Image courtesy of Woodside Energy

Gas markets in eastern Australia

This chapter covers upstream gas markets in eastern Australia, encompassing gas production, wholesale markets for gas and the transport of gas along transmission pipelines for export or domestic use.[159]

The main production basin in eastern Australia is the Surat–Bowen Basin in Queensland. There are smaller basins in South Australia, New South Wales, off coastal Victoria and in the Northern Territory. Combined, these basins account for around 37% of Australia's total gas production.[160]

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

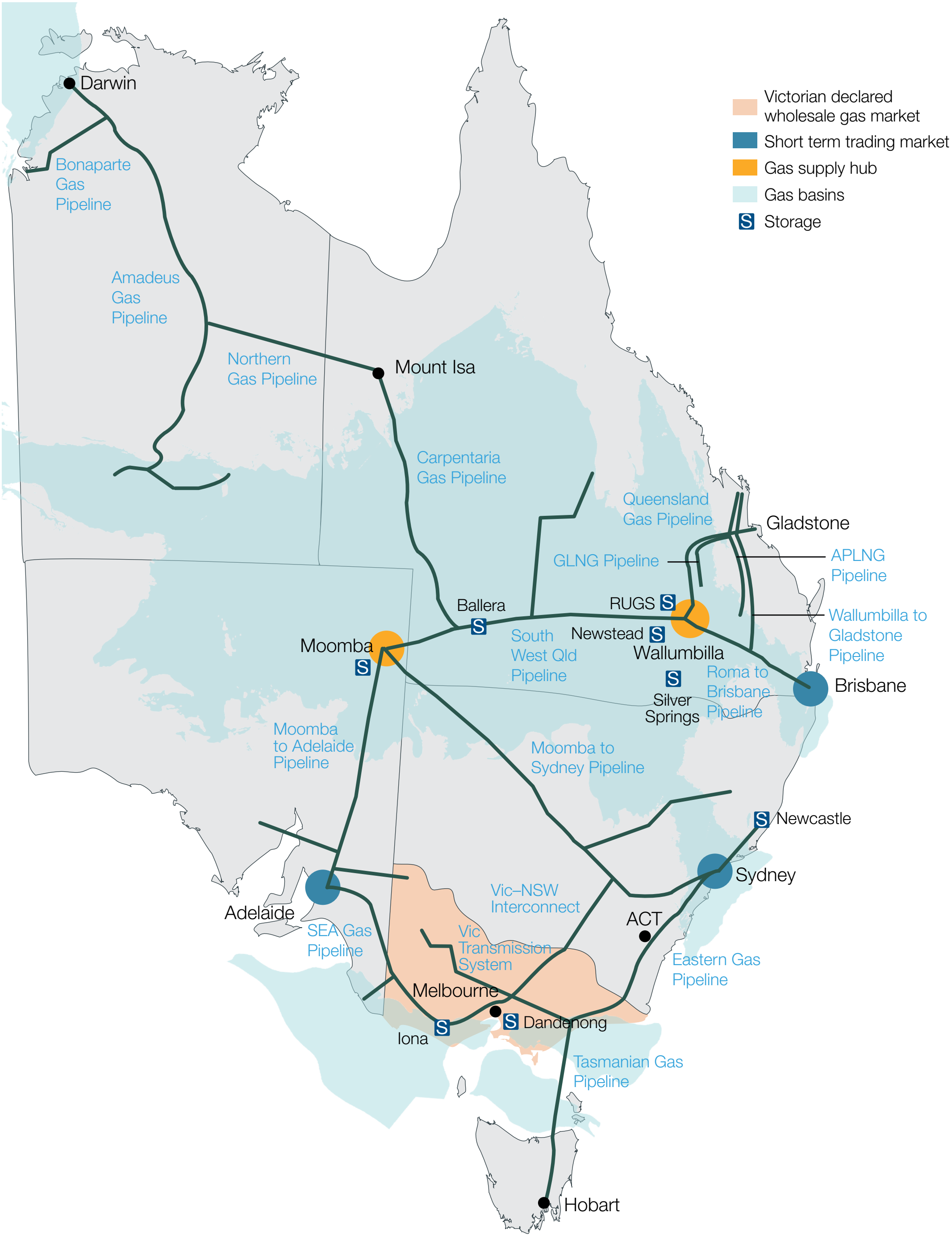
Due to the rapid expansion of the Australian LNG industry on both the east and west coasts, Australia has become one of the world's largest LNG exporters.

Since the launch of the LNG export industry in 2015, gas producers have the choice of exporting or selling gas domestically. Consequently, prices in the domestic market are influenced by international gas prices.

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

160 70% of Australia's total gas reserves are conventional gas resources and 30% are unconventional (coal seam gas) resources. Surat-Bowen accounts for most of Australia's coal seam gas (CSG) production, while most of our conventional gas resources are located off the north-west coast of Western Australia and at the end of 2019 they accounted for around 62% of total gas production.

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



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in wholesale gas markets

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

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

We publish weekly reports, gas industry statistics and our Wholesale markets quarterly reports, which cover gas spot market activity, prices and liquidity. The quarterly reports also include analysis of eastern Australia's liquefied natural gas (LNG) export sector and its impact on the domestic market. From December 2022, the AER will report a wider set of information on the export, reserve, storage, and domestic sale and swaps of gas.

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

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

Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory but plays no role in the territory's wholesale market. Facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board. We have no regulatory function in Western Australia, where separate laws apply.[a]

a The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia and AEMO operates a spot gas market there.

4.1 Gas market snapshot

Since the last *State of the energy market* report, east coast gas markets have entered a period of sustained high prices and tight supply. Over late 2021, and particularly since April 2022, gas prices in east coast gas markets have rose to and persisted at record highs.

Southern gas production is continuing to deplete reserves, increasing the risks of shortfalls, and the Iona storage facility dropped dangerously close to minimum reserves for its normal operation this winter.

Overlapping factors in the National Electricity Market from early May – including numerous coal baseload outages and peak gas generation units running for prolonged periods to fill the supply gap – have driven an unanticipated increase in gas demand from this sector despite the gas price increases. This interaction with electricity markets is putting further upwards pressure on gas prices at the same time as local gas markets are being used to cover short-term spot exposure over the higher demand winter period.

With higher gas market demand typical across winter, and the continuing requirement for additional gas generation to make up for supply constraints in baseload coal, gas and electricity prices are not expected to decrease until conditions ease in both local and international markets.[161]

In combination, these market shocks have resulted in extraordinary interventions, including:

- the Australian Energy Market Operator (AEMO) activating the Gas Supply Guarantee twice, including its first ever usage
- AEMO directing two Victorian gas-powered generators not to generate

161 A combination of factors contributed to high prices across both gas and electricity sectors, with price impacts amplified by the fact these drivers were occurring simultaneously. Separate to local market conditions, global drivers impacting fuel costs, including oil, diesel, gas, and coal, have also affected local prices.

- suspension of a market participant
- extended periods with different gas hubs in administered pricing states.

4.2 Structure of the east coast gas market

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board. Around 10% to 20% of gas is traded in these spot markets.[162] All other gas trade is struck under confidential bilateral contracts separate to these markets.

4.2.1 Contract markets

The majority of gas in Australia is traded through bilateral contracts. Contract prices reflect expectations of future market conditions, but the spot markets can reflect short-term shifts in market conditions due to factors such as gas supply and gas storage levels, the timing of LNG shipments and conditions in the electricity market. As a result, the price levels are not always aligned, but they often move in similar directions.

For many domestic users, contract prices are likely to be more indicative of the costs they face.

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

- offers by gas producers to very large customers such as major energy retailers and gas-powered generators
- offers by retailers and aggregators that buy gas from producers and on sell it to commercial and industrial (C&I) customers.[163]

Long-term gas contracts traditionally locked in prices and other terms and conditions for several years. In recent years the industry has shifted towards shorter terms (1 to 2 years) for these contracts, with review provisions.[164]

4.2.2 Spot markets

Spot markets allow wholesale customers to trade gas without entering long-term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

Three separate spot markets operate in eastern Australia – Victoria's declared wholesale gas market, the short term trading market, gas supply hubs and a separate east coast wide market for transportation and compression services.

Victoria's declared wholesale gas market (DWGM)

Victoria's declared wholesale gas market manages gas flows across the Victorian transmission system. Participants submit daily bids ranging from $0 per gigajoule (GJ) (the floor price) to $800 per GJ (the price cap). Prices in the Victorian market cover gas as well as transmission pipeline delivery. AEMO selects the least cost bids needed to match demand to establish a clearing price.

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

Short term trading market (STTM)

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

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

162 AER, Wholesale markets quarterly – Q4 2020, February 2021.

163 Public information about contract prices is unclear. Much of the pricing is private and negotiated contract outcomes are often bespoke. There is also disparity between the type of information available to large participants that are frequently active in the market and that available to smaller players. This imbalance favours large incumbents in price negotiations. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2025 gas inquiry.

164 ACCC, Gas inquiry 2017–2020, interim report, July 2018, August 2018, pp 24, 49.

Gas supply hubs

Gas supply hubs at Wallumbilla in Queensland and Moomba in South Australia are a voluntary platform for gas trading. There are 5 standard product lengths that participants can use when trading at the gas supply hubs – balance of day, daily, day-ahead, weekly and monthly. Participants can trade gas up to a year in advance of physical supply.

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

Similar to Wallumbilla, the Moomba hub is located at a major junction in the gas supply chain serving eastern Australia. Three critical pipelines – the South West Queensland, Moomba to Sydney, and Moomba to Adelaide pipelines – connect to the hub. On 28 January 2021, trade points at Culcairn and Wilton were also introduced to facilitate trades at the Victorian and Sydney gas market locations, respectively.

A significant proportion of trade occurs 'off-screen', which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate spot trades.[165]

Day-ahead auction (transportation related services)

An east coast wide market for next day pipeline transport and gas compression has operated since 1 March 2019. Unutilised (contracted but not nominated) capacity for the next day is sold the day before through an auction. This auction has been widely used to move gas between the east coast gas markets since its inception (section 4.6.2).

4.2.3 Gas Bulletin Board

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

- pipeline capabilities (maximum daily flow quantities, including bidirectional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities) and actual injections/ withdrawals.

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

Reforms are currently being considered to expand the scope of information reported (section 4.12.1).

4.3 Gas prices

Gas prices in 2022 to date have reached record highs and persisted at high levels for much of the year. This has been particularly evident in spot market prices and to a lesser extent in contract prices.

4.3.1 Gas contract prices

The ACCC has access to gas contract information and reports on these prices through its gas inquiry.

Over previous years (2019 and 2020) domestic gas contract prices tended to track falling international prices, measured using LNG netback prices. However, prices offered for 2022 had stabilised at the beginning of 2021.[166] Although prices have recently increased, the domestic price increase was substantially lower than the increase in international LNG prices, which were up by almost 230%.

165 While most gas trading occurs 'off-screen' (not traded through the gas markets), some of these trades are reported to the market operator and settled through the gas supply hub trading platform.

166 LNG netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically.

More recently, prices offered by both producers and retailers for 2022 increased to $7–$9.50 per GJ by mid-2021 compared with $6–$8 per GJ in late 2020.[167] Similarly, contract prices agreed to by C&I users increased in 2021 to $7.50–$9.90 per GJ.[168] This likely reflects significantly higher Asian LNG prices across 2021 and changing domestic market conditions from mid-2021.[169]

Producer offers diverged from increased LNG netback prices over 2021. However, improved conditions reported by C&I users, including increased supplier diversity and more flexible contract conditions, dissipated by mid-2021, particularly for supply offered from 2023. Despite forward gas prices easing over 2021, the ACCC reported many C&I users experienced difficulties in procuring supply beyond 2022, with users reporting concerns around future supply resulting in risk premiums being incorporated into contract prices.[170]

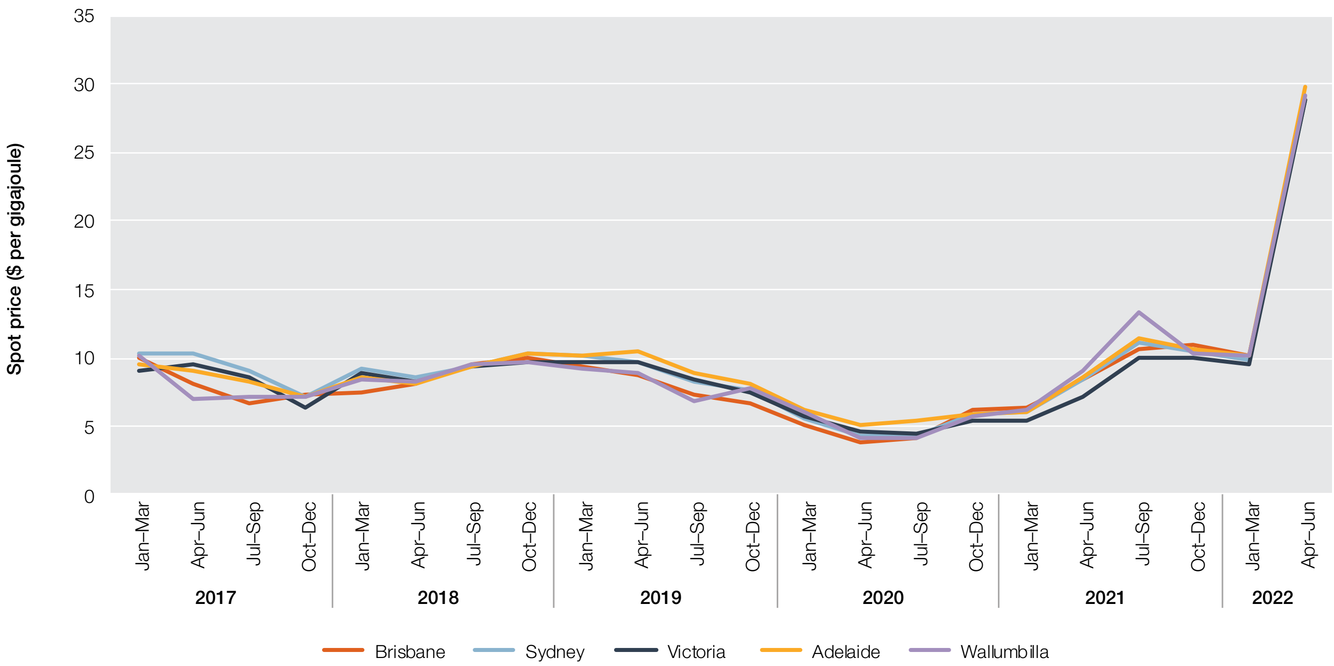
In late 2021 and early 2022, 2023 supply contract offer prices (gas supply agreements) were below international spot LNG and domestic market prices. Spec prices[171] offered for 2023 supply by gas producers increased from between $6.79 and $11.40 per GJ in the first half of 2021 to between $7.33 and $16.33 per GJ in late 2021 and early 2022.[172]

However, the ACCC expressed concern around recent extreme spot price increases in domestic and international markets, and their implications for future contract prices.[173]

4.3.2 Spot market prices

Since May 2022 spot prices have increased rapidly to record high prices, having trended upwards since reaching relatively low levels in 2020 (Figure 4.2).

Figure 4.2 Eastern Australia gas market prices



Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the 6 am schedule price.

Source: AER analysis of gas supply hub, short term trading market and Victorian declared wholesale gas market data.

167 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022 p 14.

168 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022 p 111.

169 On 1 December 2021, a voluntary code for negotiations between suppliers and users was announced to improve benefits for users. The code and will be monitored as part of the ACCC gas inquiry.

170 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, pp 61, 70.

171 Contract offers reflecting indicative prices of gas supply.

172 ACCC, Gas inquiry 2017–2025, interim report, July 2022, August 2022, p 34.

173 ACCC, Gas inquiry 2017–2025, interim report, July 2022, August 2022, p 12.

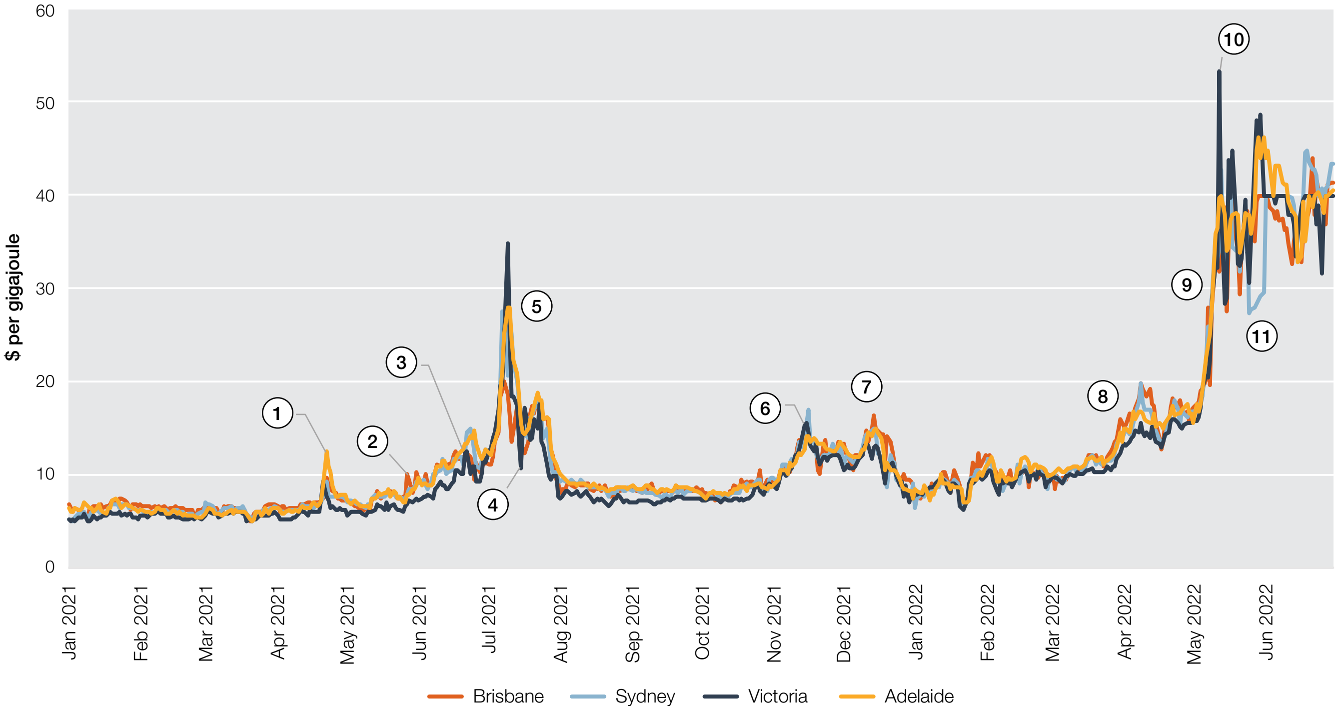
Unprecedented price volatility since May 2022

Following a noticeable increase from late March, when prices are usually subdued prior to winter, spot market prices since May 2022 have reached record highs. This reflects a series of overlapping factors, including:

- high international gas prices and changes to global supply and demand conditions, strengthening the incentive for producers to export LNG rather than supply into the domestic market
- significant demand from gas-powered generators due to other supply-side constraints in the NEM (section 4.4.1).
- demand pressures arising from residential heating demand in southern states.

Figure 4.3 sets out an annotated timeline of key pricing events in 2021 and 2022 to date.

Figure 4.3 Daily gas spot prices



1. 23 April 2021: Moomba production issues on 21 and 22 April, Iona maintenance outage (8 to 31 April) alongside increased demand in Sydney and Victoria, high gas generation demand in all regions (particularly SA) and high NEM prices.
2. From late May 2021: Increased market demand heading into winter, high gas-powered generation usage following the loss of baseload generation in the NEM (Callide power station, Queensland).
3. 19 to 22 June 2021: Victorian demand above 1 PJ and an unplanned production outage at Longford. Adelaide gas generation high during intermittent periods of low wind, gas starts flowing south as southern prices rise above northern prices, with some Callide generation units coming back online.
4. July 2021: High levels of price volatility across the southern markets, resulting in numerous significant price variations occurring (discussed in section 4.3.2).
5. 7 to 10 July 2021: High southern market prices and gas generation demand over periods of low wind. A partial Longford outage and diminishing Iona storage during cold weather (Victoria).
6. 10 to 16 November 2021: Constrained supply and abnormally high end-of-year demand in Victoria due to cold weather, alongside high export demand and elevated gas generation in Queensland.
7. 9 to 21 December 2021: High export demand and gas generation in Queensland with significant gas flows north from southern markets despite continuing capacity restrictions at Longford and historically low storage levels at Iona (Victoria). Elevated gas generation and a Moomba production outage (SA).
8. From late March 2022: Gas prices become increasingly volatile, with drivers of higher prices including a combination of cold weather, low wind levels, coal generation outages and elevated gas-powered generation, with some gas contracts reset at higher prices into the new quarter.
9. From early May 2022: Gas flowing north in contrast to gas flowing south in May 2021, coupled with increased gas demand for electricity generation (14 PJ in May compared to 10 PJ in April on mainland) influenced by baseload outages, with very high NEM prices.
10. 12 May: Consecutive demand forecast increases in Victoria and reduced $15–$30 per GJ supply, with 211 TJ of controllable withdrawals further driving up demand.
11. From late May 2022: Administered prices in Brisbane, Sydney and Victoria contribute to unprecedented gas market price volatility.

Source: AER; AEMO (raw data).

Production increased quarter-on-quarter in 2022, exceeding record levels set in 2021. In the north, production at Roma (Queensland) has remained high but output is not keeping up with exports. In addition, Moomba's yearly output (South Australia) is steadily declining. This has resulted in less gas being available for domestic use in 2021 and 2022.

Storage has also been decreasing to levels limiting supply capability (section 4.5.2). These factors have led to a trend of more gas flowing north and decreased supply into southern markets. Queensland continued to source gas supply from Victoria into April and May 2022 despite price increases across the gas markets (section 4.6).

From 24 May 2022 the suspension of a market participant triggered the Retailer of Last Resort (RoLR) provisions, putting Brisbane and Sydney into administered states until 7 June[174]. From 30 May, significant depletion of Iona storage led to an administered price cap in Victoria based on high cumulative prices, when on 14 June it became the only jurisdiction with a price cap in place this led to distorted price signals in the market.

From June, Queensland started providing more gas into southern markets after AEMO activated the Gas Supply Guarantee (GSG) to provide gas to generators in the south for the 2 June gas day.[175] After this, more gas continued to flow south at the same time as the east coast went through a particularly cold start to winter. The gas heating demand load from the cold weather was accompanied by elevated gas-powered generation due to numerous factors (section 4.4.1) driving unprecedented NEM prices (section 4.3.2).

One of the main drivers of supply risk in Victoria into late July was the depletion of Iona's underground storage inventory, where slower draw down over May and June accelerated in July.

This put drawdown rates in line with unprecedented levels observed the previous winter (section 4.5.2).[176] As a result, storage declined because ongoing gas generation demand requirements put increasing pressure on available supply. This then led to multiple notifications about threats to system security in Victoria from 11 July, culminating in the notification of potential shortfalls across the whole south-eastern region from 19 July until the end of September.[177]

Following a conference with industry, the GSG (section 4.11.2) was reactivated out to 30 September and AEMO intervened in the gas markets, directing gas-powered generators to cease taking gas from the Victorian market without supporting gas supply. Exporters agreed to make more supply available to southern markets and, despite a downward trend in prices across the markets from that time, prices over July reached their highest level since the markets commenced.

Administered pricing states

From 24 May, AEMO issued a market suspension notice to Weston Energy, as required under the Gas Rules, when the participant failed to satisfy a margin call made on the previous day. This triggered the Retailer of Last Resort (RoLR) process to transfer Weston's customers over to default retailers, moving them over to the portfolios of AGL and Origin. The process resulted in AEMO declaring a major RoLR event in the Sydney STTM and minor RoLR event in the Brisbane STTM, putting them into administered states where prices were to be set in Sydney at around $30 per GJ for 28 days and capped at $40 per GJ in Brisbane for 10 business days. Following ministerial intervention on 31 May, however, Sydney was downgraded to a minor RoLR classification (with a $40 cap to match Brisbane) and administered states pursuant to the minor RoLR event expired for both on 7 June. However, Sydney remained in an administered state for another week due to the cumulative price exceeding the threshold ($440 per GJ).[178]

In Victoria, the breach of the cumulative price threshold ($1,400 per GJ) from the 10 am schedule on 30 May also triggered administered prices.[179] In the administered price state, the cumulative price is calculated using underlying marginal clearing prices based on participants' market offers. Due to the distorted price signal in the Victorian market, participants have withheld capacity to sure up their own supply, offering gas at market value only up to levels matching their own demand requirements. This has led to shadow prices behind the $40 per GJ administered price cap (APC) frequently reaching the market price cap (MPC) of $800 per GJ, prolonging the administered state. MPC schedule pricing has been driven by higher than expected demand or participants buying off market without

174 Sydney's administered state remained until 14th June because of high prices leading to administered price caps.

175 It is likely in addition some winter contract volumes increased in June for supply of gas to the south, information as to gas sold into (including May when gas went north contrary to daily spot market pricing signals) and out of Queensland will increase partially with requirements on industry to report contract prices and key terms and conditions from 15 December 2022 under new provisions of the National Gas Rules commencing then.

176 While refilling at Iona was limited over this period last year due to a pipeline leak, in 2022 utilisation of Iona and withdrawals to top up storage levels have been influenced by higher-than-expected gas generation requirements and distorted administered state price signals leading to limited market supply being available to schedule controlled market withdrawals.

177 Including New South Wales, Victoria, South Australia and Tasmania, with the direction to take effect until either: generators have sourced gas supply to meet generation demand; the threat to system security has ended; or AEMO determines the direction is no longer required to maintain or improve reliability, system security or in the interest of public safety.

178 The STTM cumulative price threshold (CPT) is calculated from daily market prices over a rolling period measured over the previous 7 days.

179 In Victoria, due to the 5 daily scheduling intervals, the administered price is measured over the previous 35 scheduling intervals (7 days).

providing supply to match their demand requirements. However, this balance has led to contingency gas events when insufficient supply was offered and AEMO could not clear the market, with the Gas Supply Guarantee (GSG) also being invoked to prevent the expected curtailment of electricity generation (section 4.11.2).

2021 local prices and international price trends

Annual prices increased over 2021, rising by 80% from the previous year.[180] Although separate factors influenced higher prices in 2021, including the international price divide, there were numerous similarities to the other drivers of high 2022 prices.

2021 average prices were driven up by particularly high prices over the 4 months of June, July, November and December. These high prices were largely driven by local factors, with record east coast LNG exports putting upward pressure on northern prices. However, the impact of high international prices on northern prices was limited and this created a gap between local and international prices.

Like 2022, record drawdown of gas storage in Victoria and production issues at Longford (Victoria's largest production source) contributed to price volatility in the middle of 2021. Unseasonably cold temperatures over winter drove increased demand and prices later in the year (also driving Iona storage unusually low for that time of year).

4.3.3 Linkages between domestic and international prices

The growth in Queensland's LNG exports from late 2020, combined with other factors including state-based moratoriums on gas development and a tightened supply–demand balance, has placed increasing pressure on east coast domestic markets. This has combined with other factors such as state-based moratoriums on gas development, tightened the supply–demand balance leading to increased wholesale gas prices.

Over 2021, a severe northern winter combined with shipping constraints drove up Asian prices early in the year. Later in the year, competition between Asian, European and South American buyers combined with higher demand from replenishment of European storage levels. This led to higher prices in late 2021 over the following northern winter. In early 2022, the Russian[181] invasion of Ukraine put upwards pressure on global oil and gas prices. Bans on Russian oil drove countries to diversify their supply and to decrease dependence on Russia for both oil and gas, sending ripple effects across global supply chains.

In 2022 further pressure from gas-powered generation heading into the higher demand winter period contributed to driving gas market prices up to unprecedented levels.

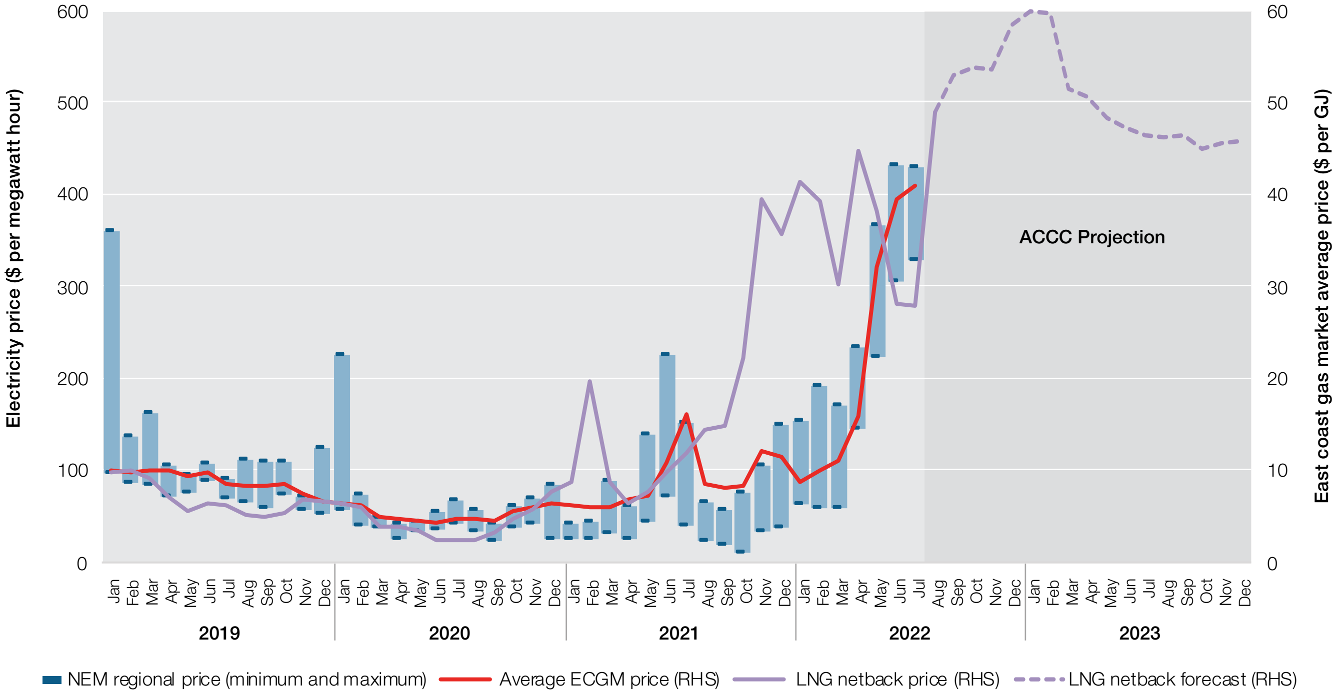
The higher NEM demand coincided with a particularly cold start to winter across the east coast, which put further pressure on the already tight supply–demand balance. Local gas prices increased from a high base of around $15–$20 per GJ from April, increasing toward international export parity levels heading into winter and closing the large gap between local and international prices from late 2021 (Figure 4.4). Following Russia's invasion of Ukraine in late February, international oil and gas prices surged, which could flow through to local gas contract pricing – offers from exporters are now starting to factor in export parity prices.[182] However, the more immediate impact to local exports has followed the curtailment of Russian gas supply to Europe, which drove up international LNG demand from alternative supply sources. While Russian gas supply to Europe was maintained and underground storage levels increased, netback prices briefly reduced below $30 per GJ in mid-2022. However, subsequent Russian supply threats resulting in pipeline flow reductions, and an explosion at Freeport LNG that took a significant amount of US LNG off the market, drove prices back up in August.

180 AER, Wholesale markets quarterly – Q4 2021, February 2022.

181 Russia is one of the biggest global producers of both oil and gas commodities.

182 ACCC, Gas inquiry 2017–2025, interim report, July 2022, August 2022, p 12.

Figure 4.4 Comparison of east coast gas market, NEM and LNG netback prices



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

Source: AER analysis of NEM, short term trading market, Victorian declared wholesale gas market and ACCC LNG netback price data.

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the northern hemisphere winter. Policy measures that influence gas use and broader economic factors can also be strong drivers of changes internationally.

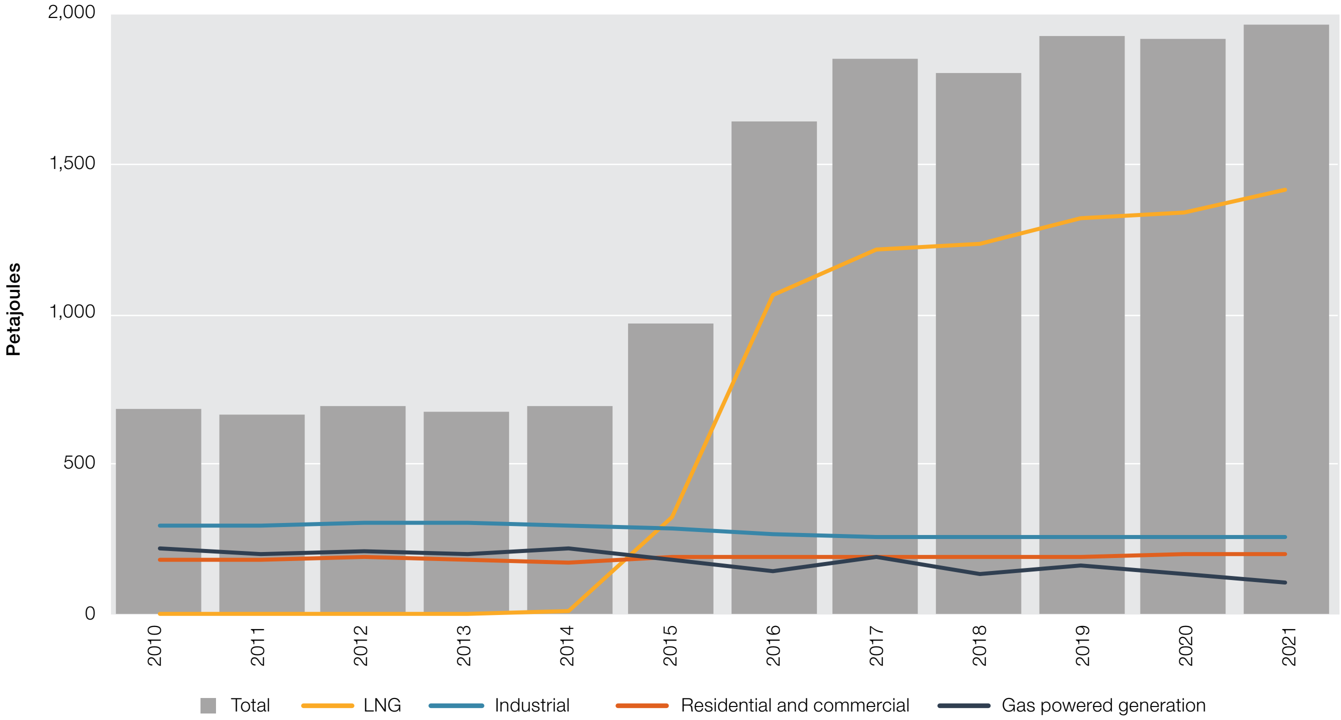
Figure 4.5 LNG netback and Wallumbilla prices

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

4.4 Gas demand in eastern Australia

Around 70% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market (Figure 4.6).

Figure 4.6 Eastern Australian gas demand



Source: AEMO, 2022 gas statement of opportunities, March 2022.

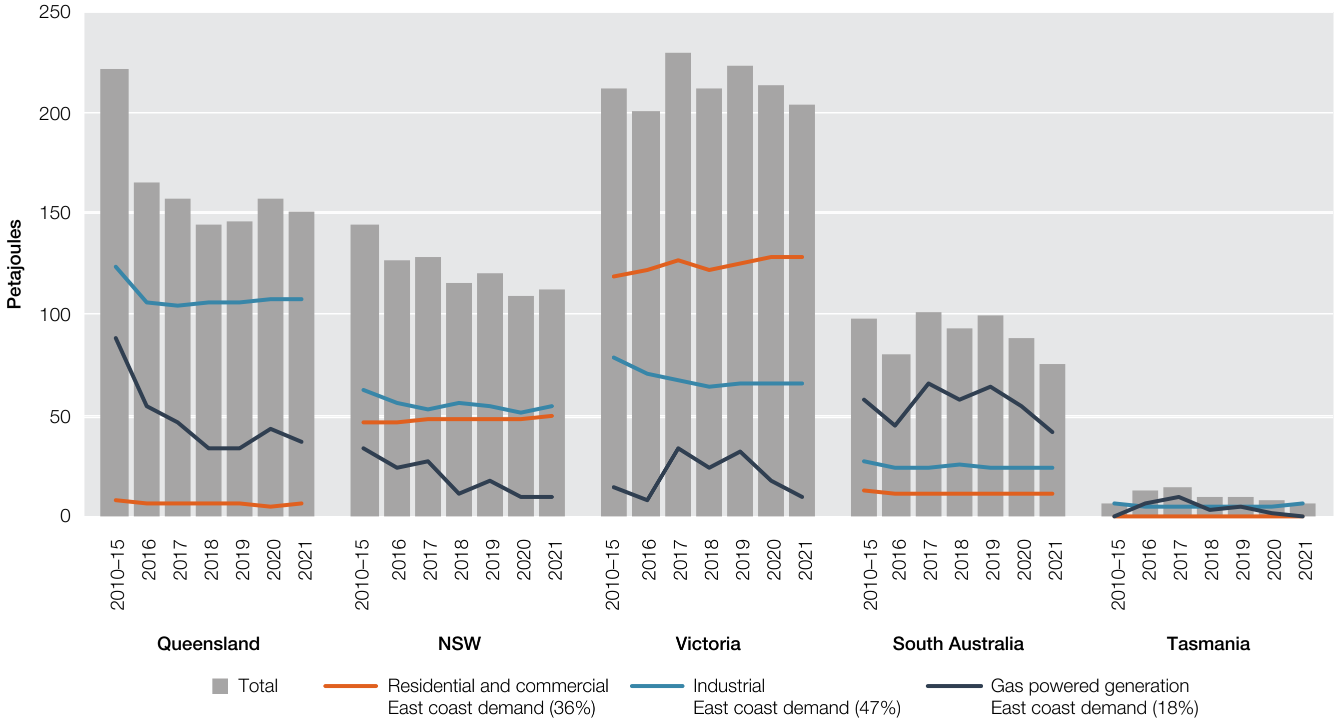
4.4.1 Domestic demand

Domestic customers in eastern Australia used around 550 petajoules (PJ) of gas in 2021 (Figure 4.7).[183] These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 47% of gas sold to the domestic market. They use it as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass and processed foods. Gas is also a major feedstock in ammonia production for fertilisers and explosives.

183 Excludes LNG. AEMO, 2022 gas statement of opportunities, March 2022.

Figure 4.7 Gas consumption in eastern Australia



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

Source: AEMO, 2021 gas statement of opportunities, March 2021.

Residential and commercial customers accounted for 36% of domestic gas demand, but this share varies from state to state. For example, in Victoria more than 60% of gas is consumed by small residential and commercial customers, who use gas mostly for heating and cooking. In Queensland, where much fewer households are connected to a gas network, the share of gas consumed by residential and commercial customers falls to 4%.

The electricity sector is another major source of gas demand, accounting for 18% of domestic gas use in 2021, down from 29% in 2017. South Australia used the most gas-powered generation in 2021 (42% of gas-powered generation in the National Electricity Market). The rapid responsiveness of gas-powered generators makes them suitable for meeting peak electricity demand and managing variable wind and solar generation. Consequently, the volume of gas used for electricity generation fluctuates with electricity market conditions. Long-term forecasting of expected usage for gas-powered generation in the National Electricity Market (NEM) is difficult due to the unpredictability of factors including unforeseen events.[184]

Domestic gas use in 2022

In 2022, gas-powered generation was up from 2021 levels across the January to March quarter. Queensland remained elevated alongside continuing baseload outages, and baseload outages in Victoria and New South Wales influenced increases from the previous quarter. This occurred alongside warmer weather driving the highest first quarter underlying electricity demand in recent years for Victoria and Queensland, particularly during humid conditions over January and extreme heatwave conditions across northern Queensland in March.[185]

Over the April to June quarter of 2022, numerous baseload generation outages in the NEM contributed to higher demand for gas generation. On top of this, limits on hydroelectric generation output related to recent flooding events and constraints on the supply and transportation of coal put further upwards pressure on demand for gas generation. NEM price spikes from late April into May were also influenced by planned and unplanned network outages limiting Queensland's access to lower priced generation from the rest of the NEM, while a similar situation affected South Australia in mid-May.

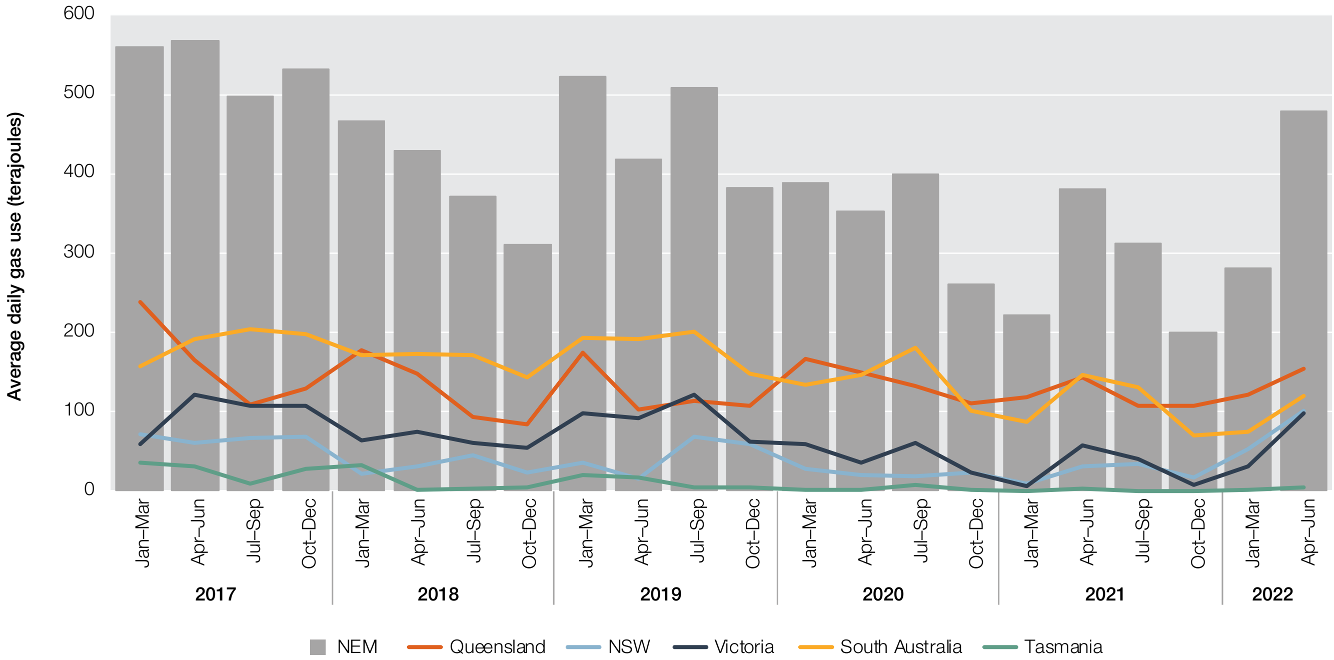
The combination of very high fuel prices, fuel constraints and fuel rationing led to unprecedented NEM prices and AEMO suspending the market (section 4.3). All these factors over the quarter saw gas-powered generation demand increase to the highest level observed for April-June since the shutdown of Victoria's Hazelwood coal-fired generator

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

185 AEMO, Quarterly Energy Dynamics Q1 2022, April 2022, p .7.

in late March 2017 (figure 4.8). On top of this, as the east coast headed into the typically higher winter demand period, it also experienced the coldest start to winter in decades[186], driving up southern gas market demand and putting further pressure on domestic supply given demand for gas-powered generation.

Figure 4.8 Quarterly gas demand for gas-powered generation



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

4.4.2 Liquefied natural gas exports

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

In eastern Australia, export gas is liquefied in processing facilities in Queensland to make it economic to store and ship in large quantities (Table 4.1). Australia also operates 5 LNG projects in Western Australia and 2 in the Northern Territory (Figure 4.9).

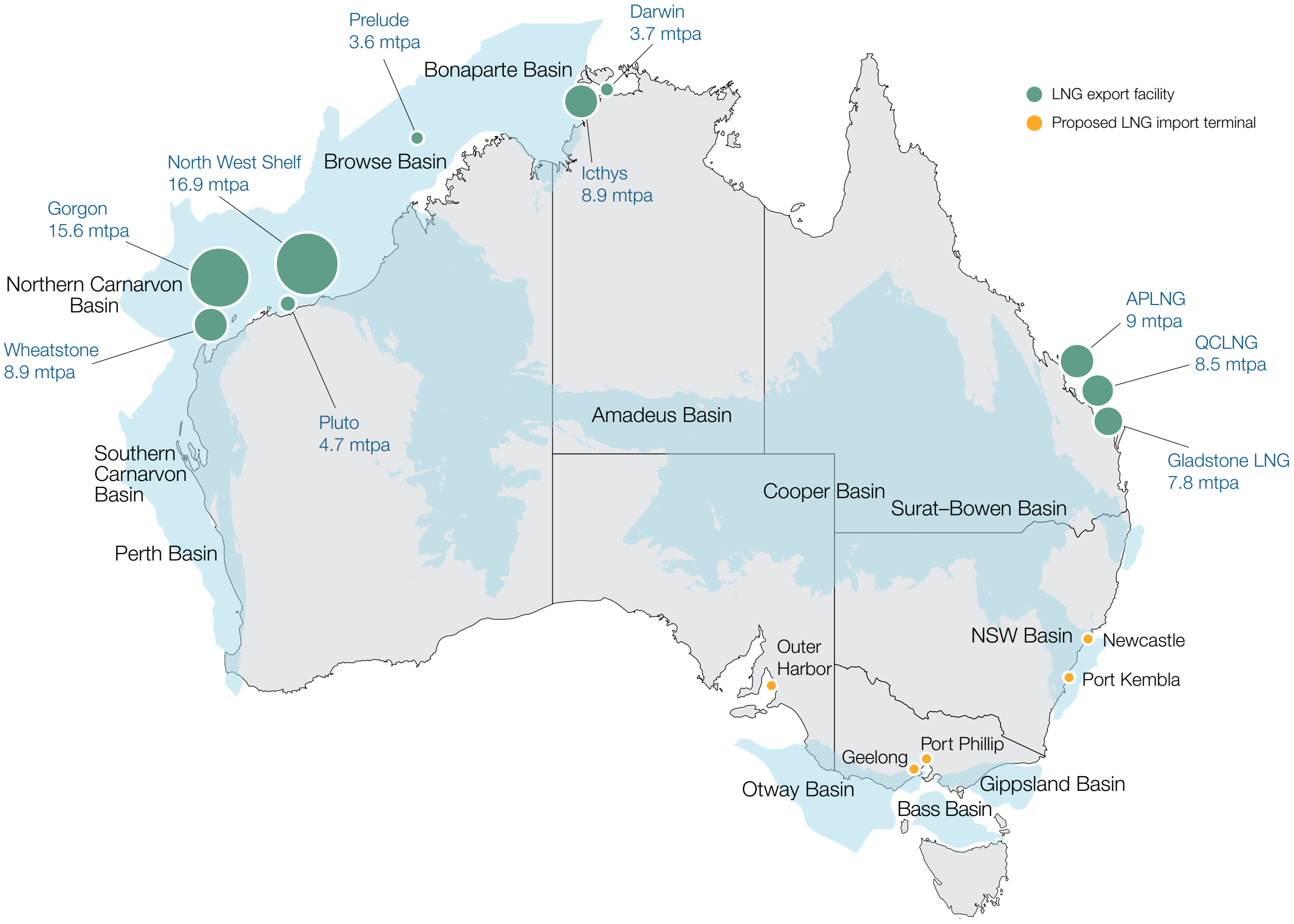
In 2021 LNG exports earned Australia $50 billion, making gas Australia's second largest resource and energy export behind iron ore[187] and Australia one of the world's largest LNG exporters in 2021. These export levels are expected to be overtaken by Qatar and the United States, due to significant growth over the next 5 years.[188]

186 The Guardian, Coldest start to winter in decades for eastern Australia with power grid under strain, June 2022.

187 Department of Industry, Innovation and Science, Resources and energy quarterly, December 2021.

188 EnergyQuest, EnergyQuarterly, March 2020.

Figure 4.9 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa).

Source: AER.

Queensland's LNG industry comprises 3 major projects, which source gas mainly from the Surat–Bowen Basin:

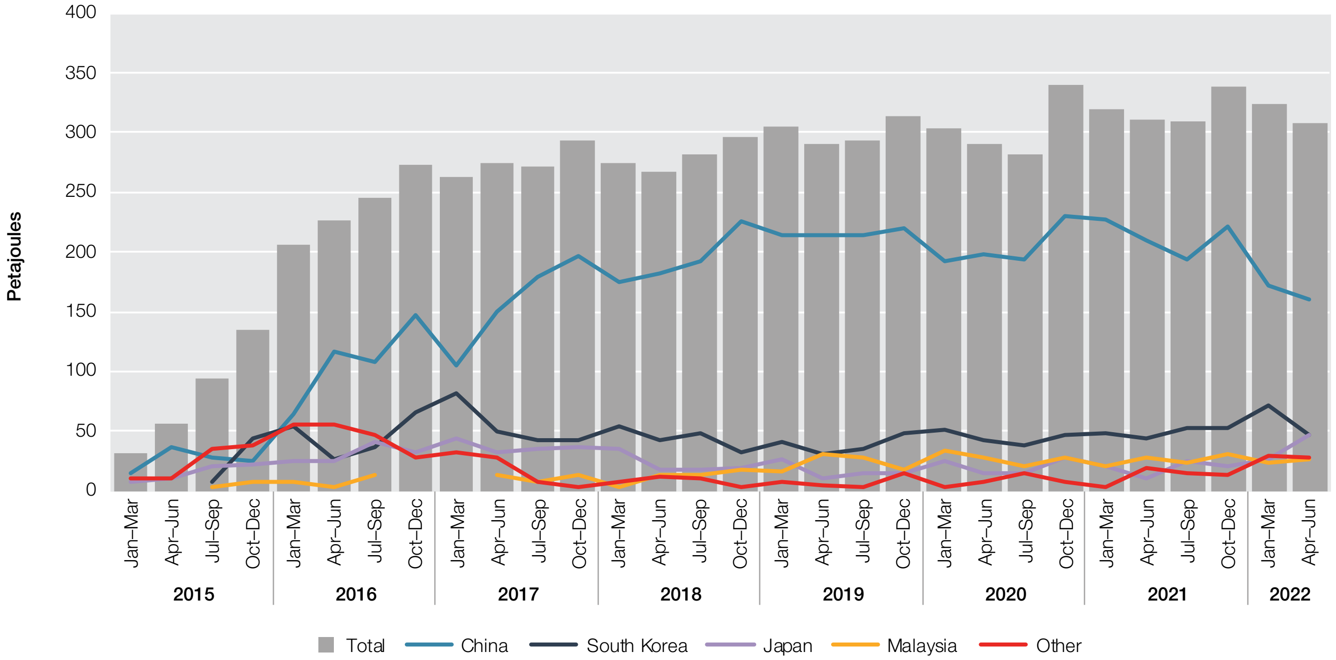
- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). Shell (73.75%), CNOOC (50% equity in Train 1) and Tokyo Gas (2.5% equity in Train 2) own the project.
- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas and Total (27.5% each) and Kogas (15%) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa.[189] Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) own the project.

These LNG projects control over 80% of reserves in eastern Australia.[190] They also source gas from other producers through long-term contracts and spot markets. East coast gas exports are typically lower mid-year, when domestic demand increases in winter, and higher over summer as northern winter conditions drive up international demand.

189 APPEA, LNG exports, APPEA website, accessed 29 May 2022.

190 ACCC, Gas inquiry 2017–2025, review of upstream competition and the timeliness of supply, issues paper, 15 September 2021, p 6.

Figure 4.10 Eastern Australian gas exports



East coast LNG exports increased to record levels over 2021 (and the fourth quarter of 2021 reaching close to the record from late 2020).[191] APLNG operated above capacity across most of 2021, contributing to record eastern Australian production levels (figures 4.10 and 4.12).

China is the primary market for eastern Australian LNG, accounting for 67% of exports in 2021 (851 PJ). These exports were 4.4% higher than the previous year's volume following the first decrease since east coast exports commenced, yet they remained lower than 2019 levels (863 PJ). While China's LNG demand is expected to continue to grow, supported by expanded industrial and residential gas use, recent declines in 2022 saw Gladstone exports to China decline to the lowest levels observed since 2017.[192] China has further relaxed macroeconomic policy to support economic growth amidst continued COVID lockdowns, with further measures expected to be introduced to achieve their 2022 growth target.[193] However, with the recent events in Europe, China has sourced additional LNG supply from Russia, increasing imports by 77% in the three months following the invasion of the Ukraine.[194]

Across the January-March quarter of 2022, our other main source of east coast LNG demand from South Korean increased, despite overall lower demand resulting from reduced gas-powered generation that coincided with increased coal-fired generation output. To curb greenhouse gas emissions, South Korea's Government had previously encouraged reduced coal generator output. However, these restrictions appear to have been lifted in April 2022 amidst record-high global LNG prices, with the construction of new nuclear facilities also expected to contribute to restrained growth in gas demand over the coming years.[195] While South Korean demand declined over April-June 2022, Japanese imports increased by a similar amount, yet long-term gas demand from Japan is also expected to decline with rising nuclear and renewable energy generation displacing gas-powered generators.

International price trends outlooks remain uncertain, influenced by potential COVID lockdowns continuing in China and the risk of further curtailments of Russian gas exports to Europe.

Northern Territory and Western Australia exports

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

191 DISER, Resources and Energy Quarterly, December 2021, p 77.

192 Chinese gas imports fell 13% over the Jan-March quarter of 2022, with Australia's share down from 7.1 million tonnes in 2021 to 5.6 million tonnes in 2022, and even large declines in US gas imports.

193 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, June 2022.

194 ibid, p 77.

195 ibid, p 78.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa – including the North West Shelf, which is Australia's largest LNG project by capacity (16.3 mtpa). The other projects are Gorgon (15.6 mtpa), Wheatstone (8.9 mtpa), Pluto (4.9 mtpa) and Prelude (3.6 mtpa).

4.5 Gas supply in eastern Australia

Gas supply to the northern gas market is largely supplied from Queensland's Surat–Bowen Basin. But gas is also sourced from the Cooper Basin in South Australia and from the Northern Territory. At times, southern gas is also transported north to meet LNG export demand. Gas from the northern fields is also required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter.

In 2021 production increased again to 4,163 TJ per day as LNG projects ramped up production, particularly in the second half of 2021, to meet record export demand (Figure 4.10).[196] This continued in 2022 with new record production levels set for both the January-March and April-June quarters, however the east coast increase was driven by higher southern output as northern production tapered off, with significant increases in gas flows into the north over both quarters compared to previous years (Figure 4.18).[197]

To avoid export controls, Queensland's LNG producers have entered into a series of Heads of Agreement with the Australian Government[198], committing to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.[199]

In 2021 and 2022 AEMO forecast an improved gas supply outlook compared to previous years but noted the 5-year forecasts for southern available production were still declining. The improved outlook in 2021 reflected progress in the planning for AIE's Port Kembla LNG import terminal, however development for the project was pushed out past winter-2023. While new greenfield infrastructure solutions are not expected to assist with potential 2023 supply shortfalls[200], brownfield solutions (including an expansion of the South West Pipeline and the duplication of the Winchelsea compressor in Victoria) may improve supply availability.[201] With a reduction in southern reserves (largely due to the decline of the Gippsland basin supplying the largest and most flexible production source)[202], the expansion of the South West Queensland and Moomba to Sydney pipeline corridor is also expected to play an important role in bringing northern gas supply to southern markets next year, with the committed stage 1 of the expansion expected to provide increased transportation capacity before winter-2023 (section 4.9.3).

Despite improved supply forecasts from 2022 in the short run, the longer-term outlook remains uncertain. In addition to further write-downs of 2P reserves reported the previous year, AEMO forecast that south-eastern gas production will drop significantly in 2023, leading to an increased risk of peak day supply shortfalls. By 2026, this is expected to occur more frequently even with no gas generation, while international conflict driving countries to diversify away from Russian gas also drives up risk to accessing LNG imports and the demand for floating storage and regassification units. Similarly, the ACCC reported a broader shortfall in supply from 2P reserves could emerge by 2026. Both AEMO and the ACCC suggested more exploration and development in southern Australia, pipeline expansions and LNG imports could mitigate the supply risks. However, the speculative nature of unsanctioned new domestic supply sources, with a range of barriers including significant investment in infrastructure to bring gas to market, have led to producers finding it increasingly difficult to obtain finance to invest in fossil fuel projects.[203]

Further factors also contribute to uncertainty surrounding long-term supply conditions, including underperformance of developed resources and the potential for southern production to decline faster than expected. Forecasts

196 Each year since 2013, gas production in Queensland has reached record levels.

197 To meet its LNG supply contracts, Santos has sourced substantial volumes of gas from other producers, diverting gas from the domestic market. The Australian Domestic Gas Security Mechanism empowers the Energy Minister to require LNG projects to limit exports or find offsetting sources of new gas if a supply shortfall is likely (section 4.11.1).

198 Department of Industry, Science, Energy and Resources, Securing Australian domestic gas supply, DISER website, accessed 12 July 2022. The new HoA was announced on 21 January 2021.

199 The government is currently negotiating a new Heads of Agreement with gas exporters to safeguard Australia's domestic supplies. The LNG projects use various methods to sell more gas domestically, including selling short-term gas on the Wallumbilla gas supply hub; launching expression of interest (EOI) processes for customers for long-term gas contracts; and entering bilateral arrangements for short-term and long-term gas contracts.

200 AEMO in its Gas Statement of Opportunities (March 2022) and the ACCC in its gas inquiry interim report (July 2022) have both forecast risks of supply shortfalls in 2023, with the ACCC forecasting a probable shortfall of 56 PJ where AEMO's forecast indicated a risk of shortfalls on peak days but sufficient gas available to meet annual demand. The sources of these differences are discussed in: ACCC, Gas inquiry 2017–2020, interim report, January 2022, February 2022, p 19.

201 AEMO, 2022 gas statement of opportunities, March 2022, pp 4, 6 and 11.
Expected Port Kembla development was delayed until late 2023, with insufficient customer contracting impacting the relocation and operation of the floating storage and regassification unit (FRSU), putting an anticipated winter-2024 operation at risk.

202 AEMO, 2022 Victorian gas planning report, March 2022. pp. 47-48.

203 ACCC, Gas inquiry 2017–2020, interim report, January 2022, February 2022, pp 15, 23, 39.

also make assumptions about undeveloped resources with uncertain reserves which are increasingly unreliable, depending on more speculative sources of supply. The decrease in 2P reserves in the Surat basin, where the decline was greatest, has seen substantial volumes of 2P reserves downgraded to 2C resources or revised down for other reasons.[204] [205] While some development proposals in eastern Australia show promising signs, others face significant regulatory hurdles linked to environmental concerns.

In response to this ongoing supply uncertainty, the Australian Government and some state governments launched initiatives to encourage new projects to supply the domestic market (section 4.11).

4.5.1 Gas reserves and production

Eastern Australia had 37,639 PJ of 'proven and probable' (2P)[206] gas reserves in February 2022, having produced over 2,000 PJ of gas in 2021 (Table 4.1).

Ownership is highly concentrated in some gas basins, but more diverse across the market as a whole (Figure 4.11). APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Table 4.1 Gas basins serving eastern Australia

	GAS PRODUCTION – 12 MONTHS TO DECEMBER 2021			2P GAS RESERVES (FEBRUARY 2022)	
GAS BASIN	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIA RESERVES (%)
Surat–Bowen (Qld)	1,532	76%	1%	29,020	77%
Cooper (SA–Qld)	91	5%	-10%	1,079	3%
Gippsland (Vic)	290	14%	14%	1,729	5%
Otway (Vic)	35	2%	-5%	685	2%
Bass (Vic)	7	0.3%	-37%	157	0.4%
Sydney, Narrabri, Gunnedah (NSW)	3	0.2%	-8%	11	0.03%
Amadeus (NT)	15	1%	3%	234	1%
Bonaparte (NT)	44	2%	-7%	4,724	13%
EASTERN AUSTRALIA TOTAL	**2,018**	**–**	**2%**	**37,639**	**–**
Domestic gas sales	586	–	-7%	–	–
LNG exports	1,432	–	6%	–	–

2P: proven plus probable reserves estimated to be at least 50% sure of successful commercial recovery.

Note: Totals may not add to 100% due to rounding. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and reserves in other basins are mainly conventional gas.

Source: EnergyQuest, EnergyQuarterly, March 2022.

Queensland's Surat–Bowen Basin holds 77% of gas reserves in eastern Australia and supplied 76% of gas produced in 2021. Queensland's 3 LNG projects produced over 90% of the basin's output in 2021.

Victorian basins account for 7% of eastern Australian reserves, but these reserves are declining largely due to anticipated decreases from Gippsland legacy fields. This is important because Victoria is the highest domestic consumer of gas. AEMO forecasts a steep decline in southern field production after 2022. Of Victorian basins, the Gippsland Basin is the largest while the Bass and Otway basins are smaller basins.

204 2C resources represent the best estimate of contingent gas reserves, which are not yet technically or commercially recoverable.

205 ACCC, Gas inquiry 2017–2020, interim report, January 2022, p 167.

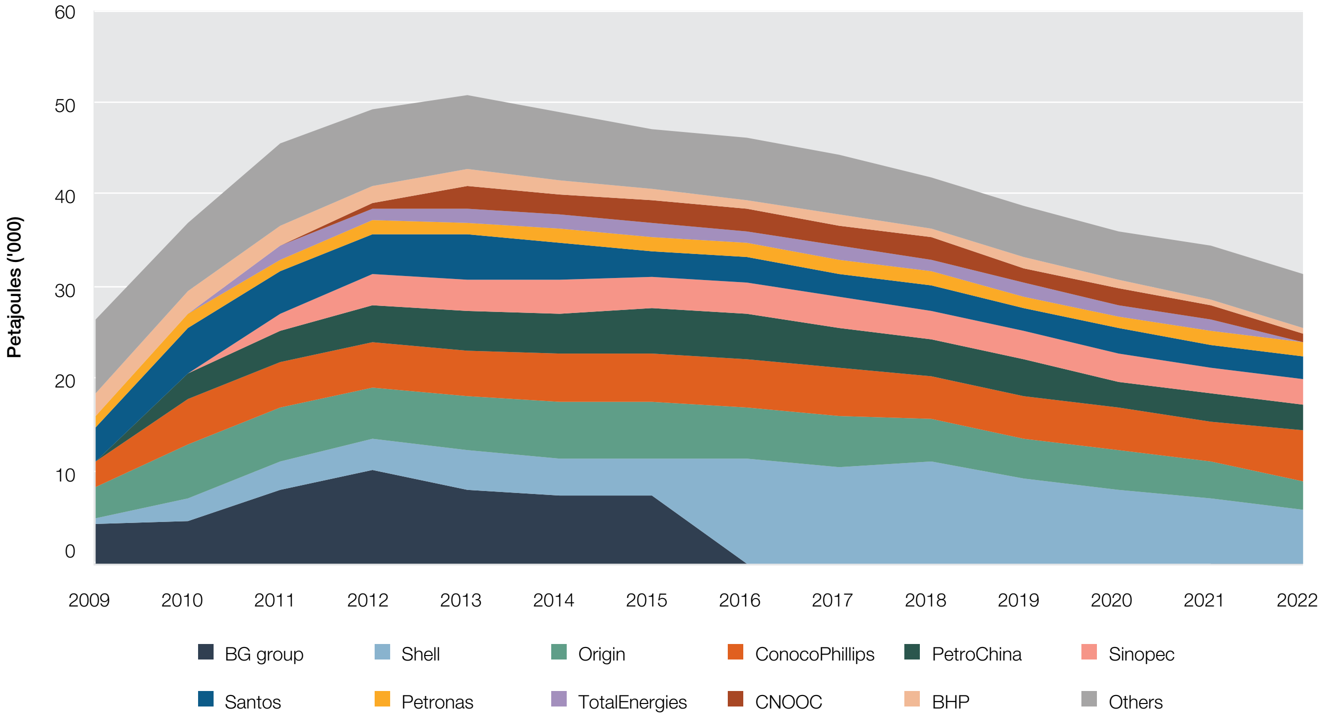
206 2P reserves are proven plus probable reserves estimated to be at least 50% certain of recovery.

The Cooper Basin in central Australia has over 1,000 PJ of eastern Australia's 2P reserves and accounted for 5% of gas production in 2021. Reserves in the basin have declined over the past decade. The Cooper Basin plays an important role as a 'swing' producer in managing seasonal and short-term supply imbalances in the domestic gas market.

NSW has significant contingent resources[207] (around 2,561 PJ) but only 11 PJ of 2P reserves and negligible current production. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin; however, an appeal against the approval led to a 12-month delay of the project, with the final investment decision now expected post-2022 (section 4.9.1).[208]

The Northern Territory has the Bonaparte Basin and the smaller Amadeus Basin. The basins are estimated to have over 4,950 PJ of 2P reserves.[209] Most gas produced is converted to LNG for export.

Figure 4.11 Market shares in 2P gas reserves in eastern Australia



Note: Aggregated market shares in 2P (proven and probable) gas reserves in the Surat–Bowen, Gippsland, Cooper, Otway, Bass and NSW basins. 2P reserves are those for which geological and engineering analysis suggests at least a 50% probability of commercial recovery.

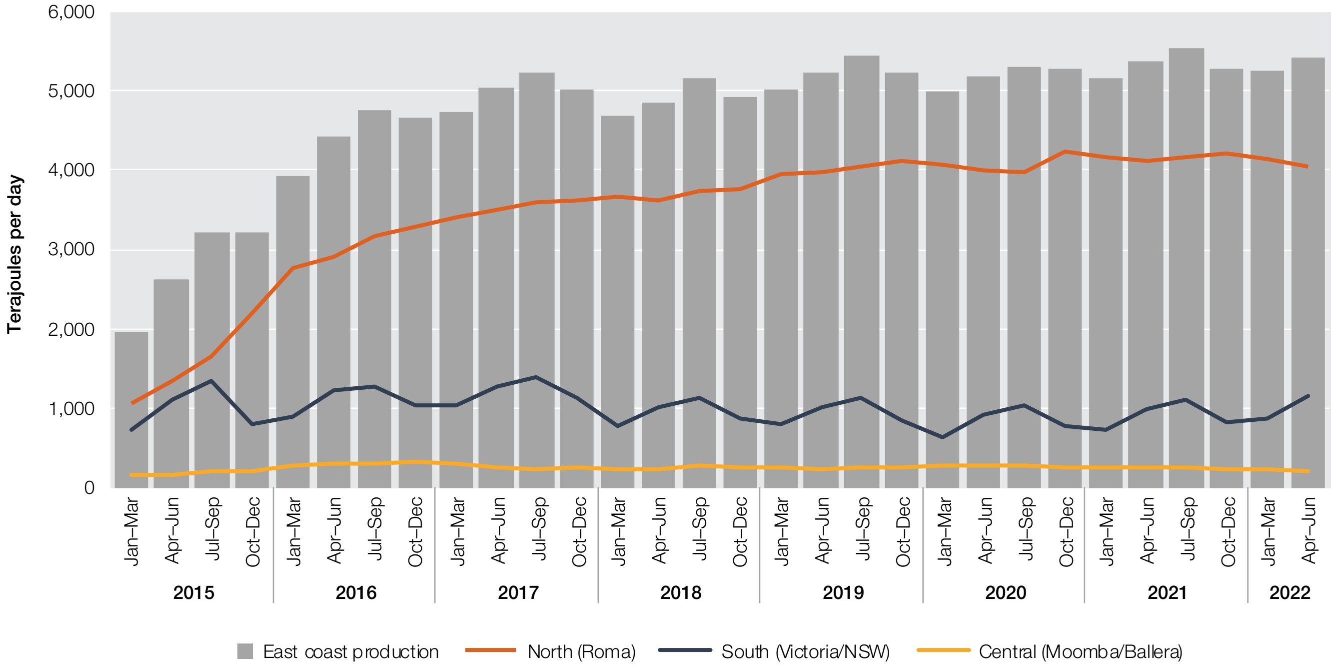
Source: EnergyQuest, EnergyQuarterly (various years).

207 3P contingent resources are reserves estimated to be potentially recoverable from known deposits, but which are not currently considered to be commercially recoverable.

208 EnergyQuest, EnergyQuarterly, December 2021, p 41 and March 2022, p 16.

209 EnergyQuest, EnergyQuarterly, March 2022, p 80. Reserves increased significantly for the Bonaparte basin in the Northern Territory (4,071 PJ). The increase followed a Santos final investment decision on Barossa and the acquisition of Oil Search.

Figure 4.12 Eastern Australia gas production



Source: AER analysis of Gas Bulletin Board data.

Record production levels occurred consecutively across the first 3 quarters of 2021, and the first 2 quarters of 2022 exceeded these levels to set new records.

Gas production in the northern states again rose to record levels in the fourth quarter of 2021 alongside unprecedented high LNG prices (figure 4.4) and record LNG exports (figure 4.10) from Queensland.[210] These export levels were also supplemented by northern gas storage supply and strong gas flows north from southern production sources (Figure 4.18).

In 2021 AEMO reported the accelerated decline of anticipated production in key southern fields,[211] with updated forecast predicting a 36% decrease from 2022-2026.[212] Despite committed new supply contributing an additional 30 PJ (or 100 TJ per day over winter) from 2023, the largest reduction in Gippsland's legacy fields is forecast to occur prior to winter 2023 (section 4.9.1).[213] The depletion of these fields is expected to place immense pressure on the southern markets on peak demand days.

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. Production from the Longford plant has been falling and the plant is becoming less reliable with plant constraints and maintenance outages increasingly disrupt production.

Changing basin profiles

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

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. Over 2019 and 2020, Surat–Bowen Basin production increased (9%), largely matching LNG export growth (10%), while southern basins decreased by a similar proportion (10%). Over 2021, strong southern supply and gas flows north to support high exports coincided with export levels growing more than Queensland production increases. The drawdown of southern supply has led to a projected shortfall in the south for 2022 and contributed to a 19 PJ surplus in the

210 AER, Wholesale markets quarterly – Q4 2021, February 2022, p v, Queensland exports over 2021 exceeded the previous year's record by about 5%.

211 AEMO, 2021 Victorian gas planning report, March 2021.

212 Total available supply from Gippsland fields is forecast to decline 36% from 312 PJ in 2022 to 200 PJ in 2026, driven by an increase in production from already producing Longford fields and committed new supply from the Kipper field. AEMO, 2022 Victorian gas planning report, March 2022, p 49.

213 Notwithstanding the increase, available Victorian production is forecast to be less than monthly winter consumption (28-30 PJ per month) from winter 2023. ibid, p 52.

north. Projected domestic supply from LNG exporters has also decreased by 52 PJ to half the level of actual supply provided in 2017 and 2018.[214]

4.5.2 Gas storage

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

- large facilities using depleted gas fields in Queensland, Victoria and South Australia:
  - Iona underground storage (Victoria) has a nameplate storage capacity of 23.5 PJ, with a delivery capability of 545 TJ per day[215] – this is the second largest supply source in the south and has the ability to deplete and refill at a much higher rate than other east coast storage facilities
  - Moomba Lower Daralingie Beds (LDB) storage (South Australia) has a nameplate storage capacity of 70 PJ, with a delivery capability of under 15 TJ per day[216]
  - Silver Springs storage (Queensland) has a nameplate storage capacity of 46 PJ, with a delivery capability of 25 TJ per day[217]
  - Roma Underground Gas Storage (RUGS, Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 58 TJ per day[218]
- LNG storage in smaller seasonal or peaking facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria[219] – these facilities have relatively high supply rates, but depletion cannot be sustained for many days due to slow refill rates
- short-term peak storage services on gas pipelines, which are mostly contracted by energy retailers – for example, the Tasmanian Gas Pipeline stores gas that can be sold into the Victorian market at times of peak demand.

The importance of storage in managing supply and demand has risen since the LNG industry began operating, with some storage facilities drawn down to meet LNG export demand and replenished when prices were low. Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks and seasonal demand. Average storage levels increased over 2020, but steady depletion over 2021 drew down storage to the lowest levels since reporting began. This brought average storage levels below 40% of capacity in late 2021 (Figure 4.13).[220] Iona has replenished significantly into 2022, but draw down of supply from the other large facilities has continued, with declining pressure in the storage wells adding to constraints on supply capability.[221] This winter, Iona storage levels have reduced to lows similar to 2021 in July and Newcastle gas storage reduced all the inventory in their LNG storage tank for the first time since the facility started operating.

214 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 19-21.

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

216 Progressive depletion of storage levels has reduced delivery capacity to 10 TJ per day from late 2021, with current delivery capabilities now sitting around 6 TJ per day since April.

217 Silver Springs delivery outlooks reduced to around 10 TJ per day from mid-October 2021, and has been sitting around 8 TJ per day or lower over most of 2022.

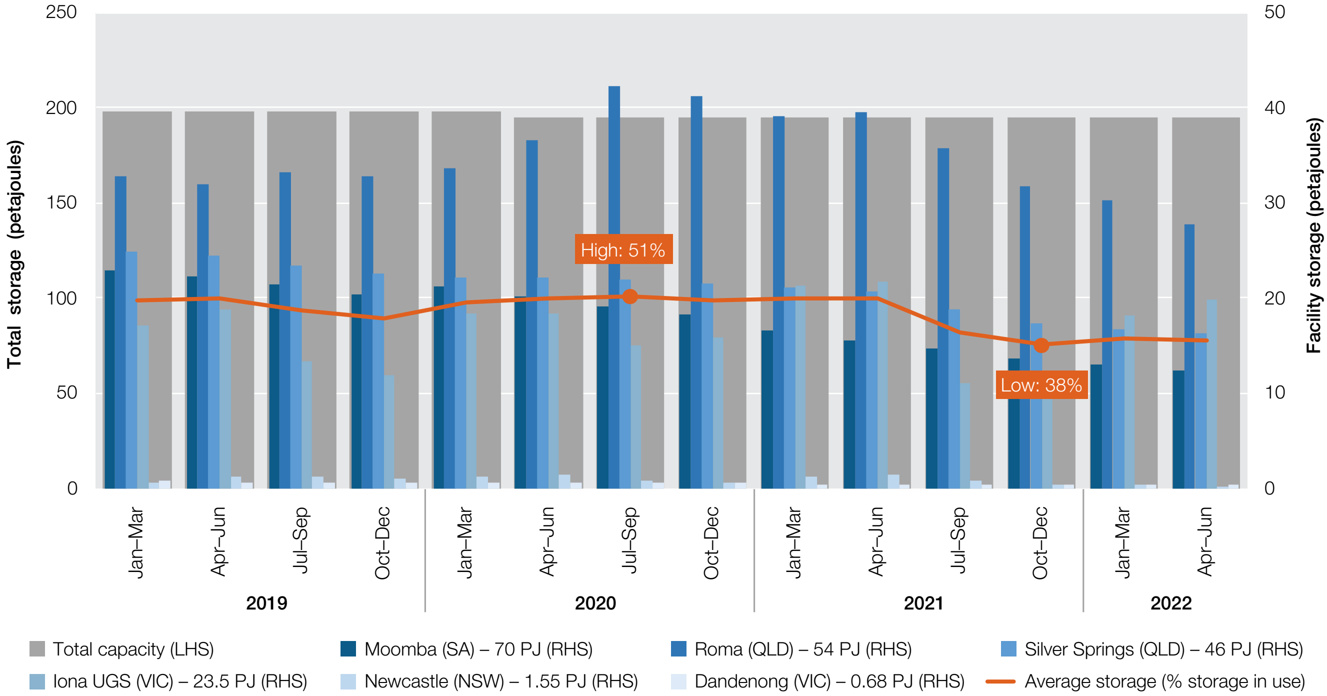
218 Following the continuing depletion of storage levels, short-term outlooks progressively reduced delivery capacity to 50 TJ per day as storage declined to 30 PJ (from 16 March), then 40 TJ per day as storage dropped to 27.6 PJ (from 27 May).

219 The Dandenong LNG storage facility reached record low levels in 2021 (since the commencement of the Declared Wholesale Gas Market in 1999), driven by a reduction in contracted capacity for winter.

220 With the exception of Iona, storage levels fell to record lows across all east coast facilities.

221 Moomba for example, has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 13 PJ limiting its physical injection capacity as low as 3 TJ per day over June.

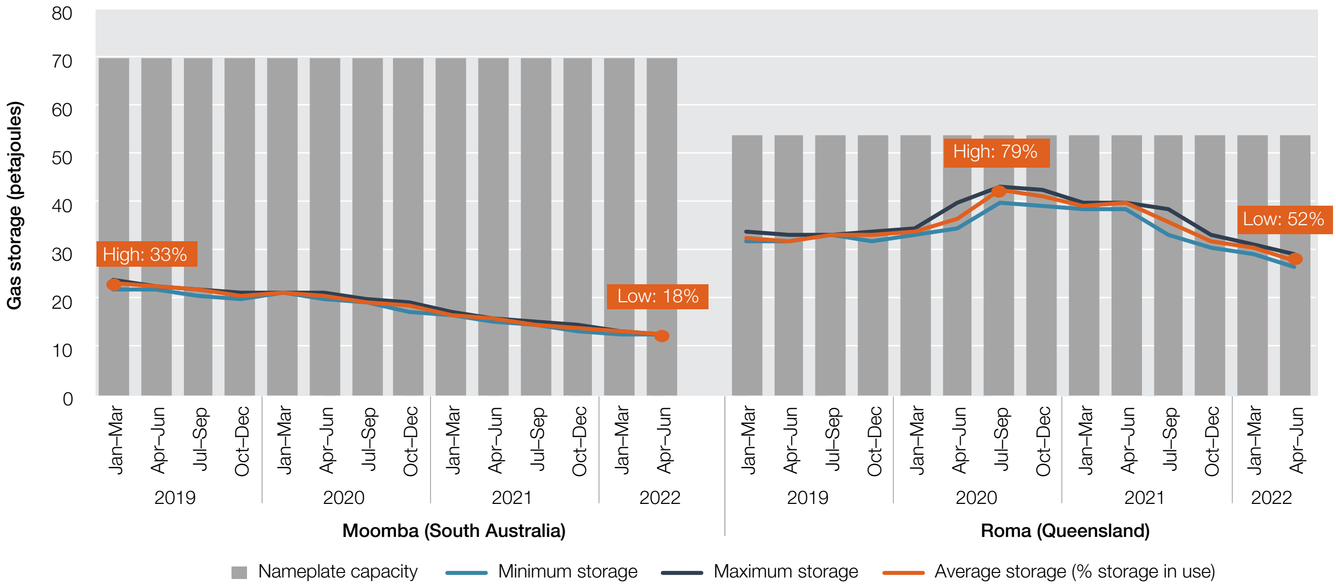
Figure 4.13 Gas storage in eastern Australia



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

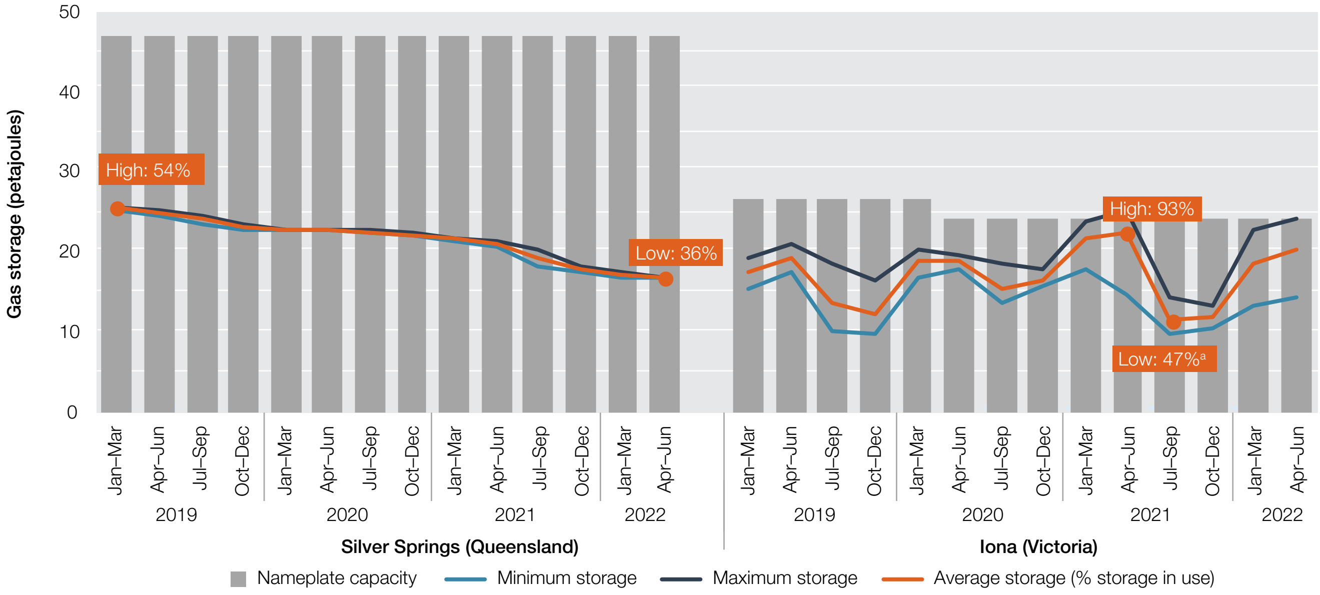
Source: AER analysis of Gas Bulletin Board data.

Figure 4.14 Large gas storage facilities – Moomba (South Australia), Roma (Queensland)



Source: AER analysis of Gas Bulletin Board data.

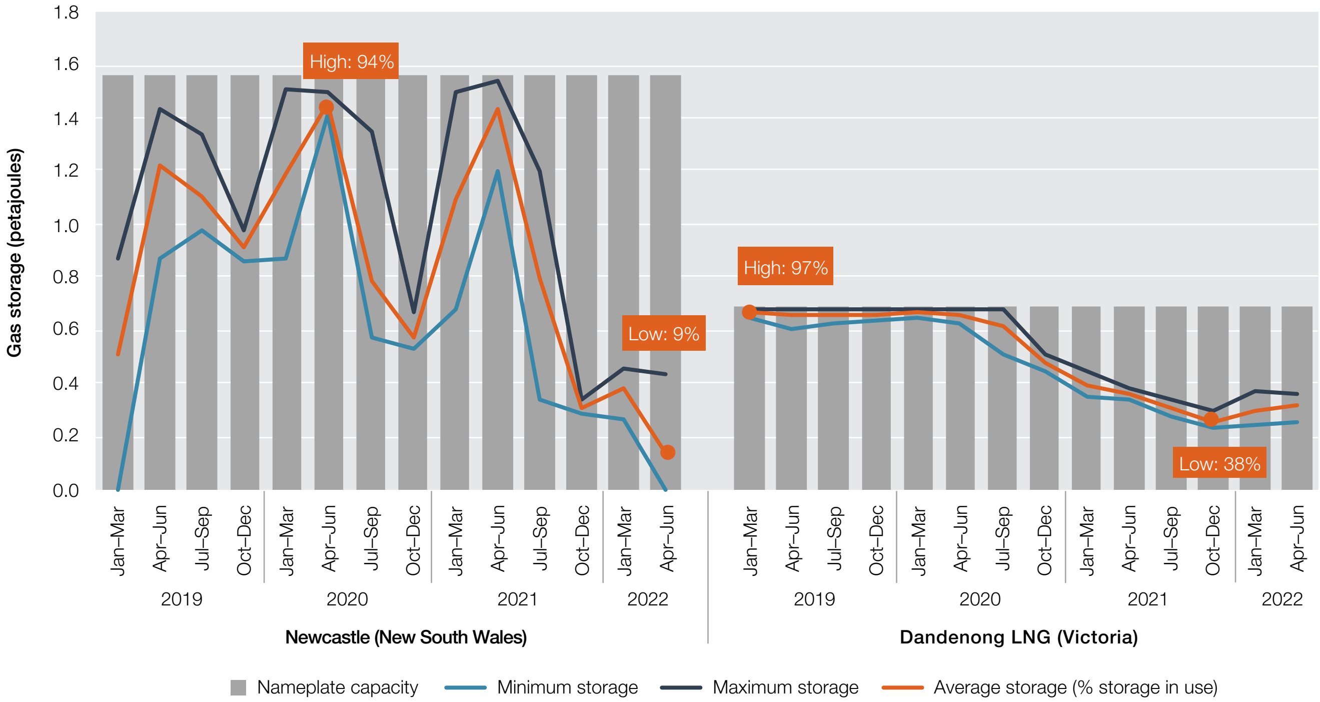
Figure 4.15 Large gas storage facilities – Silver Springs (Queensland), Iona (Victoria)



Note: [a] Lower storage inventory, lower proportionally for October – December 2018.

Source: AER analysis of Gas Bulletin Board data.

Figure 4.16 Small LNG gas storage facilities – Newcastle (NSW), Dandenong (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Investments to develop or expand storage capacity are under way.[222] Lochard Energy expanded Victoria's Iona facility in 2018 and made further improvements to the gas processing facility that became operational in 2021 and 2022.[223] This operates more dynamically than other storage facilities, with a larger capacity to inject and withdraw gas on any given day. Further expansion of storage capacity is currently taking place[224] and supply capacity is expected

222 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, p 53.

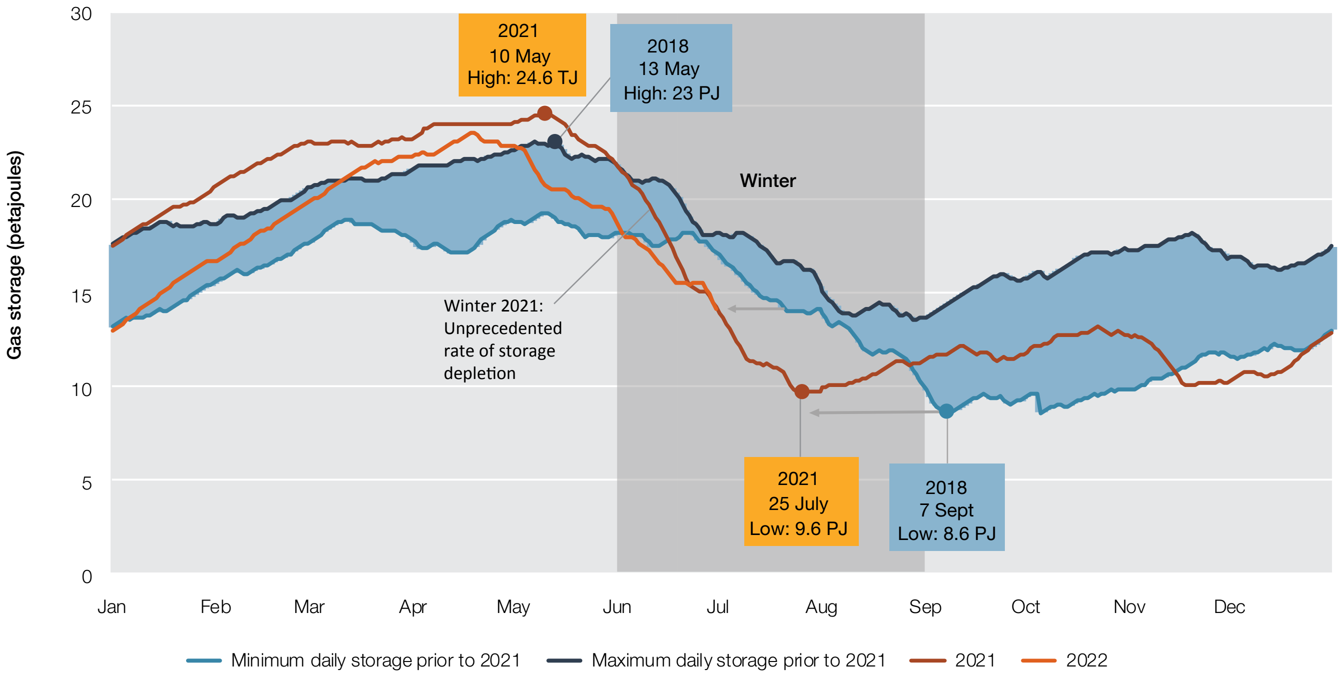
223 Following Lochard's takeover from EnergyAustralia in 2015, storage capacity has expanded significantly from a 390 TJ per day supply capacity to 530 TJ per day (17 March 2021) and 545 TJ per day (28 January 2022).

224 Lochard Energy, Seamer 2 Project – Community Update, 28 January 2022.

to increase from 545 TJ per day to 570 TJ per day in 2022. However, this capability is currently limited by existing pipeline capacity.[225]

In recent years, Victoria has become increasingly reliant on gas storage inventory from Iona. In 2021, storage levels fell to their lowest point since reporting commenced, with a similar trend occurring for winter 2022 heading into July leading AEMO to issue a notice of a threat to system security.[226] Recent upgrades have improved supply rates; however, this has also led to storage inventory being drawn down quicker than previous years. With supply reducing to these low levels earlier into winter (minimum levels have historically been observed from the end of winter), there is an increasing risk of supply being insufficient to meet demand on peak days.

Figure 4.17 Iona underground storage, low storage levels in winter 2021 and 2022



Further to this, the much smaller Dandenong LNG storage facility fell to particularly low levels in June, with recent drops in participants contracting the emergency supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, providing critical system security to avoid pressure drops at the Dandenong city gate. There is very high potential for the facility being needed next year as supply at Longford drops off. In August 2022, Energy Ministers submitted an urgent rule change to give the AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023.[227]

4.6 Inter-regional gas trade

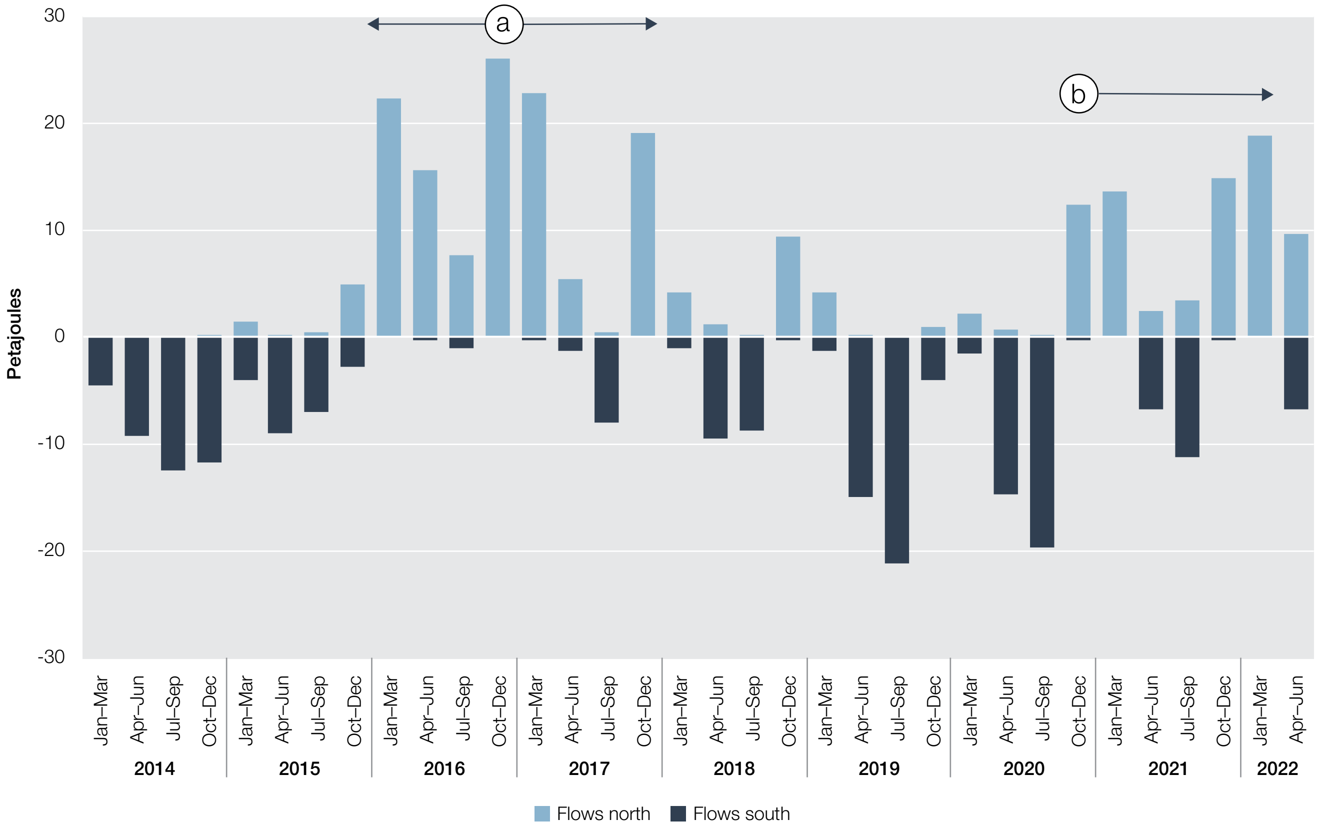
Domestic gas typically flows south in the Australian winter (to meet heating demand) and north in the Australian summer (the northern hemisphere winter) when Asia's LNG demand peaks (Figure 4.18).

225 The South West Pipeline (SWP) is currently undergoing upgrades to increase pipeline capacity that will support higher injection rates from the Iona storage facility. Further expansion of the storage facility could raise supply capacity to 600–700 TJ per day.

226 The AEMO notice was issued on 11 July, indicating the facility at current usage rates would decrease to 6 PJ by 31 July. This would result in reduced injection capability due to low pressure, increasing the risk of curtailment on peak demand days.

227 Energy Ministers Meeting, Communique, 12 August 2022.

Figure 4.18 North–south gas flows in eastern Australia



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

[a] 2016-2017: Increased southern production to meet LNG demand

[b] late 2020 onwards: record LNG exports continue to rise

Source: AER analysis of Gas Bulletin Board data.

From the last quarter of 2020, gas flows north increased to the highest level observed over the previous 3 years, in line with increases to east coast LNG export demand (figure 4.10). Flows north increased the following quarter, with larger increases the following year over October to March, while mid-year flows south have notably reduced from 2019 and 2020 levels. The day-ahead auction supported the turnaround in late 2021 as participants bought capacity on routes north. On the South West Queensland Pipeline 95% of all capacity purchased in the fourth quarter of 2020 was on routes north towards Wallumbilla. Recent activity on the auction has reversed this trend, with 61% over the January-March quarter and 85% over the April-June quarter of 2022 won on SWQP routes to transfer supply into southern markets. Since the invocation of the GSG, 99.5% of capacity has been procured through the auction over June to physically transport gas south (section 4.6.2).[228]

Data on trade flows may understate the extent of north–south gas trading. Some gas producers enter swap agreements to deliver gas to southern gas customers without physically shipping it along pipelines. An example is Shell's agreement with Santos to swap at least 18 PJ of gas.[229] Under the agreement, Shell draws on its CSG reserves to meet part of Santos's LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to meet demand in southern Australia.[230] The swap allows the producers to increase supply to the domestic market, while enabling Shell to avoid transporting gas on the South West Queensland Pipeline, which is contracted to near full capacity. To improve transparency, from 2021 participants' reporting requirements are expected to expand to encompass a range of bilateral arrangements, including physical swaps (section 4.12.1).

228 Over the April-June quarter, physical flows moved 6.2 PJ of gas north in April, falling to 3.1 PJ in May. Flows reversed in late May to transport 6.2 PJ of gas south over June. This coincided with AEMO invoking the gas supply guarantee for the first time in early June (section 4.11.2).

229 Santos, 'Santos facilitates delivery of gas into southern domestic market' [media release], August 2017.

230 EnergyQuest, EnergyQuarterly, March 2020.

4.6.1 Gas transmission pipelines

Supply conditions depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, pipeline operators are considering a range of upgrades to extend or expand existing infrastructure. For example, in 2021 APA announced the first stage of an expansion of the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets (section 4.9.3).

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

The eastern gas market's transmission system has evolved from a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre, into an integrated network. Many gas pipelines became bidirectional, and gas increasingly flows across multiple pipelines to reach its destination. Additionally, the Northern Gas Pipeline provides eastern Australia's pipeline interconnection with the Northern Territory (section 4.9.5). Access to capacity on key pipelines is important.

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

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements such as bidirectional and backhaul shipping, and park and loan services.[231]

Investments to develop or expand transmission capacity are underway (section 4.9.3).

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 5). The publicly listed APA Group is the largest owner of pipeline assets, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Another major pipeline owner with equity in numerous pipelines is Jemena. The pipelines fall under a range of different regulatory arrangements spanning full regulation to light or no regulation (Table 5.2).[232]

4.6.2 Pipeline access

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

Access to transmission pipelines on key north–south transport routes is critical for gas customers. But many critical pipelines have little or no spare, uncontracted capacity, making it difficult to negotiate access. In addition, many pipelines face little competition and charge monopolistic prices.

Reforms introduced in March 2019 made it easier to access pipeline capacity that is not fully used. Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. The reforms give other parties an opportunity to access this capacity through trading platforms.

Capacity can be acquired in 2 ways. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold in this way must be offered at a mandatory day-ahead auction. Any shipper can bid at the auction, which is finalised shortly after the nomination cut-off time a day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero, and most settlements have occurred at no cost.[233]

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

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

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

Pipeline capacity trading (day-ahead auction)

In 2022 the AER reported on the continued increase in the popularity of the day-ahead auction.[234] Over the past 3 and a half years over 160 PJ of contracted but nominated pipeline capacity has been won on the Auction across 14 of the 22 auction facilities (since it commenced in March 2019, in conjunction with the Capacity Trading Platform).[235]

Around 80% of all capacity procured was won at the reserve price of zero dollars, and almost 80% of this capacity has been won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP) which facilitate gas flows south and north between spot markets; the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP) which facilitates flows to gas-powered generators.

Over the April – June quarter of 2022, auction quantities exceeded the previous record quarterly trade level by 36%, reaching 20.9 PJ. Of this capacity, 9.4 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP), while the RPB also saw record trade (3.1 PJ).

The day-ahead auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low-priced northern gas into southern spot markets, easing price pressure in those markets.[236]

The AER's *Pipeline capacity trading – 2 year review* found day-ahead auction capacity increased liquidity in both upstream and downstream markets. It also reported on how the auction can indirectly ease supply costs for some gas-powered generators in the NEM.

However, auction activity on some pipeline remains low. In particular, the AER reported on the limited trade on the Moomba to Adelaide Pipeline and SEA Gas Pipeline System supplying the Adelaide market, although participation is increasing.[237] Under-utilisation of these pipelines may result from higher fees and lower activity levels in Adelaide compared to other markets. Auction fees can discourage smaller players in particular. While most capacity is won at the reserve price of $0 per GJ, the total cost is higher, as participants need to pay pipeline and storage operators for facility use (which can include both fixed and variable fees). Smaller participants also may be required to provide credit support, or collateral to use auction services, and in some cases these costs can be significant.

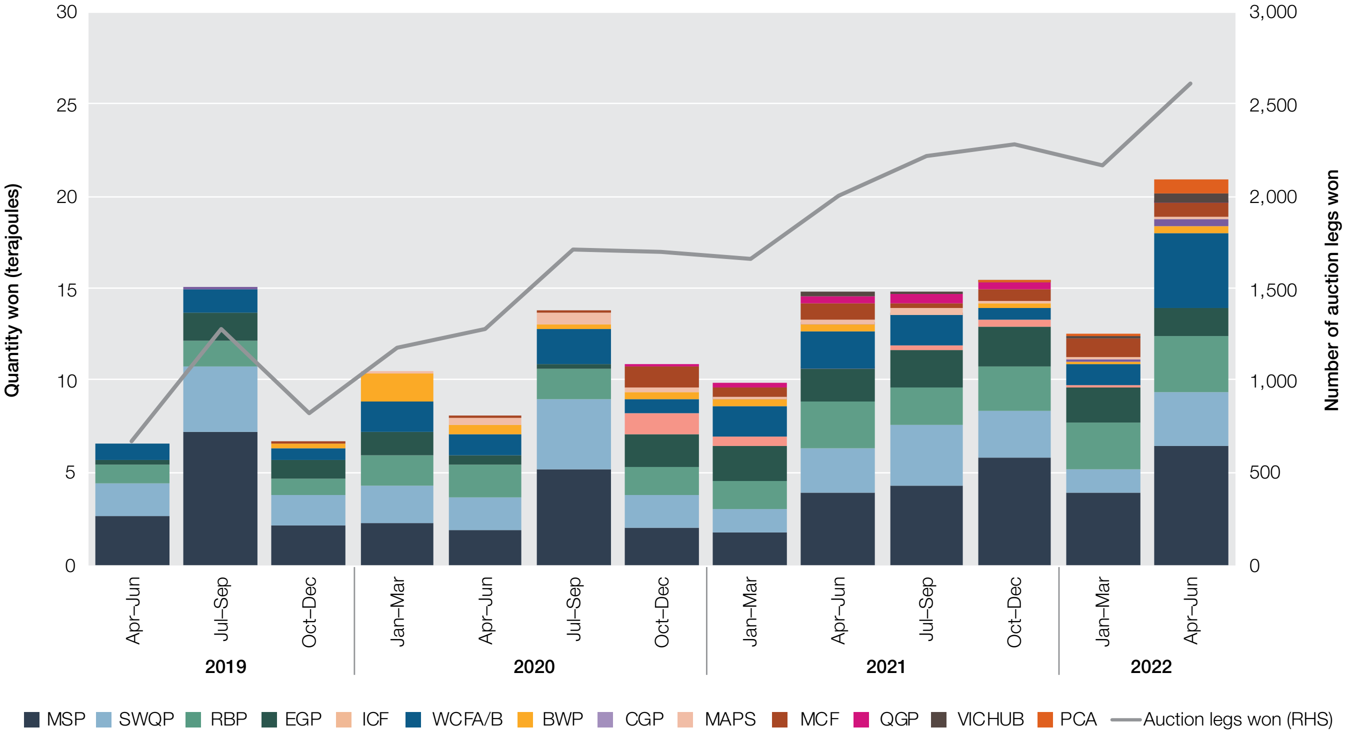
234 AER, Wholesale markets quarterly - Q1 2022 (Pipeline capacity trading update), May 2022, pp 37-48.

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

236 AER, Pipeline capacity trading – two year review, March 2021, p 23.

237 The Port Campbell to Adelaide pipeline (SEA Gas) had 816 TJ of capacity traded over April – June 2022, the first significant quantity since the auction commenced.

Figure 4.19 Day-ahead auction quantities won, by facility



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

Source: AER analysis of day-ahead auction data.

4.7 Trade in east coast gas markets

Gas markets were more liquid in 2021 than in the previous year, with trade levels in the gas supply hub rebounding and trading activity on the day-ahead auction continuing to grow.

In the first half of 2022 the drawdown of southern production reserves left those states more reliant on Queensland gas supplies going forward, yet gas continued to flow north in April and May despite increasing market volatility.

Domestic gas prices increased significantly in April 2022 ahead of the increased southern demand for gas heating over winter, with significant price increases occurring over the following months.[238]

Due to the continued upwards pressure on Victorian and short term trading market prices, and administered prices being applied in Brisbane and Sydney (following the suspension of a market participant) and Victoria (due to high prices), distorted price outcomes and participants wanting to hold on to contracted supply led to reduced supply offers. This compelled contingency market outcomes to mitigate the risks of short-term gas supply shortfalls (involuntary curtailment of uncontrollable load) from late May.

Uncertainty around the availability of sufficient supply levels beyond 2022 has also coincided with delays in bringing new supply sources online.

4.7.1 Victoria's declared wholesale gas market (DWGM)

Around 40 participants traded in the Victorian market in 2021. The market's participants include energy retailers, power generators and other large gas users, and traders.

Like the STTM, volumes traded in the Victorian market rose by 39% in 2021. Since mid-2019 there has been a consistent increase in quarterly flows of gas into Victoria through the Culcairn injection point. The majority of this is by

238 Potential upcoming shortfalls in southern gas supply, due to depleted legacy gas reserves in the Gippsland Basin, may be driving suppliers to set higher prices to limit further run-down of existing supply prior to a possible significant southern supply shortfall over winter 2023. Considering underlying contract positions reviewed in previous ACCC gas inquiry reports, local contract links to international oil and gas prices would potentially be impacted to some extent by international price increases following Russia's invasion of the Ukraine.

operators of gas-powered generation, but other participants have been increasing their deliveries recently, facilitated by the day-ahead auction.

The volume of trade in the Victorian gas futures market increased by 17% in 2021 from the previous year. Ultimately this increase still accounts for only a small proportion (less than 5%) of the total volume traded in the market.

4.7.2 Gas supply hubs (GSH)

In 2021, 17 participants traded at the gas supply hubs, all of which were active, with the entrance of a broker participant also facilitating off market trading.[239] LNG export businesses and gas producers were among the most active participants in 2021, closely followed by gentailers.[240] LNG producers are large suppliers of gas into the hubs, although operational issues can limit their participation. In addition, the physical interconnection of LNG facilities allows them to trade easily among themselves. Some market participants have suggested the scale of the LNG producers' operations may involve greater volumes than the hubs can currently absorb. Other participants include large industrial users and traders.

In 2021, 16 participants traded on-screen, with 15 actively trading. Similarly, 18 participants traded off-screen, with 17 of them active. On average, participants executed around 190 trades per month in 2021 – a reduction of 13% from 2020.

Wallumbilla hub activity

Users of the Wallumbilla hub include the LNG projects, gas-powered generators and, more recently, trader participants taking advantage of the day-ahead auction to arbitrage prices between Wallumbilla and the downstream markets.

Following a liquidity reduction in 2020, driven primarily by a collapse in on-screen trading, trading rebounded in 2021 with significant growth in off-screen activity (Figure 4.20). Notably, off-screen products tend to involve larger volumes of gas than do on-screen alternatives. In 2022 off-screen trade levels hit a record high, with 8.9 PJ traded in the April-June quarter, driven by higher volumes being traded for longer-term deliveries, including monthly product and strip trades of daily products.[241]

However, ultimately, gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral, off-market arrangements. In 2021 gas traded through the Wallumbilla hub accounted for 8.8% of total gas flows through pipelines in the Wallumbilla bulletin board zone.

Moomba hub activity

Trade at Moomba has been slow to develop. The first trade was executed in September 2017, with 141 trades executed in 2019. Similar to Wallumbilla, trades at the Moomba location decreased significantly in 2020, declining further in 2021.

Victoria and Sydney activity

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes, reaching a total of 212 TJ and 796 TJ respectively to date.[242]

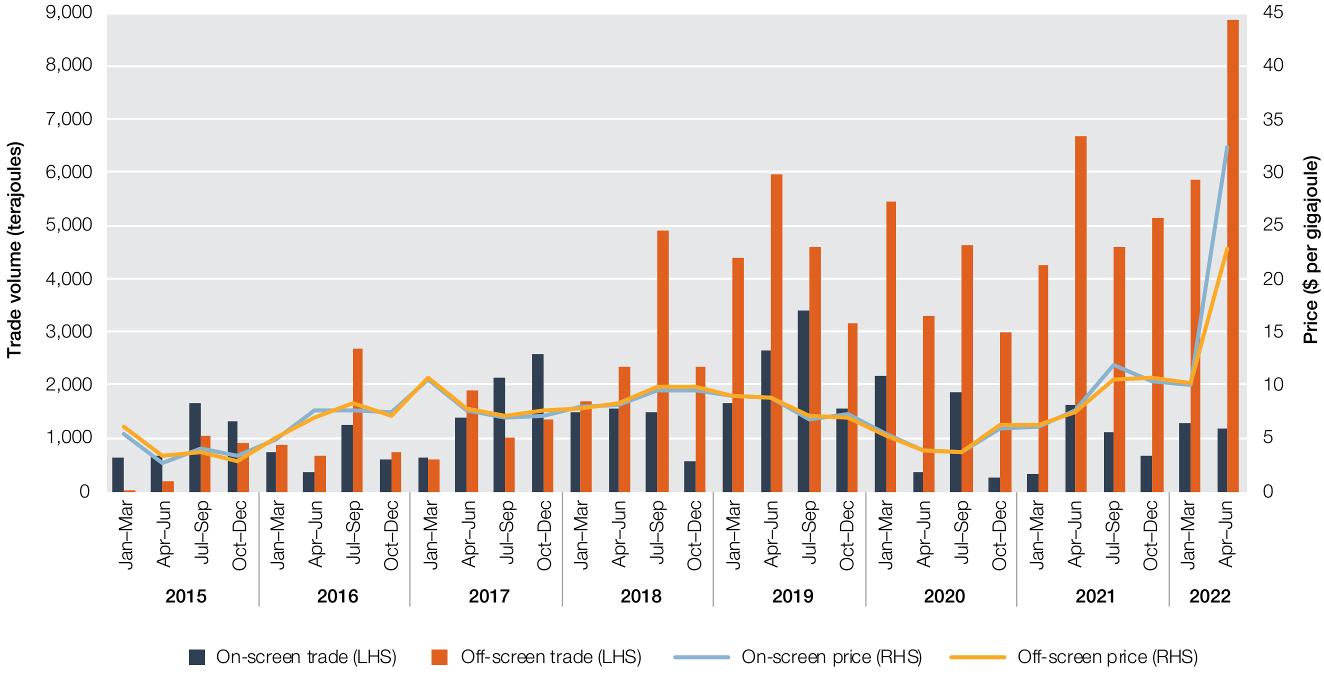
239 We consider a participant 'active' if it makes at least 12 trades in a year. The broker is not included as an active trader.

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

241 Strip trades, introduced in late 2020, allow participants more flexibility, providing the ability to bundle a string of daily products together over a selection of days, which can be traded further out (for delivery periods similar to monthly products).

242 Quantities traded from 2021 up to 30 June 2022.

Figure 4.20 Gas supply hub – on-screen and off-screen price and volume



Source: AER analysis of gas supply hub data.

4.7.3 Short term trading market (STTM)

In 2021 around 38 participants traded in the Sydney STTM, and the Adelaide and Brisbane markets had around 26 and 23 participants, respectively. The participants included energy retailers, power generators, large industrial gas users and traders. The markets are particularly useful for gas-powered generators because they can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

Shippers deliver gas for sale into the market and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users but in effect trade only their net positions – that is, the difference between their scheduled gas deliveries into and out of the market. In the fourth quarter of 2021, gas traded through the STTM met nearly 24% of demand in Sydney, 20% in Adelaide and around 10% in Brisbane.[243]

Traded volumes at the Sydney market were 19% higher in 2021 than in 2020 and 64% higher at the Brisbane market in 2021. Spot trade in the Adelaide market remained at the same level. The increased spot trade in the Sydney and Brisbane markets has been driven by higher sales volumes from large gas producers, including LNG exporters. In particular, Santos, BHP and Esso have been prominent sellers in recent years.

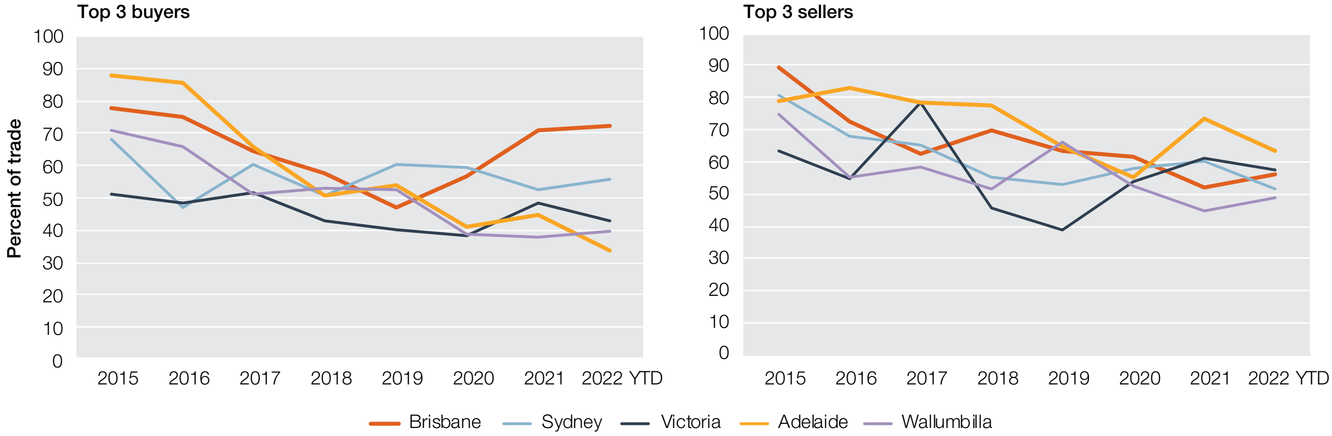
Trading profiles varied across the markets. Concentration across the top 3 sellers fell in Adelaide, Victoria and Sydney from 2021 to 2022 but rose in Brisbane and Wallumbilla (Figure 4.21). Among the top 3 buyers, concentration increased in Brisbane, Sydney and Wallumbilla. Concentration fell in Adelaide and Victoria for the same period. Importantly, the diversity of large suppliers participating in the spot markets is increasing. Similarly, in 2021 trader participants increased their share of gas scheduled into the STTM to record levels. These participants took advantage of cheap capacity won on the day-ahead auction to arbitrage prices between markets.

In 2021 participants used the STTM more heavily, with industrial participants being prominent gas purchasers. Industrial participants accounted for around 24% of trade in the STTM in 2021, compared with around 16% in 2020.

Despite traditionally benefiting from lower spot prices, high spot market exposure can be highly risky for spot market participants. From 1 January to 30 June 2022, spot prices ranged between $6.10 per gigajoule (GJ) and $53.60 per GJ. Over 2021, contract offers for gas delivery in 2022 were between $8.60 per GJ and $11.15 per GJ.

243 AER, Wholesale markets quarterly – Q4 2021, February 2022.

Figure 4.21 Top 3 buyers and sellers in eastern Australian gas markets



Note: Year-to-date (YTD) to 30 June 2022.

Source: AER analysis of data from the gas supply hub, short term trading market and Victorian declared wholesale gas market.

4.8 Development of gas import terminals

Currently, there are no importation terminals operational on the east coast of Australia. This means that Australia currently can export but not import LNG.

In early 2021, 5 LNG import terminals projects were under consideration in NSW, Victoria and South Australia. The intention was to resolve a forecast shortfall in gas supply in the southern states from winter 2023. However, delays have pushed out the potential availability of import supply to winter 2024.

The LNG import projects include:

- Australian Industrial Energy's (AIE) committed terminal at Port Kembla (NSW), which was initially scheduled to commence operating from late 2022.[244] The terminal received planning approval from the NSW Government in April 2019 and EnergyAustralia later signed as a foundation customer.[245] [246] The expected commissioning of the facility was delayed and is now expected in late 2023, with gas supply anticipated for winter 2024.[247] Squadron Energy, the private company building the import terminal, has lined up the Hoegh Galleon floating storage and regassification unit (FSRU), but had not lined up gas supply by late March.[248] The facility has planning permission for 130 petajoules (PJ) per year of LNG supply.[249]
- Venice Energy's proposed terminal at Port Adelaide, scheduled to launch by the end of 2022.[250] In late 2020 Venice announced it signed its first customer, as well as advancing a project agreement with Flinders Ports for development of the facility.[251] The project received approvals from the South Australian Government in December 2021 and is on track to begin construction in the second half of 2022 to deliver gas by winter 2024.[252] The terminal would offset supply from the Moomba to Adelaide and SEAGas pipelines providing gas from Moomba (South Australia) and Port Campbell (Victoria). Venice Energy will conduct a feasibility study to upgrade the SEAGas pipeline to flow gas bidirectionally, to enable supply into Victoria.[253]
- Viva Energy's Gas Terminal project, which is expected to deliver gas as early as 2024. The terminal would be co-located with Viva's Geelong oil refinery and is awaiting state approval. The project would require duplication of

244 EnergyQuest, EnergyQuarterly, March 2021, p 27.
245 NSW Government, 'Port Kembla gas terminal approved' [media release], April 2019.
246 AIE and EnergyAustralia, 'AIE welcomes foundational customer EnergyAustralia' [media release], May 2019.
247 AEMO, 2022 gas statement of opportunities, March 2022, p 56.
248 Reuters, UPDATE 1-Australia's first LNG import terminal seen ready by late-2023, 22 March 2022.
249 AEMO, Gas statement of opportunities, March 2022, p 74.
250 Venice Energy, 'South Australian LNG import facility advancing' [media release], November 2020.
251 Venice Energy, 'Project agreement signed for LNG import facility at Outer Harbor' [media release], November 2020.
252 Venice Energy, LNG import terminal granted development approval, December 2021.
253 Supply to Victoria would be limited by capacity on the South West Pipeline.

the South West Pipeline.[254] Viva is expected to make a final investment decision on the project by the end of 2022. The terminal is forecast to supply 140 PJ per year with a capacity of 500 to 600 TJ per day.[255]

- Vopak's import terminal in Port Phillip Bay in Victoria. Vopak is considering the feasibility of the terminal and indicated that several gas market participants had signed memoranda of understanding in support of the project.[256]
- Newcastle GasDock, proposed by Energy Projects and Infrastructure Korea. The NSW Government in August 2019 designated the project as critical significant infrastructure.[257] The facility would require multiple pipeline upgrades, expansions or duplications and is not expected to be operating before 2024.[258] While a final investment decision was expected to be made in September 2022, there has been no recent announcements regarding this proposed project.[259] [260]

In May 2021 AGL ceased development on its proposed floating terminal at Crib Point (Victoria).[261] This followed a determination in March 2021 by the Victorian Minister for Planning that the proposed terminal would have unacceptable environmental effects.[262] Another project backed by ExxonMobil was abandoned in December 2019.

4.9 Market responses to supply risk

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

4.9.1 Gas field development

Numerous projects are progressing that could bring additional supply to the domestic market:

- In Victoria, Cooper Energy commenced producing supply at the Athena gas plant (formerly Minerva) from mid-December 2021, taking gas from the Casino field that was previously processed at Iona.[263] The new production source processes gas from the Otway Basin's Casino, Henry and Netherby fields, with average production providing around 25 TJ per day since completion of the project.
- Development of the Gippsland Basin Kipper field is also progressing, with additional supply committed from 2024[264] and additional investment announced at the ADGO conference to develop and produce gas from the Kipper and Turrum fields over the next 5 years.[265] However, the depletion of supply from legacy fields contributing to the largest southern source of production has resulted in the decommissioning of fields in the Bass Strait[266], resulting in a significant drop in expected production levels from 2023.
- An increase to Port Campbell production was driven by Beach Energy committing to the development of Geographe, and Thylacine North and West fields, including the drilling of 6 new production wells.[267] Drilling commenced in February 2021 and was completed in July 2022.[268] This followed the successful drilling of the Enterprise-1 well in November 2020 and is expected to assist in returning the Otway Gas Plant to its nameplate capacity of 205 TJ per day.
- Work on existing wells in the Yolla field are also anticipated in the June to September quarter of 2022, with Trefoil supply anticipated from 2025 to increase supply to the Lang Lang Gas Plant (BassGas).[269]

254 AEMO, Gas statement of opportunities, March 2022, p 57.
255 Viva Energy Australia, Viva Energy Gas Terminal Project EES Referral, March 2020.
256 Vopak, 'News: Vopak LNG studies feasibility to develop LNG import terminal for Victoria' [media release], March 2021.
257 NSW Government, 'Newcastle gas terminal given critical status' [media release], August 2019.
258 AEMO, Gas statement of opportunities, March 2022, p 57.
259 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, p 65.
260 EnergyQuest, EnergyQuarterly, December 2021, p 29.
261 AGL Energy, 'Confirmation of Crib Point impact' [media release], May 2021.
262 Department of Environment, Land, Water and Planning (Vic), Crib Point: AGL APA gas import jetty and Crib Point – Pakenham gas pipeline, DELWP website, accessed 28 May 2021.
263 AEMO, 2022 Victorian gas planning report, March 2022. p 70.
264 ExxonMobil, Esso Australia to Expand Gas Development in the Gippsland Basin, 17 March 2022.
265 ExxonMobil, Opportunities for the Gippsland Basin and Australia's energy transition, 22 March 2022.
266 ExxonMobil, Esso Australia commences technical tender for Bass Strait decommissioning, 17 June 2022.
267 Beach Energy, Otway Offshore Project, 2020-2023 Program, June 2021.
268 ASX Announcement, Otway drilling campaign complete, 12 July 2022.
269 AEMO, 2022 Victorian gas planning report, March 2022. pp 70–71.

- In NSW, Santos proposed to develop 850 wells across its 95,000 hectare Narrabri gas project, which has the potential to supply up to 200 TJ per day.[270] An appeal against the project's approval[271], which delayed the project by 12 months, was dismissed following an unsuccessful challenge. The staged development is expected to provide up to 55 PJ per year in 2026, all of which is voluntarily committed to the domestic market.[272]
- In Queensland, APLNG started an expansion in the Surat Basin to bring 7 PJ per year online from its Murrungama field from 2022. This gas is subject to an Australian domestic manufacturing supply condition.[273]

Regulatory barriers to gas development

In some states and territories, community concerns about environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development.[274] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- The Victorian Government banned onshore hydraulic fracking and exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[275] In March 2021 the government committed the ban on fracking and CSG exploration to the Victorian Constitution.[276] Onshore conventional gas exploration will recommence from July 2021.
- In 2018 South Australia introduced a 10-year moratorium on fracking in the state's south east. It introduced the moratorium by direction and announced its intention to legislate it. However, unconventional gas extraction is allowed in the Cooper and Eromanga basins. South Australia has no restrictions on onshore conventional gas.
- The Tasmanian Government banned fracking for the purpose of extracting hydrocarbon resources (including shale gas and petroleum) until March 2020. This has since been extended to 2025.[277]
- The Northern Territory has made 51% of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory's shale gas resources.
- NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect 'biophysical strategic agricultural land', an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.[278] The state's regulations also require community consultation on environmental impact statements; and a detailed review process for major projects, as highlighted by the protracted process for Santos's Narrabri gas project.[279] Under an agreement reached in early 2020, the NSW and Australian governments set a target of increasing supply to the NSW market by 70 PJ per year.[280]

4.9.2 Liquefied natural gas import terminals

To address future supply concerns, the industry was considering numerous projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units.

- Australian Industrial Energy's (AIE) committed terminal at Port Kembla (NSW) is expected to provide gas before winter 2024. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline, with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (section 4.9.3).
- Venice Energy's proposed terminal at Port Adelaide (South Australia) is projected to potentially supply gas by winter 2024. However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.

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270 Santos, Narrabri Gas Project, Santos website, accessed 28 May 2021.

271 The project was approved by the NSW Independent Planning Commission and the Australia Government. Santos, 'Santos welcomes federal signoff on Narrabri Gas Project' [media release], 24 November 2020.

272 EnergyQuest, EnergyQuarterly, March 2022, p 133.

273 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 55.

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

275 Department of Economic Development, Jobs, Transport and Resources (Victoria), Onshore gas community information, August 2017.

276 Victorian Government, 'Enshrining Victoria's ban on fracking forever' [media release], March 2021.

277 Department of State Growth (Tas), Tasmanian Government policy on hydraulic fracturing (fracking) 2018, DSG website, accessed 28 May 2021.

278 Department of Planning and Environment (NSW), Initiatives overview, July 2018.

279 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed' [media release], 7 June 2017.

280 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions' [media release], January 2020.

- Viva Energy's Geelong (Victoria) Gas Terminal project is projected to deliver gas as early as 2024. The project would require the duplication of the South West Pipeline. Viva is expected to make a final investment decision on the project by the end of 2022.
- Vopak's import terminal in Port Phillip Bay (Victoria) is undergoing a feasibility assessment.

4.9.3 Transportation capacity expansion

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

South West Queensland and Moomba to Sydney pipelines project

APA has been expanding the pipeline corridor through Queensland into New South Wales by adding additional compression on the South West Queensland Pipeline (SWQP)[281] and the Moomba to Sydney Pipeline (MSP)[282]. The expansion enables more gas flow on pipelines where capacity is fully or close to fully contracted.[283] Stage 1 of the expansion is committed to come online before winter 2023, increasing transportation capacity by 49 TJ on the SWQP (to 453 TJ per day) and by 30 TJ on the MSP (to 475 TJ per day).[284] This will be the first of 3 stages of a 25% increase in transportation capacity.[285] The additional proposed expansion stages include:

- Stage 2 – a 59 TJ per day increase to the nominal capacity from Queensland to the southern markets, with an additional compressor station constructed on both the SWQP and MSP. This will bring the 453 TJ per day increase from stage 1 up to 512 TJ per day on the SWQP, with the 475 TJ per day capacity on the MSP to increase by 90 TJ to 565 TJ per day. Subject to foundation contracts, this stage is expected to be commissioned in the first quarter of 2024.
- Stage 3 – a further 92 TJ per day expansion with increases to capacity on both pipelines is currently in initial design phases and is subject to customer demand and project approval.[286]

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

APA is also upgrading the Victorian Transmission System (VTS), building a 51 km high pressure transmission pipeline to address a key capacity constraint currently limiting the connection of existing gas supply from the west of the state to demand in the north and east. The transportation of gas will also be assisted by the upgrade of the existing compressor station at Wollert. The project is expected to be completed in the second quarter of 2023.

The South West Pipeline (SWP) is a bidirectional facility that primarily transports gas from Port Campbell supply (gas from the Otway Basin and Iona underground storage) into Melbourne. The pipeline also supports refilling the Iona reservoir and transports gas west, fuelling the Mortlake power station and South Australia (through the SEAGas pipeline) during periods of lower demand. Limited capacity on the SWP restricts supply being provided from Port Campbell in the state's west. Following the completion of the WORM, the maximum daily capacity will increase from 447 TJ to 476 TJ on peak demand days.[287]

AEMO forecasts show the SWP constraining flows towards Melbourne during peak demand periods, when the full capacity of the Iona underground gas storage (UGS) facility is most needed. Further expansions of the SWP are proposed, to bring its capacity in line with the capacity of Iona UGS (section 4.9.4), following completion of the WORM.

The WORM was one of 4 priority projects implemented to address shortfalls highlighted in the 2021 Victorian gas planning report. However, the tight commissioning schedule presents a risk to the project being completed before winter 2023.

281 The SWQP connects to the Northern Territory through Carpentaria Gas Pipeline and is a gateway between large northern gas fields in Queensland (including the 3 Gladstone LNG projects), and southern regions with highly seasonal demand. AEMO, Gas statement of opportunities, March 2022, p 51.

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

283 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 15.

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

285 AEMO, 2022 Victorian gas planning report, March 2022. pp 76-77.

286 This potential expansion is expected to add a further 25% to the Stage 1 (12%) and Stage 2 (13%) increases. ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 67.

287 Based on AEMO modelling of a one-in-20 (5% probability of exceedance) peak system demand day. AEMO, 2022 Victorian gas planning report, March 2022. p 9.

Further expansions are not yet committed because they are subject to approval under APA's Access Arrangement. However, they have been proposed to increase supply capacity from Port Campbell to between 528 and 570 TJ per day through pipeline augmentation (compression or looping) and up to 670 TJ per day with additional looping and/or compression.[288]

Eastern Gas Pipeline expansion project

The Eastern Gas Pipeline (EGP) is a unidirectional pipeline that transports gas from the Gippsland Basin (Victoria) into Sydney. In 2021 Jemena and AIE signed a project development agreement to connect the PKET import terminal (section 4.9.2) at Kembla Grange at a capacity of 522 TJ per day. Jemena plans to modify the pipeline to allow for bidirectional flows, with an initial ability to supply 200 TJ into Victoria and up to 440 TJ towards Sydney per day.[289]

The earliest practical completion of the EGP expansion project in 2024 aligns with the planned completion of the delayed Port Kembla project, with potential future expansion including the installation of a compressor at Kembla Grange to increase daily capacity to supply as much as 323 TJ into Victoria and 550 TJ towards Sydney.

4.9.4 Storage expansion

Iona underground gas storage (UGS)

Lochard Energy is currently upgrading their underground storage facility to increase supply capabilities to 570 TJ per day[290], with 1 PJ of additional storage capacity following the drilling of a new storage well. Well pad construction of the Seamer 2 well in a field adjacent to Iona's existing field was completed in November 2021 before ministerial approval of the operational plan on 28 January 2022.[291] However, daily supply capacity into Melbourne via the South West Pipeline will be constrained to 476 TJ upon the expected completion of the WORM project in mid-2023 (section 4.9.3).

Further upgrades after the development of the Heytesbury Underground Gas Storage (HUGS) project have been proposed to add additional pipeline assets and approximately 3 PJ of additional storage capacity through construction of a new wellsite at Mylor, Fenton Creek and Tregony (MFCT) gas fields.[292] The project would increase capacity following the development of existing depleted reservoirs, with daily supply capacity increasing to 620 TJ.[293] Proposed construction would commence in October 2023 for completion by 2024, but is subject to regulatory approvals and market requirements that could delay the commencement of the project to October 2024.

Golden Beach project

A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply to assist with peak day demand in Victoria in 2024 and 2025, before operating as an underground storage facility. Golden Beach Energy received $32 million from the Australian Government in 2022 to accelerate development of the project.[294] The facility was projected to have a storage capacity of 12.5 PJ, but would require 43 PJ of production to be procured over a 2-year period before being used as a storage facility.[295]

4.9.5 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in January 2019. Current nameplate capacity of the pipeline is 90 TJ per day, but Jemena plans to increase this to 200 TJ per day by 2025.[296] This plan would also extend the pipeline to connect the Beetaloo Basin directly to the Wallumbilla gas supply hub.

Last year east coast supply from the Northern Territory averaged around 55 TJ per day until October, before declining in 2022. Supply over the first half of 2022 was down to an average of just over 30 TJ per day. This partially contributed to reduced supply into east coast markets, with gas flowing south on the Carpentaria Pipeline reducing from around

288 AEMO, 2022 Victorian gas planning report, March 2022, p 14.
289 AEMO, 2022 Victorian gas planning report, March 2022, pp 75-76.
290 Nameplate supply capacity increased from 530 TJ per day to 545 TJ per day on 28 January 2022. Storage capacity will increase from 23.5 PJ to 24.5 PJ.
291 Lochard Energy, Seamer 2 Project – Community Update, January 2022.
292 Lochard Energy, Our HUGS Project, April 2022.
293 AEMO, 2022 gas statement of opportunities, March 2022, p 55.
294 The Hon Angus Taylor MP, Unlocking critical local gas production and storage, 21 March 2022.
295 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 68.
296 Jemena, 'Jemena partners with shale gas experts to develop Beetaloo' [media release], November 2020.

90 TJ per day heading into May to around 50 to 60 TJ per day over May and June. The reduction followed NT supply declining by roughly 15 TJ per day heading into 2022, with further drops from mid-March reducing another 15 TJ out to the end of April. The drop in Carpentaria flows preceded a 2-week maintenance outage on the Phillip Creek Compressor Station from 20 May and constrained NT supply.[297]

4.9.6 Demand response

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

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, using brokers to secure supply agreements, participating in gas markets and investing in new LNG import facilities.[298] Some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments.

In addition, some C&I users are considering alternatives to gas, such as renewable energy.[299]

Government initiatives can also play a role in reducing gas demand. The ACT initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023. Other initiatives, such as the Victorian gas substitution roadmap and energy upgrades program, have identified electrification as the best solution to achieve a short-term reduction to gas consumption levels.[300]

4.10 Compliance and enforcement activities

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

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

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

Over 2021-22, two of the AER's compliance and enforcement priorities related to gas markets:

- Ensuring service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations
- Ensuring timely and accurate gas auction reporting by registered participants

High-quality market information is vital to improve transparency amongst participants and promote competition.

The AER undertook a range of compliance and enforcement activities in support of these priorities, including:

- An industry-wide review of service provider compliance against part 23 reporting requirements, to form the basis for further engagement with the sector over 2022-23 about issues identified in the review
- Targeted reviews of recovered capital values reported by specific pipeline operators
- Issuing $240,000 of infringement notices for alleged breaches of record-keeping and report requirements under the National Gas Rules relating to the day-ahead auction
- Informing industry of the causes for inaccurate or delayed AQL information through Gas Market Wholesale Consultative forums, along with highlighting new tools to identify potential 'outlier calculations'.

More detail on the AER's compliance and enforcement work is outlined in the Annual compliance and enforcement report 2021-22.

297 The outage coincided with a Blacktip production outage at the Yelcherr/Wadeye production source.

298 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, pp 73–74.

299 ACCC, Gas inquiry 2017–2025, interim report, January 2020, February 2020, p 74.

300 AEMO, Gas statement of opportunities, March 2022, p 23.

4.11 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government and some state and territory governments have intervened in the market.

4.11.1 Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism empowers the Australian Government Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[301] The resources minister may determine in the preceding September whether a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

To avoid export controls, Queensland's LNG producers entered agreements with the government committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.[302] They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[303] Following a review by the Department of Industry, Science, Energy and Resources[304], the scheme was extended until 2030.

At the time of publishing, the Australian Government is in the process of renegotiating the Heads of Agreement (HoA).[305]

4.11.2 Gas Supply Guarantee (GSG)

Facility and pipeline operators developed the Gas Supply Guarantee as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM.[306] The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023.[307]

AEMO triggered the Gas Supply Guarantee for the first time on 1 June 2022.[308] Following activation of the mechanism, gas producers in Queensland diverted gas into the domestic market and AEMO subsequently deactivated the mechanism the next day. AEMO reactivated the mechanism from 19 July following the notification of a threat to system security (TTSS) in Victoria due to insufficient storage, after directing two generators to cease taking gas from the Victorian market until 30 September (with the GSG and TTSS to remain in effect until sufficient supply is available).[309]

4.11.3 State government schemes

To encourage gas exploration, the Queensland Government grants exploration authorities for 'domestic only' exploration tenements.

As part of this grants program, it released almost 70,000 km^2 of land for exploration between 2015 and 2019, of which around 25% was reserved for domestic supply. The Queensland Government released a further 3,000 km^2 of land in September 2020, with over 15% tagged for domestic supply.[310] In 2021, the Queensland Government announced it would make 14,100km^2 available for oil and gas exploration.[311]

In January 2020, through a memorandum of understanding with the Australian Government, the NSW Government committed to bringing new gas supplies to the domestic market. It set a target of injecting an additional 70 PJ of gas per year into the NSW market.[312]

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301 Department of Industry, Innovation and Science, Australian Domestic Gas Security Mechanism, July 2018.

302 Department of Industry, Science, Energy and Resources, Securing Australian domestic gas supply, DISER website, accessed 28 May 2021.

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

304 Department of Industry, Science, Energy and Resources, Australian Domestic Gas Security Mechanism review, January 2020.

305 Energy Ministers Meeting, Communique, 12 August 2022.

306 AEMO, Gas supply guarantee, AEMO website, accessed 28 May 2021.

307 AEMO, Gas supply guarantee guidelines consultation final determination, March 2020.

308 AEMO, Gas supply guarantee, AEMO website, accessed 28 May 2021.

309 AEMO takes further steps to manage tight gas supplies, 19 July 2022, https://aemo.com.au/newsroom/media-release/aemo-takes-further-steps-to-manage-tight-gas-supplies.

310 Queensland Government, 'Queensland gas exploration ramping up' [media release], September 2020.

311 Queensland Government, 2021 Queensland Exploration program, November 2021, accessed 28 Jun 2022.

312 NSW Government, Memorandum of understanding – NSW energy package, 31 January 2020.

In April 2021 the Australian and South Australian governments announced an agreement to invest in energy infrastructure and reduce emissions in South Australia. As part of this, the state set a target of an unlocking an additional 50 PJ per year by 2023.[313]

4.11.4 ACCC gas inquiry

The Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. The inquiry was initially tasked to run until 30 April 2020, but in July 2019 the Treasurer extended it to 2025.[314]

4.11.5 Electrification of liquefied natural gas production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million to work with the Queensland Government and industry on electrifying the Curtis Island LNG facilities. The production facilities currently use their own gas as a power source in production. Partly electrifying these processes would make available up to 12 PJ of gas for delivery to the domestic market.

4.11.6 National hydrogen strategy

The Australian Government identified hydrogen as a potential fuel to facilitate cuts to emissions across energy and industrial sectors. As part of this strategy, the government is looking at introducing hydrogen to the gas distribution network as part of the mix with natural gas. Currently, hydrogen can be added to gas pipelines at concentrations of up to 10% to supplement gas supplies and a number of trials are being explored. In July 2020 the Australian Renewable Energy Agency shortlisted 7 projects to be considered as part of its $70 million fund to develop large-scale electrolysers, 3 of which are based in eastern Australia.[315]

4.12 Gas market reform

The Energy Ministers' Meeting and Energy National Cabinet Reform Committee (formerly the COAG Energy Council) direct gas market reforms, which regulatory and market bodies implement.[316] A key focus of reform is to address information gaps and asymmetries in the market. Consultation on the latest round of measures took place in 2019 and the CoAG Energy Council delivered the final decision regulation impact statement in late March 2020.[317]

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. The reforms aim to increase transparency in the gas market, improve the Gas Bulletin Board and improve the availability of information on market liquidity, prices, and gas reserves.

4.12.1 Gas Bulletin Board reforms

The Gas Bulletin Board aims to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia.

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

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

The AER assesses the quality and accuracy of the data submitted by market participants against an 'information standard' to ensure the information presented on the bulletin board has integrity.

In June 2022 states adopted the Gas Market Transparency Act, which will extend reporting to large gas users and LNG processing facilities. These laws give the AER new powers to monitor information related to price and volume in the shorter-term gas market, including how gas is exported overseas and how it is traded here in Australia. In

313 Australian Government, 'Energy and emissions reduction agreement with South Australia' [media release], April 2021.

314 ACCC, Gas inquiry 2017–2025, ACCC website, accessed 28 May 2021.

315 ARENA, Seven shortlisted for $70 million hydrogen funding round, ARENA website, accessed 28 May 2021.

316 Including the Energy Security Board, the AER, the AEMC, AEMO and the ACCC.

317 CoAG Energy Council, Measures to improve transparency in the gas market – decision regulation impact statement, March 2020.

particular, the AER will be able to monitor the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

Liquidity information

The AER publishes (on the industry statistics page of its website) quantitative metrics for assessing the liquidity of gas markets, and it regularly updates these metrics. The AER also reports quarterly on the performance of the east coast gas markets. These quarterly reports build on the liquidity statistics and contain more detailed analysis of key performance indicators across the markets. These indicators have shown signs of improvement in liquidity over time.

Price and reserves transparency

With gas markets shifting towards shorter-term contracts, and suppliers using EOI processes, the transparency of price and other market information is critical. The ACCC publishes data on LNG netback prices to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts. [318]

The ACCC also publishes data on gas reserves and resources, drawing on information provided by reserve owners. This helps market participants identify future supply issues and plan accordingly.

4.12.2 Pipeline reforms

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

318 ACCC, Gas inquiry 2017–2020 – LNG netback price series, ACCC website, accessed 28 May 2021.