Image courtesy of Woodside

4 GAS MARKETS IN EASTERN AUSTRALIA

Gas is a fossil fuel consisting mainly of methane, a naturally occurring hydrocarbon. It is created by decomposing plants and animals over millions of years. Reserves tend to be found near other solid and liquid hydrocarbon beds, such as coal and crude oil.

The main types of gas produced in Australia are conventional natural gas and coal seam gas (CSG). Conventional gas is found trapped in underground reservoirs, often along with oil, while CSG is an unconventional form of gas extracted from coal beds. Advancements in extraction techniques have improved the commercial prospects for other forms of unconventional gas, including shale and tight gas.[1]

The supply of gas to energy customers involves several steps (infographic 2). It begins with the exploration and appraisal of potential reserves for commercial viability. Gas discoveries are extracted through wells, then processed to separate the methane and ethane from impurities (such as nitrogen, carbon dioxide and sulphur dioxide), and to remove and treat any water.

In eastern Australia, almost 70 per cent of gas produced is converted to liquefied natural gas (LNG) for export, mainly to Asia. The balance is sold into the domestic market. Some gas is stored (often in depleted gas fields or LNG tanks) and can be used to augment supply at peak times. More recently, domestic gas users have explored options for importing LNG to supplement domestic gas supplies.

Gas sold to domestic customers is transported from production fields to major demand centres or hubs via high pressure transmission pipelines (figure 4.1). The pipelines have wide diameters and operate under high pressure to optimise shipping capacity. They deliver gas to power stations, large industrial and commercial customers, and energy retailers, which sell the gas to their customers. Retailers deliver gas to energy customers' pipelines via distribution networks, which are spaghetti-like networks of smaller pipes that service commercial and residential premises in cities and towns.

1 Shale gas is contained within organic-rich rocks such as shale and fine grained carbonates, rather than in underground reservoirs. The application of horizontal drilling techniques in the past five years is enhancing the economic viability of shale gas development. Tight gas is found in low porosity sandstone and carbonate reservoirs.

4.1 Gas markets in eastern Australia

This chapter considers the 'upstream' gas sector, encompassing gas production, wholesale markets for gas, and the transport of gas along transmission pipelines to demand hubs. It focuses on the eastern gas market, in which the Australian Energy Regulator (AER) has regulatory responsibilities (box 4.1).

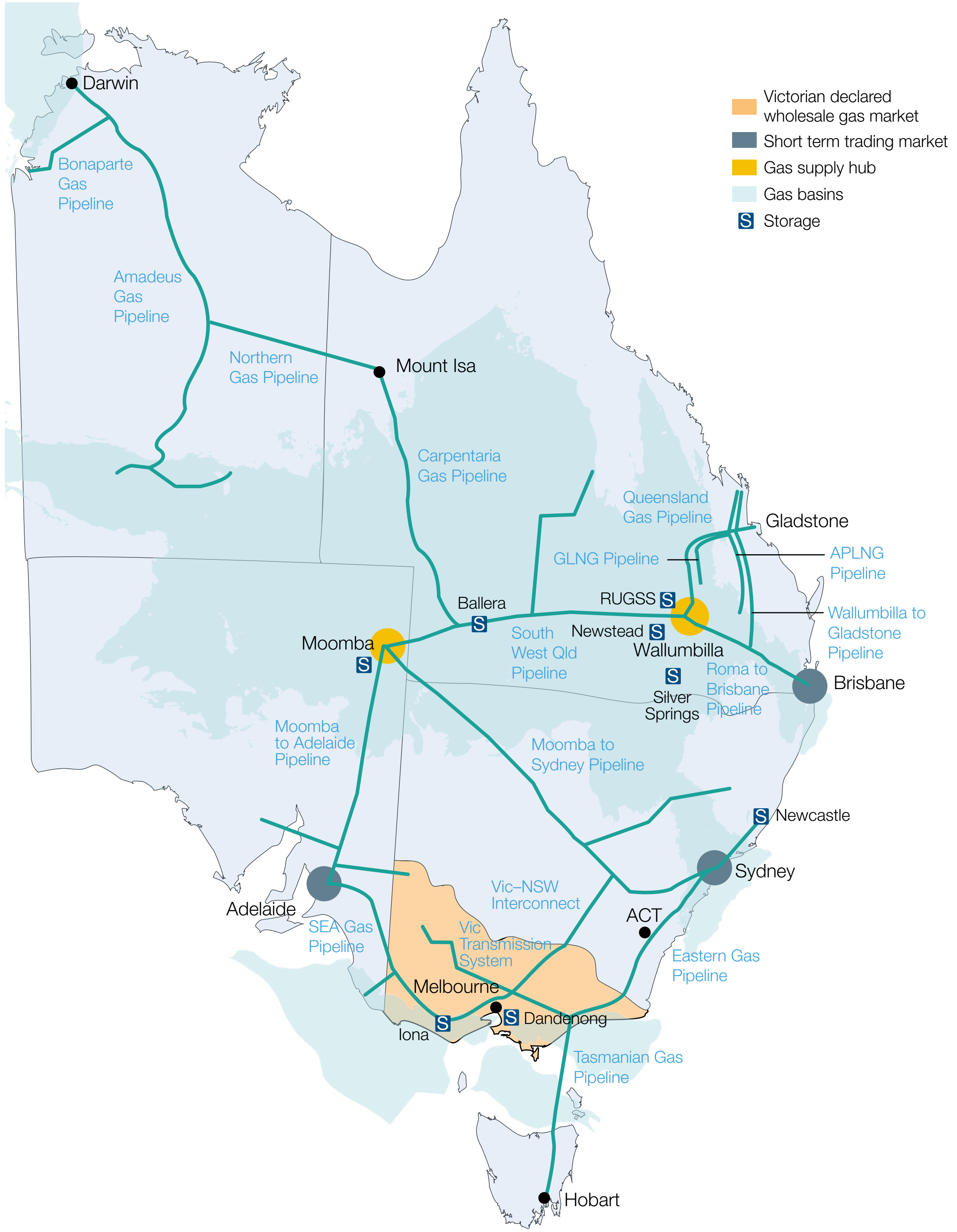
The eastern market encompasses Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). This market is interconnected by transmission pipelines, which source gas from basins and deliver it to large industrial customers and major population centres. The main production basins are the Surat–Bowen Basin in Queensland, the Cooper Basin in north east South Australia, and three basins off coastal Victoria, the largest being the Gippsland Basin. Since January 2019 the market has also sourced gas from the Northern Territory.

Commercial gas production in eastern Australia began in the 1960s. Relatively low prices at that time encouraged residential, commercial and industrial customers to use gas, which is valued for its clean burning properties. Gas use later expanded into the electricity generation market.

The eastern gas market evolved as separate state based markets, each served by a single gas basin and a single transmission pipeline. Over the past 20 years, new pipelines interconnected these markets, making it possible to transport gas from Queensland to the southern states, and (since key pipelines became bi-directional) vice versa. With the opening in 2019 of the Northern Gas Pipeline, the eastern gas market can also source gas from the Bonaparte Basin off the north coast of Western Australia and the Northern Territory.

Gas became a major export industry in eastern Australia, with the launch in 2015 of Queensland's LNG industry. The industry transformed the eastern gas market by giving producers the choice of exporting gas or selling it domestically. By 2018 around 61 per cent of eastern Australian gas production was being exported. With domestic users now competing with overseas customers to buy Australian gas, prices in the domestic market have risen to align more closely with international gas prices. Higher gas prices also impact electricity markets, which became more reliant on gas powered generation after several coal fired generators closed in 2016 and 2017.

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



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in 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); 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 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. Our monitoring role at the Wallumbilla and Moomba hubs, for example, explicitly looks to detect price manipulation. In 2019 we began a new role as the compliance and enforcement body for a scheme to auction underused capacity in transmission pipelines.

Our gas compliance focus in 2019 included the successful implementation of capacity trading reforms, and enhanced transparency. In particular, market participants are required to submit information to the Australian Energy Market Operator (AEMO) and the AER in a timely and accurate manner.

During the year, we applied more stringent compliance expectations around bulletin board reporting, including administering new civil penalty provisions to enhance the integrity of information provided. Further, to promote compliance with registration and reporting obligations, we engaged with participants that had reporting requirements for the first time. These participants included facility operators in the Northern Territory following its connection to the eastern Australian market in January 2019. Our focus in these areas continues into 2020.

In 2019 we strengthened our monitoring and reporting by publishing gas industry statistics and *Wholesale markets quarterly* reports, covering gas spot market activity, prices and liquidity. The quarterly reports include analysis of eastern Australia's liquified natural gas (LNG) export sector, and its impact on the domestic market.

Looking forward, we continue to engage with the Council of Australian Governments (CoAG) Energy Council's gas reform agenda. Under the agenda, we must administer new reporting obligations to enhance the transparency of market activity.

Alongside our work in gas wholesale markets, the AER is the economic regulator for two major transmission pipelines in eastern Australia. We also arbitrate disputes relating to 'light regulation' pipelines, and we may appoint an arbitrator to settle disputes affecting other pipelines.[a]

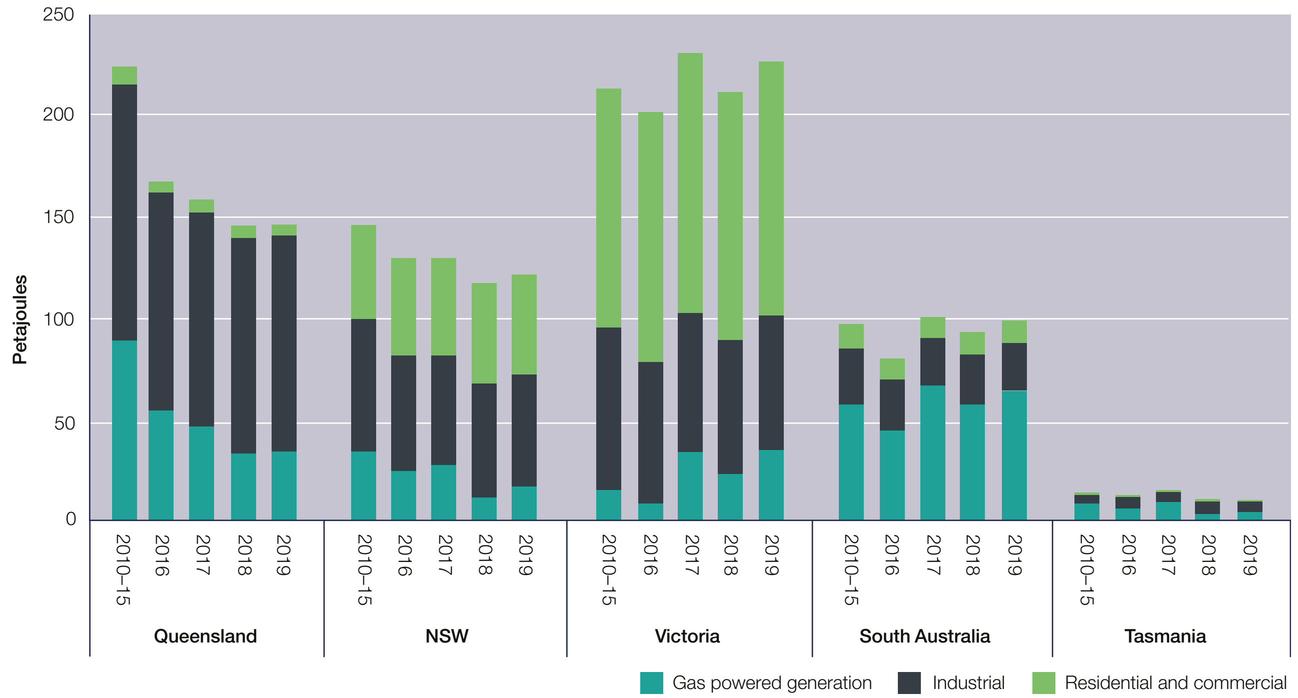
In the downstream gas industry, the AER sets reference prices for distribution networks in NSW, Victoria, South Australia and the ACT (chapter 5). In retail gas markets, we hold wide ranging responsibilities in jurisdictions that have passed the National Energy Retail Law—namely, Queensland, NSW, South Australia and the ACT (chapter 6).

Across the gas sector, we also draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. When appropriate, we propose or participate in reforms to improve the market's operation.

Outside the eastern market, the AER is the gas pipeline regulator for the Northern Territory, but plays no role in the territory's wholesale market. However, facility operators in the Northern Territory must report gas flow activity to the bulletin board, which the AER oversees. We have no regulatory function in Western Australia, where separate laws apply.[b]

a Chapter 5 outlines the different tiers of pipeline regulation.
b The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia, and AEMO operates a spot gas market there.

Figure 4.2
Gas consumption in eastern Australia



Note: Data for 2010–15 are average annual consumption over that period.
Source: AEMO, *2020 gas statement of opportunities*, March 2020.

4.2 Gas demand in eastern Australia

Domestic customers in eastern Australia used around 600 petajoules (PJ) of gas in 2019 (figure 4.2).[2] These customers included industrial businesses, electricity generators, commercial businesses and households. Industrial customers are the biggest users, consuming 43 per cent 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. In Queensland, industrial customers are the main source of domestic gas demand.

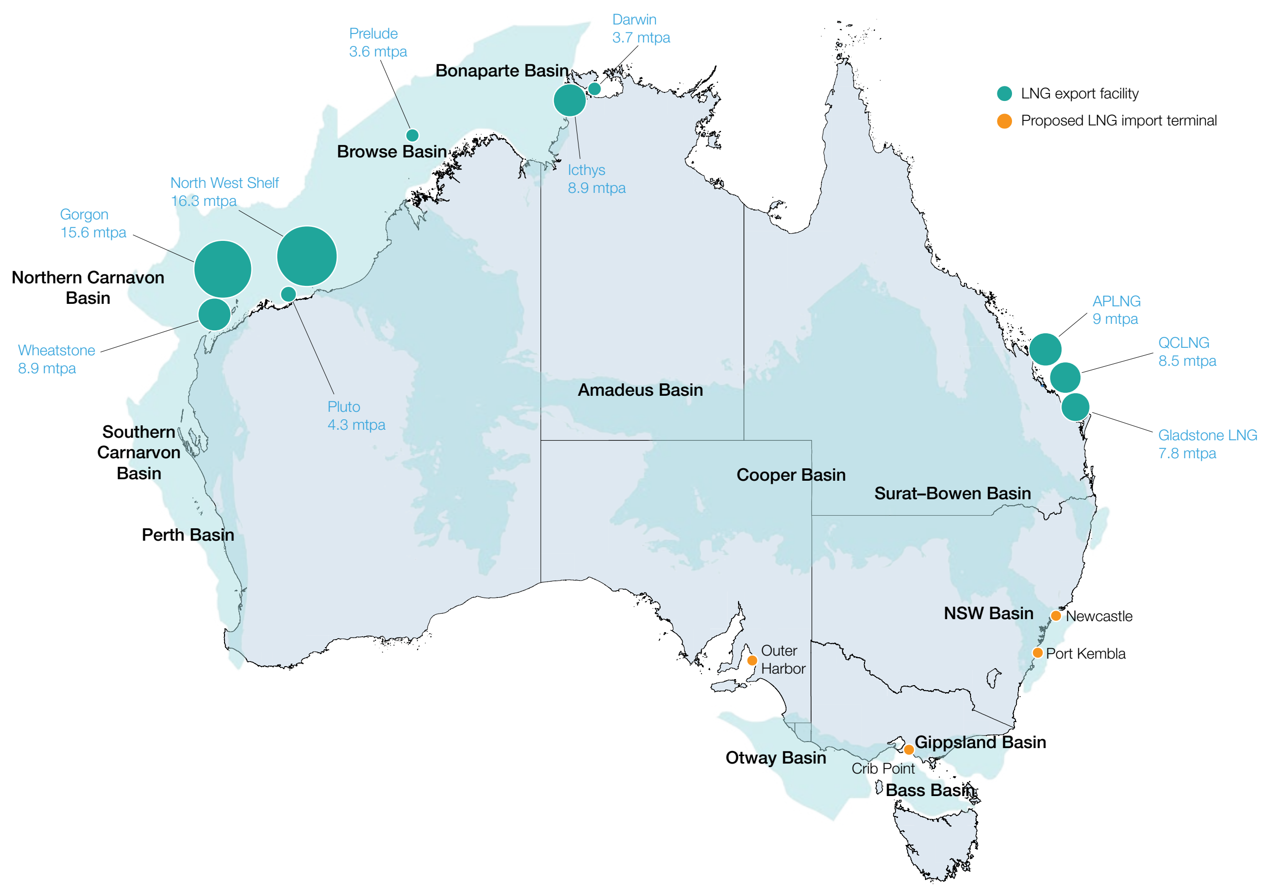
The electricity sector is another major source of demand. The rapid responsiveness of gas powered turbines makes them suitable for peak electricity generation. Gas powered generation also plays an important role in managing fluctuations in wind and solar generation. With gas generation often used to fill supply gaps in the electricity market, its level can fluctuate significantly. Gas powered generation accounted for 26 per cent of domestic gas use in 2019, down from 29 per cent in 2017 when gas generators helped fill the supply gap caused by the closure of Victoria's Hazelwood power station. South Australia has the highest ratio of gas demand for electricity generation, accounting for 42 per cent of gas demand in 2019.

Residential and commercial customers are the third major source of gas demand. Overall, they account for 31 per cent of domestic gas demand. Victoria is the only state where a majority of demand (around 60 per cent) is from small residential and commercial customers, who use gas mostly for heating and cooking. Over 80 per cent of Victorian households are connected to a gas network.[3] Around 35 000 new residential gas connections were made in Victoria each year from 2014 to 2018, mainly as part of new housing developments.[4] Residential gas penetration is around 80 per cent in the ACT, 60 per cent in South

2 AEMO, *2020 gas statement of opportunities*, March 2020.

3 AEMO, *National gas forecasting report*, December 2016.
4 AEMO, *Winter 2018—Victorian gas operations outlook*, 8 May 2018.

Figure 4.3
Australia's LNG export projects



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

Source: AER.

Australia, 45 per cent in NSW, 10 per cent in Queensland, and 6 per cent in Tasmania.[5]

In the overall energy mix, gas reliance is highest in South Australia, where it accounts for 38 per cent of primary energy consumption, followed by Victoria and Queensland (around 20 per cent in each state). It is lower in NSW, where it accounts for less than 10 per cent of energy consumption.[6] South Australia's high degree of reliance on gas reflects its dependence on gas powered generation since the closure of the state's coal fired generators.

4.3 Liquefied natural gas exports

A majority of gas produced in eastern Australia is liquefied as LNG for shipping to export markets (table 4.1). The gas is chilled to –162 degrees Celsius, which shrinks volume by 600 times and makes it economic to store and ship in large quantities. Most Australian LNG is shipped to Asia, where it is stored, regasified and injected into local gas pipeline networks.

LNG projects require major investment in processing plants, port and shipping facilities. The magnitude of this investment requires access to substantial reserves of gas, which may be sourced through the project owner's interests in gas fields, joint venture arrangements with gas producers, and/or contracts with third party producers.

5 AEMO, *National gas forecasting report*, December 2016.
6 Department of the Environment and Energy, *Australian energy statistics 2018–19*, Table C, 2019.

Alongside Queensland's LNG industry, Australia operates five LNG projects in Western Australia, and two in the Northern Territory (figure 4.3). In 2018–19 LNG exports earned Australia $50 billion, making gas Australia's third largest resource and energy export, behind coal and iron ore.[7] Australia became the world's largest LNG exporter in 2019.[8]

4.3.1 Queensland LNG industry

Queensland's LNG industry comprises three major projects, which liquefy gas sourced mainly from the Surat–Bowen Basin. The projects were made possible by the basin's vast CSG reserves, and are the world's first to convert CSG to LNG. While all projects meet a majority of their LNG requirements from reserves that they control, they also rely on third party gas. They source this gas from other LNG producers, as well as producers in central Australia and Victoria, and acquire it through long term contracts and spot markets:

- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). It began exporting LNG in January 2015, and has two trains (liquefaction and purification facilities). Shell is the principal owner (74 per cent).
- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. It began exporting in October 2015 and has two trains. Santos (30 per cent), Petronas and Total (27.5 per cent each), and Kogas (15 per cent) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa.[9] It began exporting gas in January 2016 and has two trains. Origin Energy and ConocoPhillips (37.5 per cent each), and Sinopec (25 per cent) own the project.

4.3.2 Northern Territory and Western Australia

The Northern Territory's LNG industry began in 2006 with the commissioning of Darwin LNG (3.7 mtpa capacity), which relies on gas from the Bonaparte Basin in the Timor Sea. A second project—Ichthys LNG (8.9 mtpa capacity)—launched in 2018. Both projects connect to the territory's domestic gas market as emergency supply sources, but otherwise produce gas solely for export.

Western Australia has five LNG projects with a combined capacity of around 50 mtpa. The industry began with the North West Shelf project, and the first cargo left the facility for sale to Japan in 1989. The North West Shelf project has five trains and remains Australia's largest LNG project by capacity (16.9 mtpa).

Western Australia's second LNG project, Pluto, was commissioned in 2012. Rising LNG prices provided the impetus for three more recent projects—Gorgon (2016), Wheatstone (2017) and Prelude (2019).[10]

4.4 Gas reserves in eastern Australia

Gas reserves are unexploited accumulations of gas that are expected to be commercially recoverable. Data on gas reserves are an important input to forecasting supplies of gas that may enter the market.

Different measures of gas reserves are quoted, based on geological, engineering and commercial analysis of the likelihood of successful recovery:

- Proven reserves (1P) are estimated to be at least 90 per cent certain of successful commercial recovery.
- Proven plus probable reserves (2P) are estimated to be at least 50 per cent certain of successful commercial recovery.
- A third category (3P) includes all reserves deemed at least 10 per cent likely to be commercially recoverable.

Lower levels of probability attach to *contingent* resources, which are resources considered potentially recoverable from known accumulations that are not yet technically or commercially recoverable.

This probabilistic approach to measuring gas reserves results in frequent, and sometimes substantial, adjustments. Queensland's 2P reserves, for example, were downgraded by over 4400 PJ between June 2017 and June 2019.[11]

Data on Australian gas reserves is collected through various disconnected mechanisms and bodies, resulting in a lack of clear, consistent and accurate reporting. Data standards and

7 Department of Industry, Innovation and Science, *Resources and energy quarterly*, December 2019.
8 EnergyQuest, *Energy quarterly*, March 2020.
9 APPEA, 'Australian LNG projects', web page, available at: www.appea.com.au/oil-gas-explained/operation/australian-lng-projects/.
10 Department of Jobs, Tourism, Science and Innovation (Western Australia), *Western Australia liquefied natural gas profile*, February 2020.
11 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* February 2020.

aggregation across these sources are inconsistent, and the assumptions underlying the data are often not transparent.[12]

The Australian Securities Exchange (ASX) requires listed companies to report limited data on gas reserves, but unlisted companies and those listed overseas are not obliged to report. State and territory governments each have reporting requirements, and the Australian Government collects some information (particularly on offshore resources), but much of this information is commercial-in-confidence.

Market analysts such as EnergyQuest and Energy Edge publish reserves estimates, drawing on available sources. The Australian Competition and Consumer Commission (ACCC) is also working in this area, and began publishing reserves and resources information in December 2018.

The CoAG Energy Council in 2020 was progressing reforms that would require all participants to report information on gas reserves via the Gas Bulletin Board (section 4.14.1).

4.4.1 Distribution of reserves in eastern Australia

EnergyQuest estimated eastern and southern Australia's 2P gas reserves stood at 36 116 PJ in February 2020, but noted this estimate is subject to uncertainty.[13] Reserve ownership is highly concentrated in some basins, but more diverse across the market as a whole (figure 4.4). Arrow Energy (16 per cent) is the largest holder of 2P reserves in eastern Australia. Other major reserve holders include Shell, Origin Energy, ConocoPhillips and Santos.[14]

Surat–Bowen Basin

Queensland's Surat–Bowen Basin is the largest basin in eastern Australia, with over 85 per cent of all gas reserves (table 4.1). Reserves from the basin are mainly converted to LNG for export, but the basin also supplies some gas to the domestic market. The LNG projects control over 80 per cent of reserves in eastern Australia, which are mostly CSG.[15]

Victorian basins

The Gippsland Basin is the most significant of the three producing basins in Victoria, accounting for around 7 per cent of eastern Australian reserves.[16] The Bass and Otway basins together account for 2 per cent of reserves. Total reserves across the Victorian basins are declining, mainly due to a depletion of reserves in the Gippsland Basin.

From December 2017 to February 2020, 2P reserves fell by nearly 17 per cent in the Gippsland Basin. Over the same period, 2P reserves more than doubled in the Bass Basin, and rose by more than 80 per cent in the Otway Basin. Because the Bass and Otway basins are smaller in scale, these increases did not offset the reductions in the Gippsland Basin.

A joint venture between Esso (ExxonMobil) and BHP controls a large majority of reserves in the Gippsland Basin, although Esso in September 2019 signaled an interest in selling its gas assets in the region.

Cooper Basin

The Cooper Basin in central Australia has over 1000 PJ of 2P reserves, which accounts for 3 per cent of eastern Australia's 2P reserves. In 2010 Santos entered an agreement to supply one of the Queensland LNG projects with 750 PJ of gas over 15 years, which accelerated the depletion of the basin's conventional reserves. But reserve levels stabilised recently, and rose by over 15 per cent between December 2018 and February 2020.[17]

NSW basins

NSW has significant contingent resources (around 2000 PJ) but only 7 PJ of 2P reserves, and negligible current production. Santos in 2017 applied to develop reserves near Narrabri in the Gunnedah Basin. The project has encountered widespread opposition on environmental grounds. At March 2020, it was still progressing through the NSW Government's planning process (section 4.12.1).

Northern Australia

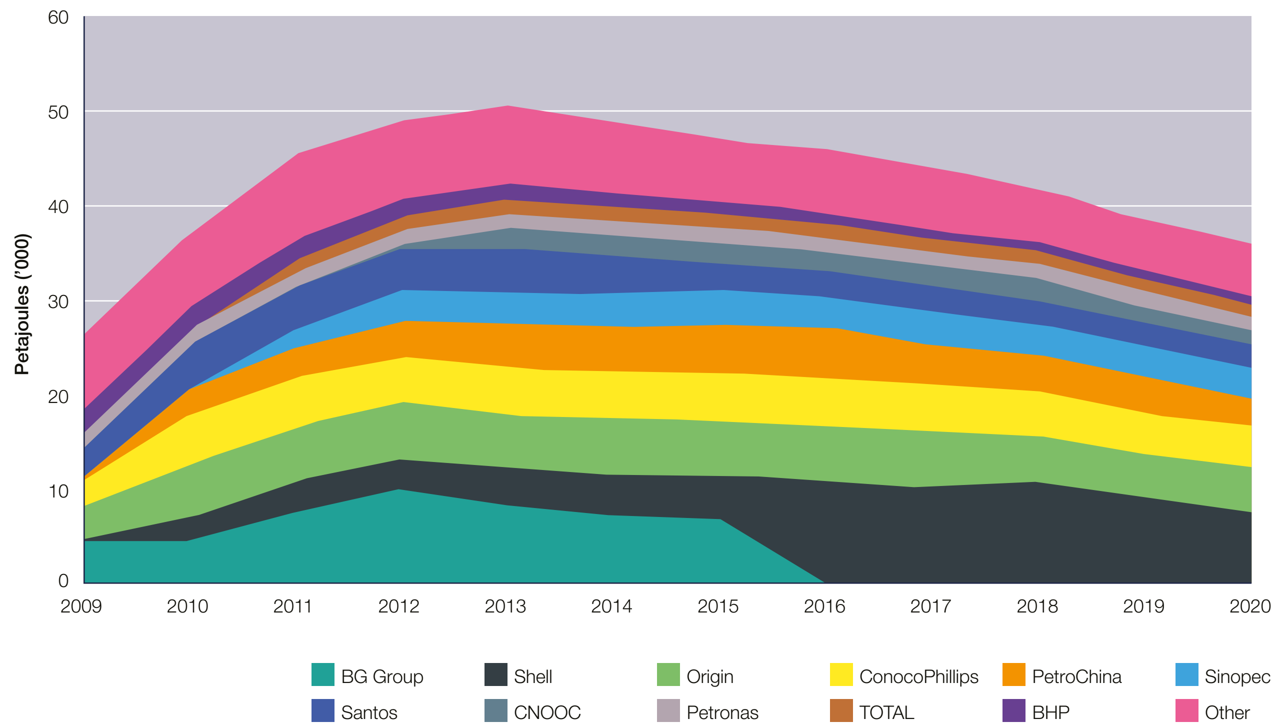
Northern Australia was historically separate from the eastern gas market, but the commissioning of the Northern Gas Pipeline in January 2019 changed this situation by linking gas fields in the Bonaparte Basin (offshore of Darwin in the Timor Sea) and the Amadeus Basin (southern Northern Territory) with Queensland.

The Bonaparte Basin was developed to support the Northern Territory's LNG industry, which is based in Darwin. The basin is estimated to have over 700 PJ of 2P reserves. Most gas produced in the basin is converted to LNG for export.

12 ACCC, *Inquiry into the east coast gas market*, April 2016.
13 EnergyQuest, *Energy quarterly*, March 2020, p. 68.
14 EnergyQuest, *Energy quarterly*, March 2020, Table 25, p. 70.
15 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020*, February 2020, p. 45.
16 EnergyQuest, *Energy quarterly*, March 2020, Table 23, p. 68.

17 EnergyQuest, *Energy quarterly*. March 2020, Table 23, p. 68.

Figure 4.4
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 per cent probability of commercial recovery.

Source: EnergyQuest, *Energy quarterly* (various years).

4.5 Gas production

In 2019 eastern Australia produced almost 2000 PJ of gas. The majority (69 per cent) was exported as LNG, and the remainder was sold to the domestic market (table 4.1).

Queensland's Surat–Bowen Basin supplied 77 per cent of gas produced in eastern Australia in 2019, including much of the gas earmarked for LNG export. Participants in Queensland's three LNG projects produced around 90 per cent of the basin's output in 2019. As well as supplying their LNG facilities, the LNG participants sell some gas into the domestic market.

Outside Queensland, the basins off coastal Victoria meet most of the remaining demand in the eastern states.
The Gippsland Basin is the most significant of the three producing basins in Victoria, meeting 13 per cent of demand in 2019. The smaller Otway and Bass basins jointly supplied 4 per cent of the market.

The Longford Gas Plant, servicing the Gippsland Basin, achieved record production in 2017, some of which was shipped to Queensland for LNG exports (figure 4.5). But production has since declined. The Australian Energy Market Operator (AEMO) forecasts a steep decline in southern field production after 2022 as a number of Gippsland Basin fields cease production in 2023 and 2024.[18]

The Cooper Basin in central Australia accounted for 5 per cent of eastern Australian gas production in 2019. The basin plays an important role as a 'swing' producer in managing seasonal and short term supply imbalances in the domestic gas market.

With the opening of the Northern Gas Pipeline in January 2019, the Northern Territory's offshore Bonaparte Basin and onshore Amadeus Basin became new suppliers to the eastern gas market. In 2019 the Northern Gas Pipeline delivered over 65 terajoules (TJ) per day on average into the eastern market.

18 AEMO, *2020 gas statement of opportunities,* March 2020, p. 5.

Table 4.1 Gas basins serving eastern Australia

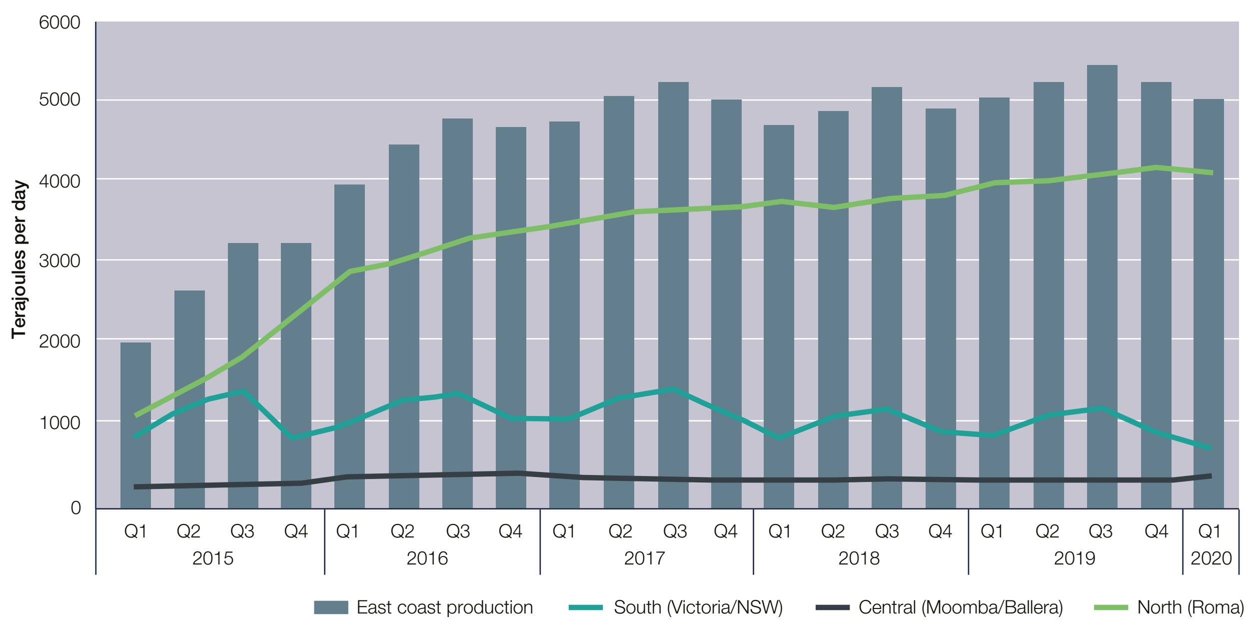
	GAS PRODUCTION—12 MONTHS TO DECEMBER 2019			2P GAS RESERVES (FEBRUARY 2020)	
GAS BASIN	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIA RESERVES (%)
Surat–Bowen (Queensland)	1 485	75	7	31 706	86
Cooper (South Australia – Queensland)	91	5	4	1 102	3
Gippsland (Victoria)	262	13	4	2 481	7
Otway (Victoria)	60	3	–11	644	2
Bass (Victoria)	11	1	–31	175	0
Sydney, Narrabri, Gunnedah (NSW)	5	0	–11	7	0
Amadeus (Northern Territory)	20	1	120	226	1
Bonaparte (Northern Territory)	51	3	24	734	2
Eastern Australia total	1 985		6	37 076	
Domestic gas sales	645		3		
LNG exports	1 340		8		

2P, proven plus probable reserves estimated to be at least 50 per cent sure of successful commercial recovery.

Note: Totals may not add to 100 per cent due to rounding. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and 2P reserves in other basins are mainly conventional gas.

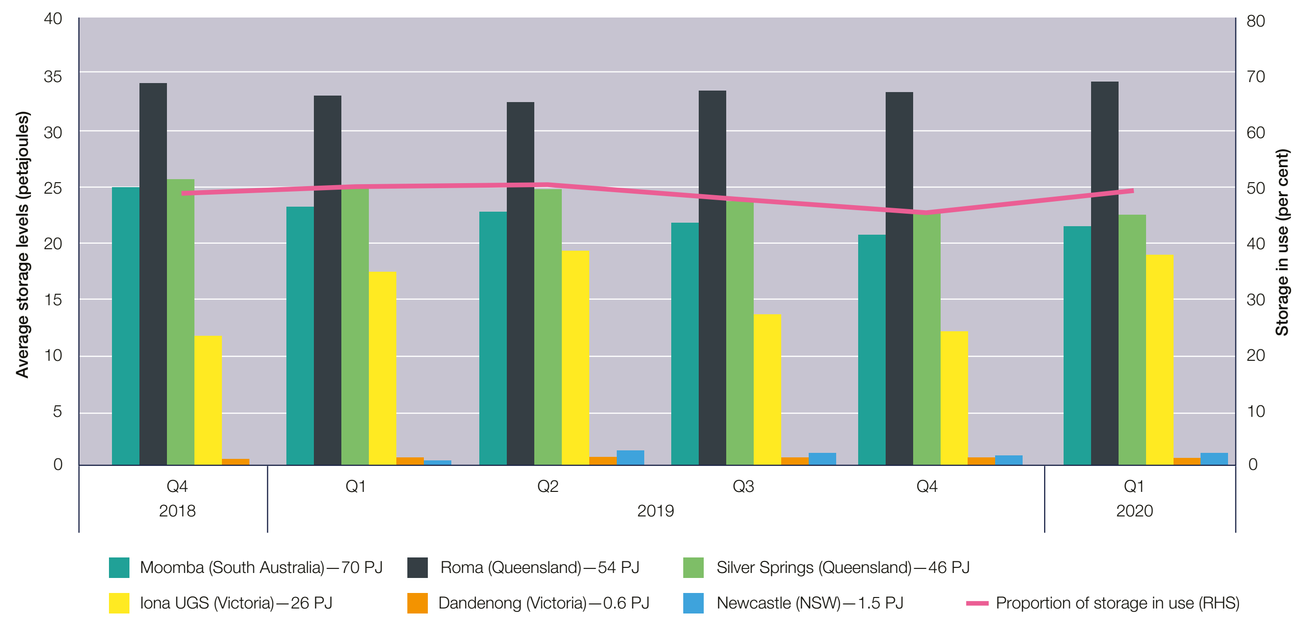
Source: EnergyQuest, *Energy quarterly*, March 2020.

Figure 4.5
Eastern Australia gas production



Source: AER analysis of Gas Bulletin Board data.

Figure 4.6
Gas storage in eastern Australia



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

Source: AER analysis of Gas Bulletin Board data.

4.5.1 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 during the period 2015–17 to help LNG projects meet shortfalls in production, to meet their export contracts. This shift accelerated a depletion of gas reserves in southern basins. High production rates in Victoria also strained production plants, causing outages.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. In the year to June 2018, Surat–Bowen Basin production growth exceeded LNG export growth. As supplies from the north increased, southern basin production eased from the peaks recorded in 2017. In 2019 Surat–Bowen Basin production rose by 7 per cent, almost matching LNG export growth (8 per cent). As a result, production in southern basins held relatively steady.

4.6 Gas storage

Storage provides a means of conserving surplus gas production for quick delivery when needed. Gas can be stored in its natural state in depleted underground reservoirs and pipelines, or post liquefaction as LNG in purpose built facilities. Transmission pipelines can also provide gas storage services.

Eastern Australia's gas storage capacity includes:

- large facilities using depleted gas fields in Queensland, Victoria and South Australia
- smaller seasonal or peaking storage facilities located near demand centres—for example, the Newcastle LNG facility in NSW, and the Dandenong LNG facility in Victoria
- short term peak storage services on gas pipelines, which are mostly contracted by energy retailers. The Tasmanian Gas Pipeline, for example, 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. Storage levels at the Roma underground, Moomba and Silver Springs facilities have been consistently drawn down to meet LNG export demand. Against this trend, Roma underground storage levels increased from the start of 2019 (figure 4.6), possibly due in part to LNG plant outages during the year.

Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks. AGL commissioned an LNG storage facility at Newcastle in 2015, and contracted to use 50 per cent of the Iona underground storage facility's capacity from January 2021 to manage seasonal demand. In June 2018 Lochard Energy began to expand its Iona capacity, expecting this storage would help manage future peak demand periods.[19] During the third quarter of 2019, this expanded gas storage helped meet Victorian gas demand on peak winter demand days, especially when they coincided with high levels of gas demand for electricity generation.[20]

The ACCC in 2020 reported few investments to develop or expand storage capacity were on the table. It noted, however, Lochard Energy's expansion at Iona will continue until 2021, with a further expansion under consideration. Lochard Energy also purchased depleted shore reservoirs near Iona, which it could use for storage development. Further, the Golden Beach gas field in the Gippsland Basin may include a storage facility that could inject gas into the Victorian transmission system at Longford. Golden Beach Energy aims to supply its first gas to the market in the second half of 2021.[21]

4.7 Gas transmission pipelines

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 pipelines are listed in table 4.2, with routes shown in figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

Historically, the eastern gas market's transmission system was a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre. Over time, the system evolved into an integrated network covering eastern and southern Australia. Many gas pipelines became bi-directional, and gas increasingly flows across multiple pipelines to reach its destination. These changes mean access to capacity on key pipelines is more important than ever.

Investment in transmission pipelines is expensive, and normally underwritten by foundation shippers through long term contracts. After its initial construction, a pipeline can be incrementally expanded to meet rising demand through compression, looping (duplication of parts of the pipeline) and extensions.

In recent years, significant transmission investment occurred to meet the needs of Queensland's LNG industry, which included expanding existing pipelines and constructing new pipelines to ship gas to LNG processing facilities. Among recent developments, the Roma North Pipeline and the Atlas Gas Pipeline were commissioned in 2019, and other pipelines are proposed to bring additional supply to the eastern markets. Additionally, Jemena's Northern Gas Pipeline (which began operations in January 2019) provides eastern Australia's first pipeline interconnection with the Northern Territory, making it possible to ship gas produced in the territory basins to eastern Australia.

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 bi-directional and backhaul shipping, and park and loan services.[22]

Transmission pipelines are separately owned from gas production 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 4.10.4).

4.7.1 Pipeline ownership

Australia's gas transmission sector is privately owned (table 4.2). The publicly listed APA Group is the largest player, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Other major pipeline owners include Jemena and Singapore Power International.

Cheung Kong Infrastructure (CKI) in 2018 led a $13 billion takeover bid for APA Group. The ACCC did not oppose the proposed acquisition, on condition that CKI divest significant gas assets in Western Australia to address competition issues.[23] After consulting the Foreign Investment Review Board, the Australian Government blocked the bid on grounds the acquisition 'would be contrary to the national interest' because 'it would result in a single foreign company group having sole ownership and control over Australia's most significant gas transmission business'.[24]

19 The Hon. Daniel Andrews MP (Premier of Victoria), 'Securing gas for future winter warmth', Media release, June 2018.
20 AER, *Wholesale markets quarterly—Q3 2019*, November 2019.
21 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* February 2020, pp. 93–4.

22 Pipelines with bi-directional 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.
23 ACCC, 'ACCC will not oppose acquisition of APA', Media release, 12 September 2018.
24 The Hon. Josh Frydenberg MP (Treasurer), 'Final Decision on the proposed acquisition of APA', Media release, 20 November 2018.

Table 4.2 Key gas transmission pipelines in eastern and northern Australia

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/DAY)	REGULATORY STATUS[1]	OWNER
Roma (Wallumbilla) to Brisbane	Qld	438	211 (125 reverse)	Full regulation	APA Group
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	627	140 (40 reverse)	Part 23 regulation	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
South West Queensland Pipeline (Wallumbilla to Moomba)	Qld–SA	937	404 (340 reverse)	Part 23 regulation	APA Group
Carpentaria Pipeline (South West Qld to Mount Isa)	Qld	840	119	Light regulation	APA Group
GLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	435	1430	15 year no coverage	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
Wallumbilla Gladstone Pipeline	Qld	334	1588	Part 23 regulation and 15 year no coverage	APA Group
APLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	530	1560	15 year no coverage	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%
Moomba to Sydney Pipeline	SA–NSW	2 029	489 (120 reverse)	Partial light regulation / partial Part 23 Regulation[2]	APA Group
Moomba to Adelaide Pipeline	SA	1 184	241 (85 reverse)	Part 23 regulation	QIC Global Infrastructure
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	797	358	Part 23 regulation	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
Vic–NSW Interconnect	Vic–NSW		223	Part 23 regulation	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	680	314	Part 23 regulation	APA Group 50%, Retail Employees Superannuation Trust 50%
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	734	129 (120 reverse)	Part 23 regulation	Palisade Investment Partners
Victorian Transmission System (GasNet)	Vic	2 035	1030	Full regulation	APA Group
Nothern Gas Pipeline (Tennant Creek to Mount Isa)	NT–Qld	622	90	Part 23 regulation	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
Bonaparte Pipeline	NT	287	80	Part 23 exemption	Energy Infrastructure Investments (APA Group 19.9%, Marubeni 49.9%, Osaka Gas 30.2%)
Amadeus Gas Pipeline	NT	1 658	120	Full regulation	APA Group

km, kilometres; TJ/day, terajoules per day.

1. *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.
2. The Moomba to Sydney Pipeline is subject to Part 23 regulation only from Moomba to Marsden. Light regulation applies to the remainder of the pipeline.

Source: AER; ACCC, interim reports of gas inquiry 2017–2025; corporate websites; Gas Bulletin Board (www.gasbb.com.au).

4.8 Gas imports

In early 2020 four LNG import terminals projects were under consideration in NSW, Victoria and South Australia. The intention is to resolve a forecast shortfall in gas supply in the southern states from winter 2024. While some of the facilities were to be operational from as early as 2020, all projects have slipped from their original timeframes because planning, environmental and other challenges have delayed their development.

The LNG import projects include:

- AGL's proposed floating terminal at Crib Point (Victoria), scheduled to begin delivering gas in early 2022[25]
- a proposed terminal at Port Kembla (NSW) by a consortium that includes Squadron Energy and JERA, scheduled to commence operations in the first half of 2021.[26] The terminal received planning approval from the NSW Government in April 2019,[27] and EnergyAustralia later signed as a foundation customer.[28]
- Venice Energy's proposed terminal at Port Adelaide, scheduled to launch by the end of 2021[29]
- Newcastle GasDock, proposed by Energy Projects and Infrastructure Korea, scheduled to commence operations in the first half of 2021.[30] The NSW Government in August 2019 designated the project as critical significant infrastructure.[31]

At March 2020 final investment decisions had not been made for any of the four LNG import projects. A fifth project backed by ExxonMobil was abandoned in December 2019.

4.9 Contract and spot gas markets

Wholesale gas is traded in two distinct types of market. A majority of gas sales in eastern Australia are struck under confidential bilateral contracts. Around 10–20 per cent is traded in spot markets, with the variation reflecting differences between those markets.[32]

4.9.1 Contract markets

Gas contracts (also known as gas supply agreements) are wholesale supply deals negotiated between sellers and buyers. In contract markets, the two main levels of supply offers 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. Prices quoted to C&I customers tend to be higher than those quoted to very large customers, partly to cover the aggregator's margins. But the ACCC found prices to C&I customers have been unreasonably high at times (section 4.11.1).

Gas contracts traditionally locked in prices and other terms and conditions for several years. More recently, the industry shifted towards shorter term contracts with review provisions. The ACCC reported in 2018 that recent contract offers favoured durations of either one or two years. Between January 2017 and April 2018 over 70 per cent of offers from producers and over 55 per cent of wholesale offers from retailers to supply gas in 2019 were part of contracts with a duration of two years or less.[33]

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 what is available to smaller players. This imbalance favours large incumbents in price negotiations.

Until recently, no accurate and useful indicative wholesale price was readily available to the market. In response, the ACCC in 2018 began publishing gas price data as part of its 2017–25 gas inquiry (section 4.14.1).

4.9.2 Spot markets

While most gas is traded under confidential contracts, 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. The oldest of the three is *Victoria's declared wholesale gas market*, established in 1999. A *short term trading market* for gas was launched in 2010, with hubs in Sydney, Brisbane and Adelaide. More recently, *gas supply hubs* launched in 2014 at Wallumbilla, Queensland, and in 2016 at Moomba, South Australia.

The three spot markets operate under different rules, follow different procedures, do not interact with each other, and have different purposes. The Australian Energy Market Commission (AEMC) in June 2017 found having multiple market designs inhibits trading between regions, increases complexity, and imposes transaction costs. It recommended the markets transition in the longer term to a single market design, based on the gas supply hub model.[34] As a first step, the gas day start times were harmonised for all east coast markets in 2019 (section 4.14.3). Progress towards harmonising the markets is otherwise slow.

An information platform—the Gas Bulletin Board—was launched in 2008 to provide transparency about gas market conditions and encourage participation in the spot markets. The following sections explain the workings of each spot market and the bulletin board. Section 4.11.2 outlines price trends in the markets.

4.9.3 Gas supply hubs at Wallumbilla and Moomba

AEMO launched the gas supply hub model at Wallumbilla, Queensland, in 2014. Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia (figure 4.7). Three critical pipelines—the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines—connect, along with several smaller transmission pipelines, with or near the hub. The diversity of supply options, contract positions, and participants around Wallumbilla create a natural point of trade.

The gas supply hub takes the form of an electronic trading platform. Participation is voluntary. Gas producers (including LNG producers), large retailers, gas powered generators, large industrial users and traders are among the participants. Gentailers (combined generation and retail businesses) and gas powered generators were among the most active participants in 2019. Activity by traders (including brokers and investors) rose to 12 per cent on average in 2019, up from 7 per cent in 2018.[35]

There were 16 active participants in the hub by the end of 2019, including two new participants. The trades are split across a range of product types (such as intra-day, day-ahead, weekly and monthly), and they can be on-screen (traded through the anonymous exchange) or off-screen (bilateral trades settled through the exchange).[36] Purely bilateral off-market trades are not reported to the hub.

In 2019 all 16 participants traded off-screen, but only 13 participated in *active* on-screen trading.[37] On average, participants executed over 300 trades per month in 2019, more than double the rate in 2018.

LNG producers are the largest suppliers of gas into the hub, 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 hub can currently absorb.[38]

The gas supply hub brokerage model allows buyers and sellers to place anonymous offers or bids for quantities of gas at nominated prices, which can be a matched on the exchange to make trades. Each price struck is unique to a particular trade. That is, no market clearing price applies to all participants.

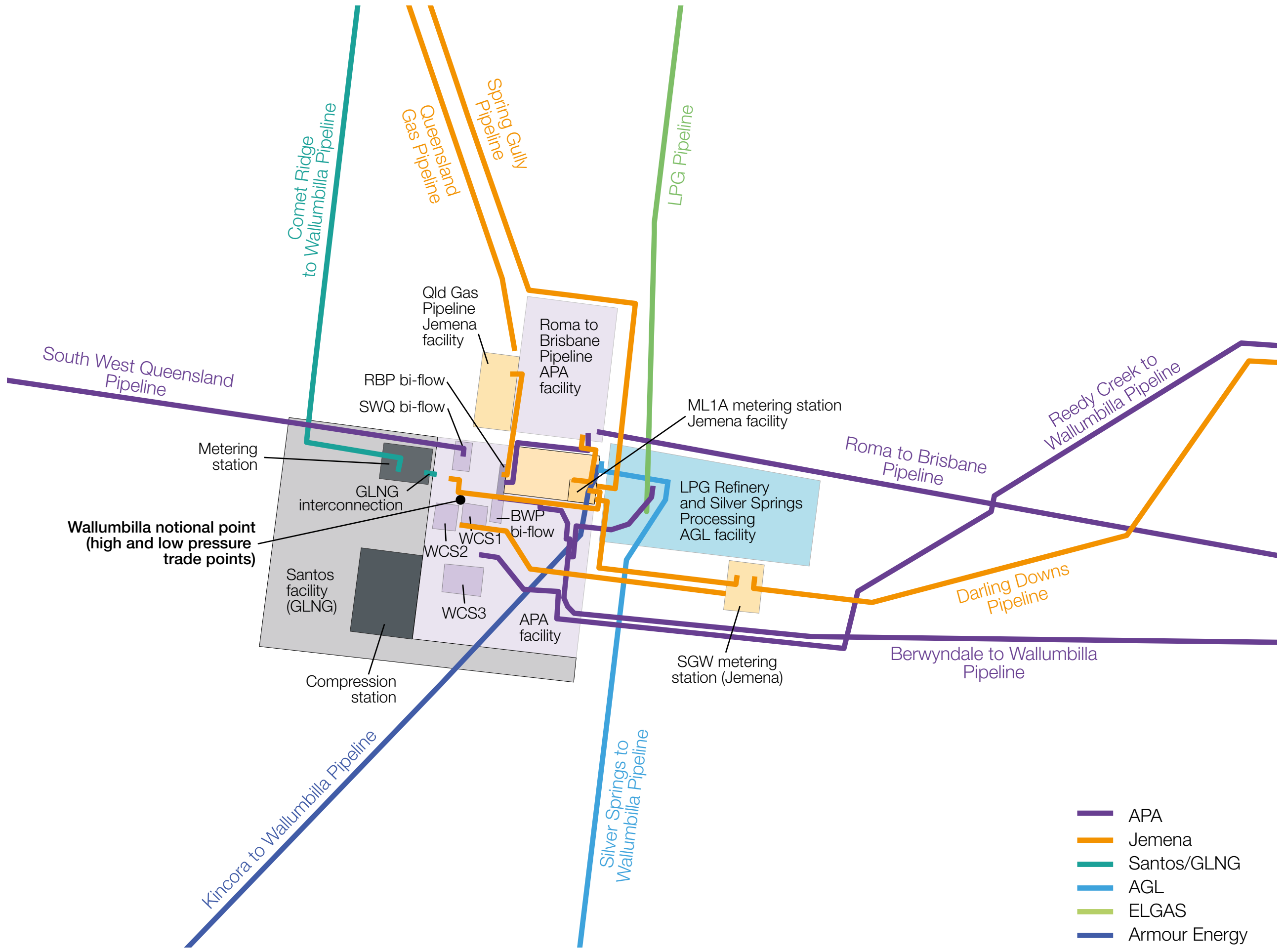
As in the other spot markets, the gas supply hub complements bilateral contracts rather than replaces them. But it allows participants to trade gas up to several months in advance of physical supply, rather than only on a daily basis as in the other markets.

Until 2017 separate prices were set at three major delivery points—the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines. But splitting trade across three locations hampered liquidity and trading. Additionally, participants needed access to the transmission pipelines serving the hub, to move gas between those three points. This access proved problematic because, while all the pipelines connect with the hub, they do not all physically interconnect with one another.

In March 2017 AEMO replaced the hub's three trading locations with a single Wallumbilla product that groups all delivery points. A single trading location improves liquidity by making it easier for participants to trade across different pipelines, thus pooling potential buyers and sellers into a single market. A separate south east Queensland product

25 AGL, 'AGL Gas Import Jetty Project', web page, available at: www.agl.com.au/about-agl/how-we-source-energy/gas-import-project.
26 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*. February 2020, p. 29.
27 NSW Government, 'Port Kembla gas terminal approved', Media release, April 2019.
28 AIE and EnergyAustralia, 'AIE welcomes foundational customer EnergyAustralia', Media release. May 2019.
29 *Australian Financial Review*, 'SA LNG import project delayed, but still "in the game"', 11 December 2019.
30 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* February 2020, p. 29.
31 NSW Government, 'Newcastle gas terminal given critical status', Media release, August 2019.
32 AER, *Wholesale markets quarterly—Q4 2019*. February 2020.
33 ACCC, *Gas inquiry 2017–2020, Interim report*, *July 2018*, August 2018, pp. 24, 49.
34 AEMC, *Review of the Victorian declared wholesale gas market—final report*, Factsheet, June 2017.
35 AER, *Wholesale markets quarterly—Q3 2019*. November 2019.
36 AER, 'Wholesale statistics', web page, available at: www.aer.gov.au/wholesale-markets/ wholesale-statistics.
37 An 'active' participant is one that completes at least 12 trades per year.
38 AER market intelligence.

Figure 4.7
Wallumbilla hub



Source: AER, accounting for consultations with APA Group and public information supplied by APA Group, Santos, AGL, the Queensland Government, Geoscience Australia and AEMO.

was also launched, which provides virtual delivery within the Roma to Brisbane Pipeline.

Despite these reforms, significant gas trading around Wallumbilla occurs bilaterally and off-market to avoid the pipeline costs of transporting gas to Wallumbilla. Participants also sometimes arrange downstream delivery points to avoid these costs.

Some participants have suggested a preference for off-screen trading, which allows them to use brokers to match trades on their behalf, or leverage their existing bilateral arrangements to facilitate spot trades.[39] Such trades can be negotiated directly over the phone and then lodged through the hub for settlement. In this way, transactions can be accelerated if on-screen bids and offers do not match.

However, new entrant participants are unable to enjoy these benefits to the same degree, because they do not have legacy arrangements. These participants are more likely to rely on the anonymous on-screen trading platform.

39 Two participants with a legacy arrangement can draw on it to quickly organise an off-screen trade, because the agreement between them is already set up. Participants without such agreements need to set up contract arrangements to process deals in the same way.

Wallumbilla hub activity

Trade at Wallumbilla has progressively increased since its launch in 2014. The LNG projects use the hub from time to time to manage variations in production and LNG plant performance. Gas powered generators are also significant users of the hub.

In 2019 liquidity at the Wallumbilla hub improved as it experienced significant growth and change. Traded volumes for 2019 were more than twice the volumes in 2017, primarily off the back of significant increases in gas traded off-screen (figure 4.8). Notably, off-screen products tend to involve larger volumes of gas than do on-screen alternatives. Also, in 2019 more participants were active off-screen than on-screen for the first time. There was also a shift in product preferences in 2019, with significant increases in the volume of gas traded through day-ahead and balance-of-day products.

Part of this growth may reflect new arrangements to auction underused pipeline capacity, which increases access to key pipeline routes such as the often congested South West Queensland Pipeline (section 4.10.4). Despite this growth, however, gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral arrangements. In 2019 gas traded through the Wallumbilla hub accounted for 9.1 per cent of total gas flows through pipelines in the Wallumbilla bulletin board zone.[40]

Moomba hub activity

AEMO launched a second gas supply hub at Moomba in central Australia in June 2016. Similar to Wallumbilla, Moomba is a major junction in the gas supply chain serving eastern Australia. Trade at Moomba has been slow to develop. While there have been offers and bids for gas at Moomba, fewer transactions have occurred there, compared with Wallumbilla.

The first trade was executed in September 2017, with 141 trades executed in 2019. Interestingly, trades at the Moomba location increased markedly from the second quarter of 2019. In particular, the number of day-ahead products greatly increased. As with trades at Wallumbilla, this increase may reflect the introduction of the pipeline capacity trading reforms (section 4.10.4).

40 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.

4.9.4 Short term trading market

A short term trading market for gas operates at three locations in eastern Australia—Sydney, Adelaide and Brisbane. AEMO operates the market, which launched in 2010. The market has a floor price of $0 per gigajoule (GJ) and a cap of $400 per GJ. Each market is scheduled and settled separately, but all three operate under the same rules (box 4.2).

Prices are volatile, reflecting short term shifts in supply and demand, including conditions in LNG export markets. Given its responsiveness to short term conditions, the market is not necessarily indicative of prices that would be struck under contracts. No ASX derivatives market has developed for the short term trading market.

In 2019 around 30 participants traded in the Sydney market, while the Adelaide and Brisbane markets each had around 15 participants. The participants included energy retailers, power generators, large industrial gas users, and traders. The markets are particularly useful for gas powered generators, because the generators can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

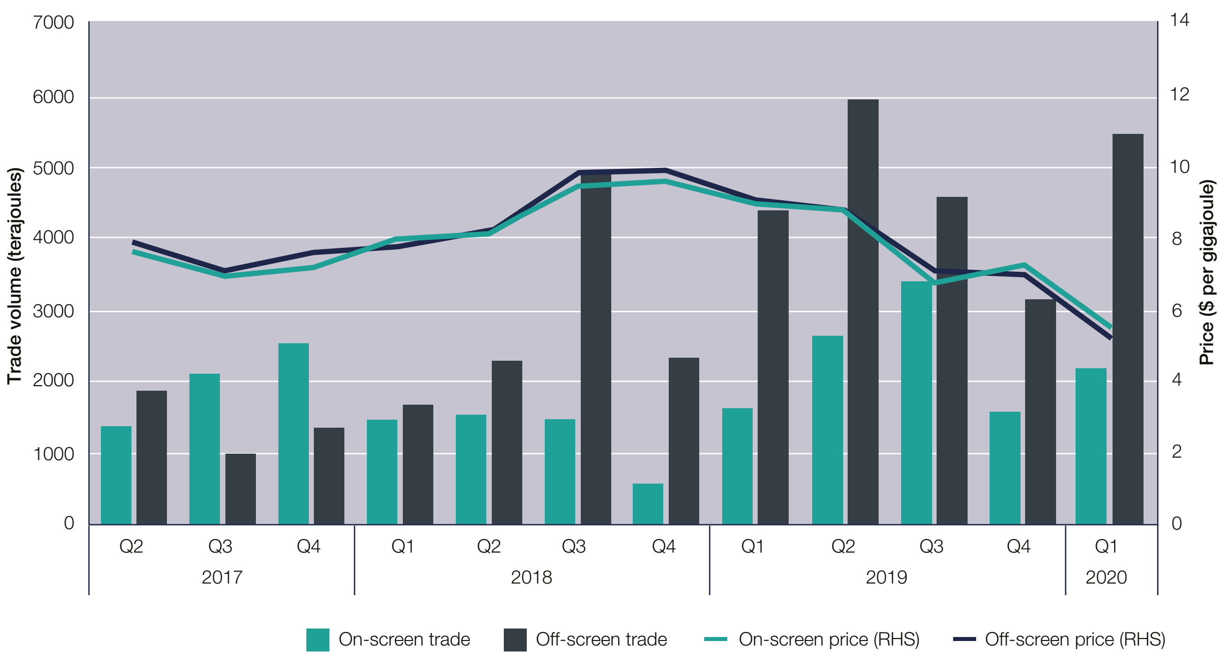
Shippers deliver gas for sale into the market, and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users, but in effect trade only their net positions—that is, the difference between their scheduled gas deliveries into and out of the market. In the fourth quarter of 2019, gas traded through the short term trading market met around 20 per cent of demand in Sydney, more than 22 per cent in Adelaide, and around 8 per cent in Brisbane.[41]

Traded volumes at the Sydney market were 54 per cent higher in 2019 than in 2018, and 17 per cent higher at the Brisbane market. Volumes at the Adelaide market fell by 11 per cent across the same period. Trading profiles varied across the markets. Benefiting from increased participation, all markets experienced less concentration across the top three sellers from 2018 to 2019 (figure 4.9). Concentration among the top three buyers increased in the Sydney and Adelaide markets for the same period.

In 2018 the ACCC reported evidence of C&I customers engaging more heavily in the short term trading market to manage their gas supply, with some users switching to the market to cover their entire demand. Those who switched found they were generally ahead (in pricing terms) of where they would have been with contracts offered to them in 2017 for 2018 supply. More generally, customers

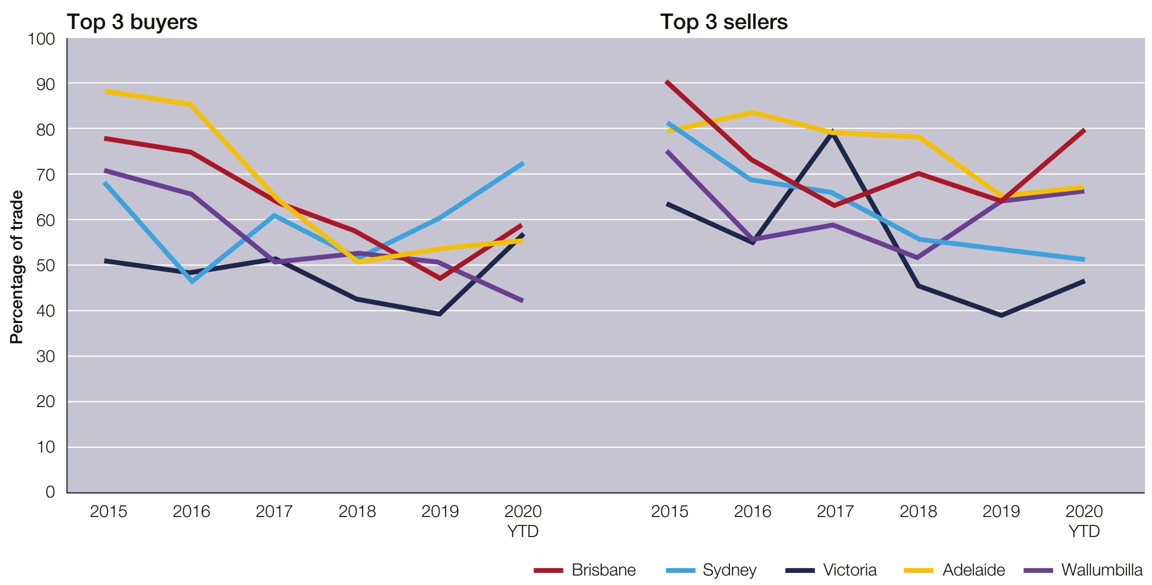
41 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.

Figure 4.8
Gas supply hub—on-screen and off-screen price and volume



Source: AER analysis of gas supply hub data.

Figure 4.9
Top three buyers and sellers in eastern Australian gas markets



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

Box 4.2 How the short term trading market works

The short term trading market allows gas trading on a day-ahead basis. The Australian Energy Market Operator (AEMO) sets a day-ahead clearing price at each hub, based on scheduled withdrawals and offers by shippers to deliver gas. All gas supplied according to the schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the rules oblige participants to bid in 'good faith'. Pipeline operators schedule flows to supply the necessary quantities of gas to each hub. As gas requirements become better known closer to the time of delivery, shippers may renominate quantities with pipeline operators (depending on the terms of their contracts).

If gas deliveries and/or withdrawals from a hub do not match the day-ahead nominations, then AEMO procures balancing gas—called market operator services (MOS)—to meet any shortfalls. Conversely, it procures storage on transmission pipelines with capacity to manage an oversupply. Participants make offers to supply MOS, which AEMO calls on in order of lowest to highest price when balancing gas is needed. The parties causing the imbalances mainly pay for the gas procured under this mechanism. The Australian Energy Regulator (AER) has reported instances of abnormally high MOS payments in parts of the market, resulting in some investigations.[a]

a AER, *State of the energy market 2017*, 2018, p. 76.

found participating in the short term market improved their negotiating power in the contract market, enabling them to wait for a suitable contract offer rather than accepting an unsatisfactory one.[42]

4.9.5 Victoria's declared gas market

Victoria launched Australia's first spot gas market—the declared wholesale gas market—in 1999, partly to help manage flows on the Victorian Transmission System. Participants submit daily bids ranging from $0 per GJ (the floor price) to $800 per GJ (the price cap). At the beginning of each day, AEMO selects the least cost bids needed to match demand. This process establishes a clearing price. In common with the short term trading market, only net positions are traded. AEMO can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term transmission constraints.

The market's participants include energy retailers, power generators and other large gas users, and traders. The AEMC reported smaller retailers and new entrants to the gas market tend to favour the spot market for sourcing gas, given the spot market's flexibility and relatively low transaction costs.[43]

As in the short term trading market, participants primarily use the market to manage imbalances in their forecast supply and demand schedules, and prices reflect day-to-day fluctuations in supply and demand. No gas producer currently uses the market as a major outlet for their supply.

Over 30 participants traded in the Victorian market in 2019. As volumes traded in the Victorian market rose in 2019 (up 65 per cent), trading concentration among the top three buyers and sellers continued to fall (figure 4.9). In 2019 the top three sellers accounted for around 40 per cent of total trade volume, down from nearly 80 per cent in 2017.

A small futures market has developed for the Victorian market, with the ASX launching a Victorian gas future product in 2013. But, there was little trade until mid-2018. Since the start of 2019, activity and trade volumes have increased significantly. Ultimately, this increase still accounts for only a small proportion (around 5 per cent or less) of the total volume traded in the market. However, increasing levels of open interest and increased spot trading in short term markets are encouraging signs.

The Victorian market differs from the short term trading market in a number of ways:

- In the short term trading market, AEMO operates the financial market but does not manage physical balancing (which remains the responsibility of pipeline operators). In the Victorian market, AEMO undertakes both roles.
- The short term trading market is for gas only, while prices in the Victorian market cover gas as well as transmission pipeline delivery to the hub.

42 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018.
43 AEMC, *Final report: biennial review into liquidity in wholesale gas and pipeline trading markets*, August 2018, p. 14.

4.9.6 Gas Bulletin Board

The Gas Bulletin Board (www.gasbb.com.au) is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. Market participants—gas producers, pipeline businesses and storage providers—supply the information to AEMO, which then publishes it. The AER monitors participants' compliance with their obligations to submit accurate data, acting when necessary to enforce compliance.

The bulletin board plays an important role in making the gas market more transparent, especially for smaller players who 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 bi-directional 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.

The bulletin board's coverage has progressively widened. Significant reforms in 2018 removed reporting exemptions, mandated greater detail for covered facilities, and lowered the reporting threshold to encompass smaller facilities (section 4.14.1). To encourage compliance, the reforms made reporting obligations subject to civil penalties. Reporting obligations were also extended to gas facility operators in the Northern Territory, following the territory's connection to the eastern gas grid in January 2019.

4.10 State of the eastern gas market

The development of Queensland's LNG export industry placed significant pressure on the eastern gas market. The pressure, combined with other factors such as state based moratoriums on gas development, tightened the supply–demand balance. This tightening led to increases in wholesale gas prices across 2017–18 as international gas prices began to bear on domestic gas prices. However, in 2019 the price pressure showed signs of easing.

Gas production in the northern states rose to record levels in 2019, peaking in October. However, agreements between gas producers and the Australian Government required this additional uncontracted gas to be offered to the domestic market on competitive terms before being offered for export. This requirement—along with a sharp fall in Asian LNG prices, increased participation in the eastern market, and reforms to improve access to critical pipelines—contributed to prices falling across the year and into early 2020.

4.10.1 Supply conditions

While a majority of eastern Australia's gas reserves are located in Queensland's Surat–Bowen Basin, those reserves are largely committed to the LNG export industry. Gas production in Queensland reached record levels in 2019, averaging just over 4000 TJ per day, as LNG projects ramped up production to meet record export demand.

Queensland's LNG projects originally planned to source their gas requirements from their own (newly developed) reserves in the Surat–Bowen Basin. But the development of gas wells by Santos's GLNG project was slower than expected. To meet its LNG supply contracts, therefore, Santos sourced substantial volumes of gas from other producers, diverting gas from the domestic market.

The tightening supply–demand balance following the commencement of LNG exports led to concerns in 2017 that gas production may not be sufficient to meet domestic demand. In response, the Australian Government threatened to instruct LNG producers to supply more gas to 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 4.13.1).

To avoid export controls, Queensland's LNG producers entered a Heads of Agreement with the Australian Government in October 2017, and a second agreement in September 2018. Under the agreements, they commit to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.

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. APLNG in 2019, for example, entered new supply agreements with gas powered generators and other large domestic customers.[44]

44 Australia Pacific LNG, 'Australia Pacific LNG delivers new gas supplies to domestic manufacturers', Media release, 4 July 2019; Australia Pacific LNG, 'Australia Pacific LNG continues strong support of domestic gas market', Media release, 26 September 2019.

More recently, gas supply concerns have eased. The ACCC forecast eastern Australia gas supply in 2020 to reach 2025 PJ—around 200 PJ *above* its forecast for domestic and LNG demand.[45] Production by LNG projects above their contractual commitments accounted for around 140 PJ of this forecast surplus.

Despite improved forecasts in the short run, the longer term outlook is uncertain. AEMO forecast that supply gaps could emerge by 2024, as Victorian production wanes.[46] Both AEMO and the ACCC suggested more exploration and development in southern Australia, pipeline expansions and/ or LNG imports could mitigate the supply risks.

Long term supply conditions are uncertain for a number of reasons. First, some developed resources may underperform, and southern production may decline faster than expected.

Second, forecasts make assumptions about undeveloped gas fields with uncertain reserves. These assumptions are increasingly unreliable, as the long term security of supply for the east coast increasingly depends on more speculative sources of supply. That is, 75 per cent of 2C resources in early 2020 were located in fields that were not yet in production or approved for development, and some 2P reserves and resources in Queensland have been written down.[47,48] 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 4.13).

Supply conditions in the northern region

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, since 2019, from the Northern Territory (via the Northern Gas Pipeline). At times, southern gas is also transported north to meet LNG export demand.

Gas production in the Surat–Bowen Basin rose exponentially from 2014 to 2017 to meet the demands of Queensland's LNG export industry. While production continued to rise, this growth tended to level out once all LNG projects reached full operation.

Despite this levelling out, Queensland production in 2019 rose to record levels of just over 4000 TJ per day. In the fourth quarter of 2019, Queensland facilities produced 4126 TJ of gas per day, compared with 3762 TJ per day in the fourth quarter of 2018. This production growth coincided with Queensland LNG exports reaching record levels (section 4.10.2). High Asian LNG prices in late 2018—when production decisions were likely made—meant record production occurred despite Asian LNG prices in 2019 being significantly lower than those in 2017 or 2018.[49]

Supply conditions also depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, new transmission capacity began operating in 2019:

- Jemena's Northern Gas Pipeline provides eastern Australia's first pipeline interconnection with the Northern Territory, allowing gas from territory basins to reach eastern Australia. The pipeline on average delivered over 65 TJ per day to the eastern market in 2019.[50] Jemena is assessing a proposed expansion of the Northern Gas Pipeline and has committed to develop further pipelines in northern Queensland. This commitment by Jemena includes connecting its Queensland Gas Pipeline to the Galilee Basin, which would bring further supply to the market.[51]
- The Roma North Pipeline and the Atlas Gas Pipeline were commissioned. Senex's Atlas project is dedicated entirely to supply the domestic market, under Queensland Government initiatives to improve supply to industrial customers.[52]

New entry

In 2018 and 2019 the number of suppliers in the eastern market rose, and producers such as Shell Energy Australia expanded their presence.[53] Also, the growth of retailers and aggregators in downstream spot gas markets disrupted dominant players and provided C&I customers with competitive alternative sources of gas.

45 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020,* February 2020, p. 27. Based on forecast production from 2P reserves.
46 AEMO, *2020 gas statement of opportunities*. March 2020, p. 44.
47 2C resources represent the best estimate of contingent gas reserves, which are not yet technically or commercially recoverable.
48 Queensland reserves were downgraded (on a net basis) by more than 4400 PJ between 1 July 2017 and 30 June 2019. See ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020,* February 2020.

49 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.
50 National Gas Bulletin Board data.
51 Jemena, 'Proposed route for the Galilee Gas Pipeline revealed', Media release, 30 July 2019.
52 Senex, available at: www.senexenergy.com.au/operations/surat-basin-gas/project-atlas/.
53 AER, *Wholesale markets quarterly—Q4 2019*, February 2020, p. 22.

Additionally, five new projects are expected to commence operations in Queensland over the next four years. The operators of these projects include APLNG, Arrow Energy, Comet Ridge and Senex. As a result, supply options to C&I gas users appear to be improving.

Supply conditions in the southern region

The Victorian gas basins and the Cooper Basin in central Australia remain pivotal to meeting domestic gas demand in southern Australia. Cooper Basin gas is largely committed to the LNG operators, but contributes to southern supply through swap agreements with independent gas producers in Queensland.[54] It is uncertain whether these agreements will continue beyond 2020.

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. After achieving record production levels in 2017, production from the Longford plant servicing the Gippsland Basin fell. The plant is becoming less reliable because it is run harder for longer, and plant constraints and maintenance outages increasingly disrupt production.

AEMO reported a short term increase in Victorian production forecasts as a number of projects reached financial investment decision. Yet, forecasts remain significantly below 2017 levels, and are expected to fall further as some key fields cease production in 2023 and 2024.[55]

Cooper Energy's Sole project in the Gippsland Basin, initially scheduled for commissioning in 2019, began commercial operation in March 2020. The project is the first new production well drilled in offshore Victoria since 2012, and is expected to produce around 25 PJ per year. Another project, the West Barracouta joint venture between Esso Australia and BHP Billiton, achieved final investment decision in late 2018, and is scheduled to be operational by 2021.

While these and other projects should provide additional supply into the southern region, the scope to increase production in the short to medium term is limited, and AEMO still identified a potential gas shortfall from 2024.[56]

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.[57] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

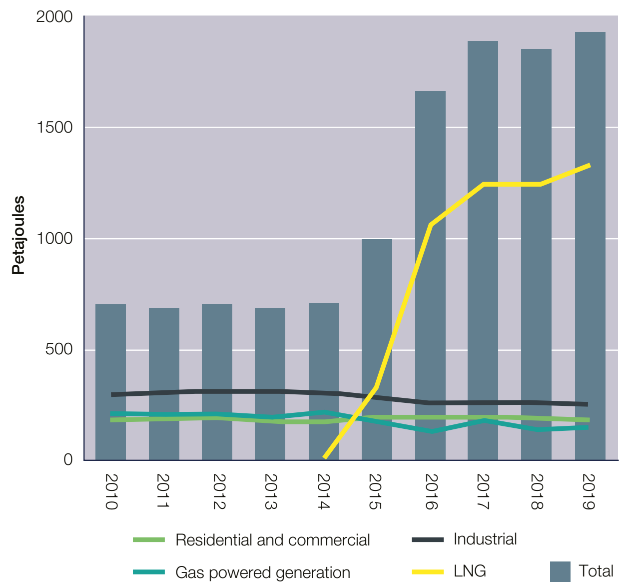
- In 2017 the Victorian Government banned onshore hydraulic fracking, and exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[58] While maintaining its ban on onshore exploration, the government in May 2018 announced the release of oil and gas acreage in the Otway Basin for exploration and development, including potential drilling from onshore, subject to regulatory approvals.[59] In March 2020 the government committed the ban on fracking and CSG exploration to the Victorian Constitution, but announced onshore conventional gas exploration could recommence from July 2021.[60]
- South Australia in 2018 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. Unconventional gas extraction is, however, 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.
- The Northern Territory in 2018 made 51 per cent 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.

Queensland does not restrict fracking. 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.[61] 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.[62] 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.[63]

4.10.2 Demand conditions

Historically, demand for eastern Australian gas derives from three main domestic sources—C&I gas users, gas powered generators and residential customers. However, with the launch of LNG exports in 2015, international customers became a new source of demand competing to buy eastern Australian gas (figure 4.10).

Figure 4.10
Eastern Australian gas demand



Source: AEMO, *2020 gas statement of opportunities*, March 2020.

Domestic gas use

Higher gas prices have weakened gas demand by industrial customers since 2014. In 2019 the closure of Remapak in Sydney and Claypave in Brisbane were linked to high gas prices.[64] Separately, AEMO reported consumption by Victorian C&I customers had declined as a result of increased domestic gas prices, and noted the closure of Dow Chemicals in Melbourne as an example of the impact of high prices.[65]

Other C&I customers have implemented strategies to reduce their gas demand, including energy efficiency improvements and fuel switching.[66] But the ACCC reported in 2020 that energy efficiency measures for C&I customers are now largely exhausted.[67]

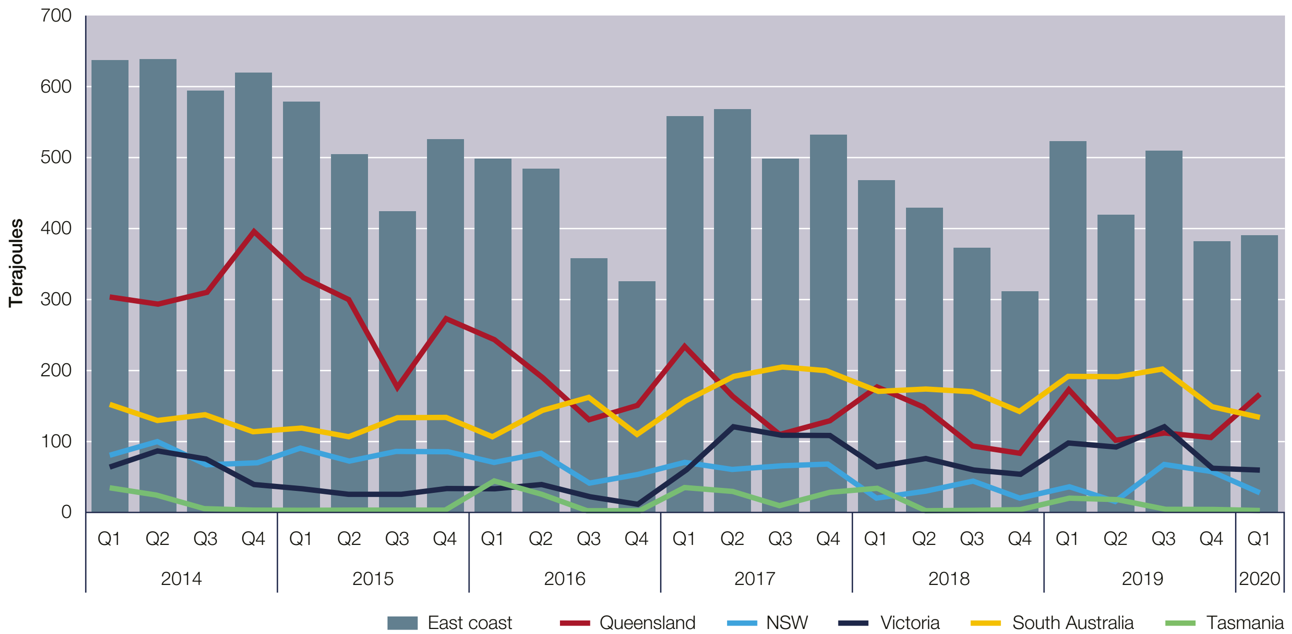
Among domestic sources of demand, gas powered generation is the most volatile source of demand (figure 4.11). Gas is a relatively expensive fuel for electricity generation, so gas generators typically operate as 'flexible' or 'peaking' plants that can be switched on at short notice to capture high prices in the electricity market. Gas demand for power generation, therefore, tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are higher. It also varies with the amount of renewable generation available (which is cheap but weather dependent).[68]

Rising gas fuel costs linked to Queensland's LNG industry, along with a shortage of gas supplies linked to state based moratoriums on gas exploration and production, stalled demand for gas powered generation in the state from 2015 to 2018. Gas powered generation slumped from 18 per cent of Queensland's electricity output in 2015 to 9 per cent in 2019. A similar squeezing off occurred in NSW.

Different conditions prevailed in Victoria and South Australia, where coal generation retirements and rising outages among remaining plant made gas generation critical to meeting electricity demand. In particular, when Hazelwood power station closed in 2017, gas powered generation rose in both states. Across 2019 some major coal generators experienced lengthy, unexpected outages. These outages required gas powered generation to increase output to cover the shortfall. Compared with 2018, gas powered generation rose from 5 to 7 per cent in Victoria, and from 52 to 54 per cent in South Australia.

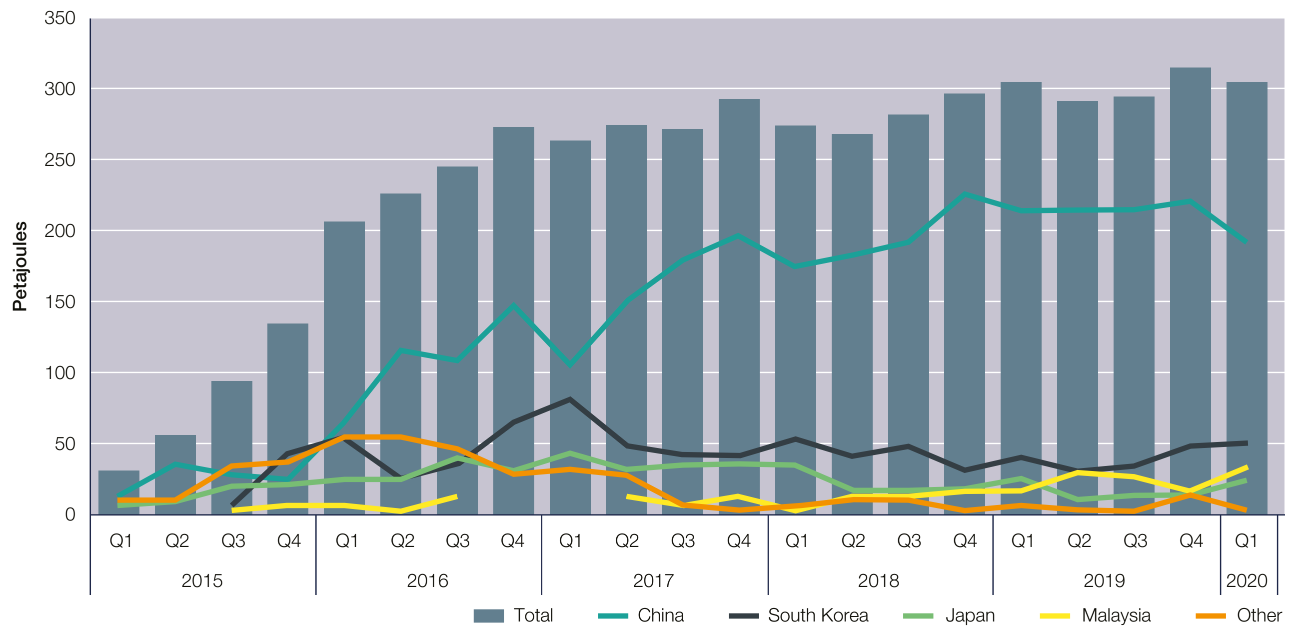
54 A domestic gas retailer also acquires some Cooper Basin gas.
55 AEMO, *Victorian gas planning report update,* March 2020, pp. 4–5.
56 AEMO, *2020 Gas statement of opportunities*, March 2020, p. 8.
57 Hydraulic fracturing, also known as fracking, is a process that involves injecting a mixture of water, 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.
58 Department of Economic Development, Jobs, Transport and Resources (Victoria), *Onshore gas community information*, August 2017.
59 Department of Industry, Innovation and Science, *The 2018 offshore petroleum exploration acreage release*, available at: www.petroleum-acreage. gov.au/.
60 Premier of Victoria, 'Backing the science, protecting farmers and boosting jobs', Media release, 17 March 2020.
61 Department of Planning and Environment (NSW), *Initiatives overview*, July 2018.
62 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed', Media release, 7 June 2017.
63 Prime Minister of Australia, and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions', Media release, January 2020.
64 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020*, February 2020.
65 AEMO, *Victorian gas planning report update*, March 2020, p. 20.
66 ACCC, *Gas inquiry 2017–2020, Interim report*, *July 2019*, August 2019.
67 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020*, February 2020.
68 EnergyQuest found a –89 per cent correlation between gas and hydroelectric generation; and a –48 per cent correlation between gas and wind generation over 42 months to June 2018. See EnergyQuest, *Energy quarterly*, September 2018, p. 35.

Figure 4.11
Quarterly gas demand for gas powered generation



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

Figure 4.12
Eastern Australian gas exports



Source: Gladstone Ports Corporation; trade statistics.

More recently, domestic spot prices for gas fell significantly (section 4.11.2). While the full impact of this price reduction on demand will take time to fully realise, it may provide relief for some customers after several years of high prices.

LNG exports

Exports continue to grow, with record volumes over 2019 (and a record quarterly volume in the fourth quarter of 2019) contributing to Australia overtaking Qatar as the world's largest exporter of LNG. Accordingly, both APLNG and QCLNG projects operated at or near capacity in 2019, contributing to record eastern Australian production levels in 2019 (figure 4.12).

China is the primary market for eastern Australian LNG, accounting for 72 per cent of exports in 2019. Chinese demand has grown each year since LNG exports commenced, with the 2019 volume (863 PJ) up 11 per cent on the previous year's volume. A key Chinese policy initiative underpinning LNG demand has been to mandate targets for switching heating fuels from coal to gas, to reduce carbon emissions and improve air quality.[69] Malaysian demand for LNG also increased year on year (with 92 PJ delivered in 2019) despite the country being a major LNG exporter.

In contrast, Japan and South Korea's demand for eastern Australian LNG fell to 220 PJ in 2019, from 365 PJ in 2017. Greater use of nuclear reactors (as well as some additional coal and solar plant) for electricity generation contributed to this shift.

Strong demand caused a surge in LNG spot prices from mid-2017. Monthly Asian spot prices reached around $14 per GJ in December 2017 and remained elevated throughout 2018. But new LNG capacity in the United States, Australia and Russia came online in 2019, creating an oversupply and driving prices lower. Delivery programs and production decisions for 2019 were set in late 2018 when LNG spot prices were high, so LNG volumes were not significantly affected.

A slowing Chinese economy, Japan's ongoing switch away from gas powered generation, and further increases in US export capacity kept downward pressure on prices in late 2019 and early 2020. Also in early 2020, the outbreak of COVID-19 contributed to reduced Asian LNG demand and weaker spot LNG and oil prices.[70] This price downturn coincided with intense price competition among oil exporting countries, which further reduced oil prices, and may ultimately affect prices for oil-linked LNG contracts. Australian exporters reported the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements and finalise investment decisions.[71]

While the potential exists for delays to LNG cargoes, it was not reported in the first quarter of 2020. Given the limited ability to reduce production from fields once developed and committed under long term contracts, LNG production and export volumes tend to lag a change in spot prices. Slowing production from the Surat–Bowen Basin from November 2019 is consistent with LNG exporters expecting softer demand conditions in 2020, as buyers exercise downward quantity limits in long term contracts in favour of spot cargoes at lower prices.

4.10.3 Interregional gas trade

A signature feature of the domestic gas market since 2014 is the role of interregional gas trades to manage the supply–demand balance. Key pipelines have been re-engineered as bi-directional, enabling them to respond more flexibly to regional supply and demand conditions.

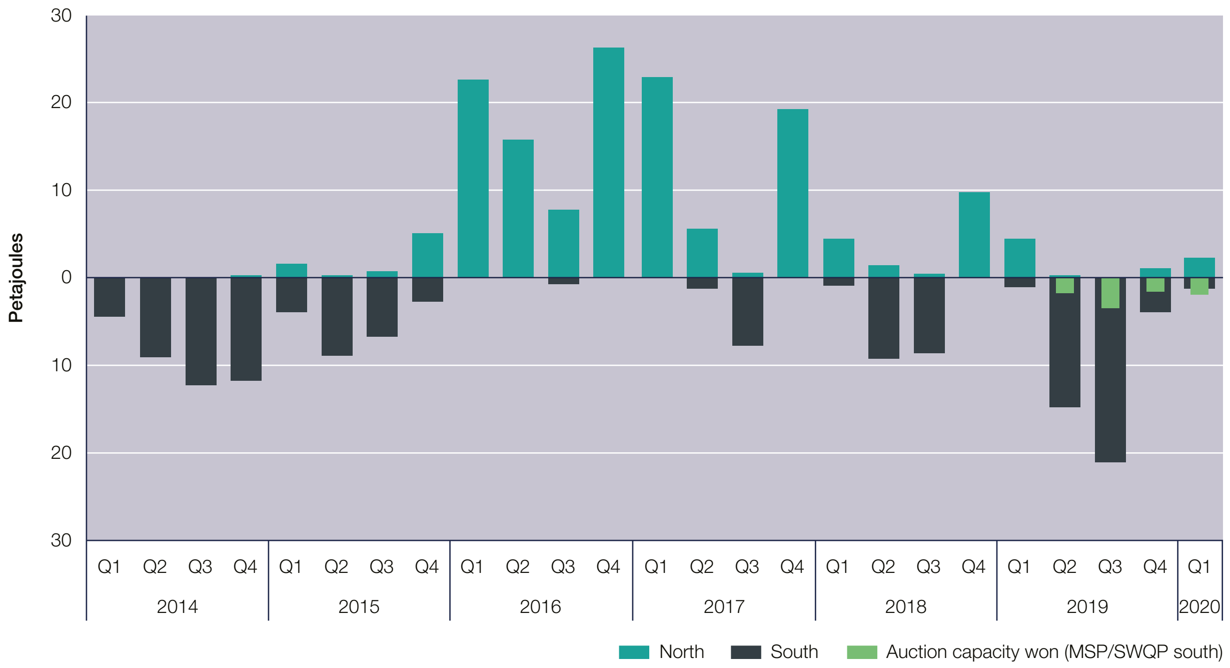
With the launch of Queensland's LNG projects in 2015, the projects began drawing substantial volumes of gas from Victoria and South Australia to cover shortfalls in their reserve portfolios. Flows then settled into a cycle of gas flowing south in the Australian winter (to meet heating demand), and north in the Australian summer (the northern hemisphere winter) when Asia's LNG demand peaks (figure 4.13).

More recently, the cycle appears to be shifting towards net southern flows—that is, less gas flowing north in summer, and more flowing south in winter. In the fourth quarter of 2019, net flows were southward. The introduction of the pipeline capacity reforms (section 4.10.4) is contributing to this shift, and significant southbound flows can be linked to pipeline capacity won at auction for routes on the key South West Queensland and Moomba to Sydney pipelines.

Conditions in the domestic electricity market also affect trade flows. Following the closure of coal fired generators in the southern states, increased demand for gas powered generation in those states drew gas south, especially during the Australian winter when heating demand peaks. In 2018

69 Department of Industry, Innovation and Science, *Resources and energy quarterly*, December 2019, p. 57.
70 EnergyQuest, *Energy quarterly*, March 2020, p. 14.
71 EnergyQuest, *Energy quarterly*, March 2020, p. 53.

Figure 4.13
North–south gas flows in eastern Australia



MSP, Moomba to Sydney Pipeline; QSN, Queensland / South Australia / New South Wales; SWQP, South West Queensland Pipeline.

Note: Flows on the QSN Link section of the South West Queensland Pipeline. Northbound flows are from the southern states into Queensland. Southbound flows are exports from Queensland to the southern states.

Source: AER analysis of Gas Bulletin Board data.

and 2019, gas flows turned southbound even before the onset of winter.

The threat of government intervention in the gas market (section 4.13) also impacted flows from late 2017. To avoid triggering intervention, Queensland's LNG producers began offering more gas to the domestic market, which increased southbound trade flows. Exporters committed to the Australian Government to first offer any uncontracted gas to the domestic market on a competitive basis.

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.[72] 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.[73] 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.

Gas flows into NSW

NSW produces little of its own gas, so it is highly trade dependent. Previously supplied by Victorian sources, NSW became more reliant on its northern neighbour as Queensland production fields ramped up and sent more gas south. As a result, gas volumes shipped along the Moomba to Sydney Pipeline and the South West Queensland Pipeline rose significantly.

The critical role of these pipelines in delivering gas to NSW on peak days highlights the risk of capacity constraints. The South West Queensland Pipeline in particular has little uncontracted capacity between Wallumbilla (Queensland) and Moomba (South Australia), which is the origin point of the Moomba to Sydney Pipeline. But capacity trading reforms introduced on 1 March 2019 eased pressures somewhat (section 4.10.4). In addition, proposals for LNG import terminals and gas pipelines that may open flows from Queensland could improve gas availability in NSW.

72 Santos, 'Santos facilitates delivery of gas into southern domestic market', Media release, August 2017.
73 EnergyQuest, *Energy quarterly*, March 2020.

4.10.4 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 pipeline businesses to have the gas delivered. To reach its destination, gas may even need to flow across multiple pipelines with different owners.

Since LNG exports began in 2015, gas flows from the southern states to Queensland, and sometimes the reverse, have helped manage interregional supply–demand imbalances. For this reason, 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.

The ACCC in 2015 found a majority of transmission pipelines on the east coast were using market power to engage in monopoly pricing.[74] Reforms were implemented to address this issue, including a new information disclosure and arbitration framework that came into effect in August 2017, and changes to full and light regulation, which came into effect in March 2019 (section 5.3).

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 two ways. First, the *Capacity Trading Platform* is a voluntary market where shippers can 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 the majority of settlements in 2019 occurred at no cost.

To promote transparency, the Gas Bulletin Board publishes prices and other key terms from all voluntary trades and auctions. The AER monitors compliance with capacity trading regulations and the proper reporting of trades, and oversees the resolution of any cost recovery disputes.

74 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 18.

Outcomes of capacity trading reform

The day-ahead auction provided access to over 41 PJ of unused, contracted pipeline capacity (across 10 pipelines) in the 12 months after it launched on 1 March 2019 (figure 4.14). Over 80 per cent of this capacity was won at the reserve price of zero. No trades occurred on the voluntary platform in 2019, with the first trade recorded in February 2020. The ACCC reported shippers expect activity in the capacity trading platform to increase over time.[75]

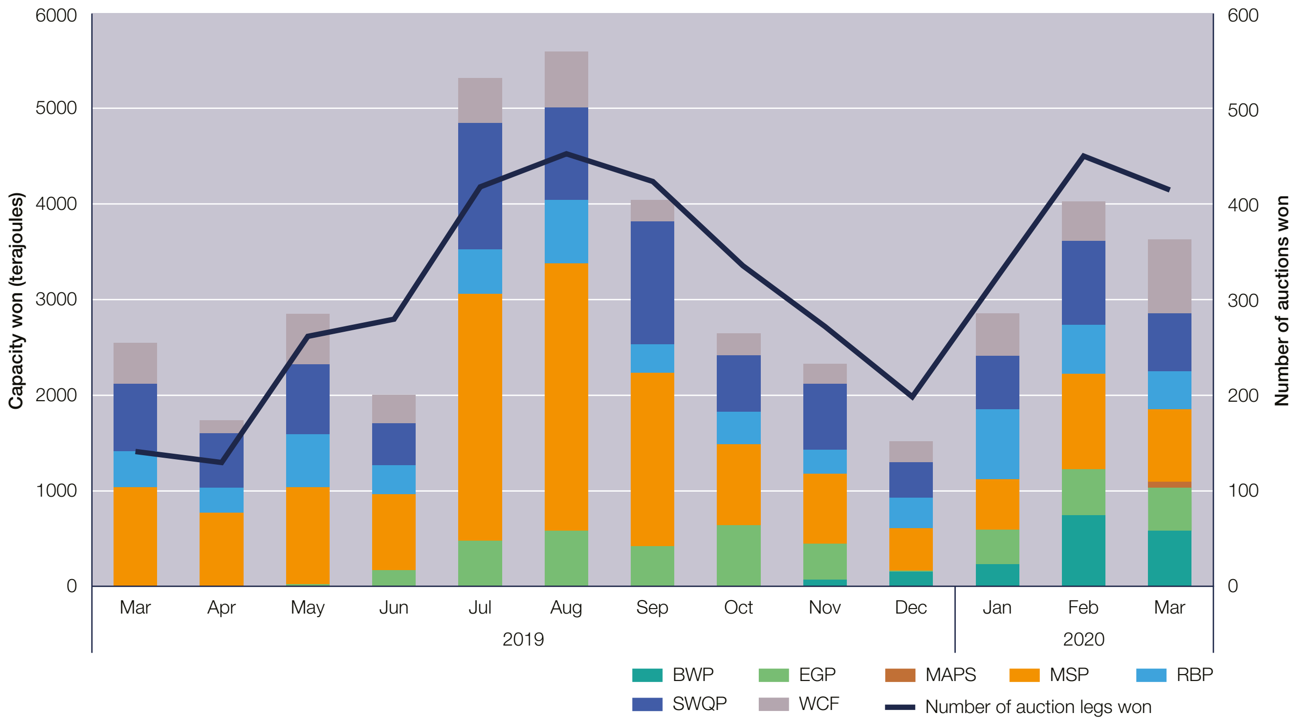
The day-ahead auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low priced northern gas into southern spot markets, easing price pressure in those markets. The AER estimated the auctions effectively reduced spot gas prices by as much as $0.76 per GJ in Sydney, and up to $0.17 per GJ in Victoria, over the six months to September 2019.[76]

The AER's *Wholesale markets quarterly* reports found day-ahead auctions increased liquidity at the Wallumbilla hub, as well as the Sydney and Victorian spot markets.[77] Separately, the ACCC reported shippers' expectations that spot market prices would more closely align as participants exploit arbitrage opportunities made possible by cheap capacity procured at auction.[78] It also indicated the auctions could indirectly ease supply costs for some gas powered generators in the National Electricity Market (NEM). As an example, the day-ahead auction delivered record capacity (317 TJ) on 31 January 2020, which facilitated gas delivery during South Australia's electrical separation from the NEM.[79]

The ACCC noted, however, some shippers consider pipeline operators may be using the capacity trading reforms to reduce the level of service flexibility provided to shippers, or to require shippers to pay more for this flexibility. Some shippers cited fixed charges levied by major pipelines servicing South Australia as a potential reason for the capacity reforms not being used in the state in the first eight months of operation.[80]

75 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 103–4.
76 AER, *Wholesale markets quarterly—Q3 2019*, November 2019, pp. 52–53.
77 AER, *Wholesale markets quarterly—Q3 2019*, November 2019, pp. 44, 52–4
78 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 101.
79 AER, *Wholesale markets quarterly–Q1 2020*, May 2020, p. 58.
80 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 6–7.

Figure 4.14
Day-ahead auction price and quantity



BWP, Berwyndale to Wallumbilla Pipeline; CGP, Carpentaria Gas Pipeline; EGP, Eastern Gas Pipeline; MAPS, Moomba to Adelaide Pipeline; MSP; Moomba to Sydney Pipeline; RBP, Roma to Brisbane Pipeline; SWQP, South West Queensland Pipeline; WCF, Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

4.11 Gas prices

The launch of LNG exports from Queensland in 2015 linked domestic gas prices (which were traditionally fairly stable) to more volatile international oil and gas prices. This link drove prices higher in 2016 and 2017, but operated in reverse in 2019 and 2020 when lower Asian prices helped drive falls in domestic spot prices.

Other factors contributing to lower domestic prices across 2019 included high levels of Queensland gas production, competition in spot gas markets, and the introduction of pipeline capacity auctions. The auctions in particular allowed some shippers to move gas from northern to southern markets at near zero transportation costs.

4.11.1 Gas contract prices

A majority of gas prices are agreed in confidential bilateral contracts, either between gas producers and large customers, or between retailers/aggregators and C&I customers (section 4.9.1).

Domestic gas contract prices historically averaged around $3–4 per GJ. But, when Queensland's LNG projects began sourcing gas from Victoria and South Australia, this demand drove contract prices higher. By early 2017, domestic prices of $22 per GJ were being quoted for a one or two year contract—almost $10 per GJ above export prices.[81] At their peak in March 2017, domestic prices offered by retailers nearly doubled LNG netback prices (box 4.3).

Following the Australian Government's market intervention in 2017 (section 4.10.1), Queensland producers began offering more gas to the domestic market at lower prices. By 2018 contract offers had eased into the high $8–11 per GJ range, aligning them more closely with Asian LNG netback prices. By late 2018 domestic gas prices were around $3 per GJ *lower* than export prices, although some customers reported some suppliers' use of EOI processes made it difficult to compare offers.[82]

81 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018.
82 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018.

Box 4.3 Liquefied natural gas netback prices

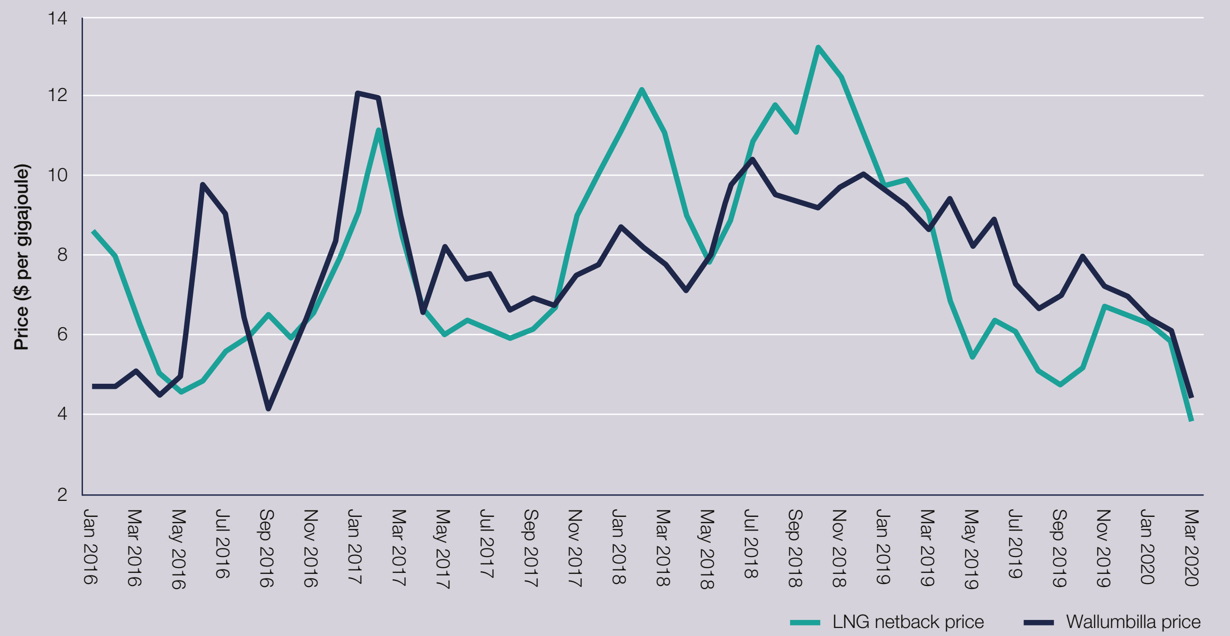
Liquefied natural gas (LNG) netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically. It is calculated as the price for selling LNG (based on Asian spot prices) and subtracting or 'netting back' the costs of converting gas to LNG and shipping it overseas. The costs include liquefaction at Gladstone, waterborne shipping to Asia, and regasification in Asia.

If LNG netback prices exceed domestic prices, then it becomes more profitable to export gas than to sell it locally. At times in 2017 the reverse situation prevailed in eastern Australia—that is, domestic gas prices exceeded LNG netback prices (figure 4.15). This situation was indicative of a dysfunctional market, where price signals were not addressing a demand–supply market imbalance.

The Australian Competition and Consumer Commission (ACCC) publishes LNG netback prices to improve transparency in the eastern gas market. The prices tend to peak during the northern hemisphere winter, when LNG demand is highest. They peaked at $13.21 per GJ in October 2018 before falling across 2019, reaching $5.19 per GJ a year later in October 2019.

Despite a slight rebound to around $6 per GJ during the northern hemisphere's winter, the LNG netback price was expected to remain suppressed into 2020, reaching as low as $3.85 per GJ in March 2020.[a]

Figure 4.15
LNG netback prices and Wallumbilla prices

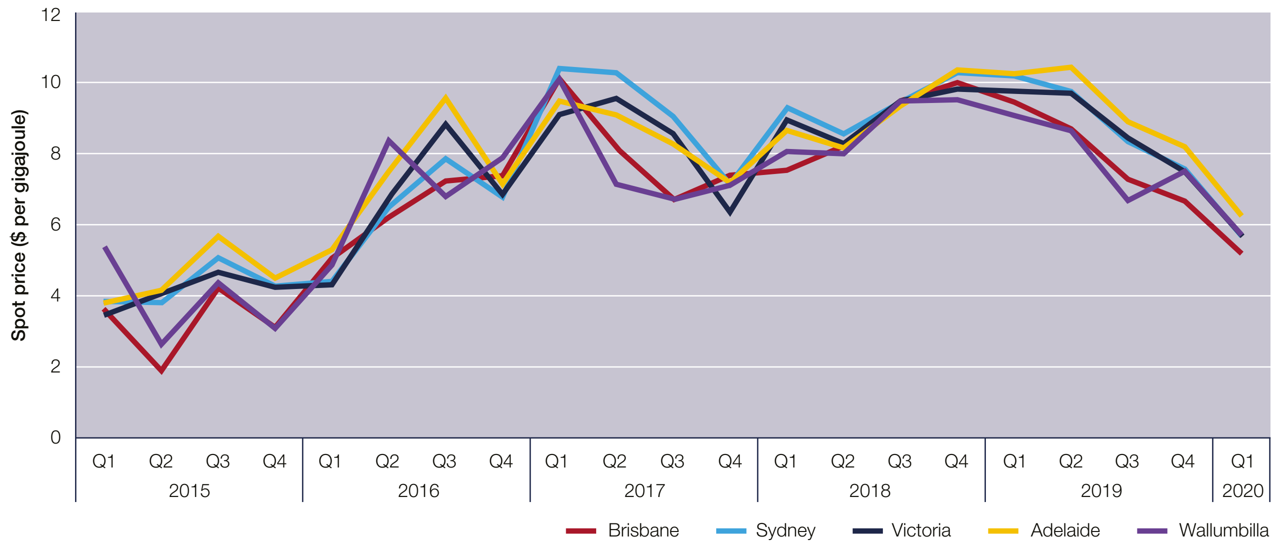


Note: The Wallumbilla price is the monthly volume weighted average price at the Wallumbilla hub for day-ahead, on-screen trades. LNG netback prices are based on domestic spot market prices on the first day each month, and expected netback prices for LNG cargoes to Asia in the following month. The 1 April LNG netback price, for example, is based on domestic spot prices for the 1 April gas day, and the netback on expected LNG spot prices for cargoes to Asia in the following month.

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

a ACCC, *LNG netback price series*, March 2020.

Figure 4.16
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.

Prices offered by Queensland gas producers for 2020 supply were mostly in the $9–10 per GJ range over 2019, but retailer offers to C&I users were in the range of $8–12 per GJ.[83] Smaller C&I customers generally have fewer options to buy gas directly from producers, and tend to face more difficulties acquiring pipeline capacity to ship the gas. Some contract prices agreed by C&I users in the first half of 2019 were higher than in the first half of 2017, when market conditions were at their tightest. Flexibility in contract terms and conditions also reportedly decreased in 2019.[84]

That said, the ACCC reported many C&I users are looking to procure gas from other sources, including directly from producers. In addition, the Queensland Government has released tenements exclusively for domestic supply, resulting in direct agreements between customers and producers.[85]

In early 2019 producer offers were broadly in line with expected 2020 LNG netback prices. But, from May 2019, producer price offers remained steady while expected 2020 LNG netback prices eased. By August 2019 producer prices were almost 25 per cent above expected 2020 LNG netback prices. In some instances, producer offers included a new fixed price component, on top of the usual LNG spot price linked component.[86]

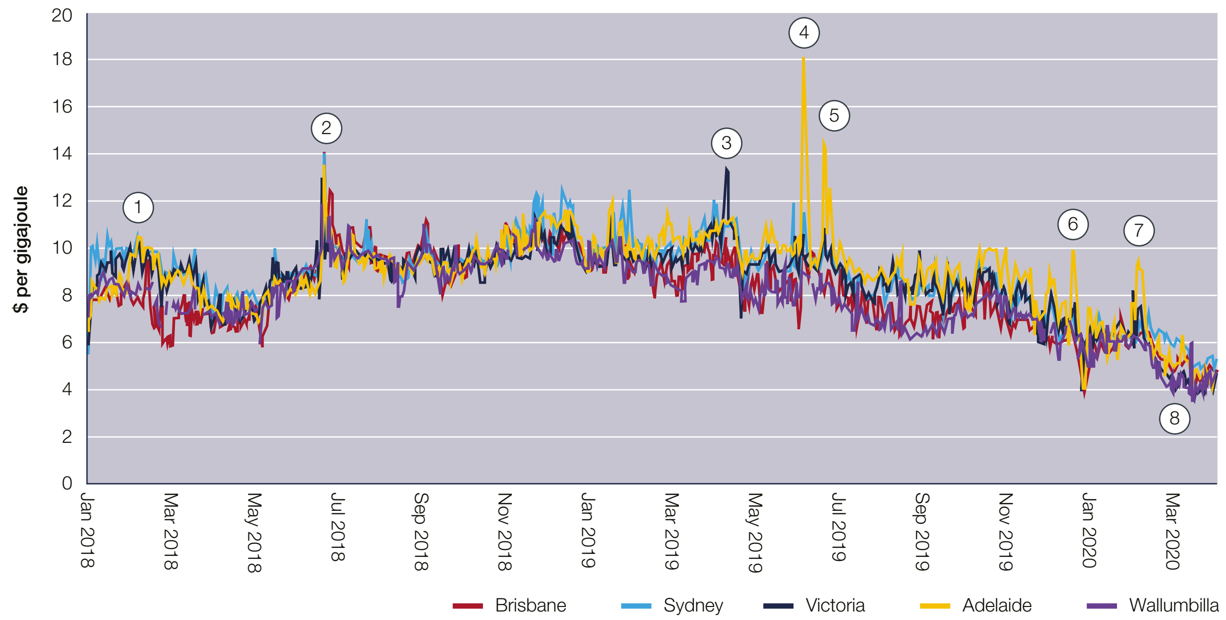
Consistent with price trends in the north, average prices offered by producers and retailers in the southern states in 2019 were above expected 2020 LNG netback prices (factoring in pipeline costs). The ACCC noted the disparity might have reflected a tight supply–demand balance in southern states.[87]

4.11.2 Spot market prices

As discussed in section 4.9, three separate spot markets for gas operate in eastern Australia—gas supply hubs at Wallumbilla, Queensland, and Moomba, South Australia; the short term trading market for gas, with hubs in Sydney, Brisbane and Adelaide; and Victoria's declared wholesale gas market. The three spot markets operate under different sets of rules, do not interact with each other, and have different purposes. Price outcomes in the spot markets do not align with contract prices, although they often move in similar directions. Contract prices reflect expectations of future market conditions, but the spot markets reflect short term shifts in market conditions relating to factors such as the timing of LNG shipments, and conditions in the electricity market.

83 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 5.
84 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 5–6.
85 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 78.
86 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 1, 44.
87 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 44.

Figure 4.17
Daily gas spot prices



1	January to April 2018	Lower Queensland demand for gas powered generation (following Queensland Government's direction to increase coal generation) led to more of the state's production being diverted south.
2	17–22 June 2018	Longford outages constrained Victorian supply, coinciding with high gas powered generation demand in South Australia, Victoria and Queensland, and a Queensland pipeline outage.
3	11 April 2019	Longford production was constrained.
4	6 June 2019	Low wind generation and production outages occurred in Victoria.
5	20 June 2019	Low wind generation and high winter gas demand occurred in Victoria and Adelaide.
6	16–20 December 2019	Temperatures were high in the southern states.
7	2–7 February 2020	Gas generation was directed on in South Australia following the outage of the Heywood interconnector in the National Electricity Market (NEM).
8	March 2020	An LNG export train outage occurred, along with excess gas supply, and low gas generation demand.

Source: AER; AEMO (raw data).

Spot prices vary seasonally, both within and across the markets. Prices can peak in summer but more typically peak in winter. In summer, gas demand for electricity generation may push up domestic spot prices. Australia's summer also coincides with the northern hemisphere winter, when Asian demand for LNG peaks. In the Australian winter, household gas demand tends to rise in the southern states for heating purposes. This increase in demand tends to push southern prices above northern prices during the winter months as southern customers pay the cost of northern gas *plus* domestic transportation costs (box 4.4).

In recent years, prices have varied significantly (figure 4.16). Along with other factors, the launch of LNG exports in January 2015 caused spot prices to increase in 2016 and 2017 as LNG producers competed with domestic customers for gas supplies (figure 4.17). While prices stabilised somewhat across late 2017 to 2018, they remained at historically high levels.

Monthly spot prices averaged around $10 per GJ in all markets in the fourth quarter of 2018. By the end of the second quarter of 2019, however, prices had already begun to fall in all markets except Adelaide, as the domestic market started mirroring the decline in LNG netback prices a few months earlier. At the same time, Queensland production continued to increase, and the newly implemented day-ahead auction of spare capacity started to provide cheap avenues for participants to bring that gas south, to compete in the Sydney, Adelaide and Victorian markets.

These factors continued to drive prices down through winter and into summer. By the fourth quarter of 2019, all

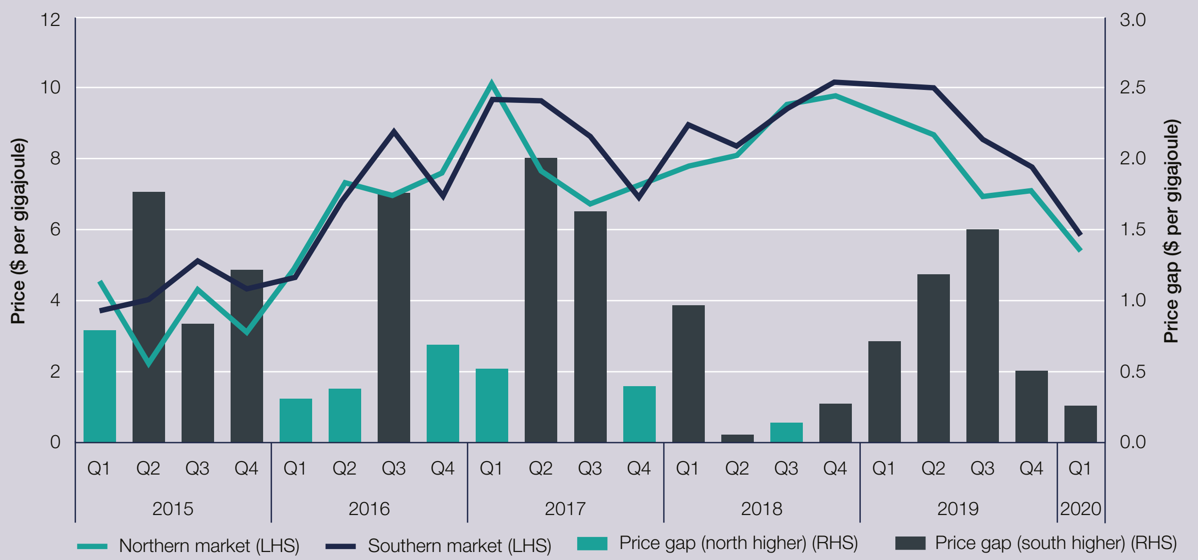
Box 4.4 North–south price divide

A significant differential between spot gas prices in Queensland (Wallumbilla and Brisbane) and the southern states was evident for much of 2019 (figure 4.18). The differential reflects contrasting demand and supply conditions in the two regions. In Queensland, higher production improved supply. But gas demand for power generation was high in the south, and gas storage levels were falling.

Historically, price gaps tend to emerge each winter as southern gas demand for heating increases. The gap is often around $2 per gigajoule (GJ), roughly the cost of transporting Queensland gas to the southern states.

But, in 2019 the day-ahead auction reforms kept the price gap narrower than it might have been. Access to cheap (or free) pipeline capacity allowed some participants to sell northern gas to southern markets at more competitive prices. Without this cheap pipeline access, southern prices would likely have been higher (section 4.10.4).

Figure 4.18
North–south gas price divide



Note: The southern market is the average of NSW, Adelaide and Victorian spot prices. The northern market is the average of Brisbane and Wallumbilla spot prices. The Wallumbilla price used for calculation is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub.

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

states were averaging prices of around $7–8 per GJ. This downward trend continued into 2020, with average prices at their lowest quarterly levels since the first quarter of 2016 in all markets.

In the first quarter of 2020, the northern markets experienced a number of trades less than $4 per GJ. In the week starting 23 February 2020, the Wallumbilla hub had the lowest weekly average price, and the lowest priced individual trade since the south east Queensland trade location was introduced in March 2017.[88]

In that same quarter, the southern markets also experienced falls in spot prices, with all southern markets seeing trades for less than $5 per GJ. Compared with the same quarter in 2019, the prices in these markets fell by around 40 per cent on average. Notably, prices in all downstream markets except Adelaide have been lower than the equivalent price for on-screen, day-ahead products at the Wallumbilla hub since the last quarter of 2019. This situation highlights a reduction in the price difference between northern and southern markets (box 4.4).

More broadly, these significant reductions in spot prices will ease pressures on C&I customers that previously high prices affected (section 4.10.2).

88 AER, *Gas weekly report, 23–29 February 2020*, March 2020.

4.12 Market responses to supply risk

Market responses to concerns about a shortage of domestic gas in coming years are being explored, including further gas development, LNG imports, transmission pipeline solutions, and demand response.

4.12.1 Gas field development

Exploration and development in a number of gas fields have increased since international oil and gas prices began to rise in 2017. Additionally, domestic gas prices and government funding improved the economics of some resources and projects. Governments across jurisdictions are offering financial or regulatory incentives for projects that target gas supplies to the domestic market (section 4.13).

The Australian Government's Gas Acceleration Program (GAP), the South Australian Government's Plan for Accelerating Exploration grant programs, and Queensland's 'domestic only' exploration tenement release are among the schemes being implemented.

Many efforts to increase gas supply focus on unconventional projects, which often face community opposition due to environmental concerns. Legislative moratoriums on onshore exploration and fracking have impeded the development of gas projects in Victoria, South Australia and Tasmania (section 4.10.1). Elsewhere, stringent regulatory processes apply, as highlighted by the stalled process for Santos's Narrabri gas project in NSW. Against this trend, the Northern Territory in April 2018 lifted its moratorium on fracking in 51 per cent of the jurisdiction.

Despite the various moratoriums and constraints in place, and sharply lower international oil prices in 2020, a number of projects are progressing that could bring additional supply to the domestic market:

- In Victoria, Cooper Energy's Sole gas field in the Gippsland Basin commenced operation in late March 2020. The gas is processed at the Orbost plant, which can produce up to 68 TJ per day after recommissioning upgrades. By late March 2020 the plant was producing at about 25 per cent capacity (17 TJ).[89] After developing Sole, Cooper Energy plans to develop its Manta gas field.
- In the Otway Basin, Beach Energy delivered its first gas in February 2020 from its Haselgrove-3 project.[90] Gas from the project, which has a capacity of 10 TJ per day, feeds into the new Katnook gas processing facility (South Australia), which the GAP scheme partly funded.
- In NSW, Santos proposed to develop 850 wells across its 95 000 hectare Narrabri gas project, which has potential to supply up to 200 TJ per day.[91] Environmental and community groups opposed the project's environmental impact. Over 23 000 submissions were made in response to the environmental impact statement, mostly in opposition.[92] The project has faced various regulatory delays. In March 2020 the NSW Government referred the project to the Independent Planning Commission to determine whether it can proceed.[93]
- In Queensland, the Kincora project (Armour Energy) began processing gas from surrounding wells in December 2017.[94] Armour Energy expanded its activity in the region after receiving a $6 million grant under the GAP scheme in March 2018. Kincora also won a Queensland Government 'domestic only' tenement release for gas exploration, based on a commitment to supply gas to the domestic market (section 4.13.5).[95] Kincora produced at an average rate of 7.5 TJ per day in the fourth quarter of 2019. Armour Energy targeted output of 20 TJ per day by the end of 2020, but production growth has been restricted.[96]
- Other Queensland projects participating in the GAP scheme include Westside's Greater Meridian project, in the Bowen Basin, and Tri-Star Fairfield's development of four new wells west of Rolleston.
- Also in Queensland, Santos and its partners launched its Roma East project in September 2019, producing around 119 TJ per day.[97] The partners invested a further $400 million in the Arcadia gas project, which launched in the third quarter of 2019 and was producing 15 TJ per day by the end of 2019.[98]

89 AER, *Gas weekly report, 22–28 March 2020*, April 2020, p. 1.
90 EnergyQuest, *Energy quarterly*, March 2020, p. 105.
91 Santos, 'Narrabri Gas Project', web page, available at: www.narrabrigasproject.com.au/ask-us-categories/the-project/.
92 Department of Planning and Environment (NSW), 'NSW Government assessment of the Narrabri Gas Project proposal update', Media release, 23 April 2018.
93 Santos, 'Narrabri Gas Project referred to Independent Planning Commission for public hearings and determination', Media release, 12 March 2020.
94 Armour Energy, 'Kincora Gas Project', web page, available at: www.armourenergy.com.au/kincora-gas-project.
95 Armour Energy, 'Kincora Gas Project', web page, available at: www.armourenergy.com.au/kincora-gas-project.
96 EnergyQuest, *Energy quarterly*, March 2020, p. 108.
97 EnergyQuest, *Energy quarterly*, December 2019, p. 114.
98 EnergyQuest, *Energy quarterly*, March 2020, p. 116.

- In June 2018 Senex and Jemena entered a partnership to bring gas from Senex's Project Atlas in the Surat Basin to the domestic market.[99] This facility and pipeline began operating in late 2019, and is dedicated to supplying domestic customers only, as part of a Queensland Government initiative to boost supply to local industrial customers. The project can deliver up to 48 TJ per day to the Wallumbilla hub.[100]
- In South Australia, Strike Energy is continuing work on its Southern Cooper gas project, which, if successful, would be the deepest CSG well drilled in Australia.[101] Strike Energy undertook pilot operations across 2019 and expects to confirm by mid-2020 whether commercial gas rates can be achieved.[102]

The impact of lower international oil prices and the COVID-19 pandemic on the domestic market is yet to be fully realised, but could delay some projects (section 4.10.2). In March 2020 Santos announced a 38 per cent reduction in 2020 capital expenditure as a result of COVID-19 and other factors.[103] Similarly, in April 2020 Origin Energy announced a pause in exploration activities in the Beetaloo Basin as a result of changing conditions.[104] It also provided guidance that APLNG development and exploration activity would reduce for the same reason, but without materially impacting production.

More broadly, the number of new gas wells drilled in Queensland—a key indicator of the production outlook for CSG producers—declined by around 30 per cent from the fourth quarter 2019 to the first quarter 2020.[105]

4.12.2 LNG import terminals

While conditions eased in the east coast gas market in 2019, considerable uncertainty remains. To address these concerns, the industry is considering at least four projects to develop LNG import facilities on the east coast (section 4.8). Each project would involve importing LNG through floating storage and regasification units.

4.12.3 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in January 2019. Jemena is evaluating a 1000 kilometre extension to supply Ergon Energy's gas powered Barcaldine power station. It also announced plans for an eight-fold increase in the pipeline's capacity, following the Northern Territory Government's decision to lift a moratorium on hydraulic fracking in 2018.[106] At April 2020 three shippers used the pipeline: Incitec Pivot, Santos and the Northern Territory's Power and Water Corporation. Since its commissioning, pipeline flows have steadily increased. In the fourth quarter of 2019, pipeline deliveries to eastern markets averaged around 72 TJ per day.[107]

4.12.4 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 are becoming direct market participants by engaging in collective bargaining agreements. As an example, in November 2017 the ACCC granted authorisation to the Eastern Energy Buyers Group of agribusinesses to establish a joint energy purchasing group to run gas and electricity supply tenders for 11 years. The arrangement allows the group to access wholesale markets at better prices than would be possible if the agribusinesses acted individually.[108]

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, participating in short term trading markets, and investing in new LNG import facilities.[109] Further, some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments. The ACCC reported one C&I user citing high gas prices as a major factor in delaying a $15 million expansion.[110]

Joint ventures between gas customers and producers are also occurring.[111] Incitec Pivot, with Central Petroleum, won a tender for a CSG tenement release by the Queensland Government, and aims to be producing by 2022.[112]

99 Senex Energy, 'Senex and Jemena fast-track Project Atlas gas to domestic market', Media release, 18 June 2018.
100 Senex Energy, 'Project Atlas', web page, available at: www.senexenergy.com.au/operations/surat-basin-gas/project-atlas/.
101 EnergyQuest, *Energy quarterly*, March 2018.
102 Strike Energy, *Half year financial report*, ASX announcement, 14 February 2020.
103 'Santos, COVID-19 response and business update', Media release, 23 March 2020.
104 Origin Energy, 'Operational and financial update', Media release, 6 April 2020.
105 AER, *Wholesale markets quarterly—Q1 2020*, May 2020, p. 53.

106 AEMO, *2018 gas statement of opportunities*, June 2018.
107 AER, *Wholesale markets quarterly—Q4 2019*, February 2020, p. 38.
108 ACCC, *The Eastern Energy Buyers Group—Authorisations—A91594 & A91595*, August 2017.
109 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018, pp. 62–6.
110 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* 18 February 2020, p. 75.
111 AEMO, *2018 gas statement of opportunities*, June 2018.
112 EnergyQuest, *Energy quarterly*, March 2020, p. 108.

In addition, some C&I users are considering alternatives to gas. Incitec Pivot, for example, is investigating the use of renewable energy instead of natural gas for expanding future ammonia production. Similarly, Australian Paper is developing a waste-to-energy plant, which could reduce its gas use by 4 PJ per year.[113]

4.13 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 governments have intervened in the market. The interventions are noted throughout this chapter, and summarised here.

4.13.1 Australian Domestic Gas Security Mechanism

The Australian Government in 2017 threatened to direct gas producers to increase gas supplies to the local market. The Australian Domestic Gas Security Mechanism, which took effect on 1 July 2017, empowers the Energy Minister to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[114] The Minister may determine in the preceding September whether a shortfall is likely in the following year, and may revoke export licenses if necessary to preserve domestic supply.

To avoid export controls, Queensland's LNG producers entered a Heads of Agreement with the government in October 2017, and a second agreement in September 2018. Under the agreements, they committed to offer uncontracted gas on reasonable terms to meet expected supply shortfalls. They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market. To meet their commitments, the LNG projects adopted a range of strategies to offer more gas domestically (section 4.10.1).

The AEMC reported some stakeholders were concerned that government intervention, while it may increase liquidity in the short term, does not correct participants' lack of confidence that they can source gas where they need it at a reasonable price. Concerns were also raised that intervention may reduce investment certainty and weaken liquidity in the long term.[115]

The Department of Industry, Innovation and Science in 2019 found the scheme had worked effectively to safeguard domestic gas supplies, and recommended retaining the scheme until 2023.[116] It also recommended a scheme amendment to reference the ACCC's LNG netback price.

4.13.2 Gas supply guarantee

In March 2017 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.[117] The guarantee identified new processes to assess and resolve potential gas supply shortfalls ahead of time.

While the guarantee has not been used, and was due to expire in March 2020, the Australian Government announced in that month that it would extend the guarantee to March 2023.[118]

4.13.3 National Gas Reservation Scheme

The Australian Government announced it would consult in 2020 on options for a National Gas Reservation Scheme.[119] It expects to reach a final decision by February 2021.[120]

4.13.4 Gas Acceleration Program

To encourage gas supply, the Australian Government in 2017 launched the $26 million GAP, offering grants of up to $6 million for projects that increase domestic gas flows in the eastern market by 30 June 2020. Four of the five successful projects are based in Queensland, including Armour Energy's Kincora expansion, Westside's Greater Meridian project, Tri-Star Fairfield's gas project, and

113 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* February 2020, p. 74.
114 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.

115 AEMC, *Final report: biennial review into liquidity in wholesale gas and pipeline trading markets*, August 2018, p. 46.
116 Department of Industry, Science, Energy and Resources, *Australian Domestic Gas Security Mechanism review*, January 2020.
117 AEMO, 'Gas supply guarantee', web page, available at: https://aemo.com.au/en/energy-systems/electricity/emergency-management/gas-supply-guarantee.
118 AEMO, *Gas supply guarantee guidelines consultation final determination*, March 2020.
119 Ministers for the Department of Industry, Science, Energy and Resources (Australian Government), 'Review finds gas policy boosts domestic supply and helps lower prices', Media release, 24 January 2020.
120 The Hon. Josh Frydenberg MP, and the Hon. Angus Taylor MO (Australian Government), 'Government acts to deliver affordable, reliable gas', Media release, 6 August 2019.

Australian Gasfields' refurbishment of the Eromang and Gilmore processing facilities. The fifth project is Beach Energy's new Katnook gas processing facility in the Otway Basin.[121] These projects are expected to deliver an additional 12 PJ by 30 June 2020, and an extra 28 PJ over five years.[122]

The Australian Government also allocated $8.4 million to support feasibility studies of exploration and development in the Beetaloo Basin. This funding would support bringing additional supply from the Northern Territory to the eastern markets.[123]

4.13.5 State government schemes

To encourage gas exploration, the Queensland Government offers grants for 'domestic only' exploration tenements. As part of this grants program, it released almost 40 000 square kilometres of land for exploration between 2015 and 2018, of which 20 per cent was reserved for domestic supply. The Queensland Government released a further 30 000 square kilometres of land in November 2019, with over 30 per cent tagged for domestic supply.[124]

In January 2020 the NSW Government committed—through a memorandum of understanding with the Australian Government—to bring 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.[125] Projects that could support the commitment include Santos's Narrabri gas project, a new transmission pipeline to Queensland, and an LNG import terminal.

The South Australian Government offered grants to increase gas supplies in the state and increase competition among suppliers. In 2017 it awarded nine grants for projects in the Cooper and Otway basins, including the drilling of four exploration wells.[126] The government also released over 13 000 square kilometres of land for exploration. The grants scheme has now wound up.

121 Department of Industry, Innovation and Science, 'Gas Acceleration Program successful applicants', web page, available at: www.business.gov.au/Grants-and-Programs/Gas-Acceleration-Program/Successful-applicants, viewed 19 October 2018.
122 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 24–5.
123 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 24–5.
124 Minister for Natural Resources, Mines and Energy (Queensland), 'Queensland turns up the gas dial', Media release, 30 October 2019.
125 Government of NSW, *Memorandum of understanding—NSW energy package,* 31 January 2020.
126 Government of South Australia, 'PACE gas', web page, available at: www. energymining.sa.gov.au/petroleum/latest_updates/pace_gas, viewed 19 February 2020.

4.13.6 ACCC gas inquiry

In April 2018 the Australian Government directed the ACCC to inquire into wholesale gas markets in eastern Australia, using its compulsory information gathering powers. While the inquiry was initially tasked to run until 30 April 2020, the Treasurer extended it in July 2019 to 2025. The ACCC has released several interim reports.[127]

4.13.7 Electrification of LNG production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million for working 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 free up to 12 PJ of gas for delivery to the domestic market.

4.13.8 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 per cent to supplement gas supplies, and a number of trials are being explored. Jemena's Power to Gas Trial, co-funded by the Australian Renewable Energy Agency (ARENA), will generate green hydrogen and inject a small percentage (less than 2 per cent by volume) into part of its gas distribution network.[128]

4.14 Gas market reform

The CoAG Energy Council directs gas market reforms, which regulatory and market bodies implement.[129] 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.[130]

127 ACCC, 'Gas inquiry 2017–2025', web page, available at www.accc.gov.au/ regulated-infrastructure/energy/gas-inquiry-2017-2025.
128 ARENA, 'Jemena power to gas demonstration', web page, available at: https://arena.gov.au/projects/jemena-power-to-gas-demonstration/.
129 Including the Energy Security Board, the AER, the AEMC, AEMO and the ACCC.
130 CoAG Energy Council, *Measures to improve transparency in the gas market—decision regulation impact statement*, March 2020.

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. The AEMC in 2016 assessed that the eastern gas market is opaque, and participants have low levels of confidence in the information that is available. The reforms aim to increase transparency in the gas market, improving the Gas Bulletin Board and improving the availability of information on market liquidity, prices and gas reserves.

4.14.1 Gas Bulletin Board reforms

The Gas Bulletin Board (www.gasbb.com.au) was launched in 2008 to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia. But its usefulness was compromised by gaps in coverage and, at times, the provision of inaccurate data.

Significant reforms in September 2018 brought the Bulletin Board closer to being a 'one stop shop' for the eastern gas system. The reforms removed reporting exemptions, mandated the provision of more comprehensive detail for covered facilities, and extended reporting obligations to smaller facilities and those in Northern Territory. The reporting threshold for transmission pipelines, production facilities and storage facilities was lowered from 20 TJ per day to 10 TJ per day.

Additionally, more comprehensive reporting was mandated for production facilities. Market participants can now access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations, and capacity outlooks. This reporting 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 include information on flows at key supply and demand locations along pipelines. Reporting obligations were also extended to regional pipelines and facilities attached to distribution pipelines.

To encourage compliance, the reforms made reporting obligations subject to civil penalties. 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 Gas Bulletin Board has integrity. The AER published a guidance note outlining its approach to enforcement.[131]

131 AER, *Guidance note—natural gas services bulletin board (enhanced information reporting)*, September 2018.

Further reforms will likely extend reporting to large gas users and LNG processing facilities from 2021. The reforms will also introduce the reporting of gas reserves and contract prices.

Liquidity information

In August 2018 the AER began publishing (on the industry statistics page of its website) quantitative metrics for assessing the liquidity of gas markets, and it regularly updates these metrics. In addition, the AER commenced reporting quarterly on the performance of the east coast gas markets, from the third quarter of 2019. These *Wholesale market quarterly* reports build on the liquidity statistics, and contain more detailed analysis of key performance indicators across the markets. Across 2019 these indicators showed signs of improvement.

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. Yet, the market lacks a single indicative price for gas, and lacks consistent gas reserve and resource information. The ACCC moved to address these issues in late 2018 when it began publishing new data on LNG netback prices.[132] The aim is for the data to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts.

Public information on gas reserves and resources in Australia also tends to lack clarity, consistency and accuracy. As such, market participants are less able to identify future supply issues and plan accordingly. For this reason, in late 2018 the ACCC began publishing data on gas reserves and resources, drawing on information provided by reserve owners.

4.14.2 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.

132 ACCC, 'Gas inquiry 2017–2020—LNG netback price series', web page, available at: www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series.

Three major pipelines—the South West Queensland Pipeline, the Moomba to Adelaide Pipeline System, and the Moomba to Sydney Pipeline—were close to fully contracted in 2018, limiting shippers' ability to transport gas between northern and southern markets.[133]

To manage pipeline congestion issues, some gas producers engage in swap agreements. They bypass the need for transportation arrangements with pipeline operators by 'swapping' rights to gas held in different physical locations. The ACCC found, however, such agreements are complicated, involve extensive negotiations and, by necessity, reveal parties' commercial positions to their competitors. Such agreements are unlikely, therefore, to be an effective long term solution to gas pipeline issues.[134]

Secondary trading in underused capacity

Congestion issues focused policy attention on ensuring any spare physical pipeline capacity is made available to the market. Reforms to launch a voluntary trading platform and a secondary compulsory auction of underused capacity took effect in March 2019. Since its commencement, the day-ahead auction in particular has had a positive impact on the east coast gas markets (section 4.10.4)

To promote transparency, the Gas Bulletin Board publishes prices and other key terms in all voluntary trades, as well as the day-ahead auction results. The AER monitors compliance with capacity trading regulations and the proper reporting of trades.

Information disclosure and arbitration

Negotiating a fair price to use a gas pipeline is an ongoing issue, with a number of reviews raising concerns about monopolistic pricing practices.[135] The reviews highlighted a lack of transparency and unequal bargaining power between shippers and pipeline operators.

These concerns led to the introduction of Part 23 in the National Gas Rules in August 2017. Part 23 requires otherwise unregulated pipeline businesses to disclose financial, service and access information, following guidelines published by the AER. Customers can use the disclosed information to negotiate gas transport contracts with pipeline operators. If agreement cannot be reached, an access seeker may apply for arbitration. Chapter 5 details the Part 23 regime.

133 ACCC, *Gas inquiry 2017–2020, Interim report, December 2017*, December 2017, p. 59.
134 ACCC, *Gas inquiry 2017–2020, Interim report, December 2017*, December 2017.
135 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 99–106; CoAG Energy Council, *Examination of the current test for the regulation of gas pipelines*, December 2016.

Scope of pipeline regulation

In July 2018 the AEMC reviewed the effectiveness of current gas pipeline regulation. Various tiers of pipeline regulation apply, including full regulation, light regulation, 15 year exemptions, Part 23 regulation and Part 23 exemptions.[136] The review recommended removing a number of inconsistencies across these tiers by:

- requiring 'light regulation' pipelines to publish prices for each pipeline service, and to report financial information similar to that required of Part 23 pipelines
- requiring the AER set an initial capital valuation for light regulation pipelines, to help users negotiate access to pipeline services. The AER currently undertakes this role only for 'full regulation' pipelines.
- extending the Gas Bulletin Board reporting obligations to all full and light regulation transmission pipelines, and requiring these pipelines to report a 36 month outlook for uncontracted capacity
- requiring full and light regulation distribution pipelines to report capacity and use information similar to that which other distribution pipelines are required to report
- including all pipeline expansions within the regulatory framework of the existing pipeline, rather than them being subject to separate arrangements
- widening the scope of pricing information to cover services, including bi-directional flow, and park and hold services.[137]

The CoAG Energy Council in late 2019 released a regulatory impact statement as part of consultation on options for delivering a more efficient, effective and integrated framework for regulating gas pipelines. A final decision is expected by mid-2020.

4.14.3 Gas day harmonisation

On 1 October 2019 the gas day start time for each market was standardised to 6.00 am. From their commencement, the different gas markets in the east coast operated with different start times, as a result of historical pipeline arrangements. This difference resulted in unnecessary costs and complexities for participants that operate over multiple locations. Harmonising the gas day start times will reduce these complexities, provide for more interconnection, and help the development of standardised market reforms.

136 Chapter 5 outlines the tiers of gas pipeline regulation.
137 AEMC, *Review into the scope of economic regulation applied to covered pipelines*, July 2018.