Wholesale markets quarterly Q4 2023

October - December

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Inquiries about this publication should be addressed to:

Australian Energy Regulator: GPO Box 3131, Canberra ACT 2601. Tel: 1300 585 165

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Changes to 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.

Wholesale markets at a glance

Q4 2023

National Electricity Market (NEM) spot prices averaged under $80 per MWh in all regions in Q4 and forward prices also fell. While these were well below 2022 levels, it will take time to be reflected in prices faced by consumers.

East coast gas spot market prices averaged $10.83 per GJ, slightly above the previous quarter.

Due to seasonally lower demand, all fuel-types generated less than last quarter except large-scale solar.

Forward electricity prices fell during the quarter for all regions traded.

Record rooftop solar contributed to low electricity demand this quarter, including record minimum demand in Victoria and South Australia.

More low-priced capacity was offered than a year ago, but in some regions less was offered than in Q3.

Low domestic gas market demand and gas generation offset high LNG export flows.

Significant volumes of gas were traded in Q4 through short term bilateral contracts for delivery over 2024, with just over 50% of those trades in price bands between $10-$12 per GJ.

Topped-up southern gas storage remains at record high levels.

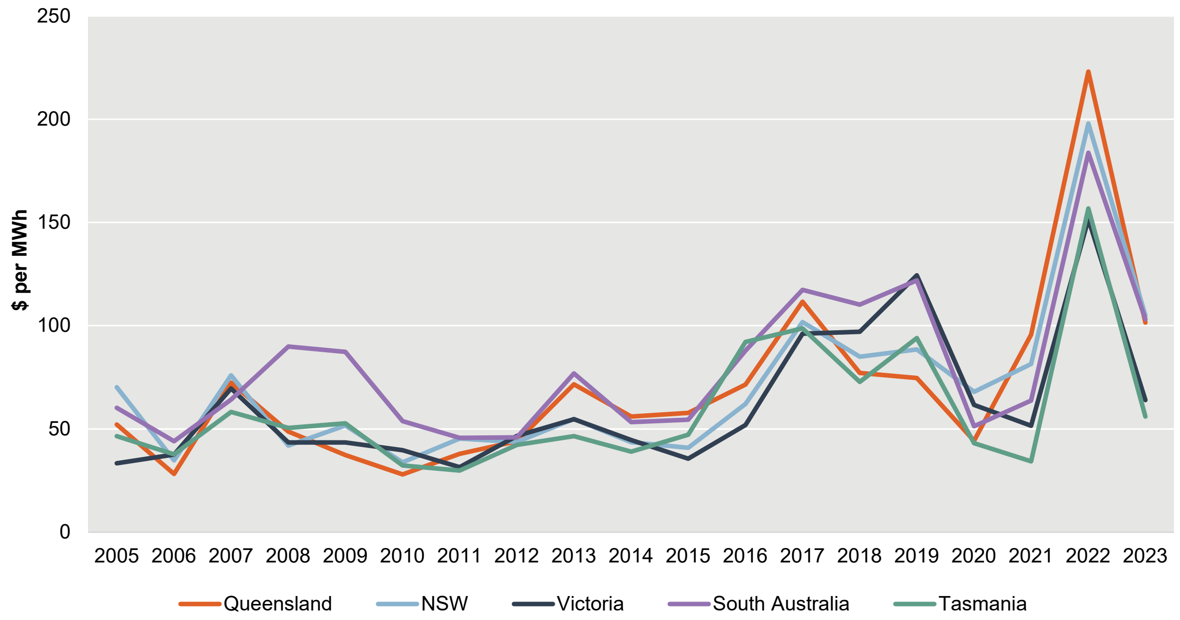
International LNG spot prices have decreased slightly over December and remain significantly lower compared to last year.

1 Rooftop and large-scale solar contributed to a continued downward trend in wholesale prices

2023 prices were well below those seen in 2022

In 2023, annual average NEM prices ranged from $56 per MWh in Tasmania to $105 per MWh in NSW (Figure 1). These prices were more in line with longer term annual averages after the record high prices of 2022. The decrease in prices from 2022 to 2023 ranged from 44% in South Australia to 64% in Tasmania.

Figure 1 Average annual prices in the NEM



Note: This chart illustrates volume weighted average annual prices, meaning prices are weighted against native demand in 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.
Source: AER analysis using NEM data.

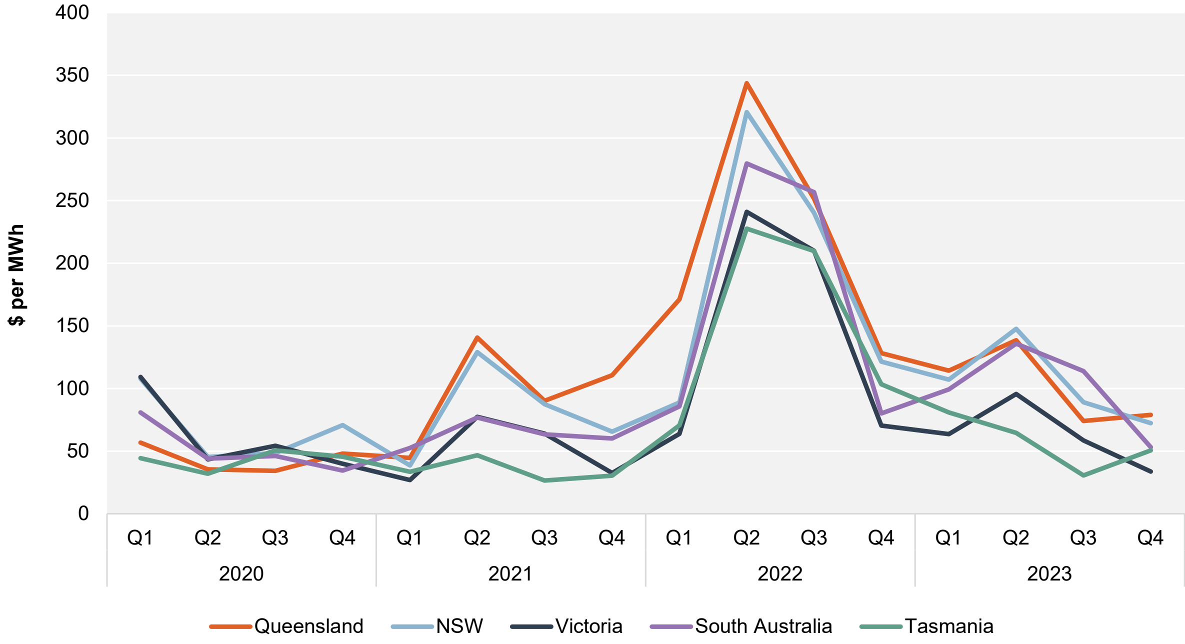
Milder winter weather conditions, lower fuel costs (in part linked to government interventions),[1] fewer coal supply issues and an increase in cheap wind and solar supply all contributed to lower NEM prices across the year.

Quarterly prices declined since last quarter in NSW, Victoria and South Australia

Quarterly average NEM prices declined from Q3 to Q4 in NSW, Victoria and South Australia, but rose in Queensland and Tasmania (Figure 2). Price increases were driven in Queensland by high demand days and in Tasmania by higher-priced hydro offers. Victoria was the cheapest region in Q4, with prices averaging $34 per MWh, while Queensland was the most expensive at $79 per MWh.

[1] AER, *State of the energy market 2023*, October 2023, p. 41.

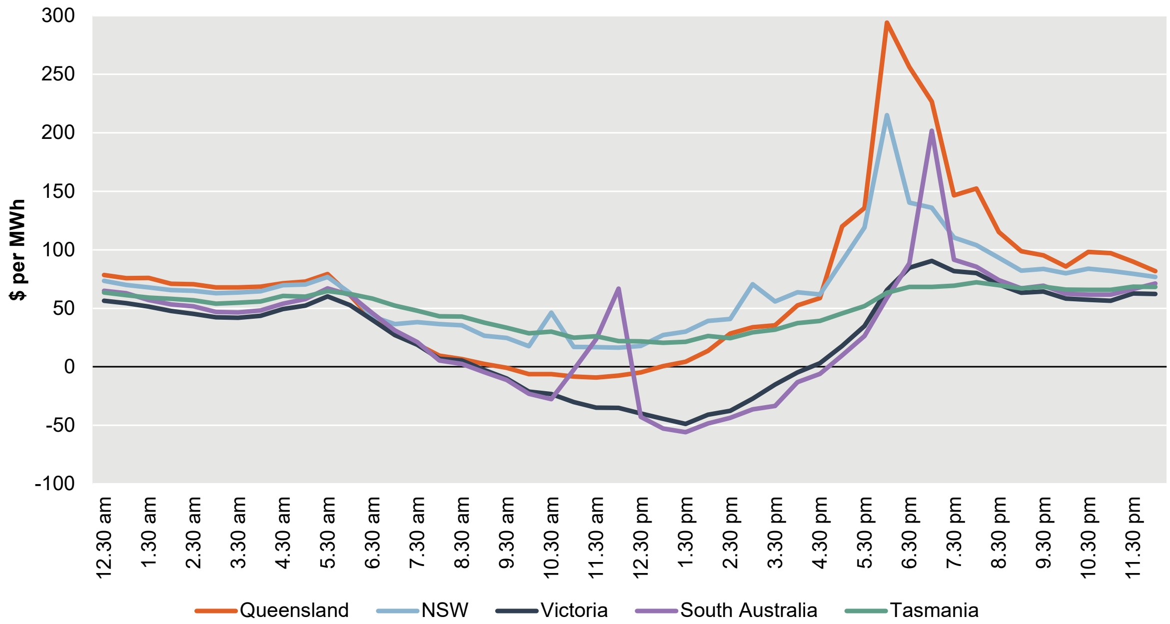
Figure 2 Average quarterly prices in the NEM



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 that which is met by local scheduled, semi-scheduled and non-scheduled generation. It does not include demand met by rooftop solar PV systems.
Source: AER analysis using NEM data.

Compared to Q4 2022, Q4 2023 prices were lower and were generally more in line with historical Q4 prices. However, the differences between daytime and evening market conditions continued to intensify. In Victoria and South Australia, average daytime prices were negative but evening peak prices averaged well over $100 per MWh in Queensland, NSW and South Australia (Figure 3).

Figure 3 Average Q4 2023 prices by time of day



Note: This chart shows the price averaged across the quarter for each half hour of the day. It shows volume weighted average quarterly prices, meaning prices are weighted against native demand in 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. Monthly average time of day prices are not always smooth due to price spikes: for example, the South Australian 30-minute price spiked to over $5,000 per MWh at 11.30 am and 12 pm on 8 December, driving a higher monthly average price for that time of day.
Source: AER analysis using NEM data.

Overall, weather conditions were milder in Q4 than many forecasts predicted which was reflected in moderate price outcomes. However, in periods of high demand, there were still high price events, albeit these were not frequent enough to have a large impact on the monthly average price. The market remains vulnerable to more frequent high price events should temperatures increase in Q1.

During the quarter, 30-minute average spot prices exceeded $5,000 per MWh in South Australia 3 times – once on 9 November and twice on 8 December – contributing $8 per MWh to the quarterly average price. In Queensland, 30-minute prices exceeded $5,000 per MWh once each on 28 and 29 December, contributing $5 per MWh to the quarterly average price. Some of the factors contributing to these events included network limitations, high demand and rebidding behaviour. We will publish a separate report examining the drivers of Q4 significant price events in more detail.

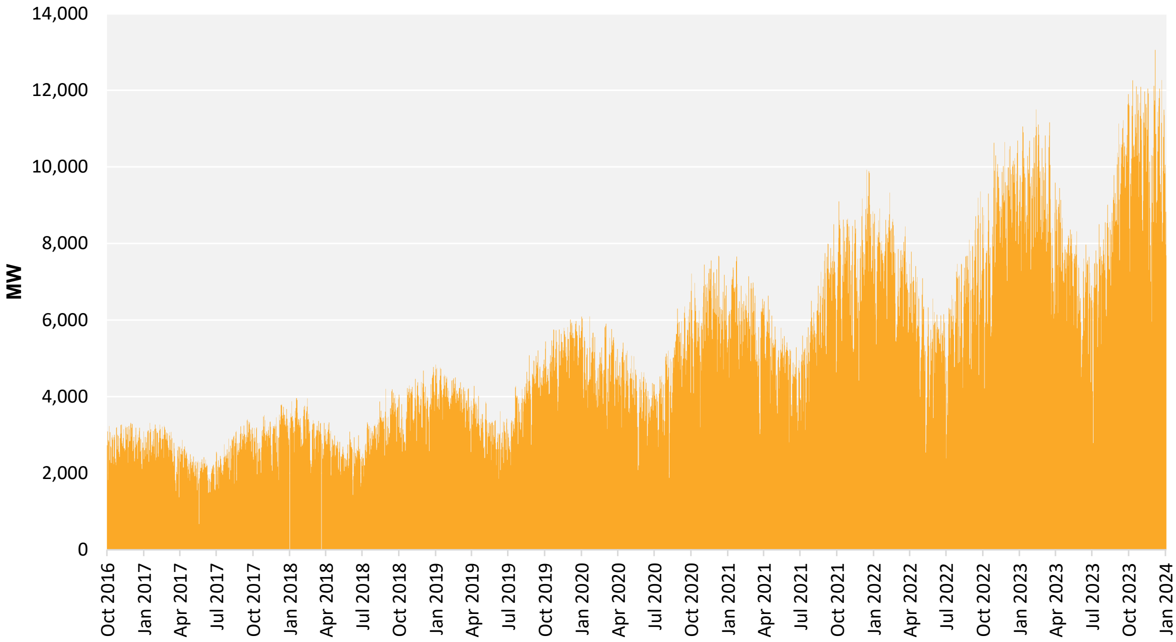
Record rooftop solar output drove record minimum daily demand in Victoria and South Australia

As is typical in Q4, average demand was lower than in Q3 in all regions but Queensland, where hot and humid Q4 periods typically increase air-conditioning requirements. These seasonal changes in demand were a key driver of price outcomes over the quarter.

Another reason demand tends to be lower in Q4 is increased rooftop solar output. More direct sunlight and lengthening daylight hours mean that PV systems can output more energy and for a longer period each day. In Q4 2023, rooftop solar output was 50% higher than in Q3.

Rooftop solar output also increased year on year due to continued strong growth in installations. Q4 output was 17% higher than in Q4 2022, while total output for 2023 was 24% higher than total output in 2022. On 6 December, rooftop solar output reached a NEM-wide all-time high of 13,058 MW, with each individual region also setting rooftop solar output records during the quarter.

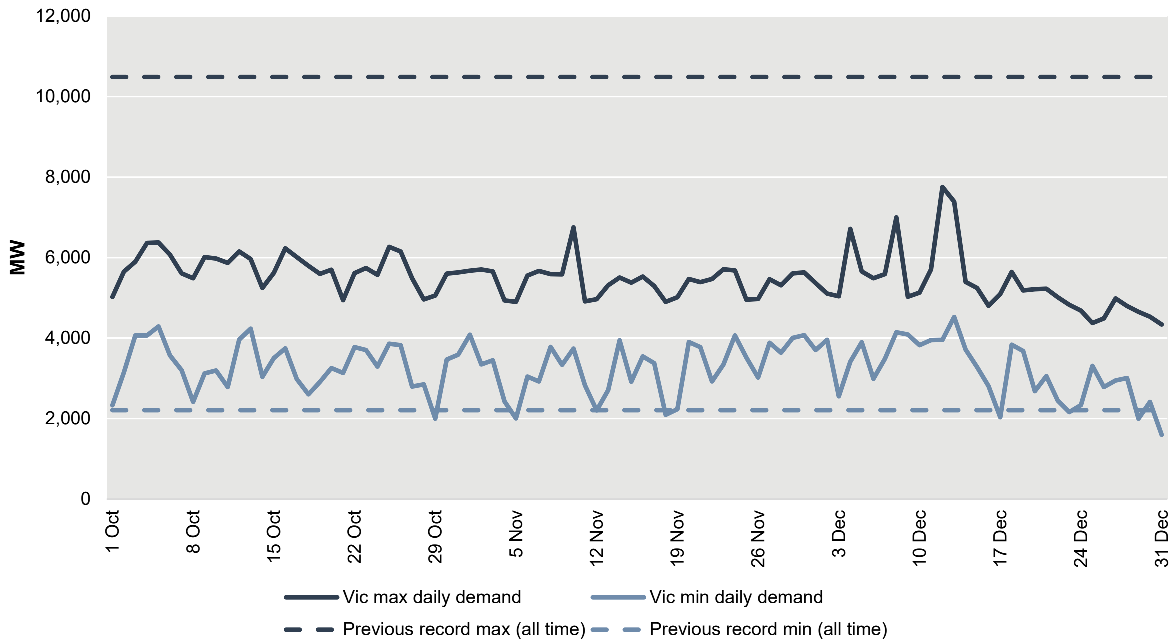
Figure 4 Daily maximum rooftop solar generation in the NEM



Note: Uses aggregated figures from half-hourly interval data.
Source: AER analysis using AEMO rooftop PV data.

The increase in rooftop solar output was a key factor in Victoria and South Australia setting minimum daily demand records during the quarter. Victorian minimum daily demand fell below the previous record of 2,209 MW on 8 separate days across the quarter and on 31 December fell to just 1,598 MW. Meanwhile, South Australian minimum daily demand fell below the previous record of 29 MW on 31 December, reaching -19 MW. This meant that rooftop solar output in South Australia was greater than the region's entire energy demand, with excess output exported to Victoria.

Figure 5 Victoria minimum daily demand



Note: Uses daily minimum native demand. 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

Source: AER analysis using NEM data.

Low demand contributes to downward pressure on prices, in some cases even contributing to negative prices. Q4 saw a record number of negative prices occurring in mainland regions.[2] These negative prices were most frequent in Victoria and South Australia. Negative prices typically occur during the day when rooftop solar output is high, in some regions contributing to negative average prices during this window (Figure 3).

When minimum demand falls to very low levels, AEMO may take steps to ensure the security and reliability of the energy system. In extreme cases, AEMO may need to direct networks to curtail solar output.[3] However, AEMO-instructed curtailment was not required this quarter. On 31 December, AEMO did seek a market response to very low demand in Victoria to manage system security but conditions subsequently improved such that intervention was not required.

Further uptake of rooftop solar may increase pressure on minimum demand in the future. Market developments such as electrification, price incentives to shift demand (such as "solar soaker" tariffs) and uptake of battery technologies have the potential to mitigate some of these pressures. However, only 9% of export customers in South Australia currently use a battery and penetration is lower in most other regions.[4]

Similarly, initiatives like flexible export limits can help customers achieve higher overall output but need to be implemented well, with meaningful customer engagement. [5] We are actively monitoring these developments, understanding that wholesale market challenges are closely entwined with customer experience.

Less low-priced capacity was offered than last quarter but more was offered than a year ago

Compared to Q3, less capacity was offered this quarter overall, while some capacity was also shifted from lower to higher prices (Figure 6). The reduction in total offers was largely due to scheduled maintenance of coal units in NSW, while gas also offered less capacity across the NEM.

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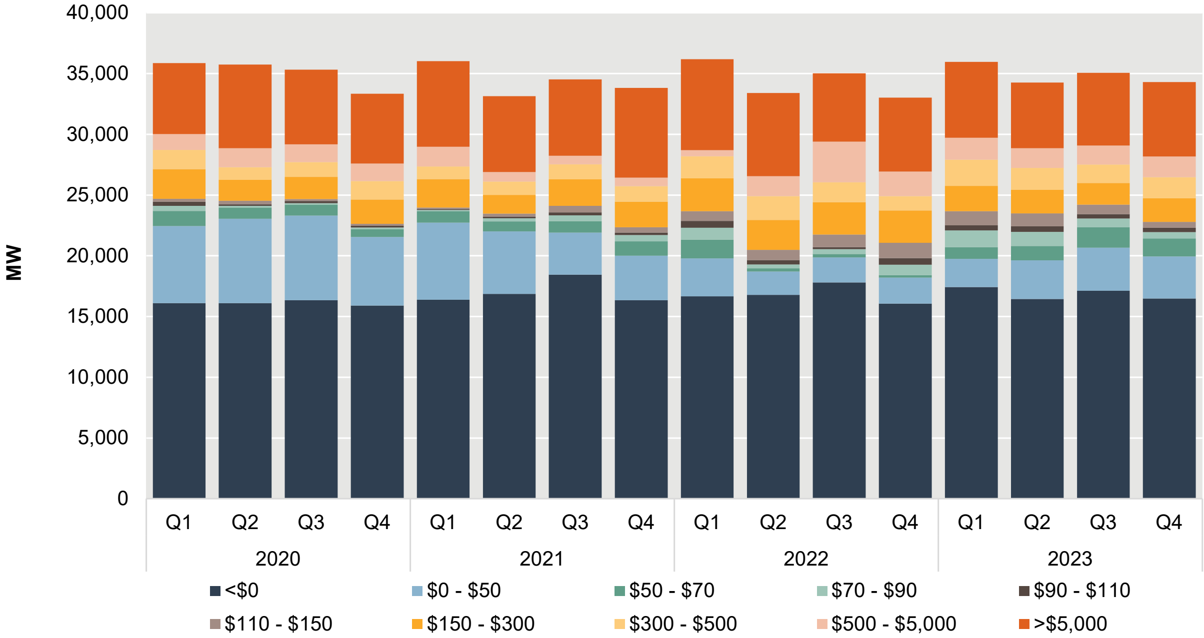
[2] Negative prices can occur in the wholesale market because generators are able to offer their capacity as low as -$1000 in order to compete to be dispatched. Where enough generators bid this way, it can lead to the market price being set below zero (i.e. generators are effectively paying to operate).

[3] AEMO, "Factsheet: Operating the grid with high roof-top solar generation".

[4] AER, *Export services network performance report*, December 2023, p. 5.

[5] For the AER's role supporting flexible export limits, see our recent report "Flexible export limits final response and proposed actions", July 2023.

Figure 6 NEM offers by price bands



Note: Average quarterly offered capacity by price bands.
Source: AER analysis using NEM data.

Compared to last quarter, 1,430 fewer MW were offered below $150 per MWh, including 926 fewer MW offered below $70 per MWh. However, nearly 700 extra MW was offered above $150 per MWh.

At a regional level, Tasmania had the most significant decrease in low-priced capacity, which was driven by a change in hydro offers. This was why Tasmanian prices increased from Q3 to Q4. Victoria and South Australia also had fewer low-priced offers than last quarter, but prices still fell in these regions due to lower demand.

In Queensland and NSW, there was a small increase in offers below $70 per MWh. In both regions, this was primarily driven by an increase in large-scale solar output, which more than offset a decrease in low-priced black coal offers. Black coal offers decreased in NSW due to a seasonal increase in planned outages and in Queensland due to a slight shift in offer behaviour.

In NSW, the increase in low-priced offers contributed to lower prices this quarter. In Queensland, the increase in low-priced offers was more than offset by higher demand, and prices increased this quarter.

Compared to Q4 2022, more cheap capacity but less high-priced capacity was offered this quarter. About 3,000 MW extra was offered below $70 per MWh, while about 1,700 MW less was offered above $70 per MWh. The increase in low-priced capacity was largely driven by black coal, amid lower fuel costs (corresponding with government interventions). Meanwhile, large-scale solar, hydro and wind also contributed to the increase in low-priced capacity. The increase in low-priced capacity from a year ago is the reason for the large drop in prices since Q4 2022.

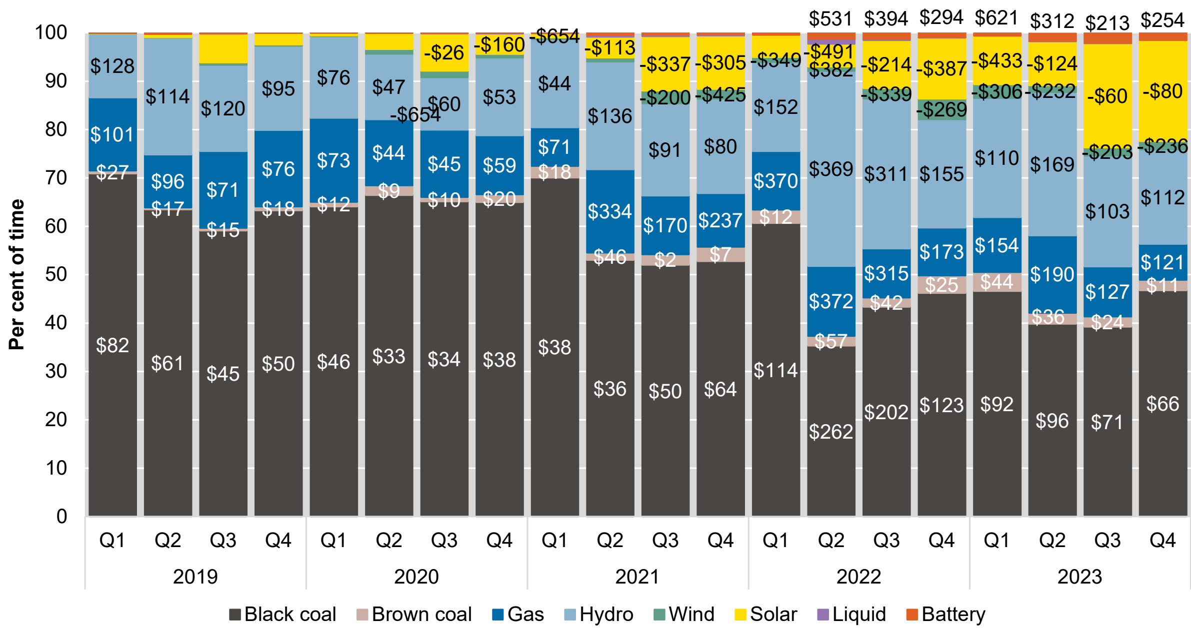
Most fuels set lower prices this quarter

In Queensland, all fuels set lower prices this quarter except hydro and batteries. Coal set price more often while most other fuels set price slightly less often.

Last quarter, we reported a remarkable increase in the amount of time large-scale solar was setting price in Queensland. This quarter, solar set price slightly less often, particularly in the middle of the day, despite an increase in large-scale solar output. This occurred because demand was higher than in Q3, requiring higher priced fuels to be dispatched. Nevertheless, solar still set price much more often than in Q4 2022.

For the most part, trends in other regions were similar to those in Queensland. In other mainland regions, large-scale solar set price much more often than in Q3 but still less often than in Queensland.

Figure 7 Price setting by generation source, Queensland



Notes: The height of each bar is the percent of time each fuel type sets the price, and the number within each bar is the average price set by that fuel type when it is marginal (that is, setting the price). The pattern in price setting changes was broadly similar across mainland regions. Charts for other regions are available on our website.

Source: AER analysis using NEM data.

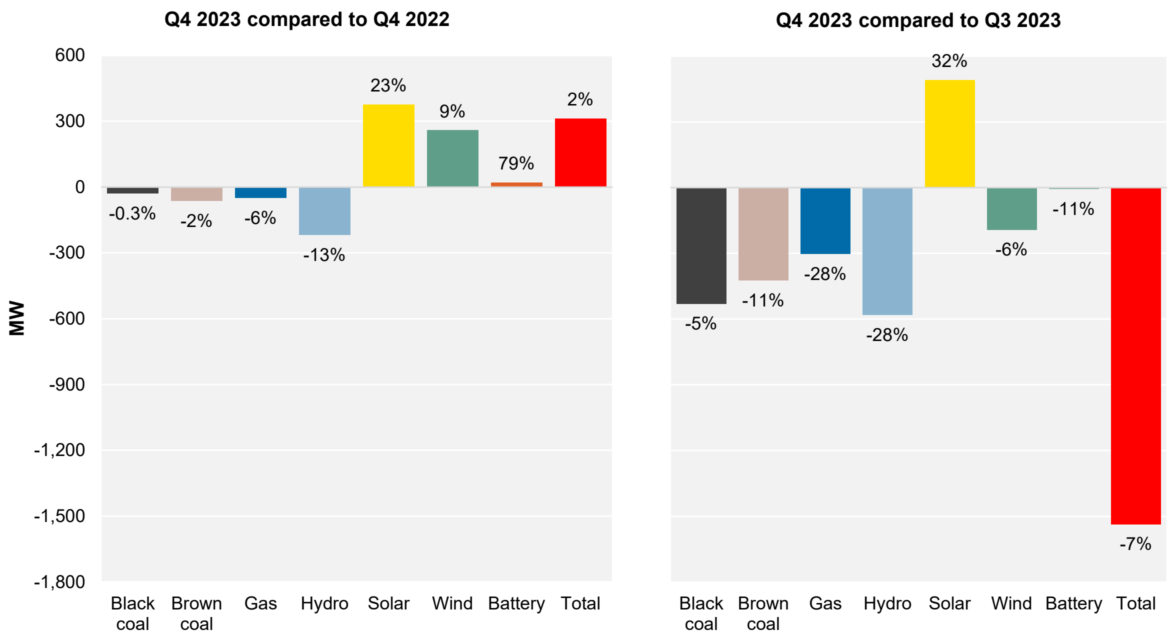
Wind and large-scale solar achieved record high share of generation output

This quarter, the proportion of generation output sourced from fossil fuels fell to a record low, providing two thirds of generation output. Meanwhile, wind and solar reached a record high share, representing 26% of output – up from a previous record share of 23% in Q4 2022.

Compared to last quarter, large-scale solar was the only fuel to increase its output while output from all other fuels decreased.

Compared to Q4 2022, solar, wind and batteries all increased output while output from coal, gas and hydro decreased. Since solar and wind are the cheapest fuels, the change in generation mix contributed to lower prices this quarter.

Figure 8 Change in NEM generation output by fuel source



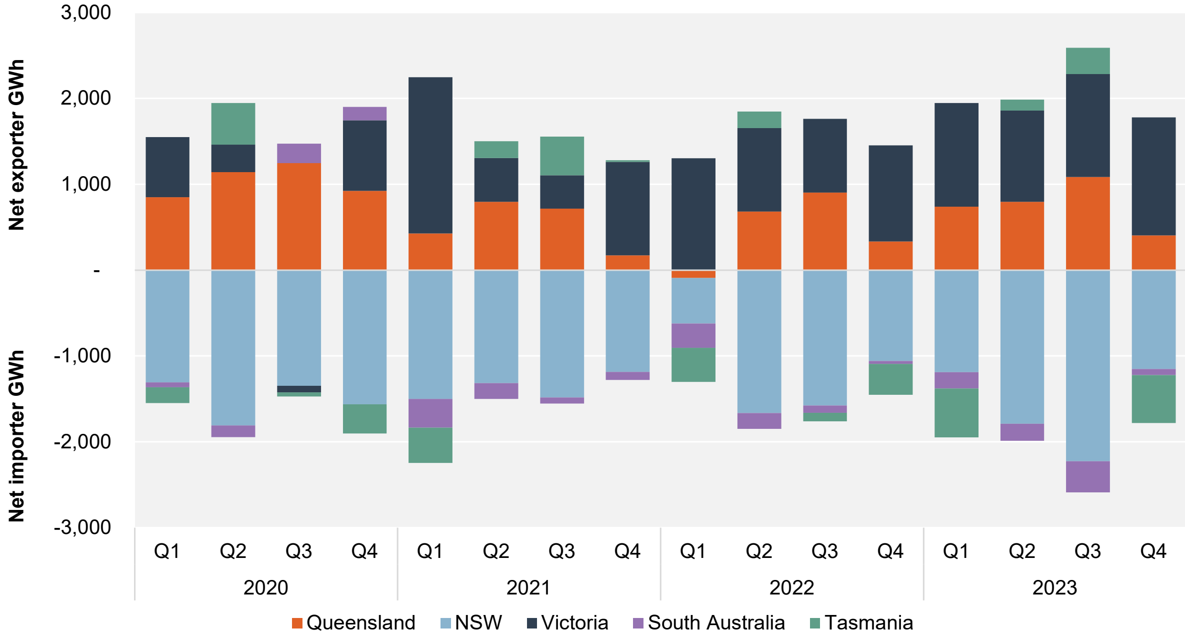
Notes: Change in average quarterly metered NEM generation by fuel type, Q4 2023 compared with Q4 2022 (left) and Q3 2023 (right). Data labels show the percentage change in output for that fuel type. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.
Source: AER analysis using NEM data

NSW and South Australia imported less than last quarter

Interconnectors allow regions to import cheaper generation from outside their borders. Queensland and Victoria tend to be net exporters, providing surplus capacity to NSW and South Australia where cheap capacity is more often scarce. Q4 2023 was consistent with this general pattern, but NSW and South Australia imported less than last quarter (Figure 9). Queensland remained a net exporter but exported less than in Q3. These changes reflected lower demand and prices in NSW and South Australia, and higher demand and prices in Queensland. Tasmania, which varies between a net importer or exporter, was a net importer this quarter, reflecting higher prices in the region. Export and import patterns were similar this quarter to Q4 2022.

Interconnector constraints are often a factor in high price events, as they can limit a region's ability to import cheap capacity. We reported on this for high price events occurring earlier in 2023, and this continued to be a factor in Q4 high price events. On 9 November, a planned network outage limited imports into South Australia. Meanwhile on 8 December in South Australia, and on 28 and 29 December in Queensland, network limitations to protect system security in severe weather led to imports being restricted. We will report on this further in our upcoming high price event report for Q4.

Figure 9 Net interconnector flows by region



Notes: Net amount of energy either imported or exported each quarter by region.
Source: AER analysis using NEM data.

Very fast FCAS services commenced this quarter

Frequency control ancillary services (FCAS) are used to maintain the frequency of the energy system. 2 new FCAS services were added this quarter – 1 second raise and 1 second lower services ("very fast" FCAS services). Currently, 16 participants are registered to provide the service, with representation in all NEM regions. Most providers are batteries or demand response aggregators.

So far, prices and costs for these new services have been much higher than for other FCAS services. For lower services, the 1 second service averaged $26 per MW this quarter, while the next most expensive service was lower regulation at $9 per MW. For raise services, the 1 second service averaged $17 per MW, while the next most expensive was raise regulation at $11 per MW.

We will continue to monitor outcomes in this market to better understand cost and price drivers. Under the National Electricity Rules (NER), the AER must report on market ancillary services for each calendar quarter.[6] We also assess competition and efficiency in FCAS markets in our biennial *Wholesale electricity market performance report*. Finally, the AER must publish a report when the price of an FCAS service exceeds $5,000 per MW for at least 2 consecutive 30-minute periods.[7] This reporting threshold was not breached during Q4 2023.

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[6] AEMC, National Electricity Rules, clause 3.11.2A. We fulfil this reporting obligation through our industry charts, published on our website, "Market statistics charts".

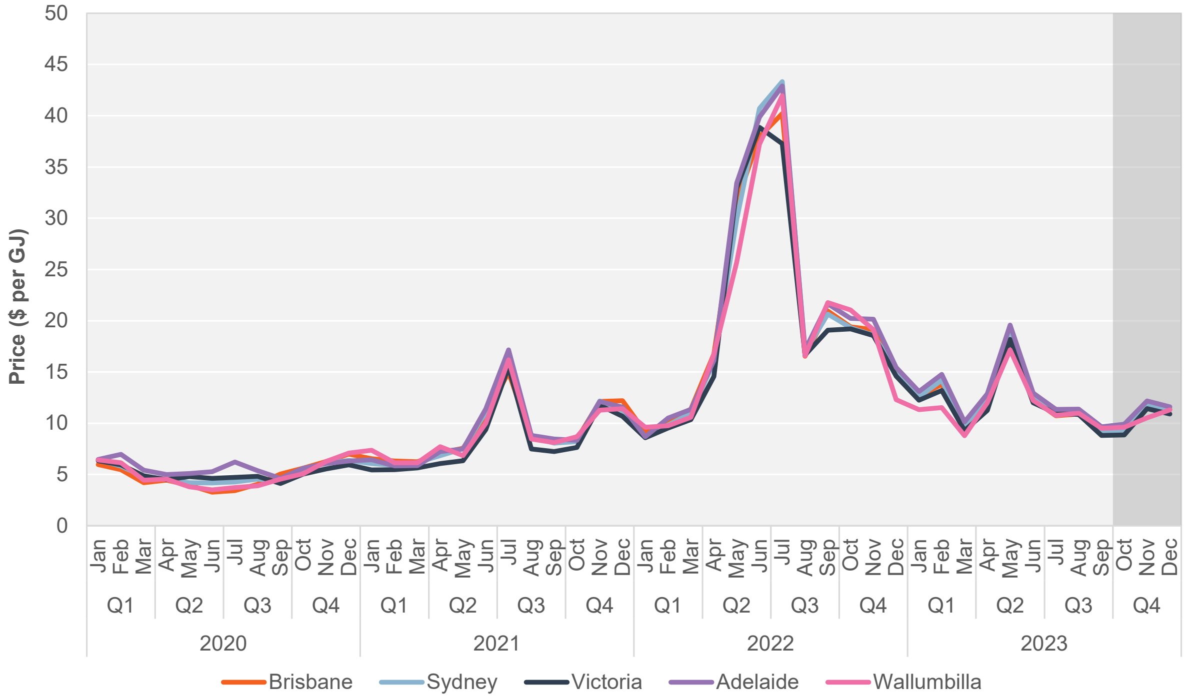
[7] AER, *Significant price reporting guidelines*, September 2022, p. 3.

2 Domestic gas spot prices remain close to 2021 levels

Gas spot market prices averaged just below $11 per GJ

Over Q4, east coast gas market spot prices averaged $10.83 per GJ, up slightly from the previous quarter by 3.8%. This is a decrease of 39% compared to Q4 2022 (Figure 10), with prices across the last half of 2023 settling to similar levels as those observed across the end of 2021.

Figure 10 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).

Prices remained between $8 and $13 per GJ for most of Q4, stabilising around $11 to $13 per GJ over December. Prices peaked at just over $14.50 per GJ in mid-November after a gradual rise from significantly lower levels at the end of Q3.[8] Following the transient price decrease, higher export volumes from mid-October put upwards pressure on domestic prices.[9] Intermittent high export flows and price increases continued through November, prior to a brief price reduction from late November driven by an LNG carrier becoming stranded at the Curtis Island export facility.[10] This disrupted supply to the international market and

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[8] The drivers of lower prices in early October were outlined in the previous quarterly report.

[9] Following an unscheduled decrease in APLNG export pipeline flows, prices in Brisbane increased by around $3 per GJ as APLNG ramped up and total daily exports reached roughly 4200 TJ over the week.

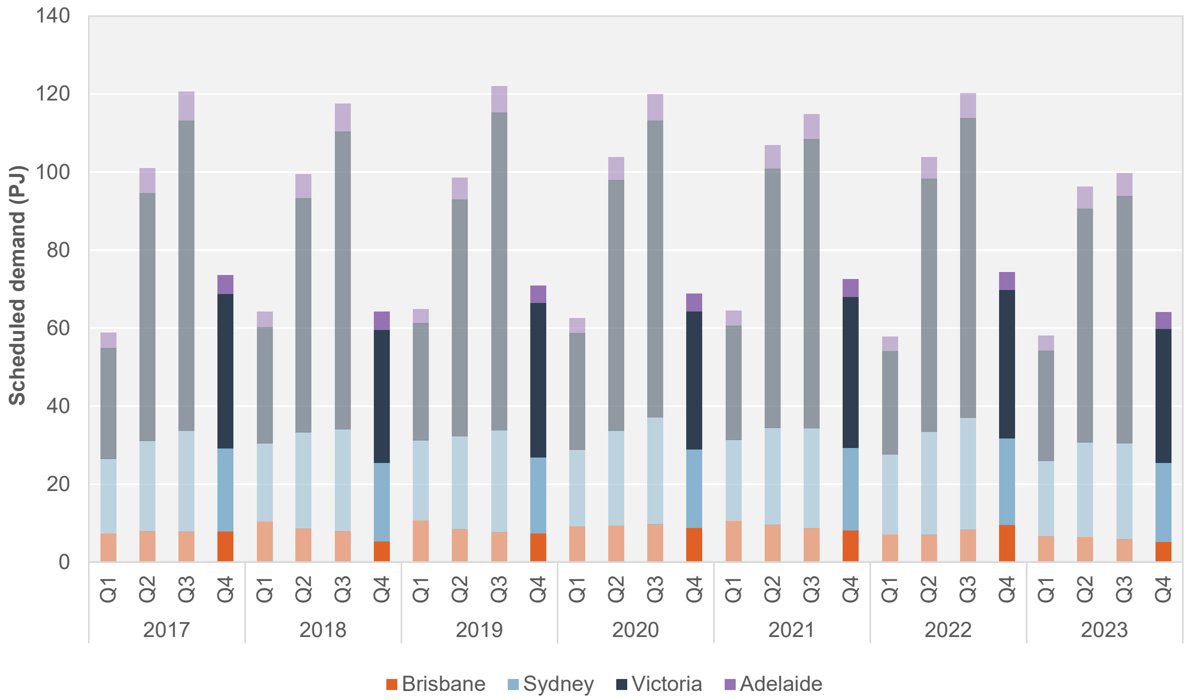
[10] The Cesi Qingdao LNG tanker became stranded on 22 November due to a propulsion failure after losing power. Reuters, Australia Pacific LNG deliveries disrupted due to tanker outage, 28 November 2023.

resulted in APLNG cutting gas flows to the docked vessel and boosting domestic sales as other vessels were blocked from entering the facility.[11]

Low demand offset other price pressures

Quarterly gas demand in downstream markets was similar to levels observed in Q4 2018, dropping to a record 10-year low (Figure 11). This followed a period of unusually low Q3 demand.[12] Demand from Gas Powered Generators (GPG) is often an important contributor to gas demand over summer periods, and was also lower over Q4. In Brisbane, Incitec's 2023 closure contributed to record low demand. These factors put downward pressure on domestic prices, offsetting potential upward pressure from high LNG export volumes.

Figure 11 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).

International price pressures decreased slightly

International LNG spot prices declined in November and December following slow increases across Q3. This is unusual compared to recent experience, where it is typical to see a continued increase in international prices as the Northern Hemisphere enters winter and heating demand rises. The outcomes over Q4 likely reflect a combination of specific seasonal factors alongside some changing patterns of international supply and demand.

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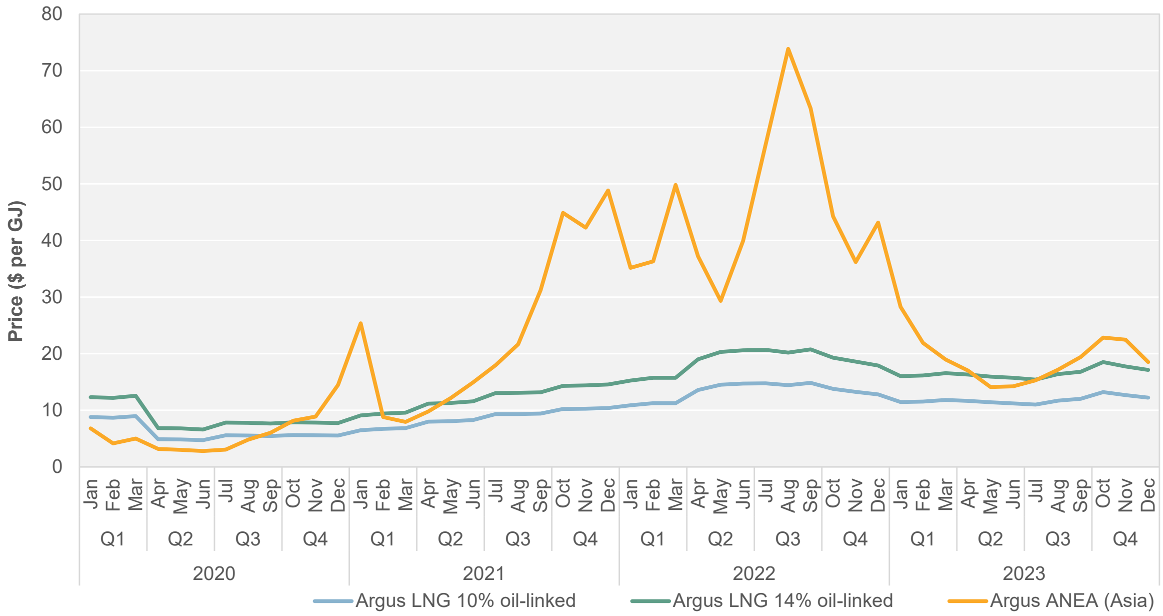
[11] Three tankers were unable to refill prior to the stranded ship's departure on 1 December.

[12] Q3 residential and commercial gas demand was down 20 PJ from the previous year due to unseasonably warm winter.

European storage inventories entered Q4 at a record high of around 97% alongside record floating storage supply.[13] This high storage combined with a mild northern hemisphere winter supressed demand, with storage levels rounding out the quarter at 87% of capacity.[14]

Alongside lower demand, other sources of LNG supply increased. In particular, LNG availability from the USA increased by 6% and Norway's availability was also up 1.5% following the resolution of unplanned outages from 2022. The low prices also saw an increase in opportunistic spot cargo buying in China, with China well serviced by domestic supply, and Japan and Korea turning to renewables and nuclear generation lowering Asian gas demand (Figure 12).

Figure 12 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.

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[13] Argus European Natural Gas Outlook, 12 October 2023.

[14] Argus direct, *Europe LNG: Des prices tick down*, 29 December 2023.

Gas Supply Hub trade was strong for Q4 with an increase in forward trade

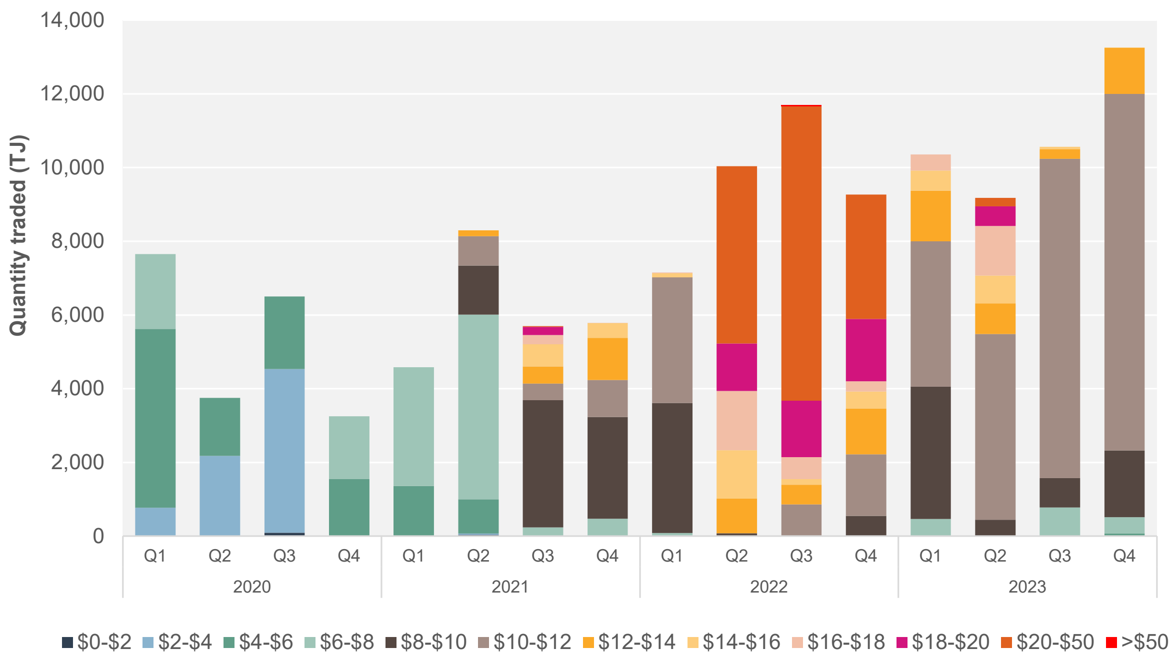
Trade on the Gas Supply Hub was again strong over Q4. Trade volumes set a quarterly record of 13.26 PJ, significantly up on Q3. This was supported by record Q4 transportation capacity won on the day-ahead auction.[15]

The record traded volume was influenced to a significant extent by a string of December transactions effectively providing a location swap for Wallumbilla gas supply, substituting the requirement for physical gas transportation. The large gas transaction swapped supply in Queensland for the same delivered quantity at a southern location. These trades covered monthly deliveries across the span of 2024 and accounted for most of the volume traded during the quarter more than a month ahead of delivery. Removing the effect of these trades, volumes remained a record high but were much closer to Q3 levels.

Exporter/producers and GPG Gentailers returned to their normal trading behaviour across the quarter, reverting to being net sellers and net buyers respectively.

The volume weighted average price for the period was $11.07 per GJ, an increase from $10.67 per GJ over Q3. Over 90% of trade across the quarter occurred at prices of $12 per GJ or less, meaning that proportions of exempt trading had relatively little impact on prices.

Figure 13 Gas Supply Hub price bands



Source: AER analysis using Gas Supply Hub (GSH) trades data.

[15] Auction surplus demand remained strongest on the Moomba to Sydney Pipeline (MSP), South West Queensland Pipeline (SWQP), Roma to Brisbane Pipeline (RBP), Eastern Gas Pipeline (EGP) and the compression facilities at Wallumbilla in Queensland (WCF) and Moomba in South Australia (MCF). These facilities represent most of the trade activity on the DAA.

Box 1: Regulated gas price cap of $12 per GJ

On 23 December 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[16] From 11 July 2023, the Australian Government implemented a Gas Market Code replacing the Order.[17] The key elements of the Code include:

- A price cap on gas of $12 per GJ (does not apply in Western Australia) to be reviewed by 1 July 2025.
- Generally, the price cap applies to gas producers and affiliates of gas producers.
- There are several exceptions (including gas to be exported as LNG, retailers that meet certain criteria, trades on the Short Term Trading Markets (STTMs) or Declared Wholesale Gas Market (DWGM), near-term (next 3 day) trades and offers on the Gas Supply Hub Exchange).[18]
- Transparency obligations to increase visibility of uncontracted gas production and its expected availability to the domestic market.
- Conduct provisions aimed at reducing bargaining power imbalances between producers and gas buyers and establishing minimum conduct and process standards for commercial negotiations.

Separate to the exceptions, the Code also allows the Minister to grant exemptions.

Further information on the price cap and the process of applying for an exemption can be found on the ACCC's website.[19]

In addition, over 2023 we observed lower levels of higher duration trade (weekly or monthly products) on the GSH alongside a higher proportion of trade in shorter term products which were exempt from the price cap. Avoiding exposure to the price cap was likely a factor in this change, but it is likely that expectations of low demand for Q4 2023 and Q1 2024 have also limited incentives to engage in forward trade. This aligns with the ACCC's forecast supply surplus over the same period, even without further domestic sales of uncontracted gas.[20] Market participants may feel confident in their ability to source gas from spot markets over summer 2023–24, resulting in reluctance to pay a premium for guaranteed delivery in the future. Gas commodities traded in November and December this quarter for 2024 delivery were mostly at $12 per GJ or less.[21]

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[16] Australian Government, Competition and Consumer (Gas Market Emergency Price) Order 2022, December 2022.

[17] DCCEEW, Mandatory Gas Code of Conduct, Department of Climate Change, Energy, the Environment and Water, 11 July 2023.

[18] Over 2022 spot trade in the downstream DWGM and STTM collectively averaged around 16% of the gas traded through the markets.

[19] ACCC, Gas price cap, Accessed 30 January 2024.

[20] ACCC, Gas inquiry September 2023 interim report, September 2023; ACCC, Gas inquiry June 2023 interim report, June 2023

[21] Except for 862 TJ traded for delivery over January at $12.25 per GJ.

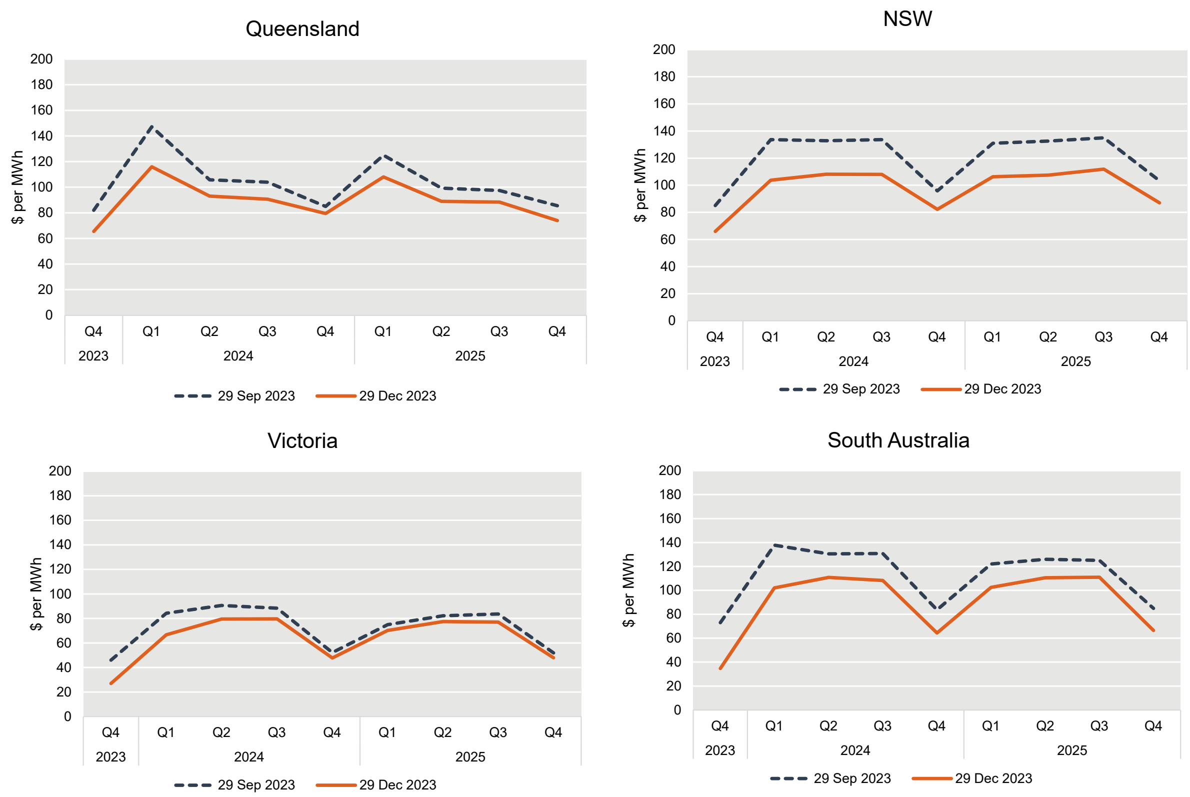
3 Electricity and gas market outlooks

NEM forward prices fell for all forward quarters in all regions

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 market and contracts markets being inextricably connected. Forward base futures prices illustrate price expectations for electricity spot prices in future periods.

Base futures prices for Q4 2023 fell over the course of the quarter in all regions, due to lower-than-expected spot prices (Figure 14).

Figure 14 Base quarterly electricity futures prices



Note: Base future prices for each quarter as of 29 September 2023 (last trading day in Q3) and 29 December 2023 (last trading day in Q3).
Source: AER analysis using NEM data.

The magnitude of the drop ranged from $17 per MWh in Queensland to $38 per MWh in South Australia. This was largely due to more favourable spring-time conditions, with moderate demand and higher renewables output driving lower spot prices. Q4 is generally low-priced compared to Q3 (when the market is subject to tighter winter conditions) but this year prices were even lower than anticipated by the market.

Forward prices also fell in all regions for the 2024 and 2025 calendar years. 2024 prices fell by over $20 per MWh in NSW and South Australia, and by over $10 per MWh in Queensland

and Victoria. Decreases for 2025 ranged from $5 per MWh in Victoria to $22 per MWh in NSW. These forward price decreases likely reflected this quarter’s mild spot market outcomes and suggest optimism that a favourable supply/demand balance will continue further into the future.

Queensland continues to have a significant premium for Q1 prices compared to winter quarters. This is likely due to the southern regions expecting more price volatility during winter, while Queensland is less affected due to its warmer climate.

Forward prices for 2024 and 2025 are now well below forward prices seen in 2022 but generally remain between $20 and $40 per MWh higher than at the end of 2021, depending on the region. While this suggests expectations for future prices are shifting downwards, contract markets are sensitive to spot conditions and will likely be impacted if prices return to higher levels in Q1.

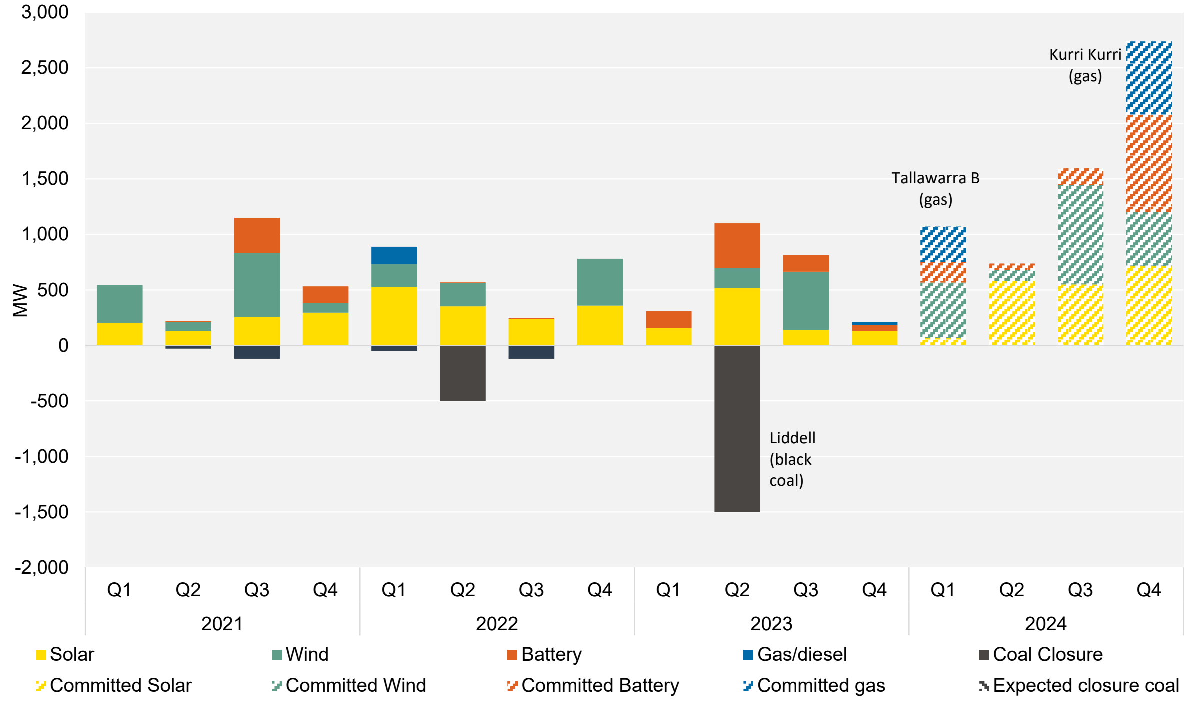
Importantly, changes in forward prices are not immediately reflected in the wholesale costs faced by all retailers. Many retailers will have purchased hedges at times when forward prices were significantly higher than they are now. As such, wholesale costs for these retailers may remain higher while these contracts remain part of their hedge book. This can contribute to a lag between wholesale prices and the prices faced by consumers.

Relatively little new generation entered the market

Across the NEM, there was relatively little new generation entry over Q4. One diesel station, one battery and two solar farms commenced generating this quarter. Together, these units will have a maximum capacity of 209 MW once fully commissioned, which is the lowest new entry for a quarter since Q3 2019. So far, the combined maximum dispatch from each of these units is 61 MW.

A significant increase in new entry is currently scheduled for 2024. However, it should be noted that some of this capacity was due to come online in 2023 but was delayed.

Figure 15 New entry and exit



Note: 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.

Significant volumes of gas traded for delivery in 2024

A significant proportion of gas trade is negotiated directly between participants outside of the AEMO-facilitated markets. Since March 2023, participants have reported details of these transactions up to a year in duration.[22]

This information has materially improved the completeness of data available on gas trade up to a year in length, the majority of which is bilateral trade. The AER published a special report in December providing analysis and insights into all short term transactions reported up to 31 October 2023 to the Gas Bulletin Board.[23] The report also includes feedback from industry stakeholders on the effectiveness of current reporting practices and recommendations to enhance this in future reporting.

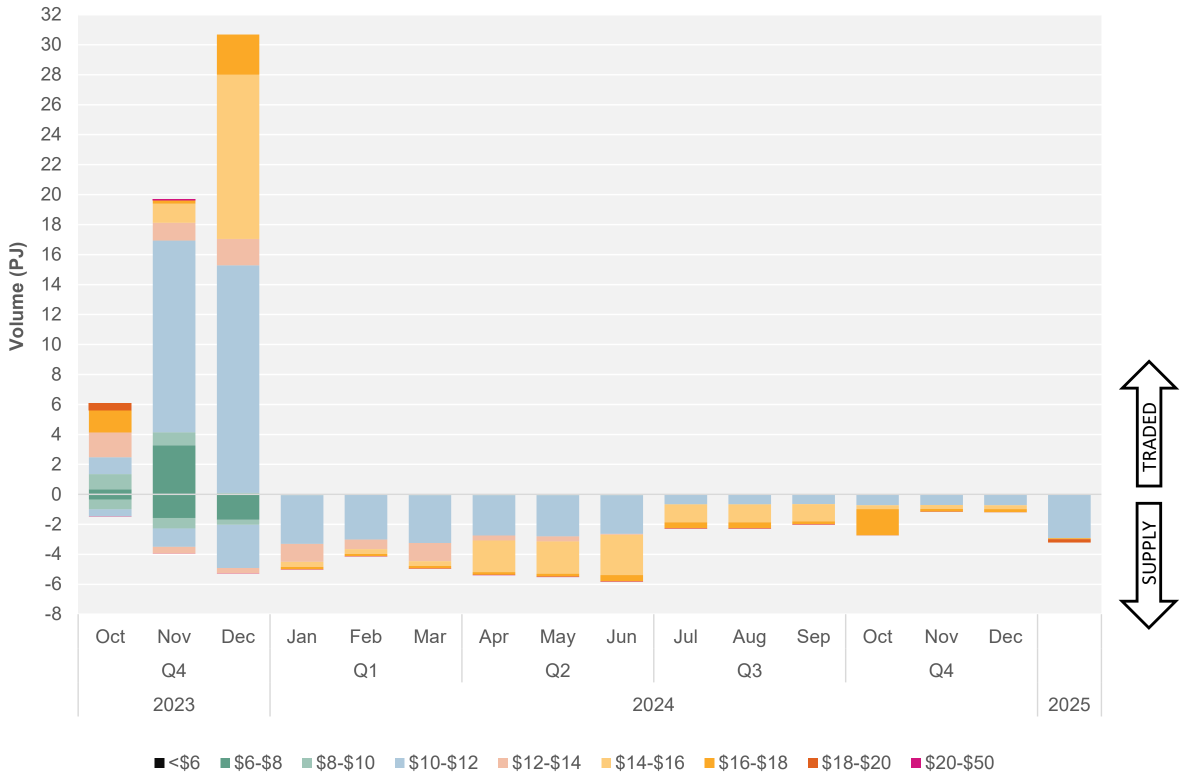
November and December saw the highest volumes of trade observed since Short Term Transaction reporting commenced. Over Q4, 56.5 PJ was traded which was almost 25 PJ more than the previous quarter. With contracts being finalised for 2024 delivery, 75% of this anticipated increase in trade covered 2024 deliveries, while only 5% was linked to deliveries across 2025.

[22] From 15 March 2023, as part of the Gas Market Transparency reforms, short term transactions with a contract length of 12 months and less are required to be reported to the Bulletin Board.

[23] AER, Special report: Wholesale gas short term transactions reporting, Australian Energy Regulator, 6 December 2023.

Just over 50% of all gas traded in Q4 for delivery over 2024 was in the price band $10-$12 per GJ, with the remainder trading in price bands between $12-$20 per GJ (Figure 16). Of the gas traded in price bands above $12 per GJ almost two thirds were linked to the JKM futures index.[24]

Figure 16 Q4 traded versus delivered quantities and price bands



Note: Traded refers to the trade date of the short term supply transaction, while supply refers to the month the gas volume will be supplied.
Source: AER analysis using Natural Gas Services Bulletin Board data.

Forward prices for supply transactions in 2024 have been higher than spot market prices observed in 2023 (Table 1).

[24] JKM is the Northeast Asian spot price index for LNG delivered ex-ship to Japan, South Korea, China and Taiwan, assessed by S&P Global Platts. When reporting short term transactions linked to the JKM futures index participants are required to report the reference price as reported on the Intercontinental Exchange on the trade date.

Table 1 Forward pricing for short term supply transactions

Period	VWA ($ per GJ)	Range ($ per GJ)	Delivered quantity (PJ)
Q4 2023	**12.40**	**9.24 – 13.69**	**24.7**
QLD	*11.56*	*8.45 – 12.82*	*16.6*
VIC	*12.76*	*12.49 – 12.97*	*4.7*
Q1 2024	**13.71**	**13.44 – 13.86**	**22.5**
QLD	*12.57*	*12.50 – 12.65*	*12.8*
VIC	*13.54*	*13.31 – 13.99*	*6.7*
Q2 2024	**14.28**	**14.14 – 14.38**	**22.7**
QLD	*13.16*	*12.97 – 13.47*	*16.2*
VIC	*15.82*	*15.35 – 15.88*	*3.9*
Q3 2024	**15.24**	**15.16 – 15.29**	**10.6**
QLD	*14.30*	*14.01 – 14.44*	*5.7*
VIC	*16.11*	*15.92 – 16.20*	*3.3*
Q4 2024	**15.13**	**14.80 – 15.85**	**8.8**
QLD	*13.56*	*12.50 – 15.64*	*3.9*
VIC	*15.61*	*15.60 – 15.81*	*3.3*
2025	**15.47**	**15.26 – 15.77**	**10**

Note: The above prices and quantities are based on the actual delivered dates of the reported transactions and include all reported supply transactions and pricing structures between 15 March 2023 and 31 December 2023. For 2023 and 2024 the pricing is further broken down for Queensland and Victoria where most of the trade has occurred. The VWA price range is the minimum and maximum price accounting for all transactions on specific days of trade within that period. Where there is not enough trades or participants reporting in a period the data is aggregated to a longer time frame.
Source: AER analysis using Natural Gas Services Bulletin Board data.

Nonetheless, as 2023 progressed, forward prices for gas delivery in 2023 declined. For example:

- in Q2 the volume weighted average (VWA) price for 2024 deliveries was $16.76 per GJ
- in Q3 the VWA price for 2024 deliveries was $14.28 per GJ
- in Q4, amidst record trade levels, the VWA price for 2024 delivery was even lower at $13.42 per GJ.

These decreasing prices are likely caused by some combination of improving expectations and decreasing uncertainty.

Gas markets remain vulnerable to shocks but high storage levels mitigate these risks

Current gas market conditions may help mitigate potential supply requirements this summer. Iona's storage inventory remained at record high levels in Victoria following minimal winter drawdown. Storage levels were topped up at the end of November and in late December, ending the year above 21.5 PJ (24.4 TJ nameplate capacity). High storage levels provide important mitigation against market shocks, such as high demand days or constraints in supply or transportation of gas.

One potential driver of supply risk over Q4 remained due to continuing planned maintenance on the Longford to Melbourne Pipeline. These ongoing works require reduced target linepack levels, limiting supply capacity from Victoria's largest production source. Linepack is gas stored on pipelines, and capacity for it has been limited by reduced pressure levels required to carry out pipeline inspections. To date, this hasn't significantly impacted the market, with one Longford plant now in standby due to recent low demand levels.

Similarly, export price pressures persist but have not so far impacted prices significantly due to low domestic demand. In Queensland, LNG export pipeline flows also reached record levels on 31 December, being above 4340 TJ. The higher exports have not influenced higher domestic prices into 2024 despite flows remaining elevated. In December, east coast overseas shipments matched their prior record of 34 cargoes, exceeding their December 2020 record quantity by over 3 PJ. This 122.5 PJ in monthly exports contributed to the third highest quarterly exports from Gladstone.[25]

[25] Quarterly Gladstone export records: 1st Q4 2020 (339.8 PJ), 2nd Q4 2021 (338.1 PJ), 3rd Q4 2023 (337.1 PJ).