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Executive summary

The Australian Energy Regulator (AER) has conducted this review of wholesale gas markets and pipeline service operators under the National Gas Law, which requires us to monitor competition and efficiency in wholesale gas markets and the behaviour of gas pipeline service providers. This 2026 report is the first broad ranging assessment of wholesale gas markets that examines these elements together and provides an assessment of whether there are market features that may be detrimental to effective competition or the efficient functioning of the market.

This report focuses on the performance of markets facilitated by the Australian Energy Market Operator (AEMO), which are primarily used by participants to trade gas in the short term. We have also assessed other aspects of the wholesale gas markets, including the bilateral contract markets for pipelines, storage and financial products. To the extent it is relevant to our assessment, we have also had regard to the market for long term gas supply agreements through which most gas is traded. The report also draws on our earlier focus reports and incorporates the Australian Energy Market Commission's previous reporting on liquidity in the facilitated wholesale gas and pipeline trading markets (Appendix A).

Separately, we regularly monitor the behaviour of gas pipeline service providers under the National Gas Law, focusing on risk arising from pipelines' natural monopoly characteristics. We report to the Energy and Climate Change Ministerial Council on pipeline conduct and must also publish a public version of the report that is not likely to identify a particular service provider. The public version is provided as Appendix B in this 2026 report.

The facilitated gas markets are performing well

There are several upstream and downstream gas markets on the east coast of Australia that are operated by AEMO and collectively referred to as the facilitated gas markets. These are:

- **The downstream wholesale spot markets**, namely the **Victorian Declared Wholesale Gas Market (DWGM)** and the **Short Term Trading Market (STTM)** hubs in Sydney, Adelaide and Brisbane, which provide for short-term gas trading.
- **The upstream Gas Supply Hubs (GSH)** at Wallumbilla, Moomba, Culcairn and Wilton, which are intended to support short-term gas trade.
- **The Day Ahead Auction (DAA)**, which provides a mechanism for spare pipeline capacity and compression services to be made available for short-term trading.

These markets support efficient short-term trading of gas, as well as liquidity and transparency in the broader east coast gas markets. Participants use these markets to source additional gas in response to periods of demand that are higher than expected or higher than covered by contracted volumes, and to balance or optimise their portfolios. While the bulk of trade in east coast gas markets is supplied through long-term bilaterally negotiated contracts for gas and transportation, the facilitated markets play an important role in ensuring gas is efficiently delivered to customers across the east coast.

Given this supporting role, we assessed the facilitated markets' performance in terms of whether they are competitive and delivering efficient short-term trading, liquidity and transparency. On this basis, the facilitated markets are performing well. The markets have grown significantly since inception and appear to be relatively competitive and efficient:

- The structure of the markets is increasingly supportive of competitive outcomes. Concentration is decreasing in several markets and the largest suppliers are infrequently required to meet demand. Barriers to participation appear low for parties with access to gas supply and transportation contracts (see chapter 3).
- Occasional high price events in the downstream spot markets appear to have been driven primarily by supply and demand factors, rather than indicating the exercise of market power (see chapter 4).
- Prices in the downstream spot markets are typically lower than prices for contracted supply, and prices are generally aligned across facilitated markets, suggesting gas is being allocated efficiently to where it is most valued (see chapter 5).
- The facilitated markets show seasonal patterns of trade that suggest they are complementing longer-term contracts in supporting trade over critical winter months (see chapter 6).
- The Day Ahead Auction has supported access to the facilitated markets by making large volumes of short-term pipeline capacity available to participants at low or no cost (see chapter 8).

We also examined the use and role of financial risk management products in managing wholesale gas market and commodity price risk. The use of financial risk management products is not widespread; however, this does not appear to be a material risk or barrier to participation in the facilitated markets. Financial risk products are primarily a complement to bilateral contracting for physical gas supply and can support efficient outcomes for some participants.

Opportunities exist to strengthen liquidity and price transparency

Notwithstanding the encouraging performance of the facilitated markets, there are opportunities for further improvement to support price transparency and encourage further liquidity. In particular:

- the facilitated markets support some price transparency, but liquidity remains a primary constraint to robust and reliable price signals
- financial products on the Australian Securities Exchange (ASX) are thinly traded, which reduces their usefulness in providing a reliable forward price curve
- the GSH provides some transparency on upstream trade, but there is lower liquidity in ‘on-screen’ trades that are more visible to the market and provide real-time information on bids and offers. Liquidity in longer-term products at the GSH also remains low.

Government is currently progressing reforms to harmonise prudential requirements across the facilitated markets, which would allow participants to net their trading positions and could reduce costs and encourage further participation. The Australian Government’s Gas Market Review noted the need to progress these reforms and it highlighted further opportunities aimed at improving efficient operation and access to the facilitated markets.

Underlying supply and demand dynamics have contributed to price outcomes and geopolitical events are a source of price risk

Prices in facilitated markets have stabilised since the unprecedented volatility experienced during market disruptions in 2022. While prices have fallen, they have generally settled at a higher level. A combination of supply and demand dynamics, including those in the broader east coast gas markets, National Electricity Market (NEM) and export gas market have contributed to price outcomes in facilitated markets over the short and long term. These factors also mean that the downstream gas markets are more susceptible to high price events, particularly over winter.

Outcomes in the downstream facilitated markets are closely linked with events in the National Electricity Market

While not the largest source of domestic demand, gas demand for gas-powered generation (GPG) is highly variable and can have a significant impact on downstream spot market outcomes. Gas is an important fuel source for generation in the NEM. GPG is typically higher during periods of high NEM prices. Higher gas demand from GPG participants during these periods can drive up prices in the facilitated gas markets and contribute to price spikes. Market outcomes between electricity and gas are increasingly connected as the changing electricity market generation mix is shifting peak GPG demand from summer to winter months, which aligns with peak residential gas usage. Conversely, entry of batteries into the NEM has and may continue to displace gas generation at times, reducing demand in gas markets.

Gas supply in the east coast gas markets is constrained and production costs have increased

Competitive and efficient gas markets depend on sufficient long-term gas supply being available at competitive prices. Difficulties in accessing sufficient and cost-effective long-term contracted supply are well documented, and the focus of the Australian Government's recent Gas Market Review. The Review made recommendations targeted at improving supply to the domestic market, which includes establishing a domestic gas reservation policy.

Higher production costs across all gas basins on the east coast and declining lower cost southern production have contributed to a general upward shift in prices. A range of potential developments are underway that would increase and diversify capacity in production, but there is uncertainty around the timing of many of these projects.

The emergence of liquified natural gas (LNG) export markets has had a significant impact on the east coast gas market

From 2010 LNG exporters invested in significant new gas production in Queensland to provide gas for export, underpinned by long term foundational contracts. The owners of 3 LNG export facilities now produce most gas on the east coast. Gas produced to support LNG exports is predominantly coal seam gas, which has higher production costs than conventional gas. With southern production in decline domestic users are increasingly reliant on this higher cost uncontracted gas produced from exporter operated fields to support domestic east coast demand.

The launch of the LNG market has also linked domestic gas prices to more volatile international oil and gas markets and means that the domestic market is more susceptible to geopolitical events that impact global gas supplies. The recent conflict in the Middle East has restricted global LNG supply and had a significant impact on global oil and LNG prices. As of late April 2026, prices in downstream domestic markets have remained steady and there is no evidence LNG exporters have increased gas purchases in short term domestic markets. The Iona storage facility is also currently full, which gives confidence for southern supply ahead of winter. However, if high international prices persist and LNG exporter uncontracted gas is required to meet domestic demand, there will be greater risk of high domestic gas prices.

Access to long-term north-south transport is a key risk to competition and efficiency

Gas transmission pipelines have natural monopoly characteristics, and ownership of key pipelines is concentrated among a small number of businesses. While the regulatory framework includes tools to mitigate market power for individual pipelines, portfolio ownership of multiple critical assets can strengthen incentives and ability to exercise market power and can weaken competitive pressure on new investment. This gives rise to two key risks:

- **Pricing and terms risk:** service providers have and may be able to exercise market power by setting prices and/or non-price terms that are less favourable than would exist for equivalent services in a competitive market
- **Investment risk:** transportation investment is vital to accommodate new sources of supply, but limited competitive tension may weaken incentives for timely and efficient investment in new or expanded pipeline capacity.

These risks are heightened as southern production declines. Southern downstream markets are increasingly reliant on a small number of gas transmission pipelines transporting gas south from Queensland. Much of the capacity on key north-south pipelines is already contracted, and for most shippers there are currently limited viable substitutes for long-term pipeline contracts. This makes access to transportation contracting a key risk for southern markets.

We will continue to monitor for evidence of market power by pipeline owners, including trends in prices and key non-price terms and conditions for access to key north to south routes. In particular, we will monitor closely new contracting on key north-south pipelines as contracted capacity becomes available over coming years, and where additional capacity is made available through pipeline expansions.

Southern storage, especially Iona, is critical to meeting winter demand

Southern gas storage plays a critical role in winter when domestic gas demand is highest. As southern production continues to decline, southern markets are increasingly reliant on gas transported from the north; however, key transmission pipelines can become constrained during peak periods. In this context, access to storage in Victoria, particularly the Iona facility is increasingly important. Iona is the only large storage facility located on the southern side of key pipeline constraints and can inject and withdraw gas quickly.

Participants typically refill Iona storage over summer, when demand and prices are often lower, and draw on it over winter to manage higher demand and supply or transport constraints. This provides flexibility to participants and reduces the risk of shortfalls during peak periods. However, Iona storage is heavily contracted and typically reaches full capacity ahead of winter. Additional storage, increased pipeline capacity, or new sources of southern supply would provide more options to meet peak winter demand.

1 Introduction

Key points

- The Australian Energy Regulator (AER) monitors and reports on whether east coast wholesale gas markets are effectively competitive and identifies impediments to competition and efficiency. We also monitor gas pipeline service providers' behaviour and compliance with regulatory obligations.
- This report focuses on the markets administered by Australian Energy Market Operator (AEMO). It also considers related markets and arrangements, financial risk management products, bilateral trading agreements and gas transportation
- This 2026 report consolidates our previous reporting on wholesale market performance and pipelines to provide a more streamlined and integrated view of market dynamics and drivers of market outcomes.
- Our findings draw on a range of data and analysis, including targeted information obtained from market participants through compulsory market monitoring information notices.

This chapter outlines which aspects of the east coast gas market we monitor as well as why and how we monitor.

1.1 Our monitoring and reporting functions under the National Gas Law

Under the National Gas Law (NGL), we are required to regularly and systematically monitor and review the performance, effective competition and efficient functioning of AEMO-administrated wholesale gas markets (the 'facilitated markets'). These include:

- **the downstream wholesale spot markets** – the **Victorian Declared Wholesale Gas Market (DWGM)** and the **Short Term Trading Market (STTM)** hubs in Sydney, Adelaide and Brisbane.
- **the upstream Gas Supply Hubs (GSH)** at Wallumbilla, Moomba, Culcairn and Wilton.
- **the Day Ahead Auction (DAA)**, which provides a mechanism for spare pipeline capacity and compression services to be made available.

The NGL also requires us to monitor and review financial risk management products and bilateral trading agreements, including their effect on facilitated market outcomes.[1]

We must report on market performance at least every 2 years and may advise the Energy and Climate Change Ministerial Council (ECCMC) on market performance and whether legislative or regulatory reform is required.[2]

1 National Gas Law, Section 30AC.

2 National Gas Law, section 30AC(2).

Separately, we regularly monitor the behaviour of gas pipeline service providers[3], focusing on risk arising from pipelines' natural monopoly characteristics. We report to the ECCMC on pipeline conduct at least every 2 years[4] and must also publish a public version of the report that is not likely to identify a particular service provider. The public version is provided as Appendix B in this 2026 report.

This 2026 report provides the first broad-ranging, long-term assessment that brings together our analysis of facilitated markets and pipeline service providers. It also draws on our earlier focus reports and incorporates the Australian Energy Market Commission's (AEMC) previous reporting on liquidity in the facilitated wholesale gas and pipeline trading markets (Appendix A).

A number of reviews, inquiries and policy reforms shape gas market outcomes and provide important context for our monitoring and reporting.

Gas Market Review

The Australian Government Gas Market Review examined the effectiveness of policy instruments introduced in response to concerns around gas supply and prices, including:

- **Gas Market Code** – a mandatory industry code intended to support adequate wholesale gas supply reasonable prices and on reasonable terms, including a ministerial exemption framework to encourage additional domestic investment and supply.
- **Heads of Agreement** (HoA) – requires liquified natural gas (LNG) exporters to offer uncontracted gas to the domestic market before offering it internationally, on competitive market terms and with reasonable notice.
- **Australian Domestic Gas Security Mechanism** (ADGSM) – is a last-resort measure that may be triggered if domestic shortfall is forecast; it has not been activated to date.

The review recommendations are broad-ranging and include establishing a domestic gas reservation scheme to replace the ADGSM, HoA and aspects of the Code's exemption framework. We note relevant findings and recommendations throughout this report.

ACCC Gas Inquiry

The ACCC's Gas Inquiry has operated since 2017 and aims to increase transparency on supply, demand and pricing in Australian gas markets. It publishes regular information on supply and pricing of gas, and reports on compliance with the HoA. It also advises the Minister for Resources on supply-demand conditions in east coast markets relevant to possible ADGSM activation.[5]

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3 National Gas Law section 63A.

4 National Gas Law, section 63B.

5 The ACCC gas inquiry has a national remit allowing examination of all goods and services across the supply chain, including aspects of pricing and availability of commodities and transportation services for both current and future needs. Consideration is also given to goods or services that assist or facilitate the supply of natural gas, such as drilling and processing services, comparing pricing, volumes and availability of natural gas for domestic consumption versus export.

The ACCC's reporting activities primarily focus on upstream supply and demand for wholesale gas rather than the facilitated markets. We have sought to minimise overlap between our respective reporting activities and draw on ACCC analysis where relevant.

The Gas Market Review recommended consolidating market monitoring and analysis through the AER and suggested Government could cease the ACCC Gas Inquiry in its current form. In light of this, we may revisit the scope and focus of future reporting.

Future Gas Strategy

The Australian Government's *Future Gas Strategy* sets out principles to guide gas policy through the transition to net zero,[6] including the importance of affordability and ensuring gas and electricity market arrangements remain fit for purpose. These principles provide context for demand and supply outlook considered in later chapters.

1.2 How we assess competition, efficiency and market outcomes

Our assessment of market performance considers whether there is effective competition and whether the markets are functioning efficiently (Box 1.1). We also consider whether features of the markets may be detrimental to the National Gas Objective.

We consider the broader context within which the facilitated markets operate, including upstream supply and demand dynamics that can affect prices, behaviour and supply in the facilitated markets. We also consider whether the facilitated markets support or hinder competition and efficiency in the broader east coast gas market. This includes assessing whether the markets are meeting their intended purpose – for example, by supporting efficient gas allocation, price discovery and price transparency, and by supporting access to the markets

Box 1.1 Competition and efficiency

Competition sits on a spectrum from monopoly to highly competitive markets. Perfect competition is rare in practice. The NGL therefore requires us to assess whether wholesale gas markets are **'effectively competitive'.**

The NGL sets out factors that we much have regard to when assessing whether there is 'effective competition' in a particular wholesale gas market:

- **Active competitors**: whether there are active competitors in the market and whether those competitors hold a reasonably sustainable position, or whether there is merely a threat to competition in the market
- **Prices reflect costs over time**: whether prices are determined on a long-term basis by underlying costs rather than the existence of market power, even though a particular wholesale gas market participant may hold a substantial degree of market power from time to time

6 Department of Industry, Science and Resources, Future Gas Strategy, viewed 9 February 2026.

- **Barriers to entry**: whether barriers to entry into the market are sufficiently low so that a substantial degree of market power may only be held on a temporary basis
- **Rivalry**: whether independent rivalry exists in all dimensions of the price, product or service offered in the market
- **Other matters**: any other matters that we consider relevant.

The NGL does not provide an explicit definition of efficiency. In this report, we use the standard economic concept of efficiency, which is commonly described as having 3 dimensions:

- **Allocative efficiency** – resources are allocated to their highest valued uses. In gas markets this means that the gas is provided to consumers who value it most.
- **Productive efficiency** – the resources used are minimised for a given level of outputs. In gas markets this means reducing the costs of producing and supplying gas.
- **Dynamic efficiency** – resources are allocated efficiently over time. In gas markets this means that the markets innovate and invest as needed, responding to changing consumer needs and new technological developments.

Our *Wholesale Market Monitoring and Reporting Guideline 2024* provides additional commentary on effective competition and efficiency, and the structure-conduct-performance framework as an analytical basis for monitoring and reviewing competition in the wholesale energy markets. We use this framework as a starting point for analysis in some areas throughout the report. However, there are limitations in applying it to the facilitated markets in isolation, as these markets are a subset of the broader east coast market and outcomes are influenced by upstream contracting, transportation and storage.

We have used a range of public and confidential information and data, including information from AEMO, the AEMC, the ACCC, the Australian Securities Exchange and market participants. We obtained information from market participants through direct voluntary engagement and through targeted compulsory market monitoring information notices issued to select participants. Information collected through these notices informed our findings in several areas, including in our observations on financial products.

We group individual participants to avoid disclosure of commercially sensitive information and may aggregate or vary these groupings to protect confidentiality. Further detail on data sources and any calculations performed can be found in the *Wholesale gas performance report 2026: Methods and assumptions* published alongside this report.

2 Gas market conditions and change drivers

Key points

- Efficient and competitive outcomes in facilitated gas markets depend upon adequate supply and competition across the broader east coast gas market supply chain.
- The facilitated markets are intended to manage short term supply and demand imbalances, support shorter term trade and provide access to spare pipeline capacity.
- Prices in facilitated markets have stabilised since the unprecedented volatility experienced during the 2022 market disruptions, but have settled at a higher level than pre-2022.
- A combination of supply and demand dynamics contribute to price outcomes in facilitated markets over the short and long term. Higher upstream production costs and declining southern production have contributed to the general upward shift in prices, while variable gas-powered generation can drive short-term price movements.
- The emergence of the liquified natural gas (LNG) export market has also had a significant impact on east coast gas markets, including the facilitated markets.

While this report focuses on the facilitated markets, we consider broader east coast gas market conditions to assess whether these are competitive and efficient. This chapter provides an overview of:

- the role of facilitated markets within the east coast gas market
- price movements in facilitated markets, and
- key supply and demand dynamics affecting outcomes across the east coast gas markets.

2.1 Overview of the east coast gas markets

The east coast gas market consists of interconnected markets for gas supply, transport, storage and compression across all Australian jurisdictions except Western Australia. Gas is extracted at various locations from underground sources across the east coast, then processed and transported over long distances via high-pressure transmission pipelines to liquified natural gas (LNG) facilities, electricity generators, large industrial customers and major population centres (Figure 2.1).

The primary sources of current gas supply come from:

- Queensland's Surat–Bowen basin (predominantly coal seam gas), which largely supplies LNG export demand and can also support southern supply requirements over winter

- conventional offshore basins south of Victoria that supply southern regions.[7]

Major gas storage facilities are located at Iona in Victoria, which provides essential southern supply capability during winter peak periods, and at Roma in Queensland, which supports supply to export operations.

Figure 2.1 Eastern gas basins, markets, major pipelines and storage

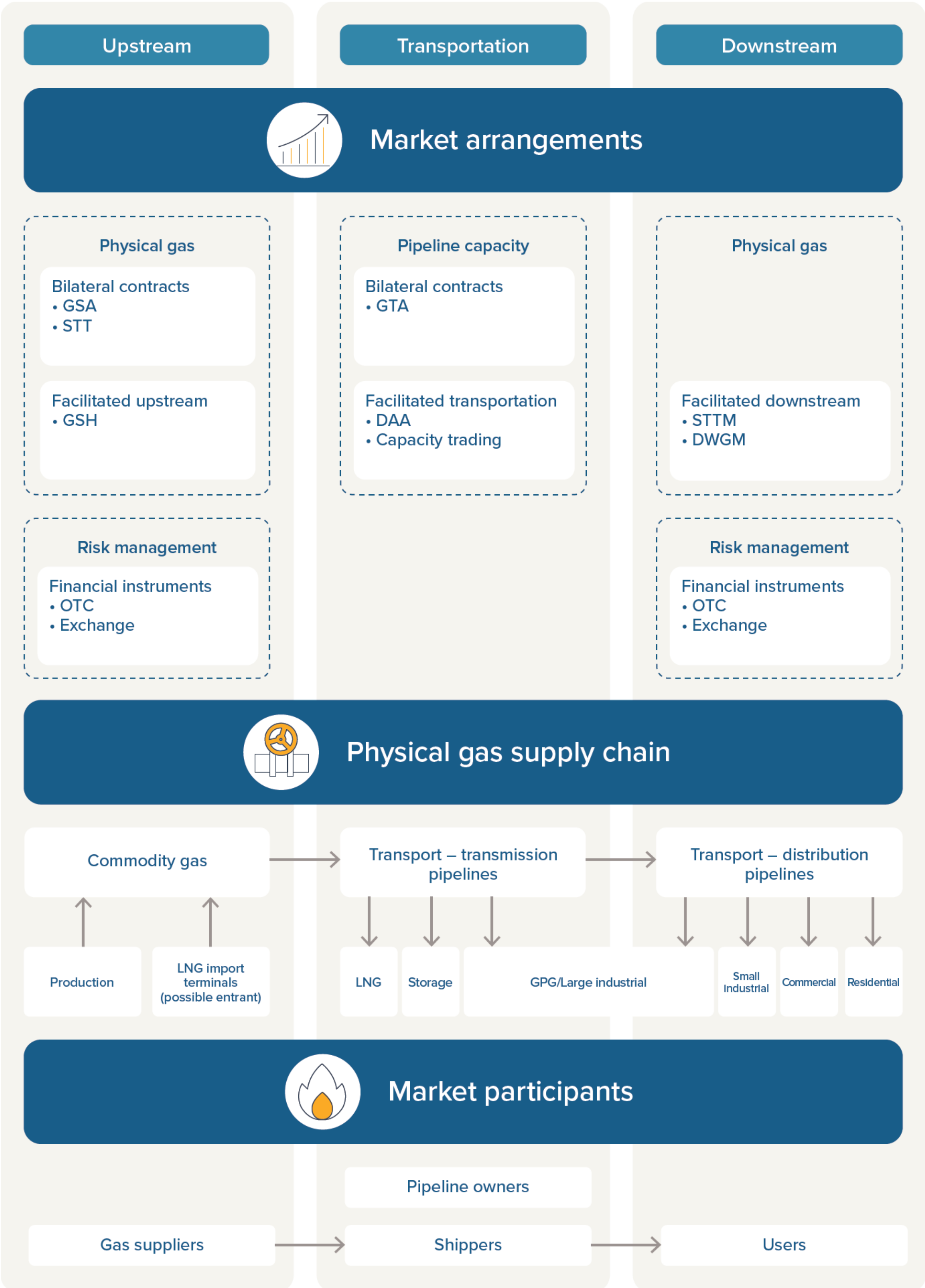
Source: AER and Gas Bulletin Board.

7 Other sources include gas produced from the Cooper Basin in northern South Australia and a few much smaller supply sources elsewhere.

2.1.1 The facilitated markets provide for shorter term trading

The east coast gas market arrangements are complex, comprising bilaterally negotiated contracts for gas and transportation, several separate markets and supply hubs that AEMO facilitates, as well as financial instruments to manage risk (Figure 2.2).

Figure 2.2 East coast gas market structure



Source: AER.

The bulk of trade in the east coast gas market is under long-term bilaterally negotiated gas supply agreements (GSA) and gas transportation agreements (GTA). Participants have historically required GSAs and GTAs to purchase and transport gas to downstream demand locations. Long-term contracts provide participants with certainty and have less risk exposure than volatile spot markets.

The upstream and downstream facilitated markets (Box 2.1) complement long-term gas trading arrangements. Collectively the facilitated markets:

- provide a market mechanism to manage short-term supply and demand imbalances
- support shorter-term gas trading between wholesale participants, allowing them to manage differences between their contract positions and supply and demand requirements, and
- provide access to spare pipeline capacity.

Net trade in the downstream spot markets accounted for around 15% of east coast demand in 2025.[8]

Box 2.1 Overview of the facilitated markets

The **Gas Supply Hub (GSH)** is a voluntary upstream trading market located around major supply chain junctions at Wallumbilla (Queensland) and Moomba (South Australia), with smaller trading locations at Culcairn and Wilton introduced from 2021. The market facilitates anonymised on-screen trades for gas up to 3 months ahead of delivery and allows participants to submit bilateral off-screen trades for financial settlement covering delivery horizons of up to a year. Gas commodity trades and notional time-based or location-based swaps are available across a range of products covering both short-term and longer-term timeframes. The bulk of trade occurs off-screen either bilaterally or facilitated via a broker.

The **downstream spot gas markets** are located at large population centres and are used to balance supply and demand. Participation in these markets is compulsory for anyone wanting to inject or withdraw gas in the market. The downstream spot markets are the Victorian Declared Wholesale Gas Market (DWGM) and the Short Term Trading Market (STTM), which operates in Adelaide, Sydney and Brisbane. The arrangements for the DWGM and STTM are similar, but there are some key differences:

- In the DWGM, participants must submit to AEMO offers to sell (injection bids) and bids to buy (withdrawal bids) gas. Offers and bids cover 5 periods through the day, with bid cut-off times an hour before the start of each period. Most of the gas traded in the Victorian market occurs at the 6 am beginning-of-day schedule.
- In the STTM, participants must also submit bids and offers, but the market operates on a day-ahead basis, meaning that the offers and bids are submitted the day before the relevant gas day. Unlike the DWGM, in the STTM bids and offers cover the entire gas day.

8 STTM and DWGM market data and AEMO, 2026 Gas statement of opportunities, (demand data for Residential & Commercial, Industrial, GPG demand, excluding the Northern Territory), Australian Energy Market Operator.

- A price floor of $0 per gigajoule (GJ) applies to bids in both the DWGM and STTM, but the price caps are different – the DWGM price cap is $800 per GJ and the STTM is $400 per GJ.

For both the STTM and the DWGM, AEMO schedules injections and withdrawals in a way that minimises price based on participants' bids and offers and available pipeline capacity. AEMO selects the lowest price offers and bids first and then progressively more expensive offers and bids until enough gas is obtained to meet demand. The last (highest priced) supply source typically sets the clearing price for each pricing period. The clearing price is paid to all participants supplying gas to the market.

AEMO also publishes provisional schedules before the gas day for both the STTM (2 and 3 days before) and the DWGM (the day before). These schedules provide signals to the market on price, supply and demand for the gas day.

Both the STTM and DWGM are settled on a net basis, meaning that participants are only paid or pay for the difference between actual injections and withdrawals. Participants can incur additional costs for deviations in injections or withdrawals from the AEMO schedule. There are different arrangements in the DWGM and STTM to manage deviations and other ancillary payments.

The **Day Ahead Auction** (DAA) facilitates trade in unused firm contracted pipeline capacity for transportation and compression services. The DAA allows a wider range of participants to procure spare capacity on transmission pipelines that might otherwise be contractually congested and unavailable to third parties, without the need to negotiate access. DAA 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.[9]

Shippers can also sell unused capacity to third parties ahead of the auction either through bilateral contracts or on the AEMO capacity trading platform. There has been no significant activity on the capacity trading platform since its introduction.

2.1.2 Financial products support risk management

Trade of physical gas is supported by financial products. These markets operate in parallel to the physical gas markets and can support a participant to manage the risks associated with short-term price volatility in wholesale spot markets by locking in prices for gas traded in the future. Financial products can be traded through exchanges or arranged bilaterally:

- In bilateral (over-the-counter or OTC) markets, 2 parties contract with each other directly (often assisted by a broker). The terms of OTC trades are negotiated between the parties, but standard terms and conditions are usually set out in International Swaps and Derivatives Association (ISDA) master agreements.
- Exchange-traded products are standardised to encourage liquidity. On the east coast, the Australian Securities Exchange (ASX) facilitates the exchange trade of financial derivatives, including the ASX Victorian Natural Gas Futures (which is cash settled) and the ASX Wallumbilla Natural Gas Futures (which is physically delivered).

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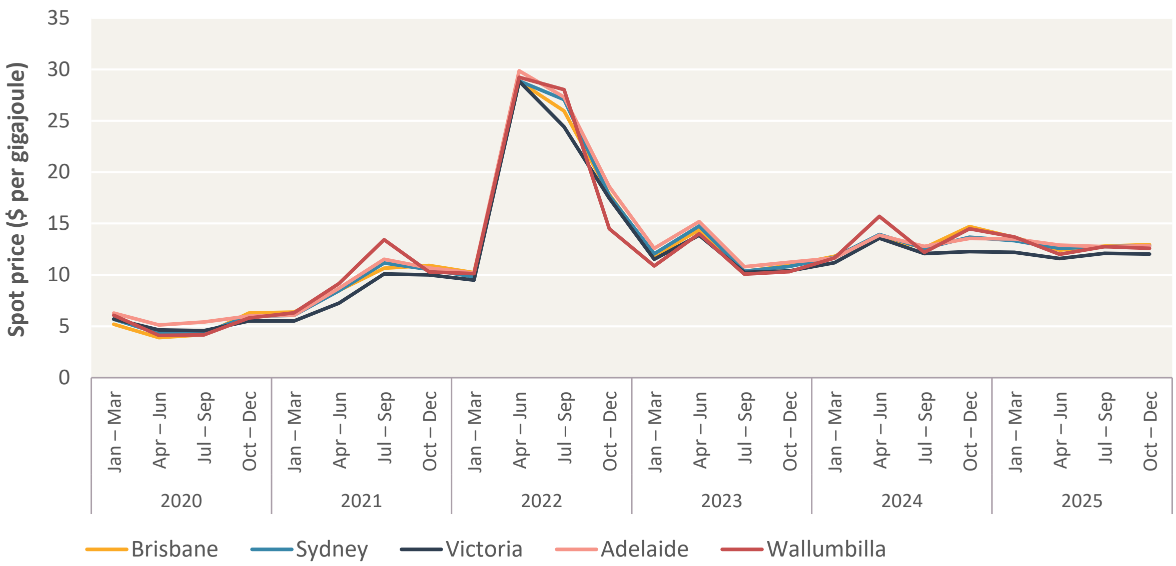
9 Although participants can win capacity for $0 per GJ, additional charges and registration fees make the real cost slightly higher.

2.2 Prices have stabilised at a higher baseline following 2022 volatility

Movements in spot prices are not necessarily an indicator of the state of competition or efficiency in the market. Prices rise and fall in response to changes in demand and supply. Wholesale gas prices are typically elevated during winter, when colder weather in southern markets increases demand for residential gas heating. Prices can also increase in summer during periods of higher gas-powered generation (GPG) in the National Electricity Market (NEM) due to increased air conditioning load or when generators are offline.

Prices in the facilitated markets spiked during market disruptions in 2022. Since then they have stabilised, but at a higher level than before (Figure 2.3). Key factors that have contributed to both short-term price volatility and long-term shifts in prices in east coast gas markets include shifts in domestic demand, higher production costs, supply constraints and interactions with international gas markets (sections 2.3–2.5). While spot gas prices fluctuate over time, it is generally within a narrower range than in the NEM.

Figure 2.3 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 imbalance price.

Source: AER.

Gas prices in downstream markets fell during 2020, averaging $5.20 per GJ for the year. Several factors contributed to the decrease, including exporters suppling more gas to the domestic market following a fall in international prices during the COVID-19 pandemic, high levels of Queensland gas production and decreased demand for gas-powered generation.

By late 2020, growth in Queensland's LNG exports, combined with a tightened domestic supply-demand balance, placed increasing pressure on east coast domestic market prices. In 2021 LNG exports rose to new record levels, with severe winter conditions in the northern hemisphere and an increase in Asian prices likely exacerbating local price rises. Spot gas prices across the downstream markets averaged $8.92 per GJ in 2021.

In 2022 both electricity and gas markets experienced volatility and extreme high prices. The annual average spot price across the downstream gas markets increased by 133% from 2021, averaging $20.81 per GJ. Across May, June and July 2022, average downstream gas market prices exceeded $40 per GJ. Over the same period monthly average electricity prices reached between $286 and $408 per MWh. These outcomes reflected a combination of domestic and international factors, as well as strong interactions between gas and electricity markets (Box 2.2).

Gas prices in the facilitated spot markets stabilised from mid-2023 and remained relatively stable through 2024 and 2025. However, prices settled at higher levels than before the 2022 events, averaging below $13 per GJ across 2024 and 2025. This reflects a general upward shift in prices driven by several supply-side factors (section 2.5-2.7).

Box 2.2 Drivers of record gas prices in 2022

Ongoing coal plant outages in the NEM, coal supply chain issues and low renewable generation output drove higher reliance on gas and hydro generation to meet electricity demand. Coal and gas-powered generators that needed to source additional fuel were exposed to high international prices. Electricity price increases triggered administered price caps and spot market suspensions.

At the same time, gas markets faced strong demand. High GPG demand, combined with elevated residential heating demand, created very tight supply-demand conditions and drove gas prices higher. In May 2022, sustained high prices led to the collapse of Weston Energy, triggering administered pricing mechanisms in both the Sydney and Brisbane STTMs.[10]

Following Weston Energy's suspension, many participants in the Sydney STTM repriced their offers and limited supply to volumes required to meet their own customer and GPG demand. The sharp reduction in gas supply offered across the markets elevated the potential for supply curtailment. For the first time, the gas supply guarantee mechanism was activated to ensure sufficient gas supply to gas-fired electricity generators.[11]

Multiple threats to system security were made from 11 July and AEMO directed market participants to cease sourcing gas supply from the Victorian market for electricity generation to balance volatile supply and demand requirements. Following these events, gas prices reduced in August 2022, with declining GPG demand and easing conditions in the NEM.

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10 The AER has previously reported on significant price variation events during the 2022 energy crisis, detailing the gas market interventions which unfolded at the time. See: AER, Significant price variation report – Winter (May to August) price variations in the Victorian Declared Wholesale Gas Market, and Adelaide, Sydney and Brisbane Short Term Trading Markets, Australian Energy Regulator.

11 Since 2023, the gas supply guarantee has been replaced by signalling functions under the east coast gas system (ECGS). See: AEMO, About the East Coast Gas System (ECGS), Australian Energy Market Operator.

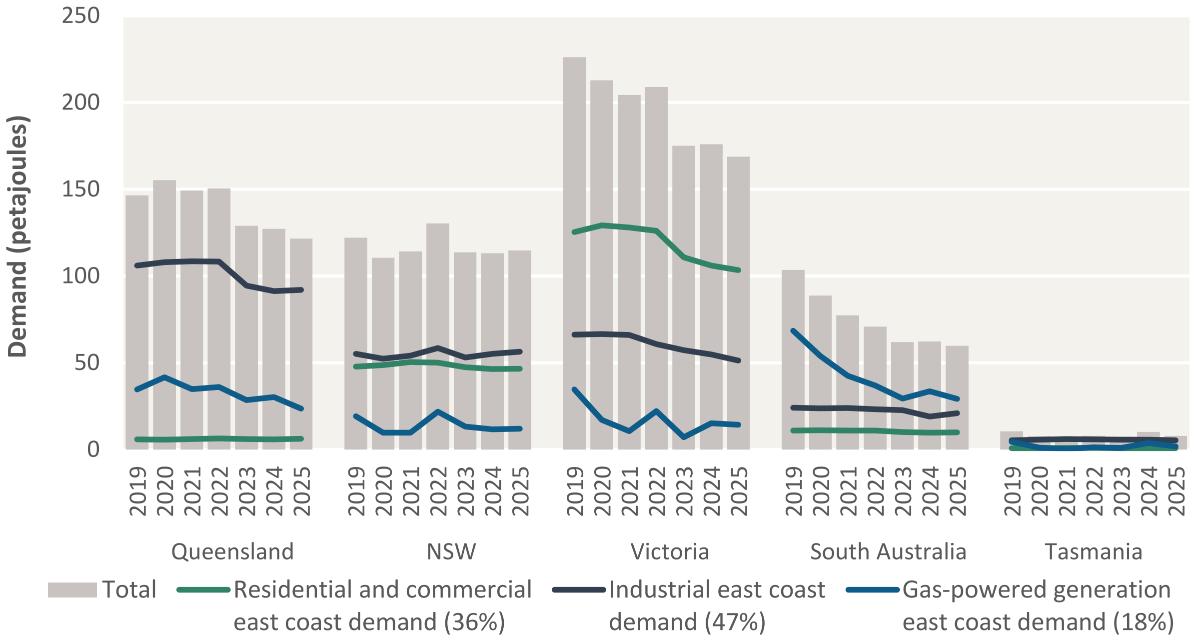
2.3 Shifts in domestic demand affect outcomes in downstream markets

2.3.1 Gas for residential, commercial and industrial are the biggest components of domestic demand

After LNG, industrial, residential and commercial use are the largest sources of gas demand across the east coast.[12] However, there are differences between the states (Figure 2.4):

- Industrial uses are the highest source of demand in Queensland and New South Wales.
- Residential and commercial users are the primary source of demand in Victoria, with significantly higher gas heating demand over the colder winter periods.
- Gas-powered generation (GPG) is the largest source of demand in South Australia, although its share has been declining in recent years.

Figure 2.4 Eastern Australian gas demand, by state



Source: AEMO, 2026 Gas statement of opportunities, March 2026.

Several states experienced a step change in domestic gas demand from 2023. In Queensland, gas demand fell almost 15% compared with the previous 4 years, primarily due to the closure of Dyno Nobel Limited's (formerly Incitec Pivot) large industrial plant at the end of 2022. Victorian demand also declined more than 15% from 2022 levels. This was primarily driven by lower residential and commercial demand, with milder winter weather, rising retail prices and increased electrification also contributing. A smaller fall in industrial demand was driven by the closure of several industrial manufacturing facilities.[13]

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12 AER, State of the energy market 2025, Australian Energy Regulator, p. 144.

13 Facilities included Exxon Mobil Altona refinery (2021), Qenos Altona (2024) and Oceania Glass (2025)

AEMO projects a decline in domestic gas demand across the east coast over the next 20 years, primarily driven by reductions in residential and commercial demand, with more moderate decreases in industrial demand and relatively stable gas generation requirements.[14]

2.3.2 GPG is the smallest component of demand but has a significant impact

GPG performs a critical role in maintaining system security and reliability in the NEM. It can respond rapidly to meet peak electricity demand and balance variable wind and solar generation.

While daily peaks in gas demand for electricity generation have remained relatively stable, total gas demand for electricity generation has declined over the past decade and in recent years has been the smallest component of domestic demand.[15] Reduced gas generation has occurred alongside the decline in coal-fired generation and rising renewable generation.

Despite its small recent contribution to overall demand, GPG demand can have a significant effect on facilitated markets because it is highly variable (Figure 2.5) and can be difficult to forecast. Gas generation is influenced by numerous external factors affecting the NEM, including extreme weather, unplanned generator outages, local coal supply disruptions and global drivers affecting electricity generation fuel costs. Under extreme conditions, like those that occurred in mid-2022, additional unexpected GPG demand can contribute to gas price volatility.

Over recent years, peaks in GPG demand have been more closely aligned with other gas market demand (Figure 2.6). Since 2022, peak GPG demand has shifted from summer to winter, occurring at the same time as peaks in other gas market demand. This shift has increased pressure on the market over winter and the risk of curtailment.

While overall GPG demand has declined over the past decade, gas usage for electricity generation is projected to remain relatively stable over the next decade as coal-fired generators are retired in the NEM.[16] AEMO forecasts increasing concentration of GPG across shorter periods to maintain system security and reliability, shifting towards higher requirements over winter months. Key factors predicted to drive this trend include lower renewable generation availability in winter, higher reliance on electricity to meet heating demand, and growing electricity storage and solar usage decreasing off-peak GPG needs.[17]

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[14] Forecast industrial consumption remains stable in the short term before declining from 2030 as electrification investments are assumed to reduce gas needs.

AEMO, 2026 Gas statement of opportunities, Australian Energy Market Operator, March 2026, p. 6.

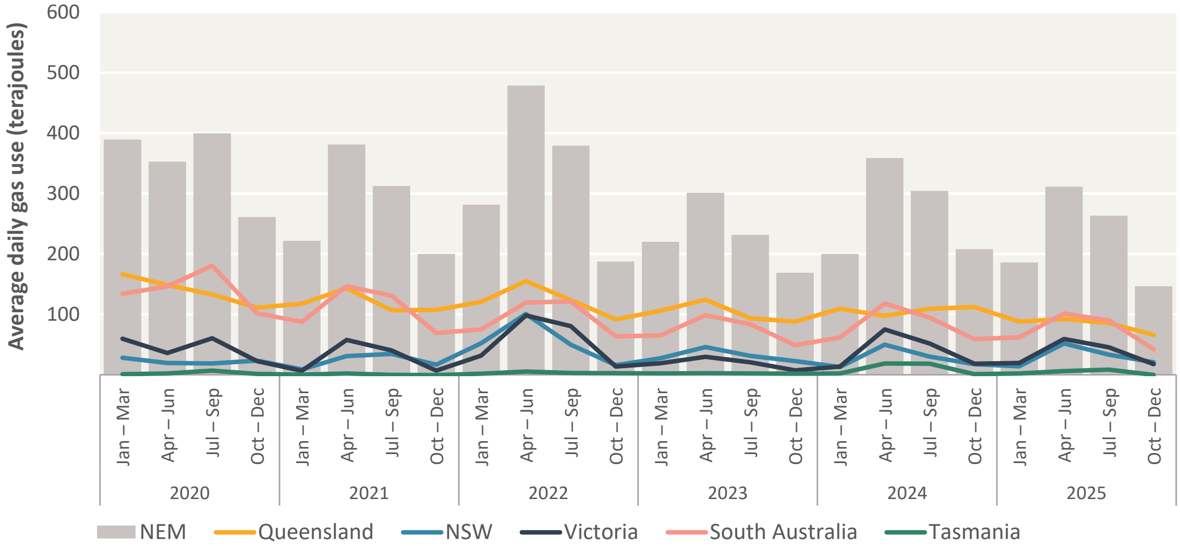
[15] Compared with residential and commercial, industrial, GPG and LNG demand. AEMO, 2026 Gas statement of opportunities, Australian Energy Market Operator, March 2026, Gas forecasting data portal.

[16] Since the 2025 GSOO, improved gas adequacy expectations have been influenced by the temporarily delayed retirement of Eraring Power Station and increasing developments in NEM battery technologies reducing expected GPG requirements.

AEMO, 2026 Gas statement of opportunities, Australian Energy Market Operator, March 2026, p. 3.

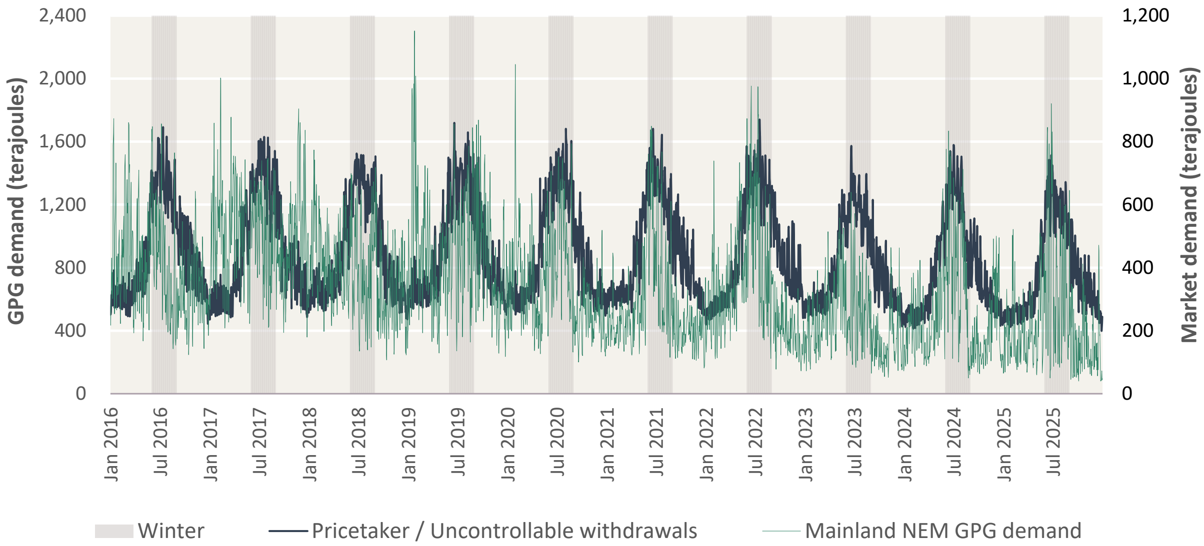
[17] AEMO, 2026 Gas statement of opportunities, Australian Energy Market Operator, March 2026, p. 6.

Figure 2.5 Quarterly gas demand for gas-powered generation



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

Figure 2.6 Increasing alignment between GPG demand and other gas demand



Source: AER analysis using gas market (DWGM and STTM) scheduling data, and National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

2.4 Production costs have increased and supply is constrained

A range of supply-side dynamics across east coast gas markets are affecting outcomes in facilitated markets and have contributed to the general upward shift in prices.

2.4.1 Upstream gas costs have been increasing

A significant proportion of wholesale gas costs comes from gas production. Production costs for proven and probable (2P) reserves and contingent (2C) resources increased across most east coast basins between 2017 and 2025, putting significant upward pressure on prices.[18]

Production costs are expected to continue to rise. Recent estimates from the ACCC Gas Inquiry indicate the full lifecycle (which includes all historical project costs) breakeven price for gas is around $11–12 per GJ for the majority of 2P reserves and 2C resources. To meet demand, the cost of marginal supply across the east coast gas markets (estimated using forward product costs that exclude sunk costs) is expected to increase to $7.8–8.8 per GJ in the medium term (2030) and up to $13–14 per GJ in the long term (2035). The ACCC has noted that market participants will likely need to draw on more costly gas as lower cost reserves are depleted and in the absence of finding alternative sources of supply.[19]

Higher production costs appear to be in part driven by depleting legacy fields in the southern states and a greater reliance on coal seam gas in Queensland.[20] New offshore Victorian gas fields have lower productivity, leading to higher average costs. Unconventional gas sourced from Queensland tends to be less flexible and more costly to respond to seasonal demand changes or unpredicted demand spikes in the southern states.[21]

Over the course of the Gas Inquiry, the ACCC has also noted a general increase in production costs and evidence of uncompetitive pricing practices from both producers and large retailers, driven by concentration in supply both within the wholesale market and upstream among gas producers.[22]

2.4.2 Southern production is declining

East coast gas users have become increasingly reliant on northern production as southern production is declining. Output from Victoria’s Gippsland Basin has been falling since 2022 due to the depletion of legacy fields supplying the Longford gas plant.[23] Planned southern gas field expansions are not large enough to offset Longford’s production decline and AEMO has forecast risks of peak day shortfalls in southern regions from winter 2029.[24]

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18 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and Department of Industry, Science and Resources, December 2025, p. 25.

19 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2025, pp. 36–37.

20 DISR, Future gas strategy analytical report, May 2024, Department of Industry, Science and Resources, p. 80.

21 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, p. 25.

22 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2018, July 2019, January 2020, January 2021.

23 Longford’s production capacity 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. The ACCC has raised concerns about supply gaps that could emerge from 2028.

24 AEMO, 2026 Gas statement of opportunities, Australian Energy Market Operator, March 2026, p. 7.

In addition to the risk of shortfalls, constrained supply conditions mean the gas markets are more vulnerable to high price events, particularly with the more frequent periods of coincident elevated winter demand and unexpected increases in GPG demand.

The ACCC has also projected that supply shortfalls in southern states will progressively widen from 2027 to 2037, primarily due to low forecast 2P reserves and a lack of new supply coming online.[25] The lack of new supply is attributed to fewer or stalled investments due to environmental and climate concerns and historical government policy restrictions. While state government policies aiming to reduce gas demand through electricity substitution are having an effect, declines in gas usage from disconnections are not occurring at a rate fast enough to offset projected declines in gas supply.[26]

The Gas Market Review has similarly noted that new sources of gas supply and production are needed, along with other strategies to reduce demand, to avoid or mitigate forecast shortfalls. It noted the Australian Government could establish a domestic gas reservation policy to ensure gas is proactively supplied to the domestic market. The Review also noted the need to address legislative and regulatory barriers to investment in new gas supply and infrastructure projects to ensure continued domestic access to reliable gas supply.[27]

2.4.3 Potential new developments remain uncertain

Market developments to meet future east coast gas supply needs, particularly for domestic demand in the south, have the potential to improve conditions for competition in the facilitated markets. There are several projects proposed or underway, but there is uncertainty around the timing of many of these projects.

Adequate pipeline and storage capacity is essential to support efficient and competitive markets. The *Gas Market Review Report* noted a critical need for new and upgraded infrastructure to transport gas produced in northern regions of Australia to southern demand centres.[28] A lack of sufficient transport or storage capacity in the east coast markets will have flow-on impacts for facilitated markets. Several transportation and storage projects aimed at improving gas supply capability have been planned in coming years (section 7.3).

Other projects being developed in southern states include potential supply from LNG import terminals in New South Wales, Victoria and South Australia. These projects are expected to become commercially viable over the next decade, potentially providing a substitute for the need to transport gas supply south from Queensland. Other southern supply projects include the development of new gas reserves in the Otway Basin and committed expansion and reprofiling of reserves in the Gippsland Basin to boost Longford supply. In New South Wales, the Narrabri gas project could deliver sizable resources, but regulatory approvals have faced significant delays.

25 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, June 2025, pp. 46–47.

26 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, June 2025, pp. 46–47.

27 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, p. 47.

28 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, p. 47.

Developments to supply gas to the Northern Territory from the Beetaloo Basin are aiming for commercial gas sales in 2026. However, shortages in the Territory's own gas supply has decreased the likelihood of Northern Territory supply being available to the east coast gas market in the near term.

2.5 Exposure to developments in LNG export markets

The emergence of LNG export markets has had a significant impact on the east coast gas markets, including the facilitated markets. In 2024 around 75% of domestic gas production was exported internationally.

2.5.1 LNG market has changed supply dynamics

From 2010 LNG exporters invested in significant new gas production in Queensland to support their LNG export activities, underpinned by long-term foundation contracts with primarily Asian partners. The owners of the 3 LNG export facilities now produce most gas on the east coast gas market. Gas produced from these facilities is predominantly coal seam gas, which has higher production costs than conventional resources (section 2.4.1).

Most LNG exporter-produced gas is sold under long-term foundational LNG contracts, with some gas sold as LNG spot cargoes on an uncontracted basis. Uncontracted gas produced from exporter-owned production facilities can be sold into the domestic market on a short- or long-term basis.

With the decline in southern production (section 2.4.2), domestic users are becoming increasingly reliant on gas produced from exporter-operated fields to support domestic east coast demand. The ACCC has reported that the 3 largest gas producers on the east coast, along with their associates, control or influence over 90% of 2P reserves and 35% of 2C resources on the east coast. The ACCC has noted that the decisions of each of the major Queensland LNG exporters have a significant impact on the short- and long-term supply-demand outlook for the east coast gas market.[29]

This has flow on effects for the facilitated markets. For example, producers supply most of the gas sold into the GSH, typically accounting for more than half of total sales.[30] The ACCC's quarterly assessments of projected supply adequacy have highlighted that short-term outlooks are increasingly dependent on the amount of uncontracted gas produced by LNG exporters.

The Gas Market Review also considered the impact of LNG export markets and made several recommendations intended to address domestic gas security concerns, including the

29 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, June 2025, p. 61.

30 AER, Gas supply hub focus report, Australian Energy Regulator, December 2024.

introduction of a prospective domestic gas reservation policy.[31] The review noted that while emergency reforms were introduced to avert domestic shortfalls (section 1.1.3), they have not established sufficient investment certainty to address long-term gas requirements.[32]

2.5.2 International LNG and oil prices affect outcomes on domestic markets

The launch of the LNG export market in 2015 linked domestic gas prices (which were traditionally stable) to more volatile international oil and gas markets. Linking domestic prices with international markets also means that the domestic market is more susceptible to geopolitical events that impact global gas supplies. Much higher export demand than domestic demand leads to higher international linkage than countries like the USA where domestic demand is higher.

Generally, domestic gas prices have increased as export quantities have risen over time, but at times the international markets also place downward pressure on domestic prices. For example, higher prices linked to international drivers were evident in 2016 and 2017 before decreases in 2019 and 2020 occurred alongside lower Asian prices.[33] Diminished mid-year export demand during the COVID pandemic also likely contributed to lower domestic prices across 2020.

There are several ways that domestic prices can be affected by international oil and gas price movements over the short and long-term. Over the longer-term, gas contracts are often linked to oil prices, with export contracts tied to global oil price benchmarks. In addition, Queensland's LNG export facilities provide producers an alternative to selling gas domestically, exposing local gas users to increased competition for gas and international LNG prices when negotiating long term contracts.

In the short term, LNG exporter decisions around their uncontracted gas can influence domestic prices. For participants with access to LNG export facilities, international LNG prices provide an alternative price to selling gas domestically. This alternative price becomes the 'opportunity cost' for exporters supplying the domestic market and affects offer prices for domestic supply.

The 'LNG netback price' is an estimate of the opportunity cost of supplying the domestic market. It is calculated by taking the price that could be received for LNG and 'netting' back the costs incurred by the suppler to convert the gas to LNG and ship it to the destination port.[34] If LNG netback prices are above domestic prices, LNG exporters have a financial

31 Proposed parameters for national reform to commence in 2027 include respecting existing contracts and ensuring additional domestic supply as contracts expire. To provide downward price pressure, export approvals would need to meet domestic supply obligations before approval, with standard commercial/market-based arrangements governing flexibility around meeting domestic and export supply obligations. It aims to encourage long-term domestic contracting to provide certainty for commercial and industrial investment, setting supply requirements well in advance of established agreements.

32 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025.

33 AER, State of the energy market 2021, Australian Energy Regulator, pp. 198, 207.

34 ACCC, Gas inquiry 2017–2030, LNG netback price series, Australian Competition and Consumer Commission.

incentive to export their uncontracted gas, and to buy additional gas from the domestic market for export. In practice, other factors may influence exporter decisions, e.g. the timing of LNG spot cargoes, liquidity of the domestic market, and the regulatory environment.

2.5.3 Current international context

The recent conflict in the Middle East is severely restricting the passage of ships carrying LNG and oil through the Strait of Hormuz. The conflict is also impacting ongoing LNG and oil production capacity. This has had a significant impact on global oil and LNG prices, with Brent oil increasing 69% from before the conflict to a high of $172 per barrel by 31 March, while international LNG prices increased 140% to a high of $33.79 per gigajoule. [35]

At the time of publication downstream domestic gas prices have been relatively subdued despite rising international oil and LNG prices. Domestic demand over the first half of 2026 has been subdued, influenced by lower GPG demand. Equally, we have not seen LNG exporters purchase additional gas from facilitated markets, or under short term contracts. Forward contract prices for 2027 have so far remained stable.

However, higher international LNG futures prices over 2026 have increased expected LNG netback prices. As at 1 May 2026, LNG netback forward prices average $20.81 per gigajoule for the remainder of 2026 and $16.60 per gigajoule for 2027.[36] If LNG exporter uncontracted gas is required to meet domestic demand over winter, then LNG exporters may have a financial incentive to supply it domestically at international prices, reflecting their higher opportunity cost. This makes the domestic market, and particularly downstream spot markets, more vulnerable to high prices.

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35 Calculated by reference to the ANEA price, reaching a peak of $33.79 per gigajoule on 19 March 2026. The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.

36 ACCC, Gas inquiry 2017–2030, LNG netback price series, Australian Competition and Consumer Commission.

3 Structure of the facilitated gas markets

Key points

- The structure of the downstream gas spot markets and the Gas Supply Hub (GSH) increasingly support competitive outcomes, with market concentration declining across most facilitated markets.
- While a small number of large, combined gas retailers with gas-powered generation (GPG) assets (‘GPG gentailers’) account for a significant proportion of offers to supply gas in the downstream spot markets, participation has broadened since 2019, with more participants offering into these markets.
- As participation has increased, offers among participants in downstream markets have become less concentrated, with the exception of the relatively small Adelaide Short Term Trading Market (STTM) hub remaining highly concentrated. Net trade, which captures gas substantively traded in downstream markets rather than simply passed through, is even less concentrated, indicating stronger competitive outcomes.
- Trade on the GSH has become less concentrated since inception. However, most trade continues to occur off-screen limiting the visibility of real-time price formation.
- Barriers to entry into the facilitated markets are low for participants with access to gas supply and transportation. However, there remain materially higher barriers to entry into long-term gas supply and transportation markets, which shape competitive outcomes over time.

Competition is influenced by the structure of the market. A participant has more opportunity to exercise market power in a market with few participants, especially during periods of high demand or if supply is constrained. The risk of sustained exercise of market power is heightened when there are high barriers to new entry.

Even where a participant holds sustained market power, it may not have an incentive to exercise it. A participant’s incentives will be influenced by factors such as the extent to which it is offering gas into a market to offset its own demand and the extent to which it has hedged against spot prices. Nonetheless, holding sustained market power increases the risk of ineffective competition.

This chapter provides an overview of the structure of the downstream wholesale gas spot markets and the upstream GSH. Downstream spot markets are located near major load centres and are compulsory for a participant wanting to inject or withdraw gas into the market. The GSH is a voluntary upstream market where participants can trade gas on-screen or off-screen. We analyse indicators of market structure and examine whether barriers to entry impact participation in facilitated markets as well as longer-term supply and contract markets.

3.1 Offers to supply gas to downstream spot markets less concentrated since 2019

Market concentration refers to the number and size of participants in a market. A concentrated market has a high proportion of gas controlled by a small number of participants and is more susceptible to outcomes that are not competitive. We used 3 measures of market concentration (Box 3.1). Market concentration has declined across most measures and in most markets since 2019.

Box 3.1 How we assess market concentration

Market share

Market share is the simplest measure of concentration. For the downstream markets, we measured market share by participants:

- Total offers - This captures the volume of gas that a participant could be scheduled and required to deliver.
- Net trade – This measures the share of gas a participant has sold into downstream spot markets without offsetting demand. This measure better reflects a participant's contribution to actual market outcomes.

We use offers and net trade into the DWGM and STTM as a proxy for capacity to assess the level of competition within those markets. In practice, this may not reflect the true capacity available in the market because participants may be able to respond to market signals and increase the volume of gas offered into the market on short notice. Equally, some offer volumes may not persist in times of market stress.

The Herfindahl Hirshman Index (HHI) summarises market concentration and allows for comparisons across downstream spot markets. HHI is calculated by summing squared market shares of all participants in the market. HHI can range from almost zero (a market with many small participants) to 10,000 for a monopoly. In this report we calculated HHI using market shares of total offers and net trade and considered HHI scores above 2,000 to be highly concentrated.

The Pivotal Supplier Test is commonly used in electricity markets to indicate the risk of the exercise of market power. PST measures the extent to which offers from one or more participants are required to meet demand and are therefore 'pivotal' to clearing the market. We have adapted this measure to apply to the downstream spot markets.[37]

[37] In downstream spot markets, there are 2 forms of demand – price insensitive demand (price taker in STTMs, uncontrolled demand in the DWGM) and price sensitive demand. We have used price insensitive demand when calculating PST because this is the level of demand that must be withdrawn from the market.

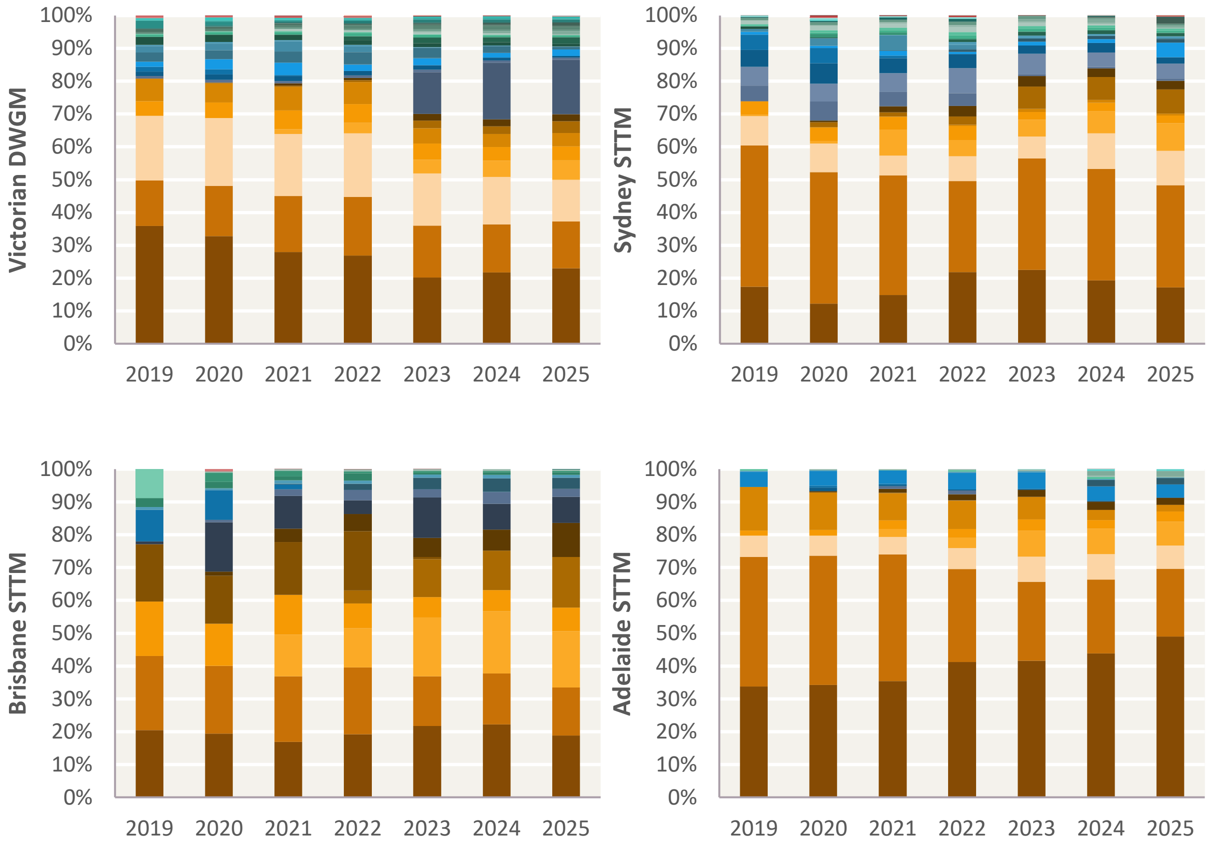
3.1.1 A few GPG gentailers make up a large proportion of offers in most downstream gas spot markets

Concentration in offers differs between downstream spot markets. However, a few large GPG gentailers are active in each market and represent a large proportion of total offers (Figure 3.1). Across the downstream markets:

- The **Victorian DWGM** is the largest downstream market on the east coast. GPG gentailers make up a large proportion of offers, and this has remained relatively consistent since 2019. In 2025 Origin, Energy Australia and AGL made up half the offers to the market. These GPG gentailers have large downstream residential demand, which represents a significant proportion of overall demand in the DWGM. In 2025 AEMO accounted for 17% of offers into the DWGM related to its contract for emergency gas at the Dandenong LNG facility.[38]
- In the **Sydney STTM**, Origin, Energy Australia and AGL made up 59% of offers to the market in 2025. This was followed by Energy Australia, Shell, SGMT and Esso and Orica.
- In the **Brisbane STTM**, GPG gentailers have a lower combined market share of total offers than in other markets, reflecting that demand for gas in Queensland and the Brisbane STTM is heavily skewed towards industrial demand (section 2.3). In 2025 Origin made up 19% of offers, followed by Shell (17%), SGMT (15%) and AGL (15%). The remaining shares of offers are spread more evenly between other participants.
- In the **Adelaide STTM**, Origin had the highest market share in 2025 at 49%, which has grown materially since 2020. Conversely, market share for the second largest market participant (AGL) has fallen from 39% in 2019 to 21% in 2025.

[38] AEMO was given powers to contract for emergency gas in 2023.

Figure 3.1 Market share of total offers in downstream spot markets



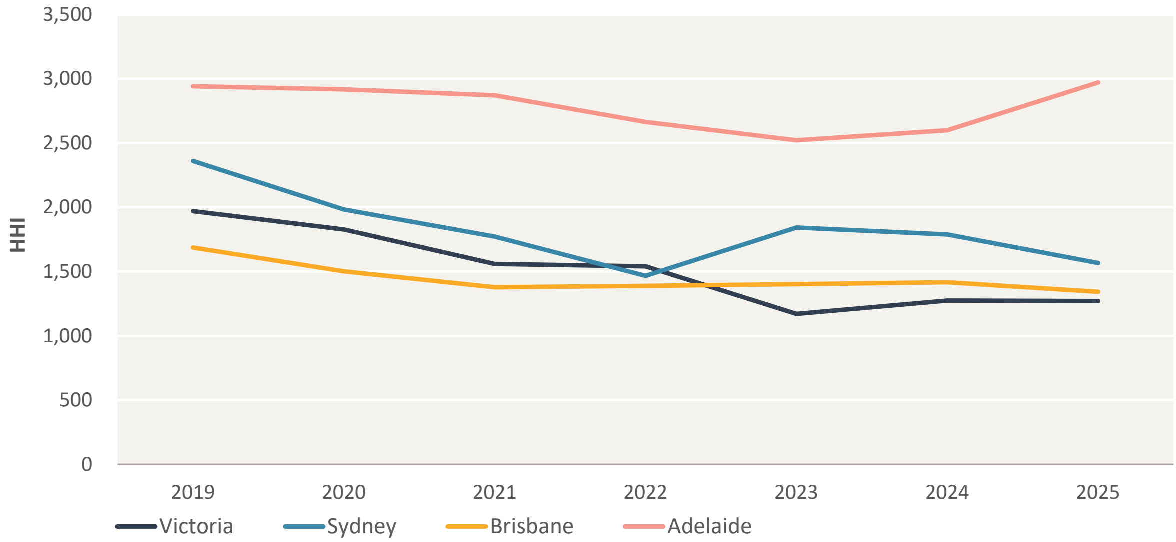
Source: AER analysis using gas market (DWGM and STTM) bidding data.

3.1.2 Offer concentration has improved since 2019 in all markets except Adelaide

Between 2019 and 2021 the number of active participants offering gas into downstream spot markets increased in all markets and across all participant groups (see Appendix A). The growth in participation contributed to lower concentration in all markets except the Adelaide STTM (Figure 3.2). The HHI of total offers in the Victorian DWGM and the Sydney and Brisbane STTMs have improved since 2019, remaining between approximately 1,000 and 2,000.

In contrast, HHI has not improved in the Adelaide STTM even while the number of active participants has grown. The HHI has increased over the past 2 years to close to 3,000, largely due to the growth in offers by the largest participant Origin, which now accounts for nearly half of the offers in the market. But concentration in net trade in the Adelaide STTM is much lower (section 3.2).

Figure 3.2 Concentration measured using annual HHI by total offers

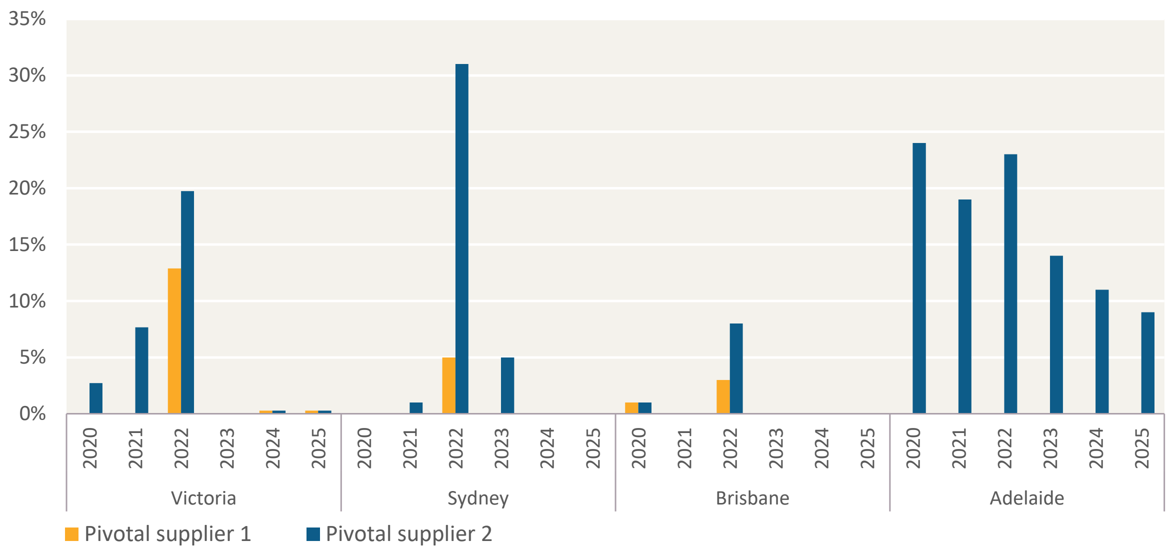


Source: AER analysis using gas market (DWGM and STTM) bidding data.

3.1.3 The two largest participants are usually not required to meet demand in most markets

The 2 largest participants have not been required to meet demand in the Victorian DWGM or the Sydney and Brisbane STTMs since 2024 (Figure 3.3). During market volatility from May to July 2022 the largest participant was required to meet demand for 47 days in the Victorian DWGM, 19 days in Sydney and 12 days in Brisbane STTMs. This occurred during a period of high GPG and residential demand (section 2.3). In the Adelaide STTM, the 2 largest participants were required to meet demand around 20% of the time in 2022, but this has steadily fallen to under 10% of the time in 2025 and mostly in the winter months.

Figure 3.3 Proportion of time offers from the largest one or two participants was needed to meet demand



Source: AER analysis using gas market (DWGM and STTM) bidding and schedule data.

3.2 Concentration of net sellers in downstream gas markets is as or less concentrated than offers

Most gas on the east coast is contracted bilaterally, but the spot markets are still compulsory for a participant wanting to withdraw or inject gas. This means most participants often simultaneously offer gas into and withdraw gas out of the market because it allows a contracted participant to offset its own demand and avoid spot market price exposure. To achieve this, participants will often offer gas at $0 per gigajoule (GJ) (Box 4.1). This was a design feature at the inception of the downstream spot markets to avoid disruption to existing bilateral contracts.

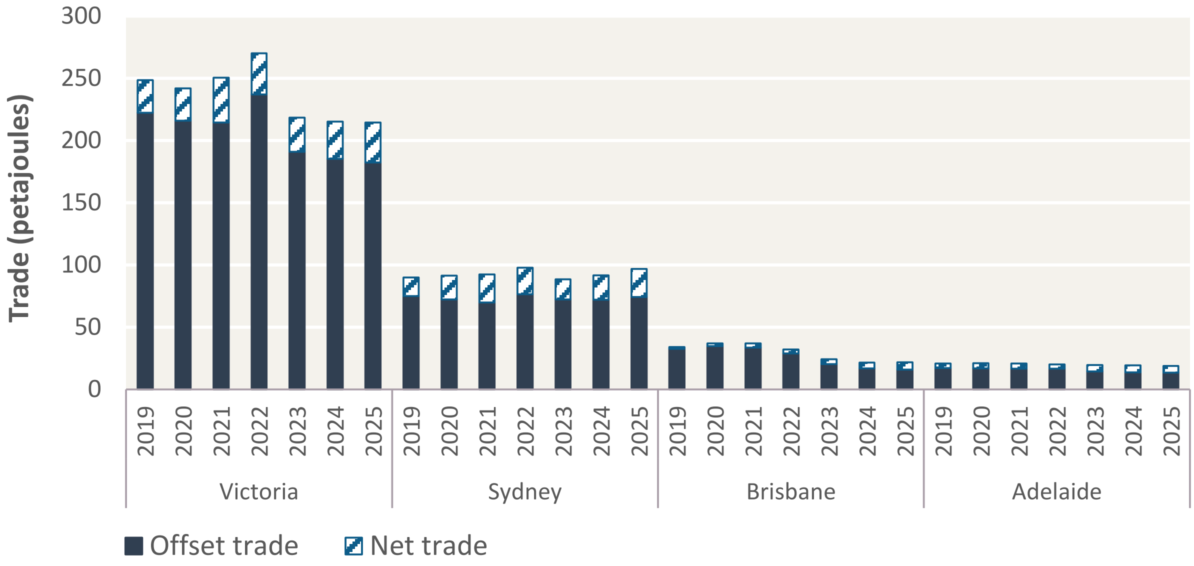
Some participants withdraw more gas from a market than they offer (‘net buyers’) while others supply more than they withdraw (‘net sellers’). Individual participants may vary day to day between net buying and net selling and there is variation within participant groups, but there are some recurring patterns. Typically, exporter/producers are net sellers, industrials and retailers are net buyers, while GPG gentailers and traders vary between net buying and net selling.

Net trade exposed participants may have more incentive to exercise market power because they are price exposed and could profit from manipulation of prices. High concentration in net trade would give rise to greater risks for effective competition than high concentration in total offers.

3.2.1 Net trade in downstream markets has increased since 2019

Net trade has increased since 2019 but remains a smaller proportion of overall trade in downstream gas spot markets (Figure 3.4). Since 2019 net trade has also increased as a proportion of total trade. In 2025 net trade represented 15% of the Victorian DWGM and between 23% and 29% of the Sydney, Brisbane and Adelaide STTMs. Section 6.4.1 explores potential drivers of increased proportion of net trade within downstream spot markets.

Figure 3.4 Total trade (offset and net) trade in downstream spot markets

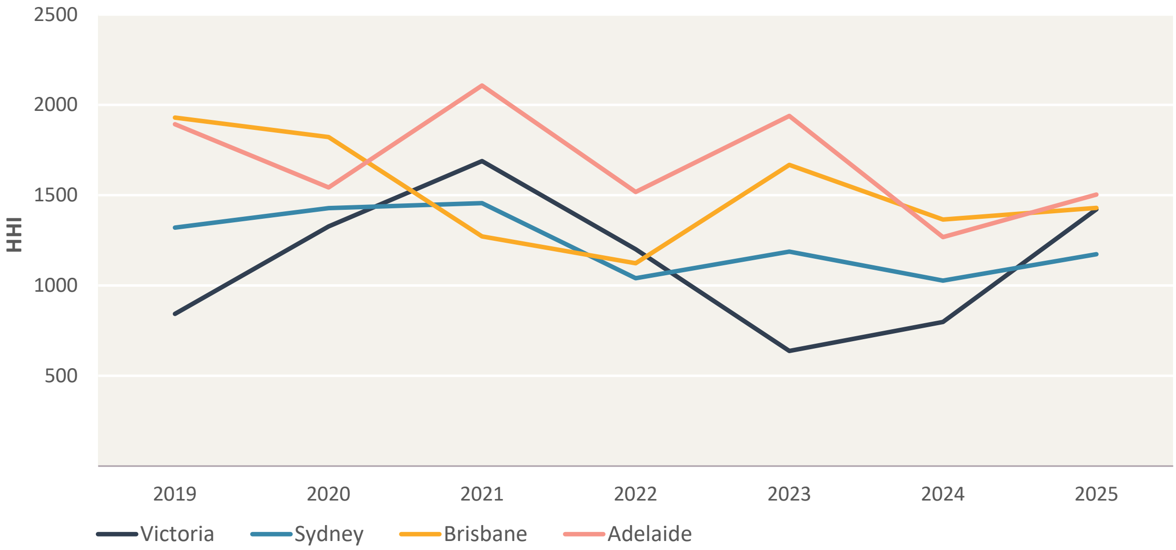


Source: AER analysis using gas market (DWGM and STTM) bidding and schedule data.

3.2.2 Concentration in net sellers is lower than total offers

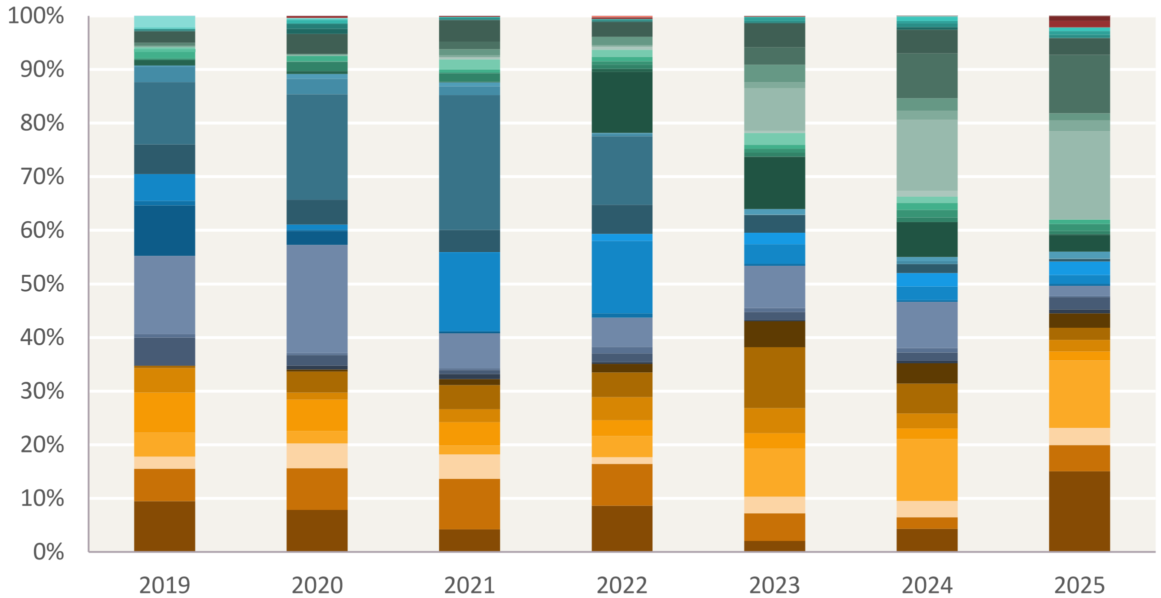
Concentration of net sellers in the DWGM and the Sydney and Brisbane STTMs is comparable to the concentration of participants offering gas into those markets (Figure 3.5). In the Adelaide STTM, concentration of net sellers is materially lower than that of offers and has been decreasing. The participants that have a higher market share on a net trade basis are often not the same participants that have a high market share in offers. The year-to-year change in market share across participants net trading gas is also more variable (Figure 3.6).

Figure 3.5 Annual HHI concentration of net sellers



Source: AER analysis using gas market (DWGM and STTM) schedule data.

Figure 3.6 Market share of net sellers in downstream spot markets



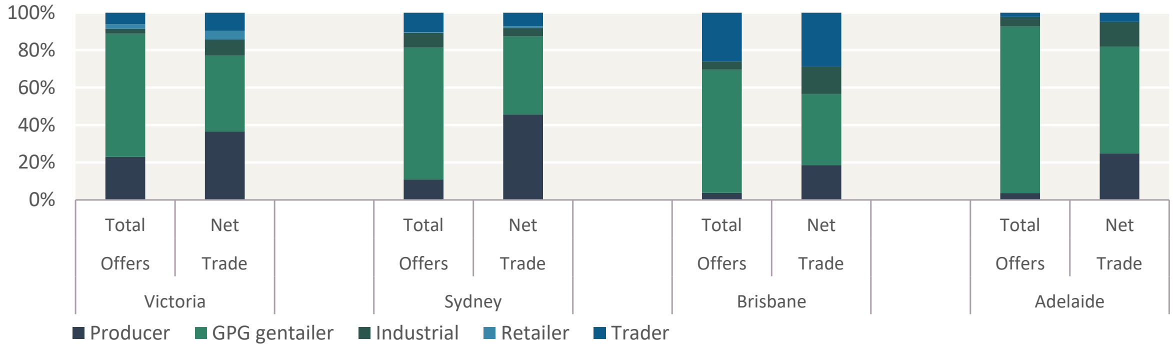
Note: The market share of net sellers sums the net sell position of a participant on a daily basis and then aggregates it across the year for each downstream spot market. This means that only on days where a participant was a net seller in a market, in the year, will it be included in the analysis.
Source: AER analysis using gas market (DWGM and STTM) schedule data.

Large GPG gentailers have a lower market share in net selling compared with total offers across all markets, although they remain the largest participant group net selling gas, except in the Sydney STTM (Figure 3.7). The large difference in GPG gentailers' market share between offers and net selling can be partly explained by their large downstream spot market demand. GPG gentailers offset this demand by offering gas into downstream spot markets at low prices. GPG gentailers also offer a high volume of high-priced offers in some markets, which rarely get scheduled.

Producers, traders and industrials have a greater market share of net selling compared to offers in most markets:

- Producers sell a large relative volume of gas into most downstream spot markets on a net basis. They are the largest participant group net selling gas into the Victorian DWGM and Sydney STTM in most years. Since 2024, producers have net sold higher volumes of gas in the Adelaide STTM compared to previous years, taking market share from GPG gentailers.
- Participation by traders increased materially from 2019 and their share of net selling is largest in the Brisbane STTM. Since 2023, traders have made up between 10% and 14% of net sales in the Victorian DWGM.

Figure 3.7 Market share of total offers and net selling in 2025, by participant type



Source: AER analysis using gas market (DWGM and STTM) bidding and schedule data.

3.3 Concentration in net selling has also decreased on the Gas Supply Hub

The design of the GSH is markedly different to the downstream markets because it is a voluntary market located upstream with options to trade longer-term products. Trade can be bilaterally negotiated 'off-screen', either directly or with the assistance of a broker then lodged on the GSH platform.

As a result of these differences, the GSH has a different composition of participants. Exporters and other producers are the dominant sellers and trade is generally for uncontracted gas. The GSH is a more natural alternative to bilateral contract trade than the downstream spot markets. We explored the GSH and its market structure in our 2025 focus report[39] and found:

[39] AER, Gas supply hub focus report, Australian Energy Regulator, December 2024.

- **Most volumes traded on the GSH are off-screen.** Since 2018 there has been significant growth in off-screen trade, which accounts for almost all growth in traded volumes on the GSH since 2021. Participants highlighted a range of reasons for the popularity of off-screen trade that explained its material growth. These included greater flexibility to meet preferences in price, volume and delivery arrangements, provision of a direct alternative to short-term trading using master gas supply agreements, ability to use brokers and anonymity. In many cases, participants viewed broker-facilitated trade as a workable alternative to on-screen trade with its own advantages.
- **Market concentration of net selling on the GSH has declined**. Since 2018, market concentration among sellers in the GSH has declined as participation increased. However, the top 3 providers of liquidity still account for a significant proportion of trade.[40] The top 3 participants have varied over time, likely reflecting the optional nature of the GSH. However, a few large exporters and producers offer the majority of gas into the market.

3.4 Barriers for entry into the facilitated markets are low

In assessing the effectiveness of competition in gas markets, we consider whether barriers to entry or expansion into the market are sufficiently low so that a substantial degree of market power may only be held by a wholesale gas market participant on a temporary basis. Where there are no barriers, uncompetitive prices should attract new entrants into markets that can profit by competing below those prices.

Barriers to participation in the facilitated markets and short-term contracting appear to be low. However, most participants operating in the facilitated markets offer gas acquired through longer-term contracting. There appear to be some barriers to securing longer-term contracts, which would likely have flow-on effects for competition in facilitated markets.

To participate in any gas markets, participants must have:

- access to gas supply, either through their own production or under contract
- transportation capacity, either through contracts won on the Day Ahead Auction (DAA), or an alternative such as swaps or storage.

3.4.1 Barriers to participation in facilitated markets

We asked participants about potential barriers to entry into the facilitated markets in consultation for our 3 focus reports. Our review found that if a shipper has both access to gas supply and transportation capacity, there appear to be few material barriers to participation in the facilitated markets. Participants did highlight a current inability to pool prudential requirements across the facilitated markets as a barrier to increased facilitated market trade.

40 Standard concentration metrics used to indicate market power are less useful for the GSH because it is voluntary and most trade is off-screen. However, we used these metrics (using net selling) to provide insight into the extent that different participants are using the GSH.

The Australian Government is progressing reform on this issue and prudential arrangements have also been under consideration as part of the Gas Market Review.[41]

For some smaller participants, the cost and complexity involved in facilitated market participation may be a potential barrier. However, the substantial growth of trader activity offers an alternative means for those participants to access the facilitated markets.

Access to transportation and storage also does not appear to be a material barrier for entry into the facilitated markets. Downstream markets are daily markets and while the GSH offers longer-term products, most trade is in daily products. From the previous market inquiry on the DAA, we understand that participants typically prefer to match the duration of their transportation capacity to the supply contracts it supports. As a result, the high volumes and low costs of capacity won on the DAA have mitigated barriers that may have existed in winning short-term transportation capacity. Swaps and storage are also available in significant volumes.

3.4.2 Barriers to long-term supply and transportation contracting

Barriers to gas market participation are greatest in long-term supply and transportation. Those long-term bilateral contracts are the core of Australian gas supply and flow into facilitated markets, which most participants use to optimise around their underlying contracts.

In general, access to supply contracts has become more expensive than pre-2022 prices and producer contracts have become less flexible over time.[42] The gas review and other recent policy measures have been focused on increasing supply of gas to domestic markets. Over recent years the ACCC has identified through its gas inquiry that available contract terms are shortening and less flexibility is available in contracts.[43]

For longer-term supply and transportation, there are potential barriers to entry. Southern gas markets depend increasingly on transportation of gas from basins in Queensland. That transportation depends on a small number of pipelines, such as the South West Queensland Pipeline (SWQP) and Moomba to Sydney Pipeline (MSP), and those pipelines are presently contracted at or near capacity. There are several expansion projects under consideration or underway to increase this capacity and some large foundation contracts due to expire in coming years, both of which may alleviate this potential barrier (section 7.1).

The facilitated markets and DAA are not a complete substitute for long-term bilateral contracting. Participants value the certainty that long-term contracting provides and exclusively trading on downstream spot markets exposes participants to spot market price risk and increased price volatility. Furthermore, despite the success of the DAA in supporting short-term transportation (section 8.1), participants have told us DAA capacity is insufficiently firm or predictable to substitute for longer-term transportation contracting.

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41 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, pp. 12, 29.

42 ACCC, Gas Inquiry 2017–2030, Australian Competition and Consumer Commission, December 2025, p. 24.

43 ACCC, Gas Inquiry 2017–2030, Australian Competition and Consumer Commission, December 2025, p. 35.

4 Conduct in the downstream wholesale gas spot markets

Key findings

- Wholesale gas offer prices in the downstream spot markets have been relatively stable over the past 3 years but are higher than the years before the 2022 energy crisis.
- Higher-priced wholesale gas offers are driven by a tighter supply-demand outlook, rather than an exercise of market power. With key supply sources like Longford in decline, participants are valuing gas higher than they used to.
- Offers across the downstream wholesale gas spot markets are interconnected, with many participants operating across all markets.
- Gas retailers with gas-powered generation (GPG) assets (‘GPG gentailers’) offer the most gas across all participant groups. Their offer behaviour at Iona highlights some reliance on the storage facility to manage high GPG demand periods.
- Two high price events in the wholesale gas markets since 2023 were predominantly driven by a combination of underlying supply and demand conditions, including supply constraints and high demand.

We have analysed whether there is evidence that a sustained exercise of market power has contributed significantly to price movements or market volatility in the downstream spot markets. Participants can use a range of short-term or long-term strategies to exercise market power, including:

- reducing the amount of gas offered to the market, which can create an artificial shortage and push up prices.
- repricing offers over longer periods to higher prices, to drive average prices higher.

This chapter assesses longer-term trends in gas offers by market participants and two case studies on high price events since 2023. We have not analysed offers in the upstream, voluntary Gas Supply Hub (GSH) because most trades are negotiated off-screen, with limited visibility over off-screen offers. However, we have found that prices between downstream spot markets and upstream GSH align (section 5.3.3), which may suggest similar factors are influencing participant behaviour across downstream and upstream markets.

4.1 Supply factors have influenced longer-term offer trends

Wholesale gas offer prices across the downstream spot markets have stabilised since 2022 but are priced higher than before the energy crisis. The higher priced offers appear to be a consequence of upstream changes in supply conditions, (sections 2.4.1 and 2.5) rather than a sustained exercise of market power.

Offers in the downstream spot markets tend to follow a seasonal trend, where higher volumes of gas supply are offered during winter, particularly at $0 per GJ, to meet heating demand (Figure 4.1). Many participants offer gas at $0 per GJ to ensure that their contracted supply for downstream demand will be scheduled into the market (Box 4.1). Beyond these seasonal trends, offer prices have largely shifted in line with supply conditions over the past several years.

Box 4.1 Why do market participants make $0 per GJ offers?

It is compulsory for participants to trade through the DWGM or STTMs if they intend to inject or withdraw gas from the Declared Transmission System (Victoria) or the Sydney, Brisbane and Adelaide hubs.

Therefore, it is common for participants to inject enough contracted gas to meet their own demand and then withdraw it. To achieve this, they will offer enough gas at $0 per GJ to ensure it is scheduled.[44] Then as a buyer, they will submit a price taker bid for the same amount of gas. A price taker bid means they will pay the market price, no matter what that price is. This ensures they will be able to withdraw the gas they offered to supply. The participant will receive the market price as a seller and pay the market price as a buyer, which nets out to $0 (the volume offered is not exposed to the spot market price).

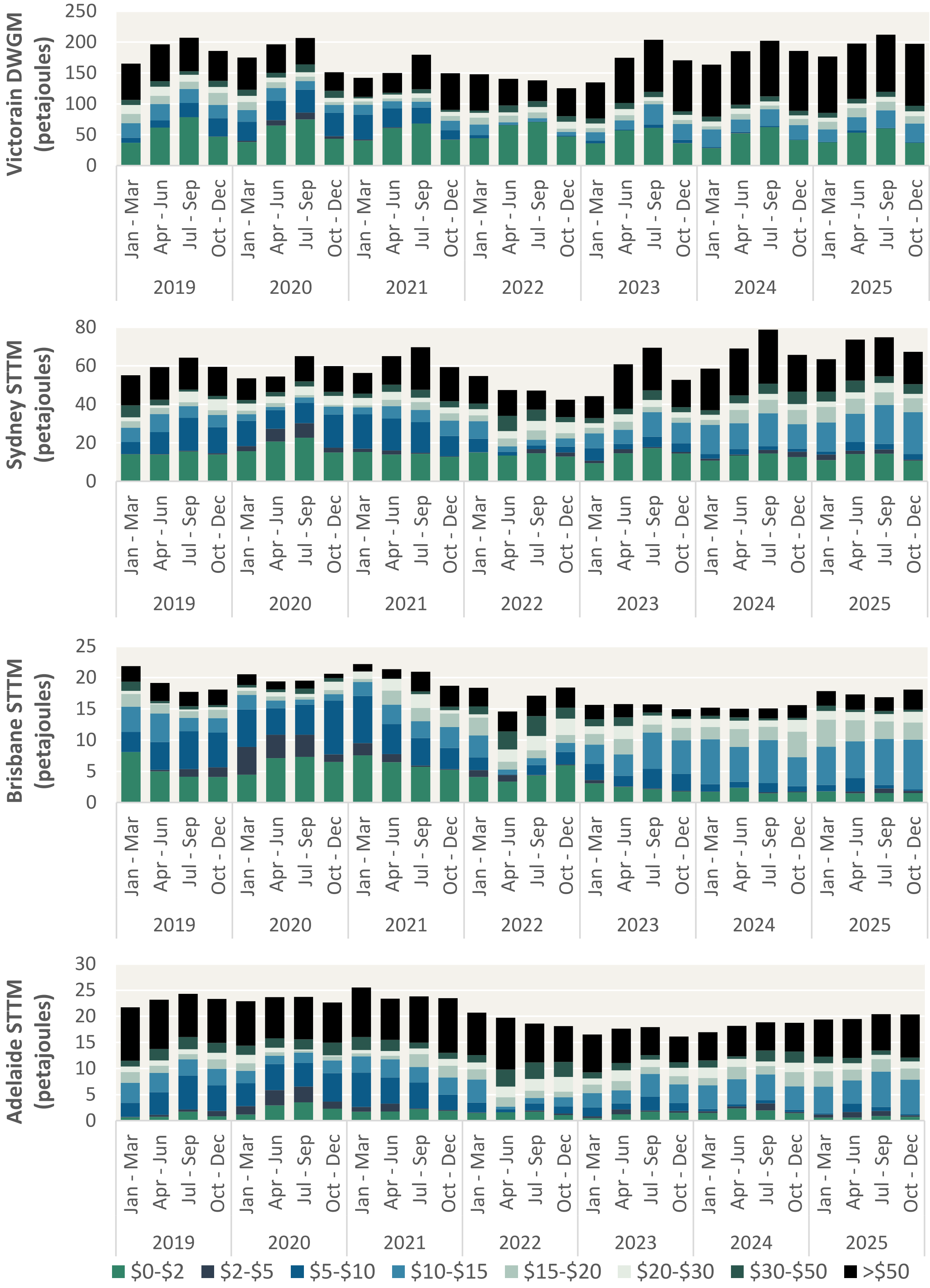
$0 per GJ offers often reflect downstream retail, commercial or industrial demand participants are required to meet. More expensive offers typically reflect additional gas that participants can supply for a certain price.

In 2019, a significant proportion of offers were made in the $5 to $10 per gigajoule (GJ) range, with downstream spot prices typically clearing around $10 per GJ. During 2020, the COVID-19 pandemic suppressed international gas demand, giving LNG exporters more incentive to supply the domestic market. With more domestic supply, many participants shifted offers down to between $2 to $5 per GJ. However, LNG exports later resumed at record levels in 2021 and many participants shifted offers back into the $5 to $10 per GJ range.

In 2022, uncertainty in both international and domestic markets led participants to offer less gas and price up their offers (Figure 4.1). Many participants only offered enough supply to cover their own demand, and $5 to $10 offers largely disappeared, being replaced by more expensive offers. Since 2022, downstream spot market offer prices have stabilised but the proportion of lower-priced offers under $10 per GJ have declined. These offers have mostly been replaced by those in the more expensive, $10 to $15 per GJ range.

44 On a gas day, all offers priced below the market clearing price are scheduled. Those who made the offers are paid the market clearing price. $0 offers are almost always scheduled, as the downstream spot markets typically clear at a price above $0.

Figure 4.1 Total offers, by price band and quarter



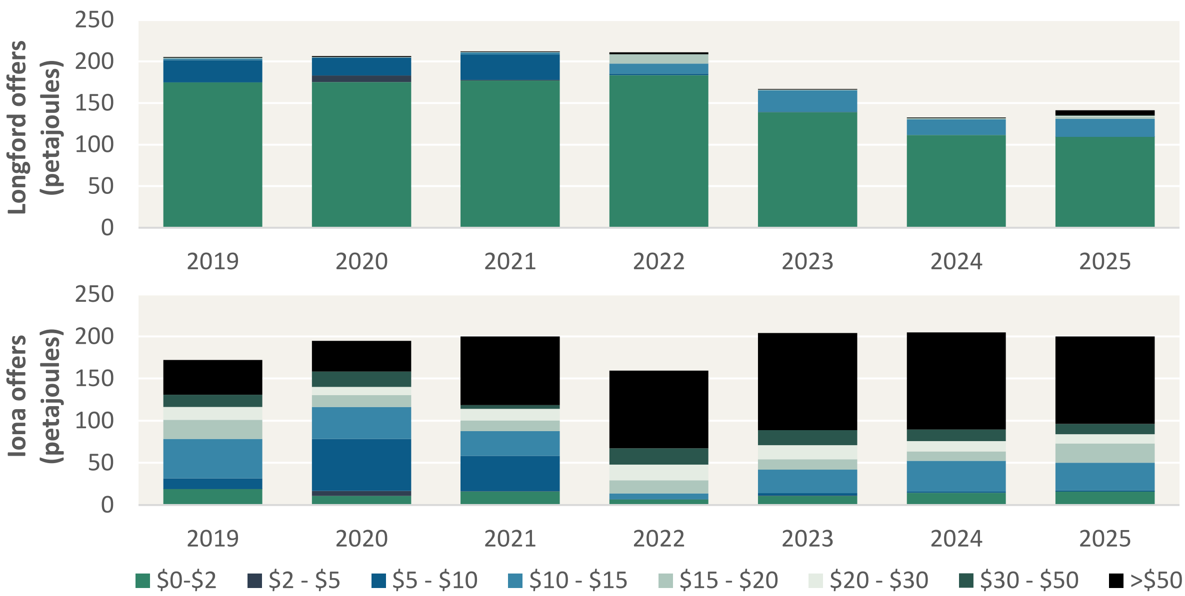
Note: Total offers are from 1 January 2019 to 31 December 2025. For the Victorian DWGM, offers are for the 6 am schedule across all injection facilities. Graphs vary in the vertical axis scale for readability of the offer bands.

Source: AER analysis using DWGM and STTM data.

Declining production in southern states is a factor driving the shift to higher-priced offers (section 2.4.2). The peak capacity of Victoria's main production facility at Longford fell from around 1,000 terajoules (TJ) a day in 2019 to 700 TJ a day in late 2024. This has led to fewer supply offers at Longford (Figure 4.2). With declining production, market participants are increasingly reliant on storage such as Iona to manage peak day winter demand. As participants are valuing storage more highly, offer prices have become more expensive at Iona compared with before 2022.

A relatively high proportion of offers in the Victorian DWGM, Sydney STTM and Adelaide STTM are priced above $50 per GJ. This offer behaviour is prevalent among GPG gentailers who have storage capacity, particularly at the Iona storage facility (section 4.2.2). These offers typically reflect gas supply participants have contracted but are saving for high demand periods.

Figure 4.2 Victorian DWGM – offers at the Longford and Iona injection facilities



Note: Total offers are from 1 January 2019 to 31 December 2025. Offers are for the 6 am schedule across the Longford and Iona injection facilities.

Source: AER analysis using DWGM and STTM data.

4.2 Offer prices are driven by demand and contracted gas supply

In addition to overall offer patterns, we have analysed offers in the downstream spot markets grouped by: GPG gentailers, retailers and industrials, producers, and traders.[45] Offers from the various participant groups are shaped by the availability of flexible, contracted gas:

- GPG gentailer, industrial and retailer participants typically have upstream, contracted gas supply that they schedule into the downstream spot markets to meet their own

45 The three LNG exporters are not active in the downstream spot markets and so have not been included as a participant group.

demand. These participants may sometimes have additional flexible gas that they can offer into the market at different price ranges.

- Producers and traders may not have downstream demand and can be more opportunistic when selling into the downstream spot markets. These participants tend to offer gas at higher price ranges, but still around the market clearing price to ensure their offers are scheduled.

4.2.1 GPG gentailers' offers reflect the need to meet retail and GPG demand

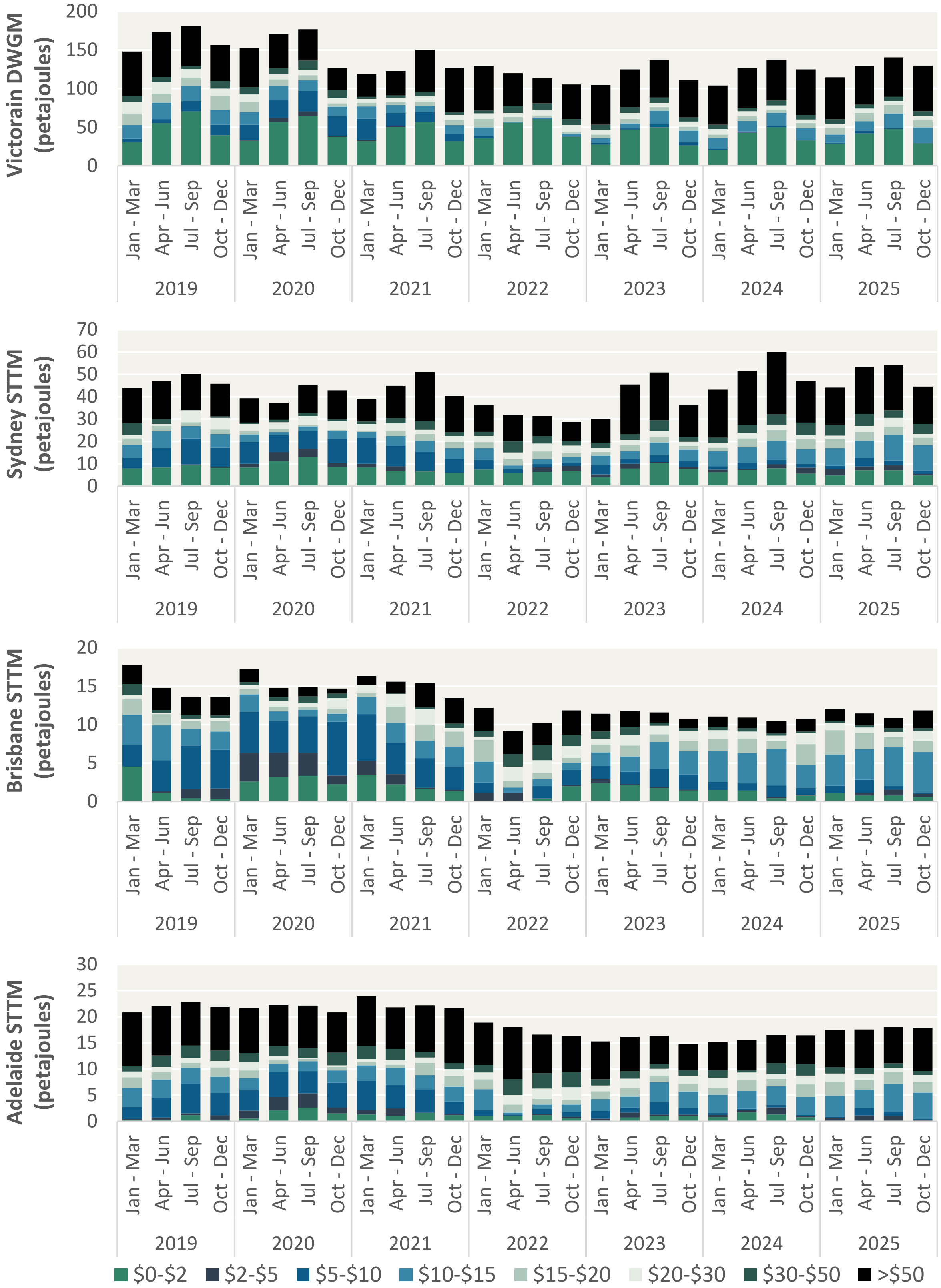
GPG gentailers supply the most gas to the downstream spot markets to service their retail customers, GPG generators and contracts. Their offer behaviour is shaped by changes in retail and GPG demand, as well as supply constraints. GPG gentailers often offer volumes of gas supply at $0 per GJ, which typically reflect contracted supply that must be scheduled through the spot markets to meet retail or GPG demand (Figure 4.3).

In the Victorian DWGM and Sydney STTM, $0 per GJ offers increase during winter due to higher retail demand for gas heating and increased GPG demand. This seasonal pattern is less noticeable in the Brisbane and Adelaide STTMs, where there is less reliance on gas heating and, in the case of Adelaide, where not all GPG demand is scheduled through the spot market.

GPG gentailers also offer a significant proportion of gas above $50 per GJ. These offers typically reflect flexible, contracted supply for future retail or GPG demand. Most offers above $50 per GJ are made at facilities with storage capabilities, including Iona storage and pipelines. Pricing a portion of offers above $50 per GJ ensures GPG gentailers:

- have enough gas stored to meet future demand (when offers priced above $50 per GJ are not scheduled) or
- are only providing additional flexible gas under severe market conditions (when offers priced at $50 per GJ or above are scheduled).

Figure 4.3 GPG gentailer total offers, by price band and quarter



Note: GPG gentailer offers are from 1 January 2019 to 31 December 2025. Graphs vary in the vertical axis scale for readability of the offer bands. For the Victorian DWGM, offers are for the 6 am schedule across all injection facilities.

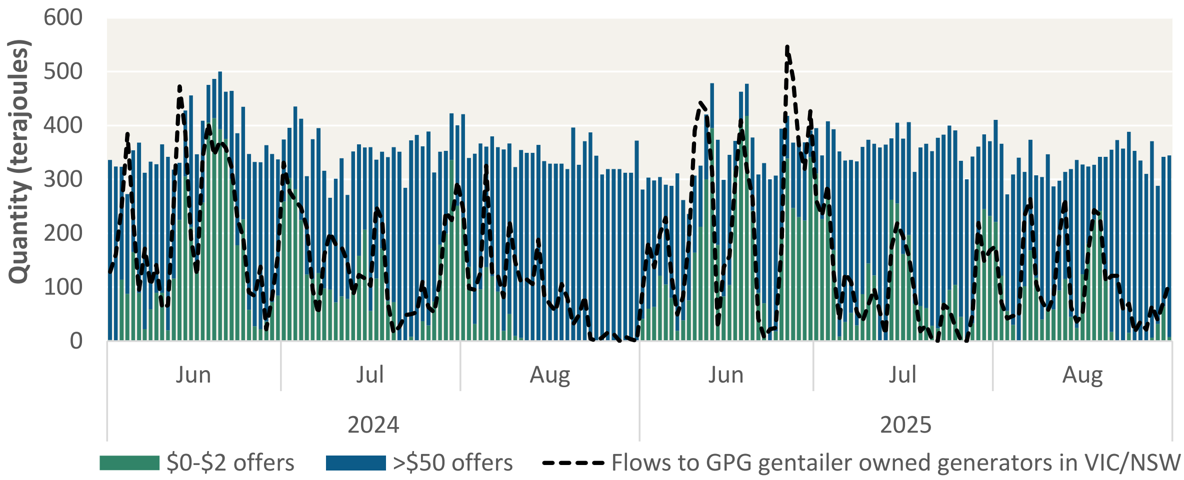
Source: AER analysis using DWGM and STTM data.

4.2.2 GPG gentailers' offers reflect some reliance on Iona storage to meet unexpected GPG demand

GPG gentailers' offers also reflect some reliance on Iona storage to meet unexpected GPG demand. When GPG demand is high, GPG gentailers have typically shifted offers priced above $50 per GJ into the $0 to $2 per GJ range. For example, Figure 4.4 shows GPG gentailers' offers at Iona between $0 to $2 per GJ and above $50 per GJ during winter 2024 and 2025 (left-hand axis). These volumes are compared with flows to GPG-gentailer-owned generators in Victoria and Sydney over the same period (right-hand axis).

High flows to GPG generators usually coincided with an increase in offers between $0 and $2 per GJ and a decrease in offers priced above $50 per GJ. This reflects that GPG gentailers were likely taking gas out of Iona storage to meet part of their GPG demand. It also reinforces that Iona storage plays a critical role in managing unexpected demand in both gas and electricity markets.

Figure 4.4 GPG gentailer offer behaviour at Iona and flows to GPG-gentailer-owned generators in Victoria and NSW



Source: AER analysis using DWGM, STTM and Gas Bulletin Board data.

4.2.3 Retailers and industrials offer gas in the spot markets to meet their own demand

Retailers and industrials both offer gas in the downstream spot markets to service their own retail or industrial demand, with a significant proportion of offers priced between $0 and $2 per GJ (Figure 4.5, Figure 4.6). Both retailers and industrials are rarely price setters in the spot markets because they offer relatively low volumes compared with other participant groups.

For retailers, $0 to $2 per GJ offers typically follow a seasonal pattern in line with retail demand, which is higher during winter. Many offers are made at the Longford production facility, as retailers often rely on it to meet their customer demand. In the Sydney STTM, retailer offers declined significantly after 2022, following the exit of Weston Energy from the market (Figure 4.5). The volume of retailer offers recovered in 2025, with new entrants and existing retailers offering more volumes than in previous years.

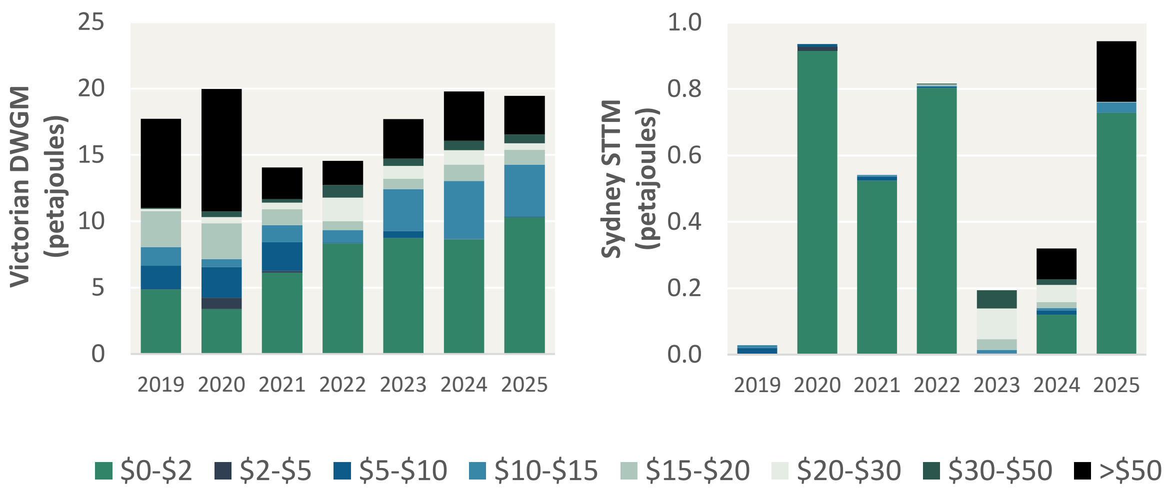
Volumes of industrial offers between $0 to $2 per GJ tend to be more consistent than retailer offers as industrial demand rarely fluctuates seasonally. However, industrials have less flexibility in their contracted supply compared to retailers and therefore offer a lower proportion of volumes outside the $0 to $2 per GJ range. Industrial offers declined in the Brisbane STTM following Dyno Nobel Limited (formerly Incitec Pivot) closing its large industrial plant in early 2023.[46] In the Sydney STTM, industrial offer volumes also declined from 2023, possibly reflecting differences in underlying contracts or some industrials potentially deciding to purchase off the spot market through retailers.

Both retailers and industrials have mostly shifted flexible offers (above $0 per GJ) into more expensive price ranges compared with 2019 to 2021:

- For retailers, the shift is likely due to depleting production at Longford. During our consultations, several participants including retailers raised concerns about Longford's declining production output, noting there are very few alternative sources of supply within Victoria.
- For industrials, some noted that their contracted gas supply was much more expensive than spot market prices. Therefore, when they did have flexible supply, they sought to recover as much value as possible while still being scheduled.

Industrials have also increasingly net bought off the spot markets since 2022. Given their position as a net buyer, their flexible offer prices are more likely reflective of market prices at the time of their offers.

Figure 4.5 Retailer total offers, by price band and year

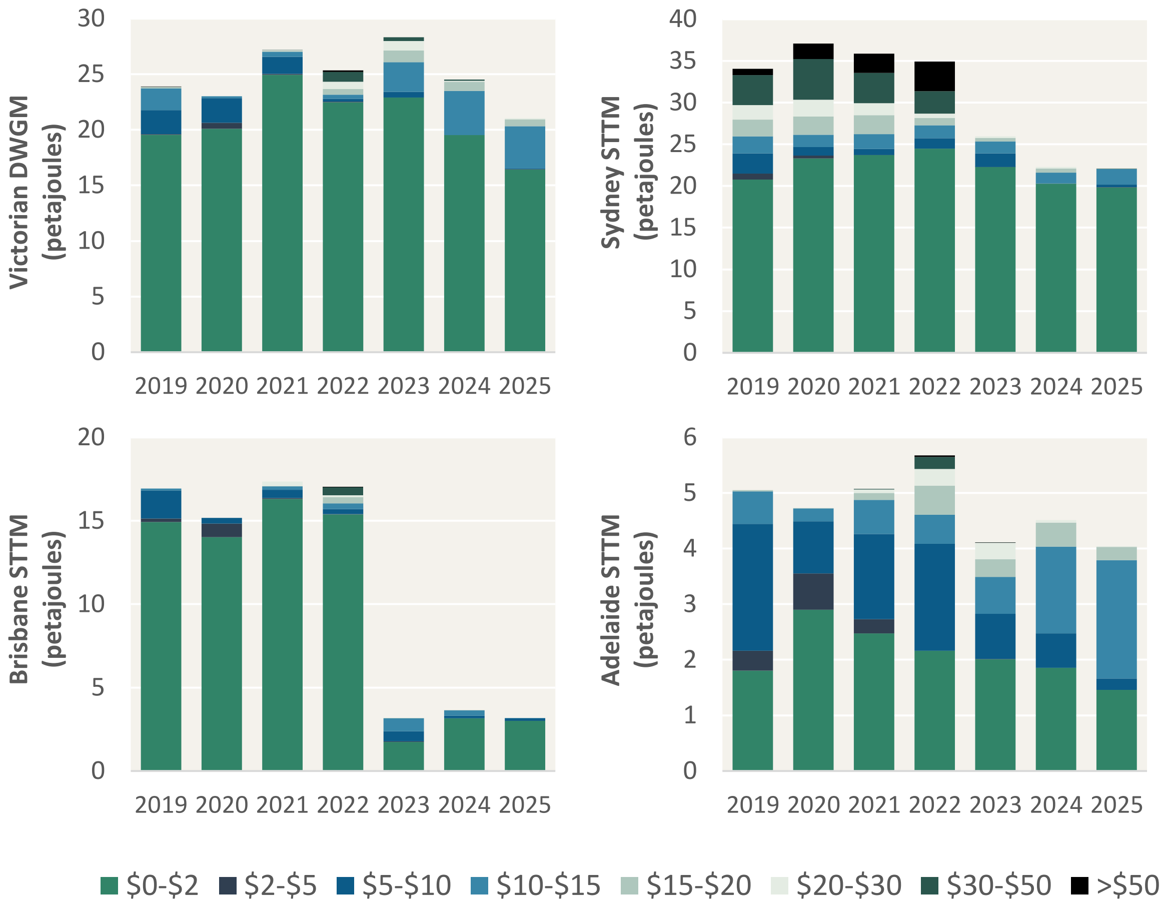


Note: Total offers are from 1 January 2019 to 31 December 2025. Graphs vary in the vertical axis scale for readability of the offer bands. For the Victorian DWGM, offers are for the 6 am schedule across all injection facilities.

Source: AER analysis using DWGM and STTM data.

46 Dyno Nobel, [Gibson Island manufacturing operations to cease at end of 2022](), media release, 8 November 2021.

Figure 4.6 Industrial total offers, by price band and year



Note: Total offers are from 1 January 2019 to 31 December 2025. Graphs vary in the vertical axis scale for readability of the offer bands. For the Victorian DWGM, offers are for the 6 am schedule across all injection facilities.

Source: AER analysis using DWGM and STTM data.

4.2.4 Producers and traders offer opportunistically in the downstream spot markets

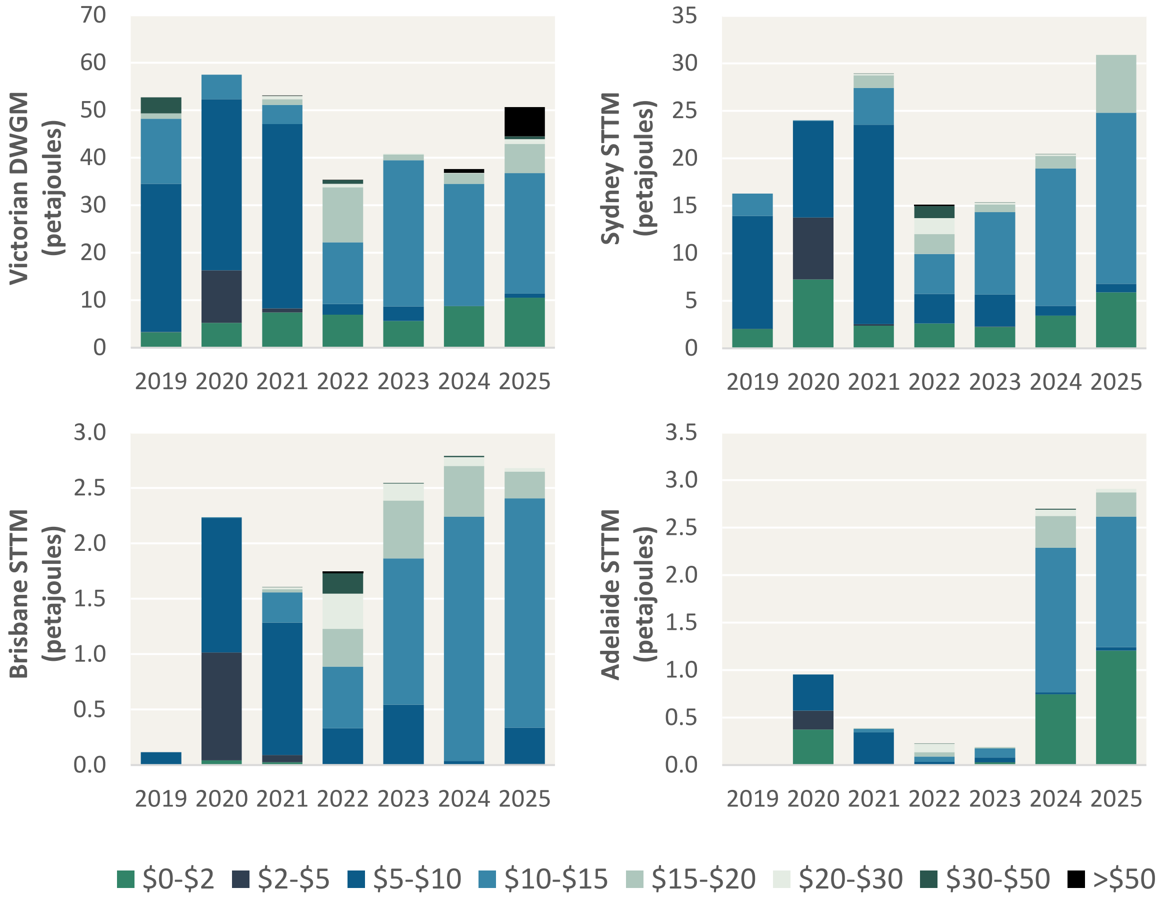
Producers and traders typically do not have downstream demand and are more opportunistic when offering supply into the spot markets. Producers typically offer gas at or slightly below the clearing price to ensure they are scheduled. Their offers tend to represent excess gas that they have not contracted out to participants through supply agreements and sell into the spot market near the clearing price.

Traders similarly offer most of their gas around the clearing price. However, they have a higher proportion of offers in higher price ranges, potentially reflecting greater flexibility. Most offers made by traders are at key transportation points, such as Culcairn, which is a key location in the Victorian DWGM to move gas northwards. This likely reflects traders seeking arbitrage opportunities across the markets.

Since 2022, both producers and trader groups have shifted offers into higher prices between $10 to $15 per GJ. Traders' offer volumes have also grown significantly since 2022 (Figure

4.7, Figure 4.8). This potentially reflects an increase in the number of smaller, non-market participants relying on traders to act as intermediaries to manage their gas positions.

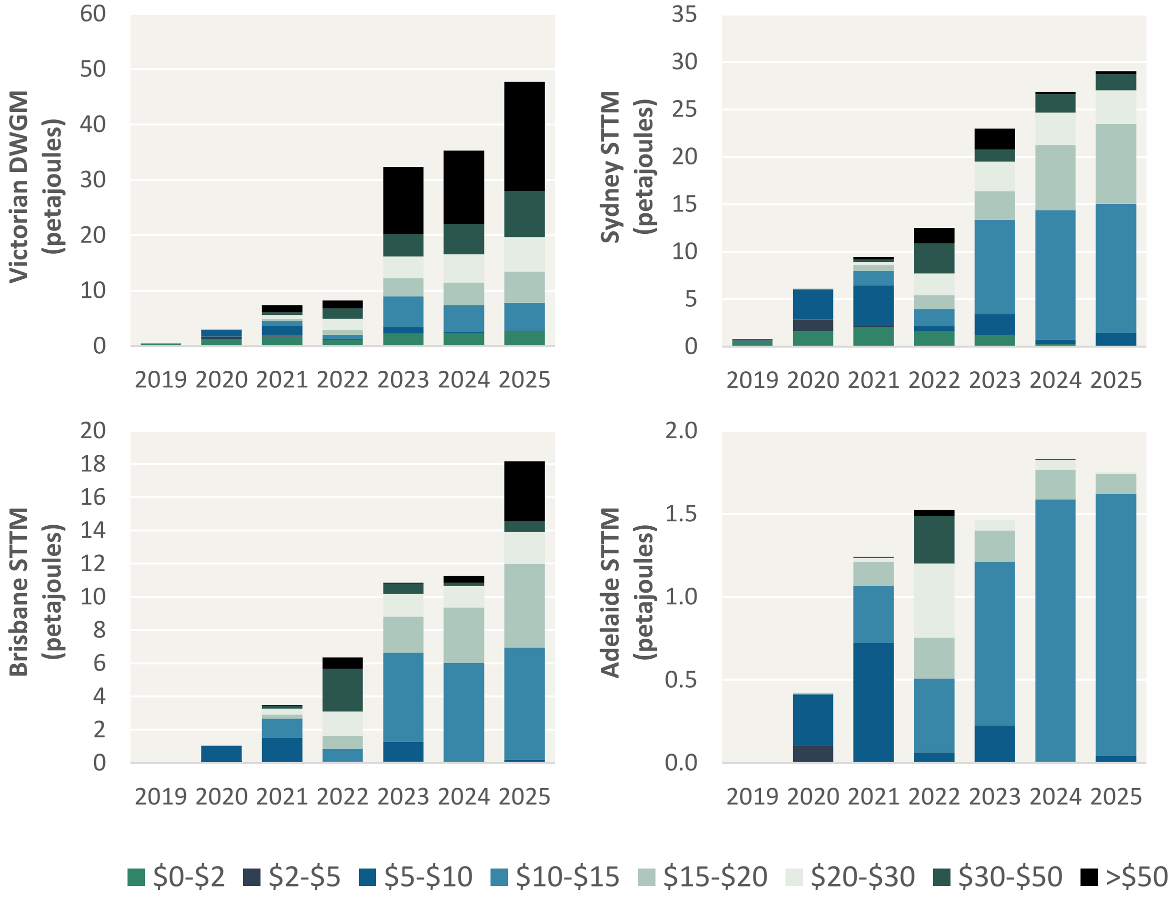
Figure 4.7 Producer total offers, by price band and year



Note: Total offers are from 1 January 2019 to 31 December 2025. Graphs vary in the vertical axis scale for readability of the offer bands. For the Victorian DWGM, offers are for the 6 am schedule across all injection facilities.

Source: AER analysis using DWGM and STTM data.

Figure 4.8 Trader total offers, by price band and year



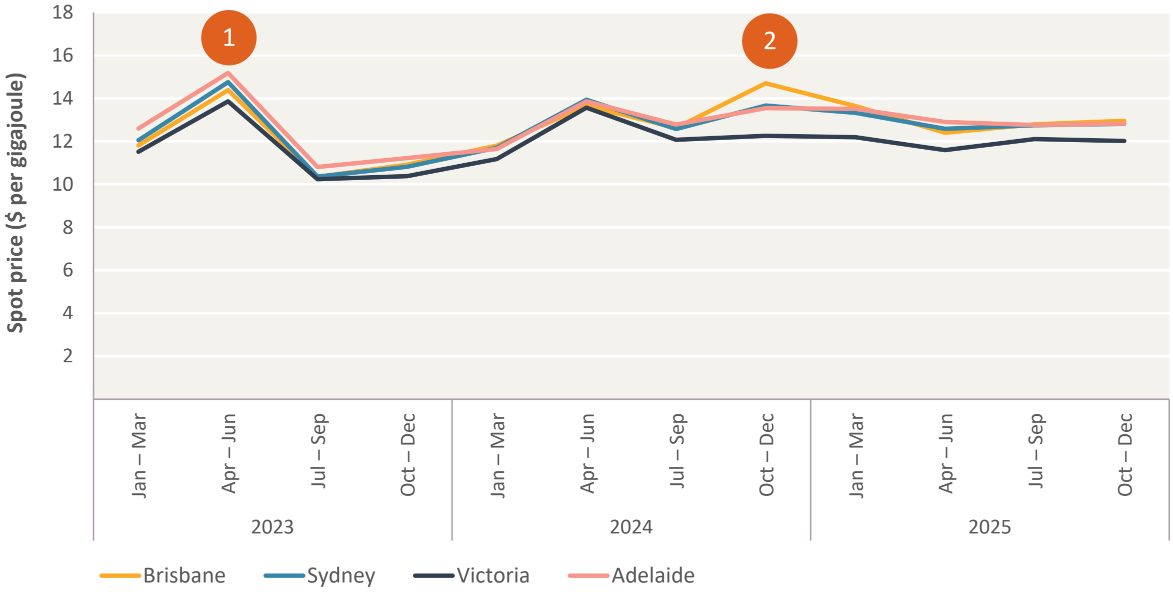
Note: Total offers are from 1 January 2019 to 31 December 2025. Graphs vary in the vertical axis scale for readability of the offer bands. For the Victorian DWGM, offers are for the 6 am schedule across all injection facilities.

Source: AER analysis using DWGM and STTM data.

4.3 Supply and demand factors have driven high price events

Beyond analysis of long-term offer trends, we have examined whether participant conduct has contributed to shorter periods of high prices in the downstream spot markets which could suggest the potential exercise of market power. We highlight 2 case studies from the past 3 years (Figure 4.9). The first was during a winter period, when price spikes are more common due to tighter supply and demand conditions. The second was during the summer when high prices are less common. High prices in these case studies were largely the outcome of supply and demand factors.

Figure 4.9 High price events in the downstream wholesale gas markets



1. High prices mostly in May 2023, driven by supply constraints at Longford, transportation constraints on the Moomba to Sydney pipeline and high Victorian demand.
2. High Brisbane prices coinciding with coal plant outages in the NEM, elevated GPG demand and high LNG export demand.

Source: AER analysis using DWGM and STTM data.

4.3.1 Case study 1 – High prices in May 2023 driven by supply and transportation constraints

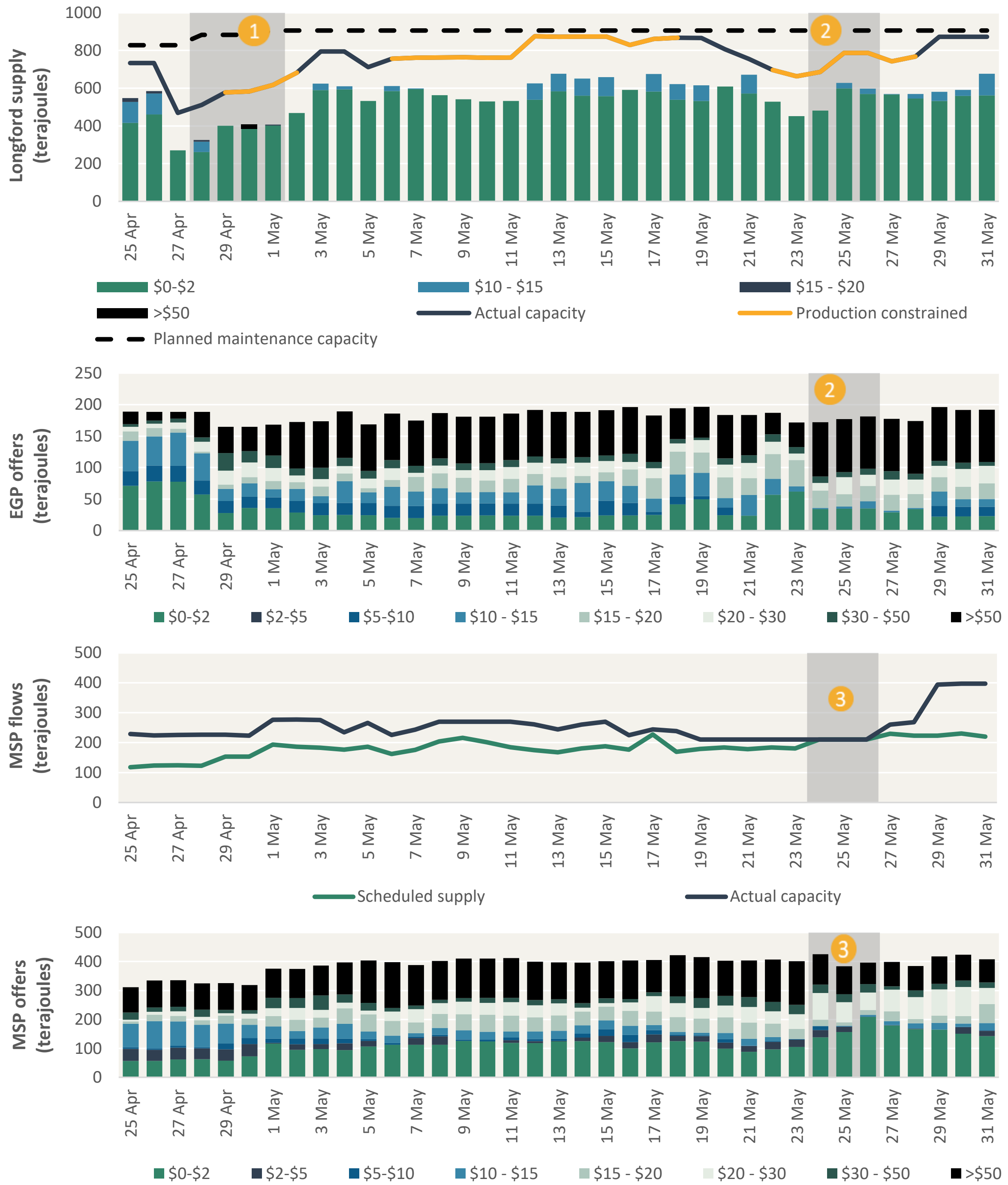
In May 2023, spot prices averaged $18.81 per GJ, reaching as high as $30 in the Sydney STTM. The high prices were primarily driven by domestic supply constraints and demand factors, rather than exercises of market power.

An unplanned compressor outage at Longford led to lower production levels than expected in late April, with several production constraints into May (Figure 4.10). This reduced cheaper supply for southern states as participants either offered less gas from Longford or priced up existing offers. Cold weather in Victoria further put upward pressure on Victorian demand and prices.[47]

Reduced production had flow-on effects to participant offers on the Eastern Gas Pipeline (EGP), which is the main pipeline used to transport gas from Victoria to Sydney. With reduced production, offers to supply gas through the EGP were priced up during May, most notably around 24 to 26 May.

[47] Maximum Victorian demand during May 2023 was 875 TJ/day. Longford did not produce above 800 TJ at any point during May 2023, meaning there were times where Longford supply was not enough to offset Victorian demand.

Figure 4.10 High price drivers in May 2023



1 An unplanned offshore compressor outage at Longford reduced actual capacity at the facility. At the time, there were also pipeline constraints on the Moomba to Sydney pipeline.

2 Production constraints at Longford led to reduced supply in Victoria, with flow on effects to offer prices on the EGP into the Sydney STTM. The proportion of offers above $15 per GJ on the EGP increased during this period. Constraints on the Moomba to Sydney pipeline persisted.

3 Scheduled supply on the MSP hit the pipeline's capacity, and expensive offers within the $20 to $30 per GJ range were scheduled. The proportion of offers between $2 to $20 offers shrank compared to days prior, reflective of Sydney STTM participants shifting flexible offers of supply into higher price ranges.

Source: AER analysis using DWGM and STTM data.

At the same time, pipeline constraints on the Moomba to Sydney Pipeline (MSP) prevented northern supply from reaching the Sydney STTM. Throughout most of May 2022, MSP flows were constrained to 320 TJ per day, lower than its 446 TJ capacity at the time.[48] In response, Sydney STTM participants shifted their offers into higher price bands to reflect constrained supply conditions.

Prices in the Sydney STTM were driven up to $30 per GJ between 24 and 26 May, when scheduled supply on the MSP hit the pipeline's maximum capacity and participants reduced the volume of cheap supply under $20 per GJ.

The increase in offer prices in May 2023 appeared to be driven by participants reactively adjusting their offers in response to supply constraints at both Longford and the MSP facilities. In the remainder of 2023, the MSP's pipeline capacity increased to 475 TJ a day, with Stage 1 expansion works being completed on the MSP on 28 May. Prices were also subdued due to the 2023 winter being rather mild, leading Iona storage to be well stocked even after winter.

4.3.2 Case study 2 – High GPG demand drove high prices in off season (October to December quarter 2024)

Prices during October to December quarter 2024 were unusually elevated for a summer period, averaging $13.55 per GJ and reaching as high as $21.09 per GJ in the Brisbane STTM.

Higher than usual GPG demand, particularly in Queensland, was a main contributing factor. During November and December, GPG demand was around 3–5 PJ higher than the same months in 2022 and 2023. This was driven by higher NEM demand and several coal outages. Higher GPG demand also coincided with high LNG export demand, at around 18 PJ higher than for the October to December quarter 2023.

With high GPG demand, participants across the downstream spot markets adjusted their offers to supply gas into higher price ranges during November and December 2024. The most notable shifts occurred in the Brisbane STTM, where GPG gentailers priced up offers into the $15 to $20 per GJ range and some participants increased their net buy volumes from the spot market (Figure 4.11). GPG gentailers were likely valuing gas higher during this period and buying gas from the spot market to meet additional demand for generation that could not be met from existing supply contracts. Higher offer prices in the Brisbane STTM may have also reflected transportation costs, as southern gas flowed north to support demand. Victorian DWGM offer prices were also higher, with more offer volumes in the $15 to $20 per GJ range during December. Higher-priced Victorian offers reflected increased exports from Victoria to help support higher GPG demand in New South Wales and Queensland.[49]

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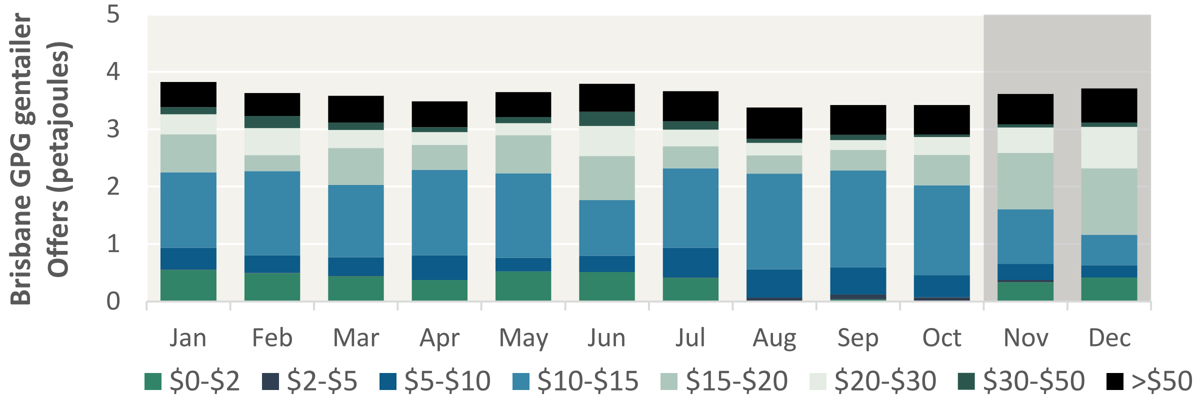
48 Pipeline constraints were planned as part of the Stage 1 expansion of the Moomba to Sydney Pipeline, with works later being completed on 28 May 2022.

49 Gas flows northwards in Q4 2024 were the highest on record. See: AER, Wholesale markets quarterly Q4 2024, Australian Energy Regulator, p. 19.

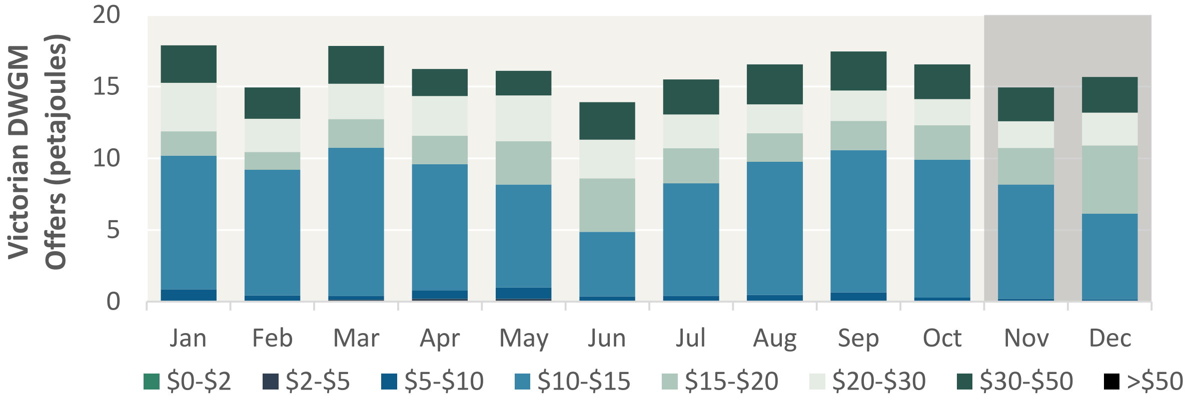
From around mid-December 2024, prices eased as demand reduced, which is usual for the summer season. With reduced demand, participants shifted their offers back into cheaper price ranges of $10 to $15 per GJ.

Figure 4.11 Brisbane GPG gentailer offer stacks by price band - 2024



Source: AER analysis using DWGM and STTM data.

Figure 4.12 - Victorian DWGM offer stacks, by price band - 2024



Note: For more visibility of flexible offers in the Victorian DWGM, $0 to $2 offers and >$50 offers have been removed as these tend to reflect either (1) offers to meet downstream demand or (2) participants preserving supply in storage.

Source: AER analysis using DWGM and STTM data.

5 Efficiency in the facilitated markets

Key points

- Prices in long-term gas supply agreements (GSA) and downstream spot markets have moved in a similar direction since 2020.
- Downstream spot prices have been consistently below delivered contract costs since 2024. Downstream spot prices are at levels we might expect in an efficient and competitive market and these prices are unlikely to attract additional gas supply into the downstream spot markets.
- Downstream spot prices below delivered contract costs may be due to higher premiums on long-term supply (at least 12 months term length) as a result of the market volatility since 2022, greater countervailing power in the spot markets for buyers, and the impact of low cost legacy contracts and the introduction of cheap transport capacity on the Day Ahead Auction (DAA). We will continue to monitor the interaction between spot and contract markets.
- There is generally a high degree of price alignment between facilitated markets, suggesting the markets are efficiently allocating gas to where it is valued most. There are some persistent differences in price between the Victorian Declared Wholesale Gas Market (DWGM) and the Short Term Trading Markets (STTM) hubs in Sydney, Brisbane and Adelaide. This is likely due to inflexibility at key southern production facilities and transport costs between routes that connect the southern markets.

In assessing effective competition under the NGL, the AER is required to have regard to, among other factors, 'whether prices are determined on a long-term basis by underlying costs rather than the existence of market power, even though a particular competitor may hold a substantial degree of market power from time to time'.[50]

In an efficient, competitive market, with low or no barriers to entry and exit, we expect prices to move broadly in line with underlying costs over the longer term. If this is not the case and prices are above cost, a current or prospective participant would have an incentive to enter the market and earn a profit (Box 5.1).

In this chapter, we consider whether prices in the facilitated markets are reflective of an effectively competitive and efficient east coast gas market. Specifically, we consider:

- the relationship between downstream spot and contract prices
- whether downstream spot prices show evidence of competition
- price alignment across the facilitated markets.

50 National Gas Law, section 30AB (b)

Box 5.1 Assessing competitive and efficient prices in the downstream spot markets

While downstream spot markets can be influenced by a range of short-term supply and demand dynamics, upstream costs including wholesale contract costs will influence prices observed in the spot markets over the long term. This is because the spot markets balance daily variation in demand and most spot trading is either secondary trading of wholesale contracted supply, or producers selling uncontracted gas where their alternative is to sell it in the contract market.

In a spot market with adequate supply and some degree of flexibility in contracted volumes, we would expect average spot market prices to move in the same direction as contract prices (for commodity and transport) over the long term. Participants with flexibility in their contract may buy (or sell) into the spot markets when the spot price is lower (or higher) than their contract price, encouraging contract and downstream spot prices to move in a similar direction over the long term.

Spot prices will also depend on the level of competition to supply the downstream spot markets. In theory, in a spot market with competitive supply and some degree of flexibility in offers, spot prices should move closer to average upstream costs over the long term. If spot prices are consistently higher than upstream costs, we would expect participants to provide additional supply. In contrast, in a spot market where suppliers face little competition, spot prices may sit considerably higher than upstream contract costs without any market response.

In reality, downstream spot prices consistently above upstream contract costs may not attract new entry. Spot markets play a relatively small role in the portfolio of most market participants and high spot prices alone are unlikely to provide sufficient incentive for new production given spot price are uncertain and new gas production has high capital costs.

Nevertheless, if spot prices are systemically higher than the costs of contracting gas over the long term, participants may have an incentive to supply additional gas from contracted supply. It may also lead current participants to source a greater proportion of their demand from the contract market. These factors would put downward pressure on spot prices. Spot prices consistently above the delivered contract cost over the long term would suggest suppliers face little competitive constraint and are able to charge above the costs of purchasing contracted supply and transportation.

Our analysis compares spot prices with the delivered contract costs for non-producing participants, including:

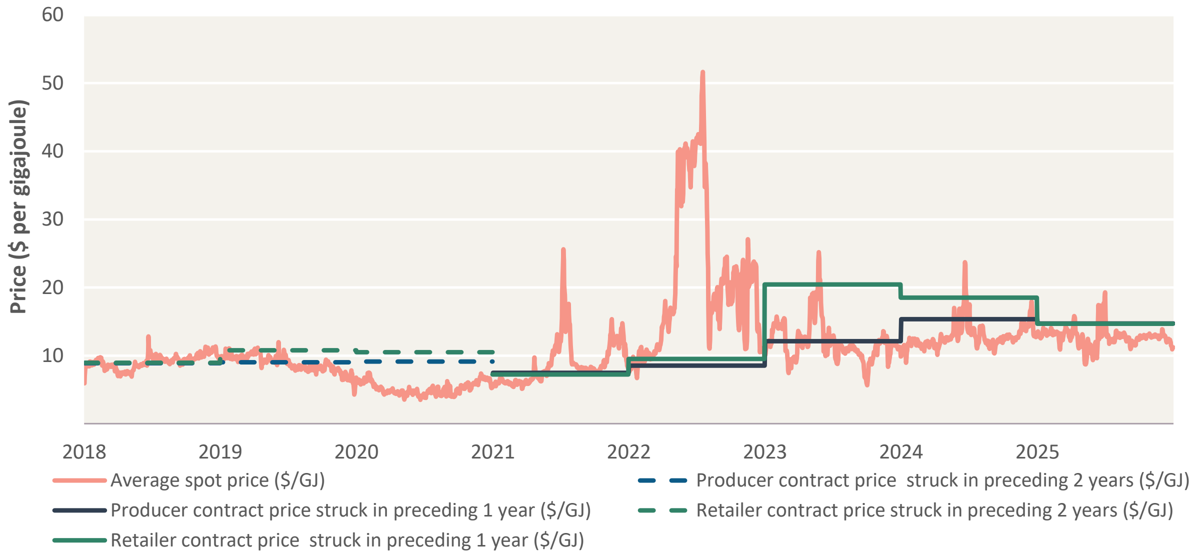
- upstream commodity costs from both short- term (12 months or less) and long-term (at least 12 months length) bilaterally negotiated contracts
- transmission pipeline costs, which may be included in prices struck in GSAs or purchased separately.

Participants may also face additional transportation fees and administrative costs to operate in the facilitated markets that we have not included in our analysis.[51]

5.1 Spot and contract prices have moved in same direction over the past 5 years

Over the past 5 years, while there have been multiple significant shocks to the gas market, both spot and long-term contract prices[52] have moved in a similar direction and settled at a higher level on average by 2025 (Figure 5.1).

Figure 5.1 Average downstream gas market spot prices and long-term GSA prices



Note: The average downstream spot price is a simple average across Brisbane, Sydney and Adelaide STTMs and the Victorian DWGM. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily imbalance price. Producer and retailer contract prices are the volume-weighted average price taken from the ACCC gas inquiry. GSA prices for delivery between 2018 and 2020 are a simple average for producer and retailer VWA prices. All contracts are for quantities of at least 0.5 PJ per year and a contract term of at least 12 months. The GSAs in this analysis have an execution date that is within 2 years of commencement of the supply year for delivery between 2018 and 2020 and execution within 1 year of commencement of the supply year for delivery between 2021 to 2025.

Source: AER analysis of STTM and DWGM data and ACCC Gas Inquiry data.

Since 2020, spot markets have shifted quickly in response to various market shocks, including COVID-19, the 2022 energy crisis and regulatory changes. In contrast, changes in long-term delivered contract prices have taken 1 to 2 years to materialise as current conditions affect participants’ price expectations and trading contracts for future delivery. Nonetheless, both contract and average downstream spot price levels for contracts struck in the preceding year followed a similar trend over the longer term:

[51] ACCC analysis of retailer cost suggests these costs are relatively small compared to commodity and transport costs. While these costs may be more significant for smaller players, they are unlikely to affect our findings.

ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, July 2019, p. 96.

[52] This refers to contracts reported by ACCC with term lengths of at least 12 months.

- **In 2018 and 2019** contract and spot market prices were fairly aligned due to relatively stable supply and demand conditions. Average producer and retailer contract prices were within a range of $8–$11 per GJ, while spot market prices averaged around $9 per GJ.
- **In 2020** downstream spot prices fell sharply due to a significant fall in LNG netback prices (section 2.5.2) just prior to the COVID-19 pandemic, followed by a significant fall in LNG export and domestic GPG demand throughout 2020 with spot prices averaging $5.2 per GJ.
- **In 2021 and 2022,** contract prices fell from the prior impact of COVID-19 and falls in LNG and oil prices, leading to LNG producers being more active in selling to the domestic market.[53] Prices averaged between $7.2 per GJ and $9.5 per GJ for producers and retailers. At the same time, domestic spot prices surged in response to rebounding LNG export prices, high domestic demand and supply constraints and the international energy crisis in 2022, reaching a peak of $25.6 per GJ in 2021 and $51.7 per GJ in 2022.
- **In 2023,** downstream spot prices fell quickly from the highs observed during the 2022 crisis and the supply-demand balance eased with reductions in projected GPG demand and mild weather.[54] In contrast, contract prices (which were negotiated during the 2022 crisis) increased significantly.
- **Since 2024** average downstream spot prices have remained above $12 per GJ. Average contract prices fell and by 2025 producer and retailer average prices had converged at $14.7 per GJ. However, average contract prices remained elevated above spot market prices. Tight supply conditions and a pause in some producer contracting in response to the development of the Gas Market Code likely placed upward pressure on prices.[55] Short-term trades in the facilitated markets were exempt from the price rules. Participants reported to the ACCC's Gas Inquiry that the $12 per GJ reasonable price level acted as a price floor in negotiations.[56]

5.2 Prices in the downstream spot markets have been below contract prices

The price of delivered contracted gas supply is the primary input cost for most spot market participants. We have evaluated the competitiveness and efficiency of spot market prices by comparing them with long-term delivered contract prices and also with short-term bilateral contract prices.

53 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, p. 146.

54 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, p. 151.

55 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, pp. 28, 151.

56 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2025, p. 42; ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, p. 38.

5.2.1 Spot market prices have been below both long and short-term contract prices

Over the past 3 years, prices in the downstream spot markets have largely been below delivered long-term contract costs (Figure 5.2). This suggests that prices in spot markets are at levels we might expect in an efficient and competitive market. These levels are unlikely to attract additional gas supply into these markets.

In 2023, prices across all the downstream spot markets averaged between $11.5 per GJ and $12.4 per GJ, moving closely around the delivered long-term contract prices that ranged from $9 per GJ to $16.7 per GJ. Average prices were all around the mid-point of their delivered contract price range.

The close alignment between spot and contract prices in 2023 likely reflects a transitory period of adjustment in the market. After market disruption in 2022, spot market prices were on a downward and stabilising trajectory, with the average downstream spot price falling from $20.8 per GJ in 2022 to $11.9 per GJ in 2023. Prices in the contract market were climbing from a lower base, as contract market suppliers would have been delivering gas traded prior to the 2022 crisis and at a time when the impact of COVID-19 was still being felt.

Over 2024 and 2025, average annual downstream spot prices were significantly below delivered long-term contract prices:

- In 2024, average annual spot prices ranged from $12.3 per GJ to $13.2 per GJ and prices across all markets were below the minimum delivered contract price by 20.2% to 27.0%.
- In 2025, prices began converging as delivered contract prices fell. Average annual spot prices ranged from $12.0 per GJ to $13.0 per GJ and they ranged from 17.7% below the minimum contract price in Victoria to a similar level as minimum contract price in Brisbane.

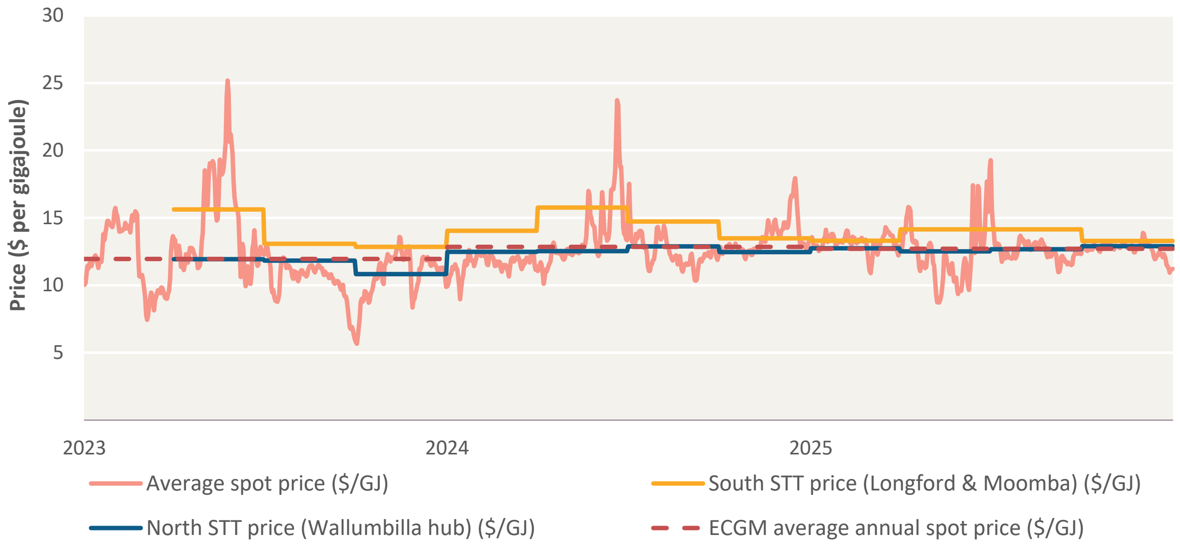
Figure 5.2 Daily downstream spot prices and delivered contract prices

Note: Delivered contract price is calculated as the volume-weighted average (VWA) long-term GSA price plus the standing price for firm transportation to the relevant spot market. The price range shows the minimum and maximum delivered price, depending on whether the GSA is from a producer or retailer and from a northern or southern location. GSA prices are the long-term GSA VWA prices reported in the ACCC gas inquiry. All contracts are for quantities of at least 0.5 PJ per year and a contract term of at least 12 months. The GSAs in this analysis have an execution date within 2 years of the supply year for delivery. The average downstream spot price is a simple average across Brisbane, Sydney and Adelaide STTMs and the Victorian DWGM.

Source: AER analysis of STTM and DWGM data, ACCC Gas Inquiry data and standing prices reported by pipeline service providers under Part 10 of the NGR.

Downstream spot prices have also been close to or lower than short-term contract prices (Figure 5.3) over the past three years.[57] Short-term contracts are more comparable in term length to spot market trade than long-term bilateral contracts. Downstream spot prices were on average $1.0 per GJ to $1.5 per GJ lower than short-term contract prices for delivery to southern states between 2023 and 2025.

Figure 5.3 Average downstream spot prices and quarterly short-term contract prices



Note: The volume-weighted average prices include all transactions for supply in the quarter. These prices exclude pricing structures linked to the STTM or DWGM, prices that are index linked or where the transaction was between related parties. North STT prices only include transactions for delivery at the Wallumbilla hub (Wallumbilla or RBP IPT locations) and the South STT price only includes transactions for delivery at the Moomba or Longford hubs. The average downstream spot price is a simple average across Brisbane, Sydney and Adelaide STTMs and the Victorian DWGM.

Source: AER analysis of STTM, DWGM and Gas Bulletin Board data.

Annual downstream spot prices were more closely aligned with northern short-term contracts (largely trades for delivery at the Wallumbilla hub) than southern short-term contracts. However, these short-term contract prices do not include transportation costs to downstream markets which would raise both north and south prices, and lead to northern delivered prices above average spot prices (around $1.0 to $2.0 per GJ higher).

Downstream spot prices appear to be consistently above long and short-term contract prices over winter months. However, this is unlikely to provide sufficient incentive for new supply because annual average prices in the spot markets are still lower. Peak day prices and higher volumes over winter only increase average annual downstream spot prices by no more than $0.2 per GJ.

Higher winter prices likely reflect scarcity and pipeline constraints, but there may also be greater ability for the exercise of market power during this time. The simplified annual average GSA price also may not account for the need for a participant to consider costs of securing more flexible contract terms or storage over the winter period to manage

57 Bilaterally traded contracts with a term length of 12 months or less.

unexpected peaks. These additional costs may mean that the effective winter price for long-term GSAs is higher.

5.2.2 Several factors contribute to spot prices being lower than contract prices

There are several reasons why downstream spot prices may generally be lower than delivered contract prices (long term and short term):

- **Gas users may place a higher premium on the certainty that a long-term gas supply agreement provides, particularly since 2022.** While both producers and users of gas typically have an incentive to trade longer-term gas contracts, market volatility and heightened uncertainty since 2022 has led producers to reduce the availability of long-term GSA offers. This has led to higher prices in the contract market and ongoing difficulties for gas users to procure long-term supply.[58] This impact appears to be lessening over time.
- **Since 2023 there may have been an oversupply of spot gas putting downward pressure on prices.** Total demand in the spot markets has been lower since 2023, particularly in Victoria and Queensland (section 2.3.1).
- **Lower spot prices may also reflect relatively less market power among net suppliers in the spot market compared with the contract market.** In the contract market, producers and large retailers may have more ability to hold off on new production or warehouse current supply for future sales. This is particularly true for contracted gas at fields that no longer require foundational gas contracts to underwrite the initial investment. In contrast, it is possible that in the spot markets market power is more balanced between sellers long on their position that are willing to sell gas at a discount and buyers who are short and require additional gas to meet essential gas demand.
- **Delivered contract costs based on legacy gas contracts and foundational transport contracts are not captured by this analysis and would likely have been significantly lower.** The volume of gas delivered between 2023 and 2025 at lower prices struck prior to 2022 is likely substantial. Long-term GSAs entered into for the 2023–2025 supply years accounted for less than half of what they did for the 2021 and 2022 supply years, when prices were significantly lower.[59] The ACCC observed a similar dynamic in their review of retailer pricing over 2014 and 2018, finding that high retailer margins were likely in part due to the lower cost legacy contracts larger retailers had entered into before price increases.[60]
- **The introduction of the Day Ahead Auction (DAA) has reduced transportation costs for some participants and may mean delivered contract costs are lower.** The majority of capacity won via the auction is won at the price floor ($0 per GJ) and a significant proportion of this is linked to routes connecting to a downstream spot market.

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58 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, p. 151.

59 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, p. 41.

60 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, January 2020, p. 119.

Cheap transport capacity may be putting downward pressure on downstream spot prices[61] but is not captured in the delivered contract costs considered in this analysis.

5.3 Prices are closely aligned across the facilitated markets

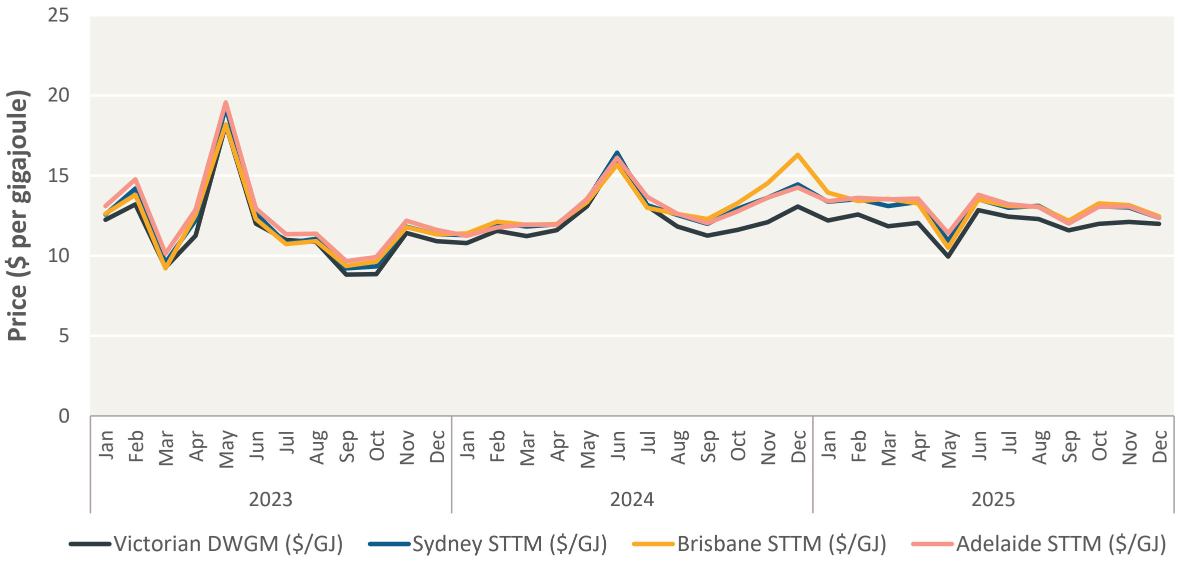
In an efficient market gas is allocated where it is valued most. Prices should reach parity across the DWGM and STTMs over the long term as participants can buy or sell gas across locations in response to price differences. Daily price variations are expected and may persist for weeks or months when there are significant shifts in demand or major supply constraints (e.g. unexpected maintenance at production facilities or transmission pipelines). However long-term price differences above transport costs between markets may be a sign of barriers to efficient gas allocation.

There is generally a high degree of price alignment between the spot markets, which suggests that gas is flowing freely across the east coast to where it is needed. There are some persistent differences in prices between the DWGM and STTM hubs, but this is likely due to a degree of inflexibility at key production facilities and transport costs between routes that connect the southern markets.

5.3.1 Average prices across downstream spot markets are closely aligned

Average prices in the downstream spot markets have been closely aligned since 2023 (Figure 5.4). The difference in monthly prices between downstream spot markets has averaged around 10% (roughly $1 per GJ) between 2023 and 2025.

Figure 5.4 Monthly average downstream spot prices



Note: Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily imbalance price.

Source: AER analysis of STTM and DWGM data.

61 AER, Day Ahead Auction Focus Report, Australian Energy Regulator, October 2024.

Large shifts in prices due to changes in supply or demand dynamics tend to affect all the downstream spot market locations in a similar way. Seasonal peaks are particularly consistent, with prices increasing by a similar magnitude over winter in all markets. However, moments of unexpected volatility, such as the high GPG and international demand at the end of 2024, have led to greater price differences between northern and southern markets.

Given the volatility of the spot markets, the difference between daily prices tends to be greater, but there is still considerable price alignment. The average difference between the highest and lowest hub prices was $1.4 per GJ in 2023 and 2024, and grew slightly to $1.5 per GJ in 2025. This gap likely reflects transport costs between markets, which would generally be around $1 to $2 per GJ.

High levels of alignment appear to be primarily driven by large participants that operate across all the spot markets and supply the majority of marginal gas that influences price outcomes. These participants appear to be optimising their portfolios by allocating gas to where it is valued most. Some price alignment may also be due to the growth of participation among traders,[62] who are likely finding opportunities to arbitrage between the markets.

5.3.2 Prices have been consistently lower in the Victorian DWGM

While prices are largely aligned and trend in a similar direction across the downstream spot markets, there has been consistently lower prices in the DWGM compared with the STTMs. The price differential between the DWGM and STTMs has also grown from $0.60 per GJ in 2023 to $1.0 per GJ in 2025. In contrast, the prices in the STTMs are more closely aligned and the differential has reduced, from an average of $0.3 per GJ in 2023 to just $0.1 per GJ in 2025.

Persistently lower prices in the DWGM may be partly due to its proximity to Longford production, which is a key source of supply for southern markets and located within the DWGM. Longford supplies gas from the Gippsland Basin and typically accounts for over 50% of southern supply. It is also the southern production source that provides the majority of additional gas required to meet winter demand for southern markets. Limits on refilling storage capacity at Iona may also contribute to lower prices where there is excess gas in the DWGM that is unable to be stored on low demand days (section 7.2.1).

Because of this, there is a significant amount of gas scheduled into the DWGM that is offered at $0–$2, which likely reflects a participant's inflexible contracted supply (Figure 5.5). In contrast to the DWGM, scheduled supply into the STTMs includes a significantly larger proportion of gas that is price sensitive (priced above $0–$2) and likely reflects supply that participants have greater flexibility to provide.

Scheduled gas offers at $0–$2 per GJ in the DWGM come primarily from the Longford production facility. The higher proportion of price insensitive $0 per GJ gas likely puts some downward pressure on prices in the DWGM compared with the STTMs.

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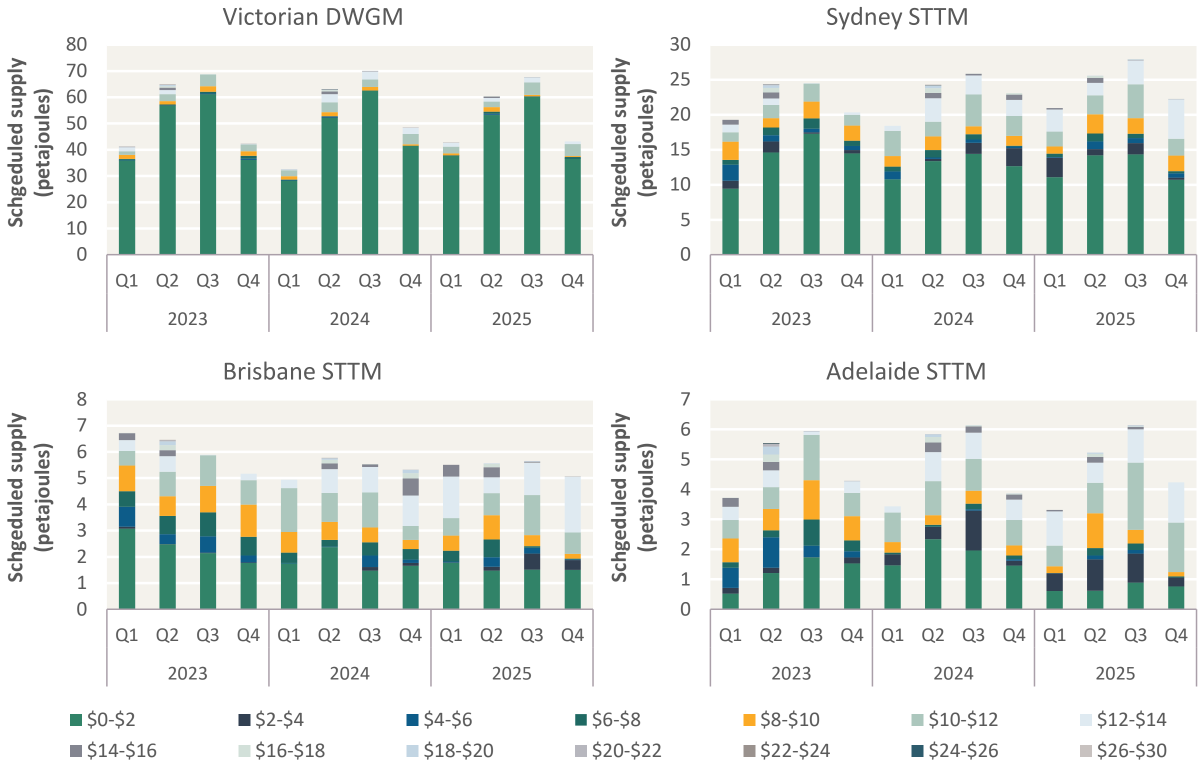
62 AER, Gas Supply Hub Focus Report, Australian Energy Regulator, December 2024; AER, Wholesale gas market focus report – Downstream spot markets, Australian Energy Regulator, May 2025.

Figure 5.5 Total scheduled supply by price band



Note: The DWGM price bands were calculated for the 6 am market schedule. The STTM price bands were calculated for the D-1 schedule.

Source: AER analysis of STTM and DWGM data

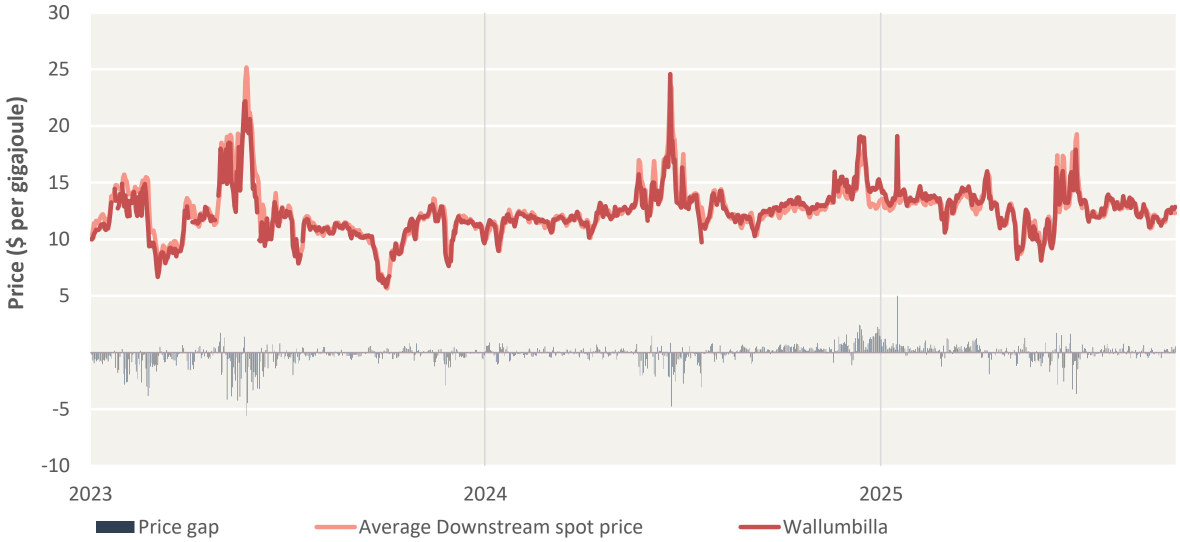
The DWGM's proximity to major southern supply sources (that is, Longford and Otway production facilities and Iona storage), also means transportation costs would be lower to supply into the DWGM compared with shipping the gas to another market (for example, along the Eastern Gas Pipeline into Sydney or along the SEAgas pipeline into Adelaide).

5.3.3 Downstream market prices have also been aligned with the Gas Supply Hub

The Gas Supply Hub (GSH) is an alternative source of gas for many downstream participants. Gas often flows south from Wallumbilla to support southern demand and a large proportion of trade on the GSH is domestic participants purchasing gas from exporters and producers. In an efficient market without network constraints, we would expect GSH prices to align with downstream prices over the long term and the price differential to reflect transportation costs between the GSH and downstream markets.

Prices have been closely aligned in recent years, with a price gap between the GSH spot price and downstream spot markets typically less than $0.5 per GJ (Figure 5.6).

Figure 5.6 Daily Gas Supply Hub price differential with downstream spot markets



Notes: The average downstream spot price is a simple average across Brisbane, Sydney and Adelaide STTMs and the Victorian DWGM. The Wallumbilla price is on-the-day and day-ahead prices for on-screen and off-screen trades at the Wallumbilla hub. Swap trades have been removed from GSH prices reported. Swap trades include supply transactions identified as swaps by our analysis or use of the GSH swap product.

Source: AER analysis of GSH, STTM and DWGM data.

There have been several periods of more significant price variation between the GSH and downstream markets, where the price gap has been significantly above transport costs, between $2 per GJ and $5 per GJ on average. These price gaps typically involve GSH prices dropping below average east coast gas prices and appear to be driven by temporary market dynamics and network constraints in gas flowing downstream:

- **In early 2023,** additional supply from QCLNG maintenance outages led to lower prices. This had a greater impact on GSH Wallumbilla prices, likely due to the market's proximity to QCLNG.
- **In winter 2023,** cold weather and constrained supply at Longford led to higher prices in the south, which was further exacerbated by constraints on the MSP flowing south.
- **In winter 2024,** cold weather combined with supply constraints at Longford put comparatively more upward pressure on prices in the south.
- **In late 2024,** higher gas generation and export demand in Queensland drove up northern prices, creating a large gap with Victoria.

6 Broader performance of the facilitated gas markets

Key points

- The facilitated gas markets have been designed to improve competition and efficiency in the wholesale gas markets. They appear to be working as intended, but adequate liquidity in these markets remains the primary barrier to further improvement.
- The facilitated markets are playing an important role in the wider east coast gas market. Liquidity has grown and there are likely opportunities to support further growth. However, the facilitated markets remain primarily a complement to bilaterally negotiated contracts, because volume and price risks are significant for participants who rely on the facilitated markets for gas supply.
- The facilitated markets show seasonal patterns of trade that suggest they are complementing longer-term contracts in supporting trade over critical winter months.
- The facilitated markets support price transparency, but liquidity remains a major constraint to robust and reliable price signals. This constrains the benefits these price signals can provide in supporting contract negotiations, forward markets and long-term investment decisions.

This chapter considers the performance of the facilitated markets supporting competition and efficiency in the broader east coast gas market. We focus on the performance of facilitated markets for the physical trading of gas; that is, the Gas Supply Hub (GSH) and downstream spot markets – the Declared Wholesale Gas Market (DWGM) and the Short Term Trading Markets (STTMs). The role and performance of the Day Ahead Auction (DAA) is explored in chapter 8.

This chapter covers:

- how the facilitated markets are designed to support competition and efficiency, and the importance of liquidity for achieving this objective
- the role the facilitated markets have played in supporting efficient short-term trading of gas, particularly over critical winter periods
- the role of the facilitated markets in supporting transparency and price discovery
- the growing role the facilitated markets appear to be playing as a complement to the wider contract market and opportunities to improve their performance.

6.1 The facilitated gas markets support competition and efficiency, but there are opportunities for improvement

The facilitated gas markets allow for accessible, structured and transparent short-term trading of gas. However, their performance is unlikely to fundamentally change the availability and cost competitiveness of wholesale gas supply because they are only a small part of the overall wholesale gas market and primarily act as a complement to long-term gas supply. Nonetheless, the facilitated gas markets play an important supporting role in complementing the contract market:

- The facilitated gas markets **support competition** by enabling participation and greater access to short-term gas, which can limit exclusionary trading practices or exercise of market power in supplying short-term gas. To a limited extent, the facilitated markets can also support the entry of new buyers who can access gas without any bilateral contracts. However, given the risks, this is unlikely to support significant new demand in the market.
- They also **support efficiency** by enabling participants to respond to short-term changes in demand and supply outside of locked in contractual arrangements, particularly as a way for participants to balance physical gas needs that inevitably deviate from longer term demand forecasts. They may also lower transaction costs and provide transparent signals for supply and demand dynamics that support better investment in supply.

The biggest challenge for the benefits of the facilitated gas markets to be realised is the extent that these markets are liquid enough for participants to have confidence in the availability of supply and reliability of prices. This is in part a consequence of their smaller role in overall gas trade and voluntary design.

In 2016, the ACCC noted that increased volume and diversity of gas suppliers was necessary in these markets to realise the benefits of flexibility and price discovery.[63] Since then, there has been substantial growth in liquidity across the facilitated markets:

- Net trade has more than doubled in the downstream spot markets, driven largely by significant growth in the Victorian DWGM and Sydney STTM.
- Total trade on the GSH has also more than doubled since 2016, primarily from growth in trade at the Wallumbilla hub.

The growth in liquidity has occurred alongside market design reforms and the development of new products. While growth in liquidity is positive, it is likely there are additional opportunities to improve market design and products offered to encourage further market growth. In our previous focus reports, we highlighted several reforms currently being progressed by government that, if implemented, would improve the performance of these markets by encouraging greater participation and overall liquidity.[64]

At the time of preparing the focus reports, many participants considered that improvements could be made to prudential requirements and harmonising products across the facilitated markets. These issues were raised again in our consultations for this report:

- Many participants viewed separate prudential requirements across AEMO-facilitated markets as overly burdensome and likely limited the level of cross-market trade.

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63 ACCC, Inquiry into the east coast gas market, Australian Competition and Consumer Commission, 2016, p. 76.

64 AER, Gas Supply Hub Focus Report, Australian Energy Regulator, December 2024; AER, Wholesale gas market focus report – Downstream spot markets, Australian Energy Regulator, May 2025.

Participants repeatedly noted that this limits increased participation in the facilitated markets.

- Participants suggested that the prudential requirements for long-term and medium-term trades on the GSH are typically larger than what is required for a gas supply agreement (GSA) and this is limiting their use.
- Participants suggested liquidity of the ASX DWGM futures contract could be improved if it was offered on a monthly basis, rather than quarterly. This would align the contract with the recently introduced ASX Wallumbilla Futures contract physically delivered on the Gas Supply Hub (GSH) at Wallumbilla and would allow participants to more accurately manage price risks caused by seasonal variations.

The Gas Market Review has also recommended governments work to encourage liquidity and longer tenor products on the GSH, including more efficient prudential arrangements.[65]

The review also recommended several other measures that could improve the availability of longer tenor products and forward trade through the facilitated markets, including a requirement through the Gas Market Code that uncontracted and reserved gas transactions for supply up to 12 months be undertaken via the GSH and establishing a forward trading market on the Victorian Declared Transmission System (DTS).[66]

6.2 Facilitated markets have helped gas flow to where it is needed most, particularly over winter

The facilitated gas markets support efficiency in the east coast gas market by:

- offering participants a centralised platform to manage short-term market dynamics and daily balancing requirements through secondary trading of their wholesale contracted supply, or in the case of producers, directly supplying uncontracted gas where it is needed
- supporting reallocation of gas between downstream markets over the peak winter period, when total domestic demand grows and participants face increased price and physical supply risks
- helping participants manage short-term positions in response to high price market events that can occur throughout the year, such as supply constraints and high demand days (section 4.3).
- assisting participants with both gas-powered generation (GPG) and gas retail operations (gentailers) to manage daily variations in their GPG demand, alongside storage and flexibility in contracts (section 4.3.2).

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65 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, p. 12.

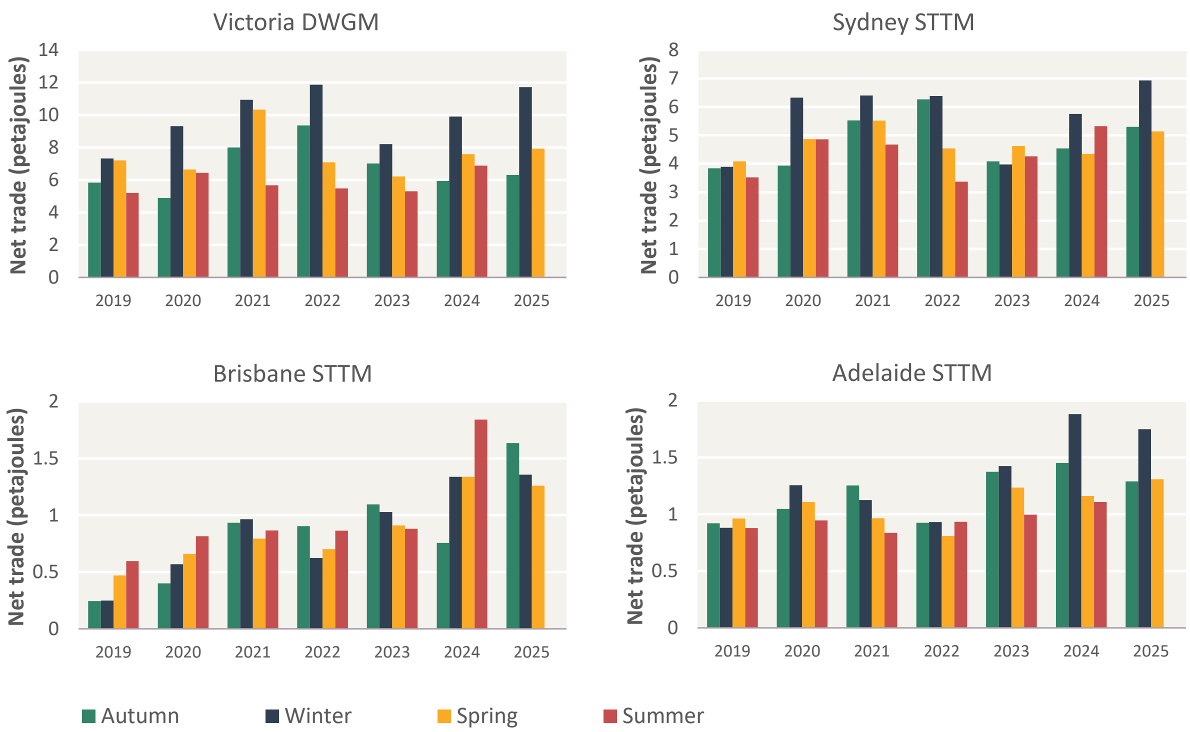
66 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, pp. 12–13.

6.2.1 Increased winter trading occurs in downstream spot markets where residential heating demand is high

Patterns of trade for gas in the downstream spot markets are highly seasonal as domestic demand peaks in winter. Higher demand in winter is primarily driven by gas heating in southern regions connected to the downstream spot markets and is strongest in Victoria.

Net trade also follows a seasonal pattern in southern downstream spot markets (Figure 6.1). Over winter, participants in southern markets are more likely to buy or sell gas on the spot markets because higher total demand means participants will more likely need to manage larger deviations in their position. Participants also need to trade on the spot markets to manage more regular high demand days during winter due to sudden cold weather, supply disruptions in the electricity market requiring increased GPG, and constrained gas supply due to network congestion.

Figure 6.1 Net trade in the downstream spot markets by season



Source: AER analysis of DWGM and STTM data.

Seasonality is clearest in the DWGM in Victoria and the Sydney STTM, where net demand has been 47% and 23% higher, respectively, on average over winter than the other seasons since 2019. GPG gentailers and retailers tend to be more active in these markets and drive higher levels of net trade over winter.

Net trade in Adelaide also follows a seasonal pattern, but this was weaker than in the DWGM and Sydney STTM prior to 2024. This likely reflects the proportionally larger role of industrial net demand in Adelaide compared with Victoria and Sydney. Industrial demand varies substantially over the year and is less likely to be concentrated in winter. However, winter trade in Adelaide has been strong since 2024, reflecting growing trade among GPG gentailers and producers over winter months.

Net trade in Brisbane has not followed a clear pattern year to year. This is likely due to little residential gas heating in Brisbane, so demand is driven by more stable industrial demand and GPG, which is driven by peak demand periods in the NEM.

However, net buying on the spot markets as a proportion of overall demand typically does not follow this same seasonal pattern because the increase in net trade over winter is not proportional to the increase in total demand. For instance, in Victoria, total demand in the DWGM often more than doubles over winter months as participants manage increased residential heating and GPG demand with contracted supply and storage.

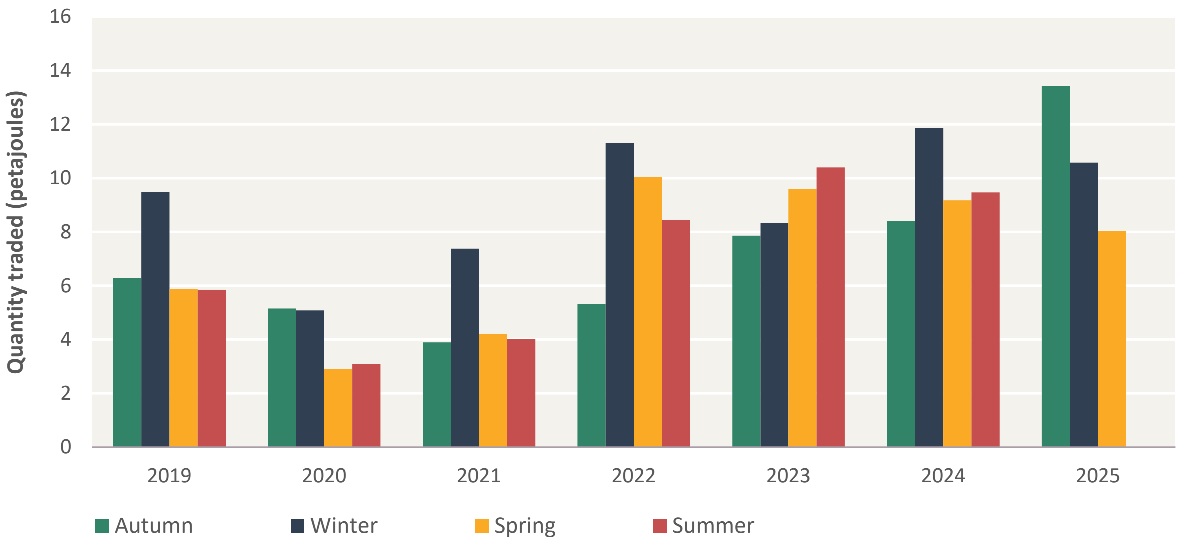
Net buying as a proportion of total demand is often larger outside of winter months in the downstream spot markets. As domestic demand and downstream spot prices typically fall from their highs over winter, participants likely shift to greater use of spot markets within their portfolio – for instance, buying spot gas to refill storage capacity for the following winter.

6.2.2 Gas Supply Hub is most active in winter but increasingly active throughout the year

The GSH supports efficient short-term commodity trading by improving domestic participants' access to gas at Wallumbilla, the key production hub in the north. Because of this, there tends to be increased trade activity for deliveries over winter on the GSH that is in part driven by exporters and producers selling gas at Wallumbilla to domestic customers, who likely use this to support downstream demand over winter in the southern states (Figure 6.2).

GPG gentailers have typically been the greatest buyers of winter gas on the GSH. However, since 2023 high winter trade has also been driven by greater buying among exporters and producers and industrials.

Figure 6.2 Total delivered GSH trade by season



Note: Swap trades have been removed from GSH volumes reported. Swap trades include supply transactions identified as swaps by our analysis or use of the GSH swap product.

Source: AER analysis using GSH data.

Over the past 3 years, seasonal trade on the GSH has shifted in response to changing winter demand and supply dynamics:

- A mild winter in 2023 resulted in lower gas trade on the GSH. Capacity constraints on the Moomba to Sydney Pipeline (MSP) during this period meant that gas couldn't flow to meet southern demand.
- During winter in 2024, high demand days were observed in downstream markets, driven by cold weather in the southern states increasing residential demand and increased GPG usage to compensate for low wind generation output. This occurred alongside strong southerly flows and large volumes of trade on the GSH.
- In autumn 2025, maintenance at the QCLNG export facility occurred alongside a large volume of gas being sold into the GSH heading into winter and Iona refilling earlier than usual. Nonetheless, winter trade on the GSH was still strong, alongside strong southerly flows to support southern demand as production at Longford reached historical lows.

While trade tends to increase over winter, there has been growth across all seasons on the GSH since 2022, alongside a general increase in the diversity of participants using the GSH. In particular, industrial users increasingly use the GSH to source gas and typically have more steady demand throughout the year.

6.3 Facilitated markets provide some price transparency but this is constrained by liquidity

A key benefit of the facilitated gas markets is that volume and pricing information is made available to the wider market. This improves transparency in the east coast wholesale gas market by supporting price discovery, forward price signals and accessible, trusted reference prices. A robust reference price can support contract negotiations upstream, the development of futures and forward markets and longer-term investment decisions.

6.3.1 Downstream spot markets

Spot market prices can signal supply or demand dynamics to the wider east coast gas market. Over the past 5 years, spot prices have at times signalled significant disruption in the market and mismatch between supply and demand balances for short-term gas. Spot markets respond to market events and so provide clear and early signals (see overview of price trends in chapter 2 and high price analysis in chapter 4) and can play a role in setting market expectations. For instance, during the high price volatility of the 2022 energy crisis, the ACCC noted that high domestic spot prices would likely flow through to long-term GSA prices, and this was observed in domestic producer and retailer offers in late 2022.[67]

Spot market prices can also inform price formation in GSAs. Some participants negotiate long-term and short-term contracts that are linked to spot market prices directly, effectively providing firm contract supply with spot price exposure. However, there is little trade in these contracts.

The ACCC has reported that 2% of long-term contracts offered by retailers to commercial and industrial (C&I) users between 2020 and 2023 were spot linked or Brent oil linked.[68] This

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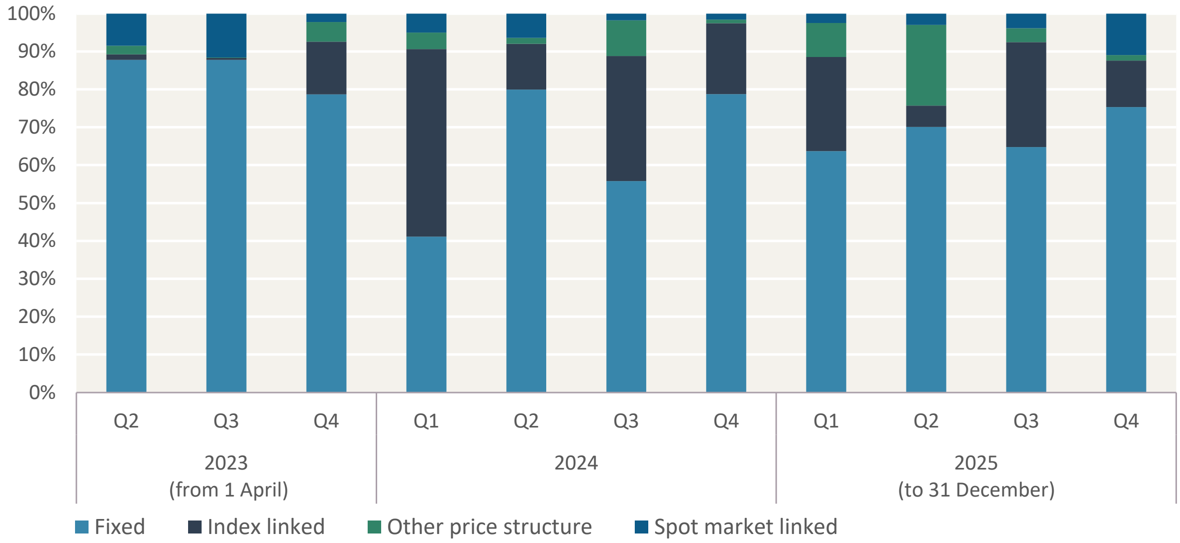
67 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, January 2023, p. 39.

68 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, p. 73.

is similar to levels we have observed in the short-term contract market since 2023 (Figure 6.3).

Figure 6.3 Price structures reported in short-term contracts



Note: Index linked contracts can be an oil index like Brent, or LNG index like JKM or another index.

Source: AER analysis using Gas Bulletin Board data.

Given the general volatility of wholesale gas spot market prices, spot-linked long-term GSAs are seen as a highly risky product and only suitable for sophisticated participants with the resources to closely manage spot price risks. Following market volatility of 2022, the ACCC noted that some retailers were responding to the increased supply and price risks by selling spot-linked contracts to C&I customers. There was also evidence that new retailers had been selling spot-linked products to small unsophisticated C&I users that were not well placed to manage the risks associated with such products.[69]

Spot-linked short-term contracts are often for 1 day delivery transactions, typically day ahead and adjusted for transport costs. In these instances, spot-linked short-term contracts are more likely reflecting the use of downstream spot market prices as a reference price for short-term bilateral trading, rather than as a mechanism to transfer spot price risk.

Beyond prices, there is market information arising from the spot markets, which supports transparency. AEMO provides a range of public reports are available to participants on daily market operations and outcomes, including on bids and offers, indicative market prices and system capacity. Participants also have access to reports on provisional schedules and estimations of demand sensitivity. These reports can help market participants assess the level of demand ahead of the trade day, supporting price discovery and opportunities for more efficient supply responses in the market.

69 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, pp. 74, 85.

6.3.2 Gas Supply Hub

GSH prices provide the market some transparency on upstream gas trade, particularly for gas sourced at Wallumbilla. Similar to the spot markets, AEMO provides a range of public reports available to participants on daily market operations and outcomes. The GSH also allows participants to trade gas ‘on-screen’ by submitting anonymous bids and offers to the platform, which are then matched based on price and quantity. This process provides participants access to real-time bids and offers, which can support price discovery.

However, since 2018 most volume traded has been ‘off-screen’, which means it was bilaterally negotiated and then settled through the GSH (section 3.3.1). Off-screen trade improves transparency in the upstream market for wholesale gas because price and volume are published publicly by AEMO, but this information is constrained to post-market outcomes On-screen trading provides greater transparency on price formation and the availability and price of upstream supply as participants have visibility of real-time bids and offers and the availability and price of upstream supply.

In previous consultations, participants suggested off-screen has become the preferred method for trade on the GSH due to the established systems and relationships participants have in place to trade bilaterally, the ease and flexibility it can provide, and the increase in broker facilitated trade. Nonetheless, on-screen trade remains used and appears to be supporting some price discovery and frequent short-term trading in smaller volumes.[70]

One barrier to improving participation of on-screen trading is anonymity. In previous consultations, participants noted concern that trading positions can be revealed when delivery obligations are issued. Reforms are under way to anonymise trade in the GSH that could support greater participation and improve liquidity for on-screen trading. AEMO would act as a central clearing body that receives bids and offers, nets and sends on netted delivery obligations to the operator of the relevant pipelines connected to the GSH on behalf of participants.[71]

6.3.3 Financial products

Exchange-traded financial products are used to hedge spot price risk and provide forward price signals. This can help participants negotiate contract prices more transparently and guide future investment and supply decisions.

In the facilitated markets, the ASX provides futures products for the DWGM and the GSH. While these products do provide forward prices 2 years out, they are currently thinly traded and feedback from our previous consultations suggest the usefulness of these products in providing a reliable forward price curve is constrained by low levels of liquidity (for more discussion see chapter 9).

6.4 Growing use of the facilitated gas markets

The facilitated markets are playing an important role in supporting participants to engage in short-term gas trade. There has been significant growth in the facilitated markets over the

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70 AER, Gas Supply Hub Focus Report, Australian Energy Regulator, December 2024.

71 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, p. 29.

past decade and evidence they are providing higher levels of trade in proportion to the broader east coast gas markets.

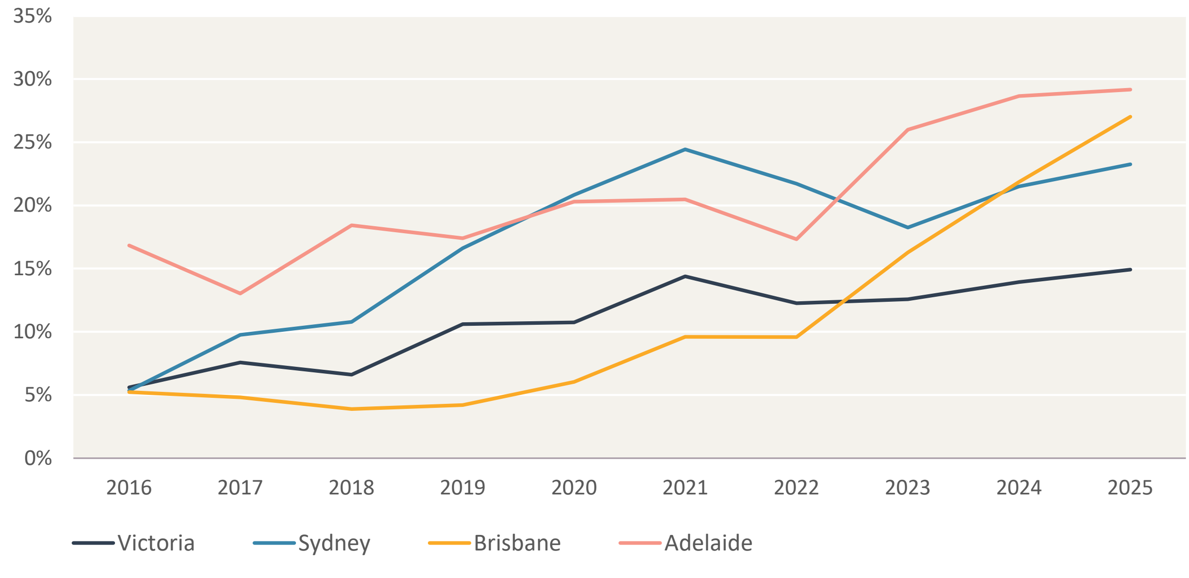
This may be a positive development, to the extent that higher levels of liquidity can provide participants with greater flexibility to respond to short-term needs and a more competitive environment for the supply of short-term gas. However, these changes may also signal challenges in the market if participants are forced to procure shorter-term gas where the availability of long-term GSAs has declined, or where participants are taking on spot market exposure without understanding the price risks.

Proportionately higher levels of trade do not necessarily mean the facilitated markets are becoming an alternative to the bilateral contract market. Participants have continued to note the importance of bilateral contracts for security of supply to manage costs and support long-term business operations and investment. Participants continue to view the facilitated markets as an important complement to balance daily deviations and manage price and volumes risks through secondary trading of gas.

6.4.1 Growth in downstream spot trading

Since 2016, growth in liquidity of net trade has occurred alongside a general shift towards a greater proportion of net trade in the downstream spot markets relative to total trade (Figure 6.4).[72]

Figure 6.4 Net trade as a proportion of total trade, by hub location



Note: Net trade and total trade are shown as net buy and total scheduled demand. These will be equal to net sell and total scheduled supply.

Source: AER analysis of DWGM and STTM data.

[72] See section 3.2 for discussion of net trade.

This does not necessarily mean participants are sourcing more gas from the spot markets as an alternative to contracted gas, but it does suggest a growing value of spot gas to the market. There are several factors that could be contributing:

- Participants may be taking on a larger proportion of spot exposure in their portfolio relative to their contracted gas. The ACCC noted a trend towards greater use of facilitated markets as a response to growing difficulties in entering GSAs since 2021 and more recently to avoid higher contract prices.[73]
- Participants could be increasingly using financial products that provide options to hedge against spot price volatility and settled through net positions (see chapter 9).
- Traders are more active in the market, operating on behalf of several buyers to manage their supply in the downstream spot markets.
- Since 2023, participants may have had an increased need to balance daily positions due to a greater imbalance in overall supply and demand in the east coast gas markets.

Preference for short-term trading among participant groups with downstream demand has also varied considerably:

- **GPG gentailers** have steadily increased their proportion of spot trading from 4% in 2016 to 12% in 2025. However, there is considerable variation between participants within the group and between years.
- **Industrials** have increased their proportion of spot trading significantly from around 12% on average to 32% in 2025.
- **Retailers** typically have the highest proportion of spot trade, but this has been declining over time. It also varies considerably within the group – some smaller retailers are 100% net buying, while others can be below 20%. Declining proportions of net trade may be in response to the increasing price and volume risks due to the volatility of the 2022 energy crisis. It may also reflect growth in the size and maturity of retailers, who may be gaining greater access to long-term gas supply and, therefore, reducing reliance on net buying from the spot markets.

6.4.2 Gas Supply Hub

The GSH is primarily used by the broader market as a complementary way to trade gas at Wallumbilla for delivery within a week to balance positions, often providing higher levels of liquidity than similar length trades in the contract market (Figure 6.5). Trade at Wallumbilla on the GSH typically accounts for around 15% to 20% of gas flows through the region and, on some days, it can account for as much as 30% to 40% of gas flows.

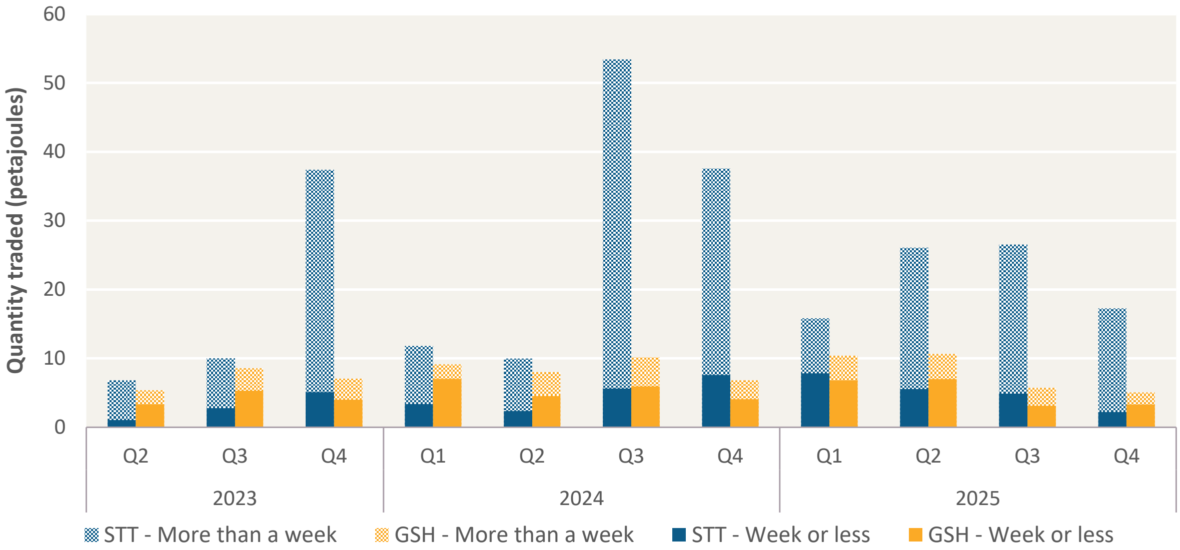
Higher levels of short-term trade may reflect lower barriers and reduced transaction costs to trade through the GSH compared with the short-term contract market. Participants have previously noted that off-screen trading on the GSH allowed participants to engage in trades with counterparties they did not have an established Master Gas Supply Agreement (MGSA)

73 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2024, pp. 43, 49.

with because it reduced credit risks and was often more convenient than using an existing MGSA and transaction notice where volumes were small.[74]

There is still significant volume of short-term contracts for delivery within a week, which likely reflects the different benefits bilateral contracting provides compared with the GSH. These transactions give participants easier access to flexibility and more bespoke terms. For example, they are often accessed under as-available terms in GSAs[75] and can also include a transportation component. This likely creates additional barriers and higher costs for smaller participants looking to source gas from Wallumbilla through the GSH. In consultation some participants noted there were high costs to transport gas from Wallumbilla to downstream markets.

Figure 6.5 Gas Supply Hub and short-term contracts in Queensland, by forward trade length



Note: GSH trade shows trades at the Wallumbilla hub by length of time between trade date and the first delivery day. STT trade shows trades at the Wallumbilla hub and RBP in-pipe trade locations by length of time between trade date and the first delivery day. Swap trades have been removed from GSH volumes reported. Swap trades include supply transactions identified as swaps by our analysis or use of the GSH swap product.

Source: AER analysis of GSH and Gas Bulletin Board data.

As legacy fields in the south continue to decline and more gas flows from the north to support southern demand, the GSH can provide participants a useful alternative to facilitate these flows. This role may grow if challenges persist in finding new southern sources of supply. In consultation, one participant noted that the GSH often provides more competitive pricing to manage daily deviations compared with the downstream spot markets, particularly over winter. However, it was also noted that this benefit depends on the ability to access pipeline services from Wallumbilla to southern markets, which is often constrained.

74 AER, Gas Supply Hub Focus Report, Australian Energy Regulator, December 2024, p. 25.

75 As-available transactions are assumed to be firm and reported as short-term transactions to the gas bulletin once quantities are nominated and accepted. See AER, Compliance Bulletin - Short term gas transaction reporting, Australian Energy Regulator, December 2025.

There may be future opportunities for the GSH to play a larger role in supporting upstream trade for longer tenor products and additional locations for trade. Participants have previously noted interest in trading longer-term products on the GSH, but onerous prudential requirements and variable fees make this costly in comparison to bilateral trade in the contract market. Some of these views were raised again by participants in consultations for this report.

In our GSH focus report we found that while several trading locations have been added to the GSH since 2016, liquidity at these locations has been low compared with Wallumbilla.[76] A trading hub on the Eastern Gas Pipeline was also introduced in early 2025. The hub is located near southern production at Longford and the Iona storage facility, which could help southern trading between hubs. So far there has been very little trade.

Low liquidity is not necessarily a sign of underlying issues. Markets can take time to mature and new products may require incremental experimentation from participants before their benefits are realised. While the Wallumbilla and Longford hubs remain natural focal points for north and south trade on the east coast, liquidity at the GSH's other trading locations may grow if new sources of southern supply enter the market, shifting key points of trade on the east coast.

[76] AER, Gas Supply Hub Focus Report, Australian Energy Regulator, December 2024.

7 Access to transportation and storage

Key points

- A small number of transmission pipelines are critical to the supply of gas from Queensland south to the facilitated markets. With no local gas supply, the Short Term Trading Markets (STTMs) in Adelaide and Sydney are currently solely reliant on this transportation of gas from interstate.
- Gas pipelines have natural monopoly characteristics, which can present opportunities for pipeline owners to hold and exercise market power. Ownership of the pipelines across the east coast is highly concentrated with a small number of businesses owning multiple key transmission pipelines.
- Storage is also critical to Victoria's gas supply, but access is limited and expensive. Demand for storage is likely to increase as Victorian production continues to decline, unless new sources of gas supply are established.
- Investment in transportation and storage is essential to avoid supply shortfalls in southern markets by 2029.

Participation in the east coast gas markets requires access to both gas supply and transportation, which is typically bilaterally contracted between participants and gas pipeline service providers. The availability and cost of this transportation is vital for the supply of gas to the facilitated markets and the broader east coast gas markets. Inability to access transportation, or alternatives, at efficient prices would impact participation in the markets and be a barrier to new entry.

Gas storage can aid participants to manage transportation or supply constraints and provide flexibility to meet peak demand requirements. Reliance on transportation and storage is expected to increase as Victorian gas production declines and the southern markets become more dependent on transportation south from Queensland to meet peak demand in winter periods.

This chapter assesses the availability and cost of transportation and storage facilities across the east coast gas markets.

7.1 Ownership of pipeline transportation is heavily concentrated

A small set of connected transmission pipelines are critical to the transportation of gas to the facilitated markets (Table 7.1). Gas pipelines exhibit natural monopoly characteristics that allow these pipeline owners to hold market power in the provision of access to the pipelines. This is because pipelines are capital intensive and rarely, if ever, have natural competitors across similar transportation routes. Further, ownership of the pipelines is heavily concentrated in a small group of pipeline owners. This market power may create inefficiencies in the gas markets, including impacting the supply of gas to the markets.

The regulatory framework under the National Gas Law (NGL) includes 2 tiers of regulation – non-scheme regulation that aims to promote negotiation through transparency and scheme regulation, where the AER approves reference services and prices based on underlying costs. All the transmission pipelines are non-scheme pipelines, except for the Roma to Brisbane Pipeline (RBP), the Victorian Transmission System (VTS) and Amadeus Gas Pipeline (AGP) in the Northern Territory.

Table 7.1 Pipeline connections and capacities

Spot market	Pipeline	Owner	DAA	Nameplate capacity
Brisbane STTM	RBP	APA	Yes	167 TJ/day from Wallumbilla GSH
Sydney STTM	MSP	APA	Yes	565 TJ/day south from Moomba GSH Connects to Wilton GSH and Culcairn GSH but limited to 195 TJ/day in regional NSW
	EGP	Jemena	Yes	336 TJ/day north from Victoria
DWGM	VTS	APA	No	1126 TJ/day west from Longford[77] 523 TJ/day east from Iona (SWP)[78] 180 TJ/day south from Culcairn GSH (VNI)
	VicHub	Jemena	Yes	150 TJ/day west from Longford
Adelaide STTM	MAPS	Epic Energy	Yes	249 TJ/day south from Moomba GSH
	PCA	SeaGas	Yes	252 TJ/day west from Victoria
-	SWQP	APA	Yes	340 TJ/day east to Wallumbilla GSH or 512 TJ/day west to Moomba GSH

Source: AER analysis of Gas Bulletin Board data.

7.1.1 Southern pipeline transportation is heavily contracted

Currently all gas flowing from Queensland to southern states must flow via APA's South West Queensland Pipeline (SWQP). The SWQP delivers gas to Moomba in South Australia for transport to either Sydney via APA's Moomba to Sydney Pipeline (MSP) or Adelaide via Epic Energy's Moomba to Adelaide Pipeline (MAPS). With no local gas supply, the Sydney and Adelaide STTMs are at present solely reliant on this transportation to access gas from interstate.

Transportation on the SWQP toward the southern markets is fully contracted in winter, with flows peaking during this period. However, the quantity of gas transported via the SWQP to Moomba does not reach maximum capacity (Figure 7.1) due to several factors, including:

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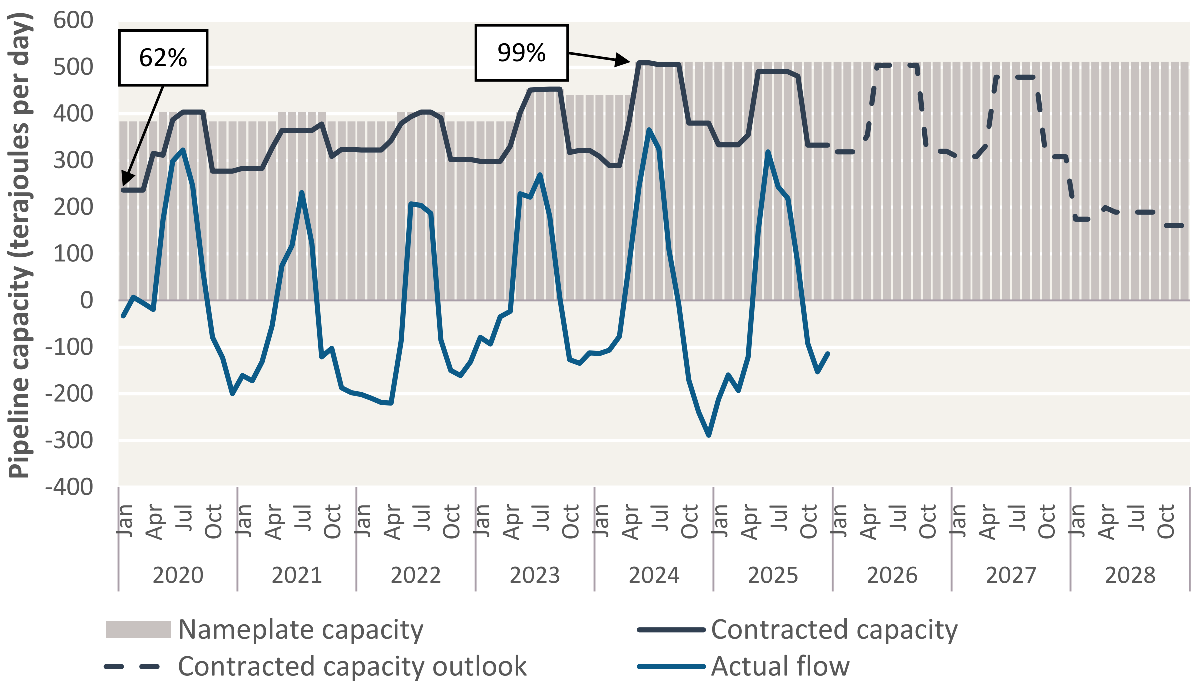
77 While the pipeline can transport 1,126 TJ/day of gas, this volume of gas is not supplied into the DWGM as Longford has reduced its production.

78 AEMO's updated capacity modelling determined the SWP's peak day capacity is reduced from 530 TJ/day to 523 TJ/day (VGRP 2025).

- Some of the SWQP's capacity is used to transport gas to delivery points along the pipeline, including Ballera for transportation north to Mt Isa, which nullifies the ability for that capacity to be used to transport gas to Moomba.
- Contracted capacity may not be nominated by the pipeline user. This contracted but unutilised capacity is made available via the Day Ahead Auction (DAA) for other users to access but may not be entirely acquired.
- The SWQP is bidirectional, which means APA may only need to transport the net demand either east or west. Participants may continue to nominate to send gas east during winter to fulfil gas supply contracts.

Figure 7.1 Contracted capacity and actual flows on the SWQP to Moomba

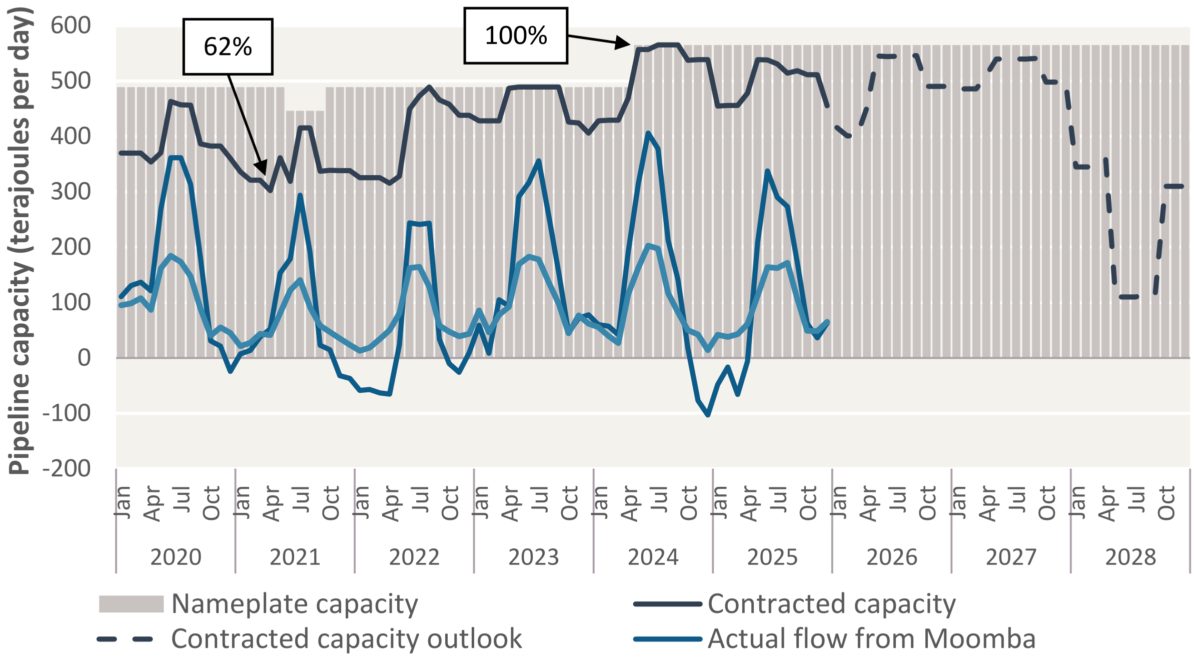


Note: The SWQP's actual flows are based on flows to and from the SWQP point at Moomba. Positive flows indicate gas flowing west into Moomba via the SWQP and negative flows indicate gas flowing into the SWQP from Moomba for transportation east.

Source: AER analysis of Gas Bulletin Board data.

Like the SWQP, the MSP is also near-fully contracted during winter periods to transport gas south into NSW and Victoria. While the MSP's actual transportation south from Moomba reached a maximum of 524 TJ per day in winter 2024 and 477 TJ per day in winter 2025, less than half of this gas reaches the Sydney STTM (Figure 7.2). This is likely due to similar reasons discussed above for the SWQP and because the MSP divides into a system of pipes so its southern capacity is shared between Sydney, Culcairn, regional NSW and the ACT. APA recently expanded the MSP and SWQP and has proposed future expansions (section 7.3). These expansions should make additional capacity available to be contracted and supply more gas to the southern states in winter.

Figure 7.2 Contracted capacity and actual flows on the MSP to Sydney



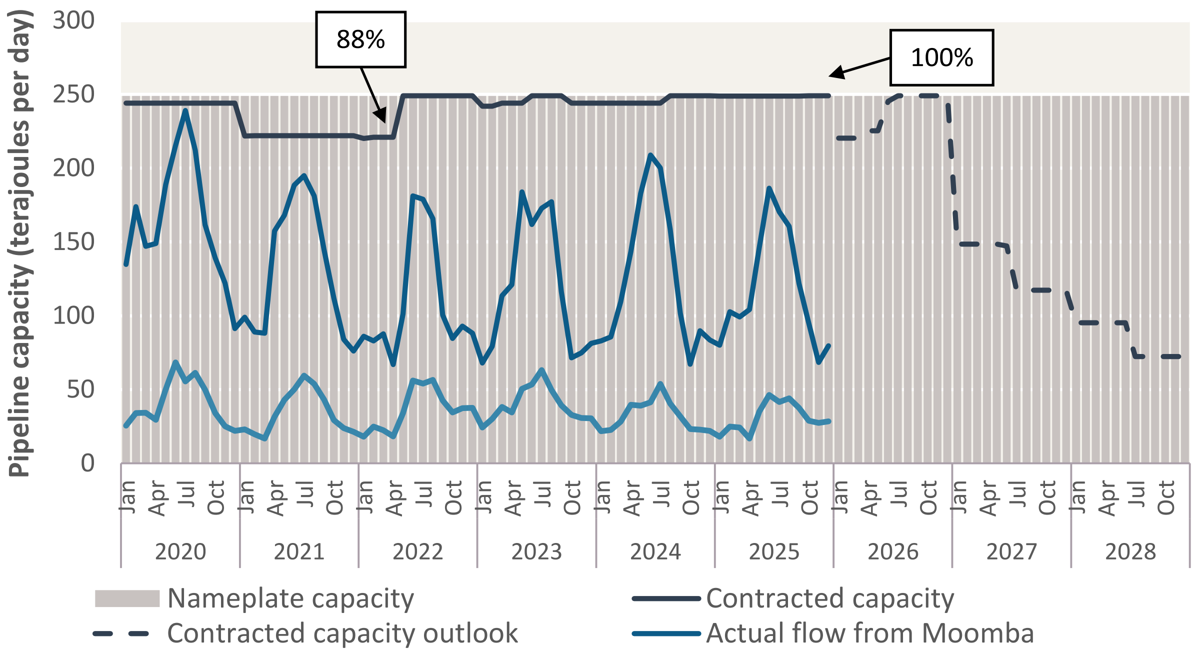
Note: Actual flows on the MSP to Sydney include gas flowing north from Victoria via Culcairn on the VNI as well as gas flowing south from Moomba.

Source: AER analysis of Gas Bulletin Board data.

The Sydney STTM can also be supplied with gas from Victoria via the EGP. However, the transportation of gas out of Victoria has been steadily declining due to decreased production at Longford and demand in Victoria during winter. Transportation of gas on the EGP reached a low in 2025, with an average of 62% of its capacity contracted and 38% of its capacity utilised.

The use of the Port Campell to Adelaide Pipeline (PCA) to transport gas to the Adelaide STTM from Victoria has also declined in recent years. Transportation of gas on the PCA dropped to an average of 31% of its capacity contracted and only 6% of its capacity utilised in 2025. The Adelaide STTM is primarily supplied by the MAPS, which is fully contracted and actual transportation reaches maximum capacity on peak demand days in winter (Figure 7.3). Like the MSP, not all the gas transported south on the MAPS reaches the STTM because most of the gas is delivered to regional South Australia, primarily to GPG that sit outside the STTM. Epic Energy has not announced plans to expand the MAPS at this stage.

Figure 7.3 Contracted capacity and actual flows on the MAPS to Adelaide



Source: AER analysis of Gas Bulletin Board data.

The Brisbane STTM is supplied by eastern flows on the RBP, which is unconstrained and its use has declined from fully contracted prior to winter 2022 down to an average of 54% of capacity contracted and 32% of capacity used in 2025. A major driver of this reduction was the closure of Incitec Pivot Fertilisers' Gibson Island manufacturing plant in Brisbane. The Brisbane STTM is small relative to larger southern markets and so the exit of a single large participant had pronounced influence on demand.

7.1.2 There currently is low capacity for transportation into Victoria

In 2025, only up to 180 TJ per day of the gas transported south from Queensland could reach Melbourne through Culcairn via the MSP and the VNI. This means Victoria is primarily reliant on Victorian gas supply to meet its winter demand despite APA's east coast gas grid expansions. This limitation, combined with declining Victorian production, increases the importance of the Iona gas storage facility for meeting winter peak demand in Victoria. It is also a driver of several different potential sources of new gas supply (section 7.3).

Unlike other Australian pipelines, the VTS is not directly contracted. Instead, transportation is acquired via the Victorian Declared Wholesale Gas Market (DWGM) through its market carriage structure. The VTS is heavily utilised in winter and reaches its nameplate capacity on peak demand days for transportation into Melbourne from Culcairn via the VNI and from Iona via the South West Pipeline (SWP). Due to high demand for the SWP, most participants choose to pay for capacity certificates that ensure their gas is scheduled when the SWP is constrained, such that they benefit from tie breaking rights. At least one participant was concerned about the high price of capacity certificates for the SWP and higher relative prices during high demand in winter periods. One participant limited the amount it used from Iona due to the price of these certificates. Transportation into Melbourne from Longford has declined since winter 2022, reflecting the declining production at the Longford Basin.

7.1.3 Gas transportation costs increase southern spot prices by $2 to $3 per GJ, but do not deter contracts as only firm option

Analysis of actual prices payable information indicates most users receive the standing offer from service providers unless they contract for a long-term and large capacity. In many cases these large contracts underwrite pipeline investment. When striking initial contracts, large users may have relatively higher countervailing market power, but this likely declines on renegotiation.

Analysis of the key transmission pipelines' reported 2025 prices suggests transportation from Queensland to southern markets adds around $2 to $3 per GJ to the cost of gas from Queensland in southern markets (Table 7.2).

Table 7.2 Cost of transportation from the Surat–Bowen Basin in Queensland to the facilitated markets

Facilitated market	Pipeline required	VWA cost	Standing price cost
Brisbane STTM	RBP	$0.69/GJ/day	$0.70/GJ/day
Sydney STTM	SWQP & MSP	$2.18/GJ/day	$2.93/GJ/day
Adelaide STTM	SWQP & MAPS	$2.17/GJ/day	$2.50/GJ/day
DWGM	SWQP & MSP	$2.18/GJ/day	$2.93/GJ/day
Wallumbilla GSH	-	-	-
Moomba GSH	SWQP	$1.22/GJ/day	$1.53/GJ/day
Wilton GSH	SWQP & MSP	$2.18/GJ/day	$2.93/GJ/day
Culcairn GSH	SWQP & MSP	$2.18/GJ/day	$2.93/GJ/day

Note: Costs do not include additional charges (such as compression costs) and so effective costs are likely to be slightly higher.

Source: AER analysis of actual prices payable data reported by the service providers.

The added cost of transportation may restrict users' financial incentive to move gas between markets and the heavily contracted transportation positions is a large sunk cost for gas prices. The DWGM's spot prices tend to be lower than the STTMs, likely because it can source most of its gas from Longford while the other markets are reliant on transportation (section 5.3).

Our analysis of the pipelines' financial information and prices indicates service providers often set prices higher than required to recoup underlying costs, including required return on investment (Appendix B). More cost-reflective transportation prices could enable higher liquidity between the gas markets. While high transportation prices do not appear to be a barrier for pipeline users to contract transportation given the high contractual congestion, there may be a barrier for smaller users and/or users without legacy positions on the pipelines. A lack of transportation alternatives for these users may reduce competition in the downstream spot markets. Higher transportation costs are also ultimately passed through to Australian consumers in the form of higher energy bills. We continue to closely monitor these prices and expect to see greater downward pressure on prices and improved negotiation on non-price terms and conditions for smaller users.

7.2 Storage is critical but limited

Storage facilities can store surplus gas produced in summer to meet high demand during winter. Access to these storage facilities can provide users with flexibility and rapid supply to meet peak demand requirements and reduce supply risks.

Access to dedicated storage is limited to only 2 third-party access storage facilities. Both are in Victoria and supply the DWGM – Lochard Energy’s Iona underground gas storage facility and APA’s Dandenong LNG storage facility.

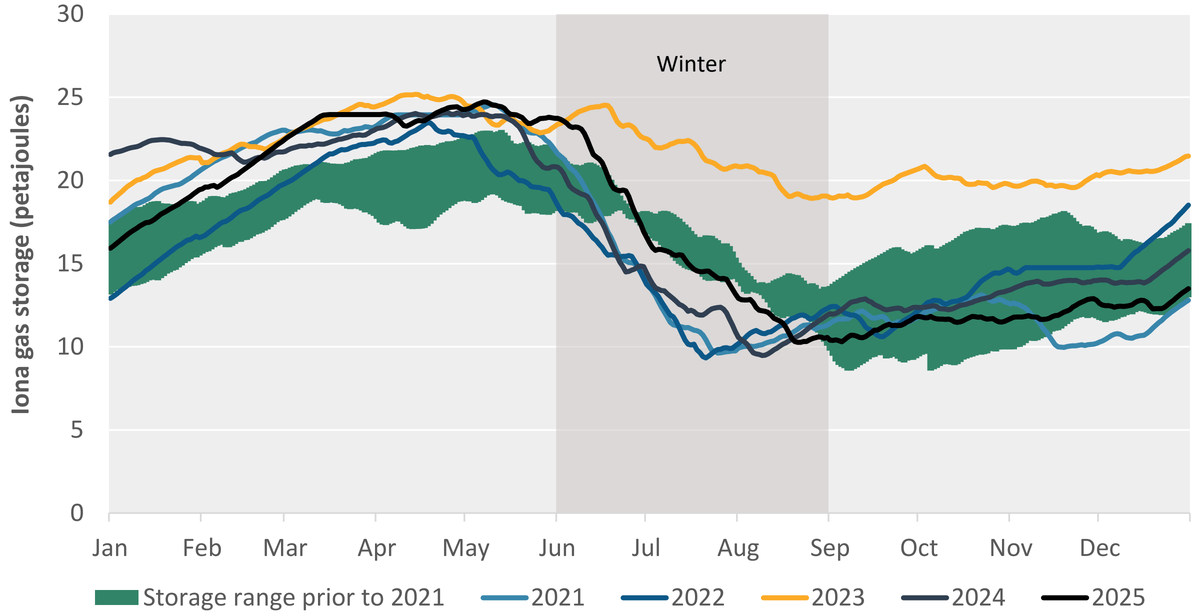
Other storage facilities are owned and exclusively used by one party. These facilities tend to have low daily supply capabilities so they cannot make a significant contribution to gas supply and have a limited direct impact on the facilitated markets.

Pipelines can also provide storage capacity via linepack and have high supply capacities that make rapid access possible and can provide flexibility. This storage may be used to support high demand for a single day and be refilled the next day if demand has lowered again. However, pipeline storage does not represent a firm storage solution comparable to dedicated storage solutions such as Iona.

7.2.1 Iona storage and supply capacity is critical to DWGM supply

Iona is the second-largest supply source in the south, with 24.4 PJ of storage capacity. Victoria is increasingly reliant on Iona’s gas storage inventory to meet peak demand in winter as supply from Longford has decreased and no other gas sources have yet been developed. Since Lochard Energy’s takeover from EnergyAustralia in 2015, several upgrades to Iona have expanded Iona’s supply capability from 390 TJ per day to 570 TJ per day in 2024. However, the faster rate of 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. Because of its importance for meeting southern peak demand over winter, it is vital Iona is fully replenished over the summer period. In 2025, storage levels refilled later but to a higher level that lasted longer than in recent years (Figure 7.4).

Figure 7.4 Iona storage levels

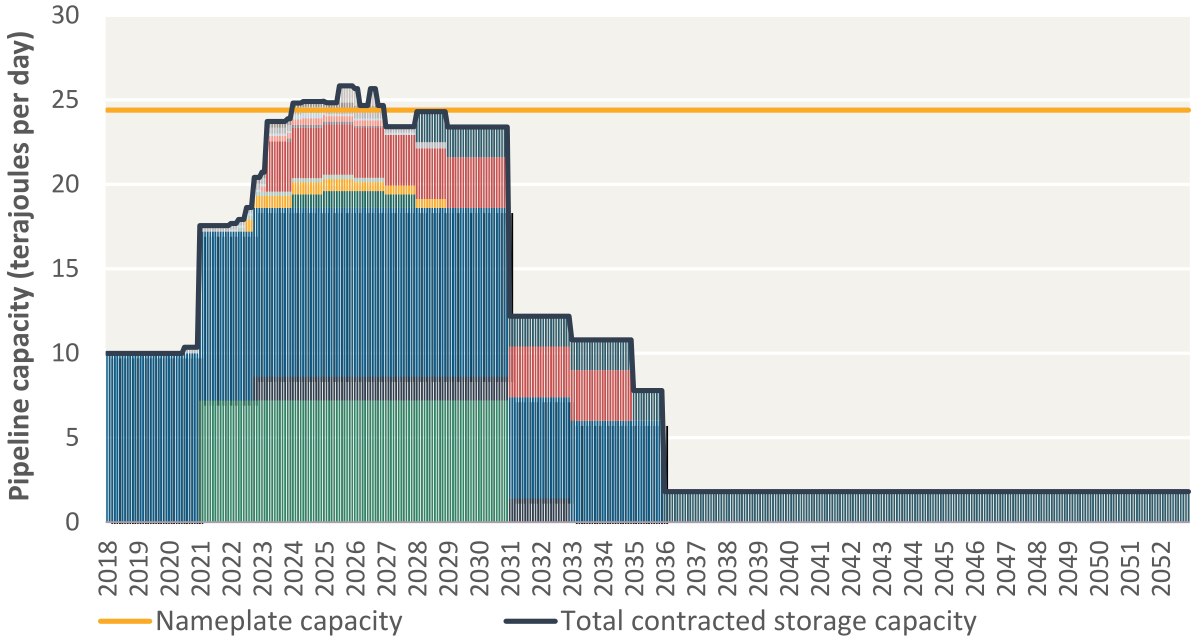


Source: AER analysis of Gas Bulletin Board data.

Access to storage services at Iona is contracted bilaterally between Lochard Energy and storage users. As at December 2025, Iona's storage capacity was almost fully contracted until 2031, with some capacity contracted until the end of 2052 (Figure 7.5):

- Most of Iona's storage is contracted by only 2 users for 10 PJ and 7.1 PJ each.
- There were 14 contracts in place for access to Iona and these contracts were entered into as early as 2015
- Gas Bulletin Board data shows there have been no secondary trades of storage capacity between users
- The storage services currently in effect are contracted for an average of 4.6 years – this contract term is longer than the average for gas supply contracts and gas pipeline contracts and may indicate greater demand to secure storage at Iona long term.

Figure 7.5 Iona contracted capacity



Note: Information is current as at 17 December 2025. This graph does not represent capacity that is yet to be contracted nor contracted capacity that rolled off prior to 2023.

Source: AER analysis of Part 18A actual prices payable information.

Iona's standard services have a fixed ratio of capacity rights – every 1 TJ per day of withdrawal capacity is provided with 0.25 TJ per day of injection capacity and 40 TJ of storage capacity. In line with contracted storage capacity, participants' rights to withdraw gas from Iona are also near-fully contracted. Iona's withdrawal capacity is shared by injections into the SWP and the PCA, with most gas contracted for injection into the SWP. Rights to inject gas into Iona are slightly less contracted. This may be due to lower demand per day for refilling Iona because this may be done over many days in non-peak periods or via as-available services if required. However, at least one participant identified lower refill capacity as an operational constraint to move gas out of Iona as it takes 4 days to refill one day of withdrawal. Iona's lower refill rate may also contribute to excess gas in the DWGM that is unable to be stored on low demand days, possibly lowering the DWGM spot price.

Participants said storage at Iona is critical but expensive. Users pay for storage in preparation for high demand days regardless of whether the high demand eventuates and this can offset the financial benefit from buying gas at a lower price in summer. This means use may be reserved to managing risk, shaping seasonal demand profiles and managing high demand days (including GPG) or when spot prices are high.

Access to Iona is contracted via firm and as-available services. Users with firm services pay a fixed price per day plus a variable price each time they use Iona. As-available services are also available and incur a variable price for usage. Iona's firm services are contracted under one or 2 tariffs depending on a user's injection into either the PCA or the SWP (Table 7.3).

Table 7.3 Iona standing prices

Service	Standing price ($2025)	Volume-weighted average price ($2025)
SWP firm service	$1.42/GJ/day + $0.11/GJ of actual use	$0.95/GJ/day
PCA firm service	$0.09/GJ/day + $0.05/GJ of actual use	$0.08/GJ/day
SWP as-available service	$1.14/GJ	–
PCA as-available service	$2.26/GJ	–

Source: Standing prices published under Part 18A of the NGR on lochardenergy.com.au.

The actual prices payable by users are typically the standing price for services with PCA injection, with only one exemption. Users pay a wider range of prices that are less than the standing price for services with SWP injection. Users generally pay the standing price for actual usage and as-available services. Unapproved as-available usage attracts a $12.66 per GJ charge.

7.2.2 Dandenong storage is a last resort

In contrast to Iona, Dandenong is much smaller at 0.68 PJ of storage capacity with a supply capacity of 237 TJ per day and refill rate of 8 TJ per day.

In June 2022, Dandenong storage fell to particularly low levels following a steep reduction in the number of participants entering storage contracts. This reduction in contracted usage coincided with APA's restructuring of its contracting model, which caused Dandenong's effective storage prices to increase significantly from December 2020. APA stopped directly offering storage services and instead required users to contract firm vapourisation services. Due to the high potential for Dandenong to be needed from winter 2023,[79] energy ministers submitted an urgent rule change giving AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023.[80]

APA's change in pricing and contracting model likely positioned Dandenong as an option of last resort if more cost-effective alternatives for supply from Longford and Iona became constrained. As supply from Longford continues to decline, use of Dandenong may increase if participants cannot find a more cost-effective alternative.

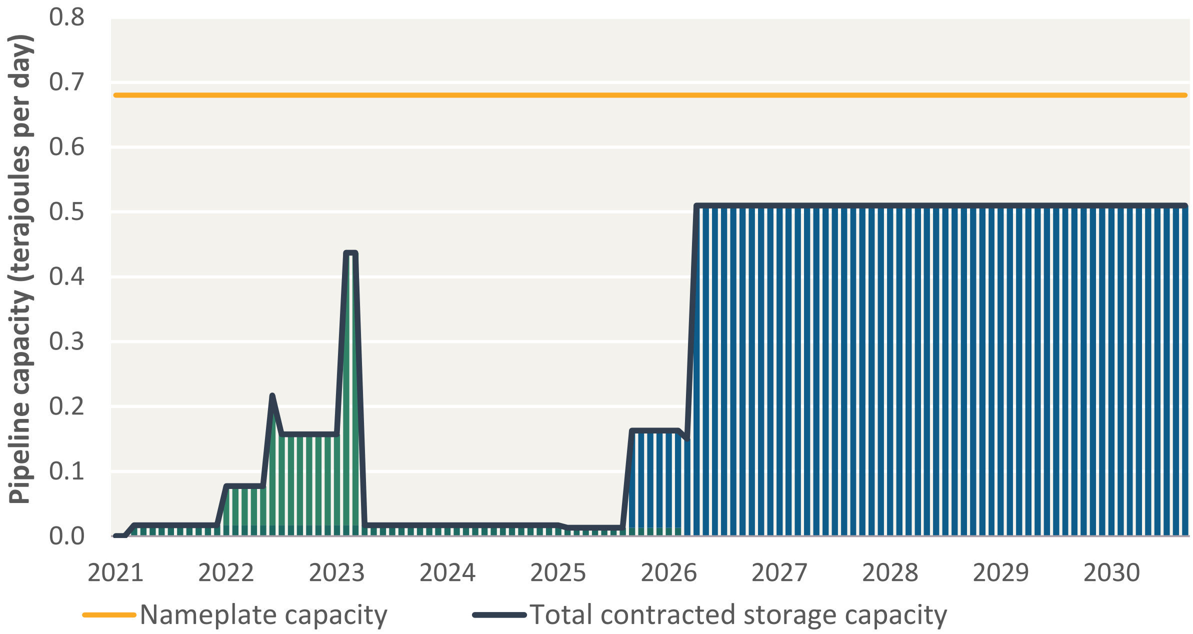
As at December 2025, there were 5 contracts for access to Dandenong. Of these 5 contracts, 3 appeared to be consistent with APA's 2020 contracting model where participants contract firm vapourisation services (that includes some storage) and supplementary storage capacity as required. The remaining 2 contracts did directly contract storage but only one

79 Dandenong was deemed to play an important role in mitigating curtailment during potential supply shortfalls and provide critical system security to avoid pressure drops at the Dandenong city gate.

80 AEMC, DWGM interim LNG storage measures, Australian Energy Market Commission, accessed 4 March 2026.

contract contained non-zero capacity. This 2021 contract was amended in October 2025 to provide the participant with 150 TJ of storage capacity and 510 TJ of storage capacity from May 2026 (Figure 7.6) with 112 TJ per day of vapourisation.

Figure 7.6 Dandenong contracted storage capacity



Note: Information is current as at 17 December 2025. This graph does not represent capacity that is yet to be contracted nor contracted capacity that rolled off prior to 2023.

Source: AER analysis of Part 18A actual prices payable information.

APA's pricing model for Dandenong, and the facility's slow refill rates, likely makes it unsuitable for use outside of contingency events. The October 2025 contract has a storage price of just $0.06 per GJ per day but the participant must pay the vapourisation cost of $225.33 per GJ and the liquification cost of $2.06 per GJ each time it withdraws or refills Dandenong. If the participant only injected and withdrew gas once in a year, the effective cost of storage would be $0.80 per GJ per day. But this price increases significantly if the participant withdraws and injects gas into Dandenong more than once per year. For example, twice a year would cost $1.54 per GJ per day and 3 times would cost $2.28 per GJ per day. This makes use of Dandenong for managing peak and low demand days very expensive and instead lends itself to only contingency gas. In comparison, daily usage of Iona to inject gas into the SWP incurs an additional cost of $0.11 per GJ on top of its volume-weighted average cost of $0.95 per GJ per day.

7.3 Coordination of pipeline and storage expansion is vital

The Australian Government's Gas Market Review noted a critical need for new and upgraded infrastructure to transport gas produced in northern regions of Australia to southern demand centres.[81] Despite a range of committed development projects, AEMO has similarly identified a need for additional new gas supply by 2030 to maintain gas supply adequacy as southern gas production continues to decline.[82]

The current and pressing need for investment in a transportation and storage has arisen in an environment where ownership of existing pipeline and storage assets is highly concentrated. Investment decisions for new capacity are also very concentrated at a time when the timing and coordination of investment is vital for entry of new supply. This poses significant risk pipeline and storage owners can act to expand their market power by shaping new supply and exercise that market power in the provision of the new supply. Major proposals for pipeline and storage expansions and construction are listed in Table 7.4.

Table 7.4 Proposed pipeline and storage projects

Owner	Project	Commission	Description
APA	SWP expansion	Winter 2029	In October 2025, APA submitted a proposal to the AER to expand capacity of the SWP from 523 TJ per day to 615 TJ per day by adding 2 compressor stations by winter 2029. This expansion would match the injection capacity of Iona in winter 2026 but may not be sufficient to also transport gas from the Otway Basin and proposed LNG import terminals. If the LNG import terminals do come online, this would place significant constraint on the SWP and push the price of capacity certificates even higher. We expect to make a draft decision in May 2026.
APA	Bulloo Interlink Pipeline	2028	New 340 km and 800 TJ per day pipeline to directly connect the SWQP to the MSP to bypass transportation constraints around Moomba.[83]
APA	MSP SWQP	Winter 2028	Addition of 3 compressors (along with the Bulloo Interlink Pipeline) to increase the MSP's capacity from 590 TJ per day to 700 TJ per day and the SWQP's capacity from 512 TJ per day to 605 TJ per day.[84]
APA	VNI	2029	Expansion to increase the VNI's capacity to 350 TJ per day to enable more gas to flow into Victoria from the MSP in NSW.[85]
APA	Riverina Storage Project	Winter 2028	New 112 km pipeline to be used for gas storage in NSW near Wagga Wagga and Uranquinty. The

[81] DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, p. 47.

[82] AEMO, 2026 Gas statement of opportunities, Australian Energy Market Operator, March 2026, p. 90.

[83] APA, East Coast Gas Grid Expansion Plan, accessed 28 January 2026.

[84] APA, East Coast Gas Grid Expansion Plan, accessed 28 January 2026.

[85] APA, East Coast Gas Grid Expansion Plan, accessed 28 January 2026.

Owner	Project	Commission	Description
			current proposal would add 0.2 PJ by 2028 and up to 0.5 PJ by 2029 of storage capacity.[86]
Lochard Energy	Heytesbury Underground Gas Storage (HUGS)	Q2 2026	Expansion of Iona's storage capacity from 24.4 PJ to 27.7 PJ using a depleted wellsite and new HUGS Pipeline. Iona's supply capacity would increase from 570 TJ per day to 615 TJ per day. Lochard Energy is exploring options to further expand Iona beyond the HUGS project via HUGS2.[87]
Jemena	EGP	Q1 2026	Bidirectional augmentation to enable 200 TJ per day of transportation south into Victoria, with the possibility of increasing this capacity to 320 TJ per day. Work was completed in 2023 to connect the EGP to PKET.[88]
Squadron Energy	PKET	Winter 2027	New LNG import terminal in Port Kembla, NSW to supply up to 130 PJ per year into NSW and Victoria at a supply capacity of 500 TJ per day.[89] PKET's floating storage and regasification unit can also be used to store the equivalent of around 3.5 PJ of gas (depending on the composition of the LNG).[90]
Viva Energy	Viva Energy Hub Gas Terminal	2028	New LNG import terminal in Geelong, Victoria to supply up to 120 PJ per year into the DWGM via a new gas pipeline and the SWP. The terminal would supply up to 750 TJ per day.[91]
Vopak	Victoria Energy Terminal	2029	New LNG import terminal in Port Phillip Bay, Victoria to supply around 76 PJ per year to 190 PJ per year of gas (depending on the composition of the LNG) into the DWGM via a new gas pipeline and the SWP. The floating storage and regasification unit can also be used to store the equivalent of around 3.8 PJ of gas (depending on the composition of the LNG).[92]
GB Energy	Golden Beach Storage Project	2029	Transition existing gas field into 19 PJ of offshore underground storage capacity in the Bass Strait with 375 TJ per day of withdrawal capacity near the Longford Gas Hub.[93]

86 APA, East Coast Gas Grid Expansion Plan, accessed 28 January 2026.

87 Lochard Energy, Heytesbury Underground Gas Storage Project, accessed 28 January 2026.

88 Jemena, LNG regasification, accessed 4 March 2026.

89 Squadron Energy, Port Kembla Energy Terminal, accessed 28 January 2026.

90 Squadron Energy, Squadron Energy's import terminal well placed to meet gas shortfall, accessed 28 January 2026.

91 Viva Energy, Viva Energy Hub Gas Terminal, accessed 26 February 2026.

92 Victoria Energy Terminal, The Project, Vopak, accessed 4 March 2026.

93 GB Energy, What we do, accessed 28 January 2026.

Owner	Project	Commission	Description
Santos	Narrabri Gas Basin Hunter Gas Pipeline	2028	New gas basin in Narrabri, NSW to supply 200 TJ per day gas to Newcastle via a new Hunter Gas Pipeline.

8 Alternatives to transportation contracts

Key points

- The Day Ahead Auction (DAA) has supported competition and efficiency in short-term gas transportation and the downstream spot markets. The DAA has made transportation capacity available on key pipelines that supply the downstream spot markets and which are otherwise highly contracted by a few shippers.
- Access to pipeline capacity through the DAA has delivered efficiency benefits as previously underutilised capacity is now available, often at costs markedly below long or short-term firm equivalents.
- The DAA has also put material downward pressure on downstream spot market prices by supporting the transportation of additional gas into these markets.
- Contracting to swap physical gas between locations can be an alternative to transportation contracts, but is not widely used between Queensland and the southern states due to declining southern gas supply.

Participants can bypass the need to contract transportation by using the DAA and/or contracting to swap gas between locations. However, these alternatives do not provide the same reliability or availability and so are only a partial substitute for firm transportation contracts.

This chapter provides an overview of the how the DAA has supported short- term gas markets and the availability of physical gas swaps.

8.1 Day Ahead Auction has supported short-term gas markets

AEMO facilitates the DAA to enable pipeline users to procure spare capacity on designated transmission pipelines and compression facilities through an auction on a day-ahead basis (Box 2.1, section 2.1).

8.1.1 The DAA supports efficiency on a short-term basis

As noted in our 2024 focus report, the DAA:[94]

- has increased gas supply in the east coast gas markets by making otherwise unused capacity available to participants at costs markedly below long or short-term firm equivalents
- may have supported the growth of activity by gas traders which has contributed to increased competition and efficiency in the facilitated markets, and improved liquidity and the promotion of price alignment between the markets

94 AER, Day Ahead Auction Focus Report, Australian Energy Regulator, October 2024.

- may have promoted more efficient use of long-term firm contracts on some key pipeline auction routes where surplus capacity has declined markedly.

However, participants may be deterred from using the DAA due to schedule misalignment between the DAA and STTMs that means participants must schedule into the STTM without knowing whether the DAA capacity will be available to support those commitments. If DAA capacity is not available, participants must either use ‘as-available’ pipeline transportation or storage. Participants with access to a storage facility or pipeline storage may have more flexibility to use the DAA, however these options are more expensive.[95]

8.1.2 Capacity won through the DAA on auction routes to downstream spot markets has increased

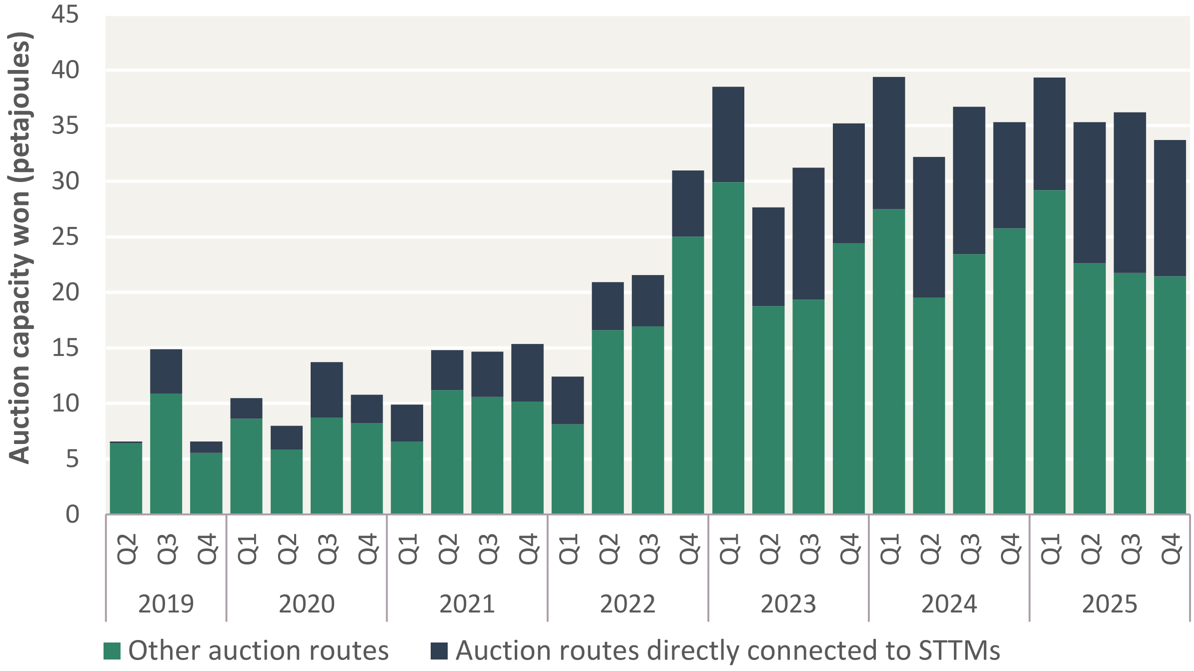
The amount of capacity won via the DAA on auction routes that directly flow into the downstream spot markets increased markedly from 2022 to 2025 and outstripped the general growth in capacity available on the DAA (Figure 8.1).

There has been particularly high use of these auction routes during peak winter periods, when it grows to almost 40% of the total quantity won via the DAA. This suggests the DAA can increase gas supply to the STTMs during high winter demand periods despite less available auction capacity due to more participants using their firm rights.

To date, most capacity has been won on the Moomba to Sydney Pipeline (MSP) auction route to Culcairn that if the only route that flows south to Victoria and the Victorian Declared Wholesale Gas Market (DWGM). However, since 2023, the Eastern Gas Pipeline’s (EGP) auction route to Sydney has become the most prominent of the auction routes that directly flow to the downstream spot markets (section 8.1.4).

95 AER, Wholesale gas market focus report – Downstream spot markets, Australian Energy Regulator, May 2025, pp. 56–57.

Figure 8.1 Pipeline capacity won via the DAA on auction routes to downstream spot markets



Source: AER analysis using DAA data.

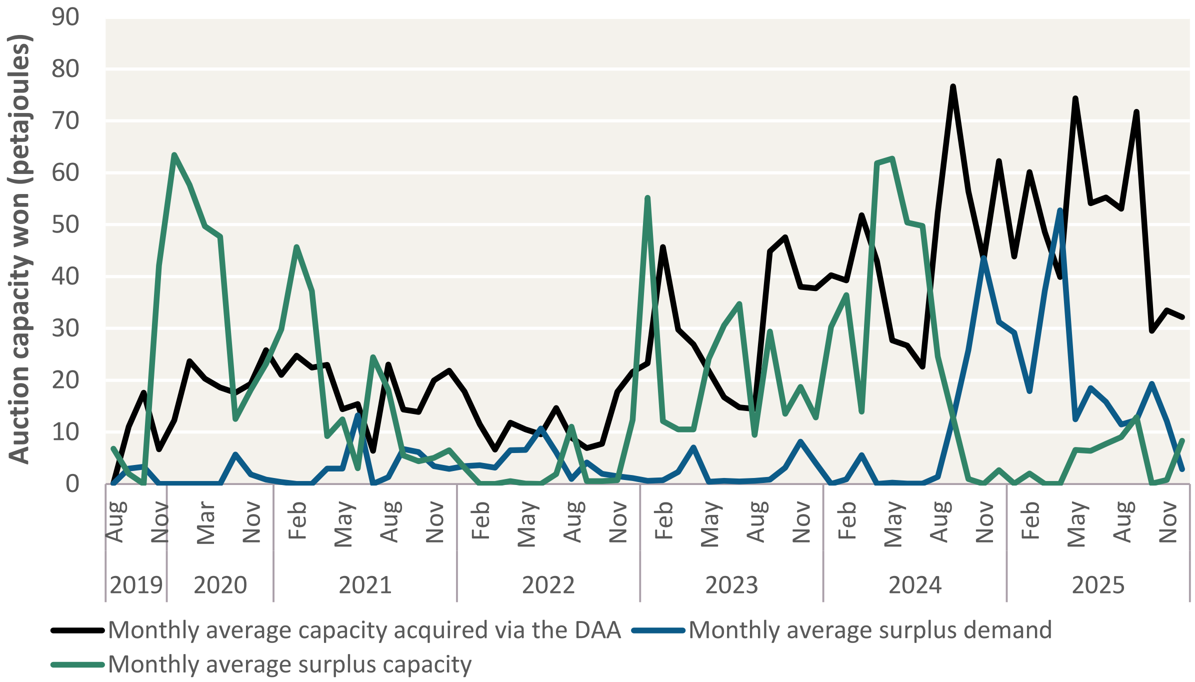
8.1.3 Prices for capacity won via the DAA are lower than prices for firm pipeline transportation

The opportunity for participants to access gas pipeline capacity at low or no cost is a key distinguishing feature of the DAA compared with alternative options to source or bypass gas transport or compression. Most (72%) capacity won via the DAA on auction routes flowing directly into the downstream spot markets is at the reserve price of $0 per GJ. The proportion won at $0 per GJ has declined in recent years, particularly on the EGP and MSP, due to more demand for capacity than is available. However, even on high demand days, prices have generally remained well below $1 per GJ and only risen to a maximum of $2.40 per GJ.

8.1.4 EGP is the most constrained and expensive auction route

The most constrained auction route is on the EGP flowing north from Victoria to Sydney. Since winter 2024, the EGP has often had more demand than supply available via the DAA (Figure 8.2). This has resulted in the EGP's capacity being typically won at relatively higher prices than on other auction routes.

Figure 8.2 Capacity won on the EGP compared with surplus demand and capacity

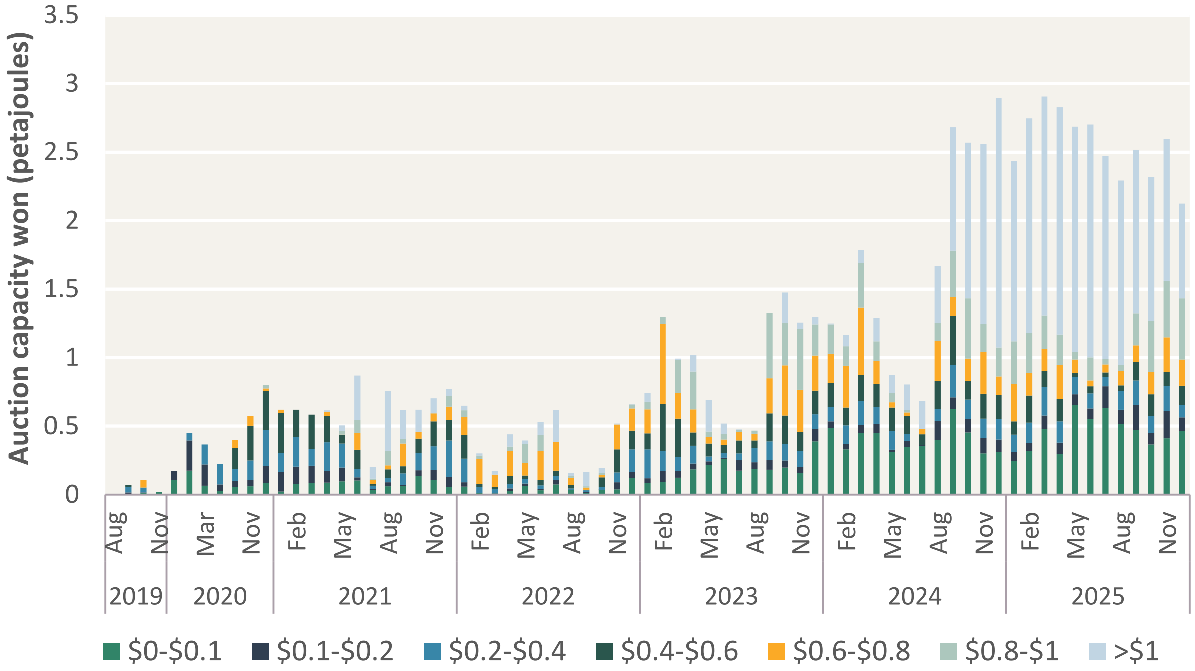


Note: Surplus capacity on the DAA routes is measured as the difference between the auction quantity limit (AQL) and the total capacity won for a given auction. Surplus capacity measures spare capacity on routes where bidding has occurred, so does not necessarily capture all nominated contracted capacity on pipelines.

Source: AER analysis using DAA data.

While the EGP previously often cleared at $0 per GJ, prices have increased significantly since the last quarter of 2024. In mid-2024, the demand for capacity approximately doubled compared with previous years and remained high throughout 2025. This is likely due to an increase in the number of participants competing for capacity to transport gas into Sydney from Victoria to be paid the generally higher Sydney prices. Participants may be more willing to use the DAA to acquire capacity on the EGP because there is significant capacity available on the EGP for contracting. This means if the participant is unable to acquire capacity through the DAA, they are still able to secure the capacity through an as-available service. This increase in demand coincided with a step change increase in the proportion of bids above $1 per GJ from 7% in 2023 to 32% in 2024 (Figure 8.4). In 2025, 53% of capacity was bid for above $1 per GJ and peaked at 60% in winter 2025. However, these DAA prices remain lower than the EGP's contracted prices.

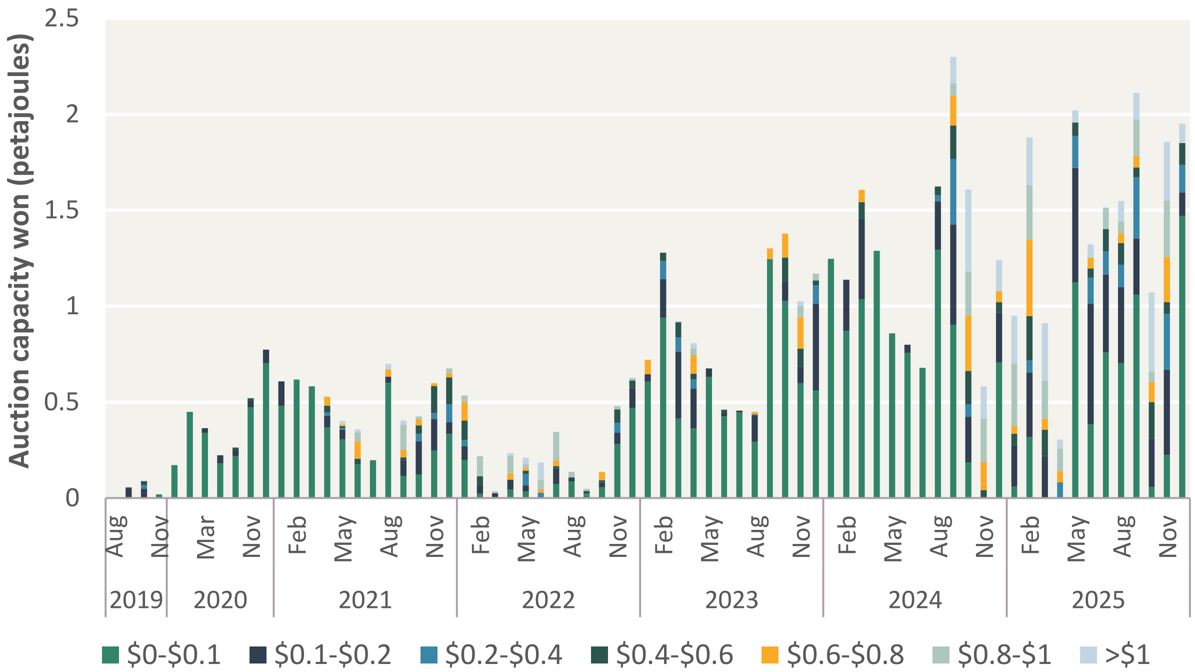
Figure 8.3 Price bids for the DAA capacity on the EGP auction route to Sydney



Source: AER analysis using DAA data.

The increased demand and bid prices pushed cleared prices up on the EGP's auction route to the Sydney STTMs (Figure 8.4). However, other EGP auction routes still cleared at $0 per GJ.

Figure 8.4 Prices paid at the EGP auction route to Sydney



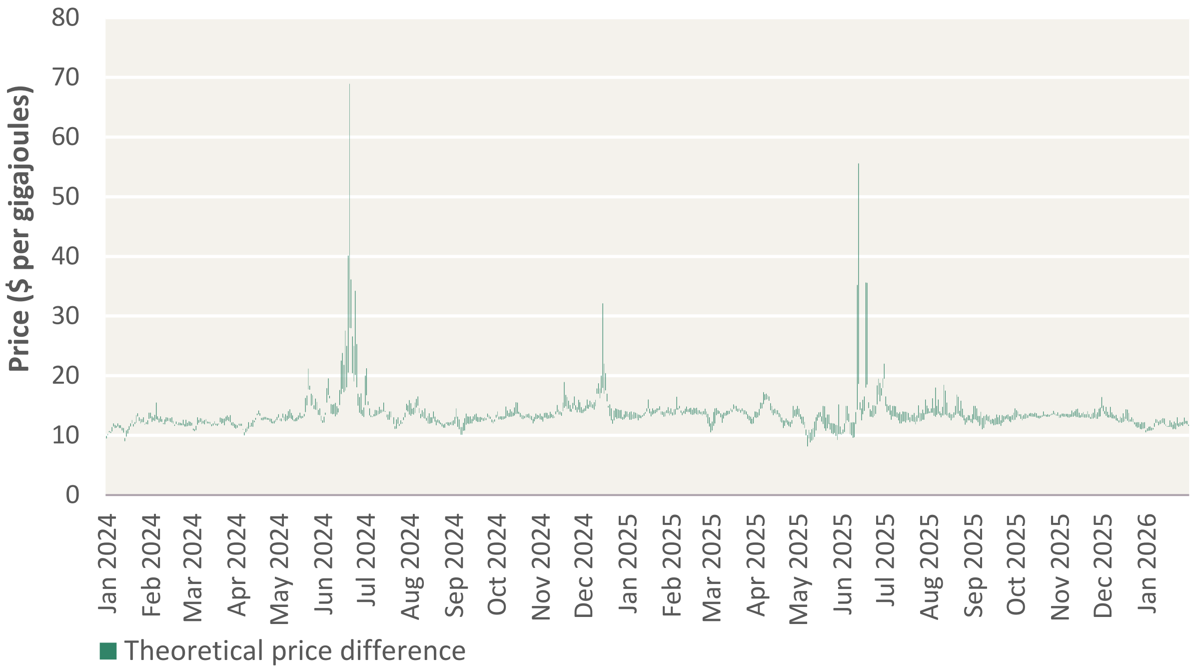
Source: AER analysis using DAA data.

8.1.5 DAA can put material downward pressure on spot markets in peak periods

Capacity won via the DAA can have material impacts on downstream spot market prices. We conducted analysis to estimate the possible impact of the DAA on the spot prices in the Sydney STTM. This analysis only provides an indicative impact, however, it illustrates that capacity won via the DAA can materially ease pressure in downstream spot markets.

Spot prices in the Sydney STTM tend to be relatively stable but prices increase in winter periods when demand is higher and transportation is constrained. Our analysis indicates winter price increases would be much greater without the capacity made available via the DAA (Figure 8.5). The DAA is estimated to have lowered the Sydney STTM spot prices by a daily average of $1.33 per GJ (9.3%) between January 2024 and December 2025. This estimation rises to $5.49 per GJ (25%) in June 2024 and $4.71 per GJ (26%) in June 2025.

Figure 8.5 Indicative impact of DAA capacity on prices in the Sydney STTM



Note: The theoretical price difference in the figure represents the maximum price impact on the Sydney STTM spot price. The bar shows the price of the highest cleared supply offer in the Sydney STTM and the indicative clearing price if incremental offers had been scheduled in line with gas quantities won via the DAA and had not been offered into the Sydney STTM.

Source: AER analysis using AEMO data.

8.2 Physical gas swaps not viable alternative for southern supply

Physical gas swaps can be an alternative to contracted gas supply and/or transportation in which parties enter bilateral agreements to exchange a specified volume of gas at different locations or times or both. The parties each pay a price for the gas they receive, with one party generally paying a higher price reflective of greater demand for gas in that location or time. Participants can also arrange swaps of pipeline imbalance positions, but this is not reported to the Gas Bulletin Board.

In 2025, around 75 PJ of gas was swapped between participants through short-term (up to 12 months) gas swaps.[96] This does not include gas swapped over a longer duration. Most gas swaps were location swaps (around 67%) rather than time swaps (around 22%) or both location and time swaps (around 11%). Location swaps can bypass the need to use gas pipelines and in doing so support price convergence and liquidity between the facilitated markets. However, the ability for participants to arrange gas swaps is limited due to contractual complexity and the availability of counterparties with a complementarily opposite gas position. Participants previously indicated that finding such a counterparty can be difficult and is likely to become even more restricted as southern production declines.[97] Supply shortfalls in southern states means gas needs to physically flow south, which necessarily places a cap on how much gas can be swapped and decreases the liquidity of swaps in the southern states.

For this report, we analysed data for around 60% of reported short-term gas swaps between 2023 and 2025.[98] Our analysis indicates swaps primarily occur between locations within Queensland (98% of transactions and 86% of gas quantity), with swaps between Ballera and Wallumbilla and within Wallumbilla being the most common. Some swaps have occurred between Queensland and the southern states, but the frequency of these swaps has reduced significantly since 2023. Swaps between Queensland and the southern states mostly happen outside of winter and a higher price is paid for receipt of the gas in Queensland. In these transactions, parties commonly pay to swap gas in Wilton or Longford for gas in Wallumbilla or Moomba. However, almost no gas is swapped in the southern states during winter.

Our analysis indicates a small number of swaps do occur between Wallumbilla and Moomba, which bypass the SWQP's cost of $1.54 per GJ per day (in 2025, not including compression) and congestion, including in winter. The maximum price paid for the swaps we analysed was $1.10 per GJ in 2024 and 2025, which is a significant increase from the maximum of $0.60 per GJ in 2023 and may reflect the step change decline in production at Longford. Some cheaper swaps were available in 2025 compared with 2024, with the minimum price dropping from $0.70 per GJ in 2024 to $0 per GJ in 2025 and the median decreasing from $1.10 per GJ to $1 per GJ. However, the volume-weighted average price has continued to increase from $0.56 per GJ in 2023 to $0.72 per GJ in 2024 and $0.83 per GJ in 2025. The volume-weighted average price for all the gas swaps we matched (between all locations) also increased significantly from $0.43 per GJ in 2023 to $0.70 per GJ in 2024 and $0.74 per GJ in 2025, with the median price for all gas swaps around $1.12 per GJ in 2025.

96 Short-term gas swaps are separately reported to AEMO by each party to the swap. This means the quantity of gas is reported twice. We have divided the total quantity of gas reported to AEMO via the short-term swaps by half to derive around 75 PJ of gas was swapped.

97 AER, Day Ahead Auction Focus Report, Australian Energy Regulator, October 2024.

98 Gas swaps are separately reported to AEMO by each participant and so we are required to undertake analysis to match these counterparties. The proportion of swaps able to be matched has increased over time, likely reflecting improved reporting practices among participants.

9 Financial risk management products

Key points

- Information collected from large gas market participants indicates financial products are not widely used or critical to participation in the facilitated gas markets.
- To the extent they are used, financial risk management products are a complement to contracting under gas supply agreements (GSAs), alongside other risk management tools like flexibility and storage.
- Liquidity in trade for ASX-listed gas products is low and has decreased since 2022. Trade in over-the-counter (OTC) financial products is more active, but is still materially lower than trade for bilateral GSAs.
- Despite limited use and low liquidity in trade, financial risk management products can support efficient outcomes in wholesale gas markets.

Understanding if and how gas market participants use financial risk management products to manage wholesale gas market and commodity price risks is important to understand the actual risk exposure participants face and, as a result, outcomes in wholesale gas markets.

This chapter examines:

- the role and availability of financial risk management products in the east coast gas markets in managing downstream spot market risk
- barriers to trading those products
- how participants manage commodity price risk.

To inform our analysis, we collected OTC financial contract information from 9 large wholesale gas market participants for the period 1 January 2023 to 30 June 2025. We also consulted with industry, meeting 16 market participants in early 2026.

Two types of markets for financial risk management products are used by market participants to manage price risk in the east coast gas market:

- **Exchange-traded markets** – Futures contracts are traded on the Australian Securities Exchange (ASX) or other exchanges. Exchange products are standardised, transparent to the wider market and include centralised clearing services.
- **Over-the-counter (OTC) markets** – Two parties contract with each other directly (sometimes assisted by a broker). The terms of OTC contracts are usually set out in International Swaps and Derivatives Association (ISDA) agreements. OTC contracts can provide greater flexibility in the types of contracts, contract terms and volumes compared to exchange traded products.

Market participants may use financial products (Box 9.1) to manage a variety of price risks. In the east coast gas market, financial products are used to manage 2 key risks:

- Wholesale gas market price risk – ASX or OTC products are used to manage exposure to wholesale gas market price risk. The ASX currently offers 3 products:

  - Victorian quarterly gas futures
  - Victorian strip futures (a combination of 4 quarterly gas futures covering a calendar or financial year)
  - Wallumbilla GSH monthly gas futures.
- Gas supply agreement contract price risk – in the east coast gas market, GSAs for firm delivery often have a price that is linked to an international commodity – for example, Brent or JKM. Market participants can manage their contract price risk by trading commodity futures either on an international exchange or OTC.

Box 9.1 Types of financial risk management contracts

Various products are traded in electricity contract markets. Exchange-traded products are standardised to encourage liquidity, while OTC products can be uniquely sculpted to suit the requirements of the counterparties. Several products are typically traded:

- **Futures contracts** allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of gas at a specified time in the future. Each contract relates to a nominated price in a particular market. Futures contracts are settled against the spot price in the relevant market – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference, and when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures contracts are known as swaps, fixed for floating swaps or contracts for difference.
- **Options** are contracts that give the holder the right – without obligation – to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product).

9.1 Role and use of financial risk management products to manage wholesale gas spot market price risk

The utility and use of financial risk management products is dictated by the structure of the market. The east coast gas market is primarily underpinned by GSAs for the delivery of physical gas, which lock buyers and sellers into prices ahead of time and give participants a degree of price certainty. Because of this, the need to rely on financial products to manage wholesale gas market price risk is reduced.

However, some market participants are trading financial risk management products to manage risk that may not be mitigated using GSAs alone. The availability of these products can support efficient outcomes in wholesale gas spot markets.

9.1.1 Financial products complement bilateral gas supply agreements

In our engagement with stakeholders, participants noted that financial risk management products mainly complement and are not a substitute to bilateral GSAs. Financial contracts can be used to manage risk alongside other tools such as flexibility in GSAs and storage. Participants identified benefits of financial risk management products, including:

- managing seasonal demand on top of a gas supply agreement diversifying risk that arises from contracting using GSAs – for example, delivery risk or permitted interruptions included in a gas supply agreement[99]
- creating financial location swaps between 2 wholesale gas markets, removing the need to contract for transport.

Where financial products are used, participants mainly trade ASX-listed futures contracts and OTC swap contracts (where a variable commodity price is swapped for a fixed price). Overall, use of these instruments appears to be occasional rather than typical.

Despite some benefits, liquidity in ASX-traded products is low. Trade in OTC products is higher, but still low when compared with bilateral GSAs or other wholesale energy markets, such as the National Electricity Market (NEM). Several factors are impacting liquidity in trade of financial risk management products (section 9.2).

Due to the structure of the market, and the prominent role of GSAs for longer-term contracting, the availability of financial risk management products is unlikely to act as a barrier to new entry to supplying gas into wholesale gas markets. Barriers to participating in the facilitated gas markets are low and to the extent that barriers exist, they exist in longer-term supply and transport (Section 3.4).

Upstream investment has historically been underwritten by long-term GSAs, which remain the primary way in which gas is supplied in the east coast. This limits the need for liquid financial contract markets linked to domestic downstream spot markets to act as a price signal and incentivise new supply.

9.1.2 ASX-traded volumes have declined materially since 2022

A quarterly futures product for the Victorian Declared Wholesale Market (DWGM) has been available on the ASX since 2007 but only began trading substantially in 2018. Between 2018 and 2022, volumes traded on the ASX ranged between 5 and 7.5 PJ, equivalent to roughly 20% of the underlying net trade on the DWGM. Following the 2022 energy crisis, traded volumes declined. This level of trade is low compared with other wholesale energy markets. For example, ASX-listed products relating to the NEM trade in volumes between 600% and 1,000% of underlying trade, noting that the NEM has a different structure that does not involve bilateral supply and transportation agreements.

In August 2024, a new Wallumbilla deliverable futures contract was introduced on the ASX. Traded volumes remain low (Figure 9.1).

DWGM futures have generally traded at higher prices than the DWGM daily spot price since the 2022 price spike. This likely reflects future price uncertainty following the high domestic spot prices that occurred in 2022 and a premium for price certainty paid by buyers. Since 2022 DWGM futures have trended down and show clear seasonality, with Q2 and Q3 prices

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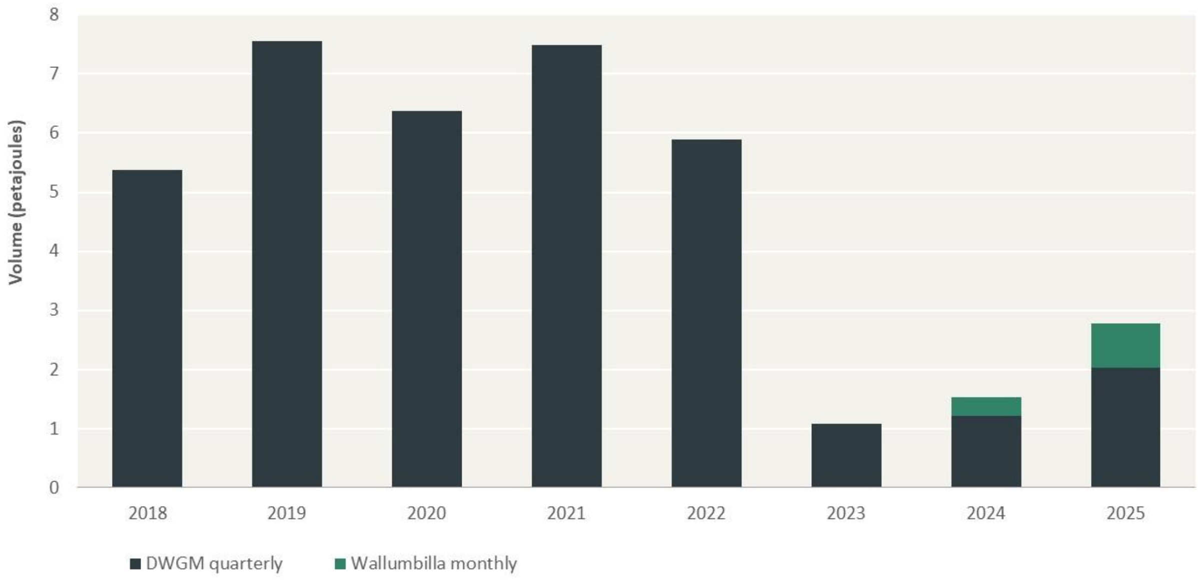
[99] Allows a gas supplier a number of agreed days they can interrupt a service (not required to deliver gas). Interruptions can be planned and unplanned.

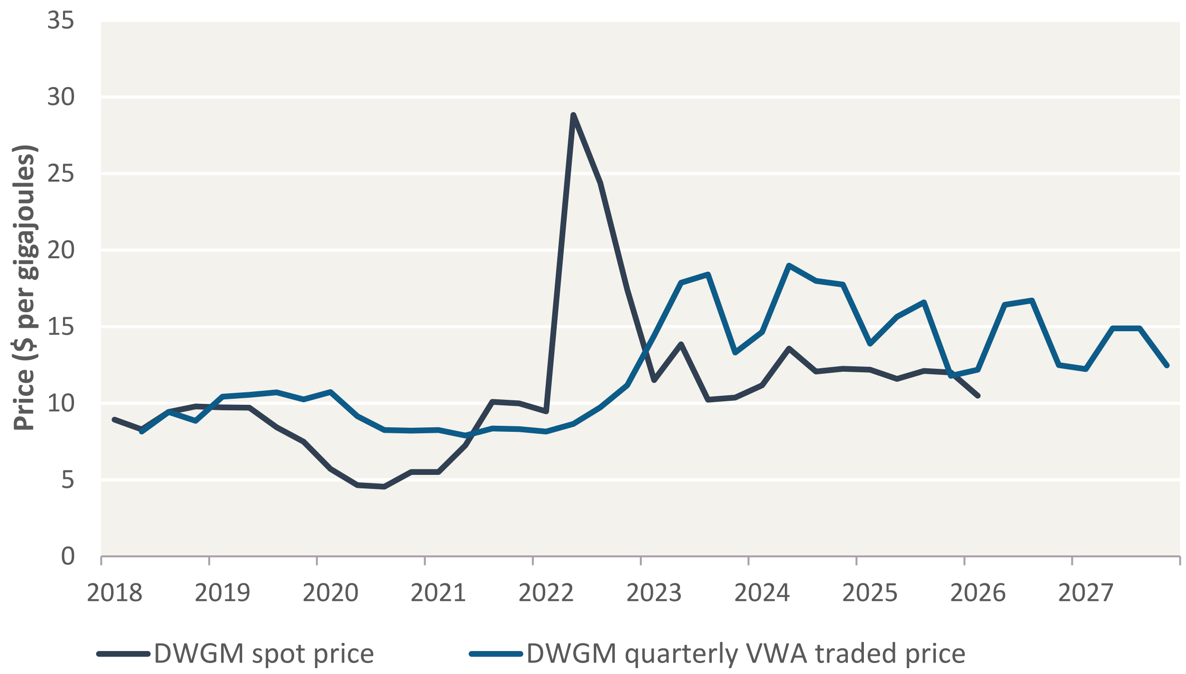
higher than Q1 and Q4 prices, consistent with higher winter demand in the DWGM (Figure 9.2).

Figure 9.1 Volume of ASX-listed futures products, by trade date



Source: AER analysis using ASX data.

Figure 9.2 VWA DWGM futures forward traded prices and DWGM daily spot price



Note: Price of DWGM futures traded is a volume-weighted price of all the trades in the respective quarter. DWGM spot price is the DWGM daily imbalance price.

Source: AER analysis using AEMO and ASX data.

9.1.3 OTC contracts linked to facilitated markets are more widely used than ASX products

Unlike ASX-traded products, no public information is available on the trade of OTC financial products. To support analysis of these instruments, we collected OTC financial contract information from 9 large wholesale gas market participants for the period 1 January 2023 to 30 June 2025. This information showed that:

- the volume of gas traded using OTC financial products is higher than volumes traded in ASX-listed products
- swap products are the primary product used
- volume weighted average prices for swaps declined over the reporting period
- other contract types traded included options, but in materially lower volumes.

For swap contracts, nearly all of the volume was traded against the DWGM or Sydney STTM price (Figure 9.3), with some smaller volumes (below 1 PJ in total) traded on the Brisbane and Adelaide STTMs. The remainder of analysis in this section will look at swap contracts traded against the DWGM and Sydney STTM.

Table 3.2 Gas OTC financial contract information – 1 January 2023 to 30 June 2025

Wholesale gas market	Trade year	Volume (PJ)	Average daily volume (TJ)	VWA traded price
DWGM	2023	5.6	0.9	$17.62
	2024	10.9	1.8	$15.46
	2025	3.4	1.6	$15.23
Sydney STTM	2023	4.8	0.9	$18.26
	2024	6.7	1.2	$14.84
	2025	2.6	1.5	$15.05

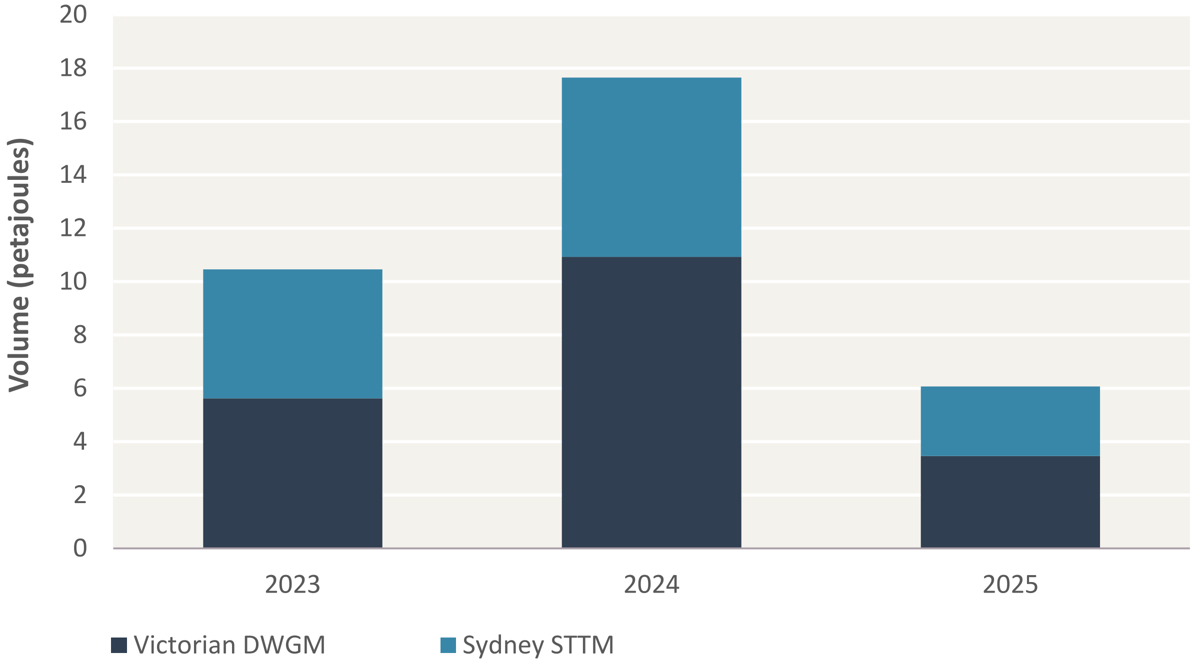
OTC volumes traded at the DWGM were materially higher than volumes traded on the ASX. This is in part driven by participants' ability to create a financial location swap between 2 downstream spot markets using OTC products. For example, if a participant is short gas in the DWGM and long gas in the Sydney STTM it can create a financial location swap by simultaneously trading financial contracts in reference to both markets. The participant can take the fixed price in a swap contract in reference to the price in the DWGM and take the floating price in a swap contract in reference to the price of the Sydney STTM. This allows it to purchase gas from the DWGM and sell gas into the Sydney STTM, locking in a fixed price at both markets and removing the need to transport the gas.

Participants also noted that:

- the ability to trade shorter-term contracts (e.g. 1 month in length) was more useful than the ASX's current DWGM product, traded on a quarterly basis, which does not directly align with the Australian winter months
- greater use of OTC contracts may reflect differences in ASX margin requirements compared to counterparty requirements.

Over the reporting period, the average contract length was around 6 months in length. Contracts typically ranged from 1 to 3 months in length up to 12 months in length. Traded volumes were typically for the year ahead. In 2024, around half of the volumes traded were for forward start in 2025, with around 32% for 2026 and 6% for 2027. 2025 trade up to 30 June was mostly for forward start in 2026, around 71%, and 12% for 2027.

Figure 9.3 Traded volumes in OTC wholesale gas market swaps – 1 January 2023 to 30 June 2025



Note: Volume of OTC trades that occurred during the year from participants who provided information.

Source: AER analysis using AER data.

Prices for swaps have trended down across the reporting period. In 2023 quarterly volume-weighted average prices traded for $17.62 at the DWGM and $18.26 in the Sydney STTM. In 2025 prices traded for $15.23 at the DWGM and $15.05 at the Sydney STTM.[100] Prices in 2023 were materially higher than domestic spot prices at the time. This likely reflects future price uncertainty following the high domestic spot prices that occurred in 2022, similar to contract pricing in ASX-listed products and bilateral GSAs.

[100] We have included fixed for floating price swaps that are used to create financial location swap between the DWGM and Sydney STTM. While participants may be primarily concerned with the difference in fixed prices between contracts, they appear to consider expectations of future downstream spot market prices.

Volume-weighted average forward prices have also fallen, from a high of $19.61 for delivery in Q3 2023 to a low of $13.55 for delivery in Q4 2026 (Figure 9.4). As with ASX-traded products, OTC products have a clear, though less pronounced, seasonal shape, with prices for delivery higher in Q2 and Q3 compared with Q1 and Q2.

Figure 9.4 Volume-weighted average OTC swap forward traded prices

Note: VWA price of OTC trades that occurred from participants who provided information.

Source: AER analysis using AER data.

9.2 Barriers to participating in financial risk management products to manage wholesale spot market risk

In our consultation, market participants noted that liquidity is the primary barrier to trading financial risk management products to manage price risk in downstream spot markets. Liquidity itself is impacted by several barriers, some enduring and some that have materialised since the 2022 energy crisis.

9.2.1 Structural barriers

Overall, fewer participants are active in financial contract markets than in the east coast gas market and downstream spot markets. Information obtained from participants shows that different participant groups have different levels of involvement in financial contract markets.

- GPG gentailers and retailers are the primary participants trading financial products. These participants are active in the NEM, where trading financial risk management products is required to participate in the market. As a result, these participants are more comfortable trading these products and have the appropriate licenses and internal processes to do so.

- Exporters and producers do not appear to be active in financial contract markets linked to downstream spot markets. This removes a large source of liquidity that otherwise might be seen in comparable wholesale energy markets. For example, in the NEM, owners of generation assets are the key suppliers of liquidity in financial contract markets.
- For producers, the ability to underwrite investment using GSAs may mean the utility of financial products is low. Equally, GSAs may be seen as a better tool to manage their risk profile.
- Industrials appear to be less active in financial contract markets. For many industrial users, gas is an input cost and price certainty is their primary concern. The availability of GSAs means they do not need to trade financial risk management products to manage price risk and they may not be large enough to realise benefits from participating in multiple markets. While unlikely to supply volumes into financial markets, if industrial participants were more active in seeking derivative products, it may increase the overall liquidity of the market.

In consultation for our 2025 downstream spot market report, many participants noted they do not have a financial license or the internal management processes established that are required to trade financial products.[101] However, participants did not suggest this was a hard barrier to accessing the financial market and so participation in financial products may improve if the benefit outweighs the costs.

Participants also noted that financial products related to the DWGM are typically settled at the 6 am price. The DWGM has 5 price intervals throughout the day, and products trading at only one interval may not provide adequate risk mitigation. Participants noted that Iona and pipeline storage are better tools to manage this risk.

9.2.2 Post 2022, market event driven barriers

After the 2022 energy crisis, liquidity for ASX-listed products decreased. Participants noted:

- During high spot market prices in 2022, ASX margin requirements became onerous, which may have impacted liquidity.
- During the crisis, several clearing houses stopped offering clearing services. The ASX noted that some new clearers have recently entered the commodity markets space on the ASX and are preparing to clear gas futures.

Additionally, market interventions since 2022 may have inadvertently affected liquidity of financial products. Some market participants noted that, following the introduction of the Gas Code, conditions in ministerial exemptions meant they were unsure if they could participate in trading the new ASX-listed Wallumbilla delivered product. This was because the product has a firm delivery obligation to a participant, despite the underlying trade being anonymous.

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[101] AER, Wholesale gas market focus report – Downstream spot markets, Australian Energy Regulator, May 2025, p. 29.

Market participants also noted that risk considerations around the use of financial products changed in 2022, when AEMO directed market participants not to withdraw gas from the DWGM unless they were also supplying gas to the DWGM.

Through its Gas Market Review, the Australian Government is considering changes to market design including operation of the Gas Code. The Gas Market Review Report, noted that reforms are being progressed, including anonymising delivery obligations at the GSH.[102] Design of market reform should consider the interaction of financial risk management products with the broader east coast gas market to mitigate unintended impacts on participants ability to utilise financial risk management products.

9.3 Managing international commodity price risk in gas supply agreements

In bilateral contracts within the east coast gas market, it is common practice for the price of a GSA to refer to an international commodity price, such as international oil or gas prices. For example, a contract may be struck with a price of 10% of the Brent oil price or 80% of the JKM gas price. In its interim reports, the ACCC reports that 23% of the volume struck under GSAs for supply in 2026 had a commodity link,[103] and around 40% of the volume struck for supply in 2027 had a commodity link.[104]

Market participants that purchase gas under a GSA with a commodity price link are exposed to fluctuations in that commodity. A market participant may choose to hedge its exposure to fluctuations in the underlying commodity using exchange-based or OTC financial products linked to the commodity price.

Markets for international commodity-based financial products are significantly more liquid than financial products trading in reference to domestic wholesale gas markets. For example, Brent can be traded on the international commodities exchange ICE, with liquidity out to nearly 5 years, while JKM can be traded out between 6 months and 2 years. Equally, there are more active counterparties in OTC financial markets for these commodities, including large international banks.

Information collected from 9 large wholesale gas participants shows that several market participants are actively trading exchange-based and OTC financial products to manage international commodity price risk. Equally, at least one smaller participant has told us that Brent linked contracts can be preferable because of the liquidity available in financial product markets, which can be traded over time.

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102 DCCEEW and DISR, Gas Market Review report, Department of Climate Change, Energy, the Environment and Water and the Department of Industry, Science and Resources, December 2025, p 29.

103 Gas supply agreements struck between July 2024 and December 2025, for volumes greater than 0.5 PJ and a contract term of at least 12 months. For other GSA inclusion criteria, please see Appendix C of the ACCC's March 2026 Gas Inquiry interim report (p 46).

104 Gas supply agreements struck between January 2025 and December 2025, for volumes greater than 0.5 PJ and a contract term of at least 12 months. For other GSA inclusion criteria, please see Appendix C of the ACCC's March 2026 Gas Inquiry interim report (p 46).

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CPI	consumer price index
C&I	commercial and industrial
DAA	Day Ahead Auction
DBVM	Depreciated Book Value Method
DCCEEW	Department of Climate Change Energy Efficiency and Water
DISR	Department of Industry, Science and Resources
DWGM	Declared Wholesale Gas Market (Victoria)
ECCMC	Energy and Climate Change Ministerial Council
EGP	Eastern Gas Pipeline
GJ	gigajoule
GPG	gas-powered generation
GSA	gas supply agreement
GTA	gas transportation agreement
GSH	Gas Supply Hub
HoA	Heads of Agreement
HHI	Herfindahl-Hirschman Index
ISDA	International Swaps and Derivatives Association
JKM	Japan Korea Marker
LNG	Liquefied natural gas
MAPS	Moomba to Adelaide Pipeline System
MGSA	Master Gas Supply Agreement
MSP	Moomba to Sydney Pipeline

NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
OTC	over-the-counter
PJ	petajoule
QCLNG	Queensland Curtis LNG
RAB	regulated asset base
RBP	Roma to Brisbane Pipeline
STTM	Short Term Trading Market
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
TJ	terajoule
VTS	Victoria Transmission System
VWA	volume weighted average