



# Gas inquiry 2017-2020

**Interim report**

July 2018

Australian Competition and Consumer Commission  
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## Acronyms

ACT	Australian Capital Territory
ACQ	annual contract quantity
ADGSM	Australian Domestic Gas Security Mechanism
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
DES	delivered ex-ship
DWGM	Declared Wholesale Gas Market
EOI	expression of interest
ESO	Energy Supply Outlook
ESOO	AEMO's Electricity Statement of Opportunities
FID	financial investment decision
FOB	free on board
FSRU	floating storage regasification unit
GBB	Natural Gas Bulletin Board
GPG	gas powered generation/generator
GSA	gas supply agreement
GSH	Gas Supply Hub
GSG	Gas Supply Guarantee
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
JCC	Japanese Customs-Cleared Crude
JV	joint venture
LNG	liquefied natural gas
MCQ	minimum contract quantity
MDQ	maximum daily quantity
MFN	most favoured nation
MMBtu	Million British Thermal Units—see below, Units of Energy
MPH	Moomba Processing Hub
NEM	National Electricity Market

NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSW	New South Wales
NT	Northern Territory
SA	South Australia
STTM	Short-term trading market
WA	Western Australia
<b>Organisations</b>	
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	AGL Energy, originally the Australian Gas Light Company
APA	APA Group
APLNG	Australia Pacific LNG Pty Ltd
APPEA	Australian Petroleum Production and Exploration Association
ASX	Australian Securities Exchange
BHP	BHP Billiton, formed from a merger of BHP (originally the Broken Hill Propriety Company) and Billiton
CNOOC	China National Offshore Oil Corporation
COAG	Council of Australian Governments
EIA	Energy Information Agency (US)
FERC	Federal Energy Regulatory Commission (US)
GBJV	Gippsland Basin Joint Venture
GLNG	Gladstone LNG
GMRG	Gas Market Reform Group
NOPTA	National Offshore Petroleum Titles Administrator
PWC	Power and Water Corporation
QCLNG	Queensland Curtis LNG Project
QGC	QGC Pty Limited, previously Queensland Gas Company
RLMS	Resource and Land Management Services

SEA	Shell Energy Australia
SEC	Securities and Exchange Commission (US)
SGH	Seven Group Holdings
SPE-PRMS	Society of Petroleum Engineers-Petroleum Resources Management System
<b>Pipelines</b>	
BWP	Berwyndale to Wallumbilla Pipeline
CGP	Carpentaria Gas Pipeline
CRP	Central Ranges Pipeline
CRWPL	Comet Ridge to Wallumbilla Pipeline Loop
CWP	Central West Pipeline
DTS	Declared Transmission System
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
QSN Link	Queensland to South Australia/New South Wales Link
RBP	Roma to Brisbane Pipeline
SEAgas	South East Australia Gas pipeline
SEPS	South East Pipeline System
SESA	South East South Australia Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline

## Glossary

**ACCC's 2015 inquiry:** The ACCC's inquiry into the East Coast Gas Market in 2015, as reported on in April 2016.

**AEMO-operated wholesale markets:** There are two broad kinds of AEMO-operated wholesale markets: demand hubs, and supply hubs. The Victorian Declared Wholesale Gas Market (DWGM) and the Adelaide, Sydney, and Brisbane Short-Term Trading Markets (STTMs) can be considered demand hubs as their primary purpose is to meet the gas requirements of a particular demand centre. These markets are compulsory—if a user sits within the defined boundaries of the market, their gas use (or supply) will be scheduled through the market by AEMO. The Wallumbilla and Moomba Gas Supply Hubs were developed primarily to facilitate the trade of gas between suppliers and large users at a particular supply centre. These markets are voluntary.

**April 2018 report:** the ACCC's third interim report, published in April 2018, in the three year inquiry into the supply of and demand for wholesale gas in Australia that commenced in April 2017.

**Aggregator:** an entity other than a gas retailer that purchases gas for the purpose of re-supply to end users (including C&I users and GPG) rather than for their own consumption.

**Banking rights:** A contractual term relating to a gas user's maximum gas usage allowance in a given period. When a gas user consumes less than their maximum, banking rights determine the extent to which the user may 'bank' the difference for later use.

**Conventional/unconventional gas:** Conventional gas is contained in sedimentary rocks such as sandstone and limestone (referred to as reservoir rock). The gas is trapped by an impermeable cap rock and may be associated with liquid hydrocarbons. The reservoir rock has a relatively high porosity (percentage of space between rock grains) and permeability (the rock's pores are well connected and the gas may be able to flow to the gas well without additional interventions). Gas is extracted by drilling a well through the cap rock allowing gas to flow to the surface. Depending on the structure of the rock containing the gas (amount of faulting or compartmentalisation), only a few wells may be required to produce gas over the life of the gas field.

Unconventional gas is a broad term that covers gas found in a range of sedimentary rocks which typically have low permeability and porosity. The International Energy Agency categorises the three major types of unconventional gas as:

- shale gas: natural gas contained within shale rock
- coal seam gas (CSG): natural gas contained in coalbeds
- tight gas: natural gas found in low permeability rock formations.

A range of techniques may be required to promote gas flow including pumping water from the rock to reduce pressure holding the gas in place (in the case of CSG) or hydraulic fracture stimulation (fracking) to open pathways for the gas to enter the well (in the case of shale gas, tight gas and some CSG). An unconventional gas field may require a large number of wells to be drilled (in the thousands for the large CSG liquefied natural gas (LNG) projects in Queensland) over its life to ensure consistent production.

**December 2017 report:** the ACCC's second interim report, published in December 2017, in the three year inquiry into the supply of and demand for wholesale gas in Australia that commenced in April 2017.

**Delivered ex-ship price:** The price of gas delivered by ship to a destination port. This term is typically used for LNG prices.

**Domestic demand:** The quantity of gas demanded by users located in Australia.

**East Coast Gas Market:** The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

**Export demand:** The quantity of Australian gas demanded by overseas buyers.

**Free on-board price:** The price of gas loaded on a ship at a port connected to an LNG plant.

**Liquefaction:** The process of liquefying natural gas.

**Liquefied natural gas (LNG):** Natural gas that has been converted to liquid form for ease of storage or transport.

**LNG netback price:** A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.

**LNG train:** A liquefied natural gas plant's liquefaction and purification facility.

**Load factor:** measures the extent to which a buyer can take more than the average daily contract quantity throughout the year, subject to the cap imposed by the annual contract quantity.

### **Pipeline transportation services**

**As available transportation service:** A service that allows the transportation of gas on an 'as available' basis, subject to the availability of capacity. This service has a lower priority than a firm transportation service.

**Firm transportation service:** A service that allows the transportation of gas on a 'firm' basis up to a maximum daily quantity and maximum hourly quantity. It has the highest priority of any transportation service.

**Interruptible transportation service:** A service that allows the transportation of gas on an 'interruptible' basis. The pipeline operator does not have an obligation to guarantee capacity and has the right to curtail the service if the pipeline becomes capacity constrained or higher priority services are required. This service has a lower priority than firm and as available transportation services.

**Park service:** A service that allows users to store gas in a pipeline, which in practice involves injecting more gas into a pipeline than what is taken out on a particular day.

**Loan service:** A service that allows users to "borrow" gas from a pipeline, which in practice involves withdrawing more gas from a pipeline than what is injected on a particular day.

### **Reserves and resources**

**Reserves:** Quantities of gas expected to be commercially recoverable from a given date under defined conditions.

**1P (proved) reserves:** Commercially recoverable reserves with at least a 90 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

**2P (proved and probable) reserves:** Commercially recoverable reserves with at least a 50 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

**3P (proved and probable and possible) reserves:** Commercially recoverable reserves with at least a 10 per cent probability that the quantities recovered will equal or exceed the estimated quantity.

**Contingent resources:** quantities of gas estimated to be potentially recoverable from known accumulations but are not yet considered able to be developed commercially due to one or more contingencies. Contingent resources may include gas accumulations for which there are currently no viable markets, where commercial recovery is dependent on technology under development or where evaluation of the accumulation is insufficient to assess if it can be produced commercially. 2C resources are classified as a best estimate of the resource (1C is the low estimate and 3C is the high estimate).

**Prospective resources:** Estimated quantities associated with undiscovered gas. These represent quantities of gas which are estimated, as of a given date, to be potentially recoverable from gas deposits identified on the basis of indirect evidence but which have not yet been drilled. Prospective resources represent a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the gas accumulation must be further evaluated and an estimate made of quantities that would be recoverable under appropriate development projects.

#### **Transportation and storage related terms:**

**Contracted but un-nominated capacity:** A quantity of contracted pipeline capacity that is not nominated to be used by a shipper on a gas day.

**Gas storage service:** A service that allows users to store gas in a facility (either underground depleted gas fields or domestic LNG storage).

**Secondary capacity:** Capacity that is on-sold by primary capacity holders on a pipeline.

**Shipper:** A user of pipeline services.

**September 2017 report:** the ACCC's first interim report, published in September 2017, in the three year inquiry into the supply of and demand for wholesale gas in Australia that commenced in April 2017.

**Southern States:** South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

**Spot market/transaction:** One-off transactions, as distinct from transactions occurring under supply contracts.

**Swap arrangement:** An arrangement between two or more gas market participants to swap rights or obligations. For example, two gas producers in different locations may swap gas delivery obligations to minimise transportation.

**Take or pay:** A contract term specifying the minimum proportion of ACQ the buyer must pay for in each year.

**Unfulfilled offer:** A written offer for supply of gas that does not result in an agreement to supply gas.

## **Units of Energy**

Joule—a unit of energy in the International System of Units

Gigajoule (GJ)—a billion ( $10^9$ ) joules

Terajoule (TJ)—a trillion ( $10^{12}$ ) joules

Petajoule (PJ)—a quadrillion ( $10^{15}$ ) joules

Million British Thermal Units (MMBtu)

## Overview

This is the fourth interim report of the Australian Competition and Consumer Commission's (ACCC) inquiry into gas supply arrangements in Australia ('the Inquiry'). The ACCC has continued its focus on the operation of the East Coast Gas Market, where there are immediate and longer-term concerns.<sup>1</sup>

Since the release of our first report in September 2017, we have seen a significant improvement in the gas supply outlook of the East Coast Gas Market. In contrast to the supply outlook in September 2017, which indicated a likely gas supply shortfall in 2018, the most recent gas supply outlook indicates that there will likely be sufficient gas for 2019. The improved supply outlook for 2019 compared to 2018 is primarily due to the following factors:

- A significantly lower forecast by the Australian Energy Market Operator (AEMO) for gas consumption by gas powered generators (GPG) – from 176 petajoules (PJ) for 2018 to 88 PJ for 2019.
- Higher aggregate production forecasts by producers in Victoria, including higher forecasts from Esso Australia and BHP Billiton as well as commencement of gas supply from Cooper Energy's Sole Project – from 348 PJ for 2018 to 370 PJ for 2019.
- Expected commencement of the flow of gas from the Northern Territory into the east coast following construction of the Northern Gas Pipeline later this year, which is expected to provide an additional 28 PJ in 2019.

Since our September 2017 report, there have also been a number of improvements in the operation of the East Coast Gas Market:

- There are now more suppliers of gas active in the market. More producers, including the Queensland liquefied natural gas (LNG) producers, are actively selling gas domestically. The LNG producers have become more active due to a combination of factors, including completion of LNG plant testing and the commitment made to the Australian Government in the October 2017 Heads of Agreement.
- At the retailer/aggregator level, new entrants in the market, such as Shell Energy Australia, are seeking to expand their presence. As a result, commercial and industrial (C&I) gas users are now more likely to receive offers from at least three retailers/aggregators.
- Domestic price offers have reduced substantially and converged with export parity (LNG netback) prices at Wallumbilla. Prices offered for gas supply in 2019 are in the high-\$8 to \$11/GJ range. This is in stark contrast to prices offered in the first half of 2017, when domestic gas offers were significantly above LNG netback prices, peaking at offers as high as \$22/GJ in March 2017.
- There is increasing transparency around market operations, both in terms of commodity gas prices and gas transportation.
- The ACCC has undertaken substantial work to monitor and report on both prices paid and offered in the market, and will soon commence publishing an LNG netback price series to address information asymmetry between gas suppliers and buyers.
- The Gas Market Reform Group, the Australian Energy Market Commission, the Australian Energy Regulator and AEMO have all undertaken – and continue to undertake

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<sup>1</sup> The East Coast Gas Market currently includes Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania. The Northern Territory will be connected to the East Coast Gas Market from 2019. This report does not cover Western Australia for reasons set out in the September 2017 report.

– work to develop and implement substantial reforms in gas transportation pricing and capacity trading. APA has also updated its reporting of uncontracted capacity on the South West Queensland Pipeline and Wallumbilla compression to improve transparency for shippers. We have also observed more secondary trading of firm pipeline capacity, allowing new entrant retailers to supply C&I gas users following our previously reported investigation of complaints about an unwillingness of some gas retailers to trade secondary capacity on some pipelines.

- Finally, there have been some positive changes to government policies in the Northern Territory and Victoria around new gas developments that should help to increase supply into the East Coast Gas Market.

However, despite these improvements, many C&I gas users are still finding market conditions extremely challenging as gas prices remain at two to three times higher than historical levels.

With production costs increasing and gas prices in the East Coast Gas Market being shaped by international LNG prices, domestic prices are unlikely to return to historical levels. International LNG prices are volatile and domestic prices might increase to reflect recent expectations of higher Asian LNG spot prices.

While many C&I users are adopting a range of strategies to manage the new market dynamics, many still face difficult long-term investment decisions and questions about their long-term operations.

For C&I gas users, ongoing price transparency (such as the publication by the ACCC of domestic prices and the LNG netback price series) and other market information will continue to be critical. Improved market transparency will help to ensure that buyers are making informed decisions about their long-term operations and will improve the overall functioning and efficiency of the East Coast Gas Market.

## **Sufficient gas supply is expected in 2019 to meet forecast demand in the East Coast Gas Market**

The immediate supply-demand outlook in the East Coast Gas Market has improved since our December 2017 report. Under current projections, there is unlikely to be a gas supply shortfall in 2019 (chart 1). The improvement in outlook since December 2017 is largely the result of a significant reduction in AEMO's 2019 forecast for gas consumption by GPG, dropping by around 47 PJ, as well as some increase in forecast production by gas producers in the Southern States.<sup>2</sup>

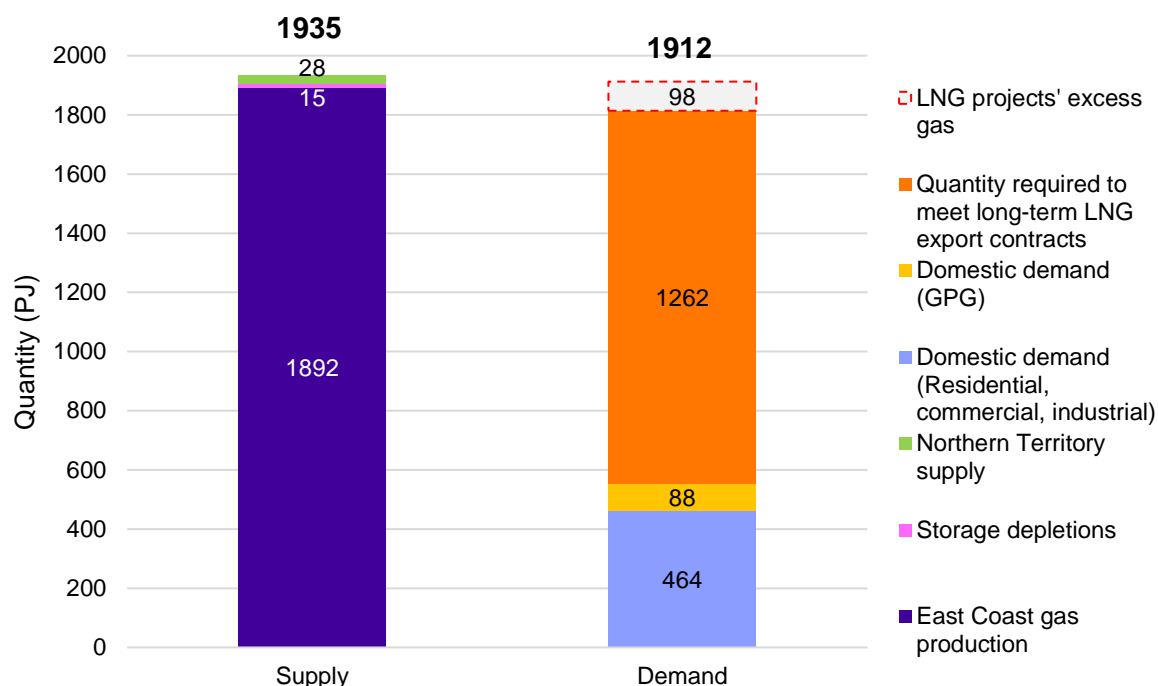
Further, as we previously reported, some producers expect to commence supplying the East Coast Gas Market from new gas sources in 2019. Most significantly, gas suppliers in the Northern Territory will be able to supply gas into the East Coast Gas Market for the first time following the construction of the Northern Gas Pipeline in late 2018. With moratoria on fracking now lifted, supply from the Northern Territory into the East Coast Gas Market could increase significantly over the coming years. Cooper Energy also expects production from the Sole Gas Project in the Gippsland Basin to commence by mid-2019.<sup>3</sup>

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<sup>2</sup> 'Southern States' is used in this report to refer to South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

<sup>3</sup> Cooper Energy and APA Group, *Orbost gas processing facility upgrade and sole gas project to deliver much needed east coast gas from mid-2019*, 23 March 2018, <http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/Minister-congratulates-Cooper-Energy-and-APA-on-Sole-gas-project.pdf>.

**Chart 1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2019**



Source: ACCC and AEMO data

Even if the demand for gas by GPG is higher than currently forecast, the likelihood that there will be a supply shortfall in 2019 remains low. The Queensland LNG producers are expecting to have 98 PJ of gas in excess of what is required to meet their existing domestic and export contractual commitments. The Queensland LNG producers have identified this as gas that can be sold either domestically or overseas.

This excess gas will likely act as a buffer should domestic demand for gas on the east coast be higher, or gas production lower, than currently forecast. The effectiveness of this buffer will depend on whether the LNG projects offer this gas to buyers in the East Coast Gas Market in a way that meets the requirements of buyers. If the gas is offered in large quantities that have to be taken over a short time period, there may not be enough domestic buyers with a capacity to consume, transport and/or store this gas.

As we reported in December 2017, the Queensland LNG producers have continued to take a range of steps to meet their commitments to supply gas to the domestic market under the Heads of Agreement signed with the Australian Government.<sup>4</sup> These steps have included expression of interest (EOI) processes to offer gas to the domestic market. Some C&I gas users have informed the ACCC that they have found these processes difficult and at odds with how they usually contract for gas (discussed further in chapter 3). The ACCC will continue to monitor and report on how the LNG producers offer gas into the East Coast Gas Market in future interim reports.

The supply-demand balance in the Southern States remains tight. However, forecast supply of 449 PJ from offshore Victoria, Camden in New South Wales, and the Cooper Basin in

<sup>4</sup> See: <https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Documents/Heads-of-Agreement-The-Australian-East-Coast-Domestic-Gas-Supply.pdf>.

South Australia is expected to be enough to meet AEMO's forecast demand of 418 PJ in the Southern States in 2019.<sup>5</sup>

The 2019 supply outlook is discussed further in chapter 1 and is subject to uncertainty in certain respects. First, the amount of gas demanded for GPG can be volatile and difficult to forecast. Second, some of the forecast production (around nine per cent) is forecast to be produced from undeveloped (and less certain) areas. Third, the nature of coal seam gas (CSG) development and the need to continue drilling wells means that there is inherent uncertainty around the quantity of gas that will be extracted.

If production in the Southern States is lower than expected, or demand is higher, then gas from Queensland will be needed to meet demand in the south. Such gas will need to be transported on APA's South West Queensland Pipeline (SWQP) or exchanged through gas swaps.

Information recently provided to the ACCC by APA indicates that while there is uncontracted firm capacity westward on the SWQP, compression capacity at Wallumbilla (necessary to compress additional gas to send it south via the SWQP) is fully contracted. Shippers may need to rely on purchasing interruptible compression to move gas south using the SWQP.

Information on the compression services available for moving gas from Queensland to the Southern States will be reported publicly on the Natural Gas Services Bulletin Board from 1 February 2019. In the meantime, the ACCC is pleased that APA has changed the information reported on its own website to provide this improved level of transparency to the East Coast Gas Market.

The ongoing and forecast tightness of supply in the East Coast Gas Market means the measures to improve market transparency (in terms of both gas supply and pipeline transportation) and to improve the overall functioning of the market remain critical as ever.

### **After significantly exceeding export parity prices last year, gas prices for 2019 have now converged with expected LNG netback prices at Wallumbilla**

Few contracts for 2019 gas supply have been struck in the early part of 2018, as both sellers and buyers seem to be delaying contracting until later in 2018.

Prices offered in the market for gas supply in 2019 have remained mostly in the high-\$8 to \$11/GJ range. This is similar to the range reported in April 2018, which followed a downward trend from the peak prices offered in early 2017.

By the end of the first quarter of 2018, the prices offered in the domestic market for gas supply in 2019 had converged with export parity prices. This is in stark contrast to the gas prices that suppliers offered to domestic gas buyers in the first half of 2017, particularly in the Southern States.

As shown in chart 2, throughout 2017, retailers/aggregators offered gas for 2019 to C&I gas users in the Southern States at prices that were well in excess of export parity prices. At their peak, prices offered by retailers/aggregators were nearly double the highest prices that C&I gas users would have expected to pay for purchasing gas in Queensland at export parity prices and then transporting that gas to their location (represented by the line depicting expected 2019 LNG netback prices at Wallumbilla plus transport to Victoria).<sup>6</sup> This is symptomatic of a gas market that was not functioning effectively in 2017.

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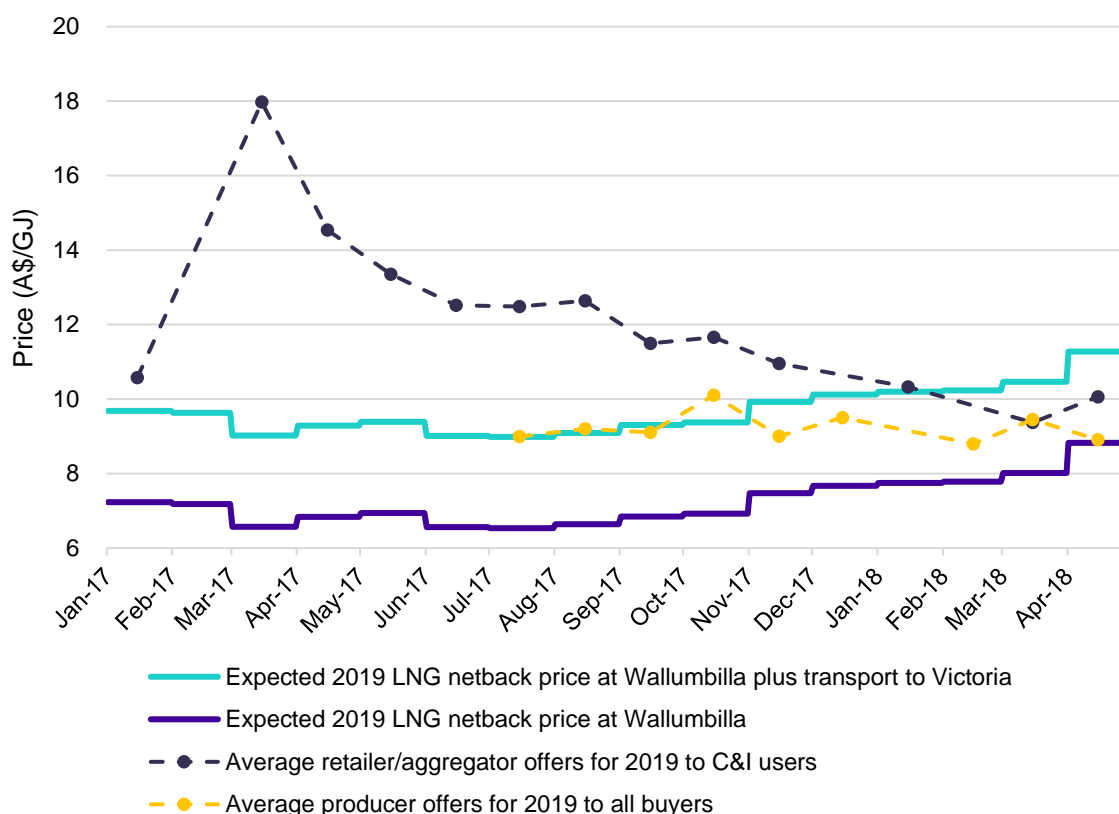
<sup>5</sup> A portion of gas from the Cooper Basin has been included in the supply forecast of the Southern States based on producers' expectations of where gas produced in the Cooper Basin is likely to be delivered in 2019.

<sup>6</sup> Prices offered to individual buyers may also be influenced by other factors, particularly non-price terms and conditions.

Many of the higher-priced offers from early 2017 were made by retailers/aggregators to smaller C&I gas users (those seeking less than 1 PJ per year), who generally do not have the option of sourcing gas directly from producers nor can easily acquire the necessary pipeline capacity. These C&I users rely on gas supply from retailers/aggregators and were affected the most when there was a significant price differential between offers made to them by retailers/aggregators and offers made by gas producers to other gas buyers in the market.

Prices for 2019 are discussed further in chapter 2.

**Chart 2: Average monthly gas commodity prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices (Southern States)**



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

Note: The chart shows average quantity weighted prices offered by southern producers (to all buyers) and retailers/aggregators (to C&I users) in each month in the period between January 2017 and April 2018. Absence of data points for particular months indicates that there were insufficient offers made in those months. The chart also shows the average LNG netback prices at Wallumbilla for 2019 expected in each month of that period. In addition, the chart shows the expected 'buyer alternative' prices in Victoria, which were derived by taking the average LNG netback prices at Wallumbilla for 2019 and adding indicative pipeline tariffs from Wallumbilla to Melbourne.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any unfulfilled offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (the ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

## Commercial and industrial gas user experience remains challenging

C&I gas users continue to report that while more suppliers are now offering gas for supply in 2019 at prices well below the prices they were offered in 2017, market conditions remain very challenging.

C&I users informed the ACCC that they are continuing to receive offers for gas priced two to three times higher than historical levels and on less flexible terms (for example, with higher take-or-pay requirements). C&I users also reported increased use of EOI processes by gas suppliers, which are making it more difficult for users to obtain and compare multiple contemporaneous offers that meet their requirements. In these market conditions, many C&I users reported entering into shorter-term, one to two year gas supply agreements.

C&I gas users are considering a range of non-traditional supply options to adjust to changing market conditions, such as purchasing gas directly from producers rather than retailers, participating in short-term trading markets, and considering LNG import proposals. Some users have also lowered their gas usage by changing fuels or increasing efficiencies.

With gas price offers remaining in the high-\$8 to \$11/GJ range, few C&I users have entered into gas supply agreements for 2019. Many continue to engage in negotiations and are facing difficult choices around their long-term investment decisions and long-term financial viability.

The ACCC considers that with the change in market dynamics in the East Coast Gas Market, it is imperative that C&I gas users make long-term investment and business decisions having regard to the strong influence LNG netback prices have on domestic prices. With the market moving to shorter-term contracts and the use by suppliers of EOI processes, ongoing price transparency (such as the publication by the ACCC of domestic prices and the LNG netback price series) and other market information continue to be critical. Improved market transparency will continue to help buyers make informed decisions about their long-term operations and improve the overall functioning and efficiency of the East Coast Gas Market.

## Changing dynamics in the East Coast Gas Market

### Fundamental changes in the East Coast Gas Market

Historically, the East Coast Gas Market was not exposed to international gas prices, the majority of gas production was in South Australia and offshore Victoria, and gas prices were low. As we noted previously, the East Coast Gas Market has undergone a significant transition, accelerated by the construction of the three LNG projects in Queensland.<sup>7</sup> This transition has altered the supply dynamics, the role of the transmission network and the factors driving domestic gas prices.

The low cost conventional gas fields in South Australia and offshore Victoria, which traditionally served the domestic market, are nearing depletion and production costs from these fields are increasing. There is now a greater reliance on CSG, which has greater production uncertainty and higher production costs.

Historically, the East Coast Gas Market's transmission system was a series of point-to-point pipelines, where gas flowed from the gas fields in Victoria and South Australia to demand centres. This transmission system now works as an integrated network, where gas will need to flow in different directions at different times. Many gas pipelines have become bidirectional and gas increasingly flows across multiple pipelines to reach its destination. These changes mean that access to capacity on key pipelines is more important than it was previously.

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<sup>7</sup> See ACCC, *Gas Inquiry 2017–2020: Interim Report*, September 2017, pp. 13–14, ACCC, *Gas Inquiry 2017–2020: Interim Report*, December 2017, pp. 16–18.

The factors driving domestic prices have also changed. Domestic prices in the East Coast Gas Market are now linked to international LNG prices, which are volatile and significantly higher than historical domestic gas prices.

These changes have fundamentally altered the dynamics of the East Coast Gas Market and have led to higher wholesale gas prices. The impact of these changes has been exacerbated by the lack of transparency across the entire gas supply chain – production, transportation and gas prices and a number of additional shorter-term factors.

## **2017: East Coast Gas Market was dysfunctional**

As we noted in our September 2017 report, a number of factors came together in 2017 to significantly disrupt the operation of the East Coast Gas Market at a time when it was already undergoing significant change.

The closure of the Northern Power Station in South Australia (2016) and the Hazelwood Power Station in Victoria (2017) led to an increase in the importance of gas for electricity generation. A number of GPGs were recommissioned to supply more electricity into the National Electricity Market (NEM),<sup>8</sup> leading to an increase in gas demand for GPG of 44 PJ from 2016 to 2017.<sup>9</sup>

The Queensland LNG producers were not actively participating in the domestic market in 2017. This was due to several coinciding events. As international oil prices fell below their long-term average, oil-linked export contracts restricted the operating cash flows of the LNG producers. Some LNG producers responded by cutting expenditure on drilling wells, which in turn lowered their expected gas production for 2018. In addition, APLNG was conducting a 90-day operational test concluding in July 2017 that required it to run its plant at full capacity for a period, so it was not able to sell gas into the domestic market during this period.

In 2017, domestic producers also forecast to supply less gas to the domestic market in 2018 than anticipated. The Gippsland Basin Joint Venture forecast a significant decline in production from 2017 to 2018.<sup>10</sup> The operations of other domestic gas producers were also impacted by low oil prices and they were not as active in the domestic market as they had been historically.

We found in our September 2017 report that some retailers were choosing not to actively market gas to C&I gas users, believing that they faced higher risks in supplying these users because of the market conditions at the time. Also in 2017, the Northern Territory announced a moratorium on fracking, while Victoria maintained its moratorium on all onshore exploration for gas and other regulatory restrictions acted to limit opportunities for new sources of gas to be identified or developed.

These short-term factors all contributed to the dire market conditions we described in our September 2017 report, where there was a significant forecast supply shortfall and C&I users were receiving very few offers (and often only one offer) for gas, at extremely high prices. In the first half of 2017 in particular, domestic price offers rose significantly above expected LNG netback prices, as shown in chart 2 above.

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<sup>8</sup> Swanbank E Power Station in Queensland: <https://www.qt.com.au/news/swanbank-station-could-keep-states-lights-on-reduc/3299673/>.

Pelican Point Power Station in South Australia: <http://www.abc.net.au/news/2017-03-29/engie-announces-40-million-dollar-upgrade-of-sa-pelican-point/8396092>.

<sup>9</sup> Actual GPG demand in 2016 was 139.12 PJ; actual GPG demand in 2017 was 183.76 PJ. See: <http://forecasting.aemo.com.au/Gas/AnnualConsumption/Total>.

<sup>10</sup> ACCC, *Gas Inquiry 2017–2020: Interim Report*, September 2017, p. 14.

## Conditions have eased in the East Coast Gas Market in 2018

The short-term factors that contributed to the market conditions observed in 2017 have now eased.

There has been significant additional investment in renewable generation over 2017 to fill the gap left by the closure of coal power plants, which may reduce the need for electricity generated by GPG. AEMO has forecast a significant decrease in GPG demand due to this increase in renewable generation in the NEM. AEMO has reduced its forecast GPG demand in 2019 from 135 PJ to 88 PJ.<sup>11</sup> However, there remains some uncertainty around the level of GPG demand because it is dependent on the amount of renewable generation (which is variable due to weather), the uncertainty around further retirement of older electricity generation plants, and unplanned outages due to aging generation assets.

The three Queensland LNG producers have been actively offering more gas to the domestic market than in early 2017. The total quantity contracted for 2018 by the LNG projects to domestic buyers has increased from 229 PJ (as at September 2017) to 305 PJ (as at June 2018). The total quantity contracted for 2019 is currently 205 PJ, with more gas expected to be contracted in the second half of 2018.

This is likely due to a combination of factors, including APLNG successfully completing its operational testing and being able to direct gas into the domestic market again, and oil prices rising and improving cash flows for all three projects, allowing further investment in and development of gas resources. The LNG producers' commitment to offer gas to the Australian domestic market at reasonable prices before selling gas in overseas markets<sup>12</sup> is clearly influencing their decisions about supplying gas to domestic customers.

Domestic producers are also supplying more gas into the East Coast Gas Market. The Gippsland Basin Joint Venture has accelerated some production and is forecasting to bring 15 PJ more gas to market in 2019 than previously expected. BHP Billiton is also forecasting additional gas production from its Minerva gas field, which was previously expected to cease production this year due to water breakthrough. Other producers have returned to being active participants in the domestic market.

At the retailer/aggregator level, new entrants such as Shell Energy Australia are now marketing gas in the East Coast Gas Market. To be able to effectively compete with the incumbent retailers, they may need access to firm pipeline capacity on key transport routes across the East Coast Gas Market. Reforms to the gas transportation market, discussed in chapter 4, should help increase access to pipeline capacity and related services on reasonable terms over time.

Additionally, and as detailed in chapter 2, the ACCC has observed offers being made to C&I users by at least three retailers/aggregators. There is now more competition between the retailers and aggregators than there was in 2017, which appears to be contributing to the lower prices being offered in the market (compared to 2017).

There are also positive signs of changes in government policies around new gas developments. The Northern Territory Government announced in April 2018 that it is lifting its ban on fracking, with exploration expected to start in 2019. This development, combined with the construction of the Northern Gas Pipeline, which will connect the Northern Territory to the East Coast Gas Market from late 2018, means that Northern Territory gas may provide further supply for the east coast in the future.

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<sup>11</sup> AEMO, *2018 Gas Statement of Opportunities*, June 2018, pp. 15, 20.

<sup>12</sup> See [https://www.industry.gov.au/sites/g/files/net3906/f/heads\\_of\\_agreement\\_-\\_the\\_australian\\_east\\_coast\\_domestic\\_gas\\_supply\\_commitment.pdf](https://www.industry.gov.au/sites/g/files/net3906/f/heads_of_agreement_-_the_australian_east_coast_domestic_gas_supply_commitment.pdf).

In May 2018, the Victorian Government announced the release of a number of offshore oil and gas exploration blocks to help build future gas supply, while maintaining its ban on onshore exploration. This new gas exploration could lead to further southern supply and may be an early indicator of further moves to support future potential gas developments.

This combination of factors has led to a market where the risk of a gas supply shortfall for 2019 appears substantially lower than predicted in 2017, with domestic prices moving more in line with LNG netback prices, and C&I users reporting improved albeit still difficult market conditions.

However, downside risks still remain. In the short-term, domestic prices do not seem likely to fall any further and may, in fact, go up given current expectations of future LNG prices. The level of GPG demand is uncertain and could be higher than currently forecast by AEMO, particularly if less renewable generation comes into the NEM or if further coal power plants are decommissioned. Many C&I gas users continue to face difficult decisions about their future operations, as discussed above and further detailed in chapter 3.

### **The future for the East Coast Gas Market**

Despite the short-term improvements discussed above, the medium-to-long term direction of the East Coast Gas Market remains challenging. Domestic gas prices continue to be shaped by LNG prices, transportation costs remain high, and there is significant uncertainty over future gas supply.

To address these issues and to function more effectively, the East Coast Gas Market requires a greater level and diversity of supply, a more efficient transportation network, and greater transparency.

As we have previously advocated in our reports, more supply and diversity of suppliers is needed, particularly in the Southern States, and the cost of any new gas will also determine the prices for gas in the Southern States.<sup>13</sup> Importing gas via an LNG import terminal is an option and there are currently four potential LNG import terminals under consideration in the Southern States. If one of these facilities is built, it could provide an additional source of supply into the Southern States, and under current market conditions, is likely to act as a ceiling or cap for domestic gas prices.

However, the most material pricing benefits for domestic gas users are likely to come if additional lower-cost gas is produced in the Southern States. For this reason, and while recognising the improvements to policy settings that have occurred recently, we continue to urge state governments to adopt policies that consider and manage the risks of individual gas development projects, rather than implementing blanket moratoria and regulatory restrictions.

Future pricing of gas in the Southern States depends on the cost of new gas supply. Domestic gas consumers might pay \$2–4/GJ less for gas if lower cost gas in significant quantities is produced in the Southern States, and if there is more competition in its supply (rather than gas being transported from Queensland or imported from overseas).

There are also a number of transportation related reforms that are currently being implemented, which are expected to improve the efficiency with which capacity is allocated and used on pipelines and compression facilities. These include the capacity trading platform and day-ahead auction which have been approved by the COAG Energy Council and are intended to commence on 1 March 2019. These reforms will enable shippers to gain

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<sup>13</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 5–7, 18, 48–53. ACCC, *Gas Inquiry 2017–2020: Interim Report*, September 2017, pp. 21–23, 69–70. ACCC, *Gas Inquiry 2017–2020: Interim Report*, December 2017, pp. 16–17.

access to more competitively priced secondary transportation capacity. In addition to these reforms, significant changes have been made to the disclosure requirements for pipelines that were previously unregulated, and that are proposed for currently regulated pipelines. These transparency measures are discussed in chapter 4.

In general, markets work better and generate more efficient outcomes the more information that is available to buyers and sellers. The benefits of transparency are greater when buyers and sellers have access to similar information. For a workably competitive market, participants need ready access to the information they require to make informed decisions about consumption, production, transportation, investment and risk management in the short and long-run.

As part of the current inquiry, the ACCC is working to improve transparency in the East Coast Gas Market by publishing the prices offered and agreed for gas supply and the prices for transportation services, and will soon commence publishing an LNG netback price series. The ACCC is also working on improving the transparency and quality of reserves and resources information by establishing a set of reporting obligations, gathering information from suppliers, and publishing that data in a meaningful way. The ACCC is also examining the cost components of retail prices and will publish its findings in future reports.

Additionally, the ACCC has been working with the Gas Market Reform Group to identify other information gaps in the market and the steps that should be taken to address these. These transparency measures are discussed in chapter 4.

## Future work of the Inquiry

This is the fourth interim report of this Inquiry, which will operate until April 2020. The ACCC expects to provide the next interim report in December 2018, three reports in 2019 (in April, July and December), and a final report in April 2020.

In each report, the ACCC will aim to further promote gas price transparency by providing updates on prices offered and agreed for gas supply across the domestic market. Updates on the pricing of transportation services will be provided annually in December reports, due to the relative infrequency of these price negotiations. In the next July report, the ACCC will report on the gas supply and demand outlook for the following year as part of any advice to the Government under the Australian Domestic Gas Security Mechanism. The July report will also provide a broader perspective on the state of the gas market by reporting on the experiences of C&I gas users in securing gas supply. The December reports will provide an update on the immediate supply and demand outlook and C&I user experiences, as well as an update on the long-term supply outlook.

In addition to our regular reporting, there are a number of other areas the ACCC will be exploring over the course of the Inquiry which will be discussed in future reports, including:

- conditions for, and pricing of, access to transportation and storage services
- retailer pricing, costs and margins
- reserves and resources reporting
- key factors influencing domestic gas prices.

The ACCC will continue to make market information available as appropriate.

# 1. Supply outlook for 2019

## 1.1. Key points

- The supply-demand outlook for the East Coast Gas Market in 2019 has improved since the ACCC's December 2017 report. Under AEMO's neutral demand scenario, there is unlikely to be a shortfall in 2019 due to a significant reduction in forecast GPG demand by AEMO as well as some increase in forecast production by producers in the Southern States.
- Since the December 2017 report, the LNG projects have changed their export plans, giving themselves more flexibility and better positioning themselves to support the domestic market in 2019.
- The LNG projects now expect to have more gas available in excess of their 2019 contractual commitments (98 PJ) that can be used for either export or to support the domestic market. However, in line with their commitment to government, the LNG projects have agreed to first offer this gas domestically before offering it overseas. This excess gas will likely act as a buffer for any unexpected changes in the needs of the domestic market.
- The LNG projects have revised down the quantity of gas required to meet their 2019 LNG contractual commitments from 1274 PJ as reported in December 2017 to 1262 PJ. The LNG projects currently have no firm expectations of how much gas they will sell on the international spot markets above their contractual requirements.
- The LNG projects have not entered into any new gas supply agreements for 2019 in recent months, however, they have continued to contract significant quantities for supply in 2018. This is likely because we are only part way through the year, and it is consistent with the approach of some gas consumers who are waiting until later in the year before contracting for 2019 supply.
- The Southern States are less likely to face a shortfall in 2019 compared to 2018, primarily due to an increase in forecast production and a decrease in AEMO's forecast GPG demand. That said, the increase in production is likely to be specific to 2019, and the supply-demand balance in the Southern States continues to represent a tight market. Gas from Queensland may be required to flow south or arranged for through gas swaps to ensure security of supply.
- Information recently reported by pipeline operator APA indicates that while there is uncontracted firm capacity westward on the South West Queensland Pipeline in 2019, compression capacity at Wallumbilla (necessary to compress additional gas to send it south via the SWQP) is fully contracted. Shippers may need to rely on purchasing interruptible compression to move gas to the south using the SWQP.

## 1.2. The supply and demand outlook for 2019 has improved

In December 2017, the ACCC reported an improvement to the supply and demand outlook for 2019, which AEMO had previously forecast in September 2017 could face a supply shortfall of up to 102 PJ.<sup>14</sup> The ACCC attributed the improvement to increases in forecast production by some of the key suppliers in the east coast but more significantly, changes in

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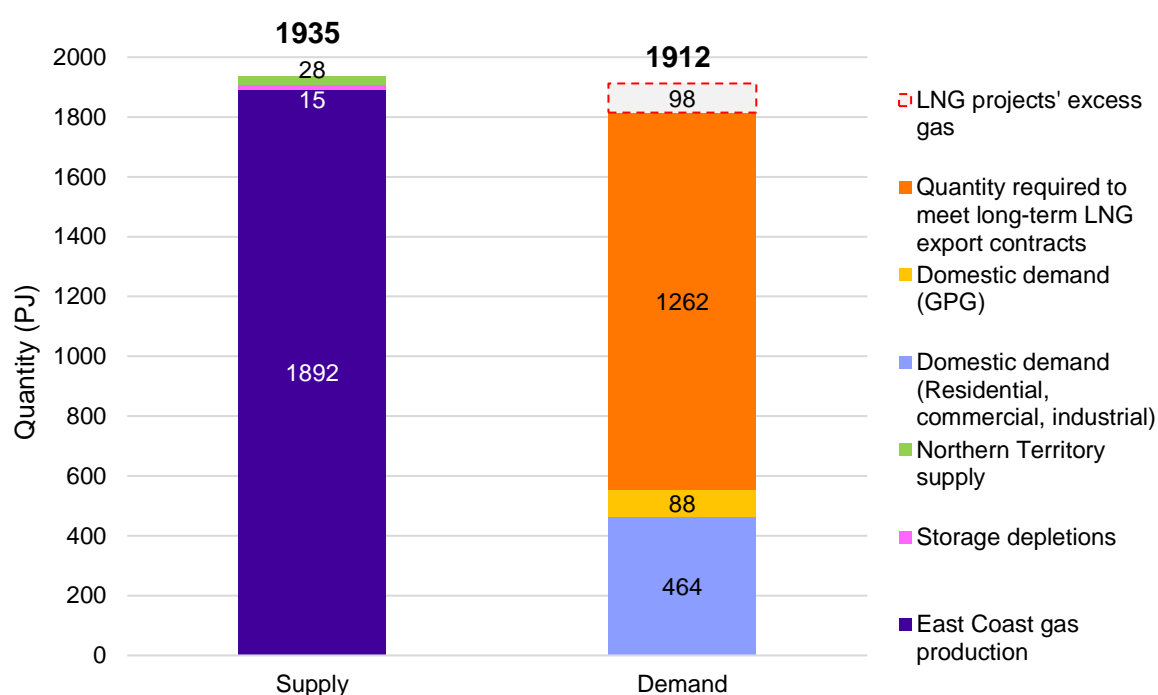
<sup>14</sup> AEMO, *Update to Gas Statement of Opportunities*, September 2017, [https://www.aemo.com.au/-/media/Files/Gas/National\\_Planning\\_and\\_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities---Update.pdf](https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities---Update.pdf).

export demand by the LNG projects as a result of the Heads of Agreement.<sup>15</sup> Since the December report, the supply and demand outlook for 2019 has improved further.

Chart 1.1 shows the ACCC’s current supply and demand outlook for 2019. It shows total forecast supply (production, storage depletions and expected gas flows from the Northern Territory to the east coast in 2019) against total demand (domestic demand plus the quantities of gas required by the LNG projects to meet their long-term export contractual commitments). The demand forecast includes the quantity of gas in excess of contractual commitments that the LNG projects forecast to have available in 2019.

The supply and LNG demand data reflected in the chart below is based on information obtained directly from producers. Domestic demand is based on AEMO forecasts.<sup>16</sup>

**Chart 1.1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2019**



Source: ACCC and AEMO data

The chart shows that, based on current projections and consistent with what the ACCC reported in its December 2017 report, the risk of a shortfall in 2019 remains low.

Forecast supply has increased from 1921 PJ to 1935 PJ since December. This is in part attributable to additional information received by the ACCC about forecast storage

<sup>15</sup> The Heads of Agreement is a commitment by the LNG projects to the Government to offer sufficient gas on reasonable terms to the domestic market for 2018 and 2019 to meet any expected shortfalls. It also includes a commitment by the LNG projects to offer gas to the domestic market on competitive terms, before offering uncontracted gas to the international market: See Department of Industry, Innovation, and Science, *The Australian Domestic Gas Security Mechanism*, October 2017, <https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Pages/Australian-Domestic-Gas-Security-Mechanism.aspx>.

<sup>16</sup> Specifically, domestic demand is based on AEMO data from its June 2018 Gas Statement of Opportunities: [https://www.aemo.com.au/-/media/Files/Gas/National\\_Planning\\_and\\_Forecasting/GSOO/2018/2018-Gas-Statement-Of-Opportunities.pdf](https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2018/2018-Gas-Statement-Of-Opportunities.pdf).

depletions, but more significantly, increases in forecast production by some of the key producers in the Southern States.

As discussed further in section 1.4, the Gippsland Basin Joint Venture (GBJV) is forecasting to produce 15 PJ more in 2019 than it had previously submitted to the ACCC. BHP Billiton is also forecasting to produce more gas in 2019 than previously expected.

Forecast storage depletions from the Roma Underground Gas Storage, Moomba and Silver Springs storage facilities have been included in the supply forecast and are expected to contribute an aggregate of 15 PJ of gas to the total supply pool. The information obtained by the ACCC indicates that the operators of these facilities currently do not expect these facilities to be refilled by the end of 2019 to their initial levels, which is consistent with the trend over the past few years. Depending on the operation of the Iona gas storage facility, there could also be additional quantities of gas available to the East Coast Gas Market from that facility in 2019.

The supply forecast for 2019 also includes gas supply from the Northern Territory. The Northern Territory will be connected to the east coast once construction of the Northern Gas Pipeline (NGP) is complete. The NGP is expected to flow gas from late 2018, and is expected to have the capacity to transport up to 35 PJ of gas per annum.<sup>17</sup> In April 2018, following the announcement that the Northern Territory fracking moratorium had been lifted (discussed further in section 1.6) Jemena, who is responsible for construction of the NGP, confirmed plans to extend and expand the NGP.<sup>18</sup> With the extension and expansion,<sup>19</sup> the NGP will have potential to bring around 700 TJ/day (or about 256 PJ/annum) of gas to the East Coast Gas Market.<sup>20</sup> Based on information provided to the ACCC, about 28 PJ of gas is currently expected to flow to the east coast from the Northern Territory in 2019.

The forecast production presented in chart 1.1 only includes production from 2P reserves. While most of this is from well-known, developed areas, about nine per cent is from less certain, undeveloped areas – that is, projects that may require additional investment before production can commence.

Chart 1.1 does not include production from contingent or undiscovered resources, which are highly uncertain. However, there is currently 14 PJ of gas forecast to be produced from contingent and undiscovered gas resources in 2019, which if realised, would contribute additional quantities of gas to the east coast.

In assessing the supply-demand balance for 2019, the ACCC has relied on AEMO's neutral domestic demand forecast from the June 2018 Gas Statement of Opportunities (GSOO).<sup>21</sup> AEMO has also forecast domestic demand for 2019 under strong and weak demand scenarios. As AEMO notes in the GSOO, these other scenarios provide 'alternative projections of consumption and peak demand with reasonable bounds on the core demand drivers,' but are less likely to occur than the neutral forecast.<sup>22</sup> It is worth noting that the difference between domestic demand in AEMO's neutral and strong scenarios is not material

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<sup>17</sup> Jemena, *Northern Gas Pipeline: Draft Environmental Impact Statement*, August 2016, <https://jemena.com.au/documents/pipeline/nelgi/chapters/1-introduction>.

<sup>18</sup> Jemena, *Jemena welcomes decision to lift fracking moratorium*, April 2018, <http://jemena.com.au/about/newsroom/media-release/2018/jemena-welcomes-decision-to-lift-fracking-moratori>.

<sup>19</sup> This reportedly would involve adding compression or looping the pipeline: <https://www.afr.com/business/jemena-says-nt-pipeline-extension-could-solve-east-coast-gas-crisis-20170503-gvwxw8k>.

<sup>20</sup> Jemena has stated that provided sufficient and appropriate gas is proven and available for transportation, it intends to commence preliminary works on the expansion and extension of the NGP in 2019: Jemena, *Jemena welcomes decision to lift fracking moratorium*, April 2018, <http://jemena.com.au/about/newsroom/media-release/2018/jemena-welcomes-decision-to-lift-fracking-moratori>.

<sup>21</sup> AEMO, *Gas Statement of Opportunities*, June 2018, [https://www.aemo.com.au/-/media/Files/Gas/National\\_Planning\\_and\\_Forecasting/GSOO/2018/2018-Gas-Statement-Of-Opportunities.pdf](https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2018/2018-Gas-Statement-Of-Opportunities.pdf).

<sup>22</sup> AEMO, *Gas Statement of Opportunities*, June 2018, pp. 11–12.

and if realised, would have only a minor impact on the supply and demand outlook of the East Coast Gas Market for 2019.

AEMO’s neutral domestic demand forecasts are set out in table 1.1. As this table shows, total forecast domestic demand has significantly reduced since the previous forecast prepared by AEMO in September 2017.

**Table 1.1: Comparison of AEMO’s domestic demand forecast between its September 2017 GSOO and June 2018 GSOO, based on AEMO’s neutral demand scenario<sup>23</sup>**

	2017 September GSOO	2018 June GSOO
<b>Residential, commercial and industrial</b>	463	464
<b>GPG</b>	135	88
<b>Total domestic demand</b>	598	552

Source: AEMO

The difference in forecast domestic demand (as shown in table 1.1) is in large part due to gas-powered generation, which is expected to play a substantially smaller role in 2019 than previously thought, due to increasing renewable generation.<sup>24</sup>

As the ACCC has previously observed, GPG can have a significant impact on the level of domestic gas demand and is highly volatile when compared to other categories of domestic demand (for example, residential and industrial demand).<sup>25</sup> This is because GPG demand is dependent on factors that are difficult to forecast accurately (such as rainfall, wind, renewable generation investment and unexpected retirement of generation or unplanned outages). This needs to be taken into account when assessing whether forecast supply in 2019 is likely to be sufficient to meet demand expectations.

In relation to LNG demand, the LNG projects have in aggregate revised down their long-term LNG contractual commitments, including feed gas requirements, from 1274 PJ in December 2017 to 1262 PJ. They currently have no firm expectations of how much gas they will sell on the international spot markets above their contractual requirements.

As shown in chart 1.1, the LNG projects currently forecast to have 98 PJ of gas available in excess of their minimum contractual export and domestic commitments, which could be used for either export or to supply the domestic market. However, pursuant to the Heads of Agreement, the LNG projects have agreed to first offer uncontracted gas domestically and, as discussed further at section 1.3, are adopting a range of strategies to help ensure they are fulfilling this commitment.

This 98 PJ of excess gas will likely act as a buffer for the domestic gas market if forecast production levels are not realised or if actual demand is higher than currently forecast by AEMO.

<sup>23</sup> The neutral scenario ‘considers demand drivers of an economy that takes the most likely pathway’: AEMO, *Gas Statement of Opportunities*, June 2018, p. 11.

<sup>24</sup> AEMO, *Gas Statement of Opportunities*, June 2018.

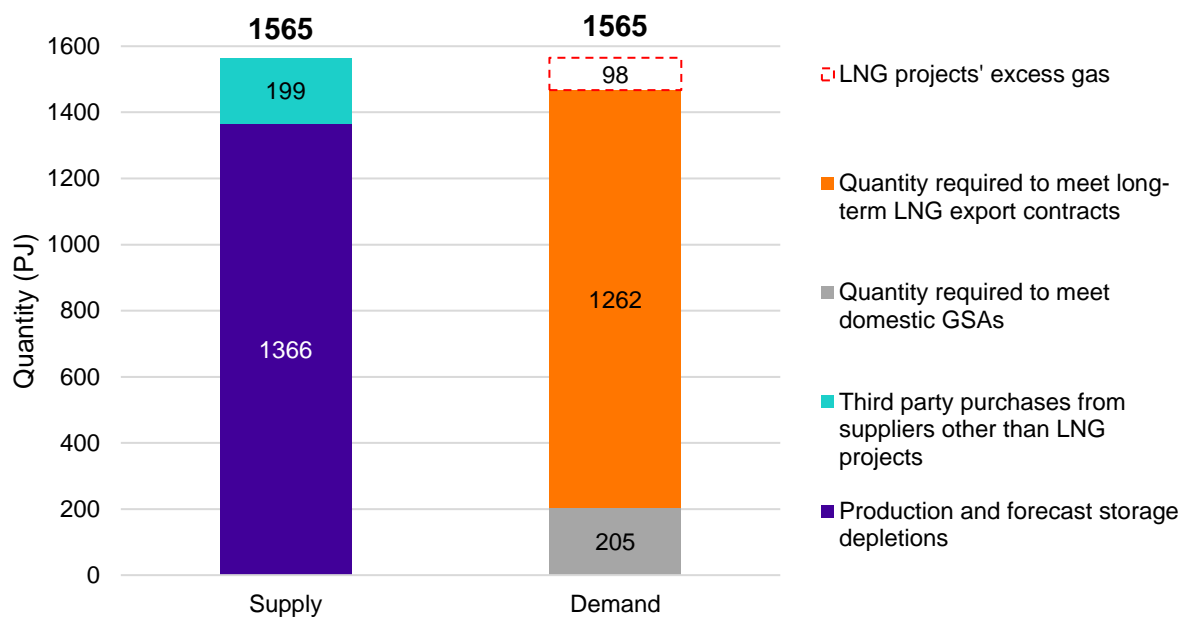
<sup>25</sup> ACCC, *Gas Inquiry 2017–2020: Interim Report*, September 2017, p. 27; ACCC, *Gas Inquiry 2017–2020: Interim Report*, December 2017, p. 23.

### 1.3. The LNG projects forecast to have enough gas to meet their commitments to the domestic and export markets in 2019

The ACCC's December 2017 report found that the LNG projects were likely to have sufficient gas to meet their existing domestic and LNG export contractual commitments and forecast LNG spot sales in 2019.<sup>26</sup>

The supply and demand balance of the LNG projects for 2019 has since been updated and is illustrated by chart 1.2 below.

**Chart 1.2: Forecast supply-demand balance of the Queensland LNG projects for 2019**



Source: ACCC data

Note: The ACCC received new information about the gas purchases and gas sales made by the LNG projects. The increases in the total quantity of third party gas and the total quantity of gas required to meet domestic GSAs from the December 2017 report primarily reflect this new information, rather than new purchases or new gas sales, respectively.

Chart 1.2 shows that, consistent with the ACCC's December 2017 report, the LNG projects are likely to have sufficient gas to meet their existing domestic and LNG export contractual commitments.

Since we reported in December 2017, the LNG projects have made some changes to their export plans. The LNG projects have revised down the quantity of gas that they expect to require in 2019 to meet long-term export GSAs by 12 PJ (from 1274 PJ to 1262 PJ).<sup>27</sup> The LNG projects currently have no firm expectations of how much gas they will sell on the international spot markets above their contractual requirements.

<sup>26</sup> ACCC, *Gas Inquiry 2017–2020: Interim Report*, December 2017, p. 28.

<sup>27</sup> These quantities include the gas requirements for fuel and processing. The quantity of LNG ultimately produced will be lower.

As chart 1.2 shows, the LNG projects are currently expecting to supply only slightly more gas to the domestic market (205 PJ<sup>28</sup>) than they are expecting to take out of the domestic market (199 PJ<sup>29</sup>). In the period between November 2017 and June 2018, the LNG projects did not enter into any new domestic gas supply agreements for 2019, however, they did continue to enter into new agreements for gas supply in 2018. In that period, contracted domestic supply by the LNG projects for 2018 gas supply increased from 271 PJ to 305 PJ. At least in part, the limited activity for 2019 supply is likely due to the fact that we are only part way through 2018 and further contracting for gas supply in 2019 is likely to occur over the remainder of this year.

The LNG projects currently expect to have 98 PJ of excess gas available for 2019 that they could either export or supply to the domestic market. Under the Heads of Agreement (signed in October 2017), the LNG projects have committed to offering sufficient gas for 2018 and 2019 to meet any expected shortfalls, through the good faith offering of gas to the domestic market on reasonable terms.<sup>30</sup> The LNG projects also committed to offering gas to the Australian domestic gas market on competitive market terms, before offering uncontracted gas to the international market. Accordingly, should the domestic market require it, it can expect to have priority over this excess gas before any decisions are made to ship it overseas.

To ensure they are meeting their commitments under the Heads of Agreement, the LNG projects are adopting a range of strategies to first offer their uncontracted gas domestically. These include selling products on the Wallumbilla Gas Supply Hub, commencing Expression of Interest (EOI) processes<sup>31</sup> and engaging in general bilateral negotiations.

Some of the LNG projects have informed the ACCC that one reason they are undertaking EOI processes is to ensure they can demonstrate that they are taking steps to meet their commitments under the Heads of Agreement. EOI processes are easier to document than general bilateral negotiations and make it easier for the LNG projects to monitor and substantiate how much gas has been offered by them to domestic buyers.

However, C&I gas users have informed the ACCC that these types of processes do not align with their needs. When C&I gas users need to purchase gas, they prefer to obtain a number of offers from multiple suppliers at the same time. Obtaining contemporaneous offers assists with price discovery and allows C&I gas users to find the best-priced offer available in the market at the time. EOI processes generally occur over particular periods of time and C&I gas users are required to conform to supplier deadlines. This can result in users having to bid for gas without having contemporaneous offers from other suppliers in the market. Users are also generally required to conform to supplier parameters, for example minimum quantity requirements, delivery points and delivery periods, which can make it challenging for users to obtain supply that fits their needs. This is discussed further in chapter 3.

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<sup>28</sup> The ACCC received new information about the gas sales made by the LNG projects. The increase in the total quantity of domestic gas sales compared to the quantity reported in December (199 PJ) is entirely due to a revision to account for this new information, rather than new sales by the LNG projects.

<sup>29</sup> The ACCC received new information about the gas purchases made by the LNG projects. The increase in the total quantity of third party gas from the December 2017 report primarily reflects this new information, rather than new purchases.

<sup>30</sup> Department of Industry, Innovation, and Science, *The Australian Domestic Gas Security Mechanism*, October 2017, <https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Pages/Australian-Domestic-Gas-Security-Mechanism.aspx>.

<sup>31</sup> For example, in April 2018, APLNG called for expressions of interest for 2019 gas supply, as well as for future supply from 2020 to mid-2023: Australia Pacific LNG, *Australia Pacific LNG commits more gas to the domestic market*, 23 April 2018, <https://www.aplng.com.au/content/dam/aplng/media-release/2018/APLNG-EOI-and-Q1-gas-sales-media-release-20180423.PDF>.

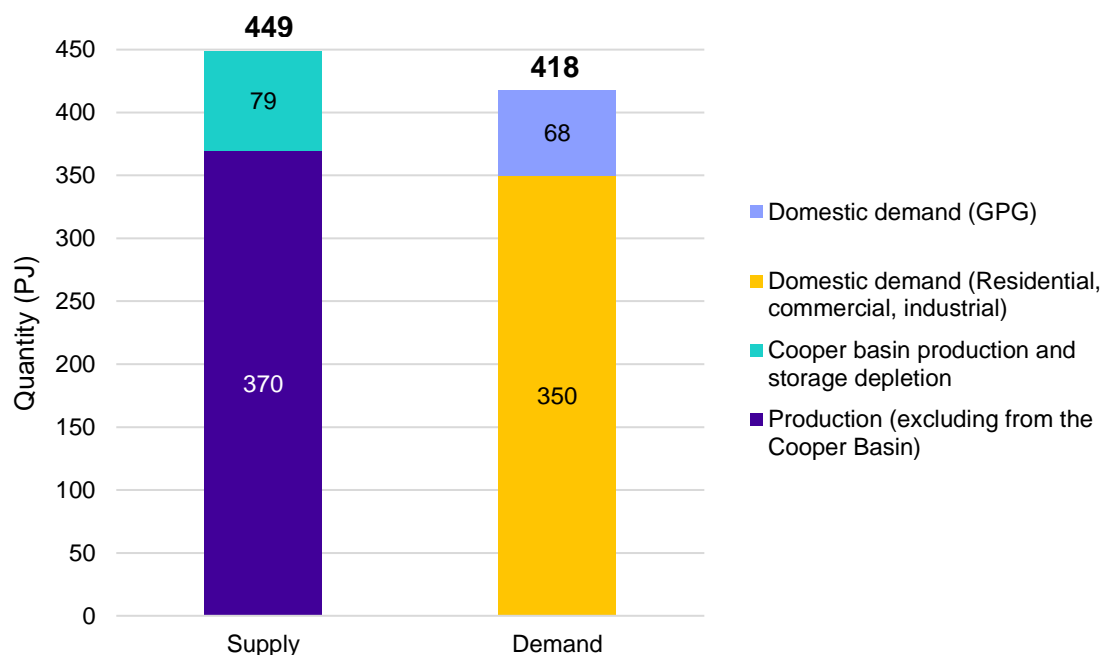
## 1.4. The supply-demand balance in the Southern States represents a tight market

Chart 1.3 compares forecast supply (production and storage depletions) against demand in 2019 for the Southern States. The production forecast in the chart includes production in offshore Victoria and Camden (NSW) and a proportion of gas from the Cooper Basin.

A portion of gas from the Cooper Basin has been included in the supply forecast for the Southern States based on producers' expectations of where gas produced in the Cooper Basin is likely to be delivered in 2019. As previously reported by the ACCC, the bulk of Cooper Basin production is contractually committed to the LNG projects in Queensland. However, for 2019, a large quantity of this gas has been swapped out to supply the Southern States.

A further portion of the Cooper Basin gas that has been included in the supply forecast relates to gas acquired from the Cooper Basin by a gas retailer, which contributes to the retailer's overall supply portfolio. The retailer has the option to physically deliver this gas to either the Southern States or Queensland, depending on the demand dynamics of its portfolio at the time. Given Queensland is expected to be self-sufficient in 2019 (as discussed in section 1.5), for the purpose of the analysis in this section, we have included this portion of gas in the supply outlook for the Southern States. However, some of this gas could end up being delivered into Queensland and, therefore, total supply of the Southern States may be lower than is shown in the chart.

**Chart 1.3: Forecast domestic supply-demand balance in the Southern States for 2019 (including a proportion of Cooper Basin gas)**



Source: ACCC and AEMO data

As shown in chart 1.3, the forecast supply-demand balance for 2019 in the Southern States remains tight and is likely to be subject to the level of realised GPG demand.

Forecast production in the Southern States (excluding from the Cooper Basin) is expected to increase from 348 PJ in 2018 to 370 PJ in 2019. This is largely attributable to increases in

forecast production for 2019 by the Gippsland Basin Joint Venture (GBJV) and BHP Billiton (as operator of the Otway Basin's Minerva gas field), as well as commencement of supply from Cooper Energy's Sole Gas Project.

As mentioned in section 1.2, the GBJV expects to produce 15 PJ more gas in 2019 than previously reported to the ACCC. Esso Australia, the operator of the GBJV, explained that production expectations of the joint venture for 2019 have improved due to bringing forward final investment decision timing for its West Barracouta project, and a flow-on resource assessment which enables accelerated gas production from one of its legacy gas fields. The West Barracouta project relates to acreage in offshore Victoria (about 6km south west of the existing Barracouta platform) that Esso Australia is currently seeking to develop.<sup>32</sup> Esso Australia has stated that the project is likely to involve the drilling of a number of subsea wells and will utilise Esso Australia's existing infrastructure in Bass Strait.<sup>33</sup> However, overall, forecast production by the GBJV in 2019 remains significantly lower than its record levels in 2017 (322 PJ), and is expected to remain at 2011–15 production levels as the GBJV's legacy gas fields continue to decline.<sup>34</sup>

BHP Billiton is also forecasting additional production in 2019 from its Minerva gas field, which was previously expected to cease production this year due to water breakthrough. As this has not occurred, Minerva has continued production beyond BHP Billiton's previous expectations. While Minerva is forecast to be able to contribute additional quantities in 2019, BHP Billiton has informed the ACCC that it is nevertheless nearing the end of its production capacity and is not expected to continue to produce gas in the medium to long-term. BHP Billiton noted that ongoing collection of production data will provide more insight into likely future production from the Minerva gas field.

Cooper Energy's Sole Gas Project in the Gippsland Basin is also expected to come online in mid-2019,<sup>35</sup> contributing much needed additional gas to the East Coast Gas Market. The project marks the first new production well to be drilled in offshore Victoria since 2012<sup>36</sup> and is expected to produce around 25 PJ per annum.<sup>37</sup>

However, apart from that project, there are very limited prospects of new gas supply emerging from production basins in the Southern States in the immediate future. New sources of gas supply will therefore be needed to offset the expected future decline in production from more traditional sources of domestic supply in the Southern States.

Forecast domestic demand in the Southern States for 2019 has reduced from what AEMO had previously forecast in September 2017—from 430 PJ to 418 PJ under AEMO's expected domestic demand scenario. This is due to reductions in forecast GPG demand, which is a

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<sup>32</sup> ExxonMobil, *Esso offshore projects*, viewed 4 July 2018, <http://cdn.exxonmobil.com/~media/australia/files/publications/fact-sheets/exxonmobil-australia-offshore-projects-fact-sheet-october-2017.pdf>, p. 3.

<sup>33</sup> ExxonMobil, *Esso offshore projects*, viewed 4 July 2018, <http://cdn.exxonmobil.com/~media/australia/files/publications/fact-sheets/exxonmobil-australia-offshore-projects-fact-sheet-october-2017.pdf>, p. 3.

<sup>34</sup> See ACCC, *Gas Inquiry 2017–2020: Interim Report*, September 2017, p. 14; ACCC, *Gas Inquiry 2017–2020: Interim Report*, December 2017, p. 30.

<sup>35</sup> Cooper Energy and APA Group, *Orbost gas processing facility upgrade and sole gas project to deliver much needed east coast gas from mid-2019*, 23 March 2018, <http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/Minister-congratulates-Cooper-Energy-and-APA-on-Sole-gas-project.pdf>.

<sup>36</sup> Minister for Resources (Victoria), *Offshore gas exploration to build future gas supply*, media release, 16 May 2018, <https://www.premier.vic.gov.au/offshore-gas-exploration-to-build-future-supply/>; Cooper Energy, *Sole-3 underway*, 2 May 2018, <http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/2018.05.02-Sole-3-spud.pdf>.

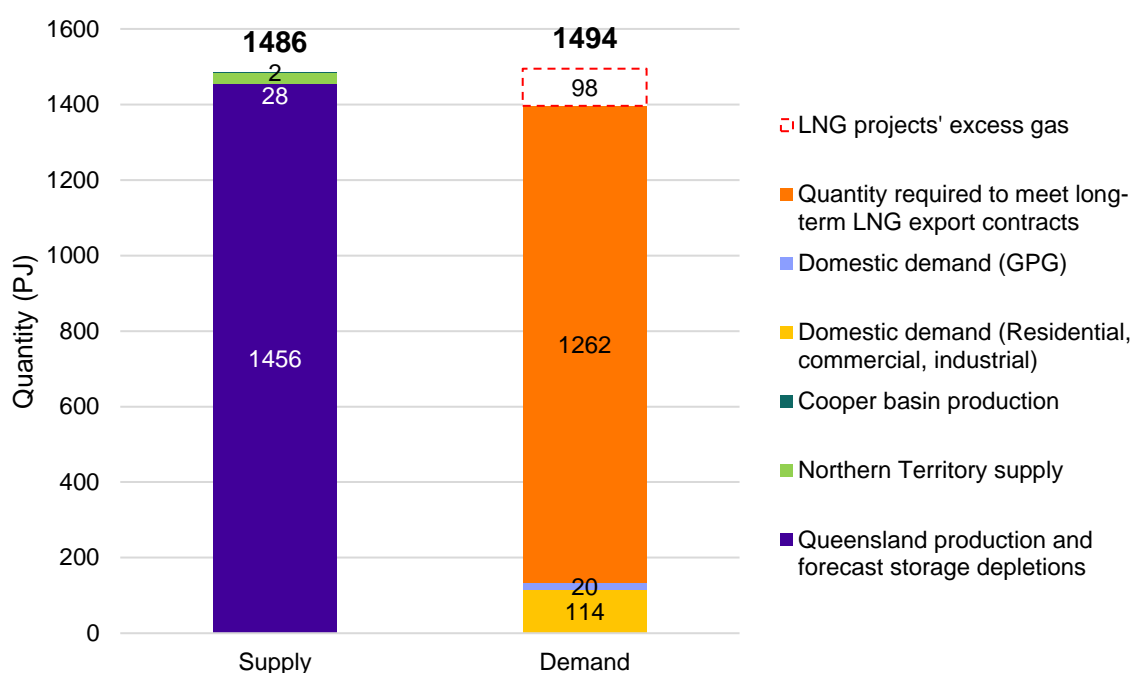
<sup>37</sup> Cooper Energy and APA Group, *Orbost gas processing facility upgrade and sole gas project to deliver much needed east coast gas from mid-2019*, 23 March 2018, <http://www.cooperenergy.com.au/Upload/Documents/AnnouncementsItem/Minister-congratulates-Cooper-Energy-and-APA-on-Sole-gas-project.pdf>.

result of increased expectations around renewable generation. However, as noted earlier, GPG demand is highly volatile and difficult to forecast. If GPG demand is greater than expected, this could shift the supply-demand balance and result in an even tighter market.

## 1.5. Queensland is expected to have sufficient gas to meet its needs in 2019

Chart 1.4 compares forecast supply (production and storage depletions) against demand in Queensland for 2019. Forecast production is comprised of Queensland’s total production, supply from the Northern Territory and a proportion of gas from the Cooper Basin in South Australia. Forecast demand is made up of AEMO’s neutral domestic demand forecast for Queensland and forecast export demand based on data provided directly by the LNG projects to the ACCC.

**Chart 1.4: Forecast supply-demand balance in Queensland for 2019**



Source: ACCC and AEMO data

Chart 1.4 shows that Queensland is likely to have sufficient gas available to meet both domestic and contractual LNG export demand. However, Queensland’s supply-demand balance would tighten significantly if the majority of the LNG projects’ excess gas was used to supply export markets.

Forecast production in Queensland (excluding the Cooper basin) is expected to decrease slightly from 1459 PJ in 2018 to 1456 PJ in 2019.

Queensland’s supply forecast also includes gas from the Northern Territory. The Northern Territory will be connected to Mt Isa in Queensland once construction of the Northern Gas Pipeline is complete (towards the end of 2018). About 28 PJ of gas is forecast to flow into Queensland via the NGP in 2019. As the NGP’s annual capacity is around 35 PJ, there is potential for additional quantities of Northern Territory gas to supply Queensland next year.

AEMO's forecast of domestic demand in Queensland in 2019 has reduced from 168 PJ to 134 PJ (under AEMO's expected domestic demand scenario). This reduction in demand is largely attributable to AEMO's lower expectations of GPG demand in 2019.

## 1.6. Recent market developments

There have been a number of developments since the start of this year that could result in additional supply being brought to the domestic market. However, due to long lead times, these developments are unlikely to have an impact on the supply outlook for 2019, or where relevant, have already been accounted for.

### **Beach Energy discovers a new gas field in the Otway Basin**

Beach Energy announced in January this year a new gas field discovery at Haselgrove-3 ST1 in the onshore Otway Basin.<sup>38</sup> Further testing and appraisal is currently underway.<sup>39</sup>

The proposed new Katnook Gas Processing Facility to be partially funded by the Federal Government's Gas Acceleration Program (discussed below) will be used to purify resources from the Haselgrove-3 ST1 well.<sup>40</sup>

### **Santos is investing in and expanding its QLD acreage**

Santos announced on 27 February 2018 that it and its GLNG partners would be investing \$900 million in upstream developments this year, including funding of the new Roma East project.<sup>41</sup> The Roma East project is expected to be developed over the next three years, supplying almost 50 PJ of gas per annum from 2020.

In late May 2018, Santos and its GLNG partners announced a further \$400 million investment in the Arcadia gas project, which at its peak is expected to deliver up to 75 TJ/day (or about 27 PJ per annum) to the gas supply for the GLNG project.<sup>42</sup>

### **Central Petroleum and Armour Energy win QLD acreage**

In March this year, it was announced that Central Petroleum and Armour Energy had won the latest tender for gas exploration acreage released by the Queensland government to promote domestic supply.<sup>43</sup> The acreage of almost 400 hectares is located just north of the Miles and Surat townships in south-west Queensland.

The acreage is expected to contribute to long-term local domestic supply, with the parties first having to put in place relevant land access agreements and to meet all necessary environmental and Native Title requirements, before being granted the Petroleum Lease.<sup>44</sup>

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<sup>38</sup> Beach Energy, *New Gas Field Discovery in the Otway Basin, South Australia*, 11 January 2018, [http://www.beachenergy.com.au/irm/PDF/6923\\_0/NewgasfielddiscoveryintheOtwayBasin](http://www.beachenergy.com.au/irm/PDF/6923_0/NewgasfielddiscoveryintheOtwayBasin).

<sup>39</sup> Beach Energy, *Quarterly report for the period ended 31 March 2018*, 24 April 2018, [http://www.beachenergy.com.au/irm/PDF/7017\\_0/Quarterlyreportfortheperiodended31March2018](http://www.beachenergy.com.au/irm/PDF/7017_0/Quarterlyreportfortheperiodended31March2018), p. 13.

<sup>40</sup> Beach Energy, *Quarterly report for the period ended 31 March 2018*, 24 April 2018, [http://www.beachenergy.com.au/irm/PDF/7017\\_0/Quarterlyreportfortheperiodended31March2018](http://www.beachenergy.com.au/irm/PDF/7017_0/Quarterlyreportfortheperiodended31March2018), p. 13.

<sup>41</sup> Santos, *Santos GLNG to invest \$900m in Queensland gas fields in 2018*, 27 February 2018, <https://www.santos.com/media-centre/announcements/santos-glng-to-invest-900m-in-queensland-gas-fields-in-2018/>.

<sup>42</sup> Santos, *Santos GLNG announces final investment decision on A\$400 million Arcadia project*, 31 May 2018, <https://www.santos.com/media-centre/announcements/santos-glng-announces-final-investment-decision-on-a-400-million-arcadia-project/>.

<sup>43</sup> The Hon. Dr Anthony Lynham (Minister for Natural Resources, Mines and Energy), QLD opens more land to meet domestic gas supply challenge, media release, 1 March 2018, <http://statements.qld.gov.au/Statement/2018/3/1/qld-opens-more-land-to-meet-domestic-gas-supply-challenge>.

<sup>44</sup> The Hon. Dr Anthony Lynham (Minister for Natural Resources, Mines and Energy), QLD opens more land to meet domestic gas supply challenge, media release, 1 March 2018, <http://statements.qld.gov.au/Statement/2018/3/1/qld-opens-more-land-to-meet-domestic-gas-supply-challenge>.

## **New East Coast Supply from Gas Acceleration Program**

On 28 March 2018, the Federal Government announced four new grants under its \$26 million Gas Acceleration Program to boost additional supply.<sup>45</sup> The funded projects include Armour Energy's Kincora Gas Acceleration Project in the Surat Basin, Westside Corporation's Greater Meridian Domestic Gas Acceleration Project in the Bowen Basin, Beach Energy's construction of a new Katnook Gas Processing Facility in the Otway Basin, and Tri-Star Fairfield's development of four new wells west of Rolleston, Queensland.

The projects are expected to produce an additional 12.4 PJ of gas for the East Coast Gas Market by mid-2020, and an extra 27.6 PJ over five years.

## **The Northern Territory has lifted its fracking ban**

On 17 April 2018, the Northern Territory government announced it would be lifting its onshore fracking moratorium.<sup>46</sup> The announcement followed the findings of an independent fracking inquiry led by Justice Rachel Pepper, which found that subject to implementing a number of recommendations, the risk of fracking can be reduced to an acceptable level. The Northern Territory government accepted the 135 recommendations stemming from the inquiry, and a detailed plan for their implementation is currently being developed. The implementation plan is expected to be released to the public in July this year.

Removing the ban on fracking is a positive development that will allow gas explorers to resume drilling of onshore areas with high potential for gas, whilst taking into account environmental considerations. It has also led to Jemena's announcement that it will extend and expand the NGP, which is expected to connect the Northern Territory to the East Coast Gas Market in the latter half of the year.

The NGP is expected to flow gas from late 2018 and to have the capacity to transport up to 35 PJ of gas per annum.<sup>47</sup> With the extension and expansion, the NGP will have potential to bring around 700 TJ/day (or about 256 PJ/annum) of gas to the East Coast Gas Market.

## **Victorian Government opens up new gas fields in the offshore Otway Basin**

On 16 May 2018, the Victorian government announced the release of five new oil and gas exploration blocks located in the offshore Otway Basin to help build future supply.<sup>48</sup> This includes potential drilling from onshore, subject to regulatory approvals,<sup>49</sup> which may signal some movement by the government towards more consideration of projects and environmental factors on a case-by-case basis.

The released areas are stated to be near major existing producing gas fields, established infrastructure and underground gas storage, and form part of the Federal Government's 2018 Offshore Petroleum Exploration Acreage Release aimed at promoting petroleum exploration in Australia's offshore waters.<sup>50</sup>

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<sup>45</sup> The Hon. Matt Canavan (Minister for Resources and Northern Australia), New east coast supply from Gas Acceleration Program, media release, 28 March 2018, <http://minister.industry.gov.au/ministers/canavan/media-releases/new-east-coast-supply-gas-acceleration-program>.

<sup>46</sup> Michael Gunner (Chief Minister of the Northern Territory), Fracking moratorium lifted – strict laws to be in place before exploration or production can occur, media release, 17 April 2018, <http://newsroom.nt.gov.au/mediaRelease/25488>.

<sup>47</sup> Jemena, 'Northern Gas Pipeline: Draft Environmental Impact Statement', August 2016, <https://jemena.com.au/documents/pipeline/nejg/chapters/1-introduction>.

<sup>48</sup> Minister for Resources (Victoria), Offshore gas exploration to build future gas supply, media release, 16 May 2018, <https://www.premier.vic.gov.au/offshore-gas-exploration-to-build-future-supply/>.

<sup>49</sup> The Age, Andres opens up coastal gas drilling, 17 May 2018.

<sup>50</sup> Department of Industry, Innovation and Science, Offshore Petroleum Exploration Acreage Release, accessed 4 July 2018, <http://www.petroleum-acreage.gov.au/>.

## Senex partners with Jemena to fast-track Project Atlas

On 18 June 2018, it was announced that Senex and Jemena have partnered to fast-track bringing gas from Senex's Project Atlas in the Surat Basin to the domestic market by late 2019.<sup>51</sup> Jemena will build, own and operate a 40 TJ/day gas processing facility and pipeline to deliver gas from the project to the Wallumbilla Hub via the Darling Downs Pipeline.

## LNG import facilities

The ACCC is aware of four entities considering the development of LNG import facilities on Australia's east coast: Australian Industrial Energy, AGL, Integrated Global Partners and ExxonMobil. These parties are considering importing LNG into the east coast through floating storage and regasification units (FSRU), which convert LNG to its gaseous state.

The LNG import terminal projects are currently in assessment stages, with Australian Industrial Energy and AGL's final investment decisions expected in 2018 and 2019, respectively.<sup>52</sup> The first deliveries of gas to the east coast could be available in 2020.<sup>53</sup>

LNG import facilities could offer new supply to the tight domestic market, an alternative to domestic gas transport, and additional storage capacity. Imported LNG is unlikely to be a source of lower priced gas, but could act as a price ceiling for the domestic market.

## Australian Industrial Energy could import LNG via Port Kembla from 2020

Australian Industrial Energy (AIE) is a joint venture between Andrew Forrest's Squadron Energy and Japanese entities JERA Co Inc and Marubeni Corporation. Its project design involves importing LNG into the east coast via Port Kembla, near Wollongong in NSW.<sup>54</sup>

The AIE plan is to import up to 100 PJ per year of LNG starting from as early as 2020.<sup>55</sup> It is reported that the proposed terminal will have a storage capacity of approximately 4 PJ, enough to supply NSW demand for 10–12 days.<sup>56</sup>

AIE intends to sell the imported gas under long-term contracts to C&I users and secure demand for imported LNG through building or investing in power generation facilities. AIE has announced Memoranda of Understanding with 12 C&I gas users, for up to 70 PJ of supply. It is reported that the 12 users collectively account for 10 per cent of national gas market demand.<sup>57</sup>

It is reported that the LNG import terminal will be connected to the East Coast Gas Market via construction of a 6km pipeline from the terminal to Jemena's Eastern Gas Pipeline.<sup>58</sup> AIE has signed a Memorandum of Understanding with NSW Ports, granting exclusive

<sup>51</sup> Senex Energy, *Senex and Jemena fast-track Project Atlas gas to domestic market*, 18 June 2018, <https://www.senexenergy.com.au/senex-and-jemena-partner-to-fast-track-project-atlas-gas-to-domestic-market/>.

<sup>52</sup> APA Group, 'APA to develop Crib Point Pakenham pipeline for AGL's LNG import facility', media release, 12 June 2018, <https://www.apa.com.au/news/asx-releases/2018/apa-to-develop-crib-point-pakenham-pipeline-for-agls-lng-import-facility/>; Australian Financial Review, 'Andrew Forrest, Japan INC team up to ship LNG to NSW', 25 Feb 2018, <http://www.afr.com/business/energy/gas/twiggy-japan-inc-team-up-to-ship-lng-to-nsw-20180225-h0wm01>; Australian Financial Review, 'Mitsubishi backs \$800m gas solution for South Australia', 13 May 2018, <https://www.afr.com/business/mitsubishi-backs-800m-gas-solution-for-south-australia-20180513-h0zzz7>.

<sup>53</sup> Australian Industrial Energy, 'Project overview', fact sheet, <https://ausindenergy.com/file/2018/06/Project-Overview.pdf>.

<sup>54</sup> Australian Industrial Energy, 'Project overview', fact sheet, <https://ausindenergy.com/file/2018/06/Project-Overview.pdf>.

<sup>55</sup> Australian Industrial Energy, 'Project overview', fact sheet, <https://ausindenergy.com/file/2018/06/Project-Overview.pdf>.

<sup>56</sup> Sydney Morning Herald, 'Forrest to build NSW's first LNG import terminal at Port Kembla', 4 June 2018, <https://www.smh.com.au/business/the-economy/forrest-to-build-nsw-s-first-lng-import-terminal-at-port-kembla-20180604-p4zja7.html>.

<sup>57</sup> Australian Financial Review, 'Forrest's gas train has left the station', 4 June 2018, <http://online.isentialink.com/afr.com/2018/06/03/9fbfdfff-c0dd-41d4-953f-eee0c0026cb5.htm.l>

<sup>58</sup> The Australian, 'Forrest-backed gas terminal to offer \$10 fixed contracts', 25 June 2018.

development rights,<sup>59</sup> and the NSW Government has declared the project as Critical State Significant Infrastructure, which sets a clear pathway for approval of the project, but is not an approval in itself.<sup>60</sup> AIE forecasts that the development cost will be \$200–300 million.<sup>61</sup>

### AGL plan to import LNG to Victoria from the 2021 financial year, subject to final investment decision

As noted in our September 2017 report, AGL is considering building and operating an LNG import terminal at Crib Point in Victoria.<sup>62</sup> AGL has executed Memoranda of Understanding with 10 C&I customers to supply up to 30 PJ of gas per year.<sup>63</sup>

If the project goes ahead, AGL expects its first gas delivery to occur during the 2020–21 financial year. AGL will make a final decision on investing \$250 million into the project sometime in the 2018–19 financial year.<sup>64</sup> AGL has contracted with APA to build a new 60 kilometre bidirectional pipeline between Crib Point and Pakenham, with capacity of at least 550 TJ/day, subject to a final investment decision being made.<sup>65</sup>

### Integrated Global Partners has announced Mitsubishi investment in South Australian LNG import terminal

Integrated Global Partners (IGP), a group of former BHP employees, are considering building an LNG import terminal at Pelican Point, Outer Harbour, near Adelaide in South Australia.<sup>66</sup> Japan's Mitsubishi Corporation has invested \$15 million to finance a feasibility study on the \$800 million project.<sup>67</sup> The imported LNG would supply a power station, that IGP are also considering building. It is not yet known whether this gas will be sold to third parties.

### ExxonMobil is contemplating an LNG import terminal to ensure gas supply in Victoria

It has been reported that ExxonMobil is considering the development of an LNG import terminal in Victoria. It is reported that ExxonMobil would use existing infrastructure at its

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<sup>59</sup> Australian Industrial Energy, 'Australian Industrial Energy Consortium Selects Port Kembla, NSW for Landmark LNG Import Terminal and Enters FEED', media release, 4 June 2018, <https://ausindenergy.com/file/2018/06/AIE-Port-Agreement-Announcement-4-June-2018-1.pdf>.

<sup>60</sup> Australian Industrial Energy, 'Port Kembla Gas Terminal Awarded Critical State Significant Infrastructure Designation', media release, 24 June 2018, <https://ausindenergy.com/file/2018/06/AIE-CSSI-release-Final-240618.pdf>.

<sup>61</sup> Australian Industrial Energy, 'Project overview', fact sheet, <https://ausindenergy.com/file/2018/06/Project-Overview.pdf>.

<sup>62</sup> See ACCC, *Gas Inquiry 2017–2020 – Interim report*, September 2017, p.40.

<sup>63</sup> Sydney Morning Herald, 'APA to build pipelines for AGL's Victorian gas import terminal', 12 June 2018, <https://www.smh.com.au/business/the-economy/apa-to-build-pipelines-for-agl-s-victorian-gas-import-terminal-20180612-p4zkwp.html>.

<sup>64</sup> AGL, 'AGL announces Crib Point as preferred site for gas import jetty and pipeline', 9 August 2017, <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2017/august/agl-announces-crib-point-as-preferred-site-for-gas-import-jetty-and-pipeline>; AGL, 'AGL reaches key milestones for proposed LNG import jetty', 12 June 2018, <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2018/june/agl-reaches-key-milestones-for-proposed-lng-import-jetty>.

<sup>65</sup> APA Group, 'apa to develop crib point pakenham pipeline for agl's lng import facility', media release, 12 June 2018, <https://www.apa.com.au/news/asx-releases/2018/apa-to-develop-crib-point-pakenham-pipeline-for-agls-lng-import-facility>.

<sup>66</sup> Australian Financial Review, 'Mitsubishi backs \$800m gas solution for South Australia', 13 May 2018, <https://www.afr.com/business/mitsubishi-backs-800m-gas-solution-for-south-australia-20180513-h0zzz7>.

<sup>67</sup> Australian Financial Review, 'Mitsubishi backs \$800m gas solution for South Australia', 13 May 2018, <https://www.afr.com/business/mitsubishi-backs-800m-gas-solution-for-south-australia-20180513-h0zzz7>.

Longford gas plant, although a location has not been officially determined.<sup>68</sup> It is possible that BHP would be involved in the project, which is in the early assessment stage.<sup>69</sup>

The development cost for this project is reported as being \$100 million.<sup>70</sup> If development goes ahead, the first gas delivery could be in 2022.<sup>71</sup>

## 1.7. Transporting gas into the Southern States

As discussed in section 1.4 above, the supply and demand balance in the Southern States represents a tight market. This means gas from Queensland may be required to flow south. Therefore, access to transport, particularly on the key north to south transport routes, remains an important focus of the ACCC in determining whether there are any constraints that prevent market participants from moving Queensland gas to the Southern markets.

In particular, the South West Queensland Pipeline continues to be a key focus. Once the Northern Gas Pipeline is commissioned in late 2018, the South West Queensland Pipeline along with the Carpentaria Gas Pipeline will be the key pipelines connecting the Northern Territory with the East Coast Gas Market.

### 1.7.1. Future capacity outlook on the key pipelines

The capacity outlook on the key pipelines used to transport gas from Queensland to the Southern States (i.e. the South West Queensland Pipeline, Moomba to Adelaide Pipeline and Moomba to Sydney Pipeline System) remains unchanged since we last reported on it in our April 2018 report. Current public information reported by the pipeline operators indicates the following for the period 2018 to 2020:

- South West Queensland Pipeline (Wallumbilla to Moomba) – Between 2018 and 2020 there is 27.4 to 194 TJ/d firm capacity reportedly available<sup>72</sup>
- Moomba to Sydney Pipeline (Moomba to Wilton) – Between 2018 and 2020 there is 22.3 to 116 TJ/d firm capacity reportedly available<sup>73</sup>
- Moomba to Adelaide Pipeline (Moomba to Adelaide) – There is no firm capacity reportedly available until 2020.<sup>74</sup>

As noted in our April 2018 report, we found that the availability of capacity on the South West Queensland Pipeline, as reported by APA on the Natural Gas Bulletin Board (Gas Bulletin Board) and in accordance with Part 23 of the National Gas Rules, did not provide an accurate picture of the availability of capacity on the South West Queensland Pipeline.<sup>75</sup>

<sup>68</sup> The Australian, 'ExxonMobil considering Victorian LNG import plant', 18 June 2018, <https://www.theaustralian.com.au/business/mining-energy/exxon-mulls-victorian-lng-import-plant/news-story/e3e3e9ec61455585204b2b5ab456b076>.

<sup>69</sup> The Australian, 'ExxonMobil considering Victorian LNG import plant', 18 June 2018, <https://www.theaustralian.com.au/business/mining-energy/exxon-mulls-victorian-lng-import-plant/news-story/e3e3e9ec61455585204b2b5ab456b076>.

<sup>70</sup> The Australian, 'ExxonMobil considering Victorian LNG import plant', 18 June 2018, <https://www.theaustralian.com.au/business/mining-energy/exxon-mulls-victorian-lng-import-plant/news-story/e3e3e9ec61455585204b2b5ab456b076>.

<sup>71</sup> The Australian, 'ExxonMobil considering Victorian LNG import plant', 18 June 2018, <https://www.theaustralian.com.au/business/mining-energy/exxon-mulls-victorian-lng-import-plant/news-story/e3e3e9ec61455585204b2b5ab456b076>.

<sup>72</sup> APA, *Transmission Assets 36 Months Uncontracted Capacity Outlook, South West Queensland Pipeline, Westernhaul*, 26 June 2018. <https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/south-west-queensland-pipeline/>.

<sup>73</sup> APA, *Transmission Assets 36 Months Uncontracted Capacity Outlook, Moomba Sydney Pipeline, Southernhaul*, 26 June 2018. <https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/moomba-sydney-pipeline/>.

<sup>74</sup> Epic Energy, *Moomba to Adelaide Pipeline System: Outlook of Available for Sale Firm Capacity*, 28 June 2018. [http://www.epicenergy.com.au/media/docs/Firm\\_Capacity\\_Outlook.pdf](http://www.epicenergy.com.au/media/docs/Firm_Capacity_Outlook.pdf).

<sup>75</sup> ACCC, *Gas inquiry 2017–2020: Interim report*, April 2018, pp. 56–57.

This finding was based on advice from APA that, depending on the specific delivery points at which primary capacity holders allocated their contracted entitlements, the time of year and whether a shipper has access to high pressure receipt points or compression capacity at Wallumbilla, there may be spare firm capacity available to other shippers.<sup>76</sup> We noted that we would work with APA to see what could be done to enable access and market entry.

### **Box 1.1 – Changes to SWQP uncontracted capacity reporting under Part 23**

Following discussions with the ACCC, APA updated its reporting of uncontracted capacity on the South West Queensland Pipeline and Wallumbilla compression to improve transparency for shippers:

- Part 23 reporting – APA has commenced separately reporting on the firm uncontracted capacity of the South West Queensland pipeline segment and Wallumbilla compressors.
- Gas Bulletin Board – APA will continue to report a single combined figure (i.e. for the South West Queensland Pipeline and the Wallumbilla compressors together) on the Gas Bulletin Board,<sup>77</sup> as it is only possible to publish a single capacity figure in each direction on a pipeline on the Gas Bulletin Board uncontracted capacity outlook. APA requested AEMO publish explanatory notes to make it clearer to market participants what the information represents, and indicating where further information is available on the APA website, which are now available on the Gas Bulletin Board.<sup>78</sup>

Prior to the changes to the uncontracted firm capacity reporting under Part 23 for the South West Queensland Pipeline, APA published a single combined outlook figure for westernhaul uncontracted capacity on the South West Queensland Pipeline (consistent with its Bulletin Board reporting), which includes both the westernhaul 'pipeline capacity' and Wallumbilla compression capacity. APA also advised that while the combined figure accurately reflects the uncontracted firm capacity that is realistically available to shippers as a firm westernhaul service, it does not separately publish the source of the contractual congestion (i.e. the pipeline or the Wallumbilla compressors) as the Gas Bulletin Board does not specify this level of detail.

This explains why there has been a significant change in uncontracted capacity information on the South West Queensland Pipeline since we last provided an update in our April 2018 report.

From 1 February 2019, operators of Bulletin Board standalone compression facilities may be required to separately report on uncontracted capacity outlook for standalone compression facilities.<sup>79</sup>

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<sup>76</sup> ACCC, *Gas inquiry 2017–2020: Interim report*, April 2018, pp. 56–57.

<sup>77</sup> Rule 171A, Part 18 of the National Gas Rules. See: <http://www.gasbb.com.au/Reports/Uncontracted%20Capacity%20Outlook.aspx>.

<sup>78</sup> See: [https://gbb.aemo.com.au/~/\\_media/Documents/Notices/2018/20180629%20-%20SWQP%20Uncontracted%20Capacity%20Outlook%20update.pdf](https://gbb.aemo.com.au/~/_media/Documents/Notices/2018/20180629%20-%20SWQP%20Uncontracted%20Capacity%20Outlook%20update.pdf).

<sup>79</sup> This requirement is included in the National Gas National Gas (South Australia) (Capacity Trading and Auctions) Amendment Rules 2018, developed by the GMRG and approved by the COAG Energy Council in late June 2018. The Amendment Rules are expected to be made no later than 1 December 2018. Under the legal and regulatory package, transitional rules will require compression facilities to report information to AEMO for publishing on the Bulletin Board until such time the compression facilities are registered as a Bulletin Board facility under Part 18 of the NGR.

### 1.7.2. Wallumbilla compression appears to be contractually congested

As discussed above, compression capacity at Wallumbilla is necessary in order 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.

As at 26 June 2018, APA reports that there is currently 0 TJ/d (out of a nameplate capacity of 737 TJ/d) of firm Wallumbilla compression (low to high pressure) available during the period between 2018 and 2020.<sup>80</sup> Further, from reviewing information provided to the ACCC under compulsory information notices, it appears that at present, two major retailers and a major producer have contracted all of the firm compression capacity at Wallumbilla during this period.

One shipper had at least around 36 TJ/d of unutilised capacity throughout the year even during its peak usage periods during the period between 1 May 2017 and 30 April 2018. It did not use any of its firm capacity for around six months. However, there were no requests from any shippers for the unutilised capacity to be made available.

These facilities play a significant role in the market and access to compression capacity can act as a potential barrier to new market entrants. We consider that the contracted but un-nominated compression capacity should be released to the market to enable other market participants, particularly new entrants, to transport gas to the Southern States.

We note that firm compression services at Wallumbilla are proposed to be sold on the capacity trading platform and be subject to the day-ahead auction from 1 March 2019.<sup>81</sup> This should incentivise primary capacity holders to sell spare capacity and can allow prospective shippers the opportunity to purchase competitively priced capacity.

### 1.7.3. Update on secondary capacity trading activity between shippers

As part of our role in monitoring the behaviour of pipeline operators and primary capacity holders, we have had discussions with a number of gas shippers about their negotiating experience in seeking access to transportation services including access to pipeline capacity through secondary trading.

In our December 2017 report, we noted the ACCC investigation into secondary capacity on regional pipelines and we reported that following the investigation, we had seen instances of retailers making capacity available in some regional areas, which had resulted in more competitive outcomes.<sup>82</sup> Our recent engagement with shippers has reinforced this conclusion.

#### **Box 1.2: More instances of shippers gaining access to secondary pipeline capacity following ACCC investigation**

One shipper, who has in the past acquired gas on a delivered basis (commodity and transport) from a major gas retailer, told the ACCC that it has recently procured gas directly from a gas producer. This was only possible because its former gas retailer had agreed to transfer firm transport capacity on one of the key pipelines transporting gas from Queensland to the South to the shipper.

The shipper said it appeared that the gas retailer, which controls a significant proportion of the capacity of the pipeline, had a 'change in attitude' and suggested this could have been

<sup>80</sup> APA, Transmission Assets 36 Months Uncontracted Capacity Outlook, Wallumbilla Compression, 26 June 2018.

<sup>81</sup> GMRG, Capacity Reform Trading Package – Final Recommendations, as endorsed by the COAG Energy Council.

<sup>82</sup> ACCC, *Gas inquiry 2017–2020: Interim report*, December 2017, p. 65.

due to government interventions and ongoing investigation and monitoring by the ACCC.

Since we last reported on the issue in December 2017, there has not been significant change in the number of executed secondary trading agreements between retailers and gas shippers for access on the key pipelines. In addition, there have been few requests from shippers for capacity to be made available on a secondary trading basis.

Releasing spare firm capacity to another market participant can result in more competition and more choices for customers, particularly in regional areas where there generally is only one gas supply option. We have heard in some instances that a lack of competition on a regional pipeline was resulting in higher prices for some users. This is discussed further in chapter 3. We will be continuing to monitor secondary capacity trading, particularly in the lead up to the implementation of day ahead auction and secondary capacity trading market reforms.

## 2. Price outlook for 2019

### 2.1. Key points

- Most offers made in the first quarter of 2018 for gas supply in 2019 were priced in the high-\$8 to \$11/GJ range. This is in line with prices offered in the latter months of 2017, following a downward trend from a peak in the first half of 2017.
- By the end of the first quarter of 2018, prices offered in the domestic market for gas supply in 2019 had converged with expected LNG netback prices at Wallumbilla for 2019. This is in stark contrast to the prices that suppliers offered to domestic buyers in the first half of 2017, which were considerably higher than expected LNG netback prices.
- As at the end of April 2018, very few of the offers made in the first quarter of 2018 were accepted. It appears that many gas buyers were delaying entering into gas supply agreements (GSAs) for 2019 until the latter part of 2018.
- On average, the gas commodity prices expected to be paid under GSAs for gas supply in 2019, entered into between 1 January 2017 and the end of April 2018, are:
  - \$8.35/GJ by all buyers<sup>83</sup> to Queensland producers
  - \$9.40/GJ by all buyers to producers in the Southern States
  - \$10.41/GJ by C&I gas users to retailers/aggregators in the Southern States.

### 2.2. Prices offered and agreed for gas supply in 2019

This section includes analysis of gas prices in arm's length offers, bids and GSAs for 2019 with a term of at least one year and an annual contract quantity of at least half a petajoule.

The prices reported throughout this chapter are wholesale gas commodity prices (sometimes referred to as ex-plant prices) and do not include separate charges for transporting gas to the user's location or other ancillary charges.

While Northern Territory suppliers will be able to supply gas into the East Coast Gas Market following construction of the NGP, we have excluded offers and GSAs by Northern Territory suppliers from the analysis in this chapter and commented separately where relevant. Due to the relatively high transport cost component involved in delivering Northern Territory gas to East Coast Gas Market, it is less meaningful to compare only the gas commodity components of these prices with those in the east coast.

The gas prices cited in this section have been estimated using the pricing mechanisms specified in each offer, bid or executed GSA along with assumptions relating to key variables such as oil prices, foreign exchange rates and CPI, where relevant. The specific assumptions used are set out in each of the relevant sections.

Where average prices are reported, these are quantity weighted average prices. The ACCC notes that the price averages cited in this section are not adjusted to reflect any differences in non-price terms specified in the offers, bids or executed GSAs, such as load factors, take-or-pay levels and make-up gas rights. These non-price terms and the flexibility they can provide may be valued differently depending on the customer and may influence the gas prices that are ultimately agreed.

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<sup>83</sup> The term 'buyers' includes retailers/aggregators as well as end users of gas.

## 2.2.1. Offers and bids for gas supply in 2019

In the ACCC's April 2018 report, we began reporting on offers made and bids received by suppliers in the East Coast Gas Market for gas supply in 2019. Our reporting covered information received by the ACCC from suppliers on offers that did not result in a GSA by 14 July 2017, and on all offers made and bids received by suppliers between 14 July 2017 and 22 January 2018. In this section, we extend that coverage with the addition of information on offers made and bids received by gas suppliers between 23 January and 24 April 2018 for gas supply in 2019.

Of the information received by the ACCC from suppliers on offers and bids for gas supply in 2019, we have included in our analysis those offers and bids that are sufficiently developed to contain clear indications of the key terms of price, quantity and supply start and end dates.

For the purpose of the analysis in this section, the gas offer and bid prices were estimated using assumptions relating to key variables (oil prices, foreign exchange rates and CPI) based on the expectations for those variables at the time of the offer or bid.<sup>84</sup>

Analysis of offer and bid pricing throughout this chapter is intended to provide an indication of price trends over time. The prices of individual offers and bids are not all directly comparable, as they can differ between non-price aspects such as quantity, flexibility, duration and delivery point. Offer and bid pricing in some instances may also reflect seasonal price fluctuations, linkages to prices of other commodities (such as oil) or, in the case of GPGs, conditions in the electricity market.

### Prices over time: offers for gas supply in 2019

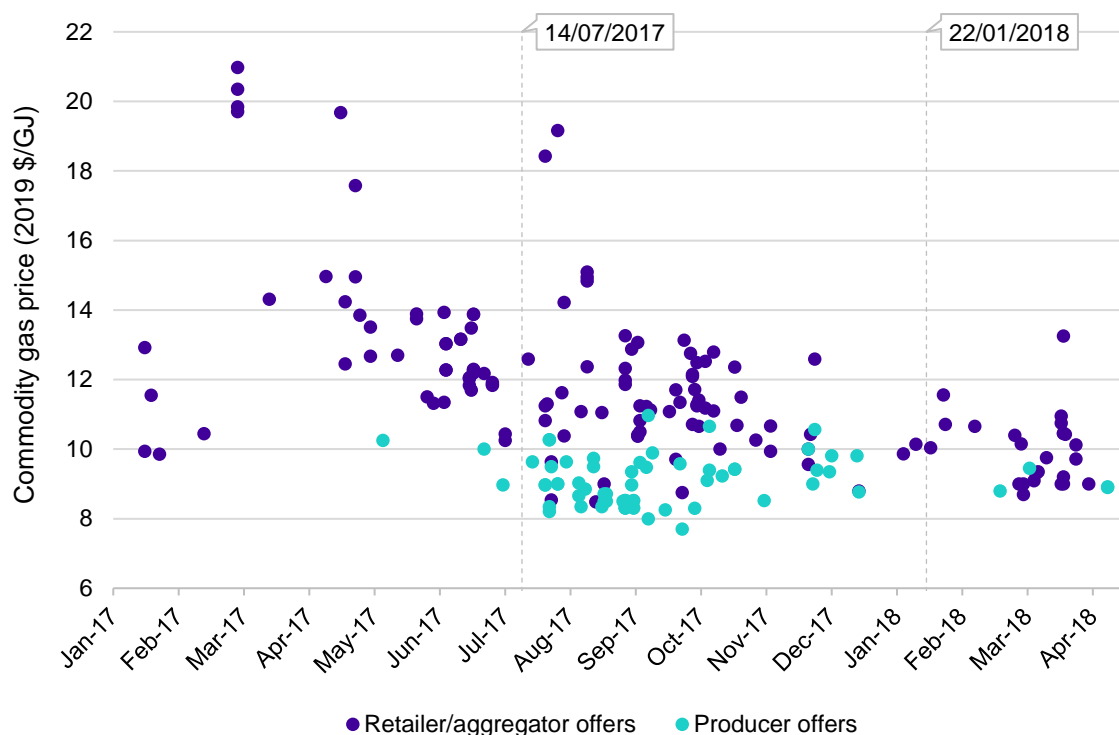
Chart 2.1 below shows the gas commodity prices included in offers made by retailers/aggregators and producers over the period from 1 January 2017 to 24 April 2018 to all gas buyers for supply in 2019. It should be noted that not all price offers in the chart (and those discussed in this section) are for unique combinations of seller and buyer. That is, some offers may reflect follow up offers that were made by the same supplier to the same customer after a previous offer did not result in a GSA. The chart is intended to give an indication of how the level of price offers in the East Coast Gas Market has evolved since the start of 2017.

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<sup>84</sup> In all estimates of 2019 offer and bid prices in this report, the following assumptions were made, where relevant:

- The expected AUD/USD exchange rate for 2019 is equal to the average rate prevailing during the month in which the offer or bid occurred.
- The expected Brent crude oil price for 2019 is equal to the average price of 2019-dated futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg).
- The applicable CPI is based on actual CPI where available at the time the bid or offer occurred (up to the most recent available quarter), and 2.5% thereafter.

**Chart 2.1: Gas commodity price offers for 2019 supply in the East Coast Gas Market**



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

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

In the ACCC’s April 2018 report, we reported a downward trend across 2017 in gas commodity prices offered by suppliers for supply in 2019, culminating in offer prices in the high-\$8 to mid-\$10/GJ range in the three months to 22 January 2018. For this report, the ACCC has obtained information on offers made by suppliers in the subsequent three month period to 24 April 2018.

Chart 2.1 shows the trend in offer prices has been flat in this period, with most in the high-\$8 to \$11/GJ range. The range of prices offered narrowed in the latter months of 2017 compared with the earlier part of 2017, and this has held throughout the early months of 2018. This may reflect a less uncertain gas supply-demand outlook for 2019 following commitments by LNG producers to make additional quantities of gas available into the domestic market.

In addition, the ACCC’s monitoring and close attention to specific deals may have had an effect. The ACCC’s monitoring and reporting of prices may be reducing information asymmetry in negotiations and, in so doing, facilitating more effective negotiations between sellers and buyers.

### Recent offers and bids for gas supply in 2019

This section discusses recent offers made and bids received by producers and retailers/aggregators.

Table 2.1 presents analysis of recent offers made and bids received by gas producers for gas supply to all buyers in 2019. The table compares the offers made and bids received in the period between 23 January 2018 and 24 April 2018 with the preceding six months.

**Table 2.1: Recent offers made and bids received by producers for gas supply in 2019 (all buyers)<sup>85</sup>**

<b>14 July 2017 – 22 January 2018</b>	<b>Offers</b>	<b>Bids</b>
Number of offers or bids	53	32
Gas commodity price range (\$/GJ)	7.70 – 10.97	7.25 – 10.27
Average gas commodity price (\$/GJ)	8.69	8.42

<b>23 January 2018 – 24 April 2018</b>	<b>Offers</b>	<b>Bids</b>
Number of offers or bids	<10	44
Gas commodity price range (\$/GJ)	8.80 – 9.45	6.14 – 9.40
Average gas commodity price (\$/GJ)	9.02	8.05

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

Table 2.1 shows a decrease in the price of bids received by producers between 23 January and 24 April 2018, compared to bids received in the prior period from 14 July 2017 to 22 January 2018. This decrease is apparent in the respective price averages and in the upper and lower bounds of the respective price ranges.

There were relatively few offers made by producers between 23 January and 24 April 2018. The ACCC understands that some producers, particularly LNG producers, are still making offers for gas supply in 2018. We expect that as the year progresses producers will be making more offers for gas supply in 2019.

In contrast, the relatively high number of bids received by producers between 23 January and 24 April 2018 reflects Expression of Interest (EOI) processes undertaken by several producers. The ACCC's September 2017 report discussed a sale of gas by GBJV via an EOI process which required interested buyers to submit bids in an auction-style sale.<sup>86</sup> Since then, more producers have used this type of process to sell gas (as discussed in section 3.3.3). Within these EOI processes, one factor boosting the number of bids appears to be buyers' use of bidding strategies involving multiple contingent bids. For example, a buyer in a recent EOI process opted to place a series of contingent bids that stepped up in price, with each subsequent bid in the series activated if the previous one was unsuccessful.

Table 2.2 presents analysis of offers made and bids received by gas retailers/aggregators for gas supply in 2019. The analysis in this table is limited to offers made to, and bids received from, C&I users. The table compares the offers made and bids received in the period between 23 January 2018 and 24 April 2018 with the preceding six months.

<sup>85</sup> Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components. Includes offers and bids for gas supply of at least 12 months duration and annual quantities of at least 0.5 PJ.

<sup>86</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, September 2017, p. 48.

**Table 2.2: Recent offers made and bids received by retailers/aggregators for gas supply in 2019 (C&I users)<sup>87</sup>**

<b>14 July 2017 – 22 January 2018</b>	<b>Offers</b>	<b>Bids</b>
Number of offers or bids	61	<10
Gas commodity price range (\$/GJ)	8.48 – 19.16	12.59 – 15.09
Average gas commodity price (\$/GJ)	10.95	13.33

<b>23 January 2018 – 24 April 2018</b>	<b>Offers</b>	<b>Bids</b>
Number of offers or bids	28	<10
Gas commodity price range (\$/GJ)	8.57 – 12.34	7.50 – 9.00
Average gas commodity price (\$/GJ)	9.49	7.68

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

Table 2.2 shows a decrease in the prices of offers made by retailers/aggregators to C&I users in the period between 23 January and 24 April 2018, compared to offers made in the prior period from 14 July 2017 to 22 January 2018. The decrease is apparent in the respective price averages and in most of the upper and lower bounds of the respective price ranges. This is mirrored in the prices of bids received by retailers/aggregators from C&I users.

Tables 2.1 and 2.2 show that retailers/aggregator offer and bid prices are generally higher than producer prices. This may reflect the inclusion of retailer-specific costs and margins as well as the value of non-price terms. The ACCC is currently working to better understand the value components that make up retail gas commodity prices, and will also examine retailers' costs and margins more broadly. The ACCC intends to report on its findings in December 2018.

As discussed above, while construction of the NGP has created scope for Northern Territory suppliers to begin making offers to, and receiving bids from, buyers in the East Coast Gas Market, these have been excluded from table 2.1 and table 2.2. In the period between 14 July 2017 and 24 April 2018, Northern Territory suppliers made a small number of offers at lower commodity gas prices relative to those reported in table 2.1 and table 2.2. However, once the cost of transportation from the Northern Territory is included, the offers from and bids to, the Northern Territory suppliers become more comparable to the delivered offers made and bids received by other suppliers in the east coast.

### **2.2.2. Prices agreed under GSAs for 2019**

In the ACCC's April 2018 report, we began reporting on prices agreed under GSAs for 2019. The April 2018 report included GSAs executed between January 2016 and 22 January 2018. So that this report covers only the prices agreed under the most recent GSAs, the analysis in this section has been limited to GSAs that have been executed since 1 January 2017. The analysis also incorporates the most recent GSAs obtained by the ACCC, which were executed between 22 January 2018 and 24 April 2018.

<sup>87</sup> Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components. Includes offers and bids for gas supply of at least 12 months duration and annual quantities of at least 0.5 PJ.

For the purpose of the analysis of producer prices, we have included GSAs executed at arm's length by producers with all counterparties. For the purpose of the analysis of retailer/aggregator prices, we have only included GSAs executed with C&I users.

In contrast to the preceding analysis of offers and bids, we estimated prices under GSAs using assumptions relating to key variables (oil prices, foreign exchange rates and CPI) based on the latest market expectations for those variables for 2019.<sup>88</sup> These market expectations have changed since we last reported on GSA prices in April.

As in the case of the offers analysis above, the reported prices are based on the wholesale commodity price of gas and do not include the cost of transporting gas to the user's location or any other ancillary costs.

Table 2.3 shows average gas prices expected to be paid for supply in 2019 under GSAs entered into by producers and retailers/aggregators. The prices in this table are not directly comparable to the prices previously reported in the April 2018 report due to the exclusion of 2016 GSAs and changed pricing assumptions. Further, both producers and retailers/aggregators have only entered into a small number of new GSAs for 2019 in the early months of this year. Due to the small number of GSAs, we have not reported prices for retailers/aggregators in Queensland and have reported a single average for retailers/aggregators in Victoria, NSW and South Australia.

**Table 2.3: Expected 2019 wholesale gas commodity prices in the East Coast Gas Market (under GSAs executed between 1 January 2017 and 24 April 2018)<sup>89</sup>**

Type of supplier	Average gas commodity price (\$/GJ)	Gas commodity price range (\$/GJ)
<b>Producers (QLD)</b>	8.35	7.63 – 8.52
<b>Producers (VIC and SA)</b>	9.40	8.75 – 11.03
<b>Retailers/aggregators (VIC, SA and NSW)</b>	10.41	9.00 – 12.57

Source: ACCC analysis of information provided by suppliers.

Table 2.3 shows that in the period between 1 January 2017 and 24 April 2018, the average of prices in GSAs executed by producers in the Southern States is higher than the average of prices in GSAs executed by producers in Queensland. The range of agreed prices in the Southern States is also wider than the range of agreed prices in Queensland, likely reflecting a greater diversity of prices across various locations in the Southern States. The north-south price differential may also result from the difference in the composition of the southern market, as there are more C&I users in Southern States than there are in Queensland.

<sup>88</sup> In all estimates of 2019 GSA prices in this report, the following assumptions were made, where relevant:

- Consistent with Commonwealth Treasury methodology, the AUD/USD exchange rate for 2019 is expected to vary around the current rate. The exchange rate assumption applied to GSAs in this report is 73.91 US cents to the Australian dollar. It is based on the monthly rate published by the RBA for June 2018.
- Expected Brent crude oil prices are assumed to vary around the current price. The Brent Spot price assumption applied to GSAs in this report is US\$76.98 per barrel free on board. It is based on the observed monthly price for May 2018.
- The CPI assumptions used to estimate GSA prices in this report are based on actual CPI where available and 2.5 per cent thereafter.

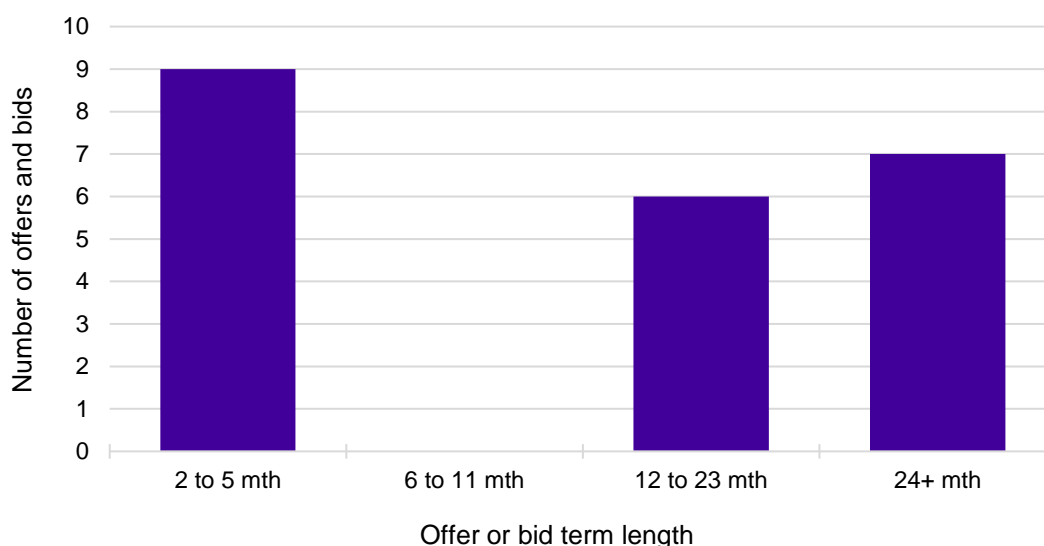
<sup>89</sup> Pricing assumptions applied to offers, bids and GSAs in this section are the same as applied in Section 2.2 above. Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components. Includes offers and bids for gas supply of at least 12 months duration and annual quantities of at least 0.5 PJ.

Table 2.3 also shows that the average of gas commodity prices in GSAs between retailers/aggregators and C&I users is higher than the average of producer gas commodity prices. However, as noted in the discussion of offer and bid prices, the difference between producer prices and retailer/aggregator prices may reflect retailer-specific costs and margins as well as the value of non-price terms available from retailers/aggregators. As previously stated, the composition of retail prices is the subject of ongoing analysis by the ACCC.

### 2.3. Prices offered and agreed for gas supply to GPGs in 2019

In this section we analyse prices of arm’s length offers, bids and executed GSAs between all gas suppliers and GPGs for supply in 2019.<sup>90</sup> Chart 2.2 breaks down the number of offers and bids with GPGs by term length. It covers offers made and bids received by suppliers between 14 July 2017 and 22 January 2018.

**Chart 2.2: Offers made and bids received by suppliers for gas supply to GPGs in 2019 by term length**



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

Chart 2.2 shows that in the period between 14 July 2017 and 22 January 2018, suppliers made and/or received 9 offers or bids for short-term gas supply (2–5 months) to GPGs in 2019, which comprised 41 per cent of all offers to and bids from GPGs in the period. This likely reflects seasonality in electricity demand, with GPGs using short-term GSAs to cover winter and/or summer peaks. Due to the prevalence of short-term supply to GPGs, the analysis of prices below is based on offers, bids and executed GSAs with GPGs with a term of at least two months and annual quantities of at least half a petajoule.<sup>91</sup>

Table 2.4 shows offers made and bids received by suppliers between 14 July 2017 and 24 April 2018 for gas supply to GPGs in 2019.

<sup>90</sup> This includes offers, bids and executed GSAs between retailers and non-affiliated GPGs.

<sup>91</sup> Where the gas supply term is less than one year, quantities have been prorated to arrive at an equivalent annual quantity.

**Table 2.4: Recent offers made and bids received by suppliers for gas supply to GPGs in 2019 for a term of at least 2 months<sup>92</sup>**

14 July 2017 – 24 April 2018	Offers	Bids
Number of offers or bids	8	14
Gas commodity price range (\$/GJ)	8.97 – 11.49	7.08 – 9.15
Average commodity gas price (\$/GJ)	9.71	7.84

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

Table 2.4 shows that the gas commodity price range for offers to GPGs spans \$2.52/GJ. As shown in tables 2.1 and 2.2 respectively, this range is narrower than the price ranges of offers made in the same period both by producers to all buyers and, in particular, by retailers/aggregators to C&I users. The same is true of the equivalent comparison of the price range of bids received by suppliers from GPGs against the price ranges both of bids received by producers from all buyers and of bids received by retailers/aggregators from C&I users.

While the number of offers to and bids by GPGs is too small to draw firm conclusions, the respective prices of offers and bids for terms of 2–5 months appear on average to be marginally higher than the prices of offers and bids for terms of at least 12 months.

The average of gas commodity prices expected to be paid by GPGs in 2019 under GSAs executed between 1 January 2017 and 24 April 2018 for a term of 12 months or more is \$9/GJ.<sup>93</sup> It is important to note that this represents only a small number of GSAs. Some GPGs may not have contracted for 2019 or may be fully contracted under legacy GSAs not included in this analysis. Further, the majority of GPGs are supplied with gas from within the portfolios of related party retailers.

The average of prices of gas to supply GPGs is similar to the average of prices of wholesale gas supply from producers to other gas buyers in the market. However, we note that some GSAs entered into by GPGs are priced higher likely due to a higher level of flexibility that is built into those GSAs. For example, a GPG may be willing to pay more under a GSA that allows for greater gas usage in the summer months when demand for GPG reaches its peak.

## 2.4. Prices paid in short-term trading markets

The price of gas in short-term trading markets is volatile and may reflect seasonal or temporary factors. It can be influenced by weather, the price that gas powered generation is receiving in the national electricity market, maintenance at processing facilities like the Longford gas plant or the requirements of market participants to balance their portfolios.

Chart 2.3 shows the daily prices at the Brisbane, Sydney and Adelaide short-term trading markets (STTMs), the Victorian DWGM and the Wallumbilla GSH from early June 2017 to early June 2018. The chart shows that prices in Queensland and the Southern States have recently converged notwithstanding a recent spike due to an outage at the Longford gas plant. For the month of June, the simple average of the prices in short-term trading markets in the Southern States was \$9.30/GJ compared to \$9.71/GJ in Queensland.

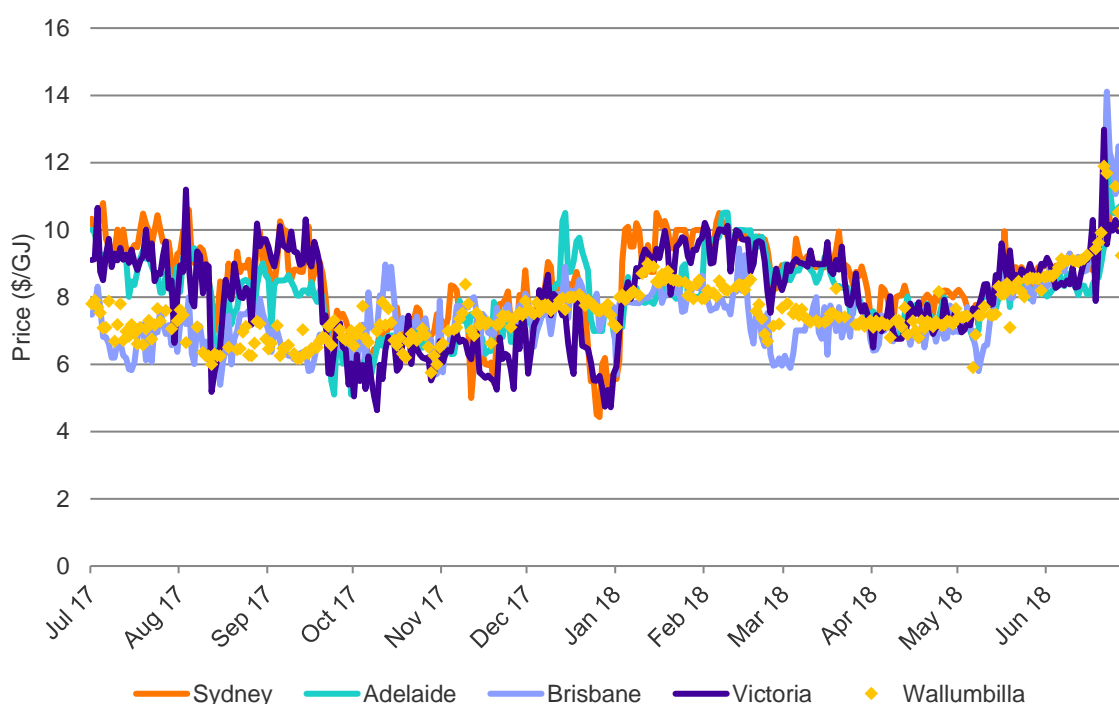
<sup>92</sup> Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components. Includes offers and bids for gas supply of at least 2 months duration and annual quantities of at least 0.5 PJ.

<sup>93</sup> Prices are for gas commodity charges only; actual prices paid by users may also include transport and retail cost components. Includes offers and bids for gas supply of at least 2 months duration and annual quantities of at least 0.5 PJ.

Recent prices in all the domestic short-term trading markets in the Southern States are lower relative to the same period in the previous year. The simple average of prices in the Sydney STTM, Adelaide STTM and the Victorian DWGM was \$8.34/GJ for second quarter of 2018 compared to \$9.65/GJ for second quarter of 2017 (a 13.6 per cent decrease).

In Queensland, the price difference has been smaller. The simple average of prices at the Wallumbilla GSH was \$8.14/GJ for the second quarter of 2018, which is about 2.6 per cent higher than the \$7.94/GJ simple average of the prices for the second quarter of 2017. Similarly, the simple average of prices at the Brisbane STTM was \$8.18/GJ for the second quarter of 2018, which is about 0.15 per cent lower than the \$8.20/GJ simple average of prices for the second quarter of 2017.

**Chart 2.3: Daily prices paid in domestic short-term markets, July 2017 to June 2018**



Source: Australian Energy Market Operator

## 2.5. The emergence of gas futures trading in the Victorian market

In this section, we report on recent activity in the Victorian gas futures market and the potential for this activity to provide benefits to the broader gas market. We have not previously reported on trading in domestic gas futures due to the absence of actual trading.

Gas futures contracts based on gas prices at the Victorian DWGM were recently traded on the Australian Securities Exchange (ASX). In April 2018, 80 gas futures contracts were traded (60 quarterly contracts and 20 yearly contracts) amounting to approximately 1.3 PJ of gas.<sup>94</sup> However, prior to April 2018, no futures contracts had been traded since October 2016. Notwithstanding the recent spike in activity, there is limited open interest and bid-ask spreads are also relatively wide indicating low liquidity (bid-ask spreads are the difference between the price bid by buyers and the price asked by the sellers).

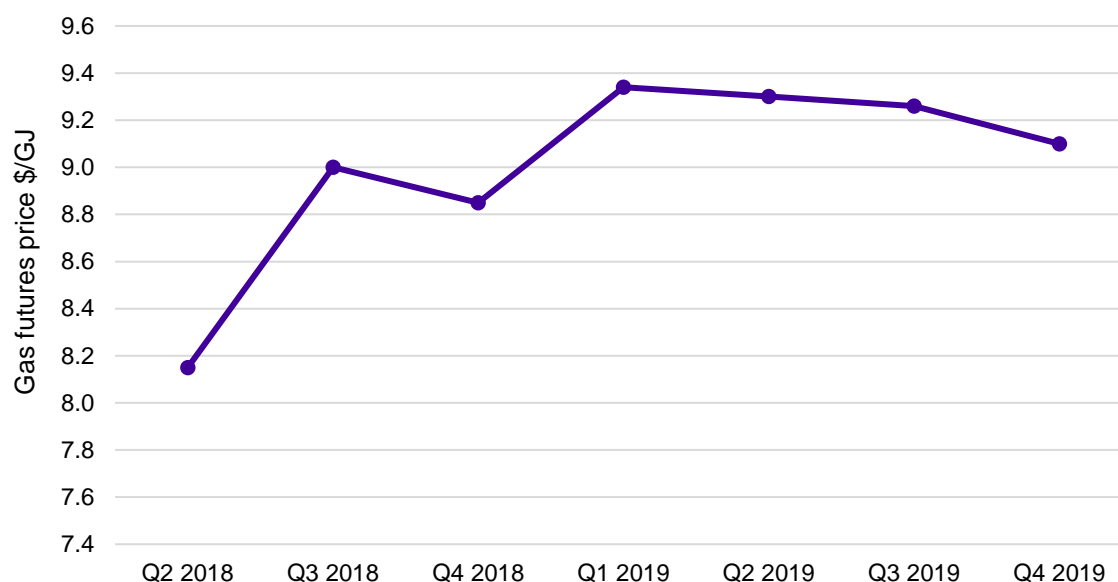
<sup>94</sup> ASX Energy Market Tradelog.

Trading on this market allows participants to hedge future gas prices. As the market becomes deeper and more liquid in the future, it may allow buyers and sellers of gas to lock in future prices without entering into a GSA. For example, a gas buyer may buy a futures contract for the coming year and rely on purchasing physical gas from the short-term market. If gas prices increase then the buyer will be compensated for the increasing cost by an increase in the value of their futures position.

Such a hedging strategy is not without risk, however, as the cash flows from a hedging position may not exactly match those from a physical position. The DWGM price for gas includes both transport and commodity charges and so is not a perfect hedge for commodity gas prices in isolation. This kind of hedging position also does not protect against ancillary charges (such as uplift charges) that a gas purchaser on the Victorian Transmission System may be exposed to.

In addition, an active futures market can provide information about expected future prices to the market, which allows it to operate more efficiently. If futures prices are high relative to current prices, participants may make 'cash and carry trades' where they seek to store gas in the present and enter into futures contracts to sell the gas in the future. Futures prices may also be used as a reference for the pricing of long-term GSAs.

**Chart 2.4: Victorian DWGM futures prices from Q2 2018 to Q4 2019**



Source: Australian Securities Exchange – Energy Derivatives Products – Victorian Natural Gas Futures

The futures prices shown in chart 2.4 indicate that market participants expect gas prices to increase from around \$8/GJ in the second quarter of 2018 to over \$9/GJ by the first quarter of 2019, and to remain in the \$9/GJ to \$9.4/GJ range for the rest of 2019. There are ASX gas futures contracts that extend beyond 2019, but there is currently no open interest in those contracts.

Futures prices can be biased if there is a cost or benefit that accrues unequally between buyers and sellers. A long position (that is, buying a futures contract) in an energy derivative is correlated to broader macroeconomic risks. Energy futures may underestimate actual future prices as the buyer of a gas future may need to be compensated for taking on such macroeconomic risk. In addition, where hedging via futures contracts is mainly desired by sellers, futures prices will be discounted by a liquidity premium that buyers must receive in order to have an incentive to provide trading opportunities to sellers.

## 2.6. Comparison of domestic offer prices against contemporaneous LNG netback expectations

This section compares prices offered for 2019 supply in the domestic market in each month between January 2017 and April 2018 against contemporaneous expectations of 2019 LNG netback prices. Similar analysis of prices agreed in GSAs is not included due to the comparatively small number of GSAs agreed for 2019 supply in each month of the relevant period.

For the purpose of our analysis, LNG netback prices have been calculated based on market expectations, at relevant points in time, of Asian LNG spot prices over the course of 2019.

Section 2.6.1 explains why we have chosen these LNG netback prices for our analysis and section 2.6.2 explains how we calculated them. Section 2.6.3 presents the findings of our comparison for prices offered in Queensland and the Southern States.

### 2.6.1. Relevant LNG netback prices

As discussed in previous reports, LNG netback prices—specifically, Asian LNG spot netback prices—are likely to be a key factor influencing domestic gas prices under current market conditions. As discussed in section 1.3, the Queensland LNG producers, in aggregate, expect to produce quantities of gas in excess of what is required to satisfy long-term LNG contractual obligations. This excess gas would likely be sold on the Asian LNG spot market if it is not used for domestic supply. A domestic gas buyer's alternative to contracting with a domestic producer is to purchase gas that would otherwise be sold on the Asian LNG spot market, and the domestic seller's alternative is to sell gas to LNG producers that would then be sold on the Asian LNG spot market. Therefore, in order to provide suppliers with a commercial incentive to supply gas to the domestic market, gas buyers would expect to pay prices that are shaped by Asian LNG spot prices.

Further, there has been a clear trend of an increase in the number of shorter term GSAs offered for domestic gas supply over recent years. Information obtained by the ACCC from suppliers shows that the majority of recent offers made across the East Coast Gas Market for gas supply in 2019 were part of GSAs with durations of either one or two years. In the period between January 2017 and April 2018, over 70 per cent of offers from producers, and over 55 per cent of offers from retailers for gas supply in 2019 were part of GSAs with durations of two years or less. Overall, almost two-thirds of offers across the market over this period were for GSAs with durations of two years or less.

For these reasons, the ACCC has used LNG netback prices based on Asian LNG spot prices to compare against prices offered in the East Coast Gas Market. For assessing domestic offers of longer durations, other LNG price markers, such as short-term and medium-term (for example, 3–5 year) multi-cargo LNG contracts, may be relevant as a basis for netback prices.

The ACCC considers that the relevant LNG netback price against which to compare prices offered for future supply in the domestic market is a forward LNG netback price—specifically, one that is based on market expectations of what Asian LNG spot prices will be during the relevant period of supply. Further, in the context of negotiation for future domestic gas supply, the forward LNG netback prices estimated at the time of negotiation are most relevant. This is because these expectations at the time of negotiation provide the best indicator of what the supplier would expect, at that time, to be its opportunity cost of supplying gas to the domestic market over the proposed period.

## 2.6.2. Calculation of forward LNG netback prices

The calculation of forward Asian LNG spot netback prices requires an indicator of market expectations of what Asian LNG prices will be during the relevant future period. For this, the ACCC has used futures prices of the Japan Korea Marker (JKM) quoted by the Intercontinental Exchange (ICE). The JKM is a widely cited measure of Asian LNG spot prices published by S&P Global Platts.

A JKM futures price for a given future month, quoted on a given day, indicates futures market participants' expectation, on that day, of the price of Asian LNG spot cargoes delivered in that given future month. This price can be converted to an LNG netback price at Wallumbilla by adjusting for the expected avoidable costs of shipping, liquefaction and transportation. For an LNG exporter contemplating selling gas as an LNG spot cargo in a future month, the LNG netback price represents the minimum price that an LNG exporter would expect to receive from a domestic gas buyer to be indifferent between selling the gas to the domestic buyer in a given month and selling the gas on the Asian LNG spot market in that month.

The domestic offers analysed in this section are all for gas supply over the entire 2019. Therefore, for the purpose of comparison, we calculated an average LNG netback price that an LNG exporter would expect to receive, at a minimum, to be indifferent between selling the gas to the domestic buyer over the entire 2019 and selling cargoes on the Asian LNG spot market over the entire 2019.

For example, we calculated the average LNG netback price for 2019 that an LNG producer would have expected to receive, at a minimum, in July 2017 as follows:

- We obtained JKM futures prices for each month of 2019 that were quoted by ICE on each day during July 2017.
- We converted the monthly JKM futures prices into LNG netback prices at Wallumbilla by:
  - converting the prices from US\$/MMBtu into A\$/GJ using contemporaneous exchange rates, and
  - subtracting the incremental costs of shipping<sup>95</sup>, liquefaction<sup>96</sup> and transportation<sup>97</sup>.
- We averaged these monthly LNG netback prices to arrive at an average LNG netback price for 2019 expected on each day during July 2017.
- We then averaged the daily LNG netback prices to arrive at an average LNG netback price for 2019 expected during July 2017.

For charts 2.5 and 2.6 below, we calculated the expected 2019 LNG netback prices at Wallumbilla in this way for each month between January 2017 and April 2018.

## 2.6.3. Domestic prices offered for 2019 supply have converged with expected 2019 LNG netback prices at Wallumbilla

This section compares prices offered for 2019 supply in Queensland and the Southern States to contemporaneous expectations of 2019 LNG netback prices.<sup>98</sup>

<sup>95</sup> We did not have the data for forward shipping costs, so we used as a proxy a preceding 12-month historical average of LNG shipping costs and losses from Gladstone to Tokyo obtained from Argus.

<sup>96</sup> We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from the LNG producers in Queensland.

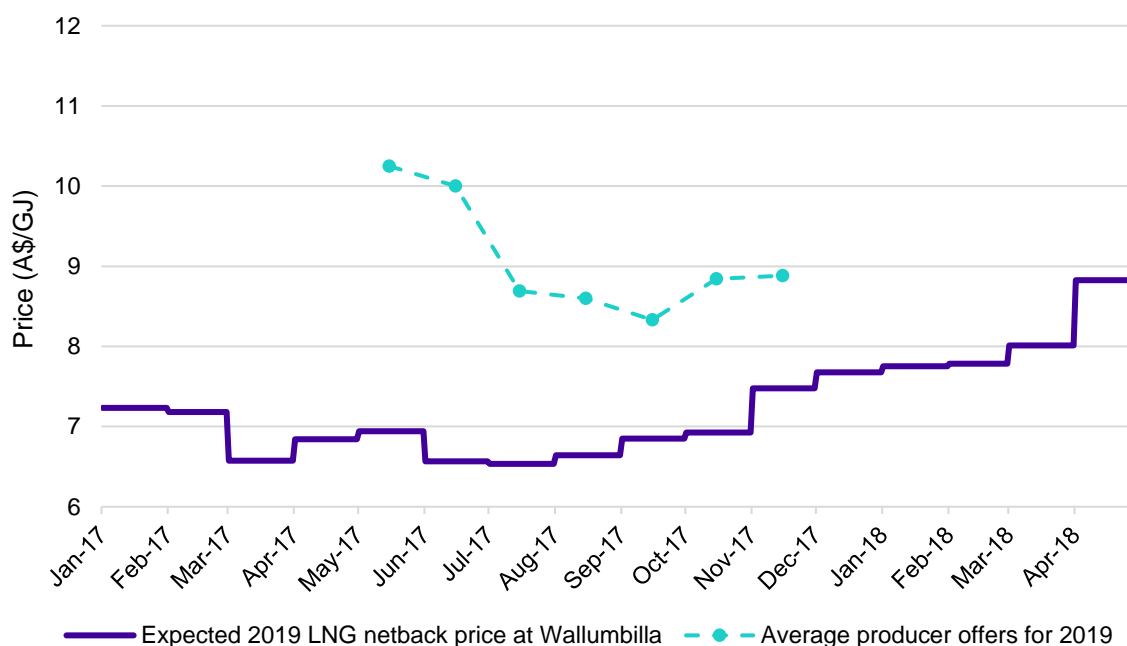
<sup>97</sup> We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from the LNG producers.

<sup>98</sup> Prices reflected in the charts do not include offers for supply of gas produced in NT. Absence of data points for particular months for each series of offers indicates that there were insufficient offers made in those months.

## Queensland

Chart 2.5 below shows 2019 LNG netback prices at Wallumbilla that were expected during each month between January 2017 and April 2018. Against these expected 2019 LNG netback prices, chart 2.5 shows quantity-weighted average prices offered by Queensland producers in corresponding months where there were prices offered.<sup>99</sup> The price averages shown in this chart are derived using the same information used in our analysis of 2019 prices in section 2.2.1 above, but for the purpose of this chart the prices offered in each month are averaged.

**Chart 2.5: Average monthly gas commodity prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices (Queensland)**



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

Note: JKM futures prices quoted by ICE before June 2017 related to futures contracts for the first half of 2019 only.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

Chart 2.5 shows that expectations of 2019 LNG netback prices remained relatively constant for the first half of 2017, after which they steadily increased. As noted in the ACCC's September 2017 report, LNG market expectations around mid-2017 were that Asian LNG spot prices for 2018–19 would average around US\$6/MMBtu. The ACCC also noted at the time that these expectations had been consistent since the start of 2016.<sup>100</sup> In particular, before mid-2017, the global LNG market had been expecting downward pressure on LNG prices over the short-term due to new sources of supply expected to come online, particularly in Australia and the US. However, as noted by EnergyQuest, during 2017 there

<sup>99</sup> The chart does not include offers from retailers/aggregators in Queensland due to the small number of offers made over the relevant period.

<sup>100</sup> ACCC, *Gas Inquiry 2017–20 – Interim Report*, September 2017, p. 66.

was an unexpected increase in Asian LNG demand, with some producers now expecting that the new supply will be easily absorbed.<sup>101</sup>

LNG market expectations of Asian LNG spot prices for 2019 increased from an average of around US\$6/MMBtu in July 2017 to over US\$8/MMBtu at the end of April 2018. As a result, as shown in the chart, expected 2019 LNG netback prices at Wallumbilla increased from around \$6.50/GJ to around \$8.80/GJ over the same period.

Chart 2.5 shows that producer offers in Queensland, which were mostly from LNG producers, were on average around \$10.25/GJ in May 2017 while 2019 LNG netback prices that were expected at that time were around \$7/GJ. Over the remainder of 2017, expected 2019 netback prices increased while average producer offer prices fell. Whereas in May 2017 the gap between average producer offers and expected 2019 netback prices was over \$3/GJ, this gap decreased to around \$1.40/GJ by November 2017.

## Southern States

As explained in our previous reports, the ACCC has adopted a bargaining framework to analyse pricing outcomes in the Southern States.<sup>102</sup> Under this framework, the pricing dynamics in the Southern States are different from those in Queensland. Due to the cost of transportation between the Southern States and Queensland, there is a range of possible pricing outcomes in gas supply negotiations in the Southern States, which would usually be expected to fall between:

- the buyer alternative (representing a ceiling in negotiations) – the LNG netback at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location, and
- the seller alternative (representing a floor in negotiations) – the LNG netback at Wallumbilla less the cost of transporting gas to Wallumbilla or the cost of production (whichever is higher).

Where a price actually achieved in a negotiation will fall within this range is likely to depend on a range of factors, including the location of the buyer, the expectations of the parties about supply and demand dynamics in the Southern States, the relative bargaining strength of the parties and the non-price terms and conditions agreed by the parties.

The supply-demand balance in the Southern States is particularly important to the outcome. If there are limited supply options for gas users in the Southern States, such as in the case of an expected gas supply shortfall, users that are unable to reach an agreement for gas supply with a southern supplier will need to transport gas from Queensland. In this scenario, gas suppliers in the Southern States would be expected to offer a buyer alternative price in every region in the Southern States.

Further, a southern supplier would be expected to seek a higher price the further away a gas user is from Queensland. Since gas users in Victoria are located further away from Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states. If, in a well-functioning market, a southern supplier were to make an offer above this, then regardless of the location of the buyer it would likely be more economic for the buyer to purchase gas from Queensland and transport it to its location.<sup>103</sup>

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<sup>101</sup> EnergyQuest, *EnergyQuarterly*, June 2018, p. 45.

<sup>102</sup> ACCC, *Gas Inquiry 2017–20 – Interim Report*, September 2017, p. 69.

<sup>103</sup> This would depend on whether the buyer is able to acquire capacity on relevant pipelines over the period of supply, as well as the pipeline tariffs that are to be paid.

Therefore, the buyer's alternative price in Victoria is indicative of the maximum price that would be likely to prevail in a well-functioning market.<sup>104</sup>

Conversely, if there were sufficient supply and diversity of suppliers in the Southern States, this would be likely to alter the relative bargaining positions of gas suppliers and gas buyers. Gas buyers would be able to source gas from another supplier in the Southern States rather than having to transport it from Queensland, and increased competition would be likely to lead suppliers to offer prices closer to the 'seller alternative' price. In this scenario, the prices offered by suppliers in the Southern States would be lower the further away the source of supply is from Queensland (but not below the marginal cost of production).

To meaningfully analyse the level of prices offered in a particular location in the Southern States using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location. The ACCC is limited in doing this by the data available for this report. However, given the level of prices offered in the Southern States over the past 18 months, it is sufficiently meaningful for the ACCC to compare the average prices offered across the Southern States with the Victorian buyer alternative prices.

Chart 2.6 below shows Victorian buyer alternative prices and expected 2019 LNG netback prices at Wallumbilla against quantity-weighted average prices offered by southern suppliers in corresponding months.<sup>105</sup> The Victorian buyer alternative prices are derived by taking expected 2019 LNG netback prices at Wallumbilla and adding indicative pipeline tariffs to Melbourne. As noted above, Victorian buyer alternative prices are indicative of the highest prices that would be expected to be offered in the Southern States. Buyer alternative prices in other locations within the Southern States would therefore be expected to lie between LNG netback prices at Wallumbilla and the Victorian buyer alternative prices.

However, we note that the LNG netback prices and buyer alternative prices shown in the chart do not account for other factors that may influence prices offered to gas buyers, such as flexible non-price terms in GSAs and retailer costs and margins.

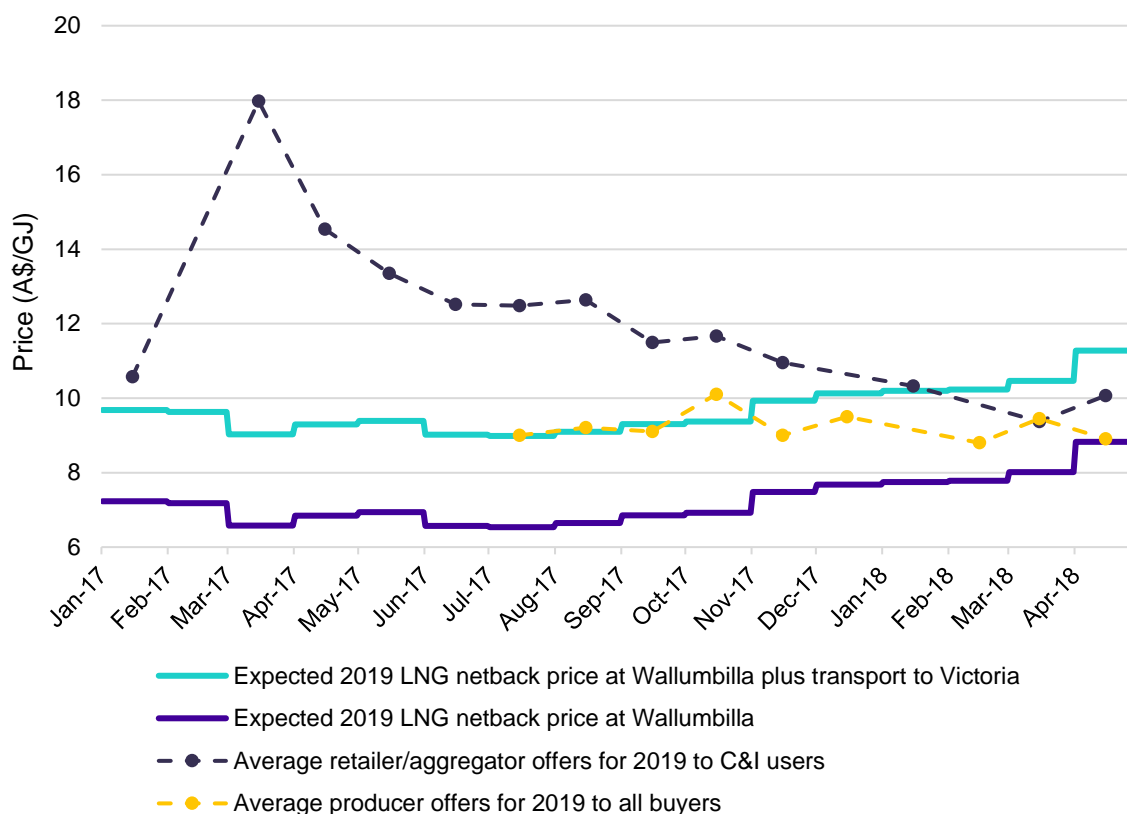
We have not included the Victorian seller alternative prices in chart 2.6 as none of the offers in our data set lie near this threshold. The Victorian seller alternative prices would be below LNG netback prices at Wallumbilla since they are derived by subtracting transportation costs from LNG netback prices.

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<sup>104</sup> We note that prices offered to individual buyers may also be influenced by other factors, particularly non-price terms and conditions.

<sup>105</sup> Absence of data points for particular months indicates that there were insufficient offers made in those months.

**Chart 2.6: Average monthly gas commodity prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices (Southern States)**



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

Note: JKM futures prices quoted by ICE before June 2017 related to futures contracts for the first half of 2019 only.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. Includes offers for gas supply of at least 12 months duration. Offers before 14 July 2017 are part of multi-year unfulfilled offers for annual quantities of at least 1 PJ. Any offers made prior to 14 July 2017 solely for gas supply in 2019 are not included (ACCC does not have this data). After 14 July 2017, all offers for quantities of at least 0.5 PJ are included.

Chart 2.6 shows that producer offers for 2019 supply in the Southern States have on average been relatively stable since January 2017, albeit with a slight decrease in early 2018. From mid to late 2017, the average of prices offered by producers in the Southern States was around \$9–\$10/GJ, being roughly around Victorian buyer alternative prices at that time. This means that during that period, producers in the Southern States offered gas to southern buyers at prices on average roughly equivalent to the maximum prices that would be expected to be offered in the Southern States in a well-functioning market. This may reflect a supplier’s expectation at the time of a supply shortfall in the Southern States in 2019.

However, from February to April 2018, the average of prices offered by southern producers was around \$9–\$9.50/GJ. These offers, which were mostly to Victorian gas buyers, were on average well below Victorian buyer alternative prices during those months. The offers were more closely aligned with expected 2019 LNG netback prices at Wallumbilla, which as noted above had been increasing since mid-2017. This indicates that, during the early months of 2018, Victorian gas buyers were able to source gas from southern producers at prices that were below the price of sourcing gas from Queensland. This may reflect changing expectations about the supply-demand balance in the Southern States in 2019.

The analysis of the prices offered by retailers/aggregators to C&I users is even more revealing about the state of the gas market over the past 18 months. Chart 2.6 shows that, at their highest point in March 2017, the average of prices in retailer/aggregator offers was around double—that is, about \$9/GJ above—Victorian buyer alternative prices. The chart also shows that in July and August 2017, averages of prices offered by the retailers/aggregators to C&I users were around \$3.50/GJ higher than the averages of prices offered by the southern producers.

This is symptomatic of a gas market that was not functioning effectively in 2017. At the retailer/aggregator price levels observed in the first half of 2017, it would have been clearly more economic for C&I gas users to purchase gas directly from southern producers or even buy gas in Queensland and transport it to their location. However, the fact that the higher-priced offers persisted for several months indicates that C&I gas users were not in position to do so.

Many of the higher-priced offers from early 2017 were made by retailers/aggregators to smaller C&I gas users (those seeking less than 1 PJ per year), who generally neither have the option of sourcing gas directly from producers nor can they easily acquire the necessary pipeline capacity. These C&I users, who were more reliant on retailers/aggregators for gas supply and delivery, were the most affected by the lack of supply and diversity of suppliers in the gas market in the first half of 2017.

Prices offered by retailers/aggregators decreased over the course of 2017 as supply-demand dynamics improved. By early 2018, the offers from retailers/aggregators to C&I users were, on average, below Victorian buyer alternative prices. As we noted earlier, these offers were to gas buyers in various locations throughout the Southern States, so some of these prices may still be near the top of the buyer alternative prices applicable in the buyer's location. Nevertheless, the chart shows that, at least for Victorian gas buyers, these offers were below the prices that these C&I users would have to pay to purchase gas from Queensland. Further, by April 2018, the gap between the averages of prices offered by retailers/aggregators and southern producers had decreased to around \$1/GJ.

Overall, there has been a clear convergence of prices offered in the Southern States for 2019 supply and contemporaneous expectations of 2019 LNG netback prices. As discussed, the most recent offers from suppliers in the Southern States have been below Victorian buyer alternative prices. This trend would be consistent with a shift in market expectations about the likelihood of a gas supply shortfall in the Southern States, and the level of competition between suppliers.

However, the ACCC considers that it is too early to draw firm conclusions about what recent offer prices indicate about the current pricing dynamics in the East Coast Gas Market. There have been relatively few offers made by southern suppliers (particularly producers) in early 2018 for 2019 supply when compared to the number of offers made during 2017.

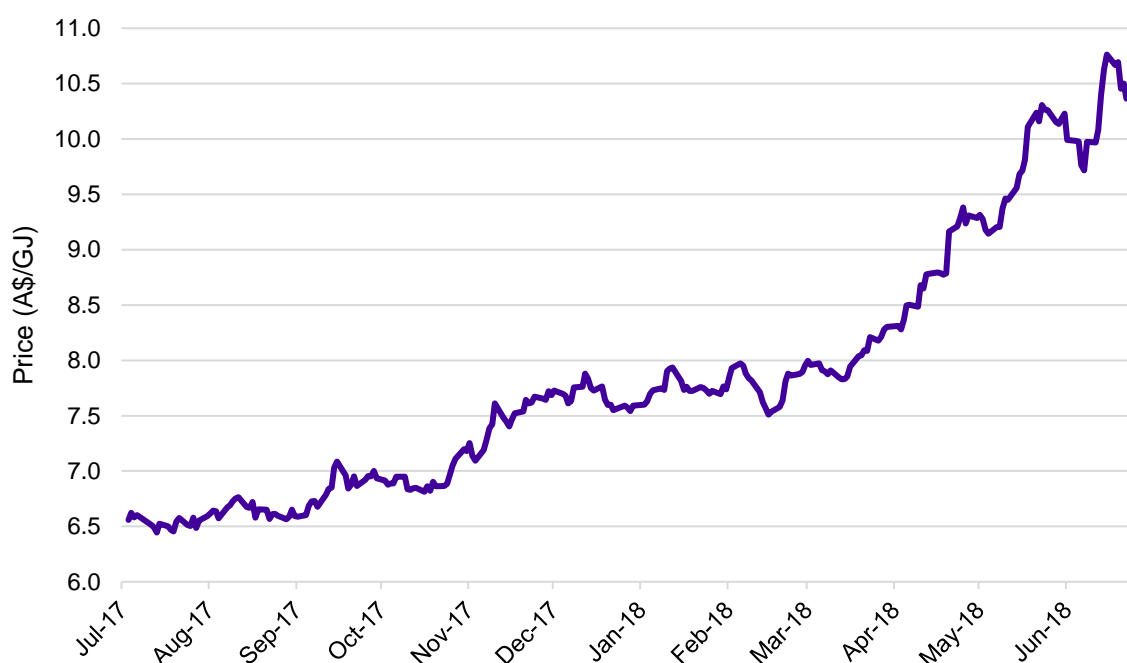
Further, the LNG netback prices and buyer alternatives calculated by the ACCC for the purpose of analysis in this section are based on: expectations of future prices indicated by JKM futures; the ACCC's approach for calculating these measures; and the ACCC's assumptions about the key economic parameters (for example, oil prices and foreign exchange rates). Suppliers may be using different approaches and assumptions to calculate these measures. For example, suppliers may be using LNG price markers other than Asian LNG spot prices and may be making different assumptions about the costs of shipping and liquefaction. Suppliers may also be using swap fees in place of some pipeline tariffs when calculating buyer alternative prices. This means that recent offers made by suppliers may be closer to their own estimates of buyer alternatives than the ACCC's estimates shown in chart 2.6.

The ACCC will continue to monitor prices offered in the East Coast Gas Market relative to expected LNG netback prices and relevant buyer and seller alternative ranges. The ACCC will report further analysis of this in the December 2018 report.

#### 2.6.4. Recent changes in expectations of 2019 LNG netback prices

As shown in charts 2.5 and 2.6 above, with changing LNG market expectations around Asian LNG spot prices, the levels of LNG netback prices and buyer alternative prices are also subject to change. The charts above show these price comparators up to the end of April 2018, in order to align with the most recent information the ACCC has obtained from suppliers for the purpose of this report. However, expectations of 2019 Asian LNG spot prices, and hence expected 2019 LNG netback prices, continued to increase until the end of June. This is illustrated in chart 2.7 below.

**Chart 2.7: Expected 2019 LNG netback prices at Wallumbilla (since July 2017)**



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

Chart 2.7 shows that expectations of 2019 LNG netback prices at Wallumbilla have increased over the past 12 months, from around \$6.50/GJ in July 2017 to over \$9/GJ by the end of April 2018. There was a further subsequent increase to over \$10.50/GJ in mid-June before a drop to around \$10/GJ by the end of June.

This increase in expectations of Asian LNG spot prices over a relatively short period shows the potential price volatility in the LNG market. It emphasises that sudden and unexpected changes in LNG demand can have short-term impacts on price expectations because LNG supply is relatively slow to respond to such changes. However, it is important to note that, while recent LNG price expectations have trended upwards, this will not necessarily continue. ICE JKM futures prices over 2020, while based on fewer trades, are lower than prices quoted for 2019.

## 3. Experiences of C&I gas users

### 3.1. Key points

- C&I gas users are now consistently reporting market conditions significantly better than we reported in our September 2017 report. Larger gas users are typically reporting offers of gas supply from at least three retailers/aggregators. We have also been told by gas users of instances where they or other retailers have been able to negotiate use of the contracted transport capacity on gas pipelines held by an incumbent retailer—bringing more competition to an area or region.
- Offers for supply of gas for 2019 have stabilised for gas users and are consistent with the levels of \$8 to \$10 per gigajoule described in the ACCC's December 2017 and April 2018 reports. However, prices are still two to three times higher than historical levels and will continue to be shaped by LNG prices.
- While some C&I gas users are adjusting more quickly than others to the changed market circumstances, all C&I gas users continue to report significant concerns about the business impacts of current gas market conditions, in particular, on longer-term investment decisions.
- With the export-exposed nature of gas markets and other changes to the market identified in our 2015 inquiry, market conditions and practices are changing for gas consumers. C&I gas users report increased use of expressions of interest processes by gas suppliers, and terms of supply being less flexible, for example, higher take or pay requirements and maximum daily quantities.
- The changes in market conditions are seeing some market participants—both gas users and gas suppliers—preferring shorter term gas supply agreements of one to two years, rather than longer term contracts.
- Some C&I gas users are increasingly open to considering a range of non-traditional supply options, such as moving from retail to producer supply, considering LNG import proposals and participating in short-term trading markets.
- Only a handful of C&I gas users have entered into gas supply agreements for 2019 this year with many continuing to engage in negotiations and many facing difficult decisions about their investment plans and long-term financial viability.
- C&I gas users have reported that the ACCC's price transparency work on its gas price series for the domestic market and its export parity (LNG netback) price series play an important role in informing them of the market and helping them in the supply negotiations.
- With the market moving to shorter term contracts and the use of supplier expressions of interest processes, ongoing price transparency and other market information will continue to be critical to ensure that buyers are making informed decisions about their long-term operations, as well as improving the overall functioning of the domestic gas markets.

### 3.2. Introduction

This report marks the third time we have reported on the experiences of gas users. As with our previous reports, we have focussed on commercial and industrial (C&I) gas users. Many of these gas users consume large quantities of gas (over 1 PJ per year each) for their production processes across a diverse range of sectors such as mining, manufacturing, agriculture and food production. These gas users represent sectors that are important contributors to the Australian economy and are also large employers, particularly in regional

areas. Many of these users are supplying in highly competitive international markets and are very sensitive to small fluctuations in their input costs.

In recent years, C&I gas users have been actively participating in the public discourse about the East Coast Gas Market. In particular, users have expressed concerns about the development of the LNG export projects in Queensland and the consequent exposure of the domestic market to international prices, as well as government moratoria and environmental controls on gas developments and low international oil prices. Some of the flow on effects to gas users include: reduced ability to obtain gas supply offers, an increase in prices offered, shorter supply terms offered, increasingly restrictive terms and conditions, and some offers being made on a 'take it or leave it' basis.<sup>106</sup>

This chapter is based on information voluntarily provided to us by C&I gas users, and presents their perspective of how the market is functioning. This information is intended to complement and give qualitative depth to the pricing and supply information in earlier chapters which is predominantly informed by information provided by gas producers and retailers under the ACCC's compulsory information gathering powers.

Between March and June 2018, we spoke with 18 C&I users from across the east coast (predominantly in the Southern States) with a combined annual consumption of around 75 PJ. These users represent a broad range of sectors and they use gas for a variety of purposes, such as a feedstock to production processes, and as a heat source for producing steam or for drying processes. Most of these users were or are seeking gas supply for 2019, while the rest already had 2019 supply locked in, but were or are looking for gas supply in future years. We also spoke with five national organisations that represent gas users to acquire aggregated, industry-wide insights. Our analysis covers the experiences of users in the market since January 2018.

We spoke with C&I users about a wide range of topics across the whole gas supply chain. Users completed a survey and participated in interviews concerning their experiences of the current market and their biggest concerns. We received a high level of quality engagement from users and this chapter details the experiences of C&I users as reported to us, particularly in relation to general market conditions, current gas offers, and the impacts of current conditions on their operations. We also focus on the primary concerns put forward by C&I users which include high gas prices, lack of competition in gas supply and long-term uncertainty.

While C&I gas users are the focus of this chapter, gas prices are also a continuing concern for households and small businesses. According to the AEMC's 2018 review of the retail market, market concentration for residential and small business supply is generally declining. Several retailers suggested to the AEMC that access to reasonably priced gas commodity and transport is a barrier for entry/expansion.<sup>107</sup> After the price increases in 1 July 2017 and 1 January 2018, the annual gas bill for a representative consumer on a median market offer increased across all jurisdictions.<sup>108</sup> More recently, announcements for pricing to apply from 1 July 2018 were more mixed, with some prices increasing, some declining, and some holding steady.<sup>109</sup> Lower pricing is available for many of these retail customers. The AEMC reported that in all jurisdictions, the annual savings to be made for the representative gas

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<sup>106</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 18–19.

<sup>107</sup> AEMC, *2018 Retail Energy Competition Review*, 15 June 2018, pp. xxiii, p. 18.

<sup>108</sup> The residential gas bill increased most in the Australian Capital Territory by \$192 and the least in South East Queensland by \$14. AEMC, *2018 Retail Energy Competition Review*, 15 June 2018, p. xvi.

<sup>109</sup> From July 2018 AGL announced a price rise for many retail customers, while EA and Origin announced reductions or no change. See AGL, *AGL cuts electricity prices across NSW, SA and Queensland*, Media Release, 8 June 2018; Origin, *Origin to cut electricity prices in Queensland and South Australia, freeze base tariffs in NSW and ACT*, Media Release, 5 June 2018; EnergyAustralia, *Households in QLD, NSW to benefit as EnergyAustralia drops rates*, Media Release, 15 June 2018.

consumer by switching from the median standing offer to the cheapest market offer were: Victoria \$690–\$751, Australian Capital Territory \$192, New South Wales \$177–\$185, South Australia \$108–\$161, South East Queensland \$31–\$45.<sup>110</sup>

### 3.3. C&I users' experience seeking gas for 2019 continues to vary as market practices change and decisions around longer term viability are faced

As we have reported previously, gas prices are much higher than historical levels, and though they have softened somewhat from peaks in 2017,<sup>111</sup> users highlighted the impacts of current market prices.

The changing nature of the gas market (to an internationally exposed market) is clearly having a significant effect on C&I gas users. Because of the new market dynamics, many C&I gas users are facing extremely difficult operational decisions.

Chapter 2 detailed the prices offered and agreed for gas supply in 2019 based on the information obtained from suppliers. Here, we discuss C&I gas users' perspectives on the offers and bids for 2019 and beyond.

This section covers only the C&I gas users who have been to market in 2018. Several of the users we consulted had not been to market yet this year, and so while their views on other topics are covered later in the chapter, their market experiences are not included in this section.

#### 3.3.1. Number of suppliers in the market has been steady since December 2017 but there are changes in how contracts are negotiated

As reported in previous reports, the size and location of a user has a material effect on the number and type of offers it is likely to receive.

For 2019 offers since January 2018, larger C&I users (over 1 PJ/a) generally noted a willingness by producers and retailers to engage and negotiate, with users receiving up to seven responses to a request for prices. However for some users, even though they received several offers, the majority of offers received did not fully meet the requirements they had set out in their request.

We have observed offers typically being made to C&I users by at least three retailers/aggregators. There is now more competition between the retailers and aggregators than there was in early 2017, which appears to be contributing to the lower prices being offered in the market (compared to 2017).

Some users felt that expression of interest (EOI) processes run earlier this year by producers and retailers were having a negative effect on competition, with some suppliers declining to respond to user offer requests because the suppliers were running their own EOI processes. The use of EOIs may reflect the tightness of supply and the relative bargaining positions of parties. In addition, LNG exporters have told us they have favoured this approach to be able to clearly document their efforts in meeting the terms of the Heads of Agreement signed with the Australian Government in October 2017. User views on EOI processes are further discussed in section 3.3.3.

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<sup>110</sup> AEMC, Consumer confidence in energy retailers drops to new lows, Media Release, 15 June 2018.

<sup>111</sup> As discussed in chapter 2 and in section 3.3.2, prices for 2019 supply are lower than those offered in 2017, but are still high for many C&I gas users.

Smaller C&I users, or those that are not located near major demand centres, generally received fewer offers, from only one or two suppliers. The annual quantity of gas contracted by the user could also affect the prices offered to them (section 3.3.2).

This lack of competitive offers was more evident where users were located in areas where one supplier controlled all or most of the capacity on the local pipeline. This is an issue that we discussed in our 2015 inquiry.<sup>112</sup> In our December 2017 report,<sup>113</sup> we noted the ACCC investigation into secondary capacity on regional pipelines and we reported that following the investigation, we had seen instances of retailers making capacity available in regional areas, which had resulted in more competitive outcomes.

We are, for example, aware of a shipper that was able to procure gas directly from a producer for the first time by acquiring transport capacity from its former retailer (see box 1.2). Similarly, we heard of a smaller, new entrant retailer who had been able to secure access to a regional pipeline which had historically been held by another large incumbent retailer. This deal reportedly enabled smaller C&I users in the area to have a choice of retailer for the first time. The success of this endeavour encouraged the new retailer to then repeat the exercise on another regional pipeline, again opening up another new area to competition.

We have, on the other hand, heard some evidence of a lack of competition on a different regional pipeline, which has resulted in higher prices for users because there is only one gas supplier they can deal with. The users of this pipeline therefore have little negotiating power to help them secure a competitive supply arrangement. One user in the area noted that their only alternative would be to use another fuel type, but fuel switching would involve costly infrastructure investments, which would not be viable even at high gas prices. The user reported that the current market uncertainty makes long-term investment decisions even more difficult.

### **3.3.2. Prices for 2019 supply are still concerning for many C&I gas users**

As noted above, high prices are one of the top three concerns of C&I gas users. As presented in chapter 2, offers made between January and April 2018 averaged in price at \$9.02/GJ for producer offers and \$9.49/GJ for retail offers for 2019 supply. These prices are significantly lower than the peak of prices offered in early 2017 (over \$20/GJ), however they are still two to three times higher than historical east coast gas contract prices and many C&I users report that these prices continue to pose significant difficulties for them.

One company put it this way:

*'At best, short-term spot prices may have eased slightly and contract offers decreased from "outrageous" to "unsustainable" for large manufacturers for 2018/19 only.'*

Southern C&I gas user, May 2018

Many C&I users reported a significant difference in the range of prices offered by various suppliers, in some cases up to \$2–\$3/GJ. Several users noted that the prices offered for multiple sites across the east coast seemed inconsistent and not representative of price differences that would be expected due to production costs in the nearby region and transport costs.

<sup>112</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, p. 153.

<sup>113</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, December 2017, p. 65.

As we have raised in previous reports,<sup>114</sup> some suppliers are making oil-linked offers for longer term deals. Some users consider these offers to be higher risk, particularly when locking in supply for a longer period, as they expose them to much greater price volatility when compared with traditional fixed pricing structures. While there are options to manage price risks through hedging products in financial markets, many C&I users are too small to manage this sort of activity, and they prefer to focus resources on core business activities rather than on complex energy procurement methods.

Some smaller C&I gas users, in particular, expressed concern about the lack of transparency and consistency in retail/wholesale offers from retailers, which significantly affected the prices they were being offered. In particular, the minimum annual consumption quantity required to qualify as a large user instead of a small business customer varied across retailers. Gas users reported that these minimum annual consumption quantities were not easily discoverable and often took significant engagement to uncover (if at all). The quantity discount offered for users categorised as larger users can be significant, meaning a potentially large cost impact for the user. Some users suggested that suppliers used 'selective user categorisation' which limited the number of competitive offers a user faced and that thresholds for quantity discounts could be standardised across suppliers.

The ACCC's view is that there is considerable uncertainty in retailer pricing approaches more broadly, including how various inputs influence prices. The ACCC has started working with gas retailers to better understand and examine the supply of gas by the retailers in greater detail (refer to section 4.5 for further detail).

### **3.3.3. More suppliers are using EOI processes to sell gas**

The trend towards supplier EOI processes is continuing,<sup>115</sup> and C&I users reported being recently invited to participate in EOI or auction style processes by at least five suppliers.

These EOI processes can be challenging from the user perspective for a number of reasons:

- Users have to bid in the dark, in the absence of information on prevailing market prices, which makes it hard for them to succeed against other gas buyers that have access to more information (e.g. retailers).
- These processes aid in the price discovery for the suppliers rather than the users, which adds to the information asymmetry.
- Users are typically asked to conform to certain parameters (such as minimum quantities or gas supply during certain time periods) rather than seeking supply that fits their needs.
- Deadlines for submitting bids can be tight, which can make it difficult for users to conduct the necessary inquiries and prepare a bid in time.

Based on reports from C&I users, EOI processes completed in 2017 do not appear to have facilitated C&I users obtaining supply directly from producers. For example, all successful bidders in the GBJV's 2017 EOI were retailers or GPG.<sup>116</sup>

### **3.3.4. Gas is predominantly offered for short-term periods and under less flexible terms**

Some C&I gas users were seeking agreements for only one year, partly in recognition of market uncertainty and pricing levels. Other users had a preference for long-term (up to five

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<sup>114</sup> For example ACCC, *Gas Inquiry 2017–2020 – Interim Report*, September 2017, p. 49.

<sup>115</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, September 2017, p. 48.

<sup>116</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, December 2017, p. 45.

year) agreements to help underpin long-term business decisions. Some users find it difficult to make long-term investment decisions without certainty in gas supply given it is a significant input cost.

Of those users that wanted longer-term agreements, most received predominantly one year offers amongst a few two to five year offers. This outcome is consistent with the trend for shorter-term offers compared to longer-term that we observed in our September 2017 report.<sup>117</sup>

While commodity gas prices may be lower overall compared to 2017, some users are concerned that risks are increasingly being shifted from suppliers to users, which increases overall costs once the additional risk is priced in. We discussed restrictive terms and conditions, including high take-or-pay<sup>118</sup> percentages, in our September 2017 report. There has been little change in the offers from suppliers in this regard. However, two C&I gas users reported that they were able to negotiate some changes to contract terms.

C&I users questioned the justification for suppliers charging a premium for greater take-or-pay flexibility, suggesting that in a tight market, suppliers will readily find demand for the untaken gas and it could be resold.

### **3.3.5. Effect of higher gas prices on investment decisions of C&I gas users**

Almost all of the C&I users we consulted are exposed to international competition in the markets in which they supply their products. As a result, these gas users report that they cannot pass on their gas cost increases to their customers because they would become uncompetitive with their overseas competitors who are not exposed to rising gas prices in their domestic markets. Instead, these users must absorb higher gas costs, unless they can use other strategies to mitigate the effects.

C&I users whose gas use makes up a large proportion of their cost of production (over five per cent) continue to be particularly affected. In response to higher gas prices, many users have reported making short-term decisions to enable continued operation of their businesses. However, the longer-term implications of higher gas prices are now being further considered as they assess their longer-term viability. In particular, those users who have to make major decisions on plant upgrades or large maintenance spends into the next decade are carefully assessing the long-term sustainability of their business.

A lesser impact has been felt by those C&I users for whom gas constitutes a smaller proportion of their costs (less than five per cent). For these users, higher gas prices still affect profitability but have a proportionally smaller effect. However, many of these users are large consumers of electricity, so the impact of higher gas prices can also be felt indirectly to the extent that higher gas prices contribute to higher electricity prices.

C&I gas users have generally sought to adopt methods to mitigate the short-term impact of increased gas costs, including through energy efficiency improvements, fuel switching, postponing capital expenditure, reducing headcount or pay increases, deferring investments or expansions and changing shift/usage patterns.

However, many have told us that current gas price levels are not sustainable for them in the long-term, and profitability is described as borderline by several users (because of gas cost increases). One user that is looking to further reduce its gas price exposure reported that each additional mitigation project has ever decreasing returns for each dollar invested.

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<sup>117</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, September 2017, pp. 50–51.

<sup>118</sup> Take-or-pay: A contract term specifying the minimum proportion of the gas supply agreement's annual contract quantity that the buyer is required to take in a particular year. The buyer is required to pay for this minimum quantity of gas regardless of whether they use it.

As more long-term investment decisions near (many of which are basic plant upgrades to meet minimum operating or safety requirements), longer-term viability is reportedly a concern for many of these users should current pricing levels be sustained. Some users will have to consider alternative strategies to reduce their future exposure, such as importing key production inputs rather than producing them in Australia, or considering whether to invest locally or divert investment to offshore operations. Other users will have to consider how they will sustain operations into the future, including decisions around contraction, partial or full closure, or moving production offshore. For some users these options are genuine possibilities over the next decade.

A number of C&I gas users have told the ACCC that they cannot sustain current prices indefinitely. Future gas supply uncertainty, volatility and lack of transparency (in particular, price and supply transparency) is said to be compounding these issues for them and making it harder to make long-term planning decisions.

### **3.3.6. Most C&I gas users are still negotiating for 2019 supply**

Many of the users mentioned above are still in negotiations for 2019 supply, while only a few have recently entered into agreements. Few 2019 contracts have been signed so far this year overall (see section 2.2.2) and many parties are continuing to negotiate further. Some users expect prices to remain higher due to international LNG market dynamics, and so they are keen to negotiate competitive, long-term supply arrangements now. Other users are of the view or are hopeful that prices may further decrease (whether as a result of the ADGSM being triggered or market forces) and are holding back on making long-term gas purchasing decisions until then.

There were a small number of C&I gas users we consulted that had already contracted for 2019 and were seeking gas supply offers for 2020 and beyond. Users reported that while several suppliers had engaged in constructive discussions, firm offers were less forthcoming and pricing indications were still too high. These users are hoping to lock in contracts by the end of the 2018.

## **3.4. C&I gas users are increasingly open to trying a range of supply options to deal with current market conditions**

We continue to see a trend of C&I users moving away from their traditional supply approach, which often consisted of re-contracting with the same retailer year on year. With the changed market conditions discussed above, users are looking at a wider suite of options. Based on user comments, there is some indication that short-term, large impact efficiency options might be starting to be exhausted and users are now considering other strategies such as considering natural gas alternatives, sourcing gas directly from producers, participating in short-term trading markets and considering supply via current proposed LNG import terminals.

### **3.4.1. Natural gas alternatives**

Following the trend observed in our September 2017 report,<sup>119</sup> a large number of C&I users are investigating the use of alternative fuels. In many cases, gas is used for heat to produce steam. Alternative fuels for these processes include diesel or coal, which vary in cost depending on circumstances but for some users can be around half the cost of gas at current prices. Other alternatives such as liquefied petroleum gas (LPG) and micro-LNG have also been seriously considered, though these options tend to be higher cost than coal or diesel.

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<sup>119</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, September 2017, p. 52.

Some users we spoke with have recently made significant investments converting boilers to run on alternative fuels to replace or significantly reduce their gas consumption. Other users are considering doing the same. For instance, if implemented, Australian Paper's waste to energy proposal could reduce its gas use by up to 4 PJ each year.<sup>120</sup>

For many users, the fuel cost comparison is much better despite the investment costs for changes to plant. A further benefit is that switching to these gas alternatives would provide more certain fuel supply and stability of pricing in the current market environment. However, C&I gas users are generally reluctant to move to more carbon intensive fuels given the environmental impact.

### **3.4.2. Moving from retailers to producers**

Large C&I users are generally more likely to consider producer supply offers than they traditionally have as these offers have tended to be more competitively priced than retailer offers. Users also noted producer supply offers can be more transparent, as they have fewer cost components so it is easier to understand what is being priced (transparency in retailer pricing is discussed further in section 4.5).

However, obtaining gas directly from producers comes with additional challenges. Some C&I users have had to become market participants and secure their own transport arrangements to enable this, which involves additional time and resources. Producer offers can also have less flexible supply conditions (for example 100 per cent take-or-pay) and different pricing structures, which can be an adjustment for users.

#### **Case study 3.1: Transitioning to producer supply**

An industrial gas user in the Southern States that consumes a high quantity of gas each year has recently entered into a new gas supply agreement with a gas producer.

For this user, input costs, including gas and electricity costs, are an important factor influencing long-term investment planning.

This user has been supplied by the same gas retailer for around a decade, with new supply agreements renegotiated bilaterally every 2–3 years.

Prior to the last agreement concluding, the user approached several producers for offers to supply, in addition to approaching their existing retailer.

All suppliers responded to the request and the user noted a willingness by the producers to engage and negotiate. While all offers were flexible on contract duration, there was a wide range in the prices that were offered. In the end, the user chose entering into an agreement with one of the producers.

This new deal has resulted in considerable annual savings compared with their previous retail arrangement and they were also able to negotiate some additional concessions on their non-price terms and conditions.

This user's experience demonstrates the benefits that increased competition can bring for users if they are able to negotiate both with producers and retailers.

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<sup>120</sup> Australian Paper, *Energy from Waste Project Summary*, p. 6.

Some users have gone even further upstream, with several examples over the past few years of C&I users partnering with producers to underpin new supply production. A recent example is Incitec Pivot's joint venture arrangement with Central Petroleum for potential future supply to its Gibson Island fertiliser facility in Queensland.<sup>121</sup>

However, not all C&I users have the option of entering into arrangements directly with producers. Some producers specify a minimum annual quantity of gas that a user must acquire to be eligible for their supply, and many smaller C&I gas users do not consume enough gas to qualify.<sup>122</sup> As we reported in the December 2017 report, one approach being trialled by smaller users is the formation of a buyers group (authorised by the ACCC<sup>123</sup>), to aggregate demand from a group of smaller users to attract direct wholesale offers from producers.<sup>124</sup>

There are some users that prefer supply from retailers rather than producers, prioritising the ease and potentially lower risk nature of retail arrangements. Some of the benefits of retail supply have traditionally included lower take-or-pay rates (meaning increased flexibility and lower risk) and all-inclusive transport arrangements (meaning users do not have to make their own transport arrangements).

### 3.4.3. LNG import proposals

As discussed in section 1.6, there are four entities that are publicly considering constructing LNG import facilities on Australia's east coast. Should at least one of these projects go ahead, it could bring gas by as early as 2020. Many C&I gas users have been engaging in discussions with these entities. For example, Australian Industrial Energy (AIE) has publicly noted it has 'significant Industrial and Commercial domestic gas customer support with the execution of 12 Memoranda of Understanding for gas offtake'.<sup>125</sup>

Users generally see the entry of new suppliers and new supply into the market as a positive. However, some are concerned that the imports may come at the expense of lower cost sources of supply and thereby prevent downward pressures on prices. There was also some anecdotal evidence that the presence of import terminal proponents making offers in the market is influencing other gas suppliers to offer gas at prices just below the proponents' offers.

Many users said they are open to discussions with import terminal proponents but that:

- they consider prices currently being offered 'un-competitively high' (even before transport costs are added)
- some prices are oil-linked, whereas they (users) prefer fixed prices
- proponents want 5–10 year deals to underpin their investment but users are hesitant to lock-in long-term prices or not able to commit for such long periods at the prices currently being offered.

Some users also expressed doubts about whether a terminal would actually be built and supply would eventuate.

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<sup>121</sup> Incitec Pivot, *Gibson Island Interim Gas Supply Update*, Media Release, 25 June 2018.

<sup>122</sup> For example, some suppliers unwilling to supply C&I users under certain quantity thresholds (of 4 or 10PJ/a). ACCC, *Gas Inquiry 2017–2020 – Interim Report*, September 2017, p. 44.

<sup>123</sup> ACCC, *The Eastern Energy Buyers Group – Authorisations – A91594 & A91595*, Final Determination 22 November 2017.

<sup>124</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, December 2017, p. 51.

<sup>125</sup> Australian Industrial Energy, *Australian Industrial Energy consortium selects Port Kembla, NSW for landmark LNG Import Terminal and enters FEED*, Media Release, 4 June 2018.

### 3.4.4. Switching to short-term trading markets

As we reported in the December 2017 report<sup>126</sup>, an increasing number of large C&I gas users have been using short-term trading markets to manage ‘overs and unders’,<sup>127</sup> particularly since take-or-pay rates have increased in their gas supply agreements, reducing their flexibility. We also reported that a number of users were considering switching to these trading markets for their entire loads from 2018 onwards. Several users did start trading on these markets this year and they have reported generally positive experiences and see their entry now as just another business risk to manage.

C&I users who switched to trading markets for 2018 told us that they are generally well ahead (in pricing terms) of where they would have been with a wholesale or retail offer they received for 2018 gas in mid-2017. As shown in section 2.4, average prices paid in short-term trading markets earlier this year were generally lower than the offers received for 2018 supply in 2017.<sup>128</sup>

One southern user who began sourcing gas exclusively on one of these markets at the beginning of 2018 has found the process easier and less costly than expected, noting risks still exist, mainly from high seasonal prices. This user is now considering entering into a new supplier contract to achieve increased longer-term certainty. However, compared to its position in 2017, it now has greater choice and negotiating power due to its current flexible supply approach. It could decide to contract only a portion or all of its load, and it has the ability to wait for a reasonable offer rather than having to accept an unsatisfactory offer due to timing constraints. This user explained it this way:

*‘Having made the decision to become a gas market participant (it) has at least taken away the highly speculative offers from retailers in the order of \$15/GJ.’*

Southern C&I gas user, May 2018

## 3.5. Continued improvements to market transparency are increasingly important

While it is promising that many C&I users are looking to make decisions focused on their long-term operation, there are difficulties and challenges for users with each of the various options they are exploring. In this context, the ACCC considers it important that information asymmetries are addressed and market transparency measures are developed to ensure that buyers are making informed decisions about their long-term operations and that the gas market of eastern Australia is a well-functioning market.

Market transparency is a key focus for the ACCC in 2018, and is discussed in further detail in chapter 4. We asked C&I users what they thought about the current state of transparency in the market, how the current reforms could help, and what more was needed.

All C&I gas users support more transparency in the market. Many users view the ACCC’s Inquiry as the primary driver of recent market improvements and consider that it is making a difference in terms of the reasonableness of offers and supplier behaviours. Users would prefer to see the Inquiry continue until the supply/demand balance is improved, and there was concern about what will happen once the Inquiry concludes in 2020.

<sup>126</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, December 2017, p. 48.

<sup>127</sup> In this context, the term short-term trading markets is used broadly to refer to all trading markets across the east coast, including the Sydney, Adelaide and Brisbane STTMs, the Victorian DWGM and the northern Gas Supply Hubs.

<sup>128</sup> ACCC, *Gas Inquiry 2017–2020 – Interim Report*, December 2017, Chapter 2. Domestic price outlook for 2018.

### **3.5.1. Information on market prices and costs helps level the playing field**

C&I gas users have informed the ACCC that there is not enough information on market prices and costs to help make informed decisions. While there is pricing information currently available on short-term trading markets, some C&I gas users are of the view that these markets are not liquid enough to be used as a reference price. Prices for longer-term contracts can only be obtained through formal enquiry processes that take a lot of time and effort. One user did consider the recent trading activity on ASX gas futures markets (discussed in section 2.5) as a welcome development, but noted that liquidity would need to increase before futures prices could be used as reliable reference prices.

C&I users reported that the ACCC's recent price reporting in particular has been valuable and they would support more price reporting to balance the current information asymmetry. Users were generally welcoming of the ACCC's upcoming publication of an LNG netback price series, and they thought the publication of a credible, independent price series by the ACCC would help with future negotiations. Some expressed concern that the price series may further lock domestic pricing at LNG netback prices, and that suppliers may seek to use it as a pricing mechanism in contracts, which could result in higher and more volatile contract prices. The LNG netback price series is discussed further in section 4.3.

Price transparency is especially critical in the current market environment where there is likely to be increased information available to suppliers and less for buyers, as a result of the shift towards EOI processes by suppliers. The ACCC is considering what level of transparency is needed in the market beyond the period of this current gas inquiry, and will be making any necessary recommendations prior to finalising the inquiry.

### **3.5.2. Information on reserves and demand supply balance, including potential shortfalls, would be very helpful**

Many C&I users indicated that increased transparency in reserves and resources would bring about substantial beneficial changes. In particular, C&I users reported that improved transparency would support increased exploration and production, thus potentially boosting supply and the number of suppliers. A better understanding of the supply outlook would also help users in making more informed consumption, contracting and investment decisions. Increased reporting, as is required in the United States for instance, would reduce risk exposure to new entrants and encourage a market response to forecast supply shortfalls.

The ACCC has been undertaking work to improve the transparency of reserves and resources information, and is expecting to commence publication of reserves and resources information in December 2018. More information on this work is in section 4.3.

### **3.5.3. Retail and transport costs are not transparent to some users**

We also asked for users' perspectives on the level of transparency of retail and transport costs and charges. Users varied in their level of confidence about how well they understood the retail cost components of their bills. For some users, it was unclear how suppliers determined both gas commodity prices and non-commodity supply charges.

Users also reported that there was not a clear pattern of pricing in the offers they received (e.g. across various locations, or larger quantities vs smaller quantities). This made comparisons of offers from different suppliers difficult. While many users said they were advised they were paying for pipeline transportation at 'cost price', they were not certain that they were paying the actual transportation costs for the supply of gas to their premises.

The ACCC is currently examining the drivers behind retailer pricing (see section 4.5).

## 4. Improving market transparency and information disclosure for better market outcomes

### 4.1. Key points

- A key focus of the inquiry to date has been to promote transparency of the East Coast Gas Market.
- The more information that is available to buyers and sellers, the better markets operate. This, in turn, results in better market outcomes, such as the more efficient use and allocation of resources.
- The ACCC has been improving gas price transparency by publishing prices offered and agreed for gas supply and transportation services across the domestic market.
- In April 2018, the ACCC announced that it would also commence publication of an LNG netback price series to further improve gas price transparency.
- In addition, the ACCC is currently undertaking work to:
  - improve the transparency of reserves and resources information, and
  - better understand the cost components that make up retail prices, as well as how these are described and understood by C&I customers.
- At the same time, the ACCC has been working with the Gas Market Reform Group (GMRG) to identify other information gaps in the market and the steps that can be taken to address these.
- In considering measures that could improve transparency of the market, the ACCC has been cognisant of the work being carried out by other government bodies, particularly in the transport space.
- The ACCC will make final recommendations on ongoing measures to improve market transparency in the final inquiry report in April 2020.

### 4.2. Overview

A key focus of the inquiry to date has been to promote transparency in the East Coast Gas Market.

In general, markets work better and generate more efficient outcomes, the more information that is available to buyers and sellers. The benefits of transparency are greater when buyers and sellers have access to similar information. For a workably competitive market, participants need ready access to the information they require to make informed decisions about consumption, production, transportation, investment and risk management in the short and long run. If this characteristic is missing from the market and decisions are instead made on the basis of incomplete, inaccurate or asymmetric information, it may result in the inefficient allocation of resources in the market and the broader economy.

The ACCC's 2015 inquiry found that the East Coast Gas Market was lacking a number of the general attributes that assist in creating a competitive market that operates efficiently and sends appropriate investment signals to market participants.<sup>129</sup> In particular, the ACCC noted:

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<sup>129</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, p. 82.

- a lack of consistent gas reserves and resources information to enable informed decisions related to the supply or use of gas, and
- the absence of an indicative price to provide a guide to the value of gas.<sup>130</sup>

Through the current inquiry, the ACCC is working to address these informational deficiencies. In particular, the ACCC has been publishing prices offered and agreed for gas supply and transportation services across the domestic market. This has been aimed at improving gas price transparency and the ability of gas users to negotiate for gas supply and transportation services. As announced in April 2018, the ACCC will also shortly be publishing an LNG netback price series to help further improve gas price transparency.

As discussed further in section 4.4, the ACCC is also undertaking work to improve the transparency of reserves and resources information. There is currently limited publicly available reserves and resources information, which affects the ability of market participants to identify expected supply problems effectively. The ACCC will establish a reporting regime, request information from suppliers based on that reporting regime, and then publish the data in a meaningful way. The ACCC intends to commence publication of reserves and resources information in December 2018.

In addition, the ACCC is currently undertaking work to better understand the cost components that make up retail prices. As part of this work, the ACCC will consider whether sufficient information on cost components is being provided to C&I customers during negotiations for gas supply with retailers. The results of this work will also be reported on in December 2018.

At the same time, in keeping with the announcement made by the Prime Minister in March 2017 (discussed further at section 4.6 below),<sup>131</sup> the ACCC has been working with the Gas Market Reform Group (GMRG) to identify other information gaps in the market and the steps that could be taken to address these. A joint recommendations paper is likely to be published later this year.

The ACCC will make final recommendations on ongoing measures to improve market transparency in the final inquiry report in April 2020.

### 4.3. Publication of an LNG netback price series

In the April 2018 report, we announced the ACCC's intention to publish an LNG netback price series on its website as a trial measure throughout this Inquiry. The price series will seek to improve gas price transparency by providing the market with an indicative price of gas for the East Coast Gas Market.

The publication of the LNG netback prices does not represent the ACCC setting a level of domestic gas prices nor the ACCC's forecast of domestic gas prices.

The publication will include LNG netback prices based on measures of recent and historical Asian LNG spot prices (extending back to January 2016) and a forward LNG netback price indicator extending to the end of the following calendar year.

For the historical series, LNG netback prices will be derived using a monthly average of the Japan Korea Marker (JKM) reported by S&P Global Platts. These monthly prices will be netted back to Gladstone using Platts estimates of the cost of shipping between Gladstone and Tokyo for the relevant month, and then netted back to Wallumbilla by adjusting for

<sup>130</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, p. 82.

<sup>131</sup> Hon. M Turnbull MP, Media Release: Measures Agreed for Cheaper, More Reliable Gas, 15 March 2017.

relevant costs of liquefaction and transportation using information obtained from the Queensland LNG producers. The ACCC will update this series on a monthly basis.

For the forward LNG netback price indicator, netback prices will be based on expected Asian LNG spot prices at the time of publication, using monthly JKM futures prices quoted by the Intercontinental Exchange (ICE). These monthly prices will be netted back to Gladstone using Argus estimates of forward shipping costs, and then netted back to Wallumbilla by adjusting for relevant costs of liquefaction and transportation using information obtained from the Queensland LNG producers. The ACCC will update this series on a fortnightly basis.

The ACCC will also publish pipeline services tariffs and other relevant information to enable gas buyers to determine an indicative cost of transportation to particular locations in the East Coast Gas Market. Further, the ACCC will publish accompanying documentation that will explain the concept of LNG netback pricing, how published prices have been calculated, and provide guidance on their interpretation.

As discussed in the April 2018 report, the final price a particular domestic C&I user may need to pay to acquire gas could vary considerably from the LNG netback price due to a range of factors specific to the C&I user's individual circumstances, including non-price terms they request in their gas supply agreement (GSA).

Over the course of the inquiry, the ACCC will continue to explore the key factors that may influence domestic gas prices in the East Coast Gas Market, including the value of non-price terms and conditions. The ACCC will discuss any findings in future interim reports and will consider whether to include this information alongside the LNG netback price publication on its website.

The ACCC expects to commence the publication in September 2018. We intend to consult with market participants on the published series during 2019.

#### 4.4. Reserves and resources

Information on reserves and resources gives market participants a better understanding of the supply outlook, which enables them to make more informed consumption, contracting and investment decisions. However, publicly available information on reserves and resources is currently limited.

The ACCC's 2015 inquiry found that the East Coast Gas Market was not signalling expected supply problems effectively, and noted the lack of transparency in the level of reserves and resources.<sup>132</sup> The inquiry found that there was no clear, consistent or accurate reporting of information on reserves and resources across the market, and that this was creating a disadvantage to gas users when negotiating new gas supply agreements with large incumbents who had greater knowledge of the market and reserve positions.<sup>133</sup> Specifically, the inquiry found that companies were required to report at different times and at different levels of geographical aggregation and that some companies were not required to report at all (for example, unlisted companies and those listed overseas).

The ACCC therefore recommended that all explorers and producers be required to publish consistent reserves and resources information using common price assumptions on the Natural Gas Services Bulletin Board.<sup>134</sup> The ACCC also recommended that the COAG Energy Council ensure geological and reserve/resources information collected by the states and territories and the Commonwealth is consistent, non-duplicative and shared.

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<sup>132</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, p. 12.

<sup>133</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 12–13.

<sup>134</sup> ACCC, *Inquiry into the east coast gas market*, April 2016, p. 13.

These recommendations were largely agreed by the AEMC in its 2015–16 East Coast Wholesale Markets and Pipelines Framework Review.<sup>135</sup> However, the AEMC did not have time to consider the ACCC’s proposal to use common price assumptions in the calculation of reserves and resources, and considered that 2P reserve reporting requirements should be bedded down before requiring resource reporting.

The COAG Energy Council agreed with the recommendations of the ACCC and AEMC for the reporting of consistent reserve and resource information by all explorers and producers.<sup>136</sup> It also agreed that this information should be displayed on the Natural Gas Services Bulletin Board in a consistent format to increase transparency and to minimise duplication between the information collected by states, territories and the Commonwealth.<sup>137</sup> The Energy Council noted that in progressing the Bulletin Board changes, consideration should be given to the ACCC’s recommendation for reporting based on common price assumptions.<sup>138</sup>

As part of its current inquiry, the ACCC is progressing its 2016 recommendations on reserves and resources. The ACCC will:

- develop a reporting regime
- request data from suppliers based on this reporting regime, and
- publish the data in a meaningful way.

In undertaking this work, the ACCC will consider which categories of reserves and resources should be reported, as well as the appropriate level of aggregation for this information.

The ACCC has already requested reserves and resources information from producers and explorers, as well as the documents on which that information is based. The ACCC will use this to better understand the methodology and assumptions currently being used by suppliers in the calculation of reserves and resources. The ACCC has also been engaging with a number of government departments and agencies that collect reserves and resources information to identify and assess the adequacy of the different reporting frameworks and reporting obligations that currently exist.

The ACCC intends to commence the publication of reserves and resources information in its December 2018 report, at which time it will seek feedback from stakeholders on the usefulness of this information.

Interested parties may contact the ACCC to discuss any preliminary views on the work stream set out in this section ([gas.inquiry@acc.gov.au](mailto:gas.inquiry@acc.gov.au)). For example, parties may wish to comment on:

- the categories of reserves and resources that should be reported
- suggested levels of aggregation for this information and the likely benefit of publishing reserves and resources information in this way, and
- the price assumptions that should be used to calculate reserves and resources.

The ACCC will commence formal consultation in December 2018.

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<sup>135</sup> AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review: Stage 2 Final Report*, 23 May 2016, p. 120.

<sup>136</sup> COAG Energy Council, *Gas Market Reform Package Appendix A – Energy Council Response to ACCC and AEMC’s reports*, 19 August 2016, pp. 5–6.

<sup>137</sup> COAG Energy Council, *Gas Market Reform Package Appendix A – Energy Council Response to ACCC and AEMC’s reports*, 19 August 2016, pp. 5–6.

<sup>138</sup> COAG Energy Council, *Gas Market Reform Package Appendix A – Energy Council Response to ACCC and AEMC’s reports*, 19 August 2016, pp. 5–6.

## 4.5. Retail pricing

Many gas users have told the ACCC that they can only source gas from one or more of the major retailers, and are unable to contract directly with producers due to the size of their demand. The retailers not only provide gas to these customers, but a delivered service which takes into account customers' demand variability throughout the year.

This highlights the unique and important role played by the retailers in the East Coast Gas Market.

To better understand this aspect of the market, the ACCC intends to examine the supply of gas by the retailers in greater detail.

In doing so, the ACCC will examine the drivers behind the delivered cost of gas faced by the customers of the three major gas retailers (AGL, EnergyAustralia, and Origin). This will include commodity costs and other costs that retailers incur in supplying gas to end-users, such as storage, transmission and distribution costs. The ACCC will also examine retailers' costs and margins.

The ACCC intends to produce 'cost-stacks' for customers in each state, to illustrate the proportion of the overall charges faced by customers that are attributable to each cost.<sup>139</sup>

As part of this work, the ACCC will also examine the degree of transparency around how these costs are described to, and understood by, customers. The project will consider how costs vary under different jurisdictional arrangements.

The ACCC will report on the results of this work in the December 2018 report.

## 4.6. Joint ACCC-GMRG work on measures to improve transparency

In March 2017, the Prime Minister announced a number of measures to 'help deliver cheaper and more reliable energy', one of which was a direction to the ACCC and the Gas Market Reform Group (GMRG) to work together to:<sup>140</sup>

*'...advise on options to quickly improve transparency in the gas market, to facilitate competition between producers and information for purchasers.*

*The scope will include the full supply chain – producers, transporters, retailers.'*

On 19 April 2017, the Commonwealth Treasurer also directed the ACCC to conduct a wide-ranging inquiry into, amongst other things, the supply of, and demand for, natural gas extracted or produced in Australia and measures to improve transparency of gas supply arrangements in Australia.

In keeping with these directions, the ACCC and GMRG are working together to identify the steps that could be taken to improve the transparency of the market. While the ACCC and GMRG are aware that steps have been taken to reduce the opaqueness of the market over the last two years, there are still a number of significant informational gaps and asymmetries across the supply chain, and there remains limited transparency beyond what is being provided through this inquiry.

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<sup>139</sup> The ACCC produced cost stacks as part of its Retail Electricity Pricing Inquiry: see ACCC, *Restoring electricity affordability & Australia's competitive advantage*, 11 July 2018.

<sup>140</sup> Hon. M Turnbull MP, Media Release: Measures Agreed for Cheaper, More Reliable Gas, 15 March 2017.

The most notable information gaps can be found in:

- the upstream segment of the supply chain, where there is currently limited transparency surrounding the reserves and resources held by a number of producers, the exploration and other upstream activities being undertaken by producers and wholesale gas prices
- the transportation and storage segments of the supply chain, where there is currently limited transparency surrounding transportation and storage charges, and
- the retail segment of the supply chain, where there is currently limited transparency surrounding the prices paid by small and large end-users for gas.

On the demand side of the market there are also a number of informational gaps, particularly in relation to LNG exports, which is now a key determinant of the demand-supply balance in the East Coast Gas Market.

While the Inquiry is shining a light on many of these issues, it is relevant to consider whether more permanent measures could be put in place to improve the transparency of the market, particularly given the adverse effects that these informational deficiencies could have on market participants, competition and the efficiency with which gas is allocated and used.

To this end, the ACCC and GMRG are considering:

- (a) the transparency measures that could be put in place so that more informed and efficient decisions can be made about consumption, production, exploration, transportation, storage and investment in infrastructure over both the short- and longer-run, and
- (b) how the transparency measures identified in (a) should be implemented (e.g. through an extension of the Bulletin Board reporting obligations, or through other amendments to the National Gas Law and/or National Gas Rules).

The ACCC and GMRG intend to publish the results of this joint work in the latter half of 2018.

The ACCC will look to develop and test the proposed measures, and will engage with the AEMC, AER and policy makers.

#### 4.7. Measures to improve transportation transparency

In addition to the work that is being carried out as part of this Inquiry to improve the transparency of the East Coast Gas Market, there are a number of transportation related transparency measures that have been proposed as part of:

- the GMRG's capacity trading reform package (see box 4.1), and
- the Australian Energy Market Commission's (AEMC) Review into the scope of economic regulation applied to covered pipelines (see box 4.2).

If implemented, the proposed transparency measures should aid the price discovery process for sales of primary and secondary capacity, which should, in turn:

- reduce search and transaction costs for shippers
- enable shippers to engage in more effective negotiations by improving their relative bargaining position, and
- improve the efficiency with which capacity is allocated and used (i.e. because shippers will be able to better assess the value of capacity).

#### **Box 4.1: Proposed transparency measures for the capacity trading reform package**

The capacity trading reform package, which will apply to transmission pipelines and compression facilities operating under the contract carriage model, is expected to come into effect in late 2018 with trade on the capacity trading platform and the day-ahead auction expected to commence on 1 March 2019. The reform package provides for the implementation of the following transparency measures, which are designed to aid the price discovery process and facilitate capacity trading and the auction:

- a reporting framework for secondary capacity trades, which will require the prices and other key terms<sup>141</sup> in all secondary capacity trades (including both bilateral and exchange-based trades) to be reported to AEMO for publication on the Natural Gas Services Bulletin Board (Bulletin Board)<sup>142</sup> shortly after the trades are entered into<sup>143</sup>
- a requirement for AEMO to publish the results of the day-ahead auction and other auction related information on the Bulletin Board on a daily basis
- the extension of the Bulletin Board reporting obligations to a number of pipelines and stand-alone compression facilities (e.g. the Wallumbilla, Moomba, Iona and Ballera compressors) that are not currently subject to any reporting obligations
- a requirement for service providers to provide AEMO with detailed information on the capacity and use of receipt and delivery points for publication on the Bulletin Board, and
- a requirement for allocation agents to provide AEMO with their contact details and other information about the allocation arrangements<sup>144,145</sup> in place at an allocation point for publication on the Bulletin Board.

Source: GMRG, Information Paper: Capacity trading reform package legal and regulatory instruments, 3 July 2018.

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<sup>141</sup> Some of the other terms to be reported include, the trade date and service term, the type of service purchased, the amount of capacity procured, the price structure and price escalation mechanism.

<sup>142</sup> Trades will be reported on the Bulletin Board on a zonal basis (or facility basis if the facility is not subject to the reforms).

<sup>143</sup> Trades carried out through the exchange must be reported by AEMO on the Bulletin Board by the end of the gas day. Trades carried out bilaterally, on the other hand, must be reported by the seller (or a reporting agent) on the Bulletin Board by the earlier of one day after the trade is executed and the day prior to the trade commencing when the service term starts after the trade date, or as soon as reasonably practicable on the trade date if the service term starts on that date.

<sup>144</sup> Allocation arrangements specify the rules to be used by the allocation agent to allocate gas that is metered as having been supplied (or deemed to have been delivered) to a multi-user receipt or delivery point between shippers using these points.

<sup>145</sup> Allocation agents will, for example, be required to provide a description of the allocation methodology used at the allocation point and a description of the process for joining and leaving the agreement (including any charges payable to become a party to the agreement).

#### Box 4.2: Proposed transparency measures for covered pipelines

The AEMC has recently completed its *Review into the scope of economic regulation applied to covered pipelines*. As part of this review, the AEMC has recommended the implementation of a number of transparency measures that are intended to enable users of covered pipelines to negotiate more effectively with service providers. These transparency measures include:

- Requiring light regulation pipelines to publish:
  - the standing terms (including the price) for each service offered by the pipeline, and
  - similar financial and weighted average price information to that which non-scheme pipelines are required to publish under Part 23 of the NGR.<sup>146</sup>
- Extending the Bulletin Board reporting obligations to all full and light regulation transmission pipelines and requiring these pipelines to report a 36 month outlook of uncontracted capacity.
- Requiring distribution pipelines that are subject to full and light regulation to report similar capacity and usage information to that which non-scheme distribution pipelines are required to report.

If these recommendations are endorsed by the COAG Energy Council, then changes will need to be made to the National Gas Rules (NGR) to implement these measures. The AEMC expects to be able to complete a standard rule change process in less than the usual six months, given the consultation that has already been undertaken as part of its review.

Source: AEMC, Final Report: Review into the scope of economic regulation applied to covered pipelines, 3 July 2018.

In addition to these proposed transparency measures, the service providers of non-exempt<sup>147</sup> non-scheme pipelines<sup>148</sup> will be required by the information disclosure provisions in Part 23 of the NGR to start publishing the following information in the latter half of 2018 and early 2019:<sup>149</sup>

- financial statements for each non-scheme pipeline
- the value of the non-scheme pipeline arising from the application of the recovered capital method specified in Part 23 of the NGR,<sup>150</sup> and
- the weighted average prices paid by users for each of the services offered by the pipeline.

<sup>146</sup> The AEMC is proposing to amend the financial reporting requirements to require the reporting of an asset value that is consistent with the method applying to full regulation pipelines rather than the value arising from the application of the recovered capital method, which service providers of non-exempt non-scheme pipelines are required to report.

<sup>147</sup> There are three categories of non-scheme pipeline that are exempt from part or all of the information disclosure under rule 585 of the NGR: (1) pipelines that do not offer third party access are exempt from the information disclosure and arbitration provisions; (2) pipelines that only have a single user are exempt from the upfront information disclosure; and (3) pipelines that have an average daily injection for the preceding 24 months of less than 10 TJ/day are exempt from the information provision requirements except the requirements to publish details of the pipeline and services offered.

<sup>148</sup> Non-scheme pipelines are pipelines that are not subject to full or light regulation under the National Gas Law (NGL) and National Gas Rules (NGR). Following the introduction of Part 23 into the NGR in August 2017, the operators of non-scheme pipelines are required to publish a range of information that shippers can use to assess whether the prices they are offered are cost reflective, unless they are exempt from doing so.

<sup>149</sup> The first publication of the financial and weighted average price information will cover a six month period, while subsequent publications will cover a 12 month period. For service providers with a calendar year or standard July – June financial year, the obligation to publish this information will commence in October 2018, while service providers with an April – March financial year will be required to publish the first report in January 2019.

<sup>150</sup> This method is set out in rule 569(4)(b).

The publication of this information is intended to enable the users of non-scheme pipelines to negotiate more effectively with service providers by allowing them to more readily assess whether the prices they are offered are reasonable. Given the important role that this information is intended to play on non-scheme pipelines, the ACCC intends to review the financial and weighted average price information that is published by service providers and report on our findings in 2019. As part of this review, we intend to examine the other information that service providers are required to publish under Part 23 (e.g. standing prices and pricing methodologies) and consider whether further improvements should be made to the level of detail and information reported by service providers.