Gas Inquiry 2017-2030

Interim update on east coast gas market

December 2024

Acknowledgment of country

The ACCC acknowledges the traditional owners and custodians of Country throughout Australia and recognises their continuing connection to the land, sea and community. We pay our respects to them and their cultures; and to their Elders past, present and future.

Australian Competition and Consumer Commission
Land of the Ngunnawal people
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Overview

Natural gas will play a critical role in Australia's transition to lower emissions. As we increasingly rely on renewables for electricity generation, gas will be required to support energy security, reliability and affordability, while remaining an important source of energy and feedstock for residential, commercial and industrial users (C&I).

Despite the importance of gas in the energy transition, east coast gas supply is in decline. Traditional supply sources such as the Gippsland Basin, which have served the east coast market for decades at a relatively low-cost, are rapidly depleting and investment in new supply has been insufficient to replace them.

In the absence of new supply in the southern states to fill the gap, consumers will depend in the near term on gas transported from Queensland. As southern haul pipeline capacity becomes increasingly constrained, southern states will likely have to depend on imported Liquefied Natural Gas (LNG). Domestic gas prices will therefore become increasingly driven by international oil and gas prices and the cost of transporting gas large distances across the east coast.

The international energy crisis in 2022 – which coincided with coalfired generator outages in the National Electricity Market (NEM) and other domestic supply-side events – highlighted the consequences of inadequate domestic gas supply and an entrenched linkage to volatile LNG markets. It also demonstrated the increasing interrelationship and susceptibility of the gas market to international and electricity market conditions.

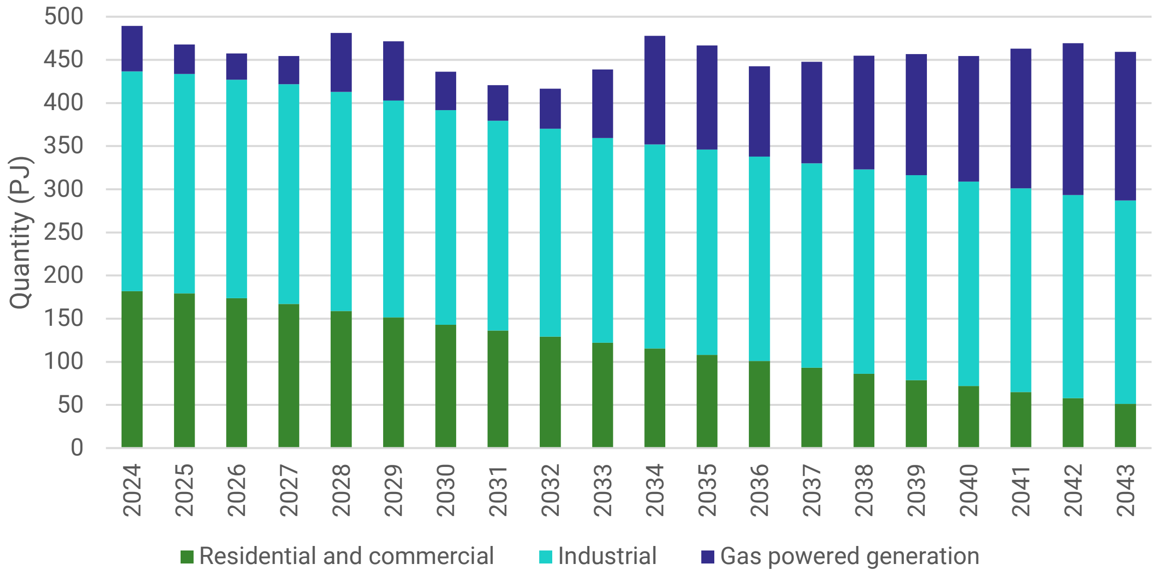
To support reliable energy and an orderly transition to a lower emissions environment, the east coast gas market needs to be well supplied. Gas demand on the east coast is expected to remain at high levels for at least the next 2 decades, as shown in chart 1.

While Australian Energy Market Operator (AEMO) forecasts a decline in residential and commercial demand as households and businesses electrify, industrial demand is expected to remain constant. Gas is needed as a core component in manufacturing and for chemical processes producing products such as fertiliser and cosmetics. Industrial users do not have technically or commercially feasible alternatives to gas for these uses and their shift away from gas will depend on technological advancements.

Demand for gas-powered generation is forecast to grow as the NEM energy mix moves from primarily baseload generation to intermittent renewables generation. This will require additional supply and infrastructure from the gas markets.

The forecast decline in residential demand for gas will affect the future of the gas distribution networks and asset stranding risks pose significant potential costs to users.

Chart 1: Forecast annual gas demand on the east coast, between 2024 and 2043



Source: ACCC analysis of AEMO 2024 GSOO data.

It is critical that policy settings promote the most efficient solutions for the gas and electricity markets. Given reliance on gas for energy security and orderly achievement of emissions targets, it will be important for governments to employ measures that:

- support competition and the operation of a well-functioning market through the transition
- provide greater policy guidance to gas users, investors and participants on the transition path, so they can make informed decisions
- encourage switching to alternative fuels where that is feasible and efficient investment in other demand-side measures through the transition.

In this context, this report:

- Continues our core inquiry work and reports on how the gas market is functioning in terms of supply, pricing, transactions and market behaviour.
- Reports the findings from our retailer behaviour review and highlights ways to further improve retailer pricing and selling practices.
- Considers the policy, regulatory and market conditions necessary to promote efficient investment in and supply of gas in the context of the energy transition.

Market conditions have improved but prices remain elevated given international dynamics

Volatile and uncertain market conditions between 2022 and early 2024 had a profound impact on market participants across the gas supply chain. Availability of gas supply and infrastructure services, prices, and the contracting environment have all been affected, with gas buyers – C&I users, retailers and other intermediaries – placed under significant pressure.

Conditions appear to have eased somewhat over the first half of 2024, at least in part driven by an expected surplus in 2025 and an increase in market activity. Based on producer supply forecasts and AEMO demand projections, we expect 77–112 PJ of excess production in the east coast over 2025 depending on LNG producers' uncontracted gas exports. In southern states, however, we expect a shortfall of up to 16 PJ.

To the extent excess Queensland gas has been offered to the domestic market, we expect it to have influenced market activity and pricing. Over late 2023 and early 2024, following a prolonged period of inactivity, several large producers received conditional Ministerial exemptions from the price rules of the *Competition and Consumer* (Gas Market Code) *regulations 2023* (the Gas Code) and resumed making offers for supply in 2025–26. We have since seen a marked increase in the number of offers made by both producers and retailers over the first half of 2024.

The increased availability of gas, together with lower international prices, appears to have contributed to a softening of domestic prices and a narrowing of the gap between producer and retailer prices. Producer offers over the first half of 2024 for supply in 2025 averaged $14.77/GJ, a 1.8% decrease from the second half of 2023, while retailer offers fell 13.4% to $15.43/GJ. Prices under executed agreements with producers increased 3% to $14.72/GJ, while retailer GSA prices fell 26% to $14.70/GJ.

Despite the projected east coast surplus and the increase in market activity, prices remain materially higher than pre-2022 levels. While lower than the highs observed in 2022, the prices agreed to over the first 6 months of 2024 for 2025 supply are around 2 times higher than they were for the 2021 supply year. This trend is broadly consistent with what has occurred with international prices, which have remained above the levels observed over 2020 and most of 2021.

We have heard from a range of gas buyers that there has been little gas available at the $12/GJ reasonable price level under the Gas Code. Almost all gas expected to be produced in 2025–26 is either committed to export or held by producers that hold conditional Ministerial exemptions from the Gas Code's reasonable price provisions. Supply commitments under such exemptions may, given large enough quantities, be expected to put downward pressure on prices. However, significant increases in supply subject to conditional Ministerial exemptions are only potentially available from 2026.

We therefore do not expect the Gas Code to have had a material impact on observed prices. The price levels we have seen offered and transacted in 2024 are broadly consistent with what we would expect given LNG netback prices in Queensland and the need to transport gas from Queensland to southern states to meet demand.

Gas buyers seek longer-term certainty, contract flexibility and greater bargaining power

While market conditions have improved and there is an expected surplus in 2025, we are seeing much less gas being contracted relative to pre-2022 levels. Up to June 2024, the amount of gas contracted for 2025 supply was about 42% of the amount contracted by June 2021 for 2022 supply.

Over the past 12 months we have engaged extensively with gas buyers in the east coast market, including C&I users, intermediaries, and retailers. In addition to the impact of price volatility over recent years, these groups have expressed concerns about changes in the way producers are offering and selling gas, in particular: the increase in shorter term contracting, the deterioration in non-price terms and conditions, and producer EOI processes.

Gas is increasingly being sold by producers under shorter-term GSAs, with most new agreements having a term of less than 2 years. There also appears to be more gas being sold on a short-term intra-year basis, particularly by LNG producers. Buyers are concerned about greater exposure to price and supply risk as a result. The shift to shorter-term contracting may also be affecting investment in user facilities and supply-related infrastructure because gas buyers do not have the price or supply certainty they require to underwrite long-term projects.

The non-price terms and conditions offered by producers also appear to have deteriorated, with an increasing number of producer GSAs providing no volume flexibility and some producers passing supply risk onto buyers through permitted interruption provisions. Gas buyers noted that they are having to rely on other tools to manage demand and supply risks that have historically been managed through GSAs.

Some gas buyers are concerned that the Gas Code may be leading to more gas being sold through Expression of Interest (EOI) processes. While the Gas Code does not mandate the use of EOIs, it appears that more are being used to market gas. Although they can be beneficial by making gas available to the broader market, buyers are concerned that the 'blind auction' nature of some EOI processes may be exacerbating imbalances in bargaining power. They are also concerned about the protracted nature of some EOI processes.

Retailer selling practices can and should improve, but underlying problems are upstream

We have completed our retailer behaviour review, which has focused on retailer pricing and selling practices when supplying gas to C&I users consuming more than 1 TJ annually over the period 2020–2024. We found that retailer practices between 2022 and early 2024 were heavily influenced by the tight and volatile market conditions experienced across the east coast gas market, which directly led to:

- constraints on retailers' access to gas, transport and storage
- a significant escalation in retailers' costs and risks
- reduced competition to supply C&I users.

More recently, as international prices have softened and producers have started to make more gas available to the market, we have seen retailers' prices fall to become more in line with producer prices. There have been some improvements in selling practices, although concerns remain about some retailers' standard selling practices.

Taking together our findings throughout the review, we consider that in the case of:

- **Retailer pricing practices:** There is no evidence of a persistent market failure or systemic problem that requires price regulation, and doing so would risk harming an already fragile competitive environment, which would operate to the detriment of C&I users.
- **Retailer selling practices:** While competition appears to have driven some recent improvements in selling practices, some retailer practices continue to fall short of what we would expect in a well-functioning retail market.

Retailing is expected to become more challenging given projected supply shortfalls, infrastructure constraints, the energy transition, and regulatory and policy uncertainty. There is also a risk that market conditions and/or competition could deteriorate again. In this context, the effects of poorer retailer practices may be felt more acutely.

To safeguard against this and promote further improvements in retailer practices, we will:

- in 2025, publish best practice guidance on retail selling practices and monitor retailers' uptake of such guidance as part of the Gas Inquiry
- in future Gas Inquiry reports, publish more information on the prices retailers are charging C&I users and the prices retailers are paying producers for gas.

This will not, however, address the underlying supply-side problems. Upstream market concentration and lack of access to sufficient gas supply are fundamental drivers of many of the problems that have flowed into the retail market. Promoting investment in supply and competition among a diversity of suppliers are key to the effective functioning of the gas market through the energy transition.

Long-term regulatory certainty and investment is essential for gas security in the energy transition

Natural gas will play a critical role in providing Australia with energy security and support an orderly transition to a lower emissions economy. As we increasingly rely on renewables for electricity generation, gas will be required to support energy security, reliability and affordability, and will remain an important source of energy and feedstock for industrial users and gas-powered generation even as residential demand declines.

Despite the importance of gas in the energy transition, east coast gas supply is in decline. The southern states are already facing seasonal shortfalls of gas, which are made up by gas from Queensland.

Measures to support efficient gas supply

The east coast has sufficient gas reserves and resources to meet current demand projections over the next decade and beyond. However, new gas production is not being brought online fast enough. There are significant barriers to new supply arising from lengthy regulatory approval processes and legal hurdles, large upfront capital costs, an uncertain policy environment, as well as a lack of competition in upstream gas markets.

There are some important measures that governments can pursue that will support more efficient and timely investment on the east coast and, more broadly, an orderly transition of the electricity and gas markets. Importantly:

- State and Commonwealth governments can reduce regulatory barriers to investment for market participants to ensure that new supply can be delivered in a timely fashion and through a diverse range of participants.
- The role of gas should be explicit in government planning for the energy transition, to give confidence and incentives for market-led solutions to achieve energy security and support gas markets in the transition. One option to help achieve this would be to develop a gas market system plan, similar to the Integrated System Plan for electricity, which would identify and coordinate needed gas investments.

Incorporating LNG imports into southern gas markets

In the short term, it seems increasingly likely that the southern states will have to import gas to meet demand. The use of LNG imports can provide some greater flexibility in meeting demand in southern states and have a lower risk of asset stranding compared to traditional investments in new supply and infrastructure. In terms of new infrastructure investment, LNG imports could be a cheaper temporary solution to southern supply gaps compared to upgrading pipelines from northern gas fields and storage facilities in the south.

Despite the advantages, LNG import prices may be higher than current domestic gas prices. Imported gas may incur additional costs not currently experienced by gas users on the east coast, including LNG shipping, liquefaction and regassification costs. LNG imports will also create new direct links to international LNG supply and prices. This will have implications for gas supply negotiations and the levels of gas price transparency on the east coast.

Continued domestic gas production will be important to limit risks to energy security on the east coast and market stability associated with reliance on international LNG markets.

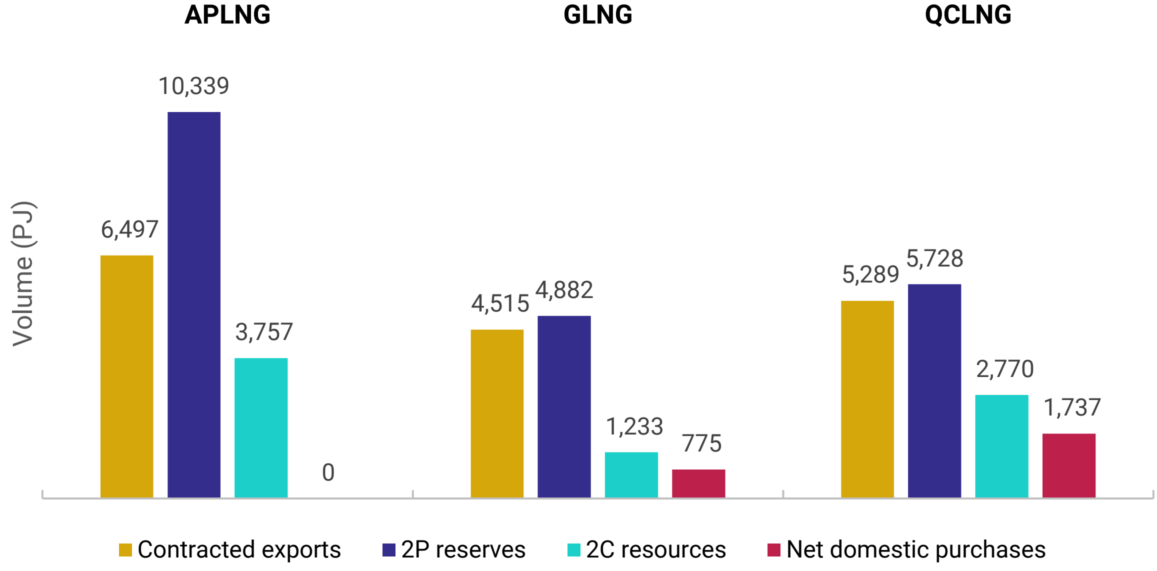
The use of LNG imports may necessitate development of additional pricing reference points on the east coast, such as an LNG import parity price, to aid southern state gas customers when negotiating. The ACCC will consider this as part of its upcoming review of the LNG netback pricing methodology and its role in determining the reasonable price under the Gas Code.

Opportunities arising from the end of LNG foundational contracts

The Queensland LNG producers and their associates control approximately 95% reserves and 35% of resources on the east coast. The majority of forecast production by these producers over the next 10 years is expected to be exported under foundational contract commitments. However, some of the LNG producers hold significant excess gas reserves and resources beyond that required to meet contractual commitments (chart 2).

A number of these producers purchase substantial amounts of gas from third parties on the east coast, despite having sufficient gas reserves to meet their contractual commitments. The LNG producers should be incentivised to fully develop their existing reserves to meet their contractual requirements, freeing up additional domestic gas supply.

Chart 2: East coast LNG remaining contracted export quantities to 2036 and sources of supply to meet contracted requirements (PJ)



Source: AEMO Gas Bulletin Board; ACCC analysis of data obtained from gas producers on long-term export, domestic purchases and domestic sales forecasts.

The ending of the foundational east coast LNG export contracts from the mid-2030s may free up considerable gas supplies for the domestic market. This creates opportunities to consider how domestic gas reserves could support east coast gas supply.

Where these reserves and resources form part of the efficient mix of supply on the east coast, it will be important to support continued investment in new production, in addition to transportation infrastructure and storage near southern demand centres. Gas producers may need to enter into long-term contracts with domestic and/or international customers to obtain the certainty needed to support such investments and reduce commercial risk.

Western Australia, Queensland and several overseas jurisdictions have arrangements to incentivise production and/or control gas exports to support supply for domestic use. In the case of Western Australia, its gas reservation policy requires that 15% of gas produced over each LNG export project's life is committed for domestic supply. A recent Western Australian Parliamentary Inquiry into this policy concluded that it had delivered adequate and affordable supplies of gas to the state's consumers.

1. Introduction

This is the 22nd interim report of the Australian Competition and Consumer Commission's (ACCC's) inquiry into gas supply in Australia (the Inquiry). The Australian Government directed the ACCC to conduct the inquiry in April 2017 with the objective of improving gas market transparency and supporting its efficient operation.

The information published in our interim reports is intended to promote understanding of gas supply arrangements, including the pricing of gas and availability of offers to supply gas, the volumes of gas supplied and available for future supply, and developments in infrastructure. Our interim reports also may inform government decision-making and policy, including with respect to the Australian Domestic Gas Security Mechanism (ADGSM).

This report continues our ongoing reporting of gas supply and pricing. We continue our focus on the east coast gas market given longstanding concerns about its transparency and efficiency. Specifically, we:

- Report on prices recently offered and agreed for gas supply in 2025 and 2026, and the short-term outlook for the supply-demand balance.
- Report on recent market conditions and contracting behaviour, including offers and contract terms and conditions.
- Present the findings of our review of gas retailer pricing and selling practices over the period from 2020 to 2024.
- Consider the policy, regulatory and market conditions necessary to promote efficient investment in and supply of gas in the context of the energy transition.

Our reporting on pricing and transactions focuses on producer and retailer gas supply to medium to large commercial and industrial (C&I) users given their reliance on wholesale gas markets (see box 1.1). We report on wholesale gas commodity prices (exclusive of transport costs) offered and agreed across the market on an arm's length basis with a term of at least one year and annual contract quantity of at least 0.5 PJ.

Our reporting on the short-term supply outlook focuses on adequacy of gas supply for 2025 based on producers' expected supply and Australian Energy Market Operator's (AEMO) demand projections.

1.1. Policy context

The Australian Government is committed to reducing greenhouse gas emissions by 43% from 2005 levels by 2030 and to net zero by 2050[1].

As the transition to net zero progresses gas will play an increasingly important role in 'firming' intermittent renewable power. It is also projected to remain a critical source of energy and feedstock for some industrial sectors until alternatives become available and affordable. While total demand for gas is expected to fall over the long-term, this is expected to be limited as gas will remain a critical fuel in the energy mix to 2050 and beyond.

A key challenge facing the east coast gas markets is a lack of investment in gas supply. A range of policy instruments have been introduced since 2017 aimed at improving gas

[1] Department of Climate Change, Energy the Environment and Water (DCCEEW), *Net Zero*, DCCEEW website, accessed 20 October 2024.

availability and affordability. These include the *Competition and Consumer* (Gas Market Code) *regulations 2023* (the Gas Code), the Heads of Agreement (HoA) with Liquefied Natural Gas (LNG) producers, and the ADGSM. We have had regard to these instruments in analysing gas supply arrangements for this report.

1.1.1. Future Gas Strategy

The Australian Government's *Future Gas Strategy*[2] is a long-term plan for gas production, consumption and substitution in Australia that outlines how the Australian Government envisages gas will support the transition to net zero.

The strategy outlines several principles that are intended to guide future policy. It highlights that during the transition to net zero, gas must remain affordable for domestic consumers and that new sources of gas supply will be needed to meet demand.

1.1.2. Gas Code

The Australian Government implemented the Code in 2023 to address long-running concerns about the imbalance in bargaining power faced by buyers when negotiating with producers, and to incentivise more domestic supply. The Explanatory Statement accompanying the Code states that its purpose is:[3]

> to facilitate a well-functioning domestic wholesale gas market with adequate gas supply at reasonable prices and on reasonable terms for both suppliers and buyers.

To achieve these objectives, the Gas Code includes:[4]

- transparency provisions, which are intended to reduce search and transaction costs for gas buyers by requiring producers to publish information on their uncontracted gas and when it is expected to be brought to market
- conduct provisions, which are intended to reduce the imbalance in bargaining power between buyers and producers and support good faith negotiations, by establishing minimum conduct and process standards for contractual negotiations
- 'reasonable price' provisions, which, in conjunction with the exemption framework, are intended to incentivise producers to commit more gas to the domestic market (including through investment in new supply) and, in so doing, place downward pressure on prices over the medium to longer-term.

The Gas Code's exemption framework provides for the following exemptions from the reasonable price provisions:[5]

- Deemed exemptions are available to small producers (i.e. producers that produce less than 100 PJ p.a.) supplying the domestic market.
- Conditional Ministerial exemptions are available to other producers where the Energy Minister and the Minister for Resources are satisfied that it is appropriate, taking into account a range of matters, including whether the exemption would promote: competition, affordability, availability, investment in supply, and production.

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2 Department of Industry, Science and Resources (DISR), *Future Gas Strategy*, DISR website, accessed 25 October 2024.

3 DCCEEW, *Fact sheet – Competition and Consumer (Gas Market Code) Regulations 2023*, DCCEEW website, accessed 7 July 2024.

4 The Gas Code also includes record keeping and reporting provisions, which are intended to enable the ACCC to monitor compliance with the Gas Code and any exemptions from the Gas Code.

5 A range of other exemptions are also available from particular aspects of the Gas Market Code.

Most producers in the east coast have now obtained either deemed or conditional exemptions from the reasonable price provisions.[6] However, they are still subject to the transparency, conduct, record keeping and reporting requirements.

1.1.3. Heads of Agreement

The Australian Government and the three east coast LNG producers[7] signed an updated HoA on 29 September 2022[8] with the objective of preventing a gas supply shortfall through access to secure and competitively priced gas for the domestic market.[9]

Under the terms of the HoA LNG producers' uncontracted gas must be first offered to the domestic market before being offered to the international market:

- for reasonable supply periods
- with reasonable notice
- on competitive market terms
- at prices no more than international customers will pay.

Additionally, the LNG producers have also committed that prices offered to domestic buyers will be internationally competitive and to increase transparency measures, including publication and reporting commitments. The ACCC monitors progress of these commitments and includes observations in relation to HoA compliance in interim reports. The current HoA is in place until 1 January 2026.

1.1.4. Australian Domestic Gas Security Mechanism

The ADGSM came into effect on 1 July 2017. Its objective is to ensure there is sufficient supply of natural gas to meet the forecast needs of Australian gas consumers.

Where a gas shortfall is forecast for Australia, the ADGSM can be activated by the Minister for Resources to limit or prohibit exports of LNG. The ADGSM includes a permission regime to grant permission to export LNG in the event the ADGSM is activated.

The Minister for Resources, prior to issuing a Minister's Determination, may work with industry to identify voluntary, industry-led solutions for shortfall avoidance, which may include additional gas to be supplied to Australian gas users.

The ADGSM is designed to be a measure of last resort and is intended to only be used if market-based solutions and other regulatory interventions fail to provide sufficient gas to Australian consumers.

To date, there have been no instances of the ADGSM being activated by the Australian Government.

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6 Over 40 entities have a small supplier exemption, while 6 entities have a CME. See ACCC website, Small gas supplier exemptions register and conditional Ministerial exemptions register, accessed November 2024.

7 Australia Pacific LNG (APLNG), Gladstone LNG (GLNG) and Queensland Curtis LNG (QCLNG).

8 DISR, *Heads of Agreement – The Australian East Coast Domestic Gas Supply Commitment*, DISR website, accessed September 2022.

9 DISR, *Heads of Agreement – The Australian East Coast Domestic Gas Supply Commitment*, DISR website, September 2022.

1.2. Information sources for this report

We have used our compulsory information-gathering powers under section 95ZK and section 53ZT of the *Competition and Consumer Act 2010* to obtain data, information, and documents from suppliers. This report includes data on market activity up to July 2024, focusing on the latest trends between January and July 2024.

We have used information received through our monitoring function under the Gas Code and have drawn on surveys of, and meetings with, C&I users (box 1.1) and publicly available information.

We have also relied upon information reported by AEMO in its 2024 Gas Statement of Opportunities (GSOO), including quarterly and annual demand forecasts for residential, C&I users and consumption for gas powered generators, and retail short-term transaction data reported to its Gas Bulletin Board. The GSOO examines risks of peak day shortfalls and infrastructure capacity across the entire gas system to meet demand. Our report examines more recent supply forecasts across the entire east coast gas market.

Box 1.1 Engagement with market participants

The ACCC engaged with 35 C&I users, market intermediates and industry bodies between July and October 2024 on recent market experiences. This has informed our understanding of market conditions and developments.

Of the 35 parties, 15 participated through surveys and meetings, 13 participated through meetings only and 7 participated in surveys only.

The feedback reflects approximately 35% of industrial market demand in 2024[10] (over 90 PJ of average annual demand).[11]

We engaged with a diverse cross section of C&I users:

- Average annual gas demand ranged from up to 100 TJ to more than 5 PJ.
- Industries included the retail, commercial laundry, mining and refining, manufacturing (food and beverage, paper and packaging, building materials) and chemical and petrochemical industries (see figure 1.1).
- Facilities were located across the east coast including Queensland, New South Wales, South Australia, Victoria, and Tasmania, and across metropolitan and regional areas.

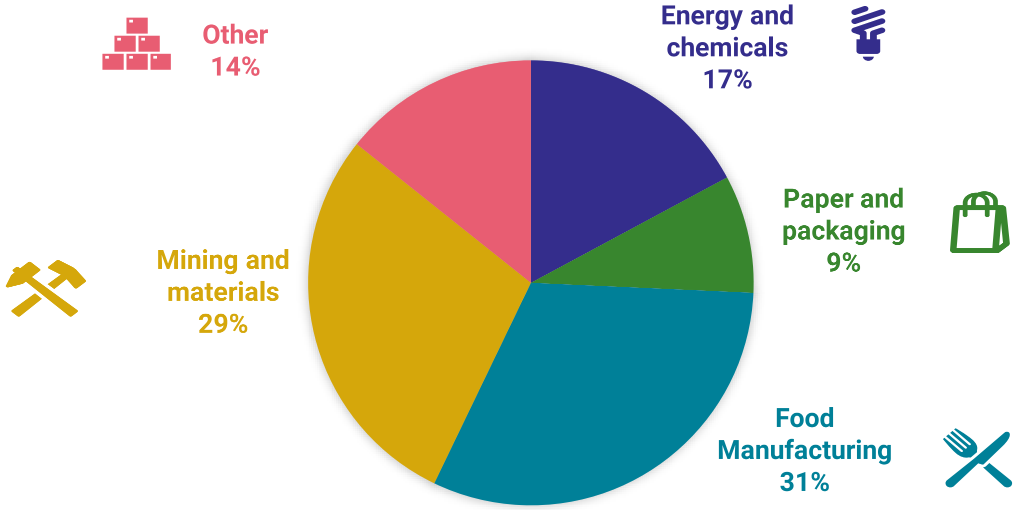
Additional insights were provided through bilateral meetings we held with:

- intermediaries that regularly engage with both retailers and end-users
- industry associations, including the Energy Users Association of Australia, Australian Forest Products Association, Australian Dairy Products Federation, Australian Food & Grocery Council, Chemistry Australia and Manufacturing Australia.

[10] Australian Energy Market Operator (AEMO), *Gas Statement of Opportunities*, AEMO website, March 2024, accessed 17 October 2024.

Figure 1.1 shows the industries represented in the ACCC's recent consultations with C&I users. Further detail for C&I engagement is in Appendix F.

Figure 1.1: Industries represented in the ACCC's C&I engagement, July to October 2024



1.3. Structure of this report

This report contains 2 parts: Part 1 focuses on the recent operation of the east coast gas market, and Part 2 considers gas sufficiency and security and the policy, regulatory and market conditions necessary to promote long-term efficient investment in gas supply.

Part 1: Operation of the east coast gas market:

- Chapter 2 reports on supply availability and prices in the east coast gas market, highlighting trends since the June 2024 interim report.
- Chapter 3 reports on recent market conduct and how gas has been transacted, with a particular focus on gas buyers' experiences and concerns following implementation of the Gas Code.
- Chapter 4 presents findings from our review of retailer behaviour. This review examined retailer pricing and selling practices over the period 2020-2024, and the key factors influencing these practices over this period.

Part 2: Gas sufficiency and security:

- Chapter 5 sets out long-term gas production and investment challenges and the influence of international developments on the shape of the domestic market.
- Chapter 6 provides an overview of new sources of gas supply and infrastructure that could potentially be brought online from 2024 to 2036, and beyond. It also outlines risks faced by producers and infrastructure providers in bringing projects online.
- Chapter 7 examines east coast gas sufficiency and security over the long term and considers measures that could help to mitigate the structural gas supply shortfalls that are expected on the east coast from 2027.

Additional supporting information is contained in the appendices.

Part 1: Operation of the east coast gas market

2. Domestic supply and price outlook

Key Points

- The east coast is expected to produce more gas than demanded in 2025. Supply is forecast to exceed demand by 77 PJ if liquified natural gas (LNG) exporters export all uncontracted gas and by 112 PJ if they export only their anticipated spot or additional sales. This is an improvement in the supply-demand outlook, largely driven by increased production from Queensland.
- Prices have continued to fall since the energy crisis in 2022. Retailer prices have fallen more than producer prices. The decrease in prices is likely to have been helped by lower international prices and increased availability of gas.
  - Prices offered by producers over the first half of 2024 for 2025 supply averaged $14.77/GJ, a 2% decrease from the previous 6 months. Prices offered by retailers over the same period averaged $15.43/GJ, a 13% decrease from the previous 6 months.
  - Average retailer prices for 2025 supply agreed under Gas Supply Agreements (GSAs) decreased by 26% to $14.70/GJ in the first half of 2024 compared to the previous 12 months. Producer prices increased by 3% to $14.72/GJ from the previous 6 months.
- LNG exporters complied with their obligations under the Heads of Agreement (HoA) with the Commonwealth Government during the first half of 2024. About half the gas offered to the market under this arrangement was supplied to the market. Most of the gas supplied was for relatively short supply periods.
- There was a marked increase in the number of long-term offers to the domestic market during the first half of 2024, but the number of agreements only increased marginally. The gas volumes contracted remain low.
- Current price levels are higher than pre-2022 levels, likely reflecting:
  - the expected supply shortfall in southern states during winter months, which means that southern gas customers will need to rely on gas supplied from Queensland where the marginal source of supply is by LNG producers
  - international prices, which remain materially higher than pre-2022 levels
  - the lack of long-term contracting activity.

2.1. Introduction

Volatile and uncertain gas market conditions over recent years have had a profound impact on market participants across the supply chain. The availability of gas supply and infrastructure services, prices, and the contracting environment have all been affected. This has, in turn, had implications for the effective operation of the east coast gas market (further detail on recent market conditions is contained in Appendix B).

Over the latest reporting period (January to June 2024), conditions in the market appear to have eased. Gas producers who have received conditional Ministerial exemptions resumed making offers for supply in 2025 and 2026. The increased availability of gas, together with lower international prices, has contributed to a softening of domestic prices over this period.

This chapter discusses the current demand-supply outlook for 2025 and 2026 (section 2.2) and the prices offered and agreed under GSAs (section 2.3). In considering price drivers, we examined the influence of regional demand-supply conditions given depleting gas resources in the south and the need, therefore, to transport gas from the north (section 2.3.3). The chapter also reports on recent pricing in Queensland, and the LNG producers' supply and demand forecasts for 2025 (section 2.3.4).

As a companion to this chapter, chapter 3 considers gas buyers' experiences in the market, including the impact of recent prices on commercial and industrial customers, how non-price terms and conditions of supply have changed, and changes to the way that gas is being offered and sold.

2.2. East coast expected to have surplus gas in 2025 and 2026

This section reports on the supply-demand outlook in the east coast gas market for 2025 and 2026 based on producer forecasts and AEMO's demand projections.

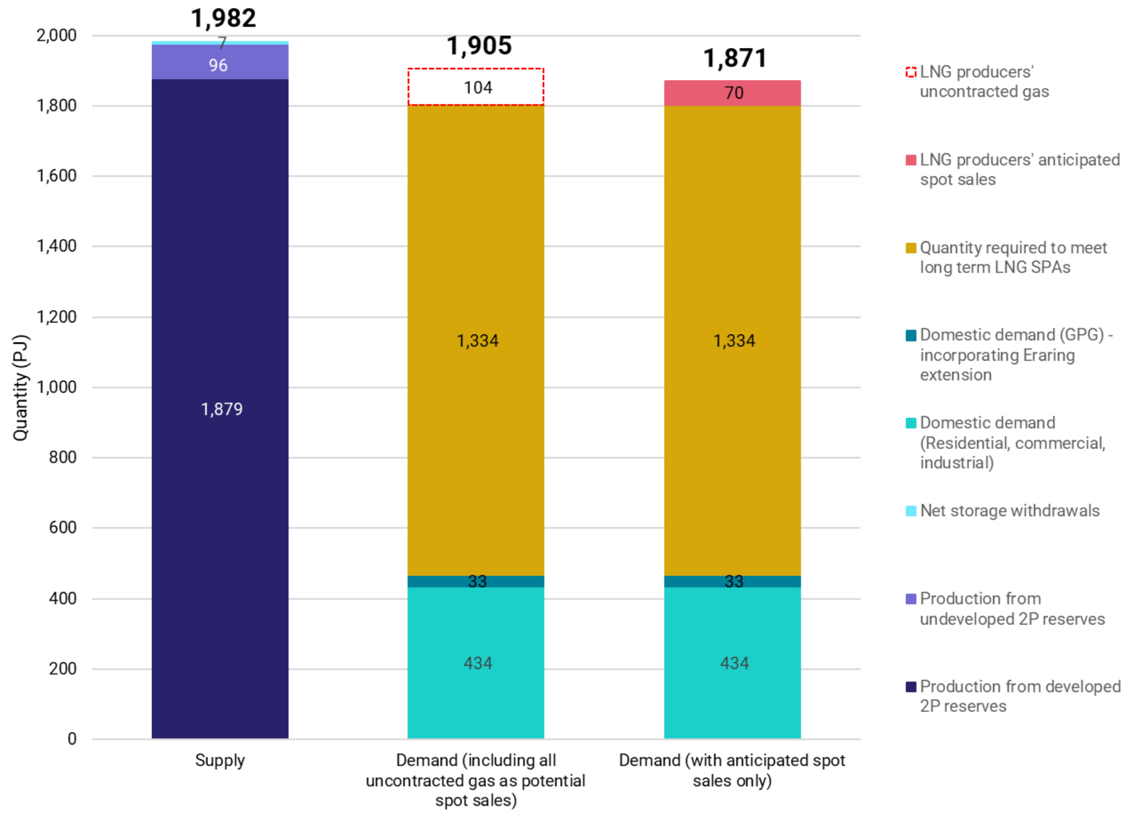
2.2.1. Improvement in short-term outlook for the east coast

The east coast is expected to have surplus gas in both 2025 and 2026. Specifically:

- There is estimated to be between 77 and 112 PJ of surplus gas in 2025 (chart 2.1). This represents between 16% and 24% of forecast domestic demand.
- The surplus in 2026 is forecast to be between 54 and 99 PJ (Appendix B).

These are slight improvements on our previous forecasts, as reported in June 2024, reflecting higher production from Queensland.

Chart 2.1: Forecast east coast supply-demand balance in 2025 (PJ)



Source: ACCC analysis of data obtained from gas producers in July and October 2024 and of the domestic demand forecast (Step Change scenario and coal retirement delay sensitivity) from AEMO's 2024 GSOO.

Note: Totals may not sum due to rounding. The quantity required to meet long-term LNG SPAs includes feed gas requirements (such as fuel) required to produce LNG. The GPG figures in this chart are based on the coal retirement delay sensitivity from AEMO's 2024 GSOO and so incorporate the effect of the extended operation of Eraring Power Station. Net withdrawals from storage reflect single party-owned storage facilities on the east coast, which can experience net withdrawals or net receipts each year. This differs from storage to meet seasonal shortfalls from third party accessible storage facilities, such as the Iona storage facility in Victoria, which are more likely to be filled and emptied throughout each year.

The latest 2025 quarter-by-quarter projections suggests that the east coast will be in surplus in each quarter, including in peak winter months and where the LNG producers export all their available uncontracted gas (chart 2.2). This is an improvement on the previous outlook, which forecast a potential supply shortfall in quarter 3 of 2025.[12]

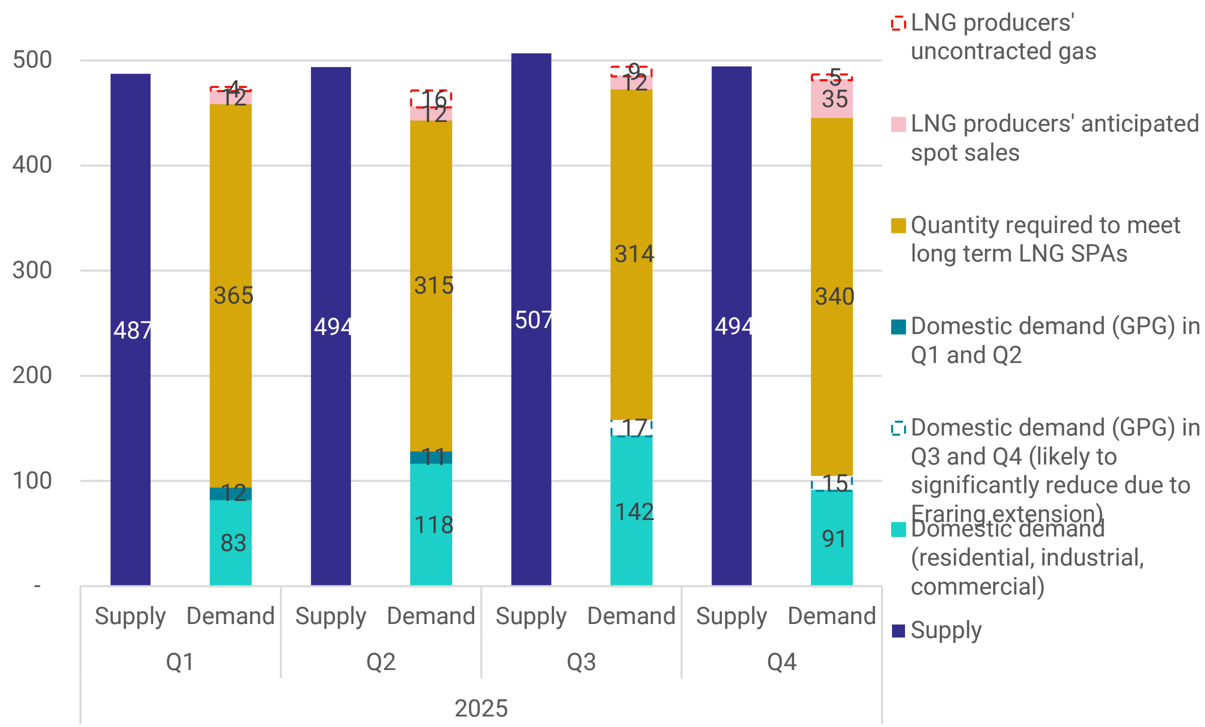
The quarterly figures do not include the impacts of the delayed closure of Eraring Power Station, which was previously expected to close by August 2025.[13] AEMO projects that the extended operation of Eraring will reduce demand for gas powered generation in the latter half of 2025. This is expected to further aid supply-demand conditions during that period.

Normally, producers enter contracts for most of the domestic demand in advance of coming years. As at October 2024, about 76% of forecast domestic demand for 2025 had been contracted, leaving a large volume (around 24%) to be contracted. We expect more volumes to be contracted using shorter-term arrangements as we move into and through 2025.

12 ACCC, Gas Inquiry June 2024 interim report, pp 21–22.

13 NSW Government Department of Environment and Heritage, NSW Government secures 2-year extension to Eraring Power Station to manage reliability and price risks, 23 May 2024, accessed 31 May 2024.

Chart 2.2: Quarterly supply-demand balance on the east coast in 2025 (PJ)



Source: ACCC analysis of data obtained from gas producers in January 2024, July 2024, and October 2024 and of the domestic demand forecast (Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), March 2024.

Note: Totals may not sum due to rounding. This chart does not include the effect of the Eraring Power Station's delayed retirement, which will likely significantly reduce GPG demand.

The latest quarterly projections reflect the shifting of some contracted export volumes between the domestic peak and off-peak demand periods as well as higher levels of gas production in Queensland.

LNG producers have used gas swap arrangements to sell more gas to the domestic market during its peak demand periods (winter) but to increase purchases of domestically-produced gas in other periods to meet their reshaped contracted export commitments.

While there is likely to be sufficient overall supply across the east coast, the southern states, as in past years, are projected to be in shortfall over the winter months. To meet this shortfall, gas will be required to be supplied from Queensland and drawn from storage (see section 2.2.2 for further details).

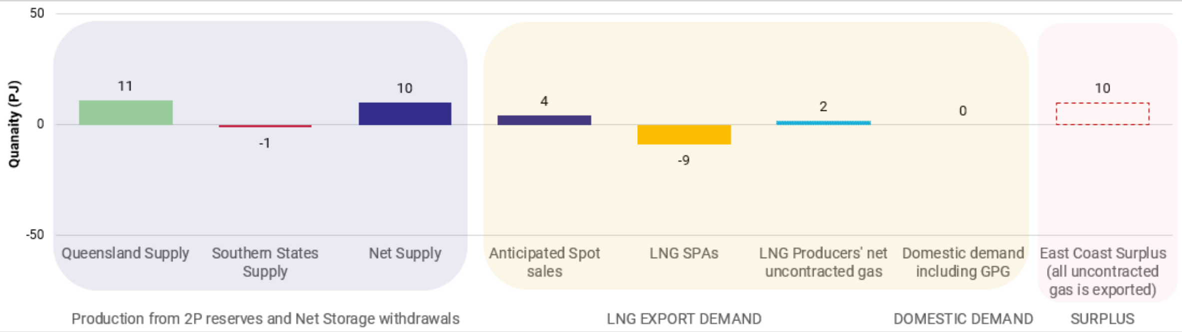
Box 2.1 provides detail on the supply-demand outlook for quarter 2 in 2025 for the east coast. This information may be relevant and be utilised to inform decision-making by the Minister for Resources under the Australian Domestic Gas Security Mechanism (ADGSM).

Box 2.1: Surplus supply is expected in 2025's quarter 2 over the east coast

The latest forecasts indicate a 22 to 38 PJ surplus over the east coast in quarter 2 of 2025. This is an improvement on the last forecast, as reported in June 2024 (a surplus of between 10 and 25 PJ).

This change is largely due to an increase in gas production by the LNG producers and a decrease in their anticipated export volumes under long term contracts (chart 2.3). The lower contracted exports are primarily due to a shift in export cargoes between the domestic peak and off-peak demand periods. The decrease in projected LNG SPA exports (9 PJ) is partially offset by an increase in anticipated LNG spot sales (4 PJ).

Chart 2.3: Reasons for change in 2025's quarter 2 east coast supply-demand outlook



Source: ACCC analysis of data obtained from gas producers in January 2024, July 2024, and October 2024 and of the domestic demand forecast (Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), March 2024.

Note: Totals may not sum due to rounding.

The southern states are expected to have a 10 PJ shortfall in quarter 2 of 2025. This shows a slight worsening of the outlook (the previous forecast was for a 9 PJ shortfall) and reflects lower anticipated gas production in the southern states.

Queensland is projected to have a supply surplus of between 32 and 49 PJ during Quarter 2, which is an improvement on the previously reported outlook of a surplus between 22 and 37 PJ. The improvement is due to higher gas production from Queensland producers (largely LNG producers) and lower contracted export cargoes.

Q2 2024 Actuals

Table 2.1 compares the forecast outlook for quarter 2 of 2024 (as published in the December 2023 report) with actual.

Actual supply and demand in quarter 2, 2024, were both lower than expected, resulting in a small surplus for the quarter. The main influences were lower than expected domestic demand and lower exports of uncontracted gas by the LNG producers.

Table 2.1: Comparison of forecast vs actuals for 2024's quarter 2 on east coast

	Quarter 2 2024 forecast	Quarter 2 2024 actuals	(*actual – forecast*)	Quarter 2 2025 forecast
Supply				
Supply total	*495*	*491*	*-4*	*494*
Demand				
Quantity to meet LNG SPAs	315	341(total export)	+26	315
LNG producers' Uncontracted gas	35	NA	NA	28
Net storage injections	NA	-12	NA	Included in supply total above
Queensland demand ex LNG	34	36	+2	30
Southern states	114	121	+7	99
Demand total	*498*	*486*	*-12*	*471*
Outlook				
Surplus/shortfall	-3	+5*	+8	+22

Source: ACCC analysis of data obtained from producers in October 2024 and AEMO Gas Bulletin Board Actual flow and Storage (all data) as at 19 October 2024.

Notes: Totals may not sum due to rounding.
*Actual supply and demand not balancing can be attributed to pipeline linepack, where gas compression can result in injected gas being greater than withdrawn gas.

2.2.2. Small shortfall expected for the southern states in 2025

The southern states are expected to face a supply shortfall of up to 16 PJ in 2025, which represents approximately 9% of forecast customer demand.

While the southern states are forecast to have a gas shortfall overall in 2025, the actual supply shortages will occur during the winter months, when demand is considerably higher due to heating needs. As has occurred in recent years, gas demand in winter months will need to be met from gas transported from Queensland and drawn from storage facilities.

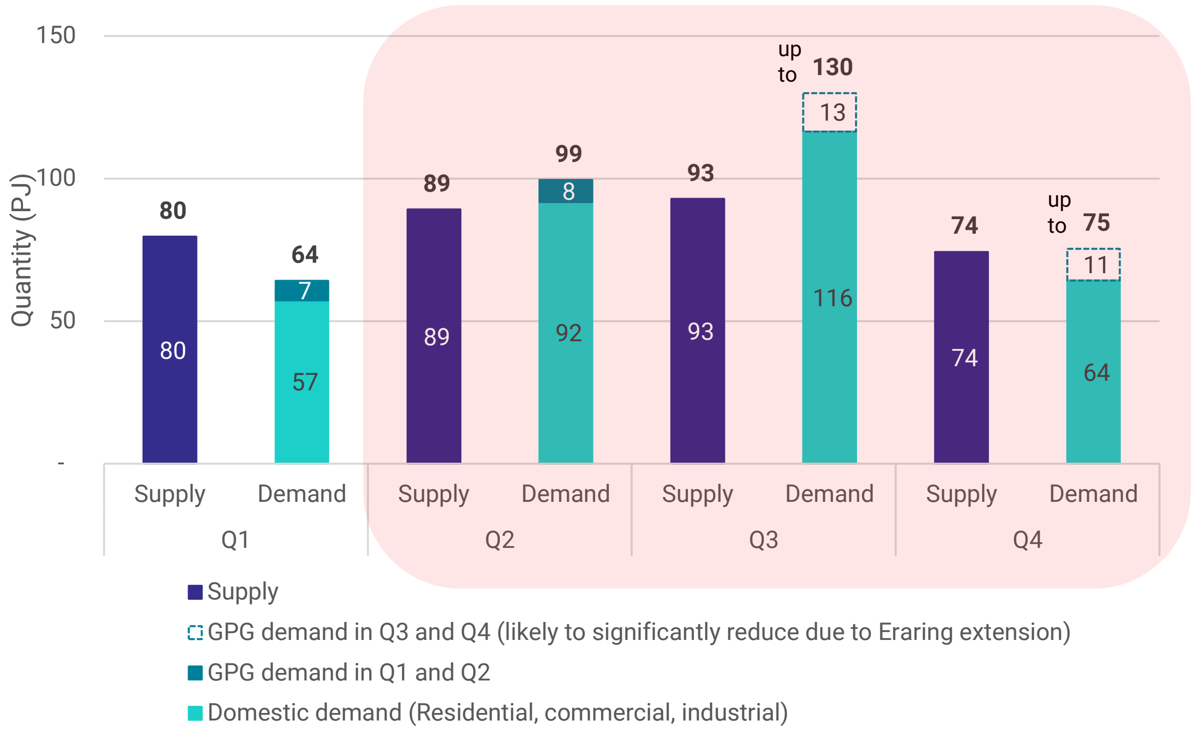
The Iona underground storage facility in Victoria is particularly important for supporting southern states. Historically, Iona is filled between November and May and discharged over winter to meet daily peak demand.

As at 17 November 2024, storage levels at Iona were at 13.9 PJ. Approximately 11 PJ of more gas is required to be stored before May 2025 to maximise storage levels ahead of winter.[14]

The forecast for the southern states does not account for the extended operation of the Eraring coal power plant in NSW. The continuation of Eraring will reduce demand for gas powered generation from August 2025, and is expected to slightly improve the outlook for quarters 3 and 4 of 2025.

[14] AEMO, Gas Bulletin Board, *Actual Flow and Storage (all data)*, accessed 19 November 2024.

Chart 2.4: Quarterly supply-demand balance in southern states in 2025 (PJ)



Source: ACCC analysis of data obtained from gas producers in January 2024, July 2024, and October 2024 and of the domestic demand forecast (Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), March 2024.

Note: Totals may not sum due to rounding. This chart does not include the effect of the Eraring Power Station's delayed retirement, which will likely significantly reduce GPG demand.

2.3. Domestic gas prices have fallen but remain above historical levels

This section reports on the prices offered to customers and bids received by suppliers, and prices expected to be paid in GSAs for supply in 2025 and 2026.[15]

All offers, bids and GSAs are for long term supply (i.e., term lengths of minimum 12 months) and volumes of a minimum 0.5 PJ. Our approach to estimating prices of offers, bids and GSAs is outlined in Appendix A.

2.3.1. Prices offered for long-term supply continued to fall

Producer and retailer prices offered in the first half of 2024 for 2025 supply continued to decrease from their highs in mid-2022 (chart 2.5). Retailer offer prices have fallen more than producer offer prices. Prices offered by producers between January and June 2024 averaged $14.77/GJ, a 1.8% decrease from the previous 6 months. Prices offered by retailers to C&I customers averaged $15.43/GJ, a 13.4% decrease from the previous 6 months. Bids to producers averaged $13.48/GJ, a 6.6% decrease from the previous 6 months.

---

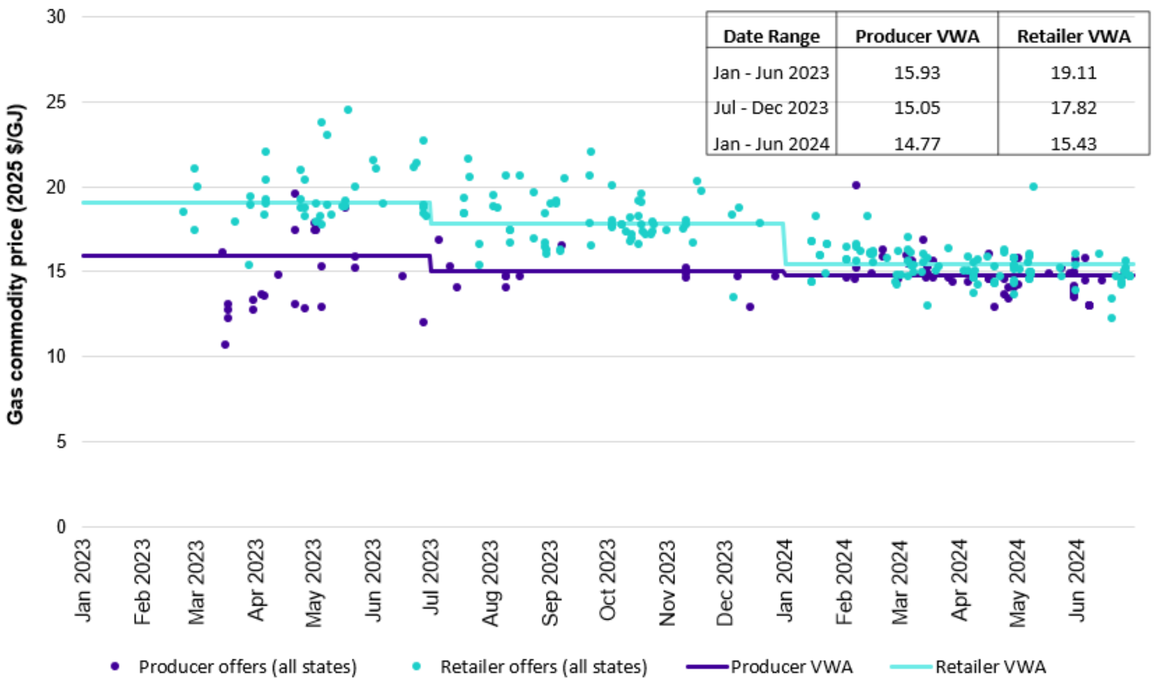
15 This section reports on prices that were offered or agreed by producers to all types of buyers, or by retailers to either C&I users and or gas-powered generators. They were made or entered into over the period from 1 January 2023 to 30 June 2024 for 2025 and 2026 supply. GSAs had fixed prices or prices are linked to a commodity price index, such as Brent Crude oil or JKM.

The spread of retailer prices offered narrowed in the first half of 2024 compared to the second half of 2023 while the spread marginally increased for producers. Between January and June 2024, offers from producers ranged from $12.95/GJ to $20.07/GJ and for retailers from $12.30 GJ to $20.03/GJ.[16]

There was a marked increase in the number of long-term offers made by producers and retailers between January and June 2024 following a period of low activity in 2023 while the Gas Code was being implemented. Retailers made 108 offers to buyers for 2025 supply, compared to 67 offers made in the preceding 6 months. Producers made 55 long-term offers compared to 14 offers made in the preceding 6 months. Overall, producers have made 61 offers since the end of the transition period of the Gas Code (i.e. between September 2023 and June 2024). The increase in the number of offers for long-term supply possibly reflects the more stable market conditions in 2024 compared to the conditions over 2021–22 (see Appendix B).

The recent increase in offers has been primarily driven by producers in the southern states. There were a limited number of offers made to buyers in Queensland.

Chart 2.5: Gas commodity prices (2025$/GJ) offered in the east coast gas market for 2025 supply



Date Range	Producer VWA	Retailer VWA
Jan - Jun 2023	15.93	19.11
Jul - Dec 2023	15.05	17.82
Jan - Jun 2024	14.77	15.43

Source: ICE, Argus, ACCC analysis of bid and offer information provided by suppliers.

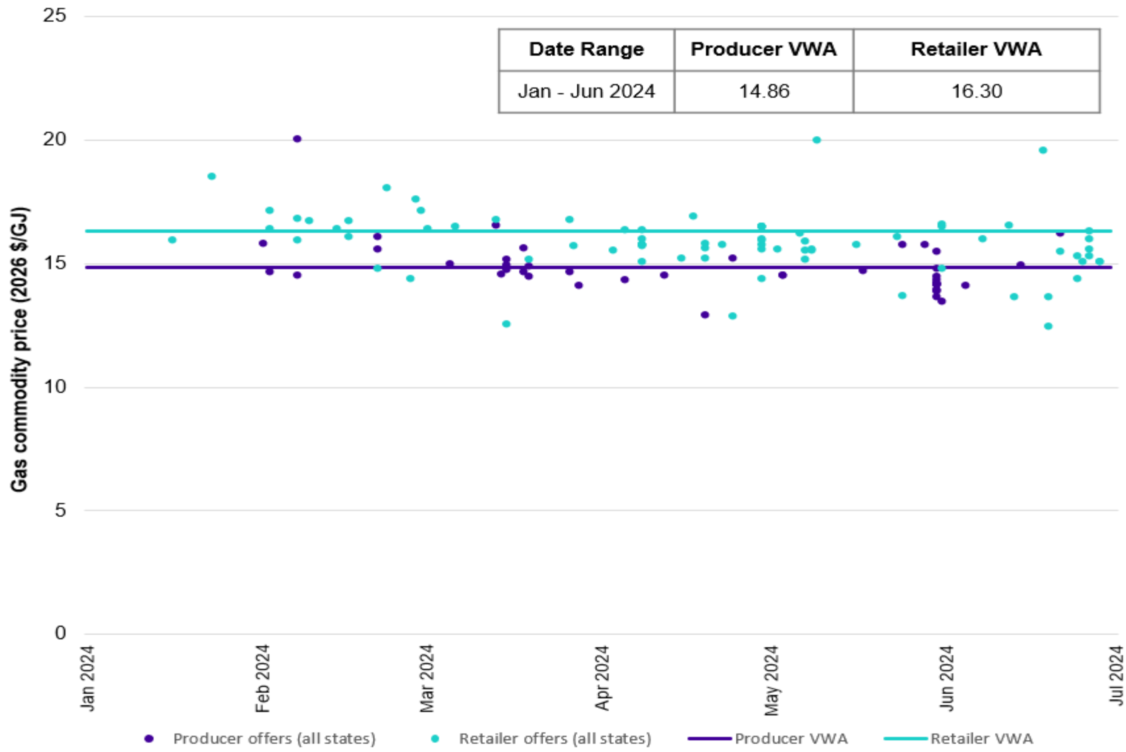
Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. The chart displays retailer offers made to all buyer categories while the volume weighted average (VWA) price only considers retailer offers made to C&I customers. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA. Historic VWA prices may differ slightly in earlier reports due to changes in the reporting period time frames.

Compared to 2025, prices offered for 2026 supply were higher (chart 2.6). The prices offered by producers between January and June 2024 for 2026 supply averaged $14.86/GJ, slightly higher than prices offered for 2025 supply. Retailer offers averaged $16.30/GJ, $0.90/GJ

16 Retailer and producer prices ranged $13.50/GJ to $22.04/GJ and $12.96/GJ to $16.87/GJ, respectively in the second half of 2023.

greater than the 2025 average. Bids to producers for 2026 supply averaged $13.38/GJ, slightly lower than the average bid for 2025 supply. The spread of prices offered by producers and retailers for 2026 supply was broadly consistent with the spread for 2025.

Chart 2.6: Gas commodity prices (2026$/GJ) offered in the east coast gas market for 2026 supply



Source: ICE, Argus, ACCC analysis of bid and offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. The chart displays retailer offers made to all buyer categories while the volume weighted average price only considers retailer offers made to C&I customers. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties if a previous offer did not result in the execution of a GSA. VWA demotes the volume-weighted average price.

2.3.2. Contracting activity for long-term supply remains low but retailer contract prices continued to decline

While producers and retailers made significantly more offers to the domestic market, the number of contracts has only increased marginally. Volumes contracted also remain low (chapter 3). Between January and June 2024, producers executed 9 GSAs (for 2025 supply) compared to 8 GSAs in the previous 6 months. Retailers executed 4 GSAs compared over to 1 GSA in the preceding 6 months.

Since the end of the transition period of the Gas Code (11 September 2023), producers have entered into an increased number of contracts. Between September 2023 and June 2024, producers entered into 23 long-term GSAs in comparison to 17 over the preceding 9 months (table 2.2). While retailers are not covered by the Gas Code, as a comparison, they have executed fewer GSAs since the Gas Code fully commenced (10) compared to the 9 months preceding the Gas Code (14).

Gas sold under short-term contracts has also increased (see chapter 3). The decrease in number of long-term GSAs executed combined with an increase in short-term contracts indicates that suppliers have not returned to pre-2022 contracting behaviours.[17]

Table 2.2: Producer GSAs prior to and after the introduction of the Gas Code

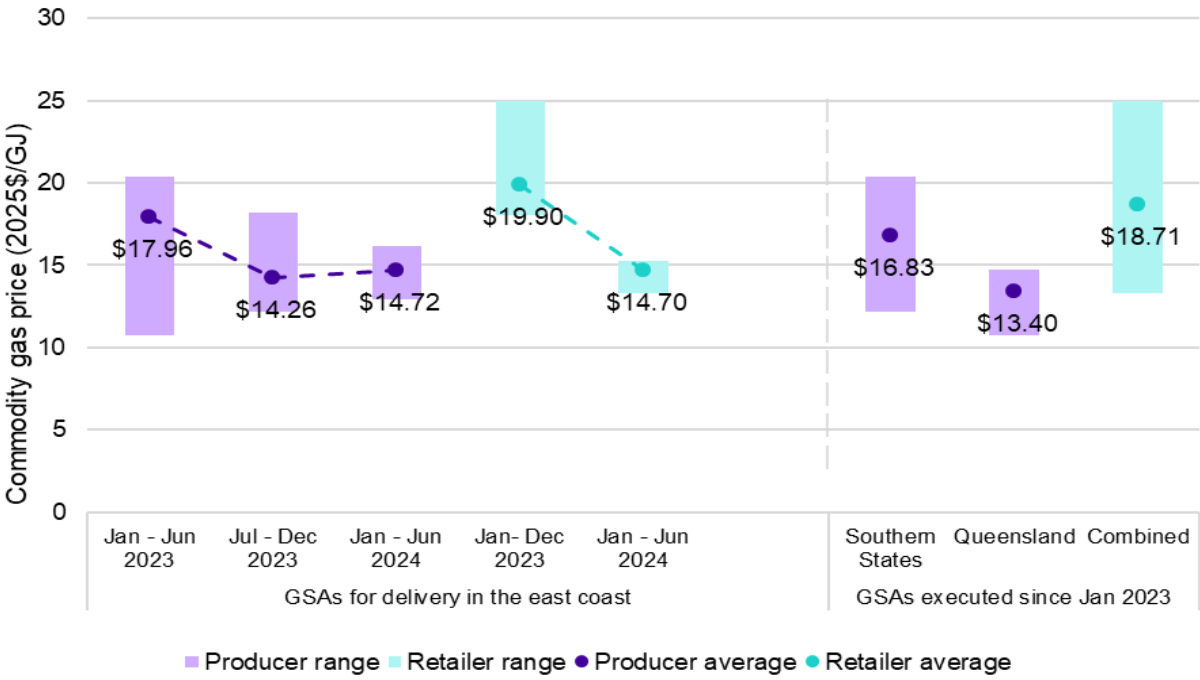
Category	1 Jan 2023 – 10 Sep 2023	11 Sep 2023 – 30 Jun 2024
Producers to all	17	23
Producers to C&I	5	8
Producers to retailers and GPG	12	13

Source: ACCC analysis of information provided by suppliers.

Note: In addition to producers entering into GSAs with C&I, retailers and GPG, producers also entered into 2 contracts with state government, after the introduction of the Gas Code.

Despite low contracting activity in the first 6 months of 2024, retailer prices agreed under GSAs for 2025 supply continued to decline (see chart 2.7). Retailer prices have fallen significantly relative to producer prices, reducing the gap between them. Average prices agreed under GSAs in the first half of 2024 slightly increased to $14.72/GJ for producers (a 3% increase compared to the previous 6 months) and decreased to $14.70/GJ for retailers, a 26% decrease compared to 2023.[18]

Chart 2.7: Gas commodity prices in the east coast gas market for 2025 supply



Source: ACCC analysis of information provided by suppliers.

Note: All GSAs are for quantities of at least 0.5 PJ per annum and a contract term length of at least 12 months. We have aggregated retailer GSAs in the January to December 2023 period due to confidentiality reasons.

17 In order to provide further insights into contracting trends, we extended our long-term pricing analysis for producers to include GSAs with volumes below 0.5 PJ. There were a further 23 producer contracts in the current period with this lower threshold. The average price was $13.03/GJ, only slightly below that presented in chart 2.7.

18 Different comparison periods are used for producer and retailer GSAs. We have aggregated retailer GSAs over the period January to December 2023 due to confidentiality reasons.

Prices in producer GSAs were higher in the southern states than in Queensland (chart 2.7). This may reflect tighter supply in the southern states with the decline in Bass Strait output and the cost of transporting gas from Queensland to the southern states (see section 2.3.3).

There has been a continued shift away from Brent-linked GSAs towards fixed-price contracts. Brent-linked GSAs constituted 7% of the total number of GSAs for 2025 supply and accounted for 30% by volume (table 2.3). This compares to the previous reporting period January 2023 to January 2024, where 27% of GSAs for 2025 were Brent-linked, representing 47% of gas volume.[19] The decline in Brent-linked contract volumes should result in a reduction in buyers' exposure to oil price volatility in 2025.

Since January 2023, there have been no longer-term GSAs executed with a pricing mechanism linked to the JKM.

Table 2.3: GSAs by pricing mechanism for supply in 2025

Year/Variable	Fixed Price	Commodity linked (Brent)	Total
Volume-Weighted Average price	$14.15/GJ	$15.33/GJ	$14.29/GJ
2025 % Count	93%	7%	100%
2025 % Quantity	70%	30%	100%

Source: ACCC analysis of information provided by suppliers.

Note: Table 2.3 separates GSAs by pricing mechanism executed between 01 January 2024 to 30 June 2024 for supply in 2025. Analysis includes GSAs which have an annual contract quantity of at least 0.5 PJ and a contract length of 12 months or more.

2.3.3. Prices reflect international prices as well as domestic supply-demand conditions

While lower than the highs in 2022, east coast gas prices remain elevated relative to historic levels (chapter 3), which is likely to reflect both the influence of international prices and domestic market conditions.

Influence of international prices on domestic prices

International prices influence domestic prices in various ways:

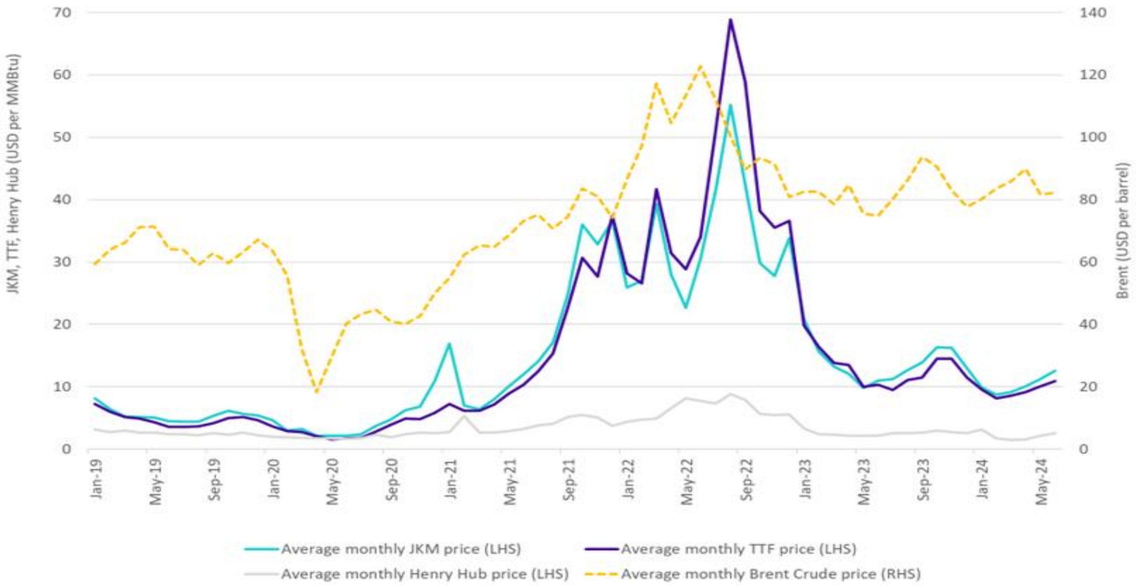
- International oil and LNG prices are directly linked to domestic prices via pricing mechanisms in GSAs, such as Brent-linked contracts, as noted above.
- They are also indirectly linked through consideration of or reference to LNG netback prices when determining fixed prices. For example, LNG producers will typically have regard to the LNG netback price (which represents their opportunity cost of supplying the domestic market) when determining prices for offer or sale of gas. Non-LNG producers may also have regard to the LNG netback price and/or international oil benchmarks when determining offer prices under fixed-price GSAs.

The recent trends in east coast domestic prices are broadly consistent with international prices (chart 2.8). For instance, international oil and LNG prices reached record highs in

19 In the previous reporting period, GSAs were aggregated over 2 reporting periods due to confidentiality reasons.

2022, reflecting concerns about tight supply triggered by the Russia-Ukraine conflict. Prices subsequently fell in 2023, largely in response to high storage and inventory levels in Europe. While international prices are now lower than in 2022, they remain higher than pre-2022 levels, which is consistent with what we are seeing in domestic prices.

Chart 2.8: International oil, LNG and gas prices



Source: ICE(JKM), Argus (TTF), EIA (Brent Crude), ACCC analysis, October 2024.

Influence of domestic supply-demand conditions

The tightening of domestic supply conditions has affected price levels. In 2021, when market conditions were relatively stable and there was a better supply-demand outlook (a surplus of 96 PJ was expected going into supply year 2021), the prices offered by producers and retailers fell from around $10/GJ to around $6–$8/GJ. Since then, the supply-demand balance has become much tighter, particularly in the southern states.

The effect of domestic supply expectations on prices has been seen in several instances. For example, going into 2023 there was an expectation that the market may experience a supply shortfall. That did not eventuate, but the expectation is likely to have placed upward pressure on domestic prices going into 2023. The decision by producers to ‘pause’ contracting in response to the development of the Gas Code in 2023 also appears to have placed upward pressure on domestic prices over that period (Appendix B).

Following the implementation of the Gas Code and the granting of conditional Ministerial exemptions in late 2023 and early 2024, producers have resumed making offers to the domestic market. The increased activity of producers has coincided with an easing of prices in the domestic market although, as noted above, prices remain high relative to the pre-2022 levels.

The reasonable price provisions in the Gas Code appear to have had limited direct impact on prices so far. This is because most producers are currently exempt from these provisions, including because they are either a small supplier or have received a conditional Ministerial exemption.

Conditions in the southern states are influencing prices

As noted in section 2, the southern states are expected to face supply shortfalls in 2025 and beyond without additional supply from southern producers. This implies that southern prices would be expected to be closer to Queensland prices plus transportation. The market prices in Queensland, in turn, are likely to be heavily influenced by LNG netback prices. The Queensland LNG exporters currently expect to have uncontracted gas that could be exported or supplied into the domestic market.

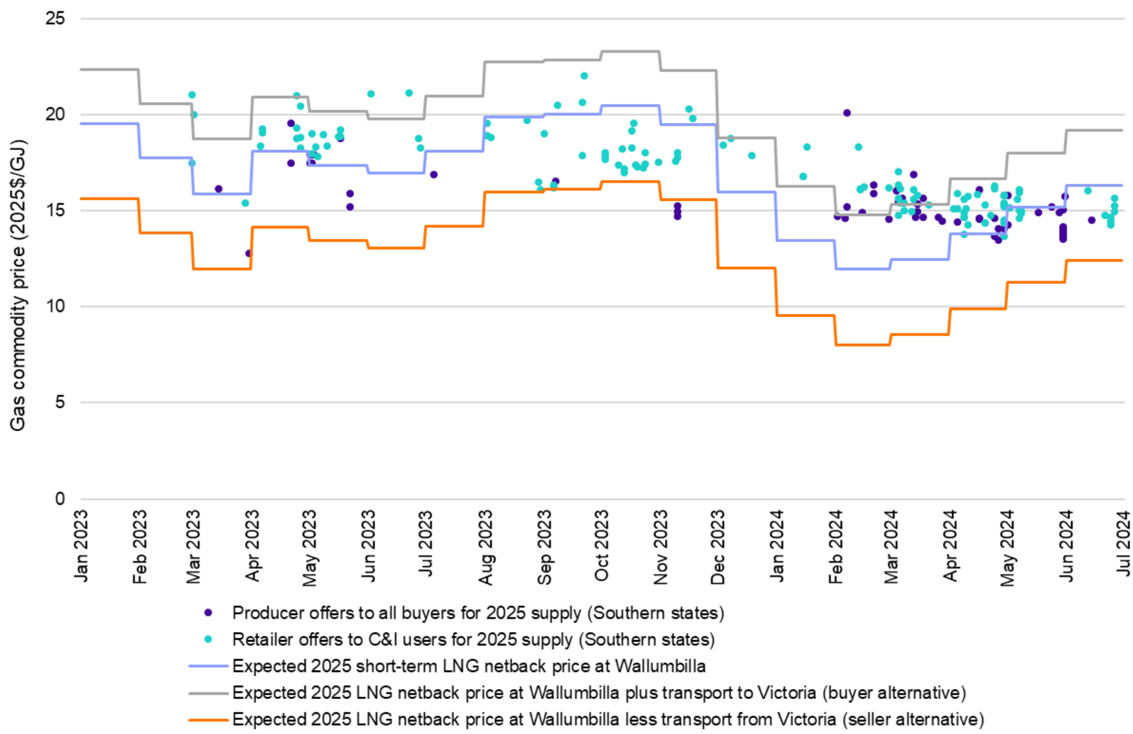
In the southern states, the market price of gas would be expected to fall within the following range:

- If there is diverse supply and strong competition in the southern states, competition will drive producers to offer a price closer to their next best sales alternative. If this alternative is to sell gas to the LNG projects in Queensland, the price that the producer in the southern states would receive is the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla (**the seller alternative – a floor price**).
- If there is a lack of supply options in the southern states and producers can set prices in the absence of competitive constraints from other producers in the southern states, then these producers can charge a price approaching the buyer's next best alternative. If this alternative is to buy gas from producers in Queensland, the price that a gas buyer would have to pay is the LNG netback price at Wallumbilla plus transport costs from Wallumbilla to the buyer's location (**the buyer alternative – a ceiling price**).

Chart 2.9 compares prices offered in the southern states with short-term netback price expectations and their buyer and seller alternatives. As shown in the chart, most offers from both producers and retailers to the southern states in 2023 for 2025 supply were below the buyer alternative price. The story has been more mixed in the first 6 months of 2024. Between January and March 2024 offer prices were above the buyer alternative, and between April and June 2024 offer prices were below the buyer alternative.

It is worth noting that all of the gas offered to the southern states in this period was made by non-LNG producers, who do not have restrictions under the HoA. In contrast, LNG producers have committed to offer prices at or below LNG netback prices under the HoA commitments. Prices trended more towards seller alternative prices in mid 2024, likely reflecting the increased activity of producers following the granting of conditional Ministerial exemptions.

Chart 2.9: Gas commodity prices (2025$/GJ) offered to the southern states for 2025 supply against short-term LNG netback expectations[3]



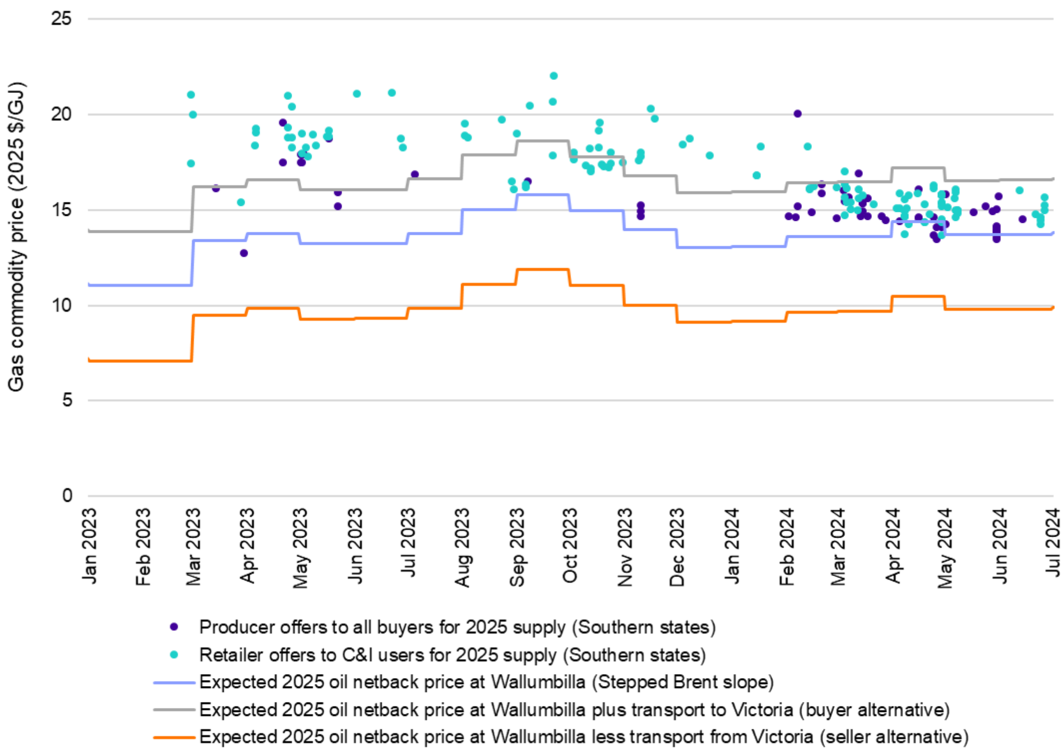
Source: ICE, Argus, ACCC Analysis of offer information provided by suppliers.

Note: All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some dots represent multiple offers that were made on the same day and contain the same price.

Chart 2.10 compares prices offered in the southern states with medium-term oil netback price expectations and respective buyer and seller alternative prices. It shows that, in 2023, most offers to buyers in the southern states for 2025 supply were above the oil-linked buyer alternative medium-term netback prices, reflecting the influence of higher international prices, lower producer activity and tighter demand-supply conditions in the southern states.

This trend changed in the first 6 months of 2024, with most of the offers made between January and June 2024 falling below the oil-linked buyer alternative price, which likely reflects the improvement in market conditions and the increased activity of producers following the granting of conditional Ministerial exemptions.

Chart 2.10: Gas commodity prices (2025$/GJ) offered for 2025 supply to the southern states against expectations of medium-term oil-linked LNG netback



Source: ICE, Argus, ACCC analysis of offer information provided by suppliers.

Note: All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some dots represent multiple offers that were made on the same day and contain the same price.

The number of offers made to buyers in southern states increased in the current reporting period. Between January and June 2024, producers made 47 offers to gas buyers in the south, compared to 5 offers in the previous 6 months. In 2023, there were only 17 producer offers for long-term gas. As indicated, LNG exporters did not make any offers to gas buyers in southern states in the current reporting period. Since the introduction of the Gas Code, non-LNG producers have increasingly engaged with the southern market.[20] The number of retailer offers to the southern states also increased to 91 in this reporting period, up by 94% from the previous 6 months.

2.3.4. Queensland prices and LNG producer forecasts

This section discusses offers in Queensland and compares offer prices for 2025 supply with expectations of LNG netback prices. It also reports on Queensland LNG producers' supply to the domestic market.

Prices to Queensland tracked below LNG netback

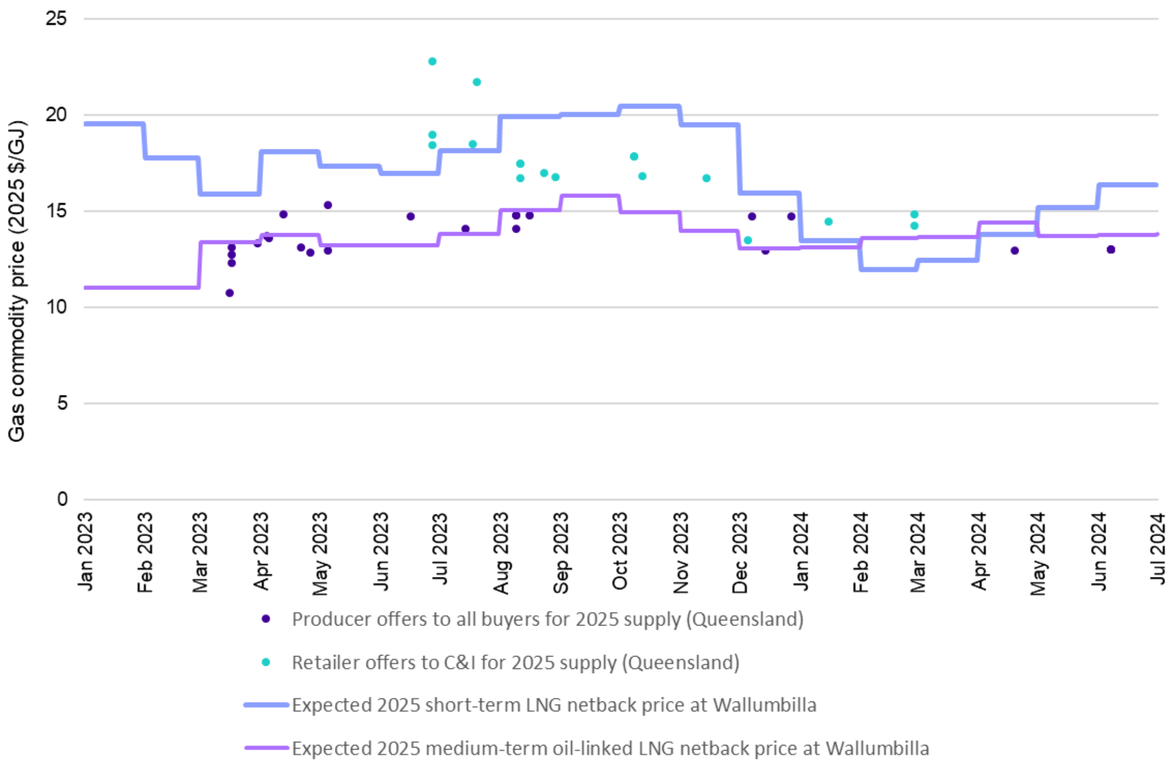
Producers made limited offers for supply in Queensland in the current reporting period between January and June 2024 (see chart 2.11). This is broadly consistent with what we

[20] This increased engagement is observed with a large reduction (from 113 PJ in April 2024 to 62 PJ in October 2024) in the volumes of available uncontracted gas from southern producers reported under the Gas Code.

have observed in Queensland in recent years.[21] There were 5 producer offers for long-term supply in this period, compared to 13 in the first half of 2023. Of the 5 offers, 4 were made by LNG exporters. Producers made just 8 offers for delivery to Queensland after the end of the transition period of the Gas Code in September 2023.

All producer offers for 2025 supply were below short-term netback prices. Similarly, most retailer offers tracked below short-term netback prices.

Chart 2.11: Gas prices ($/GJ) offered by producers for Queensland 2025 supply against expectations of short-term LNG netback and medium-term oil-linked LNG netback



Source: ACCC analysis of bid and offer information provided by suppliers.

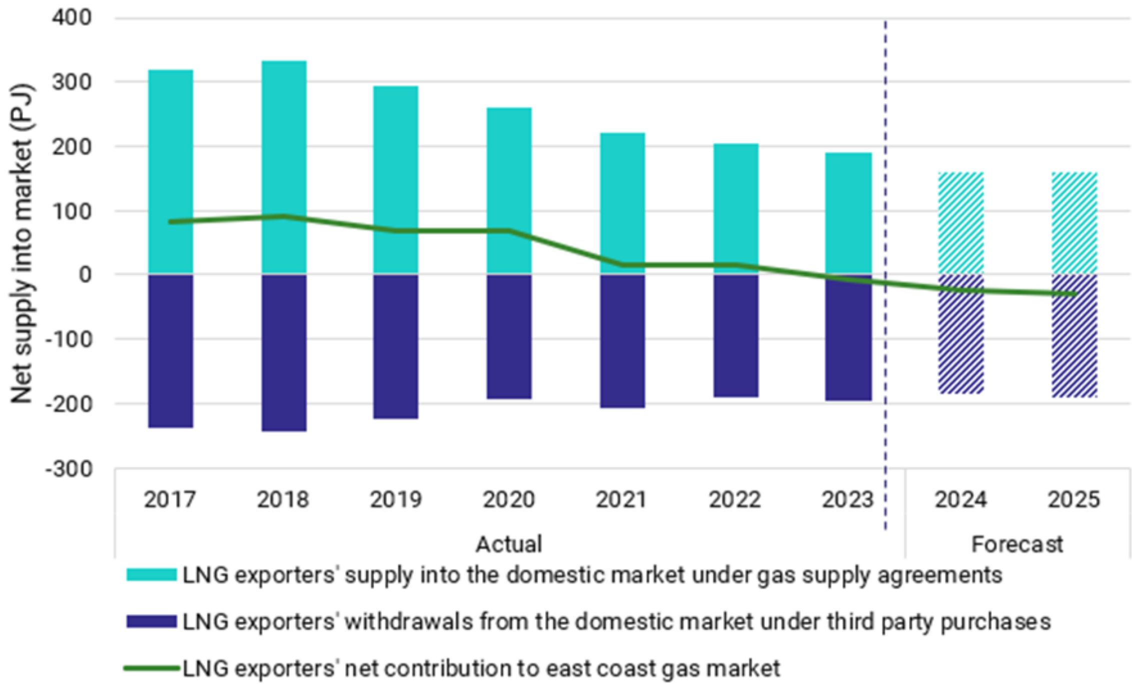
Note: All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some dots represent multiple offers that were made on the same day and contain the same price.

LNG producers' offers for long-term-gas supply to the domestic market have declined

The Queensland LNG producers have contributed between 38 and 45% of domestic demand through contracting with market participants. However, the annual volumes supplied by the LNG producers to the domestic market have been decreasing over time (see chart 2.12).

[21] Our analysis suggests that gas produced in Queensland has predominately been offered for delivery in Queensland (Appendix D). We have observed that, the proportion of Queensland gas offered to southern states has decreased from 20% for the 2022 supply year to 2% for the 2025 supply year.

Chart 2.12: LNG producers net contribution to the east coast gas market (PJ)



Source: ACCC analysis of data obtained from gas producers in July and September 2024 and of the domestic demand forecast (Step Change scenario and coal retirement delay sensitivity) from AEMO's 2024 GSOO.

Note: This chart is an aggregated position of all 3 LNG producers, and each individual LNG producers' contribution to the domestic market may differ. Chart 7.1 provides further information on each of the LNG producer's total 2P reserves, contracted exports and net domestic purchases over the long-term outlook.

Consistent with the trend in chart 2.12, LNG exporters have made limited offers for long-term supply in recent years. For example, for the 2021 supply year, LNG exporters offered around 300 PJ of gas to the domestic market under contracts with a minimum supply term of 12 months. More recently, the number of offers have fallen considerably, with just 12.21 PJ offered for 2024 supply and 6.92 PJ for 2025 supply.[22] Additionally, LNG producers have conducted limited numbers of long-term (12 months or greater) EOIs since late 2022.

Our analysis suggests that LNG exporters have offered an increasing proportion of their uncontracted gas to the short-term and spot markets since early 2022. They have also supplied gas to the domestic market through other avenues, such as the Gas Supply Hub and time and location swaps. The quantities offered in these supply mechanisms have reduced in comparison to those offered in previous supply years.

The LNG producers are expected to have significant volumes of gas available in 2025 that could be sold to the domestic market or exported as additional LNG sales. They are expected to produce 104 PJ of additional gas that is currently uncontracted (table 2.4). This is the largest volume of available gas from suppliers on the east coast. The LNG producers have reported that they anticipate exporting 70 PJ of their uncontracted gas as additional LNG sales in 2025.

Under the Heads of Agreement with the Commonwealth Government, the LNG producers are required to offer uncontracted gas to the domestic market before offering this gas to the international market. Our assessment of the LNG producers' compliance with the HoA for

22 This analysis is based on offers made since 2023 for 2025 supply.

the reporting period January to June 2024 suggests that LNG producers have complied with the HoA. During the period, LNG exporters offered around 43.1 PJ of gas to the domestic market (some of which formed part of the LNG producers' commitments under CMEs).[23] Of this amount, they sold 22.1 PJ (see Appendix C for further information).

Our analysis of offers and sales since revisions to the HoA took effect in January 2023 indicates that 222 PJ[24] of gas has been offered to the domestic market and 83 PJ[25] (~37%) of this amount has been sold. The majority of this gas was supplied on a short-term basis.

Table 2.4: LNG producers' forecast supply and contracted sales in 2025 (PJ)

LNG forecast	Q1	Q2	Q3	Q4	Total (2025)
Supply					
2P production + net storage withdrawals	352	347	353	357	1410
3rd party purchases from domestic suppliers	60	48	43	52	203
Gas swaps received	22	17	15	23	77
Demand					
Contracted east coast domestic sales	40	48	51	36	175
Quantity for LNG SPAs	365	315	314	340	1334
Gas swaps supplied	14	22	26	15	77
Uncontracted Gas Supply					
Uncontracted gas	15	28	21	40	104
Anticipated LNG spot and additional sales	12	12	12	35	70
Net uncontracted gas	**4**	**16**	**9**	**5**	**35**

Source: ACCC analysis of data obtained from LNG producers in January 2024 and July 2024.

Note: Totals may not add up due to rounding. The quantity required to meet the contractual obligations under long-term SPAs include the feed gas required to produce LNG (such as fuel).

23 See for example, Walloons Notice of Intention to Market Gas for supply in 2024 and 2025 on its website.

24 The 222 PJ includes the 26 PJ offered over the period 15 February 2023 – 8 August 2023, the 147 PJ offered over the period 9 August 2023–25 January 2024 and the 49 PJ offered over the period 26 January 2024 – 30 June 2024 (see below).
See ACCC, *Gas Inquiry 2017–2030, Interim Report*, June 2024, p 67 and ACCC, *Gas Inquiry 2017–2030, Interim Report*, December 2023, p 92.

25 The 83 PJ includes the 18 PJ sold over the period 15 February 2023 – 8 August 2023, the 43 PJ sold over the period 9 August 2023–25 January 2024 and the 22 PJ sold over the period 26 January 2024 – 30 June 2024 (see below).
See ACCC, *Gas Inquiry 2017–2030, Interim Report*, June 2024, p 67 and ACCC, *Gas Inquiry 2017–2030, Interim Report*, December 2023, p 92.

3. Gas buyers' experience

Key points

- Over the past 12 months we have engaged extensively with participants in the east coast gas market. Through that process, gas buyers commercial and industrial (C&I) users, intermediaries and retailers expressed concerns about:
  - significant increases in gas prices in recent years and the potential for this to result in further closures of Australian manufacturing
  - challenges posed by changes to the way producers are offering and selling gas.
- As gas buyers have observed, gas prices have increased significantly since 2021, due in large part to higher international prices and the tight demand-supply conditions prevailing in the east coast in 2022–2023. While prices in long-term Gas supply agreements (GSAs) have fallen from the 2022–2023 peaks, they are still around 2 times higher than they were in 2021, which is challenging for buyers, particularly those in trade-exposed industries.
- The way in which gas is being offered and sold by producers also appears to be posing some challenges for gas buyers. For instance, gas is increasingly being sold under shorter-term GSAs. Very few producers are entering into GSAs with a term of more than 2 years (particularly if it involves supply post 2026) and an increasing amount of gas is being sold on a short-term intra-year basis, particularly by LNG producers. The shift to shorter-term contracting appears to be exposing buyers to a greater level of price and supply risk. It may also be impeding investment.
- There has also been a deterioration in producers' non-price terms and conditions, with an increasing number of producer GSAs providing no take-or-pay or load factor flexibility. Some producers also appear to be passing on more supply risk to buyers through permitted interruption provisions.[26] Gas buyers have told us that this change has meant that they are increasingly having to rely on other risk management tools.
- An increasing volume of gas is also being offered through producer-led expression of interest (EOI) processes. That is, while gas continues to be sold on a bilateral basis by many producers, some of the larger tranches of gas offered to the market over the last 12 months, have been offered through an EOI process. Some buyers have asserted that these processes operate as 'blind auctions', exacerbating the imbalance in bargaining power they face. They are also concerned about the protracted nature of some EOI processes.

26 This appears to be a particular issue for supply from Longford, where the likelihood of outages has increased.

3.1. Introduction

To help inform our understanding of the conditions prevailing in the east coast gas market, we have undertaken a significant amount of engagement with gas buyers (including retailers, C&I users and intermediaries), producers and a range of industry associations over the last 12 months.

Through this engagement, gas buyers expressed concerns about the significant increase in gas prices that have occurred since 2021 and other changes that they have observed in the way in which gas is being offered and sold by producers into the east coast gas market. They raised particular concerns about:

- the prevalence of shorter-term contracting by producers
- a deterioration in non-price terms and conditions, particularly in producer GSAs
- the increased use of EOI processes by producers following the implementation of the Gas Code.

This chapter discusses these matters in turn. It should be read in conjunction with Appendix B, which provides further detail on the conditions prevailing in the market over this period.

3.2. Price increases have been challenging for gas buyers

Most of the gas buyers we have spoken to over the past 12 months told us that the prices they are having to pay for gas have increased significantly since 2021, which is presenting significant challenges. Several buyers asserted that there are likely to be further closures of manufacturing if high prices persist.

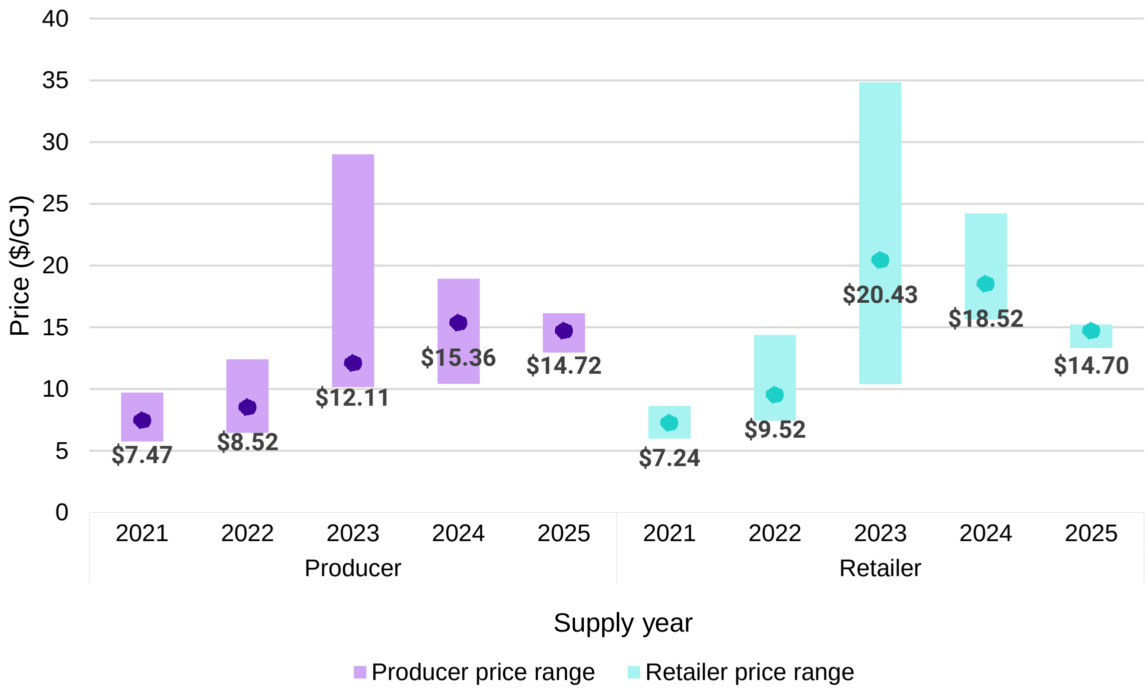
3.2.1. Gas prices remain high by historical standards

As outlined in further detail in Appendix B, the prices payable for gas in the east coast gas market have increased significantly over the past 5 years, due in large part to higher international oil and LNG prices, and domestic demand-supply conditions.

The volume weighted average prices agreed to under longer-term GSAs entered into over this period, for instance, increased from around \$7.25–\$7.50/GJ in supply year 2021 to around \$12.10–\$20.40/GJ in supply year 2023, with some buyers paying as much as \$30–\$35/GJ in 2023 (chart 3.1).

While prices under longer-term GSAs have since moderated, they remain high by historical standards, with the weighted average prices for GSAs executed in the first 6 months of 2024 for the 2025 supply year 2 times higher than they were in 2021 at around \$14.70/GJ. More recent information from C&I users and intermediaries indicates that in the latter half of 2024, they were receiving offers from producers and retailers in the \$12–\$16/GJ range for 2025 supply in the southern states.

Chart 3.1: Prices agreed to under long-term GSAs in the year immediately preceding supply years 2021–2025



Source: ACCC analysis of GSA information provided by suppliers.

Note: Quantity-weighted average prices are displayed next to the point, or below the price range. All contracts are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. The GSAs in this analysis have an execution date that is within 1 year of commencement of the supply year. Brent and JKM linked prices for 2021–23 are based on historical prices while prices for 2024–25 use forecast prices. CPI linked prices are estimated for 2024–25.

The increase in prices since 2021 has not been limited to longer-term GSAs. The prices agreed to under shorter-term GSAs (i.e. GSAs with a term less than 12 months) also increased significantly over the period, although they have since moderated to around $8–$25/GJ in the first 6 months of 2024.[27]

Prices in the AEMO-operated markets also increased over the period and were subject to a greater level of volatility, particularly in 2022, with prices ranging from $5.10–$51.65/GJ between 2021 and the first half of 2024. On an annual average basis, prices across the STTM, DWGM and GSH increased from around $9/GJ in 2021 to over $20/GJ in 2022, before settling to around $12–$13/GJ in 2023 and 2024 (chart B.1).[28]

A number of C&I users and industry associations told us that if high gas prices persist, it could result in further closures of Australian manufacturing, which they noted could have broader reaching implications for the economy and employment, including in regional areas where some manufacturers are located.

[27] ACCC analysis of data obtained from AEMO's Gas Bulletin Board

[28] In 2021, the average price across these markets ranged from $5.10–$25.60/GJ, while in 2022 it ranged from $6.70–$51.65/GJ and in 2023 it ranged from $5.75–$25.20/GJ. Over the first 6 months of 2024, it has ranged from $8.95–$23.85/GJ.

This was considered a particular risk for C&I users operating in trade-exposed industries and those using gas for feedstock or high-temperature heat processes (i.e. because there are currently no viable substitutes for gas). One industry association, for instance, stated:

> We are seeing the hollowing out of manufacturing capability in Australia, with the recent closure of 2 domestic manufacturers, including Qenos. As a result of failures in the east coast gas market and the market power of producers, Qenos were in the position where they had to go into voluntary receivership. The failure of the east coast gas market is not the sole cause; but it's a significant driver.

Another stated that:

> In the back of our members' minds is the collapse of Qenos. A big part of that is gas price. And we know some others are really at the edge of that as well. We're beginning to think this could be the beginning of the end.

3.2.2. Operation of the Gas Code's 'reasonable price' provision

C&I users and industry associations have expressed significant concerns about the increase in gas prices that has occurred over the past 5 years. Several C&I users have questioned the basis for current prices, which they noted have increased by far more than inflation. One C&I user, for example, noted that:

> A roughly 30% increase in the gas price from what it was in 2021 to what it is now is nowhere near the costs we would be able to pass onto the customers that we sell to.

A number of buyers also questioned the impact the reasonable price provision in the Gas Code is having on gas prices (see chapter 1 for further detail on these provisions and how they are intended to operate in conjunction with the exemption framework).

Several C&I users, intermediaries and some industry associations, for instance, noted that the $12/GJ reasonable price appears to be acting as a 'price floor', with one C&I user stating that *'$12/GJ gas doesn't exist'*. Another noted that:

> …there's this mythical $12/GJ gas. We asked around and could only find one example of $12/GJ gas being offered and that was in central Queensland. It was a small quantity and snapped up quickly…The $12/GJ price floor you hear about is more of a basement price – no one has ever seen it except that one example.

Some of these stakeholders attributed the lack of $12/GJ gas to the exemptions granted under the Gas Code, stating that few, if any, producers are subject to the Gas Code's reasonable price provisions. Another questioned whether the domestic supply commitments made by producers through conditional Ministerial exemptions had been sufficient to achieve the Gas Code's purpose of 'adequate gas supply at reasonable prices', or to result in a decoupling of domestic prices from international prices.

Several retailers also noted that they had seen very little gas being offered at $12/GJ:

> While some producers have offered gas to the market at $12/GJ, many have requested pricing above $12/GJ for short to medium term gas supply.

> …there is only one producer…selling gas at the Gas Market Code $12 price cap, and even then, there are considerable constraints on the offer from this single producer that makes it difficult to take the gas. All other producers are selling gas above the $12 price cap.

Most retailers also noted that the Gas Code has had little or no impact on the prices they are having to pay for gas, adding that domestic prices are primarily being driven by international prices and domestic demand-supply conditions. One retailer, for instance observed:

> …the majority of producers have been granted an exemption under the Gas Market Code. As a result, market dynamics are once again the primary factor influencing price. However, [the retailer] observed that producers are reluctant to offer supply at prices below the cap of $12/GJ. This reluctance suggests that, despite the exemption framework, the price cap is effectively serving as a minimum price for producers in the market.

Elaborating on this further, the retailer noted that with most producers exempt from the reasonable price provisions, 'market conditions and supply and demand outlook are now driving forward prices', adding that the decline in prices since 2022–2023 has been:

> …driven by other domestic and international factors (e.g. reduced demand and reductions in international Gas prices) and are not a direct result of the Gas Market Code.

This observation is broadly consistent with our own observation that the Gas Code is unlikely to have much influence on gas prices in the east coast in the near term. This is because most of the gas that is expected to be supplied into the market in 2024 and 2025 is not subject to the reasonable price provisions. While increases in market offers may have put downwards pressure on prices in the near-term, prices continue to be shaped by international LNG and oil prices, which are higher than pre-2022 levels.

Additional domestic supply and more competition will be necessary to put further downward pressure on prices. There is some additional supply identified in the short-term by producers that hold conditional Ministerial exemptions from the reasonable price provisions in the Gas Code. Significant increases in supply, also subject to conditional Ministerial exemptions, are forecast from 2026. However, in the longer-term, further significant volumes of additional supply will be required to avoid shortfalls.

3.2.3. More buyers are turning to facilitated markets, which is exposing them to more risk

Over the course of this inquiry, C&I users have told us that they have sought to offset the impact of higher gas prices, including through measures such as installing more energy efficient equipment, fuel switching (where feasible), changing gas usage patterns, deferring investments, reducing staff and other cost saving measures.[29]

An increasing number of C&I users have also told us that they are trying to reduce their gas costs by procuring more gas through the AEMO markets, either directly or via a retailer or intermediary (see section 4.2 for more detail). In doing so, these C&I users noted that they expected the prices payable in these markets to be lower than the prices they had been offered by producers and retailers under longer-term GSAs.

One C&I user, for instance, noted that:

> Firm gas price offers from suppliers in 2023 for 2024 were excessively high … It was therefore decided to proceed with a GSH/STTM exposed arrangement. A proportion

[29] See for example, ACCC, *Gas inquiry 2017–2020 interim report*, July 2018, p 62, ACCC, *Gas inquiry 2017–2025 interim report*, January 2020, p 75, ACCC, *Gas inquiry 2017–2030 interim report*, January 2023, p 72

> of [our] gas is secured through a firm contract to guarantee security of supply… The remaining amount is then exposed to the STTM/GSH.

Another noted that:

> We are using the markets out of compulsion. The prices quoted for fixed price supply are very high and would result in the closure of our operations. Spot prices have, however, remained above $12/GJ and there's also a lot of volatility in the price – last month it was more than $20/GJ. That plays havoc on our cost structures and makes it hard to get business. Customers will say no if we try to pass on these costs.

The C&I users that are now considering using the AEMO markets include some that have previously been reluctant to do so:

> Historically we had no appetite to procure gas from the spot market. We've looked at the spot market for the first time for a portion of our supply… The basis of that risk being worthwhile is the historical trend in spot which is more advantageous when prices average out.

As we have noted in prior reports, relying on the AEMO markets can be a risky strategy, because they are subject to both:

- physical risk (i.e. the risk there will be insufficient gas available in the markets)
- financial risk (i.e. the risk prices in these markets could get as high as the market price cap[30] and/or that the administered price cap may be triggered).[31,32]

The increasing use of AEMO markets is therefore a concern, particularly for C&I users that are not in a position to effectively manage their associated risks (see section 4.8 for more detail).

3.3. Gas is increasingly being sold under shorter-term contracts

In addition to the concerns raised about higher gas prices, gas buyers have told us that gas is increasingly being sold on a shorter-term basis, with:

- very few producers reportedly willing to enter into GSAs with a term of more than 2 years, particularly if it involves supply post 2026
- an increasing amount of gas being sold by producers on a short-term intra-year basis.

These changes are reportedly posing a number of challenges for gas buyers, many of whom prefer longer-term contracts because it provides greater predictability about future costs. The increased prevalence of shorter-term contracting may also be affecting investment in user facilities and supply-related infrastructure, because gas buyers do not have the price or supply certainty they require to underwrite such investments.

30 The market price cap is $400/GJ in the STTM and $800/GJ in the DWGM.

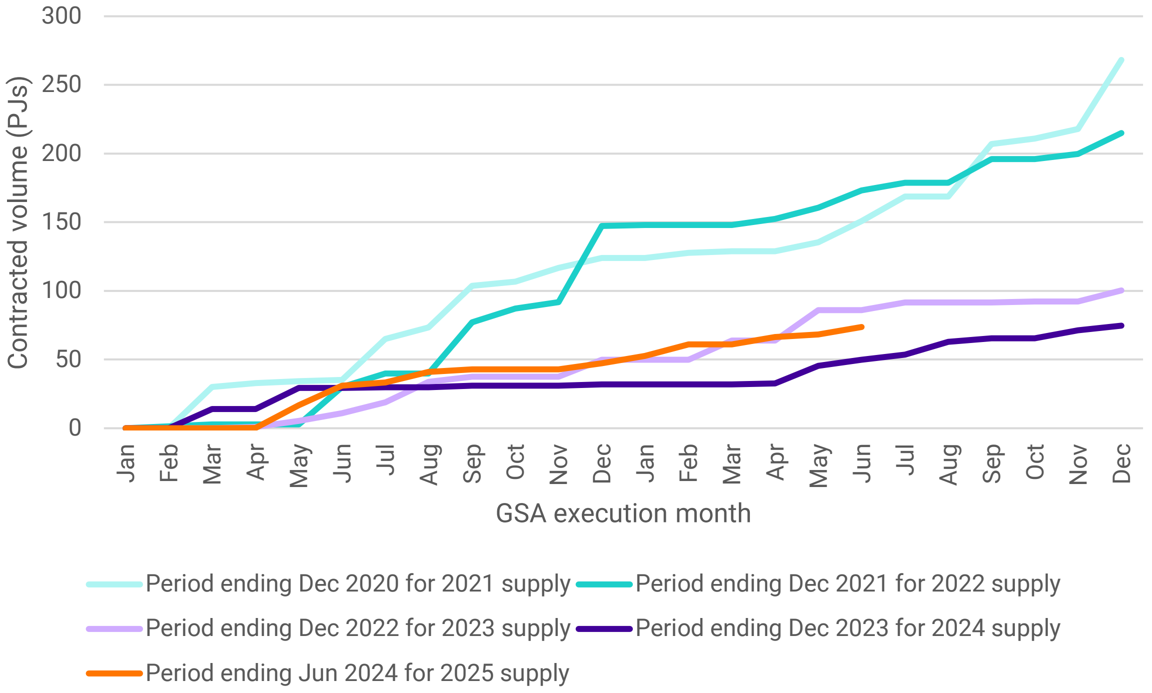
31 The administered price cap is $40/GJ in both the STTM and DWGM. The last time the administered price caps were triggered was in mid-2022 and they remained in place for some time.

32 If, for example, the administered price caps were triggered for a period of time, then buyers relying on the markets would either have to be in a position to pay $40/GJ for that gas and meet AEMO's prudential requirements during this period, or alternatively be able to reduce their demand for gas during that period.

3.3.1. Fall in volume of gas sold by producers under long-term GSAs

The volume of gas sold by producers under long-term GSAs fell significantly between 2019 and the first half of 2024, with long-term GSAs entered into for the 2023–2025 supply years accounting for less than half of what they did for the 2021 and 2022 supply years (chart 3.2).

Chart 3.2: Cumulative volumes sold under long-term producer GSAs for supply years 2021–2025



Source: ACCC analysis of GSA information provided by producers and retailers.

Note: This chart shows the volumes of gas contracted for supply under long-term GSAs for a given year in the 2 years preceding that supply year (e.g. the volume of gas contracted in 2023 and 2024 for supply year 2025).

The lower level of long-term contracting by producers is consistent with what we have observed in the offers data, with around 30% of offers made in 2023 and the first half of 2024 having a supply term of 2 or more years, compared to around 40% in 2021. The number of producers offering to supply gas beyond 2026 is also very low, with just 4 producers offering to do so in the first half of 2024.

The reduction in gas being sold under longer term GSAs is partly due to the LNG producers selling gas more on a short-term intra-year basis than under long-term contracts since 2022. For instance, in 2021 LNG producers offered to supply around 300 PJ of gas to the domestic market under longer-term contracts. Since the start of 2023, they have offered to supply 19.1 PJ on this basis (12.2 PJ in supply year 2024 and 6.9 PJ in supply year 2025).[33]

[33] This finding only includes offers that had a term length of greater than 12 months, an ACQ value of greater than 0.5 PJ and an offer date within 2 years of the start of the supply year.

The reduction in producer offers to enter into longer-term multi-year GSAs is consistent with what we have been hearing from gas buyers for some time (see box 3.1). One C&I user, for instance, stated:

> [t]here's no real gas out there after 2027. For 2025, we're relatively comfortable with the price we have. For 2026, there's still some gas around that we might be paying too much for. The concern is 2027 onward. … In the longer term, you can find Longford gas for 2025 and 2026, after that it's almost impossible.

A gas buyer also noted that:

> Some southern producers are willing to supply out to 2026, while Queensland producers are only offering to supply the first half of 2025. If there are any concerns about upstream liquidity – that would be the big one. Queensland have the largest uncontracted position on east coast by a big margin but it's being drip-fed with volume only offered for the first half of 2025. It's certainly a challenge...

A number of retailers also observed a reduction in producers willing to contract beyond 2026, with one observing that:

> Prior to the announcement of the Gas Code, it was possible to negotiate gas supply agreements over an extended forward period (e.g. up to 5-years periods). However, it is now challenging to negotiate tenures beyond 2 years in some cases. This is potentially due to general uncertainty around the availability / price of supply over the medium to longer term. The time limited nature of conditional exemptions and uncertainty around the outcomes of the 2025 Code Review could be contributing factors in this respect.

Other buyers echoed concerns about the potential for projected supply shortfalls and the upcoming Gas Code review to affect the willingness of producers to contract beyond 2026:

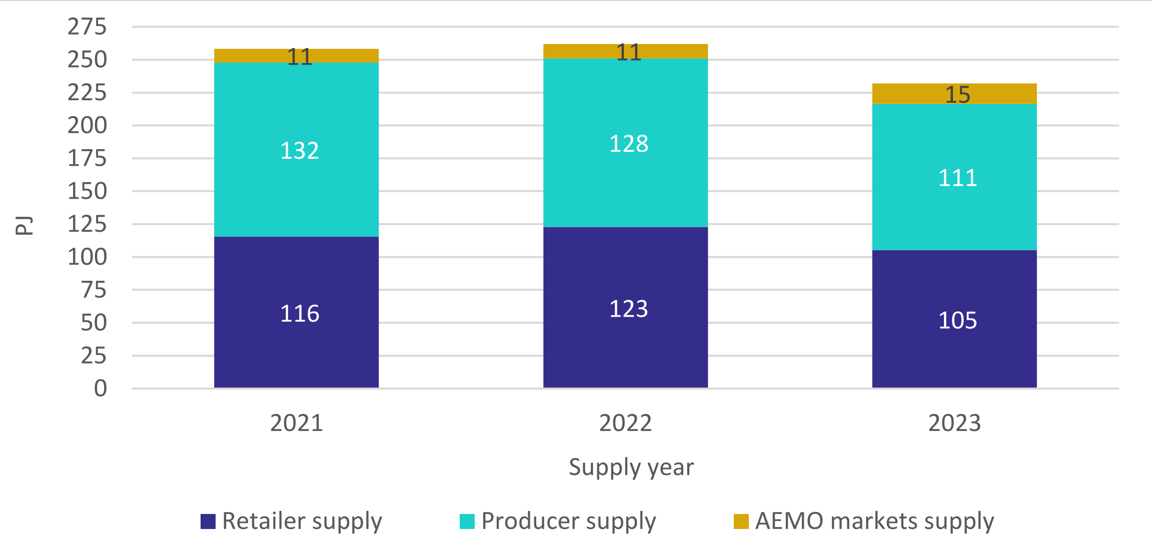
> …we've heard there's no appetite for contracts to be offered longer than 2 years. There's a lot of fear around gas supply in 2027 and 2028 from the Code review and decreases in investment in gas production. The market is not offering many options at this time due to market uncertainty.

Box 3.1: The volume of gas sold to C&I users has fallen

Since 2021 C&I users and intermediaries have been telling us about the difficulties they have experienced trying to enter into GSAs with producers and retailers for future supply years, which some responded to by procuring gas from the AEMO-operated markets.[34]

The difficulties experienced by C&I users can be seen to some extent in chart 3.3.

Chart 3.3: Gas supplied and contracted to C&I users for supply years 2021–2023



Sources: Retailer and producer supply data based on ACCC analysis of information provided by suppliers on actual volumes supplied and contracted firm supply to C&I users provided between 2022 and June 2024. AEMO market supply data based on data from the AEMO markets on the gas procured by C&I users, or by intermediaries on behalf of C&I users.

This chart shows the volume of gas supplied by producers and retailers to C&I users was relatively stable in 2021 and 2022 but fell by around 34 PJ (~15%) in 2023, with producer supply falling by 17 PJ and retailer supply by 18 PJ. While this decline was offset to some extent by an increase in gas purchased by C&I users from the AEMO markets, in total the volume of gas supplied to C&I users in 2023 was around 30 PJ lower than it was in 2022.

Around half of this reduction appears to have stemmed from the closure of Incitec's Gibson Island fertiliser plant at the end of 2022, which was consuming around 14 PJ p.a..[35] The reason for the remaining 16 PJ decline is unclear, but it is possible it reflects the effect of the higher gas prices that were prevailing in 2023, which may have resulted in some C&I users reducing their consumption of gas and/or the closure of facilities.

The reduction in gas supplied by producers and retailers to C&I users in 2023 is broadly consistent with what we have observed in more recent GSAs. It is unclear at this stage if the reduction in gas sold to C&I users under longer term GSAs reflects the conditions prevailing in the market over this period (see Appendix B) rather than a systemic decline.

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34 ACCC, Gas inquiry 2017–2025 interim report, January 2021, p 69, ACCC, Gas Inquiry 2017–2025 interim report, July 2021, p 62, ACCC, Gas inquiry 2017–2025 interim report, January 2022, p 110, ACCC, Gas inquiry 2017–2025 interim report, July 2022, p 54, ACCC, Gas inquiry 2017–2030 interim report, January 2023, p 58, ACCC, Gas inquiry 2017–2030 interim report, June 2023, p 13.

35 ACCC, Gas inquiry 2017–2025 interim report, July 2022, p 42.

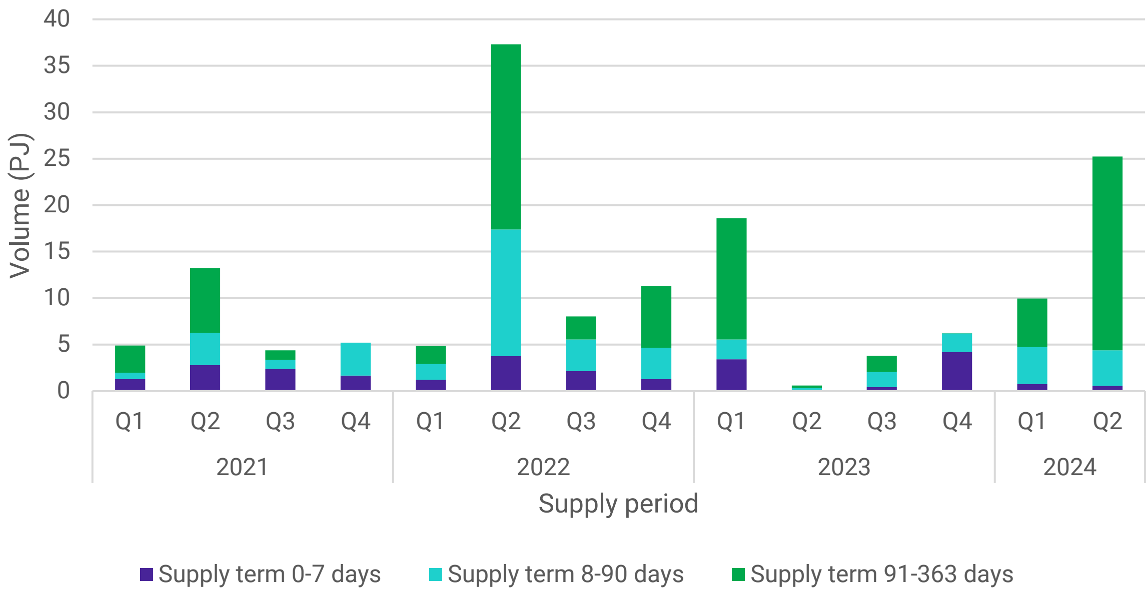
That said, it is unlikely that there will be a reversion back to the historic levels of longer-term contracting in the near term given the following, both of which are caused in part by a lack of supply certainty:

- the increased reliance that some C&I users appear to be placing on the AEMO operated markets (section 3.2), and
- the increased prevalence of shorter-term contracting by producers (section 3.3).

3.3.2. Increased sale of gas on a short-term, intra-year basis

Chart 3.4 shows the volume of gas sold by producers to gas buyers (i.e. C&I users, retailers, gas powered generators and traders) under short-term GSAs since 2021.

Chart 3.4: Gas sold by producers to gas buyers under short-term GSAs between Q1 2021 and Q2 2024



Source: ACCC analysis of GSA information provided by producers.

As this chart shows, the volume of gas sold by producers to gas buyers under short-term GSAs increased from around 28 PJ in 2021 to 62 PJ in 2022. While the volume of gas sold under short-term contracts was lower in 2023 than it was in 2022 (potentially as a result of the Emergency Price Order),[36] it was still higher than in 2021. The volumes sold in the first half of 2024 are also materially higher than they were at the same time in 2021.

LNG producers have accounted for the majority of gas sold under short-term intra-year GSAs entered into since 2022, although material volumes were also sold by non-LNG producers in the first half of 2024. Of the gas sold on this basis in the first half of 2024, C&I users accounted for 35%, retailers accounted for 60% and the remaining 5% was accounted for by GPGs and traders.

[36] The Emergency Price Order provided for the application of a $12/GJ price cap on gas sold under short-term contracts for 2023 supply. For most of Q2 2023 and some of Q3 2023, the prices in the AEMO operated exceeded $12/GJ, which may explain why less gas was sold under short-term GSAs in this period.

The shift to shorter-term intra-year contracting is reportedly posing challenges for retailers and other gas buyers, who are having to now 'stitch together' shorter-term GSAs to obtain supply volumes they would have previously procured under a longer-term GSA. It is also reportedly exposing them to a greater level of pricing and supply risk at the end of each GSA, which may be affecting their incentives to invest in their own facilities, or to underwrite supply-related infrastructure.

It is unclear at this stage what has prompted the shift to shorter-term contracting, particularly by the LNG producers who control the majority of the uncontracted gas that is expected to be available in 2025 (see section 2.6). Some potential reasons may include technical or commercial factors, or, in the case of LNG producers, incentives created by the Heads of Agreement.

3.4. Producers are providing less volume flexibility and passing on more supply risks

Gas buyers have expressed concerns about a deterioration in non-price terms and conditions being offered by producers. In particular, they have noted:

- a reduction in volume flexibility being provided by producers, with take-or-pay multipliers[37] increasing and load factors[38] decreasing
- an expansion of permitted interruption provisions in some producers' GSAs.

Gas buyers have reported that they are increasingly relying on other tools to manage demand and supply risks that have historically been managed through GSAs.

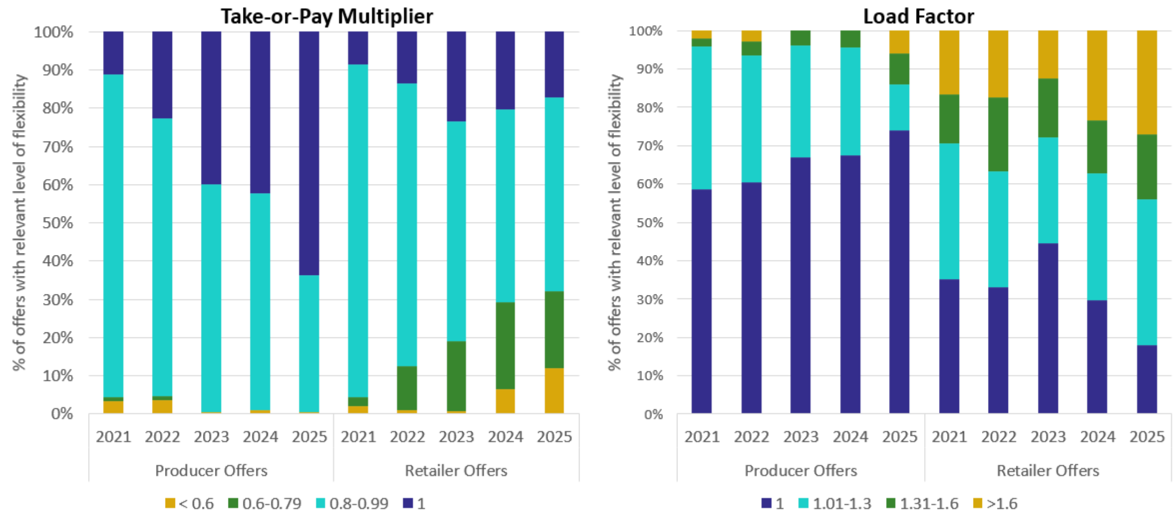
3.4.1. Reduction in volume flexibility

The charts below show the change in volume flexibility offered by producers and retailers (chart 3.5) and in the GSAs they have entered into (chart 3.6) for supply years 2021–2025.

37 Take-or-pay multipliers specify the minimum proportion of annual contract quantities (ACQ) a buyer must pay for in each year, regardless of whether they take the gas or not. A 0% multiplier implies the buyer only pays for what it takes, while a 100% multiplier implies the buyer has to pay for all the gas it has contracted, irrespective of whether they take all that gas.

38 Load factors measure the extent to which a buyer can take more than the average daily contract quantity throughout the year, subject to the cap imposed by the ACQ. A load factor of 1 implies the buyer has no flexibility to take more on a gas day than the average daily contract quantity, while a load factor greater than 1 implies that the buyer can take more on a gas day than the average daily contract quantity. The load factor may be constant through the year or may vary.

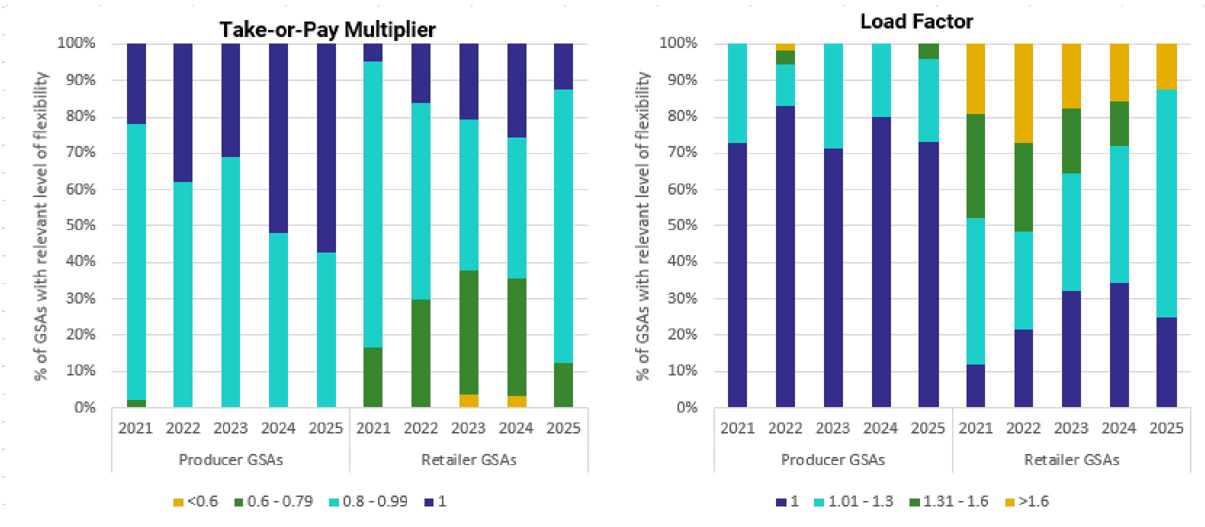
Chart 3.5: Take-or-pay multipliers and load factors in offers for 2021–2025 supply years



Source: ACCC analysis of information provided by suppliers.

Note: The offers used in this analysis have an offer date within 2 years of commencement of the supply year.

Chart 3.6: Take-or-pay multipliers and load factors in GSAs for 2021–2025 supply years



Source: ACCC analysis of information provided by suppliers.

Note: The GSAs used in this analysis have an execution date in the 2 years before the commencement of the supply year.

An increasing number of producer contracts provide no volume flexibility

As charts 3.5 and 3.6 show, producers are offering less volume flexibility, with an increasing proportion of offers and GSAs having a 100% take or pay multiplier and a 100% load factor. For example:

- around 10% of producer offers for the 2021 supply year had a 100% take-or-pay multiplier, while for the 2025 supply year this proportion reached over 60%
- around 60% of producer offers for the 2021 supply year had a 100% load factor, while for the 2025 supply year the proportion reached over 70%.

A similar pattern can be seen in GSAs, with the percentage of producer GSAs with a 100% take-or-pay multiplier increasing from 22% to 57% between supply years 2021 and 2025, while the percentage of producer GSAs with a 100% load factor increased slightly from 73% to 74%.

We have also found that just over 50% of the producer GSAs for supply year 2025 provided no volume flexibility at all, with both a take-or-pay multiplier of 100% and a load factor of 100%. This compares to 20% for supply year 2021.

From a producer's perspective, there are a number of potential reasons why volume flexibility may have reduced, particularly load factor flexibility.

For instance, some producers are more constrained in their ability to provide this type of flexibility. This is particularly the case for coal seam gas producers in Queensland, because it can be more difficult for them to increase daily production to provide load factor flexibility.

This may be increasingly the case for supply from Longford, with AEMO and others noting the Longford processing facility will be unable to provide the same peak day and seasonal flexibility it has in the past following the retirement of one of the gas plants and the reduction in the production capacity of legacy Gippsland Basin fields.[39] The reduction in load factor flexibility may also be an efficient response by producers to a tight market, because it maximises the amount of gas that can be supplied into the market.[40]

Some gas buyers have also hypothesised that the reduction in flexibility may reflect the imbalance in bargaining power they face when negotiating with producers, particularly in relation to take-or-pay.[41]

The reduction in volume flexibility offered by producers is reportedly posing challenges for buyers who have more variable demand, including retailers, GPG and some C&I users. Rather than relying on producer GSAs to provide volume flexibility, these buyers are instead using other tools to manage the variability in their demand, including storage and other measures to supplement supply (e.g. short-term or seasonal GSAs, gas timing swaps, gas call options and the AEMO markets).

Retailers are offering a greater level of volume flexibility than producers

As chart 3.5 and 3.6 show, retailers are offering and agreeing to provide a greater level of take-or-pay and load factor flexibility than producers. This is broadly consistent with what we have heard from gas buyers, who noted that retailers in general tend to offer more take-or-pay flexibility than producers.

While retailers have offered a greater level of volume flexibility than producers, there has been a moderate deterioration in the take-or-pay and load factor flexibility agreed to in retailer GSAs between supply years 2021 and 2025 (chart 3.6), with:

- the percentage of retailer GSAs with a 100% take-or-pay multiplier increasing from around 5% in supply year 2021 to 13% in supply year 2025, while the percentage of GSAs with a multiplier of 60–79% fell from 17% to 13%

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39 AEMO, *2024 Gas Statement of Opportunities*, March 2024, p 52. DCCEEW, *Reliability and supply adequacy framework for the east coast gas market – Stage 2 of framework development Consultation Paper*, June 2023, p 3.

40 This is because to provide load factor flexibility, producers have to maintain excess production capacity that may not actually be used on a day. If the producer instead sold gas on a flat basis (i.e. with a load factor of 1), then it could maximise production from the facility.

41 ACCC, *Gas Inquiry 2017–2030 – Interim update on east coast gas market*, January 2023, pp 62.

- the percentage of retailer GSAs with a load factor of 100% increasing from 12% in supply year 2021 to 25% in supply year 2025, while the percentage of GSAs with a load factor greater than 130% fell from 48% to 13%.

It is also notable that while there has been a deterioration in the volume flexibility agreed to in retailer GSAs, some retailers have offered significantly more flexibility for supply years 2024 and 2025 than they have in the past. For instance, a larger proportion of retailer offers have a take or pay multiplier less than 80% (chart 3.5). We understand from discussions with C&I users and intermediaries that some retailers are competing by offering lower take-or-pay multipliers and retailers appear more willing to negotiate on this term in 2024 than they have been in the past (see section 4.8.2 for more detail).

While some retailers are offering this flexibility, this is not yet being evidenced in retailer GSAs (chart 3.6). This may be because it can take time between offers being made and GSAs being entered into and/or buyers may consider the price being offered to provide this flexibility to be too high. As noted above, the reduction in flexibility being offered by producers means retailers are increasingly having to use other tools to provide this flexibility, which may be resulting in higher prices for contracts with such flexibility (see section 4.5 for more detail).

While C&I users have seen some improvements in the willingness of retailers to negotiate on take-or-pay multipliers, many remain concerned about the overall costs associated with take-or-pay obligations (see section 4.8.2 for more detail). Some C&I users have reportedly responded to this by reducing their contracted volumes and either relying on the AEMO markets to supplement supply, or taking more than they are contractually entitled to take and paying overrun fees to the retailer.[42]

3.4.2. There has been a deterioration in some producers' permitted interruption provisions

Over the past 2 years, C&I users and intermediaries have expressed concerns about the expansion in permitted interruption provisions in some producer and retailer GSAs.[43] Several retailers also told us that producers are increasingly transferring the risk of interruptions to retailers through permitted interruption provisions.

The expansion of these provisions has reportedly resulted in an increase in both the number of permitted interruption days and the circumstances in which the permitted interruption provisions can be triggered. One C&I user, for instance, noted:

> '[p]ermitted interruptions are worse and there are more of them… and the way the seller can access the high conditions are looser as well.'

According to gas buyers, this is primarily an issue for gas supplied out of Longford, where the likelihood of outages has increased (i.e. as a result of the decline in production, the retirement of some of the processing capacity and increased need for maintenance of the remining capacity).[44]

As discussed in further detail in section 4.8.2, the expansion in permitted interruption provisions coupled with the increased risk of interruptions at Longford, is posing a challenge for gas buyers (including retailers) that are exposed to this risk. These gas buyers are, for

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42 An overrun occurs if the buyer takes more gas than it is contractually entitled to take.

43 See for example, ACCC, *Gas Inquiry 2017–2030 – Interim update on east coast gas market*, December 2023, pp 18–19.

44 See for example, ACCC, *Gas Inquiry 2017–2030 – Interim update on east coast gas market*, December 2023, pp 18–19.

instance, having to find other ways to manage the supply risk that may arise if the provisions are exercised, including by entering into GSAs with other producers and suppliers, using storage and/or the AEMO markets to supplement supply when supply interruptions occur.

3.5. User concerns about the Gas Code's influence on EOIs

In addition to the matters discussed above, gas buyers have questioned the influence of the Gas Code on the way producers are offering gas to the east coast gas market. Users have raised particular concerns about the use of expression of interests (EOIs) and how EOI processes are conducted.

Gas buyers are concerned that the Gas Code may be resulting in more producer-led EOIs, which they noted can exacerbate the imbalance in bargaining power faced by gas buyers and lead to buyers agreeing to pay more for gas than they otherwise would in a tight market. Concerns have also been raised about the protracted nature of some EOI processes.

While the Gas Code itself does not mandate the use of EOIs, it would appear that an increasing volume of gas is being sold through producer-led EOI processes.

3.5.1. Buyers are concerned the Gas Code is exacerbating imbalances in bargaining power

A number of C&I users noted that since the commencement of the Gas Code, some producers appear less willing to engage in user-led tender processes or bilateral negotiations, preferring instead to conduct their own EOI processes. One C&I user, for example, noted that:

> In the past we had no problem getting responses to our tenders. Producers never ran EOIs. It's been a pretty swift change to where they don't want to respond to you asking for gas, they want you to go through their EOI. It's a silent auction. We give them a number and they say yes or no. We inevitably get a no.

The concerns raised by this C&I user about the 'silent' or 'blind' auction nature of EOI processes were echoed by other C&I users, who claimed that EOIs were being used by some producers to identify the maximum prices buyers are willing to pay to extract as much as possible from gas buyers. Some also noted that the blind nature of the process and the lack of insight into what producers would be willing to accept was resulting in gas buyers paying more for gas than they otherwise would, with one C&I user noting that:

> We are seeing users forced to pay higher prices through these blind EOIs. It's causing a blind bidding war, which results in higher prices to end users.

Several C&I users expressed their preference for bilateral negotiations, because, in their view, they provide for greater visibility and negotiations with producers:

> In bilateral negotiations, you can get visibility on where they sit and where you sit on certain terms. But in EOI process there's none of this.

A number of retailers also commented on the increase in producer-led EOIs since the Gas Code was implemented, with some stating this was adding to the imbalance in bargaining power faced by gas buyers, and contributing to higher prices. One retailer, for instance noted that:

> Since the commencement of the Gas Market Code, producers have run a relatively low number of EOI processes but these processes cover a large portion of the available volume in the market. During these processes, [we have] noticed that in some cases additional terms have been added including shape and transportation costs that appear to be a direct response to the Gas Market Code. [We note] that some producers that have been granted exemptions under the Gas Market Code are specifically required to run EOIs. [We do] not consider this to be a positive outcome for the East Coast Gas market.
>
> In [our] view EOIs are an inefficient mechanism for the market to interact with producers as they effectively allow sellers to use it as a price discovery tool, with limited benefits for buyers causing an imbalance in negotiating power…[Our] view is that bilateral negotiations provide a fairer platform to negotiate on price and non price terms. The EOI process post-Code implementation has become less flexible and heavily weighted to the producers' benefit.

Another observed that:

> …in a market where gas supply in general is balanced and not long, buyers are forced to bid at a higher price for fear of missing out on the EOI volumes. This creates competition to push prices up, and is not in favour of the buyer, and subsequently drives up prices for the end user….

Elaborating further on the increased use of producer-led EOIs and their concerns about the EOI process, one retailer noted:

> Producers appear to be using this mechanism more than in the past. Anecdotally, we think that producers are extremely conscious of offering quantities to the whole market – if buyers choose not to participate then they can't say that the volumes weren't offered to them…One element of the EOI process is a waste of time – that being pricing feedback! Buyers get no feedback is on "where the market is"? The only feedback that we receive as part of an EOI process is if we were successful or not.

3.5.2. Buyers are also concerned about the protracted nature of some EOI processes

In addition to the concerns outlined above, a number of gas buyers expressed concerns about the protracted nature of some EOI processes, as reflected in the following observations by 2 retailers:

> Procurement is now largely through structured EOI processes, which can extend timeframes for negotiating / formalising agreements given the prescribed steps that must be followed.
>
> Our observations of the producers' use of EOIs is that they have become a very inflexible and cumbersome process. Our observations are that producers are wary of non-compliance with the Mandatory Gas Code requirements, implying they are no longer able to respond as quickly, particularly in response to changing market conditions.

The latter of these retailers also noted that:

> The rigidity of the… Code has made it more challenging to engage with producers on an ad-hoc basis for gas supply, reducing availability from pre-price cap days. As a result contracting processes are often slower and can take several months to conclude.

Similar concerns were raised by C&I users about the challenges posed by protracted EOIs:

> The EOI process we participated in has taken many months and is not yet complete. …One of the problems is that the process is blind and we have no visibility of outcomes. We've got no idea after all these months if we can get gas or not. This makes it difficult to negotiate bilaterally with other producers at the same time because we don't know if we will be successful in the EOI.

3.5.3. Requirements of the Code in relation to EOIs

While more producers may be using EOIs following the implementation of the Gas Code, it is important to recognise that the Gas Code does not mandate the use of EOIs. Further, the EOI provisions in the Gas Code only apply if a producer is offering to supply gas for 12 months or more and issues an expression of interest to more than 2 people.[45] If these criteria are met, the producer must comply with the Gas Code's EOI publication, content and process provisions.[46]

However, if these criteria are not met, and subject to any other commitments a producer may have made in a conditional Ministerial exemption,[47] it is open to the producer to decide how to offer its gas to the market. This could involve participating in user-led tender processes, engaging in bilateral negotiations or conducting an EOI.

Based on our review of the way in which producers have offered gas to the market for a supply term of 12 months or more, it would appear that in the first full year of the Gas Code's operation: [48]

- 3 EOIs (involving the potential supply of 133 PJ between 2024 and 2030) have been subject to the Gas Code EOI requirements,[49] all of which have been undertaken by producers that have not typically used an EOI process
- the remainder of the gas offered by producers was offered bilaterally.

In keeping with our monitoring and enforcement role, the ACCC intends to continue to monitor how EOIs are being conducted, including to ensure compliance with the Gas Code's requirements. In this regard, it is worth noting that we have worked with producers over the

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45 Note that this does not apply to the reporting obligations for EOIs. These obligations require EOIs issue to more than 2 people to be reported to the ACCC within 3 business days, irrespective of the term of supply.

46 The producer must, for example, publish the EOI on its website at the same time it issues the gas EOI in a legible, prominent and unambiguous way and include a range of information in the EOI (including the quantity of gas to be supplied, the intended supply period, delivery points, conditions precedent and the last day of the open period). Subject to some caveats in the Gas Code, the producer must also keep the EOI open for 20 business days and notify potential buyers if they are successful or not within the timeframes specified in the Gas Code.

47 For example, Woodside has committed to conduct at least one EOI for each marketing period where it proposes to enter into a GSA for firm supply over a period of at least 12 months. See Minister for Climate Change and Energy, *Decision Notice – Exemption from provisions of the Gas Market Code for Woodside*, 15 January 2024.

48 It is worth noting that the number of EOIs listed above excludes those conducted by APLNG and Walloons. This is because those EOIs involved the supply of gas for less than 12 months and so are not subject to the Gas Code EOI requirements. Details of these EOIs can be found on the APLNG website and Walloons website (accessed 5 November 2024).

49 Details of these EOIs can be found on the Beach Energy website, Woodside Energy website and Central Petroleum website (accessed 5 November 2024).

past year to support compliance with the Gas Code (see box 3.2). This has included the publication of compliance and enforcement guidelines,[50] which we encourage producers to review if they are unsure of their obligations. These guidelines may also help gas buyers that want to better understand producers' obligations under the Gas Code.

Box 3.2: Monitoring of compliance with the Gas Code

The ACCC has been monitoring the compliance of producers with their obligations under the Gas Code since its implementation in 2023.

At a high level, producers appear to be complying with the reasonable pricing provisions. We have found no instances of gas being offered or sold for more than $12/GJ by producers that have not obtained an exemption from these provisions.

Producers also appear to be largely complying with the conduct provisions, although we are currently assessing some limited instances where producers may not have complied with aspects of the conduct provisions.

We have also worked with some producers to ensure they are complying with the transparency and reporting provisions.

50 ACCC, *Compliance and enforcement guidelines on the Gas Market Code*, accessed 4 November 2024.

4. Retailer behaviour review

Key Points

- We have completed our retailer behaviour review, which has focused on the retail supply of gas to C&I users. We found that in the case of:
  - **Retailer pricing practices:** There is no evidence of a persistent market failure or systemic problem requiring price regulation. There is also a risk that doing so would harm an already fragile competitive environment, with any reduction in competition operating to the detriment of C&I users.
  - **Retailer selling practices:** While competition appears to have driven some recent improvements in selling practices, some (but not all) retailer practices continue to fall short of what we would expect in a well-functioning retail market.
- Our findings have been informed by a detailed review of retailer prices and selling practices over the period 2020–2024, including key influences on these practices. We found that retailers' practices between 2022 and early 2024 were heavily influenced by the market conditions prevailing over this period, which resulted in:
  - constraints on access to gas, transport and storage services
  - a significant escalation in retailers' costs and risks
  - reduced competition to supply C&I users.
- More recently, market conditions have stabilised. As producers started to make more gas available to the market in late-2023 and 2024, we have seen:
  - retailers' prices fall to become more in line with producer prices
  - some improvements in selling practices, although concerns remain about some (but not all) retailers' standard practices.
- Looking forward, retailing is expected to become more challenging given the projected supply shortfalls, infrastructure constraints, energy transition, regulatory and policy uncertainty. There is also a risk market conditions and competition could deteriorate.
- In this context, the effects of poorer retailer practices may be felt more acutely. To safeguard against this and promote further improvements in retailer practices, we will:
  - publish best practice guidance on retail selling practices in 2025 and monitor retailers' uptake of such guidance as part of the Gas Inquiry
  - in future Gas Inquiry reports, publish more information on the prices retailers are charging C&I users and the prices retailers are paying producers for gas.
- Importantly, these measures will not address the fundamental supply-side problems still facing the east coast gas market.
  - Upstream market concentration and lack of access to sufficient gas supply are fundamental drivers of many of the problems flowing into the retail market.
  - The ACCC has long advocated for governments to remove impediments to bringing on additional gas supply, particularly in southern states. Promoting investment in supply and competition among a diversity of suppliers are key to the effective functioning of the gas market through the energy transition.

4.1. Introduction

In June 2023, we announced our intention to review the pricing and selling practices employed by retailers when selling gas to C&I users in the east coast who consume more than 1 TJ p.a. of gas.[51] The review was initiated in response to C&I user concerns about the behaviour of some retailers, particularly during 2022 and 2023. These concerns primarily centred on retailers':

- **pricing practices**, with particular concerns raised about the level of retail prices in 2022 and 2023, and questions raised about whether retailers were passing through changes in gas costs, including as a result of the Emergency Price Order and/or Gas Code
- **selling practices,** with particular concerns raised about the 'take it or leave it' approach and 'scarcity tactics' employed by some retailers in 2022 and 2023, as well as some of the standard practices employed by retailers when making offers, negotiating and contracting with C&I users.

Our review of these practices has been carried out in 2 stages:

- **Stage 1** was undertaken in the latter half of 2023 and involved a review of retailer selling practices over 2020–2023. In this stage of the review we found that: [52]
  - the conditions prevailing in the market in 2022 and 2023 had contributed to a deterioration in some retailers' selling practices
  - while there were some improvements in these practices in late 2023, some standard selling practices fell short of what would be expected in a well-functioning market.

  We therefore undertook to continue monitoring retailer selling practices in 2024 and to consider whether any reforms may be required to address systemic problems.
- **Stage 2** has been undertaken in 2024 and involved a review of retailer pricing practices over the period 2020–2024, retailer selling practices in 2024, and the influence that the following may have had on these practices over this period:

  (a) market conditions

  (b) constraints on access to gas, transportation and/or storage services

  (c) the costs and risks faced by retailers when supplying C&I users, and

  (d) competition to supply C&I users.

  We have also considered whether there are any systemic problems with these practices and, if so, how they could be addressed.

This chapter sets out our findings from Stage 2 of the review, which has been informed by information gathered using our compulsory information gathering powers, and extensive consultation with retailers, C&I users, intermediaries (i.e. energy brokers and consultants) and industry associations (see box 4.1).

In short, we have found no evidence of a persistent market failure or systemic problem with retailer pricing practices. We have also found that while competition has driven some improvements in selling practices, some (but not all) retailers' practices continue to fall

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51 This threshold has been employed because retailers supplying C&I users consuming less than this amount are subject to the customer protection framework set out in the National Energy Retail Law and National Energy Retail Rules in New South Wales, Australian Capital Territory, South Australia and Queensland, or the relevant Victorian and Tasmanian customer protection frameworks.

52 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, chapter 5.

short of what would be expected in a well-functioning retail market. We intend therefore to take a number of actions to promote further improvements in these practices.

The remainder of this chapter sets out in detail our Stage 2 findings. It commences with an overview of the role retailers play in the market and the influence the factors in (a)–(d) have had on their behaviour. The chapter then sets out our findings on retailer pricing and selling practices, and how further improvements in these practices could be achieved.

Box 4.1: Stage 2 consultation process

How we consulted with retailers

In early 2024 we used our compulsory information gathering powers to issue notices to a mix of small, medium and larger retailers. The notices were used to obtain information on each retailer's pricing practices, as well as the effect that market conditions, access to gas and infrastructure, costs, risks and competition had on their behaviour. Notices were also issued in mid-2024 to obtain updated information, and information on selling practices.

We also held bilateral meetings with retailers that are actively competing to supply C&I users, including some newer entrants. We also met with the Australian Energy Council.

How we consulted with C&I users, intermediaries and user associations

In mid-2024, we contacted C&I users, intermediaries and industry associations to inform them that we were undertaking Stage 2 of the review and invited them to respond to a set of retailer focused survey questions and to participate in bilateral meetings. In total, we received 22 responses to the retailer focused survey questions and held over 31 meetings.

As outlined in box 1.1, there was significant diversity in the C&I users we engaged with, in terms of their annual gas demand, the industries in which they operate, and the location of their facilities. Additional depth and diversity were provided through meetings with intermediaries and a range of industry associations.

Where possible, feedback provided in this consultation process has been independently verified using information obtained through our compulsory information gathering powers.

4.2. Retailers play a complex & challenging role supplying C&I users

This section provides an overview of the role retailers play in supplying C&I users in the east coast gas market and those retailers currently supplying C&I users.

4.2.1. Retailers supply just under half the gas procured by C&I users and face a range of challenges, costs & risks doing so

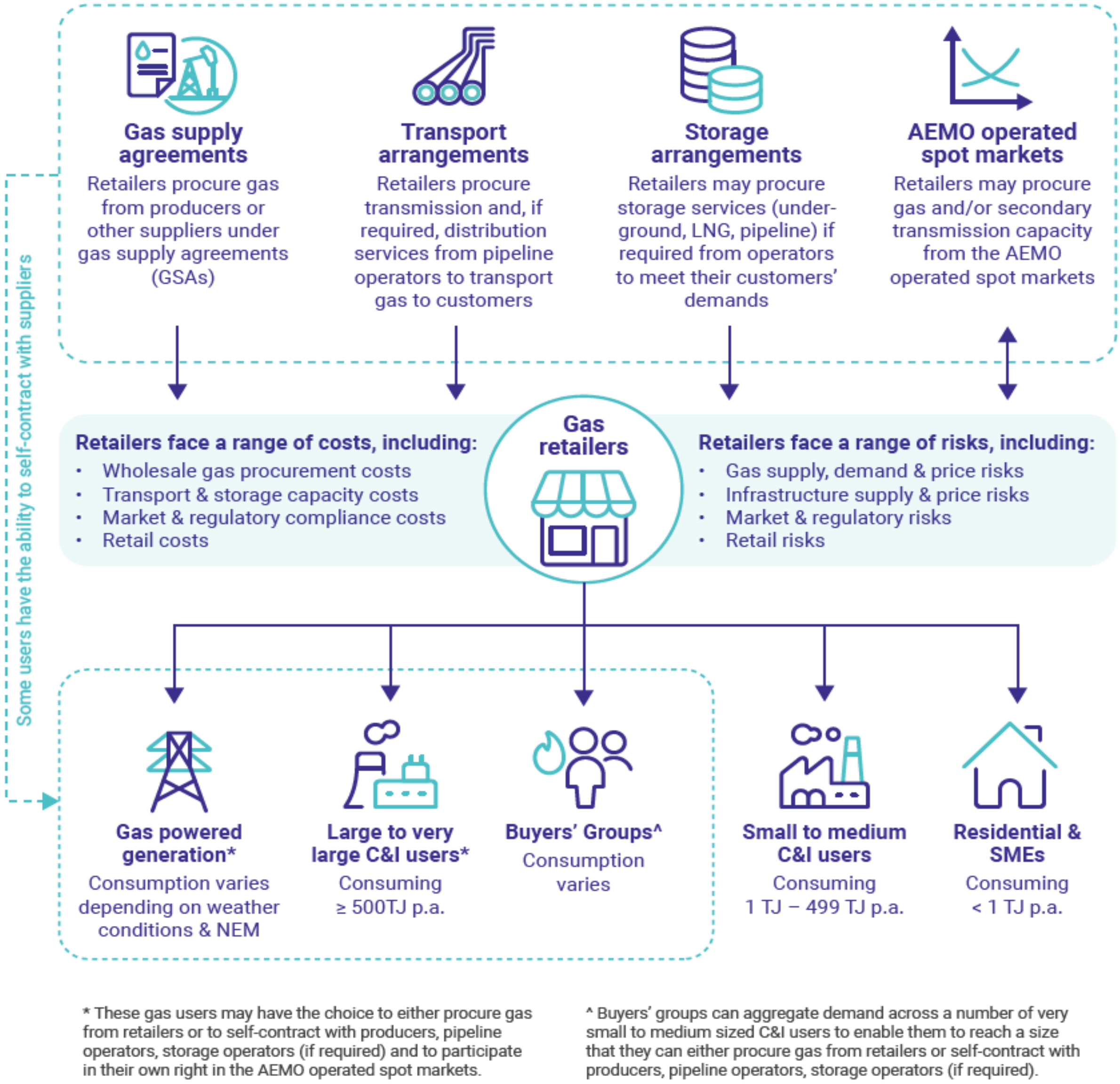
C&I users in the east coast may, depending on their size and location, have the option of procuring gas from retailers, producers and/or the AEMO operated markets.[53] Retailers can

[53] These markets include the Adelaide, Brisbane and Sydney, Short-term Trading Markets, the Victorian Declared Wholesale Gas Market and the Gas Supply Hub. Transportation capacity can also be procured through the AEMO operated day-ahead auction of contracted but unnominated capacity.

therefore face competition from producers and/or the AEMO markets to supply some C&I users. For all other C&I users, retailers represent the only means by which gas can be procured. Between 2020 and 2023, retailers accounted for just under half the gas supplied to C&I users, with producers and AEMO markets accounting for the remainder (figure 4.2).

For those C&I users supplied by retailers, the retailer is responsible for facilitating the supply of gas to the user's facility and managing the contracting and other arrangements associated with that supply. The retailer does so by aggregating gas purchased from producers or other suppliers and/or the AEMO markets, which it then transports to the user via transmission pipelines and, if required, distribution pipelines and/or storage facilities (figure 4.1).

Figure 4.1: Role played by retailers in the east coast gas market



Source: ACCC analysis.

Performing this function is complex because a user's demand for gas on a day (or within a day) can be subject to significant variability, as can the supply of gas, which is often located some distance from where it needs to be supplied. Performing this function can also expose retailers to a range of challenges, costs and risks, all of which can affect their pricing and selling practices, and their competitiveness.

4.2.2. A number of retailers compete to supply C&I users, but the position of individual retailers differs markedly

The retailers currently supplying C&I users include: AGL, Agora Retail, Alinta Energy, Aurora Energy, Eastern Energy Supply, EnergyAustralia, Engie, Origin, Perpetual Energy, PWC, Shell,[54] Snowy Hydro and Solstice Energy. In 2023, Origin was the largest retailer, accounting for 22% of C&I user supply, followed by Alinta (8%) and Shell (7%) (figure 4.2).

While some of the listed retailers have been supplying C&I users for some time, others are more recent entrants. Box 4.2 provides an overview of some of the barriers to entry and/or expansion that newer entrants can face in this part of the market, including in regional areas.

Figure 0.2 shows the main locations that retailers are currently supplying. Most locations have at least 3 retailers supplying C&I users, with some of the larger demand centres having 6–8 retailers. Some regional areas have just one retailer.

While the number of retailers operating in some locations appears large, this does not provide a good indication as to the level of competition in those locations. This is because retailers may not always be actively competing to supply new C&I customers, as several retailers told us was the case in 2022 and 2023 (see section 4.6.2). Some of the retailers in this list are also relatively small, which may limit their ability to supply larger C&I users, while others appear to play a more passive role, making few if any offers. One retailer told us:

> …there was no strategy to compete with other Suppliers, rather there was a view that if the gas was available to sell, (we) would submit a fair price. If the price was not accepted by the customer, then it was not pursued further…

[54] Shell sells gas to C&I users through Shell Energy Australia Pty Ltd (SEAu) and Shell Energy Retail Pty Ltd (SER).

Box 4.2: Barriers to entry and expansion in C&I retailing

Through prior reviews, the following barriers to entry and expansion have been identified:[55]

- constraints on access to a firm supply of competitively priced gas
- constraints on access to transportation services
- prudential requirements and other complexities associated with AEMO markets
- regulatory barriers relating to retail licences or authorisation.

While some new entrants have tried to overcome the first of these barriers by relying on the AEMO markets until they are of a sufficient size to enter into a GSA, this strategy can leave new entrants exposed to market volatility.

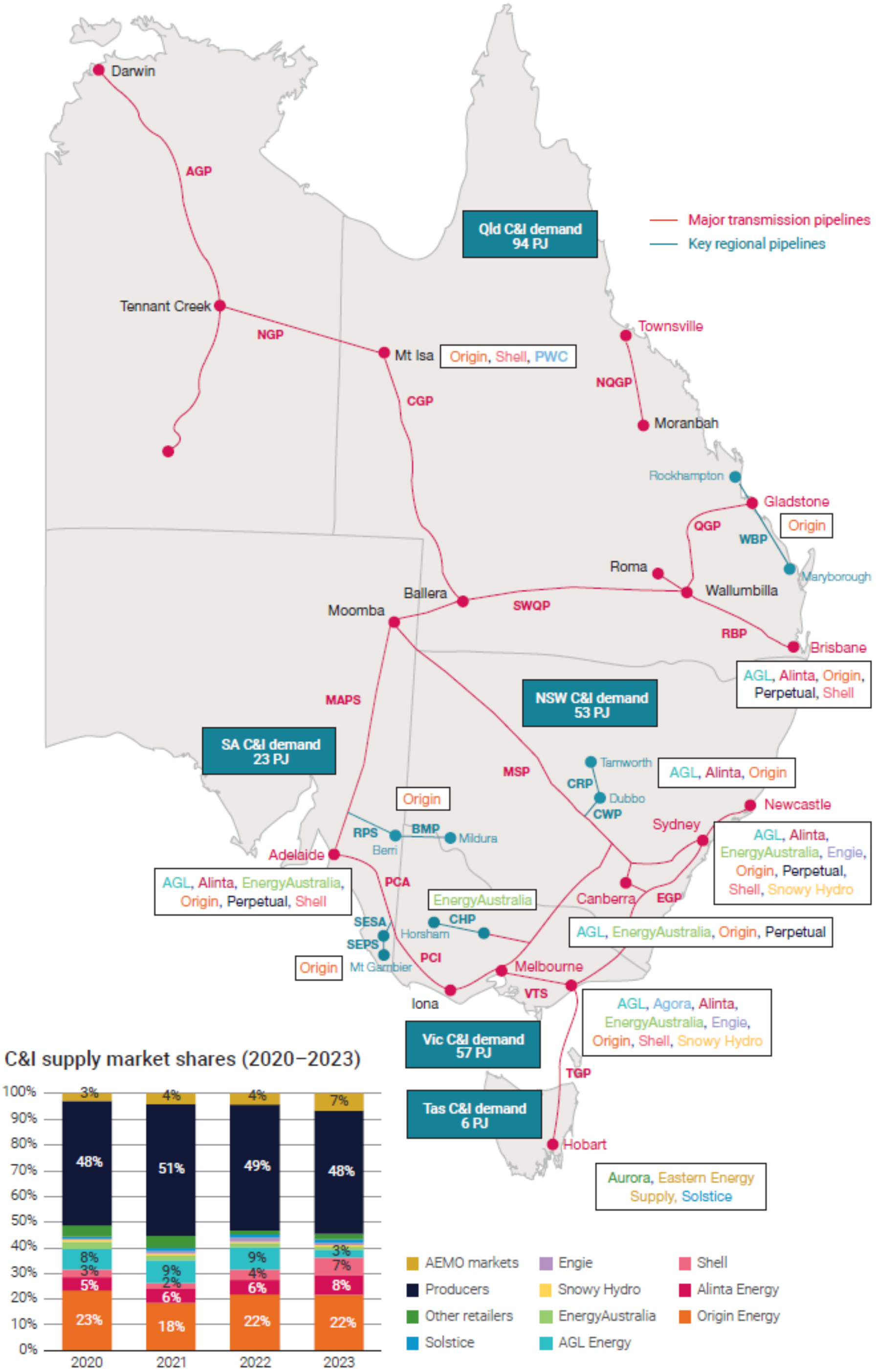
Setting this aside, it would appear from the new entry that has occurred in this market over the last 5–10 years that the barriers listed above are surmountable. The exception to this is in regional areas, where the following may also act as a barrier to entry:[56]

- constraints on access to regional pipelines that are fully contracted
- the size of the customer base, which may be too small in some regions to warrant entry given the additional fixed costs associated with supplying these areas.

[55] Farrier Swier & K Lowe Consulting, *Retailer Surveys*, 2015, AEMC, *2015 Retail Competition Review*, June 2015, AEMC *2016 Retail Competition Review*, June 2016, AEMC, *2017 Retail Competition Review*, July 2017, AEMC, *2018 Retail Competition Review*, June 2018 and AEMC, *2019 Retail Energy Competition Review*, June 2019.

[56] Farrier Swier Consulting & K Lowe Consulting, *AEMC Retail Competition Review: Retailer Surveys*, 2015, p 30.

Figure 4.2: Retailers supplying C&I users in the east coast in 2023[57]



Retailers currently supplying C&I users (excluding WA and NT)

		AGL	Agora Retail	Alinta	Aurora	Eastern Energy Supply+	Energy Australia	Engie	Origin	Perpetual Energy	PWC	Shell*	Snowy Hydro	Solstice**
Types of customers	Households-SME	✓	×	✓	✓	×	✓	✓	✓	×	×	✓ Powershop	✓	✓
	C&I	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Other large users^	✓	×	✓	×	×	✓	✓	✓	×	×	✓	✓	×
Vertical & Horizontal interests	Gas production	Small Qld interests	×	×	×	×	×	×	APLNG (27.5%)	×	×	QCLNG (73.75%) Walloons (75%) Arrow (50%)	×	×
	Other gas interests	Storage (Qld, NSW)	×	GPG linked pipeline	×	×	GPG linked pipeline	×	GPG linked pipeline	×	×	LNG linked pipelines	×	Tasmanian distribution network
	GPG	✓	×	✓	×	×	✓	✓	✓	×	×	✓	✓	×
	Electricity retail	✓	×	✓	✓	×	✓	✓	✓	×	×	✓	✓	✓

Sources: Market shares based on ACCC analysis of data provided by suppliers on gas supplied to C&I users and data from the AEMO markets on the gas procured by C&I users, or by intermediaries on behalf of C&I users. Other information based on: (a) ACCC analysis of retailer information; (b) AEMO, Gas Forecasting Data Portal, accessed October 2024; (c) ACCC, Decision under Emergency Price Order, 3 May 2023; (d) Shell Global, *Shell invests in Phase 2 of Surat Gas Project in Australia*, 12 August 2024, accessed October 2024.

There are some important differences between the retailers supplying C&I users, in terms of:

- the **size of their C&I customer base**, with some having a relatively large customer base, while others are much smaller
- the **locations they supply**, with some operating across multiple jurisdictions, while others operate in specific geographic or market areas, and some also operate in regional areas
- the **types of customers they supply**, with some only supplying C&I users, while others also supply residential, small to medium enterprises and/or other large gas users
- their **horizontal and/or vertical interests,** with most of the larger retailers having an interest in electricity retailing and GPG, while some also have interests in pipeline and/or storage infrastructure, or gas production (see box 4.3 for more detail).

Each retailer's access to gas, transportation and storage services (including under legacy or foundation contracts) also differs, as does their approach to:[58]

- gas procurement, with some retailers using a portfolio of gas supply, transport and storage contracts to supply new and existing customers, while others either enter into back-to-back arrangements with other suppliers (including other retailers) when they acquire new customers, or rely on the AEMO markets to supply their customers
- risk management, with some retailers taking more steps to hedge or otherwise shield customers from price, supply and/or demand risks, while others pass some or all of those risks directly through to C&I users.

The differences outlined above are important, because they can directly affect a retailer's ability to manage the costs, risks and challenges associated with supplying C&I users.

They can also affect an individual retailer's pricing and selling practices, and competitiveness. This point was made by C&I users and intermediaries in our 2023 engagement process, with a number noting that some retailers employed more customer-centric pricing and selling practices and were more accommodating than others.

57 Notes to figure 4.1:

- The locations reported in this figure are key locations only. A number of retailers also supply C&I users that are directly connected to transmission pipelines or via the Wallumbilla GSH.
- Regional pipeline names: SEPS (South East Pipeline System), RPS (Riverland Pipeline System), BMP (Berri to Mildura Pipeline), CHP (Carisbrook to Horsham Pipeline), CWP (Central West Pipeline), CRP (Central Ranges Pipeline), WBP (Wide Bay Pipeline).
- ^Other large users includes GPG and/or LNG producers.
- +Eastern Energy Supply commenced retailing in Tasmania in 2024.
- * The Shell Group wholly owns Shell Energy Australia Pty Ltd (SEAu), Shell Energy Retail Pty Ltd (SER), Powershop Pty Ltd, and has interests in QCLNG, Walloons and Arrow. SEAu and SER operate independently of any other interests of the Shell Group in Australia by means of a ring-fenced arrangement.
- ** Solstice Energy Holdings owns Solstice Energy Retail and Tas Gas Networks, which owns and operates the Tasmanian distribution network.

58 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, pp 96–97 and 102.

Box 4.3: Retailers' interests in gas production and legacy contracts

As part of this review, we have examined whether the interests some retailers have in gas production confer a competitive advantage on the retailer, but have found no evidence that this is the case. We have, for instance, found no evidence that these retailers are gaining better access to gas, or access on preferential terms.

This appears to largely be a result of the ring-fencing arrangements that have been put in place, which provide for varying levels of structural and operational separation and require or result in any GSAs entered into with the retailer to be on arm's length terms. The interests of other shareholders in a gas production joint venture may also operate to reinforce this. We have also found that the Gas Code may, in some instances, constrain the incentive retailers have to enter into GSAs with a related producer, because doing so could result in the retailer being subject to the Gas Code.[59]

While we have found no evidence that these interests are conferring an advantage on the retailers in question, we understand that some retailers have entered into long-term low-cost legacy GSAs that could be perceived to confer an advantage on those retailers.[60] It is also possible that foundation agreements entered into by retailers with pipeline owners and/or storage providers could give or could be perceived to give rise to such an advantage.

This point was made by a number of retailers, who noted that a retailer's access to such contracts may provide it with a competitive advantage. One retailer, for instance, noted that 'some of the large retailers have legacy contracts which allows them to be more competitive', while another noted that *'[the] inability to access legacy/foundation pipeline tariffs is always challenging'*.

While it is possible that these types of agreements may confer an advantage on a retailer, it is important to recognise that when entering into these agreements, retailers also take on a significant amount of demand and/or price risk, which may or may not pay off. This point was also made by a number of the retailers we spoke to, including those that do not have any such legacy or foundation contracts in place.

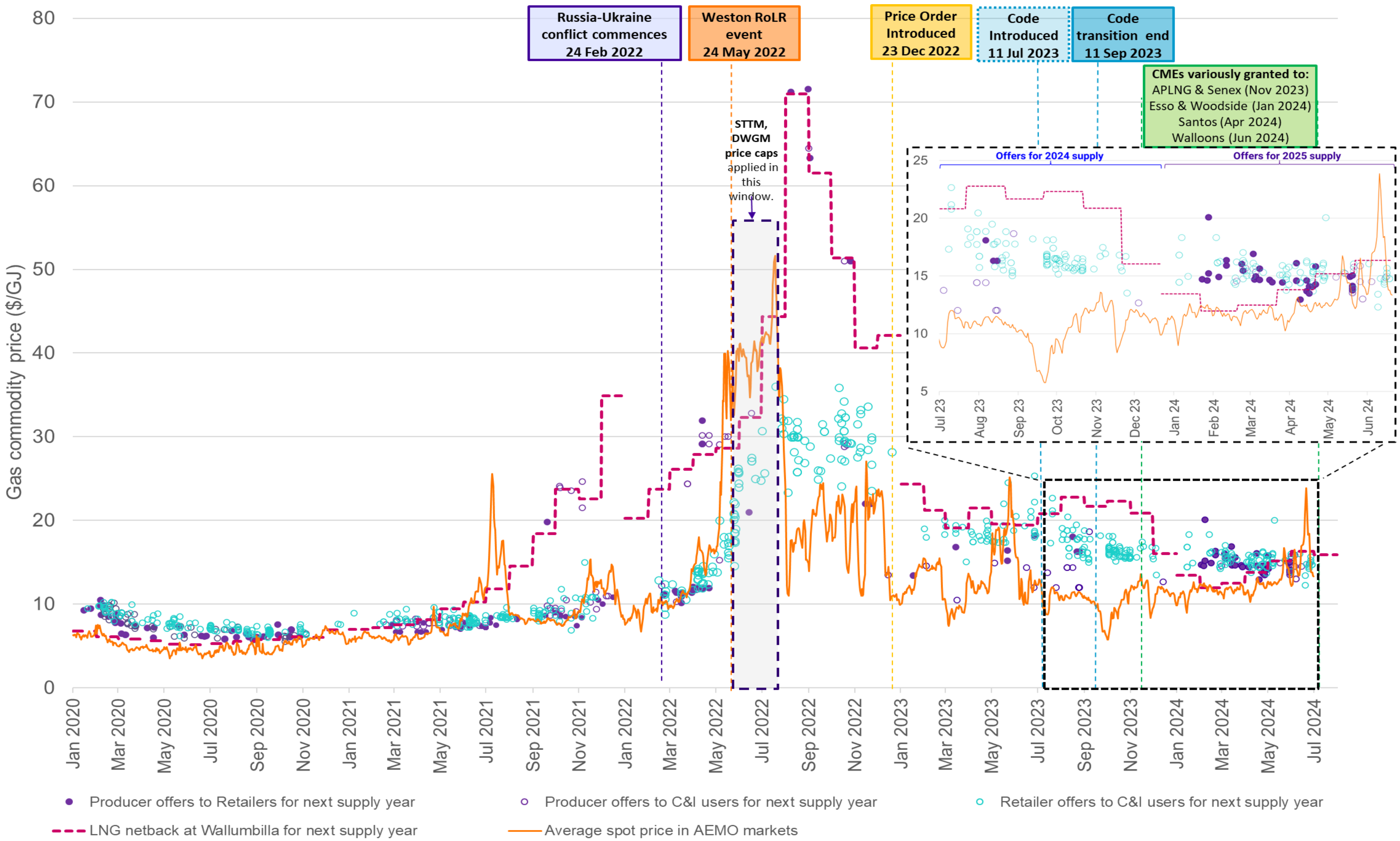
4.3. Market conditions have had a material impact on pricing & selling practices

As part of the review, we have considered the influence that market conditions may have had on retailers' pricing and selling practices over the period 2020–2024. Chart 4.1 provides some insight into the conditions that were prevailing over this period, while Appendix B provides a more detailed description of the conditions prevailing over this period.

59 This is because the Gas Code applies to covered suppliers, which is defined as a person that is an affiliate of a regulated gas producer that has entered into an agreement for the supply of gas by the regulated gas producer or another affiliate, which is not a mandatory government agreement.

60 See for example, ACCC, *Gas Inquiry 2017–2025 interim report*, January 2020.

Chart 4.1: Gas commodity prices offered in the east coast gas market between 2020–2024 for supply years 2021–2025



Sources: ICE, Argus, AER, ACCC analysis of offer information provided by suppliers.

Notes: Data includes offers made within 12 months of the commencement of the supply year. See Appendix A for additional notes relating to offers.
The average spot price has been calculated as the simple average of the Adelaide, Brisbane and Sydney STTM daily ex ante prices, DWGM daily imbalance price, and Wallumbilla day-ahead price.

As chart 4.1 and Appendix C show, the tight and volatile conditions prevailing in the market throughout 2022, together with the decision by producers to 'pause' contracting in response to the Emergency Price Cap and Gas Code development, posed significant challenges for both C&I users and retailers. They also appear to have had a material impact on retailers' pricing and selling practices, because they directly affected:

- retailers' ability to access sufficient gas, transport and storage at times during 2022 and 2023 (see section 4.4)
- the costs and risks retailers faced supplying C&I users over this period (see section 4.5)
- the ability of some retailers to compete over this period, with some retailers ceasing to market gas to C&I users for periods of time in 2022 (see section 4.6).

As one retailer described it, 2022 was a 'challenging year' due to a:[61]

> …"perfect storm" of events which included the outages in the NEM, Weston Energy failing as a retailer, and the high global gas and oil prices.

Similar sentiments were expressed by other retailers, all of whom referred to the effect that these events had on their ability to supply C&I users in 2022 and competition. Most retailers also commented on the significant challenges posed by the Weston RoLR event that occurred in May 2022,[62] with one retailer observing that:[63]

> … [the event] transferred a large pool of customers from the spot market to the portfolio of major retailers via retailer of last resort provisions. This left those retailers short and scrambling to cover their positions with gas supply. It subsequently increased demand on other retailers as those customers sought to recontract elsewhere on more competitive rates. As the market re-balanced, securing additional gas supply at short notice was challenging and this was further exacerbated as government interventions commenced and market liquidity reduced.

The difficulties experienced in 2022 continued into 2023, with most producers 'pausing' their contracting activities. The pause persisted for most of 2023 (chart 4.1) and, for some producers, appears to have extended into early 2024, as they awaited the outcome of their CME applications. Retailers described the conditions prevailing in 2023 as follows:

> Producers not pricing/selling during the introduction and implementation of the Gas Price Order and the Gas Market Code caused [us] to pause offering new contracts, and/or adding a risk premium, due to high market and operational risks to ensure physical supply to customers.
>
> The East Coast Gas Market continues to face a number of challenges including continued pressure on gas supply; lack of transparency around pricing; and concentration of market power in a small number of producers.

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61 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 106.

62 The Weston RoLR event was triggered following the suspension of Weston Energy from some of the AEMO operated markets. Weston Energy was suspended because it was unable to meet the STTM and DWGM prudential requirements. AEMO, *Short-Term Trading Market – Suspension Notice*, 23 May 2022 and AEMO, *Declared Wholesale Gas Market in Victoria – Suspension and Deregistration Notice*, 23 May 2022.

63 ACCC, *Gas Inquiry 2017-2030 Interim report*, December 2023, p 105.

Conditions in the market eased somewhat in the first half of 2024 as larger producers that had received a CME resumed making offers for supply in 2025–2026, as one retailer observed:

> Following announcements made by the Commonwealth Energy Minister relating to the issuing of Conditional Ministerial Exemptions to a range of producers, we observed an improvement in the availability of new supply offers.

The increased availability of gas, together with a softening of international and domestic prices, has enabled retailers to compete more effectively, with more offers made to C&I users and the gap between producer and retailer prices also narrowing (see sections 4.6–4.7). In our most recent engagement, several C&I users and intermediaries observed that there had been an increase in competition to supply C&I users in 2024.

4.4. Constraints on gas and infrastructure also appeared to affect pricing & selling practices

One of the more significant challenges that retailers have faced over the past 2–3 years is securing sufficient gas, transport and storage services to compete, both in terms of physical availability and availability at competitive prices. We have therefore considered the influence that this may have had on retailer pricing and/or selling practices over the period.

It would appear from our review that between 2020 and 2021, retailers were able to procure sufficient gas, transportation and storage services to meet their customers' demand. However, this started to change in 2022, with retailers noting they experienced considerable challenges procuring sufficient gas in the latter half of 2022 through to early 2024 given the conditions prevailing in the market over this period (see section 4.3). One retailer, for instance, noted that:

> Procuring gas was challenging:
>
> - During the aftermath of the Weston collapse when volatility/risks was high and market participants were cautious about selling, not knowing if the price would be even higher in the near future.
> - During the price cap period, when producers had no incentive to sell gas at a capped price when they could achieve a higher price by selling into the spot market
> - After the commencement of the Code of Conduct, as producers sought exemptions from the $12 price order and were not incentivised to sell until they had done this.

The constraints on access to gas that retailers experienced during this period included difficulties contracting gas from producers on both a short- and longer-term basis, and on the terms and conditions required to provide the flexibility required by C&I users (see section 3.5). The prices offered by producers to retailers over this period were also very high; so too were prices in the AEMO markets, which some retailers had to place greater reliance on (chart 4.1).

In addition to constraints on gas, some retailers noted that accessing firm capacity on southern haul pipelines was challenging in 2022 and 2023, given the increased demand to transport gas from Queensland south and the limited amount of uncontracted capacity. Some also told us there was little uncontracted capacity available at the Iona storage facility in this period.

The challenges experienced by retailers between mid-2022 and early-2024 appear to have resulted in retailers incurring higher costs and facing greater risks than they had in 2020 and 2021 (see section 4.5). They also appear to have contributed to the deterioration in competition that occurred over this period (see section 4.6 and some of the pricing and selling practices observed over this period (see sections 4.7–4.8). Some retailers, for instance, told us that the constraints on access to gas:

- limited their ability to sell gas at times, with some responding by ceasing to offer gas to new customers and/or limiting the term over which they could offer gas, and/or
- affected the prices they were able to offer at times in this period, with some responding by adding a premium to their prices, or by placing some C&I users on spot market-linked products until they could secure additional firm supply.

The difficulties retailers experienced procuring gas from producers over this period may have also contributed to the decision by some retailers to employ more compressed offer validity periods and/or to withdraw or amend offers in the offer validity period. They may have also posed a constraint on the ability of retailers to negotiate with C&I users, and other aspects of their selling practices in 2022 and 2023.

While market conditions appear to have improved in the first half of 2024, a number of retailers told us that it is becoming increasingly difficult to enter into longer-term GSAs with producers, with an increasing volume of gas being sold by producers on a short-term intra-year basis (see section 3.3).[64] Retailer GSA data confirms this point, with over 80% of the gas they have procured under GSAs since May 2022 having a contract term less than 1 year. Several retailers told us the increased prevalence of this form of producer contracting was making it very difficult and costly to operate, with one noting that 'you can't build a retail book on this basis'.[65]

4.5. Escalating costs & risks affected pricing and selling practices

The conditions prevailing in the east coast gas market between 2022 and early 2024 had a significant impact on retailers' costs and risks (see Appendix D for more detail on the costs and risks retailers face in supply C&I users). We have therefore considered the influence that this may have had on their pricing and selling practices over the period.

In summary, we have found that the costs retailers incurred in supplying C&I users increased significantly in 2022 and have remained high. This was principally driven by escalating gas commodity costs and constraints on access to gas between 2022 and early 2024, which also increased retailers' risk exposure.

The higher costs and risks faced by retailers over this period appear to have had a directly impact on retailers' pricing practices. They also appear to have contributed to the deterioration in some retailers' selling practices within this period (see sections 4.7–4.8).

4.5.1. The cost of supplying C&I users has increased significantly, driven by escalating commodity costs

To get a better understanding of how retailers' costs changed over the period and the influence this may have had on their pricing and selling practices, we collected information

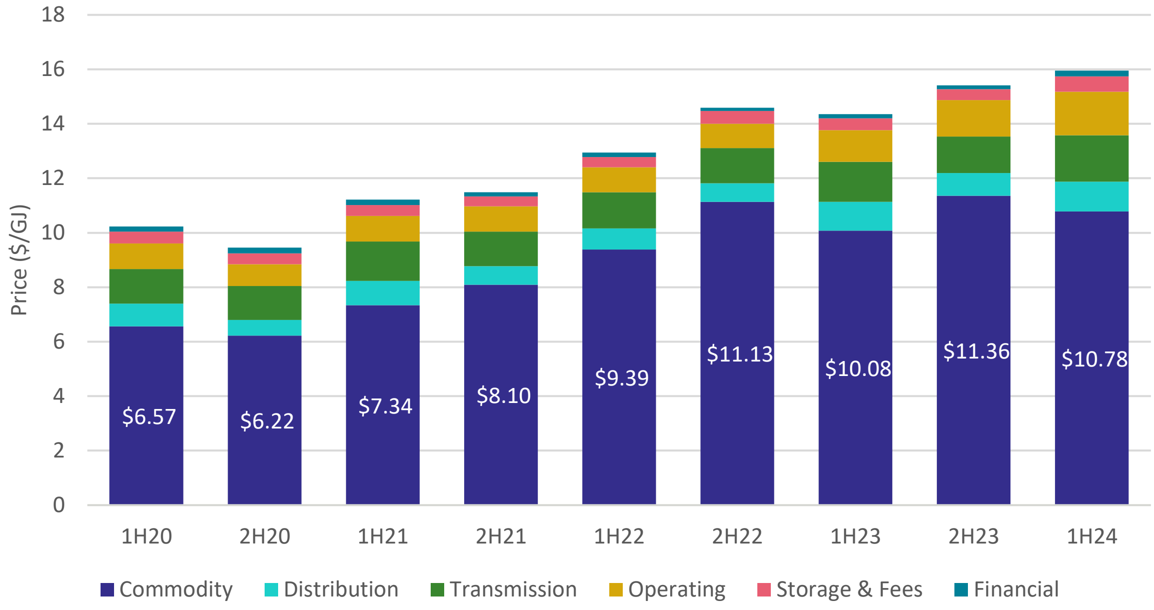
64 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 110.

65 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 110.

on the costs incurred by AGL, Alinta, EnergyAustralia, Origin and Shell in supplying C&I users between 2020 and the first half of 2024.

We used this information to generate the cost stacks set out in chart 4.2.[66] The individual cost components presented in this chart represent the direct costs to retailers of supplying gas to C&I users, which are reported on a cumulative, volume weighted average basis for the 5 retailers we obtained information from. Further detail on how the cost stacks were estimated can be found in Appendix E.

Chart 4.2: Costs incurred by retailers supplying C&I users (Jan 2020 – Jun 2024)



Source: ACCC analysis of data provided by retailers on their costs incurred in supplying C&I users.

Notes: The cost categories in this chart encompass the following:

(a) Commodity costs include the cost of procuring gas from producers or other suppliers under GSAs, the cost of procuring gas in AEMO markets (i.e. the STTM, DWGM and GSH) and gas commodity price related hedging costs.

(b) Distribution costs include the costs of procuring distribution services for C&I users located within distribution networks.

(c) Transmission costs include the cost of procuring transmission services from pipelines, or secondary capacity.

(d) Operating costs include the costs associated with customer acquisition & retention, financial & other costs, as well as regulatory compliance.

(e) Storage and AEMO fees include the costs of procuring storage, where required and the costs associated with accessing AEMO-operated markets.

(f) Financial costs include the costs associated with depreciation and amortisation.

Some fluctuations between half-yearly periods may result from seasonality effects.

As chart 4.2 shows, the total costs of supplying gas to C&I users increased from just over $10/GJ in the first half of 2020 to around $16/GJ in the first half of 2024. This represents an average increase in costs of 56% (~$5.72/GJ), most of which occurred in 2022 and 2023.

While all the cost components in this chart increased over the period, the majority of the increase can be attributed to the escalation in commodity costs that occurred in 2022 and 2023. Commodity costs increased by an average of $4.22/GJ (~74% of the total increase) from around $6.60/GJ in the first half of 2020, to around $10.80/GJ in the first half of 2024,

66 The 'cost stack' framework we have used for this analysis is similar to that used in our 2019 review of retailer pricing, with main difference being that in 2019 we examined costs on a jurisdictional basis, while in this review we have examined costs on a whole of east coast basis. Further detail on the framework we used in 2019 can be found in ACCC, Gas Inquiry 2017–2020, July 2019, chapter 4.

peaking at around $11.40/GJ in the second half of 2023. The other cost components, on the other hand, increased by just $0.03–0.66/GJ over the period.

The increase in commodity costs over this period reflects the higher prices that retailers had to pay for gas procured under:

- **Existing GSAs with a JKM, Brent crude oil or AEMO market linkage**. Prices in JKM linked GSAs, for instance, were 2–3 times higher in 2022 than they were in 2021, while prices in Brent crude oil linked GSAs were around 40% higher. Prices in AEMO market-linked GSAs also increased significantly in 2022 (chart 4.1). While the prices in these types of GSAs subsided somewhat in 2023, they remained higher than they were in 2021.
- **New GSAs entered into with producers and other suppliers with a supply term of 3 or more months**. Prices in these GSAs ranged from $11.50 to $26.30/GJ between mid-2022 and the end of 2023 for supply in 2024. Since the Gas Code was implemented, prices in retailer GSAs with producers ranged from around $11.75 to $14.50/GJ (volume weighted average $12.80/GJ) for 2024 supply.[67]

The increase in commodity costs over this period also reflects the increased reliance that some retailers had to place on the AEMO markets in the latter half of 2022 and in 2023, given the limited amount of gas being offered by producers under contract. Over this period, the average AEMO market price ranged from $5.80 to $50.70/GJ (chart 4.1).[68]

4.5.2. Retailers appear to have faced a challenging risk environment

Retailers can face a range of supply, demand, infrastructure, pricing, market and regulatory risks when supplying gas (see Appendix E for more detail). As discussed further in box 4.4, the events of 2022 and 2023, together with the constraints on access to gas and infrastructure, appear to have contributed to a significant increase in risks faced by retailers.

Some retailers responded to the increased risk by temporarily ceasing to market gas to new C&I users (see section 4.6). Several also told us that they tried to manage the supply and pricing risks in this period by placing some C&I users on spot market-linked products and/or adding a risk premium to their prices in the latter half of 2022 and into 2023, as the following statements highlight:

> During the relevant period, and in particular from mid to late 2022, [we] took on more risk when entering into contracts with C&I customers due to the uncertainty around [our] ability to procure upstream Gas from Other Suppliers, which had a flow on impact on pricing through increased risk premiums.
>
> …supply / demand conditions remained relatively tight following the volatile winter 2022 period, and [we] observed a general reduction in supply offers from producers following the announcement of the Price Order and impending Gas Market Cod[e] in December 2022. This created uncertainty around the extent to which we may be able to access additional short-term purchases if necessary to manage our portfolio and contributed to [our] decision to apply the following approach.
>
> - From around November 2022 to February 2023, [we] briefly paused the marketing of gas to new Commercial and Industrial Customers.

67 The prices quoted in this paragraph are based on all the GSAs retailers entered into with a term of 3 months or more. It differs from the analysis of prices in chapters 2–3, which is limited to GSAs with a term of 12 months or more.

68 The average spot price has been calculated as the simple average of the Adelaide, Brisbane and Sydney STTM daily ex ante prices, the DWGM daily imbalance price, and Wallumbilla day-ahead price.

- Over a similar period, [we] continued to Offer fixed pricing…to existing small Customers, but only spot linked pricing…to existing large Customers, as an alternative to default contract rates being applied.

It also resulted in an initial uplift in Offer prices to account for the increased supply risk we faced in recontracting Customers during that period of uncertainty.

The increased risk exposure may have also contributed to some of the selling practices observed in this period, including the compressed offer validity periods, withdrawal and amendment of offers that reportedly occurred between mid-2022 and first half of 2023 (see section 4.8).

Box 4.4: Additional risks faced by retailers between 2022 and early 2024

Supply and pricing risks, and regulatory uncertainty

A period of uncertainty followed the introduction of the Emergency Price Order in December 2022, which continued through the development of the Gas Code and the CME process. With most producers 'pausing' contracting in response to these measures, retailers became more exposed to supply risks. That is, the risk of not being able to secure sufficient volumes of gas to meet their customer's demand.

Some retailers responded to this risk by ceasing to make offers for a period, while others employed other strategies to minimise their exposure. For those that continued to make offers, many did so without certainty as to their ability to procure the gas required to meet those commitments, or the price that they would have to pay for that gas.

Retailers have told us that ongoing uncertainty about the future regulatory outlook for the market (including as a result of the upcoming Gas Code review) continues to pose a risk.

Mismatches in contracts and exposure to market movements

A significant portion of the contracts between producers and retailers are commodity linked (i.e. tied to Brent crude oil or JKM), whereas contracts between retailers and C&I users are predominantly fixed price. This gives rise to a risk exposure that retailers must manage (see section 4.6). While this risk can be hedged, retailers told us it was more challenging to do so over the period. One retailer, for instance, noted that:

> Hedging JKM and Brent / oil risk was challenging over the Relevant Period, as increased volatility in domestic and global Gas markets meant that many… counterparts temporarily or permanently withdrew from the market, and hence stopped quoting prices…

Compounding effects of greater volatility on retailers' operations

The timing of contracting between producers and retailers is often not aligned with those between retailers and C&I users. This creates exposure for retailers to movements in the gas price over time and requires them to forecast and manage volumes, a matter that became increasingly difficult with the greater volatility in markets from 2022.

Volatility in the operating environment also resulted in an increase in risk exposure. For example, credit risk and bad debts from C&I users increased from 2022 to 2024.

4.6. Changes in competition also appear to have influenced pricing and selling practices

In addition to the factors set out above, we have considered the influence that competition has had on retailer pricing and selling practices over the period.

In summary, we found that competition has been an important driver of innovation in pricing and selling practices over the period. We also found that the deterioration in competition that occurred in 2022–2023 likely contributed to higher retail prices and some of the selling practices observed over this period.

While competition has since improved, the events of 2022–2023 highlighted the fragility of competition in this part of the market and its susceptibility to upstream conditions. It also highlighted the potential for competition to deteriorate again in the future, with retailing expected to become more challenging through the energy transition, particularly given the projected supply shortfalls.

4.6.1. New entry has helped to drive competition and innovation in pricing and selling practices

As outlined in section 4.2, retailers supplying C&I users face competition from other retailers in most locations in the east coast (figure 4.2) and, in the case of larger C&I users, can also face competition from producers and the AEMO markets.

Over the past 5–10 years, the number of retailers competing to supply C&I users has increased, with several retailers entering and expanding over this period, including:

- Alinta and Shell, both of whom have built up a sizable customer base and market share over the period, becoming the second and third largest retailers supplying C&I users in 2023, respectively (figure 4.2).
- PWC, who started supplying C&I users in the Mt Isa region in 2019 following the construction of the Northern Gas Pipeline.
- Weston Energy, who appeared to build up a sizable C&I customer base while it was operational, but then exited in May 2022 as market conditions became more volatile.
- Agora Retail and Perpetual Energy, both of whom are more recent entrants and are in the process of building up a customer base.

The new entry and expansion that has occurred over this period appears to have provided a greater level of competitive tension in the market and posed more of a constraint on the prices retailers were able to offer C&I users. This was reflected in retailer documents we reviewed, with a number of documents referring to the prices being offered by competing retailers in 2022 and 2023, and noting they had to adjust their offers down in response to that competition.

New entry over this period has also driven some innovation in pricing and selling practices. For example, some newer entrant retailers have introduced fixed price products without CPI escalation or measures to reduce take or pay obligations, which some other retailers have now also introduced.

While new entry and competition in this part of the market has benefited *most* C&I users, there have, as the following sections highlight, been periods over the last 4 years where competition has not been as effective.

We emphasise the term 'most' because there are some locations in the east coast where there is only one retailer supplying gas to C&I users. This includes the Mt Gambier and Riverland areas in South Australia, Wide Bay area in Queensland and Carisbrook to Horsham area in Victoria (figure 4.2). In some cases this may be because a retailer has contracted all, or a substantial portion, of the pipeline capacity used to supply the region (see section 4.2).[69]

4.6.2. Competition to supply C&I users deteriorated in 2022–2023, but has since improved

Competition to supply C&I users was reportedly relatively strong in 2020 and 2021. However, this started to change in 2022, with Weston exiting in May 2022 and Engie also deciding to exit as part of its global Environmental, Social and Governance (ESG) strategy and to cease making offers to new C&I customers.

Retailers also told us that the Weston RoLR event, coupled with the difficulties they experienced procuring gas in the latter half of 2022, led to a reduction in competition, with some retailers ceasing to offer gas to new C&I customers at times over this period to ensure they could continue to supply existing customers. One retailer, for instance, noted:

> …we found it incredibly challenging to compete post 2022 ROLR event because we did not have access to upstream gas.

The deterioration in competition to supply C&I users continued into 2023, driven largely by the 'pause' in producer contracting, with several retailers telling us they had to temporarily cease offering gas to C&I users at times over the first half of 2023 given the difficulties they experienced procuring gas. There were therefore times in the first half of 2023 where there may have been just 2–3 retailers competing to supply C&I users.

The reduction in competition between retailers over this period appears to have contributed to the higher retail prices and some of the selling practices observed over this period (sections 4.7–4.8), as one retailer observed:[70]

> For periods during FY2023 there was no competition in the east coast gas market… the gas market has been challenging and uncompetitive for C&I users.

Competition from producers to supply larger C&I users was also quite limited in 2022–2023 (chart 4.1) and while some of these users were able to have recourse to the AEMO markets, this was not an option for smaller C&I users. These C&I users were therefore more exposed to the less favourable prices, and terms and conditions of supply offered by those retailers that remained active over this period.

Competition to supply C&I users started to improve in the latter part of 2023 and into 2024, with retailers and producers becoming more active in the market following the introduction of the Gas Code and, in the case of some producers, following the granting of CMEs. Retailers, for instance, told us that competition improved once producers obtained exemptions from the Gas Code and started to offer more gas to the market:

> ... the market in 2024 has returned to previous competitive levels because upstream supply has returned after some supply issues arising as a result of the Gas Market Code have been resolved through the exemption process...

The increase in the amount of gas being offered by producers into the market, together with the easing of international and domestic prices and the increase in competition to supply

[69] ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 102.

[70] ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 111.

C&I users, appears to have contributed to the reduction in prices in the first half of 2024 (see section 4.7) and improvement in retailer selling practices (see section 4.8).

C&I users and intermediaries observed a moderation in prices over this period compared to the highs reached in 2022. A number also observed an improvement in the terms and conditions being offered by some retailers and an increase in competition to supply C&I users in 2024. Several retailers that we spoke to in late-2024 also commented on the increased strength of competition to supply C&I users in 2024, with a newer entrant describing it as *'…aggressively competitive'*.

4.6.3. Retailing to C&I users is expected to become more challenging in the future, which could affect competition

Looking forward, many retailers told us they expect it to become increasingly challenging to supply C&I users. In doing so, they pointed to the following:

- difficulties securing access to sufficient gas, transportation and/or storage services on competitive terms, particularly given the projected supply shortfalls
- the uncertainty surrounding the pace of the energy transition, particularly for those C&I users for whom there is currently no viable alternative to gas
- continued regulatory and policy uncertainty and the risks associated with further government intervention, which some retailers noted could affect the willingness of producers to invest in new supply and exacerbate supply pressures
- the potential for more volatile market conditions to trigger another RoLR event
- retailer ESG pressures.

Some retailers noted the potential for one or more of these factors to result in them temporarily or permanently ceasing to supply to C&I users. One retailer, for instance, noted:

> [Our] ability to source gas supply and haulage are the key factors that would lead [us] to permanently cease supplying gas to C&I customers. Increased regulatory burden may also impact [our] appetite to supply gas to C&I customers.

Another noted the potential for another RoLR event to trigger its exit:

> …another significant ROLR event will cause supply issues. In this instance [we] could be forced to permanently cease supplying C&I users because we do not have the gas to supply these customers.

It is also possible that ESG pressures may prompt some retailers to cease supplying gas to any type of customer, while some of the other factors listed above may prompt retailers to focus on more profitable parts of the market, particularly if there are constraints on access to gas. Our prior analysis of retail margins revealed that alternative uses of gas, such as residential supply, can yield higher margins in dollar terms.[71]

The majority of retailers told us they expect it to become increasingly challenging to supply C&I users in the south, given the projected decline in production from Longford and the need for further investment, which some noted is becoming more difficult to underwrite (see chapter 6). As a number of retailers observed, the gap left by Longford will need to be met by gas supplied from either Queensland or an LNG import terminal, both of which are likely to give rise to higher prices and risks, and could affect the competitiveness of some retailers:

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[71] ACCC, *Gas Inquiry 2017–2025 Interim report*, January 2020, p 119.

> The expected seasonal shortfalls and annual supply gap…will make it increasingly difficult to purchase gas at prices that customers will willingly accept.
>
> Forecasted gas shortages after 2028 will likely restrict supply options, driving up prices and limiting flexibility...These factors will significantly impact [our] ability to provide competitive and reliable services in the future.
>
> In the future [we] may experience further difficulties procuring sufficient gas to support a competitive C&I portfolio...[We] will struggle to buy gas in a market forecast to be in shortfall.

As the preceding discussion highlights, it is possible that competition could deteriorate again in the future, particularly if the volatility and supply uncertainty experienced in 2022 and 2023 are repeated.

4.7. Retail prices escalated in 2022 and 2023, driven by changed market fundamentals

Over the course of the Inquiry, C&I users and intermediaries have expressed concerns about some aspects of retailers' pricing practices. These concerns intensified in 2022 and 2023, with a large number of C&I users and intermediaries questioning both the level of retail prices over this period and whether retailers were passing through any changes in their gas costs, including as a result of the Emergency Price Order and/or the Gas Code. Questions were also raised about whether retailers' prices are higher in regions supplied by a single retailer.

We have therefore undertaken a detailed review of retailers' pricing practices over the period 2020–2024. In doing so, we have examined the factors retailers consider when setting C&I user prices, retailers' pricing strategies and the prices C&I users were charged in this period.

In summary, we have found that the events of 2022 and 2023 had a significant influence on retailers' prices over the period, with the average prices paid by C&I users to retailers in aggregate increasing by over 90% between 2022 and 2023. This increase, as discussed in further detail in section 3.2, has had a material impact on C&I users, with many having to implement a range of measures to try and offset the impact of higher gas prices, including in some cases, scaling down their operations or closing.

While the price increases over this period have been significant, it would appear from our review that retailers' prices were generally in line with what we would expect given international prices and domestic supply-demand dynamics prevailing over this period. The prices over this period also appear to be in line with the costs retailers incurred procuring additional gas to supply their customers and the risks they faced in this period.

As market conditions started to stabilise in late 2023 and early 2024, retail prices have fallen and the gap between producer and retailer prices has narrowed. While retail prices are higher than their levels in 2020 and 2021, they appear to be broadly consistent with the prices retailers are paying producers for gas (which are also higher than they were in 2020–2021) and the underlying market fundamentals.

In regional areas where there is a single retailer operating, we have found the gas commodity price paid by C&I users to be broadly in line with what C&I users are paying in metropolitan areas where there is more competition, but the overall delivered price in these areas may be higher once transportation and other costs are taken into account.

4.7.1. Retailers consider a range of dynamic factors when determining prices and pricing strategies

Retailers consider actual costs, opportunity costs and competitor prices when determining C&I user prices

Retailers told us that when determining C&I user prices, they principally have regard to:

- The **actual costs** incurred in supplying gas to the C&I user, which include the costs of procuring gas, transport and storage services, as well as operating and financial costs.
- The **opportunity** costs associated with supplying the C&I user, which reflects the next highest value the retailers could obtain from other uses of the gas. This could include supply to LNG producers, supply to either their own or another party's GPG, supply into the AEMO markets, or supply to their residential and SME customers.
- Their **competitors' prices**, which for larger C&I users may include the prices producers are offering.

Retailers, for instance, told us that the gas supply component of their C&I user prices is typically based on **a forward-looking market value of gas** at the time they enter the contract (representing the opportunity cost of supplying gas), which they estimate having regard to:

- a number of pricing indicators (i.e. LNG netback, AEMO market prices, NEM prices, ICAP and ASX futures prices)
- feedback from customers.

Most C&I users are on fixed price contracts, but an increasing volume of gas is being sold under spot market-linked products

Between 2020 and 2023, over 98% of retailers' C&I customers were subject to fixed prices (with or without CPI escalation) with the remaining 2% subject to either an AEMO spot market linked price, or a Brent oil linked price. Although the percentage of customers on a spot market-linked product is small, we understand that the volume of gas being supplied to C&I users under such products has increased. One retailer, for instance, noted that approximately 10–15% of its C&I demand in 2023 was on a spot market linked product, which has grown from below 5% at the beginning of 2022.

As noted in section 4.5.2, the use of fixed price mechanisms in C&I contracts can be a source of risk for those retailers that have Brent oil or JKM linked GSAs with producers and other suppliers. While retailers can enter into hedging arrangements to manage pricing risk, there are costs associated with doing so. Holding all else constant, the prices retailers offer C&I users are therefore likely to be higher than producer offers linked to Brent oil or JKM, for a given quantity of gas.

Retailers amended their pricing strategies in mid-2022 and early 2023 in response to the increased gas supply and pricing risks

Many retailers also told us that their approach to setting prices changed around mid-2022 and into early 2023, in response to the risks associated with procuring sufficient gas at competitive prices (see section 4.4). As outlined in section 4.6, some retailers responded to this supply and price risk by temporarily ceasing to make offers. Others responded by changing the way they set prices, with some:

- adding a supply risk premium to their prices during this period, and/or

- changing the pricing mechanisms offered to C&I users, with some larger C&I users placed on spot market linked products during this period.

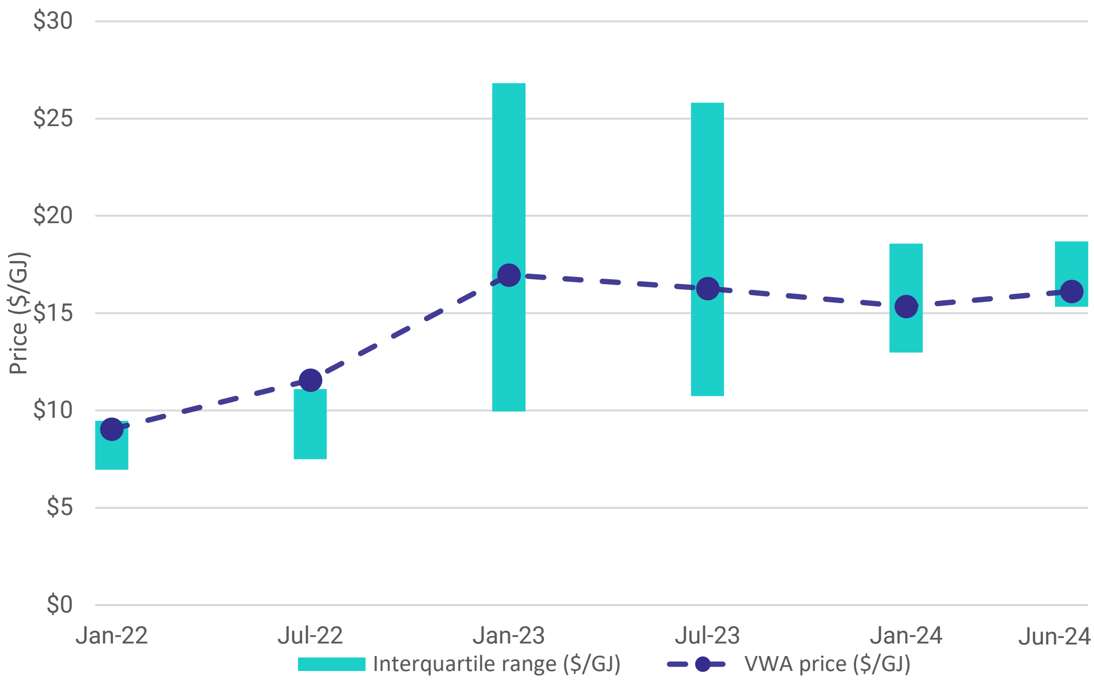
Looking forward, one retailer noted that if more gas has to be sourced from Queensland, it may have implications for the retailer's pricing strategies. While the retailer did not elaborate on the potential changes, it could conceivably result in LNG netback prices and the cost of southern haul transportation having more of an influence on prices in the south.

4.7.2. Retail prices increased significantly in 2022 and 2023, but have moderated

The average invoiced gas commodity price paid by C&I users to retailers increased by 90% between 2022 and 2023, but has since moderated

Chart 4.3, which is based on invoice data provided by retailers, shows the volume weighted average price that C&I users consuming 10 TJ p.a. or more of gas actually paid retailers for the gas commodity between January 2022 and June 2024. We note that the data used to prepare this chart differs from the GSA data we usually use when reporting on prices, because it is based on prices C&I users actually paid in the period, rather than prices agreed to in new GSAs. The annual consumption threshold used for the invoice data is also much lower than the 0.5 PJ p.a. threshold we usually use (see Appendix A).

Chart 4.3: Commodity prices paid by C&I users consuming ≥ 10 TJ p.a. (2022 – mid-2024)



Source: Gas commodity charge retailers invoiced to C&I customers issued between January 2022 and June 2024.

Notes: The interquartile range is the range between the 25th and 75th percentile price.

As chart 4.3 shows, the average price paid by C&I users to retailers for gas commodity increased from around $9 to $17/GJ (~90%) between January 2022 and January 2023, but then moderated over the remainder of 2023, reaching around $16/GJ in mid-2024. While lower than the peaks observed in 2023, the average price paid by C&I users for gas in mid-2024 was still around 80% higher than the prices being paid at the beginning of 2022 (that is, before market conditions deteriorated).

Another important point to note from this chart is the degree of variation in prices actually paid by C&I users over this period, as reflected by the interquartile range. As those ranges highlight, some C&I users were paying as much as $27/GJ in 2023, while others were paying $10/GJ in the same period. This variability had reduced by 2024, with the interquartile range around the volume weighted average price narrowing to $3/GJ by mid-2024.

The variability is not surprising given how tight and volatile market conditions were throughout 2022 and 2023. The variability between July 2022 and January 2023 also likely reflects the fact that some of Weston's customers were placed on the designated retailer's standing (default) contracts when the RoLR event occurred, as one C&I user noted:[72]

> …we went onto a default contract at close to 3 times plus the average cost per GJ we were paying and we haven't recovered…[we are] still paying in the high $20's.

One of the limitations with the invoice data is that it reflects the prices C&I users and retailers had agreed to under both older and newer GSAs. The average invoice price reported for January 2023, for instance, is likely to be lower than the prices retailers were offering C&I users around this time, because it would reflect prices agreed to in 2020 and 2021, when market conditions were better. Similarly, the average invoice price in June 2024 is likely to be higher than the prices retailers were offering around this time, because it likely includes prices that were agreed to in 2022 and 2023, when market conditions were tight and volatile.

To overcome this limitation, we have also examined the prices that retailers offered to C&I users and agreed to in GSAs over the period (see next section). Unlike the invoice data, we only obtained this data for larger C&I users consuming 0.5 PJ p.a. or more. It would appear, however, from our analysis that there is very little difference between the prices payable by larger and smaller C&I users.[73]

The prices retailers offered C&I users over the period reflected the prevailing market fundamentals

Chart 4.1 shows the prices offered by retailers to larger C&I users since 2020. It shows that in 2020 and for much of 2021, retailer offers were broadly in line with the prices being offered by producers, ranging between $6–$10/GJ for supply years 2021 and 2022.

Retailers offer prices started to increase in late 2021, reaching around $12–$13/GJ for 2023 supply just before the Russia-Ukraine conflict commenced. They then escalated to around $36/GJ in the wake of the Weston RoLR event. While high, the prices offered by retailers in 2022 for 2023 supply were lower than:

- the expected 2023 LNG netback price, which peaked at over $70/GJ in October 2022, before falling to $40/GJ in December 2022
- the prices offered by most producers for 2023 supply, which ranged from $13.50/GJ to $71.50/GJ (with half the offers exceeding $50/GJ).

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72 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 104.

73 Specifically, we found that for smaller C&I users consuming less than 500 TJ p.a., contracted quantities do not appear to have a material or consistent effect on the gas commodity prices retailers charge C&I users. For larger C&I users consuming 500 TJ p.a. or more, the prices charged by retailers appear to be marginally lower than those charged to smaller C&I users, although the difference is small. This finding is consistent with what a number of retailers told us, which is that they may apply a discount to larger C&I users. There are a number of potential reasons for this difference, including larger C&I users have other supply options, so competition may pose more of a constraint on these prices and the potential for retailers to achieve greater economies of scale supplying larger volumes.

Although retailer offers moderated somewhat in 2023, they have remained high, ranging from $13-$25/GJ for 2024 supply. The prices offered by retailers for most of 2023 were:

- lower than the expected 2024 LNG netback price at Wallumbilla for most of 2023, which ranged from $16–$24/GJ
- higher than the prices offered by most producers over this period, which ranged from $10.50–$18.70/GJ.

While the difference between retailer and producer offers grew in 2023, it is important to recognise that there was very little gas actually offered by producers in 2023 and retailers were facing escalating commodity costs, as well as significant gas supply and pricing risks. As noted in sections 0–4.5, this directly affected the prices retailers could offer in 2023.

As more gas has become available in the domestic market in the first half of 2024, retailer offer prices have fallen, ranging from $12.30–$20/GJ for 2025 supply. The offers made by retailers over this period have at times been higher than the expected 2025 LNG netback price, which ranged from $13.50–$16.30/GJ. However, they have been broadly in line with those offered by producers, which ranged from $13–$20/GJ.

This can be seen more clearly in chart 4.1, which shows that there is now very little difference between producer and retailer offers and, in some instances, retailer offers have been lower than producer offers. This is despite the fact that retailers can face greater costs and risks when supplying C&I users. For example:

- some producers sell gas on a Brent or JKM linked basis, whereas retailers tend to sell gas on a fixed price basis, which can give rise to additional costs and risks for the retailer
- most producers sell gas on an ex-plant basis, while retailers tend to sell on a delivered basis, which can give rise to additional risks for the retailer
- a large number of GSAs entered into by producers over the past 24 months have been for supply in Queensland, while most retailer GSAs are for supply in the south, which can give rise to additional costs and risks for retailers.

The trend in retailer offers outlined above is broadly consistent with what has occurred with GSAs entered into over this period. This can be seen in table 4.1, which shows the range of prices agreed to in GSAs entered into by retailers and larger C&I users between 2020 and mid-2024 for supply years 2021–2025. It also shows the range of prices agreed to in producer GSAs over this period.

As it shows, the prices agreed to in GSAs entered into by retailers increased significantly, with the volume weighted average price increasing from around $7/GJ in 2020 (for 2021 supply) to over $19/GJ in 2022 (for 2023 supply). These prices softened somewhat in 2023 to around $17.50/GJ (for 2024 supply), before moderating further in the first half of 2024 to around $14.70/GJ (for 2025 supply).

The path that retailer GSA prices took over this period was broadly in line with the path that producer GSA prices took over much of this period, and while there were periods where retailer prices were materially higher than producer prices, this appears to largely be a timing issue. For example, in 2022 most of the gas sold by producers for 2023 supply was sold prior to the commencement of the Russia-Ukraine conflict and Weston RoLR event, while most of the retailer GSAs were entered into after this when market prices were much higher.

In a similar manner to offers, table 4.1 shows that the difference between retailer and producer prices has reduced with more recent average prices for retailer GSAs now below producer GSAs for 2025 supply.

Table 4.1: Gas commodity prices in GSAs entered into between 2020 and mid-2024

Year GSA entered	Supply year	Statistics	Retailer GSAs with C&I users ≥ 0.5 PJ p.a.	Producer GSAs with C&I users and retailers
2020	2021	VWA	$7.24/GJ	$7.51/GJ
		Range	$5.99–$8.64/GJ	$5.75–$9.73/GJ
		ACQ (no. of contracts)	9.84 PJ (16)	134.70 PJ (19)
2021	2022	VWA	$9.79/GJ	$9.04/GJ
		Range	$7.45–$14.73/GJ	$6.45–$14.24/GJ
		ACQ (no. of contracts)	18.53 PJ (17)	66.96 PJ (26)
2022	2023	VWA	$19.18/GJ	$12.35/GJ
		Range	$10.38–$30.29/GJ	$10.15–$29.00
		ACQ (no. of contracts)	17.99 PJ (18)	43.55 PJ (12)
2023	2024	VWA	$17.47/GJ	$15.63/GJ^
		Range	$15.62–$19.83/GJ	$10.42–$18.93/GJ
		ACQ (no. of contracts)	12.52 PJ (14)	27.85 PJ (10)
First half 2024	2025	VWA	$14.70/GJ	$15.24/GJ
		Range	$13.31–$15.24/GJ	$12.95–$16.28/GJ
		ACQ (no. of contracts)	2.11 PJ (4)	26.32 PJ (8)

Notes: This table shows GSAs entered into by C&I users consuming ≥0.5 PJ pa and with a supply term of 1 year and above. The same inclusion criteria used in chapter 2 applies. The prices displayed in this table differ from the prices presented in chart 3.1 because this table only includes producer GSAs with retailers and C&I users, and retailer GSAs with C&I; both of which are a subset of what is presented in chart 3.1.

^ The volume weighted average price includes a number of contracts that were made as part of a CME supply commitment.

In summary, the events of 2022 and 2023 appear to have had a significant influence on retailers' prices over the period. While the price increases over this period have been considerable, our review suggests that retailers' prices were generally in line with what we would expect given international prices and domestic supply-demand dynamics prevailing over this period. As discussed further in the next section, they also appear to have been broadly in line with their costs and risks.

4.7.3. Retailer prices appear to have been broadly in line with their costs and risks

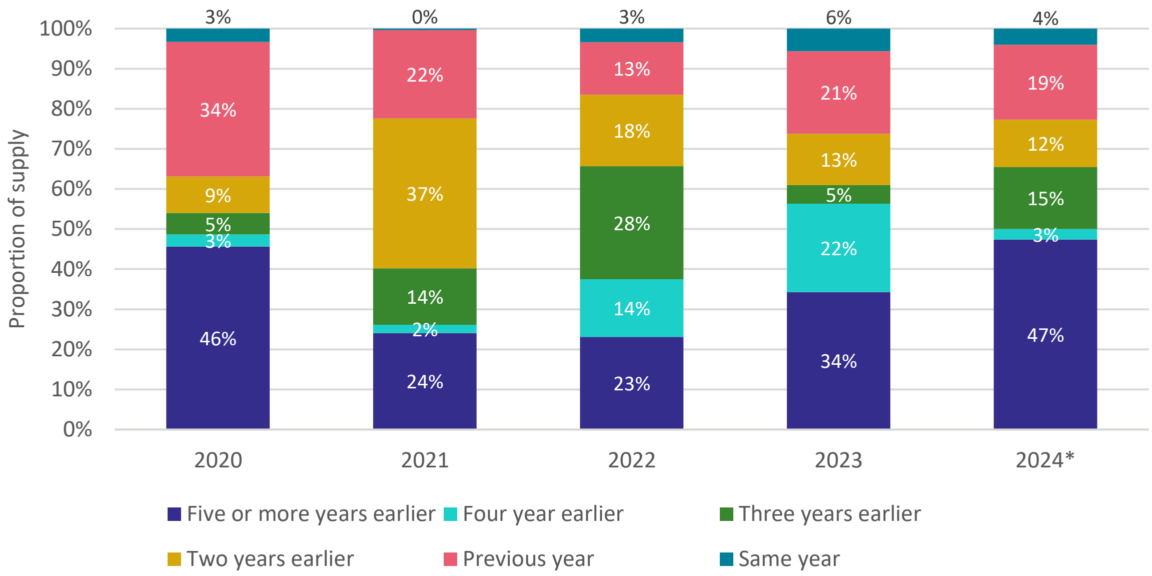
Measurement of retailers' costs

Through our engagement with C&I users, questions have been raised about whether retailers have been passing through changes in their gas commodity costs, including as a result of the Emergency Price Order and/or Gas Code. To test this, we have compared the prices that retailers have had to pay to procure additional gas to supply their customers over the period (marginal commodity cost), with the prices charged to C&I users.

We have used the marginal commodity cost, rather than the average portfolio commodity cost from the cost stack analysis, because the average cost will often reflect the outcome of gas contracting decisions made a number of years in advance of supply to customers.

This can be seen in chart 4.4, which shows that a large proportion of the gas available to retailers under their GSAs was contracted 3–5 years ago. Average commodity costs do not therefore provide the best indication of the costs that retailers have incurred sourcing additional gas to meet their customers' needs over the period.

Chart 4.4: Proportion of supply in each year by contract execution date

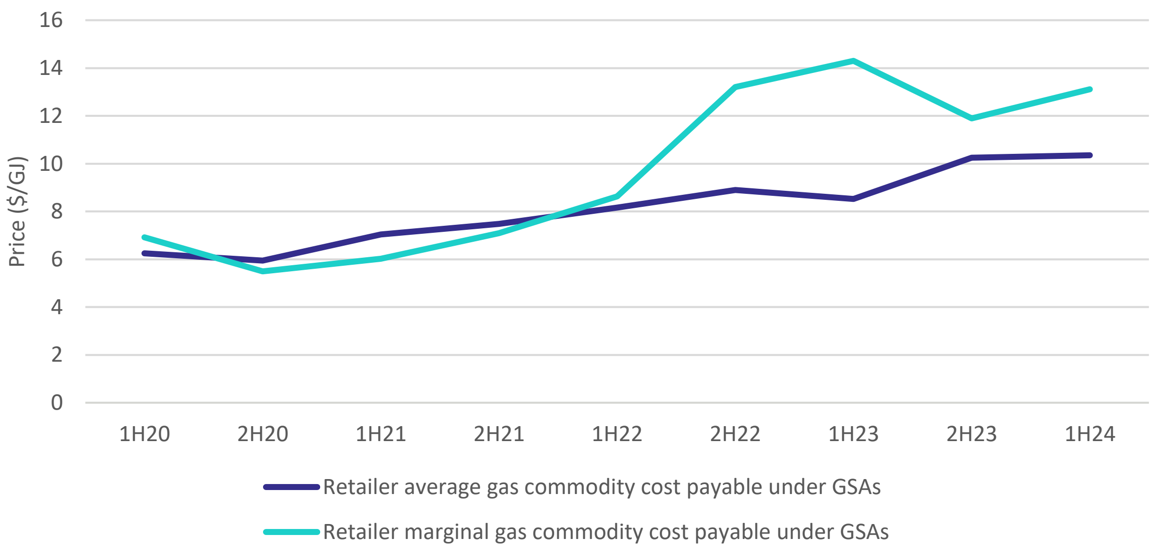


Source: ACCC analysis of data provided by retailers on the GSA contracts for supply at any time between January 2020 and June 2024.

Notes: *Does not account for contracts entered into on or after 1 July 2024 for supply in 2024.

We have estimated the marginal commodity cost for each year using information provided by retailers on the GSAs they have entered into with producers and other suppliers. The marginal commodity cost has been calculated as the volume-weighted average price under GSAs that provide for supply in the half-year period and that have been executed within one year of the end of that half-year period. The marginal commodity cost estimate is shown in chart 4.5 along with the average commodity cost from the cost stack analysis (chart 4.2).

Chart 4.5: Retailers' marginal cost of supply vs average commodity cost



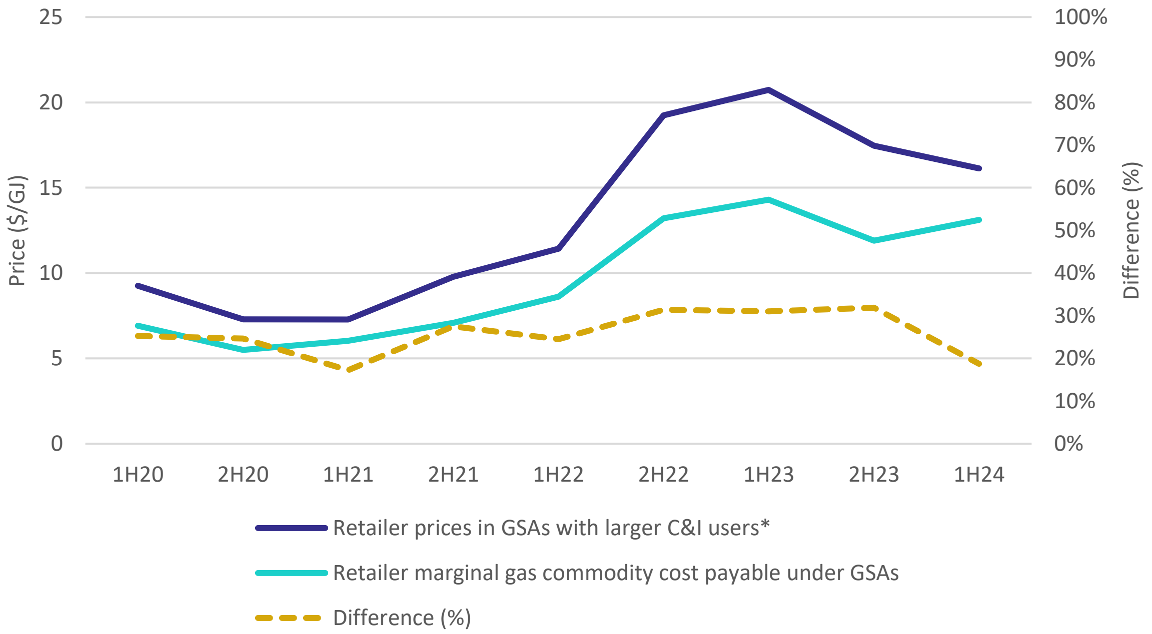
Source: ACCC analysis of data provided by gas retailers on their costs incurred in supplying C&I users, and the GSA contracts that had provided for supply at any time between 1 January 2020 and 30 June 2024.

It shows the prices retailers have paid for gas under newer GSAs were substantially higher than average commodity costs between the second half of 2022 and first half of 2023 and have remained higher into 2024. Indeed, since May 2022, the prices retailers have paid for gas under new GSAs ranged from $11.50 to $26.30/GJ,[74] while the average commodity cost ranged from $8.53/GJ to $10.35/GJ.

Retailer prices vs marginal commodity cost

Chart 4.6 compares the estimated marginal commodity cost with the volume weighted average price that retailers have agreed under contracts entered into with C&I users between 1 July 2019 and 30 June 2024. It also shows the percentage difference between marginal commodity costs and prices.

Chart 4.6: Marginal commodity costs and retail pricing to C&I users from contracting



Source: ACCC analysis of GSA contracts between retailers and producers that had provided supply to retailers at any time between January 2020 and June 2024, and GSA contracts between retailers and C&I users.

Notes: *Retail prices based on GSA contracts with term length of over one year and supply of more than 0.5 PJ p.a..

Retailer prices over the period have largely moved in line with the prices that they have recently had to pay producers and other suppliers for gas (the marginal commodity cost). While the gap between retailer prices and marginal commodity costs has grown over the period in absolute terms, the percentage difference has remained largely stable. This suggests that retailers' profit margins on additional volumes of gas have not materially changed, and that retailers are passing through changes in the commodity gas costs they incur when entering into new GSAs with C&I users, including the reduction observed since late 2023.

This finding is consistent with what retailers told us about how they determine the gas commodity component of their C&I user prices, which is that they principally have regard to the current market value of gas when determining this price. It is also consistent with the observation above that retailer and producer prices in 2024 are largely moving together at similar levels.

[74] The prices quoted in this paragraph are based on all the GSAs retailers entered into with a term of 3 months or more. It differs from the analysis of prices in chapters 2–3, which is limited to GSAs with a term of 12 months or more.

As to whether retailers passed through any reductions in commodity costs that may have been associated with the Emergency Price Order and/or Gas Code, we note that:

- In 2023, retailers procured around 23 PJ of gas at or below the $12/GJ Emergency Price Order cap. This was equivalent to around 5% of retailers' supply commitments in 2023 so had minimal impact on their costs and prices.[75]
- Between the date the Gas Code was fully implemented in September 2023 and mid-2024, retailers procured around 42 PJ of gas from producers under GSAs with a term greater than 3 months. The prices in these GSAs have ranged from $11.75 to $14.50/GJ, with the weighted average price being around $12.80/GJ.

4.7.4. Gas commodity prices paid by C&I users in regional areas appear broadly in line with those paid in metropolitan areas

We have examined whether the prices C&I users pay for gas in regional areas supplied by a single retailer are materially higher than the prices payable by C&I users in other areas where there is more competition. We focused specifically on the following areas using invoice data provided by retailers:

- the Mt Gambier and Riverland regions in South Australia
- the Gladstone region in Queensland
- the Carisbrook and Horsham regions in Victoria.

To test whether is a difference in prices in these regions, we compared the gas commodity component of the prices paid by C&I users in these regions with those paid by C&I users in metropolitan areas in the relevant states. This was done using invoice data provided by retailers for the period 2022-mid-2024.

We focused on the gas commodity component because differences in transportation costs across locations can also result in differences in the prices paid by C&I users across locations. We recognise, however, that, in limiting our analysis in this way, we may not be accounting for other charges that retailers may levy in regional areas that they do not levy in metropolitan areas.

Noting this, our analysis suggests that C&I users in these regions are **not** consistently paying more for the gas commodity component of their invoices than C&I users are paying the same retailer in metropolitan areas, where there is more competition.

We have, for instance, found that since 2022 there has been very little difference between the average gas commodity price paid by C&I users in the Mt Gambier region and those paid by C&I users to the same retailer in Adelaide. Similarly, we found that, since 2022, there has been very little difference between the average gas commodity price paid by C&I users in the Carisbrook to Horsham region and those paid in Melbourne to the same retailer.

In the case of the Wide Bay and Riverland regions, we found that while the gas commodity price charged by a retailer was moderately higher than it was in Brisbane and Adelaide for the same retailer, respectively, between 2022 and mid-2024, the difference was not persistent and appeared to diminish over time. Given the small number of customers in regional areas, it is also possible that the difference simply reflects a difference in the timing of when they entered into GSAs *vis-à-vis* those entered into in metropolitan areas.

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[75] ACCC, *Gas Inquiry 2017–2030 Interim report*, June 2024, p 63.

These findings are broadly consistent with what retailers have told us, which is that their gas commodity price does not differ across locations within a state, but the delivered price may differ as a result of the difference in the cost of transporting gas to those areas.

4.8. Retailer selling practices improved in 2024, but concerns remain about standard practices

In Stage 1 of our review, we examined retailer selling practices over the period 2020–2023. Through that review, we found that the events of 2022 and 2023 had contributed to a deterioration in some retailers' selling practices, and while we observed some improvements in late 2023, we found that some retailers' standard selling practices fell short of what would be expected in a well-functioning market. We therefore signalled our intention to revisit selling practices in Stage 2 of the review, and to consider if there have been any improvements in 2024, or if there are systemic problems that need to be addressed. [76]

In considering this question, we have consulted with C&I users, intermediaries, industry associations and retailers. In summary, we have found that some of the more fundamental concerns that were raised by C&I users in Stage 1 about some retailers employing a 'take it or leave it' approach and 'scarcity tactics' in 2022, and the first half of 2023 had abated. However, we continue to have concerns about some aspects of retailers' standard selling practices, which are not what we would expect to observe in a well-functioning market.

4.8.1. The concerns raised about the use of a 'take it or leave it' approach and 'scarcity tactics' in 2022–2023 have abated

In Stage 1 of the review, C&I users and intermediaries expressed concerns about the: [77]

- 'take it or leave it' approach employed by some retailers in 2022 and the first half of 2023, which they claimed generated a real 'sense of urgency' and exacerbated the imbalance in bargaining power they can face
- use of compressed offer validity periods (1–2 days) and the withdrawal or amendments of offers within this validity period in 2022 and the first half of 2023, with some noting that these practices appeared to have been used as a 'scarcity tactic' to place pressure on C&I users to agree to higher prices and less favourable terms.

The concerns about retailers employing a 'take it or leave it' approach appear to have largely subsided in 2024, with one user describing the current selling conditions as being '… less tense than in 2022…'.

C&I user concerns about the use of compressed offer validity periods and the withdrawal and/or amendments of offers within this period also appear to have largely subsided, as one C&I user observed:

> Before our most recent interactions, we'd have offers revoked in that 3–4 day period. That doesn't seem to happen now. Probably a reflection of more players and participants. They're open to more negotiations. A lot still had that short turnaround decision making window. Maybe a bit more lenient now. If they gave you 5 days, it's not a big deal if you come back in 7. I think that comes from volatility. When the market is volatile, everything is compressed.

[76] ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, chapter 5.

[77] ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, chapter 5.

This observation is consistent with what we have heard from retailers, with several telling us that they had reverted back to their standard offer validity periods and have not withdrawn or amended prices within the offer validity period since the second half of 2023.

4.8.2. Concerns continue to be raised about some aspects of retailers' standard selling practices

While some of the more fundamental concerns raised in Stage 1 have subsided, C&I users and intermediaries continue to raise concerns about various aspects of retailers' standard selling practices, including:

- offer validity periods, and retailers' ability to withdraw or amend offers within this period
- the willingness of retailers to negotiate with C&I users
- the extent to which some risks are being allocated to C&I users
- the adequacy of information provided by retailers.

These concerns are broadly consistent with those raised over the course of the Inquiry (see Appendix F), although it is worth noting that the significance of some concerns has varied over time, depending on prevailing conditions.

In addition to the concerns raised by C&I users and intermediaries, we have identified some concerns with the way in which spot market linked products are being sold to C&I users. Further detail on these concerns is set out below.

C&I users remain concerned about insufficient offer validity periods and the ability of retailers to amend or withdraw offers in this period

Most C&I users we spoke to told us that retailers, on average, provided an offer validity period of 3–6 days,[78] although there were some variations, with a small number noting some retailers provided more time to accept offers (ranging from 1 week to 1 month). Some users also reported that retailers have been more willing to provide extensions than they were in 2022 and 2023.

The average offer validity period reported by C&I users is broadly in line with the standard employed by most retailers, although there were a small number that provide a standard 2 week offer validity period. One retailer further clarified that this is dependent on their upstream supplier providing a similar or longer validity period. Multiple retailers also noted that they were willing to provide extensions, although one said that their ability to do so may be limited where market volatility increases the risks of holding the offer open for longer periods. This is particularly the case where a retailer has to enter into a contract with a producer or other supplier to supply the C&I user.

While C&I users have not recently experienced the compressed offer validity periods that were observed at times in 2022 and 2023, almost all C&I users thought the current offer validity periods were insufficient. One user noted that being offered 3–4 days still '*…put massive pressure to make decisions in that period*'. Consistent with what they said in Stage 1 of the review, various C&I users told us they require around 2 weeks (or more) to assess and obtain necessary internal approvals.

78 When making an offer, retailers will usually specify the period over which the offer will be open (or the date on which the offer will expire). Referred to as the 'offer validity period', this represents the time that C&I users have to assess the offer, negotiate any changes that may be required to the offer and obtain the internal approvals required to accept an offer.

In contrast to Stage 1 of the review, very few concerns were raised about retailers amending or withdrawing offers within the offer validity period in 2024. When asked about their approach to withdrawals and amendments, retailers told us that will usually only consider such actions during the validity period when there is a material movement in prices in the market. Retailers who operate on a back-to-back contracting model stated they would also consider withdrawing and/or updating offers if their underlying supply offer changed.

The retailers we engaged with told us they do not plan to change their standard approach to offers. Most of these retailers also told us that they were not aware that this remained an ongoing concern for C&I users and did not consider the concerns applied to their practices.

Mixed views were expressed about retailers' willingness to negotiate key terms, but improvements have been observed in 2024

In a similar manner to Stage 1, C&I users expressed concerns about the willingness of retailers to negotiate on some non-price terms, such as take or pay provisions. One user, for instance, stated that retailers were not willing to negotiate on this aspect and observed that there was '…always take or pay'. Some of the intermediaries we consulted with, on the other hand, noted that retailers were more willing to negotiate on these terms.

More generally, most of the C&I users and intermediaries we engaged with told us that retailers appeared more willing to negotiate in 2024. Several C&I users did, however, note that some retailers were more willing to negotiate than others, which one user considered may be driven by differences in their portfolio and organisation structure. For instance, one C&I user stated '…[t]he retailer quoted pricing above $12/GJ, however requested amendments to the Terms and Conditions were accepted by this retailer.' Some C&I users and intermediaries also acknowledged that retailers may, at times, be constrained in their ability to negotiate, with one user observing:

> Retailers are normally quite open to review their offers, but they are constrained by what they can offer.

Almost all the retailers we engaged with told us that they were generally willing to negotiate on both price and non-price terms. However, a number said that their ability to negotiate on non-price terms may be limited by their GSAs with producers or other suppliers, and if it leads to a '…loss making contract' or '…undue risk'. One retailer, for instance, observed that '[s]ome terms are impractical to negotiate due to the risk it would leave on the seller and the required increase in price to offset.'

C&I users remain concerned about risk allocation in retailer contracts

Several C&I users and intermediaries told us they continue to have concerns about the increasing number of risks being allocated to C&I users that they are not well placed to manage, with particular concerns raised about the costs and risks associated with take or pay obligations and permitted interruptions.[79] One user observed that since 2020:

> [s]uppliers are more rigid on non-price terms and conditions with a lot more risk passed on the consumers.

Most retailers told us that they try to minimise risks on behalf of their customers but several acknowledged they do pass on some of these risks to larger C&I users. Retailers also told us that they are finding it increasingly difficult to obtain the flexibility they require in their GSAs

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[79] ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, pp 117–120.

with producers to meet the needs of C&I users and, as a consequence, they are having to manage more risks, which can have cost implications (see section 4.5).

In relation to take or pay obligations, we understand that competition has prompted some retailers to offer either a zero, or very low, take or pay multiplier to smaller C&I users (see section 4.6.1). This has not, however, been offered to larger C&I users. Nor do any steps appear to have been taken by retailers (with one exception) to reduce the costs associated with take or pay obligations. As one intermediary observed:

> … it's totally fair for retailers to capture any losses… However, there is some overreach on their part at times… Retail has to make money, but some of these ToPs are an example of it being too much.

In response to these concerns, several retailers told us they were finding it increasingly difficult to obtain any take or pay flexibility in their GSAs with producers, which they noted made it difficult for them to offer the flexibility C&I users are looking for. Only one retailer told us that they have sought to mitigate the costs associated with take or pay obligations, noting that they have in some instances negotiated *'… bespoke take or pay clauses which permit the sell back of unused gas to the market'*. This is similar to the approach we highlighted in Stage 1,[80] and would appear to address the risk retailers face as a result of their own take or pay obligations, while minimising the cost impost for C&I users.

In relation to permitted interruptions, several C&I users told us that some retailers remain unwilling to negotiate on this provision, which has left them more exposed to supply interruptions that they are unable to effectively manage. In Stage 1 of the review, C&I users told us that that this risk principally related to supply from Longford, where the likelihood of outages has increased.

A number of retailers told us that producers are increasingly transferring the risk of interruptions to retailers through the permitted interruption provisions in their GSAs. Some retailers told us that they will usually try to manage this supply risk for their customers. That is, by entering into a diverse portfolio of GSAs with producers and other suppliers, and also using storage and the AEMO markets to supplement supply when required. Those retailers that employ more of a back-to-back contracting model, however, told us they have fewer options available to manage the risks than those with a diverse portfolio of GSAs. A number of retailers also told us that if they do pass this risk through, they tend to only do so in contracts with larger C&I users and that where this occurs, the price is usually discounted to reflect the increased risk to the buyer.

Concerns remain about the lack of transparency surrounding retailers' costs and how they determine prices

Most C&I users and intermediaries we spoke to believe that the offers they received from retailers contained sufficient detail on the terms and conditions of supply. However a number of users and intermediaries expressed concerns about the lack of clarity surrounding the timing and value of some retailers' charges, including transportation, connection and capacity charges.

A large number of C&I users and intermediaries also raised concerns about the lack of transparency surrounding how retailers' prices are determined, and the relationship to their underlying costs. To address these concerns and provide for a greater level of retailer accountability, a number of C&I users and intermediaries considered that there should be greater transparency of the key drivers of retailers' prices, including the prices they have to

80 ACCC, Gas Inquiry 2017–2030 Interim report, December 2023, p 118.

pay for gas and the margins they earn. However, some did acknowledge that this level of transparency may be difficult to achieve in practice.

The retailers we engaged with told us they believed their prices and charges are readily understood and they were not considering changing their approach. A number also told us that they answer any questions from C&I users (and intermediaries) when engaging with them. Despite this, one intermediary noted that they still struggled to understand the basis and nature of one retailer's charges even after seeking clarification from the retailer, which may reflect the complex nature of some charges.

Some C&I users may not be well-placed to manage the risks associated with spot market-linked products

As outlined in section 4.7, an increasing number of C&I users are relying on the AEMO markets to meet some or all of their demand, with some procuring the gas directly from the markets, or doing so via a retailer or intermediary.

Through the Stage 1 consultation process, a number of C&I users questioned whether retailers and/or intermediaries adequately explain the physical and financial risks associated with this product to C&I users. Questions were also raised about whether C&I users that were sold this product were in a position to manage any risks that do arise.[81]

In our more recent engagement, a number of the more established retailers told us that they also had concerns about the risks associated with this product and have historically only sold this product to sophisticated users and, in some cases, only with a cap. Several of these retailers told us that they will generally only offer spot market linked products in response to a request from a C&I user, and they are not the standard or preferred offering due to the associated risks. This view was reiterated by an intermediary, that observed *'…in general, exposure to spot market only occurs when the customers look for it. This is typically reserved for larger clients, and not actively marketed by most retailers'*.

While more established retailers have put these measures in place, we are concerned that some (but not all) newer entrant retailers may be selling spot linked products to C&I users that are not well placed to manage the risks associated with such products, including very small unsophisticated C&I users.

We are also concerned that some of these retailers may not be adequately explaining the physical and financial risks associated with these products to prospective customers, or putting in place arrangements to manage these risks. This is of particular concern given the potential for AEMO markets to experience more volatility in future and for market price caps to be triggered[82] if shortfalls arise. Apart from putting financial pressure on C&I users and the retailers offering these products, it is possible that this could trigger another RoLR event, the consequences of which could be significant and wide-reaching (see section 4.6).

81 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 120.

82 The market price cap is $400/GJ in the STTM and $800/GJ in the DWGM, while the administered price cap is $40/GJ.

4.8.3. Some standard selling practices continue to fall short of what would be expected in a well-functioning market

In Stage 1 of the review, we set out at a high level the selling practices we would expect to observe in a well-functioning retail market. While there have been some improvements in these practices since we completed Stage 1, **some (but not all)** retailers' standard practices continue to fall short of what we would expect to observe in such a market.

This can be seen in table 4.2, which sets out our assessment of retailers' selling practices. As the final column shows, there is room for further improvement in some selling practices, particularly given the persistent and systemic nature of some of the identified problems.

Table 4.2: ACCC assessment of retailer standard selling practices

	Persistent C&I concerns	Selling practices expected in well-functioning market	ACCC assessment of current practices
Offer processes	a. Insufficient offer validity periods, C&I users say they require at least 2 weeks. b. Concern that retailers may change prices or withdraw offers during the offer validity period without a good basis for doing so. c. Lack of responses, or timely responses, to offer requests or questions.	Retailers would be expected to: i. employ offer validity periods that provide C&I users sufficient time to evaluate offers, negotiate changes and obtain the approvals required to accept an offer ii. only amend or withdraw offers within the offer validity period where there has been a material change in the supplier's circumstances, and if so, provide an adequate explanation of this change to the prospective buyer iii. respond to C&I user requests for clarifications on offers in a timely manner.	The extremely compressed offer validity periods have ceased in 2024. Amendments and/or withdrawals of offers during the offer validity period also appear to have ceased. However, some (but not all) retailers' standard offer processes fall short of the expectations set out in i–iii.
Negotiation processes	Concerns raised about the willingness of retailers to negotiate on key terms.	Retailers would be expected to negotiate in good faith with C&I users on price and other conditions.	Improvements have occurred in this area, with retailers more willing to negotiate than they have been at times in the past. However, there is room for further improvement in this area.
Risk allocation	a. Concerns about retailers allocating risks to C&I users who may not be well placed to manage those risks (e.g. take or pay obligations and permitted interruptions). b. Some concerns raised about contractual impediments in retail contracts preventing C&I users from managing these risks.	Retailers would be expected to: i. reasonably allocate risks to C&I users when they are best placed to manage those risks ii. minimise the costs associated with any risks that are transferred to the buyer and any contractual impediments that may prevent C&I users from managing those risks.	While some retailers have taken action in these areas, the risk allocation practices employed by others continue to fall short of the expectations in i–ii.
Transparency	a. Lack of publicly available information on retailers' standard terms & conditions. b. Insufficient information on all the charges payable to a retailer why they're payable, and the relationship between their gas prices and the price retailers have to pay for gas. c. Lack of a consistent basis for retailer charges.	Retailers would be expected to: i. publish standard terms and conditions on their website ii. be as transparent as they can be with C&I users about their charges and the basis for those charges (including those charges that are to be treated as a pass through) in the offer process and over the term of the contract.	The standard approach to transparency employed by most retailers continues to fall short of the expectations in i–ii.
Spot market linked products	a. Questions as to whether customers are able to manage the risks associated with such products. b. Inadequate explanation of risks associated with these products.	Retailers would be expected to: i. only sell spot market linked products to C&I users that are well placed to manage the physical and financial risks and have access to the tools to monitor and manage the risks ii. ensure C&I users have a good understanding of the risks.	The standard approach to selling spot market linked products employed by some (but not all) retailers continues to fall short of the expectations in i–ii.

Through the Stage 2 engagement process, we asked retailers about these practices and the concerns that had been raised by C&I users and intermediaries. All the retailers that we spoke to told us they were not aware that there were problems with their standard practices but showed a genuine interest in trying to improve their practices, where possible.

It is also worth noting in this context that C&I users and intermediaries have previously told us that some retailers employ more customer-centric selling practices and were more accommodating than others. This has also been borne out in our review. Some retailers are, for instance, already employing a 2 week offer validity period. Some are also limiting their sales of spot market linked products to more sophisticated C&I users that have been fully informed of the risks. Care should therefore be taken not to assume that all retailers are employing sub-standard selling practices.

4.9. The retail market requires long-term supply certainty to be able to function effectively

Taking together our findings across stages 1 and 2 of the review, we have considered whether there is evidence of a market failure or systemic problem with retailer pricing or selling practices. To assess the value of any potential solutions, we also considered whether, if there is such evidence, the problems were transitory or more persistent in nature.

We also considered the impact that future market conditions may have on retailer pricing and selling practices. As outlined in section 4.6.3, retailing is expected to become more challenging in the future, given:

- projected supply shortfalls (particularly in the south where a signification portion of C&I demand is located) and constraints on access to southern haul transport and storage
- the uncertainties surrounding the pace of the energy transition and its impact on both gas supply and demand
- regulatory and policy uncertainty.

In summary, we have found that in the case of:

- **Retailer pricing practices**, there is no evidence of a persistent market failure or systemic problem that requires regulation and doing so could adversely affect an already fragile competitive environment.
- **Retailer selling practices**, while competition appears to have driven some improvements in these practices, some (but not all) retailers' practices continue to fall short of what would be expected in a well-functioning retail market.

Therefore, to promote further improvements in the retail market we will:

- publish best practice guidance on retail selling practices in 2025 and will then monitor retailers' uptake of the guidance as part of the Gas Inquiry
- in future Gas Inquiry reports publish more information on the prices retailers are charging C&I users and the prices retailers are paying for gas.

4.9.1. There is no case for regulating retail prices, and doing so could harm an already fragile competitive environment

In addressing the question of whether there is evidence of systemic problems in the retail market, we have considered the impact that market conditions between 2020–2024 had on retailer pricing and selling practices. As set out above, these conditions appear to have significantly constrained retailers' ability to access sufficient gas supply, transportation and storage, which then led to:

- an escalation in the costs and risks faced by retailers
- a reduction in market activity and competition to supply C&I users.

Collectively, these factors shaped retailers' pricing and selling practices over the tighter and volatile period of 2022 and during the 'pause' in producer contracting in 2023. More recently however, market conditions have stabilised, with producers resuming domestic marketing and retailers able to readily access gas and infrastructure services.

The prices we have observed offered and contracted in the market in 2024 appear to be in line with what we would expect given international gas prices and domestic supply-demand dynamics (see section 4.7). The most recent offers observed have tended below LNG netback prices in Queensland and even southern states, with the weighted average retailer prices in the first 6 months of 2024 being marginally below producer prices (chart 3.1).

Put simply, we have not found any evidence of a persistent market failure or systemic problem with retailer pricing practices that would warrant regulating retail gas prices.

As outlined in section 4.6.3, the future challenges facing retail markets are likely to give rise to higher costs and risks. They could also prompt some retailers to exit this part of the market, resulting in a potential deterioration in competition and, in turn, a deterioration in retailer pricing and/or selling practices. We consider that any regulation of retail prices would likely exacerbate the risk of some retailers exiting this part of the market and lead to further increases in retailer costs and risks, which could harm an already fragile competitive environment.

4.9.2. Greater transparency of retail costs and guidance on selling practices could drive further improvements

While we are not recommending any form of price regulation, we consider that there would be value in providing for greater transparency of retailers' gas supply costs – that is, the prices retailers are paying producers under recent GSAs. Therefore, in future Gas Inquiry reports, the ACCC will publish more information on the prices retailers are charging C&I users and the prices retailers are paying for gas. This may help to reduce information asymmetries between retailers and C&I users, and address concerns about the lack of transparency around retailers' gas costs. It will also assist governments in making more informed assessments of retailer pricing, including questions of cost pass through.

Further, while we have found no persistent premium in the prices paid for gas in regional areas where there is limited competition, we reiterate our previous recommendations in relation to regional pipelines. In our 2020 review, we found that contractual constraints on regional pipelines were preventing the full benefits of retail competition flowing through to regional areas and recommended changes to the National Gas Law and National Gas Rules to address this longstanding issue.[83] These recommendations have not yet been pursued.

In the case of retailers' selling practices, despite recent improvements some retailers' practices continue to fall short of what we would expect in a well-functioning retail market.

[83] ACCC, *Gas Inquiry 2017–2025 interim report*, January 2020, pp 111–117.

While improved market conditions and competition appears to have prompted some improvements over time, the persistent and systemic nature of some of the problems that have been identified with retailer selling practices means there is a stronger case for taking steps to promote better behaviour. This is particularly the case given the potential for the effects of poorer selling practices to be felt more acutely in the future if market conditions and/or competition deteriorate again.

Therefore, in 2025 the ACCC will publish best practice guidance on what selling practices should entail, including, but not limited to:

- offer processes
- negotiation processes
- risk allocation in retailer GSAs
- transparency
- approach to selling spot-linked products.

We consider that such guidance would:

- strengthen accountability and encourage alignment between C&I users' requirements and retailer selling practices
- improve transparency, understanding and comparability of offers, and decision-making by C&I users
- improve the bargaining position of C&I users by allowing them to make more informed decisions and have sufficient time to consider offers.

We consider that a voluntary approach is appropriate, given the potential for competition to continue to drive improvements in selling practices.

While uptake of the guidance will be voluntary, the ACCC will closely monitor and report on retailer selling practices and general uptake of the guidance as part of the Gas Inquiry. Should selling practices continue to fall short of expectations (considering the market conditions in which they are observed), the ACCC may consider further potential solutions to address any remaining issues. This could include recommending that the guidance be incorporated into a mandatory instrument.

4.9.3. The market still faces fundamental supply-side problems

While the measures outlined above are expected to drive further improvements in retailers' pricing and selling practices, they will not address the underlying issues facing the east coast gas market. Upstream market conditions and lack of access to sufficient gas supply is a fundamental driver of many of the problems that have flowed into the retail market. As one new entrant into the east coast gas market noted:

> Gas retailing is an incredibly aggressive competitive marketplace. It only fails when the market around it fails.

Key to the underlying problems are sufficiency of supply and diversity of suppliers. The ACCC has long advocated for governments to remove impediments to bringing on additional gas supply, particularly in southern states where a significant proportion of C&I demand is located and traditional supply sources are in decline. This and other long-term supply issues facing the market are discussed further in chapters 5–7 below.

Part 2: Gas sufficiency and Security

5. Gas Supply Challenges

Key points

- Natural gas will play a critical role in meeting Australia's emissions targets. As we increasingly rely on renewables for electricity generation, gas will be required to support energy security, reliability and affordability, and will remain an important source of energy and feedstock for residential, commercial and industrial users.
- Despite the importance of gas in the energy transition, east coast gas supply is in decline. The southern states are already facing seasonal shortfalls of gas, which are made up by gas from Queensland.
- In the absence of new domestic supply to fill the gap, consumers in the south will depend in the near term on gas transported from Queensland. As southern haul pipeline capacity becomes increasingly constrained, the southern states will rely on gas imports. Domestic gas prices will therefore become increasingly driven by international oil and gas prices and the cost of transporting gas over large distances across the east coast.
- Greater domestic supply would offset these effects but there continues to be insufficient investment in new gas supply and infrastructure. Current projections indicate the potential for structural shortfalls in the east coast from 2027 unless supply increases and/or demand decreases. Gas supply projects subject to conditional Ministerial exemptions under the Gas Code may delay structural shortfalls, however the decline in forecast production is overshadowed by sustained gas demand.
- There are significant challenges to investment in new gas projects and infrastructure, including lengthy regulatory approval processes, asset stranding risks and large upfront capital costs.
- International LNG demand is forecast to remain relatively strong and continue to incentivise LNG exports from Australia. An increase in international LNG supply is also expected in the coming years, which may place downward pressure on international LNG prices.

As the Australian Government's *Future Gas Strategy* and AEMO's *GSOO 2024* make clear, gas is expected to be used to support the transition of the electricity market as a firming generation source to support renewable energies.[84, 85] AEMO also projects that a substantial part of the economy, including manufacturing industries such as fertiliser, cosmetics and steel smelting, will rely on gas in the foreseeable future as they do not have alternative sources of fuel or feedstock.

As an important part of the electricity market and a sole-source input for significant parts of the economy, gas will be essential for achieving security of energy supply and orderly transition to a lower-emissions economy simultaneously.

The ACCC has previously reported on the tight supply-demand balance, including the potential for structural shortfalls in the east coast gas market from 2027. Consideration will need to be given to how to manage the projected shortfalls and the risks posed by the NEM's increasing reliance on gas-powered generation to meet Australia's energy needs

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84 AEMO, *2024 Gas Statement of Opportunities*, March 2024, p 23.

85 Department of Industry, Science and Resources, *Future Gas Strategy*, Australian Government, May 2024, p 4.

during the energy transition. Further consideration will also need to be given to facilitating an orderly net zero transition for the gas market itself. Given the primacy of ensuring sufficient gas supply, the rest of this report focuses on the investment environment and measures to encourage efficient investment.

This chapter sets out long-term gas supply and demand forecasts, including gas production and investment challenges and the influence of international developments on the shape of the domestic market. We have set out the status of major gas projects in chapter 6. Chapter 7 outlines some policy directions given the challenges set out in the earlier chapters.

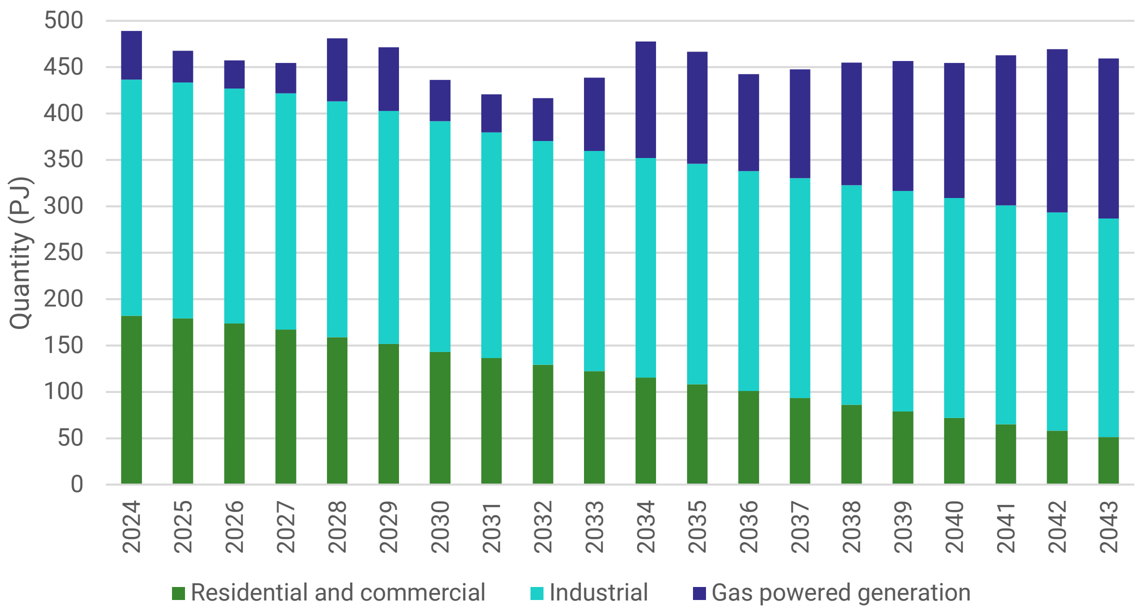
5.1. Supplying future gas demand on the east coast

This section outlines projections for gas demand and supply, the challenges with bringing new domestic gas production online, and international market trends that influence levels of investment in gas projects on the east coast.

5.1.1. Demand for gas on the east coast is expected to remain high, but GPG will comprise a greater proportion

Gas demand on the east coast is expected to remain at high levels for at least the next 2 decades. AEMO's latest forecasts suggest that annual domestic east coast gas demand will average around 450 PJ until 2043, but the composition of demand will change, with declining demand from the residential and commercial sector being offset by increased demand for gas-powered generation (chart 5.1).

Chart 5.1: Forecast annual gas demand on the east coast, between 2024 and 2043



Source: ACCC analysis of AEMO 2024 GSOO data.

AEMO's projections of falling demand for gas by residential and commercial users is based on assumptions about electrification rates, including the impact of state-level initiatives limiting future gas use and incentivising the development of alternative energy sources.[86]

While residential and commercial demand for gas is expected to decline, the rate at which consumers will switch away from gas is subject to considerable uncertainty. The Future Gas Strategy notes that the timing of when end users of gas will move to gas alternatives is unclear, particularly given barriers to electrification such as the cost of switching for low-income households and lack of choice in appliances for renters.[87]

In contrast, AEMO does not project a decline in industrial demand. Gas is needed as a core component in manufacturing and chemical processes for products such as fertiliser and cosmetics. Industrial users substituting their energy use from gas to electricity may not be technically or commercially feasible due to the high heat required, such as for smelting metals and minerals.[88] However, as noted in chapter 3, some industrial users are facing challenges from high gas prices and unreliable gas supply.

Annual demand for gas-powered generation on the east coast is expected to almost triple by 2040 compared to current levels to support the NEM.[89] Despite some uncertainty about the amount of gas that will be needed to firm the NEM during the energy transition, there is broad agreement that it will play a critical role. The flexibility of gas-powered generation will become increasingly valuable as the NEM energy mix moves from primary baseload generation to intermittent renewables generation which is inherently less reliable without firming from gas. AEMO's Integrated Systems Plan also recognises the need for 15 GW of gas-powered generation in the energy mix as the lowest cost pathway to net zero.[90]

To meet the needs of the NEM, substantial efficient investment in new gas supply and infrastructure is needed, but this is not occurring. The need to build gas supply into energy market planning is discussed further in chapter 7.

5.1.2. Southern states anticipate significant local gas supply shortages despite demand remaining strong

The east coast has sufficient gas reserves and resources to meet current demand projections over the next decade and beyond. However, most of these gas stores are in Queensland and Northern Territory, which will require substantial infrastructure connections to deliver to southern demand centres. In addition, supplying some of this gas may require development of more expensive resources.

The ACCC previously reported that Queensland production from 2P reserves is expected to be sufficient to meet forecast local demand and long-term LNG export demand until 2029. However, the supply outlook in the southern states is less favourable.[91]

The southern states are already facing seasonal and annual shortfalls of gas, with the difference being made up with gas transported from Queensland. Further, there is limited

86 The Victorian Gas Substitution Roadmap includes the issuing of rebates for energy efficient assets, with the aim to reduce residential gas use by 50% by 2030. Similarly, the ACT's 'Pathway to Electrification' commits to a phasing out of gas by banning new gas connections and mandates the installation of energy efficient appliances in new commercial and residential buildings.

87 Department of Industry, Science and Resources, *Future Gas Strategy*, Australian Government, May 2024, p 14.

88 Department of Industry, Science and Resources, *Future Gas Strategy*, Australian Government May 2024, p 14.

89 AEMO, *2024 Gas Statement of Opportunities*, March 2024, p 21.

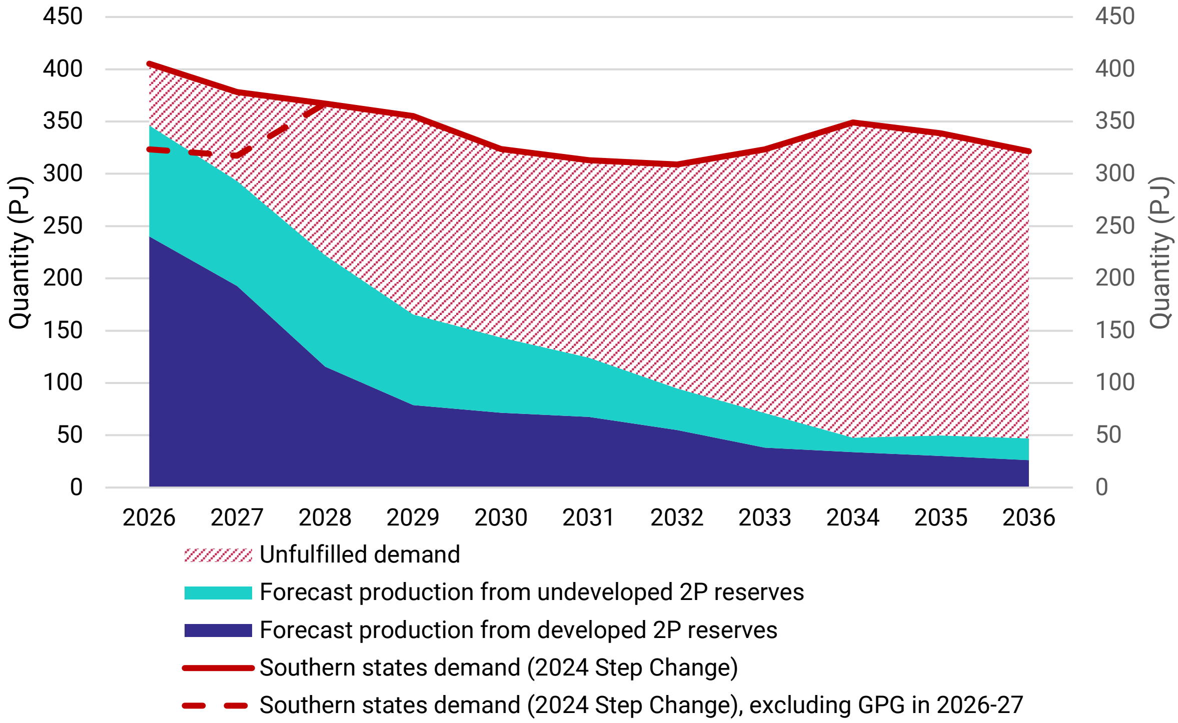
90 AEMO, 2024 *Integrated System Plan,* June 2024, p 69.

91 ACCC, *Gas Inquiry 2017–2030 Interim Report, ACCC, June 2024*, p 33.

new supply expected to come online from southern states producers in the near term. The supply that does come online is unlikely to be able to support residential, commercial and industrial demand, which comprises up to 75% of domestic demand on the east coast.

The decline in southern states' production between 2026 and 2036 is shown in chart 5.2. Between 2026 and 2036, there is forecast to be 2179 PJ of unfulfilled demand for residential, industrial, and power generation from production in southern gas fields. The annual gas shortfall is expected to rise to around 300 PJ by the mid-2030s.

Chart 5.2: Southern states supply and demand outlook, 2026–2036



Source: ACCC analysis of data obtained from gas producers as at January 2024 and domestic demand from AEMO's 2024 GSOO.

Note: This chart includes forecast production from developed and undeveloped 2P reserves in the Gippsland, Bass, Otway, Sydney, Gunnedah, and Cooper basins. Southern states demand for gas under AEMO's Step Change scenario has not been adjusted to account for the potential impact of a delayed retirement of Eraring Power Station, which is likely to lower overall GPG consumption. The dashed line represents southern states demand for gas excluding the total amount of GPG projected to be consumed in 2026 and 2027, which is presently estimated at 142 PJ over 2 years.

The southern states currently rely on gas transported from Queensland producers and the use of gas storage facilities to help meet peak demand in winter months. The expected decreases in southern production mean that, in the short term, customers in southern states will become more reliant on storage and new sources of supply, such as LNG import terminals, as gas pipeline capacity constraints will limit the quantity of gas that can be supplied from Queensland.

AEMO reports that current pipeline and storage capacity is insufficient to avoid the risk of winter gas supply shortfalls in the southern states from 2026 and more substantial annual shortfalls from 2027.[92]

Reliance on import terminals to meet southern states' demand will further increase the link between international and domestic gas prices. The potential impacts of LNG import terminals on the east coast gas market are discussed further in chapter 7.

As discussed in our June 2024 interim report, additional supply from conditional Ministerial exemptions under the Gas Code could defer the expected east coast gas shortfalls to 2028 if all identified projects go ahead.[93] However the timing and approvals of new projects remain dependent on regulatory approvals, technical feasibility and/or commercial factors.

Long-term gas demand remains uncertain as the energy transition progresses, especially for gas-powered generation, despite efforts to reduce residential gas usage.[94] However, the supply-demand gap is expected to be very large, and existing forecasts of reductions in demand are unlikely to be sufficient to meet this gap.

5.1.3. New gas production is not being brought on fast enough to meet future demand

A long-term decline in gas production in the southern states has been observed throughout the ACCC's gas inquiry and by AEMO in its annual market reports.

The market appears to have responded to signals to provide some additional gas supply, which has delayed projections of market supply shortfalls from 2025 (as contained in our December 2018 report) to 2027.[95] Forecast annual production across 2025 to 2030 has also increased over time for each given year (chart 5.3).

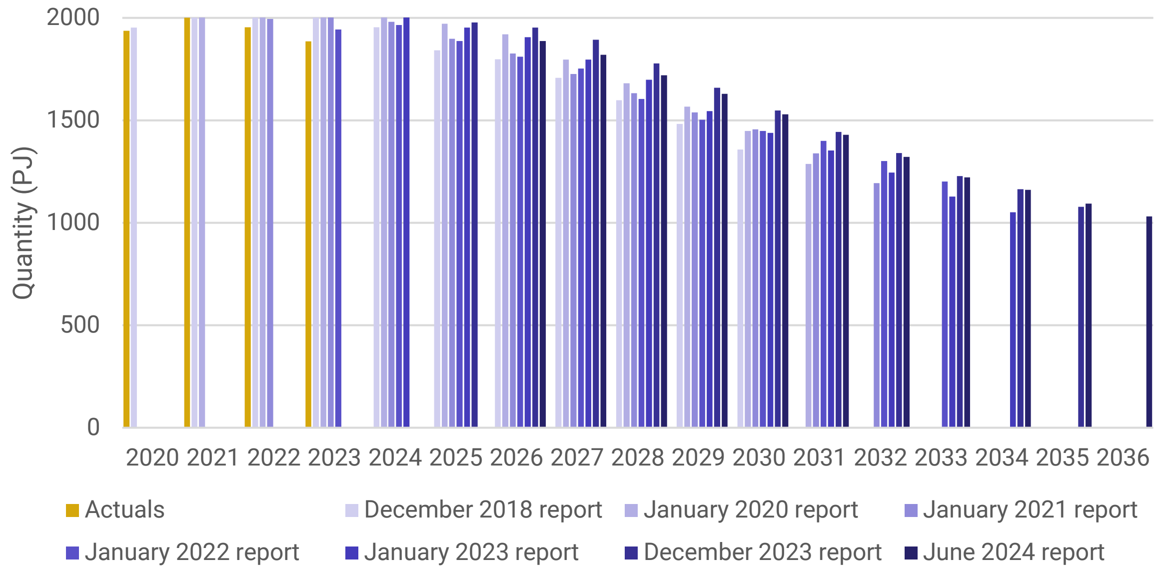
92 AEMO, *2024 Gas Statement of Opportunities*, March 2024, p 67.

93 ACCC, *Gas Inquiry 2017–2030 Interim Report*, ACCC, June 2024, p 36.

94 AEMO, *2024 Gas Statement of Opportunities*, March 2024, p 4.

95 This reflects differences in supply outlooks reported by the ACCC in its December 2018, December 2023 and June 2024 gas inquiry reports.

Chart 5.3: Forecast production from 2P reserves and actual production on the east coast



Source: Past ACCC Gas Inquiry (2017–2030) interim reports.

However, while there has been incremental new production, it has not notably altered the declining trend. In fact, projected future shortfalls have increased over time because new production has been outpaced by declining production from existing fields in the southern states and sustained gas demand. The volume of new gas supply that will need to be produced has therefore increased.

This is shown in table 5.1, which compares the cumulative supply and demand outlook as reported in the ACCC's past gas inquiry reports. Notably, between the ACCC's December 2018 and June 2024 reports, the total volume of gas shortfalls in each 11-year outlook has increased from 1,360 PJ to 3,795 PJ.

This suggests that significant levels of new investment, and more than what has been delivered in recent years, are required.

Table 5.1: Cumulative supply and demand in each 11-year outlook (PJ)

	Dec 2018	Jan 2020	Jan 2021	Jan 2022	Jan 2023	Dec 2023	Jun 2024
Queensland 2P production	16224	16320	15887	15422	14772	15015	14240
Southern states 2P production	3410	3557	2634	2271	2296	2007	1606
Total 2P production	**19634**	**19878**	**18521**	**17693**	**17068**	**17022**	**15846**
LNG demand (SPAs and spot/additional cargoes)	15150	15295	15084	15076	14838	14525	14677
Domestic demand	5844	6450	5712	5740	5481	5027	4964
Total demand	**20994**	**21745**	**20796**	**20815**	**19576**	**19551**	**19640**
Cumulative shortfalls/surpluses	**-1360**	**-1868**	**-2275**	**-3122**	**-2508**	**-2529**	**-3795**

Source: Past ACCC Gas Inquiry (2017–2030) interim reports. Domestic demand figures taken from AEMO's GSOOs.

5.2. Domestic gas production and infrastructure investment challenges

The east coast has sufficient gas reserves and resources to meet current demand projections over the next decade and beyond. With declining reserves from the Bass Strait, gas supply will likely need to come from a variety of sources, including Queensland and the Northern Territory, and potentially LNG imports. This will require investment in transportation infrastructure and storage.[96]

The Federal Government's *Future Gas Strategy Analytical Report* recognises the decline in investment in gas projects in Australia and outlines the following reasons for the decline:[97]

- global developments in oil and gas markets, such as a poor environment for access to project finance, availability of new gas investment opportunities in other parts of the world, and advances in substitutes to gas such as renewable energy technologies
- increasing restrictions in accessing finance for fossil fuel projects
- legal challenges to large gas projects and a perceived decline in the social license required for continuing development of the gas industry in Australia
- the concentration of the Australian market for gas production and transmission, which may contribute to 'gas hoarding' behaviour
- the cumulative effect of Federal and State Government interventions, including but not limited to legislation affecting gas supply and demand, including the Australian Domestic Gas Security Mechanism (ADGSM), and the Gas Code
- the broader instability of the State and Federal policy environment.

This is consistent with what we have heard from market participants. As outlined in chapter 6 and Appendix G, some of the key risks for new gas supply and infrastructure projects have been regulatory approvals, policy uncertainty including federal and state government policy changes, access to finance and commercial conditions.

Gas supply projects are complex, large in scale, and capital-intensive. Significant risk is associated with all phases of a gas project lifecycle, from exploration to appraisal and production. As a result, it often requires many years to recover the initial costs of investment which, together with the typically lengthy return-on-investment period, creates potential barriers to entry.

The AER has also noted asset stranding risks as demand declines (box 5.1).[98] The net zero transition will require more gas-powered generation alongside a reduction in residential and commercial demand, which will have impacts on the future structure of the gas distribution network and network costs.

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[96] AEMO, *2024 Gas Statement of Opportunities*, March 2024, p 60.

[97] Department of Industry, Science and Resources, *Future Gas Strategy Analytical Report*, Australian Government, May 2024, p 76.

[98] AER, *AER tackles gas pipeline regulation in an uncertain future* [media release], Australian Government, 15 November 2021, accessed 19 November 2024.

Box 5.1: Stranded asset risk and the economic life of gas-related projects and infrastructure

Stranded assets are capital investments that are no longer capable of earning an economic return prior to the end of their productive life, typically because of a change in their relative costs or prices. Stranded asset risk poses a significant threat to gas investment given the lengthy lifespans of gas projects needed to generate a return on investment.

The economic life of gas fields and infrastructure can vary significantly depending on a variety of individual factors such as the scale of the project, the applicable regulatory environment, and the overall economic climate.

While a project's construction phase may last only a few years, the operation phase can last for decades.[99] Therefore, production facilities and assets typically have a longer economic life than the fields or wells themselves. This means a field with a short-term yield relative to the asset life of its required production assets may not justify investment without the facilities being connected to numerous fields. Asset stranding risk is also greater without viable alternative uses.

Historically, producers have often modelled a project lifespan of 20–30 years, with strong potential extension.[100] Many LNG facilities have continued to be utilised past their initial long-term contract cessation date such as Woodside's North West Shelf which has remained operational since the 1980s.[101] Currently, the AER maintains a standard asset life of 55 years and 30 years for gas pipelines and compressors, respectively.[102] However, these standard asset lives have been subject to continual change and regulatory depreciation.[103] The likelihood of project extension is also more unclear as the net zero transition progresses.

The barriers to entry and investment have historically been overcome by long-term foundational contracts with gas customers to underwrite project risks and the use of joint ventures to diversify risk and strengthen financial resources.[104] However, as discussed in chapter 3, there has been a shift away from long-term gas contracting.

In the past decade, long-term foundational contracts and joint ventures have been the largest source of investment and financing in gas supply, demonstrated by the relative success of LNG projects linked with export markets. Continued investment in gas exploration on released acreage is nevertheless still needed to maintain production levels, in particular from unconventional gas fields.

Capital expenditure on new oil and gas production output was ~$60.7 billion in 2013/14 financial year, predominantly on new LNG capacity. Expenditure fell to a 12-year low of ~$7.4 billion in 2020/21, and was ~$12.4 billion in the first nine months of 2023/24.[105]

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99 Australian Energy Producers, *LNG National and Global Benefits*, Australian Energy Producers Website, June 2020, p 4.

100 Australian Energy Producers, *LNG National and Global Benefits*, Australian Energy Producers Website, June 2020, p 4.

101 Woodside Energy, *North West Shelf* [website], Woodside Energy Website, 2023, accessed 15 October 2024.

102 AER, *Draft Decision APA Victorian Transmission System (VTS) Access Arrangement 2023 to 2027, Attachment 4 Regulatory depreciation*, Australian Government, 2022, Table 4.3.

103 Frontier Economics, *Economic life for the purposes of setting the regulatory depreciation allowance*, IPART Website, 9 September 2022.

104 ACCC, *Gas Inquiry 2017–2030 Interim report, ACCC, July 2022*, p 102.

105 Institute for Energy Economics and Financial Analysis, *Resource firms show transition in exploration and capex spending*, IEEFA Website, 16 July 2024, accessed 6 November 2024.

The *Future Gas Strategy* notes that there has been a decline in exploration expenditure in recent years, suggesting the following reasons:[106]

- the exploration and production industry experienced a downturn due to the pandemic, oil market crash and the inflationary environment that followed
- investment has been limited as Australian LNG projects are currently in their production phase. International companies may also be focused on lower cost and lower risk fields in other countries.

This decline in investment in oil and gas exploration is in parallel to the energy sector's higher investment in clean energy than fossil fuels.[107]

5.3. International LNG market trends create long-term price uncertainty on the east coast

Supply to the east coast gas market has become increasingly shaped by LNG exports and the discretion of producers to sell uncontracted gas either on domestic or international markets. International circumstances such as shipping disruptions, international conflicts and climate policies of LNG importers can affect commercial decision-making on supply, production, pricing, and future investment.

Australia is expected to continue to export substantial amounts of LNG, which will continue to have flow-on impacts on domestic prices (see chapter 2 for a discussion on these impacts). However, the exact quantum of Australian LNG exports following the end of existing east coast LNG contracts is uncertain and will be influenced by policy and international demand and supply conditions.

In the next 5 years, it is broadly expected that there will be a significant increase in LNG supply from United States and Qatar (chart 5.4).[108] Institute for Energy Economics and Financial Analysis anticipates that new LNG projects could add 193 million metric tons per year (approximately 9,408 PJs) of new supply capacity from 2024 through to 2028, which equates to a 40% increase in existing international LNG supply.[109]

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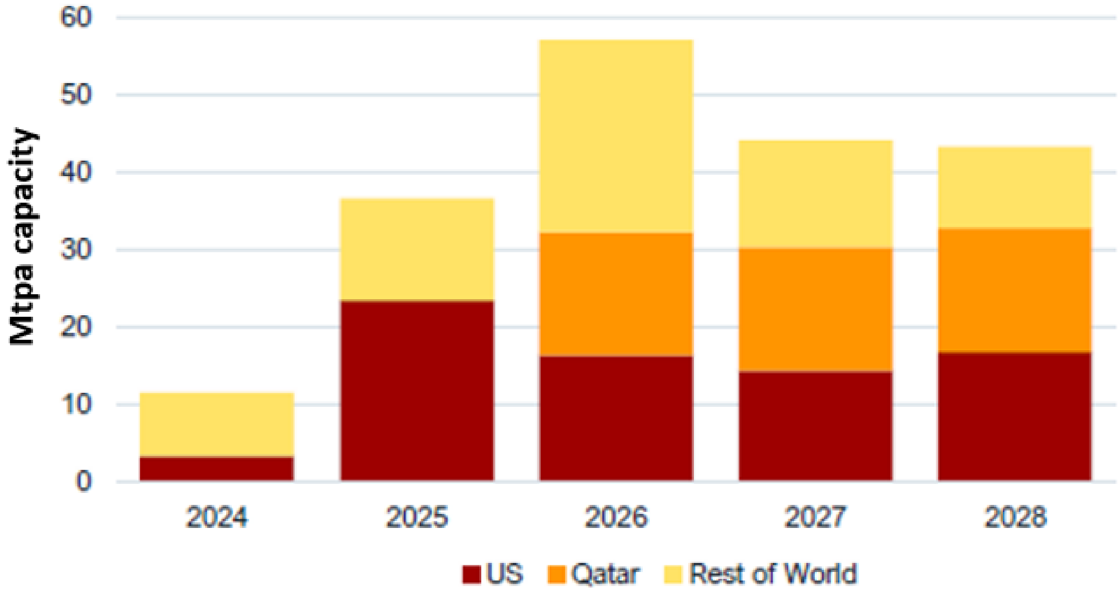
[106] Department of Industry, Science and Resources, *Future Gas Strategy*, Australian Government, May 2024, p 75.

[107] Institute for Energy Economics and Financial Analysis, *Resource firms show transition in exploration and capex spending*, IEEFA Website, 16 July 2024, accessed 6 November 2024.

[108] Institute for Energy Economics and Financial Analysis, *Global LNG outlook 2024–2028*, IEEFA Website, April 2024, pp 7–8.

[109] Institute for Energy Economics and Financial Analysis, *Global LNG outlook 2024–2028*, IEEFA Website, April 2024, p 6.

Chart 5.4: New LNG supply from projects that have commenced construction or have been approved with financially capable backers 2024–2028



Source: Institute for Energy Economics and Financial Analysis **(IEEFA).**

Increased international LNG supply could put downward pressure on international LNG prices over the medium term. While this may not substantially affect LNG producers' supply in the short term (as most of their gas production is for supporting fixed quantities under long-term foundational contracts), it may affect how they develop excess gas, which could be supplied either to the domestic market or the international spot market. It would also affect the price of LNG imports into the east coast gas markets, if these are utilised in the near term.

On the other hand, while substantial new supply is expected, if global gas demand continues to grow and there are delays to the expected projects, the impact on LNG prices may be minor. There is some uncertainty on future demand for LNG as shown in the varied expert forecasts (chart 5.5).

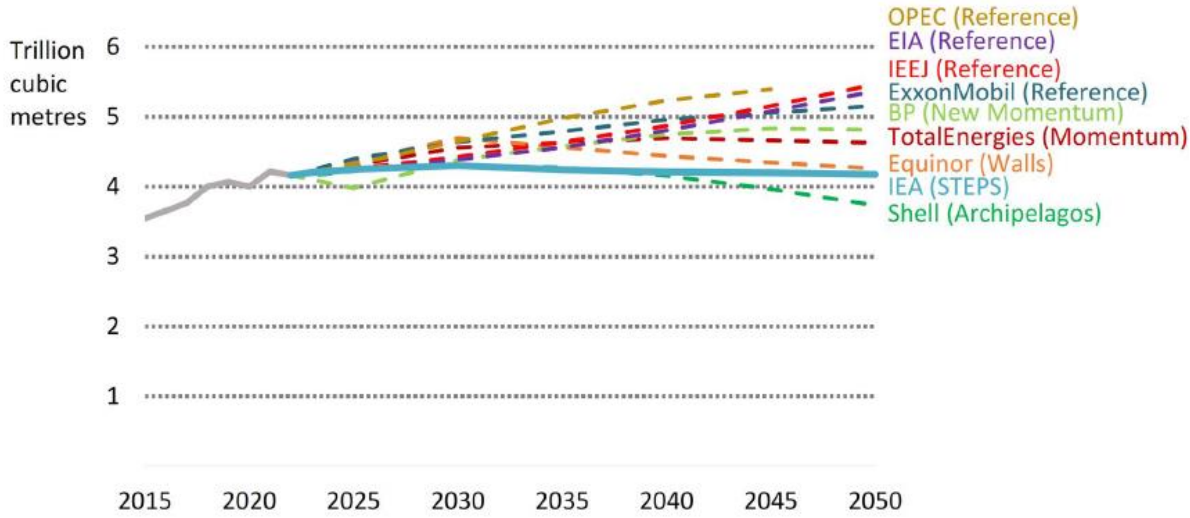
LNG demand growth is projected to be led by emerging Asian markets as they move from coal to gas-powered generation and renewable energy to meet growing energy needs while reducing their emissions.[110] However, there are some views that this increase in LNG demand may be overstated as emerging Asian markets face financial, logistical and political challenges to build LNG import capacity.[111] Increased demand from emerging Asian markets is also expected to be partially offset by declining demand through the 2030s from some of the largest LNG importers historically in Europe, Japan and South Korea.[112]

110 Department of Industry, Science and Resources, *Future Gas Strategy*, Australian Government, May 2024, p 56.

111 Institute for Energy Economics and Financial Analysis, *Global LNG outlook 2024–2028*, IEEFA Website, April 2024, p 40.

112 Institute for Energy Economics and Financial Analysis, *Global LNG outlook 2024–2028*, IEEFA Website, April 2024, p 5.

Chart 5.5: Global long-term natural gas demand forecasts comparison with IEA Stated Policies Scenario (STEPS)



Source: IEA.

Note: Projections are normalised to align all scenarios with real historic data. All projects are to 2050 except OPEC.

In the longer term, if international demand remains elevated, this will continue to incentivise Australian LNG producers to develop and export gas, and it may have effects on the prices offered for gas supply on the east coast. Under the STEPS[113] export volumes scenario there would need to be significant investment in new Australian gas supply for export and recontracting to continue high levels of exports as foundational LNG export project contracts end in the 2030s.

[113] The Stated Policies Scenario (STEPS) is one of the scenarios modelled by the IEA to forecast future global energy demand. It is designed to provide a sense of the prevailing direction of energy system progression, based on a detailed review of the current policy landscape. The STEPS provides a more conservative benchmark for the future than the Announced Pledges Scenario (APS), by not taking for granted that governments will reach all announced goals.

6. Status of gas investments and infrastructure

Key points

- There are a large volume of new gas projects that if approved, could deliver sufficient gas to meet demand over the next decade and beyond.
- Prospective gas supply sources are mostly made up of contingent 2C resources, which may be speculative, require supporting infrastructure to transport gas to where it is required, and face several barriers to coming online.
- The single largest source of potential new supply in the southern states is the Narrabri Gas Project (Narrabri). Legal challenges and community opposition have made the progression of this project uncertain.
- Queensland's Surat and Bowen basins are the largest developed basins on the east coast and are a key source of ongoing supply.
- Gas supply from the recently approved Surat Gas Project, encompassing APLNG's Towrie Project in the Bowen Basin, and Arrow Energy's specific fields that are part of the Surat Gas Project, is expected to predominantly fulfill LNG exports.
- There are other potential new sources of gas in Queensland that are subject to the Queensland Government's *Australian Market Supply Condition*, which is aimed at securing gas for the domestic market. However, these projects are yet to be approved.
- Untapped basins such as the North Bowen and Galilee Basin in Queensland, and the Beetaloo basin in the Northern Territory present strong potential for additional supply to the domestic market. However, infrastructure development and regulatory approvals are still required to ensure that these projects are connected to the east coast gas market.

6.1. Introduction

The east coast has sufficient gas reserves and resources to meet current demand projections over the next decade and beyond. With declining reserves from the Bass Strait, gas supply will need to come from a variety of sources, including Queensland, Northern Territory, and potentially LNG imports. This will require investment in transportation infrastructure and storage.

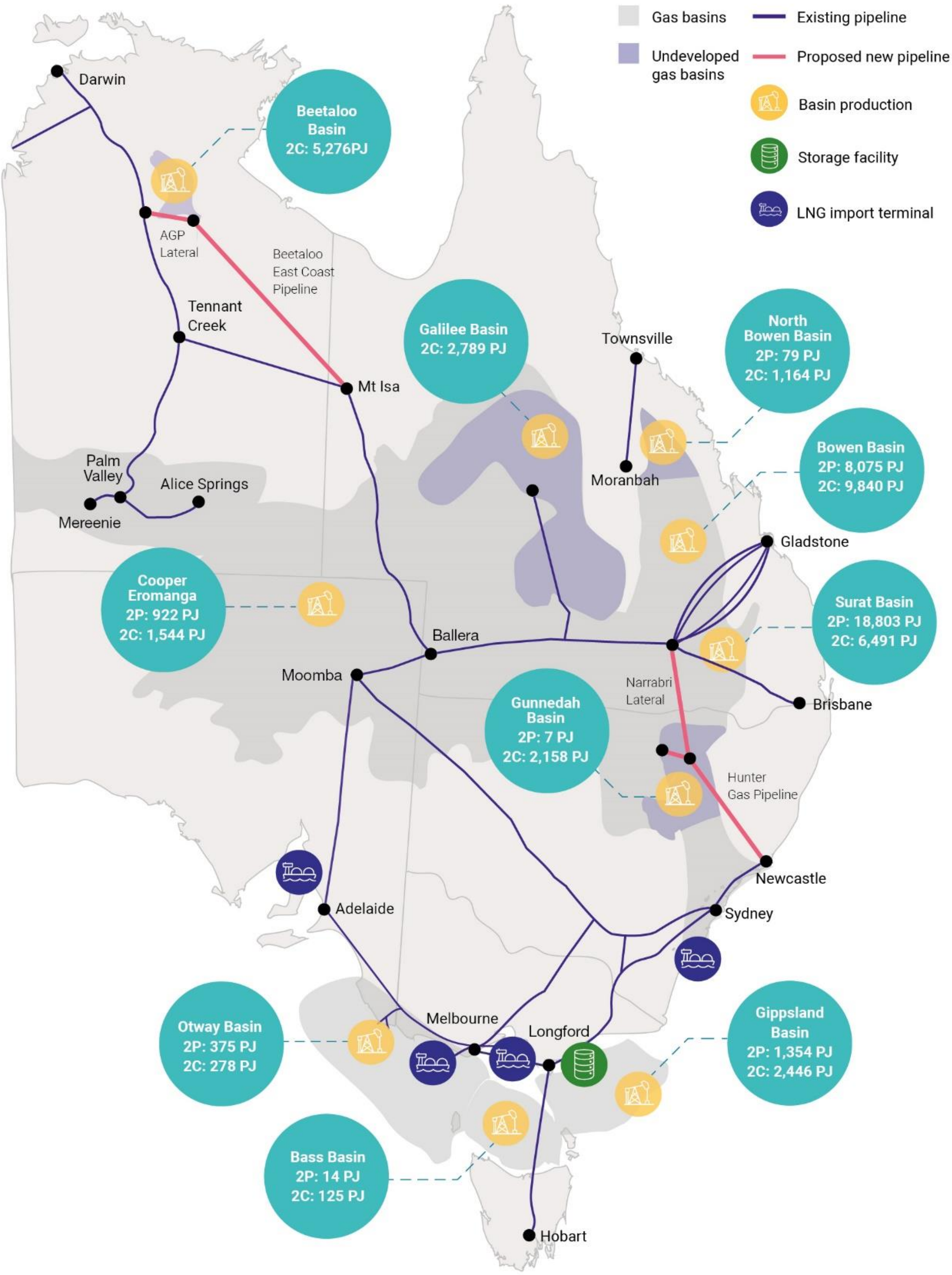
This chapter provides an overview of the new sources of supply and infrastructure that could potentially be brought online to provide gas from 2024 to 2036, and beyond. It also outlines risks faced by producers and infrastructure providers in bringing projects online.

The section covers:

- new supply and infrastructure projects in the southern states (section 6.2)
- new supply projects in Queensland (section 6.3)
- new supply and infrastructure projects in the Northern Territory (section 6.4).

A list of potential new sources of supply and total reserves and resources in the respective basins is illustrated in chart 6.1.

Chart 6.1: Current reserves and resources and potential sources of new supply



Source: ACCC analysis of data reported in the *Gas Inquiry 2017–2030*, December 2023, p 63, and public information from AEMO, Reserves Resources Reporting and Facility Developments, accessed on 19 November 2024.

6.2. New sources of production and infrastructure investment in the southern states

Gas production in the southern states is facing challenges due to declining reserves in the Bass Strait, which has historically been the largest source of gas to the region. The southern states are expecting to face shortages of gas produced from local reserves from 2026.

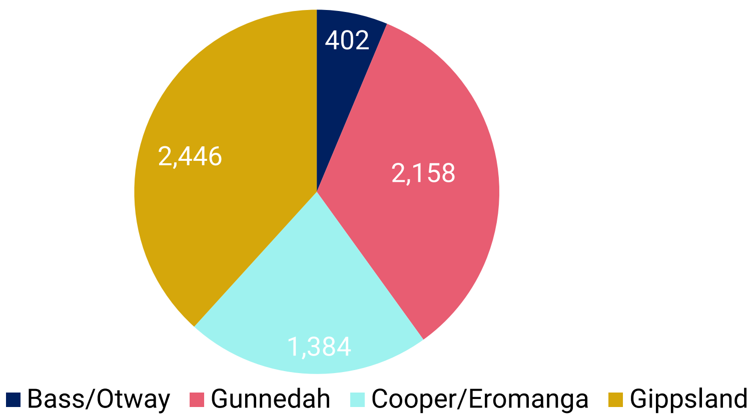
As outlined in chapter 2, investments in gas production, storage and transport are needed to reduce the risk of winter seasonal shortfalls and annual supply gaps in the southern states.[114] This section discusses:

- new gas supply projects in the southern states
- LNG import terminals
- investment in key pipeline and storage infrastructure required to connect the dispersed sources of gas to demand and to provide storage of gas for withdrawal when needed.

6.2.1. New gas supply projects in the southern states

The southern states are expected to substantially deplete their known gas reserves by the mid-2030s. However, chart 6.2 shows that there is approximately 6,390 PJ of contingent resources held by southern producers and explorers, including several supply projects that are in various stages of development.[115].

Chart 6.2: Volumes of 2C resources held in the southern states by basin (PJ)



Source: AEMO. Reserves Resources Reporting and Facility Developments, accessed 22 October 2024.

Gas producers and explorers have reported approximately 20 southern supply projects that could potentially come online between 2026 and 2035. Most of these projects propose to supply gas from 2028 onwards but have not yet been approved for development and require final investment decisions to proceed.

114 AEMO, *Gas Statement of Opportunities*, AEMO [website], 2024, accessed 28 November 2024.

115 Contingent resources are those quantities that are potentially recoverable but not yet commercial to develop, due to one or more contingencies (e.g. there is currently no viable market, the commercial recovery depends on technology under development, or the evaluation of the accumulation is insufficient to assess commerciality) see ACCC, *Gas Inquiry 2022 interim report*, p 143.

The single largest potential source of supply is the Santos Narrabri Gas Project, in New South Wales. Narrabri holds approximately 58% of identified 2C resources in the southern states and has potential to supply up to 50% of the state's gas demand requirements.[116] Santos has reported that it anticipates being able to supply gas from 2028 should the project proceed (refer to Appendix G, table G.1). However, it has been reported that a final investment decision is contingent on land access agreements, environmental surveys and initial works for the Hunter Gas Pipeline.[117]

This project relies on construction of the Hunter Gas Pipeline route, which connects Narrabri to Newcastle and the rest of the east coast. The Hunter Gas Pipeline project is opposed by Gomeroi Traditional Owners, farmers, and landholders, including for environmental reasons.[118] The main challenges facing the Narrabri project are outlined in box 6.1 below.

Box 6.1: Narrabri Gas Project – Gunnedah Basin

The Narrabri Gas Project is a large gas project located in the Gunnedah basin in New South Wales. In November 2011, Santos acquired Narrabri-based Eastern Star Gas and the company's operations in and around Pilliga, which included the Narrabri Gas Project.[119] Santos has indicated that gas production could commence in 2028.[120]

The project has received approval from the New South Wales Independent Planning Commission,[121] and is now awaiting environmental approvals. The New South Wales Government recently renewed Santos's authority to conduct surveys for the Hunter Gas Pipeline and has also granted permission for surveys related to Narrabri Lateral Pipeline.[122]

The Narrabri project has faced some challenges, including:

- Legal challenges: In 2021 there was an appeal made which raised concerns about the project on groundwater supplies and the environment 123. This appeal was rejected by the NSW Land and Environment Court in October 2021.124 In January 2023, the Gomeroi people filed a Native Title appeal[125] and in March 2024, the Federal Court upheld their appeal, ruling that the Native Title Tribunal should have allowed evidence on climate change when considering the Narrabri Gas Project.[126]

116 Santos, Narrabri Gas Project, Santos [website], 2023, accessed 14 October 2024

117 The Courier, Santos drilling for gas demand well into the future, 21 August 2024, accessed 14 October 2024.

118 G Warner, Hunter Gas Pipeline protesters to head Narrabri-Newcastle convoy, *NBN News* 23 September 2024, accessed 14 October 2024.

119 Santos, The Narrabri Gas Project: Santos in NSW, [website], 2024, accessed 28 November 2024.

120 Santos, Federal Court allows appeal against native title 'future act' decision for Narrabri Gas Project, [media release], 7 March, 2024, accessed 15 October 2024.

121 New South Wales Government Independent Planning Commission, Narrabri Gas Project [website], 2022, accessed 15 October 2024.

122 The Australian, Santos preliminary Narrabri works approved after report clears if of improper landowner negotiations, 24 September 2024, accessed 14 October 2024.

123 P Bell, Planning authority was 'legally irresponsible' approving Narrabri Gas Project, appeal court told, *ABC News*, 31 August 2021, accessed 17 October 2024.

124 P Bell, Court rejects farmers' appeal against approval of multi-billion-dollar Narrabri Gas Project, *ABC News*, 18 October 2021, accessed on 15 October 2024.

125 P Bell and L Oataway, 'Gomeroi people file Native Title appeal against Santos Narrabri Gas Project, pipeline one step closer', *ABC News*, 2023, accessed on 15 October 2024.

126 J Paras and M Tillman, Traditional owners' appeal against $3.6 billion Santos Narrabri Gas Project upheld by Federal Court,] *ABC News*7 March 2024, accessed on 15 October 2024.

- Community opposition: There have been significant opposition from the local communities and environmental groups about the project's impact on the environment, water supply and local heritage. [127]

Santos has indicated that it is working through land access, native title, pipeline licensing and remaining environmental approvals to prepare the Narrabri Gas Project for final investment decision.[128]

Proposed projects by explorers and small suppliers in the southern states

In addition to Narrabri, a significant proportion of the gas resources in the southern states are held by explorers and small suppliers. Up to ~979 PJ of contingent resources has been identified in potential projects from Emperor Energy, SGH Energy, GB Energy, and Lakes Blue Energy (Appendix G). These companies are examples that the potential development of gas resources from smaller and diverse suppliers could support greater competition in the southern markets and reduce potential shortfalls. However, these smaller scale projects can face substantial barriers and challenges in comparison and addition to their much larger counterparts.

Most of these projects have been previously reported as potential new projects. However, most have also been delayed by 1 to 2 years. The most common risks reported by this group of suppliers are financial and regulatory approvals. The ACCC previously reported that a challenge faced by small companies and explorers in the gas sector is access to capital and underwriting projects,[129] with long-term supply contracts. Environmental, social and governance concerns have started to limit the availability of debt and equity funding for gas projects[130], as evident in the reduction in Australian bank funding to fossil fuel companies.[131]

The ACCC also previously reported that access to infrastructure (in particular, gas processing facilities and gathering pipelines) is a significant barrier faced by smaller producers and producers in more marginal fields. These barriers, together with the financial risks, regulatory approval risk reported by these suppliers and the speculative nature of their status, make the possibility of the projects coming online uncertain.

The use of existing infrastructure can help connect new sources of supply to demand in the east coast gas market (see box 6.2). The ACCC previously found that introducing a third-party access regime in relation to infrastructure may increase competition and the timeliness of the delivery of new supply to the market.[132].

A breakdown of the new supply projects in the southern states is shown in table G.1 in Appendix G.

127 G Wakatama, *'Newcastle rally shows support for traditional owners in fight to stop Santos' Narrabri gas project*, *ABC News 13 October* 2023, accessed 14 October 2024.

128 Santos, *Federal Court allows appeal against native title 'future act' decision for Narrabri Gas Project* [media release], 7 March 2024, accessed October 2024.

129 ACCC, *Gas Inquiry 2017–2030 Interim report*, January 2022 p 87.

130 ACCC, *Gas Inquiry 2017–2030 Interim report*, January 2022 p 87.

131 Market Forces, *Big four Australian banks pour $3.6 billion into fossil fuels in 2023* [media release], 16 July 2024, accessed 16 October 2024; Jo Lauder, *Commonwealth Bank stops lending to fossil fuel companies without genuine emissions plan*, *ABC News*, 17 August 2024, accessed 16 October 2024.

132 ACCC, *Gas Inquiry 2017–2030 Interim report, January 2022*, p 69.

Box 6.2: Use of existing infrastructure to connect new sources of supply to the east coast

There are several gas supply developments in the southern states which highlight the potential benefits in maximising existing infrastructure and in providing access to this infrastructure. These also highlight the challenges for new and smaller producers that need to invest or rely on other parties for infrastructure.

Beach Energy is developing the Otway Offshore Gas Victoria Project (OGPP) which aims to develop gas for the east coast domestic gas market, adjacent to the company's existing permits and infrastructure. The project intends to connect gas discoveries to the OGPP. The estimated production from the OGPP, if successful, could last 30 years.[133]

Amplitude Energy (formerly Cooper Energy) has indicated plans to restart the Patricia and Baleen wells in the Gippsland basin, connected into OGPP for potential storage on the Eastern Gas Pipeline.[134] These plans may indicate maximising the use of existing infrastructure. Cooper Energy has studied existing equipment and will use test results in the overall assessment of the feasibility of this gas storage project.[135]

Emperor Energy's Judith Gas Project, located 40km offshore from the OGPP, is expected to commence production in 2029 and is an onshore gas processing plant adjacent to the existing OGPP.[136] To successfully develop the Judith Gas Project, it is understood Emperor Energy will seek to[137]:

- design and build the 40 km long subsea pipeline to transport gas from the Judith Gas project
- integrate the new pipeline with the existing infrastructure at the OGPP and the Eastern Gas Pipeline, ensuring seamless operation and gas flow.

Given the OGPP is not owned by Emperor Energy, an access to infrastructure challenge may arise and Emperor Energy may need to negotiate access to this infrastructure.

As previously noted by the ACCC, upstream competition and the timeliness of supply could be significantly improved if owners of existing upstream infrastructure provided third party access to on reasonable terms.[138]

In addition to these projects from smaller suppliers, larger players in the southern states are making some expansions to their production. Esso recently announced completion of its Kipper Compression Project,[139] and FID is expected in 2024 on their Turrum Phase 3 project (see table G.1 in Appendix G for more information). Both projects form part of the conditions of Esso's conditional Ministerial exemption from provisions of the Gas Code.[140]

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133 National Offshore Petroleum Safety and Environmental Management Authority, *Otway Offshore Gas Victoria Project Proposal* , Australian Government, 2024, accessed 14 October 2024.

134 Cooper Energy, 2024 Investor Briefing [media release], 4 June 2024, accessed 17 October 2024.

135 Cooper Energy, *Annual Report FY24*, 27 August 2024, accessed 28 November 2024, p 28.

136 Emperor Energy, *Annual Report to shareholders*, 20 September 2024, accessed 28 November 2024, p 3.

137 R Wilkinson, '*Emperor Energy begins pre-FEED for Judith gas field* ' [media release], Oil & Gas Journal, 20 May 2020, accessed 17 October 2024.

138 ACCC, *Gas Inquiry 2017–2030 Interim report,* January 2022, p 69.

139 ExxonMobil, *Esso Australia delivers crucial project for Australian natural gas supplies,* [media release],18 October 2024, accessed 20 November 2024.

140 Department of Climate Change, Energy, the Environment and Water (DCCEEW), *Competition and Consumer (Gas Market Code) Regulations 2023 – Decision Notice – Exemption from provisions of the Gas Market Code – Esso Australia*, Australian Government, 2024, accessed 20 November 2024.

6.2.2. Other potential supports to supply in the southern states

LNG import terminals

Southern states are pursuing the importation of LNG to address forecast east coast gas market shortfalls. There are 4 LNG import terminals in various stages of development, with the Port Kembla Gas Terminal in New South Wales the most advanced (table 6.1).

LNG import terminals require a floating storage and regasification unit (FSRU). These units can be redeployed depending on global demand and, as such, would be able to meet domestic short-term demand spikes as well as provide additional storage capacity at peak demand times.

The first LNG imports could commence from as early as 2026 through the Port Kembla Gas Terminal. The proposed terminals have capacity to import between 80 and 200 PJ per annum (table 6.1).

Table 6.1: Proposed LNG import terminals

Developer	Name	Status	FID date	Supply date	PJ p.a.	Key risks
Victoria						
Viva Energy	Viva Energy Gas Terminal Project	Front End Engineering Design (FEED) completed	Quarter 4, 2025	Quarter 2, 2028.	80 to160	R, C, I, MU. M
Vopak Terminals	Vopak Victoria Energy Terminal	Pre-FEED	September 2026	March 2029	150 to 200	R, F, C, I, MU, M
New South Wales						
Australian Industrial Energy (AIE)	Port Kembla Gas Terminal	Construction in progress	Complete	Quarter 2, 2026.	130	C, R, MU, M
South Australia						
Venice Energy	Venice Energy – Outer Harbour LNG Import Project	Pre-FID	October 2024	January 2027	90	C

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates **reflect estimates** only and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, i.e. securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **G** = Geologic.

The Port Kembla LNG Import Terminal is the most progressed in its development, with construction underway. The developer of this terminal anticipates that it will be able to import gas from quarter 2 2026.

Venice Energy has updated the expected supply date of its Outer Harbour LNG Import Project, which is the next most progressed proposal, from May 2026 to January 2027. Recently, Venice Energy commenced negotiations to secure an international partner with relevant skills, track record and finance to underwrite the development of the terminal.[141] Venice has stated that if the final investment decision can be made in the second half of

141 Venice Energy, *Negotiations begin on $300m SA LNG Import terminal partnership* [media release], 6 August 2024, accessed 17 October 2024.

2024 as scheduled, construction of the project will be complete by the end of 2026, which will allow start supply prior to winter in 2027.[142]

The 2 proposed import terminals located in Victoria are the least progressed, with both citing regulatory approvals as a key risk. Since we last reported in December 2023, Viva Energy has updated its expected supply date from 2027 to 2028 while Vopak Terminals has updated both its FID date from quarter 4 2025 to September 2026, and expected supply date from quarter 2 2028 to March 2029. These terminals are still awaiting regulatory approvals.

The 2 main challenges facing LNG import terminals are finding buyers to enter foundational contracts to underwrite the projects and obtaining necessary regulatory approvals. While regulatory approvals appear to have affected some of the proposed LNG import terminals, we understand that none of the developers have, at this stage, entered into agreements with customers to import LNG through their facility.[143] In the case of Venice Energy's proposed LNG import terminal project, the retailer, Origin, indicated its interest in sponsoring this project and had gone as far as entering into an arrangement to enable it to negotiate with Venice Energy on the exclusive use of this facility.[144] However, in February 2024, it was reported that Origin had decided not to proceed because large gas users were unwilling to sign multi-year agreements, raising unacceptable risks.[145]

In chapter 7, we examine in more detail the prospect and role of LNG import terminals on the east coast gas market in the short and longer term.

6.2.3. Investment in pipelines and storage infrastructure

Pipelines

The development of pipeline infrastructure is important to connect existing and new sources of supply in the east coast, including from Queensland or LNG import terminals. This section provides an update on pipeline and storage infrastructure developments in the east coast gas market.

Table 6.2 lists potential new pipelines and expansions that will improve gas delivery to the southern states.

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142 Venice Energy, *Negotiations begin on $300m SA LNG Import terminal partnership* [media release], 6 August 2024, accessed 17 October 2024.

143 A Macdonald-Smith, *Choke in gas supply makes imports, once unthinkable, almost inevitable*, *The Australian Financial Review*, 19 August 2024, accessed 17 October 2024.

144 Venice Energy, *Chairman's Update*, [media release], 15 February 2024, accessed 14 October 2024.

145 Packham, C. *Origin baulks at LNG import terminal in SA, as east coast supply pressure increases, The Australian,* 14 February 2024, accessed 10 October 2024.

Table 6.2: New and expansion of pipelines connecting the southern states and the east coast gas market

Developer	Name	Description	Nameplate capacity	Final investment decision	Commission date	Key risks
New pipelines						
Santos	Narrabri Lateral Pipeline (NLP)	Narrabri LGA Connect Narrabri Gas Project (NGP) to Hunter Gas Pipeline (HGP)	Nominal 250TJ/d (20inch sizing)	2026	2028	C, L, R
	Hunter Gas Pipeline (HGP)	Narrabri to Newcastle (JGN)				
Pipeline Expansion						
APA	East Coast Gas Grid Expansion	Additional compression and associated works on the Southwest Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP)	Stage 1 and 2 expansions collectively increased westernhaul capacity of the SWQP by approximately 101 TJ/d (from a base of 404 TJ/d to a capacity of 512 TJ/d) and the southernhaul capacity of the MSP by approximately 119 TJ/d (from a base of 446 TJ/d to a capacity of 565 TJ/d). APA is currently exploring an alternative configuration for the Stage 3 expansion of the SWQP and MSP which may include a new interconnect between the SWQP and MSP plus additional MSP compression, with the view to expanding SWQP westernhaul up to a nominal 600 TJ/d, MSP southernhaul capacity up to a nominal 700 TJ/d (supplied from both SWQP and Moomba Gas Plant) and capacity to Culcairn up to a nominal 260 TJ/d by 2028. Actual nameplate capacities of each leg to be confirmed during Front End Engineering and Design.	Stage 1 and 2 FID has occurred. Timing of MSP Stage 3a and 3b and SWQP Stage 3 is unknown at this time and is on hold pending further clarity on the outcomes of the AER SWQP regulatory review.	Stage 1 – May 2023 Stage 2 – May 2024 Stage 3a – 2026 (FID dependent) MSP Stage 3b – Unknown (FID dependent) SWQP Stage 3 – Unknown (FID dependent)	M,W,C,F,R

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates **reflect estimates** only and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, i.e. securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **G** = Geologic.

The expansion of the East Coast Gas Grid via the Moomba Sydney Pipeline and the Southwest Queensland Pipeline is important as both pipelines are key pathways for delivery of gas from Queensland, the Cooper Basin, and the Northern Territory to the southern states.[146]

The APA paused the project pending the outcome of the AER's decision on the form of regulation of the SWQP. The AER's draft decision released on 9 October 2024 mentioned that the SWQP will be subject to non-scheme regulation.[147] APA's CEO noted that if this position was maintained in the AER's final decision, it would provide confidence to invest in the East Coast Gas Grid to support energy security.[148] The timing of the final decision on South West Queensland Pipeline form of regulation review is to be determined as is subject to further consultation and feedback from stakeholders.[149]

The Narrabri Gas Project aims to supply up to 50% of New South Wales' gas requirements.[150] The timing of the final investment decision and commissioning of both Santos' Narrabri Lateral Pipeline and Hunter Gas Pipeline projects have been updated by one year since the ACCC last reported in December 2023. Nonetheless, similar to the Narrabri Gas project, the Hunter Gas Pipeline has been opposed by various groups in the region[151]. The final investment decision is subject to resolution of these challenges.

Pipeline providers have indicated that these potential projects face a range of risks to becoming committed projects (refer to in table 6.3 below and table G.3 in Appendix G). These risks range from uncertainty in obtaining regulatory and native title approvals to commercial and macroeconomic factors. The timeline and the main risks to this proposed pipeline investment are the same as previously reported. The progression of these pipelines is dependent on the outcome of the proposed LNG import terminals.

Table 6.3: New pipeline and pipeline expansion linking LNG import terminals to the east coast market

Developer	Name	Description	Nameplate capacity	FID date	Commission date	Key risks
SEA Gas	Port Campbell to Adelaide (PCA) East	Reconfiguration of the PCA to receive gas from a proposed LNG import terminal at Outer Harbor, SA, or from the MAPS for west – east transportation to Iona / South West	Up to ~ 250TJ/d (nominal) full-haul capacity in a west – east direction.	Unknown – subject to agreeing commercial terms	2026	C, R, M, L
Jemena Eastern Gas Pipeline	EGP/PKET Lateral Connection	Port Kembla	522 TJ/d (lateral capacity)	FID Taken	2025	C

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates **reflect estimates** only and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **L** = Land access. **M** = Macroeconomic.

146 APA, East coast grid expansion [website], 2024, accessed 9 October 2024.

147 Australian Energy Regulator (AER), AER makes draft decision on South West Queensland Pipeline form of regulation review, Australian Government, 9 October 2024, accessed 4 November 2024.

148 APA, APA welcomes AER draft decision on SWQP [media release], 9 October 2024, accessed 14 October 2024.

149 Australian Energy Regulator, AER makes draft decision on South West Queensland Pipeline form of regulation review, Australian Government, 9 October 2024, accessed 4 November 2024.

150 Santos, Narrabri Gas Project Factsheet, November 2023, accessed 14 October 2024.

151 J. Belzycki, 'Nobody wants this': activists hit out at Santos' Hunter Gas Pipeline, *Newcastle Herald*, 13 October 2024, accessed 27 November 2024.

Storage projects

Gas storage services enable gas to be stored for future use. Gas production remains relatively stable throughout the year, however domestic demand for gas varies, peaking especially in the colder winter months. Storage facilities allow for reserves to be built up at times of low demand and drawn from as necessary.

Gas storage facilities can promote market flexibility by providing additional supply options and are an important component of the east coast gas market. For example, additional storage options located in or near southern state demand centres could, meet winter demand peaks and potentially avoid the need for additional north to south pipeline capacity.

The Victorian government recently passed the Offshore Petroleum and Greenhouse Gas Storage Amendment Bill 2024[152] to make it easier to develop offshore gas storage projects in Victoria, including in empty gas reservoirs under the sea.[153]

In July 2024, Snowy Hydro entered into a 25-year gas storage agreement with Lochard Energy, the operator of the Iona Gas Storage Facility, which will provide for an expansion of storage capacity at Iona and allow Snowy Hydro to utilise stored gas to operate its gas fired power stations.[154] [155]

The proposed Golden Beach Energy Storage Project in the Gippsland Basin is also anticipated to provide gas supply and storage infrastructure in the east coast gas market.[156] This offshore project will use large empty reservoirs on the ocean floor and include a pipeline and compressor station that links to Longford, Victoria.[157] After a period of production, it is intended that the project will transition to store energy for domestic use.[158]

At this stage, it is understood the project has undertaken an environment effects statement[159] with the timing of the final investment decision on storage facility and commissioning of the storage capacity still to be determined. Additionally, Origin Energy has reportedly contracted 40% of this project's storage capacity.[160]

These facilities supplement the east coast gas market's largest storage facility, Iona, which has a storage capacity of 24.4 PJ and supply capacity to 570 TJ/d) following upgrades in 2023.[161]

It is important that there is investment in infrastructure to link the dispersed new sources of supply to the demand in the east coast.

152 State Government of Victoria, Offshore Petroleum and Greenhouse Gas Storage Amendment Bill 2024, 6 November 2024, accessed 11 November 2024.

153 K Rooney and M Foley, 'Victoria clears path for giant undersea gas storage project', *The Age*, 9 September 2024, accessed 16 October 2024.

154 Snowy Hydro, *Snowy Hydro signs Lochard gas storage agreement* [website], 15 July 2024, accessed 18 October 2024.

155 Lochard Energy, *Heytesbury Underground Gas Storage Project* [website], n.d., accessed 18 October 2024.

156 GB Energy, *GB Energy is developing the Golden Beach Energy Storage Project* [website], n.d., accessed 18 October 2024.

157 GB Energy, *Development* [website], n.d., accessed 18 October 2024.

158 GB Energy, *Energy Storage* [website], n.d., accessed 18 October 2024.

159 K Rooney and M Foley, 'Victoria clears path for giant undersea gas storage project', *The Age*, 9 September 2024, accessed 16 October 2024.

160 A Macdonald-Smith, 56 years on, Golden Beach gas nears production, *The Australian Financial Review*, 3 February 2023, accessed 22 October 2024.

161 AEMO, *Gas Statement of Opportunities*,, 21 March 2024, p 5, accessed 15 October 2024.

6.3. New supply projects in Queensland

6.3.1. Surat and Bowen Basins

The Surat and Bowen basins are the largest developed basins on the east coast. They provide the majority of 2P reserves and are the likely main sources of ongoing supply.

The LNG producers and their associates (through joint ventures and exclusivity arrangements), including APLNG, QCG, Santos and Arrow Energy, control of the reserves and resources in these basins. This includes around 84% of 2P reserves and 35% of 2C resources.[162]

Table G.2 in Appendix G provides a summary of the domestic supply projects that have been approved and that producers anticipate will commence production by 2029.

Table G.3 in Appendix G provides a summary of the domestic supply projects in Queensland that have not been approved for development but that producers have indicated could potentially come online between 2026 and 2035 if a final investment decision is made to proceed with the development.

Many of the projects in tables G.2 and G.3 have been previously reported in our December 2023 report as potential new projects. A small number of these projects are expected to come online within their previously reported timeframes, while others are experiencing delays of between 1 to 2 years.

APLNG's Towrie project in the Bowen basin and Arrow Energy's specific fields that are part of the Surat Gas Project in the Surat basin are the only projects approved for development since the ACCC last reported on this in December 2023. Proposed projects with the largest gas volumes that have not yet been approved are also by APLNG and Arrow Energy's Surat Gas Project. Arrow Energy, a joint venture between Shell and PetroChina, has a 27-year agreement to sell gas from its Surat Gas Project to the QCLNG facility,[163]which is operated by QGC. Given the Surat Gas Project is primarily to provide gas to QGC, it is anticipated that most of the gas produced from this project may be used by QGC to fulfill its long-term LNG export contracts.

A large proportion of the volumes of new and anticipated projects in Queensland are linked to LNG producers and so are likely to be exported under their long-term contracts. However, under the Heads of Agreement[164], excess gas produced by the LNG producers must be offered to the domestic market for reasonable supply periods, with reasonable notice, on competitive market terms and at prices no more than international customers will pay, before being offered to the international market.

The primary risk for these producers is obtaining regulatory approvals, while the timing and volumes of some projects may depend on market conditions. Unlike the southern states, only one out of the 4 suppliers (and one out of 11 projects) has indicated financing is as a substantial barrier to gas supply.

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162 AEMO, *Reserves Resources Reporting and Facility Developments*, accessed 22 October 2024.

163 Shell Global, *Shell invests in Phase 2 of Surat Gas Project in Australia* [media release], 12 August 2024, accessed 15 October 2024.

164 DISR, *Head of Agreement. The Australian East Coast Domestic Gas Supply Commitment*, Australian Government, 2022, accessed 30 October 2024.

Outside of the LNG producers, Comet Ridge's Mahalo Gas project (a joint venture between Comet Ridge (57.14%) and Santos (42.86%))[165] is expected to commence supply from as early as 2027 subject to approvals. This project has a sizeable number of reserves and resources. Gas produced from this project could be used to both supply the domestic market and to fulfil export contracts.

6.3.2. Gas subject to the Australian Market Supply Condition

The Queensland Australian domestic market supply conditions require that the holder of the authority to prospect, that is to explore for natural gas amongst other resources in Queensland, must only sell gas produced from the tenure (or a subsequent lease) to customers within Australia. [166] Recently, 6 tenders were awarded by the Queensland government for petroleum and gas exploration in the Surat and Bowen Basins. One of the 6 tenders was subject to the Australian Market Supply Condition.[167]

There is some additional gas being produced in Queensland that is solely for the domestic market. Recently, Senex announced that it would proceed with the expansion of its Atlas and Roma gas developments in the Surat Basin, which is expected to supply 60 PJ of gas annually to the east coast gas market,[168] early in 2025.[169] This gas is subject to the Australian market supply condition, as well as being part of the conditions of Senex's conditional Ministerial exemption from provisions of the Gas Code.[170] The project was previously put on hold in late 2022 in response to the federal government's energy cap announcement.[171]

Comet Ridge has a 100% interest in and is the operator of the Mahalo North project, which is subject to the Market Supply Condition.[172] In 2023, Comet Ridge and Jemena signed an MOU and pre-FEED agreement to evaluate a new 73km gas pipeline connecting the Mahalo North Project to Jemena's Queensland Gas Pipeline which is linked to entry into Queensland's gas network.[173] The Mahalo East Project, also 100% owned and operated by Comet Ridge is subject to the Market Supply Condition,[174] and the timing of supply from this project is currently unknown.

The current volumes covered by the Australian Market Supply Condition are not sufficient to cover forecast shortfalls.

[165] Comet Ridge, *Mahalo Gas Project* [website], 2022, accessed 14 October 2024.

[166] Queensland Government, *Australian domestic market supply condition*. N.y.

[167] Queensland Government Department of the Premier and Cabinet, *Gas tenders as Queensland continues to support domestic gas market* [media release], 25 June 2024, accessed 14 October 2024.

[168] Senex, *Green light for Senex's $1 billion investment to boost domestic gas supply* [media release], 26 June 2024, accessed 14 October 2024.

[169] Senex, *Senex Energy delivers on promise of more domestic natural gas supply with official opening of $1 billion expansion* [Media release], 25 November 2024, accessed 26 November 2024.

[170] Senex, *Decision Notice – Senex*, 21 November 2023, accessed 20 November 2024.

[171] D Chen, *Government approves Senex Energy's Surat Basin gas expansion plans*, *ABC News*, 26 June 2024, accessed 16 October 2024 and Beveridge, A, *Senex Energy says its gas expansion has been put on hold after energy cap announcement*, *ABC News,* 22 December 2022, accessed 16 October 2024.

[172] Comet Ridge, *Mahalo North Project* [website], 2022, accessed 16 October 2024.

[173] Topalovic, V, *New pipeline for Mahalo North project, The Australian Pipeliner*, 15 May 2023, accessed 2 December 2024; and Pipeline & Gas Journal, Comet Ridge, *Jemena Ink Deal for Mahalo North Gas Pipeline*, [website] 22 May 2023, accessed 2 December 2024.

[174] Comet Ridge, *Mahalo East Project* [website], 2022, accessed 16 October 2024.

6.3.3. North Bowen and Galilee basins

The North Bowen and Galilee basins in Queensland are a large potential source of additional supply to the east coast gas market. These basins are estimated to hold around 17,661 PJ of gas, however, current gas production levels in the region are low, at approximately 9 PJ per year.[175]

The basins are currently undergoing exploration by smaller companies such as Blue Energy, Comet Ridge and Vintage Energy (refer table G.3 Appendix G). The Glenaras project in the Galilee basin, which is 100% owned and operated by Galilee Energy, has approximately 2,500 PJ of 2C resources, and is placed to supply both the domestic and LNG export markets.[176]

The development of the basins has reportedly faced challenging geological conditions and require increased testing of cutting-edge drilling techniques to reduce the costs of production.[177]

Projects in the North Bowen and Galilee basins are proposed by companies that primarily conduct exploration activities or are relatively small producers. The timing of final investment decisions and likely supply dates of projects, which are largely speculative at this stage, are unknown. These regions are not connected to the rest of the east coast gas markets and also require gas.

Producers in the North Bowen and Galilee basins have indicated significant risks that could impede the projects going ahead. These include risks relating to regulatory approvals, land access, policy uncertainty, commercial factors and access to infrastructure and finance for the smaller producers. It is important to note that even if projects are approved, they may still take longer to come online, given these risks remain until production commences.

6.4. New sources of production and infrastructure investment in the Northern Territory

The Northern Territory holds significant gas reserves, including in the Beetaloo basin, which is a major focus for new gas projects. This basin is undeveloped but has potential to provide additional gas to the east coast gas market.

In mid-2023, the Northern Territory government lifted the moratorium on fracking in the Beetaloo Basin, allowing full-scale operations. The Northern Territory government- owned Power and Water Corporation[178] has reportedly entered into a 9-year gas supply agreement with Tamboran Resources to purchase gas.[179] The lifting of the moratorium has provided an opportunity for additional supply of gas into the east coast gas market, subject to the approval of the project and development of infrastructure.

A snapshot of the projects in the Northern Territory that are yet to be approved are shown in table 6.4. The projects are expected to have final investment decisions made in 2024 for commencement of supply in as early as 2025.

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175 DISR, *North Bowen and Galilee Strategic Basin Plan: Resources Potential* [website], n.d., accessed 18 October 2024.

176 Galilee Energy, *Glenaras Gas Project* [website], 2022, accessed 16 October 2024.

177 DISR, *North Bowen and Galilee Strategic Basin Plan: Summary of the plan* [website], n.d., accessed 18 October 2024.

178 Fitzgerald, D, *Power and Water Corp plans to buy, on-sell Beetaloo gas as Blacktip issues continue*, *ABC News*, 23 June 2023, accessed 28 November 2024.

179 S Dick, D Fitzgerald and T Morgan, '*NT government signs deal with Tamboran Resources to buy Beetaloo Basin gas*', *ABC News*, 23 April 2024, accessed 17 October 2024.

Table 6.4: Northern Territory projects not yet sanctioned that could commence supply between 2024 and 2026

Supplier	Project or field	Reserves (PJ) 2P	3P	Resources (PJ) 2C	FID	Supply year	PJ p.a	Key risks
Beetaloo basin								
Empire Energy	Carpentaria	-	-	1,739	2024	2025	9.1	R
Tamboran Resources	EP 98/76/117	-	-	1,246	2024	2026	5.7	C
	Total	**-**	**-**	**2,985**			**14.8**	

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates **reflect estimates** only and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks.

As the Beetaloo Basin is undeveloped and far removed from the east coast, substantial investment in pipeline infrastructure would be required to link the basin to the east coast gas market.[180]

The proposed new pipelines that would link supply from the Northern Territory to the east coast gas market are shown in table 6.5. The APA's new pipeline project, the NT – Beetaloo East Coast Pipeline, has an unknown final investment decision date but an expected commission date of 2028. This status is unchanged since our previous report. The commission date for the Sturt Plateau Pipeline that is the Beetaloo (Shenendoah) connecting to Amadeus Gas Pipeline in the Northern Territory is now expected to be commissioned in 2026 (previously 2025), however the financial investment decision date remains the same.

[180] ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, p 65.

Table 6.5: Proposed new pipelines linking the Northern Territory to the east coast with potential for commissioning by 2028

Developer	Name	Description	Nameplate capacity	FID date	Commission date	Key risks
APA	NT – Beetaloo East Coast Pipeline	A new pipeline facility connecting the Beetaloo Basin in NT to Mt Isa, Tamboran Resources proposed NT gas development, and expansion of the Carpentaria Gas Pipeline (CGP) to provide for additional gas supply onto the SWQP	Stage 1 – 150–200 TJ/d (New pipeline to Mt Isa ~800km) Stage 2 – 400–700 TJ/d (Looping of the CGP + compression) Stage 3 – 1000 TJ/d+ (Looping and compression)	Timing of FID is unknown as it is dependent on customer demand, subsurface results and upstream capital, which carries significant uncertainty.	2028	C,G,M,F
APA	Sturt Plateau Pipeline (SPP)	Beetaloo (Shenendoah) connecting to Amadeus Gas Pipeline (AGP) in NT	40 TJ/d (expandable up to 100 TJ/d subject to engineering and physical infrastructure upgrades)	2024	2026	C

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates **reflect estimates** only and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, i.e. securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **G** = Geologic.

Gas pipeline infrastructure projects such as the above are dependent on gas production projects coming online and linking these to the rest of the east coast gas market. The decision to proceed with infrastructure projects is contingent on final investment decisions being made by producers to bring on new supply sources, to which the pipelines would connect.[181] If the production projects are delayed or cancelled there will be no requirement to proceed with the infrastructure.

In 2023, Tamboran Resources signed non-binding letters of intent with 4 potential buyers to potentially buy gas from the Beetaloo Basin for 10–15 years, however Tamboran will still need to execute binding GSAs to confirm supply in 2028.[182] Market and commercial factors affecting customers will play a key role in the advancement of these projects.

The Beetaloo project is far more progressed in terms of regulatory approvals, timing of final investment decision and supply date than other potential sources of supply but has faced opposition due to environmental concerns (box 6.3).[183] Delays in the Beetaloo project have implications for the viability of the proposed pipeline, even before it obtains regulatory approvals. While the Northern Territory Supreme Court has recently rejected legal challenges to the Beetaloo project[184], the delays and opposition faced are a relevant consideration for any future offshore projects, potentially deterring investor appetite.

Box 6.3: Case study: Tamboran Resources

The moratorium on hydraulic fracking was lifted by the Northern Territory Government in May 2023.[185] Producers such as Tamboran Resources have entered into binding sales agreements with the Northern Territory government seeking to provide a stable supply of gas. [186]

Tamboran Resources is a key player in the Beetaloo Basin, holding the largest operated acreage position.[187] The company is taking actions to progress gas exploration in the Beetaloo basin and is expected to commence gas production, subject to final stakeholder and regulatory approvals, with a focus on ensuring sufficient gas supply for the domestic market. [188]

The project has faced a series of legal challenges from anti-fracking activists, and most recently an urgent application filed by the Environment Centre Northern Territory (ECNT) in a bid to pause the project until a decision is made by the Court on whether the project poses significant risk to water.[189] However, the NT Civil and Administrative Tribunal (NTCAT) rejected this application because the ECNT's case did not have good prospects of success,

181 ACCC, *Gas Inquiry 2017–2030 Interim report*, February 2022, p 22.

182 Tamboran Resources, *ASX Announcement*, [media release] 2 August 2023, accessed 10 October 2024.

183 R Fitzgerald, '*Tamboran Resources, NT government face another Beetaloo Basin fracking challenge under novel 'third party' laws*', *ABC News*, 28 September 2024, accessed 15 October 2024.

184 O Lathouris & M Houlbrook-Walk. *Legal bid against Beetaloo exploratory fracking project dismissed in court as protesters front resources conference in Darwin*. *ABC news*., 18 September 2024. Accessed 17 October 2024.

185 Northern Territory Government, *Hydraulic Fracking* [website], n.d., accessed 18 October 2024.

186 S Dick, D Fitzgerald and T Morgan, 'NT government signs deal with Tamboran Resources to buy Beetaloo Basin gas', *ABC News*, 23 April 2024, accessed 17 October 2024.

187 Tamboran Resources, *Tamboran's pure focus is on its acreage portfolio in the Beetaloo/McArthur Basin in the Northern Territory*, 2024, accessed 18 October 2024.

188 C Packham, '*Beetaloo developer to begin drilling within weeks as rig arrives*', *The Australian Financial Review*, 5 May 2023, accessed 15 October 2024.

189 R Fitzgerald, '*Tamboran Resources, NT government face another Beetaloo Basin fracking challenge under novel 'third party' laws*', *ABC News*, 28 September 2024, accessed 15 October 2024.

given that where there is an obligation to remedy any environmental damage, it is not clear to the NTCAT that the level of risk described is beyond what is deemed acceptable.[190]

Despite opposition to the project, the Northern Territory government has expressed support for the development of the onshore gas industry in the Beetaloo basin, citing potential economic benefits and has implemented regulations and monitoring programs to ensure that the industry operates in an environmentally safe manner.[191]

190 Smith, C. *NTCAT rejects ECNT application to overturn Tamboran's plan for Shenandoah South gas prospect*, *NT Times*, 29 November 2024, accessed 29 November 2024.

191 Northern Territory Resources, *Regulation: Gas* [website], 19 February 2024, accessed 18 October 2024.

7. Supporting east coast gas security and sufficiency

Key points

- A key challenge facing the east coast gas market is a lack of investment in gas supply.
- Existing policy measures and regulatory tools, which seek to secure gas supply in the short term, are insufficient to address the significant volume of supply and related infrastructure that will be needed.
- There are some important measures that Governments can pursue that will support more efficient and timely investment on the east coast and, more broadly, orderly transition of the electricity and gas markets. Importantly:
  1. State and Commonwealth Governments can reduce regulatory barriers to investment for market participants, to ensure that new supply can be delivered in a timely fashion and through a diverse range of participants.
  2. The role of gas should be explicit in government planning for the energy transition, to give confidence and incentives for market-led solutions to achieve energy security and support gas markets in the transition. One option to help achieve this would be to develop a gas market system plan, similar to the *Integrated System Plan* for electricity, which would identify and coordinate needed gas investments.
- Importation of gas is becoming more likely to meet demand for gas in the short term. The development of LNG import terminals on the east coast will change current market dynamics by introducing new international-linked sources of supply that are closer to southern customers.
- Uncertainty over the pricing of LNG imports may necessitate development of additional pricing reference points on the east coast, such as an LNG import parity price, to aid southern states gas customers when negotiating. The ACCC will consider this as part of our upcoming review of the LNG netback pricing methodology and our role making any determination of the reasonable price under the Gas Code.
- In the longer term, planning for infrastructure should support identification and delivery of the least-cost sources of gas. The ending of the foundational east coast LNG export contracts from the mid-2030s may free up considerable gas supplies for the domestic market. Where these reserves and resources form part of the efficient mix of supply on the east coast, it will be important that measures are taken to support continued investment in supply while also securing gas for domestic use.

7.1. Introduction

Sufficient gas is essential to achieving orderly transition to a lower-emissions economy, including ensuring the reliability of energy supply with the shift to predominantly intermittent power sources.

There are existing policy and regulatory mechanisms by which the Australian Government has sought to address gas supply shortfalls and gas affordability for consumers in the east coast. These include the Heads of Agreement between the Australian Government and the

Queensland LNG producers, the Australian Domestic Gas Security Mechanism, the Gas Code, and AEMO's powers to monitor and respond to reliability and supply adequacy risks.

These tools aim to reduce the risk of supply shortfalls by seeking to make gas available to domestic buyers or incentivise new gas supply. However, they primarily do so by redirecting existing gas supply and production to domestic needs. They do not address the underlying causes of the anticipated supply shortfalls arising from investment barriers and uncertainty, and a lack of competition in upstream gas markets.

Governments can play an important role in facilitating more efficient investment in new gas supply. In summary, we consider that:

- State and Commonwealth Governments should reduce regulatory barriers to investment impeding the timely and competitive supply of gas.
- The role of gas should be explicit in government planning for the energy transition, to give confidence and incentives for market-led solutions to achieve energy security and support gas markets in the transition. One option to help achieve this would be to develop a gas market system plan, similar to the *Integrated System Plan* for electricity, which would identify and coordinate needed gas investments.

In the short term, it seems increasingly likely that the southern states will have to import gas to meet demand. The ADGSM and the Gas Code are planned to be reviewed in 2025, and the current Heads of Agreement expires on 1 January 2026. As part of these reviews, there is an opportunity to consider the effectiveness of and potential need for strengthening of existing tools to address near-term gas supply shortfalls.

In the longer term, planning for infrastructure should support identification and delivery of the least-cost sources of gas. The ending of the foundational east coast LNG export contracts from the mid-2030s may free up considerable gas supplies for the domestic market.

Considerations relevant to gas imports and how domestic gas reserves could support east coast gas supply are discussed in sections 7.3 and 7.4.

7.2. Measures to support efficient investment in new supply and infrastructure

Planning for gas should be integrated into broader energy system planning to ensure that new supply and supporting infrastructure is brought on in the most efficient way, with consideration to Australia's climate policies, and that risks relating to the increasing interrelationship between the gas and electricity markets are effectively managed through the energy transition.

7.2.1. Integration of gas into energy system planning

We have heard that one of the key challenges faced by gas investors and market participants is policy uncertainty, with the market receiving mixed signals from governments about the pace of transition and the long-term role of gas. Some market participants have expressed concerns about the possible impact of further changes to regulation or policy on the market and on investments.

State and Commonwealth governments have adopted and progressed several policies to help and incentivise markets through the energy transition. These include the *Powering*

Australia Plan, the *Rewiring the Nation* policy, the *Capacity Investment Scheme*, *Renewable Energy Transformation Agreements*, and incorporating emissions reductions into the *National Energy Objectives*.[192] These policies seek primarily to incentivise renewable energy and supporting electricity infrastructure, including by:

- incentivising Australia's transition away from fossil fuels and providing financial and operational support for renewable energy development
- providing efficient pathways for investment in renewable energy projects[193]
- providing a variety of mechanisms that further reduce investor risk.[194,195] For example, the *Capacity Investment Scheme* introduces a guaranteed revenue floor for renewable capacity projects, which effectively underwrites any investment[196]
- offering direct funding and subsidies for investment in renewable energy production and storage, lowering upfront capital cost and further reducing financial risk.[197]

The Commonwealth Government has recently announced a review of National Electricity Market wholesale market settings, the purpose of which is to promote investment in firmed, renewable generation and storage capacity in the NEM following the conclusion of Capacity Investment Scheme tenders in 2027.[198] The terms of reference for this review states that it will not consider options that involve governments supporting new fossil fuel generation.[199]

In addition, the Commonwealth Government's *'A Future Made in Australia'* policy will facilitate private sector investment in clean energy industries and supply chains that form part of the net-zero transition.[200]

While gas will be essential for achieving security of energy supply and orderly transition to a lower-emissions economy, it is largely not yet incorporated as a priority in State and Commonwealth energy transition polices. The exclusion of gas means that there is uncertainty about how demand will be efficiently met.

State and Commonwealth Governments should provide greater clarity on the role of gas in system planning, so that investors and users can make informed investment decisions.

One option to support more timely and efficient gas supply is for governments to introduce a specific system plan for the gas markets.

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192 Department of Climate Change, Energy, the Environment and Water (DCCEEW), A number of these initiatives are summarised at: National Energy Transformation Partnership [website], Australian Government, 12 August 2022, accessed 28 November 2024.

193 DCCEEW, *Rewiring the Nation* [website], Australian Government,14 October 2024, accessed 31 October 2024. For example, the Rewiring the Nation (RTN) plan has committed significant government investment in progressing regulatory changes to support Renewable Energy Zone (REZ) development in NSW and coordinating Victorian regulatory processes to expedite development of offshore wind projects.

194 F Polzin et al, 'How do policies mobilize private finance for renewable energy? A systematic review with an investor perspective', *Applied Energy*, 15 February 2019, accessed 28 November 2024.

195 M MacGinley, R McFadden and T Joseph, *The role of capacity mechanisms in managing the transition to renewables*, *Corrs Chambers Westgarth*, 8 August 2022, accessed 1 November 2024.

196 DCCEEW, *Capacity Investment Scheme – Design Paper*, Australian Government, 29 February 2024, p 6, accessed 28 November 2024.

197 DCCEEW, *Rewiring the Nation* [website], Australian Government, 14 October 2024, accessed 31 October 2024. For example, the RTN plan has provided investment in large-scale projects such as the Victoria to New South Wales Interconnector and providing low-cost finance to the Marinus Link.

198 DCCEEW, *National Electricity Market wholesale market settings review* [website], Australian Government, November 2024, accessed 28 November 2024.

199 DCCEEW, *Terms Of Reference: Review of Market Settings in the National Electricity Market to Follow the Capacity Investment Scheme*, Australian Government, accessed 28 November 2024.

200 The Treasury, *Future Made in Australia* [website], Australian Government, accessed 1 November 2024.

Currently, AEMO's *Integrated System Plan* plays a key role in identifying and coordinating investment across the east coast electricity system (box 7.1). State Governments also coordinate investment in renewable energy projects. This supports market-led investments in network infrastructure for the energy transition and feeds into several Government initiatives, such as the *Rewiring the Nation* policy.

Gas supply and infrastructure to support both electricity and gas markets is not included in the *Integrated System Plan*. This means that there is a lack of transparency and coordination in the delivery of projects that may be necessary to support system reliability. Further, there is no acknowledgement of the specific needs of gas users who do not use electricity and whose only source of fuel is gas.

A specific gas market system plan would support identification of viable gas supply and infrastructure options, assessment of the costs and benefits to gas users of different solutions, and development of a pathway to meet the needs of both the electricity system and gas users. For example, a gas market system plan could assess the trade-offs between pipeline, storage and import options, and identify the gas supply projects that would most efficiently meet gas user needs. This would help coordinate gas market investments and give investors greater confidence.

Box 7.1: AEMO's *Integrated System Plan* for the National Electricity Market

The *Integrated System Plan* is a roadmap for the efficient development and optimisation of the National Electricity Market (NEM) in the long-term interests of consumers.[201] It seeks to coordinate investment across the electricity power system in a way that promotes efficient investment in, and the efficient operation and use of, electricity services.

As articulated by AEMO, it does this by undertaking cost-benefit analysis of various pathways for the development of the electricity system as traditional coal plants retire, and identifies an optimal development path that leads to an economic, secure and reliable energy system capable of meeting emissions policy objectives.[202]

One outcome of the *Integrated System Plan* is setting out the required electricity generation, storage and network investments to achieve an optimised electricity system. In addition, the identification of electricity infrastructure projects provides a pathway for regulatory decision making for electricity network augmentations (e.g. by the Australian Energy Regulator) which may otherwise not be available.

Gas market information utilised in the Integrated System Plan

The Australian Energy Market Commission is progressing a change to the National Gas Rules to improve the reliability and transparency of the gas market analysis AEMO relies upon in the *Integrated System Plan*. AEMO does not currently consider the costs associated with gas infrastructure investments or the availability of gas to service gas-powered generation in the quantity or price anticipated.[203]

The AEMC recently published a draft determination and draft rules that support better integration of gas market information following recommendations made by the Energy and Climate Change Ministerial Council. If implemented, the draft rule change would require AEMO to include more comprehensive information on gas market projections and better

201 AEMO, *2026 Integrated System Plan (ISP)* [website], AEMO, 26 September 2024, accessed 1 November 2024.

202 AEMO, *2026 Integrated System Plan (ISP)* [website], AEMO, 26 September 2024, accessed 1 November 2024.

203 Australian Energy Market Commission (AEMC), *National Electricity Amendment (Better integration of gas and community sentiment into the ISP) Rule 2024*, AEMC, 26 September 2024, pp 3–4, accessed 1 November 2024.

align the Integrated System Plan with the projections in the Gas Statement of Opportunities.[204]

7.2.2. Reducing barriers to domestic gas supply and infrastructure

Efficient and timely investment in gas supply and infrastructure can be further supported by reducing unnecessary regulatory barriers to new gas supply and infrastructure. This would support timely market-led solutions and ideally increase competition.

Gas producers have highlighted the timeliness of regulatory approvals as one of the more significant current barriers to investment.[205]

Lengthy regulatory assessment processes can create delays to bringing new gas supply online, increase project costs and make it more difficult to attract new investment due to risk and uncertainty. It is important to improve statutory timeframes, reduce uncertainty, and remove duplication for regulatory decisions (such as for environmental approvals) to reduce risks faced by developers and increase investor and community confidence. This is consistent with intended Government actions identified in the *Future Gas Strategy*.[206]

The ACCC has made several other recommendations in the past to reduce barriers to new gas supply and infrastructure that remain relevant, including:

- removing moratoria on new gas developments and taking a case-by-case approach to assessing new development proposals
- changes in government processes for releasing gas acreage and approving, monitoring, and enforcing compliance with work programs to achieve greater timeliness and diversity of supply
- reducing the infrastructure, regulatory and capital barriers faced by producers (particularly small producers), including by introducing a light-handed third-party access regime for upstream infrastructure (such as gas processing plants) and storage facilities that offer third-party access.

7.3. Benefits and risks of incorporating LNG imports into southern gas markets

Australia's gas markets will benefit from efficient and diverse levels of supply and infrastructure. However, in the near-term, the most realistic new supply and infrastructure prospect are the proposed LNG import terminals (chapter 6). All currently proposed terminals are located in the southern states, where most commercial and industrial user demand is located.

The use of import terminals to procure LNG shipments on a seasonal or annual basis adds potential flexibility and security of supply within the east coast gas system. However, this may fundamentally change current market dynamics by introducing a new source of

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[204] AEMC, *National Electricity Amendment (Better integration of gas and community sentiment into the ISP) Rule 2024*, AEMC, 26 September 2024, p ii, accessed 1 November 2024.

[205] ACCC, *Gas Inquiry 2017–2030 Interim report*, ACCC, June 2024, pp 43–44.

[206] Department of Industry, Science and Resources (DISR), *Future Gas Strategy*, Australian Government, 9 May 2024, p 54.

alternative supply available to gas users other than the uncontracted gas supply held by Queensland LNG producers.

7.3.1. The potential role of LNG import terminal infrastructure

LNG import terminals located in southern states offer some advantages over gas transported via pipelines, including:

- being linked to new sources of supply, including supply in LNG markets
- greater flexibility in their use as assets, including as storage facilities close to southern demand centres, which means their use as storage facilities may help meet unexpected demand or peak demand
- lower risk of asset stranding due to the ability to re-locate floating storage and regassification units when they are no longer needed.

Import terminals need not have a fixed source of supply and could source gas from more flexible options, including international LNG markets or other parts of Australia, such as Western Australia or the Northern Territory. LNG carriers, which transport gas from source to destination, can operate as virtual pipelines when domestic supply or existing infrastructure is unavailable to meet demand in southern states. In this context, LNG imports could be a cheaper and temporary solution to southern supply gaps compared to upgrading pipelines from northern gas fields and storage facilities in the south.[207]

LNG imports from another Australian jurisdiction are likely to be subject to coastal trading restrictions, or cabotage.[208] These restrictions require ships transporting cargo from one state or territory port to another state or territory port, in connection with a commercial activity, to hold certain licenses.[209] Opportunities to participate in interstate LNG trade could be constrained by licencing requirements, including by excluding foreign-flagged LNG carriers from providing transportation services (box 7.2).

Box 7.2: Australian domestic coastal shipping requirements

The *Coastal Trading (Revitalising Australian Shipping) Act 2012* regulates coastal trade via a licencing system, which authorises ships to carry passengers or cargo between ports in Australia. These licenses include:

- a general licence, available to an Australian flagged ship or Australian crewed ship, providing unrestricted access to engage in coastal trading in Australian waters for 5 years
- a temporary licence, available to foreign flagged ships engaged in coastal trading, is typically provided where eligible licence holders undertake a minimum of 5 voyages in a year. Applicants are required to specify the number of voyages, volume of cargo to be carried, expected loading dates and other information relevant to the transport of cargo between Australian ports. Any deviation from the agreed licence terms and cargo tolerance limits requires a new licence application.

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207 Grattan Institute, *There is no Australia-wide gas shortage*, Grattan Institute Website, 27 August 2024, accessed 29 August 2024.

208 Department of Infrastructure, Regional Development and Cities, Submission 15 to Senate Standing Committees on Rural and Regional Affairs and Transport, *The policy, regulatory, taxation, administrative and funding priorities for Australian shipping*, Parliament of Australia, March 2019, p 13–16, accessed 19 November 2024.

209 Ibid, and see the Coastal Trading (Revitalising Australian Shipping) Act 2012.

The development of LNG import terminals on the east coast could give rise to coastal LNG trading for the first time, creating new Australian markets for Australian LNG. Interstate trade of LNG is likely to be subject to the coastal trading regime.

There are currently no Australian LNG carriers with sufficient capacity to service this trade in the near term. Exceptions from licensing restrictions may be required to allow a sufficient fleet of LNG carriers to participate in intrastate LNG trading and support the movement of gas supply via sea. LNG carriers are costly to build and complex to operate and maintain. As such, Australian LNG producers and potentially import projects may be required to enter various ship ownership arrangements to participate in coastal trading and manage shipping risks. These could include full, partial, or shared ownership, chartering ships, and procuring services from independent ship owners of which may not have or meet the eligibility requirements for coastal trade licenses.

The ACCC has previously stated support for changes to coastal shipping laws which would foster increased competition in the coastal shipping market.[210] In particular, support for easing the regulatory burden on foreign-flagged ships in conducting coastal trades. An independent review of coastal trading is currently underway to ensure Australia's shipping regulatory framework reflects modern best practice regulation and supports the long-term sustainability of Australia's maritime industry.[211]

As floating storage and regasification units can both facilitate new sources of supply and act as storage vessels, LNG import terminals would also provide greater capacity to meet variations in demand. This is likely to be of particular importance in Victoria given that the Longford production facility's ability to offer seasonal flexibility is expected to diminish as legacy fields in the basin decline.[212]

Proponents of import terminals have indicated they have the capacity to deliver daily gas injections of around 450-800 TJ per day – roughly equivalent to the Iona storage facility withdrawal rate of 570 TJ per day.[213,214] This could be crucial for servicing future variable gas generation demand. Gas generators may also be able to better manage the price volatility in international markets that may be associated with LNG imports given that:

- most are owned by large retailers with gas and electricity portfolios and hedging arrangements in place
- they may be in a better position to pass through international prices in the NEM under different market conditions.

210 ACCC, Submission 4 to Senate Standing Committees on Rural and Regional Affairs and Transport, *The policy, regulatory, taxation, administrative and funding priorities for Australian shipping*, Parliament of Australia, 28 February 2019, p 1.

211 Department of Infrastructure, Transport, Regional Development and Local Government, *Coastal Trading Review* [website], Australian Government, accessed 28 October 2024.

212 AEMO, *Gas Statements of Opportunities 2024*, AEMO, p 52.

213 AEMO, *Gas Statements of Opportunities 2024*, AEMO, p 59.

214 AEMO, *Victorian Gas Planning Report Update 2024*, AEMO, p 10.

Box 7.3: Potential business models for LNG import terminals

Proponents of LNG import terminals have previously suggested a 'tolling' model would be adopted. This type of model requires domestic buyers to:

- secure LNG cargoes from another Australian LNG exporting jurisdiction or from the international market
- pay the LNG import terminal operator a "toll" to receive the cargo and convert LNG from liquid to gas, transmissible through domestic pipeline infrastructure.[215]

This contrasts with a 'merchant model' in which the LNG import terminal operator is responsible for securing the LNG cargoes and then selling the imported gas to domestic buyers at the facility (as used in the United States). While the tolling model is commonly used in Europe for its LNG imports, domestic gas buyers are unlikely to be familiar with navigating international commodity and financial risks. Under a merchant model, these risks are managed by the LNG import terminal owner in the first instance, who may hedge the risks and pass costs through to users.

The ACCC has previously stated that the use of import terminals does not obviate the need for continued development of domestic sources of supply.[216] Import terminals could potentially disincentivise new investment in supply sources for domestic use as long-term offtake agreements are similarly needed to secure funding for gas projects. Incentives are also likely to be lower for upgrading and maintaining important infrastructure to transport gas from Queensland to southern states, and the development of alternative supply projects in southern states.

Despite the advantages, continued domestic gas production will be important to limit risks to energy security on the east coast and market stability associated with reliance on international LNG markets.

7.3.2. Impact of LNG imports on prices

LNG imports in southern states are likely to affect prices and pricing decisions for the marginal supply of gas on the east coast, creating new direct links to international LNG supply and demand factors faced in other regions.

The introduction of LNG exports from the east coast had a similar effect on domestic prices in the lead up to the first LNG exports in 2015–16. This is because the alternative for domestic gas buyers when negotiating with domestic suppliers is to buy gas from the LNG producers that would otherwise be sold for export.

Impact of LNG imports on east coast market pricing

In a well-functioning market, the price of gas at a particular location would be shaped by the alternatives available to both buyers and sellers of gas. As discussed in chapter 2, Queensland LNG producers' gas is an important alternative source of supply for buyers in the southern states, particularly in winter months. This means that Queensland LNG export prices and the costs of pipeline and storage have an influencing role on the alternative sources of supply available to southern buyers.

215 ACCC, *Gas Inquiry 2017–2030 Interim report*, ACCC, June 2024, pp 45–46.

216 ACCC, *Gas Inquiry 2017–2030 Interim report, ACCC, June 2024*, p 45.

In this context, the ACCC developed the LNG netback price series to improve gas price transparency on the east coast and assist gas buyers concerned about the lack of competitive bargaining and adequate pricing information available to them to assist them in understanding the drivers of domestic gas prices.[217] The LNG netback prices also has a bearing on prices that are offered by LNG producers under the Heads of Agreement with the Government.

The introduction of LNG imports could alter seasonal and annual market dynamics by creating new international-linked sources for marginal supply closer to southern demand centres. This will have some implications for gas supply negotiations and the levels of gas price transparency on the east coast. As outlined below, there is uncertainty over the pricing of LNG imports, which may necessitate development of additional pricing reference points on the east coast, such as an LNG import parity price, to aid southern states gas customers.

The ACCC intends to consider this further as part of its upcoming review of the LNG netback pricing methodology and its role in determining the reasonable price under the Gas Code. The outcome of this review may have some bearing on what is considered 'competitive market terms' under the Heads of Agreement.

LNG import prices may be higher than current domestic prices

The final delivered price of supply is a key issue for proponents considering importing gas.

Imported gas, including from Australian exporters, may incur additional costs not currently experienced by gas users on the east coast. These include LNG shipping, liquefaction and regassification costs, as well as premiums to cover financial, international LNG price, foreign exchange rate and insurance risks. Additional and new costs will have an impact on east coast gas prices and become a significant component of future prices payable for supply.

The pricing of domestic gas supply would further be influenced by the method used by import terminals to procure LNG, and whether the facility maintains flexibility to receive shorter term volumes that are priced at spot or short-term prices. The ability for third parties to purchase spot cargoes through the LNG import terminals, assuming the terminals have excess capacity, will introduce additional complexity in pricing gas.

Recent studies have quantified potential differentials between prices payable for imported gas against locally produced gas supplied to the end user. These reports concluded that imported gas is likely to result in higher prices for gas users (table 7.1).

217 The ACCC publishes LNG netback prices to the Gas Inquiry 2017–2030 webpage.

Table 7.3: Possible impact of LNG imports on domestic gas pricing

Source	Key finding
Frontier Economics' analysis of potential impact of LNG imports on end user prices, prepared for the APA Group[218]	The study concluded that relying on LNG imports via the Port Kembla or Geelong terminals would result in higher prices for end users in southern states compared with sourcing gas domestically from gas resources in either Queensland's Bowen and Surat Basins or the Northern Territory's Beetaloo Basin via new and existing pipelines. A key assumption was that prices will be set by LNG imports procured during the winter months given southern states gas demand is higher in winter, even if LNG imports are not necessary to meet demand all year. The study put that, even if prices are marginal only in winter, this still accounts for a large share of total demand. As a result, the median residential gas bill for the average Victorian residential consumer was projected to increase by about \$143 a year.[219] Other modelled price consequences included: ▪ a 14 to 28% increase if industrial users in Adelaide, Melbourne or Sydney relied on LNG imports during winter, and a 55 to 110% increase if relied on all year round, depending on the delivery point ▪ a 5 to 11% increase for residential users during winter, and 12 to 28% increase if LNG imports were relied on all year around.
Australian Energy Regulator (AER) draft decision on South-West Queensland Pipeline form of regulation review[220]	The draft decision suggests prices payable by southern states gas users for imported gas would be around \$2.38/GJ–\$2.67/GJ (or 12% to 14%) higher than gas supplied from Queensland via the SWQP. The AER noted this is subject to assumptions that the price payable for gas supplied from Queensland is capped at the ACCC's LNG netback price and there is no material change in the cost of transporting gas to Sydney. However, the AER noted that if the price payable for gas supplied from Queensland exceeds the LNG netback price (e.g. because there is a supply shortfall in the east coast) and/or that transportation costs from Queensland to Sydney increase (e.g. because the pipelines need to be expanded), the price differential for gas transported from Queensland is likely to diminish.
Australian Government's Future Gas Strategy analytical report[221]	The report suggests pricing of gas from import terminals is likely to be higher than current domestic prices. Under a JKM plus pricing methodology (assuming no price caps, ability to arbitrate or hedge) between 2012 and 2024, it suggests end users would have seen costs as low as \$5.15/GJ in Melbourne (via Geelong import terminal) and \$5.44/GJ in Sydney (via Port Kembla) during the COVID pandemic, however on average paid over \$19/GJ and over \$30/GJ since the start of the Ukraine War. Delivered prices would also include a component to cover capital costs of imported terminals.

Price volatility and security from LNG imports

Sharp LNG price movements in recent years have highlighted the global market's sensitivities to conflicts and crises. Price volatility risk is driven by geopolitical factors and regional factors, such as seasonality and weather.

Australian buyers would be competing for supply with other international buyers, potentially during periods of heightened volatility in international short-term trading markets. This raises some concerns about relying on imported gas to supplement or cover impending supply shortages. For example, during our latest consultation with gas users, an industry association and a C&I user shared their concerns that imported gas would entrench domestic price exposure to international price fluctuations, and limit the ability to decouple domestic prices from international LNG prices.

One way to address this is secure medium- or longer-term supply agreements with international LNG producers and hedging arrangements to minimise price risks and gain security of supply. However, large users and smaller retailers continue to be reluctant to contract part of or their full annual volume requirements due to uncertainties about price.[222]

International LNG spot and to a degree, medium-term markets have demonstrated in recent years how significant global events such as the COVID-19 pandemic and geo-political events can quickly influence market dynamics (see charts B.1 and B.3). However, recent reports are projecting softer LNG demand and increased global liquefaction capacity in the coming years, which could result in an oversupplied LNG market. While global gas prices have moderated from recent elevated price levels, an oversupplied market could lead to lower LNG prices by 2027, provided there are no delays to the timing of new or expanded Qatari and United States' LNG export capacity.

The price of LNG procured in international markets will fundamentally determine the appetite of domestic gas users to contract part of or their full annual volume requirements via imports. New international LNG developments are reportedly being priced competitively compared to contracts signed in recent years. For example, recent Qatari contracts have been priced at an LNG slope of around 12.5% of the oil price they are linked to.[223] Agreements will vary greatly based on the terms, tenure and start date of new deals and influenced by relationships between the buyer and seller. [224] At the same time, the cost of production on the east coast is likely to rise.

7.3.3. Uncertain economics of import terminals

The commercial viability of the 4 proposed LNG import terminals remains uncertain. As noted in chapter 6, the 2 main challenges facing LNG import terminals are finding buyers to

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218 Frontier Economics, *Paper for APA Group – LNG imports on End user Prices*, Frontier Economics Website, 15 March 2024, accessed 23 July 2024.

219 APA, *Domestic gas trumps imported lng to secure our energy future*, APA Website, 19 June 2024. $143 per annum is APA's estimate that references the median bill as per the Essential Services Commission Victoria, Victorian Energy Market Report, September 2023.

220 Australian Energy Regulator (AER), *Draft decision – South West Queensland Pipeline form of regulation review*, Australian Government, 9 October 2024, pp 49–50.

221 DISR, *Future Gas Strategy Analytical Report*, Australian Government, May 2024.

222 DISR, *Future Gas Strategy Analytical Report*, Australian Government, May 2024, p 94.

223 S&P Global, *QatarEnergy-Sinopec's long-term LNG contract likely priced around 12.7% slope to oil*, S&P Global website, 9 November 2023, accessed 28 October 2024.

224 Wood Mackenzie, *Brent-linked long-term LNG contracts are back in vogue*, Wood Mackenzie website, 16 May 2023, accessed 28 October 2024.

enter foundational contracts to underwrite the projects and obtaining necessary regulatory approvals.

There appears to be some interest by users in LNG imports. Origin had initially sponsored the Venice Energy terminal. There are also reports suggesting that an increasing number of companies are examining the possibility of importing LNG, including Snowy Hydro, Woodside Energy, Shell, and industrial users, including explosives manufacturer Orica and steel producer BlueScope.[225]

However, despite this interest, we understand that none of the developers have, at this stage, entered into agreements with customers to import LNG through their facility.

It is likely that the users most likely to contract with an LNG import facility are those that can hedge their risk exposure with international pricing, manage the logistics of a multi-user tolling model, and have sufficiently certain demand and infrastructure access to fully utilise and/or store the gas. Potential customers are likely to weigh up the costs, benefits and risks of this source of supply against traditional alternatives, some of which are outlined in box 7.4.

Box 7.4: Potential reasons for user reluctance to contract with LNG import terminals

The reluctance of domestic gas users to contract with the LNG import terminals may be due to several reasons, including:

- concerns about the price for procuring LNG and tolling it through a terminal, which may expose the buyer to LNG market risk. Where the price of imported gas is uncertain or based on higher international spot price of LNG, gas users may not be prepared to enter longer term contracts with LNG import terminals.[226] This is heightened by uncertainty over future domestic prices and the availability of alternative domestic gas sources
- downstream customers not yet willing to sign long-term agreements for supply that would be sourced from LNG imports[227]
- commercial and logistical complexities associated with the proposed tolling model, which require the gas user to secure their own cargoes, ship them to the import terminal, pay a tolling fee for using the storage and regasification service, and a fee for using connecting pipelines
- potential supply management and capacity issues with balancing gas flows from LNG imports and domestic sources through existing infrastructure
- costs for storage where a cargo of gas volume is unable to be used immediately.

225 A Macdonald-Smith, 'Choke in gas supply makes imports, once unthinkable, almost inevitable', *The Australian Financial Review*, 19 August 2024, accessed 17 October 2024.

226 A Macdonald-Smith, '*Choke in gas supply makes imports, once unthinkable, almost inevitable*', *The Australian Financial Review*, 19 August 2024, accessed 17 October 2024.

227 Colin Packham, *'Origin baulks at LNG import terminal in SA, as east coast supply pressure increases', The Australian,* 14 February 2024, accessed 17 October 2024.

7.4. Long-term supply security

The east coast has sufficient gas reserves and resources to meet current demand projections over the next decade and beyond. As part of an efficient mix of supply sources of the east coast, utilisation of the known existing east coast gas reserves and resources will play a valuable role in serving the needs of the market and long-term energy security.

The Queensland LNG producers and their associates control approximately 95% of 2P reserves and 35% of 2C resources on the east coast.[228] The majority of forecast production by these producers over the next 10 years is expected to be exported under foundational contract commitments. However, some of the LNG producers hold significant excess gas reserves and resources beyond that required to meet contractual commitments.

The LNG producers' long-term foundational export contracts will be ending by the mid-2030s. This creates opportunities to consider how domestic gas reserves could support east coast gas supply.

This section outlines in greater detail the following matters to assist government planning and decision making on Australia's east coast gas security:

- the gas reserves and resources held by the LNG producers and how much they have available for development in excess of their export contract requirements
- the timing of the roll-off of the LNG producers' contracts and the amount of gas that will be uncontracted and potentially available for domestic supply
- considerations for government on opportunities to limit LNG exports to ensure that Australia's long-term gas needs are met throughout the energy transition.

7.4.1. Availability of gas held by the Queensland LNG producers

The Queensland LNG producers currently have enough gas reserved to meet their existing contractual commitments and also meet Australia's domestic gas needs for over 10 years. The amount of available gas doubles when gas resources are also included, noting that the availability of this gas is dependent on proving of commercial viability.

It is important to acknowledge that there is inherent risk and uncertainty in gas reserves and resources estimates, particularly for unconventional gas production, however these are the best and most up to date estimates that are available.

The proportion of gas reserves and resources available to LNG producers and their remaining contracted export commitments differs between each producer, as set out in chart 7.1.

APLNG has the largest amount of gas reserves and the most gas in excess of their contractual export requirements. Despite QGC and GLNG having sufficient 2P reserves to meet their contracted requirements, they plan to purchase substantial amounts of gas from third parties on the east coast. QGC is forecasting net domestic purchases of 1737 PJ to 2036, which are expected to come from Arrow Energy through their 27-year sales agreement underpinning Arrow's Surat Gas Project.[229] GLNG is forecasting to purchase 775 PJ to 2036.

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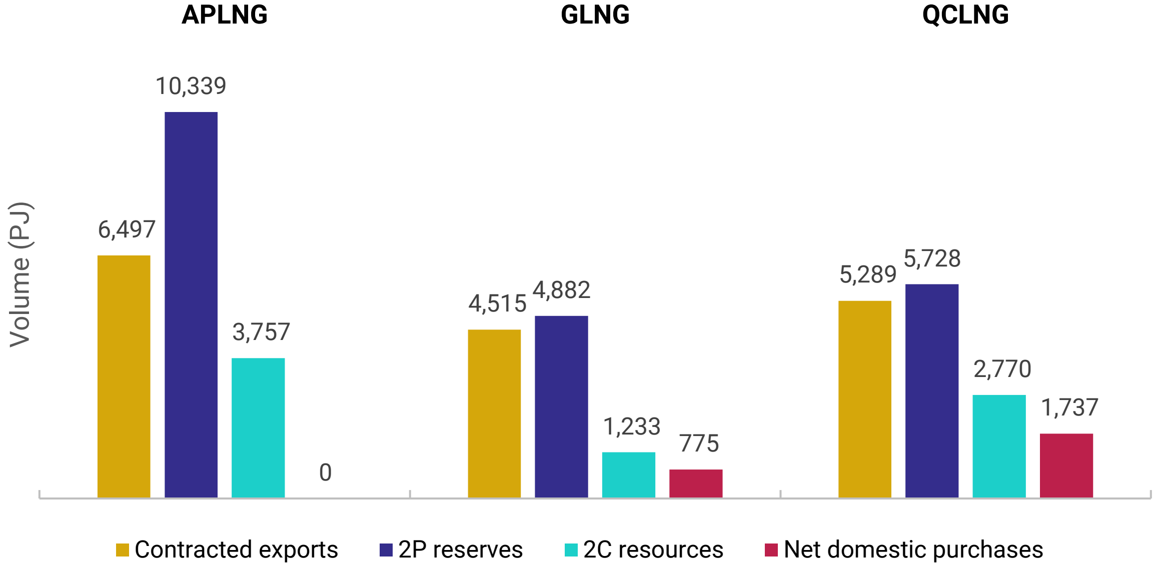
[228] ACCC analysis of public information from AEMO's Gas Bulletin Board.

[229] Arrow Energy, *Arrow Energy Surat Gas Project North expansion to start in late 2024* [media release], Arrow Energy Website, 12 August 2024, accessed 30 October 2024. Arrow Energy has approximately 6,021 PJ of 2P and 1,003 PJ of 2C reserves and resources reported on AEMO's Gas Bulletin Board as of 28 February 2024.

Chart 7.1: East coast LNG remaining contracted export quantities to 2036 and sources of supply to meet contracted requirements (PJ)



Source: Most current 2P reserves and 2C resources from each LNG producer are sourced from AEMO's Gas Bulletin Board[230]; ACCC analysis of data obtained from gas producers on long-term export, domestic purchases and domestic sales forecasts. Net domestic purchases are calculated as the difference between gas purchases from third parties in the domestic east coast market (including related parties to the LNG producers) and gas supplied into the domestic east coast market under firm gas supply agreements. [231]

Note: Numbers are in PJ.

The forecast domestic gas purchases from QGC and GLNG will be a substantial contributor to expected east coast gas shortfalls. QGC and GLNG should be incentivised to fully develop their existing 2P reserves to meet their contractual requirements, freeing up additional domestic gas supply.

7.4.2. Foundational LNG export contracts are expected to end in the 2030s, creating opportunities for domestic supply

The existing foundational export contracts will end in the 2030s. An overview of each of the LNG export contract, their contracted quantities and their likely end dates if not extended is summarised in table 7.2 based on public information.

The earliest contract roll off is expected to be GLNG's Korea Gas Corporation contract in 2031, with the remaining contract end dates clustered around 2035. Some contracts have options to extend the supply period based on mutual agreement and include provisions for temporary extensions for make-up cargoes if there is unfulfilled supply at the contracted end date, making exact end dates uncertain.

230 Note that while APLNG and QGC directly report their reserves to the AEMO's Gas Bulletin Board, GLNG does not as Santos operates each of their gas fields. GLNG 2P reserves have therefore been estimated based on Santos' Gas Bulletin Board reporting on gas fields that they have publicly stated that they operate for GLNG. APLNG data is from 30 June 2024; QGC data is from 30 December 2023; GLNG/Santos' data is from 27 February 2024.

231 APLNG's net domestic gas purchases to 2036 are forecast to be negative as they plan to supply gas to the domestic market and not purchase any from the domestic market. This has been shown in chart 7.1 as 0 for simplicity.

Table 7.2: LNG export contract overview

Exporter and contracted party	Expected contract end year	Annual contracted quantity[232]
APLNG		
China Petroleum	2036	370 PJ p.a.
Kansai Electricity Company	2036	49 PJ p.a.
QGC[233]		
CNOOC	2035	175 PJ p.a.
Tokyo Gas	2035	58 PJ p.a.
GLNG		
Korea Gas Corporation	2031	171 PJ p.a.
Petronas LNG	2036	171 PJ p.a.

Source: Public information reported by each LNG producer or associated corporate entity.[234] [235] [236]

Recently, Santos and Woodside have announced new long-term LNG contracts with Asian customers, to be delivered from their respective global LNG portfolios. This envisages a continuation of LNG exports into the foreseeable future, which may be sourced from Western Australia, Northern Territory and/or Queensland LNG export facilities.

The Queensland LNG producers have not publicly indicated their intentions to continue exporting beyond the conclusion of their foundational export contracts. They may seek to sign new contracts with their existing customers, particularly given that some of these customers are also equity holders in the Queensland LNG projects. They also have opportunities to contract gas with domestic customers.

Governments should consider the implications of the LNG producers extending their contracts or re-contracting large export volumes on securing efficient supply to the east coast market. There is an opportunity to work with the LNG producers ahead of commercial decisions on any new long-term export contracts to ensure that long-term domestic gas needs are met.

The Queensland LNG projects were underwritten by long-term foundational contracts to secure initial investment. However, unconventional gas fields, as used by the Queensland LNG producers, require continual investment to maintain production levels.[237]

Reliance on gas production from LNG producers to help meet expected east coast gas market shortfalls will require continued investment in new production, in addition to transportation infrastructure and storage near southern demand centres. This investment

232 Publicly reported amounts have been converted from mtpa to PJ for consistency with figures used throughout this report. A conversion rate of 48.747 PJs per million tonnes of LNG has been applied (rounded to the nearest PJ).

233 Note that public information on QGC's contracted LNG volumes understates their total annual contracted export volumes, as shown in chart 7.1.

234 APLNG, *Australia Pacific LNG / Long-term investments build world-class energy assets* [media release], ConocoPhillips Website, 16 May 2024, accessed 1 November 2024.

235 Shell, *In focus: Queensland Gas Company* [website], Shell Website, accessed 1 November 2024.

236 GLNG, *GLNG Project FID presentation* [PDF], ASX Announcements, 13 January 2011, accessed 1 November 2024.

237 Department of Industry, Science and Resources, *Future Gas Strategy Analytical Report*, Australian Government, May 2024, p 76.

may need to be supported by long-term contracting with domestic and/or international customers to provide long-term certainty and reduce commercial risk.

Western Australia has sought to strike a balance between securing gas for domestic use and incentivising continued investment by reserving 15% of gas production for domestic supply over each LNG export project's life. This policy, known as the Western Australian Domestic Gas Policy, has been in place since 2011. Since the introduction of this gas reservation policy, investment in new gas supply has continued at a similar pace to the east coast. A recent Parliamentary Inquiry into the Western Australian Domestic Gas Policy concluded that it had successfully delivered adequate and affordable supplies of gas to Western Australian consumers.[238]

Discussions with LNG producers on options for long-term gas security should occur as early as possible to provide the certainty needed to commit to long-term investments. We consider that any approach should seek to promote both domestic supply adequacy and an efficiently operating domestic gas market. To this end, gas held by LNG producers should be utilised to the extent needed to meet policy objectives alongside the removal of unnecessary barriers for new gas supply investment from other domestic sources.

The Western Australian model is based on contracting between Government and the LNG producers. There are other arrangements within Australia and internationally that seek to incentivise domestic production or control exports in the national interest, as outlined in box 7.5.

Box 7.5 Gas market export controls in Australia and internationally[239]

Australia

- Since 2011, WA has contracted 15% domestic gas commitments from each LNG producer over the life of each project.
- QLD introduced its 'Australian market supply condition' in 2017, which requires gas developed on specific leased acreage to be sold and used only in Australia. It in some cases also restricts the type of user that gas can be sold to (e.g. manufacturing only).
- At the national level the ADGSM, which has been in effect since 2017, can be triggered as a measure of last resort to restrict exports when there is a forecast domestic shortfall in an upcoming quarter.

United States and Canada

- The United States and Canada have public interest tests in place and require government approval for new gas export projects.
- In the United States the public interest test only applies where the gas is intended to be exported to a country that the United States does not have a free trade agreement with, however the United States does not have free trade agreements with most LNG importers. When there is a free trade agreement in place, LNG exports are automatically assumed to be in the public interest and do not need additional approvals.

238 Economics and Industry Standing Committee, *Report 8 Domestic Gas Security in a Changing World Inquiry into the WA Domestic Gas Policy: Final Report*, Parliament of Western Australia, August 2024, p 15.

239 EnergyQuest, *Domestic Gas Market Interventions International Experience – 2020 Update*, EnergyQuest Website, November 2020.

Europe

- Gas exports are not restricted in the EU. However countries such as the Netherlands and Norway have State ownership of certain aspects of gas production and transport and can make decisions on efficient gas export levels.
- The UK has no export restrictions in place. This is despite the UK being a net gas importer since 2004 and exporting substantial amounts of gas to Europe.

Middle East

- Qatar has entirely government owned gas and oil production which can set export levels, though it is market oriented. Due to abundant gas and oil reserves and a relatively small population, Qatar can export substantial quantities of gas while still meeting domestic needs and keeping domestic gas prices low.

Appendix A: Approach to reporting on gas prices

This Appendix sets out the ACCC's approach to reporting on prices offered, bid and agreed to under GSAs, as presented in chapter 2 and 3.

A.1 Parameters of reported prices

The following apply to our analysis of prices reported in chapter 2 and 3:

- Prices reported are GST exclusive.
- Prices reported are wholesale gas commodity prices and do not include separate charges for transporting gas to the user's location or other ancillary charges (although delivery charges may, in some cases, be bundled with commodity gas prices). The prices charged for transportation have been excluded from our analysis to enable a more direct comparison between the prices paid by buyers in different locations and with differing transportation requirements.
- Only arm's length transactions are included. Related party transactions are excluded to ensure that the prices reported are reflective of market conditions.
- Transactions with a term of at least one year and an annual contract quantity of at least 0.5 PJ are included in sections 2.3 and 3.2. Section 3.3 reports on short-term contracts (with a term length of less than 12 months) and prices.
- Where average prices are reported, these are volume-weighted average prices unless otherwise mentioned. Where average prices are reported for a region, these are based on the location at which the gas is to be delivered rather than the location at which the gas is produced.
- The retailer category is defined to include aggregators and other parties selling wholesale gas who are not primarily engaged in the production of gas. The following entities were classified as 'retailers' in the chapter 2 and 3, where the section 95ZK and 53ZT data is used: Origin Energy, AGL, EnergyAustralia, Engie, Alinta Energy, Shell Energy Australia, Macquarie Bank, Weston and PetroChina.

We note that prices of individual transactions are not necessarily directly comparable due to differences in non-price aspects such as flexibility, quantity, contract term and delivery point. These non-price terms and the flexibility they can provide may be valued differently depending on the customer and may influence the gas prices that are ultimately agreed. The ACCC has not sought to adjust for these factors in the analysis presented in chapter 2 and 3, but rather reports on GSA flexibilities separately.

A.2 Reporting on offers and bids

The following describes our approach to reporting on offers and bids, as presented in section 2.3, and should be read in conjunction with information above in section B.1.

- The analysis only includes those offers and bids that contain clear indications of price, quantity, supply start and supply end dates.

- The commodity gas price for each offer and bid has been estimated using the pricing mechanisms specified in each offer or bid along with assumptions relating to key variables (for example, oil and LNG prices, foreign exchange rates and inflation) based on the expectations for those variables at the time of the offer or bid.[240]
- Some producer and retailer offers specify a pricing mechanism linked to Brent crude oil prices. We calculated an indicative price in such offers using the following approach:
  - For each day in the month in which an offer was made, we calculated the expected price of Brent crude oil for the year of supply (for example, 2023) by taking a simple average of Brent crude oil prices expected in each month of that year.
  - We then averaged these daily estimates to derive a monthly estimate for the year of supply.
  - We then applied this monthly estimate to the pricing mechanism specified in the offer to arrive at an indicative price.
- A similar approach is used to calculate an indicative price for offers and bids that specify a pricing mechanism linked to JKM (LNG) prices.

A.3 Comparing domestic price offers with future LNG netback prices

In section 2.3 of this report, we compare prices offered:

- for delivery in Queensland to expectations of short and medium-term LNG netback prices in Queensland in the month the offer or bid occurred
- for delivery in the southern states to the range of prices expected under a bargaining framework, outlined in previous ACCC reports in the month the offer or bid occurred.

A.3.1 Approach to comparing offers in Queensland

We calculate LNG netback prices, based on JKM spot prices, to compare against prices offered in Queensland (where the east coast gas market's LNG export facilities are located).

Asian LNG spot markets provide an alternative for LNG producers to selling gas in the domestic market. As such, Asian LNG spot prices are likely to influence domestic gas prices under current market conditions.

While LNG netback prices are likely to play an important role in the east coast gas market, they are not the sole factor influencing domestic prices. The gas prices received by producers will also depend on the location of gas fields, the marginal cost of supply, the buyer's maximum willingness to pay and the demand-supply balance, the importance of each which will differ over time.

240 In all estimates of offer and bid prices in this report, the following assumptions were made, where relevant:
- The expected AUD/USD exchange rate is equal to the average rate prevailing during the month in which the offer or bid occurred (source: RBA).
- The expected Brent Crude oil price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg).
- The expected Japan Korea Marker (JKM) LNG price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: ICE).
- The applicable CPI is based on actual CPI where available at the time the bid or offer occurred (up to the most recent available quarter, source: ABS), and 2.5% thereafter.

To calculate an LNG netback price to compare against offers for future supply, we have:

- calculated a forward-looking LNG netback price as at the date of the offer – based on market expectations of future LNG spot prices during the period of supply – as this gives the best indication of the likely opportunity cost of supplying gas to the domestic market[241]
- used short-run incremental costs of LNG production and transport, since LNG producers are making decisions about the sale of uncontracted gas over the short-run.

We have calculated LNG netback prices using the method and assumptions used for the LNG netback price series, which is regularly published on the ACCC's website, and which is described in detail in the ACCC's Guide to the LNG netback price series. [242]

The domestic offers analysed in section 2.3 are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison for offers in a given year, 2023 as an example, we calculated an average 2023 LNG netback price that an LNG producer would need to receive to be indifferent between selling the gas to the domestic buyer over the entirety of 2023, and selling cargoes on the Asian LNG spot market in 2023.

To follow through this example, we calculated the average of LNG netback prices for 2023 that an LNG producer would have expected in July 2022 as follows:

- We obtained JKM futures prices for each month of 2023 that were quoted by ICE on each day during July 2022.
- We converted the monthly 2023 JKM futures prices into LNG netback prices at Wallumbilla by:
  - converting the prices from USD$/MMBtu into AUD$/GJ using contemporaneous exchange rates and a conversion factor between MMBtu and GJ
  - subtracting the short-run marginal costs of shipping, liquefaction[243] and transportation.[244]
- We averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2023 expected on each day during July 2022.
- We then averaged these 2023 expectations for each day of July 2022 to arrive at an average of LNG netback prices for 2023 expected during the month of July 2022.

As has been noted in the past, our approach to calculating LNG netback prices does not involve deducting the capital costs of building the Queensland LNG export facilities.[245] This is because these are sunk costs and do not influence the decisions of LNG producers, at the margin, to supply uncontracted gas to the domestic or export markets.

Moreover, LNG spot prices are determined by short-run LNG market dynamics, such as LNG supply into spot markets, the level of competition, as well as demand and the ability for buyers to switch to alternative fuel sources (such as coal). These short-run dynamics are influenced by short-run supply, which, in turn, is determined by short-run incremental costs

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241 For this, we have used JKM futures prices (source: ICE).

242 Australian Government, Australian Competition and Consumer Commission, *Guide to the LNG netback price series*, September 2022, accessed 31 May 2024.

243 We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from LNG producers in Queensland.

244 We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from LNG producers.

245 Australian Government, Australian Competition and Consumer Commission, *Guide to the LNG netback price series*, September 2022, accessed 31 May 2024.

for the marginal supplier of LNG to spot markets (which are not influenced by the capital costs of building LNG export facilities).

There may be times, however, where LNG spot prices would be sufficiently high to allow LNG producers to recover apportioned capital costs (for their relevant LNG facility). There are also likely to be periods in which the opposite would be the case.

A.3.2 Approach to comparing offers in the southern states

Due to the cost of transportation between the southern states and Queensland, there is a range of possible pricing outcomes in gas supply negotiations in the southern states, which would usually be expected to fall between:

- the buyer alternative (representing a ceiling in negotiations)–the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location
- the seller alternative (representing a floor in negotiations)–the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla.

Whether a price actually achieved in a negotiation will fall within this range is likely to depend on a number of factors, including the location of the buyer, the expectations of the parties about supply and demand dynamics in the southern states, the relative bargaining strength of the parties and the non-price terms and conditions agreed by the parties.

The supply-demand outlook in the southern states is particularly important to the outcome. If there are limited supply options for gas users in the southern states, such as in the case of an expected gas supply shortfall, users that are unable to reach an agreement for gas supply with a southern supplier will need to transport gas from Queensland. In this scenario, gas suppliers in the southern states would be expected to offer a buyer alternative price in every region in the southern states.

Further, a southern supplier would be expected to seek a higher price the further away a gas user is from Queensland. Since gas users in Victoria are located further away from Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states, all other things equal. If, in a well-functioning market, a southern supplier was to make an offer above this, then regardless of the location of the buyer it would likely be more economic for the buyer to purchase gas from Queensland and transport it to its location. Therefore, the buyer's alternative price in Victoria is indicative of the maximum price that would be likely to prevail in a well-functioning market.

Conversely, if there were sufficient supply and diversity of suppliers in the southern states, this would be likely to alter the relative bargaining positions of gas suppliers and gas buyers. Gas buyers would be able to source gas from another supplier in the southern states rather than having to transport it from Queensland, and increased competition would be likely to lead suppliers to offer prices closer to the 'seller alternative' price. In this scenario, the prices offered by suppliers in the southern states would be lower the further away the source of supply is from Queensland.

To meaningfully analyse the level of prices offered in a particular location in the southern states using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location. In the extended analysis in Appendix C, we present a buyer and seller alternative.

We note that the LNG netback price and buyer and seller alternative price do not account for other factors that may influence the prices offered to gas buyers, such as flexible non-price terms and conditions in GSAs, the contract length and, in the case of retailer offers, retailer costs and margins.

A.4 Reporting on GSA pricing and flexibility

The information in this section describes our approach to reporting on GSAs, as presented in section 2.3 and 3.3, and should be read in conjunction with information above in section B.1.

The following also applies to our analysis of GSAs:

- For the purpose of the analysis of producer prices, we have included GSAs executed at arm's length by producers with all counterparties. For the purpose of the analysis of retailer prices, we have only included GSAs between retailers with C&I users and gas-powered generators. Analysis may also include price amendments.
- We estimated prices payable using recent expectations of key variables, including, where relevant, the AUD/USD foreign exchange rate, inflation, Brent Crude oil and JKM.[246] To estimate the price payable in a given supply year, we have taken the simple average of expected prices in each supply month in that year.

We also report on the average load factor and take or pay multiplier. Both the load factor and the take-or-pay multiplier are measures of the level of flexibility allowed under the contract. Specifically:

- The load factor is calculated as the ratio of the annual aggregate of the maximum daily quantities allowed under the GSA and the annual contract quantity. The higher the load factor, the more gas a gas user can take on a given day above their average daily allowance.
- The take-or-pay multiplier is the percentage of the contracted gas that must be paid for by the buyer and is regardless of if the buyer actually takes delivery of the gas. A GSA with a take-or-pay multiplier of 100% implies that the buyer has to pay for all of the gas it has contracted to take, irrespective of whether it uses the gas in the year. A GSA with a take or pay multiplier of 0% is considered an option contract as the buyer does not have any obligation to purchase gas under the contract.

[246] This differs to our approach to reporting on prices offered and bid, in which we estimate prices based on expectations in the month the offer or bid occurred.

Appendix B: Market conditions 2021–2024

Volatile and uncertain market conditions over recent years have had a profound impact on market participants across the supply chain. The availability of gas supply and infrastructure services, prices, and the contracting environment have all been affected, with gas buyers – C&I users, retailers and other intermediaries – placed under significant pressure. This has, in turn, had implications for the effective operation of the east coast gas market.

This section discusses some of the key events, both domestic and international, that have affected the east coast gas market since 2020. This provides context for the analysis contained in chapters 3 and 4.

B.1 Tight and volatile market conditions in the latter half of 2021 and 2022 posed challenges

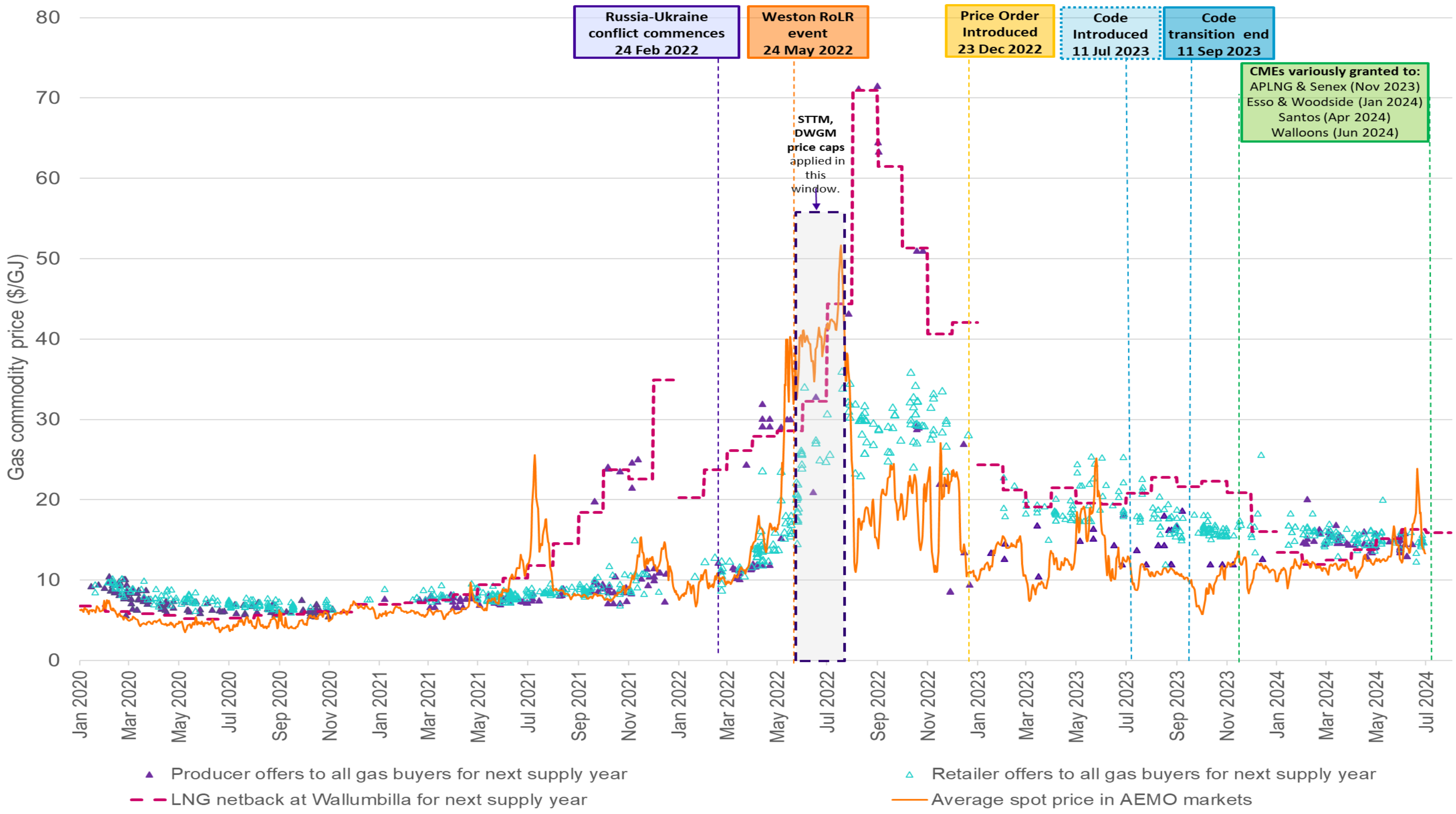
C&I users reported an easing of conditions in the east coast gas market in 2020 and the first half of 2021, with domestic gas prices falling below $10/GJ and retailers and producers reportedly more responsive to requests for offers and more willing to negotiate.[247]

This can be seen in chart B.1, which shows, the prices offered by producers and retailers for supply year 2021 fell from around $10/GJ in early 2020 to $6–$8/GJ in the latter half of 2020. This reduction in prices occurred at a time when international oil and LNG prices were relatively low (chart B.3), market conditions were relatively stable and there was a better supply-demand outlook (i.e. a surplus of 96 PJ was expected going into supply year 2021 – see chart B.2). It also occurred at a time when LNG producers were more active in the domestic market, as they sought to offset the impact of COVID-19 on LNG demand by selling gas into the domestic market.[248]

[247] ACCC, *Gas Inquiry 2017–2025 interim report*, July 2020, p 73, ACCC, *Gas Inquiry 2017–2025 interim report*, July 2021, p 62.

[248] ACCC, *Gas inquiry 2017–2025 Interim report*, January 2021, p 61.

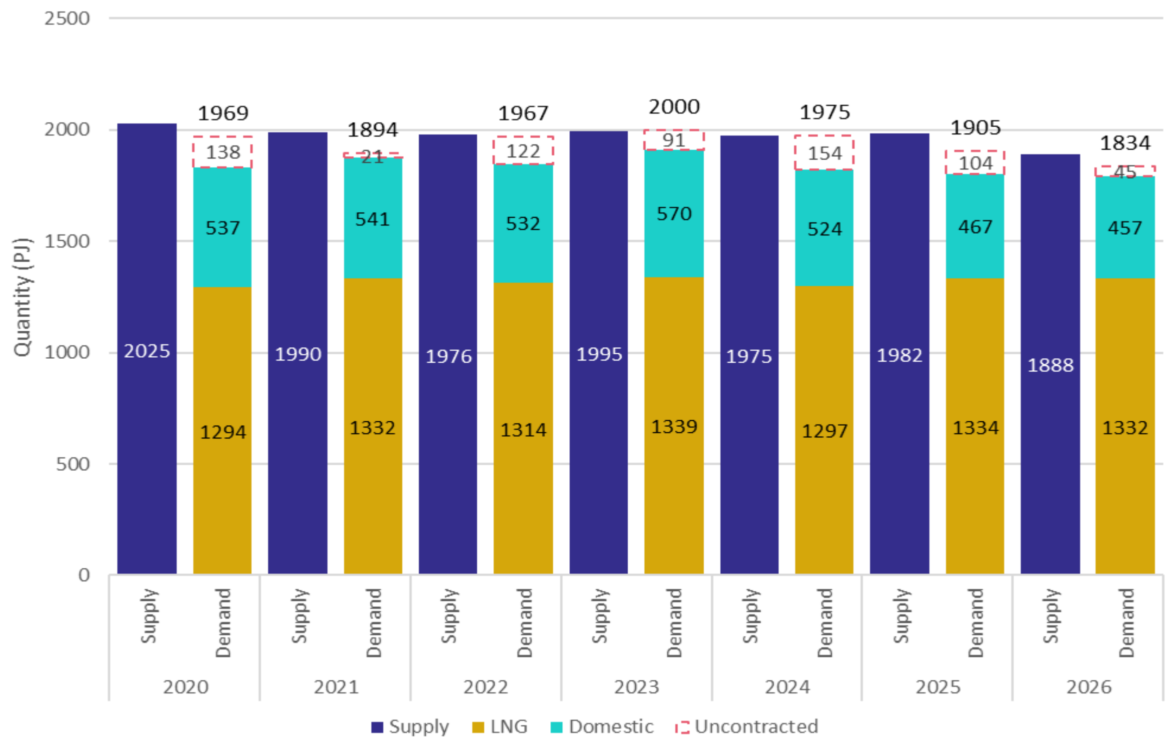
Chart B.1: Gas commodity prices offered in the east coast gas market between 2020–2024 for supply years 2021–2025



Sources: ICE, Argus, AER, ACCC analysis of offer information provided by suppliers.

Note: Data includes offers made 1 year prior to the commencement of the supply year. See Appendix A for additional notes relating to offers.
The average spot price has been calculated as the simple average of the Adelaide, Brisbane and Sydney STTM daily ex ante prices, the DWGM daily imbalance price, and Wallumbilla day-ahead price.

Chart B.2: East coast supply-demand forecast prior to commencement of each supply year



Source: ACCC analysis of data obtained from gas producers between 2019 and 2024 and of the domestic demand forecast (Central scenario) from AEMO's GSOOs.

Note: Totals may not sum due to rounding. The quantity required to meet long-term LNG SPAs includes feed gas requirements (such as fuel) required to produce LNG.

As Chart 0.1 shows, conditions started to change in the latter half of 2021, with producers and retailers making fewer offers, and international and domestic prices also increasing. The supply-demand outlook also deteriorated in 2021, with a surplus of just 9 PJ expected going into supply year 2022 (assuming LNG producers exported all their uncontracted gas) (chart B.2). By the end of 2021, producer and retailer offer prices for 2022 supply started to exceed $10/GJ.

Conditions continued to tighten in the first half of 2022, with a number of events coinciding in international LNG and oil markets,[249] the National Electricity Market (NEM),[250] and supply side of the east coast gas market,[251] contributing to a very tight demand-supply balance in the east coast and a significant escalation in international and domestic prices.

Prices in the AEMO markets, for example, more than trebled between February and May 2022, reaching peaks of $35–$49/GJ in the last week of May 2022.[252] The higher prices in these markets placed significant financial pressure on C&I users, retailers and others using the markets. It also contributed to Weston Energy's suspension from a number of the AEMO-

249 Triggered by the Russia-Ukraine conflict and a number of other events in international LNG and oil markets.

250 Triggered by unplanned outages and supply constraints at some coal generation plants, lower renewable energy generation and higher electricity demand.

251 Triggered by rain, flooding and outages, which affected supply from a number of fields in Queensland, the NT and Cooper Basin. While the reduction in supply from these sources was more than offset by an increase in supply from the Gippsland and Otway basins, the increased supply was insufficient to meet increased demand by both LNG producers and GPG.

252 AER, Gas weekly report – 22–28 May 2022 and AER, Gas weekly report – 29 May – 4 June 2022.

operated facilitated markets in May 2022,[253] which in turn triggered the Retailer of Last Resort (RoLR) arrangements in some jurisdictions.[254]

This occurred at a time when the market was already under significant pressure, with higher than forecast GPG demand, and constraints on available supply and southern haul transport (see section 0). It also occurred at a time when AEMO was having to take steps to manage the tight conditions[255] and when domestic prices were at unprecedented levels with some AEMO markets in an administered price state.[256]

The tight and volatile conditions prevailing in the first half of 2022 persisted into the latter half of 2022, with international and domestic prices remaining very high during this period. The supply-demand outlook also deteriorated even further, with a shortfall of 5 PJ expected going into supply year 2023 (assuming LNG producers exported all their uncontracted gas) (chart B.2).

Over this period, producers made very few offers, which made it more challenging for retailers and other gas buyers to procure the gas they required for 2023. In the latter half of 2022, the prices offered by those producers ranged around $13.50/GJ-$70/GJ (with half the offers exceeding $50/GJ), while retailer offers ranged around $23/GJ–$35/GJ.[257]

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253 Weston was suspended because it was unable to meet the STTM and DWGM prudential requirements. AEMO, *Short-Term Trading Market – Suspension Notice*, 23 May 2022 and AEMO, *Declared Wholesale Gas Market in Victoria – Suspension and Deregistration Notice*, 23 May 2022.

254 The RoLR event also resulted in the Brisbane and Sydney STTMs being placed into an administered state until 7 June 2022. See AER, Significant price variation report, September 2022, p 9.

255 AEMO, for example, issued a series of threat to system security notices in the DWGM and also triggered the Gas Supply Guarantee for the first time in June and July 2022. The Gas Supply Guarantee was first triggered on 1 June 2022 and was in place until 2 June 2022. It was triggered again on 19 July 2022 and remained in place until 30 September 2022.

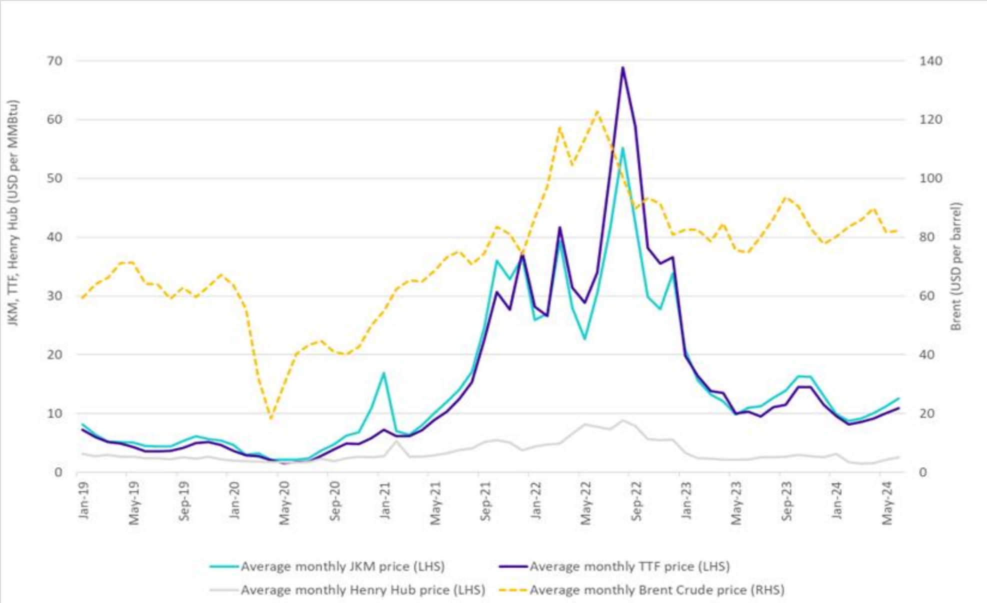
256 The $40/GJ price cap was in place in the Sydney STTM between 7 and 14 June 2022, and in the DWGM between 30 May and 1 August 2022. See AER, Significant price variation report, September 2022.

257 ACCC, *Gas Inquiry 2017-2030 – Interim update on east coast gas market*, December 2023, pp 16.

Box B.1: International oil, LNG and gas price trends

Chart B.3 shows how international oil and LNG prices have changed over the period.

Chart B.3: International prices



Source: ICE(JKM), Argus (TTF), EIA (Brent Crude), ACCC analysis, October 2024.

Oil prices

International oil prices plummeted in early 2020, falling from around US$60/bbl to US$20/bbl before making a slow recovery over the remainder of 2020. Oil prices started escalating in 2021, rising from around US$50/bbl to a peak of around US$120/bbl in mid-2022, before subsiding to around US$80/bbl in the latter half of 2022.

Throughout 2023 and much of 2024, oil prices have ranged between US$80–$100/bbl, which while lower than the peak observed in 2022, is still higher than the prices observed over much of 2021.

International LNG and gas prices

In contrast to oil prices, international LNG and gas prices were relatively steady for much of 2020. This started to change in 2021, with LNG prices experiencing significant growth in 2021 and into 2022, reaching a peak of US$70 per MMBtu in mid-2022, before falling to around US$20 per MMBtu in mid-2023. Over the remainder of 2023, international LNG and gas prices ranged between US$10–$19 per MMBtu.

International LNG and gas prices have trended up since mid-February 2024, largely driven by increased weather-related demand across the Atlantic and in Asia and actual and potential supply constraints due to the conflict in the Middle East and continuing tensions between Russia and Ukraine. Like oil prices, international LNG and gas prices are currently higher than the prices observed over much of 2021.

B.2 A ‘pause’ in contracting by some producers in 2023-early 2024 led to slowed market activity

The tight supply conditions in the market continued into 2023, with a significant east coast supply shortfall initially forecast. However, a reduction in projected demand for gas powered generation (GPG) and mild weather lead to an easing in the supply-demand balance.

While international and domestic prices softened in 2023, the decision by a large number of producers to ‘pause’ contracting in response to the implementation of the Emergency Price Order[258] and Gas Code posed challenges for gas buyers in terms of being able to procure sufficient gas, with some retailers having to cease making offers for a period in 2023 (see section 4.6). The pause in producer contracting persisted for most of 2023 (Chart 0.1) and, for some producers, appears to have extended into early 2024, as they awaited the outcome of their conditional Ministerial exemption applications.

The prices offered by those producers and retailers that were making offers in 2023 for the 2024 supply year, ranged $10–$26/GJ, which while lower than the peaks observed in 2022, remained relatively high. This is consistent with what was happening with international prices over this period and may have also reflected the tight supply-demand balance that was expected going into 2024 (chart B2)

B.3 Market conditions have improved in 2024, but concerns remain about future challenges

Conditions in the market started to ease somewhat in the first half of 2024. Larger producers that had received a conditional Ministerial exemption resumed making offers for supply in 2025–2026. The increased availability of gas, together with lower international prices, has contributed to a softening of domestic prices over this period and improved supply-demand outlook for 2025 (chart B.2). It has also reduced the gap between the prices offered by producers and retailers (chart B.1). As outlined in chapter 2, producer and retailer offer prices for the 2025 supply year ranged from around $12/GJ to $20/GJ in the first 6 months of 2024, while the prices agreed to in GSAs ranged from around $13–$16/GJ.

While lower than the highs observed in 2022, the prices agreed to over the first 6 months of 2024 for 2025 supply are around 2 times higher than they were for the 2021 supply year (see section 3.2). This trend is broadly consistent with what has occurred with international prices, which have remained above the levels observed over 2020 and most of 2021 (chart B.2).

As discussed in section 3.2, gas buyers observed that there had been an increase in competition in 2024. They also noted that while gas prices have fallen from the unprecedented levels observed in 2022 and 2023, they remain higher than the $12/GJ reasonable price set out in the Gas Code, and higher than the levels experienced before the events outlined above (see section 3.2 for more detail).

Several C&I users also told us about their difficulties experienced in securing supply beyond 2026. This is broadly consistent with what some retailers told us. That is, it is becoming increasingly difficult to find producers willing to enter into longer-term GSAs, with producers

[258] The Emergency Price Order provided for a $12/GJ cap on offers made and GSAs entered into by non-exempt producers and affiliates during the price cap period (23 December 2022 – 22 December 2023) for supply in 2023.

selling an increasing volume of gas on a short-term intra-year basis (see section 3.3).[259] Producers are also reportedly providing less volume flexibility to gas buyers, with some also transferring greater levels of supply risks to gas buyers through permitted interruption provisions (see section 3.4 for more detail).

259 ACCC, *Gas Inquiry 2017–2030 Interim report*, December 2023, pp 110.

Appendix C: Compliance with the HoA

This Appendix provides an overview of our assessment of the LNG producers' compliance with the Heads of Agreement (HoA) for the reporting period 26 January to 30 June 2024.

In summary, we have found that LNG producers have complied with their commitments under the HoA. Over this period, producers offered 49.2 PJ to the domestic market, of which 22.1 PJ was supplied into the domestic market, most of which was over relatively short supply periods.

C.1 HoA commitments

On 29 September 2022, the Australian Government and the 3 east coast LNG producers (APLNG, GLNG and QCLNG) signed an updated HoA, to operate between 1 January 2023 and 1 January 2026. The stated objective of the updated HoA is to: [260]

> …prevent a gas supply shortfall through access to secure and competitively priced gas for the East Coast domestic market.

Under the terms of the updated HoA, any uncontracted gas produced by the LNG producers must first be offered to the domestic market for "reasonable supply periods, with reasonable notice on competitive market terms" in accordance with the principle that "domestic gas customers will not pay more for the LNG exporters' gas than international customers".

As part of the HoA, LNG producers also committed to additional transparency measures, including publishing offers and EOIs on their websites to make gas available more broadly to the domestic market. They also committed to providing a quarterly report to the Minister for Resources outlining their respective actions and commitments under the HoA.

The updated HoA also provides for the ACCC to monitor and report on the progress of LNG producers' commitments under the HoA. The results of our assessment are set out below.

C.2 LNG producers offered uncontracted gas to the domestic market prior to export

For each cargo of uncontracted gas sold to the international market, LNG producers are required to provide the ACCC with evidence that equivalent gas volumes were first offered to the domestic market.

Between 26 January and 30 June 2024, the LNG producers sold 10 spot or additional LNG cargoes to the international market, which is equivalent to 38.3 PJ of gas. Over the same period, the LNG producers offered around 43.1 PJ of gas to the domestic market for supply in 2024 (some of which formed part of the LNG producers' commitments under conditional

[260] Australian Government, Department of Industry, Science and Resources, *Heads of Agreement – The Australian East Coast Domestic Gas Supply Commitment*, September 2022, accessed 3 November 2024.

Ministerial exemptions)[261] and 6.1 PJ for supply in 2025. This is in addition to the 147 PJ of gas we noted LNG producers had offered to the domestic market in the prior reporting period for supply in 2024 and 2025.[262] LNG producers appear therefore to have complied with this aspect of the HoA.

The HoA only requires LNG producers to offer gas to the domestic market. Over this period LNG producers sold 22.1 PJ of gas to the domestic market for 2024 supply. They also entered into time and/or location swaps with the domestic market for 2024 supply, involving approximately 19.3 PJ of gas.[263] While gas swaps do not provide a net increase in the volume of gas LNG producers supply to the domestic market, they can increase the amount of gas available in peak periods, such as the winter months.

C.3 Uncontracted gas was offered for relatively short supply periods but with reasonable notice

Under the HoA, LNG producers have committed to offer uncontracted gas to the domestic market for "reasonable supply periods" and "with reasonable notice" prior to offering it to the international market. Such offers can be made through EOI processes or other means, including direct marketing, through a broker or Gas Supply Hub (e.g. the Wallumbilla GSH).

Between 26 January and 30 June 2024, the LNG producers did not issue any EOIs. They did, however, use direct marketing processes (i.e. by making offers directly to domestic buyers or responding to gas buyers' bids for gas) and the Gas Supply Hub to offer uncontracted gas to the domestic market.

Of the gas offered by LNG producers to the domestic market over this period, very few offers had a term length greater than 1 year, with most of the offers providing for short-term intra-year supply.

As to the notice period, for offers for supply of around 2 or more months, the LNG producers provided sufficient notice (around 2 or more weeks) for buyers to consider the offer. They also provided reasonable notice between the date of the offer and the supply start date, to demonstrate compliance with the HoA.

C.4 The uncontracted gas was offered at prices less than or equal to the LNG netback price

Under the HoA, LNG producers have agreed to adhere to the principle that domestic gas customers will not pay more than international customers for the LNG producers' gas. They also agreed that individual prices for gas offered to domestic customers will have regard to the producers' cost of production and supply, the prices LNG producers could reasonably expect to receive for the gas in international markets and terms and conditions of supply.

261 See for example, Walloons Notice of Intention to Market Gas for supply in 2024 and 2025 on its website.

262 These offers were made between 9 August 2023 and 25 January 2024.

263 In total the LNG producers entered into swaps involving 19.3 PJ of gas, with 11.3 PJ involving other LNG producers and 8 PJ non-LNG producers.

Over the period 26 January – 30 June 2024, the LNG producers offered their uncontracted gas to the domestic market at prices that were broadly consistent with the LNG netback price. The offers made over this period appear therefore to comply with the principle that domestic gas customers will not pay more than international customers.

C.5 LNG producers complied with the transparency measures in the HoA

The HoA requires LNG producers to publish on their websites information that provides domestic customers with visibility on uncontracted gas volumes and allows domestic customers to approach LNG producers to purchase these volumes. This information, which is expected to be published every 6 months, includes:

- EOIs and/or annual delivery plans, including information on the quantity of gas the LNG producer intends to supply, the supply term, the proposed delivery point(s), price structure, offer period, offer response period and contact details
- volumes committed for sale in the previous period, by customer type
- volumes offered because of extraordinary unplanned circumstances.

Based on our review of the information published by LNG producers between 26 January and 30 June 2024, it would appear that LNG producers complied with these obligations.

Appendix D: Extended analysis of offers

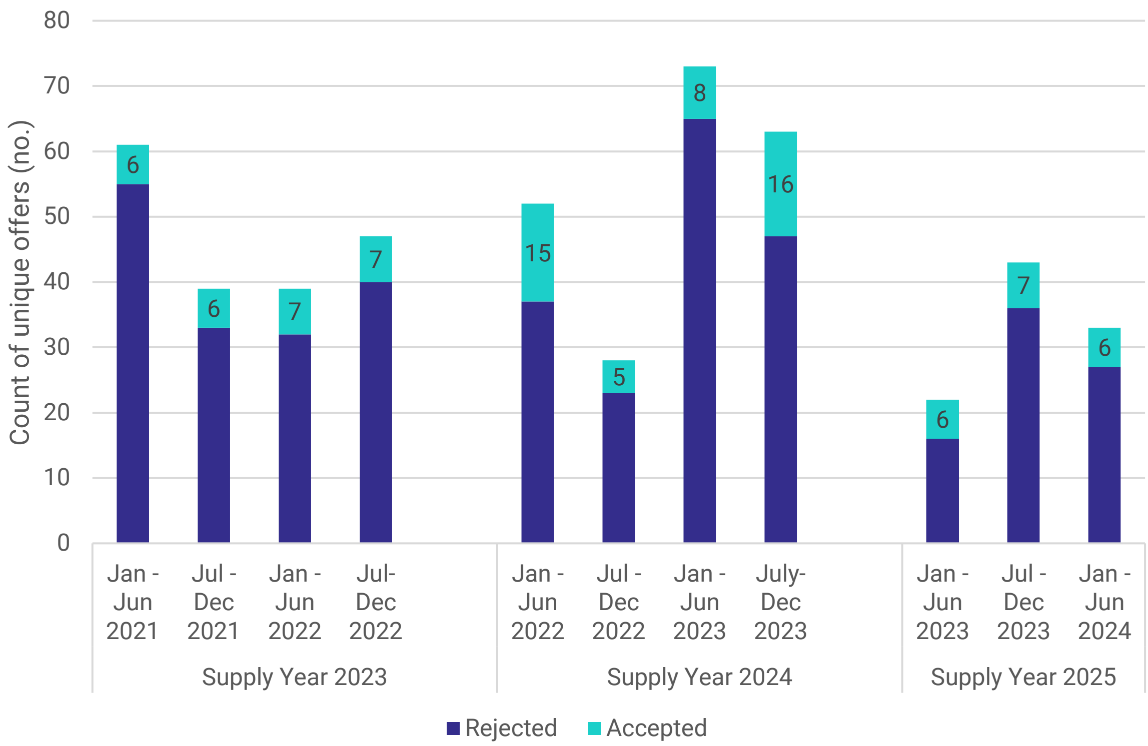
This Appendix sets out the results of additional analysis we have carried out on offers. It is based on offers involving the supply of at least 0.5 PJ p.a. over at least a 12 month period (see Appendix A for more detail).

D.1 Number of offers made to C&I users that were either accepted or rejected

Chart D.1 shows the number of unique long-term offers that were made to C&I users by producer and retailers between January 2021 and June 2024 for supply years 2023–2025, that were either accepted or rejected. It shows that the number of offers accepted by C&I users peaked for the 2024 supply year, rising from 26 for the 2023 supply year to 44 for the 2024 supply year.

It also shows that the number of unique offers made to C&I users for the 2025 supply year, when measured at a similar point in the contracting cycle to the 2023 and 2024 supply years, has been lower than what it was for 2024, but similar to the 2023 supply year levels.

Chart D.1: Number of accepted and rejected unique offers to C&I users for the 2023–2025 supply years



Source: ACCC analysis of bid and offer information provided by suppliers.

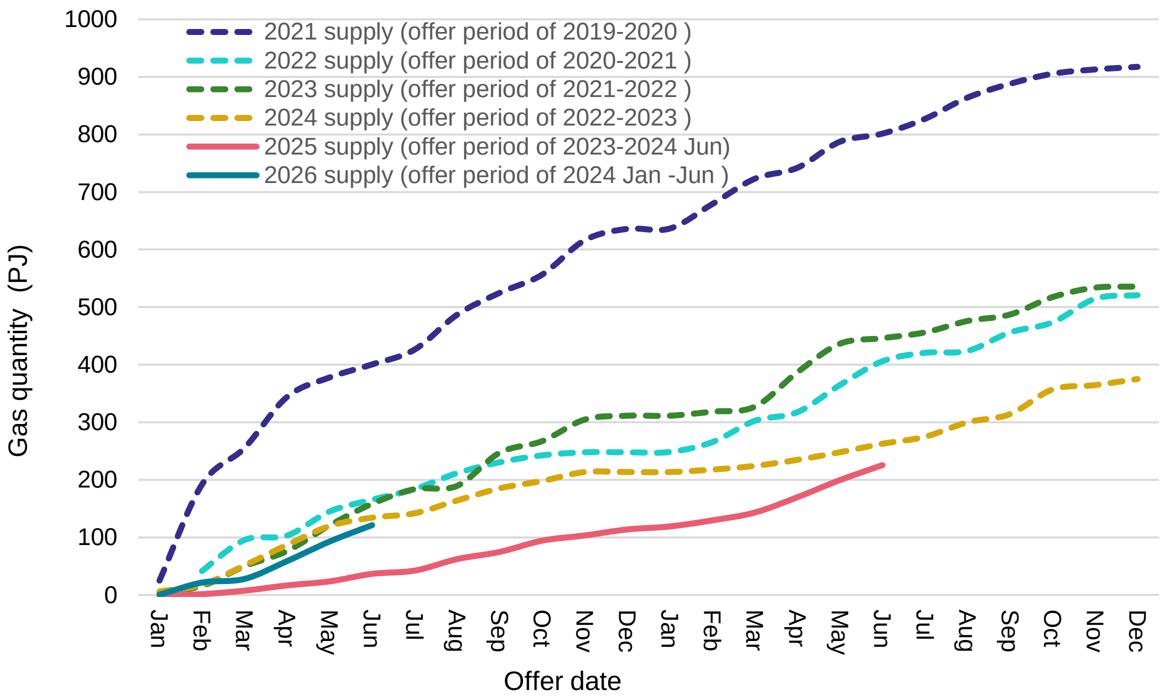
The percentage of offers accepted by C&I users was around 10% higher in 2024 than it was in 2023, with similar rates of acceptance observed in 2025.

While not shown in chart D.1, the percentage of accepted offers has been higher in Queensland than it has been in the southern states. The percentage of accepted offers in Queensland, for instance, increased from around 50% between January and June 2022 to 67% between January and June 2023. Over the same period, the percentage of offers accepted in southern states fell from around 33% between January and June 2022 to 8% between January and June 2023.

D.2 Volume of gas offered to C&I users

Chart D.2 shows the volume of gas offered by producers and retailers under offers made to C&I users for supply years 2021–2026 in the 2 years immediately preceding the commencement of the supply year. It shows that less gas was offered to C&I users for 2024 and 2025 supply, compared to prior supply years. Note that in contrast to the analysis in the preceding section, this chart is not restricted to unique offers.

Chart D.2: Cumulative volume of offers for supply to C&I users for supply years 2021–2026



Source: ACCC analysis of bid and offer information provided by suppliers.

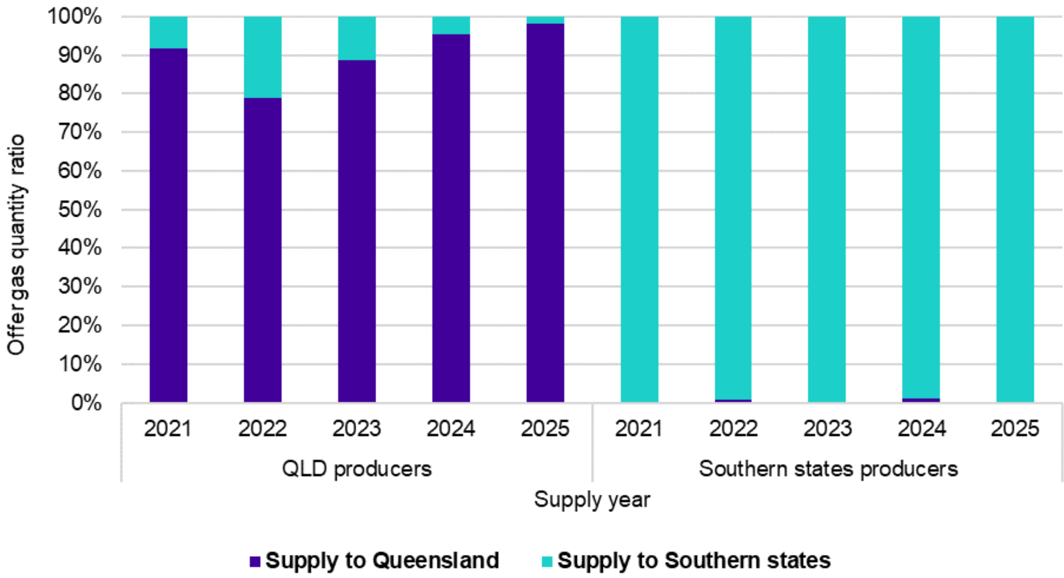
Note: Data for the 2025 and 2026 supply years is only available up to June 2024.

D.3 Offers to different delivery regions

As part of our broader analysis of offers, we have examined the delivery regions for offers made for gas produced in Queensland and the southern states for supply years 2021–2025 (chart D.3).

In short, we found that gas produced in Queensland has predominately been offered for delivery in Queensland, while gas produced in southern states has almost been exclusively offered to southern state buyers. We also observed that, the proportion of Queensland gas offered to southern states has decreased from 20% for the 2022 supply year to 2% for the 2025 supply year.

Chart D.3: Proportion (%) of total gas volume offered by Queensland and southern state producers to different delivery regions



Source: ACCC analysis of bid and offer information provided by suppliers.

Note: Only offers with clear indication of gas delivery regions of either Queensland or southern states are included in analysis. All offers are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Some offers in the chart may be between the same supplier and buyer and/or represent further offers between parties.

Appendix E: Retailers' costs and risks

This Appendix provides further detail on the costs and risks retailers face in supplying gas to C&I users. It also sets out how we have analysed retailers' costs.

E.1 Retailers face a number of costs and risks supplying gas to C&I users

As outlined in chapter 4, retailers act as the interface between their customers and gas producers, the AEMO markets, pipeline owners and storage providers. In that capacity, retailers are responsible for facilitating the supply of gas to the user's facility and managing the contracting and other arrangements associated with that supply.

The retailer does so by aggregating gas purchased from producers or other suppliers and/or the AEMO markets, which it then transports to the user via transmission pipelines and, if required, distribution pipelines and/or storage facilities. This can be seen in figure 4.1.

As the middle of that figure highlights, retailers incur a number of costs and face a number of risks in performing this function. Table E.1 provides an overview of the types of costs and risks retailers can face when supplying C&I users.

Table E.1: Types of costs and risks that retailers may face when supplying C&I users

Costs incurred by retailers	Risks that retailers may face
Commodity costs – this includes: ▪ the cost of procuring gas from producers or other suppliers under GSAs ▪ the cost of procuring gas in AEMO markets (i.e. the STTM, DWGM and GSH) ▪ gas commodity price related hedging costs.	**Gas commodity risks** – this includes the following risks: ▪ **Gas supply risk**, which is the risk that contracted supply is insufficient to meet demand and/or supply is interrupted (due to a permitted interruption, Force Majeure etc) ▪ **Gas demand risk**, which is the risk that demand (hourly, daily, annual) differs from what the retailer has contracted ▪ **Gas commodity price risk**, which is the risk that the price payable for gas exceeds what is assumed in retail prices, or is required to compete.
Transport and storage costs – this includes: ▪ **Transmission costs** (i.e. the cost of procuring transmission services from pipelines, or secondary capacity) ▪ **Distribution costs** (i.e. the costs of procuring distribution services for those C&I users operating within distribution networks) ▪ **Storage costs** (i.e. the costs of procuring storage, where required).	**Transport and storage risks** – this includes the following risks: ▪ **Infrastructure supply risk**, which is the risk that contracted transport and/or storage capacity is insufficient to meet demand and/or access to these services is interrupted ▪ **Gas demand risk**, which is the risk that customer demand is greater or lower than the capacity the retailer has contracted ▪ **Infrastructure price risk**, which is the risk that the price payable exceeds what is assumed in retail prices, or is required to compete.
Retail, regulatory & market costs – this includes: ▪ **Operating costs** (i.e. costs associated with customer acquisition & retention, financial & other costs, as well as regulatory compliance) ▪ **AEMO fees** (i.e. costs associated with accessing AEMO-operated markets) ▪ **Financial costs** (i.e. the costs associated with depreciation and amortisation).	**Retail, market & regulatory risks** – this includes the following: ▪ **Retail risks**, which includes the risk that a customer fails to pay (e.g. due to insolvency) ▪ **Market and regulatory risks**, which includes the risks that market fees or compliance costs are higher than assumed in retail prices, new regulatory obligations are introduced and the retailer fails to comply with a regulatory obligation.

E.2 Approach used to examine retailers' costs

E.2.1 Information collected from retailers

We used our compulsory information gathering powers to obtain information about the retailers' gas supply businesses for the analysis of retailer costs in chapter 4. The information we collected included:

- revenue information for each of the different customer types that retailers supply, including mass market customers (i.e. residential customers and small-medium enterprise customers), C&I customers, GPGs, LNG exporters and any other types of customers
- cost information for the retailer's gas supply business, including gas commodity costs, pipeline transmission costs, distribution costs, storage costs, AEMO fees, operating costs and financial costs (depreciation and amortisation) (see table E.1)
- quantities of gas supplied and obtained by the retailer
- customer numbers for each jurisdiction and customer type (including the number of customers acquired and lost).

We required retailers to provide this information for the operating segments that was most directly involved in incurring the cost, receiving the revenue, or obtaining or supplying the gas. This was to avoid receiving information relating to internal transactions within the retailers' overall businesses. We sought information that did not derive from transfer prices, except when no other information existed.[264]

The retailers were required to provide revenue information for each of the customer types they use when keeping financial records and preparing and lodging financial reports under the *Corporations Act 2001*. The terminology used by the retailers to categorise customers differed, but generally their approaches to determining customer types are similar.

E.2.2 Cost allocation

For the purposes of this review, we have focused on the costs retailers incur supplying gas to C&I users across the east coast. This differs from the approach we used in 2019, when we examined costs at a jurisdictional level. Focusing on costs at an east coast level has enabled us to avoid having to make any assumptions about how to allocate costs to particular jurisdictions.

We have nevertheless had to make some assumptions about how to allocate the total costs that retailers incurred across their retail gas supply operations, between the different types of customers that the retailers supply, to estimate the cost of supplying C&I customers.

The method we have used to allocate costs to states and customer types are as follows:

- Gas commodity costs: These costs have been allocated between customer types based on the volume of gas supplied to each customer type. This assumes that gas commodity costs do not vary across customer types.

264 A transfer price is a notional price or other value for the purpose of recording and / or reporting on transactions within its overall business—for example, a retailer may use transfer prices when valuing the gas it supplies to its own gas powered generators.

- Transmission costs: These costs have also been allocated between customer types based on the volume of gas supplied to each customer type.
- Distribution costs: These costs have been allocated between mass market and C&I customer types based on the pipeline tariff class. The Tariff V related distribution costs have, for instance, been allocated to mass market customers, because this tariff typically applies to small customers consuming less than 10 TJ p.a.. Tariff D related distribution costs, on the other hand, have been allocated to C&I users, because this tariff typically applies to customers consuming 10 TJ p.a. or more.
- Operating costs: These costs have been allocated between customer types based on the volume of gas supplied to each customer type.
- Financial costs: These costs have been allocated between customer types based on the total revenue generated by each customer type, with revenue used as a proxy for the value of assets required to supply each customer type.
- Other costs: These costs have been allocated based on the volume of gas supplied to each customer type.

Appendix F: Prior C&I user observations

The table below provides a summary of C&I users' observations over the term of the Gas Inquiry, including the findings of research undertaken in 2022 by SEC Newgate. [265]

Table F.1: Summary of C&I user observations from prior Gas Inquiry reports

Year	Month	Observation
2017	September	C&I users state that they are experiencing significant difficulties in securing offers on competitive terms for supply for 2018 and beyond. Most told us they only had one supplier willing to supply and non-price terms were less flexible, and contracts shorter term.
	December	C&I users told us that conditions improved since the September 2017 report, with lower prices being offered and more suppliers competing. Some retailers told C&I users they have no gas.
2018	July	C&I users told us that conditions have continued to improve, with offers now being received from at least 3 retailers. They also told us that offers for 2019 supply have stabilised and that some gas users and gas suppliers are preferring shorter term agreements.
2019	July	C&I users told us that they are experiencing difficulties, particularly in relation to price. Large C&I users also noted a willingness of producers and retailers to engage and negotiate, while smaller C&I users reported fewer offers, with some only receiving one offer.
2020	January	C&I users told us that they continue to experience difficulties, with high gas prices a particular concern. Some told us that they are looking at other alternatives, including procuring from producers or markets. Concerns also remain about supply and less flexible terms.
	July	C&I users told us that conditions had started to ease, but concerns remain about high gas prices and the imbalance in bargaining power faced by users. Concerns were raised about take or pay obligations during COVID and lack of facilitated market hedging products.
2021	January	C&I users reported an easing of gas prices but they told us they were experiencing difficulties obtaining supply post-2022. C&I users also told us that competition and selling practices had improved with suppliers more willing to negotiate non-price terms.
	July	C&I users reported a moderation of 2021 and 2022 prices. Suppliers more willing to negotiate but difficulties remain for supply post-2022. Concerns raised about a lack of transparency around how retail prices are determined and reduced retail offerings in Queensland.
2022	January	C&I users reported a deterioration in conditions, with reduced supply and higher prices for 2022. Some observed changes in retailers' pricing practices and some suppliers were withdrawing offers without explanation and unwilling to negotiate. Users also reported fewer offers.
	July	C&I users reported a further deterioration in conditions, with large jump in prices, suppliers unwilling to negotiate and offering reduced flexibility. C&I users also reported that some suppliers were delaying making offers, frequently revising/repricing offers and providing short offer response times.
2023	January	C&I users told us that their concerns had intensified, due to significant increase in prices, difficulties securing supply and some users having to rely on spot markets. C&I users reported suppliers employing more of a 'take it or leave it' approach (e.g. offers withdrawn or revised/repriced and very short offer response times) and passing on more risks to C&I users (e.g. through 100% take or pay and passing through interruption/outage risks). Some also claimed suppliers were using 'scarcity' to 'force harsher terms'. In mid-2022, we engaged SEC Newgate to undertake market research to examine the C&I market segment in detail and gain a deeper understanding of the market and the behaviour of users, particularly in relation to market engagement, market awareness and information transparency. **SEC Newgate research report** In total, SEC Newgate conducted 30 interviews between June and July 2022 with C&I users consuming more than 10 TJ p.a.. Participants represented a wide range of gas users, with over 60% supplied by retailers. The findings of the research report are summarised below:

[265] ACCC, *Gas Inquiry 2017–2030 interim report*, January 2023, pp 58–74.

Year	Month	Observation
		▪ The level of competition between gas suppliers is seen to be very poor and reduced as a result of Weston Energy's exit. ▪ Suppliers are offering less flexibility in their contract terms, with specific concerns raised about take or pay provisions and 'double dipping' by retailers in relation to these provisions. ▪ Suppliers are employing poor selling practices, with concerns specifically raised about: – unreasonable expectations for fast contract approvals (e.g. some within 24 hours with the threat of significantly higher prices) – suppliers withdrawing offers with little warning, or in some cases, submitting higher offers midway through a tender process – suppliers refusing to make offers some suppliers requiring users to accept spot market linked products.
	June	C&I users reported fewer offers for supply between 2023 and 2025 and noted that this may be a result of suppliers withholding or delaying offers for 2024 until there is further clarity about the Gas Code. C&I users also noted that there had been a deterioration in some retailers' selling practices and that while gas prices have softened since their peak in 2022, they remained concerned about the level of prices.
	December	C&I users reported prices offered for 2024 and 2025 supply had softened since their peak in 2022, but remained high. Some told us they were choosing to remain on spot market linked products despite the known risks. Users also raised concerns about the scope of suppliers' permitted interruption clauses, particularly for Longford supply. Some C&I users queried whether the benefits associated with the Gas Code would flow through to them, and the adequacy of some information that producers are required to publish under the Gas Code.
		Through Stage 1 of the retailer behaviour review into retailer behaviour, C&I users also expressed concerns about: ▪ The 'take it or leave it' approach employed by some retailers in 2022–23, with some noting it generated a 'sense of urgency' and exacerbated the imbalance in bargaining power ▪ short offer validity periods, withdrawals and/or amendments of offers, a limited ability to negotiate and the increasing number of risks being allocated to C&I users ▪ the adequacy of information provided by retailers when selling spot market linked products, particularly after the Weston RoLR event.
2024	June	In discussions with C&I users and intermediaries in March 2024, users told us that they had not observed any improvements in the availability of gas, although some reported improvements in producer engagement and offerings. Users also told us they wanted to better understand retailers' costs because they were concerned retailers were earning significant margins. Some also told us they continued to experience unfavourable offers and limited negotiation on non-price terms, such as take or pay and permitted interruption provisions. They also told us they are increasingly switching to AEMO markets for supply, due to limited gas availability and high-priced contract offers.

Appendix G: Proposed new projects and infrastructure development tables

This annexure provides details of proposed gas production and infrastructure projects and their stage of development.

Table G.1 provides an overview of the supply projects in the southern states that have not yet been approved for development but that producers have indicated could potentially come online between 2026 and 2035 if a final investment decision is made to proceed with the development.

Table G.1: New gas fields in the southern states not approved for development

Supplier	Project or field	Reserves (PJ) 2P	Reserves (PJ) 3P	Resources (PJ) 2C	FID date	Supply year	PJ p.a	Key risks
Bass basin								
Beach Energy	Trefoil	-	-	120	2025	2028	12	M,P,F,G,T
Gippsland basin								
Amplitude Energy	Patricia	-	-	10	2026	2028	1	I,C
Amplitude Energy	Baleen	-	-	4	2026	2028	1	I,C
Amplitude Energy	Manta	-	-	121	2033	2035	16	I, E&A
Emperor Energy	Judith	-	-	203	2026	2029	29	F
Esso	North Turrum	-	-	32	2024	2026	4	C,G,MU,R
GB Energy	Golden Beach Gas Field	-	-	30	2025	2027	30	F,R
Lakes Blue Energy	Wombat	-	-	329	2025	2026	20	R,F,G
Lakes Blue Energy	Trifon/Gangell	-	-	390	2028	2030	20	R,F,G
SGH Energy	Grayling-1A	-	-	27				
Gunnedah Basin								
Santos	Narrabri	7	7	1,967	2026	2028	40	I,R
Otway basin								

Supplier	Project or field	Reserves (PJ) 2P	Reserves (PJ) 3P	Resources (PJ) 2C	FID date	Supply year	PJ p.a	Key risks
Beach Energy	Artisan	-	-	38	2025	2028	8	M,P,F
Beach Energy	La Bella	-	-	29	2025	2028	6	M,P,F
Amplitude Energy	Annie	-	-	65	2025	2028	8	C,I
Lakes Blue Energy	Otway-1	-	-	-	2026	2026	2	R,F
Lakes Blue Energy	Enterprise North	-	-	-	2025	2026	11	R,F
Lakes Blue Energy	Portland Energy Project	-	-	-	2027	2029	55	R,F
	Total	**7**	**7**	**3,365**			**262**	

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates **reflect estimates** only and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, ie securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **G** = Geologic.

Totals may not add up due to rounding.

Table G.2 provides a summary of the Queensland domestic supply projects that are not yet in production but have been approved for development and anticipate will be brought online by 2029.

Table G.2: New gas fields in Queensland approved for development

Supplier	Project or field	Reserves (PJ) 2P	Reserves (PJ) 3P	Resources (PJ) 2C	Supply year	PJ p.a.	Key risks
Bowen basin							
APLNG	Towrie	8	10	11	2024	0.4	C, I,R,P,M,L, E&A
Surat basin							
Arrow Energy	PL253 – Hopeland	727	727	-	2029	32	R, L
Arrow Energy	PL305 – Castledean	147	177	-	2028	10	R, L,G
Arrow Energy	PL491 – Yeronga	420	492	0.4	2028	13	R, L,G
Arrow Energy	PL492 – Alderley	276	279	-	2026	14	R, L, G
Arrow Energy	PL493 – Wyalla	379	387	0.3	2028	14	R, L
	Total	**1,956**	**2,073**	**11**		**83**	

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates reflect **estimates only** and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, ie securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **G** = Geologic.

Totals may not add up due to rounding.

Table G.3 provides a summary of the domestic supply projects in Queensland not yet been approved for development but that producers have indicated could potentially come online by the end of 2035 if the FID is made to approve the projects.

Table G.3:New gas fields in Queensland not approved for development

Supplier	Project or field	Reserves (PJ) 2P	Reserves (PJ) 3P	Resources (PJ) 2C	FID date	Supply year	PJ p.a	Key risks
Bowen basin								
APLNG	Taroom East	-	-	5	2033	2035	1	M,C,R,P,L, E&A
Comet Ridge	Mahalo	152	262	180	2025	2027	10	C,P,R
Comet Ridge	Mahalo North	43	149	-	2025	2026	3	C,P,R
Comet Ridge	Mahalo East	-	-	31	Unknown	Unknown	Unknown	C,P,R
Denison Gas	Rolleston	-	-	97	2026	2027	5	C,R,L
Santos	Mahalo	90	103	75	2026	2028	7	C,R
Santos	Ramyard	48	64	26	2027	2028	3	C,R
Santos	Arcadia West	20	35	67	2026	2027	5	C,R
Santos	Kia Ora	-	-	33	2026	2029	2	C,R
Senex Energy	Rockybar	-	-	-	2028	2030	Unknown	G,R
State Gas	Rolleston West	-	-	279	2027	2029	0.3	E&A,G,I,C
Surat Basin								
APLNG	Ironbark	230	349	700	2025	2027	20	M,I, R,P,L, E&A
APLNG	Ramyard	620	966	253	2024	2026	36	M,I, R,P,L, E&A

Supplier	Project or field	Reserves (PJ) 2P	3P	Resources (PJ) 2C	FID date	Supply year	PJ p.a	Key risks
APLNG	Dalwogan	98	168	150	2027	2029	10	M,I, R,P,L, E&A
APLNG	Kainama	239	259	65	2029	2031	17	M,I, R,P,L, E&A
Arrow Energy	PL304 – Kedron	122	199	-	2030	2032	1	C,R,L
Arrow Energy	PL494 – Guluguba	27	261	2	2031	2033	0.2	C,R,L
Arrow Energy	PL1039 – Carn Brea	688	688	1	2026	2028	15	C,R,L
Arrow Energy	PL1040 – Halliford	363	514	73	2025	2027	19	C,R,L
Arrow Energy	PL1044 – Punch Bowl	36	38	3	2033	2035	6	C,R,L
Lakes Blue Energy	Wellesley	-	-	-	2027	2028	3	F
Senex Energy	Range	-	-	81	2027	2029	2	G,R
North Bowen basin								
Blue Energy	Sapphire	91	287	252	Unknown	Unknown	7	L
Galilee Basin								
Comet Ridge	Albany	-	-	107	-	Unknown	Unknown	C,P,R
Comet Ridge	Gunn	-	-	67	-	Unknown	Unknown	C,P,R
Vintage Energy	Albany	-	-	46	Unknown	Unknown	-	F,P,R,I
Galilee Energy	Glenaras Gas Project	-	-	2,507	-	2026	73	C,I,F
	Total	**2,865**	**4,341**	**5,099**			**248**	

Source: ACCC analysis of data obtained from developers as at July 2024 and August 2023 (Galilee Energy only). All volumes and dates reflect **estimates only** and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, ie securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **G** = Geologic.

Totals may not add up due to rounding.

Pipeline and storage infrastructure

Table G.4 provides a listing of the potential new pipelines connecting the east coast gas markets.

Table G.4: New pipelines with potential for commissioning by 2028

Developer	Name	Description	Nameplate capacity or size (Estimate)	FID date	Commission date	Key risks
APA	Kurri Kurri lateral pipeline	This buried gas transmission pipeline and storage pipeline will connect the proposed Hunter Power Project at Kurri Kurri, in New South Wales, to the existing Sydney to Newcastle pipeline, near Newcastle.	70 TJ	FID Achieved	2025	W
APA	NT – Beetaloo East Coast Pipeline	A new pipeline facility connecting the Beetaloo Basin in NT to Mt Isa, Tamboran Resources proposed NT gas development, and expansion of the Carpentaria Gas Pipeline (CGP) to provide for additional gas supply onto the SWQP.	Stage 1 – 150–200 TJ/d (New pipeline to Mt Isa ~800km) Stage 2 – 400–700 TJ/d (Looping of the CGP + compression) Stage 3 – 1000 TJ/d+ (Looping and compression)	Timing of FID is unknown as it is dependent on customer demand, subsurface results and upstream capital, which carries significant uncertainty.	2028	C,G,M,F
APA	Sturt Plateau Pipeline (SPP)	Beetaloo (Shenendoah) connecting to Amadeus Gas Pipeline (AGP) in NT	40 TJ/d (expandable up to 100 TJ/d subject to engineering and physical	2024	2026	C

Developer	Name	Description	Nameplate capacity or size (Estimate)	FID date	Commission date	Key risks
			infrastructure upgrades)			
Jemena Eastern Gas Pipeline	EGP/PKET Lateral Connection	Port Kembla	522 TJ/d (lateral capacity)	FID Taken	2025	C
Santos	Narrabri Lateral Pipeline (NLP)	Narrabri LGA Connect Narrabri Gas Project (NGP) to Hunter Gas Pipeline (HGP)	Nominal 250TJ/d (20inch sizing)	2026	2028	C,L,R
Santos	Hunter Gas Pipeline (HGP)	Narrabri to Newcastle (JGN)	Nominal 250TJ/d (20inch sizing)	2026	2028	C,L,R

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates reflect **estimates only** and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, i.e. securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **F** = Finance. **G** = Geologic.

Table G.5 provides a listing of the potential pipeline expansions connecting the coast gas markets.

Table G.5: Pipeline expansions with potential for commissioning by 2029

Developer	Name	Description	Nameplate capacity	FID date	Commission date	Key risks
APA	East Coast Gas Grid Expansion	Additional compression and associated works on the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP)	Stage 1 and 2 expansions collectively increased westernhaul capacity of the SWQP by approximately 101 TJ/d (from a base of 404 TJ/d to a capacity of 512 TJ/d) and the southernhaul capacity of the MSP by approximately 119 TJ/d (from a base of 446 TJ/d to a capacity of 565 TJ/d). APA is currently exploring an alternative configuration for the Stage 3 expansion of the SWQP and MSP which may include a new interconnect between the SWQP and MSP plus additional MSP compression, with the view to expanding SWQP westernhaul up to a nominal 600 TJ/d, MSP southernhaul capacity up to a nominal 700 TJ/d (supplied from both SWQP and Moomba Gas Plant) and capacity to Culcairn up to a nominal 260 TJ/d by 2028. Actual nameplate capacities of each leg to be confirmed during Front End Engineering and Design.	Stage 1 and 2 FID has occurred. Timing of MSP Stage 3a and 3b and SWQP Stage 3 is unknown at this time and is on hold pending further clarity on the outcomes of the AER SWQP regulatory review.	Stage 1 – May 2023 Stage 2 – May 2024 Stage 3a – 2026 (FID dependent) MSP Stage 3b – Unknown (FID dependent) SWQP Stage 3 – Unknown (FID dependent)	M,W,C,F,R
APA	Surat Hub	Expansion of the Berwyndale to Wallumbilla pipeline (BWP)	Increase to BWP nameplate of 100TJ/d to a total of ~264 TJ/d	Unknown – dependent on customer demand	2026	C,M,F
Jemena EGP	Eastern Gas Pipeline (EGP) Reversal	Allow the EGP to deliver gas southward as well as north	200 TJ/d (southern-haul capacity)	2024	2026	C,P,R
Jemena EGP	New Compressor at/near Kembla Grange	Additional southernhaul capacity on the EGP	300 TJ/d (southern-haul capacity)	2025	2028	C,P,R

Developer	Name	Description	Nameplate capacity	FID date	Commission date	Key risks
Jemena EGP	Wilton Delivery Station Modifications	Additional delivery capacity at Wilton	Increase of up to 200 TJ/d, resulting in a total of ~ 320 TJ/d nameplate capacity for the pipeline	2027	2029	C,P, R
Jemena EGP	New Compressor for MSP to EGP	Increase EGP Wilton receipt and delivery capacity	100 TJ/d – EGP Wilton receipt capacity 320 TJ/d – EGP Wilton delivery capacity	2026	2029	C,P, R
Jemena NGP	Northern Gas Pipeline (NGP) reverse capability	Allow the NGP to have a reverse flow capability of up to 60 TJ a day under reverse flow mode	60 TJ/d (Reverse/Western haul)	FID taken	2024	N/A – in progress
SEA Gas	Port Campbell to Adelaide (PCA) East	Reconfiguration of the PCA to receive gas from a proposed LNG import terminal at Outer HarborSA, or from the MAPS for west – east transportation to Iona / South West	Up to ~ 250TJ/d (nominal) full-haul capacity in a west – east direction.	Unknown – subject to agreeing commercial terms	2026	C,R,M, L
Tasmanian Gas Pipeline (TGP)	Expansion of VicHub	Additional capacity for VicHub, which links the EGP and Victorian Transmission System.	Increase from 150 TJ to 350 TJ/d	2025	2025	C

Source: ACCC analysis of data obtained from developers as at July 2024. All volumes and dates reflect **estimates only** and can be impacted by a range of factors including key risks.

Note: Key risks: **C** = Commercial factors. **R** = Regulatory risk, including state and federal regulatory approvals and other regulatory risks. **F** = Finance, i.e. securing capital and costs. **MU** = Market uncertainty. **I** = Infrastructure. **L** = Land access. **T&D** = Timing and delays. **W** =Weather. **P =** Policy uncertainty, including federal and state government policy changes. **E&A** = Exploration and appraisal. **M** = Macroeconomic. **T** = Technical. **F** = Finance. **G** = Geologic.

Appendix H: Reserves and resources

H.1 Reporting framework and data sources

The reserves and resources reporting in this Appendix use the resource classification framework and related definitions contained in the Petroleum Resources Management System (PRMS).[266]

The PRMS classifies all petroleum resources (which includes gas) naturally occurring within the Earth's crust as discovered or undiscovered.[267] Depending on the commerciality of the recovery, the discovered resources are classified as:

- Reserves – Quantities of gas anticipated to be commercially recoverable
- Contingent resources – Quantities of gas estimated to be potentially recoverable but which are not currently considered to be commercial due to one or more contingencies.[268]

There is uncertainty associated with the estimated quantities of recoverable reserves and contingent resources due to:

- uncertainty in the total amount of gas remaining
- technical uncertainty in the total gas volumes that can be recovered by the technology applied
- known variations in the commercial terms that may impact the quantity of gas recovered and sold.[269]

These uncertainties are captured by different categories of reserves and resources. Table H.1 lists the various reserves and resources classifications used in this report.

Table H.1: Reserves and resources classifications

Term	Definition
Reserves	1P (proved) – Have at least a 90% probability that quantities recovered will equal or exceed the estimate. 2P (proved + probable) – Have at least 50% probability that quantities recovered will equal or exceed the estimate. This is the best estimate of reserves. 3P (2P + possible) – Have at least 10% probability that quantities recovered will equal or exceed the estimate
Resources	2C – Best estimate of contingent resources

266 Society of Petroleum Engineers, *Petroleum Resources Management System (PRMS)*, SPE Website. revised June 2018.
267 Society of Petroleum Engineers, *Petroleum Resources Management System (PRMS)*, SPE Website. revised June 2018, p 1.
268 Society of Petroleum Engineers, *Petroleum Resources Management System (PRMS)*, SPE Website, revised June 2018, p 3.
269 Society of Petroleum Engineers, *Petroleum Resources Management System (PRMS)*, SPE Website, revised June 2018, p 11.

Developed Reserves	Quantities expected to be recovered from existing wells and facilities.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.

This Appendix contains:

- Gas field interest and reserves and resources information collected by the Australian Energy Market Operator.[270]
- Supply outlook information provided to the ACCC.

H.2 Current level of reserves and resources

Table H.2 shows the producer estimates of reserves and resources by basin and by resource classification.

[270] AEMO, *Reserves Resources Reporting and Facility Developments*, AEMO, accessed 7 October 2024.

Table H.2: Reserves and resources by basin[271]

	Reserves						Resources	Total inventory[272]
	1P Developed	1P Undeveloped	2P Developed	2P Undeveloped	3P Developed	3P Undeveloped	2C	
Queensland	11,086	2,417	13,078	12,995	15,067	16,420	20,056	51,543
Bowen and Surat	11,040	2,364	12,978	12,785	14,892	15,805	15,944	46,640
Galilee	0	0	0	0	0	0	2,789	2,789
North Bowen	0	0	0	79	0	336	1,164	1,500
Cooper Eromanga	46	54	100	132	175	279	160	614
Southern states	1,139	273	2,000	440	2,764	919	6,390	10,073
Gippsland	688	157	1,196	158	1,496	429	2,446	4,370
Gunnedah	7	0	7	0	7	0	2,158	2,165
Cooper Eromanga	197	116	408	283	677	489	1,384	2,551
Bass Otway	247	0	390	0	585	0	402	987
Onshore Northern Territory	146	30	180	41	213	42	8,320	8,575
Beetaloo	0	0	0	0	0	0	5,276	5,276
McArthur (excluding Beetaloo)	0	0	0	0	0	0	2,836	2,836
Amadeus	146	30	180	41	213	42	208	463
Total	**12,371**	**2,721**	**15,258**	**13,477**	**18,044**	**17,380**	**34,767**	**70,191**
Resource Classification								

[271] AEMO, *Reserves Resources Reporting and Facility Developments*, AEMO, accessed 7 October 2024.

[272] Total inventory is the sum of 3P Developed and Undeveloped Reserves and 2C Resources.

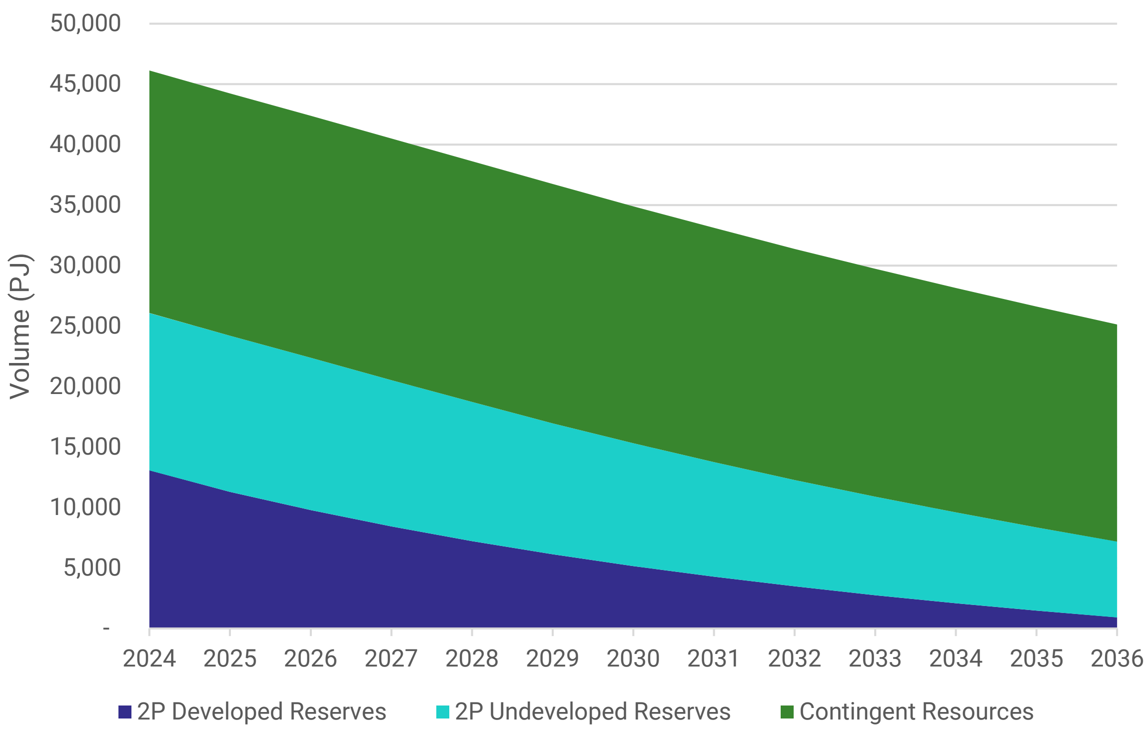
Conventional	1,401	363	2,443	666	3,510	1,312	4,110	8,931
Unconventional – Coal Seam Gas	10,968	2,357	12,812	12,811	14,531	16,068	21,236	51,835
Unconventional – Other	2	-	3	-	4	-	9,421	9,424

H.3 Queensland – Forecast reserves and resources

Chart H.1 shows the forecast reserves and resources in Queensland by reserve and resource type. The forecast of reserves and resources is obtained by subtracting forecast production from current reserves and resources. The change in reserves and resources to 2036 is expected to be:

- a 93% decrease in current 2P developed reserves from 13,078 to 910 PJ
- a 52% decrease in current 2P undeveloped reserves from 12,995 to 6,271 PJ
- an 11% decrease in current 2C contingent resources from 20,056 to 17,938 PJ.

Chart H.1:Queensland forecast reserves and resources



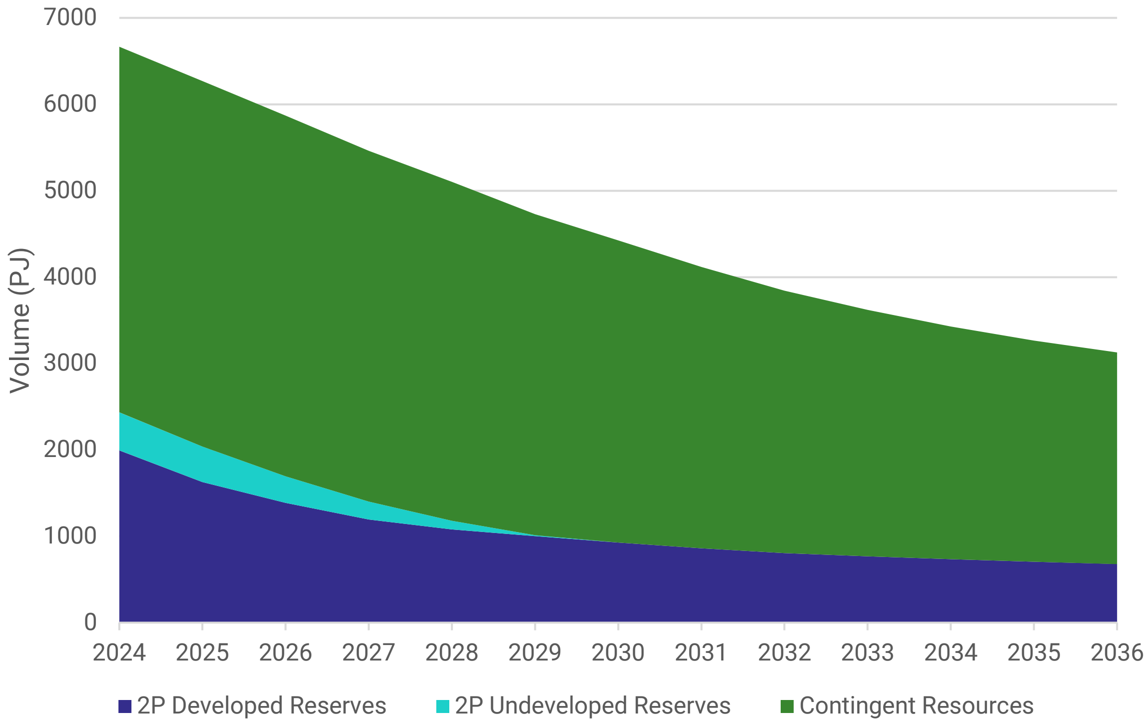
Source: ACCC analysis of AEMO Gas Bulletin Board data.

H.4 Southern states – Forecast reserves and resources

Chart H.2 shows the forecast reserves and resources in the southern states by reserve and resource type. The change in reserves and resources to 2036 is expected to be:

- a 66% decrease in current 2P developed reserves from 2,000 to 684 PJ
- a 100% decrease in current 2P undeveloped reserves from 440 to 0 PJ
- a 26% decrease in current 2C contingent resources from 6,390 to 4,610 PJ.

Chart H.2: Southern states forecast reserves and resources



Source: ACCC analysis of AEMO Gas Bulletin Board data.

Note: This does not include the Gunnedah basin reserves which yet to connected to the market. This basin consists of 7 PJ of 2P Developed reserves and 2 158 PJ of 2C resources.

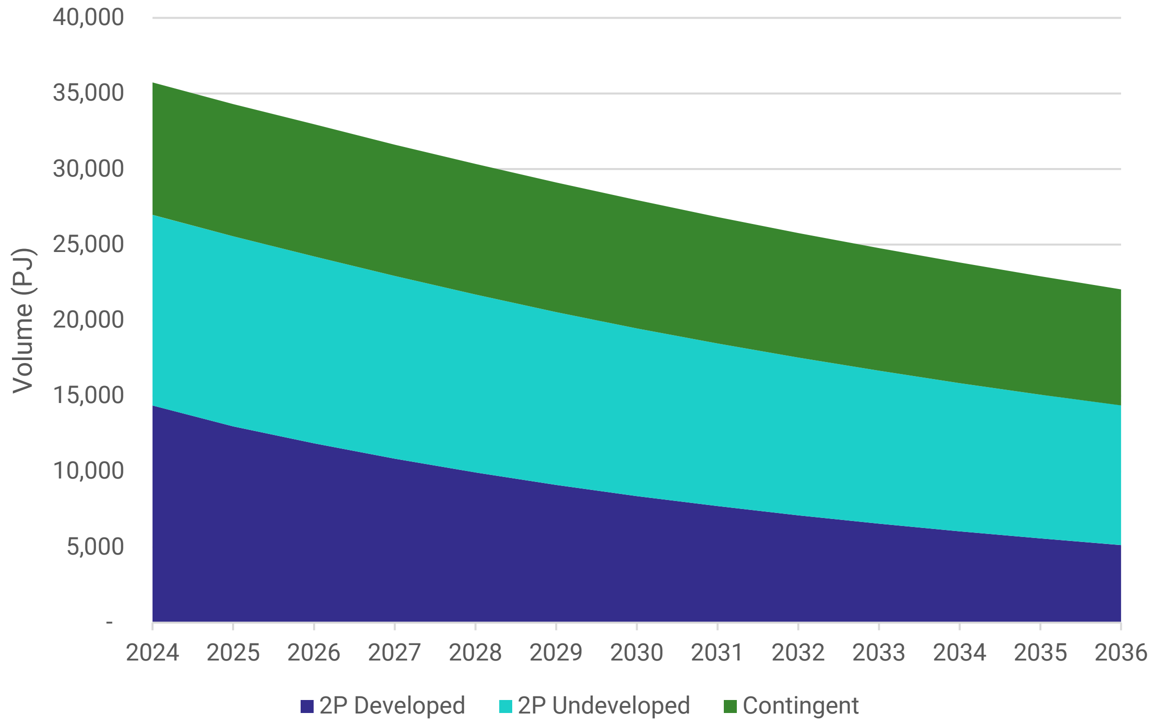
The southern states' 2P undeveloped reserves are forecast to run out in 2030, after which additional gas will need to be drawn from 2P developed reserves or additional investment into 2C resources.

H.5 LNG producers – Forecast reserves and resources

Chart H.4 shows the forecast decline of reserves and resources that the major exporters, APLNG, GLNG and QGC, expect to extract from the fields that they operate or have equity in. The change in reserves and resources to 2036 is expected to be:

- a 98% decrease in current 2P developed reserves from 9,381 to 151 PJ
- a 36% decrease in current 2P undeveloped reserves from 9,493 to 6,123 PJ
- a 10% decrease in current 2C contingent resources from 10,396 to 9,314 PJ.

Chart H.4: LNG producers' forecast reserves and resources



Source: ACCC analysis of AEMO Gas Bulletin Board data.

Glossary

ACCC's 2015 inquiry: The ACCC's inquiry into the east coast Gas Market in 2015, as reported in April 2016.

Annual contract quantity: The quantity of gas specified in the transportation contract between the buyer and the seller, based on the buyer's maximum historical 12-month usage.

Buyer alternative: the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location. It represents a price ceiling in negotiations.

Capacity trading platform: An online platform that shippers can use to trade secondary capacity ahead of the nomination cut-off time. It provides for exchange-based trading of commonly traded products and a listing service for more bespoke products. The capacity trading platform forms part of the Gas Supply Hub exchange.

Congestion: A pipeline is congested when there is insufficient spare capacity to transport the volume of gas to fulfil demand. Physical congestion refers to where demand for actual deliveries exceeds the technical capacity of the pipeline at some point in time, whereas a pipeline is contractually congested when the demand for firm capacity exceeds the technical capacity of the pipeline.

Contracted but un-nominated capacity: A quantity of contracted pipeline capacity that is not nominated to be used by a shipper on a gas day.

Conventional/unconventional gas: Conventional gas is contained in sedimentary rocks such as sandstone and limestone (referred to as reservoir rock). The gas is trapped by an impermeable cap rock and may be associated with liquid hydrocarbons. The reservoir rock has a relatively high porosity (percentage of space between rock grains) and permeability (the rock's pores are well connected and the gas may be able to flow to the gas well without additional interventions). Gas is extracted by drilling a well through the cap rock allowing gas to flow to the surface. Depending on the structure of the rock containing the gas (amount of faulting or compartmentalisation), only a few wells may be required to produce gas over the life of the gas field.

Unconventional gas is a broad term that covers gas found in a range of sedimentary rocks which typically have low permeability and porosity. The International Energy Agency categorises the 3 major types of unconventional gas as:

- shale gas: natural gas contained within shale rock
- coal seam gas (CSG): natural gas contained in coalbeds
- tight gas: natural gas found in low permeability rock formations.

A range of techniques may be required to promote gas flow including pumping water from the rock to reduce pressure holding the gas in place (in the case of CSG) or hydraulic fracture stimulation (fracking) to open pathways for the gas to enter the well (in the case of shale gas, tight gas and some CSG). An unconventional gas field may require many wells to be drilled (in the thousands for the large CSG Liquefied Natural Gas (LNG) projects in Queensland) over its life to ensure consistent production.

Day-ahead auction: An auction of contracted but un-nominated capacity. It is conducted after nomination cut-off and is subject to a reserve price of zero. Compressor fuel is provided in-kind by shippers.

Demand: The quantity of gas demanded by users located in Australia.

Downward quantity tolerance: The amount a buyer may fall short of their full Annual Contract Quantity in a Take or Pay gas sales contract without incurring penalties.

East coast gas market: The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Export demand: The quantity of Australian gas demanded by overseas buyers.

Gas storage service: A service that allows users to store gas in a facility (either underground depleted gas fields or domestic LNG storage).

Gas supply agreement: A contract between the buyer and seller for the supply of gas.

Gas transportation agreement: A contract between the shipper and the pipeline operator for the transport of gas on that pipeline.

Heads of Agreement: In the context of this report, this refers to an agreement between LNG producers and the Australian Government to offer uncontracted gas first to the domestic market on 'competitive market terms' before it is offered to the international market.

Henry Hub: The major gas hub for spot and futures trading in the United States. This hub acts as the notional point of delivery for gas futures contracts. Henry Hub is based on the physical interconnection of 9 interstate and 4 intrastate pipelines in Louisiana.

Japan Korea Marker: An international benchmark price for LNG spot cargos. It reflects the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan.

Japan Customs Cleared: Represents the average price of crude oil imported to Japan and reported by the Japanese Custom. It is commonly used as an index by LNG traders.

Liquefaction: The process of liquefying natural gas.

Liquefied Natural Gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG producer: LNG producers process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets. In this report, the term is usually used in reference to one or more of the 3 LNG producers in Queensland, being Australia Pacific LNG (APLNG), QGC, and Gladstone LNG (GLNG). There are also LNG producers in the Northern Territory and in Western Australia.

LNG netback price: A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.

LNG train: A Liquefied Natural Gas plant's liquefaction and purification facility.

Load factor: measures the extent to which a buyer can take more than the average daily contract quantity throughout the year, subject to the cap imposed by the annual contract quantity.

Looping: Increasing the capacity of a pipeline system, by adding parallel piping along parts or the whole of the route. This does not include adding compression facilities.

Pipeline transportation services

As available transportation service: A service that allows the transportation of gas on an 'as available' basis, subject to the availability of capacity. This service has a lower priority than a firm transportation service.

Compression service: A service that increases the pressure of gas to improve the efficiency of transportation. Compression services are provided by compression service facilities.

Firm transportation service: A service that allows the transportation of gas on a 'firm' basis up to a maximum daily quantity and maximum hourly quantity. It has the highest priority of any transportation service.

Interruptible transportation service: A service that allows the transportation of gas on an 'interruptible' basis. The pipeline operator does not have an obligation to guarantee capacity and has the right to curtail the service if the pipeline becomes capacity constrained or higher priority services are required. This service has a lower priority than firm and as available transportation services.

Loan service: A service that allows users to "borrow" gas from a pipeline, which in practice involves withdrawing more gas from a pipeline than what is injected on a particular day.

Park service: A service that allows users to store gas in a pipeline, which in practice involves injecting more gas into a pipeline than what is taken out on a particular day.

Producer: Gas producers extract gas and process it for transmission and sale.

Reserves and resources

Reserves: Quantities of gas expected to be commercially recoverable from a given date under defined conditions.

Developed reserves: Gas expected to be recovered from existing wells and facilities.

Undeveloped reserves: Gas that requires further investments to bring online.

1P (proved) reserves: Commercially recoverable reserves with at least a 90% probability that the quantities recovered will equal or exceed the estimated quantity.

2P (proved and probable) reserves: Commercially recoverable reserves with at least a 50% probability that the quantities recovered will equal or exceed the estimated quantity.

3P (proved and probable and possible) reserves: Commercially recoverable reserves with at least a 10% probability that the quantities recovered will equal or exceed the estimated quantity.

Contingent resources: quantities of gas estimated to be potentially recoverable from known accumulations but are not yet considered able to be developed commercially due to one or more contingencies. Contingent resources may include gas accumulations for which there are currently no viable markets, where commercial recovery is dependent on technology under development or where the evaluation of the accumulation is insufficient to assess if it can be produced commercially. 2C resources are classified as a best estimate of the resource (1C is the low estimate and 3C is the high estimate).

Prospective resources: Estimated quantities associated with undiscovered gas. These represent quantities of gas which are estimated, as of a given date, to be potentially recoverable from gas deposits identified based on indirect evidence but which have not yet been drilled. Prospective resources represent a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the gas accumulation must be further evaluated, and an estimate made of quantities that would be recoverable under appropriate development projects.

Retailer: For this report, this term captures both entities that purchase natural gas in wholesale markets to sell to retail customers and entities that purchase natural gas in wholesale markets to resell to other buyers in those markets. This includes AGL, Alinta Energy, EnergyAustralia, Macquarie Bank, Power and Water Corporation, Origin Energy, PetroChina and Shell Energy Australia.

Sale and purchase agreement: An agreement between the buyer and seller of LNG.

Secondary capacity: Capacity that is on-sold by primary capacity holders on a pipeline.

Seller alternative: the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla. It represents a price floor in negotiations.

Shipper: A user or prospective user of pipeline services.

Southern states: South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Spot market transaction: The sale or purchase of gas using a spot market. In Australia's facilitated markets, these are typically for delivery on a single gas day shortly after the transaction has been finalised. Australia's Gas Supply Hub allows for the trade of gas over longer time frames (i.e. more than one day). Spot market transactions are distinct from transactions under gas supply contracts.

Standing prices: prices or reference tariffs that pipelines subject to Part 10 of the National Gas Rules, light regulation or full regulation are required to publish.

Swap arrangement: An arrangement between 2 or more gas market participants to swap rights or obligations. For example, 2 gas producers in different locations may swap gas delivery obligations to minimise transportation.

Take or pay: A contract term specifying the minimum proportion of ACQ the buyer must pay for in each year. Take-or-pay multipliers are expressed as a percentage in GSAs and provide users with flexibility in how they manage their gas usage.

Tenement: A claim, lease or licence for the purpose of prospecting or mining gas.

Units of Energy

Joule: a unit of energy in the International System of Units

Gigajoule (GJ): a billion joules

Terajoule (TJ): a trillion joules

Petajoule (PJ): a quadrillion joules

Million British Thermal Units (MMBtu): a unit of heat; 1 MMBtu = approximately 1.055 GJ.