# Wholesale Markets Quarterly

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AUSTRALIAN ENERGY REGULATOR

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Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Tel: 1300 585 165

Email: aerinquiry@aer.gov.au

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# Summary

## Electricity markets

Annual average wholesale electricity prices across the National Electricity Market (NEM) regions were low in 2019–20, ranging from $56 per MWh in Queensland and Tasmania to $84 per MWh in Victoria. Annual prices for 2019–20 were the lowest observed since 2011–12 in Queensland, 2014–15 in Tasmania, 2015–16 in South Australia and NSW, and 2016–17 in Victoria. Across the NEM as a whole, 2019–20 marked the first time since 2014–15 that annual prices were below $85 per MWh in all regions. Average prices in Q1 and Q2 2020 in particular were lower than prices seen in recent years.

Changed supply side conditions in 2019–20 were a key driver of these lower prices. There was increased amounts of capacity offered at lower prices by coal, hydro and gas generators. A major reason behind these lower priced offers from coal and gas generators was falling fuel input costs. These offers were supplemented by increased amounts of low priced capacity from wind and solar generation.

Demand in 2019–20 was down on the previous year's levels across all quarters. In particular, summer demand was significantly lower. Notwithstanding some extreme weather events, average temperatures in Q1 2020 were lower compared to records experienced in Q1 2019. There was also a record level of household solar installations in 2019–20, which contributed further to cutting demand.

2019–20 also highlighted the ongoing transformation of the NEM that is taking place. While coal remains the dominant generation source in the NEM, 2019–20 saw record high wind and solar output and record low coal output since NEM start. Average coal output was down by more than 1000 MW, while average solar and wind output together was up by nearly 600 MW.

There were record high Frequency Control Ancillary Services (FCAS) costs in 2019–20. These costs were driven by FCAS costs in Q1 2020, when South Australia was isolated from the rest of the NEM after storms damaged transmission infrastructure. This report includes a focus story that analyses the drivers of all FCAS prices over $5000 per MW in 2019–20.

## Gas markets

Average 2019–20 gas market spot prices ranged between $5.77 per GJ in Brisbane and $7.13 per GJ in Adelaide. This is the first time since 2015–16 financial year prices have been below $7.25 per GJ in all regions. Falls in international spot gas prices have continued to bear on east coast spot prices with a long term positive correlation between Asian spot netback prices and prices at Wallumbilla in Queensland, the epicentre of east coast gas production.

Rising production in the Roma region surrounding Wallumbilla over 2019–20 contributed to a record year of east coast production and also of LNG exports. However, over the first half of 2020 there have been signs of a potential slow-down in production and exports for the first time since 2015–16. Our focus story highlights signs of some change in producer and exporter behaviour in Queensland as the economic reach of the COVID-19 pandemic widens, and as their financial positions are affected. These changes include enhanced use of storage, plant maintenance announcements exceeding last years in duration, and reduced participation through the Wallumbilla gas supply hub.

Santos and other producers were again prominent in selling gas to the southern spot markets in Adelaide, Victoria and Sydney where record trades of gas occurred over 2019–20. Our second focus story highlights that over the first sixteen months of the Day Ahead Auction, sixteen participants have acquired transportation rights and the associated cost savings gained through using the auction to transport gas. The focus story also intertwines with analysis on competition in the Sydney market where gas traders have increased their share of sales into the southern spot markets using the transport auction as a vehicle to get gas south and to arbitrage regional prices.

# Electricity markets at a glance

## Financial year 2019–20

### Spot prices

First time financial year VWA prices below $85 per MWh across all regions since 2014–15

### Demand

Lower demand from the grid driven by mild summer and more rooftop solar

### Offers

More generation offered at low prices driven by increased renewables and lower fuel prices

### Generation

Record high renewable generation and record low coal generation

### FCAS

50 Hz

Record financial year FCAS costs driven by extraordinary events in summer

### Outlook

Contract markets indicate lower prices are expected to continue

# Gas markets at a glance

## Financial year 2019–20

### Spot prices

First time average financial year prices below $7.25 per GJ in all regions since 2015–16

### Demand

Aided by transport auction, trade through all southern markets now 10 per cent or higher

### International prices

Global prices at multi year lows and bearing on East Coast spot prices

### LNG export

Record year of East Coast LNG exports

### Gas production

Record year of East Coast production

### Day ahead auction

Sixteen participants used the auction since March 2019

# About this report

We have a range of obligations to monitor and report regularly on the performance of the national wholesale electricity and gas commodity and capacity markets. Quarterly reporting on performance issues, including on some longer term trends, is a fundamental part of fulfilling these obligations. It bridges the gap between our shorter term high price event reports and our longer-term biennial *Wholesale electricity market performance report* (the performance report), which we are required to produce.

Importantly, the report draws on our online wholesale statistics which we update quarterly, and allows us to identify significant trends in the electricity and gas markets and independently evaluate developments as they emerge.

We also have obligations to report quarterly on outcomes in the frequency control ancillary services (FCAS) markets and report on prices over $5000 per MW in ancillary services markets. We fulfil both of these obligations in this report.

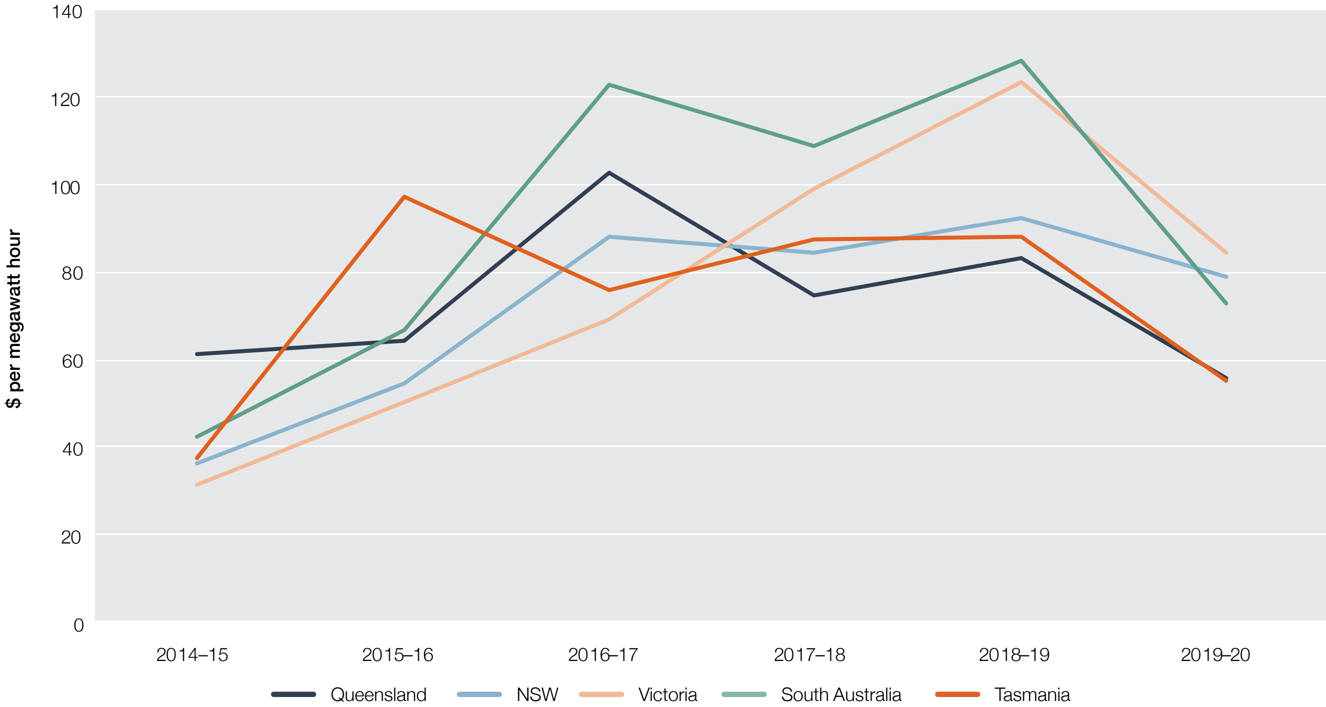
# 1. Electricity

## 1.1 Spot prices continue to fall

Average spot prices in all National Electricity Market (NEM) regions were low in 2019–20.[1] Annual volume weighted average (VWA) prices ranged from $56 per megawatt hour (MWh) in Queensland and Tasmania to $84 per MWh in Victoria (figure 1.1). Even in Victoria, South Australia and NSW, where short periods of volatility over summer led to higher average wholesale prices than elsewhere in the NEM, annual prices were still moderate by recent standards.

Prices for 2019–20 were the lowest annual prices observed since 2011–12 in Queensland, 2014–15 in Tasmania, 2015–16 in South Australia and NSW and 2016–17 in Victoria. Across the NEM as a whole, 2019–20 marked the first time since 2014–15 that annual prices were below $85 per MWh in all regions.

**Figure 1.1 Average financial year prices (VWA)**




Source: AER analysis using NEM data.

These overall pricing outcomes for 2019–20 were largely driven by lower Q1 and Q2 prices compared to last year (figure 1.2). With the exception of Q1 2020 in NSW, quarterly prices were down across all regions in Q1 2020 and Q2 2020 compared to the same period last financial year.[2]

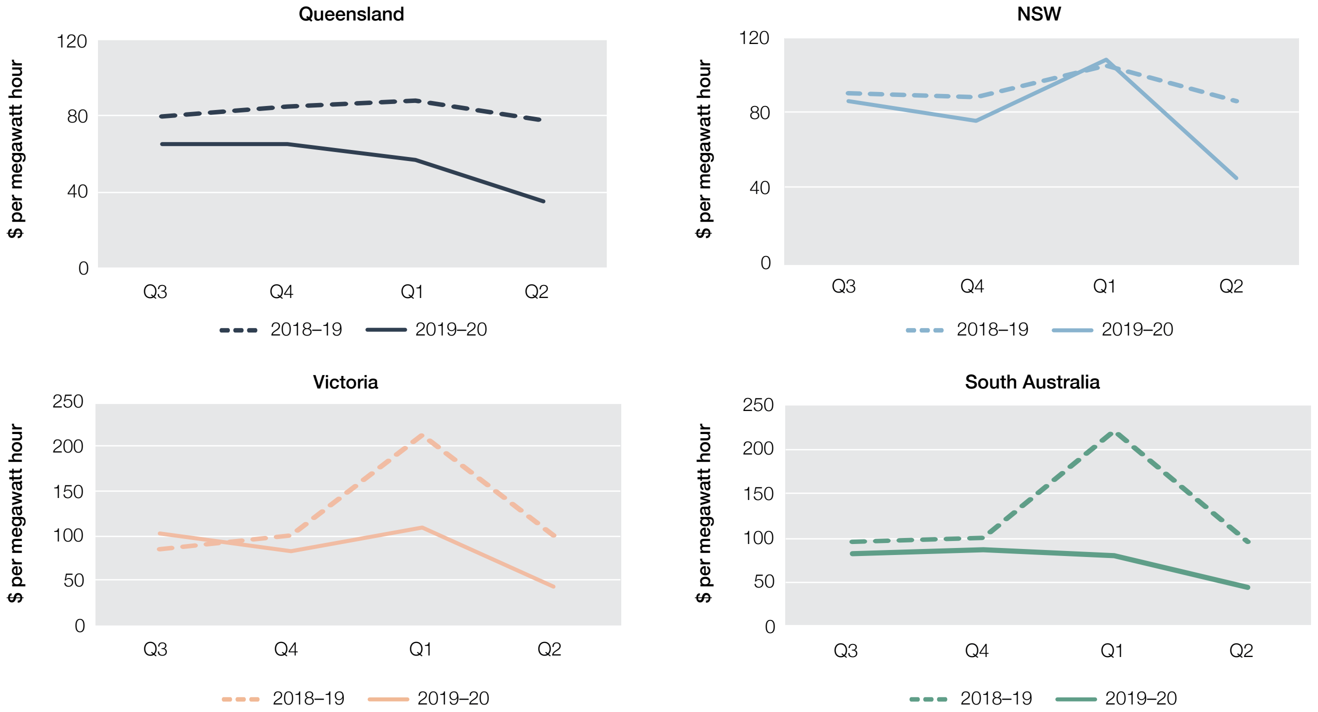
Some of the falls in prices were significant. The largest quarterly price falls were the $139 per MWh drop in Q1 2020 prices in South Australia and the $103 per MWh fall in prices in Victoria. It has to be remembered, however, that average Q1 2019 prices in Victoria and South Australia were at record or near record levels.

Q2 2020 prices in all regions were significantly lower than their 2019 levels. Q2 2020 prices ranged from $32 per MWh in Tasmania to $45 per MWh in NSW. These are the lowest quarterly prices since Q4 2011 in Tasmania, Q1 2015 in South Australia, Q2 2015 in Queensland, Q1 2016 in NSW and Q4 2016 in Victoria.

1 We report the volume weighted average (VWA) price which is weighted against native demand in each 30 minute trading interval and is an indicator of total market costs in the quarter. AEMO uses the time weighted average which is the average of spot prices in the quarter and is directly comparable to the swap contract price in the wholesale market.

2 We analyse quarter one prices in the *Wholesale markets quarterly Q1 2020*.

**Figure 1.2 Quarterly spot prices (VWA)**



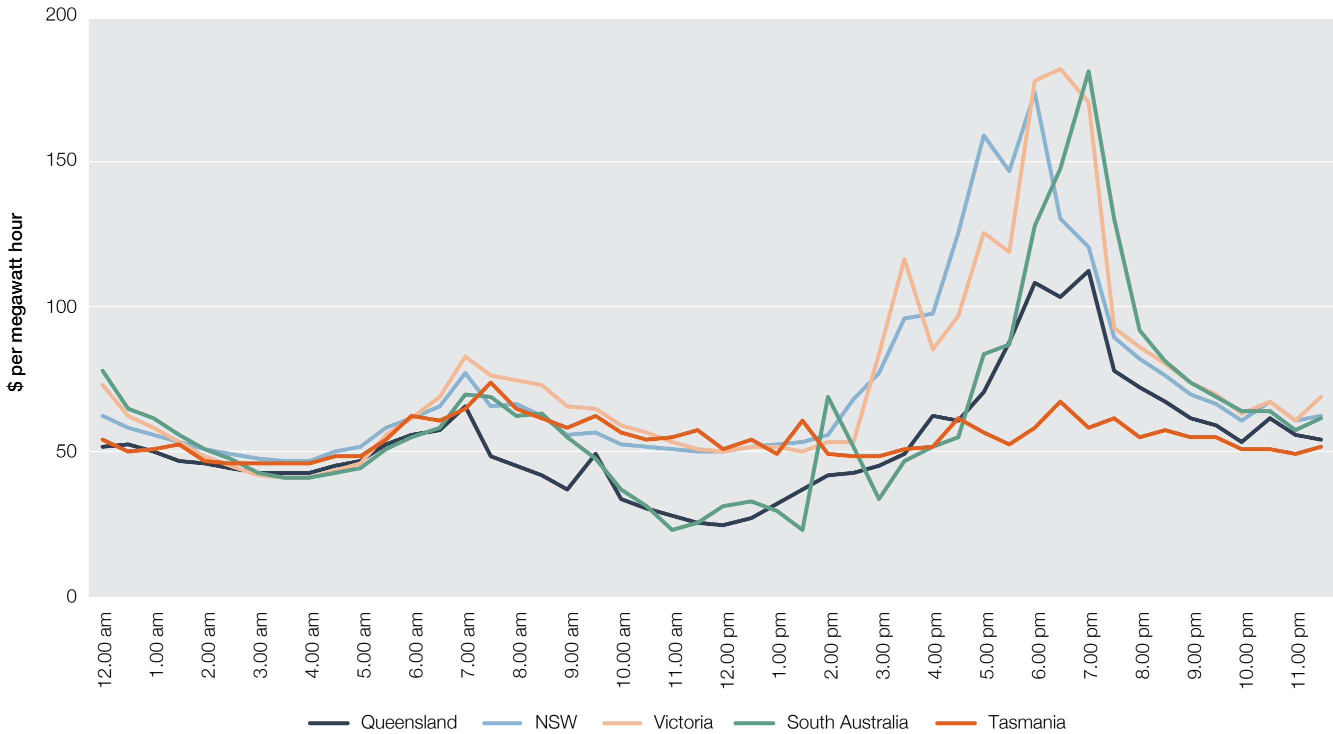

Source: AER analysis using NEM data.

Note: Compares average quarterly spot prices (VWA) in 2019–20 with the same quarter in 2018–19.

An in-depth look at prices across the NEM in 2019–20 highlights some interesting intra-day dynamics (figure 1.3). While wholesale prices are becoming lower during the day before increasing during the evening peak, the trends are not uniform across the NEM regions.

In 2019–20, Queensland and South Australia had significantly lower average prices during the middle of the day than the other regions. Increased amounts of large solar generation in Queensland and rooftop solar in South Australia were key drivers of this development.

**Figure 1.3 Average prices by time of day, 2019–20**




Source: AER analysis using NEM data.

Note: Average prices by trading interval in 2019–20, not volume weighted.

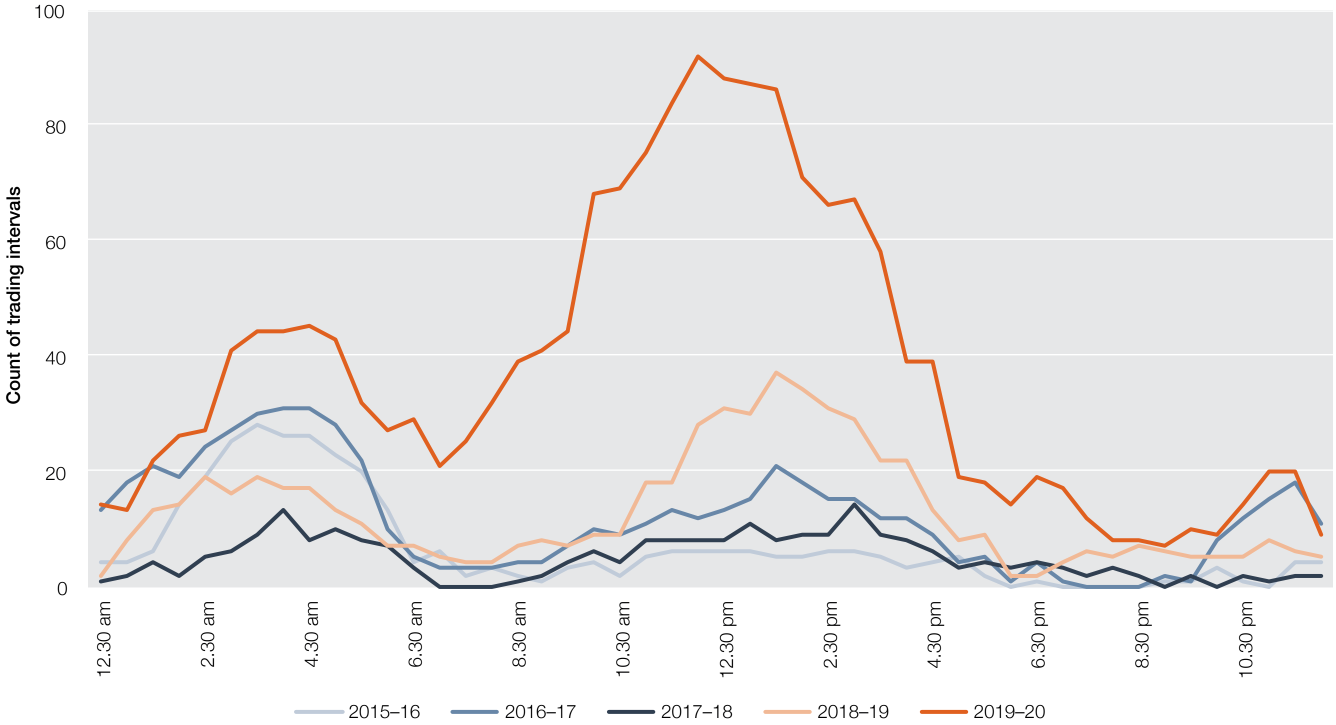
Average prices in South Australia, Victoria and NSW trended up between 2 pm and 7 pm. While prices in Queensland also trended up later in the day, average prices during the evening peak were still around $60 per MWh lower on average than in other mainland regions. High priced events in South Australia, Victoria and NSW over the summer months, due to bushfires and network outages, explain some of the difference in these prices. Our 2020 performance report will further unpack these intra-day dynamics and how they have changed over time.[3]

Average prices in Tasmania were relatively flat through the day. One reason for this is that at times of high prices on the mainland in the evening, Tasmanian generation is often offered at lower prices to ensure it is dispatched and can take advantage of these higher prices on the mainland.[4] Flows from Tasmania into Victoria in Q2 2020 were over twice those in Q2 2019.

## 1.2 Record number of negative prices

The lower prices during the middle of the day, in part, reflected the increased incidence of negative prices. While there were more negative priced trading intervals across all hours than had occurred in previous years, the number of negative prices was particularly high during daylight hours (figure 1.4).

**Figure 1.4 Count of negative prices by time of day**




Source: AER analysis using NEM data.

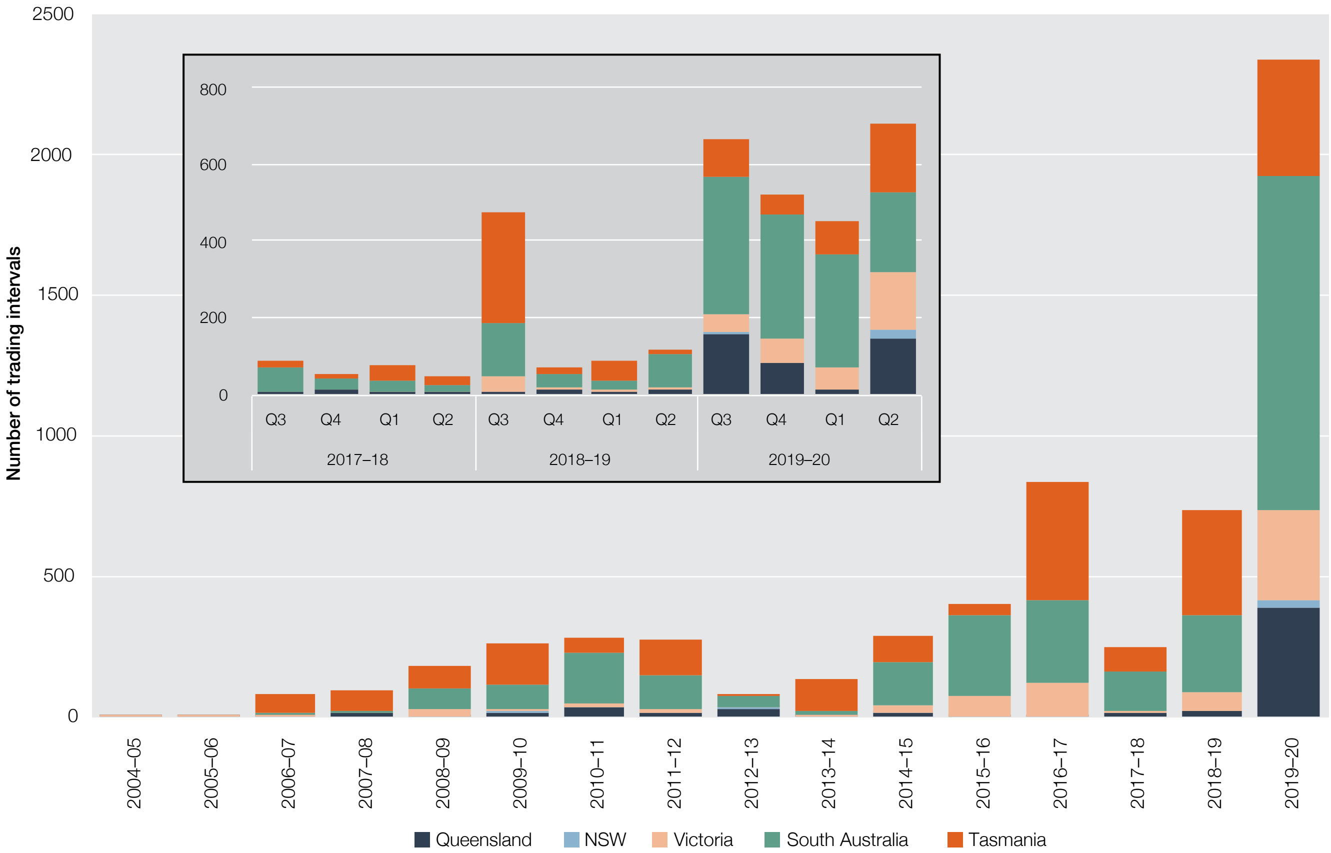
Note: Count of spot price below $0 per MWh by time of day, for each financial year.

2019–20 saw high numbers of negative prices in each quarter, peaking in Q3 2019 and then again in Q2 2020 (figure 1.5). The 2338 negatively priced trading intervals in 2019–20 were almost three times the previous high of 834 in 2016–17. While there were more negative prices in South Australia, there were increases in instances of negative prices in every region. Notably we saw the emergence of a significant number of negative prices in Queensland, as reported in our *Wholesale markets quarterly Q3 2019*, and more recently in Victoria.

3 Our biennial *Wholesale electricity market performance report* will be released in November this year.

4 We comment on this trend in the *Wholesale markets quarterly Q1 2020*.

## Figure 1.5 Annual and quarterly negative prices




Source: AER analysis using NEM data.

Note: Count of spot price below $0 per MWh in each quarter and annually.

The change in price outcomes in the market is not confined to the emergence of negative prices, however. There are many more lower priced trading intervals ($0–$50 per MWh) and these are playing a far more significant role in driving overall market price outcomes (figure 1.6). Across all regions over the past four quarters, there has been a greater contribution from prices in the $0-$50 per MWh price range and a fall in the contribution of prices over $50 per MWh (particularly $50–$100 per MWh price bands).

Highlighting this trend, for most of the time in Q2 2020 half hourly prices were significantly below their levels a year previously. For example, in Queensland 53 per cent of spot prices in Q2 2020 were less than $50 per MWh (compared to 8 per cent in Q2 2019). There were similar trends in other states with prices under $50 per MWh increasing in NSW (from 4 per cent in Q2 2019 to 45 per cent in Q2 2020), in Victoria (from 9 per cent in Q2 2019 to 44 per cent in Q2 2020), in South Australia (from 11 per cent in Q2 2019 to 46 per cent in Q2 2020), and Tasmania (from 22 per cent in Q2 2019 to 54 per cent in Q2 2020).

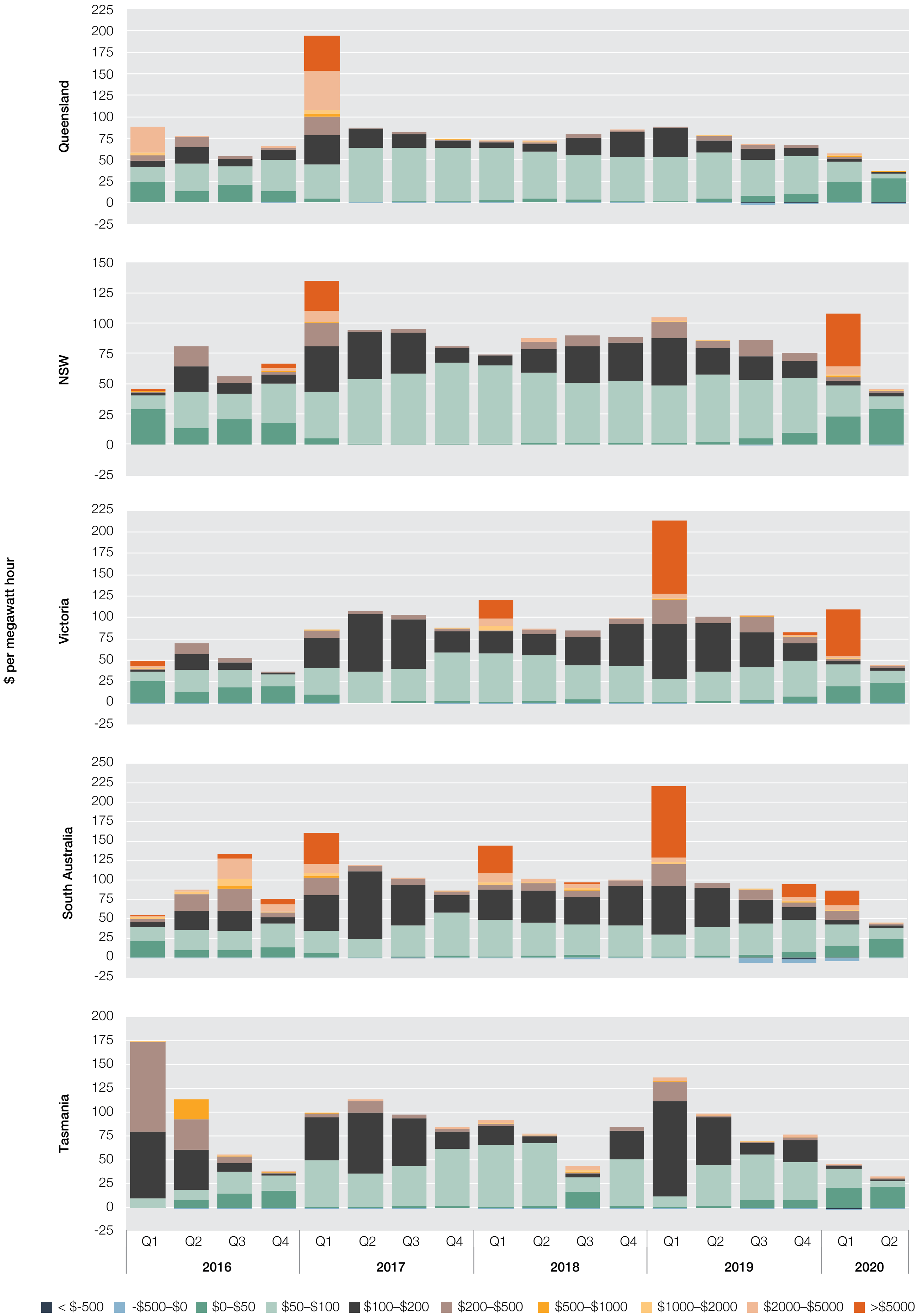
Prices over $5000 per MWh driven by extreme weather in Q1 2020 made a large contribution to overall average prices in that quarter, particularly in NSW and Victoria. For example, periods of prices greater than $5000 per MWh in NSW added $43 per MWh to the overall average price.

Average prices in Q2 2020 in all regions were not only significantly lower than prices observed in the preceding quarter or the same quarter in 2019, but were the lowest quarterly prices for a number of years.

On average, wholesale costs make up around 30 to 50 per cent of a residential electricity bill.[5] But it can take some time for wholesale electricity price falls to flow through to retail bills. This is because retailers and generators enter into financial contracts to manage the risk of fluctuating wholesale prices. Some of these contracts will have been entered into when wholesale prices were higher than they are now.

5 AER, *Wholesale electricity market performance report 2018*, p. 9.

**Figure 1.6** Contribution of different price bands to quarterly wholesale prices



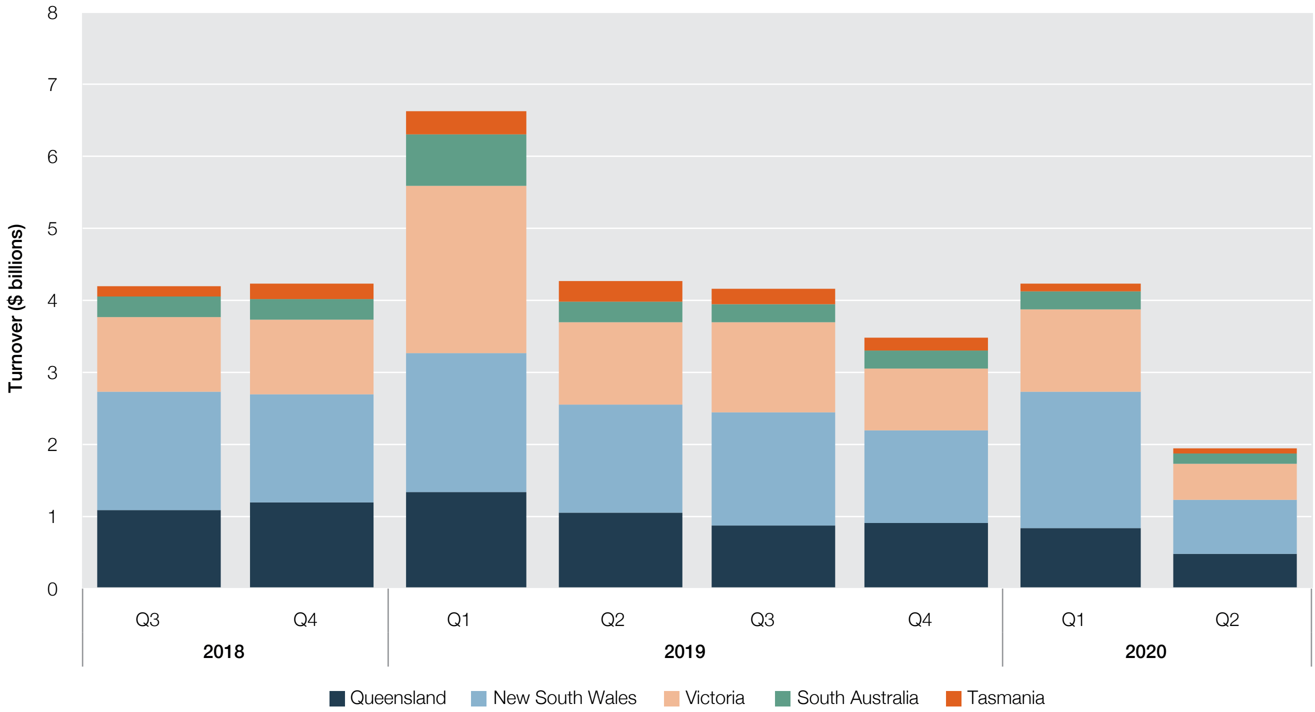

Source: AER analysis using NEM data.

Note: Shows the extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in each region.

## 1.3 NEM turnover very low in Q2 2020

Lower average quarterly prices in Q2 2020 (section 1.1) combined with lower average quarterly demand (section 1.5) resulted in significantly lower market turnover in Q2 2020 (figure 1.7). NEM turnover was around $2 billion in Q2 2020—the lowest turnover since Q2 2015 and far lower than turnover seen in recent quarters. Notably Q2 2020 NEM turnover was less than half the level of Q2 2019. However, this may not accurately represent generator revenues as contracting in particular may limit a participant's immediate exposure to these trends.

Figure 1.7 NEM turnover




Source: AER analysis using NEM data.

Note: NEM turnover is volume generated multiplied by average spot price in each region.

## 1.4 Price expectations fall in line with falling spot prices

Looking forward, price expectations are in line with the recent trends in the spot market (figure 1.8).

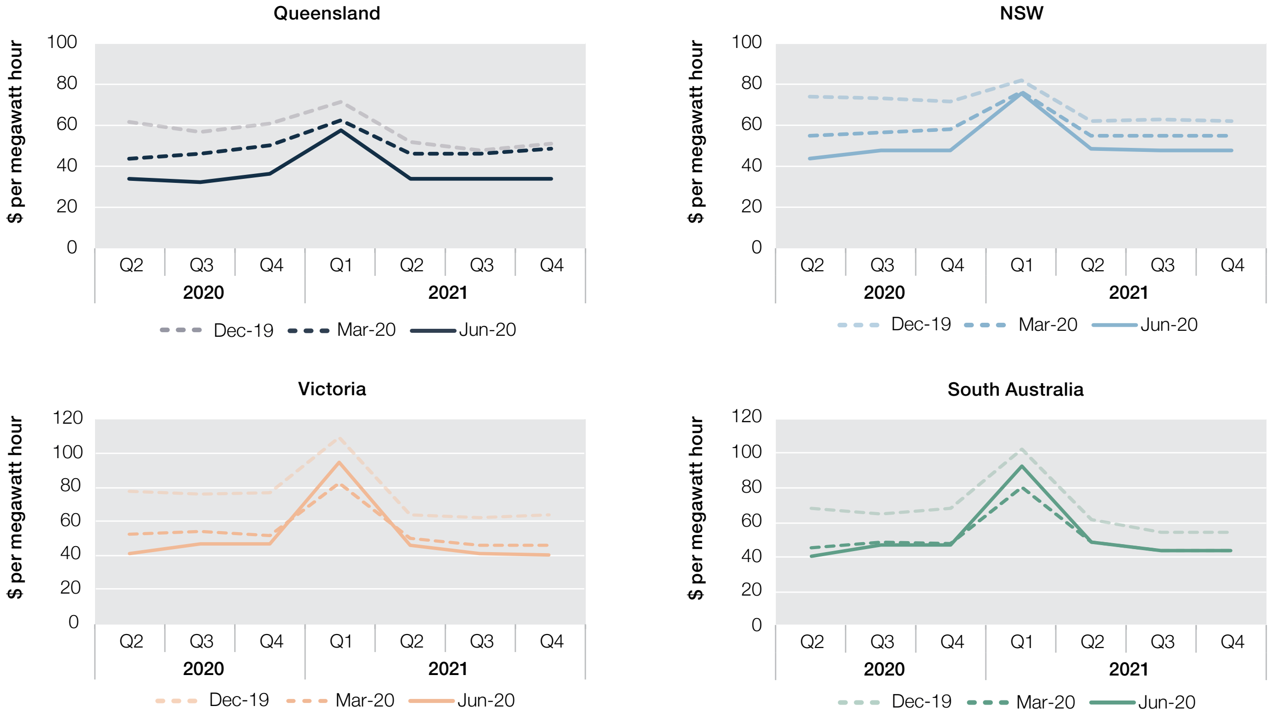
Expected futures prices experienced significant falls across all NEM regions from December 2019 to March 2020. The updated expectations at the end of June 2020 shows prices for the rest of 2020 are expected to continue to fall in Queensland and NSW, but less so in Victoria and South Australia.

Notwithstanding these differences, at the end of June, prices were expected to be low and stable across the NEM for the remainder of 2020, with quarterly prices expected to remain below $50 per MWh in all regions.[6]

Prices are expected to be higher for Q1 2021 than for other quarters, reflecting the impacts of summer conditions on demand. Q1 2021 base futures prices were between $58 per MWh and $95 per MWh at the end of June 2020. Recent price expectations for Q1 2021 in Victoria and South Australia are above where they were at the end of March, but still moderate by recent Q1 standards in these regions.

6 As at 30 June 2020.

Figure 1.8 Forward base future prices




Source: AER analysis using ASX Energy data.

Note: Closing price of base futures contracts from Q2 2020 to Q4 2021 on the last trading day in Q2 2020 (30 June) compared to the last trading days in Q1 2020 (31 March) and Q4 2019 (29 December).

## 1.5 Lower demand from the grid puts downward pressure on spot prices

In 2019–20 average demand was 440 MW less than in 2018–19. While annual demand fell in every region, it fell most heavily in NSW. The decrease was driven by a number of factors.

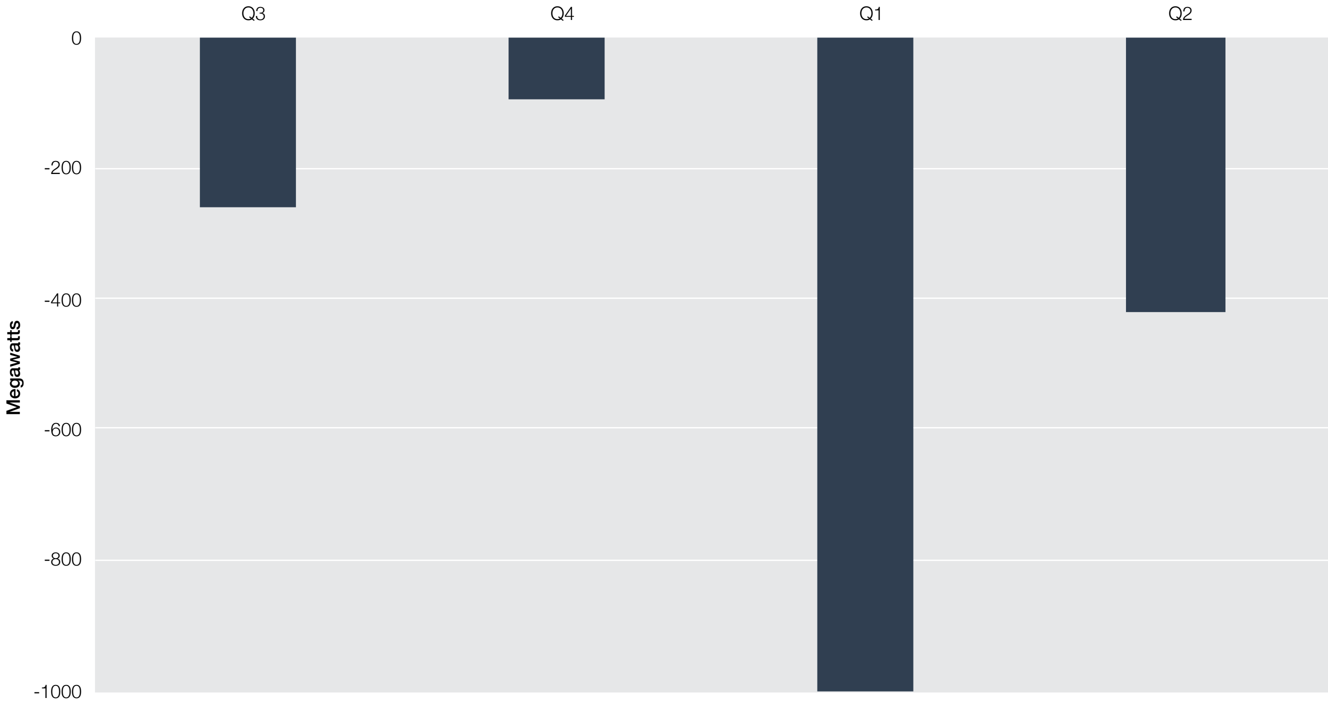
Firstly, despite the extreme bushfire season, summer conditions in 2019–20 were generally milder compared to the record hot summer conditions of the previous summer. As a result, average demand in Q1 2020 was down by 1000 MW compared to the same quarter in 2019 (figure 1.9). Q2 2020 demand also tracked lower than in Q2 2019. Some of this reduction was attributable to a fall in commercial and industrial demand due to the impact of COVID-19.[7]

In Q2 2020, minimum daily demand in South Australia fell below the previous Q2 minimum (758 MW) eight times, setting a significantly lower Q2 record (456 MW). Minimum Q2 demand in Victoria was also low in 2020, falling lower only in Q2 2017 and Q2 1999. Across the year as a whole, in South Australia we saw a fall in minimum demand in 2019–20, with minimum demand in every quarter falling below the previous record for that quarter.[8]

7 AEMO's QED has undertaken an in-depth analysis of the impact of the COVID-19 on electricity demand in the NEM. AEMO, *Quarterly energy dynamics—Q2 2020*, July 2020, p. 7.

8 We included a focus story on record low demand in South Australia in our [Wholesale markets quarterly Q4 2019].

Figure 1.9 Change in average quarterly demand, 2018–19 to 2019–20



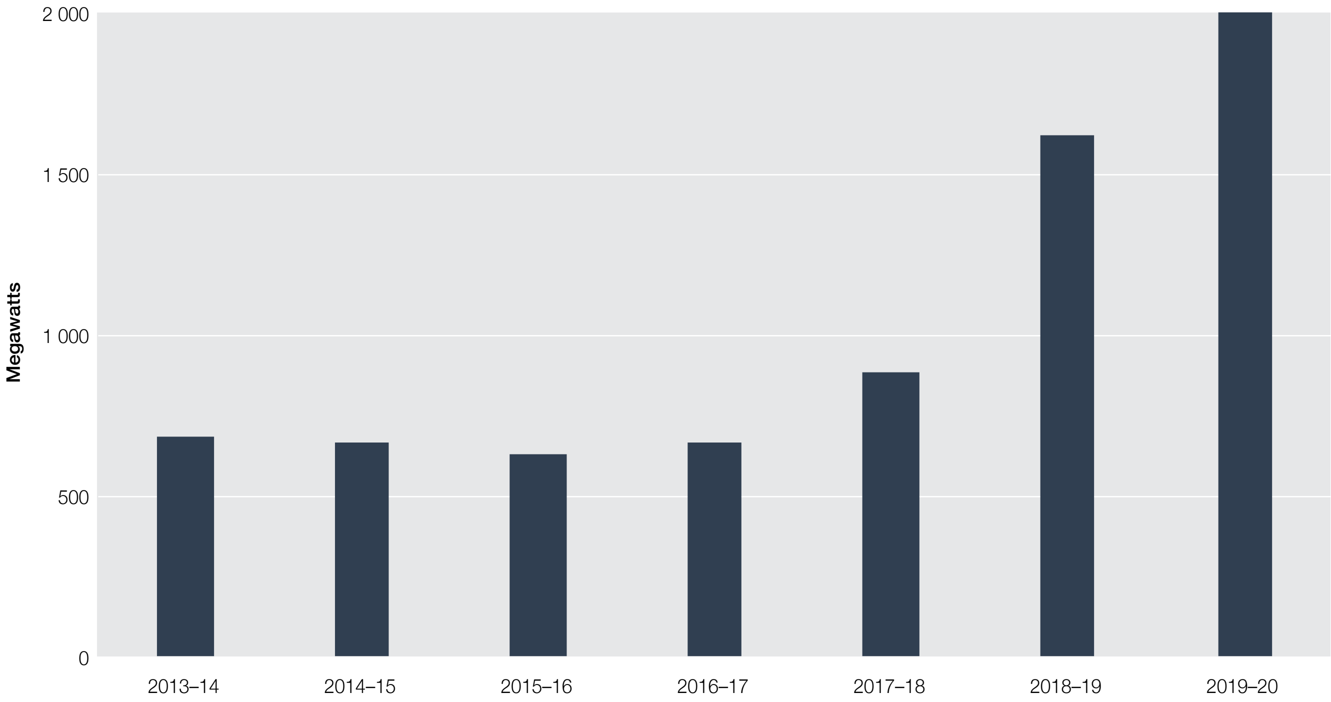

Source: AER analysis using NEM data.

Note: Uses average quarterly native demand. AER defines native demand as the sum of initial supply and total intermittent generation.

A second driver of reduced demand from the grid in 2019–20 was the increase in residential and small commercial customers meeting their own electricity needs. Government incentives, declining installation costs, environmental concerns and concerns over electricity prices saw the installation of a record level of rooftop solar capacity for the third year in a row (figure 1.10). Almost 2000 MW of rooftop solar capacity was installed in the NEM in 2019–20, a 25 per cent increase on the capacity installed in 2018–19 and more than double the capacity installed in 2017–18. Most of this additional capacity was installed in NSW and Queensland.[9] Now around 20 per cent of all households in the NEM partly meet their electricity needs through rooftop solar PV generation.

9 Rooftop solar capacity installed in 2019–20: NSW (683 MW), Queensland (609 MW), Victoria (445 MW), South Australia (239 MW) and Tasmania (23 MW).

Figure 1.10 Rooftop solar capacity installed in the NEM




Source: Clean Energy Regulator (CER), Postcode data for small-scale installations by state/territory, SGU—solar.

Note: Small generating units solar <100kW, residential and small commercial. Because new installations have 12 months to register with the CER, this data will tend to understate installed capacity in 2019–20.

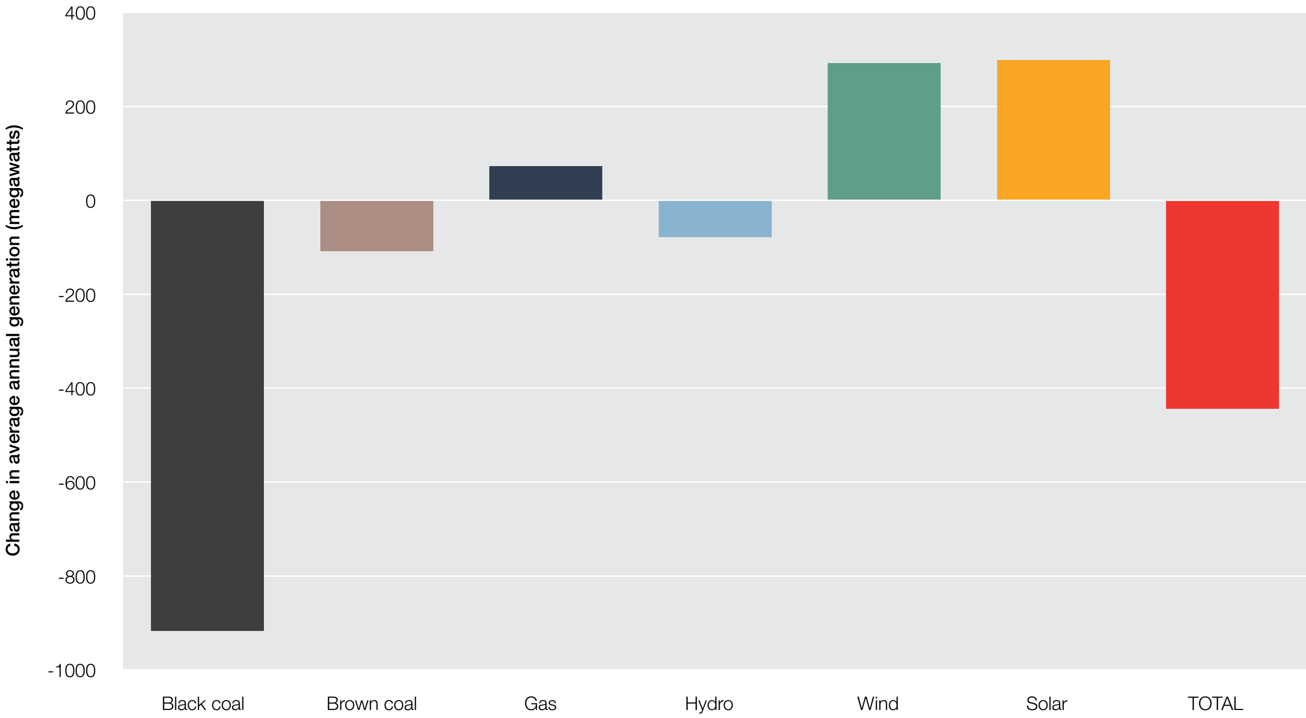
Supply side conditions in 2019–20 also converged to put downward pressure on spot prices. The following sections highlight that 2019–20 was characterised not only by increased low cost renewable generation but also by increased offers by coal, hydro and gas generators at lower prices.

## 1.6 Record high wind and solar output puts downward pressure on spot prices

Wind and solar produced record output in 2019–20. This increased renewable generation, coupled with lower demand particularly over summer, resulted in the lowest levels of annual coal generation since the start of the NEM.

The contribution of wind and large-scale solar to the total generation mix has increased from 6 per cent to 13 per cent over the last three years, while the contribution of coal has fallen from 77 per cent to 71 per cent. Driven by the surge of new wind and solar farms that entered the market towards the end of 2018–2019, and ramped up in 2019–20, annual average output from wind and grid solar increased by around 600 MW. At the same time, average coal generation decreased by over 1000 MW (figure 1.11).

**Figure 1.11 Change in average generation, 2018–19 to 2019–20**




Source: AER analysis using NEM data.

Note: Compares annual average metered generation output by fuel type in 2019–20 and 2018–19. Solar generation includes large scale generation only. Rooftop solar PV is not included as it affects demand not grid-supplied generation output.

Solar generation increased in 2019–20 in every mainland region. The largest increase was in Queensland, driven by the large number of new solar farms installed in that region. If averaged over daylight hours, the increase in solar generation in 2019–20 in Queensland was nearly 400 MW, more than the average output of a single coal generating unit at Stanwell.

Wind generation also increased in every region with the largest increase in Victoria. Increased wind generation in Victoria is likely to continue next year with the recent entry of the 335 MW Dundonnell wind farm ramping up, taking the region's share of wind capacity in the NEM up to 36 per cent.

Because demand was lower in 2019–20 and there was more low priced wind and solar renewable generation, coal generation decreased.

Low demand reduces the dispatch of the highest cost capacity first. While black coal generators generally offer between 50 to 70 per cent of their capacity below $0 per MWh, if demand is low, wind and solar will tend to displace the remaining higher priced coal. It follows then, when demand is low, a bigger proportion will be met by renewable generation and a smaller proportion will be met by coal and other more expensive fuel types.

In 2019–20, the decline in demand was mostly felt by black coal generators in NSW and Queensland where average output was down by 500 MW and 420 MW respectively, but also by brown coal generators in Victoria where output was down by over 100 MW.

Notwithstanding these reductions, coal fired generation remained the dominant supply in the NEM, meeting around 70 per cent of energy requirements this financial year. However, as the increase of rooftop solar generation continues to lower NEM demand, and the availability of low priced renewables puts downward pressure on prices during the day, we would expect to see output from coal fired generators continuing to fall.

Looking at Q2 2020 outcomes, almost 10 per cent less black coal generation was needed compared to the same quarter a year earlier (a reduction of 1150 MW). This was because, continuing financial year trends, average demand in Q2 2020 was down and the output of less expensive fuel types was up, including solar, wind and brown coal, displacing higher priced black coal.[10]

Average gas output in the NEM increased slightly (70 MW) in 2019–20. Looking at regional outcomes this was driven by an increase in gas generation in Queensland and NSW, which was largely offset by decreases in gas output

10 AEMO's QED undertakes a detailed analysis into the operations of individual stations in the black and brown coal fleets. AEMO, *Quarterly energy dynamics—Q2 2020*, July 2020, pp. 18–19.

in South Australia, Tasmania and Victoria. Looking at Q2 2020, gas generation across the NEM was slightly lower compared to Q2 2019, with notably more gas generated in Queensland and less in Victoria and South Australia.

While average hydro output in the NEM was down slightly (75 MW) in 2019–20 compared to the previous year, hydro generation was up in Q2 2020 compared to Q2 2019. The increase was driven by a large increase in Tasmania (270 MW) and to a lesser extent Victoria (100 MW). At the same time average hydro output fell in NSW (reducing by 100 MW) and Queensland (reducing by 90 MW) compared to Q2 2019. These outcomes correlated with seasonal rainfall which was above average in the south and below average in the north.[11]

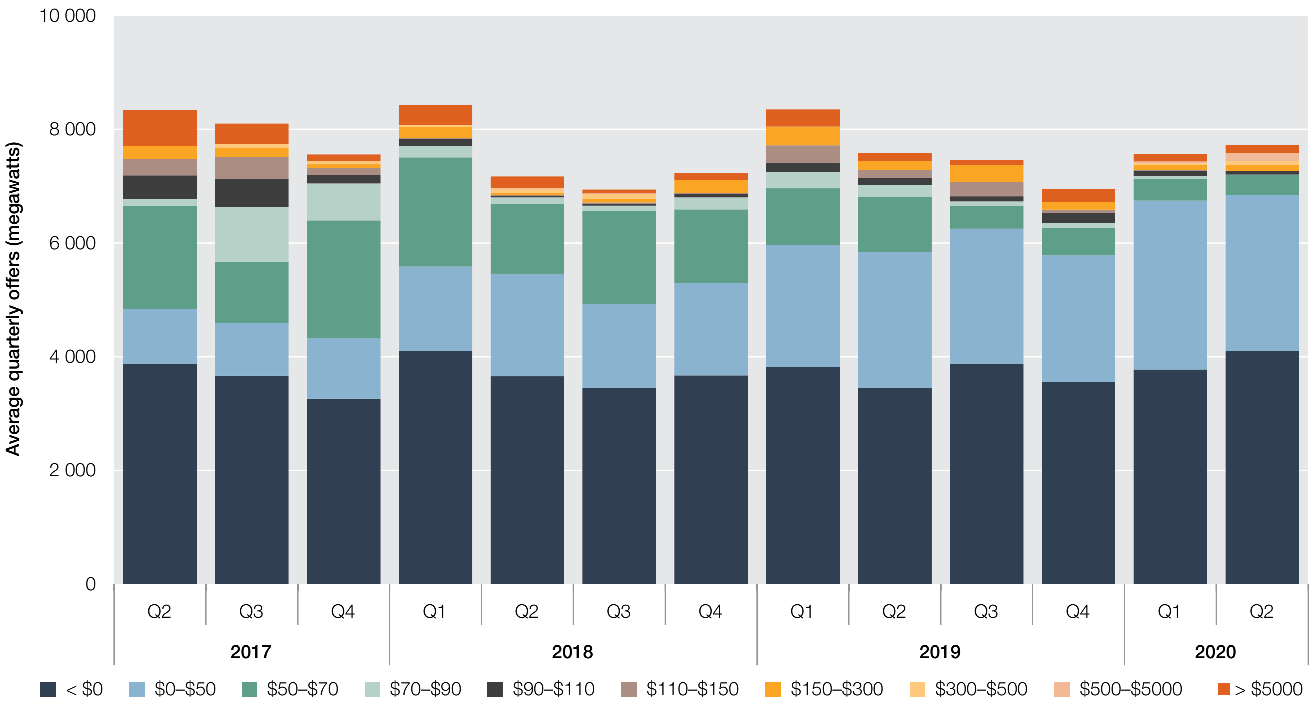
## 1.7 More lower priced capacity puts downward pressure on spot prices

Generators across the NEM offered almost 20 per cent (3700 MW) more capacity priced below $50 per MWh in Q2 2020 than they did in Q2 2019. Not since 2015–16 have generators offered so much low priced capacity into the market.

Coal contributed most to this trend. In Q2 2020, black and brown coal generators offered an additional 2000 MW into the market priced below $50 per MWh than a year earlier. This was followed by hydro (900 MW) and renewables (500 MW), with the smallest contribution to increased low priced offers coming from gas (400 MW). Geographically, the increase in low priced offers came mostly from NSW and Queensland.

Increased offers of low priced capacity from black coal generators in NSW (over 1000 MW) and from black coal generators in Queensland (680 MW) accounted for around half the total increase in low priced capacity offered into the NEM in 2019–20 (figure 1.12). As a result of these lower offers, black coal generators set the price more often and at lower prices (section 1.8).

**Figure 1.12 Offers within price bands, New South Wales black coal**




Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by NSW black coal generators within price bands.

Similarly, hydro generators across the NEM offered nearly 900 MW more capacity into the market priced less than $50 per MWh in Q2 2020 than they did in Q2 2019. Most of this was offered by hydro generators in Tasmania (470 MW) and Victoria (350 MW).

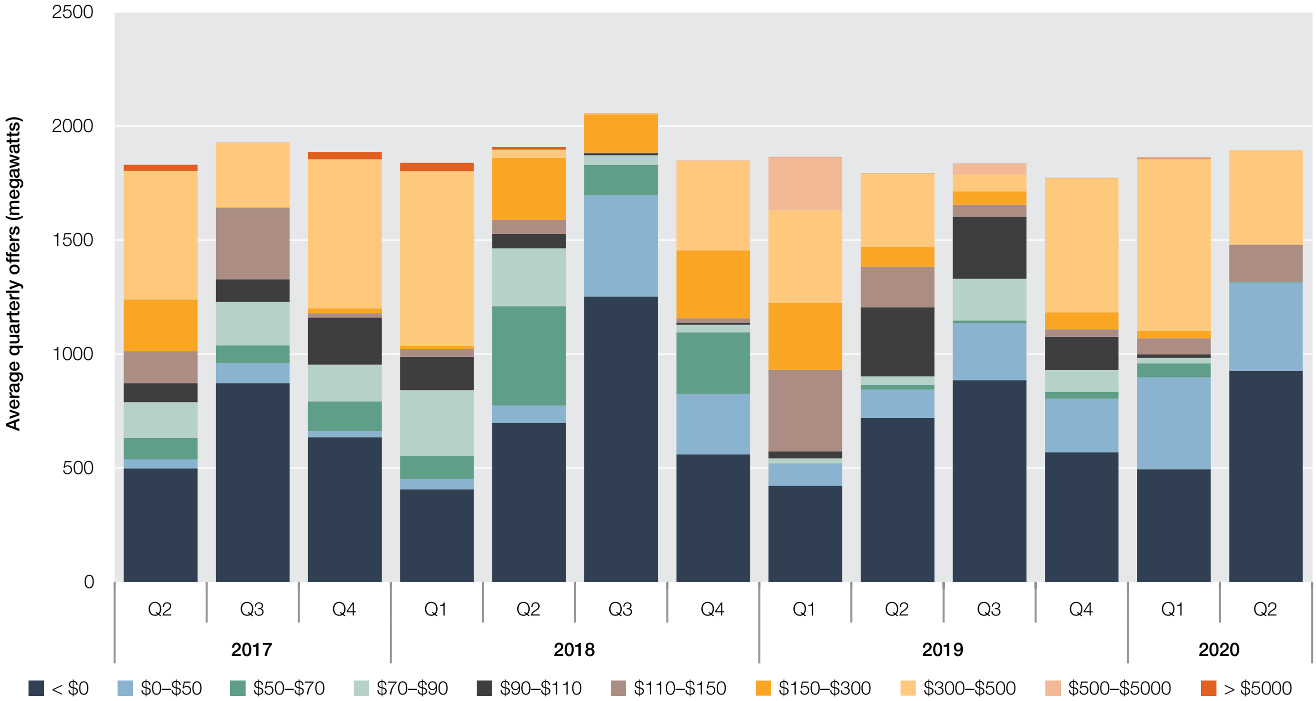
11 AEMO's QED provides a detailed analysis of the operations of individual gas and hydro stations. AEMO, *Quarterly energy dynamics—Q2 2020*, July 2020, pp. 19–20.

As a result of Tasmania's wettest autumn since 1975, Hydro Tasmania offered around 70 per cent of its hydro capacity below $50 per MWh (figure 1.13).[12] While Hydro Tasmania typically offers low priced generation in winter when rainfall is plentiful, it has not offered this much low priced capacity in Q2 since 2015.

On the mainland, hydro generators in Victoria offered over two to three times the amount of low priced capacity than they have offered in any quarter since Hazelwood power station closed. They last offered similar amounts of capacity priced under $50 per MWh in 2016. In both these regions, hydro generation displaced gas.

Hydro generators in Queensland, on the other hand, offered less capacity in the low price bands, instead shifting capacity to between $500 and $5000 per MWh. Most noticeably in Queensland, but also in NSW, hydro was displaced by gas and other renewables.

**Figure 1.13 Offers within price bands, Tasmania hydro**



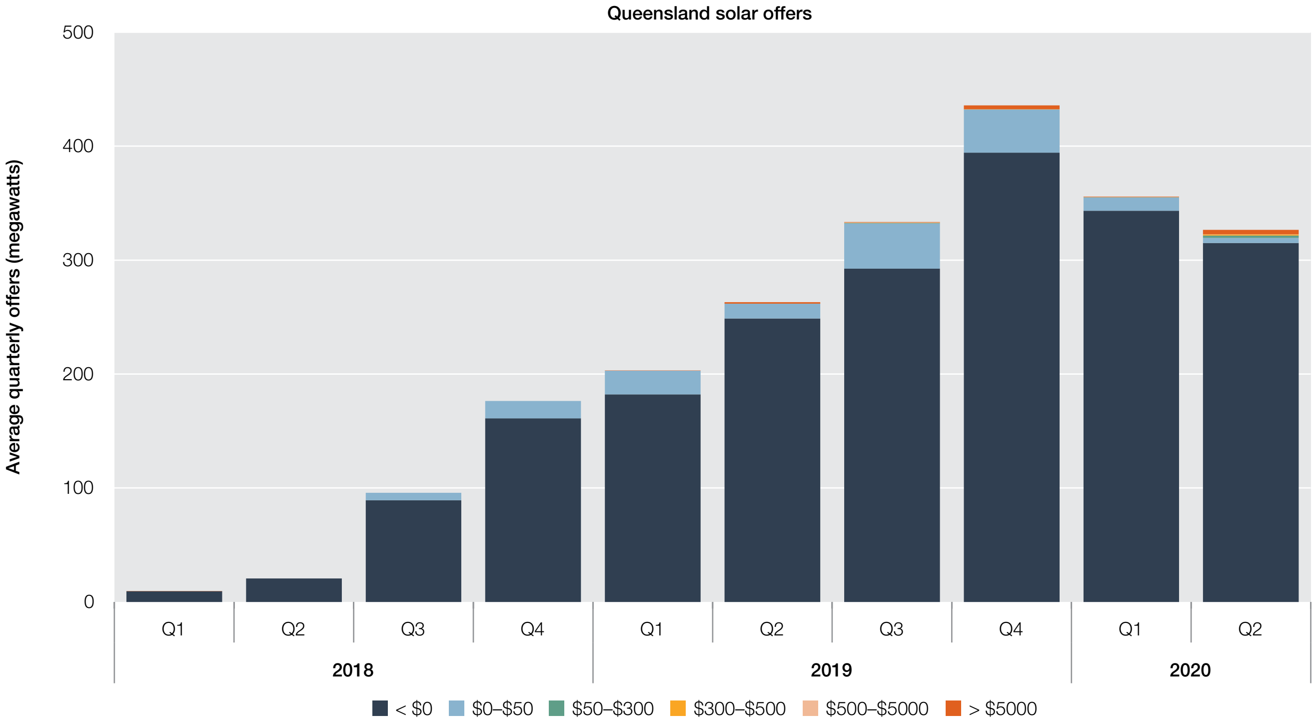

Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by Tasmania hydro generators within price bands.

Continuing the trend, renewable generators offered 500 MW more capacity priced below $50 per MWh into the market in Q2 2020 than they did in Q2 2019. Of this, wind offered 380 MW and solar offered 120 MW (figure 1.14).

12 Bureau of Meteorology http://www.bom.gov.au/climate/current/season/tas/summary.shtml.

Figure 1.14 Average quarterly offers, Queensland solar and Victoria wind





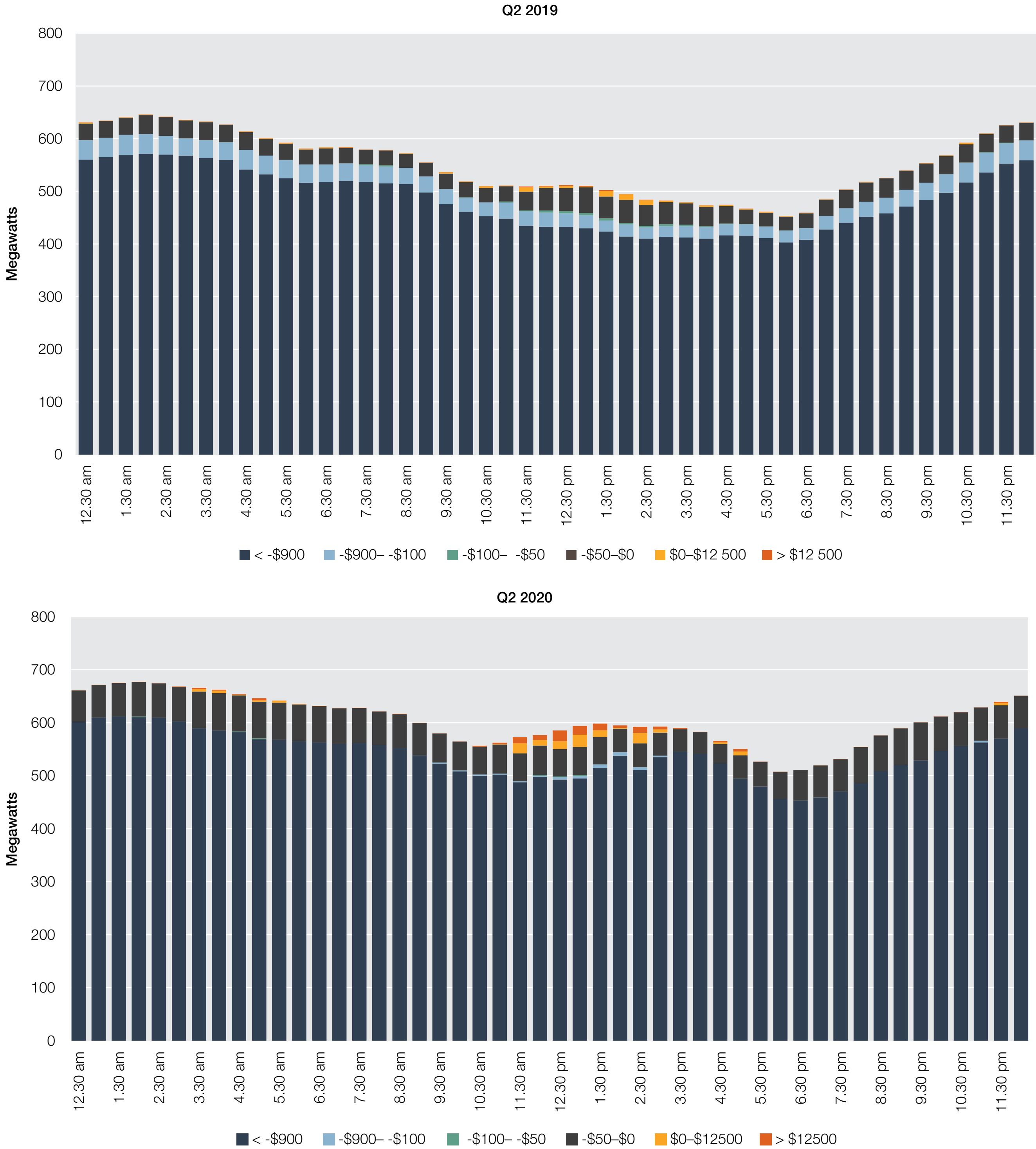
Source: AER analysis using NEM data.

Note: Quarterly average offered capacity within price bands by grid-scale solar generators in Queensland and wind generators in Victoria.

However as well as offering more low priced capacity into the market, in 2019–20 we saw the emergence of renewable generators offering capacity into the market into the highest price bands. In 2019–20, when prices were negative, or forecast to be negative, at times solar generators in Queensland and wind generators in South Australia rebid capacity from negative prices to high price bands to avoid being dispatched and effectively paying to produce electricity. This outcome is consistent with the price setter outcomes we saw, where renewable generators set higher average quarterly prices in 2019–20 than in 2018–19.

In South Australia, for example, while wind generators continued largely to offer in capacity in at low prices (and indeed offered more capacity at low prices), they also offered more capacity priced above $12 500 per MWh in Q2 2020 than they did in Q2 2019 (figure 1.15). These offers were driven by wind generators' rebidding behaviour when dispatch prices fell to negative prices.

Figure 1.15 Wind offers by time of day, South Australia—Q2 2020 compared to Q2 2019

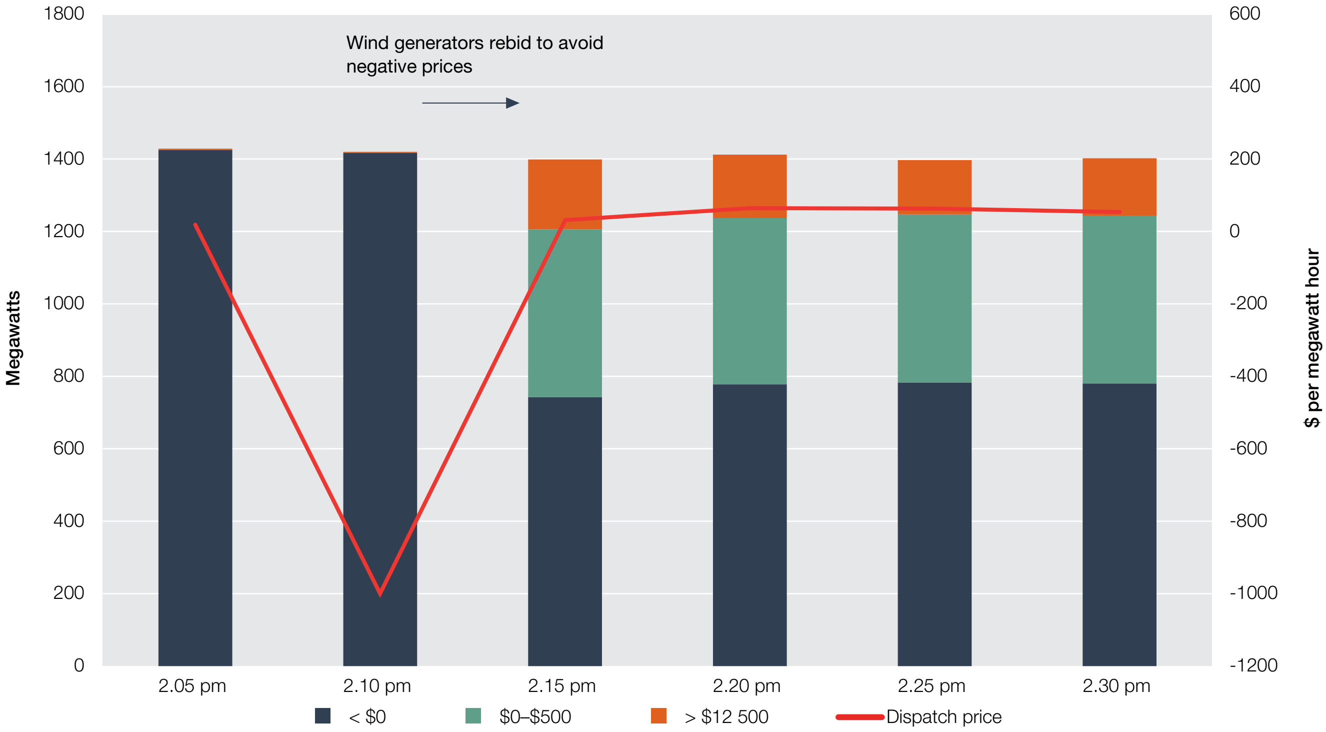



Source: AER analysis using NEM data.

Note: Compares time of day offers within price bands by wind generators in South Australia in Q2 2020, with offers in Q2 2019.

Looking at 19 May 2020 as an example, during the 2.30 pm trading interval, the dispatch price fell to the price floor of -$1000 per MWh at 2.10 pm (figure 1.16). In response, wind generators rebid more than 650 MW of capacity from the price floor to prices above $0 per MWh, including more than 190 MW above $12 500 per MWh. This rebidding behaviour happened on 12 days over the quarter.

Figure 1.16 Dispatch price and wind offers, South Australia, 19 May 2020




Source: AER analysis using NEM data.

Note: Time of day offers within price bands by wind generators in South Australia between 2.05 pm and 2.30 pm on 19 May 2020.

We have seen, and previously commented on, instances of late rebidding behaviour by various generation technologies in the NEM. What is notable in this instance is that not only is this new behaviour for wind and solar generators, but also that wind participants have rebid on occasions and reduced output without waiting for AEMO to issue a new dispatch instruction. While this is not against the current rules for semi-scheduled generators it can lead to system security issues.

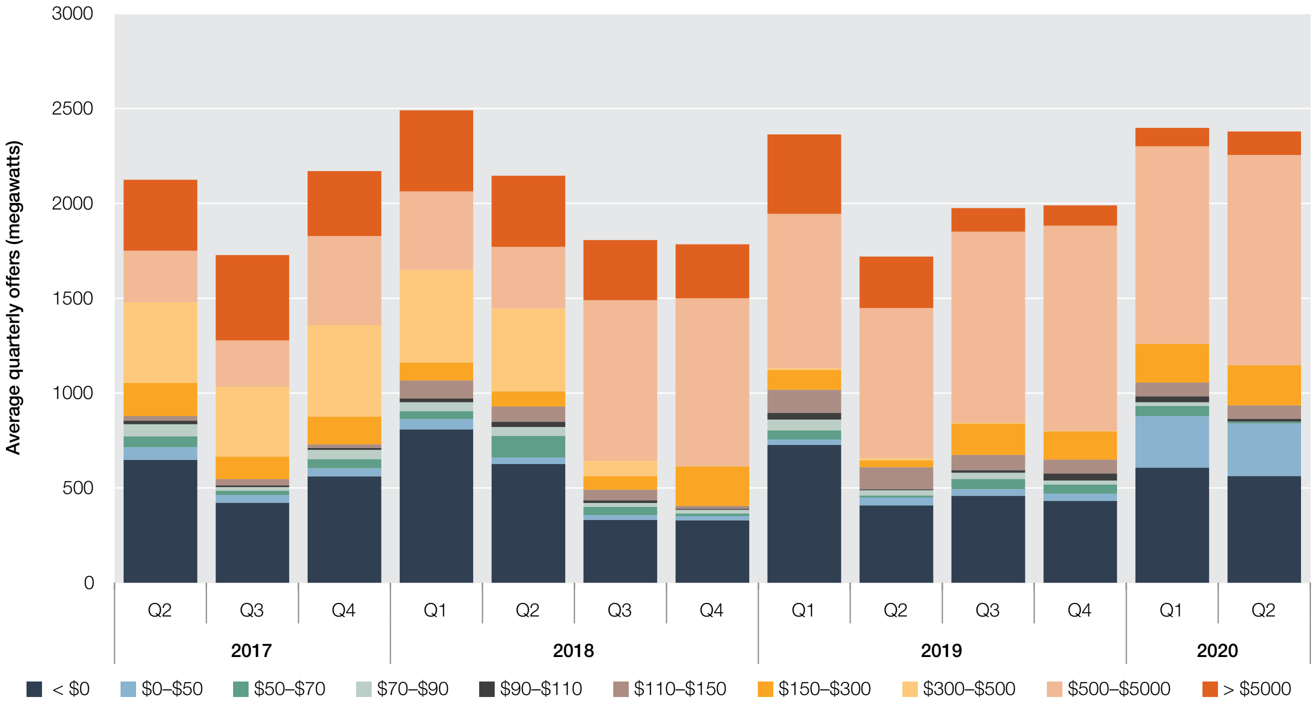
In March 2020, the Council of Australian Governments Energy Council requested we develop a rule change proposal that semi scheduled generators be obliged to follow their dispatch targets in a similar manner to scheduled generators. Our issues paper on the semi scheduled rule changes includes analysis and evidence that some semi scheduled generators have begun to deviate from their instructed output and how this behaviour has been increasing over time.[13] It also looks at the impact this behaviour is having on the NEM now, and potentially into the future as well as the benefits of having greater certainty of the output of semi scheduled generation. Submissions on the issues paper can be found on our website.

Finally, gas generators across the NEM offered around 400 MW more capacity into the market priced below $50 per MWh in Q2 2020 than they did in Q2 2019. Most of this was offered by gas generators in Queensland (390 MW) and some by gas generators in South Australia (90 MW). In fact, gas generators in Queensland offered 35 per cent of their total offered capacity at prices below $50 per MWh in Q2 2020 (figure 1.17).

In contrast, gas generators in Victoria and Tasmania offered less low priced capacity in the market. In Victoria, gas generators shifted offers from the lower price bands into higher price bands, offering only 8 per cent priced less than $50 per MWh and almost 90 per cent above $5000 per MWh in Q2 2020, this compared to over 70 per cent in Q2 2019.

13 AER, *Issues paper on semi scheduled generator rule changes*, June 2020.

Figure 1.17 Offers within price bands, Queensland gas




Source: AER analysis using NEM data.

Note: Quarterly average offered capacity within price bands by gas generators in Queensland.

## 1.8 Coal, gas and hydro set significantly lower prices

Black coal, brown coal, gas and hydro continued to set significantly lower prices compared to a year ago in every region (table 1.1). The quarterly average prices, set by the four major fuel types, were between 40 to 50 per cent less in Q2 2020 than in Q2 2019.

Table 1.1 Fall in average prices set by fuel types

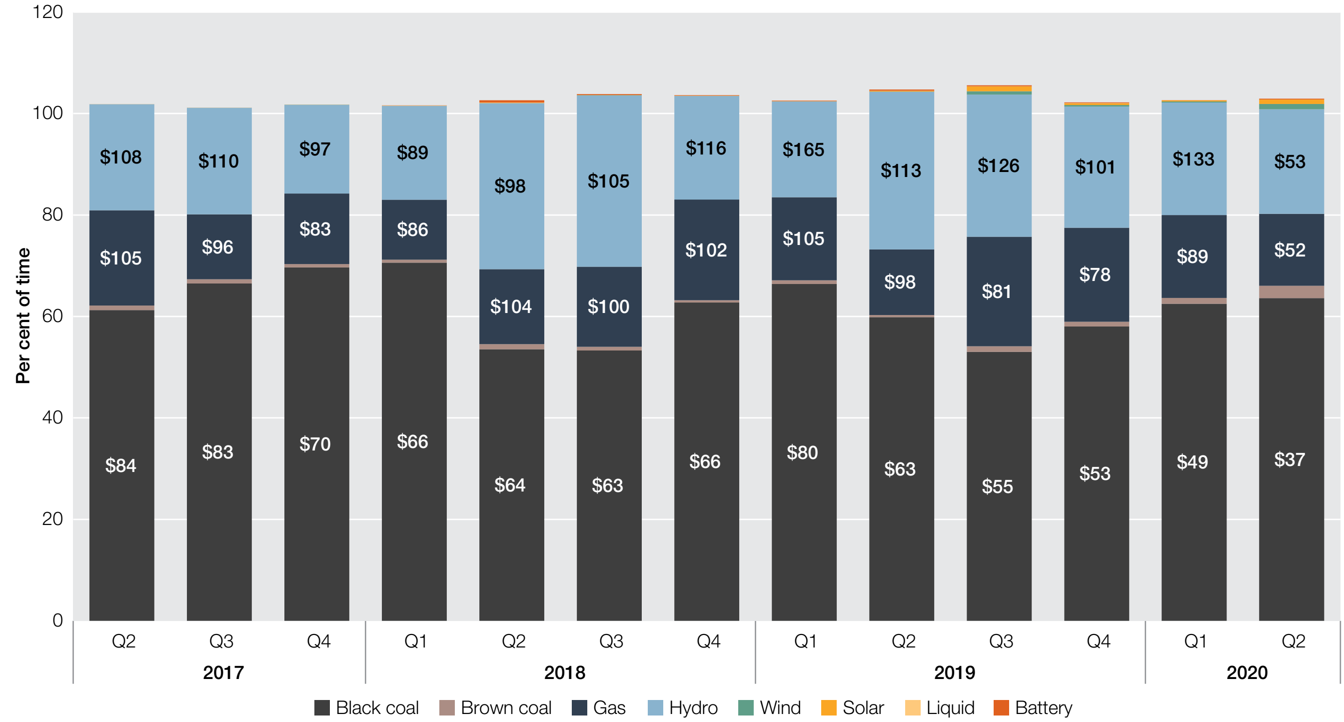
| | Q2 2019 PER MWH | Q2 2020 PER MWH | PERCENTAGE FALL (APPROX.) |
|---|---|---|---|
| Black coal | $61–63 | $33–37 | 40% |
| Brown coal | $10–16 | $7–9 | 40% |
| Gas | $96–105 | $44–54 | 50% |
| Hydro | $109–114 | $30–50 | 50% |

Note: The drop in prices is approximate and differs across regions.

In 2019–20, black coal set the price between $33 per MWh in Queensland and $37 per MWh in the southern regions. While gas set the price between $44 and $54 per MWh respectively. Neither fuel type has set prices this low since 2015 in Queensland, NSW and Victoria, or since 2016 in South Australia. We have included the price setter chart for NSW (figure 1.18) in this report. The columns show the percentage of time each fuel type contributed to setting the price in NSW, with the average price set. Quarterly average price setter data and graphs for all regions of the NEM are available as part of our online wholesale statistics.[14]

14 Price setter information over time highlights the interaction between the price offered by generators and market conditions, for example, changes in input costs, contracting trends and evolving market dynamics.

### Figure 1.18 Price setter, New South Wales




Source: AER analysis using NEM data.

Note: More than one generator or fuel type may set the price, leading to totals of greater than 100 per cent.

Over the last three years the margin between the price set by black coal and gas has generally been around $25 to $50 per MWh. However in 2019–20, the price set by gas fell more than the price set by black coal and the margin between the two fuels narrowed significantly. In Queensland, for example, the average price set by black coal was only $11 per MWh below the average price set by gas.

The average price set by hydro fell sharply over the last year, after plateauing for several years, to levels similar to those seen in 2016. For example, the price set by hydro in NSW dropped by more than half, from $113 per MWh in Q2 2019 to $53 per MWh in Q2 2020. In Tasmania, hydro set the price at $30 per MWh, even lower than the price set by black coal and the lowest quarterly price set by hydro in any region since 2012. Hydro generators typically compete against gas to be dispatched. In Q2 2020 hydro set the price below the price set by gas in Tasmania and Victoria, while in NSW and Queensland it set a slightly higher price.

Interestingly, in 2019–20 we saw wind and solar generally setting higher prices than a year ago, albeit still at prices below zero. For example, in Victoria, the average price set by wind was -$13 per MWh, the highest price in that region since 2012, and in South Australia, the average price set by solar was -$71 per MWh, the highest it's been in that region since Q1 2018. As a result of wind and solar rebidding capacity into higher price bands at times of negative prices, there have been more occasions when renewables have set the price above $0 per MWh. This has contributed to renewables setting higher average prices overall.

Turning to how often fuel types set the price, Q2 2020 saw black and brown coal setting the price more frequently, and gas and hydro setting it less frequently, than in Q2 2019. For example, in Victoria, the amount of time coal set the price increased from 35 per cent of the time to around 60 per cent of the time, whereas, the amount of time gas and hydro set the price fell to 45 per cent of the time from 70 per cent of the time.

Renewables don't set the price very frequently, however in every region, wind and solar set the price more frequently in Q2 2020 than they did in Q2 2019. For example in Victoria, solar set the price 12 times and wind almost 30 times more frequently than they did a year ago.

The increased frequency of renewables and black coal setting price, and reduced frequency of gas and hydro setting the price, is consistent with the lower levels of demand we saw in 2019–20.

## 1.9 Falling fuel prices put downward pressure on spot prices

Fuel prices for gas and black coal fell over 2019–20 which contributed to both fuel types offering more low priced capacity and setting lower prices (figure 1.19).

In particular, gas input prices fell dramatically over 2019–20. Chapter 2 details how international gas prices have continued to fall and domestic gas prices have declined to pre-LNG export levels. Consequently, the gas input proxy costs for gas generators in NSW and South Australia declined by more than 50 per cent by the end of June 2020 from their price a year earlier.[15]

Coal input costs continued to fall over 2019–20. The black coal proxy input cost in NSW, which references the Newcastle coal price, was 25 per cent lower at the end of June 2020 than at the end of June 2019, falling noticeably in the last two months of the year.[16]

In recent months we have seen the 'wedge' between proxy coal input costs and coal prices disappear as the average price set by NSW black coal generators fell more than the drop in the Newcastle thermal coal index. Lower input costs and healthy coal stockpiles enabled black coal generators to offer capacity at lower prices.[17] This combined with lower demand contributed to black coal setting the price at $37 per MWh in Q2 2020 rather than $63 per MWh in Q2 2019.[18] We will examine the relationship between generators' offers and costs in our *Wholesale electricity market performance report 2020*.

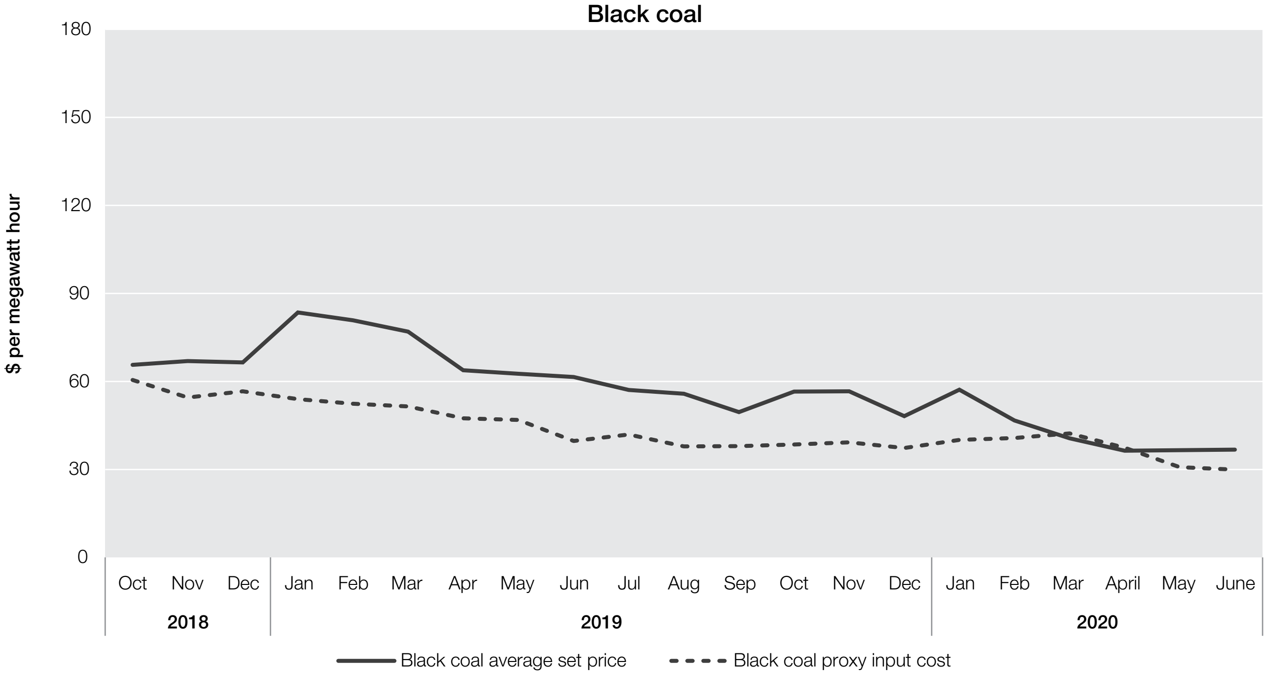
15 The gas proxy input cost is derived from the Short Term Trading Market (STTM) price (AUD$ per GJ) of a respective region, converted to AUD$ per MWh with average heat rate for gas generators. The NSW gas proxy input cost (Sydney STTM) fell to $33 per MWh in June 2020 from $77 per MWh in June 2019. The South Australia gas proxy input cost (Adelaide STTM) fell to $42 per MWh in June 2020 from $87 per MWh in June 2019.

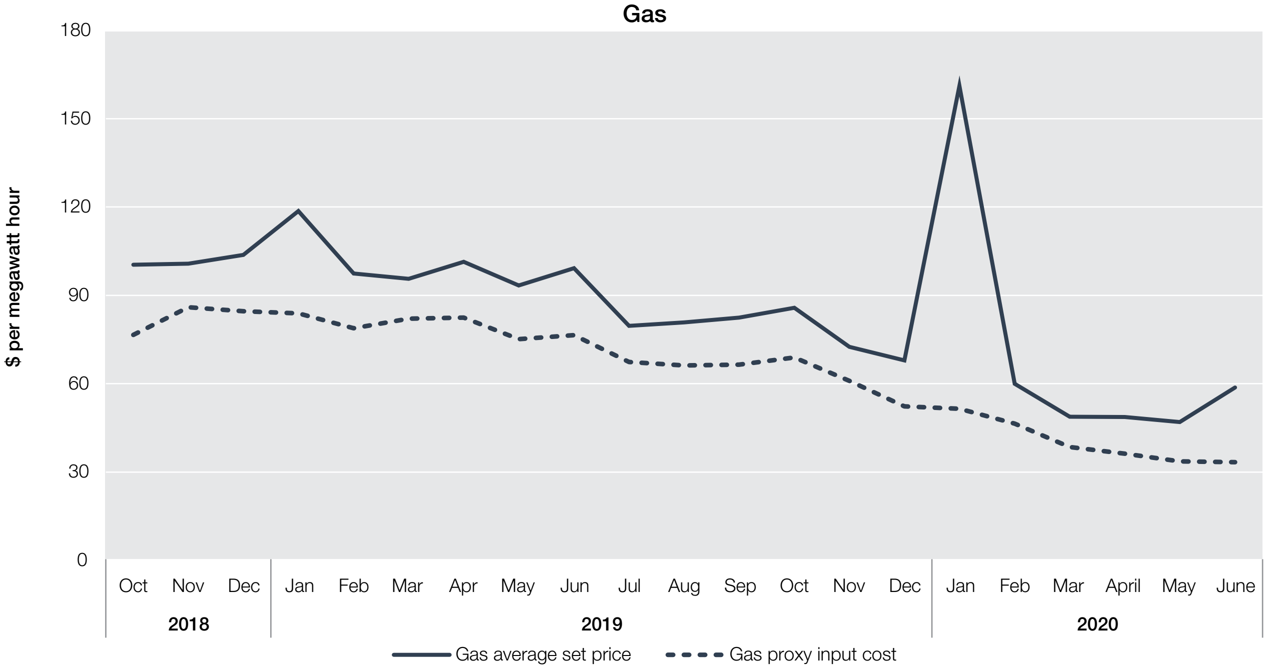
16 Black coal proxy input cost is derived from the Newcastle coal index (USD$ per tonne), converted to AUD$ per MWh with RBA exchange rate, and average heat rate for coal generators.

17 Coal stockpiles were healthier in 2019–20 than in 2018–19 due to the resolution of coal supply issues that impacted some power stations such as Mount Piper in 2018–19.

18 AEMO's *Quarterly energy dynamics–Q2 2020* includes a detailed analysis of the impact of COVID-19 on commodity prices, pp. 14, 15.

**Figure 1.19 Input costs and the price set by black coal and gas in New South Wales**




Source: AER analysis using Newcastle coal index.

Notes: Black coal proxy input cost is derived from the Newcastle coal index (USD$ per tonne), converted to AUD$ per MWh with RBA exchange rate, and average heat rate for coal generators. The gas proxy input cost is derived from the Short Term Trading Market (STTM) price (AUD$ per GJ) of a respective region, converted to AUD$ per MWh with average heat rate for gas generators.

## 1.10 New entry continues to change the generation mix

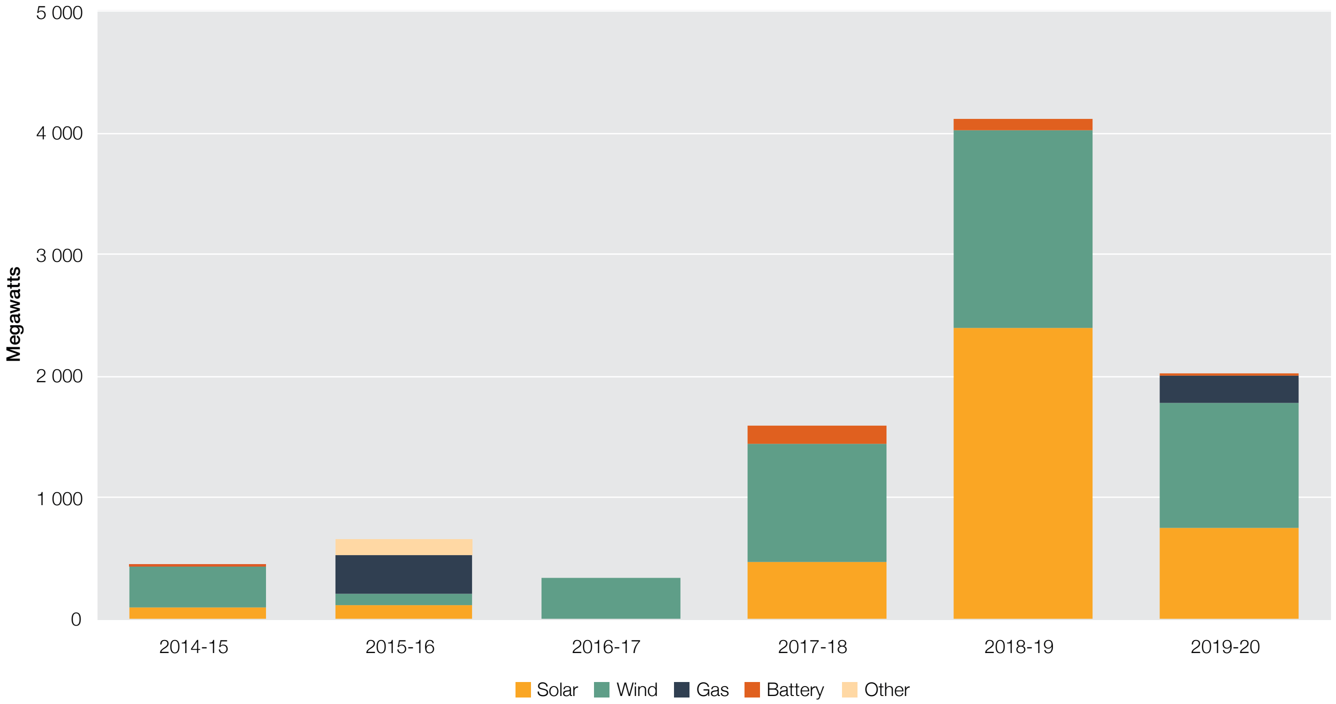
We have previously noted the impact of new entry on the changing generation mix. New capacity totalling around 2000 MW entered the market in 2019–20 of which almost 85 per cent was wind and solar (figure 1.20). Most of the new solar capacity installed was in Queensland and most of the new wind capacity installed was in Victoria.

The other 15 per cent of new entry in 2019–20 included the fast start gas power station at Barker Inlet and the Lake Bonney battery in South Australia.

While 2000 MW of new capacity entered the market in 2019–20, this was lower than projected and only half the capacity that entered in 2018–19. Delays to the commissioning of completed projects due to grid congestion and concerns around network strength, particularly in certain areas in Victoria, has meant the commencement date of numerous projects slipped into 2020–21. While Dundonnell wind farm was completed and commenced operating in March 2020, the commissioning and grid connections of a large number of its installed turbines are currently being delayed.

Looking forward, there are almost 3000 MW of committed wind and solar farms, nearly all located in NSW and Victoria. Following a fall in investor confidence in December 2019, the Clean Energy Council reported investor confidence in large-scale wind and solar farms improved in June 2020, particularly in those two regions.[19]

**Figure 1.20 Recent new entry**




Source: AER analysis using NEM data.

Notes: New entry is recorded using registered capacity. New entry is allocated to a particular year based on the first day the station produces energy. If an existing station is upgraded it is not counted as new entry.

Five new stations entered the market in Q2 2020 with a combined capacity of over 500 MW (table 1.2). Of these, four were wind farms. The largest new entry was the delayed Bulgana Green Power Hub in Victoria, a combined wind farm and battery. While not counted as new entry, in June the Hornsdale Power Reserve increased its storage capacity by 50 MW. The intention is the new capacity will provide fast response FCAS and grid services such as (synthetic) inertia, which has typically been provided by the rotating machinery of coal, gas and hydro generators.

19 Clean Energy Council, *Clean energy outlook, July 2020.*

Table 1.2 New entry, Q2 2020

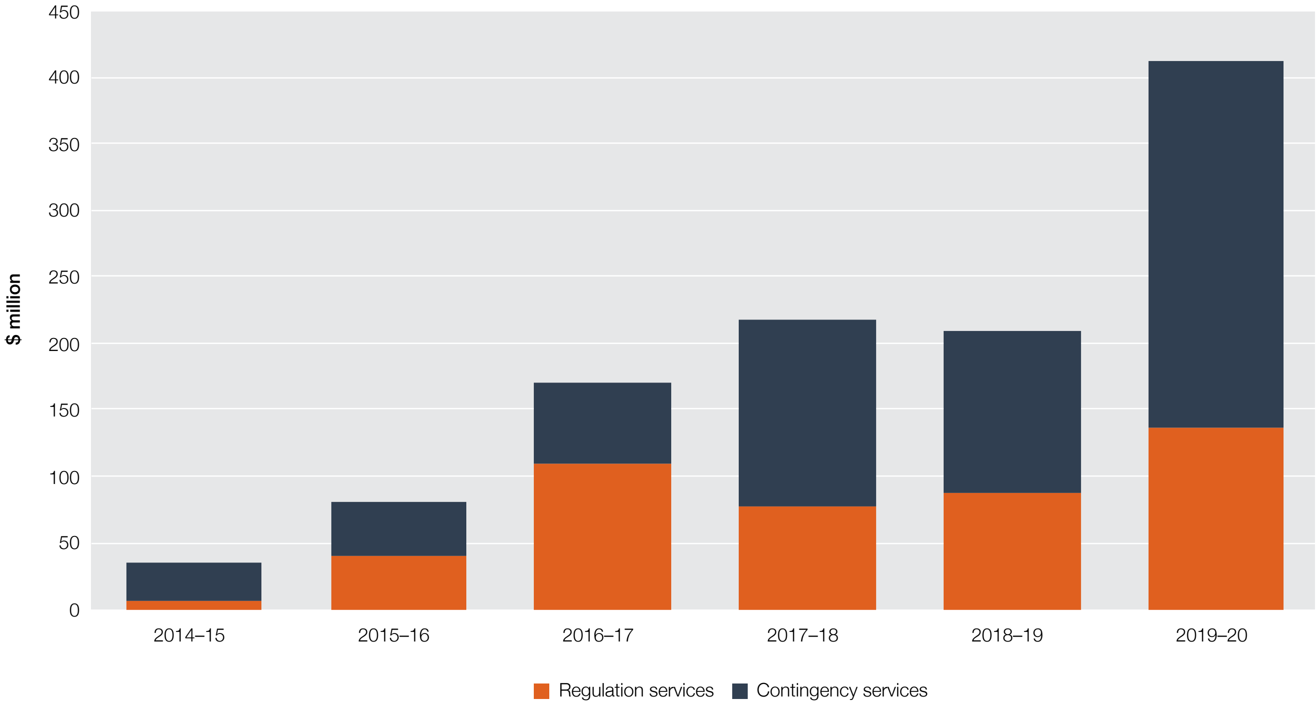
| REGION | STATION | FUEL TYPE | HIGHEST CAPACITY OFFERED Q2 2020 (MW) | REGISTERED CAPACITY (MW) | COMMENCED OPERATIONS |
|---|---|---|---|---|---|
| Victoria | Elaine Wind Farm | Wind | 43 | 84 | Apr-20 |
| Victoria | Cherry Tree Wind Farm | Wind | 58 | 58 | May-20 |
| Victoria | Bulgana Green Power Hub | Wind | 31 | 182* | May-20 |
| NSW | Goonumbla Solar Farm | Solar | 17 | 85 | May-20 |
| NSW | Gullen Range Wind Farm 2 | Wind | 3 | 110 | June-20 |

Note: * On its new registration page, AEMO lists the registered capacity of the Bulgana Green wind farm as 182 MW and the battery as 20 MW. The Bulgana Green website lists the wind farm's capacity as 194 MW.

## 1.11 Record costs for frequency control ancillary services

Annual frequency control ancillary services (FCAS) costs reached an all-time high of $412 million, mostly attributed to the extraordinary costs of Q1 2020 (figure 1.21).[20] Compared to 2018–19, contingency costs were up 125 per cent ($153 million) and regulation costs were up 58 per cent ($50 million). The largest increase was for raise 6 second services, which provide fast response to large deviations in frequency, and more than tripled.[21]

Figure 1.21 Total FCAS costs by financial year



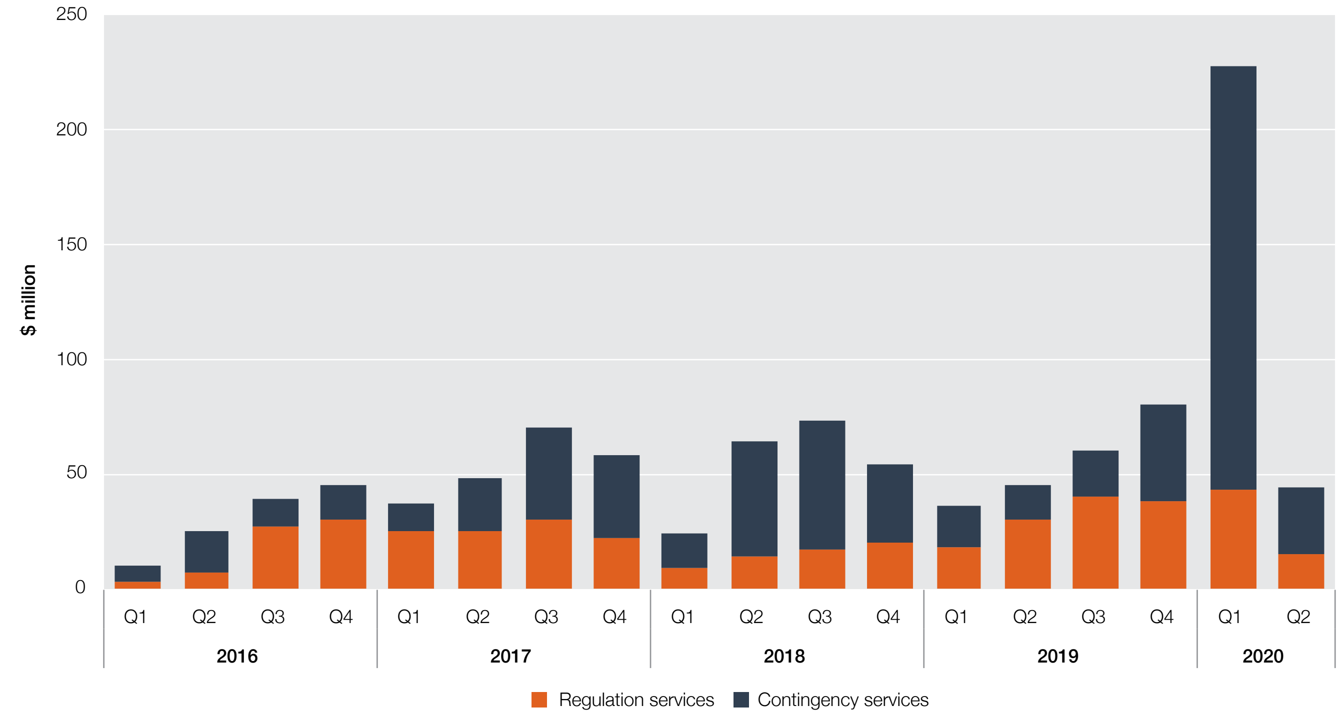

Source: AER analysis using NEM data.

After record FCAS costs in Q1 2020, FCAS costs fell again in Q2 2020 to $44 million, down 7 per cent compared to Q2 2019 (figure 1.22).

20 The focus story in this report looks at drivers of the high priced FCAS events in Q1 2020 and Q4 2019.

21 Raise 6 second increased by 228 per cent ($90 million); raise 60 second increased by 118 per cent ($33 million); raise regulation increased by 42 per cent ($28 million); lower regulation increased by 108 per cent ($22 million).

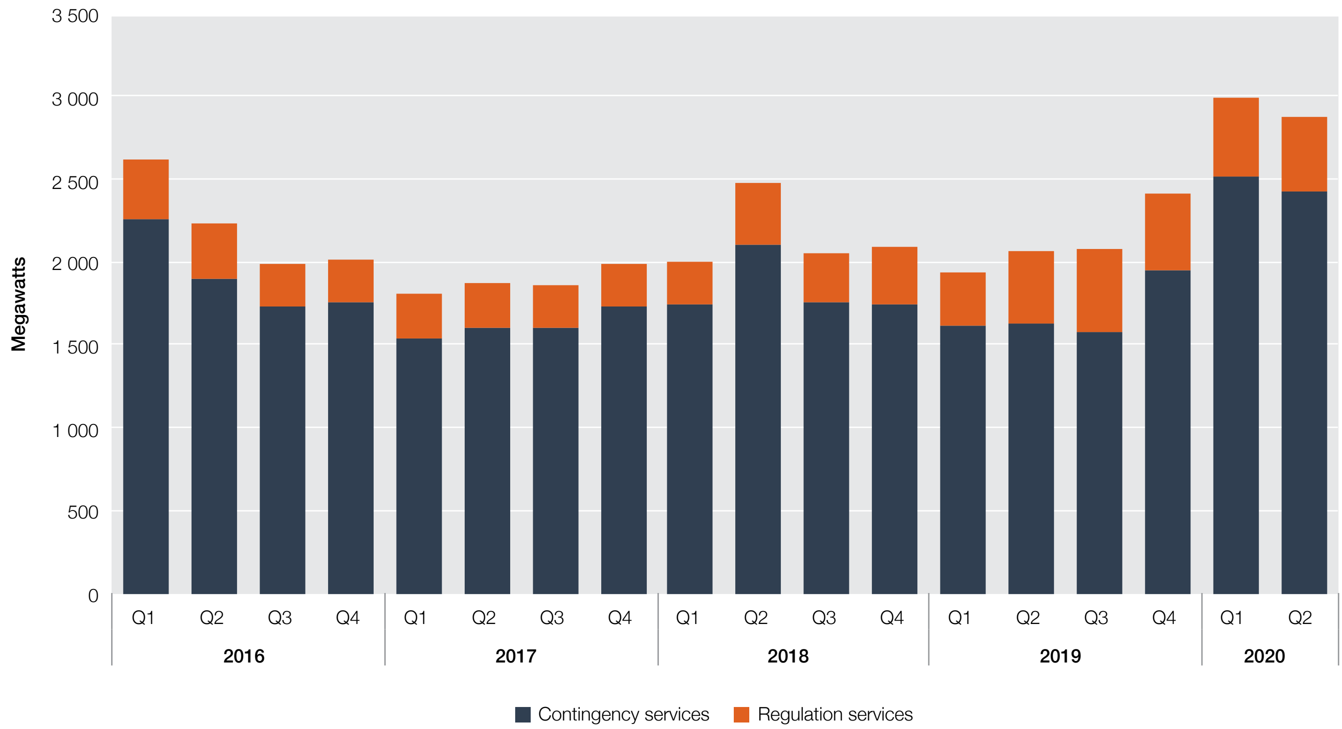
## Figure 1.22 Total FCAS costs by quarter




Source: AER analysis using NEM data.

The average amount of FCAS enabled by AEMO in Q2 2020 was at a similar level to Q1 2020 but was up by around 800MW compared to Q2 2019 (figure 1.23). The change was entirely due to an increase in both raise and lower contingency services enabled. The sustained increase is in line with AEMO's frequency review and contingency requirement expectations. Increased enablement did not see an increase in overall costs, indicating ample low priced services were available. While the enablement for all mainland regions increased, the majority of the increase was sourced from Victoria providers.

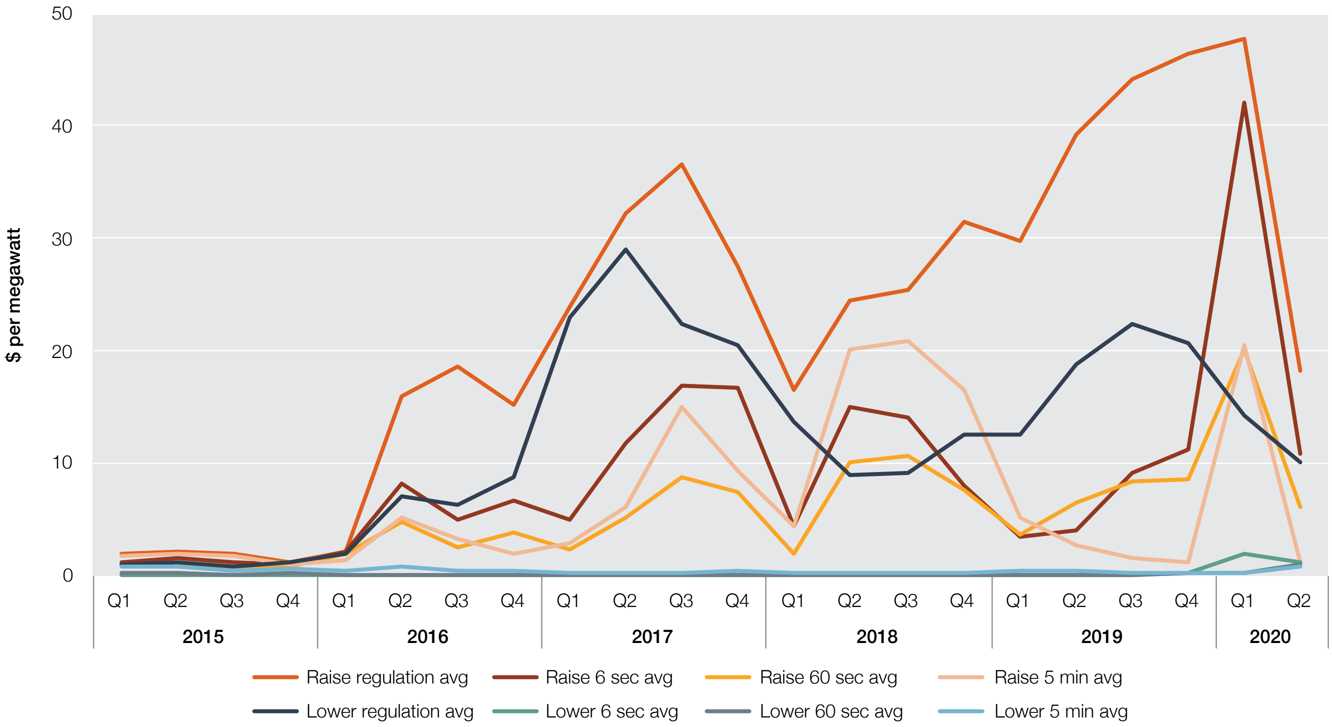
## Figure 1.23 FCAS enabled by quarter




Source: AER analysis using NEM data.

Average quarterly prices for nearly all FCAS services fell sharply in Q2 2020 following an equally sharp rise in Q1 2020 (figure 1.24). In fact, prices for all services fell below $20 per MW for the first time in over two years. Raise regulation services remain the most expensive, followed by lower regulation services and then the other raise services. There were no high price events in the ancillary service markets this quarter.

**Figure 1.24 FCAS prices by quarter, global**




Source: AER analysis using NEM data.

# Focus—Drivers of high FCAS prices

FCAS costs reached an all-time financial year high of $412 million mostly due to events in Q1 2020. There were also high priced events in November 2019 totalling around $14 million.

## High FCAS prices in Q1 2020

Local FCAS prices in South Australia exceeded $5000 per MW on 75 occasions across all services following interruptions to the Heywood interconnector between Victoria and South Australia this summer, driving record FCAS costs. The loss of Heywood caused South Australia to be electrically isolated and meant that FCAS needed to be sourced locally.

The Heywood interconnector failed on two occasions:

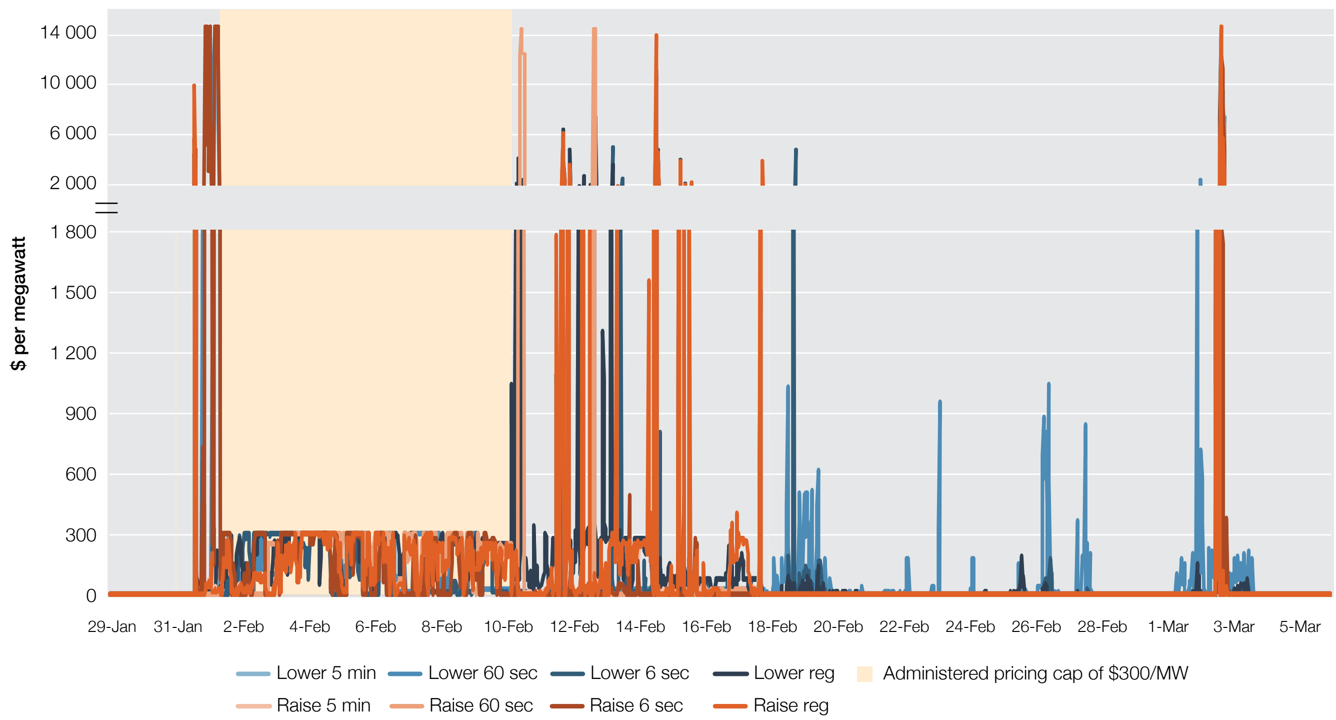
- the first outage lasted for over two weeks between 31 January and 18 February
- the second outage was on 2 March.

During these occasions, the main drivers of the FCAS price exceeding $5000 per MW were:

- a shortage of some services which led AEMO to direct two participants to provide FCAS with the resulting price hitting the price cap of $14 700 per MW
- participants rebidding FCAS capacity from prices below $5000 per MW to higher levels
- the interaction of energy and FCAS markets which effectively reduced the amount of FCAS available to the market.

Sustained high prices in the first two days of the outage triggered the administered price cap mechanism, capping FCAS prices at a maximum of $300 per MW for all services for over a week (figure 1.25).

**Figure 1.25** FCAS spot prices




Source: AER analysis using NEM data.

## Outage of the Heywood interconnector

During the afternoon of 31 January, a severe storm in western Victoria caused six high voltage transmission towers to collapse which in turn caused the Heywood interconnector, which links Victoria and South Australia, to fail. This resulted in South Australia being electrically isolated from the rest of the market and the market operator (AEMO) requiring local participants to provide all FCAS. Later in the afternoon, AEMO advised the market that the damaged lines would not be restored for a number of weeks.

During this period prices exceeded $5000 per MW in raise 6 second (R6), raise 60 second (R60), lower 60 second (L60), lower regulation (Lreg) and lower 5 minute (L5) services. We analyse below the drivers of the main three high priced periods:[22]

- 31 January to 1 February
- 10 and 12 February
- 2 March.

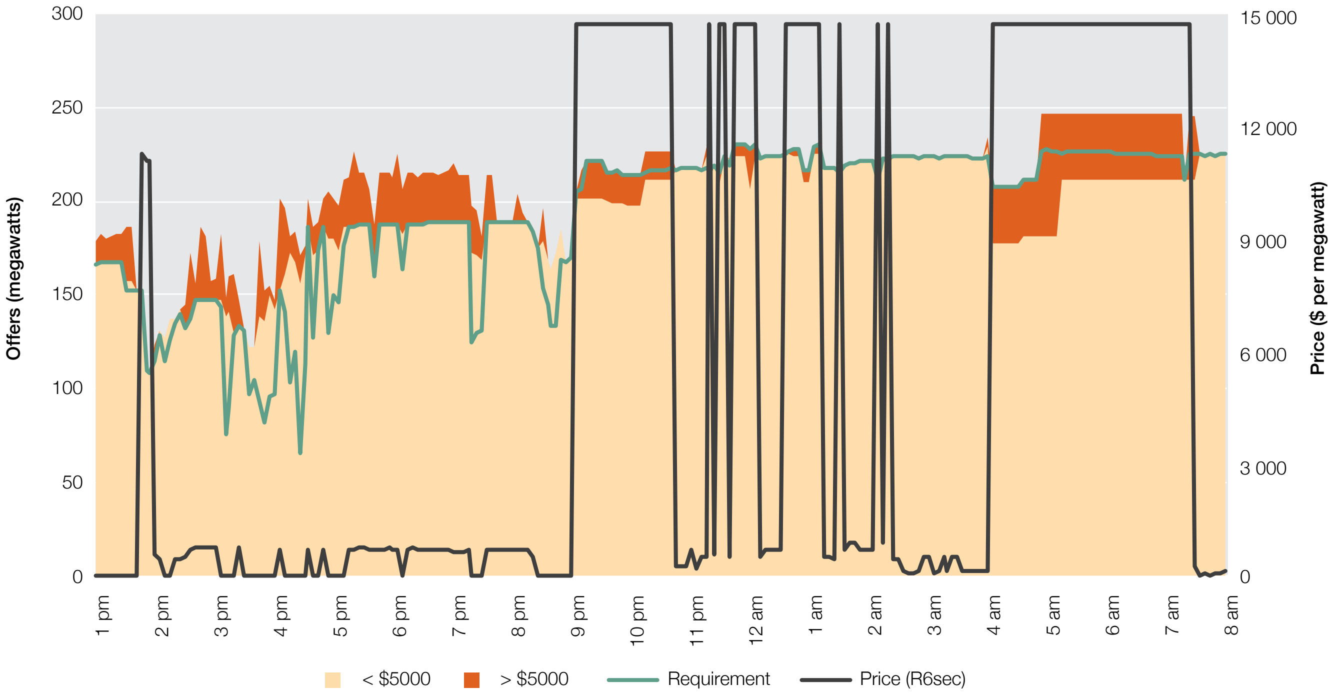
## Drivers of high prices on 31 January to 1 February

### Rebidding and a shortage of raise 6 second services

Prices for R6 and L60 contingency services exceeded $5000 per MW multiple times between 2 pm on 31 January and 7.30 am on 1 February 2020. Even though 98 per cent of R6 offered was priced below $5000 per MW, at times, capacity above $5000 per MW was needed to be enabled to meet local requirements.

Between 9 pm on 31 January and 4 am on 1 February prices fluctuated between low prices and the cap as requirements and offers below $5000 per MW changed (figure 1.26). Batteries and demand aggregators rebid capacity both up and down as their state of charge and therefore the amount of FCAS they could offer changed.[23] The price dropped at times when thermal plant was rebid from prices above to below $5000 per MW.

**Figure 1.26 Raise 6 second effective offers**




Source: AER analysis using NEM data.

22 For an explanation of the eight FCAS markets see the *Wholesale markets quarterly Q3 2019*.

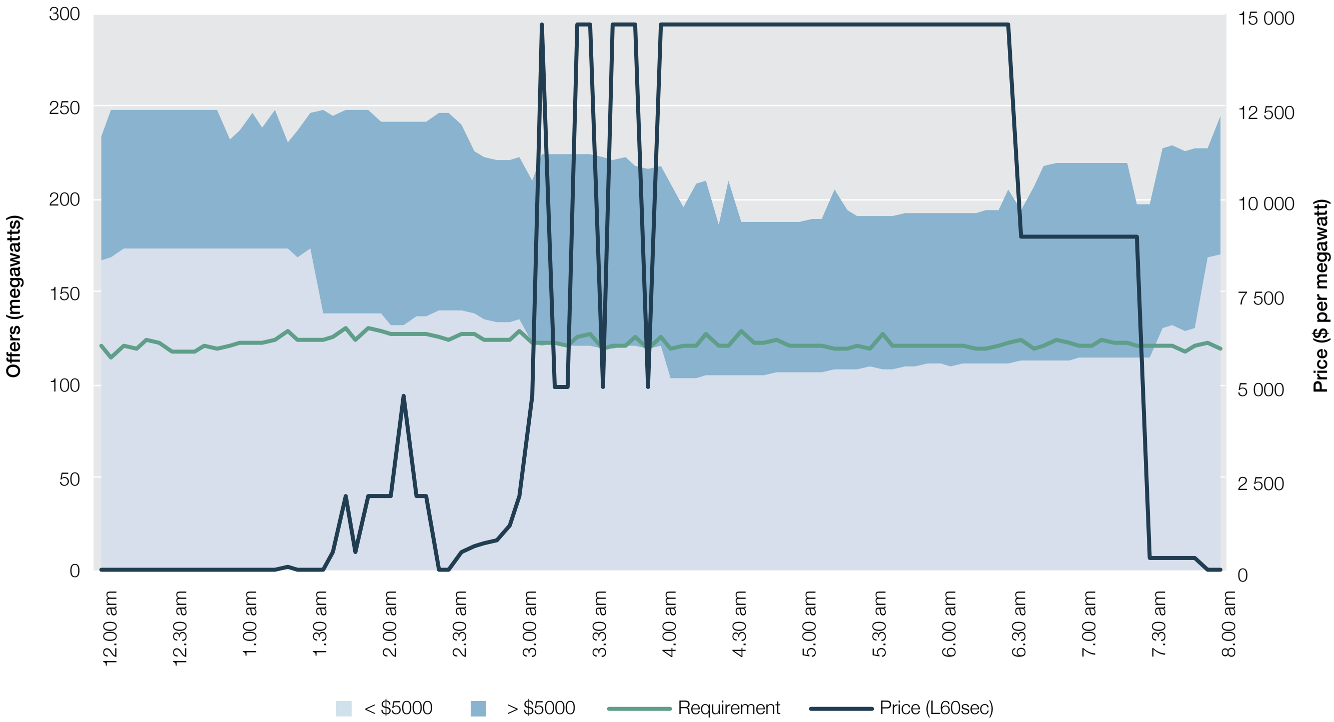
23 Demand aggregators group smaller customers together so they can behave like a single load or generator and participate in the market.

Prices went to the cap again at 4 am. The day before, Engie withdrew its offer to provide up to 35 MW of R6 at Pelican Point power station from 4.30 am. Most of this capacity was priced below $30 per MW. It did this in response to forecast negative energy prices. AEMO published a market notice (73245) identifying a possible shortfall in R6 from 4.30 am to 5 pm to elicit more supply from participants. There wasn't a sufficient response so AEMO directed a participant to provide R6 and the price went to the price cap. At 7.10 am the direction was cancelled but prices remained above $5000 per MW until 7.20 am when the cumulative price threshold (CPT), a safety net to limit price risk during such events, was triggered capping prices at $300 per MW. AEMO issued further directions to ensure enough R6 was available throughout the day.

## Rebidding of lower 60 second services

On the other hand, the spread of offers across L60 was very different (figure 1.27). On 1 February between 50 and 71 per cent of the service offered was priced below $5000 per MW. From 8.10 pm on 31 January AGL Energy rebid 60 MW of capacity at Torrens Island power station from below $45 per MW to $14 699 per MW. The reasons given were around portfolio redistribution and a change in forecast price. The price was set by Torrens Island at $14 699 per MW from 4 am to 6.30 am and then at $9000 per MW until prices were capped at $300 per MW.

Figure 1.27 Lower 60 second effective offers




Source: AER analysis using NEM data.

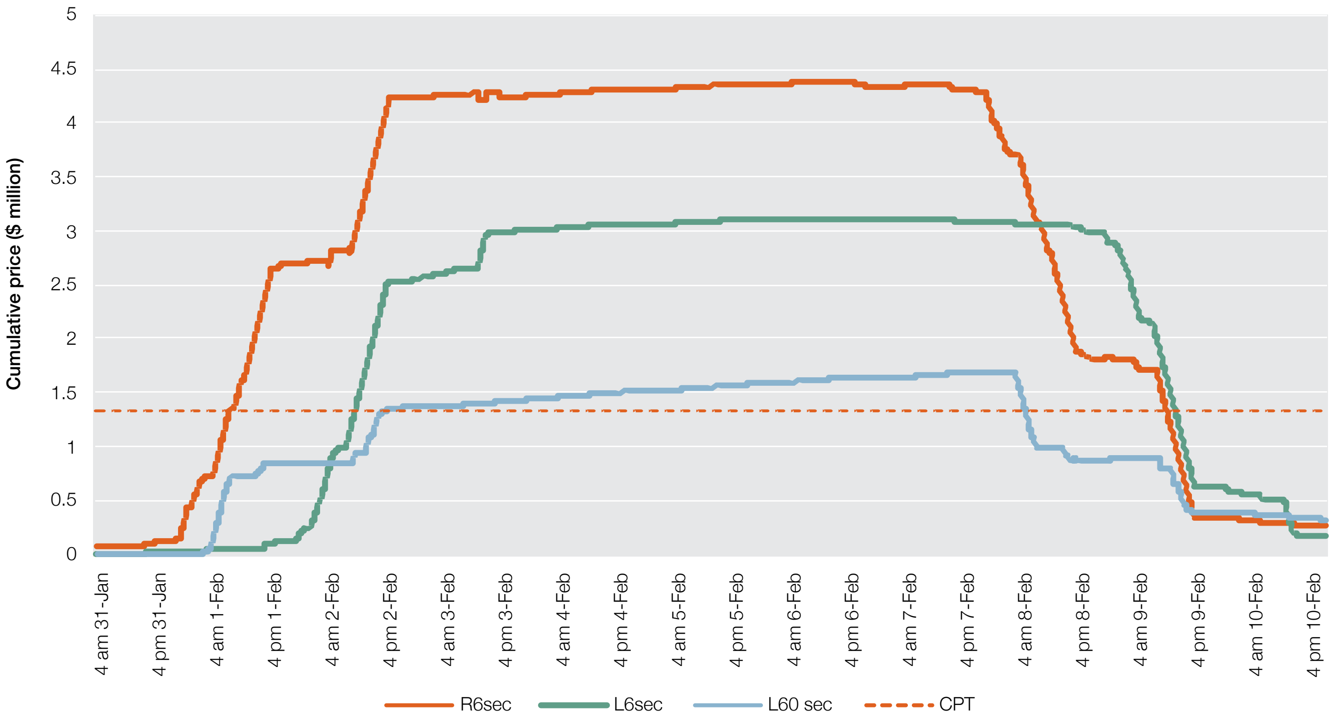
## High prices limited by capping scheme

Overall, the number of high prices was limited by a special pricing arrangement on 1 February, which saw the FCAS price capped at $300 per MW.[24] The scheme is triggered when the cumulative price of any service (R6 in this instance) exceeds six times the CPT of $221 100 (figure 1.28).[25]

24 The capping scheme took effect from 1 February at 7.25 am.

25 Under the National Electricity Rules, if the sum of the preceding 2016 dispatch interval prices (rolling seven days) exceeds six times the CPT for any ancillary service, then an administered price cap of $300 per MW is applied to all ancillary services.

Figure 1.28 Cumulative FCAS prices



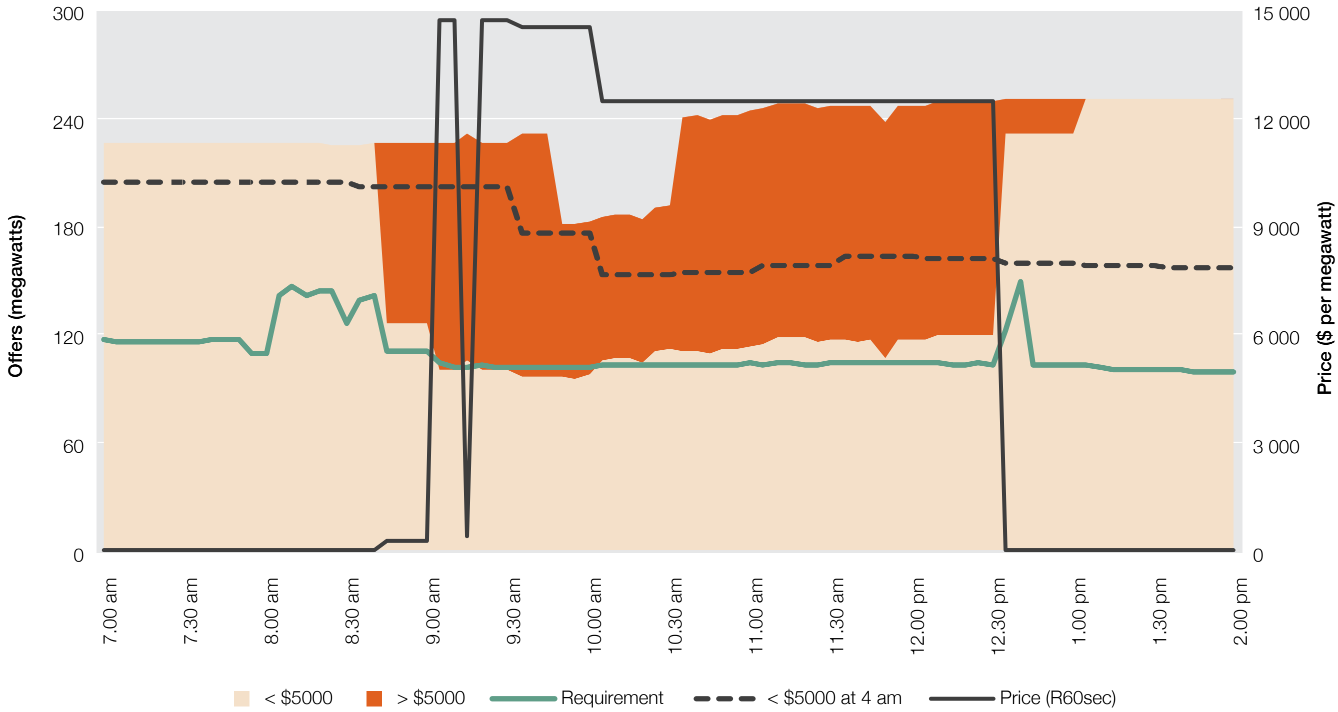

Source: AER analysis using NEM data.

Once the raise 6 second service crossed the threshold, administered pricing was put in place for all services. Administered pricing stays in place until the sum of the uncapped prices falls back under the CPT. This happened at 4 am on 10 February, when AEMO cancelled the administered pricing period.

## Drivers of high prices on 10 and 12 February

On 10 February at 4 am when the administered pricing period was lifted, all available R60 capacity was offered below $5000 per MW for 9.30 am to 12.30 pm. However, from 4.19 am AGL Energy rebid a total of up to 135 MW of capacity across Torrens Island power station and the Dalrymple battery from below $10 per MW to above $12 500 per MW (figure 1.29). The reasons given were the removal of administered pricing and changes in forecast. The R60 price from 9.30 am to 12.30 pm was set above $12 500 per MW, mostly by Torrens Island.

Figure 1.29 Raise 60 second offers, 10 February




Source: AER analysis using NEM data.

The R60 price again exceeded $5000 per MW on 12 February between 2.30 pm and 4 pm following rebidding by AGL Energy at Torrens Island power station and the Dalrymple battery.

The day before, AGL Energy rebid a combined total of 72 MW of capacity from below $0.01 per MW to above $14 500 per MW, in response to forecasts. Before the rebid, prices between 2.30 pm and 4 pm were forecast to be below $1 per MW, after their rebid, forecast prices for the same time were repeatedly above $5000 per MW. From 2.30 pm to 4 pm, the actual price was set at $14 500 per MW by Torrens Island.

L5 and Lreg services also exceeded $5000 per MW on 12 February, however this was not caused by rebidding. Between 3.15 pm and 4.25 pm, despite sufficient capacity offered below $5000 per MW, there was not enough effective capacity below $5000 per MW to meet L5 requirements due to the trade-offs in the provision of energy and FCAS. As a result, capacity above $5000 per MW needed to be dispatched. Co-optimisation between L5 and Lreg services resulted in Lreg also exceeding $5000 per MW for the respective trading intervals.

The interactions between energy and FCAS are explained in detail in the 2 March section.

## Drivers of high prices on 2 March

On 2 March 2020, at midday, the Heywood interconnector tripped due to an equipment failure at the Heywood substation in south west Victoria and South Australia became electrically separated from the rest of the power system. The AER has written an *Energy $5000 per MWh report* for further details.

To manage the unplanned outage, AEMO invoked a series of constraints and issued directions to generators to maintain power system security in South Australia. This included limiting the output of the Hornsdale and Lake Bonney batteries and ensuring local generators could provide FCAS.

Between midday and 3 pm, all FCAS markets had at least two trading intervals where the average price across the 30 minutes was above $5000 per MW. The main drivers of this were (table 1.3):

- interactions between the energy and FCAS markets
- rebidding of capacity by participants from below to above $5000 per MW.

Table 1.3 30 minute average prices for FCAS

| TRADING INTERVAL | LOWER REG ($/MW) | LOWER 5 MIN ($/MW) | LOWER 60 SEC ($/MW) | LOWER 6 SEC ($/MW) | RAISE REG ($/MW) | RAISE 5 MIN ($/MW) | RAISE 60 SEC ($/MW) | RAISE 6 SEC ($/MW) |
|---|---|---|---|---|---|---|---|---|
| 12.30 pm | ***7350*** | 150 | 362 | 3 | 4007 | 3017 | 2967 | 12 |
| 1 pm | ***14 700*** | ***14 699*** | 398 | 2187 | ***14 700*** | ***14 700*** | 1483 | ***9813*** |
| 1.30 pm | ***7459*** | ***7458*** | 9 | ***9805*** | ***6990*** | ***6990*** | | ***12 250*** |
| 2 pm | 348 | 345 | ***5005*** | ***9638*** | 79 | 87 | | ***11 333*** |
| 2.30 pm | 4088 | 4035 | 4407 | ***6730*** | ***5745*** | 4966 | ***8341*** | ***8442*** |
| 3 pm | 4973 | 1590 | ***7483*** | 45 | 2760 | 2765 | ***6667*** | 4908 |

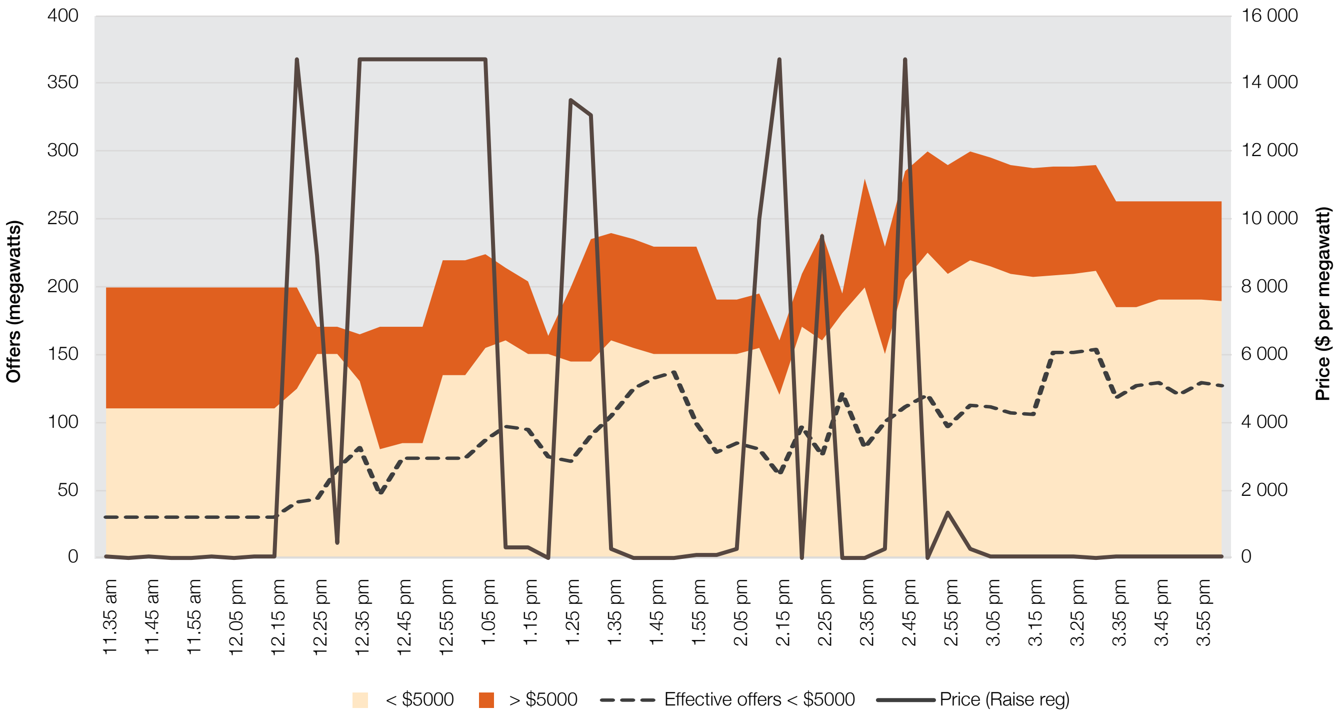
Note: Each of the trading intervals above $5000 per MW (italicised and bold) is coloured yellow where the main driver was the interaction between energy and FCAS markets, and purple where the main driver was rebidding.

## Interactions between energy and FCAS

Interactions between the energy and FCAS markets can effectively reduce the capacity of FCAS that is available to the market or can lead to pricing outcomes which differ from offers. There are trade-offs between the provision of FCAS and energy, which determines the effective availability of FCAS. For example, a generator that is operating at its maximum capacity in energy cannot generate any more to provide raise services so their effective available capacity for raise services would be 0 MW.

Average maximum capacity offered for raise regulation services was around 245 MW on the day (figure 1.30). However once the trade-off between energy and FCAS was taken into account, less than half of this capacity was available to dispatch into the market. Capacity priced below $5000 per MW was effectively reduced by around 50 MW during each dispatch interval the interconnector was out of service.

Figure 1.30 Raise regulation offers




Source: AER analysis using NEM data.

AEMO's dispatch engine co-optimises between the energy and FCAS markets to minimise the total cost of supplying all FCAS and energy markets. For example, a generator may be backed off in energy so it is able to provide more raise services. In this case offers for both services are used to determine price and can lead to a price higher than the offer for that service.

For lower 6 second (L6) service, the price was set above $14 600 per MW on a number of occasions as energy, load, and FCAS services were co-optimised. As an example, at 1.10 pm the Dalrymple battery offer for L6 in price setter was close to $0 per MW but to provide that service the Dalrymple battery had to be backed off as a load and this offer was close to the price cap. The co-optimisation of these services meant the price was set at $14 609 per MW.

### Rebidding

Participants are allowed to rebid their capacity, across energy and FCAS, into different price bands. After the trip of Heywood and the introduction of constraints and directions, participants rebid capacity from prices below to above $5000 per MW once again requiring the dispatch of capacity priced above $5000 per MW.

At 12.24 pm, AGL Energy added 10 MW at the price cap for the L5 service and shifted all but 3 MW of the 50 MW already offered at Torrens B power station unit 4 to the cap. This caused prices to increase to the cap and the unit set price for a number of dispatch intervals from 12.35 pm to 1.30 pm.

Rebids in energy also impacted outcomes in the FCAS markets, as per the trade-off between energy and FCAS discussed above. Effective 2.15 pm, AGL Energy rebid the removal of 200 MW of capacity in energy at Torrens B unit 4 in error. The removal of capacity in energy meant that unit 4 could not provide FCAS. This resulted in a drop of FCAS capacity of around 30 MW to 50 MW across all services which caused violation of constraints and spikes in FCAS prices for that five minutes. AGL Energy corrected the error through another rebid effective 2.20 pm, which brought back all capacity in energy and therefore the capacity in FCAS.

# High FCAS prices in Q4 2019

## Drivers of high prices 9 November

Prices for the L60 and L6 markets in South Australia were between $5200 per MW and $14 700 per MW for the 6 am to 7.30 am trading intervals. A line outage in Victoria meant that the Heywood interconnector was at risk of tripping and electrically isolating South Australia from the rest of the NEM. To manage system security in South Australia if this did occur, AEMO required South Australia to provide its own local FCAS. Around 85 per cent of capacity in both services was priced below $5000 per MW, but the requirement was such that capacity above $5000 per MW needed to be dispatched. Rebidding did not contribute to prices above $5000 per MW and at the time the price for energy was below $100 per MWh.

## Drivers of high prices on 16 November

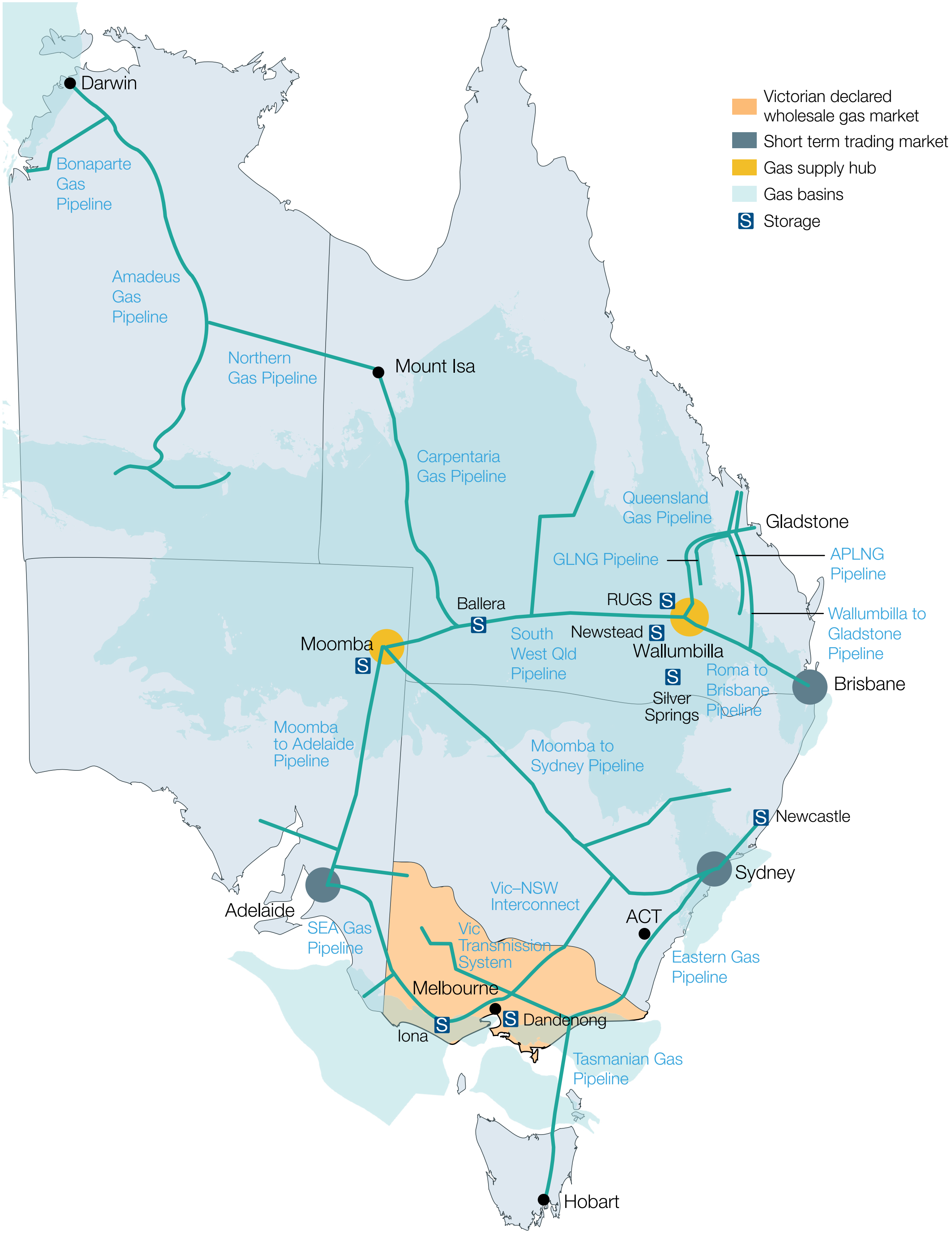
Around 6 pm the Heywood interconnector tripped due to the maloperation of protection equipment on two lines in Victoria meaning South Australia was electrically isolated and had to provide its own FCAS. Prices for L6 and R6 services exceeded $5000 per MW on numerous occasions from 6.30 pm. Rebidding did not contribute to the high prices while the price for energy reached a maximum of around $1000 per MW at 7 pm.

Ninety-four per cent of capacity for L6 was offered below $5000 per MW but the requirements for that service were such that the price was set by Pelican Point power station at the cap from 6.25 pm until 8 pm. Prices fell at 8 pm when AEMO directed Electranet to reduce load at Olympic Dam by 50 MW, decreasing the requirement for lower services to a point where capacity above $5000 per MW was not needed.

The price for R6 reached the price cap 75 per cent of the time between 9.40 pm and 11 pm when there was a shortage of supply for that service. The price in the remaining dispatch intervals was around $800 per MW due to co-optimisation of the FCAS and energy markets. The requirement for R6 services could not be reduced as the largest generation unit, which set the R6 requirement level, Pelican Point power station, had to remain on to provide energy.

Heywood returned to service at 11.10 pm after which South Australia no longer had local prices or requirements.

# 2. Gas



Victorian declared wholesale gas market
Short term trading market
Gas supply hub
Gas basins
Storage
Darwin
Bonaparte Gas Pipeline
Amadeus Gas Pipeline
Northern Gas Pipeline
Mount Isa
Carpentaria Gas Pipeline
Queensland Gas Pipeline
Gladstone
GLNG Pipeline
APLNG Pipeline
Ballera
RUGS
Moomba
South West Qld Pipeline
Newstead
Wallumbilla
Wallumbilla to Gladstone Pipeline
Roma to Brisbane Pipeline
Silver Springs
Brisbane
Moomba to Adelaide Pipeline
Moomba to Sydney Pipeline
Newcastle
Sydney
Adelaide
Vic–NSW Interconnect
ACT
SEA Gas Pipeline
Vic Transmission System
Eastern Gas Pipeline
Melbourne
Dandenong
Iona
Tasmanian Gas Pipeline
Hobart

## 2.1 International and domestic prices continue to fall hitting multi-year lows

| SPOT MARKET PRICES | | FY 16/17 | FY 17/18 | FY 18/19 | FY 19/20 |
|---|---|---|---|---|---|
| Argus LNG des Northeast Asia spot price, $/GJ[26] | | 8.29 | 10.70 | 10.49 | 5.67 |
| East coast spot market prices, $/GJ[27] | VIC | 8.58 | 8.03 | 9.67 | 6.58 |
| | SYD | 8.81 | 8.50 | 9.92 | 6.49 |
| | ADL | 8.83 | 8.06 | 10.10 | 7.13 |
| | BRI | 8.21 | 7.46 | 9.41 | 5.77 |
| | WAL | 7.84 | 7.79 | 9.19 | 6.76 |
| LNG Netback price at Wallumbilla, $/GJ[28] | | 7.16 | 8.66 | 9.84 | 5.01 |

Source: AER analysis using Argus media, DWGM, STTM, WGSH data and ACCC netback price series.

The ongoing fall in Asian gas prices continued to have significant flow-on effects for the Australian domestic gas markets. The average 2019–20 Argus Media's Northeast Asia (ANEA) LNG spot price declined by 46 per cent compared to 2018–19 to $5.67 per gigajoule (GJ).

Consequently, the LNG netback price at Wallumbilla, which uses Asian spot prices as its starting point, declined steeply as did east coast spot market prices.

East coast spot market prices ranged between $5.77 per GJ in Brisbane and $7.13 per GJ in Adelaide for 2019–20. This was the first time since 2015–16 that prices in all regions were below $7.25 per GJ.

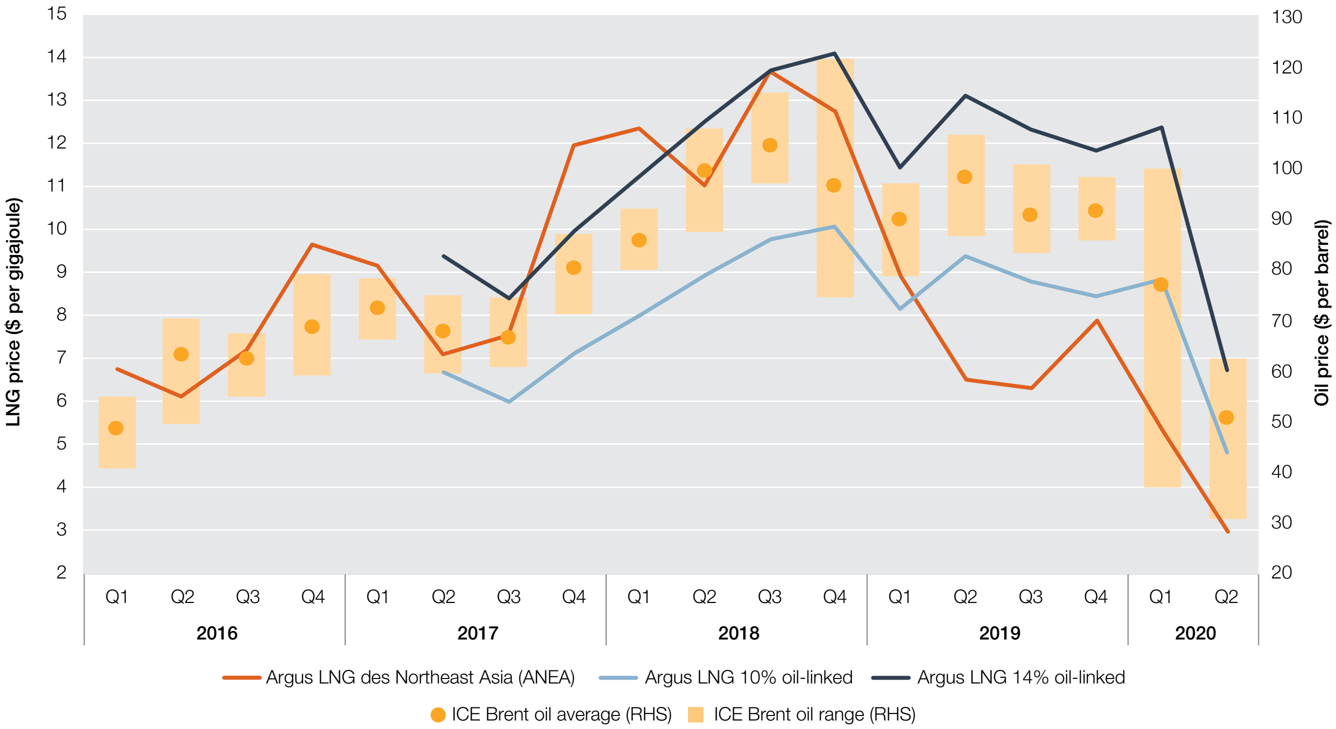
This quarter saw a further drop in international LNG prices as the COVID-19 pandemic continued to impact global markets, with the ANEA spot price falling another 44 per cent from Q1 2020 to $3 per GJ in Q2 2020 (figure 2.1). The lowest ANEA price was observed towards the end of April at $2.43 per GJ. After hitting this low, prices increased slightly, moving within the range of $2.66 per GJ and $2.94 per GJ during the month of June.

26 The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4-12 weeks before the date of delivery.

27 The Victorian price is a daily imbalance price at 6.00 am. Sydney, Adelaide and Brisbane are ex ante prices. Wallumbilla hub is the on screen, day ahead price. The Moomba hub has not been included, given it sees very few trades.

28 The ACCC calculate the Asian LNG netback price to measure the price that a gas supplier could expect to receive for exporting gas.

## Figure 2.1 Delivered Asian LNG spot price and Brent oil price




Source: AER analysis using Argus media data.

Notes: The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.

The Argus LNG 10 per cent and 14 per cent oil linked contract prices are indicative of either a 10 per cent or 14 per cent 3-month average Ice Brent crude futures slope.

The ICE Brent oil price is a month ahead settled price.

The AER obtains confidential proprietary data from Argus Media under license, from which data the AER conducts and publishes its own calculations and forms its own opinions. Argus Media does not make or give any warranty, express or implied, as to the accuracy, currency, adequacy, or completeness of its data and it shall not be liable for any loss or damage arising from any party's reliance on, or use of, the data provided or the AER's calculations.

Chinese LNG demand began to recover in Q2 2020 providing some level of support to the LNG market in Asia. However, in Japan and South Korea power sector and industrial demand remained under pressure due to COVID-19 restrictions resulting in high gas inventory levels. In addition, Asian buyers have started to explore volume reductions under their long term contracts.

Elsewhere in the global LNG market, storage levels in Europe are at record highs creating uncertainty around Europe's on-going ability to absorb excess LNG supply. In the USA, falling demand led to the cancellation of around 20–30 LNG cargoes in June, with more cargoes expected to be cancelled in the coming months.[29]

The uncertainty around the COVID-19 pandemic and the speed of economic recovery will mean international LNG markets will remain under pressure. Spot LNG prices are expected to remain supressed in the near term and continue to trade in the low $3 per GJ price range observed in June.

The drop in oil prices has also seen LNG oil-linked contract prices trend sharply downwards, albeit still at a premium to spot prices. Over the last year the Brent oil price decreased by 48 per cent, hitting a low of $31 per barrel (bbl) at the end of April before recovering to trade between $56 per bbl and $62 per bbl in June.[30]

The large drop in oil prices during the first half of 2020 was initially driven by intense price competition between the largest oil producing countries, culminating in an agreement in April to cut production by ten per cent in an effort to put a floor under the oil price.[31] The global economic slowdown due to COVID-19, including a significant reduction in domestic and international air travel, further contributed to the fall in oil prices in Q2 2020.

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29 Reuters.com 2020, Buyers of USA LNG to cancel 40–45 cargoes for August loading: sources, https://www.reuters.com/article/us-usa-lng-trade/buyers-of-us-lng-to-cancel-40-45-cargoes-for-august-loading-sources-idUSKBN23T2GJ, 23 June 2020, accessed 16 July 2020.

30 The Brent oil price is a trading classification of crude oil, which serves as a global benchmark price for the purchase of oil.

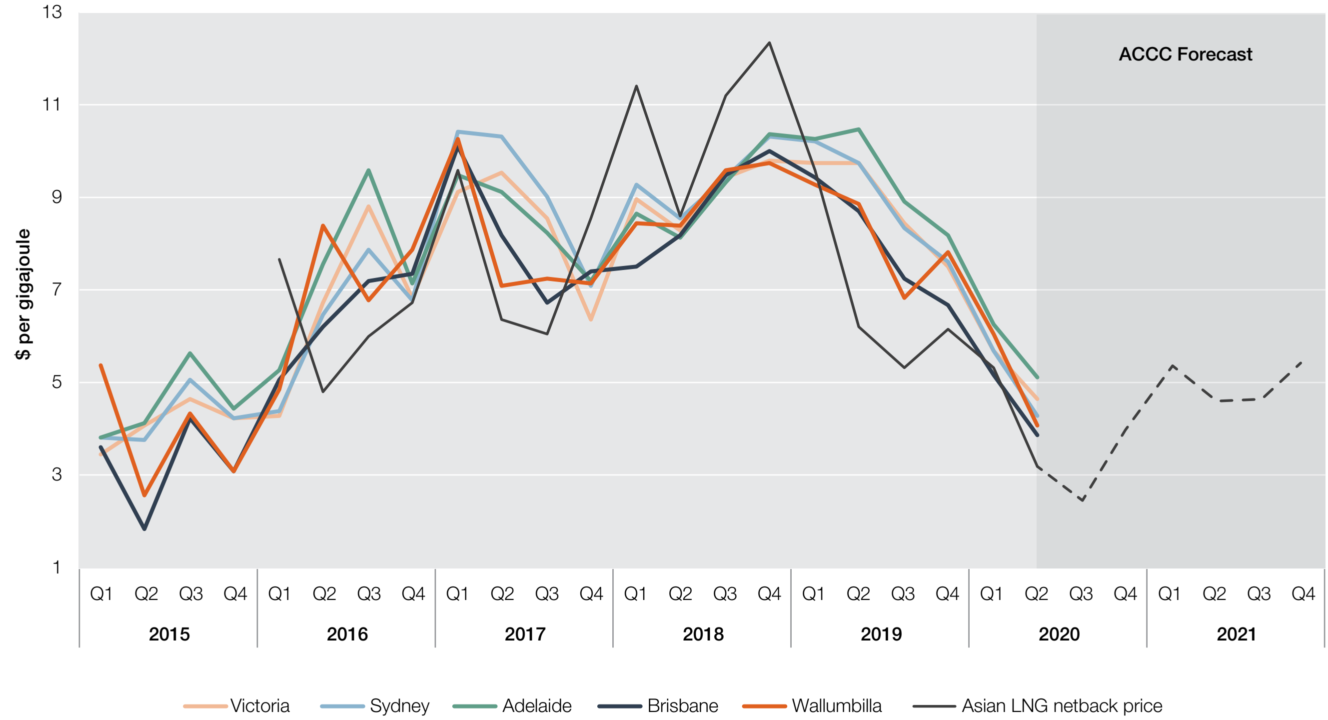
31 Bloomberg, Oil Price War ends with historic OPEC+ deal to slash output, https://www.bloomberg.com/news/articles/2020-04-12/oil-price-war-ends-with-historic-opec-deal-to-cut-production, 13 April 2020, accessed 16 July 2020.

Lower LNG spot cargo prices will continue to influence holders of oil price linked term contracts, with buyers seeking to defer term deliveries if they can substitute for spot cargoes. These parties will also look to renegotiate term contract prices and 'slopes' or 'linkages' in oil-linked gas contracts.[32]

Domestically, gas spot prices fell between 25 per cent in Brisbane and 18 per cent in Adelaide from Q1 2020. With the exception of the Wallumbilla price, this was the sixth consecutive quarter in a row of spot price falls in the domestic market. From Q2 2019 to Q2 2020 average domestic spot prices have declined 54 per cent, varying between a low of $3.89 per GJ in Brisbane to a high of $5.13 per GJ in Adelaide (figure 2.2).[33] The daily minimum price reached for this quarter was $3.37 per GJ in Victoria, $2.67 per GJ in Sydney, $3 per GJ in Brisbane and $4.10 per GJ in Adelaide.

In general, falling wholesale spot prices may not result in immediate declines in retail market offers. Gas traded in wholesale spot markets accounted for between 5 to 19 per cent of total gas market consumption last financial year (section 2.7). Larger volumes of gas were bought or sold through longer term bilateral contracts. As the east coast has linked to global markets, global pricing has entered into long term contracts with the ACCC reporting some domestic contracts featuring oil-linked or Asian spot pricing. Current reductions in east coast wholesale spot prices, along with declining global gas and oil prices, provide a strong indicator of overall falling wholesale costs which would be expected to be passed on to consumers over time.

**Figure 2.2 Domestic spot prices and Asian LNG spot netback price**




Source: AER analysis using DWGM, STTM and WGSH data, and ACCC netback price series.

Note: Wallumbilla hub is the exchange traded day ahead price. Victoria is daily imbalance price at 6:00am. Sydney, Adelaide and Brisbane are ex ante prices. The Moomba hub has not been included, given it sees very few trades.

Notably, continued falls in international LNG prices coincided with further falls in domestic prices. In our *Wholesale markets quarterly Q1 2020* we conducted a correlation analysis between the Asian LNG netback price and domestic prices.[34] Updated analysis indicates a moderate to high degree of correlation between the Queensland spot prices and the Asian LNG netback price over the last 18 months. Sustained Queensland production, along with increased production from Moomba, also continued to support lower domestic prices.

32 Gas prices may typically vary at between 10 to 14 per cent of the price of oil under these contracts (figure 2.1).

33 Three separate types of markets for gas operate in eastern Australia. The Gas Supply Hubs (GSH) at Wallumbilla and Moomba are 'upstream' exchanges for the wholesale trading of natural gas. The Short Term Trading Markets (STTM) in Brisbane, Sydney and Adelaide, and the Declared Wholesale Gas Market (DWGM) in Victoria are 'downstream' markets for managing the imbalance of gas consumption and demand.

34 AER, *Wholesale markets quarterly Q1 2020*, https://www.aer.gov.au/wholesale-markets/market-performance/wholesale-markets-quarterly-q1-2020, 18 May 2020.

The price gap between the northern and southern markets over Q2 2020 widened slightly compared to Q1 2020 as southern demand picked up over winter, drawing imports from the north and some gas from the Iona storage (figure 2.3). The price gap is, however, significantly smaller compared to the same quarter last year with a difference of only $0.69 per GJ for Q2 2020 compared to $1.18 per GJ in Q2 2019.[35] With the narrowing of the price gap between the northern and southern markets, less arbitrage opportunities existed for participants to move gas south including using day ahead transportation through the Day Ahead Auction (DAA).[36] We examine the success of the auction since it commenced in March 2019 in more detail in our focus story.

**Figure 2.3 North-South commodity price gap**


Source: AER analysis using DWGM, STTM and WGSH price data.

Note: If the price gap is positive the southern price is higher than the northern price. If the price gap is negative the southern price is lower than the northern price.

## 2.2 Another record year for Queensland production

| | | PRODUCTION AND STORAGE | | | |
|---|---|---|---|---|---|
| | | FY 16/17 | FY 17/18 | FY 18/19 | FY 19/20 |
| Production, PJ | Northern | 1 334 | 1 415 | 1 504 | 1 630 |
| | Southern | 427 | 390 | 348 | 319 |
| | Total | 1 760 | 1 805 | 1 852 | 1 948 |
| Average gas storage level, PJ | | N/A | N/A | 98.6 | 95.2 |

Note: Data for storage is not continuous, as new storage facilities have been added since 16/17.

Total east coast gas production reached a record 1948 petajoules (PJ) over 2019–20, increasing 5.2 per cent since 2018–19 despite lower gas prices. The increase was driven by larger Queensland gas plant output, outweighing continued declines in production from Victorian plants. The ongoing depletion of Victorian gas fields has been identified, by AEMO and the ACCC, as a risk to gas power generation availability in 2023–24.[37] Dependency on gas powered generators may increase in southern markets following closure of the Liddell power station in NSW across 2022–23. This may correspond with growing supply uncertainty, with production forecast to be increasingly sourced from undeveloped gas fields to meet future demand.[38]

35 Northern markets refers to the Wallumbilla (Queensland) Gas Supply Hub and Moomba (South Australia) Gas Supply Hub Exchanges and the Brisbane STTM. Southern markets refers to the Sydney and Adelaide STTMs, and the Victorian DWGM. There is only one transmission pipeline for gas connecting the northern and southern markets, which allows price gaps to develop from time to time.

36 The Day Ahead Auction is a mandatory auction of unused pipeline or compressor capacity on qualifying facilities, with a reserve price of zero dollars.

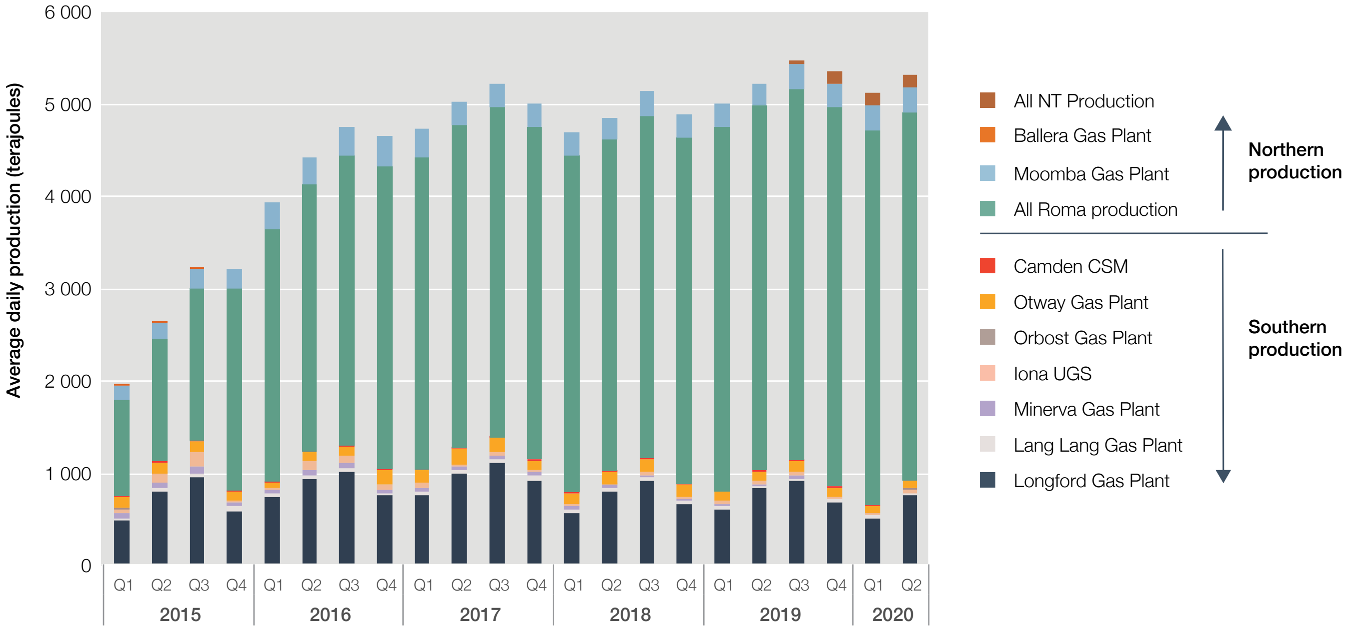
37 AEMO, *Gas Statement of Opportunities*, March 2020, pp. 10–11; ACCC, *Gas inquiry report*, January 2020, p. 12.

38 AEMO, *Gas Statement of Opportunities*, March 2020, pp. 9–10.

Production increased from Q1 2020 to Q2 2020, as the market moved into the winter peak demand period to meet residential heating demand, particularly in Victoria. The Longford gas plant in Victoria significantly increased production, from 497 terajoules (TJ) in Q1 to 745 TJ per day in Q2 but well down from the 824 TJ per day it produced in Q2 2019. Production from Queensland's Roma region (source of gas for LNG export) declined slightly from 4073 to 4000 TJ per day. Quarterly production from Roma reached a record 4126 TJ per day in Q4 2019 and the subsequent declines reflect low seasonal demand for LNG and the impacts of COVID-19 on international markets—see COVID Focus Story.

Northern Territory production facilities are now required to report production levels, following pipeline interconnection with the east coast in early 2019. Gas has consistently flowed from the Northern Territory into Queensland during this time, with quarterly production in the Northern Territory averaging around 95 TJ per day since Q4 2019 (figure 2.4). In Victoria, the Orbost facility restarted in Q2 2020 after being decommissioned in 2015, producing 22 TJ per day. The Orbost facility has capacity to produce 67 TJ per day but has been constrained following delayed commissioning due to the bushfires over summer.[39]

**Figure 2.4 East coast production**




Source: AER analysis using Natural Gas Services Bulletin Board data.

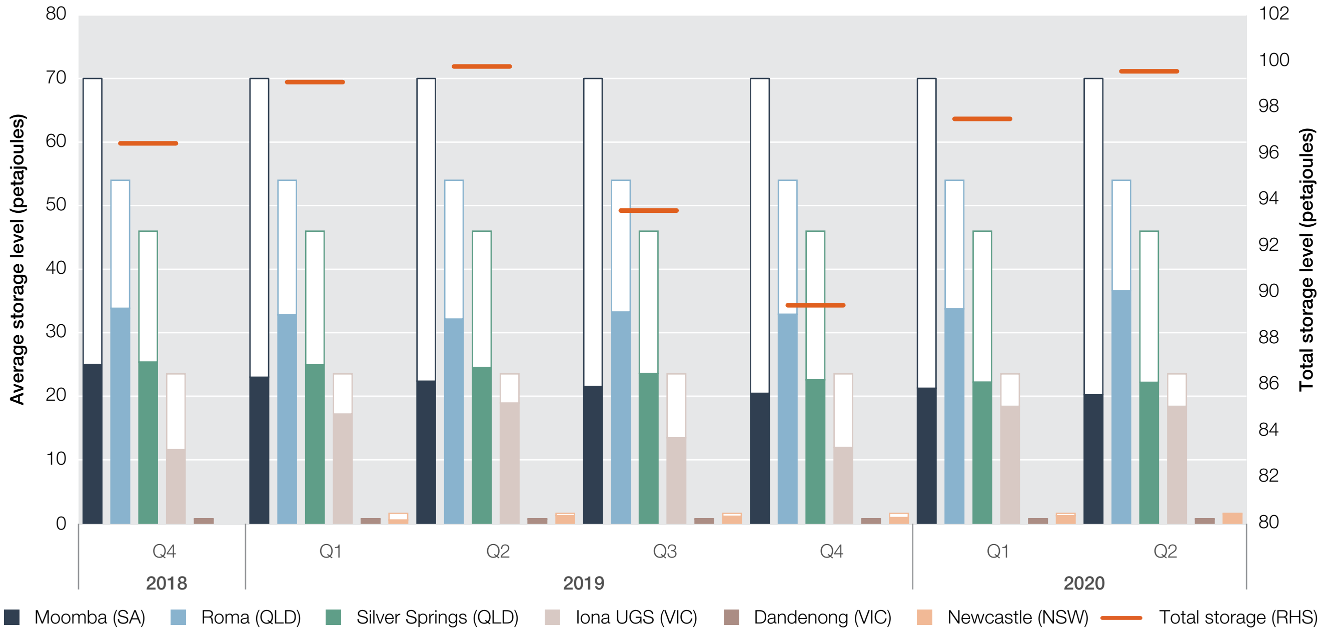
Average storage levels reached 95.2 PJ in 2019–20, declining 3.4 PJ since 2018–19 and reflecting continued declines at the large Moomba and Silver Springs facilities. This was partially offset by filling at Gladstone LNG's (GLNG) Roma underground storage facility in Queensland, which held 34.2 PJ at the end of 2019–20, an increase of 1.6 PJ from the end of 2018–19.

The gas held at the Roma storage facility has increased significantly since the end of Q1 2020. GLNG reported storage levels of 34.8 PJ on 1 April, 39.9 PJ on 1 July and 42.7 PJ on 1 August, as the storage quickly filled toward its nameplate rating of 54 PJ (figure 2.5).

This increase in storage and lower Wallumbilla trade indicates that increasingly low prices (under $4 per GJ at Wallumbilla) incentivised storage of gas rather than sales. The Roma storage facility is located close to major gas fields operated by LNG export projects.

39 APA, Orbost Gas Plant upgrade, https://www.apa.com.au/about-apa/our-projects/orbost-gas-plant-upgrade/, accessed 28 July 2020.

## Figure 2.5 Storage levels




Source: AER analysis using Natural Gas Services Bulletin Board data.

Note: Storage levels are averages across a quarter.

# 2.3 Record year of Queensland LNG exports despite COVID

| | | LNG EXPORT | | | |
|---|---|---|---|---|---|
| | | FY 16/17 | FY 17/18 | FY 18/19 | FY 19/20 |
| LNG export, PJ | | 1 055 | 1 105 | 1 173 | 1 203 |
| Number of cargoes | | 301 | 313 | 323 | 335 |
| Destination breakdown, PJ | China | 511 | 732 | 846 | 825 |
| | Korea | 233 | 181 | 151 | 177 |
| | Japan | 148 | 126 | 73 | 68 |
| | Malaysia | 27 | 38 | 78 | 104 |
| | Other | 136 | 29 | 25 | 29 |

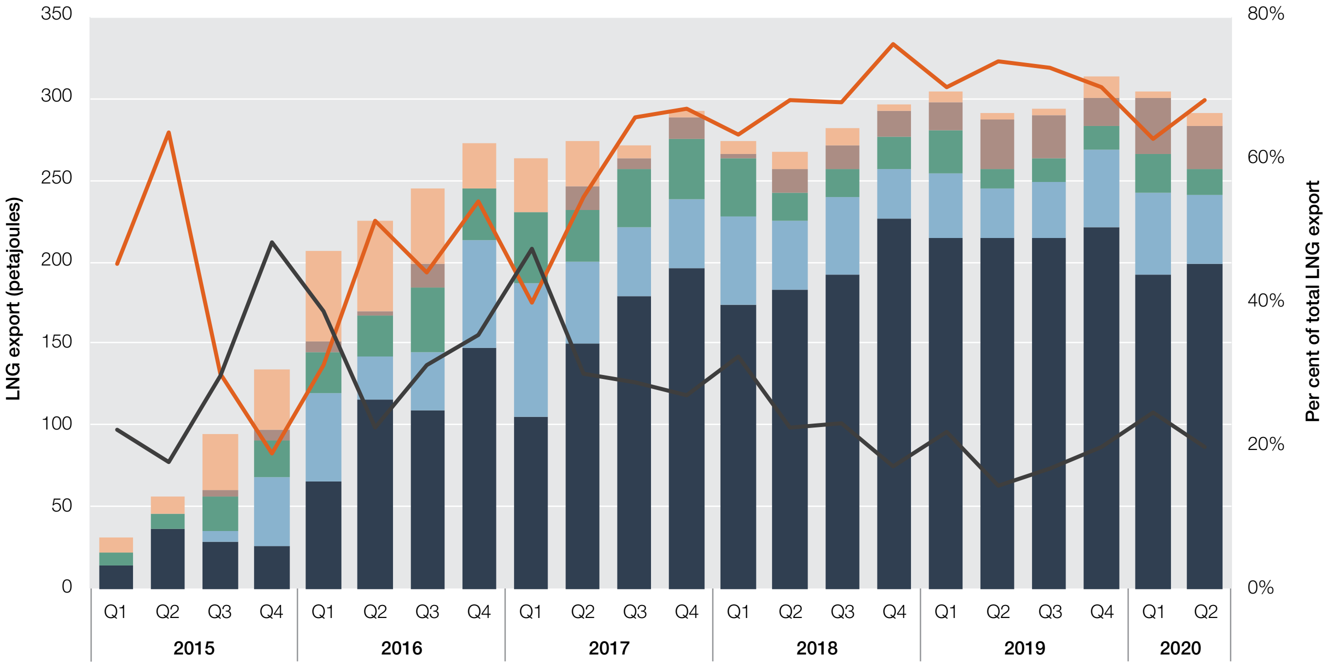
Queensland LNG exports increased to a record high of 1203 PJ in 2019–20, a rise of 2.5 per cent on 2018–19 export volumes, despite plummeting international and domestic prices. Australia remained among the two largest exporters of LNG globally, generating an estimated revenue of $47 billion in 2019–20.[40] Over the financial year, China's reduced LNG imports was offset by higher demand from South Korea and Malaysia from 2018–19 to 2019–20. A number of Asian countries have pursued policies to use more gas instead of coal for electricity generation to reduce carbon emissions.[41]

Queensland LNG exports have been relatively unaffected by the effects of COVID-19, which has reduced demand for LNG and led to reduced exports from other major exporting countries. China remains the most significant buyer of Queensland LNG and recorded an increase in imports from 192 PJ in Q1 2020 to 199 PJ in Q2 2020 (figure 2.6). This contrasts with a quarterly decline in LNG imports from other Asian customers, which may reflect the effects of reduced demand as a result of COVID-19—see Focus story. LNG export volumes in Q2 2020 were very similar to Q2 2019, with maintenance occurring over the April to June period in both years.

40 DISER *Resources and energy quarterly, June 2020*, p. 68.

41 DISER *Resources and energy quarterly, June 2020*, p. 70; EIA, EIA projects that natural gas consumption in Asia will continue to outpace supply, https://www.eia.gov/todayinenergy/detail.php?id=41795, sourced 31 July 2020.

Figure 2.6 LNG shipped from Gladstone Port by destination




Source: AER analysis using Gladstone Port Corporation data.

## 2.4 Gas Supply Hub trade volume drops in Q2 2020 as prices fall

| | GAS SUPPLY HUBS | | |
|---|---|---|---|
| | FY 17/18 | FY 18/19 | FY 19/20 |
| Number of trades | 2 054 | 2 855 | 3 199 |
| Trade volume, PJ | 14.2 | 24 | 24 |
| Volume weighted average price, $/GJ | 7.59 | 9.22 | 5.93 |

Source: AER analysis using GSH trades data.

Note: Results shown for all locations, products and trade types, excluding capacity trades.

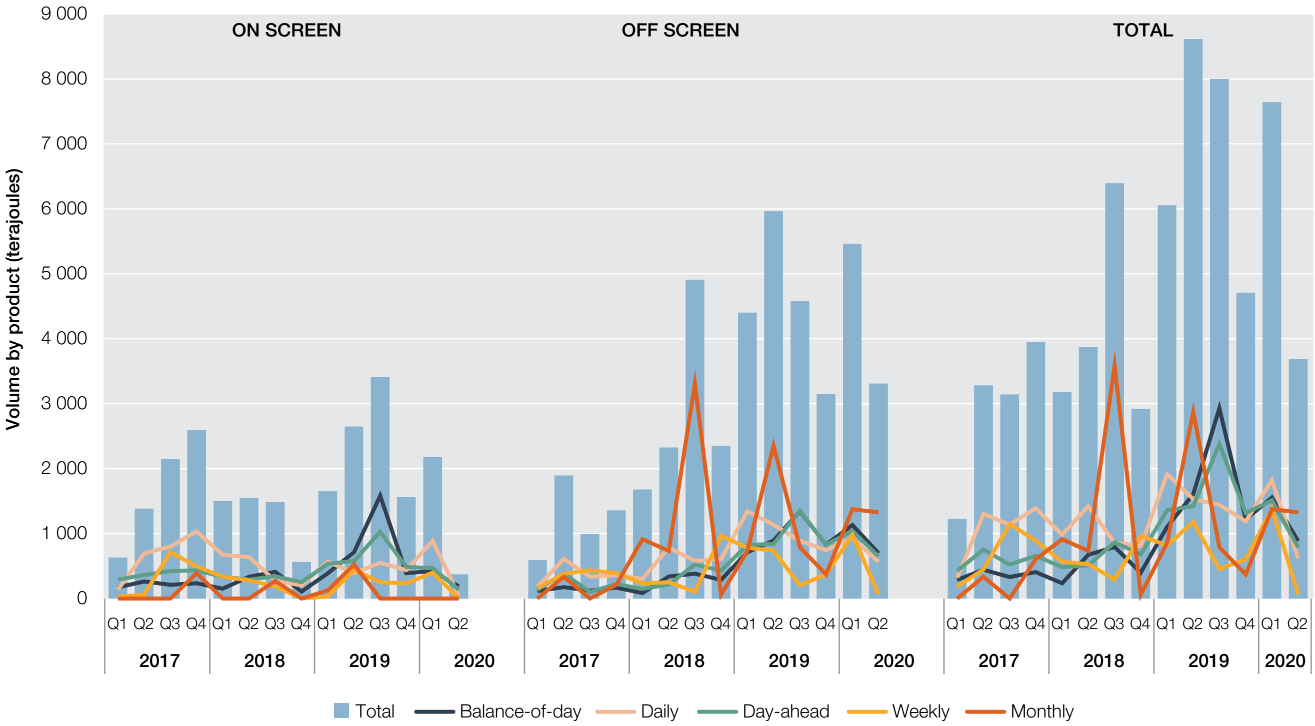
Traded volume at the Gas Supply Hubs (GSH) remained steady for the 2019–20 financial year despite significant falls in trade this quarter as prices fell.

Overall, as trade fell this quarter participants pivoted further towards trading off screen.[42] Comparatively, Q2 2020 amounted for about half the volume traded in Q2 2019 (figure 2.7). Both on and off screen trading fell, with just over 534 transactions representing a total of nearly 3700 TJ of gas. For on screen trading in particular, this was the lowest volume of gas traded at the GSH since Q2 2016. By volume, on screen, balance of day and day ahead products traded at about a quarter of Q2 2019 levels, and daily products were around 87 per cent down.[43] There were no on screen trades in weekly or monthly products.

42 Participants using the GSH can lodge trades either 'on screen' or 'off screen'. On screen trades are matched anonymously through the GSH trading platform. Off screen trades are agreed to by participants separately and then lodged through the hub for settlement. 'Off market' trades do not use GSH platform at all.

43 There are five standard product lengths that participants can use when trading at the GSH: balance of day, daily, day ahead, weekly and monthly.

Figure 2.7 Gas Supply Hub—On and off screen trade volumes by product

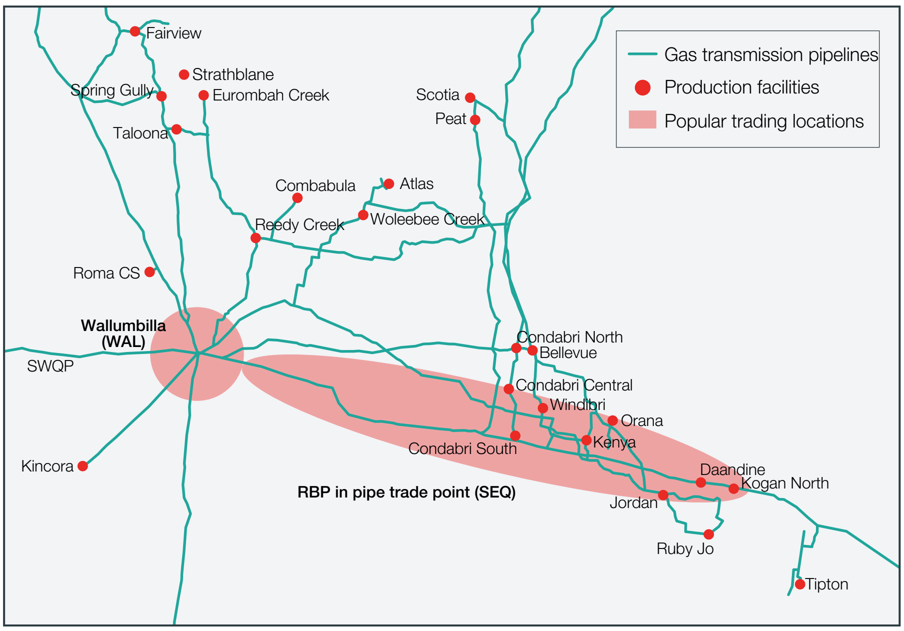



Source: AER analysis using GSH trades data.

Off screen, traded volumes did not fall to the same degree, due to significant volumes in monthly products trading towards the end of the quarter. For most products, traded quantities fell by around 20 to 50 per cent compared to Q2 2019 levels. The notable exception was in weekly products, which fell by more than 90 per cent to the lowest volume traded since Q2 2016.

While trade at all locations was reduced this quarter, gas traded at the South East Queensland (SEQ) location was notably down to the lowest levels since its introduction in Q1 2017. The GSH facilitates trade across a number of pipelines, which we group into three locations: Moomba, South Australia; Wallumbilla, Queensland (WAL); and a separate SEQ product traded at the Wallumbilla hub, which provides virtual delivery into the Roma to Brisbane Pipeline (RBP—figure 2.8). This separation is valuable as it allows several large, closely clustered gas production facilities to connect easily into the Wallumbilla hub via the RBP. This makes it a popular trading location.

Figure 2.8 Wallumbilla hub and notional trading points




Source: AER analysis, GEOScience Australia.

A contributing factor to the sharp decline in trade at SEQ is the reduction in spread products traded this quarter. Spread trades are connected trades across different locations, mostly between SEQ and WAL. These trades facilitate the movement of gas from the fields east of Wallumbilla to the South West Queensland Pipeline (SWQP) on the western side of the hub.

Participants noted that as prices have fallen, so too has the opportunity to arbitrage by shipping cheaper northern gas south. This resulted in lower trade volumes on the GSH this quarter. In addition, it is likely that the lower prices also impacted incentives to sell gas now, with participants diverting more gas into to storage this quarter (section 2.2).

There were no new participants this quarter. However, three previously active participants did not trade, bringing the number of active participants to 14. It remains to be seen whether these participants are exiting the market, or are just reducing trade activity this quarter to reflect the prevailing conditions. Ten of the 14 traded actively on screen, while all 14 were active off screen.[44]

The Wallumbilla hub churn rate for the 2019–20 financial year rose to 8.5 per cent up marginally from the year before.[45] However, this growth masks the decline in Q2 2020 as the Wallumbilla hub churn rate dropped to 5.8 per cent this quarter. While regional gas flows fell slightly, the quantity traded through the hub fell further on a proportional basis as participants chose to conduct less trades through the GSH.

Finally, this quarter the volume-weighted average price for the GSH fell to $3.85 per GJ, the lowest level since Q4 2015.[46] Our Q1 2020 report examined the emergence of higher priced on screen products since Q4 2019. While on screen prices continued to remain higher this quarter, the price difference narrowed significantly, with just 6 cents between on and off screen prices ($3.90 and $3.84 per GJ respectively), compared to around 30 cents difference observed previously.

This narrowing is due in part to the significant fall in trades at SEQ, the cheapest Wallumbilla location. However, circumstances this quarter may be reflecting broader events, and this is something we will continue to monitor.

We present further statistics on the GSH in the Appendix.

## 2.5 Day Ahead Auction competition rises driving higher prices and increased utilisation

Participation in the DAA, which commenced in March 2019, continued to rise in Q2 2020, with three new participants winning capacity for the first time bringing the total number of active participants to 15 for the 2019–20 financial year.

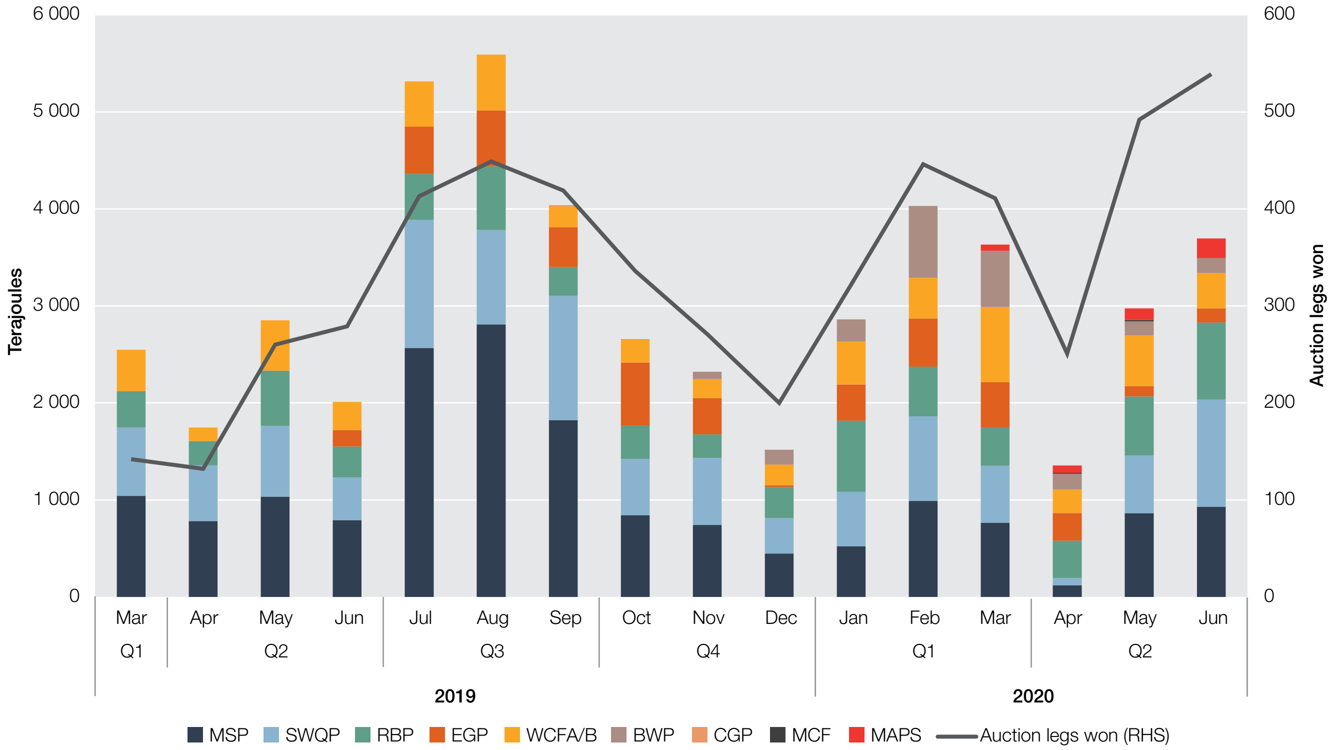
A total of 8.0 PJ of unused contracted pipeline capacity was won across nine facilities in the quarter, with capacity won on the Moomba to Adelaide Pipeline System (MAPS) continuing to increase each month as the quarter progressed (figure 2.9). Capacity was also won at Wallumbilla Compression Facility A (WCFA) this quarter after 12 months of no auction activity.

44 We consider a participant “active” if they make at least a number of trades equal to the number of months in the quarter (three) or year (12).

45 The churn rate refers to the total trade through the gas supply hubs as a proportion of total regional bulletin board gas flows.

46 Averaged across all prices, products and locations.

**Figure 2.9 Pipeline capacity won on the Day Ahead Auction**




Source: AER analysis using DAA auction results data.

Note: Quantities shown are the monthly sum of auction products allocated on each pipeline and do not necessarily represent the physical volumes of gas actually flowed for each gas day.

April 2020 saw the lowest monthly total of capacity won since the commencement of the auction, primarily caused by an apparent decrease in the need to use auction capacity to transport gas from northern to southern markets on the South West Queensland Pipeline (SWQP) and the Moomba to Sydney Pipeline (MSP).

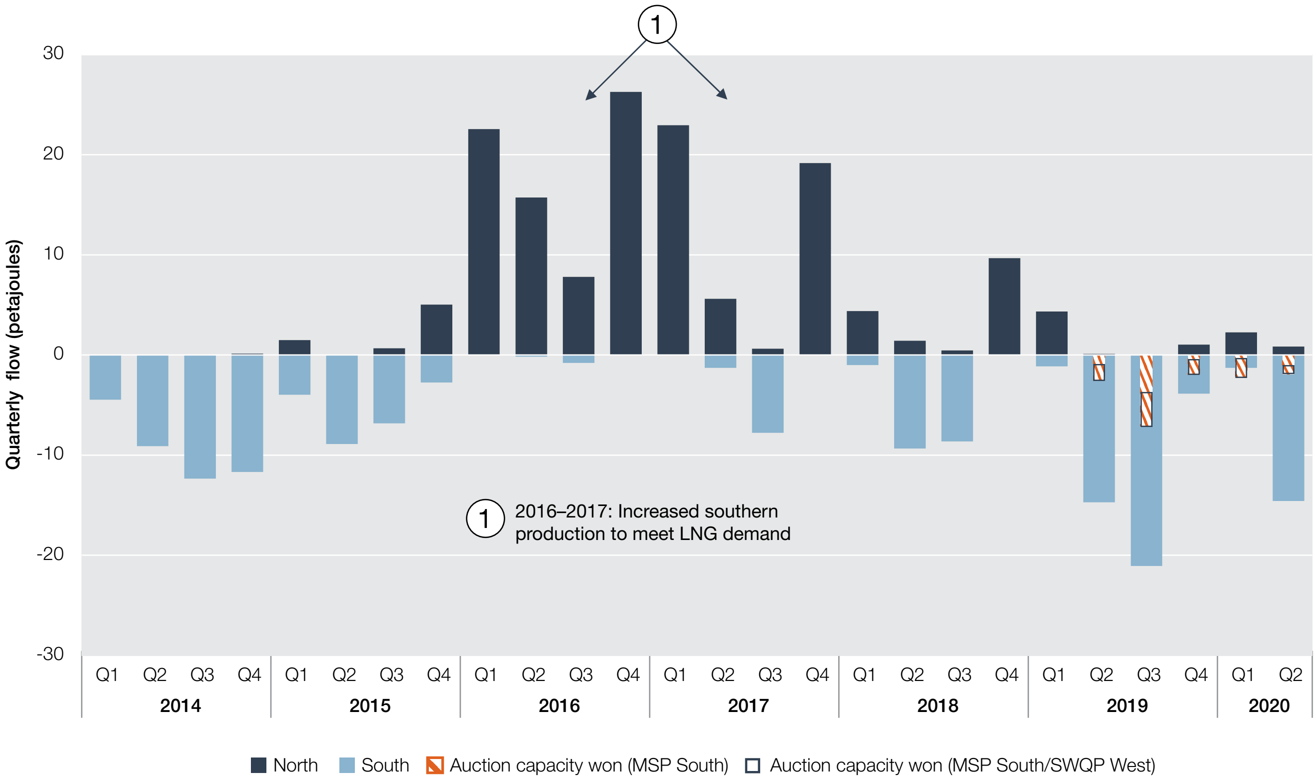
However, the remainder of the quarter saw increases in capacity won on facilities used to transport gas south, with increased competition between participants resulting in a record auction price of $1.26 per GJ for capacity won on the MSP for gas day 26 June 2020. High prices for capacity won on the MSP were observed throughout June 2020, with auction prices between $0.44 and $1.26 per GJ on all days except one, leading to record auction proceeds on this facility for the quarter. Auction limits were reached on the MSP on 41 days in Q2 2020 compared to just five days in Q1 2020, further highlighting the increase in competition on this pipeline this quarter. This was despite the number of participants bidding for capacity decreasing from nine to eight.

An overview of the first 16 months of operation is one of our focus stories this quarter with further statistics on the DAA—the east coast's newest market—set out in an infographic in the Appendix.

## 2.6 Victorian gas exports continue to decline with northern production continuing to flow south

The net gas flow from north to south was 13.8 PJ in Q2 2020, compared to 14.6 PJ for the same quarter last year. Unlike last year, some small quantities of gas flowed north on a number of days (figure 2.10). In June, there were record high flow rates on the SWQP with flows south peaking at 386 TJ per day. Gas transported via the DAA made up 13 per cent of the total flow south.

**Figure 2.10 North-South gas flows**

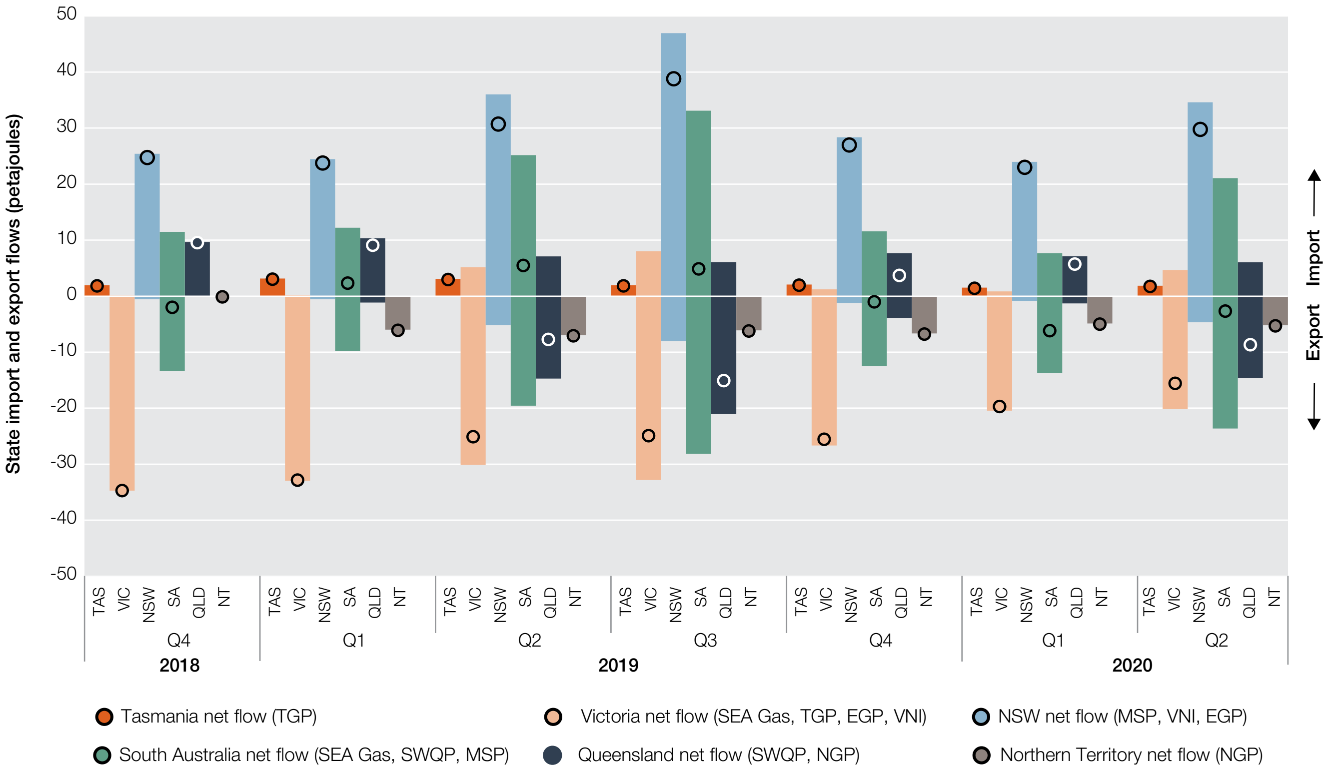



Source: AER analysis using the Natural Gas Services Bulletin Board and DAA auction results data.

Note: North-South flows depict net physical flows around Moomba—north or south. MSP South/SWQP West is a subset of MSP South auction quantities showing auction volumes linked to longer haulage from Wallumbilla.

South Australia has now been a net exporter for three quarters in a row, after importing on a net basis for the previous three quarters (figure 2.11). The stronger production levels in recent quarters from Moomba and a reduction in South Australian gas powered generation (GPG) demand led to South Australia exporting 2.6 PJ of gas on a net basis in Q2 2020. This is a significant change compared to importing 5.6 PJ of gas on a net basis during the same quarter last year.

## Figure 2.11 Interstate gas flows




Source: AER analysis using the Natural Gas Services Bulletin Board data.

Note: TGP—Tasmania Gas Pipeline; SEA Gas—includes the Port Campbell Iona Pipeline and the Port Campbell Adelaide Pipeline; MSP—Moomba to Sydney Pipeline; EGP—Eastern Gas Pipeline; VNI—Victoria-NSW interconnector; SWQP—South West Queensland Pipeline; NGP—Northern Gas Pipeline.

Queensland exported marginally more gas on a net basis this quarter, increasing from 7.6 PJ in Q2 2019 to 8.5 PJ in Q2 2020. This occurred despite a reduction in Northern Territory imports requiring more local production to meet Mt Isa demand.[47] Combined with a small increase in Mt Isa demand compared to Q2 2019, this meant that 2.5 PJ of gas flowed north on the Carpentaria Gas Pipeline (CGP) in Q2 2020.[48]

NSW remained a strong net importer of gas in Q2 2020, importing 29.9 PJ compared to 30.9 PJ for the same quarter last year. With imports from Victoria declining further in this quarter, 22.8 PJ of gas was imported to NSW on the MSP, an increase of 3.4 PJ compared Q2 2019. With flows south from Queensland to Moomba on the SWQP, and flows south from Moomba to Adelaide remaining similar to last year, the increase on the MSP flow south was driven largely by an increase in production at Moomba of 3.9 PJ in this quarter.

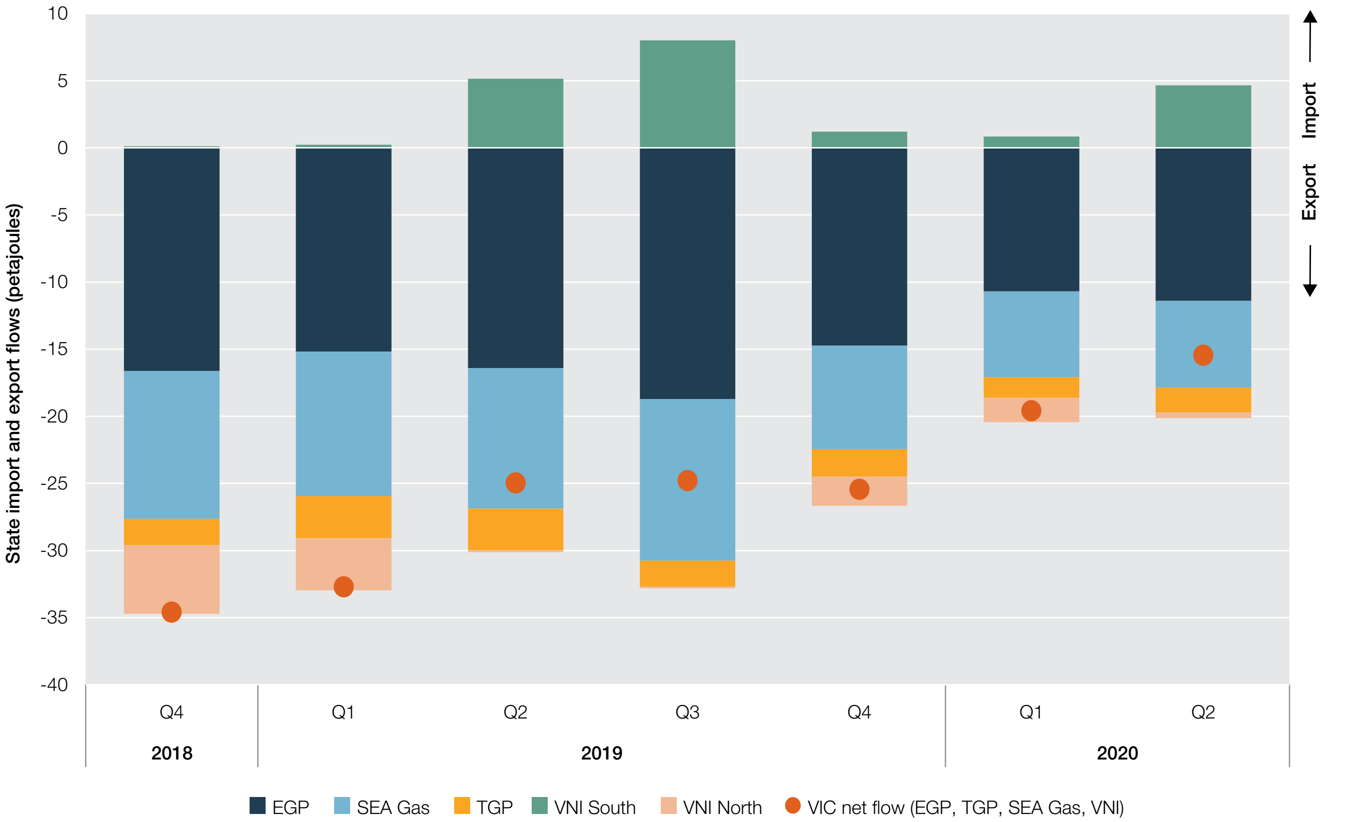
Net gas exported from Victoria in this quarter was 15.5 PJ continuing a downward trend reducing by 4.1 PJ from Q1 2020 and 9.5 PJ compared to Q2 2019 (figure 2.12). This continued reduction in gas exports from Victoria is largely due to continued declines in overall quarterly production of 10 PJ compared to last year. The majority of this reduced production occurred at Longford (7.2 PJ). Victorian Q2 gas demand marginally declined from 67.2 PJ in 2019 to 66.7 PJ this year, highlighting that reduced production has directly impacted gas exports from Victoria.[49]

47 The gas imported from the Northern Territory through the Northern Gas Pipeline is mostly used in the Mt Isa region in Queensland that is connected to the rest of the east coast Gas market through the CGP.

48 See map at front of chapter for the location of Mt Isa and pipelines.

49 Victorian gas demand is defined as the difference between all production and net gas exported interstate.

Figure 2.12 Victoria import and export gas flows




Source: AER analysis using the Natural Gas Services Bulletin Board data.

Export flows on the Eastern Gas Pipeline (EGP), Tasmanian Gas Pipeline (TGP) and South East Australia Gas Pipeline (SEA Gas) all decreased between Q2 2019 and Q2 2020.[50] The EGP flow to NSW decreased by 5 PJ, the flow on SEA Gas to South Australia decreased by 4 PJ and the flow on the TGP to Tasmania decreased by 1.2 PJ. The net gas flowing south on the Victoria to NSW interconnector (VNI) reduced from 5 PJ in Q2 2019 to 4.2 PJ in Q2 2020.[51] This gas flows directly from the northern production fields at Moomba and Queensland underscoring the importance these producers play in meeting demand in the southern states.

## 2.7 Producers and traders drive spot trade to new highs in Victoria and Sydney

| SPOT MARKET OUTCOMES | | FY 16/17 | FY 17/18 | FY 18/19 | FY 19/20 |
|---|---|---|---|---|---|
| Total net market trade volume, PJ | VIC | 17.7 | 16.2 | 20.8 | 24.8 |
| | SYD | 8.0 | 8.1 | 12.5 | 16.7 |
| | ADL | 3.5 | 3.5 | 3.8 | 3.9 |
| | BRI | 1.3 | 1.4 | 1.2 | 1.8 |
| Spot trade as a proportion of scheduled demand (%) | VIC | 7% | 6% | 9% | 10% |
| | SYD | 9% | 9% | 14% | 19% |
| | ADL | 15% | 16% | 18% | 18% |
| | BRI | 4% | 4% | 4% | 5% |

The Short Term Trading Markets (STTM) are markets for trading natural gas at the wholesale level between pipelines and distribution systems at defined hubs in Sydney, Brisbane and Adelaide. They operate under slightly different rules to the more frequently traded Victorian Delcared Wholesale Gas Market. These mandatory markets appear to be transitioning from balancing markets where retailers and gentailers have traditionally traded small supply-demand

50 See map at front of chapter for pipeline locations.

51 The VNI links the Victorian gas market with NSW and the northern markets at Culcairn. The net flow of gas through the VNI is mostly south meaning that Victoria is importing gas from the north.

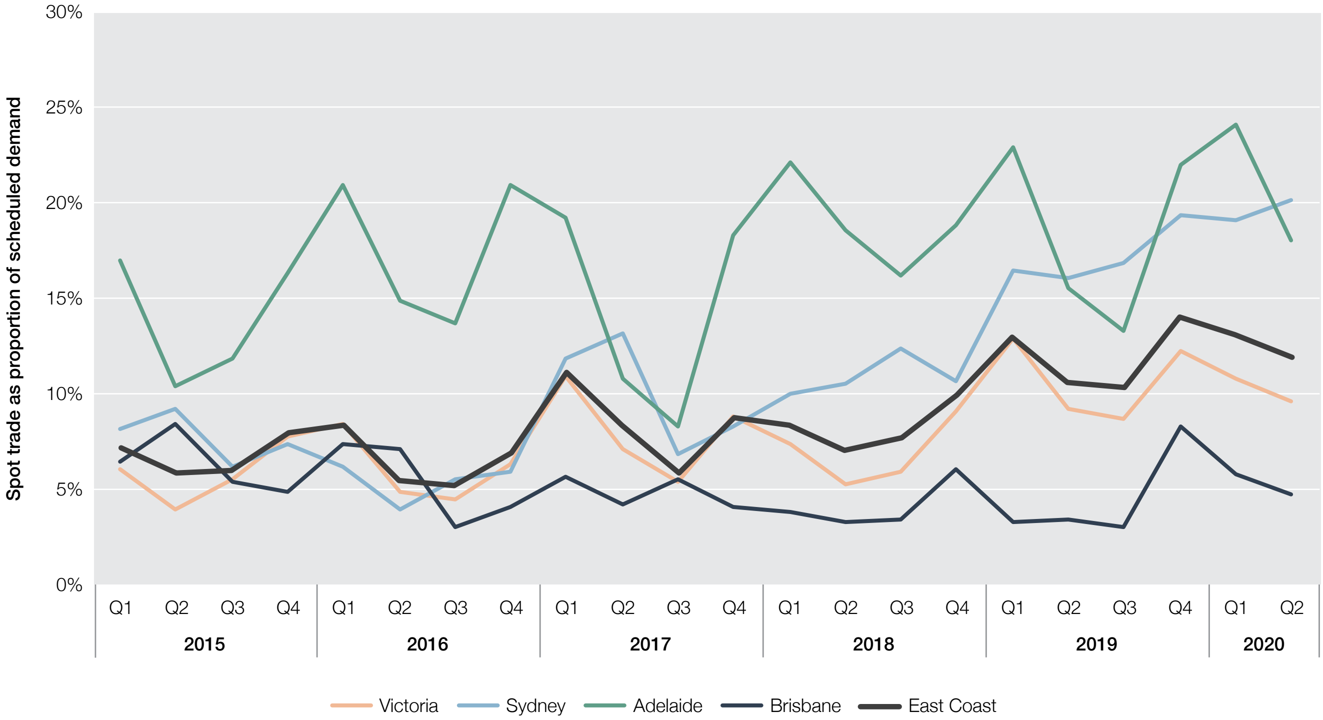
imbalances, to markets where there are a number of largely seller and buyer only participants on each side of the market.

Liquidity in these east coast gas markets maintained an upward trend this quarter, with significant rises in Victoria and Sydney where producers continued to be amongst the top sellers in those markets, along with traders (figure 2.13).[52]

Over 2019–20, close to one fifth of the trading activity in both Adelaide and Sydney occurred through spot market purchases and over 47 PJ of gas was traded across the east coast markets.

Net trades jumped to a record 20 per cent in Q2 2020 in Sydney which is the most actively traded hub in the STTM.

**Figure 2.13 Spot trade liquidity**




Source: AER analysis using STTM and DWGM data.

As domestic prices continued to decline in Q2 2020, participant offers also shifted dramatically with 96 per cent of gas offers scheduled into the Sydney market at less than $4 per GJ compared to only 59 per cent in Q2 2019 (figure 2.14). The last time a similar offer profile was observed was in Q1 2015 when LNG exporters were ramping up production resulting in excess gas flowing to the domestic market.

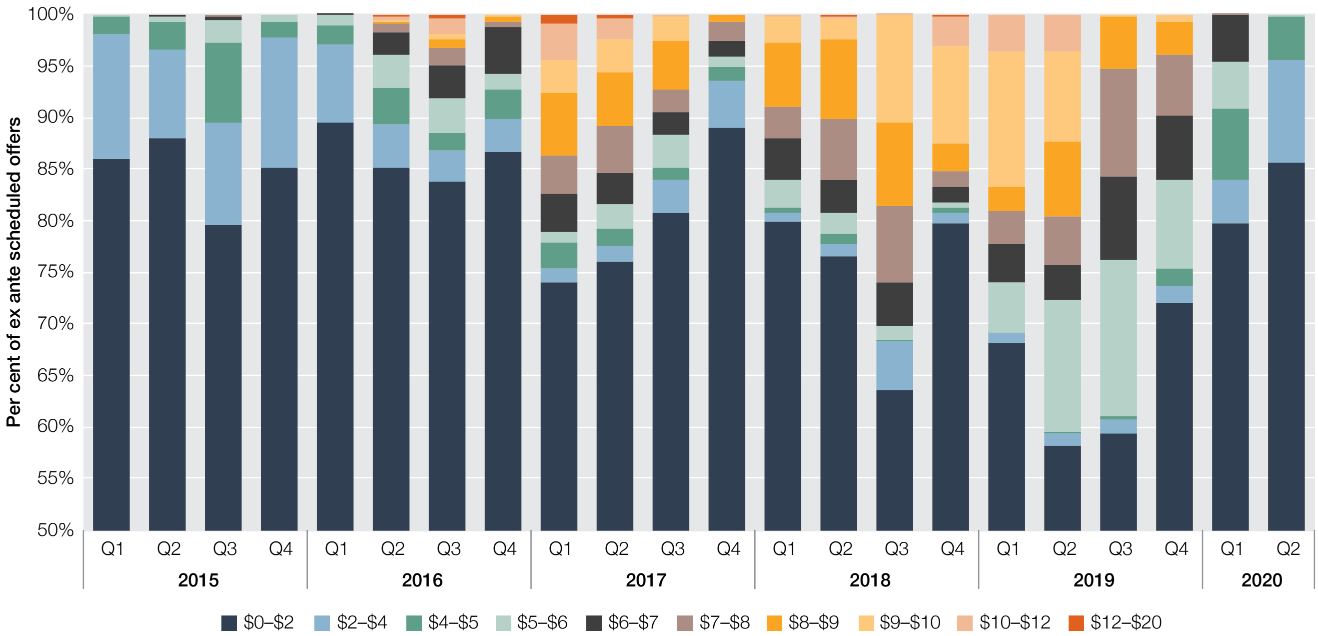
The number of participants offering gas into the Sydney market in the $0–$2 per GJ price band also significantly increased from around 10 participants in 2015 to 24 participants in 2020.

Participants are classified into five groupings for our analysis—GPG Gentailer, Retailer, Industrial, Trader or Exporter/Producer (see Appendix for details of participant grouping).

A notable shift was the increased offers of Exporter/Producers in the $0–$2 per GJ price band making up 15.5 per cent of the total offers in Q2 2020 compared to only 1.9 per cent in Q2 2019. Shell, BHP, Arrow Energy and Santos drove this outcome. In Q2 2020, Santos made up 88 per cent of offers by Exporter/Producers in the $0–$2 per GJ price band compared to only 39 per cent in Q1 2020, while Shell decreased its offers in the $0–$2 per GJ price band from 44 per cent in Q1 2020 to 5 per cent in Q2 2020.

52 While quantities traded were higher, the proportions of total net trades in most markets were lower for Q2 2020, with unusually high demand early in the quarter leading into winter.

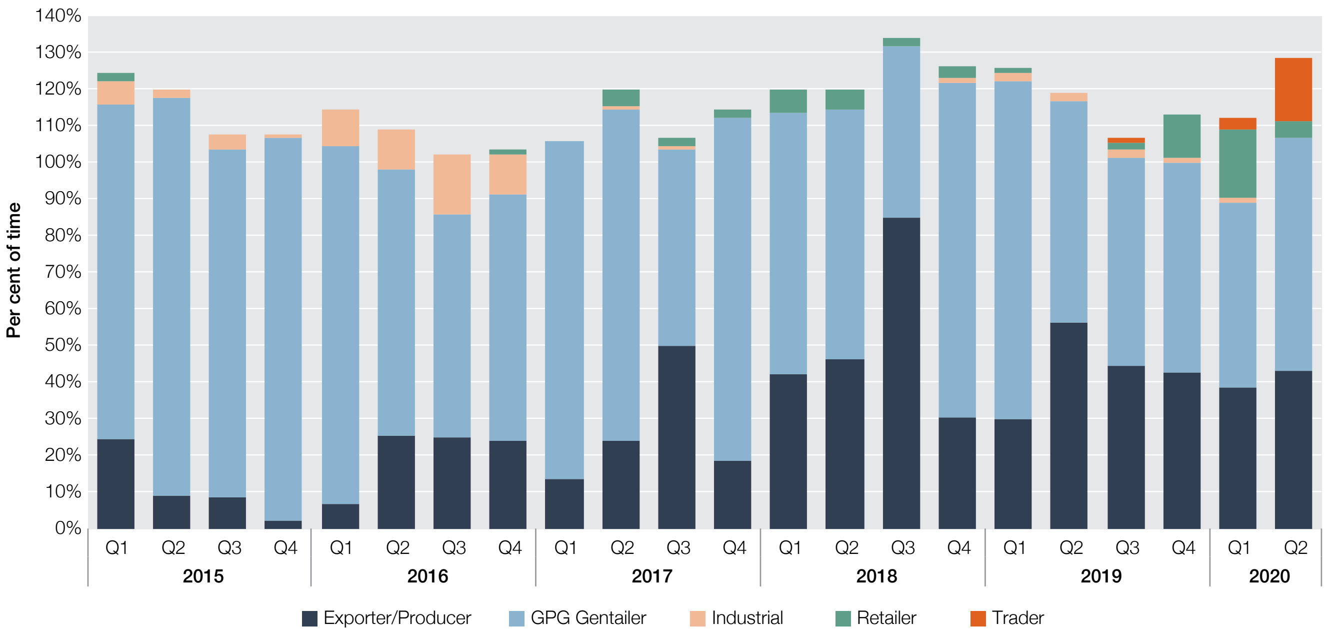
## Figure 2.14 Sydney offer bands




Source: AER analysis using STTM data

Since Q4 2019, Retailers and Traders have started to set the price more often (figure 2.15). However, EnergyAustralia (GPG Gentailer) and Santos (Exporter/Producer) were the most frequent price setters in Q2 2020 with the most frequent market clearing price being $4.50 per GJ.

## Figure 2.15 Sydney marginal price setter breakdown

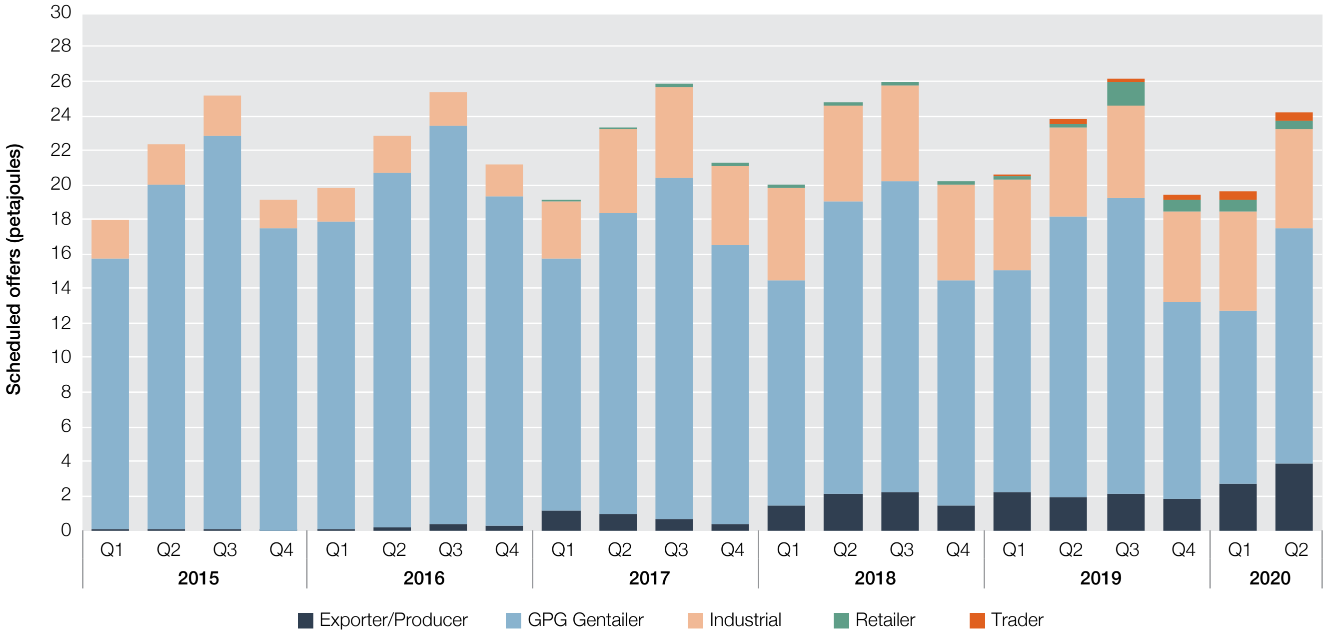



Source: AER analysis using STTM data.

Note: Tied bids at the market clearing price results in price setter totals greater than 100 per cent.

Retailers and Traders set the price 22 per cent of the time in Q2 2020 compared to not at all in the same period last year. This was despite scheduled offer volumes for Retailers and Traders combined only accounting for 4 per cent of the total volume scheduled (figure 2.16). This is an indication of more participants arbitraging gas prices between Wallumbilla in the north and Sydney in the south, supported by their ability to access pipeline capacity through the DAA. Q2 2020 also saw a significant increase in tied bids at the market clearing price. This is indicative of the narrow price bands in which gas was offered with lower overall market prices. The most frequent market clearing price for tied bids was $4 per GJ.

Figure 2.16 Sydney scheduled offers




Source: AER analysis using STTM data.

Since 2017, Exporter/Producers have continued to increase the quantity of gas offered into the Sydney market. This has coincided with more gas flowing from the north to the south by Shell and Santos and after the separation of BHP and Esso's marketing in 2019, BHP has continued to offer gas into the Sydney market from the Gippsland Basin.

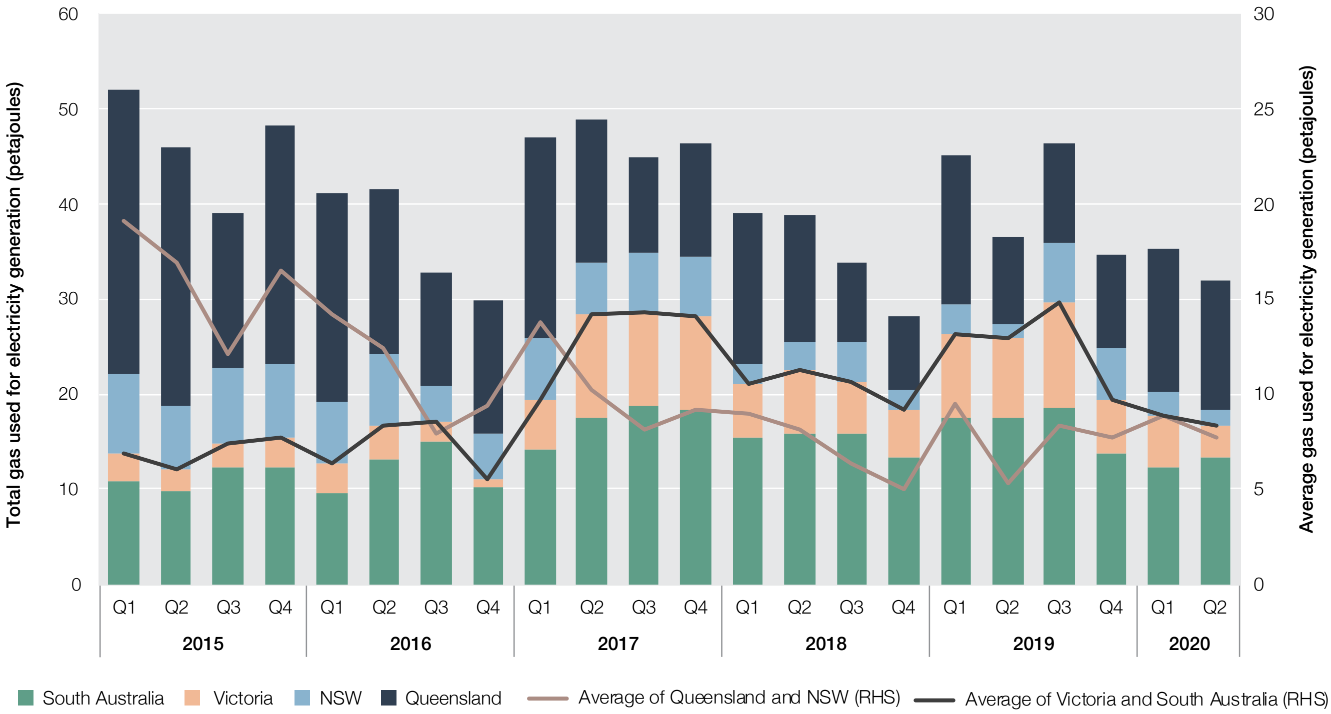
## 2.8 Gas powered generation rises overall after declining for two years

| GAS POWERED GENERATION OUTCOMES | | | | | |
|---|---|---|---|---|---|
| | | FY 16/17 | FY 17/18 | FY 18/19 | FY 19/20 |
| Total GPG, PJ | VIC | 62 | 51 | 41 | 49 |
| | NSW | 21 | 17 | 11 | 16 |
| | SA | 19 | 32 | 28 | 26 |
| | QLD | 56 | 68 | 64 | 58 |
| | TOTAL | 158 | 168 | 144 | 149 |

GPG increased from last financial year, reflecting higher demand in Q3 and Q4 of 2019, lower gas prices, less hydro generation and coal powered generator outages.

Gas demand for electricity generation declined in most regions this quarter and was 4.6 PJ lower than Q2 2019 (figure 2.17). There was an overall downward trend in GPG demand alongside large amounts of renewable capacity being installed in the electricity market. However, a number of baseload generation maintenance outages in Queensland and NSW drove higher levels of gas generation demand than would otherwise have occurred.

Figure 2.17 Gas powered generation




Source: AER analysis using NEM data.

Notes: Gas usage estimates are conversion of electricity generation output using average heat rates (GJ per MWh).

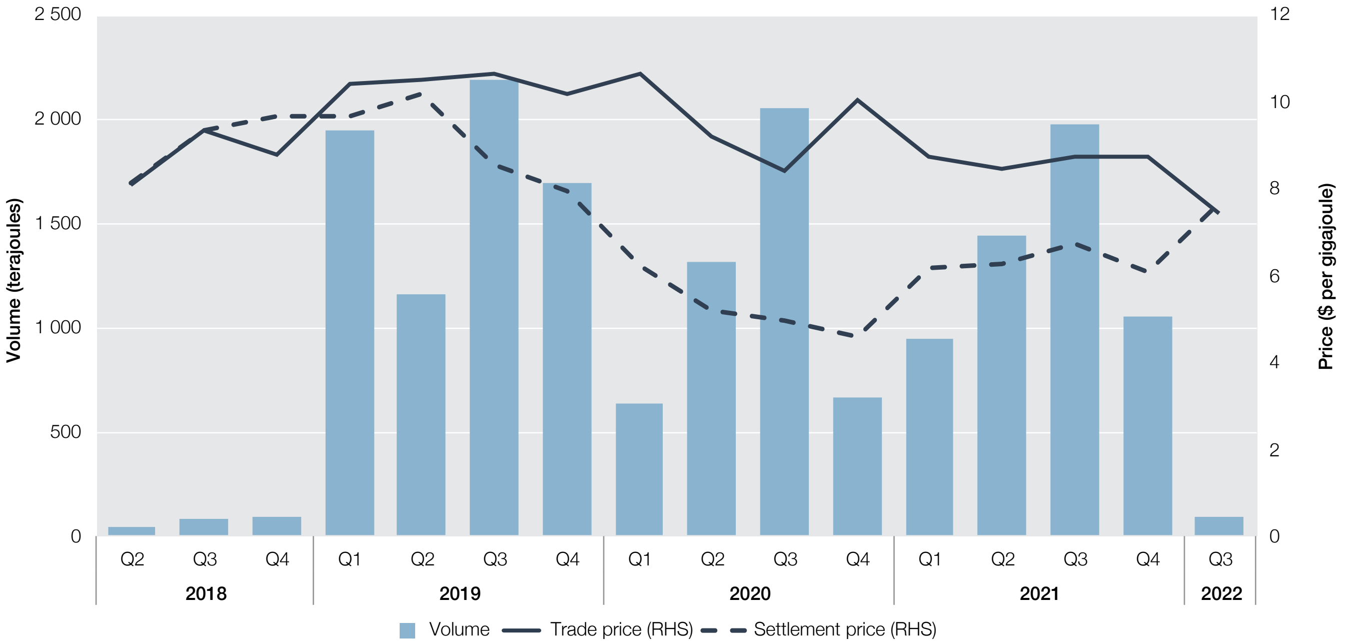
## 2.9 ASX data indicates prices expected to decline in Victoria until 2021

Trade in Victorian gas futures contracts continues to build with the number of quarterly contracts traded increasing from 224 in Q1 to 310 in Q2 2020 (table 2.1). Although Victorian contracts trade increased, it still represents only about 5 per cent of demand in the Victorian market.

Settlement prices indicate expected prices between $4.60 to $5 per GJ in the Victorian spot market over the remainder of 2020, rising to between $6.10 to $6.80 per GJ over 2021 (figure 2.18). The difference between settlement and traded contract prices shows the divergence between actual prices realised and expectations years prior in 2018 and 2019.

The Queensland based Wallumbilla gas futures contract has still not traded since listing in 2014.

Figure 2.18 ASX Victorian futures trade




Source: AER analysis using ASX Energy data.
Note: Quantities traded are volumes for any future period in each quarter.

Table 2.1 Victorian gas futures summary

| TRADE DATE | NUMBER OF CONTRACTS | QUANTITY (TJ) |
|---|---|---|
| Q2 2013 | 10 | 92 |
| Q3 2016 | 10 | 92 |
| Q4 2016 | 5 | 46 |
| Q2 2018 | 85 | 777 |
| Q3 2018 | 143 | 1303 |
| Q4 2018 | 361 | 3294 |
| Q1 2019 | 182 | 1661 |
| Q2 2019 | 276 | 2528 |
| Q3 2019 | 108 | 989 |
| Q4 2019 | 225 | 2058 |
| Q1 2020 | 224 | 2051 |
| Q2 2020 | 310 | 2842 |

Source: ASX Energy.
Note: Trade date reflects the date of transaction not contract expiry date.

# Focus—COVID impacts

## Pandemic further challenges gas sector following commodity price slump

The impacts of the COVID-19 pandemic on Australia's domestic gas markets and LNG export sector continue to unfold. Outcomes to date include changes to supply-demand profiles, project deferral, asset sales and continuing downward pressure on domestic gas prices. The more pronounced impacts relate to west coast export projects. In contrast, the LNG export sector on the east coast has shown some resilience amid the ongoing global headwinds.

Challenges to the profitability of LNG export production were already emerging through 2019, with a growing global supply glut on the back of large export project expansions. This contributed to declining international gas prices through Q3 and Q4 2019, which was followed by the early 2020 oil price crash amid price competition between oil exporting countries. The COVID-19 pandemic comes on the back of these developments, with national lockdowns disrupting gas supply-demand chains and exacerbating the persistence of downward international gas price pressures.

Price impacts have flowed through to Australia's east coast markets, with the Asian LNG netback price at Wallumbilla descending to record lows and shadowed by domestic spot prices. Sustained low spot prices can be expected to impact the economics of gas production, most particularly the profitability of higher-cost sources of gas supply.

## Global oversupply is challenging LNG exporters

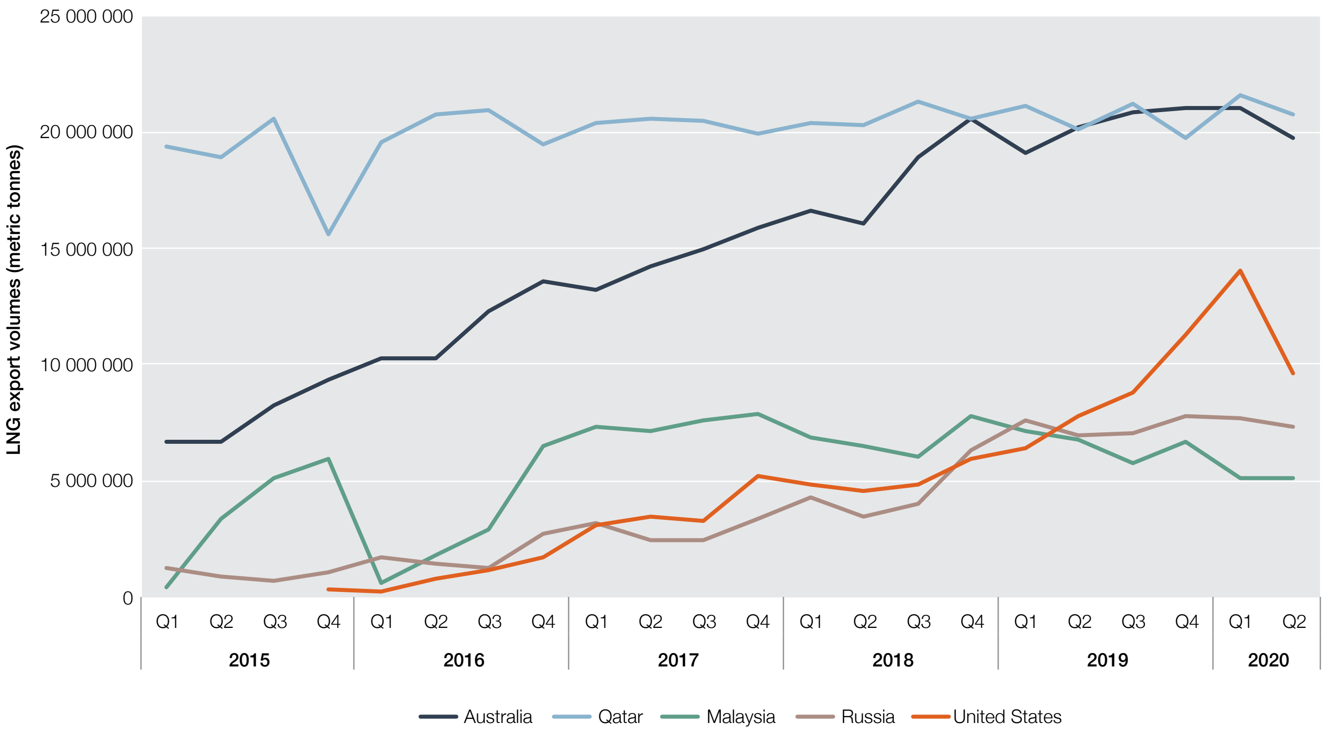
Community lockdowns, associated with the international spread of COVID-19, come amid significant growth in global LNG export capability. Project expansion has been most significant in the United States, with the ramp-up of export facilities delivering near 50 per cent growth in USA cargo volumes in 2019, making the USA the world's third largest LNG exporting country.[53]

Prior to the pandemic and international oil price collapse, export facilities in the USA were expected to continue their ramp-up, delivering increased export growth in 2020. However, USA cargo cancellations have revealed a steady decline in loadings at liquefaction facilities during 2020 (figure 2.19). In June 2020, S&P Global Platts reported that about 130 cargoes had been cancelled for loading in the USA since April 2020, with at least 40 more cargoes, scheduled for loading in August, reported to be cancelled.[54] In July 2020, Argus Media reported that USA loadings for the previous month were the lowest since December 2018.[55]

The over-supplied global LNG market presents challenges for Australian exporters, particularly in relation to seller interest in north Asian markets, the primary destination for Australian cargoes. In June 2020, Argus reported that around 14 vessels (five from Australia) were floating outside China, Japan and South Korea, with uncertainty as to how many of these cargoes were still on offer without a destination.[56]

With global LNG inventories near full, exporters may increasingly look to Asia and the world's two largest LNG importing countries (China and Japan).[57] China's expected increase in economic activity as COVID restrictions ease may see spot cargoes redirected there.

**Figure 2.19 LNG exports by country**




Source: Bloomberg.

53 DISER, *Resources and energy quarterly, June 2020*, p. 72.

54 S&P Global Platts, 22 June 2020, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/062220-august-cargo-cancellations-at-us-lng-terminals-push-summer-total-over-100, accessed 17 July 2020.

55 Argus Media, *Argus LNG daily*, Issue 20–128, 1 July 2020, p. 17.

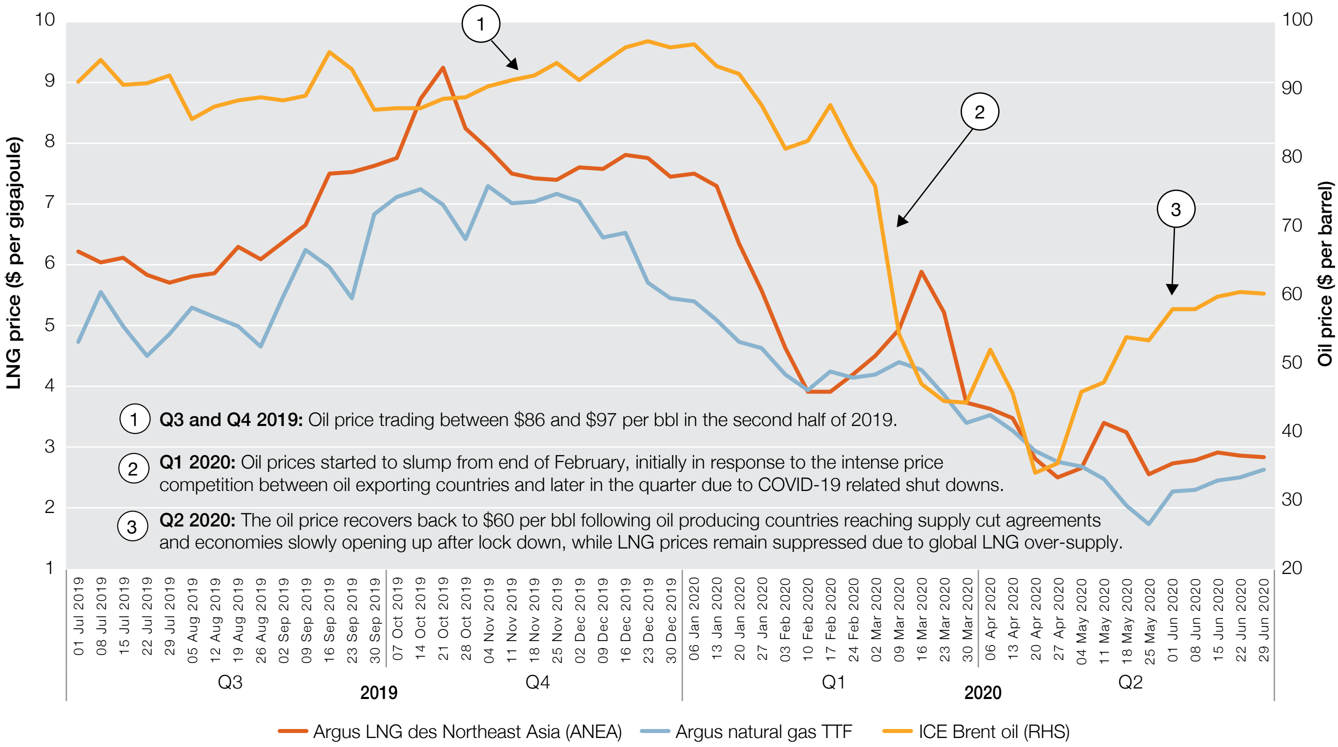
56 Argus Media, *Argus LNG daily*, Issue 20–121, 19 June 2020, p. 3.

57 Argus Media reported in late June that 'European storage sites could be filled up as early as July, potentially resulting in the diversion of excess Atlantic cargoes to Asia…', *Argus LNG Daily*, Issue 20–122, 23 June 2020, p. 2.

## Low prices challenge the profitability of Australia's LNG export sector

Record low international LNG prices, including LNG spot prices and oil prices used in contract pricing, are challenging the economics of production for the Australian export sector. Global prices have fallen dramatically over 2019–20 including in Asia, our export market (figure 2.20).

**Figure 2.20 Global LNG spot prices (Asia, Europe) and Brent Oil Price**




Source: AER analysis using Argus media data.

Notes: The Argus LNG des Northeast Asia (ANEA) price is a physical spot price assessment representing cargoes delivered ex-ship (des) to ports in Japan, South Korea, Taiwan and China, trading 4–12 weeks before the date of delivery.

The Argus Natural gas TTF price: is a month ahead delivered spot price calculated at the Title Transfer Facility (TTF) in the Netherlands.

The ICE Brent oil price is a month ahead settled price.

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There will be obvious challenges to the profitability of developing and operating unconventional gas projects, which in addition to costs associated with liquefaction for export, have significant upstream costs associated with drilling and hydraulic fracturing.

However, sustained low international gas prices are also challenging the development of conventional gas resources, as evident in the large-scale investment deferrals that have emerged in the Browse Basin off Australia's north coast. Around $60 billion in investments have been deferred beyond 2020, including Santos's Darwin LNG Barossa project and Woodside's Browse to North West Shelf, Scarborough and Pluto Train 2 developments. In addition, a restart date for Shell's Prelude floating LNG project is now uncertain given the downward trend of oil and gas prices across 2020. The project was shut down in January 2020 due to safety issues.

Commensurate with lower Asian LNG spot prices and low international oil price forecasts, earnings downgrades have been anticipated. The June 2020 report from the Office of the Chief Economist: *Resources and energy quarterly*, projects a 26 per cent decline in Australia's LNG export earnings in 2020–21.[58] Subsequently, offerings of Australian assets are mounting and include Chevron's $5–6 billion stake in the North West Shelf project and ENI's $1.6 billion sale of gas assets in the Northern Territory, which includes the Blacktip Gas Project.[59] In May 2020, ConocoPhillips completed the sale of its northern Australian and Timor-Leste assets to Santos, which included its stake in the Darwin LNG export project.

58 To accommodate forecasting uncertainty, the fall in LNG export earnings is also projected within a range of anywhere between $29 and $37 billion in 2020–21, building to falls of between $30 and $42 billion in 2021–22, *Resources and energy quarterly June 2020*, p. 76.

59 The offshore Blacktip field supplies a majority of Northern Territory domestic gas demand.

Recent offerings have extended to conventional east coast gas plays, with Exxon reported to be looking to sell a $2 billion stake in its Gippsland Basin joint venture. In April 2020, Exxon also announced that it had reduced global capital spending by 30 per cent, including suspending drilling in Bass Strait until the end of 2020 as part of its response to low commodity prices and weak demand amid the COVID-19 pandemic.[60]

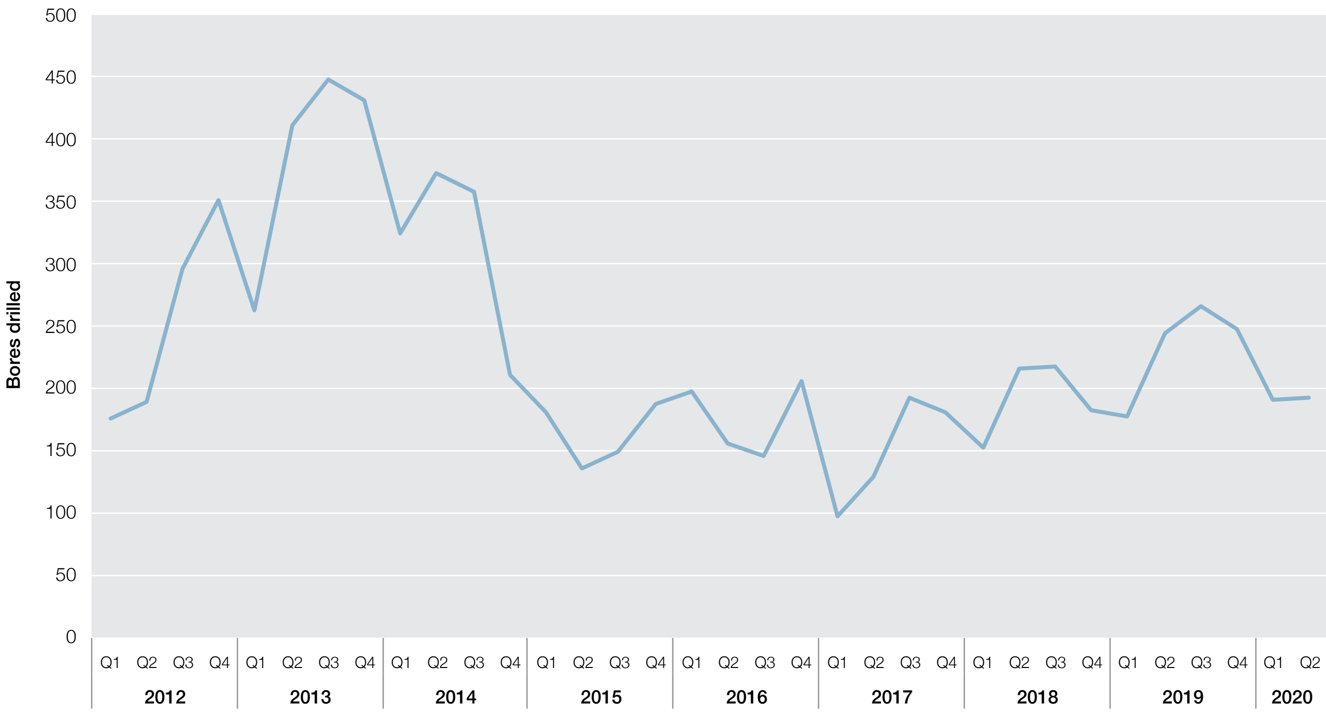
## East coast LNG exporters are showing resilience

Despite the global headwinds, a feature of the Australian gas sector has been the resilience of east coast exports to date. Announced assets sales and earnings downgrades have largely come from west coast and northern Australian producers. East coast LNG exports have held up during 2020, with the 81 cargoes shipped during Q2 2020 marginally higher than the 80 cargoes shipped during Q2 2019. This is just below the Q4 2019 total of 87 cargoes, noting that export cargoes are typically highest in Q4 in preparation for higher gas usage during the north Asian winter.

Our Q1 2020 report highlighted that, following significant year-on-year import growth, there had been a pronounced Q1 2020 decline in Chinese LNG imports as a consequence of COVID-19 lockdowns.[61] Chinese imports from the east coast averaged just below 20 cargoes per month during the 2019–20 financial year to January, slumping to 15 cargoes in February 2020 then steadily recovering to 20 cargoes in June 2020.[62]

Further to this resilience, production from Queensland's Roma gas fields has remained high, averaging 4000 TJ per day in Q2 2020, down only slightly from the record daily average of 4126 TJ per day set in Q4 2019. The number of new coal seam gas (CSG) wells drilled also remained steady, maintaining above 190 bores per quarter from Q1 to Q2 2020 after declining between Q4 2019 and Q1 2020 (figure 2.21). Drill numbers can be indicative of planned supply changes, noting that a procession of new wells is required to support ongoing production from CSG resources.

**Figure 2.21 Queensland coal seam gas bores drilled**




Source: Queensland Department of Natural Resources, Mines and Energy.

60 https://www.afr.com/companies/energy/exxon-pauses-bass-strait-drilling-20200414-p54jq1, sourced 17 July 2020.

61 *Wholesale markets quarterly Q1 2020*, pp.47-48, https://www.aer.gov.au/wholesale-markets/market-performance/wholesale-markets-quarterly-q1-2020, *Resources and energy quarterly June 2020* reports a 14 per cent decline in Chinese LNG imports for February—March 2020 compared to the same period in 2019. p. 74.

62 During the short slump, cargoes were re-directed to alternative destinations including India, where buyers were responding to low prices by increasing purchases of spot cargoes. This helped to absorb over-supply but was short-lived, with India going into COVID-19 lockdown in late March 2020. Argus subsequently reported a subsequent flood of cargoes, previously acquired by Indian buyers, into the LNG spot supply pool. *Argus LNG daily*, Issue 20–61, 26 March 2020, p. 3.

Whether east coast exporters can maintain this resilience is uncertain. Presently, they benefit from long-term contract arrangements with their Asian buyers on price terms advantageous to current market prices. Buyers do have room to exercise downward quantity limits under contracts and may have already done so.[63] However, this option may only be available prior to the contract year commencing, meaning a number of cargoes remain locked in until early 2021.

The extent to which east coast exporters can minimise earnings downgrades will continue to play out. Daily LNG prices in the Asian spot market have fallen to a record low in June 2020, averaging $2.82 per GJ with oil prices also declining.

Valuation downgrades are emerging, including Origin Energy's 15 July 2020 announcement of a $770 million write-down in the value of APLNG based on future oil price assumptions and impacts associated with the COVID-19 pandemic.[64] On 21 July 2020, Santos announced that an asset value write-down of US$700–800 million would be included in its 2020 half-year results, again due to oil price assumptions resulting from the COVID-19 pandemic.[65]

If the pandemic continues to provoke national lockdowns and suppress international oil and gas prices in the longer term, this may trigger price review clauses in LNG contracts, enabling counterparties to renegotiate terms, which may include substituting contracted cargoes for spot cargoes. Amid the unlocking of conditions in long-term contracts, east coast exporters risk growing exposure to competition from cheap gas in an oversupplied global LNG market.

## Changes to the domestic strategies of east coast exporters are emerging

The temporary reduction in east coast export cargoes, from Q1 to Q2 2020, was reflected in export pipeline flows. AEMO's *Quarterly energy dynamics—Q2 2020* reports that a total of 317 PJ flowed to Curtis Island in Q2 2020.[66] At an average of 3484 TJ per day, this was the lowest quarterly total since Q3 2018 and down from the 3835 TJ per day peak set in Q4 2019.

The reduced export flows, however, did not correspond with any significant decline in production from the Roma gas fields, nor did it correspond with a reduction in the number of CSG wells drilled from Q1 to Q2 2020. The following alternative strategies may be enabling export producers to manage inventories in the short term, rather than sell uncontracted gas (either internationally or domestically) at unprofitable prices:

- Recently, there appears to be an unwillingness to offer gas into the Wallumbilla GSH at current low prices. A distinctive feature of Q2 2020 gas market activity was a very large drop in trade at the Wallumbilla GSH, with traded volumes at approximately half Q2 2019 levels (section 2.4).
- LNG exporters may be using the Q1 to Q3 2020 period to conduct unplanned facility maintenance. Although planned winter maintenance schedules have not changed significantly, some LNG facility shutdowns have emerged at short notice. On 27 May, Australia Pacific LNG (APLNG) reported that a 5-day shutdown of half an LNG train (commencing that same day) had been extended by 18 days. In early June, GLNG provided first notice of a 13-day half-train shutdown for later that month. In July, Queensland Curtis LNG (QCLNG) notified of a 20-day maintenance period over August, meaning that overall maintenance outages on a train per day basis for 2020 far exceeds 2019 and the forecasts for 2021.[67]
- Queensland producers have in 2020 increased their use of gas storage. Gas held in the GLNG Roma Underground Storage (RUGS) facility increased during Q1 and Q2 2020 (section 2.2). This has been the first sustained period of filling since RUGS commenced reporting to the Gas Bulletin Board in September 2018. Between 9 February 2020 and the end of the 2019–20 financial year, inventories increased by 20 per cent. In July 2020, they increased further (by approximately 2.7 PJ), equivalent to around three quarters of an LNG cargo. We expect that this filling was GLNG storing its own gas production, combined with some transactions with other Queensland producers.

63 AER *Wholesale markets quarterly Q4 2019*, p. 58, https://www.aer.gov.au/wholesale-markets/market-performance/wholesale-markets-quarterly-q4-2019.

64 Origin Energy, media announcement, https://www.originenergy.com.au/about/investors-media/media-centre/origin_expects_to_recognise_non_cash_charges_in_fy2020.html, sourced 17 July 2020.

65 Santos, media announcement, https://www.santos.com/news/santos-announces-non-cash-impairment/, sourced 17 July 2020.

66 AEMO reports that the 317 PJ that flowed to Curtis Island was a decrease of 7 PJ compared to Q2 2019 and is reflected in a decrease in APLNG flows (-13 PJ) and GLNG flows (-12.7 PJ), while QCLNG flows slightly increased (+4.3 PJ), *Quarterly energy dynamics—Q2 2020*, p. 29.

67 Note that this is maintenance reported voluntarily by Qld LNG exporters. Exporters are required to report coordinated maintenance but do not have to otherwise report. Indications are some maintenance goes unreported and may have done so during the Q2 2020 period, https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/gbb-reports/lng-maintenance.

### Response to pandemic has caused some change to domestic usage profiles

In May 2020, AEMO published analysis of COVID-19 impacts on the Victorian gas market, highlighting the emergence of a later and longer morning demand peak. The report identified up to a 5 per cent increase in peak day demand and increased sensitivity of residential load to weather events. In contrast, it identified that lockdowns had coincided with a 5 per cent reduction in overall demand from C&I customers.[68]

Although this indicates a counterbalance between increased residential demand and decreased C&I demand, this relates only to the early 2020 lockdown period in Victoria. Victorian gas demand increased from the 2018–19 to 2019–20, with the overall decline in east coast gas demand for that period explained by reduced demand in other states.[69]

COVID-19 has therefore not impacted clearly on gas consumption volumes outside of changes to demand profiles in Victoria. A more significant driver of recent reduced gas demand is the use of gas for electricity generation during the period of the pandemic. Despite the availability of cheap gas, there were significant declines in gas powered generation in all states except South Australia from Q1 to Q2 2020 (figure 2.17). Although this coincides with the spread of COVID-19 and government imposed lockdowns, it is likely to be attributable to increased competition from hydro and renewable generators.[70]

## Focus—Day Ahead Auction (and Capacity Trading Platform) year in review

On 1 March 2019, two new secondary capacity trading markets were introduced into the east coast gas market. Both are designed to encourage access to contracted pipeline capacity by secondary buyers, when contracted capacity along a pipeline is not being utilised. Historically, some pipelines have been fully contracted across a year to gas shippers, meaning a pipeline's capacity can be underutilised by those shippers (when they do not require it in the year) and when there might be interest in the pipeline capacity from other shippers. The new markets are designed to facilitate easier access to any unused capacity on the east coast through a co-ordinated trading platform.

There are two means of trading within this new market:

1. In the first instance, a voluntary trading platform, the Capacity Trading Platform (CTP), is available. All shippers can choose to either use their contracted capacity or sell forward any capacity they expect to use on the trading platform. Sale revenue from trades on the CTP go to the selling shipper.
2. If shippers decide not to sell their unused capacity, any unused capacity quantity will be offered into a mandatory auction platform: the Day Ahead Auction (DAA). Any shipper can bid for this capacity and, in contrast to the CTP, all proceeds from the auction pass to the pipeline (or compression) facility operators, rather than shippers.

This new market is intended to open up access to key transport bottlenecks, where contracted capacity is held by only a few shippers. A key example is the heavily contracted SWQP, which is strategically important for north-south flows and is the only pipeline connecting Queensland with the southern states.

Participants were initially slow to partake in the auction during the first couple months in which it was run, with only one and two active participants, respectively. However, as the benefits of the auction and its operational mechanisms began to be better understood, participation increased sharply.

Pipelines and Shippers have indicated that the auction has been more successful than first thought. For Shippers, the low prices, which on a number of facilities haven't risen above the reserve auction price of $0 per GJ, have seen it favoured as the preferred method of acquiring capacity over the CTP which has only seen one small trade.

Participants have commented that the auction has increased market efficiency and optimisation, providing access and making it easier to move gas into different markets. It has also assisted in managing exposures and allowed northern producers to sell excess gas, and allowed participants to realise the advantages associated with regional price differentials.

From March 2019 to June 2020, the auction was used by 16 participants winning over 49.1 PJ of capacity across 10 different pipeline and compression facilities.

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68 AEMO, Victorian winter outlook presentation, https://aemo.com.au/-/media/files/gas/dwgm/2020/2020-winter-outlook---all-presentations.pdf?la=en&hash=DEE9E2E4783C4A990185800CDB05BFD2, accessed 30 July 2020.

69 AER, Wholesale Industry Statistics, https://www.aer.gov.au/wholesale-markets/wholesale-statistics/average-daily-regional-demand, accessed 30 July 2020.

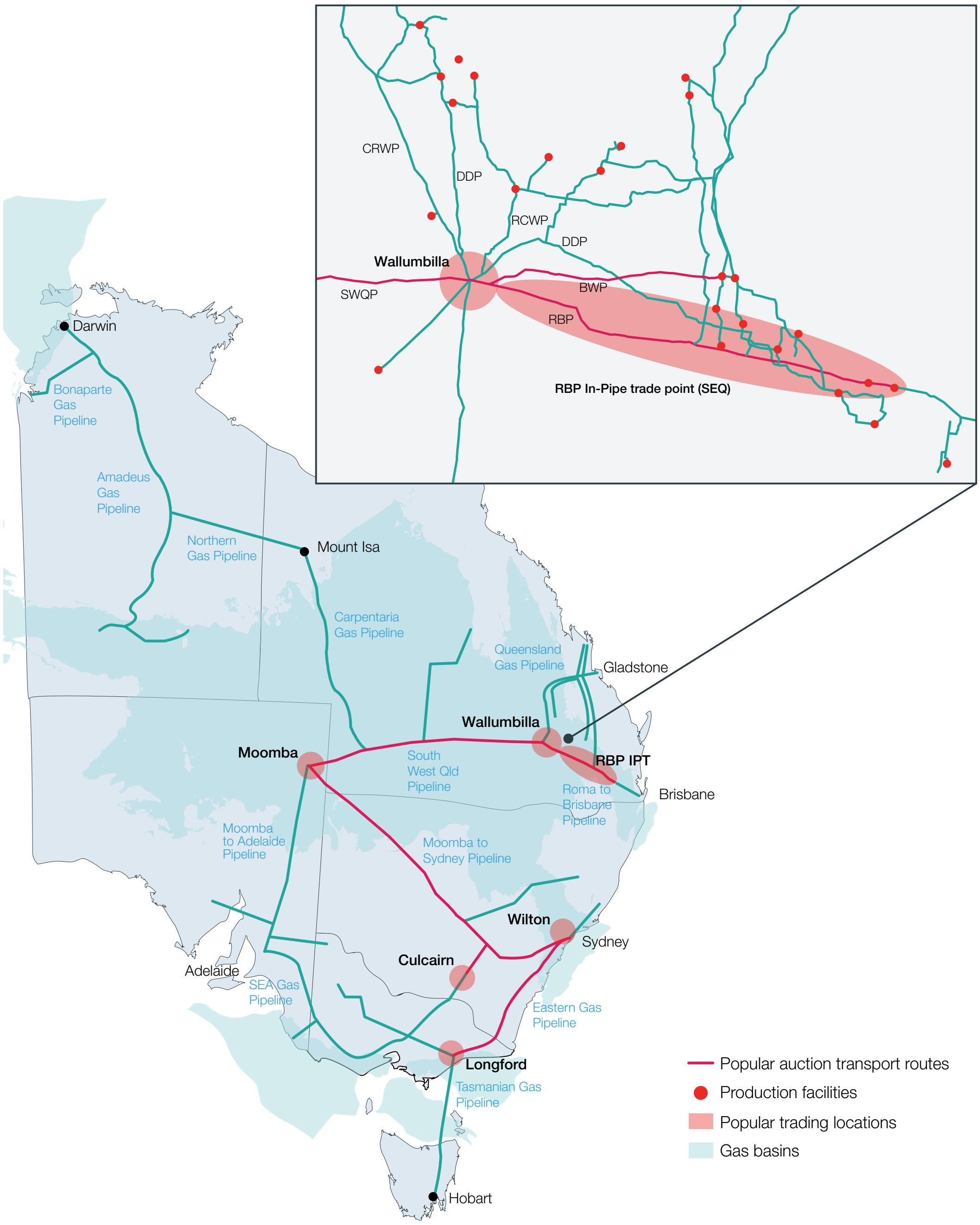
70 AEMO has reported in its *Quarterly energy dynamics—Q2 2020* that several grid-scale VRE records were set during Q2, p. 34.

## What are the popular pipeline routes and delivery and receipt points?

The DAA has facilitated transport of gas across long distances, from large production areas in Queensland toward southern states. The most popular transport routes have enabled gas produced from concentrated areas of large production fields in south east Queensland to flow toward Wallumbilla and further south towards Victorian and Sydney markets. Additionally, the auction of compression services has been popular to move gas from lower pressure pipelines connected to south east Queensland production facilities to higher pressure pipelines that facilitate this flow of gas south. The increasing volumes of auctioned pipeline and compressor capacity has coincided with increased trade volumes at Wallumbilla and in the Sydney market. To a lesser extent, the DAA has allowed gas to flow from the Longford production facility in Victoria to NSW.

Figure 2.22 illustrates the popular transport routes based on the locations of auctioned capacity from south east Queensland and Wallumbilla via the RBP, Berwyndale to Wallumbilla Pipeline (BWP) and SWQP, toward Victoria (Culcairn delivery points) and Sydney (Wilton delivery points).

**Figure 2.22 Popular Day Ahead Auction transport routes**




Source: AER analysis, DAA results data, GEOScience Australia.

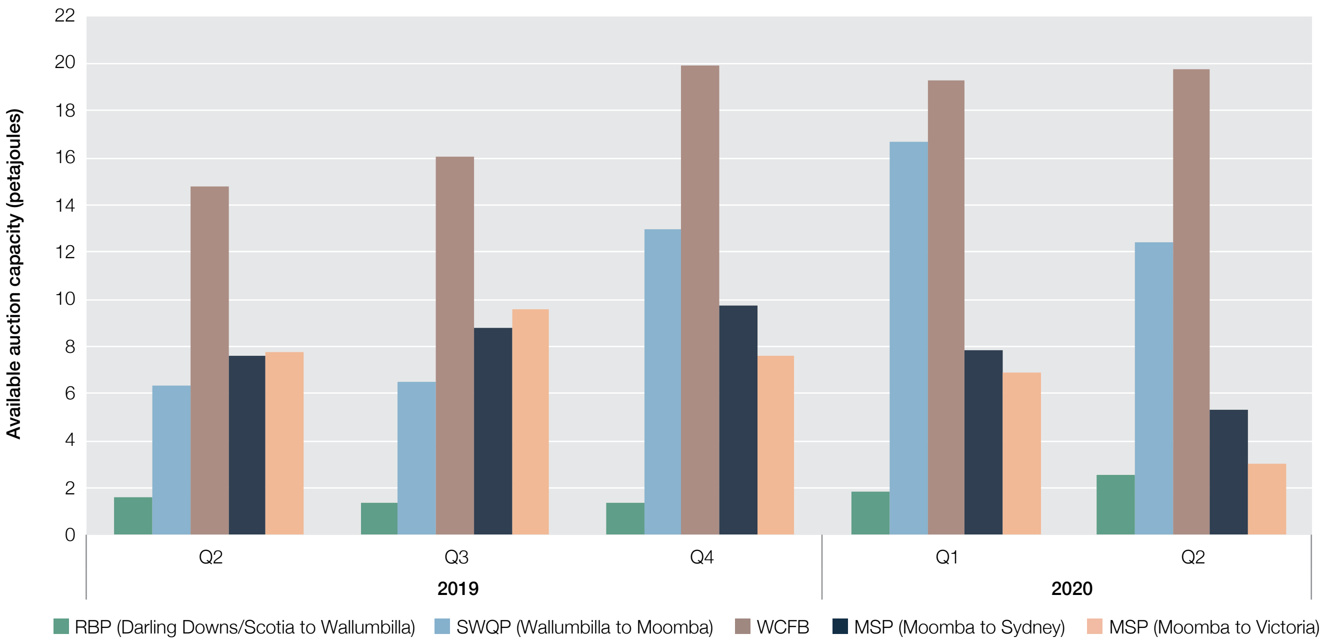
Notes: Gas transmission pipelines depicted: RBP (Roma to Brisbane Pipeline); BWP (Berwyndale to Wallumbilla Pipeline); DDP (Darling Downs Pipeline); RCWP (Reedy Creek to Wallumbilla Pipeline); CRWP (Comet Ridge to Wallumbilla Pipeline); SWQP (South West Queensland Pipeline).

## What are the trends and usage patterns?

The majority of capacity that has been won on the DAA has been used for the transportation of gas from the northern to southern markets (Wallumbilla to Victoria and Sydney), with participants being able to benefit from the price arbitrage opportunities that exist between markets (lower gas prices in the north than in the south). Increases in quantities won on these routes has been particularly prevalent in the winter months, corresponding to increases in southern demand during this period (figure 2.10).

Auction quantities available during these cooler months can be lower than in other periods (figure 2.23) and increased competition during low auction availability has resulted in high auction prices above the zero reserve price on many facilities.

**Figure 2.23 Auction capacity available on popular transportation routes**




Source: AER analysis using DAA auction results data.

Note: MSP routes have been calculated as 'stand alone' routes. However, available auction capacity for both routes is linked in that capacity won for transport from Moomba to Victoria will impact available capacity for Moomba to Sydney.

The auction has also helped facilitate the movement of gas from fields in south east Queensland to Wallumbilla via the BWP, at the zero dollar reserve price or close to it, and the heavily contracted RBP where prices have risen to a maximum of $0.60 per GJ during periods of high competition.

There are at least 12 other facilities included in the DAA that have yet to have capacity won on them. Some such as the Queensland Gas Pipeline (QGP), Tasmanian Gas Pipeline (TGP), Darling Downs Pipeline (DDP) and Iona Compression Facility (ICF) rarely have auction capacity available, while many of the other facilities have only intermittent quantities of capacity available for the auction. The lack of consistently available capacity results in uncertainty and removes the DAA as a mechanism for potential participants to acquire transport capacity on these facilities.

## Who is using the auction?

Sixteen participants have won capacity through the DAA, with the overwhelming majority of pipeline capacity won by GPG Gentailers and Traders. The auction has only seen a small number of industrial participants win capacity, with less than 0.5 per cent of total capacity won (figure 2.24).

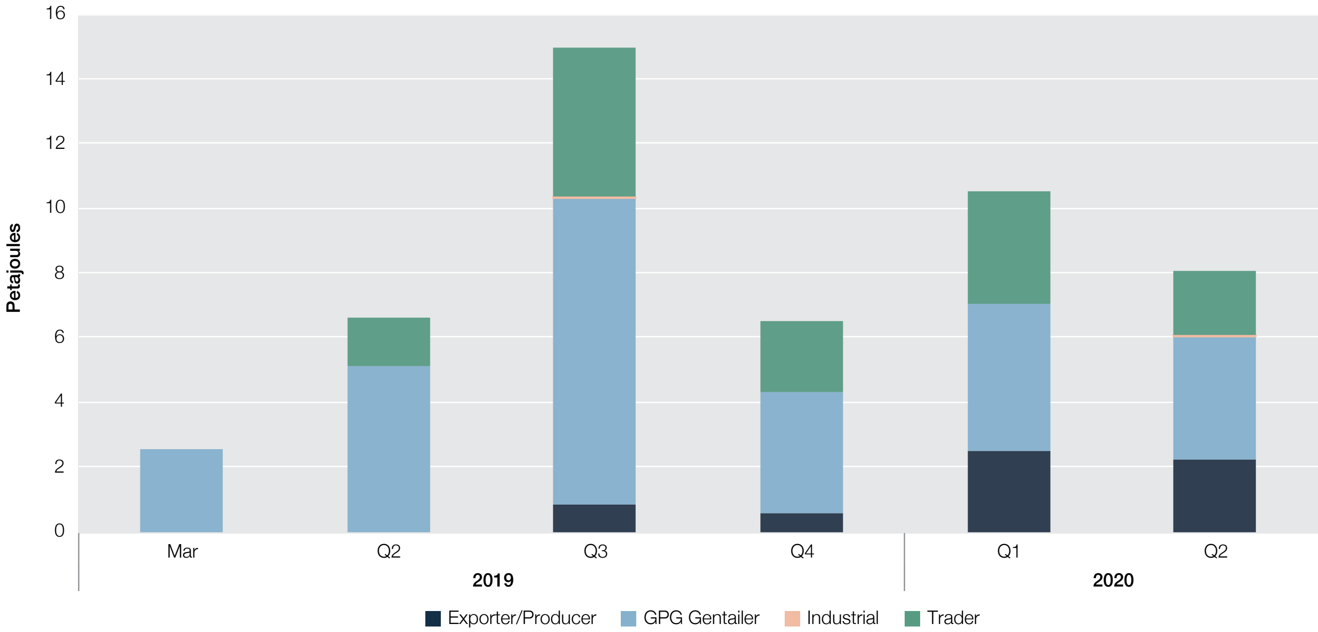
A list of auction participants in groupings is in the Appendix. The list now includes three industrial users who have registered. This is notable given the capacity won is not completely firm so may not favour users who need a fixed daily supply as industrial processes may require (and so may lock this capacity in under firm contracts). Noting the sporadic use of the auction by industrials, the auction may therefore be assisting industrials with short-term demand changes around industrial processes.

A number of participants have won capacity on pipelines for which they do not hold firm contract shipping rights. Since its commencement five uncontracted participants have won capacity on the SWQP, four on the MSP, two on the RBP, two on the MAPS and one on the CGP. The ability for uncontracted participants to acquire transport and compression capacity on facilities that have previously proven to be difficult and/or expensive has resulted in greater diversity of participants shipping gas and trading in the various markets (section 2.7).

Pipelines and facilities that are important for the transportation of gas from northern to southern markets have seen the highest amount of competition and number of participants bidding on each pipeline to win available capacity. The MSP, RBP, SWQP and combined Wallumbilla Compression Facilities have seen 12, 11, 10 and 8 active participants, respectively. With prices on the first three pipelines reaching maximum prices of over $1.00 per GJ. The BWP, CGP, Eastern Gas Pipeline (EGP), MAPS and the Moomba Compression Facility (MCF) have seen three or less participants bidding for capacity, with only the EGP experiencing levels of competition between the participants to result in auction prices of up to $0.35 per GJ.

To date, participants from each group have won capacity except for the Retailer group comprising mostly smaller participants who may consider some of the auction fixed costs a hurdle.[71]

**Figure 2.24 Auction quantities by participant type**




Source: AER analysis, using DAA auction results data.

Participants have indicated that the majority of capacity that is won is being used. Instances where capacity is not used is generally a result of issues with suppliers and the need to renominate down, the pipeline operator rejecting the nomination due to administrative issues or the trade being used for a 'system test' with only small quantities won and no intent to ship gas.

## Has there been a change in trade and pipeline flows?

Although somewhat hard to quantify, it does appears that the DAA has enabled more gas to be shipped south than in the absence of the auction, particularly in Q2 and Q3 (figure 2.10). This is not surprising as the implementation of the auction has allowed previously unused firm pipeline capacity to be used. The ability for new participants to access capacity to move gas to new markets has added more diversity to the competition of supply in these markets. On those pipelines linked to transport of gas to southern markets, auction volumes reported since March 2019 have been much higher than gas shipped under short term services over 2018.[72] We consider it likely that the DAA has caused additional movement of gas which would have not occurred but for the auction. This point is supported by increased levels of participation, by a wider range of participants trading greater volumes of gas through the DAA and commodity spot markets with many same day commodity and DAA spot market purchases.

71 ACCC, *Gas inquiry report*, January 2020, p. 104.

72 See service usage information at www.apa.com.au/our-services/gas-transmission/east-coast-grid/south-west-queensland-pipeline/.

## How do auction prices compare to the cost of other transportation options?

The main beneficiaries of the DAA have been the auction participants who win the majority of capacity at a price below other alternative transportation options. Firm capacity holders whose un-nominated/used capacity is released to the auction miss out on the proceeds of the auction sale, with proceeds being paid directly to the facility operators as part of their cost recovery process.

Costs associated with quantities won on the auction are not just limited to the price that capacity is won at. AEMO has a fixed registration charge of $15 000 for each participant and a variable charge of $0.03 per GJ of capacity won. Participants must also pay pipeline and storage operators fixed monthly fees ranging from $806 to $2917 per month to use transportation facilities, with additional variable costs of approximately $0.01 to $0.05 per GJ won.

As per the cost recovery framework, APA and Jemena have reduced auction fees levied on auction participants, as a result of they have recovered from auction proceeds. Notably, APA reduced variable charge from 4.8 to 1.3 cents per GJ, and Jemena reduced monthly fixed fees from $1000 to $500 per user since last year.

The DAA is seen by many participants as a substitute for short term transportation services such as as-available services, however in many cases using the auction is a cheaper transport option.

Typically, short term transportation services are determined on a variable usage basis and are priced at a premium to longer term services that incur a standing charge regardless of use. This pricing dynamic may discourage smaller participants wishing to arbitrage between spot markets, using transport occasionally, and wanting to avoid standing charges for transport. The benefit of the auction has been to access these short term transportation services more cheaply than under contract. We have estimated the value of this discount, net of some fees to be $30–60 million for popular transport routes, flowing gas from Queensland to Victoria and NSW since the auction commenced in March 2019. These savings over time should pass on to end users. In the *Wholesale markets quarterly Q3 2019* we highlighted the possibility that auction backed offers reduced spot market prices by 76 cents per GJ in Sydney from March to September 2019.[73]

## Interactions with the NEM

Significant auction capacity has been sold on high gas powered generation days and during other significant market events such as the electrical isolation of South Australia from the rest of the NEM in Q1 2020. Increasingly over the first 16 months of the auction higher auction quantities have been linked to delivery points on pipelines that supply gas powered generation sites in Queensland and NSW.

## Further auction developments

In March 2021, the Council of Australian Governments Energy Council will be conducting a review of the DAA for pipeline capacity, assessing the progress and market impact of the reform. We have engaged with industry throughout the first year of the auction's operation.

Some participants have expressed a desire for additional points, including park services, to potentially be included as auctioned products in further auction reforms.

73 AER, *Wholesale markets quarterly Q3 2019*, https://www.aer.gov.au/wholesale-markets/market-performance/wholesale-markets-quarterly-Q3-2019, 18 May 2020.

# Appendix A Electricity generator outages

Major generator outages Q2 2020

| STATION, COMPANY | FUEL TYPE, CAPACITY (SUMMER RATING) | NUMBER OF DAYS OFFLINE IN Q2 2020 | REASON FOR OUTAGE | RETURNED TO SERVICE |
|---|---|---|---|---|
| **Queensland** | | | | |
| Callide B, CS Energy | Black Coal, 2 units, 350 MW each | Unit 1: 34 days | Planned (13 days) | 21 April |
| | | | Planned (21 days) | Unknown |
| Callide C, Callide Power Trading | Black Coal, 2 units, 420 MW each | Unit 1: 19 days | Unplanned (4 days)—‘unit trip’ | 25 April |
| | | | Planned (13 days) | 11 June |
| | | | Unplanned (2 days)—‘technical issues’ | 19 June |
| Condamine, QGC Sales | Gas 144 MW | 10 days | Planned | 20 April |
| Gladstone, CS Energy | Black coal, 6 units, 280 MW each | Unit 1: 36 days | Unplanned (30 days)—‘technical issues’ | 1 May |
| | | | Unplanned (6 days)—‘technical issues’ | 18 June |
| | | Unit 2: 37 days | Unplanned (13 days)—‘unit trip’ | 21 May |
| | | | Unplanned (24 days)—‘plant not following target’ | 22 June |
| | | Unit 3: 17 days | Planned | 18 May |
| | | Unit 4: 29 days | Unplanned (10 days)—‘technical issues—fuel leak’ | 28 May |
| | | | Unplanned (19 days)—‘plant not following target’ | 30 June |
| | | Unit 5: 26 days | Unplanned (19 days)—‘technical issues’ | 10 June |
| | | | Unplanned (7 days)—‘technical issues’ | Unknown |
| | | Unit 6: 31 days | Planned | 29 May |
| Millmerran, Millmerran Energy Trader | Black coal, 2 units. 426 MW each | Unit 1: 18 days | Unplanned—‘fuel/mill limitation’ | 8 June |
| Tarong North, Stanwell Corporation | Black coal, 443 MW | 70 days | Planned | 10 June |

| | | | | |
|---|---|---|---|---|
| **New South Wales** | | | | |
| Bayswater, AGL Energy | Black coal 4 units, 630 MW each | Unit 1: 13 days | Unplanned—'unit trip' | 30 April |
| Eraring, Origin Energy | Black coal 4 units, 630 MW each | Unit 1: 27 days | Planned | 19 May |
| | | Unit 4: 21 days | Planned | 22 April |
| Liddell, AGL Energy | Black coal 4 units, 450 MW each | Unit 1: 23 days | Planned (1 day) | 2 April |
| | | | Unplanned (4 days—'unit trip' | 2 June |
| | | | Unplanned (18 day)—'unexpected/ plant limits' | 22 June |
| | | Unit 2: 63 days | Unplanned (38 days)—'unit trip' | 9 May |
| | | | Unplanned (7 days)—'unit trip' | 28 May |
| | | | Unplanned (18 day)—'unexpected/ plant limits' | 26 June |
| | | Unit 3: 17 days | Unplanned—'ash plant issues' | 18 May |
| Vales Point, Delta Electricity | Black coal 2 units, 660 MW each | Unit 1: 10 days | Unplanned (4 days)—'tube leak' | 19 May |
| | | | Unplanned (4 days)—'unit trip' | 11 June |
| | | | Planned (2 days) | 17 June |
| | | Unit 2: 36 days | Planned (26 days) | 27 April |
| | | | Unplanned (5 days)—'Boiler tube leak' | 23 May |
| | | | Unplanned (5 days)—'unit trip' | 12 June |
| **Victoria** | | | | |
| Loy Yang A, AGL Energy | Brown coal, 4 units, 530 MW each | Unit 3: 27 days | Planned (21 days) | 22 April |
| | | | Unplanned (6 days)—'unexpected/ plant limits' | 31 May |
| Yallourn, EnergyAustralia | Brown coal 4 units, 355 MW each | Unit 1: 22 days | Planned (7 days) | 8 April |
| | | | Planned (2 days) | 3 May |
| | | | Planned (6 days) | 11 May |
| | | | Unplanned (7 days)—'tube leak' | 24 June |
| | | Unit 2: 35 days | Unplanned (9 days)—'unit trip' | 10 April |
| | | | Planned (4 days) | 28 April |
| | | | Unplanned (16 days)—'tube leak' | 23 May |
| | | | Unplanned (6 days)—'tube leak' | 2 June |
| | | Unit 3: 14 days | Unplanned (4 days)—'superheater sprayline leak | 11 May |
| | | | Planned (10 days) | 21 June |
| | | Unit 4: 16 days | Unplanned (2 days)—'unit trip' | 13 April |
| | | | Planned (14 days) | 29 May |

Source: AER analysis using NEM data.

Notes: The table outlines major generator outages throughout Q2 2020 and the reason for the outage. The table focuses primarily on larger coal and gas generators that operate most of the time. Outages under 10 days in duration have been included in the count of days offline in Q2 2020 but have been excluded from the 'reason for outage'.

# Appendix B Gas snapshots

| PARTICIPANT LIST IN EASTERN GAS MARKET | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Market participant | Victoria | Sydney | Adelaide | Brisbane | GSHs | DAA |
| GPG Gentailer | AGL | ● | ● | ● | ● | ● | ● |
| | Alinta Energy | ● | ● | ● | ● | ● | ● |
| | Aurora Energy | | ● | | | | |
| | CleanCo | | | | ● | ● | ● |
| | EnergyAustralia | ● | ● | ● | | ● | ● |
| | Engie | ● | | | | | |
| | ERM | ● | ● | ● | ● | ● | ● |
| | Hydro Tasmania | ● | | | | | |
| | Origin | ● | ● | ● | ● | ● | ● |
| | Snowy Hydro | ● | ● | ● | ● | | |
| Exporter/Producer | Arrow | | ● | | ● | ● | ● |
| | APLNG | | | | | ● | |
| | BHP Billiton | ● | ● | | | | |
| | Esso | ● | ● | | | | ● |
| | GLNG | | | | | ● | |
| | Lochard Energy | ● | | | | | |
| | Santos | ● | ● | ● | ● | ● | ● |
| | Senex | | | | | ● | |
| | Shell | | ● | | | | ● |
| | Walloons (QGC) | | | | | ● | ● |
| Retailer | 1st Energy | ● | | | | | |
| | Click Energy | ● | ● | | | | |
| | Covau | ● | ● | | ● | | |
| | Delta Electricity | | ● | | | | |
| | Dodo | ● | ● | | | | |
| | GloBird Energy | ● | | | | | |
| | GridX | | ● | | | | |
| | Powershop | ● | | | | | |
| | Simply Energy | | ● | ● | | | |
| | Sumo Gas | ● | | | | | |
| | Visy | ● | ● | ● | ● | | |
| | Viva Energy | ● | | | | | |
| | Weston Energy | ● | ● | ● | ● | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Industrial | Adelaide Brighton Cement | | | Entered before 2017 | | | |
| | BlueScope | | Entered before 2017 | | Entered in 2018 | | |
| | Boortmalt | Entered in 2019 | Entered in 2018 | Entered in 2018 | | | |
| | Brickworks | Entered in 2020 | Entered in 2020 | Entered in 2020 | Entered in 2020 | | |
| | Caltex | | | | Entered before 2017 | | |
| | Commonwealth Steel | | Entered in 2017 | | | | |
| | Coopers | | | Entered in 2017 | | | |
| | CSR Building Products | Entered in 2018 | | Entered in 2019 | Entered in 2018 | | |
| | Incitec Pivot | | | | Entered before 2017 | Entered before 2017 | Entered in 2019 |
| | Infrabuild | Entered before 2017 | Entered before 2017 | Entered before 2017 | | | |
| | Michell Wool | | | Entered in 2019 | | | |
| | Mobil Oil | Entered in 2018 | | | | | |
| | Norske Skog | Entered in 2018 | | | | | |
| | Oceania Glass | Entered in 2020 | | | | | |
| | O-I International | Entered in 2018 | Entered in 2018 | Entered in 2018 | Entered in 2019 | | |
| | Orica | | Entered in 2017 | | | | |
| | Orora | | Entered in 2020 | | | | |
| | Paper Australia | Entered in 2018 | Entered in 2020 | | | | |
| | Qenos | Entered in 2017 | Entered before 2017 | | | Entered in 2017, Exit or inactive | Entered in 2019 |
| | SA water | | | Entered before 2017 | | | |
| | Tarac Technologies | | Entered in 2017 | Entered before 2017 | | | Entered in 2019 |
| | Weston Aluminium | | Entered before 2017 | | | | |
| Trader | Macquarie Bank | Entered in 2019 | Entered in 2019 | | | Entered in 2018 | Entered in 2019 |
| | Petro China | Entered in 2020 | Entered in 2020 | | | Entered in 2019 | Entered in 2020 |
| | Strategic Gas Market Trading | Entered in 2019 | Entered in 2019 | | | Entered before 2017 | Entered in 2019 |
| | 58 | 35 | 35 | 20 | 17 | 16 | 17 |

● Entered before 2017 ● Entered in 2017 ● Entered in 2018 ● Entered in 2019 ● Entered in 2020 ● Exit or inactive

Note: For Victoria, Adelaide, Sydney, Brisbane and the GSH the year represents when participants commenced trading. For the DAA the year represents when participants registered.

* Arrow also operates the Braemar 2 power station

| GAS SUPPLY HUBS SNAPSHOT | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 YTD |
|---|---|---|---|---|---|---|---|
| number of trades | 481 | 875 | 798 | 1 638 | 1 919 | 3 635 | 1 489 |
| trade volume, PJ<br>*% of trade by top 3 buyers : sellers* | 2.4<br>*67% : 89%* | 6.4<br>*71% : 75%* | 7.9<br>*66% : 56%* | 11.6<br>*51% : 59%* | 16.4<br>*53% : 52%* | 27.4<br>*51% : 64%* | 11.3<br>*46% : 60%* |
| trade value, $million | 5 | 24 | 57 | 89 | 148 | 219 | 54 |
| volume weighted average price, $/GJ | 2.01 | 3.66 | 7.20 | 7.68 | 9.02 | 7.98 | 4.78 |
| number of trading participants<br>*number of active participants on-screen vs. off-screen* | 8<br>*7:0* | 12<br>*11:7* | 12<br>*11:11* | 13<br>*12:9* | 13<br>*12:12* | 16<br>*13:16* | 17<br>*14:17* |
| % traded through exchange (sum bought divided by regional demand) | N/A | N/A | N/A | 4.3% | 6.1% | 9.1% | 7.3% |

Source: AER analysis using GSH trades and Natural Gas Services Bulletin Board data.

| DAY AHEAD AUCTION SNAPSHOT | 2019 | | | | 2020 | | | |
|---|---|---|---|---|---|---|---|---|
| | MAR | Q2 | Q3 | Q4 | Q1 | Q2 | FY 19/20 | Total |
| number of active participants | 1 | 4 | 6 | 6 | 11 | 12 | 15 | 16 |
| number of facilities | 4 | 6 | 6 | 7 | 7 | 9 | 10 | 10 |
| auction legs won | 142 | 671 | 1 281 | 807 | 1 179 | 1 282 | 4 549 | 5 362 |
| capacity won, TJ | 2 548 | 6 609 | 14 945 | 6 492 | 10 525 | 8 026 | 39 988 | 49 144 |
| maximum auction price, $/GJ | 0.10 | 0.61 | 1.05 | 0.30 | 0.30 | 1.26 | 1.26 | 1.26 |
| % won at $0/GJ | 82% | 88% | 71% | 87% | 82% | 78% | 78% | 79% |
| % won at ≥$0.10/GJ | 0% | 8% | 20% | 5% | 4% | 14% | 12% | 11% |

Source: AER analysis using DAA auction results data.

Note: Each auction leg won reflects the capacity acquired on a single facility through the auction—so if a participant acquired capacity from Wallumbilla to Sydney this could involve two legs—SWQP and MSP—or up to as many as four legs if capacity on the RBP and Wallumbilla compressors have also been involved.