Wholesale markets quarterly

Q3 2024

July - September

October 2024

AUSTRALIAN ENERGY REGULATOR

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Our wholesale market reporting

The AER’s wholesale markets quarterly report analyses trends in the electricity and gas wholesale markets, focusing on the most recent quarter, and alerts participants and stakeholders to issues of concern. The quarterly reports include discussion of prices, demand, generation, contracts, market outlook and new entry and exit.

A comprehensive dataset for each quarter is available on our website, including additional charts not featured in this concise report.

Additional related regular reporting from the AER covers:

- Details of significant high price events when the electricity spot market 30-minute price exceeds $5,000 per MWh and whenever consecutive 30-minute prices exceed $5,000 per MW in Frequency Control Ancillary Service markets.
- The annual State of the energy market report which presents an accessible, consolidated picture of the energy market.
- The biennial Wholesale electricity market performance report which provides longer term and more technical analysis of the performance of markets.

These scheduled reports will be supplemented by detailed special reporting on topics of interest and impact.

Contents

1 Executive Summary

This report presents trends in the wholesale electricity and gas markets over Quarter 3, July to September 2024. It provides discussion of prices, demand, generation, offers, contracts, market outlook and new entry and exit.

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

1.1 Key insights

Prices have moderated since the previous quarter across NSW, Victoria and Tasmania with milder weather reducing demand. Prices increased slightly in Queensland coinciding with an increase in baseload outages. Larger increases in South Australia were due to numerous high price periods brought on by low wind generation during high demand periods and network outages.

Overall prices in Q3 2024 remained higher than the same time last year in both gas and electricity. However, the quarter was a tale of two halves – demonstrating the strong influence of seasonal factors – higher demand drove higher prices in both electricity and gas in July and early August, before prices stabilised from mid-August until the end of September.

Electricity

- Higher demand in July and early August put upward pressure on prices. Milder weather from late August onwards brought lower demand and more moderate prices.
- Q3 had a significant number (54) of high price periods, with South Australia accounting for half these (27). These periods predominantly occurred when demand was high, wind generation was low and there were network outages.
- While wind generation was 21% higher compared with the same period in 2023, variability in output in July and early August resulted in the need for more expensive firming resources such as batteries, hydro and gas-powered generation (GPG).
- More electricity was offered into the market compared to the previous quarter, but at more variable prices and with a lower number of offers under $70/MWh. Hydro and GPG set the price significantly higher compared with the previous year.
- Previously delayed generation projects came online with significant new entry in Q3, made up of mostly wind and batteries. However, it will take some time before these units reach full output.
- Forward prices declined slightly suggesting the recent high price events have not flowed through to future prices. Prices for the relevant quarters are still higher than they were at the start of the year.

Gas

- Wholesale gas market prices were lower during Q3 compared to the previous quarter. However, prices were well above the same period of 2023, when relatively unhindered supply combined with historically low demand led prices to drop as low as $5 per GJ.
- There were fewer peak demand days for gas in Q3 compared to the previous quarter, with more stable prices from mid-August. While Iona storage dropped to very low levels during July, the facility started refilling over August and September when milder weather reduced demand. Storage levels remained far below the levels during the same period last year but above this time in 2022.
- Demand for gas-powered generation (GPG) was lower compared to the previous quarter, as colder temperatures eased, and Tasmania was able to rely more on hydro generation. GPG demand decreased across mainland regions with a significant drop in September, particularly in Victoria.
- Longford production was more stable compared with the previous quarter and produced slightly below its full capacity in Q3. With the reduced risk of supply shortfalls and a lower potential need for market intervention, AEMO revoked the threat to system security notice on 23 August.
- Pipeline flows south remained strong in July to meet increased demand, reducing in August in line with reduced southern demand. From 24 August the flow reversed and began flowing intermittently north into Queensland.

2 Electricity

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

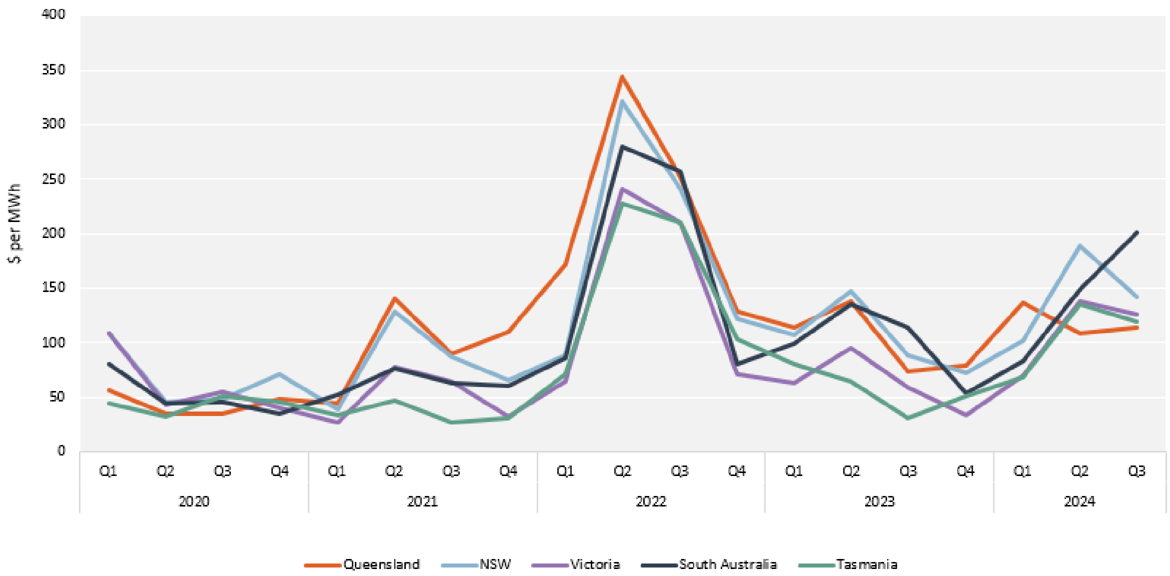
Results are based on AER analysis using National Electricity Market data.

2.1 Electricity prices

Prices peaked during the first half of the quarter due to a high number of price spikes

Average volume weighted prices in Q3 2024 ranged from $114 per MWh in Queensland to $201 per MWh in South Australia (Figure 1). Prices declined from Q2 2024 in NSW (25%), Victoria (9%) and Tasmania (12%), but increased in South Australia (35%) and Queensland (5%). Year on year prices were significantly higher across all regions, with Tasmania up 290%, Victoria up 114% and South Australia up 76%.

Figure 1 Average quarterly prices in the NEM



Note: This chart illustrates volume weighted average quarterly prices, meaning prices are 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 analysis using NEM data.

Prices this quarter were heavily affected by a high number of price periods where the 30-minute prices exceeded $5,000 per MWh – 54 high priced periods occurred in Q3, predominantly in late July and early August (47 periods). By region, these periods drove up the average quarterly price by:

- $77 per MWh in South Australia
- $29 per MWh in NSW
- $28 per MWh in Victoria

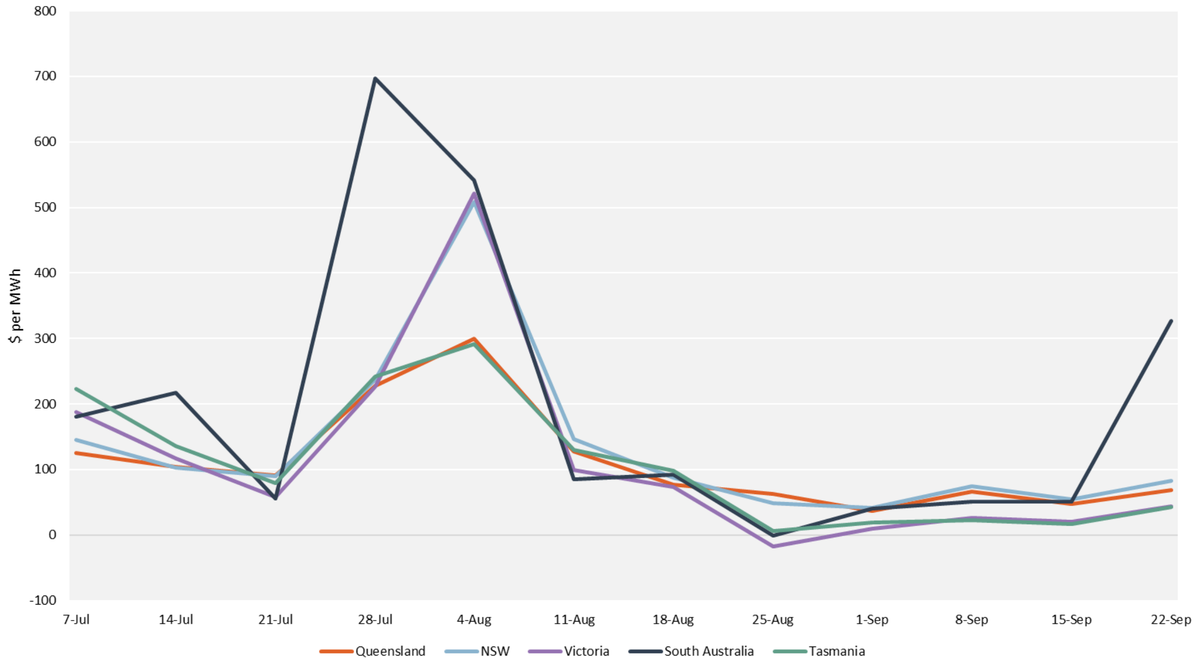
- $12 per MWh in Queensland.

The AER will publish a high price report in November 2024 on the July-September high price periods.

Lower but still elevated prices between $200 per MWh and $500 per MWh also contributed to the higher prices in the first half of the quarter, particularly for Tasmania.

From mid-August volume weighted average prices dropped significantly, falling to as low as $17 per MWh in Victoria during late August. From the week of 18 August to the end of the quarter, the weekly price in all regions remained below $100 per MWh, with the exception of South Australia which spiked to $326 per MWh in the final week of September due to more high price periods (Figure 2).

Figure 2 Average quarterly prices by week



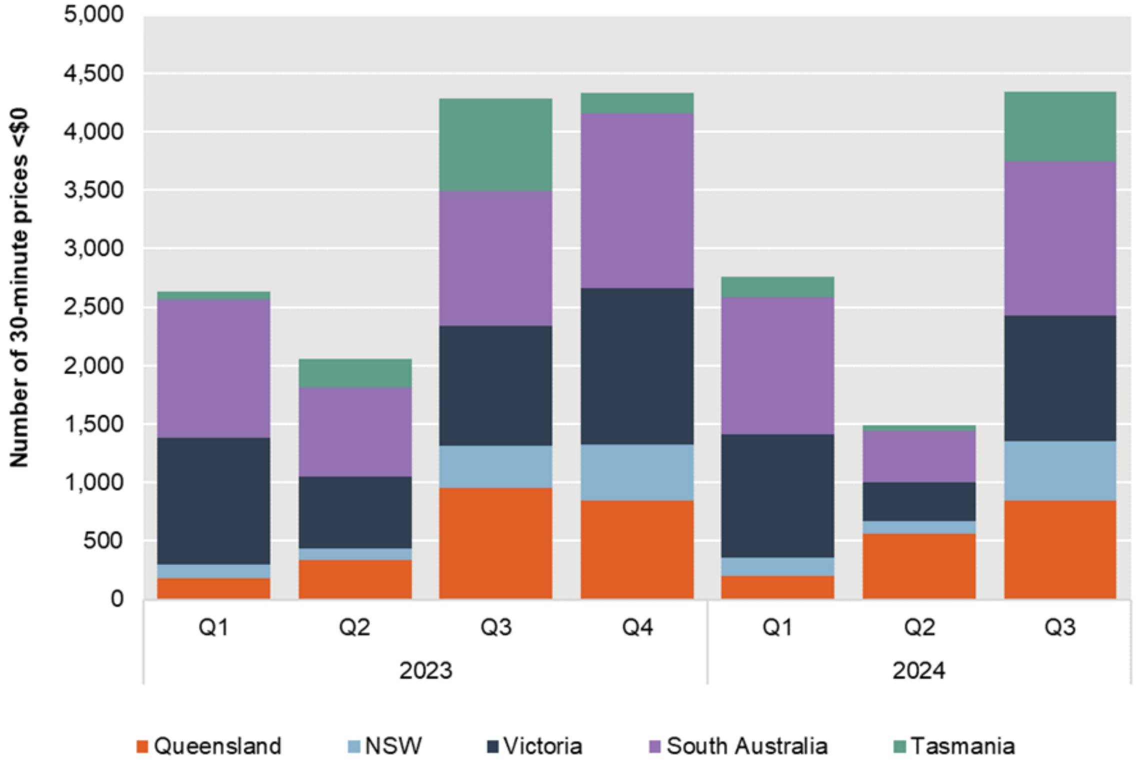
Note: This chart illustrates volume weighted average quarterly prices, meaning prices are weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER analysis using NEM data.

Compared with the previous quarter, in Q3 there were more negative prices across the NEM and within each region (Figure 3). While historically more negative prices occur in Q3 than Q2, the divergence across the range of prices observed in in 2024 were more significant than in previous years.

There were also slightly more negative prices this quarter than during the same period in 2023. The majority of these negative prices occurred in South Australia and Victoria and were due in part to higher wind generation – 30% of intervals were negative in South Australia and 24% in Victoria.

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.

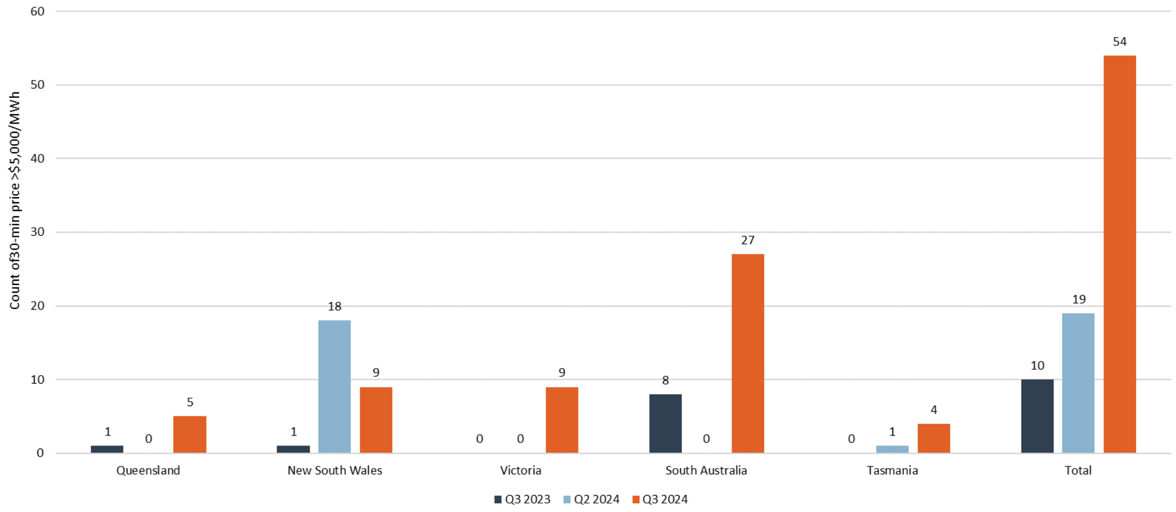
Source: AER analysis using NEM data.

High price periods occurred primarily when there was low wind and network outages

Q3 had 54 high price periods, the highest number on record for Q3 and the second highest overall[1] (Figure 4). Every region recorded at least one high price period and South Australia accounted for half of them (27). These periods predominantly occurred when wind generation was low and there were network outages.

[1] The record was 69 30-minute prices over $5,000/MWh in Q1 2008.

Figure 4 Number of periods priced over $5,000

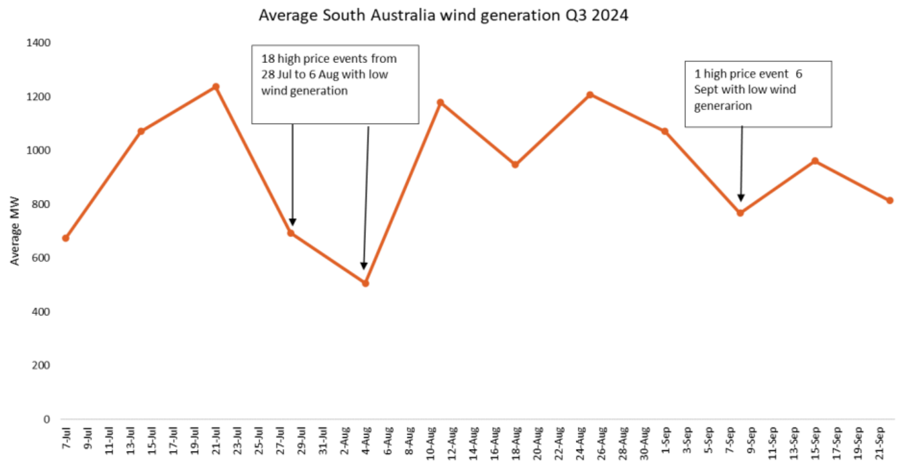


Note: This chart illustrates the number of periods where the price was exceeded $5,000.

Source: AER analysis using NEM data.

While wind generation was 52% higher than the previous quarter and 21% higher than the same time last year, it was highly variable (Figure 5). Low wind contributed to most 30-minute high price periods throughout Q3, though was not prolonged enough to significantly reduce average daily or weekly wind generation.

Figure 5 Average South Australia wind generation



Note: This chart illustrates weekly wind generation in South Australia and the timing of periods where the price exceeded $5,000.

Source: AER analysis using NEM data.

Network outages also contributed to the high price periods with the Heywood interconnector being constrained during the majority of events occurring in South Australia and Murraylink offline for both planned and unplanned outages for some of the quarter. Some market participants rebid by shifting offers to higher price bands which reduced low-priced capacity further.

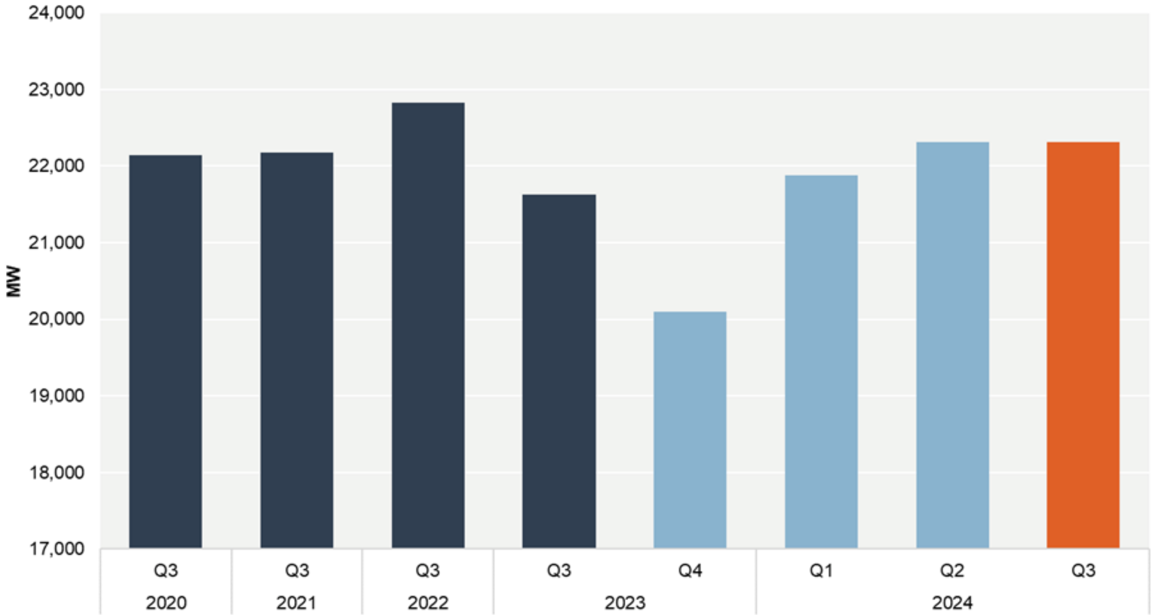
2.2 Electricity demand

Demand increased in all regions

Demand in Q3 increased across all NEM regions compared with the same period last year, with increases ranging from 2% in Queensland to 5% in Victoria. While higher demand in 2024 was in part due to colder weather over winter, it is important to note that weather conditions at the same time last year were atypically mild and included high solar output. Q3 2024 demand reflects similar levels to Q3 in 2020 and 2021 (Figure 6).

The higher demand in the first half of the quarter correlated with high prices.

Figure 6 Quarterly average NEM demand



Note: This chart uses quarterly average native NEM demand. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AER analysis using NEM data.

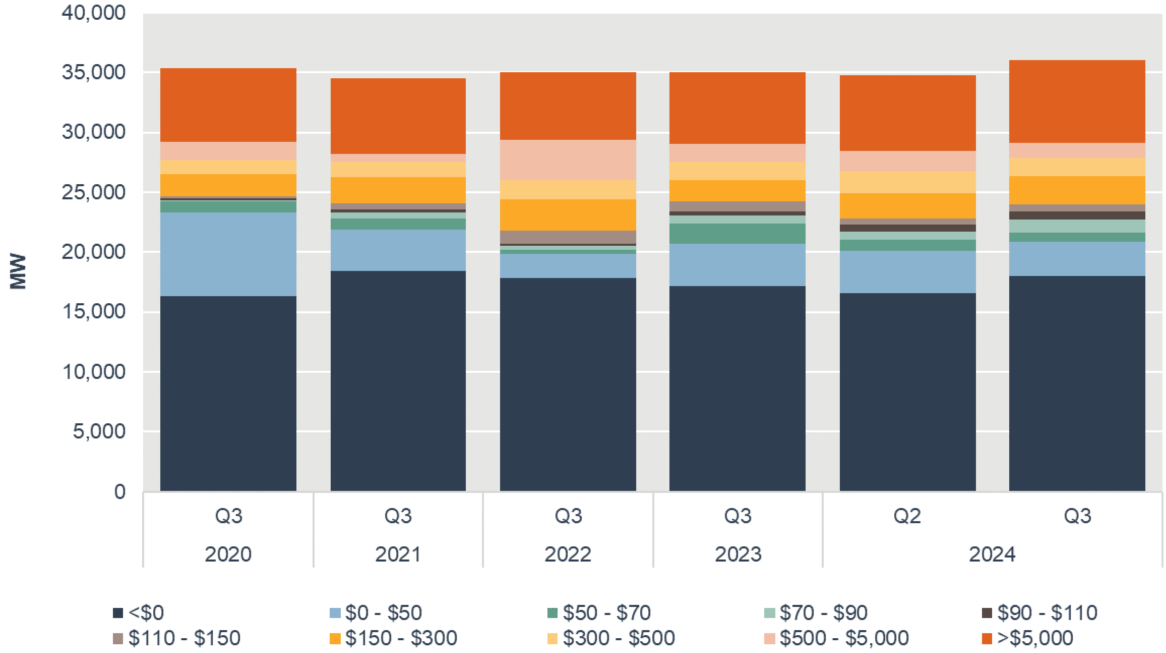
2.3 Offers

Total offers increased, but offers under $70/MWh were down

Compared to last year, an additional 972 MW of capacity was offered into the NEM due to more capacity offered by wind, gas and batteries.

The most significant changes across price bands were at the ends of the spectrum, with offers over $5,000 per MWh increasing by 960MW and offers under $0 per MWh increasing by 892 MW (Figure 7).

Figure 7 NEM offers by price band

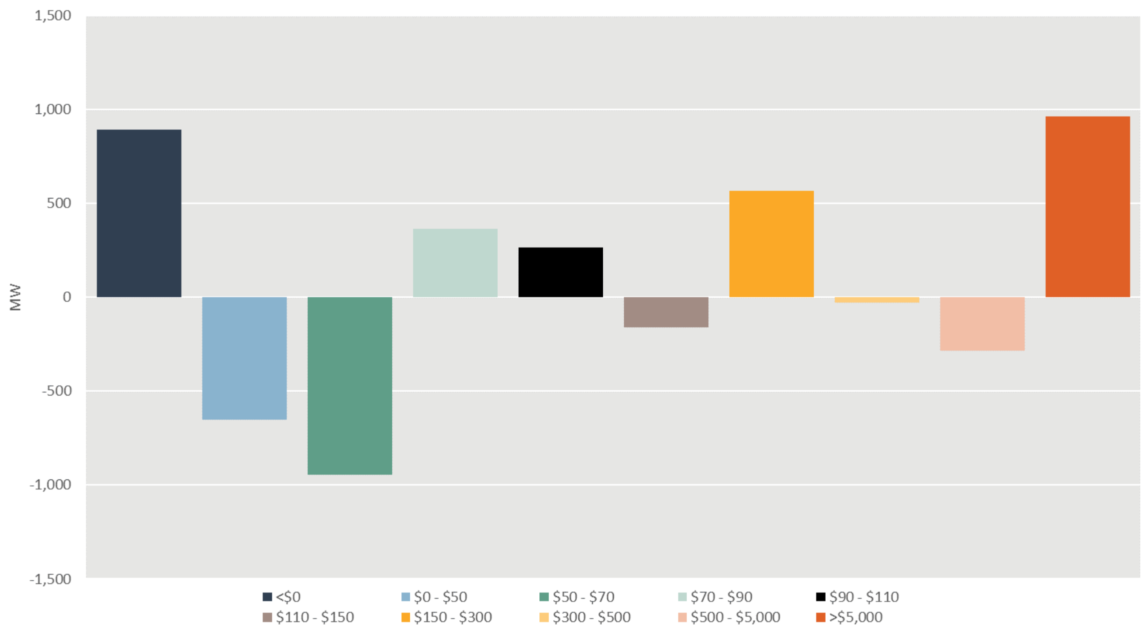


Note: This chart illustrates the average quarterly offered capacity by price bands.

Source: AER analysis using NEM data.

The majority of fuel sources increased their offers under $0 per MWh compared with the same time last year, with wind having the largest increase (650 MW). However, there was a net reduction of 704 MW in offers under $70 per MWh (Figure 8).

Figure 8 Offers in Q3 2024 compared to Q3 2023

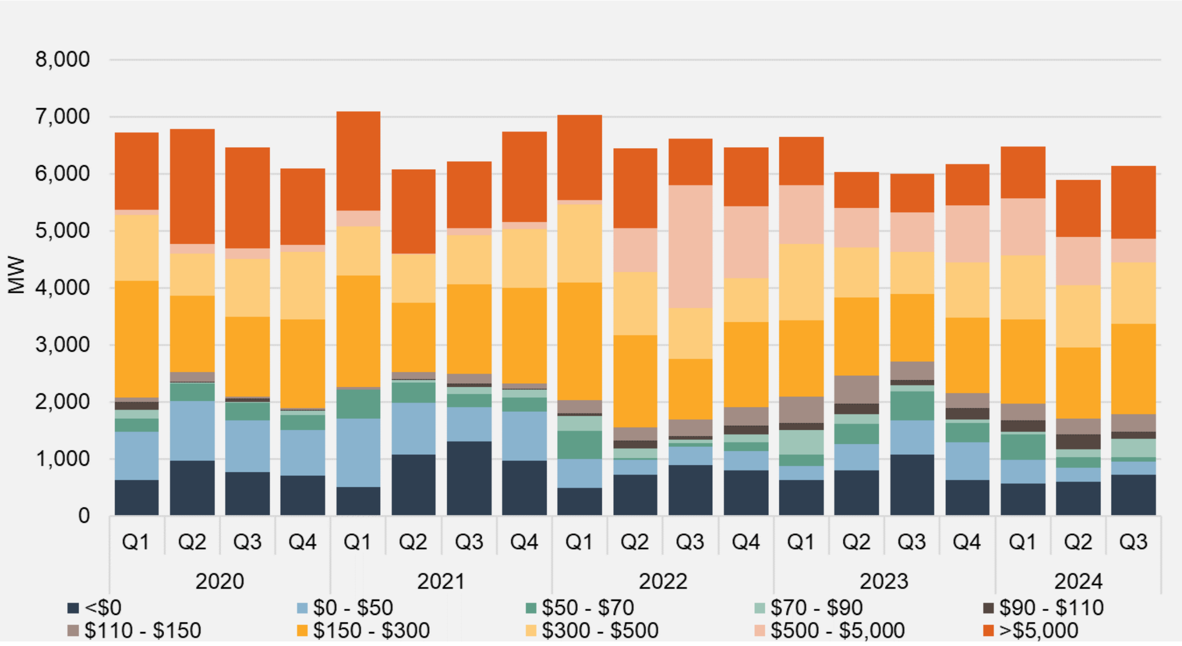


Note: This chart illustrates the difference in offers in Q3 2024 compared to Q3 2024.

Source: AER analysis using NEM data.

Hydro offered more capacity overall, with increased offers between $150 per MWh and $500 per MWh and over $5,000 per MWh (Figure 9). Hydro had the largest reduction of offers under $70 per MWh (-1,152 MW), potentially driven by low water levels at major dams.[2]

Figure 9 NEM hydro offers by price band



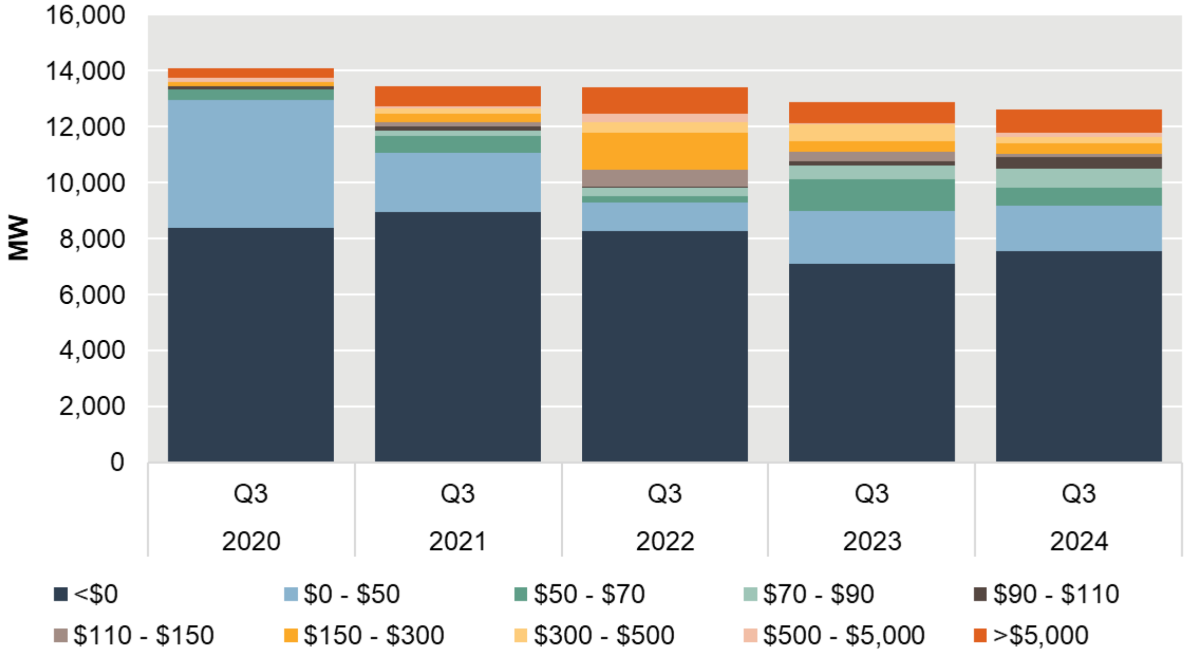
Note: This chart illustrates the average quarterly offered hydro capacity by price bands.

Source: AER analysis using NEM data.

Solar offers under $0 reduced by 79 MW, with the vast majority of solar offers still at negative prices (98%).

2 https://www.snowyhydro.com.au/generation/live-data/lake-levels/; https://www.hydro.com.au/water/lake-levels

Figure 10 NEM black coal offers by price band



Note: This chart illustrates the average quarterly offered black coal capacity by price bands.

Source: AER analysis using NEM data.

Black coal offers have decreased year on year since 2020 (this is due in part to the retirement of Liddell power station), with capacity moving towards the extremes of the price bands. Offers under $0 per MWh increased by 492 MW, and prices over $5,000 per MWh also increased by 391 MW. Total black coal offers between $0 per MWh and $5,000 per MWh decreased by 873 MW (Figure 10). While the NSW coal market interventions ended on 30 June 2024, there was an overall increase in black coal offers under $110 per MWh when compared to Q3 2023.

2.4 Price setter

Dispatchable generators are setting the price higher

Across the NEM dispatchable generation set the price higher than in Q3 2023.

- **Gas** set the price significantly higher ($159 per MWh higher in NSW, $137 per MWh higher in Victoria, and $108 per MWh higher in South Australia). While not at record levels, Q3 prices were one of the highest. This increase can be linked to the quarter's high price periods. In periods where demand was high and there was less low-priced wind generation available, gas more frequently made the marginal offer with higher prices.
- **Hydro** set the price higher than last year across most regions, ranging from $57 per MWh higher in Queensland to $75 per MWh higher in Tasmania. This increased price was particularly significant in Tasmania where hydro sets price the vast majority of the

time (73% of the time this quarter) and the increase of $75 per MWh reflected a 236% increase on Q3 2023 prices. This was likely due to lower storage levels at major dams.

- **Batteries** set the price more frequently across the NEM than the same time last year, ranging from 3% of the time in Tasmania to 6% in South Australia. This is in part due to increased battery capacity in the NEM. Batteries set prices at high levels this quarter, ranging from $355 in Queensland to $753 in South Australia. Batteries, like gas, are a peaking plant and higher prices are linked to the quarter's high price periods.

2.5 Generation by fuel source

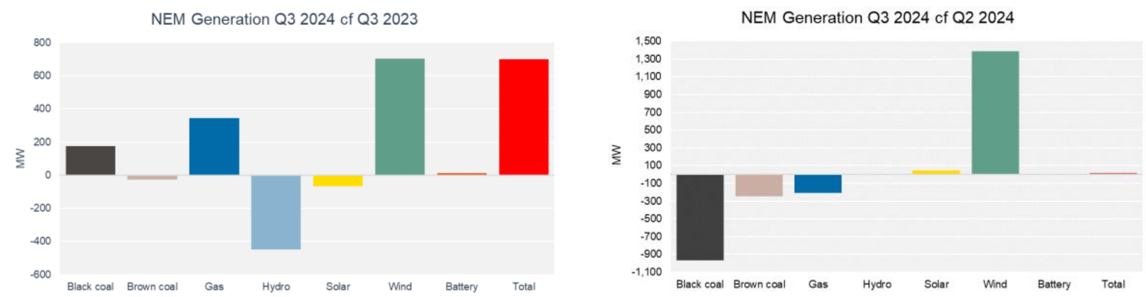
Higher demand met by wind, gas and black coal generation

Average quarterly generation was 3% higher compared with Q3 2023.

Compared with the same period last year, wind generation increased by 703 MW, gas by 346 MW and black coal by 174 MW. These increases met increased demand and also accounted for decreased generation by hydro (down 450 MW), solar farms (69 MW) and brown coal (27 MW) (Figure 11).

As expected, solar generation is lower in winter months and ramps up over spring and summer. The decrease of solar in Q3 2024 compared with Q3 2023 was due to a mixture of weather conditions and solar farms reducing their production to avoid generating at negative prices.[3]

Figure 11 Change in NEM generation output by fuel source



Note: This chart illustrates the change in average quarterly metered NEM generation by fuel type, Q3 2024 compared with Q3 2023 (left) and Q2 2024 (right). 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.

The average baseload capacity unavailable due to outages was higher than the previous quarter – for Queensland outages were up 63% to 757 MW and NSW up 42% to 350 MW in NSW (up 42%), while it decreased by 222 MW (down 37%) in Victoria. Similarly, outages increased from Q3 2023 in Queensland (2%) and NSW (18%) while decreasing in Victoria (21%) (Figure 12). Most of the outages were unplanned.

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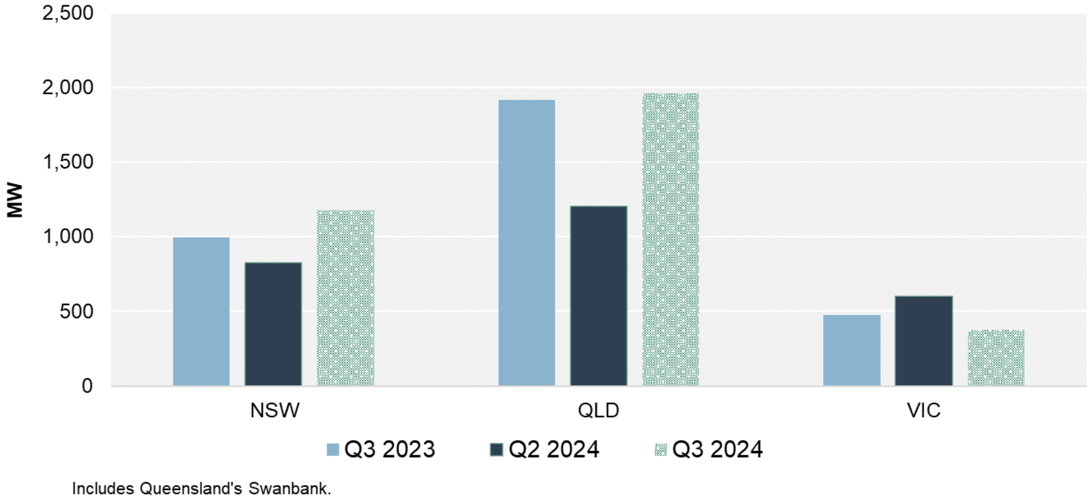
[3] McArdle, P. (2024). (Up to) 75% of Large Solar capability curtailed across the NEM, on Sunday 22nd September 2024. [online] WattClarity. Available at: https://wattclarity.com.au/articles/2024/09/22sept-solarcurtailment/ [Accessed 3 Oct. 2024].

Figure 12 Baseload outages



Note: This chart illustrates the average capacity unavailable due to baseload outages. Black and brown coal units are generally expected to operate 24x7.

Source: AER analysis using NEM data.

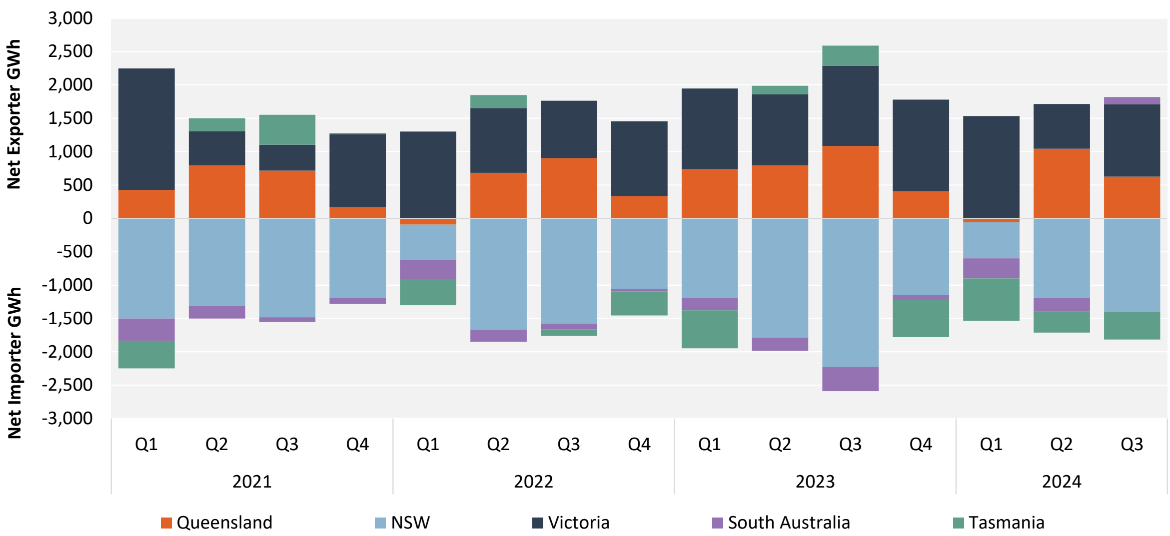
2.6 Interregional trade of electricity

South Australia was a net exporter

Interconnectors allow regions to import cheaper generation from neighbouring regions. Historically South Australia has been a net importer. In this quarter South Australia was a net exporter for the first time since Q4 2020 – exporting 423 MW while importing 317 MW (Figure 13).

During the higher wind periods (outside of its high-price periods), South Australia exported much of its renewable generation to Victoria, which was experiencing higher demand.

Figure 13 Net interconnector flows by regions



Source: AER analysis using NEM data.

3 Gas

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

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

3.1 East Coast gas market spot prices

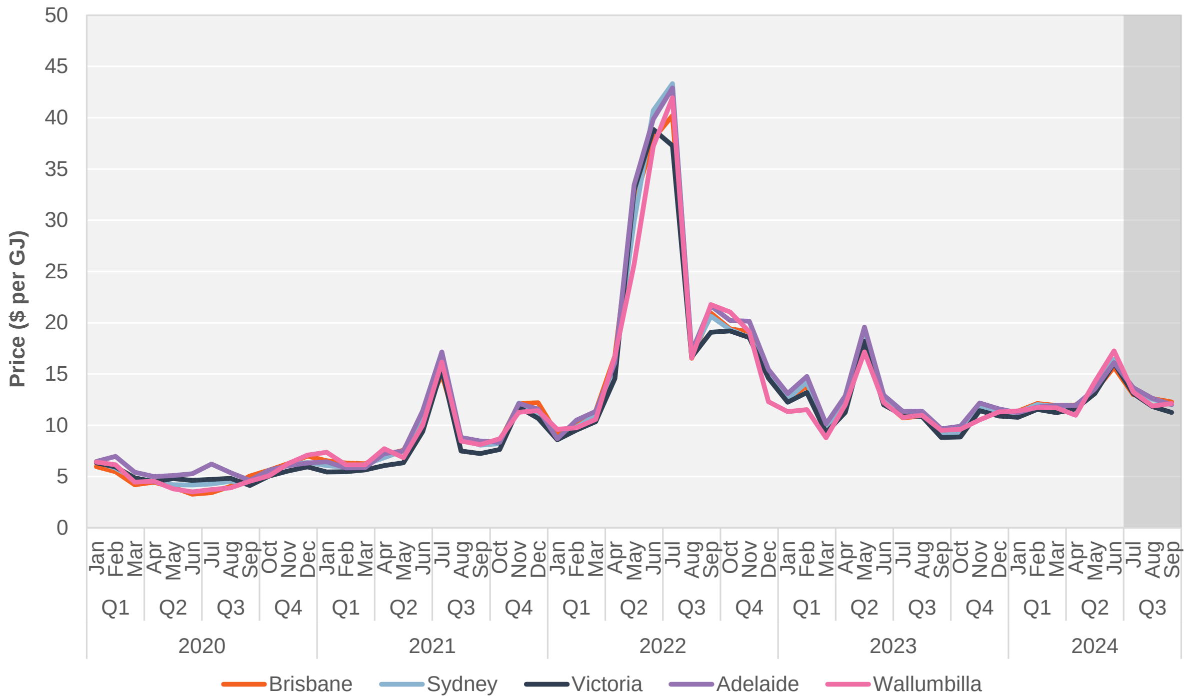
Gas prices decreased over Q3 averaging $12.51 per GJ

East Coast downstream gas market spot prices decreased by 9% from the previous quarter to $12.51/GJ. Following volatile prices in June, prices returned to more normal levels in July despite the typical elevated winter demand driving a continued drawdown of Iona storage supplies (Figure 14).

Warmer weather in August saw further price reductions and the replenishment of Iona storage inventories, with lower prices and diminished supply and demand pressures continuing into September. Lower demand was partly due to declining GPG demand in August with further reductions in September.

Price reductions between Q2 and Q3 are typical and have been observed since 2021, as cold temperatures in southern regions become less extreme in August and reduce demand in southern markets.

Figure 14 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).

Gas market vulnerability to price shocks declined as storage supply increased, leading to a decline in the need to transport gas south from Queensland. Easing supply and demand pressures also led to a reduction in supply output from Longford, which experienced historically low winter supply capabilities this year. With the reduced risk of supply shortfalls and a lower potential for the requirement of market intervention to prevent curtailment, AEMO revoked its threat to system security notice on 23 August.

Box 1: AEMO East Coast Gas System Risk or Threat Notice[4]

On 19 June AEMO issued a system risk or threat notice, identifying that the supply of gas in all or part of the east coast gas system may be inadequate to meet demand. The notice was revoked on 23 August due to easing supply and demand conditions, ahead of the projected 30 September cancellation.

The AEMO notice had outlined an expectation of an industry response to mitigate the system threat and prevent the requirement for market intervention.[5] AEMO highlighted that reduced storage delivery capacity resulting from low inventory levels heightened the risk to winter supply adequacy on peak demand days.[6]

Q3 daily spot market prices peaked in early July, with prices spiking across east coast markets on 1 and 2 July in line with high market demand levels and elevated GPG requirements. Daily prices on 2 July ranged from $15.42/GJ in Victoria to a peak of $20/GJ in Adelaide.

Price reductions occurred over the quarter, linked to periods of warmer weather in late July and August, with an unseasonably warm end to winter putting downward pressure on prices from 11 August. Average east coast gas market prices ranged between $10.34/GJ to $12.68/GJ from 11 August, averaging $11.85/GJ.[7] Prior to prices and demand easing, average east coast gas market prices in July and August outside of these warmer periods ranged from $12.85/GJ to $14.42/GJ averaging $13.62/GJ.[8] The warmer weather resulted in

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4 AEMO, East Coast Gas System Risk or Threat Notice, June 2019, East Coast Gas System Risk or Threat Notice.

5 AEMO expectations included:

- Participants taking reasonable measures to maximise production and supply from Queensland for delivery to southern jurisdiction end users, to reduce the rate of storage depletion.
- Consideration of specific gas demand requirements (including GPG) and the supply sources required to meet that demand.

6 Other potential risks outlined by AEMO identified and included:

- Gas supply and demand trends in southern jurisdictions and the impact of storage inventory depletion, particularly at Iona.
- The combination of lower than forecast Longford production and high seasonal demand and GPG, which has already significantly impacted Iona’s storage levels.
- Constrained Longford production and the expected impact on continued high withdrawals from southern storage.
- Expected storage depletion resulting from unplanned events impacting demand or supply.
- The southern supply capacity impacts due to low or depleted storage inventory.

7 Prices in individual markets ranged from $9.69/GJ in Victoria to $13.54 in Adelaide from 11 August.

8 This excludes the peak prices at the start of July. Prices in individual markets over 4 to 17 July and 29 July to 9 August ranged between $12/GJ in Brisbane to $15.57/GJ in Adelaide.

reduced southern market demand also saw southern market prices reduce below those in the north from August. While prices were above levels observed in Q3 last year, this suggests participants had not over contracted supply for the quarter like the behaviour observed in 2023.[9]

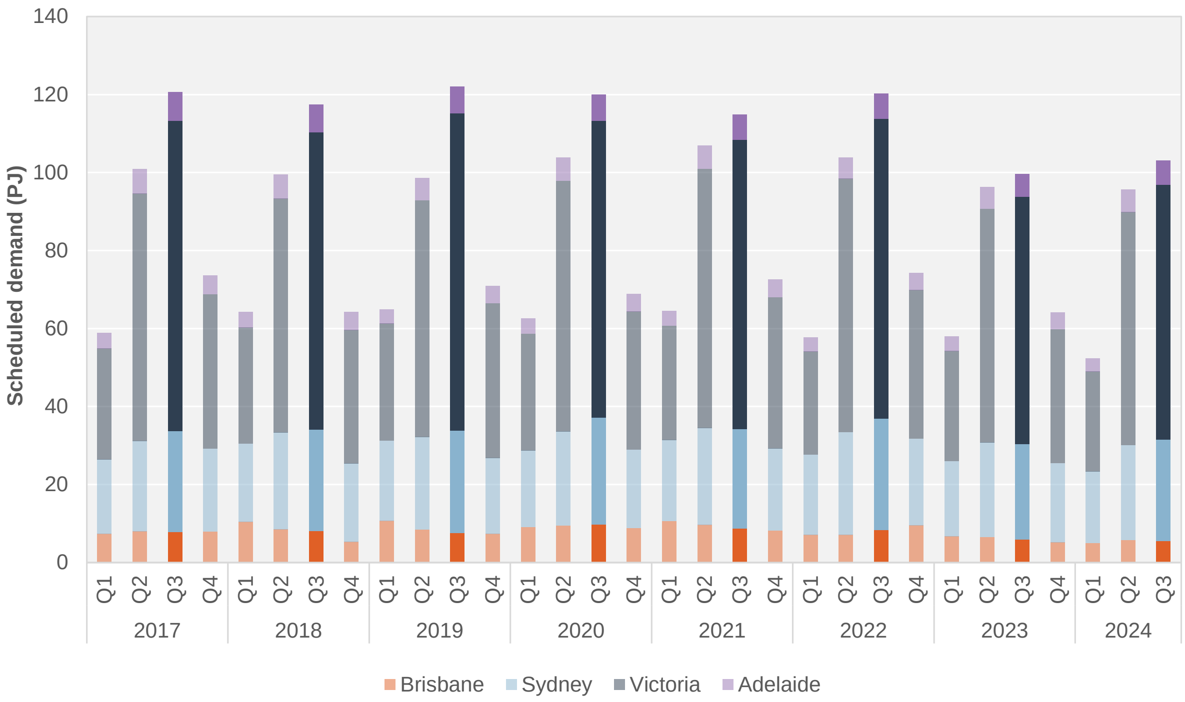
3.2 Scheduled demand for gas

Demand increased in Q3, though was lower than previous years

The typical demand increase from Q2 to Q3 was marginal in 2024, similar to the trend over the warmer winter recorded in 2023 and influenced by the warmer winter conditions from early August.

Demand over Q3 remained low on average but was slightly above last year's record low for Q3 (Figure 15). This influenced unusually low prices for Q3 2023 of $10.44/GJ.

Figure 15 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).

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9 Low prices observed at the end of September 2023 have not occurred to date in 2024. The dip in prices observed last year coincided with warmer weather and very low gas demand for the time of year. Retailers had contracted minimum levels of gas (take or pay) in winter 2023 based on higher gas demand expectations. To ensure that minimum levels of gas already contracted for (and obligated to be paid for) were dispatched, retailers needed to lower gas offer prices to sell into a low demand market.

Daily peak demand levels reduced after early August, which decreased pressure on gas reserves leading to lower prices. Q3 daily demand peaked at just over 1.5 PJ across the east coast markets on 1 August. From 11 August, peak levels remained below 1.2 PJ with average daily demand just under 936 TJ.

Tasmania also contributed to reduced gas demand, with the gas-powered Tamar Valley power station winding down from 23 August ahead of increased hydro generation output over September.

3.3 Gas storage

Iona Storage replenished in August

The Iona storage facility saw a large volume of gas withdrawn across Q3 to meet elevated winter demand and due to constrained production capacity at Longford recorded in Q2, which is Victoria's largest supply source.[10] The rapid decline in storage levels continued into July and occurred despite record levels of gas flowing south (Figure 16).[11] AEMO issued a threat to system security notice highlighting the potential requirement for market intervention to prevent curtailment (Box 1).

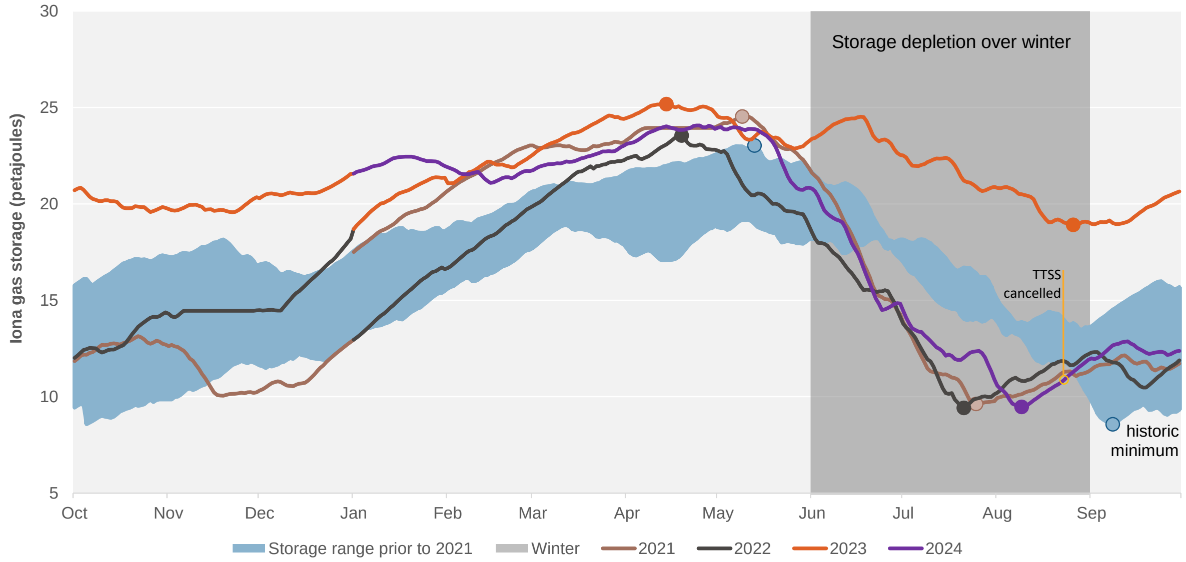
The rapid drawdown in inventories stalled during a period of warmer weather in the second half of July, which allowed participants to briefly replenish storage supply at lower market prices. Participants recommenced withdrawing gas on 27 September, with storage volumes bottoming at 9.5 PJ on 9 August.

Iona's storage levels increased over the remainder of August as market conditions eased. Reduced gas demand and increasing Iona storage levels led AEMO to cancel the threat to system security (TTSS) notice from 23 August, which was ahead of the projected 30 September cancellation (Figure 16). Iona storage levels ended the quarter above 12 PJ.

[10] Maximum capacity at Longford is scheduled to reduce to 700 TJ per day from mid-October with the retirement of gas plant 1. This will increase reliance on Iona in coming winters, with peak day supply capability from underground storage being the 2nd largest source in Victoria, having a nameplate delivery capacity of 570 TJ per day.

[11] Over 10 PJ of gas flowed south from Queensland over July, close to the record monthly flows of just under 11 PJ set in June 2024.

Figure 16 Iona underground gas storage levels



Source: AER analysis using Gas Bulletin Board data.

3.4 Gas pipeline flows

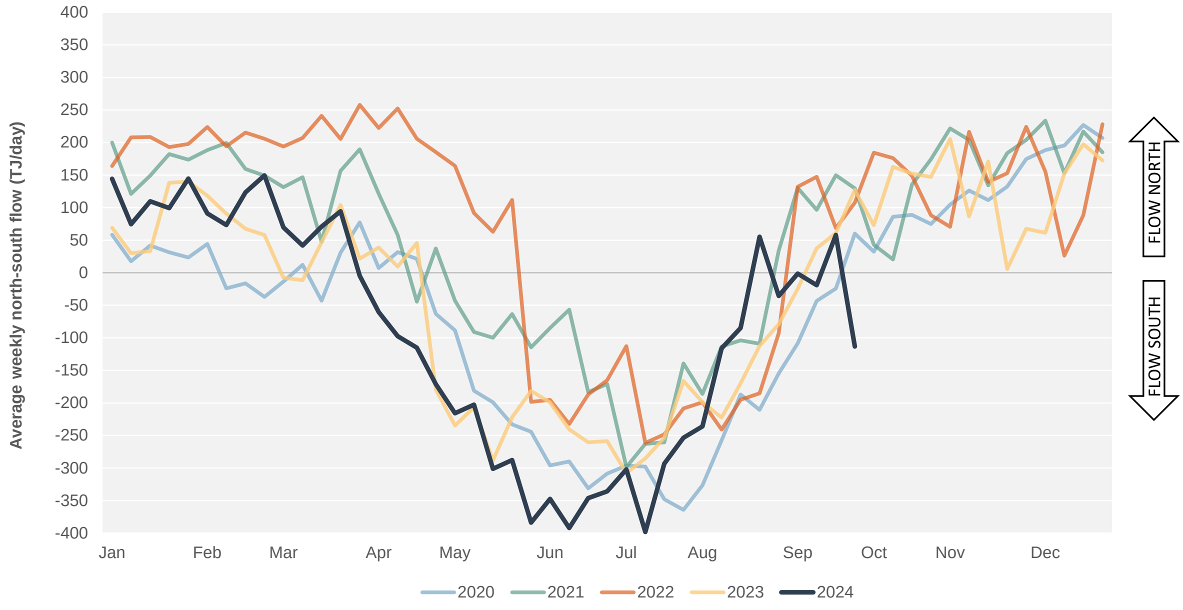
High gas flows south in July reduced from August

In winter months southern markets depend on gas flowing south from Queensland production sources to meet the increased demand. In Q3 2024 flows south remained strong in July following the completion of stage 2 capacity expansions on the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipelines (MSP). The high flows for the month saw close to 10.1 PJ of gas delivered south from Queensland, near the record level in June (10.97 PJ).

Milder weather conditions in August contributed to putting downward pressure on demand, which led to southern flows reducing below 3.4 PJ over the month. From 24 August, following the cancellation of a potential system supply threat, gas flows reversed on the QSN link and starting supplying gas intermittently back into Queensland (Figure 17).

Market participants made use of around 37 PJ of pipeline capacity won through the Day Ahead Auction (DAA) in Q3 2024, a record for the quarter and 5.5 PJ higher than the previous level in Q3 2023. There was a significant change in auction behaviour, with capacity won on the MSP and SWQP increasingly shifting to routes taking gas north rather than south from August onwards.

Figure 17 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.

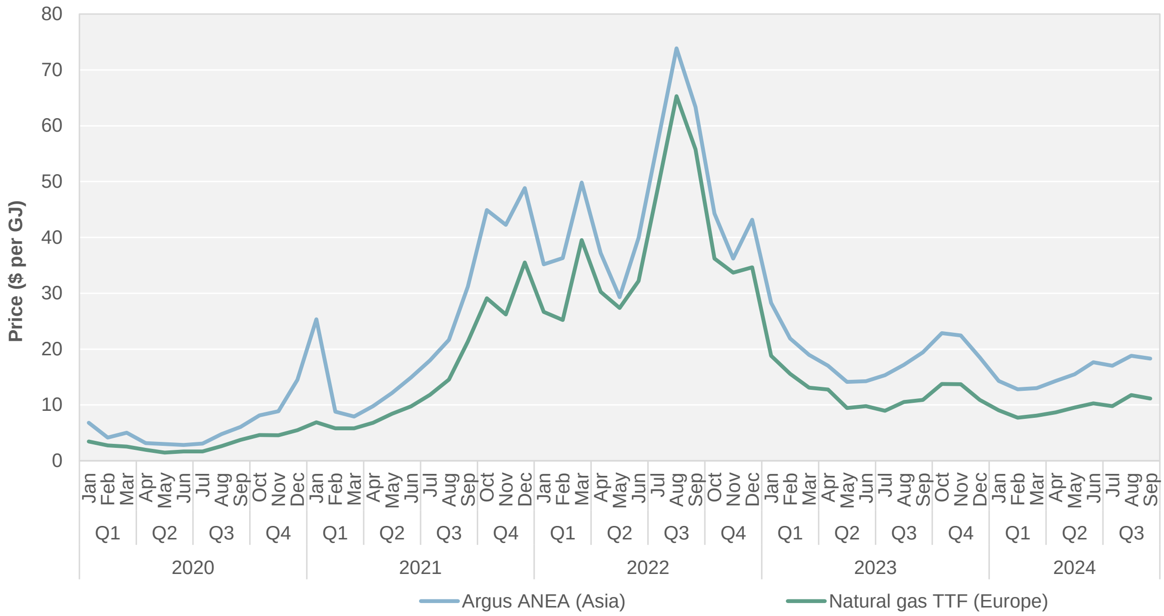
Source: AER analysis using Gas Bulletin Board data.

3.5 International LNG prices

Asian LNG demand support prices in Asia

In Q3, the ANEA price was between AUD$16.08 (12 July) to AUD$19.44 (13 August). Over the quarter, weather weighed heavily on demand as severe and prolonged heatwaves throughout Japan, South Korea and regions of South China boosted demand for gas powered generation (GPG) to meet energy demands for cooling. At the end of the quarter, the ANEA price was AUD$17.80 as cooling demand in Asia waned as the Northern Hemisphere transitioned into the winter season (Figure 18).

Figure 18 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 Natural gas TTF price is a month ahead delivered spot price calculated at the Title Transfer Facility (TTF) in the Netherlands.
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.

European inventory levels were at historical peaks at the end of Q3 as milder weather and cheaper prices promoted filling of storages, reaching 90% capacity in August. This level was achieved 10 weeks ahead of the European Unit (EU) 90% target deadline and driven by LNG imports as the EU reduces dependence on Russian piped gas.[12] There is a strong correlation between European gas prices and ANEA prices.

[12] European Commission: EU reaches 90% gas storage target 10 weeks ahead of deadline

4 Electricity and gas markets forward outlook

This section provides discussion of electricity futures prices, electricity generation entry/exit and bilateral gas contracts.

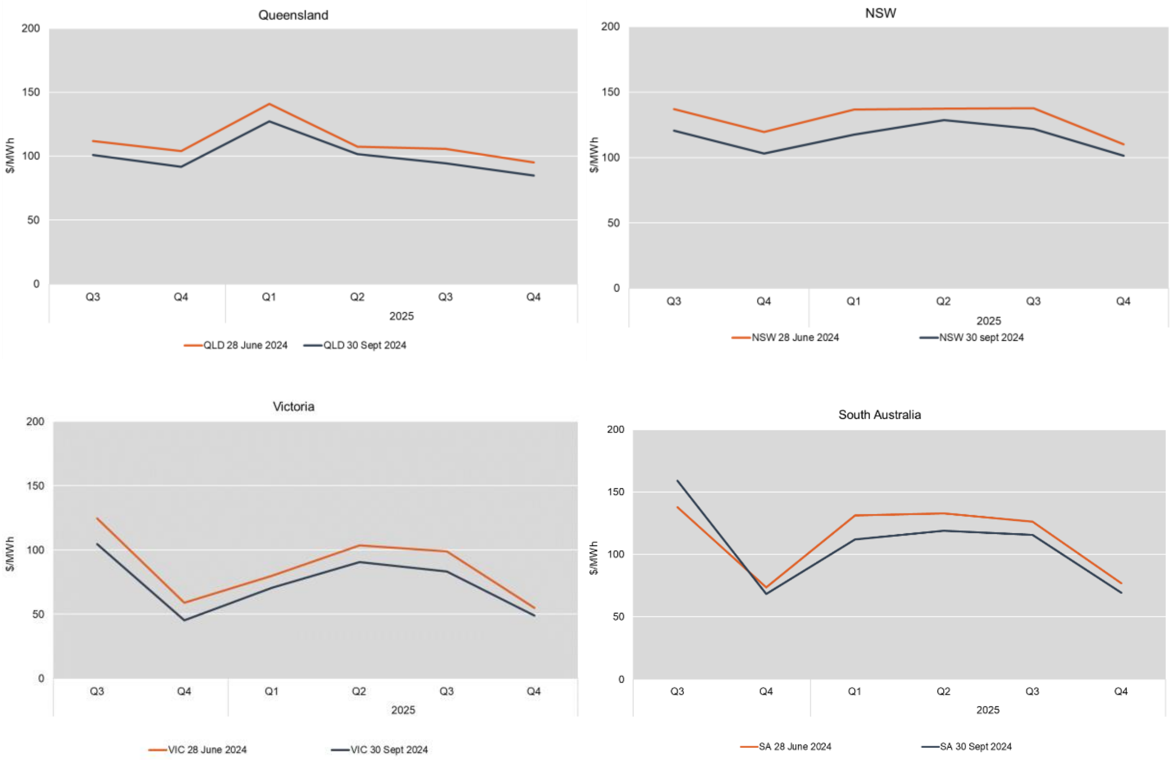
Results are based on AER analysis of ASX, AEMO and Gas Bulletin Board data.

4.1 Forward prices

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

Forward contract prices were mostly lower in all regions from Q4 2024 to end of 2025 (Figure 19).

Figure 19 Base quarterly electricity futures prices



Note: Base future prices for each quarter as of 30 June 2024 (end Q2) and 30 September 2024 (end Q3).

Source: AER analysis using NEM data

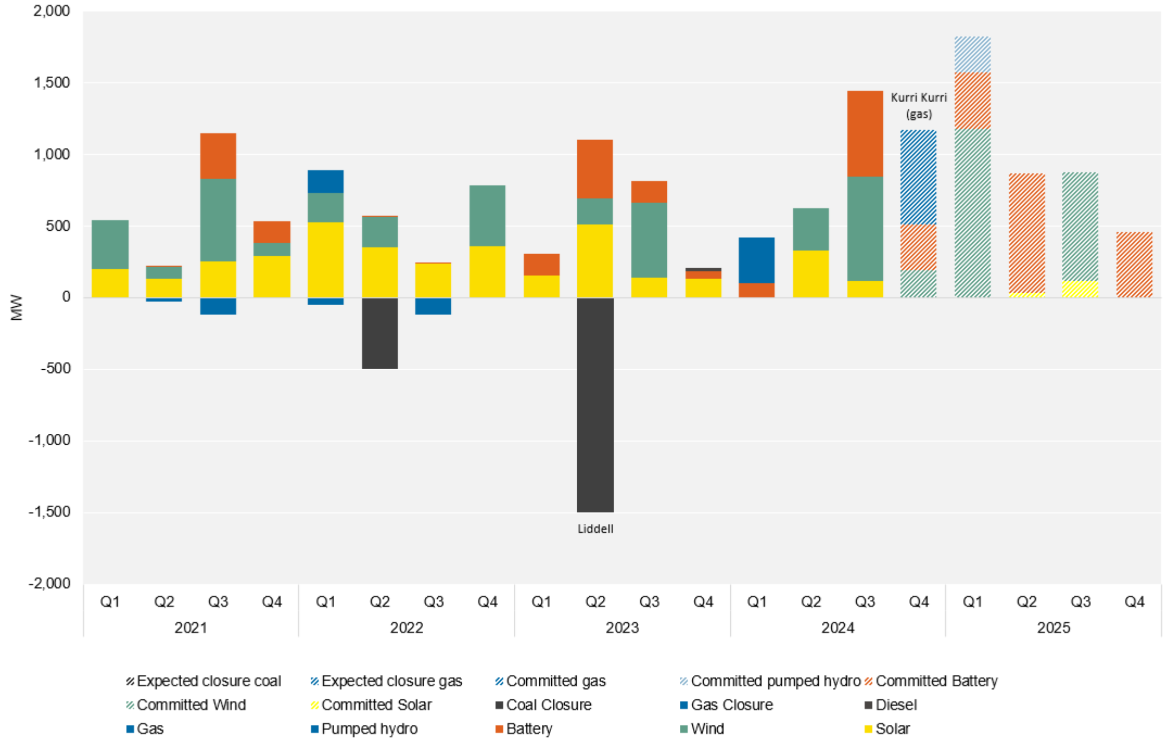
Throughout the quarter, contract prices for Q3 2025 declined slightly, suggesting the fluctuating spot prices during the first half of the quarter didn't flow through to futures prices. South Australian Q3 2024 contracts fluctuated a little more in line with peaky prices, with settled price increasing from end of July before settling again at the beginning of September.

4.2 Entry and exit of capacity

1,445 MW of new capacity came online in Q3

New entry this quarter was much higher as delayed projects came online (Figure 20). Approximately 1,445 MW of capacity was added through batteries (600 MW), wind (729 MW) and solar (116 MW), however, it will take some time before these units reach full output.

Figure 20 New entry and exit



Note: This chart illustrates entry, exit and expected new entry. 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.

4.3 Bilateral gas transactions

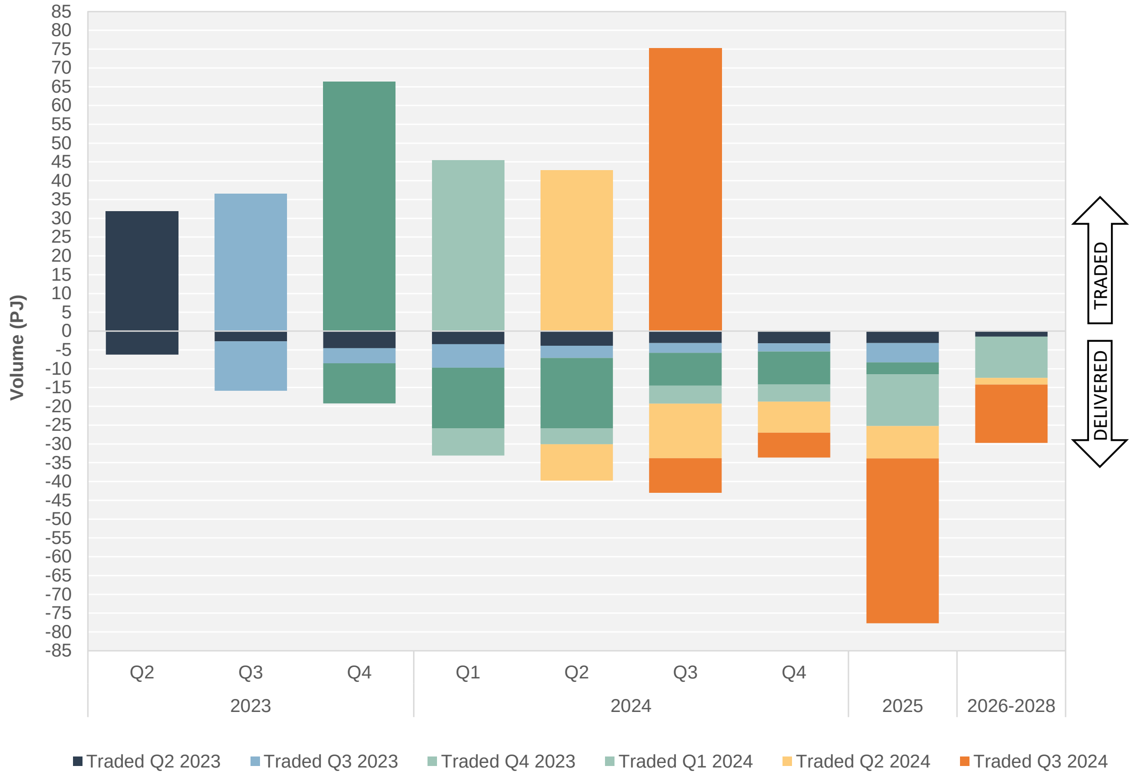
A significant proportion of gas trade is negotiated directly between participants outside of the AEMO-facilitated markets. Since March 2023, participants have been required to report details of these bilateral transactions up to a year in duration to the Gas Bulletin Board.

Short term contract prices for 2025 fell over $1 to average around $14 per GJ

There were 75.2 PJ of gas sales reported in Q3, almost double the Q3 2023 volume of 37.6 PJ, with 43.8 PJ of these sales for delivery in 2025 (Figure 21). Q3 reported transactions for delivery in 2025 is almost double the volume reported in total for the first half of 2024 (22.3 PJ). This indicates contracting activity for 2025 has been increasing as the new calendar year approaches.

Overall, the highest volumes of trade were reported for Q2 and Q3 than for the same quarters last year, which is potentially indicative of a shift to shorter term contracting (up to a year in length) and away from transactions longer in length (greater than a year).

Figure 21 Traded versus Delivered Quantities

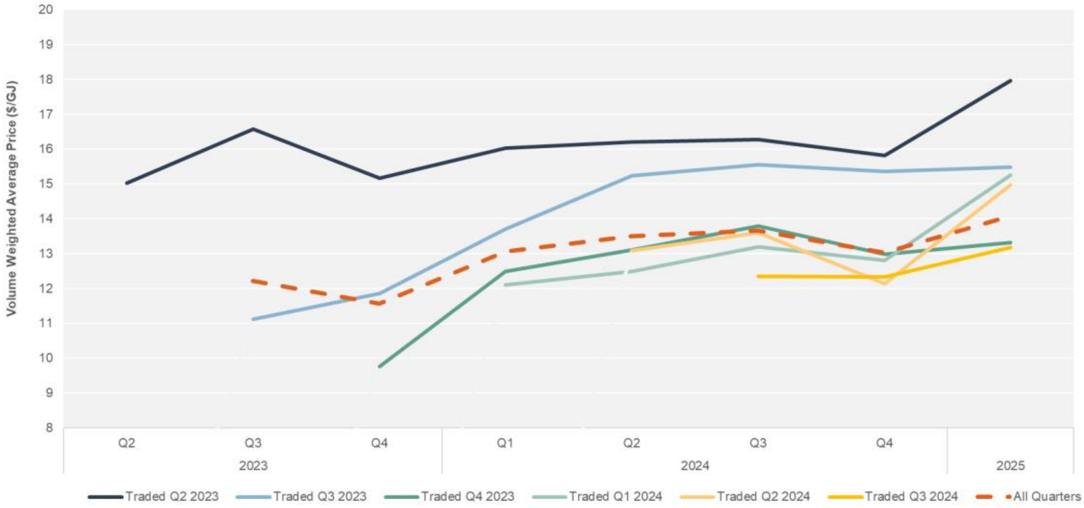


Note: Traded refers to the trade date of the short-term supply transaction, while Delivered refers to the month the gas volume will be supplied. Where there is not enough trades or participants reporting in a period the data is aggregated to a longer time frame. The trade in previous quarters before Q3 2024 has changed slightly from what was reported in our previous quarterly - 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 for which the AER monitors.

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

The volume weighted average (VWA) price for gas traded in Q3 2024 for 2025 was lower than any previous quarter (Figure 22). As a result of the lower price and larger traded quantity, the 2025 VWA price decreased by over $1/GJ to $14.09/GJ from the price reported at the end of Q2 2024. This is reflective of a large percentage of Q3 2024 trade for 2025 being in a $10-$12 price range (25%) and a $12-14 price range (46%) compared to over 100% being priced above $14 per GJ in Q2 2024.

Figure 22 VWA forward price curve based on the 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. These prices exclude pricing structures linked to the STTM or DWGM. Where there is not enough trades or participants reporting in a period the data has been aggregated.

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