



2 National Electricity Market

Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM). Generators make offers to sell electricity into the market and the Australian Energy Market Operator (AEMO) schedules the lowest-priced generation available to meet demand. The amount of electricity generated needs to match demand in real time, which means the amount being generated is continuously monitored and adjusted by AEMO. The market covers 5 regions – Queensland, New South Wales (NSW) including the ACT, Victoria, South Australia and Tasmania, and services around 11 million customers. The NEM is one of the world's longest interconnected power systems, stretching from Port Douglas in Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania.

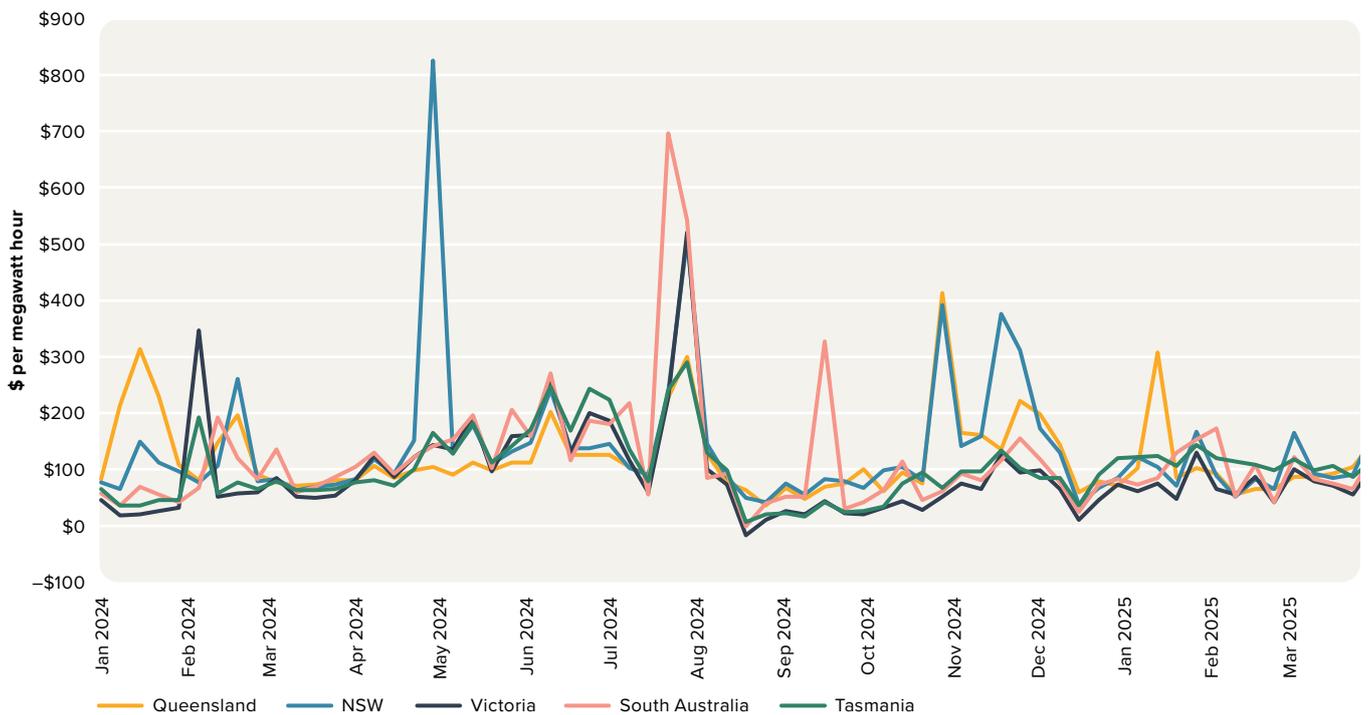
2.1 Snapshot

In the 2024 calendar year:

- Average wholesale spot prices across all regions of the NEM were higher than in 2023. Drivers included weather-related price spikes, network and generator outages and higher average demand levels. While prices were lower than the record levels reached in 2022, they were higher than pre-2022 levels.
- The proportion of prices below \$0 per megawatt hour (MWh) and above \$300 per MWh was slightly higher than in 2023. Compared with 2020, a significantly higher proportion of prices were at either end of the price spectrum. This trend has been driven by greater fluctuations in intra-day demand and by a decrease in mid-priced electricity offers.
- Demand was higher than in 2023 at all times of day, but especially during the evening peak and overnight. Before 2023, electricity demand in the NEM had declined significantly during the middle of the day, mostly due to widespread adoption of rooftop solar and the consequent reduced reliance on grid electricity during daylight hours. In contrast, demand had increased during early morning and evening peak hours, when solar output is usually low and household electricity use is high.

- The increase in electricity demand compared with 2023 was met by increased generation from a range of fuel types. Wind and solar generation increased, reflecting new entry of generation capacity. This was partly offset by a decrease in NEM hydro output, driven by the dry conditions in Tasmania. The remaining gap was filled by increased coal (helped by reduced outages) and gas-powered generation. Due to the higher use of fossil fuels, greenhouse gas emissions from electricity generation were slightly higher in 2024 than in 2023.
- Over 5 gigawatts (GW) of new solar, wind, battery and gas capacity entered the market, mostly in the second half of the calendar year. This was the largest annual new entry of capacity of the energy transition to date. A significant number of fossil fuel generators are scheduled to exit the market by the end of 2027. One new gas and one hydro power station are scheduled to come online during that time, but for the most part the closures will be replaced with new solar and wind generation and with battery storage. There were no generator closures in 2024.

Figure 2.1 Weekly average wholesale electricity prices



Note: Volume-weighted weekly average prices. Price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER; AEMO (data).

2.2 NEM overview

Nearly 400 generating units produce electricity for sale into the NEM (Figure 2.2). A transmission grid carries most of this electricity along high-voltage power lines to industrial energy users and local distribution networks (chapter 3, section 3.3). Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial and industrial energy users.

Figure 2.2 NEM key statistics



Note: MW: megawatts; B: billion; Mt CO₂-e: millions of tonnes of carbon dioxide equivalent. The change in renewable generation percentage share is expressed as a percentage point (pp) change (which is the absolute difference between 2 percentages) rather than as a per cent change. Data period is calendar year. Installed capacity and number of generating unit metrics are as at the last day of the relevant calendar year.

Source: AER; AEMO (data); Clean Energy Regulator (data); Department of Climate Change, Energy, the Environment and Water (data).

Box 2.1 How the NEM works

The NEM consists of a wholesale spot market for selling electricity and a transmission grid for transporting it to energy customers.

Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Bidirectional units, such as pumped hydro and batteries, make offers both to consume power and to provide power to the market. Similarly, scheduled loads, such as smelters, may offer to reduce their consumption as a substitute for generation. Since 2021, consumers (either directly or through aggregators) have also been able to do this (demand response).²⁷ Electricity generated by rooftop solar systems is not traded through the NEM – except for when it is offered as demand response – but it does lower the demand that market generators need to meet.

A separate price is determined for each of the 5 NEM regions. When interconnectors between regions are free-flowing, prices will be very similar across regions (with minor differences caused by transmission losses). When interconnectors are constrained (or reach their full capacity), substantial price differences between regions can emerge.

Prices in the market have a price cap and floor. In 2022 the market price cap was reviewed and set to increase year on year until reaching \$22,800 in 2027–28 (in 2022 dollars).²⁸ The market price cap is adjusted annually in line with inflation. In 2024–25, a market price cap of \$17,500 per megawatt hour (MWh) applied, along with a price floor of –\$1,000 per MWh. The price cap rose to \$20,300 on 1 July 2025.²⁹ The market floor price remains unchanged for now but the Reliability Panel will consider it as part of the 2026 Reliability Standard and Settings Review, which commenced on 19 June 2025.³⁰

As the power system operator, AEMO uses forecasting and monitoring tools to track electricity demand, generator offers and network capability to determine which generators should be dispatched to produce electricity in 5-minute blocks for every region. It dispatches the cheapest generator bids first, then dispatches progressively more expensive offers until enough electricity can be produced to meet demand.

27 Large customers can participate through the wholesale demand response mechanism and small customers can participate through their retailers in virtual power plants (VPPs).

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

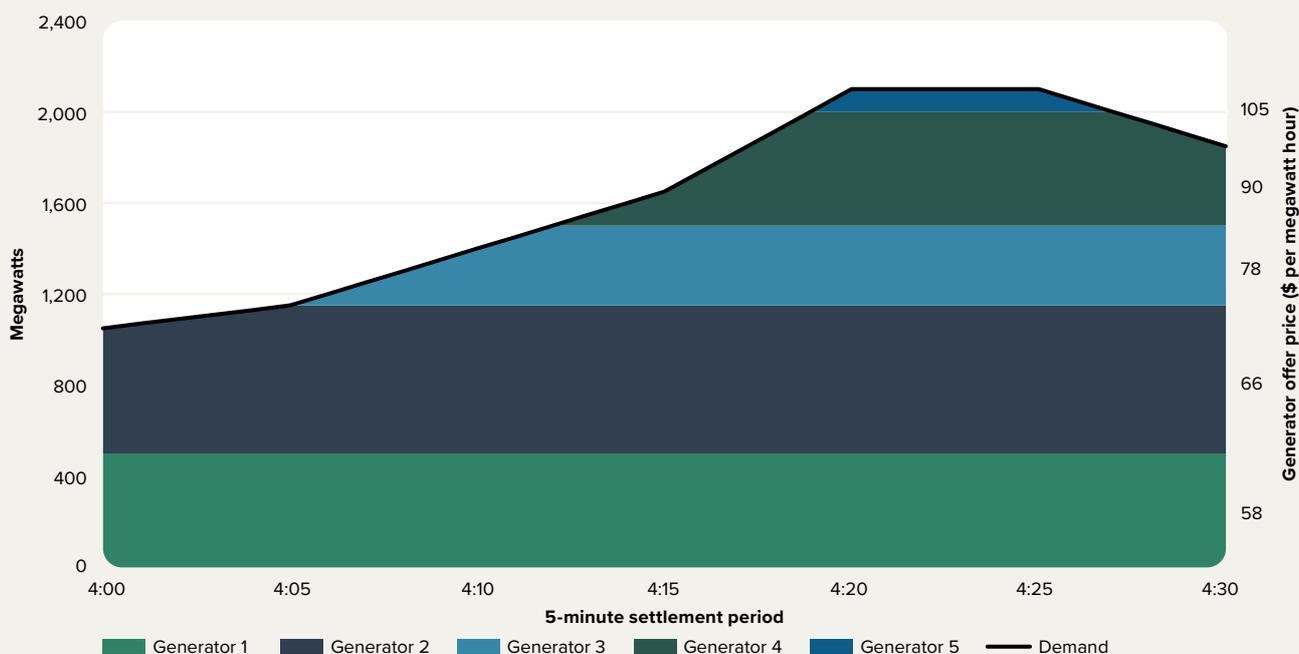
29 AEMC, [AEMC updates market price cap for 2025–26](#), Australian Energy Market Commission, 27 February 2025.

30 AEMC, [2026 Reliability Standard and Settings Review](#), Australian Energy Market Commission, accessed 26 June 2025.

The highest-priced offer needed to meet demand sets the 5-minute price in each region and is the price paid to each generator that is dispatched, regardless of their individual bids.

The Box Figure 2.1 illustrates how prices are set. In this example, 5 generators offer capacity in different price bands between 4:00 pm and 4:30 pm. At 4:15 pm the demand for electricity is 1,650 MW. To meet this demand, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is \$90 per MWh. By 4:20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of \$105 per MWh, which becomes the dispatch price for that 5-minute interval. That price is paid to all dispatched generators, regardless of their offers. This process is repeated for all 5-minute intervals.

Box Figure 2.1 Setting the price



Source: AER.

Generators can change their offers by rebidding capacity to higher or lower prices, or by increasing or decreasing the amount of capacity offered. Generators may do this right up until dispatch but must provide AEMO with a reason for each rebid.

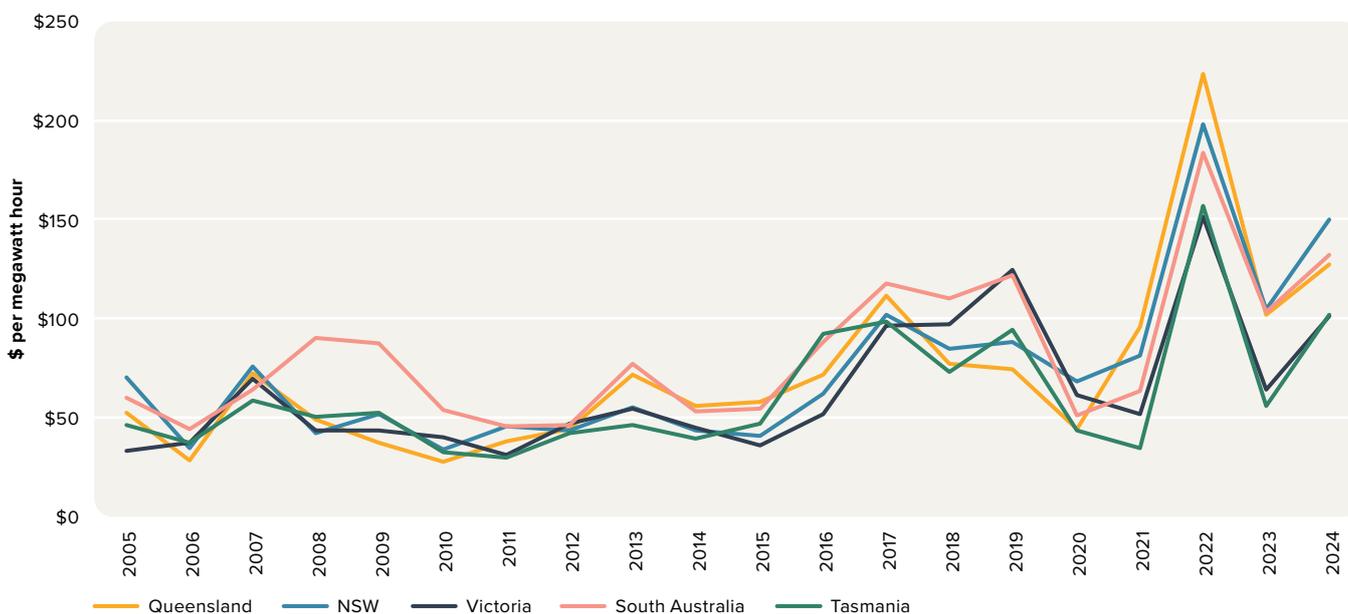
While the market is designed to meet electricity demand in a cost-efficient way, other factors can intervene. At times, dispatching the lowest-cost generator may overload the network or risk system security, so AEMO dispatches more expensive (out of merit order) generators instead.

Retailers buy electricity from the wholesale market and package it with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the NEM in several ways, such as entering into hedging contracts (derivatives) that lock in a firm price for electricity supplies in the future, by ownership of generators or entering into demand response contracts with their retail customers.

2.3 Wholesale prices and activity

Wholesale electricity prices in 2024 were higher than in the previous year in all regions. Prices remained lower than the record levels reached in 2022 (Box 2.2) but were high compared with pre-2022 levels (Figure 2.3).

Figure 2.3 Annual wholesale prices



Note: Volume-weighted annual average prices, by calendar year. Price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER; AEMO (data).

Comparing average annual prices across the NEM in 2024:

- Queensland – prices averaged \$128 per MWh, up 26% from 2023, and were affected by high demand in the summer months driving many high price events.³¹
- NSW – prices averaged \$150 per MWh, up 43% from 2023, and were affected by many high price events in late autumn and late spring.³² Generator and network outages factored in many of these price events, as did rebidding by market participants.
- Victoria – prices averaged \$101 per MWh, up 58% from 2023. Colder weather driving higher demand was a factor in the price increases during winter and coincided with a period of lower wind output. Heading into spring and early summer, prices remained higher than the previous year amid a higher rate of brown coal outages.
- South Australia – prices averaged \$132 per MWh, up 28% from 2023. Prices were particularly high in the July to September 2024 quarter, driven by many high price events.³³ Low wind output, network outages and rebidding by participants were key drivers of the high prices.
- Tasmania – prices averaged \$102 per MWh, up 82% from 2023. A key driver was hydro generators offering into the market at higher prices, which reflects lower storage levels at major dams caused by the lower-than-average rainfall in the region.

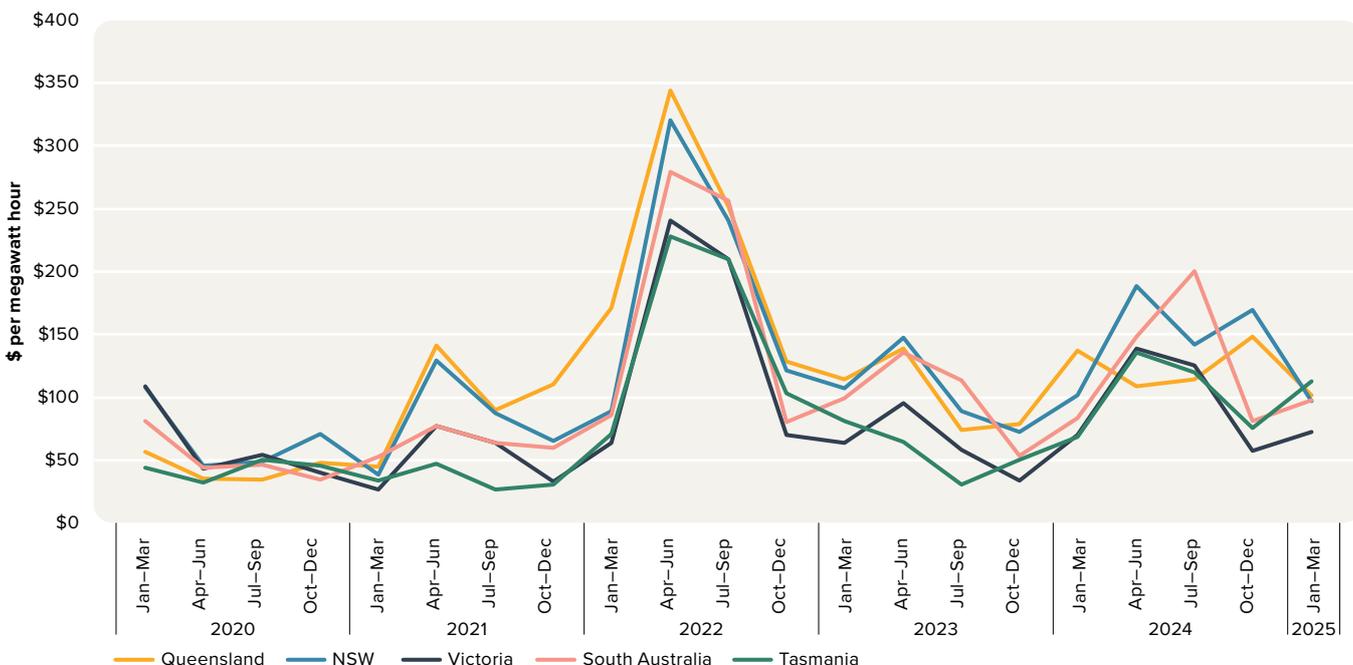
31 AER, [Prices above \\$5,000/MWh – January to March 2024](#) and [Prices above \\$5,000/MWh – October to December 2024](#), Australian Energy Regulator, May 2024 and February 2025.

32 AER, [Prices above \\$5,000/MWh – April to June 2024](#) and [Prices above \\$5,000/MWh – July to September 2024](#), Australian Energy Regulator, July 2024 and November 2024.

33 AER, [Prices above \\$5,000/MWh – July to September 2024](#), Australian Energy Regulator, November 2024.

Prices across the year varied from quarter to quarter due to typical seasonal changes as well as other factors. Prices in most regions were highest during the April to June and July to September quarters, when periods of network and generator outages combined with periods of cold weather with high demand for heating (Figure 2.4). Prices in Queensland and NSW were also high in the October to December 2024 quarter when earlier than usual warm weather combined with the usual planned generator outages that take place in the shoulder season.

Figure 2.4 Quarterly wholesale electricity prices



Note: Volume-weighted weekly average prices. Price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER; AEMO (data).

Box 2.2 Wholesale electricity prices in 2022

Wholesale electricity prices rose sharply in 2022 to reach record levels in all regions. A key driver of these prices was a dramatic increase in international prices for coal and gas, which are key fuels for electricity generation. Coal and gas-powered generators needing to source additional fuel were exposed to these high prices. These fuel cost issues were compounded by fuel supply problems, with many coal mines and rail routes impacted by heavy rain. Further, a large number of planned and unplanned coal generator outages in May and June coincided with unusually cold weather and high demand.

The increase in spot prices led to very high prices and considerable price volatility for electricity hedge contracts. It also led to an increase in the popularity of swaptions, which allow holders to lock in a price at which they may buy a hedge contract in the future. Section 2.5 includes a discussion of these dynamics.

Following the winter of 2022, the conditions that caused the high prices eased and both spot and hedge contract prices fell back to lower levels. However, given the ongoing evolution of the market, prices and market dynamics have not fully returned to pre-2022 ‘normal’.

2.3.1 Price volatility

Price volatility is a natural feature of energy markets that can signal to the market that investment in new generation or storage is needed or demand should be shifted to cheaper times. Price volatility in the NEM has increased significantly compared with 2020 in response to the interplay between intermittent generation sources and fluctuating demand.

Price volatility can involve instances of high prices, but it can also involve negative prices. Generators in the NEM may offer capacity as low as the market floor price of $-\$1,000$ per MWh. Our analysis in this section focuses on prices below $\$0$ per MWh and above $\$300$ per MWh.

Generators offer capacity at negative prices for a range of reasons. Generators whose capacity is dispatched by AEMO will receive the market price for that capacity, rather than the price they offer. Because AEMO usually dispatches the lowest-priced capacity first, a generator that bids capacity at negative prices is less likely to have its bid rejected and bidding at the market floor can ‘guarantee’ being dispatched.

Coal generators typically have high startup costs, so having to pay to continue generating for a limited period of time is usually more cost-effective than being switched off and restarting. Additionally, if a generator has entered into contracts that ensure a fixed price for the electricity it sells into the market, its exposure to negative prices may be lower.

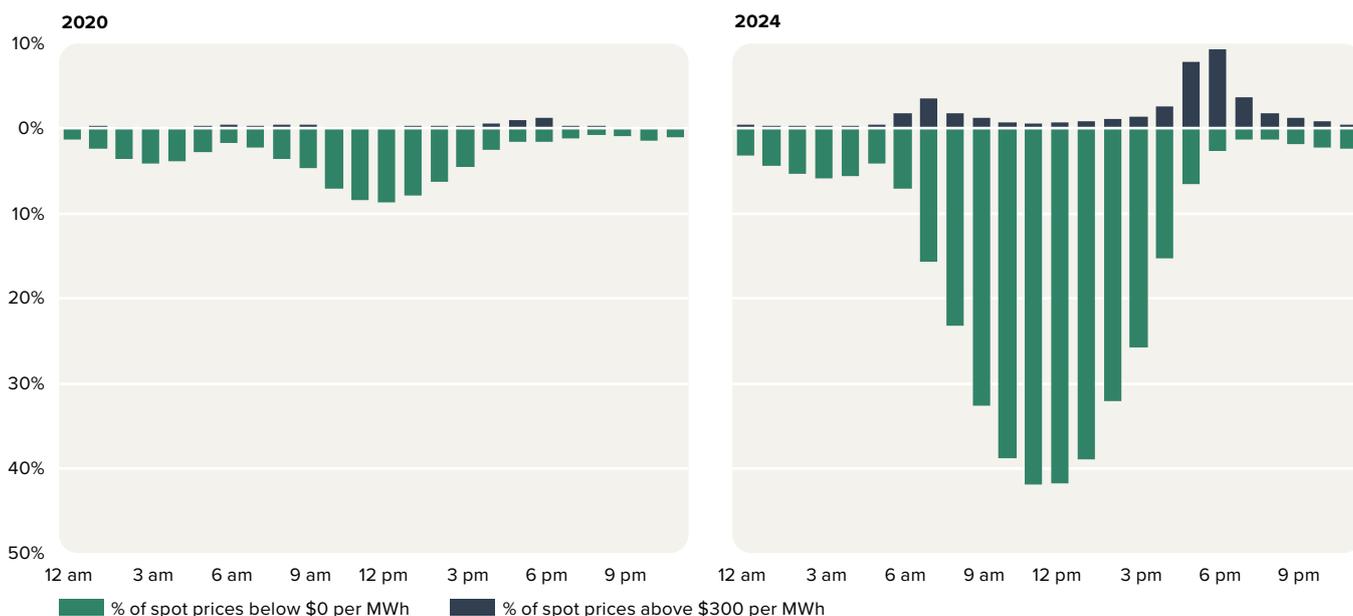
Negative prices have been more frequent since intermittent generation entered the market. Wind and solar generators have marginal costs close to zero. If wind and solar generating conditions are optimal, they may need to bid capacity at negative prices to guarantee dispatch. Some wind and solar generators also source revenue from power purchase agreements and the sale of renewable energy certificates. As such, they may operate profitably even when wholesale prices are negative. Instances of negative spot prices are highest when these technologies, alongside rooftop solar, are generating.

If electricity demand is low, the market has surplus capacity and the chances of the market settling at a negative price are higher. With multiple low-cost generators all competing for dispatch, the likelihood of negative prices increases. In recent times, negative prices have been most common in the middle of the day when large-scale solar resources are producing maximum output and the generation of rooftop solar reduces net electricity demand.

Generators may also offer capacity at high prices for a range of reasons. Generators with higher running costs, or with a need to ration limited fuel, will tend to offer at higher prices. Similarly, some generators have high start-up costs and may offer at very high prices when they do not plan to run, to avoid needing to switch on for short periods. Some gas generators have been doing this more often as more intermittent renewables have entered the market – likely because fluctuations in wind and solar output can require other generators to come on for short periods to fill gaps.

Since 2020, the frequency of both negative prices and prices above $\$300$ per MWh has increased significantly (Figure 2.5). Negative prices made up 15% of all prices in 2024, up from 3.5% in 2020. Prices above $\$300$ per MWh increased from 0.4% to 1.8% of all prices over the same period.

Figure 2.5 Percentage of prices below \$0 per MWh and above \$300 per MWh



Note: The upward y-axis shows, for each hour of the day in the chosen year, the percentage of 5-minute prices across all NEM regions that were greater than \$300 per MWh. The downward y-axis similarly shows the percentage of prices that were below \$0 per MWh. Prices were not settled in 5-minute intervals until October 2021, although prior to this dispatch was determined on a 5-minute basis using 5-minute prices. The figure presents outcomes in NEM time (Australian Eastern Standard Time).

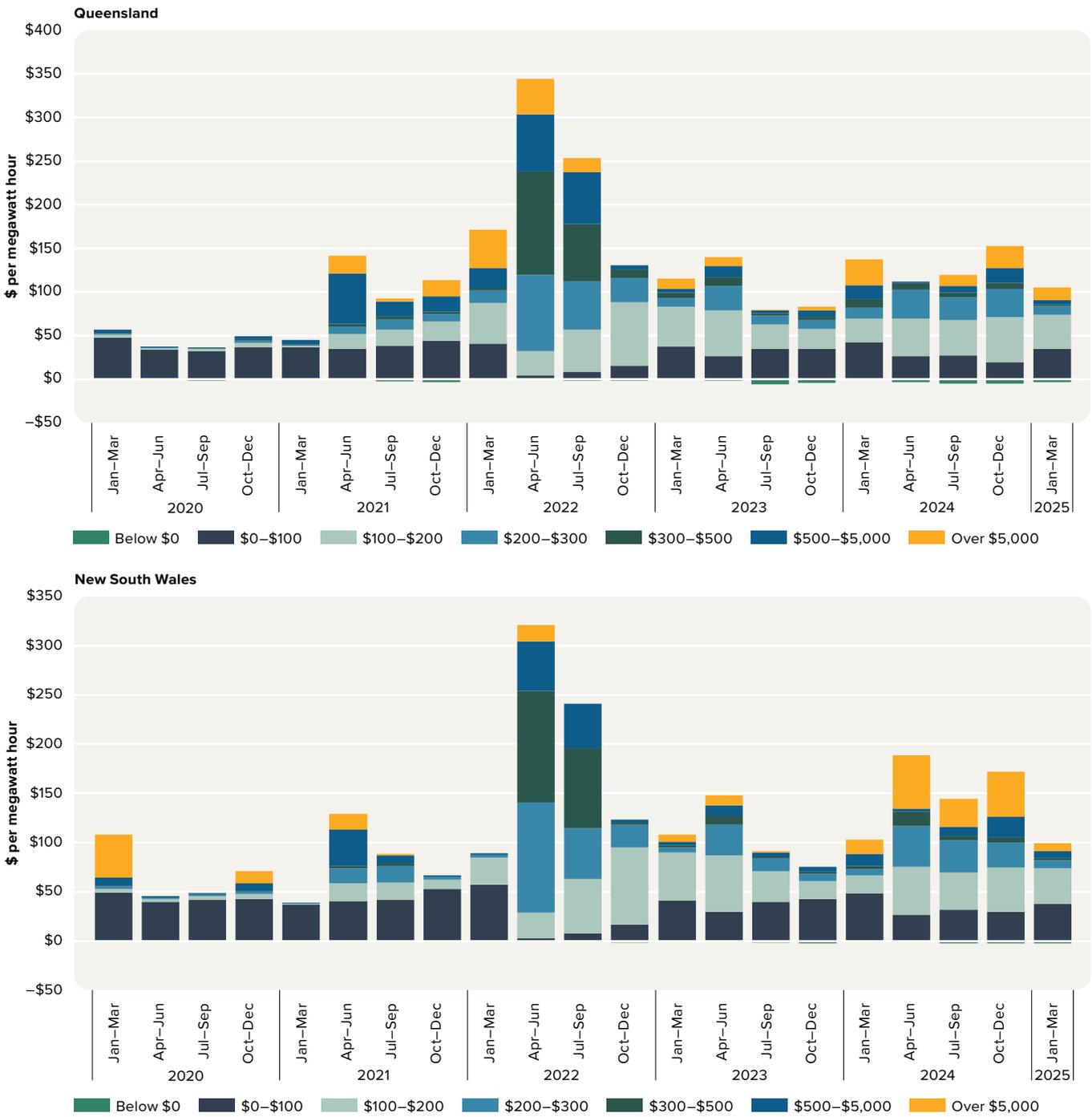
Source: AER; AEMO (data).

There have also been changes in the timing of these prices. The frequency of negative prices between 3 am and 4 am has increased only slightly – from 4.1% of the time in 2020 to 5.8% in 2024. By contrast, the frequency of negative prices between 11 am and noon has increased significantly – from 8.5% to 41.9% of the time. Meanwhile, the frequency of prices above \$300 per MWh increased at all times of day but especially during the evening peak. Between 6 pm and 7 pm, the frequency of prices above \$300 per MWh rose from 1.3% to nearly 10%.

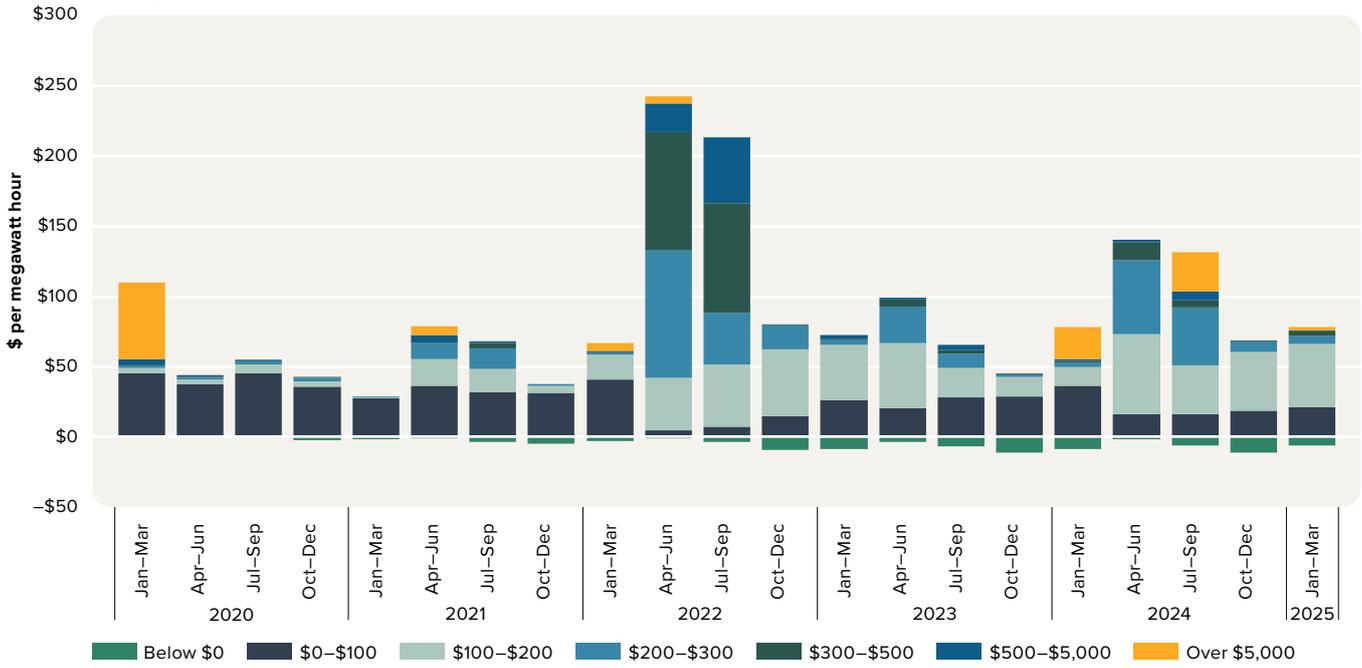
The frequency of high and low prices differed between regions. South Australia and Victoria, the regions with the highest proportion of intermittent renewable generation (Figure 2.18), accounted for most negative price occurrences in 2024, representing a combined 62% of negative prices in the NEM. South Australia and Queensland were the regions with the highest frequency of prices above \$300 per MWh. These regions represented 53% of prices above \$300 per MWh in 2024.

Despite their greater frequency, negative prices have a relatively modest impact on average spot prices compared with high prices (Figure 2.6). For example, in January to March 2025 in South Australia, negative prices reduced the quarterly average price by \$8.33 while prices above \$300 per MWh increased it by \$23.68. In the July to September quarter, the contribution from high prices was more extreme, with negative prices reducing the quarterly average price by \$7.79 while prices above \$300 per MWh added \$115.81. This is partly because when high prices do occur, they are often much more extreme than negative prices (which are often only slightly below \$0 per MWh). It is also partly because higher prices tend to occur when system demand is greater, meaning that high prices apply to a greater proportion of the electricity that is dispatched.

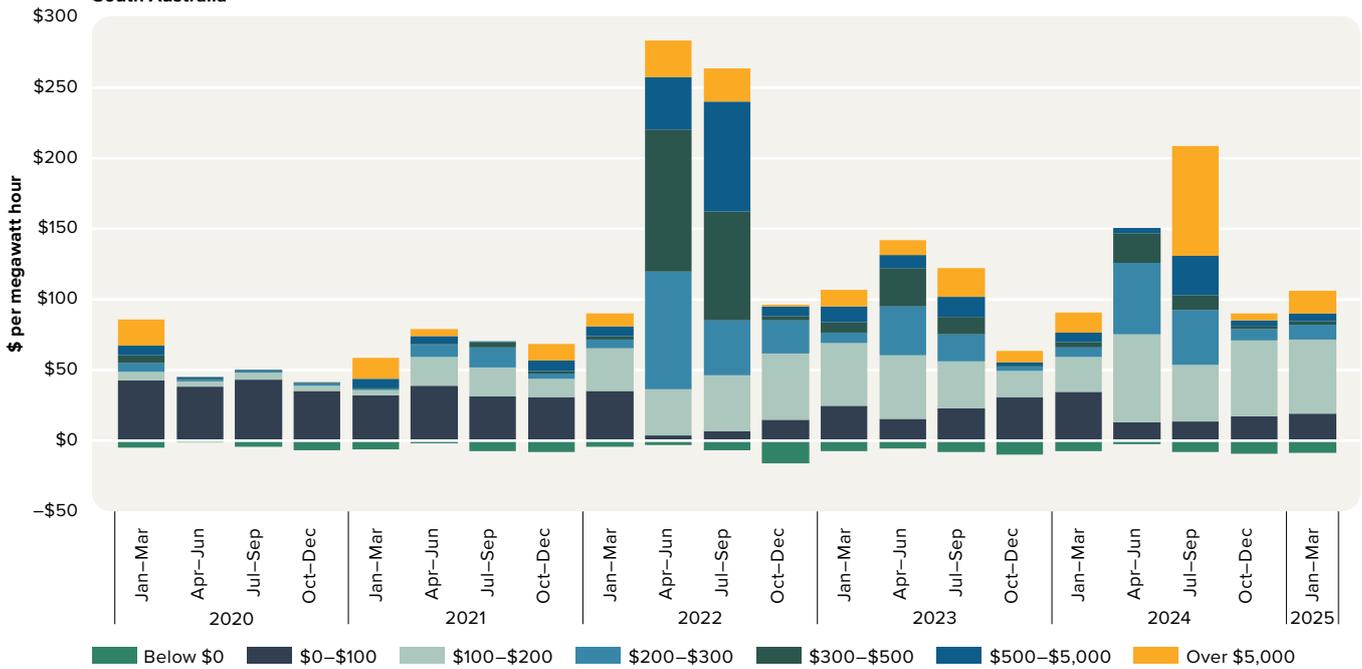
Figure 2.6 Contribution of different price bands to quarterly wholesale prices

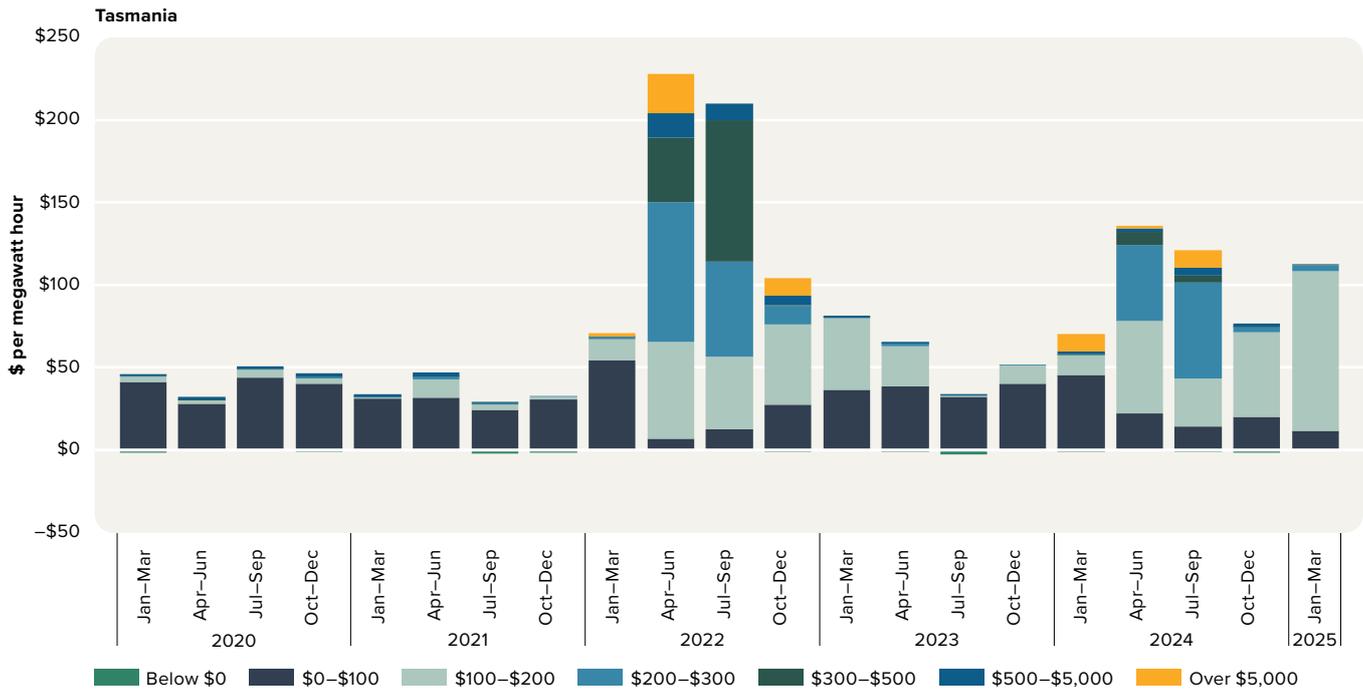


Victoria



South Australia





Note: Shows the extent to which different spot prices within defined bands contributed to the volume-weighted average wholesale prices in each region.
 Source: AER; AEMO (data).

2.4 Generator fuel costs

Fuel costs are a key determinant of a generator’s cost of producing electricity. Black coal generators can source their fuel from a range of sources, including directly from an attached mine or through short-term or long-term contracts with independent suppliers. NSW black coal generators typically acquire their fuel through contracts. Black coal producers supply domestically as well as exporting to the international market. Short-term supply contracts for coal are likely to align more closely with the prevailing international black coal price, but it is also common for the price of long-term domestic supply contracts to be set by reference to international coal price benchmark indices. Generators may also be exposed to changes in the international coal price if:

- they require additional coal that their contracts or mines cannot supply (due to supply disruptions from weather or transport congestion or other delays in delivery)
- they use spot markets to purchase coal for flexible levels of generation
- long-term contract negotiations coincide with fluctuating prices.

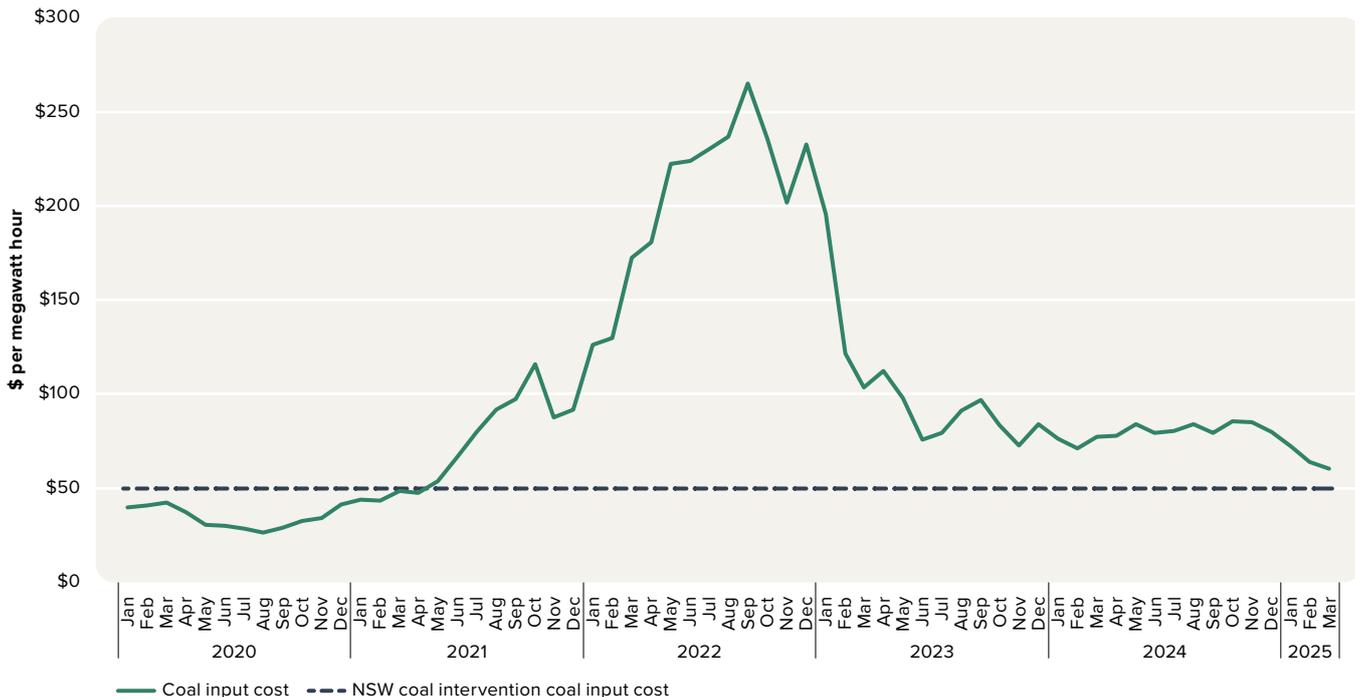
Coal generators in Victoria use brown coal rather than black coal. Brown coal is plentiful in the Gippsland region and is very low cost. It is also low quality and unsuitable for export, so its cost is not influenced by export market coal prices.

In 2024 the international export price for black coal averaged \$204.60 per tonne, which equates to a cost of generation of around \$80 per MWh (Figure 2.7). In 2024, the export price of coal was more stable than in 2022 and 2023.

As at the end of March 2025, the cost of generation based on the export price of black coal had dropped to around \$60 per MWh. Despite this drop, the generation cost remains higher than it was under the market intervention prices that were in place throughout 2023 and the first half of 2024 (about \$49 per MWh).³⁴ As such, it is likely that NSW generators are still facing higher coal costs than they were during the market intervention period.

34 AER, [NSW coal market price emergency](#), Australian Energy Regulator, accessed 30 May 2025.

Figure 2.7 Cost of producing electricity from coal



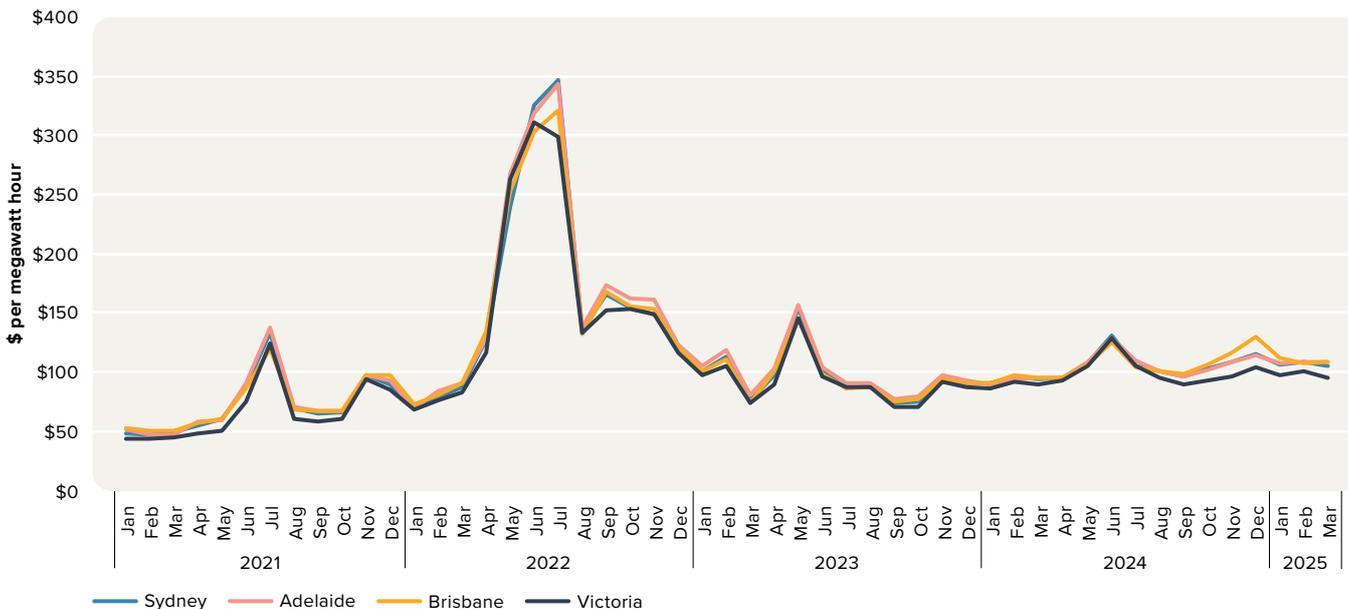
Note: To produce this analysis, we used an international reference price of coal (the NEWC index) as a proxy. To convert coal prices from US\$ per tonne to A\$ per MWh, we used the formula: \$ per MWh equals coal cost (US\$ per tonne) divided by the exchange rate (monthly average) multiplied by the heat rate (gigajoule [GJ] per MWh) divided by the 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; GlobalCoal (data).

Like black coal generators, gas-powered generators source their fuel from a variety of sources. Gas may be sourced from spot markets or through short-term or long-term contracts with suppliers. The opportunity cost of using gas for electricity generation is, among other things, selling it on the Short Term Trading Markets in Adelaide, Brisbane and Sydney, the Declared Wholesale Gas Market in Victoria, or the Gas Supply Hubs at Wallumbilla and Moomba, or exporting it as LNG. These markets are covered in section 4.2.2 in chapter 4.

In 2024, the cost of producing electricity using gas sourced from domestic markets averaged around \$100 per MWh (Figure 2.8). This was much lower than the record prices reached in 2022, but higher than pre-2022 prices.

Figure 2.8 Cost of producing electricity from gas



Note: Analysis based on domestic spot gas prices. 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 equals gas cost multiplied by 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 and a higher cost of gas in \$ per MWh.

Source: AER; AEMO (data).

2.5 Electricity derivatives market

Derivative contract markets play a pivotal role in protecting energy consumers from price volatility by enabling proactive risk management. They also influence generator behaviour by shaping investment and dispatch decisions. A liquid, accessible and adaptable contract market is integral to competitive and sustainable wholesale market outcomes.

Derivative (exchange-traded or over-the-counter) markets operate parallel to the wholesale electricity market. Prices in the wholesale market can be volatile, posing risks for market participants. Generators face the risk of low settlement prices reducing their earnings, while retailers risk paying high wholesale prices that they cannot pass on to their customers. A retailer may expand its operation and contract with many new customers at a set retail price, only to incur unexpectedly high prices in the wholesale market, ultimately leaving the retailer substantially out of pocket.

Generators and retailers can manage their market exposure by locking in prices for which they will trade electricity in the future. An alternative strategy adopted by some participants is to internally manage risk through vertical integration – that is, operating as both a generator and a retailer (gentailer) to offset the risks in each market.

Typically, vertically integrated gentailers are imperfectly hedged – their position in generation may be ‘short’ (small relative to their retail load) or ‘long’ (large relative to their retail load). For this reason, gentailers also participate in contract markets to manage outstanding exposures, but to a lesser extent than standalone generators and retailers.

Alongside generators and retailers, participants in electricity contract markets include financial intermediaries and speculators, such as investment banks. Brokers often facilitate contracts between parties in these markets.

In Australia, 2 distinct financial markets support the wholesale electricity market:

- In exchange-traded markets, electricity futures products are traded on the Australian Securities Exchange (ASX). Electricity futures products are available for Queensland, NSW, Victoria and South Australia.

- In over-the-counter (OTC) markets, 2 parties contract with each other directly (often assisted by a broker). The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements.

Exchange-traded products are standardised to encourage liquidity. OTC markets contain standardised products as well, but also offer products that can be tailored to the bespoke requirements of counterparties. Exchange-traded contracts are settled through a centralised clearing house, which acts as a counterparty to all transactions and requires daily cash margining to manage credit default risk. In OTC trading, counterparty risks are managed by participants demonstrating creditworthiness rather than margin payments. In times of high contract prices and increased volatility, the credit requirements are likely to be more onerous.

Standardised derivative products include:

- Futures contracts – these allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at a specified time in the future. Available products include quarterly base contracts (covering all trading intervals within a quarter) and peak contracts (covering specified times of generally high energy demand). As at April 2025, the ASX planned to list new Peak Load Electricity Futures Contracts that better reflect key NEM demand periods, with separate morning and evening contracts to begin listing from 30 June 2025 (section 2.5.6).³⁵ Futures can also be traded as calendar or financial year strips covering all 4 quarters of a year. Futures contracts are settled against the spot market price in the relevant region – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference; when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- Caps – these are contracts setting an upper limit on the price that a holder will pay for electricity, with the seller paying the difference between the cap (strike price) and the spot price. Cap contracts on the ASX have a strike price of \$300 per MWh. When the spot price exceeds the strike price, the seller of the cap (typically a generator) must pay the buyer (typically a retailer) the difference between the strike price and the spot price. Alternative (higher or lower) strike prices are available in the OTC market.
- Options – these are like futures contracts, but they give the holder the right (without obligation) to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product).

Two types of standard options are available through the ASX.

- Swaptions (also called base strip options) are traded for either a calendar year or financial year. The buyer pays a premium up-front to have the opportunity, in the future, to buy/sell a set of 4 quarterly base futures contracts at a set price (the strike price). They must exercise their options (convert into the underlying base futures contracts) before the expiry date (swaptions expire 6 weeks before the start of the calendar or financial year). The price of a swaption is intrinsically linked to the price of the underlying base future contracts.
- Average rate options (also called Asian options) are bought/sold for a quarter. The payout for this type of option is based on the average spot price for the quarter measured at the end of the quarter. The buyer of an average rate option pays a premium up-front and the option is automatically exercised at the end of the quarter only if the option is ‘in-the-money’ (that is, the buyer will receive a payout). An average rate option can be bought and sold until the last day of the quarter.

³⁵ ASX, [New Australian Peak Load Electricity Futures Contracts go live dates](#), Australian Securities Exchange, 22 May 2025, accessed 5 June 2025.

Trade volumes and prices of derivative products are publicly reported for exchange trades, but trading activity in OTC markets is confidential and not disclosed publicly. Under national electricity law amendments passed in May 2024, the AER received enhanced powers to collect contracts and contract-related information, including OTC trades, from market participants.³⁶ In 2024, the AER used these powers for the first time and collected contract market information, including OTC trades, pertaining to the South Australian contract market. Analysis of this information was included in the *Wholesale electricity market performance report 2024* and supported our assessment of market performance, competition and efficiency in the region.³⁷

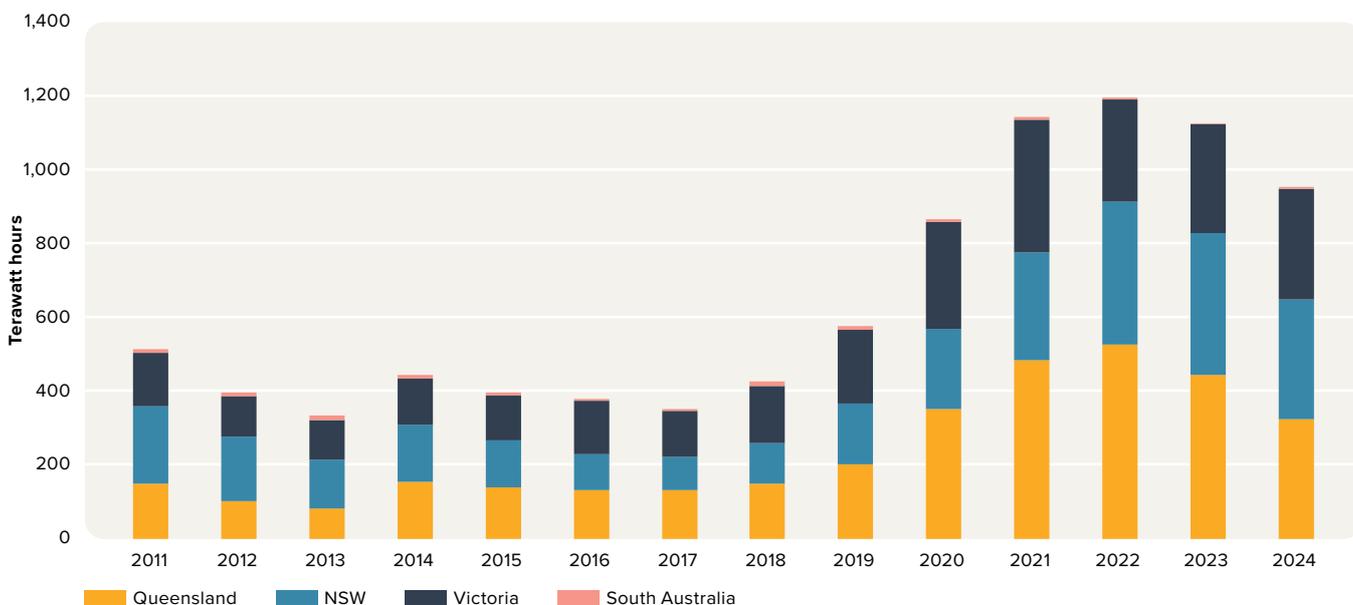
2.5.1 Exchange-traded market activity

Until 2021, the ASX was the sole futures exchange operating in the NEM, facilitating regular trades across Queensland, NSW, Victoria and South Australia. FEX Global launched a separate futures exchange in March 2021 offering a similar range of products. However, FEX Global recently halted trading in all contract markets.³⁸

Exchange-traded liquidity has historically been high in Queensland, NSW and Victoria, but low in South Australia. Liquidity in South Australia increased slightly in 2024 – albeit from very low historic levels and is still well below other regions. In 2024, Queensland, NSW and Victoria each accounted for roughly one-third of ASX-traded volume, while South Australia contributed just 0.5% of contract market trades. ASX contracts in South Australia are likely less attractive for hedging than in other NEM regions, due to the region’s unique demand and generation profiles compared with other regions. A detailed analysis of South Australia’s unique market conditions is available in the South Australia deep dive chapter of the AER’s *Wholesale electricity market performance report 2024*.

ASX annual trading volume has increased materially since 2017, more than tripling by 2021 and peaking in 2022 (Figure 2.9), coinciding with the period of record-breaking high wholesale electricity prices in the NEM (Box 2.2). Annual ASX-traded volumes decreased by 15% in 2024 compared with 2023 but remained elevated relative to pre-2021 levels. NSW and Queensland drove the decrease, recording year-on-year declines of 16% and 27% in 2024, respectively. Victoria experienced a 2% increase, while South Australia saw its trade volume rise by 121% from a very low base.

Figure 2.9 Traded volumes in ASX electricity contracts



Note: Volumes are exchange trades that occurred across the calendar year across ASX Energy futures. The axis shows the year the trade occurred rather than the period of the contract.

Source: AER; ASX Energy (data).

36 AER, [Enhanced wholesale market monitoring guideline \(2024\)](#), Australian Energy Regulator, 5 November 2024.

37 AER, [Wholesale electricity market performance report 2024](#), Australian Energy Regulator, 20 December 2024.

38 FEX Global, [FEX Global transition in Clearing and Settlement Arrangements](#), accessed 17 July 2025.

Growth in ASX trading between 2018 and 2022 was primarily driven by increased swaption activity and, to a lesser extent, by increased base futures volumes. Since exercised swaptions result in trades of the underlying base futures contracts, the rise in swaption activity contributed to the increase in base future trading volumes. A more detailed discussion of the shift towards swaptions is available in Chapter 3 of the AER's *Wholesale electricity market performance report 2024*.

Base futures contracts are typically traded in higher volumes during the April to June and September to December quarters. This pattern reflects market participants exercising options contracts, which are converted into base futures as they approach the start of the financial and calendar years.

The trade of both swaptions and quarterly base futures contracts peaked in 2022 when they represented 49% (587 terawatt hours [TWh]) and 43% (516 TWh) of total ASX trade volume, respectively. Since then, ASX base quarterly futures trading has declined by 14% in 2023 and a further 16% in 2024. Swaptions fell by 4% in 2023 and 27% in 2024 but remained the most traded contract type on the ASX, comprising 43% of traded volume in 2024. Swaptions have been the most traded product since overtaking base quarter futures in 2020. Quarterly base futures followed with a 39% share, while average rate options (10%) and caps (7%) were traded at lower levels. Monthly base futures and peak contracts were rarely traded, together making up just 0.1% of total volume.

2.5.2 Contract market liquidity ratio

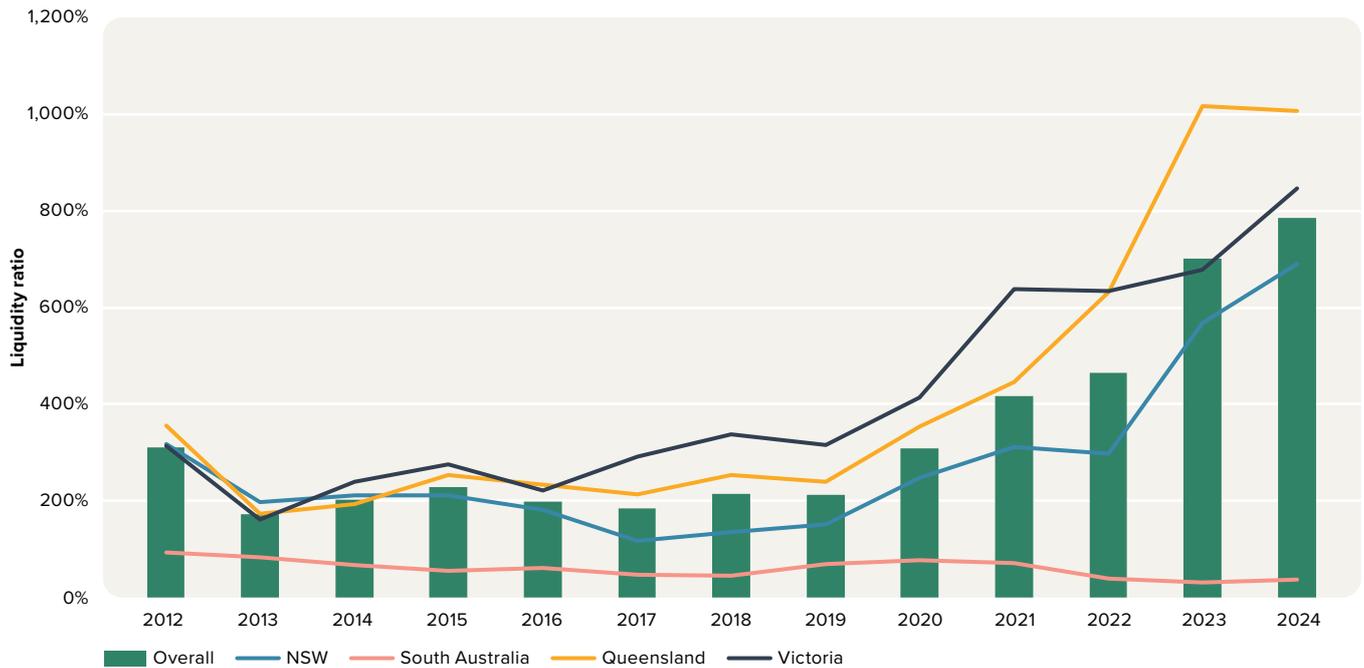
The liquidity ratio is one way to measure market liquidity. It is calculated by dividing the volume of ASX electricity contracts traded (in MWh) for a given delivery year by the spot market's native demand (also in MWh) in that same year. Higher liquidity allows market participants to trade contracts more readily and can contribute to greater price certainty.

The liquidity ratio for the mainland NEM regions has been steadily increasing since 2017, rising from 184% in 2017 to 786% in 2024 (Figure 2.10). Since 2022, the liquidity ratio has improved significantly in NSW, Queensland and Victoria, and is now at an all-time high in all regions except South Australia. In these 3 regions, total ASX contract trade volumes significantly exceeded underlying electricity demand. Given the extent of vertical integration in Victoria and NSW, this suggests substantial trading and re-trading of capacity made available for contracting.

South Australia has also seen an increase in contract liquidity in 2024, but it remains relatively low compared with other NEM mainland regions. Traded volumes are still below underlying electricity demand, with ASX contracts for 2024 representing only 37% of the region's demand – up from 32% in 2023. The region's high proportion of intermittent renewable generation, high degree of vertical integration and relatively concentrated ownership of dispatchable generation have contributed to this weaker liquidity because intermittent generation is less suited to underwriting the standard ASX-listed contracts.

ASX trades can be initiated up to 4 years in advance of delivery. Therefore, the current high liquidity ratio partly reflects elevated trading activity in previous years. With total traded volumes declining in both 2023 and 2024, the elevated liquidity ratio is unlikely to be sustained in future years.

Figure 2.10 ASX Liquidity ratio



Note: The liquidity ratio compares traded volumes to electricity native demand in each region. For this metric, trade volumes are listed for the period of the contract rather than the year the trade occurred. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER; ASX Energy (trade data); AEMO (demand data).

2.5.3 Open interest

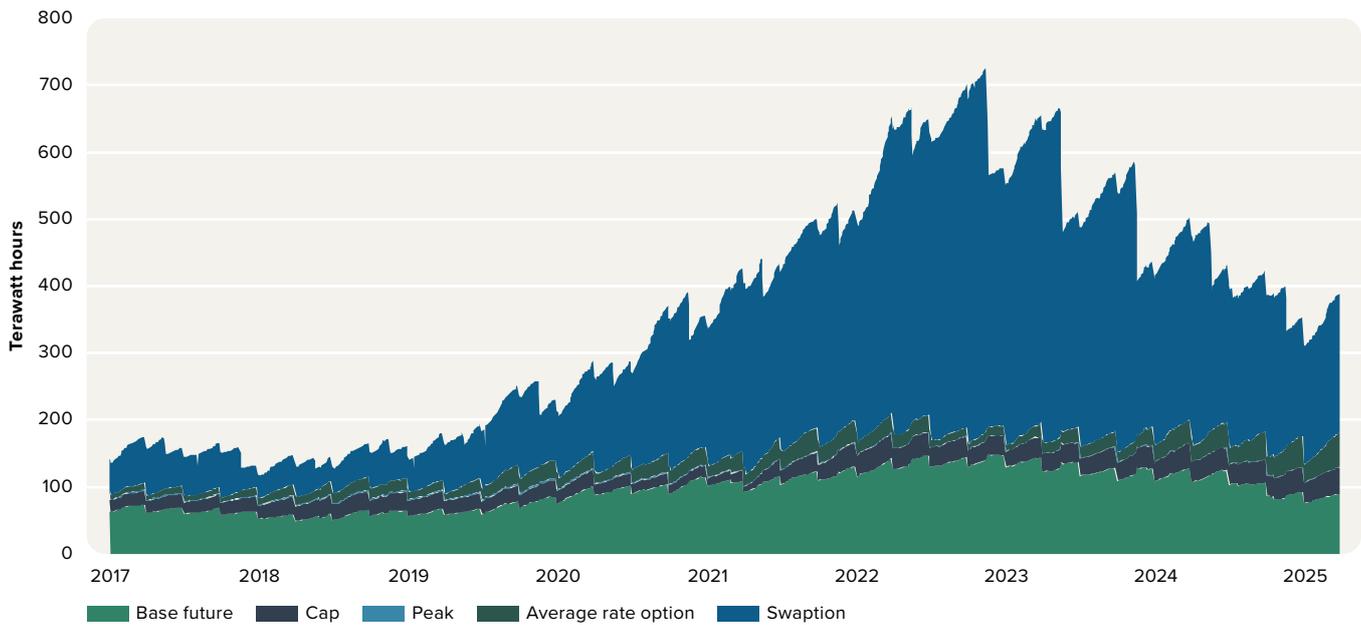
Open interest is the total number of contracts that are still active. These are contracts that have not been closed, exercised or expired as at the end of the previous trading day. Open interest serves as an indicator of market activity, as each active contract reflects an agreement between a buyer and a seller.

Open interest volumes have continued to fall through 2024 after peaking at 727 TWh on 16 November 2022 (Figure 2.11). Since then, open interest has trended downwards and was 389 TWh on 31 March 2025. This trend aligns with the overall decline in trading volumes since the 2022 peak and highlights the continued cooling of market activity. The sharper fall in open interest relative to volume indicates that a larger share of recent trades has involved closing existing positions rather than opening new ones.

This decline has been largely driven by a reduction in open interest for swaption contracts, which have dropped from a peak of 544 TWh on 14 November 2022, amid elevated market volatility in mid-2022, to 207 TWh (a reduction of 62%) as at 31 March 2025. As swaption contracts expire every 6 months, in May and November, open interest naturally decreases, creating a saw-tooth pattern. While some of this decline reflects routine contract expiry, the broader trend is downward, as fewer new option contracts are being opened to replace those expiring.

Base futures, the next most significant contract type after swaptions, have also followed a downward trend. Open interest in these contracts has fallen from a peak of 148 TWh on 28 November 2022 to 90 TWh as at 31 March 2025.

Figure 2.11 ASX daily open interest volumes, by contract type



Note: Daily open interest for all ASX energy contracts.

Source: AER analysis using ASX data.

2.5.4 Contract prices

A calendar year base futures contract covers all 4 quarters of a calendar year and allows a party to lock in a fixed (strike) price to buy or sell a constant number of megawatts per hour throughout the year. We use calendar year base futures prices to indicate overall wholesale electricity market trends and price expectations.

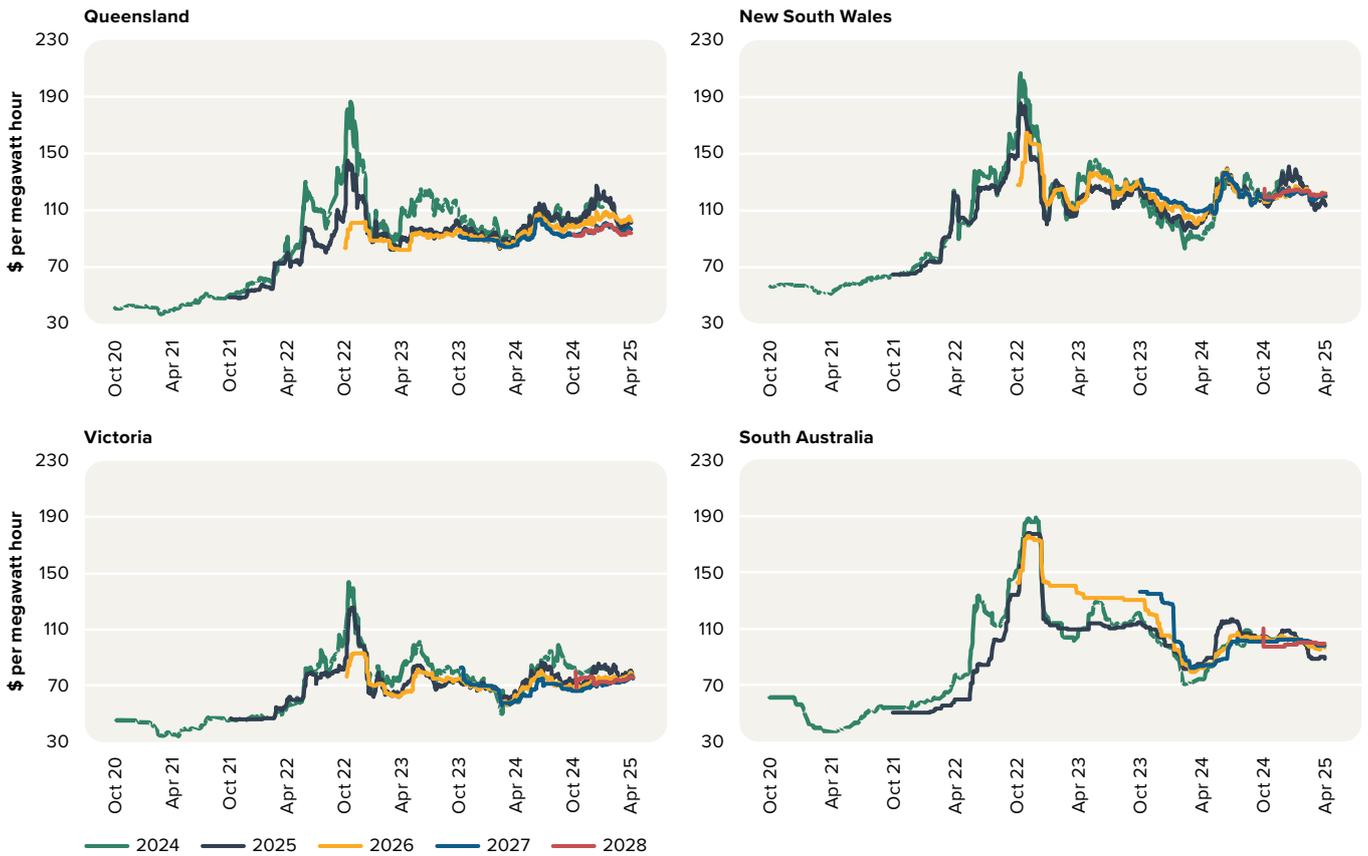
Calendar year base futures prices have fallen considerably from their 2022 peak but have remained relatively stable from early 2023 onwards. In mid-2024, prices rose modestly across all mainland regions before easing again, resulting in little net change during the 2024 calendar year (Figure 2.12). Daily price volatility also declined over the year, returning to levels last seen before 2022.³⁹

As at 1 April 2025, prices for 2025 contracts ranged between \$76 per MWh in Victoria and \$114 per MWh in NSW. Futures contracts for later years mostly traded in line with 2025 prices, ranging between \$77 per MWh in Victoria and \$120 per MWh in NSW for 2026 and between \$75 per MWh in Victoria and \$121 per MWh in NSW for 2027.

The prices of these futures contracts indicate that the market expects electricity prices to remain elevated compared with pre-2022 levels, but not to reach the record levels of 2022 (Box 2.2).

³⁹ Daily price volatility was calculated as the standard deviation of the percentage daily price changes in calendar year base futures prices.

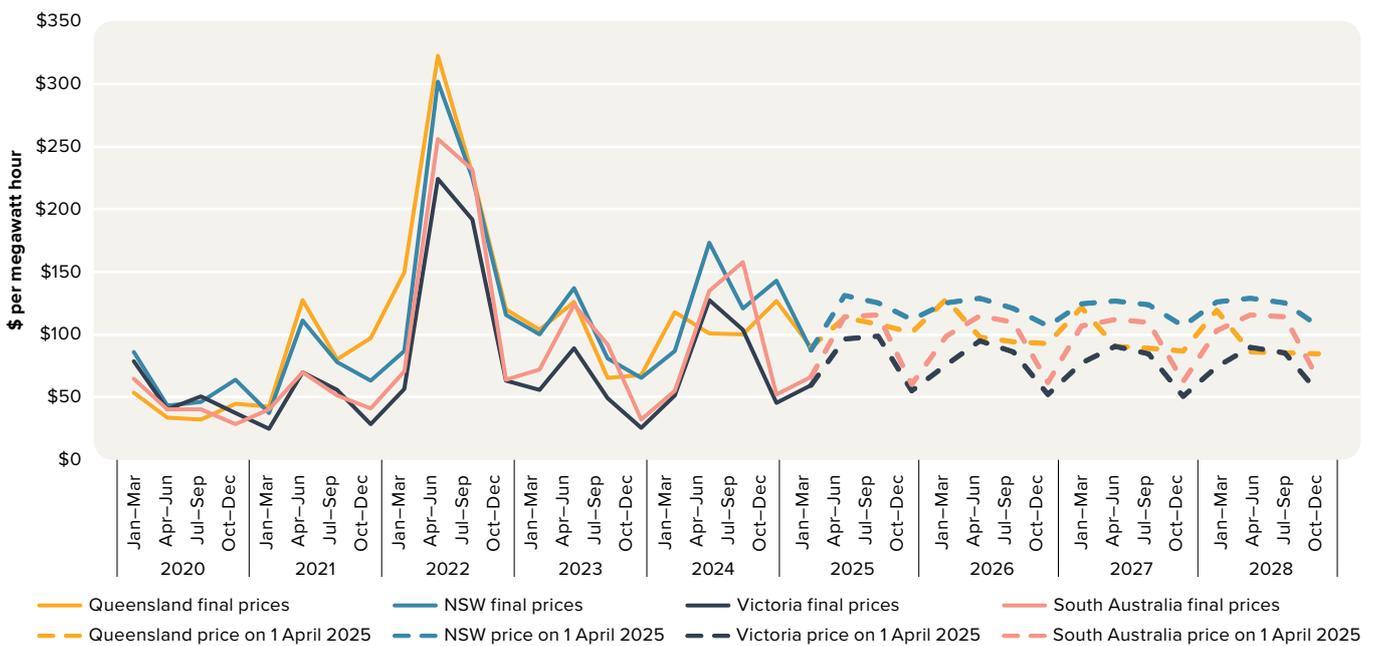
Figure 2.12 Prices for calendar year base futures



Note: Calendar year prices have been calculated by averaging the prices across the 4 base quarter products within each calendar year (calendar year base futures products do exist, but they are thinly traded). Prices are calculated based on daily settled prices at the end of each trading day.
 Source: AER; ASX Energy (data).

Quarterly base futures exhibit a seasonal profile, with prices for future quarters lowest for the October to December quarter when demand is usually at its lowest (Figure 2.13).

Figure 2.13 Prices for quarterly base futures



Note: Prices for quarterly base futures up to and including the January to March quarter 2025 are finalised (as they are no longer traded). Prices for quarterly base futures for the April to June quarter 2025 and beyond (which are still being traded) are as at 1 April 2025.
 Source: AER; ASX Energy (data).

2.5.5 Access to contract markets

Access to contract markets, either via an exchange (ASX) or in OTC electricity markets, can present a significant barrier to retailers and generators looking to enter or expand their presence in the market. Limited access restricts their ability to manage costs (for retailers) and secure revenue streams (for generators). This lack of access poses a material risk because contracts provide price certainty and revenue stability.

In the ASX market, the cash requirements for counterparties through initial and daily margining of contract positions can impose significant cash-flow constraints on retailers. Additionally, the use of standardised products with a minimum trade size of 1 MW can be prohibitive for smaller retailers, restricting them to the use of 'load following' hedges only accessible through the OTC market. OTC load following hedge contracts remove volume risk and are particularly sought by smaller or new retailers without extensive wholesale market expertise or capability.

However, credit risk can present further challenges in the OTC market. Smaller retailers may face stringent credit support requirements from counterparties, making access more difficult. Before entering into an OTC contract, counterparties typically need to establish an ISDA agreement, which is costly to set up. Furthermore, each OTC relationship requires a separate agreement, adding to administrative and financial burdens.

Access to clearing services was a key issue raised by participants following the withdrawal of Bell Potter as an ASX clearing participant amidst the significant volatility in 2022. To transact on the ASX, a market participant requires a clearer to clear and settle the transaction. The Exchange Clearing House manages its risk by imposing margin requirements on its contracting counterparties – the clearing participants – who in turn pass on these margin requirements to their clients, including retailers and generators.

In April 2024, a seventh clearing service provider (StoneX) entered the ASX electricity contracts market,⁴⁰ following the entry of Marex in October 2023.^{41 42}

2.5.6 Developments in contract markets

The increasing penetration of intermittent renewable generation has significant implications for contract markets. Unlike coal-fired generation, which historically suited the sale of standard contracts due to its steady output, renewables are weather-dependent and variable. 'Firming' this generation with energy storage and gas-powered plant could support more active and effective market participation. In response to these structural shifts, the ASX introduced new Morning and Evening Peak Load Electricity Futures Contracts in June 2025.⁴³

The existing peak load futures contracts cover 7 am to 10 pm on business days and were developed for a coal-dominated grid. These contracts no longer reflect evolving demand patterns and accounted for just 0.0005% of total ASX electricity trades in 2024. Following industry consultation in 2024, the ASX has redesigned its peak products to better reflect current operational demand patterns in the NEM.⁴⁴ The new products define morning peak as 6 am to 9 am and evening peak as 4 pm to 9 pm, from Monday to Sunday. These updated time blocks align more closely with actual periods of high net system demand and the operational needs of a grid increasingly shaped by solar during the day and higher consumption in the early morning and evening.

The new peak load contracts will be introduced progressively across NEM regions, starting with NSW on 30 June, followed by Queensland on 7 July, Victoria on 21 July and South Australia on 28 July.⁴⁵ Each regional contract will be listed quarterly out to the April to June quarter 2029, beginning with the July to September quarter 2025. This initiative aims to provide market participants with more relevant and effective tools for managing price exposure and hedging risks in a rapidly transforming energy landscape.

40 StoneX, [StoneX Obtains ASX Derivatives Clearing and Trading Membership](#), StoneX, 30 April 2024, accessed 5 June 2025.

41 Marex, [Marex becomes newest ASX futures clearing participant](#), Marex, 12 October 2023, accessed 5 June 2025.

42 ASX, [ASX Commodities Clear Contacts November 2024](#), Australian Stock Exchange, accessed 2 May 2025.

43 ASX, [ASX to list New Morning and Evening Peak Futures Contracts](#), Australian Stock Exchange, 14 April 2025.

44 ASX, [Response to consultation on ASX Australian Peak Load Electricity Futures contract redesign](#), Australian Stock Exchange, 30 September 2024.

45 ASX, [New Australian Peak Load Electricity Futures Contracts go live dates](#), Australian Stock Exchange, 22 May 2025.

2.6 Electricity demand and consumption

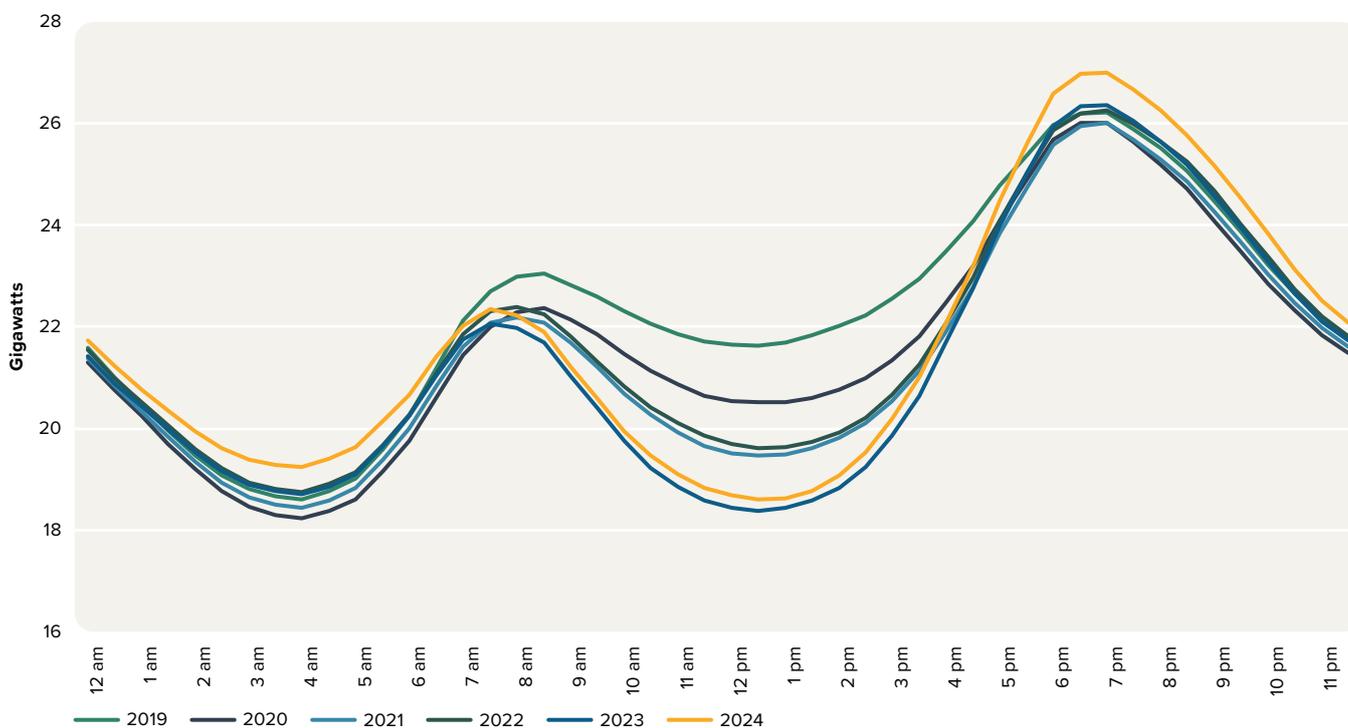
Grid demand refers to electricity sourced from large-scale generators and sold through the NEM. Electricity consumption refers to the total amount of electricity consumed and includes electricity produced by consumer energy resources, such as rooftop solar and home storage batteries. Consumer energy resources reduce grid demand because they replace electricity that would otherwise be supplied by large generators.⁴⁶

Electricity grid demand is a key driver of wholesale electricity prices and varies by time of day and season. During a 24-hour period, grid demand typically peaks in the early evening when residential use increases and rooftop solar generation falls. Seasonal peaks occur in winter (driven by heating loads) and summer (due to air conditioning), often reaching maximum levels on days of extreme heat.

Between 2019 and 2024, the NEM experienced a noticeable decline in demand during the middle of the day (Figure 2.14). This trend has been driven by the significant growth in rooftop solar installations across residential areas. As more households have installed rooftop solar, a substantial portion of daytime electricity consumption is now being met by their own onsite solar generation. This self-generation reduces the amount of electricity required from the grid during daylight hours, particularly around midday when solar output is at its peak.

Conversely, grid demand has increased during the early morning and early evening periods, commonly referred to as peak hours, in part due to population growth. During these times, residential electricity usage tends to be high – due to activities such as heating, cooling, lighting and appliance use – while solar generation is minimal or non-existent due to the lack of sunlight. As a result, households rely more heavily on the grid during these periods. With population growth contributing to higher overall consumption, peak demand has risen despite the overall decline in midday demand.

Figure 2.14 NEM average demand, by time of day



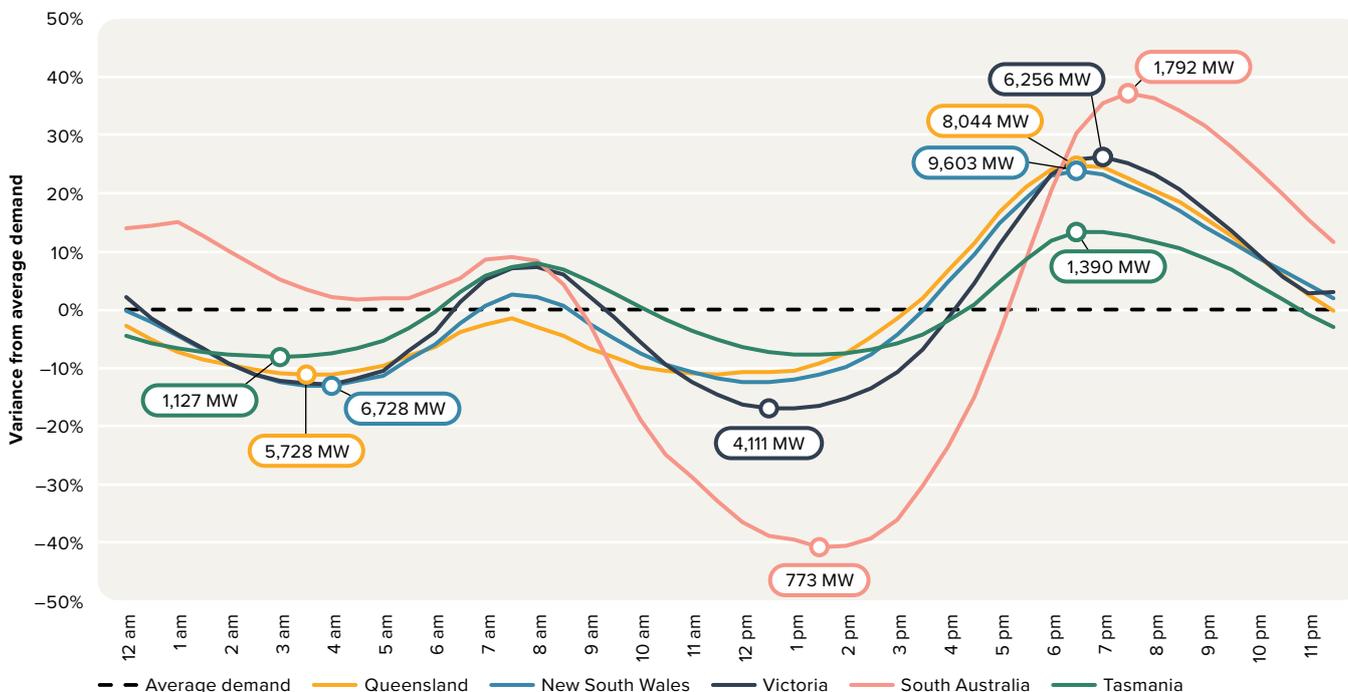
Note: The AER defines native demand as the sum of initial supply and total intermittent generation in a region. This figure presents outcomes in NEM time (Australian Eastern Standard Time). Values of y-axis do not start at zero to highlight the changes in demand.

Source: AER; AEMO (data).

⁴⁶ Consumer energy resources are distributed energy resources that are owned or leased by residential and small business consumers (or groups of consumers) that generate or store electricity or can alter demand in response to external signals. These resources include consumer loads that are flexible and efficiently optimised either through automation or direct behavioural response.

The gap between minimum and maximum demand varies considerably between regions. South Australia has the largest variation (approximately 80%), followed by Victoria, NSW and Queensland (ranging from 34% to 41%), and Tasmania has the smallest (21%) (Figure 2.15). The variability of grid demand is influenced by factors such as the level of rooftop solar uptake (which increases variability) and the proportion of electricity demand coming from heavy industry (which decreases variability).

Figure 2.15 Average demand by time of day in 2024, by region



Note: The AER defines native demand as the sum of initial supply and total intermittent generation in a region. 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; AEMO (data).

AEMO modelling shows that residential customers in the NEM currently consume around 60 TWh of electricity each year – around 40 TWh of this comes from the grid and 20 TWh is supplied by rooftop solar. Annual electricity consumption from business and industry in the NEM is around 150 TWh, almost all of which comes from the grid. Residential grid demand accounts for around 21% of total grid demand.⁴⁷

AEMO’s modelling forecasts that NEM consumption will rise by around 108% by 2050.⁴⁸ Residential electricity use is forecast to increase due to uptake of electric vehicles and greater use of electricity for heating, cooling and cooking. Business and industry consumption is forecast to increase due to economic growth, the emergence of hydrogen and electrification of transport and industrial processes.

As households increasingly meet their own electricity needs through CER, residential grid demand will likely stay about the same. However, business and industry grid demand is forecast to increase by nearly 70% by 2050, reaching around 260 TWh.⁴⁹

47 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

48 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

49 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, 26 June 2024.

2.7 Market generation sources and ownership

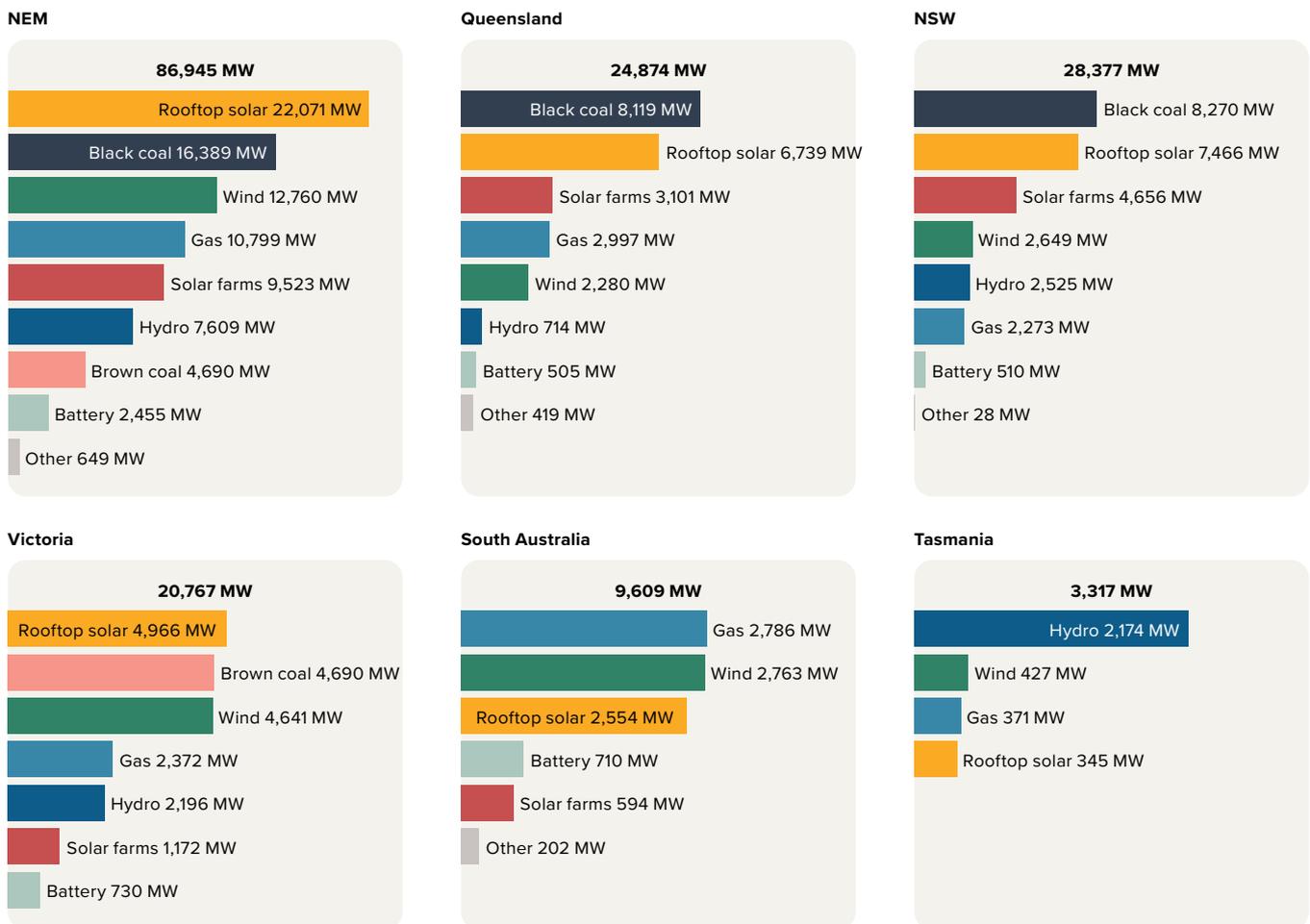
The NEM’s generation fleet uses a mix of technologies to produce electricity. The NEM’s generation mix can be measured in 2 ways – based on the registered capacity of each generating unit or based on their total generation output.

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 of their capacity. Coal generators typically produce at a high rate relative to capacity because they can generate continuously throughout the day. Wind and solar generation are intermittent and produce electricity at a lower rate relative to their capacity. Gas and hydro generators may also produce electricity at a lower rate relative to capacity, depending on a range of factors including fuel costs and availability.

2.7.1 Sources of generation

By the end of 2024, total generation capacity in the NEM was 86,945 MW. Rooftop solar had the highest capacity, totalling 25% of registered capacity, followed by black coal at 19% (Figure 2.16). The installed capacity of renewable technologies (rooftop solar, solar farms, wind and hydro) represented 60% of total capacity in 2024.

Figure 2.16 Generation capacity, by fuel source

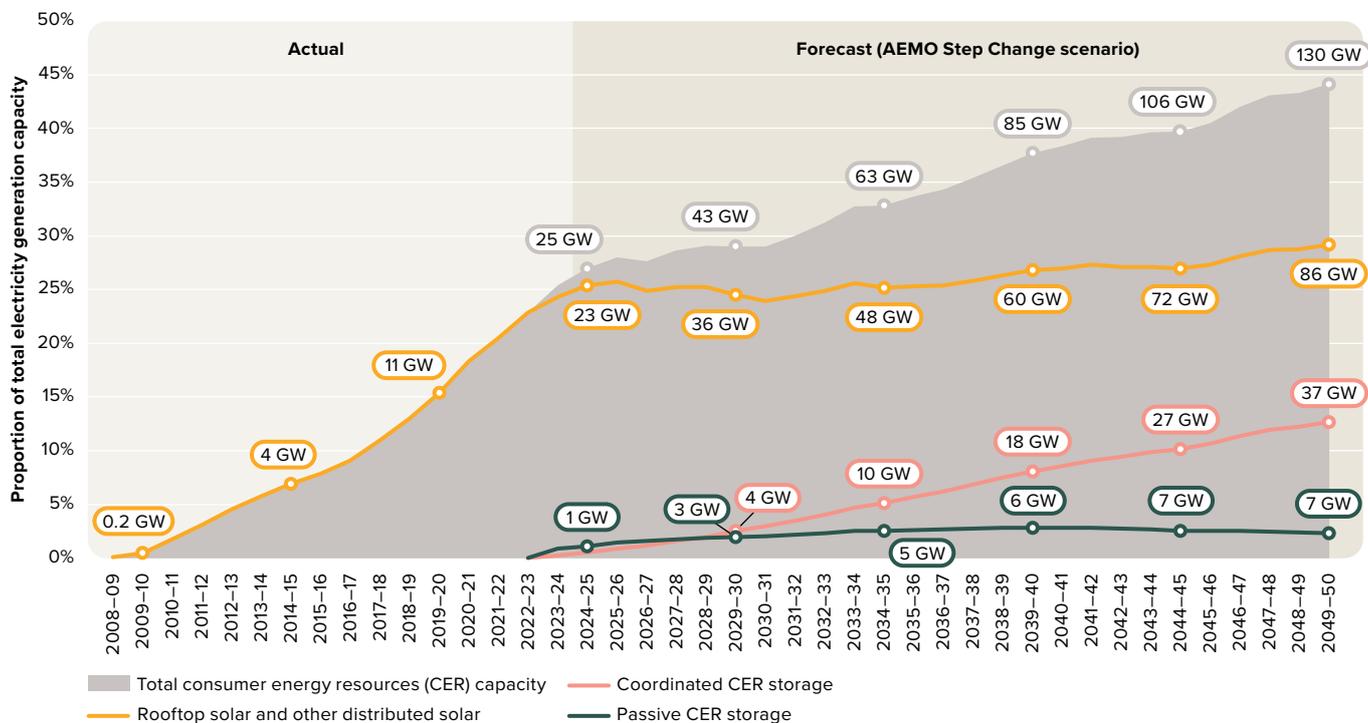


Note: Generation capacity as at 31 December 2024. Other dispatch includes biomass, waste gas, diesel and liquid fuels. Loads and non-scheduled generation have been excluded. For solar and battery units, we used the maximum capacity metric rather than registered capacity because inverter constraints may prevent these units from dispatching their full registered capacity.

Source: AER; AEMO (grid capacity data); Clean Energy Regulator (rooftop solar capacity data).

CER's share of generation capacity is expected to increase over time and AEMO forecasts it to reach 130 GW of capacity by 2050 (Figure 2.17). This is expected to represent about 45% of total NEM generation capacity.

Figure 2.17 Electricity generation capacity through consumer energy resources



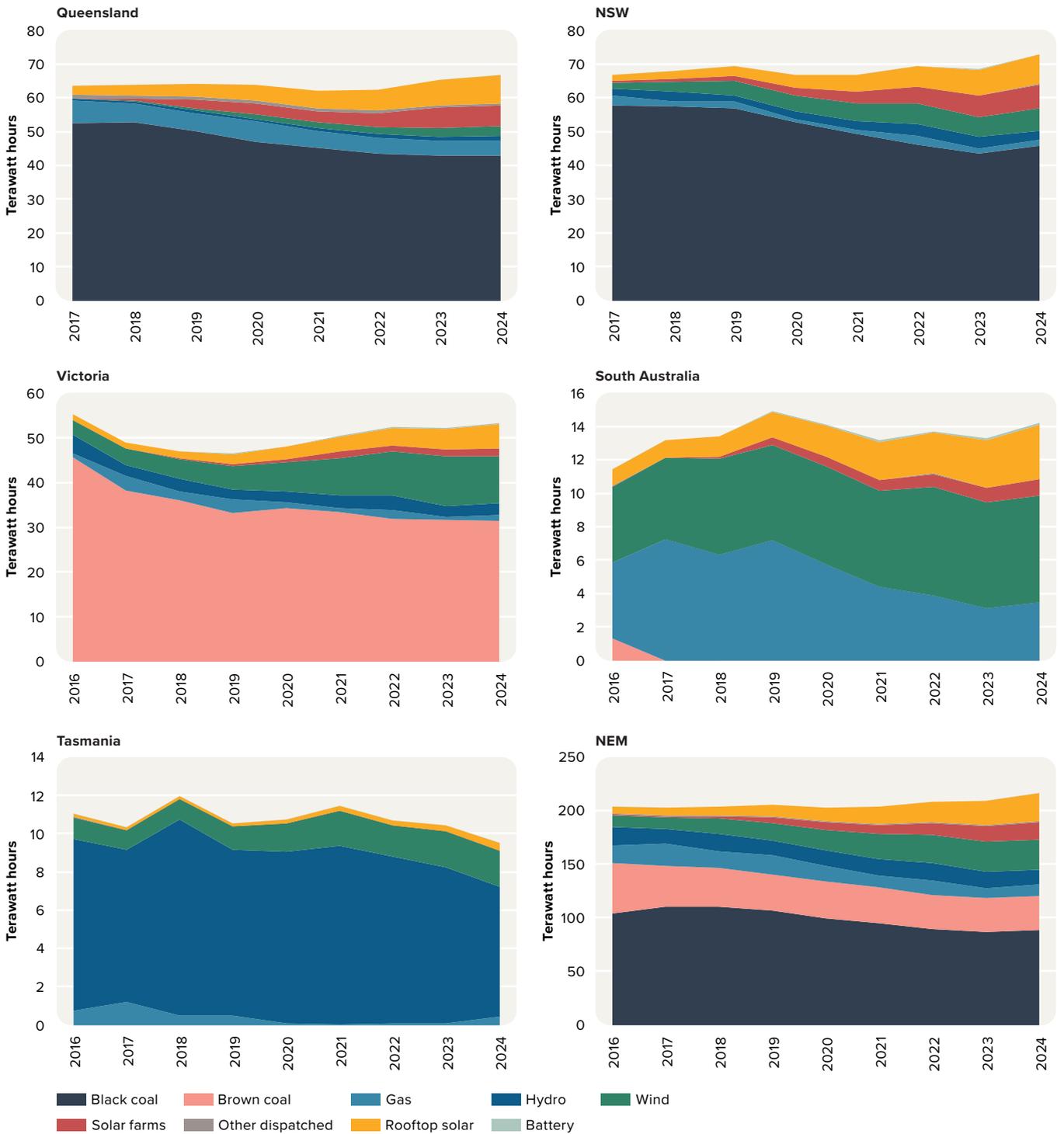
Source: AEMO, 2024 Integrated System Plan (ISP), Australian Energy Market Operator, 26 June 2024.

Generation output refers to the total amount of electricity produced over a given period. In 2024, 217 TWh of electricity was generated – 191 TWh by grid-scale generators and 26 TWh by rooftop solar systems (Figure 2.18). Compared with 2023, this represented a 2% increase in grid-scale generation output and a 13% increase in rooftop solar output (a 3% increase in generation output overall).

Coal and gas generators produced 61% of generation output, which was a slightly lower proportion than the previous year but represented a slight increase in total output. This in turn drove a 2% increase in carbon emissions from electricity generation. Renewable generators (rooftop solar, large-scale solar, wind and hydro) contributed 39% of electricity generation output, up from 38% in 2023. This modest increase was due to a 7% increase in solar and wind output being offset by an 11% decrease in hydro output. Hydro output is influenced by rainfall levels – Tasmanian hydro generation, in particular, has been impacted recently by a period of extremely low rainfall.⁵⁰

50 See for example, Hydro Tasmania, [Tasmanians to benefit from \\$122m Hydro dividend](#), Hydro Tasmania, 17 October 2024.

Figure 2.18 Generation output, by fuel source



Note: Other dispatch includes biomass, waste gas, diesel and liquid fuels.
 Source: AER; AEMO (data).

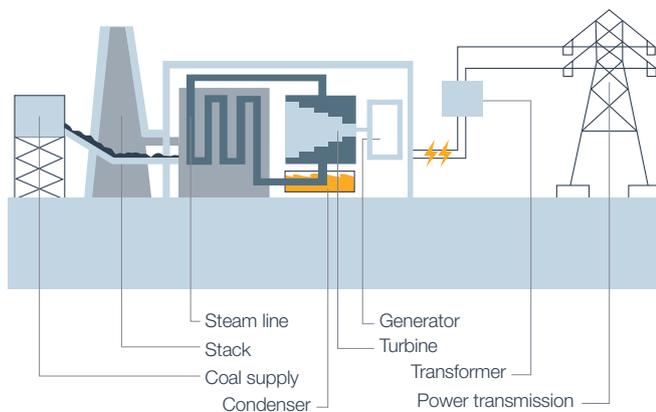
2.7.2 Characteristics of technology types

The various generation technologies (Figure 2.19) have differing characteristics that drive generator behaviours and have implications for price outcomes, as well as reliability and security of the energy system. Differences in startup, shutdown and operating costs influence each fuel type's bidding and generation strategies. Technology types also have different implications for power system security, including system strength and frequency.

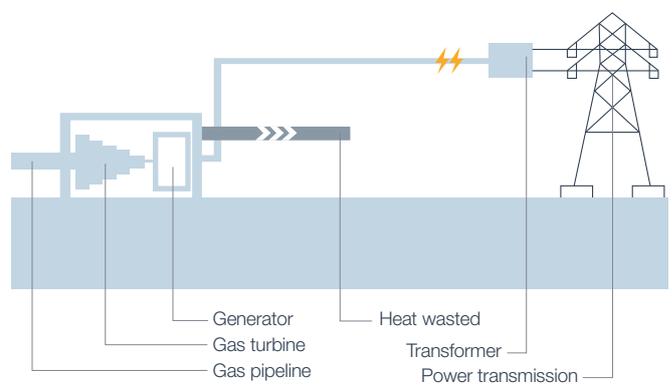
Renewable generation in the NEM has increased significantly over the past decade as Australia progresses towards carbon emissions reduction targets. By contrast, output from emissions-intensive black and brown coal generators has generally been declining, despite an uptick in 2024. Since new wind and solar generation has very different characteristics to the coal it is replacing, there are significant implications for the power system.

Figure 2.19 NEM generation technologies

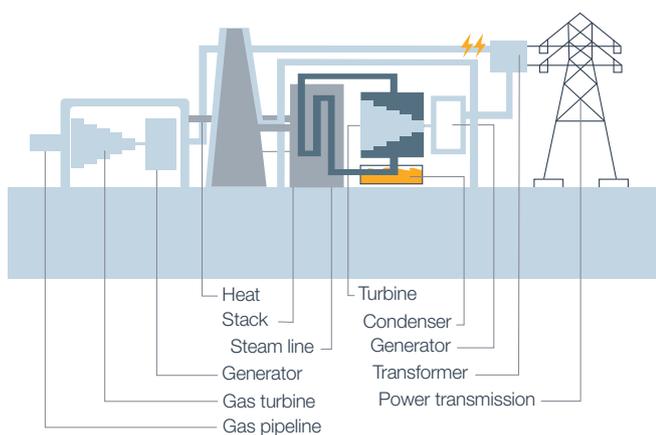
Coal-fired generation



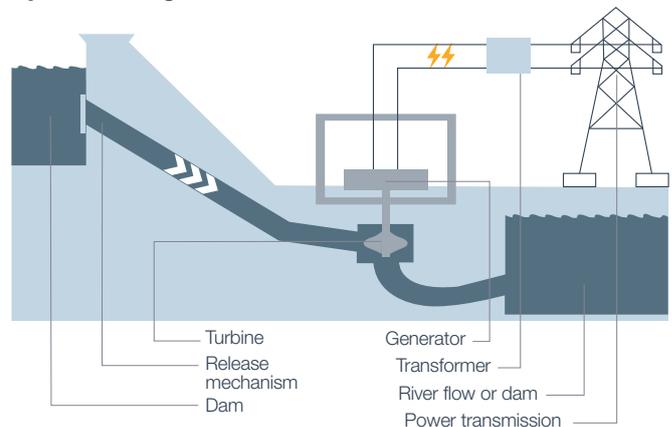
Open cycle gas-powered generation



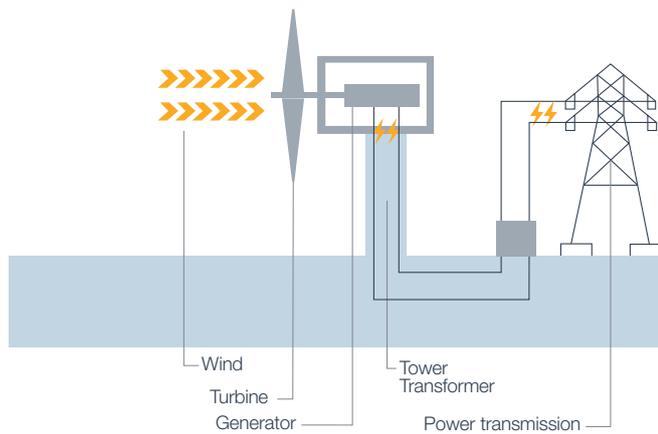
Combined cycle gas-powered generation



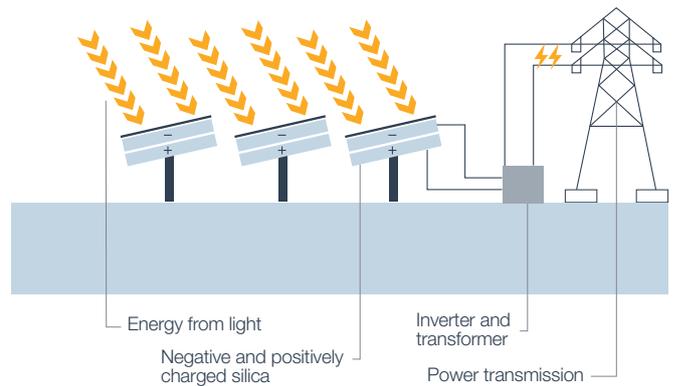
Hydroelectric generation



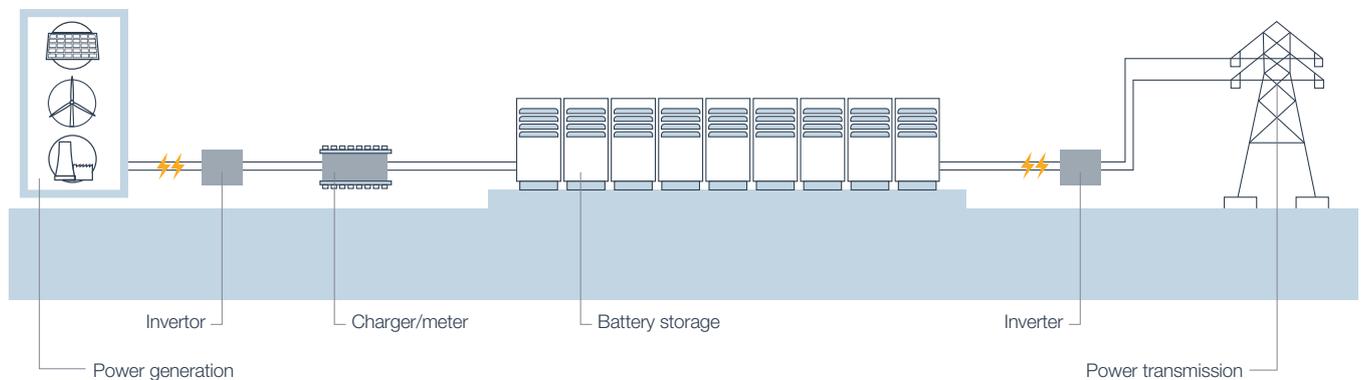
Wind-powered generation



Solar PV generation



Battery energy storage system



Traditional power sources, such as coal, gas and hydro, are dispatchable. This means they can be turned on and off as required – although some generation technologies can do this faster than others. By contrast, wind and solar generators are intermittent and can only provide energy when weather conditions are suitable. Battery storage and pumped hydro can provide further dispatchable generation output by storing the power generated by intermittent sources and supplying it back to the market when required.

An important characteristic of dispatchable generation is how quickly it can be turned on and off or ramped up and down. The output of intermittent renewables changes quickly based on the conditions and the flexibility of dispatchable generation impacts how quickly it can respond to this. Coal generators take many hours to turn on and can only ramp up and down slowly. This makes them less suited to balance the fluctuations of intermittent renewables. Gas and hydro power stations can turn on in a matter of minutes and ramp up and down much faster than coal. Meanwhile, batteries can adjust their output up and down almost instantly, which enables them to help maintain the power system in a secure state faster than other technologies. For the transition to renewables to be successful, there must be sufficient flexible generation – such as gas, hydro and batteries – to balance out the volatility in intermittent generation output and continuously meet demand for electricity in real time.

Different generation sources also face very different operating costs. Once solar and wind capacity has been installed, there is essentially no marginal cost of producing power. On the other hand, the cost of producing electricity using coal or gas is linked to the underlying fuel costs and the consistency in fuel supply. These costs can vary, but gas is typically much more expensive than coal. Hydro generators do not usually pay an explicit cost for their water but can face limited supply and may experience a high opportunity cost of generation. Similarly, a battery's cost of generation depends on the price it paid to recharge and the opportunity cost of discharging later. Changes in operating costs will influence a generator's decision on how much generation to offer into the market and at what price.

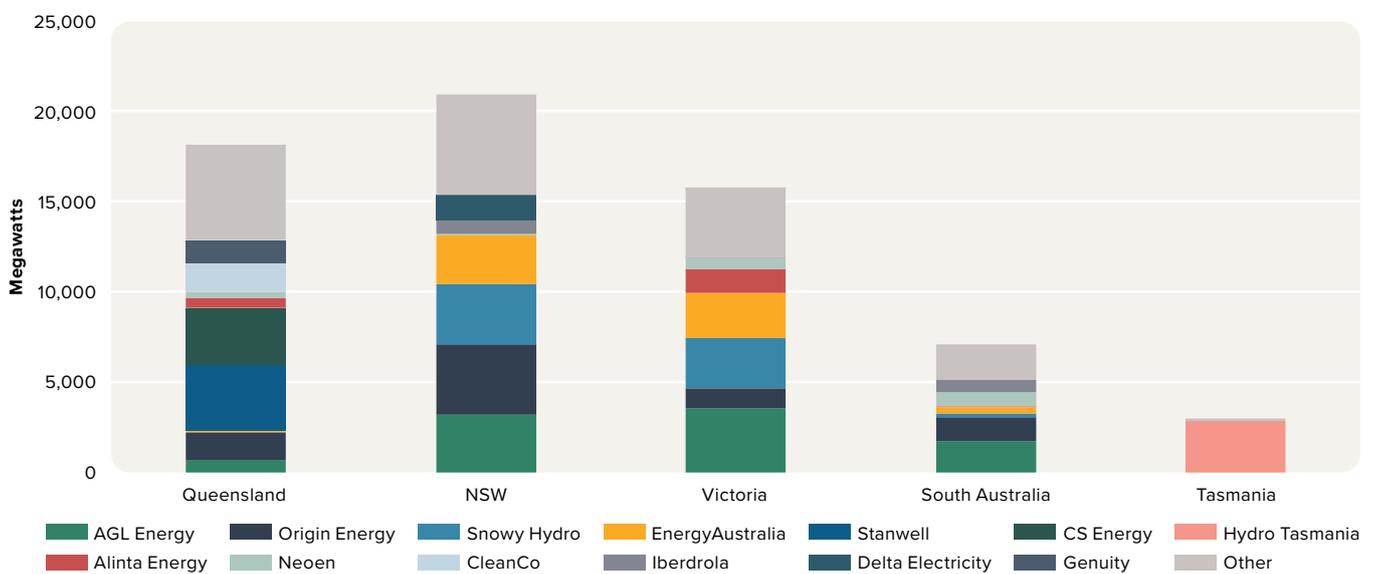
2.7.3 Market ownership and concentration

Nearly 400 generators sell electricity into the NEM. Despite significant diversity in new entry ownership in recent years, a few large participants still control a significant proportion of generation in each NEM region. Figure 2.20 shows the regional market share of the NEM’s 13 largest generation companies. In each region, the top 3 companies control:

- 46% in Queensland (Stanwell Corporation, CS Energy and CleanCo)
- 50% in NSW (Snowy Hydro, Origin Energy and AGL)
- 56% in Victoria (AGL, Snowy Hydro and Energy Australia)
- 54% in South Australia (AGL, Origin Energy and ENGIE).

Tasmania has the most concentrated electricity market in the country. The state-owned entity Hydro Tasmania controls approximately 95% of the state’s generation capacity.

Figure 2.20 Market share, by registered capacity



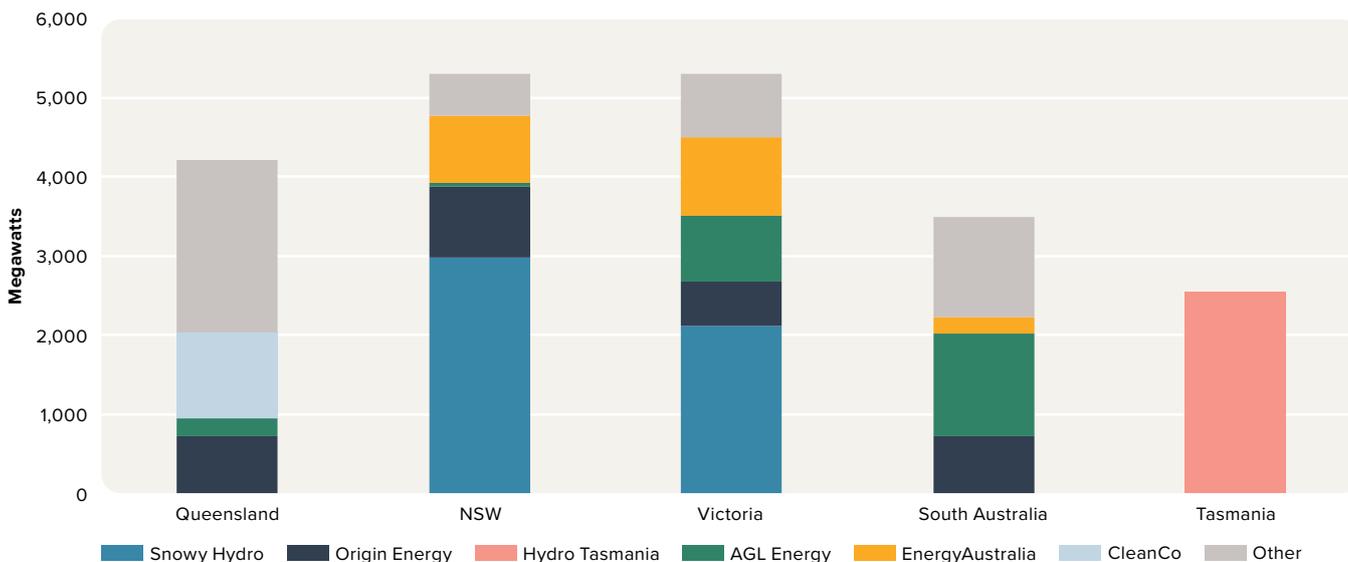
Note: This chart shows the registered capacity in each region of all market scheduled and semi-scheduled generation units (including bidirectional units but excluding market loads) registered as at 31 December 2024. For solar and battery units, we used the maximum capacity metric rather than registered capacity because inverter constraints may prevent these units from dispatching their full registered capacity. 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; AEMO (data); various online sources (ownership information).

Market concentration by share of generation output varies considerably between the periods of highest and lowest concentration in each region. Concentration tends to be lowest in the middle of the day when diversely owned renewable generation is at its peak, reducing reliance on conventional generation sources. At peak times, when conventional generation sources form a greater share of total generation, all regions are highly concentrated.

Ownership of flexible generation, which can quickly respond to changing market conditions, is particularly concentrated because a few participants control significant flexible generation capacity in NSW, Victoria, South Australia and Tasmania.

Figure 2.21 Market share of flexible generation



Note: This chart shows the registered capacity in each region for hydro, gas and batteries registered as at 31 December 2024. 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; AEMO (data); various online sources (ownership information).

Snowy Hydro controls more than 5,000 MW of registered flexible generation capacity. Most of these assets are in NSW and Victoria and, as a result, Snowy Hydro controls 56% of flexible generation in NSW and 40% in Victoria. In addition, Snowy Hydro is developing Snowy 2.0, which would add a further 2,200 MW of flexible capacity to its portfolio and its 750 MW gas-fired power station near Kurri Kurri will start generating shortly. Origin Energy is the second-largest provider of flexible generation, with significant capacity across the mainland regions. Collectively, Snowy Hydro and Origin Energy control 62% of all flexible capacity across NSW and Victoria.

As coal stations close and the market depends more heavily on renewable generation, flexible generation will play an increasingly important role in the market at peak times. Detailed analysis of market structure and competition, including concentration and competition in the supply of flexible capacity, in addition to broader market outcomes, are addressed in the AER's Wholesale electricity market performance report, most recently in December 2024.

2.8 Trade across regions

Interconnectors enable energy transfers between the NEM's 5 regions. Interconnectors generally deliver energy from lower-priced regions to higher-priced regions. They also increase the reliability and security of the power system by enabling demand in one region to be met by generation from an adjacent region.

The ability of generators to supply energy to other regions is limited by the capacity of the transmission network and the capacity of the interconnector. This capacity can change depending on the direction of flow, outages on the network or other physical constraints, and limits that AEMO imposes to manage system security.

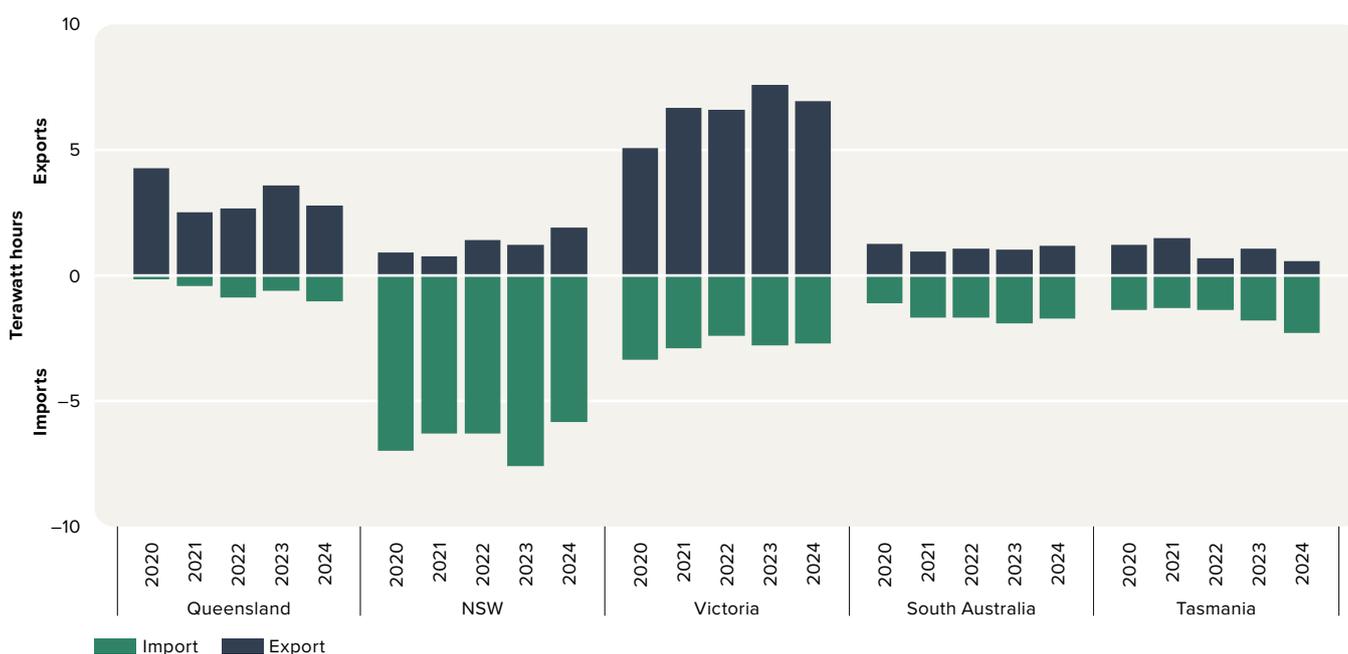
An interconnector is constrained when the volume of electricity flowing across it reaches its technical limit. Each interconnector has a nominal limit, which represents its capacity in optimal conditions, but its technical limit at any given time could be lower – for example, due to outages or grid congestion on nearby transmission lines.⁵¹ When an interconnector is constrained, cheaper sources of generation in one region cannot replace more expensive generation in another, effectively separating those regions into separate markets (price separation). Interconnector constraints are often a factor in high price events.

51 AEMO, [Interconnector capabilities](#), Australian Energy Market Operator, April 2024.

To support the transition to renewable generation, new transmission infrastructure will be needed. AEMO’s 2024 Integrated System Plan provides a coordinated whole-of-system plan for efficient development of the power system in the NEM to ensure needs are met in the long-term interests of consumers. As part of this transition, several major interconnector transmission projects are planned or underway. More information on transmission projects is set out in section 3.13.7 in chapter 3.

Queensland and Victoria tend to be net exporters of energy, providing surplus electricity to NSW and South Australia. This was the case in 2024, when Queensland and Victoria were net exporters of energy and NSW, South Australia and Tasmania were net importers (Figure 2.22). Tasmania’s trade position varies with environmental and market conditions; throughout 2023 and 2024 it was a net importer of electricity. In 2023 and 2024, Hydro Tasmania experienced a substantial decline in hydro generation due to below-average rainfall.⁵² It also ran its gas-fired assets at the Tamar Valley Power Station more frequently to manage the generation shortfall, including the Combined Cycle Gas Turbine, which operated from 6 June 2024 to 23 August 2024.

Figure 2.22 Inter-regional trade



Note: Gross amount of energy imported and exported by each region.
 Source: AER; AEMO (data).

52 Office of the Tasmanian Economic Regulator, [Energy In Tasmania Report 2023–24](#), Executive Summary, March 2025, p. i.

2.8.1 Market alignment and network constraints

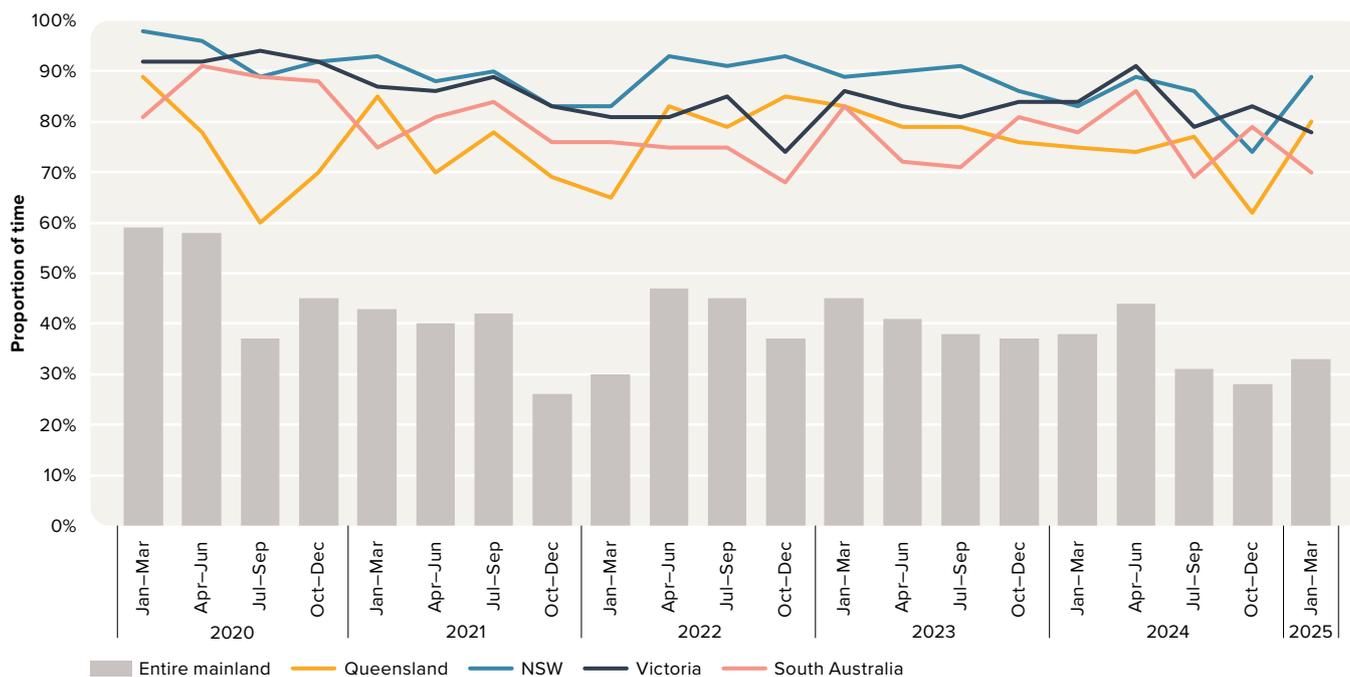
The market sets a separate spot price for each NEM region. When interconnectors are unconstrained, competitive pricing pressure from neighbouring regions brings prices into alignment across the NEM (with slight variations caused by physical losses that occur when transporting electricity). At these times, the NEM functions more like a single market than a collection of regional markets, because generators are exposed to competition from generators in other regions.

As coal-fired generators retire and new generation sources are developed in different locations, new areas of network constraint are emerging – often due to line capacity limitations or system security considerations. These constraints can affect electricity prices by limiting the flow of cheaper power to the market and may also influence inter-regional trade dynamics in the future.

For example, we reported in the *Wholesale electricity market performance report 2024* that the Victoria to NSW interconnector has been subject to increasingly frequent instances of energy flowing ‘counter price’ from a high-priced region to a low-priced region. Counter-price flows occur when electricity flows in the opposite direction to price to manage network congestion. These flows diminish the efficiency of the market and the extent to which a lower priced region can provide a competitive constraint.⁵³

In recent years, price alignment across regions has been falling. This overall trend continued in 2024 in all regions, with a particularly sharp drop during the October to December quarter in Queensland and NSW. In the January to March quarter 2025, alignment increased in Queensland and NSW but decreased in Victoria and South Australia (Figure 2.23).

Figure 2.23 Price alignment in mainland NEM regions



Note: Inter-regional 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.

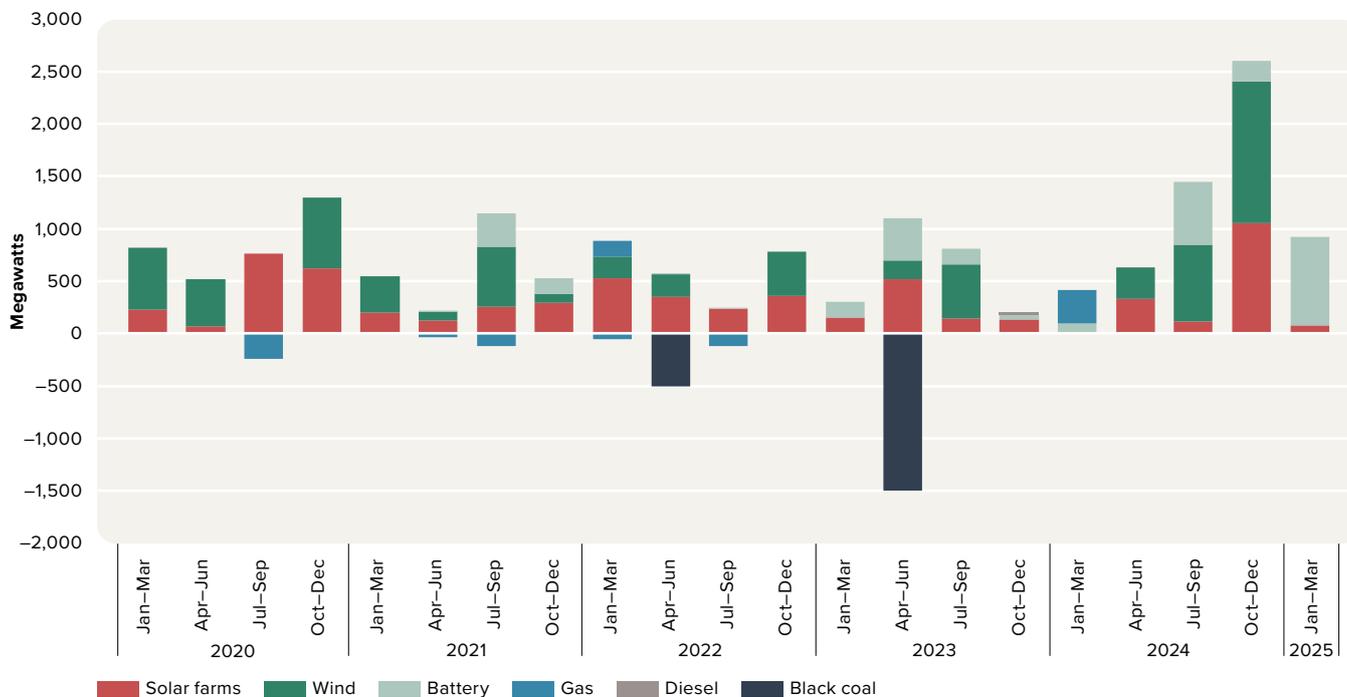
Source: AER; AEMO (data).

53 AER, *Wholesale electricity market performance report 2024*, Australian Energy Regulator, 20 December 2024. p. 67.

2.9 Generation investment and plant closures

Over 16 GW of new grid-scale solar, wind and battery investment has been added to the NEM since the beginning of the 2020, with around 5.1 GW entering in 2024 (Figure 2.24).

Figure 2.24 New generation investment and plant withdrawal



Note: This chart illustrates market entry and exit. 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. The new entry date is taken as the first day the station receives a dispatch target. Solar reflects large-scale solar and does not include rooftop solar.

Source: AER; AEMO (data).

The new capacity that entered during 2024 included:

- 2,381 MW of wind capacity, located in all regions except Tasmania
- 1,501 MW of solar capacity, located in NSW, Victoria and Queensland
- 891 MW of battery capacity, located in all regions except Tasmania
- 320 MW of gas capacity from Tallawarra B, a new gas peaking plant in NSW.

In addition to this, 921 MW of new capacity entered the market in the January to March quarter 2025, which included 845 MW of new battery capacity located in NSW, Queensland and Victoria, and a 76 MW solar farm in Victoria.

Large volumes of fossil fuel generators are scheduled to close by the end of 2027, including 2,892 MW of black coal and 980 MW of gas. AEMO's Generation information workbook lists 6,773 MW of committed projects⁵⁴ that are not active and are expected to come online during this period, including:

- 2,363 MW of solar
- 1,094 MW of wind
- 750 MW of gas
- 250 MW of hydro
- 2,316 MW of batteries, with an energy storage capacity of 5,997 MWh.

⁵⁴ Projects that will proceed, with known timing, satisfying all 5 of AEMO's commitment criteria (which are around land rights, contracts finalisation, planning applications, finance and construction dates). The [generation information workbook](#) (accessed 19 May 2025) was last updated 15 April 2025. We have removed projects that have commenced dispatching generation. For more information on the commitment criteria, see AEMO's [Reliability Forecasting Consultation Paper](#), October 2022, accessed 30 May 2025.

Projects have been taking longer to reach the commissioning stage in recent years. This might be caused by a range of factors, including financial market volatility, supply chain constraints, construction challenges, and environmental and planning approvals.⁵⁵ On-time delivery of new projects will be important to ensure the ongoing reliability of the NEM.

2.10 Power system reliability and security

Reliability is about the power system being able to consistently supply enough electricity to meet consumers' demand. Security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. System reliability and security both need to be carefully managed through the energy market transition.

2.10.1 Power system reliability

The energy market transition has increased the risk of reliability gaps. Coal plant closures remove a source of firm capacity that could historically be relied on to operate when needed. As contribution from weather-dependent generation increases, the power system must respond to increasingly large and sudden changes in output caused by changes in weather conditions and dispatch decisions by plant operators.

Reliability risks are typically highest over summer, particularly at times of peak demand. But they may also emerge at other times in the year, when solar or wind output is low, or there are transmission or plant outages.

The Retailer Reliability Obligation (RRO) is a mechanism that was designed to be a longterm solution to ensure reliability at the lowest cost. It facilitates the market to prepare for and eliminate forecast reliability gaps before they occur.

AEMO makes reliability forecasts under the RRO, which are incorporated into its annual Electricity Statement of Opportunities (ESOO) report.⁵⁶ When AEMO identifies a material reliability gap 3 years and 3 months out, it will apply to the AER to trigger the RRO by making a reliability instrument. Each Minister for Energy in a NEM region can also trigger the RRO by making an instrument directly.

Where a reliability instrument is made, liable entities (retailers and other parties that purchase electricity directly from the wholesale energy market) are on notice to enter into sufficient qualifying contracts with generators to cover their share of a once in 2 years peak demand event and report their net contract position to the AER.⁵⁷

In its 2024 ESOO, AEMO identified reliability gaps for NSW and Victoria for the summer of 2028–2029. In response, the AER triggered the RRO on 22 October 2024 and made reliability instruments for these regions.

⁵⁵ AEMO, [Integrated System Plan](#), Australian Energy Market Operator, June 2024.

⁵⁶ AEMO, [NEM Electricity Statement of Opportunities \(ESOO\)](#), Australian Energy Market Operator.

⁵⁷ For more information on the RRO, see AER, [Retail Reliability Obligation](#), Australian Energy Regulator, accessed 30 May 2025.

Box 2.3 How reliability is measured

Reliability outcomes are measured in terms of unserved energy – that is, the amount of energy required by consumers that cannot be supplied due to a shortage of capacity. The reliability standard requires any shortfall in power supply to not exceed 0.002% of total electricity demand. It has rarely been breached, but AEMO has increasingly intervened in the market in recent years to manage forecast supply shortfalls.

While the 0.002% target is used to assess market performance and the appropriateness of reliability settings such as the market price cap, a stricter interim reliability measure of 0.0006% was introduced in 2020 and is currently scheduled to run until 30 June 2028.⁵⁸ The interim reliability measure is used as a trigger for 2 mechanisms to prevent forecast supply shortages from occurring. If it forecasts unserved energy will exceed the 0.0006% threshold, AEMO can:

- request the AER to trigger the RRO and organise for liable entities to enter sufficient qualifying contracts to cover their share of a 1-in-2-year demand event; this can occur up to 3 years before a forecast reliability gap
- if a forecast reliability gap persists, contract out of market capacity under the reliability and reserve trader mechanism to reduce the risk of a supply gap.

The reliability standard excludes outages caused by ‘non-credible’ threats, such as bushfires and cyclones, because the power system is not engineered to cope with these issues and the cost of doing so would be prohibitive. It also excludes supply interruptions originating in local distribution networks. Around 95% of a typical customer’s power outages originate in distribution networks and are caused by local power line and substation issues.

In effect, the standard sets a level of unserved energy that balances the cost of providing reliability against the value that customers place on avoiding an unexpected outage.

The Reliability and Emergency Reserve Trader (RERT) is another mechanism used to address reliability risks. It enables AEMO to use reserve contracts to prevent load shedding (deliberate disconnection of customers to prevent potentially significant damage to the power system) or other threats to reliability. When forecast reliability is outside the relevant standard, AEMO can pay large industrial customers to standby to reduce their consumption should this be required to prevent load shedding. AEMO may also pay generators from outside the market to standby in case additional supply is required.

Reserves procured under the RERT must be ‘out of market’. Any generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT. AEMO maintains a panel of RERT providers that can provide short notice and medium notice reserve if required. Panel members for short notice RERT agree on prices when appointed to the panel, whereas panel members for medium notice RERT negotiate the price when reserves are required. AEMO may procure long notice reserve through invitations to tender, where it has 10 weeks or more notice of a projected shortfall, as well as interim reliability reserves if the stricter reliability target is forecast to be exceeded.

Market participants that provide short notice reserves are compensated if the reserves are activated, or pre-activated, but are not compensated based on availability. In contrast, participants that provide long run or interim reliability reserves are compensated for making generation available. The RERT should only be activated if necessary to avert load shedding or other risks to reliability and system security. The capacity activated under the RERT scheme is typically more expensive than that acquired through the market; this is a cost that is ultimately borne by customers.

The cost incurred by AEMO for these standby services should be less expensive than the projected cost of load shedding for customers. The values of customer reliability (VCR) are thresholds set by the AER.⁵⁹ VCR seek to reflect the value different types of customers place on reliable electricity supply under different conditions and are usually expressed in dollars per kilowatt hour of unserved energy. A guiding principle of RERT payments is that they should not exceed the VCR, but doing so is not prohibited.⁶⁰

58 AEMC, [Final rule to extend Interim Reliability Measure](#), Australian Energy Market Commission, September 2023.

59 AER, [Values of customer reliability](#), Australian Energy Regulator, accessed 2 April 2025.

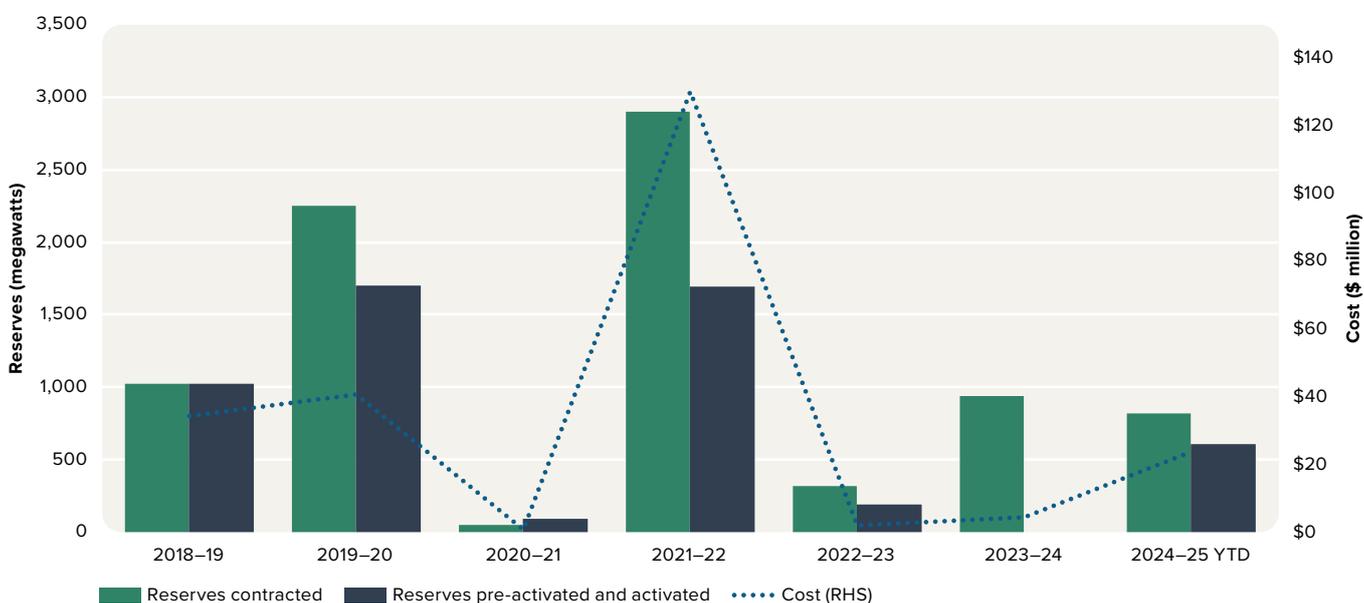
60 AEMC, [National Electricity Amendment \(Enhancement to the Reliability Emergency Reserve Trader\) rule 2019](#), Australian Energy Market Commission, May 2019.

AEMO entered into interim reliability reserve (IRR) contracts for the first time in 2023, following reliability shortfalls identified in its 2023 Electricity Statement of Opportunities. In preparation for the summer period, AEMO contracted a total of:

- 100 MW of IRR in Victoria and 10 MW in South Australia for the period 1 December 2023 to 31 March 2024
- 19 MW in Victoria for the period 1 January 2024 to 31 March 2024.⁶¹

These contracted interim reliability reserves were not activated or pre-activated but incurred an availability cost totalling \$4,252,685 for the 2023–24 financial year. AEMO also entered into several short notice contracts in response to forecast lack of reserve 2 conditions on 14 December 2023, 27 January 2024 and 13 February 2024, totalling 807 MW. Unusually, AEMO did not pre-activate or activate any of the contract capacity, but the total cost of RERT was still higher than the previous year (Figure 2.25) due to the IRR contracts.

Figure 2.25 Interim reliability reserves and short notice contracted costs



Note: Reliability and Emergency Reserve Trader (RERT) costs include costs for availability, pre-activation, activation and other costs (including compensation costs). 2024–25 YTD includes data to the end of March 2025.

Source: AER analysis of AEMO's RERT reporting.

Following shortfalls identified in its 2024 ESOO, AEMO's preparation for the 2024–2025 summer period included contracting a total of:

- 127 MW of IRR in South Australia, covering the period from 1 January 2025 to 31 March 2025. The total amount payable by AEMO was \$19,089,765.⁶²
- 85 MW of IRR in NSW, covering the period from 1 December 2024 to 31 March 2025. The total amount payable by AEMO was \$1,201,336.⁶³

AEMO also entered into several contracts in response to a forecast lack of reserve level 2. Of these, 605 MW were pre-activated and 65 MW were activated. The total amount payable was \$3.55 million. The cost per MWh was \$56,359.⁶⁴

61 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q4 2023](#), Australian Energy Market Operator, February 2023.

62 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q1 2025](#), Australian Energy Market Operator, 15 May 2025, accessed 20 June 2025.

63 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q4 2024](#), Australian Energy Market Operator, February 2025, accessed 1 May 2025.

64 AEMO, [Reliability and Emergency Reserve Trader \(RERT\) Quarterly Report Q4 2024](#), Australian Energy Market Operator, February 2025, accessed 1 May 2025.

The RERT has averted multiple instances of load shedding since the initiative began, but doing so comes at significant cost to the consumer. Typically, RERT costs have been calculated in reference to the MWh usage of activated contracted capacity. The average cost of the RERT in the previous 5 financial years has been just over \$36,000 per MWh, nearly double the current market price cap of \$20,300 per MWh.

AEMO's 2024 ESOO stated that 'If further investment beyond current committed and anticipated projects is delayed or does not materialise, AEMO forecasts reliability gaps will exist over the coming years in some NEM regions.'⁶⁵ Increased volumes of interim reliability reserves or long notice reserves may be required in the future to meet reliability shortfalls. This cost will ultimately be borne by customers.

2.10.2 Security performance in the NEM

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. System strength refers to the power system's ability to ensure correct operation of network protection equipment and maintain stable voltage waveforms. To ensure a secure power system, system security and system strength must be maintained within defined limits.

Frequency control markets

As part of AEMO's market operations, it is required to maintain system frequency within a secure range (between 49.85 and 50.15 hertz). Any deviations from this range should not exceed more than 1% of the time over any 30-day period. Maintaining system security during the energy transition has been a key focus of the NEM market bodies. Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 hertz. The NEM has 10 FCAS markets, which are either regulation services or contingency services.

- Regulation services operate continuously to balance minor variations in frequency caused by small changes in demand or supply during normal operation of the power system.
- Contingency services manage large frequency changes from sudden and unexpected shifts in supply or demand, they are used less often, and are purchased as either raise or lower services.

Historically, regulation services costs were recovered from participants that contributed to frequency deviations (causer pays).

- Raise contingency services costs were recovered from generators.
- Lower services costs were recovered from market customers (usually retailers).

From 8 June 2025, the NEM implemented frequency performance payments (FPP), a double-sided incentive that rewards or charges participants based on their impact on system frequency. Building on the existing 'causer pays' model, FPP applies to all generation and load units with appropriate metering. Units that help stabilise frequency receive payments, while those that worsen deviations incur charges. Participants without suitable metering (the 'residual') are assigned a share of total FPP and regulation FCAS costs, based on their proportion of energy consumed or sent out within each dispatch interval.

AEMO acquires FCAS through a co-optimised market that coordinates offers from generators and other participants in both energy and FCAS markets to minimise overall cost.

- Local FCAS services are provided from market participants in a region when that region is electrically islanded from the NEM.
- Global FCAS services occur when services are provided in a region that is connected to other regions, through available interconnectors.

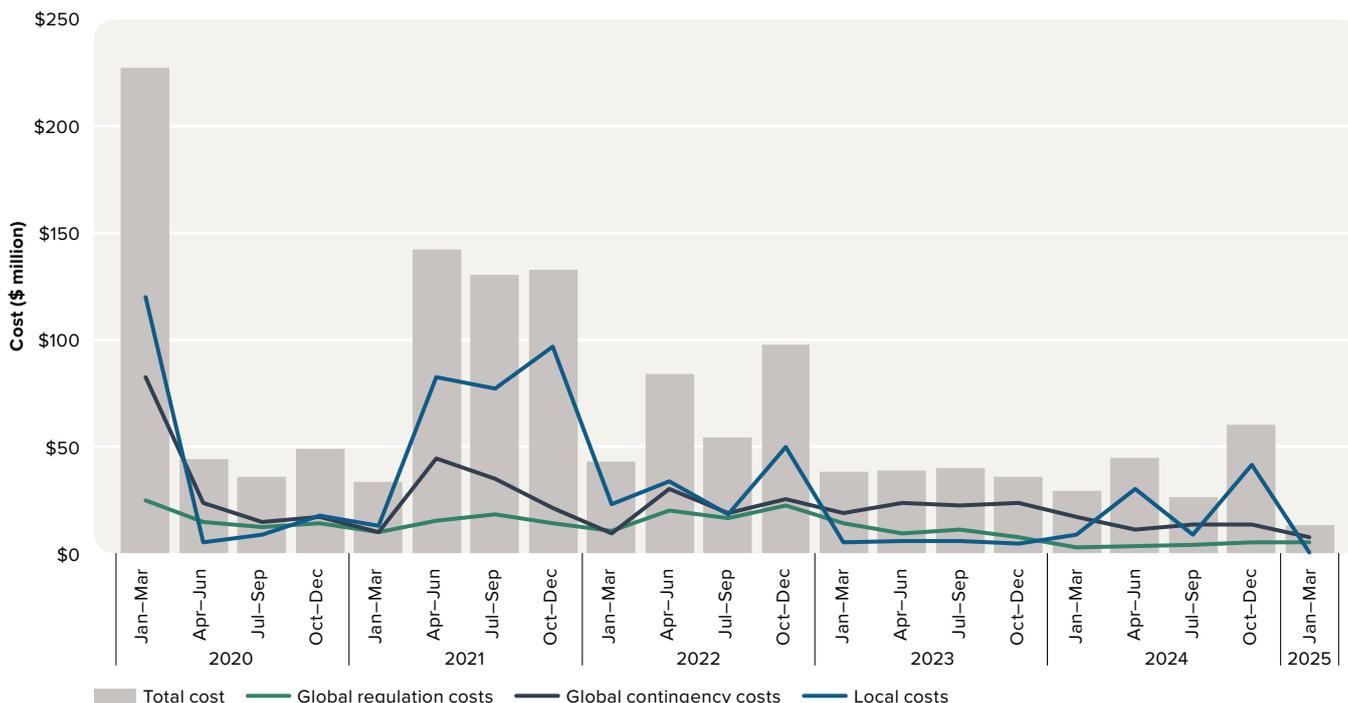
Fewer participants operate in FCAS markets than in the wholesale electricity market, but participation is growing – as at 1 January 2025, 46 participants were registered to provide services across the NEM, with some participants providing services in multiple regions. Of the 46 participants, 17 participants were providing FCAS in Queensland, 19 in NSW, 20 in Victoria, 18 in South Australia and 3 in Tasmania. New generation technologies, such as batteries, demand response and virtual power plants, can offer FCAS services and in some cases have been displacing incumbent providers (coal, gas and hydro).

65 AEMO, [2024 Electricity Statement of Opportunities](#), Australian Energy Market Operator, August 2024, accessed 2 June 2025.

Total FCAS costs increased by 5% in 2024 compared with 2023 (Figure 2.26). Global FCAS costs decreased by 45% and local FCAS costs increased by 315%, compared with 2023.

The decline in global costs in 2024 continued a longer-term trend and reflected lower costs for both regulation and contingency services. This likely reflects increased competition, due to the increase in the number of participants registered to provide FCAS services. While local FCAS costs were higher in 2024 than in 2023, they were lower than costs in 2020 to 2022. Of the \$89 million in local costs incurred in 2024, \$71 million was incurred in the April to June and October to December quarters of 2024. \$64 million of the local costs incurred during these quarters were for Queensland services, and mostly 6-second services.

Figure 2.26 Total FCAS costs



Note: Record FCAS costs in the January to March quarter 2020 were due to high local costs in South Australia when it was islanded for several weeks following the loss of the Heywood interconnector. In January 2020 bushfires also drove high prices across the NEM.

Source: AER; AEMO (data).

Other system security market features

Security performance can be impacted by changing system conditions (including extreme weather events) and uncertain supply demand balance. AEMO now reports annually on system security needs across the NEM for the coming 10-year period. Its 2024 system strength report identified that all regions except South Australia are expected to experience system strength shortfalls over the next 3 years unless investment or services are provided by the relevant system strength service provider in each region.⁶⁶

System security services have historically been provided by synchronous generators (coal, gas and hydro).⁶⁷ These services can be replicated by other technologies, with appropriate market settings. Options can include synchronous condensers, retrofitting of clutches to existing/future gas turbines and grid-forming inverter-based resources solutions (such as batteries). System strength service providers are currently undertaking the process to plan for and procure system strength ahead of the first binding requirements starting on 2 December 2025.

66 AEMO, [2024 System Strength Report](#), Australian Energy Market Operator, February 2025, p. 3.

67 Synchronous generators are large spinning units that have turbines that spin at the same speed as the frequency of the power system. As a result, there is an electro-mechanical 'link' between the mechanical energy of the generator and the electrical frequency of the power system. Asynchronous generators are those that connect to the power system using inverters, such as wind and solar.

AEMO use of directions

AEMO has powers to direct market participants to take relevant actions to maintain or restore power system security or system strength. Directions are intended as a last resort intervention when the market has not delivered the necessary requirements.

The energy transition is necessitating more frequent directions from AEMO to maintain power system security. In South Australia, directions to market participants to take action to maintain or restore power system security have been in place for a substantial amount of time for the past several years.⁶⁸

In May 2025, AEMO published plans to reduce the requirement for the number of synchronous generators required to operate in South Australia from 2 to 1, assuming certain criteria are met.

2.11 Market reforms and policy developments

Market reform and policy development through 2024 and into 2025 focused on the NEM's transition towards a low-emissions energy system. These efforts build on the Australian Government's legislated Net Zero Plan⁶⁹ and the rollout of the Capacity Investment Scheme (CIS),⁷⁰ and seek to evolve market design to reflect the changing dynamics of the electricity system.

The Australian Government has completed 2 CIS tender rounds for the NEM. The successful projects for the South Australia–Victoria Dispatchable Tender were announced on 4 September 2024 and for the CIS Tender 1 – NEM Generation on 11 December 2024.⁷¹ Together, these tenders approved 25 projects, expected to begin operation from 2027, delivering 6.4 GW of wind and solar generation capacity and 2.1 GW (7.2 gigawatt hours [GWh]) of storage capacity. CIS Tender 3 – NEM Dispatchable (targeting 4 GW or 16 GWh) and CIS Tender 4 (targeting 6 GW) are expected to announce successful bids in September and October 2025, respectively.⁷² This continued rollout supports Australia's 2030 target of 82% renewable electricity and 32 GW of new capacity.

In November 2024, the Australian Government launched a review of the NEM wholesale market settings, led by an independent expert panel and supported by the Department of Climate Change, Energy, the Environment and Water. The review aims to recommend settings that will encourage investment in firmed renewable generation and storage post-CIS, and to deliver a roadmap for reform aligned with Australia's National Electricity Objectives.⁷³

In December 2024, the AEMC made a final rule determination to better integrate price-responsive resources – such as community batteries, virtual power plants and flexible loads – into the NEM.⁷⁴ This rule was prompted by a 2023 rule-change request made by AEMO.

Demand response was already able to register to participate in the NEM via the wholesale demand response mechanism, which was implemented in October 2021. Participation rates in the mechanism have been low, with the AEMC reporting in March 2025 that only 74 MW of capacity had been registered and 1,258 MWh dispatched since the mechanism's inception.⁷⁵ Most of this was offered into the market at very high prices. Meanwhile, there has been continued entry of price-responsive resources that are unscheduled and not fully integrated into market operations.

Not accounting for price-responsive resources in the operation of the electricity system can lead to higher energy prices, which drive inefficient investment in generation, storage and demand response. It can also lead to greater demand forecast errors, which increase FCAS requirements and prices. The new rule attempts to address these problems. It enables price-responsive resources to become dispatchable, introduces short-term incentives to drive participation and establishes monitoring to improve forecast accuracy. AEMO is progressing implementation through its NEM Reform Program.⁷⁶

68 AEMO, [Quarterly Energy Dynamics Q2 2024](#), Australian Energy Market Operator, July 2024.

69 DCCEEW, [Net Zero](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

70 DCCEEW, [Capacity Investment Scheme](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

71 DCCEEW, [Closed CIS tenders](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

72 DCCEEW, [Open CIS tenders](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

73 DCCEEW, [National Electricity Market wholesale market settings review](#), Department of Climate Change, Energy, the Environment and Water, accessed 23 April 2025.

74 AEMC, [Integrating price-responsive resources into the NEM](#), Australian Energy Market Commission, accessed 23 April 2025.

75 AEMC, [Review of the Wholesale Demand Response Mechanism](#), Australian Energy Market Commission, accessed 12 June 2025.

76 AEMO, [Integrating Price Responsive Resources into the NEM \(IPRR\)](#), Australian Energy Market Operator, accessed 23 April 2025.

2.12 Compliance and enforcement activities

The AER's compliance and enforcement work ensures that important protections are delivered and rights are respected. It gives consumers and energy market participants confidence that energy markets are working effectively and in their long-term interests. This ensures consumers can participate in market opportunities as fully as possible and are protected when they cannot do so.

Compliance work helps to proactively encourage market participants to meet their responsibilities and enforcement action is an important tool when alleged breaches occur.

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in the NEM.

In 2025–26, the AER's key compliance priority for wholesale electricity markets is supporting power system security and market efficiency. This includes a focus on:

- network service providers' compliance with network outage and generation connection obligations
- generator performance standards
- generator availability obligations.⁷⁷

Since July 2024, the AER's compliance and enforcement work in the NEM has included:

- **Court-ordered penalty for Callide Power Trading:** On 25 May 2021, a catastrophic failure at the Callide C4 unit caused widespread supply disruptions. Although the unit's prolonged outage was due to unrelated incidents, it remained offline until 30 August 2024. On 9 February 2024, the AER commenced proceedings in the Federal Court against Callide Power Trading Pty Ltd (Callide Power Trading) for failing to comply with performance standards at the Callide C power station.⁷⁸ On 4 February 2025, the Federal Court ordered Callide Power Trading to pay a \$9 million penalty – the highest ever imposed for a breach of performance standards under the National Electricity Rules.⁷⁹
- **Retailer Reliability Obligation (RRO):** On 8 August 2024, the AER finished its review of the RRO Auditors Panel. As a result of the review, the AER published a revised version of the Auditors Panel Handbook, launched the Auditors Panel Conflict of Interest Register and updated the current Auditors Panel membership and contact details.⁸⁰ On 23 August 2024, the AER also published 4 guidance notes to help participants understand their obligations under the RRO.⁸¹
- **Industry guidance:** The AER issued industry correspondence outlining expectations for the accurate use of self-forecasting by semi-scheduled generators.

Further detail on the AER's compliance and enforcement work was outlined in the Annual compliance and enforcement report 2024–25, released in July 2025.⁸²

77 AER, [AER compliance and enforcement priorities 2025–26](#), Australian Energy Regulator, June 2024.

78 AER, [Callide Power Trading: alleged breaches of the National Electricity Rules](#), Australian Energy Regulator, February 2024.

79 AER, [Callide Power Trading: breaches of the National Electricity Rules](#), Australian Energy Regulator, February 2025.

80 AER, [Review of Retailer Reliability Obligation Auditors Panel](#), Australian Energy Regulator, August 2024.

81 AER, [AER published Retailer Reliability Obligation Guidance](#), Australian Energy Regulator, August 2024.

82 AER, [Annual compliance and enforcement report 2024–25](#), Australian Energy Regulator, 23 July 2025.