Wholesale markets quarterly

Q2 2025

April - June

July 2025

AUSTRALIAN ENERGY REGULATOR

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Contents

1 Executive Summary

This report presents trends in the wholesale electricity and gas markets over Quarter 2, April to June 2025. It focuses on wholesale energy prices and their drivers, including demand, generation, offers, contracts, market outlook and new entry and exit.

Results are based on AER analysis using data from the National Electricity Market (NEM), Australian Energy Market Operator (AEMO), Australian Securities Exchange (ASX), East Coast gas market, Gas Bulletin Board and Argus media.

1.1 Key insights

Trends across the quarter were in part driven by a warm autumn period, before a spike in cold weather from the onset of winter.

High price events played a significant role in increased wholesale electricity prices this quarter, with most events occurring in June. Batteries played an increasing role in setting the price, particularly in the evening peaks. Higher renewable generation, primarily from wind and large-scale solar, displaced coal and gas generation.

Gas prices varied significantly over the quarter as lower than usual demand in May weighed on prices before they picked up again in June alongside colder weather, coal outages and higher GPG demand. Overall, prices were sitting lower than a year ago across all domestic spot markets. Although Longford experienced some production issues early in the quarter, there was adequate supply which was highlighted by higher storage levels than usual at Iona (Victoria's largest gas storage facility) going into winter and drawdowns increasing only in June.

Electricity

- Compared with the previous quarter, wholesale electricity prices in Q2 2025 increased in all regions. The higher final volume weighted electricity prices for the quarter were primarily driven by high price events that occurred over 3 days towards the end of the quarter on 11, 12 and 26 June 2025. Prices on these 3 days contributed between 20% to 38% of the final volume weighted electricity prices for the quarter across different regions.
- Compared with the same quarter in 2024, Q2 2025 electricity prices increased in all regions, except NSW where the price was essentially unchanged.
- There were significantly more high electricity price events this quarter (66 energy events, plus 10 FCAS events) than a year ago (19 energy events, plus 15 FCAS events), which was a major driver of higher wholesale electricity prices in Queensland, Victoria, South Australia and Tasmania.
- The number of negative-priced 30-minute periods in the NEM increased compared with Q2 2024. This was due to an increase in low-priced offers by large-scale solar and wind generators, as well as higher rooftop solar output.
- The total volume of offers was higher compared with the previous year, with increases in all fuel types except black coal and diesel. The largest increases were recorded at either

end of the price spectrum, in offers below $0 per MWh and above $5,000 per MWh. Increases in the volume of offers below $0 per MWh were mainly driven by large-scale solar and wind generation, while increases in offers above $5,000 per MWh were mainly driven by dispatchable generation (mainly hydro, gas and battery).

- The increase in low priced offers by wind and solar were largely offset by a reduction in low priced coal and gas offers. The reduction in the volume of black coal offers were driven by increased baseload outages, with unavailable volumes up 28% compared to Q2 2024. These outages were a combination of planned and unplanned.
- Year on year, batteries set the price more often in all regions, and at higher prices. On the mainland, batteries set the price between 17.1% and 23.1% of the time and even more frequently during the evening peak. Notably, batteries accounted for only around 1% of generation in Q2 2025. Hydro and gas set the price lower compared to a year ago (excluding gas in Queensland). But gas set the price less often in all regions, with hydro also setting the price less often in NSW, South Australia and Victoria. Both black coal and brown coal set the price higher in all regions compared to a year ago, the only exception was black coal in NSW. Black coal set the price less often in all regions except Queensland, and brown coal set the price less often in NSW and Tasmania.
- The level of new entry increased compared to last quarter, with 1,456 MW of new generation capacity (wind, solar and battery). Most new capacity did not start generating until June 2025 and is yet to reach its maximum output.
- Both electricity base futures and cap[1] prices for Q2 2025 were elevated, again primarily driven by high price events in the spot market in June 2025. Victoria and South Australia recorded the second highest Q2 base future prices (the highest price was in Q2 2022) and Victoria reached a new record for Q2 cap prices. Forward prices were also impacted, with Q3 2025 base futures prices rising by 4% to 21% during Q2 2025, the exception was Queensland where prices remained relatively stable.

Gas

- Gas prices decreased from Q1 2025 due to lower than usual demand and were around 10% lower than Q2 last year. Prices varied significantly over the quarter in response to changing demand, with the average east coast price being $10.70 per GJ in May compared to $13.40 per GJ in June.
- Demand for gas in Q2 2025 was lower than in the same period last year and the lowest ever recorded for a Q2 (89 PJ). In May, warmer than usual weather decreased GPG demand. However, this changed in June when colder weather and coal outages led to higher GPG demand and put upward pressure on demand and prices.
- Longford production was the lowest Q2 output on record (48.4 PJ) and marginally lower than levels last year, but production increased over June as capacity outlooks and demand increased.

[1] The standard cap contract traded in the market is a “$300 cap”. This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period (AEMC: Spot and contract markets).

- Iona maintained levels close to full capacity throughout May. However, storage levels began to drop sharply over June due to cooler weather, production outages at Longford and higher GPG demand. Iona capacity at the end of June was 17 PJ and still higher compared to levels observed in previous years at the same time.
- Gas flows were predominantly still north in April, but gas started to flow sharply south from mid-May and into June as southern demand increased.
- International LNG prices came down from Q1 as the northern hemisphere transitioned to summer. However, ongoing geopolitical tensions mean prices were elevated despite mild Asian demand.
- Record trade volumes for Q2 (75 PJ) were reported for short term bilateral contracts up to a year in length. The average volume-weighted price for delivery over the remaining quarters of 2025 is $13.52 per GJ and $14.01 per GJ in 2026, with cheaper trades struck in Q2 2025 mostly on fixed price terms.

2 Electricity

This section provides discussion of electricity prices, demand, offers, generation, coal availability and interconnector flows.

Results are based on AER analysis using NEM data sourced from AEMO.

2.1 Electricity prices

Wholesale spot prices[2] increased significantly in all regions

Compared with the previous quarter, wholesale spot electricity prices rose significantly in all regions across the NEM, primarily driven by a sharp increase in the number of high price events on 11, 12 and 26 June 2025. Prices on these 3 days contributed between 20% (in Queensland) to 38% (in Victoria) of the final volume weighted average prices for the quarter. Quarterly average price increases ranged between $34 per MWh in Queensland (+33%) to $96 per MWh in Victoria (+132%).

Compared with the same quarter in the previous year, Q2 2025 prices increased in all regions except NSW where the price was essentially unchanged (Figure 1):

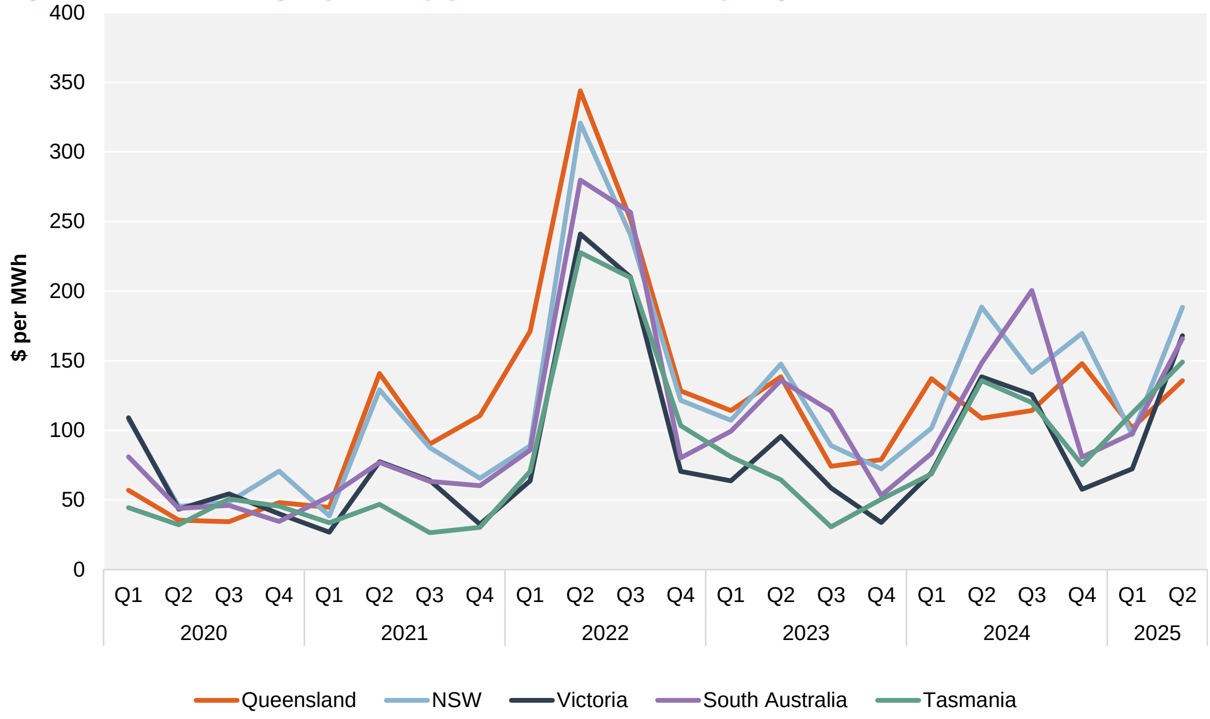
- NSW – $188 per MWh, no change from Q2 2024
- Victoria – $168 per MWh, up 21% from Q2 2024
- South Australia – $166 per MWh, up 12% from Q2 2024
- Tasmania – $149 per MWh, up 10% from Q2 2024
- Queensland – $136 per MWh, up 25% from Q2 2024.

Price increases in Queensland, Victoria, South Australia and Tasmania were primarily driven by high price events particularly during evening peaks, while prices for the rest of day remained at similar or even lower levels compared with a year ago.

Wholesale electricity contracts that hedge the price of electricity in the future as opposed to the spot markets are not traded in the NEM and are discussed separately in Section 4.1.

[2] The NEM is a wholesale spot market where electricity is traded every 5 minutes. The AER monitors volume weighted average prices, meaning prices are weighted against native demand in each region. AEMO generally uses time-weighted average prices in their publications.

Figure 1 Average quarterly prices in the NEM by region



Note: This chart illustrates volume weighted average quarterly prices, meaning prices are weighted against native demand in each region. Uses quarterly average native demand for each region. The AER defines native demand as that which is met by local scheduled, semi-scheduled and non-scheduled generation. It does not include demand met by rooftop solar PV systems[3].

Source: AER analysis using NEM data.

This quarter saw 66 high price energy events (plus 10 FCAS events) where the 30-minute prices exceeded $5,000 per MWh. This was the second largest number of high price energy events in a quarter (the highest was Q1 2008 with 69 energy events). There were 8 events in Queensland, 19 in NSW, 15 in both Victoria and South Australia and 9 in Tasmania.

A combination of factors contributed to the high price events this quarter, including coal generator outages (both planned and unplanned), low wind output, interconnector limitations and rebidding behaviours. Although quarterly average wind generation was higher compared with a year ago, low or very low wind output within the 30-minute intervals when high price events occurred was a main contributor, especially on 11 and 26 June 2025.

On 11 and 12 June 2025, high price events occurred in all regions and on 26 June 2025, high price events occurred in all regions except Queensland. High price events on these 3 days drove up the quarterly average prices significantly (Figure 2).

By region, the quarterly average prices excluding these 3 days were:

- $129 per MWh in NSW ($188 per MWh including these 3 days)
- $117 per MWh in Tasmania ($149 per MWh including these 3 days)
- $109 per MWh in South Australia ($166 per MWh including these 3 days)

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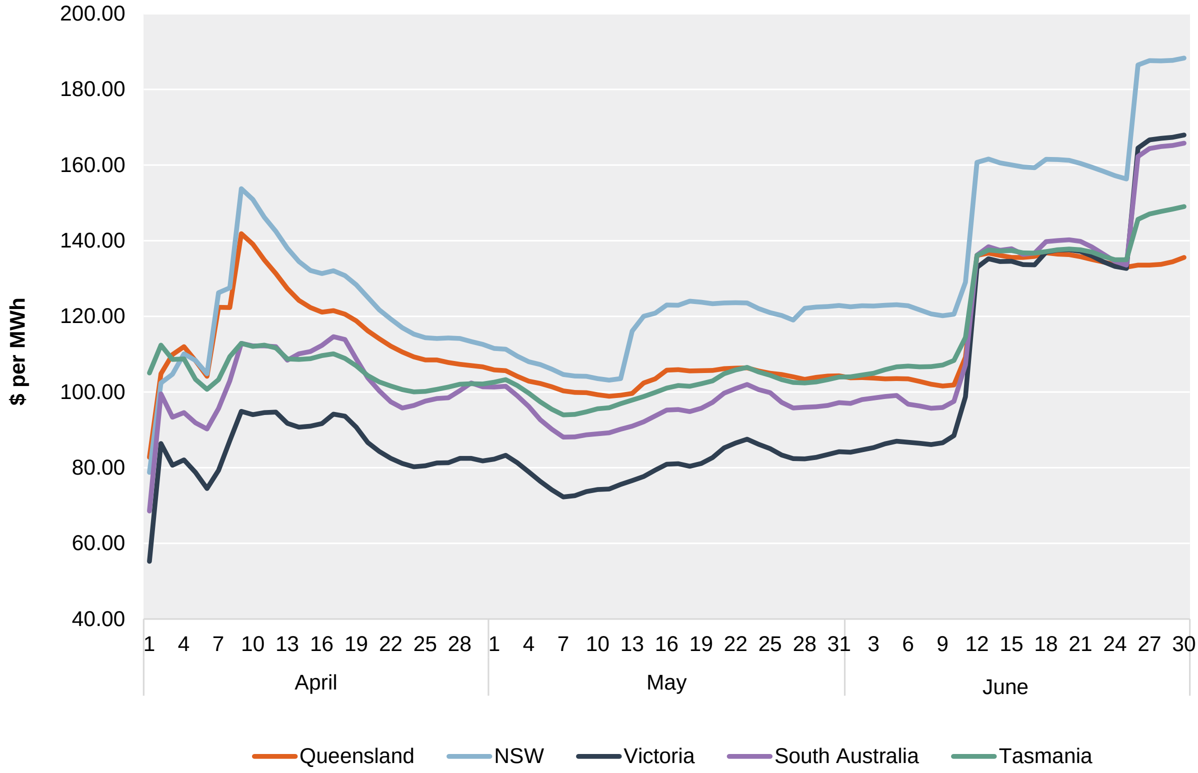
3 For definitions of demand terms used by AEMO in its reporting, see *Demand terms in the EMMS data model*, June 2024.

- $108 per MWh in Queensland ($136 per MWh including these 3 days)
- $104 per MWh in Victoria ($168 per MWh including these 3 days).

The AER will publish a high price report in August 2025 containing detailed analysis of the April to June high price periods.

Figure 2 Cumulative daily prices in the NEM by region



Note: This chart illustrates cumulative daily volume weighted average prices, meaning prices are weighted against cumulative native demand for each day in each region. Uses daily cumulative native NEM demand.

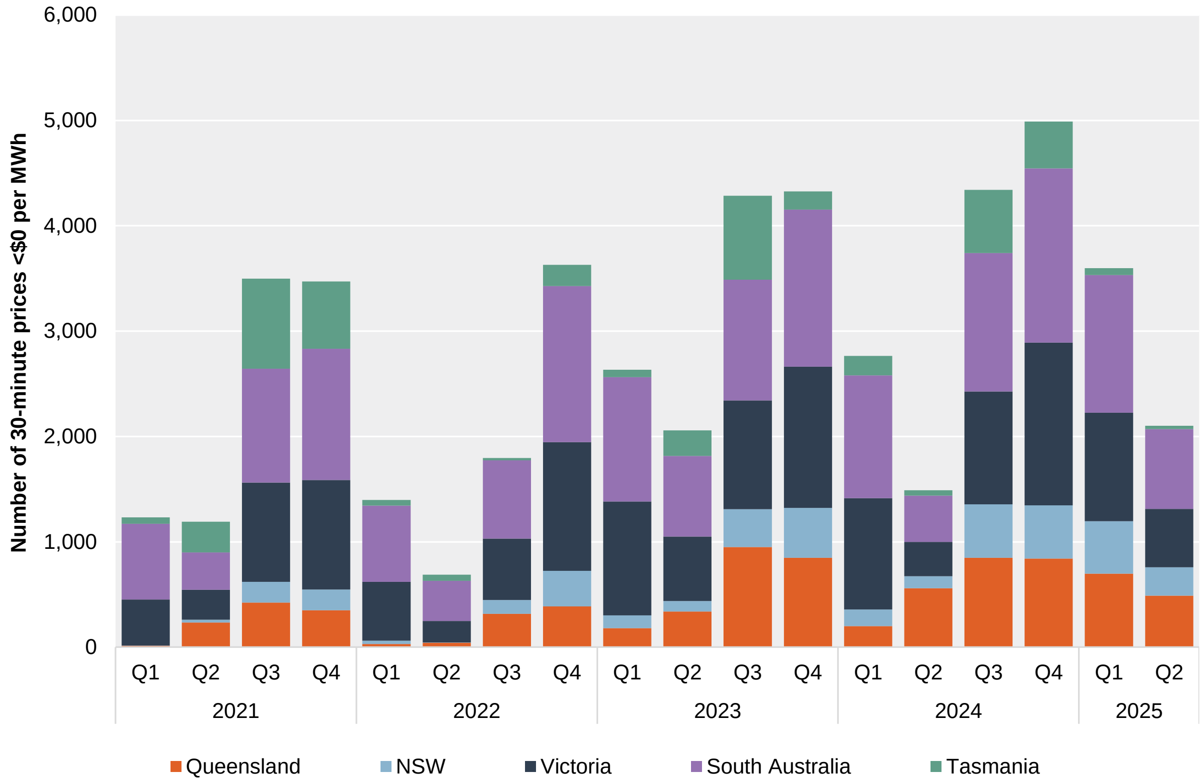
Source: AER analysis using NEM data.

Year on year increases in the number of 30-minute negative prices slightly offset the price rises this quarter. In Q2 2025, the NEM recorded 2,101 negative 30-minute price periods, 612 more (+41%) compared with the same period last year (Figure 3). South Australia and Victoria continued to record the largest number of negative price intervals (756 and 554 respectively), driven by higher rooftop solar output, increased wind generation and, to a lesser extent, increased large-scale solar.

By region, negative prices reduced the quarterly volume-weighted average prices by:

- $3 per MWh in South Australia (up from $2 per MWh in Q2 2024)
- $2 per MWh in Queensland (down from $3 per MWh in Q2 2024)
- $2 per MWh in Victoria (unchanged from $2 per MWh in Q2 2024)
- $1 per MWh in NSW (up from $0 per MWh in Q2 2024).

Figure 3 Count of 30-minute negative prices per quarter



Note: This chart illustrates the number of 30-minute prices under $0 for each quarter.

Source: AER analysis using NEM data.

2.2 Electricity demand

Demand rose slightly compared with a year ago

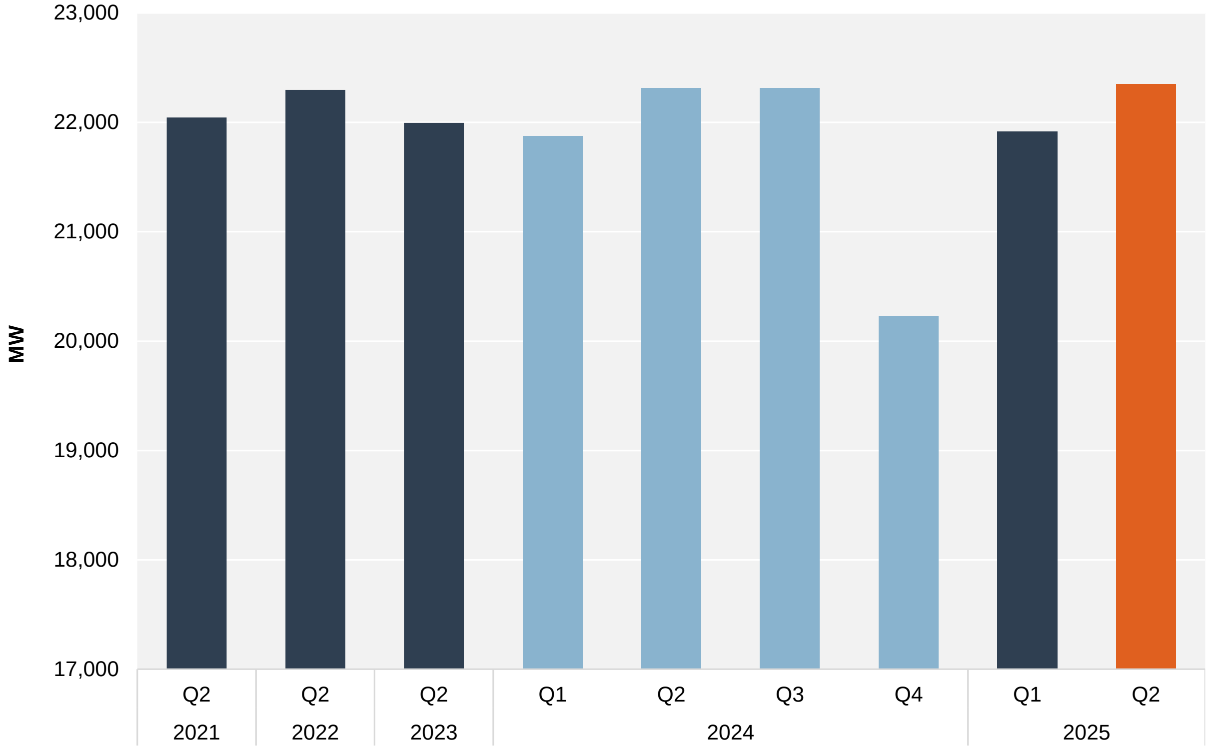
In Q2 2025, the quarterly average demand increased slightly compared with Q2 2024. Demand increased in South Australia (+4.8%), Queensland (+0.9%) and Victoria (+0.3%), though fell in Tasmania (-6.0%) and NSW (-0.3%).

In Victoria, demand continued to increase in the evening peak and overnight and was lower during solar hours due to higher rooftop solar output, which reduced demand from the grid. In Tasmania, demand was lower throughout the day due to higher average temperatures in autumn for most of the state[4].

No record for either minimum or maximum daily demand record was set this quarter. However, both minimum and maximum demand started to rise towards the end of the quarter due to cold temperatures and was elevated on 11, 12 and 26 June 2025 when multiple NEM wide high price events occurred.

4 Bureau of Meteorology: Tasmania in Autumn 2025 (accessed 8 July 2025).

Figure 4 Quarterly average NEM demand

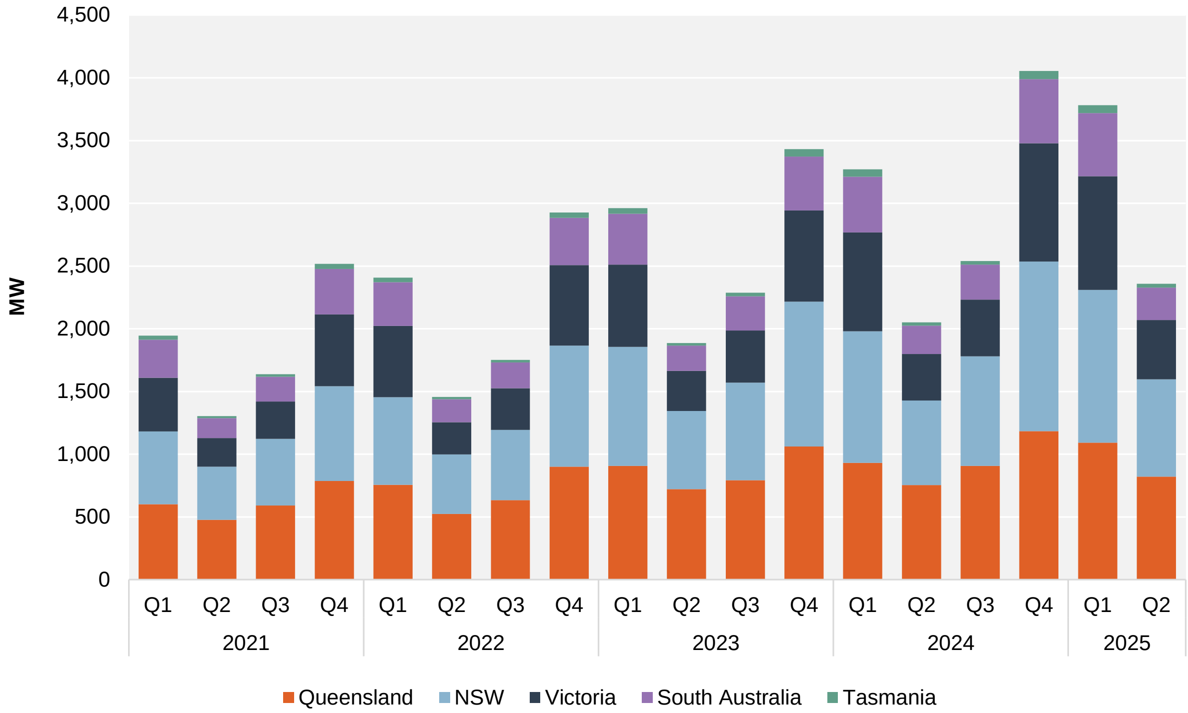


Note: The AER defines native demand as that which is met by all local scheduled, semi-scheduled and non-scheduled generation. It does not include demand met by rooftop solar systems.

Source: AER analysis using NEM data.

Compared with the same quarter last year, average rooftop solar output increased in all regions due to increased installations, with Victoria (+27%) and South Australia (+15%) recording the largest rises (Figure 5). This result continues the year-on-year growth in rooftop solar output.

Figure 5 Quarterly average rooftop solar output



Note: Shows average rooftop solar output by region and quarter. Due to the time-of-day pattern of solar output, maximum output can be several times higher than average output.

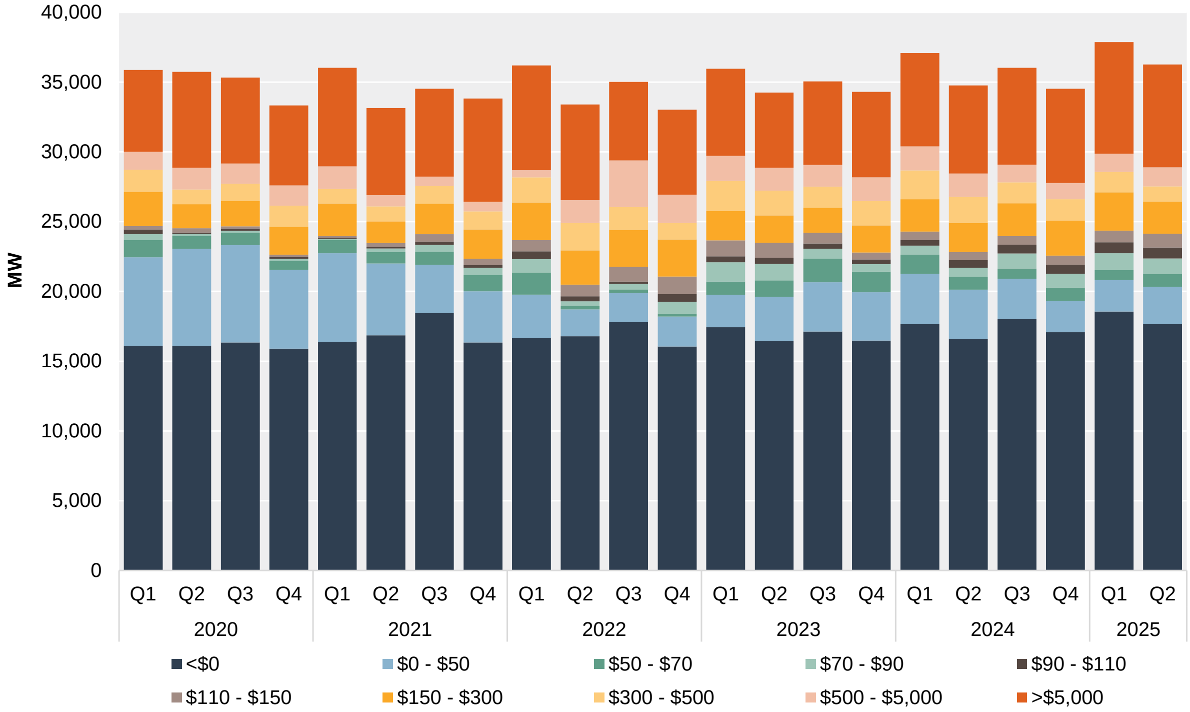
Source: AER analysis using AEMO rooftop PV data.

2.3 Offers

Total offers increased and shifted towards both ends of the price spectrum

The volume of total offers increased by 1,507 MW compared with Q2 2024, with all fuel types increasing their total offers except black coal and diesel. Wind (1,011 MW), battery (814 MW) and large-scale solar (319 MW) all increased their total offers significantly, while black coal reduced its offers by 946 MW, partly driven by higher baseload generator outages compared to a year ago (Section 2.6).

Figure 6 NEM offers by price band

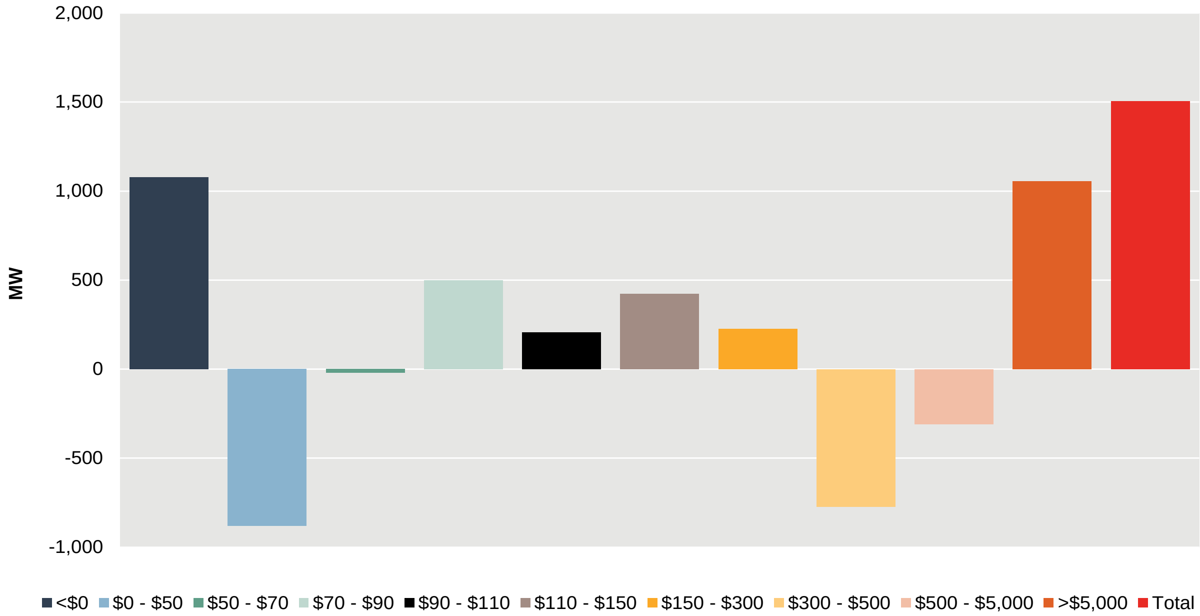


Note: Average quarterly offered capacity by price bands.

Source: AER analysis using NEM data.

The largest increases in the volume of offers in Q2 2025 compared with the same quarter last year were recorded at either end of the price spectrum (below $0 per MWh and above $5,000 per MWh).

Figure 7 NEM offers in Q2 2025 compared to Q2 2024

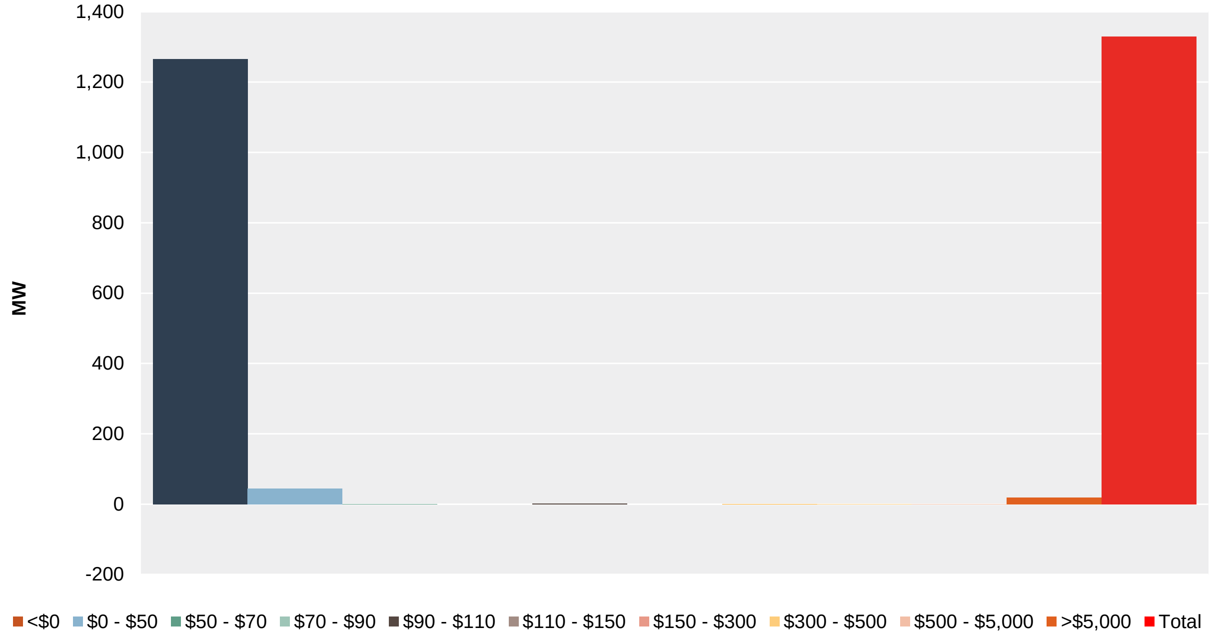


Note: Change in NEM average quarterly offered capacity by price bands from Q2 2024 to Q2 2025.

Source: AER analysis using NEM data.

The volume of offers below $70 per MWh only increased by 177 MW. Increases in low priced offers by wind (998 MW) and large-scale solar (312 MW) were largely offset by decreases in offers by black coal (1,020 MW) and gas (169 MW) in these price bands.

Figure 8 NEM intermittent renewable offers in Q2 2025 compared to Q2 2024



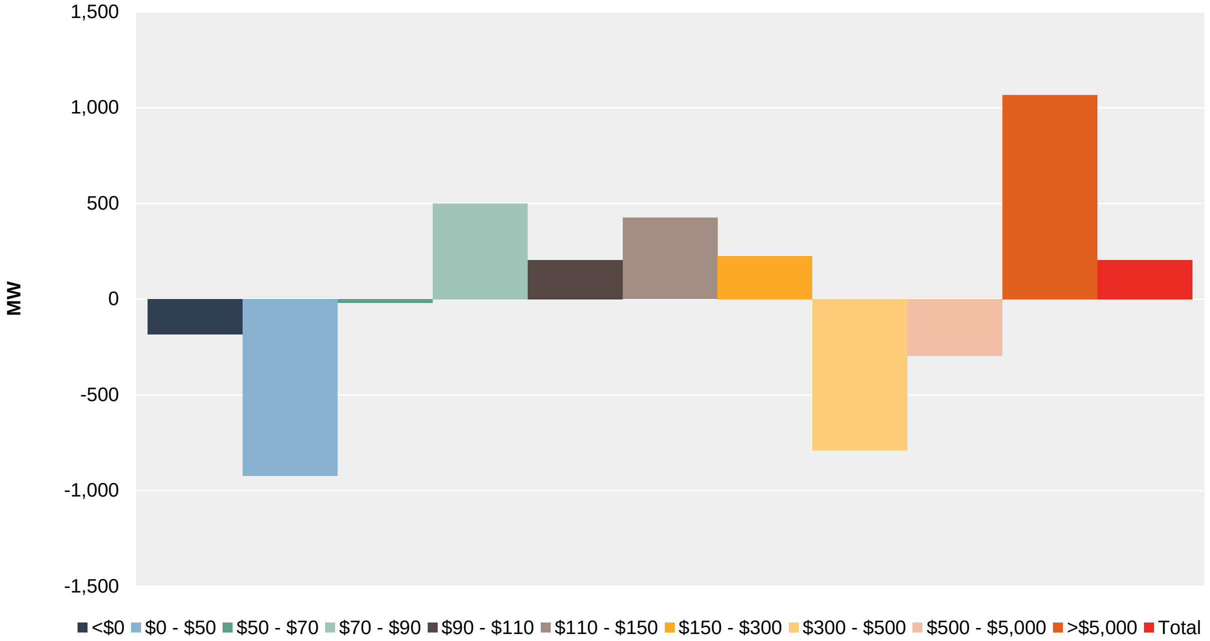
Note: Change in NEM intermittent renewable average quarterly offered capacity by price bands from Q2 2024 to Q2 2025. This combines wind and solar offers.

Source: AER analysis using NEM data.

Offers between $70 per MWh and $300 per MWh increased by 1,356 MW, mainly due to increases in offers by black coal (482 MW), hydro (395 MW) and brown coal (152 MW). Offers above $5,000 per MWh increased by 1,053 MW, driven by dispatchable generation (hydro 550 MW, gas 278 MW, battery 146 MW, black coal 74 MW and brown coal 17 MW).

International coal prices have remained above the market intervention price since the intervention ended on 30 June 2024. Higher fuel costs, combined with a reduction in capacity due to planned and unplanned generator outages, have contributed to black coal generators reducing their total offers and shifting offers to higher prices. Gas-powered generators also shifted offers towards mid-priced and high-priced price bands despite lower fuel costs compared with a year ago (Section 3.1).

Figure 9 NEM dispatchable generation offers in Q2 2025 compared to Q2 2024



Note: Change in NEM dispatchable generation average quarterly offered capacity by price bands from Q2 2024 to Q2 2025. This combines black coal, brown coal, gas, hydro and battery.

Source: AER analysis using NEM data.

2.4 Price setter

Batteries set the price higher and more often in all regions

Compared with the same time last year, batteries[5] set the price more often and at higher prices across all regions, most significantly during evening peaks. In mainland regions, the percentage of time batteries set the price varied between 17.1% in Queensland and 23.1% in South Australia. Despite frequently setting the price, battery generation accounted for a very small 1% of the NEM generation this quarter (Section 2.5).

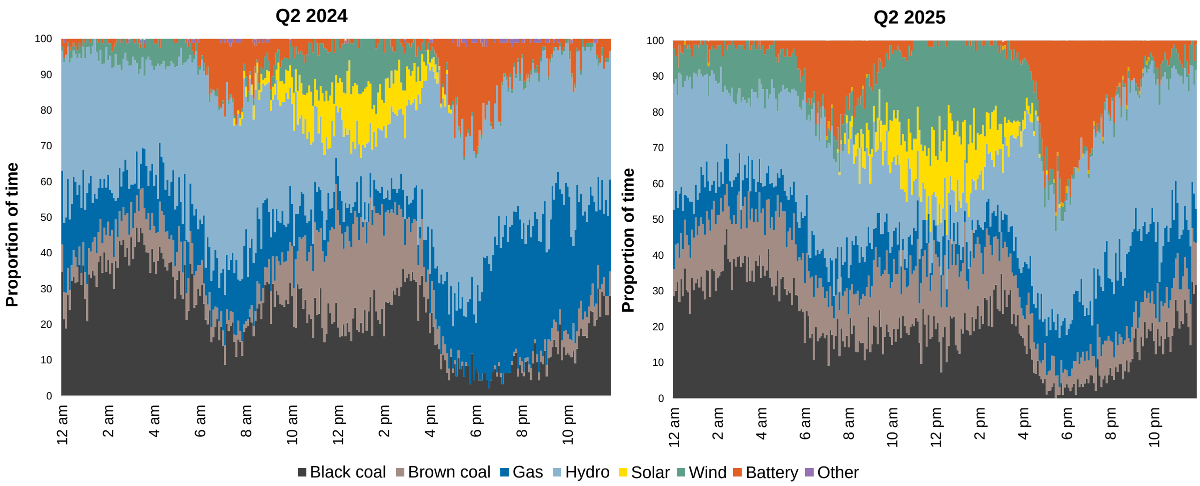
Compared with Q2 2024, wind generation set the price more often across all NEM regions except Tasmania, with significant increases in South Australia (5% to 13%) and Victoria (4% to 9%). In South Australia and Victoria, wind set the price more often across all times compared to a year ago (Figure 10).

Hydro and gas generation set the price lower compared with a year ago in all regions, with the only exception being gas generation in Queensland. Gas set the price less often in all regions and hydro set the price less often in NSW, South Australia and Victoria. Both black coal and brown coal set the price higher in all regions compared to a year ago, except black

5 Batteries can set the price as a generator or a load. Loads can set price when it is more cost effective to reduce load consumption by 1 MW than to increase generation by a MW. Reducing load consumption can lead to reduced generation requirements, which can mean that more expensive generation is not required to meet demand.

coal in NSW. Black coal set the price less often in all regions except Queensland and brown coal set the price less often in NSW and Tasmania.

Figure 10 Price setter by time of day, Victoria, Q2 2024 and Q2 2025



Note: Time of day charts include battery setting prices as generators only. Figure presents outcomes in NEM time (Australian Eastern Standard Time).

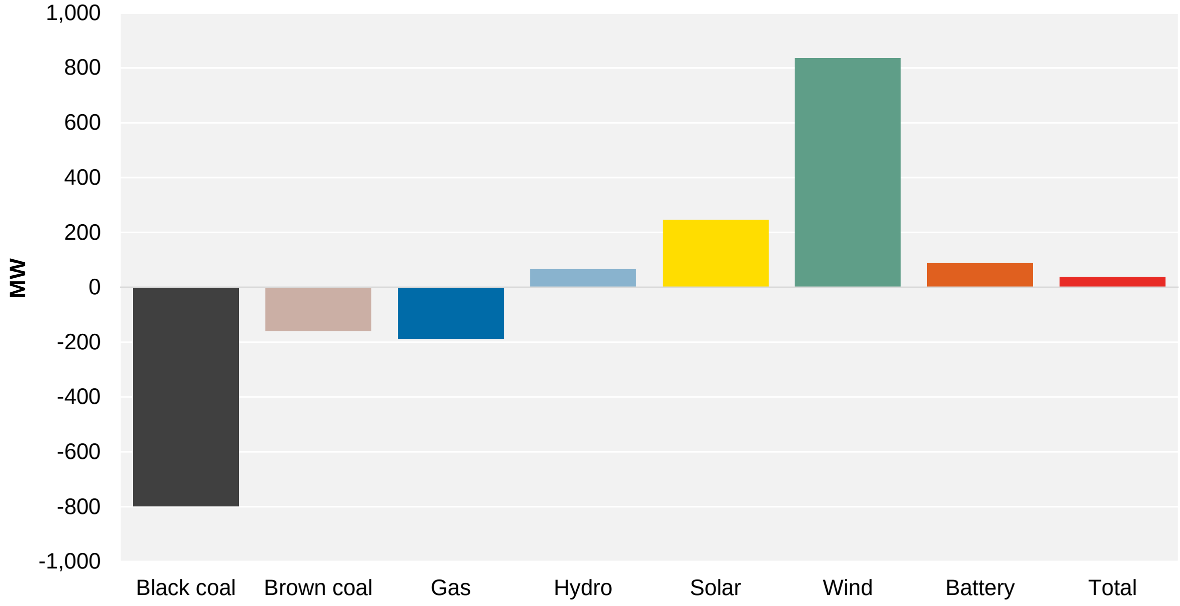
Source: AER analysis using NEM data.

2.5 Generation by fuel source

Coal and gas were displaced by intermittent renewable generation

Total NEM generation increased by 0.2% compared with a year ago. Black coal (down 799 MW), gas (down 188 MW) and brown coal (down 160 MW) generation was displaced by intermittent renewable generation, with wind and large-scale solar up 835 MW and 246 MW respectively. Battery discharge volumes continued to grow significantly compared with the previous quarter (+65%) and previous year (+119%), notably off a small base.

Figure 11 Change in NEM generation output by fuel source, Q2 2025 vs Q2 2024



Notes: This chart illustrates the change in average quarterly metered NEM generation by fuel type, Q2 2025 compared with Q2 2024. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

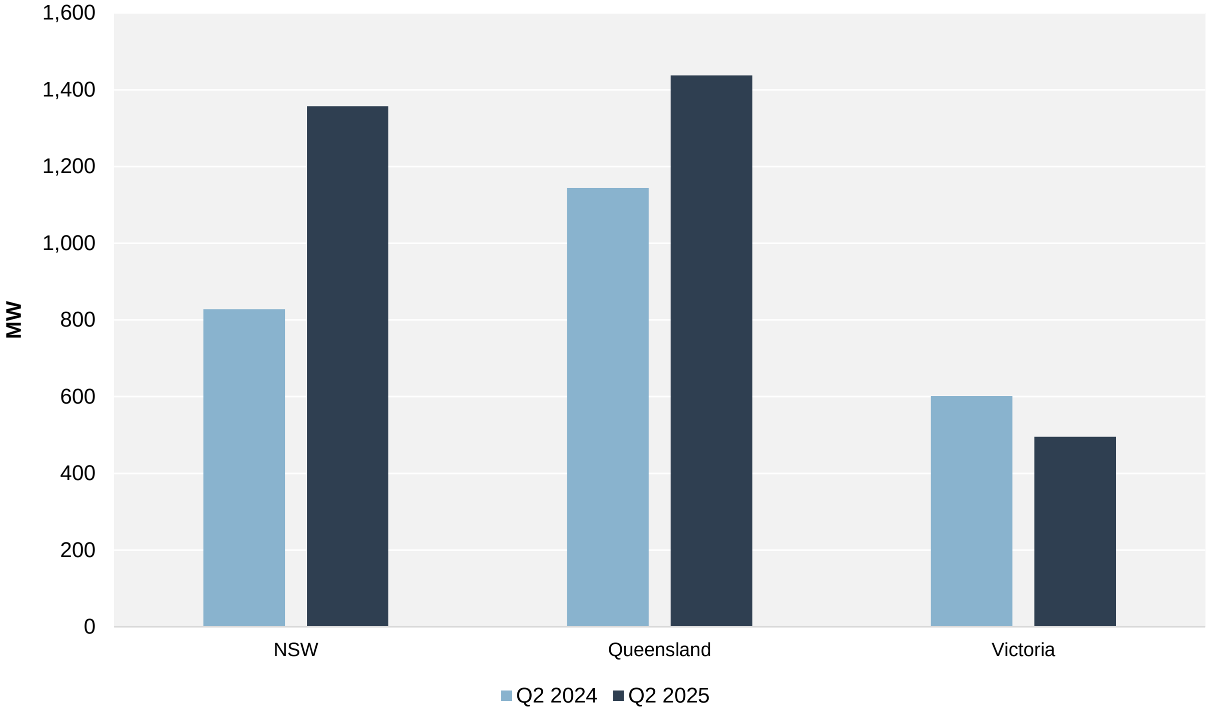
Source: AER analysis using NEM data

2.6 Coal outages

Coal capacity offline due to outages increased both quarterly and annually

Overall, the average level of coal capacity unavailable due to outages increased by 716 MW (+28%) compared with Q2 2024. The increase was driven by NSW (529 MW) and Queensland (293 MW), and slightly offset by a reduction in Victoria (107 MW). In NSW, planned outages for Mount Piper units and unplanned outages for Bayswater units contributed to the year-on-year increase. In Queensland, unplanned outages for Gladstone units and the recently returned Callide C units, and planned outages of Callide B units contributed to the increase.

Figure 12 Average capacity unavailable due to coal outages, Q2 2024 and Q2 2025

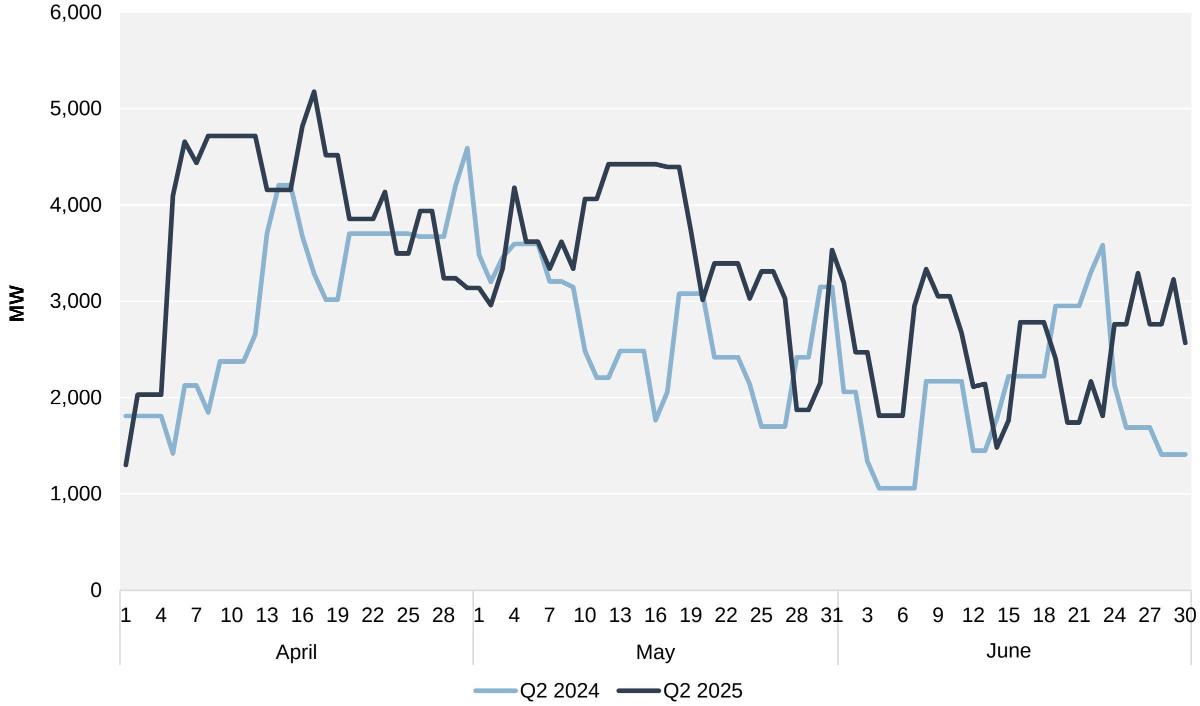


Note: This chart illustrates the average registered capacity unavailable due to coal outages. The AER counts units as unavailable only if the unit is completely offline for the whole day (This differs from AEMO's method to calculate its outage data and this can lead to differences between AEMO and AER's reported outage data).

Source: AER analysis using NEM data.

Outages usually peak in spring and autumn seasons when units are shut down for planned maintenance as demand is relatively low in these seasons. Outages increased significantly from the beginning of April 2025 and remained elevated throughout the quarter (Figure 13). Capacity offline due to outages was higher compared with the same time last year on 11, 12 and 26 June 2025.

Figure 13 Daily NEM coal capacity offline



Note: Daily registered capacity unavailable due to coal outages. The AER counts units as unavailable only if the unit is completely offline for the whole day (This differs from AEMO's method to calculate its outage data and this can lead to differences between AEMO and AER's reported outage data).

Source: AER analysis using NEM data.

2.7 Interregional trade of electricity

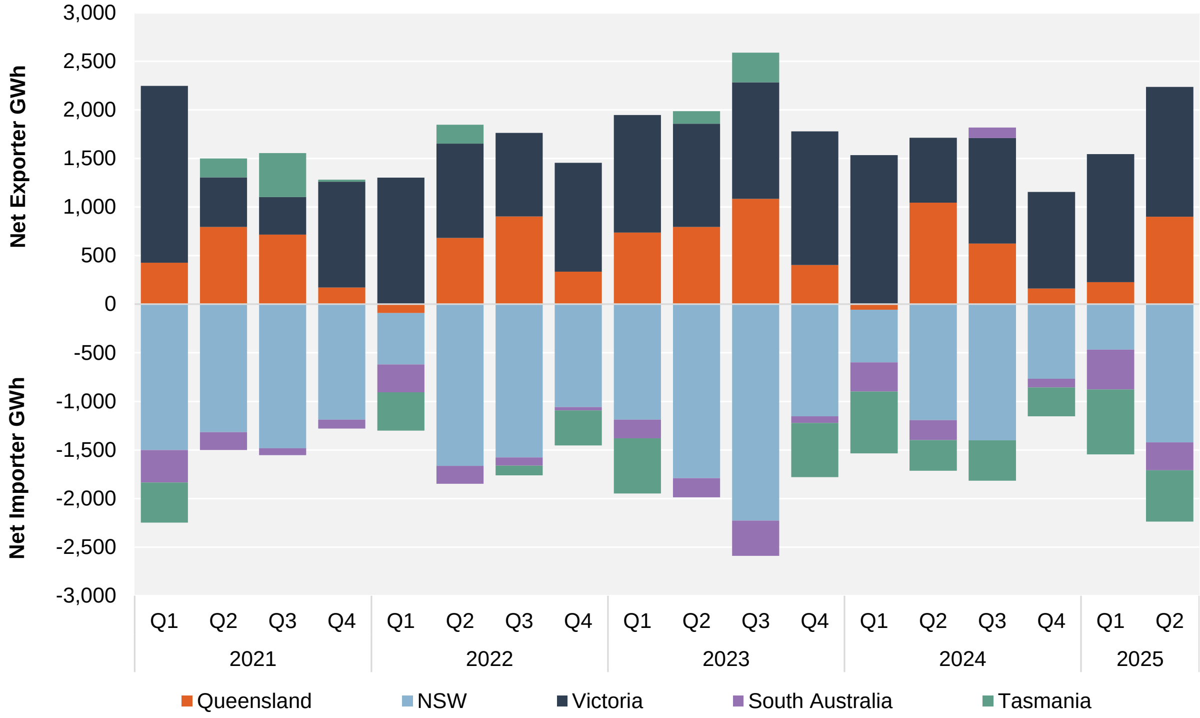
Victoria's net exports increased to meet NSW and Tasmania's import demand

Interconnectors allow regions to import cheaper generation from neighbouring regions. Queensland and Victoria tend to be net exporters, providing surplus capacity to NSW and South Australia. This pattern continued this quarter.

Queensland's net exports increased from the previous quarter, following the typical seasonal pattern when exports are usually high as demand is low leading into winter. Net exports decreased compared with the same quarter last year due to interconnector limitations and higher year on year demand in Queensland.

Victoria's net exports increased from the previous quarter and the previous year, recording the highest Q2 net exports since Q2 2016. This was partly due to increased generation in Victoria and higher demand for imported electricity from NSW and Tasmania. Net imports in NSW and Tasmania were both higher year on year. Reduced black coal generation partly due to outages in NSW and decreased hydro generation in Tasmania drove the demand for imported electricity.

Figure 14 Net interconnector flows by regions



Note: Net amount of energy either imported or exported each quarter by region.

Source: AER analysis using NEM data.

3 Gas

This section provides a discussion of gas domestic prices, demand, storage and transportation, and international prices and demand.

Results are based on AER analysis using data from the East Coast gas market, Gas Bulletin Board and Argus media.

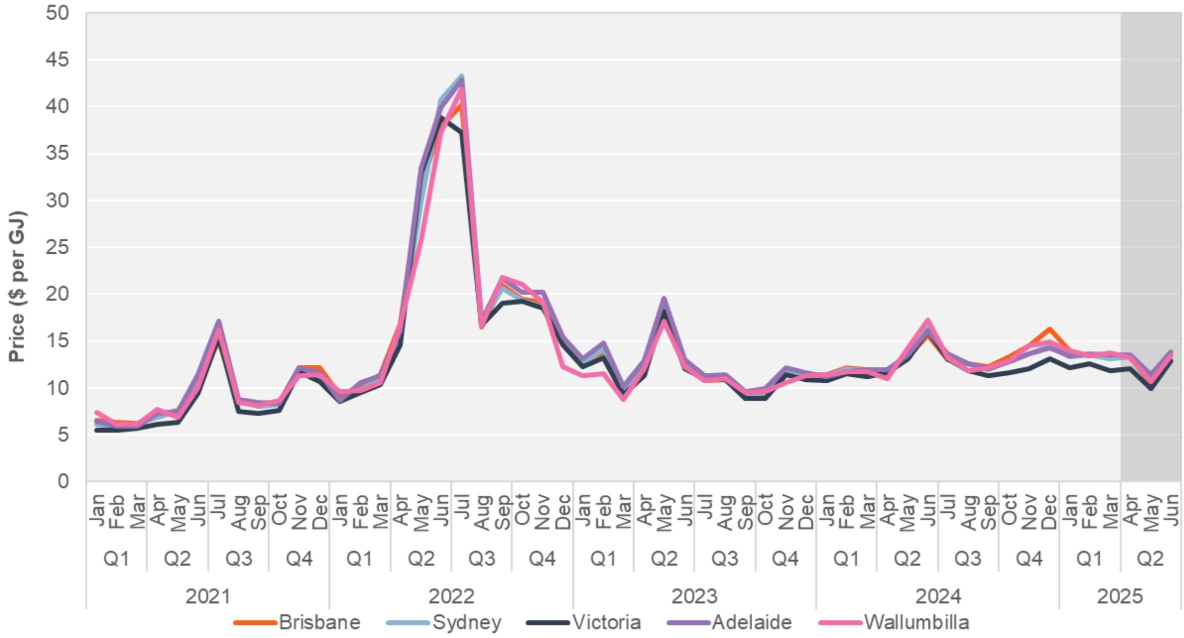
3.1 East Coast gas market spot prices

Gas prices largely decreased in Q2 averaging $12.37 per GJ

East Coast downstream gas market spot prices decreased by 6.0% from the previous quarter to $12.37 per GJ and were 10.1% lower than Q2 2024 (Figure 15).

Lower prices were driven by unusually warm weather and low demand in May alongside higher than usual levels of supply. This was partly due to additional domestic supply towards the end of May that coincided with maintenance at the QCLNG export facility. Average quarterly prices ranged from $11.59 per GJ in Victoria to $12.90 per GJ in Adelaide. Prices in Victoria remained around $1-$2 per GJ lower than prices in the STTM regions (Adelaide, Brisbane and Sydney) over April and May. The margin in prices narrowed in June as heating and GPG demand put comparatively greater pressure on Victorian prices.

Figure 15 East coast gas market average monthly prices



Note: The Wallumbilla price is the day-ahead exchange traded price.
Source: AER analysis using east coast gas market (ECGM) data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets and Wallumbilla gas supply hub data).

There was substantial variation in prices through the quarter. Prices were particularly low in May with an average of $10.70 per GJ. Victoria reached a low of $6.87 per GJ in early May. Downstream prices increased to $13.42 per GJ in June, with prices climbing late in the month and reaching a peak of $18.65 per GJ on 30 June. Higher prices were driven by increasing winter demand late in the quarter and higher June GPG demand alongside constrained supply in Victoria due to an unplanned compressor outage at Longford.

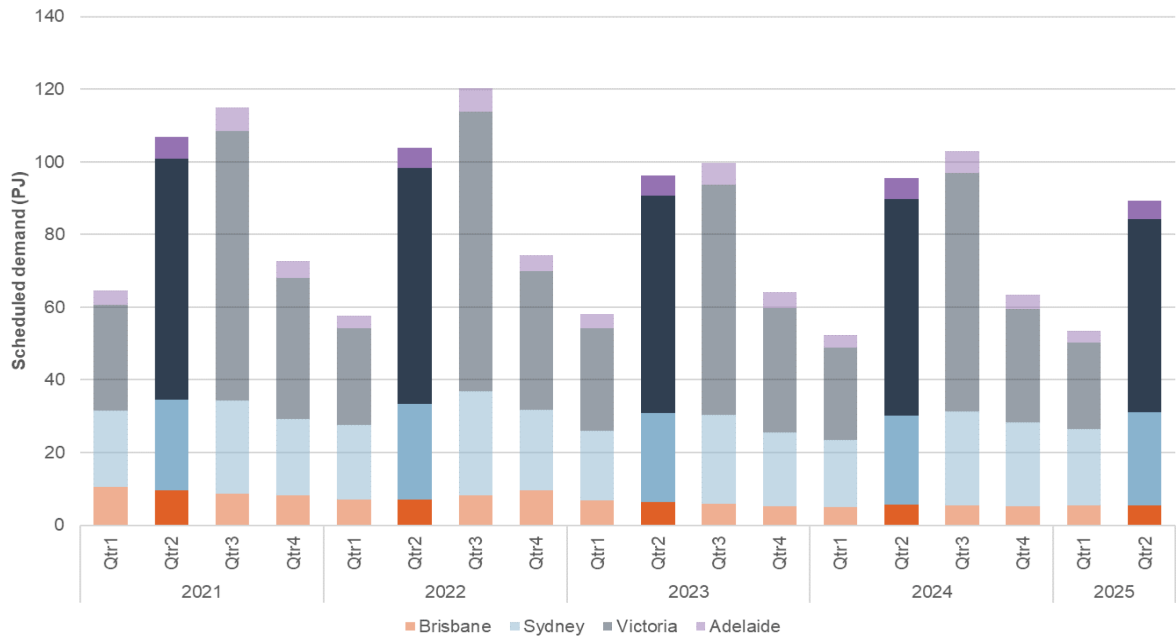
Net trade in the downstream spot markets were higher than the previous quarter and Q2 last year, driven largely by a significant increase in trading over June in Victoria and Sydney.[6] The additional northern supply from QCG contributed to record trade of 14.7 PJ on the Gas Supply Hub, up from 13.2 PJ traded in Q1 2025 and 11.1 PJ in Q2 2024.

3.2 Scheduled demand for gas

Demand increased in Q2 but lower than previous years

Demand increased from the previous quarter to 89.4 PJ, as is typical for this time of year; however, it was the lowest ever Q2 demand on record and materially lower than in Q2 2024 (down 6.2 PJ) driven by record low Victorian demand (Figure 16).

Figure 16 Scheduled demand in east coast gas markets



Note: Scheduled demand based on beginning-of-day forecast demand data (6 am Victorian DWGM schedule and ex-ante STTM schedules for Brisbane, Sydney and Adelaide). Brisbane demand includes one gas powered generator (GPG) and Victoria demand includes Jeeralang, Laverton, Loy Yang B, Newport, Somerton and Valley Power GPG.

Source: AER analysis using east coast gas market (ECGM) data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets).

Downstream Victorian demand was particularly low in April and May, down 3.7 PJ and 3.2 PJ respectively compared to the same months in 2024. Lower demand was largely due to warmer than average weather and resulting lower GPG demand. GPG demand then rose sharply in Victoria, New South Wales and South Australia over June following coal

6 In the different downstream spot markets on a given day a market participant can be both buying and selling gas referred to as their net position. The daily net positions of participants have been aggregated over the quarter as an indicator of overall trade in the downstream markets.

generation outages in the NEM. Victoria reached a high of 382 TJ of gas flow to GPG on 26 June.

3.3 Gas production and storage

Southern production constrained or below capacity

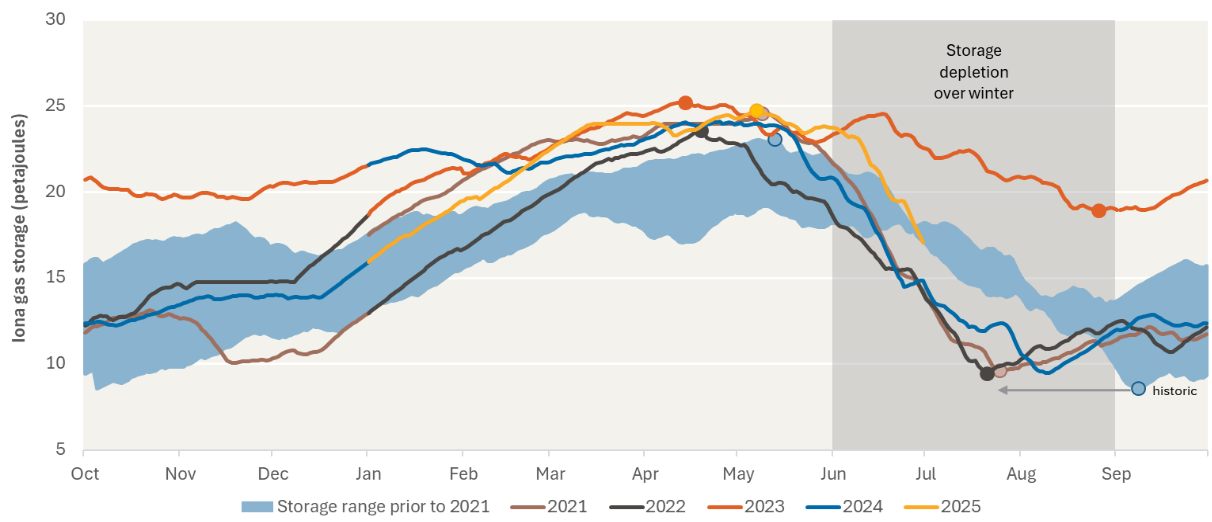
Quarterly production levels at Longford were 48.4 PJ, the lowest on record and marginally lower than the same time last year. Longford is Victoria's primary source of supply. Output was lower due to planned offshore maintenance in April and May and an unexpected compressor outage early in June. Production increased throughout June after maintenance resolved and demand picked up. Longford's medium-term outlook remained at around 700 TJ throughout winter.

In April, flooding around the Moomba hub in South Australia led to a reduction in production capacity at the Moomba gas plant, with average daily production lower at 209.4 TJ in Q2 compared to 237.2 TJ in Q1.[7] Flood rectification and restoration works are ongoing to bring the plant back to full capacity.

Iona storage levels remain sufficient for the remainder of winter

Iona continued refilling over April and maintained higher than usual levels over May due to record low demand in Victoria and additional northern supply from QCLNG's maintenance. Storage was drawn down significantly over June at an average rate of 223 TJ per day as Longford experienced production issues alongside colder weather and higher GPG demand (Figure 17). By the end of June Iona capacity was at 17 PJ, more than 2 PJ higher compared to levels typically observed in previous years at the same time.

Figure 17 Iona underground gas storage levels



Note: Dots represent minimum and maximum storage levels for each period.
Source: AER analysis using Gas Bulletin Board data.

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7 AEMO, Gas supply adequacy and reliability conference minutes 24 April 2025, Australian Energy Market Operator, accessed 30 June 2025.

3.4 Gas pipeline flows

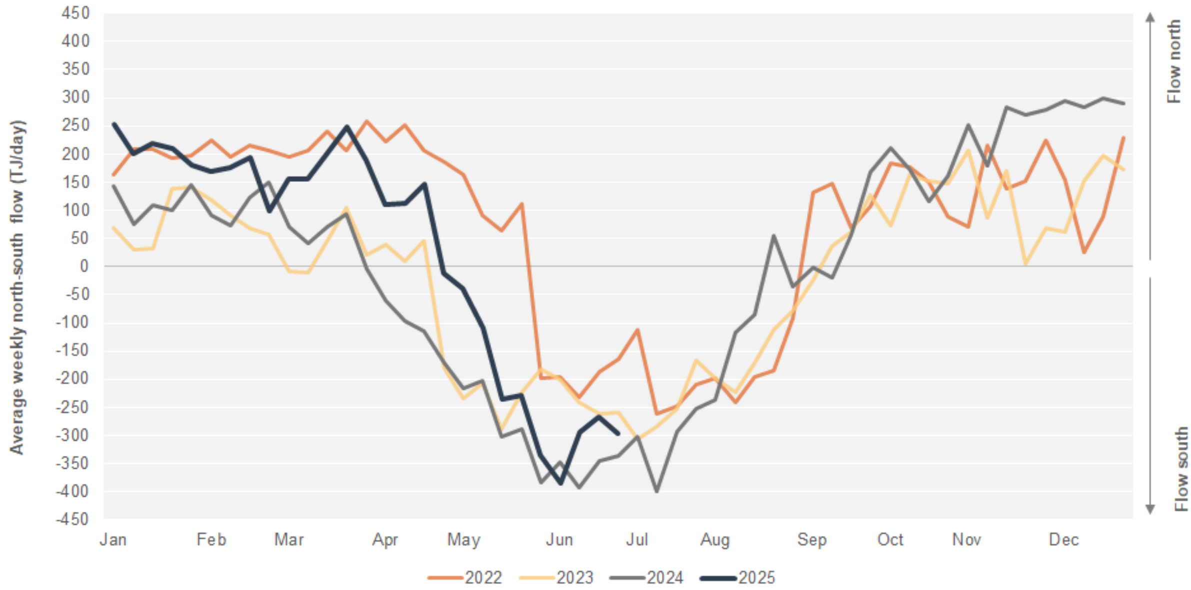
Gas started to flow sharply south in May and June

In April, amidst record low Victorian demand, gas continued to flow north, with 3.6 PJ moving in that direction.

However, in May gas flows started to shift south and markedly increased in June to 9.6 PJ as demand increased in southern markets. This was underscored by a record daily flow south on 9 June of 468 TJ per day.

Capacity won on the Day Ahead Auction (DAA) supported higher southerly flows later in the quarter. In April only 0.4 PJ of DAA capacity was won on Moomba to Sydney Pipeline (MSP) routes south from Moomba, compared to 1.3 PJ in May and 3.0 PJ in June.[8]

Figure 18 North-South gas flows



Note: North-South flows depict net physical flows on the SWQP around Moomba – north or south calculated as a weekly average.

Source: AER analysis using Gas Bulletin Board data.

3.5 International LNG prices

Despite geopolitical tension, LNG prices in Asia fell over the quarter

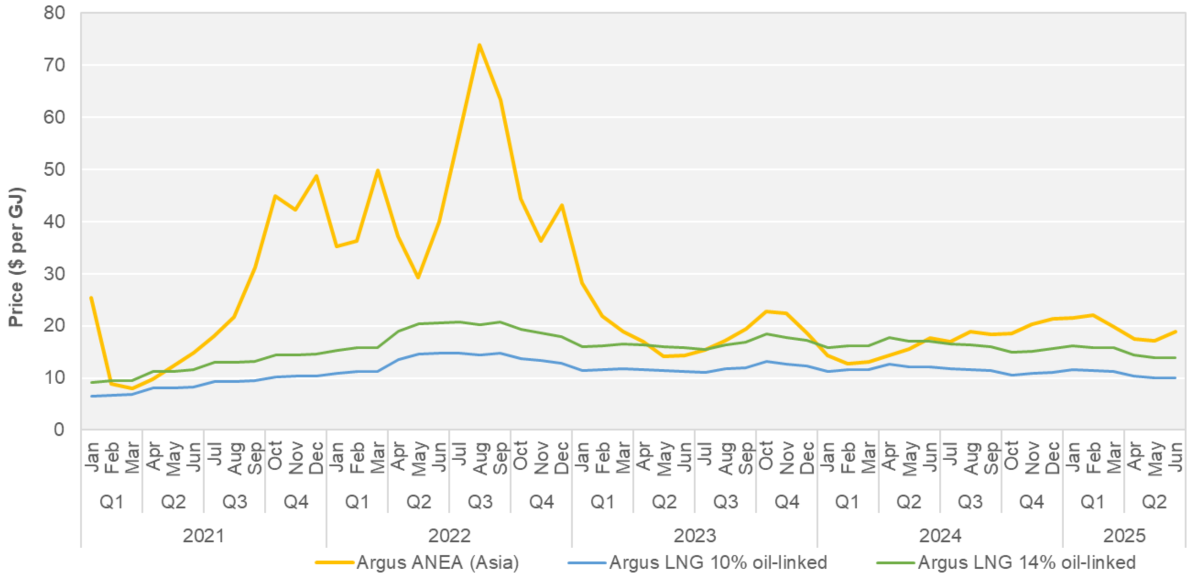
International LNG prices declined early in the quarter as the northern hemisphere transitioned into summer. The Asian LNG spot price, measured by Argus LNG Northeast Asia Price (ANEA), dropped below $20 per GJ throughout April and May, also driven by weak demand in the wider Asia region. ANEA prices rose once again in June amid on-going

8 Quantities won on the DAA on the MSP were up from last quarter, however they were lower than levels observed in Q2 2024. The maximum clearing price this quarter on the MSP was $0.60 per GJ, lower than Q1 2024 ($1.62 per GJ) and Q2 2024 ($1.22 per GJ).

geopolitical tensions in the middle east, peaking at $21.40 per GJ late in the month at the height of tensions before easing again.

ANEA prices remained higher than the same time last year as they tracked comparatively higher prices in Europe. The average midpoint ANEA price for Q2 2024 was $15.75 per GJ compared with $17.86 per GJ in Q2 2025.

Figure 19 International LNG spot prices



Note: The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.
The Argus LNG 14% and 10% oil linked contract prices are indicative of a 14% and 10% 3-month average Ice Brent crude futures slope.
The AER obtains confidential proprietary data from Argus Media under license, from which data the AER conducts and publishes its own calculations and forms its own opinions. Argus Media does not make or give any warranty, express or implied, as to the accuracy, currency, adequacy, or completeness of its data and it shall not be liable for any loss or damage arising from any party's reliance on, or use of, the data provided or the AER's calculations.

Source: AER analysis using Argus Media data.

3.6 Other gas events

Significant price variation in the Sydney hub

In June, the significant price variation (SPV) reporting threshold of $250,000 for the provision of Market Operator Services (MOS) in the Sydney STTM was breached.[9] MOS is a mechanism used to balance differences between the forecast supply requirement and the actual supply outcomes. The mechanism has a commodity and service component, where

[9] In accordance with the National Gas Rules (the Rules), the AER is required to publish a report whenever there is a significant price variation (SPV) in the Victorian Declared Wholesale Gas Market (DWGM) or Short Term Trading Markets (STTM). The AER has published guidelines setting out what constitutes a SPV event.

providers of MOS services that can park or loan gas get paid as bid for the amount of the service required on a given day.

Table 1 shows SPV events in the Sydney STTM for the last 12 months and illustrates the distribution of costs allocated for MOS services on these days. The June 2025 event will be investigated in a significant price variation report to be published by the AER in Q4 2025. For the MOS events on 28 November, 14 December and 20 December 2024 the AER published a SPV report in March 2025.[10]

Table 1 Significant price variations in the Sydney STTM in previous 12 months[11]

Date	MSP MOS cost	EGP MOS cost	Total service cost
28 November 2024	$180,785.42	$848,982.44	$1,029,767.86
14 December 2024	$43,435.90	$262,246.81	$305,682.71
20 December 2024	$1,120.34	$321,878.07	$322,998.41
30 June 2025	**$36,590.22**	**$273,935.60**	**$310,525.82**

Source: AER analysis using east coast gas market data for the Sydney short term trading market (STTM).

10 AER, Significant price variation report Sydney STTM - November and December 2024, Australian Energy Regulator, 20 March 2025.

11 EGP = Eastern Gas Pipeline, MSP = Moomba to Sydney Pipeline.

4 Electricity and gas markets forward outlook

This section provides discussion of electricity futures prices, electricity generation entry/exit and bilateral gas contracts with deliveries in the future and ASX gas futures prices.

Results are based on AER analysis of ASX, AEMO and Gas Bulletin Board data.

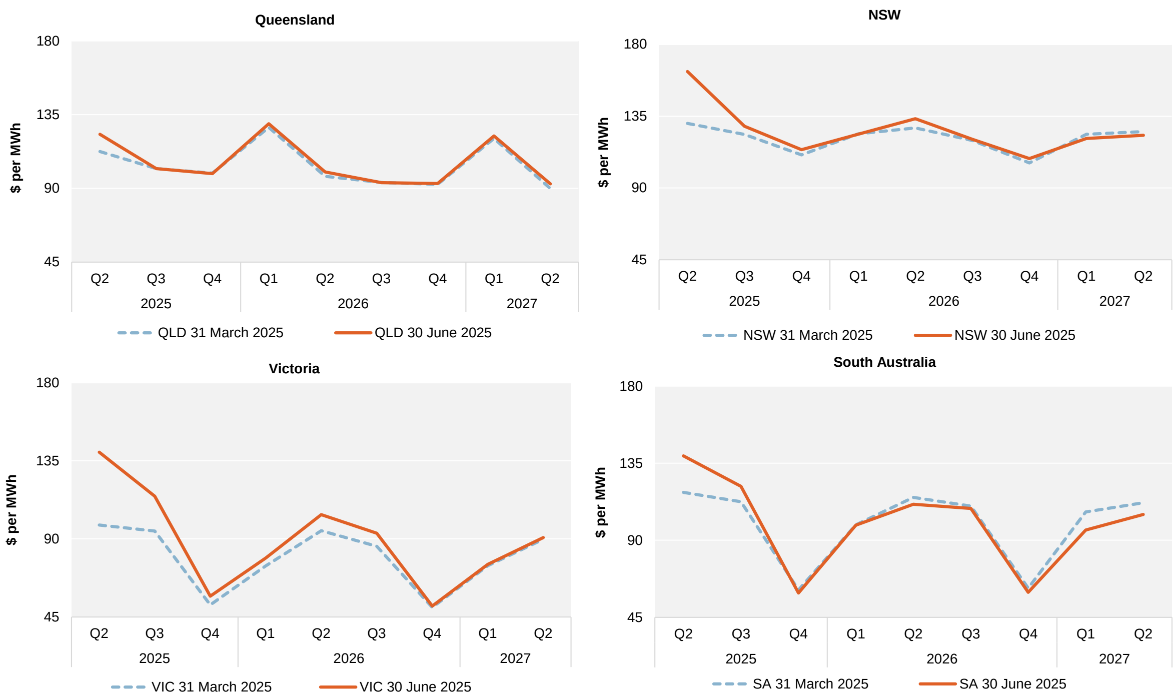
4.1 Forward prices

Strong forward electricity prices as at the end of Q2 2025

Generators and retailers enter derivative contracts to secure the price of electricity in the future. This function is integral to protecting both parties against price fluctuations in the spot markets, and results in the physical electricity market and financial contracts markets being inextricably connected. The prices of forward base futures can illustrate price expectations for electricity spot prices in future periods.

During the second quarter of 2025, Q2 2025 base futures prices increased between 9% in Queensland and 43% in Victoria. Final Q2 2025 base futures prices were elevated, with both Victoria and South Australia recording the second highest Q2 final base futures prices (the highest prices were in Q2 2022). Strong base futures prices this quarter were mostly driven by high price events in the wholesale spot markets in June 2025, which also affected forward electricity prices. In particular, Q3 2025 base futures prices rose during Q2 2025 in all NEM regions except Queensland, ranging from 21% in Victoria to 4% in NSW (Figure 20).

Figure 20 Change in electricity base futures prices during Q2 2025

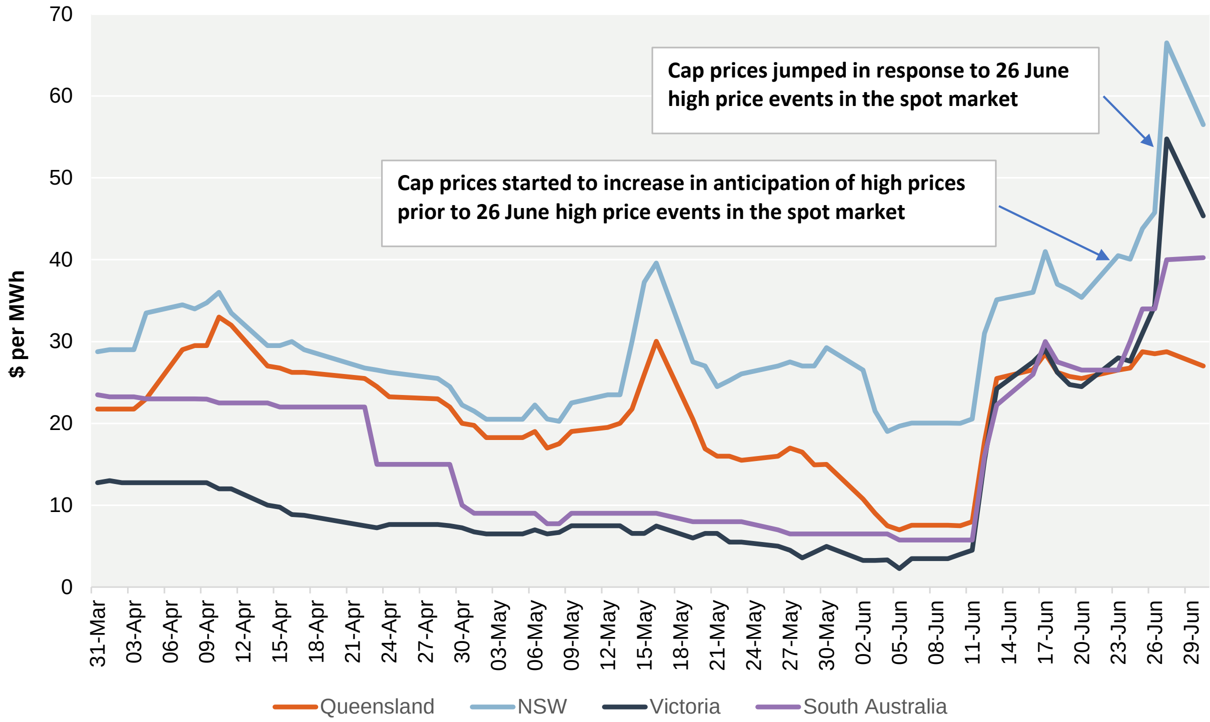


Note: Base futures prices for each quarter as of 31 March 2025 (end Q1) and 30 June 2025 (end Q2).

Source: AER analysis using ASX data.

The high price events in the wholesale spot markets in June 2025 were also reflected in the final Q2 2025 cap prices, with final cap prices increasing in all regions between 24% in Queensland and 256% in Victoria. Cap prices were low and were trending downwards in April and May 2025 before increasing sharply on 12 June 2025 in response to the NEM wide high price events in the wholesale spot markets. Cap prices remained elevated and increased sharply again in response to high price events in the spot market on 26 June 2025 (Figure 21).

Figure 21 Q2 2025 cap prices, 31 March 2025 to 30 June 2025

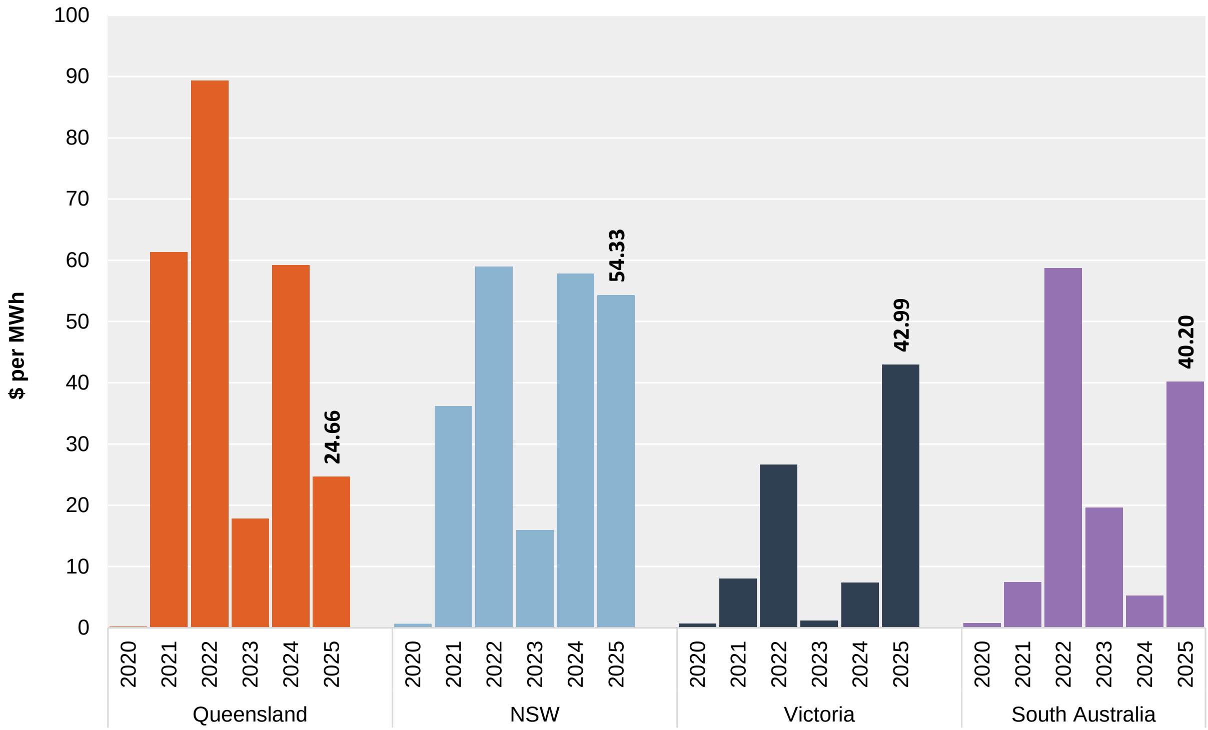


Note: Cap prices for each day from 31 March 2025 to 30 June 2025.

Source: AER analysis using ASX data.

By the end of Q2 2025, Victoria set a new record for the highest Q2 final cap payout at $42.99 per MWh which was well above the previous record of $26.62 per MWh set in Q2 2022. South Australia recorded the second highest Q2 cap payout with the highest record set in Q2 2022 (Figure 22).

Figure 22 Final Q2 cap payout, 2020 to 2025



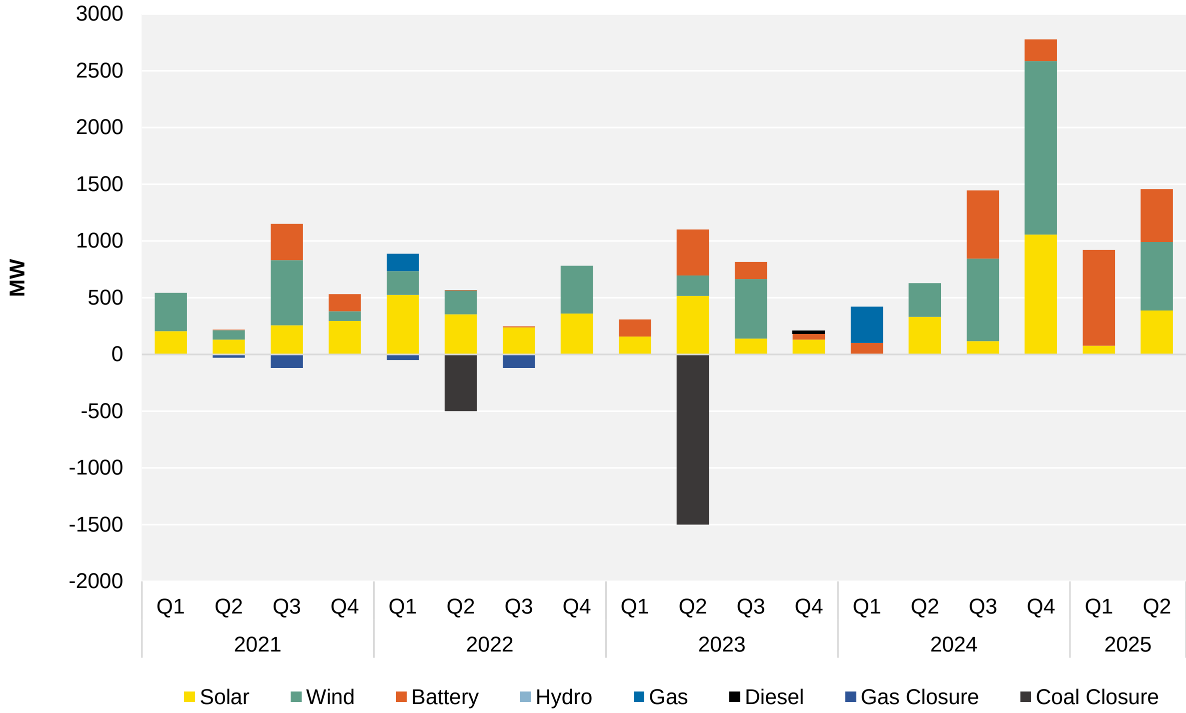
Source: AER analysis using ASX data.

4.2 Entry and exit of capacity

1,456 MW new generation capacity came online

New generation entry totalled 1,456 MW this quarter (Figure 23). This comprised of 603 MW of wind generation, 466 MW of battery and 387 MW of solar. The majority of this new capacity only commenced generating in June 2025 and has not yet reached maximum output (Table 2).

Figure 23 Quarterly entry and exit



Note: This chart illustrates market entry and exit. Uses registered capacity, except for solar and batteries where we use maximum 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 analysis using NEM data.

Overall, AEMO's Generation information workbook lists 4,204 MW of committed projects[12] that are not yet operational but are expected to come online over the next 12 months, of which 2,986 MW will be dispatchable generation.

Table 2 New projects that commenced generation during the quarter

Region	Fuel type	Station	Capacity (MW)	Highest dispatched volume (MW)
QLD	Solar	Aldoga Solar Farm	387	125
QLD	Wind	Clarke Creek wind farm stage 2	103	5
SA	Battery	Mannum Battery Energy Storage System	100	5
SA	Battery	Templers BESS	111	35
VIC	Wind	Golden Plains Wind Farm East	248	70
VIC	Battery	LaTrobe Valley BESS	100	101
VIC	Battery	Ulinda Park BESS	155	5
VIC	Wind	Wambo wind farm	252	6

Note: This table lists market new entry for this quarter. It uses registered capacity, except for solar and batteries where we use maximum 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 analysis using AEMO Generator Information.

12 Projects that are expected to proceed with confirmed timing and meet all five of AEMO's commitment criteria are listed in the NEM April 2025 Generation Information Workbook (accessed 1 July 2025). The AER has excluded projects that have already commenced dispatching generation.

Entry of Snowy Hydro's 750 MW Hunter Power Project (also known as Kurri Kurri) has been further delayed. However, one of its gas turbines was fired up for the first time in July 2025 and full commercial operation is expected in Q3 2025[13].

4.3 Bilateral gas transactions

A significant proportion of gas trade is negotiated directly between participants outside of the AEMO-facilitated markets. Since March 2023, participants have been required to report details of these bilateral transactions up to a year in duration to the Gas Bulletin Board.

Record high Q2 volumes traded through short term bilateral contracts

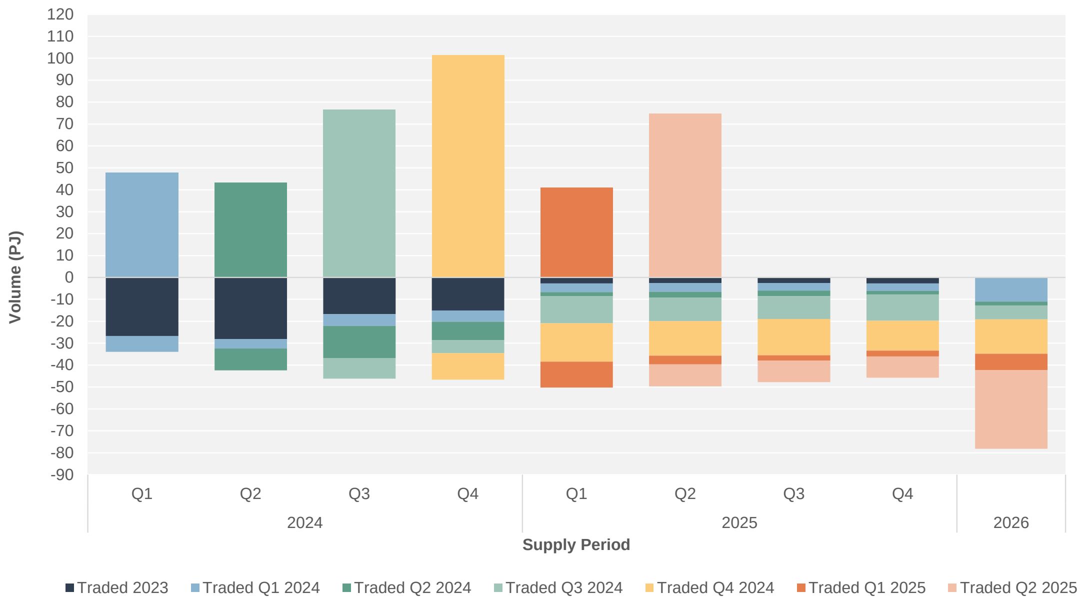
In Q2 2025, there were 75 PJ of gas sales reported through short term bilateral contracts, a significant increase compared to the 41 PJ traded in Q1 this year (Figure 24). This quarter's volumes also exceeded Q2 2024 by 73%, with 1-year contracts making up around 38% of the total volume traded. This is consistent with recent reporting from the ACCC, which observed a shift away from longer-term contracting towards shorter-term contracts.[14]

Around 50 PJ of gas was delivered in Q2 2025 under short-term bilateral contracts, similar to the previous quarter. For oncoming quarters, 46 to 48 PJ have been marked for delivery based on trades up to the end of Q2 2025. The volume of contracts traded for delivery in 2026 is now just over 78 PJ, with almost 36 PJ traded in Q2 this year.

13 Kurri Kurri fires up for the first time, accessed 10 July 2025.

14 The ACCC's June 2025 Interim Gas Inquiry report highlights the shift away from long-term contracting, where the average length of gas supply agreements now only covers 12 months of supply. Conversely, both the term lengths and volumes sold under short term contracts have increased significantly. ACCC, Gas inquiry June 2025 interim report, Australian Competition Consumer Commission, accessed 8 July 2025.

Figure 24 Traded and delivered quantities



Note: Traded volume refers to the trade date of the short-term supply transaction, while delivered volume refers to the quarter the gas volume will be supplied. Where there is not enough trades or participants reporting in a period the data has been aggregated or not included in the reporting. The trade in previous quarters before Q2 2025 have changed slightly from what was reported in our previous quarterly report – this reflects a feature of the reporting framework where contracts can be amended / volumes updated before delivery but is also reflective of late or inaccurate reporting which the AER monitors.

Source: AER analysis using Natural Gas Services Bulletin Board data.

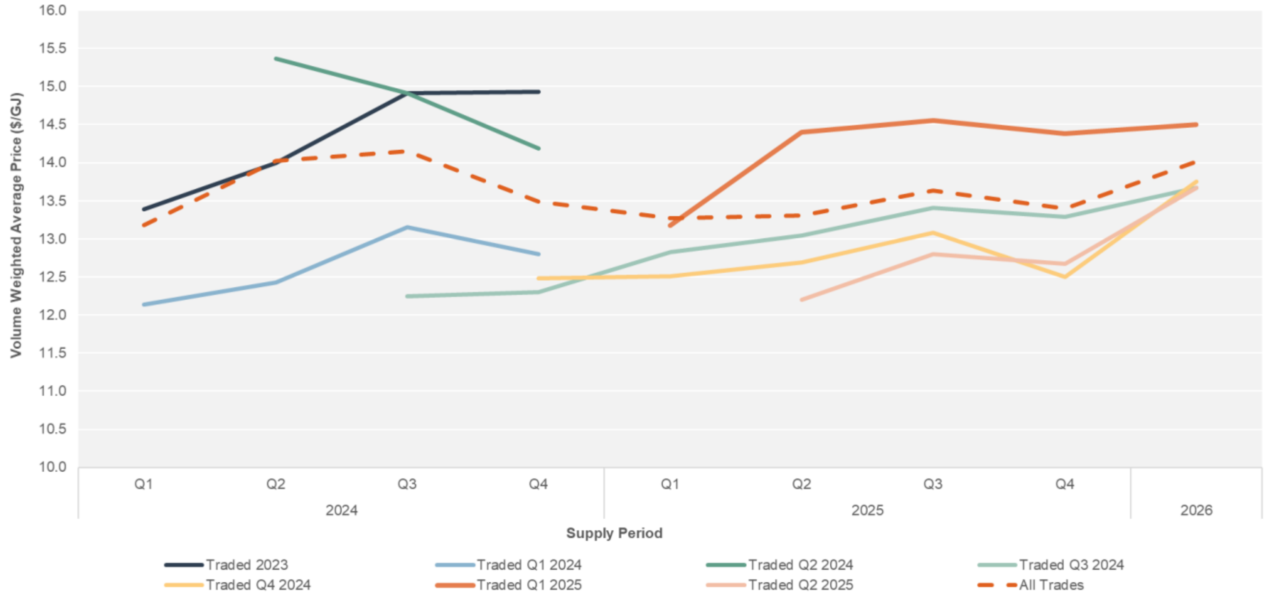
Short term contract prices for 2025 continue to average below $14 per GJ

Short term gas contracts traded in Q2 2025 were, on average, struck at lower prices compared to Q1 2025 and Q2 2024. The volume weighted average (VWA) price was $13.31 per GJ for short-term contracted gas deliveries in Q2 2025 (Figure 25). Contracts secured for delivery in the same quarter were priced the cheapest, averaging $12.20 per GJ. This aligned with lower prices in the downstream spot markets.

With over two years of short-term contracts data, it appears that VWA prices for forward deliveries are typically highest in Q1, before lowering in Q2. For instance, more than 60% of the volume traded in Q1 2025 for gas deliveries in Q3 to Q4 this year were priced in the $14 – $16 per GJ range. In comparison, short-term gas contracts traded in Q2 2025 for delivery in the same quarters were priced cheaper, at $12.73 per GJ on average.

Higher prices in Q1 may be indicative of participants who were unable to secure gas contracts at the end of the previous year, leaving them exposed to Q1 trading activity where lower volumes are traded at higher prices. The decrease in prices between Q1 and Q2 may also reflect more certainty around forward pricing. For example, a higher proportion of the traded volume in Q2 2025 was at a fixed price (71%), with fewer volumes linked to index-based price structures compared to Q1 2025 (6% in Q2 versus 26% in Q1).

Figure 25 VWA forward price curve based on traded quarter



Note: The above volume weighted average prices are based on the supply dates of the reported transactions in the quarter the transactions occurred, except for 2023 where all transactions are grouped together. These prices exclude pricing structures linked to the STTM or DWGM or where the transaction was between related parties. Prices also exclude contracts for delivery in the Northern Territory. Where there is not enough trades or participants reporting in a period, the data has been aggregated or not included in the reporting.
Source: AER analysis using Natural Gas Services Bulletin Board data.

Based on all trades to date, forward prices for gas to be delivered over Q3 and Q4 in 2025 are at $13.63 per GJ and $13.40 per GJ, respectively. For 2026, pricing expectations remained similar to previous quarters, where the VWA price of gas traded in Q2 2025 for 2026 delivery converged with trades struck in Q3 and Q4 2024. Following the end of Q2 2025, the VWA price for 2026 gas is at $14.01 per GJ, lower than the price reported last quarter ($14.29 per GJ).

For one-year contracts delivering over 2026, the VWA price based on all trades reported to date is $13.75 per GJ, with prices ranging between $10.35 per GJ to $16.90 per GJ. Around 60% of the volume traded under one-year contracts for 2026 is on fixed price terms.

4.4 ASX Gas Futures

Continued limited trade in the ASX Wallumbilla Natural Gas Futures Product

The ASX Wallumbilla Natural Gas Futures product is a monthly product which can be traded up to 3 years in the future with each futures contract of gas representing a delivery obligation of 100 GJ per day of the calendar month being traded. Five (5) business days before the beginning of the month traded, any open interest positions are converted to physical obligations on the Gas Supply Hub (GSH) in a Monthly Netted Product deliverable at the Wallumbilla High Pressure Trade Point, referred to as Delivery Exchange for Physical (Delivery EFP).

Over Q2 2025, trade on the ASX Wallumbilla Natural Gas Futures product remained limited, though was slightly higher than Q1 2025. Throughout the quarter, a total of 29 futures were traded compared to the 26 futures traded in Q1. This equates to 87.4 TJ when delivered, which is 12% higher than the 78 TJ from Q1. The bulk of the trade was done in April, where 19 out of the 29 futures were traded.

Delivery Exchange for Physical (EFP) prices in Q2 2025 ranged from $12.90 per GJ to $14.70 per GJ, decreasing as the quarter went on. Overall, this is less expensive than the previous quarter where EFP prices averaged $14.33 per GJ and comparable to the VWA price of monthly products traded on the GSH (Wallumbilla hub) during Q2 2025 ($13.70 per GJ).

Looking ahead to futures with settlement dates in the rest of 2025, there are 22 futures traded (67 TJ, noting not all interest may remain open for physical delivery) with prices in the range of $12-$15 per GJ. For deliveries in 2026 – 2027, bid prices sit in the $11-$15 per GJ range while asking prices fall within a $13-$17 per GJ range.