



4 Gas markets in eastern Australia

This chapter covers upstream gas markets in eastern Australia, encompassing gas production, wholesale markets for gas and the transport of gas along transmission pipelines for export or domestic use.²⁸³ Much of the chapter is focused on markets facilitated by the Australian Energy Market Operator (AEMO), but also includes information on bilateral commodity gas trades up to a year in duration.²⁸⁴

The main production basin in eastern Australia is the Surat–Bowen Basin in Queensland, which accounts for 65% of east coast production but less than 30% of Australia’s total production. There are smaller basins in South Australia, New South Wales (NSW), off coastal Victoria and in the Northern Territory. Most of Australia’s gas resources are conventional, including a large proportion off the north-west coast of Western Australia. Unconventional (coal seam gas) production is primarily supplied from the Surat–Bowen Basin.

The eastern gas market is interconnected through transmission pipelines, which source gas from these basins and deliver it to liquefied natural gas (LNG) facilities for export and to large industrial customers and major population centres for domestic use (Figure 4.1).

Due to the rapid expansion of the Australian LNG industry on both the east and west coasts, Australia has become one of the world’s largest LNG exporters. Since the launch of the LNG export industry in 2015, gas producers have had the choice to export gas or sell it domestically. Consequently, prices in the domestic market are influenced by international gas prices.

Australian exports accounted for 20% of global exports in 2023, alongside Qatar (20%) and the United States (21%).²⁸⁵ On the east coast, exports accounted for 75% of gas demand in 2024, significantly exceeding domestic consumption levels.²⁸⁶

283 The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern Australian gas market in Queensland, NSW, Victoria, South Australia, Tasmania and the ACT.

284 AEMO-facilitated markets include the Short Term Trading Market hubs and the Gas Supply Hub. Bilateral commodity reporting under the Gas Rules commenced in 2023, adding to secondary bilateral transaction reporting since 2019.

285 Department of Industry, Science, Energy and Resources, [Resources and energy quarterly](#), March 2025, p. 55.

286 Compared with residential and commercial, industrial and gas-powered generation demand, LNG demand accounted for 75% of gas consumption on the east coast in 2024. AEMO, [2025 Gas Statement of Opportunities](#), March 2025, p. 100.

Figure 4.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in wholesale gas markets

The Australian Energy Regulator (AER) has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the wholesale level, we monitor and report on gas spot markets in Sydney, Brisbane, Adelaide and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); short-term secondary capacity markets for gas transportation; and activity on the Gas Bulletin Board, which is an open access information platform covering the eastern gas market.

We monitor the markets and bulletin board to ensure participants comply with the National Gas Law and National Gas Rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to promote confidence in the gas market to encourage participation. We also monitor the markets for particular irregularities and wider inefficiencies. For example, our monitoring role at the Wallumbilla and Moomba hubs explicitly looks to detect price manipulation. We are also the compliance and enforcement body for AEMO-facilitated auctions for secondary capacity in transmission pipelines.

We publish various reports, including gas industry statistics and our Wholesale markets quarterly reports, which cover gas spot market activity, prices and liquidity. The quarterly reports also include analysis of eastern Australia's liquefied natural gas (LNG) export sector and its impact on the domestic market. From July 2023, the AER began reporting more information on the export, reserve, storage, and domestic sale and swaps of gas. In May 2024, new wholesale market monitoring powers were legislated to facilitate a review of gas contract markets. Additional reporting from 2025 onwards will consider this new information alongside associated spot market impacts and implications on final costs faced by consumers.

The AER also has regulatory responsibilities for transmission and distribution pipelines (chapter 5) and retail markets (chapter 6).

We continue to engage with energy ministers' gas reform agenda and, when appropriate, we propose or participate in reforms to improve the market's operation. We also draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities.

Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory but plays no role in the territory's wholesale market. Facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board.

We have no regulatory function in Western Australia, where separate laws apply. In Western Australia, the Economic Regulation Authority is the economic regulator for gas markets and pipelines and AEMO operates a gas spot market.

4.1 Snapshot

- 2024 price outcomes in gas spot markets were similar on average to 2023. In the first half of the year, spot prices were generally lower than the same time in 2023. This pattern reversed in the second half of the year and spot prices were generally higher than 2023 equivalents (section 4.3).
- In the second half of 2024, short-term (up to a year in length) bilateral gas contracting was at its highest levels since reporting of those contracts began in March 2023. This may suggest a trend towards shorter-term contracting (sections 4.3.1 and 4.3.2).
- Transportation capacity upgrades on the north–south pipeline corridor to increase the flow of gas south were completed in May and June 2024, delivering more supply from Queensland to southern markets (sections 4.6 and 4.8.3). Northern flows along the same pipeline also increased later in the year, contributing supply to record-high exports.
- The second quarter of 2024 saw spikes in gas-powered generation (GPG) output to offset periods of low wind and solar generation (section 4.4.1). This highlights strong interdependencies between electricity and gas markets in the National Electricity Market (NEM).
- Gas markets remain vulnerable to weather-driven peak demand days, when existing supplies to southern states must be supplemented with drawdowns from storage. Southern gas storage inventory at Iona depleted rapidly over June and July 2024 before easing market conditions allowed storage levels to replenish in August, averting the potential threat of a supply shortfall (section 4.5.4).

- Depleting offshore legacy gas fields in Victoria continue to limit southern production and increase supply shortfall risks. Production from Longford was higher over 2024 than 2023, breaking a recent trend of year-on-year declines. However, projected reductions in coming years are expected to drive a 47% decline in total southern production capacity by 2029. Over 30% of the projected decline is driven by reduced output from the Gippsland region, with one of Longford's 3 production trains taken offline in October 2024 (section 4.5.3).

4.2 Structure of the east coast gas market

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board that provides up-to-date information about gas flow. Around 10% to 30% of gas is traded in these spot markets, varying by location. All other gas trade is made under confidential bilateral contracts separate to these markets.

4.2.1 Contract markets

Most gas in Australia is traded through confidential bilateral contracts, which secure future supply and transportation capacity and limit participants' exposure to price fluctuations present in downstream markets. Contract prices generally reflect expectations of future market conditions, but shorter-term transactions in spot markets can reflect short-term shifts in market conditions due to factors such as immediate gas supply and gas storage levels, the timing of LNG shipments and conditions in the electricity market. As a result, their price levels are not always aligned, but they often move in similar directions.

For many domestic users, contract prices are likely to be more indicative of the costs they face than spot prices in the AEMO-facilitated gas markets.

The 2 main types of gas contracts (also known as gas supply agreements) are:

- contracts by gas producers to very large customers, such as major energy retailers and gas-powered generators
- contracts by retailers and aggregators that buy gas from producers and onsell it to commercial and industrial (C&I) customers.²⁸⁷

Long-term gas contracts historically locked in prices and other terms and conditions for several years. More recent analysis has continued to indicate an increasing shift towards shorter-term contracts (one to 2 years) since 2021.²⁸⁸ While an increase had previously been observed in the number of longer-term contracts executed at higher volumes, the overall volumes contracted for 2024 were lower than for 2023.²⁸⁹

4.2.2 Facilitated gas markets

Facilitated markets allow wholesale customers to trade gas without entering long-term contracts. Facilitated market trading can be a useful mechanism for participants to manage imbalances in their contract positions if their demand for gas changes close to the delivery date.

Several separate facilitated gas markets operate in eastern Australia – Victoria's Declared Wholesale Gas Market, the Short Term Trading Market, the Gas Supply Hub and the Day Ahead Auction, a separate east coast market for transportation and compression services.

287 Public information about contract prices was unclear. Much of the pricing was private and negotiated contract outcomes are often bespoke. There was also a disparity between the type of information available to large participants that are frequently active in the market and that available to smaller players. This imbalance favoured large incumbents in price negotiations. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2030 gas inquiry. Further reforms following the gas market transparency review require participants to report information to AEMO (from 15 March 2023) for publication on the Bulletin Board, including reserves resources reporting, facility developments, LNG spot transactions and bilateral short-term supply and swap transactions.

288 ACCC, [Gas inquiry 2017–2030, interim report, December 2024](#), Australian Competition and Consumer Commission, December 2024, pp. 40, 44–45.

289 In 2023, producers executed 12 gas supply agreements (GSAs), contracting 43.55 PJ, while retailers executed 18 GSAs, contracting 17.99 PJ. In 2024, producers executed 10 GSAs, contracting 27.85 PJ, while retailers executed 14 GSAs, contracting 12.52 PJ. These volumes relate to gas traded between suppliers and C&I users. ACCC, [Gas inquiry 2017–2030, interim report, December 2024](#), Australian Competition and Consumer Commission, December 2024, p. 77.

Victoria's Declared Wholesale Gas Market (DWGM)

Victoria's DWGM manages gas flows across the Victorian Transmission System and is the largest downstream spot market in eastern Australia.²⁹⁰ Participants submit daily supply and demand bids ranging from \$0 per gigajoule (GJ) (the floor price) to \$800 per GJ (the price cap).²⁹¹ Daily scheduling in Victoria occurs across 5 scheduling intervals over the gas day starting at 6 am, with subsequent adjustments over 4-hour intervals to account for physical or contractual constraints on gas supply and changes to forecast demand levels. Prices in the Victorian market cover gas as well as transmission pipeline delivery. AEMO selects the least-cost bids needed to match demand to establish a clearing price.

AEMO operates the financial market and manages physical balancing, including by scheduling gas injections at above market price to alleviate short-term transmission constraints if any arise.

Short Term Trading Market (STTM)

The STTM is a short-term trading market for gas, with hubs in Sydney, Brisbane and Adelaide, that allows gas trading on a day-ahead basis. AEMO sets a clearing price at each hub based on daily scheduled supply and demand by shippers to deliver gas, with a price floor of \$0 per GJ and a cap of \$400 per GJ.²⁹² Pipeline operators schedule flows to supply the necessary quantities of gas to each hub.

AEMO operates a balancing service – called market operator services (MOS) – to meet any variations in gas deliveries or withdrawals from the schedule. These services are mainly paid for by the parties causing the imbalance.

Gas Supply Hub (GSH)

Gas supply hubs at Wallumbilla in Queensland and Moomba in South Australia are a voluntary platform for gas trading. In contrast, the DWGM and STTM are mandatory for supplying the connected distribution systems. Gas can be transported through the 2 hubs and across other smaller locations on the east coast. Transactions can occur via an on-screen trading platform to automatically match supply and demand based on order price differences or through separate bilateral contracts (known as off-screen trades). Participants can use 5 standard product lengths when trading at the gas supply hubs – balance of day, daily, day-ahead, weekly and monthly. Participants can trade gas through the hubs up to a year in advance of physical supply.

Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade. A single trading location makes it easier for participants to organise their gas trade across multiple pipelines, thus pooling potential buyers and sellers into a single market.

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board that provides up-to-date information about gas flow. Around 10% to 30% of gas is traded in these spot markets, varying by location. All other gas trade is made under confidential bilateral contracts separate to these markets.

²⁹⁰ Over 2024, supply to the Victorian gas market (totalling almost 200 PJ) exceeded the combined supply to the other 3 downstream spot markets in Adelaide (19.7 PJ), Brisbane (22.3 PJ) and Sydney (96.8 PJ) – totalling just under 140 PJ. On peak days, Victorian demand can exceed 1 PJ, more than double that of the next largest hub in Sydney, which peaked at a record high above 420 TJ on 20 June 2024.

²⁹¹ Supply offered in the DWGM is scheduled using 'injection bids', while demand for controllable (priced) and uncontrollable (forecast) demand are referred to as 'withdrawal bids'.

²⁹² In the STTM, supply 'offers' are scheduled alongside demand 'bids', with priced bids (only scheduled at or above the price of offered supply) determined after clearance of uncontrollable (forecast) demand bids (referred to as 'price taker' bids).

Like Wallumbilla, the Moomba hub is located at a major junction in the gas supply chain serving eastern Australia. Three critical pipelines – the South West Queensland, Moomba to Sydney and Moomba to Adelaide pipelines – connect to the hub. On 28 January 2021, trade points at Culcairn and Wilton were also introduced to facilitate trades at the Victorian and Sydney gas market locations. On 6 March 2025, AEMO introduced the Eastern Gas Pipeline (EGP) and Iona underground storage trade points alongside swap products for the notional transfer of gas between different locations. These can be traded to achieve similar physical outcomes to trading spread products.²⁹³

A significant proportion of trade on the Gas Supply Hub occurs ‘off-screen’, which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate the trading of gas supply. This can include shorter-term spot trades, and commodity trades over longer timeframes ahead of gas delivery, depending on the product traded.²⁹⁴

Day Ahead Auction (transportation-related services)

Gas produced in one region can help address a supply shortfall elsewhere, provided transmission pipeline capacity is available to transport the gas. However, several key pipelines experience contractual congestion, which arises when most or all of a pipeline’s capacity is contracted, making the pipeline unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity. Reforms introduced in March 2019 enable participants to access unutilised pipeline capacity across the east coast.

Unutilised (contracted but not nominated) pipeline transport and gas compression capacity for the next day is sold the day before through an auction facilitated by AEMO. Since its inception, the auction has been widely used to move gas between the east coast gas markets. Since late 2022, participation in the auction has increased significantly and consecutive records for capacity won have been set, with amounts procured more than double the highest levels observed across previous years (section 4.6.2).

4.2.3 Gas Bulletin Board

The Gas Bulletin Board is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. It plays an important role in making the gas market more transparent, especially for smaller players that may not otherwise be able to access day-to-day information on demand and supply conditions. It supplies information such as:

- pipeline capabilities (maximum daily flow quantities, including bidirectional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities) and actual injections/withdrawals
- gas field information – reserves and resources, movement, development status, commercial recovery, including information on the basis of estimate preparation, and prices underpinning reserve and resource estimates
- LNG export and import information – shipment dates and volumes as well as detailed reporting of spot LNG transactions
- short-term gas supply and swap transactions with a contract length up to a year
- 36-month outlooks for uncontracted primary firm capacity (compression, storage, production and LNG import facilities) and short/medium-term outlooks for smaller users.

The bulletin board includes an interactive map showing gas plant capacity and production data, and gas pipeline capacity and flow at any point in a network.

Reforms were implemented in March 2023 that expanded the scope of information reported, with some participants required for the first time to report to the Gas Bulletin Board (section 4.11.2).

293 Location swaps are now available on the Gas Supply Hub at the following locations: Wallumbilla and Moomba, Moomba and Wallumbilla, Wallumbilla and Culcairn, Culcairn and Wallumbilla, Wallumbilla and Wilton, Wilton and Wallumbilla, EGP and Wallumbilla, and Wallumbilla and EGP. Spread products allow for the matching of supply and demand submitted at different locations in the Wallumbilla hub (WAL and SEQ location products) and between the Wallumbilla and Moomba hubs (WAL and MOO location products).

294 Most gas trading occurs ‘off-screen’ (not traded through the gas markets), but some of these trades are reported to the market operator and settled through the Gas Supply Hub trading platform.

4.3 Gas prices

Gas market prices are typically elevated during winter periods, when colder weather in southern markets increases demand for residential gas heating. This is particularly significant in the larger Victorian market, where daily demand can exceed 1 petajoule (PJ) on cold days. Gas prices can also increase during summer periods, influenced by higher demand for gas-powered generation in the electricity market, which coincides with warmer temperatures and increased demand for air conditioning.

4.3.1 Gas contract prices

Gas contracts can take many different forms, with variations in the time between traded and delivery dates and the timespan in which the gas is delivered over. For example, gas can be contracted to be delivered in daily quantities for weeks or months at a time and can range from 1 to 10 years in length domestically. LNG export contracts are set over longer periods of around 20 years.²⁹⁵

Market participants are required to report their gas contract information to the ACCC. The ACCC then reports on these prices through its gas inquiry responsibilities. The inquiry's interim updates consider numerous factors that affect contract prices, including the impact of domestic market supply and market price trends, LNG export activity and links to international prices (section 4.3.4).

Mandatory Gas Code of Conduct (\$12 reasonable price provision)

Following the introduction of the Competition and Consumer (Gas Market Emergency Price) Order in late 2022, the Australian Government implemented a Mandatory Gas Code of Conduct to replace the order on its expiry in 2023. The Code came into effect with a 2-month transitional period from 11 July 2023, with the aim to ensure domestic users' ability to contract for gas at reasonable prices and on reasonable terms.

The Code adopted a \$12 per GJ reasonable price provision and provides an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing domestic medium-term demand. It also includes transparency obligations on uncontracted gas production and expected domestic availability, as well as conduct provisions and process standards for commercial negotiations. A review of the Code is being undertaken in the second half of 2025.

Contracting activity significantly increased in the second half of 2024

The ACCC reports on gas supply agreements (GSAs) in its inquiry reports.²⁹⁶ The number of GSAs executed by producers and retailers for supply in 2025 and 2026 more than doubled in the second half of 2024 compared with the first half of the year. The volume of gas sold under GSAs for 2025 supply also increased – producers sold 58 PJ in the second half of 2024 compared with 28 PJ in the first half of 2024, and retailers sold 31 PJ compared with 2 PJ.

Most GSAs agreed to in the second half of 2024 for 2025 and 2026 supply have a term length of 1 year. This is despite many gas buyers, including C&I users, preferring longer, multi-year contracts.

For GSAs covering 2025 supply:

- Average prices agreed under producer GSAs in the second half of 2024 were \$13.58 per GJ, a 10% decrease from prices in the first half of the year.
- Prices agreed under producer GSAs for delivery in southern states was higher than prices for delivery in Queensland. This may reflect tighter supply in southern states and the cost of transporting gas south from Queensland.
- Prices agreed under retailer GSAs in the second half of 2024 averaged \$14.51 per GJ, a 1% decrease from the preceding 6 months.
- Retailers offered more flexible terms than producers, which may reflect their ability to manage changes in demand on a portfolio basis.

²⁹⁵ RBA, [Understanding the East Coast Gas Market](#), Reserve Bank of Australia, March 2021.

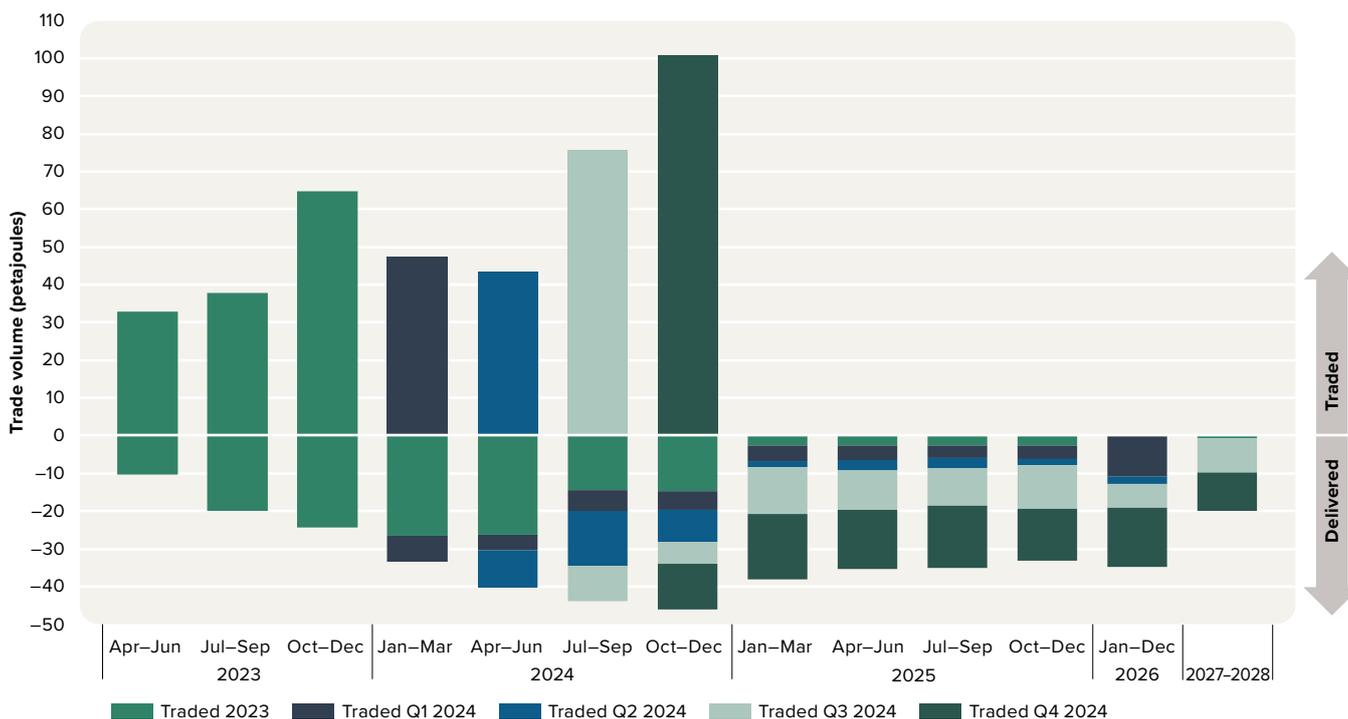
²⁹⁶ ACCC, [Gas inquiry 2017–2030, Interim update on long-term contract prices for July–December 2024](#), Australian Competition and Consumer Commission, March 2025.

For GSAs covering 2026 supply, average prices agreed under producer contracts in the second half of 2024 fell 2% compared with the first half of the year, to \$13.94 per GJ. Prices under producer contracts were higher in southern states than in Queensland. Prices agreed under retailer GSAs over 2024 averaged \$13.55 per GJ.

4.3.2 Short-term transaction reporting

With a significant proportion of gas trade being contracted directly between participants outside of AEMO-facilitated markets, increased reporting of bilateral gas supply contracts was introduced in March 2023.²⁹⁷ The Gas Market Transparency reforms require parties to report details of bilateral transactions up to a year in duration to the Gas Bulletin Board.²⁹⁸ Figure 4.2 shows a breakdown by quarter of the reported transactions by trading date and delivery date since April 2023.

Figure 4.2 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 timeframe.²⁹⁹

Source: AER analysis using Natural Gas Services Bulletin Board data, accessed 8 April 2025.

For supply in 2024, 267 PJ of gas sales were reported. Most of that occurred over the July to September (75.5 PJ) and October to December (100.9 PJ) quarters. The combined volume of 176.4 PJ over these quarters is an increase of 72% compared with the same period in 2023. Most of the gas traded over October to December was for delivery over 2025 and 2026, with 61.4 PJ of these sales for delivery in 2025, 15.7 PJ for delivery in 2026 and 10.2 PJ for delivery over 2027 to 2028. Two years of short-term bilateral transactions have now been reported – these show that trade significantly increases in the last quarter of the year, when participants secure and finalise supply for the following year and beyond.

297 DCCEEW, [Regulatory amendments to increase transparency in the gas market](#), Department of Climate Change, Energy, the Environment and Water, 19 November 2020.

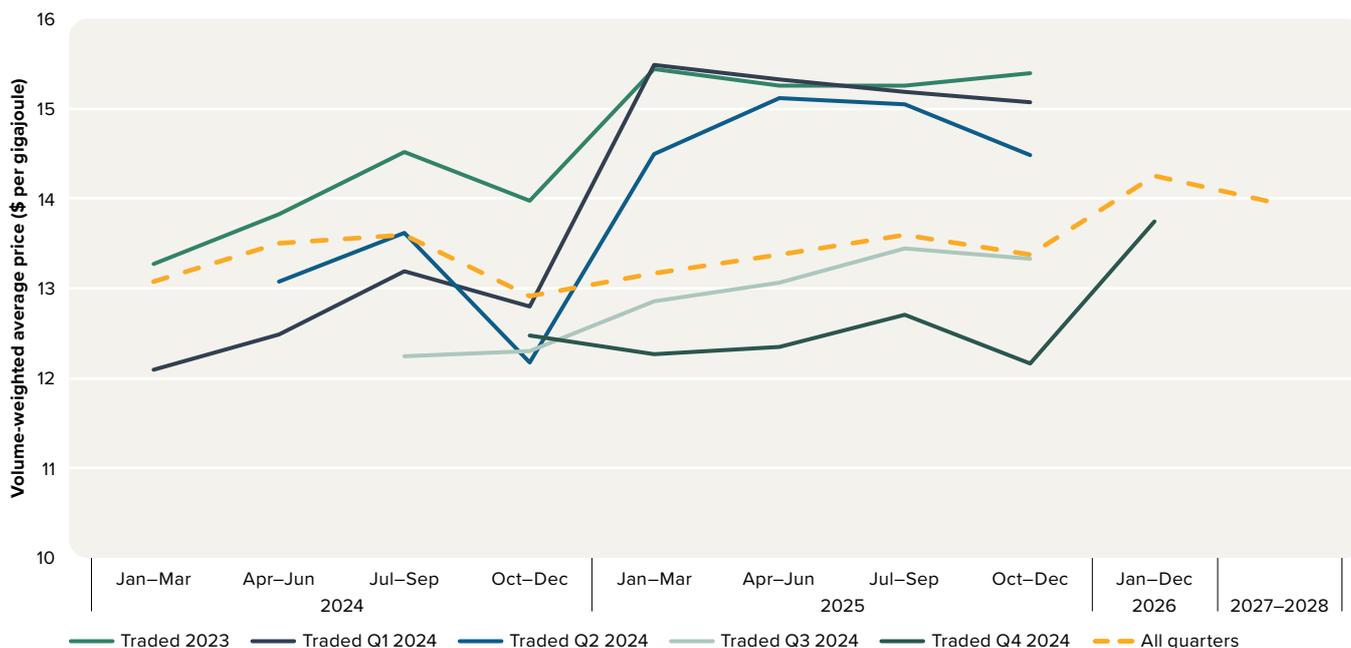
298 The AER published a special report in December 2023 providing analysis and insights into all short-term transactions reported up to 31 October 2023 to the Gas Bulletin Board. The report also included feedback from industry stakeholders on the effectiveness of current reporting practices and recommendations to enhance this in future reporting. AER, [Special report: Wholesale gas short term transactions reporting](#), Australian Energy Regulator, 6 December 2023.

299 Differences in volumes reported previously reflects a feature of the reporting framework, where contracts can be amended or volumes updated before delivery. It is also reflective of late or inaccurate reporting, which the AER monitors.

Overall, the volumes of trade reported in the last 2 quarters of 2024 were the highest volumes of trade reported since reporting commenced in March 2023, with prices trending lower over 2024. Rather than indicating a higher volume of total gas supplied, higher volumes of trade may indicate a reallocation of gas supply contracts to shorter-term contracts (up to a year in length) and away from transactions longer in length (greater than a year). These longer-term transactions are not currently reported to the Gas Bulletin Board but are reported on by the ACCC (section 4.3.1).³⁰⁰

Over 2024 the forward volume-weighted average (VWA) price continued to trend lower every quarter – the VWA price for gas traded across October to December 2024 for delivery over 2025 was \$12.38 per GJ, the lowest compared with all previous quarters (Figure 4.3). Volume-weighted average prices were \$13.37 per GJ for gas deliveries over 2025 and \$14.25 per GJ for deliveries over 2026.

Figure 4.3 Volume-weighted average forward price curve based on the traded quarter



Note: The volume-weighted average prices are based on the supply dates of the reported transactions in the quarter the transactions occurred for 2024, while all transactions for 2023 have been grouped together. These prices exclude pricing structures linked to the STTM or DWGM or where the transaction was between related parties. Where there are not enough trades or participants reporting in a period, the data has been aggregated.

Source: AER analysis using Natural Gas Services Bulletin Board data, accessed 8 April 2025.

ASX Wallumbilla Natural Gas Futures product

The new ASX Wallumbilla Natural Gas Futures product commenced trading on 19 August 2024 for first delivery in October 2024.³⁰¹ It is a monthly product that can be traded up to 3 years in the future, with each futures contract of gas representing a delivery obligation of 100 GJ per day of the calendar month being traded. 5 business days before the beginning of the month traded, any open interest positions³⁰² are converted to physical obligations on the GSH in a Monthly Netted Product deliverable at the Wallumbilla High Pressure Trade Point, referred to as delivery exchange for physical (Delivery EFP). This product aims to provide a transparent forward price curve out to 3 years, improve liquidity at the GSH and provide an additional hedging tool for participants to manage their risk.

Over the October to December quarter 2024, trading of the product increased but volumes remained low overall – 26 futures contracts were traded for the quarter, equating to 80 terajoules (TJ) when delivered. Prices for these products also increased over the quarter in line with movements observed in other domestic gas markets, with Delivery EFP prices ranging from \$13.00 per GJ to \$13.50 per GJ.

300 The ACCC in its [December 2024 interim report](#) also noted that gas is increasingly being sold by producers under shorter-term Gas Supply Agreements, with most new agreements having a term of less than 2 years.

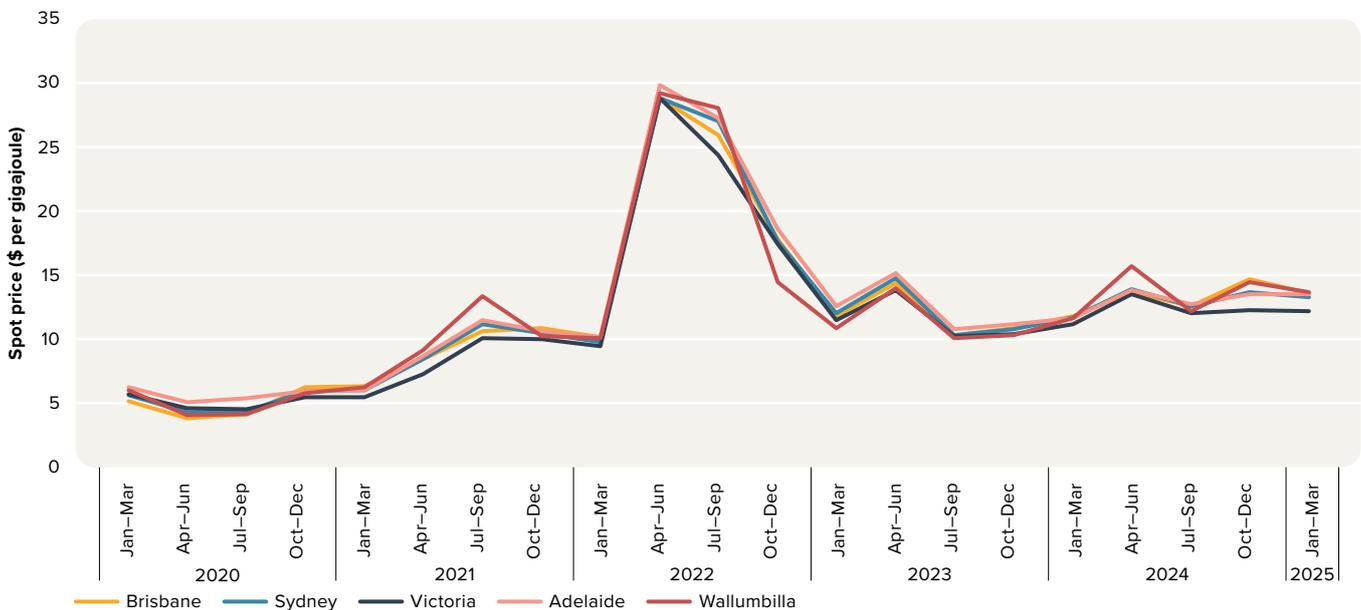
301 ASX, [Trade our derivatives market](#), Australian Stock Exchange, accessed 27 June 2025.

302 Open interest refers to outstanding contracts that have not been closed or settled, representing open positions held in the contracts, which can be used to assess market sentiment and the strength of price trends.

4.3.3 Spot market prices

Gas spot market prices over the second half of 2024 averaged just over \$13 per GJ, up 23% compared with prices across the second half of 2023 (Figure 4.4).³⁰³ This was influenced by higher LNG exports and GPG gas usage driving increased demand.

Figure 4.4 Eastern Australian gas market prices



Note: The Wallumbilla price is the volume-weighted average price for day-ahead, on-screen trades at the Wallumbilla Gas Supply Hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily weighted imbalance price.

Source: AER analysis of Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market data.

Gas spot market prices in 2024 and 2025

Following a period of stable prices across the start of 2024, increased prices over the April to June quarter coincided with high demand days and constrained supply and put pressure on gas storage levels in Victoria. Despite increased gas flows south from Queensland and pipeline capacity expansions on the north–south pipeline corridor, limited flows further south into Victoria contributed to a greater reliance on Iona’s storage supply, driving a rapid depletion of storage inventory. From late May, rapid drawdowns on Iona pushed up prices and resulted in numerous high-priced gas days from mid-June.³⁰⁴ These price impacts in Victoria flowed through to other markets in southern regions, with limited increases also observed in Brisbane.³⁰⁵

303 Cold weather and constraints limiting production and transportation capacity drove up prices just before winter 2023, resulting in higher prices over the April to June quarter.

304 Additional information on prices, supply and demand over winter 2024 are outlined in the [State of the energy market 2024](#) report.

305 Cold weather driving higher residential heating demand and higher gas generation requirements across mainland regions of the NEM, alongside reduced capacity at Longford (Victoria’s largest supply source) due to offshore maintenance, increased participants’ reliance on southern storage.

Box 4.2 AEMO East Coast Gas System Risk or Threat Notice³⁰⁶

On 19 June 2024 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 implemented to remain in place until 30 September, with AEMO outlining an expectation of an industry response to mitigate the system threat and prevent the requirement for market intervention.³⁰⁷ AEMO revoked the threat notice ahead of schedule on 23 August as supply and demand trends improved across all southern regions and Iona underground storage inventories recovered over August (Figure 4.20).³⁰⁸

After settling somewhat over the July to September quarter, increased prices for the following quarter were influenced by record exports coinciding with periods of elevated gas generation in Queensland. While gas flows north over the October to December quarter mirrored similar highs observed across in the corresponding fourth quarter in 2016, they were significantly elevated compared with flows over the October to December period in recent years.³⁰⁹ These high flows were supported by record gas flows north from Victoria, supplementing high Roma production levels to supply record export demand. This offset relatively low downstream market demand levels for the quarter.

Periods of higher gas prices from mid-November to mid-December primarily influenced the Brisbane market, with flow through effects on other downstream markets. This was largely driven by elevated gas-powered generation (GPG) demand in Queensland that prompted GPG gentailers to adjust gas market offer profiles across their east coast portfolios. The impact of these adjustments was less evident in Victoria, resulting in a larger average price gap emerging of around \$3.50 per GJ when Brisbane prices reached their highest levels.³¹⁰

Average annual domestic gas prices increased over 2024, rising by 7% from the previous year. Price increases occurred alongside several cold spells during winter and higher GPG demand towards the end of the year.

East coast gas price spikes occurred on several occasions over the period and tended to coincide with spikes in Queensland's GPG output and Queensland's NEM spot prices; the latter exceeded \$300 per MWh on more than 50 occasions during Brisbane's high gas prices.

From mid-December, GPG demand fell and lessened the incentive to transport Victorian gas north, easing gas price pressures. This saw refilling of gas storage at Iona recommence following a temporary pause over the high-priced period, with the facility reaching full capacity before winter 2025.

306 AEMO, [East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, June 2019.

307 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.

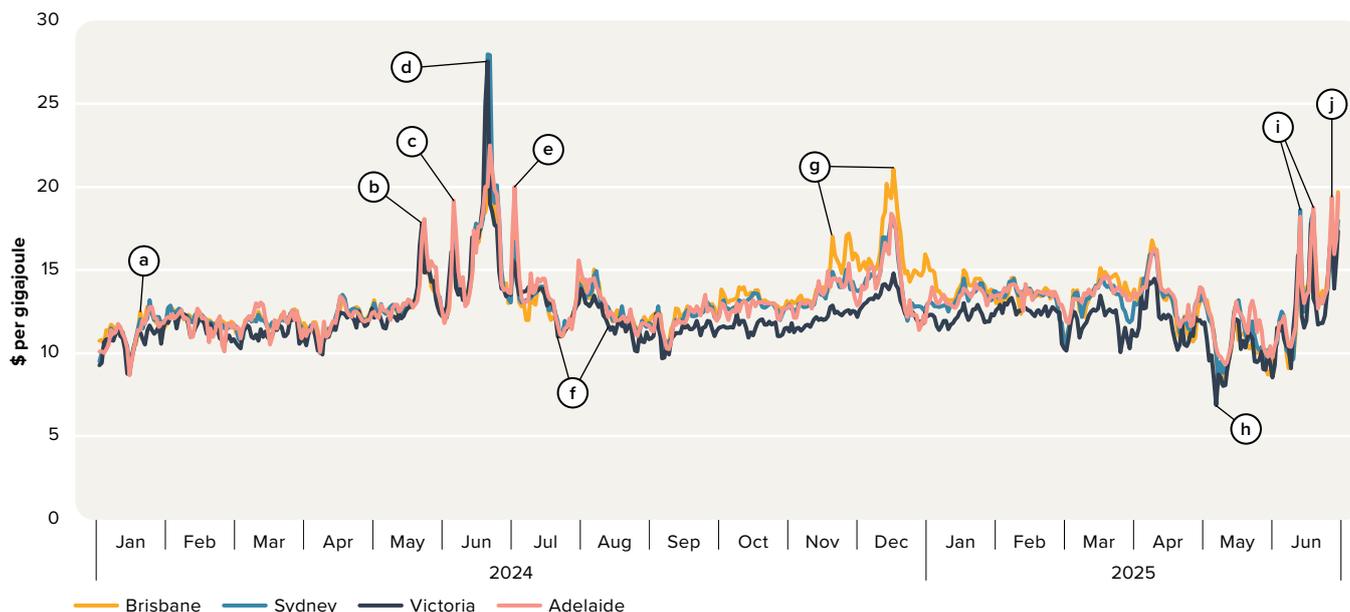
308 Replenishment of Iona's gas storage levels were assisted by warmer weather easing pressure on demand, alongside reduced gas-powered generation output.

309 High flows in 2016 coincided with the commencement of east coast LNG exports following completion of construction.

310 Daily prices in Victoria did not exceed \$14.80 per GJ in the quarter, whereas daily prices in Brisbane remained above that level and peaked at just over \$21 per GJ on 16 December. Prices in Brisbane exceeded \$15 per GJ on 35 occasions. Adelaide also recorded 12 days above that level and Sydney recorded 9 instances.

Figure 4.5 sets out an annotated timeline of key pricing events in 2024 and 2025 to date.

Figure 4.5 Daily gas spot prices



- Note:
- a From mid-January 2024: Increased price stability in downstream markets, with historically low market demand offsetting elevated LNG export flows.
 - b 21 to 23 May 2024: Cold weather driving increased heating demand, offshore maintenance constraining Longford supply and elevated mainland GPG demand.
 - c 4 to 6 June 2024: Cold weather demand and elevated GPG and delayed Longford ramp-up following maintenance.
 - d 18 to 22 June 2024: Continuing constrained output from Longford with high demand and high GPG, continued reliance on Iona storage supply and elevated Tasmanian GPG demand due to drought conditions reducing hydro-electric generation. A pipeline constraint in Victoria also resulted in significant ancillary payments to compensate for the scheduling of higher priced gas.
 - e 1 to 2 July 2024: High market demand and elevated GPG.
 - f 21 to 26 July and 11 August 2024 onwards: Reduced market demand and GPG eases price pressures, with an unseasonably warm end to winter in August.
 - g 18 November to 20 December: Higher gas generation demand in Queensland driving up prices in Brisbane, with price impacts flowing through to STTM hubs in Adelaide and Sydney. Record Queensland export demand places further upwards pressure prices, with a significant price gap emerging between Victoria and Brisbane.
 - h 4 to 13 May 2025: Full Iona storage inventory and low demand in Victoria put downward pressure on prices.
 - i 11 to 14 June 2025: Unplanned compressor outage at one of Longford's 2 remaining gas plants significantly reduced production capacity during a period of high GPG demand. Cold weather impacting southern regions also drove high gas market demand, with Victoria exceeding 1 PJ per day and Sydney peaking above 400 TJ on 13 June.
 - j 26 to 30 June 2025: High coincident GPG demand coinciding with a number of baseload generator outages across the NEM and continued high coincident gas market demand.

Source: AER; AEMO (raw data).

Significant price variations in late 2024

The significant price event reporting threshold for market operator services (MOS) was triggered in the Sydney STTM on 3 occasions in November and December 2024.

MOS, also known as balancing gas, is required to manage everyday pipeline deviations. A pipeline deviation occurs when there is a difference between the total quantity of gas nominated by the pipeline's shippers and the quantity of gas physically delivered. There are 2 kinds of pipeline deviations – positive (when more gas is delivered) and negative (when less gas is delivered, resulting in gas being 'parked' upstream of the hub on a pipeline). When actual gas deliveries are higher than final nominations, the difference is allocated as increase MOS; when actual gas flows are lower than final nominations, the difference is allocated as decrease MOS. Increase MOS is provided to the hub from gas stored on the pipeline. Participants that loan this gas are compensated for this service through service payments. Decrease MOS requires the use of capacity on the pipeline to store gas that could not be delivered to the hub. Similarly, participants that park this gas are compensated for this service through service payments.

Market operator services involve allocating costs to market participants due to gas delivered deviating from schedules. AEMO is responsible for overseeing and allocating payments between market participants. Daily total MOS payments above \$250,000 are rare and the AER is required to report on any high-priced MOS events above that threshold within 60 business days after the final settlement run for the month in which the event occurred.³¹¹ MOS payments mainly occur when there are deviations between demand and supply compared with scheduled amounts, but it can also be driven by physical pipeline dynamics, where differences in pressure between transmission pipelines and the lower-pressured distribution system impact contracted gas deliveries.³¹² This can result in counteracting MOS (CMOS) requirements, where additional supply from one pipeline offsets under-delivered supply from the other (in excess of differences between forecast and actual supply/demand). The AER did not identify any compliance issues as part of the report.

The 3 events were driven by different factors but all related to the requirement to temporarily store (park) gas that could not be physically delivered to the hub on the Eastern Gas Pipeline (EGP).

While CMOS requirements impacted costs on 28 November and 14 December, outcomes for 20 December were primarily driven by over-forecast demand.

Table 4.1 Drivers of high MOS service payments in the Sydney STTM

| Date | Unplanned reduced network pressure ^a | Pipeline flow and pressure dynamics | Supply (over or under supply) | Demand (over or under forecasting) | Low pipeline flows | Pipeline renominations |
|----------------------------|---|-------------------------------------|-------------------------------|------------------------------------|--------------------|------------------------|
| 28 November ³¹³ | Yes | Yes | No | No | No | No |
| 14 December ³¹⁴ | No | No | Yes | Yes | Yes ^b | Yes ^b |
| 20 December ³¹⁵ | No | No | Yes | Yes | No ^c | No ^c |

Note: a The AER has a [compliance bulletin](#) designed to avoid MOS when there are pressure reductions. However, this relies on prior knowledge (before the gas day) that network pressures need to be reduced.
b Indicates that the driver did contribute to high MOS service costs on a certain day, but only in combination with other drivers.
c Indicates that the driver was not a main contributor to high MOS service costs on a certain day, but it may have some influence over MOS outcomes.

Source: AER analysis using STTM data. Pressure data provided by Jemena Gas Networks (network operator of the Sydney distribution network). EGP flow data provided by Jemena (pipeline operator of EGP).

For more detailed information on these events and the use of MOS on the affected days, see the Significant price variation report Sydney STTM – November and December 2024.³¹⁶

311 Market operator service (MOS) 'service costs' have rarely exceeded this threshold, happening on 15 prior occasions since the start of the STTMs, with high-priced MOS events occurring only 5 times in the Sydney market since 2016 and on one occasion in each of the Adelaide and Brisbane hubs.
312 The Moomba to Sydney Pipeline (MSP) operates on a pressure-controlled delivery system into Sydney, where low pressure in the hub (distribution network) is closely met by additional supply to compensate for short-term supply shortfalls. The Eastern Gas Pipeline operates in a similar way for deliveries into the Wollongong sub-network but uses flow-controlled deliveries into the main distribution system that provide gas supply to the main trunkline. Both pipelines deliver gas into the Wilton distribution point.
313 On 28 November, an unforeseen reduction in the Sydney distribution network's pressure resulted in additional (unnominated) supply flowing from the Moomba to Sydney Pipeline (MSP), impacting scheduled deliveries on the EGP (requiring gas to be parked on the pipeline). This resulted in MOS service payments accruing to \$1,029,768.
314 On 14 December, participants renominated scheduled MSP supply over to the EGP on a day with lower than forecast hub demand. This resulted in low net flows physically supplying gas to the Sydney hub from the MSP. To meet backhaul demand upstream of the hub on the MSP, increase MOS was allocated on the pipeline to make up for the shortfall in nominated supply. As a result, MOS service payments accrued to \$305,683.
315 On 20 December, over-forecast demand resulted in MOS being allocated due to the scheduled oversupply of gas being parked on both pipelines (primarily on the EGP), with MOS service payments accruing to \$322,998.
316 AER, [Significant price variation report Sydney STTM](#), Australian Energy Regulator, March 2025.

4.3.4 Domestic spot prices and international price trends

Average annual domestic gas prices increased over 2024, rising by 7% from the previous year. Price increases occurred alongside several cold spells during winter and higher GPG demand towards the end of the year. While prices did not reach the unprecedented levels of 2022, they remained elevated – sitting around 44% higher than average downstream market prices in 2021.

Linkages between domestic and international prices

Since 2021, competition between Asian, European and South American buyers increased demand for LNG during the Northern Hemisphere winter periods. Late 2022 saw a peak in international price levels, with supply concerns in Europe due to geopolitical conflicts and infrastructure outages (Figure 4.6). Global demand surged across Europe and Asia to secure gas stocks and increase storage levels. After peaking in late 2022, international price levels reduced significantly into 2023 but remained elevated compared with historical levels.

From mid-2023, domestic prices were on par with international price levels and remained relatively stable as international prices gradually increased to the end of the year.³¹⁷ At the end of 2023, European storage inventories entered the October to December quarter at a record high of 97% full alongside record floating storage supply.³¹⁸

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the Northern Hemisphere winter. A mild Northern Hemisphere winter at the end of 2023 also suppressed demand,³¹⁹ reducing pressure on international prices into 2024 alongside increases in other sources of LNG supply.³²⁰

In 2024, international LNG spot prices gradually decreased across January and February before starting to rebound slightly from March, with prices in February reaching some of the lowest levels observed over the past 2 years. Ahead of the Australian winter, local prices had risen above international price levels due to numerous supply and demand factors, particularly in the southern markets that experienced a prolonged stretch of cold weather (Figure 4.7). This trend reversed across the remainder of the year, with international prices increasing above domestic levels due to the seasonal shift from summer to winter in the Northern Hemisphere.

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the Northern Hemisphere winter.

From mid-2024 until November 2024, European reservoir levels were significantly higher than their 5-year average and reached a 90% capacity level approximately 3 months earlier than is typical. However, drawdowns on European stock levels occurred earlier and at a higher rate than the 5-year average, putting upwards pressure on LNG prices to Europe. To avoid being stranded for gas supply and having to pay higher prices, as seen in 2022, Asian inventories were also stocked in advance. This led to a premium in LNG prices for deliveries to Asia compared with Europe, which steadily eased.

In the Northern Hemisphere, unpredictable weather variations over the Asian summer contributed to demand for spot cargoes and high LNG prices. Japan and Korea experienced intense and unpredictable heat waves while China experienced wet and cooler temperatures in the south but hot and dry in the north. These factors put upward pressure on gas-powered generation for cooling demand. Although some parts of Europe faced heatwaves, adequate supply and lower-than-expected LNG prices combined with increased availability of piped gas, ensuring that Europe was adequately stocked for winter.

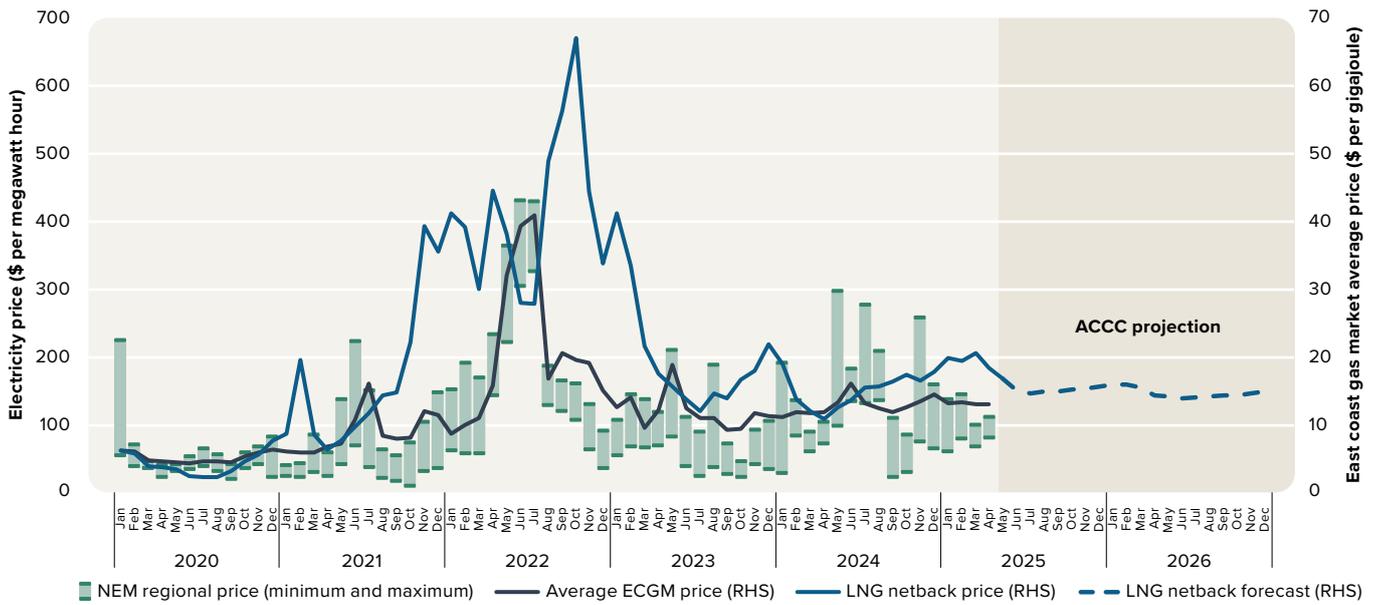
317 While international price levels had decreased significantly from record highs in the years prior, they remained above the historical trend in mid-2023.

318 AER, [Wholesale markets quarterly – Q4 2023](#), Australian Energy Regulator, January 2024.

319 Storage levels rounded out the quarter at 87% of capacity. Argus direct, *Europe LNG: Des prices tick down*, 29 December 2023.

320 LNG availability from the United States increased by 6% and Norway's availability was also up 1.5% following the resolution of unplanned outages from 2022.

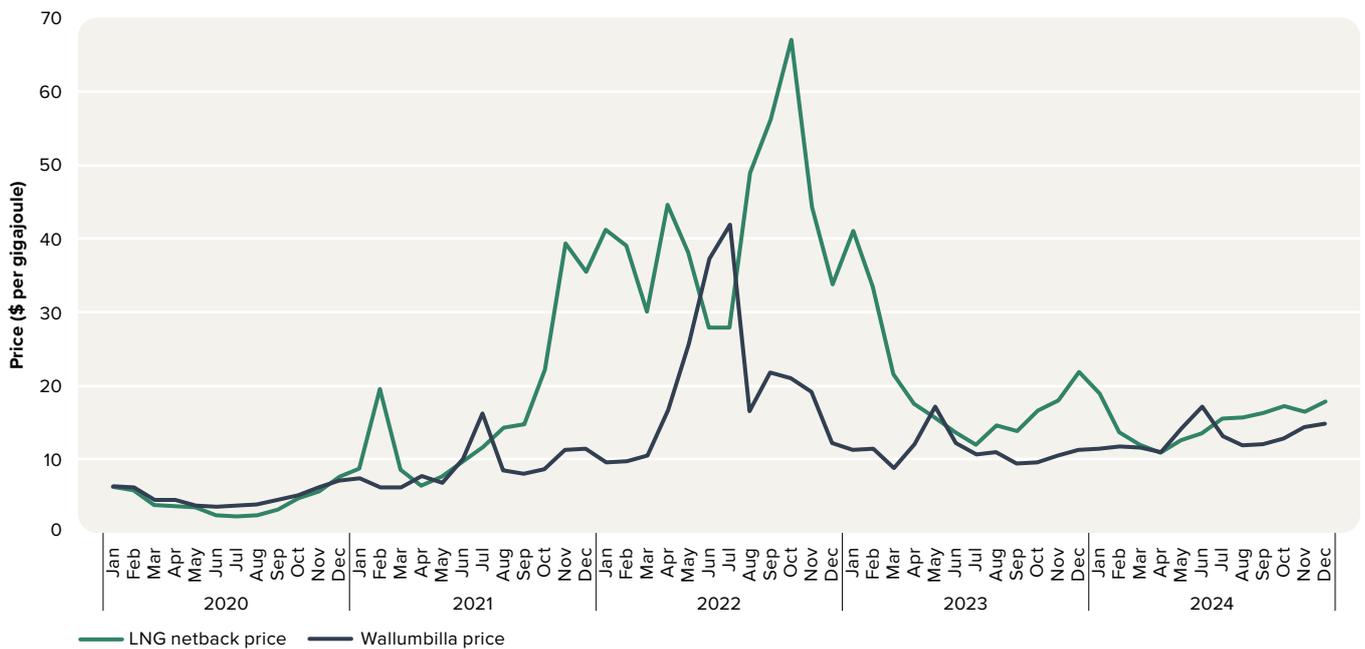
Figure 4.6 Comparison of east coast gas market, NEM and LNG netback prices



Note: ECGM is east coast gas market. NEM is National Electricity Market. The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers. LNG netback forecast 28 June 2024.

Source: AER analysis of NEM, Short Term Trading Market, Victorian Declared Wholesale Gas Market and ACCC LNG netback price data.

Figure 4.7 LNG netback and Wallumbilla prices



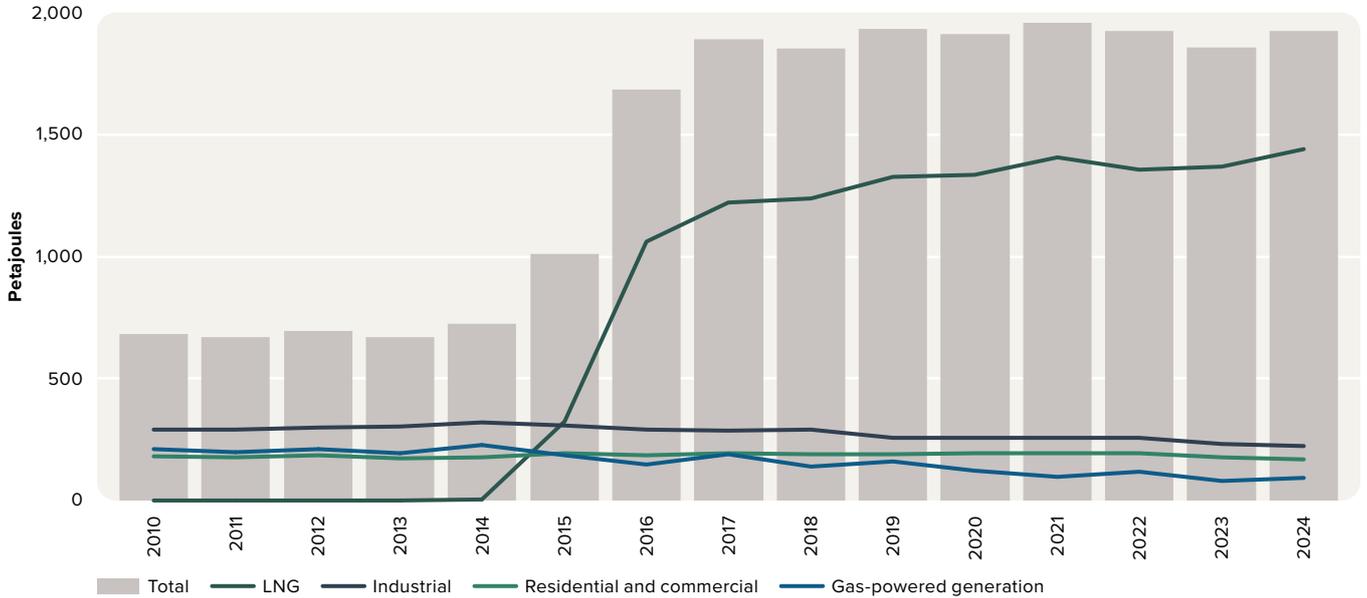
Note: The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.

Source: AER analysis of gas supply hub data; ACCC (LNG netback prices).

4.4 Gas demand in eastern Australia

Around 75% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market (Figure 4.8).

Figure 4.8 Eastern Australian gas demand



Source: AEMO, 2025 Gas Statement of Opportunities, March 2025.

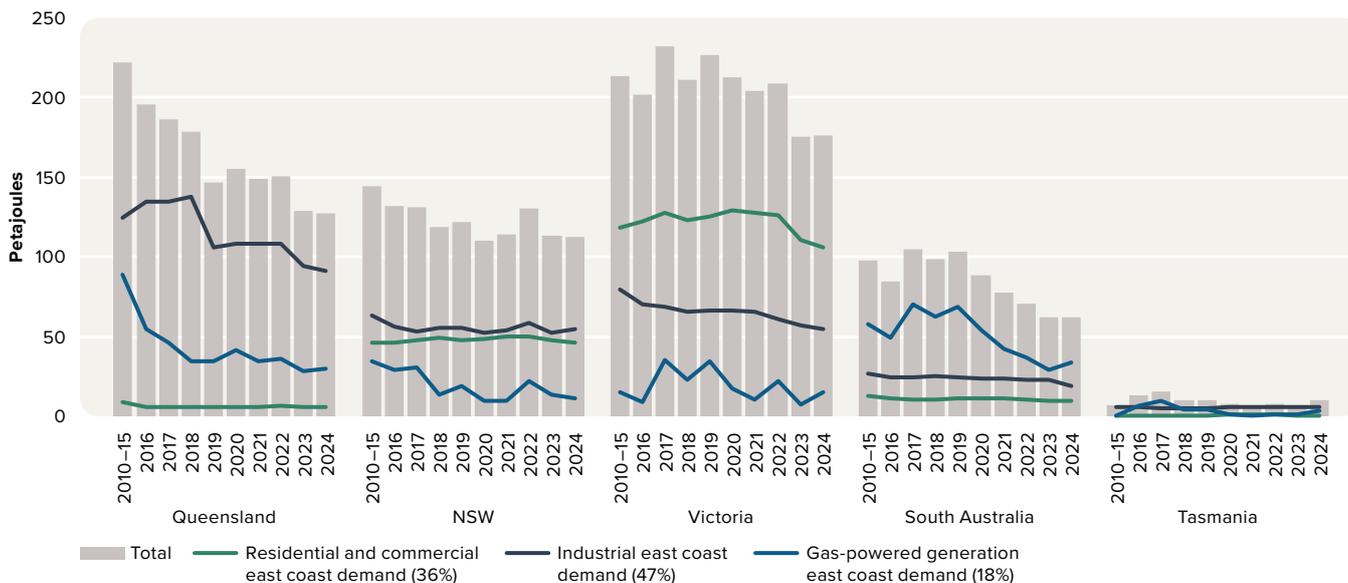
4.4.1 Domestic demand

Domestic customers in eastern Australia used around 488 PJ of gas in 2024 (Figure 4.9).

These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 46% of gas sold to the domestic market in 2024. Gas is used as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass and processed foods. Gas is also a major feedstock in ammonia production for fertilisers and explosives.

Figure 4.9 Eastern Australian gas demand, by state



Note: Data for 2010–15 is average annual consumption over that period.

Source: AEMO, 2025 Gas Statement of Opportunities, March 2025.

Residential and commercial customer demand levels vary from state to state. In Victoria, 60% of gas is consumed by small residential and commercial customers, who use gas mostly for heating and cooking. In Queensland, where fewer households are connected to a gas network, the share of gas consumed by residential and commercial customers is much lower, at around 5%.

Electricity generation is another major source of gas demand, accounting for 19% of domestic gas use in 2024, down from peak levels of around 30% before 2020. South Australia and Queensland used the most gas-powered generation (GPG) in 2024 (each using 36% and 32% of GPG in the NEM, respectively). The rapid responsiveness of gas-powered generators makes them suitable for meeting peak electricity demand and managing variable wind and solar generation. Consequently, the volume of gas used for electricity generation fluctuates with electricity market conditions. Long-term forecasting of expected usage for GPG in the NEM is difficult due to the unpredictability of relevant drivers such as weather, availability of other fuel types and unforeseen events.³²¹

Gas-powered generation use in 2023 and 2024

In 2024, GPG gas usage remained low across mainland regions, albeit slightly above 2023 levels (Figure 4.10).³²² At the start of 2024 average quarterly GPG demand fell to the lowest quarterly level observed over the past decade, before lower wind and solar generation output over the April to June quarter led to increased need for higher priced GPG, pushing up electricity prices in southern regions.

GPG output further increased over the July to September quarter, contributing to a quarterly gas demand record alongside increased LNG export demand, despite historically low downstream market demand. This maintained upwards pressure on gas prices for the rest of 2024. Increased GPG requirements in Queensland from mid-November to mid-December had a significant impact on downstream gas prices in the Brisbane STTM. This price pressure in turn flowed through to southern markets.

These events illustrate the ongoing complexity of gas-powered generation acting as a firming capacity in the NEM. Demand for GPG to fill in at times of low renewable generation output and high demand can be unpredictable. This is particularly evident when low renewable generation coincides with elevated gas demand driven by colder weather or electricity system constraints, potentially leading to price

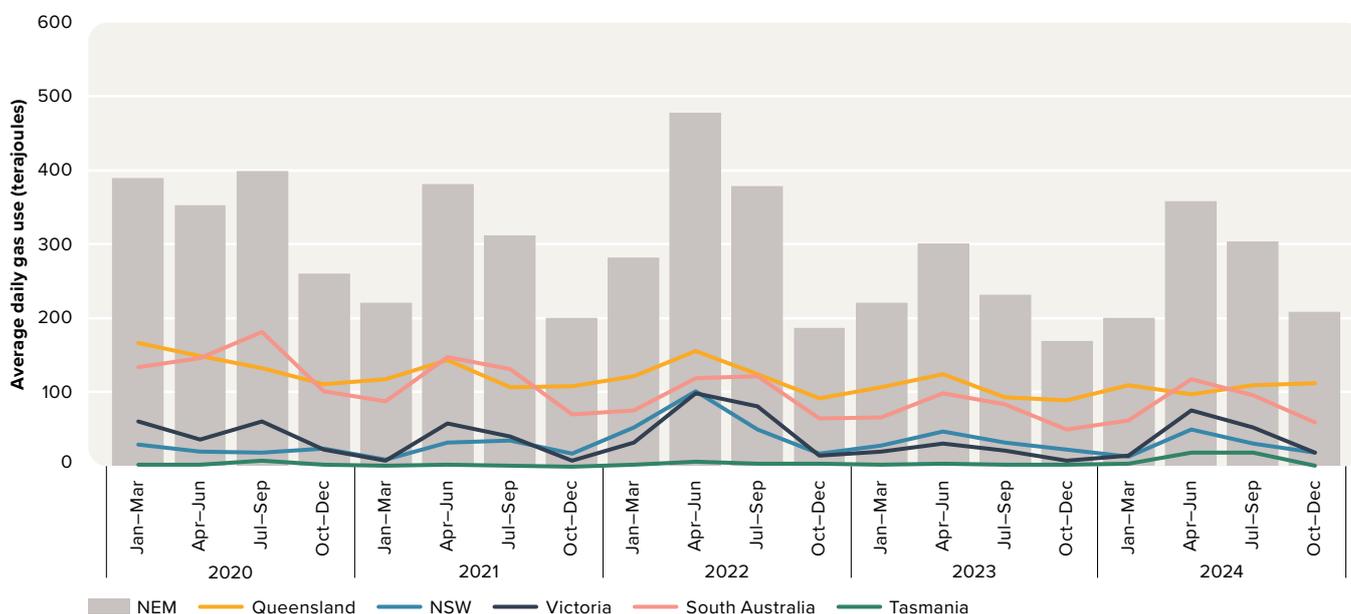
321 Multiple events, including baseload generation retirement, coal shortages during hot weather, bushfires and flooding, transmission outages, and prolonged coal generation maintenance outages and plant failures, have affected the NEM in previous years.

322 Increases in GPG gas usage were primarily driven by more generation in Victoria and South Australia last year, with NEM regions having fallen record low levels of GPG output in 2023.

spikes or gas shortfalls. Despite generally declining demand for gas across the east coast, GPG demand is projected to increase in the coming years unless new sources of firming capacity can be found to replace it. AEMO's Integrated System Plan (ISP) forecasts flexible gas capacity of 8.8 GW will be needed by 2030–31, climbing to 15.4 GW by 2051–52.

Projections indicate 7.8 GW of the existing GPG fleet will still be in service by 2030. A total of 750 MW of committed generation and 200 MW of anticipated GPG will be needed to avoid generation shortfalls between now and 2030. New generation capacity of 12.8 GW is needed by 2051–52.³²³ At the same time, governments are taking actions to reduce consumption of natural gas in order to meet net zero commitments. These include encouraging electrification where possible and investing in alternative fuels where electrification is not suitable, such as for industrial processes involving high temperatures or where methane is a feedstock rather than a source of energy. This poses challenges to the market in identifying least-cost options for avoiding shortfalls while also minimising the creation of redundant investment. The various actions being taken to stabilise supply-demand balances are discussed further in section 4.10.

Figure 4.10 Quarterly gas demand for gas-powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

4.4.2 Liquefied natural gas exports

Most of the gas produced in eastern Australia is exported as liquefied natural gas (LNG).

In eastern Australia, export gas is liquefied in processing facilities in Queensland to make it economic to store and ship in large quantities. There are also 5 LNG export projects in Western Australia and 2 in the Northern Territory (Figure 4.11).

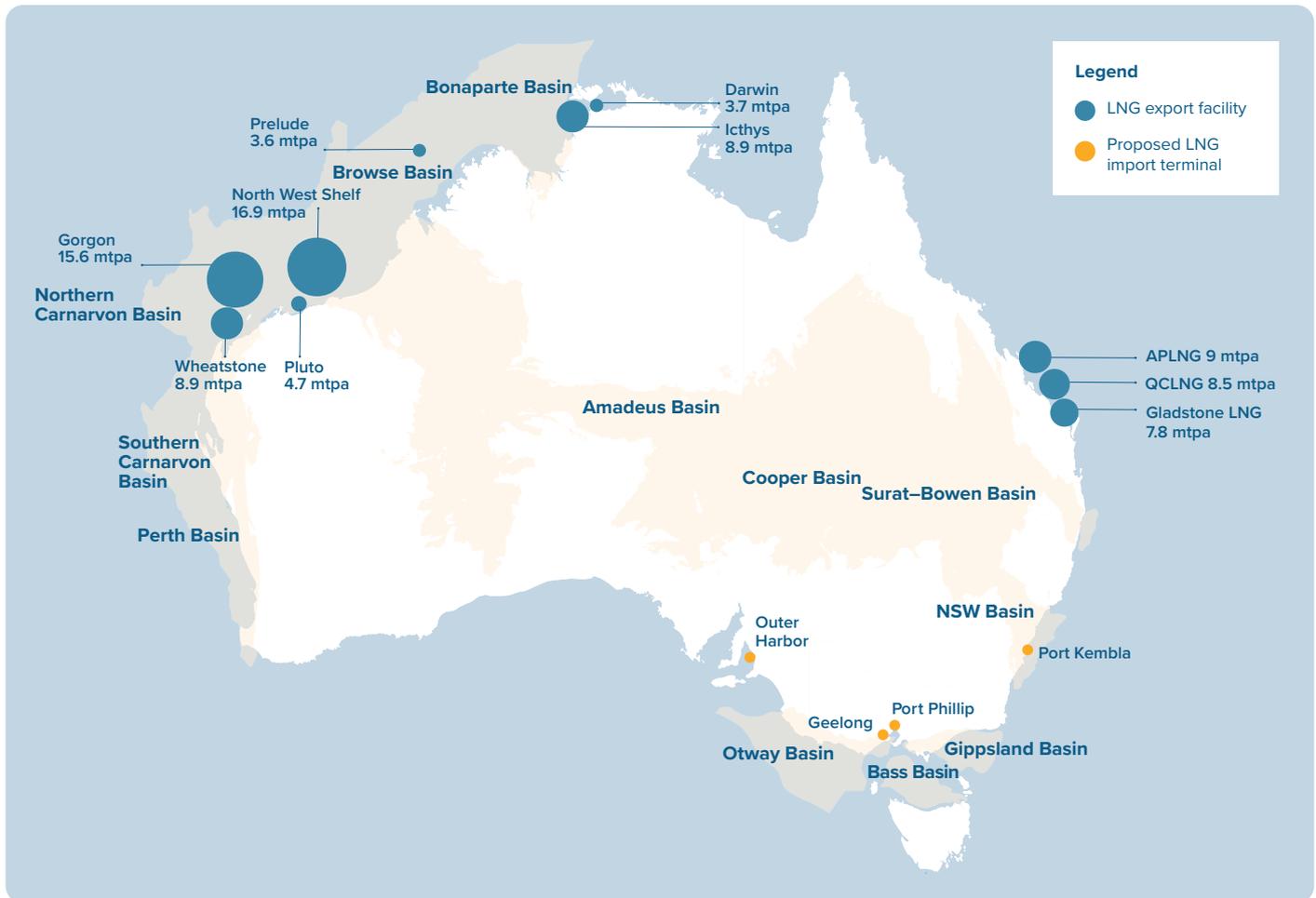
Forecast export revenue totalled \$72 billion for 2024–25, up from \$68.5 billion for 2023–24.³²⁴ The Department of Industry, Science and Resources forecast revenue to decline to \$45 billion by 2029–30, largely due to an expected easing in LNG prices. Gas remains one of Australia's largest resources and energy exports behind coal and iron ore. Australia was the second highest exporter of gas in 2023 behind the United States, following the restart of Freeport LNG in Texas.³²⁵

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

324 Department of Industry, Science and Resources, [Resources and energy quarterly](#), March 2025.

325 Department of Industry, Science and Resources, [Resources and energy quarterly](#), March 2024.

Figure 4.11 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa). EPIK ceased development of a Newcastle import terminal due to the project being economically unfeasible.

Source: AER; Department of Industry, Science and Resources, Resources and energy quarterly, March 2025.

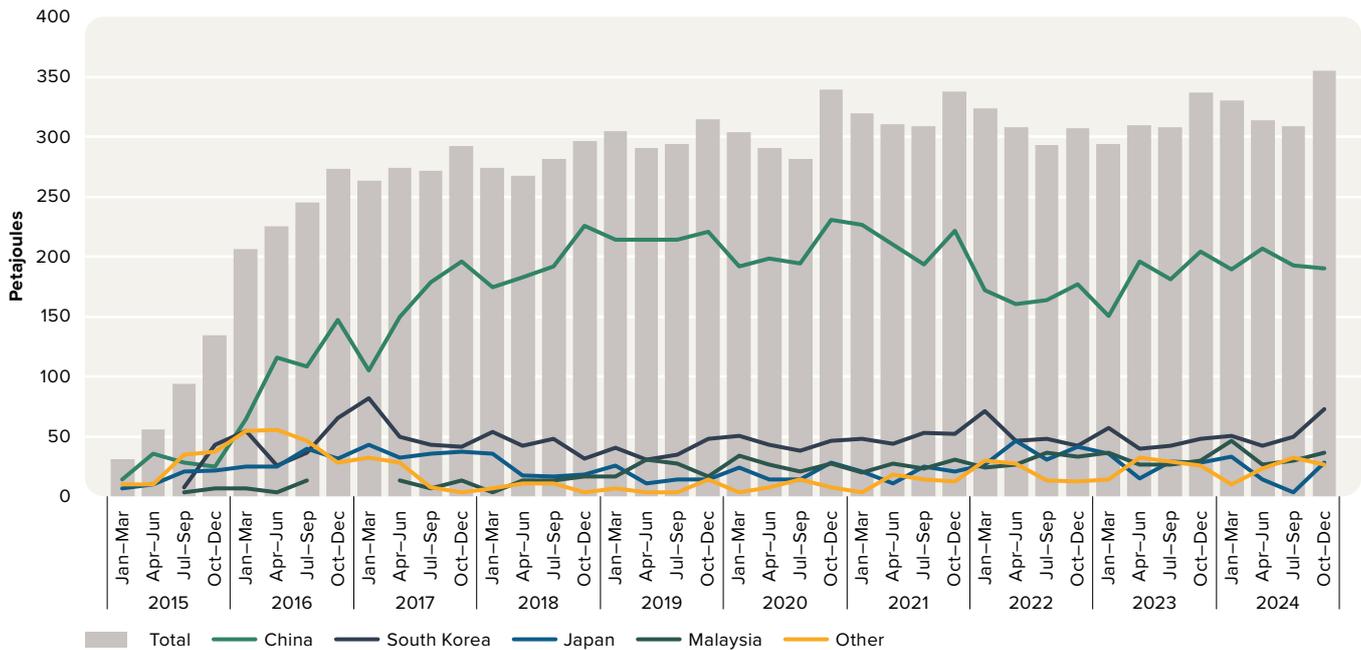
Queensland's LNG industry comprises 3 major projects, which source gas mainly from the Surat–Bowen Basin. Gas production volumes are measured in millions of tonnes of LNG per annum (mtpa).

- Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 mtpa. Shell (73.75%), CNOOC (50% equity in Train 1) and Tokyo Gas (2.5% equity in Train 2) collectively own the project.
- Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas (27.5%), Total (27.5%) and Kogas (15%) collectively own the project.
- Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa. Origin Energy (37.5%), ConocoPhillips (37.5%) and Sinopec (25%) collectively own the project.

These LNG projects control around 84% of 'proven and probable' (2P) reserves in eastern Australia.³²⁶ They also source gas from other producers through long-term production contracts and use spot markets to manage volatility and ensure they can meet their long-term exports supply obligations. East coast gas exports are typically lower mid-year, when the gas produced supplements increased domestic demand over winter, and higher over the rest of the year as Northern Hemisphere winter conditions drive up international demand.

326 ACCC, *Gas inquiry 2017–2030, interim report*, Australian Competition and Consumer Commission, December 2024, p. 115. 2P reserves represent proven and probable reserves (probable reserves are deemed 50% likely to be commercially recoverable).

Figure 4.12 Eastern Australian gas exports



Source: AER analysis using Gladstone Port Corporation data.

East coast LNG exports have risen consistently since they began in 2015. They remained at lower levels across 2022 and 2023 compared with the record high volumes exported in late 2020 and 2021 but began to climb again from late 2023. East coast exports increased above 1,300 PJ for the first time in 2024. Exports reached quarterly record levels across each quarter of the year, peaking at 355 PJ in October to December 2024 (Figure 4.12). Total export pipeline deliveries to Curtis Island reached record daily flow rates above 4,300 TJ per day on numerous occasions in 2024, primarily in December.³²⁷

China remained the primary market for eastern Australian LNG in 2024, accounting for 60% of exports (779.5 PJ), up slightly from the previous year (733 PJ, 59%).

International gas markets have been relatively stable over the past year following supply shocks during 2022 and then forced readjustments in 2023.³²⁸ Record gas flows south occurred across winter 2024 alongside record exports (Figure 4.21).

Northern Territory and Western Australia exports

The Northern Territory’s LNG projects are Darwin LNG (3.7 mtpa capacity) and Ichthys LNG (8.9 mtpa capacity). Both projects connect to the territory’s domestic gas market as emergency supply sources but otherwise produce gas for export.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa – including the North West Shelf, which is Australia’s largest LNG project by capacity (16.9 mtpa). The other projects are Gorgon (15.6 mtpa), Wheatstone (8.9 mtpa), Pluto (4.7 mtpa) and Prelude (3.6 mtpa).

327 Daily flows exceeded 4,300 TJ per day on 6 occasions in December, reaching a record of 4,389 TJ on 25 December 2024.

328 Department of Industry, Science and Resources, [Resources and energy quarterly](#), March 2025.

4.5 Gas supply in eastern Australia

Gas supply to the northern regions of eastern Australia is largely supplied from Queensland's Surat–Bowen Basin. Gas is also sourced from the Cooper Basin in South Australia and was supplemented by supply from the Northern Territory from 2019 to 2024. Gas from Queensland is required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter. At other times of the year, southern gas is also transported north to meet LNG export demand. Ensuring sufficient gas remains in Australia to service the domestic market is a key priority for governments. Both AEMO and the ACCC regularly assess and publish analysis on future supply conditions and the likelihood of future shortfalls so that these can be addressed ahead of time.³²⁹

4.5.1 Background

Southern states rely on local gas production to supply most of their gas demand. However, as production in southern states has declined, sourcing gas from Queensland has become increasingly important, particularly during the Australian winter.

Output from Victoria's Gippsland Basin has been falling due to the depletion of legacy fields supplying the Longford gas plant.³³⁰ From 2023, east coast gas users have become more reliant on northern production. Gippsland's projected peak day production capability has been falling since 2022 and remains significantly lower than prior levels. AEMO's latest *Gas Statement of Opportunities* report projects an improved outlook over the next few years, with southern peak day shortfalls from 2025 now delayed until 2028 due to demand forecast reductions and the delayed retirement of the Eraring Power Station.³³¹

4.5.2 Current conditions

Despite historically low average gas demand levels, colder weather from late May 2024 drove up southern demand compared with the mild Australian winter in 2023. Due to the significant changes in demand driven by cold weather, southern gas markets are persistently vulnerable to cold weather events. Last year, tight supply and demand conditions were exacerbated by reduced production capability at Longford, Victoria's largest source of supply. This increased participants' reliance on obtaining gas from southern storage and Queensland gas fields to meet demand in southern markets. Other events in the Northern Territory and Tasmania also put upward pressure on the tight supply-demand conditions in southern markets.

Northern Gas Pipeline (NGP) gas shortfall

Although southern demand for gas from northern regions has increased, supply previously provided to the east coast from the Northern Territory ceased between Q2 2024 and Q1 2025, resuming in April 2025. Production issues at the Blacktip offshore gas fields led to the pipeline connection between Queensland and the Northern Territory being restricted, with industrial demand on the Carpentaria Pipeline now reliant on gas supplies from South East Queensland. The pipeline has now been reconfigured to flow gas into the Northern Territory, with the NGP reverse capability project completed in August 2024 (section 4.8.5).

329 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator; ACCC, [Gas inquiry 2017–2030](#), Australian Competition and Consumer Commission.

330 Longford is the largest and most flexible source of southern gas supply.

331 This is due to lower forecasts for residential, commercial and industrial users and the temporary reduction in expected peak day GPG requirements and the extended availability of the Eraring Power Station. AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 68.

Loss of containment event on the Queensland Gas Pipeline

On Tuesday 5 March 2024 a loss of containment on the Queensland Gas Pipeline (QGP) resulted in a large fire south-west of Rockhampton (Figure 4.13).³³² 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.³³³ Pipeline flow and customer offtakes began ramping up the following day at a reduced operating pressure of 105 TJ, ramping up to 118 TJ per day from mid-May and to 130 TJ per day from early September. The pipeline was returned to normal operating pressure of 145 TJ per day from 10 December following the completion of pipeline repairs on the isolated pipeline segment.³³⁴

Figure 4.13 Queensland Gas Pipeline and surrounding downstream infrastructure



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

³³² 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 and Jemena coordinating the response to increase gas supply. 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.

³³³ Large industrial customer curtailments remained in place, but most large users had transitioned to contractual pro-rata allocations agreed with Jemena, the pipeline operator.

³³⁴ AER, *Wholesale markets quarterly – Q4 2024*, Australian Energy Regulator, January 2025, p. 22.

4.5.3 Gas reserves and production

Eastern Australia had 31,968 PJ of ‘proven and probable’ (2P) gas reserves reported by AEMO in the *2025 Gas Statement of Opportunities*.³³⁵ Of these 2P reserves, 29,728 PJ (93%) is concentrated in the north including the Surat, Bowen and Cooper basins in Queensland and the Amadeus Basin in the Northern Territory.

Ownership is highly concentrated in some gas basins, but more diverse across the east coast. APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Queensland’s Surat–Bowen Basin holds almost 90% of the 2P gas reserves in eastern Australia and supplied close to 80% of gas produced in 2024.

In Victoria, the Gippsland Basin is the largest basin, while the Bass and Otway basins are smaller. These 3 basins account for 6% of eastern Australian 2P reserves, but production has continued to decline due to anticipated decreases from Gippsland legacy fields. This is important because Victoria is the highest domestic consumer of gas. AEMO forecasts a steep decline in southern field production in the coming years.

The Cooper Eromanga Basin in central Australia has just over 900 PJ of eastern Australia’s 2P reserves, with reserves in the basin declining over the past decade. The Cooper Eromanga Basin plays an important role as a ‘swing’ producer in managing seasonal and short-term supply imbalances in the domestic gas market.

NSW has significant contingent resources³³⁶ (around 1,500 PJ) but only 6 PJ of 2P reserves and no current production since AGL’s Camden facility ceased production in late August 2023. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin, but final investment decisions depend on project approvals being cleared (section 4.8.1).

The AER is required to report annually on price assumptions used by field owners to prepare their annual gas field reserve estimates as part of the Gas Market Transparency reforms.³³⁷ The median contracted reserve price for 2025 was \$10.44 per GJ, ranging from \$10.43 per GJ to \$10.86 per GJ for the 5-year period from 2025 to 2029. For the same period the median uncontracted reserve price assumptions were higher, at approximately \$12 per GJ. Both contracted and uncontracted reserve prices showed year-on-year increases of approximately 4%. This largely reflects the consumer price index (CPI) but for contracted prices it was also influenced by large field-level price variations – some fields reported year-on-year price changes exceeding 25%.³³⁸

Location-based analysis of uncontracted prices indicated the average price for southern basins is higher than northern basins. The price differential increases across the 5-year period from approximately \$1 per GJ in 2025 to over \$3 per GJ in 2029. Noting the increased reliance on northern gas to meet southern demand, the higher southern price expectations possibly reflect a competitive pricing once the transportation cost for moving gas from the north is considered.

335 AEMO, *2025 Gas Statement of Opportunities*, Australian Energy Market Operator, accessed 20 March 2025.

336 2C contingent resources are reserves that are estimated to be potentially recoverable from known deposits but are not currently considered to be commercially recoverable.

337 AER, *Wholesale gas reserves price assumption report: Insights into the gas reserves prices assumptions reported to the AER covering calendar year 2024*, 15 April 2025, Australian Energy Regulator, April 2025, accessed 9 May 2025.

338 Uncontracted reserve prices refer to forecast price assumptions made on the value of 2P gas reserves that have not been locked into existing contractual arrangements. The assumptions made on the value of these reserves are required to be verified by independent qualified gas industry professionals.

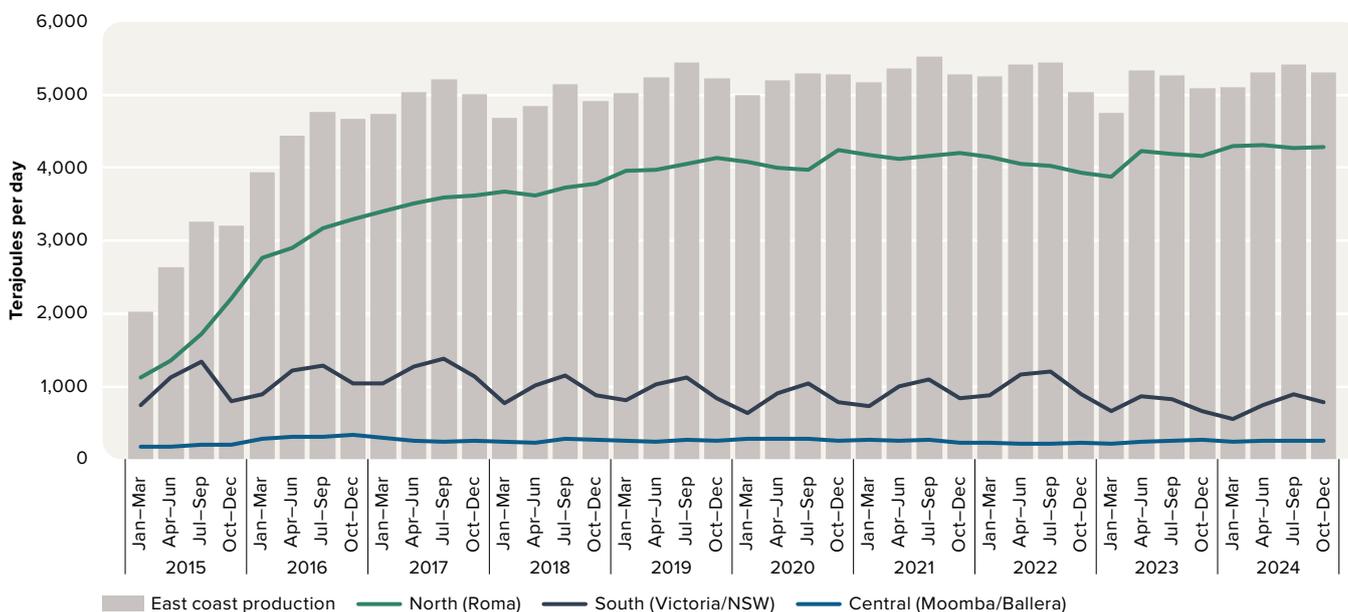
Table 4.2 Gas basins serving eastern Australia

| Gas basin | Gas production – 12 months to December 2024 | | | 2P gas reserves (December 2024) | |
|--------------------------|---|--|-------------------------------|---------------------------------|--|
| | Petajoules | Share of eastern Australian supply (%) | Change from previous year (%) | Petajoules | Share of eastern Australian reserves (%) |
| Bowen and Surat (Qld) | 1,571 | 81% | 4% | 25,763 | 90% |
| Galilee (Qld) | 0 | 0% | 0% | 0 | 0% |
| North Bowen (Qld) | 0 | 0% | 0% | 79 | 0.3% |
| Cooper Eromanga (SA–Qld) | 92 | 5% | 2% | 923 | 3% |
| Gunnedah (NSW) | 0 | 0% | –100% | 7 | 0.02% |
| Gippsland (Vic) | 212 | 11% | –8% | 1,354 | 5% |
| Bass Otway (Vic) | 61 | 3% | 44% | 390 | 1.4% |
| Beetaloo (NT) | 0 | 0% | 0% | 0 | 0% |
| McArthur (NT) | 0 | 0% | 0% | 0 | 0% |
| Amadeus (NT) | 11 | 1% | –18% | 221 | 0.8% |
| Total | 1,947 | 100% | – | 28,735 | 100% |

Note: 2P: proven and probable reserves estimated to be at least 50% sure of successful commercial recovery. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and reserves in other basins are mainly conventional gas. Totals may not add to 100% due to rounding.

Source: AER analysis of Gas Bulletin Board data (production). ACCC, [Gas inquiry 2017–2030, interim report, December 2024](#), Australian Competition and Consumer Commission, December 2024, p. 76.

Figure 4.14 Eastern Australian gas production



Source: AER analysis of Gas Bulletin Board data.

Roma production reached record quarterly levels across 2024, peaking at an average daily output above 4,300 TJ per day over the April to June quarter (Figure 4.14). This coincided with record quarterly export levels across 2024. Export cargo levels over the October to December quarter reached 355 PJ, exceeding the previous record of 340 PJ set over the same period in 2020.

From mid-June, new gas supply from the Otway Gas Plant in Victoria increased to more than 150 TJ per day on average, reaching daily output levels close to 200 TJ over winter.³³⁹ Moomba production also continued to increase over late 2023, with average daily output close to 250 TJ across 2023 and 2024.³⁴⁰

Looking forward, southern production is forecast to decrease by more than 30% over the next 5 years, driven by depleting legacy fields in the Gippsland region.

Longford production decline

Victoria's largest supply source at Longford has been running down reserves from its depleting legacy fields in the Gippsland Basin in recent years. Since 2023, supply levels from Longford have declined markedly compared with previous years (Figure 4.15). While production output over 2024 remained comparable to 2023, this was influenced by low gas consumption and increased winter supply from Queensland last year, rather than reflecting available production capacity at that time.³⁴¹

In 2024, continued production declines saw Longford's supply over the January to March quarter drop to approximately 35PJ. This was the lowest level recorded since the commencement of Bulletin Board reporting in mid-2008.³⁴² In 2024, Longford production over the January to March quarter was well below available capacity.³⁴³ Reduced output continued in the April to June quarter with a delayed ramp-up following planned maintenance, which was scheduled to conclude in late May but instead prevented supply levels reaching expected higher rates until late June.

Since 2023, supply levels from Longford have declined markedly compared with previous years

Over the July to September quarter 2024, southern gas production saw increased supply from the Otway and Orbost gas plants offset the decline in production from Longford³⁴⁴, with new production from the Enterprise gas field commencing in June.³⁴⁵ Increased output from the Otway gas plant continued to drive higher southern production levels in Victoria over the October to December quarter, assisted by Longford increasing supply by 3.7 PJ to 50 PJ.

Higher available production capacity over 2024 was the result of fewer maintenance outages compared with 2023.³⁴⁶ While production levels at Longford have been aided by the Kipper Compression Project³⁴⁷ being commissioned from October, the facility's production capability remains limited to around 700 TJ per day, with higher output levels observed during winter 2024 no longer achievable.³⁴⁸

339 Production from Port Campbell (including the Otway and Athena gas plants) increased from 38 PJ in 2023 to 56 PJ in 2024, with the connection of new gas supply to the Otway Gas Plant including the Enterprise field in mid-2024 and the Thylacine West wells later in 2024. AEMO, [2024 Victorian gas planning report](#), Australian Energy Market Operator, March 2024, p. 9.

340 Average production in 2022 was just over 220 TJ per day. Increased production coincides with an increase in the number of wells drilled in the Cooper Basin throughout 2023. AEMO, [Quarterly Energy Dynamics Q4 2023](#), Australian Energy Market Operator, January 2024, p. 57.

341 AEMO, [2024 Victorian gas planning report](#), Australian Energy Market Operator, March 2024, p. 9.

342 Available production capacity of 45 PJ was also at the lowest level recorded. AEMO, [Quarterly Energy Dynamics Q1 2024](#), Australian Energy Market Operator, April 2024, p. 56.

343 Offshore maintenance at Longford from mid-January to mid-February saw participants draw down on Iona's underground storage inventories, which were at record high levels heading into 2024 following a mild 2023 winter.

344 AEMO, [Quarterly Energy Dynamics Q3 2024](#), Australian Energy Market Operator, October 2024, p. 58. Longford's production capacity also reduced in October 2024 following the retirement of the Gas Plant 1 processing facility, with the upcoming retirement of Gas Plant 3 expected later this decade.

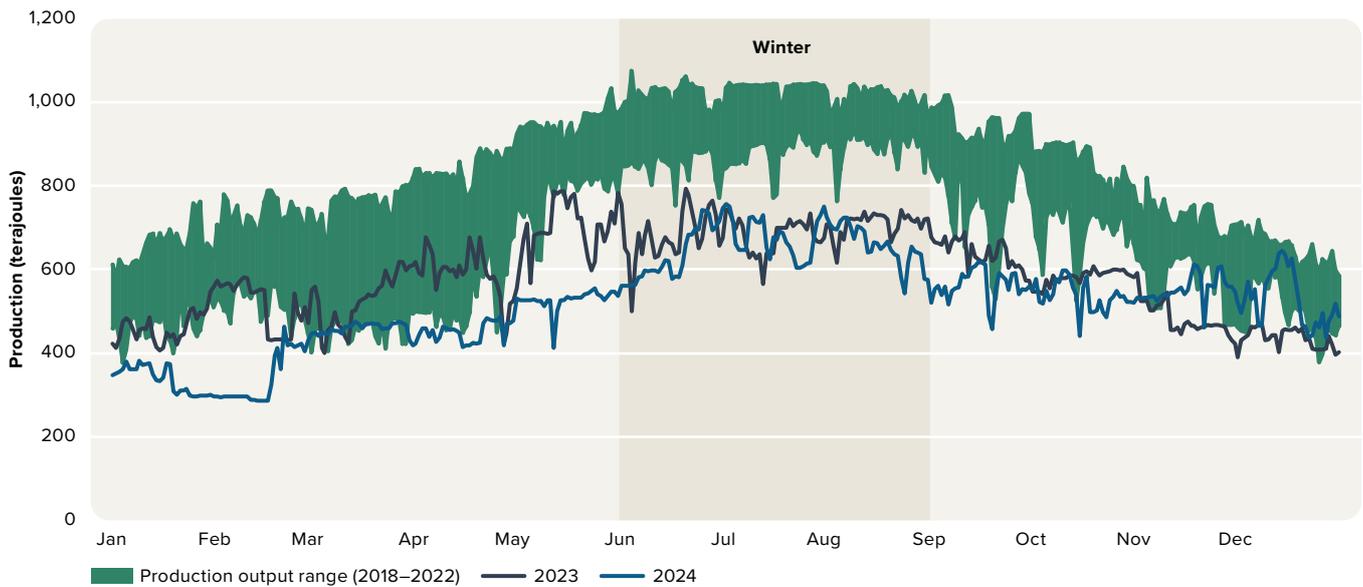
345 Beach Energy, [Enterprise project](#), Otway Gas Plant, accessed June 2025, accessed June 2025.

346 AEMO, [Quarterly Energy Dynamics Q4 2024](#) Australian Energy Market Operator, January 2025, p. 57.

347 ExxonMobil, [Esso Australia delivers crucial project for Australian natural gas supplies](#), 18 October 2024.

348 Longford Gas Plant 3 operation is expected to extend to December 2028 (from December 2027), thereby improving the forecast maximum daily production in winter 2028.

Figure 4.15 Longford production levels since 2018



Source: AER analysis of Gas Bulletin Board data.

Gippsland’s peak day production capacity is forecast to be 680 TJ until mid-2025, representing a 198 TJ reduction from the previous year’s forecast.³⁴⁹ Forecast 2025 Victorian production has fallen from 296 PJ to 257 PJ, a 39 PJ (13%) reduction from the previous year’s forecast.³⁵⁰ Total southern production is also projected to decrease by 47% from 1,165 TJ per day in 2025 to 618 TJ per day in 2029. Production from the Longford plant has been falling and the plant is becoming less reliable, with plant constraints and maintenance outages increasingly disrupting production.³⁵¹

Changing basin profiles

Activity in all gas basins across eastern Australia has evolved to meet the needs of the LNG industry. Production from the Surat–Bowen Basin is mainly earmarked for export. But supply from other eastern Australian basins rose between 2015 and 2017 to help LNG projects meet their export contracts (Figure 4.21). This shift accelerated a depletion of gas reserves in southern basins. AEMO and the ACCC have identified the ongoing depletion of southern gas fields as a significant risk to supply in the coming years.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market (section 4.10.1). Over 2019 and 2020, Surat–Bowen Basin production increased (9%), largely matching LNG export growth (10%), while production from southern basins decreased by a similar proportion (10%). Over 2021, strong southern supply and gas flows north to support high exports coincided with export levels growing more than Queensland production increases. Gas shortfalls are expected to emerge from 2027 unless new sources of supply are made available.³⁵² Potential gas supply has been identified by producers to reduce the risk of near-term shortfalls, but this is mostly conditional on the ability to obtain regulatory approvals and make final investment decisions (section 4.5.5). Import terminals may also help address supply gaps, but their viability is subject to international price movements and the ability to secure foundation customers to contract gas supplies.³⁵³ These would be a supplement to other supply solutions, including pipeline, production and storage developments (section 4.8).

349 AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 53.

350 AEMO, [2025 Victorian gas planning report](#), Australian Energy Market Operator, March 2025, p 3.

351 Capacity is decreased to around 700 TJ per day following the retirement of Gas Plant 1 from October 2024. This makes production capability reliant on the remaining 2 production trains, elevating the likelihood of production capacity halving in the event of an issue with either of the remaining plants.

352 ACCC, [Gas inquiry 2017–2025, interim report, December 2024](#), Australian Competition and Consumer Commission, January 2025, p. 92.

353 Import terminals will not replace the requirement to develop more domestic supply sources.

4.5.4 Gas storage

Storage facilities can store surplus gas produced in summer for use during higher demand winter periods, providing supply flexibility and quick delivery capability to meet peak demand requirements. Refill and drawdown rates for these facilities can be impacted by connected pipeline capacity and low storage levels, limiting the amount of gas in storage that can be replenished or delivered. Eastern Australia's gas storage capacity includes 3 different ways of storing gas.

- Large facilities use depleted gas fields in Queensland, Victoria and South Australia.
 - Iona underground storage (Victoria) has a nameplate storage capacity of 24.4 PJ, with a delivery capability of 570 TJ per day³⁵⁴ – this is the second largest supply source in the south and can deplete and refill at a much higher rate than other east coast storage facilities. The facility typically refills with large quantities of gas, which are drawn down over the higher demand winter period (Figure 4.18).
 - Moomba Lower Daralingie Beds storage (South Australia) has a nameplate storage capacity of 70 PJ, with a delivery capability of less than 5 TJ per day (Figure 4.17).³⁵⁵
 - Silver Springs storage (Queensland) has a nameplate storage capacity of 45 PJ, with a delivery capability of 8 TJ per day (Figure 4.18).³⁵⁶
 - Roma Underground Gas Storage (Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 60 TJ per day (Figure 4.17).³⁵⁷
- LNG storage is in smaller seasonal or peaking facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria (Figure 4.19).³⁵⁸ These facilities have relatively high supply rates, but depletion cannot be sustained for many days due to slow refill rates. The primary use for the Dandenong LNG facility is to store small volumes of gas to be injected quickly into the Victorian Transmission System to cater for short-term peak requirements and manage threats to system security.
- There are short-term peak storage services on gas pipelines, which are mostly contracted by energy retailers – for example, the Tasmanian Gas Pipeline stores gas that can be sold into the Victorian market at times of peak demand.

The Dandenong LNG and Iona underground storage facilities are the only ones that currently provide storage services to third parties in the east coast gas market.³⁵⁹ The importance of storage in managing supply and demand has risen since the LNG industry began operating, with some storage facilities drawn down to meet LNG export demand and replenished when prices were low. Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks and seasonal demand. Average storage levels have decreased since 2021 and in the July to September quarter 2022 reached their lowest levels since reporting commenced in late 2016. This brought average storage levels down to one-third of capacity (Figure 4.16).³⁶⁰ Iona entered 2024 above the record high storage level reached the previous year. However, high utilisation this winter has resulted in rapid depletion of inventories despite high levels of gas flowing south from Queensland. The drawdown of supply from

354 The maximum supply rate achieved in 2021 with a nameplate capacity of 530 TJ per day was 455 TJ.

355 Progressive depletion of storage levels has reduced delivery capacity to 10 TJ per day from late 2021, with current delivery capabilities now sitting around 5 TJ per day since April 2022.

356 Silver Springs delivery outlooks reduced to around 10 TJ per day from mid-October 2021 and have been sitting around 8 TJ per day or lower since 2022.

357 Short-term capacity outlooks for the Roma Underground Gas Storage facility generally range from 25 TJ per day to 60 TJ per day, occasionally reaching up to 80 TJ per day.

358 The Dandenong LNG storage facility reached record low levels in 2021 (since the commencement of the Declared Wholesale Gas Market in 1999), driven by a reduction in contracted capacity for winter. Following a rule change by the AEMC, AEMO now acquires uncontracted gas storage supply at the facility and acts as a buyer and supplier of last resort to mitigate potential supply shortfalls, ensuring the facility is at or near full capacity heading into winter. The rule change was initially due to end on 31 December 2025, with a [consultation](#) proposing a 3 year extension to the interim arrangements initiated on 1 May 2025.

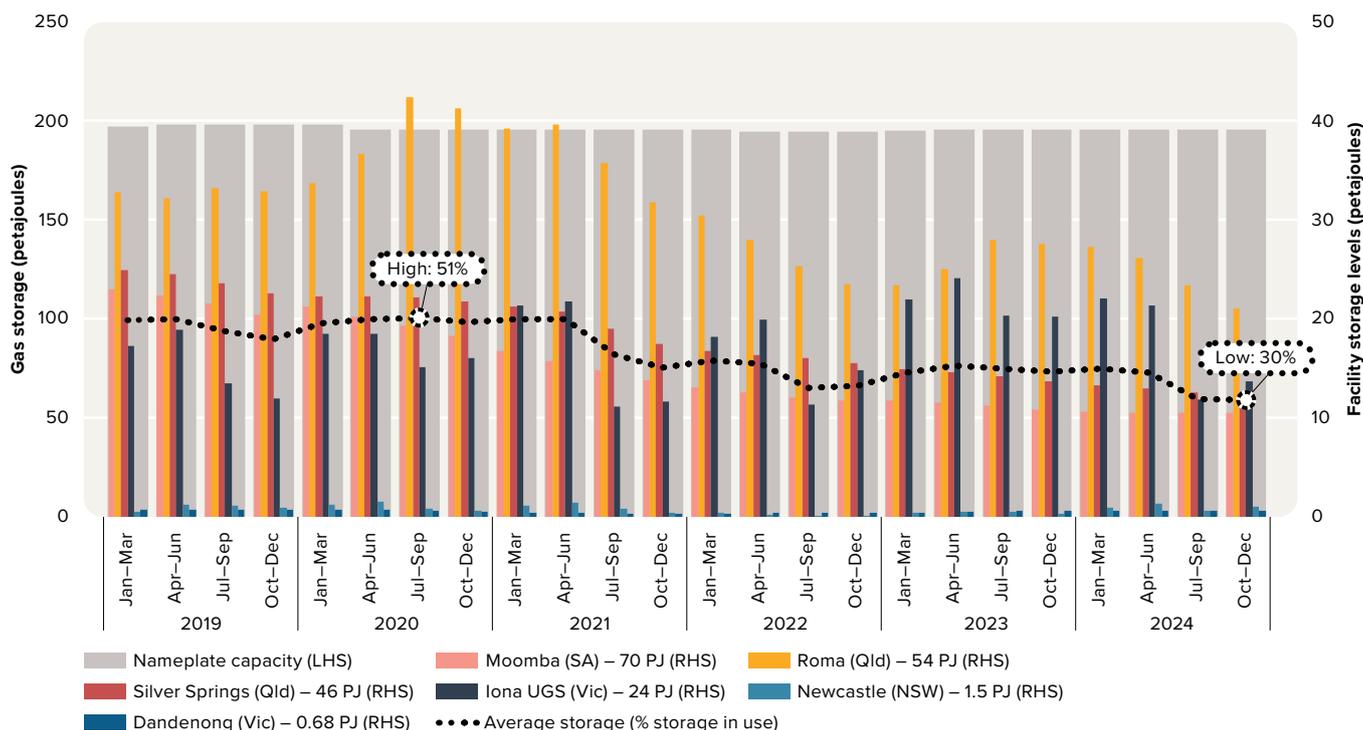
359 ACCC, [Gas inquiry 2017–2030, interim report, December 2023](#), Australian Competition and Consumer Commission, December 2023, p. 127.

360 Storage levels fell to record lows across all east coast facilities in 2022, with this trend continuing at most facilities in the following years. Utilisation of storage at the larger and more flexible Roma and Iona storage facilities over 2024 contributed to total east coast storage levels falling to a new low for the last quarter of the year.

other large facilities has also continued, with declining pressure in the storage wells slowing the rate at which gas can be withdrawn from storage to supply the markets (Figure 4.17 and Figure 4.18).³⁶¹ This demonstrates the dominant impact of weather-driven demand levels on supply adequacy for the southern states.

In contrast, some refilling at the Roma facility in Queensland over 2023 saw supply rates³⁶² return to higher levels, while refilling of the smaller Newcastle gas storage facility commenced in December 2022 and storage levels were at close to full capacity by late April 2024 after some utilisation across late 2023.³⁶³ After 2024 winter utilisation, Newcastle storage levels had decreased to around one-third of full capacity by late August but have since refilled towards full capacity from late 2024 and into 2025. Low daily supply capabilities at the Moomba and Silver Springs storage facilities mean they do not make a significant contribution to gas supply.

Figure 4.16 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.

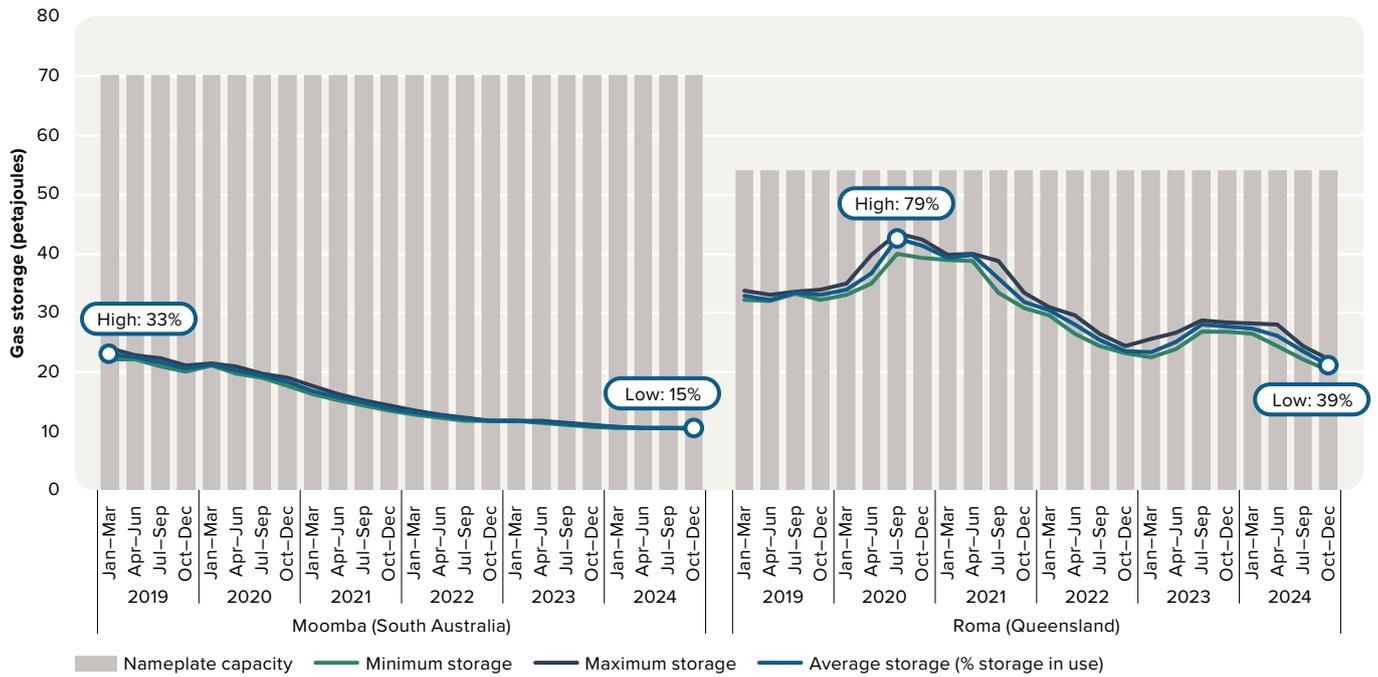
Source: AER analysis of Gas Bulletin Board data.

361 For example, Moomba has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 11 PJ limiting its physical injection capacity as low as 2 TJ per day since June 2022.

362 Different levels of storage can impact the daily supply capability of storage facilities.

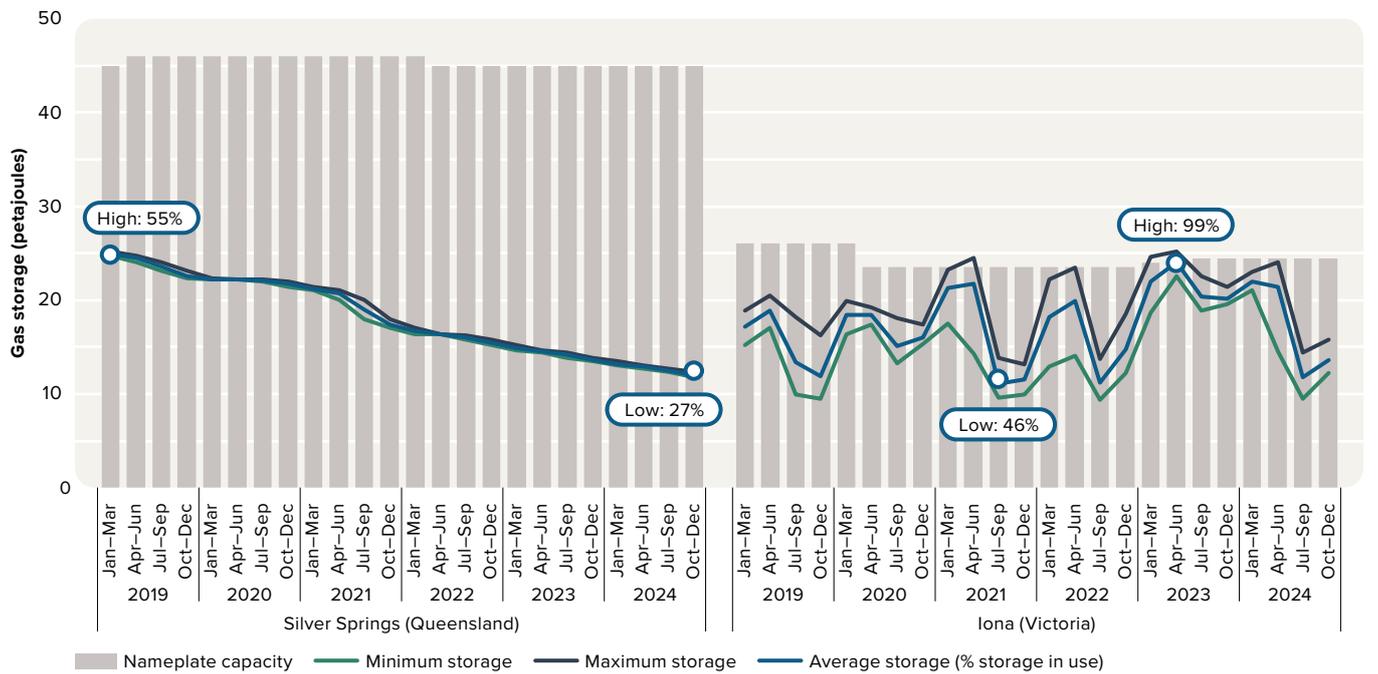
363 In June 2022, Newcastle gas storage reduced all the inventory in its LNG storage tank for the first time since the facility started operating. The facility filled to around one-third of capacity over winter 2023, with lower utilisation during a period of lower than usual demand.

Figure 4.17 Large gas storage facilities – Moomba (South Australia) and Roma (Queensland)



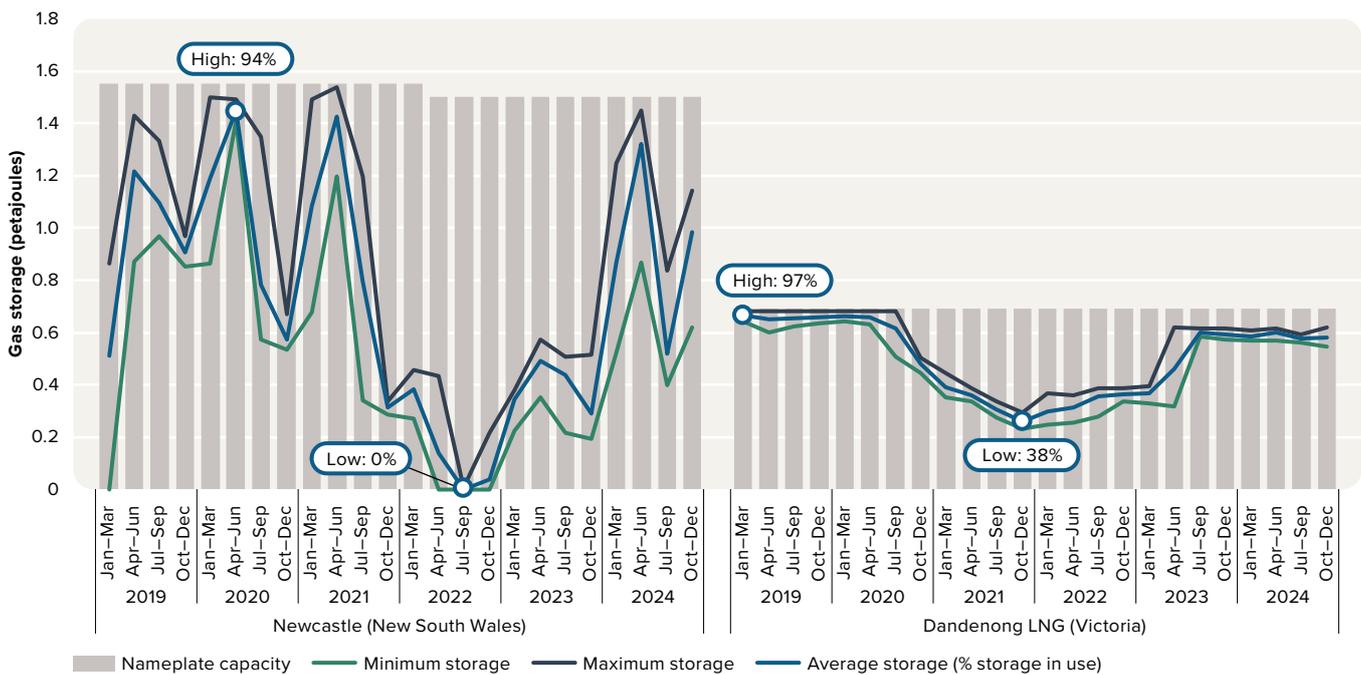
Source: AER analysis of Gas Bulletin Board data.

Figure 4.18 Large gas storage facilities – Silver Springs (Queensland) and Iona (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Figure 4.19 Small LNG gas storage facilities – Newcastle (NSW) and Dandenong (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Unlike other storage facilities, Lochard Energy’s Iona underground gas storage facility (Iona) operates more dynamically, with higher supply and refill rates, and is an integral southern supply source during winter. Since 2018, upgrades to Iona have expanded storage capacity and supply capability in the Victorian gas market.³⁶⁴

Victoria has become increasingly reliant on gas storage inventory from Iona. Recent upgrades have effectively increased Iona’s peak day supply capability to 530 TJ per day. However, supply into the Victorian market is still limited by available pipeline capacity in the transmission system (section 4.8.3).³⁶⁵ Both the facility and transmission system upgrades have resulted in the facility being better able to respond to daily supply requirements. However, much faster depletion of storage levels in recent years has demonstrated an increased risk of reducing storage inventories to critically low levels before the end of the peak winter demand period.

In 2021 and 2022, storage levels fell to their lowest point since reporting commenced (Figure 4.20). The significant drawdown on gas inventories reduced available supply capacity to very low levels by mid-winter in both years. The fast depletion in 2022 led AEMO to issue a notice of a threat to system security, which remained in place until 30 September.³⁶⁶ In contrast to the mild winter conditions that resulted in record high winter storage levels in 2023, similar storage drawdown in 2024 mirrored the high rates recorded over the preceding 2 years. The 2024 notice was revoked on 23 August due to improvement in gas supply and demand trends.³⁶⁷

Preparatory works have commenced on the Heytesbury Underground Gas Storage (HUGS) Project to expand storage capacity through the development of existing depleted gas fields.³⁶⁸ This could potentially increase Iona’s storage capacity by 3.3 PJ by 2026. HUGS and Golden Beach are 2 proposed projects under consideration for development near southern load centres in Victoria (section 4.8.4).

364 Following Lochard’s takeover from EnergyAustralia in 2015, the storage facility’s supply capacity has expanded significantly from 390 TJ per day to 530 TJ per day (17 March 2021), 545 TJ per day (28 January 2022) and 558 TJ per day (1 January 2023). The most recent upgrade increased the facility’s supply capability to 570 TJ per day in early 2024.

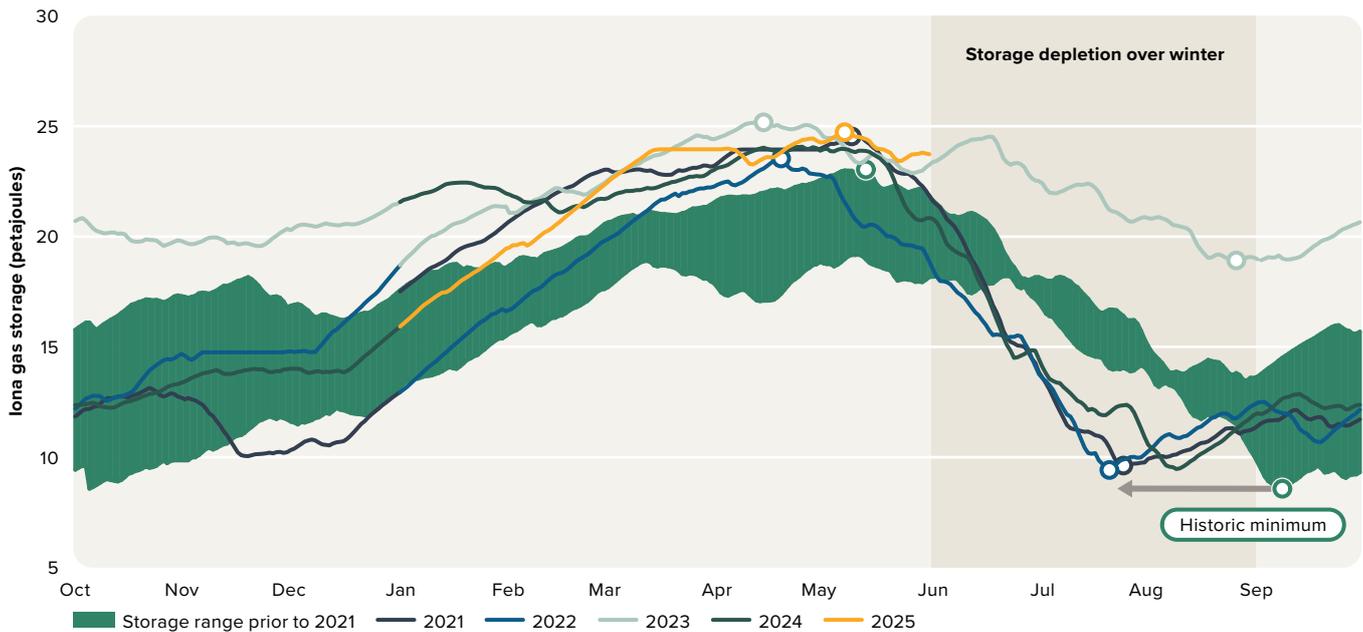
365 A new pipeline segment added to Victoria’s transmission system’s Western Outer Ring Main (WORM) and a second compressor at Winchelsea have been commissioned and are now operational. These upgrades have increased peak supply capacity to Melbourne by 83 TJ per day. AEMO, [2024 Gas Statement of Opportunities](#), March 2024, pp. 44, 55.

366 The AEMO notice highlighted the possibility of reduced injection capability at Iona due to low pressure, increasing the risk of curtailment on peak demand days.

367 AEMO, [Recovery of East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, 23 August 2024.

368 Lochard Energy, [Heytesbury Underground Gas Storage \(HUGS\) Project](#). Pipeline construction initially scheduled to begin in early 2025 has been rescheduled to commence in late 2025 but is not expected to impact the target operation date for the project.

Figure 4.20 Iona underground storage, rapid winter depletion rates since 2021



Source: AER analysis of Gas Bulletin Board data.

In 2022, the much smaller Dandenong LNG storage facility fell to particularly low levels in June following a reduction in participants contracting supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, as well as providing critical system security to avoid pressure drops at the Dandenong city gate. Due to the high potential for the facility to be needed from winter 2023, energy ministers submitted an urgent rule change giving AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023. The facility entered winter 2024 at close to full capacity and has since refilled to full capacity ahead of winter 2025.³⁶⁹ As the buyer and supplier of last resort, AEMO is required to publish a report setting out a range of information on its activities.³⁷⁰

4.5.5 Outlook

Despite improved short-run supply forecasts, the longer-term outlook remains uncertain. While decreases in projected demand for gas generation, residential and commercial demand and industrial gas usage had improved previously reported forecast shortfalls, further improvements now project a surplus in supply for 2025 and 2026 due to higher Queensland production.³⁷¹ However, production is still expected to become increasingly reliant on uncertain and undeveloped sources of supply, with Victoria's primary supply source having already declined due to legacy gas fields in the Gippsland Basin coming to the end of their productive lives. Potential supply shortfalls have been forecast to occur in southern states in the coming years and across the east coast from 2027.³⁷² Recent projections indicate the potential for a small shortfall in southern states over winter 2025.³⁷³ High levels of demand over the peak winter period in 2024 displayed an increased risk of peak day shortfalls, with heavy reliance on Iona gas storage inventories despite significantly higher volumes of gas flowing south.³⁷⁴

369 The facility ended winter 2024 with 11.9 PJ (49% of nameplate capacity) after refilling from 10 August, with an unseasonably warm end to winter putting downwards pressure on market demand, which eased prices.

370 AEMO, [LNG Summary Report](#), Australian Energy Market Operator.

371 ACCC, [Gas inquiry 2017–2030, interim report](#), December 2024, Australian Competition and Consumer Commission, 10 January 2025, p. 18.

372 ACCC, [Gas inquiry 2017–2030, interim report](#), June 2024, Australian Competition and Consumer Commission, July 2024, p. 33.

373 Forecast supply and demand levels do not consider the extended operation of the Eraring coal-fired power station in NSW, which is expected to reduce gas-powered generation requirements from August 2025. ACCC, [Gas inquiry 2017–2030, interim report](#), December 2024, Australian Competition and Consumer Commission, July 2024, p. 22.

374 Storage depletion in 2024 mirrored the rapid rates of drawdown that occurred in 2021 and 2022, yet higher supply output from Longford in previous years reduced the requirement for gas to flow south from Queensland.

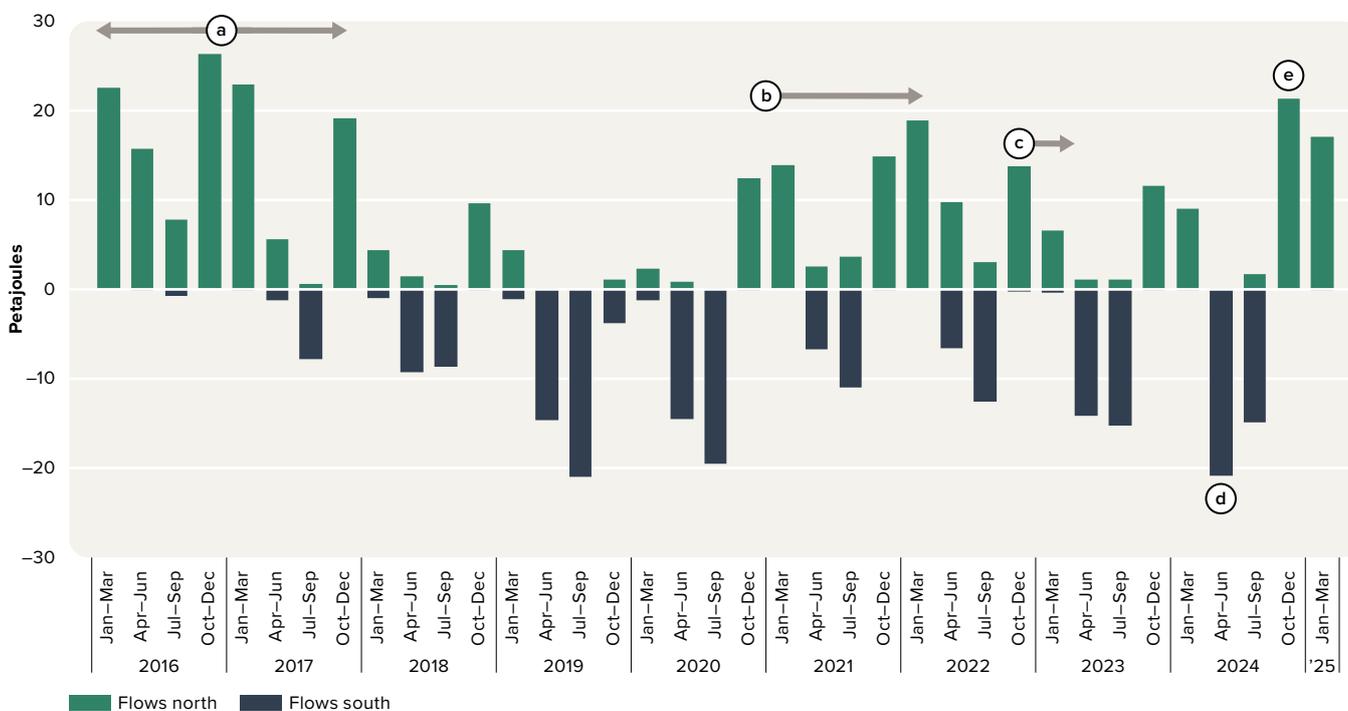
More supply and associated infrastructure is clearly needed, but projects proposed to increase production between 2026 and 2029 have been delayed, reportedly due to long regulatory approval processes and planned maintenance.³⁷⁵ The speculative nature of unsanctioned new domestic supply sources, with a range of barriers including significant investment in infrastructure to bring gas to market, have led to producers finding it increasingly difficult to obtain finance to invest in fossil fuel projects.³⁷⁶

Further factors also contribute to uncertainty surrounding long-term supply conditions, including underperformance of developed resources and the potential for southern production to decline faster than expected. Forecasts also make assumptions about undeveloped resources – uncertain reserves, which are increasingly unreliable, depend on more speculative sources of supply. While some development proposals in eastern Australia have shown promising signs, others face significant regulatory hurdles linked to environmental concerns. Uncertainties also exist around projected demand levels due to factors such as electrification policies across different regions of the east coast.

4.6 Inter-regional gas trade

Domestic gas typically flows south in the Australian winter (to meet heating demand) and north in the Australian summer (the Northern Hemisphere winter) when Asia’s LNG demand peaks (Figure 4.21).

Figure 4.21 North–south gas flows in eastern Australia



Note: Flows on the QSN (Queensland / South Australia / New South Wales) Link segment of the South West Queensland Pipeline (flowing through the Moomba location).

- a 2016 to 2017: increased southern production to meet LNG demand.
- b Late 2020 onwards: record LNG exports continue to rise.
- c Late 2022 onwards: LNG exports reduce closer to 2019 levels.
- d Winter 2024: additional compressors commissioned on the Moomba to Sydney Pipeline and South West Queensland Pipeline in May and June. Expanded capacity facilitates record monthly gas flows south in June (close to 11 PJ).
- e Late 2024: record quarterly LNG export level.

Source: AER analysis of Gas Bulletin Board data.

375 ACCC, [Gas inquiry 2017–2030, interim report](#), June 2024, Australian Competition and Consumer Commission, July 2024, p. 36.

376 ACCC, [Gas inquiry 2017–2030, interim report](#), January 2023, Australian Competition and Consumer Commission, January 2023, p. 125.

Northerly gas flows increased from late 2020 in line with record exports (Figure 4.12) and reduced flows south over winter periods (Figure 4.21, note b). Over the January to March quarter 2024, flows remained predominantly northerly despite reduced production from Longford, with exports for the quarter at the highest quarterly level observed over the previous years. While northern export flows for the April to June quarter continued at high levels, southerly flows increased significantly from May 2024. Demand to bring gas south over the April to June period exceeded capacity to do so, resulting in drawdown from southern storage facilities.³⁷⁷

From June 2024, stage 2 capacity expansions increased shippers' ability to bring gas south on the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP) (section 4.8.3). As a result of this and elevated southern market demand over winter, a record volume of gas flowed south from Queensland over June 2024. Southerly flows reached close to 11 PJ and increased the quarterly quantity shipped south to a level equal to the record reached in 2019 (Figure 4.21, note d).

Over the last quarter of 2024 and into the January to March quarter 2025, high export levels led to the highest level of gas flows north observed since early 2017 (Figure 4.21, note e). In contrast, following the stage 2 expansion of the north to south transmission corridor (section 4.8.3), increases in Day Ahead Auction activity in June on the Moomba to Sydney Pipeline and South West Queensland Pipeline occurred primarily on routes bringing gas south through Moomba.³⁷⁸

Data on trade flows may understate the extent of north–south gas trading. Some gas producers enter swap agreements to deliver gas to southern gas customers without physically shipping it along pipelines. To improve transparency, from 2023 participants' reporting requirements were expanded to encompass a range of bilateral arrangements, including physical swaps (section 4.11.2).

4.6.1 Gas transmission pipelines

Supply conditions depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, pipeline operators are considering a range of upgrades to extend or expand existing infrastructure. For example, APA has announced projects to expand east coast pipeline transportation and storage capabilities following completion of its South West Queensland Pipeline and Moomba to Sydney Pipeline upgrades in 2024 (section 4.8.3).

Wholesale customers buy capacity on transmission pipelines to transport their gas purchases to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (key pipeline routes are shown in Figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

The eastern gas market's transmission system has evolved from a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre, into an integrated network. Many gas pipelines became bidirectional and gas increasingly flows across multiple pipelines to reach its destination. While the Northern Territory was connected to the east coast transmission pipelines in 2019, steadily declining output from the offshore Blacktip gas field led to the interim closure of the Northern Gas Pipeline (section 4.8.5). Access to capacity on key pipelines is important because it provides participants with more options to purchase and move gas between different regions. This ability to move gas gives participants a wider range of options to manage their portfolios across different regions, making it easier to arbitrage the purchase and sale of gas supply without the need to negotiate swap agreements.

Gas production and transmission pipeline assets are owned by separate companies. A gas customer must negotiate with a gas producer to buy gas and separately contract with one or more pipeline businesses to get the gas delivered. This separation adds a layer of complexity to sourcing gas, especially for smaller customers (section 4.6.2).

377 Significant auction capacity was won on auction routes south on the Moomba to Sydney Pipeline reaching almost 2.5 PJ for May 2024.

378 Capacity won on auction on routes bringing gas south accounted for 98% of the record 3.5 PJ of capacity won in June on the MSP, while increases on the SWQP saw over 90% of capacity won on southern routes (1.3 PJ).

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements, such as bidirectional and backhaul shipping, and park and loan services.³⁷⁹

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 5). The publicly listed APA Group is the largest owner of pipeline assets, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Another major pipeline owner with equity in numerous pipelines is Jemena. The pipelines fall under different regulatory arrangements, now classified as either scheme or non-scheme pipelines under recent pipeline reforms (section 5.3 and Table 5.1).³⁸⁰

4.6.2 Transport services and pipeline access

Wholesale gas customers buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas production companies and gas pipelines are separately owned, so a gas customer must negotiate separately with producers to buy gas and with pipeline businesses to have the gas delivered. To reach its destination, gas may need to flow across multiple pipelines with different owners and use compression to facilitate the movement of gas.

Capacity on some pipelines is fully contracted to gas shippers that may not fully use it. Access to transmission pipelines on key north–south transport routes is critical for gas customers. But if many critical pipelines have little or no spare, uncontracted capacity, it makes it difficult to negotiate access. In addition, many pipelines face little competition and may charge monopolistic prices.

Reforms introduced in March 2019 made it easier to access this capacity to pipelines and compression facilities, giving other parties an opportunity to procure capacity through trading platforms or win auctioned quantities.

Capacity can be acquired in 2 ways through AEMO-facilitated markets. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold must be offered at a mandatory Day Ahead Auction. Any shipper can bid at the auction, which is finalised shortly after the cut-off time for nominations one day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero and most settlements have occurred at no cost.³⁸¹ Shippers may also be able to enter into bilateral contracts with third parties and onsell their pipeline capacity outside of the AEMO-facilitated markets.³⁸²

379 Pipelines with bidirectional flows can ship gas in both directions. Backhaul shipping is the 'virtual transport' of gas in a direction opposite to the main flow of gas. Parking gas is a way of temporarily storing gas in the pipeline by injecting more than is to be withdrawn. Loaning gas allows users to inject less gas into the pipeline than is to be withdrawn.

380 Full regulation pipelines have their prices assessed by the AER. Light regulation pipelines do not have their prices assessed by the AER, but parties can seek arbitration to address a dispute. Part 23 pipelines are subject to information disclosure and arbitration provisions. Exempt pipelines are subject to no economic regulation. Chapter 5 outlines the various tiers of regulation.

381 Although participants can win capacity for \$0 per GJ, additional charges and registration fees make the real cost slightly higher.

382 Bilateral trades are submitted to the Gas Bulletin Board and reported on the AEMO website.

Pipeline capacity trading (Day Ahead Auction)

Since the commencement of the Day Ahead Auction in March 2019, over 330 PJ of contracted but un-nominated pipeline capacity has been won across 16 of the 22 auction facilities (Figure 4.22).³⁸³

In late 2024 the AER released a focus report on the Day Ahead Auction, assessing the extent it has supported efficiency and competition in the east coast gas wholesale market.³⁸⁴ Analysis found the Day Ahead Auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low-priced northern gas into southern spot markets, easing price pressure in those markets.³⁸⁵

However, auction activity on some pipelines remains relatively low. Underutilisation may result from higher auction fees, which can discourage smaller players in particular. While most capacity is won at the reserve price of \$0 per GJ, the total cost is higher, because participants need to pay pipeline and storage operators for facility use (which can include both fixed and variable fees). Smaller participants also may be required to provide credit support or collateral to use auction services – in some cases, these costs can be significant. The ability to sell off pipeline capacity through bilateral contracts may also reduce the need for the auctions, especially if a shipper can predict its changes in demand well in advance.

Close to 80% of all capacity procured through the Day Ahead Auction has been won at the reserve price of \$0 per GJ and almost two-thirds of this capacity has been won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP), which facilitate gas flows south and north between spot markets; and the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP), which facilitate flows to several gas-powered generators. Around 20% of total capacity won has been won on the Wallumbilla B compressor (WCFB).³⁸⁶

Trade over the January to March quarter 2024 (39.4 PJ) exceeded the record set over the same period in 2023.³⁸⁷ Of this capacity, around one-third or 13.4 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP). The quantity won for the period on the SWQP set a record at close to 5.5 PJ and the WCFB also set a record of 10.8 PJ.

APA has announced projects to expand east coast pipeline transportation and storage capabilities following completion of its South West Queensland Pipeline and Moomba to Sydney Pipeline upgrades in 2024.

While quantities won on the auction decreased markedly from the first quarter's record levels, quantities won across the April to June quarter 2024 continued to exceed previous record levels for April to June quarters. This trend continued with consecutive quarter on quarter increases, despite a slight reduction in trading over the October to December quarter. Trade over the April to June quarter saw participants using the auction to send gas south, particularly in June when volumes on southern routes reached a record 3.1 PJ on the MSP.

383 There has been no significant activity on the voluntary capacity trading platform since its introduction.

384 AER, [Wholesale gas market focus report: Day Ahead Auction](#), Australian Energy Regulator, 3 October 2024.

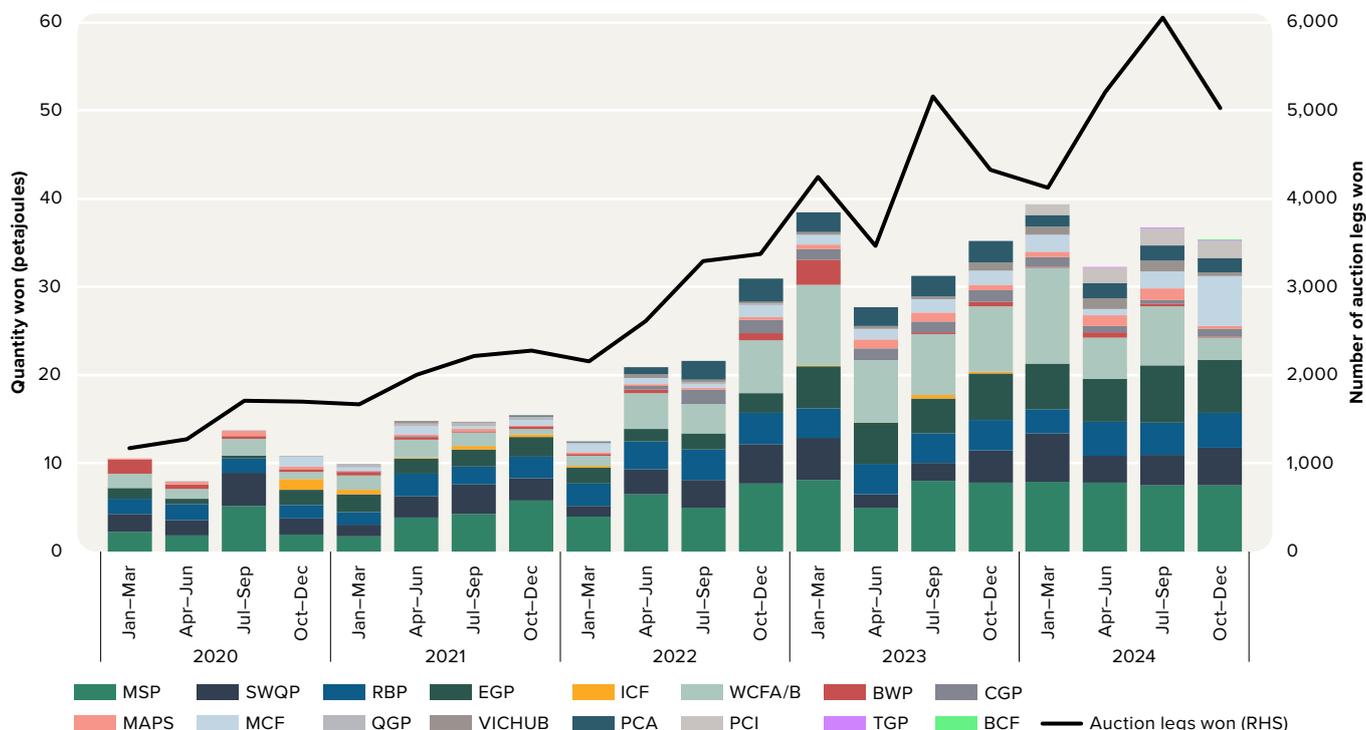
385 The AER's *Pipeline capacity trading – two-year review* found Day Ahead Auction capacity increased liquidity in both upstream and downstream markets. It also reported on how the auction can indirectly ease supply costs for some gas-powered generators in the NEM. AER, [Pipeline capacity trading – two-year review](#), March 2021, Australian Energy Regulator, p. 23.

386 The Wallumbilla B facility can compress gas to a restricted specification, rather than the Australian Standard gas specification of the Wallumbilla A facility, allowing participants with the ability to provide gas at the restricted specification the opportunity to win capacity on the auction.

387 The January to March quarter record set in 2023 was 24% higher than all prior quarters since the auction commenced, and around 3 to 4 times higher than previous January to March quarters.

The July to September 2024 quarter saw a significant change in behaviour compared with the previous quarter – from August, capacity won on the MSP and SWQP increasingly shifted onto routes taking gas north. This trend continued into the following quarter alongside high northerly gas flows.

Figure 4.22 Day Ahead Auction quantities won, by facility



Note: BCF: Ballera Compression Facility; BWP: Berwyndale to Wallumbilla Pipeline; CGP: Carpentaria Gas Pipeline; EGP: Eastern Gas Pipeline; ICF: Iona Compression Facility; MAPS: Moomba to Adelaide Pipeline; MCF: Moomba Compression Facility; MSP: Moomba to Sydney Pipeline; PCA: Port Campbell to Adelaide Pipeline; PCI: Port Campbell to Iona Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; TGP: Tasmania Gas Pipeline; VICHUB: VicHub (eastern Victoria); WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of Day Ahead Auction data.

4.7 Trade in east coast gas markets

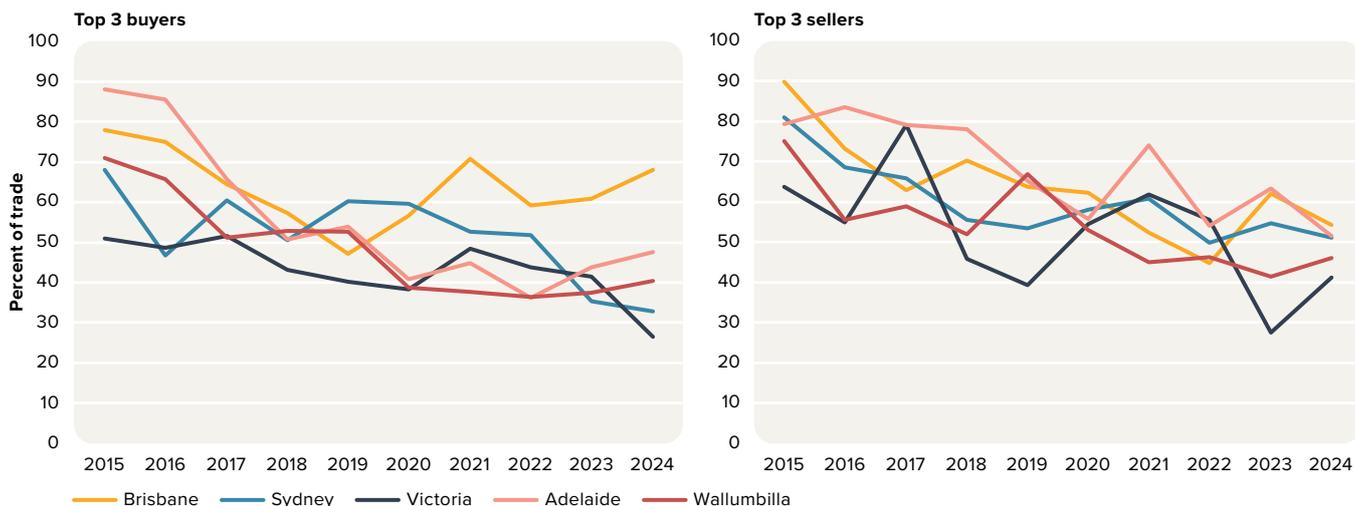
In 2024, gas markets remained liquid with continued high trade levels in the Gas Supply Hub, supported by increasing levels of transportation capacity won through the Day Ahead Auction.

In downstream Short Term Trading Market (STTM) hubs and the Declared Wholesale Gas Market (DWGM), net trade in 2024 reached levels higher than 2023 but lower than in 2022 and 2021, peaking over the winter months when severe cold weather in southern states in May and June led to several high demand days. This aligned with an increase in Day Ahead Auction capacity won on the Moomba to Sydney pipeline and South West Queensland Pipeline to bring gas south (section 4.6.2). The last quarter of 2024 saw record net trade volumes over the October to December quarter, largely driven by increased participation in the Brisbane hub of the STTM with the entry of new participants.

In the Gas Supply Hub, strong trade from the July to September quarter of 2024 set a new quarterly record for traded commodities, reaching 14.4 PJ. At the Day Ahead Auction, the capacity won remained high, with the first quarter of 2024 setting a quarterly record high of 39.4 PJ. Overall, more than 143.6 PJ of auction capacity was won in 2024 across all the auction facilities, 8% higher than in 2023.

The top 3 buyers and sellers at a given point in time generally account for a significant proportion of gas trades across all east coast regions. Trading profiles varied across the markets. The concentration of trades among the top 3 sellers increased in the Victorian DWGM and the Wallumbilla Gas Supply Hub, with decreases recorded in other regions – with Sydney remaining relatively stable (Figure 4.23). In Victoria, the proportion increased by 50%, following 2 years of declines in the level of trade attributed to the top 3 sellers. Among the top 3 buyers, the proportion of gas purchased in 2024 increased in Brisbane by 12%, with marginal increases also observed in Adelaide and the Wallumbilla Gas Supply Hub. In Sydney, the concentration of buyers remained relatively stable while in the Victorian DWGM, the proportion dropped from 42% in 2023 to 27% in 2024.

Figure 4.23 Top 3 buyers and sellers in eastern Australian gas markets



Source: AER analysis of data from the Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market.

4.7.1 Victoria’s Declared Wholesale Gas Market (DWGM)

In 2024, 40 participants traded in the Victorian market. The market’s participants include energy retailers, power generators and other large gas users, and traders. Net traded volumes reached above 30 PJ, increasing by 9% from 2023, with higher levels of mid-year and end-of-year trade. Despite this increase, total trade in Victoria did not reach 2021 and 2022 levels.

The volume of trade in the Victorian gas futures market, which is designed to support the trading and hedging needs of Victorian gas market participants, was down 32% in 2024 compared with the previous year. Ultimately, this quantity still accounts for only a small proportion (less than 5%) of the total volume traded in the spot market.

4.7.2 Gas Supply Hub (GSH)

In 2024, 25 participants traded at the gas supply hubs, 24 of which were active in trading both on-screen and off-screen products. Numerous off-market trades were facilitated by a broker participant. On average, participants executed around 515 trades per month in 2024 – an increase of 22% from 2023. LNG export businesses and gas producers remained the most active participants in 2024, accounting over half of the total volume sold at the Gas Supply Hub. Gentailers were the second most active participant group, accounting for 30% of the volume sold.³⁸⁸

LNG producers are large suppliers of gas into the hubs, although operational issues can limit their participation. In addition, the physical interconnection of LNG facilities allows them to trade easily among themselves. Some market participants have suggested the scale of the LNG producers’ operations may involve greater volumes than the hubs can currently absorb. Other participants trading were large industrial users.

388 Gentailers are participants that own electricity generation assets and retail market portfolios.

In 2024, an increase in shorter-term trades at the Gas Supply Hub persisted, with most deliveries occurring closer to the date of trade (Figure 4.24). This is different to the trend seen in 2021 and 2022, where larger forward trade volumes indicated participants locking in gas supply prior to winter. The lower volumes of forward trade suggest a greater reliance on spot market trade to meet participants' demand levels over winter. Overall trade volumes in 2024 were up 8% compared with 2023, with the proportion of gas traded within 3 days of the delivery date increasing from 48% in 2023 to 57% in 2024.

Wallumbilla hub activity

Wallumbilla is the larger of the 2 primary hubs that make up the Gas Supply Hub. Users of the Wallumbilla hub include the LNG projects, gas-powered generators and trader participants taking advantage of the Day Ahead Auction to arbitrage prices between Wallumbilla and the downstream markets. Trade at the Wallumbilla hub represents the bulk of gas traded through the Gas Supply Hub.

In 2021, off-screen trade at Wallumbilla began to increase with the trend continuing into 2023. However, in 2024 the volume of off-screen trades was marginally lower (3%) than in 2023. Despite this, overall trade volumes at Wallumbilla in 2024 remained higher compared with 2023, due to an uptick in on-screen trades (which increased by 66%), and were particularly high in the January to March quarter 2024.

Gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral, off-market arrangements. In 2024, gas traded through the Wallumbilla hub accounted for around 18% of total gas flows through pipelines in the Wallumbilla bulletin board zone, slightly higher than in the previous year. In total, close to 43 PJ of gas was traded for delivery in 2024.

Moomba hub activity

Trade at Moomba has been slow to develop. The first trade was executed in September 2017 and 141 trades were executed in 2019. Like Wallumbilla, trades at the Moomba location decreased significantly in 2020, declining further in 2021 before a very slight upturn in 2022. However, an upturn in 2023 saw traded quantities reach 3.8 PJ – this was partially driven by an upturn in trade levels on the Moomba to Sydney Pipeline.

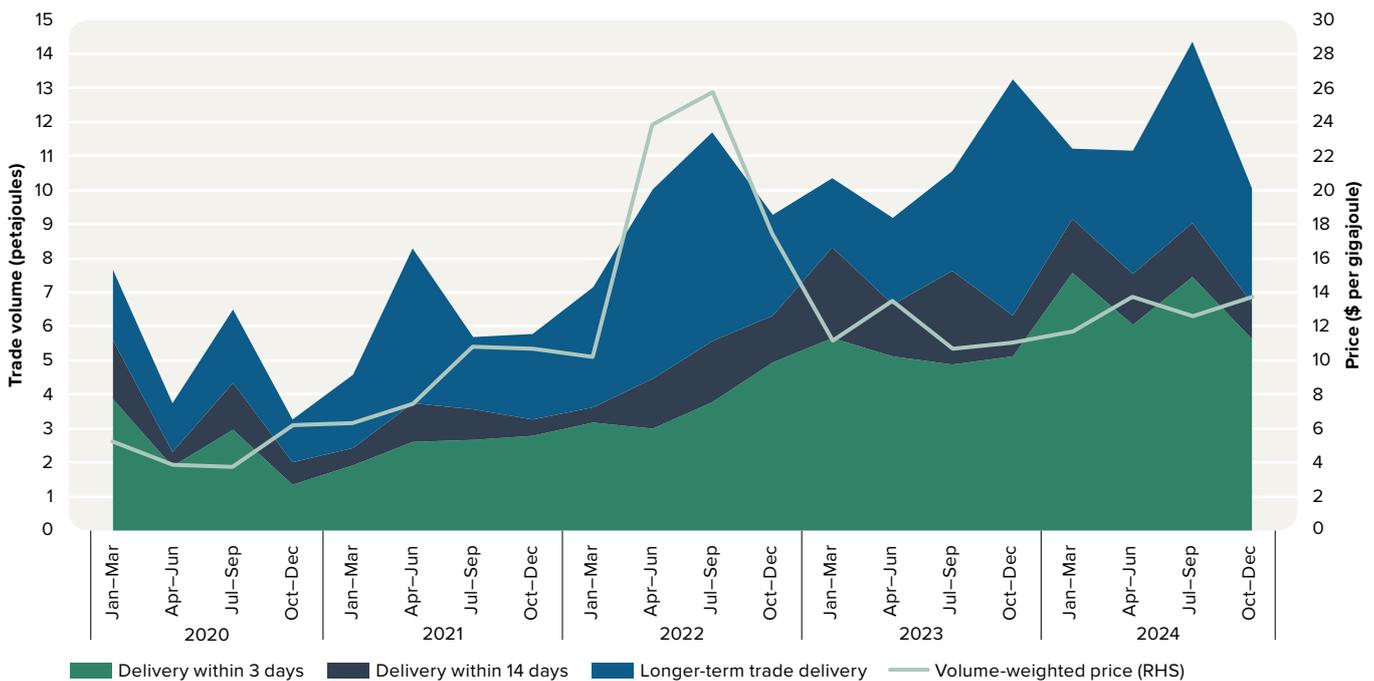
In 2024, 5.8 PJ of gas was traded at Moomba, a 53% increase from 2023 volumes. This was partially due to a drastic increase in trades on the Moomba to Adelaide pipeline, with traded volumes increasing by almost 300%. While still significantly lower trade levels than at Wallumbilla, trades at Moomba represented around 11% to 12% of the total volume of gas traded through the Gas Supply Hub in 2024.

Activity at other locations

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes since becoming available in 2021, reaching a total of 315 TJ and 3,250 TJ respectively by the end of 2024.³⁸⁹

³⁸⁹ Quantities traded from 2021 up to 31 December 2024.

Figure 4.24 Gas supply hub – increase in shorter-term trade



Note: Volume-weighted average price includes all Gas Supply Hub products (excluding capacity trading platform) at all locations, excluding brokered sales.
 Source: AER analysis of Gas Supply Hub data.

4.7.3 Short Term Trading Market (STTM)

In 2024, 40 participants traded in the Sydney STTM, 30 participants traded in the Adelaide market and 22 in the Brisbane market. The participants included energy retailers, power generators, large industrial gas users, gas producers and exporters, and traders. The markets are particularly useful for gas-powered generators because they can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

Shippers deliver gas for sale into the market and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users but in effect trade only their net positions – that is, the difference between their scheduled gas deliveries into and out of the market.

In 2024, quarterly net trade levels accounted for 19.1% to 24.4% of the total scheduled demand in the Sydney market and 16.5% to 29.9% in Brisbane. Brisbane has historically traded below 10% of market demand but has seen an uptick since 2023 as more participants are trading in the spot market. In Adelaide, the proportion of trade reached to near record high levels above 30% in the January to March quarter 2024. In Sydney, which has the highest volume of traded quantities across the STTM hubs, net trade levels across 2024 were up 22% from the previous year (19.7 PJ), with scheduled demand 4% higher (91.7 PJ).

4.8 Market responses to supply risk

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response. AEMO's *Gas Statement of Opportunities* reports have repeatedly highlighted the risk of both short-term and long-term shortfalls in the east coast gas markets, particularly due to the depletion of legacy gas fields in Victoria's offshore Gippsland Basin. However, several projects that could help fill the supply gap have either stalled, been postponed or abandoned.

4.8.1 Gas field development

Numerous projects have been progressing to bring additional supply to the domestic market:

- In Queensland, Senex expanded the Atlas gas fields to increase production from February 2025, with plans for the expansion of the Roma North gas fields having progressed from anticipated to committed status.³⁹⁰ The Roma North Expansion project is currently under construction, with both projects to provide an additional daily processing capacity of 57 TJ and 28.5 TJ, respectively.³⁹¹
- In Victoria, Cooper Energy announced plans to expand its Otway gas hub. After commencing production at the Athena gas plant (formerly Minerva) from mid-December 2021.³⁹² However, a downgrade of reserves at the Thylacine North and Enterprise fields in the Otway Basin has reduced levels of forecast production from these gas fields.³⁹³ The proposed 3-well drilling program targets backfilling declining Otway fields to supply into the existing Athena gas plant with a potential to supply 90 TJ per day of production by 2028.
- Exxon Mobil announced funding of the Kipper Compression Project in the January to March quarter 2022, committing supply from 2024 and additional investment to develop and produce gas from the Kipper and Turrum fields over the following 5 years.³⁹⁴ While additional gas is expected to be processed at Longford from 2026, supply is not expected to increase winter capacity to levels previously supplied by their depleting legacy field production.³⁹⁵ In addition to the Turrum phase 3 project, the Gippsland Basin Joint Venture is considering the Longford Late Life Optimisation project to maximise production from depleting reserves later in the decade.³⁹⁶
- Beach Energy committed to the development of Geographe and Thylacine North and West fields to increase Port Campbell supply, including the drilling of 6 new production wells commencing in February 2021. From mid-May 2023, Otway's actual daily production output increased above 170 TJ, reaching close to 200 TJ across the April to June quarter 2024. Total production output from Otway over the second half of 2024 reached almost 30 PJ, compared with just over 20 PJ across the first half of the year. Beach Energy has also prioritised the ongoing development of its Yolla West field and deferred final investment decision for Trefoil, which is now considered as potential supply.³⁹⁷ The same strategic decision was also made for White Ibis, Bass and Yolla West due to the developments not meeting minimum investment requirements.³⁹⁸
- A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply before providing storage capability (section 4.8.4). In late November 2024, offshore geotechnical investigations commenced to assess the seabed's suitability for supporting a drilling rig and the offshore pipeline route.³⁹⁹
- Beach Energy discovered Artisan 1 as part of the Otway drilling campaign completed in 2022, which has the potential to be developed pending final investment decision.

390 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 48.

391 The Roma North project was originally scheduled to be operational before winter 2025.

392 Athena sources gas from the Otway Basin's Casino, Henry and Netherby fields, some of which was formerly processed at Iona (Casino). The East Coast Supply Project, formerly known as the Otway Phase-3 Development (OP3D) project, was originally targeted to bring additional gas to the market before winter 2025. Wells at the Annie, Juliet and Isabella fields are currently undergoing exploration well drilling.

393 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, pp. 48, 67.

394 ExxonMobil, [Opportunities for the Gippsland Basin and Australia's energy transition](#), 22 March 2022.

395 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2023, p. 63.

396 The project depends on the progression of the Turrum phase 3 project. AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2023, p. 63.

397 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2023, p. 63.

398 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2025, p. 68.

399 AEMO, [2023 Victorian gas planning report](#), Australian Energy Market Operator, March 2025, p. 67.

- Gas supply from Amplitude Energy’s Manta field could be processed at the Orbost Gas Plant as a backfill after Sole field production declines. The project requires an appraisal well to be drilled prior to a development decision.
- Other potential projects include redevelopment of Gippsland’s Longtom field previously processed at the Orbost Gas Plant (Seven Group Holdings Energy) and the Wombat field (Lakes Blue Energy) with an estimated supply capacity of 10 TJ per day.
- In NSW, Santos proposed to develop 850 wells across its 95,000-hectare Narrabri gas project, with the potential to supply up to 200 TJ per day. The staged development was expected to provide up to 55 PJ per year in 2026, all of which had been voluntarily committed to the domestic market and has now been fully committed following a recent ruling. Appeals against the project’s approval have delayed any final investment decision, which now depends on project approvals being cleared.⁴⁰⁰ The recent Native Title Tribunal ruling has cleared the project, allowing the lease of land for the development of gas extraction to assist with southern gas shortfalls. The project is contingent on the planning approval and construction of a 450 km gas pipeline connecting the project to the Moomba to Sydney Pipeline.

Barriers to gas development

In some states and territories, community concerns about environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development.⁴⁰¹ Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- The Victorian Government banned onshore hydraulic fracturing and exploration for and mining of coal seam gas or any onshore petroleum until 30 June 2020.⁴⁰² In March 2021 the government committed the ban on fracking and coal seam gas exploration to the Victorian Constitution.⁴⁰³ Onshore conventional gas exploration recommenced from July 2021. Other projects, such as the development of new or existing storage solutions, also face regulatory hurdles such as environmental assessments being approved by government.
- In 2018 South Australia introduced a 10-year moratorium on fracking in the state’s south-east. It introduced the moratorium by direction and announced its intention to legislate it. However, unconventional gas extraction is allowed in the Cooper and Eromanga basins. South Australia has no restrictions on onshore conventional gas.
- The Tasmanian Government banned fracking for the purpose of extracting hydrocarbon resources (including shale gas and petroleum) until March 2020. This has since been extended to 2025.⁴⁰⁴
- The Northern Territory has made 51% of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory’s shale gas resources.
- NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect ‘biophysical strategic agricultural land’, an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.⁴⁰⁵ The state’s regulations also require community consultation on environmental impact statements and a detailed review process for major projects, as highlighted by the protracted process for Santos’s Narrabri gas project.⁴⁰⁶ Under an agreement reached in early 2020, the NSW and Australian governments set a target of increasing supply to the NSW market by 70 PJ per year.⁴⁰⁷

400 The Australian Government approved the project in November 2020, with the conditions of approval consistent with those set by the NSW Independent Planning Commission. In December 2022, the Native Title Tribunal conditionally decided to allow land leases for the project’s development, which was subsequently delayed by a good faith appeal being lodged. The appeal was overturned in 2024 with an order for the reassessment of environmental concerns.

401 Hydraulic fracturing, also known as fracking, involves injecting a mixture of water, sand and chemicals at high pressure into underground rocks to release trapped pockets of oil or gas. A well is drilled to the depth of the gas or oil-bearing formation, then horizontally through the rock. The fracturing fluid is then injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets that contain oil or gas. The sand carried by the fluid keeps the fractures open once the fluid is depressurised, allowing oil or gas to seep out.

402 Victorian Department of Economic Development, Jobs, Transport and Resources, Onshore gas community information, August 2017.

403 Victorian Government, [Enshrining Victoria’s ban on fracking forever](#), media release, March 2021, accessed 17 July 2025.

404 Tasmanian Department of State Growth, Tasmanian Government policy on hydraulic fracturing (fracking) 2018, accessed 17 July 2025.

405 NSW Department of Planning and Environment, Initiatives overview, July 2018.

406 NSW Department of Planning and Environment, ‘Community views on Narrabri Gas Project to be addressed’, media release, 7 June 2017.

407 Prime Minister of Australia and Premier of New South Wales, ‘NSW energy deal to reduce power prices and emissions’, media release, January 2020.

4.8.2 Liquefied natural gas import terminals

To address future supply concerns, market participants have proposed numerous gas projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units.

- Due to uncertainty around the contracting of gas supply, AIE's terminal at Port Kembla (NSW) was reclassified by AEMO and removed from the list of anticipated projects feeding into forecast supply outlooks. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline (EGP), with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (section 4.8.3). Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023, while physical construction at the LNG Terminal has been completed and commissioning work is underway.⁴⁰⁸
- Venice Energy's Outer Harbour LNG project at Port Adelaide (South Australia) is projected to potentially supply gas by 2027.⁴⁰⁹ However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, which is currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.
- Prior to the completion of the Venice Outer Harbour project, the Adelaide Energy Bridge has been reported to act as an interim supply source, making gas supply of up to 150 TJ per day (50 PJ per year) available to South Australia before the end of 2025 until the end of 2028.
- Viva Energy's Geelong (Victoria) Gas Terminal project is forecast to supply up to 140 PJ per year, have a capacity of 620 TJ per day and potentially be operational from 2028.⁴¹⁰
- Vopak's import terminal in Port Phillip Bay (Victoria) is planned to have a supply capacity of up to 778 TJ per day, supply around 270 PJ per year and be operational from 2028.
- EPIK ceased development of a Newcastle import terminal in early 2023 due to the project being economically unfeasible.⁴¹¹

4.8.3 Transportation capacity expansion

To assist with reducing existing gas supply transportation constraints, pipeline expansions have been progressing to bring more gas south from Queensland, bring more gas from western Victoria into Melbourne, and provide upcoming import supply with the ability to provide gas to NSW and Victoria.

APA pipeline expansions

South West Queensland and Moomba to Sydney pipelines project

APA has been expanding the pipeline corridor through Queensland into NSW by adding additional compression on the South West Queensland Pipeline (SWQP)⁴¹² and the Moomba to Sydney Pipeline (MSP).⁴¹³ The expansion enables more gas flow on pipelines where capacity has been fully or close to fully contracted.⁴¹⁴

408 Squadron Energy, [Port Kembla Energy Terminal](#), accessed 13 May 2025. The forecast supply capacity of 500 TJ per day is projected to be available from 2026 following physical mechanical completion. AEMO, 2024 [Victorian gas planning report](#), Australian Energy Market Operator, March 2024, p. 64.

409 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 65.

410 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 65.

411 AEMO, [Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2023, p. 65; Mandurah Mail, [Gas market volatility kills off \\$590m gas terminal](#), 3 February 2023.

412 The SWQP connects to the Northern Territory through the Carpentaria Gas Pipeline and is a gateway between large northern gas fields in Queensland (including the 3 Gladstone LNG projects) and southern regions with highly seasonal demand.

413 The MSP connects the Moomba hub in South Australia to southern markets in Sydney/ACT and Victoria (through Young and the Victoria/New South Wales Interconnector). Seasonal (non-peak) capacity on the MSP can be limited by up to 50% due to annual maintenance, while southern haul capacity on the VNI lateral can be limited by dynamic interactions between Young, Sydney and GPG requirements at Uranquinty.

414 ACCC, [Gas inquiry 2017–2025, interim report](#), Australian Competition and Consumer Commission, February 2022, p. 15.

Stage 1 of the expansion was completed by June 2023, increasing transportation capacity by 49 TJ on the SWQP (to 453 TJ per day) and by 30 TJ on the MSP (to 475 TJ per day).⁴¹⁵ Further stage 2 expansions on the pipelines added 2 more additional compressors, with commissioning completed by June 2024, increasing transportation capacity by 59 TJ on the SWQP (to 512 TJ per day) and by 90 TJ on the MSP (to 565 TJ per day). These were the first 2 of 4 initially proposed stages, with a recently announced fifth stage to add flexibility to stages 3 and 4 and upgrade capacity in the Victorian Transmission System (VTS).

Further APA pipeline expansions

In addition to the Kurri Kurri Lateral Pipeline (KKLP) project, other projects announced by APA in a 5-year East Coast Gas Grid expansion plan are projected to deliver a 24% increase in north-to-south gas transportation capacity for delivery from Young (NSW) to southern market demand centres in NSW and Victoria.⁴¹⁶ These would supplement existing expansions of the north–south pipeline corridor, which took place in 2023 and 2024, and added around 25% of additional transportation capacity into southern regions.⁴¹⁷

Committed projects to increase north-to-south transportation capacity in 2025 and 2026 have reached final investment decision, including the Moomba to Sydney Ethane Pipeline (MSEP) conversion project and the Moomba to Sydney Pipeline (MSP) off-peak expansion project.

- The MSEP conversion project is targeted for completion in 2025 and is projected to provide an additional 20 TJ per day of supply capacity from Moomba to Victoria, or 25 TJ per day to Sydney, through conversion of the existing pipeline to natural gas.⁴¹⁸
- The MSP off-peak capacity expansion project will deliver 2 pressure regulation skids to increase capacity in summer months during pipeline maintenance periods, with new capacity expected to come online in summer 2025 and 2026. This would raise summer capacity to 80 to 120 TJ per day to support gas storage refill at Iona.

Other medium-term projects being progressed include the Bulloo Interlink (stage 3) and Riverina storage pipeline (stage 4).

- The stage 3 expansion is expected to increase transportation capacity from northern basins to southern markets by 24%, including the proposed delivery of a new 380 km pipeline (the Bulloo Interlink) connecting the South West Queensland Pipeline (SWQP) to the MSP, and 2 new compressors between Moomba and Young, and Young and Culcairn.⁴¹⁹ Stage 3 compression upgrades have been split into 2 phases:
 - Stage 3a consists of an additional compressor on the MSP between Moomba and Young and will increase the nominal capacity of the MSP by 34 TJ per day to 599 TJ per day.
 - Stage 3b consists of an additional compressor between Young and Culcairn to provide a capacity increase of 41 TJ per day to Culcairn and a further 5 TJ per day for the mainline MSP.
- The stage 4 expansion aims to deliver additional storage and delivery capacity to support projected requirements for peak gas-powered generation (Riverina storage pipeline) with new compression and pipeline infrastructure. If progressed, stage 4 would add new storage capacity in winter 2028 and 2029 (section 4.8.4).
- The stage 5 expansion has the potential to expand the MSP and VTS systems to 350 TJ per day from Young (NSW) to Wollert (Victoria) through the addition of new compressors, reconfiguration works and new metering and pressure regulation infrastructure.

415 Stage 1 of the expansion includes an additional compressor on the SWQP and an additional compressor between Moomba and Young on the MSP.

416 APA Group, [APA's East Coast Gas Expansion Plan](#), 24 February 2025.

417 South West Queensland and Moomba to Sydney pipelines project stage 1 and stage 2 expansions.

418 The incremental capacity increase would raise the total southbound capacity on the MSP from 565 TJ per day to 590 TJ per day.

419 The project would progressively increase MSP capacity from 590 TJ per day to 700 TJ per day. SWQP capacity would increase from 512 TJ per day to 605 TJ per day and capacity between Young and Melbourne would increase from 190 TJ per day to 229 TJ per day.

South West Pipeline, Western Outer Ring Main (WORM) project

The South West Pipeline (SWP) is a bidirectional facility that primarily transports gas from Port Campbell supply (gas from the Otway Basin and Iona underground storage) into Melbourne. The pipeline also supports refilling the Iona reservoir and transports gas west, fuelling the Mortlake power station and South Australia (through the SEAGas pipeline) during periods of lower Victorian demand.⁴²⁰

In 2024, APA upgraded the Victorian Transmission System by building a 51 km high-pressure transmission pipeline to address a key capacity constraint previously limiting the connection of existing gas supply from the west of the state to demand in the north and east. The WORM pipeline was commissioned in February 2024, increasing capacity on the South West Pipeline from 447 TJ per day to 506 TJ per day, facilitated by the addition of a second compressor station at Winchelsea.⁴²¹ The transportation of gas was also assisted by the upgrade of the existing compressor station at Wollert.

While capacity on the SWP has increased, supply from the Iona underground storage facility remains constrained below the facility's maximum supply capacity.

Further proposed expansions are not yet committed because they are subject to approval under APA's Access Arrangement. However, they have been projected to increase supply capacity from Port Campbell to between 528 TJ and 570 TJ per day through pipeline augmentation (compression or looping) and up to 670 TJ per day with additional looping and/or compression.⁴²²

Eastern Gas Pipeline expansion project

The Eastern Gas Pipeline (EGP) is a unidirectional pipeline that transports gas from the Gippsland Basin (Victoria) into Sydney. In 2021 Jemena and AIE signed a project development agreement to connect the PKET import terminal (section 4.8.2) at Kembla Grange. If the project is developed, Jemena plans to modify the pipeline to allow for bidirectional flows, with an initial ability to supply 200 TJ into Victoria and up to 440 TJ towards Sydney per day.⁴²³

4.8.4 Storage expansion

AEMO has highlighted that new storage developments are required to address southern gas supply risks after 2034.⁴²⁴ These developments will be required in conjunction with other supply solutions such as pipeline and production expansions to provide more gas to southern markets over winter. Storage solutions provide increased supply flexibility during peak times, having the capability to rapidly ramp up and down, and the potential to relieve existing bottlenecks in network capacity.

Toward the end of the 2030s, all options assessed in AEMO's *Gas Statement of Opportunities* report will require about 500 to 550 TJ per day of additional injection capacity from southern storages. To put this in perspective, 2 current uncertain projects, Golden Beach and the HUGS Phase 2 project, can provide up to 525 TJ per day in total.

Iona underground gas storage – HUGS

Lochard Energy upgraded its underground storage facility to increase supply capabilities to 570 TJ per day, with a recently commissioned South West Pipeline (SWP) expansion – the WORM pipeline upgrade – increasing transportation capacity into Melbourne to 530 TJ per day (section 4.8.3).

Further upgrades after the development of the Heytesbury Underground Gas Storage (HUGS) project have been proposed to add additional pipeline assets and additional storage capacity of 1.8 PJ to 3.5 PJ, increasing supply capacity by up to 45 TJ per day from 2027.⁴²⁵

420 Limited capacity on the SWP restricts supply being provided from Port Campbell in Victoria's west.

421 The capacity for flow from Melbourne to Port Campbell is maximised on days of low demand, with the current maximum at 350 TJ per day, having risen by 154 TJ per day following the completion of WORM. AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 60.

422 AEMO, [2022 Victorian gas planning report](#), Australian Energy Market Operator, March 2022, p. 14.

423 Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023. The EGP could also be upgraded to flow 325 TJ per day to Victoria.

424 AEMO, [2025 Gas Statement of Opportunities](#), March 2025, p. 90.

425 Construction of a new wellsite at Mylor, Fenton Creek and Tregony (MFCT) gas fields Lochard Energy, [Our HUGS Project](#), April 2022, accessed May 2025.

An increasing reliance on Iona following recent capacity expansions has enabled a more rapid drawdown rate of storage inventory levels. Due to low pressure levels, when Iona's storage inventory falls below 6 PJ withdrawal capability also decreases, potentially reducing to half of the facility's usual supply capacity. The Iona gas storage facility will continue to play a critical role in meeting southern gas demand requirements in winter due to declining output from Longford's legacy gas fields diminishing the supply capabilities at Victoria's largest supply source.

Golden Beach project

A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply to assist with peak day demand in Victoria before operating as an underground storage facility.

The facility is forecast to supply up to 35 PJ over 2 years from mid-2026 (delayed from 2025), with an initial delivery capacity of up to 125 TJ per day for winter 2026.⁴²⁶

Kurri Kurri Lateral Pipeline (KKLP) project

APA Group's KKLP project is a gas transmission and shallow storage facility under construction near Newcastle. It is designed to provide 62 TJ of daily supply capacity and 72 TJ of storage capacity for the new Hunter Power Station in NSW.⁴²⁷ The facility will also connect into the Sydney Short Term Trading Market and is scheduled for completion in early 2025.

Riverina storage pipeline

A recently announced plan to build a new pipeline in NSW could add around 200 TJ of storage capacity by 2028, with a potential expansion projected to increase storage to around 500 TJ by 2029. The storage expansion is part of a 5-stage project to increase supply capacity from Queensland to southern regions (section 4.8.3).

4.8.5 Northern Territory gas

From 2019, Jemena's Northern Gas Pipeline connected the east coast gas pipeline transmission system to supply in the Northern Territory. However, production issues at the offshore Blacktip gas field have led to the closure of the Northern Gas Pipeline.

Since the pipeline commenced operation, it has delivered more than 80 PJ of gas to the east coast. Initial supply across 2020 and 2021 saw pipeline deliveries average around 55 TJ per day before a decline from 2022.⁴²⁸ Reduced flows on the pipeline from 2022 have mirrored production declines at the Yelcherr gas plant, the largest supply source in the Northern Territory sourcing gas from the offshore Blacktip gas field (Figure 4.25). Short-term production output at the Yelcherr gas plant increased above 40 TJ from late March 2025 following a ramp down close to zero from mid-December. However, this remains below initial daily production levels above 80 TJ reported from mid-2019.

Reduced supply from Blacktip led to average flows decreasing to just over 30 TJ per day over the first half of 2022 before production issues resulted in flows ceasing from October to mid-December 2022.⁴²⁹ Subsequent flows averaged below 20 TJ per day, fluctuating up to a high of just over 50 TJ before the pipeline's closure from late February 2024. As a result, this has contributed to reduced supply and increased demand in the east coast markets, with supply on the Carpentaria Pipeline now requiring gas to be sourced from east coast production sources.

426 AEMO, [2022 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2024, p. 63.

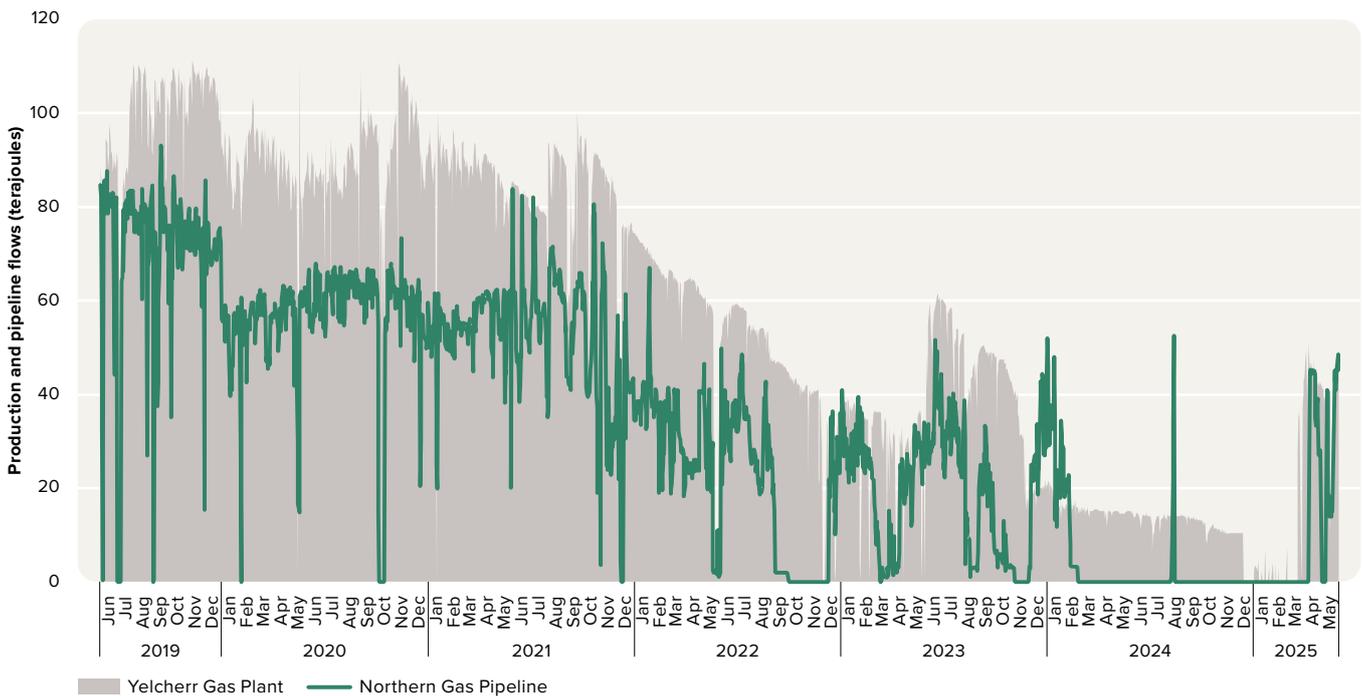
427 Construction of the KKLP project commenced in October 2023. APA, [Kurri Kurri Lateral Pipeline project](#), accessed 12 May 2025.

428 With the prospect of other potential gas sources being brought online in the Northern Territory, Jemena had planned to connect Beetaloo Basin supply to the Queensland's Wallumbilla gas supply hub and increase capacity on the pipeline from its nameplate 90 TJ per day up to 200 TJ per day by 2025.

429 The low pressure in the pipeline forced Jemena to temporarily shut down the pipeline due to safety concerns, requiring Mount Isa to be supplied from east coast production sources.

The Northern Territory presently relies on alternative and interim gas arrangements, including with Darwin LNG exporters.⁴³⁰ While the Carpentaria gas field has progressed from uncertain to anticipated, projected production levels would not provide sufficient supply to meet increasing industrial demand and the Northern Territory’s ongoing reliance on gas-powered generation.⁴³¹ These factors contribute to a heightened risk of supply shortfalls in the event of production outages and high gas-powered generation requirements, particularly if they coincide with peak winter demand in the southern markets that are increasingly reliant on Queensland gas supply. With inadequate local supply and uncertainty around production levels from the Yelcherr gas plant, the Northern Gas Pipeline was reconfigured to flow gas into the Northern Territory.⁴³² While this provides a backup solution to address forecast supply gaps in the Northern Territory, it also raises the risk of providing Queensland supply to southern markets when supply and demand conditions tighten over winter.

Figure 4.25 Northern Gas Pipeline flows and Yelcherr production decline



Source: AER analysis of Gas Bulletin Board data.

430 AEMC, [NT Emergency Gas Supply Arrangements](#), Australian Energy Market Commission, 15 August 2019.

431 The Carpentaria gas field is expected to produce 10 TJ per day from 2026, increasing to 25 TJ per day (9 PJ per year) from 2027. AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 12.

432 The Northern Gas Pipeline reverse capability project was completed in August 2024.

4.8.6 Demand response

Volatile markets and the expiry of legacy gas supply agreements are prompting commercial and industrial (C&I) customers to take a more active role in gas procurement. Some customers have become direct market participants by engaging in collective bargaining agreements.

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, using brokers to secure supply agreements, participating in gas markets and investing in new LNG import facilities.⁴³³ Some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments.

In addition, some C&I users are considering alternatives to gas, such as renewable energy, as longer-term options.⁴³⁴ The suitability of options such as electrification or switching to green hydrogen, biomethane or other biofuels is set out in more detail in the *Future Gas Strategy Analytical Report*.⁴³⁵

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response.

In the more immediate term, demand response has a key role in managing peak day shortfalls. Although a formal demand response mechanism is not yet in place in wholesale gas markets, the Energy and Climate Change Ministerial Council has requested the Australian Energy Market Commission (AEMC) introduce an administered demand response mechanism as part of a broader supplier of last resort mechanism (section 4.10.4). A study by ACIL Allen of suitability of C&I users to supply demand response indicates that up to 22 TJ per day could potentially be used to absorb shortfalls with 6 hours or less notice.⁴³⁶

Governments have also started enacting policies to reduce residential gas demand. The ACT Government initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023.⁴³⁷

Victoria's Gas Substitution Roadmap and Energy Upgrades program identified electrification as the best solution to achieve a short-term reduction to gas consumption levels for residential consumers.⁴³⁸ The roadmap offers options and support for Victorian residential and small commercial consumers who are interested in switching from gas to solar or electricity.

Since 1 January 2024, all new homes in Victoria requiring a planning permit are required to be all-electric, with new homes and residential subdivisions no longer able to connect to the gas network.

433 ACCC, [Gas inquiry 2017–2025, interim report](#), January 2021, Australian Competition and Consumer Commission, February 2021, pp. 73–74.

434 ACCC, [Gas inquiry 2017–2025, interim report](#), January 2020, Australian Competition and Consumer Commission, February 2020, p. 74.

435 DISR, [Future Gas Strategy Analytical Report](#), Department of Industry, Science and Resources, 9 May 2024.

436 AEMC, [ECGS Supplier of Last Resort Mechanism](#), Australian Energy Market Commission, July 2024, p. 82. 22 TJ per day is calculated as 28% of 82 TJ per day, based on data obtained as part of the demand response study.

437 ACT Government, [ACT reaches milestone preventing new fossil fuel gas connections](#), media release, 8 June 2023.

438 AEMO, [2025 Gas Statement of Opportunities](#), Australian Energy Market Operator, March 2025, p. 5.

4.9 Compliance and enforcement activities

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

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

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

For 2023–24, the AER's compliance and enforcement priority relating to gas markets was to clarify obligations and monitor compliance with reporting requirements under the new Gas Market Transparency Measures.

4.9.1 Compliance with Gas Market Transparency Measures

New gas market transparency reforms were legislated in late 2022, following the passage into law of the National Gas Amendment (Market Transparency) Rule 2022. These reforms promote transparency in east coast gas markets through enhanced and expanded reporting of traded gas volumes and prices and the provision of information on overall gas supply adequacy to the Gas Bulletin Board and to AEMO's *Gas Statement of Opportunities*.

New participant reporting to the Gas Bulletin Board commenced on 15 March 2023. The AER has focused on the following activities:

- Continued to work with AEMO and market participants recognising the enhanced compliance risks associated with entities that are reporting for the first time, engaging with individual participants and communicating our compliance expectations more broadly through industry forums and AER publications.⁴³⁹
- Monitored the behaviour of service providers, viewing them as a critical tool to inform our power to initiate form of regulation reviews to ensure that the appropriate level of regulation is applied to pipelines to promote access. Our findings are published on the AER website in our first *Gas pipeline monitoring and transparency: report on the behaviour and compliance of gas pipeline service providers*.⁴⁴⁰
- Analysed the contracted and uncontracted reserve price assumptions of gas field operators submitted yearly to the AER. These price assumptions coincide with the requirement to provide reserve volume information to AEMO. The findings are published on the AER website in our second wholesale gas reserves price assumptions report for contracted prices and uncontracted gas reserve price assumptions reported to the AER for the 2024 calendar year.⁴⁴¹ Alongside this report, we also released an updated reserve price assumption submission template.⁴⁴²
- Reviewed compliance with requirements under Part 27 of the National Gas Rules pertaining to East Coast system reliability and supply adequacy. This was supported by consultations with AEMO, our analysis of the data reported under Part 27, compliance self-reports and our compliance assessments.
- Published our final *Day Ahead Auction Record Keeping Guideline*, which sets out how facility operators and transportation facility users must record and maintain nomination and renomination data relevant to the AER's monitoring functions.⁴⁴³

439 Previous activities included working with AEMO and participants on short-term transaction reporting and reserves and resources reporting.

440 AER, [Gas pipeline monitoring and transparency report 2025](#), Australian Energy Regulator, 26 March 2025.

441 AER, [Wholesale Gas Reserves Price Assumption Report 2025](#), Australian Energy Regulator, 15 April 2025.

442 AER, [AER Reserves Reporting Template – Gas Transparency Measures](#), Australian Energy Regulator, 2025.

443 AER, [Day Ahead Auction Record Keeping Guideline](#), Australian Energy Regulator, 2 August 2024.

4.9.2 Other compliance and enforcement activities

The AER also carried out the following activities, some of which relate to the AER's 2024–25 Compliance & Enforcement Priority 5 – Monitor and enforce compliance with reporting requirements under the new Gas Market Transparency Measures:

- The AER has undertaken a number of compliance and enforcement activities in relation to the Auction Quantity Limit (AQL) obligations for the Day Ahead Auction (section 4.2.2) which determines how much capacity is available to be won at auction.
 - In April 2025 the Federal Court ordered 4 Jemena subsidiaries (collectively, Jemena) to pay penalties totalling \$5.5 million for breaches of the Gas Rules related to the DAA. During court proceedings, Jemena admitted that between 1 March 2019 and 22 February 2022 it breached rules 649(1) and 653(1)(a) of the Gas Rules by failing to determine AQLs in accordance with the procedures developed by AEMO and the Part 24 information standard. The contravening conduct resulted in incorrect AQLs being provided to AEMO and had the potential to result, in some instances, in auction participants paying above what they otherwise would have paid.⁴⁴⁴
 - In July 2024 a market participant submitted a self-report to the AER, advising that it had underreported AQLs by 4 TJ for 27 days between May and June 2024 and by 9 TJ for one day in July 2024. We conducted an assessment and found that the underreporting of these AQLs contributed to DAA constraints on 3 gas days – 4 June, 5 June, and 14 June – resulting in a total loss of 7,178 GJ of auction capacity and collectively \$27,235.22 in overpayments by 5 shippers. After the review, we met with the participant to communicate the review outcome. The participant reimbursed the affected shippers for their overpayments.
 - Following Shell's failure to submit daily forecasts as required by the Gas Rules, Shell Energy Retail and Powershop, both subsidiaries of Shell Energy Australia (Shell), completed an administrative undertaking that required Shell to submit quarterly demand data comparing forecast and actual demand in the Adelaide, Brisbane and Sydney Short Term Trading Markets between 1 January 2023 and 31 December 2024. This undertaking by Shell further prompted enquiries into the accuracy of daily demand forecasts on the STTM by other market participants due to the revelation that there are trends and patterns in unpredictability and inaccuracies of demand forecasting. As part of the undertaking, Shell entities also volunteered information on its monitoring of demand forecasting accuracy; we are continuing to monitor the accuracy of Shell and other STTM participant forecasts due to their potential impact on market price outcomes.

More detail on the AER's compliance and enforcement work is outlined in the *Annual compliance and enforcement report 2024–25*.

4.10 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand and prolonged price volatility seen in 2022, the Australian Government and some state and territory governments have intervened in the market. This has included measures to increase supply stability, reduce demand and limit price volatility, and provide additional monitoring powers to market bodies.

In 2017, the Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. The inquiry was initially tasked to run until 30 April 2020, with successive governments extending the inquiry to 2025 (in July 2019) and then out to 2030 (in October 2022).⁴⁴⁵

4.10.1 Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism (ADGSM) empowers the Australian Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.⁴⁴⁶ Since 2017, the minister has been able to determine if a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

⁴⁴⁴ AER, [Jemena penalised \\$5.5 million for breaching National Gas Rules](#), 11 April 2025.

⁴⁴⁵ ACCC, [Gas inquiry 2017–2030](#), Australian Competition and Consumer Commission, accessed 10 May 2025.

⁴⁴⁶ Department of Industry, Science and Resources, [Australian Domestic Gas Security Mechanism](#), July 2018.

Following the introduction of this mechanism, Queensland's LNG producers entered agreements with the Australian Government, committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.⁴⁴⁷ They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.⁴⁴⁸ In 2023, following a review by the Australian Government Department of Industry, Science and Resources, the scheme was extended until 2030. The changes made to the ADGSM introduced more flexibility to activate the mechanism to secure domestic supply on a quarterly basis, rather than the yearly timeframe in the previous regulations.⁴⁴⁹

The new reforms came into place on 30 March 2023 with a newly negotiated Heads of Agreement with east coast LNG exporters in place until 1 January 2026. To prevent a gas supply shortfall, an additional 157 PJ of gas was committed to the east coast market in 2023. The Australian Government has not yet activated the ADGSM.

On 30 June 2025, the Department of Climate Change, Energy, the Environment and Water opened a consultation to carry out a combined review of the Australian Domestic Gas Security Mechanism (ADGSM), Gas Market Code (section 4.10.5) and the Heads of Agreement with east coast liquified natural gas exporters. The review is being carried out to examine the effectiveness of the existing mechanisms and identify possible improvements, while also considering long-term policy settings and reforms for Australia's gas markets to support investment and energy security.

4.10.2 Gas Supply Guarantee

The gas industry developed the Gas Supply Guarantee as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM. The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023, with a review recommending a further extension to March 2026.⁴⁵⁰ The Gas Supply Guarantee has since been replaced by AEMO's new reliability and supply adequacy functions and powers under the National Gas Law and National Gas Rules (NGR), which came into effect in May 2023.⁴⁵¹

AEMO triggered the Gas Supply Guarantee for the first time on 1 June 2022.⁴⁵² Following activation of the mechanism, gas producers in Queensland diverted gas into the domestic market and AEMO subsequently deactivated the mechanism the next day. AEMO reactivated the mechanism from 19 July 2022 following notification of a threat to system security in Victoria due to insufficient storage, after directing 2 generators to cease taking gas from the Victorian market until 30 September 2022. The Gas Supply Guarantee and threat to system security remained in effect until sufficient supply was available.⁴⁵³

In March 2024, AEMO issued a threat to system security notice in response to the Queensland Gas Pipeline (QGP) fire, and the resulting isolation of a section of the QGP between the Rolleston Compressor Station and Oombabeer due to a rupture of the pipeline. Prior to revocation of the notice in December 2024, AEMO made directions to:⁴⁵⁴

- facilitate gas supply into the QGP
- curtail supply to relevant entities
- maintain supply to end users, necessary to mitigate the consequence of inadequate supply to as low as reasonably practicable.

447 Department of Industry, Science and Resources, Securing Australian domestic gas supply, accessed 10 May 2025.

448 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.

449 The Hon Madeline King MP, [Reforms ensure domestic gas supply, protect long-term contracts](#), Minister for Resources and Minister for Northern Australia, media release, 30 March 2023.

450 AEMO, [Gas supply guarantee guidelines consultation final determination](#), Australian Energy Market Operator, 25 March 2020.

451 ACCC, [Gas inquiry 2017–2030, December 2023](#), Australian Competition and Consumer Commission, December 2023, p. 105, footnote 128.

452 AEMO, Gas Supply Guarantee, Australian Energy Market Operator, accessed 28 May 2021.

453 AEMO, [AEMO takes further steps to manage tight gas supplies](#), Australian Energy Market Operator, 19 July 2022.

454 AEMO, [East Coast Gas System – Queensland Gas Pipeline event, Final Post-Intervention Report](#), Australian Energy Market Operator, December 2024.

Similarly, in June 2024, AEMO issued a threat to system security notice (section 4.3.3) anticipating that the supply of gas to the east coast market would be inadequate to reach demand.⁴⁵⁵ This notice was ultimately revoked in August 2024 without exercise of directions, following market responses to the notice.⁴⁵⁶

4.10.3 Better integration of gas into the Integrated System Plan

In recognition of the uncertainty surrounding future demand for gas, governments have taken actions to better integrate gas assumptions into the Integrated System Plan (ISP). On 19 December 2024, the AEMC released its final determination on *Better integration of gas and consumer sentiment into the ISP*.⁴⁵⁷

The rule change sets out several areas of specific gas analysis that significantly influence development of the electricity system. These include costs associated with gas infrastructure investments and the likelihood or commercial feasibility of GPG in the ISP, and availability of gas to service GPG in the quantity or price anticipated. The rule change:

- requires the AEMO to include gas development projections in the ISP to provide rigour and clarity around the gas analysis that informs the ISP
- allows AEMO to access gas information it collects under the NGR and use it as an input for analysis in the ISP
- amends the NGR to ensure confidentiality protections for the gas information is maintained
- requires AEMO to develop projections about the future utilisation of gas infrastructure and collated pipeline closures or conversion dates.

4.10.4 Additional powers for AEMO to support reliability and supply adequacy

In March and April 2025, the AEMC initiated consultation on a further set of significant rule change proposals outlining longer-term solutions to manage threats to the east coast gas market. These include:

- a reliability standard to apply to east coast gas supply, which would be used to assess the sufficiency of the supply of covered gas and the capacity of relevant infrastructure, and would be based on a value of gas customer reliability to be determined by the AER and similar to the AER's role in setting the value of customer reliability for electricity⁴⁵⁸
- a 'notice of closure for gas infrastructure' rule change request to extend the medium-term capacity reporting requirements in Part 18 of the NGR to require the reporting of planned closure of supply and delivery infrastructure at least 36 months before closure – it would apply to operators of production, pipeline, compression and storage facility infrastructure that meet the Bulletin Board reporting threshold⁴⁵⁹
- an east coast gas supply projected assessment of system adequacy mechanism, specifically over short-term (7-day) and medium-term (12-month) horizons.⁴⁶⁰

The AEMC has also received an 'ECGS supplier of last resort mechanism' rule change request. This would give AEMO power to establish a storage reserve and/or reserve of any other gas service, such as demand response or gas supply, and to use that reserve in the absence of a response from market participants, as a last resort.⁴⁶¹

455 AEMO, [East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, 19 June 2024.

456 AEMO, [Revocation of East Coast Gas System Risk or Threat Notice](#), Australian Energy Market Operator, 23 August 2024.

457 AEMC, [Better integration of gas and community sentiment into the ISP](#), Australian Energy Market Commission, December 2024.

458 AEMC, [ECGS Reliability standard and associated settings](#), Australian Energy Market Commission, March 2025.

459 AEMC, [ECGS Notice of closure for gas infrastructure](#), Australian Energy Market Commission, 26 June 2025.

460 AEMC, [ECGS Projected assessment of system adequacy](#), Australian Energy Market Commission, April 2025.

461 AEMC, [ECGS Supplier of last resort mechanism](#), Australian Energy Market Commission, July 2024.

4.10.5 Competition and Consumer (Gas Market Emergency Price) Order

On 23 December 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months, effectively introducing a price cap of \$12 per GJ on gas producers and affiliates of gas producers (regulated producers) on the east coast.⁴⁶² Several exemptions to the cap included LNG exports, downstream market trade in the Short Term Trading Market (STTM) and Declared Wholesale Gas Market (DWGM), and retailers that met certain criteria.⁴⁶³

From 11 July 2023, as part of the Energy Price Relief Plan announced in December 2022, the Australian Government implemented a Mandatory Gas Code of Conduct.⁴⁶⁴ The Code aims to ensure that east coast gas users can contract for gas at reasonable prices and on reasonable terms. It also includes a 2-month transitional period to allow companies to adapt to the conduct provisions, record keeping and process standards for commercial negotiations. The key elements of this code include:

- the price cap, initially set at \$12 per GJ, with the first mandated review of the Code by 1 July 2025
- an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing medium-term demand
- 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.

4.10.6 National hydrogen strategy

The Australian Government has identified hydrogen as a potential alternative fuel to natural gas to facilitate emission reductions across energy and industrial sectors. It released its *National Hydrogen Strategy 2024* setting out 4 objectives for the development of a hydrogen industry that benefits Australia's communities and economy, enables Australia's net zero transition and positions Australia as a global hydrogen leader.⁴⁶⁵

AEMO's ISP models a green energy export scenario to examine potential requirements of expanding the existing transmission system and to present different options to replace retiring coal-fired generation assets.

Recently, the Future Gas Strategy has noted low-emission gases – such as biomethane, hydrogen, ammonia and e-methane – have the potential to substantially decarbonise gas supply chains.

4.10.7 State government schemes

State governments are responsible for different elements of gas infrastructure and exploration in Australia – for example, approving new gas exploration licences in their respective jurisdictions.

To encourage stability in the domestic supply of gas, the Queensland Government grants exploration authorities for 'domestic only' exploration tenements. As part of this grants program, it released almost 70,000 km² of land for exploration between 2015 and 2019, of which around 25% was reserved for domestic supply. The Queensland Government released a further 3,000 km² of land in September 2020, with over 15% tagged for domestic supply.⁴⁶⁶ In 2021, the Queensland Government announced it would make 14,100 km² available for oil and gas exploration.⁴⁶⁷ In June and July 2022, the Queensland Exploration Program released prospect tenders for petroleum and gas exploration (8 areas, 14,420 km²) and greenhouse gas storage (14,500 km²).⁴⁶⁸ In May 2024, the Queensland Government announced \$21 million in funding to support exploration in the Bowen Basin.⁴⁶⁹

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

463 The cap also exempted near-term trades on the upstream Gas Supply Hub exchange that occurred within a 3-day window of the delivery date and provided the minister powers to grant additional exemptions outside of the standard exceptions that were delegated to the ACCC. A list of exempted entities is available on the ACCC's [Gas price exemptions register](#). The delegation commenced on 23 December 2022.

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

465 Australian Government, [National Hydrogen Strategy 2024](#), September 2024.

466 Queensland Government, 'Queensland gas exploration ramping up', media release, September 2020.

467 Queensland Government, [2021 Queensland Exploration program](#), November 2021, accessed 28 June 2022.

468 Queensland Government, [Queensland Exploration Program](#), Business Queensland, accessed 25 May 2023.

469 Queensland Government, '[\\$21 million in grants to accelerate energy supply](#)', media release, accessed 9 May 2025.

In January 2020, through a memorandum of understanding with the Australian Government, the NSW Government committed to bringing new gas supplies to the domestic market. It set a target of injecting an additional 70 PJ of gas per year into the NSW market.⁴⁷⁰

In April 2021 the Australian and South Australian governments announced an agreement to invest in energy infrastructure and reduce emissions in South Australia. As part of this, the state set a target to unlock an additional 50 PJ per year by 2023.⁴⁷¹

In April 2022 the Australian and Northern Territory governments signed an energy and emissions reduction agreement to deliver affordable and reliable power and unlock gas supplies to help prevent shortfalls in the market.

4.11 Gas market monitoring reforms

The Energy and Climate Change Ministerial Council (ECMC) agreed to an expedited package of carefully designed measures expanding the AER's gas and electricity market monitoring powers.⁴⁷² This follows the introduction of new laws providing the AER with greater powers to monitor wholesale gas and electricity markets, which was passed into legislation on 23 June 2022.⁴⁷³

The reforms stem from findings by bodies such as the AEMC, the ACCC and the Gas Market Reform Group on shortcomings in the current regulatory framework. The reforms aim to increase transparency in the gas market, improve the Gas Bulletin Board and improve the availability of information on market liquidity, prices and gas reserves.

4.11.1 Enhanced wholesale market monitoring

The National Energy Laws Amendment (Wholesale Market Monitoring) Bill 2023 (Amendment Bill) was proclaimed on 8 May 2024, enhancing the AER's wholesale market monitoring and reporting functions to include wholesale gas markets and electricity and gas contract markets. Access to contracts and related information will provide the AER with visibility of the underlying drivers influencing participant behaviour in gas and electricity markets, allowing for the examination of effective competition and whether wholesale markets are operating efficiently. Improved understanding and insights will allow for the AER's existing suite of reports to be enhanced to provide timely and transparent information to relevant stakeholders throughout the energy transition.

In November 2024, the AER released its final guideline on wholesale market monitoring and reporting, setting out how the AER will approach its wholesale market roles including use of these new market monitoring powers.⁴⁷⁴ Following this, the AER consulted on a set of market monitoring information collection instruments (Orders and Notices).

In response to stakeholder feedback, the AER decided to engage further with stakeholders before finalising these instruments.⁴⁷⁵

In the interim, in June 2025, the AER commenced further consultation on a more targeted gas Notice to collect over the counter contract and risk information in advance of the first gas wholesale market monitoring report to be delivered under this new power in 2026.

470 Department of Climate Change, Energy, the Environment and Water, [Memorandum of understanding – NSW energy package](#), 31 January 2020.

471 Australian Government, [‘Energy and emissions reduction agreement with South Australia’](#), media release, 18 April 2021, accessed 2 July 2025.

472 Department of Climate Change, Energy, the Environment and Water, [Amending the Australian Energy Regulator Wholesale Market Monitoring and Reporting Framework](#), 15 February 2024, accessed 17 July 2025.

473 AER, [AER welcomes new powers to keep watch on wholesale gas markets](#), news release, Australian Energy Regulator, 1 July 2022.

474 AER, [Wholesale market monitoring and reporting guideline – Version 1](#), Australian Energy Regulator, November 2024.

475 AER, [Update on Market Monitoring Information Orders](#), Australian Energy Regulator, 28 May 2025, accessed 2 July 2025.

4.11.2 Gas Bulletin Board reforms

The Gas Bulletin Board is a publicly accessible source of information. Data was published to the Bulletin Board commencing 1 July 2008 and aims to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia.

Market participants can access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations and capacity outlooks. This adds transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must submit daily disaggregated receipt and delivery point data to the Bulletin Board. The data includes information on flows at key supply and demand locations along pipelines.

The AER assesses the quality and accuracy of the data submitted by market participants against an ‘information standard’ to ensure the information presented on the Bulletin Board has integrity.

In June 2022 states adopted the National Gas Amendment (Market Transparency) Rule 2022, which extended reporting to large gas users and LNG processing facilities. These laws give the AER new powers to monitor information on price and volume in the shorter-term bilateral gas contract market, including how gas is exported overseas and how it is traded in Australia. In particular, the AER now monitors subsets of information on the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

In March 2025, AEMO released its biennial review of the Gas Bulletin Board,⁴⁷⁶ in which it reviewed the effectiveness of the Bulletin Board. AEMO found it largely effective and made recommendations on measures to improve the usefulness and effectiveness of reporting on the Gas Bulletin Board.

Price and reserves transparency

Transparency of price and other market information is critical for effective market functioning. The ACCC publishes data on LNG netback prices to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts (section 4.3.1).⁴⁷⁷

Reporting of new information commenced on 15 March 2023, requiring participants to provide information to AEMO through the Gas Bulletin Board. New information published on the Bulletin Board includes reserves and resources reporting, facility developments, LNG Transactions and Short Term Transactions (section 4.3.2).⁴⁷⁸

These reforms were designed to enhance transparency in the eastern and northern Australian gas markets, to address information gaps and asymmetries relating to:

- gas and infrastructure prices
- supply and availability of gas
- gas demand
- infrastructure used to supply gas to end markets.

More information on the introduction of regulatory amendments can be found on [energy.gov.au](https://www.energy.gov.au).⁴⁷⁹

476 AEMO, *Gas Bulletin Board biennial report – Biennial review of the Gas Bulletin Board*, Australian Energy Market Operator, March 2025.

477 ACCC, *Gas inquiry 2017–2030 – LNG netback price series*, Australian Competition and Consumer Commission, accessed 16 July 2025.

478 AEMO, *Reserves Resources Reporting and Facility Developments and LNG and Short Term Transactions*, Australian Energy Market Operator, accessed 16 July 2025.

479 Department of Industry, Science, Energy and Resources, *Regulatory amendments to increase transparency in the gas market*, 19 November 2020.

4.11.3 Future of gas strategy and transition to net zero

With Australia's commitment to net zero by 2050, governments have been consulting on how to shift from natural gas to renewable energy sources throughout the economy. The Australian Government released its Future Gas Strategy in May 2024, which explains the principles the Australian Government will use to guide policymaking about gas to support the transition to net zero. The guiding principles note the importance of gas remaining affordable for Australian users throughout the transition to net zero, and that gas and electricity markets must adapt to remain fit for purpose throughout the energy transformation. The strategy reiterates Australia's commitment to supporting global emissions reductions to reduce the impacts of climate change and reaching net zero emissions by 2050.⁴⁸⁰

480 DISR, [Future Gas Strategy](#), Department of Industry, Science and Resources, May 2024.