Wholesale markets quarterly Q1 2024

January - March

April 2024

AUSTRALIAN
ENERGY
REGULATOR

Australian Government

Inquiries about this publication should be addressed to:

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

AER reference: 16260570

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.

Q1 2024

Wholesale markets at a glance

Domestic gas spot prices remain close to 2021 levels, averaging under $12 per GJ, driven by low demand over summer.

Electricity spot prices were higher than last quarter in all regions, despite an increase in low-priced offers. Weather was a key price-driver, with heat causing higher demand while a severe storm in Victoria caused network outages.

Heat and humidity drove record maximum electricity demand in Queensland.

Average forward electricity prices for 2025 fell in all regions, but Q1 2025 prices rose in Queensland and NSW.

Tallawarra B gas station and a battery commenced generating electricity this quarter. Further new capacity has been delayed to later this year.

Strong short-term trade on the gas supply hub and day ahead pipeline capacity auction, with close to 90% below $12 per GJ.

Unusually, Queensland was a net importer. Victoria was the only net exporter of electricity this quarter.

A majority of supply volumes agreed in Q1 for delivery over 2025–26 were linked to future oil prices, translating to $14–16 per GJ prices.

Decreased electricity baseload outages reduced demand for gas-powered generation to record lows for Q1, offsetting reduced supply from Longford.

Gas markets will remain vulnerable to shocks going into winter but high storage levels will mitigate these risks.

AUSTRALIAN ENERGY REGULATOR

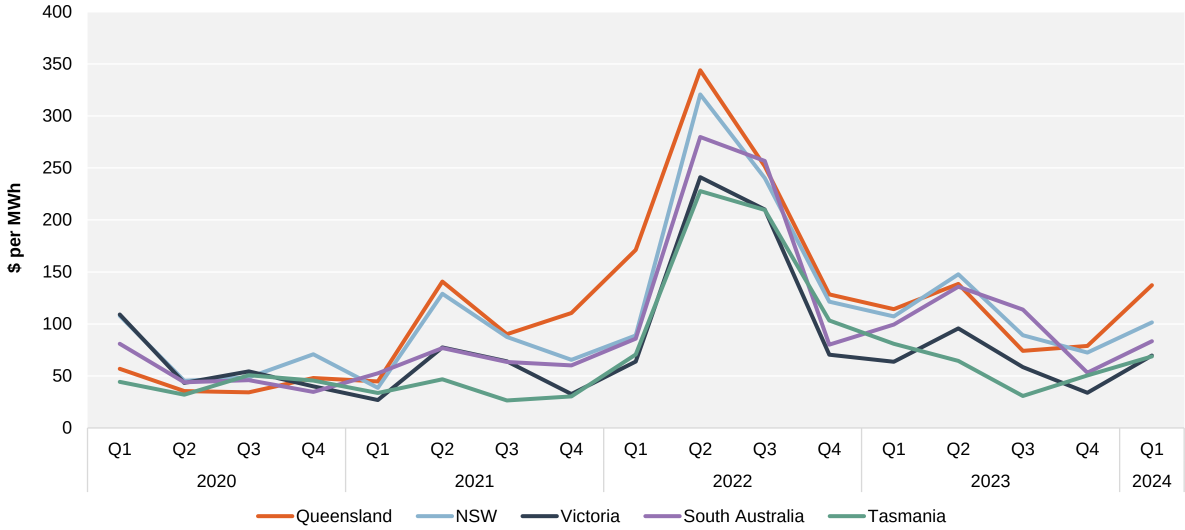
1 Prices were higher than last quarter despite an increase in low-priced offers

Weather related high price events drove up quarterly average prices in Queensland and Victoria

In Q1 2024, average volume weighted NEM prices ranged from $69 per MWh in Tasmania to $137 per MWh in Queensland. This represented an increase from last quarter's moderate price outcomes across all regions, ranging from a $18 per MWh increase in Tasmania to a $58 per MWh increase in Queensland.

Compared to Q1 2023, average prices this quarter were higher in Queensland (by $23 per MWh) and Victoria (by $6 per MWh). In both regions, prices this quarter were impacted by weather-related high price events. Meanwhile, average prices decreased in NSW, Tasmania and South Australia, by $6 per MWh, $12 per MWh and $16 per MWh respectively.

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 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.

Energy prices in the NEM follow a seasonal pattern. As is often the case in the first quarter of the year, price outcomes in Q1 2024 were impacted by weather. The 2023-24 summer was Australia's third warmest on record, marked by widespread and persistent heat, and this led to higher demand and prices.[1] In Queensland, hot and humid weather (which leads to higher air conditioning requirements) drove a material increase in demand from the last week of December through to February 2024. At times, Queensland's demand exceeded the available cheaper capacity able to be drawn from NSW and this contributed to high price

[1] Bureau of Meteorology (BOM), "Australia in summer 2023-24", 1 Mar 2024.

events on several occasions this quarter. Further information will be set out in the AER's next high price report.

In Victoria, severe storms on 13 February 2024 led to the collapse of multiple transmission towers. The storm damage impacted supply of electricity to neighbouring regions South Australia and Tasmania, and contributed to high price events in all three regions. More information regarding this event can be found in our recent report.[2]

The AER is required to investigate and report on instances where the 30-minute average spot price[3] for a given region exceeds $5,000 per MWh. In Q1 2024, regional spot prices exceeded the $5,000 per MWh threshold 26 times, more than double the 12 instances in Q1 2023 and the most instances in a first quarter since 2020. Queensland recorded 11 breaches of the $5,000 per MWh threshold, which contributed an additional $30 per MWh (an increase of almost 30%) to the average quarterly price. In Victoria, the $5,000 per MWh threshold was breached on 5 occasions, adding $23 per MWh to the average quarterly price. NSW and South Australia each saw prices above $5,000 per MWh contribute $14 per MWh to the average quarterly price.

Record maximum demand in Queensland, record minimum Q1 demand in Victoria and South Australia

NEM average demand in Q1 2024 was higher than last quarter, reflecting higher temperatures (Figure 2). Demand was also higher than in the last three Q1s reflecting that these were La Niña summers, which are generally marked by cooler than average maximum temperatures.[4] Q1 2020, the last El Niño summer, had higher average demand than Q1 2024. At a regional level, average demand increased in Queensland and NSW compared to Q1 2023, while it decreased in Victoria.

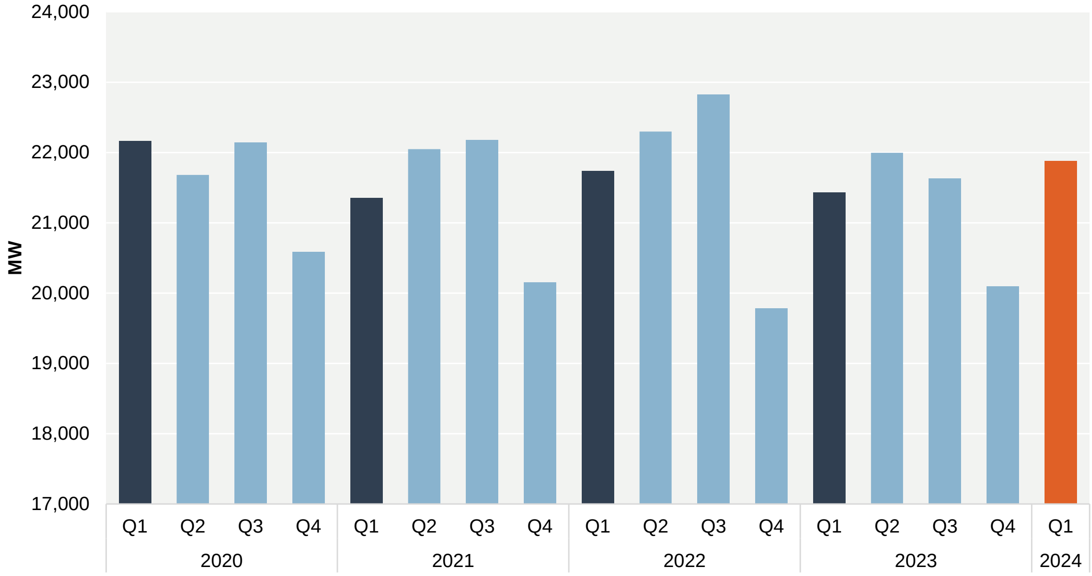
---

[2] AER, Electricity and FCAS prices above $5,000 per MWh in Victoria, Tasmania and South Australia, 13, 21 and 27 February 2024, April 2024.

[3] Typically there are 4,320 30-minute periods in a quarter (90 days).

[4] Bureau of Meteorology (BOM), "What is La Nina and how does it impact Australia", August 2016.

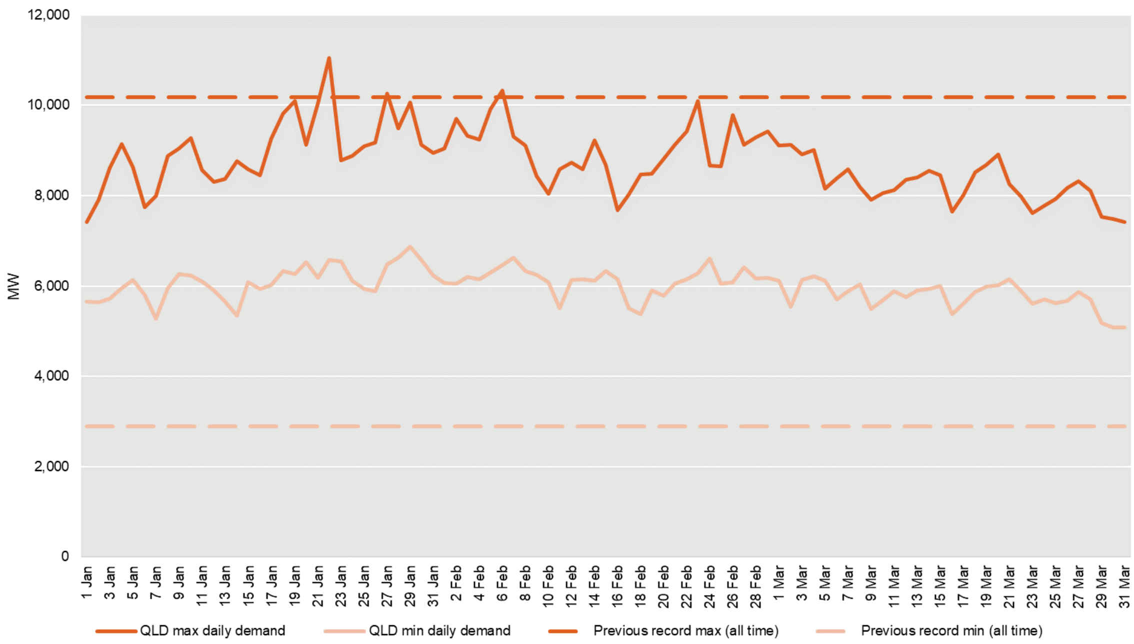
Figure 2 Quarterly average NEM demand



Note: Uses quarterly average native NEM demand. The AER defines native demand 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.

Demand in all mainland regions increased from last quarter as temperatures rose. This was most significant in Queensland, where maximum demand exceeded the previous all-time record 3 times during the quarter, including by as much as 800 MW on 22 January 2024 (Figure 3).

Figure 3 Queensland daily maximum demand sets all-time record



Note: Uses daily maximum 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.

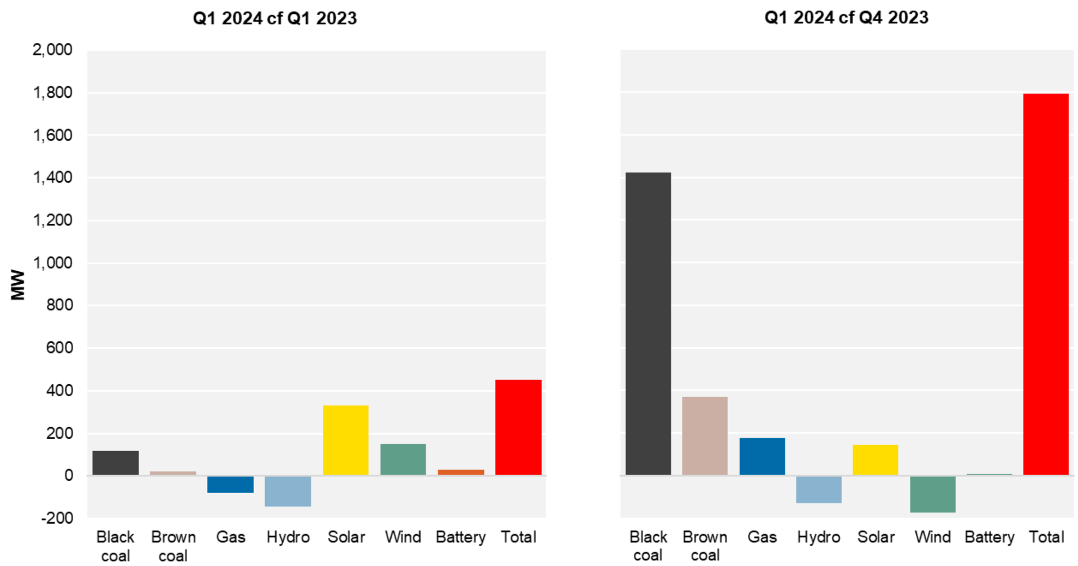
While summer temperatures can drive higher demand levels, the longer daylight hours and more direct sunlight can also lead to higher generation by rooftop PV systems. This can lead to reduced demand for electricity from the grid. Rooftop solar output reached new heights in Q4 2023, when the summer season started, and remained high for the majority of Q1 2024.

The reduction in grid demand enabled by rooftop solar led to Q1 records being set for minimum daily demand in Victoria and South Australia. Minimum demand records are typically set on sunny yet mild summer days when rooftop solar output is high but air-conditioning requirements are low.

Increased demand since last quarter met by coal, gas and solar

Average quarterly generation increased from last quarter and was higher than Q1 2023, due to higher demand (Figure 4). Coal, gas and solar generation increased from last quarter, partly offset by a decrease in hydro and wind generation. Battery output remained about the same.

Figure 4 Change in NEM generation output by fuel type



Note: Change in average quarterly metered NEM generation by fuel type, Q1 2024 compared with Q1 2023 (left) and Q4 2023 (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 AEMO data.

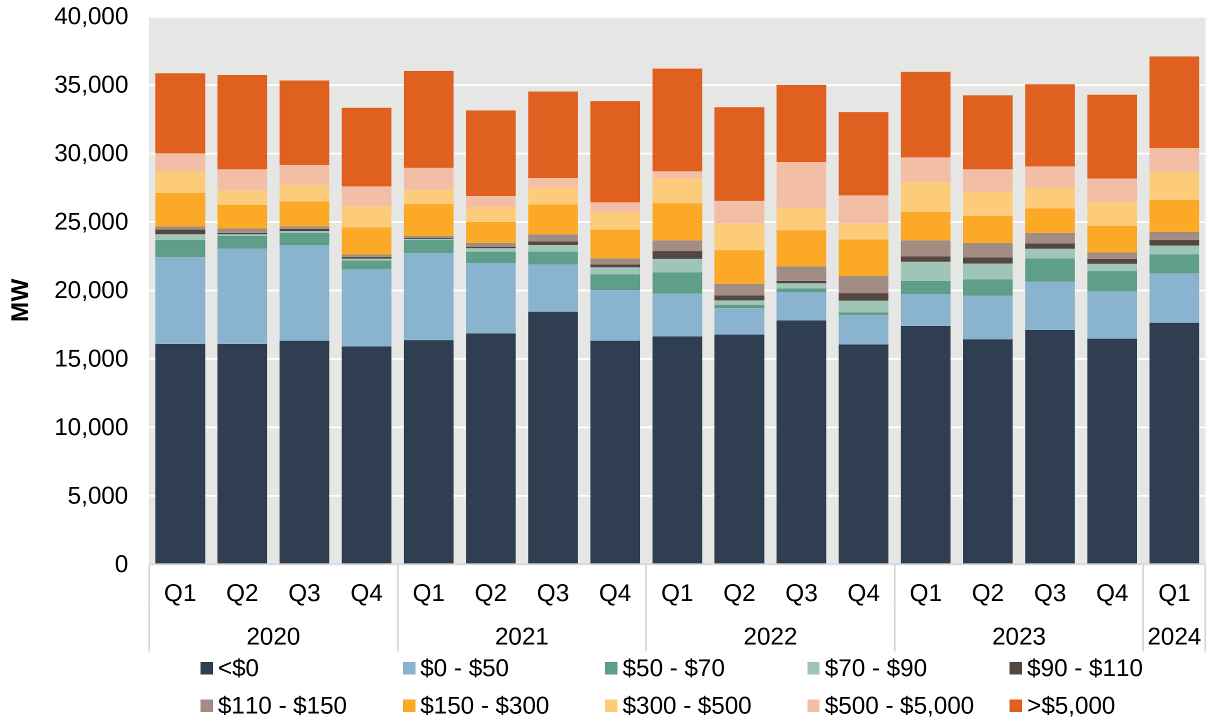
Compared to a year ago, both black and brown coal's output increased slightly, driven by an increase in low-priced offers. Solar, wind and batteries generated more than a year ago, reflecting new entry into the market. Wind and solar combined accounted for a slightly higher generation share at 23%, up from 22% last year.

More low-priced capacity was offered this quarter

Total offers in NEM averaged 37,088 MW this quarter, which was an increase of about 2,800 MW from last quarter and of about 1,100 MW from Q1 2023 (Figure 5) – much of which was offered below $50 per MWh. This was the highest level of average quarterly offers since Q1 2017 despite this being the first Q1 since Liddell power station's exit in April 2023.

The increase in capacity since last quarter included about 1,200 MW offered below $0 per MWh. This increase in low-priced offers was largely driven by increased black coal offers in Queensland and NSW amid fewer outages. In Victoria and South Australia, more capacity was offered this quarter but largely within higher price bands. However in Tasmania, which has high winter rainfall and primarily hydro generation, slightly less capacity was offered this quarter – including at low prices.

Figure 5 NEM offers by price bands



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

Compared to Q1 2023, the largest increase in offers was between $0 and $50 per MWh – with nearly an extra 1,300 MW offered in this price range. NSW and Victoria were the primary regions driving this. In Queensland, more capacity was offered below $0 per MWh than a year ago but this was partly offset by a decrease in offers between $0 and $70 per MWh. In South Australia, the extra capacity offered was mainly in higher price bands while Tasmania had more capacity below $70 per MWh but less offered in some higher price bands.

Overall, offer trends indicate that price increases this quarter were generally not supply-driven. In Queensland and NSW, higher prices occurred despite a large increase in low-priced capacity from last quarter. This was also true of the increase in Queensland and Victoria prices compared to Q1 2023.

Baseload outages decreased

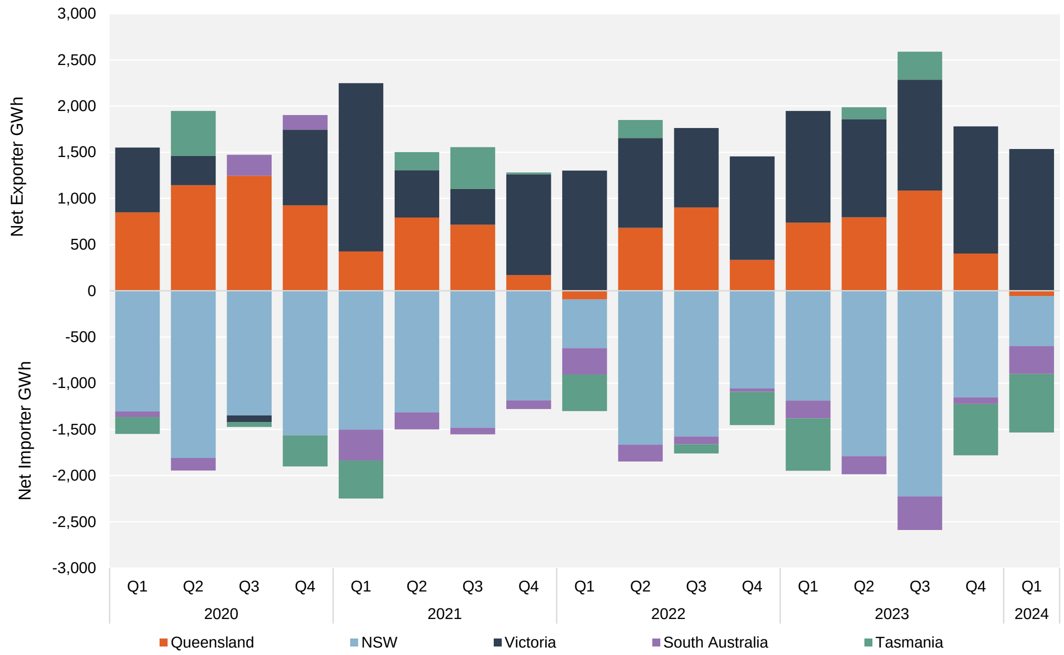
A key driver of the increase in offers this quarter was a reduction in baseload outages across all regions. Average baseload capacity unavailable due to outage fell by around 330 MW in Victoria, 680 MW in Queensland and 1,170 MW in NSW, compared to the previous quarter. For all regions, outages were significantly lower than in Q1 2023, with offline capacity falling to levels similar to Q1 2021 in Victoria and Queensland, and lower in NSW than in any Q1 over the previous 5 years.

Queensland net importer, Victoria the only net exporter

Interconnectors allow regions to import cheaper generation from neighbouring regions. Historically, Victoria and Queensland tend to be net exporters, providing surplus baseload energy to NSW and South Australia. This quarter, Victoria exported net about 1,600 GWh and was the only net exporter (Figure 6). Queensland was a net importer of 58 GWh due to high demand this quarter.

Interconnector and network constraints are often a factor in high price events, as they can limit a region's ability to import lower priced capacity, as was the case in Queensland, NSW and South Australia high price events this quarter. For example, after the Victorian extreme weather event, ongoing storm damage limited South Australia's ability to import from Victoria, which contributed to instances of higher prices in the region. We explain this in more detail in our recent high-price report published in April 2024.[5]

Figure 6 Net interconnector flows by region



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

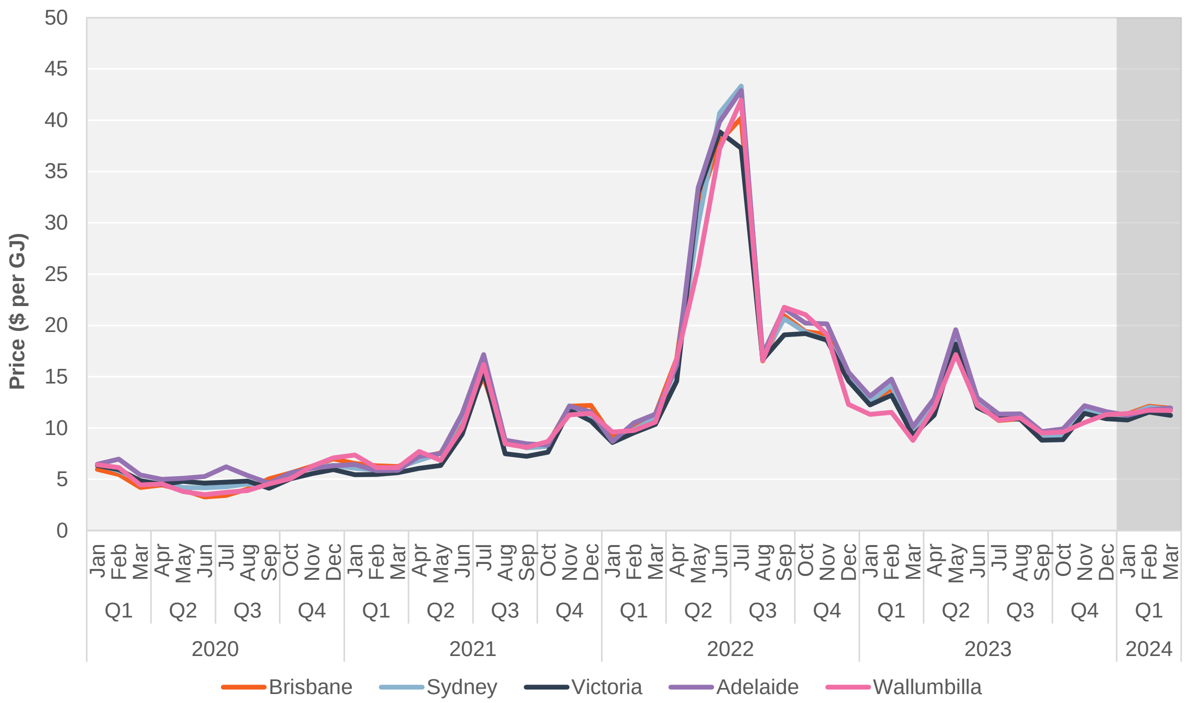
[5] AER – Prices above $5,000 MWh – 13,21,27 February 2024 (Victoria, Tasmania and South Australia), April 2024

2 Domestic gas spot prices remain close to 2021 levels

Gas spot market prices averaged below $12 per GJ

Over Q1, east coast gas market spot prices averaged $11.58 per GJ, up from the previous quarter by 6.9% but down 3.4% from Q1 2023. Average daily prices have remained relatively stable from mid-January, while average monthly prices have remained at similar levels since November (Figure 7).

Figure 7 East coast gas market average monthly prices



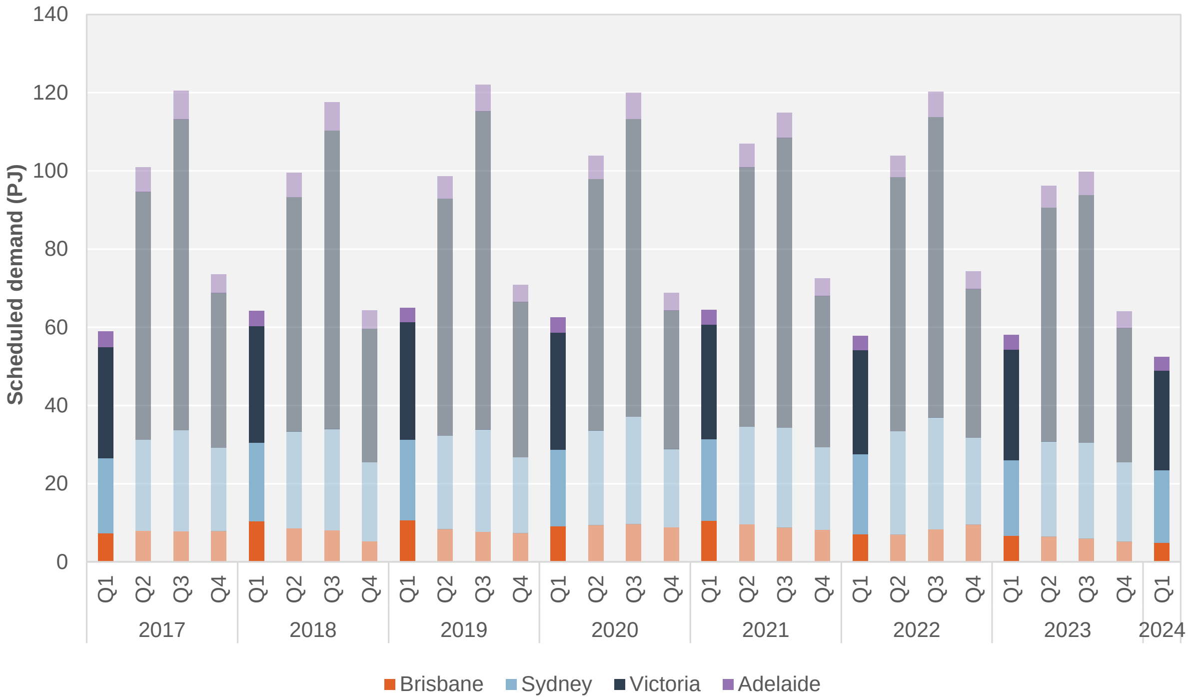
Note: The Wallumbilla price is the day-ahead exchange traded price.
Source: AER analysis using east coast gas market (ECGM) data (includes: Victoria, Adelaide, Brisbane and Sydney gas markets and Wallumbilla gas supply hub data).

Apart from some lower daily prices in early and mid-January, prices ranged from $10 to just over $13 per GJ in downstream markets. While LNG export pipeline flows remained strong across the quarter, lower than usual domestic demand maintained downward pressure on prices. This was despite a month of reduced supply capacity at Longford, Victoria’s largest production facility, with participants utilising the high levels of storage at Iona to supply the market.

Low demand offset other price pressures

While gas demand is typically low during Q1, this quarter saw record low Q1 demand levels (Figure 8). Residential and commercial gas demand was at its lowest first quarter level in a decade, continuing the same trend observed for the previous quarter. Demand from Gas Powered Generators was also at its lowest first quarter level for the past decade despite a 17% increase from the previous quarter, due to decreased electricity baseload outages reducing demand for GPG.[6] This and other contributing factors, such as mild winter weather, put downward pressure on domestic prices and offset any upward pressure from high LNG export volumes. Gas continued to flow predominantly north through the pipelines, which is typical for the time of year, despite low production output from Longford. Alongside these northerly flows supporting export activity, demand for east coast production is also elevated on the Carpentaria Gas Pipeline due to a lack of supply flowing from the Northern Territory since early February. The supply issue on the Northern Gas Pipeline followed a similar situation in 2022 when on 2 occasions gas transportation on the Northern Territory's only connection to the east coast ceased over 3-month intervals each time. This was due to a significant reduction in supply from the offshore Blacktip gas field which has continued since early 2021. Jemena has advised its customers they do not expect flows on the Northern Gas Pipeline to recommence until at least June.

Figure 8 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 remained low

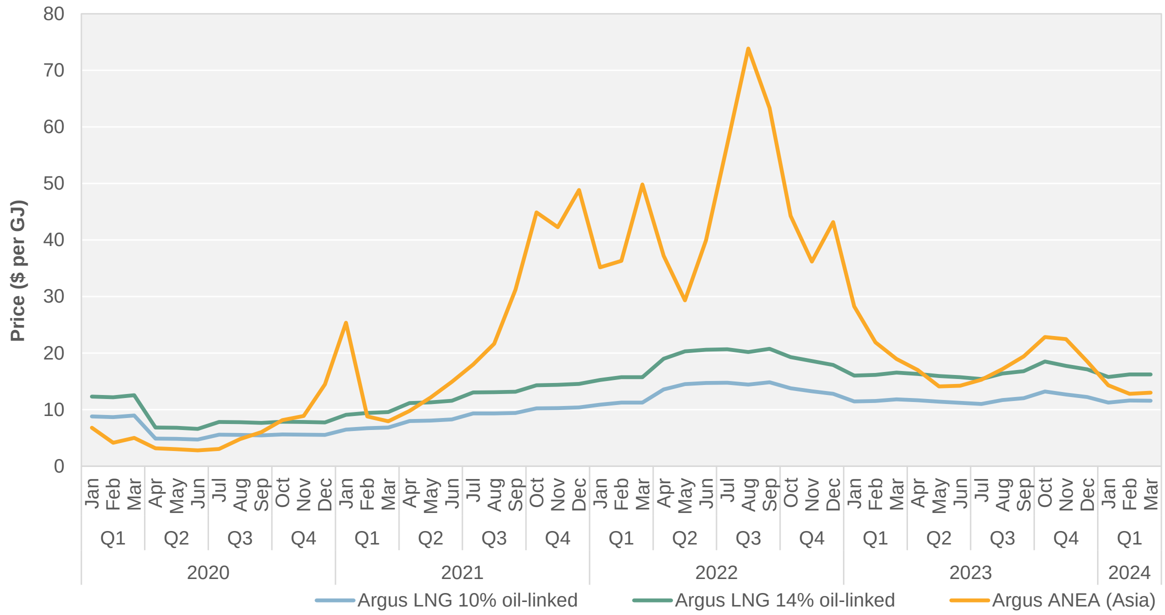
International LNG spot prices were relatively stable across the quarter, with a gradual decrease over January and February before a slight rebound in March. They ended the quarter at $13.72 per GJ, down from $16.38 per GJ at the end of December. Prices in late February reached some of the lowest levels recorded over the past two years reflecting a combination of high storage inventory levels and reduced demand in overseas markets. If the

[6] Demand from Gas Powered Generators (GPG) is often an important contributor to gas demand over summer periods

trend of lower LNG prices is sustained, domestic prices could be trading at a premium to prices in Asian markets. We would expect this to strengthen incentives for Exporter/Producers to sell in the domestic markets and put downward pressure on domestic spot prices if supply isn't otherwise constrained.

European storage inventories entered Q1 at a record high for the quarter of around 97% and finished the quarter above 2023 levels for the same time last year, alongside record floating storage supply.[7] This high storage combined with a mild northern hemisphere winter supressed demand from overseas. Seasonal factors are strong drivers of international demand and prices for gas. Continued reduction in international prices indicates ongoing low demand and adequate global supply (Figure 9).

Figure 9 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.

Gas Supply Hub trade was strong for Q1

Trade on the Gas Supply Hub (GSH) was again strong over Q1. Trade volumes set a quarterly record of 11.2 PJ (Figure 10), the highest traded volume in Q1 since the GSH commenced in 2014. This was supported by record transportation capacity won on the day

---

[7] Floating storage supply refers to LNG reserves stored offshore in floating storage regasification units.

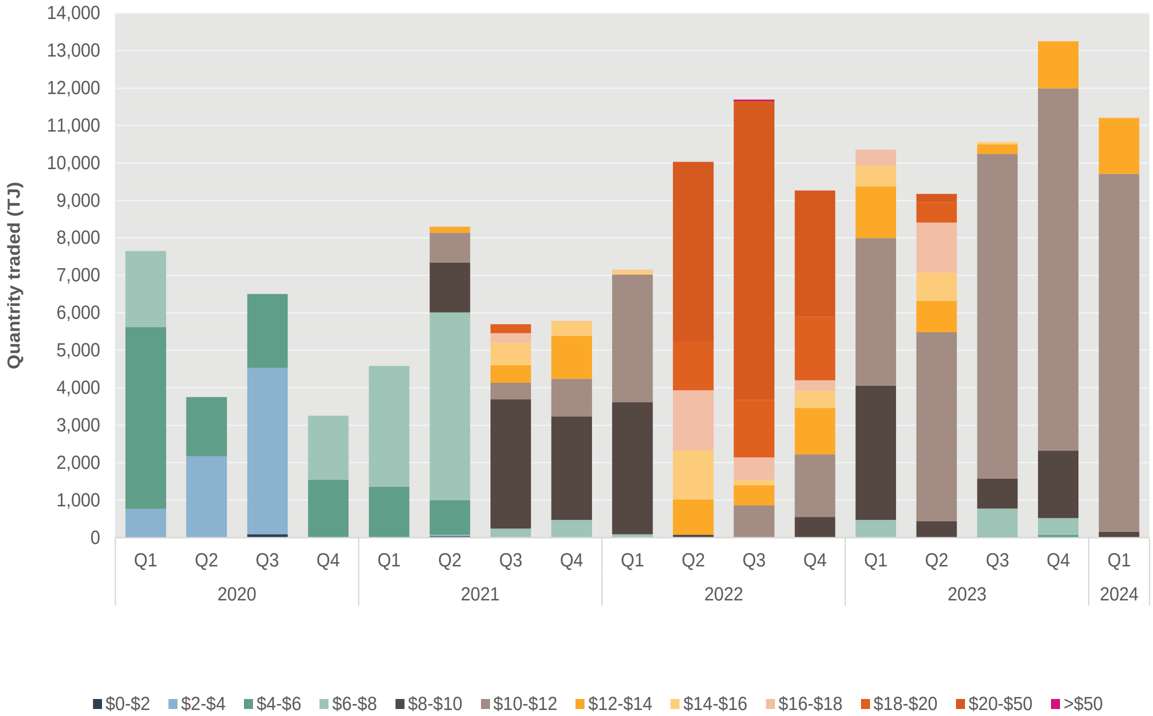
ahead auction (Figure 11), and the proportion of day ahead capacity won at $0 per GJ falling to its lowest level at just over 60% of capacity won.

While most gas trading occurs ‘off-screen’ (traded bilaterally), some of these trades are reported to the market operator and settled through the GSH trading platform. However, Q1 2024 saw on-screen trading account for over one-third of total GSH transactions, with a traded volume of 4.3 PJ, which is a record high for any quarter. Most of the products traded had short-term delivery windows, accounting for 84% of the traded volume. This was evenly split between the Balance of Day (3 PJ), Daily (3 PJ) and Day Ahead products (3.4 PJ).

On the sell side, trade was dominated by Exporter/Producers, with the highest ever recorded quarter at 8.1 PJ. On the buy side, industrial and Exporter/Producer participants increased purchases, while Traders and GPG Gentailers reduced purchases compared to the previous quarter.

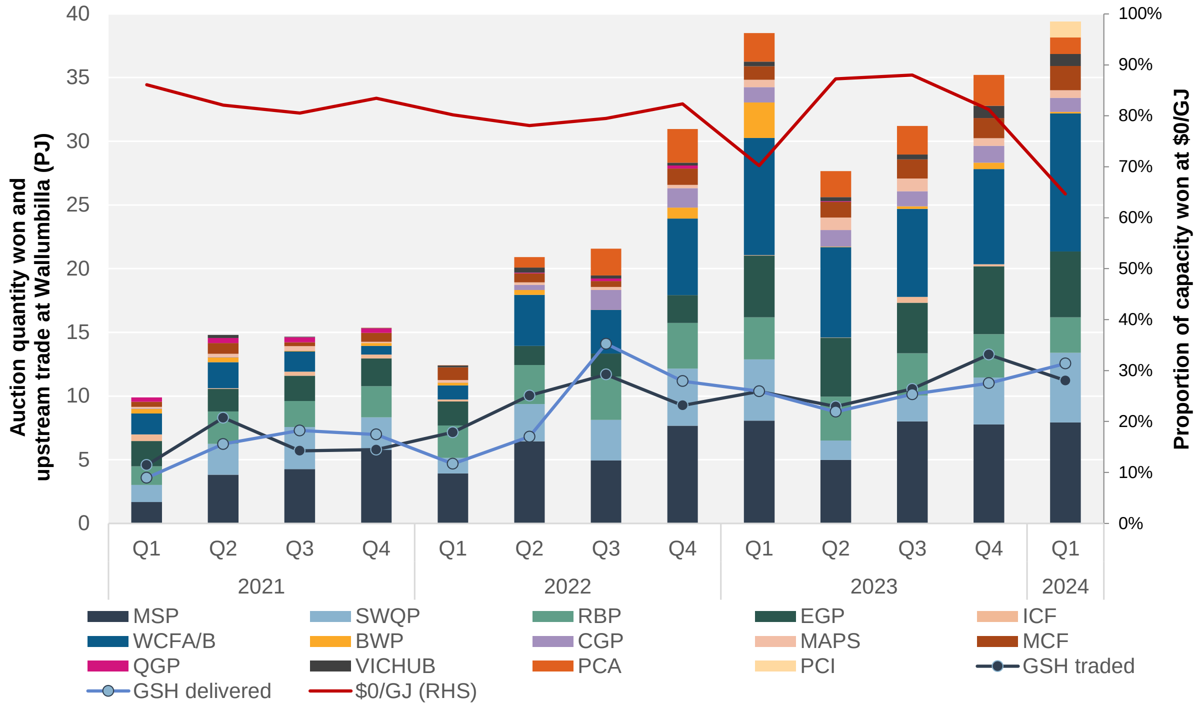
Prices ranged from $8.80 per GJ to $16 per GJ, with close to 90% of the gas traded below $12 per GJ and less than 2% of the transactions over $12.50 per GJ. The volume weighted average price for all products increased to $11.67 per GJ from $11.07 per GJ in Q4 2023.

Figure 10 Gas Supply Hub price bands



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

Figure 11 Day ahead auction transportation capacity won and gas supply hub trades



Source: Day Ahead Auction and Gas Supply Hub data.

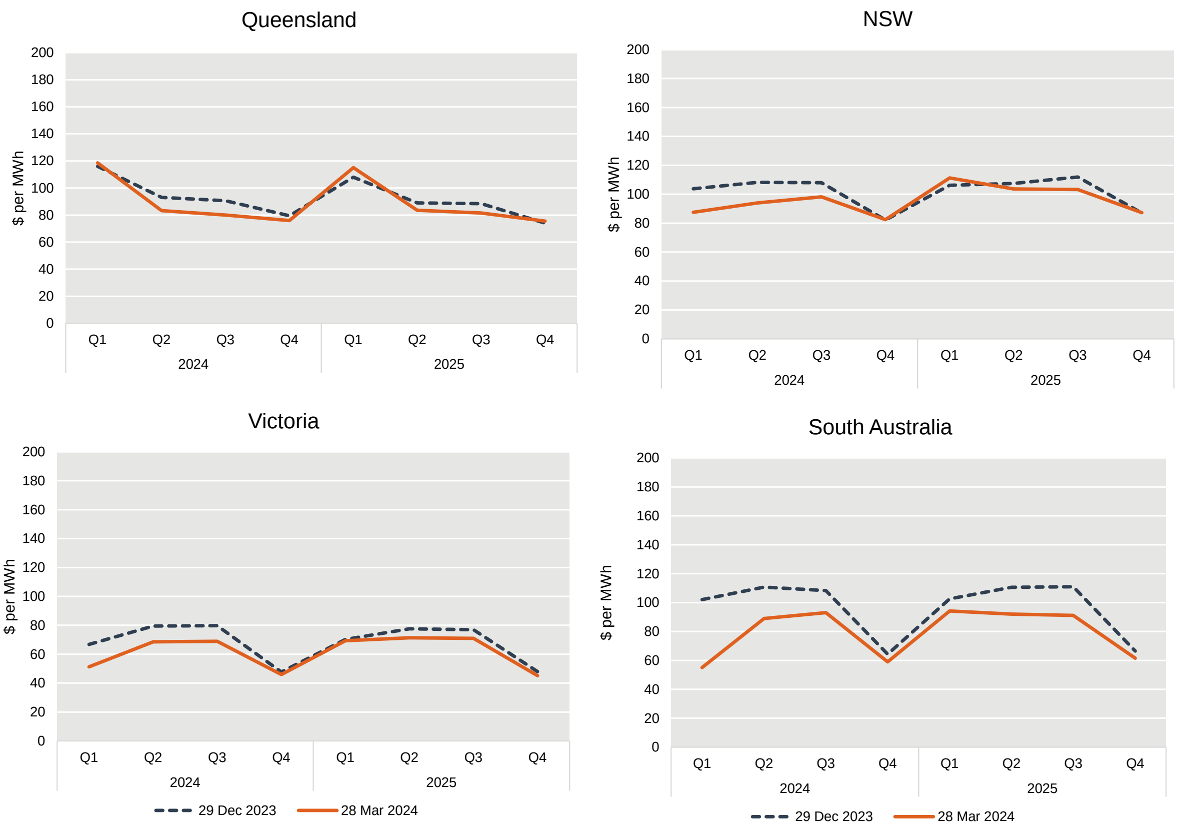
3 Electricity and gas market outlooks

NEM forward prices fell for most forward quarters in all regions

Generators and retailers enter derivative contracts to limit the price volatility they are exposed to when purchasing from a wholesale spot market. 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.

Average forward prices for the 2025 calendar year fell in all regions (Figure 12). Decreases for 2025 ranged from $1 per MWh in Queensland to $12 per MWh in South Australia. In Victoria and South Australia, this may have reflected this quarter's mild spot market outcomes. Notably in Victoria, Q1 2024 prices were low despite the events of 13 February which pushed up final base future prices by $15 per MWh.[8]

Figure 12 Base quarterly electricity futures prices



Note: Base future prices for each quarter as of 28 March 2024 (last trading day in Q1) and 29 December 2023 (last trading day in Q4).
Source: AER analysis using NEM data.

[8] Final base future prices refers to the price against which the contract is settled, and is equal to the average spot price for the quarter.

In Queensland and NSW, Q1 2024 final base future prices were much higher. Queensland had its 3rd highest Q1 final base future price and NSW its 4th highest, driven by weather conditions. This was reflected in increased Q1 2025 prices for both regions.

For Queensland, this meant that an already significant premium on Q1 future prices grew larger this quarter. While southern regions often experience higher prices during winter, Queensland expects higher prices in summer due to its warmer climate and lower need for space heating in winter.

Overall, forward prices for 2024 and 2025 are now well below forward prices seen in 2022 but remain higher than 2020 and 2021. While this suggests expectations for future prices continue to shift downwards, contract markets remain sensitive to market conditions. Key drivers of contract prices in the coming year are likely to include the impact on spot prices of the conclusion of the NSW coal market intervention from mid-2024, the effectiveness of the gas code of conduct, and whether the scheduled Eraring closure takes place in 2025.

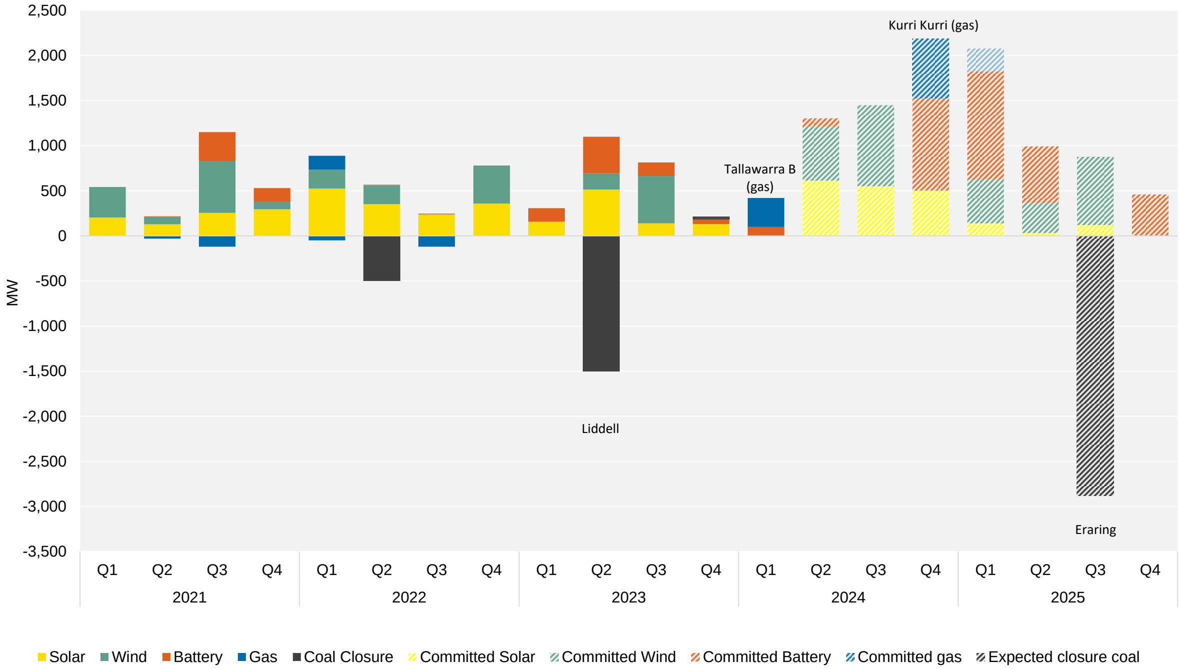
Importantly, changes in forward prices are not immediately reflected in the wholesale costs faced by all retailers. Many retailers will have purchased hedges at times when forward prices were significantly higher than they are now. As such, wholesale costs for these retailers may remain higher while these contracts remain part of their hedge book. This may 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 Q1. Tallawarra B Gas Station and one battery commenced generating this quarter. Together, these units will have a maximum capacity of 420 MW once fully commissioned.

A significant increase in new entry is currently scheduled for the rest of 2024 (Figure 13), with some of this being capacity that was due to come online in 2023 but has been delayed.

Figure 13 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 PV systems. Committed projects include some projects that are listed as anticipated in AEMO's Generator Information.
Source: AER analysis using [AEMO Generator Information as at February 2024](#).

Large supply volumes traded for delivery out to 2026

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 transactions up to a year in duration to the AER.[9]

In Q1 the supply volumes traded in January and February were 5.9 PJ and 7.1 PJ respectively, a significant reduction from the December peak volumes of 35.3 PJ, which was mostly related to the finalisation of supply contracts towards the end of the year for delivery in 2024. However, in March 2024, trade volumes began to increase again, with 30.4 PJ of supply contracts reported with significant volumes for delivery over the remainder of 2024 as far out as 2026.

Around 50% of all gas supply transactions traded over the quarter were for delivery in 2025 and 2026 with the majority trading in a price band between $14-$16 per GJ linked to a Brent oil price. Higher future price expectations is also supported by forward price data, with forward prices for supply transactions in 2024 have been higher than spot market prices observed in 2023 (Table 1).

[9] 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.

Table 1 Forward pricing for short term supply transactions

Period	VWA ($ per GJ)	Range ($ per GJ)	Delivered quantity (PJ)
Q1 2024	**12.99**	**11.73 – 13.47**	**30.9**
QLD	*12.08*	*10.61 – 12.64*	*18.3*
VIC	*13.54*	*13.33 – 13.92*	*7.2*
Q2 2024	**13.87**	**13.62 – 13.94**	**27.7**
QLD	*12.92*	*12.63 – 13.25*	18.6
VIC	*15.22*	*14.61 – 15.73*	*5.4*
Q3 2024	**14.47**	**14.42 – 14.51**	**16.8**
QLD	*13.87*	*13.72 – 13.99*	*6.8*
VIC	*14.73*	*14.64 – 14.86*	*6.6*
Q4 2024	**14.24**	**13.90 – 14.84**	**14.5**
QLD	*13.51*	*12.51 – 15.49*	*4.3*
VIC	*14.00*	*13.87 – 14.25*	*6.9*
2025	**15.80**	**15.46 – 16.10**	**21.4**

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 March 2024. For 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.

We have observed that the VWA prices for delivery over 2024 has declined quarter on quarter, as more contracts are being entered into at lower prices. For example, in our Q4 2023 Wholesale Quarterly report we reported the VWA price for Q2 2024 and Q3 2024 as $14.28 per GJ and $15.24 per GJ respectively. Whereas the Q2 and Q3 2024 VWA prices are now lower at $13.87 per GJ and $14.47 per GJ.

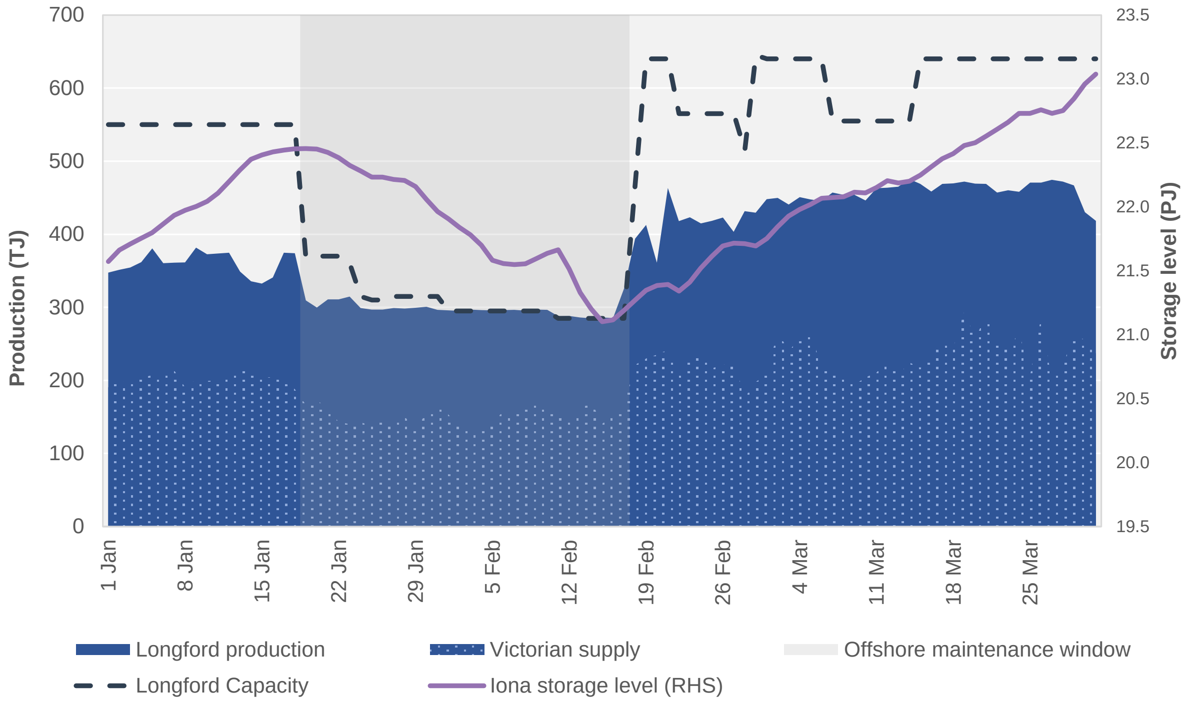
Gas markets remain vulnerable to shocks going into winter but high storage levels mitigate these risks

Iona's storage inventory remained at high levels in Victoria following a slight drawdown during January and February. Sufficiency of Iona storage levels are heavily dependent on the upcoming weather conditions and winter demand.

While the level of storage is slightly lower than Iona's previous 2023 high-storage level observed the same time in 2023, the drawdown was aligned with lower-than-expected supply from Longford from due to offshore maintenance and storage levels began to recover at the end of late March, to around 23 PJ (Figure 14).

Similarly, export price pressures persist but have not significantly impacted prices to date due to low domestic demand. In Queensland, LNG export pipeline flows also reached a record of 4,340 TJ on 31 December. The higher exports have not influenced higher domestic prices into 2024 despite flows remaining elevated above 4,000 TJ per day over Q1. In December, east coast overseas shipments matched their prior record of 34 cargoes, exceeding their December 2020 record quantity by over 3 PJ. While exports for this quarter were down from near-record quarterly exports over Q4 2023, Q1 exports of 330 PJ were at their 4th highest level to-date.[10]

Figure 14 Longford production outage and usage of Iona gas storage



Source: AER analysis using Victorian gas market and Gas Bulletin Board data.

Longford production decline and plant decommissioning

Planned maintenance work continued on the Longford to Melbourne Pipeline, which connects Melbourne to Victoria's largest production source at Longford.[11] Constraints to manage lower pressure requirements, which started from 18 September 2023, were scheduled to remain in place through to April. The required pipeline repairs have now been completed.

Longford Gas Plant 1 is forecast to cease production and decommission before the end of July this year. The shutdown of Gas Plant 1 will leave two remaining gas plants, with both required to achieve the 2024 peak day capacity of 700 TJ per day. If either of the two

---

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

[11] Scheduled repairs on the T60 pipeline have been completed and the pipeline has been returned to normal operating pressure and capacity. Increases to linepack from early April are anticipated to continue as demand increases.

remaining plants is unavailable, the total production capacity of Longford Gas Plant could be reduced by up to 350 TJ per day, which would put immediate pressure on Iona to provide replacement supply from storage.

While there have not been any significant price impacts in the markets so far, system vulnerability has increased in the event of large unforeseen increases in gas market demand or gas-powered electricity generation. However, there is still time for storage levels at Iona to continue to further increase prior to the expected start date of increased winter demand. Iona ended the quarter 500 TJ above the level reached in mid-January prior to the Longford outage, sitting at 23 PJ by 31 March.

Risk of southern shortfalls from 2025

AEMOs recently released *Gas Statement of Opportunities* (GSOO) report forecast domestic demand to be higher from 2026, and throughout the 2030's with expectations of gas generation requirements increasing from previous forecasts.

The report highlighted the risk of shortfalls during extreme peak demand days are now expected from 2025, 2 years later than expected in the 2023 GSOO. However, while expected peaks in gas generation, residential and commercial and industrial demand have reduced for the rest of the 2020s, anticipated supply projects in the coming years are only projected to reduce the magnitude of peak day shortfalls but not delay the risk, with weather outcomes expected to be a key diver of potential shortfalls.

Due to the declining supply from Gippsland basin, the delivery of committed infrastructure developments on schedule, maintaining the availability of shallow storages and curtailing GPG demand at peak times are all likely to play a key role in averting any near-term shortfalls. [12]

Loss of containment event on the Queensland Gas Pipeline

On Tuesday 5 March, a loss of containment on the Queensland Gas Pipeline **(QGP)** resulted in a large fire south-west of Rockhampton (Figure 15). AEMO directed Westside to divert gas supply from their Meridian gas production facility, the only main production source downstream of the fire, and issued curtailment directions to downstream consumers. A backflow process was also initiated on the adjacent GLNG export pipeline to support Meridian supply, with APLNG, GLNG, Meridian & Jemena co-ordinating the response to increase gas supply.

The large industrial users impacted by the incident were taken offline or run at minimum standby load for safety reasons, with some smaller regional towns also affected downstream of the QGP's Wide Bay offtake.

AEMO held a follow-up conference with industry stakeholders on 8 March to provide updates on expected repair timeframes, and subsequently advised on the completion of welding repairs on 12 March that preceded further inspections, pipeline coating and backfilling of gas, and additional works on pressure protection systems.

[12] Production levels from 2027 are highly dependent on potential or uncertain projects being completed.

From 17 March, the QGP was recommissioned at a reduced operating pressure, with Meridian supply directions being revoked as gas flows resumed on the affected pipeline segment.[13]

Restoration work was completed during the week of 18 March and the pipeline re-commenced independent operation. Flows increased, at reduced operating pressure, to an expected maximum flow rate of around 105 TJ. The closure of the pipeline segment did not result in a notable impact in downstream market prices, though end users of the pipeline remain on restricted rates until a higher operating pressure can increase the maximum capacity to its usual limit of 145 TJ per day.

Figure 15 Queensland Gas Pipeline and surrounding downstream infrastructure

Source: AER analysis using Gas Bulletin Board facility information and AEMO's detailed gas pipeline map.

[13] Large industrial customer curtailments remained in place, but most large users had transitioned to contractual pro-rate allocations agreed with Jemena, the pipeline operator.