Image courtesy of Cooper Energy

4 GAS MARKETS IN EASTERN AUSTRALIA

Gas is a fossil fuel consisting mainly of methane, a naturally occurring hydrocarbon made up of one carbon atom and four hydrogen atoms. Gas 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 of this report). It begins with the exploration and appraisal of potential reserves for commercial viability. Gas discoveries are extracted through wells as 'wet gas', which is 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, over 60 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 drawn on to augment supply at peak times.

Gas sold to domestic customers is transported from production fields to major demand centres or hubs via high pressure *transmission pipelines*. 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. Applying 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 'upstream' gas markets in which the Australian Energy Regulator (AER) has regulatory responsibilities (illustrated in figure 4.1). The upstream sector encompasses gas production, wholesale markets for trading gas and Insert the transport of gas along transmission pipelines to demand hubs.

The chapter's principal focus is on the eastern gas market, encompassing 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 in south east Queensland, north east South Australia, and offshore basins in Victoria.

The AER's regulatory responsibilities in the eastern gas market relate to wholesale market monitoring and enforcement, and gas pipeline regulation. It also has responsibilities in the downstream sector, both in gas distribution (chapter 5) and gas retailing (chapter 1).

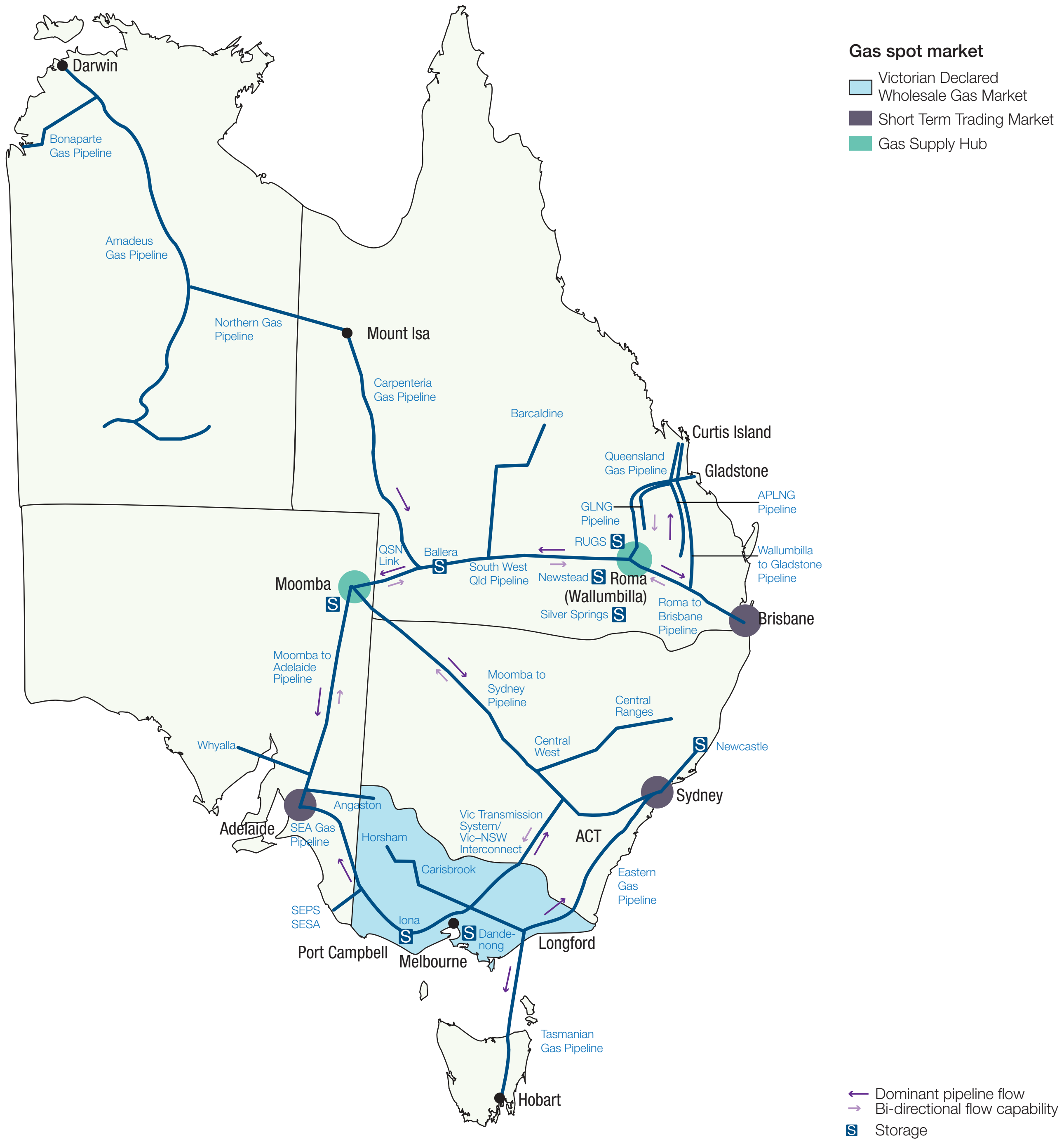
Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory, but plays no role in the territory's wholesale market. The AER has no regulatory function in Western Australia, where a separate regime applies.[2] The AER's role in gas markets is summarised in box 4.1.

Gas production in eastern Australia began around 50 years ago. The main production basins are the Surat–Bowen Basin in Queensland, the Cooper Basin in South Australia and three basins off coastal Victoria, the largest of which is the Gippsland Basin. 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, because the rapid responsiveness of gas powered turbines make them suitable for peak electricity generation capacity and combined cycle intermediate load generation. Gas powered generation also plays an important role in managing fluctuations in intermittent wind and solar generation. More recently, gas has become a major export industry in eastern Australia, with the launch in 2015 of major LNG projects.

2 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 4.1
Eastern gas markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

CHAPTER 4 GAS MARKETS IN EASTERN AUSTRALIA

Box 4.1 The AER's role in gas markets

The Australian Energy Regulator 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, 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. Our focus areas include data quality and market behaviour, and the readiness of market participants to comply with reforms occurring in the market. In 2018 we launched a more stringent compliance framework for the Bulletin Board to ensure the integrity of the information it provides. We also began administering new civil penalty provisions relating to breaches.

We draw on our market monitoring capabilities to regularly report on gas market activity. In 2018 we began publishing data on prices and liquidity in spot gas markets, which we update regularly. We also monitor the markets for particular irregularities and wider inefficiencies. Our monitoring role at the Wallumbilla and Moomba hubs includes an explicit focus on detecting price manipulation.

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

From 2019 we will monitor and enforce compliance with reforms to improve access to underused capacity in transmission pipeline, including bilateral trading and mandatory auctioning of contracted capacity that is not in use.

In the downstream gas industry, we set 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, NSW, Queensland, South Australia and the ACT (chapter 1).

Across the gas sector, we draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. Where appropriate, we propose or participate in reforms to improve the market's operation. Our current work in this area includes providing resources to the Australian Competition and Consumer Commission's 2017–20 gas inquiry.

a. The different tiers of pipeline regulation are outlined in chapter 5.

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 pipeline investment has interconnected these markets, making it possible to transport gas from Queensland to the southern states, and (since key pipelines became bi-directional) vice versa. This interconnected network further expanded with the opening in December 2018 of the 622 kilometre (km) Northern Gas Pipeline linking Tennant Creek in the Northern Territory with Mount Isa in Queensland. For the first time, the new pipeline allows the eastern gas market to source gas from the Bonaparte Basin in the Timor Sea (located between the Northern Territory and East Timor).

The development of Queensland's LNG industry transformed the eastern Australian gas markets, giving producers choice between exporting their 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 following the closure of several coal fired generators in 2016 and 2017.

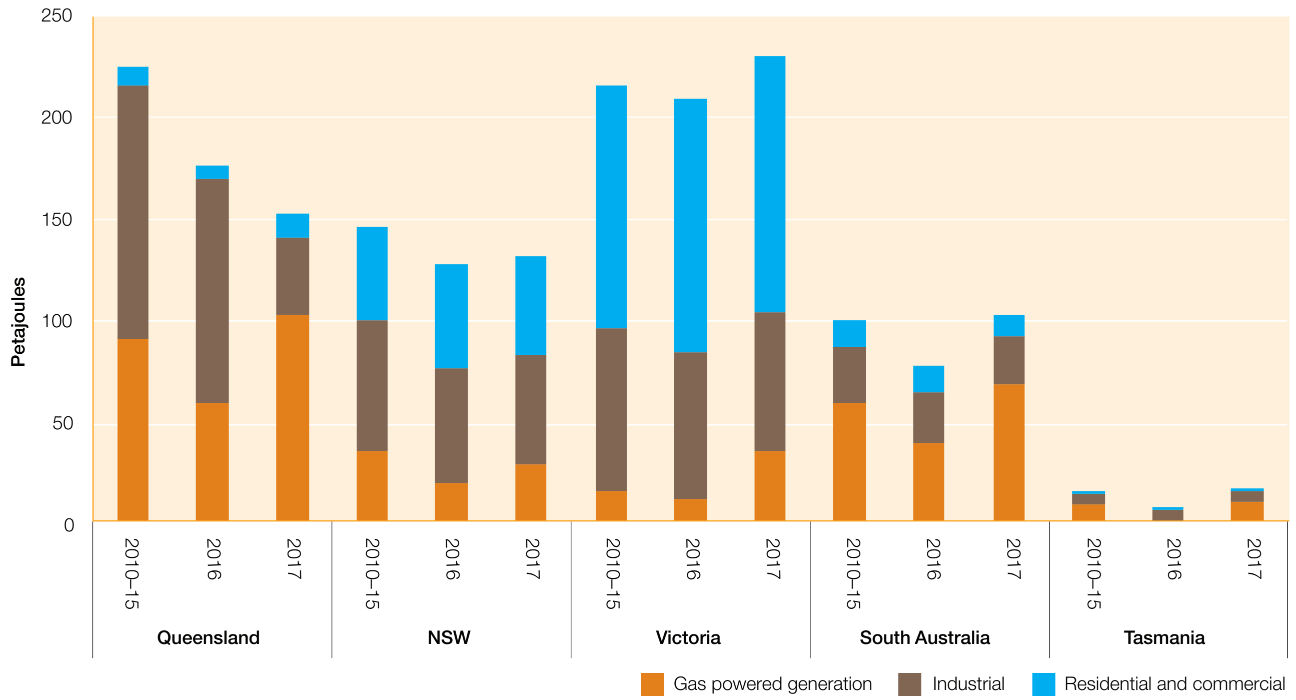
4.2 Gas demand in eastern Australia

Domestic customers in eastern Australia used around 630 petajoules (PJ) of gas in 2017. These customers included commercial and industrial (C&I) businesses, electricity generators and households. C&I customers are the biggest users, consuming 41 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.

The electricity sector is another major customer, using gas to fuel generators. Gas powered generation accounted for 29 per cent of domestic gas sales in 2017. The remaining 30 per cent was sold to residential and commercial customers, for purposes such as heating and cooking.[3]

Reliance on gas is highest in South Australia, where it accounts for 41 per cent of primary energy consumption, followed by Queensland and Victoria (20 per cent in each). Gas reliance is lower in NSW, where it accounts for 10 per cent of energy consumption.[4] South Australia's high degree of reliance on gas reflects its dependence on gas powered generation, which has risen since the closure of major coal fired generators.

Figure 4.2
Gas consumption in eastern Australia



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

Source: AEMO, *National gas forecasting report*, 2016; AEMO, *2018 Gas Statement of Opportunities*, June 2018.

The composition of domestic gas consumption differs across jurisdictions (figure 4.2). In South Australia, electricity generation accounted for 66 per cent of gas demand in 2017. Industrial demand dominates in Queensland, while industrial and residential demand are roughly equal as the main components in NSW.[5]

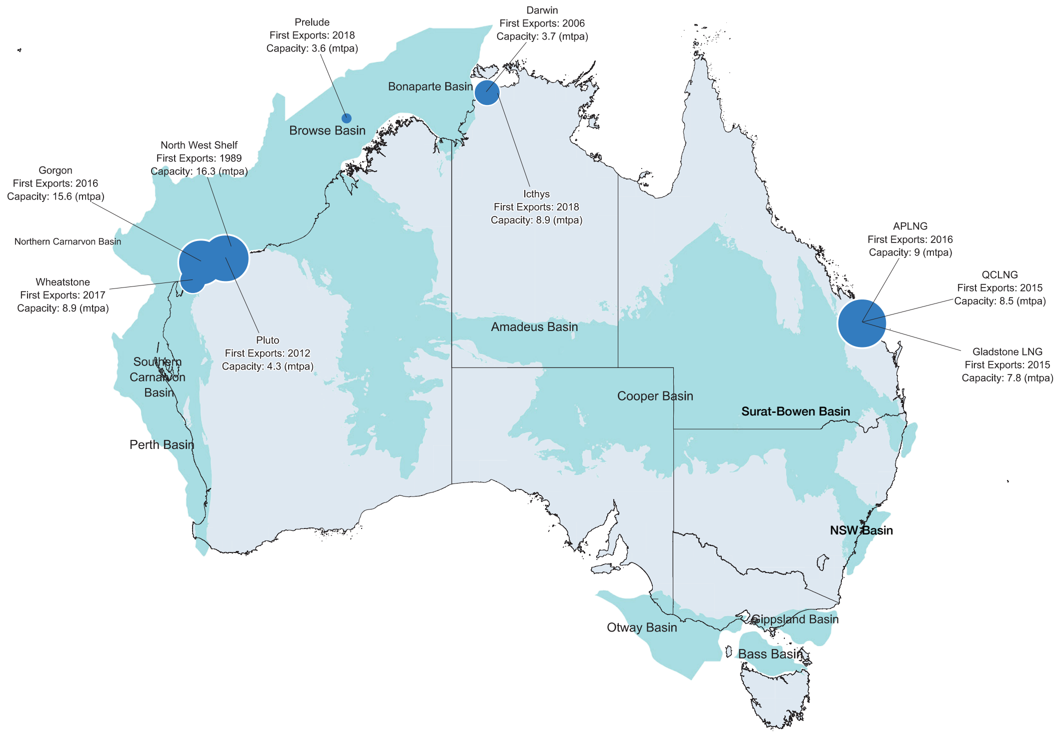
Victoria is the only state where a majority of demand (55 per cent) is from small residential and commercial customers, who use gas mostly for heating and cooking. Over 80 per cent of Victorian households are connected to a gas network.[6] Around 35 000 new residential gas connections were made in Victoria each year from 2014–18, in part due to new housing developments as the state's population grows.[7] Residential gas penetration is around 80 per cent in the ACT, 60 per cent in South Australia, 45 per cent in NSW, 10 per cent in Queensland and 6 per cent in Tasmania.[8]

Domestic gas demand (and its composition) is shifting over time. Total consumption has declined since 2014, mainly

3 AEMO, *2018 Gas Statement of Opportunities*, June 2018. Calendar year data for 2017.
4 Department of the Environment and Energy, *Australian Energy Statistics 2016–17*, Table C.
5 AEMO, *2018 Gas Statement of Opportunities*, June 2018, p. 15
6 AEMO, *National Gas Forecasting Report—2016*.
7 AEMO, *Winter 2018—Victorian Gas Operations outlook*, 8 May 2018.
8 AEMO, *National Gas Forecasting Report,* December 2016.

Figure 4.3

Australia's LNG export projects



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

Source: AER.

because competition for gas supplies by the LNG industry drove up fuel prices for gas powered generators, making it less economical to run that plant. Higher gas prices also reduced industrial consumption. The closure of coal fired generators in South Australia and Victoria led to a recovery in consumption by gas powered generators in those regions in 2017 (section 4.9.1).

4.3 Liquefied natural gas exports

Eastern Australian gas producers exported 1145 PJ of gas in 2017–18, compared to 740 PJ of sales to domestic customers (table 4.1).

Gas exports are converted to LNG for efficient shipping. LNG is produced by cooling gas and condensing it to a liquid so it to make it easier to store and transport. The gas is chilled to –162 deg Celsius, which shrinks volume by 600 times and makes it economic to ship gas in large quantities.

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. Most Australian LNG is shipped to Asia, where it is stored, regasified and injected into local gas pipeline networks.

Alongside Queensland's LNG industry, Australia operates five LNG projects in Western Australia, and two in the Northern Territory (figure 4.3). More than $230 billion has been invested in the industry over the past decade[9], and in 2018 Australia was the world's second largest LNG exporter.[10] Prices and revenue in the industry surged during 2018 due to rising oil prices and strong Chinese demand. In 2017–18 LNG exports earned Australia $31 billion, making gas Australia's third largest resource and energy export, behind coal and iron ore.[11]

9 COAG Energy Council, *Gas Market Reform Package—Bulletin Two*, August 2016.

4.3.1 Queensland LNG industry

As noted above, Queensland's LNG industry has transformed the eastern Australian gas market. The industry is based around three major projects at Gladstone, which liquefy and purify gas shipped along gas transmission pipelines from where it is extracted in the Surat–Bowen Basin. The projects—the world's first to convert CSG to LNG—were made possible by the basin's vast CSG reserves. The industry's scale is enormous, even by global standards.

The *Queensland Curtis LNG (QCLNG) project* began exporting LNG in January 2015, and launched a second train (liquefaction and purification facility) in July 2015. Shell is the principal owner (73.75 per cent through its ownership stake in BG Group). China National Offshore Oil Corporation (CNOOC) owns 25 per cent of the project and Tokyo Gas a 1.25 per cent interest. The project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). In December 2017 QCLNG contracted with Arrow—a joint venture between PetroChina and Shell—to buy the majority of gas produced from Arrow's substantial reserves.[12] In 2018 it contracted to use APLNG's pipeline network to transports this gas to market.[13]

The *Gladstone LNG (GLNG) project* commissioned its first train in October 2015, and a second in May 2016. Santos (30 per cent), Petronas and Total (27.5 per cent each), and Kogas (15 per cent) own the project. The ramp-up to full production was slower than expected, with the project initially relying on third party gas for 50 per cent of its plant feedstock. By 2018 this ratio had fallen to around 30 per cent.[14] The project has capacity to produce 7.8 mtpa. In May 2018 GLNG committed to invest more than $400 million in the Arcadia gas project in the Bowen Basin to supply additional gas to its LNG plant.[15]

The *Australia Pacific LNG (APLNG) project* began exporting gas in January 2016. Origin Energy and ConocoPhillips (37.5 per cent each), and Sinopec (25 per cent) own the APLNG project, which has capacity to produce 9 mtpa.[16] The project's second train began operating in October 2016, although operation testing delayed formal commissioning until 2017. APLNG's financial obligations required it to demonstrate its LNG trains could run at maximum output for an extended time without technical difficulties.

4.3.2 Northern Territory LNG industry

The Northern Territory's LNG industry began in 2006 with the commissioning of Darwin LNG, which relies on gas feedstock from the Bonaparte Basin in the Timor Sea. A second project—Ichthys LNG—launched in 2018. The project transports gas by undersea pipeline from the North West Shelf off Western Australia to onshore processing facilities near Darwin. Ichthys LNG's onshore facilities include two LNG trains. After repeated delays installing its offshore facility (including due to bad weather conditions), gas production from the project's offshore wells began in July 2018.[17]

4.3.3 Western Australia LNG industry

Western Australia has five LNG projects. 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.

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 (2018). Prelude expects to begin exporting in late 2018.

4.4 Gas reserves

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

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

10 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, March 2018

11 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, September 2018, p. 51.

12 Arrow Energy, *Surat Gas Project*, www.arrowenergy.com.au/Operations/Arrow-in-the-Surat-Basin/surat-gas-project.

13 APLNG, *Australia Pacific LNG to share infrastructure and secure additional gas supply to diversify portfolio*, 5 November 2018.

14 EnergyQuest, *Energy Quarterly, September 2018*, p. 14.

15 Australian Financial Review, *Santos commits to $400m Arcadia gas project to bolster GLNG* supplies, May 2018.

16 APPEA, *Australian LNG* projects.

17 EnergyQuest, *Energy Quarterly,* September 2018, p. 103.

- *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 sure 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*—those considered potentially recoverable from known accumulations, but for other reasons are not yet technically or commercially recoverable.

This probabilistic approach to measuring gas reserves results in frequent, and sometimes substantial, adjustments. Eastern Australia's 2P reserves, for example, were written down by around 2000 PJ between June 2017 and June 2018, mostly attributable to large write downs in Arrow Energy's reserves in Queensland.[18]

Nor is there clear, consistent and accurate *reporting* of gas reserves in Australia, with data collected through various disconnected mechanisms and bodies. There is little consistency in data standards and aggregation across these sources, and the assumptions underlying the data are often not transparent.[19]

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. EnergyQuest estimated eastern Australia's 2P gas reserves stood at 42 907 PJ in August 2018, but noted this estimate is subject to uncertainty.[20]

The Australian Competition and Consumer Commission (ACCC) is undertaking work to improve transparency in this area, and expects to commence publishing reserves and resources information in December 2018. The Gas Bulletin Board (section 4.8.6) will also begin publishing information on gas reserves in 2019.

18 EnergyQuest, *Energy Quarterly*, September 2018, p. 27.
19 ACCC, *Inquiry into the east coast gas market*, April 2016.
20 EnergyQuest, *Energy Quarterly*, September 2018, p. 12.

4.4.1 Ownership of gas reserves in eastern Australia

Reserve ownership is highly concentrated in some basins, but more diverse across the market as a whole (figure 4.4). Shell (26 per cent) became the largest holder of 2P gas reserves in eastern Australia after acquiring BG Group in 2016 (figure 4.5). Other major reserve holders include ConocoPhillips and Origin Energy (which each hold 11 per cent), and PetroChina (9 per cent).

Falling LNG prices and declining share prices for LNG participants from 2015 prompted a number of takeover bids, including Shell acquiring BG Group. Santos rejected a takeover bid by private equity fund Sceptre Partners in October 2015 and another bid by Harbour Energy in May 2018.[21]

In September 2017 Beach Energy purchased Origin Energy's conventional upstream gas business (Lattice Energy), tripling its market share in 2P reserves. In addition, Mitsui completed its takeover of Australian Worldwide Exploration on 2 May 2018, providing Mitsui with an interest in the Bass Basin.

4.4.2 Surat–Bowen Basin

Queensland's Surat–Bowen Basin is the largest basin in eastern Australia, with almost 90 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.

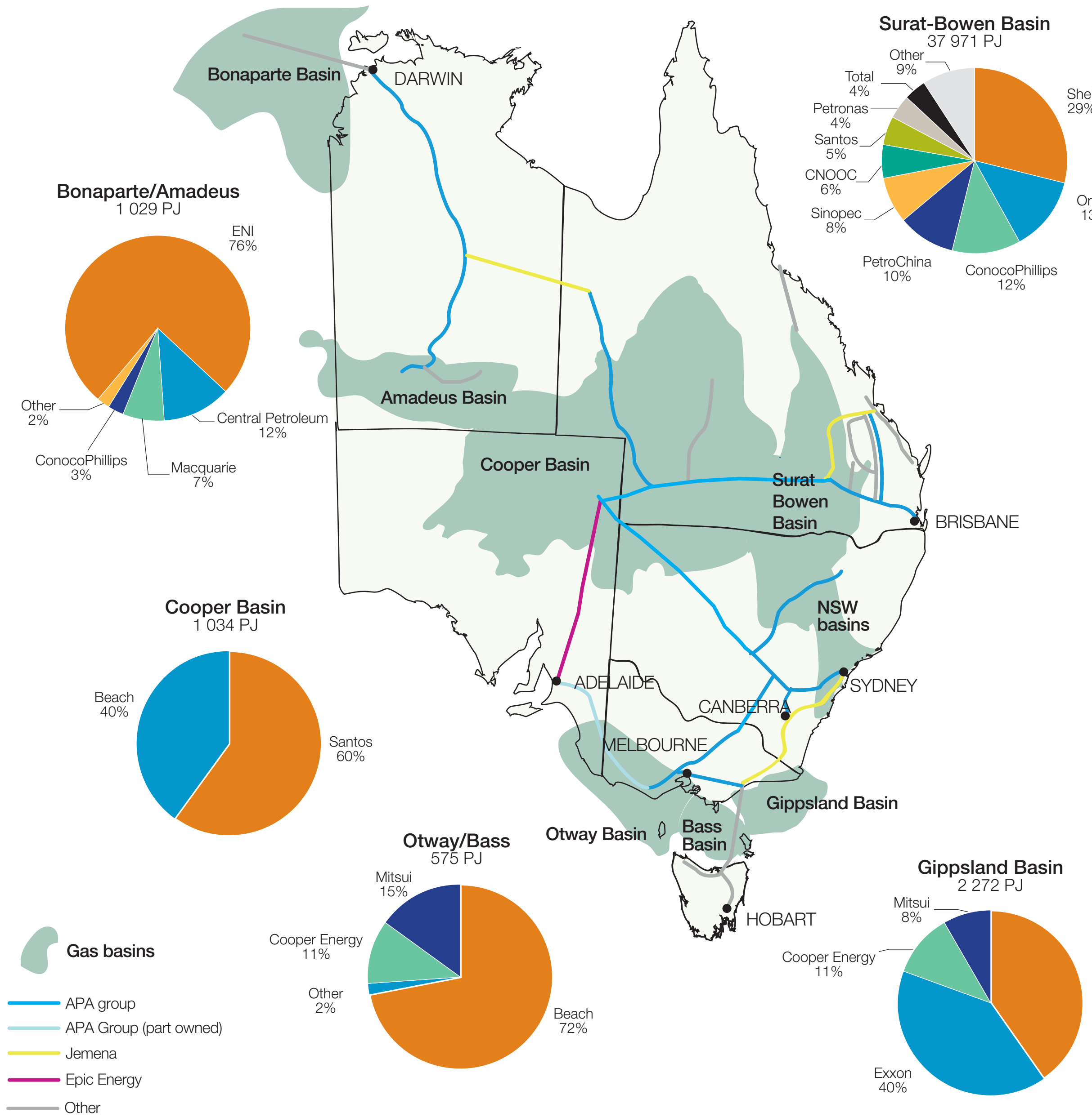
Participants in Queensland's three LNG projects control a majority of reserves in the basin, which are mostly CSG. Shell (29 per cent) is the largest equity holder, followed by Origin (13 per cent), ConocoPhillips (12 per cent), PetroChina (10 per cent), Sinopec (8 per cent), CNOOC (6 per cent), Santos (5 per cent), Petronas (4 per cent) and Total (4 per cent).

4.4.3 The Victorian basins

The Gippsland Basin is the most significant of the three producing basins in Victoria, accounting for 5 per cent of eastern Australian reserves. A joint venture between Esso (ExxonMobil) and BHP controls 80 per cent of reserves in the basin. The principal producers in the smaller Otway Basin and Bass Basin are Beach Energy (72 per cent), Mitsui (15 per cent) and Cooper Energy (11 per cent).

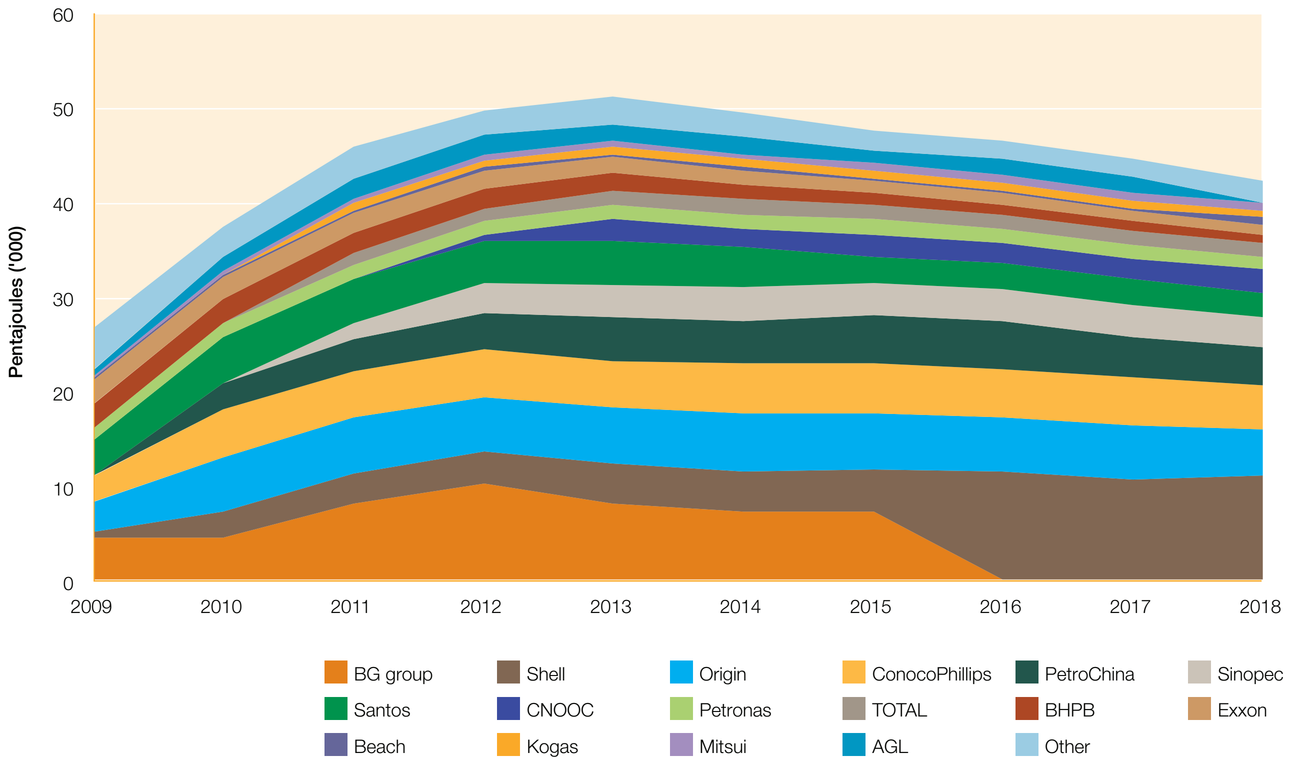
21 Australian Financial Review, *Santos rejects Harbour Energy's $14.4b takeover bid*, 22 May 2018.

Figure 4.4
Eastern gas market—basin and transmission pipeline ownership



Note: Ownership at 30 June 2018. Pie charts illustrate shares in 2P (proven plus probable) gas reserves by basin.
Source: AER; EnergyQuest (data commissioned by AER).

Figure 4.5
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).

Reserves in the Victorian basins are declining. In the year to June 2018, 2P reserves fell by 14 per cent in the Bass Basin and by 12 per cent in the Gippsland Basin, partly offset by a 43 per cent increase in reserves in the Otway Basin.[22] EnergyQuest noted considerable volatility in reserve assessments for Victoria, describing some recent revisions and updates as 'confusing'.[23]

4.4.4 Cooper Basin

The Cooper Basin in central Australia has around 1000 PJ of 2P reserves and almost 6000 PJ of contingent resources. A joint venture led by Santos (66 per cent) and Beach Petroleum (34 per cent) controls most reserves in the basin, which accounts for 2 per cent of eastern Australia's 2P reserves. Other participants in the basin include Senex, Icon Energy, Strike Energy and Real Energy.

Santos entered an agreement in 2010 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 more recently, and rose in the year to June 2018. Almost 75 per cent of contingent resources in the Cooper Basin are from unconventional sources, primarily shale gas. Extracting these resources presents significant technological challenges.

4.4.5 NSW basins

NSW has significant contingent resources (2254 PJ) but less than 30 PJ of 2P reserves, and negligible current production. Santos in 2017 applied to develop reserves near Narrabri in the Gunnedah Basin. The project prompted widespread opposition, with over 20 000 submissions being made during the environmental impact statement process.

22 EnergyQuest, *Energy Quarterly,* September 2018, Table 23. p. 66.
23 EnergyQuest, *Energy Quarterly,* September 2018, Table 23. p. 25.

Table 4.1 Gas basins serving eastern Australia

	GAS PRODUCTION—12 MONTHS TO JUNE 2018			2P GAS RESERVES (AUGUST 2018)	
GAS BASIN	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIAN RESERVES (%)
Surat–Bowen (Qld)	1 368	73	8	37 971	88
Cooper (SA–Qld)	84	4	3	1 034	2
Gippsland (Vic)	291	15	–4	2 272	5
Otway (Vic)	68	4	–21	502	1
Bass (Vic)	18	1	20	73	0
Sydney and Narrabri (NSW)	6	0	9	26	0
Amadeus (NT)	10	1	68	199	0
Bonaparte (NT)	38	2	–1	830	2
Eastern Australia total	1 883		4	42 907	
Domestic gas sales	738		3		
LNG exports	1 145		5		

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

Note: Most production and reserves in the Surat–Bowen and NSW basins are CSG. Production and 2P reserves in other basins are mainly conventional gas.

Source: EnergyQuest, *Energy Quarterly*, September 2018.

4.4.6 Northern Australia

Northern Australia was historically insulated from the eastern gas market, but the commissioning of the Northern Gas Pipeline in 2018 changed this situation by linking gas fields in the Bonaparte Basin (offshore of Darwin in the Timor Sea) with Queensland.

The Amadeus Basin historically met all gas demand in the Northern Territory. The basin has around 200 petajoules of 2P reserves but has been in decline. The offshore Bonaparte Basin was developed to support the Northern Territory's LNG industry, which is based in Darwin. The basin is currently estimated to have over 800 PJ of 2P reserves. Most gas produced in the basin is converted to LNG for export. Eni is the major equity holder in the Northern Territory basins, with 76 per cent of 2P reserves, followed by Central Petroleum (12 per cent), Macquarie (7 per cent), ConocoPhillips (3 per cent).

4.5 Gas production

In the year to June 2018, eastern Australia produced almost 1900 PJ of gas, with a majority (61 per cent) exported as LNG. The remainder was sold to the domestic market (table 4.1).

Queensland's Surat–Bowen Basin supplied 73 per cent of gas produced in eastern Australia in the year to June 2018, including much of the gas earmarked for LNG export. Gas production in the basin has risen exponentially since 2014. Participants in Queensland's three LNG projects produced over 95 per cent of the basin's output in the year to June 2018. As well as supplying their LNG facilities, the LNG participants sell some gas into the domestic market.

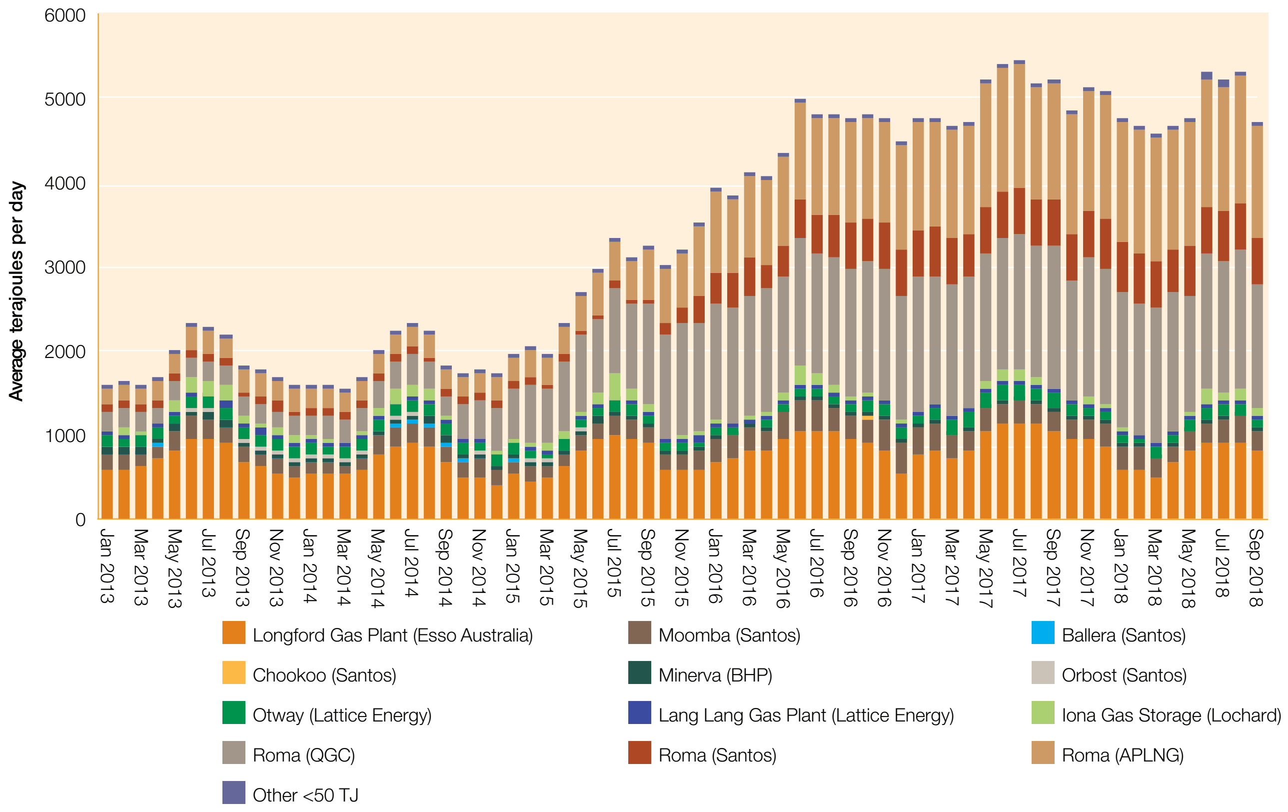
Outside Queensland, the basins off coastal Victoria meet most of the remaining demand in the eastern states. The Gippsland Basin is the most significant of the three producing basins in Victoria, meeting 15 per cent of demand. The smaller Otway and Bass basins jointly supply 5 per cent of the market.

The Longford gas plant, servicing the Gippsland Basin, achieved record production in 2017, some of which was shipped to Queensland for LNG exports (figure 4.6). But production is expected to decline in 2018 and beyond. Despite falling reserves, the Australian Energy Market operator (AEMO) forecast production from the Gippsland Basin to remain stable out to 2022.[24]

The Cooper Basin in central Australia accounts for 4 per cent of eastern Australian gas production. The basin plays an important role as a 'swing' producer in managing seasonal and short term supply imbalances in the domestic gas market.

24 AEMO, *2018 Gas statement of opportunities*, June 2018, p. 11.

Figure 4.6
Eastern Australia gas production



Source: AER; Gas Bulletin Board (data).

With the opening of the Northern Gas Pipeline in December 2018, the Northern Territory's offshore Bonaparte Basin will become a new supplier to the eastern gas market in the near future.

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 meet domestic demand and shortfalls in Queensland production to meet export contracts.

This shift accelerated a depletion of gas reserves in southern basins, leading to concerns in 2017 of an imminent shortfall. 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. Surat–Bowen Basin production in the year to June 2018 rose by 8 per cent, faster than LNG export growth (5.5 per cent). Production also rose in the Cooper Basin. With Queensland production able to meet more of the domestic demand, production in southern basins fell by around 5 per cent over this period.

4.6 Gas storage

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

Eastern Australia's gas storage facilities include:

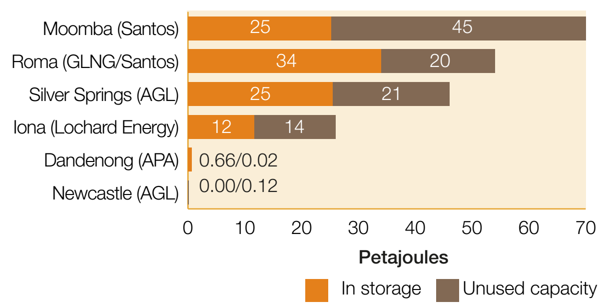
- large facilities using depleted gas fields in Queensland, Victoria and South Australia
- smaller seasonal or peaking storage facilities located near demand centres—for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria
- short term peak storage services on gas pipelines, which are mostly contracted by energy retailers.

The 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 had significantly depleted by 2018, as stocks were run down to meet LNG export demand (figure 4.7).

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 launched an expansion of its Iona capacity, anticipating this storage would help manage future peak demand periods, such as in winter.[25]

Transmission pipelines can also provide gas storage services. The Tasmanian Gas Pipeline in 2017 was offering storage in its pipeline, for example, which could be drawn on for sale into the Victorian market at times of peak demand.

Figure 4.7
Gas storage in eastern Australia



Source: AER; Gas Bulletin Board, 2 December 2018.

4.7 Gas transmission pipelines

Wholesale customers must buy capacity on transmission pipelines to transport their gas purchases from processing plants to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (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 transmission 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 before.

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 (duplicating parts of the pipeline) and extensions.

Since 2010 $1.5 billion has been invested or committed in new transmission pipelines, interconnections, and enhancements to existing pipelines in eastern Australia.[26] Significant investment has occurred to meet the needs of Queensland's LNG industry, including capacity expansions on existing pipelines and constructing new pipelines to ship gas to LNG processing facilities. Additionally, Jemena's Northern Gas Pipeline, completed in 2018, provides eastern Australia's first pipeline interconnection with the Northern Territory, making it possible to ship gas produced in the Northern 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.

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 4.9.4).

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

25 Premier of Victoria, *Securing gas for future winter warmth*, media release, June 2018.

26 APGA, *ACCC report highlights importance of continued pipeline investment*, media release, 13 December 2017.

Table 4.2 **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
South West Queensland Pipeline (Wallumbilla to Qld–SA border)	Qld	755	404 (340 reverse)	Part 23 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%)
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 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%
Berwyndale to Wallumbilla Pipeline	Qld	112	164 (276 reverse)	Part 23 exemption	APA Group
Wallumbilla to Darling Downs Pipeline	Qld	205	270 (530 reverse)	Part 23 exemption	Beach Energy
Comet Ridge to Wallumbilla Pipeline	Qld	127	950 (175 reverse)	Part 23 exemption	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
North Queensland Gas Pipeline (Moranbah to Townsville)	Qld	391	108	Part 23 exemption	Palisade Investment Partners
QSN Link	Qld–SA	182	404 (340 reverse)	Part 23 regulation	APA Group
Moomba to Sydney Pipeline	SA–NSW	2029	489 (120 reverse)	Partial light regulation / partial Part 23 regulation[2]	APA Group
Moomba to Adelaide Pipeline	SA	1184	241 (85 reverse)	Part 23 regulation	QIC Global Infrastructure
Central West Pipeline (Marsden to Dubbo)	NSW	255	10	Light regulation	APA Group
Central Ranges Pipeline (Dubbo to Tamworth)	NSW	294	7	Full regulation	APA Group
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 (150 reverse)	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
APA Victorian Transmission System	Vic	2035	1030	Full regulation	APA Group
South Gippsland Pipeline	Vic	250		Part 23 exemption	DUET Group
Northern 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	1658	120	Full regulation	APA Group

QSN, Queensland to South Australia/New South Wales; TJ/d, 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: Gas Bulletin Board (www.gasbb.com.au); AER; ACCC, Gas Inquiry 2017–2020, interim reports; corporate websites.

routes into Melbourne, Sydney, Brisbane and Darwin. Other major pipeline owners include Jemena and Singapore Power International.

Cheung Kong Infrastructure (CKI) and its associates in 2018 launched 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.[27] On 20 November 2018, following consultation with the Foreign Investment Review Board, the Australian Government blocked the bid on grounds the acquisition 'would be contrary to the national interest' as 'it would result in a single foreign company group having sole ownership and control over Australia's most significant gas transmission business.'[28]

4.8 Contract and spot gas markets

Wholesale gas is traded in two distinct types of markets. Around 90 per cent of gas sales in eastern Australia are struck under confidential *bilateral contracts*, with the remaining 10 per cent traded in *spot markets*.[29]

27 ACCC, *ACCC will not oppose acquisition of APA*, media release, 12 September 2018.
28 The Hon. Josh Frydenberg MP (Treasurer), *Final Decision on the proposed acquisition of APA*, media release, 20 November 2018.
29 AER estimate derived from public sources and discussions with market participants.

4.8.1 Contract markets

Bilateral gas contracts (also known as gas supply agreements) are wholesale supply deals negotiated between sellers and buyers. There are two main levels of contracting: 1. supply offers by gas producers, which are typically available to very large customers such as major energy retailers and gas powered generators and, 2. supply offers by retailers and other aggregators that buy gas from producers and on-sell it to C&I customers. Prices quoted to C&I customers tend to be higher than to very large customers, in part because they must cover the aggregator's margins. But the ACCC found prices to C&I customers have been unreasonably high at times (section 4.10.1).

Gas contracts traditionally locked in prices and other terms and conditions for several years at a time. More recently, the industry has shifted towards shorter term contracts with review provisions. The ACCC reported in 2018 that recent contract offers for gas 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 durations of two years or less.[30]

Public information about contract prices is opaque. Much of it 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.

30 ACCC, *Gas inquiry 2017–2020—Interim report*, July 2018, pp. 24, 49.

4.8.2 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 for gas operate in eastern Australia. The oldest of the three is *Victoria's declared 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 at Wallumbilla, Queensland in 2014 and at Moomba, South Australia in 2016.

The three spot markets operate under different rules, do not interact with each other, and have different purposes. The Australian Energy Market Commission (AEMC) in June 2017 found the disjointed nature of having multiple market designs inhibits trading between regions, increases complexity and imposes transaction costs. It recommended in the longer term eastern Australia's spot markets transition to a single market design, based on the gas supply hub model currently operating at Wallumbilla and Moomba.[31]

An information platform—the Gas Bulletin Board—was launched in 2008 to provide transparency about gas market conditions and so encourage participation in the spot markets. The AER monitors the bulletin board, as well as the spot markets, and reports regularly on activity. It also monitors participants' compliance with the underpinning rules, and takes enforcement action where necessary.[32]

The following sections explain the workings of each spot market, as well as the bulletin board. Price trends in the spot markets are outlined in section 4.10.2.

4.8.3 Gas supply hubs at Wallumbilla and Moomba

AEMO launched the gas supply hub model at Wallumbilla, Queensland, in March 2014. Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia (figure 4.8). Three critical pipelines—the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines—along with several smaller transmission pipelines, connect 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 and gas powered generators were among the most active participant categories in 2017, with increased activity by traders also evident.[33]

Around 11 participants were active each month in the first half of 2018, with 100 trades or more executed in a typical month. The trades are split across a range of product types (such as intra-day, day-ahead, weekly and monthly) and include both on-market and off-market trades.[34]

LNG producers are the largest suppliers of gas into the hub, and some competitive tension appears to have developed between two of them. But operational issues tend to limit their participation at the hub. One factor is the existing physical interconnection between LNG facilities allows them to trade easily among themselves. Some participants have suggested sudden changes in their operations typically involve volumes greater than what the hub can currently absorb.[35]

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

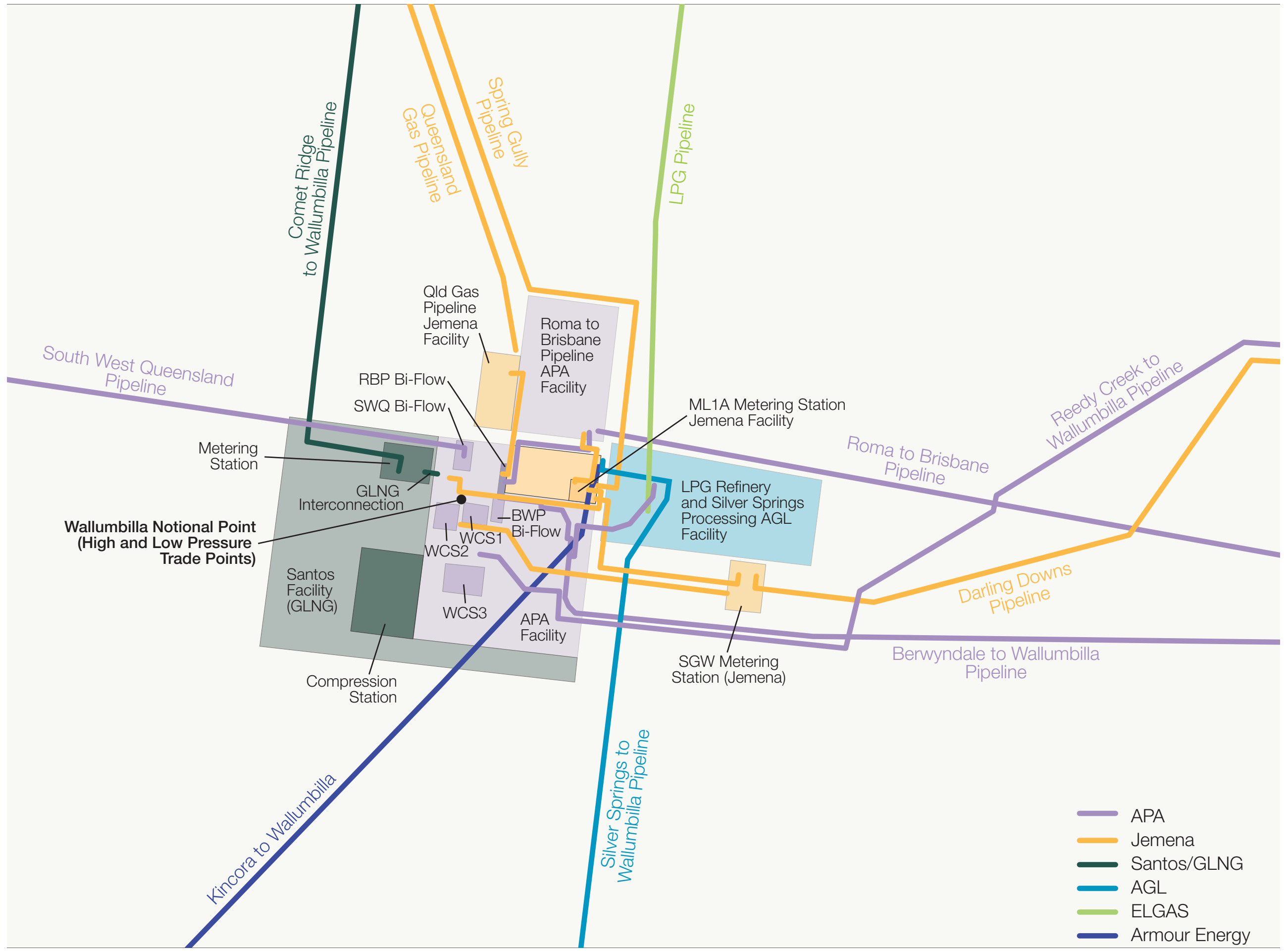
As in the other spot markets, the gas supply hub complements bilateral contracts rather than replacing them. But the hub model allow participants to trade gas up to several months in advance of physical supply, rather than only on a daily basis as in the other markets.

Until 2017 separate prices were set at each of the hub's 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. To address this problem, in October 2016 AEMO introduced a compression product that enables transporting gas from low to high pressure locations within the hub. Participants

31 AEMC, *Review of the Victorian declared wholesale gas market—final report*, factsheet, June 2017.
32 AER, *Compliance reporting*, available at: www.aer.gov.au/wholesale-markets/compliance-reporting.

33 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018 p. 30.
34 AER, *Wholesale statistics*, at: www.aer.gov.au/wholesale-markets/wholesale-statistics.
35 AER market intelligence.

Figure 4.8
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.

can also enter location swaps that allow gas to be received at one location in the hub and delivered to another without physically moving gas between those points.

In March 2017 AEMO replaced the hub's three trading locations with a single Wallumbilla product that groups together all delivery points (box 4.2). 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 (SEQ) product 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 paying pipeline costs to transport gas to Wallumbilla. Participants also sometimes arrange downstream delivery points to avoid these costs.

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, few transactions have occurred. The first trade was executed in September 2017, and by mid-2018, around 10 trades had been executed. The AEMC reported stakeholder views that transportation and operational issues are barriers to trade at the Moomba hub, including uncertainty about injection and delivery points.[36]

36 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018.

Box 4.2 Wallumbilla hub activity

Trade at Wallumbilla has progressively increased since its launch in 2014 (figure 4.9). Initially, some LNG projects used the hub to sell surplus 'ramp' gas during the run-up to commissioning new LNG trains. Once operational, they continued to use the hub from time to time to manage variations in production and LNG plant performance. This use involved alternate periods of selling surplus supply and buying gas when LNG plant performance was not keeping up with export obligations. EnergyQuest reported Queensland Curtis LNG in particular has acted as a 'swing' producer into the domestic market when domestic prices are high.

Other participants in the hub include gas powered generators such as Stanwell, Alinta, Origin, Arrow Energy and ERM, as well as industrial users such as Incitec Pivot. Gas powered generators sourced significant volumes of gas from the Wallumbilla hub in 2017, helping push prices up to $10–15 per gigajoule. But, with all six LNG trains then in operation and absorbing gas supplies, traded volumes at the hub did not rise in response to these high prices.

The Australian Energy Market Commission (AEMC) reported in June 2018 that quantitative indicators of liquidity at the Wallumbilla hub have improved over the past two years. Traded volumes were 47 per cent higher in 2017 than a year earlier.[a] Participation was also higher, with gas powered generators and energy retailers among the most active participants. There was also a shift in product preferences with growth of more than 300 per cent in daily, weekly and monthly products, compared with 30 per cent growth in balance of day and day-ahead trades.

Volumes continued to grow in 2017–18, with prices mostly struck at $7–10 per gigajoule. The upturn was partly attributable to Australian Government intervention in 2017 requiring LNG producers to sell more gas into the domestic market (section 4.12.1). Queensland's gas powered generators were also active buyers at Wallumbilla when electricity demand was high.

Despite this growth, transmission pipeline capacity has been raised as an impediment to hub trading, because all gas traded needs to be physically shipped to a hub location. Reforms in 2019 to introduce a day-ahead capacity auction may help to overcome this issue by enabling trade in pipeline capacity (section 4.13.2).

A number of participants suggested more flexibility to negotiate delivery points and storage options would make the hub more useful for trading, given these options are possible in bilateral trading. In general, stakeholders consider that the hub design should cater better for bespoke needs.[b]

We are working with the AEMC to improve data on liquidity at Wallumbilla, and in 2018 we began publishing a range of liquidity indicators.[c]

a AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 10, 30, 41.
b AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018.
c AER, *Industry statistics,* available at: www.aer.gov.au/industry-information/industry-statistics.

In 2016 the AEMC recommended using the gas supply hub model as a template for new market arrangements in eastern Australia. A northern hub would be located at Wallumbilla and largely retain the market model already in place there. The southern hub located in Victoria would use the same market arrangements.[37] The reforms require significant legislative changes in several jurisdictions. Progress to date has been slow.

4.8.4 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 hub is scheduled and settled separately, but all three operate under the same rules.

Prices are volatile, reflecting short term shifts in supply and demand, including conditions in LNG export markets. Given its responsiveness to short term conditions, participants consider the market is less useful as an indicator of prices that would be struck in bilateral contracts. No ASX derivatives market has developed for the short term trading market.

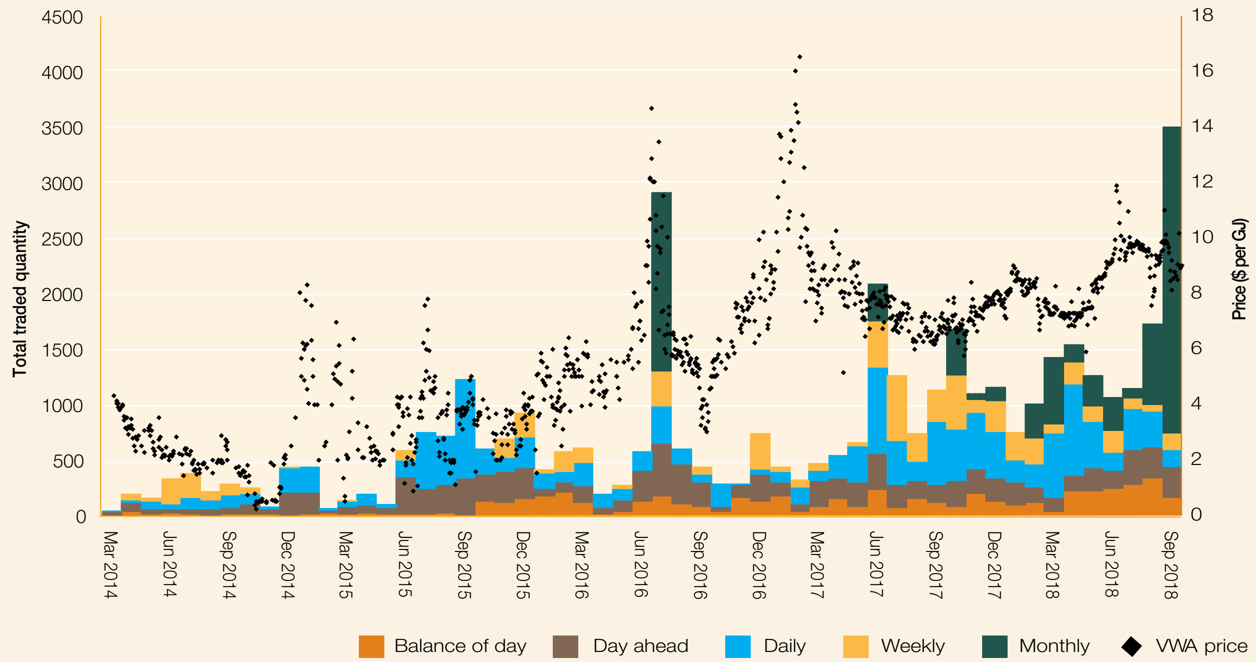
On average, around 22 participants were active at the Sydney hub in 2017. The Adelaide and Brisbane hubs each had around seven active participants.[38] The participants included energy retailers, power generators, large industrial gas users, and traders. The market benefits gas powered generators because it can supply volumes of gas at short notice when electricity demand is high and/or electricity supply is constrained.

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 only trade their net positions—the difference between their scheduled gas deliveries into and out of the market. In Sydney, around 10–15 per cent of total gas demand is met through the market. Volumes in Brisbane and Adelaide tend to be smaller.[39]

Gas producers gave evidence to the ACCC in 2016 that they lack confidence in the market's ability to supply significant volumes of gas.[40] But while no gas producer currently uses the short term trading market as a major outlet for supply, some participants with flexibility in their day-to-day gas requirements—including a number of smaller retailers—use the market to manage imbalances in their contract positions. LNG projects also sometimes trade in the market to manage their portfolios.

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

Figure 4.9
Gas trades and prices at Wallumbilla hub



TJ, terajoule; GJ gigajoule.
Source: AER, AEMO (data).

37 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review, stage 2 final report*, May 2016.

38 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 29–33. An active participant is one that has been engaged in trading on the market at least once in any given month by submitting a valid bid or an offer.

39 AEMC, *Stage 1 Final Report: East Coast Wholesale Gas Market and Pipeline Frameworks Review*, p. 90.

40 ACCC, *Inquiry into the east coast gas market*, April 2016.

where they would have been with contracts they had been offered in 2017 for 2018 supply. More generally, customers 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. One customer said participating in the market had 'taken away the highly speculative offers from retailers in the order of $15 per GJ'.[41]

The AEMC found traded volumes at the Sydney hub were 84 per cent higher in 2017 than a year earlier, but volumes declined by 22 per cent at the Adelaide hub and 5 per cent at the Brisbane hub. Trading profiles varied across the hubs. Energy retailers tended to be more active in Adelaide than at the other hubs.[42]

How the market works

The short term trading market allows gas trading on a day-ahead basis. 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, 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 required. Gas procured under this mechanism is mainly paid for by parties causing the imbalances. The AER has periodically reported instances of abnormally high MOS payments in parts of the market, resulting in a number of investigations.[43]

4.8.5 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.

41 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 66.
42 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 12, 32.
43 AER, *State of the Energy Market 2017*, p. 76.

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.[44]

On average, around 26 participants were active in the Victorian market in 2017.[45] The participants included 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, due to its flexibility and relatively low transaction costs.[46] Industrial users and traders showed the greatest increase in activity in 2017.

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.

The AER estimated volumes traded in the Victorian market were 60 per cent higher in 2017 than a year earlier.[47] This trend was consistent with higher volumes of local gas being available in the Victorian market in 2017, following a return to full service of the Iona underground gas storage facility, and unusually high volumes of production at the Longford processing facility. The AER will update trading data on its website throughout 2019.

A small futures market has developed for the Victorian market, although trading is sporadic and liquidity remains low. In April 2018 80 gas futures contracts were traded (60 quarterly contracts and 20 yearly contracts), amounting to about 1.3 PJ of gas.[48] Trade has grown over 2018, with just over 5 PJ of 2019 futures traded at November 2018.[49]

The Victorian market differs from the short term trading market in a number of respects, including:

44 See AEMO, *Guide to Victoria's declared wholesale market*, 2012, available at: www.aemo.org.au.
45 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 35–36. Note: An active participant is one that has been engaged in trading on the market at least once in any given month by submitting a valid bid or an offer.
46 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 14.
47 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 14.
48 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 47.
49 AER estimate, based on market intelligence.

- 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.

The AEMC reviewed the Victorian gas market in 2017 at the request of the Victorian Government.[50] The AEMC found the market has structural limitations, and recommended a number of reforms. It also recommended the market eventually transition to a new 'southern hub' that would also incorporate the short term trading market hubs in Sydney and Adelaide. The southern hub would feature a brokerage model similar to that operating at Wallumbilla (section 4.8.3). AEMO reported in 2018 that the Victorian Government was considering reforms to the Victorian market that do not involve a transition to a southern hub.[51]

4.8.6 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 is responsible for publishing it. The AER monitors participants' compliance with their obligations to submit accurate data, taking action where necessary to enforce compliance.

The bulletin board plays an important role in making the gas market more transparent, especially for smaller players, such as small gas producers and retailers, who may not otherwise be able to access day-to-day information on demand and supply conditions.

The information supplied on the bulletin board includes:

- pipeline capabilities (maximum daily flow quantities, including bi-directional flows), pipeline and storage capacity outlooks, 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.

50 AEMC, *Final Report: Review of the Victorian declared wholesale gas market*, 30 June 2017, p. i.
51 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 1.

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.

Recent changes to the bulletin board

The bulletin board's coverage has widened incrementally since 2015. Significant reforms taking effect in September 2018 removed most reporting exemptions and mandated more comprehensive detail for covered facilities. To encourage compliance, the reforms also made reporting obligations subject to civil penalty provisions.

Reporting obligations were also extended to gas facility operators in the Northern Territory, in recognition that the Northern Gas Pipeline now connects the Territory with the eastern gas grid.

The reforms are detailed in section 4.13.1.

4.9 State of the eastern gas market

While Queensland's LNG export industry has brought significant investment and growth to the state, it has also caused disruptive price increases in the eastern Australian gas market. The industry, launched in January 2015, increased demand for Australian produced gas and placed pressure on gas reserves in southern Australia.

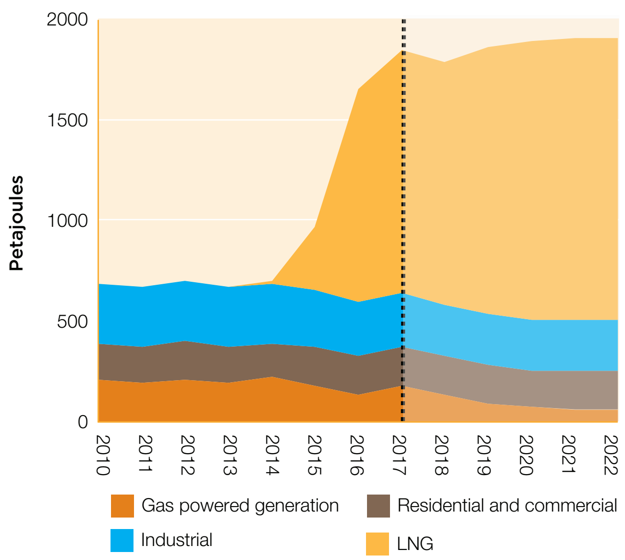
High gas demand for electricity generation following the closure of coal fired generators, regulatory restrictions on developing new gas supplies, and impediments to pipeline access for transporting gas, all further intensified market pressures. These pressures peaked in 2017 before Australian Government intervention led to more gas supplies being diverted to the domestic market. Despite this intervention, the market remained tight in 2018, and wholesale prices continue to be set at levels two to three times above historical levels.

4.9.1 Demand conditions

Domestic demand for gas derives from three sources—C&I gas users (around 41 per cent of domestic demand), gas powered generators (29 per cent), and residential customers (29 per cent). With the launch of LNG exports in 2015, international customers became a new source of demand competing to buy Australian gas. LNG supply rose exponentially from 2015–17 and now outweighs supply to the domestic market (figure 4.10).

Figure 4.10

Eastern Australian gas demand



Note: Data are actual demand to 2017 and forecasts from 2018.

Source: AEMO, *2018 Gas Statement of Opportunities*, June 2018.

Among domestic sources of demand, gas powered generation is the most volatile source of demand. Gas demand by C&I users and residential customers is more stable, although high gas prices have impacted C&I customers. Several gas intensive producers consider high prices a significant risk to commercial viability.[52] Coogee Chemical's decision to mothball a methanol plant, Qenos laying off 15 per cent of its workforce, and EnergyQuest describing Incitec Pivot's fertiliser plant's position as 'precarious'[53] were each reportedly linked to high gas prices.

LNG producers

Queensland's three LNG projects were originally anticipated to source their gas requirements from their own reserves in the Surat–Bowen Basin. But the development of gas wells by Santos's GLNG project was slower than expected, requiring it to source substantial volumes of gas from other producers to meet its LNG supply contracts. EnergyQuest estimated GLNG relied on third parties for around 30 per cent of its LNG plant feedstock in the June quarter of 2018[54] sourcing much of it from other Queensland fields and the Cooper basin. QCLNG also purchases gas from outside its portfolio, having signed a 27 year gas supply agreement with Arrow Energy in December 2017.[55]

LNG exports from Queensland peaked during summer 2017–18, when exporters took advantage of high Asian demand due to a particularly cold winter, which coincided with the need for high capacity use associated with operational testing.

Strong demand caused a surge in LNG spot prices from mid-2017, which, coupled with rising oil prices, translated into surging revenues for the Queensland industry. Monthly Asian spot prices reached around $14 per GJ delivered in December 2017. LNG prices were 25 per cent higher in the June quarter 2018 than in the same quarter in 2017, and 44 per cent higher than in 2016.[56]

Despite this strong demand, the Queensland projects only operated at around 77 per cent of capacity in mid-2018, compared with rates for the two largest projects on the west coast of 89–95 per cent.[57] In part, this outcome reflects the LNG producers diverting more gas to the domestic market following the Australian Government's gas market intervention in 2017 (section 4.12.1). In the June quarter 2018 almost 16 per cent of Queensland gas production flowed to the domestic market[58]—similar to the rate supplied to the domestic market in Western Australia under the state's gas reservation policy.

Future demand for Australian LNG is uncertain. Several LNG projects in the United States are scheduled to come online in 2019, creating a significant new global competitor in the Asian LNG market.[59] But LNG demand is strengthening in China and South Korea as those countries shift from coal towards gas and renewables in electricity generation and domestic use. This behaviour shift is driven in part to reduce carbon emissions, and reduce the localised health impacts of fine particulate pollution caused by burning coal.

In the first six months of 2018 China's LNG imports increased 53 per cent on an annualised basis.[60] The Chinese government aims to raise the share of energy provided by gas from 5.3 per cent in 2015 to 8.3–10 per cent in 2020. Japan's LNG imports, however, are expected to fall by around 5 per cent between 2017 and 2020, as the country's nuclear plant is brought back online, with seven of its 24 plants having resumed operation by March 2018.[61]

52 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, pp. 13, 62–63.
53 EnergyQuest, *Energy Quarterly*, June 2018, p. 22.
54 EnergyQuest, *Energy Quarterly,* September 2018, p. 14.
55 Arrow Energy, *Arrow Energy agrees deal for Surat Basin reserves*, media release, 1 December 2017.
56 EnergyQuest, *Energy Quarterly,* September 2018, p. 94.
57 EnergyQuest, *Energy Quarterly,* September 2018, p. 82.
58 EnergyQuest, *Energy Quarterly,* September 2018, p. 11.
59 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, March 2018; Institute for Energy Research, *U.S. to become a major LNG exporter*, October 2017.
60 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, September 2018, p. 49.

Gas powered generation

Around 29 per cent of domestic demand for Australian gas is for power generation. 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).[62]

Rising gas fuel costs linked to Queensland's LNG industry and a shortage of gas supplies stalled demand for gas powered generation from 2015. The share of gas powered generation in the national electricity market (NEM) generation mix fell from 12 per cent in 2013–14 to 9.5 per cent in 2017–18 (figure 2.8). The decline was most pronounced in Queensland, coming off a high associated with sales into the domestic market by LNG exporters during the commissioning phases of their projects. Gas powered generation slumped from 21 per cent of Queensland's electricity output in 2014–15 to 9 per cent in 2017–18. A similar squeezing of gas powered generation occurred in NSW.

Different conditions prevailed in Victoria and South Australia, where the retirement of coal generators made gas generation critical to meeting electricity demand, particularly when weather conditions for wind and solar generation were unfavourable. Outages at coal generators also contributed to gas generation in 2017–18 being 270 per cent higher in Victoria and 160 per cent higher in South Australia than two years earlier (figure 4.11).

AEMO in 2018 forecast lower levels of gas powered generation in 2019 as new wind and solar plants come online to reduce the gap left by coal plant closures (section 4.9.5).

4.9.2 Supply conditions

While a majority of eastern Australia's gas reserves are located in the Surat–Bowen Basin, those reserves are largely committed to the LNG export industry. The Victorian gas basins and the Cooper Basin in central Australia are, therefore, pivotal to meeting domestic gas demand in southern Australia. But reserves in those basins are declining and scope to increase production in the short to medium term is limited. The decline in recoverable reserves has been accelerated by the Victorian and Cooper basins supplying gas to LNG projects to meet production shortfalls in Queensland. With a few exceptions, declining reserves in legacy fields have not been offset by new gas field developments (section 4.11).

Both onshore and offshore exploration expenditure has declined, mirroring a significant fall in oil prices that dampened investors' appetite for risk (figure 4.12). Exploration expenditure in the first quarter of 2018 was at its lowest quarterly level in four years.[63] While oil prices began to recover in 2016, exploration investment has been slow to respond and legacy reserves continue to dwindle. While some development proposals show promising signs, others face significant regulatory hurdles linked to environmental concerns.

In response to this weakness in exploration activity, the Australian Government and some state governments have launched initiatives to encourage new projects to supply the domestic market (section 4.12).

Supply conditions in the Surat–Bowen Basin

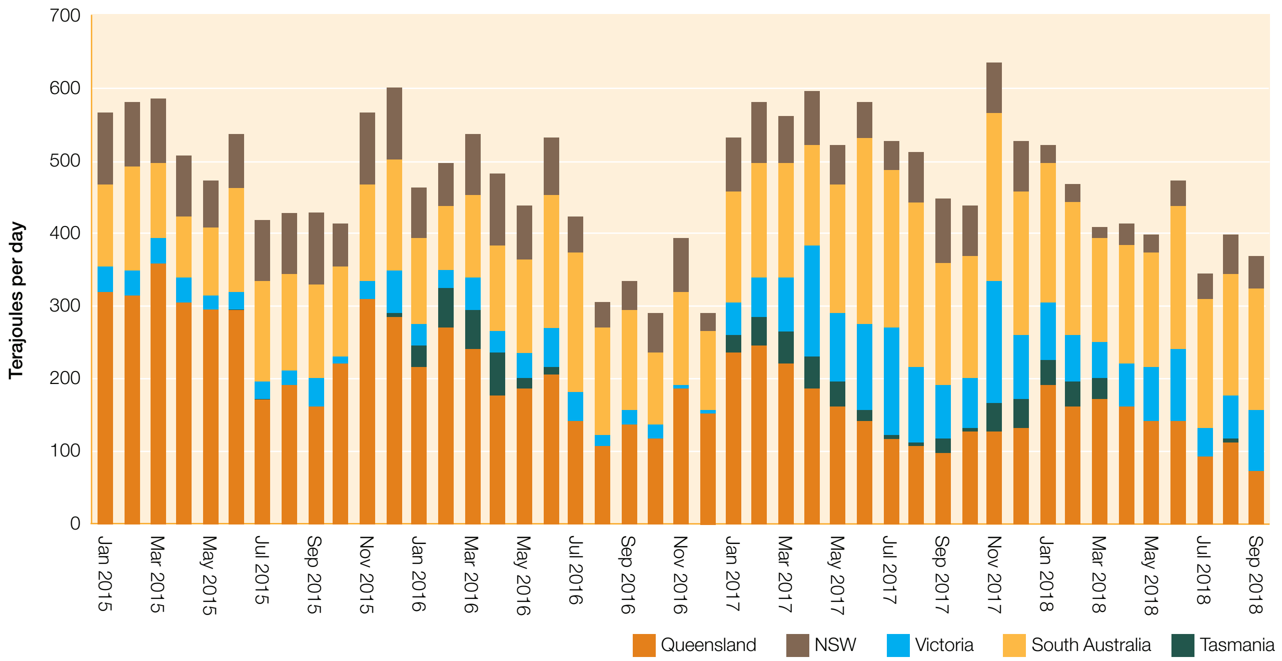
Gas production in the Surat–Bowen Basin rose exponentially from 2014–17 to meet the demands of Queensland's LNG export industry. While production continues to rise, this growth levelled out somewhat in 2017–18 as the three LNG projects reached full operation.

In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government in 2017 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 4.12.1).[64]

61 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, September 2018, p. 49; World Nuclear Association, *Nuclear Power in Japan*, July 2018.
62 EnergyQuest found a minus 89 per cent correlation between gas and hydroelectric generation; and a minus 48 per cent correlation between gas and wind generation over 42 months to June 2018. See EnergyQuest, *Energy Quarterly,* September 2018, p. 35
63 Australian Bureau of Statistics, *8412.0 Mineral and Petroleum Exploration,* March 2018.
64 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.

Figure 4.11

Monthly gas demand for gas powered generation



Source: AER, AEMO (data).

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), in which they committed to offer uncontracted gas on reasonable terms to meet expected future domestic supply shortfalls.

The LNG projects have since used various methods to sell more gas domestically. These methods include selling products on the Wallumbilla Gas Supply Hub, launching expression of interest (EOI) processes for customers and entering bilateral negotiations.[65] Santos' GLNG project, which sources gas from southern Australia to meet its export commitments, has been especially active in entering new supply agreements with gas powered electricity generators and other large domestic customers.[66] With the LNG projects offering more gas to the domestic market, daily production set new records at Roma in 2018.

Completing operational testing of the APLNG project in 2017 also increased Queensland gas supplies to the domestic market. Additionally, launching the Reedy Creek to Wallumbilla Pipeline in May 2018 allowed APLNG to transport gas directly to the Wallumbilla hub.

More generally, the rise in oil prices improved cash flows for all three LNG projects, allowing further development of gas resources. EnergyQuest reported an upswing in drilling for development wells in the Surat–Bowen Basin in 2018.[67]

The ACCC also noted the number of suppliers in the market has risen, with new entrant retailers and aggregators such as Shell Energy Australia expanding their presence. As a result, supply options to C&I gas users appear to be improving.

Supply conditions in Victorian basins

According to Esso, one of the Gippsland Basin's large legacy fields has depleted earlier than expected, with another two fields expected to be depleted in the early 2020s.[68] Production in Gippsland is currently transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce.

The Longford gas plant servicing the Gippsland Basin achieved record production in 2017, taking advantage of high gas prices and periods of high demand for gas powered generation. But Longford flagged lower production in 2018. The plant is becoming less reliable as it is run

65 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 27

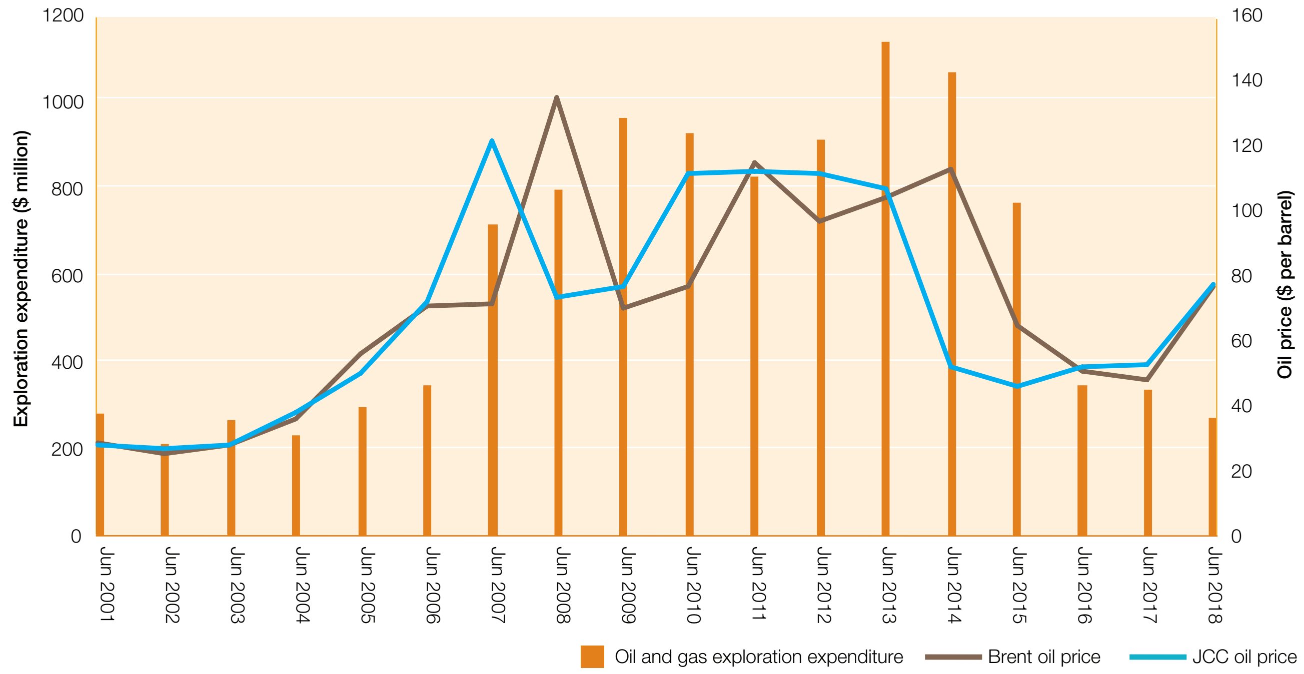
66 Santos media centre 14 August 2017, 8 September 2017, 22 November 2017, 15 February 2018 and 27 February 2018.

67 EnergyQuest, *Energy Quarterly,* September 2018, pp. 85–87.

68 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018

Figure 4.12

Brent oil price and exploration expenditure



Note: Annual data to 30 June.

Source: Exploration: Australian Bureau of Statistics, *8412.0 Mineral and Petroleum Exploration,* March 2018; Oil price: Business Insider (markets.businessinsider.com/commodities/oil-price).

harder for longer, and plant constraints and outages increasingly disrupt production (box 4.3 and figure 4.13).

The ACCC reported a recovery in production forecasts for Victoria in 2019, including higher forecasts by legacy producers Esso Australia and BHP. But forecasts remain significantly lower than 2017 production levels. In the longer term, EnergyQuest predicts gas production from Victoria's offshore fields will fall by 57 per cent in 2022 from the peak achieved in 2017.[69]

Cooper Energy's Sole project in the Gippsland Basin is expected to come online in mid-2019. The project marks the first new production well to be drilled in offshore Victoria since 2012 and is expected to produce around 25 PJ per annum. Esso Australia also expects to bring forward a final investment decision for its West Barracouta project.[70] The ACCC identified limited other prospects of new gas supply from the southern states in the immediate future.

Most potential developments are subject to risk and uncertainty, as illustrated by Esso's recent drilling in the Dory prospect, initially thought to be one of the largest untapped gas resources in Victoria. After several months and $120 million in drilling expenditure, no new resources had been discovered by November 2018.[71] More generally, production costs in new offshore projects coming online in the southern basins tend to be relatively high, posing challenges for commercial viability.

69 EnergyQuest, *Energy Quarterly*, June 2018.

70 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 29.

71 Matt Chambers, *Exxon's $120m Bass Strait bet fails to deliver gas,* The Australian, 15 November 2018.

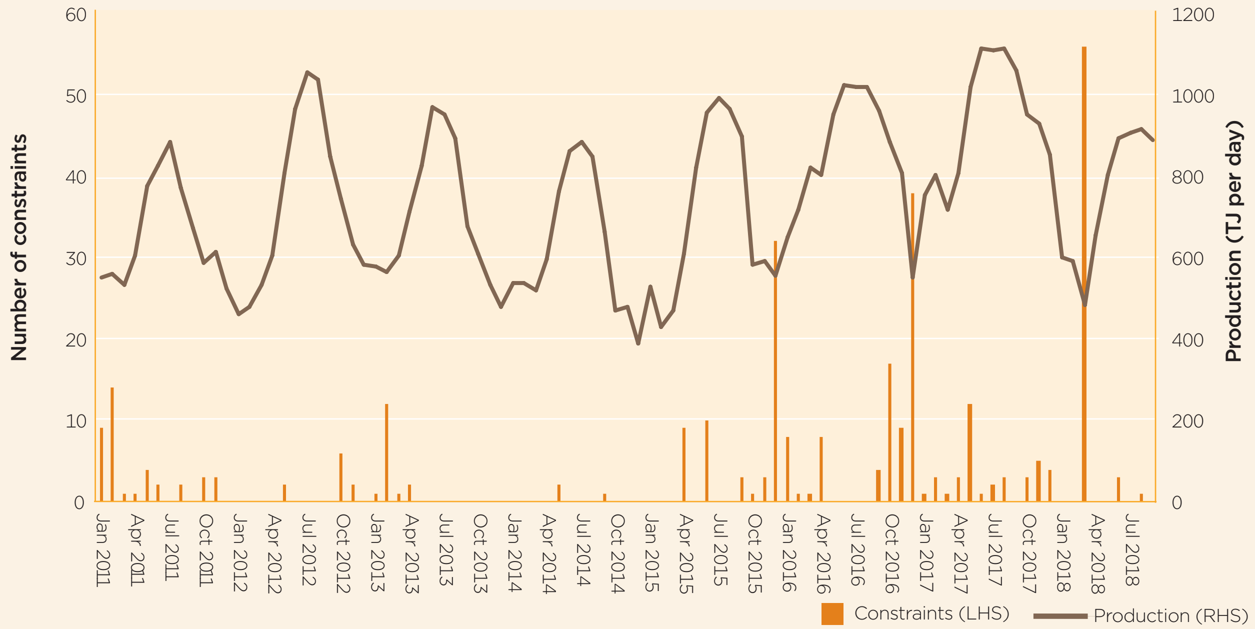
Box 4.3 Gas security issues in Victoria

The Australian Energy Market Operator (AEMO) declared threats to gas system security in Victoria on three occasions in 2017–18.

The most significant event occurred on 30 November 2017, when high temperatures and an outage at Victoria's Loy Yang A coal power station caused a spike in demand for gas powered electricity generation during the day. The high temperatures also caused compressors supplying one of Longford's three gas processing plants to trip (figure 4.13). The outage coincided with high gas demand in surrounding areas of Victoria, resulting in forecasts that local gas pressure would fall below acceptable operating limits. AEMO declared a threat to system security and intervened in the market by directing back-up gas supplies from the Iona storage facility into the system.

The intervention cost the market over $260 000 as gas was scheduled out of merit order, most of it coming from storage. The incident triggered an Australian Energy Regulator investigation, with the findings published in January 2018.[a]

Figure 4.13
Longford monthly production and outages



Note: Daily production (supply). Daily constraints used as proxy for outages.

Source: AER; Gas Bulletin Board.

AEMO also declared threats to gas system security in Victoria on 3 August 2017 and 22 February 2018:

- On 3 August 2017 higher than expected gas powered generation coincided with an unplanned maintenance outage at the Dandenong LNG storage facility, which supplies emergency gas to Victoria. Gas demand on the day reached 1300 terajoules, the highest level since August 2008.
- On 22 February 2018 overheating caused an unplanned outage at a compressor station, limiting gas supply from Longford to the Victorian Transmission System. The outage meant gas pressure into the south west pipeline supplying western Victoria was at risk of falling below minimum thresholds. Similar to the November 2017 event, AEMO scheduled out of merit gas supply from the Iona storage facility, which injected enough gas to maintain pipeline pressures.

a AER, *Significant price variation report: Victorian gas wholesale market, ancillary payments, 30 November 2017*, 29 January 2018.

4.9.3 Regulatory barriers to exploration and development

In some states and territories, community concerns about environmental risks associated with fracking[72] have led to legislative moratoria and regulatory restrictions on onshore gas exploration and development. Victoria, South Australia, Tasmania and Western Australia all have onshore fracking bans in place, covering all or part of those states. NSW has no outright ban in place, but significant regulatory hurdles have stalled development proposals. In 2018 the Northern Territory's ban on fracking was partially lifted. Queensland does not restrict fracking.

- The Victorian Government banned onshore hydraulic fracking, exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[73] 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. The release relates to the Australian Government's 2018 Offshore Petroleum Exploration Acreage Release aimed at promoting petroleum exploration in offshore waters.[74]
- South Australia's newly elected government 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 purposes of extracting hydrocarbon resources including shale gas and petroleum until March 2020.
- NSW does not ban onshore exploration, but applies significant regulatory restrictions including 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.[75] 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' Narrabi gas project.[76]
- Following an independent inquiry[77], the Northern Territory Government in April 2018 lifted its moratorium on fracking by announcing it would make 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. It also led to Jemena announcing it would extend and expand its new pipeline linking the Northern Territory to the eastern gas market. The ACCC forecast the pipeline would provide an additional 28 PJ of gas to the eastern market in 2019.[78] Following the upgrade, it will have potential to transport over 250 PJ per year.
- Western Australia has implemented a ban on fracking for existing and future petroleum titles in the South West, Peel and Perth metropolitan regions.

4.9.4 Pipeline access

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

Since LNG exports began in 2015, gas flows from the southern states to Queensland, and more recently the reverse, have become an efficient response to managing interregional supply–demand imbalances. So, access to transmission pipelines on key north–south transport routes is critical for gas customers.

But gaining access to pipeline capacity has proved difficult for many customers. The ACCC found many pipelines face little competition and charge monopolistic prices.[79] It cited extensive evidence, including a pipeline that had raised its prices by over 90 per cent despite declining volumes.

72 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 and then horizontally through the rock. The fracturing fluid is the injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets containing 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.

73 Department of Economic Development, Jobs, Transport and Resources (Vic), *Onshore Gas Community Information*, August 2017.

74 Department of Industry Innovation and Science, *The 2018 Offshore Petroleum Exploration Acreage Release*, at: www.petroleum-acreage.gov.au/.

75 Department of Planning and Environment (NSW), *Initiatives Overview*, July 2018.

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

77 *Independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory, Final Report to the Northern Territory Government*, 27 March 2018.

78 ACCC, *Gas inquiry 2017–2020—Interim report*, July 2018, p. 24.

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

Other major pipelines were earning internal rates of return of around 20 per cent.

At present, only a handful of pipelines have their prices assessed by the AER. Additionally, several key pipelines have little or no spare capacity, making it difficult to negotiate access. The AEMC in 2018 reported some primary and secondary pipeline capacity is being offered for sale on pipeline operators' websites and on the gas supply hub. It noted seven major transmission pipelines published capacity offers in 2016 and 2017, but actual trades occurred on only two of those pipelines. Publicly reported trade volumes constituted only a fraction of the nameplate capacity of those pipelines.[80]

The ACCC reported congestion issues on many key pipelines. It found APA Group's reported capacity availability for the South West Queensland Pipeline did not provide an accurate picture of actual capacity. The pipeline is a key element in the north–south pipeline grid, and also connects the Northern Territory with the eastern gas market. The Moomba to Adelaide Pipeline (a key route into Adelaide) reportedly has no firm capacity available until 2020. The ACCC also reported compression services at Wallumbilla appear to be contractually congested.[81]

Reforms making it easier for gas customers to negotiate access to underused capacity on transmission pipelines will be implemented in 2019 (section 4.13.2.).

4.9.5 Supply–demand balance

A sharp rise in demand for eastern Australian gas since 2014 (mainly for LNG exports), combined with uncertainties about future gas supply, heightened concerns in 2017 that gas production may not be sufficient to meet domestic demand. In that year, the ACCC and AEMO raised imminent threats a gas supply shortfall could emerge as early as 2018. The ACCC described the market as 'dysfunctional', noting various factors had disrupted the market at a time when it was already undergoing significant change.[82]

Key factors impacting the market in early 2017 included:

- higher gas demand for power generation in Victoria and South Australia following the closure of coal fired generators
- a lack of domestic supply from Queensland's LNG producers due to low oil prices scaling back their drilling activity. In addition, operational testing at the APLNG plant in 2017 restricted its capacity to sell gas into the domestic market.
- forecasts of declining gas production in Victoria in 2018.

But the supply outlook was more optimistic in 2018. In June AEMO forecast a supply gap for the east coast market was unlikely to materialise until at least 2030. The ACCC in July 2018 also noted a significantly improved gas supply outlook, reporting the risk of a gas supply shortfall for 2019 was substantially lower than predicted in 2017.

A key contributor to the improved supply outlook was the Australian Government's threat of market intervention in 2017, which prompted the LNG producers to sell more gas to the domestic market (section 4.9.2). Other key factors included:

- significantly lower forecast gas demand for power generation—AEMO in 2018 forecast demand of 88 PJ, compared with its 2017 year-ahead forecast of 176 PJ. It attributed the shift to higher levels of renewable generation.
- higher production forecasts by Victorian producers for 2019 (including from the new Sole project)
- new gas flows entering the market from the Northern Territory (section 4.11).

The ACCC noted uncertainty remains despite improved conditions. First, gas demand for power generation can be volatile and difficult to forecast. Second, some production (around 9 per cent) is forecast to come from undeveloped (and less certain) gas fields. Third, the nature of CSG development and the need for continuous drilling of wells means there is inherent uncertainty around the quantity of gas that will be extracted.[83]

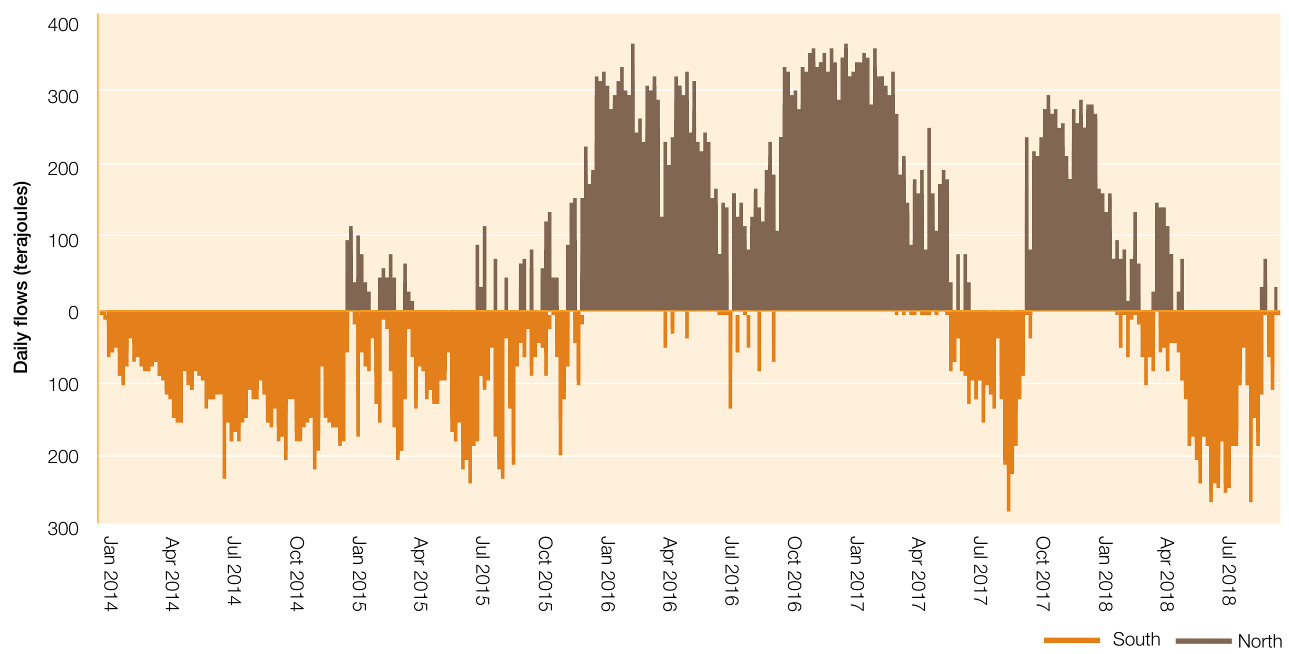
Some commentators question AEMO's forecast of no east coast gas supply gaps before 2030. EnergyQuest describes the conclusion as 'surprising,' arguing it relies on all current 2P resources being successfully developed, and early development of contingent resources from around 2021, despite limited recent investment that might enable this development.[84]

4.9.6 Interregional gas trade

A signature feature of the domestic gas market since 2014 is the role of interregional gas trades to manage the supply–

80 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 15–16.
81 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, pp. 37, 74. Compression capacity at Wallumbilla is necessary to transport gas on the South West Queensland Pipeline to the southern states if a shipper does not have access to high pressure receipt points at Wallumbilla.
82 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 18.
83 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 15.
84 EnergyQuest, *Energy Quarterly*, September 2018, p. 12.

Figure 4.14
North–south gas flows in eastern Australia



Note: Flows on the QSN Link section of 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; Gas Bulletin Board (data).

demand balance. Key pipelines have been re-engineered as bi-directional, enabling them to respond more flexibly to regional supply and demand conditions.

Queensland's LNG producers shipped substantial volumes of surplus gas to the southern states in 2014 during the production ramp-up to commissioning LNG trains. But once LNG exports began in 2015, the direction of trade reversed, as LNG projects drew gas from Victoria and South Australia to cover shortfalls in their own reserve portfolios. This trend has continued, most noticeably during the northern hemisphere winter (Australian summer) when Asia's LNG demand peaks (figure 4.14).

Conditions in the domestic electricity market also affect trade flows. Increased demand for gas powered generation in the southern states following the closure of coal fired generators draws gas south, especially during the Australian winter when heating demand peaks. In 2018 gas flows turned southbound even before the onset of winter. The shift was accentuated by weak local demand for gas in Queensland, following state government intervention in the electricity market that weakened demand for gas powered generation (section 2.12.1).

The threat of government intervention in the gas market (section 4.9.2) 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. Despite high LNG prices in early 2018 (the northern hemisphere winter), less gas flowed north in the domestic market during this period than in 2016 or 2017.

Santos' GLNG project, which sources gas from southern and central Australia to meet its export commitments, has been especially active in facilitating more gas supplies to the domestic market since 2017. It entered new supply agreements with southern gas generators Qenos (to supply ethane gas) and Wesfarmers, and made a $900 million investment in new gas field developments.[85]

The data on trade flows may understate the impact of government intervention in the gas market. Some gas producers entered swap agreements to increase deliveries to southern gas customers *without* physically shipping it along pipelines. An example is Shell's agreement

85 Santos media centre 14 August 2017, 8 September 2017, 22 November 2017, 15 February 2018 and 27 February 2018.

with Santos to swap at least 18 PJ of gas.[86] Under the agreement, Shell draws on its CSG reserves to meet part of Santos' LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to meet demand in southern Australia.[87] The swap allows the producers to increase supply to the domestic market, but allows Shell to avoid accessing the South West Queensland Pipeline.

Gas flows into NSW

NSW produces little of its own gas and is, therefore, highly trade dependent. EnergyQuest in 2018 reported Queensland was supplying more gas to NSW following the Australian Government's market intervention, displacing some supplies from Victoria. This shift reflected in a significant rise in gas volumes being shipped along the Moomba to Sydney pipeline. EnergyQuest considers the pipeline now plays a critical role in providing gas to NSW on peak days.[88]

The ACCC in April 2018 reported signs of constraints in available pipeline capacity to NSW. In particular, the South West Queensland Pipeline has very limited uncontracted capacity between Wallumbilla (Queensland) and Moomba (the origin point of the Moomba to Sydney Pipeline). If south bound gas requirements continue to grow, these pressures may intensify.[89]

4.10 Gas prices

LNG export demand, combined with supply issues in southern and central Australia, contributed to a sharp escalation in wholesale gas prices, especially in 2016 and the first half of 2017. Prices stabilised to some degree from late 2017 into 2018, but remained at historically high levels.

More generally, the factors driving domestic gas prices have changed. Domestic prices are now linked to international oil and LNG prices, which are volatile and significantly higher than historical domestic gas prices.

4.10.1 Gas contract prices

A majority of gas prices are agreed in confidential bilateral contracts, with two main types of contracting—supply offers by gas producers to large customers, and supply offers by retailers and other aggregators to C&I customers.

86 Santos, *Santos facilitates delivery of gas into southern domestic market*, media release, August 2017.
87 ACCC, *Gas inquiry 2017–2020—Interim report*, September 2017, p. 35.
88 EnergyQuest, *Energy Quarterly*, September 2018, p. 23.
89 ACCC, *Gas inquiry 2017–2020—Interim report*, April 2018, p. 55.

Retailer and aggregator offers tend to be higher than producer prices, partly because they include retailers' costs and margins.

Gas contracts traditionally locked in prices and other terms and conditions for several years. More recently, the industry has shifted towards shorter term contracts with review provisions. The ACCC reported in 2018 that recent contract offers favoured durations of 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 durations of two years or less.[90]

Public information about contract prices is limited. Price information is often private and particular to specific contracts and negotiations. There is also disparity between the type of information available to large participants such as gas producers and retailers, 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. The ACCC in 2018 began publishing gas price data as part of its 2017–20 gas inquiry (section 4.13.1).

Contract price levels

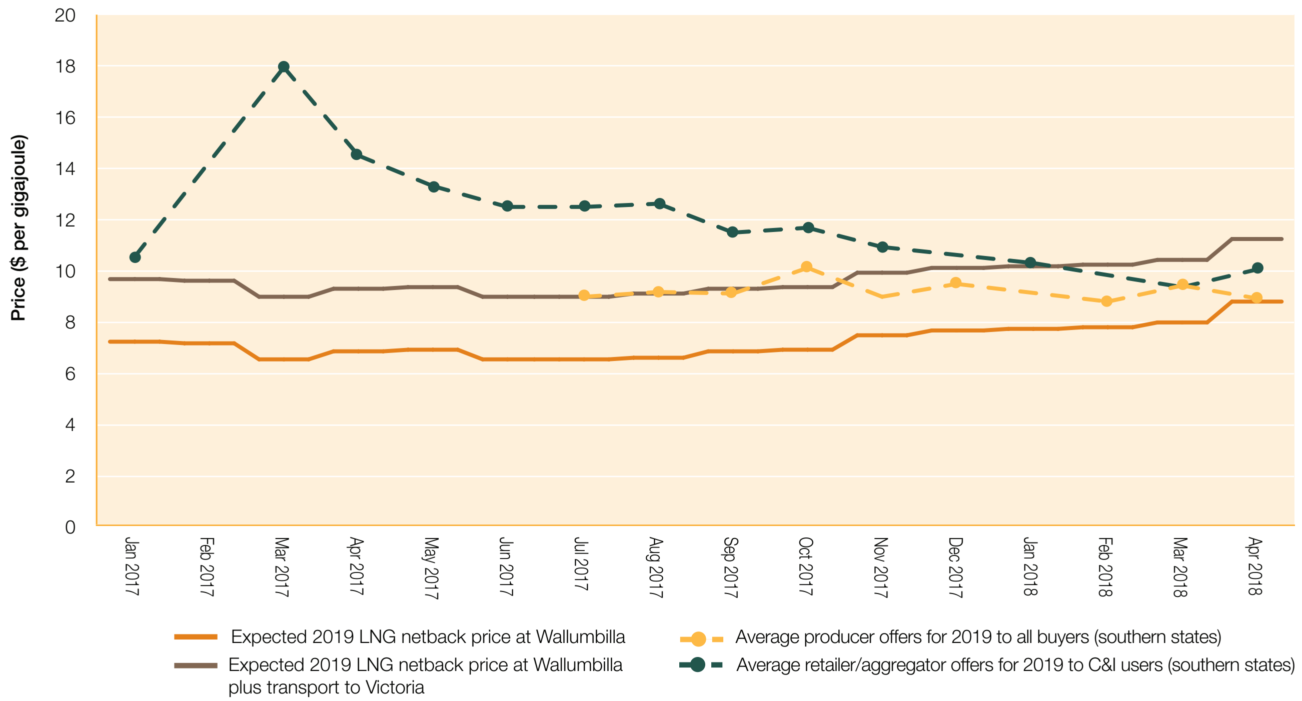
Domestic gas contract prices historically averaged around $3–4 per GJ. But when Queensland's LNG projects began sourcing gas for their projects from Victoria and South Australia, contract prices rose. The ACCC in March 2015 observed prices of around $4–5 per GJ. By early 2017 prices of $22 per GJ were being quoted for a one or two year contract—almost $10 per GJ above export prices.[91] Contract prices executed by gas producers tended to be higher in the southern states than those executed in Queensland.

Following the Australian Government's market intervention in 2017 (section 4.9.2), Queensland producers began offering more gas to the domestic market at less onerous prices. By 2018 contract offers for supply in 2019 had eased back into the high $8–11 per GJ range, aligning them more closely with LNG netback prices (box 4.4 and figure 4.15).

Rising international LNG prices meant by late 2018, domestic gas prices were around $3 per GJ *lower* than export prices. Despite this outcome, domestic offers remained two to three times above historical prices and were often on less flexible terms. C&I users also reported

90 ACCC, *Gas inquiry 2017–2020—Interim report*, April 2018, p. 49.
91 ACCC, *Gas inquiry 2017–2020—Interim report* , July 2018

Figure 4.15
Gas price offers for 2019 supply and expected 2019 LNG netback prices



Note: Average monthly gas prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices. Prices are for gas commodity only. Actual prices paid may include transport and retail costs. Includes offers for gas supply of at least 12 months duration.

Source: ACCC, *Gas inquiry 2017–2020—Interim report*, July 2018 report (chart 2.6); Intercontinental Exchange, Argus (data).

the use of EOI processes by gas suppliers was making it more difficult to compare offers.[92]

Figure 4.15 illustrates movements in gas contract prices in the southern states relative to LNG netback prices. In 2017 offers for 2019 gas supply to C&I gas users were well above export parity prices. At their peak in March 2017, domestic prices offered by retailers and aggregators nearly doubled LNG netback prices. In an efficient market, a Victorian gas customer should have been able to buy gas for around $10 per GJ—the export parity price plus the cost of transporting gas from Queensland to Victoria.

While prices being quoted by gas producers were much closer to export parity prices, smaller C&I customers generally do not have options to buy gas directly from producers. Nor can easily they acquire the pipeline capacity to ship the gas. These users were affected more than other gas buyers by the record gas price offers being quoted in early 2017.

92 ACCC, *Gas inquiry 2017–2020—Interim report* , July 2018.

Prices offered by retailers and aggregators decreased over the course of 2017 as market dynamics improved. By early 2018 price offers had aligned with expected 2019 LNG netback prices at Wallumbilla, which have increased since mid-2017. By mid-2018 domestic price offers were tracking *below* export parity prices.[93]

4.10.2 Spot market prices

As discussed in section 4.8, three separate spot markets for gas operate in eastern Australia—*gas supply hubs* at Wallumbilla, Queensland and Moomba; the *short term trading market* for gas, with hubs in Sydney, Brisbane and Adelaide; and Victoria's *declared 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, though they often move in similar directions. But while contract prices reflect expectations of future market conditions, the spot markets reflect short term shifts

93 ACCC, *Gas inquiry 2017–2020—Interim report*, July 2018, pp. 52–56.

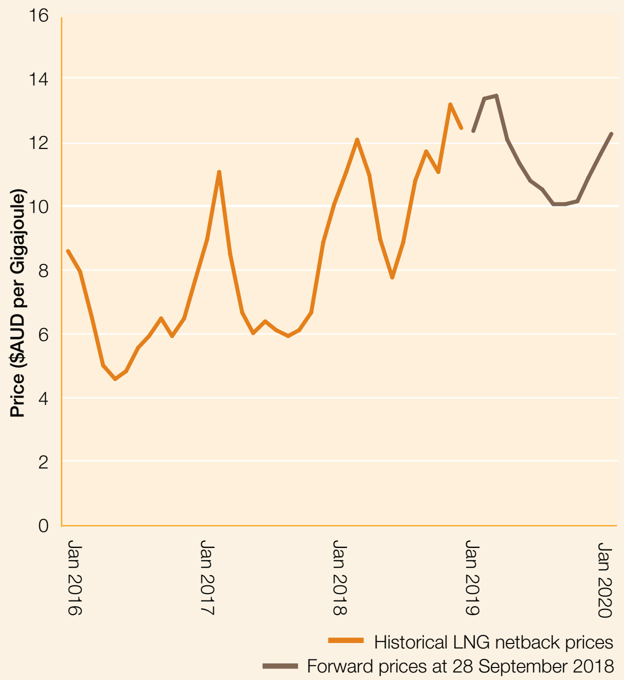
Box 4.4 Liquefied natural gas netback prices

LNG netback prices estimate the export parity price 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 cost include liquefaction at Gladstone, waterborne shipping to Asia and regasification in Asia.

If LNG netback prices exceed domestic prices, it becomes more profitable to export gas than to sell it locally. At times during 2017 the reverse situation prevailed in eastern Australia—domestic gas prices exceeded LNG netback prices. 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 publishes LNG netback prices to improve transparency in the eastern gas market. LNG netback prices tend to peak during the northern hemisphere winter, when LNG demand is highest. Expected netback prices for 2019 supply reached $12 per GJ in February 2018, before easing during the year. A global shift in oil and LNG prices during 2018 saw LNG netback prices move higher during the year, with expectations they will keep rising until the northern hemisphere's 2018–19 winter, when they could reach levels around $15 per GJ (figure 4.16).

Figure 4.16
LNG netback prices



Note: Prices at 28 September 2018.

Source: ACCC, www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series; historical prices: S&P Global Platts; LNG futures prices: Intercontinental Exchange; forward LNG freight prices: Argus Media Ltd.

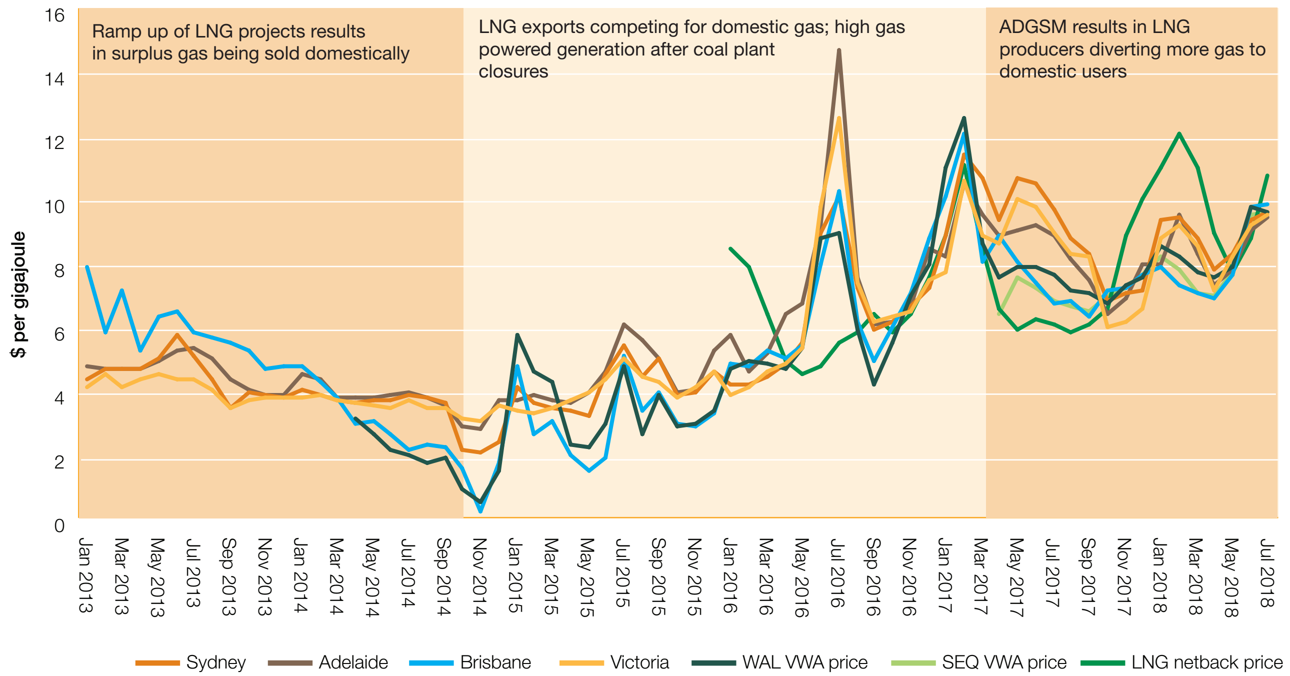
Table 4.3 Gas spot prices

	GAS PRICE ($ PER GJ)					
	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18
Sydney	5.20	4.03	3.44	5.05	8.81	8.50
Adelaide	5.09	4.31	3.77	5.74	8.83	8.06
Brisbane	5.92	4.55	2.28	4.66	8.21	7.46
Victoria	4.49	3.87	3.63	4.99	8.58	8.03
Wallumbilla		2.74	2.74	4.37	8.27	7.80
South east Qld					7.32	7.49

Note: Prices are annual weighted averages. Sydney, Adelaide and Brisbane prices on short term trading market; Victorian prices on Victorian declared market; Wallumbilla and south east Queensland prices at Wallumbilla hub.

Source: AER, AEMO.

Figure 4.17
Spot gas and LNG netback prices



ADGSM, Australian Domestic Gas Security Mechanism; SEQ, south east Queensland; VWA, volume weighted average; WAL, Wallumbilla.

Note: Spot prices are monthly weighted averages. 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; AEMO; ACCC (LNG netback prices).

in market conditions relating to factors such as the timing of LNG shipments and conditions in the electricity market.

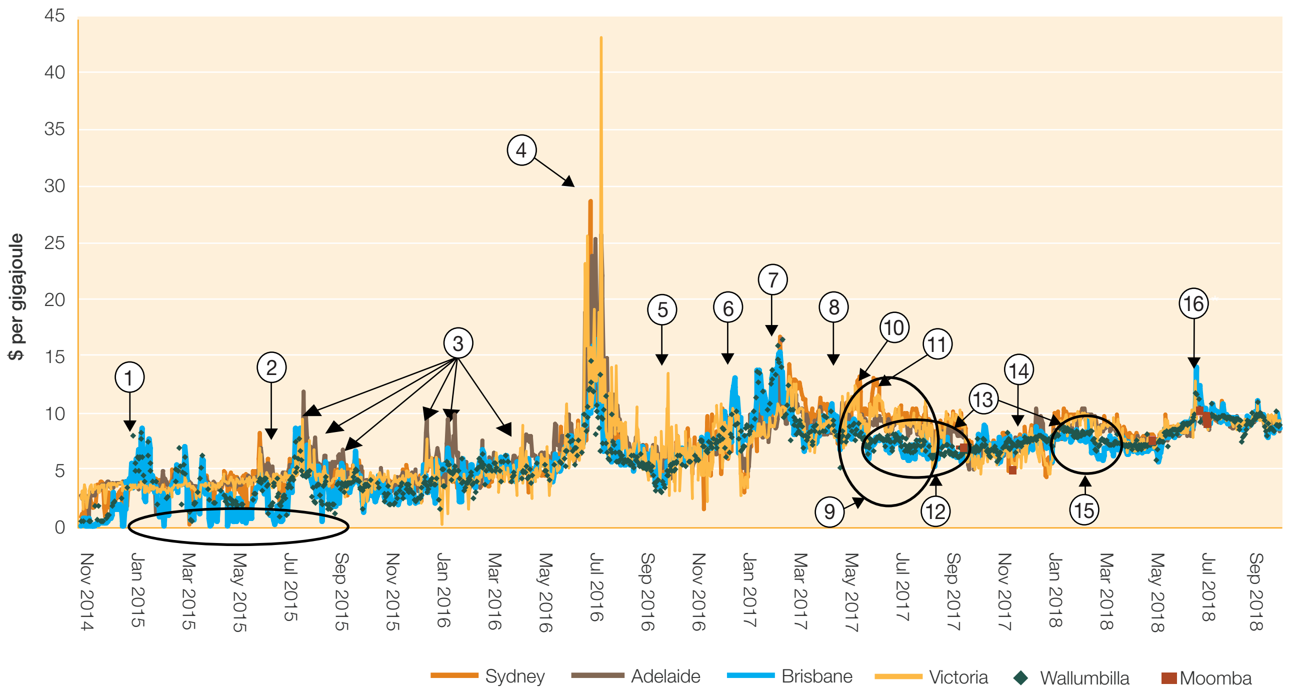
The launch of LNG exports in January 2015 caused spot prices to increase as LNG producers competed with domestic customers for gas supplies (table 4.3 and figures 4.17 and 4.18). Prices spiked in winter 2016, when LNG demand coincided with high domestic demand for heating and a rise in gas demand for power generation following the shutdown of South Australia's Northern power station. The retirement of Victoria's Hazelwood generator in March 2017 again put pressure on the market, with gas powered generation being called on to fill some of the gap in the electricity market.

Spot prices vary seasonally, both within and across the markets. Prices tend to peak in summer and winter. In summer, gas demand for electricity generation tends to 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 (box 4.5).

Monthly spot prices averaged $10–12 per GJ in all spot markets in February 2017. As noted, market intervention by the Australian Government in 2017 increased gas supplies to the domestic market and eased price pressures in the later months of 2017. Prices again tracked higher from November, when plant outages at Longford affected southern supplies. A particularly cold winter in the northern hemisphere fuelled high LNG demand in the early months of 2018, at times coinciding with high domestic demand for gas powered generation. Spot prices eased during autumn 2018, before again moving higher as winter approached.

Despite some price stability returning to the market in 2017–18, monthly prices continued to average $6–$10 per GJ—well above prices before LNG exports began. Average prices for the year in Sydney, Victoria and Adelaide remained above $8 per GJ for a second year.

Figure 4.18
Daily gas spot prices



1	Jan 2015	First LNG exports from Queensland.
2	Jan to Sep 2015	Low prices when LNG producers sold ramp gas on spot markets.
3	Jul 2015 to Apr 2016	Low wind generation coincided with high electricity demand, spiking gas powered generation demand when gas supplies were limited (multiple instances).
4	Winter 2016	Southern gas diverted to Queensland to supply LNG producers, high gas powered generation following closure of Northern power station, and high winter demand.
5	1 Oct 2016	Longford plant outage reduced gas flows to zero for several hours.
6	19 Dec 2016	Longford outage (planned) coincided with high gas powered generation.
7	Jan 2017	LNG exports increased, drawing gas supplies from the south, coinciding with high gas powered generation demand over summer.
8	27 Apr 2017	Australian Government announced Ministerial discretion to limit LNG exports to address domestic gas shortfall (ADGSM).
9	May to mid-Aug 2017	APLNG (Santos) project in testing mode, limiting ability to supply domestic gas.
10	Mid-May 2017	Closure of Hazelwood generator coincided with Longford maintenance and higher winter demand.
11	Winter 2017	High gas powered generation as coal plant out for maintenance during cold weather period.
12	Mid-May to Oct 2017	Outages on Queensland export pipelines motivated increases in gas flows south.
13	Mid-May to Oct 2017, and Jan to Apr 2018	Threat of ADGSM motivated LNG producers to divert more gas to domestic market, easing price pressure.
14	30 Nov 2017	Longford outage coincided with high gas powered generation, and LNG prices rose off high Asian demand.
15	Jan to Apr 2018	Lower Queensland demand for gas powered generation following Queensland Government direction to increase coal generation led to more Qld production diverted south.
16	17 to 22 Jun 2018	Longford outages constrained Victorian supply, coinciding with high gas powered generation demand in South Australia, Victoria and Queensland, and a Queensland pipeline outage.

Box 4.5 North–south price divide

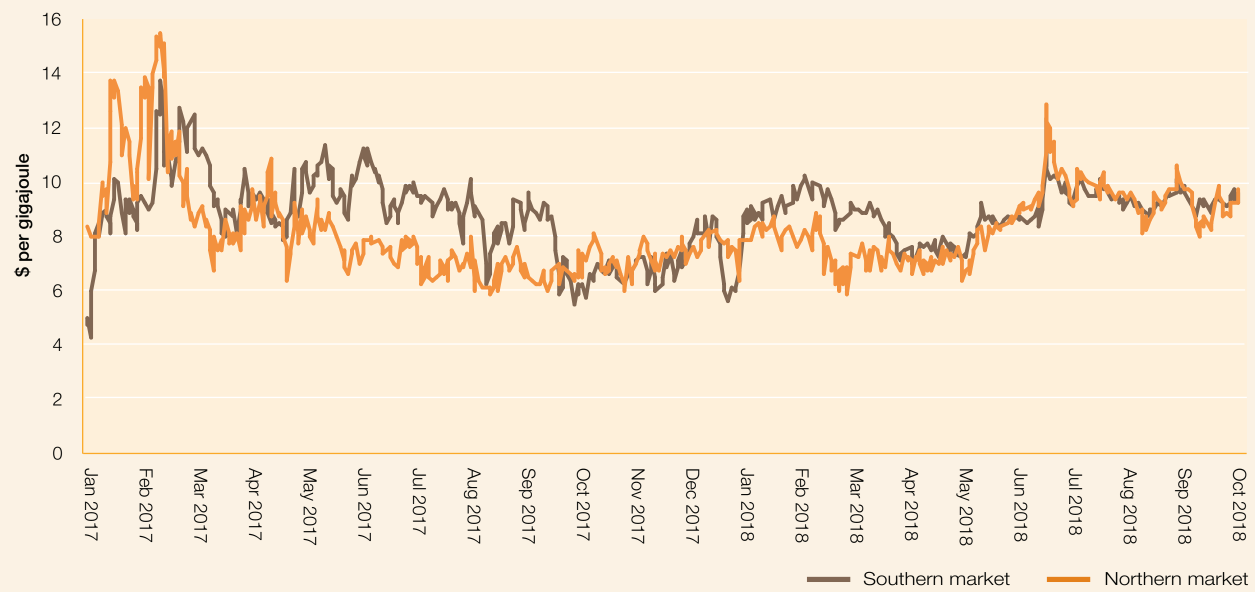
A significant differential between spot gas prices in Queensland (Wallumbilla and Brisbane) and the southern states emerged for much of 2017 (figure 4.19). Southern gas was more expensive by over $2 per GJ for much of this period—roughly the cost of transporting Queensland gas to the southern states.

The price difference reflected contrasting demand and supply conditions in the two regions. In Queensland, a significant rise in gas production at Roma (Queensland) in 2017 increased supply, while outages at LNG plants suppressed gas demand. But high demand for gas powered generation in southern Australia coincided with tight supply in the region.

The price differential eased in late 2017 following the Australian Government's market intervention. But it returned in early 2018 when gas plant outages in Victoria (section 4.9.2) meant the southern states relied more on Queensland gas, thus incurring pipeline costs.

Prices largely converged from March 2018, partly because swap agreements between Queensland producers and southern buyers allowed more gas to enter the southern markets without using pipeline transport, resulting in significant transport savings. Storage may also have played a role, as participants used the Iona facility to store gas during off-peak months for reinjection during the winter peak.

Figure 4.19
North–south gas price divide



Note: Southern market is average of NSW, Adelaide and Victorian spot prices. Northern market is average of Brisbane and Wallumbilla spot prices.
Source: AER.

4.11 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, importing LNG, transmission pipeline solutions, and demand response.

4.11.1 Gas field development

Exploration and development in a number of gas fields has increased since international oil and gas prices began to rise in 2017. Additionally, higher domestic gas prices and government funding have improved the economics of some resources and projects. Governments are offering financial or regulatory incentives for projects targeting gas supplies to the domestic market (section 4.12). 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 moratoria on onshore exploration and fracking have impeded the development of gas projects in Victoria, South Australia and Tasmania (section 4.9.3). Elsewhere, stringent regulatory processes apply, as highlighted by the stalled process for Santos' 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 moratoria and constraints in place, a number of development projects look positive and could result in additional supply being brought to the domestic market.

In Victoria, Cooper Energy's Sole gas field in the Gippsland Basin is scheduled to begin commercial production in July 2019.[94] The project, which can produce up to 68 terajoules (TJ) per day, will link to the Orbost Gas Plant, which is being upgraded to treat the gas. Cooper Energy plans to develop its Manta gas field, after developing Sole.

Beach Energy in January 2018 announced a new gas discovery in the Otway Basin.[95] The proposed Katnook Gas Processing Facility (to be partly funded by the GAP scheme) will purify resources from the project.[96]

The Victorian Government in May 2018 released five new oil and gas exploration blocks in the offshore Otway Basin. The release forms part of the Australian Government's Offshore Petroleum Exploration Acreage Release program, aimed at promoting petroleum exploration in Australia's offshore waters.[97]

In NSW, Santos aims to develop 850 wells across its 95 000 hectare Narrabri Gas Project, which has potential to supply up to 200 TJ per day.[98] Environmental and community groups have widely opposed the project's environmental impact. Over 23 000 submissions were made in response to the environmental impact statement, mostly in opposition.[99] The project's status will be determined by the Independent Planning Commission. At July 2018 the project was awaiting an independent review.

In Queensland, the Kincora project (Armour Energy) began processing gas from surrounding wells in December 2017.[100] Armour is expanding its activity in the region after receiving a $6 million grant under the GAP scheme in March 2018. The project is expected to deliver 6.9 PJ by June 2020.[101] 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 4.12.3).[102]

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 LNG partners announced they would invest $900 million in upstream developments in 2018,[103] including the Roma East project, which is expected to produce 50 PJ of gas annually from 2020. The partners also announced a further $400 million investment in the Arcadia gas project, which at its peak would deliver about 27 PJ per annum to the GLNG project.[104]

In June 2018 Senex and Jemena announced a partnership to fast track bringing gas from Senex's Project Atlas in the Surat Basin to the domestic market by late 2019.[105] Jemena will build a 40 TJ per day gas processing facility and pipeline to deliver gas from the project to the Wallumbilla Hub.

In South Australia, Strike Energy is continuing work on its Southern Cooper Gas Project which, if successful, would be the deepest coal seam gas well drilled in Australia.[106] Production testing to confirm commercial quality was scheduled for 2018.[107]

4.11.2 LNG import terminals

While conditions eased in the east coast gas market in 2018, considerable uncertainty remains. To address these concerns, industry was considering at least four projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units. EnergyQuest reported the facilities are relatively inexpensive ($250–300 million each) compared to building new pipeline infrastructure or paying long haul transmission charges from Queensland.[108]

AGL expects to reach a final investment decision in 2018–19 on its $250 million LNG import terminal near Melbourne. A proposal by Australian Industrial Energy for a LNG import terminal near Wollongong (NSW) is also progressing, aiming to receive its first gas by 2020. The NSW Government has tagged the plan with 'critical state significant infrastructure' status to help streamline regulatory processes.[109] Mitsubishi is considering an import terminal in South Australia to supply gas to the domestic market and for gas powered generation in the state.[110] A fourth proposal, by ExxonMobil, would use existing infrastructure at its Longford gas plant in Victoria.[111]

4.11.3 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in 2018. Jemena is evaluating a 1000 km 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.[112] The pipeline has begun signing customers, including Incitec Pivot to deliver gas to its fertiliser plant until the end of 2019.[113] The government aims for gas exploration to resume during the 2019 dry season.[114]

4.11.4 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. 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 arrangements allows the group to access wholesale markets at better prices than would be possible if they acted individually.[115]

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 new LNG import facilities.[116] Some users have lowered their gas use by changing fuels or increasing efficiencies. MSM Milling's canola processing facility in NSW, for example, will replace LPG gas with a 4.88 megawatt biomass fired boiler using waste timber.[117]

Joint ventures between gas customers and producers are also occurring.[118] Incitec Pivot, in partnership with Central Petroleum, won a tender for a coal seam gas tenement release by the Queensland Government, and aims to be producing by 2022.[119]

94 Cooper Energy, *Sole-3 flow-back completed successfully*, ASX Announcement, 6 July 2018.
95 Beach Energy, *New Gas Field Discovery in the Otway Basin, South Australia*, 11 January 2018.
96 Beach Energy, *Quarterly report for the period ended 31 March 2018*, 24 April 2018, p. 13.
97 Department of Industry, Innovation and Science, *Offshore Petroleum Exploration Acreage Release*, accessed 4 July 2018, www.petroleum-acreage.gov.au/.
98 Santos, *Narrabri Gas Project*, available at: www.narrabrigasproject.com.au/ask-us-categories/the-project/.
99 Department of Planning and Environment, *NSW Government assessment of the Narrabri Gas Project proposal update*, media release, 23 April 2018.
100 Armour Energy, *Kincora Gas Project,* available at: www.armourenergy.com.au/kincora-gas-project.
101 Minister for Resources and Northern Australia, *New East Coast Supply from Gas Acceleration Program*, media release, 28 March 2018.
102 Armour Energy, *Kincora Gas Project,* available at: www.armourenergy.com.au/kincora-gas-project.
103 Santos, *Santos GLNG to invest $900m in Queensland gas fields in 2018*, media release, 27 February 2018.
104 Santos, *Santos GLNG announces final investment decision on A$400 million Arcadia project*, media release, 31 May 2018.
105 Senex Energy, *Senex and Jemena fast-track Project Atlas gas to domestic market*, media release, 18 June 2018.
106 EnergyQuest, *Energy Quarterly*, March 2018.
107 Strike Energy, *JAWS-1 Project Update*, ASX Announcement, 26 June 2018.
108 EnergyQuest, *Energy Quarterly*, September 2018, p. 32–33.
109 Australian Financial Review, *Forrest plan earns 'strategic' status*, June 2018.
110 EnergyQuest, *Energy Quarterly*, September 2018, p. 33.
111 The Australian, *ExxonMobil considering Victorian LNG import plan*, 18 June 2018.
112 AEMO, *2018 Gas Statement of Opportunities*, June 2018.
113 The Australian, *Incitec secures gas supply deals*, June 2018.
114 Hon. Matt Canavan, *Harnessing the potential of Northern Territory's gas industry,* 15 November 2018.
115 ACCC, *The Eastern Energy Buyers Group—Authorisations—A91594 & A91595*, August 2017.
116 ACCC, *Gas inquiry 2017–2020—interim report,* July 2018, p. 62–66.
117 ARENA, *MSM Milling Biomass Fuel Switch Project,* available at: www.arena.gov.au/projects/msm-milling-biomass-fuel-switch/.
118 AEMO, *2018 Gas Statement of Opportunities*, June 2018.
119 Australian Financial Review, *Incitec lures Richard Cottee back to Queensland's coal seams,* 1 March 2018.

4.12 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 referred to throughout this chapter, but are collated and summarised here.

4.12.1 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.[120] 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), in which they committed to offer uncontracted gas on reasonable terms to meet expected future 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 4.9.2).

The AEMC reported some stakeholders were concerned that, while government intervention may increase liquidity in the short term, it does not correct the underlying issue of participants lacking confidence 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.[121]

4.12.2 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 applicants announced in 2018 are based in Queensland. The fifth project was in South Australia's Otway Basin (section 4.11).[122]

4.12.3 Queensland and South Australian schemes

The Queensland and South Australian governments each have run programs to encourage gas exploration in the form of grants for 'domestic only' exploration tenements.

Queensland has released exploration tenements available exclusively for domestic gas supply. Senex won the first tender under the scheme in 2017, and in 2018 as gained a licence to produce. It expected to supply the eastern gas market within two years. In 2018 Central Petroleum and Armour Energy won a tender to explore 400 hectares in south west Queensland for gas exclusively for the Australian market.[123]

The South Australian Government's Plan for Accelerating Exploration scheme offered grants to increase gas supplies in the state and increase competition between suppliers. In 2017 nine grants were awarded to Santos, Senex, Strike, Beach and Vintage.[124] The scheme has now wound up.

4.12.4 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. The inquiry will run until 30 April 2020 and has released several interim reports.[125]

4.13 Gas market reform

The COAG Energy Council is directing gas market reforms, which are being implemented by regulatory and market bodies including the AER, AEMC, AEMO and ACCC.

120 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.
121 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 46.

122 Department of Industry, Innovation and Science, *Gas Acceleration Program*, www.business.gov.au/Assistance/Gas-Acceleration-Program/Gas-Acceleration-Program-successful-applicants, accessed 19 October 2018.
123 Queensland Government, *Gas supply fast tracks to east coast market*, media statement, 29 March 2018.
124 Government of South Australia, PACE gas, available at www.energymining.sa.gov.au/petroleum/latest_updates/pace_gas, accessed 19 October 2018.
125 ACCC, *Gas inquiry 2017–2020*, available at www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020.

4.13.1 Improving transparency

A number of reforms aim to improve transparency in the gas market, including reforms to the Gas Bulletin Board and improving the availability of information about market liquidity, prices and gas reserves.

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 took effect in September 2018 to bring the bulletin board closer to being a 'one stop shop' for the east coast gas system. The reforms remove most avenues for reporting exemptions and mandate provision of more comprehensive detail for covered facilities. Reporting obligations were also extended to facilities in the Northern Territory, recognising the Northern Gas Pipeline now connects the territory with the eastern gas market.

Many gas facilities were covered for the first time in 2018, including gas storage facilities, which play an important role in assessing the future supply–demand balance. The Roma underground storage facility near LNG gas fields in south east Queensland was among the facilities covered for the first time. Significantly, 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. For the first time, market participants can access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations, and capacity outlooks. This reporting brings added transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must now submit daily disaggregated receipt/delivery point data. 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 for the first time. The AER will assess the quality and accuracy of the data submitted by market participants against a new 'information standard' to ensure the information presented on the bulletin board has integrity. The AER published a compliance note outlining its approach to enforcement.

In 2019 the AEMC will progress further bulletin board reforms that extend reporting to large gas users and LNG processing facilities, and to the reporting of gas reserves.

Liquidity information

The AEMC in August 2018 published its first review into liquidity in wholesale gas spot markets and pipeline capacity trading markets. The review publishes quantitative and qualitative indicators based on a survey of market participants. The AEMC found most indicators reflect improved liquidity at the Wallumbilla gas supply over the past two years. Complementing the review, the AER in August 2018 began publishing a range of quantitative metrics for gas markets on the industry statistics page of its website. It will regularly update this data.

Price and reserves transparency

With gas markets shifting towards shorter term contracts and suppliers using EOI processes, transparency on price and other market information is critical. 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.[126] It will also publish a volume weighted wholesale gas price series. Publishing this data aims to help gas users negotiate more effectively with gas producers and retailers when entering into new gas supply contracts.

Public information on gas reserves and resources tends to lack clarity, consistency and accuracy, which limits the ability of market participants to identify future supply issues and plan accordingly. In late 2018 the ACCC began publishing data on gas reserves and resources, drawing on information provided by reserve owners.

4.13.2 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 it unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity.

Three major pipelines—the South West Queensland Pipeline, Moomba to Adelaide Pipeline System and the

126 ACCC, *Gas inquiry 2017–2020—LNG netback price series*, available at: www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series.

Moomba to Sydney Pipeline—were close to fully contracted in 2018, limiting shippers' ability to transport gas between northern and southern markets.[127]

To manage pipeline congestion issues, some gas producers engage in swap agreements—bypassing 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, therefore, unlikely to be an effective long term solution to gas pipeline issues.[128]

Secondary trading in underused capacity

Congestion issues have focused policy attention on ensuring any spare physical pipeline capacity is made available to the market. Reforms to launch a voluntary trading platform for underused capacity take effect in March 2019. The platform will enable secondary trading of contracted pipeline capacity that is not being used. It will also apply to compression facilities. Any underused capacity that is not traded will be put to a compulsory day-ahead auction with a reserve price of zero.[129]

To promote transparency, prices and other key terms in all voluntary trades, as well as the day-ahead auction results, will be published on the Gas Bulletin Board. Standardised provisions in capacity trading contracts will make capacity easier to trade.

The AER will monitor compliance, including with capacity trading regulations and the proper reporting of trades. We will also oversee the resolution of any disputes over cost recovery.

Information disclosure and arbitration

Negotiating a fair price to use a gas pipeline is an ongoing issue, with concerns about monopolistic pricing practices raised by the ACCC,[130] as well as by Dr Michael Vertigan's review for COAG in 2016.[131] The reviews highlighted a lack of transparency and unequal bargaining power between shippers and pipeline operators.

These concerns led to introducing 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 can apply for arbitration. Chapter 5 describes the Part 23 regime in more detail.

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.[132] The review recommended removing a number of inconsistencies between these tiers by:

- requiring 'light regulation' pipelines to publish prices for each pipeline service, as well as reporting similar financial information to that required for 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 similar capacity and use information to that which other distribution pipelines are required to report
- including all pipeline expansions within the regulatory framework of the existing pipeline, rather than being subject to separate arrangements
- widening the scope of pricing information to cover services, including bi-directional flow, and park and hold services.[133]

The COAG Energy Council in late 2018 proposed rule changes to implement the reforms, which the AEMC aims to finalise in March 2019.[134]

127 ACCC, *Gas inquiry 2017–2020—Interim report*, December 2017, p.59.
128 ACCC, *Gas inquiry 2017–2020—Interim report*, December 2017.
129 Gas Market Reform Group, *Capacity Trading Reform—Implementation.*
130 ACCC, *Inquiry into the east coast gas market*, April 2016, pp.99–106.
131 COAG Energy Council, *Examination of the current test for the regulation of gas pipelines*, December 2016.

132 Chapter 5 outlines the tiers of gas pipeline regulation.
133 AEMC, *Review into the scope of economic regulation applied to covered pipelines*, July 2018.
134 AEMC, *AEMC fast tracks draft rules to improve regulation of covered gas pipelines*, media release, 6 December 2018.