AUSTRALIAN COMPETITION & CONSUMER COMMISSION

Gas inquiry 2017–2025

Interim report

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Australian Competition and Consumer Commission

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

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Acronyms

ACQ	annual contract quantity
CCA	*Competition and Consumer Act 2010* (Cth)
C&I	commercial and industrial
CPI	Consumer Price Index
CSG	coal seam gas
DWGM	Declared Wholesale Gas Market
EBIT	earnings before interest and taxes
EBITDA	Earnings before interest, tax, depreciation and amortisation
FID	financial investment decision
GJ	Gigajoule
GPG	gas powered generation/generator
GSA	gas supply agreement
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GTA	gas transportation agreement
HHI	Herfindahl—Hirschman Index
JKM	Japan Korea Marker
LNG	liquefied natural gas
MDQ	maximum daily quantity
MMBtu	Million British Thermal Units–see below, Units of Energy
MOU	Memorandum of Understanding
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
PJ	Petajoule
REPI	ACCC's Retail Electricity Pricing Inquiry
RIS	Regulation Impact Statement
STTM	Short-term trading market
TJ	Terajoule

Organisation

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
AIE	Australian Industrial Energy
APPEA	Australian Petroleum Production and Exploration Association
ASX	Australian Securities Exchange
COAG	Council of Australian Governments
GBJV	Gippsland Basin Joint Venture
GMRG	Gas Market Reform Group
IPART	Independent Pricing and Regulatory Tribunal
ICE	Intercontinental Exchange
PWC	Power and Water Corporation
RBA	Reserve Bank of Australia
SGH	Seven Group Holdings

Pipelines

AGP	Amadeus Gas Pipeline
CGP	Carpentaria Gas Pipeline
DDP	Darling Downs Pipeline
EGP	Eastern Gas Pipeline
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NGP	Northern Gas Pipeline
PCA	Port Campbell to Adelaide Pipeline
PCI	Port Campbell to Iona Pipeline
QGP	Queensland Gas Pipeline
RBP	Roma to Brisbane Pipeline
SEPS	South East Pipeline System
SESA	South East South Australia Pipeline
SWQP	South West Queensland Pipeline

TGP	Tasmanian Gas Pipeline
WGP	Wallumbilla Gladstone Pipeline

Overview

This is the January 2020 interim report of the Australian Competition and Consumer Commission's (ACCC's) inquiry into gas supply in Australia (the Inquiry). The ACCC has maintained its focus on the operation of the East Coast Gas Market, where there are both immediate and longer-term concerns.[1]

The East Coast Gas Market's exposure to export markets and the related step change in gas prices continued to have real impacts over 2019.

While C&I users continue to try to reduce their overall gas costs, most have told us they have largely exhausted all opportunities to reduce their gas use through energy efficiency improvements. Many are now actively exploring alternative energy sources or looking at other ways to reduce their gas costs, including by sourcing gas directly from producers and making greater use of short-term trading markets.

Despite these efforts, Remapak and Claypave announced in the first quarter of 2019 that they would go into administration, and both are now in liquidation. The trend of companies closing what have become unprofitable regional plants (due to high gas prices) has also continued in the second half of 2019, with Kimberley-Clark closing its western Sydney plant and Norske Skog announcing the sale and closure of its Albury Mill.

In our July 2019 report, we reported that the likelihood of a gas supply shortfall in 2020 was lower than it had been for 2019. This was due to an increase in forecast gas production for 2020, the Australian Energy Market Operator (AEMO) forecasting lower consumption by gas powered generators (GPGs) and LNG producers expecting to produce gas in excess of their contractual commitments.

Since our July 2019 report, the supply outlook for 2020 has improved slightly, with gas producers increasing their expected production by 6 PJ. Projected supply for 2020 is now at 2025 PJ while demand is forecast to be 1831 PJ, not including LNG producers' excess gas. The supply-demand balance in the Southern States has also improved. The likelihood of a shortfall in 2020, although still subject to uncertainty, now appears even lower than it did in our July 2019 report.

The improvements in the 2020 supply outlook have not translated into any material improvements in prices faced by C&I users.

Prices offered in the East Coast Gas Market have remained relatively steady, mostly within a range of around $9–12/GJ. However, domestic price offers have not fallen in line with the decline in LNG netback (export parity) price expectations for 2020. We have also observed some prices offered by producers in Queensland include a fixed price component, on top of an LNG spot price linked component.

The divergence of domestic offers from expected LNG prices is a key concern for the ACCC and we will investigate this further in 2020.

The long term supply outlook for the East Coast Gas Market from 2021–2031 remains uncertain. The Southern States risk facing a shortfall in the medium-term unless:

[1] The East Coast Gas Market currently includes Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania. We also monitor the flow of gas from the Northern Territory into the east coast through the Northern Gas Pipeline. This report does not cover Western Australia for reasons set out in the September 2017 Interim Report.

- more exploration and development occurs in the south to compensate for declining ex-Longford production
- more investment occurs in north-south transportation infrastructure to enable greater volumes of gas from Queensland or the Northern Territory to flow south, and
- one or more LNG import terminals are developed.

To avoid any unnecessary duplication of pipelines and other inefficiencies, the ACCC recommends that the development of this infrastructure, where feasible, be coordinated by state and territory governments during the planning and approval process, and operated on a third party access basis. We also support governments actively managing tenements to ensure producers bring gas to market in a timely manner and to prevent larger producers from 'warehousing' gas. A greater diversity of suppliers will be most effective in achieving this and, for its part, the ACCC will continue to closely monitor producers' development decisions.

Ensuring new gas supply is brought to market when and where it is needed also depends on whether transportation and storage services are available at economically efficient prices. While considerable regulatory reform has been undertaken, progress on achieving efficient transportation and storage prices has been slow and some concerns continue to emerge.

Our latest analysis shows that there was limited contracting of transportation services in the first half of 2019. Most transportation charges have therefore increased in line with inflation over this period. Where new contracts were entered into, the prices payable on some pipelines have fallen (particularly for as-available and interruptible transportation services), but there have been some increases too. In relation to storage, some users of the Iona and Dandenong storage facilities have experienced some price increases in the last 12 months.

As noted in our July 2019 report, we have conducted further analysis to:

- understand the effect that the capacity trading reforms are having on the East Coast Gas Market, the behaviour of facility operators and if there are any impediments to trade
- re-examine access to single-shipper pipelines in some regional areas, in response to a number of concerns raised with us by potential shippers on these pipelines and
- better understand the drivers of the margins we reported for the three largest gas retailers in our July 2019 report and the extent to which they are a long term concern (as well an examination of some of the indicators of competitiveness).

Our findings are outlined below.

Pressures on the longer term outlook for the East Coast Gas Market are increasing

Our work on the Inquiry to date has highlighted the ongoing need for a greater level and diversity of supply in the market, the need for greater transparency and a more efficient transportation and storage network.

With declining production from established southern gas reserves, there is significant uncertainty about whether future supply from gas reserves and resources will be sufficient to meet overall demand on the east coast.

Factors that contribute to this uncertainty include the significant and continued write-downs of 2P reserves and resources in Queensland by LNG producers and their affiliates and the increasing reliance on future gas supply from coal seam gas (CSG) resources. Queensland reserves have been downgraded on a net basis by more than 4400 PJ between 1 July 2017 and 30 June 2019.

Concerns about the adequacy of future gas supply are exacerbated by the blanket moratoria and regulatory restrictions in some states and territories which inhibit further gas exploration and development of new gas resources, especially in Victoria and New South Wales.

There is also a significant proportion of reserves and resources held by LNG producers and their affiliates, who may have more incentives or internal pressures than small or mid-tier domestic-only producers to delay bringing gas to market, or developing new gas supply sources in a timely manner.

These incentives and pressures can also affect the timing of investment in gas pipeline and storage infrastructure necessary to ensure gas is transported from where it is produced to where it is needed by gas users. With future gas supply likely to be primarily sourced from Queensland (and potentially also the Northern Territory), the need for further and efficient investment in pipelines and storage is likely to increase over time.

Shorter contracting periods for gas supply, transportation and storage agreements could inhibit this investment, as pipeline and storage owners require some certainty of future demand and revenues in order to undertake the significant expenditures ordinarily required to supply these services.

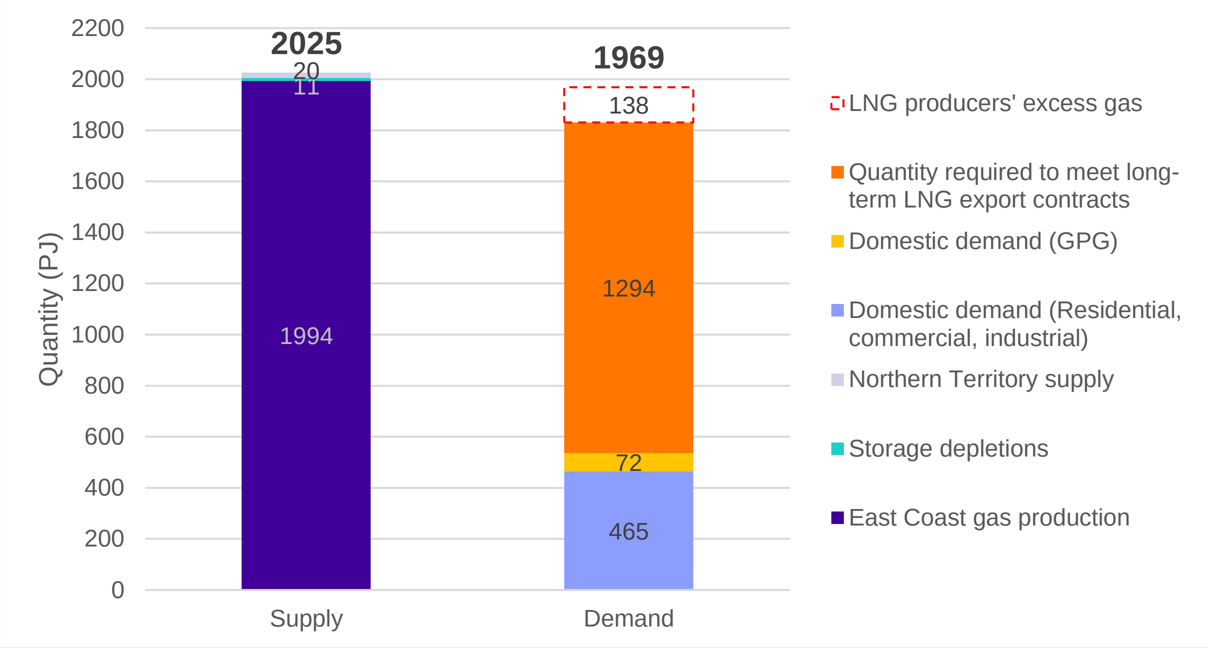
There remain considerable challenges in the East Coast Gas Market in the medium to long term and the ACCC continues to urge state and territory governments to:

- adopt policies that consider the risks of individual gas development projects
- actively manage gas tenements to ensure new gas developments are developed in a timely manner and to prevent larger producers from 'warehousing' gas
- coordinate the development of pipeline and storage infrastructure, to avoid unnecessary duplication of pipelines and other inefficiencies, to be operated on a third party access basis.

Sufficient gas supply is still expected in 2020 in the East Coast Gas Market

The east coast gas supply outlook for 2020 has improved slightly since we reported in July 2019. Chart 1 shows that it is now less likely there will be a shortfall in 2020.

Chart 1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2020



Note: Totals may not add up due to rounding.

Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[2]

Since we reported in July 2019:

- producers have, in aggregate, revised their 2020 production forecasts upwards by 6 PJ, and
- there has been an increase in gas contracted to be supplied into the East Coast Gas Market, with LNG producers contracting an additional 33 PJ to domestic buyers (meaning there is now less excess gas that could be sold into international spot markets).

Overall, LNG producers are now forecasting to supply 209 PJ in aggregate to the domestic market in 2020—more than they are expecting to take out (202 PJ), reversing the situation we reported in July 2019.

LNG producers also expect to have 138 PJ of gas available in excess of their current 2020 contractual commitments, which could be used for either export or to supply the domestic market. Under the Heads of Agreement signed with the Federal Government, LNG producers have committed to offering this gas to domestic buyers on competitive market terms prior to offering it to the international market. This excess gas will likely act as a buffer should a shortfall arise in the domestic market.[3]

The supply-demand balance in the Southern States is largely unchanged from what we reported in July 2019 but remains uncertain and subject to:

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[2] AEMO, *Gas statement of opportunities*, March 2019. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

[3] The effectiveness of this buffer will depend on whether LNG producers offer this gas to buyers in the East Coast Gas Market in a way that meets the requirements of buyers. If LNG producers offer gas in large quantities that have to be taken over a short time period, there may not be enough domestic buyers who are able to consume, transport and/or store this gas within the time constraints.

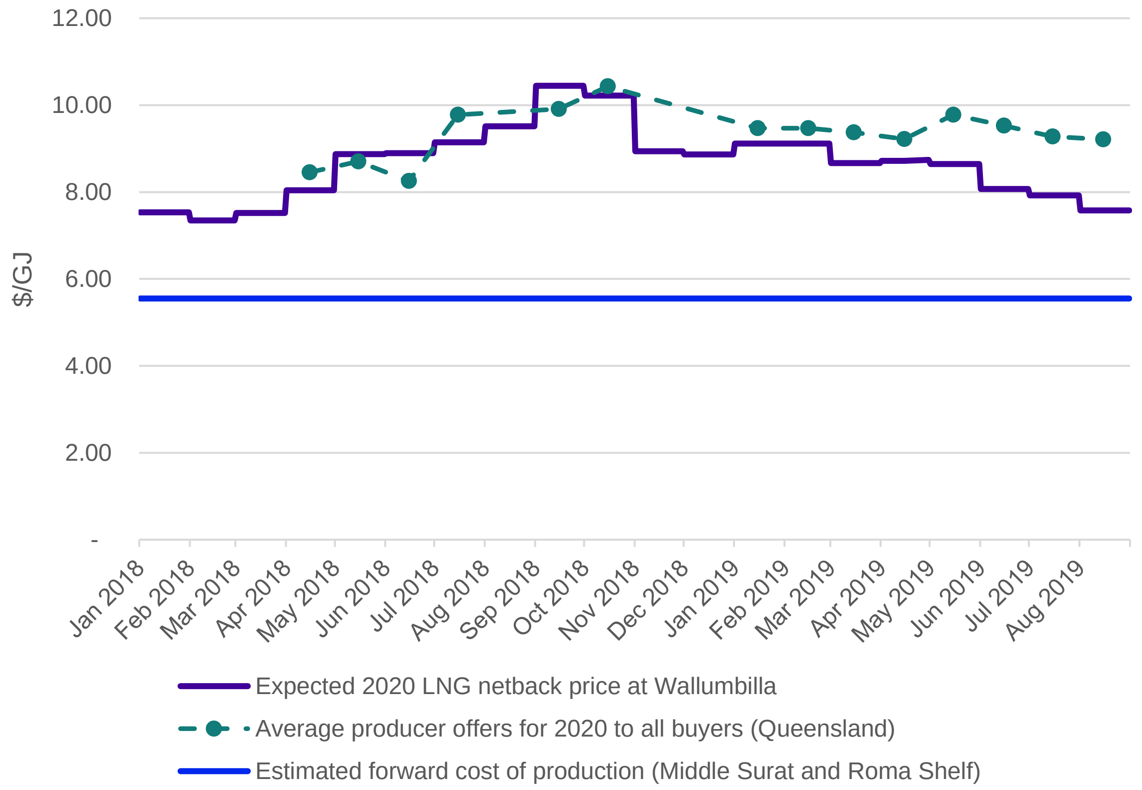
- the quantity of gas produced in the south, particularly the Cooper Basin, that will be delivered into Queensland; if more gas from the south is supplied into Queensland than is currently expected, then the supply-demand balance in the south will be considerably tighter
- realised demand for gas from GPG, which is dependent on factors that are difficult to forecast accurately (such as rainfall, wind, temperature, availability of renewable generation, unexpected retirement of generation or unplanned outages).

Domestic price offers have not fallen in line with expected LNG netback prices for 2020

Gas producer offers have mostly been within the $9–10/GJ range over 2019, while retailer offers have largely remained in the range of $8–12/GJ.

In contrast, expected 2020 LNG netback prices have trended downwards over 2019 and by the end of August were around $7.50/GJ. This downward trend has not been reflected in prices offered in the east coast market.

Chart 2: Averages of monthly gas commodity prices offered by producers in Queensland[4] for 2020 supply against contemporaneous expectations of LNG netback prices



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

Note: The chart includes averages of prices offered for gas supply agreements with a term between 1 and 3 years, and does not include oil-linked offers.

[4] Some offers made in Queensland may include transport to locations far from Wallumbilla. It may not be meaningful to compare these offers to LNG netback price at Wallumbilla. For this reason, offers made for gas supply at locations far away Wallumbilla have not been included in this chart.

Chart 2 shows that since May 2019, average producer prices offered in Queensland have been above expected 2020 LNG netback prices. Average offers in Southern States from both producers and retailers have been above expected 2020 LNG netback prices over 2019.

Of particular concern is the inclusion of a fixed price component, above a JKM-linked[5] component that is equivalent or close to LNG netback prices, observed in some offers by LNG producers.

The disparity of price offers from (and above) LNG netback prices may be due to a number of factors including uncertainty around the supply-demand balance (including differences between the north and south, and the level of demand for GPG) and the non-price terms and conditions associated with particular offers. We will examine this issue in more detail in 2020, as noted above.

Average prices agreed by C&I users under contracts with producers and retailers over the first half of 2019 have increased, and are now higher than they were in the first half of 2017, a period in which market conditions were particularly challenging for C&I gas users and when offers were peaking. The average level of flexibility in contracts, in the form of take or pay multiplier and load factor, has also decreased since we last reported in July 2019.

Recent reforms are bringing about more efficient transportation prices on some pipelines but outcomes are mixed and progress is slow

Our 2015 East Coast Gas Inquiry found that the majority of transmission pipelines on the east coast were using their market power to engage in monopoly pricing. A number of reforms were subsequently implemented to try to address this issue, including the information disclosure and arbitration framework (Part 23) which came into effect in August 2017 and some of the Australian Energy Market Commission's (AEMC) recommended changes to full and light regulation, which came into effect in March 2019.

While there are positive signs, progress in achieving efficient transportation prices has been slow and unevenly spread among shippers and pipelines. Our most recent analysis of the prices charged for pipeline services in July 2019 shows most prices increasing in line with inflation. While there have been improvements, some of which have been quite significant, they have been limited to a sub-set of pipelines and new contracts.[6]

However, improvements in new contract prices on some pipelines have been accompanied by reports of other concerning behaviour. Some shippers have indicated that pipeline operators are unwilling to sell their services at a discount to the standing price because the prices would be reported through our inquiry and they would need to offer it to other shippers. Other shippers have noted that pipeline operators may be using the capacity trading reforms (discussed below) as an excuse to reduce the level of service flexibility provided to shippers, or to require shippers to pay more for this flexibility. We would be concerned if pipeline operators were using price transparency provided through our inquiry or the capacity trading reforms to justify higher prices.

The slow transition of prices to more efficient levels on other pipelines may also, in part, reflect the medium to long term nature of some gas transportation agreements, with prices only expected to change when contracts are re-negotiated. It may also reflect some of the

5 The JKM is S&P Global Platts' price assessment for physical LNG spot cargoes delivered ex-ship into northeast Asia.

6 For example, prices have fallen significantly on both the Tasmanian Gas Pipeline (TGP) and Carpentaria Gas Pipeline (CGP), but have increased on both the Port Campbell to Adelaide (PCA) Pipeline and Moomba to Adelaide Pipeline System (MAPS).

other matters we identified in our July 2019 review of the operation of Part 23[7], which found that:

- some pipeline operators are not taking their information disclosure obligations seriously and may be exploiting information asymmetries to the detriment of shippers, and
- the threat of arbitration from smaller shippers may be viewed as less credible and smaller shippers may therefore be required to pay more.

To address these concerns, we recommended a range of improvements to Part 23 that are designed to pose more of a constraint on the behaviour of pipeline operators and to empower shippers. These recommendations are being considered as part of the COAG Energy Council's Gas Pipeline Regulation Impact Statement.[8] Some of the reforms being contemplated by this RIS process may further facilitate more efficient transportation prices.

The capacity trading reforms are having a positive influence on the market, but some facility operator charges may deter trade

The capacity trading platform (CTP) and day-ahead auction of contracted but unused capacity (DAA) were implemented on 1 March 2019 to facilitate the trade of capacity on transmission pipelines and stand-alone compression facilities providing third party access. In the first eight months of its operation, the DAA was used to transport up to 18 PJ of gas, most of which was transported from Queensland to New South Wales and Victoria at the auction's reserve price of zero. While no trades occurred on the CTP in the first eight months, shippers expect this to occur over time.

While the main beneficiaries of the reforms have been auction participants, the ability of shippers to procure relatively cheap capacity in the DAA to bring lower cost gas south has also placed downward pressure on prices in the Sydney and Victorian facilitated gas markets and, to a lesser extent, the National Electricity Market. The AER estimates that the DAA has resulted in prices in the Sydney STTM being \$0.14–\$0.76/GJ lower and prices in the Victorian DWGM being \$0.08–0.17/GJ lower than what they would otherwise have been between 1 March 2019 and 30 September 2019.[9]

Although early indications are positive, a number of shippers have noted that the structure and level of some facility operators' standardisation charges may be impeding the use of the CTP and DAA. The fixed charges levied by the major pipelines servicing South Australia were cited by some shippers as a potential reason why the DAA has not been used in this state in the first eight months of operation. To address this issue, some shippers suggested these facility operators reduce their fixed charges and/or that consideration be given to amending the cost recovery provisions in the National Gas Rules.

The ACCC agrees further consideration should be given to the cost recovery provisions and recommends that this be examined, either as part of the AEMC's upcoming liquidity review, or the COAG Energy Council's 2021 post implementation review of the reforms.

7 The information disclosure and arbitration framework for non-scheme pipelines set out in Chapter 6A of the National Gas Law and Part 23 of the National Gas Rules, which came into effect on 1 August 2017.

8 COAG Energy Council, Options to improve gas pipeline regulation – Consultation RIS, 1 November 2019, http://www.coagenergycouncil.gov.au/publications/council-releases-gas-pipeline-regulation-impact-statement-consultation and COAG Energy Council, Measures to improve transparency in the gas market—Consultation RIS, 8 August 2019, http://www.coagenergycouncil.gov.au/publications/measures-improve-transparency-gas-market-consultation.

9 AER, *Wholesale Markets Quarterly—Q3 2019*, November 2019, pp. 52–53.

Problems still exist accessing some regional gas pipelines and longer-term policy solutions should be considered

In our 2015 inquiry, concerns were raised by a number of gas users about the lack of competition in regional areas and the attempts by some incumbent retailers to try and restrict competition by either not offering stand-alone pipeline capacity, or only offering to sell this capacity at a relatively high price.

We investigated this issue over the course of 2016–17, focusing on one particular incumbent retailer's behaviour on a number of regional pipelines. Following our investigation, we saw some improvements in the behaviour of the incumbent retailer, including instances of the incumbent retailer making capacity available for use by shippers. However, concerns continue to be raised about the inability of other retailers and C&I users to access pipelines in regional areas where a pipeline's capacity is fully contracted to an incumbent retailer.

Our most recent examination of this issue has found that:

- the incumbent retailers that have contracted all the capacity may not have a strong incentive (or ability) to release unused capacity back to the pipeline operator, or to sell unused capacity to another retailer or gas user
- some regional pipeline operators appear to be actively discouraging shippers from seeking access even when the incumbent retailer's gas transportation agreement has expired, or is due to expire in the near future.

We are examining some of the behaviour we have identified to determine if any of it constitutes a potential breach of the *Competition and Consumer Act 2010* (CCA).

We also recommend a number of longer-term policy solutions be considered as part of the COAG Energy Council's Gas Pipeline RIS. These remedies should reduce the barriers that pipeline access may otherwise pose to competition in these areas and would involve amending the National Gas Law and/or the National Gas Rules to:

1. include a capacity surrender mechanism that would provide for the release of capacity by an incumbent retailer to other shippers
2. prohibit pipeline operators from engaging in behaviour that would prevent or hinder access to the pipeline and from misrepresenting the availability of capacity.

The three largest gas retailers should have capacity to absorb increases in their gas costs as their low price legacy supply contracts expire

Our July 2019 report analysed the prices, costs and margins of AGL, EnergyAustralia, and Origin in supplying gas to customers across the east coast and found that the margins of these retailers between 2014 and 2018 period were well in excess of what we would expect.

For mass market customers, average margins (measured using EBITDA[10]) were between 19 and 23 per cent and for C&I customers average margins grew over the period from 13 per cent to 28 per cent.

In our July 2019 report, we noted that the high margins were due in part to low cost gas obtained by the retailers under long term legacy contracts, but that this advantage may be temporary as these contracts expire and new contracts are entered into at today's higher market prices. In this regard, we noted that the big three retailers' average gas procurement commodity costs increased each year from about $4/GJ in 2015 to around $6.50/GJ in 2018.

[10] Earnings Before Interest Taxation Depreciation and Amortisation.

In contrast, the average price paid under contracts executed since the start of 2017 to August 2019 was around $8.50 to $9/GJ.

Our further examination of long term legacy contracts shows that the number of legacy contracts, and the proportion they represent of the retailers' total gas portfolios significantly reduced in 2018. This proportion will decline further in 2019 and again in 2021.

From 2018 the majority of the retailers' portfolios will be made up of gas obtained under relatively new agreements. The high margins observed in our July report indicate the retailers have the capacity to absorb the increase in commodity costs by reducing their margins, rather than increase customer prices.

Our most recent analysis indicates that using a higher commodity cost reflective of current market conditions, results in margins for the three largest retailers appearing to decrease significantly. The average retailer margin for mass market customers would fall to 9 per cent, and for C&I customers the margin falls to around 6 per cent (although the C&I estimate is less reliable due to the nature of the underlying data). These estimated margins are more in line with those identified in our Retail Electricity Price Inquiry (REPI) for electricity retailers and previously considered reasonable by IPART[11].

Downward pressure on margins should also occur in those areas where competition is more effective.

Our most recent analysis review indicates that the signs of effective competition differ between the states in the east coast. Victoria, with the largest number of mass market customers in the east coast shows the most positive signs of competition, with 15 retailers competing to supply customers in this state. In contrast, Queensland, ACT and Tasmania show the weakest signs of competition, with only two or three retailers (and significantly smaller numbers of customers).

Overall, our analysis of legacy contracts suggests that the margins of the big three retailers identified in this inquiry may be transitory. However, we note that to the extent that the retailers' margins are used by the big three retailers to absorb the increasing wholesale costs, there may not be a noticeable reduction in retail gas prices. Moreover, their competitors—the smaller retailers—are likely to already face higher cost structures that more closely reflect current gas market prices and therefore may not have the same capacity to absorb increasing wholesale costs in their retail margins.

This difference in the cost structures of the big three retailers compared to their competitors means there is scope (and incentive) for the big three retailers to price well enough below their competitors to maintain their market position and/or force their competitors to exit the market. This will be the case for a significant number of years into the future.

We will therefore continue to monitor retailer price offers and market shares over the course of this inquiry, to identify any competition concerns that may emerge and require further examination.

Future work of the Inquiry

On 25 July 2019 the Treasurer wrote to the ACCC extending the Inquiry into the gas market until December 2025. The ACCC is considering how best to conduct the inquiry over this longer time frame.

11 The New South Wales Independent Pricing and Regulatory Tribunal.

The terms of reference for the ACCC Gas Inquiry state that the ACCC is to hold an inquiry into:

- measures to improve the transparency of gas supply arrangements in Australia
- the supply by persons in the gas industry of, and demand for natural gas extracted or produced in Australia, or imported into Australia
- the supply of, and demand for, natural gas transportation services in Australia by persons in the gas industry (including without limitation gas pipeline operators and other persons who have access to pipeline capacity).

We are also required to monitor and report on:

- the pricing and availability of offers to supply gas
- the volumes of gas supplied or available for current or future supply, including natural gas extracted or produced in Australia, or imported into Australia
- the pricing, volume and availability of gas for domestic supply compared to the pricing, volume and availability of gas for export
- the pricing, volume and availability of other goods or services, such as good or services for drilling for, storing or processing gas, that enable, assist or facilitate the supply of gas or gas transportation services in Australia.

The ACCC is required to submit interim reports to the Treasurer no less frequently than every six months.

In keeping with the terms of reference, we will continue to provide greater transparency of the market, and use our compulsory information-gathering powers to report regularly on:

- gas prices, in particular, relative to expected LNG netback prices
- the supply and demand outlook (both in the short and medium-long term)
- user experiences
- gas transportation and storage prices.

We will continue to undertake analysis into key or emerging market issues, as we have done to date in respect of, for example, reserves and resources reporting, retailer margins, gas production costs, the operation of Part 23 of the National Gas Rules and delivered gas prices in Australia compared to the prices paid overseas.

Over the course of the inquiry we intend to examine the following issues and their implications for the East Coast Gas Market:

- analysis of the factors that lead to differences between domestic gas prices and LNG netback prices (e.g. non-price terms and conditions and electricity prices)
- LNG import terminals
- concentration of tenement rights and competitiveness of gas supply across the domestic East Coast Gas Market, and
- access to storage and processing facilities.

Our focus will initially be on better understanding the factors that affect domestic gas prices. We welcome input from interested stakeholders on issues they consider should be subject to further analysis during the course of the Inquiry.

As the Inquiry shifts to a longer term market monitoring focus, and mindful of the long term regulatory burden our reporting will create for those responding to our compulsory information-gathering notices, we will:

- shift to reporting twice a year, on a six-monthly basis (consistent with the Treasurer's direction), and
- work with affected parties to develop standardised information-gathering notices to be issued and responded to at set times throughout the year.

Our next report is due in mid-2020, which will focus on the supply demand outlook for 2021, gas prices, user experience and gas transportation prices.

We will also continue to:

- publish the LNG netback price series on our website
- make market information available as appropriate, and
- make recommendations where we consider it appropriate and necessary to do so.

1. Supply outlook and upstream activities

1.1. Key points

- The supply and demand outlook for the East Coast Gas Market in 2020 indicates sufficient supply to meet forecast domestic and export demand, and has slightly improved since the ACCC's July 2019 report, due to producers increasing expected production by 6 PJ.
- LNG producers have contracted an additional 33 PJ to domestic buyers for 2020 between June and August 2019. They expect to contribute more gas to the East Coast Gas Market in 2020 than they take out.
- The supply-demand balance in the Southern States has improved slightly, but remains tight and is subject to some uncertainty as it depends on the quantity of gas produced in the Cooper Basin that flows into the Southern States, and realised demand from GPG.
- The long term supply outlook for the East Coast Gas Market from 2021 to 2031 is uncertain. Whether supply will be sufficient to meet demand will depend on the level of:
  - domestic demand, expectations of which fluctuate significantly
  - LNG exports, particularly the quantity of LNG spot sales, which could be up to 3295 PJ above their contractual commitments over this period
  - realised gas production, which will depend on the performance of CSG fields in Queensland and the timing of production from undeveloped 2P reserves, and
  - success in developing contingent and undiscovered gas resources.
- The long term supply outlook for the Southern States from 2021 to 2031 is also highly uncertain. Whether supply will be sufficient to meet demand will depend on whether:
  - more exploration and development occurs in the south to compensate for declining ex-Longford production
  - more investment occurs in north-south transportation infrastructure to enable greater volumes of gas from Queensland or the Northern Territory to flow south, and
  - one or more LNG import terminals are developed.
- The majority of reserves and resources continue to be located in Queensland and held by LNG producers. Almost 90 per cent of 2P reserves and around 63 per cent of 2C resources are located in Queensland. Over 80 per cent of 2P reserves are controlled by LNG producers, either directly or through gas purchases from related entities.
- 2P reserves have continued to fall, particularly in Queensland, where 2P reserves were downgraded by 4400 PJ on a net basis between 30 June 2017 and 30 June 2019.
- The long term security of supply in the east coast is becoming increasingly dependent on more speculative sources of supply, with 75 per cent of 2C resources located in fields that are not yet in production, or approved for development.
- The majority of 2C resources are located in the Bowen, Beetaloo, Galilee and Gunnedah basins. Additional infrastructure will be required to bring this gas to market. To avoid unnecessary duplication of assets and other inefficiencies, the development of this infrastructure should, where feasible, be coordinated by governments and operated on a third party access basis.
- Governments should also consider using measures, such as active tenement management, to ensure producers bring gas to market in a timely manner, prevent larger producers 'warehousing' gas, and encourage greater diversity of suppliers.

1.2. Sufficient gas supply is expected in 2020 to meet forecast demand in the East Coast Gas Market

In July 2019, the ACCC reported that there was unlikely to be a gas supply shortfall in 2020. LNG producers were forecast to have 168 PJ of gas available in excess of their contractual commitments that could be sold domestically or exported. The ACCC found that, given the Heads of Agreement, this excess gas would likely act as a buffer for the domestic market if expected production was not realised or if demand was higher than forecast.[12]

Chart 1.1 shows the ACCC's updated supply-demand outlook for 2020. It shows total forecast supply (production, storage depletions, and expected gas flows from the Northern Territory to the east coast in 2020) against total forecast demand (domestic demand plus the quantities of gas required by LNG producers to meet their long term export contractual commitments).[13] The demand forecast includes the quantity of gas that LNG producers expect to have available in excess of their contractual commitments for 2020.

The supply and LNG demand data reflected in the chart below is based on information obtained directly from producers. The domestic demand forecast is based on AEMO's neutral scenario and is unchanged since the July 2019 report.[14]

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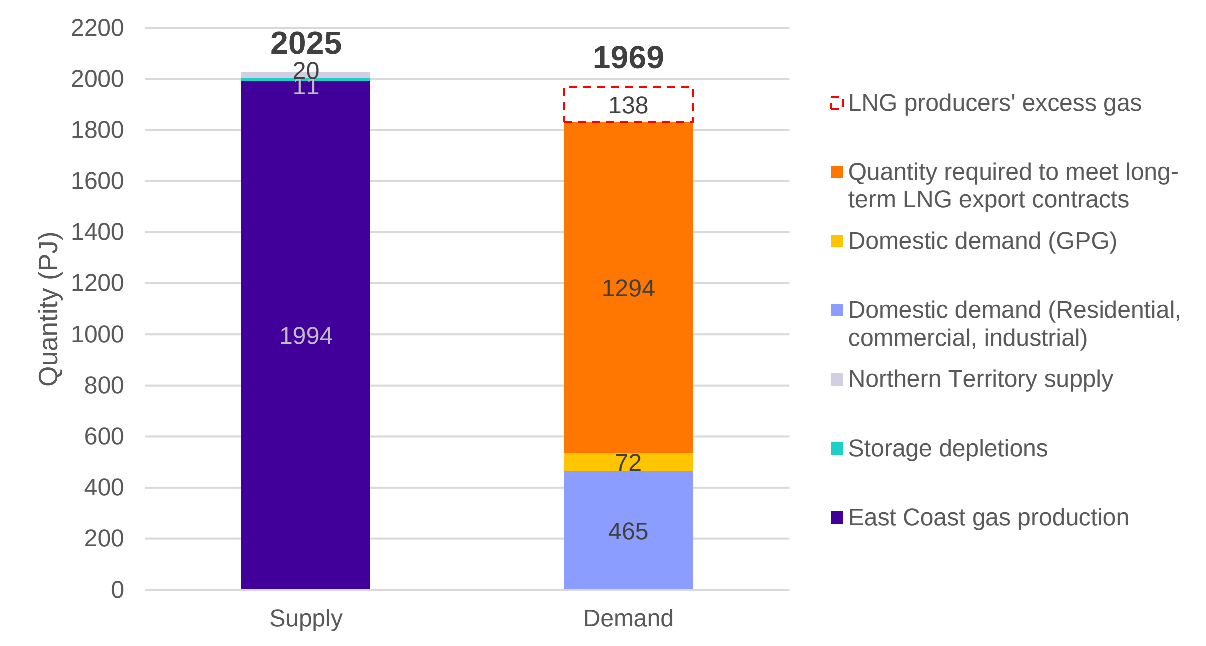
12 The Heads of Agreement between the Australian Government and LNG producers applies to both 2019 and 2020. Under the agreement, LNG producers have committed to offer uncontracted gas to the domestic market on competitive market terms prior to it being offered to the international market. The agreement applies in both the presence and the absence of a gas supply shortfall (although, in the event of a shortfall, LNG producers have committed to offering gas to the domestic market on 'reasonable terms'). For more details see Department of Industry, Innovation and Science, Heads of Agreement—the Australian east coast domestic gas supply commitment, 28 September 2018, https://www.industry.gov.au/sites/default/files/heads-of-agreement-2018-prime-minister-and-east-coast-lng-exporters.pdf.

13 Quantities required to meet long term LNG export contracts are based on LNG producers' expectations as at August 2019. The quantity actually supplied under these contracts in 2020 may vary due to, for example, flexibility provisions in the contracts, the execution of additional contracts or unexpected LNG plant maintenance.

14 Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

Chart 1.1: Forecast supply-demand balance in the East Coast Gas Market (including supply from the Northern Territory) for 2020



Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[15]

Note: Totals may not add up due to rounding.

As chart 1.1 shows, the supply and demand outlook for 2020 has improved since the ACCC's July 2019 report. Since then, producers have, on aggregate, revised their 2020 production forecasts upwards by 6 PJ. There has also been an easing on the demand side, primarily due to additional contracting by LNG producers to domestic buyers. In the period between 25 April 2019 and 22 August 2019, LNG producers' contracted an additional 33 PJ to domestic buyers. This means there is less excess gas that could potentially be sold overseas.

Based on these current projections, there is expected to be sufficient supply to meet domestic and contractual LNG export demand in 2020. However, the supply-demand outlook will tighten if domestic or LNG demand is higher than anticipated, or if expected production is not realised.

The forecast production presented in chart 1.1 only includes production from 2P reserves. While most of this production is expected to be from well-known developed areas, about 12 per cent is expected to be from less certain, undeveloped areas 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 17 PJ of gas forecast to be produced from contingent and undiscovered gas resources in 2020, which, if realised, would contribute additional quantities of gas to the east coast.

The Northern Territory is now connected to the east coast via the Northern Gas Pipeline (NGP). Currently, about 20 PJ of gas is expected to flow to the east coast from the Northern

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15 AEMO, *Gas statement of opportunities*, March 2019. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

Territory in 2020, slightly less than what was reported in the July 2019 report (21 PJ). As the capacity of the NGP is 35 PJ per annum, there is potential for more gas from the Northern Territory to be transported to the east coast in 2020, assuming this gas is available.

Chart 1.1 takes into account the forecast storage levels of the Roma, Moomba, Silver Springs and Newcastle storage facilities. Overall, these facilities are expected to contribute 11 PJ of gas to the East Coast Gas Market. However, based on their forecast storage levels in 2020, storage facilities may be able to provide additional quantities of gas to the east coast if the need arises. Furthermore, depending on their operation, other storage facilities, such as the Iona underground or Dandenong LNG gas storage facilities, may also be able to provide additional quantities of gas to the East Coast Gas Market in 2020.

LNG producers expect to have 138 PJ of gas available in excess of their current 2020 contractual commitments, which could be used for either export or to supply the domestic market. However, in keeping with the Heads of Agreement, LNG producers have committed to offering this gas to domestic buyers on competitive market terms prior to offering it to the international market, even if no shortfall is expected.[16] This excess gas will likely act as a buffer should a shortfall arise due to higher domestic demand or lower gas production than is currently forecast.

Gas producers, other than LNG producers, expect to produce a total of 566 PJ in 2020.[17] As at 22 August 2019, these producers had contracted 318 PJ to retailers, out of 489 PJ of gas contracted for supply in 2020. [18] This is an increase of 29 PJ compared to what these producers had contracted as at the time of our July 2019 report.[19]

As the ACCC has previously observed, GPG demand can have a significant impact on the level of domestic gas demand, and is highly variable relative to other categories of domestic demand (such as residential or industrial demand).[20] This is because gas demand by GPG is dependent on factors that are difficult to forecast accurately (such as rainfall, wind, investment in renewable generation, unplanned outages and unexpected generation retirement). This needs to be taken into account when assessing whether forecast supply in 2020 is likely to be sufficient to meet demand expectations.

In AEMO's analysis of the risk factors affecting its forecasts, it rates higher than expected GPG demand as 'possible'. AEMO's analysis states that 'if generation from wind farms or solar generators is lower than expected (within the normal range of annual variability), or [if] 10 per cent of committed renewable generation projects are delayed, GPG demand could be up to 22 PJ higher'.[21] However, LNG producers appear to have a sufficient quantity of excess gas to meet an increase in GPG demand of this magnitude.

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16 For more details see Department of Industry, Innovation and Science, Heads of Agreement—the Australian east coast domestic gas supply commitment, 28 September 2018, https://www.industry.gov.au/sites/default/files/heads-of-agreement-2018-prime-minister-and-east-coast-lng-exporters.pdf.

17 Source: ACCC analysis of data obtained from gas producers as at August 2019; includes storage depletions.

18 Source: ACCC analysis of data obtained from gas producers as at August 2019.

19 Source: ACCC analysis of data obtained from gas producers as at April 2019 and August 2019. A gas producer has provided us with updated information resulting in a revision to the figure published in our July 2019 report.

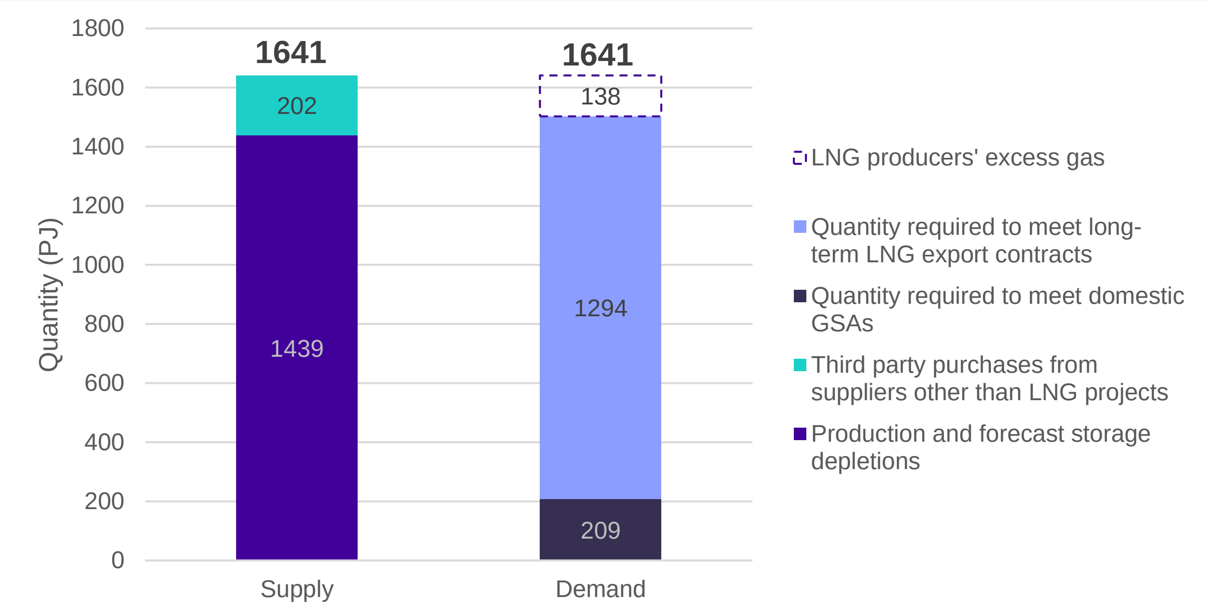
20 ACCC, *Gas Inquiry 2017–2020 Interim Report*, September 2017, p. 27; ACCC, *Gas Inquiry 2017–2020 Interim Report*, December 2017, p. 23; ACCC, Gas Inquiry 2017–2020 Interim Report, July 2018, p. 25; ACCC, *Gas Inquiry 2017–2020 Interim Report*, December 2018, p. 31; ACCC, Gas Inquiry 2017–2020 Interim Report, July 2019, p. 32.

21 AEMO, *Gas statement of opportunities*, March 2019, p. 9; see also section 4.4.1.

1.3. LNG producers are forecast to have enough gas to meet their domestic and export commitments in 2020

Chart 1.2 presents the updated supply-demand outlook for LNG producers in 2020, based on information obtained directly from LNG producers by the ACCC.

Chart 1.2: Forecast supply-demand balance of LNG producers in 2020



Source: ACCC analysis of data obtained from LNG producers as at August 2019.[22]

Note: Totals may not add up due to rounding.

Consistent with the ACCC's July 2019 report, chart 1.2 shows that LNG producers are likely to have sufficient gas available to meet their domestic and LNG contractual commitments in 2020.

LNG producers, in aggregate, expect to contribute 209 PJ of gas to the domestic market in 2020, which is more than they are expecting to take out (202 PJ). This is a reversal of the situation reported in our July 2019 report, when LNG producers, in aggregate, expected to take out 203 PJ in 2020, compared to the 176 PJ they expected to contribute. This reversal reflects the 33 PJ increase in LNG producers' contractual commitments to domestic buyers since the July 2019 report.

LNG producers currently forecast 138 PJ of gas available in excess of their current 2020 contractual commitments, which they could export or sell to the domestic market. In line with their commitments to the Australian Government, this uncontracted gas must first be offered to the domestic market on competitive market terms before it is offered to the international market.[23]

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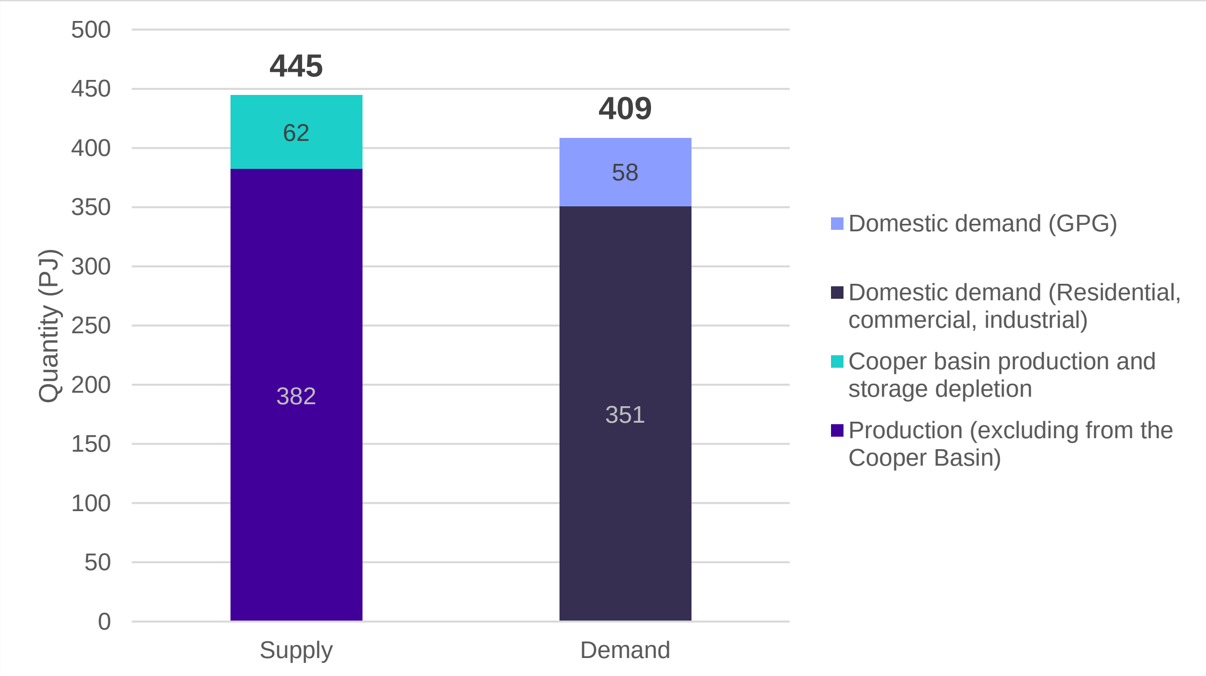
[22] Quantities required to meet long term LNG export contracts are based on LNG producers' expectations as at August 2019. The quantity actually supplied under these contracts in 2020 may vary due to, for example, flexibility provisions in the contracts, the execution of additional contracts, or unexpected LNG plant maintenance.

[23] For more details see Department of Industry, Innovation and Science, Heads of Agreement—the Australian east coast domestic gas supply commitment, 28 September 2018, https://www.industry.gov.au/sites/default/files/heads-of-agreement-2018-prime-minister-and-east-coast-lng-exporters.pdf.

1.4. The supply-demand outlook in the Southern States for 2020 remains tight

The overall forecast supply-demand balance in the Southern States (presented in chart 1.3 below) remains largely unchanged from what the ACCC reported in the July 2019 report. Forecast supply is based on data obtained directly from producers by the ACCC. Domestic demand is based on AEMO's forecasts and is unchanged since our July 2019 report.[24]

Chart 1.3: Forecast domestic supply-demand balance in the Southern States for 2020 (including a proportion of Cooper Basin gas)



Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[25]

Note: Totals may not add up due to rounding.

As chart 1.3 shows, there is expected to be sufficient supply to meet forecast demand in the Southern States in 2020. However, this will largely depend on the level of gas produced, particularly in the Cooper Basin, that flows south, and the level of realised GPG demand.

Forecast production in the Southern States (excluding the Cooper Basin) has increased slightly from 378 PJ (as reported in the July 2019 report) to 382 PJ. This primarily reflects an increase in expected production in the Otway Basin.

There has also been a small increase in forecast supply from the Cooper Basin (which includes forecast gas production and storage depletions) from 60 PJ to 62 PJ. It is important to note that a portion of the Cooper Basin gas that has been included in the supply forecast is based on producers' expectations of where gas produced in the Cooper Basin is likely to be delivered in 2020, taking into account swap agreements. As previously reported, the bulk of Cooper Basin production is contractually committed to the LNG projects in Queensland.

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[24] Specifically, domestic demand is based on AEMO's neutral domestic demand scenario from its March 2019 Gas Statement of Opportunities.

[25] AEMO, *Gas statement of opportunities*, March 2019. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

While the Cooper Basin is expected to contribute to Southern States' supply in 2020, due to swap agreements, this may not be the case for future years.

Another portion of the Cooper Basin gas that the ACCC has included in the supply forecast relates to gas acquired by a retailer, which contributes to the retailer's overall portfolio. Where the retailer will deliver this gas will ultimately depend on the demand dynamics of the retailer's portfolio at the time. As the retailer could end up delivering some of this gas into Queensland, total gas supply in the Southern States may be lower than is shown in the chart.

On the demand side, GPG continues to be a critical factor influencing the supply and demand balance in the Southern States. If GPG demand is greater than expected, this could shift the supply-demand balance and result in an even tighter market. As at the end of the September quarter, realised GPG demand for 2019 was around 40 PJ higher than AEMO's neutral scenario forecast for 2019 from AEMO's 2019 Gas Statement of Opportunities (GSOO).[26] This was the result of a combination of factors, including coal-fired power station outages, weather conditions, low wholesale gas prices, and lower than expected hydro generation, demonstrating the inherent uncertainty involved in forecasting gas consumption for GPG.[27]

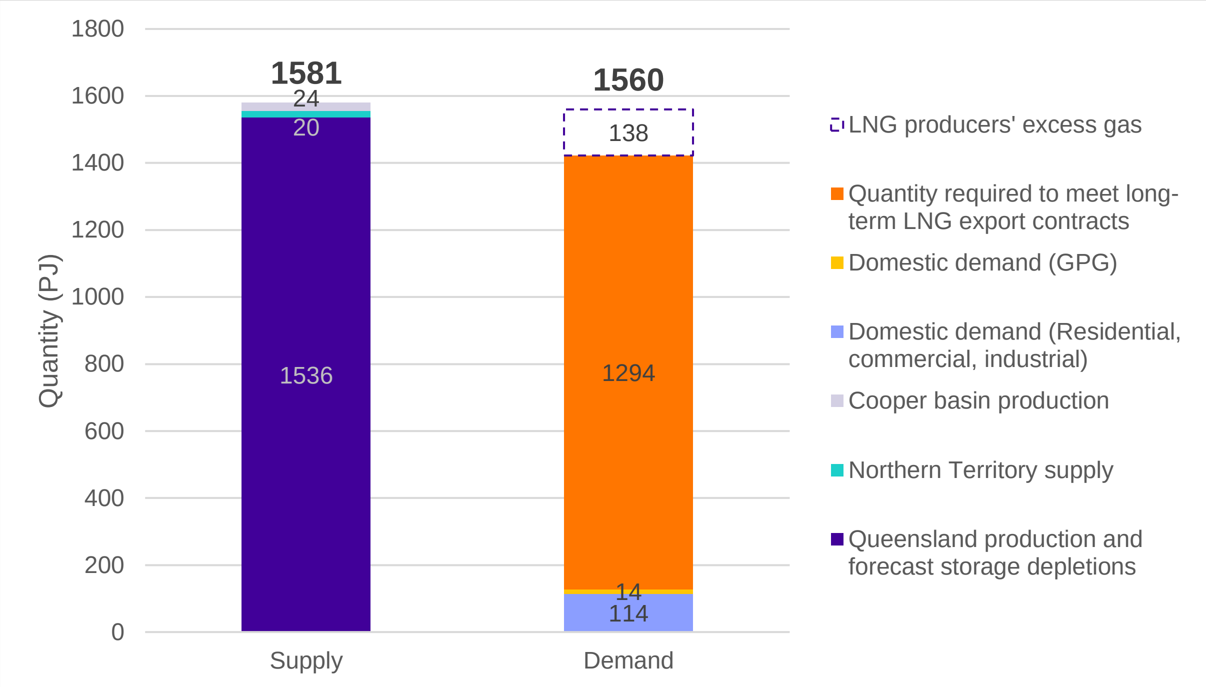
1.5. Queensland is likely to have sufficient gas to meet its needs in 2020

Chart 1.4 updates the supply-demand outlook for Queensland in 2020. Forecast supply is comprised of Queensland's total production plus forecast storage depletions, expected supply from the Northern Territory and a portion of gas from the Cooper Basin (based on producers' delivery expectations and taking into account gas swaps). Forecast demand is made up of AEMO's neutral domestic demand forecast for Queensland from its March 2019 GSOO and is unchanged since the July 2019 report. Forecast export demand is based on data provided directly by producers to the ACCC.

[26] Comparison made based on data published by AEMO in their Quarterly Energy Dynamics reports and by the AER in their wholesale statistics and their Wholesale Markets Quarterly.

[27] For more details see AEMO, *Quarterly Energy Dynamics*, Q1 2019, pp. 15 and 24; AEMO, *Quarterly Energy Dynamics*, Q3 2019, pp. 15 and 24; AER, *Wholesale Markets Quarterly—Q3 2019*, November 2019, pp. 12–14 and 41.

Chart 1.4: Forecast supply-demand balance in Queensland for 2020



Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[28]

Note: Totals may not add up due to rounding.

Consistent with the July 2019 report, chart 1.4 shows that there is likely to be sufficient production in Queensland to meet both domestic and contracted LNG export demand in 2020, even in the absence of gas from the Cooper Basin or Northern Territory. However, Queensland's supply-demand balance will tighten if the majority of the LNG projects' excess gas is used to supply export markets.

Based on current firm gas supply commitments, 20 PJ of gas is expected to flow into Queensland from the Northern Territory in 2020. As the NGP's annual capacity is around 35 PJ, there is capacity available on the NGP for additional gas to flow from the Northern Territory, in the event that there is gas available.

1.6. The long term supply outlook for the East Coast Gas Market remains uncertain

The ACCC last reported on the long term supply-demand outlook in December 2018, for the period 2020–2030. The outlook at that time indicated that the supply-demand balance in the East Coast Gas Market would remain tight over the coming decade, with future supply and demand uncertain.

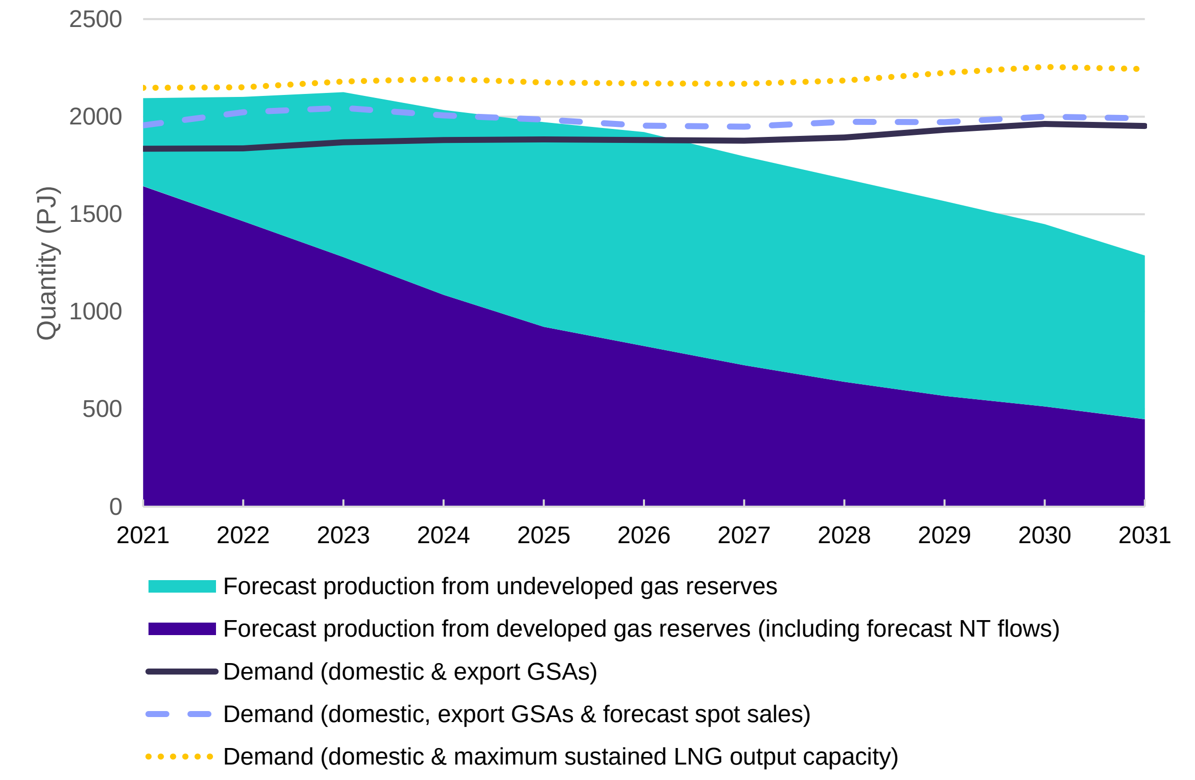
In this report, the ACCC is reporting on the forecast supply-demand balance in the East Coast Gas Market, as well as in Queensland and the Southern States, for the ten-year period 2021–2031.

[28] AEMO, *Gas statement of opportunities*, March 2019. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

Chart 1.5 shows the forecast supply-demand balance in the East Coast Gas Market over this period, based on forecast production from 2P reserves. The chart does not include production from contingent or undiscovered resources which is presented separately in chart 1.6.

Forecast production and LNG export demand are based on data obtained directly from producers. Domestic demand is based on AEMO's neutral domestic demand scenario from its March 2019 GSOO.

Chart 1.5: Forecast gas supply (including from the Northern Territory) compared to forecast demand, East Coast Gas Market, 2021–2031



Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[29]

Notes:

1. Export demand includes expected feed gas requirements.
2. The forecasts in this chart exclude gas expected to be produced by the Leigh Creek Energy Project because this gas is intended to produce 'synthetic natural gas' and the technology required to do so is still being tested.

As chart 1.5 shows, the long term supply and demand outlook for the East Coast Gas Market remains tight and uncertain. Sufficient gas is forecast to be produced from 2P reserves to meet expected domestic demand and LNG contractual commitments in the short to medium term. However, current projections indicate that gas production from 2P reserves will be insufficient to meet expected demand in the medium to long term.

Since the ACCC reported in December 2018, there have been increases in domestic and LNG export demand expectations for the ten-year period, which have been offset by

[29] AEMO, *Gas statement of opportunities*, March 2019. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

increases in forecast 2P production. Whether supply will be sufficient to meet demand in the long term remains dependent on whether new or additional sources of supply are developed and brought to market. Box 1.1 (p. 24) outlines measures some governments have taken to encourage additional exploration, and sections 1.8 and the discussion below consider other potential sources of supply.

Chart 1.5 shows that initially a large proportion of 2P production is expected to be from developed 2P reserves (that is, from existing wells). However, the proportion of 2P production from existing wells is unsurprisingly expected to decline over time so that just over half of forecast 2P production will come from developed 2P reserves over the outlook period. This means that the East Coast Gas Market will become increasingly reliant on production from undeveloped 2P reserves. The performance of these reserves is not yet known, and is likely to require approvals or investments before production can commence (as new wells will need to be drilled). The ultimate timing of production of this gas will therefore depend on whether it is economic to invest in developing these areas when it is required.

The shift in forecast production from developed to undeveloped 2P reserves is most evident between 2021 and 2025. Over this period, a number of new projects are expected to commence production, and table 1.1 provides an overview of the expected timing of some of the most significant of these projects. Of the projects listed in this table, Arrow Energy's Surat Gas Project represents the single largest source of production from undeveloped 2P reserves in the east coast, and is expected to contribute slightly less than 20 per cent of production from undeveloped 2P reserves over the outlook period.[30] While information received by the ACCC indicates that Arrow Energy expects to commence production from this project in 2020, this project is yet to receive a final investment decision.[31]

Table 1.1: Expected timing of material undeveloped 2P reserves

Project/field	Basin	Operator	Expected timing
Surat Gas Project	Surat	Arrow Energy	2020
Mahalo Project	Bowen	Comet Ridge	2022
Ironbark	Surat	APLNG	2021–2023[32]
Ramyard, Kainama, Murungama, Dalwogan, Woleebee, Spring Gully	Surat	APLNG	2021–2024
Don Juan	Surat	Senex Energy	2021[33]
Trefoil	Bass	Beach Energy	2023–2024[34]

Source: ACCC analysis of data obtained from gas producers as at August 2019.

30 This figure includes expected production from the Kogan North Joint Venture.

31 Australian Financial Review, 'Senex races towards start-up of gas sales at Atlas', 28 October 2019.

32 Expected timing given by Origin, see Australian Financial Review, 'Senex Energy bankers up for Origin Energy's Ironbark', 29 October 2018. Following APLNG's acquisition of the Ironbark field in August it is unknown if this timing will be maintained.

33 Pilot development is likely to commence in this year. See Senex Energy, *2019 annual report*, https://www.senexenergy.com.au/wp-content/uploads/2019/09/Senex-2019-Annual-Report.pdf, p. 26.

34 Beach Energy, *Annual report 2019*, https://www.beachenergy.com.au/wp-content/uploads/2019/08/BeachEnergy_AnnualReport2019.pdf, p. 35.

It is also noteworthy that, with the exception of the Trefoil field, all of the projects or fields in table 1.1 involve the development of coal seam gas (CSG). As the ACCC has noted in other reports, producers can face a range of technical and financial challenges when developing CSG.[35] This is highlighted by the significant reserves downgrades that have occurred over the last two years (see section 1.9.2). When coupled with the uncertainty surrounding the expected timing of production, there is a risk that actual supply may be less than forecast over the decade to 2031.

Nevertheless, the long term supply outlook has improved. Compared to what the ACCC reported in December 2018, producers have, on average, increased expected production from 2P reserves by 90 PJ per annum. This has offset increases to forecast domestic and export demand, resulting in the overall long term supply-demand balance remaining stable.

Chart 1.5 includes gas contracted to be delivered into the East Coast Gas Market from the Northern Territory on a firm basis. At present, the quantities of gas expected to flow into the East Coast Gas Market from the Northern Territory over the period 2021–2031 is less than the capacity of the NGP. This means that if there is available gas in the Northern Territory, additional quantities of gas could be delivered to the east coast over the outlook period.

Over the course of the long term outlook, there is also the possibility that the capacity of the NGP will be expanded, to up to 256 PJ per annum.[36] Whether this expansion occurs will primarily depend on the results of exploration expected to be conducted by Origin, Santos and Empire Energy in the Beetaloo Basin in the 2019–2020 financial year.[37] If successful, this exploration activity may provide the east coast with a new source of supply, provided this gas is directed to the domestic market.

On the demand side, LNG producers' currently anticipate using around 81 per cent of their LNG trains' maximum sustained LNG output capacity to meet their long term export contractual commitments over the outlook period. LNG producers' could export an additional 3295 PJ if they utilised their LNG trains at their maximum sustained LNG output capacity over the 2021–2031 outlook period.[38] Over this period, LNG producers' currently expect to sell 1053 PJ on the LNG spot markets.[39]

AEMO is forecasting domestic demand to be 59 PJ higher, on average, for each year in 2021–2031 based on its 2019 GSOO compared to its 2018 GSOO. In part, this reflects significant long term uncertainty about the level of domestic demand, which means that AEMO's forecasts can differ significantly year on year. It also reflects the high variability of GPG demand. For the period 2010–2018, the average difference in actual GPG demand between years has been 31 PJ.

As noted in section 1.2 above, GPG demand is difficult to forecast accurately because it depends on a number of factors such as rainfall, wind, investment in renewable generation, unplanned outages and unexpected generation retirement, which are themselves difficult to

[35] ACCC, *Inquiry into the east coast gas market*, April 2016, p. 44.

[36] Jemena, 'Jemena welcomes decision to lift fracking moratorium' (Media release), April 2018, https://jemena.com.au/about/newsroom/media-release/2018/jemena-welcomes-decision-to-lift-fracking-moratori.

[37] Empire Energy, 'Northern Territory operations update' (ASX announcement), 23 October 2019, https://empireenergygroup.net/wp-content/uploads/23.10.19-ASX-Announcement-Northern-Territory-Operations-Update.pdf; Origin Energy, 'Getting back on the ground in Beetaloo' (Blog post), 16 April 2019, https://www.originenergy.com.au/blog/getting-back-on-the-ground-in-the-beetaloo/; Australian Financial Review, 'Northern Territory fracking 'to become a reality', 29 May 2019, https://www.afr.com/companies/energy/northern-territory-exploration-to-become-a-reality-20190528-p51s4x.

[38] This figure includes feed gas requirements (such as fuel) required to produce LNG.

[39] This figure includes feed gas requirements (such as fuel) required to produce LNG.

forecast. Between 2021 and 2031, a number of coal-fired power stations are also expected to close, in whole or in part[40], which AEMO expects will increase GPG demand.[41]

Additional unexpected closures of coal-fired power stations, or earlier than anticipated closures, could see GPG demand further increase, similarly to what occurred following the unexpected closure of the Hazelwood power station in 2017 (which saw GPG demand increase from 139 PJ in 2016 to 184 PJ in 2017).[42] While annual GPG demand has been trending downwards since its peak of 220 PJ in 2014, its high variability is a source of significant forecast uncertainty.

There is also the possibility that realised demand could be lower than forecast due to demand reductions in response to high or increasing gas prices. This could occur if gas users reduce their purchases of gas, adopt energy efficiency measures, substitute gas for alternative fuels or some combination of these. Compared to its 2018 GSOO, AEMO notes in its 2019 GSOO that there is now a greater potential for gas usage to decrease. A number of C&I users have also informed us that they are utilising these measures through our user survey (see chapter 3).

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40 These include Liddell (NSW), Callide B (Qld) and Vales Point B (NSW) coal-fired power stations, and units 1–3 of the Yallourn W (Vic) power station. For more information on expected generation closures see AEMO, *Generation information*, https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

41 AEMO, *Gas statement of opportunities*, March 2019, p. 27.

42 AEMO, *Gas statement of opportunities*, March 2019, p. 26. AEMO note that this closure was accompanied by extended outages of Yallourn and Loy Yang coal-fired power stations.

Box 1.1: Government measures to encourage exploration and increase domestic gas supply

A number of Australian governments have recently announced or implemented policies that aim to encourage exploration and increase the domestic supply of gas in the long term. These include:

- The South Australian Government's Plan for Accelerating Exploration (PACE) Gas grant program, which over two rounds gave grants to assist with the drilling of four exploration wells with the aim of delivering up to an additional 2000 PJ of gas to the domestic market.[43]
- The Queensland Government's progressive release of over 39 000 square kilometres for exploration tenements via a competitive tender process since 2015, with an additional 30 000 square kilometres released for bidding in November 2019.[44] Exploration in north-west Queensland basins is also being encouraged through the Strategic Resources Exploration Program.[45]
- The Commonwealth Government's Gas Acceleration Program which offered matched grant funding of up to $6 million for projects looking to provide new gas to domestic consumers by 30 June 2020.[46] The 2019 Federal Budget also included $8.4 million 'to support feasibility studies to accelerate gas supplies from the Northern Territory to the east coast market by opening the Beetaloo Sub-basin for exploration and development'.[47]

PACE Gas grants have thus far assisted in the spudding of two exploration wells, with another two wells yet to be drilled.[48] Three of the exploration wells are located in the onshore Otway Basin, while one will be in the Cooper Basin.

The South Australian Government has also recently released 13 584 square kilometres for exploration in the Cooper, Otway, Eromanga and Warburton basins.[49]

Through its tenement release program, the Queensland Government has released nearly 70 000 square kilometres for gas exploration, with around a quarter having domestic supply obligations.

The ACCC has previously noted potential issues with attaching domestic supply obligations to tenements, including that they may not increase overall supply to the domestic market, may increase tenement concentration, and may not provide pricing benefits to all market participants.[50]

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43 Department of Energy and Mining, *PACE Gas*, http://www.energymining.sa.gov.au/petroleum/latest_updates/pace_gas.

44 Hon. Dr. Anthony Lynham, 'Queensland turns up the gas dial' (Media release), 30 October 2019, http://statements.qld.gov.au/Statement/2019/10/30/queensland-turns-up-the-gas-dial.

45 Department of Natural Resources, Mines and Energy, *Strategic Resources Exploration Program*, https://www.dnrme.qld.gov.au/mining-resources/initiatives/strategic-resources-exploration-program.

46 Business, 'Gas Acceleration Program', Australian Government, https://www.business.gov.au/Grants-and-Programs/Gas-Acceleration-Program.

47 Department of Treasury, Budget Paper No. 2: Budget Measures 2019–20, https://budget.gov.au/2019-20/content/bp2/download/bp2.pdf, p. 78.

48 Cooper Energy, 'Dombey-1 spudded in the onshore Otway Basin' (ASX announcement / Media release), 11 September 2019, https://www.cooperenergy.com.au/Upload/Dombey-spud-announcement.pdf; Senex Energy, 'Gemba-1 gas exploration well flows at 8 mmscfd on test' (ASX announcement), 17 December 2018, https://www.senexenergy.com.au/wp-content/uploads/2018/12/2018.12.17-Gemba-1-gas-exploration-well.pdf.

49 Hon. Dan van Holst Pellekaan, 'New petroleum exploration acreage in Cooper and Otway basins' (Media release), 27 May 2019, https://www.danvhp.com.au/2019/05/new-petroleum-exploration-acreage-in-cooper-and-otway-basins/.

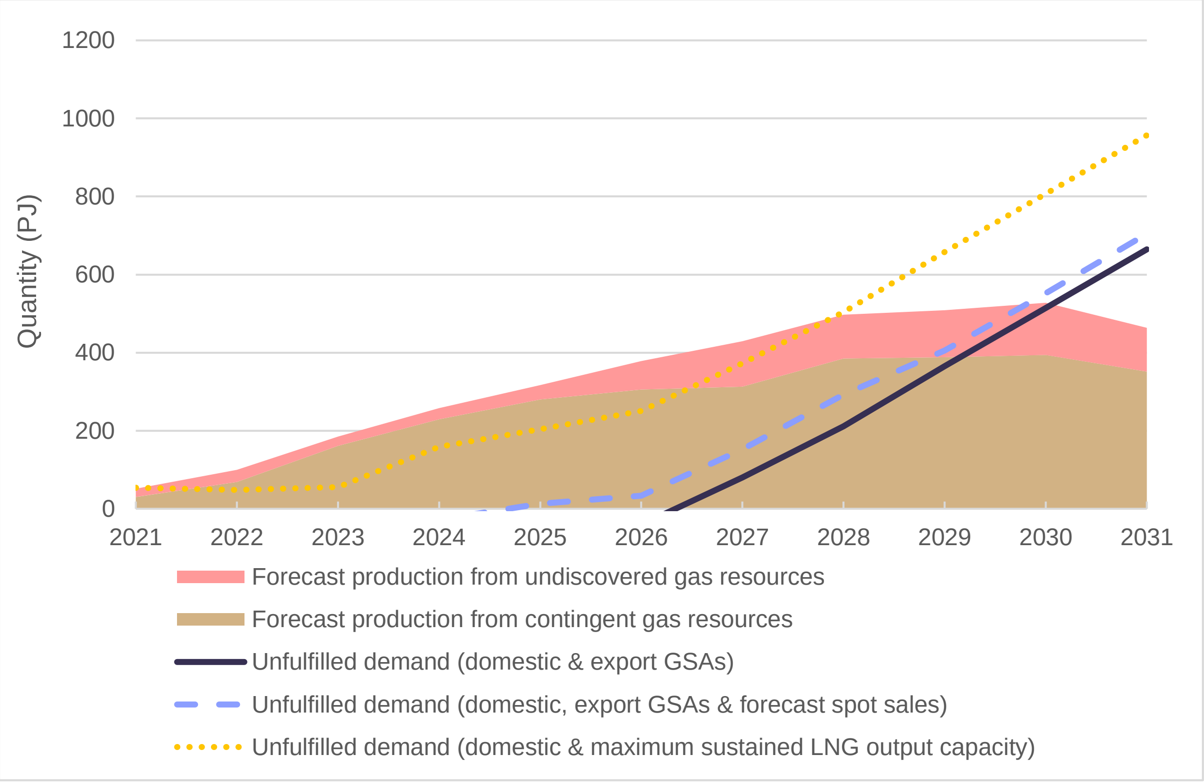
50 For more details see ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2019, pp. 37–39.

Gas Acceleration Program grants have been awarded to Armour Energy, Westside and Tri-Star to expedite the drilling of an additional 16 wells for the Kincora Project, the Greater Meridian joint venture, and the Fairfields Gas Project, respectively. These projects are expected to deliver an additional 12 PJ by 30 June 2020, and an extra 28 PJ over five years.[51]

The Commonwealth Government has also recently announced that it will work with state and territory governments to implement a National Gas Reservation Scheme in the east coast.[52] A final decision on the scheme is expected to be made by February 2021.[53]

Chart 1.6 assumes that production from 2P reserves in chart 1.5 will be realised and shows potential gas production from contingent and undiscovered resources against the remaining unfulfilled demand (that is, the difference between demand and production from 2P reserves, as presented in chart 1.5).

Chart 1.6: Unfulfilled demand and forecast production from contingent and undiscovered gas resources, East Coast Gas Market, 2021–2031



Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[54]

Note: Export demand includes feed gas requirements.

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51 Hon Matt Canavan, 'New east coast supply from Gas Acceleration Program' (Media release), 28 March 2018, https://www.minister.industry.gov.au/ministers/canavan/media-releases/new-east-coast-supply-gas-acceleration-program.

52 Hon Matt Canavan, 'EnergyQuest report highlights success of Coalition gas policy' (Media release), 5 December 2019, https://www.minister.industry.gov.au/ministers/canavan/media-releases/energyquest-report-highlights-success-coalition-gas-policy.

53 The Australian, 'Federal government to go ahead with gas reservation on east coast', 5 December 2019.

54 AEMO, *Gas statement of opportunities*, March 2019. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

Chart 1.6 shows that forecast production from contingent and undiscovered resources, if realised, could alleviate some of the potential supply gaps over the outlook period. However, there can be significant challenges to the development of contingent and undiscovered resources, so the exact timing and likely quantities of production from contingent and undiscovered resources are highly uncertain.

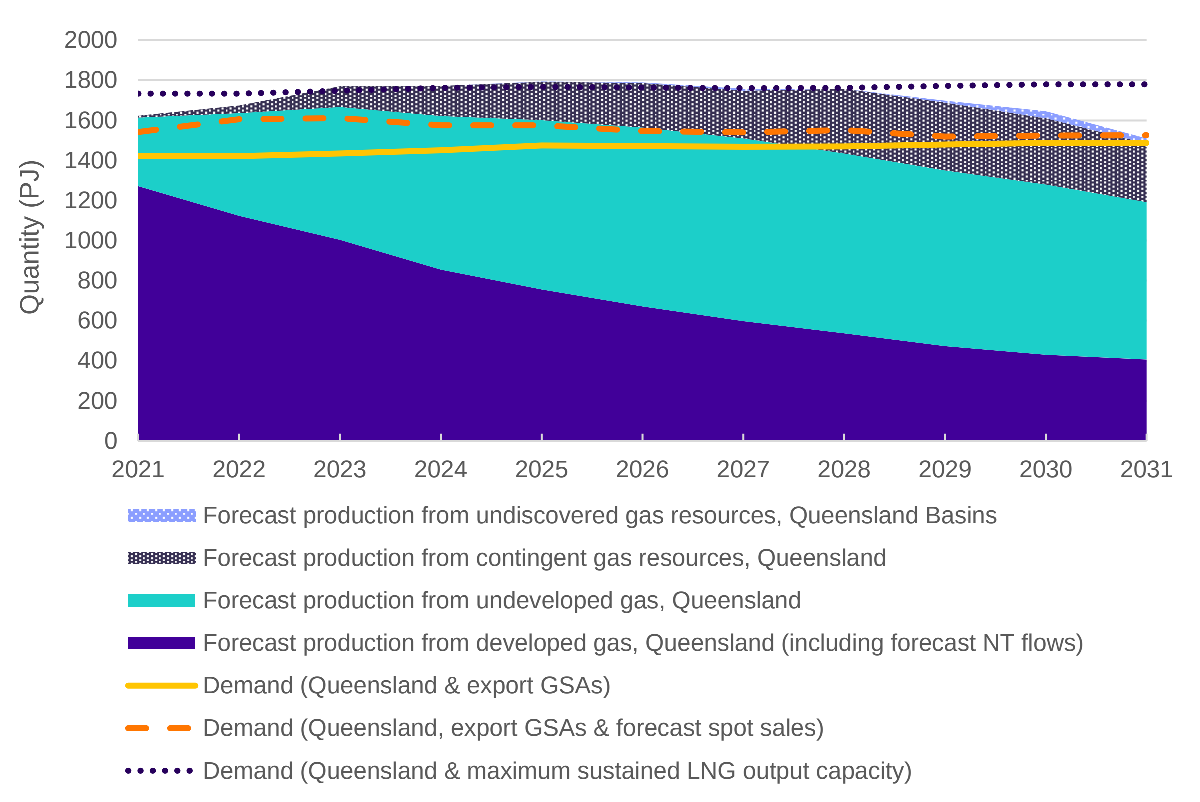
This uncertainty is highlighted in that, compared to the December 2018 report, producers have, on average, revised down their expected production from contingent resources by 4 PJ per annum, and their expected production from undiscovered resources by 22 PJ per annum. There have also been substantial downgrades to 2C resources in the last 12 months, as discussed further in section 1.9.1.

1.7. The outlook for Queensland is more positive than the East Coast as a whole, but significant uncertainty remains

Chart 1.7 shows the forecast supply-demand balance in Queensland over 2021–2031, based on forecast production from developed 2P reserves, undeveloped 2P reserves, contingent resources and undiscovered resources in the Surat, Bowen, Galilee and Isa Super basins.

Forecast production and LNG export demand are based on data obtained directly from producers. Queensland's domestic demand is based on AEMO's neutral domestic demand scenario from its March 2019 GSOO.

Chart 1.7: Forecast gas supply (including from the Northern Territory) compared to forecast gas demand, Queensland, 2021–2031



Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[55]

Note: Export demand includes expected feed gas requirements.

Chart 1.7 shows that in the near to medium term, there is likely to be sufficient gas produced from 2P reserves to meet LNG contractual and domestic demand forecast. However, over time, Queensland will become increasingly reliant on more speculative sources of gas supply in order to meet current demand expectations.

The amount of gas production realised will be heavily influenced by the decisions of LNG producers who hold the majority of 2P reserves in Queensland (and the east coast, see section 1.10.1). These decisions will depend on a number of factors, such as the performance of CSG wells, production costs, expected future and contemporaneous gas prices, and crucially, choices made regarding how much gas to supply to the domestic and export markets.

Chart 1.7 also takes into account gas expected to be delivered into Queensland from the Northern Territory under firm gas supply contracts. As noted in section 1.6 above, there is the potential for between 12–221 PJ of additional gas to flow into the East Coast Gas Market per annum (depending on whether the NGP is expanded). Whether this eventuates will largely depend on the outcome of onshore exploration planned to be conducted in the Beetaloo Basin and whether this gas is supplied to the domestic or export market.

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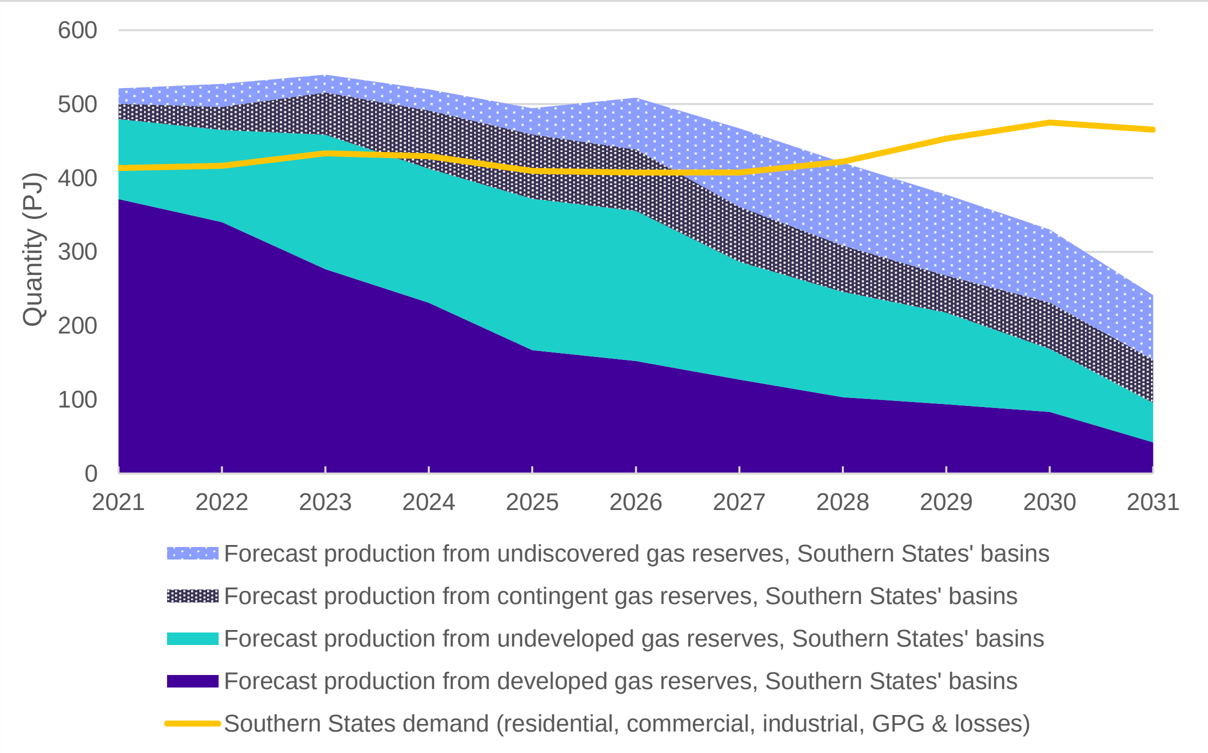
55 AEMO, *Gas statement of opportunities*, March 2019.
Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

1.8. The southern states risk facing a shortfall in the medium term

Chart 1.8 presents the long term supply-demand outlook in the Southern States for 2021–2031, based on forecast production from developed 2P reserves, undeveloped 2P reserves, contingent resources and undiscovered resources in the Bass, Cooper, [56] Gippsland, Otway and Sydney basins.

Forecast production is based on data obtained directly from producers, while Southern States' demand is based on AEMO's neutral domestic demand scenario from its March 2019 GSOO.

Chart 1.8: Forecast gas supply compared to forecast gas demand, Southern States, 2021–2031.



Source: ACCC analysis of data obtained from gas producers as at August 2019 and of domestic demand forecast (neutral scenario) from AEMO's March 2019 GSOO.[57]

Note: The forecasts in this chart exclude gas expected to be produced by the Leigh Creek Energy Project because this gas is intended to produce 'synthetic natural gas' and the technology required to do so is still being tested.

Consistent with AEMO's findings in its March 2019 GSOO, chart 1.8 shows that current projections indicate that there is a risk of a shortfall in the Southern States from 2024 onwards, unless:

- more exploration and development occurs in the south
- more investment occurs in north-south transportation infrastructure to enable greater volumes from Queensland or the Northern Territory to flow south, and/or
- one or more LNG import terminals are developed.

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56 Note that a portion of Cooper Basin production occurs in Queensland.

57 AEMO, *Gas statement of opportunities*, March 2019. Consistent with the approach taken by AEMO in its 2018 GSOO, the ACCC has combined domestic demand attributed to losses with the residential, commercial and industrial category.

Chart 1.8 shows a rapid decline in production from developed 2P reserves. This decline reflects declining ex-Longford production (the Southern States' largest source of gas supply). Initially, ex-Longford production is forecast to meet approximately 71 per cent of the Southern States' demand in 2021, but by 2031 this is expected to decline to 11 per cent of Southern States' demand. Given the decline in forecast production, the Southern States' will be increasingly reliant on less certain types of gas production and the flow of gas south, from Queensland, the Cooper Basin and/or the Northern Territory.

As previously reported by the ACCC, in the near to medium term the bulk of Cooper Basin gas is contracted to GLNG in Queensland under the 'Horizon contract' entered into with Santos.[58] This contract was signed in 2010 and is set to expire in 2025. In the near term, this means that unless swap agreements are entered into, the quantity of gas available in the Southern States will be significantly less than shown in chart 1.8.

Whether domestic supply is sufficient to meet demand in the Southern States will depend on whether there is adequate investment in infrastructure to transport gas from Queensland and/or the Northern Territory to the Southern States. As noted in section 4.3.1, a number of investments are being considered by pipeline operators. If these eventuate, they could improve the security of the Southern States' supply.

Additional supply may also be available to the Southern States through the construction of one or more LNG import terminals. At present, five import terminals have been proposed[59], all of them to be located in the Southern States.[60] Two of these are scheduled to begin operations in the first half of 2021 (the AIE terminal at Port Kembla and EPIK's terminal at Newcastle), although a final investment decision is yet to be made in relation to either of these projects.[61]

AIE's proposed import terminal at Port Kembla has received 'Critical State Significant Infrastructure' status from the NSW government and has also received planning approval. Operations are, however, expected to be delayed with AIE seeking to increase the potential import capacity to 180 PJ per year.[62] The other terminal, EPIK's proposed Newcastle terminal, has also received 'Critical State Significant Infrastructure' status from the NSW government.[63] The proposed capacity of this terminal is 110 PJ per annum.

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58 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 60.
See also, Santos, 'Santos to supply 750PJ of portfolio gas to GLNG' (Media release), 25 October 2010, https://www.santos.com/media/1799/251010_santos_to_supply_750pj_of_portfolio_gas_to_glng.pdf.

59 ExxonMobil recently announced it would not be proceeding with the proposed terminal in Victoria on the basis of a lack of customer interest. See SMH, 'ExxonMobil shelves Victorian gas import terminal plan', 2 December 2019.

60 AIE at Port Kembla (NSW), EPIK at Newcastle (NSW), AGL at Crib Point (Vic), and Venice Energy at Adelaide (SA)

61 AIE, 'AIE welcomes foundation customer EnergyAustralia' (Media release), 22 May 2019, https://ausindenergy.com/file/2019/05/EnergyAustralia-Customer_220520190_FINAL.pdf; EPIK, 'EPIK's Newcastle GasDock LNG import terminal declared Critical State Significant Infrastructure by NSW government', 14 August 2019.

62 Hon. John Barilaro, Hon. Rob Stokes & Hon. Matt Kean, 'Port Kembla gas terminal approved' (Media release), 29 April 2019, https://www.planning.nsw.gov.au/News/2019/Port-Kembla-gas-terminal-approved; see also Australian Financial Review, 'Forrest's gas import plan delayed by growing pains', 19 August 2019.

63 Hon. John Barilaro & Hon. Rob Stokes, 'Newcastle gas terminal given critical status' (Media release), 14 August 2019, https://www.planning.nsw.gov.au/-/media/Files/DPE/Media-Releases/2019/August/media-release-newcastle-gas-terminal-given-critical-status-20190814.pdf

1.9. Reserves and resources

To further inform the longer term supply outlook, the ACCC has sought information from producers[64] on:

- their holdings of reserves and resources in the east coast (onshore and offshore) and the Northern Territory (onshore only) as at 30 June 2019 and the gas price assumptions used to assess the commerciality of reserves
- the movement in 2P reserves that has occurred between 30 June 2018 and 30 June 2019 and an explanation for any material upgrade or downgrade in this period, and
- the development status of their gas fields and the main barriers to the commercial recovery of contingent resources.

Box 1.2 provides further detail on the information sought from producers.

Box 1.2: Information sought from producers and bases upon which information is reported

The ACCC sought a range of information from producers on their reserves and resources holdings using the concepts set out in the Society of Petroleum Engineers' Petroleum Resources Management System (PRMS).[65] PRMS is a widely used principles-based standard that provides for a consistent approach to the calculation of petroleum quantities.

The reserves and resources estimates were collected on the basis of the producers' net revenue interests (i.e. a producer's revenue share of gas sales after deducting royalties and share of production owing to others under applicable lease and fiscal terms) in the sales quantities of gas (i.e. quantities available for sale excluding quantities consumed in operations, flared or lost in operations) from all gas containing fields.

The specific information that the ACCC sought is summarised in the table below.

Type	Information requested		
Reserves	1P (proved) Have at least a 90% probability that quantities recovered will equal or exceed the estimate	2P (proved + probable) Have at least a 50% probability that quantities recovered will equal or exceed the estimate	3P (proved, probable, possible) Have at least a 10% probability that the quantities recovered will equal or exceed the estimate
	Broken down into developed[66] and undeveloped[67] reserves		
Resources	2C (best estimate of contingent resources)		
Gas field information	Information on whether the field is: • currently producing, approved for development, or another stage of development		

[64] The term 'producer' is used in this report to refer to those entities that are currently producing gas and those that are not currently producing but have an interest in gas reserves and/or resources.

[65] Society of Petroleum Engineers, *Petroleum Resources Management System* (PRMS), revised June 2018.

[66] Quantities expected to be recovered from existing wells and facilities.

[67] Quantities expected to be recovered through future significant investments.

	• a conventional gas field, coal seam gas field, or unconventional gas field • a dry gas field (mostly methane), gas condensate field (mainly condensates or liquid hydrocarbons) or an oil field (where gas is found associated with oil).
Development status	Information on the main barriers to the commercial recovery of 2C resources in a field, and the supplier's intentions for the future development of the field.
Movements in 2P Reserves	Movements in reserves over the last 12 months broken down into: production, extensions of a field's proved area, net acquisitions, reserves upgrades (i.e. changes resulting from the commercialisation of resources or reclassification of 3P to 2P reserves), reserves downgrades (i.e. changes resulting from the reclassification of 2P reserves to 3P reserves or contingent resources), and other revisions.
Gas price assumptions	Information on the gas price assumptions used to assess a project's commerciality, with separate assumptions reported for both contracted and uncontracted reserves.

1.9.1. The majority of reserves and resources are located in Queensland and held by LNG producers

When a gas reservoir is discovered, the gas within the reservoir can be classified as either a reserve or resource, depending on its commerciality. Reserves are those quantities that are expected to be commercially recoverable. Contingent resources, on the other hand, are those quantities that are potentially recoverable but not yet commercial to develop, due to one or more contingencies (e.g. there is currently no viable market, the commercial recovery depends on technology under development, or the evaluation of the accumulation is insufficient to assess commerciality).[68]

Within each category of reserves and resources there are different confidence levels associated with the ability to recover the relevant quantities (for example, reserves may be classified as proved, probable, or possible, while contingent resources may be classified as low, best or high estimate). However, 2P (proved plus probable) reserves and 2C resources are often viewed as the best estimates of reserves and resources, because they represent the "most realistic assessment of a project's recoverable quantities".[69]

1.9.2. Reserves and resources estimates

To understand the range of potential recovery outcomes, producers were asked to provide the best estimate of their 1P, 2P and 3P reserves and 2C contingent resources in the east coast (onshore and offshore) and the Northern Territory (onshore only) as at 30 June 2019. The estimates provided by producers are set out in table 1.2, while box 1.3 provides an overview of the gas price assumptions used to assess the commerciality of reserves.

68 Society of Petroleum Engineers, *Petroleum Resources Management System* (PRMS), revised June 2018, p. 3.

69 ibid, p. 14.

Table 1.2: Reserves and resources as at 30 June 2019 (PJ)

	Reserves			Contingent Resources
	1P	**2P**	**3P**	**2C**
East Coast Gas Market				
Bowen Basin (Qld)	4 072	6 388	8 181	15 520
Surat Basin (Qld)	10 788	26 100	29 680	5 575
Cooper Basin (Qld/SA)	524	1 020	1 720	2 117
Gippsland Basin (Vic)	1 929	2 627	2 978	1 911
Otway Basin (Vic)	378	622	910	137
Bass Basin (Vic)	88	110	132	160
Sydney Basin (NSW)	9	9	9	-
Gunnedah Basin (NSW)	-	-	-	2 059
Galilee Basin (Qld)	-	-	-	2 775
Clarence-Moreton Basin (NSW/Qld)	-	-	-	668
Isa Super Basin (Qld)	-	-	-	163
Total east coast (onshore and–offshore)	**17 787**	**36 876**	**43 610**	**31 084**
Onshore Northern Territory				
Amadeus Basin	185	235	269	196
Beetaloo Basin	-	-	-	6 600
McArthur Basin	-	-	-	6
Total NT (onshore)	**185**	**235**	**269**	**6 802**
Total East Coast + NT	**17 972**	**37 111**	**43 879**	**37 887**
CSG	*80%*	*80%*	*79%*	*64%*
Conventional natural gas	*16%*	*12%*	*13%*	*8%*
CSG plus conventional natural gas in field	*3%*	*7%*	*7%*	*1%*
Other unconventional gas	*0%*	*0%*	*0%*	*24%*
Conventional plus unconventional in field	*1%*	*1%*	*2%*	*3%*

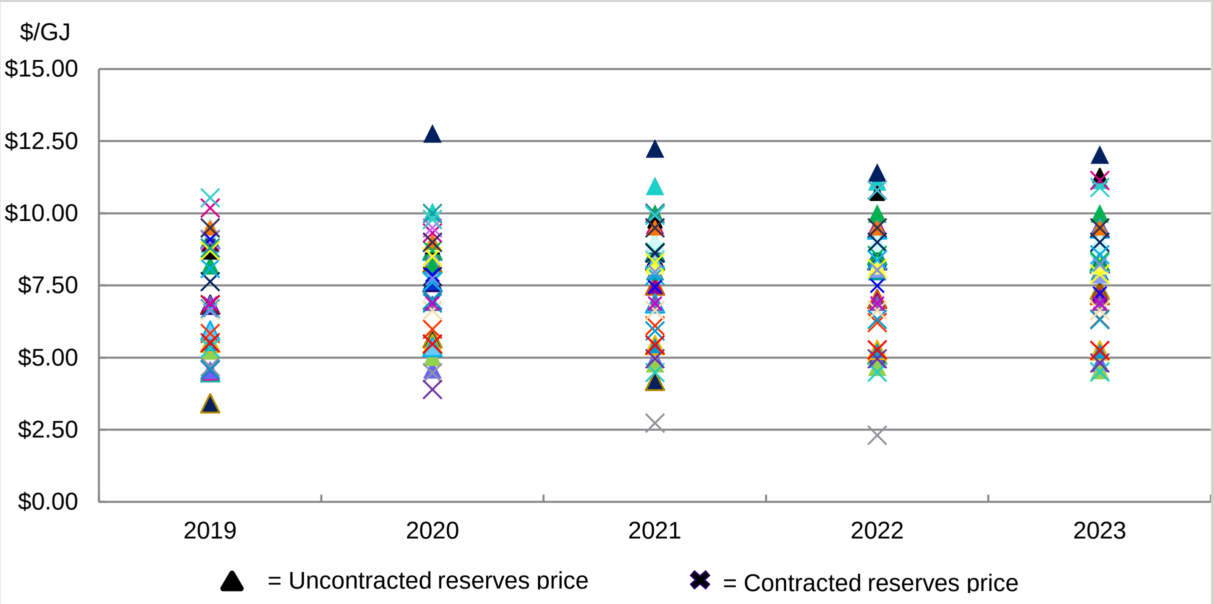
Source: ACCC analysis of data supplied by gas producers.

Notes: 1. Totals may not add up due to rounding. 2. The estimates in this table exclude the Leigh Creek Energy Project in South Australia because this project is intended to produce ‘synthetic natural gas’, and the ACCC understands that the technology required to do so is still being tested by Leigh Creek Energy (including a number of environmental studies) and that further environmental approvals are required before commercial quantities of gas can be produced. 3. The estimates provided by a small number of producers include relatively small volumes of ethane and carbon dioxide. 4. The category ‘other’ in the table includes: ‘conventional and CSG’ and ‘conventional and unconventional’.

Box 1.3: Gas price assumptions underpinning the reserves and resources estimates

Gas prices are a key determinant of a project's commerciality. As part of the ACCC's request for information, producers were asked to provide the gas price assumptions used to assess the commercial viability of contracted and uncontracted gas over the period 2019– 2023. These assumptions are summarised in chart 1.9, with separate markers used to identify the assumptions used for contracted and uncontracted reserves.

Chart 1.9: Gas price assumptions underpinning producers' reserve estimates (real $2019)



Source: ACCC analysis of data obtained from producers.

Chart 1.9 shows that the gas price assumptions vary markedly across producers, with the gas price assumptions underpinning the current estimates of:

- contracted reserves ranging from $2.31/GJ[70]–$11.14/GJ (average $7.45/GJ)
- uncontracted reserves ranging from $3.42/GJ[71]–$12.77/GJ (average $7.99/GJ).

In relation to the prices assumed for uncontracted reserves, the top end of this range is lower than what was reported to the ACCC in 2018 (i.e. $12.77 versus $14.50/GJ) and the average over the five year period is also lower than what was previously reported (i.e. $7.99 versus $8.39/GJ).[72] It is also worth noting that some producers have previously stated that their price assumptions for uncontracted reserves do not necessarily reflect their expectations about the price they expect to receive in the short to medium term (i.e. because they are used to assess the viability of reserves over the longer term) and may change each time reserves are estimated.

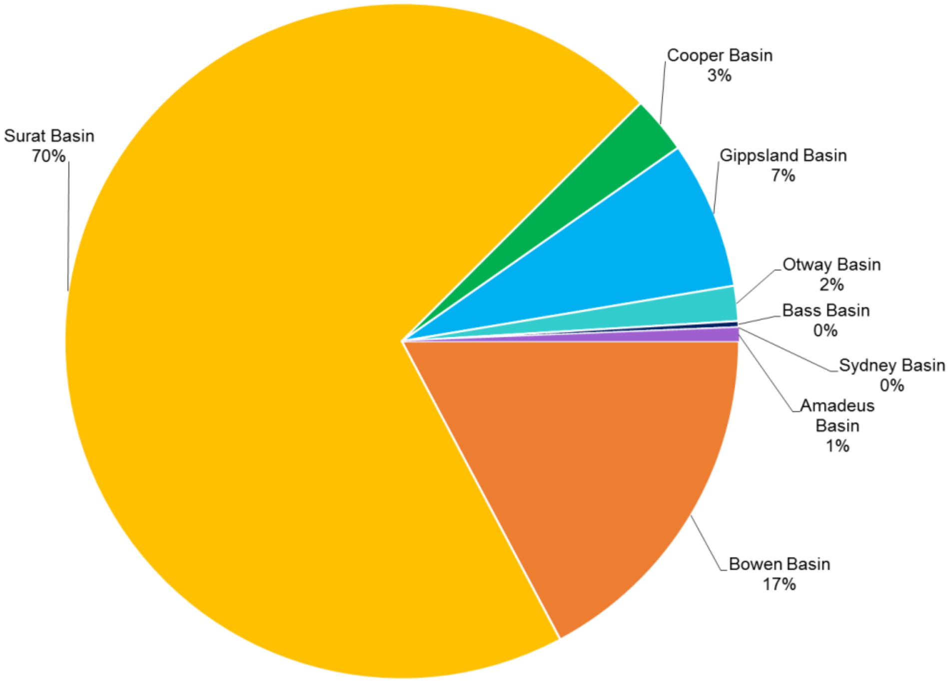
70 This reflects a price a producer would use, with other contracted and uncontracted gas prices, to calculate a weighted average price to book reserves.

71 ibid.

72 ACCC, *Gas Inquiry 2017-2020 Interim Report*, December 2018, p. 50.

As table 1.2 shows, there are currently 37 111 PJ of 2P reserves in the east coast and onshore Northern Territory, 48 per cent of which are classified as proved reserves and the remainder as probable reserves. The majority of these 2P reserves are located in CSG fields in Queensland, with 70 per cent of 2P reserves located in the Surat Basin and 17 per cent in the Bowen Basin (see chart 1.10). The remaining 2P reserves are located in offshore Victoria (nine per cent), the Cooper Basin (three per cent), the Amadeus Basin (0.6 per cent) and the Sydney Basin (0.02 per cent).

Chart 1.10: 2P reserves by basin (at 30 June 2019)



The downside risk and potential upside associated with these 2P reserve estimates, can be seen in the 1P and 3P reserves estimates, with:

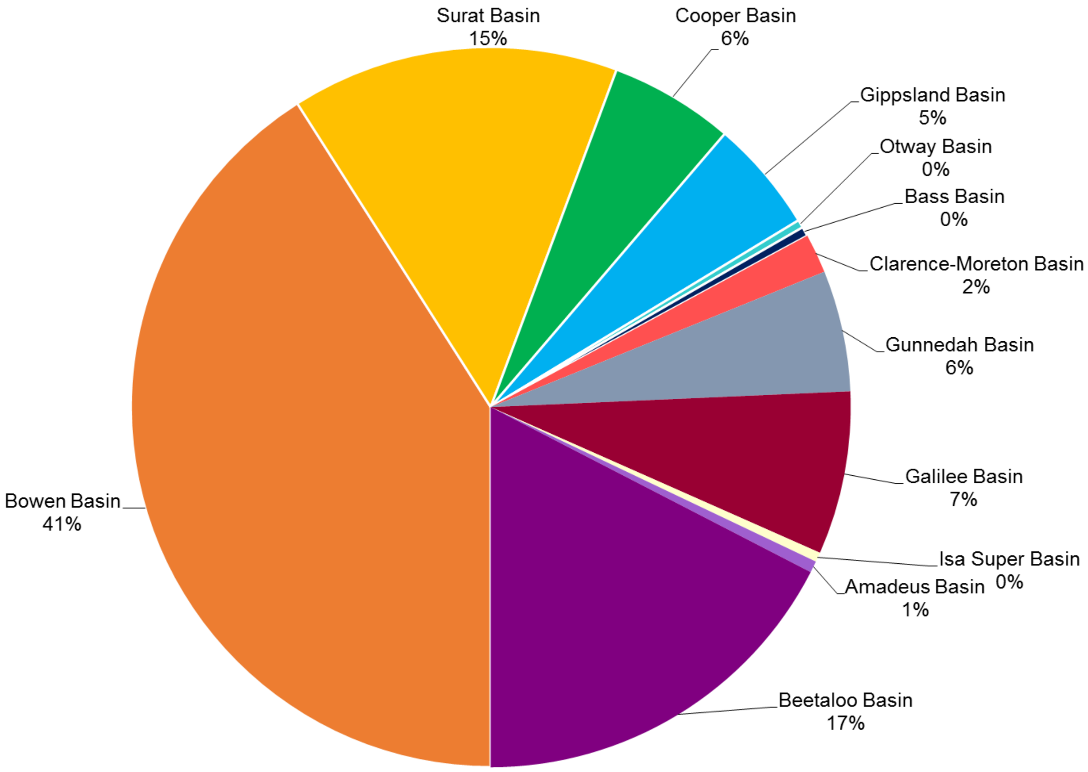
- 1P reserves being over 50 per cent lower than the 2P reserves estimate (17 972 PJ)
- 3P reserves being just 18 per cent higher than the 2P reserves estimate (43 879 PJ).

Put simply, the reserve estimates provided by producers suggest there is material downside risk (particularly in the Surat Basin where 1P reserves account for around 40 per cent of 2P reserves) to the 2P reserves estimates and limited upside potential at present.

In a similar manner to 2P reserves, the majority of the 37 887 PJ of 2C resources are located in Queensland, with 41 per cent located in the Bowen Basin, 15 per cent in the Surat Basin and 7 per cent in the Galilee Basin (see chart 1.11). The Beetaloo Basin in the Northern Territory also contains a significant quantity of 2C resources (17 per cent), as does the Gunnedah Basin in New South Wales (6 per cent). While CSG accounts for the majority of the 2C resources (64 per cent), other unconventional sources of gas (e.g. tight gas and shale gas) located primarily in the Bowen, Beetaloo and Cooper basins, are starting to account for an increasing proportion of 2C resources (24 per cent).

As noted in section 1.6, producers can face a range of technical challenges when developing CSG and other unconventional gas fields. A significant degree of uncertainty therefore surrounds whether these contingent resources will be commercially recoverable in the future. Some insight into this uncertainty can be found in the change in contingent resources that has occurred in the last 12 months. Over this period, 2C resources in the east coast fell by 2534 PJ (about 7.5 per cent), the majority of which were estimated to be in unconventional gas fields.

Chart 1.11: 2C resources by basin (at 30 June 2019)



1.9.3. Producers' holdings of reserves and resources

Chart 1.12 shows the proportion of 2P reserves and 2C resources held by producers in the east coast and onshore Northern Territory as at 30 June 2019.

As this chart shows, over 80 per cent of 2P reserves are currently held by LNG producers in Queensland, either through ownership or through gas purchases from other related entities. APLNG holds the greatest share (32 per cent), QGC holds the second highest share (19 per cent) and has also acquired the bulk of Arrow Energy's 2P reserves (16 per cent),[73] while Santos-GLNG controls the third highest share (16 per cent). Amongst the other producers, the GBJV accounts for the greatest proportion of 2P reserves (6 per cent), followed by Beach Energy (2.2 per cent), Westside (1.8 per cent), Senex (1.6 per cent) and a range of other small to mid-tier producers (i.e. AGL, Armour Energy, Blue Energy, Central Petroleum, Cooper Energy, Macquarie Mereenie, Mitsui, OG Energy, Stanwell and Tri-Star).

The story differs somewhat at a contingent resource level, with LNG producers currently holding around 47 per cent of 2C resources.[74] Other relatively large holders of 2C resources include Origin and Falcon Oil through their joint venture interests in the Beetaloo Basin (18 per cent), Galilee Energy through its interests in the Galilee Basin (8 per cent), Westside

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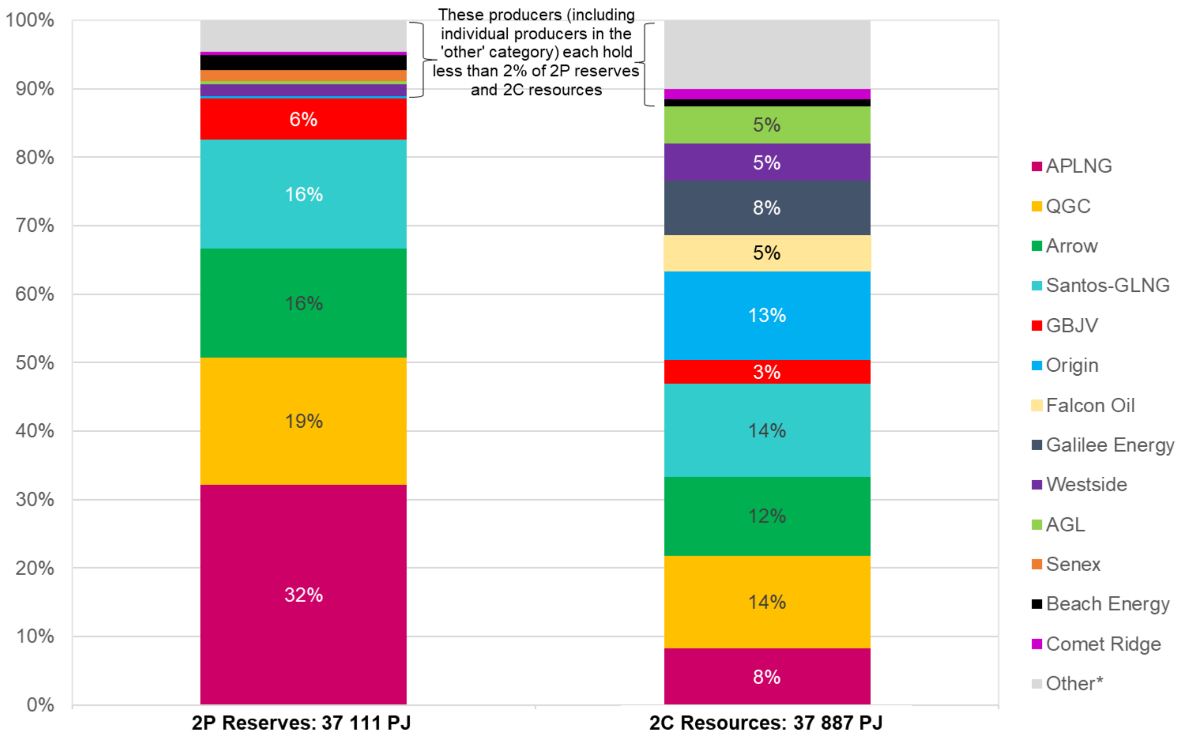
73 Arrow Energy is a joint venture between Shell and PetroChina. In December 2017, Arrow agreed to supply the QCLNG project (in which Shell is also a participant) with uncontracted gas from its Surat Basin fields for 27 years: https://www.arrowenergy.com.au/media-centre/latest-news/pages/2017/arrow-energy-agrees-deal-for-surat-basin-reserves.

74 Note the proportion of 2C resources controlled by LNG producers is lower than what was reported in the December 2018 report. The difference can largely be attributed to the inclusion in this report of the 2C resources in the Beetaloo Basin and other onshore basins in the Northern Territory, which were not included in the December 2018 report.

(5 per cent) and AGL (5 per cent) through their respective interests in the Bowen Basin. The remainder are held by a range of small to mid-tier explorers and producers.

Chart 1.12: 2P reserves and 2C resources held by producers (at 30 June 2019)



Source: ACCC analysis of data obtained from gas producers.

Notes:

1. Estimates of reserves and resources are based on net revenue interests.
2. Santos-GLNG's share of 2P reserves and 2C resources include Santos, Petronas, Kogas and Total's interests in the GLNG Joint Venture Project, as well as Santos's non-GLNG interests.
3. QGC's share of 2P reserves and 2C resources include Tokyo Gas and CNOOC's interests in the QCLNG project. APLNG's share of 2P reserves and 2C resources include Origin, ConocoPhillips and Sinopec.
4. GBJV's share of 2P reserves and 2C resources include ExxonMobil and BHP's interests in the Gippsland Basin, including their interests in the Kipper joint venture.
5. The 'other' category includes Armour Energy, BHP's Otway interests, Blue Energy, Central, Cooper Energy, Macquarie Mereenie, Mitsui, OG Energy, Prize Petroleum, Real Energy, SGH Energy, Stanwell, Strike, Tri-Star and Vintage Energy.

See also notes to table 1.2.

1.9.4. 2P reserves have continued to fall over the last 12 months

In our December 2018 report, we noted that 2P reserves had fallen by over 10 per cent (4994 PJ) in the 12 months to 30 June 2018.[75] To get a better understanding of the changes in 2P reserves that have occurred in the intervening period, producers were asked to provide information on the movement in their 2P reserves over the period 30 June 2018 and 30 June 2019 arising as a result of production, the extension of an existing field's proved area, reserves upgrades,[76] reserves downgrades[77] and other revisions.

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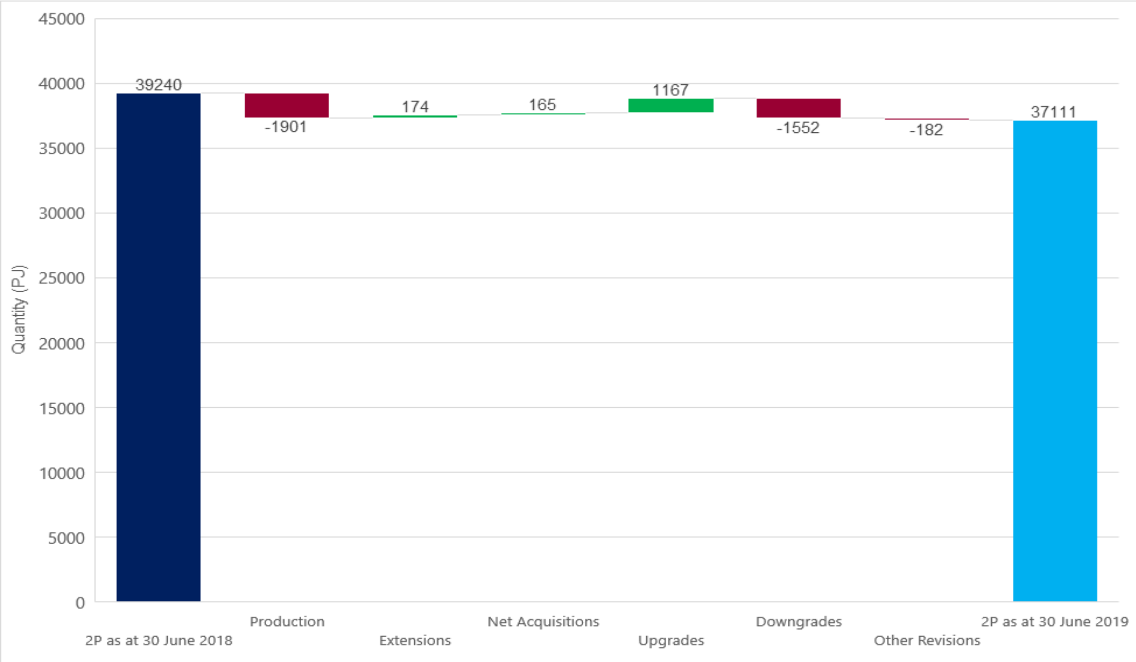
[75] ACCC, *Gas Inquiry 2017–2020 Interim Report*, December 2018, p. 52.

[76] The term 'reserves upgrade' is used in this context to refer to changes in 2P reserves resulting from the commercialisation of resources or the reclassification of 3P to 2P reserves.

The information provided by producers indicates that 2P reserves in the east coast and onshore Northern Territory fell by a further 5 per cent (2129 PJ) in the 12 months to 30 June 2019. As chart 1.13 shows, the decline can largely be attributed to the production (1901 PJ), reserves downgrades (1552 PJ) and other write-downs (182 PJ) that occurred in the last 12 months, which were not sufficiently offset by the additions from reserves upgrades (1167 PJ) and extensions of proved areas (174 PJ).

Chart 1.13: Changes in 2P reserves in the east coast and onshore Northern Territory, 30 June 2018 to 30 June 2019



Source: ACCC analysis of data obtained from producers.

Note: Totals may not add up due to rounding. See also notes to table 1.2.

The decline in 2P reserves that has occurred between 30 June 2017 and 30 June 2019 is a continuing concern to the ACCC, particularly given that most of the decline has occurred in Queensland, which the East Coast Gas Market has become increasingly reliant upon. Of particular concern is the reserves downgrade and other downward revisions that have occurred in Queensland over this period, with over 5700 PJ[78] of 2P reserves in the Bowen and Surat basins written down. While there have been some offsetting reserves upgrades in these basins over the same period, on a net basis 2P reserves have been downgraded by over 4400 PJ.[79]

This downgrade of reserves is, as EnergyQuest has previously observed,[80] at odds with the assumed progression of resources, which is that under the right market conditions contingent resources (or a portion thereof) become commercially viable to develop and are

77 The term 'reserves downgrade' is used in this context to refer to changes in 2P reserves resulting from the reclassification of 2P reserves to 3P reserves or contingent resources.

78 2P reserves in the Bowen and Surat basins were written down on a net basis (i.e. reserves downgrades less reserves upgrades) by 3819 PJ in 2017-18 (see ACCC, *Gas Inquiry 2017-2020 Interim Report*, December 2018, p. 52) and by a further 1910 PJ in 2018-19 (i.e. -1910 = -1300-158-141) See table 1.3.

79 As noted above, 2P reserves were written down on a net basis by 3819 PJ in 2017-18 (see ACCC, *Gas Inquiry 2017–2020 Interim Report*, December 2018, p. 52) and by a further 592 PJ in 2018-19 (i.e. -592= 228-158+356+733-1300-451). See table 1.3.

80 EnergyQuest, Energy Quarterly, March 2019, p. 14.

reclassified as reserves. The opposite, however, seems to be true in Queensland, with reserves that were previously found to be commercially viable to develop no longer being found to be so even though domestic gas prices have increased in the intervening period. This is concerning given it is occurring at a time when more, rather than less, reserves are required to meet projected demand.

Further detail on the changes in 2P reserves that have occurred in each basin in the east coast and onshore Northern Territory over the last 12 months can be found below.

Changes in 2P reserves by basin

Table 1.3 sets out the changes in 2P reserves that have occurred in each basin over the last 12 months and the sources of these changes.

Table 1.3: Changes in 2P reserves in the east coast and onshore Northern Territory by basin, 30 June 2018 to 30 June 2019 (PJ)

	2P at 30 Jun 2018	Produced	Extension	Net Acquisition	Reserves Upgrade	Reserves Downgrade	Other Revision	2P at 30 Jun 2019	% Chge
Bowen	6 299	-337	-	-	228	-158	356	6 388	1%
Surat	28 101	-1 079	-	98	733	-1 300	-451	26 101	-7%
Cooper	1 021	-98	45	-	91	-1	-39	1 020	-0.1%
Gippsland	2 905	-289	7	-	25	-4	-17	2 627	-10%
Otway	486	-66	122	68	22	-2	-8	622	28%
Bass	72	-14	-	-	66	-6	-8	110	53%
Sydney	13	-4	-	-	-	-	-	9	-30%
Clarence-Moreton	80	-	-	-	-	-80	-	-	-100%
Amadeus	262	-13	-	-	-	-	-14	235	-10%
Total	**39 240**	-1 901	174	165	1 167	-1 552	-182	37 111	-5.4%

Notes: Totals may not add up due to rounding.

As this table shows, 2P reserves fell in most basins over the last 12 months, with the only exceptions to this being:

- the Bass Basin where 2P reserves grew by 53 per cent over the period as a result of a reserves upgrade in the Trefoil field operated by Beach Energy[81]
- the Otway Basin where 2P reserves grew by 28 per cent over the period, primarily as a result of reserves upgrades and the extension of proved areas in a number of the onshore and offshore fields operated by Beach Energy[82] and reserves upgrades by Cooper Energy[83]

81 Beach Energy, *Annual Report 2019*, 19 August 2019, p. 34.

82 ibid, p. 18.

83 Cooper Energy, *Reserves and Resources as at 30 June 2019*, p.1.

- the Bowen and Cooper basins where 2P reserves were relatively flat over the period, because the production, reserves downgrades and other downward revisions that occurred in these basins was largely offset by reserves upgrades, extensions of proved areas and/or other upward revisions.

In contrast to these basins, 2P reserves fell in the:

- **Clarence-Moreton Basin**: All the 2P reserves in this basin have been reclassified as contingent resources in the last 12 months, with Arrow noting the absence of a project development plan at this time and the difficulties it has experienced carrying out appraisal and development activities given the close proximity of its interests in this basin to urban communities
- **Sydney Basin**: 2P reserves in this basin declined in line with production, which is consistent with AGL's plan to progressively decommission its assets in this basin from 2023[84]
- **Amadeus Basin**: 2P reserves in this basin fell by 10 per cent, as a result of both production and the downward revision to reserves arising as a result of the underperformance of the Palm Valley field operated by Central Petroleum[85]
- **Gippsland Basin**: 2P reserves in this basin also fell by 10 per cent, because the small addition to reserves was not sufficient to offset the higher level of production from this basin and the reserves downgrades and/or other downward revisions that occurred in the Sole field,[86] and other fields in the Gippsland Basin
- **Surat Basin**: 2P reserves in this basin fell by 7 per cent, because the additions to reserves were not sufficient to offset the production from this basin and the reserves downgrades and other downward revisions that occurred in other fields operated by Arrow, APLNG, QGC and Santos-GLNG.

Although the Surat Basin experienced the smallest percentage decline in 2P reserves over the last 12 months, on an energy basis it experienced the largest decline, with reserves in the basin falling by 2000 PJ. As table 1.3 shows, one of the key contributors to the decline was the 1751 PJ write-down[87] of 2P reserves arising as a result of reserves downgrades and other downward revisions. Over 75 per cent of this write-down occurred in Arrow's fields and while there were some offsetting reserves upgrades in other fields controlled by Arrow, in net terms its 2P reserves were written down by 747 PJ in the Surat Basin.[88] This write-down in the Surat Basin follows a 2933 PJ write-down of Arrow's 2P reserves in the Bowen Basin in 2018[89] and other write-downs of reserves and exploration assets by APLNG, Origin and QGC in the Surat Basin in 2017–18.[90] The remainder of the write-down in the Surat Basin occurred in the fields operated by APLNG, Santos-GLNG and QGC. APLNG also wrote down some of its 2P reserves in the Bowen Basin.

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84 AGL, *Review of gas assets and exit of gas exploration and production*, 4 February 2016.

85 Central Petroleum, *2019 Annual Report*, p. 3.

86 Cooper Energy, *Reserves and Resources as at 30 June 2019*, p. 3.

87 The term 'write-down' is used here to jointly refer to reserves downgrades and other downward revisions. As noted in box 1.2 the term 'reserves downgrades' refers to a reclassification of 2P reserves to either 3P reserves or contingent resources.

88 According to Arrow, the reclassification was primarily due to the prior 2014 reserves information being updated in 2018, which incorporated changes to the Surat Gas Project development concept, additional available data and differences in the geological modelling.

89 ACCC, *Gas Inquiry 2017-2020 Interim Report*, December 2018, p. 53.

90 The Australian, *Origin Energy writes off exploration costs at Queensland coal seam gas field*, 31 July 2018, Origin, Investor presentation, *2018 half-year results: half year ended 31 December 2017*, 15 February 2018, p. 17 and The Australian, *Shell's $390m asset write off casts doubt on CSG reserves*, 2 May 2017.

The extent of the write-down that has occurred in the Bowen and Surat basins over the last two years is significant and highlights some of the technical challenges producers can face when developing unconventional sources of gas and the uncertainty surrounding the long term performance of these fields. It is also possible that it reflects, as a number of smaller producers have suggested, decisions on the part of some LNG producers and their affiliates to 'bank' or 'warehouse' gas by delaying the development of some fields to meet their own commercial priorities.

One small producer in Queensland, for example, stated that it is "being prevented from developing its current modest reserves and resources due to the adjacent permit holder… not progressing their existing government approved…projects, for apparently global strategic reasons". Another small producer stated that one of the main barriers to the commercial recovery of its 2C resources is that its joint venture partner, which is a larger producer, is "not motivated to pursue a larger development".

There are, as these statements suggest, a number of reasons why larger producers may want to 'bank' or 'warehouse' gas. A larger producer may, for example, have access to sufficient reserves to meet its existing supply obligations but want to keep the resources as 'insurance' in case its other fields fail to perform in the manner expected in the future. Or it may be able to access cheaper gas to meet its supply obligations. A larger producer may also be subject to some form of internal resourcing or capital constraint, which means it has to prioritise the development of other projects (including international projects). It also raises questions as to whether the reason for the write downs may be because a larger producer is seeking to withhold supply to maintain or raise prices.

While there is no evidence at this stage that producers are seeking to withhold supply for this purpose, the ACCC is concerned that larger producers and LNG producers in particular may have the ability to delay the development of much needed new sources of supply to suit their commercial priorities at the expense of the domestic market. The ACCC intends therefore to closely monitor producers' development decisions over the remaining term of the inquiry and calls on parties who have made large write downs to provide clear and compelling reasons for those write downs.

1.9.5. The long term security of supply in the east coast is becoming increasingly dependent on more speculative sources of supply

With 2P reserves declining in a number of basins, the long term security of supply in the east coast is becoming increasingly dependent on the development of undeveloped reserves, contingent resources and/or LNG import terminals (see sections 1.6–1.8). It is also becoming increasingly dependent on CSG and other unconventional sources of supply (see table 1.2), which as noted above face their own technical challenges. It is relevant therefore to consider the development status of the reserves and resources in the east coast and onshore Northern Territory and other barriers that may affect the recovery of reserves and resources.

Development status of reserves and resources

Table 1.4 provides a summary of the information that producers provided on the development status of their reserves and resources.

Table 1.4: Reserves and resource in the east coast and onshore Northern Territory by stage of development, as at 30 June 2019 (PJ)

		Reserves			Contingent Resources
		1P	**2P**	**3P**	**2C**
Developed Reserves		13 106	16 255	17 101	n.a.
Undeveloped Reserves and Resources	Field in production	4 511	15 073	17 760	9 096
	Approved for development	244	1 164	1 364	530
	Other	111	4 619	7 654	28 261
Total		**17 972**	**37 111**	**43 879**	**37 887**
Developed % of Total		*73%*	*44%*	*39%*	*0%*
Undeveloped % of Total		*27%*	*56%*	*61%*	*100%*

Source: ACCC analysis of data obtained from gas producers.

Note: Totals may not add up due to rounding.

As table 1.4 shows, over half of the 2P reserves (56 per cent) are currently undeveloped. In contrast to developed reserves, where gas is expected to be recovered from existing wells and facilities, further investment will be required to recover these undeveloped reserves. Having said that, a significant portion of these undeveloped reserves (78 per cent) are located in fields that are either in production or approved for development.

This means that producers have all the necessary approvals and have already made, or have committed to making, the investment in infrastructure required for production with development ready to begin or already under way. There is therefore a greater likelihood that gas from these fields will be produced in the medium term than there is for gas in fields that are not yet in production or not yet approved for development. That is not to say there is no risk associated with the development of these reserves; it is just that the hurdles to developing reserves in fields that are either in production or approved for development reserves should be lower.

In contrast to 2P reserves, the majority of 2C resources (75 per cent) are located in gas fields that are not yet in production or approved for development. The majority of these resources are located in CSG and unconventional gas fields in the Bowen, Beetaloo, Galilee and Gunnedah basins, which face a range of technical, commercial and regulatory barriers. It is therefore likely to be some time before these resources are considered commercially recoverable and capable of being supplied into the East Coast Gas Market, if at all. Further detail on the barriers these projects may face is provided below.

Barriers to the commercial recovery of 2C resources

Contingent resources are those quantities of gas that are potentially recoverable but not yet commercial to develop. Some of the barriers to the commercial recovery of 2C resources that producers cited in their responses to the ACCC include:

(a) geological factors, such as the permeability, depth, and tightness of the reservoir and the level of impurities in the reservoir

(b) commercial factors, such as the relatively high development costs and access to the capital required to carry out appraisal activities and to develop the resources

(c) access to the infrastructure required to bring the gas to market (e.g. processing facilities and pipelines), which must either be developed as part of the project, or in those cases where there is existing infrastructure located in close proximity to the field, may be negotiated with the operators of these facilities

(d) land access, Indigenous Land Use Agreements, regulatory and environmental approvals.

Of the barriers listed above, the geological factors listed in (a) were the most commonly cited barrier by producers with 2C resources in CSG and other unconventional gas fields. A number of producers in the Bowen and Surat basins, for example, cited the difficulties associated with demonstrating commercial flow rates from deep, tight and/or low permeability coals using existing techniques.

Assuming these geological hurdles and the other barriers outlined in (b)-(d) can be overcome, which is a significant assumption, the development of these contingent resources is likely to take some time and to require significant investment by producers.

Further investment in pipeline capacity will also be required to bring gas from some of the new sources of supply (e.g. the Bowen, Galilee, Gunnedah and Beetaloo basins to market). While we understand that preliminary work is already underway on the development of pipeline routes for some projects (see section 4.3.1), there is a risk that if a more coordinated approach to the development (in terms of the pipeline route and size) and use of these pipelines is not taken, then the most efficient pipeline will not be developed. A lack of coordination could, for example, result in:

- duplication of pipelines (e.g. because the size and/or route of the pipeline that is developed does not reflect all the potential demand in the area), or
- the selection of a pipeline route that prioritises linking new sources of supply to the pipeline operator's existing assets, rather than the most efficient route.

The inefficient development of these pipelines could adversely affect the commercial viability of developing some of the resources in these basins and, in so doing, limit the volume of gas supplied from these areas. They could also adversely affect end users of gas if the higher transportation charges are passed through to users.

The ACCC therefore considers there is a role for state and territory governments to coordinate the development of pipelines that are required to bring new sources of supply to market, where it is feasible to do so. The ACCC also encourages governments to consider requiring these pipelines to be:

- developed through a competitive process using, for example, the competitive tender provisions in the National Gas Rules[91], and
- operated on a third party access basis (i.e. so all producers in the region have an opportunity to use the asset, which will reduce the unit cost of transporting gas).

Apart from minimising the cost of transporting gas from these new sources of supply, these measures should also encourage efficient investment and use of gas and gas pipelines, and reduce the barrier that the construction of pipeline infrastructure may otherwise pose to the development of new sources of supply.

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[91] The competitive tender provisions in the National Gas Rules allow the proponents of new pipelines (e.g. prospective users or government bodies) to apply to the Australian Energy Regulator to have a proposed tender approved as a competitive tender process. If the tender is approved, the price and non-price terms and conditions established through the competitive process can be locked in for the period specified in the tender and made available to other users.

1.9.6. Active tenement management and greater oversight of producers will be required to ensure gas is brought to market in a timely manner

As production from developed reserves declines and greater reliance is placed on undeveloped reserves and contingent resources being developed in a timely manner, it will be increasingly important for governments to actively monitor producers' compliance with their permits[92] and be prepared to take action for noncompliance where appropriate.

Where it is feasible to do so, governments should also consider using other measures to:

- encourage producers to bring gas to market in a timely manner (for example, by issuing exploration permits for shorter terms and/or requiring production to commence within a shorter period of time than the maximum time in regulations)
- discourage larger producers from 'banking' or 'warehousing' gas (for example, by requiring permits to be relinquished if these producers do not comply with approved development/work programs and/or by not granting new tenements to producers that already control significant volumes of undeveloped reserves and resources), and
- encourage greater diversity of suppliers (for example, by granting new tenements to small to mid-tier producers and explorers).

The ACCC understands that the Queensland Department of Natural Resources, Mines and Energy (DNRME) has taken a number of steps in this regard [93] and encourages other governments to consider implementing similar measures.

We also continue to encourage state and territory governments to adopt policies that consider and manage the risks of individual gas development projects, rather than implementing blanket moratoria and regulatory restrictions.

For its part, the ACCC will continue to actively monitor the behaviour of producers in terms of bringing gas to market, as well as monitoring the level of concentration in tenement holdings and on the supply side of the market more generally.

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92 The term 'permit' is used in this context to jointly refer to permits, authorities and licences and any other variants that governments use to enable producers to undertake exploration, appraisal and production activities.

93 The DNRME has, for example:

- required production in some of the tenements that have been awarded through the domestic gas supply program to commence within a relatively short period of time
- issued potential commercial areas for shorter periods of time than the maximum 15 year term specified in legislation.

2. Domestic price outlook for 2020

2.1. Key points

- Over the course of 2019, prices offered by gas producers for 2020 supply largely remained steady within the range of $9–10/GJ, while prices offered by retailers to C&I users in the Southern States were in the $8–12/GJ range, constituting a slight downward shift in prices between March and August 2019.
- After reaching a peak of almost $11/GJ in October 2018, expected 2020 LNG netback prices at Wallumbilla trended downwards over the course of 2019 and by the end of August were around $7.50/GJ.
- Over the 12 month period to April 2019, the averages of producer price offers in Queensland were broadly in line with expected 2020 LNG netback prices. Since May 2019, however, falling expected 2020 LNG netback prices have not been reflected in the averages of producer prices offered in Queensland. By August 2019 producer price offers were almost 25 per cent above expected 2020 LNG netback prices. In some instances, this reflects the addition of a fixed price component by some LNG producers, on top of a JKM-linked component that is equivalent or close to LNG netback prices.
  - Understanding the disparity between the averages of domestic prices offered in Queensland and expected LNG netback prices is a priority for the ACCC over the course of the inquiry. This is particularly so in light of recent reports that APLNG is seeking to sell an additional six to 12 LNG cargoes in 2020 through a short-term LNG contract.
  - The ACCC intends to undertake further work on factors that influence domestic contract gas prices.
- The averages of prices offered by producers and retailers in the Southern States over 2019 were also above expected 2020 LNG netback prices, sitting in line with the Victorian buyer alternative in some months, with producer price offers increasing over the second quarter of 2019. Offered prices in the Southern States may be reflective of the tight supply-demand balance in the Southern States.
- Analysis of average prices in GSAs executed over six month intervals, from the second half of 2016 to the end of June 2019, shows that the averages of prices agreed by C&I users under GSAs increased in the second half of 2018 and the first half of 2019. The average of prices observed in the first quarter of 2019 were in line with those observed in 2017.
- The average of prices for 2020 expected to be paid under GSAs entered into between 1 January 2018 and 22 August 2019 are:
  - $8.52/GJ by all buyers to producers in Queensland
  - $9.73/GJ by all buyers to producers in the Southern States
  - $10.33/GJ by C&I gas users to retailers in Queensland
  - $10.68/GJ by C&I gas users to retailers in the Southern States.
- The average level of flexibility in GSAs, in the form of take or pay multiplier and load factor, has decreased since the ACCC last reported in July 2019.
- Prices in the facilitated gas markets across the East Coast Gas Market trended down over the course of 2019. There has also been a reduction in futures trading on the Victorian Declared Wholesale Gas Market since the ACCC's July report.

2.2. Introduction

This chapter presents information about wholesale gas prices in the East Coast Gas Market. Box 2.1 sets out the key parameters relevant to the analysis in this chapter. The ACCC's approach to price reporting in relation to particular areas is set out in further detail as relevant below.

Box 2.1: Parameters of reported prices

Unless specified otherwise, the following applies to the analysis of gas supply agreements (GSAs) and offers and bids in this chapter.

- The prices reported are wholesale gas commodity prices and do not include separate charges for transporting gas to the user's location or other ancillary charges (although delivery charges may, in some cases, be bundled with commodity gas prices). The prices charged for transportation have been excluded from the analysis to enable a more direct comparison between the prices paid by buyers in different locations and with differing transportation requirements.
- Only arm's length transactions are included. Related party transactions are excluded to ensure that the prices reported are reflective of market conditions.
- Only those transactions with a term of at least one year and an annual contract quantity of at least 0.5 PJ are included.
- Where average prices are reported, these are quantity-weighted average prices.
- The following entities were classified as 'retailers': Origin Energy, AGL, EnergyAustralia, Alinta Energy, Shell Energy Australia and Macquarie Bank.[94]
- The prices of individual transactions are not necessarily directly comparable due to differences in non-price aspects such as flexibility, quantity, contract term and delivery point. These non-price terms and the flexibility they can provide may be valued differently depending on the customer and may influence the gas prices that are ultimately agreed. The ACCC has not sought to adjust for these factors in the analysis presented in this chapter.

Gas suppliers in the Northern Territory have commenced supplying gas into the East Coast Gas Market via the Northern Gas Pipeline (NGP) (see Chapter 1). We have included Northern Territory suppliers' prices in the analysis in this chapter only where gas is delivered into the East Coast Gas Market. Due to the relatively high transport cost component involved in delivering Northern Territory gas to the East Coast Gas Market, it is less meaningful to compare prices for gas that is delivered to an east coast customer in the Northern Territory.

2.3. Prices offered for gas supply by retailers for 2020 have softened slightly in 2019

This report marks the third time we have reported on offers made and bids received by suppliers in the East Coast Gas Market for gas supply in 2020. We extend our previous coverage with the addition of information on offers made and bids received by gas suppliers between 25 April 2019 and 22 August 2019.

Box 2.2 below sets out the ACCC's approach to reporting on offers and bids.

[94] See Glossary for further details.

Box 2.2: Approach to reporting on offers and bids

The information in this box should be read in conjunction with the information in box 2.1. The following also applies to the analysis of offers and bids in this section:

- The analysis only includes those offers and bids that contain clear indications of price, quantity, and supply start and end dates.
- The commodity gas price for each offer and bid has been estimated using the pricing mechanisms specified in each offer or bid along with assumptions relating to key variables (for example, oil and LNG prices, foreign exchange rates and inflation) based on the expectations for those variables at the time of the offer or bid.[95]
- Some producer and retailer offers specify a pricing mechanism linked to Brent crude oil prices. We calculated an indicative price in such offers using the following approach:
  - For each day in the month in which an offer was made, we calculated the expected price of Brent crude oil for the year of supply (for example, 2020) by taking a simple average of Brent crude oil prices expected in each month of that year.
  - We then averaged these daily estimates to derive a monthly estimate for the year of supply.
  - We then applied this monthly estimate to the pricing mechanism specified in the offer to arrive at an indicative price.
- A similar approach was used to calculate an indicative price for offers and bids that specify a pricing mechanism linked to JKM (LNG) prices.

Analysis of offer and bid pricing throughout this chapter is intended to provide an indication of price trends over time. As explained in box 2.1, the prices of individual offers and bids are not necessarily comparable as they can differ in non-price aspects. 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 gas powered electricity generation (GPG), conditions in the electricity market.

Since September 2017, the Queensland Government has awarded a number of tenements to gas suppliers that have domestic supply conditions, including one tenement with a condition to supply domestic manufacturers only. For the purpose of the analysis in this report, the ACCC has:

- included offers and bids for gas produced in tenements with domestic supply conditions (as these conditions permit the sale of gas to retailers)
- excluded those from the sole tenement that requires gas to be supplied to domestic manufacturers, because prices observed in these offers and bids may not be comparable to other prices in the East Coast given the limited number of potential purchasers of this

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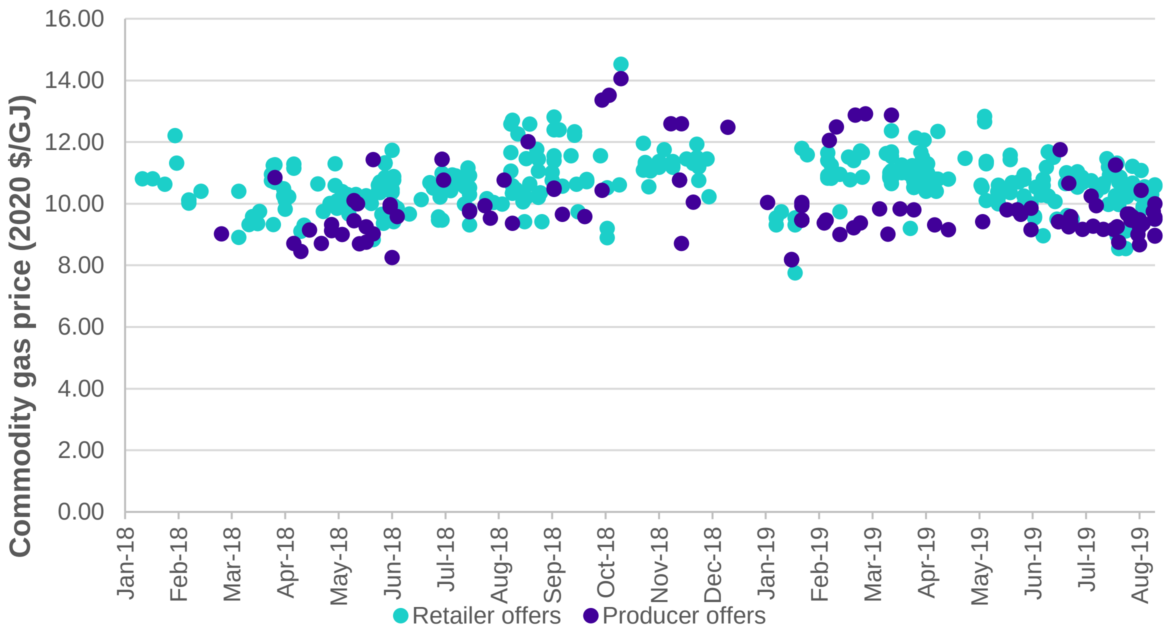
[95] In all estimates of offer and bid prices in this report, the following assumptions were made, where relevant:

- The expected AUD/USD exchange rate is equal to the average rate prevailing during the month in which the offer or bid occurred (source: RBA).
- The expected Brent crude oil price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: Bloomberg).
- The expected Japanese Customs Cleared (JCC) crude oil price is derived using the expected Brent crude oil price as a proxy.
- The expected Japan Korea Marker (JKM) LNG price is equal to the average price of futures contracts traded during the month in which the offer or bid occurred (source: ICE).
- The applicable CPI is based on actual CPI where available at the time the bid or offer occurred (up to the most recent available quarter, source: ABS), and 2.5 per cent thereafter.

gas. We note that these prices appear to be towards the lower end of the range of prices presented in this chapter.

Chart 2.1 below shows the gas commodity prices included in offers made by producers and retailers for supply in 2020 over the period from 1 January 2018 to 22 August 2019. Not all price offers in the chart (and those discussed in this section) are for unique combinations of seller and buyer, and some offers may reflect follow-up offers that were made from the same supplier to the same buyer after a previous offer did not result in a GSA. The chart is intended to give an indication of how the level of prices offered for gas supply in 2020 has evolved since January 2018.

Chart 2.1: Gas commodity prices offered for 2020 supply in the East Coast Gas Market



Source: ACCC analysis of offer information provided by suppliers.

Note: Prices are for gas commodity only. Actual prices paid by users may also include transport and retail cost components. All offers are for quantities of at least 0.5 PJ per annum and a term of at least 12 months.

Chart 2.1 shows that throughout 2018, there was a slight upward trend in prices offered by producers, with most offers concentrated in the $8–12/GJ range. Since January 2019, however, the range of prices offered by producers has narrowed, with the majority of producer offers falling between $9/GJ and $10/GJ. While there were a small number of offers above $10/GJ in 2019, the majority of these had pricing that was linked to Brent crude oil prices. A fall in Brent crude oil futures has resulted in reduced offer prices for offers linked to oil prices when compared to similar oil linked offer prices seen in early 2019.[96]

Throughout 2018, prices offered by retailers also increased moderately, falling largely within the range of $9–$13/GJ, before appearing to stabilise in the early months of 2019 (with most offers in the range of $10–12/GJ). Chart 2.1 shows that, from May to August 2019, there was a slight downward movement in prices offered by retailers for supply in 2020. While the majority of offers remained in the $10–12/GJ range, an increasing number of offers were made in the $8/GJ to $10/GJ range. This slight reduction in offer prices was observed in the

[96] Average future Brent crude oil prices for 2020 fell by just over 10 per cent between April and August 2019.

offers made by all retailers, as opposed to being the result of a single retailer reducing its offer prices.

This also coincided with a change in the composition of retailer price offers. In the period January 2019 to April 2019, the total number of retailer offers were disproportionately distributed among retailers, with a small number of retailers making the majority of retailer offers. Conversely, from April to August 2019, the total number of retailer offers was more evenly distributed among all retailers.

The ACCC's July 2019 report noted that there was a divergence between retailer and producer offers in the early part of 2019.[97] Chart 2.1 shows that in the months leading up to August 2019, the difference between offer prices from producers and retailers has narrowed, primarily due to lower retailer offer prices.

Table 2.1 presents analysis of recent offers made and bids received by gas producers for gas supply to all buyers in 2020. The table compares the offers made and bids received over three periods:

- 1 January 2018 to 23 January 2019 (period 1)
- 24 January 2019 to 24 April 2019 (period 2)
- 25 April 2019 to 22 August 2019 (period 3).[98]

97 ACCC, Gas Inquiry 2017-20 Interim Report, July 2019, p. 47.

98 Period 1 covers 'recent offers and bids' we reported in the April 2019 report, period 2 relates to information presented in the July 2019 report and period 3 covers offers and bids we have received since.

Table 2.1: Recent offers made and bids received by producers for gas supply in 2020 (all buyers) [99]

Period 1: 1 January 2018 to 23 January 2019	Offers	Bids
Number of offers or bids	49	76
Gas commodity price range ($/GJ)	8.18–14.05	6.29–11.30
Quantity weighted average gas commodity price ($/GJ)	10.46	9.06
Period 2: 24 January 2019 to 24 April 2019	**Offers**	**Bids**
Number of offers or bids	21	46
Gas commodity price range ($/GJ)	9.00–12.91	8.00–12.59
Quantity weighted average gas commodity price ($/GJ)	10.44	9.54
Period 3: 25 April 2019 to 22 August 2019	**Offers**	**Bids**
Number of offers or bids	43	31
Gas commodity price range ($/GJ)	8.67–11.75	7.50–10.69
Quantity weighted average gas commodity price ($/GJ)	9.60	9.19

Source (periods 1 & 2): ACCC, Gas Inquiry 2017–2020 Interim Report, July 2019, table 2.1, and additional information received after the publication of that report.

Source (period 3): ACCC analysis of offer and bid information provided by suppliers.

Table 2.1 shows that the average of prices offered by producers in period 3 (120 days) was $0.84/GJ lower than in period 2 (91 days). Similarly, the average bid price received by producers in period 3 was $0.35/GJ lower than in period 2.

Offers made by producers in period 3 for gas supply in 2020 were on average $0.41/GJ higher than bids received by producers. This premium is to be expected, given that offers made by suppliers are typically priced higher than bids made by buyers. However, this difference has decreased from period 2, where on average offers made by producers were $0.90/GJ higher than bids received.

The average prices offered in both periods 2 and 3 were below those in period 1 (which covered all of 2018 and part of January 2019). For example, the average price offered by producers in period 3 was $0.86/GJ lower than in period 1. The average bid prices received in periods 2 and 3 were higher than in period 1, with the period 3 average being $0.13/GJ higher than the period 1 average.

Table 2.2 presents analysis of offers made and bids received by retailers for gas supply in 2020. The data in this table are limited to offers made to, and bids received from C&I gas users in the same periods as table 2.1.

99 Some gas supply agreements reflect higher per GJ pricing in the table due to highly flexible delivery terms or being significantly weighted to the winter months, when domestic demand is higher. It is this flexibility or bespoke load profile that contributes to the overall contract price, making it not directly comparable to other contracts.

Table 2.2: Recent offers made and bids received by retailers for gas supply in 2020 C&I gas users

Period 1: 1 January 2018 to 23 January 2019	Offers	Bids
Number of offers or bids	159	11
Gas commodity price range ($/GJ)	8.83–14.52	6.80–12.40
Quantity weighted average gas commodity price ($/GJ)	10.63	8.87
Period 2: 24 January 2019 to 24 April 2019	**Offers**	**Bids**
Number of offers or bids	73	<5
Gas commodity price range ($/GJ)	7.75–12.36	7.08–10.82
Quantity weighted average gas commodity price ($/GJ)	11.07	10.01
Period 3: 25 April 2019 to 22 August 2019	**Offers**	**Bids**
Number of offers or bids	84	15
Gas commodity price range ($/GJ)	8.54–12.83	7.57–10.70
Quantity weighted average gas commodity price ($/GJ)	10.49	9.32

Source (periods 1 & 2): ACCC, *Gas Inquiry 2017–2020 Interim Report*, July 2019, table 2.2.

Source (period 3): ACCC analysis of offer and bid information provided by suppliers.

Table 2.2 shows that offers made by retailers and bids received by retailers from C&I gas users were on average less expensive in period 3 than in period 2. On average, offers made by retailers were $0.58/GJ lower and bids received by retailers were $0.69/GJ lower.

Offers made by retailers for gas supply in 2020 were on average $1.17/GJ higher than bids received by retailers in period 3. This is a small increase on the bid/offer difference observed in period 2 of $1.06/GJ.

Average prices offered in period 3 were marginally lower than those in period 1, whereas the average prices bid in period 3 were $0.45/GJ higher than in period 1.

2.4. Prices offered for gas supply in 2020 are higher than contemporaneous LNG netback price expectations and production costs

This section compares prices offered for 2020 supply in the East Coast Gas Market in each month between January 2018 and August 2019 with:

- expectations of 2020 LNG netback prices at the time the offer was made, based on market expectations (at the time the offer was made) of Asian LNG spot prices over the course of 2020 (see box 2.3) [100]

[100] Where the phrase ‘expected LNG netback prices’ or similar phrases are used in this report, we refer to LNG netback prices calculated on the basis of Asian spot LNG futures prices, which represent LNG futures market participants’ collective expectations of Asian spot LNG prices for given futures contract months. The ‘expected LNG netback prices’ shown in this report do not represent an ACCC forecast of international or domestic gas prices.

- the estimated cost of gas production, which is based on the estimated breakeven gas price of the marginal supplier of gas, in the relevant region, for 2020 (see box 2.4).

Information obtained by the ACCC from gas producers in the east coast indicates that they are unlikely to use expected future LNG spot prices to assess prices in domestic contracts with a term beyond three years. In part, this is due to the volatility in Asian LNG markets (see section 2.4.1 below), and the fact that LNG spot futures markets have little to no liquidity beyond a few years into the future.

On this basis, the ACCC has included in the analysis for this section only those offers that relate to contracts with a term between one and three years. Offers that specify pricing mechanisms linked to oil prices have also been excluded from this analysis, as expectations around future oil and LNG prices can be markedly different.

Sections 2.4.2 and 2.4.3 present the findings of our comparison for prices offered in Queensland and the Southern States for supply in 2020.

Box 2.3: LNG netback prices used for comparison

The ACCC has used LNG netback prices based on Asian LNG spot prices to compare against prices offered in the East Coast Gas Market. Asian LNG spot markets provide an alternative for LNG producers to selling gas in the domestic market. As such, Asian LNG spot prices are likely to influence domestic gas prices under current market conditions. While LNG netback prices currently play an important role in the east coast market, they are not the sole factor influencing domestic prices. The gas prices received by producers will also depend on the location of the gas fields, the marginal cost of supply, the buyer's maximum willingness to pay and the demand-supply balance, the importance of which will differ over time.

To calculate an LNG netback price to compare against offers for future supply, we have:

- calculated a forward-looking LNG netback price as at the date of the offer—based on market expectations of future LNG spot prices during the period of supply—as this gives the best indication of the likely opportunity cost of supplying gas to the domestic market[101]
- used short-run incremental costs of LNG production and transport, since LNG producers are making decisions about the sale of excess gas over the short-run.

We have calculated LNG netback prices using the method and assumptions used for the LNG netback price series, which is regularly published on the ACCC's website, and which is described in detail in the ACCC's Guide to the LNG netback price series.[102]

The domestic offers analysed in this section are all for gas supply over the entire calendar year. Therefore, for the purpose of comparison, we calculated an average 2020 LNG netback price that an LNG exporter would expect to receive to be indifferent between selling the gas to the domestic buyer over the entirety of 2020, and selling cargoes on the Asian LNG spot market in 2020.

For example, the ACCC calculated the average of LNG netback prices for 2020 that an LNG producer would have expected in July 2019 as follows:

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[101] For this, the ACCC has used futures prices of the Japan Korea Marker (JKM) quoted by the Intercontinental Exchange (ICE).

[102] ACCC, Guide to the LNG netback prices series, https://www.accc.gov.au/system/files/Guide%20to%20the%20LNG%20netback%20price%20series%20-%20October%202018.pdf.

- The ACCC obtained JKM futures prices for each month of 2020 that were quoted by ICE on each day during July 2019.
- The ACCC converted the monthly 2020 JKM futures prices into LNG netback prices at Wallumbilla by:
  - converting the prices from US$/MMBtu into A$/GJ using contemporaneous exchange rates and a conversion factor between MMBtu and GJ, and
  - subtracting the short-run marginal costs of shipping, liquefaction[103] and transportation.[104]
- The ACCC averaged these monthly LNG netback prices to arrive at an average of LNG netback prices for 2020 expected on each day during July 2019.
- The ACCC then averaged these 2020 expectations for each day of July 2019 to arrive at an average of LNG netback prices for 2020 expected during the month of July 2019.

Capital costs and the LNG netback price

The ACCC's approach to calculating LNG netback prices does not involve deducting the capital costs of building the Queensland LNG export facilities. This is because these costs are sunk and do not influence the decisions of LNG producers, at the margin, to supply excess gas to the domestic or export markets.

However, this does not mean that domestic C&I users are necessarily paying these capital costs. LNG spot prices are determined by short-run LNG market dynamics, such as LNG supply, the level of competition, as well as demand and the ability for buyers to switch to alternative fuel sources (such as coal). These short-run dynamics are influenced by short-run supply, which in turn is determined by short-run incremental costs for the marginal supplier of LNG to spot markets (which are not influenced by the capital costs of building LNG export facilities). In the short-run, LNG suppliers with excess gas would be willing to liquefy and supply this gas to LNG spot markets provided spot prices were higher than their incremental costs, regardless of whether it would allow them to recover apportioned capital costs for that LNG.[105] In other words, unlike long-term LNG contract prices, LNG spot price formation is not influenced by LNG plant capital costs.

There may be times, however, where LNG spot prices would be sufficiently high to allow LNG producers to recover apportioned capital costs (for their relevant LNG facility). There are also likely to be periods in which the opposite would be the case. Historically low spot prices in recent months, which have been well below prices payable for LNG under long-term contracts, may not allow for recovery of capital costs. By some estimates, the long-run costs of the Queensland LNG projects are above USD$10/MMBtu, well above current LNG spot prices.[106]

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103 We estimated the incremental costs of liquefaction and fuel used in the operation of the LNG trains based on data obtained from LNG producers in Queensland.

104 We estimated incremental costs of transporting gas from Wallumbilla to the LNG trains based on the data from LNG producers.

105 Productivity Commission 2015, Examining Barriers to More Efficient Gas Markets, Commission Research Paper, Canberra.

106 Ferrier Hodgson, *National Resources Insights*, 2017

Box 2.4 Cost of production used in this section

In 2018, the ACCC engaged Core Energy (Core) to develop detailed estimates of the gas production costs facing producers in the East Coast Gas Market.[107] For individual supply regions across the east coast, Core estimated both full lifecycle costs of production and forward costs of production for 2P reserves as at 31 December 2017.

The analysis in this section compares price offers for 2020 supply with estimates of forward production costs, since over the short-term producers are likely to continue producing gas as long as they expect to recover their operating costs.

Core Energy's report on gas production costs estimated the costs of production for a range of areas. The ACCC has chosen to use the estimated forward costs for the marginal source of supply in Queensland and Victoria, as this would likely set the price floor in negotiations between gas suppliers and buyers in those states.

For Queensland, the ACCC chose the Middle Surat and Roma Shelf supply region as it has material uncontracted 2P reserves (9260 PJ) that Core expected to be in production in 2020 and that Core estimated to have the highest forward cost ($5.55/GJ).

The choice of the marginal supplier in Victoria is more complicated. Based on the bargaining framework set out in box 2.5 below, the marginal supplier in Victoria comes into the analysis in the circumstances where substantially more gas is produced in the Southern States than there is demand in the Southern States (such that the prices start to trend towards the seller alternative). In those circumstances, the production costs of the marginal supplier in the Southern States would set the floor in pricing negotiations. It is likely that additional production from new sources would be required for the Southern States to reach such a state. In those circumstances, the new source of supply would likely be the marginal supplier.

It is difficult to predict what the new source of supply would be or what the forward production cost of the marginal supplier is likely to be. For the purpose of the analysis in this chapter, the ACCC has chosen the Sole gas field as a proxy for the costs of a new marginal supplier. The Sole field is a new source of production in the south and its costs are therefore indicative of the likely costs of a new supplier. According to Core's estimates, Sole had 249 PJ of 2P reserves with an estimated forward production cost of $5.60/GJ as at 31 December 2017.[108]

2.4.1. LNG netback price expectations for 2020 have trended down over 2019

Over the period from September 2017 to August 2019, Asian LNG spot prices exhibited significant volatility. This volatility was also seen in the futures market for Asian LNG, which has resulted in significant variability in expectations of future LNG netback prices.

Chart 2.2 shows the fluctuations in expected LNG netback prices at Wallumbilla for 2020, based on Asian LNG spot prices, in the period between 29 September 2017 and the end of August 2019.

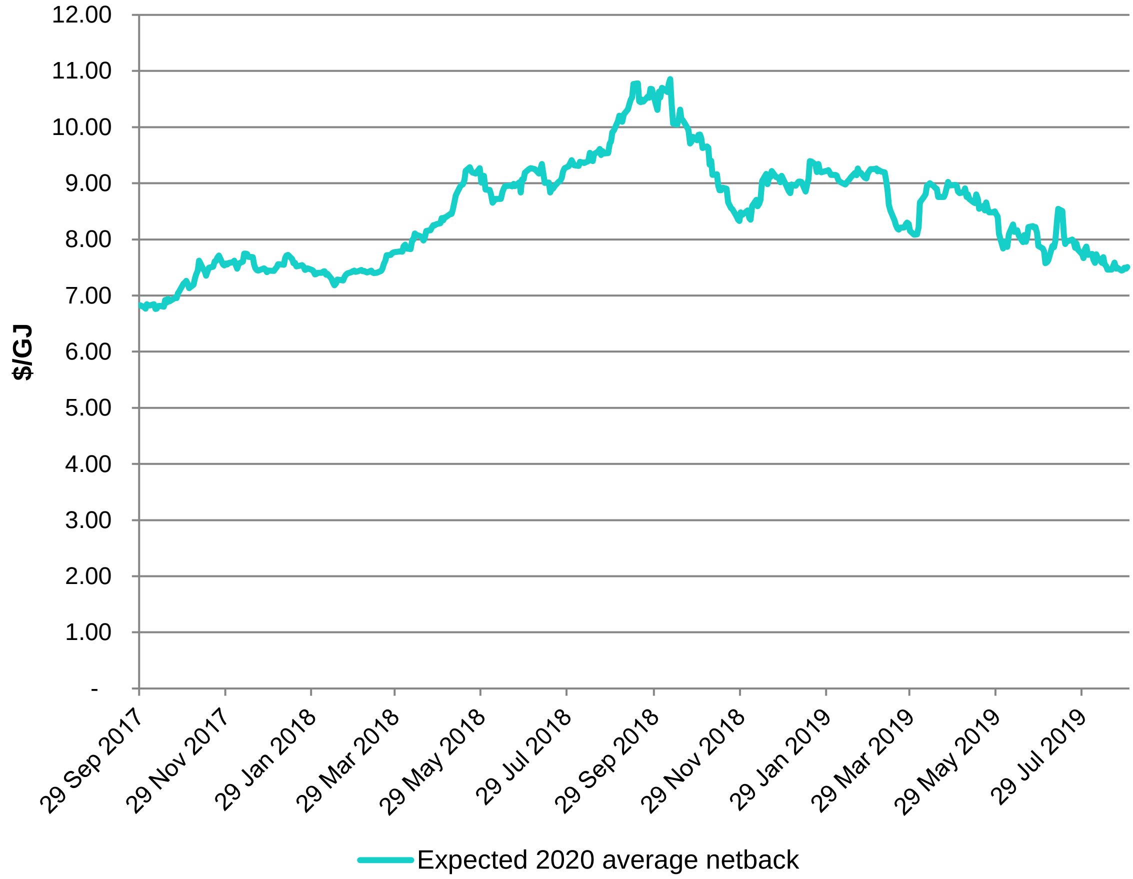
The LNG netback prices in the chart were calculated using the approach set out in box 2.3, with one difference — each point in the chart represents a daily average of expected LNG

[107] Core Energy, Gas Production Cost Estimates: Eastern Australia, 2018 https://www.accc.gov.au/system/files/Core%20Energy%20report%20for%20ACCC%20-%20November%202018.pdf.

[108] The ACCC intends to update the assumptions and costs estimates for future reports using data published by AEMO on production costs in the East Coast Gas Market.

netback prices across the entirety of 2020 (compared to a monthly average in section 2.4.2 below). The chart below differs from the ACCC's regular publication of LNG netback prices, in that it shows how expectations of LNG netback prices for the entirety of 2020 have changed over time, rather than showing expected forward prices for each month. This provides a basis for comparing offers for 2020 gas supply against expected LNG netback prices (see sections 2.4.2 and 2.4.3 below).

Chart 2.2: Expected LNG netback prices at Wallumbilla for 2020



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

Note: Forward shipping estimates were not available for all of 2020 prior to 7 December 2018. Expected LNG netback prices for 2020 prior to 7 December 2018 use a combination of 2019 and 2020 forward shipping costs as an input.

Chart 2.2 shows that expected LNG netback prices for 2020 have followed a downward trend since October 2018, falling from almost $11/GJ to about $7.50/GJ by the end of August 2019. Expected 2020 LNG prices have continued to exhibit volatility over 2019, but remained below or near $8/GJ from June to the end of August 2019 (with the exception of a short-lived spike in July 2019).

The downward trend in LNG netback prices is due to a similar downward trend in North Asian LNG futures prices, stemming from increased LNG supply as new LNG export facilities came online in the US and Western Australia, and relatively subdued LNG demand from Asia and Europe. Market commentary remains mixed about likely future prices beyond

2020, with most commentators predicting that LNG prices will recover either throughout 2021 or by the end of 2021.[109,110]

2.4.2. Domestic price offers for 2020 supply in Queensland have not decreased in line with expected LNG netback prices for 2020

This section compares prices offered for 2020 supply by producers in Queensland to contemporaneous expectations of 2020 LNG netback prices and estimated forward cost of production.

Chart 2.3 below compares the quantity-weighted average prices offered by gas producers in Queensland with:

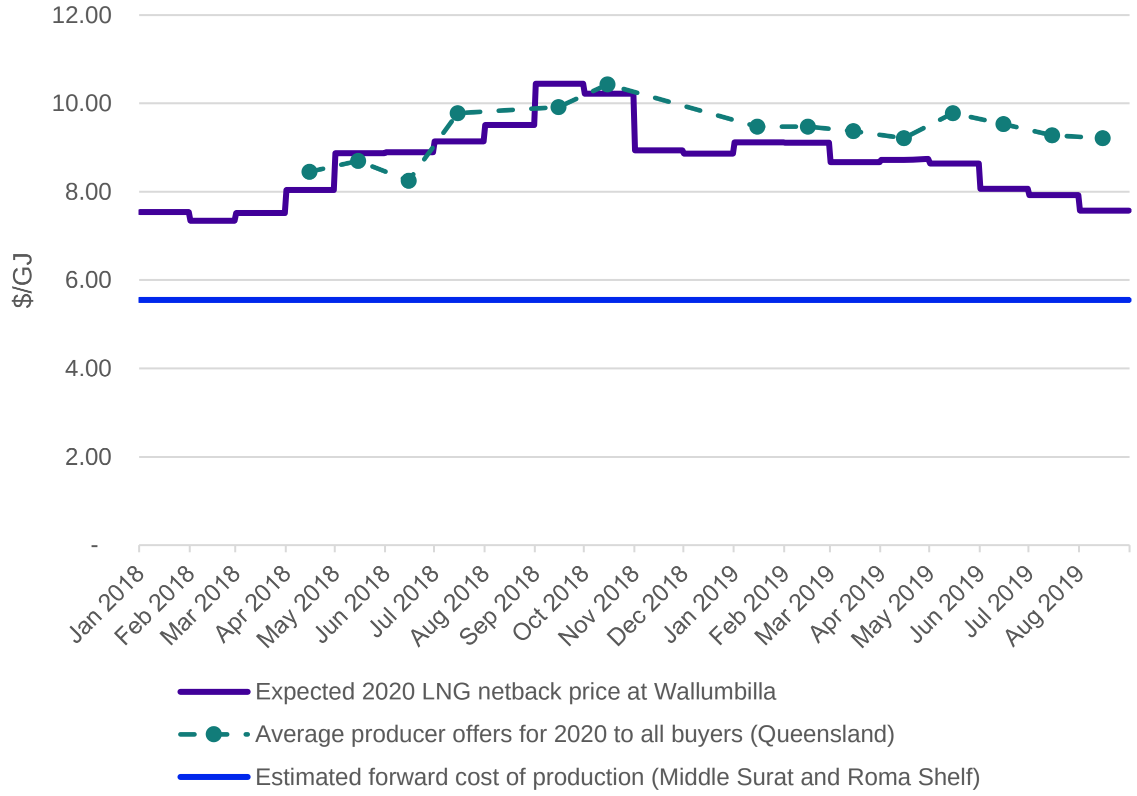
- the averages of expected LNG netback prices at Wallumbilla for 2020 in each month between January 2018 and August 2019[111]
- the estimated forward costs for the marginal supplier in Queensland.

[109] Office of the Chief Economist, *Resources and Energy Quarterly*, June 2019.

[110] McDonald-Smith A., *LNG glut to force US shutdowns: Fesharaki*, Australian Financial Review, 12 December 2019.

[111] The chart does not include offers from retailers in Queensland due to the small number of offers made over the relevant period.

Chart 2.3: Averages of monthly gas commodity prices offered by producers in Queensland[112] for 2020 supply against contemporaneous expectations of LNG netback prices



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

Note: The chart includes averages of prices offered for gas supply agreements with a term between 1 and 3 years, and does not include oil-linked offers.

In our July 2019 report, we noted that the averages of prices offered by producers in Queensland for 2020 supply appeared to have followed expected 2020 LNG netback prices. However, chart 2.3 shows that this was not the case from May to August 2019—falling expected 2020 LNG netback prices have not been reflected in the averages of prices offered by producers in Queensland (which have largely remained within a narrow range over 2019).

Chart 2.3 shows that the monthly averages of offer prices for the supply of gas in 2020 in Queensland have remained within the $9–9.50/GJ range over the course of 2019, with the exception of May 2019 when a large offer with a relatively high, JKM-linked price increased the average to almost $9.80. In contrast, monthly average expected 2020 LNG netback prices at Wallumbilla have steadily declined over 2019, falling from $9.12/GJ in January 2019 to $7.58/GJ in August 2019.

By August 2019, the final month for which we have data, the average of offer prices for 2020 supply in Queensland was $1.63/GJ higher than expected 2020 LNG netback prices at Wallumbilla (this is almost 22 per cent more than expected LNG netback prices for 2020).[113]

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[112] Some offers made in Queensland may include transport to locations far from Wallumbilla. It may not be meaningful to compare these offers to LNG netback price at Wallumbilla. For this reason, offers made for gas supply at locations far away Wallumbilla, such as Mt Isa, have not been included in this chart.

This disparity can be observed in the prices offered by all suppliers in Queensland, including LNG producers. In some instances LNG producers have made offers that include a fixed price component, on top of a JKM-linked component that is equivalent or close to LNG netback prices.

This difference in price offers from expected LNG netback prices for 2020 is highly concerning and understanding the cause of this disparity is a priority for the ACCC over the course of this Inquiry.

Understanding this price differential is particularly important in light of recent reports that APLNG is offering to sell an additional six to 12 LNG cargoes in 2020 through a short-term LNG strip contract.[114,115] These cargoes would likely be sold at prices reflective of current market expectations for LNG spot prices over 2020, which as noted above, are below domestic price offers in Queensland.

Given our concerns, the ACCC will undertake further analysis of the factors that may be influencing domestic gas prices, relative to LNG netback prices, and monitor and report on prices offered to the domestic market. The ACCC will also report on LNG spot sales in 2020.

It is not clear why this disparity has emerged and whether it is transitory or reflective of a longer-term trend. It is also unexpected in light of the improved domestic short-term supply-demand outlook. As noted in chapter 1, there is likely to be sufficient supply in 2020 to meet forecast demand, with LNG producers expected to have about 138 PJ of excess gas that they could supply to either the domestic market or sell via spot markets (at prices in line with LNG netback prices).

That said, as noted in the ACCC's July 2019 report, there are several limitations to the comparison between prices and expected LNG netback prices.

- The analysis in chart 2.3 is based on a relatively small number of offers, which means that average prices in individual months may be disproportionately influenced by outliers.
- Some of the prices offered by producers for 2020 supply are part of multi-year offers. The pricing in these offers may reflect market fundamentals, including expected LNG netback prices, over the entire life of the contract (rather than just for 2020). As noted above, expectations around future LNG prices are volatile and subject to a significant degree of uncertainty.
- Producers often make offers in the course of negotiations that take place over a period of up to several months—changes in LNG netback price expectations, which can occur rapidly, may take time to flow through to price offers and as a result, offers may not always reflect contemporaneous LNG netback price expectations. That said, while LNG prices declined relatively consistently to August 2019, offers by Queensland producers over the period January to August 2019 remained within a narrow range.

There are also other factors that may influence domestic gas prices compared to LNG netback prices.

Many GSAs contain non-price terms and conditions that may increase the costs of supplying gas to C&I gas users, particularly under GSAs that provide a high degree of flexibility. This could potentially create a wedge between LNG netback prices and domestic price offers. Moreover, committing to supply gas over a 12 month (or more) period may create risks for gas suppliers relative to shorter supply periods. These are risks that LNG producers may not

113 The ACCC notes that not all offers in Queensland are made at Wallumbilla. As a consequence, some offer prices may reflect transportation costs, and this may in turn affect comparisons to LNG netback prices.

114 Platts S&P Global, *LNG Daily*, vol. 16, iss. 235, 28 November 2019.

115 Argus Media, *LNG Daily*, iss. 19-237, 29 November 2019.

face when selling LNG on spot markets. This, in turn, may mean that LNG producers would expect a higher price for supplying domestic users rather than exporting LNG as spot sales. The ACCC notes, however, that chart 2.3 shows periods in which average offered prices were below contemporaneous LNG netback expectations, which may suggest that the effect of non-price terms and conditions, and any risks associated with supplying domestic C&I users, would be relatively minimal. These factors would also be unlikely to explain the widening disparity between average domestic price offers and expected 2020 LNG netback prices.

In addition, prices offered in the East Coast Gas Market will be responsive to the domestic supply-demand balance. While it is likely that there will be sufficient supply to meet demand in 2020 (see chapter 1), there are factors that could lead to a tightening of the supply-demand balance, such as lower than forecast production or higher than anticipated GPG demand. As noted in chapter 1, the quantity of gas that will be used for GPG in 2020 is uncertain, and will ultimately depend on conditions in the National Electricity Market.

These factors may be influencing the decisions of gas suppliers in terms of the quantities being offered to the market, the timing of offers, and the prices at which gas is being offered. In other words, prices offered at a point in time may, in part, be influenced by the quantity of gas being offered to the market at that time and the quantity of gas being sought by gas users (under long-term GSAs). Prices may also be influenced by the number of suppliers making offers at a point in time and the future contractual commitments of gas suppliers.

Nonetheless, it is surprising that Queensland price offers did not continue to fall over the period between May and August 2019. It is our expectation that LNG producers would have sought to take advantage of the difference in domestic and expected LNG netback prices by increasing their sales of gas to the domestic market (which, all other things equal, would be expected to put downward pressure on prices).

2.4.3. Domestic price offers for 2020 supply in the Southern States remain well above LNG netback prices

As explained in our previous reports, the ACCC has adopted a bargaining framework to analyse pricing outcomes in the Southern States.[116] Under this framework, the pricing dynamics in the Southern States are different from those in Queensland. Box 2.5 explains the ACCC's bargaining framework and how it is used to assess prices offered in the East Coast Gas Market.

[116] ACCC, *Gas Inquiry 2017–20–Interim Report*, September 2017, p. 69.

Box 2.5: ACCC bargaining framework

Due to the cost of transportation between the Southern States and Queensland, there is a range of possible pricing outcomes in gas supply negotiations in the Southern States, which would usually be expected to fall between:

- the buyer alternative (representing a ceiling in negotiations)—the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location, and
- the seller alternative (representing a floor in negotiations)—the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward 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 number of factors, including the location of the buyer, the expectations of the parties about supply and demand dynamics in the Southern States, the relative bargaining strength of the parties and the non-price terms and conditions agreed by the parties.

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

Further, a southern supplier would be expected to seek a higher price the further away a gas user is from Queensland. Since gas users in Victoria are located further away from Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states, all other things equal. If, in a well-functioning market, a southern supplier were to make an offer above this, then regardless of the location of the buyer it would likely be more economic for the buyer to purchase gas from Queensland and transport it to its location.[117] 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.[118]

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 forward cost of production. The forward cost of production therefore sets the floor price in any gas supply negotiation.

To meaningfully analyse the level of prices offered in a particular location in the Southern States using this bargaining framework, it is necessary to compare those prices to the buyer/seller alternative range in that specific location. In the analysis below we present a buyer and seller alternative for Victoria.

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117 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.

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

Chart 2.4 shows quantity-weighted average prices offered by suppliers in the Southern States between January 2018 and August 2019 for supply in 2020 compared to the range within which gas prices would be expected to fall using the bargaining framework set out in box 2.5.

The upper end of the range is the buyer alternative in Victoria—indicative of the highest price that would be expected to be offered in the Southern States under the bargaining framework—which is derived by taking averages of expected LNG netback prices at Wallumbilla for 2020 and adding indicative pipeline tariffs to Melbourne. Buyer alternative prices in other locations in the Southern States would be expected to lie between LNG netback prices at Wallumbilla and Victorian buyer alternative prices.

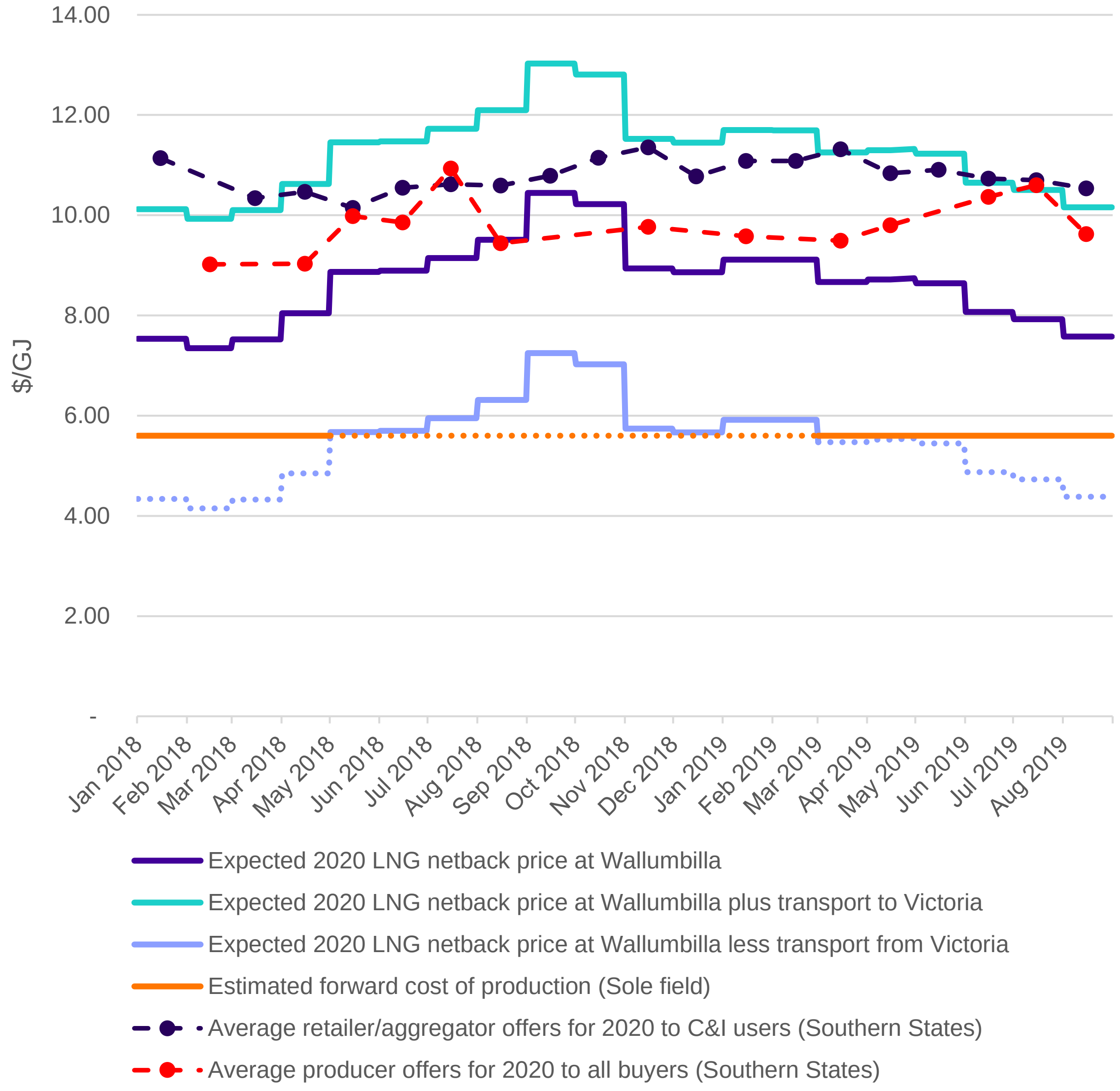
The lower end of the range is the seller alternative in Victoria, determined by the higher of:

- the averages of expected LNG netback prices at Wallumbilla for 2020 less indicative pipeline tariffs from Melbourne to Wallumbilla[119]
- the cost of production of the marginal source of supply.

The ACCC notes that the LNG netback price and buyer and seller alternative price do not account for other factors that may influence the prices offered to gas buyers, such as flexible non-price terms and conditions in GSAs, the contract length and, in the case of retailer offers, retailer costs and margins.

[119] Indicative pipeline tariffs are based on the costs of transporting gas from Wallumbilla to Melbourne via Sydney (for the buyer alternative), and the costs of transporting gas from Melbourne to Wallumbilla via Moomba, including processing costs at Moomba to ensure the gas meets the specifications for conversion to LNG. Costs of transportation between Melbourne and Wallumbilla (via Moomba) for north flowing gas, and between Wallumbilla and Culcairn for south flowing gas are published on the ACCC's website (https://www.accc.gov.au/system/files/Map-2-A3.pdf). An indicative tariff from Culcairn to Melbourne is published on APA's website (https://www.apa.com.au/our-services/gas-transmission/east-coast-grid/victorian-transmission-system/). Pipeline losses and processing costs at Moomba were published in the ACCC's East Coast Gas Inquiry 2015 final report (https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015/report).

Chart 2.4: Average of monthly gas commodity prices offered for 2020 supply against contemporaneous expectations of 2020 LNG netback prices (Southern States)[120]



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

Note: The chart includes averages of prices offered for gas supply agreements with a term between 1 and 3 years, and does not include oil-linked offers.

Chart 2.4 shows that over the course of 2019, the average of prices offered in the Southern States for 2020 supply by producers remained between $9.50/GJ and $10.60/GJ, increasing over the period from March to July 2019 to be in line with the Victorian buyer alternative. The high averages of prices offered in June and July 2019 reflected several high-priced offers for gas supply with a high degree of flexibility—removing these offers would lower the averages in June and July 2019 to be more in line with other months. Nonetheless, the averages of prices offered by producers has increased over the period in which LNG netback prices, and

[120] Some gas supply agreements reflect higher per GJ pricing in the chart due to highly flexible delivery terms or being significantly weighted to the winter months, when domestic demand is higher. It is this flexibility or bespoke load profile that contributes to the overall contract price, making it not directly comparable to other contracts.

the Victorian buyer alternative, decreased. The average subsequently decreased to below $10/GJ in August 2019.

The averages of prices offered by retailers were broadly in line with the Victorian buyer alternative over 2019, with the averages remaining between $10.00/GJ and $11.50/GJ. These averages declined over the period March to August 2019, but not as much as the decline in expected LNG netback prices and the Victorian buyer alternative, which fell from $11.25/GJ in March to $10.16/GJ in August. By August 2019, the averages of prices offered by producers and retailers in the southern states were well above contemporaneous expected 2020 LNG netback prices and were close to the buyer alternative.

It is unclear why the averages of prices offered in the Southern States remain around the Victorian buyer alternative.

As discussed in section 2.4.2, there are various considerations in comparing domestic prices to export parity prices. In addition, there are several other relevant considerations when comparing prices offered in the Southern States with LNG netback prices and the buyer and seller alternatives. In particular, the prices observed in offers made in the Southern States will depend on the:

- expectations of the parties about supply and demand dynamics in the Southern States
- location at which the gas is delivered to the buyer.

These factors can differ over time, and, given the small number of offers made in some months, can in turn lead to movements in the average of prices in chart 2.4 that can differ from movements in expected LNG netback prices at that same time.

Moreover, under the bargaining framework, one reason prices might tend towards the buyer alternative is if there is not sufficient gas produced in the Southern States to meet demand and gas from Queensland is needed. As noted in chapter 1, there is projected to be sufficient supply in the Southern States to meet expected demand. However, the ACCC notes that the supply-demand balance in the Southern States remains uncertain, and will ultimately depend on the quantity of gas that flows south from the Cooper Basin, and on demand for GPG.

As noted above, the ACCC intends to undertake further work on factors other than LNG netback prices that may influence domestic price offers, and will continue to monitor and report on prices offered for supply in the Southern States.

2.5. Prices agreed under GSAs

2.5.1. C&I gas users will pay similar prices in contracts entered into in the first half of 2019 as those entered into in 2017

The analysis in this section of the chapter provides information on how prices in GSAs entered into by producers and retailers with C&I users have evolved over time.

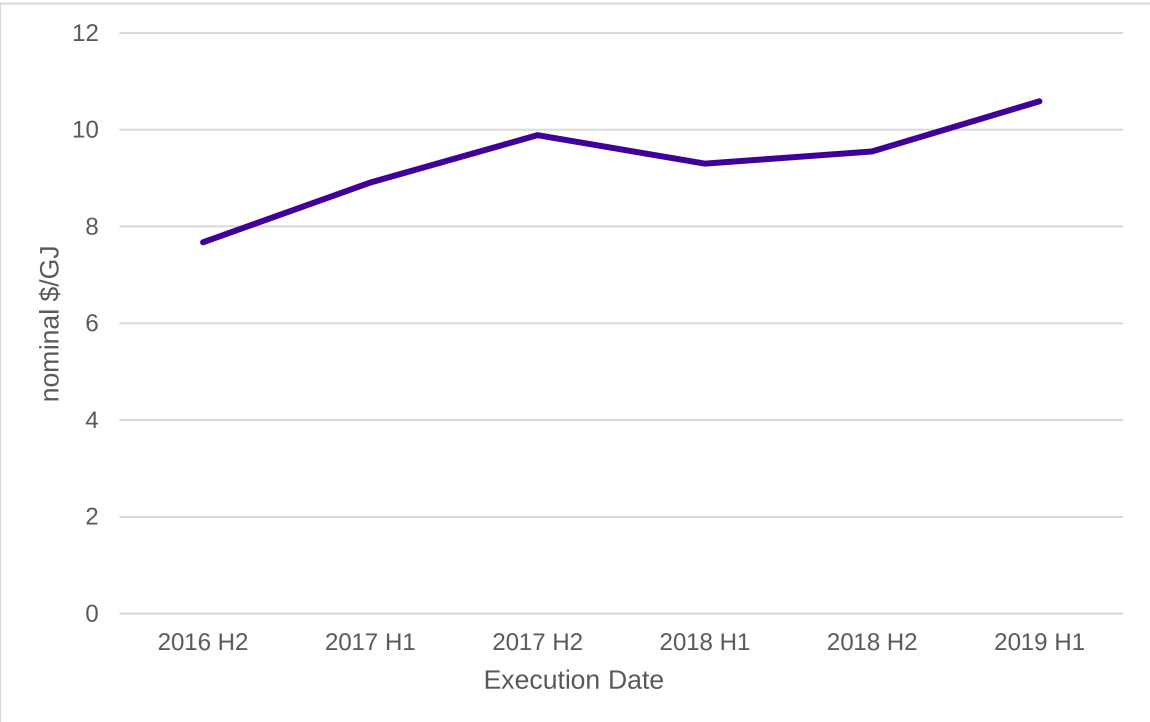
Chart 2.5 presents the quantity-weighted average of prices under GSAs executed in half yearly intervals from the second half of 2016 to the first half of 2019. The approach for calculating these prices is set out in box 2.6. Each point on the chart represents a quantity-weighted average of base commodity prices under all the applicable GSAs executed in that half-year interval.

Box 2.6: Approach to creating the GSA time series

The series in chart 2.5 includes GSAs executed with C&I gas users (excluding retailers, LNG producers and GPG gas users). For this series, the ACCC:

- included GSAs executed at arm's length
- included GSAs from both producers and retailers
- included GSAs for delivery across the whole of the east coast (i.e. Queensland and the Southern States)
- included GSAs for supply with a total contracted quantity of at least 0.5PJ and for a term of at least 12 months
- included only fixed price GSAs (i.e. excluded any GSAs linked to oil or JKM). Oil and JKM-linked contracts have been excluded from this analysis, as expectations around future oil and North Asia LNG prices can be markedly different
- excluded GSAs with non-price terms and conditions that are not reflective of the market as a whole
- calculated a quantity-weighted average nominal price of each GSA using the base commodity price (i.e. not including separate transportation or other ancillary charges) and the annual contract quantity specified in the GSA for the first year of supply
- calculated a half yearly quantity-weighted average based on all the applicable GSAs that were executed in that half yearly interval, irrespective of the term of the GSA.

Chart 2.5: Quantity-weighted average wholesale gas commodity prices in GSAs executed with C&I gas users in the East Coast Gas Market in each half yearly interval from the second half of 2016 to the first half of 2019



Source: ACCC analysis of information provided by suppliers.

Chart 2.5 shows that prices agreed by C&I gas users in newly executed GSAs rose sharply between the second half of 2016 and the second half of 2017. Quantity-weighted average GSA prices subsequently softened to between $9–10/GJ in 2018 as more gas was made available to the domestic market following the signing of the Heads of Agreement between the Australian Government and LNG producers in October 2017.

However, the first half of 2019 saw average GSA prices increase significantly, with average prices over 10 per cent higher in the first half of 2019 than the second half of 2018. This is similar to the level of growth in average GSA prices in the second half of 2017. It also marks the first time, over the period covered by the chart, that average prices to C&I users, calculated on a half-year basis, exceeded $10/GJ.

There are two factors that explain the increase in average GSA prices since the beginning of the second half of 2018.

First, average GSA prices agreed between retailers and C&I users have increased, with more recent GSAs being executed at higher prices. Prices in GSAs executed between producers and C&I users have, in contrast, not materially changed over the first half of 2019. The net effect has been an increase in the average of GSA prices agreed between all suppliers and C&I users in the second half of 2018 and the first half of 2019.

Second, the first half of 2019 saw an increase in the relative proportion of gas to be supplied by retailers under GSAs entered into by C&I users (in that period). On average, prices in retailer GSAs tend to be higher than those in GSAs executed by producers, and this change has thus resulted in average prices increasing in the first half of 2019.

If the data in the chart were disaggregated into quarterly prices, it would show that in the first quarter of 2019, average quarterly GSA prices reached an all-time high, surpassing the peak last seen in the third quarter of 2017 (a period in which many C&I gas users faced extremely difficult market conditions). Average quarterly GSA prices in the second quarter of 2019 (not shown in the chart) were lower than in the first quarter of 2019, but were still above $10/GJ and close to the high prices seen in the third quarter of 2017.

Notably, these prices are well above those observed in facilitated gas markets over 2019 (see section 2.6.1), which likely reflects that drivers of pricing for long-term GSAs can differ from factors influencing pricing of shorter term products in the facilitated gas markets.

2.5.2. Prices agreed under GSAs for supply in 2020 in recent months have been relatively stable

This section analyses GSAs for supply in 2020 that were executed between 1 January 2017 and 22 August 2019.

The analysis in this section covers GSAs for supply in 2020 (and beyond for some GSAs) that were entered into between 1 January 2018 and 22 August 2019. A similar approach was adopted for the ACCC's July 2019 report, which covered GSAs entered into between 1 January 2018 and 24 April 2019. In contrast, the ACCC's April 2019 interim report covered GSAs for 2020 supply entered into over the entirety of 2017 and part of 2018. This limits the comparability of GSA prices published in this report to those published in the ACCC's April 2019 Interim report.

Box 2.7 below sets out the ACCC's approach to reporting on prices agreed under longer-term GSAs.

Box 2.7: Approach to reporting on prices agreed under GSAs

The information in this box should be read in conjunction with information in box 2.1. The following also applies to the analysis of prices agreed under GSAs:

- 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 prices, we have only included GSAs between retailers and C&I users.
- In contrast to the preceding analysis of offers and bids, we estimated prices under GSAs using assumptions relating to key variables, including, where relevant, AUD/USD, inflation and the Platts Japan Korea Marker (JKM). The assumptions used in this report are based on market expectations for those variables for 2020.[121]
  - These market expectations have changed since we last reported on GSA prices. AUD/USD exchange rates and inflation, for example, are expected to be lower than was expected. A reduction in inflation reduces expected GSA prices, while a reduction in the AUD/USD increases expected GSA prices (as oil and JKM prices are denominated in USD). The net effect of the change in expectations is lower expected GSA prices than would be expected using our previous assumptions.
- 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 separate charges for transporting gas to the user's location or any other ancillary costs. In some instances, however, transport and other costs may be bundled into a single wholesale gas price. This is accounted for in the analysis by categorising GSA prices by the location of the delivery point rather than the location of the source of the gas.
- In addition to average prices, we are also reporting corresponding average load factors and take or pay quantities. Both the load factor and take or pay multiplier are a measure of the level of flexibility allowed under the contract.
  - The load factor is calculated as the ratio of the annual aggregate of the maximum daily quantities allowed under the GSA and the annual contract quantity. The higher the load factor, the more gas a gas user can take on a given day above their average daily allowance.
  - The take or pay multiplier is the percentage of the contracted gas that must be paid for by the buyer whether or not the buyer actually takes delivery of the gas. A GSA with a take or pay multiplier of 100 per cent implies that the buyer has to pay for all of the gas it has contracted to take, irrespective of whether it uses the gas in the year. A GSA with a take or pay multiplier of 0 per cent is considered an option contract as the buyer does not have any obligation to purchase gas under the contract.
- Consistent with the approach adopted in previous reports, we categorise GSA prices by the location of the delivery point rather than the location of the source of the gas.

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[121] In all estimates of 2020 GSA prices in this report, the following assumptions were made, where relevant:

- Consistent with Commonwealth Treasury methodology, the AUD/USD exchange rate for 2020 is expected to vary around the current rate. The exchange rate assumption applied to GSAs in this report is 0.6926 US cents to the Australian dollar. It is based on the monthly rate published by the RBA for October 2019.
- The CPI assumptions used to estimate GSA prices in this report are based on actual CPI where available and 2.5 per cent thereafter.
- The LNG price assumptions used to estimate JKM linked GSA prices in this report are the JKM futures prices on the ICE exchange for each month in the 2020 calendar year, quoted on 29 November 2019.

Table 2.3 shows quantity-weighted average gas prices expected to be paid for supply in 2020 under GSAs entered into by producers. The prices in this table are not necessarily comparable to the prices reported in the July 2019 report due to changed pricing assumptions and because a larger sample of GSAs was available for analysis in this report than in the July 2019 report.

Table 2.3: Expected 2020 wholesale gas producer commodity prices in the East Coast Gas Market (under GSAs executed between 1 January 2018 and 22 August 2019)[122]

Type of supplier (delivery region)	Average gas commodity price ($/GJ)	Gas commodity price range ($/GJ)
Producer (QLD)	8.52	8.11–9.63
Producers (VIC, SA and NSW)	9.73	8.86–10.82

Source: ACCC analysis of information provided by suppliers.

Producer prices in Queensland are lower than those reported in the July 2019 report and producer prices in the Southern States are marginally lower. The decrease in Queensland is due to a large, recently executed contract that has a relatively low price compared to the average previously reported. This contract was sufficiently large to reduce the quantity-weighted average Queensland price. Producer prices in the Southern States have remained stable relative to those reported in our last interim report.

The range of agreed GSA prices is largest for the Southern States, at $1.96/GJ, reflecting a larger number and variety of GSAs. The upper end of the range has shifted higher in South Australia, since the ACCC last reported in July 2019, due to new contracting at higher prices while the range of prices in NSW has remained steady. In Victoria, the already wide range has increased since our July 2019 report due to the lower end of the range shifting downwards. In Queensland, the range is larger at $1.52/GJ, although the range of agreed GSA prices has decreased at the lower end in Queensland.

Table 2.4 shows quantity-weighted average gas prices expected to be paid for supply in 2020 under GSAs entered into by retailers. As is the case with the producer prices presented above, the prices in this table are not directly comparable to the prices reported in the July 2019 report as the pricing assumptions have changed and because a larger sample of GSAs was available for this report.

122 Pricing assumptions applied to GSAs in this section are the same as applied in Section 1.3 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 2.4: Expected 2020 wholesale gas retailer commodity prices in the East Coast Gas Market (under GSAs executed between 1 January 2018 and 22 August 2019)[123]

Type of supplier	Average gas commodity price ($/GJ)	Gas commodity price range ($/GJ)
Retailers (QLD)	10.33	10.00–10.94
Retailers (VIC, SA and NSW)	10.68	9.19–11.57
Retailer (NSW)	10.95	9.54–11.57
Retailer (SA)	10.22	9.19–11.06
Retailer (VIC)	10.42	9.65–10.79

Source: ACCC analysis of information provided by suppliers.

Retailer quantity-weighted average prices have largely remained unchanged for both Queensland and the Southern States, as a whole, since we last reported in July 2019.

In the Southern States, quantity-weighted average GSA prices have increased in South Australia and New South Wales, and decreased marginally in Victoria.

The increase in quantity-weighted average prices in South Australia likely reflects that recently executed GSAs are relatively more expensive and the fact that South Australian prices were previously lower than those in other states in the south (with prices in new GSAs being more in line with prices in Victoria and New South Wales). Moreover, the number of existing contracts in South Australia was relatively small, meaning that prices in newly executed GSAs have had a relatively large impact on the quantity-weighted average price. The increase in prices in NSW is marginal and is due to the majority of new GSAs being executed at higher prices than existing contracts for 2020 supply. In Victoria, recently executed GSAs span a range of prices, in the mid to high $10 range.

Consistent with previous observations, the average of prices for gas supplied by retailers is higher than that supplied by producers in all regions.

2.5.3. Recently executed GSAs are less flexible than earlier GSAs

In this section, we report on the quantity-weighted average of load factors and take or pay multipliers in GSAs. Load factors and take or pay multipliers are key terms and conditions in GSAs, that may influence the cost of supplying gas and the value to a gas user of the gas supplied under a GSA.

This is because suppliers who enter into flexible GSAs will need to ensure they can supply a quantity of gas, either on a daily basis or over the life of the contract, which the buyer may not actually take. This, in turn, might mean that the supplier needs to reserve gas (at the expense of extra sales), use storage facilities, and maintain sufficient processing and pipeline capacity (where applicable) to deliver the contracted quantity regardless of whether the buyer elects to take the entire contracted quantity.

[123] Pricing assumptions applied to GSAs in this section are the same as applied in Section 1.3 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.

As such, the value of these non-price terms and conditions in GSAs are potentially an important qualifier when considering the commodity price of gas under the GSA.

Table 2.5 shows the quantity-weighted average load factor and take or pay multipliers under GSAs for supply in 2020 entered into by producers.

Table 2.5: Expected 2020 average Load Factor and average Take or Pay Multiplier in the East Coast Gas Market (under producer GSAs executed between 1 January 2018 and 22 August 2019)

Type of supplier	Load Factor	Take or Pay Multiplier %
Producers (QLD)	1.09	94
Producers (VIC, SA and NSW)	1.58	93

Source: ACCC analysis of information provided by suppliers.

The average load factor under GSAs executed by producers has increased in Queensland and has declined in the Southern States compared to those reported in the July 2019 report.

In Queensland, newer GSAs for 2020 supply have moderately higher load factors than existing contracts (which had load factors that were equal or relatively close to 1), leading to a marginal increase in the Queensland quantity-weighted average load factor. In the Southern States, the average load factor has decreased as a result of newer contracts being entered into having lower load factors than the average load factor of existing contracts.

Producer GSAs with low take or pay multipliers are uncommon, with take or pay multipliers in producer GSAs generally being between 90 and 100 per cent. The average take or pay multiplier under GSAs entered into by producers has increased marginally in all jurisdictions, with the largest increase observed in Queensland. Average take or pay multipliers between different jurisdictions have also converged to between 92 and 94 per cent.

Based on these measures, the level of flexibility in producer GSAs for 2020 supply, entered into since January 2018, has decreased since our July 2019 report.

Table 2.6 shows the quantity-weighted average load factor and take or pay multiplier under GSAs for supply in 2020 entered into by retailers.

Table 2.6: Expected 2020 average Load Factor and average Take or Pay Multiplier in the East Coast Gas Market (under Retailer GSAs executed between 1 January 2018 and 22 August 2019)

Type of supplier	Load Factor	Take or Pay Multiplier %
Retailer (NSW)	1.12	91
Retailer (SA)	1.12	93
Retailer (VIC)	1.19	81
Retailer (QLD)	1.15	86
Retailer (VIC, SA and NSW)	1.13	89

Source: ACCC analysis of information provided by suppliers.

The average load factor under retailer GSAs executed in both Queensland and the Southern States is approximately the same as that previously reported in July 2019. In the Southern States, the average load factor has decreased in Victoria, increased in South Australia and remained largely unchanged in New South Wales. Similar to what was observed with producer GSAs, the reduction in load factor in Victoria is due to newer Victorian contracts having lower load factors than earlier GSAs. The opposite is true for South Australia, with newly executed GSAs, which have relatively high load factors, leading to an increase in the average load factor in that state.

Across the different jurisdictions, the range of the average of load factors under retailer GSAs has narrowed to between 1.12 and 1.19.

Retailer GSAs provide more flexibility around take or pay multipliers on average than producer GSAs, which is consistent with retailers being able to better manage flexibility in GSAs due to having more expansive gas portfolios or the ability to use storage services provided by pipelines and/or dedicated storage facilities. Take or pay multipliers in retailer GSAs are generally between 80 and 100 per cent.

The average take or pay multiplier under GSAs entered into by retailers has remained approximately the same in all jurisdictions with the exception of South Australia. The average take or pay multiplier in South Australia has increased due to a large, recently executed GSA in that state, which has a 100 per cent take or pay multiplier.

2.6. Prices in facilitated markets

This section reports on prices and quantities of gas traded in short-term trading markets, as well as activity in the Victorian gas futures markets.

2.6.1. Prices paid for short-term products in the facilitated markets fell in 2019

Chart 2.6 shows the daily prices paid for gas in the facilitated gas markets in the Southern States (the simple average of the Victorian DWGM, the Sydney STTM and the Adelaide STTM) and Queensland (the simple average of the Wallumbilla Gas Supply Hub (GSH) and the Brisbane STTM) from September 2018 to September 2019.[124] The chart also shows the absolute price difference between the northern and southern markets.

Chart 2.6: Daily prices paid in domestic facilitated gas markets, September 2018 to September 2019

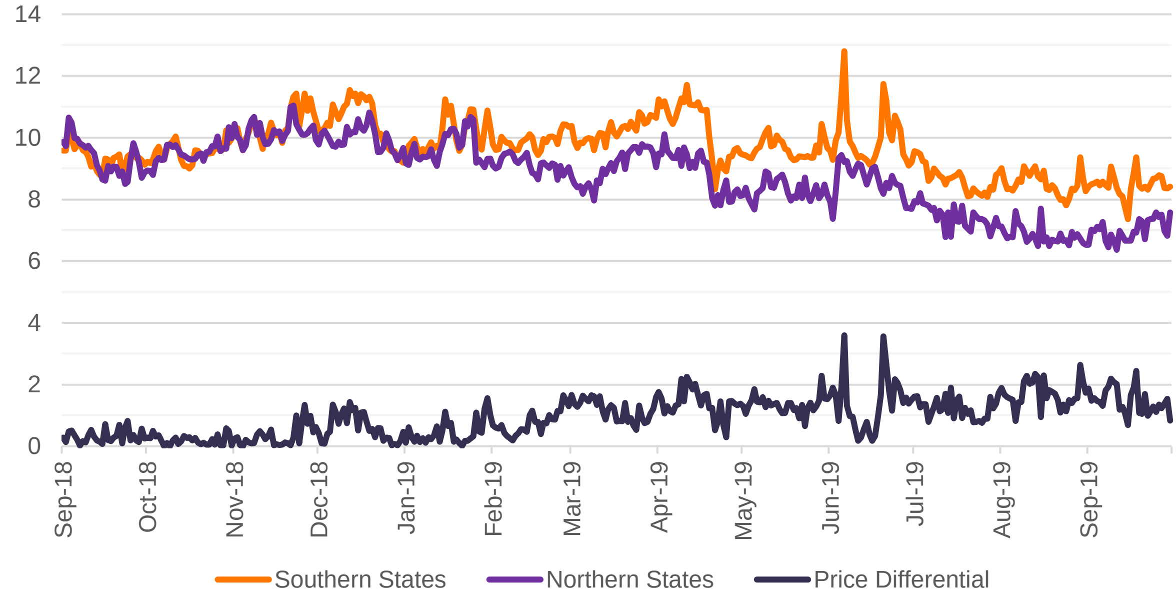

Chart 2.6 shows that since the July 2019 report, the simple average of prices in the facilitated gas markets in Queensland and Southern States have decreased, with the exception of a brief spike in prices in late June. Between July 2019 and September 2019, the prices paid in these markets in Queensland and the Southern States have fluctuated between $6.30/GJ and $9.60/GJ.

As noted by the Australian Energy Regulator, in their Wholesale Markets Quarterly Report for Q3 2019, there are several factors that may have contributed to the fall in prices in facilitated markets in recent months.[125] These factors are:

- lower Asian LNG spot prices
- surplus gas production in Queensland
- access to cheaper pipeline capacity, to transport gas from Queensland to New South Wales and Victoria, via the Day-Ahead Auction of contracted but unused capacity (DAA).

LNG spot prices have trended downward over the course of 2019. While this partly reflects seasonal price movements, an increase in global LNG supply over 2019 has pushed LNG spot prices below those seen in recent years. LNG spot prices were approximately 50 per cent lower in Q3 2019 than in Q3 2018. Falling LNG netback prices would, all other things equal, be expected to put downward pressure on prices in facilitated markets.

Moreover, while LNG exports have remained relatively steady over 2019, gas production in the north has increased, and the DAA has facilitated shippers moving gas from northern to southern markets at near zero auction costs.

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124 Prices for gas at the Wallumbilla GSH do not include delivery to demand centres (as is the case for prices in the STTMs). This means that comparisons between the GSH and other facilitated markets are not necessarily ‘like for like’.

125 Australian Energy Regulator, *Wholesale Markets Quarterly – Q3 2019*.

The ACCC's July 2019 report noted a divergence between prices in the Queensland and Southern States from March 2019 to June 2019.[126] This divergence has slightly increased in Q3 2019. The average absolute price difference between Queensland and the Southern States in Q3 2019 was $1.47/GJ, which is an increase on the quarterly averages of $1.38/GJ in Q2 2019 and $0.80/GJ in Q1 2019. At the end of September 2019, the simple average of prices in Southern States was about $8.40/GJ, compared to $7.60/GJ in Queensland.

While the overall average divergence between Queensland and Southern States facilitated gas market prices has been slightly increasing over 2019, the AER notes in their Wholesale Markets Quarterly Report for Q3 2019 that the winter price gap — which is when the difference between Queensland and Southern State prices is traditionally at its largest — has narrowed in 2019 in Victoria and New South Wales, relative to some earlier years, largely as a result of the new DAA (see chapter 4 for more detail).[127]

Prices in the Southern States' facilitated gas markets in Q3 2019 were lower than equivalent prices in Q3 2018. The simple average of prices in the Southern States' markets in Q3 2019 was $8.55/GJ, compared to $9.40/GJ in Q3 2018 (a 9 per cent decrease).

Prices have fallen even further in Queensland when comparing Q3 2019 with equivalent prices in Q3 2018. The simple average of prices in Queensland in Q3 2019 was $7.08/GJ, compared to $9.42/GJ in Q3 2018, a difference of $2.34/GJ (a 25 per cent decrease).

The fall in these prices contrasts with trends observed in prices agreed in GSAs of at least one year entered into by C&I users (see section 2.5.1).

The total quantity of gas traded in the Southern States' facilitated gas markets (Sydney, Victoria, and Adelaide) increased from 90.22PJ in Q2 2019 to 114.36PJ in Q3 2019 (an increase of 27 per cent). This increase likely reflects seasonal trends, and was primarily driven by an increase in the volume traded in Victoria, from 60.67PJ in Q2 2019 to 81.38PJ in Q3 2019, with smaller increases observed in both the Adelaide and Sydney facilitated gas markets.

The quantity of gas traded over the Brisbane STTM in Q3 2019 fell from the previous quarter's figures. The total amount of gas traded in Q3 2019 was 7.66PJ, compared to 8.43PJ in Q2 2019 and 10.66PJ in Q1 2019.

Similarly, the total quantity of gas traded through the Wallumbilla GSH fell from 8.62PJ in Q2 2019 to 8.00PJ in Q3 2019.

2.6.2. Victorian wholesale gas futures trading has fallen

Natural gas futures contracts are listed by the ASX on the Victorian DWGM. These futures contracts provide a mechanism for market participants to manage their exposure to uncertain future gas prices. Since the July 2019 report, there has been a decline in trading activity for gas futures on the DWGM.

Monthly trading activity over the five months from June to October 2019 was as follows:

- in June 2019, there were 15 quarterly contracts traded for 2019 futures, 50 quarterly and 10 yearly contracts traded for 2020 futures, and 40 quarterly and 5 yearly contracts traded for 2021 futures
- In July 2019, there were no contracts traded for 2019 futures, 45 quarterly and 5 yearly contracts traded for 2020 futures, and 10 quarterly contracts traded for 2021 futures

126 ACCC, *Gas Inquiry 2017–20 – Interim Report*, July 2019.

127 Australian Energy Regulator, *Wholesale Markets Quarterly – Q3 2019*, November 2019, p. 53.

- In August 2019, there were 3 quarterly contracts traded for 2019 futures, and no contracts traded for 2020 or 2021 futures
- In September 2019, there were 5 quarterly contracts traded for 2019 futures, 15 quarterly and no yearly contracts traded for 2020 futures, and 30 quarterly and 5 yearly contracts traded for 2021 futures
- In October 2019, there were no contracts traded for 2019 futures, 20 quarterly contracts traded for 2020 futures, and no contracts traded for 2021 futures.

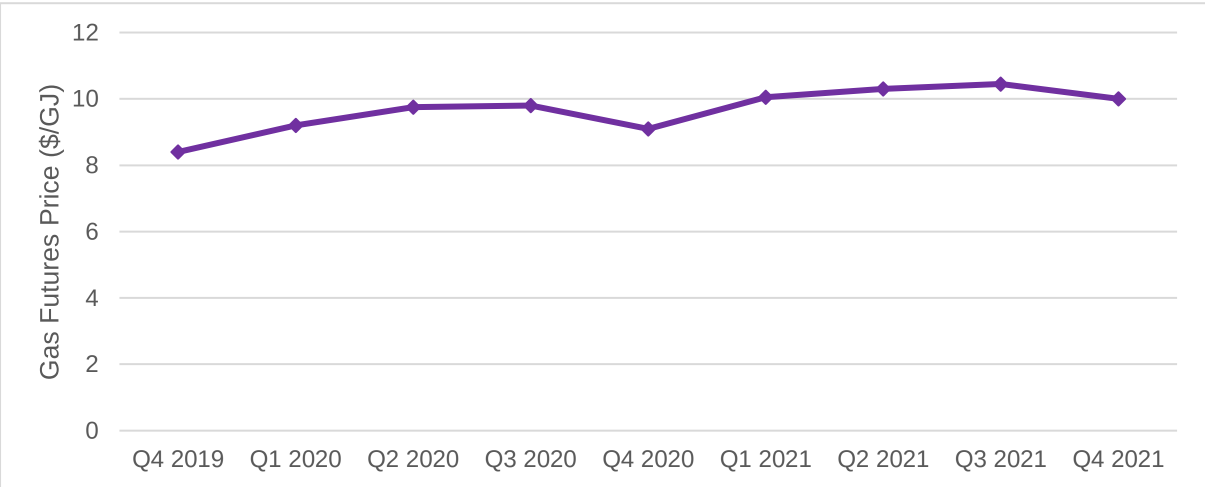
The level of trading activity over the five months June to October 2019 — 233 quarterly and 25 yearly contracts — represents a 32 per cent decrease on the level of trading activity during the first five months of 2019 (which, over that period, was 353 quarterly and 30 yearly contracts).

The average number of contracts traded per month on the DWGM over the period June to October 2019 has also fallen relative to the period from January to May 2019, falling from an average of 77 contracts traded per month to 52 contracts per month.

As at mid-November 2019, there were 525 outstanding quarterly futures contracts for the period from Q4 2019 to the end of 2021. This is a reduction on the 628 outstanding contracts reported in the July 2019 report. A decrease in the open interest for quarterly futures contracts, as well as the decline in futures contract trading over the period June to October 2019, would suggest a reduction in DWGM futures market liquidity since the last report.

Chart 2.7 presents prices for Victorian DWGM futures. It shows that, since the ACCC's July Report, market participants have slightly lowered their expectations of future DWGM gas prices in Q4 2019, and over 2020 and 2021. Market participants expect future spot prices to remain between a range of $8/GJ and slightly above $10/GJ over the period.

Chart 2.7: Victorian DWGM futures prices from Q4 2019 to Q4 2021



3. Recent experiences of C&I users

3.1. Key points

- Most C&I users have contracted for gas in 2020, but small C&I users report long-term supply past 2022 remains uncertain.
- C&I users continue to report difficult circumstances, with the primary concern being gas prices and their impact. Consistent with all previous surveys the price of gas was one of the top three concerns of all responding gas users. For the first time, concerns about availability of supply equalled concerns about lack of competition.
- High gas prices have led to a number of businesses becoming unviable:
  - In the second quarter of 2019, paper products manufacturer Kimberly-Clark laid off its Western Sydney workforce consisting of 220 employees,
  - In October 2019 Norske Skog announced the sale and closure of its Albury mill resulting in job losses,
  - During the first quarter of 2019 Remapak, a Sydney-based producer or polystyrene coffee cups made an administration announcement. This has been followed by a September decision to liquidate; and
  - Claypave, a Queensland-based brick and paving manufacturer, which went into administration in the first quarter of 2019, transitioned from voluntary administration to liquidation in April.
- High gas prices have led a number of business to review profitability:
  - Incitec Pivot announced a strategic review of its fertiliser business in September. Possible outcomes include sale, demerger, or retain and invest; and
  - CSR divested its remaining glassworks.
- C&I users reported postponing capital investment and upgrades as high gas prices compress profit margins. One business in regional Victoria put plans for a $15 million expansion on hold.
- C&I users continue to explore a range of options to source gas. Some are sourcing gas directly from producers and many are using (or considering using) the facilitated gas markets, including examining mechanisms such as futures products and financial swaps to hedge their exposure on these markets.

3.2. Key concerns of C&I users remain prices, supply and lack of competition

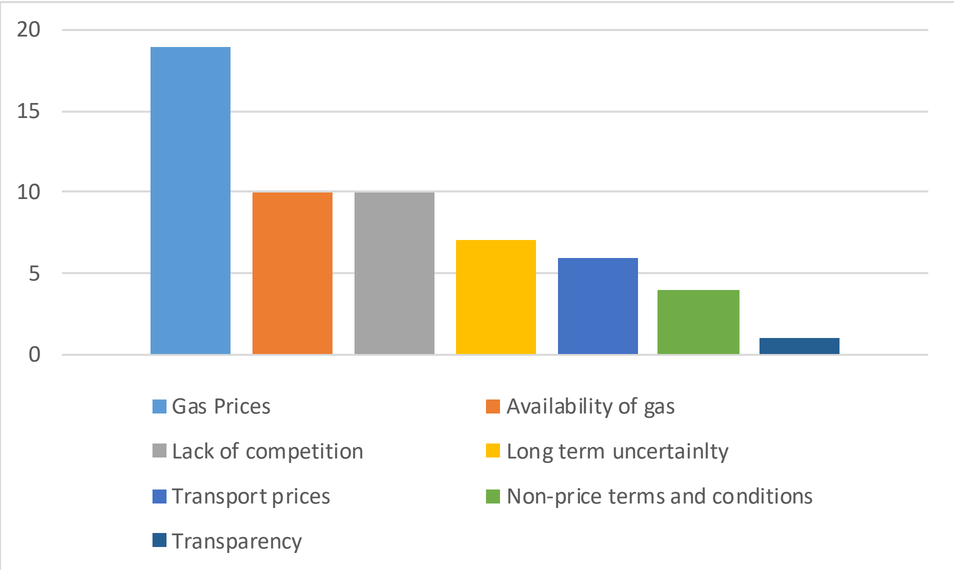
During August and September 2019, the ACCC invited 35 large and small commercial and industrial (C&I) users to take part in a survey to gain an insight into their most recent experiences in the gas market. We received 20 survey responses from C&I users from across the east coast (predominantly in the southern states) with a combined annual consumption of more than 90 PJ/a. This represents almost half the C&I market on the east coast. The survey respondents represented a broad range of sectors. For some natural gas is a raw material (feedstock) for creating fertilisers, explosives, chemicals, and plastics. Other C&I users purchase gas for use as a heat source for boilers and furnaces, for producing steam, or for drying processes.

This is the sixth occasion the inquiry has sought the views of gas users through a voluntary survey.[128] In a number of instances confidentiality agreements required by producers and retailers prior to engagement have constrained respondents from engaging with the ACCC and providing all the information gas users viewed as relevant to the inquiry.

Survey responses were primarily obtained from large C&I users (usage over 1 PJ per year) who use gas for their production processes. C&I users represent sectors that are important contributors to the Australian economy and are also large employers, particularly in regional areas. Many C&I users supply their products to highly competitive international markets and are very sensitive to small fluctuations in their input costs.

The survey asked C&I users to rank the key issues they were facing in the market. Chart 3.1 shows users' top three concerns from seven options. As in the previous survey when considering current market conditions, the C&I users we surveyed ranked gas prices as one of their top three most important concerns in relation to their gas supply. For the first time, concerns about availability of supply equalled concerns about lack of competition.

Chart 3.1: Gas prices, availability of gas and lack of competition among suppliers are top three concerns for C&I users



Note: The y-axis represents the number of participants that ranked each concern in their top three. There were 19 responses to this question.

These issues were of particular concern to C&I users that compete in international markets and are unable to pass on the gas price increases, and C&I users whose gas use makes up a large proportion of their cost of production (over five per cent).

The remainder of this section outlines the concerns that C&I users have raised about:

- gas prices and the impact they are having on the viability of their operations
- the availability of gas and their recent contracting experience
- the new ways in which C&I users are procuring gas and dealing with the risks associated with gas prices.

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[128] The ACCC has previously surveyed and conducted meetings with C&I gas users in: September and December 2017, July and September 2018, and in June 2019.

3.3. High gas prices are impacting the viability of C&I users, and influencing their investment

As reported in section 2.5, C&I users are paying an average of more than $10/GJ for gas under new contracts executed in the first half of 2019. The average of GSA prices in the first quarter of 2019 were higher than those signed in the peak period of early 2017. However, gas prices offered in 2019 are significantly lower than the peak prices offered in early 2017 (with some of those offers above $20/GJ). Many C&I users have stated that prices over $10/GJ pose significant difficulties for them.

In this regard, it is worth noting that the majority of C&I users surveyed have accepted higher gas prices as the new market norm and have made a number of changes to their businesses to adapt to these changed dynamics.[129] A number of C&I users have tried to mitigate the impact of increased gas costs through:

- energy efficiency improvements
- fuel switching
- reducing headcount or pay increases
- deferring investments or expansions
- changing shift/usage patterns.

Some C&I users have also deferred major plant upgrades or large maintenance spends. For example, one C&I user stated that higher gas prices were the major factor in delaying a $15 million expansion in regional Victoria. The expansion was expected to add more than 100 staff to the existing 330 strong workforce. This user stated passing on prices to clients resulted in some customers converting to imported products.

> *"We have delayed our plant construction. Margins have compressed, with gas cost being the most significant factor. We are undergoing a round of cost cutting and price rises with the aim to get margins back to an acceptable level. If we are successful in meeting our cost reduction targets, we can go ahead with the planned expansion plans. We continue with low cost aspects of planning preparation for the build, but tenders for construction and the like are now being held back."*
>
> *East coast gas user, September 2019*

As gas prices reach about $9–$10/GJ, those C&I users that have addressed the inefficiencies outlined above have limited options for further reductions to their gas use without significant capital investment.

> *"We have become as efficient as possible. Further reductions in gas use would require major capital investments, changing the technology rather than tinkering around the edges. In a low margin, volatile business environment this sort of capital investment which has a 10 year return is not feasible."*
>
> *East coast gas user, October 2019*

A large number of C&I users are also exploring alternatives to gas.[130] Incitec Pivot, for example, is undertaking a $2.7 million feasibility study to expand its ammonia producing Moranbah facility in Queensland.

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[129] ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 26.

[130] ACCC, *Gas Inquiry 2017–2020—Interim Report*, September 2017, p. 52 and ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2018, p. 63, ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 82.

Incitec Pivot is a fertiliser and explosive maker with plants at Gibson Island, Phosphate Hill, Moranbah and Moura. Vice President, Group Energy Strategy, Tim Lawrence said current gas pricing available for long-term supply contracts challenged the economics of expanding ammonia manufacturing at the Moranbah site in Queensland.

> "*Inevitably, such pricing jeopardises other industrial projects in Eastern Australia as well. "The green hydrogen/green ammonia project will not reduce the existing gas demand at the facility, but rather offset a potential increase in demand. The production of green hydrogen is using solar power to supply a water electrolysis facility to supply pure hydrogen feedstock. The green ammonia capacity under consideration is approximately 20% of the current ammonia production, equivalent to approximately 1.2PJ per annum of natural gas demand." Incitec Pivot, Vice President, Group Energy Strategy, Tim Lawrence*

If feasible, the proposed solar hydrogen facility would include up to 160 MW of electrolysis capacity and a 210 MW solar farm co-located at Moranbah.[131] The Moranbah facility uses over 8PJ of gas per year.

Australian Paper is progressing with an energy-from-waste plant after successful completion of a $7.5 million feasibility study.[132] If implemented, Australian Paper's waste to energy proposal could reduce its gas use by up to 4 PJ each year.[133]

One C&I user reported that they are considering converting to LPG because it would cost 25 per cent less than natural gas, but there will also be costs required to convert their equipment.

A number of C&I users that have to make major decisions on plant upgrades or large maintenance spends in to the next decade have advised that they are carefully assessing the long-term sustainability of their business. Others have advised rising gas prices may make their operations unviable leading to closures.

For example, in July, Kimberly-Clark Australia ceased operations at its Ingleburn Mill in Sydney, with around 220 staff losing their jobs.[134] In October 2019 Norske Skog announced the sale and closure of its Albury mill. The mill was purchased by Visy and ceased newsprint production in December last year.[135]

In addition, during the first quarter of 2019 Remapak, a Sydney-based producer of polystyrene coffee cups made an administration announcement. This has been followed by a September decision to liquidate.[136] Claypave, a Queensland-based brick and paving manufacturer, which went into administration in the first quarter of 2019, transitioned from voluntary administration to liquidation in April.[137]

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[131] Incitec Pivot, News, Dyno Nobel conducts feasibility studies to assess renewable hydrogen at Moranbah facility,30 September 2019, Accessed 22 October 2019

[132] ABC News, Australian Paper to proceed with Victorian-first energy-from waste project, 7 February 2019, https://www.abc.net.au/news/2019-02-07/victorian-first-energy-from-waste-project-gets-green-light/10791686.

[133] Australian Paper, Energy from Waste Project Summary, p. 6. 27 September 2018, Accessed 8 January 2020.

[134] Kimberly- Clarke, News, Kimberly-Clarke Announces Closure of Ingleburn Mill, 3 April 2019, Accessed 21 October 2019.

[135] Norske Skog, English Press Releases, Norske Skog announces sale and closure of Albury mill, 3 October 2019. Accessed 25 November 2019

[136] Worrells, Ress Release: Remapack Transitions from Voluntary Administration to Liquidation- Assets for Sale, 6 September 2019, Accessed 18 November 2019.

[137] Worrells, Press Release, Claypave creditors place company in to liquidation, 30 April 2019. Accessed 18 November 2019.

3.4. Concerns around supply certainty and less flexible contract terms persist

In our July report many users reported that they were still engaging in discussions with a range of suppliers for supply from 2020[138], and several had also participated in producers' expression of interest gas sales processes. More C&I users have since sourced gas for 2020 and have indicated suppliers were constructively engaging in preliminary discussions for 2021. However, small C&I users report supply remains uncertain past 2021. Several users indicated that they hope to finalise longer term contracts by the end of 2019.

Users continue to express concerns about the lack of competition among gas suppliers, which they noted accorded suppliers a greater degree of bargaining power in negotiations. Kagome, a tomato processor in regional Victoria, is a small C&I user. In August its' chief executive Jason Fritsch characterised engagement from retailers, and the willingness of retailers to negotiate terms as extremely poor.

> *"There is literally no negotiation with gas companies. The attitude is 'here is the contact, take it or leave it.' The retailers offer prices that bring users just shy of bankruptcy".*
>
> *Jason Fritsch, Chief Executive, Kagome*

In contrast, a number of large C&I users (over 1PJ/a) described improved engagement from retailers and producers, including a willingness to negotiate on some terms.

One larger C&I user noted:

> *"We have experienced slightly better behaviour as suppliers feel the pressure of softer domestic spot and global spot prices forward. But that isn't translating to a material price change from the April 2019 campaign".*
>
> *East coast gas user, September 2019*

As discussed at 2.4.1 the average level of flexibility in GSAs, in the form of take or pay and load factor multipliers, has decreased since the ACCC last reported in July 2019.

3.5. C&I users are sourcing gas in a range of ways

Several C&I users have altered their approach to sourcing gas. In the past many C&I users simply rolled over their supply contract with a retailer upon expiry. Many C&I users are now looking for gas from a diverse range of supply sources and, when required, contracting their transportation requirements directly. Some users that previously obtained their gas from retailers have started to procure gas directly from producers, others are making greater use of the facilitated gas markets and some have engaged in discussions with the LNG import facility proponents.

3.5.1. Users are increasingly sourcing gas directly from producers including as joint venture partners and from new domestic only tenements

Some C&I users are working with producers to directly source gas, sometimes from new domestic only tenements.

[138] ACCC, Gas Inquiry 2017–2020—Interim Report, July 2019, p. 80.

Incitec Pivot has entered into a GSA with APLNG, to supply Incitec's Gibson Island fertiliser plant until the end of 2022. The deal has reportedly secured around 450 jobs at the Gibson Island plant.[139] Incitec Pivot is also developing a gas tenement as a joint venture partner with Central Petroleum.

In 2019 Santos signed a memoranda of understanding to supply Narrabri gas to C&I users Brickworks and Perdaman Group, as well as gas wholesaler Weston Energy. Subject to the project's approval, Santos would supply Brickworks with up to 3 PJ of Narrabri gas per year for seven years, and Weston with 10 PJ per year for ten years.[140]

Production at Senex's Project Atlas in Queensland's Surat Basin is quarantined for supply to domestic customers on the east coast under Queensland government rules intended to increase supplies for local manufacturers and industrial gas buyers. Initial deals for the sale of Atlas gas have been signed with CSR, packaging company Orora, and glassmaker O-I Australia.[141] Small C&I users are also changing the ways they source and use gas to reduce their gas supply costs. One small C&I user said the business now continually monitors its supply arrangements to achieve reductions.

Some users reported sourcing gas from the facilitated gas markets. As we reported in July 2019, an increasing number of large C&I users have been using facilitated gas markets (short-term trading markets (STTMs) in Sydney, Adelaide and Brisbane, the Wallumbilla Gas Supply Hub, and the Declared Wholesale Gas Market (DWGM) in Victoria) to manage 'overs and unders', particularly since take-or-pay rates have increased in their gas supply agreements, reducing their flexibility.[142]

We previously 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 as a business risk to manage.

Large C&I users reported they have been able to realise significant savings by using the facilitated gas markets. As reported in section 2.5.1 the daily prices paid for gas in the short-term markets in the Southern States (the simple average of the Victorian DWGM, the Sydney STTM and the Adelaide STTM) and Queensland (the simple average of the Wallumbilla GSH and the Brisbane STTM) this year were generally lower than the offers received in 2018 for 2019 supply.

One C&I user explained their decision to join the facilitated gas markets this way:

> *"Our gas costs will increase by over 20–25% across our manufacturing footprint in CY20 as a result of market conditions. In order to manage the increase in gas costs, we had to become a direct market participant and develop a self-management structure for gas as opposed to using a retailer to support us. Through direct market participation and self-management, we have taken on additional risks which have historically been managed by retailers".*
>
> *East coast gas user- October 2019*

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139 The Sydney Morning Herald, 'Gibson Island fertiliser plant to stay open, saving 450 jobs', 4 June 2019, https://www.smh.com.au/business/companies/gibson-island-fertiliser-plant-to-stay-open-saving-450-jobs-20190604-p51u92.html.

140 Santos, Santos signs MOUs with Brickworks and Weston Energy for Narrabri gas (Media Release), 9 May 2019: https://www.santos.com/media-centre/announcements/santos-signs-mous-with-brickworks-and-weston-energy-fornarrabri-gas/.

141 Angela Macdonald-Smith, Senex ramps up gas spend as it turns to profit, *Australian Financial Review*, 20 August 2019.

142 ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 84.

Another large C&I user noted that:

> *"We have long been a commodity hedger, hedging oil was run of the mill for us so moving to the wholesale market made sense especially as we are a low margin business and high energy costs can be life and death for the business".*
>
> *East coast gas user, October 2019*

One large C&I user, who switched to contracting 100 per cent of their gas from the facilitated gas markets, characterised it as a positive experience:

> *"We have "become comfortable" buying in the spot market and we haven't seen and don't expect any price deals below the spot price. This requires new producer volumes to become available".*
>
> *East coast gas user, September 2019*

Some small C&I users are using the facilitated markets. One user is sourcing all their gas, totalling 1.1PJ/a, from the Victorian DWGM. However, other small C&I users have indicated that the potential cost and risk associated with participation in these markets are too great. For example, one user has explored using the DWGM, but found that the cost required to pressurise the gas to transport from Victoria to its site interstate was too high to make this option viable.

C&I users who require a constant supply of gas (for example, glass manufacturers) are hesitant to risk the exposure associated with the facilitated gas markets. For these users an inability to procure gas could result in machinery failures and cessation of production for some time. These users therefore tend to only participate in the facilitated gas markets to manage 'overs and unders' on a day.

> *"We will be a wholesale participant in each of the gas markets from 2020 and will use spot purchasing and selling to balance the physical deliveries from our wholesale gas sale agreement with our actual consumption".*
>
> *Melissa Perrow, General Manager Energy, Brickworks*

One of the risks associated with the facilitated gas markets is that it can leave C&I users exposed to fluctuations in prices. While there are some ASX futures products that C&I users can use to hedge their exposure to prices in the DWGM and the Wallumbilla GSH, there are no equivalent market based products currently available in the STTMs. One C&I gas user did, however, inform us that a financial institution is starting to offer an over the counter STTM swap product that participants can use to hedge their exposure to prices in this market. This is a financial swap product that enables the buyer to receive certainty on price linked to a particular location e.g. Sydney STTM which is different to physical gas supply where users have the option of transporting it to a different location.

> *"The benefit of [an over the counter STTM swap product] this is that it removes the need for a gas transportation agreement (included in the swap price) and there aren't supply interruptions from maintenance etc".*

While the C&I user chose not to use the product, they thought it was a good initiative and will reassess their position in the future.

> *"The offered price was not attractive enough to forgo the flexibility we were able to negotiate with a gas producer. But, we do use financial swaps for hedging our exposure to the electricity spot market".*
>
> *East coast gas user, October 2019*

The ACCC notes that retailers are also offering financial hedging products to their customers.

3.5.2. Some users have considered LNG imports but many are concerned about the effect it may have on prices

There are a number of entities considering building LNG import facilities on the east coast. Both small and large C&I users have had discussions with the LNG import terminal proponents. However, small C&I users have reported that they are unable to source gas from LNG import proponents as their loads do not satisfy minimum purchase requirements.

In contrast, a number of large C&I users have signed MOU's with LNG import terminal proponents. However, these large C&I users have indicated discussions about long term supply arrangements are inflexible, with proponents offering little take or pay flexibility and high oil linked prices. Two gas users noted that there is limited ability to take advantage of spot cargo buying in the short term given facility scheduling.

Previously, users generally characterised the entry of new suppliers and new supply in the market as beneficial.[143] However, as import terminals become more likely with the AIE (Port Kembla) project attaining planning approval, some C&I users have raised concerns about the potential impact of LNG terminals on domestic gas prices.[144]

One C&I user put their concerns as follows:

> *"LNG import terminals will permanently introduce an LNG import-parity and local processing cost price reference for the domestic market. This is at least $1.50 - $2/GJ higher than LNG export parity on a netback basis, in our assessment."*
>
> *East coast gas user, October 2019*

As discussed in section 1.8, AIE has requested to increase the number of annual LNG shipments from 26 standard vessels of 170 000 cubic metres to up to 46 variable-sized carrier shipments.[145]

The ACCC intends to examine the development of LNG import terminals and their potential market impact as part of this inquiry.

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143 ACCC, Gas Inquiry 2017–2020—Interim Report, July 2019, p. 85

144 Sydney Morning Herald, Port Kembla gas terminal gets planning go-ahead, 29 April 2019. Australian Financial Review, The Forrest gas train really is rolling now, 24 May 2019.

145 AIE, Media Release, AIE lodges project modification to meet seasonal demand, October 2019, Accessed 12 November 2019.

4. Transportation and storage

4.1. Key points

- In those cases where new contracts were entered into between January and July 2019, we have seen some reduction in prices, particularly for as available and interruptible transportation services, but there have been some increases as well. There has been limited contracting activity in the first half of 2019 and as a result the majority of transportation prices have increased in line with inflation.
- Some shippers have experienced a significant increase in the charges payable at the Iona underground storage facility and Dandenong LNG storage facility.
- A range of shippers have advised us that some pipeline operators are no longer willing to sell their services at a discount to the standing price because the prices would be reported through our inquiry and they would need to offer the discount to other shippers. Some shippers have also noted that pipeline operators may be using the capacity trading reforms as an excuse to reduce the level of flexibility provided to shippers, or to require shippers to pay more for this flexibility. We would be concerned if pipeline operators were using price transparency or the capacity trading reforms to justify higher prices.
- Pipeline investment continues to be focused on bringing new sources of gas supply to the East Coast Gas Market, with pipeline operators exploring options to facilitate the supply of gas from domestic gas reserves and import terminal facilities. Limited investment in storage capacity is currently being proposed.
- In March 2019 the capacity trading reforms came into effect. There are signs these reforms, which include a capacity trading platform (CTP) and day-ahead auction (DAA), are having a positive influence on the East Coast Gas Market, with the DAA having been used to transport a significant volume gas from Queensland to New South Wales and Victoria in the first eight months of operation.
- While early indications are positive, the ACCC is concerned that the structure and level of the standardisation charges levied by some facility operators may be discouraging shippers from using the CTP and DAA and may mean that the expected efficiency improvements from the reforms are not realised. The ACCC suggests that further consideration be given to the cost recovery provisions as part of the AEMC's upcoming liquidity review, or the post implementation review of the capacity trading reforms.
- Concerns continue to be raised with us about the inability of C&I users and other retailers to access pipelines in regional areas where the capacity has been fully contracted to an incumbent retailer. Following further examination of this issue we have found that access to pipeline capacity remains a problem on a number of regional pipelines and is inhibiting competition in these areas.
- We are currently considering whether any of the conduct we have observed in relation to some regional pipelines constitutes a possible contravention of the CCA. Additionally, we have identified a number of longer-term policy solutions that should be considered as part of the COAG Energy Council's Gas Pipeline Regulation Impact Statement (Gas Pipeline RIS).
- The ACCC intends to continue to examine the contracting activities of pipeline operators and consider the cost reflectivity of prices for the duration of the inquiry.

4.2. With some exceptions, transportation and storage prices are relatively unchanged

Over the course of the Inquiry the ACCC has reported on the prices paid for firm forward haul services by shippers. In our last interim report, we extended the period of analysis to July 2016 – January 2019 and also expanded its scope, by including as available, interruptible and short-term firm transportation services, as well as park and loan services. We also included the standing prices[146] published by pipeline operators.

Using information provided by pipeline operators, we have updated this analysis to include the prices payable for firm forward haul, as available and interruptible and park and loan services on major pipelines as at July 2019. We have also updated the analysis to include the prices payable for use of the Dandenong LNG and Iona underground storage facilities. Box 4.1 outlines the approach we have used when reporting prices.

The map at figure 4.1 provides a snapshot of the minimum and maximum prices paid by shippers for firm transportation and storage services in July 2019.

As we observed in earlier reports, on pipelines and storage facilities where there has been limited contracting activity, prices have tended to increase only in line with inflation. On other pipelines where a greater level of contracting activity has occurred, prices have been subject to a greater degree of variability. The discussion in the remainder of this section focuses on those cases where there have been more material changes in price as a result of contracting activity.

Before outlining the changes that have occurred, it is worth noting that through the C&I user survey and discussions the ACCC held with shippers regarding the capacity trading reforms (see section 4.4), shippers made a number of observations about their recent experiences negotiating with pipeline operators.

A number of shippers, for example, noted that some pipeline operators were unwilling to sell their services at a discount to the standing price. These pipeline operators reportedly informed the shippers that if they were to offer a discount to one shipper, then they would have to offer it to other shippers because the prices would be reported through the Inquiry. A number of other shippers also noted that some pipeline operators appeared to be using the capacity trading reforms as an excuse to reduce service flexibility and/or to extract additional revenue for services that had been provided in the past at no additional cost.

While the ACCC has not been in a position to verify these claims, we would have concerns if the transparency of prices being provided through the Inquiry is being used by some pipeline operators as an excuse not to engage in meaningful negotiations with shippers and to justify higher prices. We would also have concerns if pipeline operators were trying to misrepresent the effect of the capacity trading reforms (or any other reforms) and to use this as an excuse to either offer less flexibility, or to require shippers to pay more for this flexibility.

The ACCC intends to continue to examine the contracting activities of pipeline operators and consider the cost reflectivity of prices for the duration of the Inquiry.

146 The term ‘standing prices’ is used to refer to the standing prices required to be published for pipelines subject to Part 23 of the NGR, the prices that pipelines subject to light regulation are required to publish for light regulation services and the reference tariffs that pipelines subject to full regulation are required to publish.

Box 4.1: Approach to reporting prices

The prices reported in this section have been sourced from invoices issued for July in all years except 2019, where prices have been obtained for both January and July. The prices are based on invoices issued under contracts entered into for a term of one month or longer.

Pipeline prices

The following applies to the pipeline prices reported in this section.

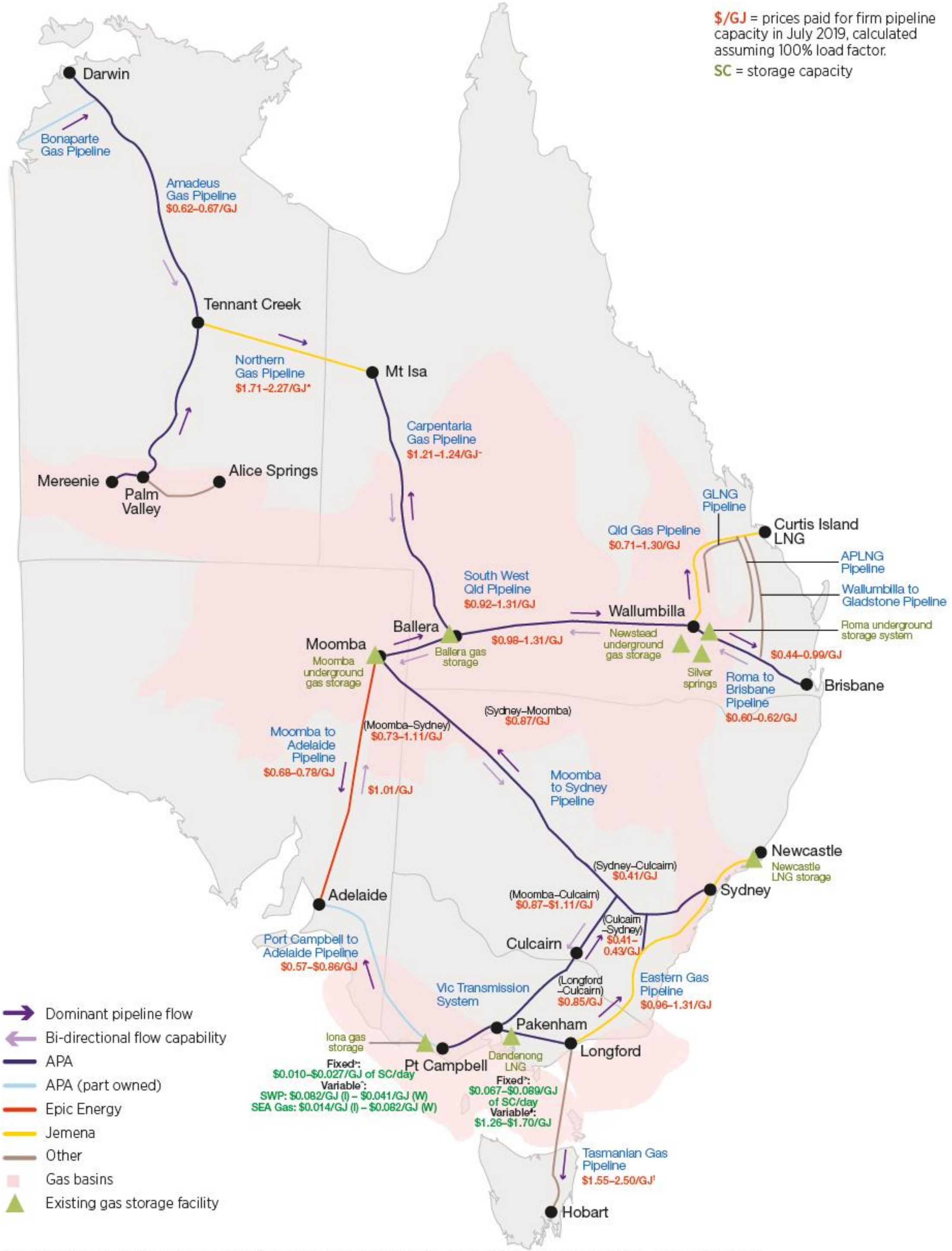
- Actual prices in transportation agreements may vary due to differences in key commercial terms. This may reflect differences in load factor, capacity commitments, service flexibility, contract length, the time at which the prices were agreed or reviewed and whether services are provided across a number of pipelines.
- Where relevant, the prices reported for some pipelines include the prices payable for other services required to use that pipeline, such as compression in the case of the South West Queensland Pipeline (SWQP), and the nitrogen removal service in the case of the Northern Gas Pipeline (NGP).
- The term ‘maximum’ is used in the charts and map to refer to the highest price paid by shippers in the relevant period, while the term ‘minimum’ is used to refer to the lowest price. The term ‘new prices’ is used to refer to prices payable under contracts and variations negotiated since 1 August 2017, which are identified in the first period the price is payable.
- Firm forward haul services: Some firm forward haul services are based on a capacity charge only (i.e. $/GJ of MDQ), while others are based on a throughput charge ($/GJ) or a combination of the two. In the latter two cases, the prices have been converted to a $/GJ of MDQ measure, assuming a 100 per cent load factor (i.e. assuming the shipper uses all the capacity it has contracted).
- As available and interruptible services:
  - The prices payable for as available and interruptible transportation services, and park and loan services have been included even when the quantity supplied in that month is zero. The prices reported for these services therefore represent the prices that would be paid under the shipper’s contracts if the services had been supplied
  - APA’s short-term firm, services are included in the as available and interruptible services category, as is APA’s interruptible service, which is only available when a pipeline is fully contracted. APA’s day-ahead firm and within-day services have not been included in the analysis of contract prices, however standing prices for these services are shown.

Storage prices

The reported prices for the Dandenong LNG and Iona underground storage facilities include a fixed and variable charge. The fixed charge is a charge for the storage capacity and is measured on a price per GJ of storage capacity per day basis. The variable charge, which is measured on a dollar per GJ basis, reflects the liquefaction cost at the Dandenong LNG facility and the storage injection and withdrawal charges at the Iona underground storage facility.

Actual prices in storage agreements may vary due to differences in key commercial terms. This may reflect differences in capacity commitments, storage, withdrawal and injection rates, service flexibility, contract length and the time at which the prices were agreed or reviewed.

Figure 4.1: Firm transportation and storage prices in east coast and Northern Territory



Notes: The transportation and storage prices are based on invoices in July 2019 provided by operators, and exclude GST.

Actual prices in transportation and storage agreements may vary due to differences in key commercial terms. For transportation this may reflect differences in load factor, capacity commitments, service flexibility, contract length, the time at which the prices were agreed or reviewed (including whether a contract is a foundation agreement) and whether services are provided across a number of pipelines. For storage this may also reflect differences in capacity commitments, storage, withdrawal and injection rates, service flexibility, contract length and the time at which the prices were agreed or reviewed.

* Tariffs include the cost of the nitrogen removal service.

\- While this pipeline is a bi-directional pipeline, the prices reported are for northern haul services only.

! In prior reports the TGP prices were only reported between Longford and Hobart. Prices on the TGP now reflect all prices payable between Longford and Zone 2.

\# The variable charge for the Dandenong LNG storage facility reflects the liquefaction cost.

^ The variable charge for the Iona gas storage facility reflects the charge for injection into the storage facility (I) and withdrawal from the storage facility (W).

> While prices have been expressed on a $/GJ of SC/day basis, the ACCC understands that storage services are generally sold under agreements with contract terms of one year or more and not on a day-to-day or short-term basis.

4.2.1. Since January 2019 firm forward haul prices have, with some exceptions, largely continued to rise with inflation

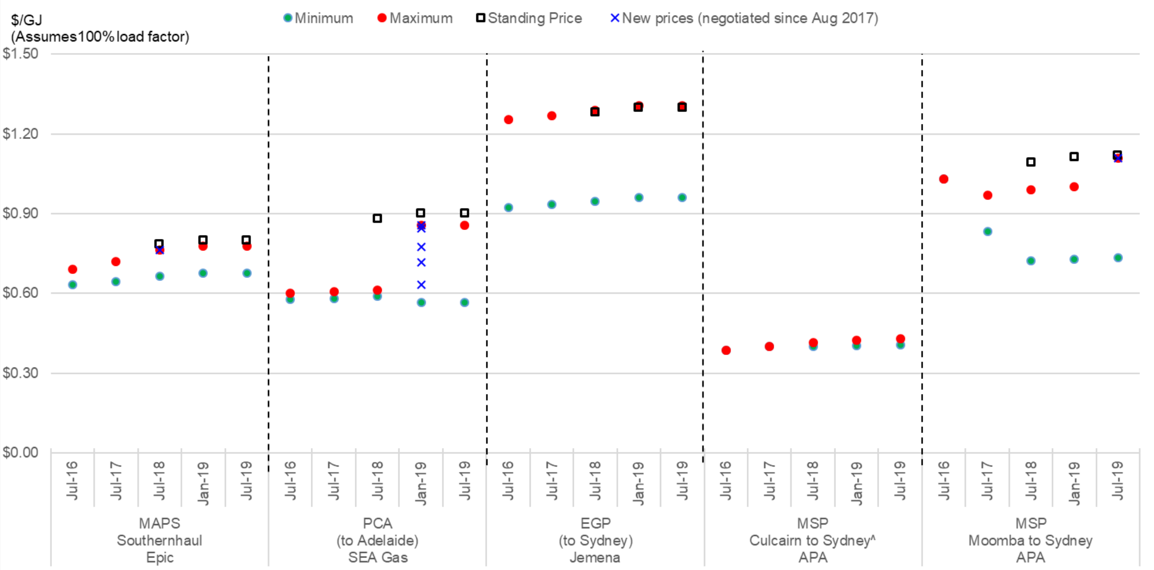
Chart 4.1 shows the minimum and maximum prices paid by shippers for firm forward haul services between July 2016 and July 2019 on key pipelines in Queensland and the Northern Territory (Northern Pipelines) and the Southern States (Southern Pipelines). The chart also shows prices payable for new contracts and variations (identified in the first period in which that price is payable) negotiated since the introduction of Part 23 of the National Gas Rules (NGR) in August 2017.

Chart 4.1: Firm forward haul transportation prices (nominal)

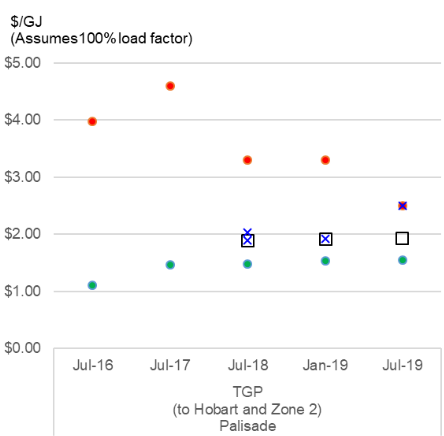
Northern pipelines

*Includes the cost of the mandatory nitrogen extraction service
** Includes compression costs.

Southern pipelines



^ No standing price has been published for this service.



*TGP pricing changed from a distance based tariff to a zonal tariff as at 1 January 2018.

Since our July 2019 report, the prices paid by shippers for firm forward haul transportation on most pipelines have remained relatively stable, with the only real exceptions to this being the Carpentaria Gas Pipeline (CGP) and Tasmanian Gas Pipeline (TGP), where prices have continued to fall.

As noted in our July 2019 report, the prices payable on the CGP under new contracts and variations have fallen over the past two years. This reduction is in line with the reduction in the CGP's standing price that occurred in mid-2018, when the standing price fell from $1.62/GJ to $1.21/GJ. Between January and July 2019, prices on the CGP have continued to fall, with a number of C&I users able to secure significant reductions in prices. As chart 4.1 shows, the maximum and minimum price paid for firm forward haul services on the CGP is now broadly aligned with the standing price.

Chart 4.1 also shows that since January 2019, the maximum price paid for firm forward haul services on the TGP has fallen from $3.30/GJ to $2.49/GJ, a reduction of 24 per cent. This price reduction follows other significant reductions obtained by shippers under new contracts and variations since July 2018. As previously noted,[147] these reduced prices followed an arbitration under Part 23 of the NGR that was completed in April 2018. The maximum price paid on the TGP has now fallen 66 per cent since the arbitration decision.

In contrast to the TGP and CGP, the maximum price paid by a shipper for firm forward haul services from Moomba to Sydney via the Moomba to Sydney Pipeline (MSP) has increased from $1.00/GJ to $1.11/GJ. The new maximum price reflects the price a shipper has agreed to pay for a shorter term contract for capacity over the peak winter period.

As noted in our April 2018 and July 2019 reports, APA is offering a bundled firm forward haul service from Wallumbilla to Sydney or Culcairn (connecting to the Victorian Declared Wholesale Gas Market (DWGM)), with a standing price of $2/GJ. Based on our review of invoices it would appear that no shippers were using this service in January or July 2019.

In relation to standing prices, most of these prices continued to increase in line with inflation. The only exceptions to this occurred on the two pipelines that are subject to full regulation:

- the Amadeus Gas Pipeline (AGP), where the reference tariff fell by 2 per cent from $0.5726 to $0.5609 in July 2019
- the Roma to Brisbane Pipeline (RBP), where the reference tariff for the long-term firm service fell by 6 per cent from $0.7147 to $0.6740 in July 2019.

In both of these cases, the reference tariffs that were approved by the AER provided for a reduction in reference tariffs to occur over the access arrangement period.[148] The AER's decision for the RBP also provided for the reference tariff to be reduced if APA earned any revenue from the provision of rebateable services (i.e. in-pipe trading, capacity trading and park and loan services). The revenue earned by APA from the provision of these services increased significantly in 2018, which has contributed to the 6 per cent reduction in prices on this pipeline.[149]

While the reference tariff for the long-term firm service on the RBP has fallen to $0.6740/GJ, the published tariff on APA's website for this service is $0.7299/GJ,[150] which is 8.3 per cent *higher* than the reference tariff. When asked about this difference, APA informed the ACCC

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[147] ACCC, *Gas Inquiry 2017–2020 Interim Report*, December 2018, p. 101; July 2019, p. 122

[148] AER, RBP Access Arrangement 2017–22—Overview, November 2017, p. 19 and AER, AGP Access Arrangement 2016 to 2021–Overview, May 2016, p. 18.

[149] APA, RBP Notification of Annual Tariff Adjustment, 14 May 2019.

[150] APA website, accessed November 2019: https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/current-tariffs-and-terms/

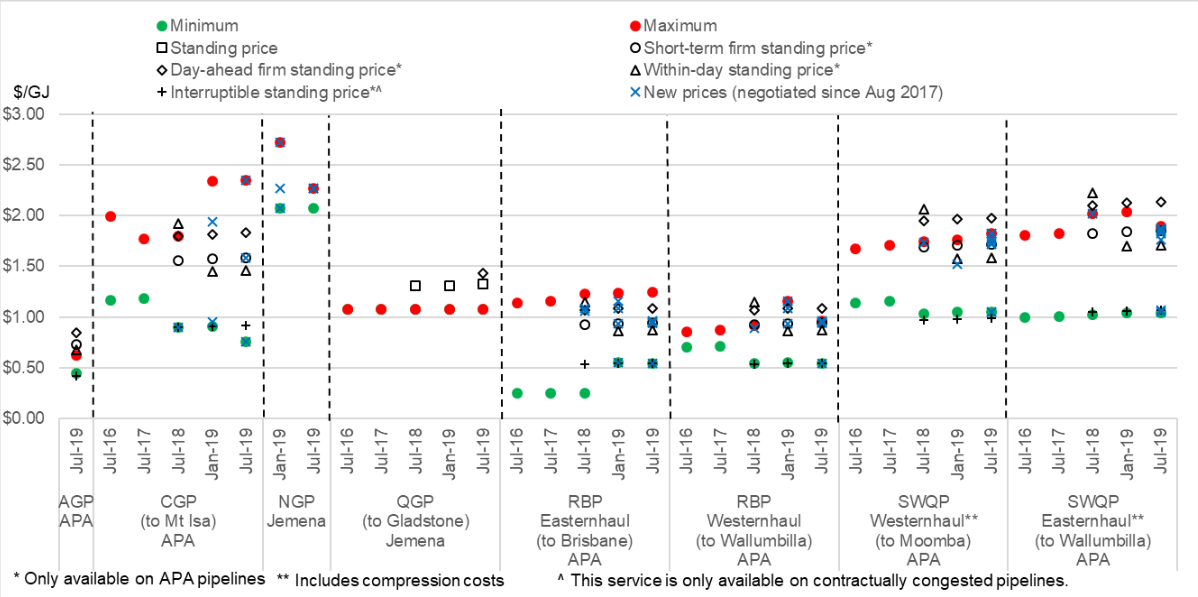
that the reference service is subject to the terms of the access arrangement, which includes provisions that differ from APA's standard GTA that applies to its published tariffs. APA, for example, noted that the access arrangement includes annual tariff adjustments to reflect changes in inflation, the cost of debt, and rebates from the sale of rebateable services on the pipeline, while the standard GTA only provides for tariffs to reflect changes in inflation.

4.2.2. As available and interruptible prices have improved under some of the new contracts entered into since January 2019

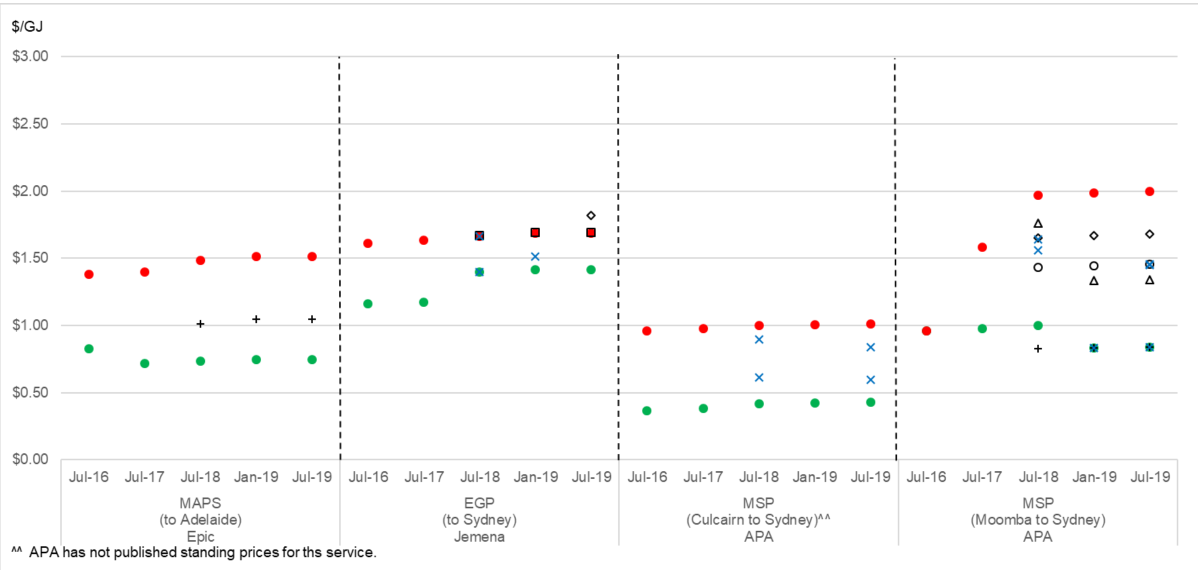
Chart 4.2 shows the minimum and maximum prices payable by shippers for as available and interruptible transportation services between July 2016 and July 2019, as well as the prices agreed in more recently negotiated contracts on Northern and Southern pipelines.

Chart 4.2: As available and interruptible transportation charges

Northern pipelines[151]



Southern pipelines



151 Due to an increase in the number of customers, this chart now includes data for the AGP.

As this chart shows, some shippers have been able to secure lower prices under new contracts. For example, one shipper on the NGP received a 17 per cent price reduction under Jemena's discounted as-available rate in 2019, while another shipper on the RBP negotiated a smaller reduction.

While not included in chart 4.2, the spread of prices continues to increase on several APA pipelines as more customers enter into contracts that include new shorter term day-ahead and within-day services. This is particularly evident on the SWQP where the maximum price has increased to $2.24/GJ in both directions (i.e. Moomba to Wallumbilla and Wallumbilla to Moomba). As noted in our July report, the standing prices for these services continue to be priced at 120–150 per cent of the long-term firm price, although we have seen limited use of these services to date.

There has been little movement in standing prices for these services since our July 2019 interim report, except on the:

- EGP and QGP, where Jemena has introduced a day-ahead firm service, with a standing price set at 140 per cent of the long-term firm price, which is higher than the 130 per cent premium it applies to as available services
- AGP, where the reduction in the reference tariff for long-term firm services (see section 4.2.1) has flowed through to APA's short-term firm, day-ahead, within-day and interruptible service.

In contrast to the AGP, the reduction in the reference tariff for the long-term firm service on the RBP has not flowed through to shorter term services on the RBP. The prices for these services are instead based on the $0.7299/GJ published tariff, which as noted in section 4.2.1 is 8.3 per cent higher than the reference tariff.

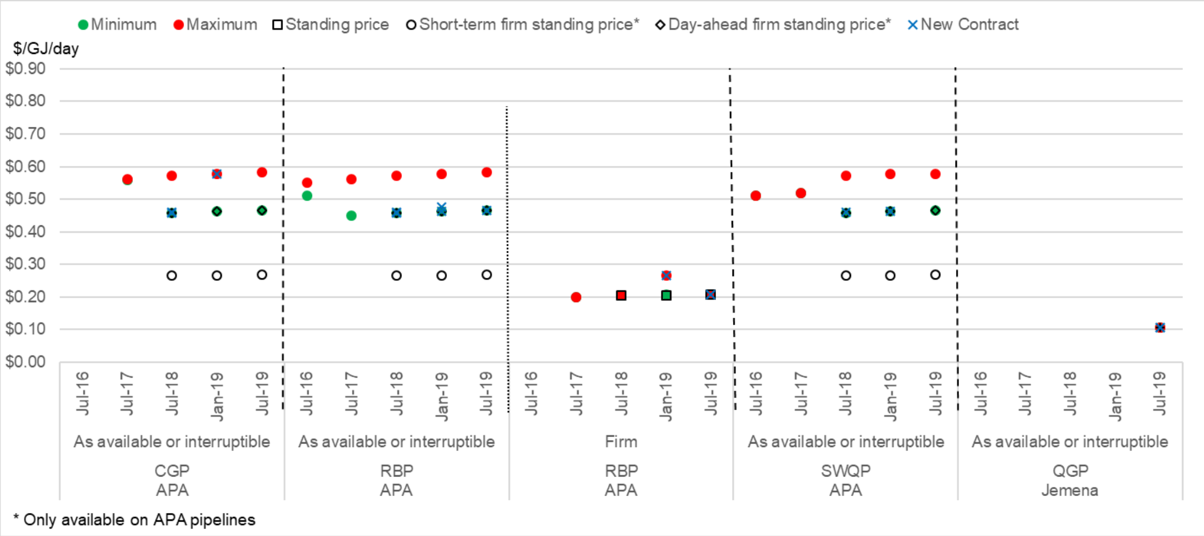
4.2.3. Prices for park and loan services continue to vary widely

Chart 4.3 shows the maximum and minimum prices payable by shippers for park and loan services (both firm and as available or interruptible services) between July 2016 and July 2019, as well as the prices agreed in more recently negotiated contracts on Northern and Southern pipelines.

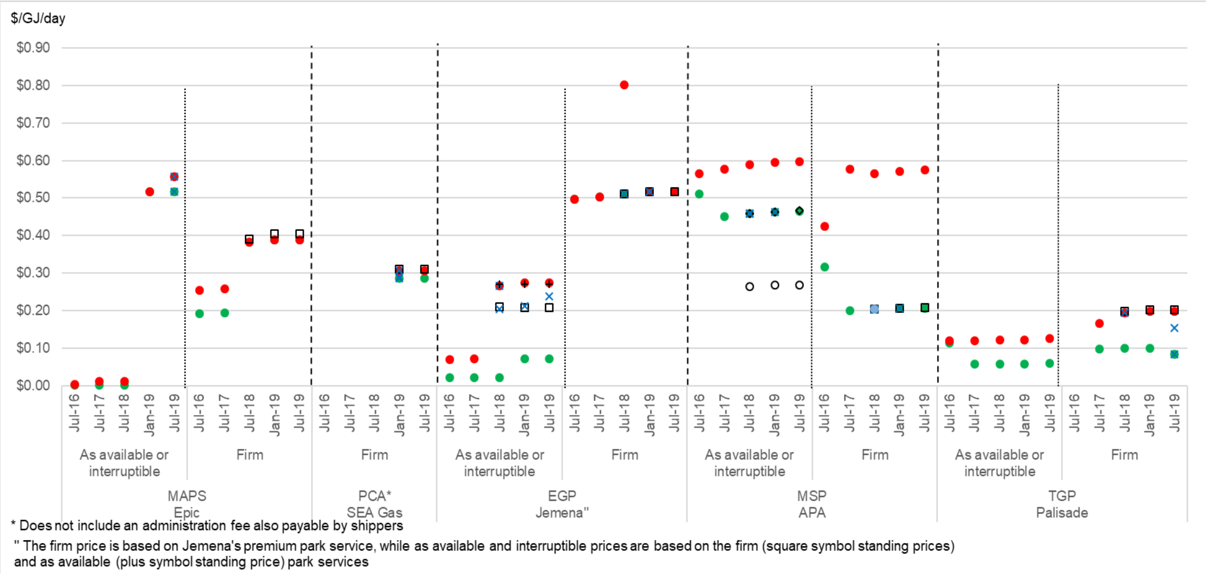
As this chart shows, the prices payable for park and loan services continued to vary considerably across pipelines in July 2019, with the prices payable for firm park and loan services ranging from $0.08/GJ to $0.57/GJ, while prices payable for as available and interruptible park and loan services ranged from $0.06/GJ to $0.60/GJ. The prices payable for these services can also vary significantly between shippers using the same pipeline, as highlighted by the prices paid by shippers on the MSP and the Eastern Gas Pipeline (EGP).

Chart 4.3: Park and loan service charges

Northern pipelines



Southern pipelines



4.2.4. Storage prices have generally increased since July 2018

The Dandenong and Iona storage facilities are the only two dedicated storage facilities that provide storage services to third parties in the East Coast Gas Market. In our December 2018 interim report, we reported the prices paid for storage services on these facilities in July 2018. The map at figure 4.1 updates this analysis by setting out the prices payable for these services in July 2019.

As figure 4.1 shows, the prices paid for storage at the Dandenong LNG storage facility is significantly higher than at the Iona underground storage facility. This reflects the different costs associated with the use of these two facilities. The Dandenong LNG storage facility, for example, is used to store small amounts of gas to be injected quickly to address short-term peaks and system security issues in Victoria. In contrast, the Iona underground storage facility tends to be used to store large amounts of gas during the summer months, which can then be withdrawn in winter to meet peak demand.

Since July 2018, the spread of prices for the fixed charge at the Iona underground storage facility has broadened from $0.013–$0.021/GJ to $0.010–$0.027/GJ of storage capacity per day in July 2019. This represents a 23 per cent fall in the minimum price and a 29 per cent increase for the maximum price paid. The variable charges for the injection and withdrawal of gas to the Iona storage facility, on the other hand, have increased in line with inflation, with variable charges of[152]:

- $0.014/GJ for injection into storage and $0.082/GJ for withdrawal from storage via the Port Campbell to Adelaide (PCA) Pipeline, and
- $0.082/GJ for injection into storage and $0.041/GJ for withdrawal from storage via the South West Pipeline (SWP).

In contrast to the fixed charges payable on the Iona underground storage facility, the fixed prices for storage at APA's LNG facility have increased in line with inflation from $0.066–$0.087/GJ in July 2018 to $0.067–$0.089/GJ of storage capacity per day in July 2019. The variable charges, on the other hand, have increased from $1.24–$1.34/GJ to $1.26–$1.70/GJ, with some shippers experiencing a 27 per cent increase in their variable charge. This increase appears to reflect a cost pass through relating to the cost of liquefaction.

In contrast to pipelines, storage providers are not currently required to publish the standing prices for storage services.[153] As we noted in our joint ACCC-GMRG recommendations on measures to improve the transparency of the gas market, the absence of this information may make it difficult for prospective users of these facilities to determine whether to seek access and, if they do, to assess the reasonableness of the prices offered. We therefore recommended that storage providers be required to report the standing prices (including the standard terms and conditions) for their services and information on the prices actually paid by users of these facilities. This recommendation is being consulted on as part of the COAG Energy Council's Transparency Regulation Impact Statement (Transparency RIS).

4.3. Investment in pipelines and storage facilities continues to be focused on bringing new sources of supply to the market

While there has been some investment in improving capacity on constrained pipelines, the focus of pipeline operators continues to be on bringing new sources of supply to the East Coast Gas Market. In the past year, two new pipelines have been commissioned, or are soon to be commissioned (the Roma North Pipeline and the Atlas Gas Pipeline), with a number of operators currently considering investments in new pipelines. Further investment is also to be carried out to expand the capacity of the Iona underground storage facility.

Further detail on the proposed investments in pipelines and storage facilities is provided below.

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152 In the December 2018 interim report, the ACCC incorrectly reported:

- Iona facility withdrawal from storage charges as injection to storage charges, and
- Iona facility injection to storage charges as withdrawal from storage charges.

This has been rectified in this report.

153 The requirement for storage facilities to publish standing prices is currently under consideration by the COAG Energy Council as part of the Transparency RIS. http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Measures%20to%20Improve%20Transparency%20in%20the%20Gas%20Market%20-%20Regulatory%20Impact%20Statement%20-%2020190808.pdf.

4.3.1. There are a number of proposals to build new pipelines, but there is some uncertainty as to whether they will be developed

As noted in our December 2018 report, pipeline investment continues to be focused on bringing new sources of supply to market.

In June 2018, Senex Energy announced that Jemena would build, own and operate a 40TJ/day gas pipeline and processing facility to transport gas from Senex Energy's Project Atlas in the Surat Basin to the Wallumbilla Hub via the Darling Downs Pipeline.[154] Construction of the pipeline has now been completed, while construction of the gas processing facility is ongoing. The project is expected to be commissioned and deliver first gas by the end of 2019.[155] Jemena has also completed a $50 million acquisition of Senex Energy's Roma North pipeline and gas processing facility, after commissioning and performance testing was successfully completed in September 2019.[156]

In addition to these projects, Jemena and APA are both working on proposals to build pipelines that would connect the Galilee Basin with the East Coast Gas Market.

Jemena, who in October 2017 signed an MOU with Galilee Energy to deliver gas from the Glenaras Gas Project to the East Coast Gas Market,[157] continues to progress its pipeline development plans. In July 2019, Jemena released its proposed route for the Galilee Gas Pipeline (GGP), which will connect to the QGP near Injune. Jemena expects the pipeline will initially transport up to 200TJ of gas per day. [158] Jemena has previously indicated that it will look to extend the NGP to the Galilee Basin as part of its Northern Growth Strategy[159], see section 1.2 for more information.

In May 2019, APA, Comet Ridge and Vintage Energy also signed an MOU providing for APA to build, own and operate a pipeline that would connect Comet Ridge and Vintage Energy's fields in the Galilee Basin to Moranbah, with a second phase of pipeline development to connect to the East Coast Gas Market.[160] The Queensland Government granted APA a survey licence for the proposed pipeline in August 2019.[161]

These two pipeline developments are contingent on the producers making a final investment decision. There is therefore a great degree of uncertainty surrounding the development of these pipelines.

In a similar vein, there is uncertainty surrounding APA's proposed development of the Western Slopes Pipeline (WSP), which is contingent on the NSW Government's decision regarding the development of the Narrabri Gas Project. A further source of uncertainty for this project is the proposed development of the Hunter Valley Pipeline, with the NSW

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154 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/.

155 The Australian Pipeliner, *Atlas pipeline completed,* 17 October 2019, https://www.pipeliner.com.au/2019/10/17/project-atlas-pipeline-completed/.

156 Oil and Gas Australia, *Senex completes $50 million sale of Roma North gas processing facility and pipeline*, 13 September 2018 https://www.oilandgasaustralia.com.au/senex-completes-50-million-sale-roma-north-gas-processing-facility-pipeline/.

157 Jemena, *Jemena fast-tracks plans to connect Galilee Basin to the east-coast gas market,* 17 October 2017 https://jemena.com.au/about/newsroom/media-release/2017/jemena-fast-tracks-plans-to-connect-galilee-basin.

158 Jemena, *Proposed route for the Galilee gas Pipeline Revealed,* 30 July 2019, https://jemena.com.au/about/newsroom/media-release/2019/proposed-route-for-the-galilee-gas-pipeline-reveal.

159 Jemena, *Jemena fast-tracks plans to connect Galilee Basin to the east-coast gas market,* 17 October 2017, https://jemena.com.au/about/newsroom/media-release/2017/jemena-fast-tracks-plans-to-connect-galilee-basin.

160 APA, *Galilee Basin gas a step closer to the east coast*, 30 May 2019, https://www.apa.com.au/globalassets/apa---galilee-basin-gas-a-step-closer-to-the-east-coast.pdf.

161 APA, *APA progress unlocking galilee gas basin supply*, https://www.apa.com.au/globalassets/asx-releases/2019/2019-08-05-apa-progresses-unlocking-galilee-gas-basin-supply.pdf.

Government recently extending the planning approval for the pipeline for a further five years.[162] The proposed 420km pipeline would run from Wallumbilla to Newcastle, via the Narrabri Gas Project and the Hunter Valley, connecting to the EGP.[163]

As the examples listed above demonstrate, pipelines that are built to facilitate new sources of supply to the market are often the outcome of memoranda of understanding (MOU) entered into between individual producers and pipeline operators. Gas producers have told the ACCC that access to pipeline infrastructure is acting as a barrier to the commercialisation of 2C resources. To avoid duplication of assets and other inefficiencies, the development of this infrastructure should, where feasible, be coordinated by governments and operated on a third party access basis, as set out in section 1.9.5.

If a decision is made to proceed with the development of any of the LNG import terminals, then further investment in pipelines will also be required to connect the pipeline to the East Coast Gas Market. APA has recently released a proposed pipeline route to connect Australian Industrial Energy's proposed Port Kembla Gas Terminal to the MSP near Wilton.[164]

In relation to expansions, AEMO's 2019 Victorian Gas Planning Report noted that APA's proposed Western Outer Ring Main (WORM) pipeline, connecting Wollert to Plumpton on the Victorian Transmission System, is now a committed project and is expected to be commissioned during 2021.[165] AEMO expects the WORM project to increase SWP transportation capacity, improve system security through increased system linepack, and support peak day GPG demand.

4.3.2. In contrast to pipelines, limited investment is currently proposed for storage

In contrast to pipeline investment very few investments to either expand storage capacity or develop new storage capacity are currently proposed.

Lochard Energy has committed to increase the capacity of the Iona underground gas storage facility from 480TJ/day[166] to 520TJ/day by 2021, with a further expansion up to 570TJ/day still under consideration.[167]

In April 2019, Lochard Energy also purchased the Heytesbury assets from Origin Energy.[168] These assets are a collection of depleted on shore reservoirs, located near the Iona underground gas storage facility, which may have potential for underground gas storage development complementing the expansions noted above.

The ACCC understands that the Golden Beach Gas Field, located approximately 3 km offshore in the Gippsland Basin, may transition to a natural gas storage facility two years following initial gas production.[169] If this is to occur, the facility could supply peak demand by

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162 The Australian Financial Review, *Hunter pipeline to slash cost of Queensland gas transport*, 23 October 2019, https://www.afr.com/companies/energy/hunter-pipeline-to-slash-costs-of-qld-gas-transport-20191022-p53368.

163 Hunter Gas Pipeline, Hunter Gas Pipeline Project, http://www.huntergaspipeline.com.au/hunter-gas-pipeline.

164 APA, Port Kembla to Wilton pipeline, https://www.apa.com.au/about-apa/our-projects/port-kembla-to-wilton-pipeline/

165 AEMO, *Victorian Gas Planning Report*, March 2019, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2019/2019-VGPR-Full-Report.pdf

166 AEMO, *Natural Gas Bulletin Board*, https://www.aemo.com.au/Gas/Gas-Bulletin-Board/Reports.

167 AEMO, *Victorian Gas Planning Report*, March 2019, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2019/2019-VGPR-Full-Report.pdf, p. 57.

168 The Australian Financial Review, *Origin Energy, QIC's Lochard sign storage assets deal,* 4 February 2019, https://www.afr.com/street-talk/origin-energy-qicbacked-lochard-sign-heytesbury-deal-20190201-h1aqkq.

169 Golden Beach Energy, https://gbenergy.com.au/.

injecting gas into the Victorian Declared Transmission System at Longford.[170] Golden Beach Energy is aiming to supply first gas to the market in the second half of 2021.[171]

4.4. The capacity trading reforms are having a positive influence on the East Coast Gas Market

On 1 March 2019, two new market mechanisms were introduced to facilitate the trade of secondary transportation capacity on multi-user transmission pipelines and stand-alone compression facilities that are providing third party access, have a nameplate rating of 10 TJ/day or more and are operating under the contract carriage model:[172]

- the Capacity Trading Platform (CTP), which forms part of the Gas Supply Hub (GSH) and allows shippers to trade secondary capacity prior to the close of trade on gas day D-1, using either the exchange or the listing service for more bespoke products
- the Day-Ahead Auction (DAA) of contracted but unused capacity, which is conducted by the Australian Energy Market Operator (AEMO) shortly after nomination cut-off time on gas day D-1 and is subject to a reserve price of zero.

These two mechanisms, coupled with other elements of the capacity trading reform package (see box 4.2), are expected to improve the efficiency with which capacity is allocated and used on transportation facilities by:[173]

1. making capacity products more fungible and reducing search and transaction costs
2. providing shippers with access to secondary capacity (procured through either the CTP or DAA) on reasonable terms
3. improving the incentives firm capacity holders have to sell any spare capacity they may have prior to nomination cut-off time[174]
4. limiting the ability of facility operators to set the price of day-ahead capacity above the levels that would be expected in a workably competitive market by adopting a zero reserve price and allowing the market to determine the value of this capacity.

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170 AEMO, *Victorian Gas Planning Report, March 2019,* https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2019/2019-VGPR-Full-Report.pdf, p. 57.

171 Golden Beach Energy, Development, https://gbenergy.com.au/development.

172 These reforms will initially apply in the Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania and Victoria (outside the Declared Transmission System). At the time the decision was made to implement the reforms, the Energy Council agreed to implement a derogation that will delay the DAA to transportation facilities located wholly or partly in the Northern Territory. The Energy Council also agreed to direct the AEMC to conduct a review in 2020 (at the earliest) into whether the reforms should apply in Western Australia.

173 GMRG, *Capacity Trading Reform Package: Final legal and regulatory framework*, 22 November 2018, pp. 16-18.

174 The DAA is expected to improve the incentives that firm capacity holders have to release spare capacity prior to nomination cut-off because there will be no benefit to firm capacity holders in trying to withhold capacity from others that may value it more when it will be automatically released through the auction. Firm capacity holders will also miss out on the proceeds of the sale if the capacity is released in the auction rather than being sold prior to nomination cut-off, because the auction proceeds will be paid to facility operators.

GMRG, *Capacity Trading Reform Package: Draft legal and regulatory framework,* 19 March 2018, p. 16.

Box 4.2: Key elements of the capacity trading reform package

The key elements of the capacity trading reform package include:

- The CTP, which provides for exchange based trading of standardised products and a listing service. The standardised products that can be traded through the CTP include day-ahead and longer dated[175] firm forward haul and park services on all of the major transmission pipelines and firm compression services on major stand-alone compression facilities. These products rank ahead of the auction product in terms of nominations, renominations and curtailments.
- The DAA, which provides for the release of capacity that has been contracted by firm capacity holders but has not been nominated for use on the next gas day, shortly after nomination cut-off time. The products that auction participants can procure through the DAA include standardised day-ahead forward haul, backhaul or stand-alone compression services. These products rank below firm transportation services[176] from a nomination, renomination and curtailment perspective, but above as available and interruptible services.
- A number of measures to make capacity more fungible and facilitate trade, including the development of standard Operational Transportation Service Agreements (OTSAs), which establish the standard contract terms between transportation facility operators and shippers for use of the capacity procured through CTP, DAA and bilateral trades.
- A reporting framework for secondary capacity trades, that provides for the publication of prices and other key terms agreed to in trades conducted bilaterally and through the CTP, as well as information on the clearing prices in the DAA.
- A standard market timetable, which was implemented on 1 October 2019 and provided for the harmonisation of gas day start times and nomination cut-off times.

Full exemptions from the reforms (excluding the reporting framework and standard market timetable) are available to facilities that are not providing third party access. Conditional exemptions from the DAA and the requirement to publish an OTSA are also available to facilities with a nameplate rating of less than 10 TJ/day or that are servicing a single shipper.

Although the reforms have only been in place for a relatively short period of time, there are signs that they are having a positive influence on the East Coast Gas Market. The DAA, for example, has been used to procure around 27 PJ of contracted but unused capacity in the first eight months of its operation, the majority of which was procured on the transportation facilities connecting Queensland with New South Wales and Victoria at the auction's reserve price of zero.

While early indications are positive, questions have been raised about the effect that the reforms are having on shippers and facility operators and if there are any factors that may be impeding trade, given during the first eight months of operation no trades were conducted through the CTP and no auctioned capacity was procured on some key pipelines. The ACCC has therefore carried out a preliminary review of the reforms and, in doing so, focused on the effect that they have had on the East Coast Gas Market, the behaviour of facility operators and whether there may be any impediments to trade.

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175 The longer-dated products include a daily product (available on a six day rolling basis), a weekly product (available on a four week rolling basis) and a monthly product (available on a three month rolling basis).

176 For a two year transitional period, the auction also ranks below transportation rights that were acquired on or before 19 March 2018 that are used to transport gas to a gas-fired generation site and are currently treated as firm once scheduled (e.g. as available and some authorised overrun services).

To help inform the review, the ACCC has had recourse to publicly available information published on the Natural Gas Services Bulletin Board (Bulletin Board) and the Wholesale Statistics page on the AER's website. The ACCC has also sought feedback from AEMO and the AER on the operation of the reforms and consulted a sample of small and larger shippers, some of whom are already using the new market mechanisms and others that are either considering or not considering doing so. C&I users that participated in the ACCC's user survey were also asked their views on these matters. For ease of reference, the term 'shippers' is used in the remainder of this section to refer to the shippers we consulted and the C&I users that responded to the survey.

In addition to this consultation, the ACCC used its compulsory information gathering powers to obtain information from a number of facility operators[177] on the impact of the reforms on their prices, service offerings and the charges used to recover the costs associated with the reforms ('standardisation charges'). It is important to note that our intention in collecting information on standardisation charges was not to duplicate the review that the AER is currently conducting on facility operators' standard OTSAs, standardisation costs and charges (see box 4.2).[178] Rather, it was to understand whether these charges could be acting as an impediment to trade.

We understand that the AER is due to publish the findings of its review in March 2020. We also understand that a more detailed review of the design and effectiveness of the reforms will be carried out by the COAG Energy Council as part of a post-implementation review that is expected to occur in 2021,[179] and that the AEMC may also consider some of these issues in its 2020 gas and transportation markets liquidity review. The ACCC has not therefore sought to examine these issues in any detail.

The remainder of this section sets out the results of our preliminary review, which commences with an overview of the performance of the DAA and CTP over the first eight months of operation and then examines the potential impediments to trade and the effect of the reforms on facility operators' behaviour.

4.4.1. The DAA has been used to transport a significant volume of gas from Queensland to southern markets in the first eight months

Between 1 March 2019 and 31 October 2019, shippers used the DAA to procure around 27 PJ of contracted but unused capacity on a number of APA and Jemena operated pipelines and compression facilities, which enabled up to[180] 18 PJ[181] of gas to be transported to end-markets. As noted above, most of the capacity procured over this period was used to transport gas from Queensland to New South Wales and Victoria. Some of the capacity was also used to transport gas from Victoria to New South Wales and from the Northern Territory to Queensland via the CGP. Further detail on the facilities on which capacity was procured through the DAA and where gas was transported to is provided in chart 4.4 and table 4.1. Some of the key auction statistics are also provided in table 4.2.

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177 Information was obtained from APA, Epic Energy, Jemena, SEA Gas, Palisade and Lochard.

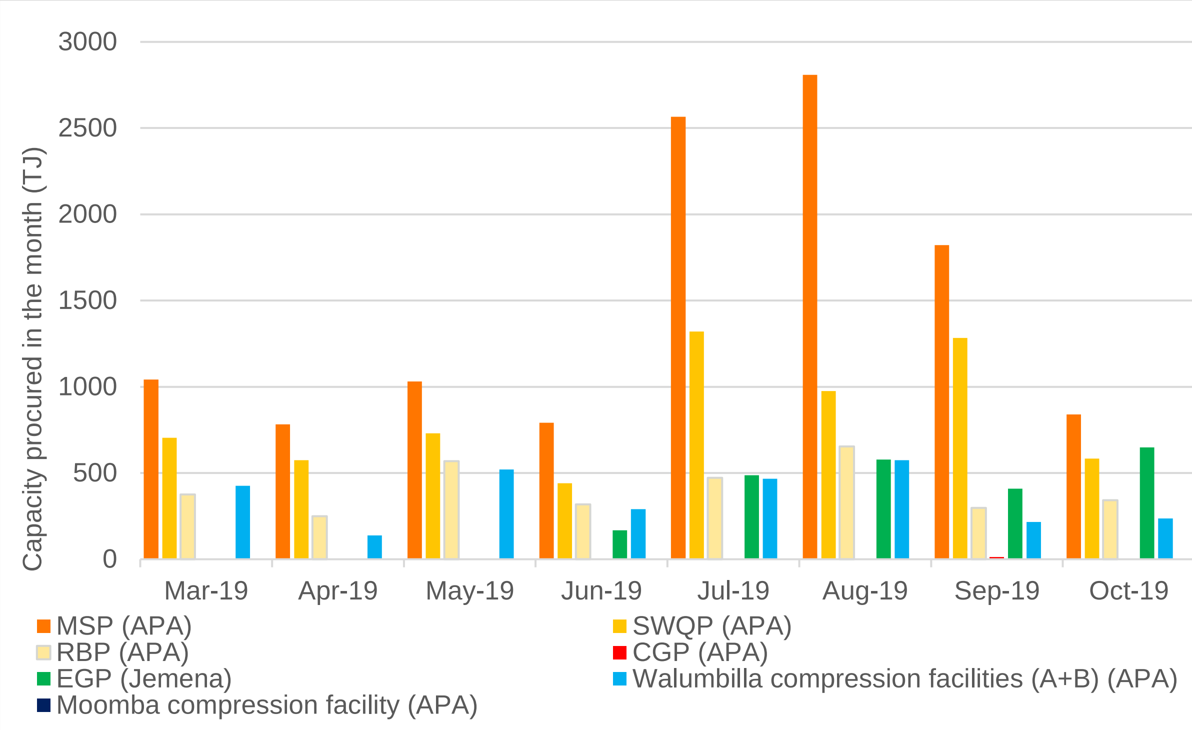
178 AER, Review of Standard OTSAs and Standardisation Costs and Charges, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-standard-otsas-and-standardisation-costs-and-charges/initiation.

179 GMRG, *Capacity Trading Reform Package: Final legal and regulatory framework— Explanatory note*, 22 Nov 2018, p. 99.

180 The term 'up to' has been used because an auction participant that procures capacity through the DAA may not actually nominate to use all of the capacity.

181 Note that these numbers differ, because the 27 PJ it is based on the amount of capacity procured on each facility, rather than reflecting the amount of gas transported as a result of the DAA. There is a difference between these two measures because a large number of participants submit bids to procure capacity across a number of pipelines. For example, a shipper wanting to transport 10 TJ of gas from Wallumbilla to Sydney, would submit a linked bid to procure 10 TJ of capacity on WCFB, the SWQP and the MSP. In this example, the amount of capacity procured across the three facilities is 30 TJ, while the amount of gas transported as a result of the bid is just 10 TJ.

Chart 4.4: Capacity procured through the DAA (1 Mar 2019–30 Oct 2019)



Source: ACCC analysis of information from the Bulletin Board and the AER's Wholesale Statistics.

Note: The chart presents the total amount of capacity procured through the DAA, rather than the total amount of gas transported as a result of the DAA.

Table 4.1: Where the capacity was used to transport gas to (up to 31 October 2019)

Facility		Capacity procured	Where capacity was used to transport gas to
APA	MSP	11.7 PJ	60% used to transport gas from Moomba to Culcairn delivery zone (enabling supply into Victorian DWGM and other locations in the zone, such as the Uranquinty power station)
			40% used to transport gas from either Moomba or Culcairn (via Victorian DWGM) to the Wilton delivery zone (enabling supply into Sydney STTM and other locations in zone)
	SWQP	6.6 PJ	99.6% used to transport gas from Wallumbilla or Ballera to Moomba
			0.4% used to transport gas between Wallumbilla zones
	RBP	3.3 PJ	90% used to transported gas to Wallumbilla (the majority of which came from the Darling Downs receipt zone)
			7.5% used to transport gas to the Western Downs and Darling Downs delivery zones (which include the Oakey, Swanbank and Braemar power stations)
			2.5% used to transport gas to Brisbane.
	CGP	0.01 PJ	100% used to transport gas from the NGP interconnect to Ballera.
	Wallumbilla compression	2.9 PJ	100% used to transport gas between the low pressure and high pressure points in Wallumbilla, the majority of which was then supplied into the SWQP
	Moomba compression	0.0001 PJ	100% used to transport gas between the low pressure and high pressure points at Moomba enabling supplied into the SWQP
Jemena	EGP	2.3 PJ	100% used to procure gas between Longford and the Horsley Park delivery zone (enabling supply into the Sydney STTM and other locations in the zone, such as the Tallawarra power station).

Source: ACCC analysis of information from the Bulletin Board and the AER's Wholesale Statistics.

Table 4.2: Key auction statistics (1 March 2019–31 October 2019)

Parameter		Value
No. of registered participants		15
No. of auction participants procuring capacity through the DAA		7
Total amount of gas capable of being transported as a result of the DAA		18 PJ
Amount of capacity procured on all facilities	Total amount procured	27 PJ
	Daily minimum	10 TJ/day
	Daily maximum	282 TJ/day
	Daily average	110 TJ/day
No. of times auctioned capacity curtailed		1
Proportion of capacity cleared at zero reserve price		81%

Source: ACCC analysis of operational information provided by AEMO, information from the Bulletin Board and the AER's Wholesale Statistics.

Most of the auctioned capacity has been procured at a zero reserve price, benefiting auction participants and other markets

Over 80 per cent of the capacity procured in the first eight months of the DAA's operation cleared at the auction's reserve price of zero,[182] although there were some peak days, particularly over the winter period, where shippers paid more for auctioned capacity.[183] For example, in August 2019, the maximum price paid for capacity on the SWQP was $1/GJ, while the maximum price paid for capacity on the MSP and EGP, were $0.56/GJ and $0.35/GJ, respectively. The price on the RBP, on the other hand, peaked in September at $1.05/GJ.

The peak prices observed on the SWQP and RBP in August-September coincided with periods during which firm capacity holders on these pipelines were using most of their contracted capacity. The amount of capacity released through the auction during these periods was therefore much lower than what it had been in other periods. When coupled with relatively high demand for auction capacity during the winter period and a greater level of competition between auction participants, the auction clearing price on these pipelines rose well above the auction reserve price.

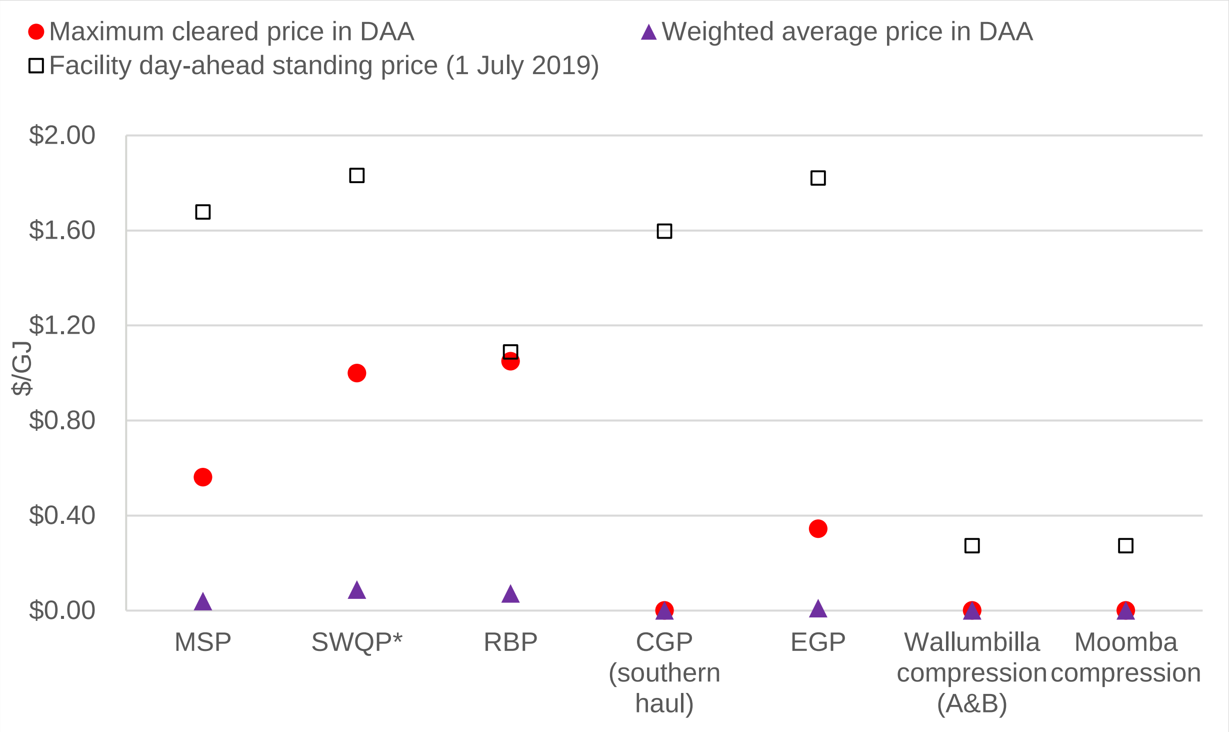
While the prices paid for capacity on a number of the facilities were substantially higher on peak days than the reserve price, they were still lower than the prices charged by facility operators for an equivalent service (see chart 4.5). For example, the maximum price paid for capacity on the SWQP, MSP, CGP Wallumbilla and Moomba compression facilities was 45−100 per cent lower than APA's standing prices for day-ahead capacity on these facilities,

182 While the reserve price is zero, auction participants must pay a range of fixed and variable fees to AEMO and service providers to procure capacity through the auction. So there is still a cost associated with procuring this capacity. Further detail on these charges is provided in section 4.4.4.

183 AER, Wholesale Markets Data: Day Ahead Auction—Range of non-zero prices traded, https://www.aer.gov.au/wholesale-markets/wholesale-statistics/day-ahead-auction-%E2%80%93-range-of-non-zero-prices-traded.

while the maximum price paid on the EGP was 81 per cent lower than Jemena's standing price for day-ahead capacity on the EGP.

Chart 4.5: DAA prices vs facility standing prices (1 Mar 2019–30 Oct 2019)



Sources: Auction prices based on operational information provided by AEMO. Standing price data obtained from the APA[184] and Jemena[185] websites.

Notes: * The SWQP charge excludes the cost of compression.

Apart from benefiting auction participants, the ability of shippers to procure relatively cheap capacity through the DAA has had a range of flow on benefits in some of the facilitated gas markets and, to a lesser extent, the National Electricity Market (NEM) (see box 4.3 for further detail).

Box 4.3: Effect of the DAA on other markets

Effect on the facilitated gas markets

Most of the capacity procured through the DAA between 1 March 2019 and 31 October 2019 appears to have been used to exploit the arbitrage opportunities that have existed between the facilitated markets in the north (i.e. the GSH and Brisbane STTM) and those in south east Australia (i.e. the Sydney Short Term Trading Market (STTM) and Victorian Declared Wholesale Gas Market (DWGM)). Auction capacity has, for example, been used to transport gas from the Wallumbilla and Moomba trading locations on the GSH to both the Sydney STTM and the DWGM on days when the prices in the GSH were below the STTM and DWGM prices.

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[184] APA, current tariffs and terms, https://www.apa.com.au/our-services/gas-transmission/current-tariffs-and-terms/current-tariffs-and-terms/ (accessed August 2019).

[185] Jemena, Eastern Gas Pipeline—Transportation Tariffs Effective 1st January 2019, https://jemena.com.au/documents/pipeline/egp-tariff.aspx (accessed August 2019).

The use of the auction capacity in this manner has placed downward pressure on the prices in the Sydney STTM and the DWGM, particularly over the winter period, which has benefited participants relying on those markets (including those C&I users that procure gas directly from the STTM or DWGM). Estimates developed by the AER, for example, suggest that the use of the DAA resulted in prices in these markets being reduced by $0.08–$0.17/GJ in the DWGM and $0.14–$0.76/GJ in the Sydney STTM between 1 March 2019 and 30 September 2019.[186]

In addition to placing downward pressure on prices in these markets, the DAA appears to have contributed to:

- a greater level of liquidity in the GSH,[187] as well as:
    - greater volumes of gas being traded at the Wallumbilla and Moomba trading locations, with a significant increase in the number of day-ahead, daily and balance of day products traded both through the exchange and off-market using the GSH pre-match service[188]
    - an increase in the number of trades in the Wallumbilla-Moomba spread product (i.e. a swap product between Wallumbilla and Moomba),[189] particularly during winter when the amount of capacity on the SWQP released into the DAA fell[190]
- a greater level of liquidity in the Sydney STTM and DWGM and a material increase in the net trade volume in these two markets.[191]

As a number of shippers observed, the new capacity trading mechanisms appear to have been the 'missing link' across the facilitated gas markets, with market participants now able to access capacity more readily and at a market determined price.

Looking forward, shippers expect the prices in the facilitated gas markets that can be accessed using capacity procured through the DAA and/or CTP to follow each other more closely, as auction participants continue to exploit arbitrage opportunities. However, as one shipper noted this can work both ways. That is, prices in the facilitated markets in the Southern States may also increase if prices in the Queensland facilitated markets increase. For example, if gas prices in Queensland increase in summer as a result of greater levels of LNG exports occurring during the northern hemisphere winter, prices in the southern markets would also be expected to rise.

Effect on the NEM

In addition to being used to supply the facilitated gas markets, auction participants have used some of the auction capacity to supply gas to GPGs in New South Wales and Queensland on an opportunistic basis. The NEM prices in these regions are therefore expected to be lower than what they otherwise would have been, although as some shippers noted the benefits may not necessarily be substantial.

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186 AER, *Wholesale Markets Quarterly—Q3 2019*, November 2019, pp. 52–53.

187 ibid, pp. 43–45.

188 AER, Wholesale statistics website, https://www.aer.gov.au/wholesale-markets/wholesale-statistics?f%5B0%5D=field_accc_aer_sector%3A5.

189 The spread product essentially involves the swap of gas between Wallumbilla and Moomba, with the buyer of such a product becoming the buyer at one location and a seller at the other location.

190 AER, Wholesale Markets Quarterly – Q3 2019, November 2019, p. 46.

191 ibid, pp. 50–51.

While early indications are positive, the DAA is yet to be used on some key pipelines

In addition to the facilities set out in chart 4.4, auction capacity is being made available on a number of other transportation facilities that are used to transport gas to, or within:

- South Australia (i.e. the Moomba to Adelaide Pipeline System (MAPS), the PCA Pipeline, the South East South Australian (SESA) Pipeline, the South East Pipeline System (SEPS) and the Iona compression facility)
- Tasmania (i.e. the TGP)
- Queensland (i.e. the Darling Downs Pipeline (DDP), the Queensland Gas Pipeline (QGP), the Roma Pipeline, the Wallumbilla Gas Pipeline (WGP), the Berwyndale to Wallumbilla Pipeline (BWP) and the Ballera compression facility), and
- Victoria (i.e. the VicHub Pipeline and Port Campbell to Iona (PCI) Pipeline).

No auction capacity had, however, been procured on any of these facilities as at 31 October 2019. We asked shippers that we consulted with why this may be the case. The factors that some of the shippers cited in response to this question can be summarised as follows:

(a) The standardisation charges levied by some facility operators may be deterring shippers from entering into the contractual arrangements required to use the capacity procured through the DAA on these facilities (see section 4.4.3 for more detail).

(b) The risk of the auction product being curtailed may be higher on some pipelines (or parts thereof), because of differences in the nature of demand. A number of shippers, for example, noted the potential for the risk of curtailment to be higher on South Australian pipelines, because of the reliance of this state on more intermittent generation. Elaborating on this further, shippers noted the GPGs in this state may have to renominate to use their capacity relatively quickly on a gas day (for example, if the wind drops), which could result in the auction product being curtailed in some locations.

(c) Some facilities, such as the MAPS, are heavily utilised and, as a consequence, there may be limited auction capacity available in the locations shippers require it, or the risk of curtailment may be higher.

(d) Users of some facilities may have contracted all of the capacity they require on a firm basis and may not be in a position to use additional capacity procured in the DAA.

On those pipelines where the standardisation charges are relatively high and there is a greater risk of curtailment, shippers may be using lower cost and lower risk options, such as procuring gas through an STTM or the DWGM, or entering into locational gas swaps.

One shipper also observed that there are limits on the ability of C&I users to rely on the DAA, because most C&I users cannot risk having insufficient gas delivered to their site on a day, or having their gas stranded in a location, because they are unable to procure auction capacity on a day. This shipper added that to use the DAA, auction participants need to know that they can win the capacity, or be willing to take the risk that they may not be able to procure capacity on the day.

In addition to these factors, some of the shippers we spoke to noted that they had either experienced delays in getting all of the contractual arrangements in place with facility operators that they require to use the DAA (or the CTP), or were prioritising their contracting efforts. Some also noted internal resource constraints had delayed their participation in the DAA. These delays, which are discussed in further detail in section 4.4.3, may also partially explain why no auctioned capacity has been procured on some facilities.

4.4.2. No trades had occurred on the CTP in the first eight months

In contrast to the DAA, no trades had been conducted through the CTP in the first eight months of its operation. There were, however, two bilateral off-market trades over this period, one of which involved the sale of 3.5 TJ/day of capacity on the MAPS for 8.5 months, while the other involved the sale of 0.6 TJ/day of capacity on the SESA pipeline for just under six months.[192] Based on the information reported on the Bulletin Board, these appear to be relatively bespoke trades that would not have been able to be conducted using the standardised products available through the CTP.

Shippers identified a range of potential reasons for why no CTP trades have occurred

In a similar manner to the DAA, we asked shippers for their views on why no trades had been conducted through the CTP.

Some of the reasons they cited were the same as those set out in section 4.4.3 (i.e. the standardisation charges levied by some facility operators and the delays some had experienced in entering into the required contractual arrangements). A number of shippers also claimed that most firm capacity holders have only contracted the capacity they require[193] and do not have any spare capacity to sell, and those that do have spare capacity may be reluctant to sell it if:

- the price they expect to receive for this capacity is lower than the costs associated with selling the capacity, which is likely to be the case at present given the majority of auctioned capacity has cleared at a zero reserve price (see table 4.2)
- it means losing the flexibility they require to manage deviations in the projected demand for gas on a day (e.g. through the use of renominations), which is likely to be more of an issue for retailers and GPGs.

Reflecting the interrelationships between the CTP and DAA, these shippers noted that the CTP is only likely to be used when:

- auction quantities are not consistently available at a low price, or when there is a greater risk of the auction product being curtailed
- the prices available through the CTP exceed the direct and indirect costs (e.g. the opportunity costs associated with the loss of flexibility) associated with selling capacity.

In addition to these factors, some shippers noted that:

- Gas trades are occurring through alternative means that do not require the use of transportation capacity, including through the use of locational gas swaps, the STTM and the DWGM. Some shippers noted this may represent a lower cost option to using the CTP for those participants in a position to utilise these alternative mechanisms.
- Shippers may be reluctant to incur the fixed costs associated with having the arrangements in place to use the CTP at present (see table 4.3 for more detail), because it is unclear when liquidity might emerge.

While the shippers we consulted with did not expect any changes to occur in the short-term, a number did note that as legacy contracts roll-off, the demand for firm secondary capacity

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[192] Natural Gas Bulletin Board, *PCT Reports–Secondary capacity trades,* 2 July 2019 and 15 August 2019.

[193] The ACCC has not sought to verify this observation and notes that it is not possible to do so on the basis of publicly available information.

increases (e.g. in response to higher auction clearing prices and/or higher levels of auction curtailment) and the market matures, more activity is likely to be seen on the CTP.

4.4.3. Potential impediments to participation in the CTP and DAA

The shippers we consulted with identified a number of potential impediments to participating in the DAA and CTP. These impediments are outlined below.

The time taken to negotiate amendments to GTAs and internal resourcing constraints has delayed the participation of some shippers in the markets

To be able to trade capacity through the CTP and/or procure capacity through the DAA, shippers must be registered with AEMO.[194] To use the capacity procured through the CTP and/or DAA, a shipper must also have its existing GTA with a facility operator amended, or enter into a standard OTSA with the relevant facility operator. All of the shippers we spoke with informed us that they had opted to amend their existing GTAs, rather than entering into a standard OTSA. Some of the shippers noted that they had decided to amend all of their GTAs at once, while others had either prioritised the amendment of GTAs on the facilities they wanted to procure capacity on, or were waiting until their existing GTAs expire.

While no concerns were raised about the AEMO registration requirements, the majority of shippers we spoke to indicated that it had taken a considerable amount of time to negotiate amendments to their existing GTAs with facility operators, which had delayed their participation in the CTP and DAA. Shippers cited a number of reasons for the protracted nature of these negotiations, including:

- facility operators seeking to negotiate a range of other unrelated and, in some cases, contentious, amendments to the GTAs at the same time
- the complexity of the GTA requiring amendment
- the number of GTAs requiring amendment.

Some shippers also noted that internal resourcing constraints had meant the process to amend their GTAs and to implement their own systems and processes had taken some time to complete and delayed their participation in the CTP and DAA. One shipper, for example, noted that because the CTP and DAA are voluntary markets, other mandatory requirements, such as the implementation of the new standard market timetable, had taken priority and delayed their use of the CTP and DAA.

The level and structure of some facility operators' standardisation charges may be deterring shippers from using the CTP and DAA

To use the CTP and/or the DAA, shippers must pay for the capacity they procure through these market mechanisms. They must also pay a number of fixed and variable charges to enable AEMO to recover the projected costs of establishing, operating and administering the CTP and DAA and associated aspects of the reforms.[195] Shippers may also be required to pay facility operators a 'standardisation charge', which can be used by facility operators to recover the incremental costs incurred in establishing and maintaining standard OTSAs and the systems and processes required to facilitate the CTP and DAA (see box 4.4).

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194 Shippers wanting to use the DAA must also enter into an auction agreement with AEMO to become an auction participant.

195 AEMO, *2019-20 AEMO Final Budget and Fees*, June 2019.

Box 4.4: Standardisation charges rule requirements

Provision has been made in rule 634 of the NGR for facility operators to have a “reasonable opportunity” to recover the “reasonable” “incremental” costs they incur in establishing and maintaining standard OTSAs and the systems and processes required to facilitate the CTP and DAA. This rule also states that the facility operator must not seek to recover these costs from shippers more than once and requires the standardisation charges levied by facility operators to:

- insofar as practicable, reflect the outcomes of a workably competitive market
- allocate the standardisation costs among transportation facility users in a reasonable manner (whether under operational transportation service agreements or otherwise)
- recover the standardisation costs over time in a manner that promotes efficient trade in, and utilisation of, transportation capacity.

These cost recovery and charging principles have been classified as civil penalty and conduct provisions, which means that the AER and/or affected shippers may take enforcement action if a facility operator fails to comply with these principles.

To enable the AER and shippers to monitor compliance with these principles, rule 634 requires facility operators to publish a schedule of the standardisation charges and information in reasonable detail to explain:

- how the standardisation costs were incurred
- how the standardisation charges have been calculated
- how any proceeds from the DAA have been taken into account in the calculation of the standardisation charges.

Facility operators must also keep a record of their standardisation costs and the charges imposed on shippers for five years.

The ACCC understands that the AER is currently conducting a review of facility operators’ standardisation costs and charges, as part of a broader review of the compliance of facility operators’ standard OTSAs with the relevant provisions in the NGR and the Operational Transportation Service Code. This review, which was required under the transitional rules, is due to be completed by 1 March 2020.

In addition to this ‘hard wired’ review, rule 635 provides for the AER to conduct a review of a standard OTSA[196] and the charges under the agreement (which includes the standardisation charges) at any time, either at the request of a shipper (including a prospective shipper) or on its own initiative.

[196] The AER can also conduct a review of an agreement prepared in accordance with an exemption condition provided for in rule 611(6) of NGR.

Table 4.3 sets out AEMO's fees and charges and facility operators' standardisation charges as at 1 November 2019. While not shown in this table, a number of facility operators have amended their charges since the reforms were implemented. SEA Gas, for example, has increased its fixed monthly charge by approximately 40 per cent.[197] Palisade, on the other hand, has recently reduced its standardisation charges by over 60 per cent,[198] while Epic has reduced its charges on the SEPS by 33 per cent.[199] Lochard has also recently restructured its standardisation charges (from a wholly variable charge of $0.50/GJ to a combined fixed and variable charge of $750 per month plus $0.02–$0.046/GJ).[200] The ACCC understands that the changes to Palisade and Lochard's charges may reflect the work the AER has been doing with facility operators as part of its review of facility operators' standard OTSAs, standardisation costs and charges.

197 SEA Gas, Schedule of Charges, Website accessed 27 February 2019 and 31 October 2019, https://seagas.com.au/services/access-to-services/.

198 This difference has been calculated assuming the charges are paid over a three year period, which is consistent with what Palisade has assumed for cost recovery purposes. See TGP, Standardisation Charge Schedule, 1 November 2019.https://www.tasmaniangaspipeline.com.au/client-assets/Part%2023/20191101%20TGP%20Standardisation%20Charge%20Schedule%20-%20Final.pdf.

199 See Epic, Facility Specific Terms–South East Pipeline System, Version 2, 4 November 2019 and Epic, Facility Specific Terms–South East Pipeline System, Version 1, 22 January 2019.

200 Lochard Energy, OTSA Standardisation Cost Charges as at 7 October 2019 and 1 March 2019–6 October 2019, https://lochardenergy.com.au/our-business/our-products/.

Table 4.3: CTP and DAA fees and charges (as at 1 November 2019)

Facility operator	Facilities/Market	Fixed charge ($)	Variable charges ($/GJ)	
			Capacity procured in CTP ($/GJ)	Capacity procured in DAA ($/GJ)
AEMO's fees and charges				
AEMO	DAA and CTP	DAA registration fee $15 000	$0.024–$0.044 (depending on term of product)	$0.034
		GSH licence (commodity + CTP): $12 000 per annum (fee rebated if trader enters into transactions above a mthly threshold)		
Facility operators' standardisation charges				
APA	SWQP, RBP, BWP, WGP, CGP, MSP, SESA, Wallumbilla & Moomba compression	$806.42 per mth	$0.024	$0.048
Jemena[1]	EGP, VicHub, QGP, DDP, NGP	$1 000 per mth	$0.0003–$0.00480[2]	
Epic	MAPS	$2 917 per mth	n.a.	n.a.
	SEPS	$833.33 per mth	n.a.	n.a.
SEA Gas[3]	PCA and PCI	$4 935 per mth	n.a.	n.a.
Palisade	TGP	Upfront charge: $733.39 per mth[4]	n.a.	n.a.
		Ongoing fee: $263.89 per mth		
		OTSA one off fee: $3 000		
Origin	Roma Pipeline	$0	$0	$0
Lochard	Iona compression	$750 per mth	$0.02	$0.0461
Santos	Ballera compression	Upfront one-off charge: $5 000	n.a.	n.a.

Source: AEMO Gas Market Fee Schedule 2019–20 and information obtained from facility operators' websites as at 1 November 2019.

Notes:

1. Jemena also requires firm capacity holders to pay $0.0003–$0.00480/GJ for any firm MDQ that is held but not used in a month by the firm capacity holder (this charge applies to MDQ that is sold by the primary capacity through a bilateral or exchange trade as well as contracted but unused capacity).
2. Different charges are payable on Jemena's assets with $0.0003 payable on the DDP, $0.0018 on the VicHub, $0.0166 on the NGP, $0.022 on the QGP, $0.0048 on the EGP.
3. SEA Gas also requires shippers to pay $362 per bilateral trade and for trades of other entitlements.
4. This amount is payable over 36 months (the total up front cost is $26 402.04).

While most shippers we consulted accepted that AEMO and facility operators should have an opportunity to recoup the costs associated with establishing and maintaining capacity trading arrangements, concerns were expressed about:

- the level and structure of the standardisation charges levied by some facility operators and the potential for these charges to discourage shippers from trading their capacity or procuring auctioned capacity on some facilities
- the potential for some facility operators to try and recover more than the incremental costs associated with establishing and maintaining the standard OTSAs and the systems and processes required to facilitate trade.

The ACCC understands that the AER is currently considering the latter of these matters, as part of its review of standard OTSAs, standardisation costs and charges. The remainder of this section therefore focuses on the concerns raised about the level and structure of some facility operators' standardisation charges.

Level and structure of standardisation charges

In our discussions with shippers, a number noted the significant variation in the level and structure of charges levied by facility operators. Some facility operators, for example, are charging both a fixed and variable charge, while others are recovering their costs entirely through fixed charges, and in some cases through an upfront fee. The level of charges also differs, ranging in the case of the fixed charges from $750 to $4935 per month, while the variable charges range from $0.0003/GJ to $0.048/GJ for the DAA and $0.0003/GJ to $0.024/GJ for the CTP.

The standardisation charges levied by SEA Gas on the PCA pipeline and Epic on the MAPS attracted the most comment from the shippers we consulted. In both of these cases, the facility operators have sought to recover all of their costs through a fixed monthly charge of $2917–$4935 per month (or $35 004–$59 220 per annum), which is 3–6 times higher than the fixed charges levied by APA and Jemena. As a number of shippers noted, the use of a relatively high fixed charge on these pipelines could discourage shippers, and in particular smaller shippers, from using the DAA or the CTP on these facilities.

A high fixed charge could, for example, discourage participants who only want to secure a small amount of capacity to supplement their firm capacity, from using the DAA and the CTP. Smaller shippers may also be unable to justify paying such a high charge, particularly if the benefits associated with procuring capacity are expected to be relatively low (e.g. if the mechanisms are only used for opportunistic purchases of capacity). This observation highlights another problem with the charging structures adopted by Epic and SEA Gas, which is that smaller shippers are required to pay the same amount as larger shippers, even though their use of the CTP and DAA is likely to be much lower. This problem does not arise under the fixed and variable structures used by APA and Jemena, because while all shippers have to pay the fixed monthly charge, shippers that procure more capacity through the CTP and/or DAA will pay more for doing so through the variable charge.

The observations that shippers made about Epic and SEA Gas' standardisation charges, are similar to those that AEMO made in its submission to the AER's review of standard OTSAs, standardisation costs and charges:[201]

> *"Some facility operators have elected to recover their costs entirely through fixed charges recovered on either a monthly or annual basis, and also through upfront charges which are charged on top. A high fixed fee weighting may be negatively*

[201] AEMO, Submission to the AER Review of Facility Operator Compliance with the Rules Relating to Standard Operational Transportation Service Agreements, 25 July 2019, p. 2.

impacting participation on the CTP in particular. Capacity trades are likely to occur at a lower frequency than commodity trades or auction purchases as the market grows. Such trades may include participants trading capacity to manage maintenance outages or seasonal variations in demand. High fixed costs are likely to act as a deterrent to these types of trades, as the fixed costs may outweigh the value of a single trade even if it is for a substantial volume.

Relatively high fixed or upfront costs are likely to impact auction participation. Given the non-firm nature of auction capacity, participants are likely acquiring auction capacity to arbitrage between markets and/or to supplement their firm capacity. Such activity in the auction is likely to be intermittent in nature and high fixed fees are likely to act as a barrier to participation. In general, high fixed costs disproportionately negatively impact those with smaller gas portfolios (typically new entrants, large users, and small retailers). This may shrink the pool of potential participants for CTP products and the auction.

…

Ultimately, as the market is voluntary, if participation is low on a facility then the facility operator will not be able to recover their implementation and ongoing costs. As such, the implementation of efficient fee arrangements should be in the best interest of both shippers and facility operators. An exception could be where a facility operator benefits from a lack of auction participation through greater use of as available services that are charged at higher rates."

Apart from limiting the opportunities available to shippers in South Australia, there is, as AEMO notes, a risk that if Epic and SEA Gas maintain their current charging structure then they will be unable to recover their costs. There is also a risk that other facilities that are connected to the MAPS and PCA may be unable to recover their costs. For example, if SEA Gas maintains its fixed charge on the PCA, then it could affect:

- Lochard's ability to recover its costs, because a shipper will only use the Iona compression service if it can procure capacity on the PCA
- APA's ability to recover its costs on the SESA Pipeline, which is connected to the PCA
- Epic's ability to recover its costs on the SEPS, which is also connected to the PCA.

To address these issues, a number of shippers suggested that Epic and SEA Gas consider reducing their fixed charges and adopting a similar charging structure to that used by APA, Jemena and Lochard (i.e. a combined fixed and variable charge). The ACCC supports this suggestion and would encourage Epic and SEA Gas to amend their charging structure.

While APA's charging structure was viewed more positively by shippers, a number did note that if the DAA or CTP was used to move gas across a number of facilities, the costs could add up very quickly. For example, if a shipper wanted to use the DAA to transport gas from the Darling Downs zone on the RBP to Sydney, then it would have to pay the fixed monthly charge and variable charge for the four facilities it uses (i.e. the RBP, a Wallumbilla compression facility, the SWQP and MSP). The effective cost to the shipper would therefore be a fixed monthly charge of $3225 and a variable charge of $0.192 for each GJ transported from Darling Downs to Sydney.

Some shippers also expressed concern about Jemena's decision to try and recover some of the standardisation costs from firm capacity holders that do not use all of their firm capacity. This approach is not being used by any other facility operator. While the charge levied by Jemena is relatively low ($0.0003–$0.0048/GJ), its application is quite broad, with the charge payable on both contracted but unused capacity and any capacity that the firm capacity holder sells (bilaterally or through the CTP). The concerns in this case appear to be that firm capacity holders may bear a disproportionate share of the costs of the reforms, and that the charge may result in shippers reducing their capacity requirements to minimum levels when they enter into their next GTA. This may, in turn, result in less capacity being released through the DAA and shippers having to procure higher cost short-term capacity directly from Jemena.

Other issues

In addition to the matters set out above, some shippers suggested that an alternative approach to facility operator cost recovery may be required to overcome the issues outlined above and to encourage greater use of the CTP and DAA. The two alternatives that shippers identified, include:

Recovering facility operators' costs on a smeared basis across all shippers, rather than on a user pays basis. This could either be done at a facility level or by pooling all of the facility operators' costs and coming up with a single charge payable by all shippers, irrespective of what facilities they use.

Mandating the use of a consistent charging structure across facility operators and placing more of a constraint on the level of those charges.

In its submission to the AER's review, AEMO also noted the importance of a "more balanced and consistent fee structure" across facility operators. In doing so, AEMO noted that: [202]

> *"This may involve facility operators recovering their costs over time through a mix of both fixed and variable charges determined in a similar and consistent ratio. We note that some facility operators have adopted such an approach and we would encourage this model to be adopted more generally. Ultimately, inefficient fee structures have the potential to undermine the policy objective of this reform to support the efficient allocation, utilisation and pricing of transportation facility capacity across the east coast."*

The ACCC agrees with AEMO and shippers that further consideration should be given to the facility operator cost recovery provisions, as the success of the reforms could be stymied by inappropriate standardisation charges. While there may be other factors that are contributing to this absence of trading activity on the MAPS, PCA and PCI pipelines (see sections 4.4.1), concerns were consistently raised by the shippers we consulted that Epic and SEA Gas's standardisation charges were too high and may be discouraging the use of the DAA and trade on these facilities. We therefore recommend that this issue be considered in more detail, either as part of the AEMC's upcoming liquidity review, or as part of the COAG Energy Council's 2021 post implementation review.

4.4.4. The reforms appear to be posing more of a constraint on facility operators, but greater trade between shippers could put further downward pressure on prices

One of the key objectives in implementing the capacity trading reforms was that it would limit the ability of facility operators to set the price of day-ahead capacity above what would prevail in a workably competitive market. We have therefore considered the effect the reforms have had on the prices charged by facility operators.

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[202] AEMO, *Submission to the AER Review of Facility Operator Compliance with the Rules Relating to Standard Operational Transportation Service Agreements*, 25 July 2019, p. 2.

On those pipelines where auctioned capacity is procured, the ability of facility operators to charge auction participants excessive prices for day-ahead capacity is being constrained by the DAA, as highlighted by the difference between the auction clearing prices and the prices charged by facility operators for day-ahead services (see chart 4.5). That is not to say that all shippers are paying lower prices for day-ahead capacity, because there are a number of shippers that are not auction participants that are still relying on procuring as available, interruptible or short-term firm services from facility operators. These shippers are therefore still having to pay a premium for day-ahead capacity (see chart 4.5).

More generally, the capacity trading reforms appear to have placed some downward pressure on the prices that some facility operators are charging shippers for as available, interruptible and short-term firm services (see section 1.2.2). As we noted in our July 2019 report, the incidence of excessive pricing of these services has fallen, with most shippers paying 110–160 per cent of the firm transportation tariff for these services (the majority of whom are paying 110–130 per cent) in January 2019. While some shippers have been able to negotiate lower prices for these services in the last six months (see section 1.2.2), most shippers are still paying between 110–160 per cent of the firm transportation tariff for as available, interruptible and short-term firm services.

The limited movement over this period is probably not surprising given there are currently only seven active auction participants and facility operators have faced limited competition from firm capacity holders selling their spare capacity to date. If these conditions change, then the demand for as available, interruptible and short-term firm services should decline, which could place further downward pressure on the prices charged by facility operators for these services.

4.5. Access to regional pipelines remains an issue and requires longer-term solutions

Gas users in regional areas are typically supplied by smaller transmission pipelines, or laterals off major arterial pipelines (jointly referred to in this section as regional pipelines). The capacity of regional pipelines is often controlled by a single retailer that has contracted all, or a significant proportion of, the pipeline capacity. Other retailers that want to supply these areas on a firm basis, or C&I users that want to transport gas in their own right, must therefore either acquire capacity from the incumbent retailer, or be prepared to underwrite an expansion of the pipeline, both of which can constitute a significant barrier to entry.

In such circumstances there is a risk that the single retailer may charge prices in excess of what would prevail in a workably competitive market, or impose unduly onerous terms and conditions on gas users. While there may be circumstances where it is not efficient for an additional retailer to supply an area (for example because of a small customer base and high fixed costs) this could potentially change over time. It is important therefore that access to pipeline capacity does not act as a barrier to retail competition in these areas.

Concerns about the ability of customers in regional areas to access the full benefits of retail competition are long-standing, having been raised by the AEMC's review of the effectiveness of retail competition in South Australia in 2007[203], and in subsequent AEMC reviews of retail competition.[204] They were also raised during the 2015 Inquiry, with a number of gas users expressing concerns about the lack of competition in regional areas. Concerns were also raised in this context about the attempts by some incumbent retailers to

[203] AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia*, September 2008, p. xiv.

[204] AEMC, *2014 Retail Competition Review, Final Report*, 22 August 2014, p. 195.

try and restrict competition in regional areas by either not offering stand-alone pipeline capacity, or by only offering to sell stand-alone capacity at a relatively high price.[205]

The ACCC's enforcement division investigated this issue in further detail over 2016–17, focusing on one particular incumbent retailer's behaviour on a number of regional pipelines. Following the completion of the investigation we saw some improvements in the behaviour of the incumbent retailer, with some capacity being released to another retailer and one C&I user on some of the pipelines we investigated.[206] However, as we reported in our July 2019 report, a number of parties continue to raise concerns with us about the inability of prospective users to access pipelines in regional areas in instances where the pipeline's capacity has been fully contracted to a retailer.[207]

To get a better understanding of the extent of the problem, we have used our compulsory information gathering powers to obtain information and documents from the operators of a sample of regional pipelines in the east coast and the incumbent retailers that have contracted all of the capacity on these pipelines. The sample included three regional pipelines located in Victoria, South Australia and Queensland, all of which are owned by different pipeline operators. We also spoke with a number of retailers and C&I users that have tried to obtain access to these pipelines to get a better understanding of the barriers that prospective users of these pipelines can face.

The information obtained through this process revealed that access to pipeline capacity remains a problem on a number of regional pipelines and that the inability for other shippers to access these pipelines is inhibiting competition in these areas. The key issues that we have identified in this regard are that:

- the incumbent retailers that have contracted all (or a substantial proportion of) the capacity may not have a strong incentive or ability to release unused capacity back to the pipeline operator, or to sell unused capacity to another retailer or gas user
- some regional pipeline operators appear to be actively discouraging other retailers and gas users from obtaining access to capacity even when the incumbent retailer's GTA has expired, or is due to expire in the near future.

We are currently considering whether any of the conduct we have observed constitutes a possible contravention of the *Competition and Consumer Act 2010* (CCA). We have also considered whether there are any longer term remedies that could be implemented through the National Gas Law (NGL) and/or the NGR to address this long-standing issue. The options that we have identified to reduce the barriers to entry posed by these pipeline access issues, which could potentially be considered as part of the COAG Energy Council's Gas Pipeline RIS, are set out in further detail below.

In addition to these access related issues, we have observed one pipeline operator attempting to exercise its market power in negotiations with the incumbent retailer, by trying to double the price payable for capacity on the pipeline (see box 4.5 for more detail). Apart from placing upward pressure on the prices payable for gas in the regional areas serviced by this pipeline, the behaviour of the pipeline operator in this case could discourage other retailers that are considering supplying this regional area. We therefore support a number of the measures that the COAG Energy Council is considering as part of the gas pipeline RIS, which should impose greater discipline on regional pipeline operators (see box 4.5).

The ACCC will continue to monitor the behaviour of retailers in regional areas over the course of this inquiry.

[205] ACCC, *Inquiry into the east coast gas market*, April 2016, p.153.

[206] ACCC, *Gas inquiry 2017-2020 interim report*, December 2017, p. 65.

[207] ACCC, *Gas inquiry 2017-2020 interim report*, July 2019, p. 116.

Box 4.5: Pipeline operator may be attempting to exercise market power

Based on the material we have been provided, it would appear that one of the pipeline operators in the sample of regional pipelines that we have examined has attempted to exercise its market power during contract negotiations with the incumbent retailer. While an agreement is yet to be reached on this pipeline, we understand from the material that we have been provided that the price offered by the pipeline operator at the expiry of the incumbent retailer's contract is more than double what the retailer had previously been required to pay for transportation services.

While we understand there are remedies available to the incumbent retailer under Part 23 of the NGR if it does not agree with the offer proposed by the pipeline operator (i.e. the retailer could utilise the arbitration mechanism under Part 23), the behaviour of the pipeline operator is concerning and highlights the importance of implementing some of the other measures that are being contemplated as part of the Gas Pipeline RIS, including:[208]

- removing the coverage test as a gateway to full regulation, so that the threat of a heavier handed form of regulation is more credible
- according the regulator greater responsibility for monitoring the behaviour of service providers and allowing the regulator to refer pipelines for a form of regulation assessment if it suspects market power is being exercised
- strengthening the negotiation frameworks and dispute resolution mechanisms
- requiring all pipelines, irrespective of their size and number of shippers, to publish a basic set of access information, including information on service availability, the service provider's standing prices and the method used to determine these prices, as well as information on the prices paid by other shippers.

Together these measures should impose more discipline on regional pipeline operators to provide access on reasonable terms. The proposed transparency measures should also address the concerns that some shippers have previously raised with us regarding the exemption that single shipper and smaller pipelines are able to obtain from disclosing their standing prices, pricing methodologies and other access related information.[209]

The remainder of this section provides further detail on the pipeline access issues we have identified and sets out some longer term solutions that could be considered by the COAG Energy Council as part of the Gas Pipeline RIS.

4.5.1. Incumbent retailers may not have a strong incentive to release capacity

As noted in our July 2019 interim report, concerns have been raised by a number of C&I users located on regional pipelines, about their ability to obtain stand-alone transportation capacity from the incumbent retailer (see box 4.6). While we have seen instances of capacity being released by an incumbent retailer to a C&I user and to another small retailer that supplies C&I users, this has only occurred on those pipelines that we investigated in 2016−17 and does not, as far as we can tell, represent a more permanent or widespread change in approach by the incumbent retailer.

[208] COAG Energy Council, *Consultation RIS: Options to improve gas pipeline regulation*, November 2019, pp. 126-127.

[209] See the discussion in ACCC, *Gas inquiry 2017-2020 interim report*, July 2019, pp. 131-132.

Box 4.6: Concerns raised through the user survey

In the user survey conducted in the first half of 2019, one C&I user that is located on a regional pipeline serviced by a single retailer, noted that during its contract negotiations the retailer had sought to increase its charge from around $25/GJ (with transportation costs accounting for around $15/GJ) to over $30/GJ. The user informed us that while it had approached a number of other potential suppliers:

> *"It has been conveyed to us by retailers we approached for gas pricing that all the gas line capacity has been purchased thus other retailers are unable to trade gas on the line. It is not clear to us if the physical capacity of the line is consumed or fully utilised".*

Another large C&I user informed us that they had previously been supplied by a retailer that held all the capacity on a regional lateral, but decided to seek offers from a number of other gas suppliers. While the user found better deals for gas, access to transportation capacity was an issue. The user noted that while they had approached their original retailer about relinquishing capacity, they were told the retailer had other uses for the capacity, but a bundled gas and transport offer was available. The user then indicated that it intended to discuss the issue with the ACCC, and was subsequently offered a commercially satisfactory arrangement by the retailer.

This is probably not surprising, given the benefits that are likely to be associated with controlling all, or a substantial portion of, the supply of gas to a regional location. In such circumstances, the incumbent retailer is unlikely to have a strong incentive to release capacity to the pipeline operator (assuming it can do so under its GTA), or to another shipper. To the contrary, the incumbent retailer is likely to have an incentive to retain its contracted capacity regardless of whether it is being used to avoid a loss of market share and/or to avoid facing competitive pressure from a new entrant.

On other transmission pipelines in the East Coast Gas Market, the incentive to withhold capacity has been overcome through the introduction of the DAA (see section 4.4). However, as noted in box 4.5, exemptions from the DAA are available to single shipper pipelines and to pipelines with a nameplate rating below 10 TJ/day. [210] Another mechanism is therefore likely to be required to address this ongoing issue, which is acting as a barrier to entry in some regional areas.

Two options that we have identified that could potentially be considered as part of the COAG Energy Council's Gas Pipeline RIS, would involve amending the NGL and/or the NGR to include a capacity surrender mechanism that could be applied to pipelines where a retailer has contracted all of a pipeline's capacity, which could either be invoked:

- where it can be demonstrated that a retailer has contracted all of a pipeline's capacity and standalone transportation is not being made available by the retailer (in control of all of a pipeline's capacity) at competitive prices, or
- where an end-user decides to contract with another retailer, or to self-contract.

Under both of these options, the pipeline operator would, subject to some caveats,[211] be required to sell the capacity to the other retailer or end-user on reasonable terms.

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210 The ACCC understands that the exemptions from the DAA were implemented to try and minimise the impost on pipelines where limited trade was likely to occur.

See GMRG, *Capacity Trading Reform Package: Final legal and regulatory framework–Explanatory Note*, 22 November 2018, p. 12.

211 For example, there may need to be some eligibility criteria to provide pipeline operators some protections from a contracting perspective (see for example, the criteria that have been adopted in Part 24 of the NGR).

The key difference between these two options, is that under option 1, a prospective shipper or end-user would be required to demonstrate that the incumbent retailer is not making capacity available at competitive prices, while under option 2, they would just need to show that the end-user has decided to contract with another retailer, or to self-contract. The hurdle for capacity to be released is therefore lower under option 2 than it is under option 1.

Another benefit of option 2 is that it is likely to be easier to administer, because it would not require a regulator to make a decision as to whether capacity is being made available at competitive prices. Rather, it would just require the relevant parties to inform the pipeline operator of the change. While option 2 offers a number of benefits over option 1, it may expose retailers and pipeline operators to a greater level of risk of churn, which could impose additional costs on these parties. There would be value therefore in consulting on both of these options as part of the Gas Pipeline RIS.

4.5.2. Some regional pipeline operators appear to be trying to prevent other shippers gaining access to their pipeline

One of the more surprising findings of this examination, was that some regional pipeline operators appear to be attempting to prevent potential new shippers obtaining access to their pipeline. In one instance, for example, a pipeline operator appeared to try and deter a prospective user by misrepresenting their ability to provide access. Prospective users of this pipeline also told the ACCC that the pipeline operator had made it difficult for them to obtain basic access related information, including information on transportation charges.
In another example, a pipeline operator informed a prospective user that it would be in a position to discuss possible contractual arrangements with the user, only after negotiating arrangements with the incumbent retailer were resolved. This was despite the fact that the incumbent retailer's contract was due to expire and there was nothing in the pipeline operator's contract with the retailer that either prevented the pipeline operator from negotiating with others, or provided the incumbent retailer with a first right of refusal.

There are a number of potential reasons why pipeline operators may be trying to restrict access to a single retailer. It may, for example, reflect the operation of some of the reforms that have recently been implemented, which may be providing pipeline operators with an incentive to remain a 'single shipper' pipeline and avoid a number of regulatory obligations. As explained further in box 4.5, single shipper pipelines can apply for an exemption from the reporting requirements under Part 23 of the NGR and from the DAA and other aspects of the capacity trading reforms (see section 4.4).

The reluctance to allow other shippers to use the pipeline may also stem from the additional costs that are likely to be associated with becoming a multi-user pipeline (e.g. metering costs and the costs of establishing allocation arrangements and managing nominations), which a pipeline operator may be trying to avoid.[212]

There may also be provisions in the contracts that pipeline operators have with the incumbent retailer that discourage them from selling capacity to other users, or expanding capacity for other users. For example, we have observed a provision in one GTA that prevents the pipeline operator from expanding the pipeline, unless the existing shipper is first offered the opportunity to surrender some or all of their reserved capacity (up to an amount not exceeding the proposed increase in capacity). A provision such as this may reduce the incentive the pipeline operator has to consider selling capacity to another shipper, because it may result in them being no better off (or potentially worse off as a result of transaction costs).

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[212] See for example, Gas Pipelines Victoria, *Submission on GRMG Consultation Paper–Capacity Trading Reform Package*, 26 April 2018, p. 3.

Box 4.7: Effect of exemptions on pipeline operator's incentives

Part 23 of the NGR ('Part 23') sets out the information disclosure and arbitration framework for non-scheme pipelines.[213] This framework was introduced in August 2017 to reduce the information asymmetry and imbalance in bargaining power shippers can face when negotiating with pipeline operators. Part 23 requires pipeline operators to publish a range of information to enable shippers to carry out a high-level assessment of the reasonableness of a pipeline operator's offer. This includes, amongst other things, information on:

- the standing terms for each service (which includes the standing price and standard terms and conditions) and the method used to calculate the standing price
- the weighted average prices paid by shippers for pipeline services
- a range of financial information
- other information about the pipeline, pipeline services, service usage and service availability.

An exemption from some or all of these disclosure requirements can currently be obtained by single shipper pipelines and pipelines that fall below the specified size threshold (i.e. pipelines that have an average daily injection for the preceding 24 months of less than 10TJ/day). Single shipper pipelines, for example, can obtain an exemption from all of the upfront information disclosure obligations,[214] while pipelines that fall below the specified size threshold can obtain an exemption from all the information disclosure obligations except the obligation to publish details of the pipeline and services offered.

In addition to these exemptions, single shipper pipelines and pipelines with a nameplate rating less than 10 TJ/day can apply for a conditional exemption from the DAA and the requirement to publish an OTSA (see box 4.5 for more detail).

If a single shipper pipeline was to offer access to another shipper then it would lose its single shipper exemption. It would therefore have to incur the costs associated with publishing the information required under Part 23 and participating in the DAA, which could act as a deterrent to becoming a multi-user pipeline.

While there are a number of reasons why regional pipeline operators may not want their pipelines to become multi-user facilities, a refusal to engage in meaningful discussions with prospective users about access to capacity is concerning, particularly when it deters the entry of other retailers and the benefits that can flow to users from greater competition.

As noted in section 4.5, the ACCC is currently considering whether any of this conduct constitutes a possible contravention of the CCA. We have also considered whether there are longer-term solutions that could be implemented through the NGL and NGR to address the behaviours that we have observed.

As noted above, the COAG Energy Council is currently reviewing the regulatory framework applying to gas pipelines through a Gas Pipeline RIS. As part of this process, we understand the Energy Council is considering whether the safeguards that currently apply to operators of light regulation pipelines should apply under Part 23, including the prohibition on conduct that would prevent or hinder access to the pipeline services. As said in our submission to the Consultation RIS, the ACCC supports this proposal because it should deter pipeline

213 A non-scheme pipeline is a pipeline that is not subject to either full or light regulation, but is subject to the information disclosure and arbitration framework in Part 23 of the NGR.

214 Single shipper pipelines are still subject to the access request and negotiation framework as well as the arbitration mechanism.

operators from behaving in some of the ways that we have observed. We also support the proposal that the relevant regulator be accorded greater responsibility for monitoring the compliance of pipelines with these safeguards and the behaviour of pipeline operators more generally.

To further discourage pipeline operators from misrepresenting the availability of capacity or the terms of access more generally, we would also suggest the Energy Council consider extending the application of the access information standard in the NGR to other aspects of Part 23.[215] Currently, this information standard only applies to the information disclosure requirements in Division 2 of Part 23 and the access offer information provisions in rule 562. It does not, however, apply to the information that pipeline operators may provide prospective shippers through a preliminary enquiry process, or when making an access offer. In our view, there would be value in extending the application of this provision to these aspects of Part 23 and to the negotiation frameworks applying under full and light regulation.

Finally, we would suggest that, as part of the Gas Pipeline RIS, consideration be given to amending the NGL and/or NGR to prohibit pipeline operators that are supplying more than one end-user from contracting all of the pipeline's capacity to a single retailer, unless provision is made for capacity to be relinquished by the retailer if an end-user decides to contract with another retailer (or to self-contract). As noted in section 4.5, when considering this option, regard should be had to any demand risk that may be imposed on a pipeline operator from the introduction of such a provision.

[215] The access information standard is set out in rule 551(2) of the NGR and requires, among other things, that information is not false or misleading in a material particular. It should be noted that under rule 551(1) of the NGR the requirement to prepare, publish and maintain information in accordance with the access information standard is a civil penalty provision.

5. Retailer pricing

5.1. Key points

- Legacy contracts accounted for 90 per cent of the major retailers' gas portfolios in 2014, dropping to 40 per cent in 2018. This lead to a change in average commodity costs from $4/GJ in 2015 to $6.50/GJ in 2018.
- Legacy contracts will continue to diminish in importance as time goes on, dropping to an average of less than 20 per cent of the major retailers' gas portfolios by 2021.
- The impact on customers from this change is less certain. There is evidence that suggests the retailers have the capacity to absorb the increase in commodity costs by reducing their margins. However the extent to which retailers may raise customer prices, or absorb cost increases through a reduction in margins, will in part depend on the presence of constraints limiting the retailers' ability or willingness to raise prices — such as the level and effectiveness of competition faced by the retailers.[216]
- Indicators of the effectiveness of competition for supply of gas to mass market customers vary by jurisdiction:
  - Victoria shows the greatest number of signs of effectiveness of competition, with the largest number of retailers and the lowest levels of concentration
  - New South Wales and South Australia also show positive signs, with increasing numbers of retailers and decreasing levels of concentration
  - Queensland, the ACT, and Tasmania show fewer signs of the effectiveness of competition, but this may to a large extent be due to the small size of each of these markets, and the low gas penetration and average gas usage in Queensland and Tasmania.
- Gas market offers are potentially complex and confusing for consumers to compare. There may be value in governments considering the merits of implementing other measures to improve consumer experiences and outcomes in the supply of gas to mass market customers.

5.2. Introduction

The ACCC's July 2019 report provided further analysis on the prices, costs and margins of AGL, EnergyAustralia, and Origin in supplying gas to customers across the east coast.[217]

The report found that the margins of the big three retailers during 2014 to 2018 were high, and well in excess of the margins the ACCC was expecting.

For mass market customers, average margins were consistently high across the period and ranged between 19 and 23 per cent of the delivered price of gas.

For C&I customers, average margins grew over the period from 13 per cent to 28 per cent of the delivered price of gas.

Chart 5.1 below illustrates the cost stack analysis for mass market and C&I customers across the period.

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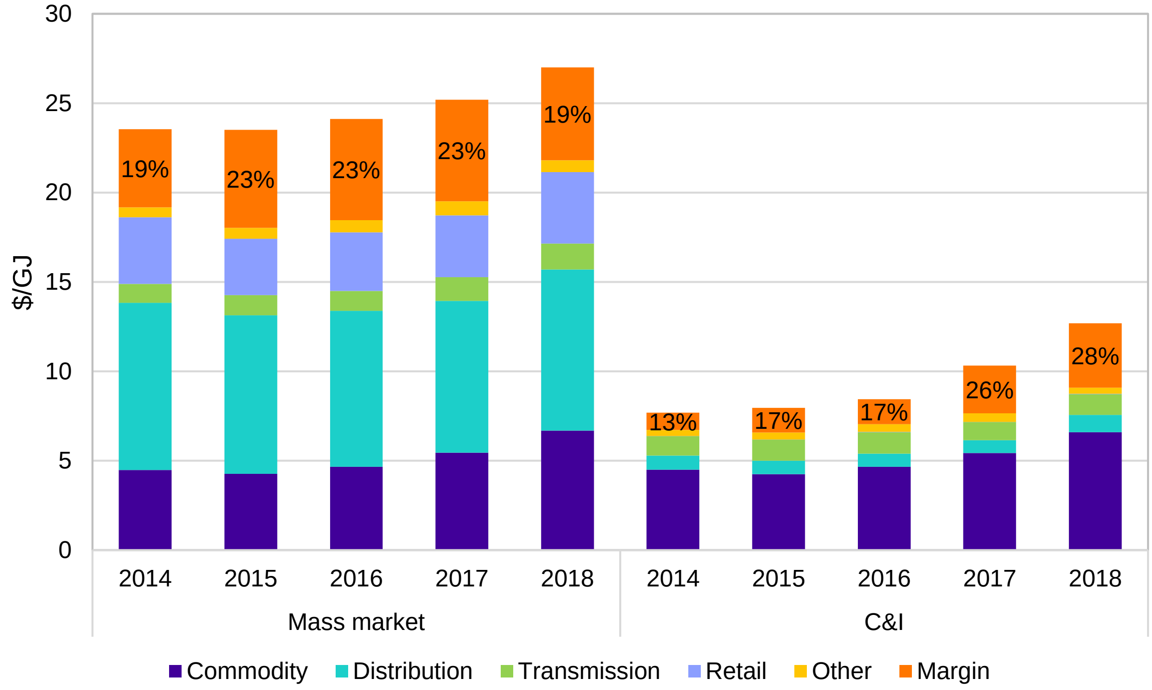
[216] We note that care needs to be taken in interpreting these results for reasons described in sections 5.3.1 and 5.4.4.

[217] The ACCC's 2019 July report presented information from the following jurisdictions: Queensland, Victoria, South Australia, and New South Wales (including the ACT). Tasmania was excluded because the big three retailers don't operate in Tasmania.

Chart 5.1: Cost stacks for whole East Coast Gas Market, mass market and C&I



Source: ACCC analysis of information provided by the major retailers.

Note: Costs are allocated to the mass market and C&I customer segments, and margins are estimated, based on the approach outlined in section 5.3.

We noted that the high margins were due in part to low cost gas obtained by the retailers under long-term legacy contracts, but that this advantage may be temporary as the retailers enter new contracts at today's higher market prices to replace expiring legacy contracts. We said we would investigate the role legacy contracts played in the level of margins observed.

We also considered whether market concentration and consumer disengagement may be contributing to margins being paid by mass market customers. We noted we would undertake further work to better understand the supply of gas to mass market customers and the effectiveness of competition.

This chapter provides an update on these two areas and is structured as follows:

- Section 5.3 explains the ACCC's approach to analysing the retailers' prices, costs and margins
- Section 5.4 describes the proportion legacy contracts made up of the retailers' total supply during the 2014 to 2018 period and future years, and considers the potential market impacts as legacy contracts expire
- Section 5.5 examines some of the indicators of effective competition in the supply of gas to mass market customers (the retail gas market)
- Section 5.6 sets out our conclusions and recommendations.

5.3. The ACCC's approach to analysing retailer pricing, costs, and margins

The ACCC's July 2019 report used a 'cost stack' approach to reporting on retailer pricing, costs and margins.[218] This section explains the approach to constructing the cost stacks presented in the July 2019 report, our approach to measuring margins and the reasons why we described the margins as high.

5.3.1. Our cost stack analysis

Chart 5.1 above is one of the cost stack charts presented in the July report. The chart show the delivered prices, costs components and resulting margins averaged across the three major retailers for the East Coast Gas Market.

Each cost stack was derived by taking average delivered prices for each state and customer type and subtracting allocated costs. The delivered prices were calculated by dividing revenues by volumes supplied, which the retailers provided on a per-location and customer type basis. Costs were allocated using an approach developed in consultation with the retailers.[219] Costs were then subtracted from the delivered prices to estimate margins.

The ACCC's July 2019 report set out some caveats that should be kept in mind when interpreting the results.[220] Of particular relevance to this chapter, the July 2019 report notes (emphasis added):

> The cost stacks show the estimated margins actually realised in each year averaged across all volumes supplied (as distinct from the margins that the retailers expected to earn when entering into a particular contract).
>
> They reflect all costs incurred and revenues received in respect of gas supply in that year.
>
> *This includes both costs incurred and revenues received under contracts executed at different points in time prior to the supply year for which margins are calculated.*
>
> *This means that the costs and revenues used to calculate the margins can reflect market dynamics at different points in time*.[221]

How we measured and assessed retailer margins

In the July 2019 report, we used EBITDA (earnings before interest, tax, depreciation and amortisation) as the measure of retail gas margins. Using this measure of margins ensures they account for profits after cost of goods sold (that is, commodity, distribution, transmission and other costs) and deduct retail operating costs. However the approach excluded an allowance for a return on capital. To the extent that these costs are significant, a margin that accounts for this (such as EBIT) would be lower, however the ACCC did not conduct an assessment of an appropriate return on capital in the report.

In assessing the retailers' margins in the July 2019 report, the ACCC had regard to New South Wales' Independent Pricing and Regulatory Tribunal (IPART) June 2016 final determination on regulated retail gas prices. As part of its assessment, IPART considered

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218 ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 92.

219 More detail on the cost allocation approach is set out in section 4.4.2, p. 91, of the ACCC's July 2019 report.

220 A full description of all the caveats is provided in section 4.4.3, p. 92, of the ACCC's July 2019 report.

221 ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 92.

independent analysis which estimated a reasonable EBITDA range that would be consistent with the costs an efficient and prudent retailer would incur in a competitive market.[222]

In its final determination, IPART used an EBITDA range of 6.3 to 7.3 per cent, based on the independent analysis, to assess the pricing proposals of the retailers.[223] Further, the analysis used by IPART included an examination of comparable margins used by regulators in other jurisdictions and found that, with the exception of South Australia, they were generally at the lower end of this range.[224]

Notably, in the ACCC's Retail Electricity Pricing Inquiry (REPI) final report, the ACCC found that average EBITDA margins across the National Electricity Market (NEM) in 2017–18 for residential and small to medium enterprise electricity customers—equivalent to the mass market category used in this report—were both eight per cent, and that margins for C&I customers were two per cent.[225]

As set out above, the margins for mass market customers were consistently high and ranged between 19 and 23 per cent, whereas margins for C&I customers grew from 13 per cent to 28 per cent. In describing these margins as high, the ACCC had regard to the reasonable EBITDA range used by IPART and the margins found in the ACCC's REPI report.

5.4. Legacy contracts over time—and potential market impacts

This section explains what legacy contracts are, and how they can impact retailer margins. We also look at the proportion of the retailers' total supply was made up from legacy contracts during the 2014 to 2018 period, the proportion expected for future years, and consider the impact on competition and customers that may arise as these contracts expire over time.

5.4.1. What are legacy contracts and why do they impact margins?

The vast majority of the retailers' gas requirements are met under gas supply agreements (GSAs) with producers and other suppliers.

Before 2010, gas prices under GSAs were steady and relatively low at around $3–4/GJ. However, from late 2010, around the time Queensland's three LNG projects were being developed, gas prices across the east coast began to increase.

More recently, gas prices across the east coast have been shaped by LNG netback prices, tight supply-demand dynamics, and rising costs of domestic production. This has seen gas prices agreed under long-term GSAs increase to around $10/GJ.[226]

The retailers entered into a number of long-term GSAs before 2010, at low prices, which were still on foot during the 2014 to 2018 period. These GSAs are referred to as legacy contracts throughout this chapter.

While the retailers have been similarly exposed to increasing wholesale market prices when seeking to enter into new GSAs over recent years, during the 2014 to 2018 period their gas supply portfolios still included significant quantities of gas supplied under a range of legacy contracts. The low prices paid by the retailers under these legacy contracts had the effect of lowering their average commodity costs relative to market prices.

[222] IPART, *Review of regulated retail prices and charges for gas from 1 July 2016*, June 2016, p. 41.

[223] IPART, *Review of regulated retail prices and charges for gas from 1 July 2016,* June 2016, p. 41.

[224] SFG Consulting, *Estimation of a competitive profit margin for gas retailers in New South Wales*, April 2010, p. 7.

[225] ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 95.

[226] ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 104.

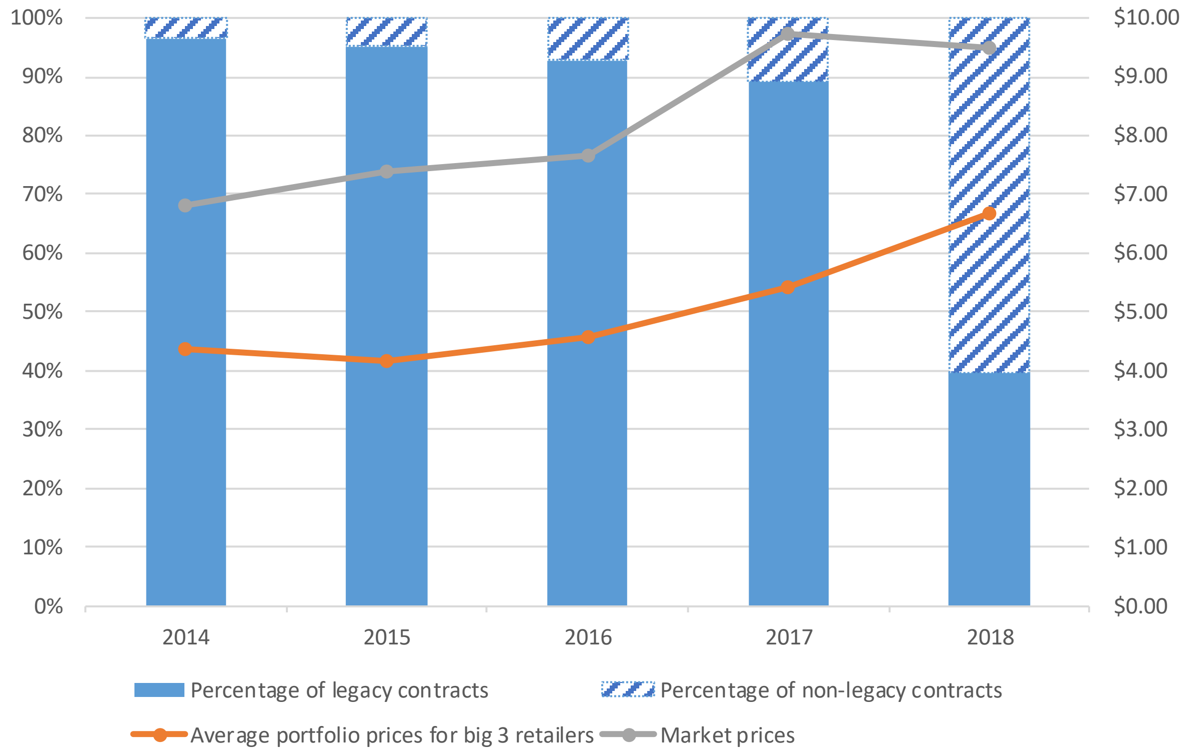
Given our approach to calculating retailer margins involves subtracting the costs incurred by the retailers from the revenue received from their customers, factors that lower the retailers' costs—such as legacy contracts—will contribute to an increase in margins (all other things being equal).

5.4.2. The proportion of gas sourced from legacy contracts declined over 2014 to 2018

We have conducted further analysis to understand the extent to which legacy contracts contributed to the retailers' low average commodity costs during the 2014 to 2018 period.

During the period, the legacy contract position of each of the retailers varied. We have observed variability in the number of contracts, the proportion they made up of each retailers' total supply volumes, annual contract volume and contract duration. This should be taken into account when interpreting the analysis below—which shows aggregated information of the big three retailers. Our findings are set out in Chart 5.2 below.

Chart 5.2: The proportion of gas sourced from legacy contracts declined over 2014 to 2018



Source: ACCC analysis of information provided by the major retailers and Oakley Greenwood, Gas Price Trend Review 2017, March 2018.

Note: The chart shows the average commodity costs incurred / paid by the retailers in each year from 2014 to 2018. The market prices reflect prices agreed in each year from 2014 to 2018.
2014 and 2015 market prices are weighted average nominal wholesale prices using state average nominal wholesale prices per state and percentage of gas consumed per state across the East Coast market using Oakley Greenwood data.
2016 to 2018 prices are weighted average nominal wholesale prices per volume of gas sold in the East Coast market using ACCC data.
The Big 3 Portfolio Average Price is the weighted average prices of retailer commodity cost averaged across states and customer types.

Legacy contract percentage is the percentage of total retailer legacy contract volumes over total retailer gas volumes supplied.

The chart shows that the volumes of gas sourced from legacy contracts as a proportion of the volumes of gas supplied to customers declined each year during the period. The largest reduction occurred in 2018, when the proportion fell from nearly 90 per cent to just under 40 per cent. This reflects the expiry of the retailers' legacy contracts over the period.

The retailers needed to enter into new agreements to replace their expiring legacy contracts. As these new agreements were at higher prices, the retailers' average commodity costs increased. This is also shown in the chart above, where the retailers' average commodity costs increased each year from about $4/GJ in 2015 to around $6.50/GJ in 2018.

Despite the increase, the retailers' average commodity costs remained well below the market price each year. This would have benefitted the retailers as they were able to sell gas at higher market prices. Also, it may have provided them with a cost advantage relative to competitors with higher commodity costs—such as the prices a new entrant would have faced.

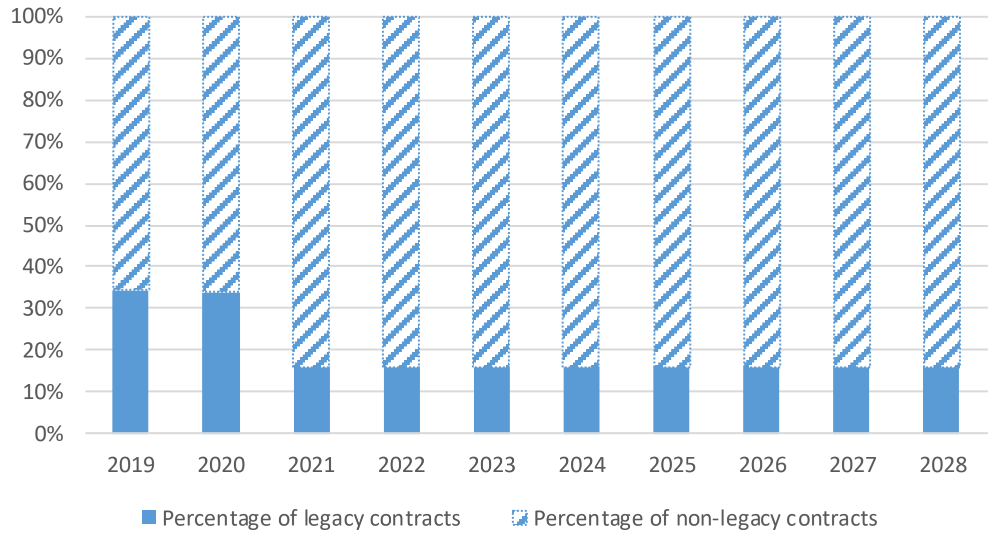
The difference between the retailers' average commodity cost and the market price, however, narrowed significantly in 2018. While this was in part due to a decrease in the market price, the increase in the retailers' average commodity cost played a greater role—likely due to the large reduction in the proportion of gas sourced from legacy contracts that year.

This reduction in the retailers' cost advantage would likely benefit their competitors. However we note the retailers' are likely to retain some cost advantage relative to their competitors—particularly smaller retailers and new entrants—who would typically face higher gas prices due to the lower volumes being purchased.

5.4.3. Legacy contracts will continue to roll off in the coming years

The volumes of gas sourced from legacy contracts as a proportion of the volumes of gas supplied to customers is expected to continue to fall from 2019 onwards as Chart 5.3 below illustrates.

Chart 5.3: The proportion of gas sourced from legacy contracts will continue to decline



Source: ACCC analysis of information provided by the major retailers.

Note: Legacy contract percentage is the percentage of total retailer legacy contract volumes over total retailer gas volumes supplied. For this analysis, we have assumed that retailers' total contract volumes across the period will remain at 2018 levels.

Following the decline from 90 per cent to just under 40 per cent in 2018, the proportion declines further to 35 per cent in 2019, and then again in 2021 to 16 per cent where it is expected to remain steady for the remainder of the period.[227]

As the retailers enter into new agreements at higher prices to replace their expiring legacy contracts there will likely be a continuation of the increase in their average commodity costs.

Both Origin and AGL have referred to their increasing commodity costs in their most recent respective financial reports for the 2018–19 financial year.[228] Origin reported a 20 per cent increase in its commodity costs over 12 months, from $5.70/GJ to $6.60/GJ.[229] AGL reported an increase from $5.30/GJ to $6.30/GJ 'driven by low-cost gas contracts replaced with contracts priced at current market levels'.[230]

The ACCC has considered whether the retailers' new agreements may also lead to a similar cost advantage to that which arose due to legacy contracts. On this, we make the following observations. For a similar cost advantage to occur, it would require the prices under the new agreements to be lower than the actual domestic market prices in future years. It is difficult to know with reasonable certainty whether or not this will occur, because future market prices are not known. That said, in the event a cost advantage did arise, the shorter duration of the retailers' new agreements relative to legacy contracts is likely to mean the advantage is short lived. Generally, the retailers' legacy contracts had a duration of around 10 years, with several in excess of this. The retailers' new agreements are typically for much shorter periods.

227 We note that our analysis has assumed a constant level of supply for each year and that, to the extent actual volumes supplied by the retailers vary, this in turn will change the proportions.

228 The ACCC's reporting on retailer pricing is on a calendar year basis, whereas AGL and Origin report on a financial year basis. Therefore, the prices are not directly comparable nor does the ACCC expect them to be.

229 Origin, *Annual Report 2019*, September 2019, p. 34.

230 AGL, *AGL Energy Limited Annual Report 2019*, August 2019, p. 45.

5.4.4. The impact of the retailers' rising commodity costs is uncertain

The ACCC's July 2019 report found that for 2018, the average retailer margin across the east coast for mass market customers was 19 per cent, and for C&I customers was 28 per cent.

However, if we recalculate the retailers' margins using a higher commodity cost of $9.49/GJ (the market price for 2018 used in Chart 5.2 above), margins decrease considerably.

For mass market customers, the average retailer margin reduces to nine per cent, and for C&I customers the margin becomes six per cent.

This may suggest that, with an average gas commodity cost of $9.49/GJ, with other costs and revenues remaining the same, the big three retailers have the capacity to absorb the increase in commodity costs by reducing their margins.

However, care needs to be taken in interpreting these results for reasons described in section 5.3.1 above and in the ACCC's July 2019 report. There are limitations to using the cost stack analysis to forecast prices and margins, in particular:

- it is based on highly aggregated information that focusses on the whole East Coast Gas Market and the three retailers' combined. While the margins observed in the July 2019 report were generally still high, they varied widely between states and between individual retailers due to differences in average delivered prices between states and costs of supply[231]
- other costs and revenues are unlikely to remain the same in future years—what we have observed with legacy contracts could also apply to other costs such as transportation and storage, as well as the retailers' contracts to supply customers. As these roll off, and new agreements are struck, the average costs and revenues (which determine the average delivered price of gas faced by customers used in the cost stack analysis) will likely change as a result—which in turn will impact margins.

Even if the retailers left their 2018 prices unchanged for customers throughout 2019 and 2020, there would still likely be an increase in the average delivered price of gas as older sales agreements with customers expire, and a larger proportion of sales are made up of relatively higher 2018 prices. This demonstrates the lag in the cost stack analysis, where the costs, prices, and margins are reflective of market dynamics from different points in time—instead of just representing the market dynamics in the year of a particular cost stack.[232]

The extent to which the big three retailers may raise customer prices, or absorb cost increases through a reduction in margins, will in part depend on the presence of constraints limiting the retailers' ability or willingness to raise prices. One such constraint could come from competition from other retailers and suppliers.

As noted above, the retailers' low average commodity costs compared to market prices may have given them a cost advantage relative to competitors with higher commodity costs—such as what a new entrant may have faced.

However rising average commodity costs may have the effect of eroding this cost advantage, as was observed in 2018. If this is the case, it could lead to a change in market

[231] ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 93.

[232] See chapter two of this report for more information on offered prices, and prices agreed under GSAs, by gas suppliers, including gas retailers. Note that the data presented in chapter 2 may not be directly comparable with the information presented in this chapter.

conditions which improve the position of the competitors of the big three retailers, and potentially make the market more attractive to new entrants.[233]

The increase in new suppliers entering the market or expanding their operations to supply C&I customers may be a sign that this is already occurring—although we emphasise that we cannot be certain of the extent that these are related. As noted in the July 2019 report, there have been a number of new suppliers enter the market or expand their business operations to supply C&I customers. Around the same time that supply from the big three retailers to C&I customers fell, we identified an increase in supply from newer suppliers Alinta Energy, Shell Energy Australia, and Power and Water Corporation, as well as an increase in direct contracting with C&I users by gas producers.[234]

There have also been some positive developments in the market for the supply of gas to mass market customers. The number of retailers supplying mass market customers across the east coast overall has increased.[235] Also, there is evidence that in some parts of the market the big three's competitors are offering gas at comparable or cheaper prices.[236] This is set out in the AER's recently published Annual Retail Markets Report for 2018–19, which provides analysis of residential gas prices in Queensland, South Australia, New South Wales, the Australian Capital Territory, and Victoria.[237] The market for the supply of gas to mass market customers is examined in more detail in section 5.5 below.

5.5. Indicators of the effectiveness of competition in retail gas markets

The presence of high retail margins can be an indicator that certain (or all) suppliers in a particular market have a degree of market power. However, care must be taken not to infer the presence of market power solely from consideration of retail margins. This is because relatively high retail margins may be consistent with effective competition in the long-run. This might be the case, for instance, where:

- Market participants need to incur substantial one-off capital costs. In this instance, high margins may be needed to ensure suppliers are able to fully recover these costs (and earn a normal rate of return on their investment) over the long-run
- A firm operates across a number of markets, and incurs significant common/overhead costs. In these circumstances, high retail margins may be necessary in order that the firm can make a contribution towards the recovery of these costs across all business units
- Barriers to entry are low. In this context, the presence of high retail margins may simply reflect transitory market power; and any such margins may be eroded by ongoing market forces (including new entry).

An analysis of the effectiveness of competition in a particular market therefore requires consideration of a range of additional factors other than simply retail margins.

[233] We note that the costs and cost structures of new entrants and smaller retailers / suppliers may vary significantly from that of the big three.

[234] ACCC, *Gas Inquiry 2017–2020—Interim Report*, July 2019, p. 86.

[235] AEMC, *2019 Retail Energy Competition Review—Final Report*, June 2019, p. 27.

[236] AER, *Annual retail markets report 2018-19*, November 2019, p. 109.

[237] We note that the retailers and their offers vary for each jurisdiction and each distribution zone/s in each jurisdiction.

The purpose of this section of our report is to consider a range of other characteristics of retail gas markets in order to understand whether suppliers of retail gas (and in particular the "Big 3") are likely to have a degree of enduring market power and therefore not likely to be subject to effective competition in the long-run. Factors considered in this section of the report include:

(a) the number of alternative suppliers of retail gas that act as competitors to each other

(b) measures of market share and concentration

(c) the degree of customer switching between different retail suppliers of gas

(d) indicators of the ease of entry into the supply of retail gas.

The analysis focuses on mass market customers by jurisdiction

The focus of this analysis is on the supply of gas to mass market customers. Mass market customers are made up of both residential and small to medium enterprises.[238] Generally, these are customers who consume less than one TJ per annum; and receive gas via a distribution network.

We also observe there appear to be a number of different indicators of the effectiveness of competition depending on the state or territory within which retail gas to mass market consumers is supplied. For this reason, we have considered separate markets for the supply of retail gas to mass market consumers in:

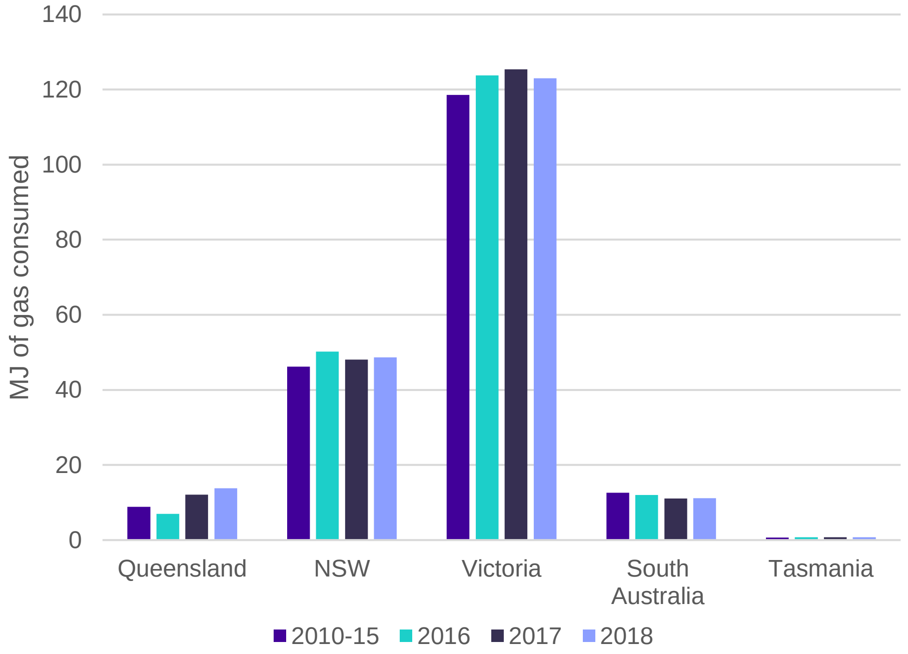
- Queensland
- South Australia
- New South Wales
- the Australian Capital Territory[239]
- Victoria
- Tasmania.

Importantly, the degree to which gas is consumed by (and available to) retail customers varies considerably from one jurisdiction to the next. For instance, Chart 5.4 clearly demonstrates that gas consumption levels are considerably higher in Victoria, where it is more than double that of the next highest consuming state (New South Wales). In contrast, consumption levels in Tasmania are particularly low. This partly reflects the absence of a major gas pipeline into Tasmania prior to 2004; or a distribution network in the north of the state before 2005 (and the south of the state before 2007). It is also noteworthy that none of the three major gas retailers in Australia (Origin, Energy Australia and AGL) operates out of Tasmania.

[238] In some cases, data was only available for residential customers. This is noted where relevant.

[239] The ACCC notes that while certain data relied upon in this section separates out the ACT from New South Wales, the retail margin analysis set out earlier in this chapter includes the ACT within the broader New South Wales geographic area.

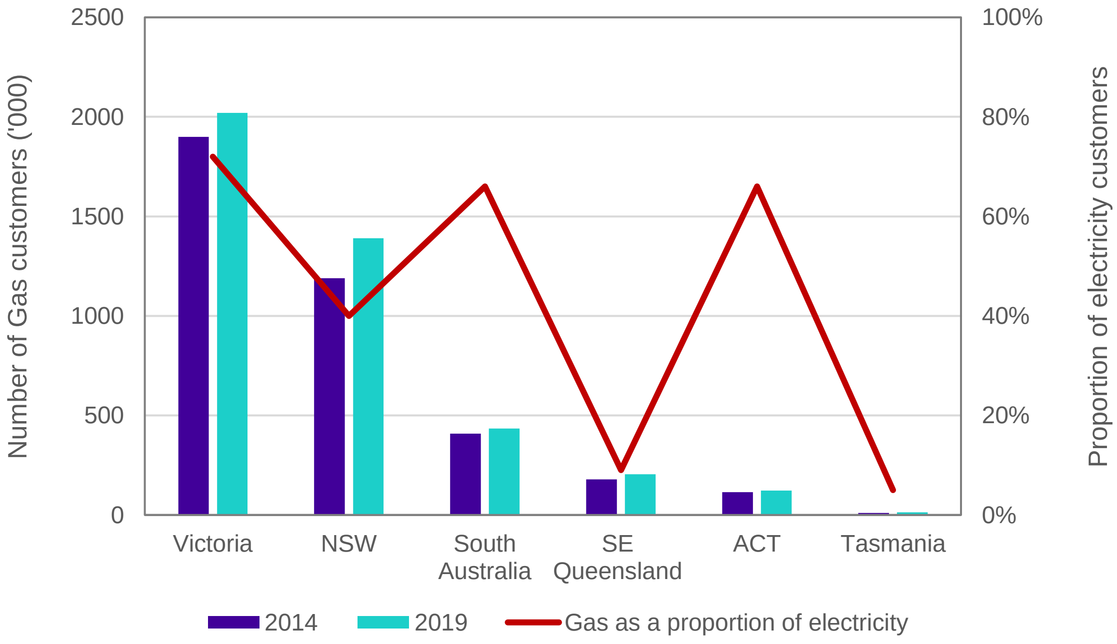
Chart 5.4: Gas consumption is greatest in Victoria



Source: AEMO, National Gas Forecasting Report, 2016; and 2018 Gas Statement of Opportunities, March 2019.

Further, the number of gas customers varies considerably from one jurisdiction to the next. This is shown in Chart 5.4 which sets out both the growth in the number of gas customers in each jurisdiction between 2014 and 2019; as well as the proportion of electricity customers relative to gas customers in each of these jurisdictions.

Chart 5.5: Victoria has largest number of gas customers



Source: AEMC, Retail Energy Competition Review, 2019.

Chart 5.5 shows that while the number of gas customers increased in all jurisdictions between 2014 and 2019, gas is consumed by only a small number of customers relative to electricity in South East Queensland and Tasmania.

The analysis does not separate out different regional features within jurisdictions

The ACCC also notes that the indicators of competition relied upon in this report do not separate out regional and urban conditions. This caveat is important because while, for instance, retail gas consumers in central Adelaide may have five or six retail gas suppliers to choose from; consumers in more regional areas of South Australia are likely to have more limited gas supply options available to them. Similarly, while retail consumers in Melbourne may have as many as 15 different retail suppliers of gas they can choose from, customers in regional areas such as Horsham or Ararat may only have one supplier available to them.

Further, the extent to which price offerings available to consumers across a particular jurisdiction can vary.

The analysis set out below does not seek to undertake a “deep dive” into the extent to which conditions vary across different regions within a particular state or territory, and instead considers indicators of competition from a broader “whole of state” perspective.

The analysis relies heavily on published material from other authorities

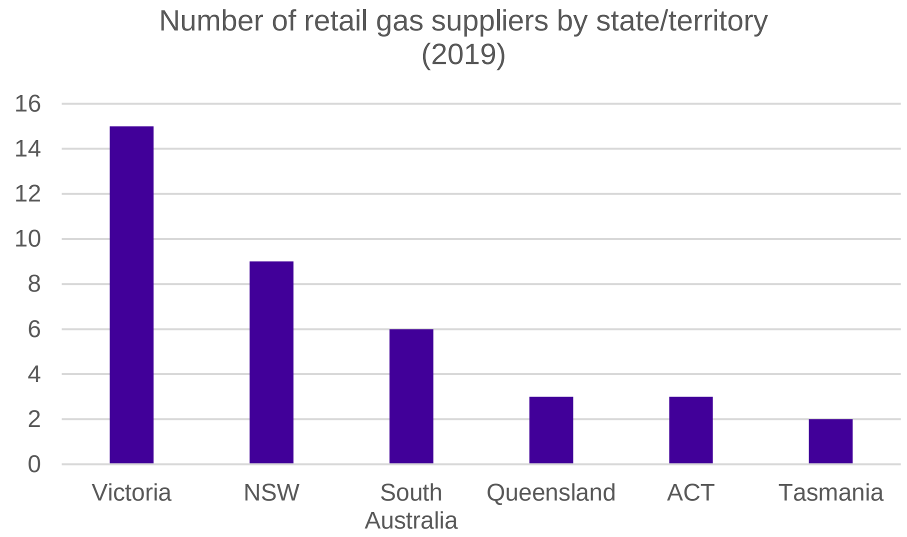
For the purposes of this report, the ACCC has not sought to collect additional data from market participants on key market characteristics. Instead, we have relied on published material by other independent authorities, including the Australian Energy Market Commission (AEMC), the Australian Energy Regulator (AER), the Australian Energy Market Operator (AEMO), and other individual jurisdictional agencies.

5.5.1. The number of competing suppliers varies across different states

Information reported annually by the AEMC indicates there is a wide variance in the number of suppliers of retail gas to mass market consumers in each of the separate state and territories referred to above. This is reflected in Chart 5.6 below, which shows that in 2019 there are a number of alternative suppliers of retail gas in Victoria (15), New South Wales (nine) and South Australia (six). In contrast, however, there are far more limited alternatives in Queensland[240] and the Australian Capital Territory (three each), and Tasmania (two).

[240] The ACCC notes that in Regional Queensland, there are only two retail suppliers of gas, with a third supplier in South East Queensland.

Chart 5.6: Victoria has the largest number of suppliers, while Tasmania has the fewest



Source: AEMC's 2019 Retail Energy Competition Review, 28 June 2019, figure 3.8.

While the number of suppliers in a given market is not determinative of the effectiveness of competition within it, the ability to switch to a greater number of alternative suppliers is likely to lead to greater choice and product differentiation for consumers. In this instance, chart 5.6 suggests there is likely to be a greater level of competitive constraint on retail gas suppliers in Victoria, New South Wales and South Australia relative to that which might exist in Queensland, the Australian Capital Territory and Tasmania.

5.5.2. Market concentration is lowest in Victoria and South Australia

A second common indicator of the effectiveness of competition in a market is the level of market share held by different suppliers, and the extent to which these shares are "concentrated" in the hands of only one or two major suppliers. Markets with a larger number of suppliers with significant market shares are likely to be more consistent with effective competition than ones where only one or two suppliers have the substantial majority of market share.

One indicator of market concentration regularly used in competition assessments of markets is the Herfindahl-Hirschman Index (HHI). HHI measures are determined by summing the square of the market share of each market participant; and can range from a value of zero to 10 000. Measures closer to 10 000 are indicative of a more heavily concentrated market; whereas measures closer to zero indicate a broader spread of market shares across a larger number of market participants. In merger analysis, for instance, the ACCC notes that, generally, it will be less concerned about mergers that result in a post-merger HHI of less than 2000.[241] Similarly, the United States Department of Justice and Federal Trade Commission note that "highly concentrated markets" are those with an HHI greater than 2500.[242]

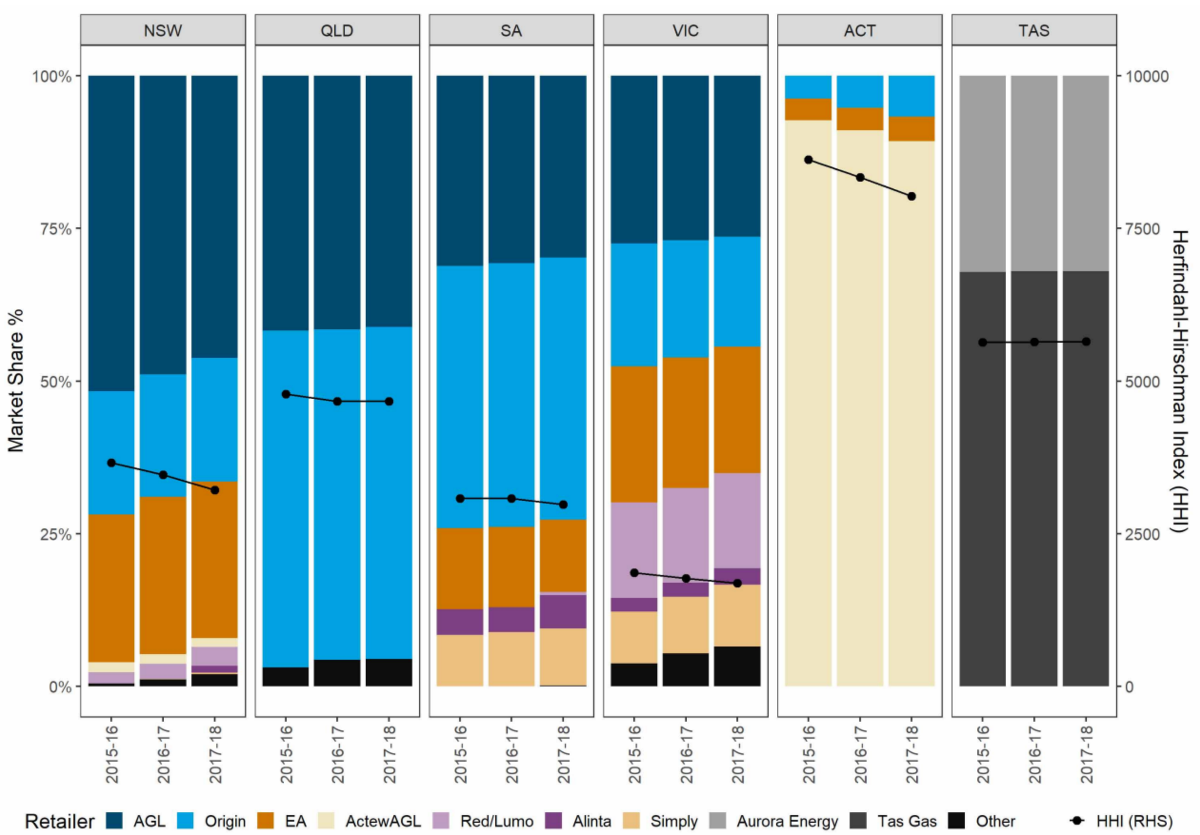
241 ACCC, *Merger Guidelines*, 2008 at p. 35.

242 U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, August 19, 2010, at p. 19.

Data reported by the AEMC (and copied in Chart 5.7 below) shows that market concentration levels:

- have been steadily declining in New South Wales in recent periods, where Red Lumo, Alinta and others have taken share off market leader AGL. In 2017–18, HHI levels were, however, still a little above 2500
- marginally declined in South Australia to be a little above 2500 in 2017–18. This appears to be mainly due to Alinta and Simply increasing their market shares at the expense of AGL, and to a lesser extent Energy Australia
- are lowest in Victoria, where the large number of retail suppliers (and the growth of Alinta and others) saw HHI levels fall below 2000 in 2017–18
- are particularly high in the ACT, with Actew/AGL enjoying a market share consistently higher than 85 per cent. While the level of concentration appears to be declining as Energy Australia and Origin take market share off Actew/AGL, the HHI measure in the ACT is still well above 7500 suggesting this is a highly concentrated market
- have been consistently greater than 5000 in Tasmania, where Tas Gas has maintained a market share close to 70 per cent of the market
- have been around 5000 in Queensland, where two large suppliers (AGL and Origin) have commanded combined market shares of around 95 per cent in recent years.

Chart 5.7: Victoria has the lowest levels of market concentration, Australian Capital Territory has the highest



Source: AEMC's 2019 Retail Energy Competition Review, 28 June 2019, figure 3.10

Note: Based on residential information

These measures suggest that all retail gas markets other than Victoria have high levels of concentration—with the Tasmanian, Queensland and Australian Capital Territory markets exhibiting particularly high levels of market concentration. As indicated above, however, Queensland and Tasmania are states/territories where gas is consumed by relatively small numbers of customers (especially compared to the number of electricity customers), suggesting these are fairly shallow markets compared to other states/territories.

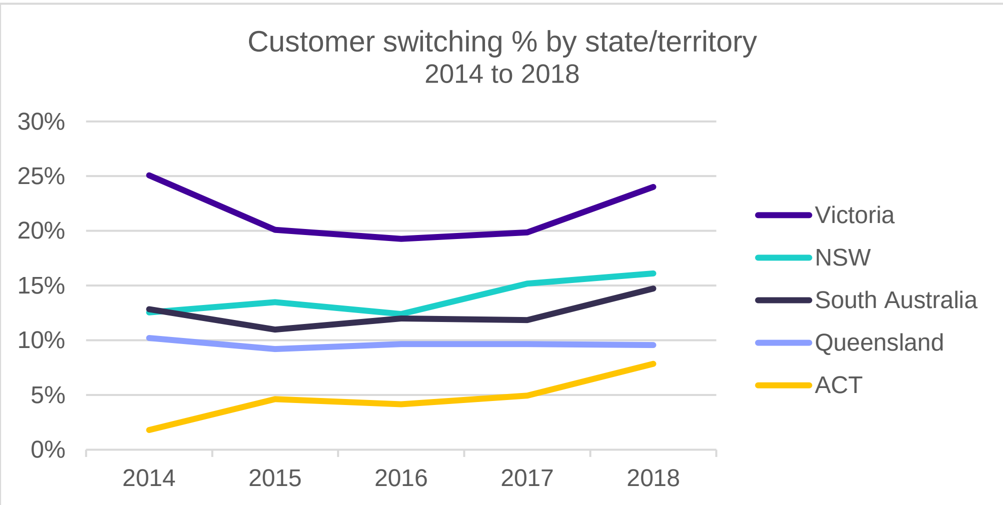
5.5.3. Customer switching is high in Victoria and growing in most jurisdictions

The extent to which customers are able to switch between alternative suppliers can be an indicator of the extent to which different market suppliers are able to apply competitive constraints on each other. Markets where switching is low may indicate either a dearth of competitive options/rivalry between suppliers in a market, or that there are barriers to switching for consumers that limit the ability of rival firms to effectively compete with each other.

Data reported by the AEMC (and reproduced in Chart 5.8 below) indicates the level of switching in retail gas markets has varied by state and territory in recent years. In this respect, switching over the period from 2014 to 2018 has been:

- relatively high in Victoria, with annual levels ranging from between 19.27 per cent and 25.08 per cent. Most recently, 24.02 per cent of retail gas customers switched supplier in 2018
- consistently higher than 10 per cent per annum in New South Wales and South Australia. In 2018, switching was highest over the five year period at 16.11 per cent in New South Wales and 14.73 per cent in South Australia
- close to 10 per cent in Queensland, ranging between 9.2 per cent and 10.21 per cent over the five year period analysed
- low, but increasing, in the ACT. In 2014, only 1.8 per cent of retail gas customers switched supplier, but this rose to 7.85 per cent in 2018.

Chart 5.8: Victoria has the highest levels of customer switching, while the ACT has the lowest levels



Source: AEMC's 2019 Retail Energy Competition Review, 28 June 2019, figure 3.11.

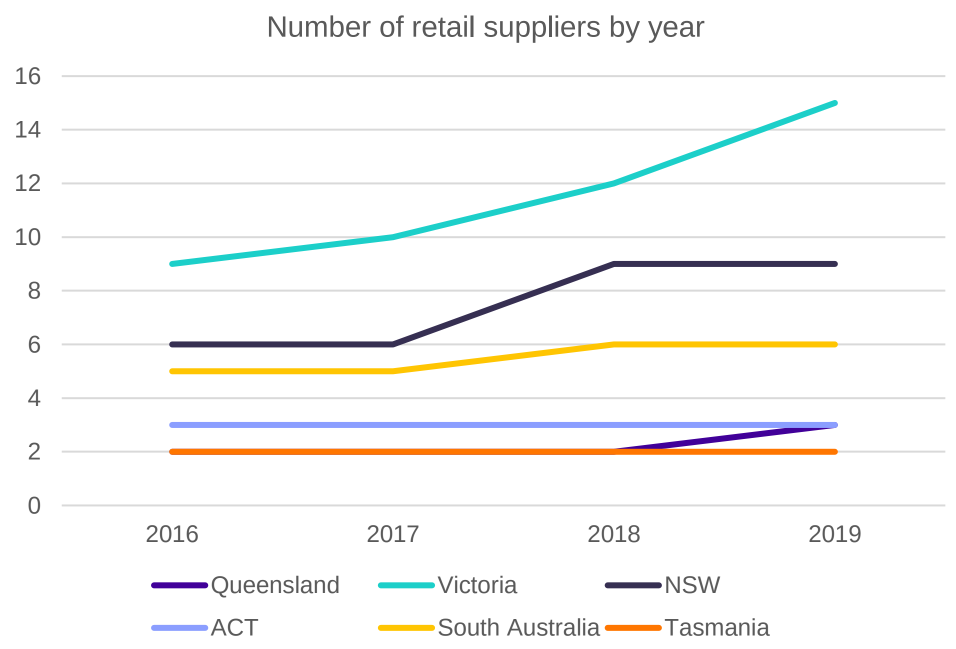
5.5.4. Indicators of the ease of entry/expansion in retail gas markets

The ease with which new firms can enter and/or existing firms can expand their operations is a critical measure of the effectiveness of competition in any market. Where barriers to entry/expansion are low, an incumbent firm may only be able to earn unreasonably high profits for a short period before other firms will enter/expand their operations in order to compete away an incumbent's profits.

Measures of the annual change in retail gas suppliers in each state and territory suggest that barriers to entry may be lower in Victoria, New South Wales and South Australia than they are in other jurisdictions. This is reflected in Chart 5.9 below, where the number of suppliers between 2016 and 2019:

- increased from nine to 15 in Victoria[243]
- increased from six to nine in New South Wales
- increased in South Australia from five to six
- increased from two to three in Queensland (noting that the number of suppliers remained at two in Regional Queensland)
- remained unchanged in Tasmania and the Australian Capital Territory.

Chart 5.9: Victoria has the largest number of retailers, while Tasmania has the fewest



Source: AEMC's 2019 Retail Energy Competition Review, 28 June 2019, figure 3.8.

While not definitive, these measures may suggest barriers to entry are lower in Victoria, New South Wales and South Australia relative to other states and territories.

Further, changes in HHI values and the level of switching referred to in sections 5.5.2 and 5.5.3 above suggest the ability of new entrants or smaller market participants to expand and

243 The ACCC notes that in Victoria there are presently 17 different brands. However, two businesses in Victoria offer two brands in the market such that there are only 15 suppliers in Victoria.

win market share from larger incumbents is greater in Victoria, New South Wales and South Australia. This is reflected in the lower (and declining) measures of concentration in these states.

We have considered a number of potential causes of barriers to entry/expansion in retail gas markets, as set out below.

Access to Gas Supply, Transportation and Storage

For a potential supplier considering entering a particular retail gas market, the ability to access wholesale gas and transportation infrastructure necessary to move it from its source to major population centres is critically important.

In this respect, the ACCC notes recent observations from the AEMC that some gas retailers claimed it was difficult to access reasonably priced gas and transportation and that this was a barrier for entry/expansion.[244]

The ACCC notes that the uncertainty around the supply-demand outlook over the immediate and longer term, particularly in respect of gas supply, may act to inhibit a potential supplier from entering the retail gas market. The lack of sufficient supply and diversity of suppliers may also make it more difficult to access gas at reasonable prices.

Further, the ACCC has previously reported on issues around the pricing of and access to transportation infrastructure. Many of these issues are the focus of a number of reforms, including the capacity trading platform and day ahead auction. We have also reported on the pricing of gas storage in the Iona and Dandenong LNG storage facilities.

The ACCC will continue to focus on issues around access to and pricing of gas supply, transportation and storage, given the potential for them to present barriers to entry / expansion in the retail gas market.

Economies of Scale & Market Size/Penetration

In most markets, firms need to incur a combination of fixed and variable costs in order to supply services to consumers. To the extent suppliers face large fixed costs and low variable costs of providing services, the average cost of providing additional units of output (or serving additional customers) is likely to decline as levels of supply increase. This gives rise to economies of scale over certain levels of output; and can, in turn, generate what is referred to as a “Minimum Efficient Scale (MES)” of supply. This refers to the minimum size (typically, in terms of output, capacity or customer base) that a firm requires to reach in order to compete effectively with incumbent suppliers in a market.

MES is an important determinant of the number of firms a market may be able to profitably support. Where MES is high relative to the level of demand in a market, the market will be able to support fewer market participants. In these circumstances, barriers to new entry can be high, as new entrants will feel it is unlikely they can secure enough demand to reach MES (and therefore compete with incumbent suppliers).

It follows, therefore, that where demand for a product is higher at any given level of prices in a market, MES is likely to be able to be achieved by a greater number of suppliers. Survey data reported by Farrier Swier Consulting referred to above indicates two factors that are

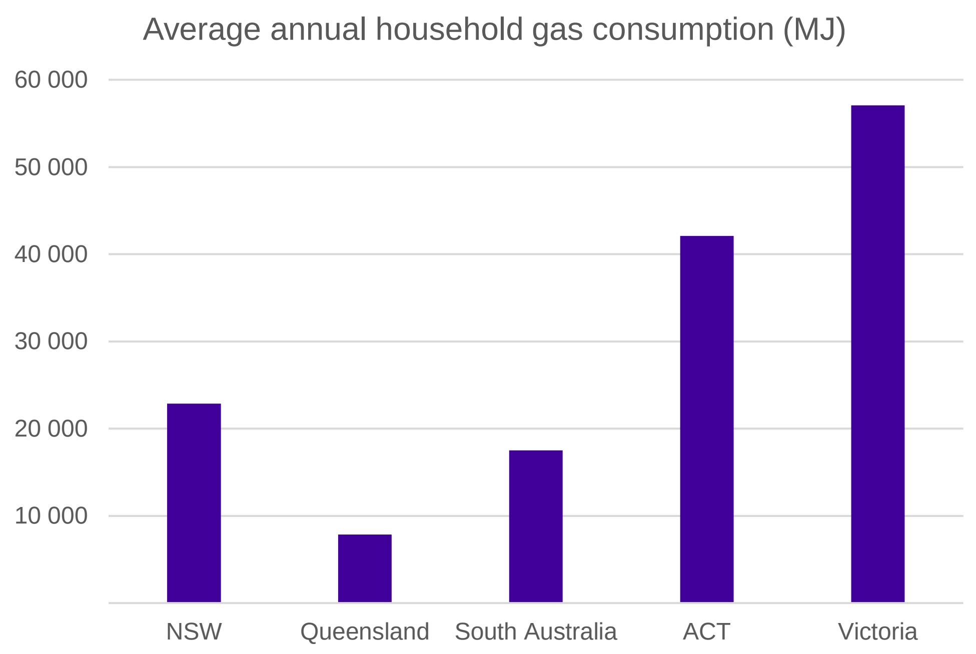
[244] AEMC, *2019 Retail Energy Competition Review—Final Report*, June 2019, p. xiv.

likely to bear on potential entrants' perceptions of whether market entry would be feasible: the level of gas market penetration; and the size of the market.[245]

As shown in Chart 5.5 above, gas penetration is particularly low in Tasmania and South East Queensland, where gas customers represent only five per cent and nine per cent respectively of the number of electricity consumers in these areas. This contrasts with Victoria where gas customers represent 72 per cent of electricity customers; and South Australia (66 per cent); the ACT (66 per cent) and New South Wales (40 per cent). Given the low penetration levels in Tasmania and South East Queensland, potential market entrants are likely to consider the size of the potential market they could compete for is considerably smaller than entrants considering entering some of the other states/territories.

Further, data reported by the AEMC shows that the average level of retail gas consumption by mass market customers varies considerably across different states and territories in Australia. As demonstrated in Chart 5.10 below, retail gas consumption levels per household are significantly higher in Victoria than other states and territories.

Chart 5.10: Victoria and the ACT have the highest levels of average gas consumption



Source: Information from the AEMC and AER.

While average household gas consumption levels (as well as gas market penetration) are relatively high in the ACT compared to some other states, the total level of gas consumption in the ACT is still likely to be relatively low compared to other states given the smaller population base in the ACT.

Customer inertia

As indicated above, evidence of customer switching can be an important indicator of the effectiveness of competition in particular markets. Further, the willingness of customers to switch between rival suppliers of a service is an important consideration for a potential

245 Farrier Swier Consulting, *2016 Energy Retailer Survey—Report for the Australian Energy Market Commission*, 30 March 2016, pp. 82–88.

entrant to a new market—that is, if customers are less inclined to be prepared to switch suppliers, there is a lesser likelihood a new entrant will have success in building a customer base following entry into the market.

Factors that lessen the likelihood of customers switching between suppliers include a lack of information about different options available to them; the complexity of offers supplied by retailers (and hence the ability of customers to easily consider which retail options are best for them); and the time and cost to invest in assessing different offers in order to be prepared to switch from their existing supplier.

In this respect, the ACCC notes CSIRO has undertaken a study of behavioural factors likely to influence the extent to which consumers engage with different offers in the Victorian retail energy market. This study found a number of factors acted as barriers to consumers engaging with and understanding different energy supply offerings, including:[246]

- consumers having low visibility and awareness of their actual energy consumption levels so that they can readily compare different offers available in a market
- a lack of "social awareness". That is, consumers have low visibility over which retail suppliers their peers choose. This can be significant in circumstances where consumer decisions are often influenced by the behaviour and decisions of others
- poor levels of "energy literacy", whereby consumers have very low understanding of how energy is supplied, priced and regulated
- perceptions of the complexity of understanding and comparing retail price offers given consumers have low levels of awareness of their consumption levels and energy literacy
- consumers having a "status quo bias", whereby energy consumption behaviour is habitual.

5.5.5. Indicators of effective competition vary depending on jurisdiction

Our assessment of the indicators of effective competition to supply mass market customers in the east coast states indicates that the signs of effective competition differ between the states, with Victoria showing the most positive signs and Queensland, Australian Capital Territory and Tasmania showing the weakest signs.

In Victoria, there are more suppliers, less concentration, and greater customer switching than in any other jurisdiction examined. However, access to wholesale gas is a potential barrier to further entry or expansion. There are no indications that there are structural barriers in Victoria at this time.

Both New South Wales and South Australia show signs of increasing competition. They each have more suppliers now than they did five years ago, the concentration levels are decreasing and they have increasing rates of customer switching.

Queensland, the Australian Capital Territory, and Tasmania have fewer suppliers than other jurisdictions, higher levels of market concentration, and lower levels of switching. To a large extent, this is driven by the size of these markets, and for Queensland and Tasmania, the lower gas penetration and average consumption levels. In these circumstances, it is likely that these features of each market make them less attractive to new entrants.

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[246] CSIRO, *Exploring the drives and barriers of consumer engagement in the Victorian retail energy market*, April 2017, pp. 2−8.

5.6. Conclusion and recommendations

Having found that the major retailers were achieving high average margins in our July 2019 report, for this report we sought to understand the impact of legacy contracts on those margins and whether they indicated longer term structural or competition concerns. We have found that the proportion of retailers' gas portfolios from legacy contracts has significantly declined over the period of our margins analysis. We have also found that legacy contracts contribute less than 20 per cent to retailers' gas portfolios from 2021 onward.

This change in balance of contracts means that retailers' average commodity costs are increasing. The impact of these increasing costs, on both margins and prices is uncertain although the big three retailers have the capacity to absorb the increase in commodity costs by reducing margins and further downward pressure on margins should also occur in those areas where competition is more effective.

For this report, we have also examined the indicators of the effectiveness of competition for supply of gas to mass market customers, finding that signs of effective competition vary between jurisdictions. Victoria shows the largest signs of effective competition, with the least concentration and largest number of suppliers. New South Wales and South Australia also are showing many positive signs. In contrast, Queensland, the Australian Capital Territory, and Tasmania show fewer positive signs, largely because they are significantly smaller markets, and in the case of Queensland and Tasmania have much lower gas penetration and average gas usage.

Overall, the retailer margins we have identified in this inquiry may not be cause for ongoing concern. However, any diminution of the relatively high margins of the big three retailers over time may not result in noticeably lower gas prices. This is because their competitors are likely to face much higher cost structures that more closely reflect current gas market prices.

This difference in the cost structures of the big three retailers compared to their competitors means there is scope (and incentive) for the big three retailers to price well enough below their competitors to maintain their market position and/or force their competitors to exit the market. This will be the case for a significant number of years into the future.

We will therefore continue to monitor retailer price offers and market shares to identify any competition concerns that may emerge and require further examination, particularly in supplying the C&I market segment which has been a key focus of our Inquiry.

We note that the retail gas market is already the subject of regular reports by both the Australian Energy Market Commission (AEMC) the Australian Energy Regulator (AER), and jurisdictional regulators.

The AEMC is required to report annually on the state of retail competition in gas and electricity.[247] In June this year, the AEMC published its sixth report into retail competition.[248]

The AER also publishes a number of reports focussed on the retail market. In November, the AER published its annual retail markets report for 2018–19[249] and in September published a report on affordability retail markets.[250]

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247 The AEMC's Terms of Reference are available here – https://www.aemc.gov.au/sites/default/files/2019-01/2018-SCER-Terms-of-Reference.pdf.

248 The AEMC's 2019 Retail Energy Competition Review – https://www.aemc.gov.au/market-reviews-advice/2019-retail-energy-competition-review.

249 https://www.aer.gov.au/retail-markets/performance-reporting/annual-retail-markets-report-2018-19.

250 https://www.aer.gov.au/retail-markets/performance-reporting/affordability-in-retail-energy-markets-september-2019.

Gas market offers, like electricity market offers, are potentially complex and confusing for consumers to compare. There may be value in governments considering the merits of implementing other measures to improve consumer experiences and outcomes in the supply of gas to mass market customers.

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.

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.

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.

Retailer: For the purpose of this report, this term captures both entities that purchase natural gas in wholesale markets to sell to retail customers and entities that purchase natural gas in wholesale markets to resell to other buyers in those markets. This includes AGL, Alinta Energy, EnergyAustralia, Macquarie Bank, Power and Water Corporation, Origin Energy and Shell Energy Australia.

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.

Transportation and storage related terms:

Contracted but un-used 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 or prospective user of pipeline services.

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)