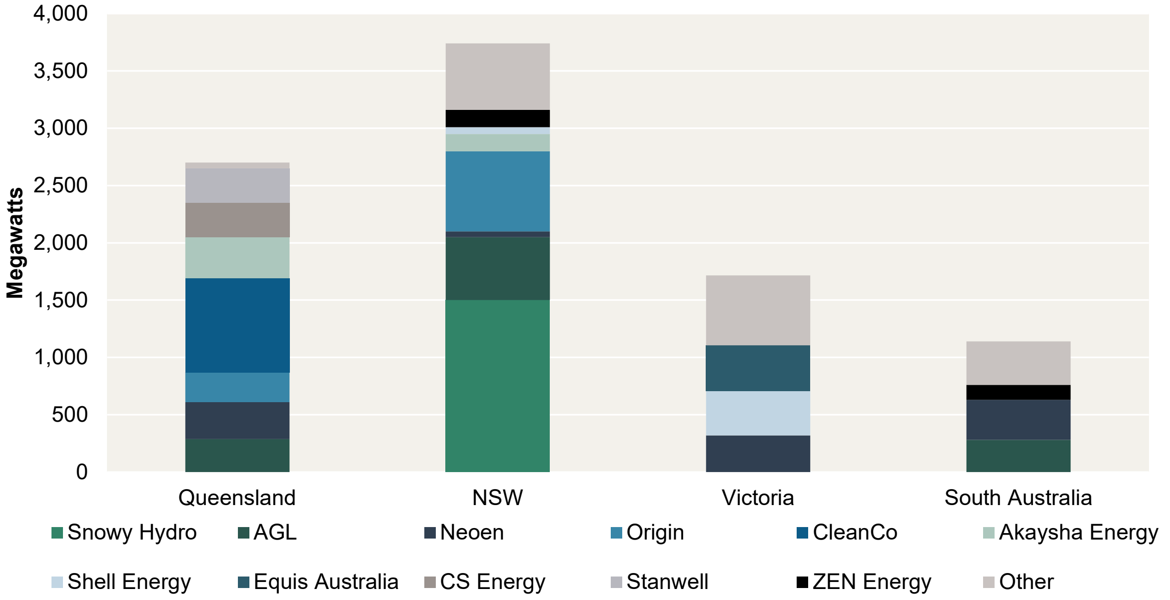
37 Acciona grew significantly over the period, from 2% market share (328 megawatts) to 6% share (1,638 megawatts).

38 AEMO, NEM April 2026 Generation information, Australian Energy Market Operator, 30 April 2026, accessed 22 May 2026. Committed projects meet all 5 of AEMO's commitment criteria.

Figure 4.8 Market share, by registered capacity, shaping service



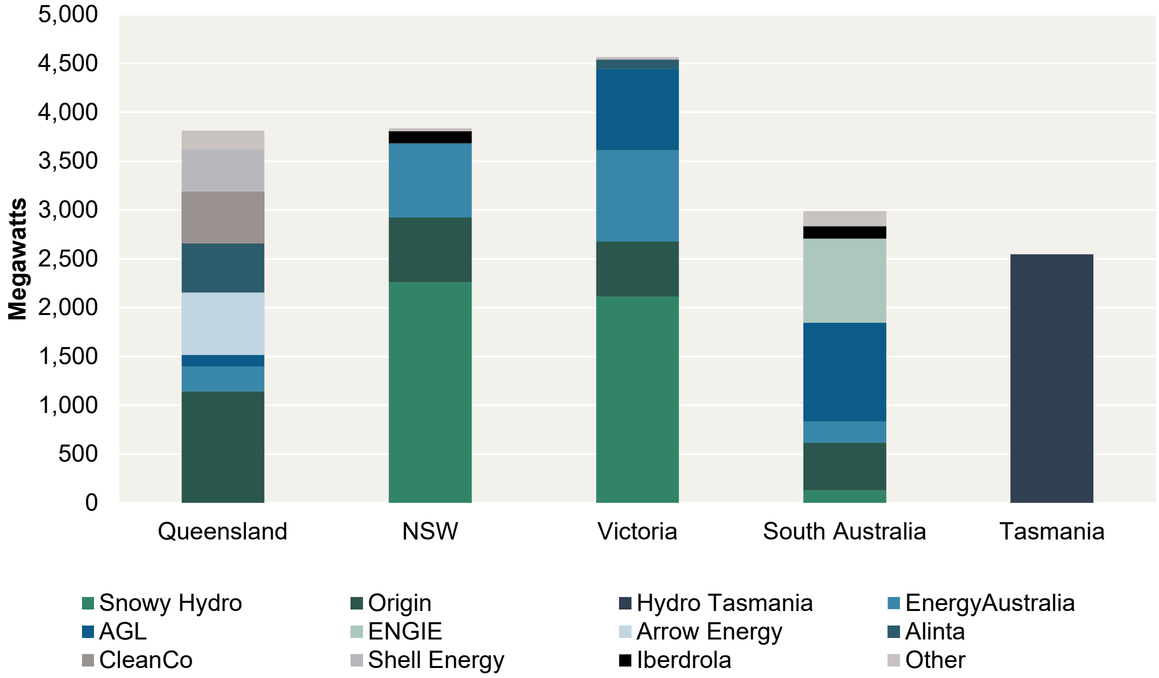
Note: Registered capacity share uses registered capacity of all market scheduled and semi-scheduled generation (excluding market loads) registered at 31 December 2025. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Registered capacity is classified by service broadly in line with the NEM Review framework. Our shaping category includes battery and pumped hydro generation.
Source: AER analysis using AEMO registration data and market research.

Firming is currently the most concentrated of the generator service types

Firming – which is provided by gas, non-pumped hydro, diesel and other liquid fuel generation – remains the most concentrated service type and has shown little evidence of becoming less concentrated. The 3 largest providers – Snowy Hydro, Origin Energy and Hydro Tasmania – owned the output from 56% of total NEM capacity at 31 December 2025 (Figure 4.9), unchanged from the market share held by these companies at 30 June 2024. The individual regions were even more concentrated and also mostly unchanged compared with 30 June 2024:

- In Queensland – where ownership of this service is most diverse – Origin Energy, Arrow Energy and CleanCo own the output from 61% of firming capacity.
- In NSW, Snowy Hydro, Origin Energy and EnergyAustralia owned the output from 96% of firming capacity, compared with 93% at 30 June 2024. Snowy Hydro's market share recently increased due to the commissioning of its 750 megawatt (MW) Hunter power station.
- In Victoria, Snowy Hydro, EnergyAustralia and AGL owned the output from 85% of firming capacity.
- In South Australia, AGL, Engie and Origin Energy owned the output from 79% of firming capacity.
- In Tasmania, the state government–owned Hydro Tasmania controls all firming assets.

Figure 4.9 Market share, by registered capacity, firming service



Note: Registered capacity share uses registered capacity of all market scheduled and semi-scheduled generation (excluding market loads) registered at 31 December 2025. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Registered capacity is classified by service broadly in line with the NEM Review framework. Our firming category includes generation from gas, non-pumped hydro, diesel and liquid fuels.
Source: AER analysis using AEMO registration data and market research.

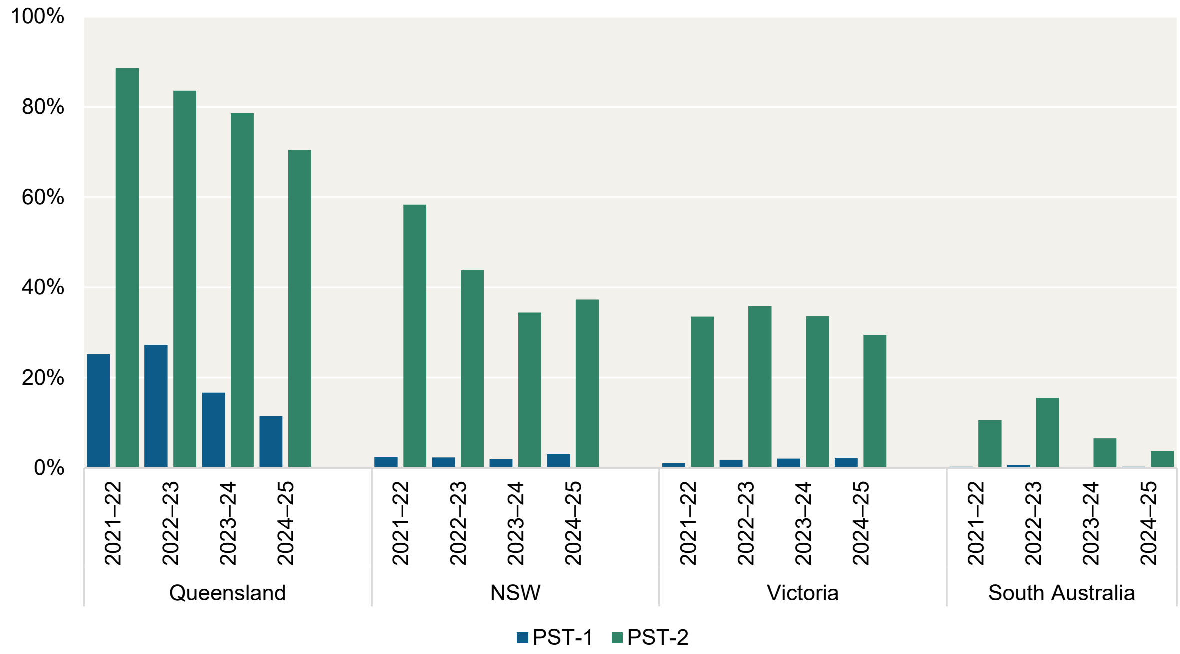
4.1.4 Large participants remain pivotal to meeting demand at key times

From 2022–23 to 2024–25, the share of time some output from the largest participant (PST-1) was needed to meet demand fell significantly in Queensland, from 27% to 11% (Figure 4.10). In part, this reflects the return to service of Callide C power station, which has reduced the dominance of the largest participant, Stanwell. Other factors also played a role, including entry of new capacity into the Queensland market and improved performance of the Queensland–NSW interconnector.

Stanwell remained the most frequent pivotal supplier, with some of its generation required 11% of the time in 2024–25, down from 27% in 2022–23. CS Energy was pivotal 1.6% of the time, down from 4.6%, despite Callide C's return to service.

Compared with Queensland, other regions were less reliant on the largest suppliers. In South Australia, the largest supplier was pivotal to meeting demand 0.2% of the time in 2024–25, down from 0.6% of the time in 2022–23. In NSW, the largest supplier was pivotal 3.0% of the time, up from 2.3%, and in Victoria 2.1% of the time, up from 1.8%.

Figure 4.10 Proportion of time some generation from the largest 1 or 2 participants was needed to meet demand



Note: The first measure shows periods when some output from the largest participant was required to meet market demand. The second measure shows periods when some output from 1 of the 2 largest participants was required to meet demand. The chart shows the percentage of intervals in each category. Data excludes administered pricing periods, when the price is capped, as well as market suspension periods.
Source: AER analysis using NEM data.

Reliance on the 2 largest participants (PST-2) fell in all regions, consistent with the recent decreases in market concentration discussed in sections 4.1.1, 4.1.2 and 4.1.3. In Queensland, where reliance on the largest participants is highest, some output from 1 of the largest 2 suppliers (always Stanwell and CS Energy) was needed 70% of the time in 2024–25, down from 89% in 2021–22.

In NSW, output from 1 of the 2 largest suppliers was needed to meet demand 37% of the time in 2024–25, down from 58% in 2021–22. AGL was less frequently a pivotal supplier, following the closure of Liddell power station in April 2023, with Origin and Snowy Hydro being the most frequent joint pivotal suppliers in 2024–25 – 36% of the time, down from 38% in 2021–22.

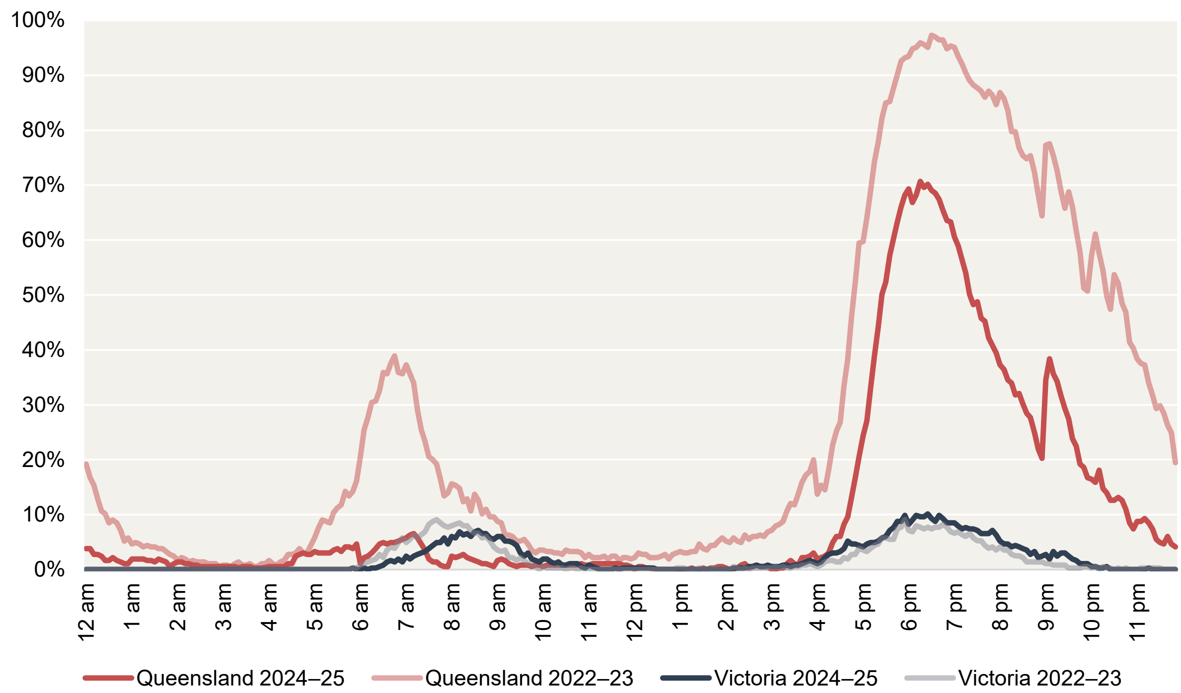
In Victoria, reliance on the largest participants declined only slightly in 2024–25 compared with 2022–23. Some generation from either AGL or Snowy Hydro was required 28% of the time, down from 35% in 2022–23. South Australia followed a similar trend to Victoria – reliance on the 2 largest participants decreased when comparing 2024–25 with 2022–23.

Queensland has the highest PST-1 and PST-2 percentages despite market concentration (HHI) being lower than in some of the other regions. One reason for this is the size of the 2 largest participants relative to the overall regional market. Stanwell and CS Energy are much larger than other participants in Queensland, contributing 819 and 406 points, respectively, to Queensland's average HHI score in 2024–25. The next highest were Genuity (94 points) and Origin (61 points). In NSW, the third-largest participant, AGL, contributed 352 points for 2024–25. Another reason for Queensland's higher PST percentages is the scale of regional demand compared with its ability to import generation from other regions. Total import capacity for the region is a maximum 957 MW, while demand is typically over 6,500 MW. NSW and Victoria have higher import capacity, while South Australia and Tasmania have much lower demand.

In all regions, reliance on the largest suppliers was highest during the evening peak, when demand remained strong and solar output is low. In Queensland, the largest supplier was needed to meet demand 70% of the time at 6.30 pm in 2024–25, compared with just 1% of the time at noon (Figure 4.11). Even in Victoria, where suppliers are rarely pivotal, the largest supplier was still needed to meet demand 10% of the time at 6 pm.

The large fall in Queensland during the evening peak was due to both 3,258 MW of new entry between 30 June 2023 and 30 June 2025 and the high starting reliance on Stanwell and CS Energy. Under most market conditions in Queensland, the 2 largest participants were previously required. This meant new entry drove a larger change. In other regions, reliance on the 2 largest participants was more likely to be associated with tighter market conditions. This meant new supply had a smaller impact.

Figure 4.11 Proportion of time some output from the largest supplier in Queensland and Victoria was needed to meet demand, by time of day[39]



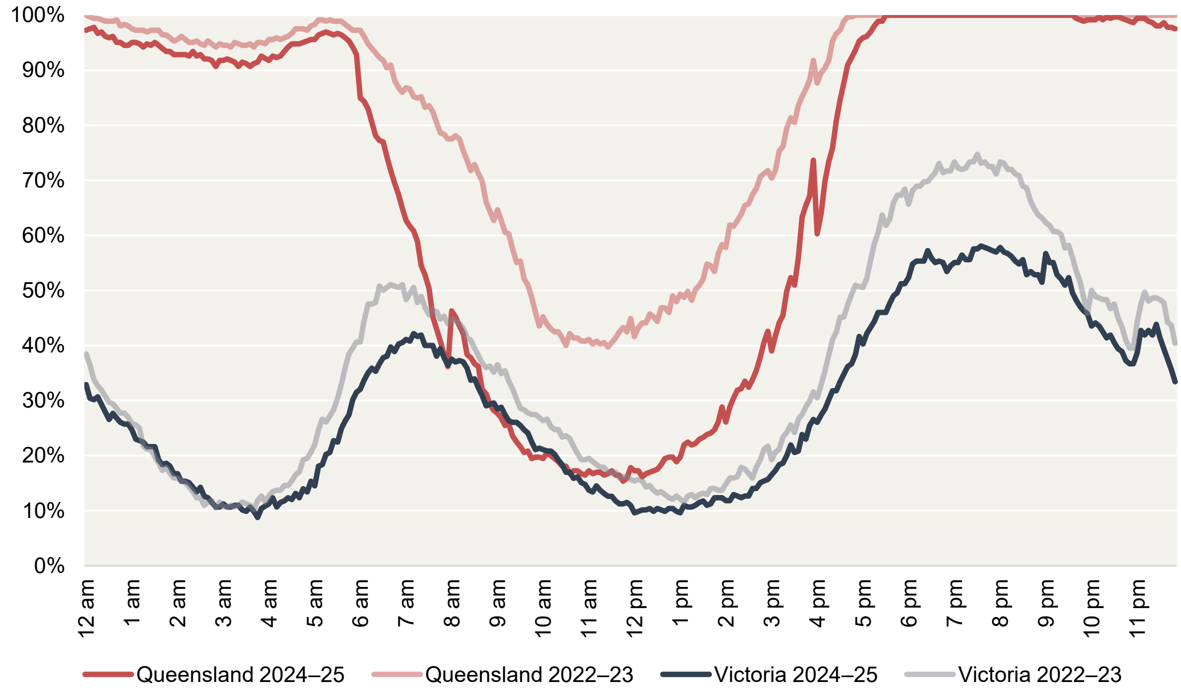
Note: The chart shows the proportion of the time that the available generation of the largest participant was required to meet market demand, by time of day.
Source: AER analysis using NEM data.

Trends for the 2 largest participants were similar to those for the largest participant during the evening peak, but they differed overnight. In Queensland, some generation from 1 of the 2 largest participants was always needed during the evening peak, as well as for the first half

39 Charts and data for NSW and South Australia are available in the Market Structure data book.

of the night (Figure 4.12). In Victoria, some generation from 1 of the 2 largest participants was needed about half the time during the evening peak. While this declined overnight, there was still much greater reliance on these generators between 9 pm and midnight than during the middle of the day.

Figure 4.12 Proportion of time some output from 1 of the 2 largest suppliers in Queensland and Victoria was needed to meet demand, by time of day[40]



Note: The chart shows the proportion of the time that some generation from 1 of the 2 largest participants was required to meet market demand, by time of day.
Source: AER analysis using NEM data.

Although reliance on the largest suppliers has declined, 1 or 2 large participants are still needed to meet demand for a significant share of time in some regions – particularly in Queensland and during evening peak periods. This means lower average concentration has not eliminated the potential for large suppliers to exercise market power when supply is tight.

4.2 FCAS is usually competitive, but local requirements can create concentrated, high-priced markets

FCAS is used alongside the spot market for energy to maintain system frequency within a safe operating band (Box 2.2). The Australian Energy Market Operator (AEMO) operates energy and FCAS markets through co-optimisation to minimise overall costs by jointly dispatching energy and FCAS requirements.

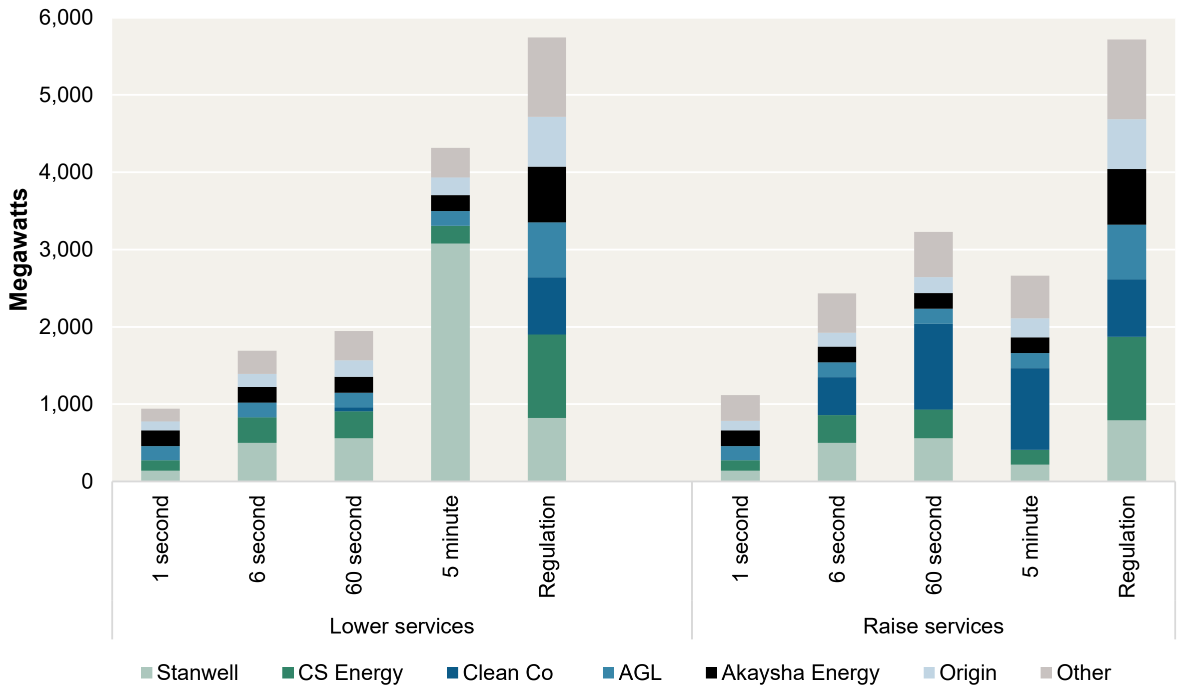
FCAS is usually procured through global (that is, whole of NEM) markets, with services supplied across regions. These markets are generally competitive and FCAS costs have

40 Charts and data for NSW and South Australia are available in the Market Structure data book.

steadily fallen over the past 5 years (section 2.5) as battery entry has increased competition. However, when a region is separated or at risk of separation, local FCAS requirements may be introduced. This tends to occur in Queensland, South Australia and Tasmania,[41] which are at the ends of the grid. In these circumstances, only local providers can meet the requirement. Where local supply is concentrated, competition may be weak and prices can become very high.

Queensland illustrates that local FCAS requirements do not necessarily result in high prices. The market is currently relatively unconcentrated, with the largest 2 providers controlling less than half of registered capacity for most services (Figure 4.13). Consistent with this, local FCAS costs were low (less than $10 million per quarter) throughout 2025. Costs were higher ($44 million) in the October to December quarter of 2024, but this still represented just 2% of total Queensland energy market revenue.

Figure 4.13 Registered capacity for each FCAS service, Queensland



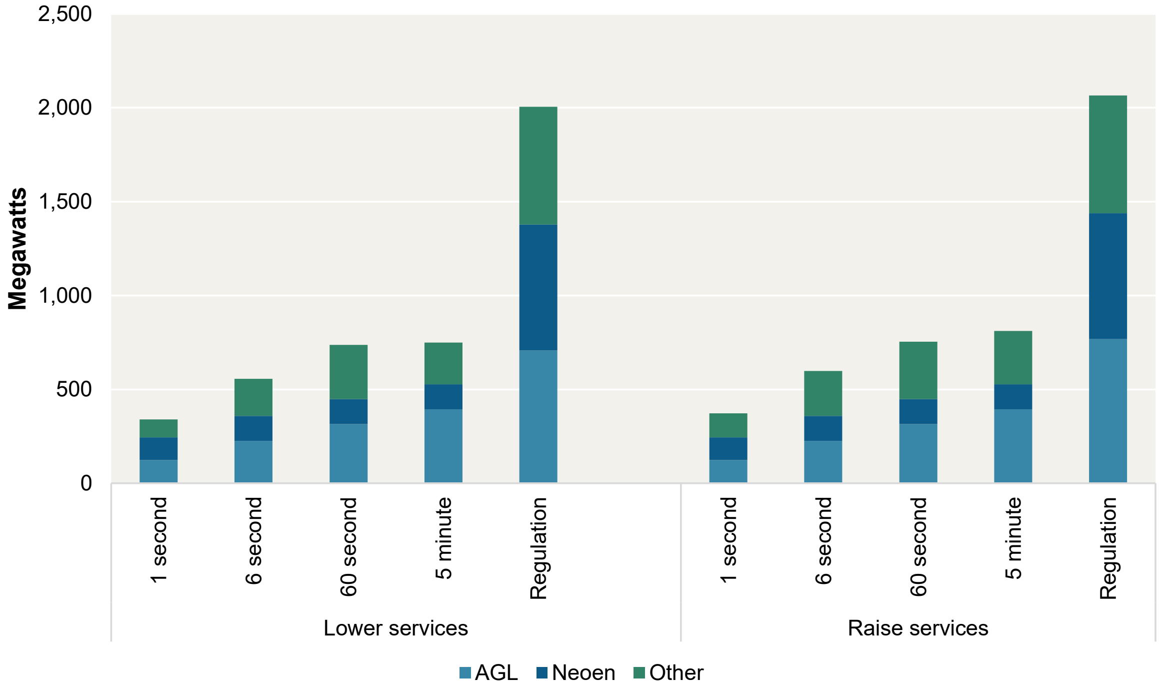
Note: Data show the total maximum capacity registered to provide each service at 7 April 2026. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset.
Source: AER analysis using NEM data.

Where only a small number of local providers can meet the requirement, those providers may face limited competitive pressure and have greater ability to affect prices. In South Australia, local FCAS markets are concentrated. Most of the capacity registered to provide FCAS in the region is owned by just 2 companies – AGL and Neoen (Figure 4.14). When

41 In Tasmania, nearly all generation capacity – including nearly all capacity registered to provide FCAS – is owned by the state government's Hydro Tasmania. The dynamics of Tasmanian energy markets differ substantially from those in mainland regions, and the Office of the Tasmanian Economic Regulator (Otter) has a role to promote competition and efficiency in Tasmania's electricity supply industry.

there is a local FCAS requirement in the region, these providers may not face significant competition. At these times, prices in the South Australian market can be high.

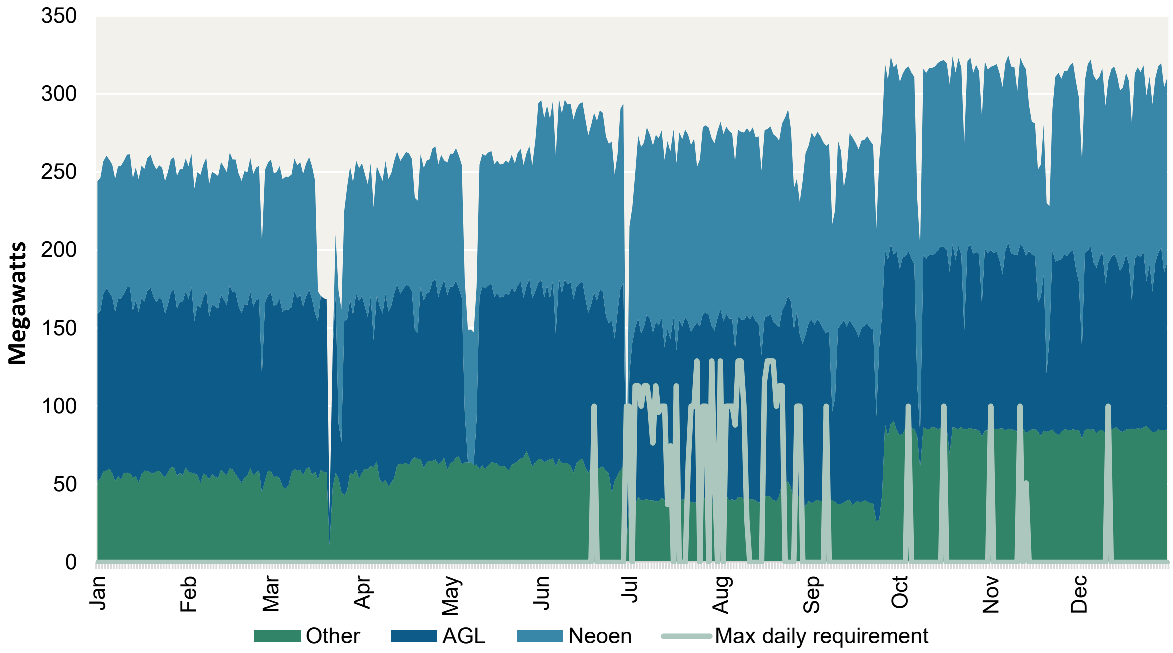
Figure 4.14 Registered capacity for each FCAS service, South Australia



Note: Data show the total max capacity registered to provide each service at 7 April 2026. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset.
Source: AER analysis using NEM data.

For example, during a planned network outage on the Heywood interconnector in July to September 2025, local South Australian FCAS provision was required. For the 1-second lower service, these requirements were often too large to be met by smaller providers alone (Figure 4.15), meaning some capacity from AGL or Neoen was needed to meet demand, increasing their ability to influence local prices.

Figure 4.15 Daily average capacity offered and daily maximum local requirement for 1-second lower service in South Australia in 2025



Note: The stacked area shows the daily average actual capacity offered in the local 1-second service by registered participant in 2025. The line shows the highest local 1-second FCAS requirement in South Australia each day.
Source: AER analysis using NEM data.

This resulted in materially higher costs, with costs for the lower 1-second service alone reaching $47 million for the quarter, compared with $73 million for all 10 FCAS services across the NEM.[42] These higher FCAS costs flowed through to the AER's 2026–27 default market offer determination for South Australia, contributing to a $7.73 per MWh increase in the ancillary services component of wholesale costs compared with the previous Default Market Offer. This offset the overall reduction in South Australia's wholesale cost component by 66%.[43]

Conditions eased by the October to December quarter of 2025. Smaller providers increased the amount of capacity they offered, reducing reliance on AGL and Neoen when local FCAS was required. Although South Australia continued to face local FCAS requirements for the 1-second service at times, these requirements were only slightly above the volume offered by smaller providers. Consistent with the more competitive conditions, prices did not breach the AER's reporting thresholds and quarterly costs were low.

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42 Further detail is provided in the AER's high price event report for the quarter. AER, Prices above $5,000 per MWh – July to September 2025, Australian Energy Regulator, 1 December 2025, accessed 22 May 2026.

43 AER, Final determination – Default market offer prices 2025–26, Australian Energy Regulator, 26 May 2025, pp. 39–40, accessed 10 June 2026.

4.3 Vertical integration can affect participant behaviour

Section 4.1 shows that some larger participants have opportunities to exercise market power in certain circumstances. However, a participant's incentive to exercise market power, given the opportunity, is shaped by its retail position, level of contracting and, in some cases, government intervention or direction.

The effect of vertical integration depends on whether a participant's generation portfolio is long, short or broadly matched to its retail load.

Vertical integration continues to be a significant feature of the NEM; the incentives that vertically integrated participants face may vary depending on how much generation they control against their retail load. A participant with just enough generation to broadly cover its retail position in a region (a neutral portfolio) is less likely to profit from raising spot prices because any additional revenue in its wholesale business would be offset by higher retail costs. A participant that is short in generation may face a similar disincentive. By contrast, a participant that has more generation than retail load (that is, 'long') may have stronger incentives to benefit from higher spot prices, because the additional wholesale revenue would only be partly offset by higher retail costs.

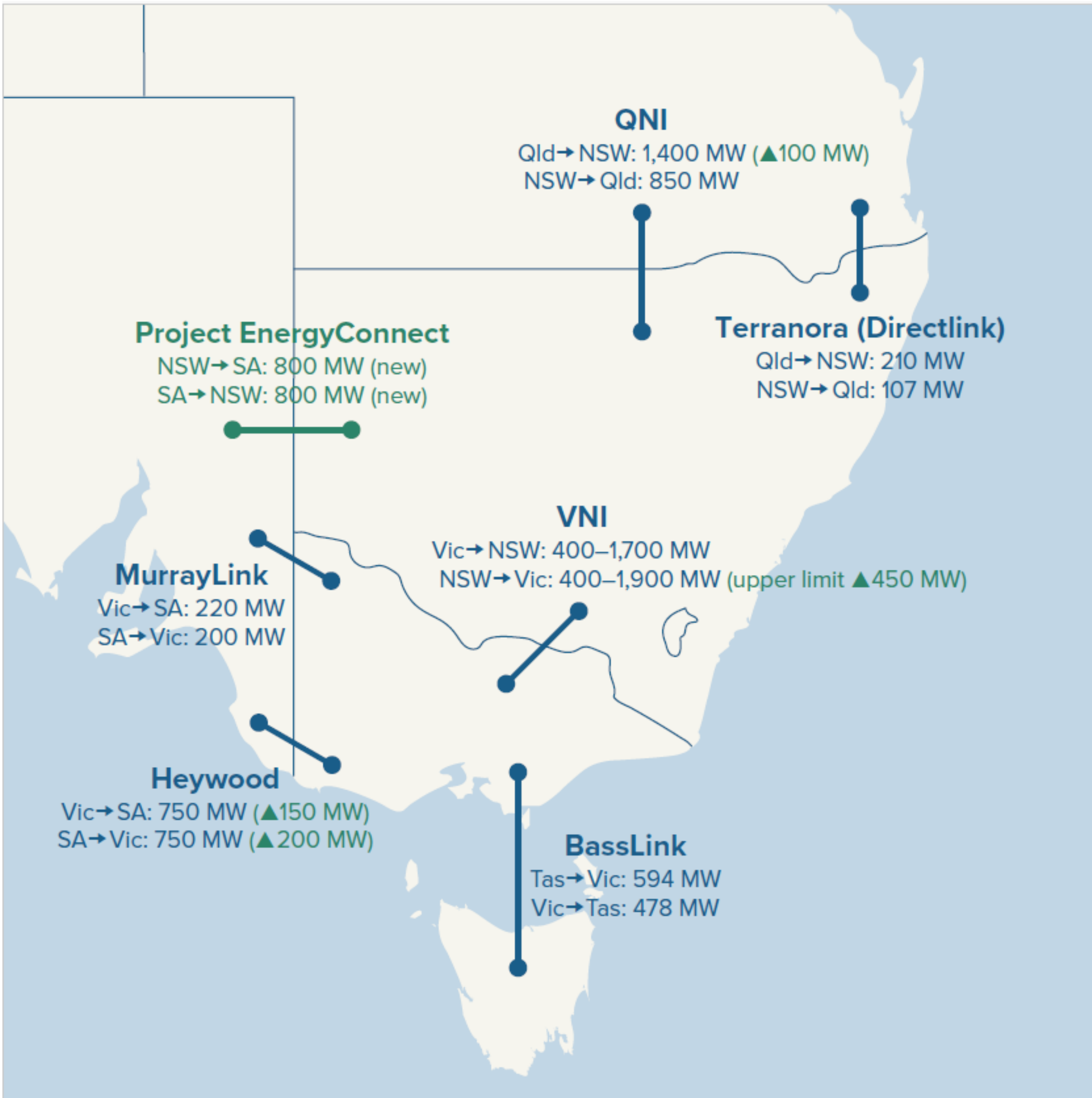
In theory, a contracted generator can also benefit from withholding capacity if influencing spot prices in the short run leads to higher priced contracts or higher default market offer prices in the future. In these cases, it is even possible that a generator that is short or neutral to the spot may be (temporarily) willing to take losses in the spot market.

Vertical integration provides a natural hedge against spot price volatility, but it is only one way participants manage exposure to spot prices. Contracting also plays an important role. As discussed in chapter 3, participants use contract markets to manage price risk, and our analysis now also draws on confidential contract data collected under the AER's expanded wholesale market monitoring powers. This means concentration measures alone do not fully indicate the risk of market power: incentives also depend on how exposed participants are to spot prices.

4.4 Interconnectors can constrain local market power, but only when capacity is available

Interconnectors enable energy transfers between the NEM's 5 regions (Figure 4.16). They can strengthen competition in the NEM by allowing lower-cost generation in one region to displace higher-cost generation in another. This can reduce the ability of local suppliers to influence prices. However, that competitive pressure depends on the interconnector being available and unconstrained.

Figure 4.16 Interconnection in the NEM

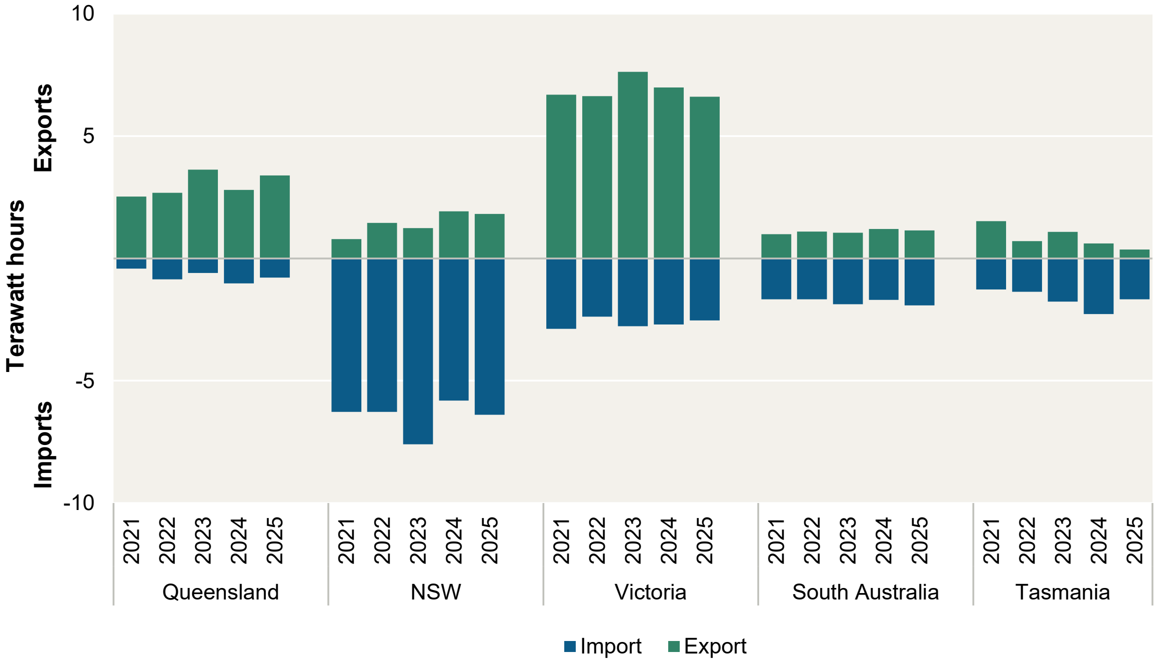


Note: The map shows the interconnector capabilities that will be in place once Project EnergyConnect stage 2 is completed. Stage 2 is scheduled for integration into the National Electricity Market Dispatch Engine (NEMDE) on 1 October 2026. For VNI capacities, AEMO provides a nominal capacity range in each direction rather than a single value. It explains that 'The nominal capacity of VIC1-NSW1 is highly dependent on the output of Murray generators (for New South Wales to Victoria) and Lower/Upper Tumut generators (for Victoria to New South Wales). VIC1-NSW1 can bind in either direction for high demand in New South Wales or Victoria.'
Source: AER map using data from AEMO's Interconnector capabilities report, September 2025, accessed 4 June 2026, and from AEMO's Project EnergyConnect market integration project, accessed 4 June 2026.

An interconnector is constrained when the flow across it reaches its technical limit. This limit can change depending on the direction of flow, outages on the network or other physical constraints and limits AEMO imposes to manage system security. When an interconnector is constrained, regions separate into distinct markets. This is referred to as 'price separation'.

In practice, lower-priced generation and this competitive pressure most often comes from Victoria and Queensland, which tend to be net exporters (Figure 4.17). NSW and South Australia more often rely on imports, while Tasmania's position varies with environmental and market conditions. In recent years, Tasmania has been a net importer because low rainfall reduced hydro inflows in 2023–24 and 2024–25.

Figure 4.17 Interregional trade



Note: Gross amount of energy imported and exported by each region.
Source: AER analysis using NEM data.

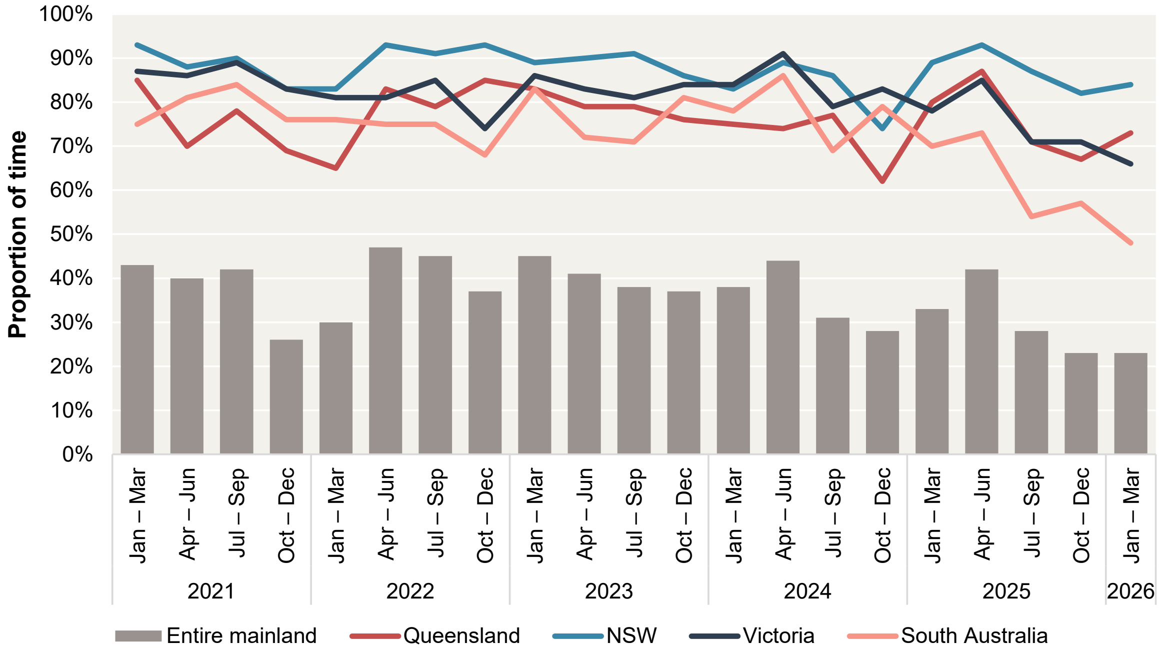
4.4.1 South Australia was less often price-aligned with Victoria in 2025, reducing competitive pressure

Interregional price alignment can provide an indication of how effectively interconnectors constrain local market power. When interconnectors are constrained, regions are more likely to separate into distinct markets and local generators may have greater ability to influence prices. When interconnectors are unconstrained and prices are aligned, local generators face stronger competitive pressure from other regions.

Price alignment of mainland NEM regions has trended slightly downwards in recent years (Figure 4.18). In 2023, prices were aligned across all mainland regions 40% of the time, but this had fallen to 32% of the time by 2025.

Prices across all mainland regions are aligned only part of the time, but each region is usually aligned with at least one neighbouring region. South Australia has recently been the clear exception, reflecting reduced alignment with Victoria during planned outages on the Heywood interconnector.

Figure 4.18 Price alignment in mainland NEM regions



Note: Interregional price alignment shows the proportion of the time that prices in one NEM region are the same as those in at least one neighbouring region, accounting for transmission losses. Entire mainland price alignment shows the proportion of the time all mainland NEM regions are the same.
Source: AER analysis using NEM data.

4.4.2 Victoria–NSW interconnector binds frequently in summer at levels well below its nominal limit

Each interconnector has a nominal limit (Figure 4.16). Physical constraints on the interconnector or nearby network can lead to real-time limits well below the nominal limit.[44] This can impede an interconnector's ability to provide a competitive constraint from other regions. It can also affect the efficiency of market outcomes by distorting the economic dispatch of generators and hence prices. Despite these impacts, a certain level of congestion is expected in an efficient market where the cost of expanding the network to eliminate congestion is greater than the cost of congestion.

An interconnector is export-constrained when flow over the interconnector reaches the technical export limit. Similarly, it is import-constrained when flow reaches the import limit. When flow is at either the export or import limit, we say the interconnector is binding.

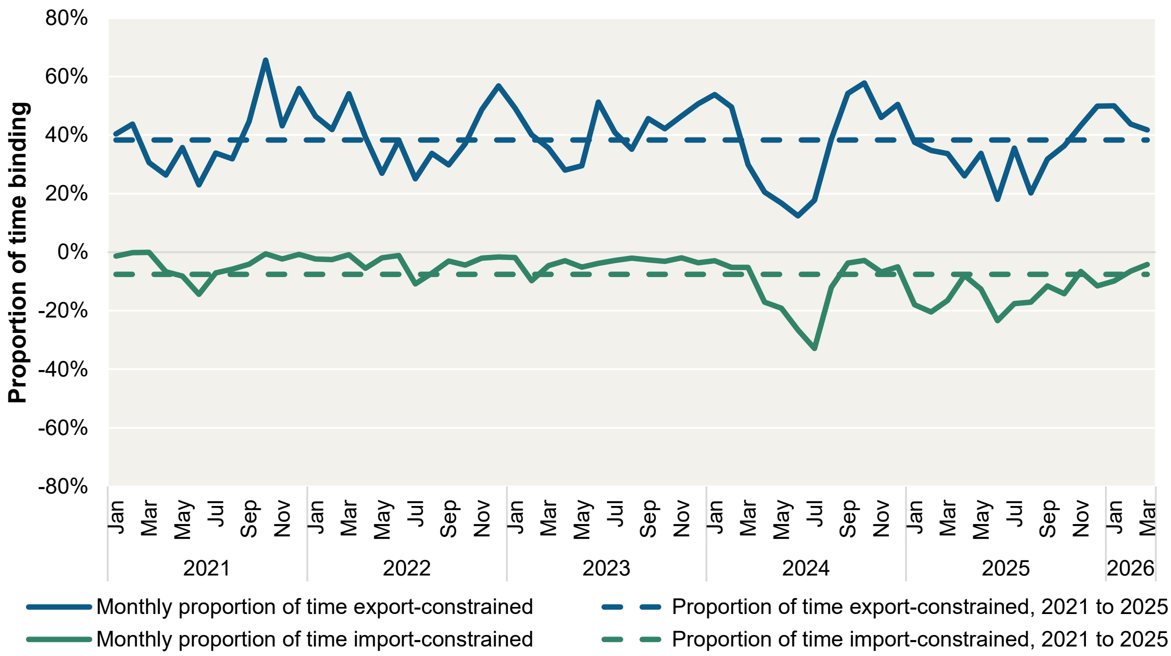
Our analysis of congestion examines how frequently interconnectors are binding and examines the average flow on the interconnector when it is export-constrained versus when

44 There are 2 types of congestion – 'system normal' and 'outage'. System normal is when the network is limited by the normal operation of the grid, while outage congestion is when the network is limited by line outages. Outage congestion often results in the network operating at less capacity compared with that of system normal conditions.

it is import-constrained. Analysis of the Victoria–NSW interconnector (VNI) is presented below as a case study.[45]

VNI illustrates how interconnector performance can diverge materially from nominal capacity, particularly in summer. In summer, the interconnector is export-constrained (that is, at maximum flow towards NSW) much more frequently – nearly 50% of the time in recent years, compared with around 30% of the time in winter (Figure 4.19). In winter, the interconnector is more often import-constrained (that is, at maximum flow toward Victoria) than in summer. But typically even in winter, it is more often export-constrained than import-constrained.

Figure 4.19 Average monthly proportion of time the Vic–NSW interconnector is export-constrained versus import-constrained

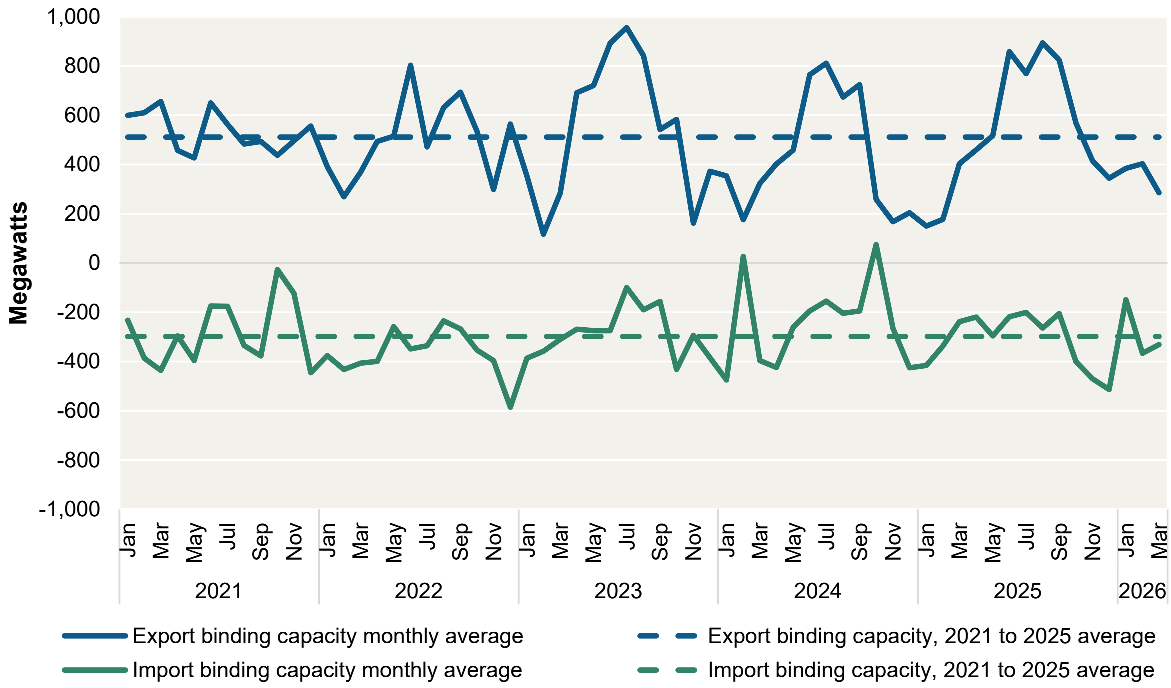


Note: Chart shows the proportion of time that flow on the interconnector was equal to the export limit or the import limit.
Source: AER analysis using NEM data.

Not only is VNI more export-constrained in summer, but it does so at a lower export limit. For example, in January 2025, the interconnector bound on average at a flow of 150 MW towards NSW (in June 2025, the average export limit was 858 MW). This compares with a nominal export capacity of up to 1,700 MW, suggesting that the performance of the interconnector in summer is poor (Figure 4.20).

45 Data for the other interconnectors is available in the Market Structure data book.

Figure 4.20 Average monthly export and import limit for VNI when binding



Note: Chart shows the average interconnector flow when the interconnector is binding at the export limit and when it is binding at the import limit. If flow is at both limits, the interval is classified according to which direction is effectively constrained: export-constrained when the price is higher in NSW and import-constrained when the price is higher in Victoria.
Source: AER analysis using NEM data.

At times, VNI's export limit falls below 0 MW. When this happens, the interconnector cannot export from Victoria to NSW and may instead require electricity to flow from NSW to Victoria, even when prices are lower in Victoria. These counter-price flows occur most often in summer.

Poor performance of VNI in summer coincides with strong generation in southern NSW, where several large solar farms are located. Transmission constraints can limit the transfer of this generation to the Sydney load centre, restricting flows into NSW and, in some cases, forcing counter-price flows into Victoria.[46]

Counter-price flows are inefficient because they can result in more expensive generation in the higher-priced region being dispatched ahead of cheaper generation in the lower-priced region. They can also weaken the competitive constraint that imports would otherwise provide in the higher-priced region. In addition, counter-price flows create negative settlement residues, which increase costs for transmission network service providers, which are subsequently recovered from consumers (see section 4.5).

However, these inefficiencies need to be weighed against the cost of increasing transmission capacity to the Sydney load centre. Alternative market reforms, such as locational marginal

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46 AEMO, Quarterly Energy Dynamics Q4 2024, Australian Energy Market Operator, January 2025, p. 45; AEMO, Quarterly Energy Dynamics Q4 2025, Australian Energy Market Operator, January 2026, p. 42; Allan O'Neil, What's happening around Wagga?, WattClarity, 30 November 2023.

pricing, may also reduce these inefficiencies, but would introduce significant additional complexity.

4.4.3 New interconnectors have the potential to change interregional competition

New interconnector projects could materially change competition between regions by improving access to lower-cost supply and reducing reliance on local generation during tight conditions.

Three interconnector projects are currently committed, anticipated or actionable. These projects may improve power system reliability and security and may strengthen competitive constraints on large participants in neighbouring regions. In some circumstances, they may provide an alternative to generation investment or may enable more cost-effective sources of generation to meet the needs of a neighbouring region.

To minimise the risk of overinvestment in transmission (where consumers pay more than is efficient) or underinvestment (where consumers experience lower reliability or higher than necessary wholesale prices), interconnector investment decisions currently undergo cost-benefit analyses by network service providers.

The interconnector projects are:

- Project EnergyConnect (PEC), an interconnector to directly link South Australia and NSW for the first time. The project is being delivered in 2 stages, with stage 1 now complete and delivering 150 MW of capacity in both directions.[47] For market dispatch and settlement purposes, this capacity is currently being included as part of the existing Heywood Interconnector (between Victoria and South Australia). AEMO is scheduled to include PEC in National Electricity Market Dispatch Engine (NEMDE) from 1 October 2026, with related settlement changes effective from 2 November 2026.[48] The interconnector aims to deliver greater security and competitive constraint but will also increase the complexity of interregional power flow.
- MarinusLink, a new interconnector connecting Tasmania and Victoria. In October 2022, the Australian, Tasmanian and Victorian governments agreed to joint ownership of the project, which will be delivered in 2 stages: Stage 1 as a 750 MW link, with a second 750 MW link planned for a later stage. On 6 February 2026, the AER published its final decision on Marinus Link's Stage 1, Part B (Construction costs) proposal for the 2025–30 regulatory control period.[49] Construction of Stage 1 is expected to commence in 2026 and be completed by 2030. The AER expects Marinus Link Pty Ltd to submit its Stage 2 regulatory proposal in 2029 prior to the commissioning of the first Marinus Link cable in 2030.

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47 AEMO, Project EnergyConnect – Market Integration Stakeholder Information Session 13 April 2026, Australian Energy Market Operator, 13 April 2026, accessed 16 May 2026.

48 AEMO, Project EnergyConnect – Market Integration project, Australian Energy Market Operator, accessed 16 May 2026. AEMO's high level impact assessment, linked to this page, discussed the complexities introduced to interregional settlements as a result of PEC and how they will be managed.

49 AER, Final decisions on Stage 1 costs to deliver Project Marinus, Australian Energy Regulator, 6 February 2026, accessed 16 May 2026.

- VNI West, a proposed high-capacity transmission line between Victoria and NSW. This interconnector is an actionable project under AEMO's Integrated System Plan. In May 2024, the AER published its decision to approve Transgrid's contingent project application for capital expenditure to undertake early works related to the NSW portion of the project.[50] Transgrid expects construction to begin in 2027, with an expected completion date in 2030 – but construction costs are yet to be approved by the AER.

4.4.4 Transmission outages can weaken competition and increase prices

Transmission network outages can materially weaken competitive pressure by preventing some generation from accessing the market. When this occurs, it can reduce the competitive constraint on unaffected generators and increase prices for consumers.

Although outages are ideally scheduled to minimise market effects, actual impacts can be much larger if demand, supply or network conditions differ from what was anticipated.

The transmission service target performance incentive scheme (STPIS) incentivises transmission network service providers (TNSPs) to improve service standards. It aims to offset incentives for TNSPs to reduce expenditure at the expense of network performance. The STPIS includes a market impact component (MIC), which was designed to provide an incentive for TNSPs to minimise the impact of planned outages.

The AER's 2023 Review of incentives schemes for networks found that the MIC was not working as intended and proposed that it be suspended.[51] In April 2025, the AER published STPIS version 6, which suspended the MIC.[52] Under normal arrangements, this change would not take effect until the next regulatory control period, but a rule change made by the AEMC in May 2026 allowed the AER to disapply the MIC for performance early.[53]

The AER is undertaking work to find a replacement for the STPIS MIC. Since late 2025, we have established a working group comprised of market bodies, generators, consumer groups and network operators to explore suitable replacements for the suspended MIC. This work was specifically identified as requiring resolution as part of the NEM wholesale market settings review. The AER continues to collaborate with the working group on issues that include ways to identify the market impact of transmission outages. We are aiming to identify a mechanism to replace the MIC in the latter half of 2026.

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50 AER, Transgrid VNI West contingent project application stage 1 early works, Australian Energy Regulator, 6 May 2024, accessed 16 May 2026.

51 AER, Review of electricity transmission service standards incentive schemes, Australian Energy Regulator, 6 November 2024, accessed 15 May 2026.

52 AER, Service target performance incentive scheme V6, Australian Energy Regulator, 17 April 2025, accessed 15 May 2026.

53 AEMC, Early application of a revised transmission Service Target Performance Incentive Scheme, Australian Energy Market Commission, 14 May 2026, accessed 15 May 2026.

4.5 Settlement residue auctions enable hedging against regional price separation, but can influence participant behaviour

Price separation creates risks for participants that contract across regions. Settlement residue auctions (SRAs) allow participants to hedge this risk by purchasing rights to future interregional settlement residues.

AEMO holds quarterly auctions to sell the rights to future residues (Box 4.2). Energy market participants use these auctions to manage the risk of regional price separation. Financial speculators without an energy generation business may also participate in these auctions.

Box 4.2 How settlement residue auctions work

SRAs are a financial mechanism that allow participants to manage the risks associated with price differences between regions.

When electricity flows between regions, price differences can arise. The resulting settlement residue is calculated as the difference between the price in the importing region and the price in the exporting region, multiplied by the amount of energy transferred.

- When electricity flows from a lower-priced region to a higher-priced region, settlement residues are positive, meaning AEMO collects more funds through the settlement process than it pays out.
- When flows occur in the opposite direction (counter-price flows), settlement residues are negative.

These price differences create risks for participants with operations across multiple regions. For example, a participant with generation in one region and retail customers in another may face higher costs in its retail business than it earns from its generation if prices diverge.

SRAs allow participants to hedge against this risk. AEMO auctions the rights to future positive settlement residues for specific interconnectors, directions of flow and time periods (for example, Victoria to NSW for January–March 2026). AEMO currently sells the following maximum number of settlement residue units for each directional product:

- NSW to Queensland – 550 units until January–March 2027, 750 units thereafter
- Queensland to NSW – 1,200 units until January–March 2027, 1,300 units thereafter
- South Australia to Victoria – 770 units
- Victoria to South Australia – 880 units
- NSW to Victoria – 1,300 units
- Victoria to NSW – 1,500 units
- Tasmania to Victoria – 500 units (first auction held June 2026, for July–September 2026 onwards)
- Victoria to Tasmania – 500 units (first auction held June 2026, for July–September 2026 onwards).

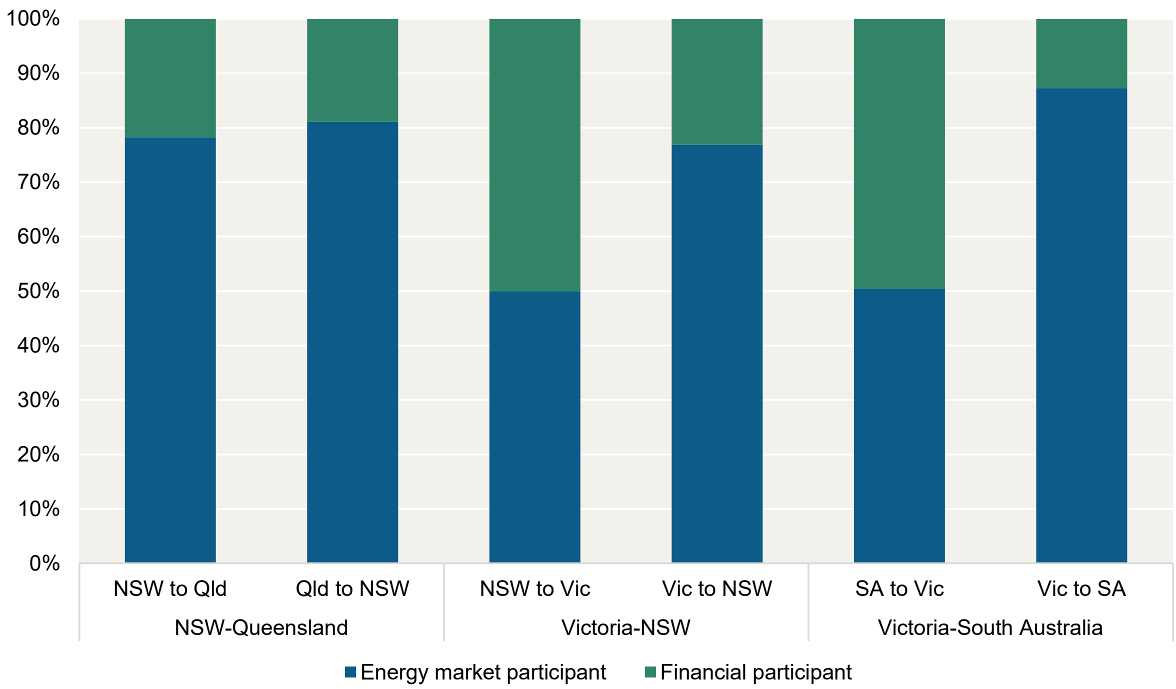
AEMO holds auctions each quarter. SRA units for each product are auctioned in 12 tranches, with the first tranche auctioned 3 years before the relevant quarter and the final tranche sold just before the start of the quarter. Any unsold auction units from a given tranche are rolled over to the next tranche, while unsold units from the final tranche are allocated to the TNSP.

Because SRA holders benefit when positive price separation occurs, SRA positions may also affect incentives in some circumstances.

4.5.1 NEM participants purchased most 2025 SRA units, suggesting SRAs were mainly used for hedging

For 2025 SRA products, most auction units were purchased by energy market participants. This was the case for all directional products except NSW to Victoria and South Australia to Victoria, where financial participants purchased an almost equal share of SRA units (Figure 4.21). This suggests that, at least for 2025 products, SRAs were used primarily as a hedge against the risk of regional price separation.

Figure 4.21 Proportion of SRA units purchased by energy market participants versus financial participants for 2025 products



Note: Share of settlement residue auction units purchased by NEM participants and financial participants for each interconnector direction, using all 12 tranches for the 2025 products. Volumes include units which were later sold as secondary units.
Source: AER analysis using confidential settlement residue auction data provided by AEMO.

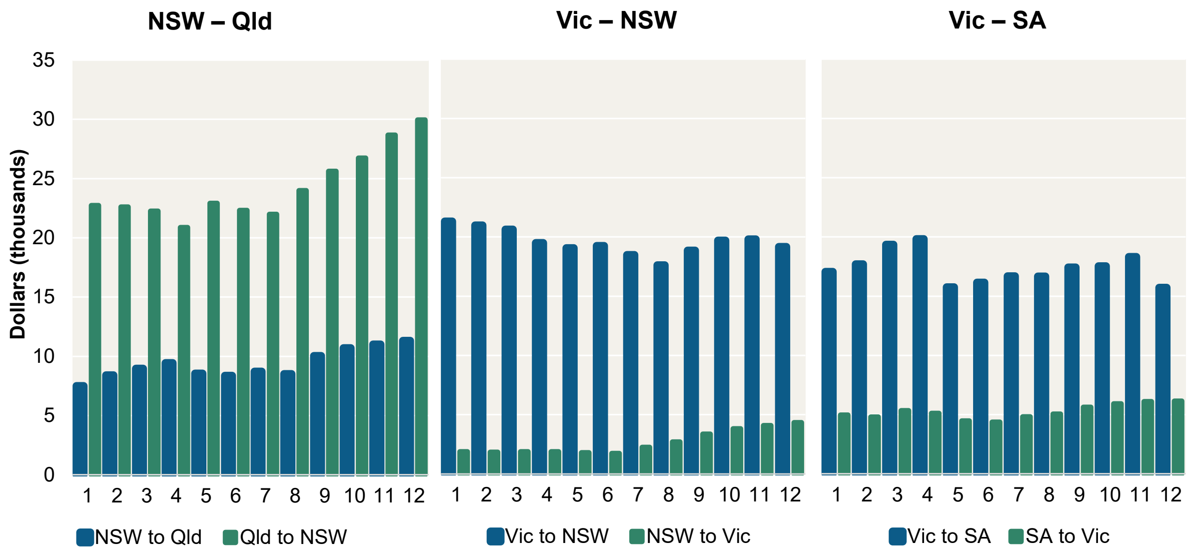
Financial participants accounted for only around 30% of all 2025 SRA units purchased. They purchased a greater proportion of auction units closer to the settlement quarter compared with the earlier tranches. Looking ahead to future years, financial participants have bought almost twice as many units in the initial 4 tranches for 2027 than they did for these same tranches for 2025 products.[54] This may indicate increasing participation by financial players over time. Financial participants play an important role in providing additional liquidity into the market.

4.5.2 SRA prices reflect expectations about regional price separation and interconnector performance

SRA prices differ markedly across products and tranches, reflecting expectations about interregional flows, price separation and interconnector performance.

Prices tend to be highest for Queensland to NSW, Victoria to NSW and Victoria to South Australia products (Figure 4.22). These directional paths tend to have the highest volumes of flow (Figure 4.17) and the largest settlement residues.

Figure 4.22 Average unit price for each tranche by interconnector for 2025 products



Note: Average price paid by tranche for each settlement residue auction unit of each directional interconnector, across the 2025 products. SRA units for each product are auctioned in 12 tranches, with the first tranche auctioned 3 years before the relevant quarter and the final tranche sold just before the start of the quarter.
Source: AER analysis using confidential settlement residue auction data provided by AEMO.

Movements in SRA prices also appear consistent with broader changes in regional pricing and interconnector performance. The price of Queensland to NSW units rose across successive tranches for 2025 products, likely reflecting the growing premium of NSW prices over Queensland prices since 2022 (Figure 2.1). Larger price differences between regions increase the likelihood that positive settlement residues will accumulate and SRA units will provide higher value.

By contrast, the price of Victoria to NSW units declined across tranches. This may reflect weaker performance on the Victoria-NSW interconnector, discussed in section 4.4.2, including more frequent export constraints in summer and lower binding export limits. This

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54 The AER has access to SRA auction data going back to 2022, which gives us a full dataset for 2025 quarters (but only a partial dataset for earlier products). For later products (2026 and onwards), we only have earlier tranche data because not all auctions have yet been held.

reduced performance is likely to have lowered expected positive settlement residues, reducing the expected value of these SRA units.

SRA prices also vary by quarter for a given directional path. NSW to Queensland units tend to be most valuable in the January to March quarter, when Queensland demand and prices are typically highest and imports from NSW are greatest. By contrast, Queensland to NSW units tend to be most valuable in the April to June and July to September quarters, when NSW demand is highest.

The Victoria to NSW product has not shown a clear seasonal pattern, but it has consistently sold at lower prices across quarters, again suggesting that deteriorating VNI performance has reduced the expected value of these units.

These price trends, together with growing financial participation, indicate that SRAs provide a useful signal of market expectations about interconnector performance and regional divergence.

4.5.3 SRAs may affect participant incentives

SRAs are primarily a hedging tool, but once a participant has purchased SRA units, they can affect its incentives. This effect depends on the participant's generation position, SRA holdings and ability to influence interconnector flows or regional price separation.

A participant that holds SRAs may have an incentive to optimise between returns from physical generation and returns from SRA units. This is most relevant where its bidding behaviour can affect whether an interconnector binds and prices diverge between regions. For example, SRA holdings may:

- reduce the incentive to generate in the higher-priced region
- increase the incentive to generate in the lower-priced region
- affect the operation of plant subject to constraints that can influence interconnector flows and regional price separation.

Accordingly, SRAs – like other financial hedges in the electricity market – are relevant to assessing participant behaviour.

5 Participant conduct

Participant offer behaviour has changed materially as the NEM supply mix has shifted. New wind, solar and battery capacity has added more low-priced and flexible capacity, while coal, gas and hydro generators have moved some capacity into higher price bands to avoid uneconomic dispatch or to conserve fuel and water. Most observed changes appear consistent with changing supply conditions, but portfolio analysis shows ownership structure may influence how capacity is offered during tight conditions.

Key findings

- Battery entry and automated rebidding have made participant conduct more dynamic, with the number of bids submitted to AEMO increasing sharply in recent years, particularly in FCAS markets.
- Total capacity offered into the market has increased over the past 5 years and the offer stack has become more polarised. During this period, growth in offered capacity has been concentrated below $0 per megawatt hour (MWh) and above $300 per MWh, while capacity between $0 and $300 per MWh has remained broadly unchanged. This shift is most pronounced during the day, when low-priced solar output is abundant and coal, gas and hydro generators are more likely to move capacity to higher price bands to avoid uneconomic dispatch.
- Low-priced capacity remains below 2021 levels. Capacity offered below $50 per MWh increased between 2024 and 2025 but remained below 2021 levels at most times of day. Black coal was the key driver: after fuel prices rose in 2022, generators shifted substantial capacity from below to above $50 per MWh, with much of it moving into the $50 to $100 per MWh range.
- Batteries are increasingly influencing price outcomes. As battery capacity has grown, batteries are setting prices more often and appear to be reducing both negative price outcomes and high price events by absorbing low-priced electricity and adding flexible capacity during higher-priced periods.
- Battery ownership structure may affect offer behaviour in tight conditions. In NSW in 2025, in-portfolio batteries offered less capacity at low prices during tight market conditions than standalone batteries, suggesting portfolio incentives may influence whether battery capacity is positioned to dispatch.
- Gas generators have reduced low- and mid-priced offers across all times of day, particularly during the evening peak. Most of this capacity has been shifted to higher prices. This has reduced the amount of dispatchable capacity available before higher-priced offers are needed, although this has been offset by an increase in battery capacity.
- Most shifts in participant offers appear consistent with changing costs, fuel availability, water availability and renewable output. However, some portfolio behaviour does not appear to be fully explained by underlying conditions and may represent the exercise of market power.

When assessing effective competition, the National Electricity Law requires us to consider the extent to which market power is sustained. Instances of transient market power alone are not sufficient to conclude competition in the NEM is not effective.

Participants can exercise market power in several ways. They may use strategies within a trading day to spike prices, or they may engage in longer-term strategies. These strategies may in turn affect contract prices. In this chapter, we assess the offers of participants into the market and whether they may reflect the exercise of market power.

Some behaviours that appear to be a potential exercise of market power may instead be efficient responses to changing market conditions or a plant's technical requirements. We assess participant conduct in each region over the long term to see if changes in offers can be explained by underlying supply conditions. Where it can, the conduct may be less likely to indicate the exercise of market power.

We also examine how generator conduct changes based on background market conditions. For example, we look at how the prices at which capacity is offered vary depending on whether the market is well-supplied or tight (Box 5.1).

Generator conduct is shaped by opportunities and incentives. Even if market power has not been exercised, behaviour may lead to inefficient market outcomes. If participants are offering or rebidding capacity in a way that prevents the lowest-cost generation from being dispatched, this can cause allocative inefficiency regardless of intent to influence the price.[55]

Market participants with a portfolio of assets consider their entire portfolio when making offer decisions in the market. Participants may also have sold financial products to hedge their generation positions and vertically integrated participants also have retail customers to supply. Participants incorporate all these elements into their decision-making. For this reason, we have performed portfolio analysis of the largest generators in the NEM and presented relevant case studies in this chapter.

Box 5.1 Metrics used to assess bidding behaviour against market conditions

Our analysis of offer behaviour has typically considered average capacity offered in different price bands over defined time periods (such as quarterly). This provides useful information on changes in behaviour over time but may obscure how participants respond to the underlying conditions in particular dispatch intervals.

Time-of-day analysis provides further insight. For example, it can distinguish between middle-of-day periods when demand is typically lower and supply more abundant, and evening peak periods when demand tends to be higher and solar output lower. However, market conditions can vary materially from day to day, so time-of-day analysis can mask periods when the market is unusually tight or unusually well supplied.

55 Allocative efficiency means that resources are allocated to their highest value uses. In wholesale electricity markets, this means the electricity that is demanded by consumers is provided by the lowest cost supply and demand-side options.

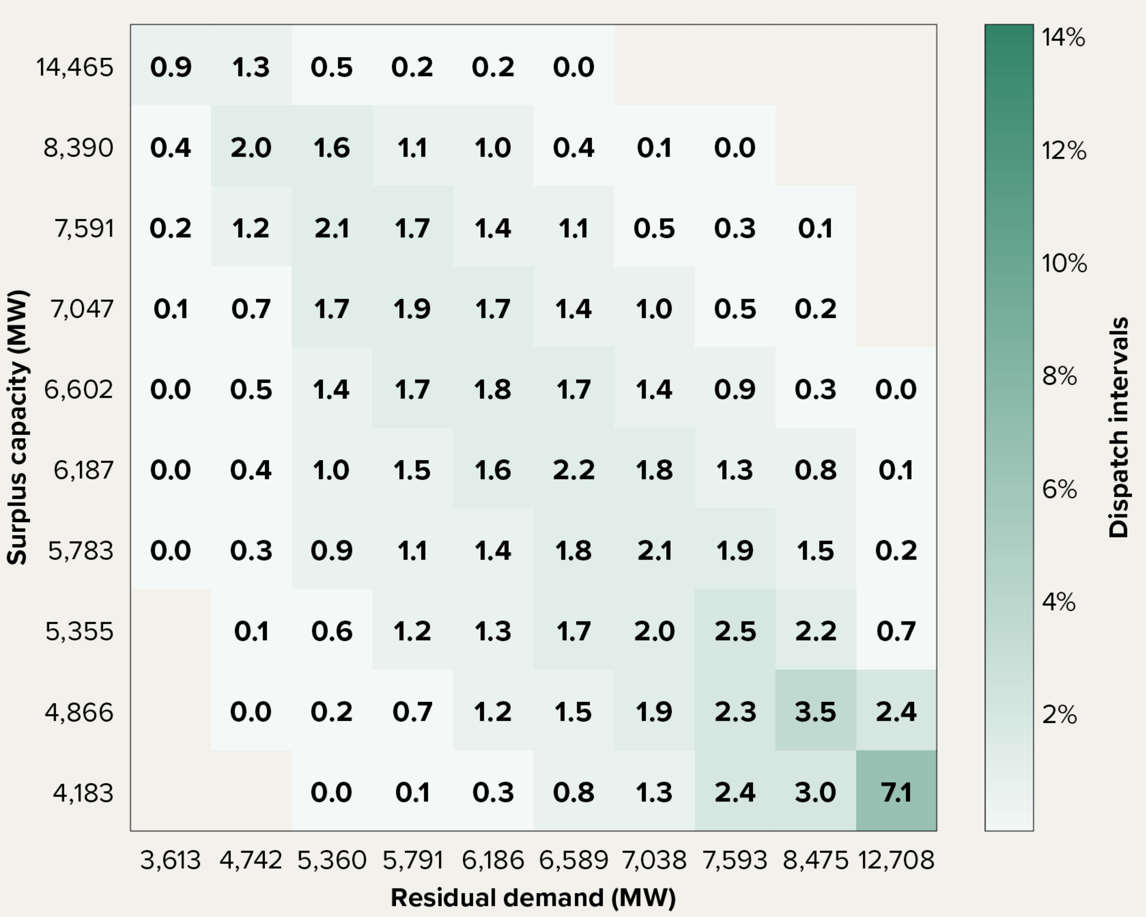
In previous performance reports, we used surplus capacity to assess offer behaviour more directly against underlying conditions. In this report, we build on this approach by introducing residual demand as a second measure of underlying conditions:

- Surplus capacity measures available capacity that is above regional total demand, assessed at the regional level and including capacity that can be imported from neighbouring regions. Higher surplus capacity generally indicates stronger competitive constraint and less reliance on individual participants. Lower surplus capacity indicates tighter supply conditions.
- Residual demand measures the amount of demand that remains to be met by dispatchable generation after output from variable renewable generation has been accounted for. Because variable renewable generation has very low marginal costs, higher residual demand indicates greater reliance on dispatchable generators and, all else being equal, greater potential for their bidding behaviour to affect market outcomes.

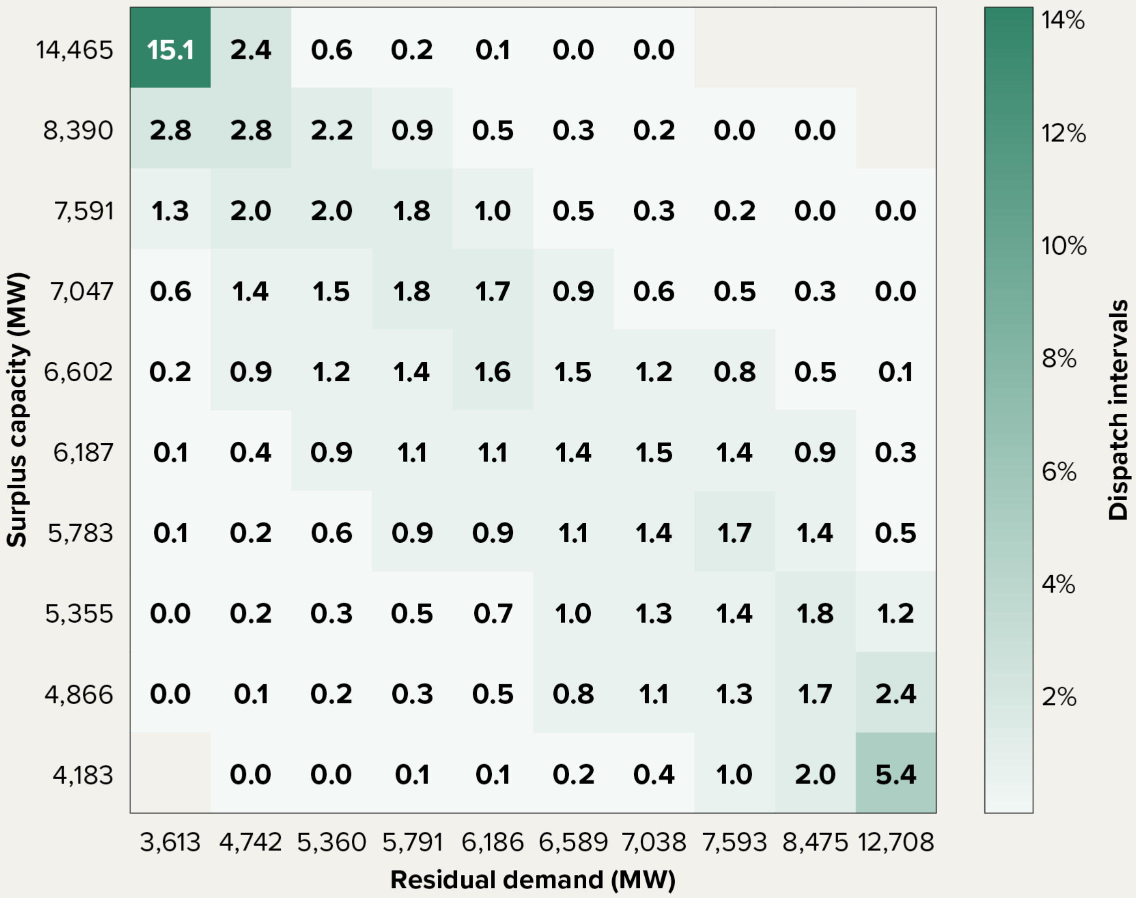
When surplus capacity is high and residual demand is low, supply conditions are abundant and reliance on dispatchable generation is reduced. As surplus capacity declines and residual demand rises, the market tightens, increasing reliance on dispatchable generation.

Box figures 5.1 and 5.2 show how often different combinations of surplus capacity and residual demand occurred. These are grouped into 10 bands (deciles) based on the past 5 years of data (2021 to 2025). For example, in NSW, 15.1% of dispatch intervals in 2025 occurred when surplus capacity was very high (top 10% of past observations) and residual demand was very low (bottom 10%). This is a large increase from 0.9% of intervals in this category in 2021.

Box figure 5.1 Percentage dispatch intervals, by surplus capacity and residual demand levels, NSW in 2021



Box figure 5.2 Percentage dispatch intervals, by surplus capacity and residual demand levels, NSW in 2025



We assessed the offer behaviour of generators within these different market conditions. For gas (section 5.1.6) and coal (section 5.2.2) we did this by assessing the volume of capacity offered above a threshold linked to estimated short-run marginal cost, which we referred to as 'marked-up capacity'.[56] For battery analysis (Case study 1), we assessed the volume of capacity offered above and below the market clearing price across different market conditions.

In previous reports, we assessed offer behaviour under different market conditions using a quantity-weighted average offer price. This approach could be affected by changes in offers at prices well above or below the levels most relevant to dispatch or cost. In this report, we instead assess the volume of capacity offered above relevant thresholds, which provides a more targeted measure of behaviour likely to affect market outcomes.

Overall, this framework allows us to assess how offers vary with market conditions and can be used as a screening tool to identify conduct that may warrant closer examination as possible exercise of market power.

56 Our mark-up price for coal generators was AEMO's estimated short-run marginal cost plus a buffer of $50 per MWh. Our mark-up price for gas generators was AEMO's estimated short-run marginal cost plus a 25% buffer.

5.1 New entry of solar, wind and battery capacity is driving changes in offer behaviour across the NEM

In the 5 years from 2021 to the end of 2025, 6.4 gigawatts (GW) of large-scale solar, 5.8 GW of wind and 5.9 GW of battery storage capacity entered the NEM. This new capacity has materially changed the supply mix and has been a key driver of the significant shifts in market dynamics and participant behaviour over the period.

5.1.1 Number of bids submitted by generators has increased sharply in recent years

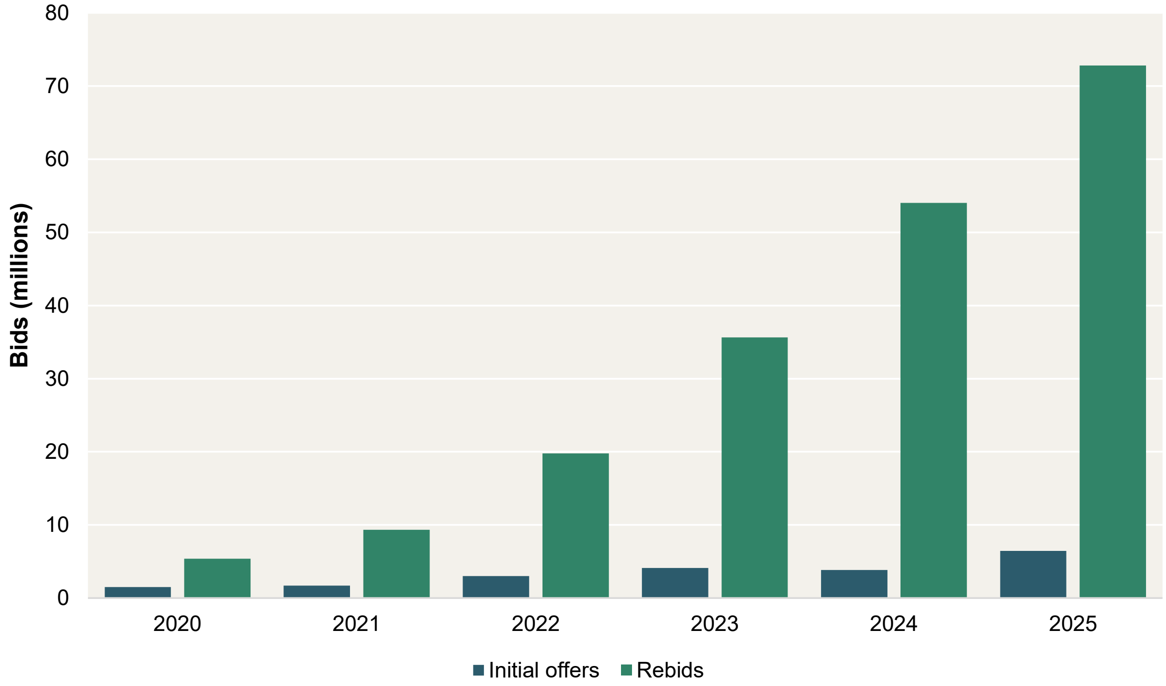
Generators and storage providers submit offers to AEMO to supply or use electricity at different prices and for different periods. Offers can be classified as either initial offers or rebids. Initial offers comprise all bids submitted by 'gate closure', which is at 12.30 pm NEM time (Australian Eastern Standard Time) on the day before dispatch. From that point on, a generator's 10 price bands are fixed. Generators can rebid by shifting volumes between those price bands right up until dispatch.

Rebidding close to dispatch can allow participants to respond to changing conditions and costs, improving allocative efficiency by helping ensure lower cost generation is dispatched ahead of higher cost generation. However, late rebidding can also make it harder for competitors to respond. To support competition and efficiency, the market rules require participants to rebid 'as soon as practicable' after becoming aware of a material change in conditions that leads them to change their offer.[57] Participants must also provide a reason for each rebid, including the time the change in circumstances occurred, when they became aware of it, the reason category and a brief, specific and verifiable explanation.

The number of offers submitted to AEMO increased from 6.8 million in 2020 to 79 million in 2025 (Figure 5.1), driven primarily by rebids. Over this period, the number of initial offers roughly quadrupled (increasing from 1.5 million to 6.5 million), while the number of rebids increased 14-fold (from 5.4 million to 73 million). The change is not simply a function of more participants entering the market, nor of evolutions in market design; it reflects a shift towards more dynamic technology-enabled bidding, particularly by batteries, across both energy and FCAS markets.

57 AEMC, National Electricity Rules, Australian Energy Market Commission, clause 3.8.22, accessed 27 May 2026.

Figure 5.1 Count of initial offers and rebids submitted to AEMO



Note: Count of offers submitted to AEMO in all energy and FCAS markets. Initial offers are offers submitted prior to 12.30 pm the previous day. Rebids are offers submitted after 12.30 pm the previous day (that is, once the pre-dispatch period has begun).
Source: AER analysis using NEM data.

The recent proliferation of bids has been driven by various factors.

- More generating units contributed to the increase but only accounted for a relatively small portion. Registered generating units increased from 295 at the end of 2020[58] to 420 by the end of 2025, while bids per unit increased from about 23,000 to 189,000 over the same period.
- Similarly, the 2 new FCAS markets introduced in October 2023 account for only a small part of the increase.
- 5-minute settlement was introduced to the NEM in October 2021, strengthening incentives for generators to optimise dispatch closer to real time and supporting entry of rapid-response technologies into the market.
- The entry of these technologies, particularly batteries, has been the largest driver of the increase in bids. The number of battery rebids increased from 2.6 million in 2020 to 49 million in 2025, accounting for 64% of the increase in total bids over that period. The number of bids from all newer technologies – also including wind, solar, virtual stations, demand response aggregators and ancillary service providers – increased from 3.7 million to 72 million over the period. Incumbent technologies – coal, gas, liquid fuel and hydro stations, as well as scheduled loads – increased their number of bids from

58 AER, State of the energy market 2022, Australian Energy Regulator, 29 September 2022, p. 17, accessed 27 May 2026.

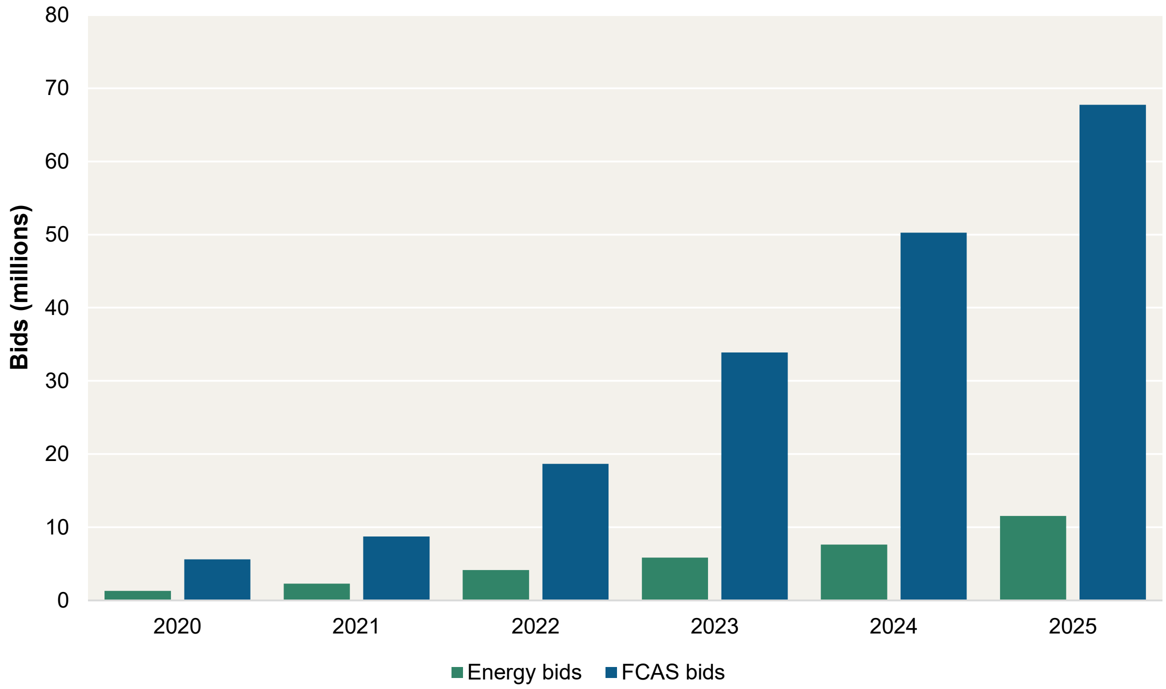
3.1 million to 7.7 million, with most of this increase corresponding with the start of 5-minute settlement.

Batteries bid at a much higher frequency than most other generation technology types for several reasons:

- energy constraints: state of charge and opportunity costs can change quickly, affecting the value of discharging now versus later
- technical flexibility and automation: batteries can change output quickly and often use automated bidding systems, enabling frequent bid updates
- multi-market optimisation: batteries are well-suited to providing FCAS services because of their fast response times, meaning they optimise behaviour across energy and FCAS markets, making frequent rebids to do so.

The increase in bidding is concentrated in FCAS markets, where batteries have a technical advantage and stronger incentives to update offers frequently. FCAS bids have increased 12-fold since 2020, reaching 68 million in 2025, compared with a 9-fold increase in energy bids from 1.3 million to 12 million.

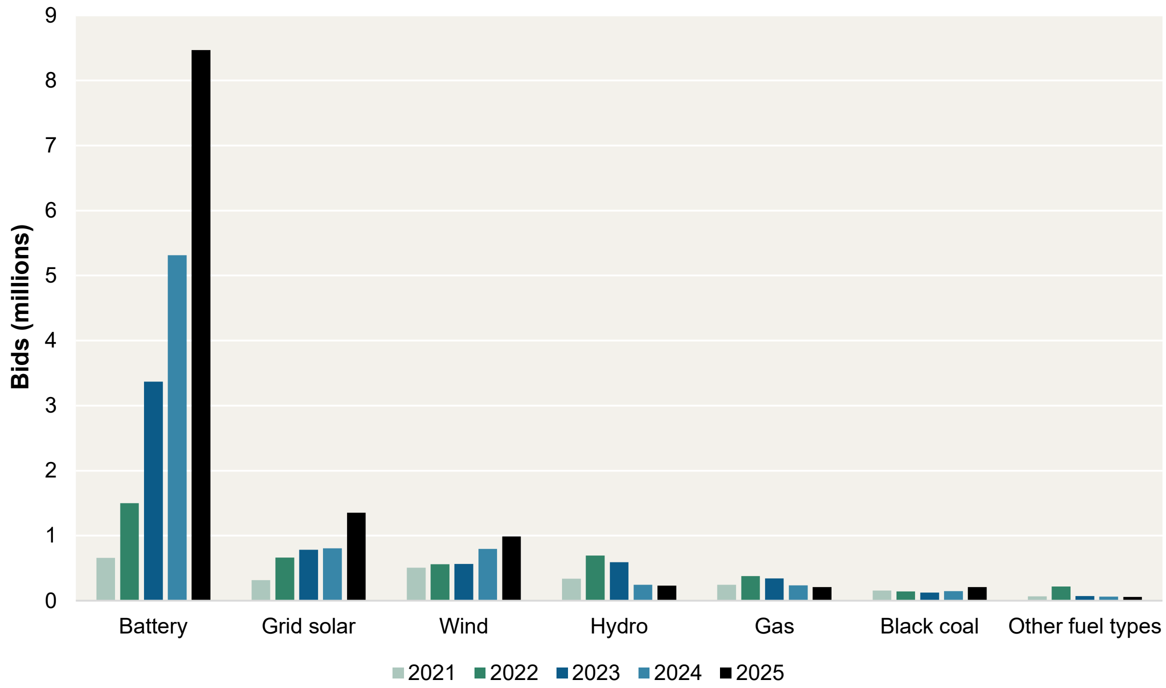
Figure 5.2 Count of energy bids and FCAS bids submitted to AEMO



Note: Count of offers submitted to AEMO. Includes both ‘initial offers’ (offers submitted prior to 12.30 pm the previous day) and ‘rebids’ (offers submitted after this time).
Source: AER analysis using NEM data.

Batteries were responsible for 73% of energy market bids in 2025, compared with 29% in 2021. Wind and solar also significantly increased their number of bids over the period. Coal, gas and hydro combined submitted fewer bids in energy markets in 2025 than in 2021.

Figure 5.3 Count of energy bids submitted to AEMO, by fuel type



Note: Count of offers submitted to AEMO in energy markets (does not include FCAS offers). Includes both 'initial offers' (offers submitted prior to 12.30 pm the previous day) and 'rebids' (offers submitted after this time).
Source: AER analysis using NEM data.

A higher frequency of bidding in the NEM, enabled by auto-bidding systems and/or artificial intelligence (AI) technology, can improve market efficiency. More frequent bidding may help ensure that offers better reflect plant capabilities and changing market conditions in real time. It may also allow participants to respond more quickly to price signals and system needs. More sophisticated bidding technology is also important for orchestrating consumer energy resources, which could deliver significant efficiency benefits.

At the same time, new bidding technologies can create risks, which may include:

- non-compliance with the National Electricity Rules, particularly if participants do not maintain oversight of the bids being submitted on their behalf
- increased opportunities for market manipulation or other conduct that could undermine market integrity
- potential for collusive behaviour, whether intentional or otherwise, arising from sophisticated AI and algorithmic bidding – for example, where different market participants use a common third-party AI technology that treats this combined capacity as a block.[59]

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[59] See, for example, AEMO, General power station risk review 2025, Australian Energy Market Operator, p. 74, 31 July 2025, accessed 28 May 2026; AEMC, Addressing the risk of algorithmic collusion, Australian Energy Market Commission, July 2024, accessed 28 May 2026; DCCEEW, National Electricity Market wholesale markets settings review, Department of Climate Change, Energy, the Environment and Water, pp. 115–118, 16 December 2025, accessed 28 May 2026; AER, 2026 review of the Rebidding and Technical Parameters Guideline, Australian Energy Regulator, pp. 12–15, 24 March 2026, accessed 28 May 2026.

These risks matter because they have the potential to result in market price shifts, including higher prices for consumers. This was recognised by the National Electricity Market wholesale market setting review, which recommended market bodies and the Australian Competition and Consumer Commission should work together to develop a broader understanding of the risks and opportunities created by algorithmic bidding to inform regulatory responses, including rule changes if needed.

The AER is working to mitigate these risks, including by publishing guidance on automated bidding. This guidance sets out best-practice expectations to help participants comply with their obligations under the NER when using their own or third-party auto-bidding software.[60] The guidance was first considered as part of proposed updates to the AER's Rebidding and Technical Parameters Guideline. Given the decision to delay updates to the Guideline,[61] the AER has decided to publish this guidance separately.

5.1.2 NEM offered capacity is increasingly at the lower and upper ends of the price scale

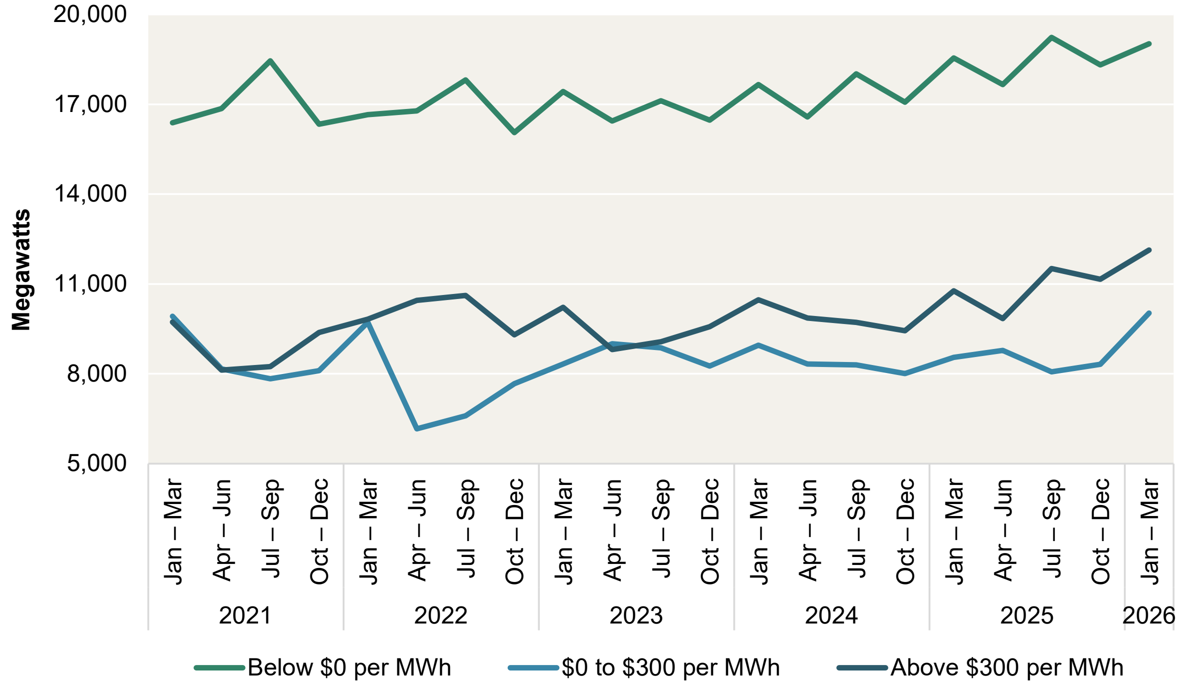
Since 2021, participants have offered more capacity into the market, but the increase hasn't been evenly distributed across price bands. The average volume of capacity offered below $0 per MWh increased by 8% (1,433 MW), while the volume offered above $300 per MWh increased by 22% (1,951 MW). In contrast, the capacity offered between $0 and $300 per MWh was broadly unchanged, decreasing by 1% (77 MW).

This indicates a more polarised offer stack, with more capacity either seeking dispatch at very low prices or positioned only to dispatch when prices are higher. This matters because a more polarised offer stack can result in more volatile prices. Since 2021, spot prices below $0 per MWh and above $300 per MWh have both become more frequent (Figure 2.2).

60 AER, Automated bidding and utlisation of third-party services Compliance Bulletin, Australian Energy Regulator, 5 August 2026, accessed 7 August 2026.

61 AER, AER Rebidding and Technical Parameters Guideline Consultation Update, Australian Energy Regulator, 19 June 2026, accessed 7 August 2026.

Figure 5.4 NEM quarterly average offered capacity, by price band

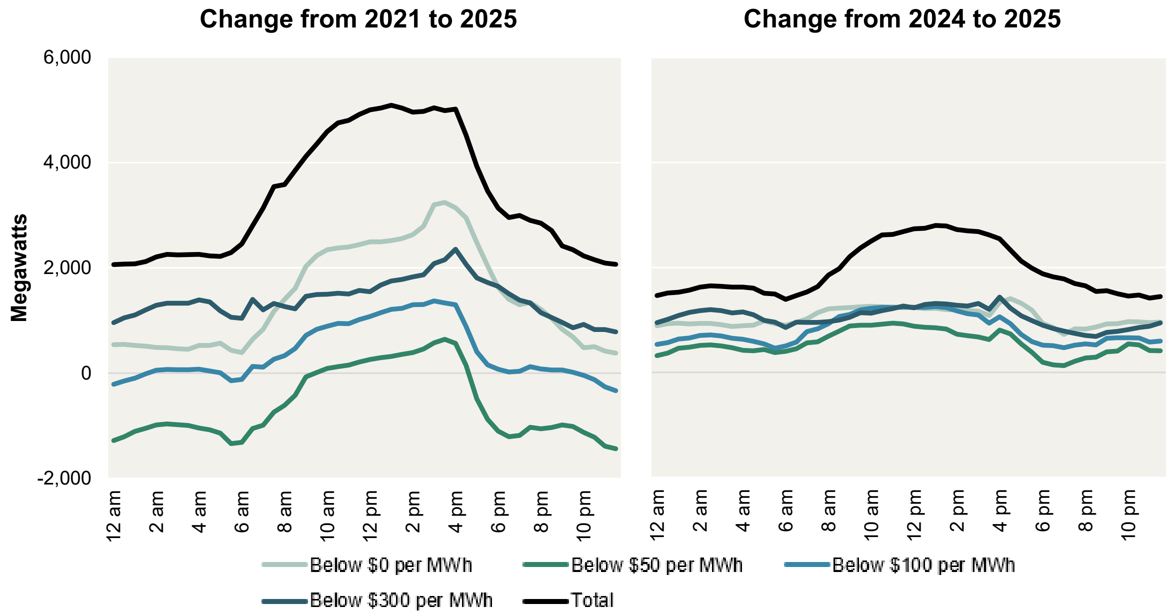


Note: Quarterly average capacity offered by NEM generators within price bands.
Source: AER analysis using NEM data.

5.1.3 Solar has driven the increase in low-priced offers in the middle of the day

Since 2021, capacity priced below $0 per MWh increased at all times of day, with the largest increase during the day (Figure 5.5). This increase was driven by low-priced solar offers, while coal and gas generally made fewer low-priced offers.

Figure 5.5 Change in NEM capacity offered below price thresholds, by time of day



Note: Change in annual average offered capacity by NEM generators below price thresholds, by time of day. Categories are cumulative. For example, the change in capacity offered below $50 per MWh includes changes in

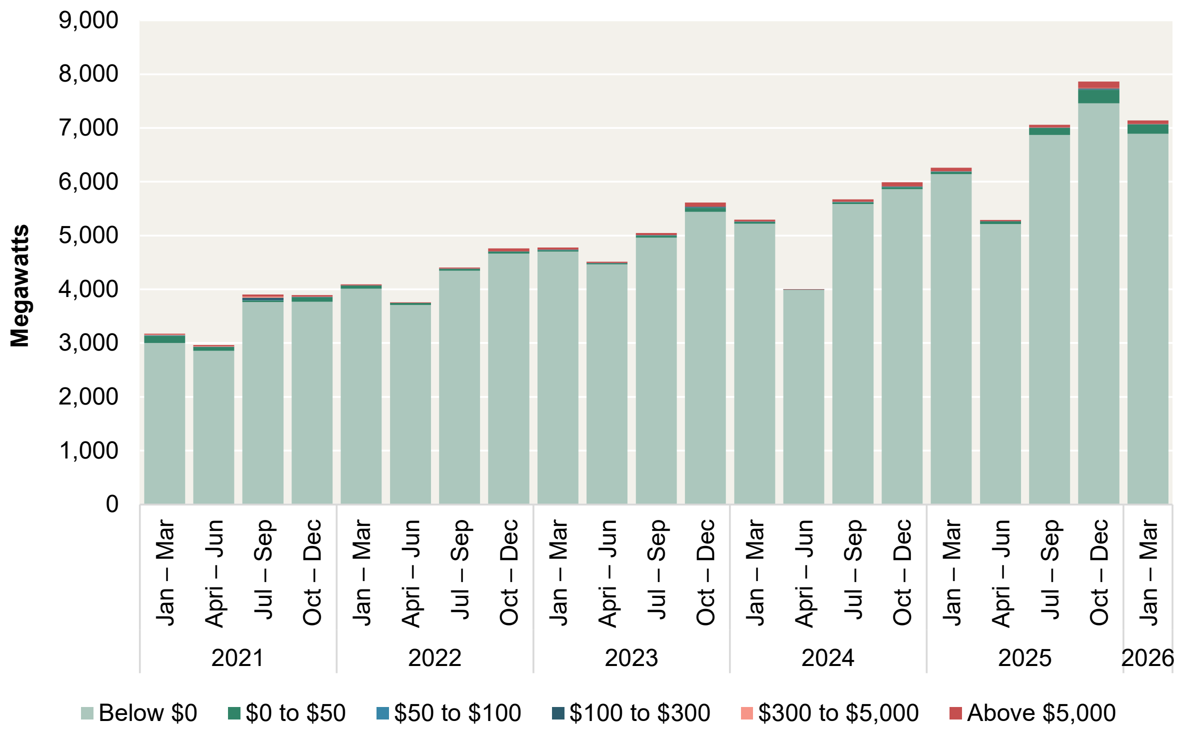
capacity offered below $0 per MWh and between $0 per MWh and $50 per MWh. Left chart shows change between 2021 and 2025, while right chart shows change between 2024 and 2025.
Source: AER analysis using NEM data.

The increase in negative-priced offers has been offset by a decrease in capacity priced between $0 and $50 per MWh, primarily reflecting changes in coal and hydro offers. As a result, total capacity offered below $50 per MWh remained lower than in 2021 at most times of the day, except between 9:30 am and 5 pm, due to solar offers. Capacity offered below $50 per MWh increased modestly from 2024 to 2025 across all times of the day, driven primarily by wind and solar, and to a lesser extent battery offers. This contributed to the decline in price volatility over the past year (section 2.1.2).

5.1.4 Wind, solar and batteries are reshaping the offer stack

New entry of wind and solar added a significant amount of low-priced capacity into the market (Figure 5.6), with the effect strongest during the day. In 2025 this amounted to around 4,400 MW of low-priced capacity overnight and around 9,600 MW in the middle of the day.

Figure 5.6 Quarterly average wind and solar offers, by price band



Note: Quarterly average capacity offered by NEM wind and solar generators within price bands.
Source: AER analysis using NEM data.

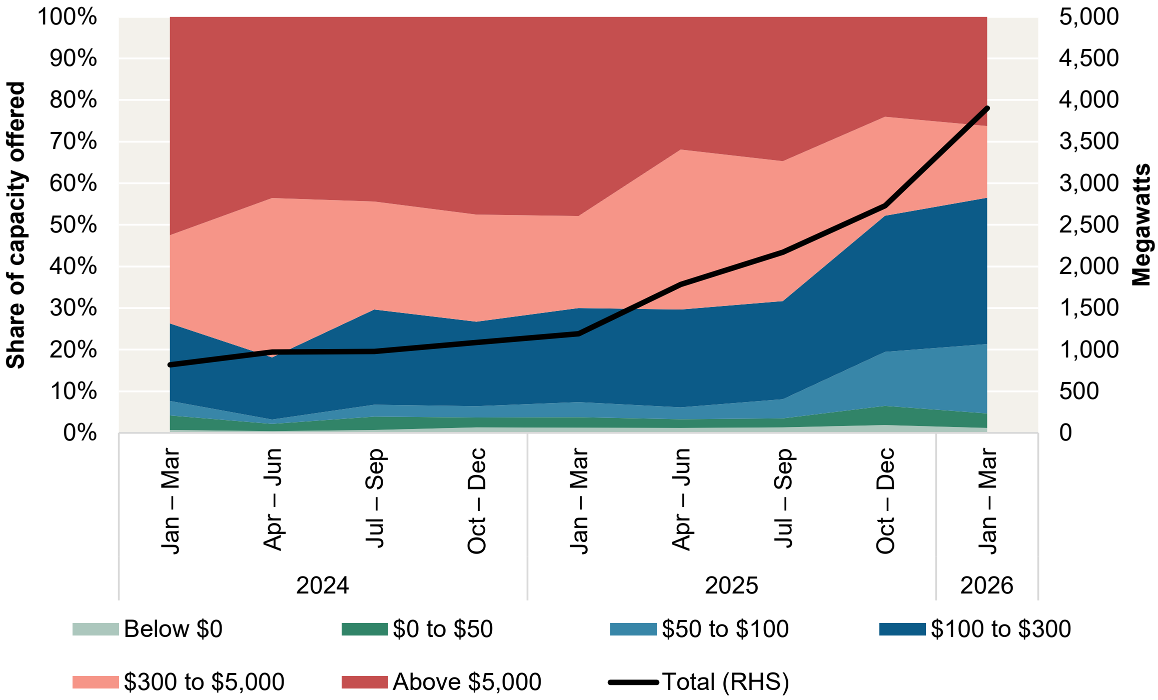
In response to lower daytime prices, coal, gas and hydro generators reduced the amount of low-priced capacity offered during the day (section 5.2.1 and section 5.1.5). Coal units are increasingly reducing output to avoid uneconomic dispatch during these times, while gas and hydro generators are less likely to generate at all during these periods.

Battery entry is changing the offer stack in a different way. In 2025 batteries were installed in the NEM at a faster rate than wind or solar. In energy markets, batteries make a profit from arbitrage. The wider the spread between the price they pay to charge and what they receive to dispatch generation, the more revenue they earn. Therefore, they are generally incentivised to discharge when prices are high. By discharging at this time, they also provide additional supply, which can reduce prices. Conversely, batteries are incentivised to charge when prices are low to keep their costs down.

Batteries are offering to discharge more capacity into the market and most of the new capacity has been offered below $300 per MWh (Figure 5.7). Coal, gas and hydro are offering less in these price bands and more in higher price bands, which is leading to batteries displacing these fuel types, particularly in the evening peak. This has also coincided with a reduction in evening peak prices.

At the same time, cap futures prices have declined, particularly in Queensland. This suggests that expectations of extreme price risk have eased. The availability and conduct of batteries are likely playing a role in this.

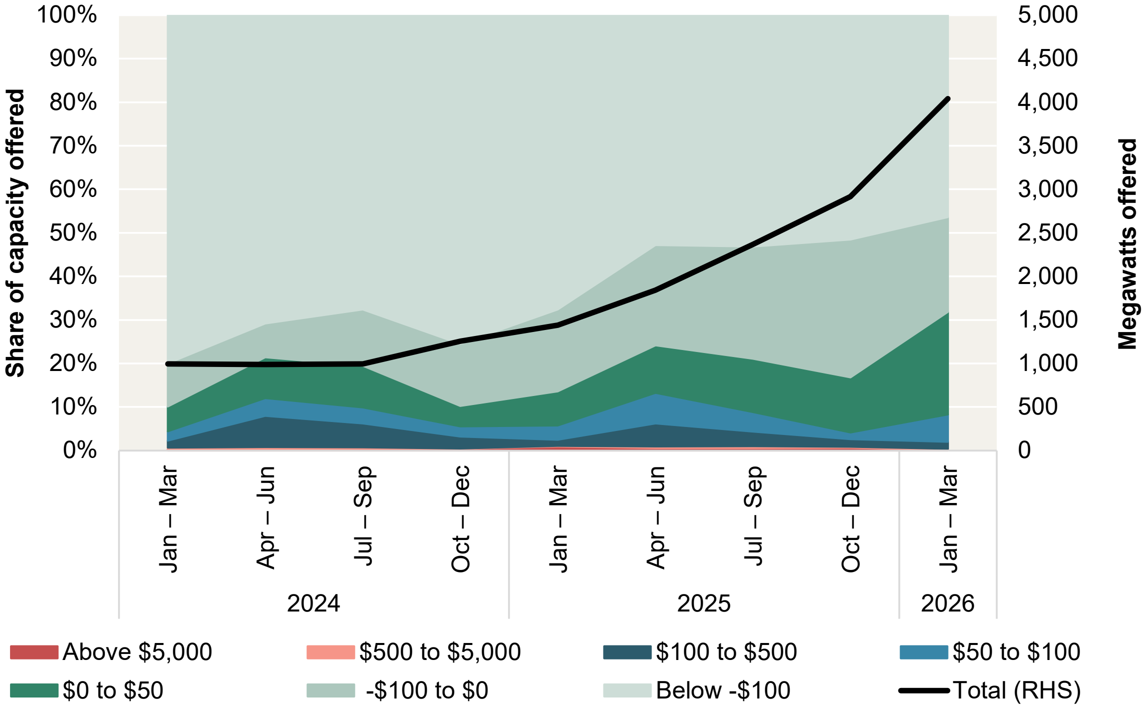
Figure 5.7 Share of NEM battery generation offers within price bands



Note: Quarterly average discharge capacity offered by NEM batteries. Stacked area shows the proportion of capacity offered within each price band, while the line shows the total quarterly average capacity offered.
Source: AER analysis using NEM data.

On the charging side, battery offers have shifted from lower to higher prices (Figure 5.8). Batteries are increasingly not requiring payment to charge and in some cases are willing to pay to charge. In the January to March quarter of 2024, 90% of battery charge offers were below $0 per MWh and 80% were below –$100 per MWh. By January to March 2026, these shares had fallen to 68% and 46%, respectively.

Figure 5.8 Share of NEM battery load offers, by price band



Note: Quarterly average charge capacity offered by NEM batteries. Stacked area shows the proportion of capacity offered for charging within each price band, while the line shows the total quarterly average capacity offered.
Source: AER analysis using NEM data.

These patterns are consistent with greater competition between batteries, with batteries needing to pay more to charge and accept lower discharge prices to be dispatched. This has coincided with reduced price volatility in the market and is consistent with battery entry increasing market competition and efficiency.

Case study 1 – Battery offer behaviour varied based on ownership class

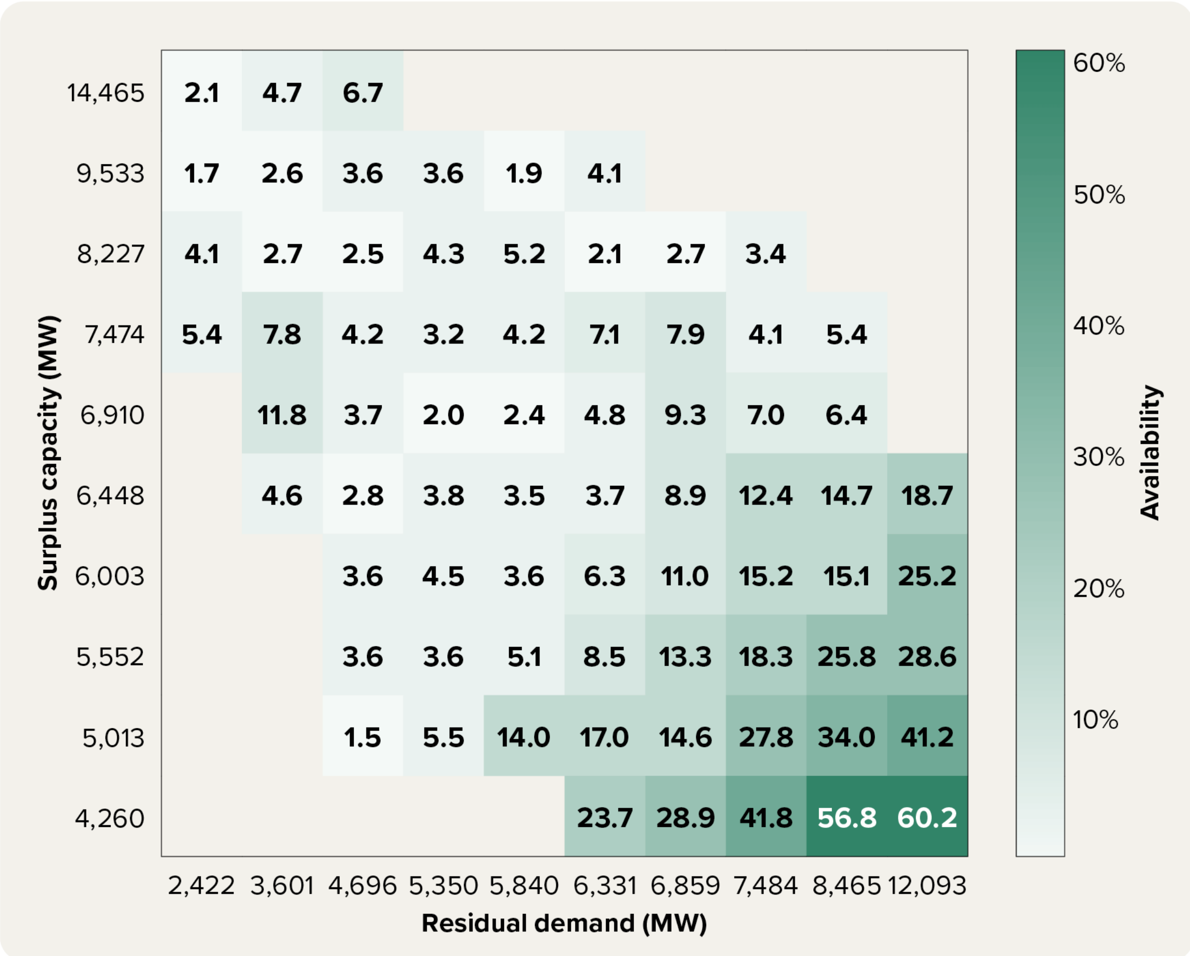
In NSW in 2025, batteries in a portfolio offered materially less capacity below the market clearing price than standalone batteries did, particularly during the tightest supply conditions. This suggests ownership structure may influence how batteries are offered when the market is most reliant on dispatchable capacity.

Because charging costs and expected opportunity costs can change quickly, we did not assess battery offers against an estimated cost benchmark. Instead, we modified the approach outlined in Box 5.1 and assessed the share of capacity offered below the market clearing price. This indicated the share of capacity a battery was willing to dispatch and how this changed based on market conditions.

The case study covered 7 grid-scale batteries in NSW: 2 standalone batteries, where battery generation accounted for the entire portfolio in 2025, and 5 in-portfolio batteries, where battery generation accounted for less than 25% of the portfolio.

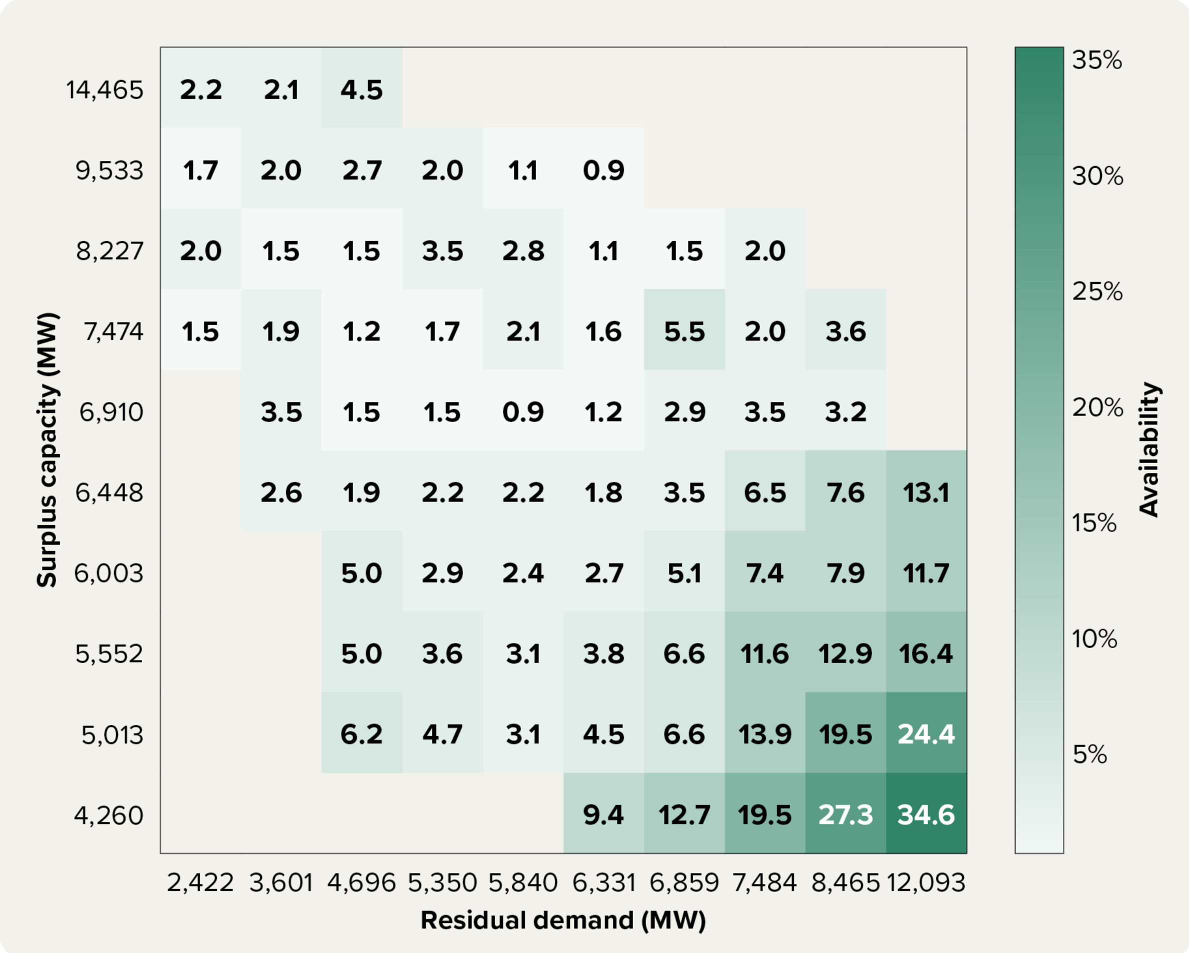
We found clear differences between the behaviour of the 2 standalone batteries and the behaviour of the 5 in-portfolio batteries. The differences were largest in tight supply conditions. In intervals with the lowest surplus capacity and highest residual demand, standalone batteries offered 60% of their capacity below the market clearing price, compared with 35% for in-portfolio batteries. We observed similar differences between in-portfolio and standalone batteries in Victoria, while in Queensland and South Australia the distinction was less evident. Capacity offered below the market clearing price is more likely to be dispatched, so a lower share indicates a greater tendency to keep capacity priced above the level needed to generate.

Figure 5.9 Average percentage of battery capacity willing to be dispatched, by surplus capacity and residual demand levels – standalone batteries, NSW, 2025



Note: Matrix categorises dispatch intervals based on levels of surplus capacity and residual demand. Rows are defined by which decile of surplus capacity the dispatch interval falls into, and columns are defined by deciles of residual demand. Values in the cells represent the average proportion of capacity offered above the market clearing price during these dispatch intervals by standalone batteries. Standalone batteries were defined as those where the owner did not control any other NEM generation assets.
Source: AER analysis using NEM data.

Figure 5.10 Average percentage of battery capacity willing to be dispatched, by surplus capacity and residual demand levels – in-portfolio batteries, NSW, 2025



Note: Matrix categorises dispatch intervals based on levels of surplus capacity and residual demand. Rows are defined by which decile of surplus capacity the dispatch interval falls into, and columns are defined by deciles of residual demand. Values in the cells represent the average proportion of capacity offered above the market clearing price during these dispatch intervals by in-portfolio batteries. In-portfolio batteries were defined as those where registered capacity made up less than 25% of total portfolio capacity.
Source: AER analysis using NEM data.

The observed bidding patterns in NSW suggest a divergence in commercial strategy between standalone and in-portfolio batteries. Standalone batteries appear to adopt a volume-maximising arbitrage approach, showing a greater willingness to reposition capacity from high price bands to lower prices as conditions tighten, to capture potential high price events. In contrast, in-portfolio batteries anchor more capacity in high price bands. Even during very tight market conditions, a substantial share of capacity remains offered at elevated price bands rather than being repositioned to ensure dispatch.

These differences may reflect underlying commercial incentives. Since standalone batteries do not have a broader generating portfolio receiving revenue when prices spike, their operators may have stronger incentives to maximise dispatch volumes during scarcity and capture revenue with the battery.

By contrast, in-portfolio batteries may be operated to support outcomes across the participant's broader portfolio. For example, a battery may be held in reserve to hedge against the risk of a generating unit outage during periods of high prices, particularly where the participant has retail load or contractual hedge obligations. Such behaviour may result in more efficient market outcomes.

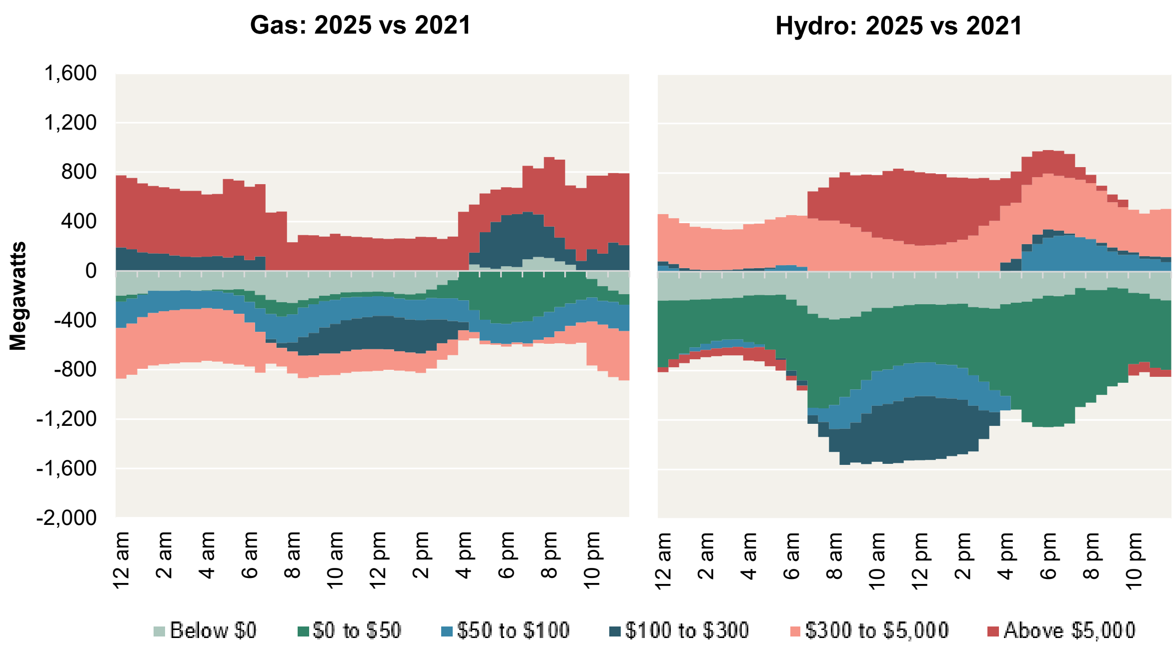
However, withholding battery capacity from dispatch may also allow prices to rise, increasing revenue from other generating assets in the portfolio. If this behaviour cannot be explained by differences in charging costs or other operational factors, it may constitute economic withholding.

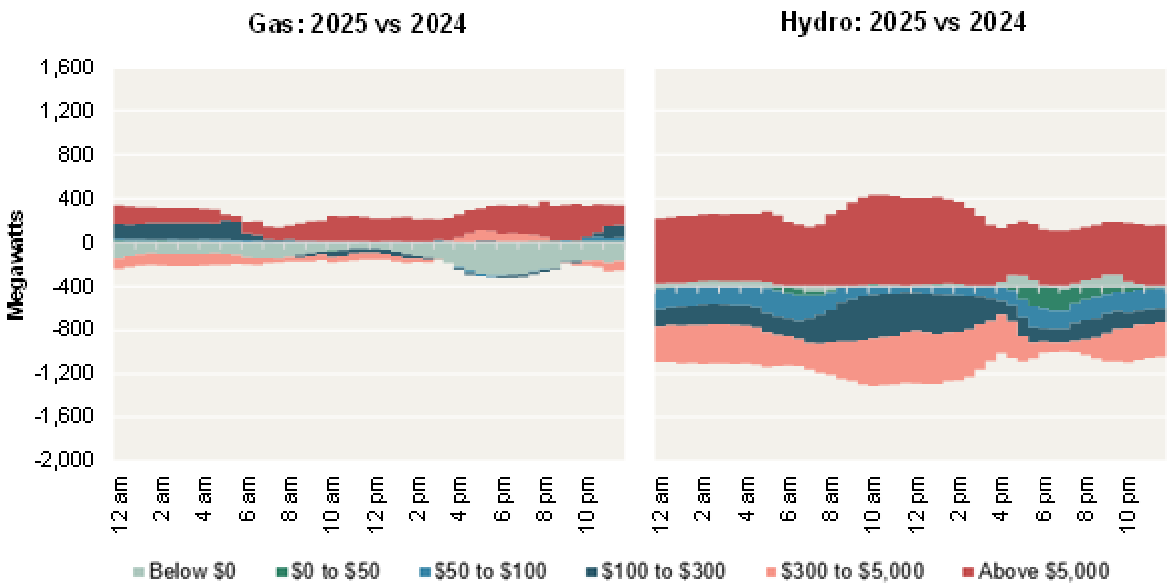
Economic withholding is not necessarily unlawful, but it can lead to inefficient market outcomes. We will continue to monitor whether the differences in behaviour between standalone and in-portfolio batteries persist as more batteries enter the market – particularly during tight supply conditions, when offer decisions can have the greatest effect on market outcomes. We are interested in whether different bidding strategies may be contributing to or detracting from efficient price outcomes.

5.1.5 Gas and hydro generators offered less low-priced capacity in the evening peak

As battery capacity has increased, gas and hydro generators have reduced the amount of low-priced capacity they offer, particularly during the evening peak. This has coincided with more battery capacity being offered in the same price bands and lower average prices at these times. This suggests batteries are increasingly competing with incumbent peaking generators and reducing the value of gas and hydro dispatch in some peak periods. Coal behaviour has also shifted, but for different reasons, as discussed in detail in section 5.2.

Figure 5.11 Change in gas and hydro offers, by price band and time of day





Note: Change in annual average capacity offered by gas and hydro by price band, by time of day. Top charts show change from 2021 to 2025, while bottom charts show change from 2024 to 2025.
Source: AER analysis using NEM data.

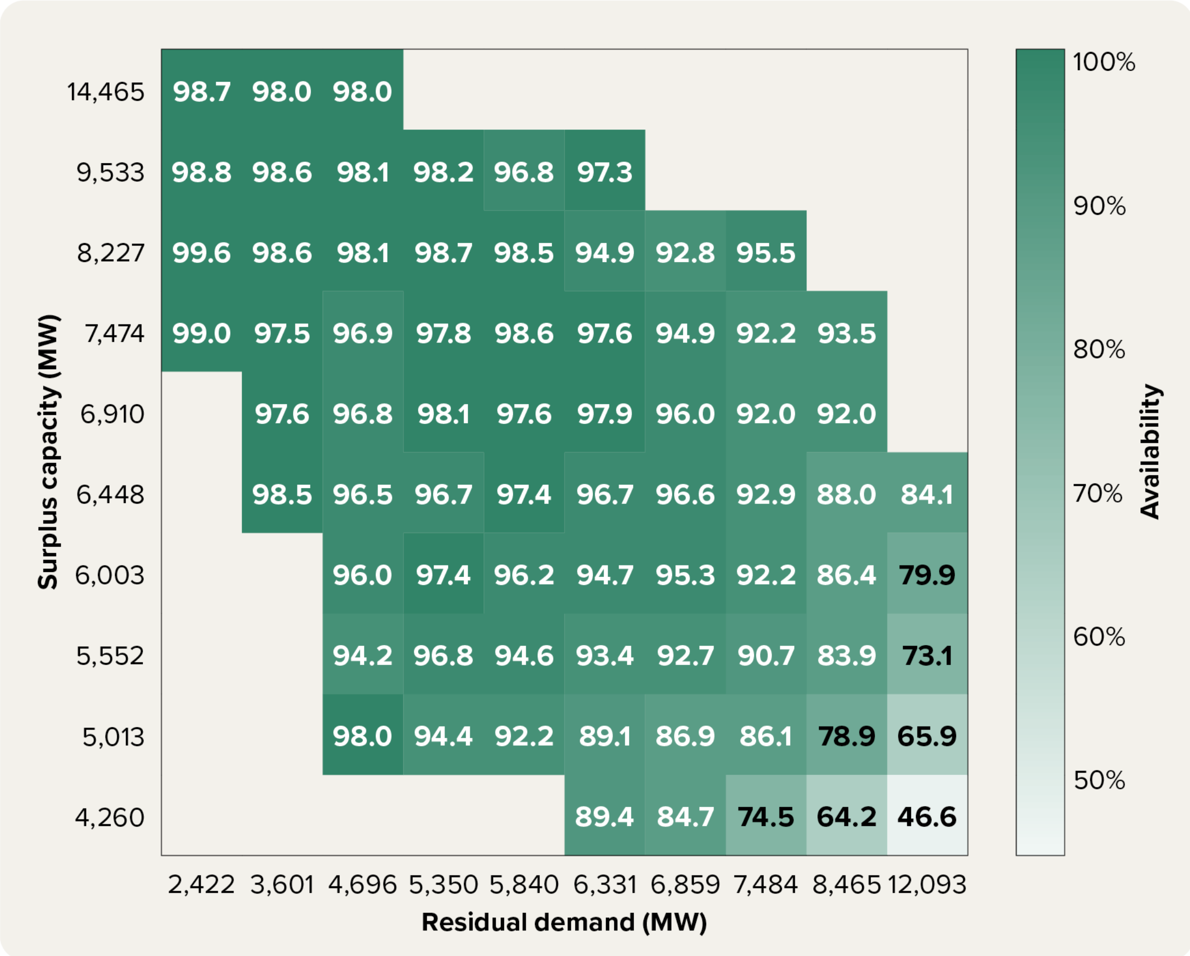
5.1.6 Greater share of gas capacity offered at a mark-up in abundant supply conditions

Gas generators marked up the largest share of capacity when supply was abundant and progressively shifted more capacity below the mark-up threshold as conditions tightened. This suggests gas offers generally responded to market conditions, although some capacity remained above the threshold even during tight periods.

Using our bidding behaviour framework (Box 5.1), we assessed how the share of gas capacity offered above the mark-up threshold varied with market conditions. The threshold is linked to short-run marginal cost. However, gas generators also incur material startup costs, which vary by technology. Therefore, the price required to recover a generator's costs depends on its short-run marginal costs, startup costs and expected run time.

In the most abundant NSW supply conditions in 2025, when surplus capacity was in the highest decile and residual demand in the lowest decile, around 99% of gas capacity was offered above the threshold (Figure 5.12). Queensland, Victoria and South Australia all show a similar trend.

Figure 5.12 Average gas capacity marked up, by surplus capacity and residual demand levels, NSW, 2025



Note: Matrix categorises dispatch intervals based on levels of surplus capacity and residual demand. Rows are defined by which decile of surplus capacity the dispatch interval falls into, and columns are defined by deciles of residual demand. Values in the cells represent the average proportion of capacity offered at a mark-up during these dispatch intervals. Gas mark-up capacity is defined as capacity offered above the AEMO ISP short run marginal cost estimate, plus a 25% buffer.
Source: AER analysis using NEM data and AEMO ISP short run marginal cost assumptions.

As market conditions tightened – with declining surplus capacity and rising residual demand – gas generators progressively shifted capacity below the mark-up threshold. This indicates they were more willing to be dispatched in tight market conditions. However, a significant share of gas capacity remained above the threshold in the tightest conditions – amounting to 35% of capacity in South Australia, 38% in Queensland, 47% in NSW and 59% in Victoria.

This pattern is consistent with a defensive bidding strategy during periods of elevated prices. Generators may position capacity at higher price levels to avoid starting for short-duration price spikes, while retaining the flexibility to participate if prices persist. As conditions tighten further, some capacity is repositioned to more competitive levels to enable dispatch and capture higher prices.

Gas generators may be maintaining some capacity at high prices, even in tight market conditions, for various reasons. Some of these reasons could be efficient, such as to avoid high startup costs or to conserve fuel. However, where generators are part of a broader portfolio that benefits from elevated prices, maintaining capacity at higher price levels may also increase spot prices received by other assets. This behaviour would be considered economic withholding. We intend to explore this in further detail in future performance reports.

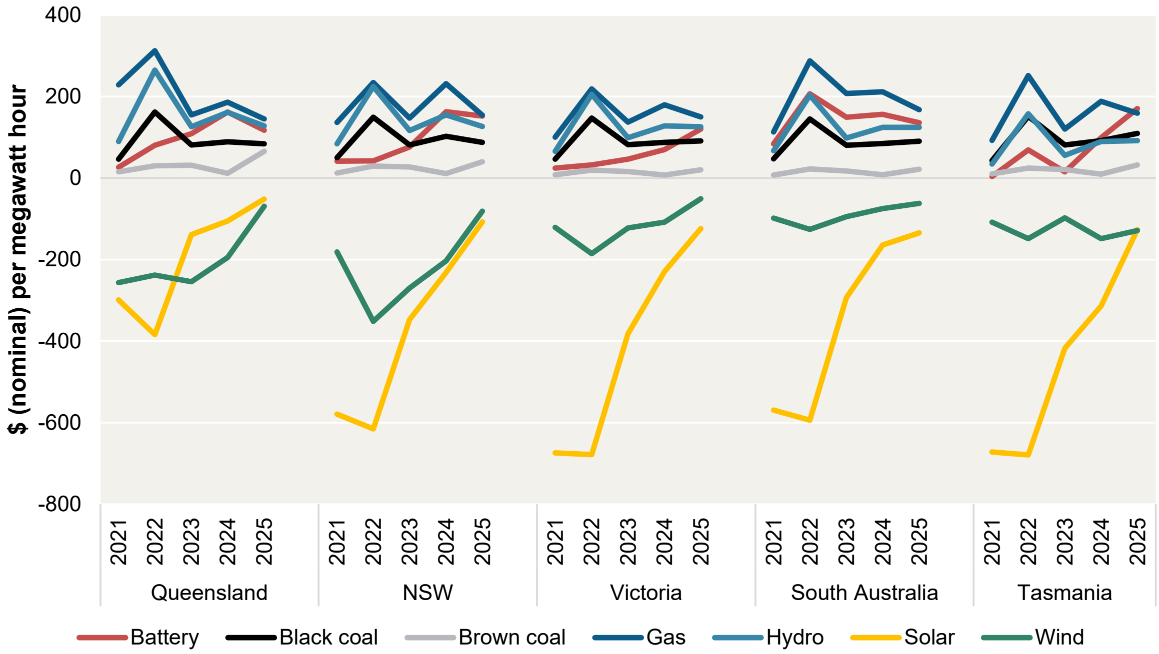
5.1.7 Average prices set by wind and solar generators have become less negative

Average prices set in NEM regions vary widely by fuel type. Gas, which faces high fuel costs, tends to set the highest prices. By contrast, wind and solar tend to set the lowest prices because they have a marginal cost of $0 per MWh and may also receive off-market revenue through renewable energy certificates and power purchase agreements.

In recent years the prices set by wind and solar have trended upwards (Figure 5.13). While these prices remain negative on average, they have become less negative than previously. This may reflect changes in commercial incentives, including tighter conditions in power purchase agreements and lower renewable energy certificate revenue. When certificate or contract revenue is lower, renewable generators have less incentive to generate at very low spot prices. Battery charging demand may also be lifting middle-of-the-day prices by absorbing some low-priced solar output and preventing prices from falling as far below $0 per MWh.

These shifts do not appear to indicate that competition has become less effective in constraining wind and solar generators. Average prices set by wind and solar remain well below estimates of the levelised cost of wind and solar generation, respectively (section 6.1.2).

Figure 5.13 Average prices set in the NEM, by region and fuel type



Note: Annual average price set in each region by each fuel type. Average price set by batteries includes price setting by both the generation and the load side.
Source: AER analysis using NEM data.

Figure 5.13 also shows that prices set by other fuel types appear to have broadly moved in line with costs, with 2 exceptions:

- Gas-fired generators set lower prices in 2025 than in 2024, despite domestic gas prices remaining at similar levels. This may reflect competitive pressure from batteries and other dispatchable capacity reducing the prices that gas generators could set.
- Batteries set higher prices in 2024 and 2025 than earlier periods in many regions. However, before 2024, batteries rarely set prices in energy markets. Prices set by batteries have declined in late 2025 and early 2026.

5.2 Black coal offer prices have broadly moved in line with proxy fuel costs

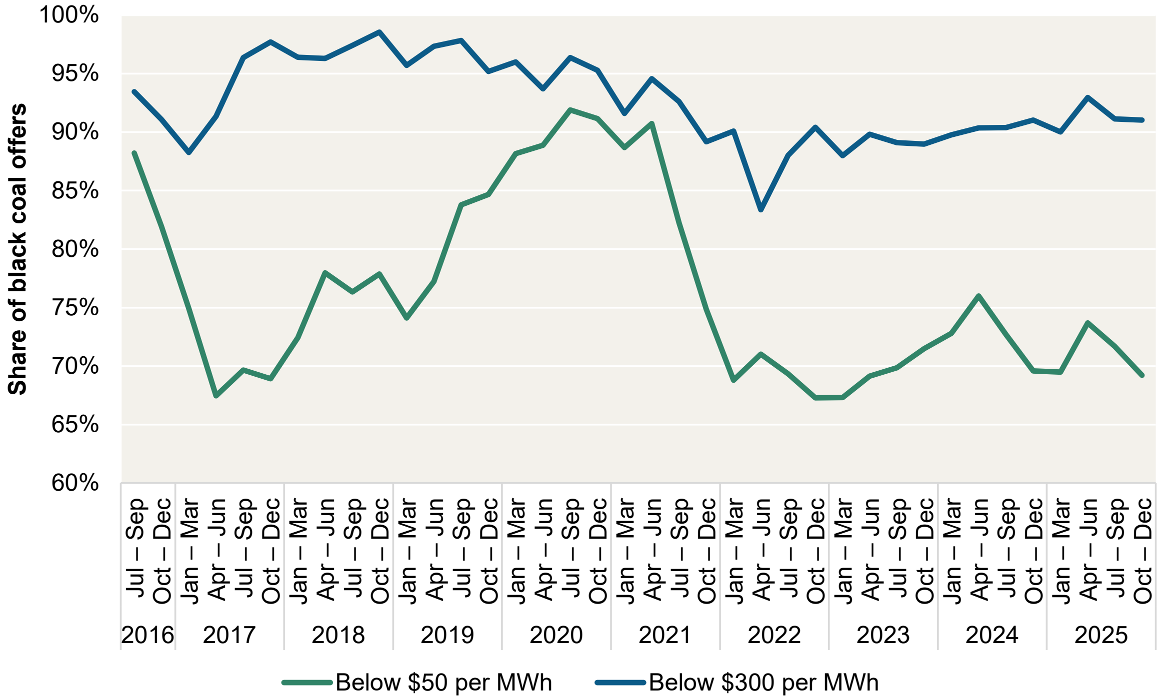
Historically, coal-fired generation was low cost and supplied most of the NEM's electricity. Over time, decarbonisation policies and increasing costs have reduced coal's share of total generation. While coal-fired generation supplies a smaller share of the NEM, black coal remains the largest source of generation and is a frequent price setter in NSW and Queensland. Therefore, changes in black coal offers continue to affect price outcomes and the amount of low-priced capacity available to the market.

5.2.1 Low-priced black coal offers remain below 2021 levels

In 2022, the higher cost and reduced availability of fuel meant many coal generators repriced discretionary capacity from mid to higher prices. This was to avoid uneconomic dispatch and, in some cases, to ration fuel.

Fuel price and supply constraints have eased, but international coal prices remain high compared with pre-shock levels. Our proxy for black coal input costs, based on export prices from the port of Newcastle, averaged $64 per MWh in 2025 – almost double the $34 per MWh level in 2020 (section 2.4.3). Consistent with this, the share of black coal capacity offered below $50 per MWh fell from 90% in 2020 to 70% in 2025 (Figure 5.14). The share increased during the coal market intervention, when fuel costs were capped from 22 December 2022 to 30 June 2024, but declined again after the intervention ended.

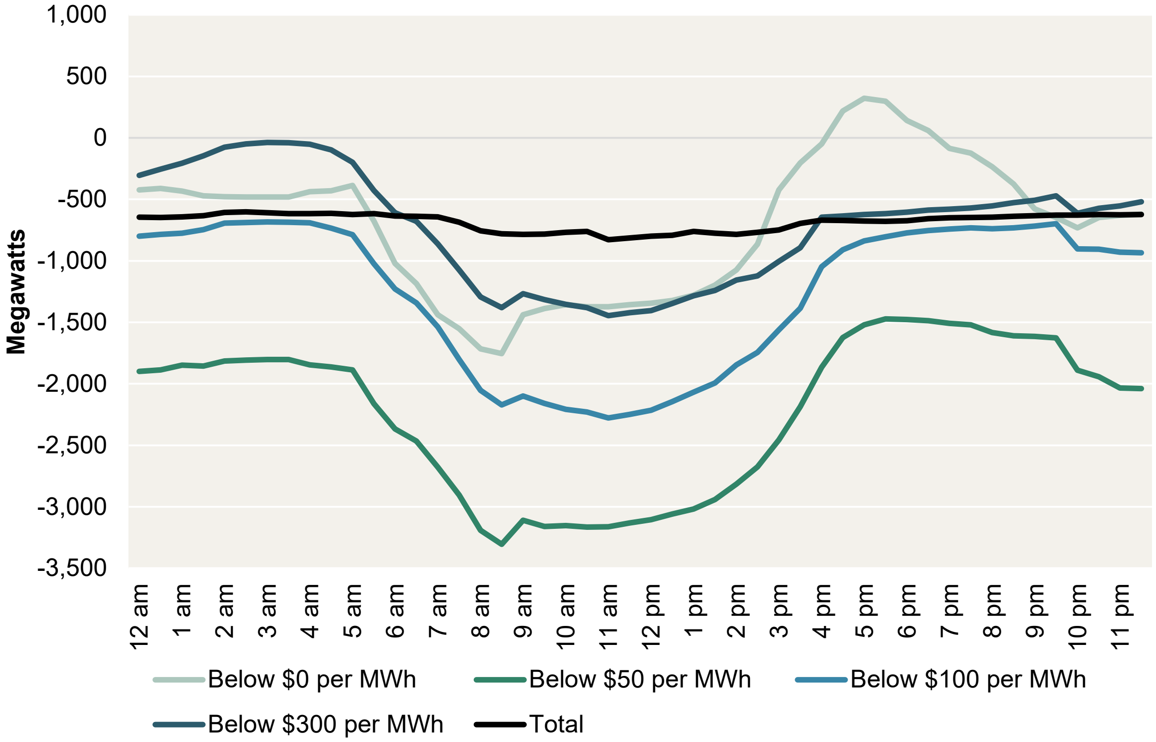
Figure 5.14 Share of total black coal offers priced below $50 and $300 per MWh



Note: Quarterly average proportion of black coal capacity offered below $50 per MWh and below $300 per MWh.
Source: AER analysis using NEM data.

Fuel costs explain much of the broad shift away from offers below $50 per MWh. However, the time-of-day pattern suggests costs are not the only driver. Black coal offers below $50 per MWh declined at all times of day (Figure 5.15), with the largest reductions during the day when solar output is highest and prices are often lowest. This suggests coal generators are also repositioning capacity to avoid uneconomic dispatch during low-price solar periods. By contrast, the reduction was smallest during the evening peak, when prices are generally higher and coal generators have stronger incentives to remain available for dispatch.

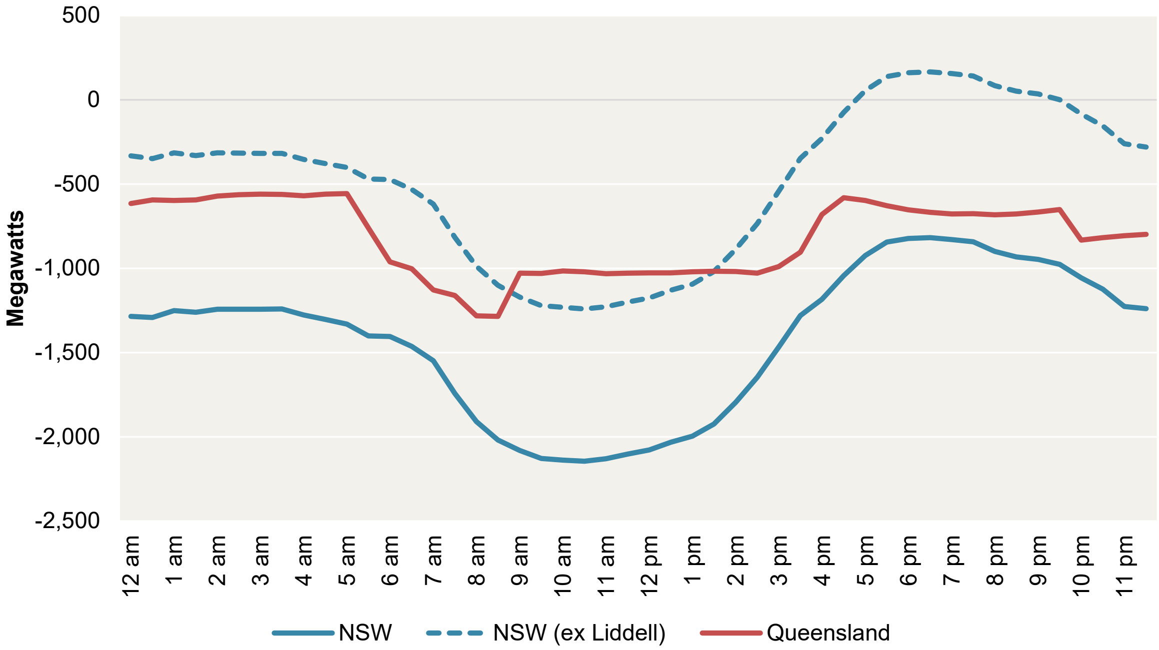
Figure 5.15 Change in black coal capacity offered below price thresholds, by time of day, between 2021 and 2025



Note: Change in annual average black coal capacity offered below price thresholds, by time of day, from 2021 to 2025. Categories are cumulative. For example, the change in capacity offered below $50 per MWh includes changes in capacity offered below $0 per MWh and between $0 per MWh and $50 per MWh.
Source: AER analysis using NEM data.

Patterns differed between regions. In NSW, after accounting for the closure of AGL's Liddell power station in 2023, capacity priced below $50 per MWh increased during the evening peak (Figure 5.16). This may reflect generators seeking to ensure they are dispatched into higher-priced evening periods. By contrast, in Queensland, capacity offered below $50 per MWh fell at all times of day. This occurred despite Queensland having a greater share of 'mine-mouth' coal generators, for which fuel costs are not linked to international coal prices.

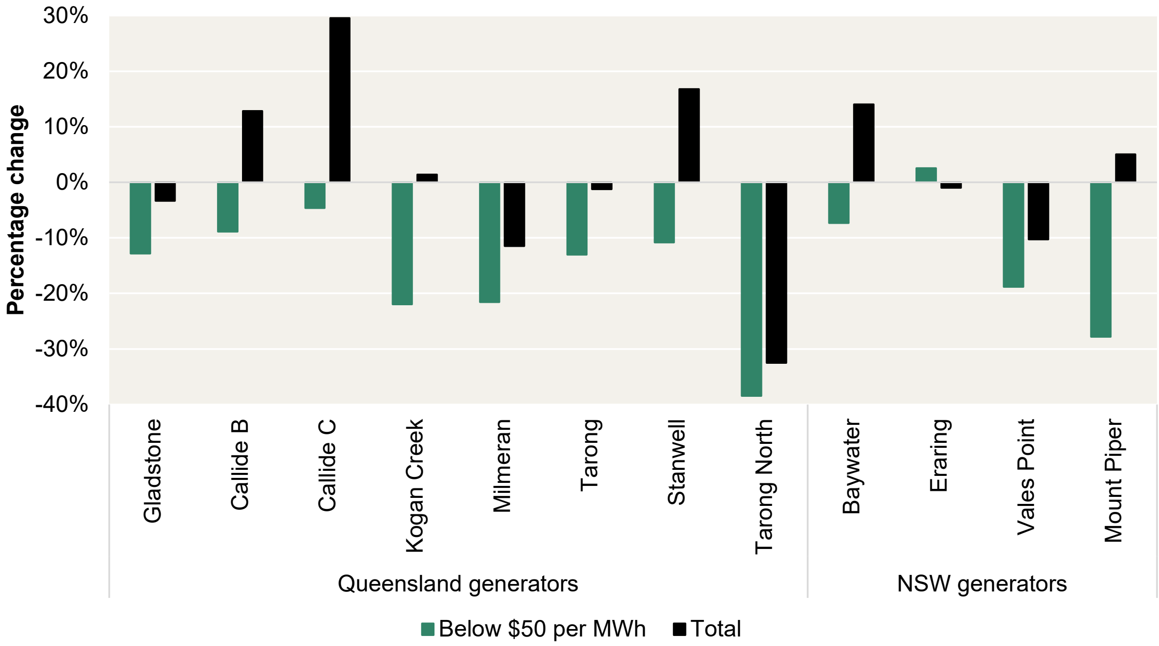
Figure 5.16 Change in black coal capacity offered below $50 per MWh, by time of day, between 2021 and 2025



Note: Change in annual average black coal capacity offered below $50 per MWh, by time of day, from 2021 to 2025. As part of the change in NSW reflects the closure of Liddell power station, the chart also shows NSW outcomes excluding Liddell.
Source: AER analysis using NEM data.

Across NSW and Queensland, every black coal power station except Eraring reduced the amount of capacity it offered below $50 per MWh between 2021 and 2025. Higher fuel costs and efforts to avoid dispatch during low-priced solar periods are likely to explain some of this shift. However, visible market conditions may not explain all of the shift in offer behaviour.

Figure 5.17 Station-level change in black coal offers below $50 per MWh and in total offers between 2021 and 2025



Note: Percentage change in annual average offered capacity by black coal power stations from 2021 to 2025. Chart shows both the change in total offered capacity and the change in capacity offered below $50 per MWh during this period. Liddell is excluded as it closed in 2023.
Source: AER analysis using NEM data.

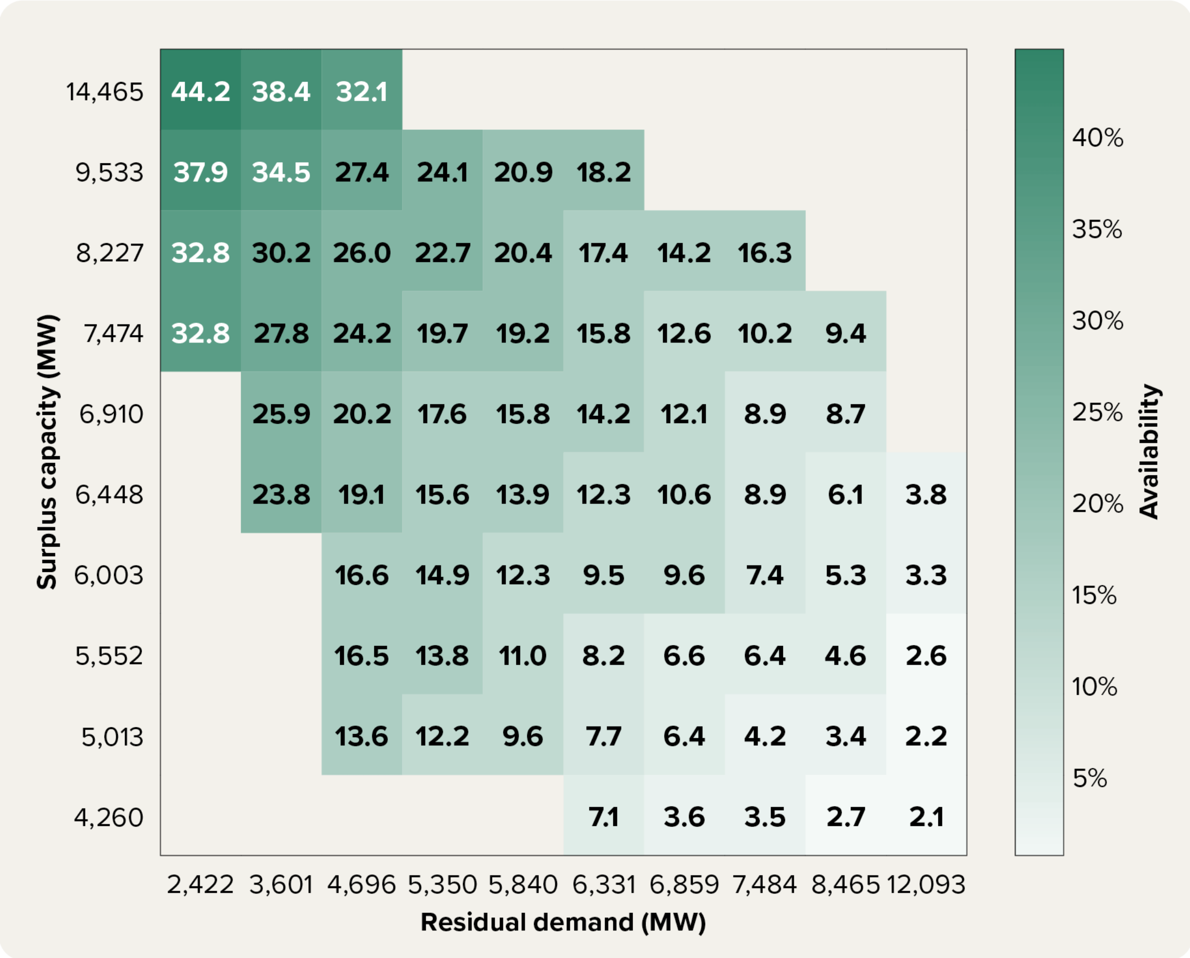
5.2.2 Black coal generators offered less capacity at a mark-up price when supply was tight

Like gas generators (section 5.1.6), black coal generators tended to offer more capacity into the market at lower prices when supply conditions were tight. This suggests coal generators were more likely to prioritise dispatch when the market relied on their capacity, rather than systematically withholding capacity during scarcity. However, Queensland coal generators retained slightly more capacity at a mark-up in tight conditions than NSW coal generators.

In 2025 in NSW, marked-up capacity was highest when supply was abundant – up to 44% of capacity was above the threshold when surplus capacity was highest and residual demand lowest (Figure 5.18). In the tightest conditions, only 2.1% of capacity remained above the threshold. Between these extremes, the proportion of capacity offered at a mark-up declined steadily as conditions tightened.

These higher-priced offers by coal generators tend to occur when the market is oversupplied. These offers more likely indicate coal seeking to limit dispatch into low prices, rather than exercising market power to push up prices. When the market is tight, NSW coal generators appear to prioritise dispatch rather than systematically withholding capacity.

Figure 5.18 Average percentage of black coal capacity marked up, by surplus capacity and residual demand levels, NSW, 2025



Note: Matrix categorises dispatch intervals based on levels of surplus capacity and residual demand. Rows are defined by which decile of surplus capacity the dispatch interval falls into, and columns are defined by deciles of residual demand. Values in the cells represent the average proportion of capacity offered at a mark-up during these dispatch intervals. Black coal mark-up capacity is defined as capacity offered above the AEMO ISP short run marginal cost estimate, plus a $50 per MWh buffer.
Source: AER analysis using NEM data and AEMO ISP short run marginal cost assumptions.

Queensland black coal generators and Victorian brown coal generators showed a similar pattern, with the largest share of capacity above the threshold in abundant supply conditions. In both Queensland and Victoria, less than 30% was offered above the threshold even when supply was most abundant. However, Queensland retained a higher share of marked-up capacity in tight conditions, with at least 10% of capacity offered above the threshold even in the tightest periods.

Overall, these results suggest that changes in the offers from coal generators are largely responding to market conditions.

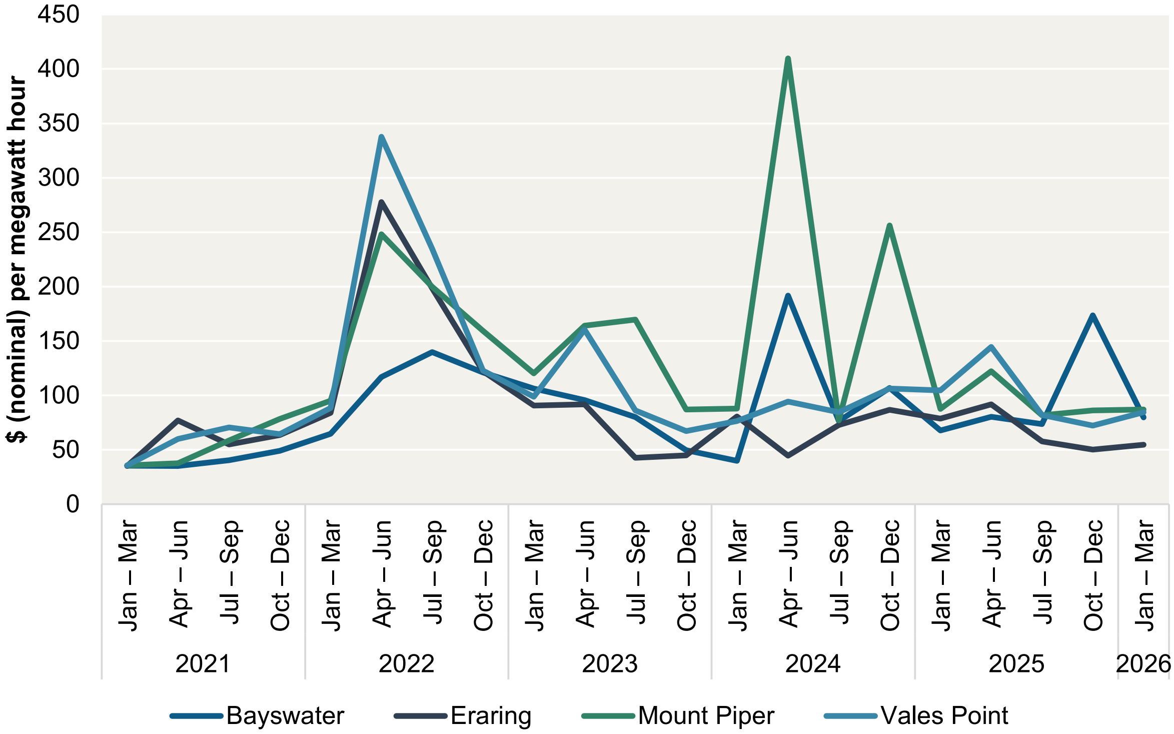
5.2.3 NSW black coal price-setting outcomes were more stable in 2025

Black coal remains the most frequent price setter in Queensland and NSW (section 2.4.4) and frequently sets the price in other regions. Because black coal is often marginal – albeit less often during peak times than overnight – changes in the prices set by coal generators can materially affect regional spot prices, volatility and contract market expectations. In 2022, NSW black coal generators set higher prices after fuel prices rose following Russia's invasion of Ukraine (Figure 5.19). As fuel prices fell, including due to fuel price interventions by the Australian and state governments, prices set by these generators also declined.

In the April to June quarter 2024, commercial rebidding by Mt Piper and Bayswater power stations contributed to high price events and lifted average price-setting outcomes.[62] Since then, NSW coal generators generally set prices below $150 per MWh. The exceptions were Mt Piper in October to December 2024 and Bayswater in October to December 2025. In Bayswater's case, commercial rebidding again contributed to the higher average price set.

Overall, prices set by NSW black coal generators have mostly moved with changes in fuel costs. However, some commercial rebidding episodes indicate coal generators can exercise transient market power during particular market conditions.

Figure 5.19 Quarterly average price set by NSW black coal generators

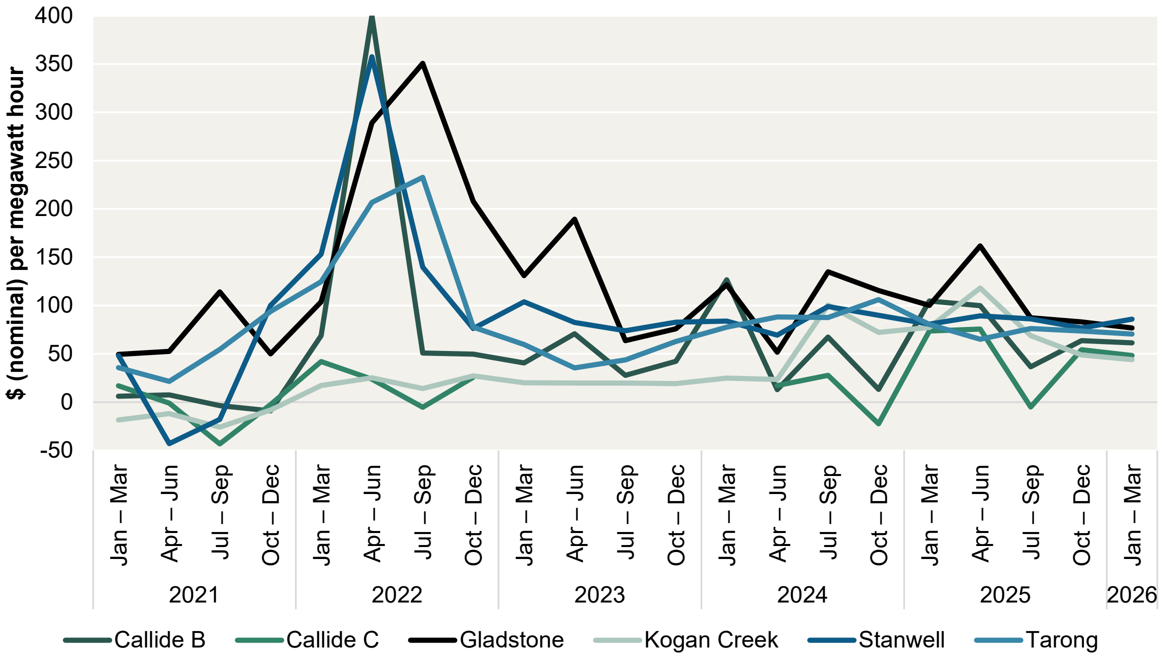


Note: Quarterly average price set by NSW black coal power station.
Source: AER analysis using NEM data.

Queensland shows a similar post-2022 moderation but at slightly lower average price-setting levels than NSW. Queensland has 8 generators, 6 of which set the price frequently (Stanwell's Tarong North power station and Genuity's Millmerran power station set price infrequently). Like in NSW, several Queensland black coal stations set the price at much higher levels in 2022, amid high fuel prices and fuel supply constraints (Figure 5.20).

62 AER, Prices above $5,000/MWh – April to June 2024, Australian Energy Regulator, 17 July 2024, accessed 13 June 2026; AER, Wholesale electricity market performance report 2024, Australian Energy Regulator, p. 86, 20 December 2024, accessed 13 June 2026.

Figure 5.20 Quarterly average prices set by Queensland black coal generators



Note: Quarterly average price set by Queensland black coal power station. Tarong North and Milmerran have been excluded because they set price relatively infrequently.
Source: AER analysis using NEM data.

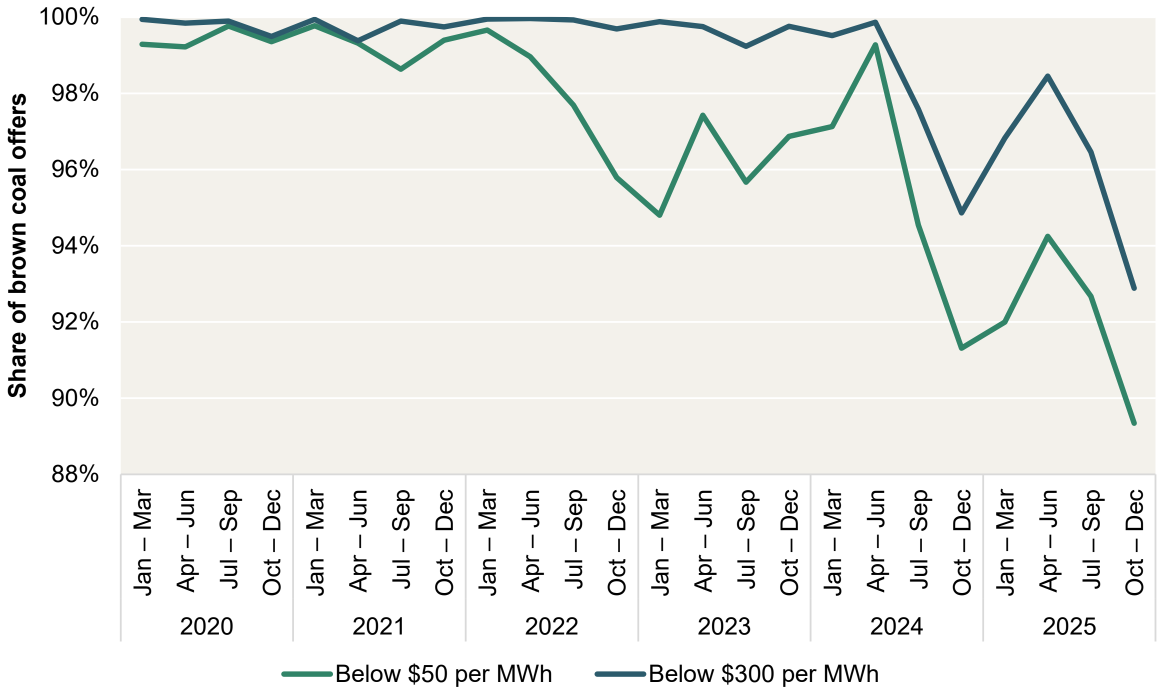
Since then, average prices set by Queensland black coal generators have declined. Between 2023 and 2025, most stations set prices between $0 and $150 per MWh. Compared with NSW coal generators, lower prices in Queensland may reflect the predominance of ‘mine-mouth’ generators with lower, more stable costs. We explore the behaviour of Queensland coal generators in section 5.3 through a case study of Stanwell Corporation’s portfolio.

5.2.4 Brown coal offers have shifted to higher prices in the middle of the day

Victoria’s 3 brown coal power stations are not exposed to international prices because brown coal is low quality and not suitable for export. As such, brown coal generators tend to face lower and more stable fuel costs than black coal generators.

Prior to 2022, nearly all brown coal capacity was offered below $50 per MWh. Brown coal remains mostly offered at low prices, but since mid-2024 generators have shifted a small share of capacity into higher price bands. In 2025 over 90% of brown coal capacity was still offered below $50 per MWh on average and over 95% was offered below $300 per MWh (Figure 5.21).

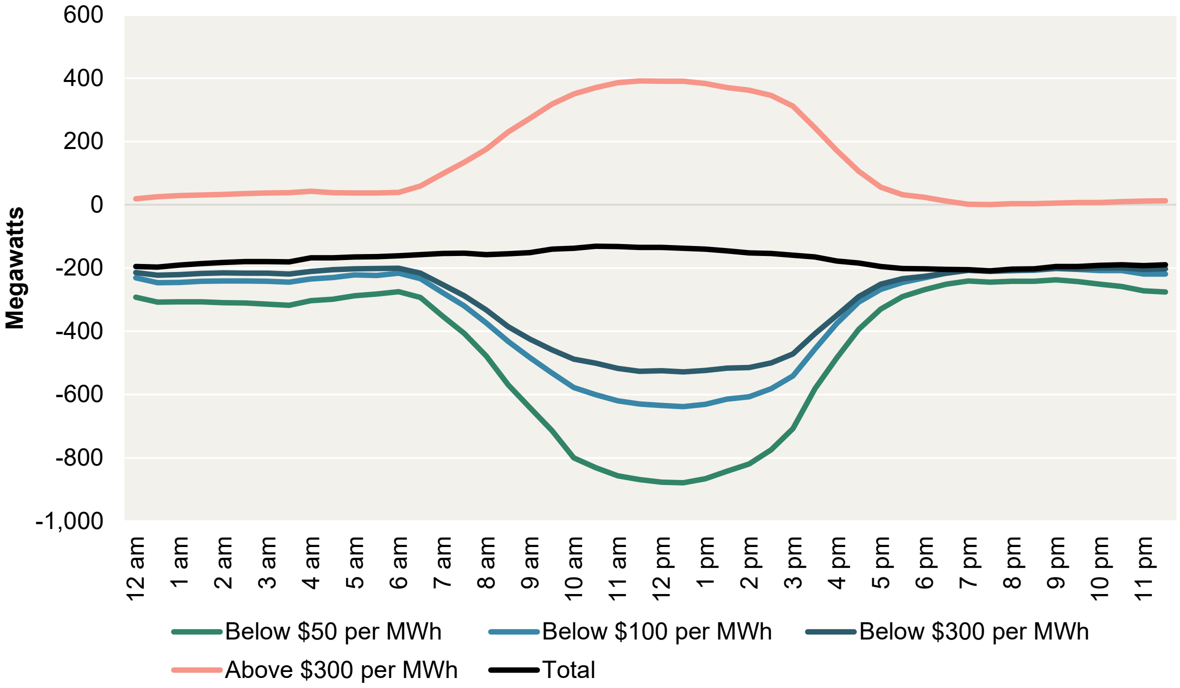
Figure 5.21 Share of total brown coal offers priced below $50 and $300 per MWh



Note: Quarterly average proportion of brown coal capacity offered below $50 per MWh and below $300 per MWh.
Source: AER analysis using NEM data.

Brown coal's shift to higher-priced offers has mostly occurred during the day, when solar output is high and Victorian spot prices tend to be lowest. This suggests brown coal generators are increasingly repositioning some capacity to avoid dispatch during low or negative price periods, despite their relatively low and stable fuel costs.

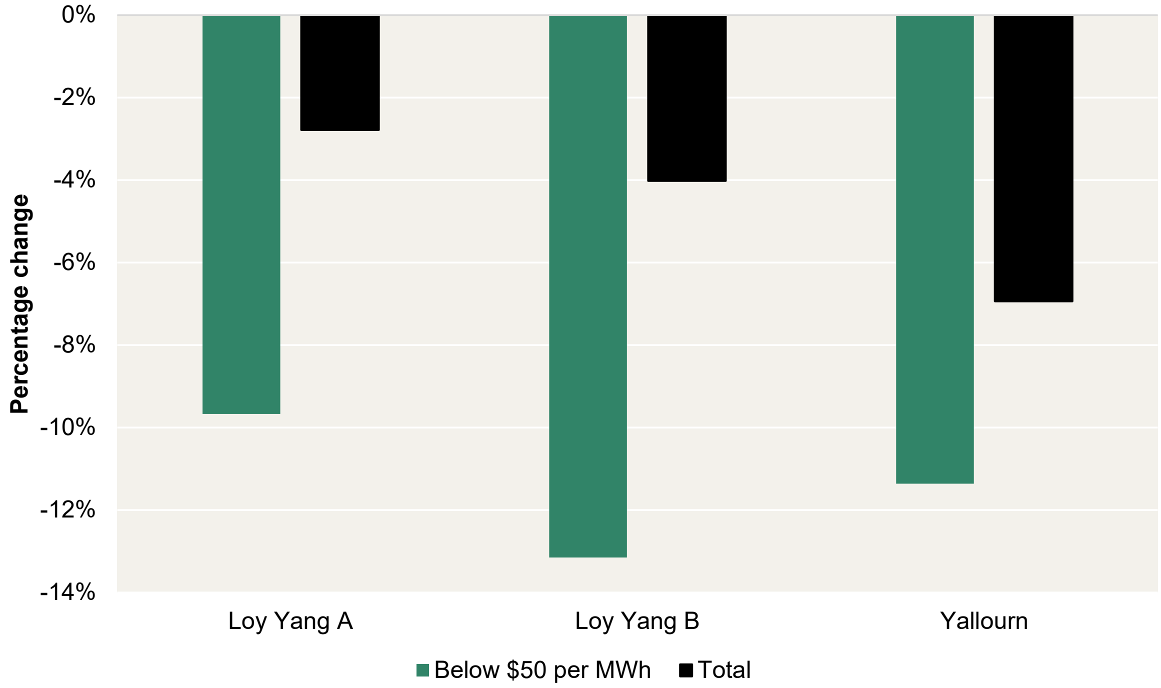
Figure 5.22 Change in brown coal capacity offered below price thresholds, by time of day, between 2021 and 2025



Note: Change in annual average brown coal capacity offered above or below price thresholds, by time of day, from 2021 to 2025. Categories are cumulative. For example, the change in capacity offered below $50 per MWh includes changes in capacity offered below $0 per MWh and between $0 per MWh and $50 per MWh.
Source: AER analysis using NEM data.

Each brown coal station offered less capacity in 2025 than in 2021 (Figure 5.23). However, for each station, the reduction in capacity below $50 per MWh was larger than the reduction in total capacity. Among the 3 brown coal stations, Alinta Energy's Loy Yang B shifted the most capacity from below to above $50 per MWh. This shift in behaviour is discussed further in section 5.5.

Figure 5.23 Station-level change in brown coal offers below $50 per MWh and in total offers between 2021 and 2025



Note: Percentage change in annual average offered capacity by brown coal power station from 2021 to 2025, showing both total offered capacity and capacity offered below $50 per MWh.
Source: AER analysis using NEM data.

5.3 Queensland black coal shifted capacity from low-price to mid-price bands

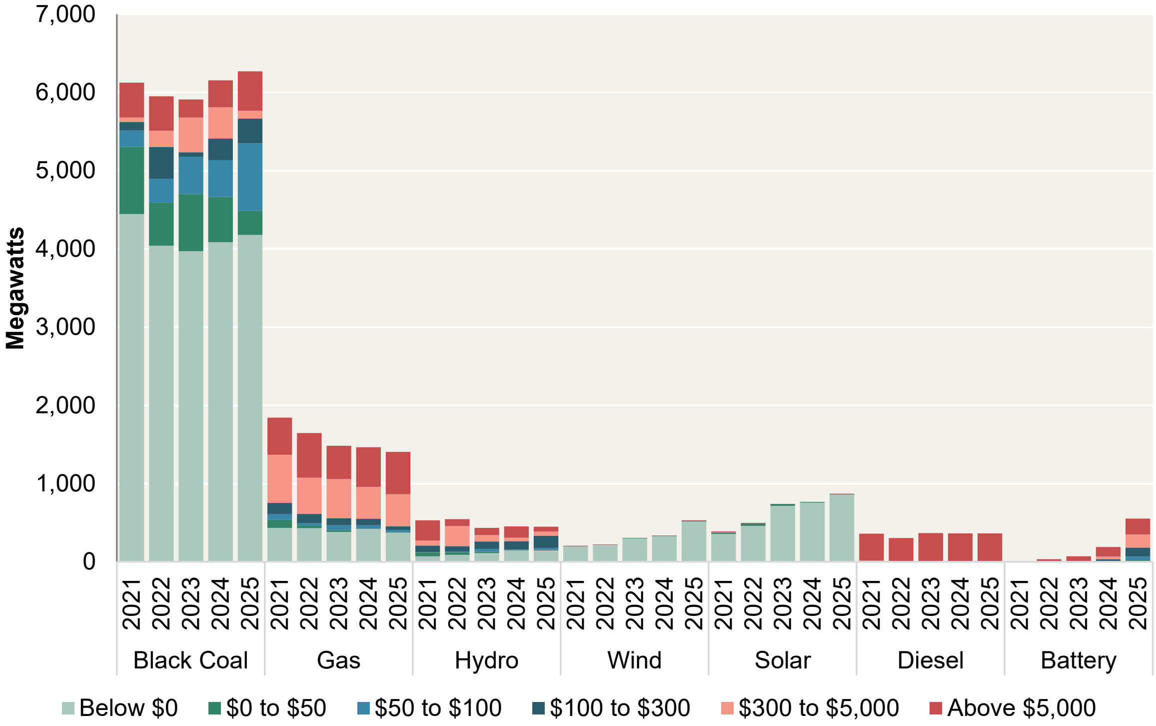
Queensland remained heavily reliant on black coal generation and total black coal offers increased as CS Energy's Callide C units returned to service in 2024 following long outages (Figure 5.24).

However, the additional availability did not translate into more low-priced coal capacity. Instead, capacity offered between $0 and $50 per MWh fell by 267 MW, while capacity offered between $50 and $100 per MWh increased by 392 MW. A 91 MW increase in capacity offered below $0 per MWh only partly offset the reduction below $50 per MWh.

This shift may reflect an end of Queensland Government directions to state-owned generators in mid-2024. During 2023 and the first half of 2024, these directions appear to have reduced fuel price exposure and supported low-priced coal offers, similar to the NSW coal intervention that was in place at the same time. From mid-2024 – when the NSW coal intervention ended – Queensland black coal generators offered more capacity at higher price bands. This would be consistent with the Queensland intervention also ceasing effect around that time, although the details and end date of the directions were not made public.

Restructuring of coal supply contracts for Coronado for Stanwell and Batchfire for CS Energy could also be a factor.[63]

Figure 5.24 Queensland offers, by fuel type



Note: Annual average capacity offered by Queensland generators within price bands.
Source: AER analysis using NEM data.

Queensland gas offered less total capacity and less capacity below $300 per MWh in 2025, continuing longer running trends. This reduced the amount of mid-priced dispatchable capacity available from gas.

Wind, solar and hydro all increased their low-priced capacity in Queensland. Battery capacity offered in the region increased by 190% (363 MW) in 2025, with a growing share being offered below $300 per MWh.

Case study 2 – Stanwell shifted coal capacity from low-price to mid-price bands

Stanwell Corporation shifted a material share of capacity from below to above $50 per MWh after mid-2024. Some capacity was moved into the $50 to $100 per MWh range and some into higher price bands. The changes in offer behaviour across Stanwell Corporation's portfolio are likely linked to the coal intervention.

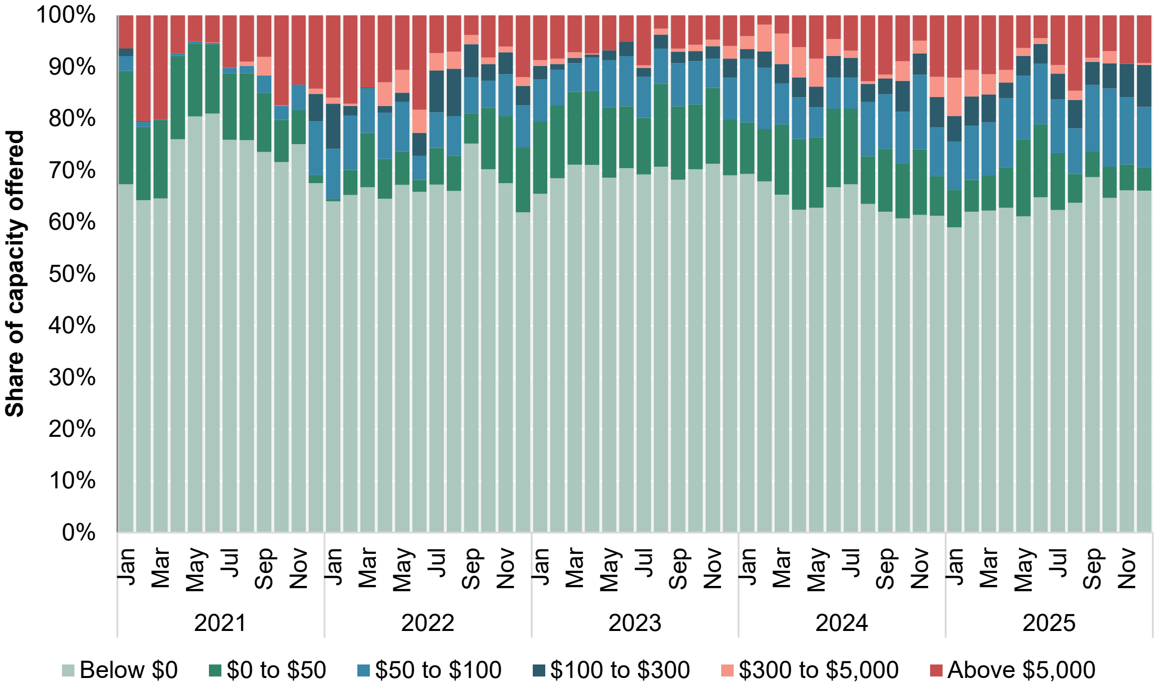
State-owned Stanwell Corporation is Queensland's largest participant by share of both registered capacity and generation output, and its coal units frequently set the Queensland

[63] See, for example, Industry Queensland, Coronado strikes Stanwell deal to boost cash position, 10 June 2025, accessed 7 August 2026; The Courier Mail, Taxpayers shell out $110m to keep Callide's coal mine afloat, 18 June 2025, accessed 7 August 2026.

price. Stanwell Corporation owns the Stanwell, Tarong and Tarong North coal power stations as well as output from Clarke Creek and Wamboin wind farms, Blue Grass solar farm and Tarong battery.

Stanwell Corporation continues to offer most of its capacity at low prices, but the share of its capacity offered below $50 per MWh has declined since 2023 (Figure 5.24). Throughout 2023 and the first half of 2024 around 80% of Stanwell's capacity was offered below $50 per MWh, on average. Since then, it has fallen to about 70%. Some of this capacity was shifted to between $50 and $100 per MWh, while some was shifted to higher prices.

Figure 5.25 Share of Stanwell's capacity offered in different price bands



Note: Monthly average capacity offered by Stanwell Corporation in each price band. The chart includes units for which we consider Stanwell to hold trading rights, which may differ from AEMO registration. Trading rights are allocated based on ownership of each unit's output where available, and asset ownership otherwise. Output is allocated pro rata where ownership changed during 2025 or where multiple owners hold interests in a unit.
Source: AER analysis using NEM data and other publicly available information.

These shifts in offer behaviour have been reflected in higher average prices set by Tarong power station, Stanwell's second-largest generator. From March to November 2023, Tarong typically set prices at around $40 per MWh on average (Figure 5.20). This increased to around $80 per MWh in December 2023 and remained elevated through 2024 and 2025, with monthly average prices set ranging between approximately $60 and $110 per MWh. Over 2023 to 2025, Tarong set the price around 5% to 10% of the time in Queensland, depending on the month. Therefore, the shift in prices set by Tarong is likely to have materially influenced regional price outcomes.

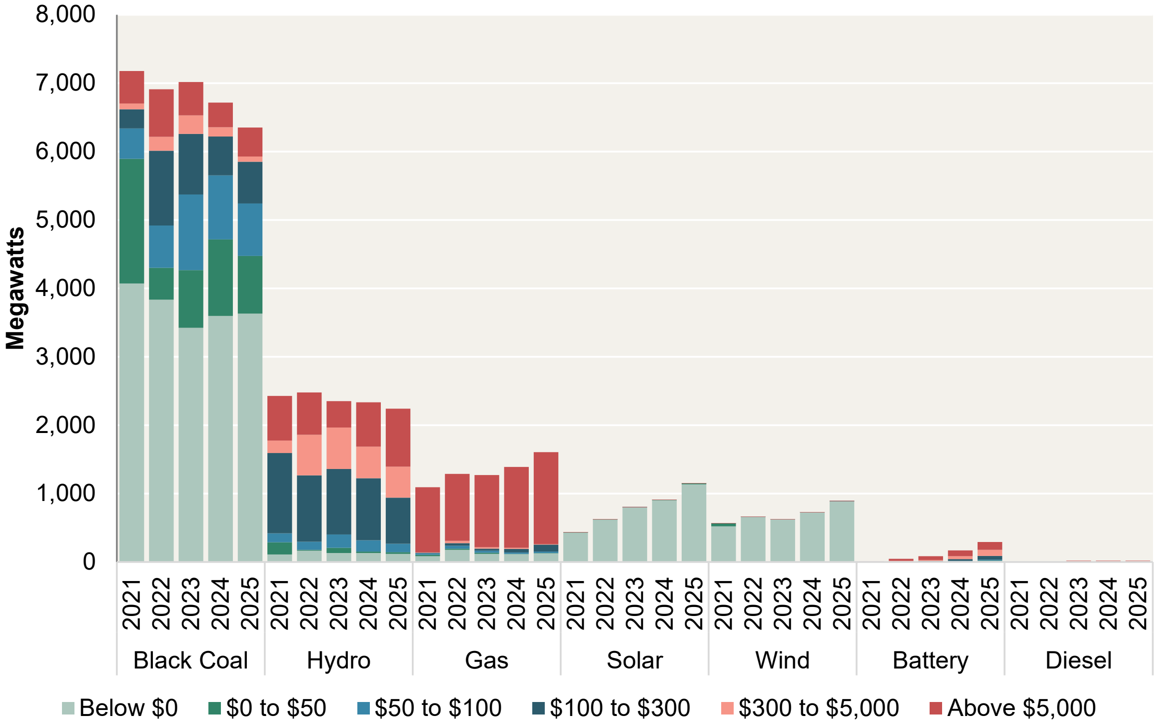
Stanwell power station tends to set the price around 5% to 15% of the time in Queensland – slightly more often than Tarong. During 2023, Stanwell set higher prices than Tarong – usually between $60 and $110 per MWh. During 2024 and 2025, the prices set by Stanwell power station remained fairly consistent, while the prices set by Tarong power station increased.

While the changes in offer behaviour across Stanwell Corporation's portfolio are likely linked to the coal intervention, some of its power stations are 'mine-mouth'. Tarong power station is situated at Meandu Mine, which supplies coal exclusively to the Tarong and Tarong North power stations. Typically, mine-mouth coal stations have lower, more stable fuel costs than generators that rely on purchasing and transporting coal from mines that supply international markets. In addition, Stanwell did not report any issues with production at Meandu Mine during the period when offer behaviour changed. As such, visible market conditions may not explain all the shift in Stanwell Corporation's behaviour.

5.4 In NSW, low-priced coal offers fell after the market intervention ended

Like Queensland, NSW is heavily reliant on black coal. Total coal capacity offered declined in 2024 and 2025 following the closure of AGL's Liddell power station in April 2023. Against that backdrop, coal capacity offered below $50 per MWh increased slightly in 2024 before falling again in 2025. This timing is consistent with the end of the coal market intervention in mid-2024. While in place, the intervention capped the price of coal at $125 per tonne, equivalent to around $49 per MWh in production costs, and likely supported lower-priced offers.

Figure 5.26 NSW offers, by fuel type



Note: Annual average capacity offered by NSW generators within price bands.
Source: AER analysis using NEM data.

Hydro generators in NSW have progressively reduced capacity offered below $300 per MWh, largely driven by Snowy Hydro's offers. This reduced the amount of mid-priced firming capacity available in NSW, as discussed in Case study 3.

Total gas offers have increased following the entry of EnergyAustralia's Tallawarra B power station in June 2024. However, gas capacity offered below $300 per MWh increased by only

63 MW from 2024 to 2025, suggesting the additional gas capacity has mostly been positioned at higher prices. This likely reflects growth in low-priced solar, wind and battery offers, which have contributed to lower and less volatile prices and reduced the need for gas generation.

Case study 3 – Snowy Hydro shifted capacity from below to above $300 per MWh in NSW

Snowy Hydro shifted more NSW hydro capacity into higher price bands during 2024 and 2025, including a material shift from below to above $300 per MWh in July 2025. The available evidence suggests this mainly reflected tighter water availability and a need to conserve hydro resources, rather than conduct that led to higher average prices being set.

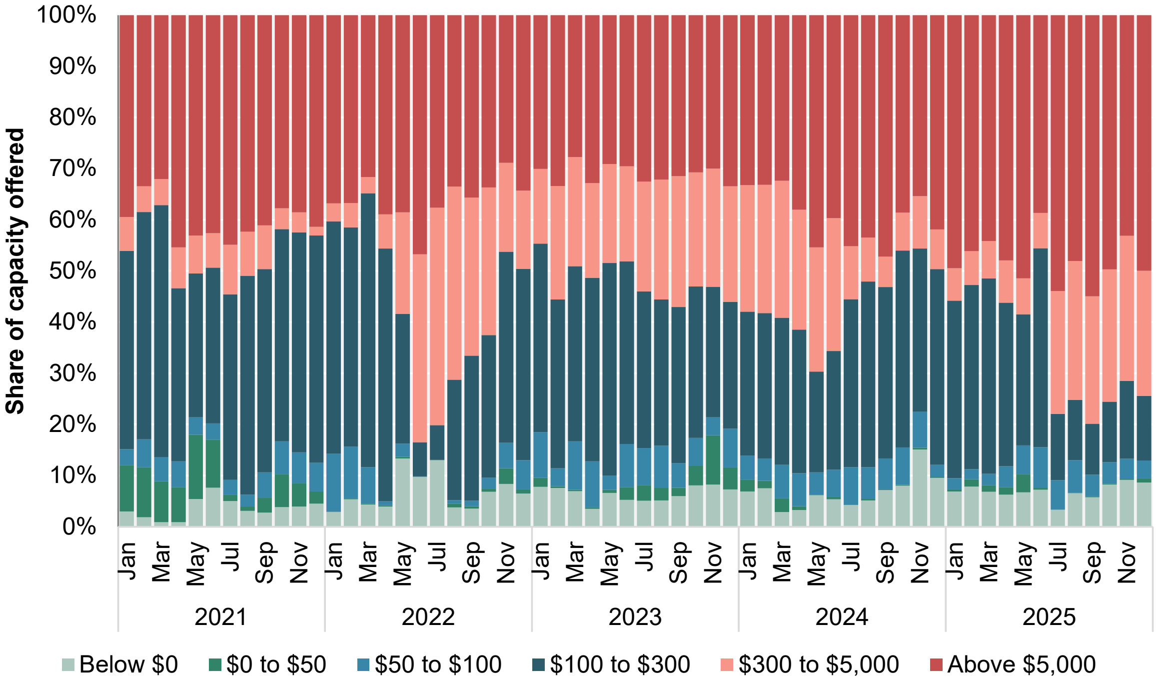
Snowy Hydro owns a significant share of capacity in NSW, including 59% of firming capacity. As a result, its offers are a significant contributor to regional outcomes, particularly when firming capacity is needed.

Most of Snowy Hydro's generation output comes from its hydro assets, particularly the 1,500 MW Tumut 3 and 616 MW Upper Tumut power stations. A variety of factors impact the value of water and how Snowy Hydro offers its capacity into the market. For example:

- Hydro generation is constrained by water availability and environmental water release limits. Generation must also be carefully managed around projected water availability, electricity demand and availability of other generation. As a result, the marginal offers from hydro generators can be influenced by the behaviour of other fuels, particularly coal and gas.
- Tumut 3 is a pumped hydro station, meaning it can function like a large battery, purchasing electricity off the spot market to refill its dams, enabling it to generate more in the future. But this also means its behaviour is influenced by pumping costs and by the expected spread between the price it expects to pay to pump versus the price it expects to receive from generating.
- Hydro assets can receive revenue from large-scale generation certificates (LGCs) if they generate more than a pre-set baseline in a given year. This can increase the incentive to generate if they are close to reaching the baseline or have exceeded the baseline and are able to earn generation certificates. The value of LGCs fell considerably in 2025. After ranging between $40 and $60 per MWh from 2021 to 2024, the LGC price was $32.25 per MWh on 1 January 2025 and fell to just $6.25 per MWh by the end of 2025. As a result, the potential for LGC revenue is likely having a diminishing impact on participant incentives.

Snowy Hydro offered a progressively larger share of its capacity above $5,000 per MWh throughout 2024 and 2025 (Figure 5.27). In July 2025, it also shifted a significant volume of capacity from below to above $300 per MWh. These offer changes contributed to a decline in Snowy Hydro's NSW generation output over this period.

Figure 5.27 Share of Snowy Hydro's NSW capacity offered in different price bands



Note: Monthly average proportion of capacity offered by Snowy Hydro in NSW, in each price band. The chart includes units for which we consider Snowy Hydro to hold trading rights, which may differ from AEMO registration. Trading rights are allocated based on ownership of each unit's output where available, and asset ownership otherwise. Output is allocated pro rata where ownership changed during 2025 or where multiple owners hold interests in a unit.
Source: AER analysis using NEM data and other publicly available information.

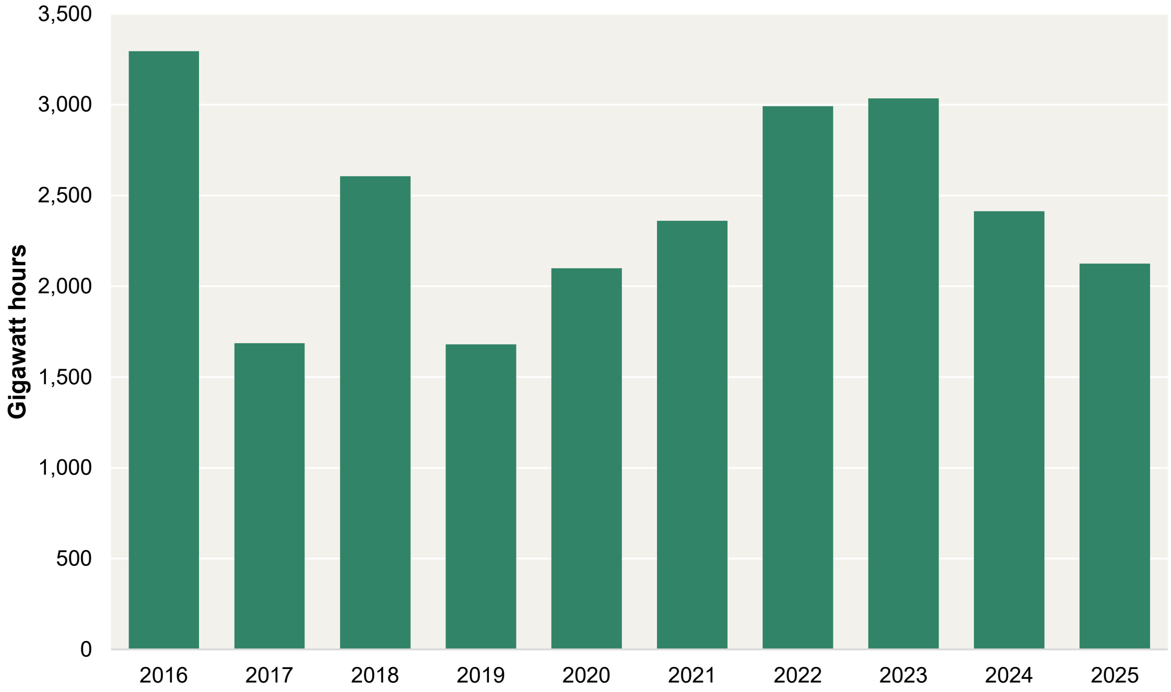
It appears that these changes were driven by a need to conserve water. In both the 2023–24 and 2024–25 water years,[64] inflows to Snowy Hydro's dams were lower than expected.[65] Across 2023–24, the level of storage fell by 659 gigalitres to 2,526 gigalitres.[66] In addition, annual generation output from Tumut 3 and Upper Tumut fell in both 2024 and 2025 (Figure 5.28).

64 A water year is from 1 May to 30 April of the following year.

65 Snowy Hydro, Annual Report: For the Financial Year ended 30 June 2025, pp. 2, 38, accessed 11 June 2026.

66 Snowy Hydro, Generation: Water, accessed 13 June 2026.

Figure 5.28 Annual output from Snowy Hydro's hydro assets in NSW



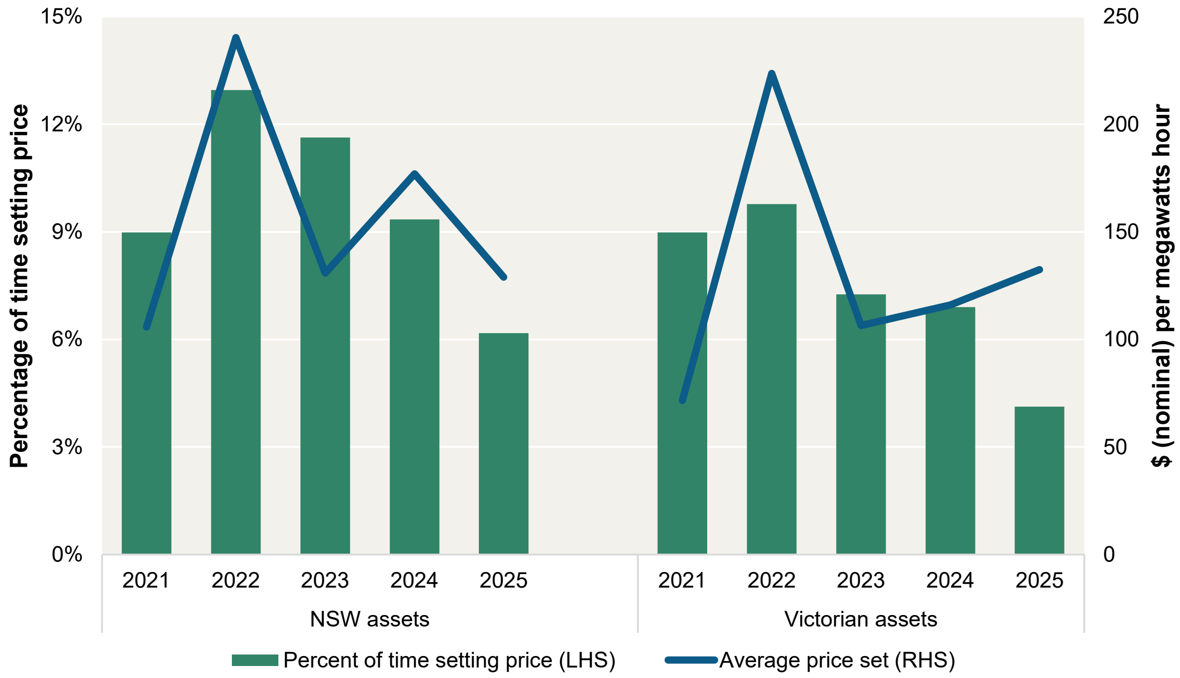
Note: Combined annual output from Snowy Hydro's Tumut 3, Upper Tumut, Guthega and Blowering power stations.
Source: AER analysis using NEM data.

Price-setting outcomes further support this. Since 2022, the frequency of Snowy Hydro's price-setting in NSW has consistently declined (Figure 5.29). It is likely that Snowy Hydro's repricing of capacity has contributed to it being the marginal supplier less often.

Average prices set by Snowy Hydro in NSW have also declined significantly compared with 2022, when market prices were high. While its NSW hydro assets set higher prices in 2024 than in 2023, these prices declined again in 2025. Snowy Hydro's Victorian assets generally set lower prices in NSW than its NSW assets, despite these prices increasing slightly in 2024 and 2025.

Over the same period, Snowy Hydro has signed power purchase agreements with wind and solar farms in NSW. These have allowed Snowy Hydro to access cheaper generation, as well as LGC revenue, without needing to rely as heavily on its hydro and gas assets.

Figure 5.29 Prices set by Snowy Hydro in NSW



Source: AER analysis using NEM data.

Overall, changes in Snowy Hydro's NSW offers have been associated with reduced dispatch and price-setting frequency, rather than an increase in prices set. This indicates that observed changes in behaviour are more consistent with shifts in supply conditions and water availability than with the exercise of market power to increase prices.

5.5 In Victoria, more capacity brown coal was offered above $50 per MWh, contributing to higher price-setting outcomes at times

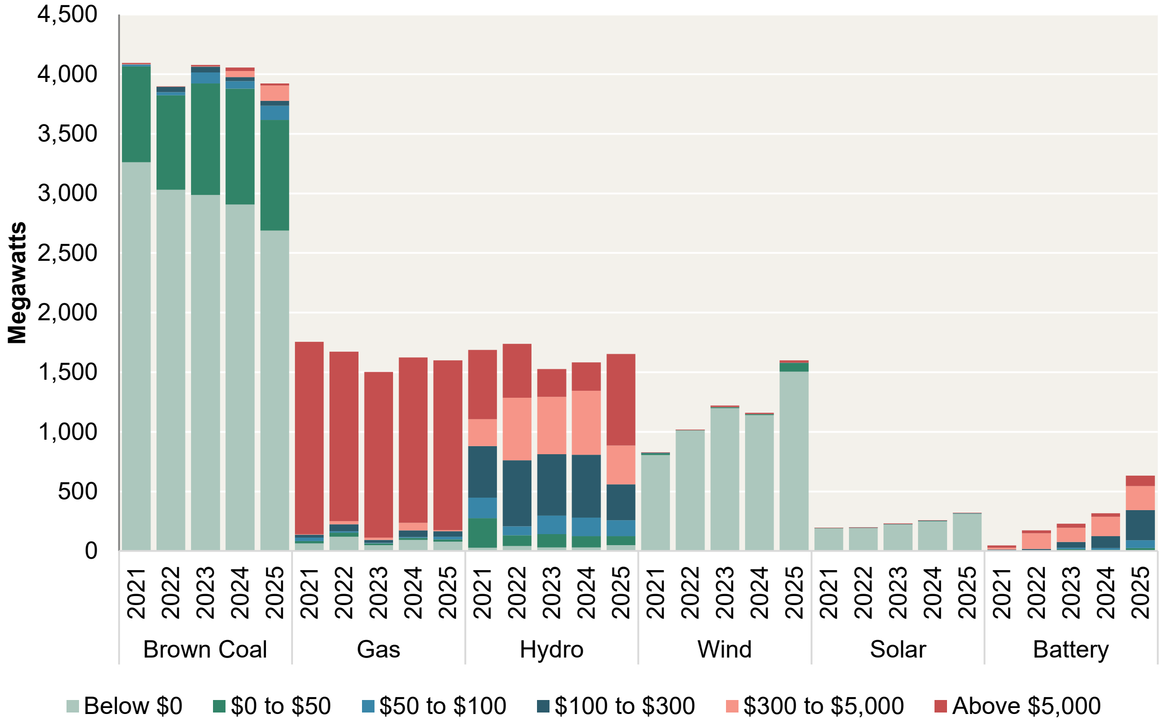
Victoria continues to have the lowest and least volatile wholesale prices in the NEM, supported by substantial low-cost brown coal generation and growing wind and battery capacity (section 5.2.4). However, offer behaviour has shifted within the brown coal fleet. In particular, Alinta Energy's Loy Yang B power station has moved some capacity from very low prices into higher price bands, which has contributed to higher price-setting outcomes at times.

Most brown coal capacity is offered into the market at low prices. However, the share of capacity that brown coal generators offer above $0 per MWh has been increasing in recent years. In 2025, capacity offered above $50 per MWh represented 8% of total brown coal capacity, but the shift is notable because brown coal remains a low-cost and important source of supply in Victoria (Figure 5.21).

Victoria also has substantial gas and hydro capacity. Most Victorian gas generators are peakers that typically offer into the market at high prices, with little change in this pattern in recent years.

Victorian hydro offers also shifted higher in 2025, with less capacity below $300 per MWh and substantially more capacity above $5,000 per MWh. This shift was largely driven by Snowy Hydro's 1,500 MW Murray power station, which accounts for most of the region's hydro capacity. As discussed in section 5.4, below-average dam inflows in 2023–24 and 2024–25 have likely contributed to this change in offers.

Figure 5.30 Victorian offers, by fuel type



Note: Annual average capacity offered by Victorian generators within price bands.
Source: AER analysis using NEM data.

Victoria has significant wind capacity. Wind offers increased substantially in 2025 following a dip in 2024 associated with lower wind conditions. Battery capacity offered also increased significantly in 2025, including at prices below $300 per MWh. Solar offers have increased modestly over the past 5 years.

Case study 4 – Alinta Energy offered more capacity above $50 per MWh and set higher prices

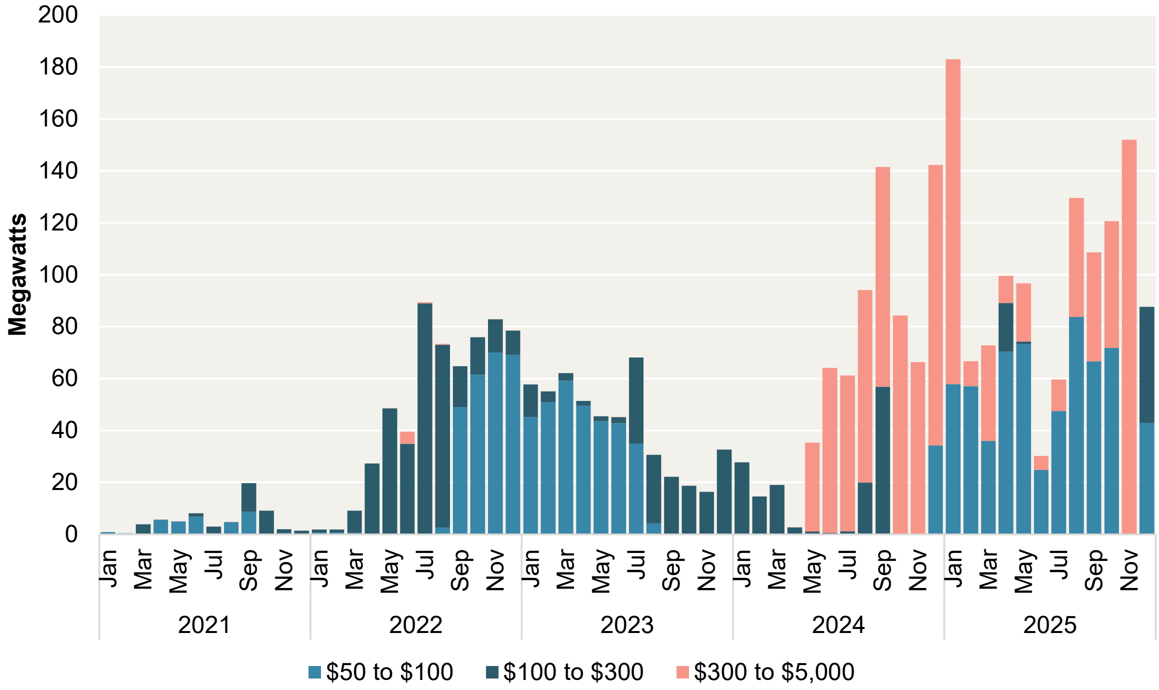
Alinta Energy was Victoria's second-largest participant by share of generation output in 2025. Its portfolio is dominated by the 1,000 MW Loy Yang B brown coal power station, with relatively small gas, wind and solar assets.

Alinta offered most of its capacity below $50 per MWh, which reflects the nature of its portfolio. Most of Loy Yang B's capacity is typically offered below $0 per MWh to ensure dispatch, with the remainder largely priced between $0 and $50 per MWh. Offers from Alinta's wind and solar assets are also mostly below $0 per MWh, while its gas-fired Bairnsdale plant is generally offered above $5,000 per MWh.

In recent years Alinta has increased the volume of capacity offered between $50 and $5,000 per MWh. In 2022 and 2023, additional capacity in this range was offered at Loy Yang B. In

2024, the volume at Loy Yang B declined, while some of Bairnsdale's capacity moved into the $300 to $5,000 per MWh range. In 2025, this capacity at Bairnsdale was repriced above $5,000 per MWh, while a material volume between $50 and $5,000 per MWh re-emerged at Loy Yang B (Figure 5.31).

Figure 5.31 Alinta Energy's capacity offered in Victoria between $50 and $5,000 per MWh

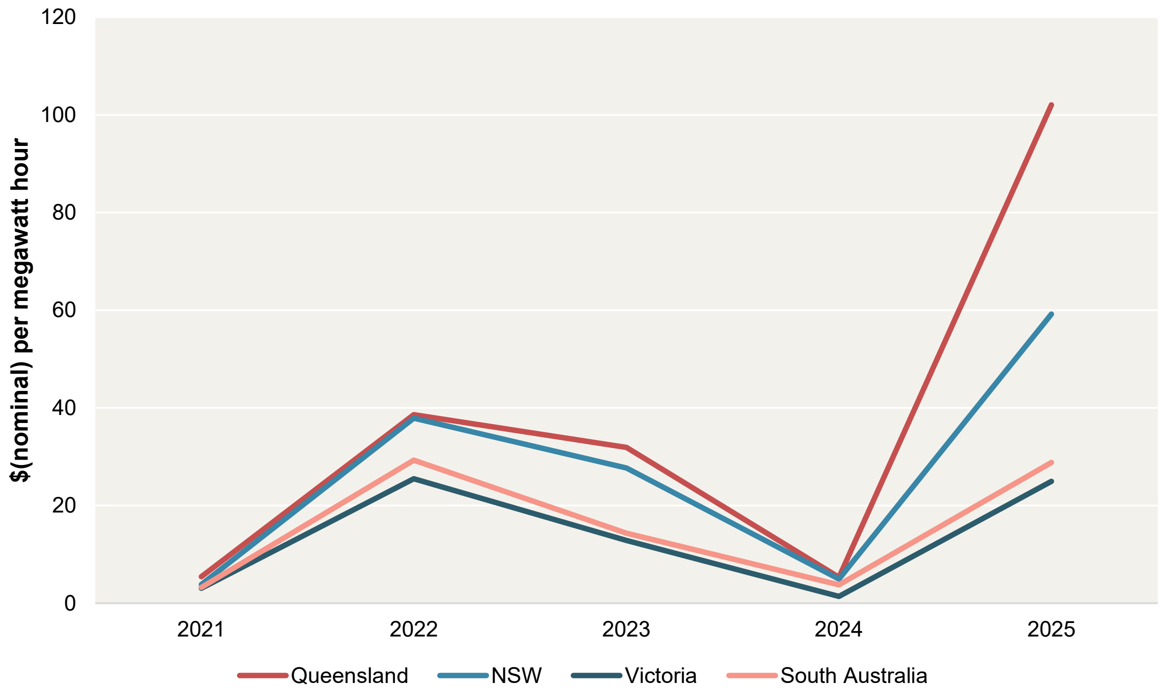


Note: Monthly average capacity offered by Alinta Energy in Victoria, in price bands between $50 and $5,000 per MWh. The chart includes units for which we consider Alinta to hold trading rights, which may differ from AEMO registration. Trading rights are allocated based on ownership of each unit's output where available, and asset ownership otherwise. Output is allocated pro rata where ownership changed during 2025 or where multiple owners hold interests in a unit.
Source: AER analysis using NEM data and other publicly available information.

The timing of these higher-priced offers suggests more than one driver. Much of this capacity was offered during the middle of the day, consistent with Loy Yang B seeking to avoid dispatch during periods of negative prices. Some capacity was also offered at these prices overnight, when prices are typically higher, suggesting the shift was not solely a response to negative daytime prices.

Price-setting outcomes further support this interpretation. The average price set by Loy Yang B increased across all regions in 2025 (Figure 5.32). In Victoria, the average price set by Alinta remained moderate at around $25 per MWh, but there was substantial monthly variation. In June, Loy Yang B set the Victorian price 5% of the time and at an average of $135 per MWh. In other regions, Loy Yang B set the price less frequently, but at higher average prices.

Figure 5.32 Prices set by Loy Yang B power station in each region



Note: Annual average price set by Alinta Energy's Loy Yang B power station in each mainland NEM region.
Source: AER analysis using NEM data.

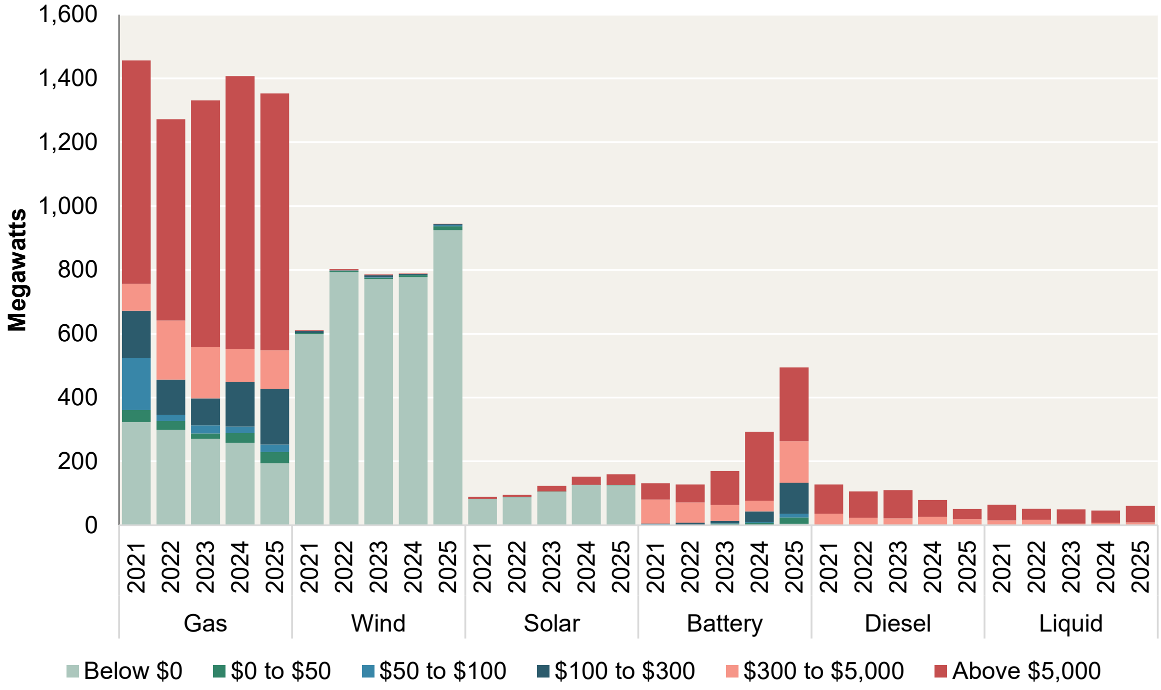
Overall, while most of Alinta's capacity in Victoria continues to be offered at low prices, a portion is offered at higher prices, which has contributed to setting higher prices at times. However, Victorian wholesale electricity prices continue to be the lowest and least volatile in the NEM.

5.6 AGL submitted more mid-priced offers in South Australia, but volatility remains high

South Australia remains the NEM region most exposed to price volatility because it has relatively limited low-priced and mid-priced dispatchable capacity and is positioned at the end of the grid, where its price is more likely to separate from other regions (section 4.4). Its predominant dispatchable fuel source is gas (Figure 5.33), but the amount of gas capacity offered at low prices has declined since the closure of AGL's Torrens Island A power station in 2020 and 2021. Against this backdrop, AGL increased the amount of capacity offered below $150 per MWh in late 2024 and 2025, particularly during evening peak periods.

High renewable penetration and declining minimum demand have at times made gas generation uneconomic in South Australia despite synchronous generation being required for system security. This led AEMO to direct some gas units to operate. Since May 2025, 2 non-market ancillary service contracts have procured the necessary system security services, reducing the need for directions (section 6.3.1).

Figure 5.33 South Australian offers, by fuel type



Note: Annual average capacity offered by South Australian generators within price bands.
Source: AER analysis using NEM data.

Renewable and battery offers continued to grow in 2025. Wind offers resumed growth after plateauing between 2022 and 2024, while solar offers continued to trend upward. Around 21% of solar capacity was offered above $5,000 per MWh, likely reflecting solar generators seeking to avoid dispatch during negative price periods.

Battery capacity also grew strongly and is now the third-largest fuel type in South Australia by offered capacity, with a greater share offered below $300 per MWh in 2025.

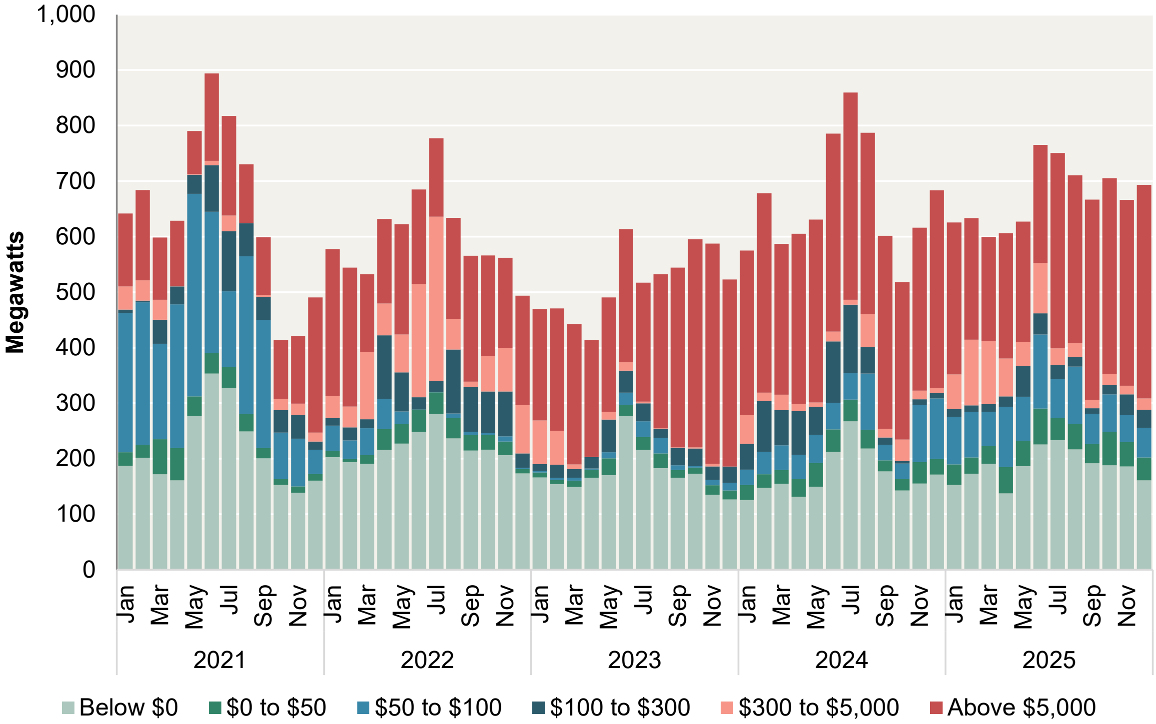
Case study 5 – AGL offered more capacity in South Australia below $150 per MWh, particularly at peak times

AGL is South Australia's largest participant, accounting for 23% of registered capacity and 21% of output in 2025. This share has declined over time due to new, more diversified generation entering and the closure of some of AGL's gas units.

At the end of 2025, AGL's South Australian portfolio comprised 1,011 MW of gas, 442 MW of wind and 280 MW of battery capacity. AGL typically offers most of its wind below $0 per MWh, while much of its gas and battery capacity is offered above $5,000 per MWh.

AGL's gas offers have shifted over time. In 2021, substantial capacity was offered below $100 per MWh. By 2022, most of this capacity had been removed or shifted to higher prices, coinciding with a significant increase in gas prices driven by Russia's invasion of Ukraine. In 2023, capacity offered between $0 and $5,000 per MWh was further reduced. Offers in these price bands partially recovered in late 2024 and 2025, with average capacity offered between $0 and $5,000 per MWh increasing from 72 MW in 2023 to 199 MW in 2025. Most of this increase in capacity occurred below $150 per MWh.

Figure 5.34 AGL offers in South Australia

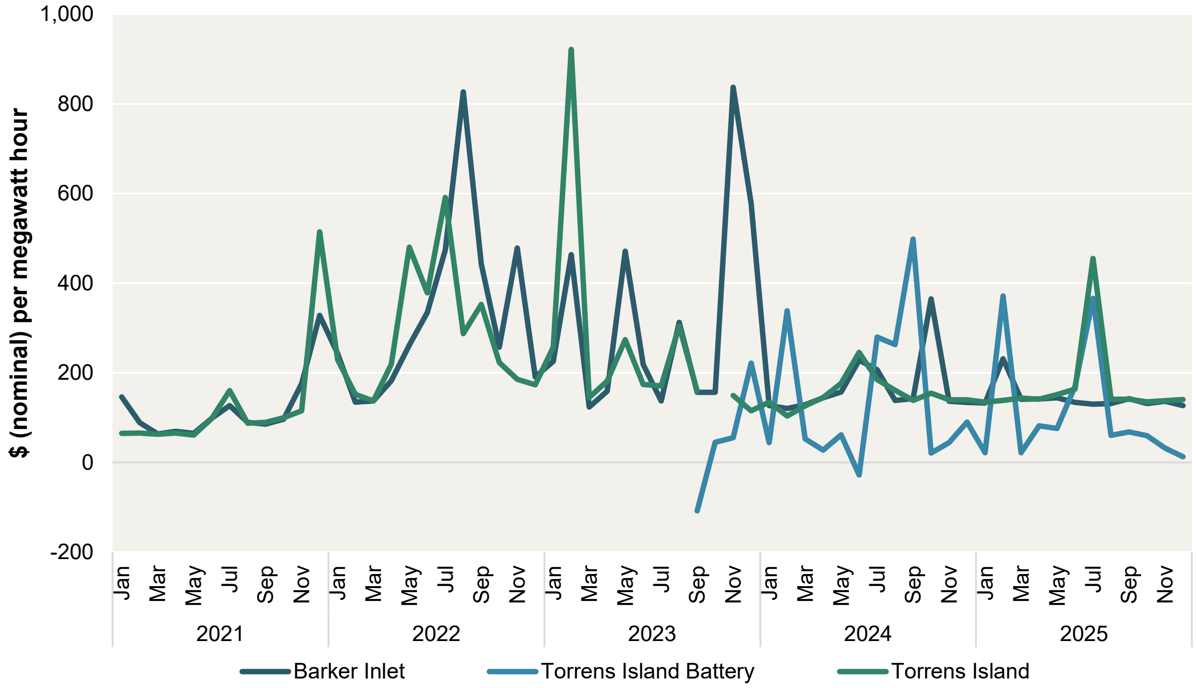


Note: Monthly average capacity offered by AGL in South Australia in each price band. Unlike other charts in the chapter, the chart uses a $150 price threshold instead of a $100 price threshold. The chart includes units for which we consider AGL to hold trading rights, which may differ from AEMO registration. Trading rights are allocated based on ownership of each unit's output where available and asset ownership otherwise. Output is allocated pro rata where ownership changed during 2025 or where multiple owners hold interests in a unit.
Source: AER analysis using NEM data and other publicly available information.

This matters because capacity offered in middle price bands reduces market volatility. South Australia has the smallest share of capacity offered between $0 and $300 per MWh of all NEM regions and some of the highest price volatility. It also has the lowest share of dispatch intervals with prices between $0 and $100 per MWh (Figure 2.2). Greater volatility increases risk and costs for participants. Volatility and high price events can also significantly impact average prices. In some high-priced years, such as 2024, volatility was a key driver – though in 2022, the main driver of high average prices was a shift in prices from below $100 per MWh to between $300 and $500 per MWh.

There are some indications that changes in AGL's offers are helping to moderate volatility. The increase in capacity offered below $150 per MWh has been most pronounced during evening peak periods, when prices tend to be more volatile. Consistent with this, AGL's Torrens Island and Barker Inlet power stations generally set lower and more stable prices in 2025, with monthly averages typically below $150 per MWh, aside from occasional spikes. The Torrens Island Battery has typically set even lower prices, but with greater variability.

Figure 5.35 Monthly average prices set by Torrens Island, Barker Inlet and Torrens Island Battery power stations in South Australia



Note: Monthly average price set by AGL's Barker Inlet, Torrens Island and Torrens Island Battery power stations in South Australia.
Source: AER analysis using NEM data.

Overall, AGL's increase in offers below $150 per MWh is a positive development because it adds capacity in the part of South Australia's offer stack that has been relatively thin. However, the scale of the shift is not large enough to materially change the region's structural exposure to volatility. South Australia continues to exhibit the highest spot price volatility in the NEM. Further increases in low-priced and mid-priced dispatchable capacity – through battery entry, increased imports or additional flexible generation – are likely needed to achieve a more sustained reduction in volatility. Project EnergyConnect may contribute to this once fully operational, noting the complexities associated with its looped transmission configuration (section 4.4.3).

5.7 Low-priced hydro offers in Tasmania are yet to recover, following a period of low rainfall

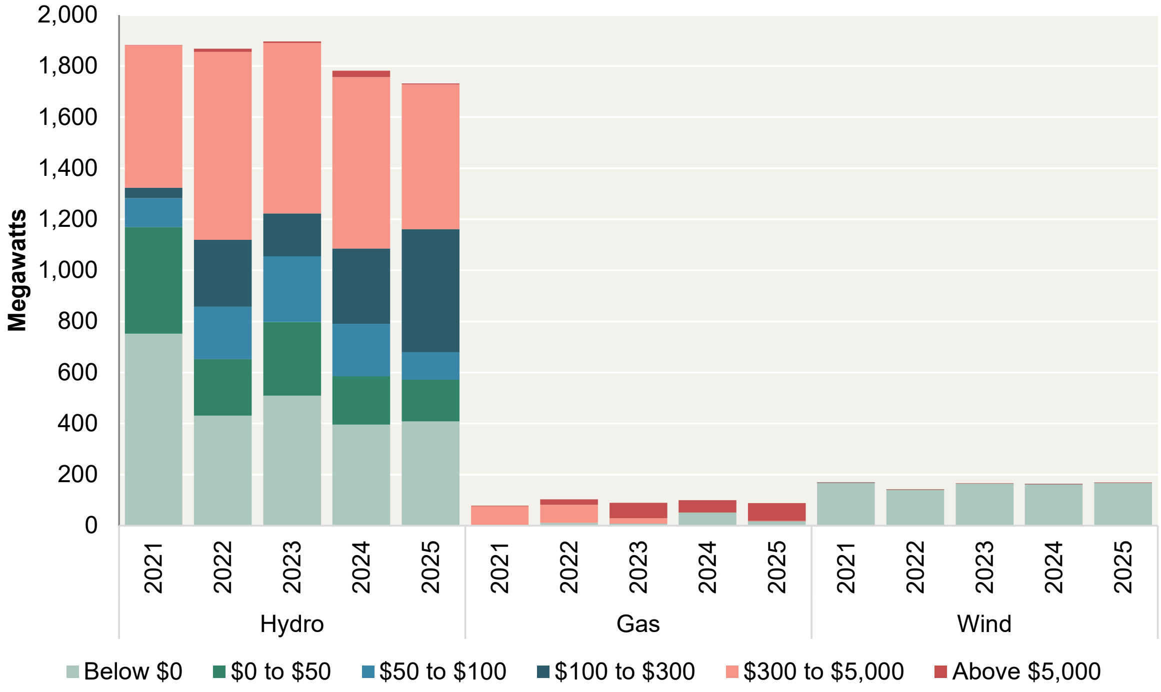
Hydro Tasmania reduced low-priced and mid-priced offers in 2022 and, after a partial recovery in 2023, shifted some capacity back to higher prices in 2024 and 2025. The persistence of higher-priced offers appears more consistent with lower rainfall and reduced hydro inflows than with a strategy to increase prices.

Hydro Tasmania controls most generation in Tasmania, so its offer behaviour largely determines offers in the region. However, the prices at which Hydro Tasmania may offer wholesale contracts are regulated, which may limit its incentive to exercise market power.

Hydro generation makes up most of Hydro Tasmania's portfolio, with wind and gas-fired generation comprising about one-quarter of its capacity. This means water availability is a key driver of offer behaviour, while Tamar Valley gas generation can provide backup when hydro inflows are low or winter demand is high.

Hydro Tasmania's offer behaviour has shifted in stages. In 2022, it reduced its low-priced and mid-priced offers (Figure 5.36) during a period of high NEM spot prices, likely to avoid using too much water. In 2023, as NEM spot prices partly returned to lower levels, some capacity was repriced back to lower levels. In 2024, Hydro Tasmania shifted some capacity back to higher prices and most of this remained at higher prices in 2025.

Figure 5.36 Tasmanian offers, by fuel type



Note: Annual average capacity offered by Tasmanian generators within price bands.
Source: AER analysis using NEM data.

The persistence of higher-priced offers appears to reflect water conservation rather than a strategy to push up prices. In 2023–24 and 2024–25, Tasmania experienced very low rainfall, which reduced inflows to its hydro reservoirs.[67] During this period, it ran its gas-fired assets at Tamar Valley Power Station more frequently than usual to manage the generation shortfall during peak winter demand. This included running its combined cycle gas turbine – which had not been used since 2019 – from 6 June 2024 to 23 August 2024 and again from 11 to 27 August 2025. Tasmania has also relied more heavily on imports from Victoria in recent years (section 4.4).

Overall, the evidence suggests Tasmania's reduced low-priced hydro offers are best understood as a response to constrained water availability.

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[67] Hydro Tasmania, 2025 Annual report, p. 14, accessed 16 May 2026; Office of the Tasmanian Economic Regulator, Energy in Tasmania Report 2024-25, p. 8, accessed 16 May 2026.

6 Entry and exit

Significant increases in new entry contributed to lower prices, but the outlook remains challenging with approaching coal exits and weak investment signals for most fuel types.

Key insights

- Between 2021 and 2025, NEM capacity grew by 17 GW. More than half of this new capacity entered the market after October 2024, materially increasing supply and contributing to lower prices.
- Government support remained a key driver of investment in new generation, but delivery remained mixed with few projects progressing from tender success to completed projects. Government involvement is likely to play a central role for the foreseeable future as governments progress development of the Electricity Services Entry Mechanism in response to the NEM Review recommendations.
- Batteries have the strongest outlook for new investment, but the recent fall in price spreads will affect the investment outlook. Wind, solar and gas all face weaker entry signals for different reasons: elevated construction costs for wind and gas, and weak revenue capture for solar. Solar projects may improve their investment outlook where they are developed as hybrids with batteries.
- More coal-fired generation capacity (6 GW) is scheduled to close over a 10-month period in 2028–29 than exited over the previous decade.
- The transition is changing how system security is maintained. New network support and control ancillary service (NSCAS) arrangements significantly reduced reliance on AEMO directions in 2025, but system security costs remained broadly the same. The reliability and emergency reserve trader (RERT) was not activated in 2025, but availability payments were incurred under interim reliability reserve (IRR) contracts.
- Rising network congestion costs indicate that current transmission access and pricing arrangements are not directing new generation to locations that minimise system costs. Policy measures and increased transmission investment may address some locational issues, but broader market design constraints are likely to continue limiting efficient use of network capacity.

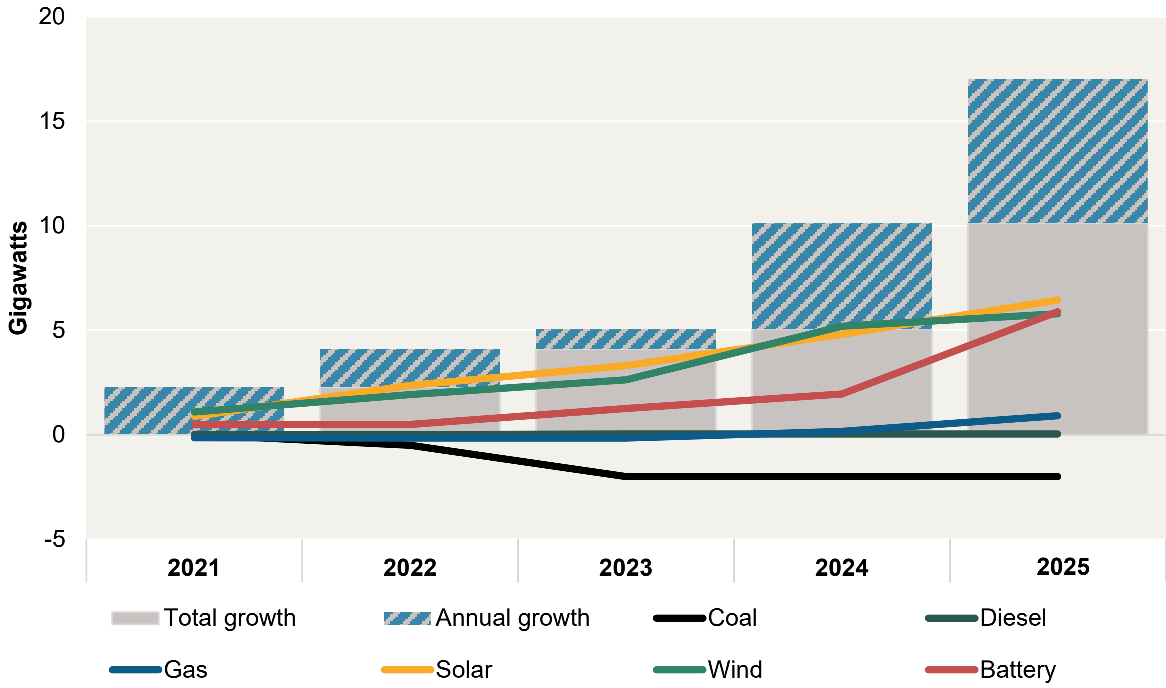
6.1 New entry

6.1.1 New generation capacity entering the market accelerated after October 2024

Between 2021 and 2025, NEM capacity grew by 17 GW. More than half of this new capacity entered the market after October 2024 (Figure 6.1). This marked a significant acceleration in generation growth, which contributed to lower wholesale prices (chapter 2) and increased market offers (chapter 5).

Solar (6.4 GW), battery (5.9 GW) and wind (5.8 GW) accounted for almost all new capacity added over the period. Gas-powered generation (904 MW) capacity also increased over the period, despite several closures, largely reflecting Tallawarra B entering in January 2024 and Snowy Hydro's Hunter Power Station turbines entering in the second half of 2025. Diesel (28 MW) capacity increased slightly, while coal (−2 GW) fell due to the closure of Liddell.

Figure 6.1 Net cumulative new capacity in the NEM



Note: Registered capacity is used for all fuel types except for solar and batteries where maximum capacity was used. The new entry date was taken as the first day the station received a dispatch target. Solar reflects large-scale solar and does not include rooftop solar PV systems.
Source: AER analysis using AEMO data.

While entry since October 2024 was strong, most of the new generation projects were still in the earliest stage of development as at April 2026 (345 GW). Only 13 GW had reached the committed stage (most advanced) and a further 24 GW was anticipated.[68] Committed generation projects were concentrated in batteries (6.5 GW), with smaller volumes of hydro (2.5 GW), solar (2 GW) and wind (1.7 GW).[69]

6.1.2 Price signals favour batteries and remain weak for other generation technologies

We assessed whether current market conditions provide a commercial incentive for new generation entry by comparing recent wholesale market revenues with the estimated cost of new investment for each technology. Where revenues are below costs, market incentives for entry are considered weak.

68 AEMO classifies the progress of proposed generation developments using 5 criteria. Committed projects meet all 5 criteria (land, contracts, planning, finance and construction), anticipated projects meet 3 criteria and publicly announced projects do not meet any of the criteria. AEMO, NEM Generation information publication, Australian Energy Market Operator, April 2026.

69 AEMO, NEM Generation information publication, Australian Energy Market Operator, April 2026.

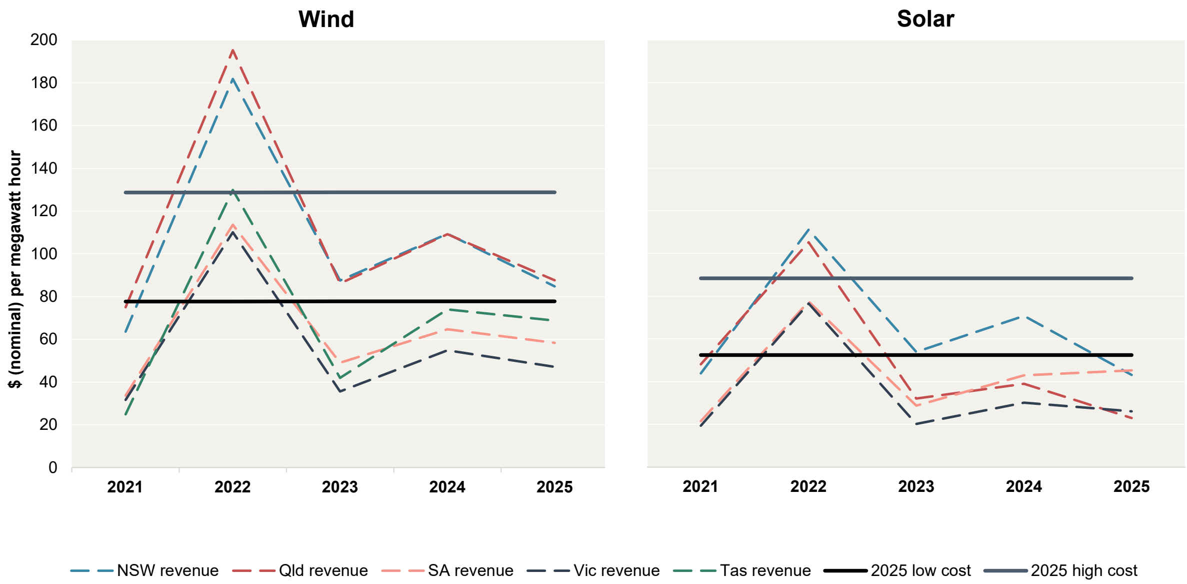
This comparison also provides an indication of where government support may still be needed. Technologies with stronger market-based investment signals are likely to require less support, while weak signals suggest a greater risk that governments may need to underwrite new entry.

The analysis indicates batteries currently have the strongest signal for new entry, but the recent fall in price spreads will affect the investment outlook. Wind, solar, gas and coal all face weaker investment conditions for different reasons. However, this analysis is only intended to be a proxy, because real-world investment decisions are based on a range of factors, including future expected revenue, contract arrangements, other market and non-market sources of revenue, as well as overall market conditions and confidence.

Wind and solar face different challenges – wind from higher costs and solar from weaker revenue

Solar and wind projects both face weak price signals (Figure 6.2), but for different reasons. Solar is relatively inexpensive compared with other types of technology and capital costs have decreased since July 2023.[70] However, grid-scale solar now earns lower wholesale market revenue because it competes against rooftop solar and does not generate at peak times.

Figure 6.2 Volume-weighted average revenue compared with costs for solar and wind



Source: AER analysis using AEMO data and levelized cost of electricity analysis conducted by CSIRO as part of its 2025–26 GenCost report.

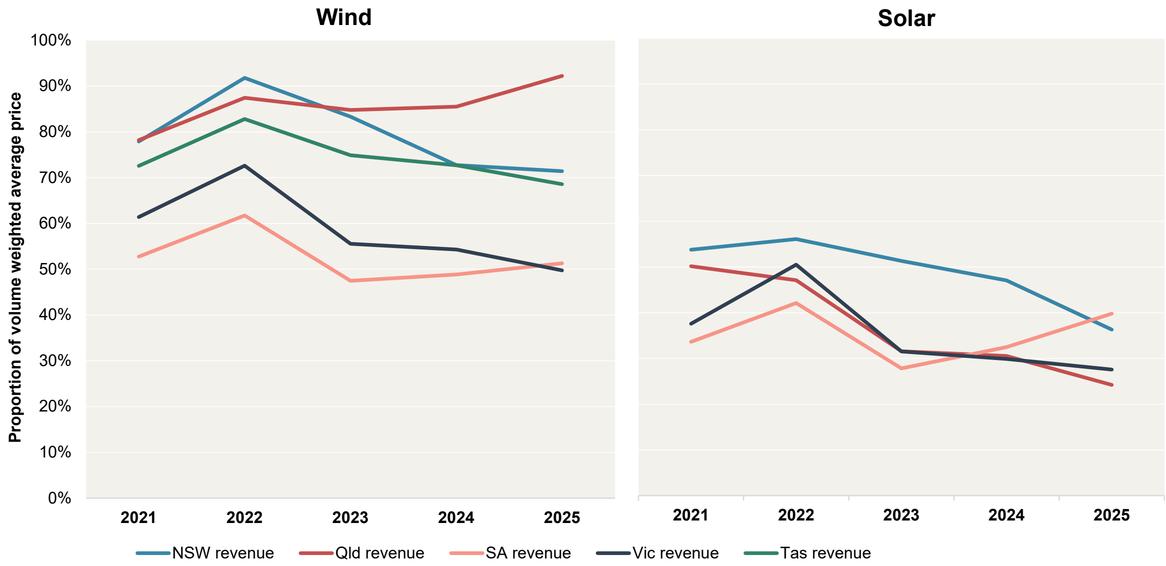
Wind generation is less exposed than solar to daytime revenue because it operates across a wider range of hours (Figure 2.13). However, this advantage is not sufficient to offset higher construction costs. Although wind capital costs decreased by 5% in 2025, they remain 47% above their pre-2022 levels.[71] Future business cases for wind and solar may weaken as

70 Costs for many technologies increased in 2022 following the COVID-19 pandemic due to global supply chain constraints.

71 CSIRO, GenCost 2025-26: Final report, July 2026, p. 22.

rising renewable saturation further suppresses wholesale market revenue (Figure 6.3). Renewable projects' revenues may be supported by increasing demand during periods of excess renewable generation, such as during the day when solar generation is optimal, either through increased storage or demand shifting. There is also an opportunity to locate future renewable projects at complementary resource sites or develop hybrid projects (combining solar or wind with a battery).

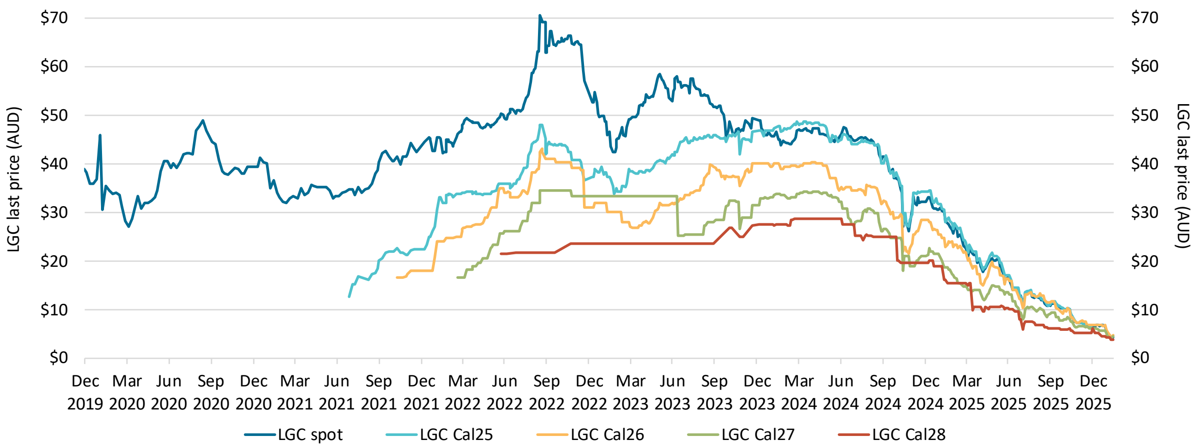
Figure 6.3 Wholesale market revenue for solar and wind compared to regional average



Source: AER analysis using AEMO data.

Large-scale generation certificates have previously supplemented wind and solar revenue and incentivised investment in renewable generation. However, certificate spot prices fell by 81% over 2025 and forward prices experienced similar declines (Figure 6.4). With the Renewable Energy Target scheduled to end in 2030, renewable projects will no longer be able to rely on the certificates to supplement wholesale market revenue.

Figure 6.4 Large-scale generation certificate spot and forward prices

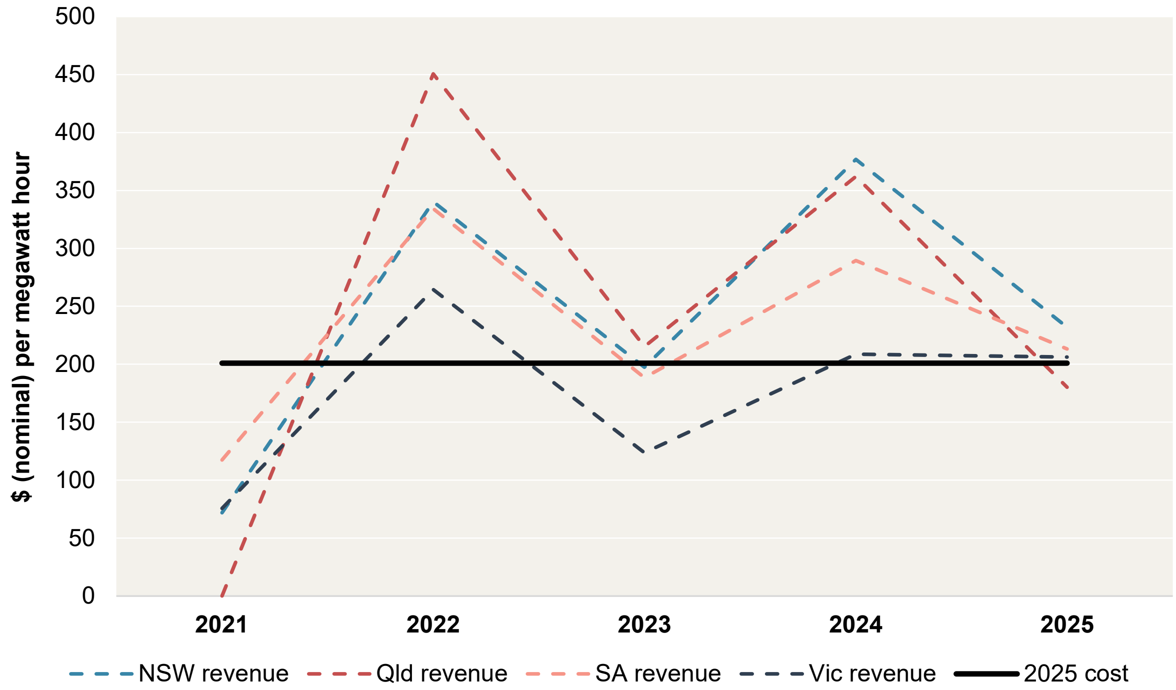


Note: Each large-scale generation certificate (LGC) is for 1 MWh of generation.
Source: Clean Energy Regulator.

Batteries have the strongest price signals for new entry, driven by high revenues and falling costs

Among the technologies assessed, batteries have the strongest standalone investment signal, combining strong revenue opportunities with rapidly falling costs (Figure 6.5). Batteries earn revenue from daily price volatility by charging at low prices and discharging during higher-priced periods. Batteries had the highest reductions in capital cost, decreasing by 32% since 1 July 2024.[72] Together, these factors give batteries the strongest market-based case for new entry. But the recent fall in price spreads will affect the investment outlook.

Figure 6.5 Volume-weighted average revenue compared with costs for 2-hour battery



Source: AER analysis using AEMO data and levelised cost of storage analysis conducted by CSIRO in its 2023 Energy Storage Roadmap and updated with data from its 2025–26 GenCost report.

Longer-duration batteries (4-hour and 8-hour batteries) have experienced similar decreases in costs.[73]

Rising costs and turbine shortages have weakened the case for new gas entry

The commercial case for new open-cycle gas generation has deteriorated as costs have risen rapidly and delivery has become more difficult (Figure 6.6). Construction costs for gas open cycle (large) generation increased sharply, up by around 67% since 1 July 2023 (and 93% since 1 July 2022),[74] which has materially worsened the investment outlook for new entry. The increased costs reflect higher turbine prices, tight equipment supply and persistently high construction costs. There are also challenges in acquiring turbines, with

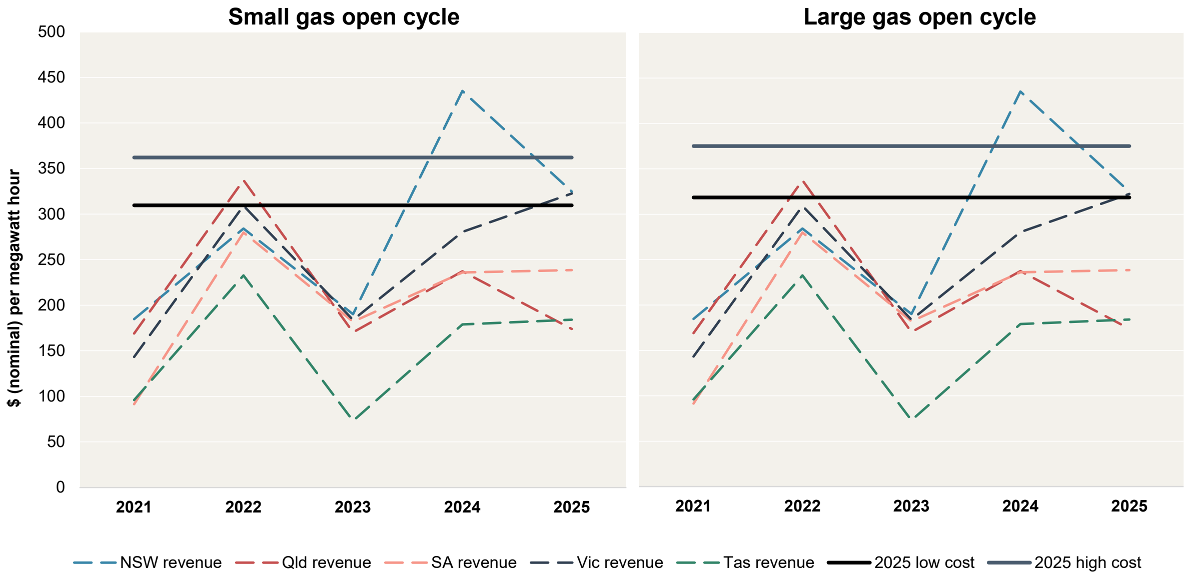
72 CSIRO, GenCost 2025-26: Final report, July 2026, p. 22.

73 CSIRO, GenCost 2025-26: Final report, July 2026, p. 24.

74 CSIRO, GenCost 2025-26: Final report, July 2026, p. 22.

reports suggesting wait times of 2 to 6 years.[75] Together, these factors suggest that new gas entry is becoming more difficult to justify on a commercial basis.

Figure 6.6 Volume-weighted average revenue compared with costs for large and small gas open cycle technology



Source: AER analysis using AEMO data and levelised cost of electricity analysis conducted by CSIRO as part of its 2025–26 GenCost report.

Black coal entry is not economically viable

Coal-fired generation is capital-intensive with high fixed costs that need to be recovered over long operating lives. This exposes any new investment to a heightened risk of asset stranding in a decarbonising market. Coal generation is also designed for continuous operation, rather than operation during peak price periods, which means it earns lower average wholesale market revenues than other dispatchable technologies that mainly operate during high priced periods.

Recent cost pressures have increased the cost of black coal without carbon capture and storage (CCS) by around 18% since 1 July 2024.[76] Due to these higher costs it is unlikely black coal could recover its costs. To avoid future carbon risk new coal investment may include CCS.[77] Black coal with CCS is even more expensive and as such unlikely to recover costs (Figure 6.7). There is currently no proposed investment for new coal-fired generation in the NEM.

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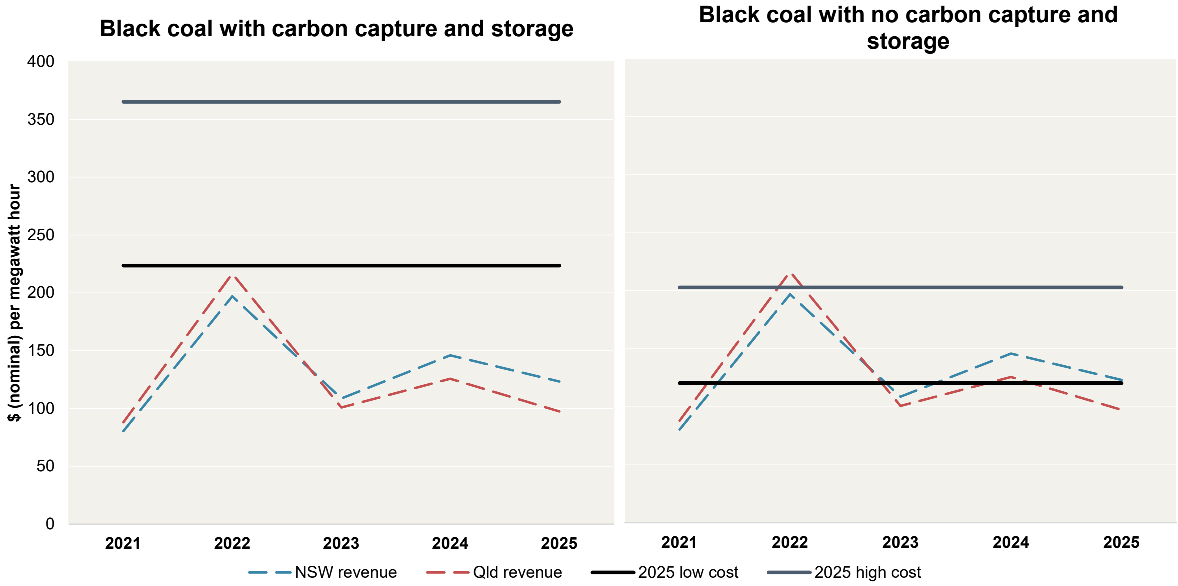
75 Bloomberg, The Gas Turbine Shortage Might Be a Climate Problem, October 2025; Wood Mackenzie, Gas turbine prices soar 195% as market faces supply-demand crisis, April 2026.

76 CSIRO, GenCost 2025-26: Final report, July 2026, p. 22.

77 Department of Climate Change, Energy, the Environment and Water, Net Zero, accessed 29 April 2026.

Figure 6.7 Volume-weighted average revenue compared with costs for black coal



Source: AER analysis using AEMO data and levelised cost of electricity analysis conducted by CSIRO as part of its 2025–26 GenCost report.

6.1.3 Government support remained a key driver of investment

A key driver of investment in new generation capacity has been direct and indirect government support. Government intervention was driven by the need to replace a rapidly aging coal fleet and meet emissions targets under Australia's Net Zero Plan.

Exchange-traded contracts are generally available around 3 years ahead, which is a short period relative to the life of new generation assets. This limits the ability of market prices alone to support long-term investment. While investors can secure revenue through longer-term contracts, such as power purchase agreements, these can be difficult to obtain, increasing reliance on government support.

Governments have adopted different approaches to support investment in new generation and storage. The Australian Government Capacity Investment Scheme, the NSW Energy Infrastructure Roadmap and the South Australian Firm Energy Reliability Mechanism reduce the risk of an investment by underwriting the projects following a tender process. These schemes share risk through revenue guarantees, with costs borne either by taxpayers or recovered from electricity consumers.

Victoria previously held auctions through the Victorian Renewable Energy Target but shifted toward increased public ownership through the Victorian Government-owned State Electricity Commission. The Victorian Government aims to deliver 4.5 GW of new renewable generation and storage by 2035 through investment via the State Electricity Commission. At July 2026, the State Electricity Commission has supported the entry of a 600 MW battery and has a pipeline of a 100 MW battery to be paired with a 119 MW solar farm and a separate 205 MW wind farm.[78]

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78 State Electricity Commission, Investments, accessed 9 July 2026.

The Queensland and Tasmanian governments use direct investment. Queensland's 2025 Energy Roadmap changed the state's approach to the energy transition and illustrated a broader form of intervention, with a direct role in managing both the transition and near-term reliability outcomes. The Roadmap directed $400 million for investment in renewables, gas and storage over the next 5 years, as well as $1.6 billion to improving existing state-owned coal, hydro and gas assets.[79]

6.1.4 Government schemes have supported projects, but delivery remains mixed

A successful tender outcome does not necessarily result in new capacity entering the market. The results of the second Victorian Renewable Energy Target auction were announced in October 2022 and projects were intended to be operational by the end of 2024.[80] To date, only one of the 6 solar farms is operational and 2 are still under construction.[81] The remaining 3 projects are yet to reach final investment decision as at April 2026.[82]

AEMO classifies the progress of proposed generation developments using 5 criteria (land, contracts, planning, finance and construction). Committed projects meet all 5 criteria, anticipated projects meet 3 criteria and publicly announced projects do not meet any of the criteria.

A relatively small proportion of successful Capacity Investment Scheme projects have progressed to financial commitment or completion. This likely reflects a range of factors, including project lead times, planning and approval processes and changes in project costs. To date, there have been 2 pilot tenders, including the joint tender with the NSW Energy Infrastructure Roadmap, and 5 full tenders for NEM generation or dispatchable investment. To date only 214 MW has been completed. Most of the approved capacity has only been publicly announced, with just 9.2 GW anticipated and 2.6 GW committed (Figure 6.8).

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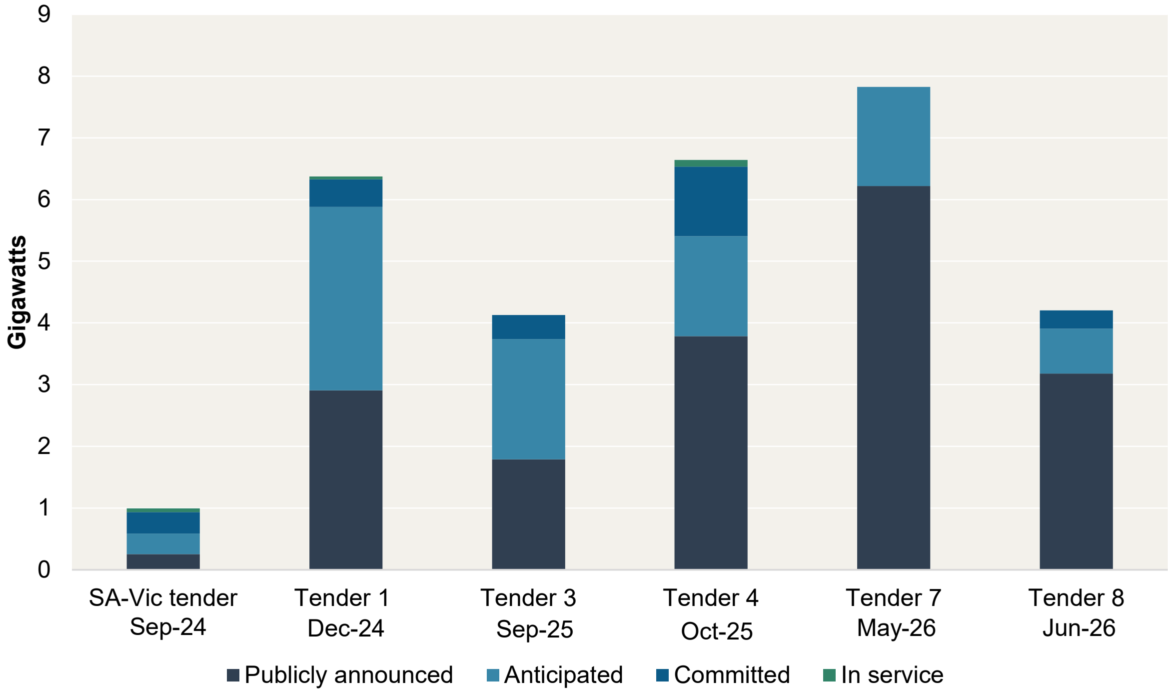
79 Queensland Treasury, Queensland Energy Roadmap, accessed 2 June 2026.

80 Victorian Auditor-General's Office, Managing the Transition to Renewable Energy, December 2025, p. 17.

81 The 2 projects are expected to commence generation in 2027, although one of these was acquired by the State Electricity Commission of Victoria prior to advancing. Victorian Auditor-General's Office, Managing the Transition to Renewable Energy, December 2025, accessed 16 June 2026.

82 AEMO, Generation information, Australian Energy Market Operator, April 2026.

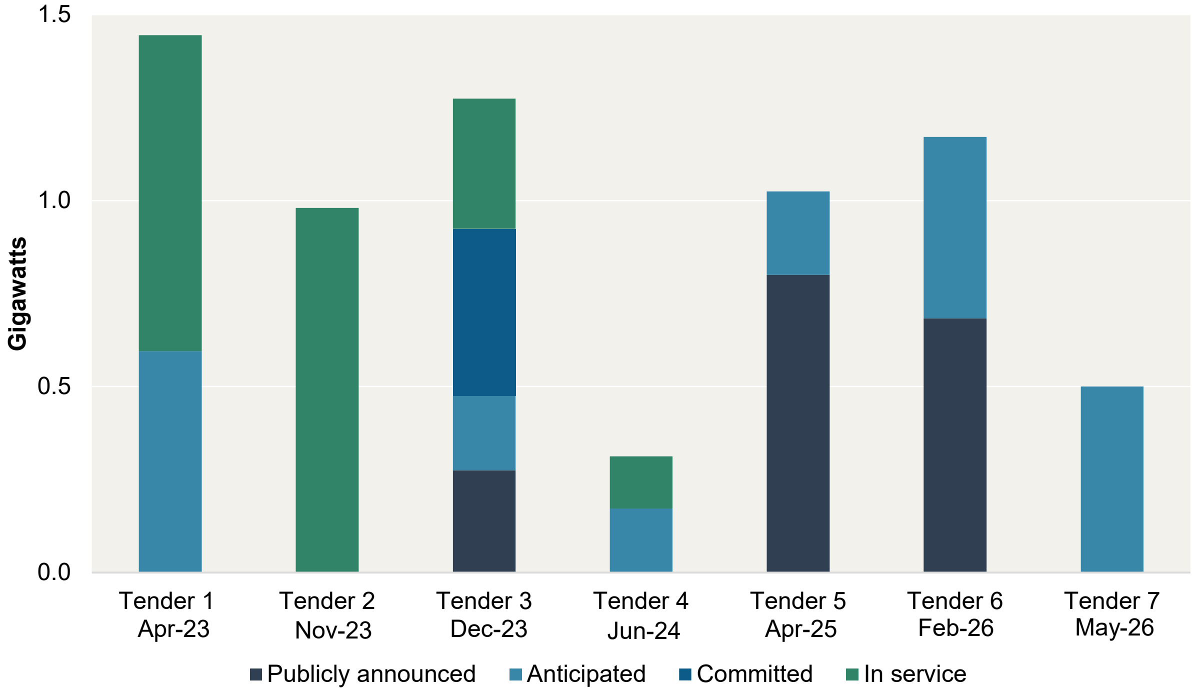
Figure 6.8 Australian Government Capacity Investment Scheme progress



Note: Tender 2 is not included because it was for the Western Australian Wholesale Electricity Market. The ‘In service’ category also includes projects that are ‘in commissioning’.
Source: AER analysis using Capacity Investment Scheme tender announcements and AEMO July 2026 Generator Information.

The NSW Energy Infrastructure Roadmap has translated a larger share of awarded projects into operating capacity than the Capacity Investment Scheme. However, a substantial share of successful bid capacity remains only anticipated or publicly announced. There have been 7 tender processes, including a joint tender with the Capacity Investment Scheme, which have supported the entry of 2.3 GW of new capacity since the Roadmap started in 2023. This new capacity is part of the 6.8 GW of new wind, solar and battery capacity awarded across 25 successful developments. Of the remaining successful bid capacity, 2.2 GW is anticipated, 449 MW is committed and 1.9 GW of capacity is only publicly announced.

Figure 6.9 NSW Energy Infrastructure Roadmap progress



Note: Demand response projects have not been included. The 'In service' category also includes projects that are 'in commissioning'.
Source: AER analysis using NSW Roadmap tender announcements and AEMO July 2026 Generator Information.

The South Australian Firm Energy Reliability Mechanism is designed to incentivise investment in long-duration dispatchable capacity (generation or storage that can continuously supply electricity for more than 8 hours). This generation is intended to complement variable wind and solar and reduce risks of supply shortfalls and price volatility. It operates through a Firm Energy Target, competitive tenders and long-term contracts to support both new and existing providers of firm capacity. The scheme was established in 2025, with capacity targets covering 2028, 2029 and 2031. On 29 May 2026, the outcomes of the first tender were announced, awarding support to 6 long duration (8-hour) batteries delivering 517 MW (4,136 MWh) of battery capacity, with this capacity forming part of larger project sites. As of July 2026, around half of the Tender 1 capacity is only publicly announced with the rest anticipated.

Taken together, these outcomes suggest that while government schemes have been important in bringing projects forward, they have not yet consistently converted awarded capacity into timely, delivered supply.

6.1.5 NEM Review proposed a plan for longer-term investment

Existing government programs are focused on delivering investment this decade, but substantial new capacity will still be needed after 2030. This creates a need for a more enduring market mechanism to support investment in zero-emission and dispatchable generation. In the absence of a long-term investment framework, weak market signals are likely to delay new projects, increasing costs and undermining reliability for consumers.

In late 2024, the Australian Government announced an independent review of the NEM. The panel's final report was provided to energy ministers in December 2025. In March 2026 energy ministers (other than Queensland) agreed in-principle to a coordinated package of reforms to address investment barriers.

The panel recommended energy ministers establish an Electricity Services Entry Mechanism (ESEM) to provide a long-term investment signal and procure bulk zero-emissions energy, shaping and firming generation. The mechanism includes a competitive tender process for standardised, fungible contracts to offer stable income streams tied to the delivery of defined electricity services. Detailed policy design is now underway and a draft legislative package is intended for endorsement and stakeholder consultation ahead of the first ESEM tender by the end of 2027.

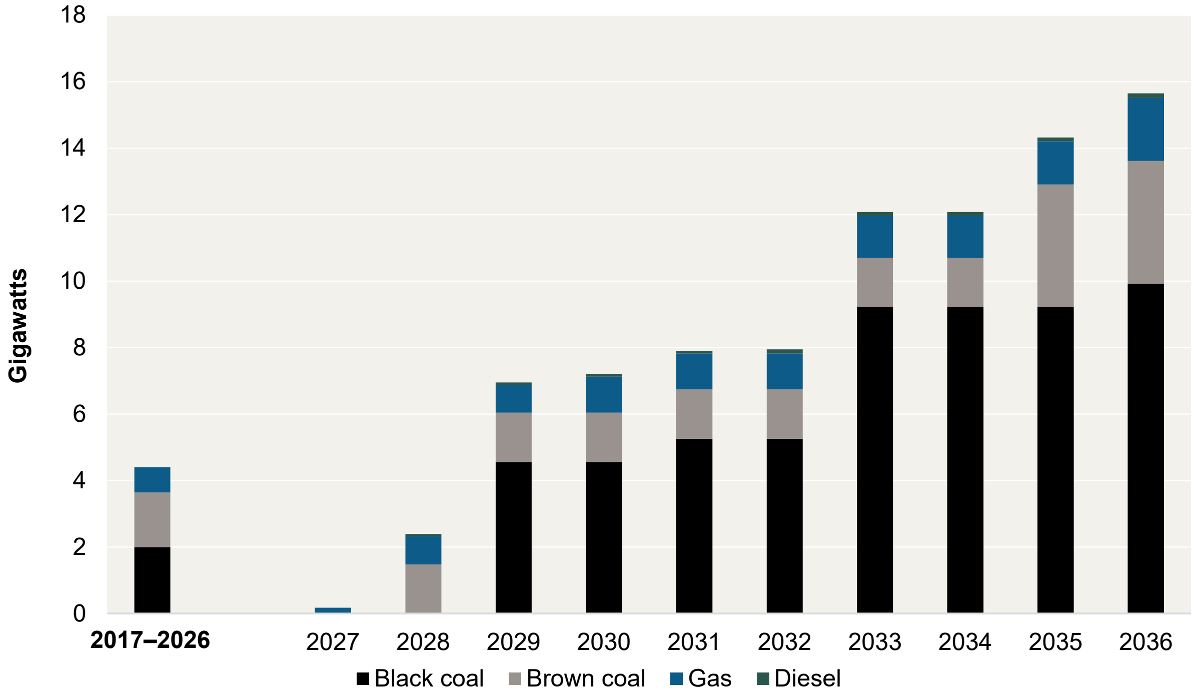
A notable feature of the proposed ESEM is support would only apply in the later years of a project's life when existing commercial contracting arrangements become more limited. This means projects would still need to secure market revenues in their early years – the mechanism is designed to address longer-term revenue risk rather than fully underwrite projects from the outset.

6.2 Exit

6.2.1 More thermal capacity is scheduled to exit in 10 months than exited over the previous 10 years

Thermal generation exit is set to increase over the next decade, with around 15.7 GW expected to close. Most of this is coal-fired generation, including 9.9 GW of black coal and 3.7 GW of brown coal, although smaller volumes of gas (1.9 GW) and diesel (143 MW) are also scheduled to exit (Figure 6.10).

Figure 6.10 Cumulative exit from the NEM

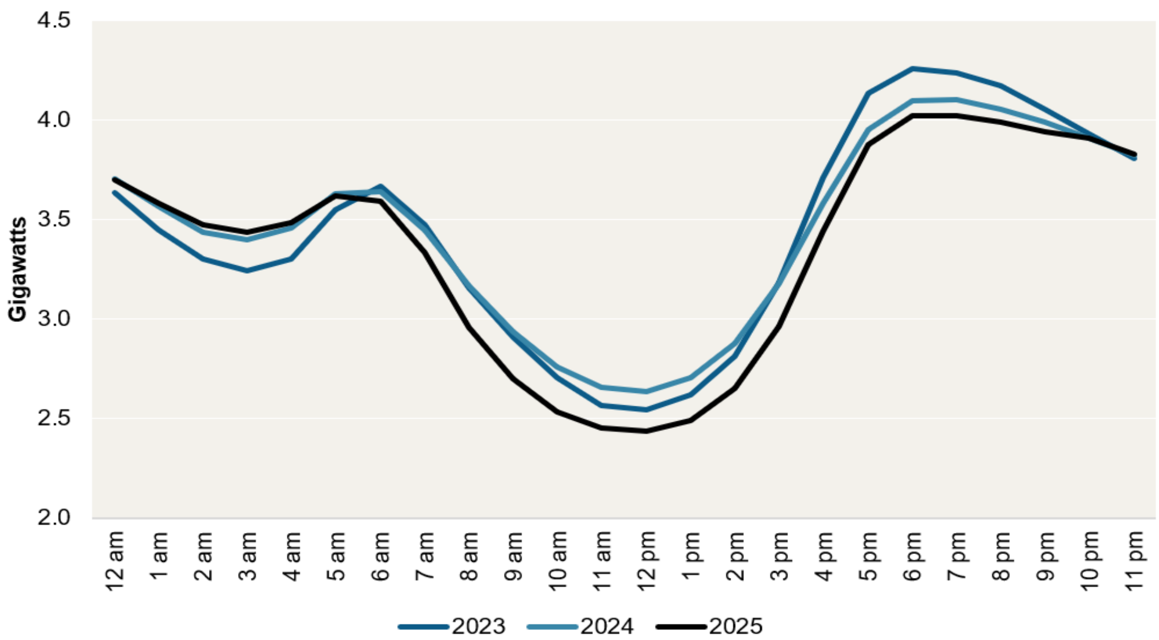


Source: AEMO, Generating unit expected closure year – July 2026.

The NEM's coal capacity has already fallen from around 30 GW across 26 stations in 2012 to around 21 GW across 15 stations as at April 2026. Half of the remaining coal fleet, representing around 13.6 GW, is scheduled to retire by 2036. The most recent coal-fired power station closure was the last 3 units at Liddell in NSW in April 2023. This means the NEM is moving from gradual coal exit to a period of more concentrated and material withdrawal of supply.

The next major closures are Victoria's Yallourn in 2028, followed in 2029 by Australia's largest power station, Eraring in NSW, and Gladstone in Queensland. Together, these 3 closures mean more capacity (6 GW) will close over a 10-month period than closed over the past decade. Because these are large, concentrated withdrawals rather than gradual retirements, they increase the risk of market volatility and reliability pressure if replacement capacity is delayed or does not align with demand. In 2025, these units provided around 4 GW on average at peak times (Figure 6.11). Peak average native demand in the NEM was 27.4 GW at 6:30 pm in 2025 (Figure 2.11). The average generation from these 3 generators may continue to decline as closure approaches and new generation enters the market.

Figure 6.11 Average output from Yallourn, Eraring and Gladstone



Source: AER analysis of AEMO data.

The price of base futures gives an indication of where market participants expect spot prices to be in the future and can feed into future retail prices. Many factors contribute to the market's expectation of future prices, including expected future supply conditions. It should be noted that contracts for 2028 and 2029 are currently thinly traded and prices can change over time. At 1 July 2026:

- Victorian base futures for the 4 quarters following the closure of Yallourn (July 2028 to June 2029) were trading at materially higher prices than the equivalent quarters in 2026 and 2027.
- NSW base futures for the 2 quarters following the closure of Eraring (July to December 2029) were trading at higher prices than the equivalent quarters in 2026, 2027 and 2028.

- Queensland base futures for the 2 quarters following the closure of Gladstone (July to December 2029) were trading at similar prices to 2027 and 2028.

6.2.2 Planned closure dates continue to change

The closure schedules continue to evolve, with closure dates for several power stations brought forward or delayed (Table 6.1Table 6.1 Expected thermal generator closure to 2036):

- Eraring (2,880 MW) – Eraring's closure timetable has shifted several times. Eraring was initially due to close in 2032 but its owner, Origin Energy, brought the closure date forward to 2025. In 2024, the NSW Government offered financial support to delay Eraring's closure until August 2027 and no later than April 2029. Origin extended operation until August 2027 but did not opt into the NSW Government's offer.[83] In January 2026, Origin Energy announced it would extend operation until 30 April 2029.
- Gladstone (1,680 MW) – In October 2025, Rio Tinto brought forward the closure of Gladstone Power Station from 2035 to 2029.
- Callide B (840 MW) – In April 2025, the Queensland Government announced it would extend operation of the Callide B Power Station from 2028 to 2031.
- The closure of 3 South Australian gas plants has been delayed – Osborne (180 MW) delayed one year to 2027, Torrens Island B (3 units, 600 MW) delayed 2 years to 2028[84] and Hallett (217 MW) delayed 4 years to 2036.
- The closure of 3 South Australian diesel-powered plants (Port Lincoln Gas Turbine units 1 and 3 and Snuggery, with a combined total of 136.5 MW) has been delayed by one year to 2028 after being brought forward from 2030.

Table 6.1 Expected thermal generator closure to 2036

Expected closure year	Region	Station	Fuel type	Registered capacity (MW)
2026	SA	Torrens Island B unit 1	Gas	200
2027	SA	Osborne	Gas	180
2028	SA	Torrens Island B units 2, 3 and 4	Gas	600
		Port Lincoln Gas Turbine units 1 and 3	Diesel	73
		Snuggery	Diesel	63

83 NSW Government, Media statement: Eraring power station, accessed 2 June 2026. In the 2024 agreement, the NSW Government offered to underwrite a portion of Origin Energy's potential financial losses if Origin agreed to share any profits with the government. Origin was required to notify the NSW Government if it wished to opt in to the risk-sharing arrangement but chose not to do so. The offer is not ongoing and ends in 2027.

84 Government of South Australia, Government negotiates energy security agreement, accessed 2 June 2026; AGL, Torrens Island B power station to close in 2026, November 2022. AGL reached an agreement with the SA Government to keep 3 units at Torrens Island B operating until 30 June 2028, after announcing in November 2022 that it would close the gas plant in 2026.

Expected closure year	Region	Station	Fuel type	Registered capacity (MW)
	Vic	Yallourn W units 1, 2, 3 and 4	Brown coal	1,480
2029	NSW	Eraring units 1, 2, 3, and 4	Black coal	2,880
	Qld	Gladstone units 1, 2, 3, 4, 5 and 6	Black coal	1,680
2030	SA	Dry Creek Gas Turbine units 1, 2 and 3	Gas	156
		Mintaro Gas Turbine	Gas	90
2031	Qld	Callide B units 1 and 2	Black coal	700
2032	NSW	Eraring Gas Turbine	Diesel	42
2033	NSW	Vales Point units 5 and 6	Black coal	1,320
		Bayswater units 1, 2, 3 and 4[85]	Black coal	2,640
	Vic	Somerton	Gas	170
2035	Vic	Loy Yang A units 1, 2, 3 and 4	Brown coal	2,210
	Qld	Barcaldine	Gas	37
2036	SA	Hallett	Gas	217
	NSW	Hunter Economic Zone	Diesel	28
	Qld	Tarong units 1 and 2	Black coal	700
		Swanbank	Gas	385

Source: AEMO, Generating unit expected closure year – July 2026.

6.3 Changing system needs

6.3.1 The transition is changing how system security is maintained

As thermal generation exits, system security is increasingly being maintained through dedicated services and interventions rather than as a by-product of synchronous generation. Services such as inertia, system strength and frequency response were traditionally provided by coal and gas units but now need to be procured or directed more explicitly.

AEMO has issued system security directions to market participants to maintain power system stability, requiring units to increase or decrease generation, provide frequency control ancillary services (FCAS) or follow specific dispatch outcomes. These directions have predominantly been required in South Australia due to lower levels of synchronous thermal

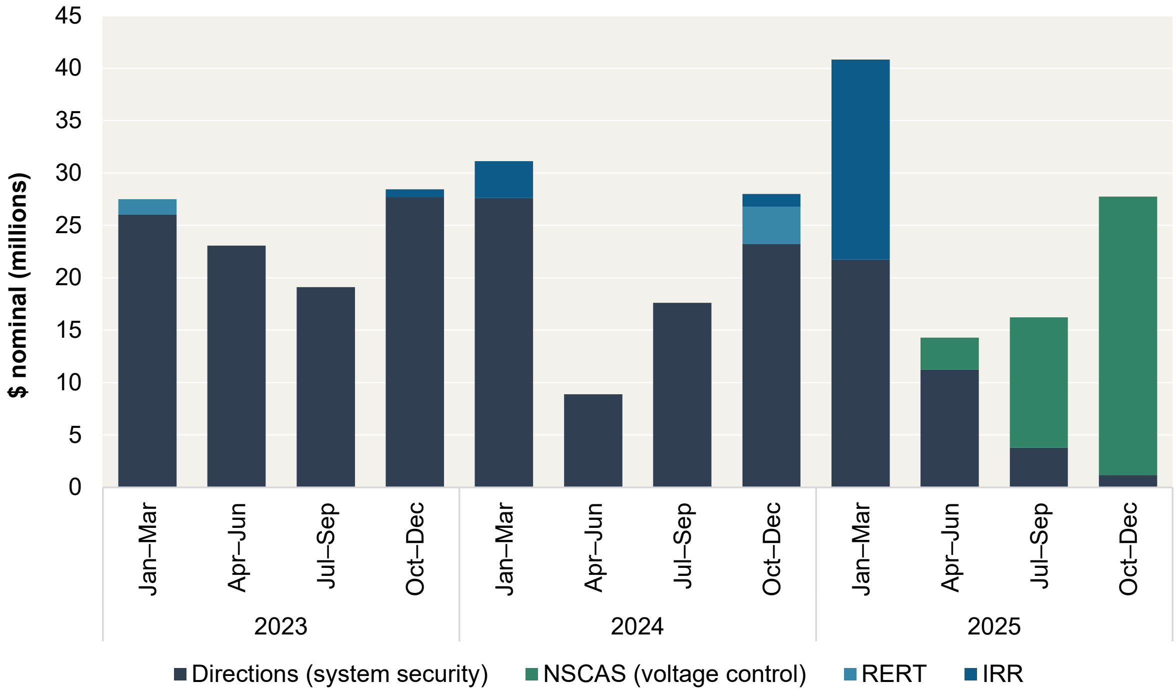
85 AGL, AGL in the Hunter Region, accessed 2 June 2026. AGL indicates Bayswater is expected to close between 2030 and 2033.

generation and weaker system strength. AEMO has also used its direction powers to maintain Minimum System Load in South Australia.[86]

In May 2025, 2 network support and control ancillary service (NSCAS) arrangements were introduced in South Australia. NSCAS are non-market ancillary services that provide pre-arranged capabilities to control power flows and system conditions on the transmission network and are used during normal operations to maintain power system security and reliability (including voltage, inertia and system strength requirements) or to increase network transfer capability. They are typically dispatched or activated as part of AEMO's routine operational toolkit, before more intrusive interventions are required.

The NSCAS introduction materially reduced reliance on directions, because NSCAS services are dispatched before directions are issued. The share of dispatch intervals with directions fell from 65% in October–December 2024 to 3% in October–December 2025, and direction costs fell from $23 million to $1 million. However, total system security costs remained broadly unchanged at around $28 million in both quarters, indicating that the reform reduced reliance on directions without materially lowering the overall cost of maintaining system security (Figure 6.12).

Figure 6.12 System security costs



Note: IRR: interim reliability reserves. RERT: reliability emergency reserve trader. NSCAS: network support and control ancillary service.
Source: AEMO, Quarterly Energy Dynamics Q4 2025, p. 45.

The reliability and emergency reserve trader (RERT) is an intervention that allows AEMO to contract for emergency reserves, such as generation or demand response, that are not otherwise available in the market. RERT is used as an emergency backstop after other

86 AEMO, Managing Minimum System Load, Australian Energy Market Operator; AEMO, QED Q4 2025, Australian Energy Market Operator, p. 44.

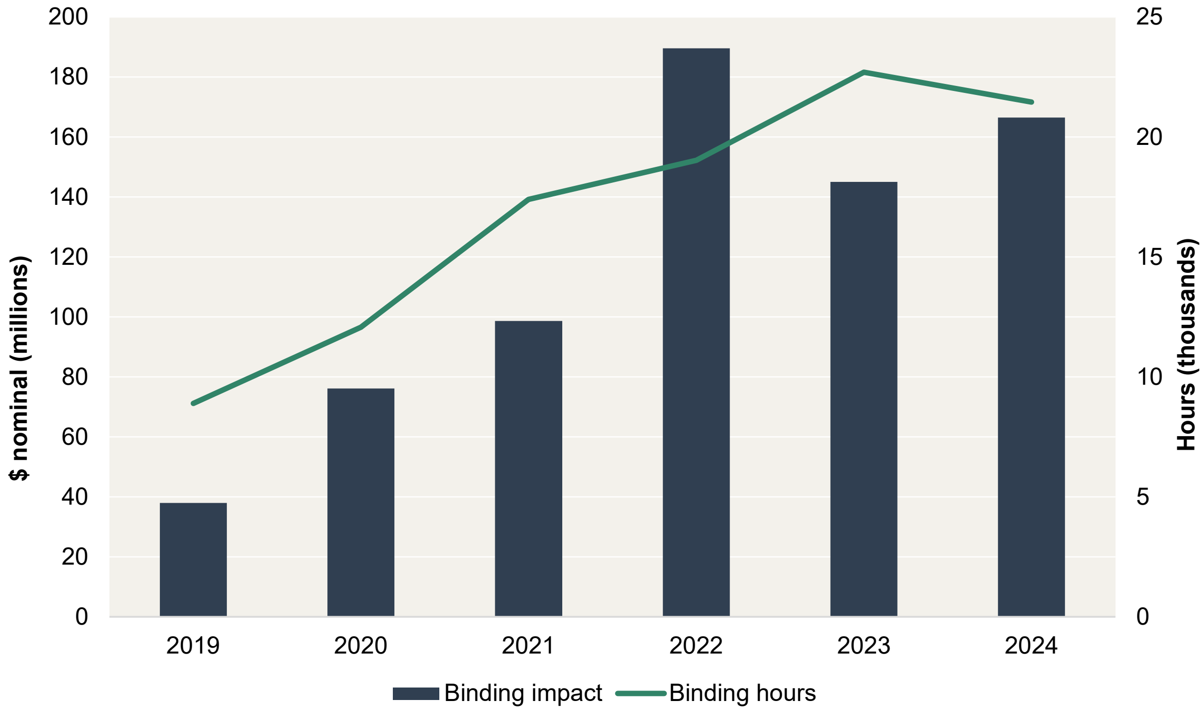
market options have been exhausted, typically during periods when the supply-demand balance is tight. Initially, RERT was rarely needed, only being used 3 times between 1998 and 2016. From 2017 to 2024, RERT was called on by AEMO every year, but in 2025 AEMO did not activate RERT. AEMO can also procure interim reliability reserves (IRR) up to 3 years in advance where it has forecast a reserve gap. There were $19 million in availability payment costs for IRR contracts in NSW and South Australia in January to March 2025 to address the reserve gaps identified in AEMO's 2024 Electricity Statement of Opportunities.

6.3.2 Network congestion continues to increase as new entry concentrates in constrained parts of the grid

The power system is transitioning from one dominated by a small number of large, consistently operating generators to one with a more decentralised and dynamic mix of low-emission technologies.

In this context, the adequacy of transmission access and pricing arrangements remains a concern. Network congestion trended up over the 5 years to 2024 (Figure 6.13), reflecting uncoordinated entry of new generation into constrained parts of the grid. While some congestion is a normal feature of an efficient network, persistent and excessive congestion suggests locational price signals are weak or absent, leading to inefficient investment outcomes. Rising congestion costs highlight the importance of improved coordination between transmission and generation investment to minimise system costs and impacts on consumers.

Figure 6.13 Duration and estimated cost of network congestion



Note: Data excludes impacts from FCAS, outages, network support and commissioning constraints. Further details can be found at AEMO congestion information.
Source: AER analysis of AEMO congestion information.

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AI	Artificial intelligence
ASX	Australian Securities Exchange
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DCCEEW	Department of Climate Change, Energy, the Environment and Water
ESEM	Electricity Services Entry Mechanism
FCAS	Frequency control ancillary services
FERM	Firm Energy Reliability Mechanism (South Australia)
GJ	Gigajoule
GW	Gigawatt
HHI	Herfindahl-Hirschman Index
IRR	Interim reliability reserve
ISDA	International Swaps and Derivatives Association
LGC	Large-scale Generation Certificate
MIC	Market impact component
MMIO	Market Monitoring Information Order
MWh	Megawatt hour
MW	Megawatt
NEL	National Electricity Law
NER	National Electricity Rules
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine

Term	Definition
NSCAS	Network support and control ancillary services
OCGT	Open cycle gas turbine
OTC	Over-the-counter
PEC	Project EnergyConnect
PPA	Power purchase agreement
PST	Pivotal supplier test
PV	Photovoltaic
RERT	Reliability and emergency reserve trader
SRA	Settlement Residue Auction
STPIS	Service target performance incentive scheme
TNSP	Transmission network service providers
TWh	Terawatt hour
VNI	Victoria to NSW interconnector
WEMPR	Wholesale electricity market performance report