Wholesale Markets Quarterly

Q1 2020

January–March

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AUSTRALIAN ENERGY REGULATOR

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Electricity markets

Average wholesale electricity prices in most National Electricity Market (NEM) regions were low in Q1 2020. Individually, prices this quarter were the lowest Q1 prices observed since 2012 in Queensland, 2015 in Tasmania, 2016 in South Australia, and 2017 in Victoria. Even in Victoria and NSW, where short periods of volatility led to somewhat higher average wholesale prices than elsewhere in the NEM, prices were still moderate by recent Q1 standards. Notably, Q1 2020 marked the first time since 2015 that Q1 prices were below $110 per MWh in all regions.

A number of factors contributed to these price outcomes. Notwithstanding some extreme weather events and high demand early in the quarter, weather conditions in Q1 2020 were generally mild. This led to lower levels of summer demand. In addition, spot prices for fuel inputs for gas and coal generators were lower, which was reflected in lower priced offers from these generators. These offers were supplemented by increased amounts of low priced solar generation.

These high level outcomes, however, do little to explain the series of extraordinary events the wholesale electricity market faced in Q1 2020.

At the start of the quarter, most regions experienced extreme weather conditions and bushfires. This drove the highest number of Lack of Reserve 2 (LOR 2) hours across the NEM in the last four years. These extraordinary conditions also resulted in some short periods of high prices in January across NSW, Victoria and South Australia. We have already released detailed reports into these half hour prices over $5000 per MWh, a requirement under the National Electricity Rules. However, these extreme events were managed well by the Australian Energy Market Operator, and there were no actual reserve shortfalls. This report contains a focus story discussing the management of supply shortfalls in the NEM.

In February, South Australia was isolated from the rest of the NEM after storms damaged transmission infrastructure. While South Australia maintained electricity supply to meet demand throughout this period, the separation meant South Australia was required to provide its own Frequency Control Ancillary Services (FCAS). This led to record FCAS costs for the quarter.

And by the end of the quarter, Australia, like the rest of the world, was in midst of dealing with the COVID-19 pandemic. While it is difficult to identify the precise impact the pandemic is having on overall demand at this early stage, it does not appear to be having as significant an impact on overall demand in the NEM as observed in some overseas markets. The associated economic downturn from COVID-19, however, appears to be having an impact on forward wholesale electricity prices, with futures prices falling across the regions. Monitoring the impact of COVID-19 on the NEM will be a focus for the AER throughout 2020.

This report also includes a focus story on the Retailer Reliability Obligation (RRO). The RRO, which is designed to ensure there is sufficient dispatchable resources, was triggered for the first time in January.

Gas markets

Prices in downstream markets ranged from $5.20 in Brisbane to $6.27 per GJ in Adelaide with all prices at their lowest levels since Q1 2016. This was the fifth quarter in a row that prices fell in the Brisbane, Victoria and Sydney markets.

As with domestic prices, the sharp decline in international gas prices observed through late 2019 has continued. One of our focus pieces this quarter identifies a positive long term correlation between LNG netback and domestic spot gas prices.

Domestically, Roma production and east coast LNG export remained high, and only reduced slightly from last quarter's record levels. However, some participants announced the potential for sustained reductions in production as oil price drops, the economic reach of the COVID-19 pandemic, and share price falls impact businesses' cash flows.

Further downstream, participants continued to be highly active in the wholesale markets. Strong demand from commercial and industrial users drove higher levels of purchased gas. On the supply side, Santos, BHP and Shell were again prominent in selling gas to southern markets, and Sydney in particular. In Brisbane, Arrow Energy was a major supplier this quarter.

Finally, this quarter saw an increase in activity through the now one year old Day Ahead Auction of pipeline capacity. Notably, there was record daily auction activity at the time South Australia became isolated from the rest of the NEM. Participants appeared to use the auction to rebalance positions for supplying the gas-driven South Australian electricity market.

Electricity markets at a glance
Q1 2020

Spot prices

First time Q1 prices below $110 per MWh across all regions since 2015

Demand

Mild summer and more rooftop solar led to lower summer demand

Generation

More generation offered at low prices, driven by lower fuel prices

Extraordinary events

Bushfires, infrastructure damage and COVID-19

FCAS

50 Hz

SA separation drove record FCAS costs

Outlook

Contract markets expecting low prices to continue

Gas markets at a glance
Q1 2020

Spot prices

Downstream prices at lowest levels since Q1 2016 ranging from $5.20 to $6.27/GJ

Domestic demand

Significantly down from Q1 2019 in SA and other states reflecting decline in power generation sector demand

International prices

International oil and spot gas prices plummet hitting record lows

LNG export

The mix of deliveries changed slightly away from China

Gas production

Lowest quarterly production at Longford in 5 years

Spot markets

Producers selling spot gas to industrials—trade about 10% of demand

1. Electricity

1.1 Quarterly spot prices

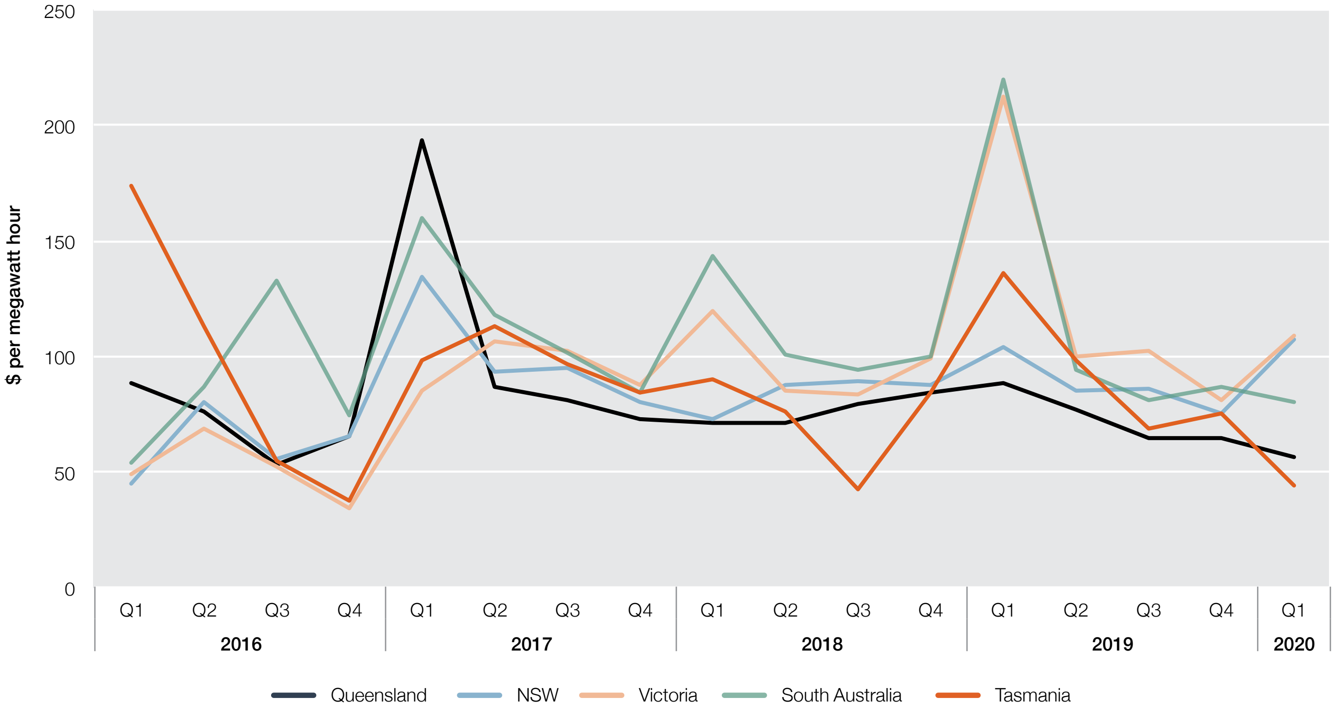
- For the first time since 2015, Q1 average prices were below $110 per MWh in each region.
- Queensland, Tasmania, South Australia and Victoria saw their lowest Q1 prices since 2012, 2015, 2016 and 2017, respectively.

Quarterly volume weighted average (VWA) spot prices in most National Electricity Market (NEM) regions were low in Q1 2020. Quarterly prices ranged from $44 per MWh in Tasmania to $109 per MWh in Victoria (figure 1.1). Even in Victoria and NSW, where short periods of volatility led to somewhat higher average wholesale prices than elsewhere in the NEM, prices were still moderate by recent Q1 standards.

Individually, prices this quarter were the lowest Q1 prices observed since 2012 in Queensland, 2015 in Tasmania, 2016 in South Australia and 2017 in Victoria. Across the NEM as a whole, Q1 2020 marked the first time since 2015 that Q1 prices were below $110 per MWh in all regions.

In some regions, these price outcomes were markedly different from those a year earlier. In Victoria and South Australia, Q1 average prices were down well over $100 per MWh on prices a year previously. Comparisons with Q1 2019 outcomes, however, are difficult because weather conditions in Q1 2019 were generally hotter than in Q1 2020, which drove higher demand (section 1.4).

Figure 1.1 Quarterly spot prices (VWA)



Source: AER analysis using NEM data.

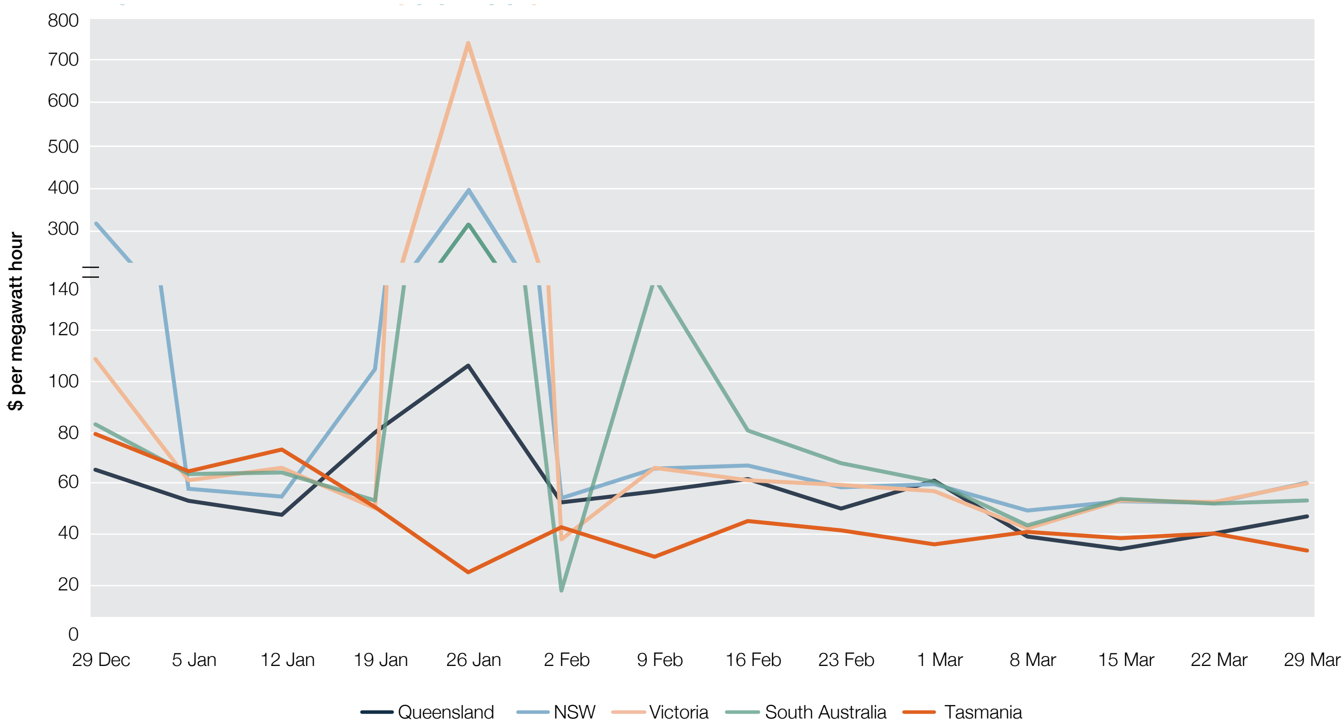
Across the quarter, average weekly prices were subject to significant week to week volatility until mid-February (figure 1.2). For the first week of the quarter, average spot prices in NSW were over $300 per MWh. This was largely driven by the events of 4 January, where high demand and network outages due to bushfires resulted in the spot price rising above $5000 per MWh between 4 pm and 6 pm.

The week beginning 26 January saw average weekly spot prices reach $744 per MWh in Victoria, $399 per MWh in NSW, and $317 per MWh in South Australia. On 30 January, higher than forecast demand, lower than forecast wind generation and generator trips saw spot prices in Victoria and South Australia rise above $10 000 per MWh for the 6.30 pm and 7 pm trading intervals. On 31 January, South Australia was isolated from the rest of the NEM for 18 days after storms damaged transmission infrastructure. Due to constraints invoked by Australian Energy Market Operator (AEMO), tight supply and demand conditions driven by hot weather, and technical plant issues, prices exceeded $5000 per MWh in NSW, Victoria and South Australia.

From the week beginning 16 February, prices in all regions progressively converged and remained below $74 per MWh for the remainder of the quarter. This coincided with generally milder weather and lower demand. The fact that prices were moderate from mid-February drove the overall quarterly price outcomes highlighted earlier.

Tasmania was the lowest priced region for six weeks in the quarter. Interestingly, Tasmania's lowest weekly price for the quarter was in the week beginning 26 January, where the four mainland regions had their highest weekly prices for the quarter. It appears that throughout much of this week, Tasmania's generation capacity was being offered in a way to ensure it was dispatched and could take advantage of the higher prices on the mainland.

Figure 1.2 Weekly spot prices (VWA)



Source: AER analysis using NEM data.

Notes: Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter.

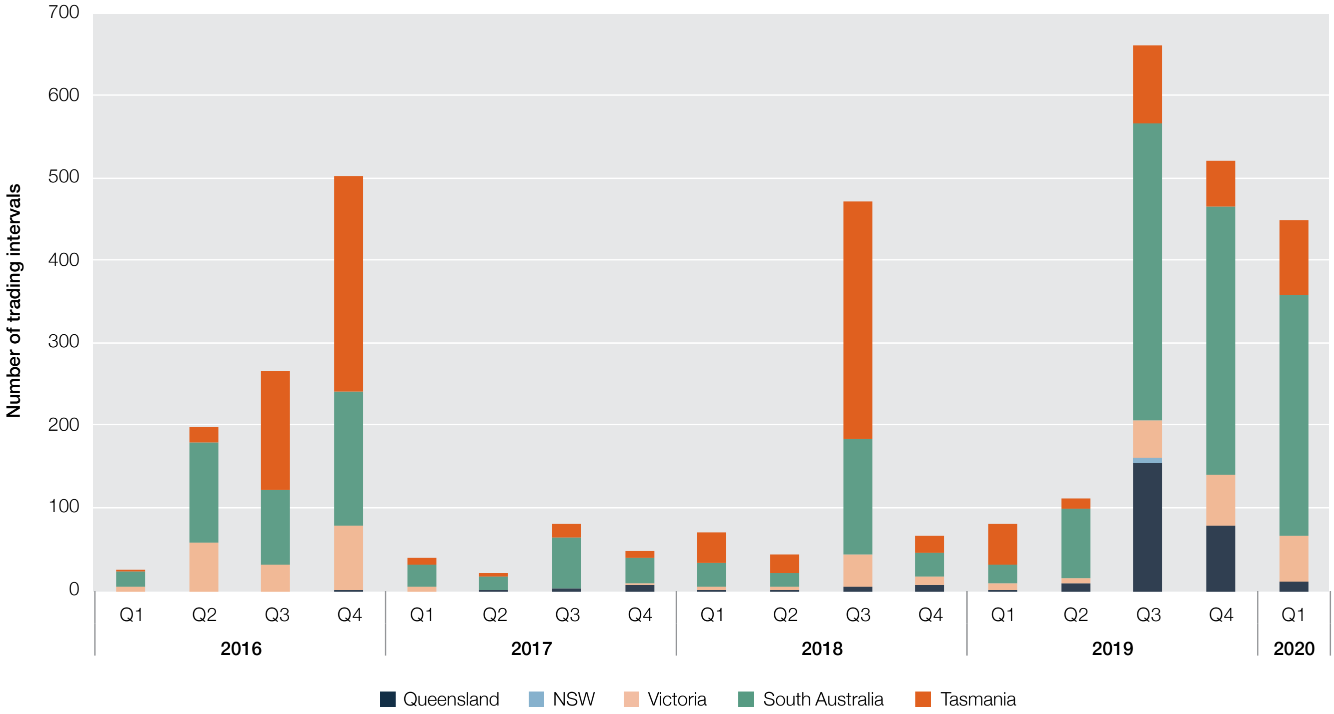
Breaking down these prices further reveals a number of other significant outcomes in the quarter.

First, the few hours of high prices made a significant contribution to overall price outcomes in Victoria and NSW. Prices above $5000 per MWh contributed $54 per MWh (or 50 per cent) to the overall Victorian quarterly price of $109 per MWh and $43 per MWh (or 40 per cent) to the overall NSW quarterly price of $108 per MWh.

Further, for most of the time in Q1 2020 half hourly prices were significantly below their levels a year previously. For example, in Victoria 88 per cent of spot prices in Q1 2020 were less than $70 per MWh (compared to 15 per cent in Q1 2019). In NSW, 87 per cent of spot prices in Q1 2020 were less than $70 per MWh (compared to 22 per cent in Q1 2019), while in South Australia, 84 per cent of spot prices in Q1 2020 were less than $70 per MWh (compared to 15 per cent in Q1 2019).

Finally, there were a record number of negative prices in Q1 2020 (figure 1.3). There were 450 negative prices in Q1 2020—more than four times higher than the previous Q1 record of 104 negative prices in 2014. South Australia accounted for almost two thirds of the total negative prices across the NEM in Q1 2020. These prices reduced the Q1 average spot price in South Australia by just under $5 per MWh. Over 40 per cent of the negative prices in South Australia in Q1 occurred while South Australia was separated from the rest of the NEM. This was driven by a combination of relatively cooler temperatures and higher wind generation at this time.

Figure 1.3 Quarterly negative prices



Source: AER analysis using NEM data.

Notes: Count of spot price below $0 per MWh in each quarter.

1.2 Contract Markets

- Actual price outcomes in Q1 2020 were generally lower than the market expected, particularly in South Australia and Victoria.
- Contract markets are expecting lower spot prices to continue.

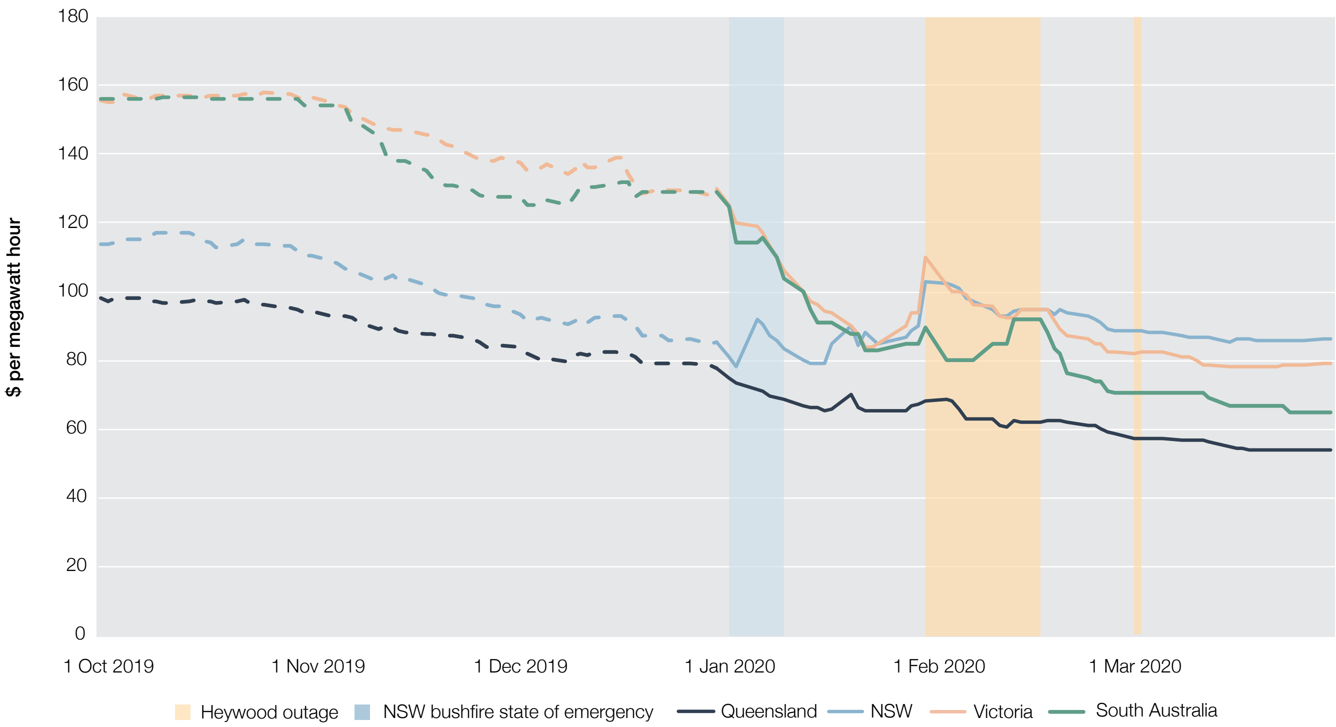
Coming into Q1 2020, there were expectations of high wholesale prices, particularly in Victoria and South Australia (figure 1.4). While the price of base futures decreased throughout Q4 2019, base futures prices for Q1 2020 were still around $130 per MWh in South Australia and Victoria at the start of the quarter.

Base futures prices for Q1 2020 continued to fall in both Victoria and South Australia as the quarter progressed. This reflected the lower than expected wholesale prices that generally prevailed throughout the quarter in both regions.

In NSW, base futures prices for Q1 2020 increased significantly in January. This increase reflected the higher than expected wholesale prices in NSW in January, driven by the periods of high prices in early January during the bushfires and again at the end of the month.

Another feature of how futures markets operated throughout Q1 2020 is that the close alignment of Victorian and South Australian prices that was expected at the start of the quarter did not eventuate. This was largely driven by the Heywood outage which separated South Australia from the rest of the NEM and caused a stronger alignment of contract prices in NSW and Victoria. This was then reflected in expectations for the rest of the quarter.

Figure 1.4 Base future prices Q1 2020



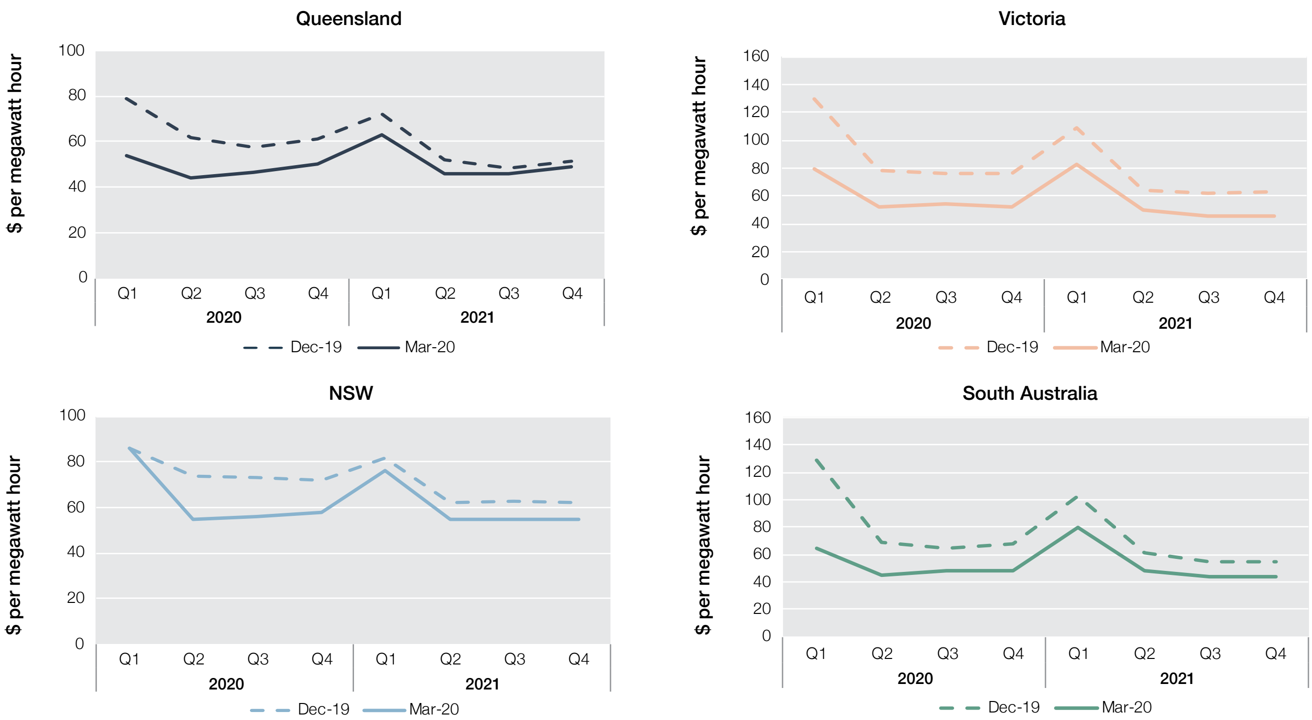
Source: AER Analysis using ASX Energy data.

Notes: Daily closing price for Q1 2020 quarterly base futures from 1 October 2019 to 31 March 2020. NSW declared state of emergency from 2 to 10 January. Heywood interconnector outage from 31 January to 17 February and on 2 March.

Looking forward, base futures price expectations are in line with the recent trends we have seen in the market. Prices are expected to be low and stable across the NEM for the rest of 2020, with quarterly prices expected to remain below $60 per MWh in all regions (figure 1.5). As is typical in the NEM prices are expected to be higher for Q1 2021, but still moderate at between $63 and $83 per MWh.

These expectations of futures prices have shifted significantly recently. By the end of Q1 2020, prices were expected to be significantly lower than what was expected at the end of Q4 2019, across all regions and in all quarters. While the expected impacts of COVID-19 on economic activity will have been a factor, this shift in expectations appears to largely reflect the market outcomes in Q1 2020. Notably, prices in the NEM, and particularly in Victoria and South Australia, were generally much lower than expected in Q1 2020. This seems to be influencing expectations of ongoing lower prices in future.

Figure 1.5 Forward base future prices



Source: AER analysis using ASX Energy data.

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

1.3 Lack of reserve

- Despite the extreme events that occurred in the quarter, there was always enough reserve capacity to satisfy demand.
- The market experienced the highest number of hours of actual LOR 2 conditions in the last four years with the majority occurring in NSW.

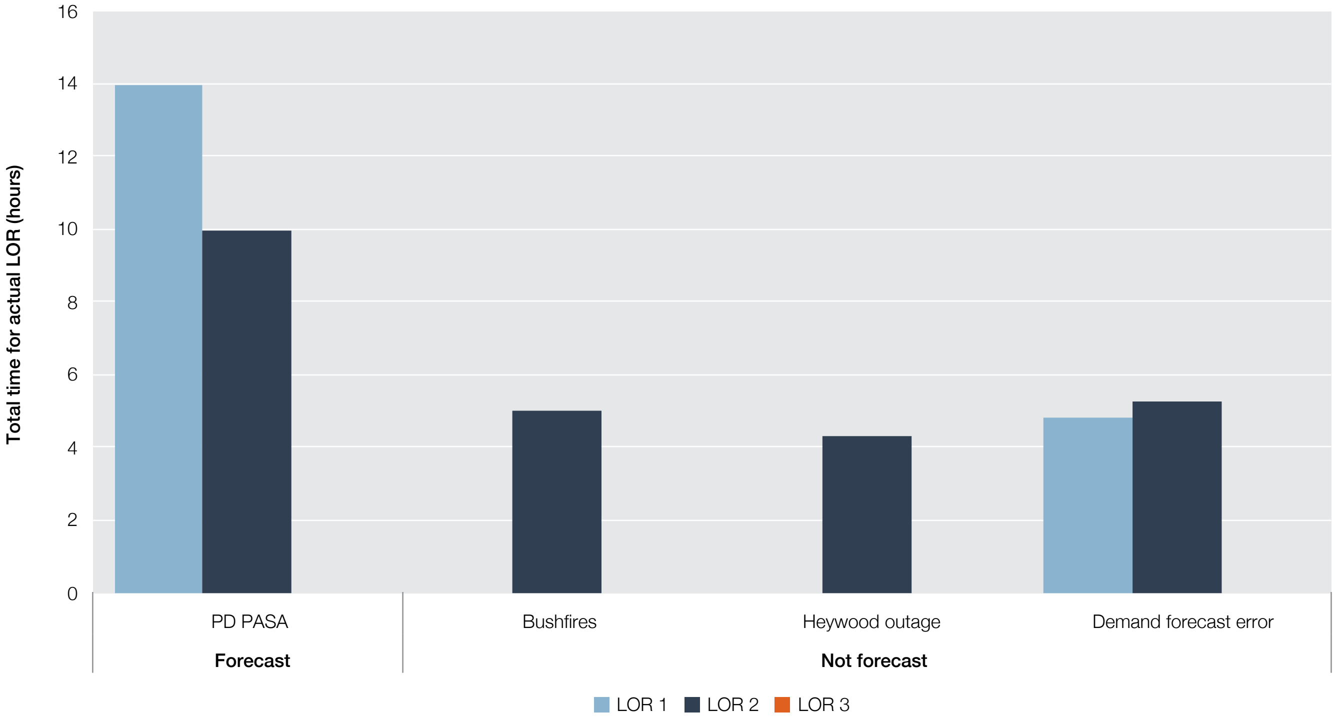
Lack of reserve (LOR) notices are an indicator of the supply demand balance and are an important tool to communicate potential and actual shortfalls to the market. When forecast reserve capacity falls below certain thresholds, AEMO uses forecast LOR notices to elicit a market response to increase generation or reduce demand. Actual LOR notices are issued if the market response is insufficient or an unplanned event occurs.

There are three reserve thresholds which relate to managing the power system in the event of a defined number of unplanned failures of either transmission or generating equipment (credible contingencies). One of our focus pieces this quarter provides a more detailed explanation of LOR thresholds and AEMO's levers to manage the market in periods where there are low levels of reserve.

Nearly half of the LOR conditions that occurred in Q1 2020 were not forecast in pre-dispatch (figure 1.6). The majority of the conditions that weren't forecast were LOR 2 that resulted from unplanned extreme events such as the bushfires around the Snowy region and the unexpected loss of the Heywood interconnector in January.[1]

LOR conditions that were due to 'demand forecast errors' occurred as a result of higher than forecast demand on 30 January in Victoria and South Australia and on 1 February in NSW.

Figure 1.6 Actual lack of reserve conditions in Q1 2020



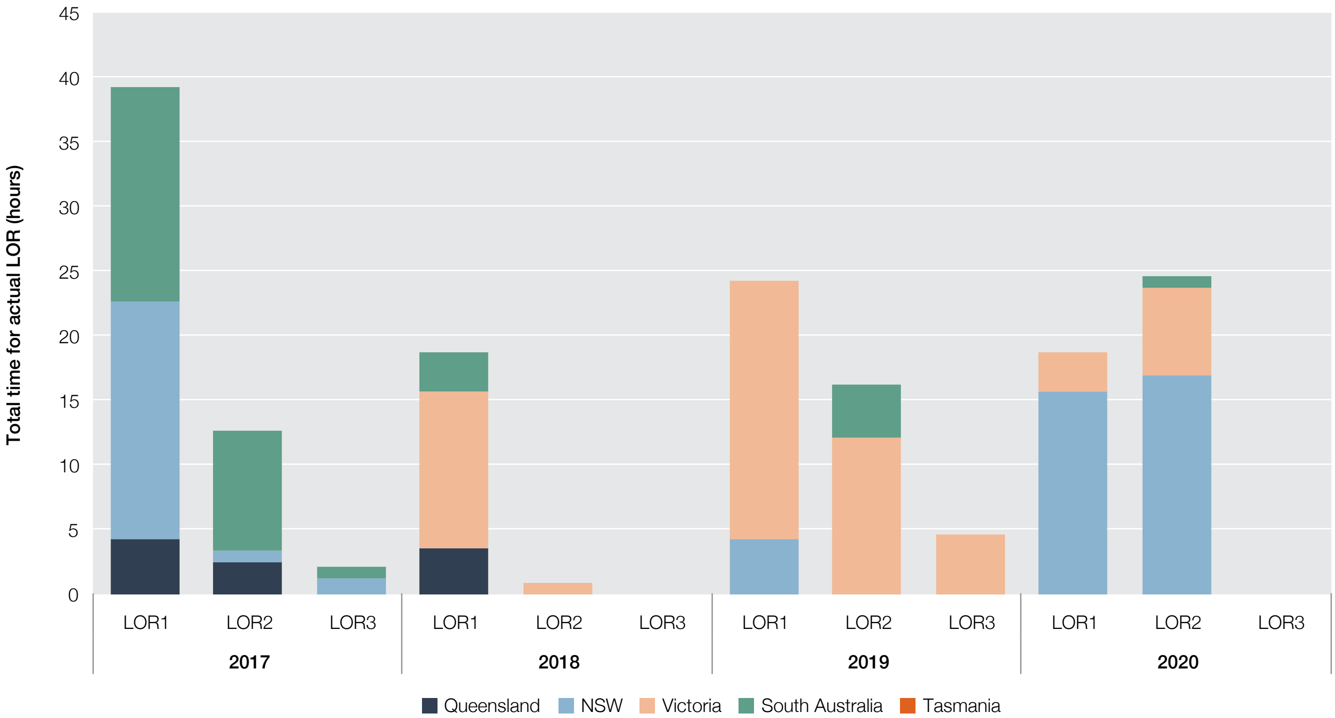
Source: AER analysis using NEM data.

Notes: Actual LOR conditions in Q1 2020. Bushfires refers to the events in NSW on 4 January. Heywood outage refers to the events on 31 January. Demand forecast error refers to periods where demand was higher than forecast causing the reserve levels to be lower than expected.

Q1 2020 saw the highest number of hours of LOR 2 conditions in the last four years. These occurred across seven days in the first half of the quarter with the majority in NSW (figure 1.7). Despite the extreme events that occurred in Q1 2020, no LOR 3 conditions occurred. That is, in Q1 2020 there was always enough reserve capacity to satisfy demand in the market.

1 An actual LOR 2 occurs if the single largest credible contingency would result in there not being enough supply to meet demand in a region.

Figure 1.7 Lack of reserve conditions in Q1



Source: AER analysis using NEM data.

Notes: Total number of hours based on the difference between the 'actual' and 'cancellation' notices. In the absence of a cancellation notice (occurred in 2017), the forecast cancellation time was used.

1.4 Demand

- Demand was low this quarter as a result of generally mild temperatures and increased rooftop solar.
- To date, restrictions enacted in response to the COVID-19 pandemic do not appear to be significantly influencing demand in the NEM.

Demand was low across most regions of the NEM in Q1 2020. This was a result of a generally mild summer (notwithstanding some extreme weather events) and an increased contribution from rooftop solar. Demand was particularly low in South Australia, where it reached record Q1 lows.[2] There were also lower levels of demand in NSW and Victoria compared to Q1 2019.

In Q1 2020 demand in South Australia, NSW and Victoria trended lower than in Q1 2019 (figure 1.8). In contrast, average demand in Queensland and Tasmania was relatively unchanged. The reduction in overall demand in these regions was driven by fewer days of high demand due to hot weather in 2020 than in 2019, and more days of low demand.

Our analysis also shows that demand trended down in each region as the quarter progressed. This is expected as temperatures fall with the transition from summer to autumn, reducing air conditioning demand.

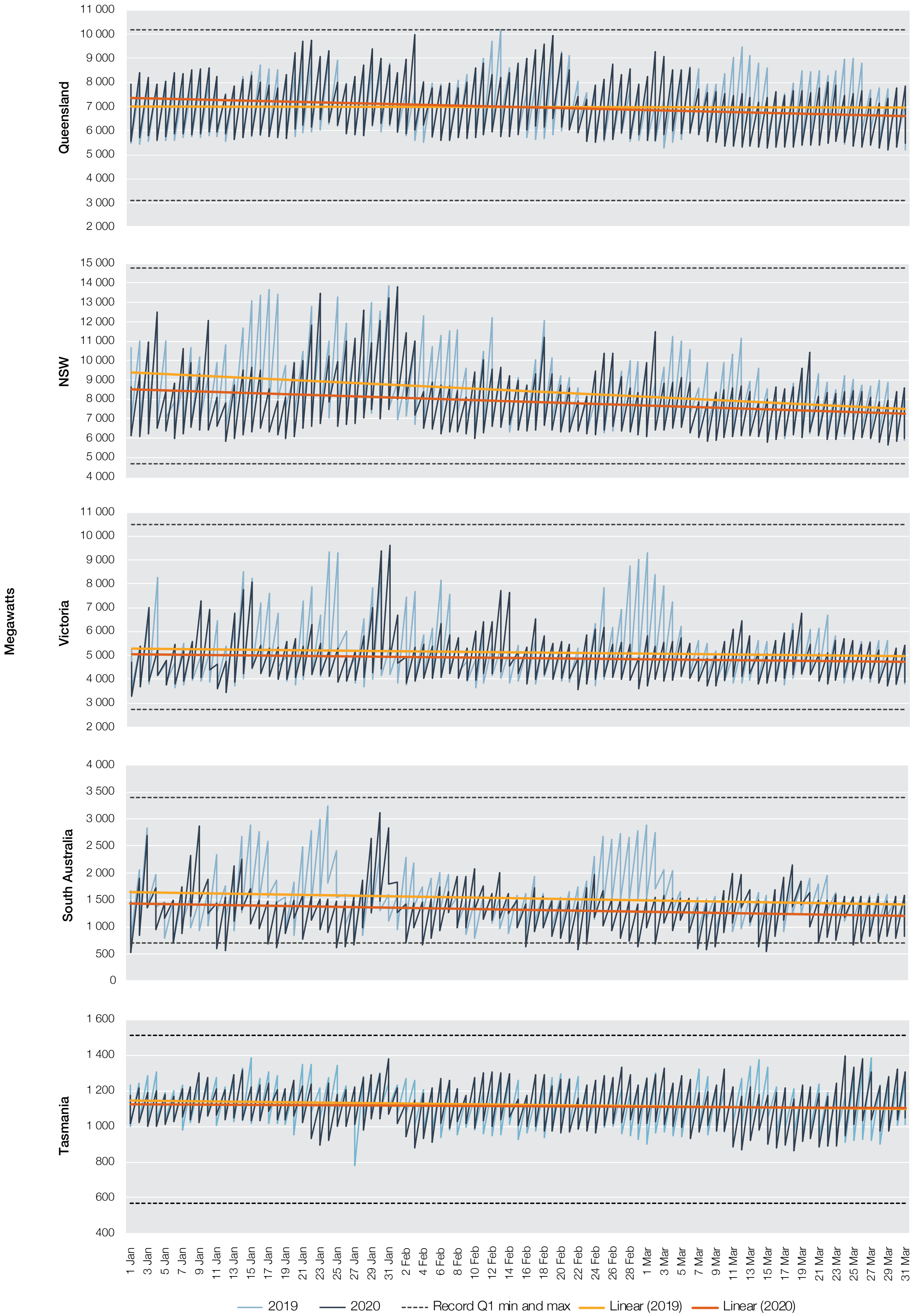
Demand fell comparatively more in South Australia than in any other region compared to Q1 2019. This quarter, demand fell below 700 MW, not only for the first time, but on 21 different days. On one of those days, South Australia experienced a new record Q1 minimum demand of 526 MW. Victoria also experienced its lowest Q1 demand since 1999.

Even though demand was generally lower than last year, there were individual days of high demand across the quarter, which were driven by high temperatures. Notably, extreme temperatures on the last two days of January led to a coincidence of high demand across NSW, Victoria and South Australia. This, and the separation of South Australia from the rest of the NEM contributed to prices above $5000 per MWh in the three regions.[3]

2 Demand in this report refers to demand met from the grid (i.e. native demand). It does not include demand met from other sources, such as rooftop solar. Importantly, rooftop solar generation decreases demand.

3 We examine the factors leading to those prices in more detail in our $5000 reports.

Figure 1.8 Q1 2020 demand compared to Q1 2019



Source: AER analysis using NEM data.

Notes: Uses daily maximum and minimum native demand from 1 January to 31 March in 2019 and 2020. Record refers to the highest and lowest record native demand that has occurred in each region during Q1 since market start.

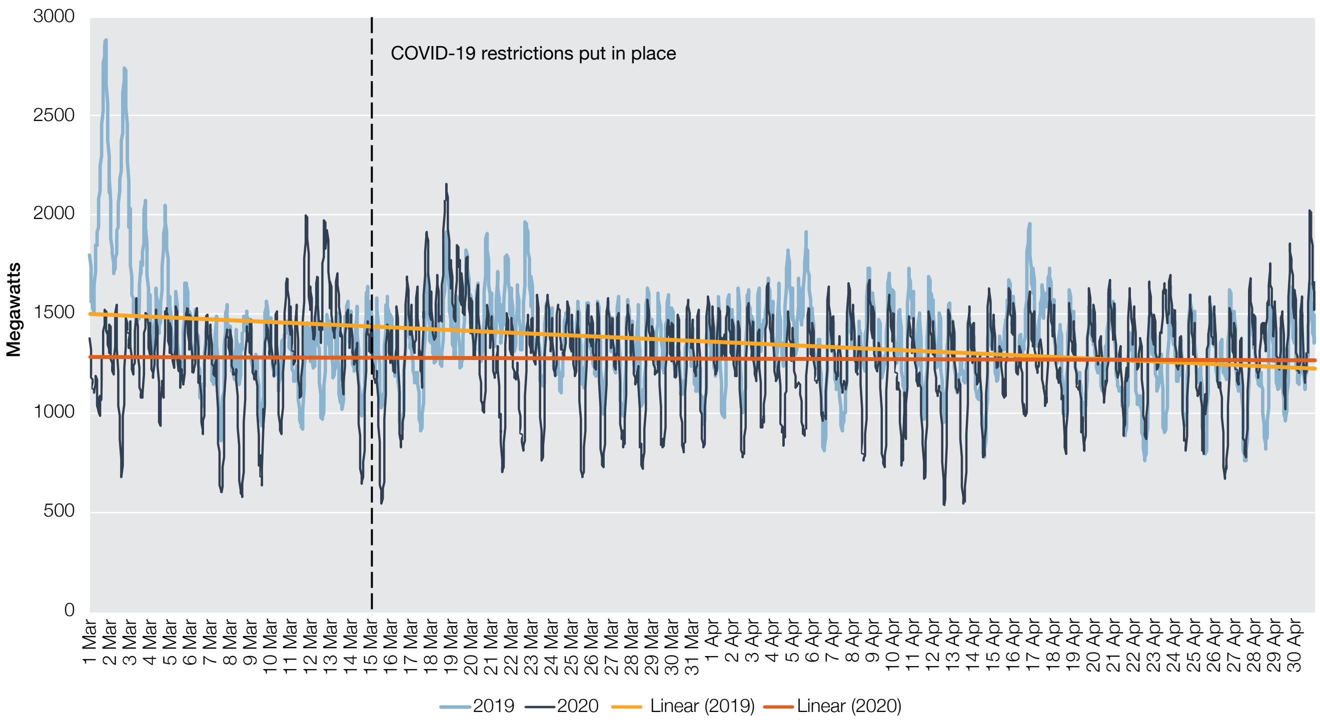
COVID-19 restrictions do not yet appear to be having an impact on demand

As highlighted above, demand tracked down as Q1 2020 progressed in each region. While this is a trend we tend to see every year in the NEM, we have more closely tracked demand trends from when the COVID-19 restrictions were put in place in mid-March to see if these restrictions are having any additional impact on overall demand.

To date, there does not appear to be a significant impact on demand as a result of these measures. Generally, demand has continued to trend down since the beginning of March in all regions. In NSW for example, the downward trend in demand seen in recent weeks appears to be similar to the reduction in demand observed at this time last year (figure 1.9).

So far, there does not appear to be a major 'step down' in demand from when these restrictions were put in place. Indeed, prevailing weather still seems to be the key driver of demand changes. Notably, the days of highest demand (in early and mid-March) were all on the hottest days. This weather drove high demand, even after COVID-19 restrictions had been put in place. Compared to other international markets, this may suggest that COVID-19 may not have the same impacts on demand in the NEM. That said, it is early days and we are closely monitoring demand trends.

Figure 1.9 Recent New South Wales demand, 2020 compared to 2019



Source: AER analysis using NEM data.

Notes: Uses daily maximum and minimum native demand from 1 March to 30 April 2019 and 2020.

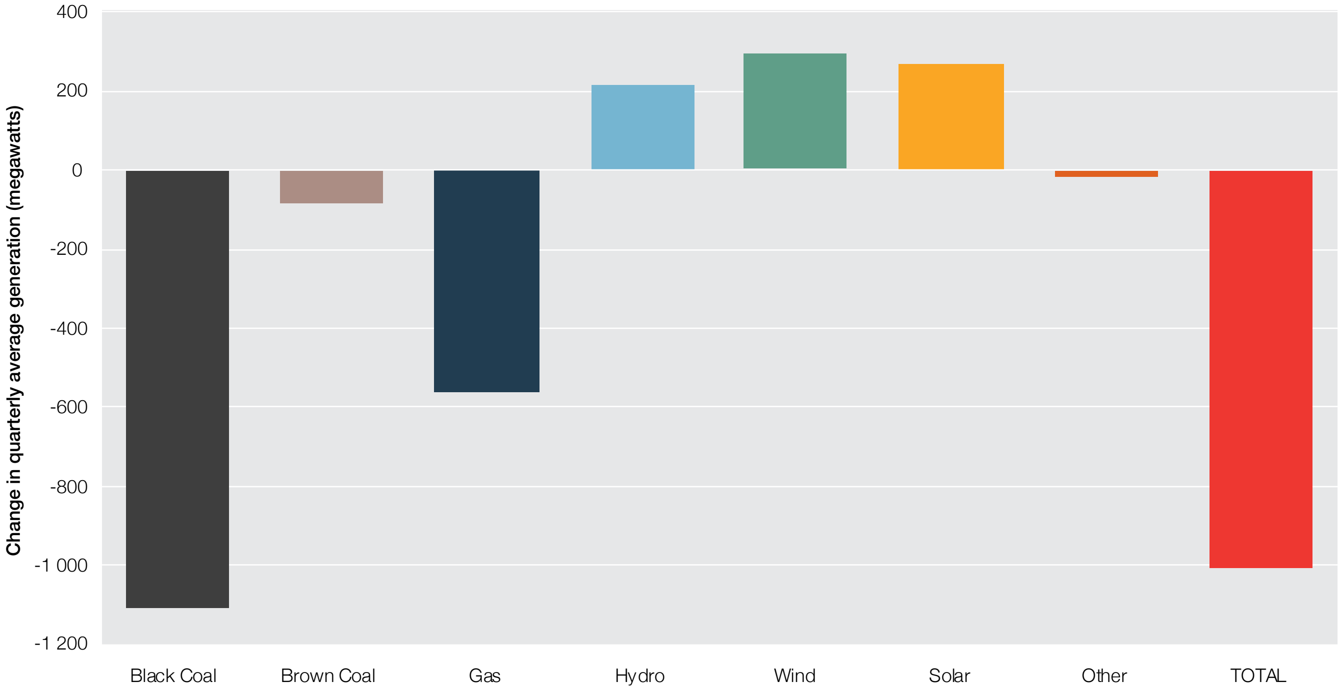
1.5 Generation

› Average quarterly generation in the NEM was lower in Q1 2020 than in Q1 2019. The fall was observed mostly in lower levels of black coal and gas generation.

Average quarterly generation in the NEM was 1000 MW (or 4 per cent) lower in Q1 2020 than in Q1 2019, reflecting low summer demand (figure 1.10). The largest reduction was in black coal generation, which was lower by 1100 MW, and gas generation, which was lower by 560 MW.

While average thermal generation was lower, wind, solar and hydro generation were higher in Q1 2020 than in Q1 2019. Some of this lower priced renewable generation displaced higher priced thermal generation, even though fuel input costs for thermal generation were notably lower than a year ago (section 1.7).

Figure 1.10 Generation Q1 2019 to Q1 2020



Source: AER analysis using NEM data.

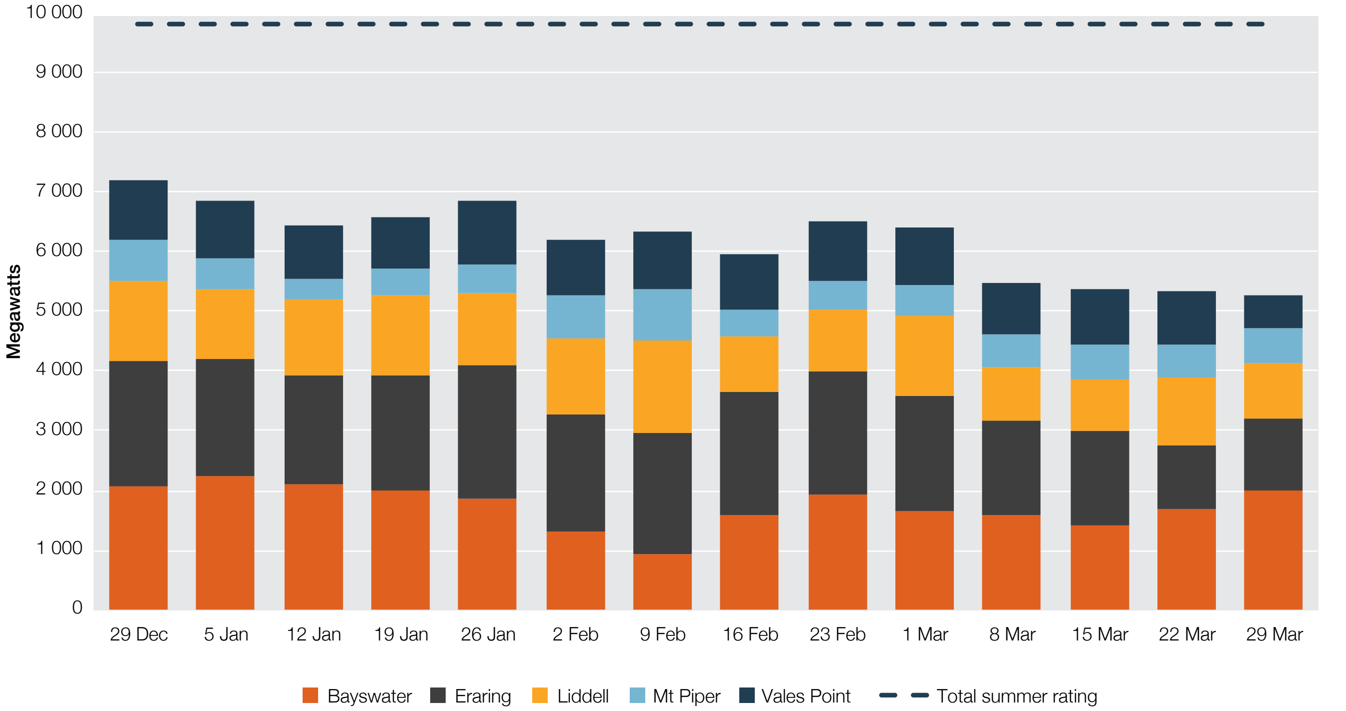
Notes: Compares quarterly average metered generation output by fuel type in Q1 2020 and Q1 2019. Solar generation includes large scale generation only. Rooftop solar PV is not included as it affects demand not grid-supplied generation output.

Nearly all of the reduction in black coal generation occurred in NSW. Average quarterly black coal generation in NSW was down 880 MW compared to Q1 2019 with generation levels falling as the quarter progressed (figure 1.11). In part this reflected demand conditions in NSW, with Q1 2020 demand falling more in NSW than in some other regions. It also reflected lower generator availability, with NSW black coal generators less available in Q1 2020 than in Q1 2019, as a result of significant outages (table 1.1).

Units at Bayswater power station were off for a combined total of 85 days, which reduced the station's average availability over the quarter by 475 MW. In the first two weeks of February two Bayswater units were offline and generation in the week starting 9 February was less than half that at the start of the quarter.

Units at Mount Piper power station were off for a combined total of more than 60 days, which reduced its average availability by 350 MW compared to Q1 2019. The majority of Mount Piper outages were for planned maintenance. In addition, generation at Liddell and Eraring fell in March as a result of outages.

Figure 1.11 New South Wales black coal average weekly generation, by station

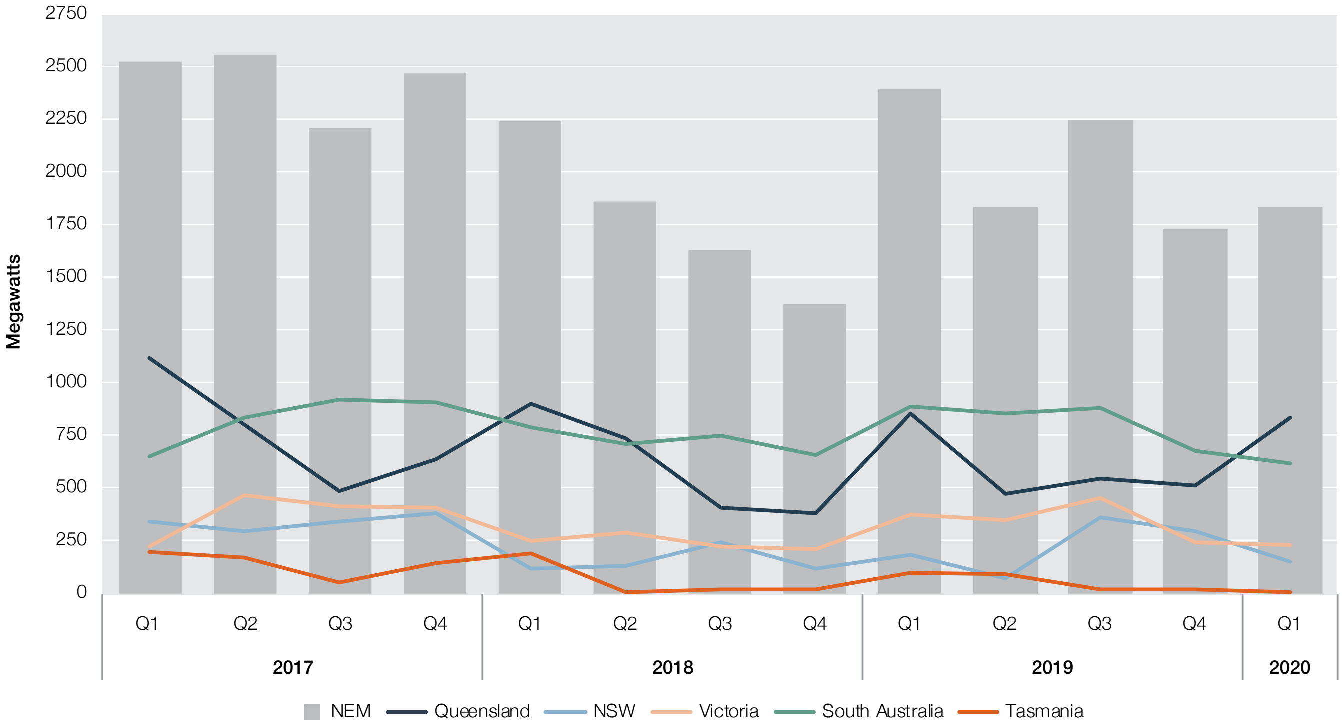


Source: AER analysis using NEM data.

Notes: The stacked bar indicates average station generation by week. Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter. The dotted line indicates the maximum summer rating or maximum amount of availability that all the NSW black coal stations could offer during summer.

Gas generation in the NEM was significantly lower in Q1 2020 than in Q1 2019, falling to its lowest Q1 level in the last five years (figure 1.12). This happened despite significant reductions in the wholesale price of gas (section 2.1) and was driven by lower demand, particularly in South Australia and Victoria.

Figure 1.12 Gas, average quarterly generation



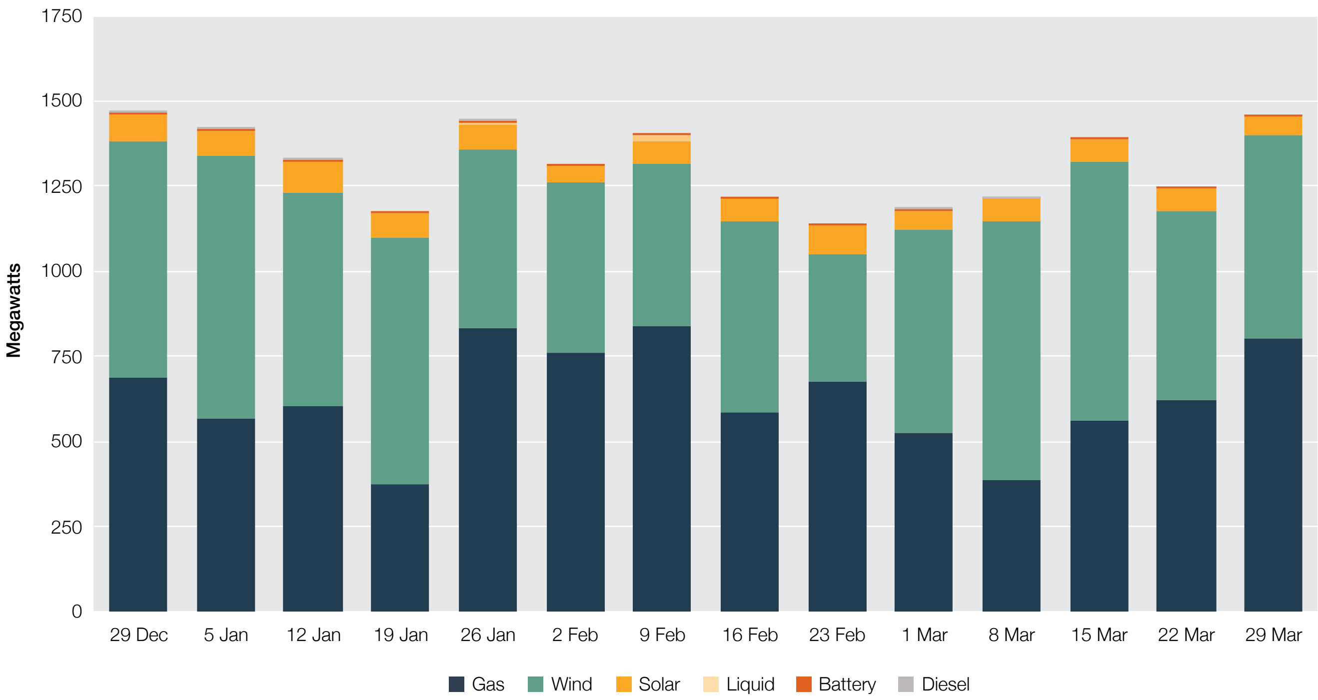
Source: AER analysis using NEM data.

Notes: The lines indicate the average quarterly gas generation by region. The bars indicate NEM-wide gas generation in each quarter.

While gas generation was lower in every region compared to Q1 2019, the fall in South Australia accounted for almost half the total reduction in the NEM. Gas generation was also significantly lower in Tasmania and Victoria.

The 30 per cent fall in gas generation in South Australia was largely driven by lower demand in the region. South Australia relies almost exclusively on wind and gas generation (figure 1.13). In Q1 2020, this lower demand predominantly impacted gas generation. Weeks where overall generation was low tended to have low levels of gas generation.

Figure 1.13 South Australia, average weekly generation



Source: AER analysis using NEM data.

Notes: The stacked bars indicate average generation for each fuel type by week. Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter. Solar generation includes large scale generation only. Rooftop solar PV is not included as it affects demand not grid-supplied generation output.

In addition to the impact of lower demand, there were high levels of wind generation in the weeks starting 19 January and 8 March in South Australia, which displaced gas generation. In those weeks wind generation accounted for around 60 per cent of average weekly generation in the region, while gas accounted for only 30 per cent.

There were, however, some periods of higher gas generation in the quarter. Starting the last week of January, high temperatures in NSW, Victoria and South Australia drove higher levels of gas generation. This continued into the first two weeks of February as South Australia became electrically separated from the rest of the NEM. During this period, additional gas generation was dispatched in South Australia as wind generation was constrained down to maintain power system security in the region. The second period of high gas generation in South Australia occurred in the last week of the quarter, coinciding with brown coal outages in Victoria.

While average thermal generation in the NEM was lower, wind, solar and hydro generation were higher in Q1 2020 than in Q1 2019. Average wind generation output was 18 per cent higher in Q1 2020 than in Q1 2019 as an additional 1550 MW of wind capacity entered the market, almost half in Victoria. Similarly, solar generation output was 54 per cent higher in Q1 2020 than in Q1 2019 as almost 1200 MW of additional grid scale solar entered the market, mostly in Queensland and NSW. Finally, hydro generation output was also higher, with the increase occurring mostly in Tasmania and NSW.

Table 1.1 Major generator outages

STATION, COMPANY	FUEL TYPE, CAPACITY SUMMER RATING	NUMBER OF DAYS OFFLINE IN Q1 2020	REASON FOR OUTAGE
Queensland			
Condamine, QGC Sales	Gas 144 MW	70 days	Planned
Gladstone, CS Energy	Black coal, 6 units, 280 MW each	Unit 1: 25 days	Unplanned—'turbine vibrations', 'technical issues'
		Unit 2: 15 days	Unplanned—'technical issues'
		Unit 3: 33 days	Planned (8 days)
			Unplanned (25 days)—'technical issues'
		Unit 4: 47 days	Planned (35 days)
			Unplanned (12 days)—'unit trip', 'technical issues'
Tarong, Stanwell Corp	Black coal 4 units, 350 MW each	Unit 4: 25 days	Unplanned—'tube leak'
Tarong North, Stanwell Corp	Black coal, 443 MW	48 days	Planned
NSW			
Bayswater, AGL Energy	Black coal 4 units, 630 MW each	Unit 2: 16 days	Unplanned—'unit trip', 'plant limits'
		Unit 3: 13 days	Unplanned—'plant failure'
		Unit 4: 55 days	Unplanned—'plant failure', 'unit trip'
Liddell, AGL Energy	Black coal 4 units, 450 MW each	Unit 2: 10 days	Unplanned—'load/ramp variation'
		Unit 3: 21 days	Unplanned—'unit trip', 'tube leak'
Mount Piper, EnergyAustralia	Black coal 2 units, 650 MW each	Unit 1: 19 days	Planned (7 days)
			Unplanned (12 days)—'tube leak'
		Unit 2: 43 days	Planned
Victoria			
Loy Yang A, AGL Energy	Brown coal, 4 units, 530 MW each	Unit 2: 38 days	Unplanned—'plant limits', 'plant failure'
Yallourn, EnergyAustralia	Brown coal 4 units, 355 MW each	Unit 1: 10 days	Unplanned—'plant failure', 'unit trip'

Source: AER analysis using NEM data.

Notes: The table outlines major generator outages throughout Q1 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 Q1 2020 but have been excluded from the 'reason for outage'.

1.6 New entry

- Six new generators totalling over 800 MW of capacity entered the market this quarter.
- The largest of the new entrants was the 335 MW Dundonnell wind farm in Victoria.

Table 1.2 New entry

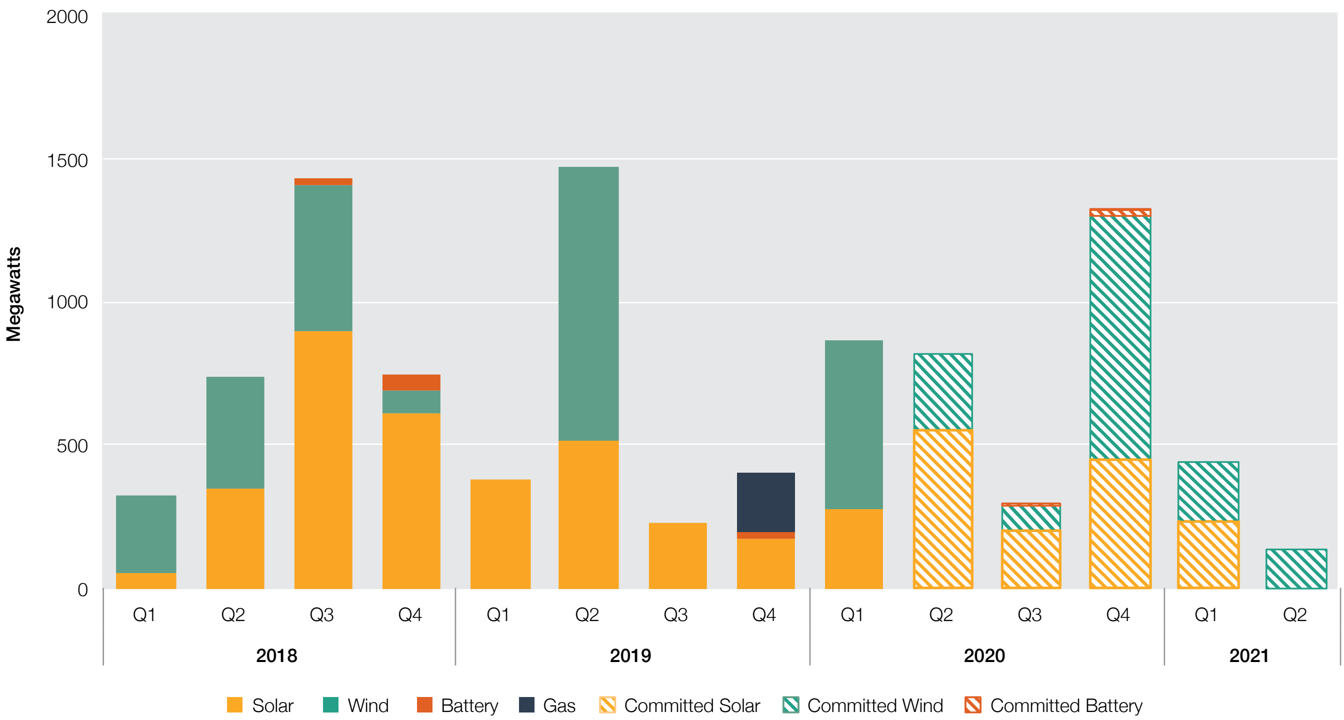
STATE	STATION	FUEL TYPE	HIGHEST CAPACITY OFFERED IN Q1 2020 (MW)	REGISTERED CAPACITY (MW)	COMMENCED OPERATIONS
Queensland	Yarranlea solar	Solar	97	103	January 2020
Queensland	Maryrorough solar farm	Solar	13	35	March 2020
NSW	Bomen solar farm	Solar	5	100	March 2020
Victoria	Dundonnell wind farm	Wind	4	335	March 2020
Tasmania	Cattle Hill wind farm	Wind	56	158	January 2020
Tasmania	Granville Harbour wind farm	Wind	26	112	February 2020

Three new wind farms with a total registered capacity of almost 600 MW and three new solar farms with a total registered capacity of almost 240 MW entered the market in Q1 2020 (table 1.2). Most of the new capacity was located in Victoria and Tasmania, with no new capacity entering in South Australia.

The largest new entrant was Dundonnell wind farm (335 MW) operated by Tilt. It was one of six projects underwritten by the Victorian Renewable Energy Auction Scheme in 2018 and is guaranteed to receive $56 per MWh for 15 years. Almost 90 per cent of its production is covered by long term contracts with the Victorian Government and Snowy Hydro. The wind farm is expected to be at full capacity by Q4 2020.

Since Q1 2019, almost 3000 MW of new generation has entered the market. A further 3000 MW of additional capacity is due to enter the market over the remainder of 2020 (figure 1.14).

Figure 1.14 Active and committed new entry



Source: AER analysis using NEM data.

1.7 Fuel costs

› Falling fuel prices have led to black coal and gas setting lower prices.

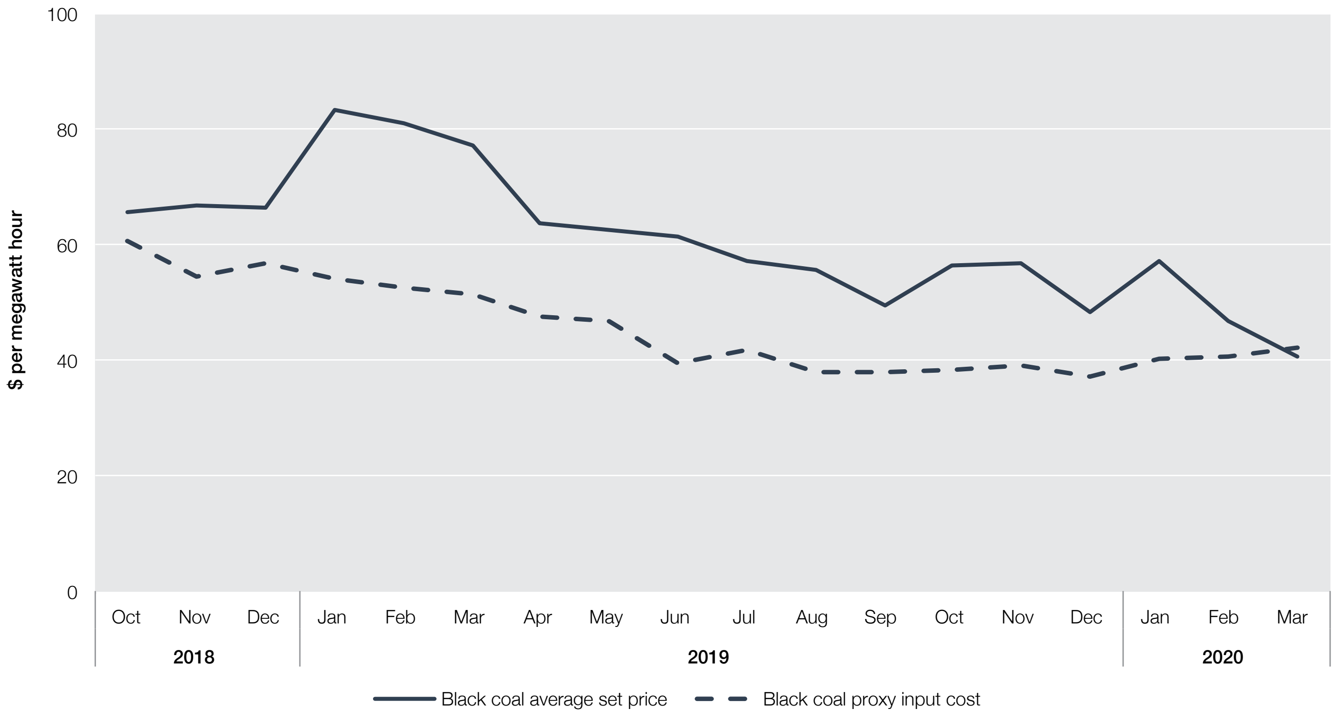
To assess how changes in fuel costs affect the NEM, we currently compare the price at which black coal or gas generators set price against the prices for those fuels. In the absence of detailed generator cost data, we use commodity prices as a proxy for input costs.

One of the main drivers of lower prices in Q1 2020 has been lower fuel costs. Lower fuel costs have led to increased offers of lower priced capacity. In turn, this has put downward pressure on the level at which black coal and gas set the price. Over the last year, the prices set by black coal and gas generators have trended downwards.

The proxy input costs for coal and gas generators are both lower than they were a year ago (figure 1.15–1.17).[4] In the case of gas, these prices continued to fall into 2020 (section 2.1).

In NSW, the price set by black coal has generally tracked the falling international coal price since the end of Q1 2019. In January 2020, there was an increase in the prices set by black coal generators from December levels, but the price they set in January 2020 was still more than $20 per MWh lower than in Q1 2019. Since February, the price set by black coal has been falling. Interestingly in March, the price set by black coal fell below the black coal proxy input cost where the average price set by black coal generators in NSW ($47 per MWh) was at its lowest level since late 2016.

Figure 1.15 International reference price for Newcastle spot thermal and coal, and average monthly price when black coal generators set the price in New South Wales



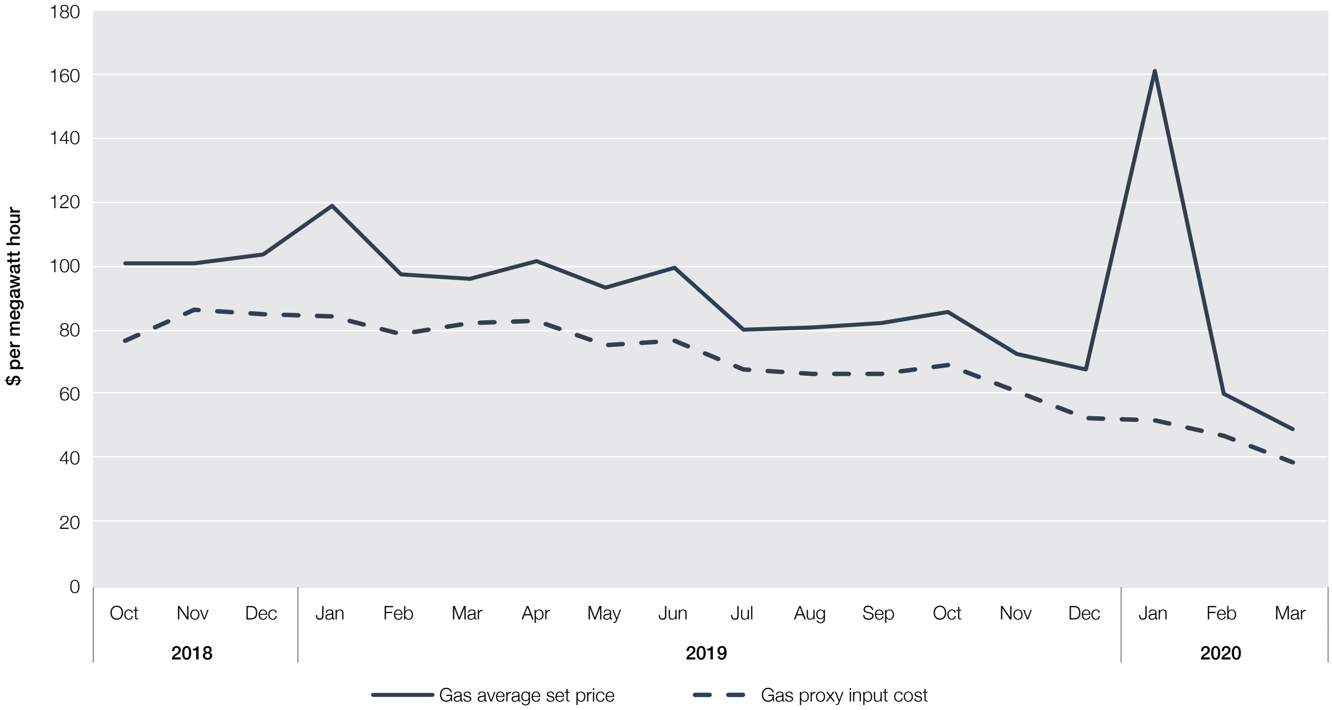
Source: AER analysis using globalCOAL data.

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

In NSW, the average price set by gas generators also generally followed the declining fuel price (figure 1.16). The exception to this was in January when the higher average price set by gas generators was driven by instances of high prices of above $5000 per MWh due to bushfires and high temperatures in NSW.

4 To assess how changes in fuel costs affect the NEM, we compare the price at which black coal or gas generators set price against the prices for those fuels. In the absence of detailed generator cost data, we use commodity prices as a proxy for input costs.

Figure 1.16 Sydney gas market price and average monthly price when gas generators set the price in New South Wales



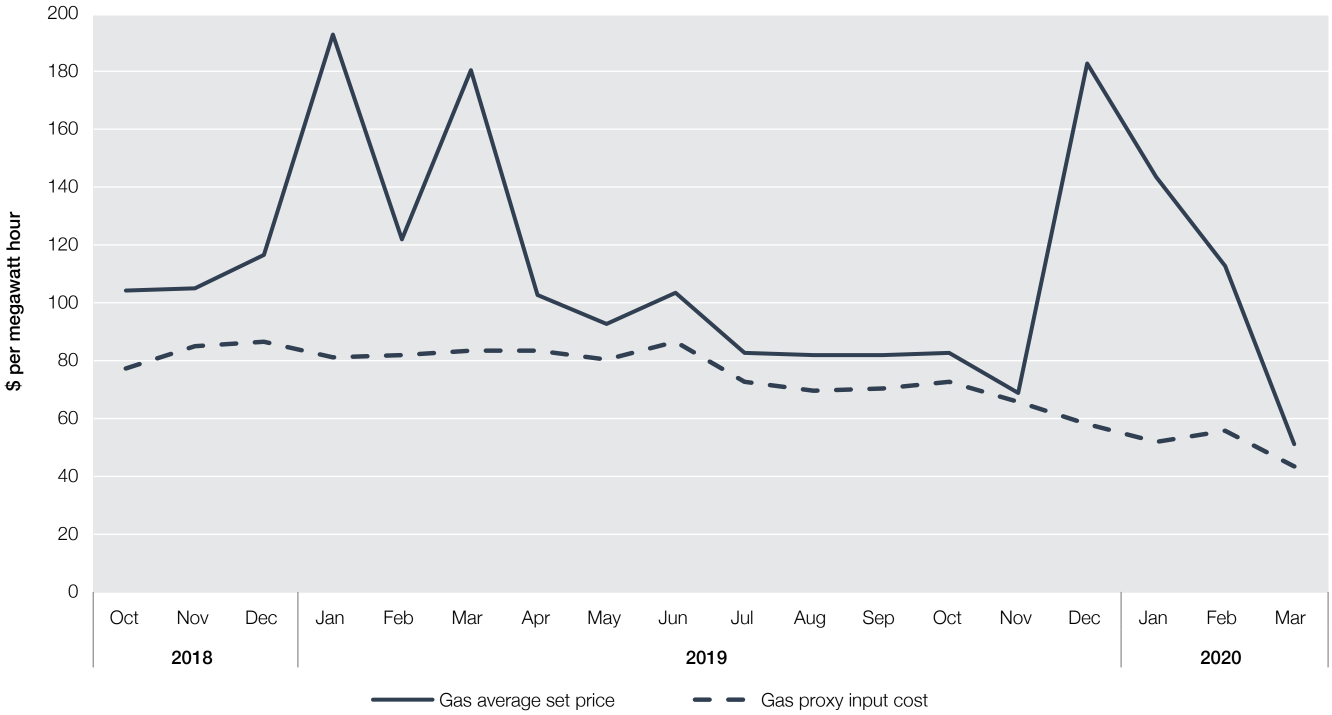
Source: AER analysis using NEM and gas price data.

Notes: Gas proxy input cost derived from Sydney Short Term Trading Market (STTM) price (AUD$ per GJ), converted to AUD$ per MWh with average heat rate for gas generators.

In South Australia, the average price set by gas generators also generally followed the declining fuel price (figure 1.17). However, this relationship broke down over summer. From December 2019 to February 2020, South Australian gas generators set the price at higher levels as a result of instances when the spot price exceeded $5000 per MWh or when South Australia was electrically separated from the rest of the NEM.

In March, the price at which South Australian gas generators set price realigned with falling gas prices. The average price set by gas in South Australia was down to around $50 per MWh.

Figure 1.17 Adelaide gas market price and average monthly price when gas generators set the price in South Australia



Source: AER analysis using NEM and gas price data.

Notes: Gas proxy input cost derived from Adelaide Short Term Trading Market (STTM) price (AUD$ per GJ), converted to AUD$ per MWh with average heat rate for gas generators.

Some gas plant is run as “peaking” plant and might only operate a couple of times a year when supply and demand conditions are the tightest. Other gas generators fill an “intermediate” role in the market. As a result, peaking gas generators typically set the price at higher levels than their intermediate counterparts. When accounting for peaking gas generators separately to intermediate plant, we observe that:

- In NSW, intermediate plant set the price at $145 per MWh in January, while peaking plant set it at $602 per MWh.
- In South Australia, intermediate plant set the price at $105 per MWh in January, while peaking plant set it at $954 per MWh.

We discuss the impact of lower fuel costs on black coal and gas generators’ offers and the subsequent impact on prices in section 1.8 and section 1.9.

1.8 Participant offers

› Generators offered more low priced capacity into the market this quarter compared to the same quarter last year, except in South Australia.

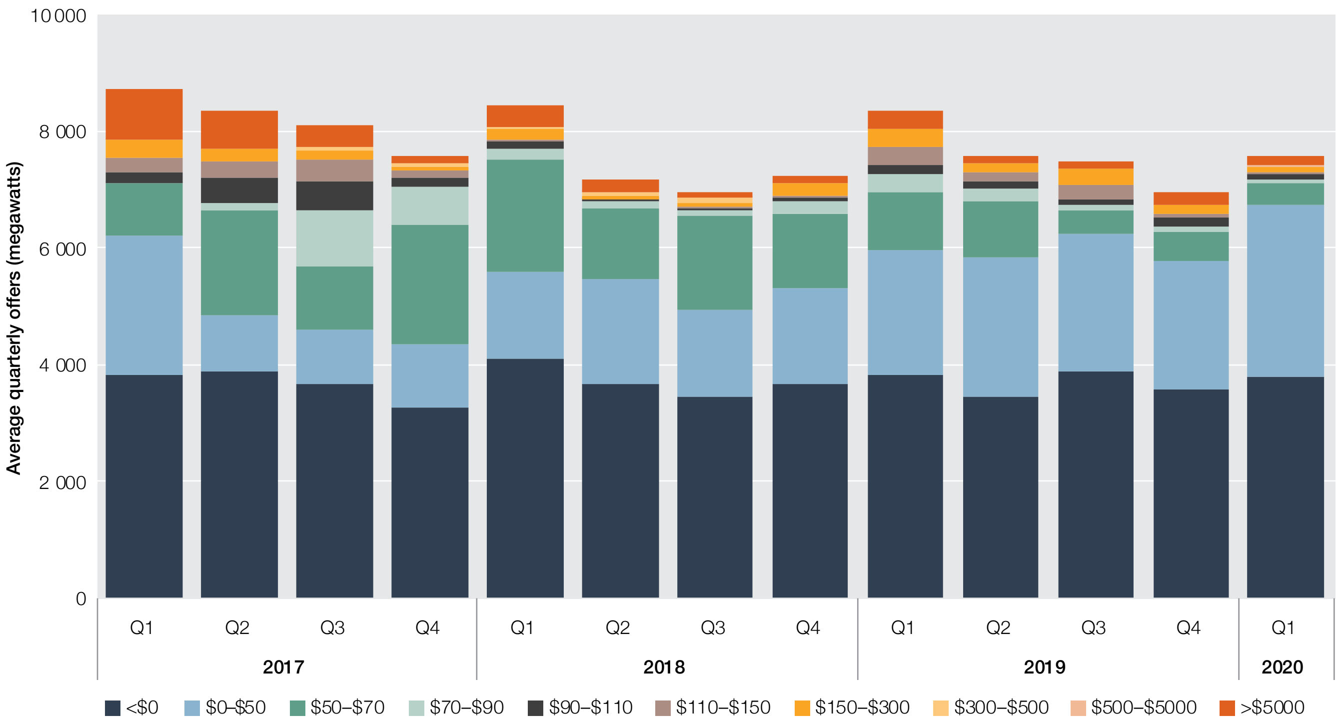
The AER monitors participant offers because how capacity is offered into the market, and at what price and amount, can significantly impact market outcomes.

Generators offered 12 per cent more capacity priced below $50 per MWh into the market this quarter compared to Q1 2019, despite offering slightly less total capacity.

NSW generators contributed most to this change, offering over 1000 MW more capacity priced below $50 per MWh, but offering around 800 MW less total capacity compared to Q1 2019 (figure 1.18). In Queensland, generators also offered an additional 700 MW of low priced capacity into the market compared to Q1 2019. For both regions, this was largely driven by changes in black coal offers.

NSW black coal generators offered more capacity priced below $50 per MWh in Q1 2020 than in any quarter since 2016. Similar to the broader market, this occurred while the total amount of capacity offered in Q1 2020 was less than in previous Q1s. This trend emerged as the quarter progressed. At the start of the quarter, NSW black coal generators offered around 9000 MW into the market. By the end of the quarter, this had reduced to just over 6300 MW due to outages including at Mount Piper, Liddell and Bayswater power stations (figure 1.19).

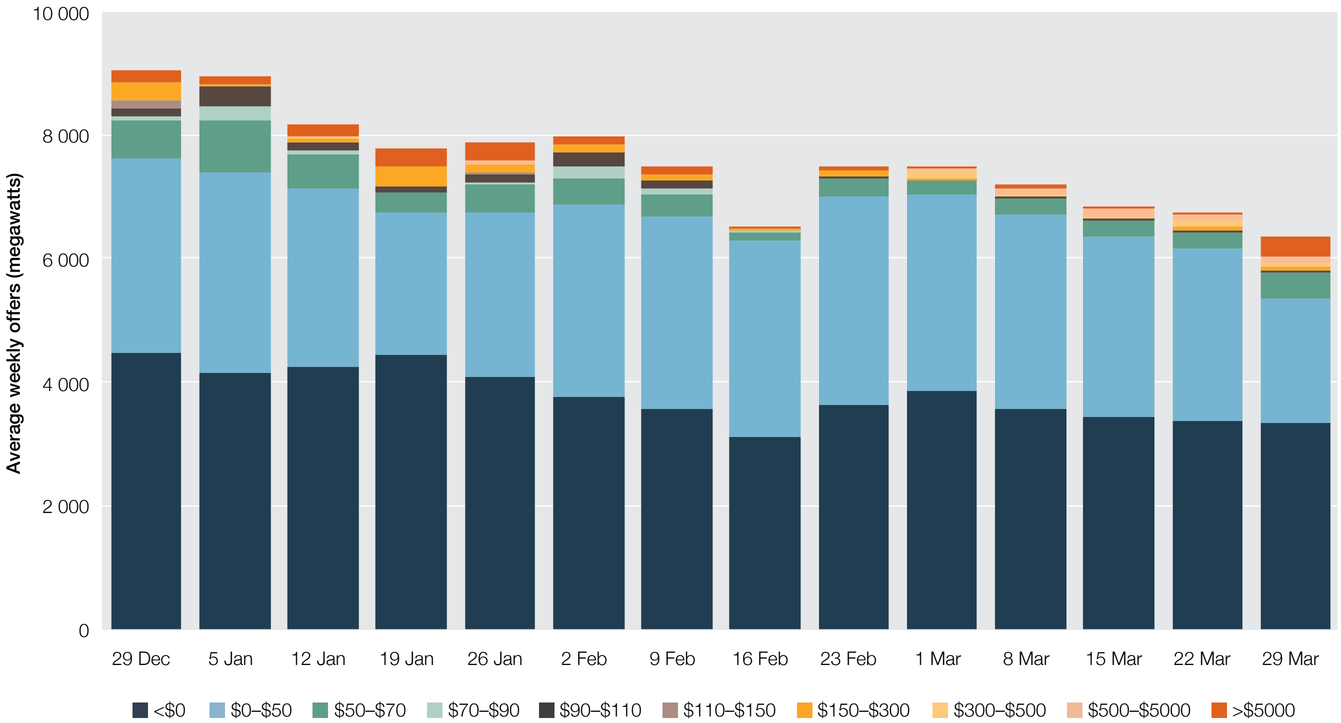
Figure 1.18 New South Wales black coal quarterly offers, by price thresholds



Source: AER analysis using NEM data.

Notes: Quarterly average offered capacity of NSW black coal generators within price thresholds.

Figure 1.19 New South Wales black coal weekly offers, by price thresholds



Source: AER analysis using NEM data.

Notes: Weekly average offered capacity of NSW black coal generators within price thresholds. Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter.

In South Australia, local generators changed their offers in response to the unfolding conditions while they were electrically separated from the NEM (figure 1.20). The change in offers varied by fuel type.

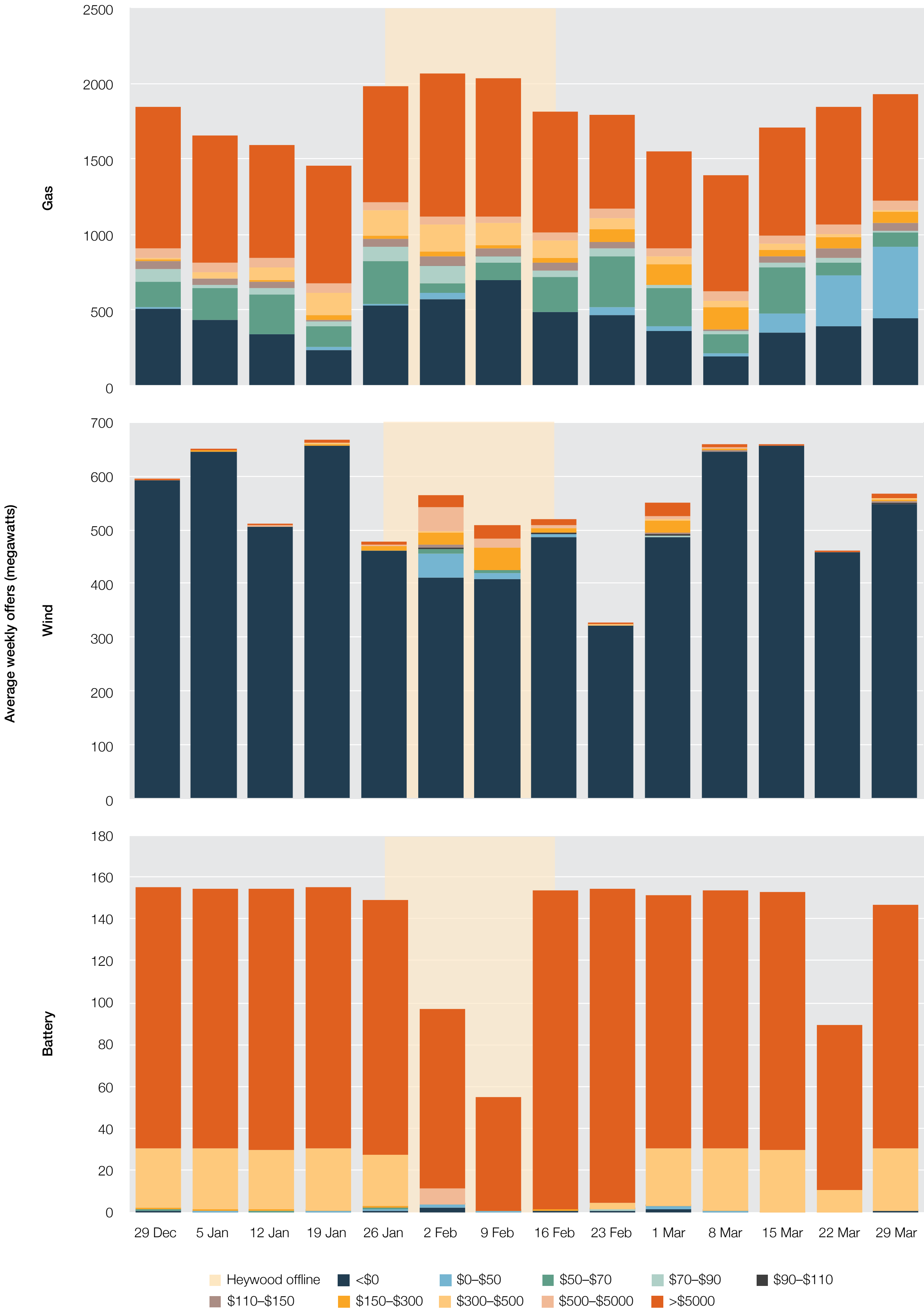
Gas generators offered 6 per cent less capacity into the market over Q1 2020 compared to last year, except during the weeks of separation when South Australia gas generators offered more capacity into the market. During this period South Australia needed to meet its own demand and gas generators were directed on by AEMO to maintain system security. Towards the end of March, Torrens Island and Pelican Point power stations offered more capacity into the market, likely in response to lower wind generation and brown coal generator outages in Victoria.

Wind generators in South Australia offered less capacity during the weeks of separation. In some cases they were constrained down to maintain system security, in others they offered capacity to avoid negative prices and high FCAS costs.[5] Before and after the separation, wind generators offered nearly all their capacity below $0 per MWh. But, during the separation much of this capacity was shifted into higher price bands, including over $5000 per MWh.

The batteries in South Australia also offered significantly less capacity during the separation. This is because they were directed by AEMO to stay at constant state of charge and not dispatch. During those weeks, batteries shifted nearly all of their offered capacity to over $5000 per MWh. In the week starting 22 March, reduced battery offers were driven by a planned outage at the Hornsdale power reserve.

5 Contingency costs for raise FCAS services are recovered from generators and are pro-rated on the basis of the amount generated. FCAS costs in South Australia reached record levels over this period.

Figure 1.20 South Australia gas, wind and battery weekly offers, by price thresholds



Source: AER analysis using NEM data.

Notes: Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter.

Finally, brown coal generators offered similar levels of capacity this quarter to last year, with slightly more capacity offered below $0 per MWh. However, this changed across the quarter. In the first week, brown coal generators offered 3600 MW at prices below $0 per MWh. But, by the last week of the quarter this had reduced to 2200 MW. Some of this change in capacity was due to generators shifting negatively priced offers to below $50 per MWh. Also, towards the end of the quarter, some brown coal generators offered less capacity due to outages.

1.9 Price setter

- Lower fuel costs faced by black coal and gas generators have enabled them to offer more low priced capacity into the market. As a result, the prices set by these two fuel types have been trending down since Q1 2017.
- All the major fuel types set lower prices in Q1 2020 than in Q1 2019 in all regions, except South Australia.

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.

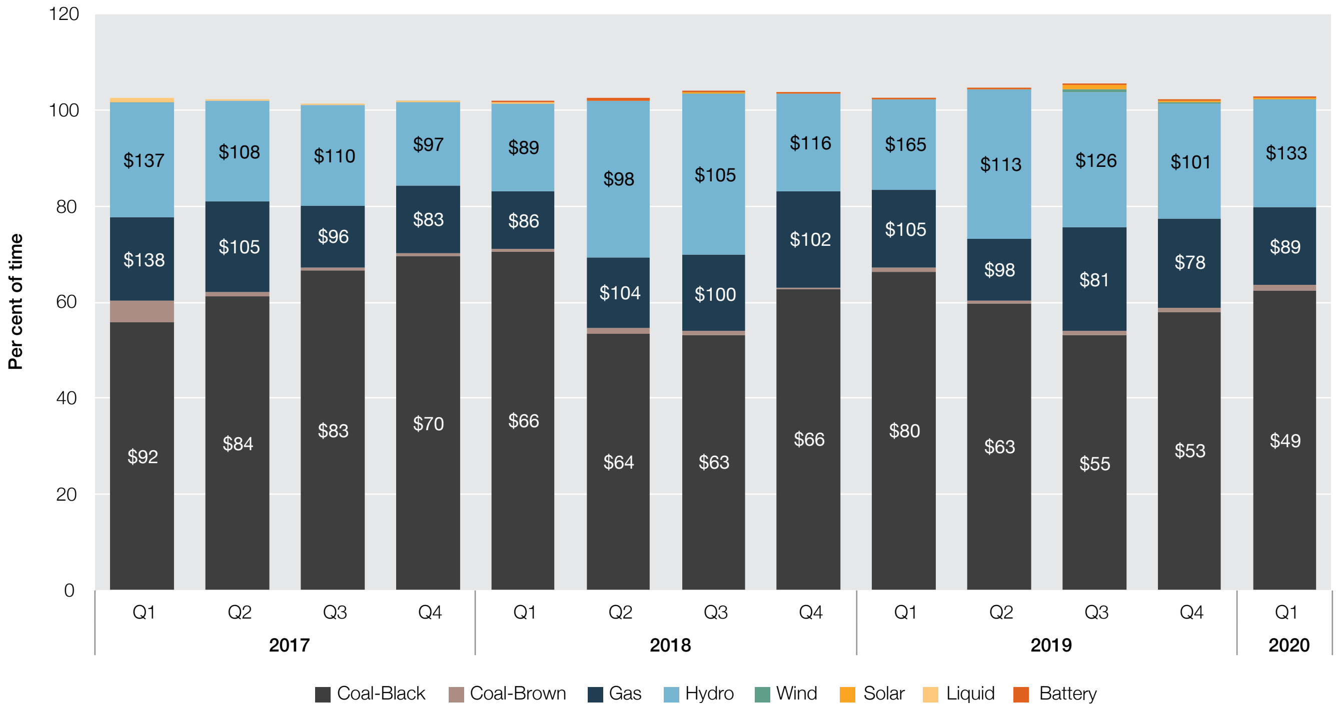
All the major fuel types set lower prices in Q1 2020 than in Q1 2019 in every region except South Australia. Quarterly average price setter data and graphs for all regions of the NEM are available as part of our online quarterly statistics.[6]

Lower fuel costs, which led to more low priced capacity being offered into the market (section 1.8), has also reduced the prices set by black coal and gas generators. Because these two fuels set the price around 80 per cent of the time in mainland regions, this has had a direct bearing on spot prices.

In NSW, black coal, gas and hydro all set significantly lower prices in Q1 2020 than they did in Q1 2019 (figure 1.21). The price set by black coal generators in NSW has been trending down nearly every quarter since the start of 2017 and in Q1 2019 black coal set the price below $50 per MWh compared to $80 per MWh in Q1 2019. Similarly, the price set by gas generators in NSW has been falling since mid-2018 setting the price at $89 per MWh in Q1 2020. The price set by hydro was only lower in comparison to the high price it set in Q1 2019.

6 Our quarterly statistics are available on our website.

Figure 1.21 Price setter by fuel type in New South Wales, quarterly



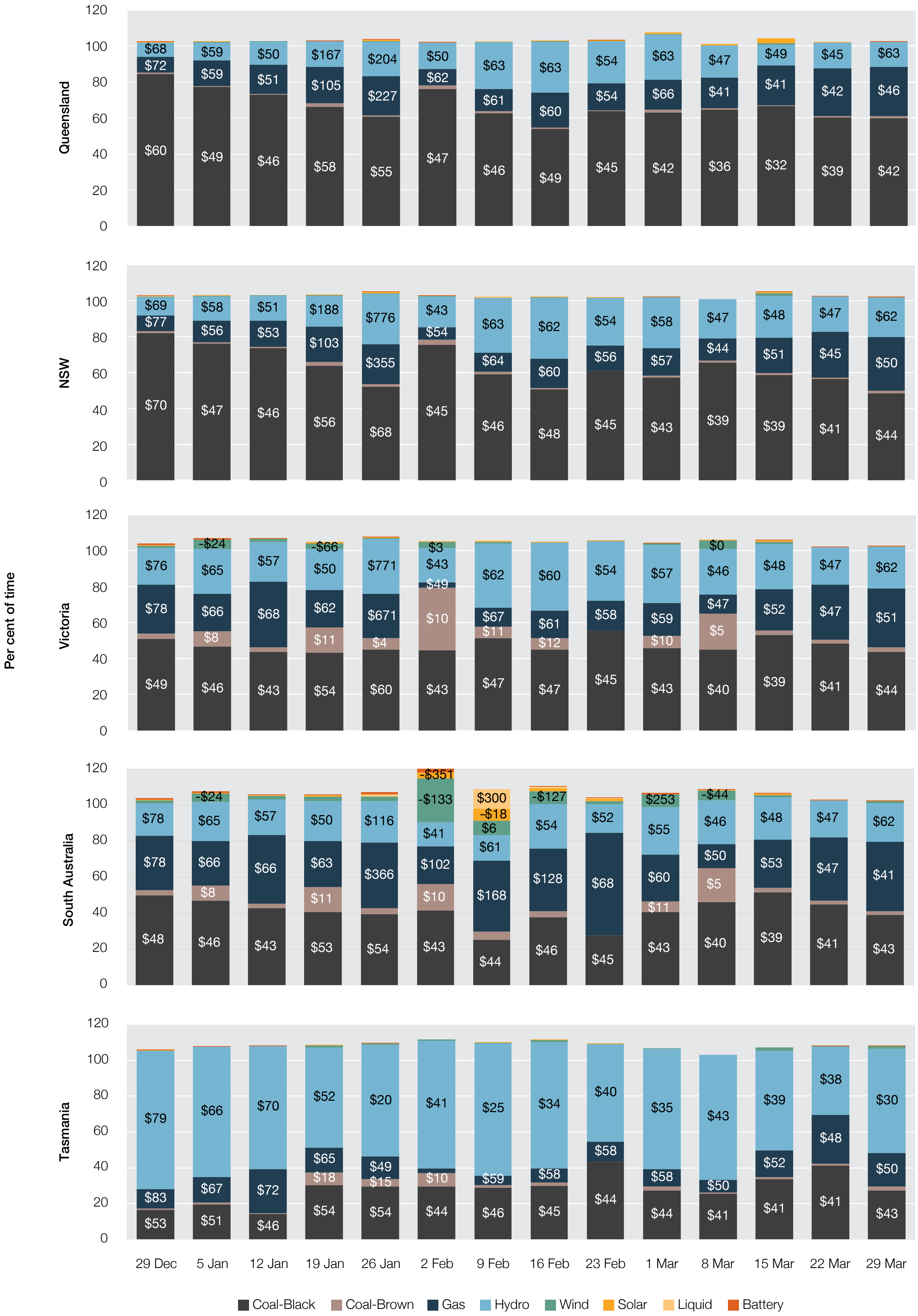
Source: AER analysis using NEM data.

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

In Victoria, the price set by black coal and gas generators has been falling, although the fall in the price set by gas generators has been less constant. The amount of time black coal and brown coal generators set the price in Q1 2020 increased to its highest level since the closure of the Hazelwood power station at the end of March 2017, setting it 56 per cent of the time in Q1 2020. In particular, the first week of the South Australian separation event saw an increase in the amount of time brown coal set the price in Victoria—more than 30 per cent of the time (figure 1.22). In that same week, black coal generators set the price more often in Queensland and NSW and at cheaper prices, largely because South Australia was unable to import from these regions.

In South Australia, the price set by black coal and gas has been falling. The average price at which wind and solar generators set the price in South Australia was higher than in recent quarters, but was still below $0 per MWh. Wind and solar set the price more often in South Australia in the weeks the region was electrically islanded.

Figure 1.22 Price setter by fuel type and region, weekly



Source: AER analysis using NEM data.

Notes: Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter. More than one generator or fuel type may set the price, leading to totals of greater than 100 per cent.

1.10 Interconnectors

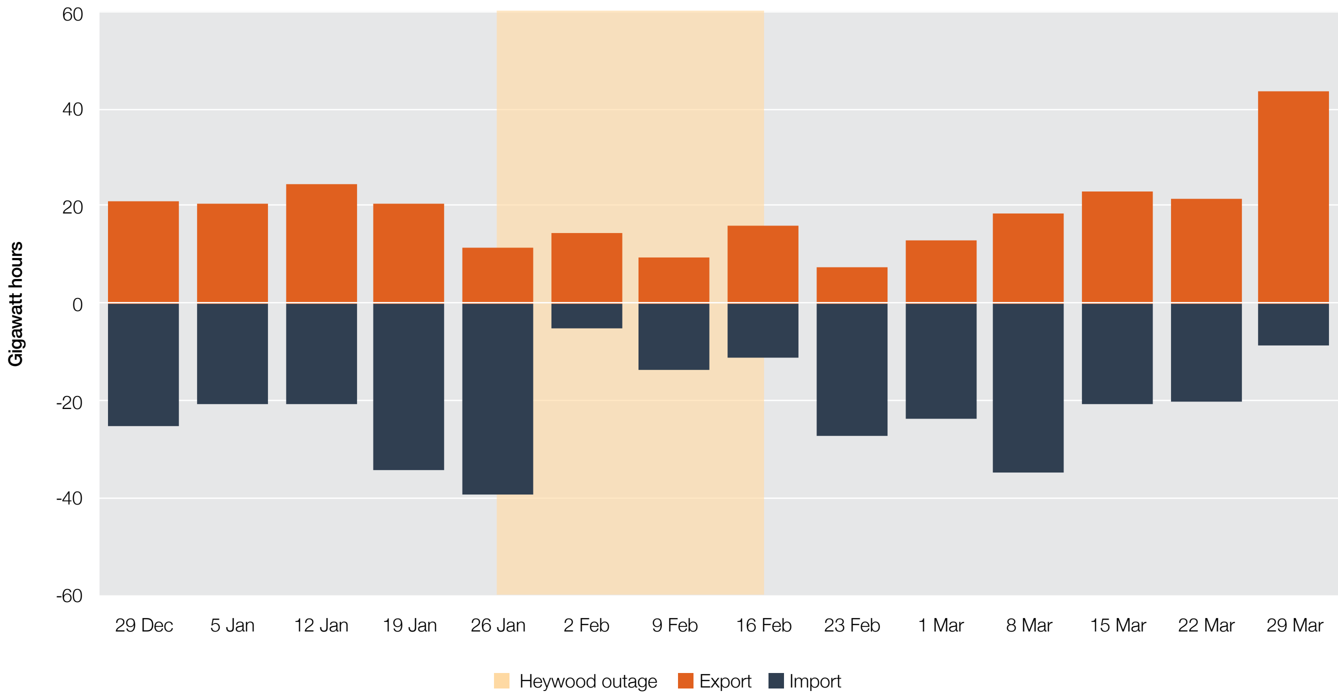
› Interconnector flows were largely impacted by extraordinary events during the quarter, in particular the extended Heywood outage between Victoria and South Australia. Otherwise flows were relatively unchanged.

Trade between NEM regions over interconnectors provides some competition between participants across regions. Interconnector flows were impacted by extraordinary events during the quarter, in particular the extended outage of the Heywood interconnector between Victoria and South Australia.

At the end of January, a local storm in Victoria damaged six transmission towers connecting to the Heywood interconnector. This caused an extended outage of the interconnector which separated South Australia from the rest of the NEM for 18 days. The separation event led to a reduction in imports into South Australia (figure 1.23). Once the interconnector was back in service import levels returned to previous levels. During this period, any exports into Victoria were limited to flows over Murraylink (constrained as it was the largest contingency). There were also limited flows of around 30 MW over the Heywood interconnector as AEMO put in place system arrangements to keep the Portland smelter operating which is located next to the Heywood interconnector.

The interconnector tripped again on 2 March, due to equipment failure at a Heywood substation. This outage lasted for a matter of hours.

Figure 1.23 South Australia Q1 2020 weekly interconnector flows—exports and imports



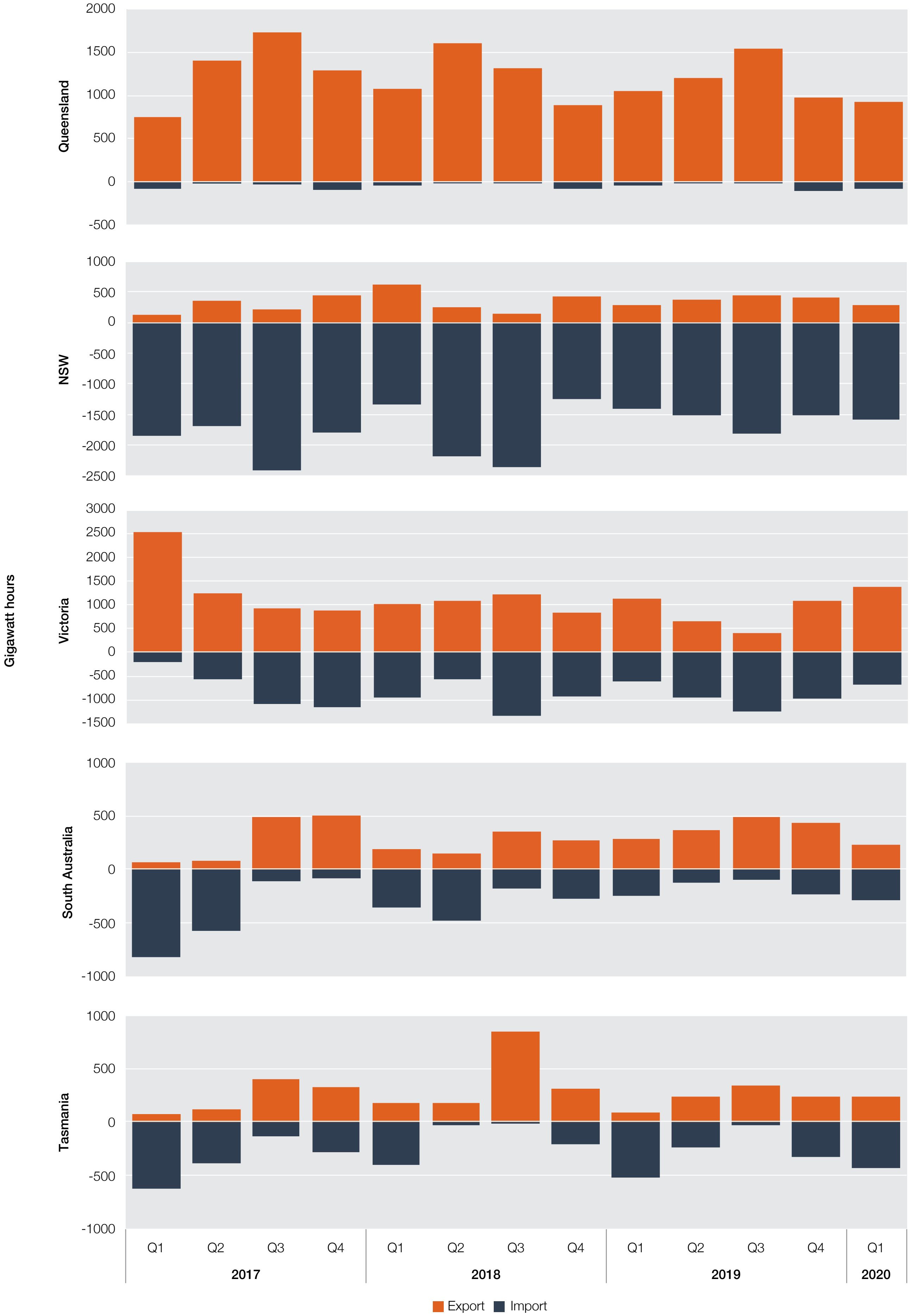
Source: AER analysis using NEM data.

Notes: Total amount of generation imported and exported in the relevant week. Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter.

Extraordinary events also impacted interconnector flows between NSW and Victoria this quarter. On 4 January, bushfires around the Snowy Mountains in NSW saw multiple unplanned network outages occur in quick succession. As a result, the NSW to Victoria interconnection was interrupted, which electrically separated the two regions. However, flows resumed the same day.

Interconnector flows between other regions in the NEM were mostly impacted by price differences between regions (figure 1.24). Exports from Queensland were lower through most of Q1 2020 compared to recent quarters due to less instances of negative prices, however they picked up in the last three weeks. It was the lowest export level from the region since Q1 2017. Exports from Victoria were up due to lower prices in Victoria and conversely, imports into NSW increased as a result of the higher prices in NSW. With the outage of the Heywood interconnector, exports from Tasmania were higher compared to Q1 2019.

Figure 1.24 Regional interconnector flows—exports and imports



Source: AER analysis using NEM data.

Notes: Total amount of energy either imported or exported for each quarter.

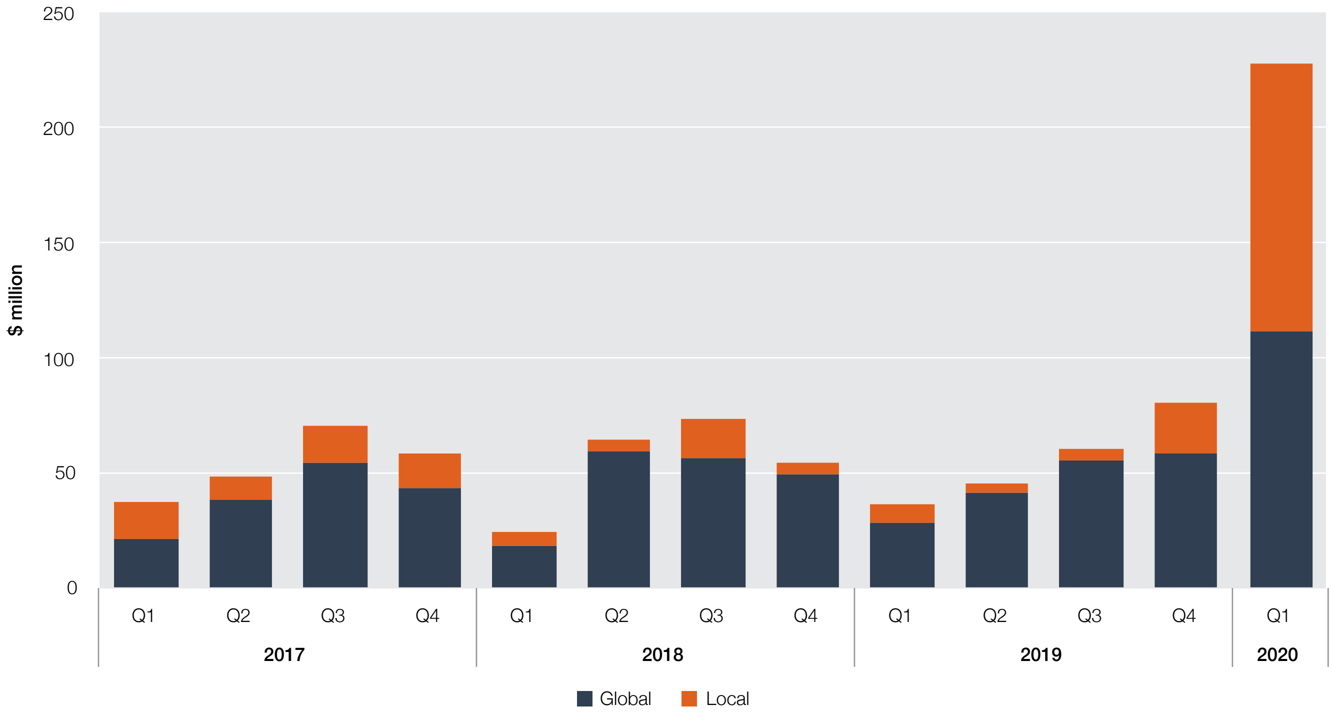
1.11 Frequency control ancillary services

- Total FCAS costs for the quarter were a record $227 million, about half of which were high local costs in South Australia.
- FCAS prices exceeded $5000 per MW both globally, and locally in South Australia.

The AER has a requirement to report quarterly on outcomes and trends in ancillary services markets. This requirement is met through this report. We also publish more detailed ancillary services markets data in our quarterly online statistics.[7]

Total frequency control ancillary services (FCAS) costs for the quarter were a record $227 million. This is six times the FCAS costs in Q1 2019. Whereas in Q1 2019 FCAS costs were only 0.5 per cent of total energy costs, this quarter they increased to 5.4 per cent. Half of the total costs were for global services and half were for local services, nearly all in South Australia (figure 1.25).

Figure 1.25 Total FCAS costs—global and local



Source: AER analysis using NEM data.

FCAS are used to maintain the frequency of the power system. There are eight services, half increase the frequency if it's too low, and half decrease the frequency if it's too high. FCAS requirements can be global or local. Local requirements occur when a region is electrically isolated from the rest of the NEM and needs to provide its own FCAS.

FCAS fall into two categories:

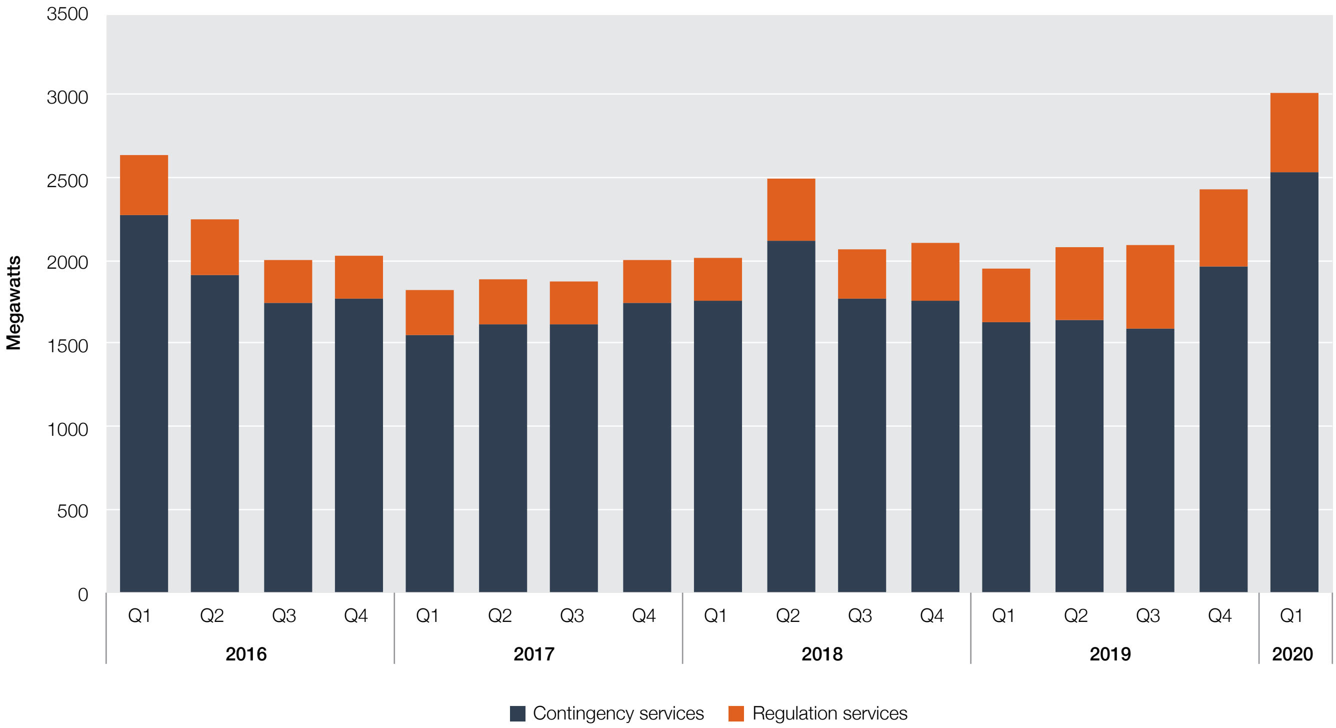
- Regulation services which continuously balance small changes in frequency
- Contingency services (6 second, 60 second and 5 minute) which are called upon to respond to large changes in frequency, which can occur after a contingency event.[8]

Total FCAS costs increased this quarter because more global and local FCAS were required (figure 1.26). The average amount of total FCAS enabled increased by around 500 MW compared to the previous quarter—around half for global FCAS (met across all regions) and the other half for local FCAS in South Australia (met solely by providers in South Australia).

7 Our quarterly statistics are available on our website.

8 There are three contingency services to increase the frequency and three to decrease the frequency. Raise services respond to a reduction in supply and are paid for by generators. Lower services respond to a reduction in demand and are paid for by consumers. Participants will not be supplying these services until a contingency occurs but are paid according to their enablement.

Figure 1.26 FCAS enabled



Source: AER analysis using NEM data.

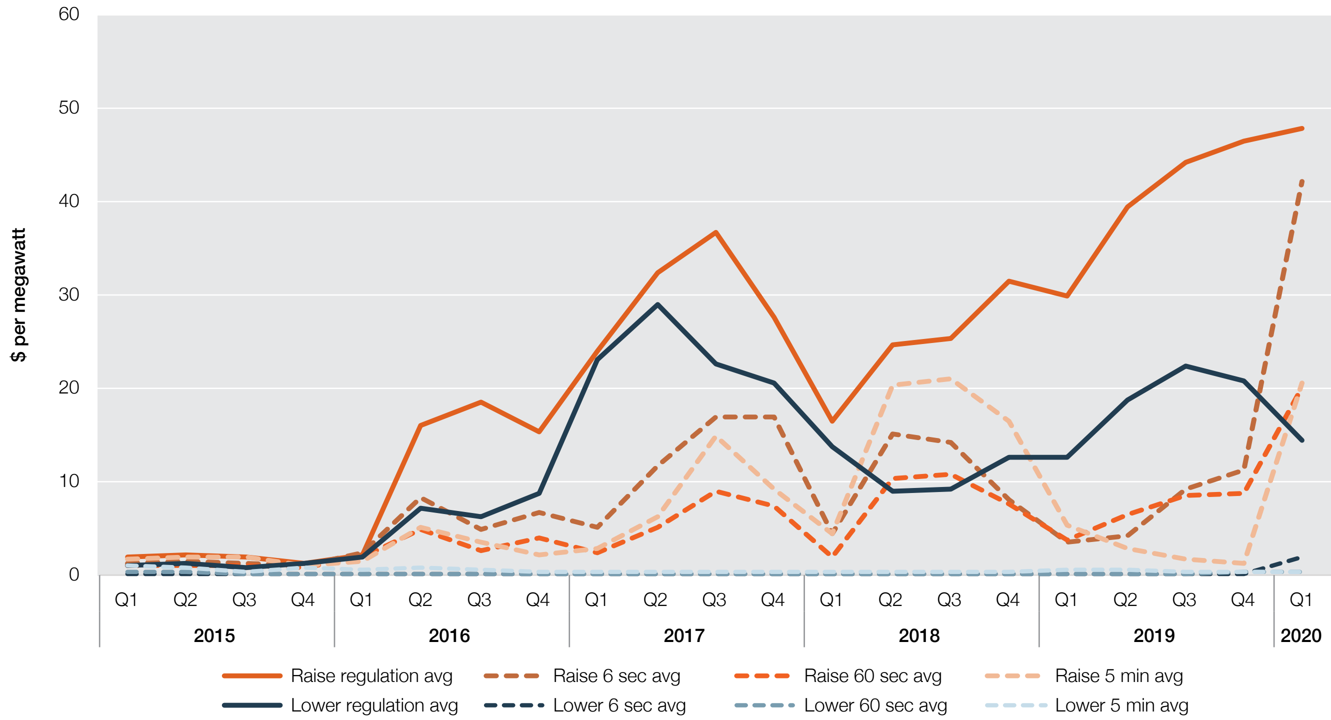
Global FCAS

The increase in the amount of global FCAS enabled was due to an increase in the amount of contingency services enabled. As part of its review of frequency in the NEM, AEMO has been reviewing the amount of contingency FCAS it requires, slowly increasing it until January this year.[9] AEMO expected the change would materially increase contingency FCAS requirements.

The cost of global FCAS increased both as a result of the increase volumes enabled and as a result of an increase in prices. Average prices for seven of the eight global services increased in Q1 2020 compared to Q4 2019, with a significant increase in the prices for raise contingency services (figure 1.27). Record prices for raise services were driven by the exceptional events that occurred in the quarter, including the bushfires on 4 January and the loss of the Heywood interconnector. Global FCAS prices exceeded $5000 per MW numerous times over the quarter. Our detailed reports into these prices, which is a requirement under the National Electricity Rules, analyse these events.

9 From September 2019 AEMO progressively began reducing the load relief assumption it used to calculate contingency FCAS requirements. On 16 January it reduced it from 0.6 per cent to 0.5 per cent. Load relief is the inherent change in demand as a result of movements in frequency away from 50Hz and can be used to offset the amount of frequency services procured to restore the frequency to within normal limits.

Figure 1.27 Quarterly average global FCAS prices

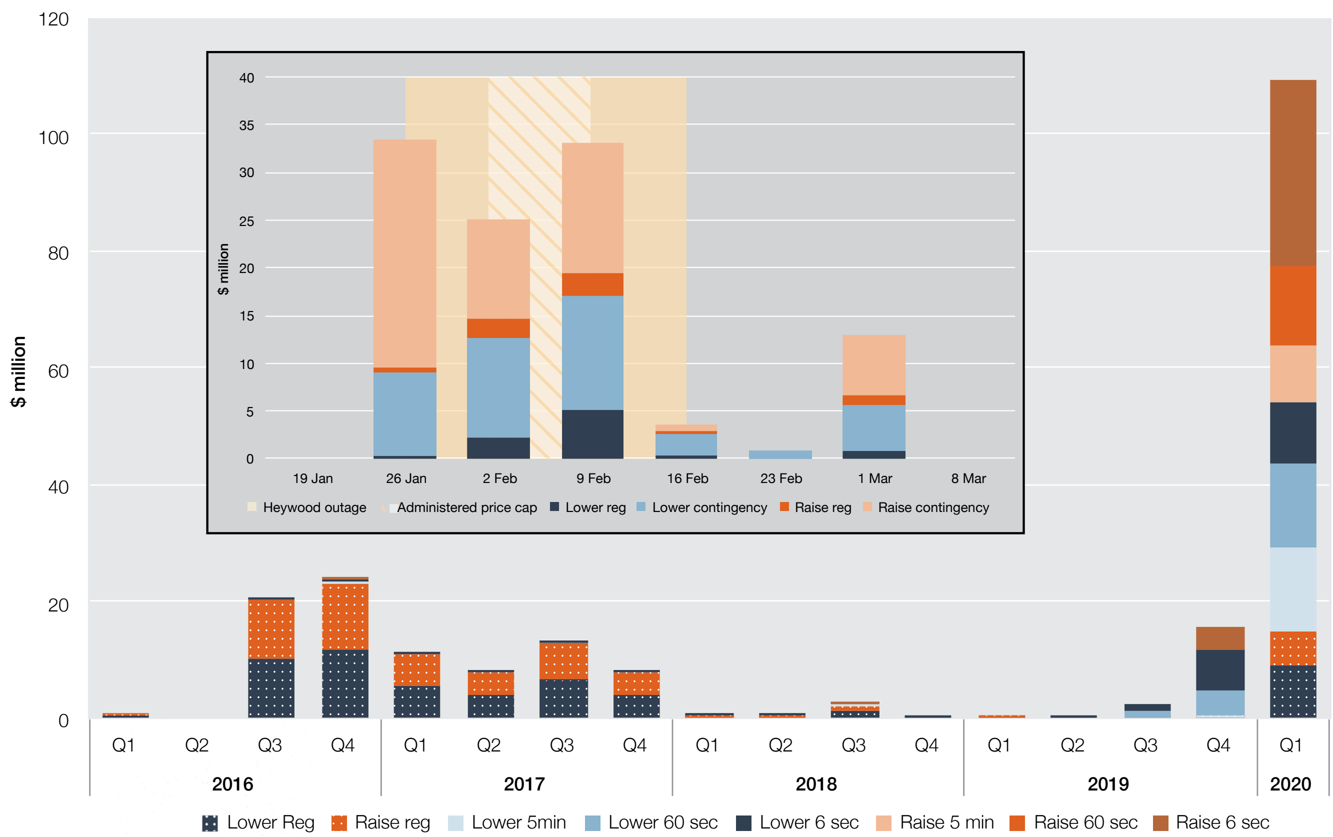


Source: AER analysis using NEM data.

Local South Australia FCAS

Local FCAS costs in Q1 2020 were $116 million (figure 1.28) of which $109 million were for local South Australian costs.

Figure 1.28 Quarterly and weekly local FCAS costs in South Australia

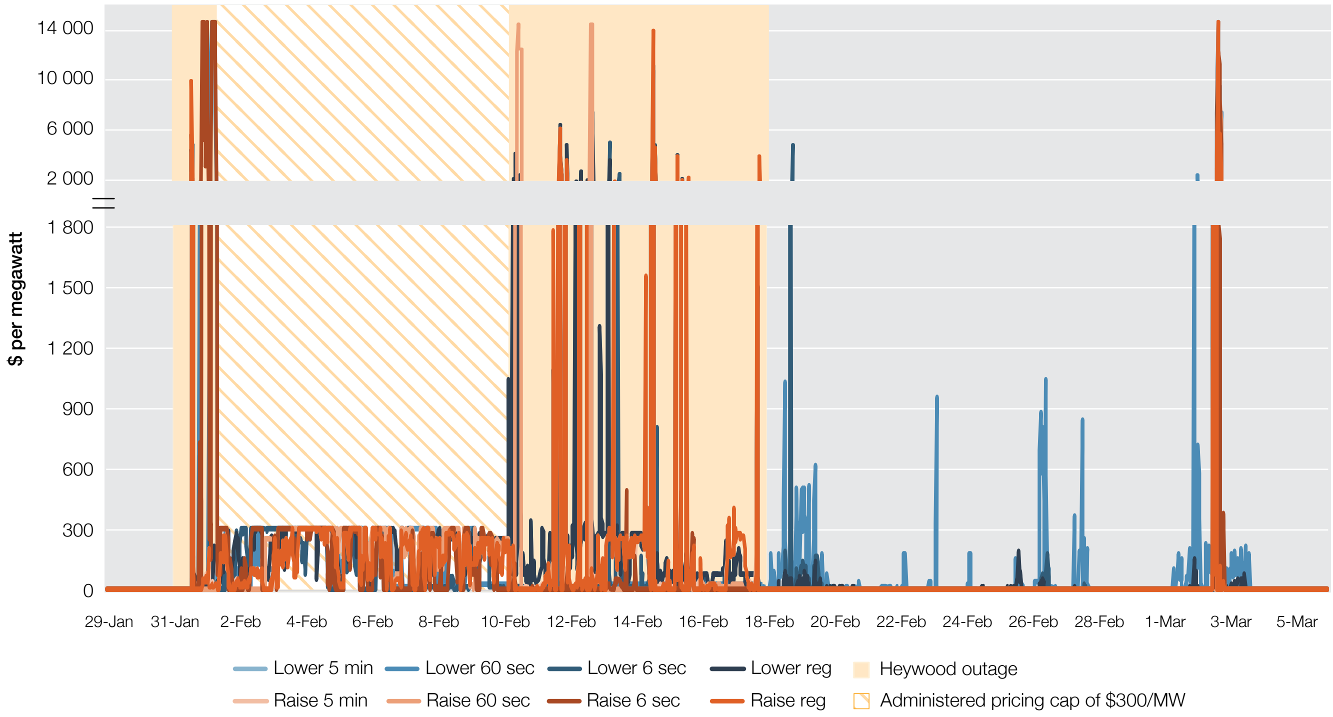


Source: AER analysis using NEM data.

Local FCAS costs were high in South Australia because during the 18 days the Heywood interconnector was out in February and on 2 March, it was unable to source these services from other regions. Costs were driven by high offer prices, limited availability and an increase of around 250 MW of FCAS South Australian generators needed to provide.

The demand and supply conditions for FCAS in South Australia meant at times FCAS offered at prices above $5000 per MW was needed to meet the local requirements. This contributed to high prices for local South Australia FCAS (figure 1.29). Prices in South Australia were high for an extended period triggering the cumulative price threshold (CPT) on 1 February. The CPT is a price safety net mechanism designed to cap local FCAS prices for all services at $300 per MW and was in place for around 10 days.

Figure 1.29 South Australia local FCAS prices



Source: AER analysis using NEM data.

Our *Wholesale electricity market performance report*, which is due to be released in November 2020, will examine in more detail the performance of FCAS markets in South Australia in this period, including the offer behaviour of FCAS providers.

Focus—How AEMO manages potential supply shortfalls

› This focus examines the levers that were at AEMO's disposal for managing the events that occurred over Q1 2020.

AEMO is responsible for managing the operation of the energy system in Australia, including the NEM. In particular, it ensures there is enough supply to meet ever-changing demand, and manages potential shortfalls in supply. This is a complex task which increases in difficulty as demand rises and the level of reserve capacity falls, particularly in the peak periods around summer.

The summer of Q1 2020 saw a number of days with low levels of reserve capacity. In addition, the market had to deal with some extreme conditions, including bushfires and damaging winds, which caused a number of unplanned network outages. This focus story explains some of the 'levers' at AEMO's disposal should it need to intervene to maintain power system security or reliability during these times.

In explaining the levers at AEMO's disposal in these circumstances, we will highlight the events of 4 January 2020.[10]

10 We examine the events of 4 January 2020 in more detail in our prices above $5000 per MWh report.

On this day, bushfires around the Snowy Mountains in NSW saw multiple unplanned network outages occur in quick succession resulting in more than 2500 MW of generation in the region unable to be dispatched. At the same time, high demand driven by hot weather caused low levels of reserve.

AEMO has many levers at its disposal

AEMO has many levers at its disposal to manage the power system in periods of tight demand and supply. These levers are designed to increase available generation or reduce demand. Notably, the majority of these levers are designed to assist AEMO in resolving projected shortfalls before they eventuate (figure 1.30).

Figure 1.30 Managing supply shortfalls

TEN YEARS	• Inform the market, annually, of projected shortfalls	ESOO, LT PASA
2 YEARS	• Inform the market, weekly, of projected shortfalls	EAAP, MT PASA
1 YEAR	• Procure long notice reserve contracts	RERT
1 WEEK	• Seek market response for projected shortfalls, procure reserve contracts	ST PASA, RERT
PRE-DISPATCH	• Seek market response for projected shortfalls, procure reserve contracts	PD PASA, RERT
EVENT	• Dispatch reserve contracts • Instruct load shedding (residential customers as a last resort)	RERT, load shedding

AEMO tries to resolve projected supply shortfalls ahead of time

Typically the market operator tries to resolve any projected supply shortfalls ahead of time. AEMO may do this by using forecasts to elicit a market response, procuring reserve contracts, and/or rescheduling or delaying network outages.

Elicit market response through forecasting

AEMO constantly forecasts to a range of planning horizons. Longer term forecasts encourage a market response to projected shortfalls. These include:

› The *Electricity statement of opportunities* (ESOO), which forecasts market outcomes over the next 10 years, to assist existing and potential participants with long-term investment planning. It is published annually.

› The *Medium term projected assessment of system adequacy* (MTPASA) forecasts shortfalls over a two year horizon using participants' best estimates of the future availability of their existing generating units. MTPASA is updated weekly.

› The *Energy Adequacy Assessment Projection* (EAAP) measures the potential impact of constraints on supply by assessing fuel availability for generators over a two year horizon.

Over a shorter timeframe, AEMO uses *Short term PASA* (ST PASA) to forecast over the coming week, and *Pre-dispatch PASA* (PD PASA) to forecast for the coming day.

Lack of reserve (LOR) notices are an indicator of the supply demand balance and are an important tool to communicate potential and actual shortfalls to the market. When forecast reserve falls below certain thresholds in ST PASA or PD PASA, AEMO uses forecast LOR notices to elicit a market response to increase generation or reduce demand.

There are three reserve thresholds which relate to managing the power system in the event of a defined number of unplanned failures of either transmission or generating equipment (credible contingencies).

- LOR 1—there is not enough reserve to account for the two largest credible contingencies combined.
- LOR 2—there is not enough reserve to allow for the single largest credible contingency.
- LOR 3—there is not enough available generation to meet demand.

If the market responds, and the response is sufficient to remove the forecast supply shortfall, AEMO will issue a notice cancelling the forecast LOR condition. Actual LOR notices are issued if the market response is insufficient or an unplanned event occurs.

On 4 January 2020, the event was unexpected so AEMO had no opportunity to elicit a market response. As a result, it had no opportunity to issue a forecast LOR notice before publishing an actual LOR 2 notice for NSW.

Reschedule planned network outages

Network service providers are required to schedule outages with AEMO, which it incorporates into its forecasting. They also update AEMO regarding the length of time required for the outage of those network elements. Should AEMO forecast a supply shortfall, it may negotiate with network service providers to reschedule or delay such an outage.

As summer is typically when supply shortfalls are most likely to occur due to the high demand that comes with hot weather, most network service providers will take planned maintenance in other parts of the year.

In preparation for this summer, AEMO and network service providers co-ordinated preparation plans to better understand and manage potential risks. This included:

- Confirming preventative maintenance on critical elements of the transmission network including bushfire mitigation and network upgrade plans.
- Maximising transmission availability during periods when it would be required, such as on days of high demand during hot weather.[11]

Procure reserve contracts

AEMO uses the Reliability and Emergency Reserve Trader (RERT) mechanism to contract for reserves, which are to be called on in times of serious risk to market conditions. These reserves can take the form of additional or backup generation, or demand response capacity that is not otherwise participating in the NEM. RERT contracts can be procured over both long and short term.

The long notice RERT can be procured up to 12 months in advance of a forecast supply shortfall. AEMO can procure medium and short notice RERT if it observes an insufficient market response to address a forecast supply shortfall to satisfy the reliability standard.

In advance of summer, AEMO entered into two reserve contracts to ensure there were enough reserves available. Both contracts were in Victoria with a combined capacity of 72 MW.[12]

On 4 January 2020, after issuing the actual LOR 2 notice, AEMO negotiated to procure short notice RERT contracts. It entered into RERT agreements with two participants.[13]

If a supply shortfall eventuates, AEMO has levers at its disposal on the day

If a projected supply shortfall can't be resolved ahead of time, AEMO still has options at its disposal on the day. This includes activating RERT contracts, or directing participants. If the shortfall persists, as a last resort, AEMO can instruct industrial and residential customer load shedding.

On 4 January, AEMO declared a LOR 2 for NSW shortly after network outages occurred, and later invoked RERT contracts.

11 AEMO summer readiness plan 2019–20.

12 RERT contracted for summer 2019–20.

13 RERT contracted for 4 January 2020.

Activating reserve contracts

When entering into RERT contracts, AEMO will agree with the participant on when they can be called on to activate the procured reserves. Tight supply and demand conditions that result in LOR notices are typically when such reserves would expect to be activated. Supply side reserves will inject additional generating capacity into the market. Whereas, demand side reserves will ease pressure on the market by having large or significant users reduce their demand.

On 4 January 2020, AEMO activated 68 MW of RERT contracts, in order to alleviate the LOR 2 conditions from 6.20 pm to 9.45 pm. AEMO also pre-activated one longer-standing RERT contract, however as this contract was for use during LOR 3 conditions only, it did not activate those reserves. The activation and pre-activation of RERT had an estimated cost of $7.3 million.[14]

Directing market participants

As the market operator, AEMO is empowered to issue directions to market participants in order to maintain system reliability or security. If the reserve contracts are not sufficient to alleviate the supply shortfall, AEMO may issue directions to market participants to increase reserve levels.

On 4 January 2020, AEMO was unable to issue directions for reliability in NSW, as the extreme conditions made it impossible for the generators it would call on to contribute. This was due to either unsafe operating conditions, or outages in the transmission network.

Instructing load shedding

AEMO can issue instructions for load shedding to temporarily reduce or cut off supply to customers. It does this by instructing network service providers, who in turn temporarily shut off sections of their networks. Typically, this occurs during instances when AEMO considers the action necessary to maintain or restore the security or reliability of the power system, or for reasons of public safety.

There are two types of instructions that AEMO may issue to network service providers:

- load shedding of industrial and commercial load,
- involuntary customer load shedding of residential load.

Load shedding of industrial and commercial load is implemented ahead of involuntary customer load shedding.

As a final resort, involuntary customer load shedding of residential load is done in a rotating fashion, in accordance with jurisdictional priorities to minimise the impact on any individual customer.

There have been two occasions over the last 10 years where supply shortfalls have resulted in involuntary load shedding of residential load (February 2017 in NSW and January 2019 in Victoria).

The use of these levers comes at a cost

The use of RERT contracts, directions and instructions are important levers AEMO can use to ensure there is enough supply to meet demand. However, the use of these levers come at a cost to energy users, in addition to the price of electricity.

There are three main costs associated with RERT contracts:

- availability costs—a broad capacity payment for the service over a specified timeframe
- pre-activation payments—some services incur costs to be on stand-by for a specific event
- activation costs—the actual use of the reserves.[15]

The estimated total cost of RERT in Q1 2020 was around $31.2 million. More information on the use of RERT in Q1 2020 can be found in AEMO's RERT quarterly report.[16]

14 RERT activation estimates on 4 January 2020.

15 Rule determination—enhancement of the RERT. Other indirect costs include administration and compensation payments to participants.

16 A new reporting requirement following the enhancement of the RERT, AEMO is required to publish a quarterly RERT report in accordance with clause 3.20.6 of the National Electricity Rules.

AEMO used these levers a number of times this quarter

Throughout Q1 2020, high demand and extreme events saw AEMO use the levers on several occasions.

In total AEMO identified seven periods actual LOR 2 conditions occurred. 4 January in NSW was one of these periods. The others include:

- 23 January in NSW
- 30 January in Victoria and South Australia[17]
- 31 January in Victoria and NSW[18]
- 1 February in NSW.

AEMO activated RERT contracts on three days across the quarter, 4 January in NSW, 23 January in NSW and 31 January in both NSW and Victoria.

On 23 January in NSW, AEMO activated the RERT in response to an actual LOR 2 condition. A total of seven contracts with a combined 152 MW were activated, as well as the pre-activation of additional 302 MW over two further contracts (though ultimately not activated) at an estimated cost of $8.8 million.

On 30 January in Victoria and South Australia, AEMO contracted but did not activate 60 MW and 227 MW of RERT in each region respectively.

The final use of the RERT in the 2019–20 summer came on 31 January in NSW and Victoria following actual LOR 2 conditions in both regions. 134 MW of RERT contracts in NSW, and 185 MW of contracts in Victoria were activated. Additionally, 304 MW of contracts were pre-activated in NSW, and 40 MW pre-activated in Victoria, though neither were activated. The estimated costs for the action on 31 January came to approximately $15.1 million.

Despite the actual LOR 2 condition that occurred in NSW on 1 February, AEMO did not enter into any RERT contracts.

Notably, AEMO did not issue any LOR 3 notices this quarter, compared with Q1 2019 where AEMO issued two LOR 3 notices in Victoria and instructed load shedding to keep the system in a secure state.

Focus—The Retailer Reliability Obligation

- The RRO was triggered for the first time in January 2020. This focus explains the RRO and highlights the lack of trading during Q1 2020 for the forecast reliability gaps.

The Retailer Reliability Obligation (RRO) is designed to support reliability in the NEM by incentivising retailers and some large energy users to contract or invest in dispatchable and 'on demand' resources. The RRO commenced on 1 July 2019 and was triggered for the first time on 9 January 2020.

How does the RRO work?

If AEMO forecasts a material reliability gap in a region three years and three months out, it will apply to the AER to trigger the RRO (figure 1.31).[19] This is known as the T-3 reliability instrument. The AER then commences a two month review, which considers the process AEMO followed to forecast the gap and allows for stakeholder feedback. If the instrument is approved the RRO is officially triggered.

Once the RRO has been triggered, for the next two years (between T-3 and T-1) liable entities (who are mainly retailers and large customers, which have chosen to opt-in) are on notice to enter into sufficient qualifying contracts to cover their share of demand during the time of the forecast reliability gap. A Market Liquidity Obligation (the MLO) is also triggered at this time and the largest generators in the region must offer to buy and sell standard energy contracts on the Australian Securities Exchange (ASX) at certain times each day. This process is designed to ensure there are contracts available to smaller market customers.

17 Prices above $5000 per MWh in Victoria and South Australia on 30 January 2020 report.

18 Prices above $5000 per MWh in NSW, Victoria and South Australia on 31 January 2020 report.

19 A reliability gap is when forecast unserved energy is greater than 0.0002 per cent in a region. AEMO uses its *Electricity Statement of Opportunities* to publish these forecasts annually. This is known as the reliability forecast.

If AEMO still forecasts the reliability gap to occur one year and three months out, they will again apply to the AER to trigger the next stage of the RRO. This is known as the T-1 reliability instrument. Again the AER has a two month period to review the instrument and if approved it triggers the next stage of the RRO.

At this stage, liable entities must disclose their contract positions to the AER. They do this by submitting reports, which detail contracts they have purchased to cover their expected demand for electricity during the reliability gap. AEMO can also commence procurement of emergency reserves through the RERT framework. This is to address the remaining gap.

At the time of the forecast reliability gap (also known as T) if actual system peak demand exceeds a forecast one-in-two year peak demand, which has been specified by AEMO in the reliability forecast, the AER will assess the compliance of liable entities. The AER does this by comparing the size of their contract positions against their share of the one-in-two year demand at T. Any liable entity, which was under contracted in one or more reliability gap trading intervals will have to cover their proportional share of the RERT costs (if RERT has been dispatched by AEMO). This occurs through the Procurer of Last Resort mechanism, whereby AEMO recovers the RERT costs from under contracted liable entities. The AER can also choose to take compliance action.

Figure 1.31 RRO key milestones

T-3 ▶

- AMEO requests T-3 instrument
- AER assesses and approves/rejects T-3 instrument

T-2 ▶

- MLO begins
- Contracting begins
- Large customers can opt in

T-1 ▶

- MLO finishes
- AEMO requests T-1 reliability instrument
- AER assesses and aproves/rejects T-1 instrument
- Liable entities provide Net Contract Position to AER
- AEMO commences RERT procurement

T

- AEMO performs normal duties
- If systems peak demand exceeds one-in-two year demand AER must assess compliance

Source: AER.

The South Australian Minister's ability to trigger the RRO

Along with the normal process of the RRO being triggered by AEMO identifying a forecast reliability gap, the South Australian Minister also has the ability to trigger the RRO in their state.

The South Australian Minister may make a T-3 instrument if it appears to the Minister, on reasonable grounds, that there is a real risk that the supply of electricity in all or part of South Australia may be disrupted to a significant degree on one or more occasions during a period in the instrument.

The South Australian Minister's T-3 instruments are not reviewed by the AER. However before they make an instrument they must consult with the AER and AEMO. The T-3 reliability instrument takes effect from the date of publication in the South Australian Government Gazette. The Minister may also vary or revoke the T-3 reliability instrument via a subsequent notice in the gazette.

The South Australian Minister cannot make T-1 reliability instruments, only AEMO and the AER via the normal process have the ability to do this. No other state minister has the ability to trigger the RRO in their region.

On 9 January 2020, the South Australia Minister for Energy and Mining triggered the RRO in South Australia for the first quarters of 2022 and 2023.

Under South Australia's declaration, the details of the prescribed periods are:

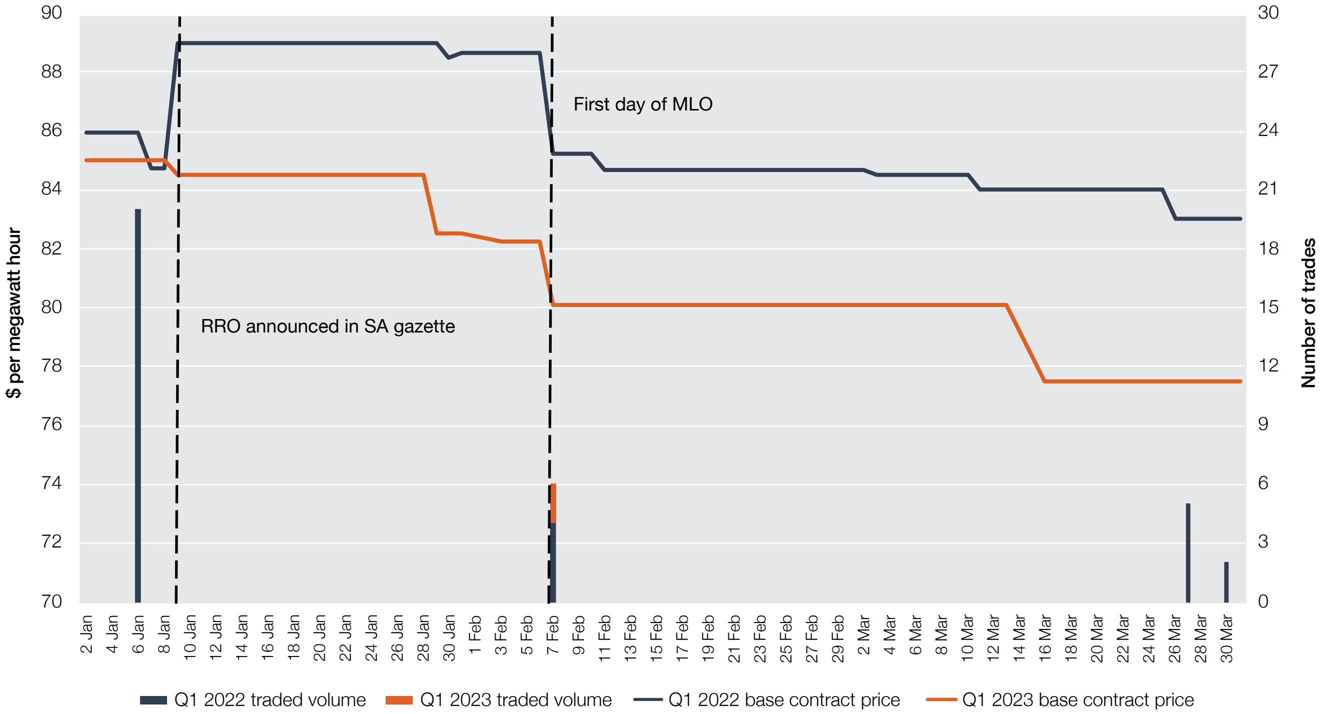
- each working weekday from 10 January 2022–18 March 2022 for the trading periods between 3 pm and 9 pm EST
- each working weekday from 9 January 2023–17 March 2023 for the trading periods between 3 pm and 9 pm EST.

The Market Liquidity Obligation

The MLO is a market making requirement designed to facilitate transparency and liquidity in the trading of electricity futures contracts relating to a forecast reliability gap. MLO generators are required to post bids and offers at certain times, with a maximum spread, on the ASX for standardised products that cover the period of the gap.

On 7 February 2020, South Australian MLO generators Origin Energy, AGL Energy and Engie began performing their MLO duties. They must post bids and offers for the defined gaps in Q1 2022 and Q1 2023.

Figure 1.32 Q1 2022 and 2023 trading activity



Source: ASX data.

Since the South Australian RRO and MLO began there has been minimal trading of quarterly base futures products (figure 1.32). On the first day of the MLO (7 February) contracts for both Q1 2022 and Q1 2023 were traded during the MLO trading window. While the contracts that were traded toward the end of March weren't in the MLO trading window, they were for Q1 2022 which covers the first reliability gap stated by the South Australian Minister.

The price for both contracts has decreased over the quarter, however caution is advised when using it as a guide for future prices due to the low number of trades.

Changes to the RRO trigger

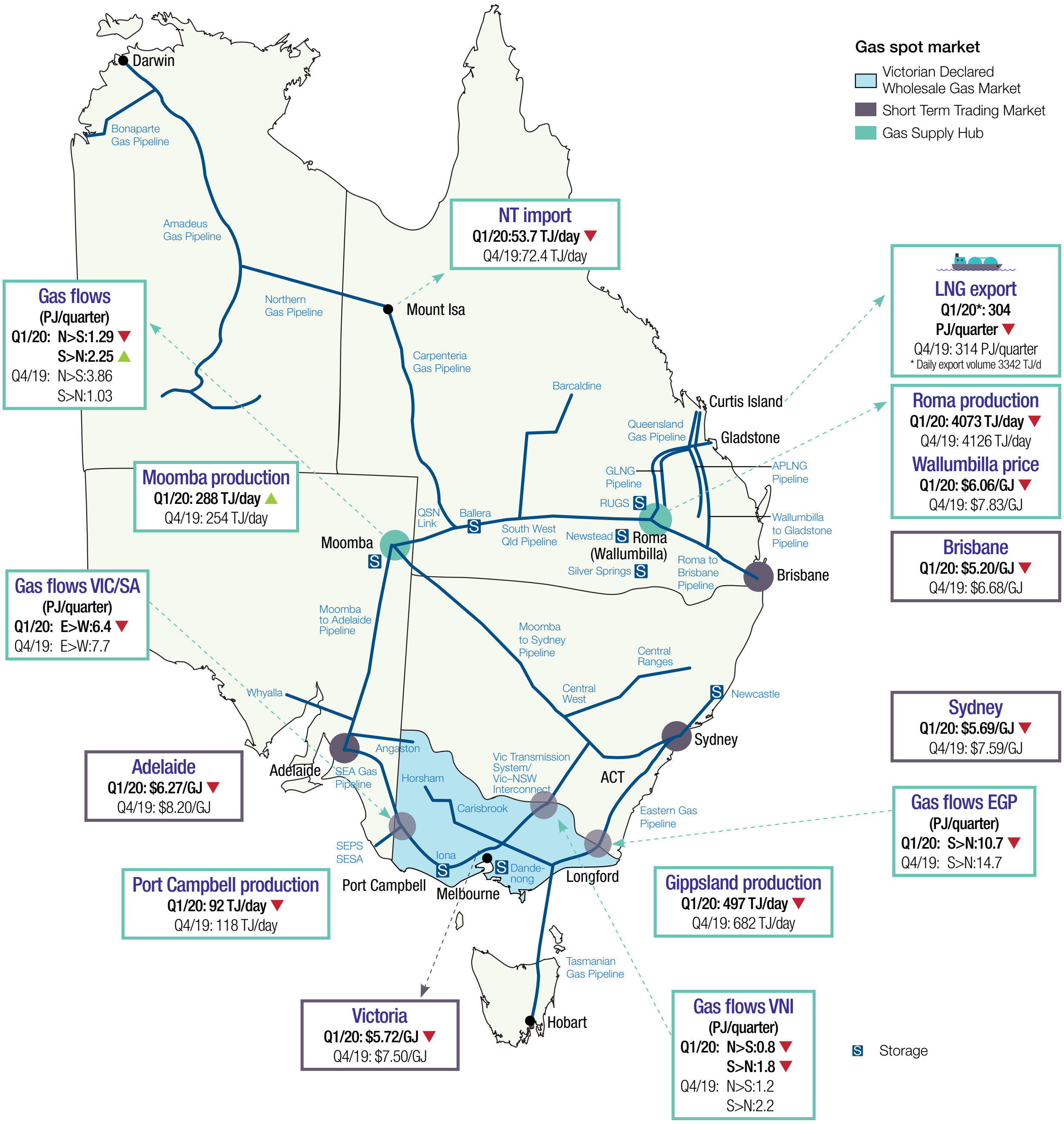
At the Council of Australian Governments' Energy Council meeting on 20 March 2020, it was agreed that the trigger mechanism for the RRO should be changed as an interim measure to deliver further reliability within the NEM. The trigger proposed is that unserved energy does not exceed 0.0006 per cent in any region in any year (changing from 0.002 per cent). There is no change to the level of contracting required by liable entities.

The Energy Security Board will be consulting on the draft rule and law changes needed to make this change in the near future.

2. Gas

EAST COAST WIDE SNAPSHOT	Eastern States Combined[b]					BRI	VIC	SYD	ADL	BRI	VIC	SYD	ADL
	2015	2016	2017	2018	2019	Q1 2019				Q1 2020			
average spot market price, $/GJ	$4.03	$6.73	$8.56	$9.11	$8.82	$9.42	$9.74	$10.21	$10.26	$5.20	$5.72	$5.69	$6.27
						$9.91				$5.72			
total net market trade volume, PJ[a]	25.2	24.1	33.6	30.7	45.9	0.34	5.51	3.37	0.84	0.52	4.42	3.72	0.93
						10.1				9.6			
spot trade as a proportion of scheduled demand (%)	6.5%	6.2%	8.1%	8.1%	11.9%	3.2%	12.9%	16.4%	22.8%	5.7%	10.7%	19.0%	24.0%
total GPG, PJ	185	145	187	140	163	15.7	8.9	3.3	17.4	15.1	5.4	2.6	12.2
						45.2				35.3			
total production, PJ	976	1605	1815	1781	1896	449				453			
LNG export, PJ	317	950	1101	1119	1204	304				304			
(+) net interstate import, PJ						10.3[c]	0.2	24.5	12.2	7.1	0.8	24	7.7
(-) net interstate export, PJ						-1.1[c]	-33	-0.5	-9.8	-1.3	-20.4	-0.8	-13.7
(+) total import from North, PJ	+22.4	+1	+9	+19	+40.8	1.14				1.29			
(-) total export to North, PJ	-7.2	-72.4	-48.4	-15.9	-5.5	-4.35				-2.25			
average underground gas storage level, PJ	N/A	N/A	N/A	N/A	95.5	99.1				98			

a January 2015 net market trade volume for Victoria was estimated due to unavailability.
b Eastern states include Queensland, Victoria, NSW and South Australia.
c Interstate flow data in this column is by the State of the City.



Gas spot market
Victorian Declared Wholesale Gas Market
Short Term Trading Market
Gas Supply Hub
Darwin
Bonaparte Gas Pipeline
Amadeus Gas Pipeline
Northern Gas Pipeline
Mount Isa
Carpenteria Gas Pipeline
Barcaldine
Curtis Island
Gladstone
Queensland Gas Pipeline
GLNG Pipeline
APLNG Pipeline
RUGS
Roma (Wallumbilla)
Newstead
Silver Springs
Wallumbilla to Gladstone Pipeline
Roma to Brisbane Pipeline
Brisbane
QSN Link
Ballera
South West Qld Pipeline
Moomba
Moomba to Adelaide Pipeline
Moomba to Sydney Pipeline
Central Ranges
Central West
Newcastle
Sydney
Whyalla
Angaston
Adelaide
SEA Gas Pipeline
Horsham
Carisbrook
Vic Transmission System/ Vic–NSW Interconnect
ACT
Eastern Gas Pipeline
SEPS SESA
Iona
Port Campbell
Melbourne
Dandenong
Longford
Tasmanian Gas Pipeline
Hobart
Storage
NT import
Q1/20:53.7 TJ/day
Q4/19:72.4 TJ/day
Gas flows (PJ/quarter)
Q1/20: N>S:1.29
S>N:2.25
Q4/19: N>S:3.86
S>N:1.03
Moomba production
Q1/20: 288 TJ/day
Q4/19: 254 TJ/day
Gas flows VIC/SA (PJ/quarter)
Q1/20: E>W:6.4
Q4/19: E>W:7.7
Adelaide
Q1/20: $6.27/GJ
Q4/19: $8.20/GJ
Port Campbell production
Q1/20: 92 TJ/day
Q4/19: 118 TJ/day
Victoria
Q1/20: $5.72/GJ
Q4/19: $7.50/GJ
LNG export
Q1/20*: 304 PJ/quarter
Q4/19: 314 PJ/quarter
* Daily export volume 3342 TJ/d
Roma production
Q1/20: 4073 TJ/day
Q4/19: 4126 TJ/day
Wallumbilla price
Q1/20: $6.06/GJ
Q4/19: $7.83/GJ
Brisbane
Q1/20: $5.20/GJ
Q4/19: $6.68/GJ
Sydney
Q1/20: $5.69/GJ
Q4/19: $7.59/GJ
Gas flows EGP (PJ/quarter)
Q1/20: S>N:10.7
Q4/19: S>N:14.7
Gippsland production
Q1/20: 497 TJ/day
Q4/19: 682 TJ/day
Gas flows VNI (PJ/quarter)
Q1/20: N>S:0.8
S>N:1.8
Q4/19: N>S:1.2
S>N:2.2

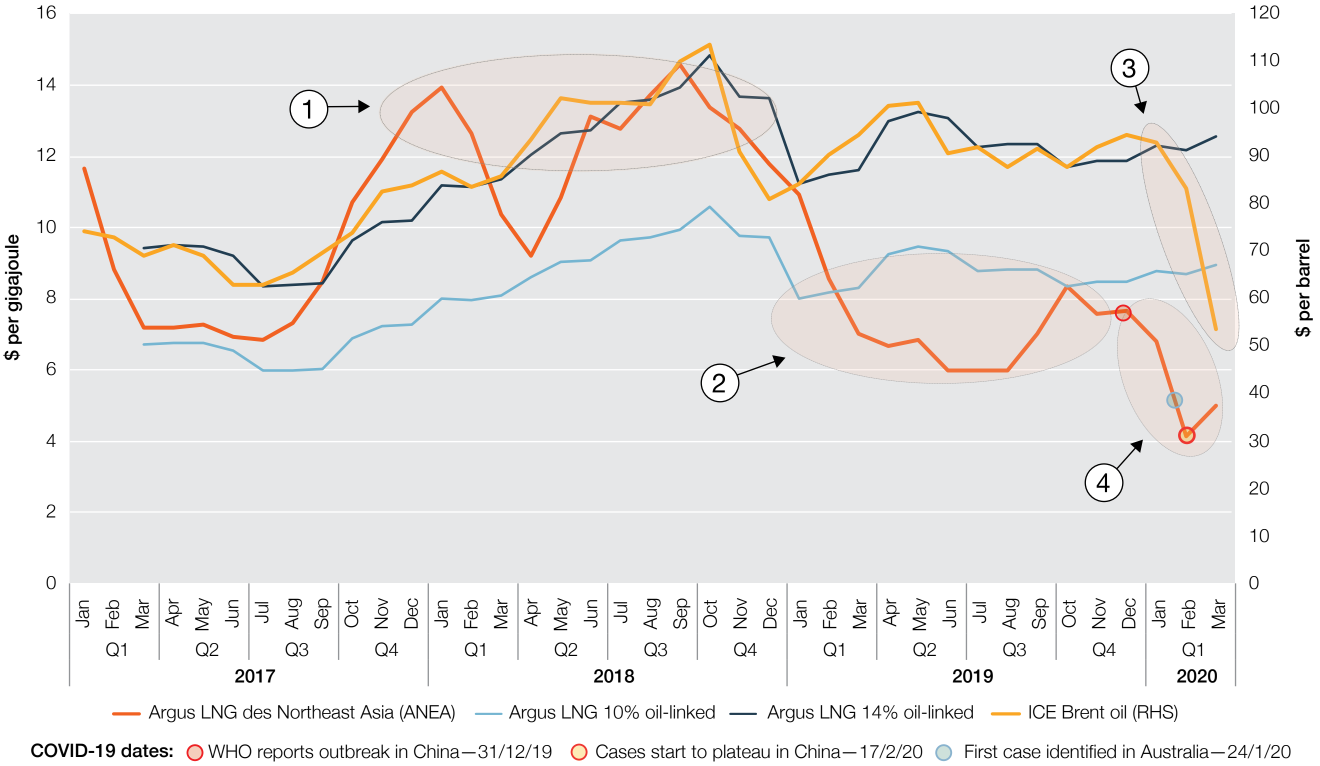
2.1 Quarterly spot prices

- International LNG spot prices fell to multi-year lows, with the daily ANEA spot price trading below $4 per GJ.
- Spot domestic prices continued to decline in all markets, aligning with international prices.

This quarter, international LNG prices reached their lowest levels since 2015. Argus Media's Northeast Asia (ANEA) price reached a daily low of $3.65 per GJ on 31 March (figure 2.1).[20]

Since peaking at $13.67 per GJ in Q3 2018, the ANEA spot price has fallen around 60 per cent to an average of $5.33 per GJ this quarter. Across 2019, an oversupply in global markets and falling demand put downward pressure on price, which continued into 2020. In addition, a mild Asian winter and a greater available supply of LNG combined with intensive price competition and the COVID-19 pandemic to trigger a dramatic drop in international prices this quarter.[21]

Figure 2.1 Delivered Asian LNG spot price and Brent oil price



1 **2018:** Asian spot gas prices traded around 12-14% of oil price. LNG export contracts at Gladstone are linked to the oil price at about 14%

2 **2019:** Asian spot prices plummet to reflect less than 10% of oil linked contract prices as global markets were oversupplied. Buyers incentivised to swap contract purchases for spot purchases

3 **Q1 2020 Oil prices:** Oil prices started to slump from the end of February, initially in response to intense price competition between oil exporting countries such as Saudi Arabia and Russia. Later in the quarter the worldwide shut down due to COVID-19 put further downward pressure on the oil price

4 **Q1 2020 LNG prices:** Asian spot prices fall to below $4/GJ in January and February. Demand is suppressed due to a milder Asian winter, high inventories and impact of COVID-19 lockdown. Mid-February Asian spot prices start to recover slightly

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% and 14% oil linked contract prices are indicative of either a 10% or 14% 3-month average Ice Brent crude futures slope.

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

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

21 The Asian winter is typically a period of higher LNG prices due to increased demand for heating.

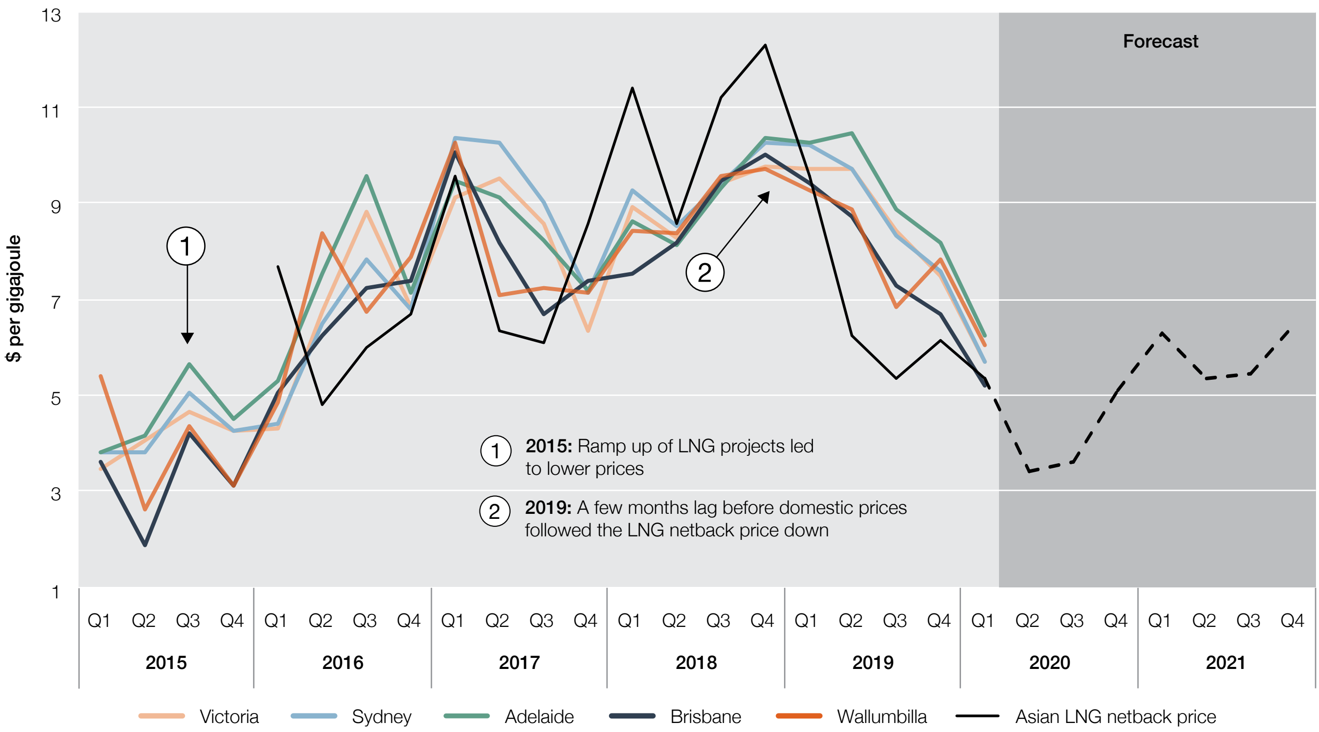
China is a major source of global demand for LNG. In January and February 2020 the spot price of LNG began to decline dramatically as China enacted measures to reduce the spread of the COVID-19 pandemic, which impacted its gas demand. By mid-February the spread of COVD-19 in China started to slow, allowing for a gradual relaxing of the restrictions.[22] As these restrictions relaxed, Chinese demand began to return. This, combined with stable demand in other major international customers such as South Korea and Japan, supported a small rise in the spot price during the second half of Q1 2020.

As COVID-19 spread around the world towards the end of the quarter, more countries imposed measures to contain the outbreak. In particular, India's restrictions led to some Indian LNG importers declaring a 'force majeure' and delaying imports.[23] This put further pressure on LNG supply and prices at the end of the quarter. Ultimately, COVID-19 has resulted in unprecedented levels of market uncertainty.

Separately, reductions in oil prices have affected the price of many international LNG contracts, which are linked to oil prices. Towards the end of February 2020, intense price competition between oil exporting countries including Saudi Arabia and Russia led to a slump in global oil prices. Over Q1 2020 the Brent oil price dropped from a high of $99.4 per barrel to a low of $36.9 per barrel at the end of the quarter, a price drop of 63 per cent.[24] This oil price slump was further exaggerated by the COVID-19 pandemic, which put more downward pressure on the oil price. As a result, it is expected that oil-linked LNG contract prices will start to trend downwards in Q2 2020.

Domestically, spot prices traded at their lowest levels in all markets since Q1 2016. Average prices for Q1 2020 in the downstream markets varied between a low of $5.20 per GJ in Brisbane to a high of $6.27 per GJ in Adelaide (figure 2.2).[25]

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.

22 John Hopkins University and Medicine 2020, Coronavirus Resource Center, https://coronavirus.jhu.edu/map.html, accessed 15 April 2020.

23 Oilprice.com 2020, Coronavirus Lockdown Forces India To Halt LNG Imports, https://oilprice.com/Latest-Energy-News/World-News/Coronavirus-Lockdown-Forces-India-To-Halt-LNG-Imports.html, 26 March 2020, accessed 13 April 2020.

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

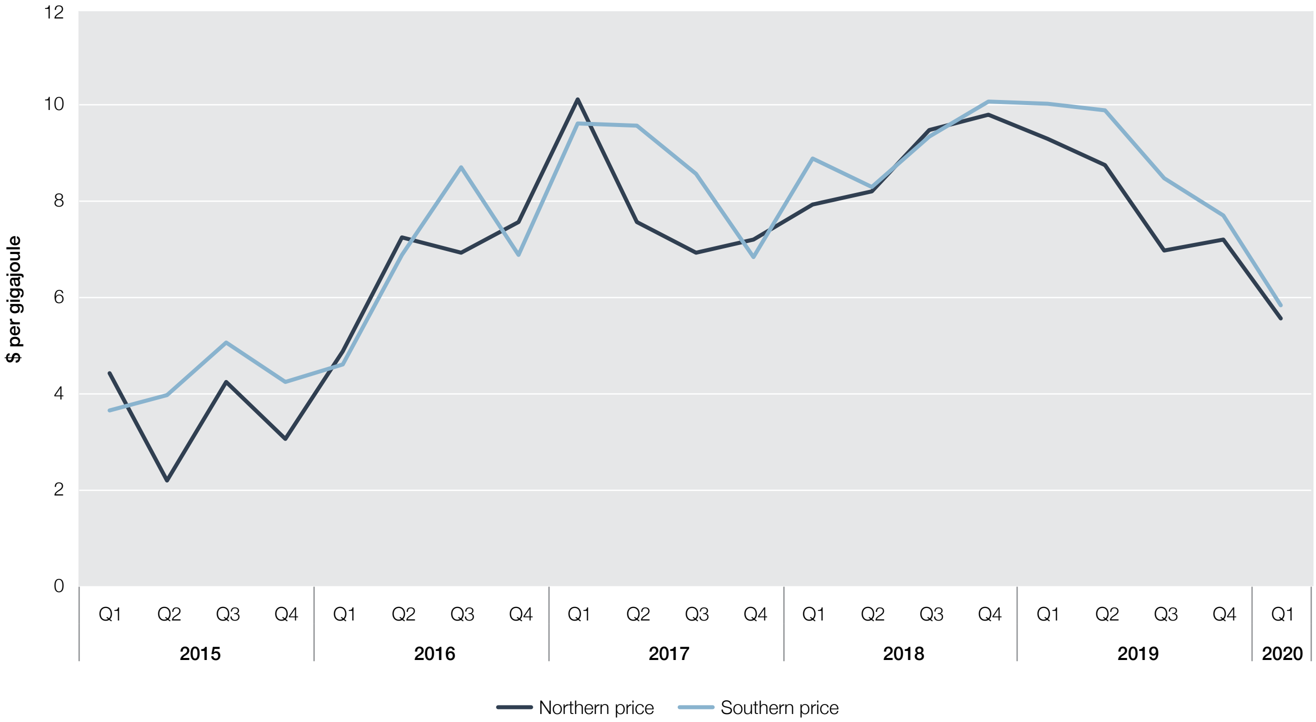
25 Three separate types of markets for gas operate in eastern Australia. The Gas Supply Hubs (GSH) at Wallumbilla and Moomba are "upstream" exchanges for the wholesale trading of natural gas. The Short Term Trading Markets (STTM) in Brisbane, Sydney and Adelaide, and the Declared Wholesale Gas Market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

Significant reductions in international LNG prices, and Queensland production remaining at high levels, contributed to the decline in domestic prices this quarter. All markets traded for less than $5 per GJ during Q1 2020. Individually, Victorian prices reached a daily minimum average of $4.08 per GJ, Sydney $4.17 per GJ, Brisbane $3.64 per GJ and Adelaide $4.66 per GJ.

Upstream, the on screen, day ahead price at the Queensland Gas Supply Hub at the Wallumbilla location remained higher than downstream prices in Victoria and NSW. When considering the price for both on and off screen trades, and all product types, the average price was $5.40 per GJ this quarter, which closely aligned with the Asian LNG netback price for Q1 2020 of $5.33 per GJ.[26] These price movements show a strong correlation between the Asian LNG netback price and the domestic spot prices at the Queensland Gas Supply Hub. We examine this in further detail in our focus story which looks at correlations separately for the Wallumbilla and South East Queensland trading points.

The price gap between the northern and southern markets continued to close from Q4 2019, with a difference of only $0.26 per GJ for Q1 2020 (figure 2.3).[27] This is the lowest Q1 price gap in the last two years and was driven by lower southern demand, and access to cheap transportation through the Day Ahead Auction (DAA).[28]

Figure 2.3 North-South commodity price gap



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

In 2017 and 2019 the price gap between the north and south opened up as seasonal demand in the southern markets increased, which provided arbitrage opportunities to participants. In addition, the now year-old DAA has provided participants with access to cheap (or near free) pipeline capacity reducing the cost of domestic transportation from northern to southern markets. We will continue to monitor the north-south price gap in future quarters, and the impact of the DAA in reducing the difference between regions.

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

27 Northern markets refers to the Wallumbilla (Qld) Gas Supply Hub and Moomba (SA) 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.

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

2.2 Production and storage

- Total east coast gas production is down, with most significant declines in southern markets.
- Producer announcements indicate emerging project delays and expenditure cuts due to global oil price slump and COVID-19 pandemic.
- Increase to total east coast storage inventories, with Moomba storage filling for first time in 5 years.

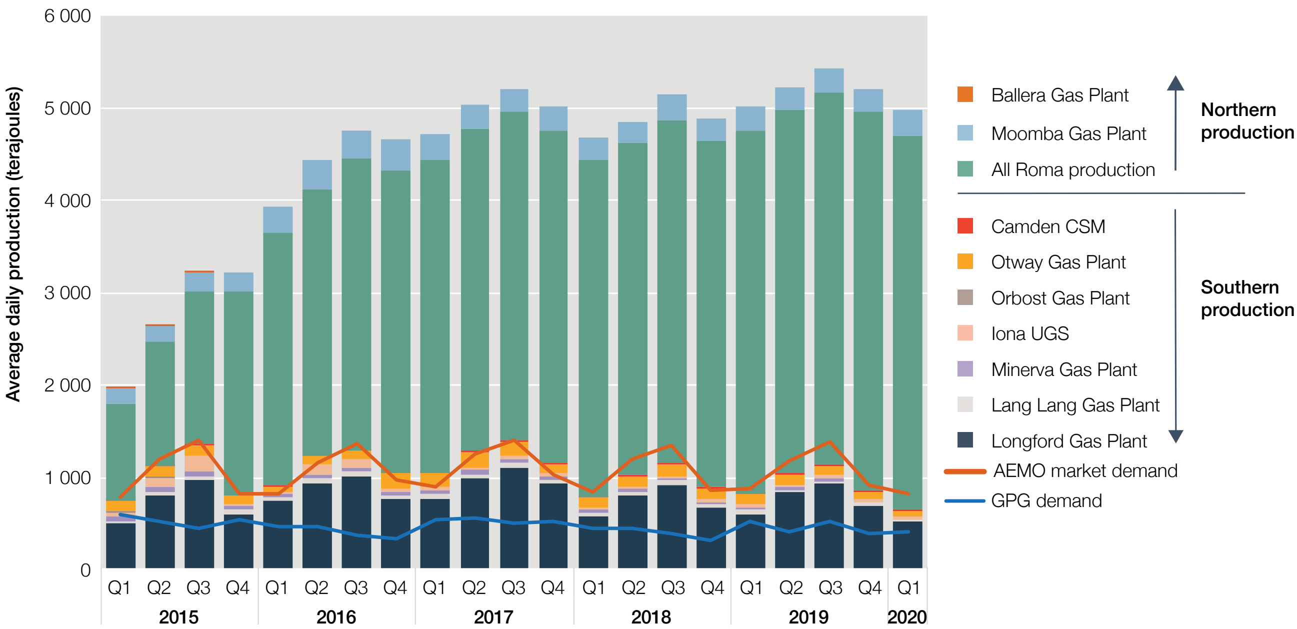
Total east coast gas production decreased for the second successive quarter, declining from an average of 5220 TJ per day, during Q4 2019, to 4995 TJ per day during Q1 2020 (figure 2.4). This is expected given that production declines occur in association with lower summer demand, including reduced household gas heating demand and decreased C&I demand due to holiday shutdowns. High summer temperatures can create gas demand spikes for electricity generation but gas powered generation (GPG) was very low this quarter (section 2.8). An increase in LNG exports could have offset lower domestic demand, however LNG exports also declined slightly this quarter (section 2.3).

There was a very small decline in total northern market production, from 4380 TJ per day in Q4 2019 to 4361 TJ per day in Q1 2020.[29] The small decline was concentrated in Queensland and was partially offset by a 31 TJ per day increase in Moomba production.

Overall, the gap between northern and southern production widened, mostly due to very low output from the Longford gas plant. Longford was impacted by successive periods of off-shore maintenance; the plant's average daily production this quarter of 452 TJ was less than half of its nameplate capacity of 1115 TJ per day and its lowest quarterly production since Q1 2015. Production from Victoria's Otway Basin was also significantly low, averaging 64 TJ per day, its lowest quarterly output on record.

In total, the northern fields—including production volumes destined for export—have been the dominant source of gas for the eastern Australia market over the last five years.

Figure 2.4 East Coast production



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

29 Northern market production in this case refers to gas produced in Roma, Queensland and Moomba, South Australia.

Individually, Queensland production declined from its record daily average of 4126 TJ set in Q4 2019. However, at 4073 TJ, production persisted above 4000 TJ per day for the third successive quarter, after first reaching this level in Q3 2019. It remains to be seen whether these high production levels can be sustained. Record production in Q4 2019 coincided with record quarterly exports from Gladstone ahead of north Asia's high-demand winter period. Seasonal declines from these production levels are anticipated but will likely be exacerbated in 2020 by reduced global LNG demand due to the COVID-19 outbreak and sharp falls in international oil prices.

Producer announcements toward the end of Q1 2020 indicated emerging project delays and reduced capital investment in response to COVID-19 and oil price declines. These include a hold on drilling operations in the Bass Strait by ExxonMobil and a 38 per cent reduction in capital expenditure by Santos.[30] Origin Energy announced a pause on its Northern Territory Beetaloo Basin exploration program as part of a revised 25–30 per cent reduction in capital expenditure in 2021. Origin's announcement includes targeting a $300–400 million reduction in APLNG upstream expenditure.[31] The number of new gas wells drilled in Queensland—a key indicator of the production outlook from coal seam gas producers—declined by approximately one third from Q4 2019 to Q1 2020. This decline occurred despite Senex's well drilling program in the Surat Basin—which has also reduced from 110 to 85 wells—suggesting a more pronounced decline in drilling activity across Queensland's three LNG producers.[32]

Progress on advanced projects included market delivery of gas from Cooper Energy's Sole gas field in the Gippsland Basin, supported by the March recommissioning of Victoria's Orbost Gas Plant (68 TJ per day nameplate rating). On 6 March 2020, ExxonMobil, despite pausing other Bass Strait drilling, announced drilling milestones at its West Barracouta project, expecting to bring gas to the domestic market in early 2021.[33] On 17 April 2020, Shell announced a final investment decision on the first phase of the Arrow Energy Surat Gas Project in Queensland. The project will produce gas for both the domestic market and export. Shell forecasts the development of 2500 new wells over the life of the project, with the first phase of production beginning in 2021.[34]

Q1 2020 policy announcements included the lifting of the Victorian Government moratorium on onshore exploration for conventional gas reserves, allowing exploration from 1 July 2021.[35] The Australian and NSW governments also announced a deal to facilitate investment opportunities to supply an additional 70 petajoules of gas to the domestic market each year.[36]

Total gas storage increased by 9.3 per cent from Q4 2019 to Q1 2020 (figure 2.5). This was largely driven by filling at Victoria's Iona Underground Storage facility following its depletion through the higher demand Q3 and Q4 periods. Iona is undertaking this filling in preparation for the Victorian winter. Gas held at the facility averaged 18 653 TJ per day in Q1 2020, increasing from 11 945 TJ during Q4 2019. The Q1 2020 level was slightly higher than the 17 200 TJ averaged during Q1 2019.

There were small increases to gas held at Moomba LDB Storage and Queensland's Roma Underground Gas Storage from Q4 2019 to Q1 2020. The Moomba increase, from 20 446 to 21 240 TJ, follows more than five years of gradual depletion.

30 Santos COVID-19 Response and Business Update, 23 March 2020, https://www.santos.com/news/santos-covid-19-response-and-business-update/.

31 Origin Operational and financial update, 6 April 2020, https://www.originenergy.com.au/about/investors-media/media-centre/operational_and_financial_update.html.

32 Senex Energy Quarterly Report for period ending 31 March 2020, https://www.senexenergy.com.au/wp-content/uploads/2020/04/2053331.pdf.

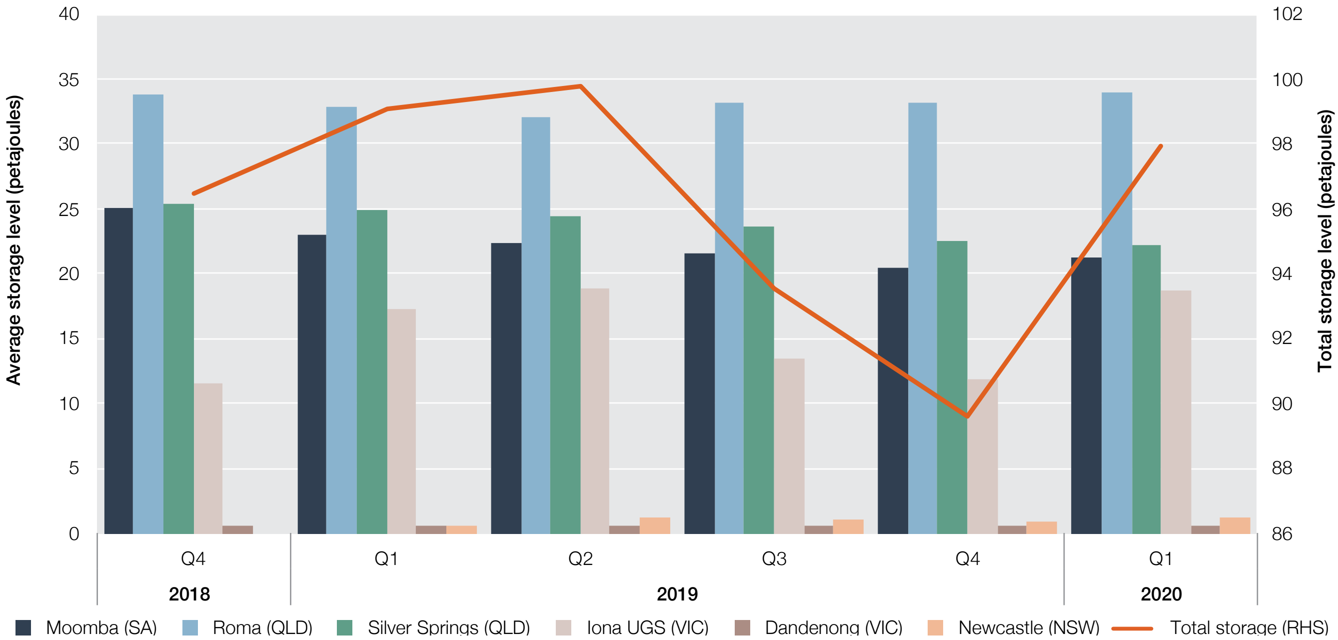
33 ExxonMobil news release, 6 March 2020, https://www.exxonmobil.com.au/News/Newsroom/News-releases-and-alerts/2020/Esso-drilling-for-West-Barracouta-gas.

34 Shell Australia media release, 17 April 2020, https://www.shell.com.au/media/2020-media-releases/shell-invests-in-arrow-energy-surat-gas-project.html.

35 Premier of Victoria media release, 17 March 2020, https://www.premier.vic.gov.au/backing-the-science-protecting-farmers-and-boosting-jobs/.

36 Prime Minister of Australia and Premier of NSW joint media release, 31 January 2020, https://www.pm.gov.au/media/nsw-energy-deal-reduce-power-prices-and-emissions.

Figure 2.5 Storage levels



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

2.3 LNG exports

- Small decline in east coast exports from record volumes shipped in Q4 2019.
- Pronounced decline in deliveries marked to China amid COVID-19 pandemic, with increased deliveries to other Asian ports.
- The full impact of the international oil price slump and COVID-19 pandemic on the Australian LNG export sector is yet to be fully realised.

LNG exports underwent a small decline after reaching record levels in Q4 2019. This is consistent with the longer term trend, as Q4 is typically the peak export period ahead of the northern hemisphere winter and strong Asian demand (figure 2.6). Q1 2020, however, saw significant changes to ports of destination, with the Chinese account for total export volumes declining from 70 to 63 per cent.

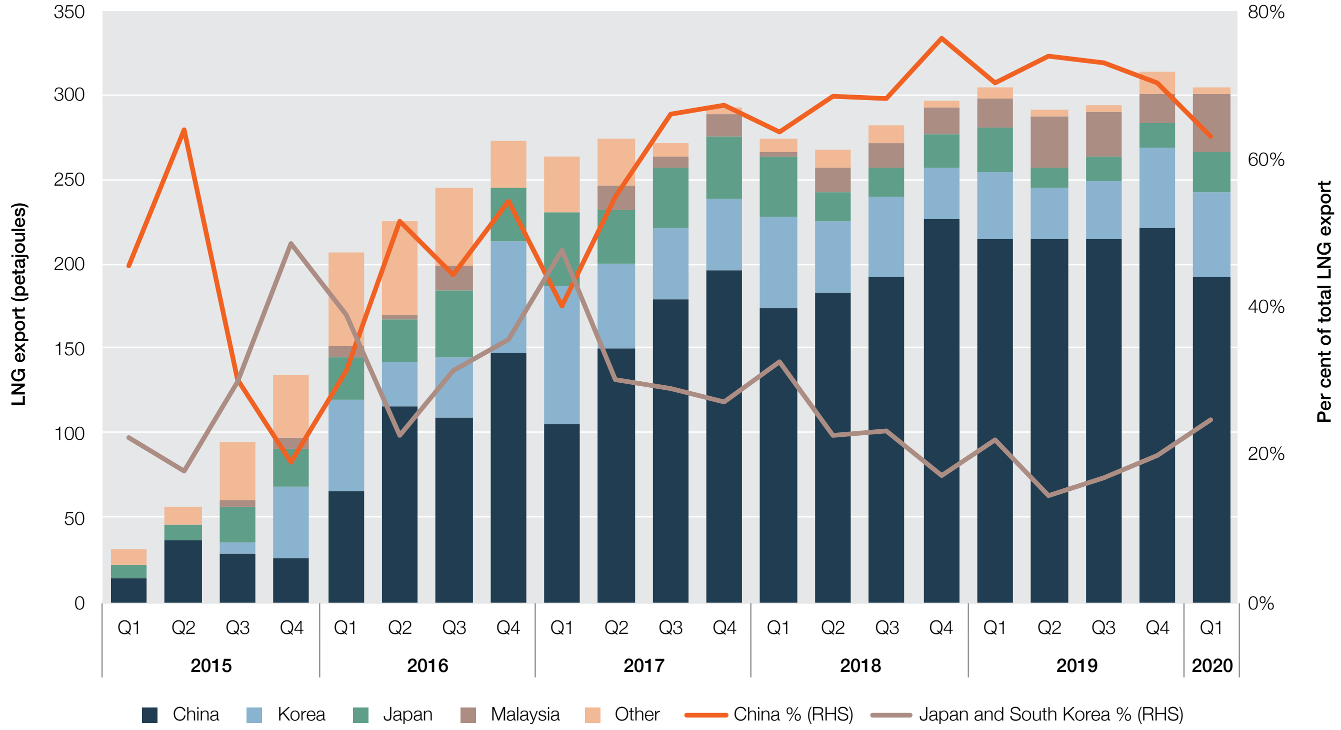
The decline in Chinese LNG demand is a result of high inventories, due to an unseasonably warm winter in north Asia, followed by forced industrial shutdowns due to the COVID-19 outbreak. This was the lowest quarter of reported exports to China since Q2 2018.

The decline in Chinese imports was off-set by a combined 5 per cent increase in exports to Japan and South Korea and a doubling in exports to Malaysia. Also, relatively strong Q1 2020 exports, from Gladstone, may have been assisted by cargo redirections early in the quarter, before the worsening COVID-19 pandemic led to more widespread restrictions.

We anticipate seeing the impact of COVID-19, low international oil prices and share price falls on Australia's LNG export sector more clearly in Q2 2020. The extent of local gas production cuts, and reduced LNG processing, will become more evident in coming months.[37]

37 Queensland long-term LNG export contracts are linked to international oil prices, meaning the global oil price slump directly impacts producer revenues and share values.

Figure 2.6 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Port Corporation data.

2.4 Gas Supply Hub outcomes

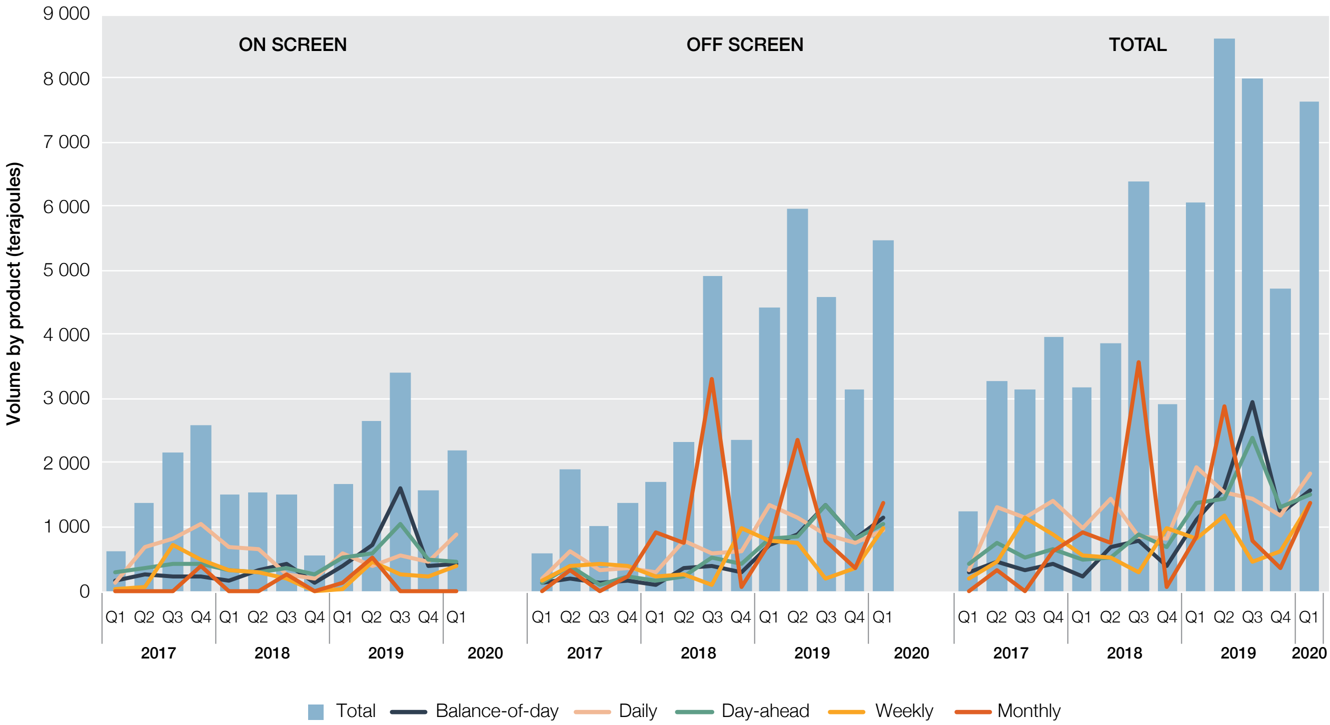
- Trade at the Gas Supply Hub (GSH) rose in Q1 2020 as significant falls in prices encouraged activity.
- More participants led to a reduction in market concentration amongst the top three buyers.

GAS SUPPLY HUBS SNAPSHOT	2014	2015	2016	2017	2018	2019	2020 YTD
number of trades	481	875	798	1 638	1 919	3 635	956
trade volume, PJ *% of trade by top 3 buyers : sellers*	2.4 *67% : 89%*	6.4 *71% : 75%*	7.9 *66% : 56%*	11.6 *51% : 59%*	16.4 *53% : 52%*	27.4 *51% : 64%*	7.6 *43% : 66%*
trade value, $million	5	24	57	89	148	219	40
volume weighted average price, $/GJ	2.01	3.66	7.20	7.68	9.02	7.98	5.23
number of trading participants *number of active participants* on-screen *vs.* off-screen	8 *7:0*	12 *11:7*	12 *11:11*	13 *12:9*	13 *12:12*	16 *13:16*	17 *14:17*
% traded through exchange (sum bought divided by regional demand)	N/A	N/A	N/A	4.3%	6.1%	9.1%	8.3%

Source: AER analysis using GSH trades data; natural gas bulletin board.

In Q1 2020 traded quantities at the GSH rose from Q1 2019 levels (figure 2.7). In total, there was over 7600 TJ of gas traded this quarter across 956 transactions. This is the highest activity for a Q1 since GSH start, up from the around 6000 TJ traded in Q1 2019 across 931 transactions.

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



Source: AER analysis using GSH trades data.

Overall participants continued the trend of striking more trades off screen, with more than twice the volume of gas traded off screen than on screen across Q1 2020. This continues as off screen products remain cheaper than on screen alternatives for balance-of-day, daily and day-ahead products. Balance-of-day products in particular were on average 78 cents per GJ more expensive if purchased on screen. We explore the difference in on and off screen prices further in our focus story.

Compared to the same time last year, most products traded at higher levels in Q1 2020. Only daily products saw a fall in trade, due to a reduction in off screen activity. Increased trade volume may be due to the lower prices that have emerged in recent months. Participants are also using more gas to fuel GPG in Queensland, and to invest into storage.

Two new participants commenced trading in the GSH in Q1 2020. However, one previously active participant did not trade. This brings the total number of participants in the GSH to 17 for this quarter. Following last year's trend, more participants were active off screen than on. All 17 actively traded off screen in Q1 2020, but only 14 actively traded on screen products.[38]

Reflecting the growth in participants, market concentration among buyers reduced. The top three buyers for Q1 2020 accounted for 43 per cent of volume traded, down from the 2019 average of 51 per cent. However, the top three sellers continued the trend of increasing concentration across 2019, and accounted for 66 per cent of volume traded in Q1 2020.

The churn rate for Q1 2020 rose slightly compared to levels seen in Q1 2019.[39] Wallumbilla increased from 8 per cent in Q1 2019 to 8.3 per cent this quarter. Similarly, the Moomba hub churn rate was 0.2 per cent in Q1 2020, compared with 0.1 per cent a year earlier.

38 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).

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

Table 2.1 Gas Supply Hubs—Churn rate by hub

QUARTER	MOOMBA	WALLUMBILLA	QUARTER	MOOMBA	WALLUMBILLA
Q2 2017	-	4.4%	Q4 2018	0.1%	8.3%
Q3 2017	0.0%	5.3%	Q1 2019	0.1%	8.0%
Q4 2017	0.0%	5.6%	Q2 2019	1.3%	8.7%
Q1 2018	-	4.1%	Q3 2019	0.9%	13.6%
Q2 2018	0.0%	6.0%	Q4 2019	0.4%	6.1%
Q3 2018	0.1%	5.6%	Q1 2020	0.2%	8.3%

Source: AER analysis using gas supply hub data, Natural gas bulletin board.

2.5 Day Ahead Auction outcomes

- Five new participants won capacity on the Day Ahead Auction in Q1 2020.
- Capacity was won on the Moomba to Adelaide Pipeline System for the first time for the transportation of gas south.
- Record daily capacity was won following South Australia's isolation from the NEM on 31 January 2020.

DAY AHEAD AUCTION SNAPSHOT

	2019				2020	
	MAR	Q2	Q3	Q4	Q1	Auction to Date
number of active participants	1	4	6	6	11	13
number of facilities	4	6	6	7	7	10
auction legs won	142	671	1 281	807	1 179	4 080
capacity won, TJ	2 548	6 609	14 945	6 492	10 525	41 118
maximum auction price, $/GJ	0.10	0.61	1.05	0.30	0.30	1.05
% won at $0/GJ	82%	88%	71%	87%	82%	80%
% won at ≥$0.10/GJ	0%	8%	20%	5%	4%	10%

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.

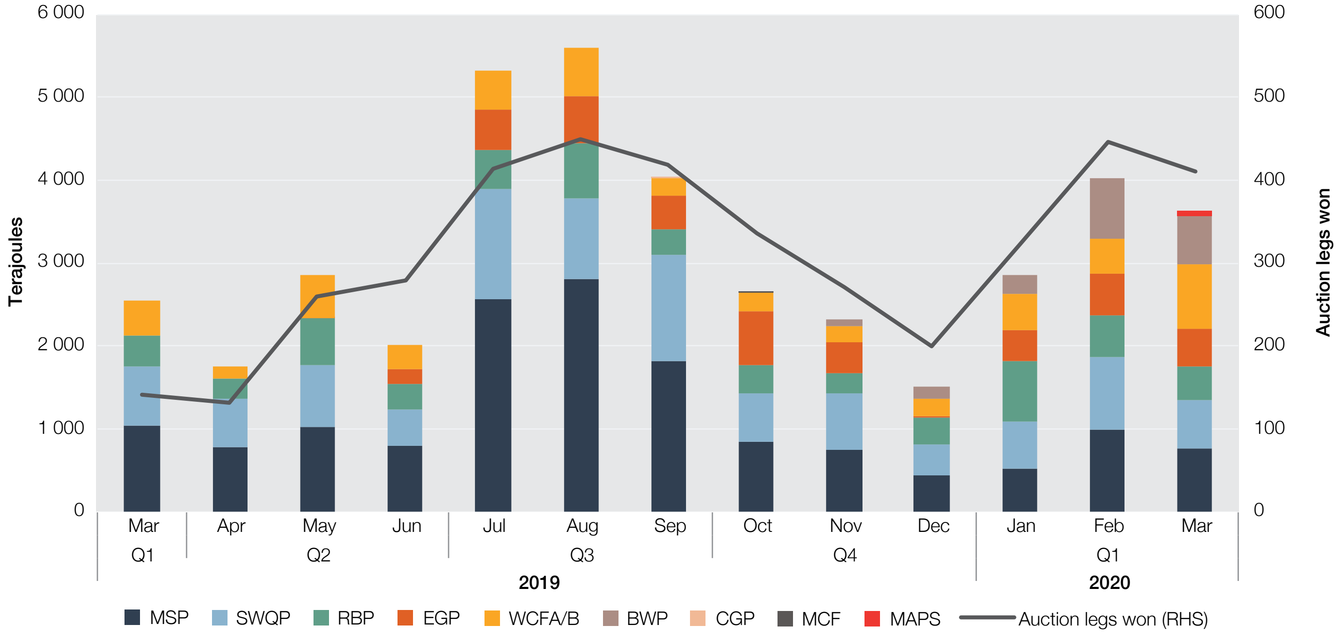
March 2020 saw the Day Ahead Auction (DAA) move into its second year of operation, with participants winning over 41.1 PJ of unused contracted pipeline capacity across 10 facilities since its commencement.[40] The number of participants winning capacity increased by five in Q1 2020, as market participants continued to recognise the opportunity presented by the DAA for low cost gas transportation.

The number of auction legs and total capacity won increased in Q1 2020 compared to the previous quarter, with increases observed on all facilities and more activity around Wallumbilla (figure 2.8). Considerable increases in capacity won to bring gas south to Wallumbilla were observed on the Berwyndale to Wallumbilla Pipeline (BWP) compared to the previous quarter. Auction capacity was also won on the Moomba to Adelaide Pipeline System (MAPS) facility for the first time.

40 We explain how the DAA and capacity trading works in the Appendix.

Q1 2020 saw four of the highest auction days since the commencement of the DAA, including record capacity won (317 TJ) in the evening on 31 January 2020, this coincided with the NEM separation event in South Australia earlier in the day. Almost a third of the capacity won on this day was on the South West Queensland Pipeline (SWQP) to bring gas from Wallumbilla, Queensland to Moomba, South Australia. The second highest monthly number of auction legs ever won was in February.

Figure 2.8 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.

The heavily contracted Roma to Brisbane Pipeline (RBP) continued to see high levels of competition for auction capacity, with auction utilisation rates increasing by 18 per cent to 80 per cent in Q1 2020 (table 2.2).[41] The high number of days (60 days) where auction limits were reached is reflected in the higher prices observed on this facility, including a maximum price of $0.30/GJ, compared to other facilities. Capacity won on the Moomba to Sydney Pipeline (MSP), Eastern Gas Pipeline (EGP) and BWP was under $0.01/GJ and all capacity won on the South West Queensland Pipeline (SWQP), MAPS and Wallumbilla Compression Facility B (WCFB) was at $0/GJ.

The first trade on the capacity trading platform (CTP) was completed in February for 1 TJ. The differences between the CTP and DAA are noted in the Appendix to this report. The preference for using the DAA to date reflects the cheap auction pricing outcomes. Bids and offers for short term capacity on the CTP, which operates in advance of the auction, have been largely non-existent as buyers in particular wait for the auction.

41 The auction utilisation rate represents the proportion of available auction capacity that was won by participants.

Table 2.2 Available capacity and utilisation on the Day Ahead Auction

PIPELINE/METRIC	MARCH 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020
SWQP (Wallumbilla to Moomba)					
No. days capacity unavailable	0	0	0	0	0
No. days auction limit reached	0	18	51	0	0
Available auction capacity utilised (%)	17	31	55	15	14
Demand above auction limit (TJ)	0	183	1424	0	0
EGP (Longford to Sydney)					
No. days capacity unavailable	4	0	7	2	0
No. days auction limit reached	0	0	8	11	2
Available auction capacity utilised (%)	-	35	49	55	30
Demand above auction limit (TJ)	0	0	299	148	19
RBP (Darling Downs/Scotia to Wallumbilla)					
No. days capacity unavailable	1	1	5	7	0
No. days auction limit reached	11	45	77	59	60
Available auction capacity utilised (%)	76	75	94	62	80
Demand above auction limit (TJ)	47	523	1604	1303	1330

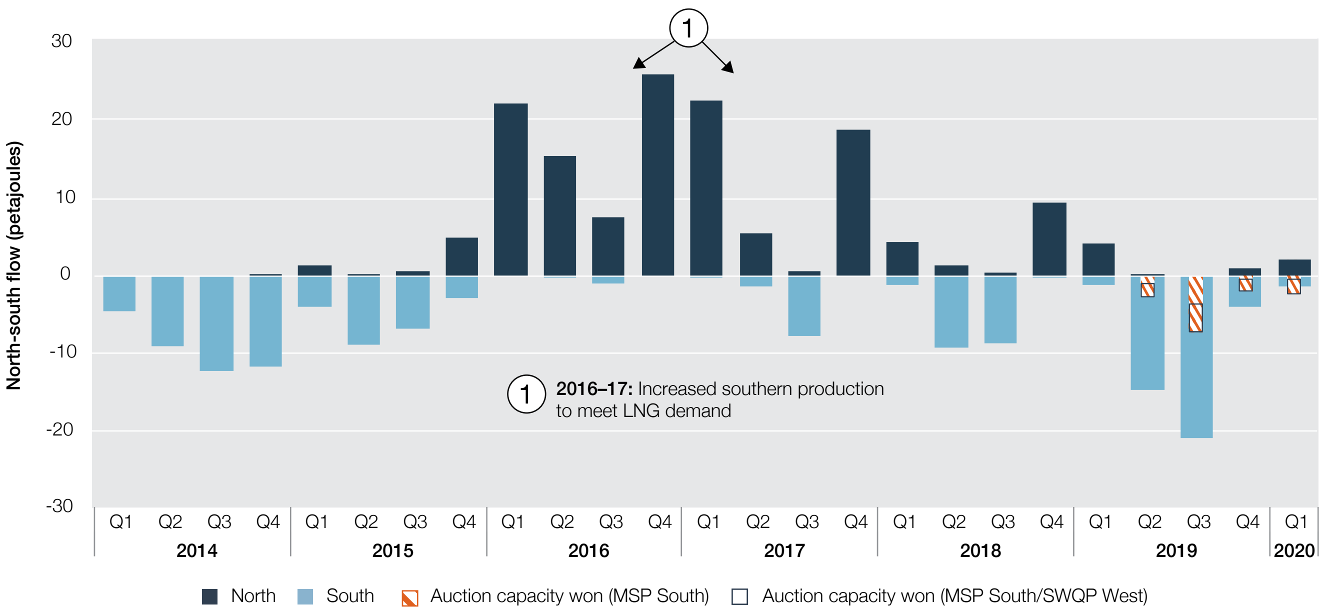
Source: AER analysis using DAA auction results data.

2.6 Flows between north and south

- Lower physical gas volumes in Q1 2020 are flowing between north and south as Queensland becomes less import reliant year round.
- The prominence of Victoria as a gas exporter to other East Coast markets is continuing to decline.

Overall, in net terms around 1 PJ of gas flowed north in Q1 2020, which was a reduction of just over 2 PJ from net flows north in Q1 2019 (figure 2.9). This reduction can be attributed in part to the Northern Gas Pipeline being commissioned in early 2019 as well as increases in gas production in Queensland over the same period making Queensland less import reliant year round.

Figure 2.9 North-South gas flows



Source: AER analysis using the Natural Gas Services Bulletin Board and Day Ahead Auction data.

Notes: 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.

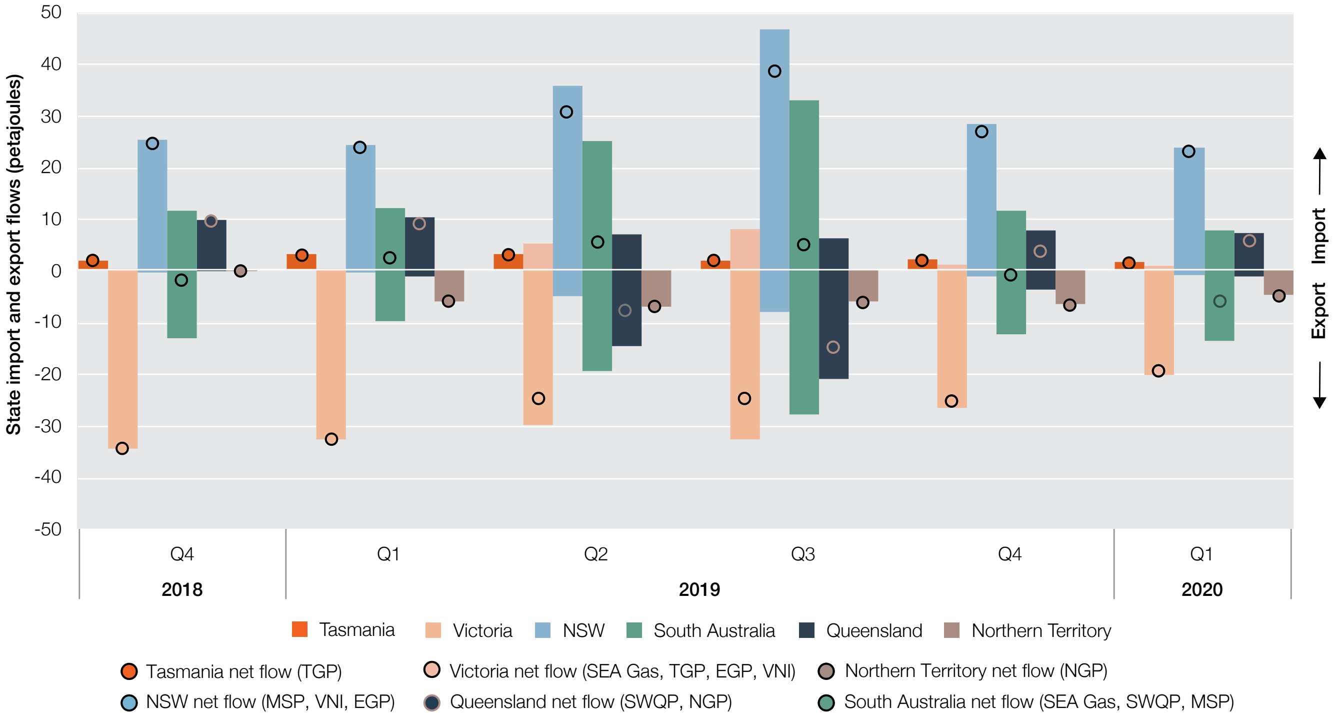
With the continued alignment of prices across markets (figure 2.2) and the gap between the northern and southern prices closing even further (figure 2.3), less arbitrage opportunities existed to incentivise the flow of gas from north to south. As a result, southerly flows remained at similarly low levels as in Q1 2019.

This was also the first quarter since the introduction of the DAA that more capacity was won on the combined MSP and SWQP route than the actual amount of physical gas flowing south through Moomba. This highlights that the DAA is able to be used by individual participants to move gas 'contractually' against the prevailing physical flow to place it in other locations for power generation or gas sales purposes.

At a state level, the prominence of Victoria as a gas exporter to the other East Coast markets is in decline. In Q1 2020, Victoria's total net gas exports reduced to 19.6 PJ, a reduction of 13.1 PJ from Q1 2019 (figure 2.10).[42] This can be broken down by destination into a reduction of 1.6 PJ to Tasmania, 4.4 PJ to South Australia and 7.1 PJ to NSW. The main reason for this decline is the continued reduction in production from the Longford gas plant.

This loss in production to the East Coast gas market has been largely made up by increases in production from Queensland, as well as gas imports from the Northern Territory beginning in 2019. Santos and Shell are two northern producers that have been more prevalent over 2019 and into 2020 in moving gas south. Additionally, a range of other participants are using the new DAA routes south to compensate for reductions in Longford production.

Figure 2.10 Interstate gas flows



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

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

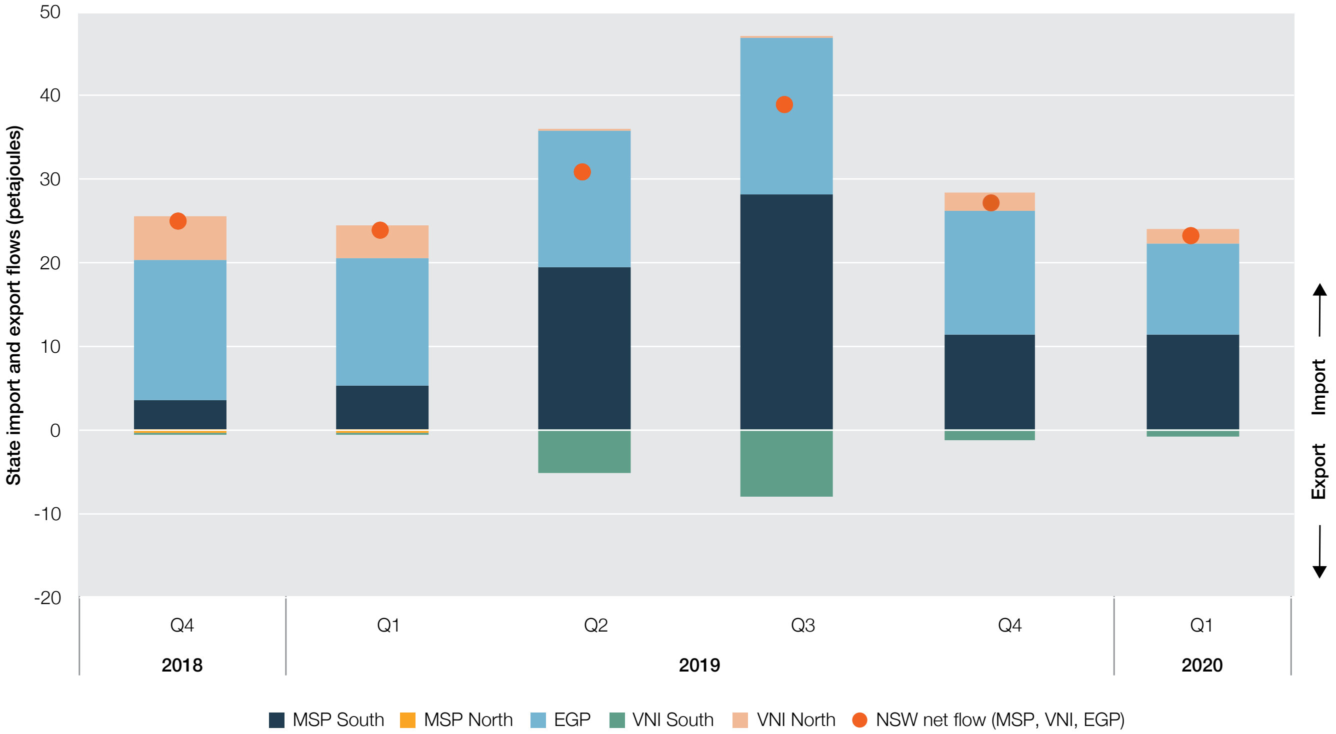
42 In figure 2.10 the total export flow from a state is the sum of all export gas flows (shown as a negative value). The total import flow to a state is the sum of all import gas flows (shown as a positive value). The net state flow is the difference between the total export flow and the total import flow and can be either positive or negative depending if the state is a net exporter (negative) or net importer (positive). As an example, for Victoria the total export flows is the sum of the flow on the EGP to NSW, the two SEA gas pipelines to South Australia, the flow to Tasmania on the TGP and the flow north on the VNI to NSW. The total import flow is only the flow south on the VNI to Victoria from NSW. The difference between these two values is the net gas flow, with Victoria always a net exporter of gas.

Queensland maintained strong production levels throughout the quarter producing 14.6 PJ more gas in Q1 2020 compared to the same period in 2019. This increased production assisted in offsetting a reduction in import from the Northern Territory of 1.1 PJ, and a net reduction of gas flowing from Moomba into Queensland of 2.3 PJ for Q1 2020. The NGP recorded its lowest quarterly flow since commissioning of 53.7 TJ per day compared to an average flow in 2019 of 70.4 TJ per day. This reduction in flow observed on the NGP started from 1 January 2020 and is most likely due to a change in customer demand upon recontracting.[43]

The total net flow of gas imported to NSW for Q1 2020 was 23.1 PJ, only marginally lower than Q1 2019, but the proportion of gas imported from Victoria reduced from 79 per cent of the total in Q1 2019 to only 50 per cent in Q1 2020, with the remainder being made up of gas flowing south on the MSP from the northern states (figure 2.11). Net gas flowing south on the MSP from Moomba was 6.4 PJ higher for Q1 2020 compared to Q1 2019 and can be attributed to the following:

- An increase in Moomba production of 3.5 PJ.
- A reduction in the net gas flow from Moomba to Queensland of 2.3 PJ becoming available for redirection to NSW.
- A small reduction in the flow on the Moomba to Adelaide Pipeline (MAPS) flowing south from Moomba of 0.2 PJ.

Figure 2.11 NSW import and export gas flows



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

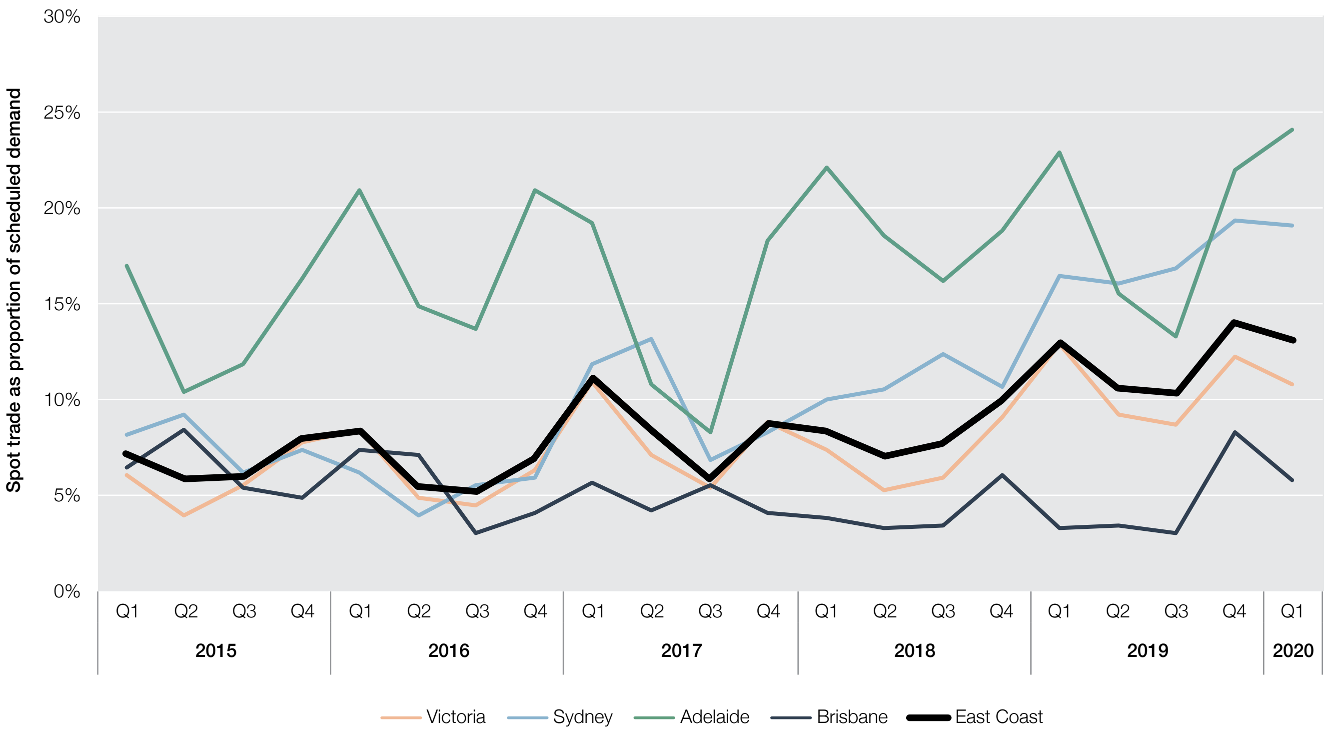
43 Jemena 2020, Jemena announces new gas transportation contract, https://jemena.com.au/about/newsroom/media-release/2018/jemena-and-senex-partner-to-fast-track-new-gas-(1), accessed 1 May 2020.

2.7 Spot market outcomes

› Continued trend in increased spot trade in the downstream markets.
› Significant participation by upstream sellers (mainly producers) and downstream buyers (including many industrial customers).

Liquidity in the east coast gas markets largely maintained at the recent high levels of trade observed over the previous quarter and was notably up from Q1 2019 (figure 2.12). While there was a slight decrease from the previous quarter in most markets, activity in Adelaide increased with net trades accounting for almost a quarter of market demand, reaching its highest level to date. Producers had the highest level of activity on the sales side, while industrial users were prominent gas purchasers.

Figure 2.12 Spot trade liquidity



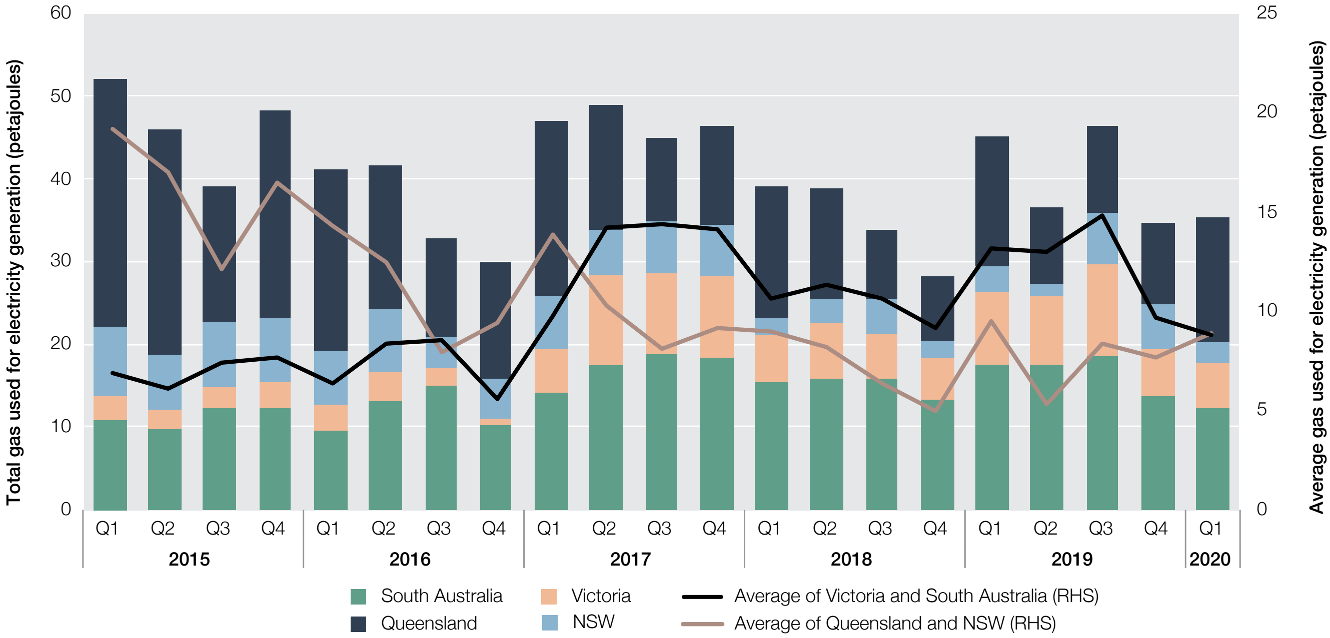
Source: AER analysis using gas bulletin board data.

2.8 Gas powered generation demand

- Gas usage for electricity generation was lower in southern regions and higher in Queensland.
- SA GPG was notably lower compared to previous Q1 trends.
- Queensland GPG absorbed excess gas from high local gas production levels.

Gas demand for electricity generation declined further this quarter in southern regions (figure 2.13). This occurred alongside mild weather and subdued gas market demand, with gas generation across the east coast dropping to levels significantly lower than those across Q1 2019. However, gas generation increased in Queensland from the previous quarter. Whilst Roma production and export volumes were slightly down from the previous quarter, production remained high in Queensland alongside a significant reduction in gas flowing to southern states. This local supply fed the increased gas generation while market prices were low.

Figure 2.13 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 Financial market outcomes

- Trade in futures declined significantly in Q1 2020 compared to Q1 2019.
- Increase in trading activity this quarter for Q2 and Q3 2020 futures.

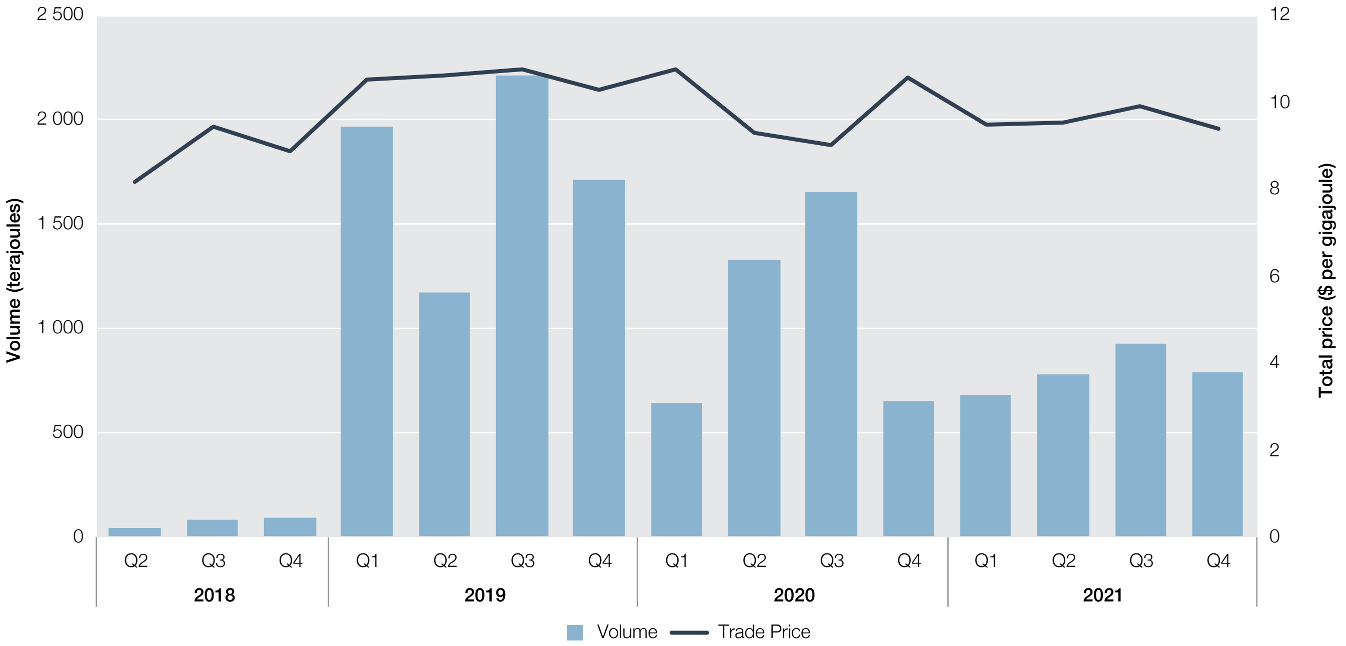
Financial market trade in Q1 2020 declined significantly from Q1 2019, while there was further growth in futures traded for both Q2 and Q3 2020 (figure 2.14). In total, there were 60 trades in quarterly products over Q2 2020 (up from 15 contracts traded over the previous quarter) and 84 trades for Q3 2020 (up from 20 contracts over Q4 2019).[44] [45] The average price of gas bought and sold (the trade price) was $10.70 per GJ for Q1 2020, and the contract ultimately settled for $8 per GJ, resulting in a loss to those who took a long position.

Quarterly and yearly (strip) products are available for participants in the Victorian gas market to limit their exposure to the spot price by setting a price for future financial transactions. Amounts traded only equate to a very small proportion of the total physical volume traded through the gas market (around five per cent or less). Futures trade continues to build, matching higher levels of pure net trade in the spot markets.

44 Q2 2020 trades: 85 contracts were traded up to the end of Q4 2019. This increased to 145 contracts traded by the end of Q1 2020.

45 Q3 2020 trades: 95 contracts were traded up to the end of Q4 2019. This increased to 179 contracts traded by the end of Q1 2020.

Figure 2.14 ASX Victorian futures trade



Source: AER analysis using ASX data.

Notes: Quantities traded are volumes for any future period in each quarter.

Focus—Relationship between East Coast spot prices and Asian LNG netback price

Box 2.1—Domestic spot prices and LNG netback price

There are three price categories that we focus on in the correlation analysis below:

Downstream spot price: This is the wholesale spot price by downstream market (STTM Sydney, STTM Adelaide, STTM Brisbane, DWGM Victoria). Prices for Brisbane, Adelaide and Sydney are a day ahead price (ex ante) and Victoria is at 6 am on the gas day.

Upstream spot price: is the spot price in the South East Queensland (SEQ) and Wallumbilla (WAL) locations of the Wallumbilla Gas Supply Hub in Queensland. Prices used in this analysis are calculated using volume weighted average price for all products and all trade types in SEQ or WAL location.

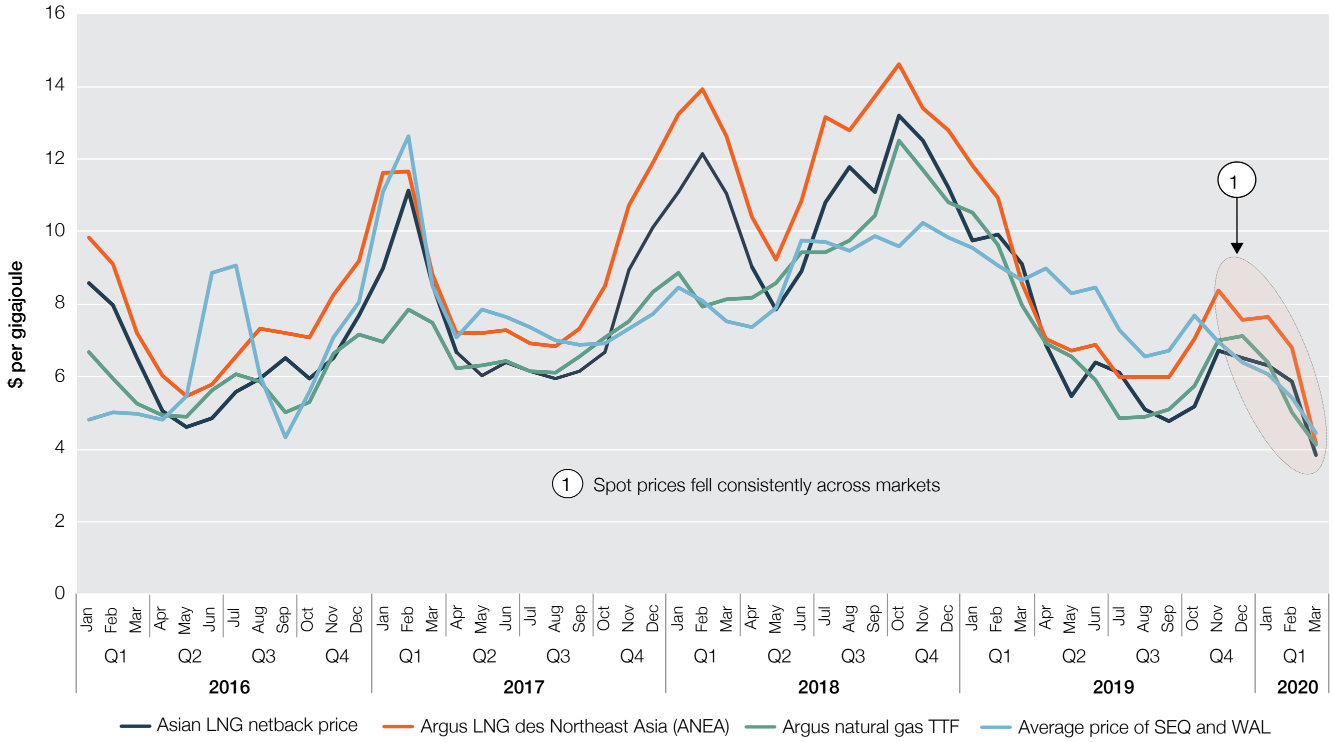
Monthly LNG netback price: The LNG netback price is a measure of the price that a gas supplier could expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port. LNG netback prices used in this analysis refer to historical monthly Asian spot LNG netback prices at Wallumbilla, as published by the ACCC. The ACCC use the Japan Korea Marker (JKM) price as assessed daily by S&P Global Platts as a measure of Asian LNG spot prices in its calculations.

Following observations of a trend down in international and domestic prices in previous AER reports, we have further quantified and explored the relationship between domestic spot prices (upstream and downstream) and the LNG netback price. In doing so, we have performed linear correlation analysis across two time periods: between January 2016 and March 2020, and between January 2019 and March 2020. The prices we used for this analysis were:

- Monthly East Coast wholesale spot prices (this includes both Upstream and Downstream spot prices).
  - For upstream prices in Queensland we separated out the analysis to look at both the SEQ and WAL trading points which reflect geographically different points of trade and connection in the Roma gas region where export pipelines and domestic gas pipelines connect adjacent to production facilities.
- LNG netback prices.

Upstream spot prices aligned more closely with the LNG netback price in Q4 2019 and Q1 2020. Over the same period, we have also observed a sharp fall in the Queensland upstream price (SEQ and WAL), which was mirrored by a reduction of a similar magnitude in the LNG netback price (figure 2.15).

Figure 2.15 Gas Supply Hub spot price, Asian LNG netback price and international delivered spot prices



Source: AER analysis using Argus Media data, WGSH prices and the ACCC netback price series.

Notes: The Argus LNG des Northeast Asia (ANEA) price: is Argus Media's Northeast Asia price calculation. It 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 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

The ANEA price recorded a daily traded low of $3.65 per GJ in March 2020, for delivery in the second half of April 2020. Similarly, the European Natural gas TTF price also recorded a daily traded low of $3.36 per GJ for delivery in April 2020 as gas prices slumped worldwide.

Domestically, we also observed a downward trend in Queensland upstream prices (SEQ and WAL) and LNG netback price calculations. In March 2020, Queensland upstream (SEQ and WAL) and downstream prices (Brisbane) fell to their lowest level in five years of around $4 per GJ, while calculated LNG netback prices were mostly below $4 per GJ as well. This price movement was largely driven by the decline in global LNG prices over 2019, which was further accelerated in Q1 2020 due to the COVID-19 pandemic. This reduction was then exacerbated even further by lower LNG demand in Asia due to a milder winter and higher inventory levels as discussed in section 2.1.

Is there a long-term and strong relationship between domestic spot prices and LNG netback price in Wallumbilla?

The result of Pearson correlation coefficients for both periods assessed, indicate a long-term correlation between Queensland spot prices and the LNG netback price to a moderate to high degree of correlation (figure 2.16).[46] The degree of correlation is stronger in the shorter period (2019–2020) compared to the longer period (2016–2020), where the correlation coefficient improves from a range of 0.56–0.75, to 0.69–0.76. In addition, the coefficients for all prices are positive, which confirms that domestic spot prices and LNG netback prices moved in the same direction, either increasing or decreasing across the same analysed period.

46 Pearson correlation coefficient (r value) is a measure of the linear correlation between two variables. It gives indication of the degree of correlation and the direction of the relationship between two variables. Pearson coefficient lies in the range from -1 to +1. The absolute r value indicates the relationship strength. The larger the number, the stronger the relationship.
In this report, we interpret r values as below (cited from Hinkle DE, Wiersma W, Jurs SG (2003). Applied Statistics for the Behavioral Sciences 5th ed. Boston: Houghton Mifflin).

Figure 2.16 Correlation coefficient between domestic spot prices and LNG netback price at Wallumbilla

Correlation coefficient for 51-month period (January 2016–March 2020)

	SEQ	WAL	Brisbane	Sydney	Victoria	Adelaide	LNG netback at Wallumbilla
SEQ	1						
WAL	0.9863	1					
Brisbane	0.9349	0.9634	1				
Sydney	0.7500	0.8502	0.8464	1			
Victoria	0.7516	0.8061	0.8279	0.9515	1		
Adelaide	0.7594	0.7705	0.8224	0.8639	0.9381	1	
LNG netback at Wallumbilla	0.7513	0.6080	0.5654	0.4292	0.3290	0.2934	1

Correlation coefficient for 15-month period (January 2019–March 2020)

	SEQ	WAL	Brisbane	Sydney	Victoria	Adelaide	LNG netback at Wallumbilla
SEQ	1						
WAL	0.9849	1					
Brisbane	0.9750	0.9794	1				
Sydney	0.9584	0.9727	0.9897	1			
Victoria	0.9247	0.9551	0.9694	0.9905	1		
Adelaide	0.9215	0.9517	0.9618	0.9728	0.9813	1	
LNG netback at Wallumbilla	0.7634	0.6828	0.6912	0.6275	0.5621	0.5440	1

Degree of correlation

Higher **Lower**

Source: AER analysis, ACCC netback price series.

Notes: WAL and SEQ are separate trading points in the Wallumbilla/Roma gas production region.

r value = 0: no correlation

0.9 < r < 1: very high positive correlation

0.7< r <0.9: high positive correlation

0.5< r <0.7: moderate positive correlation

0.3< r <0.5: low positive correlation

r<0.3: no or negligible correlation

r = 1: postive and perfect correlation

r = -1: negative and perfect correlation.

The degree of correlation between the LNG netback price and Queensland prices is stronger than in the southern markets (Sydney, Victoria, Adelaide), which had coefficients of between 0.29–0.42. Southern spot prices are affected by variable transportation costs from the north, seasonal pricing, and localised southern supply and demand conditions, including constraints and demand fluctuations.

In the northern market, the SEQ spot price has the strongest correlation with the LNG netback price. Participants generally prefer to trade more in SEQ than in WAL since the SEQ trade point was added in March 2017. Trades in SEQ account for the largest proportion of trade in the GSH, at about 40 to 70 per cent of total trades. Meanwhile the WAL location accounted for between 25 to 40 per cent of total GSH trade in the same period. Spot prices in SEQ are more representative of trade activities in the GSH, which is linked to LNG export activities in Gladstone. Trades at WAL usually represent shorter term products (except in Q3 2019), whereas both shorter and longer-term products are frequently traded in SEQ.[47]

We observed a high likelihood of a lag time of about two months existing between domestic prices and the LNG netback price. When analysed, a two month lag showed the highest correlation coefficient, compared other lag lengths (figure 2.17).

47 Shorter term products refer to balance of day, daily and day ahead products. Longer term products are weekly and monthly. See box 2.2 for further explanation of GSH product types.

Figure 2.17 **Correlation coefficient between Queensland spot prices and LNG netback at Wallumbilla, with lag**

LNG netback at Wallumbilla					
SEQ no lag	0.7634	WAL no lag	0.6828	BRI no lag	0.6912
SEQ 1M lag	0.8091	WAL 1M lag	0.7281	BRI 1M lag	0.7139
SEQ 2M lag	0.8159	WAL 2M lag	0.7475	BRI 2M lag	0.7219
SEQ 3M lag	0.7951	WAL 3M lag	0.7361	BRI 3M lag	0.7155
SEQ 4M lag	0.7598	WAL 4M lag	0.7092	BRI 4M lag	0.6864
SEQ 5M lag	0.7199	WAL 5M lag	0.6760	BRI 5M lag	0.6455
SEQ 6M lag	0.6909	WAL 6M lag	0.6567	BRI 6M lag	0.6172

Source: AER analysis, ACCC netback price series.

Differences in delivery times between LNG sales and domestic sales are likely to explain the lag time before domestic prices follow LNG netback prices:

- The LNG netback prices published by the ACCC are based on Platts' JKM price assessments for LNG to be delivered in that month. Platts assess the prices over monthly window leading up to about six weeks before expected delivery, with each daily assessment providing the most up to date assessment of expected prices in that month.[48]
- Sellers offering gas at WAL or SEQ today may consider future LNG price outcomes, when pricing gas locally for more immediate delivery.

Other factors may be driving down domestic prices on the East Coast

Domestic spot prices are affected by other factors apart from the LNG netback price. On the supply side, excess domestic production in recent quarters—especially record production in Queensland—and the introduction of new imports from the Northern Territory put downward pressure on domestic spot prices. On the demand side, gas usage for power generation (GPG) is becoming more variable and unpredictable. GPG in all southern markets declined sharply since Q3 2019 whereas GPG in Queensland continued to increase over the same period. Further, industrial gas demand reduced in recent quarters due to the declining manufacturing driven by high gas contract prices.[49]

The market has also become more competitive with 17 participants in the upstream market and 32 participants in downstream markets. Traders are also more active with more sellers in the downstream markets improving market liquidity. The lower transportation cost of gas on some pipelines, mainly driven by cheaper pipeline capacity being won through the Day Ahead Auction, also put downward pressure on gas prices.

Separately, in September 2018 LNG exporters signed a Heads of Agreement with the Australian Government. Under this arrangement, exporters have committed to supply uncontracted gas to the domestic markets on competitive terms first. The recent higher correlations we observed in the upstream spot price may reflect this commitment made to the Australian Government.

The recent announcement by the Victorian government to remove the moratorium on gas exploration within Victoria from July 2021, may exert further downward pressure on future contract prices in Victoria.[50]

Are we seeing a pass through from wholesale spot prices to retail prices?

The extent to which wholesale spot prices pass through to retail prices depends on the composition of total retail costs in each state. In Queensland, NSW, and South Australia, wholesale costs constitute 30 per cent or less of the total cost of a retail bill for residential customers. Network costs in these states account for the largest proportion of retail bill costs, at around 50 per cent to 60 per cent. Retail costs and retailer margins account for the smallest proportion at around 20 per cent.

48 For example, an historical LNG netback price for March 2020 will be based on an average of JKM price assessments, calculated separately for each day of March, and then averaged over the month. Which means that the netback price will be based on the JKM as reported between 16 January and 15 February 2020 (commencing six week ahead).

49 ACCC, *Gas Inquiry—January 2020 interim report*, February 2020.

50 Victorian Chamber of Commerce and Industry, Lifting gas moratorium helps secure Victoria's energy future, ,accessed 6 May 2020 https://www.victorianchamber.com.au/news-media/all/2020/03/lifting-gas-moratorium-helps-secure-victorias-energy-future , accessed 6 May 2020.

In NSW and South Australia, we observed positive price movements for the 'big three' retailers—AGL Energy, Origin Energy and EnergyAustralia—as well as other retailers between September 2019 and January 2020 (figure 2.18). In NSW, the cheapest market conditional offer across the big three retailers reduced by about 1 per cent, and offers from other retailers reduced by about 1.7 per cent. In South Australia, the lowest market offer of the big three and other retailers reduced by 1.5 per cent and 1.9 per cent respectively.

In Queensland, retail prices were stable for the big three retailers between September 2019 and January 2020, despite wholesale spot prices falling further in Queensland than other states. Queensland's retail gas market is relatively small compared to other states, with only three retailers operating across two distribution networks.

Figure 2.18 Change in estimate residential annual bill using cheapest market conditional offers in January 2020, compared to September 2019

		2019	2020	DIFFERENCE
NSW[a]	Big 3 retailers	$867.1	$858.7	-0.97%
	All retailers	$867.3	$852.4	-1.72%
VIC[b]	Big 3 retailers	$1 309.1	$1 281.1	-2.14%
	All retailers	$1 362.8	$1 378.9	1.18%
SA[c]	Big 3 retailers	$936.3	$921.7	-1.55%
	All retailers	$941.9	$924.2	-1.88%
QLD[d]	Big 3 retailers	$618.8	$615.2	-0.57%
	All retailers	$626.2	$626.9	0.12%

Notes: 2019 data was collected on 13 September 2019 and 2020 data was collected on 16 January 2020.

a. We focused on the Jemena distribution zone as it represents more than 80 per cent of residential customers in NSW

b. We considered all distribution zones in Victoria

c. Only Australian Gas Network (AGN) was available in South Australia

d. We focused on the AGN distribution zone, which covers Brisbane

Source: Energy Made Easy data, AER analysis.

In Victoria, wholesale costs account for the largest proportion of total retail bill costs at more than 40 per cent. Victoria has the largest number of residential customers, so network costs and some retail costs are lower on a per customer basis.[51] Retail price reductions was observed in Victoria for the big three retailers between September 2019 and January 2020. The estimated residential annual bill in Victoria under the market conditional offer reduced by about 2.1 per cent in January 2020. However, we didn't see a similar movement in prices from other retailers (65 per cent of other retailers increased offers), partly impacted by the increase in recent network price changes in Victoria.[52]

In general, falling wholesale costs may not result in immediate declines in retail market offers by retailers. Gas traded in wholesale spot markets accounted for about 10–12 per cent of total gas consumption in eastern Australia. Nearly 90 per cent of gas is bought or sold through bilateral contracts, and it may take longer for wholesale price movements to be reflected in these contract markets. Also, retailers usually adjust their overall pricing strategy at fixed points in time such as the end of a financial year (although the best offers from a retailer are more frequently adjusted). The positive price movement observed in the retail market by the 'big three' retailers in Victoria, NSW and South Australia is a good sign that wholesale cost reductions are starting to flow through to the retail market. We will keep monitoring the effect of wholesale spot price to long-term contract and retail markets in the coming reports.

51 Nearly 2 million residential customers by end of 2018–19.

52 AER, Distribution tariff determination, https://www.aer.gov.au/communication/aer-approves-2020-distribution-tariffs-for-victorian-and-albury-gas-customers, accessed 6 May 2020.

Focus—On screen and off screen prices at the Gas Supply Hub

In consultation with industry, the Australian Energy Market Operator (AEMO) launched the gas supply hub model at Wallumbilla, Queensland, in 2014, and at Moomba, South Australia in 2016.

The gas supply hub takes the form of a voluntary electronic trading platform facilitated by AEMO. Participants can trade a variety of standardised product types, including intra-day, daily, day-ahead, weekly and monthly (box 2.2). These products can be traded anonymously through the online exchange (“on screen”) or agreed to bilaterally and then lodged through the hub for settlement (“off screen”). Purely bilateral, “off market” trades are not reported to the hub.

As on screen trades are the result of an anonymous, automatically-matched process, they are more reflective of real-time supply and demand dynamics in the market. While off screen prices generally follow on screen prices, changes in outcomes may be influenced by other underlying factors, such as participants’ bilateral arrangements.

Box 2.2—Gas Supply Hub products

There are five standardised products that can be traded on the Gas Supply Hub:

Balance of day (On the day) products are traded on the gas day to manage imbalances.[a] Delivery commences one clear hour after the transaction is struck.

Day ahead products are standardised for delivery over a gas day. These products are traded one day before the gas day.

Daily products are standardised for delivery over a gas day. These products may be traded from between 2–7 days before the intended gas day.

Weekly products deliver gas over a period of seven consecutive gas days, commencing on Sunday. These products may be traded from between 4 weeks to 2 days before the gas day of commencement.

Monthly products deliver gas over a calendar months’ worth of gas days. On screen, these may be traded as far as three months in advance, but no sooner than 2 days before the gas day of commencement.

a. A gas day is a 24 hour period commencing at 6 am.

Why do participants trade on screen or off screen?

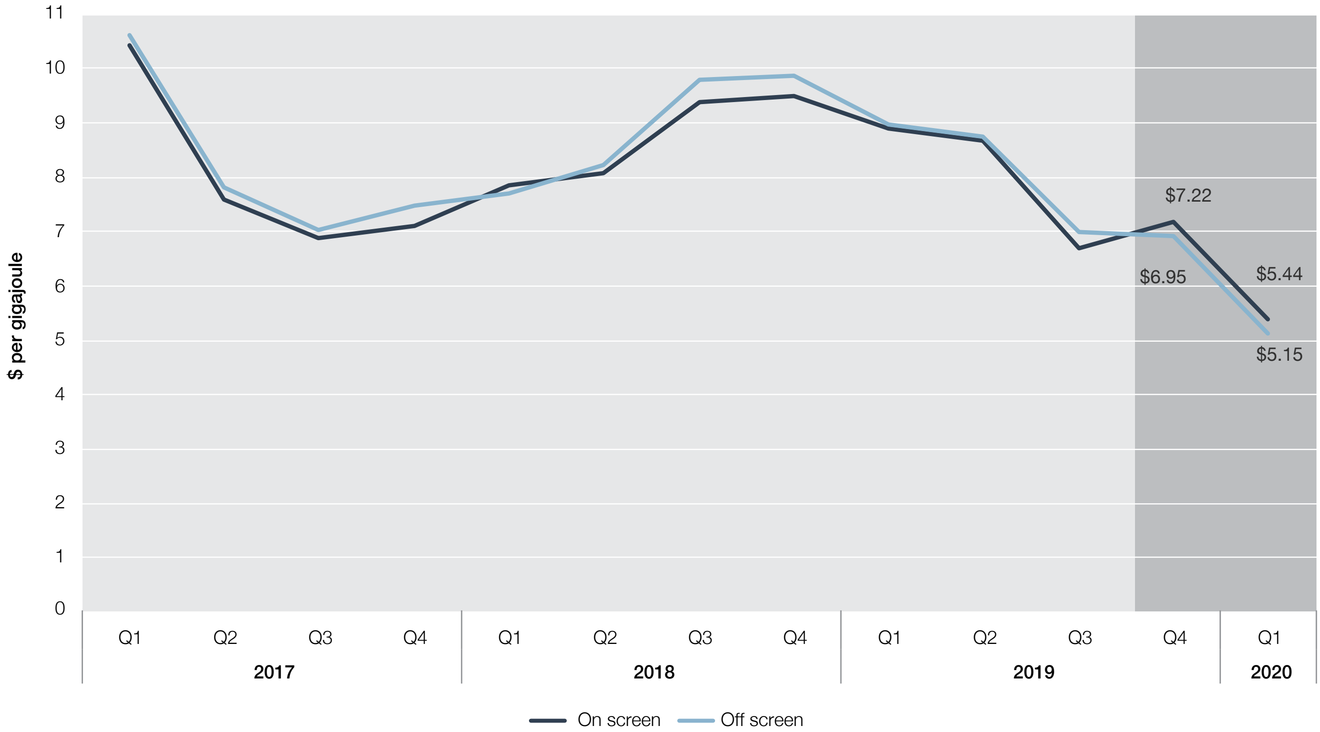
Initially participants traded primarily on screen. From mid-2015 off screen trade increased, overtaking on screen trade for 2016. With the introduction of the single trading location in March 2017, all trade increased. Off screen trade has remained the preferred trade type since 2018, in some cases more than doubling the volume of gas traded on screen. Notably, off screen trades tend to involve larger volumes of gas than on screen alternatives.

Some participants have suggested a preference for off screen trading, which allows them to use brokers to match trades on their behalf, or leverage pre-existing bilateral arrangements to facilitate spot trades. Such trades can be negotiated directly over the phone and then lodged through the hub for settlement. In this way, transactions can be accelerated if on screen bids and offers do not match. However, new entrant participants are likely to be more reliant on the anonymous on screen trading platform as they may not have legacy arrangements in place.

Is there a difference between on screen and off screen price outcomes?

On screen and off screen prices generally move in a similar fashion. Occasionally, these prices separate from each other (figure 2.19).

Figure 2.19 Gas Supply Hub—on and off screen VWA price, all locations



Source: AER analysis using gas supply hub data.

Notes: Values shown include both Wallumbilla and Moomba hubs.

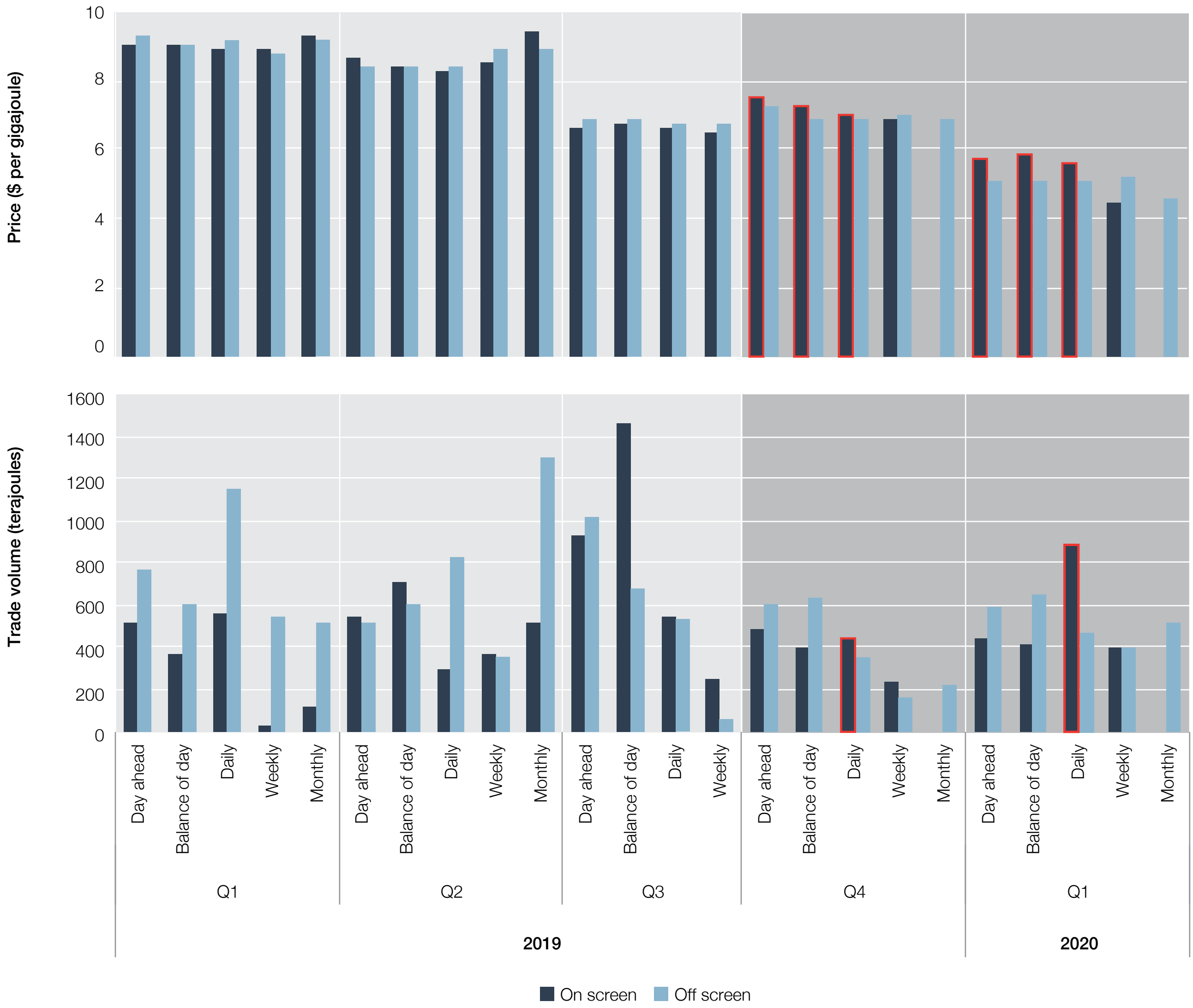
In the last three years, there were three quarters where on screen products traded higher on average than their off screen alternatives. For the last two quarters, on screen products traded about 30 cents per GJ higher than off screen products on average. Notably, this is a reversal of the broader trend in the last two years where if prices deviated, off screen products were more expensive.

This is important as when on screen products are priced higher, participants may be more inclined to trade off screen then they already are. With less trade on screen, the automatic price discovery process can be impeded. In turn, this restricts the use of on screen trading as a price signal for market participants.

Further analysis reveals several factors contributing to increased on screen prices. In particular, the shorter-term products (balance of day, daily and day ahead) traded at the WAL and SEQ locations were driving the on screen prices higher (figure 2.20).[53]

53 The Wallumbilla Gas Supply Hub originally traded different products across the three main pipelines it connected to (the South West Queensland, Roma to Brisbane and Queensland Gas Pipelines). However in 2017, AEMO replaced the three different locations with a single Wallumbilla (WAL) product that grouped them together. AEMO also launched a separate south-east Queensland (SEQ) product, which provides virtual delivery into the Roma to Brisbane Pipeline.

Figure 2.20 Gas Supply Hub—trade quantity and price by product, WAL and SEQ locations



Source: AER analysis using gas supply hub data.

Notes: Values shown do not include WAL Non-netted, and Moomba locations.

Generally, day ahead, daily and balance of day products all traded at a higher price on screen than off screen in the last two quarters. Balance of day products had the greatest price difference, on average trading 78 cents per GJ higher on screen than off screen in Q1 2020. Against the trend, weekly products traded more than $1 per GJ higher off screen than on screen this quarter, and no monthly products were traded on screen. Despite this, shorter-term products drove the on screen price higher as these products accounted for 64 per cent of total volume traded.

In particular, trade at the WAL and SEQ locations exaggerate outcomes, as these two locations accounted for 75 per cent of all trade in Q4 2019 and 62 per cent in Q1 2020. In these locations, participants primarily traded the shorter term products, which amounted to 82 per cent and 72 per cent of trade in Q4 2019 and Q1 2020 respectively. Additionally, participants traded twice the volume of daily products on screen versus off screen. This resulted in on screen daily products being the highest traded product in these locations. And, on average, these products were traded for about 56 cents per GJ higher than the off screen alternatives.

In Q1 2020, more than 80 per cent of gas traded using shorter-term products was traded at the Roma to Brisbane Pipeline in-pipe trade point (RBP IPT) and the Wallumbilla High-Pressure trade point (WAL HP).[54] For both of these locations, balance of day, daily and day ahead products were all higher priced on screen than off screen.

Gas traded at WAL HP was particularly more expensive on screen, with day ahead products, for example, trading 73 cents per GJ higher on average. WAL HP is often a more expensive product as it reflects the cost of compressing the gas to higher pressures for transmission. Notably, gas traded on screen at WAL HP increased this quarter by

54 Both the RBP IPT and WAL HP trade points are virtual delivery locations. That is, ownership of the gas is not transferred at a physical delivery point, rather it is effectively traded in transit. From the WAL HP location, gas may be directed to or from the South West Queensland pipeline. From the RBP IPT, gas may be directed to or from the Roma to Brisbane pipeline.

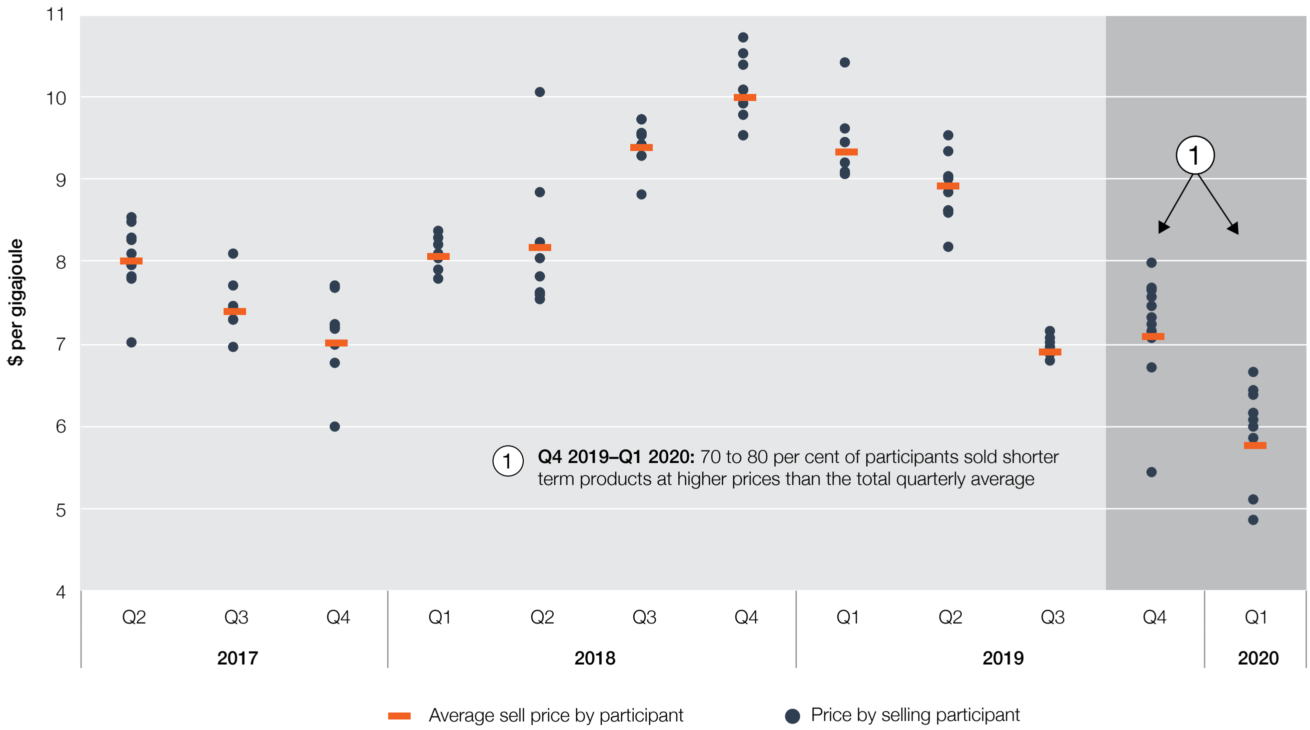
more than 30 per cent compared to Q1 2019. In addition, more gas was traded on screen at WAL HP than off screen. This is the first time this has happened since Q1 2018—the last time on screen prices were more expensive than off screen.

Part of this increase may be linked to additional capacity made available to participants through the Day Ahead Auction (DAA). The DAA mandates the sale of any excess contracted pipeline capacity, which is often sold for significantly less than it would otherwise cost to access. In Q1 2020, participants in the auction won the highest ever capacity for Wallumbilla Compression Facility B, which links to the WAL HP trade point. So, access to cheap capacity on the DAA may have encouraged participants to purchase more gas on screen for delivery at WAL HP.

Who contributed to higher on screen prices?

Some participants supported the outcomes observed in the last two quarters, selling on screen for prices significantly higher than they paid when buying (figure 2.21). On certain days in particular, there was limited competitive pressure to sell gas on screen for lower prices.

Figure 2.21 Gas Supply Hub—on and off screen VWA prices



Source: AER analysis using GSH data.

Notes: Values shown for on screen trades at Wallumbilla Hub only.

Interestingly for Q1 2020, a number of the higher prices observed in the shorter term products sold on screen have been set by newer participants.[55] This may be evidence of a potential issue in the gas supply hubs, as in a competitive market, we would anticipate new entrants to place downward pressure on prices. We will continue to monitor this and intend to report further on the level of competition in on screen product in future *Wholesale markets quarterly* reports.

What we're seeing may not be the full picture

Other factors may be affecting outcomes in a way that is not immediately clear. For example, some participants can designate an "alternate delivery point" when arranging off screen trades for delivery further afield (for example to the southern markets). While the delivery end point is elsewhere, the gas is purchased and lodged through the Hub. Therefore, the recorded price for these transactions is typically higher than other Hub trades, reflecting the additional domestic transportation costs.

55 There were four new participants in the gas supply hubs across Q4 2019 and Q1 2020.

As a result, if we were to exclude these trades from the off screen price series, the off screen price would be lower. Ultimately, this means that the difference between on and off screen prices is greater than it initially appears. So, these trades may be sending misleading price signals to market participants.

Additionally, a lack of transparency in the broader eastern Australia gas market hinders detailed analysis. The trades reported through the Gas Supply Hub do not capture the purely bilateral, off market transactions. These off market trades account for the majority of gas traded. In Q1 2020, trade at the Wallumbilla Gas Supply Hub accounted for only 8.3 per cent of total gas flows through the Wallumbilla Bulletin Board region. As such, conditions in off market trading may be influencing participants' motivation to trade through the Gas Supply Hub. However, as off market activity is more opaque, it is difficult to assess the extent of this influence.

Appendix

Domestic spot market prices

There are many influences on spot gas prices including seasonal demand, unplanned outages and changes over time in the number of sellers and buyers. Some important enduring drivers of gas spot contract prices are noted below.

Long-term contract prices: The majority of gas is sold under long-term contract including by producers to retailers who then can sell excess volumes (under contract) into spot markets. Average prices invoiced by Victoria gas producers increased from around $4 per GJ in 2014 to around $8 per GJ by Q4 2018 and this is influencing the price at which excess contracted gas is bid into spot markets.[56]

Global (Asian) LNG prices: The Queensland LNG exporters participate as both exporters and sellers of gas to the domestic market. Given perfect arbitrage, domestic prices and international prices (e.g. netted back to Wallumbilla) could settle to an equilibrium price. The ACCC Gas Inquiry, in its September 2017 Interim report, found that the majority of gas exporters and producers considered the Asian spot price as the relevant comparator for assessing likely domestic prices.[57] This was supported by a prevailing view that there would be sufficient production in Queensland for exporters to meet long term foundation LNG contracts (oil price linked) and sell opportunistic spot LNG export cargoes. The ACCC reported that 13 LNG spot cargoes were sold over 2018.[58] The AER's analysis is that the Asian spot netback relationship appears particularly strong for gas sold through domestic spot markets.

Production Cost Floor: If the Asian LNG netback price became lower than production costs, then LNG exporters may seek to reduce production rather than sell spot cargoes internationally or domestically at a loss. The floor price for exporters has been reported to be around $4 to $6 per GJ in Queensland depending on the project.

National Electricity Market: In summer 2017 gas prices followed high NEM prices up in Queensland.[59] Further, when gas prices fall significantly—such as happened in the LNG ramp up phase in 2015—fuel substitution in the NEM from coal back to gas can occur, supporting the price of gas.

Domestic spot transport prices

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 across 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 South West Queensland Pipeline, which is strategically important for north-south flows and is the only pipeline connecting Queensland with the southern states.

The first trade on the CTP occurred in February 2020. The DAA has been more widely used however, with 13 participants buying over 41 PJ of spot capacity day ahead in the first year of operation.

56 ACCC, *Gas inquiry, April 2019 Interim Report*, p. 41.

57 ACCC, *Gas inquiry, September 2017 Interim Report*, p. 67.

58 ACCC, *Gas Inquiry, April 2019 Interim Report*, p. 15.

59 AER, *State of the Energy Market report, 2018*, p. 196.

PARTICIPANT LIST IN EASTERN GAS MARKET

	Market participant	Victoria	Sydney	Adelaide	Brisbane	GSHs	DAA
GPG Gentailer	AGL	● dark	● dark	● dark	● dark	● dark	● orange
	Alinta Energy	● dark	● light blue	● dark	● dark	● dark	● orange
	Aurora Energy		● dark				
	CleanCo				● orange	● orange	● orange
	EnergyAustralia	● dark	● dark	● dark		● light blue	● orange
	Engie	● dark					
	ERM	● dark	● dark		● dark	● dark	● orange
	Hydro Tasmania	● dark					
	Origin	● dark	● dark	● dark	● dark	● dark	● orange
	Snowy Hydro	● dark	● dark	● light blue	● light orange		
	Stanwell				● dark	● dark	● orange
Exporter/Producer	Arrow				● orange	● dark	● green
	APLNG					● dark	
	BHP Billiton	● orange	● orange				
	Esso	● dark	● dark				● orange
	GLNG					● dark	
	Lochard Energy	● light blue					
	Santos	● dark	● dark	● dark	● dark	● dark	● orange
	Senex					● green	
	Shell		● orange				● orange
	Walloons (QGC)					● dark	● orange
Retailer	Click Energy	● dark	● light blue				
	Covau	● dark	● dark				
	Delta Electricity		● dark				
	Dodo	● dark	● dark				
	GloBird Energy	● light orange					
	GOEnergy		● purple		● purple		
	GridX		● dark				
	Powershop	● light blue					
	Simply Energy		● light blue	● dark			
	Sumo Gas	● light blue					
	Visy	● dark	● dark	● dark	● dark		
	Viva Energy	● light orange					
	Weston Energy	● light blue	● dark	● light blue	● light orange		
Industrial	Adelaide Brighton Cement			● dark			
	BlueScope		● dark		● light orange		
	Boortmalt	● orange	● light orange	● light orange			
	BP				● dark ● purple	● dark	
	Brickworks	● green	● green	● green	● green		
	Caltex				● dark		
	Commonwealth Steel		● light blue				
	Coogee Energy	● purple					
	Coopers			● light blue			
	CSR Building Products	● light orange		● orange	● light orange		
	Incitec Pivot				● dark	● dark	● orange
	Infrabuild	● dark	● dark	● dark			
	Michell Wool			● orange			
	Mobil Oil	● light orange					
	Norske Skog	● light orange					
	Paper Australia	● light orange					
	O-I International	● light orange	● light orange	● light orange	● orange		
	Orica		● light blue				
	Orora		● green				
	Qenos	● light blue	● dark			● light blue ● purple	● orange
	SA water			● dark			
	Tarac Technologies		● light blue	● dark			● orange

Trader	Macquarie Bank	Entered in 2019	Entered in 2019			Entered in 2018	Entered in 2019
	Petro China					Entered in 2019	Entered in 2020
	Strategic Gas Market Trading	Entered in 2019	Entered in 2019			Entered before 2017	Entered in 2019
	59	32	31	19	17	18	18

● 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