AUSTRALIAN COMPETITION & CONSUMER COMMISSION

Gas Inquiry 2017-2030

Interim update on east coast gas market

December 2023

Acknowledgement 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
23 Marcus Clarke Street, Canberra, Australian Capital Territory, 2601

Important notice

The information in this publication is for general guidance only. It does not constitute legal or other professional advice, and should not be relied on as a statement of the law in any jurisdiction. Because it is intended only as a general guide, it may contain generalisations. You should obtain professional advice if you have any specific concern.

The ACCC has made every reasonable effort to provide current and accurate information, but it does not make any guarantees regarding the accuracy, currency or completeness of that information.

Parties who wish to re-publish or otherwise use the information in this publication must check this information for currency and accuracy prior to publication. This should be done prior to each publication edition, as ACCC guidance and relevant transitional legislation frequently change. Any queries parties have should be addressed to the
Director, Content and Digital Services, ACCC, GPO Box 3131, Canberra ACT 2601.

ACCC 12/23
www.accc.gov.au

Contents

Acronyms

Terms	
ACQ	Annual contract quantity
ADQ	Average daily quantity
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
DWGM	Declared Wholesale Gas Market
EOI	Expression of interest
GPG	gas powered generation/generator
GSAs	Gas Supply Agreements
GSOO	Gas Statement of Opportunities
JKM	Japan Korea Marker
LNG	liquefied natural gas
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
RoLR	Retailer of Last Resort
SPAs	Sale and Purchase Agreements
Organisation	
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator

AER	Australian Energy Regulator
AIE	Australian Industrial Energy
ICE	Intercontinental Exchange
RBA	Reserve Bank of Australia
Pipelines	
AGP	Amadeus Gas Pipeline
CGP	Carpentaria Gas Pipeline
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
PCA	Port Campbell to Adelaide Pipeline
QGP	Queensland Gas Pipeline
RBP	Roma to Brisbane Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
VTS	Victorian Transmission System
LNG plant	
GLNG	Gladstone LNG
APLNG	Asia Pacific LNG
QGC	Queensland Curtis LNG
Units	
MMBtu	Million British Thermal Units–see Glossary, Units of Energy
GJ	Gigajoule
PJ	Petajoule
TJ	Terajoule

Interim report findings

Short-term supply outlook

Sufficient gas for 2024

There is expected to be enough gas to meet east coast demand, even if all LNG producer uncontracted gas is exported.

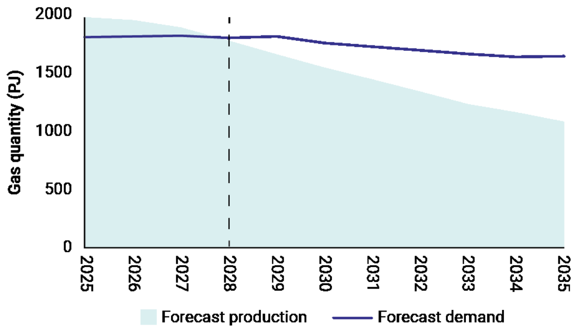
Projected surplus up to
71 PJ in 2024

Lower gas offers for 2024 supply
Gas producer offers are 80% lower than 2023, despite sufficient gas production to meet demand.

Long-term supply outlook

Gas supply sufficient until shortfall in 2028

There is forecast to be enough gas to meet east coast demand until 2028, where a 23.7 PJ shortfall is expected. The shortfall is delayed 1 year from previous forecasts.



Long-term supply outlook dependent on new developments or demand changes
There will be a role for gas as part of the renewable energy transition. New gas may need to be developed to meet demand. If sufficient gas is not developed, gas demand will need to reduce (for example, increased electrification, lower LNG exports or less gas-powered generation).

Domestic price outlook

Gas prices fallen from peak in 2022
For 2024 gas supply, producer offers averaged $14.6/GJ

45%▼
compared to the preceding 6 months

Retailer gas prices lower
Retailer offers for 2024 supply averaged $19.5/GJ

21%▼
compared to the preceding 6 months

Price cap has impacted the domestic market
Producers have sold gas to the domestic market under short-term contracts for 2023 supply, at or below $12/GJ, since the price cap was introduced in December 2022.

Retailer behaviour review

ACCC's 2-stage review into retailer behaviour
Stage 1 focusing on retailer selling practices, is informed by broad stakeholder engagement.

Consensus on recent challenging market conditions
There was a consensus across stakeholders that tight and volatile conditions in 2022 and 2023 posed significant challenges for all market participants.

Stakeholder concerns regarding retailer selling practices
Stakeholders observed a deterioration in selling practices in 2022 and early 2023, primarily around offer validity periods, withdrawals and amendments and the inability to negotiate. Some (but not all) retailers recognised this deterioration and attributed it to the need to manage their exposure to market volatility.

Some improvements in late 2023
Towards the end of our consultation in late 2023, stakeholders reported some improvements in market competition and a return to retailers' standard selling practices.

The ACCC will continue monitoring retailer behaviour in 2024

2024

Stage 2 of the review will focus on retailer pricing practices. We will also continue to monitor retailer selling practices.

Overview

This is the December 2023 interim report of the Australian Competition and Consumer Commission's (ACCC's) inquiry into gas supply in Australia (the Inquiry). It reports on the east coast domestic supply and price outlook and related matters including the experiences of commercial and industrial (C&I) users and stage 1 of our retailer behaviour review.

A period of significant change

This report draws on supply and pricing information from February to August 2023, some additional data in October 2023, and surveys of C&I user experience during this time.

The report covers a period of significant change. During the period the Gas Market Emergency Price Order (the price cap) of $12/GJ was still in place, and the Government consulted on and commenced the Gas Market Code (the Code).[1] At the same time, international markets saw Liquified Natural Gas (LNG) prices decline in the first half of 2023, while the domestic market remained tight.

The report contains a number of interesting findings on the east coast gas market however given the period of change, the timing of the data collection and only early implementation of the Code, it is not possible to draw conclusions about the impact of one factor or another at this time.

Implementation of the gas market code

The latter half of 2023 saw the implementation of the Code. The Code commenced on 11 July 2023 and, following a two-month transition period, came into effect in full on 11 September 2023 (see timeline below for details).

The Code is intended 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. The Code has requirements and a framework for exemptions, which together, are intended to incentivise producers to commit more gas to the east coast domestic market.[2]

The effects of the Code on domestic gas supply are not yet clear because the information for this report was collected only until August 2023, before the Code commenced in September 2023. These effects, as well as the impact of the broader policy environment on the gas market, will become apparent over time and will be closely monitored by the ACCC. A review of the Code, scheduled for 2025, will be an opportunity to systematically examine the Code's impact on the operation of the east coast gas market.

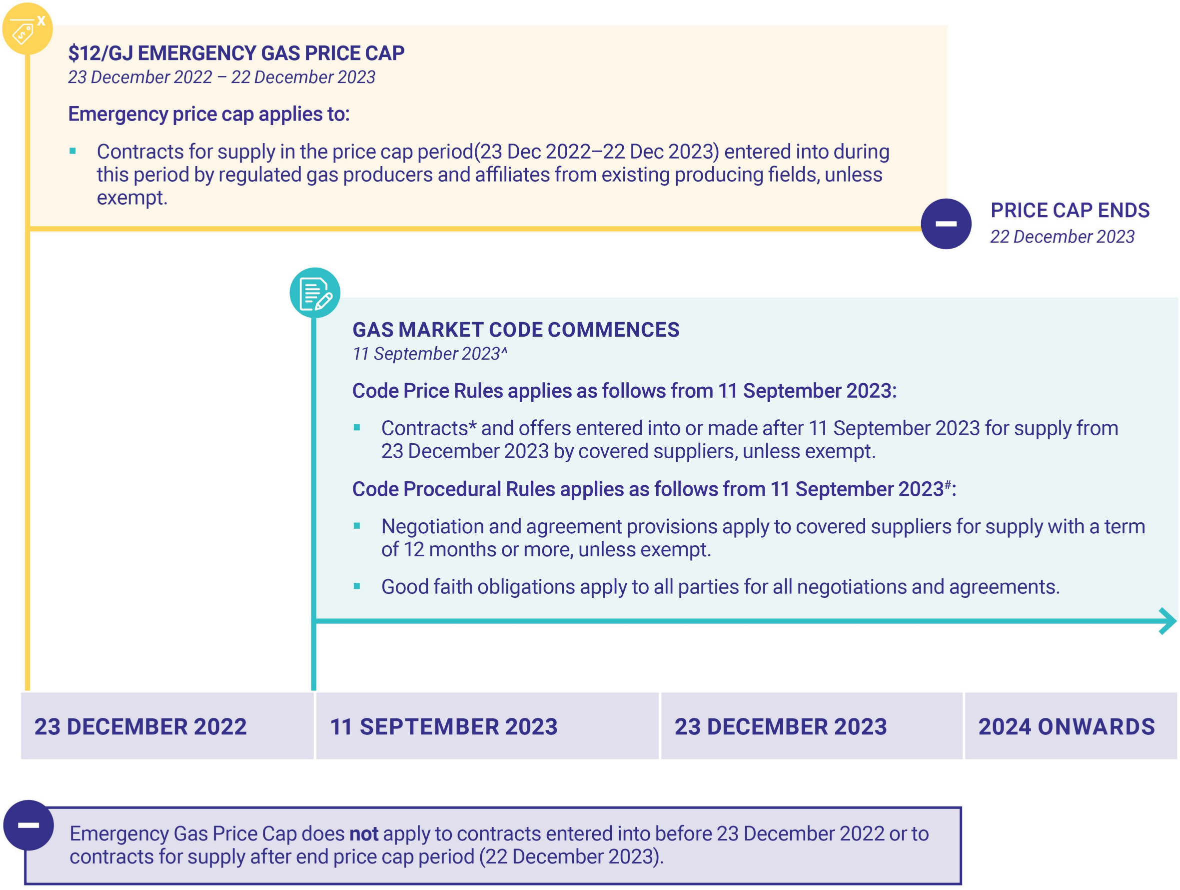
---

1 The Code applies to regulated gas producers and any affiliates that have a current supply agreement with the regulated gas producer, or intend to enter into such agreements. Certain exemptions to the pricing provisions apply in certain circumstances. A deemed exemption from the Code is also available to retailers that meet the criteria set out in section 53 of the Code.

2 More specifically, the Code sets out minimum conduct, process and transparency obligations that, together, are intended to support good faith negotiations. The Code also specifies a $12/GJ price anchor, which together with the exemption framework, is intended to incentivise producers to commit more gas to the east coast domestic market. The exemption framework provides for a range of exemptions which include, amongst others, deemed exemptions for producers that produce less than 100 PJ p.a. and are supplying the domestic market, and conditional Ministerial exemptions which can be granted jointly by the Energy Minister and Resources Minister. The ACCC is responsible for monitoring and enforcing compliance with the Code, including compliance with the conditions specified in a Ministerial exemption.

The illustration below provides a high-level overview of these reforms. It does not capture all the exemptions, transitional and other arrangements provided by the price cap and the code.

Timeline of policy reforms



* Includes agreements entered into before the commencement of the Code but varied after that where the variation determines price.

\# Date of application depends on when negotiations commenced.

^ The 11 September 2023 date reflects a 2-month transitional period to allow suppliers to adapt to their new obligations.

Sufficient gas for 2024 but additional commitments needed for winter

The supply-demand outlook indicates there will likely be sufficient gas to meet demand in 2024, but with a reduced surplus compared to the forecast in our June 2023 interim report. While total domestic production and supply has not changed, the LNG producers have more uncontracted gas that could be exported.

During the colder winter months of 2024, the LNG producers will need to commit small amounts of additional gas to the domestic market to avert a shortfall. However, the use of gas swap arrangements by LNG producers appears to be reducing the size of potential gas supply shortages in winter.

In those winter months, the southern states (New South Wales, Victoria, South Australia and Tasmania) are expected to face larger shortfalls of locally produced gas. This means that gas supplied from Queensland will be needed to avert winter shortages. There is sufficient pipeline capacity to transport the required gas south.

Gas volumes offered and contracted for 2024 are lower, despite recent uptick

The majority of gas produced for the domestic market is sold under contracts with C&I users and retailers.

There has been an increase in the number of contracts executed and volumes of gas contracted for the supply of gas in 2024. However, overall, the volume of gas contracted for supply in 2024 is less than at comparable times in previous years, despite there being sufficient production expected to meet demand.

Producers and retailers have offered lower volumes of gas to the domestic market in 2023 for 2024 supply. The volumes offered by producers between February and August 2023 for 2024 supply was 80% lower compared to the corresponding offers for 2023 supply.

Large volumes of gas remain to be contracted in 2024 and 2025. Gas producers are now required to publish available uncontracted under the rules of the Code. This new information shows a significant proportion will likely be required to fulfil domestic demand.

Sufficient supply forecast until 2028 due to higher production and lower exports

Australia is in a period of energy transition to renewable energy. Gas is expected to have a critical role over the next two decades to maintain power grid security, maintain supply to commercial and industrial customers, and support households as they electrify.

The latest information suggests that the east coast gas market is likely to have sufficient supply to meet energy needs throughout the transition until 2028. The potential for gas shortfalls has been delayed by 1 year due to net increases in forecast gas production in some producing regions and materially lower forecasts of LNG exports.

That said, the southern states will face significant shortages from locally produced gas from 2027. Gas transported from Queensland is expected to continue to play a critical role in covering potential supply gaps.

In the longer-term, current expectations of gas demand through the energy transition will still require additional sources of gas supply. There will be gas shortfalls without the development of new gas fields, pipelines and potentially LNG import terminals or without a significant reduction in demand.

Domestic prices have fallen from the 2022 peak

Prices offered by producers in 2023 for 2024 supply have continued a downward trend since falling from the peak of $49/GJ in August 2022.

Producer prices offered between February and August 2023 for 2024 supply averaged $14.6/GJ, a 45% decrease from the preceding 6 months. Average prices offered by retailers ($19.5/GJ) were 21% lower in the same comparison. We note that producers and retailers have different cost structures with retailer prices often higher as they offer a bundle of services:

- Since the introduction of the price cap, from 23 December 2022 to 8 August 2023, producers have sold gas to the domestic market under short-term contracts at or below $12/GJ for 2023 supply.
- International prices for natural gas and LNG play a role in shaping domestic prices offered and agreed in Gas Supply Agreements (GSAs). International LNG prices trended downward in the first half of 2023. While international prices have fallen from the highs in 2022, they were above long-term historical averages in September 2023.

Stage 1 of the review into retailer behaviour

Gas retailers play a critical role in the east coast gas market, acting as the interface between their customers and gas producers, pipeline owners, storage providers and the AEMO facilitated markets. In this capacity, retailers incur a range of costs and also face a range of risks and challenges in supplying their customers, all of which can affect their pricing and selling practices and their ability to compete to supply C&I users.

In June 2023 we announced our intention to undertake a 2-stage retailer behaviour review:

- Stage 1, described in this report, has focused on retailer selling practices
- Stage 2, which is to be conducted in 2024, will build on Stage 1 with a focus on retailer pricing practices, including the costs, risks and other factors influencing pricing decisions and if retailers are passing through changes to wholesale gas and other costs.

Stage 1 of the review has been informed by significant information and engagement with a wide range of stakeholders. Amongst these stakeholders, there was a general consensus that tight and volatile conditions in the east coast gas market over the last 2 years, posed significant challenges for both retailers and C&I users and contributed to:

- a deterioration in competition among retailers to supply C&I users, with only 2–3 retailers reportedly active in the market in 2022 and the first half of 2023
- a deterioration in some (but not all) retailers' selling practices, with C&I users telling us that some retailers were employing more customer-centric selling practices than others in this period.

Consultation also revealed the position of individual retailers differs, with some better placed to manage the costs, risks and challenges associated with supplying C&I users than others. The position of individual C&I users also differed, with some C&I users better placed to negotiate with retailers than others. C&I users also told us that their experiences differed across retailers, with some retailers employing more customer-centric selling practices than others. Care should therefore be taken when considering the feedback on retailer selling practices not to assume that all retailers are necessarily engaging in the practices.

The stakeholders we spoke to about retailer selling practices, told us that they were primarily concerned with short offer validity periods, offer withdrawals and amendments, the willingness of retailers to negotiate, risk allocation, spot market linked products and the adequacy of information provision by retailers. Particular concerns were raised with the perceived 'take it or leave it' approach employed by some retailers in 2022 and early 2023.

In response to these concerns, most retailers told us their selling practices had not changed over 2022–23. However, some did acknowledge there was a deterioration over this period, which they attributed to the need to manage their risks including their exposure to market volatility and the increased costs, risks, and complexities of retailing during the period.

Towards the end of our consultation, stakeholders informed us that in the latter half of 2023 there had been some improvements in competition and a resumption to retailers' standard selling practices. While encouraging, some retailers' standard selling practices do fall short of what we would expect in a workably competitive market.

As the interface between the wholesale market and retail customers, it is possible that some of the poorer selling practices may reflect what retailers have faced when procuring gas from producers. It is possible therefore that the recently implemented Code, together with increased competition to supply C&I users, could lead to further improvements in retailer selling practices over the next year.

We intend therefore to continue to monitor retailer selling practices in 2024 to assess how the implementation of the Code flows through to retailer practices and if selling practices have improved in the areas identified in Chapter 5. If we do identify systemic issues with retailer behaviour, we may make recommendations to the Australian Government to address the identified issues. We would therefore encourage retailers to take the opportunity to consider the concerns raised by C&I users and take steps to improve their practices.

Future work of the Inquiry

We expect to publish the next update to the supply-demand outlook in March 2024 and our next full interim report in June 2024.

We will also continue to publish the LNG netback price series and make information available and policy recommendations as appropriate and necessary — including in relation to Stage 2 of the retailer behaviour review.

As noted above, the ACCC has new functions under the Code. We intend to report on our work in this area and continue to assist the Minister for Resources with monitoring and reporting on LNG producer's compliance with the updated Heads of Agreement (HoA).

1. Short-term supply outlook

Key points

- The east coast gas market is likely to have sufficient supply to meet forecast demand in 2024, with information indicating that supply may be up to 71 PJ higher than demand projections:
  - The outlook will be tight, as supply is expected to equal demand, if the LNG producers export all of their currently uncontracted gas
  - Gas supply is expected to be 71 PJ higher than demand if the LNG producers export only their anticipated spot and additional LNG sales.
- In quarter 2 of 2024 LNG producers will need to commit at least 3 PJ of their uncontracted gas to the domestic market to prevent a shortfall. If they export only their anticipated spot and additional LNG sales, there will be a surplus of 21 PJ.
- While the east coast gas market is forecast to have excess supply in 2024, we expect that there will be less available to the domestic market than previously reported. This is because LNG producers are expecting to produce and acquire more gas from other producers in 2024 than previously estimated. If this additional supply is exported as LNG, there will be less available to the domestic market.
- Seasonal variability in gas demand may contribute to winter shortfalls in the southern states. While there is likely to be sufficient supply across the east coast, colder winters and higher heating demands in the southern states mean that local production is expected to be insufficient to meet demand. This will need to be made up with gas in storage or transported from Queensland. Additional gas placed into storage may need to be transported from Queensland in the summer periods to avoid congesting pipelines in winter.
- The LNG producers are forecast to have 154 PJ of uncontracted gas available to them in 2024, which is 43 PJ more than previously reported. This increase in uncontracted gas is due to an increase in forecast 2P production, net storage withdrawals, a decrease in forecast long-term LNG exports, and additional supply from gas swap arrangements.

1.1. Introduction

This chapter outlines the 2024 supply and demand outlook for both the east coast gas market as a whole and the southern states. It also provides an update of the ACCC's quarterly supply-demand outlooks first published in March 2023, and subsequently updated in June and September 2023.

In evaluating whether there is likely to be sufficient gas to meet forecast demand in the east coast market in 2024 we consider:

- **total forecast supply of gas on the east coast**, including net withdrawals from storage and expected gas flows from the Northern Territory into Queensland
- **total forecast demand**, including domestic demand and the quantities of gas required by the LNG producers to meet their long-term LNG Sale and Purchase Agreement (SPA) commitments and spot and additional LNG sales.

Continuing from the June 2023 and September 2023 interim reports, this chapter provides information on pipeline and storage capacity in the east coast gas market, as well as known market events that may have an impact on our current and previous forecasts.

A comparison of quarter 2 2023 forecasts, published in our March 2023 interim report, with actuals from the Australian Energy Market Operator's (AEMO) Gas Bulletin Board (GBB)[3] is also included in this chapter.

1.1.1. The role of LNG producers on the east coast market

The east coast LNG producers (APLNG, GLNG and QGC)[4] sell their gas to international LNG buyers but are also a major source of supply in the east coast market. We report the difference between their incomings (their gas production and contracted purchases from other domestic producers) and outgoings (their contracted sales to the domestic market and to international LNG buyers) as their uncontracted gas. These uncontracted quantities of gas could be:

- sold to the domestic market, including through flexibility arrangements within existing contracts with domestic customers
- sold as spot or additional LNG cargoes on the international market
- sold as additional volumes to long-term LNG SPA customers, including through customers' ability to call on additional volumes above minimum take-or-pay volumes
- placed or sold into gas storage facilities
- sold to other producers, including as part of swap arrangements.[5]

We also refer in this chapter to net uncontracted gas. This is the uncontracted gas left over after anticipated spot or additional LNG cargoes.

---

3 AEMO, *Gas flows and capacity outlooks* [website], n.d., accessed 1 August 2023.

4 Throughout this report, any reference to the LNG producers refers only to these three LNG producers in Queensland.

5 In this report, when we refer to uncontracted gas, we refer to an aggregated quantity calculated using the sum of inputs and outputs for each of the LNG producers. This may differ to the amount of uncontracted gas individual producers may consider themselves to have and may vary from our calculations for them individually. Variations may be due to, for example, customer flexibility or buffers to account for contingencies.

The volumes of gas potentially sold as spot or additional LNG cargoes are subject to Heads of Agreement (HoA)[6] requirements. These require that uncontracted gas is first offered with reasonable notice on competitive market terms to the Australian domestic market before being offered to the international market as LNG spot or additional cargoes.

Box 1.1: Sources of supply and demand data

Our supply and demand forecast is based on data obtained from east coast gas producers and AEMO.

Supply data reflects east coast gas producers' forecasts of production from 2P (probable) developed and undeveloped reserves, net withdrawals from storage, and flows from the Northern Territory. This is based on information obtained directly from producers in response to compulsory information gathering notices issued in October 2023.

Demand data is based on:

- LNG producers' forecasts of gas that will be exported under long-term LNG SPAs with international buyers. We include volumes of LNG SPA demand based on 'expected commitments' under take-or-pay requirements in long-term LNG supply contracts, which typically reflect minimum annual contracted quantities required under these long-term contracts.
- LNG producers' uncontracted gas, calculated using the sum of inputs and outputs for each of the LNG producers.
- LNG producers' forecasts of gas that will be exported as spot or additional LNG cargoes from their uncontracted gas. These are anticipated, not committed figures.
- Forecasts of domestic gas demand obtained from AEMO, included in its March 2023 Gas Statement of Opportunities (GSOO) report.

AEMO annually produces 20-year forecasts for domestic gas demand for their GSOO. Forecasts are broken down by the source of demand, including residential and commercial demand, industrial demand, and gas power generation (GPG) demand. In this report, we have used AEMO's forecast of domestic gas under the 'Orchestrated Step Change' scenario from the 2023 GSOO. AEMO's 2023 GSOO states that "this scenario reflects observed trends impacting residential, commercial and industrial consumption and the likely near-term continuation of these trends". For further discussion on our choice of demand scenario from AEMO's 2023 GSOO, please see the ACCC's March 2023 Gas Inquiry interim report.

Demand forecasts that are more focused on a short-term outlook may become available (including by AEMO) and we will continue to consider what source of demand forecast information we will use in the future. These information sources reflect a forecast of supply and demand at a point in time. There is an element of forecasting risk and actual supply or demand may differ. However, these reflect the best available estimates of the outlook for the east coast market in 2024.

[6] For more information on the Heads of Agreement between the Australian Government and East Coast LNG Exporters, please see Department of Industry, Science and Resources, *Heads of Agreement. The Australian East Coast Domestic Gas Supply Commitment*, [website], 2022, accessed 1 November 2023.

1.2. East coast outlook in 2024

This section examines the supply-demand outlook in the east coast gas market for 2024, using the latest available information collected from gas producers.

Our analysis shows that the east coast is expected to have sufficient gas to meet demand in 2024, even if LNG producers export all the uncontracted gas that is available to them. However, if LNG producers export only what they currently anticipate, there will be a surplus of 71 PJ.

This section covers:

- The annual outlook for supply and demand in 2024 and the reasons for any key changes in the latest information from producers
- The seasonal outlook for supply and demand through the four quarters of 2024, with a particular focus on the potential for supply shortages in the winter months
- The regional outlook in the southern states where more material supply shortages are expected and an examination of how shortages can be averted.

This section particularly highlights the supply and demand outlook in quarter 2 of 2024. The market outlook in this quarter will be considered by the Government in December 2023 under the Australian Domestic Gas Security Mechanism (ADGSM).

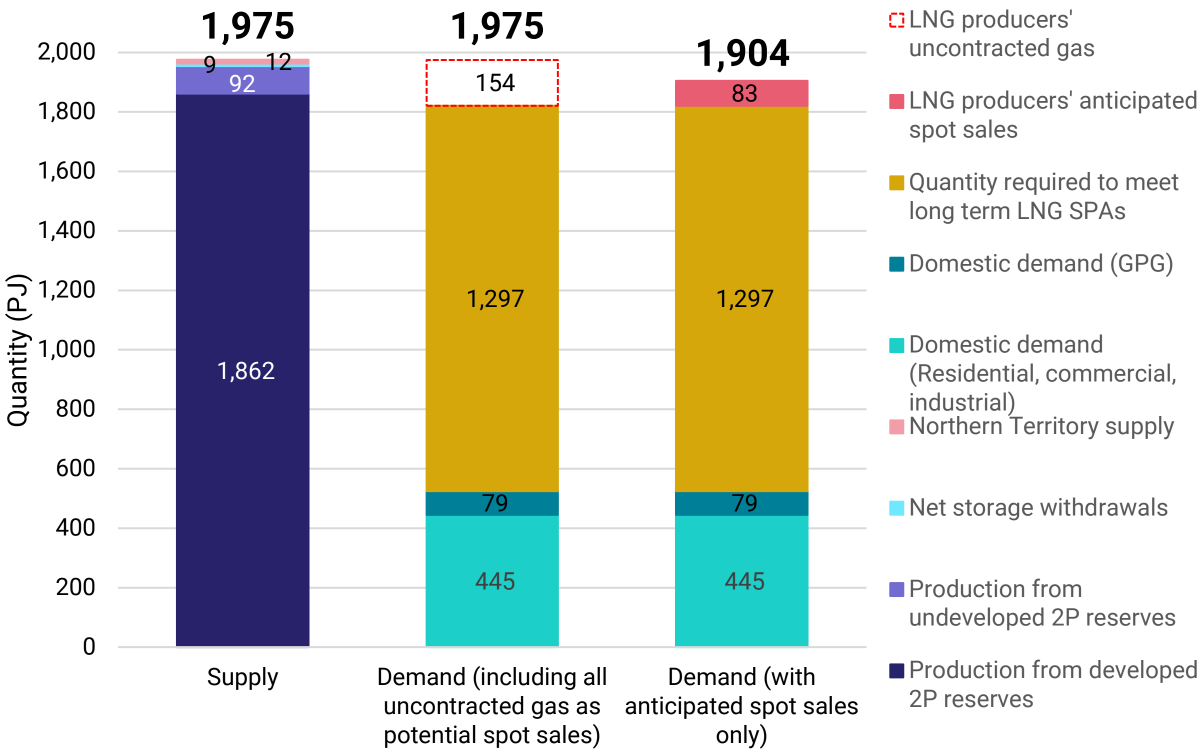
1.2.1. A reduced surplus is expected on the east coast in 2024

Chart 1.1 sets out the forecast supply-demand outlook in the east coast gas market for the 2024 supply year. There is forecast to be sufficient gas produced, withdrawn from storage or flowed into the east coast gas market to meet forecast demand, even if the LNG producers export all of their uncontracted gas as spot or additional LNG cargoes.

However, this outlook is finely balanced. We expect that recent policy reforms, such as the Gas Market Code (the Code), could change the volumes LNG producers sell to the domestic market. This will be the case if LNG producers offer additional volumes of domestic supply in return for a Ministerial exemption to the pricing requirements of the Code.

If the LNG producers only export what they currently anticipate they will sell as LNG spot or additional sales, then there will be 71 PJ of gas available to the east coast market.

Chart 1.1: Forecast east coast supply-demand balance in 2024 (PJ)



Source: ACCC analysis of data obtained from gas producers in October 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO's March 2023 GSOO.

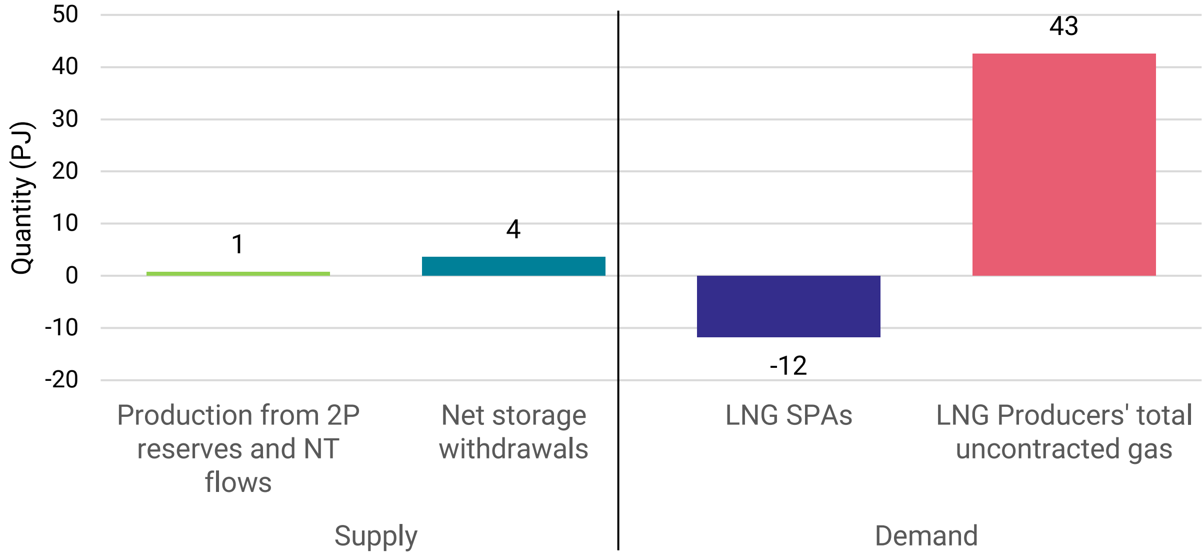
Note: Totals may not add up due to rounding.

Our June 2023 interim report found that there would be sufficient gas supply to meet demand in 2024 with a forecast surplus of 27 PJ even if all uncontracted gas is exported.[7] Our latest forecast indicates sufficient gas for 2024 if all uncontracted gas is exported.

Total forecast supply and demand for 2024 have increased by 5 PJ and 31 PJ respectively since our June 2023 interim report. Chart 1.2 breaks down the reasons for these changes.

[7] ACCC, *Gas inquiry June 2023 interim report,* Gas Inquiry 2017–2030, ACCC, June 2023, p 22.

Chart 1.2: Reasons for change in 2024 supply-demand outlook



Source: ACCC analysis of data obtained from gas producers in April 2023, June 2023 and October 2023.

Note: Totals may not add up due to rounding.

Additionally, the LNG producers have increased their anticipated LNG spot and additional sales in 2024 by 35 PJ compared to our previous forecast. If the LNG producers export only what they have anticipated, this will reduce the forecast surplus by 14 PJ from the 90 PJ reported in our June 2023 interim report.

While there has been a slight increase in forecast supply in 2024, there have been reductions in supply in some regions of the market, including the Otway Basin. This may be partially due to reductions in customer nominations for supply in 2024 from this region.[8] The reduced supply is offset by increases in forecast supply in the Cooper and Surat basins.

LNG producers are now forecast to have more uncontracted gas in 2024

A key change in the outlook for 2024 is that the LNG producers are forecast to have significantly larger volumes of uncontracted gas, from which a significant amount is being earmarked for currently uncontracted but anticipated LNG spot cargoes and additional sales.

The uncontracted gas figure has increased by 43 PJ mainly due to a combination of three factors (shown further in section 1.3):

- a 19 PJ increase in forecast 2P production and net storage withdrawals
- a 12 PJ decrease in forecast in long-term LNG exports
- a 2 PJ decrease in net contribution to the domestic market (sales to minus purchases from the domestic market).

A small contributing factor affecting our forecast uncontracted gas is that we have changed our reporting to take into account the effect of the LNG producers' gas swap agreements. LNG producers are forecast to receive 10 PJ of additional gas on a net basis through gas swaps with other market participants in 2024. These swaps are between years, as opposed

[8] C Packham, *Beach Energy blames Origin for revenue slump*, *The Australian Business Review*, 25 October 2023, accessed 26 October 2023.

to swaps between different times of the year. This is the first time we have reported gas swap volumes for the whole of 2024.

This increase in uncontracted gas contrasts with the long-term outlook from 2025 to 2035 as shown in Chapter 3. The long-term outlook shows that LNG producers are forecast to have significantly less uncontracted gas available to them in the future and are forecast to make fewer spot and additional LNG sales.

Production and GPG remain key influences on the outlook

While we are currently forecasting that the east coast gas market is likely to have enough gas to meet forecast demand in 2024, there is uncertainty for both supply and demand across the east coast market:

- GPG demand could be higher or lower than forecast if weather conditions differ from what is expected and/or there are generator outages. Delays to new renewable generation could also cause increased GPG demand. GPG demand is forecast to decrease from 123 PJ in 2023 to 79 PJ in 2024.
- Gas supply could fall short of the volumes forecast due to production issues, investment choices or other factors. Flows from the Northern Territory could be lower than forecast, as occurred in 2022 due to production issues at the Blacktip Field.[9] Supply could also be higher than forecast. The southern states may be especially at risk of variable production as gas fields there come towards the end of their productive life. Further information on the effects this may have on Commercial and Industrial (C&I) users is discussed in Box 1.2.

Box 1.2: Users are concerned about the increased reliance placed on permitted interruption (PI) clauses, with some suppliers citing the heightened risk of outages at Longford.

Several C&I users and intermediaries that responded to our survey told us that the number and type of permitted interruptions provided for in Gas Supply Agreements (GSAs) has increased, particularly for supply out of Longford.

They noted that this appeared to be related to the risks surrounding production from the Longford gas plant due to the decline in production from gas field, the potential risk of a reserves shortfall and the increased need for maintenance of the gas plant.

A number of users and intermediaries, for example, told us that they have been warned by suppliers about the potential for supply interruptions in 2024 and 2025, due to Longford outages.

One C&I user told us that in a recent producer EOI the number of permitted interruptions days for technical and maintenance reasons had increased from around 10-15 days p.a. to 20-40 days p.a. This user noted that the definition of “firm” supply has also changed and stated that it seems “almost impossible” to get a price for firm supply now from Longford. It also noted that other clauses are also being inserted into GSAs to:

> ‘…give suppliers a free out in the event of gas supply not measuring up.’

[9] ACCC, G*as inquiry June 2023 interim report*, Gas Inquiry 2017–2030, ACCC, June 2023, Appendix A

> '…contract terms also include significant reserves shortfall type clauses which give (some) suppliers the ability to re-visit the firmness of supply in the event of gas field reserve changes.'

Some C&I users are already feeling the effects of these provisions, with one C&I user telling us that it has already experienced multiple days of interruption and stating that:

> '…now the [supply] risk is being borne on the buyer-side.'

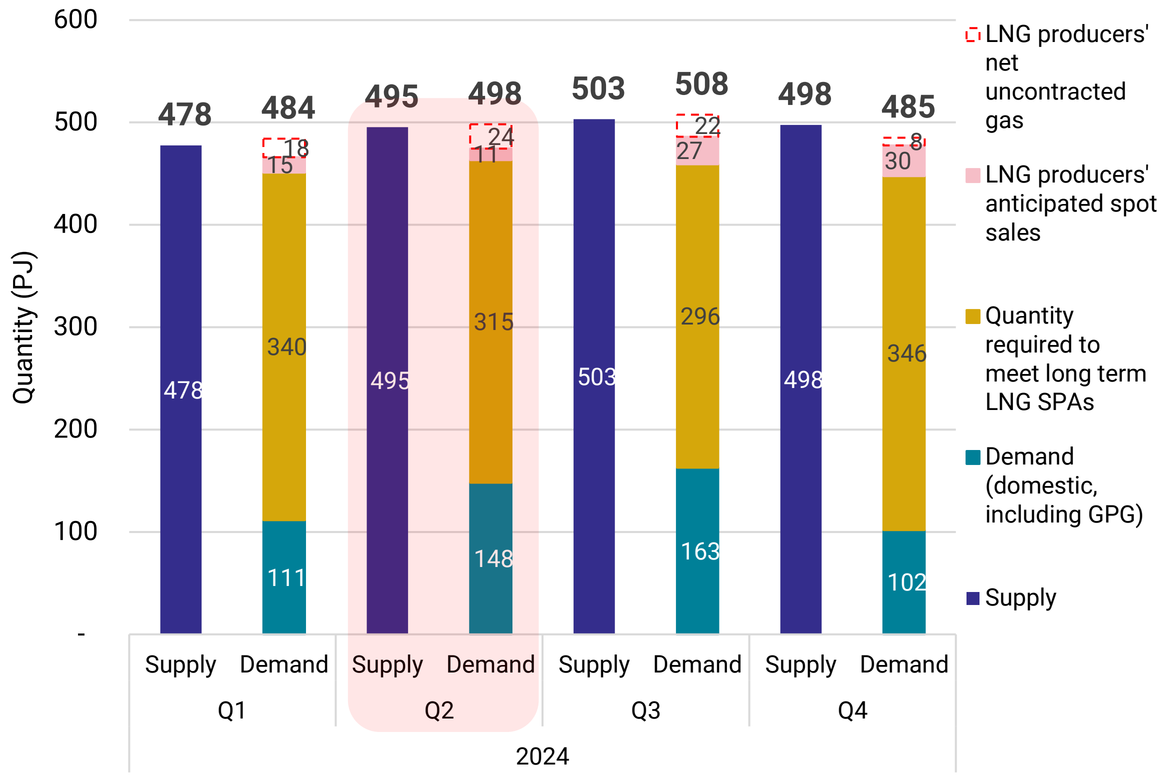
The issues that C&I users have raised in this context highlight some of the risks surrounding the supply of gas from Longford, from which production is expected to reduce in future years due to the depletion of large legacy fields. They also highlight the challenges that these risks are likely to pose for C&I users, retailers and gas powered generators (GPG) that procure gas from Longford, and the market more generally.

1.2.2. Gas swaps have smoothed supply throughout the year

This section provides a quarterly breakdown of the supply-demand balance for 2024, with a focus on quarter 2 and the impact of gas swap arrangements. The quarterly outlook provides insights into the expected availability of gas throughout the year to meet forecast demand, including identifying whether there are specific seasons that are at risk of supply shortfalls.

Chart 1.3 sets out the forecast supply-demand outlook across the east coast gas market for 2024 by quarter. This shows that there is likely to be sufficient gas to meet demand in all quarters of 2024, but only if LNG producers export only what they anticipate as LNG spot cargoes and additional sales. There will be supply shortages in most quarters if the LNG producers export all of their uncontracted gas.

Chart 1.3: Quarterly supply-demand outlook in 2024 (PJ)



Source: ACCC analysis of data obtained from gas producers in October 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), AEMO, April 2023.

Note: Totals may not add up due to rounding, including to the totals shown in this chart.

There is likely to be sufficient gas in quarter 2 2024

There is expected to be sufficient supply to meet forecast demand in quarter 2, if the LNG producers commit at least 3 PJ of uncontracted gas to the domestic market in addition to their existing commitments.

This outlook for quarter 2 2024 is the same as was reported in the ACCC's June 2023 interim report. Both gas supply and demand have increased in this quarter by equal amounts. In particular, the LNG producers have additional uncontracted gas available to them.

Box 1.3: Forecast and actual supply and demand for quarter 2 2023

Table 1.1 examines the forecast for quarter 2 2023, published in the March 2023 report, with actuals obtained using AEMO GBB[10] data.

The quarter 2 2023 forecast data was collected in January 2023, shortly after the implementation of the Gas Market Emergency Price Order. It is unclear what impact the uncertain policy environment had on the forecast.

Table 1.1: Comparison of Q2 2023 actuals with Q2 2023 forecasts

	Q2 2023 forecast	Q2 2023 Actuals	Q2 2024 forecast
Supply			
Production	506.8	484.8*	493.6
Net storage withdrawals	-	-0.7	-
Demand			
Quantity required to meet long-term LNG SPAs*	324.6	339.2	315.1
Uncontracted gas	28.7	-	35.0
Queensland demand	39.6	32.4	34.2
Southern states demand	119.7	119.3	113.9
Demand total	512.6	490.9*	498.1
Outlook			
Surplus/shortfall	-5.8	-6.8	-4.5

*Note: There are some closed systems in proximity to the east coast gas market that are not tracked by AEMO's Gas Bulletin Board. As these are small closed systems with no storage, this will increase both the supply and demand values proportionally.

Supply and demand were both lower than expected in quarter 2 2023. This was driven by the LNG producers not exporting all of their forecast uncontracted gas and lower Queensland domestic demand.

LNG export demand had a slight increase in contracted sales, but a big reduction in spot sales. Queensland's lower demand was due to two main factors: the weather over the quarter was warmer than average and gas powered generation was at the second lowest quarter 2 level since 2006.

Table 1.1 also shows reduced forecast supply and domestic demand in quarter 2 2024 compared to quarter 2 2023.

10 AEMO, Gas Bulletin Board, accessed at Gas flows and capacity outlooks [website], n.d., accessed 3 October 2023.

Gas swaps smooth the outlook throughout the year

Table 1.2 shows our previous quarterly forecast supply-demand outlooks for 2024, along with the change since our June 2023 interim report. The table shows any potential surpluses and shortfalls in each quarter, as positive and negative figures respectively, if all uncontracted gas is exported.

Table 1.2: Change in quarterly forecasts in 2024 if all uncontracted gas is exported

	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Supply-demand balance in June 2023 report	7	-3	-11	33
Supply-demand balance in September 2023 report	1	-	-	-
Updated supply-demand balance	-6	-3	-4	12
Change since June 2023	-14	0	7	-21
Contribution from net gas swaps	**-10**	**6**	**8**	**-15**

As noted above, a change in our approach compared to our June 2023 interim report is the inclusion of the effect of gas swaps. For example, GLNG have offered seasonal swap products to the market, whereby they supply gas to the domestic market in the winter quarters when gas is most needed domestically and receive it back in the summer months.[11]

The effects of these types of seasonal swaps is to provide a 'smoothing' effect on the market, whereby any potential surpluses in the summer months and shortfalls in the winter months are reduced. These effects are shown in our data in Table 1.2.

With updated information, we now forecast that quarters 1-3 of 2024 will face a shortfall if the LNG producers export all of their uncontracted gas. To avert a shortfall, producers could bring forward supply, or LNG producers could commit additional uncontracted gas to the domestic market instead of exporting it.

11 Santos GLNG, *GLNG commitment to support the domestic market* [website], n.d., accessed 10 November 2023.

Box 1.4: Gas swap arrangements

The LNG producers and other participants in the domestic market enter into gas swap arrangements. Since our September 2023 interim report, we have considered the impact of these gas swap arrangements on the market outlook. We have done this by changing our calculation of the LNG producers' uncontracted gas to account for the difference between the gas received by the LNG producers and the gas supplied by the LNG producers.

The impact of gas swap arrangements in 2024

In 2024, LNG producers are expected to have an additional 10 PJ of gas available to them through these gas swaps. An expectation might be that the annual net gas swap value is nil, however transactions (either the sale or purchase) are completed across calendar years.

In quarter 2 of 2024 LNG producers' aggregate net gas swaps are -6 PJ, meaning the LNG producers return gas to domestic producers or retailers. This corresponds with the increase in domestic demand as winter commences in quarter 2.

The gas swap positions of the LNG producers for each quarter can be found in Table 1.2 above.

Features of gas swap agreements

We have reviewed a number of gas swap agreements, particularly those of the LNG producers. Gas swaps can be time or location swaps, and the duration of the swaps can vary: from short-term, to seasonal, to inter-year. Individual swap transactions are generally governed under master agreements, but individual transactions can replace clauses contained in the master agreements. Gas swap agreements can involve an exchange of money. Our review of gas swap agreements will continue in future reports.

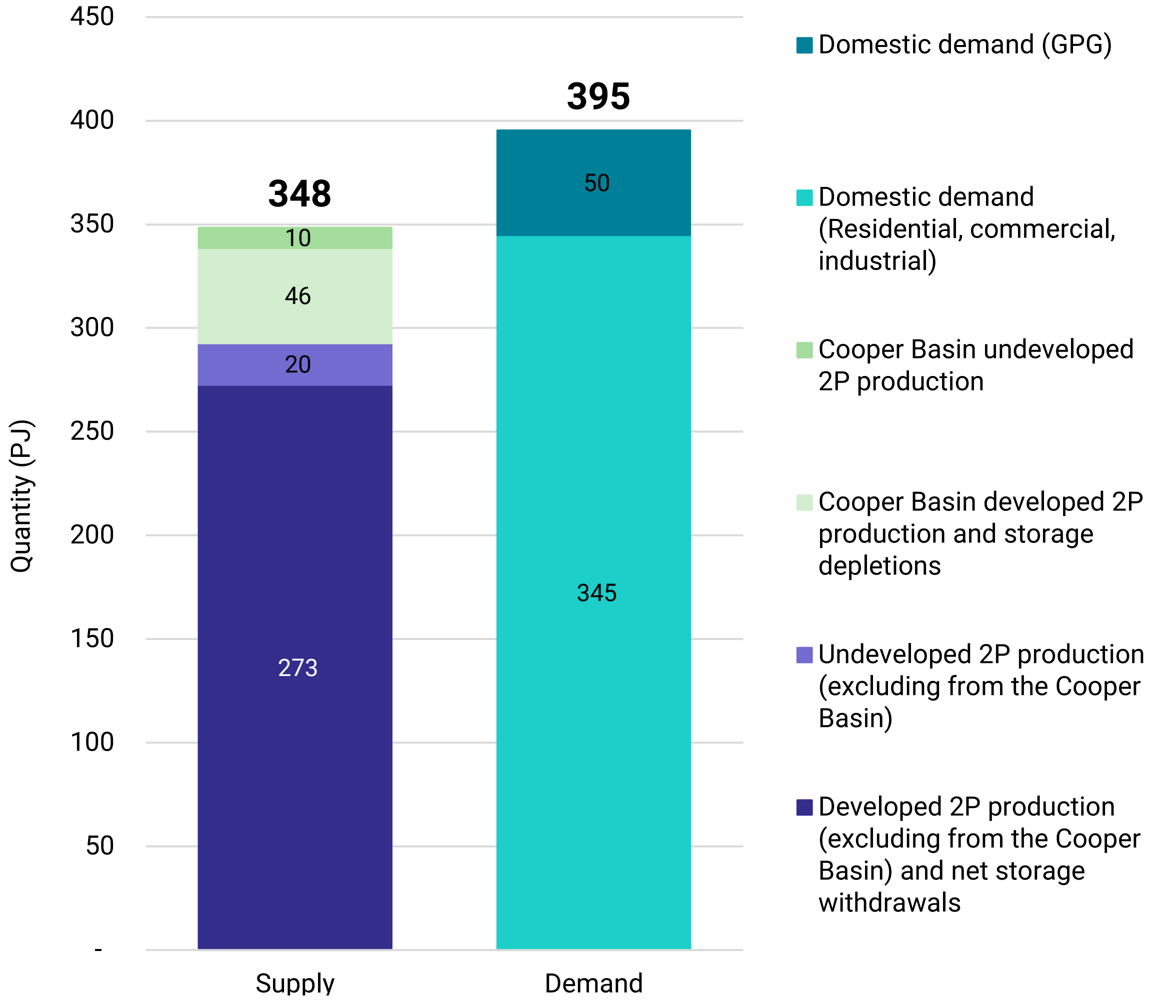
1.2.3. The southern states will need additional gas in winter

This section shows the supply and demand balance for gas in the southern states. These states are the key source of domestic demand in the east coast, including substantial residential and commercial and industrial demand.

However, demand for gas in these states is expected to significantly exceed gas production in the southern states. Forecast gas shortfalls in the southern states will need to be made up with gas from Queensland and with gas brought out of storage.

Chart 1.4 sets out the forecast supply-demand balance in the southern states for 2024. It shows that demand in the southern states (395 PJ) is forecast to exceed supply (348 PJ) by 47 PJ in 2024. This is a slight worsening compared to our last forecast in June 2023, which anticipated a shortfall of 44 PJ in 2024.

Chart 1.4: Forecast supply-demand balance in the southern states in 2024



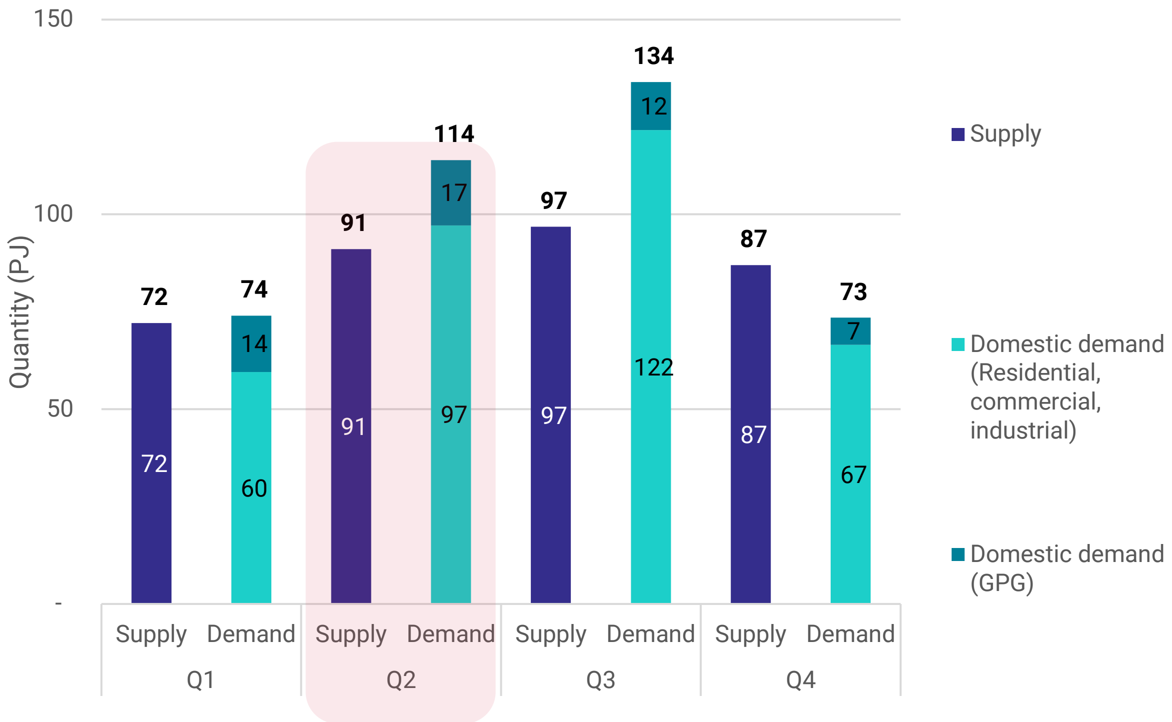
Source: ACCC analysis of data obtained from gas producers in October 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), AEMO, April 2023.

Note: Totals may not add up due to rounding.

Forecast non-Cooper basin production in the southern states has decreased by 17 PJ, almost entirely caused by a 16 PJ decline in Otway basin production. However, this has mostly been offset by increases in Cooper Basin production (15 PJ).

Chart 1.5 shows the quarterly breakdown in the southern states' supply-demand balance. This shows that the outlook worsens in the colder months, with a 23 PJ shortfall expected in quarter 2 and a 37 PJ shortfall expected in quarter 3. This is driven by increases in gas heating driving up residential demand.

Chart 1.5: Quarterly supply-demand balance in southern states in 2024 (PJ)



Source: ACCC analysis of data obtained from gas producers in October 2023 and of the domestic demand forecast (Orchestrated Step Change scenario) from AEMO, Gas Statement of Opportunities (GSOO), AEMO, April 2023.

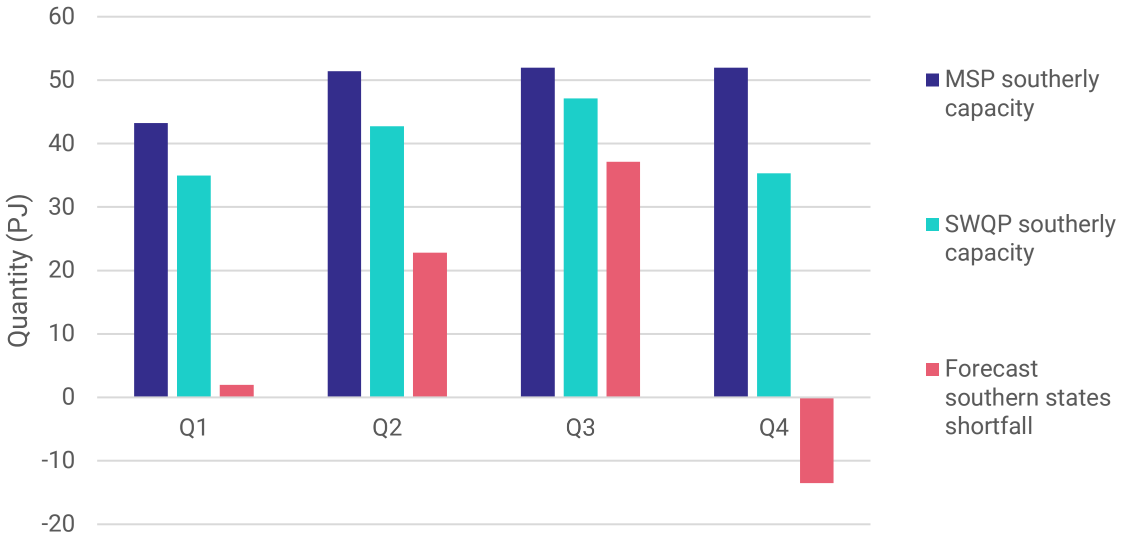
Note: Totals may not add up due to rounding.

Gas will be required from Queensland to avert southern shortfalls

Two major pipelines connect the Queensland and Northern Territory gas fields to the southern states – the Moomba Sydney Pipeline (MSP) and the South West Queensland Pipeline (SWQP). These pipelines enable gas to flow in both directions, transporting gas to where it is needed. Historically, gas through these pipelines flows south from May to September, addressing southern states gas demand with cheaper gas during the cooler months.

Chart 1.6 shows the capacity on key southerly pipelines compared with the forecast shortfalls for the southern states in each quarter of 2024.

Chart 1.6: Maximum potential capacity on key pipelines that can transport gas to southern states (PJ)



Source: Analysis of information provided by suppliers and from AEMO's Gas Statement of Opportunities.

Note: Pipeline capacity is provided in PJ as we are looking at aggregate available capacity across each quarter. AEMO's Gas Statement of Opportunities report, published in March 2023 and due for publication in March 2024, explores the east coast gas market's ability to meet daily demand peaks.

These pipeline capacity outlooks account for recent and forecast upgrades. As previously reported, APA Group have recently upgraded the operational capacity of southerly gas flow through the MSP and SWQP ready for winter 2023. These upgrades increased the MSP's capacity from 446 TJ/day to 475 TJ/day for southerly flow, and the SWQP's capacity from 404 TJ/day to 453 TJ/day.[12] Both pipelines are expecting further upgrades in time for winter 2024. The MSP is expected to increase to 565 TJ/day and the SWQP is expected to increase to 512 TJ/day.[13]

The SWQP and MSP should be able to transport sufficient gas south to meet any forecast shortfall. However, there may be individual days during winter where southern demand is expected to peak as cold weather drives up demand for both electricity and gas for heating alongside commercial and industrial consumption.[14] During these peak days, gas supply may need to be sourced from storage as well as gas pipelines from the north. The combined use of storage and pipelines to avert southern shortfalls is explored by AEMO in its March 2023 GSOO and further below.[15]

Gas from storage will also be required during peak days

Storage facilities, along with pipelines, are key gas market infrastructure and are used for daily and seasonal balancing of gas supply and demand. The Iona underground storage facility in Victoria is particularly important, being located in the state with the highest domestic demand.

---

12 AEMO, Gas Statement of Opportunities, AEMO, 16 March 2023, p 59.

13 AEMO, Gas Statement of Opportunities, AEMO, 16 March 2023, p 59.

14 AEMO, *Gas Statement of Opportunities*, AEMO, 16 March 2023, p 70.

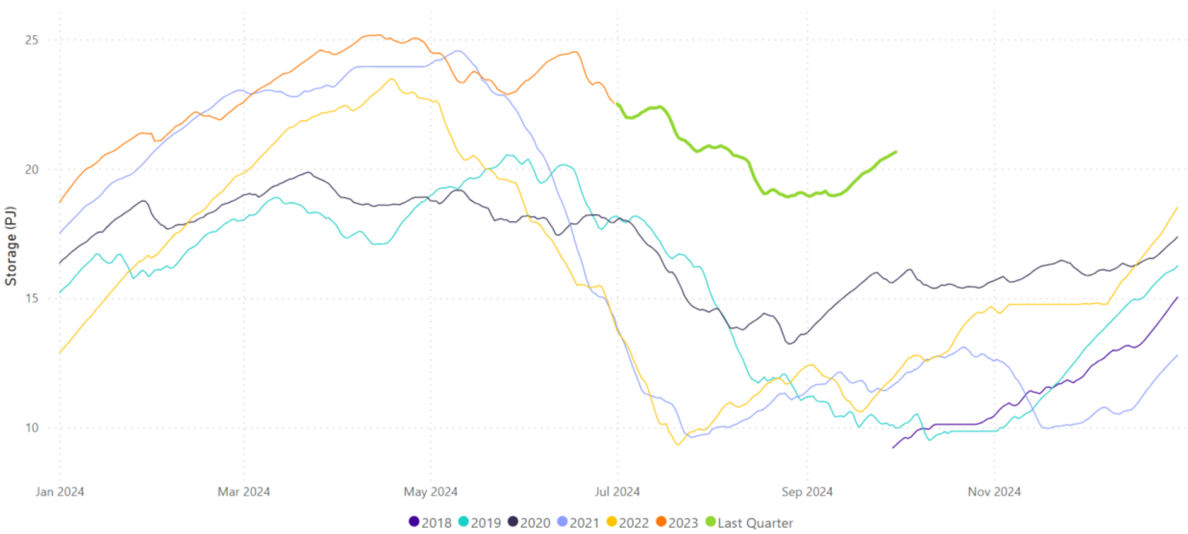
15 AEMO, *Gas Statement of Opportunities*, AEMO, 16 March 2023, pp 70–74.

Historically, Iona is filled between November and May and then discharged over the cooler months to meet daily peak demand.

We note that Iona has operated differently throughout the cooler months of 2023, with lower gas powered generation and milder weather resulting in lowered gas usage.[16] Iona's storage levels have remained high through the winter of 2023, with no additional threat to system security notices issued by AEMO during quarter 3 2023, leaving it well placed to address southern states demand in the cooler months of 2024. Chart 1.7 shows the storage levels at Iona over the past five years.

In future years, the combination of Iona's storage and upgraded southerly gas flows from the MSP and SWQP (as mentioned above) may be needed to address peak demand in the southern states.

Chart 1.7: Year-on-year Iona underground storage levels



Source: AEMO, Gas Bulletin Board, [website], accessed October 2023.

1.3. LNG producers are key to a supply surplus in 2024

The LNG producers hold significant influence over the 2024 supply-demand balance on the east coast, with LNG exports forecast to reach 1,380 PJ in 2024, including additional and spot sales. This represents 74% of production from 2P reserves on the east coast. While the LNG projects were developed primarily to export gas to international customers, they source some of their exported gas from the domestic market. They also produce some gas that can be sold to the domestic market.

The LNG producers and their associates have influence over close to 90% of 2P reserves in the east coast market.[17] This provides these producers with the capacity to prevent any east coast shortfall, but they have the ability and incentive to divert that gas into more profitable export markets. However, we note that over time the Code and the HoA are expected to have

16 AER, *State of the Energy Market 2023*, AER, 5 October 2023, p10.

17 ACCC, *Gas inquiry July 2022 interim report*, Gas Inquiry 2017–2030, ACCC, July 2022, Chapter 5.

an impact on the ability and incentive for these producers to divert gas back into the domestic market.

Table 1.3 shows the forecast aggregated supply-demand breakdown for the LNG producers in 2024. The table also shows the changes in the supply-demand forecasts for 2024 since our June 2023 report.

Table 1.3: LNG producers' forecast supply and contracted sales in 2024 (PJ)

	Q1	Q2	Q3	Q4	2024 Total	Change in 2024 forecast
Supply						
Production from 2P reserves + net storage withdrawals	357	354	352	355	1,417	+19
3rd party purchases from suppliers other than LNG projects	42	46	48	49	185	+6
LNG producers' gas swaps received	25	18	17	31	91	Not available
Total supply available to LNG producers	424	418	416	434	1,692	
Demand						
Domestic demand						
Contracted east coast market demand	36	43	47	35	161	+4
Export demand						
Quantity required to meet long-term LNG SPAs	340	315	296	346	1,297	-12
LNG producers' gas swaps supplied	15	24	25	16	81	Not available
Total contracted LNG demand	391	383	368	397	1,538	
LNG producers' total uncontracted gas	**33**	**35**	**48**	**38**	**154**	**42**
LNG producers' anticipated LNG spot and additional sales (out of their uncontracted gas)	**15**	**11**	**27**	**30**	**83**	**36**
LNG producers' net uncontracted gas	**18**	**24**	**22**	**8**	**71**	**7**

Source: ACCC analysis of data obtained from LNG producers in October 2023.

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).

1.3.1. LNG producers' quarterly production capacity outlook

LNG producers can use their uncontracted gas to produce spot and additional LNG cargoes, up to the capacity limits of their LNG facilities. Spare capacity to export additional cargoes beyond SPA volumes can be estimated using the information provided in Table 1.4 (LNG producers' impact on the supply-demand balance in 2024) and GBB Medium Term Capacity Outlook data.[18]

Estimating spare capacity is useful to establish whether LNG producers may be able to export their uncontracted gas or whether it is likely to be retained for the domestic market. For instance, if LNG producers had little estimated spare capacity after exporting SPA volumes and anticipated spot sales then it would be highly unlikely that any uncontracted gas could be exported. On the other hand, LNG producers with spare capacity may be incentivised to export uncontracted gas if LNG prices are higher than domestic prices.

Subtracting the total volume of forecast LNG production from total LNG production capacity for each quarter results in the following estimates of spare capacity, shown for each quarter in Table 1.4. Three scenarios are shown:

- All uncontracted gas is exported.
- Only anticipated spot sales and SPA volumes are exported.
- Only SPA volumes are exported.

Table 2.4: Estimated LNG plant spare capacity (PJ) over 2024

Scenario	Q1	Q2	Q3	Q4	2024
All uncontracted gas is exported	23	12	25	20	80
Anticipated spot sales plus SPA exported	41	36	47	28	152
Only SPA volumes exported	56	47	73	58	235

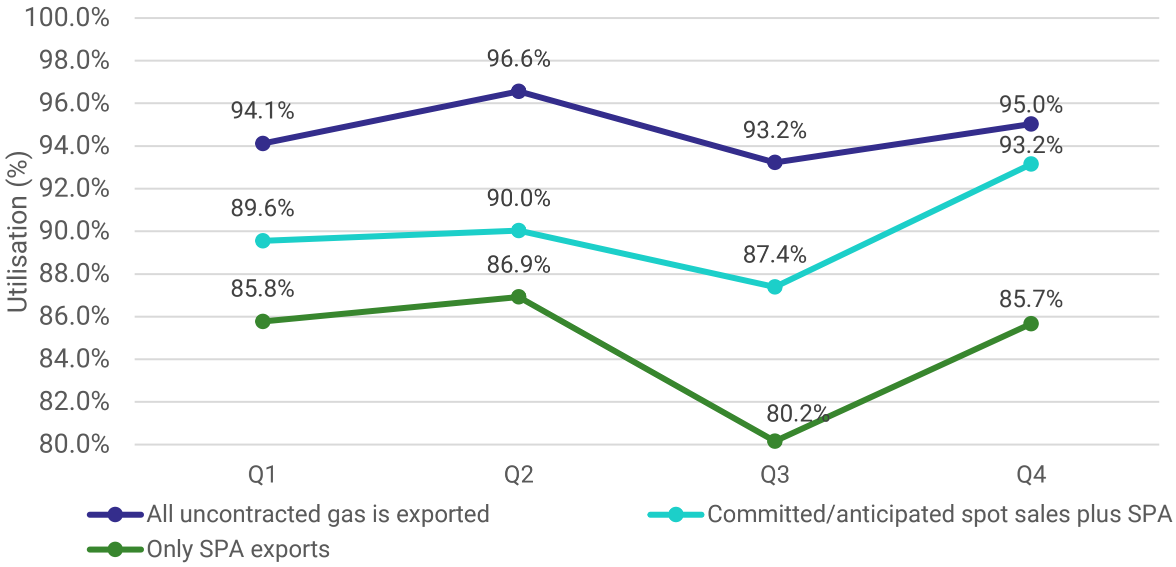
Source: ACCC analysis of data obtained in October 2023 from producers. This estimate is based on ACCC analysis of Gas Bulletin Board data provided under AEMO's medium term capacity outlook and nameplate capacity outlook data sheets. AEMO, https://aemo.com.au/energy-systems/gas/gas-bulletinboard-gbb/data-gbb/gas-flows, accessed on 1 October 2023.

Note: Totals may not add up due to rounding.

Chart 1.8 shows the aggregated utilisation rate for the LNG facilities for each scenario. While the chart shows quarterly utilisation, across all of 2024 utilisation would average 94.8% if all uncontracted gas is exported, 90.1% if only SPA and committed spot sales are exported, and 84.7% if only SPA volumes are exported.

[18] This estimate is based on ACCC analysis of GBB data provided under AEMO's medium term capacity outlook and nameplate capacity outlook data sheets. AEMO, Gas flows and capacity outlooks [website], n.d., accessed 1 August 2023.

Chart 1.10: Forecast utilisation (%) of LNG plants under three scenarios over 2024



Source: ACCC analysis of data obtained in October 2023 from producers. This estimate is based on ACCC analysis of Gas Bulletin Board data provided under AEMO's medium term capacity outlook and nameplate capacity outlook data sheets. AEMO, https://aemo.com.au/energy-systems/gas/gas-bulletinboard-gbb/data-gbb/gas-flows as at 1 October 2023.

Note: Totals may not add up due to rounding.

Under all scenarios, there will be available capacity to increase exports. As such, LNG producers will have a choice between diverting their uncontracted gas to the domestic market or exporting the uncontracted gas, subject to the requirements of the Code and the HoA. Note that these figures represent the aggregate spare capacity and the capacity available to each LNG producer differs.

These are high-level estimates only, based on analysis of public information reported to the AEMO's GBB. LNG trains may undergo unanticipated maintenance that may result in less available capacity. Likewise, SPA volumes may increase or decrease closer to the date which may result in lower or higher spare capacity than estimated. All these factors may result in there being less or more spare capacity than expected.

2. Domestic contracting outlook

Key Points

- The majority of gas produced for the domestic market is sold under contracts with C&I users and retailers. Producers enter into short-term contracts (e.g. supply for 12 months or less) and long-term contracts (e.g. supply over 12 months). Remaining gas is transacted on the short-term trading markets.
- Between February and August 2023, there was an increase in the number of contracts executed and volumes of gas contracted for the supply of gas in 2024. In the previous 6 months, the numbers and volumes of contracting was flat.
- However, overall, the volumes of gas contracted for supply in 2024 is less than in previous years, despite there being sufficient production expected to meet demand:
  - The volumes offered by producers for 2024 supply is 80% lower compared to the corresponding offers for 2023 supply.
  - The volumes contracted by producers for 2024 supply were below the volumes contracted at comparable times for 2023 supply and significantly below contracted volumes for 2021 and 2022 supply.
  - The total amount of volume contracting to C&I users for supply in 2024 is lower than comparable times in previous years.
- Producers have also sold less gas under short-term contracts, short-term spot markets and the Gas Supply Hub compared to previous years.
- Gas producers are now required to publish available uncontracted volumes under the rules of the Gas Markets Code. This new information shows a significant proportion will likely be required to fulfil domestic demand in both 2024 and 2025. This suggests large volumes of gas still remain to be contracted over the next two years.
- C&I users and retailers noted an expectation that there would be increased contracting in a shorter window to meet this demand.

2.1. Introduction

This chapter reports on contracting between producers, retailers and end users of gas in the east coast gas market. It presents analysis of:

- volumes of gas sold through short-term contracts and spot markets in 2023
- levels of contracting for 2024
- analysis of available gas from producers under the Gas Markets Code (the Code).

This section includes analysis of contracted gas from Gas Supply Agreements (GSAs), aggregated contracted gas figures sourced from gas market participants, and interviews with gas users.

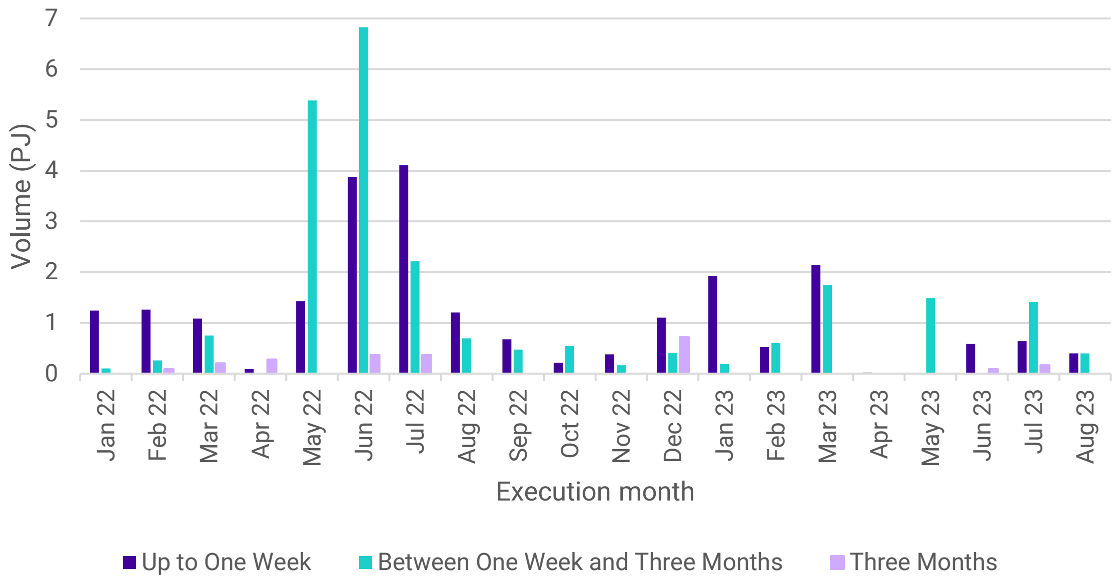
2.2. Gas sold under short-term contracts and in short-term markets

This section examines volumes of gas sold through short-term contracts and in AEMO operated spot markets in 2023, finding that volumes sold have decreased compared to previous years. This updates analysis from our June 2023 interim report.

2.2.1. Producers sold less gas under short-term contracts in 2023 compared to 2022

Chart 2.1 shows volumes of gas sold under producer GSAs for firm supply. For this section, we have only considered GSAs for delivery within 12 months of execution and a supply term of up to 3 months.

Chart 2.1: Contract volumes agreed to under firm producer GSA by term length for delivery within 12 months of execution



Source: ACCC analysis of information provided by suppliers

In 2023, producers have sold less gas to the market under GSAs with a term length of 3 months or less than they did in 2022. Producers sold higher volumes of gas in quarter 1 2023 than quarter 1 2022, mostly due to an increase of gas available due to an unplanned outage on QGC's LNG export facility. Volumes sold in the middle two quarters of 2023 were significantly below the volumes sold over the same period in 2022.

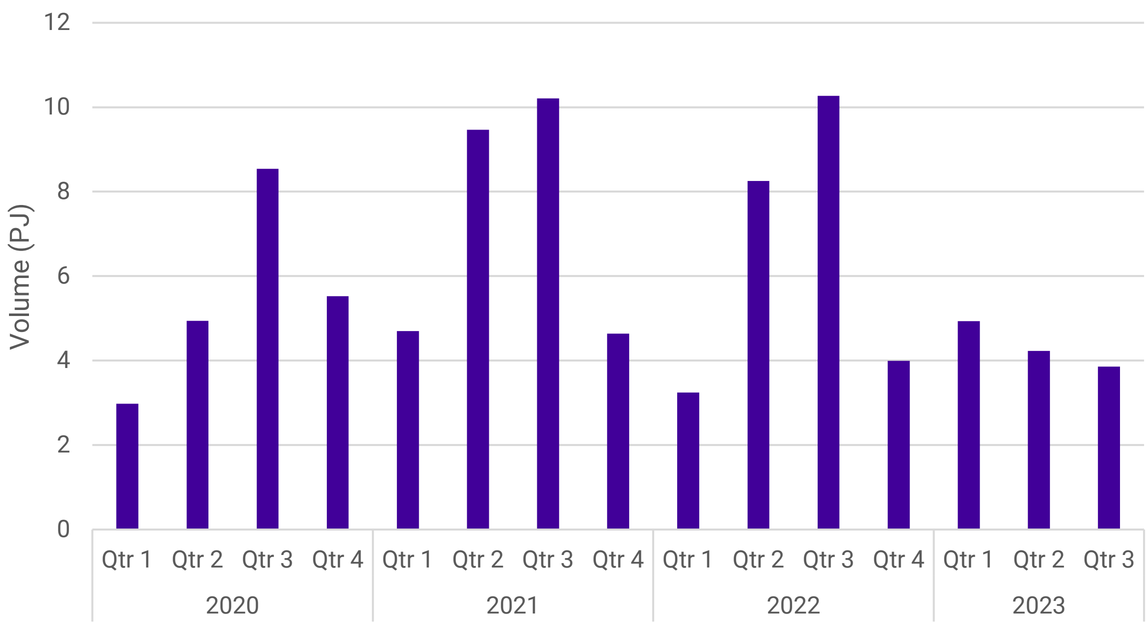
This is consistent with the volumes sold by producers on the large wholesale short-term markets for gas, which allow retailers or large customers to purchase gas without entering into long-term contracts. These include the Wallumbilla Gas Supply Hub (GSH) in Queensland, the Declared Wholesale Gas Market (DWGM) in Victoria and domestic short-term trading markets (STTMs) in Adelaide, Sydney and Brisbane.

In 2022, LNG producers made up 76% of the volumes sold under GSAs with a term length of up to 1 week, and 78% of the volumes sold with a term length between 1 week and 3 months. This trend continued with LNG producers making up 70% and 89% of volumes respectively so far in 2023.

2.2.2. Producers sold lower volumes on spot markets in 2023 compared to previous years

Chart 2.2 shows the volume of gas sold by producers and exporters on certain spot markets (STTMs, DWGM) across the last 4 years.

Chart 2.2: Volumes sold on short-term markets by producers/exporters (STTMs, DWGM)



Source: ACCC analysis of information provided by AER.

Note: Trade has been netted across producer/exporter buy and sell positions to calculate the total volume of gas sold.

Quarter 1 2023 saw producers and exporters sell a larger volume of gas via the domestic STTMs and the DWGM compared to previous first quarters. As noted in our June 2023 Gas

Inquiry report,[19] this increase in volume reflects additional gas being made available to the domestic market due to several outages on one of QGC's export trains.

Since then, the volume of gas sold by producers and exporters has decreased compared to previous comparable quarters. Producers and exporters sold less gas in quarter 2 and quarter 3 2023 compared to the volumes sold over the previous 3 years.

In its quarter 3 wholesale markets quarterly report, the AER noted that quarter 3 demand on short-term markets (STTM and DWGM) was at its lowest point in 10 years, largely influenced by unseasonably warm weather. Low prices in September was also a result of retailers contracting minimum levels of gas (take or pay) based on higher gas demand expectations. To ensure that minimum levels of gas already contracted for (and obligated to be paid for) are dispatched, retailers have had to lower gas offer prices and sell into a low demand market. The AER report also noted that while international spot netback prices are still well above $10, there are potential arbitrage opportunities for exporters to buy gas domestically and increase export volumes.[20]

Trade on the Wallumbilla Gas Supply Hub over quarter 2 and quarter 3 2023 remained strong, though lower than volumes traded in 2022. Producers sold less volume on the GSH and were net buyers of gas for delivery in quarter 3.[21]

2.3. Gas sold under longer-term contracts

This section shows the volumes of gas offered and sold under longer-term gas contracting for 2024 and 2025.[22]

There has recently been an uptick in the number of long-term gas contracts executed and the volumes of gas contracted for supply in 2024. However, as of August 2023, overall less gas has been offered and contracted for 2024 compared to previous years at the same point. A significant proportion of producers' available gas, as required to be published under the Code, will be needed to fulfil demand in 2024 and 2025.

This is consistent with the experiences faced by C&I users and intermediaries about delays in the volumes of gas offers and contracting for 2024 and limited volumes of supply being offered, as shown in Box 2.1. This also aligns with the reported difficulties experienced by retailers to secure gas for 2024 supply which we discuss further in Chapter 5.

Box 2.1: A rush in contracting activity is expected towards the end of 2023

Through the discussions we held with C&I users and intermediaries between August and October 2023, we were informed that a number of users had delayed their contracting for 2024 supply because of the high prices and limited number of supplier offers available in the first half of the year.

---

19 ACCC, *Gas Inquiry 2017 – 2030: Interim update on east coast gas market June 2023*, 2023.

20 AER, *Wholesale markets quarterly: Q3 2023 October 2023*, 2023.

21 AER, *Wholesale markets quarterly: Q3 2023 October 2023*, 2023.

22 This section reports on our analysis of offers for supply quantities of at least 0.5 PJ, a term length of minimum 12 months and with fixed prices or prices linked to a commodity price index (such as Brent Crude oil).

Elaborating on this further, a number of C&I users and intermediaries noted that in response to the introduction of the Gas Market Emergency Price Order in December 2022 and the development of the Code, fewer producers were making offers for 2024 supply. A number of these stakeholders also told us that:

- they were informed by larger producers and LNG exporters that they were unable to make offers, because they needed to understand the impact of these interventions.
- where producer offers were made, they were conditional on the producer receiving an exemption from the Code, or included caveats on the prices offered.

Several stakeholders also told us that there was limited producer contracting following the commencement of the Code, with some producers informing them that they were awaiting the outcome of the Ministerial exemption process.

A number of stakeholders told us that the 'pause' (or 'drought') in producer contracting in the first half of 2023 has made it very difficult to secure supply for 2024. One stakeholder for example noted:

> '[The market] went from large producers running EOI processes, to only a couple of PJs offered at the beginning of the year.'

Based on our engagement with C&I users and intermediaries in September and October, it would appear that a large volume of gas demand is yet to be contracted for 2024. Noting that contract renewals are common in early January, the retailers that we spoke to as part of the retailer behaviour review also confirmed this was the case, with one retailer describing it as a 'contracting cliff' that was likely to pose a number of challenges towards the end of 2023.

While several buyers that are in the market told us that they expect to close on contracts by the end of 2023, there remains concern that the limited contracting by producers in early 2023 will mean that there is insufficient supply to meet the expected demand for 2024 as the contracting window closes.

2.3.1. Volumes of gas offered are lower than previous years

The volume of gas offered for supply in 2024 over the past 2 years has materially reduced compared to offers for supply in previous years.

Between February and August 2023, producers offered 16 PJ for supply in 2024. This was 80% lower than corresponding volumes offered over comparable times for 2022 and 2023 supply years. This is consistent with the marked reduction in the number of offers made by producers, as outlined in Chapter 4.

There was also a marked reduction in the volume of gas offered by retailers compared to previous years. Between February and August 2023, retailers offered 81 PJ for supply in 2024. This is a decrease of 45% and 33% compared to equivalent times for 2023 and 2022.

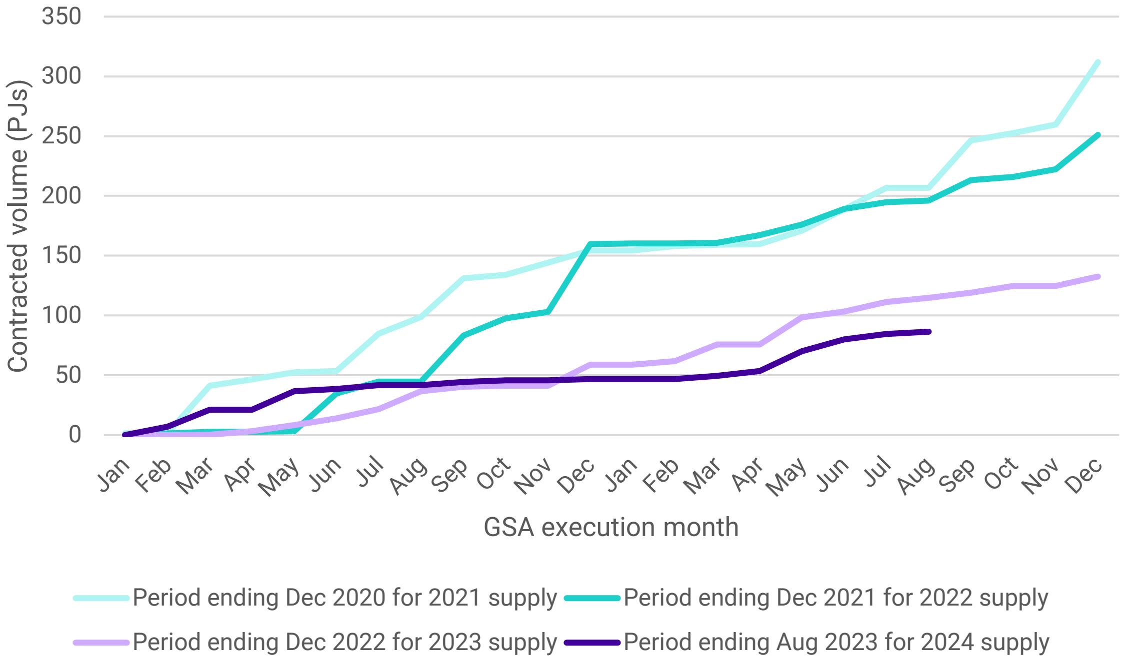
However, as discussed in Chapter 5, C&I users and intermediaries have informed us that retailers have been making more offers recently to the market.

2.3.2. There has been a recent uptick in contracting

There has been a recent increase in the numbers of long-term gas contracts executed and the volume of gas contracted for supply in 2024.

Chart 2.3 shows the volume of gas contracted for a given supply year in the 2 calendar years preceding the supply year. This reflects data up to 8 August 2023 for volumes contracted under GSAs for the 2024 supply year.

Chart 2.3: Cumulative volume of GSAs agreed for supply



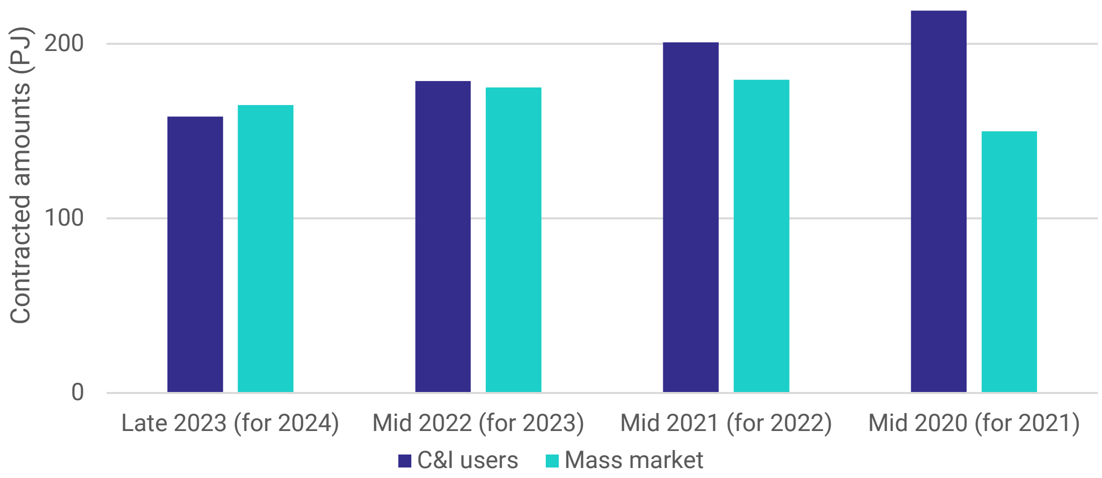
Source: ACCC analysis of information provided by suppliers.

There has been a recent increase in the number of GSAs for 2024 supply. As shown in Chart 2.3, the volume of gas contracted for 2024 supply increased between May and August 2023. This is consistent with an increase in the number of contracted executed.

This recent increase followed a long period of flat contracting. As a result, the total volume of gas agreed under GSAs remains below the volume at a comparable time for 2023 supply. The volumes are significantly lower, by approximately 100 PJ, compared to 2021 and 2022 levels over comparable timeframes.

This is consistent with the total volumes of gas contracted to end users. Chart 2.4 shows that contracting to C&I users has been occurring increasingly closer to when the gas is needed. The amount of gas contracted to C&I customers for a given year at the midpoint of the preceding year has been decreasing steadily over the last 4 years.

Chart 2.4: Contracted quantities to C&I and mass market gas users (PJ)



Source: ACCC analysis of data obtained from gas producers and retailers in October 2023 and August of 2020 – 2022.

2.3.3. There has been some recent contracting for 2025 supply

Between February and August 2023, suppliers contracted large volumes of gas for supply in future years beyond 2024. Most of these volumes were contracted under GSAs with term lengths of at least 3 years, with some agreements extending beyond 2030.

Table 2.1 shows the volume of gas committed, between 15 February to 8 August 2023 only, under all GSAs (both short-term and long-term) for supply in 2024 and beyond.

Table 2.1: Contracted volumes by supplier type (PJ)

Seller	2024	2025	2026 to 2035
Retailer	14.5	7.0	25.0
Producer	39.3	56.3	259.2
LNG producer	-	-	-
Total	53.7	63.3	284.1

Source: ACCC analysis of information provided by suppliers.

Note: The table reports volumes committed under GSAs with short- (less than 12 months) and long-term lengths (12 months or more). Some of the volumes, especially in the outer years, are contingent on a final investment decision by the supplier.

In the medium term, most gas contracted in the time period analysed was committed by non-LNG producers, with more gas contracted for 2025 than 2024. There have been relatively strong contracting volumes by these producers over the longer-term, with many of the contracts having longer supply term lengths. LNG producers have not made any firm commitments in 2023, up to 8 August, for supply in 2024 or beyond.[23]

23 They have made firm commitments for supply in 2024 in previous years, however.

2.4. Volumes of uncontracted gas

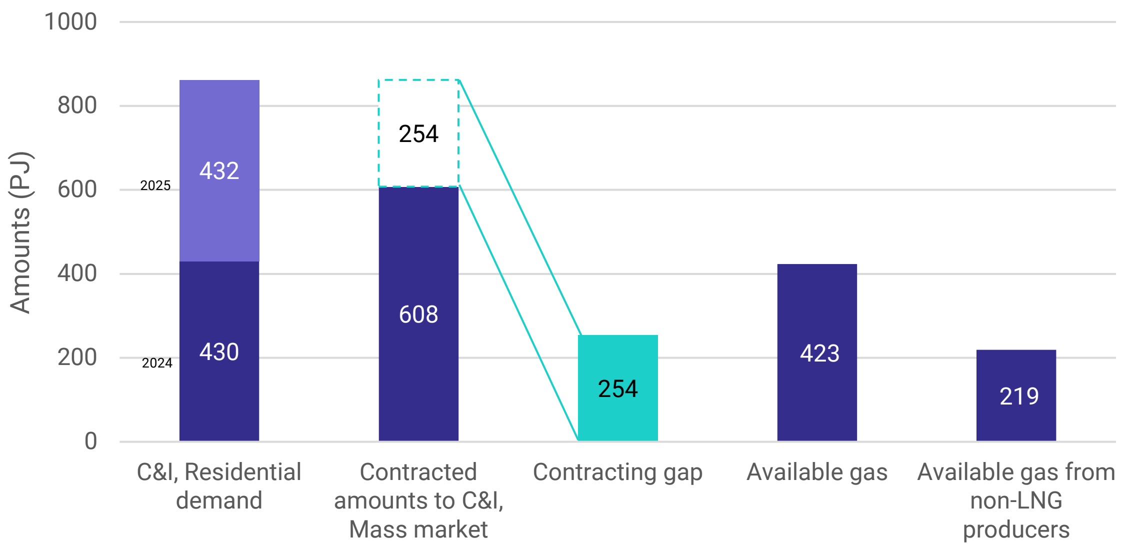
Under the Code, gas producers have published their quantities of gas that are expected to be available for sale to the market over a 2-year period. This section provides a comparison of this available gas with the levels of contracting currently seen in the market to show that a significant portion will be needed to fulfil gas demand.

As part of the Code, gas producers are required to publish information for the period 11 September 2023 to 10 September 2025 which sets out:

- the volume of uncontracted regulated gas that is likely to be available to the supplier in the period
- the volume of that uncontracted gas that the supplier intends to be the subject of a gas Expression of Interest (EOI), a gas initial offer or a gas final offer in the 24 month period
- the volume of that uncontracted regulated gas to be supplied under an agreement into which the supplier intends to enter in the 24 month period.

Chart 2.5 provides a comparison of the volumes of available uncontracted gas, as reported by producers, and the proportions of domestic demand that is currently uncontracted. This shows that a significant amount of contracting (254 PJ) needs to occur to ensure that sufficient gas is provided under contracts to meet domestic demand for C&I and residential users over the next two years. However, there is likely to be sufficient available gas (423 PJ) to meet total demand.[24]

Chart 2.5: Comparison of available gas and contracted amounts in 2024-25



Source: ACCC analysis of data obtained in October 2023 from producers, AEMO, Gas Statement of Opportunities, AEMO, 16 March 2023 and producer's websites.

Note: Forecast demand reflects C&I and residential demand from AEMO's 2023 GOO, Orchestrated Step Change scenario. Contracted supply to C&I and mass market users was reported to the ACCC by gas producers and retailers in August and October 2023.
Totals may not add up due to rounding.

24 The volumes of available gas reported by gas producers is for the 24-month period from September 2023. This does not align precise with forecast demand and contracted supply in 2024 and 2025. However, it is sufficiently close that it provides a useful indication of how much of this available gas may be required.

The available gas is from both domestic gas producers and LNG producers. A significant proportion (48%) of available gas is held by the LNG producers. It seems likely that available gas will also be offered to the LNG market if Heads of Agreement requirements are met. As outlined in Chapter 1, LNG spot and additional sales are anticipated to reach 83 PJ in 2024. A similar quantity of spot sales in 2025, assuming this will come from available gas, would leave only 257 PJ of gas to be contracted.

There are some caveats to the above. Although the ACCC uses its information gathering powers on a wide section of the market, we do not have information on quantities of contracted gas for all non-operating gas producers.[25] Those non-operating producers we do not have information for represent around 25 PJ of 2P production in 2024.[26] Therefore, our figures may understate the level of contracted gas.

[25] We seek information on gas production levels from all significant operating producers, however.

[26] It is not clear the quantity of contracted gas production we do not have visibility over in 2025 due to the way information we receive is aggregated.

3. Long-term supply outlook

Key points

- Australia is in a period of energy transition. Over the next two decades, while the economy reduces its reliance on coal, gas will continue to have a critical role to maintain power grid security. It will also remain important for large commercial and industrial users and support residential users as they gradually electrify their households.
- Ensuring the market supplies sufficient gas throughout the energy transition is important. The latest information suggests that the east coast gas market is likely to have sufficient supply to meet current forecasts of demand until 2028. After this time, additional sources of gas production and supply will be required, absent a significant change in demand.
- Nevertheless, the southern states will face significant gas supply shortages from 2027. In contrast, Queensland is expected to have sufficient gas to meet demand up until 2029. Therefore, gas transported from Queensland is expected to continue to play a critical role in covering potential supply gaps in the near term.
- This outlook is an improvement on previous forecasts, as the forecasted potential gas shortfall has been delayed by 1 year. The improved outlook is influenced by three key factors, including:
    1. Net increases in Surat and Bowen basin production forecasts of 94 PJ each year on average from 2027. However, production from these basins could be utilised for LNG export.
    2. Domestic demand declining as consumers transition to alternative fuels and renewables, in line with the governments commitments to reach net zero by 2050.
    3. Overall lower forecast LNG exports, especially lower forecast LNG spot sales during the expected shortfall years.
- A number of projects under development need to be completed in a timely manner to meet estimated production levels. This will facilitate between 10 PJ and 84 PJ per annum of gas production to the east coast gas market by 2028.
- Averting currently anticipated future gas supply shortfalls will likely require the development of new gas fields and pipelines and potentially LNG import terminals. There is a large volume of potential new projects that could deliver sufficient gas to meet gas demand over the next decade, especially if gas demand were to increase. However, these supply sources may be more speculative and expensive to produce and face significant risks. Continued market stability and investment is required to foster the timely development and completion of these projects.
- The Australian Government is developing the Future Gas Strategy to better understand the future demand for gas, and balance the needs of consumers, industry and future generations through the transition. It is expected to shine a light on the medium (to 2035) and long-term (to 2050) plan for gas supply and demand in Australia. This initiative complements the purpose of the Gas Market Code, to ensure users can contract for gas supply at reasonable prices and on reasonable terms. We anticipate that available gas committed by producers under the Code will be available from 2024.

- On the demand side, energy demand management solutions are needed over the longer-term. The ACT and Victorian Governments have restricted new gas connections in residential households to reduce gas dependency. However, technical and financial constraints remain key challenges and risks to achieving Australia's net-zero goals.

3.1. Introduction

This chapter provides an overview of the long-term outlook for supply and demand for the east coast market as a whole and for Queensland and the southern states.

Gas is expected to play an important role in supporting Australia's transition to renewables and will continue to be a critical part of the energy mix on the east coast. As highlighted by AEMO, some gas demand over the longer-term is expected to continue as gas is essential for power generation, industrial processes, and residential heating, especially in the south.

However, gas supply is forecast to decline faster than demand over the long-term. Our January 2023 interim report found that without increases to production above the declining levels currently forecast, gas shortfalls on the east coast can be expected from 2027. Continued investment in gas will be needed to ensure that supply does not fall below demand, particularly from non-conventional sources.

With the current forecast production falling faster than gas demand is reducing, the Australian Government is developing the Future Gas Strategy, to better understand future demand for energy, particularly gas, and balance the needs of consumers and industry through the energy transition.

Providing signals to key stakeholders, including Government and industry, about any potential deterioration in forecast supply will be important, especially to provide appropriate signals to governments to offer incentives for demand reduction and to prompt industry to bring new supply to market in a timely manner. The Gas Market Code (the Code) was also recently implemented with the purpose of facilitating a well-functioning domestic wholesale gas market with adequate gas supplies at reasonable prices and on reasonable terms for both suppliers and buyers.

The ACCC Gas Inquiry has also made several recommendations on reforms to reduce regulatory barriers to the efficient and timely development of new and diverse gas projects, including:

- removing moratoria and taking a case-by-case approach to approving new gas developments
- changes in government processes for releasing gas acreage and approving, monitoring and enforcing compliance with work programs
- 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
- facilitating a more coordinated approach to the planning of the pipelines required to bring new sources of supply to market and encouraging these pipelines to be developed through a competitive process and operated with third-party access.

In this chapter, we report on:

- the long-term market outlook, including the impact of LNG producers
- demand on the east coast, in the context of the energy transition
- forecast production, including new gas supply sources coming online by 2028
- government initiatives to facilitate supply on the east coast.

3.2. Long-term market outlook

This section sets out the long-term supply outlook for the east coast gas market for the period between 2025 to 2035.

Our short-term supply-demand outlook in Chapter 1 shows that the east coast is expected to have sufficient supply to meet forecast demand in 2024. Over the longer-term, our latest analysis indicates that the east coast gas market is expected to dip into a 23.7 PJ shortfall in 2028 (assuming LNG producers export only the spot sales that are currently anticipated).

The last time we reported on the long-term outlook was in the January 2023 interim report. At the time, we observed a deteriorating outlook with supply shortfalls expected unless new supply was brought online, with a supply shortfall on the east coast expected to emerge by 2027. The latest information represents an improvement on our last update, delaying the potential shortfall by a year.

While the overall east coast is expected to have sufficient gas to meet customer demand until 2028, the southern states is a different story. The southern markets are expected to dip into a shortfall in 2024, and remain in a finely balanced surplus until 2027, where there is expected to be a sharp decline in gas supply.

There remains some uncertainty around the timing and extent of potential shortfalls in the east coast. In the near term, the decisions of LNG producers on whether to sell uncontracted gas as spot and additional LNG cargoes could affect when domestic gas shortages occur. However, over the longer-term, meeting the needs of gas users through the energy transition on the east coast will require the development of new gas supply sources. This is considered throughout this chapter.

Box 3.1: Sources of supply and demand data

The supply and LNG demand data used in this chapter was obtained directly from producers in response to compulsory information notices issued in August 2023.

Producers provided forecast production quantities from developed and undeveloped 2P reserves, possible reserves, contingent and prospective resources and forecast flows from the Northern Territory into Queensland. The LNG producers also provided forecast estimates of LNG export demand under long-term supply agreements and projected LNG spot or additional sales.

The long-term supply outlook includes forecast production from the Bowen (including the north Bowen), Surat, Galilee, Cooper, Gippsland, Bass, Otway, Gunnedah and Sydney basins. Production from the Northern Territory is included via expected flows from the Northern Territory into the east coast.

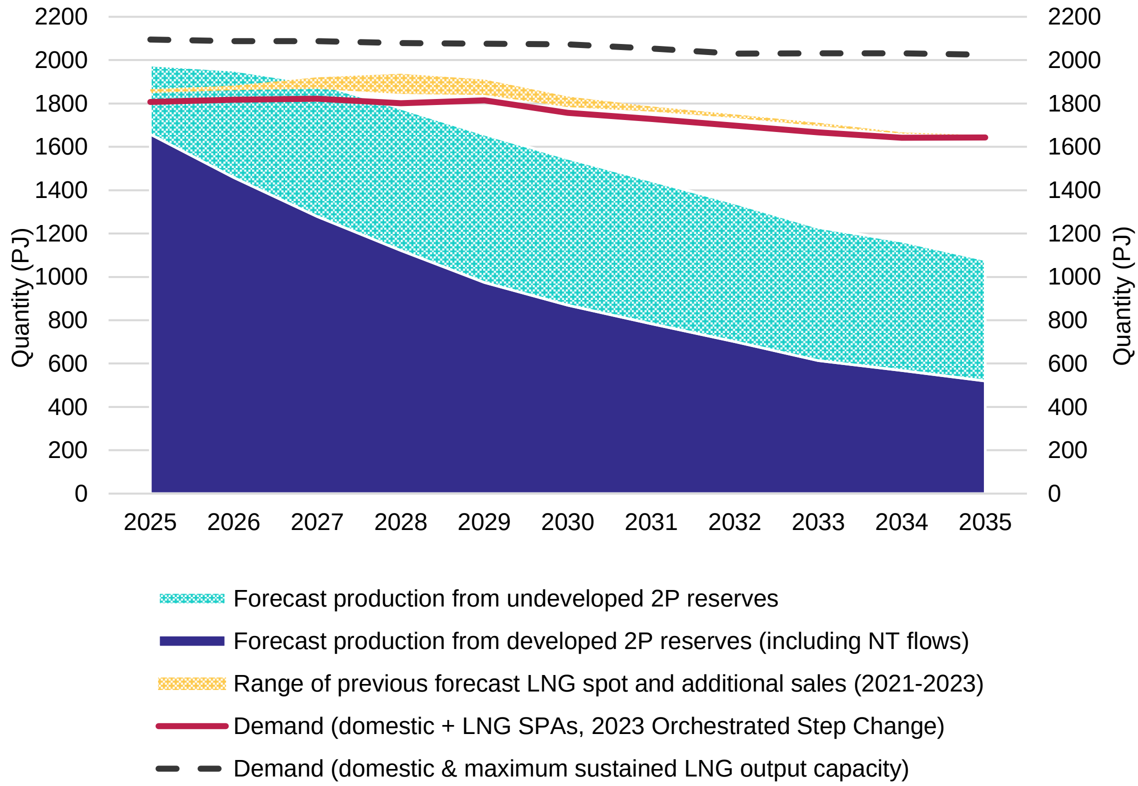
The domestic demand forecast used for the long-term outlook is based on AEMO's March 2023 Gas Statement of Opportunities (GSOO). We have adopted the Orchestrated Step Change scenario for our analysis of domestic demand on the east coast. Forecasts are broken down by state and by the source of demand, namely residential and commercial demand, industrial demand, and gas powered generation (GPG) demand.

In addition to information on long-term supply and demand, this chapter contains insights into the experiences of commercial and industrial (C&I) users relating to supply. We collected this information through surveys and in bilateral meetings with C&I users. This information is detailed in Box 3.2.

3.2.1. Gas shortfalls forecast on the east coast from 2028

Chart 3.1 shows the long-term demand and supply outlook for the east coast gas market, with supply including only production from developed and undeveloped 2P reserves. Production from 2P reserves has substantially improved since we last reported in the January 2023 interim report and is expected to be sufficient to meet projected domestic demand and LNG export demand (including spot and additional cargoes) until 2028.

Chart 3.1: Forecast supply from 2P reserves and demand in the east coast, 2025–35



Source: ACCC analysis of data obtained from gas producers as at September 2023 and domestic demand from AEMO's March 2023 GSOO.

Notes: Export demand includes feed gas requirements (such as fuel) required to produce LNG. Forecast spot and additional LNG sales represent flexible quantities that, if produced, could be exported, placed into storage, or sold to the domestic market. The maximum sustained LNG output capacity is based on the present point in time and does not account for potential unplanned maintenance, aging of facilities, changes in CSG feedstock or other factors that may affect capacity over the period.

The outlook to 2030 has improved in comparison to forecasts reported on in previous years. The 3 key factors contributing to this change are:

- increased forecast gas production in the Surat, Bowen and Cooper basins (see Chart 3.7 in section 3.4)
- decreased forecast domestic demand (down 20 PJ on average between 2025 and 2030 from the 2022 Progressive Change scenario, see Chart 3.6 in section 3.3)
- decreased forecast exports from LNG producers, including significant reductions in forecast LNG producer spot cargoes and additional gas.

The significant reduction in expected LNG spot and additional sales may have a material impact on the supply-demand balance on the east coast, as more gas may be expected to be available to the domestic market. Chart 3.1 shows the range of total forecast spot and additional LNG sales (minimum and maximum) as reported to us since 2021. This shows that, if LNG producers exported the maximum that they had previously anticipated, the east coast market would experience a shortfall of 28 PJ in 2027 and 160 PJ in 2028. These anticipated shortfalls have now reduced significantly.

This demonstrates that the east coast market outlook is sensitive to changes in domestic gas demand, new gas supply continuing to come online and the decisions of LNG producers to export gas. As we discuss further in this chapter, meeting the needs of energy consumers and industry through the transition will require sufficient gas to be produced and supplied to the domestic market at reasonable prices. While there is expected to be sufficient gas to meet demand in the medium term, over the longer-term gas may be required from new, more uncertain sources of production or from alternative avenues such as the proposed LNG import terminals.

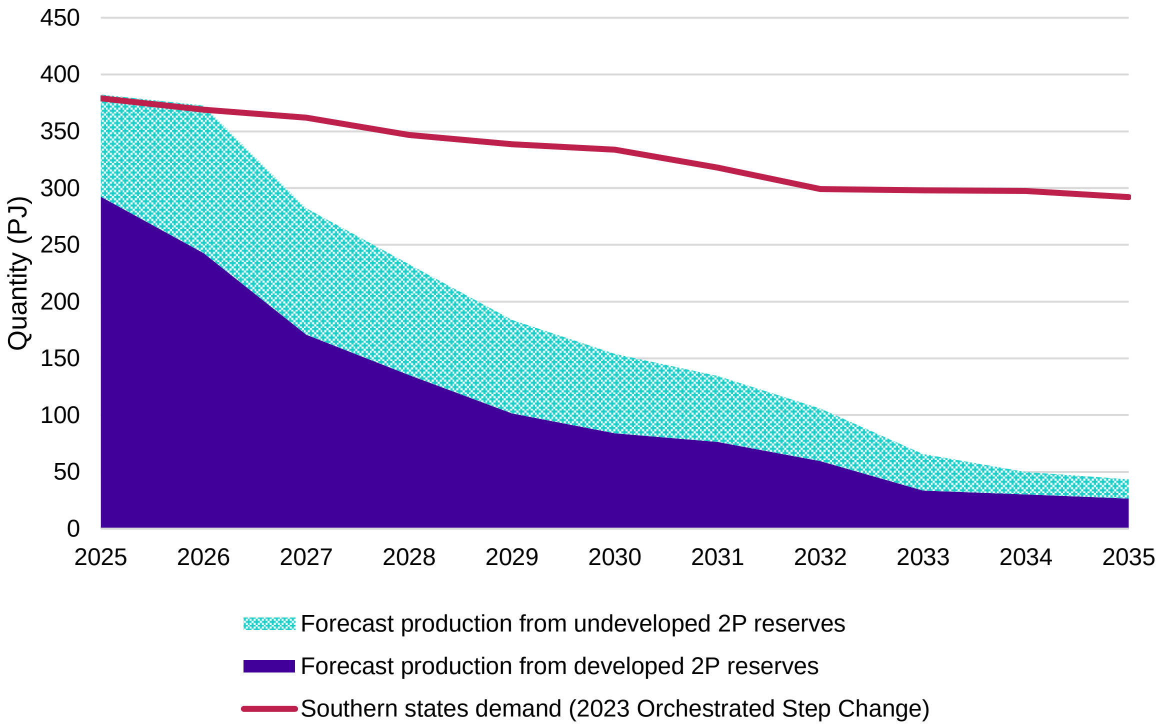
3.2.2. Southern states may experience material shortfalls from 2027

The east coast gas market is typically broken into two separate regions — Queensland and the southern states (Victoria, NSW, South Australia and Tasmania).

While the east coast is expected to have sufficient gas to meet demand until 2028, the southern states is expected to dip into a shortfall in 2024, and remain in a finely balanced surplus in 2025 and 2026 before declining into a shortfall from 2027 onwards.[27] As shown in Chart 3.2, the southern states are projected to face a supply shortfall of 2P reserves of around 80 PJ in 2027, growing to 250 PJ in 2035.

[27] Chapter 1 discusses supply dynamics in southern states, including the impact of supply flowing from the Cooper basin.

Chart 3.2: Forecast supply and demand in the southern states, 2025–35



Source: ACCC analysis of data obtained from gas producers as at September 2023 and domestic demand from AEMO's 2023 GSOO.

Note: This chart includes forecast production from developed and undeveloped 2P reserves in the Gippsland, Bass, Otway, Sydney, Gunnedah and Cooper basins.

In contrast, the supply and demand outlook is more favourable in Queensland than it is in the southern states. In Queensland, production from 2P reserves are expected to be sufficient to meet forecast domestic demand and long-term LNG export demand until 2029–30. It is the production from Queensland that is contributing to the overall east coast market surplus in the near term.

As discussed in Chapter 1, gas is regularly transported from Queensland to the southern states to meet gas supply shortfalls.[28] This is typical during the winter months where in the southern states an increase in gas demand from residential heating exceeds the amount of gas produced. As reported by AEMO[29] and previous Gas Inquiry reports,[30] the southern states require gas to be withdrawn from storage and transported from Queensland to meet the spike in demand during winter.

In the next few years, it is likely that Queensland producers will be relied upon even more to cover southern states shortfalls, which are expected to occur from 2027 (or sooner given the finely balanced outlook in the southern states). This additional gas may be required only during winter or there may be emerging gas shortages during warmer months depending on domestic demand and southern production.

---

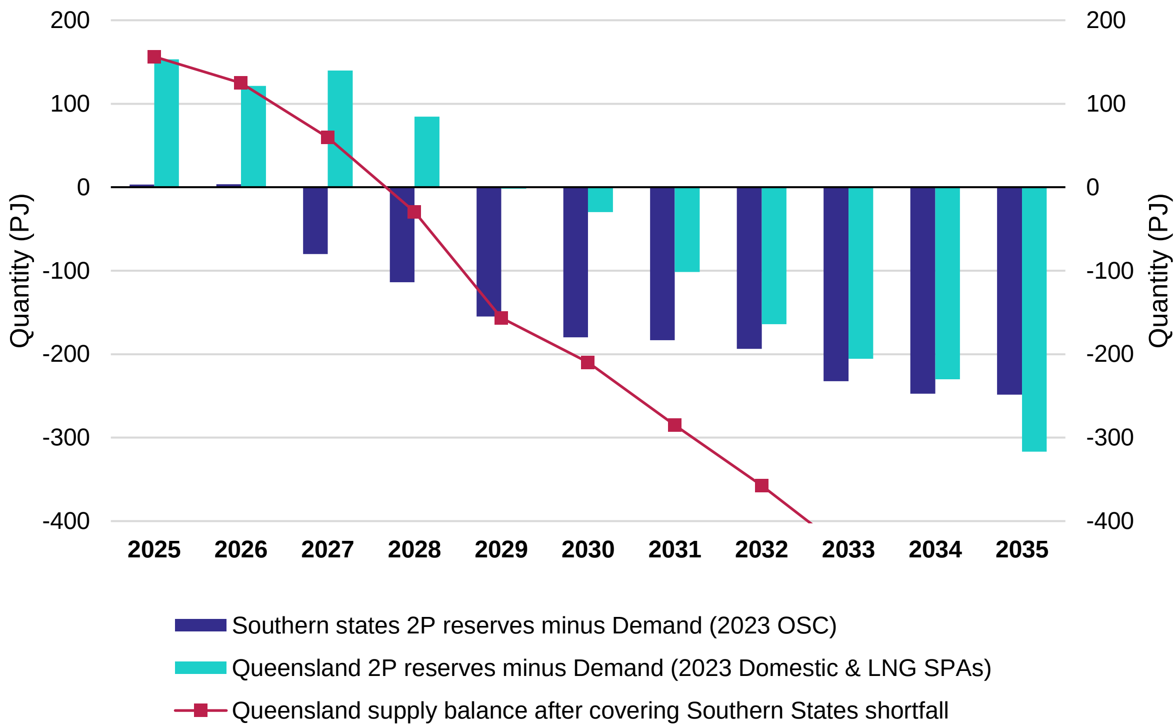
28 Appendix A of this report provides information about firm transport and storage prices.

29 AEMO, [Gas Statement of Opportunities](), AEMO, April 2023, p 72.

30 ACCC, [Gas Inquiry 2017 - 2030 interim report](), ACCC, June 2023, p 27.

Chart 3.3 shows the impact of a heavy reliance on gas transported south. Queensland's independent outlook shows a significant surplus until 2028. If this gas is transported to the southern states, the southern states shortfall can be delayed by one year.

Chart 3.3: Regional Supply Outlook for 2025 – 2035



Source: ACCC analysis of data obtained from gas producers as at September 2023 and domestic demand from AEMO's 2023 GSOO.

As there is a substantial amount of gas that will need to be transported from 2027, it is essential that pipeline infrastructure has sufficient capacity. Analysis of pipeline capacity and expected flows suggest that there is sufficient pipeline and storage capacity to transport 97 PJ[31] of Queensland gas to meet the southern states shortfall during the winter peak demand periods (i.e. May to September).[32] The magnitude of the remaining shortfalls will depend on whether LNG producers sell spot and additional LNG cargoes (and how much), which is discussed in the next section.

In the long-term, the reduction in supply from 2P reserves will lead to gas supply shortages in both the southern states and Queensland. As we discuss in section 3.4, additional new supply will need to come from:

- the development of possible reserves, contingent and prospective resources in the Bowen, Surat, Galilee, Cooper, Gippsland, Bass, Otway and/or Gunnedah basins
- the development of one or more LNG import terminals in the southern states.

---

31 This is calculated by adding the capacity available through the Moomba Sydney Pipeline (MSP), 512 TJ/day for 153 days (1 May to 30 September), approximately 78 PJ, and the nameplate capacity of Iona underground gas storage less its cushion level, approximately 19 PJ.
Note the MSP is selected rather than the South West Queensland Pipeline (SWQP) as there is production in Moomba that the SWQP pipeline capacity does not account for while the MSP capacity does.

32 AEMO, Gas Bulletin Board - Reports, accessed 31 October 2023.

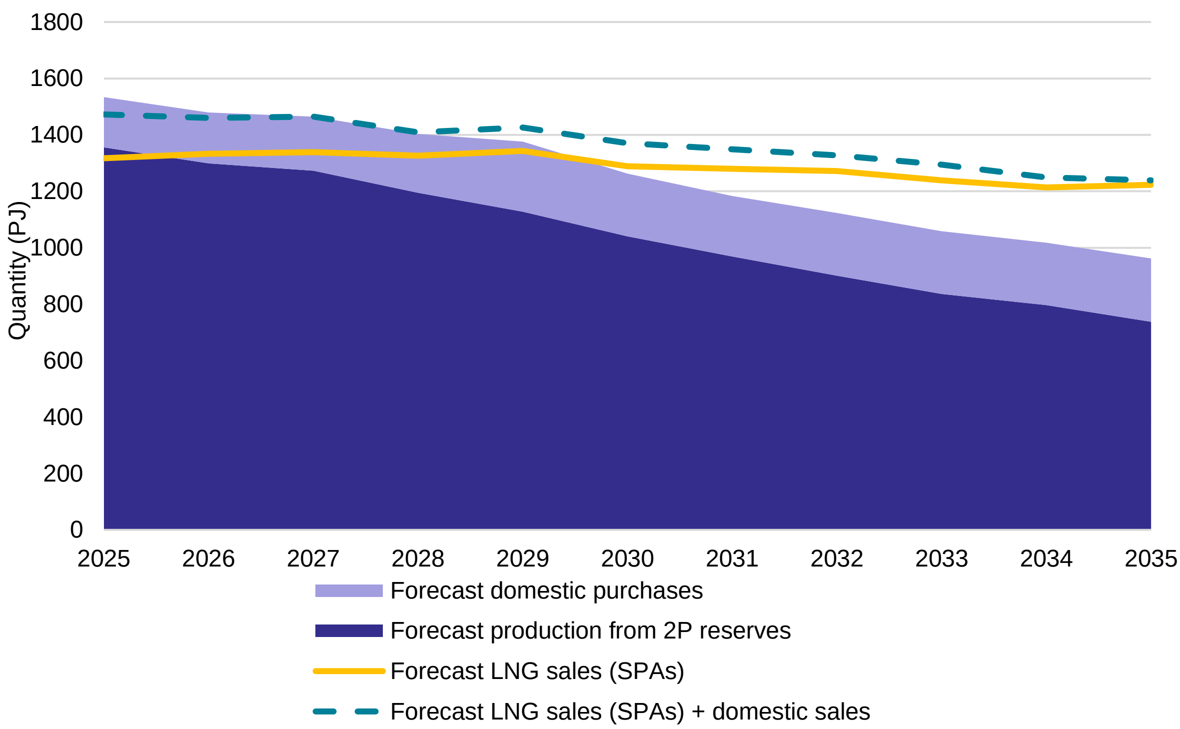
It may also be necessary to divert some of the gas that would otherwise be exported as LNG into the domestic market if new supply in the south cannot be developed rapidly enough to meet demand. The Code and LNG producer Heads of Agreement (HoA), which require LNG producers to offer uncontracted gas to the domestic market first on internationally competitive market terms before it is exported, is likely to have some influence on behaviour and incentives. The role of the LNG producers in the market is discussed below.

3.2.3. LNG producers are forecasting less uncontracted gas

The Queensland LNG producers' actions and any uncontracted gas in their possession have been important to meeting the needs of domestic gas users. LNG producers and their associates have influence over nearly 90% of the 2P reserves on the east coast.[33] However, LNG producers have committed under the HoA to offer to the domestic market any uncontracted gas they have. Any excess uncontracted gas not sold to the domestic market can then be exported as spot cargoes or additional sales.

Chart 3.4 shows this long-term position of the LNG producers, including their combined production from 2P reserves, purchases and sales from the domestic market, and sales under long-term LNG SPAs. The LNG producers will have uncontracted gas where forecast production and domestic purchases are greater than forecast domestic sales and LNG SPA exports.

Chart 3.4: Long-term position of the Queensland LNG producers



Source: ACCC analysis of data obtained from gas producers as at September 2023.

The above chart shows that most of the LNG producers' gas is forecast to be sold domestically and into international markets under long-term contracts (SPAs). However,

[33] ACCC, *Gas Inquiry 2017 - 2030 interim report*, ACCC, July 2022, p 93.

excess gas can be sold into the domestic market or the international market as LNG spot or additional cargoes. Over the past five years, LNG producers have produced excess gas and sold it into the domestic market, as well as international markets. The gas sold into the domestic markets have helped avert domestic gas shortfalls, including most recently in 2022.[34]

In our January 2023 report, we forecast that LNG producers would collectively continue to have uncontracted gas available to be offered to the domestic market until 2028. This provides the east coast market with an option to avert domestic gas shortfalls.

However, the latest information suggests that the LNG producers now expect to only have excess uncontracted gas available until 2026.[35] As shown in Table 3.1, the total volumes of uncontracted gas expected to be available for LNG producers from 2025 onwards have reduced since we previously reported in the ACCC's Gas Inquiry January 2023 interim report.

Table 3.1: Uncontracted gas available by Queensland LNG producers, PJ

Quantity (PJ)	2025	2026	2027	2028	2029	2030	2031	2032	2033	3034
December 2023	61	20	-1	-6	-50	-107	-166	-204	-235	-232
January 2023	86	70	28	54	-10	-80	-137	-191	-243	-251
Difference	-24	-50	-29	-60	-40	-27	-29	-13	8	19

Source: ACCC analysis of data obtained from gas producers as at September 2023.

Note: Uncontracted gas is calculated as the difference between gas supply available to LNG producers (from 2P production and domestic purchases) minus contracted demand from LNG exports and domestic contracts. LNG producers' uncontracted gas is negative where they are forecasting insufficient gas supply to meet contracted demand.

The decline in anticipated uncontracted gas is due to:

- increases in contracted LNG export demand by some LNG producers
- decreases in production by some LNG producers in the near term
- material decreases in forecast purchases of gas from domestic third parties.

In addition, as mentioned in section 3.2, the latest information indicates the LNG producers have significantly reduced their expected spot and additional LNG sales.

The impact on the east coast market from the reduction in the LNG producers' forecast uncontracted gas is unclear. However, it suggests that there is less gas available from the LNG producers which could be diverted into the domestic market to fill an unexpected increase in domestic demand. On the other hand, reductions in gas purchased from domestic third parties may mean more gas is available to the domestic market from providers other than LNG producers.

The observed changes in uncontracted gas volumes may reflect the current market uncertainty due to government policies and new regulatory measures. The effect of these changes may take time to settle. For example, the introduction of the Code may result in LNG producers redirecting gas earmarked for LNG spot sales to the domestic market and/or developing additional supply for domestic consumption as part of their supply commitments.

[34] ACCC, *Gas Inquiry 2017 - 2030 interim report*, ACCC, June 2023, p 30.

[35] This is in aggregate across the three LNG producers. Individual producers have uncontracted gas available.

While we would expect the continual development of new production, the quantity of additional gas to be produced from existing supply sources is unlikely to replace the need to develop new sources of production. This is clear given that LNG producers are currently not expecting to produce or purchase sufficient volumes of gas to meet their long-term contractual commitments. This is evident by the volumes of negative uncontracted gas shown above.

3.3. Gas demand on the east coast

3.3.1. The long-term role of gas on the east coast

Gas will continue to play a critical role as a flexible and dependable source of energy as Australia transitions to renewable sources of energy.

AEMO reported that 'Gas-fired generation will play a crucial role as coal-fired generation retires. It will provide essential power system services to maintain grid security and stability, particularly following unexpected outages or earlier than expected generation withdrawal. This critical need for peaking gas-fired generation will remain through to 2050'.[36]

However, there is significant uncertainty surrounding the extent of natural gas demand over the longer-term, with demand sensitive to a number of factors. These include:

- weather, especially in cold months where gas demand increases for space heating
- speed of electrification and development of alternative fuels
- unplanned outages requiring gas power generation to cover the firm capacity in the event of a prolonged outage, and particularly where wind and solar generation is insufficient to meet demand
- the strength of the economy affects the natural gas market as well. During periods of economic growth, increased demand for goods and services from the commercial and industrial sectors can lead to increased natural gas consumption.

The Future Gas Strategy is intended to understand the future demand for gas, and balance the needs of consumers, industry and future generations through the transition. This includes strategies to maintain Australia's international reputation as a trusted energy supplier, given there will be long-term export demand due to existing long-term contracts, but also ongoing demand for natural gas within the Asia-Pacific region.

The Future Gas Strategy also suggests gas consumption will decline, due in large part to policies promoting clean energy and energy efficiency. These policies include:

- The Victorian Government ban on new gas connections for all residential construction from 1 January 2024.[37] This policy was introduced as part of Victoria's energy reform towards net zero commitments, and to assist in accelerating the state's transition to renewables. This will limit the growth in residential demand and lead to a reduction in gas consumption over time as appliances associated with new builds are electrified.

---

36 AEMO, *2022 Integrated System Plan*, AEMO, June 2022, p 11.

37 Department of Transport and Planning, *Victoria's Gas Substitution Roadmap*, Victorian State Government, September 2023.

Victoria currently has the highest use of residential gas in Australia with 80% of all households connected to gas.[38]

- The ACT Government implemented a similar ban on new gas connections in newly constructed homes from 1 January 2024.[39] This supports existing policies to reduce emissions. Currently, two-thirds of Canberra homes use natural gas for any combination of space heating, water heating and cooking.[40]
- Some councils in Sydney, NSW are in the process of updating relevant planning rules to require all new residential and non-residential development applications to be all-electric.[41] However, a ban on new gas connections is not enforceable, as NSW laws prevent councils from introducing planning controls that set higher environmental requirements than are in place at a state level.[42]

AEMO reported that 'while gas volumes may decline, the key role for gas generation will be to provide flexible and firm electricity supply, albeit less frequently than historically, but with greater importance to maintain National Electricity Market (NEM) reliability'.[43] Natural gas will also be needed by C&I users for industrial processes into the foreseeable future (see Box 3.2).

Box 3.2: Some C&I users are considering decarbonisation pathways that will involve a transition from gas, but in the short-term may result in increased gas demand.

A number of users who responded to our survey told us that they are considering different options to decarbonise their operations to meet their internal sustainability targets.

Most of these users operate in industries that are difficult to abate, with no ready or viable substitutes to natural gas. Several of these emphasised that gas currently remains essential as their plants and equipment are reliant on gas and they typically face long-term investment cycles, with significant investment required to utilise alternative energy sources (if they were financially viable).

Some users told us that it is not viable to shift away from gas immediately. Other users told us that meeting their internal sustainability targets may result in higher gas demand for a period as they substitute away from more carbon intensive energy sources (such as coal). While this may increase demand in the short-term, these users told us they are continuing to explore alternatives to natural gas, that may result in lower gas demand in the medium term.

For example, a large manufacturer told us that prior to electrifying or switching to green hydrogen, it would need to upgrade its furnaces to use natural gas only (rather than natural gas and coal as is currently the case). The user expects this will increase its gas usage in the near term, however subsequent upgrades aim to reduce future gas usage on net.

The potential for some C&I users' gas demand to increase as a result of their decarbonisation efforts is consistent with AEMO's Orchestrated Step Change scenario

38 Premier of Victoria, *New Victorian Homes To Go All Electric From 2024* [media release], Victoria State Government, 28 July 2023.

39 ACT Government, *ACT Pathway to electrification* , ACT Government, 2023.

40 ABC News, *No new gas connections for ACT homes and businesses from 2023 under plan to phase out fossil fuels*, 4 August 2023.

41 AFR, *Sydney may ban gas for new homes*, 22 August 2023.

42 The Guardian, *City of Sydney wants to ban gas in new builds – can it do it and is it worth it?,* 25 August 2023.

43 AEMO, *Gas Statement of Opportunities*, AEMO, April 2023, p 23.

(discussed in the next section). Over the longer-term, however, C&I users expect gas demand to fall as they switch to substitutes.

As a number of users pointed out, future adoption of alternative fuels will ultimately depend on the technical and commercial feasibility of these fuels for individual users. The commercial feasibility will, in turn, depend on the cost of the alternative fuels (compared to natural gas) and whether they can obtain carbon credits and meet any requirements with respect to carbon credit schemes. As the 'incumbent' fuel for many users, the price and availability of gas will affect the commercial viability of alternative fuels.

The key alternative fuels that C&I users told us they are considering are biogas, biomethane and hydrogen.

Biogas and biomethane

Biogas and biomethane have a similar specification to natural gas and are therefore substitutable for gas in most users' existing processes.

Some users told us that they currently consider that biomethane is more likely to be financially viable for their operations than hydrogen, because it can be used in existing facilities and has lower production costs. A C&I user observed that for their operations:

> 'We are focused on biomethane opportunities because it is commercially viable today, unlike green hydrogen, which has an extremely high production cost and is uneconomic in the foreseeable future.'

Another user, however, noted that biofuels are not currently viable for its operations because the quantity of fuel stock required is very large and the 'set up required to use alternative fuels is cost and space prohibitive' for 'behind-the-meter' projects (i.e. projects located at a user's site).

Hydrogen

Users that responded to our survey generally agree that the timelines to transition to hydrogen (or blended hydrogen products) are longer than those for biomethane, to 2030. Those users who are pursuing hydrogen projects, or have considered the use of hydrogen, told us that decarbonisation objectives have been the primary driving factor.

3.3.2. The demand forecast we have relied upon in this report

The domestic demand forecast used in this chapter is based on AEMO's 20-year forecasts provided in the GSOO.[44] We have adopted the Orchestrated Step Change scenario for our analysis. The scenario factors in:

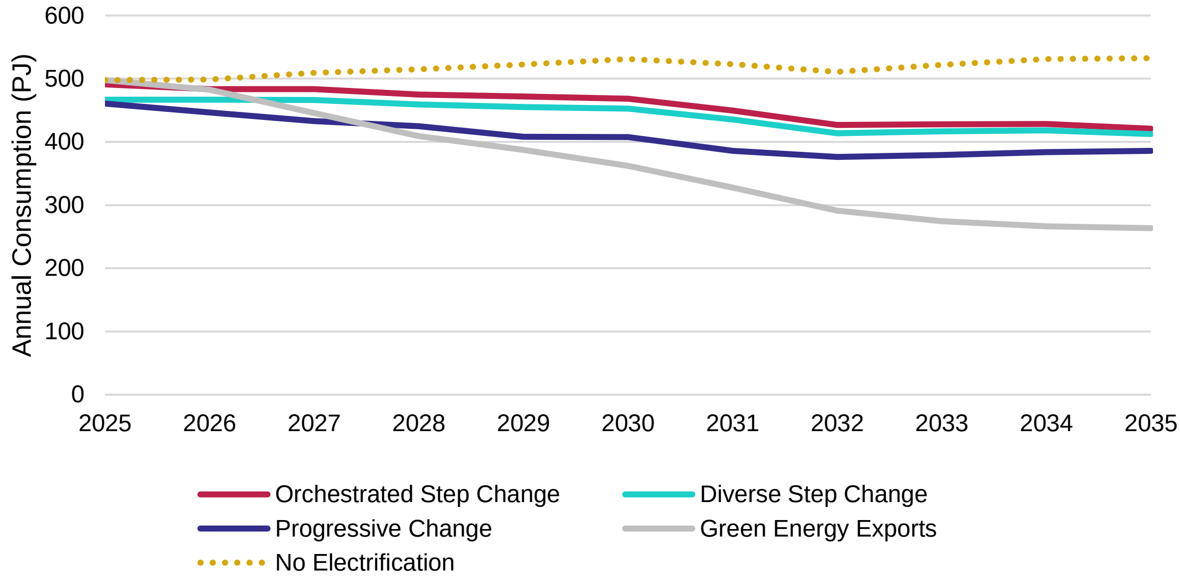
- moderate economic growth, as well as projected growth in population and gas connections on the east coast
- the Government's net zero commitments being achieved over the long-term.

To achieve this, AEMO assumes gas consumers take up opportunities to reduce their emissions through electrification where technically practical and financially feasible.

For illustrative purposes, the different forecast demand scenarios contemplated in AEMO's 2023 GSOO are shown in Chart 3.5.

[44] AEMO, *Gas Statement of Opportunities*, AEMO, April 2023.

Chart 3.5: Domestic demand scenarios and sensitivities in the 2023 GSOO



Source: AEMO 2023 GSOO.

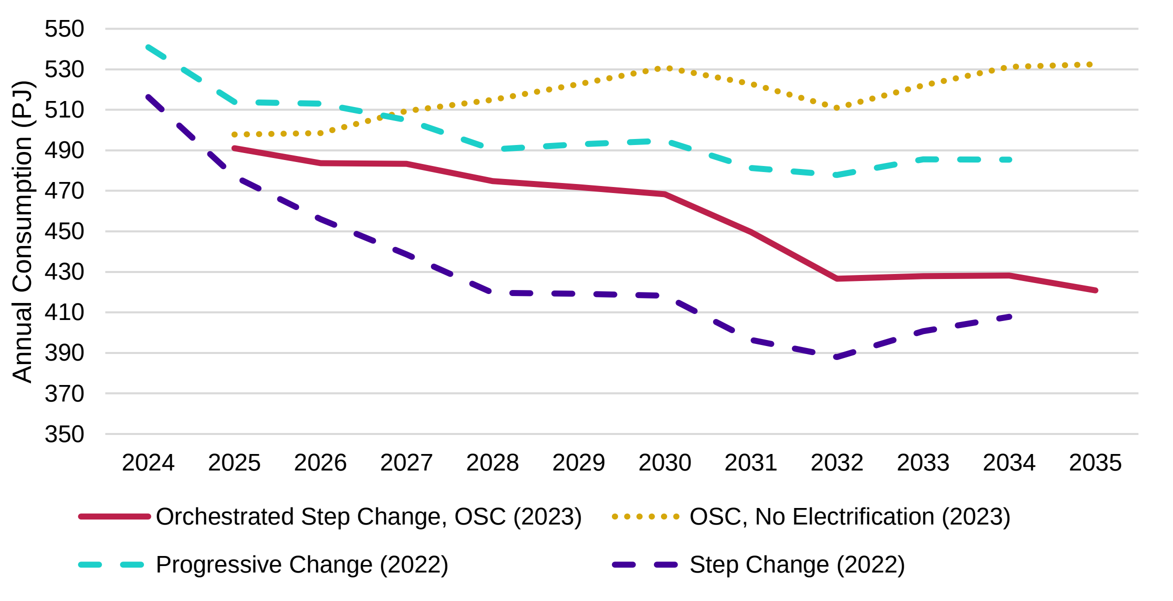
There are substantial differences between projections in different AEMO demand scenarios, reflecting some uncertainty about drivers of future gas demand. However, the scenarios diverge substantially as soon as 2026, with a difference in domestic demand of around 157 PJ by 2035 between the Orchestrated Step Change and Green Energy Exports scenarios.

AEMO also examined the possible impact of a halt to current and future forecast electrification, primarily to model the potential influence of slower electrification on gas adequacy, and this is presented as the Orchestrated Step Change - No electrification sensitivity. The difference in forecast demand between the Orchestrated Step Change, no electrification sensitivity and Green Energy Exports scenarios is as much as 269 PJ per year by 2035.

Box 3.3: Contrasting Orchestrated Step Change scenario against domestic demand scenarios used in previous reports

In our January 2023 interim report, we used the Progressive Change and Step Change scenarios in AEMO's 2022 GSOO for estimates of domestic demand.[45] These are shown in Chart 3.6 as the dashed lines and the Orchestrated Step Change demand scenario used in this chapter is shown as the solid line.

Chart 3.6: AEMO 2022 GSOO scenarios against 2023 GSOO scenarios



The 2023 Orchestrated Step Change scenario falls between the 2022 Progressive and Step Change projections. The difference between the Orchestrated Step Change and Progressive change scenarios is around 20 PJ per year until 2030.

We consider AEMO's GSOO forecasts to represent the best continuation of observed trends. All demand forecasts have a degree of uncertainty, as demand is driven by several factors including population growth and economic growth. However, we see the Orchestrated Step Change representing a conservative view which does not anticipate significant demand destruction driven by external economic forces.

3.4. New supply continues to come online, while some gas projects are delayed

The improvement in the market outlook has been partially driven by increases in forecast gas production. This section:

- discusses the changes in forecast developed and undeveloped 2P production since we previously reported
- provides an overview of the new supply projects that are expected to come online in the next 5 years, despite some projects being delayed.

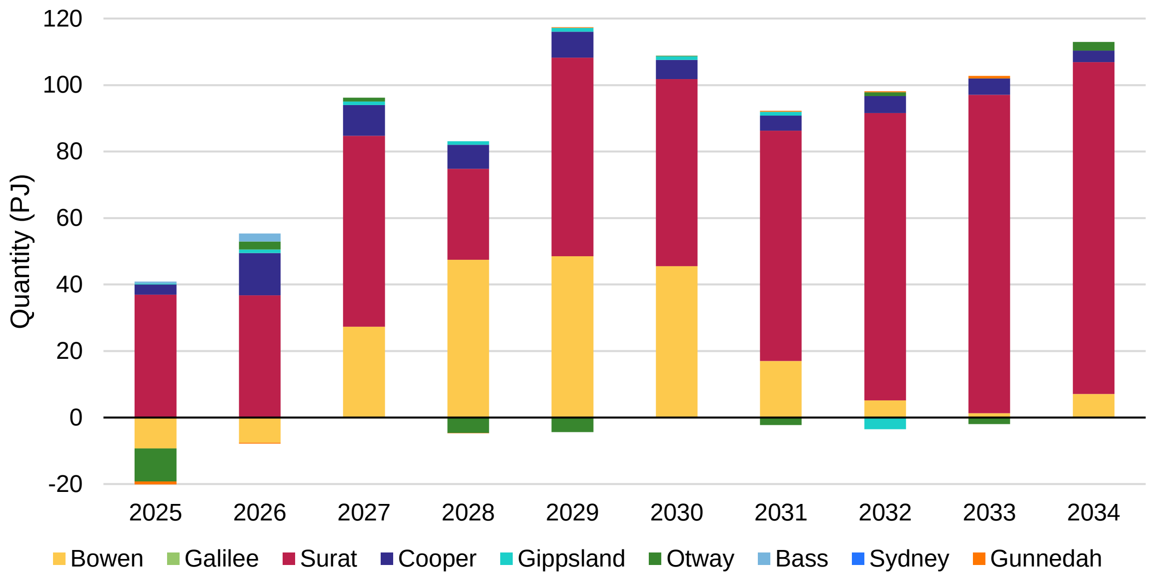
45 AEMO, *Gas Statement of Opportunities*, AEMO, March 2022.

3.4.1. Increased production in Surat, Bowen and Cooper basins

The latest information suggests that production from 2P resources is expected to increase over the next decade. This is based on information collected from producers in August 2023 and compares to the forecast production we reported in January 2023.

Chart 3.7 shows the net change in 2P production by the basin in contrast to the January 2023 interim report. The key drivers of the improved forecasts are projects in the Surat, Bowen and Cooper basins which are forecast to bring substantial additional volumes online by 2035. The net change in production on the east coast overall is around 1.2% in 2025 and continues to increase to around 7% by 2030.

Chart 3.7: Sources of new supply, net change by basin, 2025-34



Source: ACCC analysis of data obtained from gas producers in August 2022 and August 2023.

While production forecasts have improved, increased production forecasts have tended to be reported by Queensland producers that have links to LNG export projects. This suggests that any increase in production may be earmarked to fulfill long-term SPA or spot and additional LNG sales, especially as production from LNG producers' existing fields declines.

The latest information indicates that domestic only production has not increased materially, rather it has decreased, as seen in forecasts for the Victorian Otway and Gippsland basins.

Box 3.4: Gas flows from Victoria into Queensland in 2022

LNG producers account for the largest source of demand in the east coast gas market. They source gas by:[46]

- producing their own gas in the Surat and Bowen basins in Queensland
- buying gas from other producers who operate in the Surat and Bowen basins
- buying gas from producers who operate in the Cooper basin
- buying gas from retailers who source gas from other producers.[47]

Gas produced in Victoria represents the only other[48] current source of supply in the east coast market.

However, the Petroleum Legislation Amendment Act 2020 restricts the sale of Victorian gas to LNG producers as well as to 3rd parties who onsell for non-domestic use.[49]

Our June 2023 report highlighted that in 2022 net northward flows of gas from Victoria occurred from January into May.[50] We stated that Victorian gas was transported into Queensland to meet LNG producer and domestic demand.[51]

However, sufficient gas was produced in the Cooper Basin over the same period[52] to account for all flows into Queensland.[53] As well, New South Wales and South Australia had domestic demand.

Considering the legislation cited above and the alternative sources of supply available to LNG producers, we find it unlikely that LNG producers utilised gas produced in Victoria for export. It is more likely that northward flows of Victorian gas were transported to New South Wales, South Australia and Queensland to meet domestic demand.

The improved outlook relies heavily on 2P undeveloped reserves which in some cases are yet to receive investment approval and the necessary regulatory approvals to begin production. Developments are often stalled or delayed by geological, technical, financial, and/or regulatory factors. We discuss the impact of these factors in the two case studies on new supply sources in Boxes 3.5 and 3.6.

Despite these challenges, producers have continued to make investment decisions over time and there is a pipeline of new gas supply sources coming online. Chart 3.8 shows the change in the profile of forecast 2P production on the east coast. This suggests that continual exploration and development of gas fields is occurring and supply in the near term, while tight in some years, may not be as alarming as initially expected.

---

46 Analysis of ACCC data provided by producers and retailers relating to production and contracted sales data.

47 All retailers who are contracted to supply to LNG producers source a portion of their portfolio from Queensland and/or the Cooper Basin.

48 Around 1 PJ is produced in NSW each year however, this is a nominal amount and not included as a source of LNG supply.

49 Petroleum Legislation Amendment Act 2020 (Vic), clause 152A.

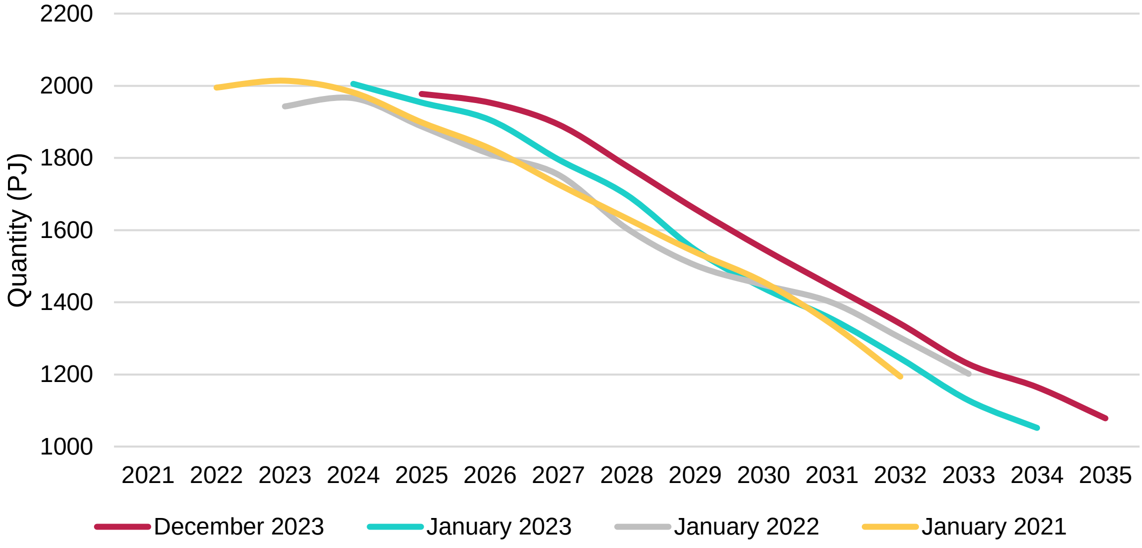
50 Observing net northward pipeline flows into May is counter trend, as gas is usually observed to start flowing south to meet seasonal winter demand by then.

51 ACCC, *Gas Inquiry January 2023 interim report*, Gas Inquiry 2017–2030, ACCC, January 2023, p 67.

52 ~28 PJ were quoted as flowing into Queensland for the period January to May 2022. Over this same period 33.5 PJ were produced at Moomba. Data extracted from AEMO, *Gas Bulletin Board*, AEMO, accessed 27 October 2023.

53 AEMO, *Gas Bulletin Board*, AEMO, accessed 27 October 2023.

Chart 3.8: Change in forecast 2P (developed and undeveloped) production over time.



Source: ACCC analysis of data obtained from gas producers as at September 2023.

3.4.2. Major projects expected to come online in the next 5 years, included in the long-term forecast (and delays)

The forecast production over the next decade is expected to come via gas fields currently in production and from which there are substantial reserves. There are also new projects under development that are expected to come online in the next 5 years and contribute to the increase in forecast production we have observed in this report.

This section provides information on the new projects that are included in the total forecast production across the east coast. This gives insights into the location and timing of these projects, as well as the risks associated with bringing new gas to market. This is based on information collected from producers in August 2023.

Table 3.2 provides a snapshot of the domestic supply projects that are not yet in production, but which producers have approved for development and anticipate will be brought online in the next 5 years. 7 projects were reported to us as approved for development. These projects have an estimated combined production amount of 10 PJ per annum anticipated to be available to the east coast gas market by 2025.

Table 3.2: New gas fields 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	0.40	C
Surat Basin							
QGC	PL 1008	0	0	1	2024	0.05	G
QGC	Goog-a-Binge	3	5	0	2025	0.15	C
Arrow	Surat Gas Project	1649	1658	1	2025	1.34	R, L, T&D, I
Otway Basin							
Beach	Enterprise	96	121	-	2024	6.4	R, T&D
Cooper Basin							
Vintage	Vali	101	210	-	2023	1.00[54]	C
Vintage	Odin	-	-	38	2023	1.00[55]	C
					Total	**10**	

Source: ACCC analysis of data obtained from gas producers as at August 2023. All volumes and dates reflect estimates only and can be impacted by a range of factors including key risks.

Note: Totals rounded.
Production from these projects are not additional to our current long-term supply forecast, as annual production amounts have been attributed to these projects within the forecast.
Key risks: **C** = Commercial factors. **G** = Geologic, i.e. gas geology and ease of extraction. **R** = Regulatory approvals, including state and federal. **L** = Land access. **T&D** = Timing and delays. **I** = Infrastructure.

The total production forecasts include a further 7 developments that are expected to bring additional supply to market and these are summarised in table 3.3. These have not yet reached a final investment decision and as such are not approved for development. If committed to and successfully brought online, they will contribute an estimated 84 PJ per annum to the east coast market by 2028, however may face higher risks to being realised.

54 Vali field successfully delivered first gas in 2023. However, the field is still in appraisal stage and the quoted production volume is not indicative of future annual production.

55 Odin field successfully delivered first gas in 2023. However, the field is still in appraisal stage and the quoted production volume is not indicative of future annual production.

Table 3.3: New gas fields with 2P reserves 'not approved' for development with estimated annual production accounted for in the long-term supply forecast.

Supplier	Project or field	Reserves (PJ) 2P	Reserves (PJ) 3P	Resources (PJ) 2C	Final investment decision	Supply year	PJ/ pa	Key risks
Bowen Basin								
Comet Ridge	Mahalo North	43	110	-	2024	2026	4	F, P, R
Blue Energy	Sapphire	66	253	214	2025	2026	7	R, C, F
Surat Basin								
APLNG	Ironbark	230	349	700	2024	2026	27	M, I
APLNG	Ramyard	620	966	253	2024	2026	21	M, I
Arrow	Surat Gas Project	1132	1366	68	2024	2026	12	C, R, L
APLNG	Dalwogan	98	168	150	2025	2027	11	M, I
Arrow	Surat Gas Project	122	197	1	2026	2028	2	C, R, L
						Total	**84**	

Source: ACCC analysis of data obtained from gas producers as at August 2023. All volumes and dates reflect estimates only and can be impacted by a range of factors including key risks.

Note: Totals rounded.
Key risks: **C** = Commercial factors. **R** = Regulatory approvals, including state and federal. **L** = Land access. **I** = Infrastructure. **F** = Finance, i.e. securing capital and costs. **P** = Policy uncertainty, including federal and state government policy changes. **M** = Macroeconomic, including international gas and oil prices and market dynamics.

A number of these projects have previously been reported to us and included in earlier inquiry reports. While some of these projects remain on schedule, there have been some delays:

- Surat Gas Project and Enterprise remain on track to deliver first gas within previously reported timeframes
- Ironbark, Goog-a-Binge, Sapphire, Mahalo North and Dalwogan report delays of 1–2 years
- In contrast, Ramyard is scheduled to come online 2 years earlier than previously reported.

There are also new projects that were not previously reported on, or their status has materially improved. These include:

- Vali and Odin fields, where new producer Vintage has successfully delivered first gas within anticipated timeframes.[56]
- PL 1008 or Towrie, small projects that were not approved for development at the time of our January 2023 report. Both projects should commence supply in 2024, with PL 1008 completed on schedule and Towrie advanced by 4 years from 2028 to 2024.

A significant component of new forecast gas production is attributable to Arrow's Surat Gas Project. This project accounts for a large portion of known east coast 2P reserves. Production from the project is expected to increase as additional fields come online and production figures stabilise. Arrow anticipates that annual production will increase

56 Vintage Energy, *Gas flow starts from Vali: revenue starts for Vintage; new supply to eastern Australia* [media release], 22 February 2023, and Vintage Energy, *Odin operational update* [media release], 20 September 2023.

incrementally year on year from first gas in 2025 up to ~110 PJ/p.a. by 2028 as new fields come online, which has been included in the long-term forecast. The annual production in Tables 3.2 and 3.3 only represents Arrow's estimates for the first year of production.

As the production amounts from the projects in Tables 3.2 and 3.3 are accounted for in our current long-term forecast, significant delays or cessations will worsen the outlook prior to and beyond 2028.

Key risks to these projects bringing first gas to the east coast gas market within current timeframes predominantly relate to commercial considerations and obtaining state and federal regulatory approvals. Shared regulatory and land access risks highlight the fact that even for projects that have achieved financial approval for development, factors beyond their control impact their ability to deliver first gas and thereby help to avert a shortfall.

Illustrative of pressures experienced by producers, Armour Energy was recently placed under voluntary administration and receivership.[57] While operations are currently ongoing,[58] the effect on Armour Energy's future operations is unclear.

Our case study on Senex's Surat Basin expansion plans explores the impact non-investment related factors can have on projects.

[57] KordaMentha Restructuring and McGrath Nicol, *Armour Energy Limited (Receivers and Managers Appointed) (Administrators Appointed)* [ASX announcement], 13 November 2023, accessed 15 November 2023.

[58] KordaMentha Restructuring and McGrath Nicol, *Armour Energy Limited (Receivers and Managers Appointed) (Administrators Appointed)* [ASX announcement], 13 November 2023, accessed 15 November 2023.

Box 3.5: Case study on Senex's Surat Basin expansion

Senex has had approvals in place since 2022 to expand their Atlas and Roma North operations in the Surat Basin:

- initially increasing production to 60 PJ/p.a. by 2025
- subsequently doubling production to 120 PJ/p.a. by 2027.[59]

However, these expansion plans were paused in December 2022 following the Government announcement of plans for the Code.[60]

Senex stated government intervention in the market resulted in a lack of confidence to invest in new gas developments, until the scope of the intervention and its impact on contracting was known.[61]

Since the announcement of the final design of the Code in June 2023,[62] Senex has resumed its intentions to expand their Surat Basin operations[63] and has entered into new gas supply agreements based on increased production.[64]

Senex anticipates production will have reached 60 PJ/p.a. by 2025, and double to 120 PJ/p.a. by 2027.[65] As such, if current anticipated production figures are realised and maintained in the long-term, there is potential for an additional ~60 PJ/p.a. of gas to be available to the east coast market that is not accounted for in either the long-term forecast or as a new supply project.

In this instance, rapid policy changes leading to market uncertainty paused investment in bringing new gas to market, however Senex has maintained consistent timeframes following on from the Code's finalisation.

3.5. Potential sources of new gas supply and infrastructure to avert future shortfalls

In this section, we provide an overview of the new sources of supply and infrastructure that could potentially be brought online to improve supply adequacy once supply shortages emerge. We have considered new gas projects that producers may bring online over the next 5 years but are not currently included in production forecasts.

In section 3.2, we identified that a gas supply shortfall on the east coast could be expected as early as 2028. In the near term, gas transported from Queensland will likely be sufficient to avert gas shortages in southern states. However, in the longer-term additional supply is

59 Senex Energy, *"Options to ensure the domestic wholesale gas market delivers for Australians" consultation submission*, Senex, 7 February 2023, p.2.

60 Senex Energy, *Federal Government gas intervention puts $1 billion Atlas expansion in Queensland at risk* [media release], Senex, 22 December 2022.

61 Senex Energy, *Federal Government gas intervention puts $1 billion Atlas expansion in Queensland at risk* [media release], Senex, 22 December 2022.

62 Treasurer, *New Gas Code secures supply at reasonable prices for Australian users* [media release], Federal Government, 14 June 2023.

63 Senex Energy, *Atlas*, Senex, accessed 15 November 2023.

64 See for example: Senex Energy, Senex Energy and AGL sign deal to deliver energy security for Australians [media release], Senex, 16 June 2023 and Senex Energy, *Senex and EnergyAustralia gas deal to deliver energy security for Australians* [media release], Senex, 3 July 2023.

65 Senex Energy, *Energy for the future - Future growth opportunities*, Senex, accessed 15 November 2023.

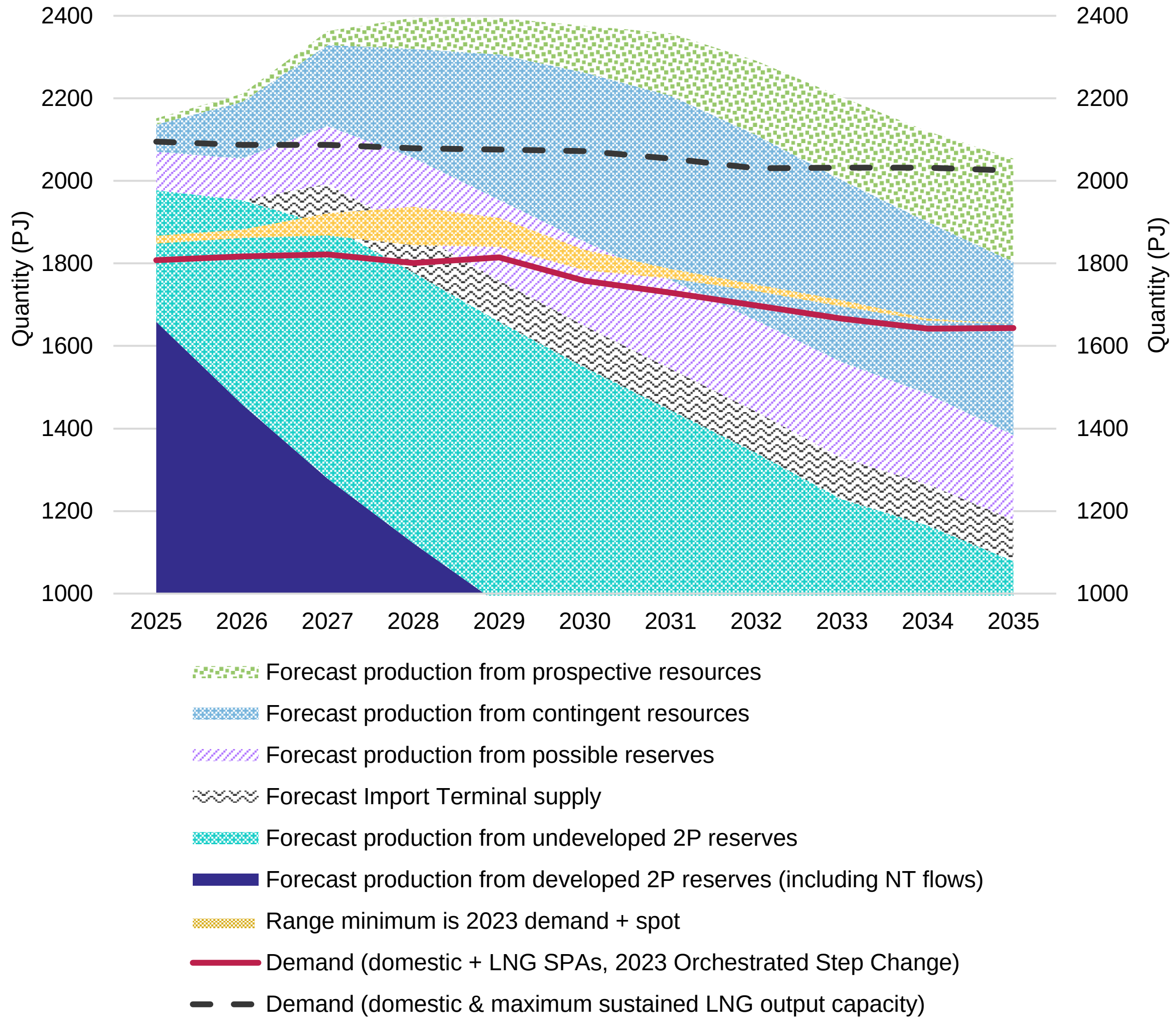
required to meet forecast demand that cannot otherwise be met by production from existing 2P reserves (assuming projected domestic demand for gas does not significantly decrease).

As shown in Chart 3.9, the east coast gas market could have more than sufficient gas supply to meet current demand projections over the next 10 years, including to export maximum volumes of LNG capacity. However, this additional supply would need to come from:

- the development of possible reserves, contingent and prospective resources in the Bowen, Surat, Galilee, Cooper, Gippsland, Bass, Otway, Beetaloo and/or Gunnedah basins
- the development of one or more LNG import terminals in the southern states.

These new gas sources have the potential to deliver significant new volumes of gas. However, these sources of supply are more speculative (i.e. possible reserves, contingent or prospective resources) and face significant risks, as well as being potentially more costly to produce. Additional pipeline infrastructure may also be required to enable gas to be transported to where it is required, while additional storage capacity will be required to manage seasonal supply and demand variation.

Chart 3.9: Potential for other supply sources to meet unfulfilled demand in the east coast, 2025–35

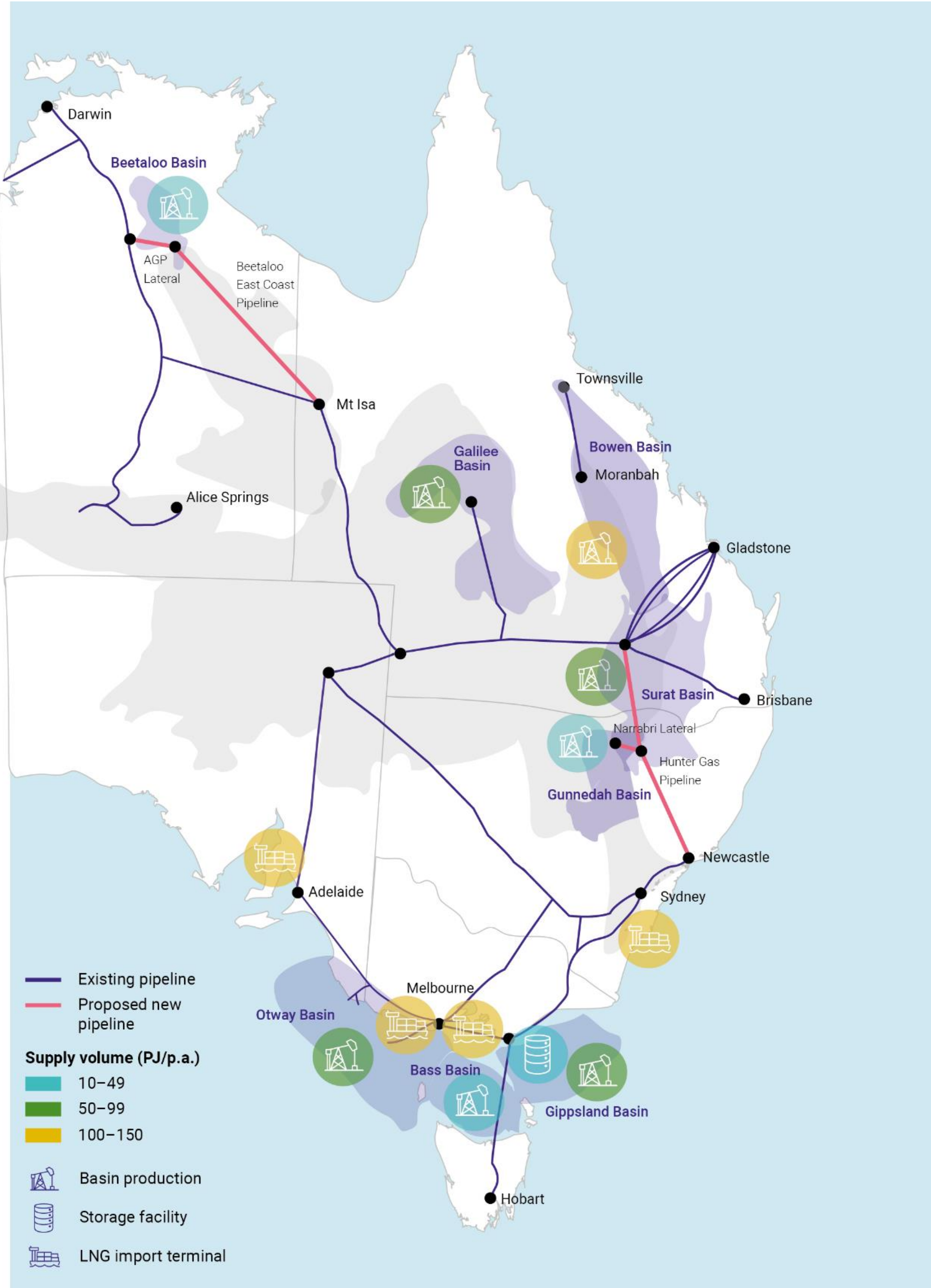


Source: ACCC analysis of data obtained from gas producers as at September 2023 and domestic demand from AEMO's March 2023 GSOO

While there is an apparent need for additional supply and the associated infrastructure, development of most of the proposed supply and infrastructure projects has been delayed by 12–24 months where last reported to us. We discuss the impact of delays in a case study on the Cooper Energy Otway Phase-3 Development.

Figure 3.1 shows the location of the potential new supply projects, production by basin and major infrastructure projects that could come online by 2028. This shows that there are a number of new gas fields and infrastructure projects that have the ability to increase supply to the east coast gas market, both in Queensland and the southern states as well as the Northern Territory. With a few exceptions, the majority of these projects are yet to reach final investment decisions. As such it should be emphasised that these represent potential sources of additional supply only and are not committed projects.

Figure 3.1: East coast market map with potential new sources of supply that could come online by 2028.



Source: ACCC analysis of data obtained from gas producers as at August 2023 and August 2022 (Beetaloo Basin only) and public information on the *Hunter Gas Pipeline - Project Background and Status - Fact Sheet* (Santos, 2022)

Note: Map includes non approved projects from tables 3.2 and 3.3, as such ~100 PJ of basin production is accounted for in our long-term forecast.

3.5.1. New supply projects not yet approved for development

This section provides an overview of the domestic supply projects in basins that have not yet been approved for development but that producers have indicated could potentially come online by the end of 2028, if a final investment decision is made to proceed with their development.

Table 3.4: New gas fields 'not approved', with potential to deliver gas by 2028

Supplier	Project or field	Reserves (PJ) 2P	Reserves (PJ) 3P	Resources (PJ) 2C	Final investment decision	Supply year	PJ/ pa	Key risks
Bowen Basin								
State Gas	Rolleston West	-	-	91	2024	2023*	6	C, R, I, T&D
State Gas	Reid's Dome	-	-	196	2024	2025	10	R, W, T&D, T, C
Comet Ridge	Mahalo	152	262	180	2024	2026	15	C, F, P, R
Santos	Mahalo	95	109	82	2025	2026	6	C, R
Denison Gas	Denison South	-	-	542	2024	2026	18	C, L, R, E&A
Santos	Kia Ora	-	-	35	2025	2026	2	C, R
Denison Gas	Denison North	-	-	369	2025	2027	14	C, L, R, E&A
Santos	Arcadia West	-	-	105	2026	2027	5	C, R
Santos	Ramyard	47	64	26	2027	2028	3	C, R
State Gas	Rolleston West	-	-	187	2027	2028	8	F, E&A, G, C, I, R, T&D
State Gas	Morella	-	-	59	2026	2028	6	F, E&A, G, C, R
Surat Basin								
QGC	PL 510	-	-	4	2024	2026	0.16	C, G
Lakes Blue Energy	Wellesley	-	-	-	2027	2028	3	F
Gunnedah Basin								
Santos	Narrabri	7	7	1969	2025	2027	40	PA, NT
Bass Basin								
Beach	Trefoil	-	-	108	2024	2028	11	M, P, F, MU, G, T
Gippsland Basin								
SGH Energy	Longtom	-	-	206	2024	2025	16	C, I
Esso	North Turrum	-	-	64	2024	2026	10	C, I
Lakes Blue Energy	Wombat	-	-	329	2025	2026	20	R, F, C
Emperor	Judith	-	-	210	2024	2028	27	F
Otway Basin								
Lakes Blue Energy	Otway-1	-	-	-	2024	2025	2	R, F
Lakes Blue Energy	Enterprise North	-	-	-	2024	2025	10	R, F
Beach	Artisan	-	-	38	2024	2026	6	M, P, F, MU
Beach	La Bella	-	-	25	2024	2026	5	M, P, F, MU
Cooper Energy	Annie	-	-	32	2025	2027	6	F, C
Lakes Blue Energy	Portland Energy Project	-	-	-	2026	2028	55	R, F, C
Galilee Basin								
Galilee Energy	Glenaras Gas Project	-	-	2507	-	2026	73	C, I, F
Beetaloo Basin								
Empire	Carpentaria	-	-	1739	2023	2025	-	R
						Total	**374**	

Source: ACCC analysis of data obtained from gas producers as at August 2023. All volumes and dates reflect estimates only and can be impacted by a range of factors including key risks. Note: Totals rounded. *Rolleston West 2023 supply date relates to sales from gas production testing.
Key risks: **C** = Commercial factors. **R** = Regulatory approvals, including state and federal. **L** = Land access. **I** = Infrastructure. **F** = Finance, ie securing capital and costs. **P** = Policy uncertainty, including federal and state government policy changes. **M** = Macroeconomic, including international gas and oil prices and market dynamics. **MU** = Market uncertainty. **G** = Geologic, ie Gas geology and ease of extraction. **T&D** = Timing and delays. **T** = Technical, ie technology development. **E&A** = Exploration and appraisal. **W** = Weather. **NT** = Native Title determination. **PA** = Pipeline approvals.

All of these have been reported to us previously as potential new projects. A portion remain on track within previously reported timeframes, while others are experiencing delays of up to 2 years.

As some of the projects in Table 3.4 relate to resources with low recoverability probability, timing is fluid and dependent on the development of technology and methodologies to recover the gas. As such, development of these sources is speculative and will require both market confidence and regulatory approvals in order to be successfully brought online. Chart 3.9 illustrates projects such as these can improve the supply outlook.

Our case study on Cooper Energy's Otway Phase-3 project explores the impact factors beyond investment can have on new sources of supply being brought online.

Box 3.6: Case study of Cooper Energy's Otway Phase-3 project

Cooper Energy announced in 2019 the discovery of the Annie field[66] and subsequently announced plans in 2022 to develop it as part of the Otway Phase-3 Development.[67]

As reported to us as late as August 2022 Cooper Energy anticipated making a final investment decision on Annie in 2023 and bringing on supply in 2025.[68]

However, Cooper Energy announced open ended delays to these timeframes following the December 2022 Government announcement of plans for the Code resulting in market and investment uncertainty.[69]

On commencement of the Code in July 2023, Cooper stated that they had reached resolution with the Code and their status as a small domestic producer.[70] They announced:

> 'We welcome policy certainty and stability, in the form of the Code, to facilitate investment into new gas supply.' [71]

The development of the Annie field has progressed, however is facing delays of 2 years on previously anticipated timeframes, with first gas now not anticipated to come online until 2027.

Some of the projects listed in table 3.4 represent sources of supply from previously undeveloped basins such as the Beetaloo, Galilee and Gunnedah. All of these basins require substantial investment in pipeline infrastructure to facilitate supply to the east coast gas market. However, if risks such as developing infrastructure, securing finance, successful production testing and obtaining regulatory approvals can be overcome, these basins have the potential to provide substantial new volumes of gas to the east coast market.

While we do not have up to date figures relating to Tamboran's Beetaloo project, Tamboran are progressing their intention to deliver gas to the east coast market. In line with this they have recently entered into an initial agreement with pipeline developer APA to jointly develop

66 Cooper Energy, *New gas field discovery at Annie* [media release], Cooper Energy, 6 September 2019.

67 Cooper Energy, *Offshore Otway gas hub growth plan* [media release], Cooper Energy, 18 May 2022.

68 Cooper Energy, *Offshore Otway gas hub growth plan* [media release], Cooper Energy, 18 May 2022.

69 Cooper Energy, *Half-Year Financial Report*, Cooper Energy, 31 December 2022, p 5.

70 Cooper Energy, *Financial Report*, Cooper Energy, 30 June 2023, pp 5 and 8.

71 Cooper Energy, *Government Mandatory Gas Code of Conduct* [media release], Cooper Energy, 11 July 2023.

pipelines connecting Beetaloo with the east coast market,[72] as well as signing letters of intent with a number of east coast gas retailers for the supply of gas from 2028.[73]

Concerning the Gunnedah Basin, it is anticipated that development of the Narrabri field will reduce NSW reliance on gas from other states.[74] Santos has plans for the development of a new processing facility at Narrabri with between 150 – 200 TJ/day capacity. The Narrabri Gas Project is planned for commissioning by Santos in 2027, and is currently awaiting a Native Title decision, anticipated by the end of 2023.

3.5.2. Other potential sources of additional supply

LNG Import Terminals

In addition to the domestic supply projects outlined above, there are currently four proposals to develop LNG import terminals, all of which are located in the southern states. As we have previously observed, we do not expect all of these projects to be developed.

As a completely novel method of gas supply in Australia, these projects have their own unique risks and uncertainty. However, all require certain common components to be viable:

- stable access to a floating storage regasification unit (FSRU) for the life of the project
- consistent domestic demand and customer commitments
- pipeline infrastructure to transport gas from the FSRU to existing pipelines.

Table 3.5 provides an overview of these proposals. The locations of the proposed import terminals are mapped in Figure 3.1.

Table 3.5: LNG import terminals proposed to service the east coast gas market

Developer	Name	Current status	Final investment decision	Supply date	PJ/pa	Key risks
South Australia						
Venice Energy	Venice Energy – Outer Harbour LNG Import Project	Pre-FID	November 2023	May 2026	80	*MU, F
New South Wales						
Australian Industrial Energy (AIE)	Port Kembla Energy Terminal	Construction underway	Complete	Quarter 2, 2026	130	R, MU, C
Victoria						
Viva Energy	Viva Energy Gas Terminal Project	FEED completed	Quarter 4 2024	Quarter 2 2027	80 to 140-160	R, MU, C, I
Vopak Terminals	Vopak Victoria Energy Terminal	Pre-FEED	Quarter 4 2025	Quarter 2 2028	150 to 200	R, MU, C, I

Source: ACCC analysis of data obtained from developers as at August 2023. 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 approvals, including state and federal. **I** = Infrastructure. **F** = Finance ie securing capital and costs. **MU** = Market uncertainty.
*The key risks cited by Venice in their August response to us will be negated if a terminal use agreement is finalised following on from the exclusivity agreement between Venice and Origin Energy.[75]

72 Tamboran Resources, *APA signs initial agreement to commence work to connect Tamboran's Beetaloo Basin assets* [ASX announcement], Tamboran Resources Limited, 23 June 2023.

73 Tamboran Resources, *Tamboran increases total domestic East Coast LOIs to 600 – 875 TJ per day* [ASX announcement], Tamboran Resources Limited, 28 August 2023.

74 Santos, *Narrabri Gas Project*, Santos, 2014, accessed 31 October 2023.

75 Venice Energy, *Exclusivity Agreement reached on SA LNG Terminal* [media release], Venice Energy, 27 October 2023.

Estimates of annual import capacity by terminal vary from 80 to 200 PJ/p.a. It should be emphasized that these amounts are estimates only and actual supply from LNG import terminals will vary dependent on a number of factors, including FSRU and pipeline gas compression and capacity. As a result, where we include an LNG import terminal in chart 3.9 and figure 3.1, we have assumed potential supply to be a standard 100 PJ/p.a.

Developers of LNG import terminals anticipate supply will come online between 2026 and 2028 and the projects in Table 3.5 are all at varying stages of development.

Port Kembla Import Terminal is the most progressed, having achieved a final investment decision and secured a long-term contract for an FSRU in 2021.[76] Construction is reported to be 70% complete.[77] Despite this progress regulatory approvals, market uncertainty and commercial arrangements are key risks to the project supplying gas by 2026.

Venice Energy – Outer Harbour LNG Import Project is the second most progressed project, having successfully obtained all regulatory approvals. A final investment decision is expected in November 2023, with siteworks anticipated to commence in late 2023.[78] As well, Venice has an agreement with an international shipper for the contracting of an FSRU.[79]

Venice recently announced an exclusivity arrangement with Origin Energy for the terminal to supply Origin with up to 110 PJ/p.a. for a minimum of 10 years.[80] The successful completion of a terminal use agreement with Origin will mean the risks cited by Venice in table 3.5 are negated.

The proposed import terminals based in Victoria are the least progressed, with both citing regulatory approvals as a key risk. Since we last reported on them these projects have experienced delays of 1 to 2 years in obtaining necessary approvals. Both also cite market uncertainty and infrastructure as further risks.

New pipelines and expansions

Developing pipeline infrastructure and capacity is essential to improve the effectiveness of bringing new sources of supply to the east coast market.

In line with this, a number of major new pipelines are being explored to connect new supply projects to the east coast gas market by 2028. These are summarized in Table 3.6 and represented in Figure 3.1.

76 Squadron Energy, *AIE and Höegh LNG Sign Deal To Secure NSW and Victoria's Energy Future; Co-Develop New Generation Clean Energy Transport Potential* [media release], *Squadron Energy*, 30 November 2021.

77 AFR, *Andrew Forrest's Port Kembla LNG import vision put to the test*, 14 September 2023.

78 Venice Energy, *What we do: Outer harbour LNG project*, Venice Energy, accessed 31 October 2023.

79 Venice Energy, *Outer Harbor Project secures leading international LNG shipping partner* [media release], Venice Energy, 6 July 2021.

80 Venice Energy, *Exclusivity Agreement reached on SA LNG Terminal* [media release], Venice Energy, 27 October 2023.

Table 3.6: New pipelines with potential for commissioning by 2028

Developer	Name	Description	Nameplate capacity	Final investment decision	Commission date	Key risks
APA	Shenandoah South to Amadeus Gas Pipeline (AGP)	Beetaloo (Shenandoah) connecting to AGP in NT	~40 - 100 TJ/day	2024	2025	C, MU, F
Santos	Hunter Gas Pipeline (HGP)	Narrabri to Newcastle	250 TJ/day	2025	2027	L, R
Santos	Narrabri Lateral Pipeline	Connect Narrabri Gas Project to HGP	250 TJ/day	2025	2027	L, R
APA	NT - Beetaloo - East Coast Pipeline	Connect Beetaloo Basin to east coast gas network via Carpentaria Gas Pipeline (CGP).	~500 TJ/day	Unknown	2028	C, MU, F

Source: ACCC analysis of data obtained from developers as at August 2023.[81] 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 approvals, including state and federal. **F** = Finance, ie securing capital and costs. **MU** = Market uncertainty. **L** = Land access.

As mentioned previously fields in the Beetaloo and Gunnedah basins represent new sources of supply. Additional pipeline infrastructure to connect Tamboran's Beetaloo project in stages with the east coast gas market are being explored by APA.

Substantial pipeline infrastructure is also required to connect Santos's proposed new Narrabri Gas Project in the Gunnedah Basin with the east coast gas market. Santos acquired Hunter Gas Pipeline Pty Ltd in 2022, and now owns an approved underground pipeline route to connect Newcastle in New South Wales with Wallumbilla in Queensland.[82] Construction of the Narrabri Lateral Pipeline will connect Gunnedah Basin to the Hunter Gas Pipeline and the east coast market. Santos has stated: "*…our goal is to work with infrastructure developers and owners to construct the pipeline and deliver much-needed gas to east coast domestic markets in the shortest timeframe possible*."[83] However Santos has faced a number of setbacks to the Narrabri project including a current Native Title appeal.[84] Successful development of the HGP will increase the overall competitiveness of the east coast gas market by offering alternative transmission pathways, as well as providing capacity for additional supply.

Each of these pipelines are yet to achieve final investment decisions. Each represent an opportunity to increase gas delivery volumes through additional transport options. However, each also face risks to becoming committed projects and reaching commissioning by 2028. These risks range from commercial and financial considerations and an uncertain market to obtaining regulatory approvals and land access arrangements.

Table 3.7 summarises major pipeline expansions that have potential for commissioning by 2028.

---

81 Santos, *Hunter Gas Pipeline - Project Background and Status - Fact Sheet*, Santos, September 2022.

82 Santos, *Santos Acquires Hunter Gas Pipeline Pty Ltd To Get Narrabri Gas To Domestic Market As Soon As Possible* [media release], Santos, 11 August 2022.

83 Santos, *Santos Acquires Hunter Gas Pipeline Pty Ltd To Get Narrabri Gas To Domestic Market As Soon As Possible* [media release], Santos, 11 August 2022.

84 Commonwealth Courts, *GOMEROI PEOPLE v SANTOS NSW PTY LTD AND SANTOS NSW (NARRABRI GAS) PTY LTD* [QUD13/2023], Federal Court of Australia, 13 January 2023.

Table 3.7: Pipeline expansions with potential for commissioning by 2028

Developer	Name	Description	Nameplate capacity	Final investment decision	Commission date	Key risks
APA	Western Outer Ring Main (WORM)	Buried gas pipeline, ~51km, to provide a new connection between Plumpton in Melbourne's west and Wollert in the north. + Upgrade to existing compressor station at Wollert.	Additional capacity of 23 TJ/day for the South West Pipeline, up to 517 TJ/day.	Complete	Jan 2024	W, F, T&D, R, L
APA	East Coast Gas Grid Expansion	Stage 1 & 2 - increase winter peak capacity of the East Coast Grid by 25%, through works on the South West Queensland Pipeline (SWQP) and Moomba to Wilton Pipeline (MWP). Stage 3a – additional capacity increase.	Stage 1 and 2 - increase SWQP capacity to 512 TJ/day + MSP capacity to 565 TJ/day. Stage 3a - increase MWP to 599 TJ/day.	Stage 1 and 2 - Complete. Stage 3a – not passed FID.	Stage 1 - May 2023 (online). Stage 2 – prior to Winter 2024 (underway). Stage 3a - July 2025 (FID dependent).	W, F, T&D, R, L, MU, C
Jemena EGP	Project Marlin	New 12km lateral - connect Port Kembla Energy Terminal (PKET) with Eastern Gas Pipeline (EGP) NSW. + Bi-directional upgrades to EGP.	Lateral - 522 TJ/day. Bi-directional - 200 TJ/day south (PKET to Longford).	Lateral: Complete. Bi-directional EGP upgrades ~mid-2024.	Lateral: Complete late 2023. Commissioning dependent on PKET. EGP upgrades: subject to VIC customer requirements & contract execution.	C
Tasmanian Gas Pipeline (TGP)	Expansion of VicHub	Increase gas receipt options for the TGP via EGP Longford.	Increase capacity from 129 TJ/day to between 150 - 350 TJ/day.	2024	2024-2025	C
SEA Gas	Port Campbell to Adelaide (PCA) East	Bi-directional reconfiguration of the PCA to send gas west - east (SA to VIC).	In development.	Unknown - subject to commercial agreements.	Unknown – potentially as early as 2026	C, P, R, MU, L

Source: ACCC analysis of data obtained from developers as at August 2023. 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 approvals, including state and federal. **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.

APA is currently furthering its East Coast Grid Expansion to increase the daily nameplate capacity of both the South West Queensland Pipeline (SWQP) and the Moomba Sydney Pipeline (MSP). Once stages 1 and 2 of the expansion are complete the peak capacity of the east coast grid will be increased by 25%. The most current information from APA is that Stage 2 will be complete in time for winter 2024 to provide additional transport capacity to the southern states during peak seasonal demand. Any progression of Stage 3a of the expansion is dependent on a final investment decision.

Jemena's proposed bi-directional reconfiguration of the Eastern Gas Pipeline (EGP) is related to the Port Kembla Import Terminal. Similarly SEA Gas commissioned a joint study with Venice Energy into the viability of converting the Port Campbell to Adelaide (PCA) pipeline for bi-directional flows.[85] If committed to and undertaken these reconfigurations would facilitate the utilization of existing pipeline infrastructure to support gas flows into Victoria. It can be expected that any furthering to their respective statuses will be linked to anticipated additional sources of supply available via an LNG import terminal in either NSW or SA.

Within Victoria, APA's efforts to address a capacity constraint in the Victorian Transmission System (VTS) are progressing. APA has expedited completion of a new compressor at the Winchelsea Compressor Station to increase capacity of the South West Pipeline (SWP). This project was completed in August 2023 and in combination with the additional capacity offered by the Western Outer Ring Main (WORM), will increase capacity flow from the SWP into the VTS to 528 TJ/day. The WORM is currently under construction and is anticipated to be commissioned in January 2024.

Although these works have meant an improvement on available peak-day supply, the SWP still constrains supply into the VTS.[86] Further augmentation plans by APA to increase the capacity of the SWP to 570 TJ/day have been put on hold indefinitely. Collectively, regulatory approvals, market uncertainty and commercial factors have contributed to these plans being put on hold.

Common to all of the proposed and progressing pipeline projects is a theme of market uncertainty where commercial arrangements and finance are cited as risks as is difficulty obtaining regulatory approvals and land access arrangements.

Storage

Gas storage services provide the option to store gas for future use. Gas production remains relatively stable throughout the year, yet domestic demand for gas varies, peaking particularly in colder winter months. Storage facilities allow for reserves to be built up at times of low demand and withdrawn from as necessary. Sufficient storage capacity close to areas of high demand ensure gas can be delivered at peak times where needed, in a timely manner.

Table 3.8 summarises the gas storage developments with potential for commissioning prior to 2028. These are yet to achieve final investment decisions and as such are proposed projects only.

85 Venice Energy, SA LNG Import Terminal can serve the east coast – study confirms [media release], Venice Energy, 4 May 2023.

86 AEMO, 2023 Victorian gas planning report, AEMO, p 58.

Table 3.8: Gas storage developments with potential for commissioning by 2028

Developer	Name	Description	Nameplate capacity	Final investment decision	Commission date	Key risks
GB Energy	Golden Beach Energy Storage	New gas storage field - 3km offshore with compression and dehydration facilities located onshore, and interconnection in the immediate vicinity of the Longford Gas Plant and the Eastern Gas Pipeline Compressor Station.	Up to 35PJ of gas storage capacity - 250 TJ/day withdrawal - 125 TJ/day injection.	Q2 2024	Initial commissioning will be for blowdown of gas currently in the structure at 125TJ/d ~mid 2026. Transition to storage and expansion to 250 TJ/day withdrawal rates ~mid 2027.	F, P
Lochard Energy	Heytesbury Underground Gas Storage expansion project (HUGS Project)	Expansion of Iona Gas Storage Facility – Victoria.	Increase Iona's capacity from 570 TJ/day and 24.4PJ nameplate capacity to 615 TJ/day and 26.2 PJ nameplate capacity.	Q3 2024	Commissioning late 2025 - with injection and withdrawal services expected to be available from January 2026.	R, T&D, G

Source: ACCC analysis of data obtained from developers as at August and November 2023. 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 approvals, including state and federal. **F** = Finance, ie securing capital and costs. **T&D** = Timing and delays. **P** = Policy uncertainty, including federal and state government policy changes. **G** = Geologic, ie gas geology and ease of extraction.

Golden Beach Energy Storage is proposed for development in the Gippsland Basin, about 3km offshore of the township of Golden Beach. The project has the capacity to utilise the Golden Beach Gas Field to store up to 35 PJ of gas with withdrawal rates of up to 250 TJ/day. Prior to the project reaching storage phase ~43 PJ of 2C resources currently in the field will be withdrawn and supplied to the east coast market over a ~2 year period.[87] Withdrawal is anticipated to begin mid 2026, following which the field will be transitioned to a storage facility, reaching full capacity mid 2027 at the earliest. The project is not yet approved and is seeking to make a final investment decision by mid 2024. Since the project was last reported to us timeframes have been delayed by 1 year and government policy changes have been added as a key risk.

Lochard's proposed plans with the HUGS Project are to further expand the storage capacity of their Iona facility. These plans will see Iona increase its storage capacity from 24.4 PJ to 26.2 PJ, and withdrawal capacity from 570 TJ to 615/TJ per day from 2026, dependent on reaching a final investment decision in 2024.

[87] ACCC, *Gas Inquiry 2017 - 2030*, ACCC, January 2023, p 130. For sales agreement see also: Origin, *Origin secures more gas for domestic users* [media release], Origin Energy, 26 February 2019.

3.6. Initiatives to improve the outlook

The outlook on the east coast is continually evolving. However, current government initiatives underway, aimed at identifying the challenges and risks, will present opportunities for market participants. These measures include:

- introducing the Code to provide the market with greater certainty and incentivise investment in developing new gas supply sources
- continuing to model the impacts of government policies which shape demand forecasts provided by AEMO in their GSOO
- developing initiatives as part of the Future Gas Strategy report to lower gas dependency over time, and developing pathways for industry to adopt alternative fuels and renewables.

This section considers various measures and incentives to help achieve the above goals.

3.6.1. Supply commitments made under the Code and their impact on long-term supply

The Government recently introduced the Code 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.

As noted in the overview, the Code has specific pricing rules, reporting requirements and an exemptions framework. Ministerial exemptions from the Code's pricing requirements and penalty provisions are considered where a producer commits to supply additional gas to the domestic market. Producers which are granted an exemption may have the conditions of their exemption published, including specific information about their commitments.

While it is too soon to determine whether the Code has achieved its purpose and we are still assessing the impact of the new provisions, proposed commitments to date from producers appear to be increasing domestic only supply over the next 10 years.

The Code is expected to be reviewed in mid-2025.

3.6.2. Updates to demand in AEMO's 2024 GSOO

Government policies, including commitments to net-zero emissions targets and the transition from coal to gas to renewables, are shaping long-term demand projections.

AEMO finalised their 2023 Input, Assumptions and Scenarios Report (IASR) study, which is relied on to develop the demand scenarios in the GSOO and related Integrated System Plan. The methodology used refines the approach and inclusion of sensitivities, assumptions, and government policies to improve the accuracy of demand forecasts.

AEMO's new demand scenarios are expected to incorporate:

- greater minimum rates of decarbonisation reflecting government commitment towards significant transition measures across the NEM
- energy futures to examine system needs and impacts of the energy transition, to allow greater inclusion of expected change in the field of economics and technology

- consumer investment in consumer energy resources (CER)
- electrification/transition of other sectors to alternate energy resources.

The 2024 GSOO is also expected to include information on gas production and demand from the Northern Territory. We expect to adopt the updated central demand scenario for our next report that includes an overview of the long-term outlook.[88]

3.6.3. Future Gas Strategy

The Government is currently developing a Future Gas Strategy to help plan for and support Australia's transition to net zero.

The Future Gas Strategy will provide a medium- (to 2035) and long-term (to 2050) plan for gas supply and demand in Australia. As discussed in this chapter, Australia requires a clear and long-term strategy to help government, industry and gas users make decisions as we transition to renewables. The strategy aims to:

- support decarbonisation, including 43% below 2005 emissions by 2030 and net zero by 2050
- promote energy security and affordability
- maintain international trade relationships, ensuring we remain reliable and trusted suppliers of LNG to our region and build our clean energy exports
- help trade partners on their own net zero pathway.

The strategy intends to investigate the supply-demand balance of gas to 2050 to meet net zero emissions. We anticipate this will also include measures to reduce gas dependency as key net zero milestones are reached. Additionally, it will look at where, when and how much Australian gas is needed.

Box 3.7: European energy demand management solution

The European Union (EU) initiated a 'European Gas Demand Reduction Plan' in response to an unprecedented gas supply shock and higher natural gas prices. The EU agreed to reduce demand by 15% compared to the previous 5 years between August 2022 and March 2023. This was deemed necessary to avert a winter energy crisis in 2023.[89]

A range of policy measures to support the objectives were introduced on industrial users of natural gas including:

- introducing a series of policy measures to incentivise fuel switching (i.e. replacing gas with alternative sources of energy) and decreasing gas consumption
- financial assistance for heat pump systems retrofits in houses
- public awareness campaigns to encourage a behavioural change.

Increasing imports of gas intensive products over locally manufactured goods, combined with the increased use of alternative fuels for industrial processes, significantly lowered the EU's gas demand.[90]

88 Further information is available at the AEMO GSOO and AEMO Forecasting Reference Group webpages.

89 European Commission, *The European Green Deal*, European Union, accessed 25 October 2023.

90 IEA, *Europe's energy crisis: What factors drove the record fall in natural gas demand in 2022*, 14 March 2023.

The EU successfully reduced natural gas consumption by 19% or 41.5 BCM by January 2023 (approximately 1500 PJ)[91]. Additionally, the change in gas consumed for power generation, industrial, commercial, and residential contributed to an overall 13% decrease in the EU annual natural gas consumption.

Recently, the Department of Industry, Science and Resources closed their consultation on the Future Gas Strategy discussion paper.[92] It anticipates publishing the final report around mid-2024.

[91] European Council – Council of the European Union, *Infographic - Gas demand reduction in the EU*, 5 June 2023.

[92] Department of Industry, Science and Resources, *Future of Gas Strategy: consultation paper*, Australian Government, October 2023.

4. Domestic price outlook

Key Points

- Prices offered in 2023 for 2024 supply have fallen from their highs in mid-2022. The volume-weighted average price for offers made between February and August 2023 for 2024 supply was:
  - $14.60/GJ for producers, a 45% decrease from the preceding 6 months. The average price for producer offers were similar to those offered in the first half of 2022.
  - $19.50/GJ for retailers, a 21% decrease from the preceding 6 months. The average price for retailer offers remain 17% higher than those offered in the first half of 2022.
  - Producers and retailers have different cost structures, with retail prices often higher than producer prices as retailers offer bundled services. Retailer offers may lag producer offers as gas is bought and sold in different periods.
- Fewer offers were made in 2023 for 2024 supply than in equivalent periods for previous years.
  - Producers made 12 offers between February and August 2023 for 2024 supply, 70% lower compared to the first half of 2022.
  - Retailers made 72 offers between February and August 2023 for 2024 supply, 10% lower compared to the first half of 2022.
- Prices payable under Gas Supply Agreements executed between February and August 2023 for 2024 supply as volume-weighted averages were:
  - $17.69/GJ for producers, a 3% increase from the previous six months. Average producer prices were 30% higher than the first half of 2022.
  - $19.38/GJ for retailers, a 12% decrease from the previous 6 months. Average retail prices were 50% higher than the first half of 2022.
- Since the implementation of the Gas Market Emergency Price Order on 23 December 2022 to 8 August 2023, producers have sold gas under short-term contracts for 2023 supply at or below $12/GJ.
- Under the Heads of Agreement commitments, the east coast LNG producers offered over 26 PJ of gas, directly and in EOIs, to the domestic market between 15 February and 8 August 2023 for supply in 2023, in addition to previous offers of over 274 PJ for 2023 supply made between 19 August 2022 and 15 February 2023. They sold 3.6 PJ of spot or additional LNG cargoes to the international market over the same period.
- C&I users have reported that prices have fallen from record highs but remain still high impacting their business operations.

4.1. Introduction

This chapter reports on domestic gas prices in the east coast gas market highlighting the trends since the June 2023 Gas Inquiry interim report.

It presents analysis and information on:

- historical and forward international gas prices
- domestic prices for supply in 2024 under bids and offers for a term length of minimum 12 months
- domestic prices payable and flexibilities available for supply in 2024 under Gas Supply Agreements (GSAs) for a term length of minimum 12 months
- domestic prices for short-term contracts (for a term length of less than 12 months)
- prices on Australian Energy Market Operator (AEMO) controlled spot markets.

It also provides a high-level assessment of LNG producers' compliance with the Heads of Agreement (HoA) for the reporting period from 15 February 2023 to 8 August 2023.

Where relevant, it presents C&I users' views and experience in the east coast gas market, based on the information provided by a sample of users surveyed by ACCC between August and October 2023.

Appendix A reports on transport and storage prices.

Appendix B sets out the ACCC's approach to reporting on prices.

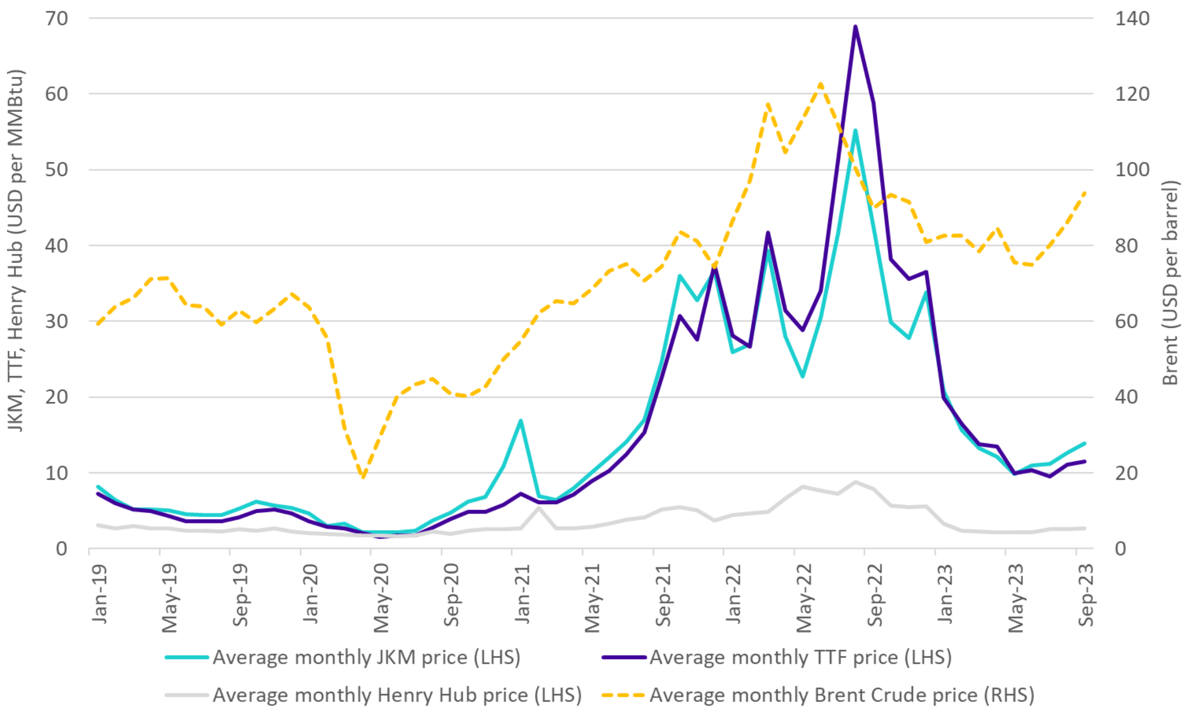
4.2. Trends in international prices

International prices for natural gas and LNG have played a role in shaping domestic prices offered and agreed in GSAs. They influence the price of gas supplied to the east coast domestic gas market by some domestic suppliers.[93]

Chart 4.1 presents the historical monthly averages for Brent Crude and international gas prices including the Japan/Korea Marker (JKM), Henry Hub (HH) and Dutch Title Transfer Facility (TTF).

93 ACCC, LNG netback price series: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series, 16 October 2023.

Chart 4.1: Historical Brent Crude and international gas prices, Jan 2019 to Sep 2023



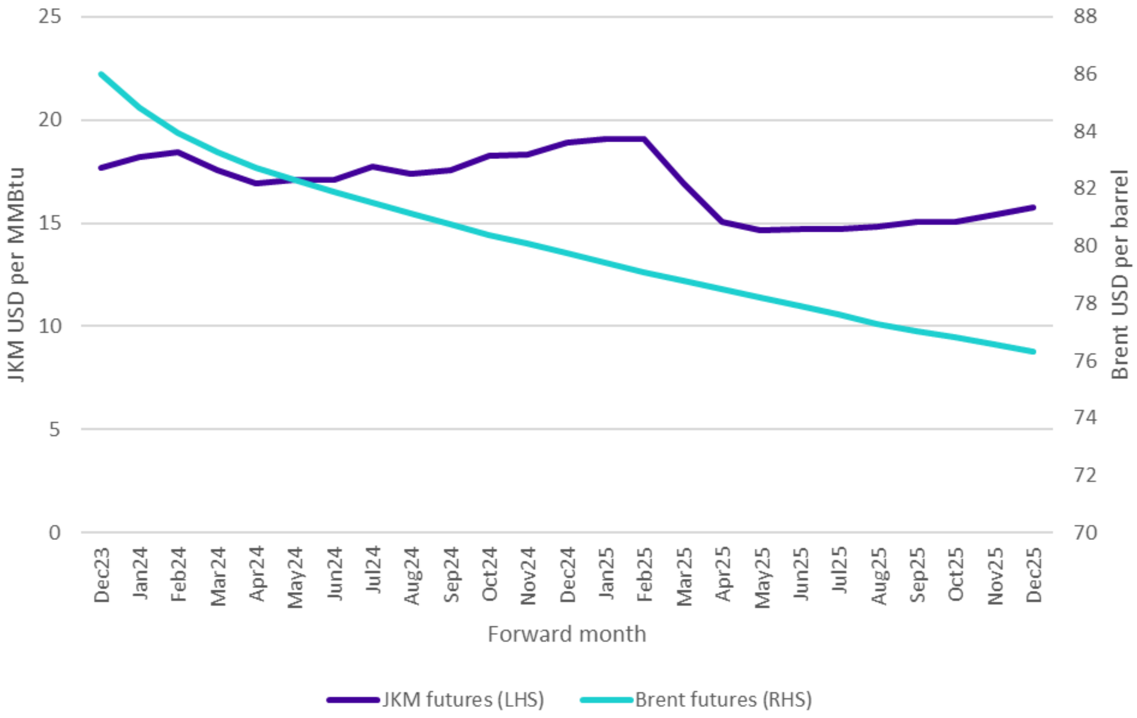
Source: ICE (JKM), Argus (TTF), EIA (Brent Crude), ACCC analysis., October 2023.

International LNG prices trended downward in the first half of 2023 before slightly increasing since then. The JKM, TTF and Brent prices averaged USD$13.88/MMBtu, USD$11.45/MMBtu and USD$93.72/barrel, respectively, for the month of September 2023.

While JKM and Brent prices have fallen from record highs in 2022, the prices in September 2023 were still above long-term historical averages.

Chart 4.2 sets out the estimated forward prices for JKM and Brent crude traded on 12 October 2023.

Chart 4.2: Forward estimates of JKM and Brent Crude



Source: ICE, ACCC analysis.

Note: JKM and Brent futures are presented as monthly averages traded on 12 October 2023.

The JKM future prices fluctuate over the forward period ranging from a high of USD$19.10/MMBtu in February 2025 to a low of USD$14.68/MMBtu in May 2025. Over the same period, Brent Crude future prices decrease from USD$86.00/barrel in December 2023 to USD$76.31/barrel by December 2025.

4.3. Prices for supply in 2024 under long-term bids and offers

Price cap does not apply to contracts for supply after the price cap period (23 December 2022 – 22 December 2023)

This section reports on prices in offers made to customers and bids received by suppliers for 2024 supply. Our analysis includes offers and bids that contain clear indication of price, quantity, and supply start and end dates.

The offers and bids we include in our analysis also match the following criteria:

- Were made by producers to all buyers or retailers to C&I users and gas-powered generators (GPG) for 2024 supply over the period from 1 January 2022 to 8 August 2023.
- Had fixed prices or prices linked to a commodity price index, such as Brent Crude oil.
- Were for supply quantities of at least 0.5 PJ and a term length of minimum 12 months.

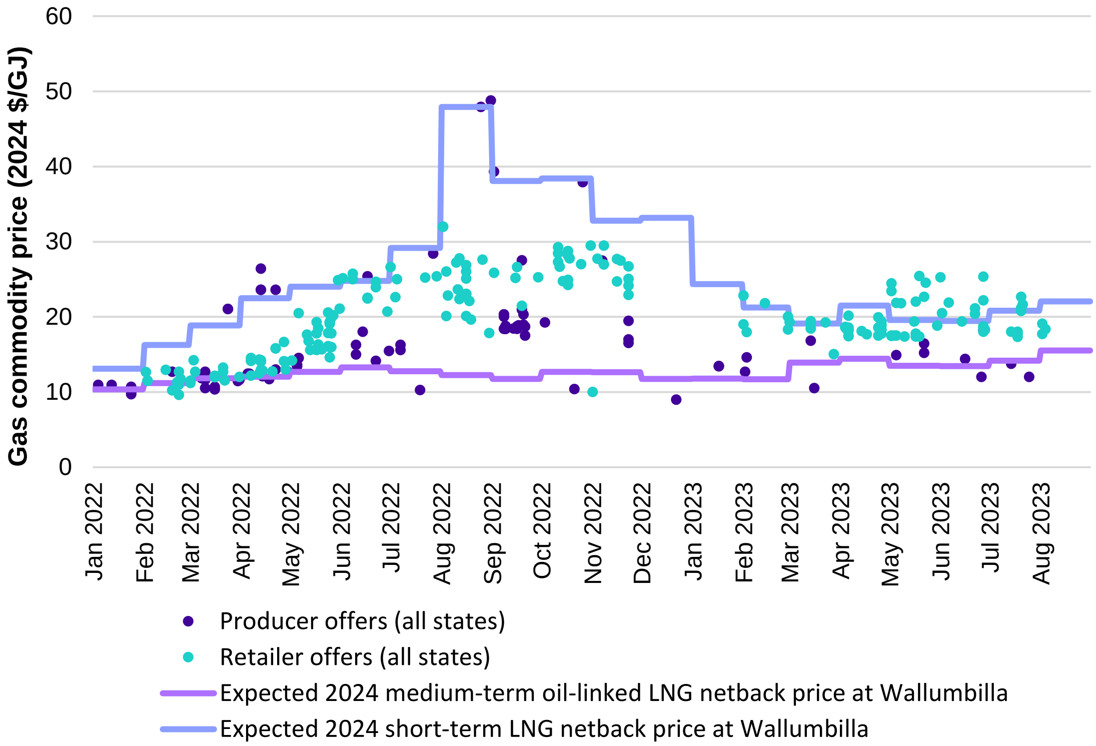
We estimate the price of each offer and bid using the approach outlined in Appendix B. As explained in Appendix B, the prices of individual offers and bids are not necessarily comparable as they can differ in non-price aspects, such as delivery location, quantity, contract term and contract flexibility.

Offer and bid pricing in some instances may also reflect seasonal price fluctuations, linkages to prices of other commodities (such as oil), price expectations over the length of the contract (not only the supply year in discussion) or, in the case of GPG and conditions in the electricity market.

4.3.1. Offer prices have fallen from highs in mid-2022 and there were fewer offers.

Chart 4.3 shows offers made by producers and retailers between January 2022 and August 2023 for 2024 supply and compares these offers with short-term and medium-term LNG netback prices at Wallumbilla.

Chart 4.3: Gas commodity prices (2024$/GJ) offered in the east coast gas market for 2024 supply compared to LNG netback prices[94]



Source: 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.[95] 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 if a previous offer did not result in the execution of a GSA.

The prices offered by producers for 2024 supply have continued a downward trend in 2023 since falling from the peak at $48.78/GJ in August 2022.

Prices offered by non-LNG producers between February and August 2023 for 2024 supply have been more consistent with the medium-term oil-linked netback price. Medium-term oil-linked netback prices for 2024 are $5/GJ - $8/GJ lower than short-term LNG netback prices. As of 8 August 2023, LNG producers have not made any offers in 2023 for 2024 supply. Offers made by LNG producers in 2022 for 2023 supply were in line with short-term LNG netback prices.

Similar to producer offers, prices offered by retailers for 2024 supply trended downward in the first half of 2023, falling from the high prices experienced in mid-2022. Prices remained higher than those offered by producers, with some prices materially higher and above short-term LNG netback prices. We would expect to see retail prices often exceed producer prices, reflecting different cost structures as retailers manage gas on a portfolio basis and offer additional flexibility. We are undertaking a review into retailer behaviour, including retailer pricing behaviour (see Chapter 5).

[94] We have updated the method of calculating the expected 2024 medium term oil-based LNG netback price series to reflect transportation, plant operations and efficiency costs more accurately. Additionally, we have updated the LNG oil-slope to reflect Gaffney Cline's recent estimates in its June 2023 report (as available on the ACCC website).

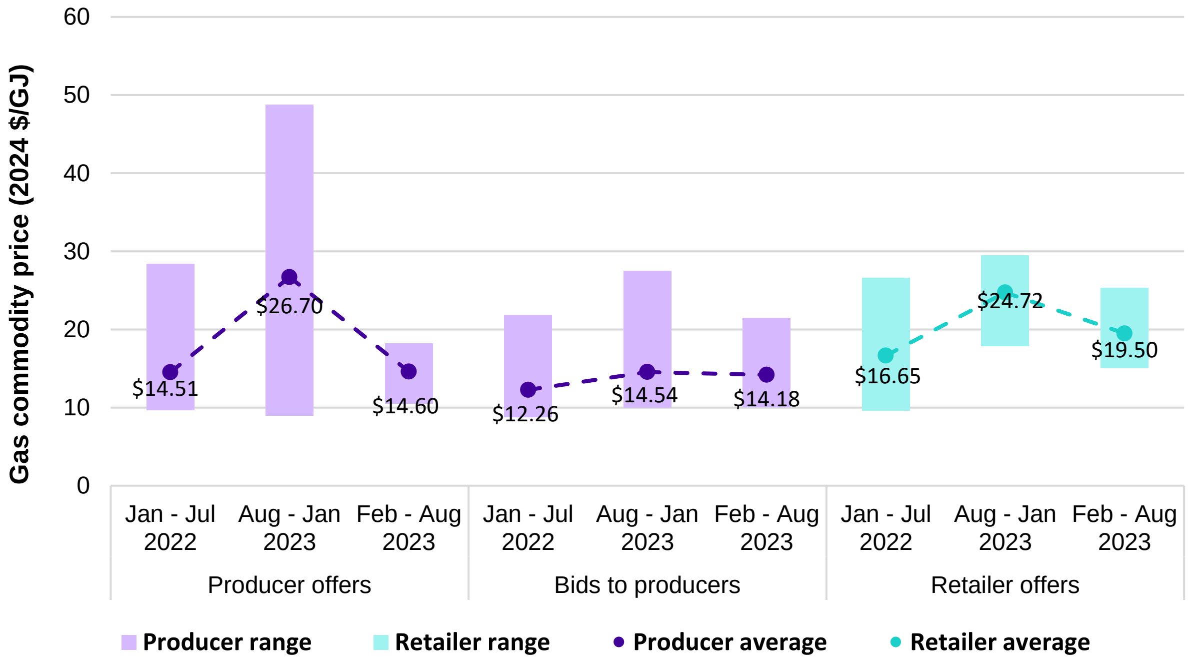
[95] Appendix A of this report provides information about transport costs.

While the prices have decreased, there is a marked reduction in the number of offers made. Producers made only 12 offers between February and August 2023 for 2024 supply, 60% lower than in the preceding 6 months and 70% lower compared with similar times last year. C&I users reported that fewer producers were making offers for 2024 supply (Box 2.1 in Chapter 2). We expect to see increased levels of producer engagement with the domestic market following the finalisation of the Code.

Between February and August 2023 retailers made 72 offers for 2024 supply, a decrease of 10% compared to the first half of 2022.

Chart 4.4 compares the volume-weighted average price of offers made or bids received by producers and retailers for gas supply in 2024.

Chart 4.4: Gas commodity prices (2024$/GJ) in the east coast gas market for 2024 supply



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

Note: Volume-weighted average prices are displayed next to the point. 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 if a previous offer did not result in the execution of a GSA.

The volume-weighted average price of producer offers made between February and August 2023 for 2024 supply was $14.60/GJ, a 45% decrease from the previous 6 months. Average prices for producer offers were similar to those offered in the first half of 2022. Producer offers made between February and August 2023 ranged from $10.49/GJ to $18.20/GJ. The spread of producer prices offered in this period has reduced from the previous periods.

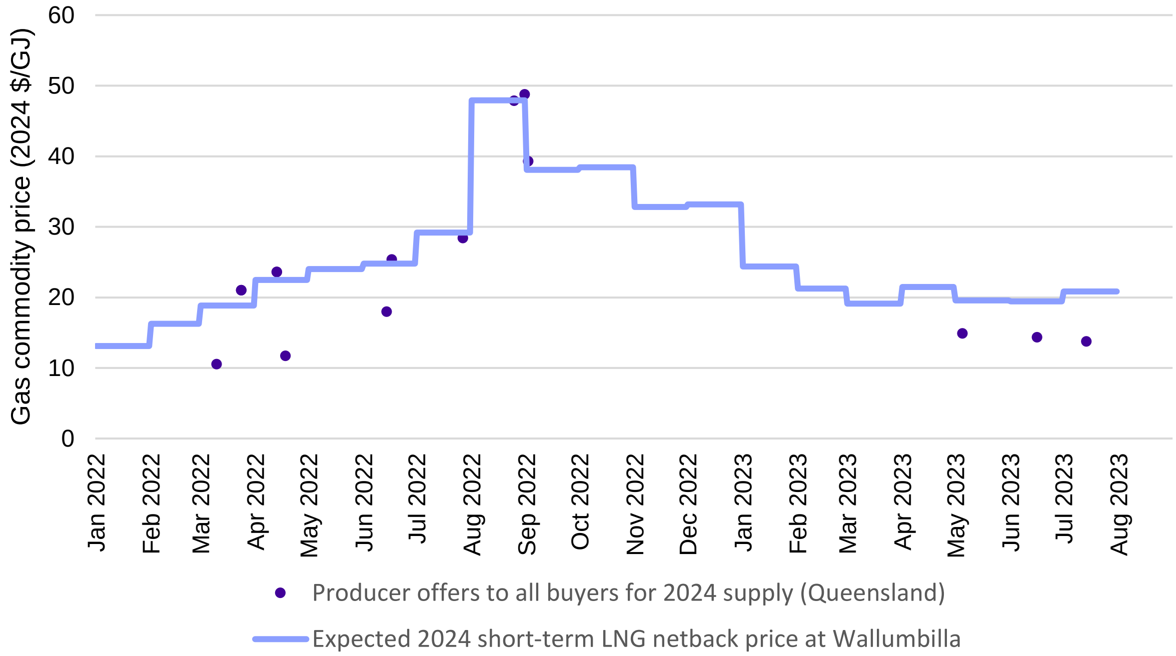
The volume-weighted average price of retailer offers made between February and August 2023 for 2024 supply was $19.50/GJ, a 21% decrease from the previous 6 months. Average prices for retailer offers remain 17% above the first half of 2022. Retail offers made between February and August 2023 ranged from $15.05/GJ to $25.32/GJ.

Bids to producers averaged $14.18/GJ over the February to August 2023 period, broadly consistent with the bids prices observed in the previous 6 months ($14.54/GJ).

4.3.2. Prices for supply in Queensland in 2024 tracked below short-term LNG netback prices.

Chart 4.5 presents offers made by producers between 1 January 2022 and 8 August 2023 for supply in Queensland in 2024.

Chart 4.5: Gas commodity prices (2024$/GJ) offered by producers to all buyers for 2024 supply (Queensland) and short-term LNG netback expectations



Source: ACCC analysis of information provided by suppliers.

Note: This chart only includes offers that relate to contracts with a term of 1 to 3 years. Offers with pricing mechanisms linked to oil prices have been excluded.

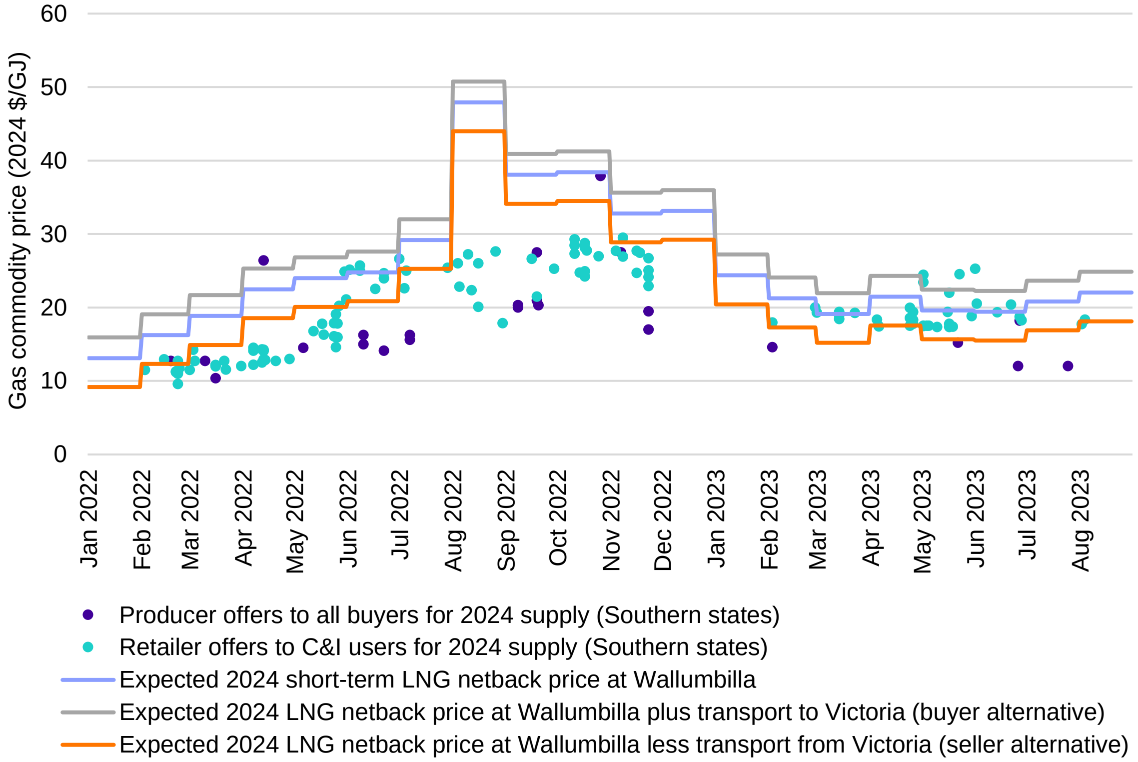
Prices offered by producers in the first half of 2022 for supply in Queensland in 2024 largely tracked the short-term LNG netback price. Since mid-2023, producer prices have tracked below short-term LNG netback prices and what producers could expect on a short-term basis in the international market. As noted in section 4.3.1, between February and August 2023, LNG producers made no offers to the domestic market for 2024 supply.

4.3.3. Most retailer offers to the southern states for 2024 supply tracked between short-term LNG netback buyer and seller alternatives; Producer offers in 2023 were lower than retailer offers.

Chart 4.6 compares offers in the southern states for 2024 supply with short-term LNG netback prices and the buyer and seller alternatives.[96]

[96] The buyer alternative reflects the LNG netback price at Wallumbilla plus the cost of transportation. The seller alternative is the LNG netback price at Wallumbilla less the cost of transportation of gas to Wallumbilla (from the south). They are defined in detail in Appendix B.

Chart 4.6: Gas commodity prices (2024$/GJ) offered to the southern states for 2024 supply against short-term LNG netback expectations



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

Note: This chart only includes offers that relate to contracts with a term of 1 to 3 years. Offers with pricing mechanisms linked to oil prices have been excluded.

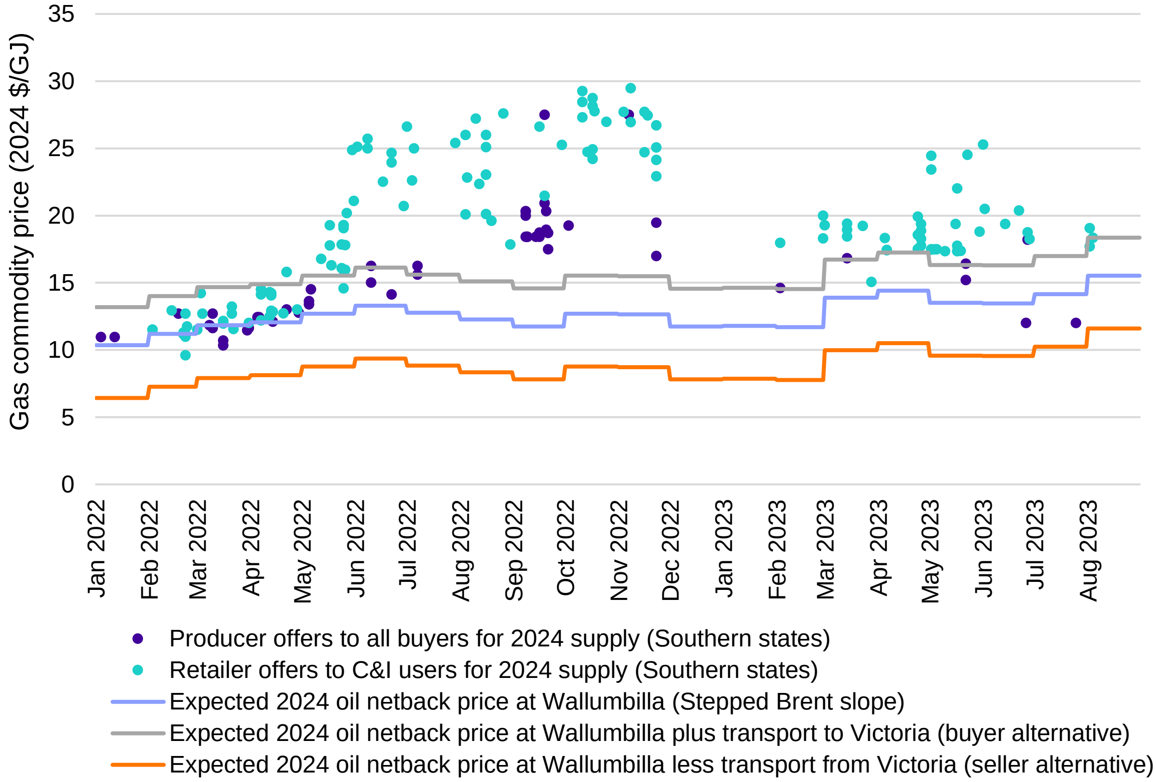
Prices offered by retailers between February and August 2023 for 2024 supply in southern states are, generally, lower compared to those offered in the second half of 2022. Retail prices offered in 2023 have tracked between short-term LNG netback buyer and seller alternative prices, which is consistent with previous findings of the Gas Inquiry.

Producer offers continued to be priced lower than both the buyer and seller alternatives.

4.3.4. Most producer offers to the southern states for 2024 supply tracked between oil-linked netback buyer and seller alternative prices; Most retailer offers for 2024 supply were higher than oil-linked buyer alternative prices.

Chart 4.7 compares offers made between January 2022 and August 2023 by producers and retailers in the southern states for 2024 supply, with medium-term oil-linked LNG netback buyer and seller alternative prices.

Chart 4.7: Gas commodity prices (2024$/GJ) offered for 2024 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: Offers specifying pricing mechanisms linked to JKM prices have been excluded. The chart only includes offers that relate to contracts with a term of 1 to 3 years.

Most producer offers made between February and August 2023 for 2024 supply in southern states were between the oil-linked buyer and seller alternative prices. Producer offers made in mid-2022 were priced above the buyer alternative. The decrease in producer offer prices in 2023 reflects a return to the trend observed historically, noting the low volume of offers being made.

Most retailer offers made in 2023 for 2024 supply were higher than oil-linked buyer alternative prices.

C&I users have reported that prices offered have fallen from their peak but remain high.

Box 4.1 Prices have softened since their peak but are still high & placing pressure on C&I users.

Between August and November 2023 we met with a large number of C&I users and intermediaries. They told us that that the prices offered for 2024 and 2025 supply years had softened since winter 2023, but remain high. An intermediary, for example, noted in August 2023 that:

> 'The situation right now is much better that it was half a year ago. In Q1 2023 retailers were unable to provide offers either at spot or at fixed prices due to the market intervention. Since then, participation has improved with some larger retailers being able to procure gas around $17/GJ, but $18 – 19/GJ is the norm.'

C&I users and intermediaries told us that:

- the offers received prior to winter 2023 for 2024 supply were around $20/GJ
- the offers received in September and November for 2024 supply ranged from around $15-$20/GJ, with many around the $15-$18/GJ level.

Some also told us that producers had indicated similar pricing for 2025 supply.

Several C&I users and intermediaries also observed that retailer offers were lower than producer offers. A number of C&I users expressed disappointment that prices have not fallen more towards the $12/GJ level, with one user noting that the:

> 'soft winter has only reduced [prices for 2024 and 2025] term contracting down a couple of dollars at the best.'

Most of the C&I users that we consulted that had received offers noted that contract prices remain above $12/GJ and while several expect prices to stabilise, there is a concern that the $12/GJ price anchor in the gas code will act as a price floor. We note however that most of these offers were made before the gas code's pricing rules came into effect.

There is also a concern that competition will not drive prices down, with one stakeholder noting that there appears to be some 'clustering of prices' around the same price level even though some suppliers have much lower upstream costs. When asked how this clustering arises, the stakeholder noted that some suppliers are very good at working out what offers are being made and pricing at that level, adding that it takes just one unsuspecting buyer to give that information to a supplier.

C&I users noted that while prices recently offered are lower than they were in July 2023, they are still around two times higher than what they were able to procure gas for in 2021.

Several users emphasised that at current prices, there is a real risk that they will no longer be able to continue to operate, which could have flow on effects across the broader economy and regional areas (where a number of larger C&I users are located). One stakeholder, for example, noted that:

> 'Trade exposed companies for which gas is a material input cost face a difficult choice. If increased costs cannot be passed on, they can switch fuels if it is technically and commercially viable to do so. Otherwise, they must consider investing outside Eastern Australia.'

Several medium to large C&I users also told us they are choosing to remain on spot products even though they understand the risks, because their operations are not viable at the offered contract prices.

4.4. Prices payable and flexibility available under long-term GSAs for 2024 supply

Price cap does not apply to contracts for supply after the price cap period (23 December 2022 – 22 December 2023)

This section reports on the prices that gas buyers on the east coast are expected to pay for supply in 2024 and the agreed levels of flexibility in GSAs.

GSAs in this analysis:

- are entered into by producers with all buyers, and by retailers with all buyers except other retailers, between 1 January 2022 and 8 August 2023
- have fixed prices or prices linked to a commodity price index, such as Brent Crude oil
- have an ACQ of at least 0.5 PJ and a term length of at least 12 months.

As with the analysis of bids and offers, we estimate prices under GSAs using assumptions relating to several variables, including the AUD/USD exchange rate, the consumer price index, and the price of oil and LNG. While bids and offers are priced using expectations of these variables at the time the bid or offer was made, GSA prices payable are estimated based on current market expectations for the relevant supply year.

4.4.1. Prices agreed under GSAs between February and August 2023 for 2024 supply remain higher than those agreed in the first half of 2022.

Chart 4.8 presents volume-weighted average wholesale gas commodity prices expected to be paid under GSAs executed by producers and retailers for delivery in the east coast gas market in 2024.

The left-hand side of the chart presents average prices payable by producers and retailers in the east coast market under GSAs executed between January 2022 and August 2023 by reporting period. The right-hand side of the chart compares average prices payable under GSAs executed between January 2022 and August 2023 for delivery in Queensland with the southern states.

Chart 4.8: Gas commodity prices (2024$/GJ) payable under GSAs in the east coast gas market for 2024 supply

Source: ACCC analysis of GSA information provided by suppliers.

Note: Volume-weighted average prices are displayed next to the point. All GSAs are for quantities of at least 0.5 PJ per annum and a contract term of at least 12 months. Prices are based on assumptions as at 1 November 2023.

Average prices agreed under producer GSAs executed between February and August 2023 for 2024 supply rose by 3% to $17.69/GJ from the previous reporting period. The prices agreed by retailers averaged $19.38/GJ, a decrease of 12% from the previous reporting period. Average prices for producers and retailers in the February to August 2023 period are 30% and 50% higher than the prices agreed in the first half of 2022, respectively.

Average GSA prices for supply in Queensland in 2024 were higher than in the southern states. This was largely driven by the higher retailer prices in Queensland.

The average prices for GSAs executed by producers between February and August 2023 are higher than contemporaneous offers and bids reported in the previous section. This is in part driven by the different price indices used to forecast prices for GSAs compared to prices for offers and bids.[97]

Our methodology for GSA prices relies on actual price indices at a given point in time (1 November 2023 for this report) and then applies forecast assumptions from that date. The prices for offers and bids use actual price indices at the date of the offer, then forecast assumptions from the date of the offer. This difference in our methodology ensures that the GSA prices are reported as close as possible to current market expectations for the relevant supply year and the offer prices are reported as close as possible to actual prices sellers observed and expected at the time of the offer.

97 Our methodology is explained in Appendix B.

The resulting price differences between producer offers and GSAs may reflect the movements in the underlying price assumptions. For example:

- differences between forecast and actual CPI
- changes in actual and forecast international commodity prices (Brent, JKM)
- changes in actual and forecast foreign exchange rates.

Table 4.1 shows the proportion of GSAs and quantity of gas supplied by pricing mechanism.

Table 4.1: GSAs by pricing mechanism for supply in 2024

Year/variable	Fixed Price	Commodity linked (Brent)	Total
Volume-weighted average price	$15.21/GJ	$15.85/GJ	$15.56/GJ
2024 % Count	78%	22%	100%
2024 % Quantity	45%	55%	100%

Source: ACCC analysis of information provided by suppliers.

Note: Table 4.1 separates GSAs by pricing mechanism executed between 1 January 2022 to 8 August 2023 for supply in 2024. It does not include information from GSAs executed prior to 2022 for supply in 2024. Additionally, our analysis includes GSAs which have an annual contract quantity of at least 0.5 PJ and a contract length of 12 months or more.

International commodity-linked GSAs made up 22% of the total number of GSAs for 2024 supply and accounted for 55% of the volume of gas to be supplied. As noted in Section 4.2, international oil prices have escalated over the second half of 2023, which has resulted in higher forecast prices for oil-linked producer GSAs than oil linked producer offers. Retailer average prices are less affected by movements in commodity indices because a greater proportion of their GSAs have fixed prices.

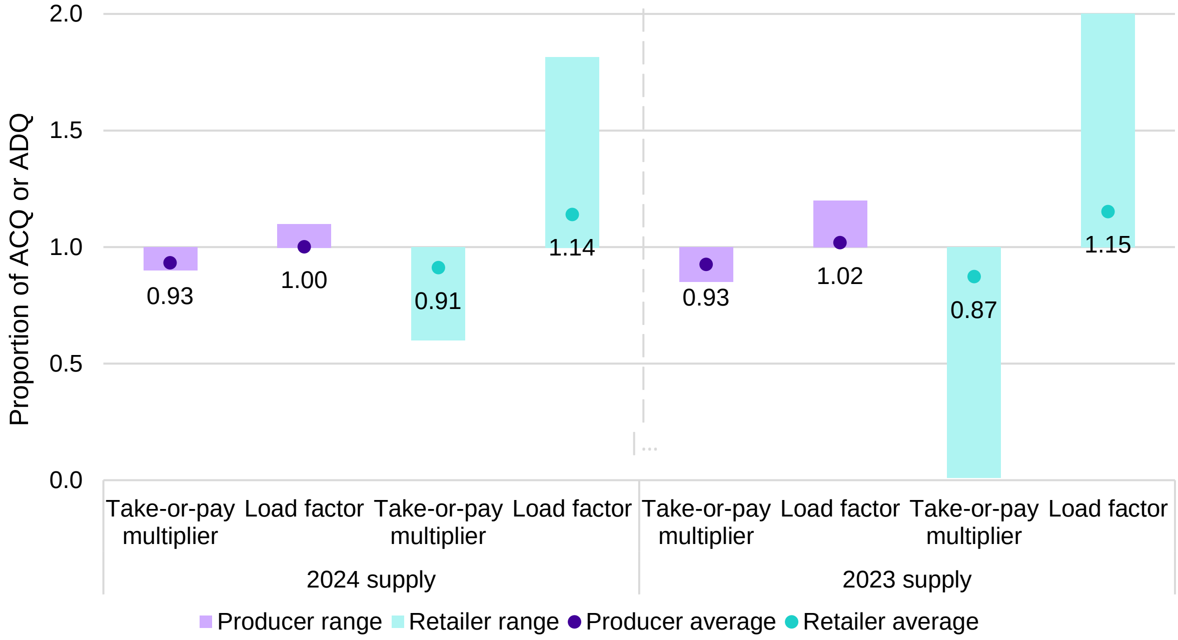
Since January 2021, there have been no GSAs executed with a pricing mechanism linked to JKM that meet our inclusion criteria.

4.4.2. Flexibility under GSAs for supply in 2024

This section reports on volume-weighted average take or pay multipliers and load factors in GSAs. The take or pay multiplier and the load factor are key terms in GSAs that, in practice, provide buyers with flexibility in how they manage their gas usage.

Chart 4.9 shows average flexibility under GSAs for 2024 supply compared to the flexibility under GSAs for 2023 supply.

Chart 4.9: Average load factor and take or pay multiplier under GSAs entered into in the east coast gas market for 2024 and 2023 supply



Source: ACCC analysis of information provided by suppliers.

Note: GSAs for 2024 supply were executed between January 2022 and August 2023, while GSAs for 2023 supply were executed between January 2021 and December 2022.

Producer GSAs provided similar levels of flexibility for supply in both 2023 and 2024.

Flexibility provided by retailers for 2024 decreased compared to 2023. Average take or pay in retailer GSAs for supply in 2024 was 91% with a range between 60% and 100%. This is a reduction in the take or pay level and range observed in 2023. The average load factor for retailer GSAs remains broadly consistent in both 2023 and 2024, with the maximum load factor decreasing from 201% to 182%.

Retailers offered a greater level of flexibility than producers in both supply years. Better flexibility offered by retailers may reflect that they are in a better position to provide flexibility in GSAs to C&I gas users, as retailers can manage changes in the demand for gas on a portfolio basis and may have greater access to underground or pipeline storage.

4.5. Prices payable under short-term GSAs for 2023 supply

Price cap applies to contracts entered into after 23 December 2022 for supply during the price cap period (23 December 2022 – 22 December 2023)

This section reports on the prices for 2023 supply since the introduction of the price cap from 23 December 2022 to 8 August 2023, based on:

- GSAs executed by producers with a term length between 1 day and 12 months based on the data reported in response to the ACCC's compulsory information notices.

- Short-term transactions for bilateral trades occurring outside AEMO operated spot markets and data from the Wallumbilla Gas Supply Hub, DWGM and STTMs (provided by the AER).

The price cap limits the price of gas sold under new contracts during the 12-month period that commenced on 23 December 2022 to $12/GJ.

4.5.1. During the price cap period, producers have sold gas to the domestic market at or below $12 for supply in 2023.

Table 4.2 displays short-term GSAs for supply in 2023, reported by producers from 23 December 2022 to 8 August 2023.

Table 4.2: Short-term producer GSAs for supply in 2023

Seller	Volume-weighted average price ($/GJ)	Minimum ($/GJ)	Maximum ($/GJ)	Volume (PJ)	Data Source
LNG Producers	$11.12	$7.00	$12.00	20.3	s95ZK
Non-LNG Producers	$10.82	$6.50	$12.00	2.8	s95ZK

Source: ACCC analysis of information provided by suppliers

Between 23 December 2022 and 8 August 2023, producers have sold 23.1 PJ of gas to the domestic market at or below $12/GJ for 2023 supply. All this gas was contracted with a term period of less than 1 year. Of the 23.1 PJ sold by producers, around 12.8 PJ was sold for a term length of 3 months or less, with the remaining 10.3 PJ sold for a term length of between 3 and 12 months.

LNG producers provided most of the gas under short-term GSAs over this period, with around half of the volume reflecting outcomes of EOIs conducted by APLNG in late 2022 (2 PJ)[98] and QGC in early 2023 (8 PJ).[99]

Producers primarily sold gas under short-term GSAs to retailers, totalling around 18 PJ, which represents around 4% of forecast 2023 residential and C&I demand. About 1.5 PJ was sold directly to C&I customers or GPG with the remainder of gas (3.3 PJ) sold to other producers.

From March 2023, suppliers have been required to report short-term bilateral transactions to AEMO Bulletin Board.[100] A review of this information indicates some producer contracts with prices that appear to be in excess of $12/GJ. These contracts largely reflect as available gas with prices linked to domestic spot market prices, with contracts executed before the price cap was introduced. The ACCC will continue to monitor and review contract prices. In the event we identify potential non-compliance, we will take appropriate action.

98 Australia Pacific LNG, *Australia Pacific LNG executes new domestic gas sales*, APLNG, 2023, accessed 5 December 2023.

99 Shell, *Walloons*, Shell, 2023, accessed 5 December 2023.

100 Short-term transaction data is not directly comparable to ACCC section 95ZK data. It includes contracts for as available gas and contracts with spot market price pass throughs that were signed before 23 December 2022 (price cap period).

Short-term transaction data shows that between March and August 2023 retailers sold 18.8 PJ of gas to the domestic market that are primarily for supply in 2023. Retailer GSAs are not subject to the price cap and had a volume-weighted average price of $15.73/GJ, compared to $11.12/GJ for LNG producers and $10.82/GJ for non-LNG producers. It is important to note, however, that AEMO short-term transaction data is not directly comparable to information obtained under ACCC compulsory information notices. Short-term transaction data includes contracts for as available gas and contracts with spot market price pass throughs, which can influence the contract price.

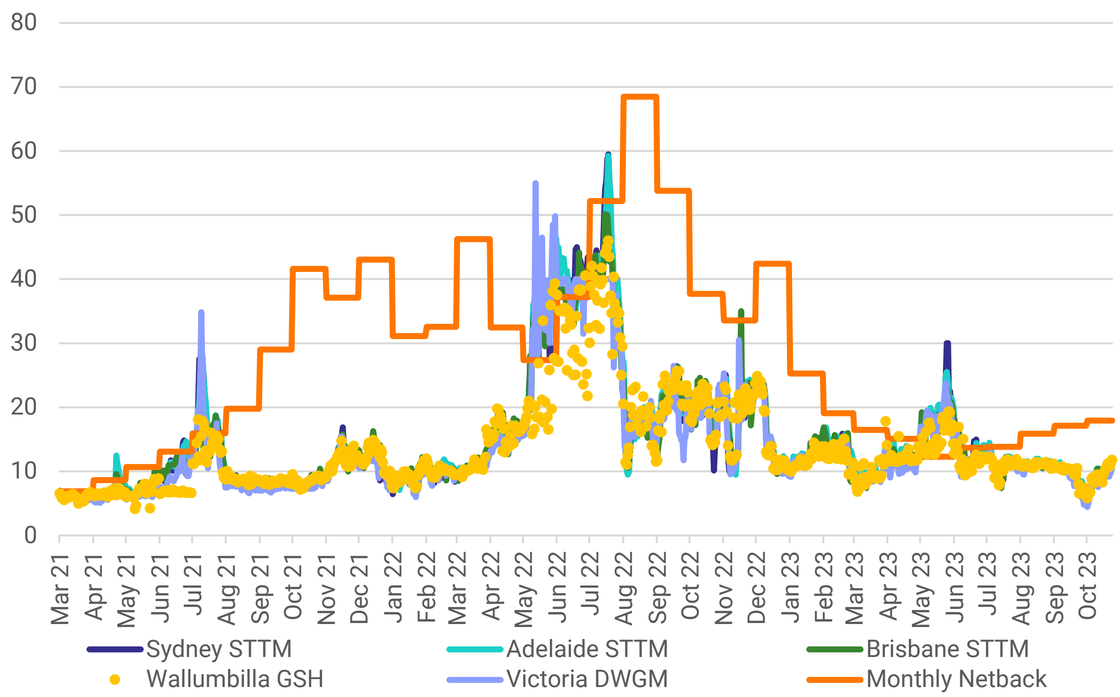
4.6. Spot market prices

4.6.1. Spot market prices increased over winter, though not as high as winter 2022, before falling in the second half of the year

Price Cap does not apply to short-term trading markets, and near term (next 3 days) trades and offers on the Wallumbilla Gas Supply Hub

Chart 4.10 shows daily prices in AEMO operated spot markets including the DWGM, GSH and STTMs compared to short-term LNG netback.

Chart 4.10: Prices on AEMO operated spot markets



Source: AEMO, ACCC (LNG Netback), S&P Global Platts.

Domestic spot prices that remained high in mid-2022 fell in the first half of 2023. Spot prices increased in May 2023, temporarily exceeding contemporaneous LNG netback prices, peaking at $30/GJ (Sydney STTM) on 25 May 2023. Following the peak, prices fell closer to

$10/GJ in June. Since then, prices have stabilised, averaging around $10/GJ on short-term markets in Q3 2023, while contemporaneous LNG netback prices increased.

4.7. Heads of Agreement

This section provides a high-level assessment of the LNG producers' compliance with the HoA for the reporting period between 15 February 2023 and 8 August 2023.

The Australian Government and the 3 east coast LNG producers signed an updated HoA on 29 September 2022 with the objective of preventing a gas supply shortfall through access to secure and competitively priced gas for the east coast domestic market.[101]

Under the terms of the HoA, 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.

LNG producers have additionally committed to increased transparency measures, including publishing offers and EOIs on their website to make gas available more broadly to the Australian domestic market, and providing a quarterly report to the Minister for Resources outlining their respective actions and commitments under the HoA.

The ACCC will continue to monitor and report on the progress of the commitments LNG producers have made under the updated HoA as part of our ongoing gas inquiry reporting.

4.7.1. LNG producer offers to the domestic market

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 15 February and 8 August 2023, east coast LNG producers sold 3.6 PJ of spot or additional LNG cargoes to the international market. Over the same period the east coast LNG producers offered over 26 PJ, directly and in EOIs, to the Australian domestic market for supply in 2023. This is in addition to the volumes offered to the domestic market in the previous reporting periods. In our June 2023 report, we noted that LNG producers had already offered over 274 PJ of gas for 2023 supply made between 19 August 2022 and 15 February 2023.

During this period, LNG producers sold 18.06 PJ for supply in 2023 to the domestic market (17.41 PJ to non-LNG producers and 0.65 PJ to each other).

LNG producers also traded gas via time and location swaps. Between 15 February 2023 and 8 August 2023 LNG producers swapped approximately 24.66 PJ (10.44 PJ with non-LNG producers and 14.22 PJ with each other) of gas with buyers in the Australian domestic market for 2023 supply. Gas swaps do not provide a net increase in the volume of gas LNG producers supply to the Australian domestic market. However, gas swaps can provide increased liquidity to the market, particularly over periods of peak gas demand.

[101] Department of Industry, Science and Resources, Heads of Agreement - The Australian East Coast Domestic Gas Supply Commitment, September 2022.

4.7.2. Equivalent volumes offered to the domestic market with reasonable notice

Under the HoA, LNG producers have committed to not offer uncontracted gas to the international market without first offering to the Australian domestic gas market with reasonable notice on competitive market terms.

LNG producers used direct offer processes, EOIs, short-term markets, and customer bids to supply to the domestic market in demonstrating compliance with the HoA.

In general, the offers used to demonstrate compliance with the HoA provided sufficient notice of around 2 or more weeks for gas buyers to consider the offer, and reasonable notice of around 2 or more months between the date of the offer and the supply start date.

In this reporting period we have observed a reduction in the average term length of offers. No offers were reported with a term length of greater than 1 year, and an increasing proportion of gas is being sold through Gas Supply Hubs and Short Term Trading Markets where gas is sold for supply the next day or within a week.

4.7.3. International competitiveness of domestic offers

Under the HoA, LNG producers have committed to offer internationally competitive prices to the domestic market and to have regard to spot and term LNG prices they could reasonably expect to receive when making domestic offers.

We have observed that LNG producers have continued to make offers consistent with LNG netback prices or regard to LNG netback prices in their offers and EOIs. Offers at LNG netback prices can be considered internationally competitive and meet the HoA commitments.

We further note that an increasing proportion of gas has been offered through GSHs and short-term markets with a corresponding decline in the proportion of gas offered through EOI processes or via long-term contracts. Prices at the Wallumbilla GSH and the STTMs have been below the ACCC’s LNG netback price throughout this reporting period except for the period between 2 May 2023 and 19 June 2023.

We note that while LNG netback prices have fallen from their record highs in mid-2022, they remain above their long-term averages.

4.7.4. Transparency measures

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:

- expressions of interest and/or Annual Delivery Plans
- volumes committed for sale in the previous period, by customer type (for example, Commercial and Industrial, GPG, retailer, LNG producer)
- volumes offered because of extraordinary unplanned circumstances, and what the extraordinary unplanned circumstances were.

In general, the LNG producers have published useful information on their websites. Under the HoA they are expected to publish more information to provide domestic customers with increased visibility of uncontracted gas. Our preference is that LNG producers provide all required information on their website, including EOIs offering uncontracted gas, Annual Delivery Plans, volumes committed for sale in the previous period and details on volumes offered due to extraordinary unplanned circumstances.

5. Retailer behaviour review

Key Points

- In June 2023, the ACCC commenced a review of retailer behaviour, focusing on retail supply to C&I customers. The review is being carried out in line with the ACCC's inquiry role to, among other things, inquire into measures to improve the transparency of gas supply arrangements in Australia. The ACCC initiated this in response to C&I users' concerns about the selling and pricing practices of some retailers.
- The review is being conducted in 2 stages:
  - Stage 1, reported on in this chapter, has focused on **retailer selling practices** and involved extensive consultation with C&I users, intermediaries, retailers and industry associations.
  - Stage 2, which is to be conducted in 2024, will build on Stage 1 with a focus on **retailer pricing practices**, including the costs, risks and other factors influencing pricing decisions.

Stage 1 – Key observations

- Stakeholders agreed that tight and volatile conditions in the east coast market over the past 2 years posed significant challenges for retailers and C&I users, and contributed to a deterioration in competition to supply C&I users and some retailers' selling practices.
- Consultation also revealed that C&I user experiences differed across retailers, with some retailers more accommodating and employing more customer-centric selling practices than others. Care should therefore be taken not to generalise across retailers.
- Stakeholders observed the following about retailer selling practices:
  - C&I users' concerns primarily centred on short offer validity periods, withdrawals and/or amendments of offers, the limited ability to negotiate and the increasing number of risks being allocated to C&I users. Concerns were also raised about the spot market linked products, and the adequacy of information provided by retailers.
  - Particular concerns were raised with the 'take it or leave it' approach employed by some retailers in 2022 and early 2023, with some C&I users noting it generated a real 'sense of urgency' and exacerbated the imbalance in bargaining power.
- Many retailers told us that their standard selling practices did not change over this period. However, some acknowledged there was a deterioration in 2022 and early 2023, which was attributed to the need to manage their exposure to market volatility and the increasing costs, risks and complexities associated with retail supply.
- Towards the end of our consultation, stakeholders informed us that in the latter half of 2023 there were some improvements in competition and a resumption to retailers' standard selling practices. While encouraging, some retailers' standard selling practices do appear to fall short of what we would expect in a workably competitive market.

- As the interface between the wholesale market and retail customers, some of the poorer selling practices may reflect what retailers have faced when dealing with producers. It is possible therefore that the recently implemented Gas Market Code, together with increased competition to supply C&I users, could lead to further improvements in retailer selling practices.
- We intend to continue to monitor these practices in 2024. If we identify any systemic issues in retailer behaviour, we may make recommendations to the Australian Government.

5.1. Introduction

In the June 2023 interim report, we announced our intention to carry out a review of retailer behaviour, in line with the ACCC's role as part of this inquiry to, among other things, inquire into measures to improve the transparency of gas supply arrangements in Australia.

The ACCC initiated this review in response to the concerns commercial and industrial (C&I) users have raised about some retailers selling and pricing practices. The review is intended to provide transparency on retailer practices and examine whether there are any systemic issues that would benefit from any recommendations to the Australian Government.

The review, which is focusing on retail supply to C&I users that exceed the small customer threshold (i.e. consuming more than 1 TJ p.a.),[102] is being conducted in two stages, with:

- **Stage 1**, reported on in this chapter, focusing on **retailer selling practices** and, in particular, how retailers interact with C&I users when making offers, negotiating and when entering into contracts for the supply of gas
- **Stage 2**, to be undertaken in 2024, building on Stage 1 by focusing on **retailer pricing behaviour** and the costs, risks and other factors that may be influencing this behaviour.

To help inform Stage 1 of the review, we consulted retailers, C&I users, intermediaries (i.e. brokers and energy consultants) and industry associations (see Box 5.1 for more detail on the consultation process). Where possible, we have also independently validated the feedback using information obtained over the course of the Inquiry through the use of our compulsory information gathering powers.

Box 5.1: Stage 1 consultation process

How we consulted retailers and industry associations

On 2 August 2023, we advised those retailers currently supplying C&I users that consume more than 1 TJ p.a. and the Australian Energy Council (AEC) of the review and on 7 August 2023, we conducted an information session to provide further detail of the scope and staging of the review.

In mid-August, we sent these retailers and the AEC a questionnaire. The questionnaire sought information on each retailer's operations over the period 2020-2023. It also sought their observations on current and future market conditions, competition to supply C&I

102 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 NSW, ACT, SA and Queensland; or
- the relevant Victorian and Tasmanian customer protection frameworks.

users, retailer selling practices and any factors that may have affected retailers' ability to compete and/or their selling practices over the period 2020-2023.

We received responses to the questionnaire from the AEC, AGL, EnergyAustralia, Origin, Power and Water Corporation (PWC), Shell and Tas Gas Retail. We also held bilateral meetings with all of these parties, as well as Alinta and Engie.

The retailers supplying C&I users exhibited some diversity in their operations, in terms of:

- the locations in which they operate, with some only operating in specific jurisdictions or regions, while others operate in all mainland capital cities and some regional areas
- the size of C&I users they supply, with some retailers only supplying C&I users that consume between 1 TJ p.a. and 5 PJ p.a., while others also supply those consuming more than 5 PJ p.a.
- the scale of their C&I customer base in terms of customer numbers and volumes supplied
- their operating model and vertical and/or horizontal interests, with some having interests in gas production, pipelines, gas powered generation (GPG) and/or electricity retailing, while others do not
- their approaches to both gas procurement and risk management.

How we consulted C&I users, intermediaries and industry associations

On 2 August 2023, we contacted C&I users, intermediaries and industry associations in the east coast to inform them of the review. We also sent C&I users and intermediaries a survey to get a better understanding of their approach to procuring gas and their observations on current and future market conditions, competition to supply C&I users and retailers' selling practices in the period 2020-2023.

In total, we received 20 survey responses. We also held over 30 bilateral meetings between mid-August and October, with C&I users, intermediaries and industry associations.

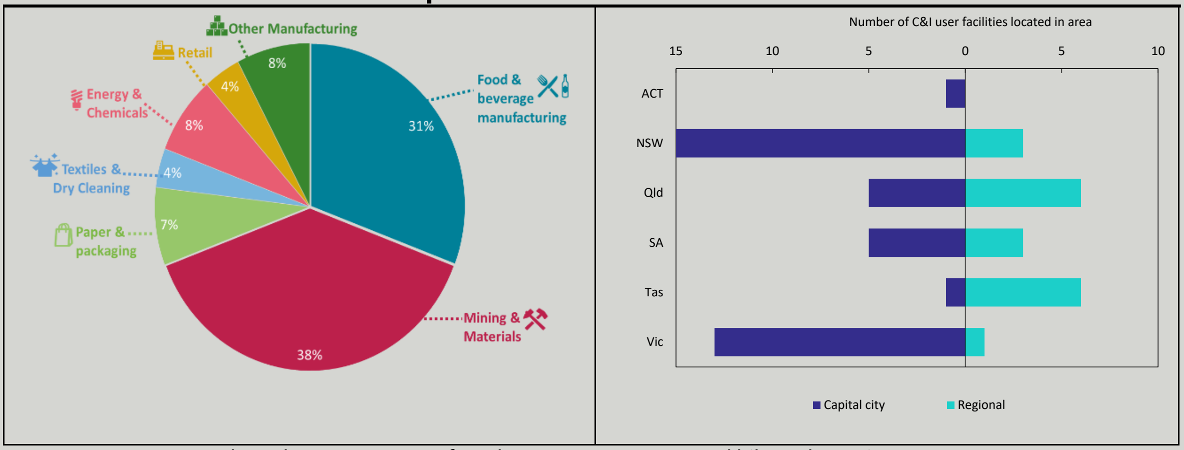
Like retailers, there was significant diversity in the C&I users that we engaged with, in terms of:

- their annual gas demand, which ranged from medium levels of annual consumption (10 TJ p.a. – 499 TJ p.a.) to very large levels of annual consumption (> 5 PJ p.a.)
- the industries in which they operate (see left hand side of Figure 5.1)
- the location of their facilities, with representation from each state and territory, and from both metropolitan and regional areas (see right hand side of Figure 5.1)
- their approach to procuring gas and use of intermediaries, with some C&I users contracting directly with retailers, while others use intermediaries to help inform their decision making.

Additional depth and diversity were provided through bilateral meetings with a number of intermediaries and industry associations, including the Energy Users Association of Australia (EUAA), Australian Aluminium Council, Australian Dairy Products Federation, Australian Food & Grocery Council, Chemistry Australia and Manufacturing Australia.

Figure 5.2: Industries and locations in which C&I users operate

Industries in which C&I users operate*	Locations of C&I users' facilities



* Percentage measures based on percentage of total C&I user responses and bilateral meetings.

The remainder of this chapter sets out the observations from Stage 1 of the review. Commencing with an overview of the role retailers play in the market and the challenges that recent market conditions have posed for both retailers and C&I users, the chapter then sets out the feedback provided on retailer selling practices and the potential for intermediaries to have a conflict of interest if they are paid differential commissions by retailers. It concludes by setting out the next steps for our review of retailer behaviour.

5.2. Role played by retailers in east coast market

5.2.1. Retailers play a critical role in the market

Gas retailers play a crucial role in the east coast gas market, facilitating the supply of gas to a wide range of end users (including C&I users, GPG, households and small to medium enterprises) and managing the contracting arrangements, costs, risks and challenges associated with that supply. They do so by aggregating gas purchased from producers and/or the AEMO operated spot markets, which they then transport to customers via transmission pipelines and, if required, distribution pipelines and/or storage facilities.

As Figure 5.2 highlights, retailers, in effect, act as the interface between their customers and gas producers, transmission and distribution pipeline owners, storage providers and the AEMO operated spot markets. Retailers may also face competition from producers for the supply of gas to larger C&I users that are able to self-contract, or to a group of smaller C&I users represented by a buyers' group. For all other C&I users, retailers represent the primary,[103] and at times, the only means by which gas is procured, with gas either delivered by the retailer to the user's site, or to a location requested by the user.

While not shown in this figure, intermediaries can also play an important role in helping C&I users make more informed decisions about their retail supply and/or self-contracting arrangements. That is, by conducting tenders on behalf of C&I users, evaluating tender responses, negotiating with suppliers on behalf of C&I users and/or providing other advisory

[103] Some C&I users may also be able to procure gas directly from the AEMO facilitated markets if they are registered to operate in those markets, or indirectly via an energy consultant who is registered in these markets.

services. Some intermediaries may also help manage their clients' day-to-day gas requirements, including participation in the markets.

In most cases, retailers will supply gas to their customers under a fixed price mechanism, with the gas commodity and other cost components fixed in advance and only adjusted for inflation and any specified pass through costs (e.g. transportation costs) over the term of the retail supply agreement. Some retailers may also offer to supply gas to customers under a floating price mechanism, with the gas commodity component typically linked to either:

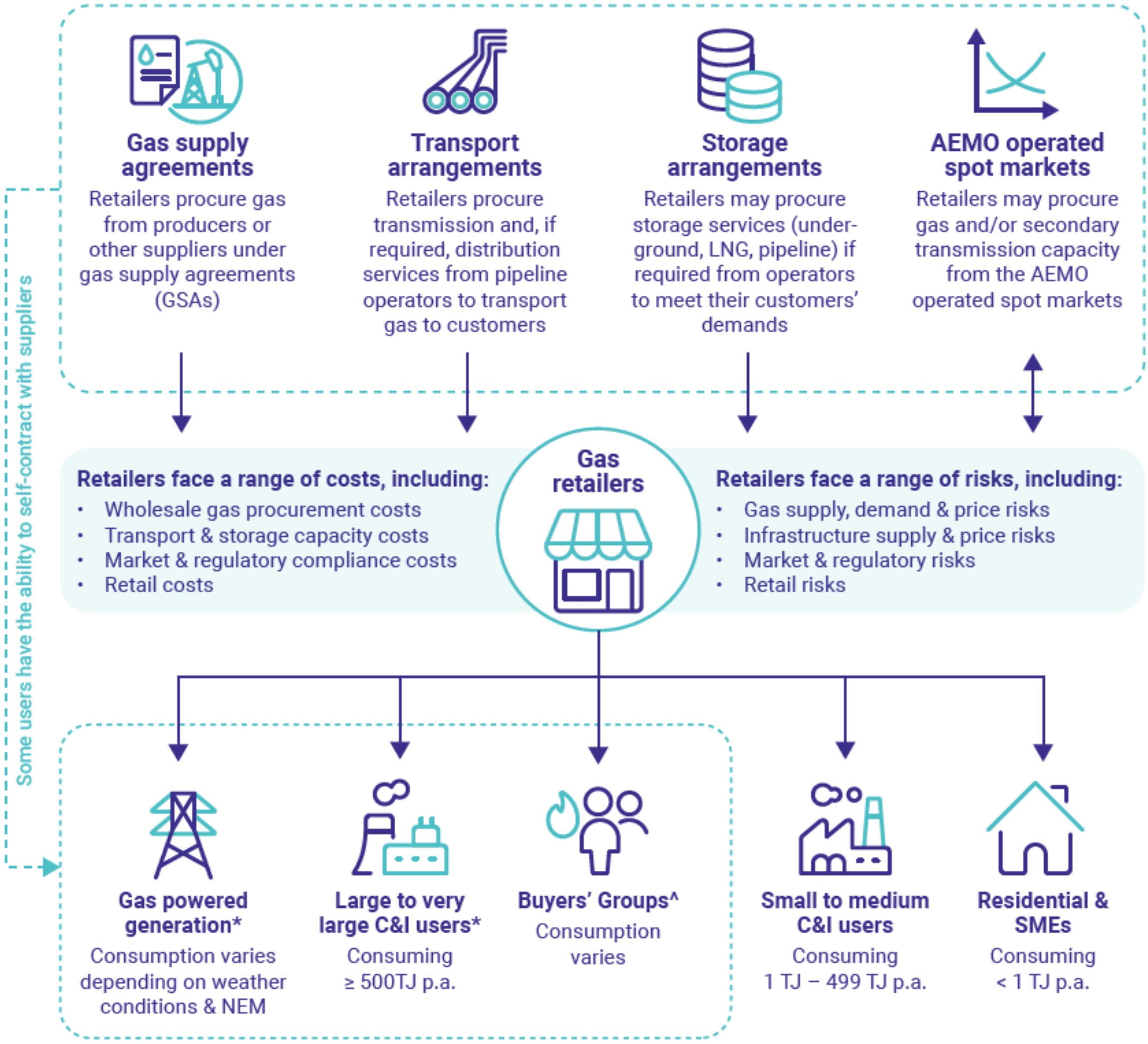
- an AEMO operated spot market (e.g. the STTM, DWGM or GSH)[104]
- an oil or LNG price marker (e.g. Brent crude oil or JKM)[105].

For ease of reference in the remainder of this chapter, we use the term 'spot market linked products' to refer to retail supply agreements where the gas price is linked to the price in an STTM, DWGM or the GSH.

104 ACCC, Gas inquiry 2017-2025 interim report, July 2020, pp. 77-78.

105 ACCC, Gas inquiry 2017-2025 interim report, July 2022, pp. 58.

Figure 5.2: Retailer position in east coast supply chain



* These gas users may have the choice to either procure gas from retailers or to self-contract with producers, pipeline operators, storage operators (if required) and to participate in their own right in the AEMO operated spot markets.

^ Buyers' groups can aggregate demand across a number of very small to medium sized C&I users to enable them to reach a size that they can either procure gas from retailers or self-contract with producers, pipeline operators, storage operators (if required).

5.2.2. Retailers face a number of costs, risks and challenges in supplying C&I users

Retailers incur a range of costs supplying gas to C&I users. They can also face a number of risks, some of which can be hedged, or managed through other means. Further insight into the types of costs and risks retailers may face can be found in Table 5.1.

Table 5.3: Types of costs and risks that retailers may face when supplying C&I users

Costs incurred by retailers	Risks that retailers may face
Wholesale gas costs – this includes: ▪ the cost of procuring gas from producers or other suppliers under GSAs ▪ the cost of procuring gas in AEMO operated spot markets (i.e. the STTM, DWGM and GSH) ▪ gas price related hedging costs.	**Wholesale gas risks** – this includes: ▪ **Gas supply risk:** the risk that contracted supply is insufficient to meet demand and/or that supply is interrupted (due to a permitted interruption, Force Majeure event or other failure to supply)[106] ▪ **Gas demand risk:** the risk that hourly, daily, annual and/or longer-term customer demand is greater than,[107] or lower than,[108] what the retailer has contracted ▪ **Gas price risk:** the risk that the price the retailer pays for gas is higher than what was assumed when setting retail prices,[109] or higher than what is required to compete.
Transport and storage costs – this includes: ▪ the cost of procuring transmission services from pipeline operators, or secondary capacity from the AEMO operated Capacity Trading Platform (CTP) or Day-Ahead Auction (DAA) ▪ for C&I users in distribution networks, the cost of procuring distribution services ▪ if required, the cost of procuring storage (underground, LNG or pipeline) services.	**Transport and storage risks** – this includes: ▪ **Infrastructure supply risk**: the risk contracted transport and/or storage capacity is insufficient to meet demand and/or access to these services is interrupted[110] ▪ **Gas demand risk:** the risk that customer demand is greater or lower than the capacity the retailer has contracted ▪ **Infrastructure price risk**: the risk that the price the retailer pays for transport or storage prices is higher than what was assumed when setting retail prices,[111] or higher than what is required to compete.
Market and regulatory costs – this includes: ▪ the costs of participating in AEMO operated spot markets (including the regulated retail gas markets in relevant jurisdictions) ▪ the costs of complying with any regulatory requirements.	**Market and regulatory risks** – this includes the risk that:[112] ▪ market and/or regulatory compliance costs are higher than what was assumed when setting retail prices ▪ new regulatory obligations are introduced that result in an increase in a retailers' costs and/or makes it more difficult to access gas, transport or storage. ▪ the retailer fails to comply with a regulatory obligation
Retail costs – this includes the costs associated with billing systems, metering, marketing and other retailer related costs.	**Retail risks** – this includes the risk that a customer fails to pay (e.g. due to insolvency).[113]

106 The tools available to manage this risk include entering into GSAs from different supply sources, procuring gas from the spot markets, using storage services and/or passing the risk through to customers.

107 The tools available to manage this risk include entering into GSAs with greater volume flexibility, entering into additional GSAs, procuring gas from spot markets, using storage services and/or passing the risk to customers.

108 Lower demand also poses a risk because of the fixed cost nature of the obligations in GSAs, transportation and storage contracts. The tools available to manage this risk include entering into GSAs with lower take or pay multipliers, selling excess gas or capacity to others, placing excess gas in storage and/or passing some of the risk through to customers.

109 Retailers can face price risks where they enter into fixed or floating price (e.g. spot market, oil or LNG linked) GSAs.

- Fixed-price GSAs may protect retailers from the risks of adverse price movements, but do not allow them to take advantage of any advantageous price movements (i.e. there is potentially an opportunity cost).
- Floating-price GSAs allow retailers to benefit from advantageous price movements, but will also expose them to the impacts of any adverse price movements.

The tools available to manage floating price risk include oil and foreign exchange hedging products, ASX futures contracts for GSH or DWGM linked products and/or passing through the risk to customers by employing the same price mechanism.

110 The tools available to manage this risk include entering into firm transport/storage contracts, procuring gas from the spot markets if an interruption occurs and/or passing the risk to customers (e.g. via a permitted interruption clause).

111 The tools available to manage this risk include entering into fixed price contracts with pipeline and storage service providers and/or passing through increases in these costs to customers.

112 The tools available to manage this risk include cost pass through and change of law provisions in retail agreements.

113 The key tool available to manage this risk is creditworthiness provisions in retail supply agreements.

Retailers can also face challenges accessing the gas, transportation and/or storage capacity they need to compete to supply C&I users, which can also affect their selling practices. As outlined in more detail in section 5.3, access to gas and transportation capacity has been particularly challenging over the last 2 years, with:

- tight supply conditions and a reduction in contracting by gas producers in 2022 and 2023 making it more difficult for retailers to access the gas they require over this period
- contractual constraints on some of the pipelines connecting Queensland to the southern states in 2022, making it more difficult for retailers to access the gas and transportation capacity they required (following the recent expansion of the South West Queensland and Moomba to Sydney pipelines, these constraints have been alleviated).[114]

Retailers that are considering operating in some regional areas may also find it challenging to access capacity on pipelines where a single retailer has contracted all, or a large proportion of, the capacity. In our January 2020 interim report, we set out the results of our review into the impact of these contractual constraints. In short, we found that they were preventing the full benefits of retail competition flowing through to regional areas. We therefore recommended a number of changes to the National Gas Law and National Gas Rules to address this long-standing issue, which included providing for a capacity surrender mechanism.[115] We intend to revisit this issue in Stage 2 of the review to get a better understanding of the impact on prices in these regions.

5.2.3. The position of individual retailers can differ, making it difficult to generalise across retailers

As the discussion above highlights, the position of retailers in the market, together with the costs, risks and challenges that they face in supplying C&I users, means that the role of retailers is inherently complex.

The complexities that an individual retailer will face and its ability to manage these complexities will differ depending on its retail operations. It will, for instance, depend on:

- the locations the retailer supplies
- the types of customers the retailer supplies
- their approach to gas procurement (e.g. some retailers hold a portfolio of GSAs that they use to supply C&I users, others only procure gas when they acquire new customers via back-to-back arrangements, while others rely on the AEMO operated spot markets)
- their internal risk limits and approach to risk management
- their operating model (including any vertical or horizontal interests they may have).

For example:

- retailers with better access to gas (including through long-term legacy contracts) and transport capacity are likely to be better positioned to manage some of the complexities than those who do not (noting long-term supply and transport contracts can also carry risks)

[114] Natural Gas Services Bulletin Board, GasBBuncontractedcapacityoutlookfuture.csv, GasBBuncontractedcapacityoutlookhistory.csv, AEMO Gas Bulletin Board Gas Flows and Capacity Outlooks, accessed 1 November 2023.

[115] ACCC, Gas inquiry 2017-2025 interim report, January 2020, pp. 111-117.

- retailers with interests in gas production and/or gas powered generation are likely to be better positioned to manage some of the complexities than those who do not (noting these interests in themselves also carry risks).

Differences in these areas can also affect an individual retailer's pricing and selling practices, including the degree of flexibility the retailer can offer in retail supply agreements. They can also affect an individual retailer's ability to compete to supply C&I users. These differences mean that it can be very difficult to generalise across retailers.

This point was made by a number of C&I users and intermediaries, who informed us that their experience differed across retailers, with some retailers perceived to be more accommodating and employing more customer-centric selling practices than others. Some care should therefore be taken when considering the feedback provided on retailer selling practices not to assume that all retailers are necessarily engaging in particular selling practices.

5.3. Impact of market conditions on C&I users and retailers

5.3.1. Market conditions were very difficult for C&I users and retailers in 2022

Market conditions were very tight in the lead up to winter 2022

As conditions in the east coast gas market have tightened over the last 5 years, the market has become more susceptible to unexpected changes in demand and supply. This susceptibility was evident in the first half of 2022, when a number of coincidental events in international LNG markets,[116] the National Electricity Market (NEM),[117] and supply side of the east coast market,[118] led to a very tight demand-supply balance in the lead up to winter.

These events triggered a chain of events that had a range of adverse effects on C&I users, retailers and the market more generally. Prices in spot markets, for example, more than trebled between February and May 2022, reaching peaks of $35-$49/GJ in the last week of May.[119] The higher prices in these markets placed a significant amount of financial pressure on C&I users, retailers and other market participants exposed to these markets.

They also contributed to Weston Energy's exit, with Weston suspended from the Brisbane and Sydney STTM and DWGM on 24 May 2022 because it was unable to meet margin

116 Triggered by the Russia-Ukraine conflict and a number of other events in international LNG markets.

117 Triggered by significant unplanned outages and supply constraints experienced by a number of coal generation plants, lower renewable energy generation and higher electricity demand.

118 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.

119 AER, *Gas weekly report - 22 – 28 May 2022*, AER website, 2022, accessed 1 November 2023 and AER, *Gas weekly report - 29 May – 4 June 2022*, AER website, 2022, accessed 1 November 2023.

calls.[120] This suspension triggered the Retailer of Last Resort (RoLR) arrangements in some jurisdictions and the transfer of Weston Energy's customers to designated retailers.[121]

The tight conditions were exacerbated by the Weston RoLR event, which had a significant impact on C&I users, retailers and the broader market

As outlined in Box 5.2, the RoLR event had a significant financial impact on Weston's customers, with most transferred from a spot market linked product to the designated retailer's standing (also referred to as default) offer, as one C&I user observed:

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

Box 5.2: Weston RoLR event

What prompted the RoLR event?

On 23 May 2022, AEMO suspended Weston Energy from the STTM and the DWGM for failing to satisfy margin calls, with the suspension taking effect on 24 May 2022.[122] Weston's suspension from these markets constituted a RoLR event under both the National Energy Retail Law (NERL) (for customers in the Australian Capital Territory, New South Wales, Queensland and South Australia) and the *Gas Industry Act 2001* (Victoria) (for customers located in Victoria).[123]

Weston's customers in these jurisdictions were therefore automatically transferred to the designated RoLRs (i.e. AGL, ActewAGL, EnergyAustralia and Origin).[124] In Tasmania, where there is no gas RoLR mechanism, Tas Gas Retail offered to supply Weston's customers.

What happened in the wake of the RoLR event?

Estimates published by the Australian Energy Regulator (AER) and Victorian Essential Services Commission (ESC) suggest Weston had over 580 C&I customers directly impacted by the exit.[125]

We have heard that having to absorb such a large number of customers in a very short period of time placed significant pressure on the designated RoLRs and Tas Gas Retail and also meant that they had to enter the market to procure material volumes of gas at a time when the market was already under significant pressure. One retailer, for example, stated:

120 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.

121 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.

122 AEMO, Declared Wholesale Gas Market in Victoria – Suspension and Deregistration Notice, 23 May 2022 and AEMO, Short-Term Trading Market – Suspension Notice, 23 May 2022.

123 AER, RoLR Notice, 31 May 2022 and ESC, Notice from the Essential Services Commission – Weston Energy – Gas Market Participation Revoked, 27 May 2022.

124 AGL was the designated RoLR in JGN's NSW distribution network, the Allgas Queensland distribution network and AusNet's Victorian distribution network. ActewAGL was the designated RoLR in EvoEnergy's ACT distribution network. EnergyAustralia was the designated RoLR in AGN's Victorian network. Origin was the designated RoLR in AGN's SA, NSW and Queensland distribution networks, MultiNet's Victorian distribution network and APA's NSW Central Ranges network. AER, RoLR Notice, 31 May 2022 and ESC, Notice from the Essential Services Commission – Weston Energy – Gas Market Participation Revoked, 27 May 2022.

125 AER, *AER ensures continued supply for former Pooled Energy and Weston Energy customers*, AER website, 2022, accessed 1 November 2023, and ESC, *Statement on Weston Energy Pty Ltd*, ESC website, 2022, accessed 1 November 2023.

'As a retailer of last resort, [xx] acquired additional customers without any corresponding wholesale supply arrangements, so in order to manage its exposure, [xx] entered the market to procure material volumes at a time when the market was already under significant pressure.'

Some retailers that we spoke to expressed concerns about the effectiveness of some aspects of the RoLR arrangements. Concerns, were for example, raised about limitations with the AER's directions power, the fact that the RoLR arrangements can be triggered when a retailer is not insolvent (as was the case with Weston) and the lack of timely information on the failed retailer's customers. The ACCC understands the Australian Energy Market Commission (AEMC) is currently considering these issues in its RoLR review.[126]

What impact did the RoLR event have on the broader market?

The impact of Weston's exit was not limited to Weston's customers. Rather, it affected the broader market. One retailer, for example, noted that:

'The Weston RoLR event had a significant impact on the C&I market, in relation to:

- competition for, and the supply of, gas and products offered by retailers; and
- customers' willingness to take on the risk associated with a spot product.'

The RoLR event also posed significant challenges for the designated retailers and the market more generally, as one retailer observed:

'… [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 re-contract 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.'

This statement is consistent with what designated retailers told us, which is that they had to enter the market to procure additional volumes of gas to meet the needs of Weston's customers. This occurred at a time when the market was already under significant pressure, with higher than forecast GPG demand, constraints on available supply and contractual constraints on key southern haul pipelines.[127] It also occurred at a time when AEMO was having to take steps to try and manage the tight conditions[128] and when prices were at unprecedented levels, with:

- prices in the AEMO operated spot markets averaging around $40/GJ in the 2 month period following Weston's exit, reaching peaks of $50-$59/GJ[129] in July 2022, with the

126 AEMC, *Review into the arrangements for failed retailers' electricity and gas contracts*, Directions Paper, May 2023.

127 Following the recent expansion of both the South West Queensland Pipeline and Moomba to Sydney Pipeline, these contractual constraints appear to have been alleviated.

128 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 a voluntary arrangement implemented in 2017 that could be triggered if AEMO identified a shortfall in gas available to meet GPG demand in a peak NEM period. 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. The Gas Supply Guarantee has since been replaced by AEMO's new reliability and supply adequacy functions and powers under the National Gas Law and National Gas Rules, which came into effect in May 2023.

129 AER, Significant price variation report, September 2022, p. 28.

Sydney STTM and DWGM also subject to a $40/GJ administered price cap at points in this period[130]

- prices offered by producers that had any available short-term supply to retailers, reportedly ranging from around $30/GJ to $40/GJ over the same period.

The prices that retailers had to pay to procure additional gas for Weston customers provide some insight into the significant challenges that the Weston RoLR event posed for both retailers and C&I users, the effects of which are still being felt by some retailers and C&I users.

Tight market conditions continued throughout the latter half of 2022, posing further challenges for C&I users and retailers

Figure 5.3 provides further insight into the conditions prevailing in the latter half of 2022. As this figure shows, prices in the AEMO operated spot markets eased somewhat in the latter half of 2022, but remained high. The average LNG netback price for 2023 supply, on the other hand, continued to rise in response to the Russia-Ukraine conflict and other international events, peaking at over $70/GJ in October, before falling to around $40/GJ in December 2022. In the latter half of 2022, the prices offered for domestic supply in 2023 also increased, with:

- the prices offered by producers to retailers and C&I users ranging from around $13.50/GJ to $71.50/GJ (with half the offers exceeding $50/GJ)
- the prices offered by retailers to C&I users ranging from around $23.40 to $35.90/GJ.

C&I users and intermediaries that were in the market at this time noted that it was very difficult to get offers for 2023 supply and, in those cases where they were able to get offers, the prices were 2-3 times higher than what they were in 2021 and less volume flexibility was offered. A number of C&I users also informed us that their operations were not viable at these contract price levels. They decided therefore to use the domestic spot markets, even though they understood the risks associated with doing so.

The challenges referred to by C&I users were echoed by retailers, with one retailer noting that 2022 had been 'a challenging year' due to a:

> '…"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 on competition.

One of the factors some retailers told us contributed to tight conditions in the latter half of 2022 was that producers made very few offers over this period. One retailer, for example, noted that:

> '…the lack of longer term offers at a reasonable price made it challenging to procure gas for C&I users.'

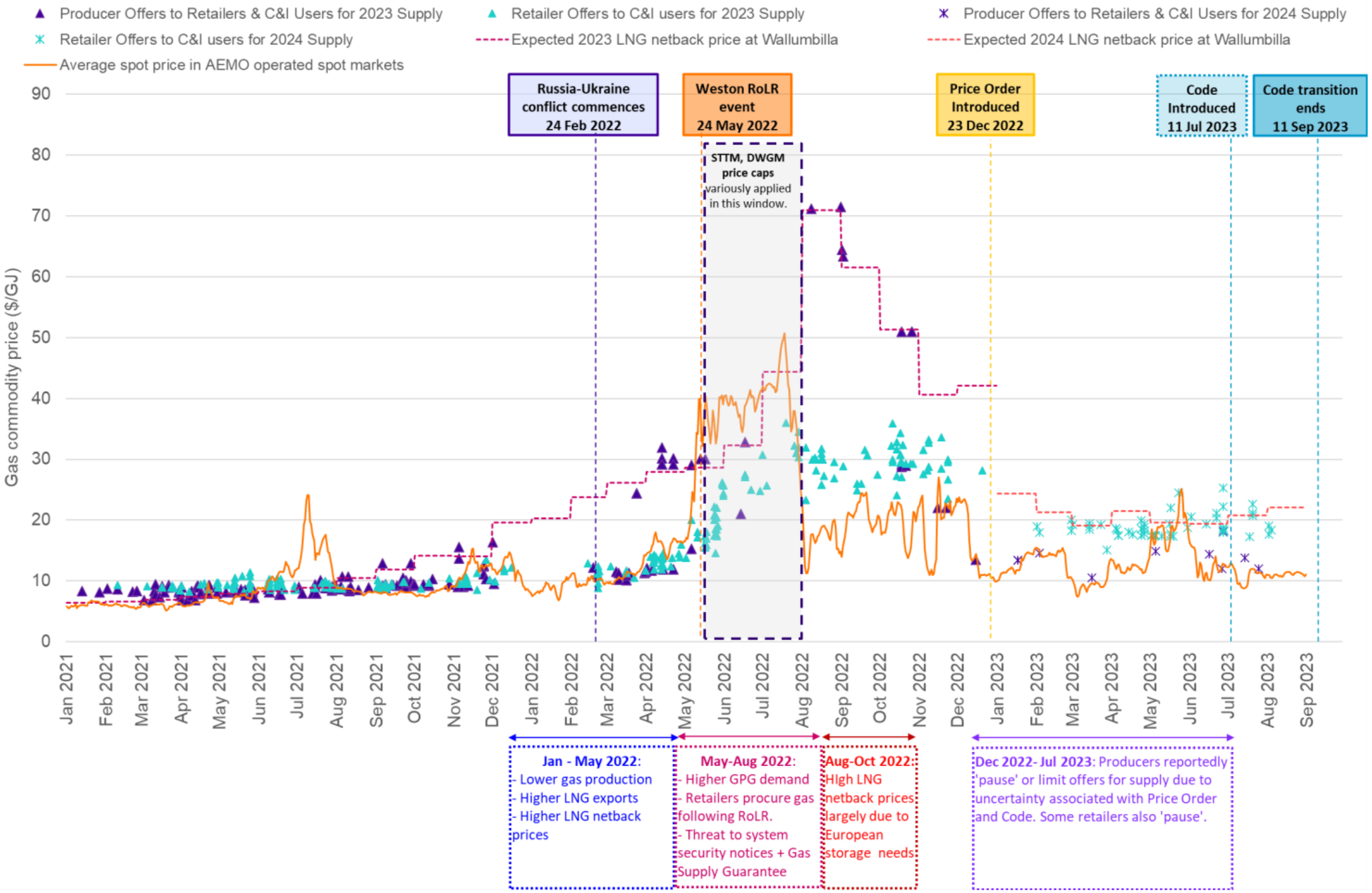
Elaborating on this further, a number of retailers told us the tight supply conditions, and limited contracting by gas producers, meant that at times they had to focus on supplying

[130] 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.

their existing customers, rather than competing to supply new customers. Some retailers also noted that contractual constraints on pipelines used to transport gas from Queensland to southern states, limited the amount of gas that could be transported south on a firm basis. It is worth noting that following the recent expansion of both the South West Queensland Pipeline and Moomba to Sydney Pipeline, these contractual constraints appear to have been alleviated.

The challenges that retailers faced in accessing gas and transportation capacity over this period appear to have contributed to the difficulties that C&I users experienced over this period and adversely affected competition.

Figure 5.3: Gas commodity prices offered in the east coast gas market between 2021-2023



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

Note: Data includes offers made between 1 January 2021 and 31 December 2022 for 2023 supply, and offers made between 1 January 2023 and 8 August 2023 for 2024 supply. See chart 4.3 for further detail on the offers for 2024 supply made in 2022 and 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 the Wallumbilla day-ahead price.

5.3.2. A 'pause' in contracting by producers in 2023 has posed additional challenges for C&I users and retailers

Prompted by concerns about high gas prices in the latter half of 2022, the Australian Government announced in December 2022 that it would implement both the Gas Market Emergency Price Order (the price cap) and the Gas Market Code (the Code), both of which would apply to producers but not retailers (see Overview for details). The price cap[131] came into effect on 23 December 2022 and will end on 22 December 2023, while the Code came into effect on 11 July 2023, but did not become fully operational until 11 September 2023.

In late 2022 and through 2023, most producers reportedly 'paused' their contracting activities and, in some cases, terminated negotiations that were close to being finalised. We were also told that some larger producers appeared to be waiting for the outcome of the Code Ministerial exemption process before making offers.

The contracting pause limited the ability of retailers to procure gas and make offers

Since the contracting 'pause' in the first half of 2023, there has been an observed increase in volumes contracted for 2024 supply between May to August 2023 . However, the total volume agreed under GSAs still remain below the volume at a comparable time for 2023 supply (see Chapter 2 for more detail).

Like 2022, the reduction in contracting by producers affected retailer contracting activities, with several C&I users informing us that they found it difficult to obtain offers in the first half of 2023. Some retailers also informed us that they had to 'pause' or limit their own contracting with C&I users because of difficulties in procuring gas from producers.

> '…there was a lot of uncertainty on the part of sellers, and they stopped marketing gas for a period of time in order to fully understand the price cap. This certainly limited the ability for us to offer gas to C&I users for 2023.'
>
> '[...] briefly paused quoting new acquisition customers for part of FY23 due to challenges in sourcing supply given the introduction of the December 2022 Emergency Price Order and the then impending reasonable price provisions.'

Retailer activity can be seen in Figure 5.3. It shows that retailers made fewer offers for 2024 supply in the first half of 2023[132] than they did during the equivalent period in 2022, with the prices offered by retailers over this period ranging from $15-$25/GJ. Over the same period:

- the small number of producer offers for 2024 supply ranged from around $10-$18/GJ
- the LNG netback price at Wallumbilla for 2024 supply ranged from around $19-$24/GJ
- the average price in AEMO operated spot markets ranged from around $7/GJ-$25/GJ.[133]

[131] The price cap, provides 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.

[132] Data collected up to early August 2023.

[133] 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 the Wallumbilla day-ahead price.

One of the difficulties many retailers noted they faced in making offers in 2023 was that there was a general expectation that the price cap would flow through to retailer prices, even though retailers were not subject to the price cap and producers only made small volumes of gas available at $12/GJ (see section 4.5). We heard similar expectations in our discussions with C&I users, with a number expressing some frustration about the fact that the benefit of the price cap did not appear to have flowed through to gas users.

As set out in more detail in section 4.5, it would appear that only 23 PJ of gas has been made available by producers under contract at or below the price cap of $12/GJ by 8 August 2023. Of the 23 PJ, retailers were able to procure around 18 PJ in total (or around 0.5 to 3 PJ each). This represents around 4% of forecast residential and C&I demand in 2023,[134] which highlights that retailers were only able to contract a small amounts of gas relative to their supply commitments. It is likely that retailers had contracted a large portion of their gas portfolio based on expected supply commitments prior to the implementation of the price cap. One retailer informed us, most of their contracting for 2023 supply had been completed by the time the price cap came into effect.

Stakeholders informed us that, for gas made available at or below the price cap, some contracts provided for less gas to be supplied in winter. One retailer told us that this meant it had to enter into other arrangements (including swaps, storage and other arrangements), to smooth the supply out over the year, which resulted in a higher effective price than $12/GJ.

Conditions appear to have improved in the latter half of 2023, but C&I users and retailers are concerned about the future outlook

Although not shown in Figure 5.3, C&I users and intermediaries have informed us that retailers have been making more offers since the information used to generate this figure was collected (August 2023). They also noted that retailer offers have softened somewhat to around $15/GJ-$18/GJ, with some observing retailer offers below producer offers (see Box 4.1).

While offer prices have reportedly fallen, C&I users remain concerned about the impact of high gas prices on their operations, with several noting that if high prices persist, there is a real risk they will have to close their operations, which could have flow on effects across the economy.

Looking forward, a number of C&I users, intermediaries and retailers noted the potential for the east coast gas market to become more volatile and subject to greater security of supply risks. When asked if the Code could help to mitigate these risks, many noted that it was too early to determine the Code’s impact.

Retailers noted they were keen to see how the exemption framework will operate and the impact of supply commitments made as part of the Ministerial exemption process. Some retailers noted that if the supply commitments only result in gas becoming available on a short-term intra-year basis, then it will become increasingly difficult for retailers to operate. The move to shorter term intra-year contracting by some producers and/or LNG producers is a more general concern that some retailers have raised, with one noting that ‘you can’t build a retail book on this basis’.

134 Based on AEMO’s forecasts for residential, commercial and industrial demand in 2023. See AEMO, 2023 Gas Statement of Opportunities – report figures and data, Figure 7.

Some of the other feedback that we received from stakeholders is set out in Box 5.3.

Box 5.3: Other feedback provided on the Code

Through the Stage 1 engagement process and our general C&I survey that was carried out between August and October 2023, we received a range of feedback on the Code. A number of C&I users, intermediaries and retailers, for instance informed us that:

- producer offers made up to September 2023 were 'well in excess' of $12/GJ for supply in 2024 and beyond
- the price cap of $12/GJ appeared to be acting as a 'price floor' rather than a 'price cap'
- some producers seemed to try and rush GSAs through before the Code became fully operational, while others appeared to be holding off until Ministerial exemptions were determined.

Some C&I users also questioned whether any of the benefits associated with the Code would flow through to them, with some observing this had not occurred with the price cap.

Questions were also raised about the adequacy of some of the information that producers are required by the Code to now publish, with specific concerns raised about the 24 month outlook for uncontracted gas. One intermediary noted that reporting a single uncontracted supply number for the 24 month period was unhelpful because it provided no insight into when the gas may be available within that period. It is worth noting that in the period following this concern being raised, the ACCC released its proposed determinations regarding suppliers' record keeping, publishing and reporting obligations. The proposed determinations, among other things, requires covered suppliers to publish the volume of uncontracted regulated gas that is likely to be available to the supplier in each quarter of the 24 month period.

5.3.3. Competition to supply C&I users deteriorated in 2022, but there have been some recent improvements

Several retailers informed us that the Weston RoLR event, coupled with the difficulties in procuring gas from producers under term contracts, led to a reduction in competition to supply C&I users in the latter half of 2022. Some retailers, for example, told us that they had to cease competing for new customers to ensure they could meet their obligations to supply existing customers. The deterioration in competition continued into the first half of 2023, driven in large part by the inability to procure gas from producers, as a number of retailers observed:

> 'For periods during FY2023 there was no competition in the east coast gas market… Retailers were therefore unable to procure gas from producers. Throughout FY2023, the gas market has been challenging and uncompetitive for C&I users.'
>
> 'The inability of non-producing retailers to procure gas at reasonable prices, has meant competition has waned.'

C&I users and intermediaries also commented on the limited degree of retail competition over this period, with some noting that at times there only appeared to be 2-3 retailers competing. They also noted the impact that the reduction in competition had on their bargaining power, with some stating it may have contributed to the high prices and the 'take it or leave it' approach and 'scarcity' tactics employed by **some (but not all)** retailers over this period (see section 5.4 for more detail).

Concerns were also raised by a number of C&I users about the lack of competition in some regional areas where a single retailer operates. One C&I user, for example, noted that:

> 'The preferred position of our incumbent retailer, lack of commercially viable alternatives and the previous (and currently unknown) willingness for wholesalers to negotiate directly has created a perceived/real imbalance.'

Through our discussions with C&I users and intermediaries it became clear that while most were dissatisfied with the level of competition, their individual retailer experiences differed, with some having a more positive experience than others. Some retailers were, for example, viewed as being more accommodating and customer-centric, while others were not.

Towards the end of our consultation process, a number of C&I users, intermediaries and retailers told us that there were some signs that competition was improving, with at least 5 retailers reportedly actively competing to supply C&I users in the latter half of 2023. Notwithstanding this improvement, C&I users generally remain concerned about the level of competition to supply C&I users and the impact this can have on their bargaining power and retailer behaviour. We intend to examine this further in Stage 2 of our review.

5.4. Feedback on retailer selling practices

Through the consultation process, C&I users, intermediaries, industry associations and, in some cases, retailers, expressed concerns about a number of aspects of some retailers' selling practices. Broadly, the concerns related to:

- retailer offer validity periods and amendments or withdrawals of offers within this period
- the willingness of retailers to negotiate with C&I users
- the extent to which some risks are being transferred from retailers to C&I users
- the sale of spot market linked products to C&I users that may not be well placed to understand or manage the risks associated with these products
- the sufficiency and comparability of information provided on retail charges.

The concerns that have been raised about each of these aspects of retailer selling practices are outlined below, along with the feedback provided by retailers and our observations on the better practices in these areas.

We note that some of the more significant concerns that were raised about retailer selling practices relate to behaviour that occurred in 2022 and the first half of 2023. As conditions in the market have started to ease and competition has started to improve, we have heard that some of these practices have ceased. That is not to understate the effect that these practices had on C&I users, during what was a very challenging time. It does, however, provide some important context for some of the observations that follow.

5.4.1. Retailer offer validity periods and withdrawals or amendments of offers within this period

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.

C&I users are concerned about offer validity periods & the potential for such compressed validity periods, offer withdrawals or price increases to be used as a ‘scarcity’ tactic

Some C&I users and intermediaries informed us that the offer validity period employed by many retailers ranges from 3 to 6 days. However there appears to be some variation across retailers, with some providing 7 days and one providing 10 days. We also heard reports of more compressed offer validity periods (of 1-2 days) being employed by some retailers in 2022 and early 2023:

> ‘…in mid-2022, there were instances where offer validity periods were reduced to two days. This made it difficult to seek internal approval and execute the agreements in the short time frame.’

Most C&I users told us that a 3-6 day offer validity period provides them insufficient time to properly assess offers, negotiate with the retailer (where that is possible) and obtain the necessary internal approvals, as the following statements reflect:

> ‘…not all retailers provide their offer on the same date. Some may provide earlier than the due date. So by the time we get all offers we have less days to evaluate and negotiate and present a recommendation for internal approval, then we can move to legal contract review and signing. The retailer offer requires all of those steps to be completed, i.e. the contract needs to be executed in less than 7 days from the time we receive the offer. Timing is too short.’

> ‘…by the time you socialise and get approvals for offers internally the offer has expired.’

Some C&I users also told us that the time they require to obtain internal approvals has increased in the wake of the 2-3 fold increase in gas prices, because they can no longer rely on the same delegated authorities that they had in place.

When asked how long they need to undertake the steps set out above, most C&I users told us they need a ‘minimum of 2 weeks’. There were, however, some exceptions to this, with one C&I user with a more complex organisational structure, stating it needs around 28 days to obtain the necessary approvals. This C&I user told us that it had been able to negotiate an extension to the offer validity period so it could obtain the relevant approvals. Other C&I users also noted the potential to seek an extension, but stated that this was not possible with all retailers and that it came with the risk the offer would be withdrawn or increased.

The other concern that was raised in this context is that some retailers have included a caveat in their offers, which enables them to amend or withdraw the offer **within** the offer validity period. Some C&I users noted that these provisions were relied upon heavily in 2022 and early 2023, when the prevalence of offer withdrawals and amendments increased.

Elaborating further on what occurred in 2022 and early 2023, a number of the C&I users and intermediaries that were in the market at the time noted that:

- Offer validity periods were more compressed, with some retailers providing C&I users C&I users as little as 1-2 days to accept offers.
- There were more instances of retailers amending or withdrawing offers in this period, with many of the C&I users and intermediaries that we consulted telling us they had offers withdrawn or amended. We also heard from:
  1. one C&I user who told us that a retailer amended the price in its offer 3 times and withdrew its offers on a number of occasions in 2022
  2. an intermediary who told us a number of retailers were 'pull[ing] their offers' and 'refus[ing] to quote' during the period of gas market volatility in 2022.
- Some retailers were delaying responses to queries and/or negotiations in this period, which then meant offers lapsed and higher prices then offered. One C&I user, for example, told us they had 'no option but to accept' a higher offer from a retailer after the initial offer expired because the user was waiting for the retailer to respond to a query. This user stated that delays in responding to customer queries should not result in greater financial costs to the customer.

Some of the C&I users and intermediaries that we spoke to noted that these practices generated a real 'sense of urgency' and underscored the 'take it or leave it' approach employed by **some (but not all)** retailers in 2022 and early 2023. A number of these stakeholders suggested that these practices may have been employed by some retailers during this period as part of a 'scarcity' tactic to place pressure on C&I users to agree to higher prices and less favourable terms:

> 'They are clearly playing the scarcity card. Banking on fear.'
>
> '[in the last 12 months there has been] more pressure to sign or the price may increase.'

A similar observation was made by one of the retailers we spoke to, who stated that:

> '…we have seen other retailers provide short-term validity to drive a decision from customers by creating urgency, particularly post the RoLR event in May 2022.'

Many retailers stated that their approach to making offers did not change in 2022 or 2023, but some informed us changes were required to manage their exposure to market conditions

In the voluntary questionnaire, we asked retailers if their offer validity periods and/or their approach to amending or withdrawing offers changed over the period 2020-2023. Many retailers stated that their approach had not changed over this period.

There were, however, a small number that noted that they shortened their offer validity periods in 2022 and early 2023, in response to the tight and volatile market conditions.

> '[we] set up more stringent time frames in relation to offers to C&I customers when pricing in Cal2022, this was mostly a reflection of market price volatility at unprecedented levels and the shorter validity period by upstream suppliers for any offers made.'

> '…the offer validity period changed…in CY2022 due to the RoLR event and introduction of $40/GJ market cap. Since mid-2023, the offer validity period reverted back.'

As to withdrawals or amendments of offers, retailers told us that while rare, these actions may be necessary:

> '…in extreme circumstances where there has been significant movement in the market.
>
> '…in market conditions that would expose [it] to unmanageable risk.'

The other interesting point that emerged in retailers' responses to the questionnaire was the difference in the standard offer validity periods employed by retailers, which ranged from 5-10 days. When those with shorter offer validity periods were asked why this was the case, they stated that:

> '…market volatility means that it would present an unacceptable risk to [the retailer to] hold offer prices any longer [than 5-6 days].'
>
> '…market conditions can be volatile, and this timeframe [of 5 days] allows for the most up to date pricing.'

Another noted that it may be required by retailers that take a back-to-back approach to procuring gas to manage their upstream contracting exposure.

Another retailer with a longer offer validity period, on the other hand, stated that retailers should generally be in a position to hold an offer open for 7 days in 'normal' market conditions because prices are not expected to move significantly in this period.

5.4.2. Willingness of retailers to negotiate with C&I users

C&I users believe that retailers generally act in good faith, but in many cases are unwilling to negotiate on price or non-price terms and conditions

Through the C&I retailer survey, we asked if C&I users and intermediaries consider that retailers act in good faith in their dealings with C&I users. With some limited exceptions, many C&I users and intermediaries generally believe that retailers act in good faith, both in negotiations and over the term of their retail supply agreements.

Concerns were, however, raised about the willingness of retailers to negotiate. Many C&I users and intermediaries, for instance, stated that they believe retailers are 'unwilling' to negotiate on price and only 'somewhat willing' to negotiate non-price terms. However, some did observe that the willingness to negotiate differs across retailers. One intermediary, for example, observed that some retailers are more willing to negotiate, while others are 'quite rigid'. Another C&I user stated that:

> 'Prices are often offered with a 'take it or leave it' response. However, we received really good support from our current retailer...[who also] showed flexibility and a willingness to be flexible to manage our take or pay exposure. '

A large number of the C&I users and intermediaries we spoke to also noted that as conditions in the market deteriorated in 2022 and the first half of 2023, it became more of a seller's market. This reportedly resulted in **some (but not all)** retailers employing a harder line 'take it or leave it' approach, with little if any negotiation on offers:

> 'Little negotiation – it is a classic take it or leave it scenario.'
>
> '…there is no selling anymore. They set the price and customers request supply.'
>
> '…there is no negotiation around the majority of our gas contracts – it is very much a take it or leave it scenario. If you want a lower take or pay percentage you pay for it.'
>
> 'Retailers tend to use the market conditions to their advantage, some of them can be quite aggressive in negotiations, particularly when dealing with C&I users who have limited options.'
>
> '…retailers are not willing to lower the prices when the other retailer have slightly lower price as well. The attitude of retailers is very fixed, they are unaffected by the adverse consequences of prices on consumers.'

A retailer also commented on the 'take it or leave it' approach employed by some retailers, noting that it had:

> '…lost several customers to 'take it or leave it" offers from a competitor (Producer/Retailer) as recently as June 2023.'

As to when the 'take it or leave it' approach emerged, some C&I users suggested it commenced in 2022, while others suggested it has been a more persistent problem. The diversity of views expressed on this issue can be seen in the following statements:

> '[Retailers] used to be a lot more willing [to negotiate on price or price structure]. They seem to be more constrained with price the past year.'
>
> 'You don't negotiate – you provide your usage requirements and receive a price – negotiations per se stopped years ago.'

Some retailers state that they are willing to negotiate most provisions, but their ability to do so in the last 2 years has been constrained by market conditions

Through our voluntary questionnaire, retailers were asked if there were any price or non-price terms they would not negotiate, or were restricted in their ability to negotiate. Some retailers told us that while they are willing to negotiate most terms, there are some exceptions to this. One retailer, for example, stated it:

> '…may not be willing to negotiate on ToP if this creates an exposure to upstream supply arrangements.'

A number of retailers also noted that while they are usually willing to negotiate with C&I users, their ability to do so was significantly constrained in 2022 and the first half of 2023. One retailer, for example, stated that:

> 'Unfortunately, there were times when we were unable to negotiate price due to the market conditions.'

Another retailer noted that it had to implement a minimum contract term and minimum take or pay multiplier for a period of time to manage its exposure to the market volatility. This meant that it was unable to negotiate in the way it would ordinarily.

5.4.3. Transfer of risks from retailers to C&I users

A number of the C&I users and intermediaries that we consulted stated that retailers were transferring an increasing number of risks to C&I users that they are not well placed to manage, including take or pay obligations and permitted supply interruptions.

5.4.3.1. Take or pay obligations

C&I users note that high take or pay multipliers in a high price environment expose them to greater financial risk that they are not well placed to manage

In discussions with a number of C&I users and intermediaries, we were told that some retailers are no longer applying take or pay obligations to very small C&I users, which was viewed as a positive development. Other C&I users told us that they are still subject to these obligations and that the take or pay multipliers were increasing, with some suggesting that a 100% take or pay multiplier 'is now normal'.

While concerns about take or pay obligations are not new, a number of C&I users and intermediaries told us that the 2-3 fold increase in gas prices over the past 2 years has meant that their effects are being felt more acutely and exposing C&I users to greater financial risk.

As one intermediary observed, the risk exposure can be quite significant when the economic outlook is uncertain, as the COVID-19 pandemic shut downs in 2020 and 2021 highlighted.[135] Elaborating on this further, this intermediary noted that if economic conditions deteriorate and C&I users have to scale down their operations, they will still be subject to high take or pay obligations, which will place further financial pressure on these companies. The same intermediary noted that reducing contract quantities is not a viable option to address the risk, because if a C&I user requires more gas it can be subject to high overrun charges. They did however clarify that the risk of overrun is lower than the risk of take or pay.

A number of the C&I users that we spoke to questioned why take or pay provisions are included in retail supply agreements, with one noting that these types of provisions are not typically employed in other markets. Others stated that these provisions allow retailers to 'double dip' by charging C&I users for the gas they don't use and then selling that gas, often at a higher price.

Some also noted that C&I users are not usually in a position to mitigate the cost impost associated with taking less than their take or pay obligations, because they don't have the transport, storage and/or market arrangements required to sell gas themselves.

We also understand from work carried out in the 2015 Inquiry that some (but not all) standard retail supply agreements expressly prohibit customers from reselling gas obtained under a GSA that they don't require to third parties. As we observed in the 2015 Inquiry, the combination of a take-or-pay provision and a resale restriction creates significant additional

---

135 ACCC, Gas Inquiry 2017-2030 interim report, July 2020, p. 76-77.

risks for the user, because if the user cannot meet its take-or-pay commitment due to an unexpected demand fluctuation, the user will need to pay for gas that it is does not need and is prevented from selling that gas to a third party.[136]

While some of the C&I users that we spoke to suggested take or pay obligations can be removed, others noted that there may be other ways to minimise the cost impost for C&I users, while also addressing the risk faced by retailers (see for example, Box 5.4).

Box 5.4: Alternative approach to take or pay

An alternative approach to take or pay that we have previously been advised of is a take or pay provision that only requires the C&I user to pay the difference between the contract price and the average spot market price (where there is a positive difference on any volumes it does not use but that form part of the take or pay commitment.[137] Formulaically, this arrangement can be expressed as follows:

> Volume of gas taken x contract price + if(Volume of gas taken < Take or pay quantity),[(Take or pay quantity – Volume of gas taken) x (max[(contract price – average spot market price),0]), 0]

For example, if a C&I user had a retail supply agreement with a gas price of $18/GJ, an annual contract quantity of 10 TJ, an 80% take or pay multiplier, then under a standard take or pay provision it would be required to pay for 8 TJ at $18/GJ (i.e. $144,000), even if it only required 7 TJ in that year. That is, it would pay $18/GJ both the 7 TJ it took and the 1 TJ it did not take but was required to pay for as a result of the 80% take or pay multiplier.

If instead the retail supply agreement had the alternative take or pay provision outlined above, then the C&I user would be required to pay the following:

- if the average spot price over the year was $10/GJ, the C&I user would pay $134,000 (i.e. $18/GJ x 7 TJ + $8/GJ x 1 TJ)
- if the average spot price over the year was $20/GJ, the C&I user would pay $126,000 (i.e. $18/GJ x 7 TJ + $0/GJ x 1 TJ).

As this example shows, if the spot market price is lower than the contract price, the C&I user pays the difference between the spot and contract price on any volumes it does not take. If, however, the spot market price is higher, then the C&I users will not be required to pay anything further.
As we noted in our July 2020 interim report, this type of take or pay provision could address the risk that retailers face as a result of their own upstream take or pay obligations, while also minimising the cost impost for C&I users.

Some retailers note that their ability to offer lower take or pay multipliers is constrained by their upstream gas supply agreements

In our discussions with retailers, we asked about their approach to take or pay obligations. Some retailers confirmed that they were generally no longer imposing a take or pay obligation on very small C&I users, but that larger C&I users are still subject to these obligations.

136 ACCC, Inquiry into the east coast gas market, April 2016, p. 72.
137 ACCC, Gas Inquiry 2017-2030 interim report, July 2020, p. 77.

Some retailers also told us that their standard take or pay multipliers tend to range from 70% to 80%, but that they may negotiate alternative values. One retailer also told us that in 2022 it had to move away from its standard take or pay multiplier to manage its exposure to market volatility, but 'the situation has now returned to normal'. This may help to explain the difference between the standard multipliers retailers say they employ and what C&I users have observed over the last 2 years.

Some retailers that we spoke to also told us that their ability to offer more flexible take or pay obligations was constrained to some extent by the take or pay provisions in their upstream gas supply arrangements. One retailer, for example, noted that:

> '…producer offers, generally, have become less flexible over time—that is, there has been increasingly limited load flexibility in offers and increasingly higher take or pay terms.'

5.4.3.2. Permitted interruptions

C&I users note that permitted interruptions expose them to supply risks that they are not well placed to manage

Several C&I users and intermediaries told us that the number and type of permitted interruptions provided for in **some (but not all)** retailer supply agreements appears to have increased.

One C&I user, for example, noted that it had been interrupted multiple times in the last year under its agreement with a retailer, which affected its operations on those days. It also noted that the number of permitted interruption days in its retailer supply agreements had increased. Other C&I users noted that the number of permitted interruption days in retailer offers has increased materially, which would pose an operational risk.

One of these C&I users noted that the increase appeared to be related to the risks surrounding production from the Longford gas plant and planned outages of this plant. A similar view was expressed by an intermediary. This intermediary also noted that while customers may have in the past entered into contracts with unlimited permitted interruptions in exchange for a lower commodity cost, there was a greater risk in doing so now, given the increased likelihood of outages at Longford.

One of the C&I users told us that while retailers had in the past tried to minimise the impact of producer related permitted interruptions on C&I users (i.e. by sourcing gas from the spot markets, storage or other parts of their portfolio), **some (but not all)** were no longer doing so. This user acknowledged that some retailers may be better positioned than others to manage this risk, adding that retailers with more diverse supply portfolios, or upstream interests 'can move molecules from other sources', while other retailers may not be able to do so.

The same C&I user told us that they are trying to negotiate changes to permitted interruption provisions to ensure that they are only triggered for technical supply reasons and not for commercial reasons (e.g. if a supplier can get a better price for gas on the day). This user did clarify that to date the provisions have only been triggered for genuine supply issues.

In a similar manner to take or pay obligations, we were told that many C&I users are not in a position to manage the supply interruptions by obtaining supply from elsewhere. This is because they do not have the transport and other market arrangements in place to be able to procure their own gas on the days permitted interruptions occur.

Retailers note that some retailers are better placed than others to manage permitted interruptions for C&I users

We also asked a number of retailers about the concerns that C&I users raised about transfer of the risk of permitted interruptions from retailers to C&I users. The retailers that we spoke to told us that they were unsure about the source of this change, but noted that it could reflect an increased likelihood of interruptions occurring, particularly at Longford.

Irrespective of the reason for the change, one retailer told us that it would usually be a retailer's responsibility to manage this risk for customers:

> 'Retailers are normally required by necessity to manage a customer's risk of permitted interruptions as major producer suppliers will not cover that risk and cover themselves with volume interruption rights. Retailers will seek to cover this type of volume risk by diversifying supply sources and procuring storage products. This additional risk in part explains the higher retail price of aggregator retailers relative to wholesale producer sales.'

5.4.4. Sale of spot market linked products to C&I users

C&I users questioned whether the risks associated with spot market products are adequately explained by retailers and intermediaries

Through the consultation process, a number of stakeholders questioned whether retailers and/or intermediaries adequately explain the risks associated with spot market linked products to C&I users that procure these products. That is, the risk that prices in these markets increase significantly (including up to the market price cap[138]), or become subject to the administered price cap for a period of time.[139]

This question was predominantly raised in relation to Weston Energy, with C&I users and intermediaries questioning whether some of Weston's customers:

- understood the risks associated with the STTM and DWGM linked products they had purchased, with some suggesting some of Weston's customers may have considered there to be little risk associated with these products based on prior performance of the markets
- were in a position to manage any risks that did arise, with a number suggesting that some of Weston's customers may have lacked the market intelligence and/or ability to manage these risks on a day-to-day (or intra-day) basis.

One of the intermediaries we spoke to also questioned why the sale of spot linked products is not restricted to C&I users that satisfy the 'sophisticated investor' test in the *Corporations Act 2001* (Cth), or an equivalent test. At a high level, the sophisticated investor test requires an Australian Financial Services Licence (AFSL) holder to be satisfied that a person has sufficient experience in using and investing in financial products or services before selling certain products to that person.[140] That is, they have sufficient experience to assess the merits of the product or service and understand the risks associated with that product or service.

---

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

[139] The administered price cap is $40/GJ in both the STTM and DWGM.

[140] See section 761G and 761GA of the *Corporations Act 2001* (Commonwealth).

Retailers are also concerned about the sale of spot market linked products to C&I users that do not have a good understanding of the risks, with some taking steps to address the issue

Many retailers echoed the concerns raised by C&I users and intermediaries. These retailers, for example, questioned why such a sophisticated product was sold to customers that were not in a position to either monitor, or act on, the risks posed by the markets, including government departments and very small C&I users (including some that may have fallen below the small customer threshold).

A number of retailers also told us that following Weston's exit they were more cautious in offering spot products to C&I users, with some noting they had ceased to offer spot linked products. Another retailer told us that it has always 'exercised care and discretion when determining whether it is appropriate to supply a spot market linked product to a particular C&I user and even so, would not offer this product without a price cap'. Others told us they spend time with C&I users and intermediaries explaining the risks associated with the product before entering into the agreement.

As a number of retailers noted, intermediaries also have a role to play in this regard. That is, by ensuring that their clients understand the risks associated with these products and have access to the tools required to monitor and manage their exposure, before they enter into an agreement.

5.4.5. Sufficiency and comparability of information provided on retail charges and the drivers of these charges

While retailer offers specify the key terms of supply, C&I users noted that it can be difficult to compare offers and that they would like more information from retailers

Through both the user survey and retailer questionnaire we asked if retailer offers set out key terms such as contract quantities, delivery points, take or pay provisions, gas commodity, transportation and other charges. C&I users, intermediaries and retailers confirmed that this is the case. Retailer offers are also typically accompanied by their standardised retail supply agreements, so that C&I users have a good understanding of the terms and conditions of supply in advance of entering into the agreement.

While the key terms of supply are included in offers, some C&I users and intermediaries noted that the breakdown of the charges can differ across retailers and that this can make it difficult to compare offers on a like for like basis.

Some of the C&I users that we spoke to also noted that they would like to have a better understanding of the drivers of retailers' gas commodity charges, although a number did acknowledge this may be difficult to achieve in practice. One of the C&I users that we spoke to also suggested that retailers publish their standard terms and conditions on their website, so that C&I users can review them in advance of seeking an offer.

While not directly related to retailer selling practices, a small number of stakeholders also called for greater transparency of the commissions (or other payments) that an intermediary will receive from a retailer prior to the C&I user accepting an offer. In doing so, they noted the potential for intermediaries (i.e. energy brokers and/or consultants) not to act in the best interests of their C&I user clients **if** they receive commissions (or other payments) from retailers that are not disclosed to the client. The term 'if' has been bolded in the preceding sentence, because in those cases where an intermediary is paid directly by the client and does not receive a payment from a retailer, the conflict of interest should not arise.

C&I users also want more information on transportation costs, which are often treated as a pass through by retailers

A number of C&I users expressed concerns about the lack of transparency surrounding transportation costs. They noted that transportation costs are often treated on a 'pass through' basis by retailers and can form a material part of a customer's bill (particularly for those located in distribution networks).[141]

C&I users noted that a lack of transparency in this area meant that they had no way of verifying the transportation charges that are passed through to them, including any changes to these charges that are passed through during the term of their contracts. One C&I user that faced a material increase in its transportation costs during its contract term, told us that it had tried to verify the cost with the relevant pipeline owner, but was informed that this information was confidential and could not be provided.

Concerns were also raised by some C&I users about:

- transport costs being far higher than what they had understood from retailers when entering into their retail supply agreement
- higher transport costs being retrospectively applied by retailers in some instances
- the inability of some retailers to be able to explain the basis for their capacity charges, which includes transport charges.

These C&I users called for greater transparency of the transport costs that are to be passed through by the retailer, both prior to entering into their agreement and during the agreement if these costs change.

Retailers were largely unaware of C&I user concerns about information provision

Through our voluntary questionnaire, we asked retailers about the concerns that have previously been raised by C&I users about the difficulties in comparing offers and information provision. Many retailers told us that they were unaware of this concern, with one retailer noting:

> 'We have not received this feedback from brokers representing retail customers, or customers themselves. We are regularly sent feedback from brokers advising where our offer was placed which suggests they are able to compare between retailers. Offer differentiation is valued by customers.'

One retailer noted that retail offers are reflective of the risks that the retailer and/or customer may be exposed to, which will vary across retailers and make it difficult to establish comparable terms.

141 Appendix A sets out transport and storage prices.

5.4.6. While there have been recent improvements in retailer selling practices, retailers could do more in this area

As outlined in section 5.2 retailers play an important but very complex role in the market, acting as the interface between their customers and producers, pipeline operators, storage providers and the spot markets, and having to manage the costs, risks and challenges associated with supply.

This role became even more complex in 2022 and the first half of 2023, with tight and volatile wholesale market conditions, further exacerbated by the Weston RoLR event in mid-2022 and the pause in producer contracting in 2023. As section 5.3 highlights, these conditions posed significant challenges for retailers and resulted in some having to cease competing for a period of time.

The very challenging market conditions, coupled with the reduction in competition, appear to have also been associated with the deterioration in **some (but not all)** retailers' selling practices over the last 2 years and exacerbated the imbalance in bargaining power faced by C&I users.

As conditions in the wholesale market have started to ease in the latter half of 2023 and some retailers have started to compete again, there have reportedly been some improvements in retailers' selling practices, with some reverting back to their standard practices. For example:

- the compressed offer validity periods appear to have ceased and the prevalence of offer revisions and withdrawals has fallen
- retailers appear to be more willing to negotiate on key terms (including take or pay obligations) than they were in 2022 and the first half of 2023 and some of the imbalance in bargaining power experienced in this period has diminished.

The spot market volatility in 2022 and Weston RoLR event, also appears to have prompted improvements to the way in which retailers sell spot market linked products.

While these recent improvements are encouraging, some standard selling practices, which C&I users have expressed concerns about in the past (see Appendix C) do appear to fall short of what we would expect to observe in a workably competitive market (see Table 5.2 for a high level overview of what we would expect in such a market).

To some extent, this may reflect the poor selling practices that retailers themselves have faced when dealing with producers. It is possible therefore that the minimum standards for offer validity periods, withdrawals and terminations of offers, and negotiations implemented through the Code could lead to improvements in retailers' own selling practices over the next year.[142] Increased competition to supply C&I users could also lead to further improvements in retailer selling practices.

We intend therefore to continue to monitor retailer selling practices as part of our broader review of retailer behaviour in 2024. In doing so, we will be looking for further improvements

[142] The Code, for example, provides for a minimum offer validity period of 15 business days, which means that retailers may be in a better position to offer C&I users more time to consider offers. Similarly, the limitations on the circumstances in which producers can withdraw or terminate offers may also reduce the need for retailers to withdraw or terminate offers. See for example, the definitions of gas initial offer open period and gas final offer open period in section 4(1), as well as the withdrawal and termination provisions in sections 17, 19, 21-23 of the *Competition and Consumer (Gas Market Code) Regulations 2023*.

in line with the selling practices that we would expect to observe in a workably competitive market, as set out in Table 5.2.

If, as a result of this monitoring of selling practices and/or our broader review of retailer behaviour, we identify any systemic issues, we may consider making recommendations to the Australian Government on how to deliver a better functioning retail market. We would therefore encourage retailers to take this opportunity to consider the concerns that have been raised and take steps to improve their selling practices voluntarily.

Table 5.4: Selling practices we would expect to observe in a workably competitive market for retailer supply to C&I customers

Area	Selling practices
Offer process	Retailers operating in a workably competitive market would be expected to: ▪ 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 ▪ 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 ▪ respond to C&I user requests for clarifications on offers in a timely manner.
Negotiations	Retailers operating in a workably competitive market would be expected to negotiate in good faith with C&I users on price and other key terms and conditions.
Risk allocation	Retailers operating in a workably competitive market would be expected to: ▪ reasonably allocate risks to C&I users when they are best placed to manage those risks ▪ minimise the costs associated with any risks that are transferred to the buyer (see for example, Box 5.4) and any contractual impediments that may prevent C&I users from managing those risks.
Spot market linked products	Retailers operating in a workably competitive market would be expected to sell spot market linked products to C&I users when they are reasonably satisfied that the C&I user has a good understanding of the risks associated with these products and has access to the tools required to monitor and manage their day-to-day exposure.
Transparency	Retailers operating in a workably competitive market would be expected to: ▪ publish their standard terms and conditions on their websites ▪ 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, such as transportation charges and commissions payable to an intermediary) during both the offer process and over the term of the contract.

5.5. Next steps in the retailer behaviour review

We will shortly commence Stage 2 of our retailer behaviour review, which will build on the work undertaken in Stage 1. In Stage 2, we will continue to monitor retailer selling practices. We will also be undertaking a more detailed review of retailer pricing practices, which will examine:

- the prices retailers are charging C&I users (including in regional areas) and how these prices have changed over time
- the factors that may be influencing retailer pricing behaviour (i.e. the costs, risks and constraints on access to gas and other services retailers may face, as well as competition to supply C&I users) and how these have changed over time

- whether retailers are passing through changes in gas and other costs to C&I users.

In a similar manner to Stage 1, we intend to consult closely with retailers, C&I users, intermediaries and industry associations during this stage of the review.

Appendix A – Transport and Storage Prices

A.1. Prices for pipeline firm haulage services

We analysed the minimum, maximum and standing prices paid for transmission pipeline firm haulage services in July 2023, and how these prices have changed between July 2022 and July 2023. As Table A.1 shows, prices for most pipelines have increased approximately in line with inflation, which was 6.0% over the 12 months to the June 2023 quarter.[143]

Table A.1: Firm Haulage Service Prices as at July 2023

Pipeline	Price ($/GJ) (as at July 2023)			Price change between July 2022 and July 2023 (%)		
	Min	Max	Standing Price	Min	Max	Standing Price
AGP	0.459	0.795	0.362	10.14%	6.03%	5.51%
NGP	2.288	2.380	2.601	7.62%	7.83%	7.83%
CGP	1.357	1.419	1.408	5.26%	6.02%	5.15%
QGP (to Gladstone)	0.710	1.488	1.157	0.00%	7.27%	7.27%
RBP Easternhaul	0.637	1.060	0.637	42.25%	5.68%	1.81%
RBP Westernhaul	0.675	0.762	0.637	6.03%	6.03%	1.81%
SWQP Westernhaul	1.102	1.541	1.523	6.67%	4.90%	5.15%
SWQP Easternhaul	1.037	1.477	1.645	7.03%	7.27%	5.15%
MAPS Southernhaul	0.743	0.992	0.904	6.89%	7.27%	7.27%
PCA	0.628	1.102	0.949	5.09%	33.16%	0.00%
EGP	1.069	1.486	1.486	6.12%	3.32%	7.83%
MSP (Culcairn to Sydney)	0.471	0.488	0.483	6.77%	6.03%	5.17%
MSP (Moomba to Sydney)	0.775	1.366	1.292	-4.11%	6.59%	5.16%
TGP	1.538	3.094	2.751	6.50%	7.83%	7.83%

Source: ACCC analysis of data supplied by pipeline operators, standing price data from pipeline operator websites.

Note: Pipeline operators escalate their standing prices at the beginning of the calendar year. In addition to this, APA adjusts its prices quarterly in April, July and October. Minimum and maximum prices change frequently based on GTAs that have either commenced, expired or been varied during the relevant period. Standing prices are for a reference service and may not include the specific terms and conditions available in in commercially negotiated services. Where relevant, the prices reported for some pipelines include the prices payable for other services required to use that pipeline, such as compression in the case of the South West Queensland Pipeline (SWQP), and the nitrogen removal service in the case of the Northern Gas Pipeline (NGP).

143 https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/jun-quarter-2023.

A.2. Storage in the southern states

Fluctuations in gas production in the southern states has placed increasing importance on storage facilities. The Dandenong LNG and Iona underground storage facilities, owned by APA and Lochard Energy respectively, are the only facilities that currently provide storage services to third parties in the east coast gas market.

The need for sufficient storage capacity to meet peak southern demand in winter means that storage prices will contribute to the delivered price of gas in the south. Lochard charges a fixed price for contracted storage capacity, as well as injection and withdrawal charges, with the latter making up a relatively small part of the overall cost of storage. The variable charge for the facility reflects the charge for injection into the storage facility from either the South West Pipeline (SWP) or the SEA Gas Pipeline, or withdrawal from the storage facility to either of those pipelines.

Table A.2 shows that prices at the Iona gas storage facility have changed in line with inflation since July 2022.

Table A.2: Iona storage prices ($/GJ), July 2019 to July 2023

		July 2019 ($/GJ)	July 2020 ($/GJ)	July 2021 ($/GJ)	July 2022 ($/GJ)	July 2023 ($/GJ)
Fixed (per day)		0.010–0.027	0.015–0.025	0.015–0.026	0.015–0.027	0.017–0.032
Variable	Injection from SWP	0.082	0.083–0.093	0.084–0.094	0.086–0.097	0.092–0.104
	Withdrawal to SWP	0.041	0.042–0.047	0.042–0.047	0.043–0.048	0.046–0.052
Variable	Injection from SEA Gas	0.014	0.014	0.014	0.014–0.015	0.015–0.016
	Withdrawal to SEA Gas	0.082	0.083–0.093	0.083–0.094	0.086–0.097	0.092–0.104

Source: ACCC analysis of data supplied by Lochard.

Table A.3 shows the prices paid for storage at the Dandenong LNG facility from July 2019 to July 2023.

Table A.3: Dandenong LNG storage prices ($/GJ), July 2019 to July 2023

	July 2019 ($/GJ)	July 2020 ($/GJ)	July 2021 ($/GJ)	July 2022 ($/GJ)	July 2023 ($/GJ)
Storage (per day)	0.067–0.089(fixed)	0.069–0.092(fixed)	0.099–0.134	0.103–0.185	0.111–0.200
	1.26–1.70(variable)	1.30–1.70(variable)			
Liquefaction			1.694	1.620	1.962

Source: ACCC analysis of data supplied by APA.

Note: Storage prices at Dandenong LNG from July 2021 have been calculated by dividing the total amount paid by the user for firm vaporisation, by the total amount of storage provided to that user.

Appendix B – 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 the Domestic Price Outlook chapter, and the prices for gas transport and storage services as presented in Appendix A.

B.1. Parameters of reported prices

The following apply to our analysis of prices reported in chapter [4]:

- 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 4.3 and 4.4. Section 4.5 reports on short-term contracts (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.
- 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' where the 95ZK data is used: Origin Energy, AGL, EnergyAustralia, ENGIE, Alinta Energy, Shell Energy Australia, Macquarie Bank, PetroChina and Weston Energy.

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 the Domestic Price Outlook chapter, but rather reports on GSA flexibilities separately in these sections.

B.2. Reporting on offers and bids

The information in this section describes our approach to reporting on offers and bids, and should be read in conjunction with information above in section B.1.

The following also applies to our analysis of offers and bids.

- The analysis only includes those offers and bids that contain clear indications of price, quantity, supply start and 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.[144]
- 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, 2022, 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.

B.3. Comparing domestic price offers with future LNG netback price expectations

In the Domestic Price Outlook Chapter, we compare prices for offers with short-term LNG netback prices and medium-term oil-linked netback prices.[145]

Section 4.3.1 of the chapter compares offers with both short-and medium-term netback prices.

In section 4.3.2. and 4.3.3, we compare offers with fixed or JKM-linked prices and a term of 1-3 years:

- for delivery in Queensland to expectations of short-term LNG netback prices in Queensland in the month the offer or bid occurred.
- for delivery in the southern states to short-term buyer and seller alternative netback prices, outlined in previous ACCC reports, in the month the offer or bid occurred.

---

144 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.

145 We have updated our medium-term oil-linked netback price calculation to more accurately reflect transportation, plant operations and efficiency costs. This update has decreased the overall oil-linked prices by approximately $1/GJ compared to the calculations used in previous reports. Additionally, we have updated the LNG oil-slope to reflect Gaffney Clines's recent estimates in its June 2023 report (As available on the ACCC website).

In section 4.3.4, we compare offers with fixed or Brent-linked pricing and a term of 1-3 years:

- for delivery in the southern states to medium-term oil-linked buyer and seller alternative netback prices, outlined in previous ACCC reports, in the month the offer or bid occurred.

B.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, which is 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 likely play an important role in the east coast gas market, they are not likely to be 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 which will differ over time.

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[146]
- 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 is described in detail in the ACCC's 'Guide to the LNG netback price series'.[147]

The domestic offers are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison for offers in a given year, 2021 as an example, we calculated an average 2021 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 2021, and selling cargoes on the Asian LNG spot market in 2021.

For example, we calculated the average of LNG netback prices for 2021 that an LNG producer would have expected in July 2020 as follows:

- We obtained JKM futures prices for each month of 2021 that were quoted by ICE on each day during July 2020.
- We converted the monthly 2021 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

146 For this, we have used JKM futures prices (source: ICE).

147 ACCC, Guide to the LNG netback price series, September 2022.

- subtracting the short-run marginal costs of shipping, liquefaction[148] and transportation.[149]

- We averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2021 expected on each day during July 2020.
- We then averaged these 2021 expectations for each day of July 2020 to arrive at an average of LNG netback prices for 2021 expected during the month of July 2020.

As has been noted before, our approach to calculating LNG netback prices does not involve deducting the capital costs of building the Queensland LNG export facilities. This is because these costs are sunk 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 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.

B.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.

Where a price achieved in a negotiation will fall within this range will 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

---

148 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.

149 We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from LNG producers.

Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states, all other things being equal. If, in a well-functioning market, a southern supplier were 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 our analysis, we present a buyer and seller alternative for Victoria.

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.

B.4. Reporting on GSA pricing and flexibility

The information in this section describes our approach to reporting on GSAs, as presented in section 4.4.1 and should be read in conjunction with information above in section B.1

The following also applies to our analysis of GSAs:

- In our analysis of producer prices, we have included GSAs executed at arm's length by producers with all counterparties. Our analysis of retailer prices has included GSAs between retailers with C&I users and GPG. 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.[150] 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 in section 4.4.2. 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 applied regardless of whether or not the buyer actually takes delivery of the

150 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.

gas. A GSA with a take-or-pay multiplier of 100% implies that the buyer must pay for all of the gas it has contracted to take, irrespective of whether it takes 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.

B.5. Approach to reporting pipeline and storage services and prices

There are several different types of pipeline transportation services:

- **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.
- **As available transportation service**: A service that allows the transportation of gas subject to the availability of capacity. This service has a lower priority than a firm transportation service.
- **Interruptible transportation service**: A service that allows the transportation of gas but where 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, where a pipeline has both types of service, as available transportation services.
- **Park service**: A service that allows users to store gas in a pipeline. In practice this involves injecting more gas into a pipeline than what is taken out on a particular day.
- **Loan service**: A service that allows users to "borrow" gas from a pipeline. In practice this involves withdrawing more gas from a pipeline than what is injected on a particular day.
- **Compression service**: A service that increases the pressure of gas to improve the efficiency of transportation. Compression services are provided by compression service facilities.

B.5.1. Approach to reporting prices

The prices reported in this section exclude GST and are based on invoices issued under contracts entered into for a term of one month or longer, and reflect the terms and conditions specified in those contracts.

Any percentage changes in price are stated in nominal, rather than real, terms.

B.5.2. Method used to report pipeline prices

Prices payable for haulage services are reported only where the price applies to transportation across the full length of the pipeline.

The prices for some firm forward haul services are recovered through a capacity charge only i.e. $/GJ of Maximum Daily Quantity (MDQ), while others are recovered through a variable charge ($/GJ), or a combination of the two. In the latter two cases, the prices have been converted to a $/GJ of MDQ measure, assuming a 100% load factor, i.e. assuming the shipper uses all the capacity it has contracted. Where the price charged is specified in several tiers, a single rate is calculated using a weighted average.

The prices payable for as available and interruptible transportation services, and park and loan services have been included even when the quantity supplied in that month is zero. The prices reported for these services therefore represent the prices that would be paid under the shipper's contracts if the services had been used.

The as available and interruptible services category includes APA's 'short-term firm' services, as well as APA's interruptible service, which is only available when a pipeline is fully contracted. APA's day-ahead firm and within-day services have not been included in the analysis of contract prices.

Where relevant, the prices reported for some pipelines include the prices payable for other services required to use that pipeline, such as compression in the case of the South West Queensland Pipeline (SWQP), and the nitrogen removal service in the case of the Northern Gas Pipeline (NGP).

Charges relating to imbalances and overruns are not included in our analysis.

B.5.3. Method used to report storage prices

The prices payable for use of the Dandenong LNG and Iona underground storage facilities comprise both a fixed and variable charge. The fixed charge is payable for storage capacity and, although storage services are generally sold under contract terms of a year or more, has been expressed on a dollars per GJ of storage capacity per day basis ($/GJ/day) to enable comparability. The variable charge, on the other hand, is measured on a dollar per GJ basis ($/GJ) and incurred when gas is injected or withdrawn. This charge is used to recover the liquefaction cost at the Dandenong LNG facility and the storage injection and withdrawal charges at the Iona underground storage facility.

B.5.4. Pricing terminology

The term 'maximum price' is used in this section to refer to the highest price paid by shippers in the relevant period, while the term 'minimum price' is used to refer to the lowest price.

The term 'standing price' is used to refer to:

- the price pipeline operators subject to Part 23 of the NGR are required to publish as part of the standing terms for each service offered by the pipeline
- the prices pipelines that are subject to light regulation are required to publish for light regulation services
- the reference tariffs that pipelines subject to full regulation are required to publish.

B.5.5. Comparability of prices

The prices payable by shippers for use of pipelines and storage facilities will reflect, among other things, the terms and conditions specified in their transportation and storage agreements and when the prices were agreed. The actual prices payable by shippers to use one of these facilities may therefore differ as a result of differences in capacity commitments (including withdrawal and injection rates for storage), service flexibility (e.g. hourly flexibility, load factor), contract length, the time at which the prices were agreed or reviewed (including whether a contract is a foundation agreement or will fund an expansion) and whether services are provided across a number of assets.

Appendix C – Prior observations by C&I users

This appendix provides a summary of the observations made by C&I users over the term of the Gas Inquiry and the findings of the research undertaken by external expert SEC Newgate commissioned to inform the January 2023 interim report.[151]

Table B.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 have improved since the September 2017 report, with lower prices being offered and more suppliers competing. Some retailers have 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 prices for 2021 and 2022 with suppliers more willing to negotiate, but difficulties remaining for supply post-2022. Concerns were also raised about the lack of transparency surrounding 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 also observed changes in retailers' pricing practices and noted that 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.

[151] ACCC, Gas Inquiry 2017-2030 interim report, January 2023, pp 58–74.

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'.
	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 producer code. C&I users also observe a deterioration in retailer selling practices. C&I users also noted that while gas prices have softened since their peak in 2022, they remain significantly concerned about gas prices.

In mid-2022, the ACCC 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.

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 SEC Newgate research report[152] are summarised in the table below.

Table B.2: Summary of findings in SEC Newgate research report

Key findings	
2022	▪ 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 3 days with the threat of significantly higher prices and some only being given 24 hours) ▪ 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 linkage ▪ There is limited transparency on transport costs and arrangements ▪ Terms and conditions vary significantly across suppliers and costs are broken down differently, with some C&I users suggesting that standard 'fair' contracts be developed ▪ Concerns were raised about limited regulatory oversight and the ability of Weston to be a retailer without having sufficient supply. Concerns raised about the high prices Weston's customers faced (typically over $40/GJ)

152 SEC Newgate Research Report, Commercial and Industrial Customer Attitudes to the East Coast Gas Market, 24 August 2022. A copy of this report is available on the ACCC website.

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 a large number of 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.

Domestic demand: The quantity of gas demanded by users located in Australia.

Downward quantity tolerance: The amount a buyer may fall short of its 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: Is the major gas hub for spot and futures trading in the United States and 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: Is 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 on the basis of 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 the purpose of 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 and Shell Energy Australia.

Sale and purchase agreement: An agreement between the buyer and seller for LNG. In this report

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.