Wholesale Markets Quarterly Q4 2019

February 2020

AUSTRALIAN ENERGY REGULATOR

Australian Government

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Electricity markets

In the fourth quarter of 2019 (Q4 2019) we observed significantly lower average wholesale prices than in the same quarter a year ago in all National Electricity Market (NEM) regions. Average Q4 prices in 2019 were between 10 and 20 per cent lower compared to the prices a year previously.

Average wholesale prices ranged from $65 per MWh in Queensland to $87 per MWh in South Australia. This was the first time since Q4 2017 that average prices in all regions were below $90 per MWh.

The demand pattern and the amount of generation available varied considerably across Q4 2019. For the majority of the quarter, demand conditions were benign. In South Australia in particular, demand fell to a record minimum of 456 MW and fell below the previous record seven times across the quarter. One of the focus stories in this quarterly discusses South Australian record minimum demands and the impact of the continued growth of rooftop solar PV. In contrast, later in the quarter demand in Queensland and South Australia peaked at near record levels.

The generation mix also changed significantly during Q4 2019. The start of the quarter saw a series of coal generator outages continue, which meant that there was a strong reliance on gas generation to meet demand. The generation mix switched back to coal as the quarter unfolded and the outages were largely resolved.

Market conditions changed significantly late in the quarter. There were a number of half hour prices over $5000 per MWh in South Australia and Victoria in late December. These prices were driven by high demand at the time of extreme weather conditions. We have released our detailed reports into these prices—a requirement under the National Electricity Rules—in conjunction with this report.

This period of extreme weather and ongoing unavailability of some generation plant (particularly in Victoria) late in Q4 2019 raised concern that there would be insufficient generation available to ensure reliable electricity supplies. Overall, however, the market coped well with these extreme events. The increased availability of generation late in Q4 2019 as generator outages were progressively resolved, meant there were no actual reserve shortfalls in the quarter and reserve contracts were only dispatched once.

Gas markets

Overall, the East Coast spot market continued to exhibit signs of increased competitive activity, with domestic spot prices converging towards an Asian LNG spot netback price. Downstream wholesale spot prices trended down again with prices falling for the fourth quarter in a row to below $8 per GJ in Victoria and Sydney. In contrast, prices increased at the upstream supply hub at Wallumbilla in line with an uptick in Asian spot prices.

Increased participation from sellers in the downstream markets is a growing trend, which is likely to be putting downward pressure on spot gas prices. The commitments made by LNG exporters to first offer uncontracted gas to the domestic market, which might otherwise be sold at Asian LNG spot prices, is also an important factor for lower spot gas prices.

Quarterly gas production was at record levels at Roma, Queensland. Similarly, Queensland LNG exports were at record levels despite falling Asian LNG spot prices. The focus study of this report is on LNG export activity and highlights that record production over 2019 is likely to have been connected to LNG price expectations for 2019 as existed in late 2018. In contrast, LNG prices in late 2019, and expected prices over 2020, might suggest reduced Roma production and LNG exports over 2020.

Increased downstream spot trade over 2019 continued in Q4 with BHP and Shell using their access to production to participate in downstream spot markets alongside other producers such as Esso and Santos. The Day Ahead Auction of pipeline capacity also continued to be used to bring gas south, although opportunities to profit from arbitraging the northern spot prices were limited as the price gap between the north and south closed.

Electricity markets at a glance
Q4 2019

Spot prices

Average prices fell in all regions by up to 20%

Demand

Minimum demand fell in all regions. Record low in SA

Generation

Major black coal outages resolved. Continued increase in solar generation

Offers

More capacity offered at lower prices

Under pressure

The market operated well under extreme conditions from mid-December

Outlook

The outlook for Q1 2020 improved as outages resolved over the quarter

Gas markets at a glance
Q4 2019

Gas commodity spot prices

Fell for fourth quarter in a row to prices under $8/GJ

Gas powered generation

Q4 2019 GPG slightly higher than Q4 2018 across all states

Gas production

Record quarterly production by QLD fields

LNG export

Up from Q3 levels to new quarterly record

Net gas flow

First Q4 since 2014 of net flows south

Market utilisation rate

East Coast spot trade higher in Q4 2019 than Q4 2018

Gas storage level

Small decline in storage from Q3

Auction of pipeline capacity

Reduced usage in Q4 post winter

1. Electricity

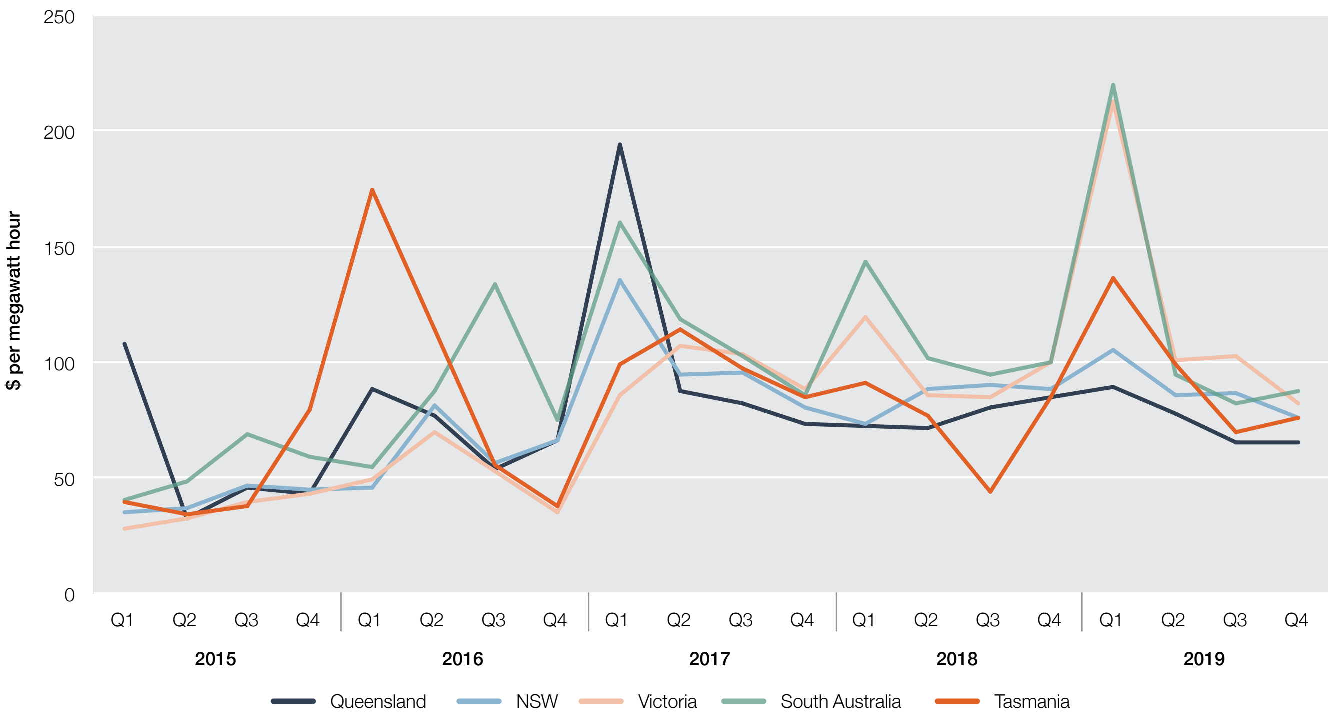
1.1 Quarterly spot prices

- Quarterly prices in all regions were lower in Q4 2019 than in Q4 2018, despite some half hourly prices above $5000 per MWh in South Australia and Victoria during the quarter.
- For the first time since Q4 2017, quarterly prices in every region were lower than $90 per MWh.

Quarterly volume weighted average (VWA) spot prices were lower in Q4 2019 than in Q4 2018, despite South Australia and Victoria experiencing half hourly prices above $5000 per megawatt hour (MWh).

Quarterly prices in all regions were lower than $90 per MWh for the first time since Q4 2017, ranging from $65 per MWh in Queensland to $87 per MWh in South Australia (figure 1.1). In Queensland and Victoria, Q4 2019 marked the lowest quarterly price since 2016.

Figure 1.1 Average quarterly spot prices (VWA)

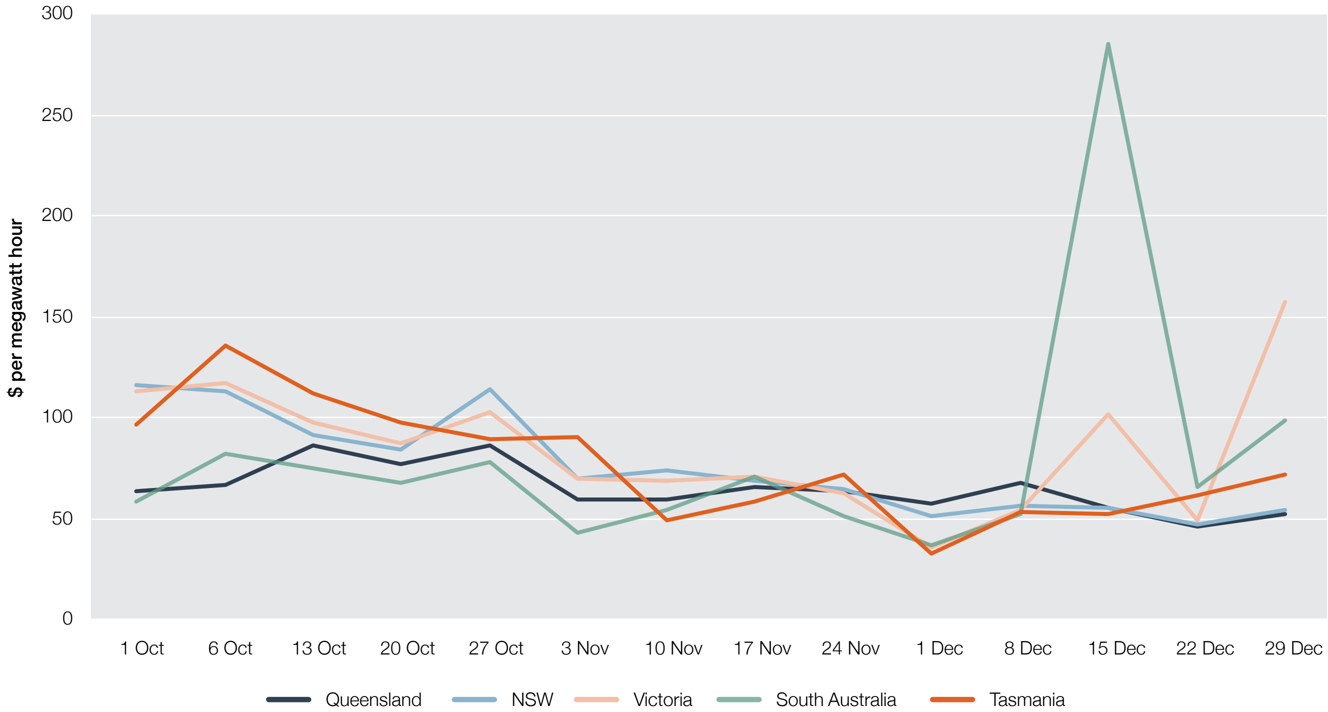


Source: AER analysis using NEM data.

Across the quarter, average weekly prices generally trended downwards until December (figure 1.2). For the weeks beginning 15 December in South Australia and 29 December for Victoria, the average weekly spot price increased to $285 per MWh and $155 per MWh, respectively. These high average prices largely reflected instances where demand was high during hot weather where the spot price exceeded $5000 per MWh.

In South Australia, there were a high number of negative spot prices during October and November, continuing from the record levels reached in Q3 2019. For the first half of the quarter, this saw South Australia experience the lowest average spot price in the NEM. However, following two spot prices reaching $14 700 per MWh in December, by the end of Q4 2019 quarterly average spot prices in South Australia were the highest in the NEM.

Figure 1.2 Average weekly spot prices (VWA)



Source: AER analysis using NEM data.

Notes: Weeks run Sunday to Saturday, weeks commencing 1 October and 29 December are partial weeks.

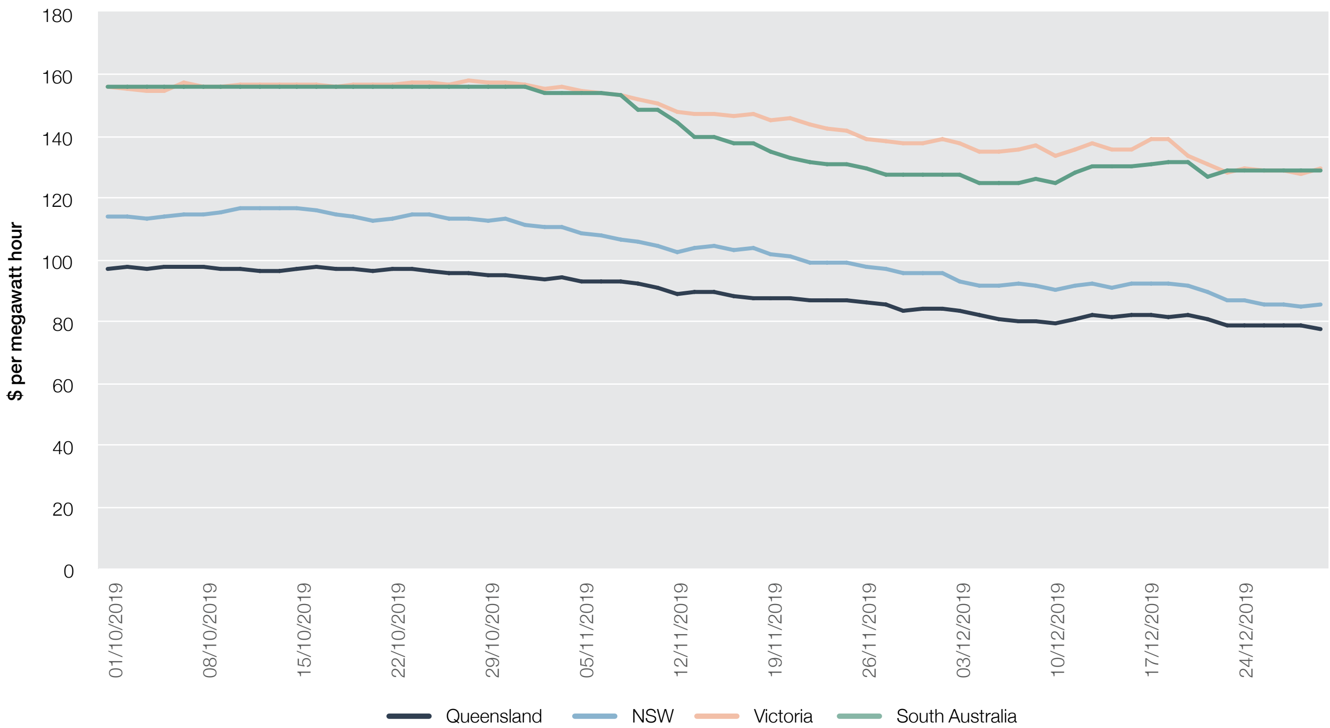
1.2 Price expectations

- Q1 2020 price expectations decreased throughout Q4 2019 across all mainland regions as major generator outages were resolved.
- Following Q1 2020, base futures prices are expected to decrease and be stable for the rest of 2020.

Financial markets indicate that Q1 2020 price expectations were revised as the price of forward base futures decreased throughout Q4 2019 across all mainland regions (figure 1.3).[1]

In Victoria and South Australia in particular, base futures prices fell by nearly $30 per MWh over the quarter from nearly $160 per MWh at the start of October down to around $130 per MWh at the end of December.[2] This decrease in future prices coincided with major baseload generators returning to service after outages in Queensland, NSW and Victoria.

Figure 1.3 Base future prices Q1 2020



Source: AER analysis, ASX Energy data.

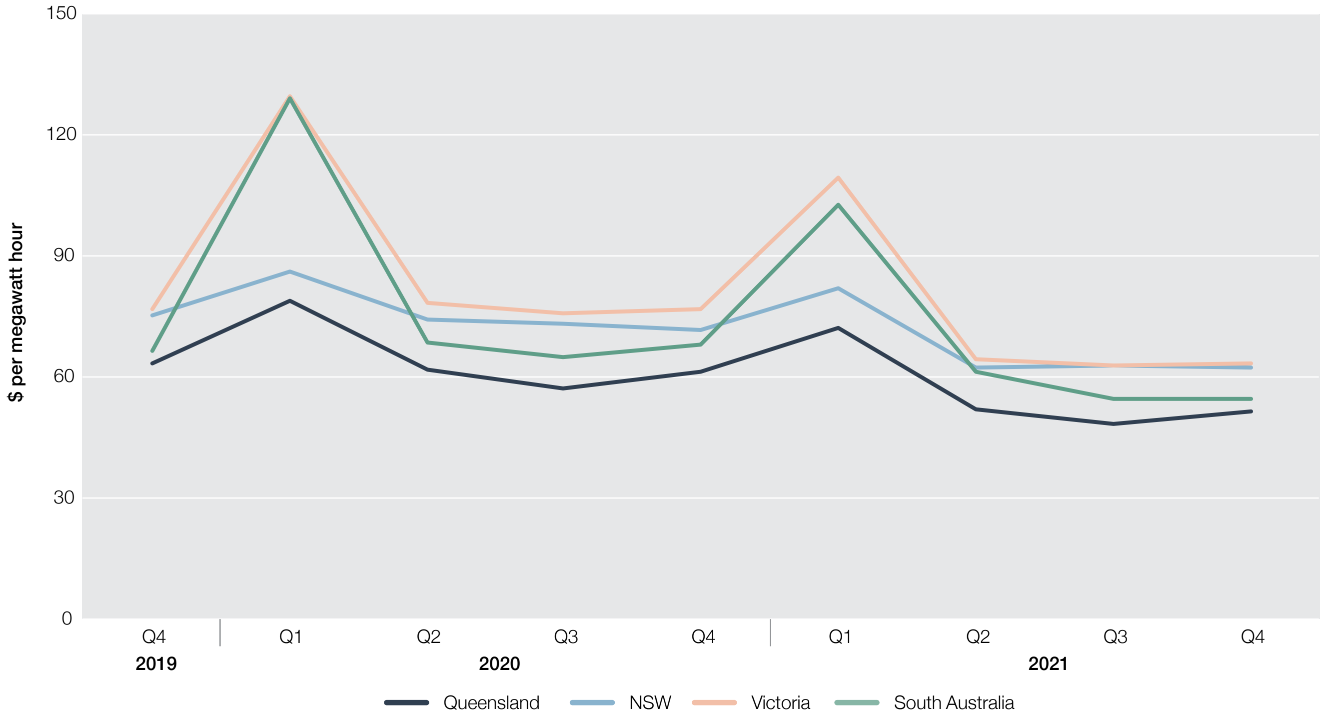
Notes: Daily closing price for Q1 2020 quarterly base futures throughout Q4 2019.

Looking forward, base futures price expectations are in line with the recent trends we have seen in the market. Following summer, prices are expected to decrease and be relatively stable for the rest of 2020 (figure 1.4). Expectations for Q1 2021 are for prices to be higher in Victoria and South Australia than in Queensland and NSW. In all regions, base futures prices for Q1 2021 are lower than for Q1 2020. However, those future price expectations tend to be less reliable due to the low volumes traded in the forward years.

1 Base load futures continue to be the primary market traded futures contract ahead of peak and cap contracts. This section refers to outcomes for quarterly base load futures market.

2 Subsequently, base futures prices across all mainland regions have continued to fall since the close of Q4 2019.

Figure 1.4 Base future prices



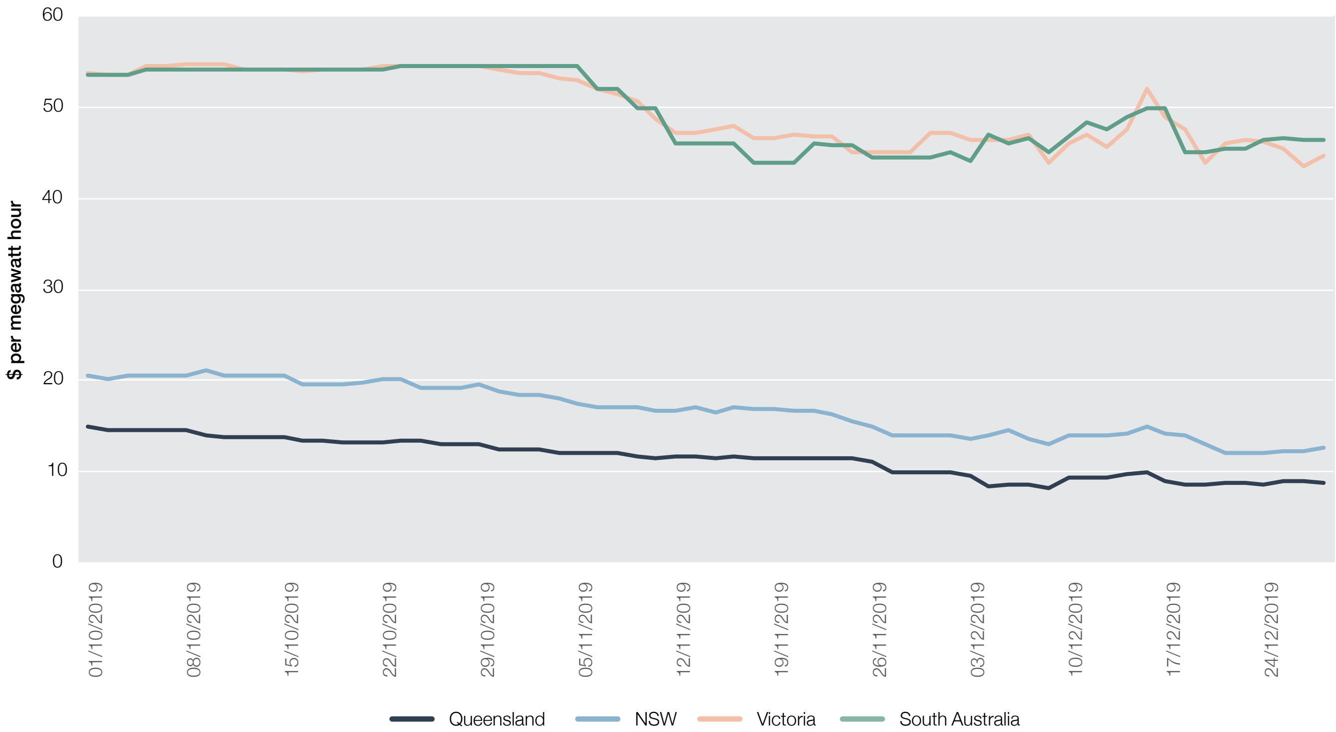
Source: AER analysis, ASX Energy data.

Notes: Daily closing price for each quarterly base futures contract for the last trading day in Q4 2019.

In the NEM, cap contracts are used to provide a hedge against the spot price exceeding $300 per MWh. The price for Q1 2020 cap contracts decreased in all regions as major generators returned to service throughout Q4 2019 (figure 1.5). This may indicate that interested parties expected less occasions of the spot price exceeding $300 per MWh as generation came back online.

Victoria and South Australia have traditionally experienced more occurrences of spot prices above $300 per MWh. This volatility has been reflected in the price of cap contracts in both Victoria and South Australia being more than double the price in Queensland and NSW.

Figure 1.5 Cap contract prices Q1 2020



Source: AER analysis, ASX Energy data.

Notes: Daily closing price for Q1 2020 quarterly cap contracts throughout Q4 2019.

1.3 Demand

- In Q4 2019 we observed demand in some regions falling to record minimum levels in October and November, and then increasing to almost record maximum levels in December:
  - Demand in South Australia fell below the previous minimum demand record seven times over the quarter, setting a record low of 456 MW.
  - Demand in South Australia then rose to within 176 MW of record maximum demand when December temperatures exceeded 40 degrees.
- Maximum demand in Queensland got to within 665 MW of record maximum demand.

The pattern of demand over the quarter reflected the typical transition from spring to summer.[3] However, in some instances this transition in Q4 2019 was more pronounced than previously with demand in some regions falling to record lows in October and November, and then increasing to almost record highs in December.

Minimum demand in South Australia (456 MW) was lower in Q4 2019 than it has ever been, reflecting the growth of rooftop solar PV that has continued to reduce demand from the grid during the day. In fact, minimum daily demand dipped below the previous minimum record seven times over the quarter (figure 1.6). The low demand was driven by:

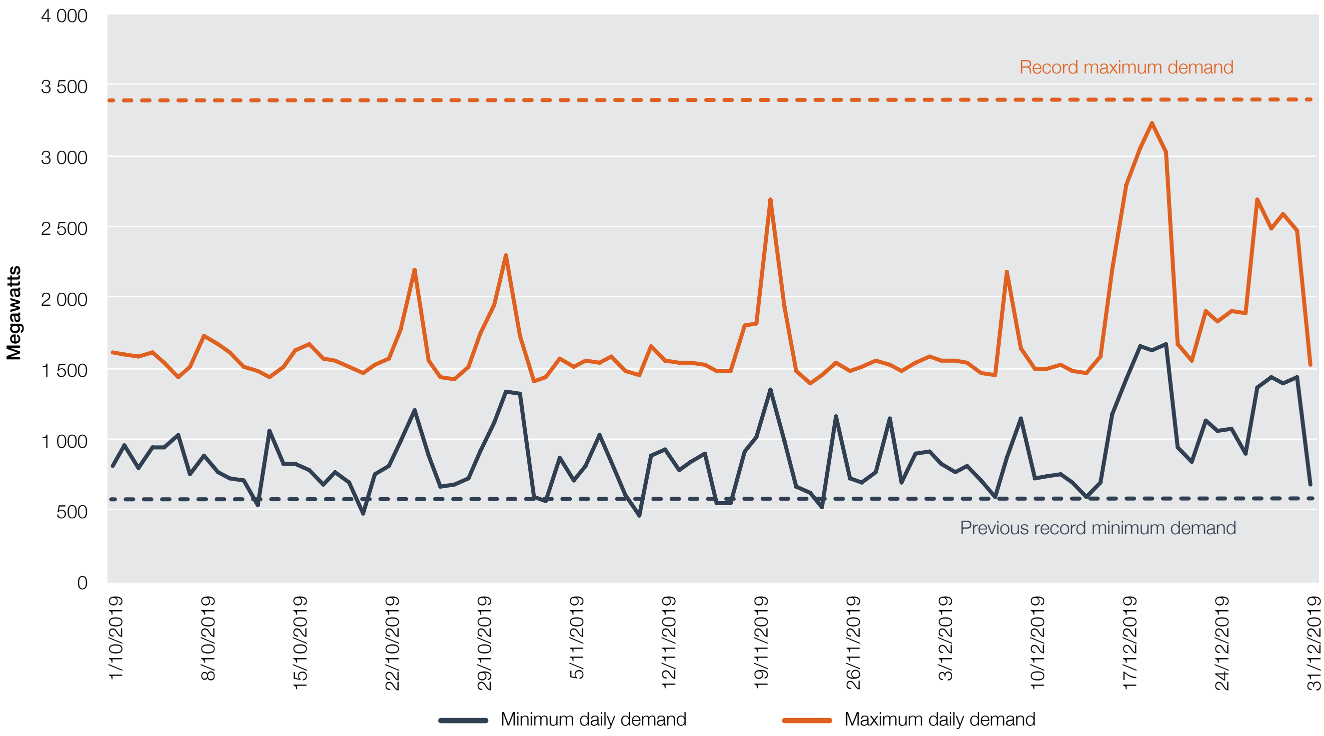
- low levels of heating and cooling typical in October and November, and
- a continued increase in the amount of rooftop solar PV generation in South Australia.

Our focus story on record low demand in South Australia explains the drivers of record minimum demand in more detail.

3 This discussion of demand refers to native demand. Native demand in a region is demand that is met by local generators that offer electricity into the market and by generation imports into the region. Native demand excludes rooftop solar PV.

Towards the end of Q4 2019, South Australia experienced very high demand, which was driven by extreme temperatures in December. A new record maximum Q4 demand of 3220 MW was set on 19 December 2019, which was only slightly lower than the record maximum demand set in January 2011 (figure 1.6).

Figure 1.6 South Australia minimum and maximum daily demand Q4 2019

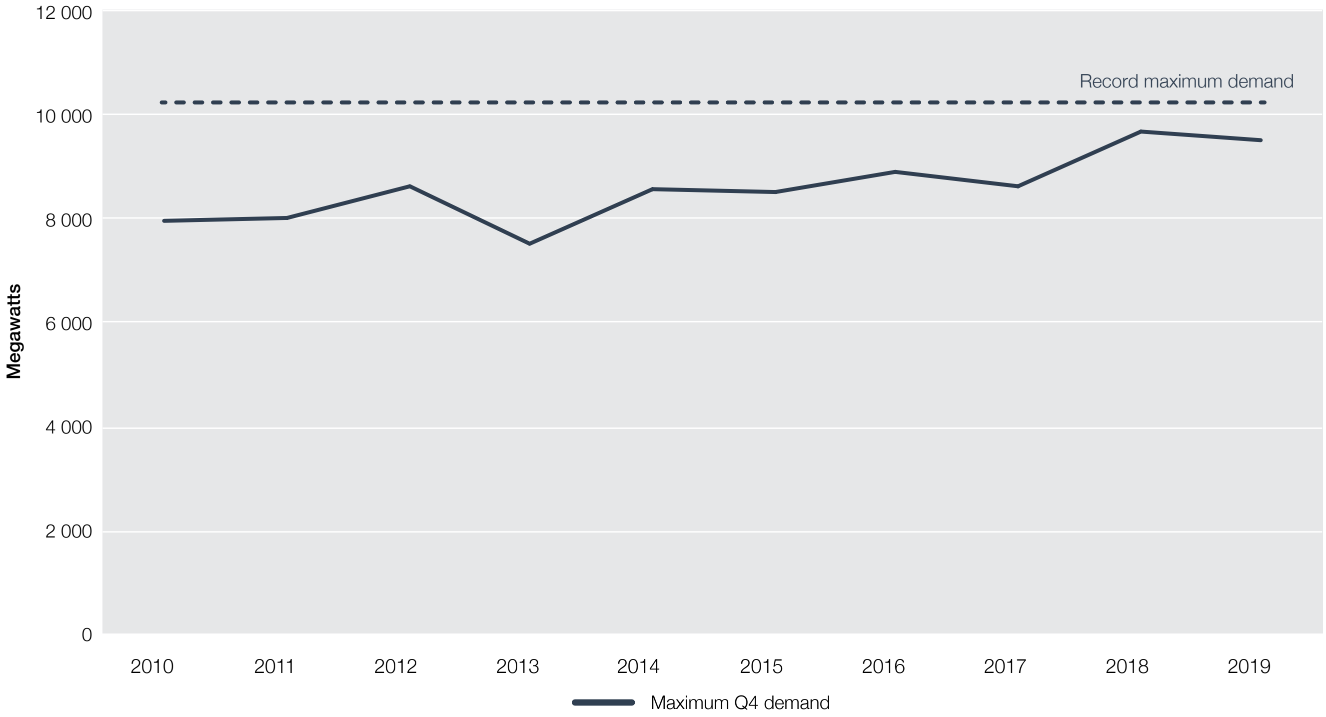


Source: AER analysis using NEM data.

Note: Uses native demand. Dotted lines are record maximum and minimum demand in South Australia prior to Q4 2019.

Maximum Q4 demand in Queensland has generally been increasing since 2013 (figure 1.7). Maximum Q4 demand in 2019 (over 9500 MW) was only slightly lower than the record Q4 demand set in 2018. On 16 December demand reached within 665 MW of record Queensland demand. Increasing maximum demand is being driven by increasing electricity requirements of the LNG exports and gas extraction sectors in Queensland. The gas section highlights that in Q4 2019, Australia became the largest LNG exporter in the world.

Figure 1.7 Maximum Q4 demand Queensland



Source: AER analysis using NEM data.

Note: Uses native demand. Solid line is maximum Q4 demand, dotted line is all-time maximum demand in Queensland.

1.4 Generation

- At the start of Q4 2019, planned and unplanned outages of black coal and brown coal generators led to reduced coal output and more gas generation.
- As outages were resolved coal generation output increased, decreasing the need for gas generation.
- Renewable generation continued to increase across all mainland regions, particularly large scale solar generation in Queensland.
- There were no actual reserve shortfalls and reserve contracts were dispatched once.

The mix of generation output changed significantly during Q4 2019. This largely reflected the large number of planned and unplanned outages at the start of the quarter—outages that were largely resolved as the quarter unfolded.

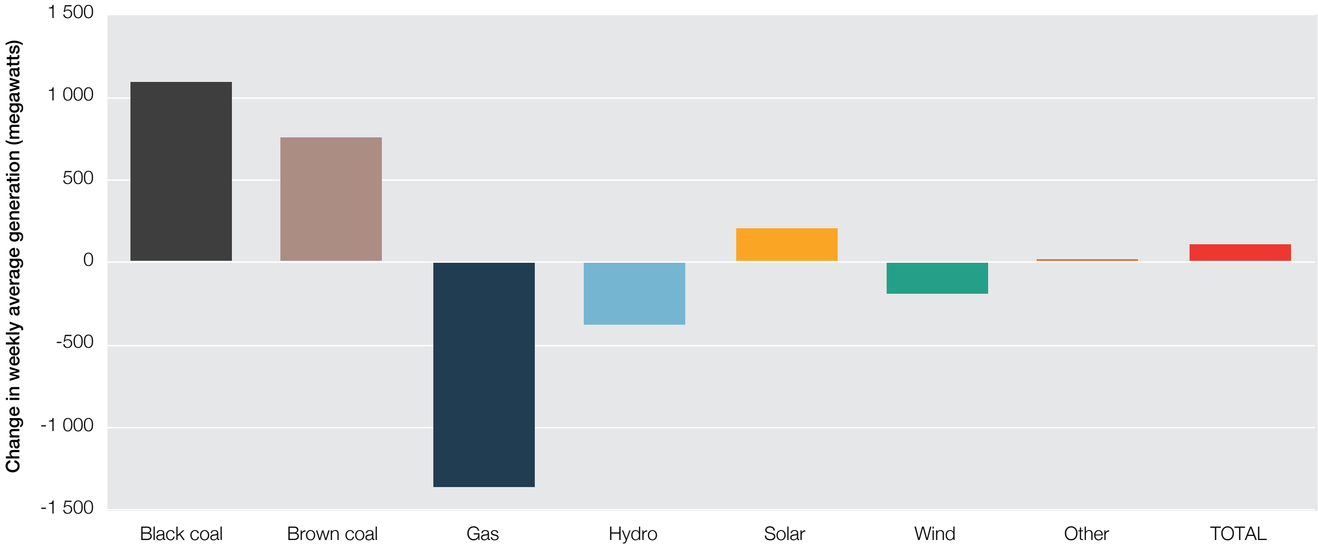
Across Queensland, NSW and Victoria, six major generator outages were underway at the start of Q4 2019. These six major outages alone reduced available black and brown coal generation by more than 2500 MW in the first days of October. Throughout October and November, more planned and unplanned outages occurred. However, by the end of December, most outages had been resolved and generation availability had reached close to summer ratings (table 1.1).

The reduced availability of black coal and brown coal generators due to outages was predominantly met by increased gas generation. In particular, gas powered generators Tallawarra (NSW), Darling Downs (Queensland) and Newport (Victoria) operated more during October and November when there were the most outages.

This transition through the quarter is highlighted by comparing generator output at the start and end of Q4 2019 (figure 1.8). This demonstrates:

- an increase in average black coal output of around 1100 MW and brown coal output of around 750 MW from levels at the start of the quarter as coal outages were resolved
- a reduction in gas generation output and, to a lesser extent, hydro output from levels at the start of the quarter, as gas generation primarily filled the gap created by the coal outages
- an increase, to a lesser extent, of large scale solar generation as more generators entered the market and ramped up to full capacity.

Figure 1.8 Change in average NEM generation output over Q4 2019

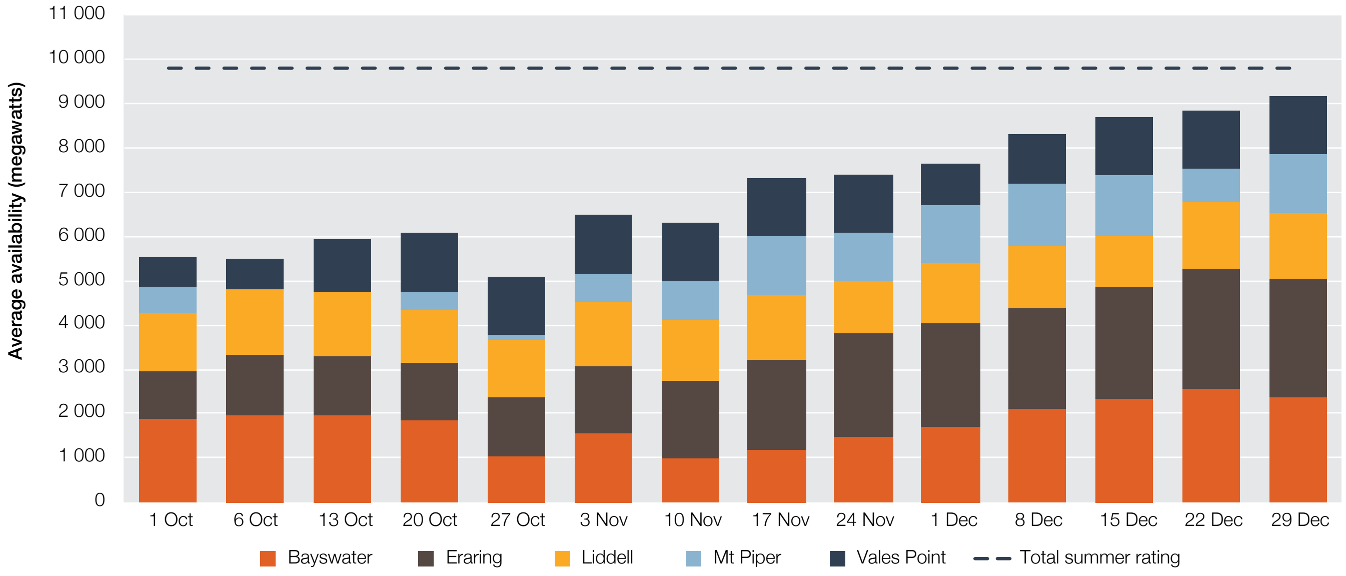


Source: AER analysis using NEM data.

Note: Figure compares weekly average metered generation output by fuel type across the NEM in the week commencing 6 October and 22 December 2019. Solar generation includes large scale generation only. Rooftop solar PV is not included as it affects demand not grid-supplied generation output.

The trend of coal generation outages progressively being addressed through the quarter is particularly illustrated by black coal generator availability in NSW (figure 1.9). By the end of Q4 2019, average black coal available capacity in NSW was up some 3500 MW on the levels at the start of the quarter. Indeed by the end of Q4 2019, average available black coal capacity in NSW came close to summer ratings. The remaining difference between NSW black coal availability and summer ratings was primarily due to reduced availability at AGL Energy's Bayswater and Liddell power stations.

Figure 1.9 Black coal in New South Wales over Q4 2019



Source: AER analysis using NEM data.

Notes: The stacked bars indicates average station availability by week. The dotted line indicates the summer rating or maximum amount of availability that all the black coal stations could offer during summer.

Table 1.1 Major generator outages

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q4 2019	REASON FOR OUTAGE	RETURNED TO SERVICE
Queensland				
Callide C, Callide Power Trading	Black coal 2 units, 420 MW each	Unit 3: 73 days	Planned	14 December
Gladstone, CS Energy	Black coal 6 units, 280 MW each	Unit 1: 38 days	Planned (4 days)—started in Q3 2019	5 October
			Unplanned (34 days)—'unit trip'	23 November
		Unit 2: 10 days	Unplanned—'tube leak'	31 October
		Unit 5: 18 days	Planned	7 December
		Unit 6: 25 days	Planned (6 days)	12 October
			Planned (11 days)	10 November
Kogan Creek, CS Energy	Black coal 730 MW	29 days	Planned (4 days)—major overhaul started in Q3 2019	4 October
			Unplanned (14 days)—'steam penthouse issue'	26 October
			Unplanned (11 days)—'unit trip'	4 January
Tarong, Stanwell Corporation	Black coal 4 units, 350 MW each	Unit 4: 62 days	Planned	9 December
New South Wales				
Bayswater, AGL Energy	Black coal 4 units, 630 MW each	Unit 1: 22 days	Unplanned (19 days)—'plant failure'	28 November
		Unit 2: 10 days	Unplanned—'plant failure'	18 November
		Unit 4: 65 days	Planned	4 December
Eraring, Origin Energy	Black coal 4 units, 720 MW each	Unit 1: 35 days	Unplanned—'ID fan issues'	5 November
		Unit 3: 51 days	Planned (51 days)	22 November
Mount Piper, EnergyAustralia	Black coal 2 units, 650 MW each	Unit 1: 32 days	Planned (20 days)	22 October
			Planned (7 days)—'coal conservation'	28 December
		Unit 2: 42 days	Unplanned (38 days)—'mill management'	13 November
Liddell, AGL Energy	Black coal 4 units, 450 MW each	Unit 1: 15 days	Planned (2 days)—started in Q3 2019	3 October
			Planned (13 days)	6 December
		Unit 2: 16 days	Planned (11 days)	31 October
		Unit 4: 11 days	Planned	22 December
Vales Point, Delta Electricity	Black coal 2 units, 660 MW each	Unit 5: 17 days	Planned (11 days)—started in Q3 2019	12 October
Victoria				
Loy Yang A, AGL Energy	Brown coal 4 units, 530 MW each	Unit 2: 89 days	Unplanned—electrical issues (since May)	-
Yallourn, EnergyAustralia	Brown coal 4 units, 355 MW each	Unit 1: 25 days	Planned (10 days)—started in Q3 2019	11 October
		Unit 2: 14 days	Planned—started in Q3 2019	15 October
		Unit 3: 14 days	Planned (11 days)	17 December
		Unit 4: 18 days	Unplanned (16 days)—'tube leak'	19 November
Mortlake, Origin Energy	Gas 2 units, 259 MW each	Unit 2: 85 days	Unplanned—electrical issues (since July)	24 December (as anticipated)

Source: AER analysis using NEM data.

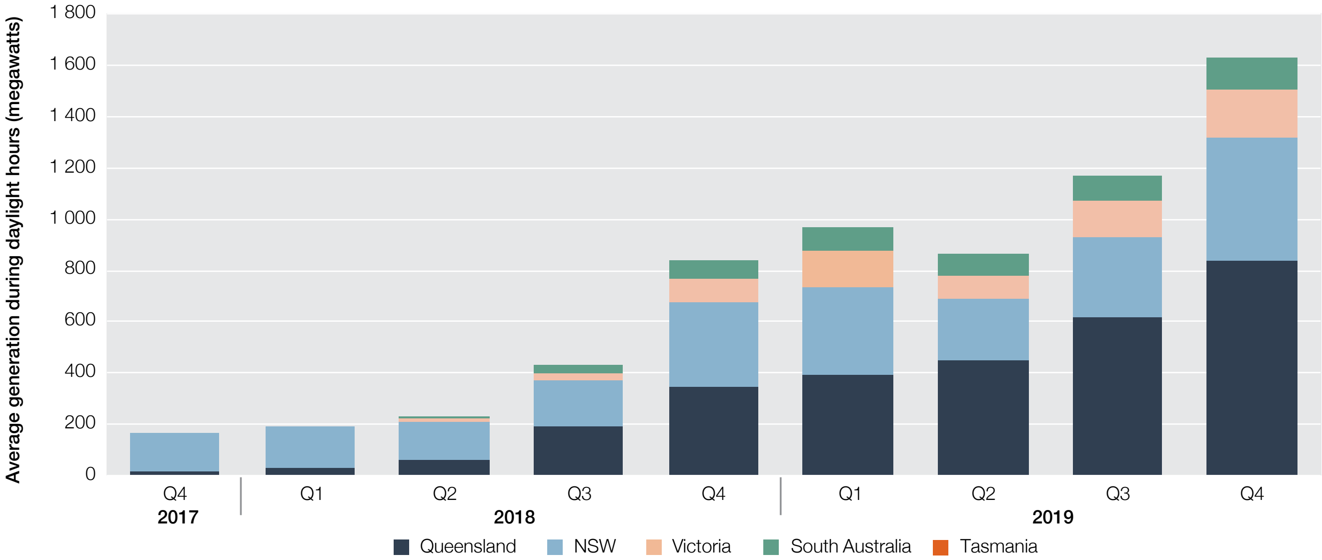
Notes: The table outlines major generator outages throughout Q4 2019 and the reason for the outage. The table focuses primarily on larger coal and gas generators that operate most of the time. Due to a high number of unplanned outages under 10 days in duration, these have been included in the count of 'days offline in Q4 2019' but have been excluded from the 'reason for outage'.

Large scale solar generation continued to increase

Large scale solar generation continued to increase throughout Q4 2019, particularly in Queensland and NSW. While large scale solar generation across the NEM increased by more than 100 MW between the first and last weeks of the quarter, this is part of a longer term trend that has gathered pace in the past year.

This trend is the most pronounced in Queensland. Average large scale solar generation for Q4 2019 was around 420 MW, which marked an increase of more than 110 MW compared to Q3 2019 and nearly double that of Q4 2018 (figure 1.10).

Figure 1.10 Large-scale solar generation output by region



Source: AER analysis using NEM data.

Notes: Average is over daylight hours using the trading intervals from 6.30 am to 6 pm.

No reserve shortfalls

Expectations of extreme weather and resulting high demand and unavailability of generation plant led to concerns late in Q4 2019 that there would be insufficient generation available to ensure reliable electricity supplies. Despite these challenging conditions, there was sufficient generation to meet demand throughout Q4 2019 and Reliability and Emergency Reserve Trader (RERT) contracts were only dispatched once (in Victoria on 30 December 2019). As noted above, generator outages were progressively resolved and while there was still some ongoing generator outages late in Q4 2019 (particularly in Victoria), sufficient generation was available as demand increased late in the quarter.

1.5 New entry

- There were four new entrants in Q4 2019 including the Barker Inlet gas generator in South Australia.
- Eleven projects scheduled to enter the market in 2019 were delayed.
- Over the next 12 months there is 3500 MW of committed projects scheduled to enter the market.

There were four new entrants in the market this quarter, with a total registered capacity of over 350 MW (table 1.2).

Table 1.2 New market entry

STATE	STATION	FUEL TYPE	SCHEDULE TYPE	HIGHEST CAPACITY OFFERED IN Q4 2019 (MW)	REGISTERED CAPACITY (MW)	COMMENCED OPERATIONS
South Australia	Barker Inlet	Gas	Scheduled	210	210	October 2019
South Australia	Lake Bonney Storage	Battery	Scheduled	25	25	October 2019
NSW	Nevertire	Solar	Semi-scheduled	26	105	December 2019
NSW	Limondale 2	Solar	Semi-scheduled	5	29	December 2019

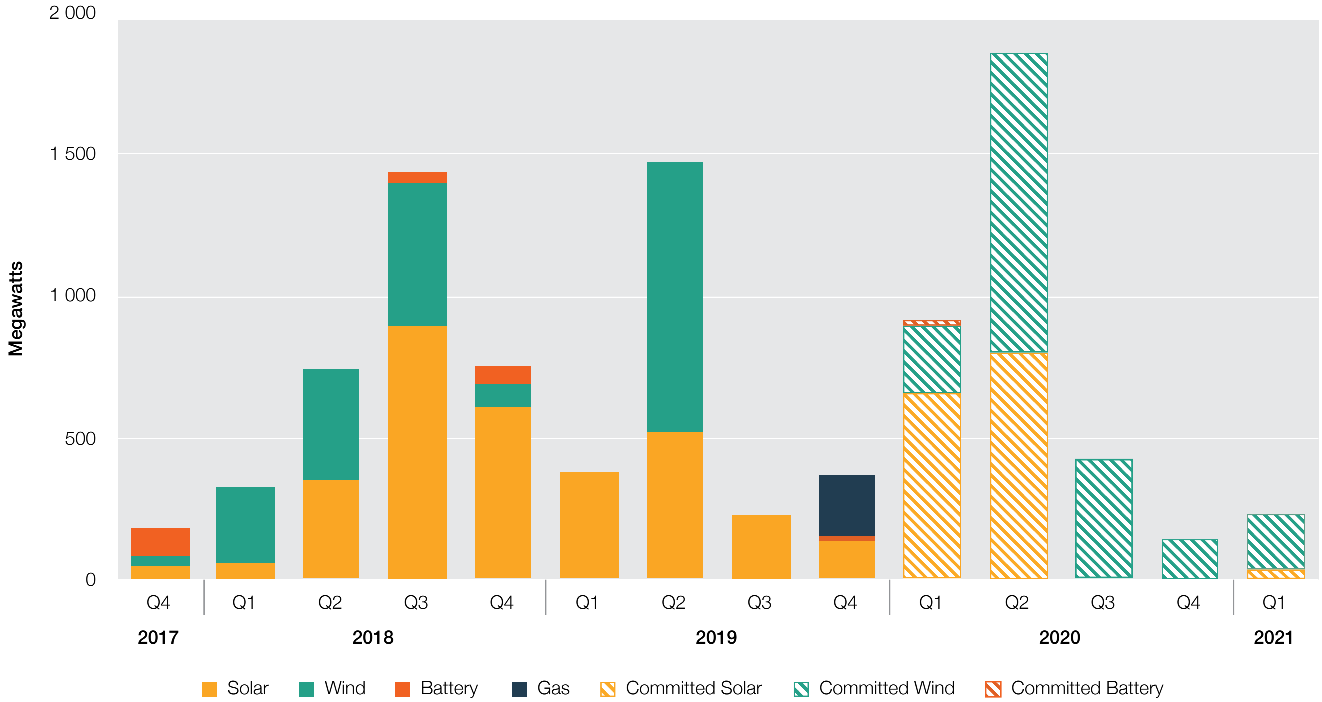
The largest new entry was the Barker Inlet power station in South Australia, with a capacity of 210 MW. It was commissioned by AGL Energy to act as replacement for the aging Torrens Island A station. Barker Inlet is the first flexible gas generator to be commissioned since Mortlake in 2012. There is currently no other committed flexible gas generators due to enter the market.

Infigen's Lake Bonney battery in South Australia also entered the market. It is a 25 MW lithium-ion battery system, which in combination with the Lake Bonney wind farm, is designed to provide 'firm' renewable electricity contracts. The battery is also registered to provide FCAS services.

Eleven committed projects scheduled to commence in 2019 were delayed as a result of commissioning and connection issues. These projects, mostly large scale solar and wind farms, will have a combined registered capacity of around 1300 MW.

Including these projects, there is around 3500 MW of committed large scale solar and wind generation capacity scheduled to enter the market over 2020, with most due to come online by the middle of the year (figure 1.11).

Figure 1.11 New and committed investment in the NEM



Source: AER analysis using NEM data.

1.6 Participant offers

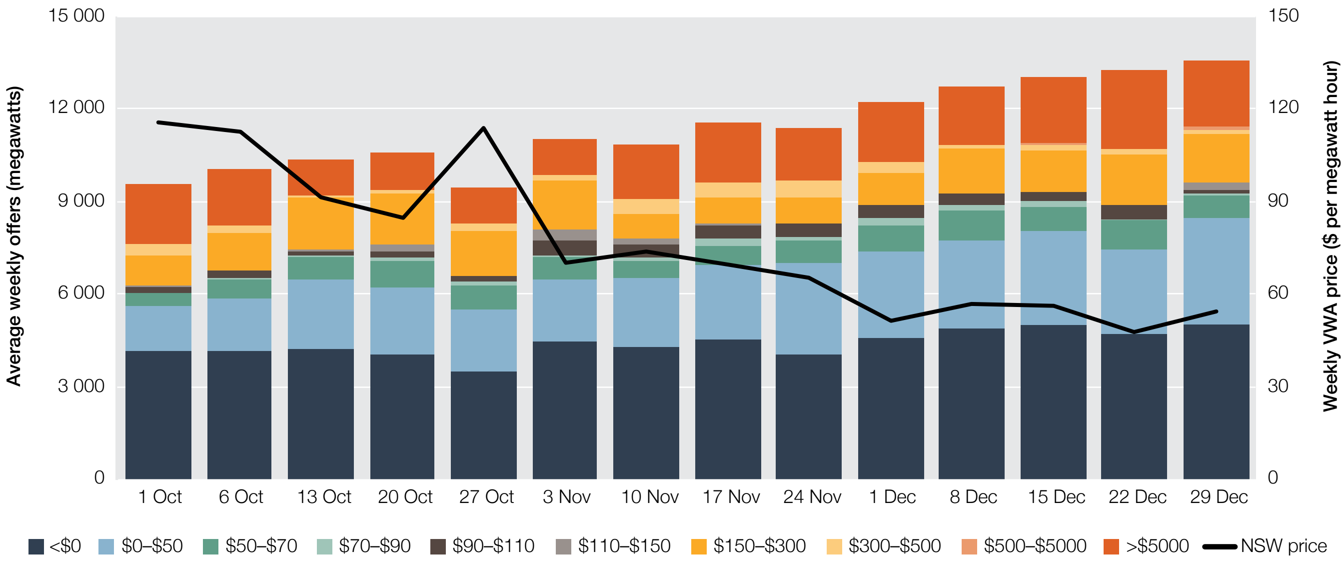
- Participant offers across Q4 2019 were impacted by black and brown coal outages at the start of the quarter.
- Less low priced capacity was offered at the start of the quarter but as coal generation came back online, offers of low priced capacity increased. This increase in low priced capacity put downward pressure on prices.

Participant offers across the quarter were impacted by the black and brown coal outages (section 1.4). As a result of the outages, coal generators, who typically offer most of their capacity at low prices, offered less capacity into the market. As these outages were resolved, offers of low priced capacity increased.

In particular, outages of black coal generators significantly contributed to reduced offers of low priced capacity in NSW at the start of Q4 2019 (blue and green bands in figure 1.12). By the end of the quarter when outages were resolved, NSW generators offered around 2000 MW more capacity priced below $90 per MWh (around a third more than at the start of Q4 2019).[4]

4 Average weekly offers from all generators in NSW.

Figure 1.12 New South Wales average offers by price band over Q4 2019

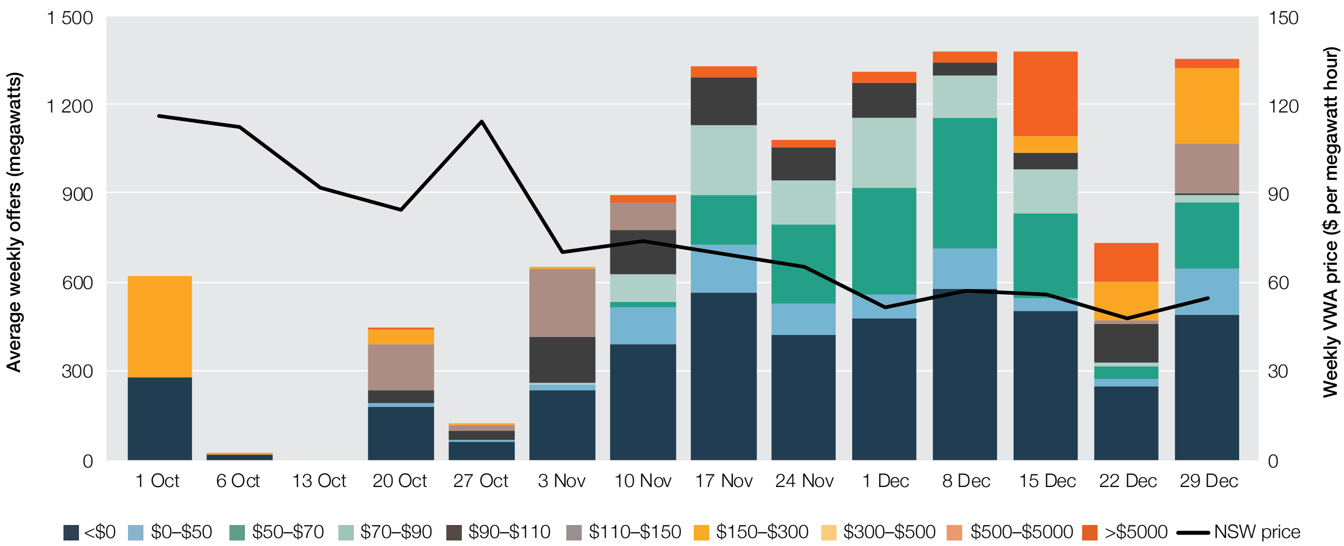


Source: AER analysis using NEM data.

Notes: Weeks run Sunday to Saturday, weeks commencing 1 October and 29 December are partial weeks.

One of the major outages in NSW during the quarter was at Mt Piper power station. Changes in the offers of the 1300 MW black coal power station contributed significantly to the offer and price outcomes in NSW. As outages were resolved, it alone offered 1000 MW more capacity into the market by the end of Q4 2019 (figure 1.13).

Figure 1.13 Mt Piper power station average offers by price band over Q4 2019



Source: AER analysis using NEM data.

Notes: Weeks run Sunday to Saturday, weeks commencing 1 October and 29 December are partial weeks.

More solar capacity was offered in all mainland regions, and more wind capacity was offered in NSW, Victoria and South Australia in Q4 2019 compared to a year ago. This meant, despite the coal outages discussed above, significantly more capacity was offered on average in Queensland and South Australia, compared to Q4 2018. As solar and wind generation was often offered below $0 per MWh this contributed to lower price outcomes in the quarter, but not to the same extent as in Q3 2019.

1.7 Price setter

- Black coal generators set the price more often as the quarter progressed displacing more expensive fuels such as gas and hydro from setting price.
- Solar generators in Queensland and wind generators in South Australia continued to set price at negative prices particularly early in the quarter.

In all regions, the amount of time black coal generators set the price increased significantly as the quarter progressed. As black coal set the price more often, more expensive fuels such as gas and hydro were increasingly displaced (figure 1.14).

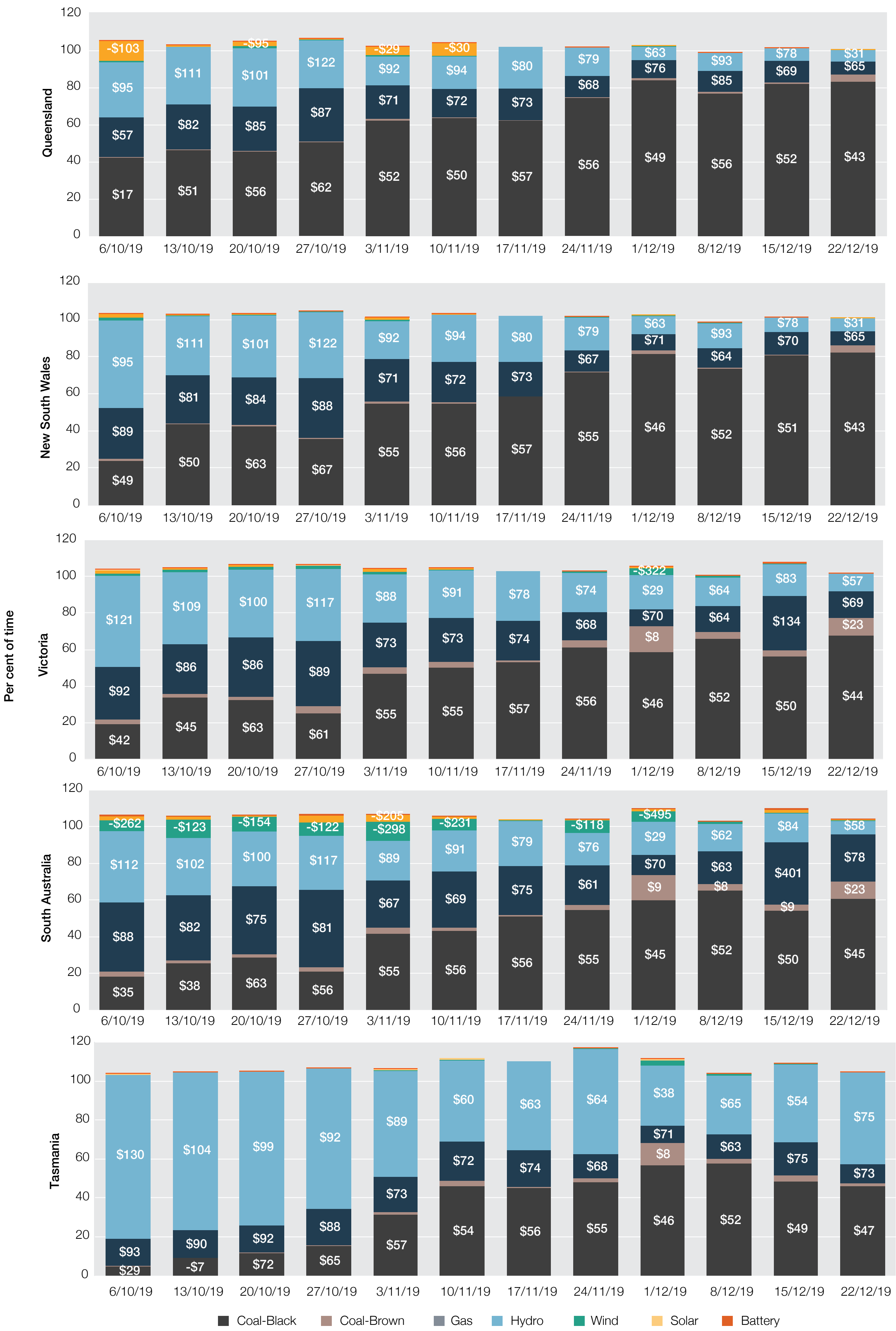
The trend of black coal setting the price more often is seen most strongly in Queensland and NSW but carries across all mainland regions. By the end of Q4 2019, black coal was setting the price 80 per cent of the time in both Queensland and NSW whereas gas and hydro only set the price around 15 per cent of the time. This marks a significant shift from the start of Q4 2019 where black coal set the price far less often, and gas and hydro set the price the majority of the time.

Black coal setting the price more often contributed significantly to the falling weekly spot prices that we saw over much of Q4 2019.

There was one exception to this trend. During the week starting 15 December, gas set the price more often than in the preceding weeks in South Australia and Victoria. During this week, gas was increasingly required to meet demand as temperatures reached over 40 degrees.

One of the trends identified in our *Wholesale markets quarterly—Q3 2019* report was the increase in the time solar generators in Queensland and wind generators in South Australia set the price. These generators continued to set the price at negative prices particularly in the first half of Q4 2019. In Queensland, solar generators set the price 2.4 per cent of the time at an average price of -$73 per MWh. In South Australia, wind generators set price for around 6 per cent of the time at an average price of -$235 per MWh. Solar and wind set the price less often as demand increased later in Q4 2019.

Figure 1.14 Price setter by fuel type and region over Q4 2019



Source: AER analysis using NEM data.
Notes: Weeks run Sunday to Saturday, figure only includes complete weeks throughout Q4 2019 from 6 October to 28 December.

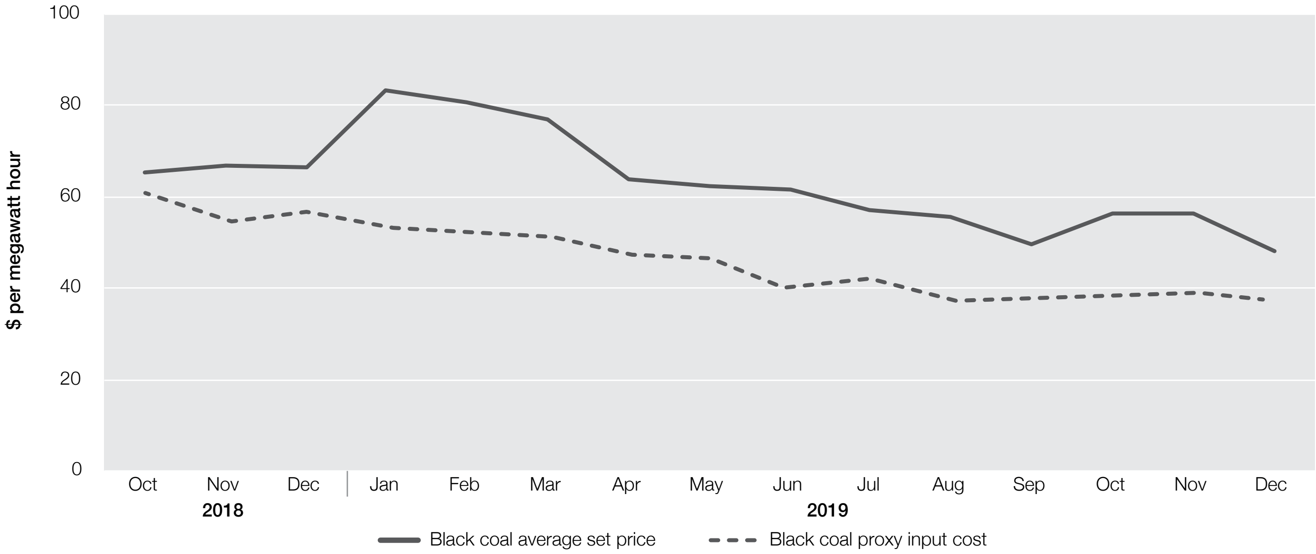
1.8 Fuel costs

- Average price set by black coal generators increased in October and November but then decreased in December as major black coal generators returned to service after outages.
- Average price set by gas generators tracked declining east coast spot prices, however as gas didn't set price often, falling gas prices didn't contribute much to price outcomes.

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.

In NSW, the price at which black coal set price has generally tracked the falling international coal price since April (figure 1.15). However, during October and November the price at which black coal set price increased relative to the international coal price. This corresponded with a number of major generator outages. As these outages were resolved, the price at which black coal generators set price once again more closely tracked coal prices throughout December 2019.

Figure 1.15 International reference price for Newcastle spot thermal coal and average monthly price when black coal generators set the price in NSW



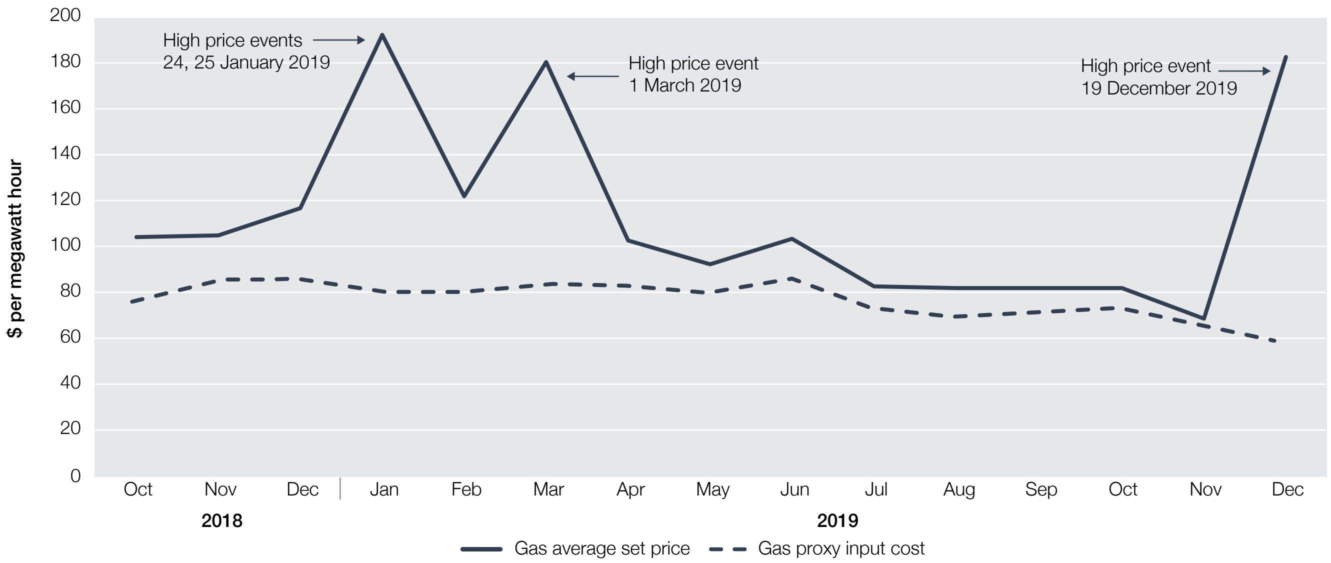
Source: AER analysis using NEM and globalCOAL data.

Note: 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.

Average wholesale gas spot prices dropped again this quarter (section 2.1). Using the average spot price in the Adelaide Short Term Trading Market (STTM) as a proxy for the marginal cost of gas generators, the average price set by gas generators in South Australia has generally tended to track the declining fuel price (figure 1.16). This relationship, however, breaks down when there are high prices, such as those we observed in January and March 2019 and more recently in December.

We will undertake a more detailed assessment of the relationship between participant costs and market price outcomes, including examining periods where input costs and prices diverge, as part of our next *Wholesale electricity market performance report* due in December 2020.

Figure 1.16 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.

Note: 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.

1.9 Interconnectors

- Exports from Queensland into NSW in Q4 2019 were down approximately 560 GWh, compared to Q3 2019. This was linked to a drop in the number of negative prices in Queensland.
- Exports from Victoria in Q4 2019 were up approximately 250 GWh compared to Q4 2018 and up approximately 690 GWh compared to Q3 2019.
- South Australia price aligned with Victoria less often in Q4 2019 compared to Q4 2018.

Trade between regions over interconnectors provides some competition between participants across regions. There were no major outages of interconnectors in Q4 2019, though constraints on interconnectors (particularly Basslink) saw price alignment levels down.

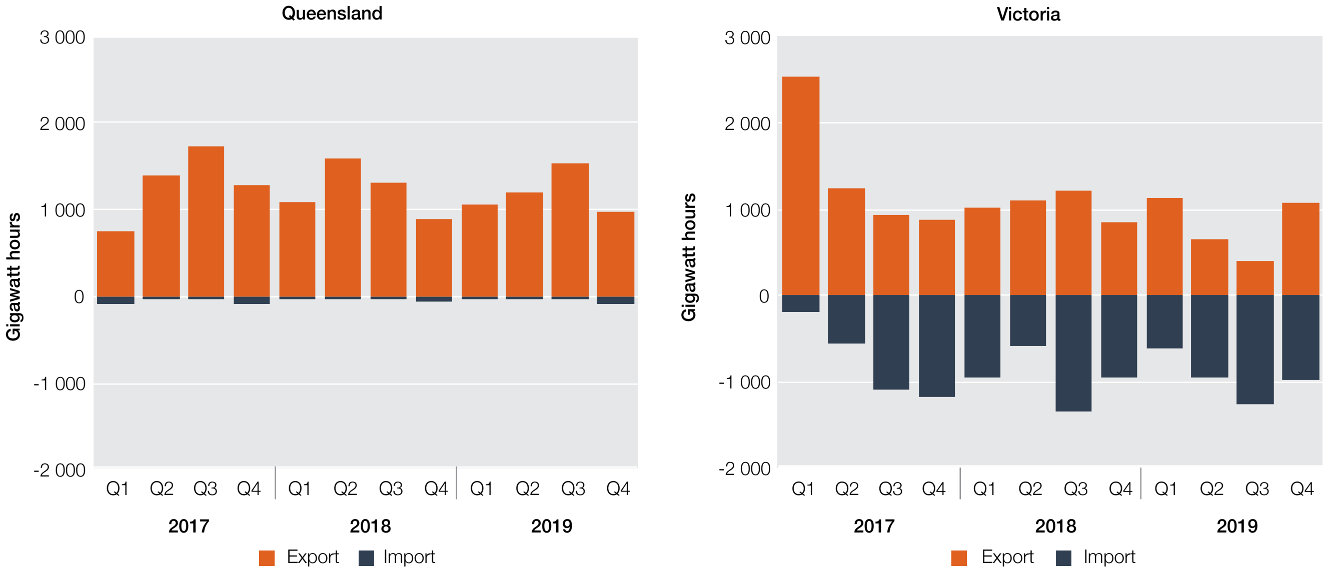
Queensland continued to be a net exporter, exporting 90 GWh more in Q4 2019 than in Q4 2018 driven by lower spot prices than NSW and an influx of new renewable generation (figure 1.17). However, exports from Queensland into NSW in Q4 2019 were down around 560 GWh (approximately 36 per cent) compared to Q3 2019. This is linked to a drop in the number of negative prices in Queensland as demand has increased with the hotter weather. This saw price alignment between Queensland and NSW increase from a low of 79 per cent in Q3 2019 to 86 per cent, though levels were not as high as in Q4 2018 at 92 per cent.

Lower prices in Victoria as large coal-fired generators came back online from major outages in Q3 2019 saw exports from Victoria in Q4 2019 up approximately 690 GWh and more than double compared to Q3 2019 (figure 1.17). Compared to Q4 2018, exports increased 250 GWh (approximately 30 per cent) and import levels were similar.

Price alignment of South Australia with Victoria in Q4 2019 was down 11 per cent compared to Q4 2018. This is due to both the Heywood and Murraylink interconnectors being constrained more often during the quarter. Constraints were often related to re-classified contingencies such as line outages or voltage control issues in the Victoria region.

Despite there being no major outage of Basslink, price alignment levels between Tasmania and Victoria stayed the same and exports to Victoria in Q4 2019 dropped, compared to Q3 2019. This is mostly due to the number of constraints upon Basslink and lower prices in Victoria for Q4 2019.

Figure 1.17 Interconnector flows for Queensland and Victoria



Source: AER analysis using NEM data.

1.10 Frequency control ancillary services (FCAS)

- Quarterly FCAS costs increased to $80 million (equal to 2.3 per cent of NEM energy costs).
- The increase was largely due to increased costs of contingency services, in particular raise 6 second services.
- AEMO progressively increased the amount of contingency services enabled over the quarter.
- There were also two FCAS high priced events which increased costs for lower 6 second (new record) and lower 60 second services.

Frequency control ancillary services (FCAS) are used to maintain the frequency of the system. Raise services increase the frequency if it's too low and lower services decrease the frequency if it's too high. There are two categories of FCAS, both of which can be used to raise or lower the frequency of the NEM:

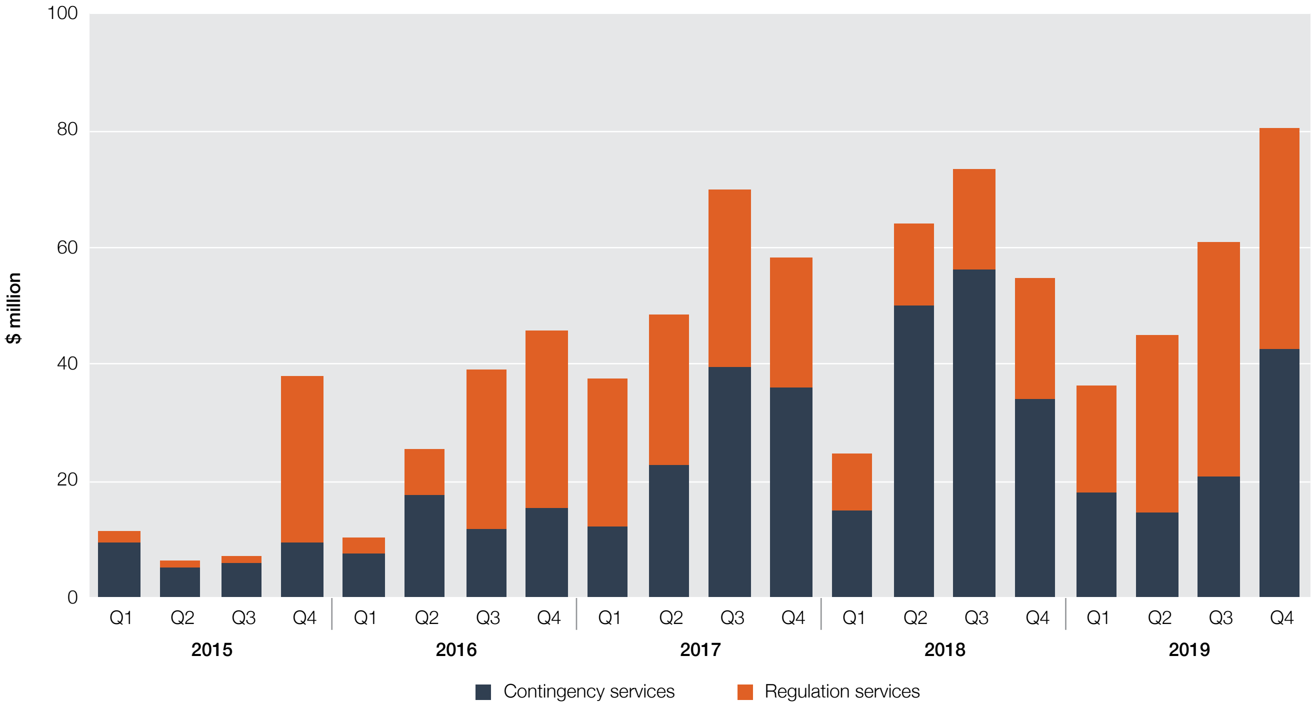
- regulation services which continuously balance small changes in frequency, and
- contingency services (6 second, 60 second and 5 minute) which are called upon to respond to large changes in frequency.[5]

Quarterly FCAS costs increased

Quarterly FCAS costs increased to their highest level since 2008 and the drivers are explained in greater detail in the FCAS focus section. The total costs for all ancillary services in Q4 2019 was over $80 million which was 47 per cent higher than in Q4 2018 (figure 1.18). In Q3 2019 FCAS costs were equal to less than 1.5 per cent of NEM energy costs but this quarter they increased to an amount equal to 2.3 per cent of NEM energy costs.

5 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 1.18 Total FCAS costs

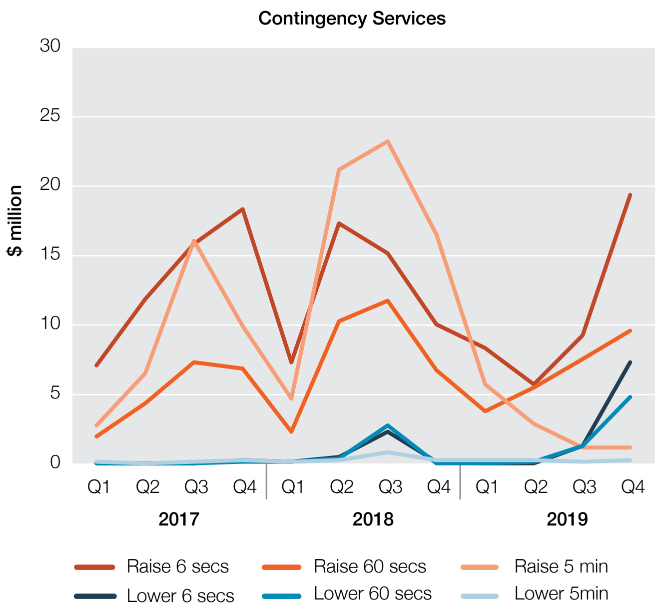


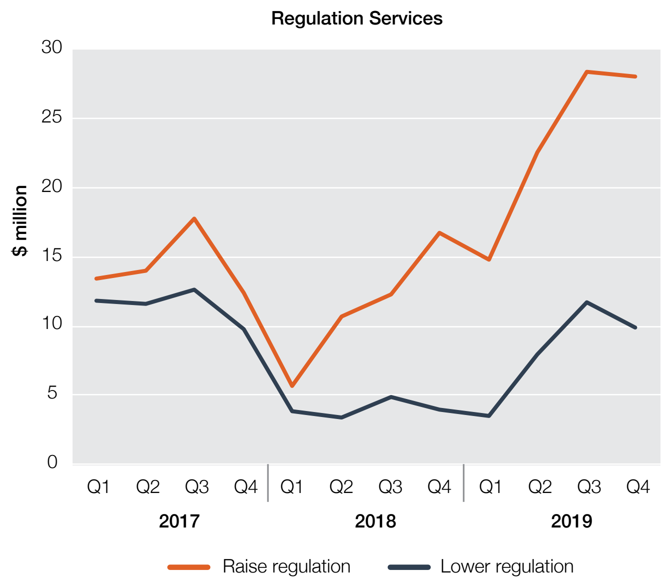
Source: AER analysis using NEM data.

The increase in FCAS costs was largely driven by an increase in the cost of contingency services, in particular 6 second and 60 second raise and lower services (figure 1.19). Of these, the cost of raise 6 seconds services increased the most. The increase in the costs of contingency services reflected:

- an increase in the amount of contingency services enabled as a result of a change in the way AEMO calculates contingency FCAS requirements, and
- two FCAS high price events in South Australia.

Figure 1.19 Total FCAS costs by service





Source: AER analysis using NEM data.

Figure 1.19 above shows, even though it fell slightly, the highest cost continued to be for raise regulation services. The cost of raise regulation services was $28 million, accounting for a third of total FCAS costs for the quarter. The cost of lower regulation services fell in Q4 2019 compared to Q3 2019, as did the cost of raise 5 minute services.

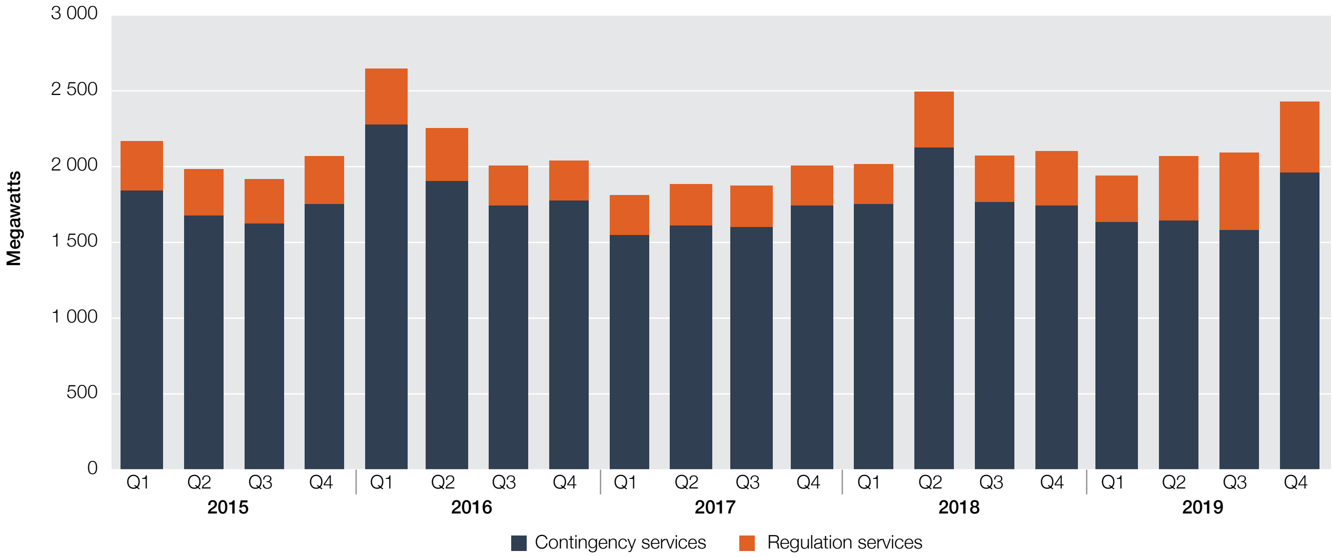
Two FCAS high priced events in South Australia

There were two high priced FCAS events in South Australia which increased the costs for lower 6 second (new record) and lower 60 second services. The first event was due to a network outage in Victoria which led AEMO to invoke constraints. The second was due to an unplanned outage of the Heywood interconnector. Both these events isolated South Australia from the rest of the market so it needed to provide its own FCAS. To meet the local requirements, capacity offered above $5000 per MW was needed. Our detailed reports into these prices, a requirement under the National Electricity Rules, will be available shortly.

More FCAS was enabled

The amount of FCAS enabled by AEMO in Q4 2019 increased by over 300 MW (or 16 per cent) compared to both Q4 2018 and the previous quarter. As noted above this was mostly due to an increase in the amount of contingency services (figure 1.20). From September 2019 AEMO progressively began reducing the load relief assumption it used to calculate contingency FCAS requirements.[6]

Figure 1.20 Total FCAS enabled



Source: AER analysis using NEM data.

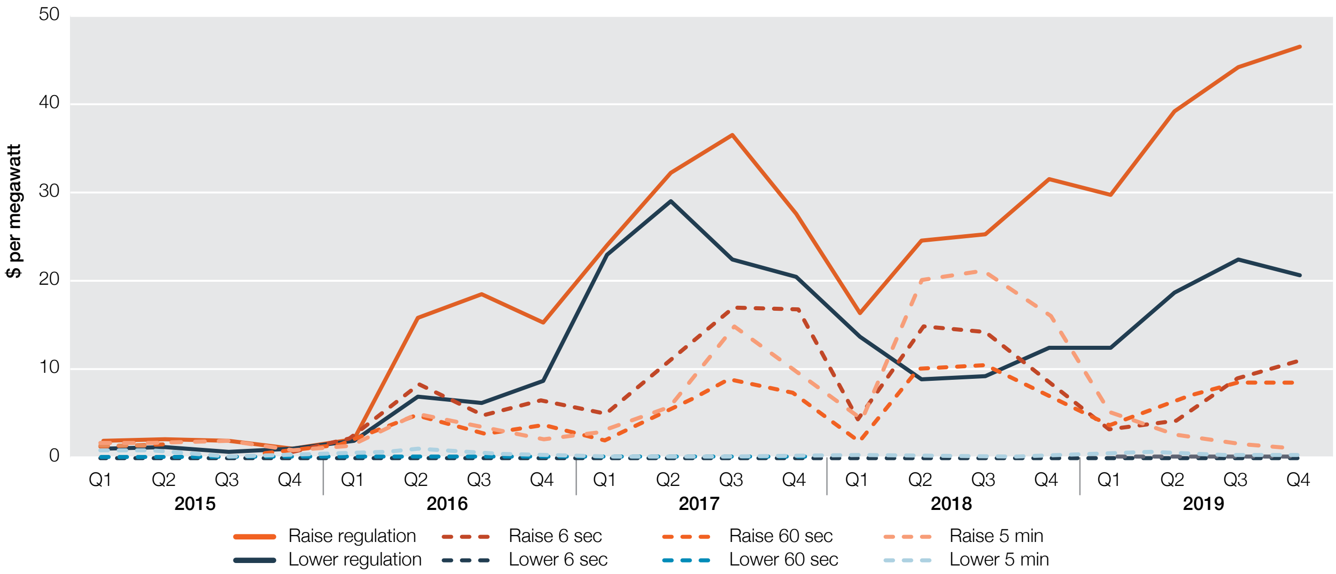
FCAS prices

The most notable price outcome for the quarter was the increase in the price for raise regulation, raise 6 second and raise 60 second services compared to Q3 2019 (figure 1.21). Particularly, the price of raise regulation services increased to record levels. In contrast, the price for raise 5 minute services continued to fall.

The price for lower regulation services, after increasing for five quarters, fell in Q4 2019. Prices for the other lower services remained low.

6 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 1.21 Average quarterly FCAS prices



Source: AER analysis using NEM data.

FCAS providers

Of the four new entrants in the NEM in Q4 2019, only the Lake Bonney battery is registered to provide FCAS services. It is registered to offer a maximum of 25 MW.

Focus—Record low demand in South Australia

- In Q4 2019 demand in South Australia fell to a record low of 456 MW on 17 October.
- The primary driver behind falling South Australian demand is an increase in rooftop solar penetration:
  - 35 per cent of households in South Australia now have a rooftop solar system installed.
  - In Q4 2019, rooftop solar met almost 15 per cent of all demand in South Australia.

South Australia set a new record low for native demand on 10 November 2019, driven by the continued growth of rooftop solar PV. As it continues to grow, solar is changing the shape of demand curve—with lower minimums during the day, and more significant fluctuations as the sun goes down. As a result, the requirement for more traditional forms of generation during the day is lower.

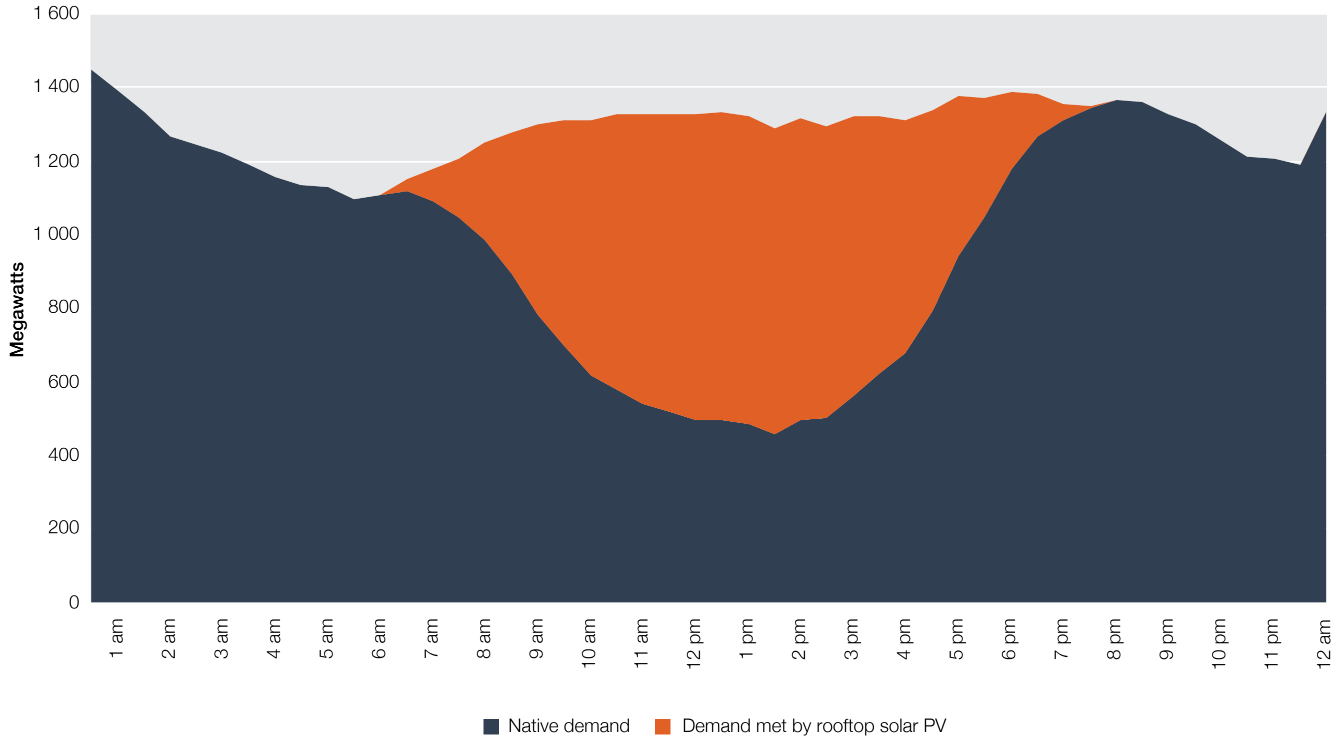
Why did we see a record low demand?

On 10 November 2019, during the half-hour ending 1.30 pm, native demand reached a low of 456 MW. Indeed, six other days this quarter were below the previous record of 580 MW, set in October 2016.

Native demand is calculated as the power requirement of consumers that is met by generation within a region plus imports from other regions. It does not include rooftop solar PV, which is behind the meter. Rooftop solar PV systems are electricity generating solar panels (sized less than 100 kWh) which are mounted to rooftops of homes and small businesses that have the effect of offsetting native demand.

Figure 1.22 below demonstrates how a large proportion of the demand in the region (the orange portion) was met by rooftop solar PV systems. There is a strong correlation between the rise of rooftop solar PV and reduction of native demand during daylight hours.

Figure 1.22 South Australian demand—10 November 2019



Source: AER analysis using NEM data.

Why is this happening in Q4?

Native demand is most likely to be at its lowest in Q4 due to typical seasonal variations and high rooftop solar PV output:

- Autumn (April and May) and spring (September, October, November) traditionally have the lowest underlying demands as there is much less heating or cooling load when weather conditions are moderate. The lowest demands happen during the weekends of these months when there is also lower demand from industry.
- Available sunlight peaks around the summer solstice (Christmas), so rooftop solar PV output in October and November is among the highest of the year—around double that of April and May.

So, while demand is low in both spring and autumn, rooftop solar PV production is much higher in spring, making Q4 the prime time for record low demands to occur. With the installation rates of rooftop solar PV continuing to rise, we would expect to see records broken in October and November.

Rooftop solar is now significant and growing

Generation from rooftop solar PV systems in South Australia is growing strongly. Both installation rates and system size are increasing:

- The number of small-scale rooftop solar PV systems installed each year has increased year on year for the last five years. This is consistent across both residential systems (less than15 kWh) and small scale commercial systems (15–100 kWh). As table 1.3 shows, installation rates of residential systems have doubled between 2015 and 2018, while commercial systems have tripled.
- The average capacity of systems is also increasing. In 2015 the average residential system size installed in South Australia was 4.6 kWh. In 2019, the average capacity has increased by over 40 per cent to 6.6 kWh. The average size of small scale commercial systems has also been rising from 29.8 kWh in 2015 to 38.7 kWh in 2018.

Table 1.3 Rooftop solar installations—South Australia

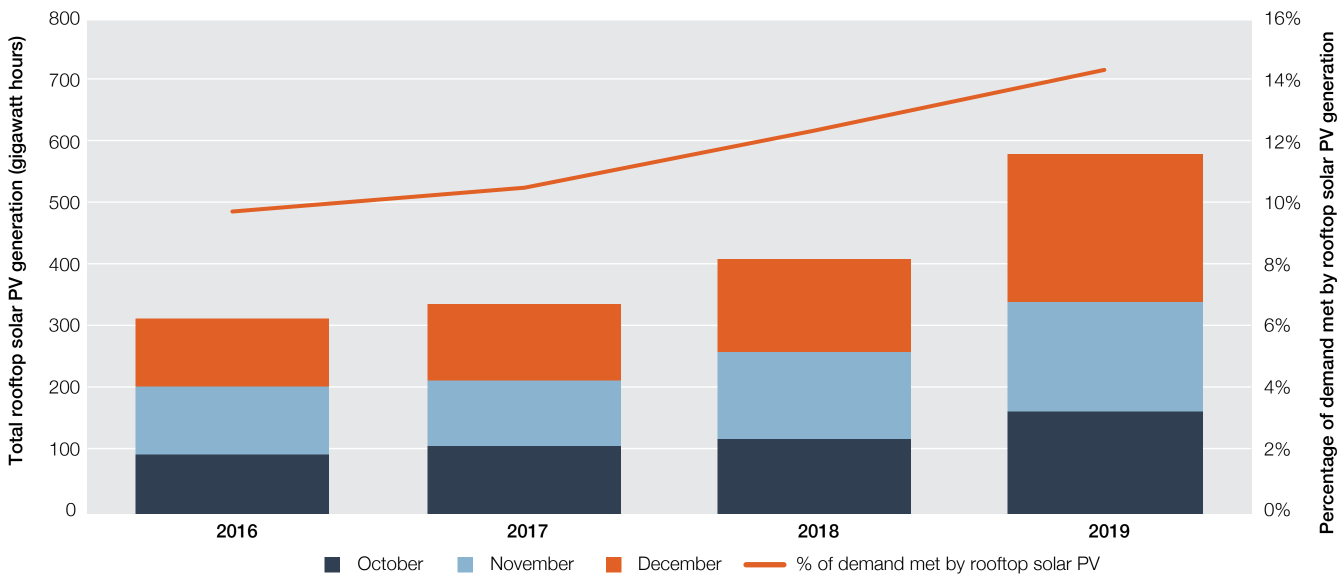
YEAR	SMALL-SCALE - RESIDENTIAL (<15KWH) NO. OF SYSTEMS INSTALLED	CAPACITY OF SYSTEMS INSTALLED (MW)	AVERAGE SIZE OF SYSTEMS INSTALLED (KW)	SMALL-SCALE - COMMERCIAL (15-100KWH) NO. OF SYSTEMS INSTALLED	CAPACITY OF SYSTEMS INSTALLED (MW)	AVERAGE SIZE OF SYSTEMS INSTALLED (KW)
2015	11 635	53.3	4.6	446	13.3	29.8
2016	12 038	58.1	4.8	566	19.6	34.7
2017	15 267	81.1	5.3	923	34.2	37.1
2018	20 538	122.5	6	1349	52.1	38.7
2019*	19 932	130.8	6.6	1200	39.2	32.7

Source: AER analysis using Clean Energy Regulator data.

Note: 2019 data does not cover whole year.

While the number of rooftop solar PV is rapidly increasing, the rate at which new installations are being connected is also increasing. The total installed capacity in South Australia is over 1100 MW. This growth has made small scale solar a significant component in the generation mix. In Q4 2019, rooftop solar PV generation accounted for 14.4 per cent of South Australian demand, up from 9.8 per cent in the same quarter in 2016.

Figure 1.23 Rooftop solar PV generation—South Australia Q4

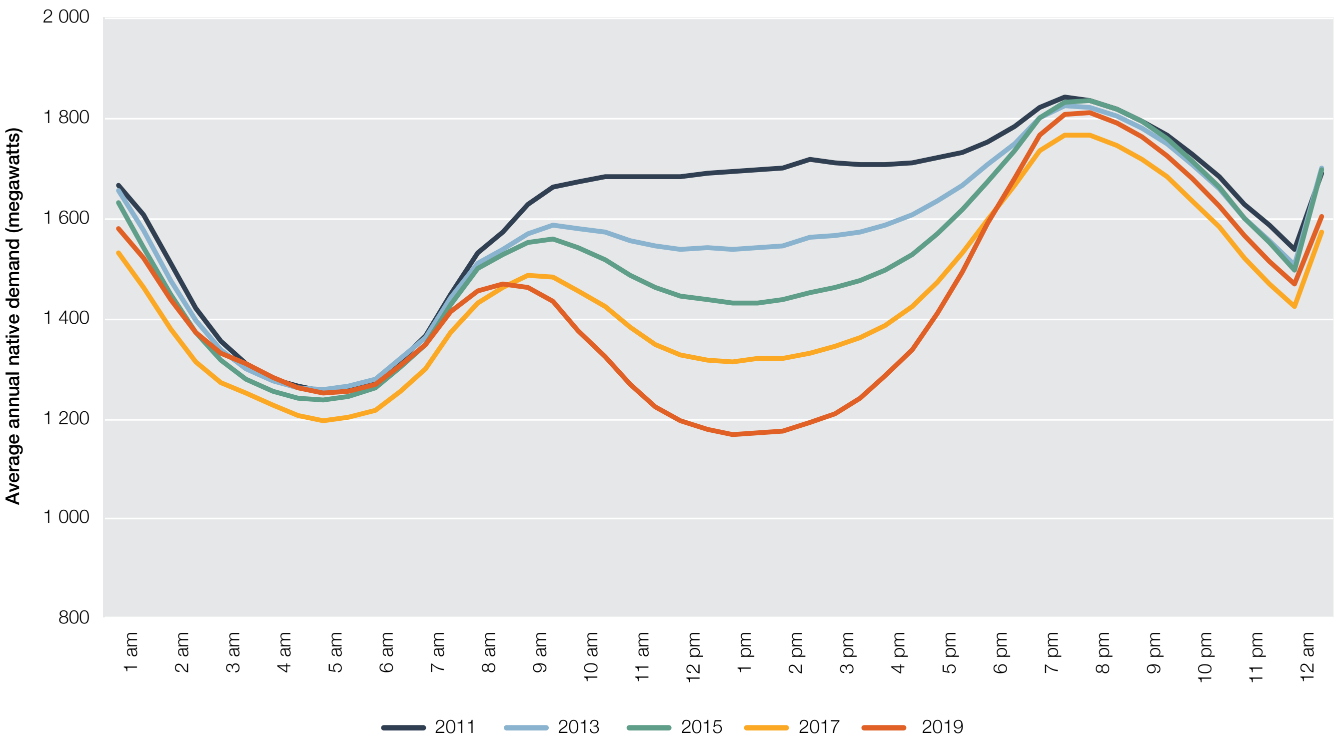


Source: AER analysis using NEM data.

Solar is changing the shape of demand

This growth is dramatically affecting the shape of the native demand curve. During daylight hours houses are drawing from rooftop solar PV instead of the grid. This “missing demand” matches the shape and size of rooftop solar output.

Figure 1.24 Average annual native demand—South Australia



Source: AER analysis using NEM data.

For example, the time of minimum demand has moved from night to daytime. In 2011, 100 per cent of daily minimum demands in South Australia happened between 11 pm and 6.30 am. Now, more than 70 per cent of daily minimum demands occur during daylight hours. The most likely time for a minimum demand to occur is between 11.30 am and 2.30 pm. The change in Q4 is even more dramatic. In 2019, over 90 per cent of daily minimum demands in October and November occurred during the day.

While rooftop solar PV is resulting in some instances of minimum demands happening during the day in other NEM regions, it is happening much less often. This is due to the higher proportion of industrial load that makes up the demand in these regions. In Queensland, where solar rooftop PV penetration sits at around 35 per cent of households, slightly higher than in South Australia, the number of days in which the minimum demand occurs during the day is less than 20 per cent. Victoria and NSW the figure is less than 10 per cent.

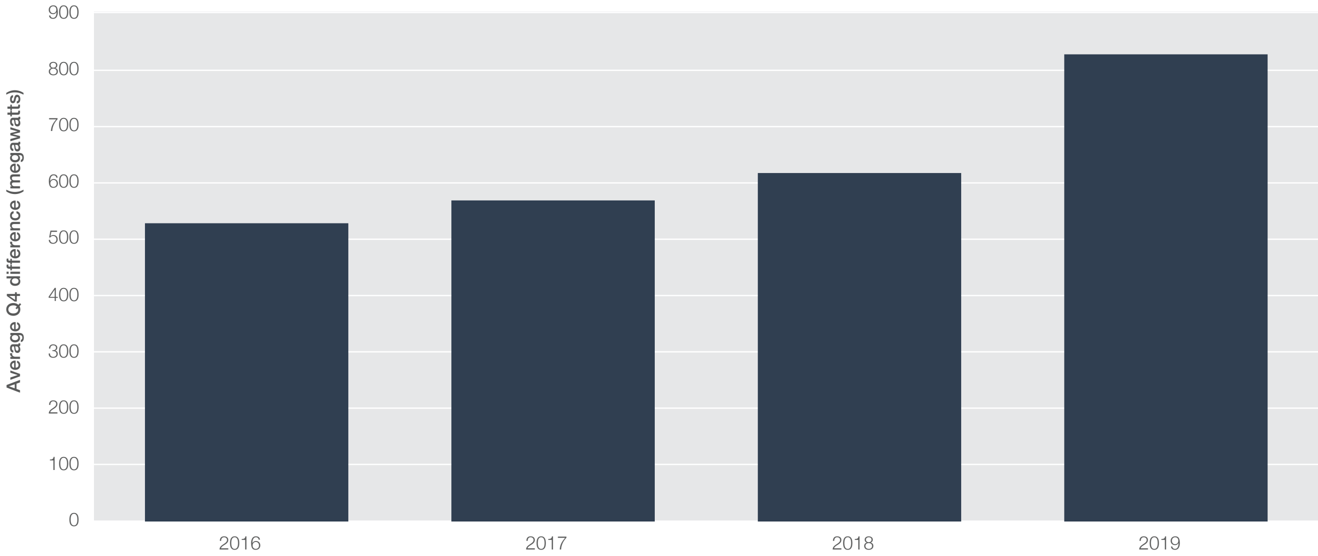
Rooftop solar has little impact on peak demand

In contrast, the time of peak demand hasn't been affected. In 2019 almost half of South Australia's peak demands occurred between 6.30 pm and 7.30 pm, when solar is producing very little. On average, across the year rooftop solar generation during this hour of the day produced just 16 MWh of generation. Even in summer when the days are longer, this number is, on average, only 54 MWh.

Widening gap between maximum and minimum demand

Given that rooftop solar PV is reducing demands during the day but is generally not available at times of peak demand, the gap between minimum and maximum demands is growing. Figure 1.25 shows how minimums and maximum demands have been getting further apart in the past four years. The average daily difference between the minimum and maximum native demand for Q4 increased from 617 MW in 2018 to 828 MW in 2019 (increase of 34 per cent). The majority of this difference is due to reduction in minimum demands from rooftop solar PV.

Figure 1.25 Average difference between daily minimum and maximum demand - South Australia Q4



Source: AER analysis using NEM data.

With solar output being reduced during periods of peak demands, just as much generation from other sources is required to be available to meet the peak demand. This is posing a number of challenges for AEMO and participants leading to a change in how traditional baseload units are operated. Older gas and coal units do not have the flexibility to turn off during the day when demands are low and return for the evening peak. As a result, generators are having to change the way that their units are operating and also how they structure their bids.

What about batteries?

As rooftop solar PV continues to grow, the changes to the shape of demand—lower minimums with unchanged peaks—will increase the value battery storage systems can provide. However, total installed battery capacity is still too small to make a significant impact. To date, over a quarter of a million small scale rooftop PV systems have been installed in South Australia. Less than 2500 of these were installed with concurrent battery storage capacity. This represents less than 1 per cent of all installed systems. Battery installations are on the rise though. In 2018, 5.1 per cent of rooftop solar systems installed in South Australia had battery storage capacity (up from 3.8 per cent the previous year).

Focus—Drivers of increased FCAS costs

- Changes in participants' offers and requirements has led to high regulation FCAS prices and costs over recent quarters.
- The increase in requirements, and to a lesser extent changes in the effective availability, in the raise 60 second and raise 6 second services contributed to increased prices and costs.
- The decrease in the requirement and increase in the effective availability below $1 per MW has caused a decrease in price and cost in raise 5 minute services from Q1 2019.

In Q4 2019, quarterly FCAS costs increased to their highest level since 2008. This focus story looks at the two main drivers for the increase:

- a change in participant offers
- an increase in the amount of FCAS required by AEMO.

It also builds on the FCAS focus story from our *Wholesale markets quarterly—Q3 2019*.

The costs and prices for regulation and raise contingency FCAS services have increased over the recent quarters (figure 1.18 and figure 1.19). The exception is for raise 5 minute services, which has decreased in cost and price.

Regulation FCAS services

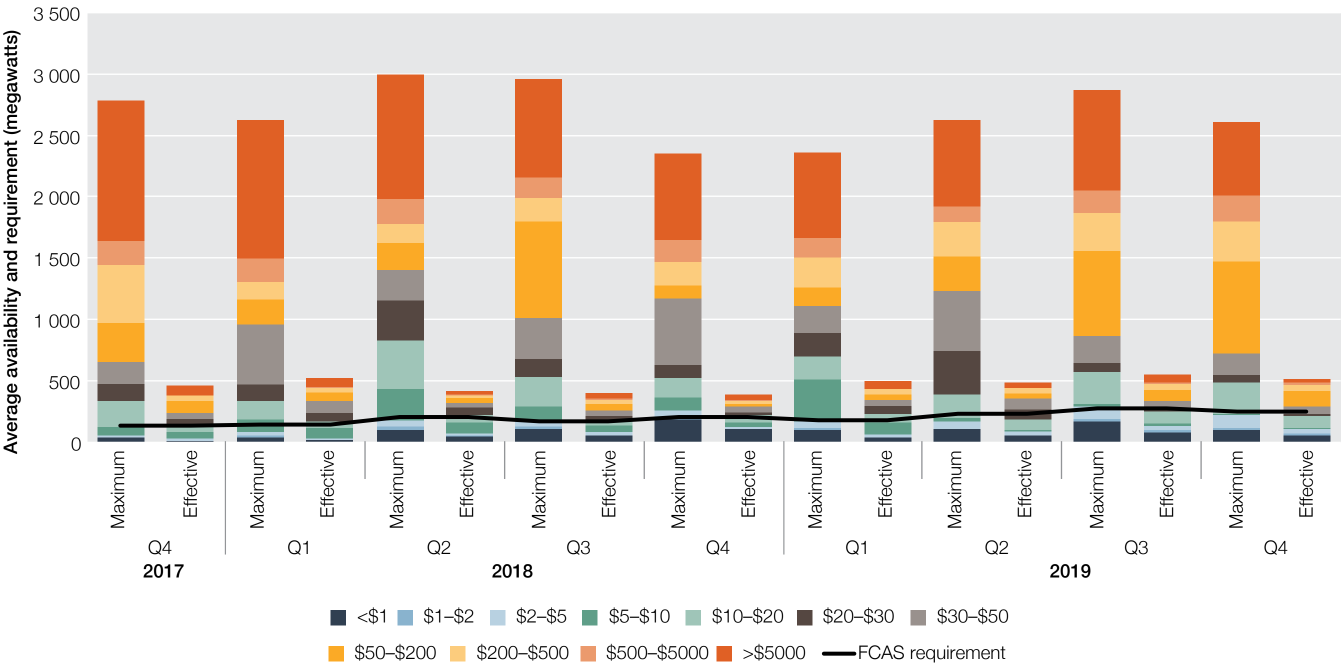
The increase in regulation costs has been driven by a decrease in low priced capacity and an increase in the requirement for regulation services. Having changed most significantly, we use raise regulation below in our examples explaining the outcomes we have observed.

Change in participants' offers

Effective availability accounts for around 20 per cent of the maximum availability for raise regulation services (figure 1.26). The difference between maximum availability and effective availability is due to the trade-off between the FCAS and energy markets. For example, a generator that is operating at its maximum capacity cannot provide raise services so their effective available capacity for raise services would be zero. So, in other words only a fifth of raise regulation services offered by participants can actually be used.

Over recent quarters, the effective capacity of raise regulation services priced between $5 and $10 per MW has decreased, while that between $10 and $20 per MW has increased significantly. In Q4 2019, average effective availability priced between $0 and $30 per MW decreased by 55 MW compared to Q3 2019.

Figure 1.26 Raise regulation maximum and effective availability



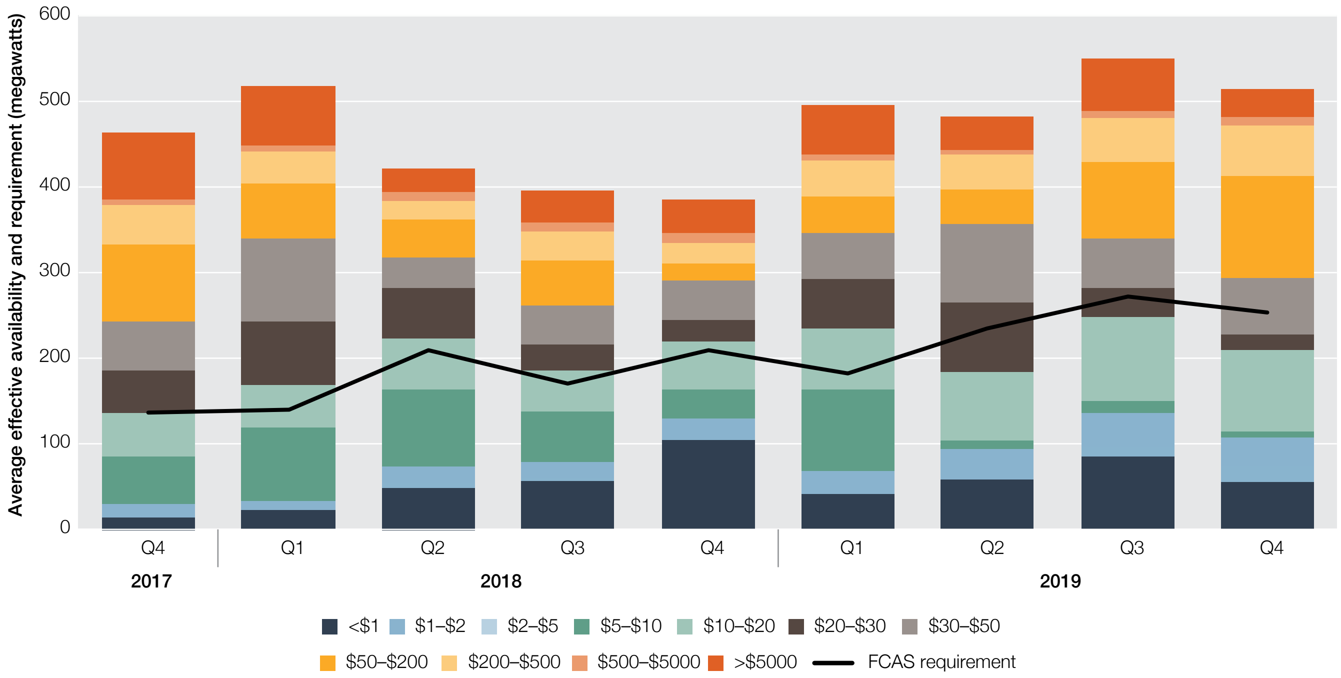
Source: AER analysis using NEM data.

Change in regulation FCAS requirements

As highlighted in our Q3 2019 report, AEMO has increased mainland regulation FCAS on several occasions recently due to deteriorating frequency performance. This coincides with the amount and cost of regulation services enabled increasing.

Raise regulation requirements have been increasing since Q4 2017 (figure 1.27). In Q4 2019, the average raise regulation FCAS requirements dropped about 19 MW from record levels in Q3 2019, but remained high. Costs remained high as the decrease in regulation FCAS requirements did not fully offset the reduction in low priced capacity. The average price for raise regulation services reached a record of $46 per MW in Q4 2019. Lower regulation services followed a similar trend.

Figure 1.27 Raise regulation effective availability and requirement



Source: AER analysis using NEM data.

Raise contingency FCAS services

The increase cost in contingency services, especially raise services has been driven by changing offers and to a lesser extent an increase in requirements for those services. Except for raise 5 minute services, which has had a decrease in costs.

Raise 6 and 60 second services

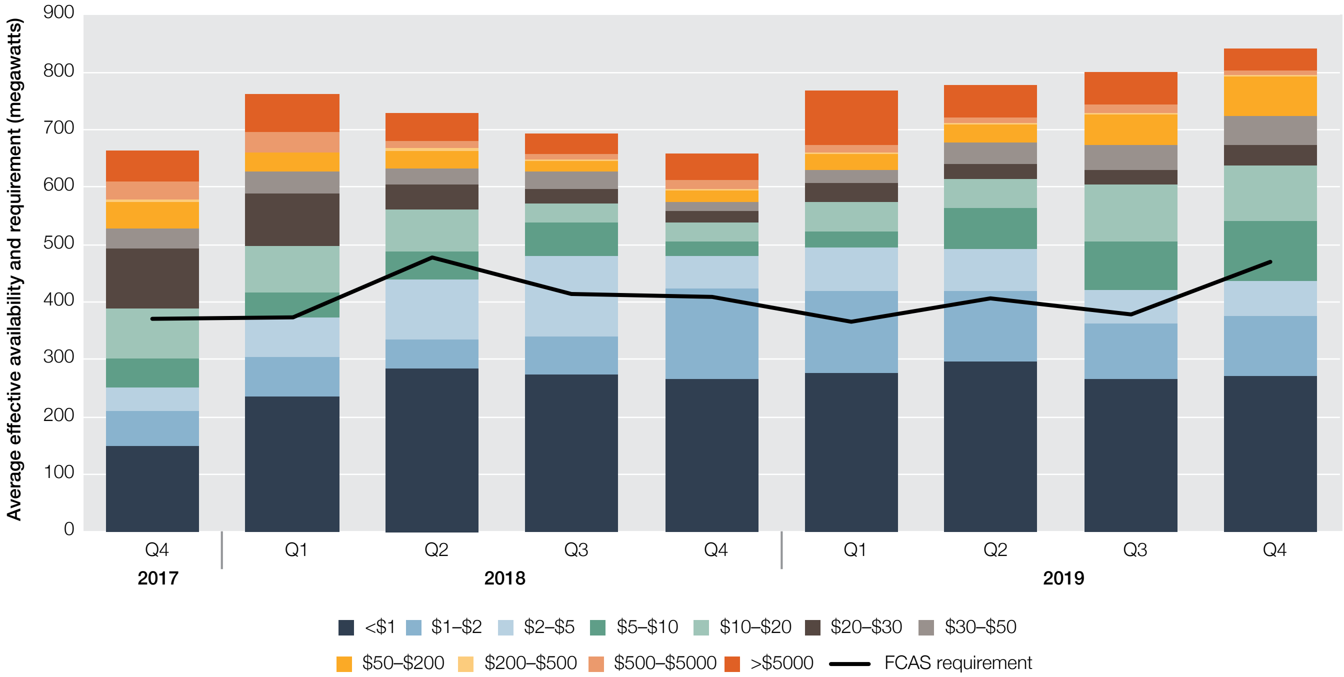
AEMO changed the way it calculates contingency FCAS requirements and stated the change will materially increase contingency FCAS requirements. It indicated an increase was likely to occur from September 2019.[7]

The requirements for raise 6 and 60 second services have increased since Q1 2019 with raise 6 second requirements increasing by 105 MW and raise 60 second increasing by 107 MW with a big increase in this quarter. As well as the increase in the requirement, there has been a change in participants' offers.

For raise 6 second services, which has had the biggest increase in costs, effective availability below $2 per MW dropped and that between $5 and $10 per MW increased (figure 1.28). For raise 60 second services, capacity below $2 per MW increased and that between $2 and $5 per MW dropped when compared with Q1 2019. Combined, these have caused average prices to increase from $3 per MW in Q1 2019 to $11 per MW in Q4 2019 for raise 6 second services and $4 per MW to $9 per MW for raise 60 second services.

7 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 1.28 Raise 6 second effective availability and requirement



Source: AER analysis using NEM data.

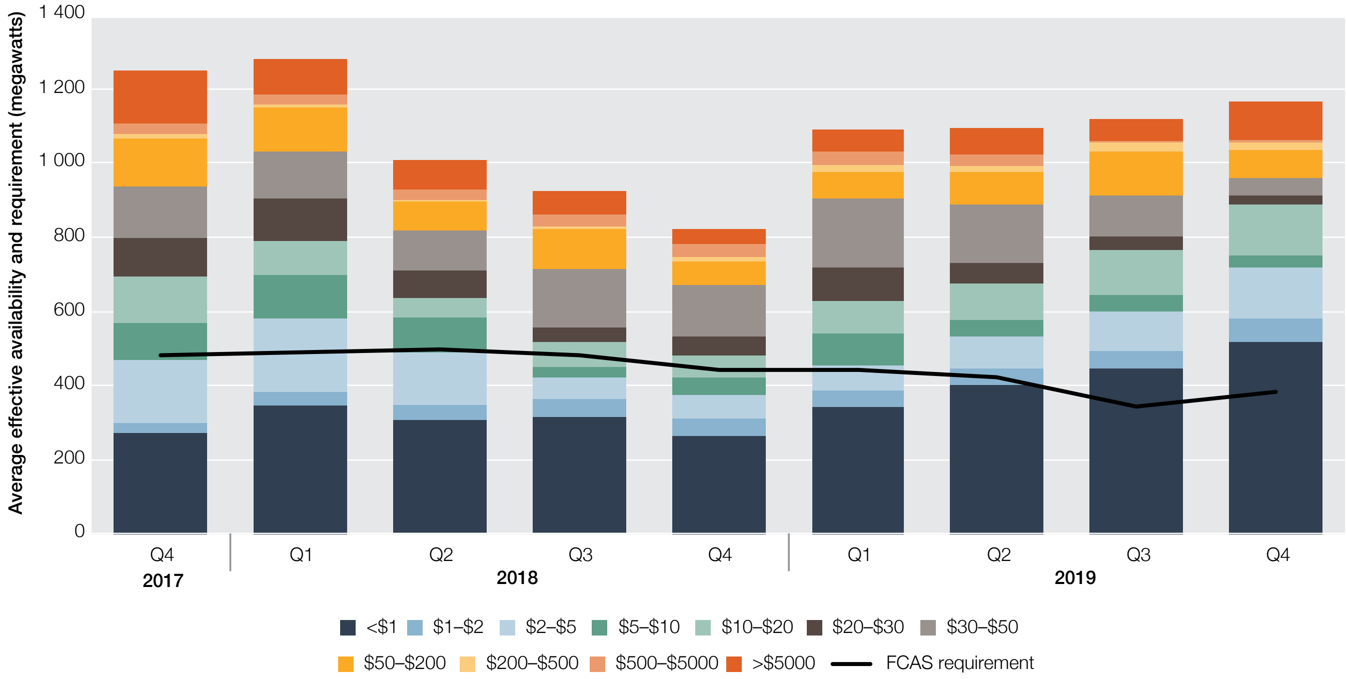
Raise 5 minute services

Unlike the other raise contingency services the cost of raise 5 minute services has fallen, due to an increase in low priced capacity and to a lesser extent a reduction in requirements for the service. Consequently, the raise 5 minute price has decreased to around $1 per MW, the lowest since Q4 2015.

Figure 1.29 shows an increase in capacity priced below $1 per MW and a decrease in capacity priced between $2 and $5 per MW. In addition, the average effective availability below $1 per MW increased from 271 MW in Q4 2017 to 516 MW in Q4 2019.

The requirement for raise 5 minute services was decreasing until this quarter when it increased (as forecast in the Q3 2019 report).

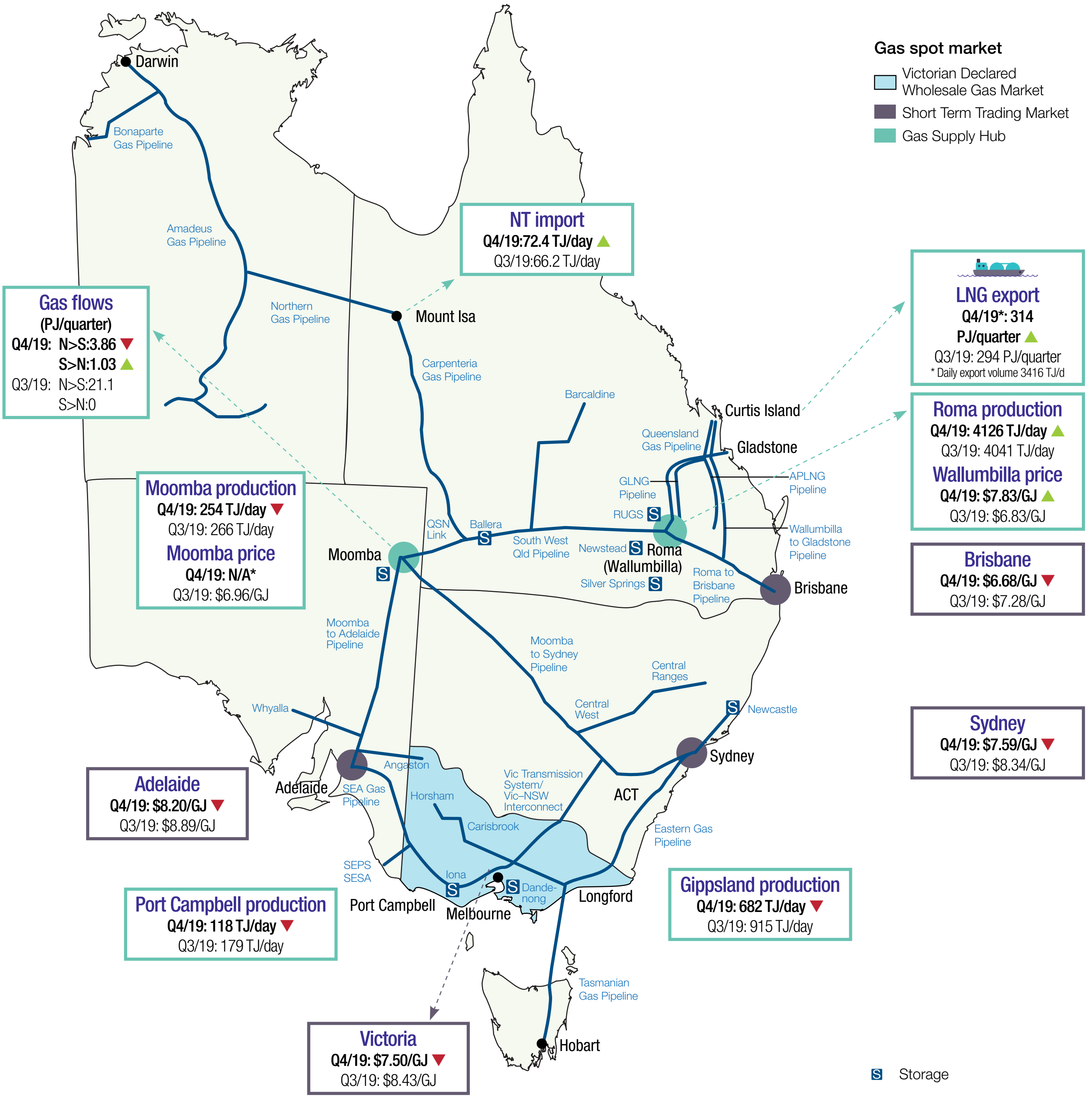
Figure 1.29 Raise 5 minute effective availability and requirement



Source: AER analysis using NEM data.

2. Gas

Figure 2.1 Eastern gas markets, major production, pipelines and storage



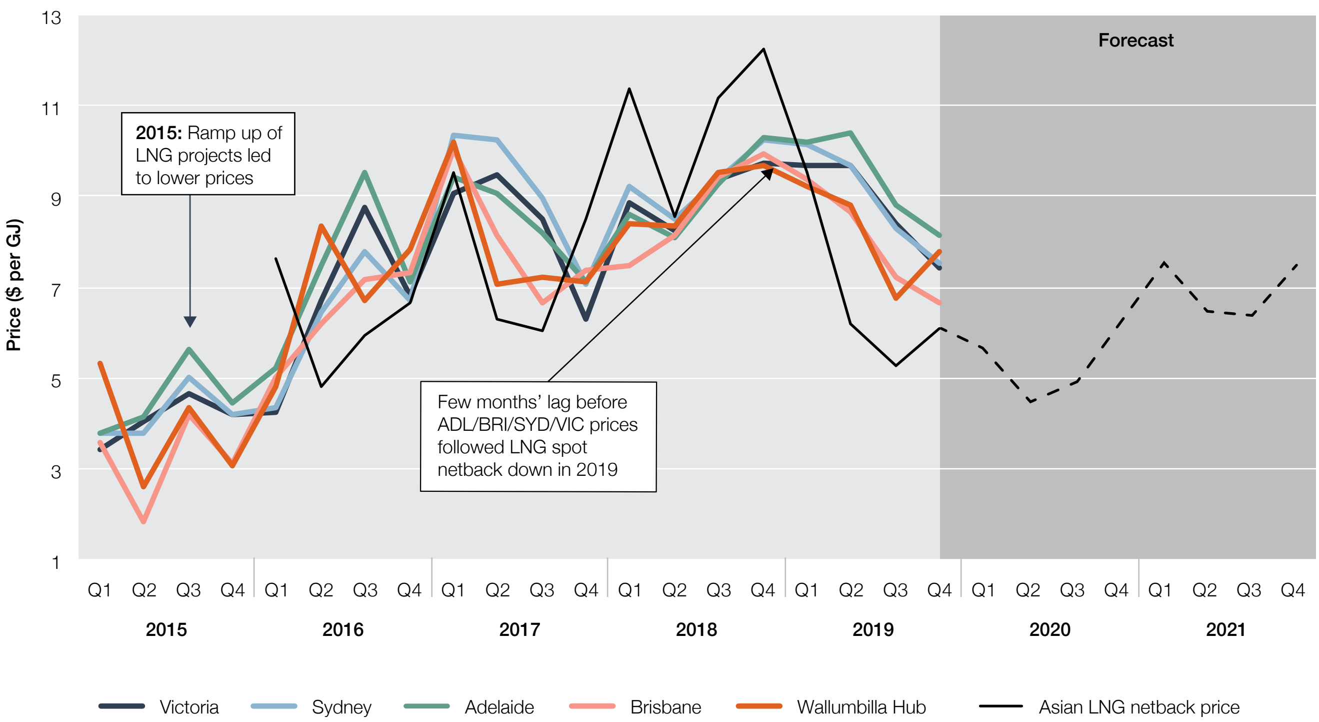
*No exchange trade occurred in the Moomba hub in Q4

Note: Northern markets consist of Wallumbilla, Moomba and Brisbane (including gas imported from NT). Southern markets include Adelaide, Sydney and Victoria.

2.1 Quarterly spot prices

- Prices in downstream spot markets continued to decline from Q3 with prices in Adelaide remaining the highest in the South.
- Prices at the upstream production hub at Wallumbilla in Queensland increased, in line with increases in Asian LNG spot prices.
- Overall, domestic spot prices converged closer to an Asian LNG spot netback price.

Figure 2.2 Domestic spot prices and Asian LNG spot netback price



Source: AER analysis using DWGM, STTM, WGSH 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.

Downstream gas spot prices ranged between $6.68 per gigajoule (GJ) in Brisbane and $8.20 per GJ in Adelaide over Q4 2019 and declined in all markets compared to the previous quarter.

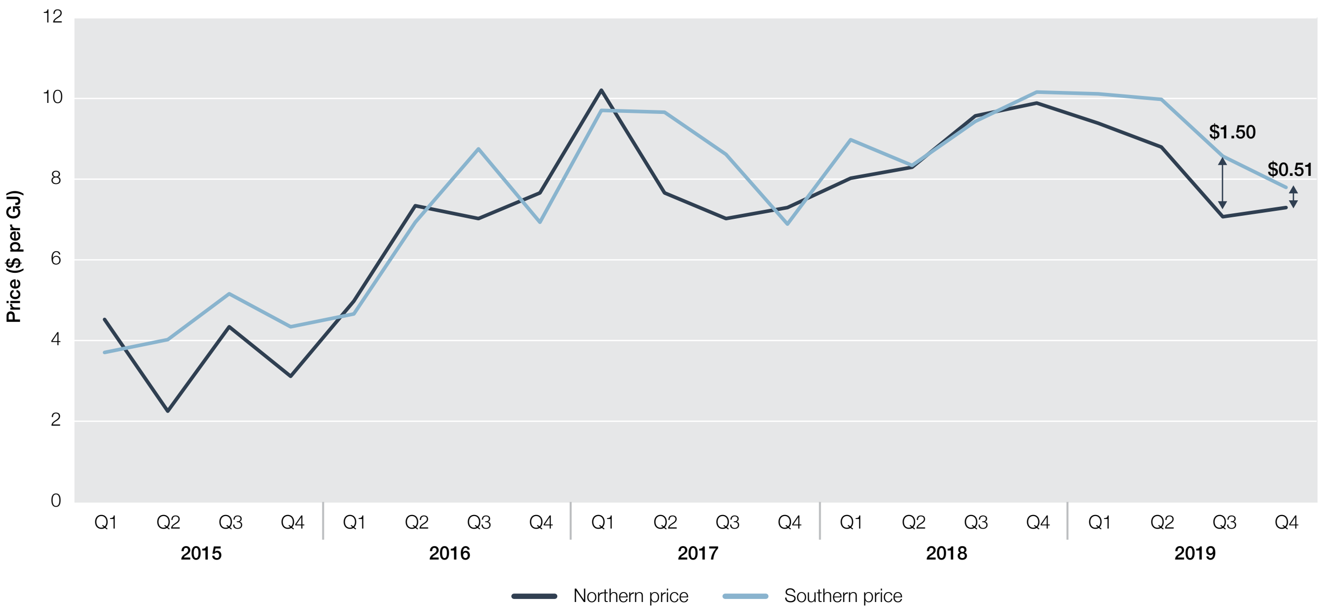
The upstream Wallumbilla Hub day-ahead, exchange traded gas spot price increased by about $1 per GJ from Q3 2019 to $7.83 per GJ. However, the price paid for off screen, bilateral day-ahead trades only went up to $7.28 per GJ—indicating a significant benefit to being able to purchase bilaterally. The rise in the Wallumbilla price coincided with upward movements in the Asian LNG spot netback price by $1.08 per GJ.

The Asian LNG spot netback price, calculated at Wallumbilla was $1–2 per GJ below downstream spot prices in Q4 2019. This means downstream spot prices were closely aligned with that netback price, factoring in recovery of domestic transportation costs of $1–2 per GJ to those markets.

Prices in Victoria and Sydney fell below $8 per GJ in Q4 2019, a level not seen since Q4 2017. Brisbane recorded the lowest prices, reflecting a large step increase in gas sales offered at prices below $4 per GJ.[8] Although a number of factors may affect domestic spot prices (see appendix), the following factors appeared to have driven this outcome:

- Queensland gas production increased significantly from approximately 4041 TJ per day in Q3 2019 to 4126 TJ per day in Q4 2019.
- Demand declined by 32 per cent from Q3 2019, reflecting a decline in residential/industrial demand in the South as well as lower gas consumption by electricity generators.
- Continued competition in sales of spot gas among larger players also appears to be placing downward pressure on southern market prices.

Figure 2.3 North-South commodity price gap



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

Note: The Q4 2019 figures have been amended from figures published in the Q3 2019 report.[9]

The Q4 2019 price gap between northern and southern markets highlighted in figure 2.3 narrowed from Q3 but still remained relatively spread at $0.51 per GJ when compared to Q4 results of previous years.

8 See section 2.4 Downstream markets for information about increased competition from sellers into gas markets.

9 Northern price figures have been revised to reflect corrections to our estimation methodology.

2.2 East Coast outcomes

- Production in Roma, Queensland increased to reach a new record quarterly high.
- Flows from Queensland to southern markets declined significantly, yet net flows continued southward for the third consecutive quarter.

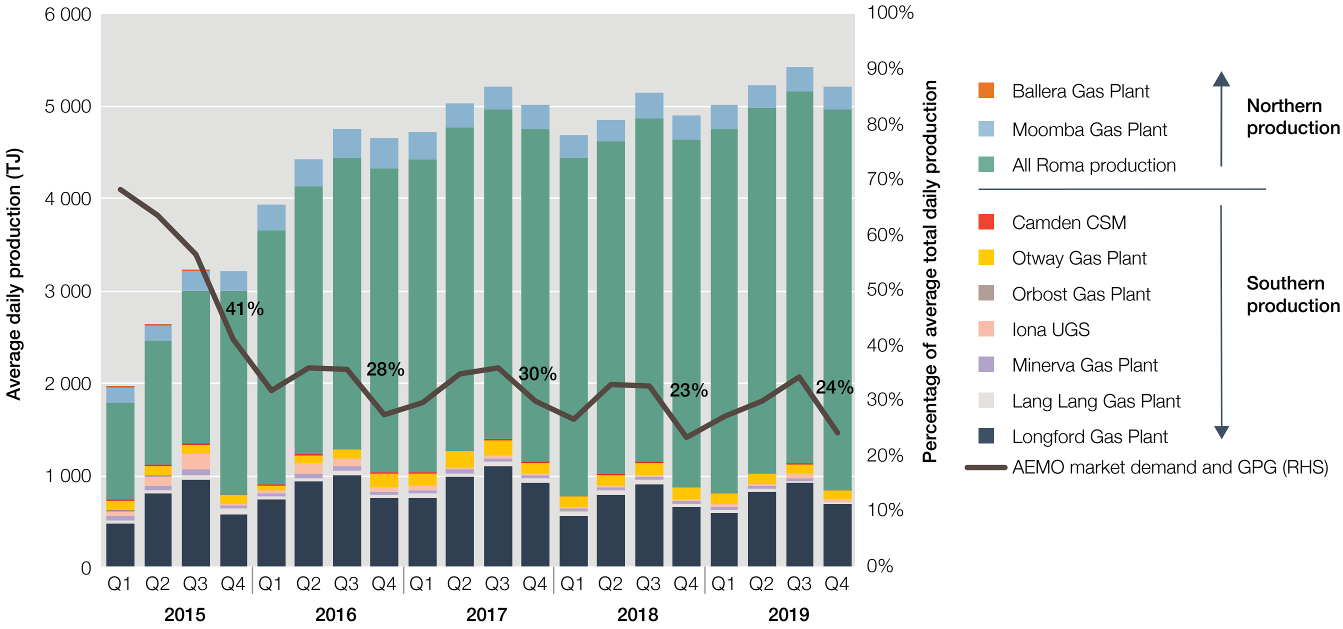
EAST COAST WIDE SNAPSHOT													
	Eastern States Combined[b]					BRI	VIC	SYD	ADL	BRI	VIC	SYD	ADL
	2015	2016	2017	2018	2019	Q4 2018				Q4 2019			
average spot market price, $/GJ	$4.03	$6.73	$8.56	$9.11	$8.82	$10.01	$9.80	$10.29	$10.35	$6.68	$7.50	$7.59	$8.20
						$10.11				$7.49			
total net market trade volume, PJ[a]	25.2	24.1	33.6	30.7	45.9	0.32	4.34	2.13	0.88	0.56	6.35	3.76	0.97
						7.7				11.6			
spot trade as a proportion of scheduled demand (%)	6.5%	6.2%	8.1%	8.1%	11.7%	6.0%	9.1%	10.6%	18.8%	8.2%	12.3%	19.3%	21.9%
total GPG, PJ	185	146	187	140	163	7.8	5.0	2.1	13.2	9.8	5.7	5.5	13.6
						28.1				34.6			
total production, PJ	976	1605	1815	1781	1896	449				478			
LNG export, PJ	317	950	1101	1119	1204	296				314			
(+) total import from North, PJ	+22.4	+1	+9	+19	+40.8	+0.01				+3.86			
(-) total export to North, PJ	-7.2	-72.4	-48.4	-15.9	-5.5	-9.67				-1.03			
average underground gas storage level, PJ	N/A	N/A	N/A	N/A	95.5	96.4				89.6			

a January 2015 net market trade volume for Victoria was estimated due to unavailability
b Eastern states include Queensland, Victoria, NSW and South Australia

Production

Figure 2.4 shows east coast gas production averaged 5220 TJ per day over Q4 2019, a decrease of 214 TJ per day from Q3 2019. Total production comprised declines in southern market production but increased production in Queensland.

Figure 2.4 East Coast production



Source: AER analysis using Natural Gas Services Bulletin Board data, NEM data, DWGM and STTM data.

Note: The Q4 2019 figures have been amended from figures published in the Q3 2019 report.[10]

Gas production in Queensland reached a record quarterly level of 4126 TJ per day compared to the previous quarterly record of 4041 TJ per day in Q3 2019. Gas production in Queensland has increased significantly over 2019 and has contributed to reductions in prices across east coast markets with more gas being widely available. Higher Queensland production occurred, peaking in October 2019, despite a reduction in domestic demand from 1875 TJ per day in Q3 to 1274 TJ per day in Q4. This decline is typical at this time of year when heating demand is low, industry reduces output during holidays, and gas powered generation is called upon less to provide electricity supply.

New production facilities in Queensland and the NT registered to report production on the Gas Bulletin Board during Q4 2019. These included Yelcherr gas plant (Blacktip) (108 TJ per day) in the NT and Roma North (16 TJ per day), and Yellowbank (10 TJ per day) in Queensland.

A decline in southern production, from Q3 to Q4 2019, was mostly attributable to the Longford production facility, which produced 682 TJ per day in Q4, compared to 915 TJ per day in Q3. The Q4 2019 Longford production of 682 TJ per day is slightly larger than 648 TJ per day in Q4 2018. The Longford facility announced a number of offshore and onshore maintenance events as reason for production volumes below nameplate capacity of 1115 TJ per day.

10 The figure sources latest data bulletin board data which has been retrospectively updated for Q3 2019.

In Q4 2019, Roma production accounted for approximately 4126 TJ per day, around 80 per cent of total east coast production. This is a significant increase in production from Q4 2018, when production was 3762 TJ per day. Table 2.1 shows the composition of the largest production fields in Roma. The Ruby Jo and Eurombah Creek production facilities together added an additional 49 TJ per day to total production volumes during Q4 2019 compared to the previous quarter.

Table 2.1 Gas production in Roma, Queensland (TJs per day)

PRODUCTION FACILITY	PRODUCTION VOLUMES Q3 2019	PRODUCTION VOLUMES Q4 2019	NAMEPLATE CAPACITY
Wolleebee Creek (QGC)	644	617	757
Ruby Jo (QGC)	409	437	503
Fairview (Santos)	402	403	430
Jordan (QGC)	332	326	507
Combabula (APLNG)	262	279	286
Orana (APLNG)	186	195	197
Bellevue (QGC)	194	190	243
Condabri south (APLNG)	178	184	190
Eurombah Creek (APLNG)	152	173	190
Condabri central (APLNG)	168	164	190

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

Note: QGC is the name of an upstream entity operated by Shell.

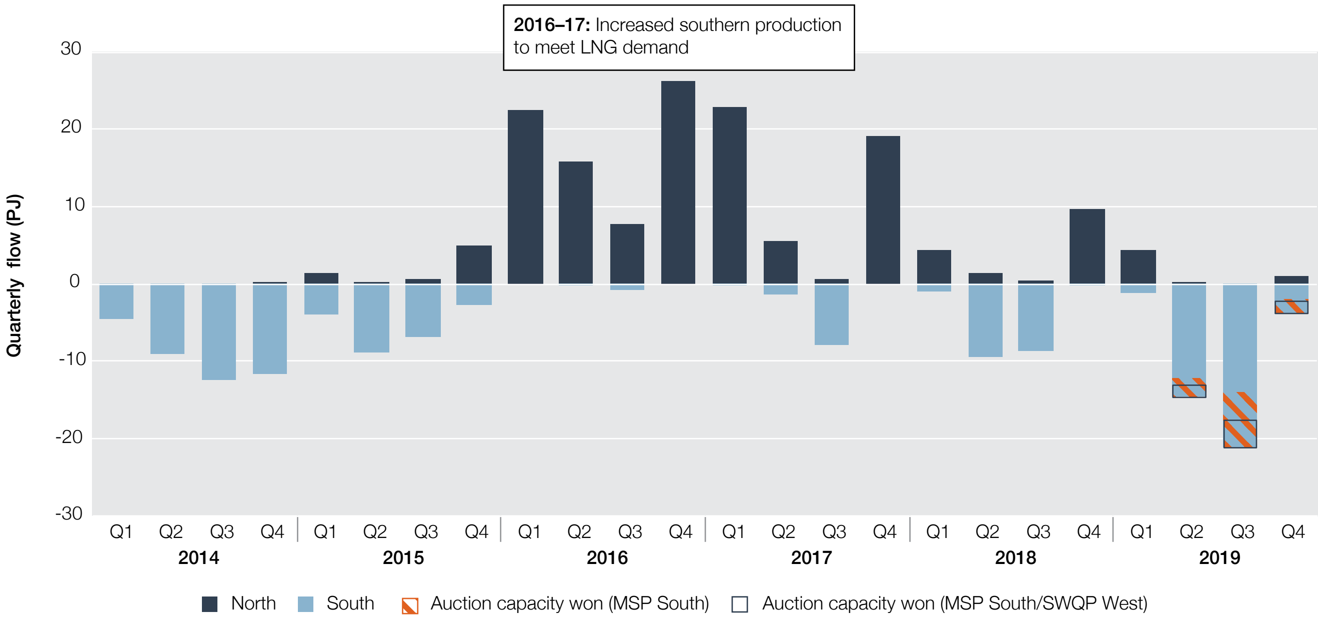
Flows between north and south

Since 2016, production in Queensland has risen, resulting in less gas needing to be sourced from southern states to produce LNG for Queensland exports.

Figure 2.5 shows that gas has typically flowed from southern markets to Queensland during Q4, coinciding with times of high LNG export volumes. However, in Q4 2019, net flows have been southward, with only 1026 TJ moving north from southern markets compared to 9667 TJ during the same period the previous year. As Queensland reached record production volumes in Q4 2019, there has been less reliance on gas from southern markets to meet increasing LNG export demand.

Gas flows from northern markets southbound also reduced significantly; however, the net flow stayed southwards for the third consecutive quarter as southern residential and gas powered generation demand declined. Additionally, as prices converged across markets, there may have been less incentive to arbitrage price differences, resulting in less gas flowing gas south. Nevertheless, the auction of pipeline capacity did aid the flow of gas south for participants wishing to arbitrage.

Figure 2.5 North-South gas flows



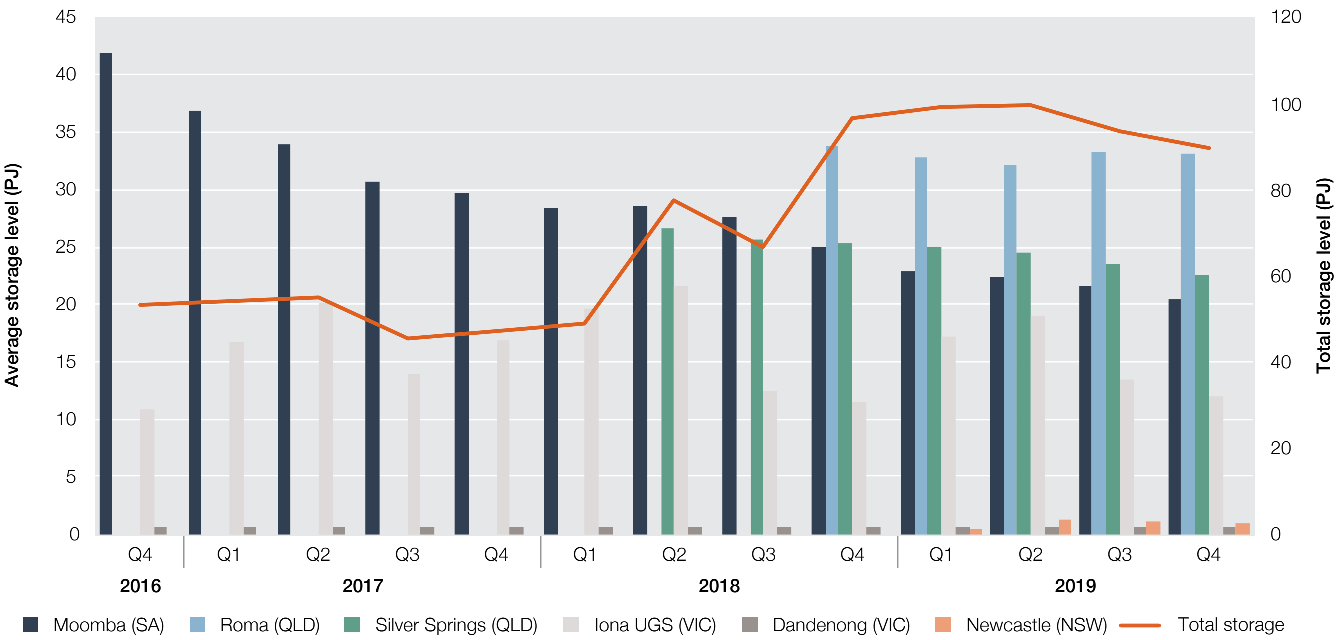
Source: AER analysis using the Natural Gas Services Bulletin Board and Day Ahead Auction data.

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

Storage

Figure 2.6 average gas storage levels in Victoria were lower than Q3 2019. In states outside of Victoria, a number of large storage facilities have been consistently drawn down, particularly as LNG export facilities were commissioned from 2015. These storage facilities do not show a seasonal usage profile, as does Victoria.

Figure 2.6 Storage levels



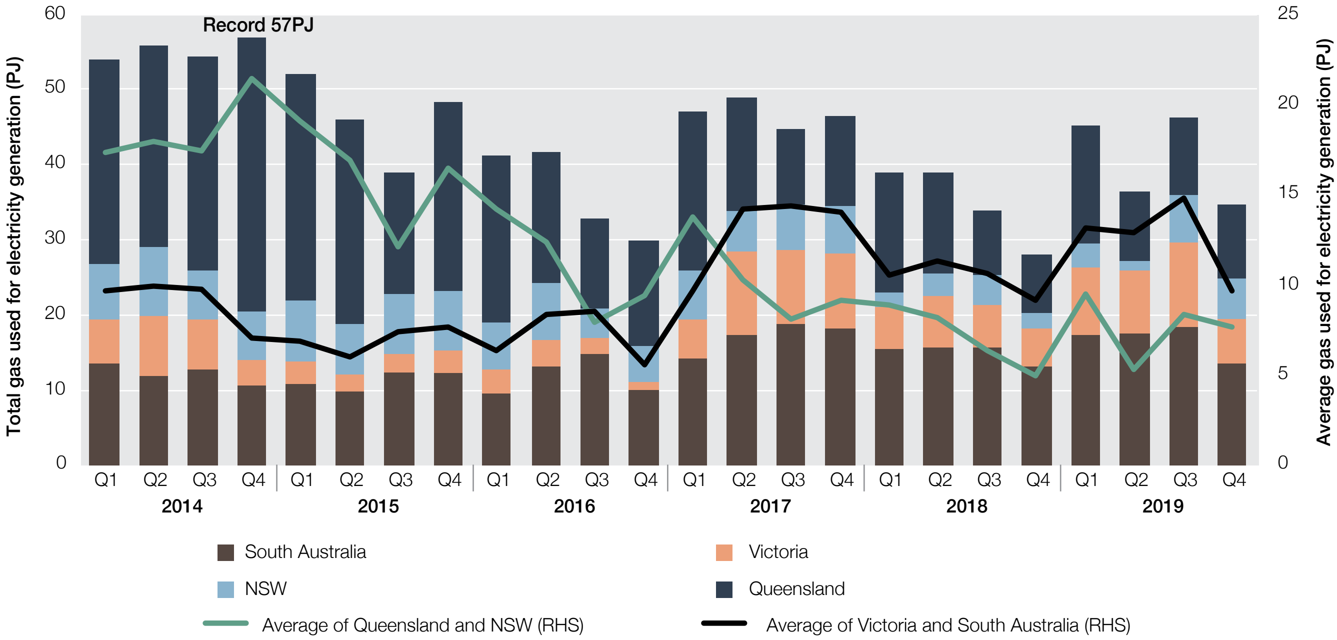
Source: AER analysis using Natural Gas Services Bulletin Board data.

Note: Roma, Silver Springs underground storage facilities are long established facilities but only commenced reporting of storage data pursuant to legislation in 2018.

Gas powered generation demand

Figure 2.7 shows gas demand for electricity generation declined in Q4 2019 from Q3 across all states. As outlined in the electricity component of this report (table 1.1), a number of baseload generators underwent outages, which required some gas powered generation to support electricity supply in the NEM. Following the return to service of baseload generators during the quarter, gas demand for generation declined.

Figure 2.7 Gas powered generation



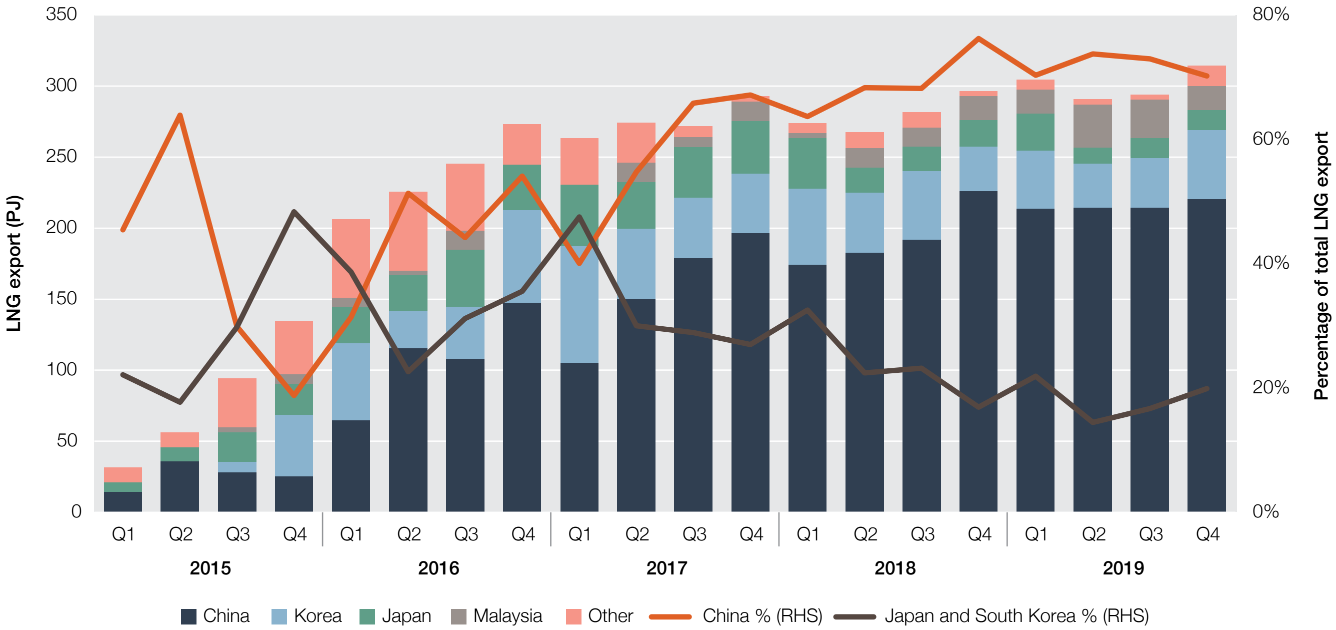
Source: AER analysis using NEM data, ACIL Allen data.

2.3 Upstream market outcomes

- East Coast LNG exports reached a quarterly record as Australia became the largest global LNG exporter in 2019 based on WA/NT/Qld export calculations.
- Day Ahead Auction volumes decreased this quarter at the same time as less gas flowed south. However auction capacity was won on the Berwyndale to Wallumbilla Pipeline and the Moomba Compression Facility for the first time.
- Wallumbilla exchange reported trades were down from Q3 2019 but up compared to Q4 2018, with trade overall continuing to be skewed towards off screen bilateral trades.

LNG exports

Figure 2.8 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Ports Corporation data.

Record exports from Gladstone contributed to Australia overtaking Qatar as the world's largest exporter of LNG.[11] Total export volumes from Queensland was 1204 PJ for 2019, an increase of 84 PJ from 2018.

As the largest buyer of Gladstone LNG, China absorbed increased Queensland gas production receiving 88 PJs more in 2019 than in 2018. Figure 2.8 shows greater than 70 per cent of cargoes being marked for China from Gladstone over 2019. A key Chinese policy initiative underpinning LNG demand has been to mandate targets for switching heating fuels from coal to gas to reduce carbon emissions and improve air quality.[12]

Japan has steadily been re-starting nuclear reactors for power generation since the Fukushima nuclear meltdown. Figure 2.8 shows a steady decline in LNG exports to Japan over the time that nuclear restarts have occurred.[13]

South Korea has been transitioning away from coal and nuclear toward gas for electricity generation which is reflected in an increase in its LNG imports since Q3 2018.[14]

11 Australian Financial Review, Australia beats Qatar to become world's No.1 LNG exporter, 6 Jan 2020 referring to analysis performed by Energy Quest.

12 Department of Industry Innovation and Science, Resources and Energy Quarterly, December 2019, p. 57.

13 Department of Industry Innovation and Science, Resources and Energy Quarterly, December 2019, pp. 56–57.

14 Department of Industry Innovation and Science, Resources and Energy Quarterly, December 2019, p. 59.

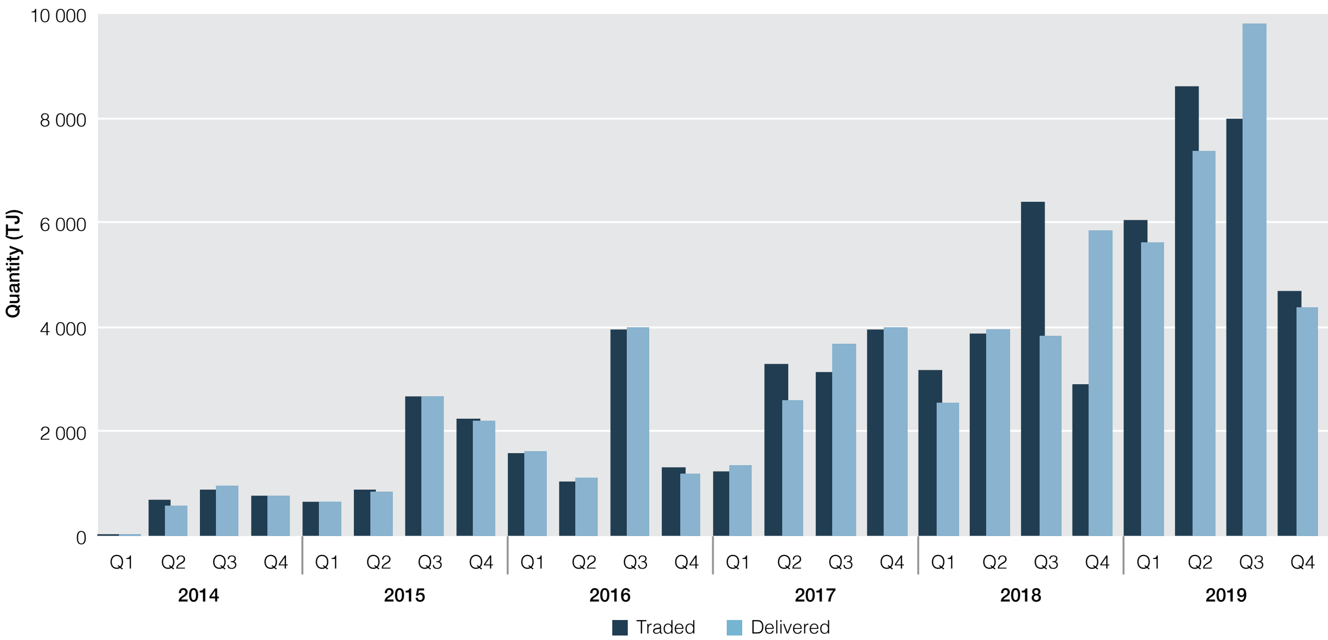
Gas Supply Hub outcomes

GAS SUPPLY HUBS SNAPSHOT	2014	2015	2016	2017	2018	2019
number of trades	481	875	798	1638	1919	3635
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%*
trade value, $million	5	24	57	89	148	219
volume weighted average price, $/GJ	2.01	3.66	7.20	7.68	9.02	7.98
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*
% traded through exchange (sum bought divided by regional demand)	N/A	N/A	N/A	4.3%	6.1%	9.1%

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

In Q4 2019, traded quantities at the GSH rose from Q4 2018 levels, despite falling from highs across 2019 (figure 2.9). Delivered quantities were lower than the same time last year, however this reflects the high number of monthly products traded in Q3 2018, which were delivered into Q4 2018.

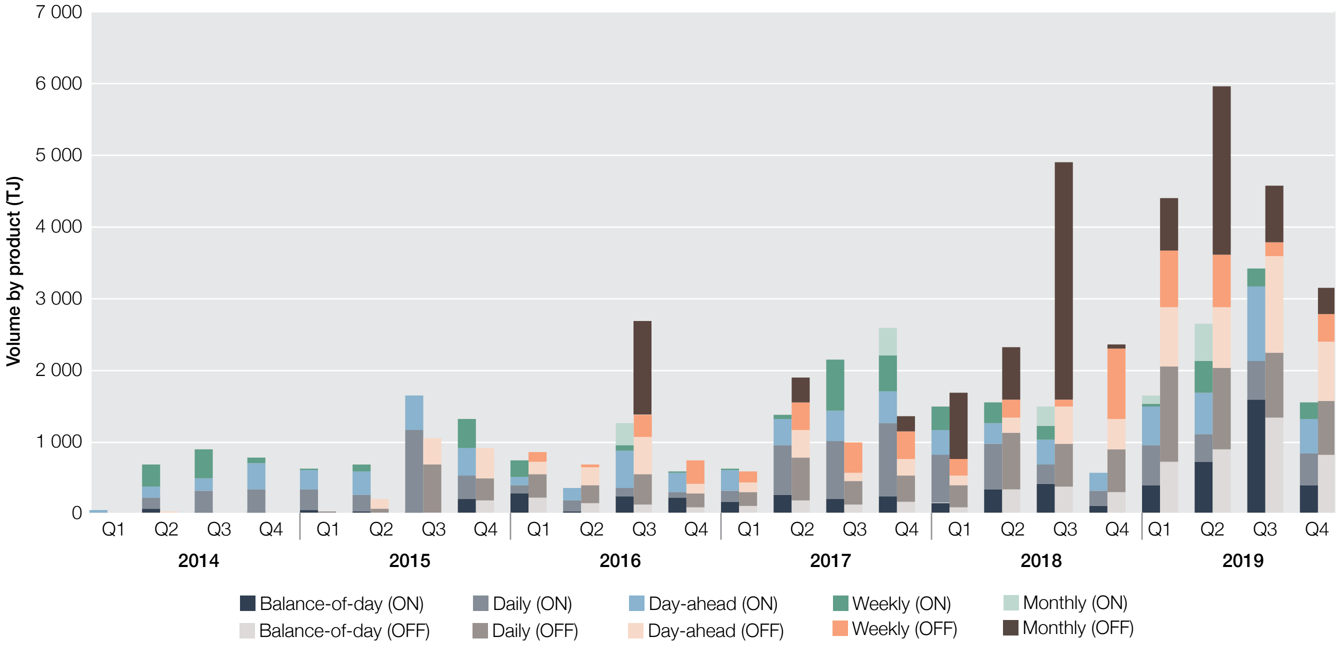
Figure 2.9 Gas supply hub—traded and delivered quantities



Source: AER analysis using GSH trades data.

In total, there was just over 4700 TJ of gas traded this quarter across 703 transactions. Overall, participants continued to show a preference for off screen trading, with more than twice the volume of gas traded off screen than on screen across Q4 2019 (figure 2.10). Further, analysis of the day ahead prices for on screen as compared to off screen trades indicates on average this product cost 55 cents per GJ more if purchased on screen ($7.83 per GJ). We are continuing to monitor the liquidity of the on screen market.

Figure 2.10 Gas supply hub—On and off screen trade volumes by product



Source: AER analysis using GSH trades data.

Compared to the same time last year, most products traded at higher levels in Q4 2019, reflecting the general increase in activity we saw across 2019, particularly for balance of day, daily and day ahead products. Weekly products are the exception, trading at lower levels this quarter than in Q4 2018.

The number of participants trading in the GSH rose to 16 as two new participants commenced trading this quarter.[15]

Despite the rise in active participants in 2019, market concentration saw mixed outcomes. The top three buyers for 2019 accounted for 51 per cent of volume traded, down from 53 per cent last year. However, the top three sellers for 2019 were responsible for 64 per cent of volume traded, and increase from 52 per cent in 2018.

Table 2.2 Gas supply hub—Churn rate by Hub[16]

QUARTER	MOOMBA	WALLUMBILLA	QUARTER	MOOMBA	WALLUMBILLA
Q1 2017	-	2.0%	Q3 2018	0.1%	5.6%
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%

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

Note: The Q4 2019 figures have been amended from figures published in the Q3 2019 report.[17]

The total annual churn rate ended the year at 9.1 per cent. When treated separately, the Wallumbilla hub fell down to 6.1 per cent in Q4 2019 (table 2.2). The Moomba hub churn rate rose compared to Q4 2018, achieving a 0.4 per cent churn rate for this quarter.

15 See list of participants under figure 2.12 under section 2.4.

16 Churn rate refers to the per cent traded through the exchange, calculated as sum of gas bought divided by regional demand. N/A results are those quarters where there was no gas traded on the Moomba Hub.

17 These figures have been revised to reflect corrections to our estimation methodology.

Day Ahead Auction outcomes

DAY AHEAD AUCTION SNAPSHOT	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
number of active participants	1	2	4	3	4	5	6	5	6	6
auction legs won	142	132	260	279	413	449	419	336	271	200
capacity won, TJ	2548	1747	2853	2010	5315	5590	4040	2652	2322	1518
maximum auction price, $/GJ	0.10	0.28	0.70	0.61	0.65	1.00	1.05	0.30	0.19	0.15
% won at $0/GJ	82%	95%	89%	79%	74%	53%	91%	81%	92%	89%
% won at ≥$0.10/GJ	0%	1%	9%	13%	19%	32%	4%	9%	3%	3%

Source: AER analysis using DAA auction results data.

Note: Each trade reflects a leg acquired through the auction—so if capacity is acquired from Wallumbilla to Sydney on a day this could involve two legs—SWQP and MSP—or up to as many as four legs if capacity on the RBP and Wallumbilla compressors has also been involved to move gas south.

The Day Ahead Auction (DAA) has resulted in over 30.6 PJ of unused contracted pipeline capacity being won across nine facilities in the ten months since its commencement, with 6.5 PJ won in Q4 2019. Sixteen organisations have registered to participate with eight taking part to date. The number of active participants has remained at a similar level to last quarter.[18]

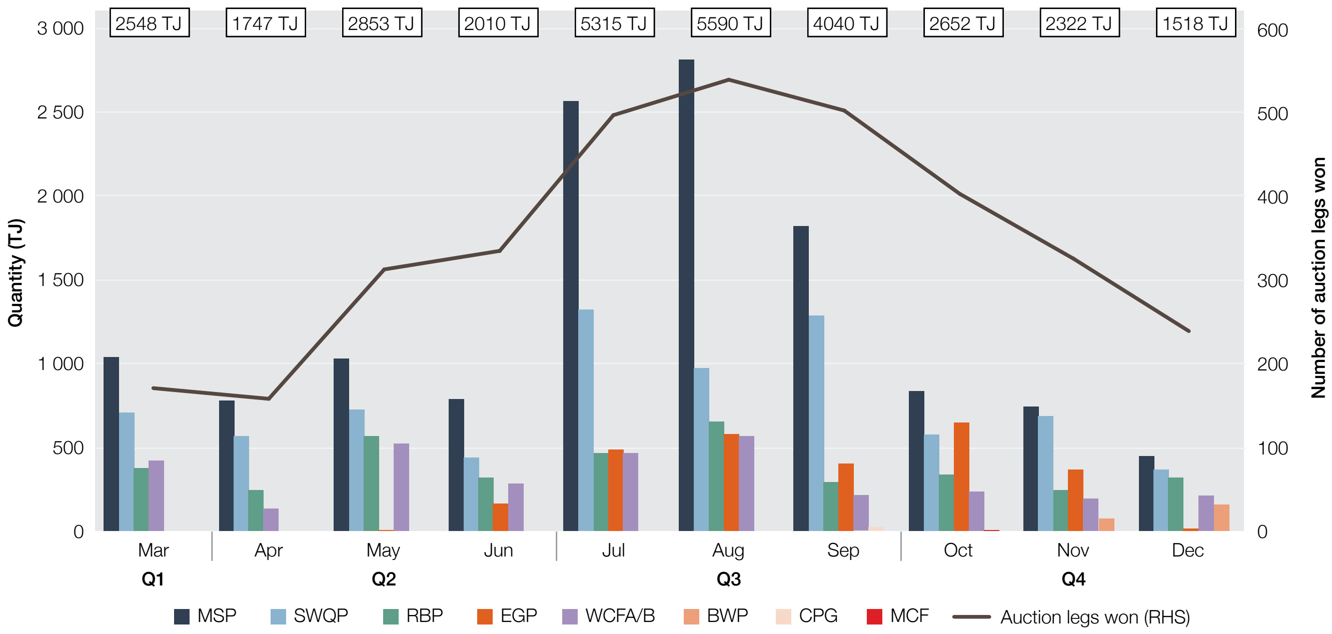
The number of auction legs and total quantities won decreased in Q4 2019, with December experiencing the lowest volumes of capacity won since the commencement of the auction. This was primarily due to less demand to move gas south following the winter period (figure 2.11), leading to decreases in auction capacity won on the Moomba to Sydney Pipeline (MSP) and South West Queensland Pipeline (SWQP). Auction activity was observed on the Berwyndale to Wallumbilla Pipeline (BWP) and Moomba Compression Facility (MCF) for the first time.

The percentage of auction legs won at $0 per GJ increased in Q4 as demand for auction capacity decreased and more auction capacity became available.[19] Auction legs won at greater than $0 per GJ were only observed on the Roma to Brisbane Pipeline (RBP), Eastern Gas Pipeline (EGP) and BWP (only one leg), highlighting the continued competition for capacity on these pipelines. With particular reference to westwards transport on the RBP in October, where available auction capacity was 100 per cent utilised. October also saw an increase in quantities won on the EGP, the highest observed since the commencement of the auction.

18 See list of participants under figure 2.12 under section 2.4.

19 This price represents the cost of capacity won through the auction. Additional cost pass-through provisions also apply to recoup administrative costs related to capacity won. These costs can vary depending on usage as fixed costs apply; indicatively if the auction is being used to transport capacity from Wallumbilla to Victoria or Sydney then charges could equal around 40 cents a day if 1 TJ a day of auction services are being bought.

Figure 2.11 Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using DAA auction results data.

Notes: 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 SWQP and RBP are both heavily contracted year round, with firm contract holders typically contracting on a flat daily basis up to their maximum seasonal load requirements. It is not surprising then that the utilisation of auction capacity on the SWQP (west) dropped to 10 per cent by the end of the quarter and to 55 per cent on the RBP (west). It is likely to reflect that firm shippers were holding excess off peak, spare capacity as a consequence of their 'flat' volume contracts, which, although auctioned, was not in high demand given the overall smaller flows of gas south.

Auction capacity continued to be available on all days on the SWQP, while capacity was unavailable for seven days on the RBP and three days on the EGP in Q4 2019.

The degree to which demand for auction routes on the RBP, SWQP and EGP was higher than the quantities available is provided in table 2.3. Although excess demand on the SWQP and EGP dropped to zero by the end of Q4 2019, there was still some demand above the auction limit on the RBP in all the months of Q4. Excess demand on the MSP was not calculated given all capacity won for Q4 2019 was at $0 per GJ. It can be assumed that there was no excess demand for this quarter on the MSP as prices greater than $0 per GJ are generally only observed when daily auction limits are reached.

Table 2.3: Capacity availability and utilisation on the Day Ahead Auction on 3 pipeline routes[20] [21]

PIPELINE/METRIC	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
RBP										
Number of days capacity unavailable	1	0	1	0	0	0	5	3	1	3
Number of days auction limit reached	11	4	14	27	26	26	25	28	20	11
Available auction capacity utilised (%)	76	68	79	98	95	94	100	100	80	55
Demand above auction limit (TJ)	47	110	167	247	363	482	759	699	430	175
SWQP										
Number of days capacity unavailable	0	0	0	0	0	0	0	0	0	0
Number of days auction limit reached	0	0	6	12	24	26	1	0	0	0
Available auction capacity utilised (%)	19	23	56	60	92	95	38	18	19	10
Demand above auction limit (TJ)	0	0	75	88	724	699	1	0	0	0
EGP										
Number of days capacity unavailable	4	0	0	0	0	1	6	2	0	1
Number of days auction limit reached	0	0	0	0	1	3	4	11	0	0
Available auction capacity utilised (%)	-	-	3	41	56	56	61	80	43	15
Demand above auction limit (TJ)	0	0	0	0	3	87	208	168	0	0

Source: AER analysis using DAA auction results data.

Following the introduction of the DAA on 1 March 2019, the AER has required pipeline and compressor operators to report daily pipeline nominations data on all DAA routes monthly. Further analysis of these scheduling outcomes on the MSP, which transports the bulk of gas from north to south, were done. Our analysis found since the introduction of the DAA, there has been a consistent increase in the percentage of gas transported as part of the auction compared to other next-day transportation services. This is despite the majority of gas transported south on this pipeline being under long-term firm transportation service agreements. The low costs associated with transportation via the DAA has resulted in the auction service consistently being preferred over other next-day transportation services by registered auction participants. We will closely monitor the dynamics of auction volumes and transportation service preferences going forward, including the interactions between auction pricing and as available pricing.

2.4 Downstream market outcomes

- There was a continued trend in increased spot trade in the downstream markets aligned with significant participation by upstream sellers, including: BHP, Esso, Santos, Shell, as well as some retailers and traders bringing gas south.
- There was an increased number of quarterly ASX Victorian spot futures sold with the prices maintaining above $10 per GJ out to 2021 despite spot prices falling in Victoria for the fourth consecutive quarter to below $8 per GJ.

Participation

The number of participants in gas markets continued to grow with the addition of PetroChina and CleanCo who commenced trading in the Wallumbilla Gas Supply Hub during Q4 2019.

Table 2.4 shows participants across commodity and pipeline capacity markets on the East Coast.

20 Percentages have been calculated using data from days when auction capacity was won on the dominant pipeline route. Days where capacity was available, but nothing won, were not included.

21 The auction was not run on two days in April 2019 due to a system error on one day and no bids being received on the other.

Table 2.4 Participant list in gas trading markets[22]

PARTICIPANT LIST IN EASTERN GAS MARKET							
	Market participant	Victoria	Sydney	Adelaide	Brisbane	GSHs	DAA
Gentailer	AGL	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017	Entered in 2019
Gentailer	Alinta Energy	Entered before 2017	Entered in 2017	Entered before 2017	Entered before 2017	Entered before 2017	Entered in 2019
Gentailer	Arrow					Entered before 2017	
Gentailer	Aurora Energy		Entered before 2017				
Gentailer	CleanCo					Entered in 2019	Entered in 2019
Gentailer	Delta Electricity		Entered before 2017				
Gentailer	EnergyAustralia	Entered before 2017	Entered before 2017	Entered before 2017		Entered in 2017	Entered in 2019
Gentailer	Engie	Entered before 2017					
Gentailer	ERM	Entered before 2017	Entered before 2017		Entered before 2017	Entered before 2017	Entered in 2019
Gentailer	HydroTas	Entered before 2017					
Gentailer	Origin	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017	Entered in 2019
Gentailer	Snowy Hydro	Entered before 2017	Entered before 2017				
Gentailer	Stanwell				Entered before 2017	Entered before 2017	Entered in 2019
Exporter/Producer	APLNG					Entered before 2017	
Exporter/Producer	BHP Billiton	Entered in 2019	Entered before 2017				
Exporter/Producer	Esso	Entered before 2017	Entered before 2017				Entered in 2019
Exporter/Producer	GLNG					Entered before 2017	
Exporter/Producer	Lochard Energy	Entered in 2017					
Exporter/Producer	Petro China					Entered in 2019	
Exporter/Producer	QGC					Entered before 2017	
Exporter/Producer	Santos	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017	Entered in 2019
Exporter/Producer	Shell		Entered in 2019				Entered in 2019
Exporter/Producer	Walloons Coal Seam Gas						Entered in 2019
Retailer	Click Energy	Entered before 2017	Entered in 2017				
Retailer	Covau	Entered before 2017	Entered before 2017				
Retailer	Dodo	Entered before 2017	Entered before 2017				
Retailer	GloBird Energy	Entered in 2018					
Retailer	GOEnergy		Exit or inactive		Exit or inactive		
Retailer	GridX		Entered before 2017				
Retailer	Lumo Energy	Exit or inactive	Entered before 2017	Entered in 2018			
Retailer	Powershop	Entered in 2018					
Retailer	Red Energy		Entered before 2017	Entered in 2017	Entered in 2018		
Retailer	Simply Energy		Entered in 2017	Entered before 2017			
Retailer	Sumo Gas	Entered in 2017					
Retailer	Visy	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017		
Retailer	Viva Energy	Entered in 2018					
Retailer	Weston Energy	Entered in 2018	Entered before 2017	Entered in 2017	Entered in 2018		
Industrial	Adelaide Brighton Cement			Entered before 2017			
Industrial	BlueScope		Entered before 2017		Entered in 2018		
Industrial	BP				Entered before 2017; Exit or inactive	Entered before 2017	
Industrial	Caltex				Entered before 2017		
Industrial	Cargill Malt	Entered in 2019	Entered in 2018	Entered in 2018			
Industrial	Com Steel		Entered in 2017				
Industrial	Coogee Energy	Exit or inactive					
Industrial	Coopers			Entered in 2017			
Industrial	CSR Building Products	Entered in 2018		Entered in 2019	Entered in 2018		
Industrial	Incitec Pivot				Entered before 2017	Entered before 2017	Entered in 2019
Industrial	Michell Wool			Entered in 2019			
Industrial	Mobil Oil	Entered in 2018					
Industrial	Norske	Entered in 2018					
Industrial	Paper Australia	Entered in 2018					
Industrial	O-I International	Entered in 2018	Entered in 2018	Entered in 2018	Entered in 2019		
Industrial	OneSteel	Entered before 2017	Entered before 2017	Entered before 2017			
Industrial	Orica		Entered in 2017				
Industrial	Qenos	Entered in 2017	Entered before 2017			Entered in 2017; Exit or inactive	Entered in 2019
Industrial	SA water			Entered before 2017			
Industrial	Tarac Technologies		Entered in 2017	Entered before 2017			Entered in 2019
Trader	Macquarie Bank	Entered in 2019	Entered in 2019			Entered in 2018	Entered in 2019
Trader	Strategic Gas Market Trading	Entered in 2019	Entered in 2019			Entered before 2017	Entered in 2019
	Total active market participants	31	31	19	14	17	16

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

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

Trade volumes and liquidity in spot market

Spot trade in East Coast gas markets is dominated by the top three buyers and sellers in each region (figure 2.12). These participants have accounted for between 50 and 90 per cent of the net quantities traded at the spot price since 2015.

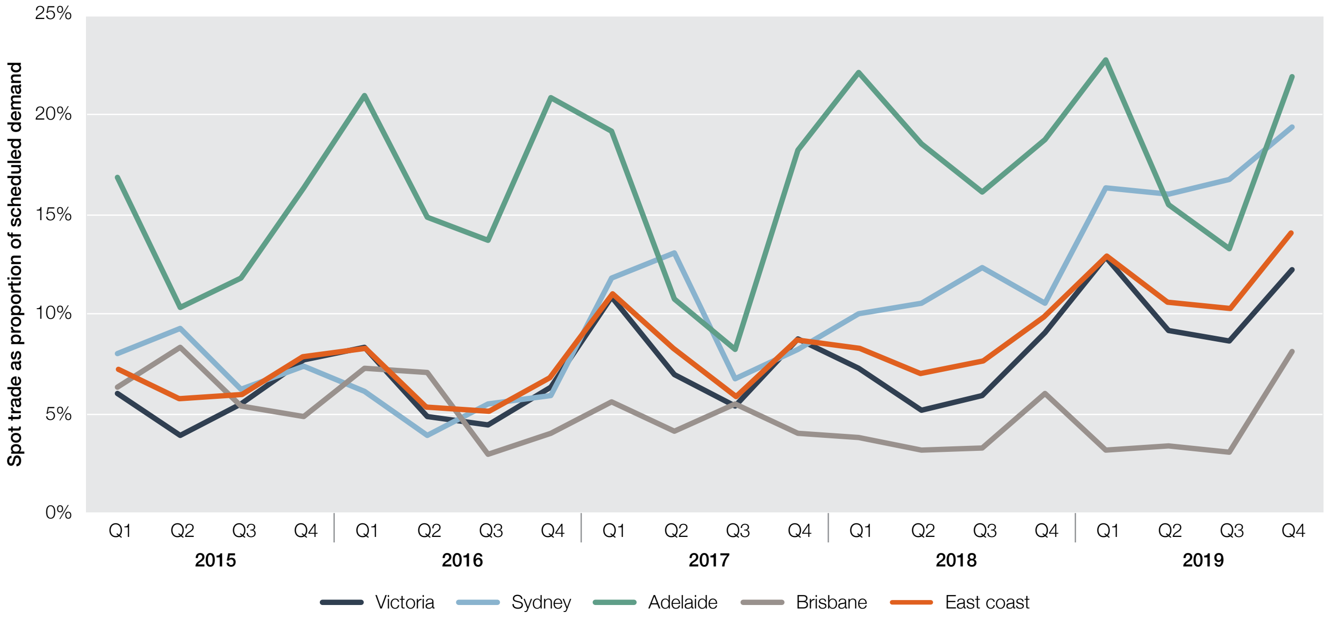
The general downward trend continued across the markets over the last quarter, showing a decrease in the concentration of trades around the top three participants. Proportions for 2019 remained stable (in Adelaide) or generally continued to fall over the last quarter of 2019 (in Victoria, Sydney and Brisbane).

Figure 2.12 Top three buyers and sellers in spot markets

Source: AER analysis using DWGM, STTM data.

While there remains a reliance on bilateral contracts to supply gas to the East Coast markets, further increases to quantities traded in the spot markets were observed over Q4 2019 (figure 2.13). Adelaide, which generally has the highest proportion of gas traded through the market, remained relatively flat over the longer term. Other regions showed more significant increases in net trade activity over Q4 2019, increasing to just under 20 per cent in Sydney and rising to 12 per cent and 8 per cent in Victoria and Brisbane respectively.

Figure 2.13 Spot trade liquidity

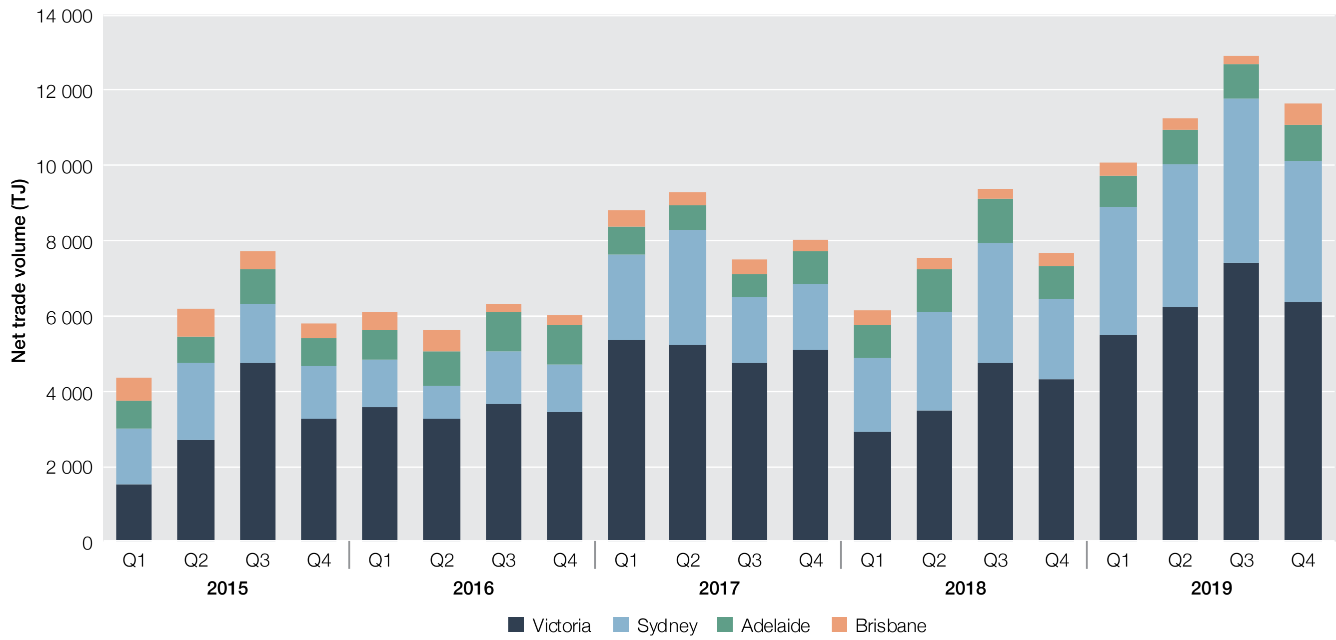


Source: AER analysis using DWGM, STTM data.

Note: The Q4 2019 figures have been amended from figures published in the Q3 2019 report.[23]

The recent increase in net sales into in the downstream southern spot markets is a result of significant participation by upstream sellers: BHP, Esso, Santos, Shell, alongside a few retailers and traders bringing gas south (figure 2.14).

Figure 2.14 Total net trade quantity



Source: AER analysis using DWGM, STTM data.

This highlights the trend to increased volumes traded through the Sydney, Brisbane and Victorian markets from Q4 2018, with Adelaide recording a slight increase in trade. The dramatic increase in Brisbane trades reflect large net sales by Caltex.

23 These figures have been revised to reflect corrections to our estimation methodology.

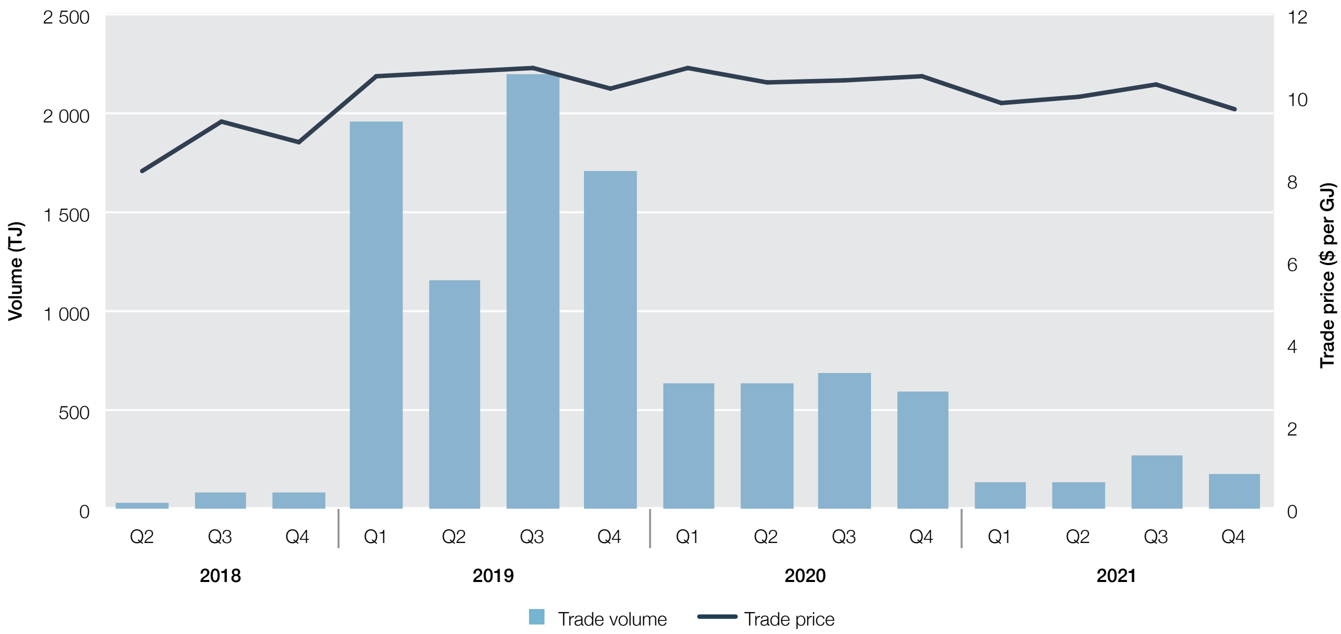
Trade in financial markets

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. The ASX launched the Victorian gas futures product in 2013, with little subsequent trade until Q2 2018. Since then activity and trade volumes have increased significantly from the start of 2019. While the 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), an increasing level of open interest, alongside increased spot trading in short term markets presents encouraging signs.

There were 225 trades in quarterly products over Q4 2019 (up from 135 contracts traded in Q3 2019 but down from 361 contracts traded in Q4 2018). The average price of gas bought and sold (the trade price) was $10.20 per GJ for Q4 2019, and the contract ultimately settled for $8 per GJ, resulting in a loss to those who took a long position.

Futures trade continues to build matching higher levels of pure net trade in the spot markets.

Figure 2.15 ASX Victorian futures



Source: AER analysis using ASX data.

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

Focus—East Coast LNG exports 2019 and beyond

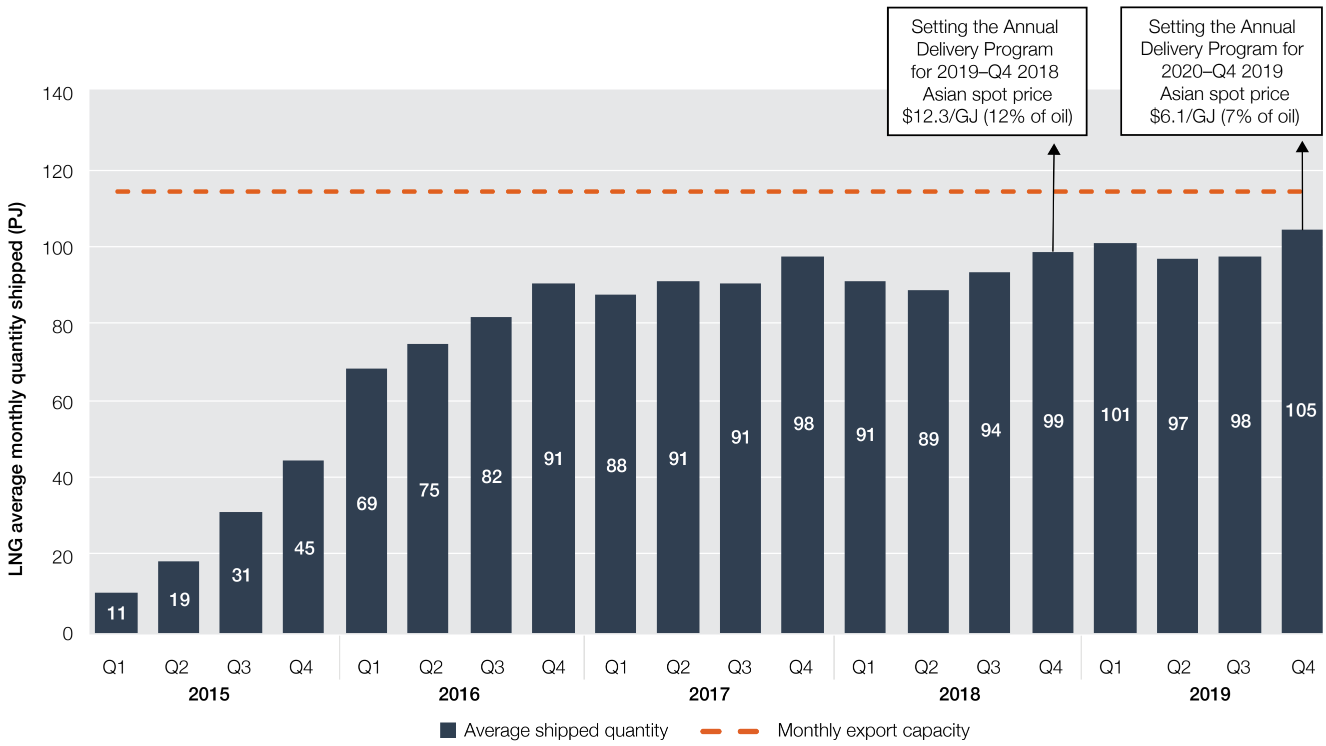
International LNG market outcomes continue to influence East Coast domestic market outcomes. The majority of East Coast gas production is now exported to Asia with pricing outcomes in the export market heavily influencing domestic production and pricing. The following factors were notable in 2019:

- Record gas production in Queensland occurred following high international prices in 2018.
- In total across WA, NT, and Queensland; Australia increased its relative share of Chinese demand and became the number one LNG exporter globally.
- Asian LNG spot prices fell significantly.
- There is some evidence that Asian buyers have exercised downward quantity limits in late 2019 for longer term contracts linked to Queensland exports—this may reduce expected production over 2020 (since October 2019, production has slowed in Queensland).
- Low Asian LNG spot prices are expected to persist over 2020, this might cause domestic spot prices linked to the Asian LNG spot price to maintain at levels of around $6 to $8 per GJ.

Year in review 2019

Gas production in Queensland reached record levels in 2019, as the three LNG exporters, APLNG, GLNG and QCLNG, achieved high production levels in Roma that translated into record LNG exports. This occurred despite Asian LNG spot prices declining significantly throughout 2019 from high price levels over 2018 and 2017. Gas production in Roma peaked in Q4 2019 reaching record levels in October before declining over November and December. Figure 2.16 illustrates prices in the LNG market when production decisions were likely to have been made for 2019 and 2020. The high Asian LNG spot price in Q4 2018 helps to explain higher annual delivery programs by East Coast exporters for 2019 to sell spot cargoes, and to meet commitments by buyers to purchase term cargoes under long-term contracts over 2019.[24] Given delivery programmes and limited ability to reduce production from fields once developed, it is likely that a number of spot cargo sales continued over 2019 despite prices falling.[25]

Figure 2.16 East Coast LNG exports and LNG prices



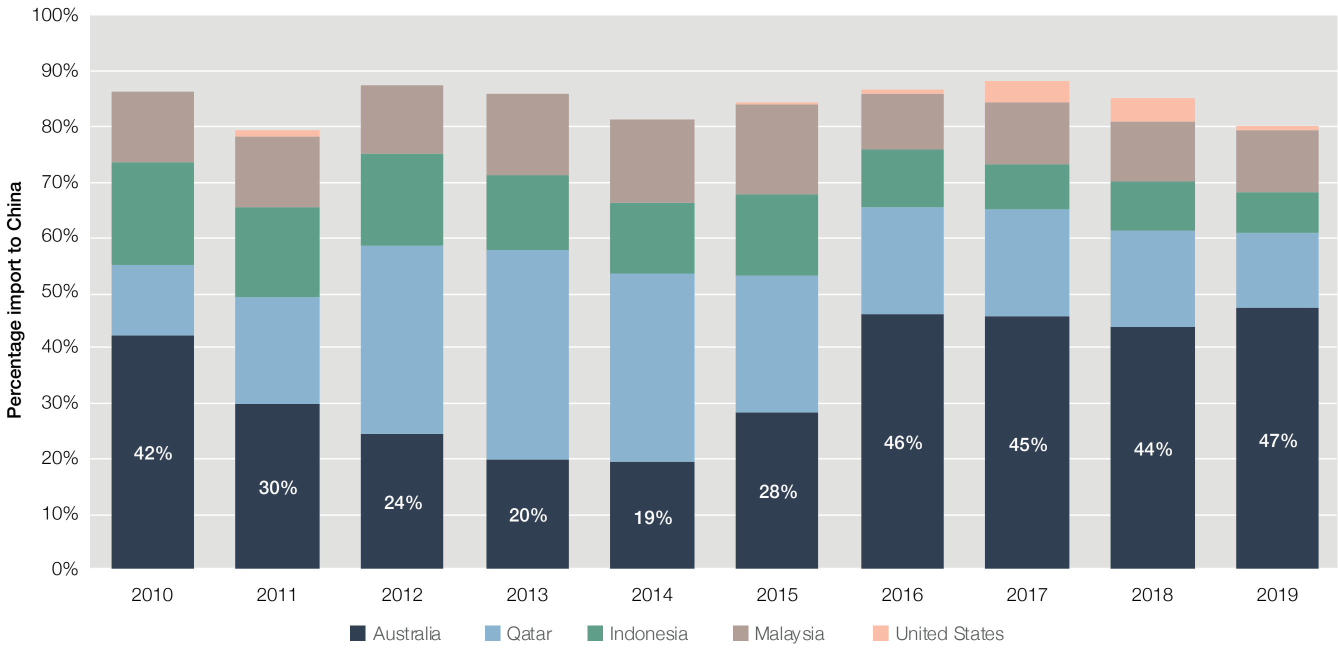
Source: AER analysis using Gladstone Port Corporation, APPEA and ACCC data.

The demand for Australian LNG from China remained strong throughout 2019 and supported the record production levels observed on the East Coast. Figure 2.17 highlights that 47 per cent of LNG imports to China originated from Australia in 2019, the highest level in a decade. So although Chinese LNG demand has slowed down in 2019, the demand for Australian LNG has remained robust, supporting the record production levels observed on the East Coast.

24 Term cargoes are long term contracted cargoes at an oil price with some flexibility year to year in actual volumes to be taken in general the higher the Asian LNG spot price for gas relative to the oil price, the more attractive it will to be to commit to more term cargoes.

25 ACCC, Gas Inquiry, April 2019 Interim, pp. 52–53 notes 23 spot cargoes were exported from Gladstone in 2017 and 12 in 2018; Origin Energy, Origin 2019 investor briefing day presentation, https://www.originenergy.com.au/content/dam/origin/about/investors-media/origin_2019_ibd_final_asx.pdf, November 2019, accessed 9 January 2020 highlights a short run marginal cost of APLNG Asian LNG exports of around A$4/GJ at Gladstone indicating for it spot cargo would have been profitable even with declining Asian spot prices over 2019.

Figure 2.17 China LNG import country of origin



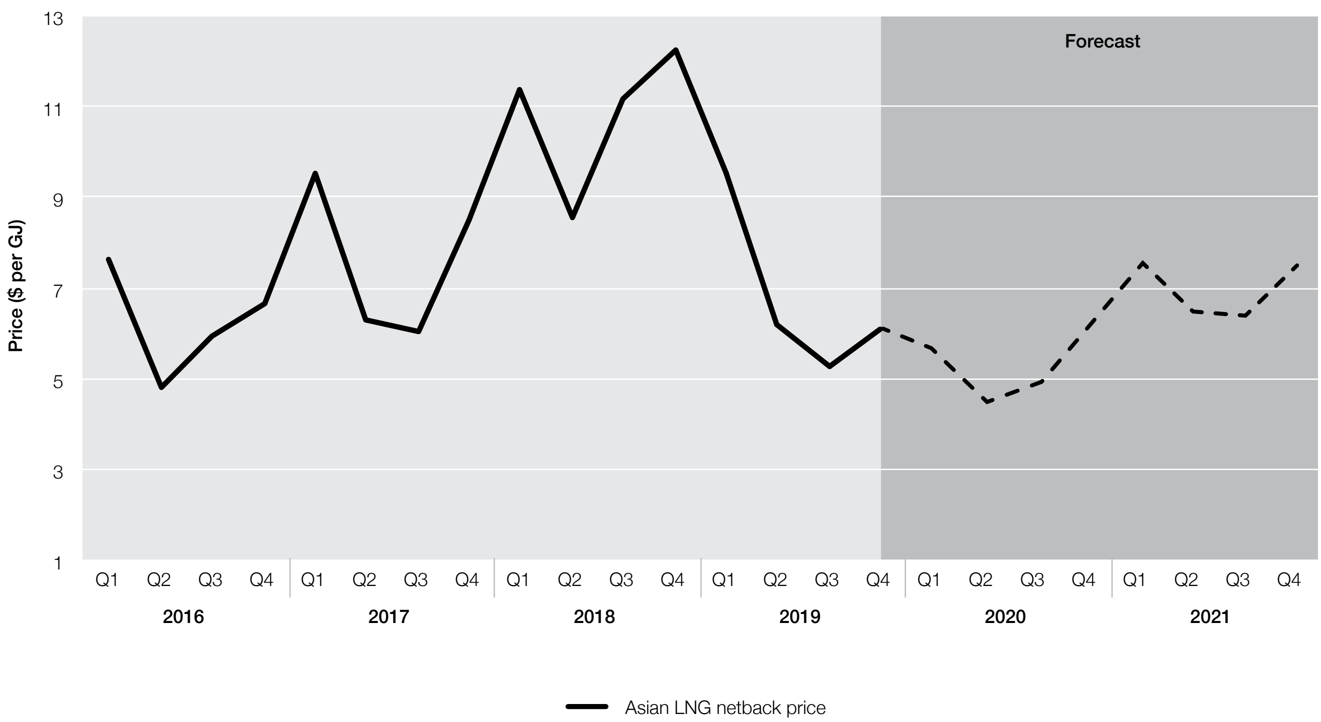
Source: AER analysis using Bloomberg data.

2020 Global near term LNG outlook

Supply and demand side factors

Asian LNG spot prices in 2020 are expected to remain suppressed, driven by a combination of increased LNG supply and continued downward pressure on demand. This trend may also lead to downward pressure on domestic spot gas prices throughout 2020.

Figure 2.18 Historical and forecast international netback price



Source: AER analysis using ACCC netback price series.

East Coast LNG production is closely linked to Asian LNG markets with 90 per cent of the East Coast LNG exported to China, Japan and South Korea in Q4 2019. China is the main destination of East Coast LNG, accounting for almost three quarters of the LNG exported. Supply and demand fundamentals currently influencing the Asian LNG market include:

Asian demand fundamentals:

› Uncertainty of trade negotiations affecting the Chinese economy and easing of coal-to-gas conversions in China.
› Korea supporting more LNG sales given power sector transition away from nuclear and coal.
› Japan favouring coal over gas for electricity generation and nuclear restarts reducing LNG demand.

Supply fundamentals:

› USA export capacity increasing close to combined capacity of Gladstone export projects over 2020.[26]
› Australian export projects with potential to raise output.

LNG pricing revisions

The significant reduction in Asian LNG spot prices over 2019 appears likely to be influencing the prices charged for LNG deliveries away from historic long-term contract prices toward current relatively lower Asian LNG spot prices. LNG buyers appear to have exercised rights of downward quantity tolerance to reduce term contract purchase volumes over 2020 in favour of trades at spot prices.[27]

LNG contract prices are often linked to an oil price percentage. The LNG contracts underpinning the construction of the Gladstone LNG facilities featured oil-linked prices reported to be around 14 per cent of an oil price with small variances across projects.

Figure 2.19, shows in 2017 and 2018 the Asian LNG spot price trended closer to the foundation contract 14 per cent oil-linked price and was always higher than the 10 per cent oil linked price. This trend changed dramatically over the course of 2019 with the Asian LNG spot price dropping under the 10 per cent oil-linked price in Q2, bottoming at $6.34 per GJ in Q3. It increased again in Q4 but remains lower than the 10 per cent oil-linked price at $7.88 per GJ.

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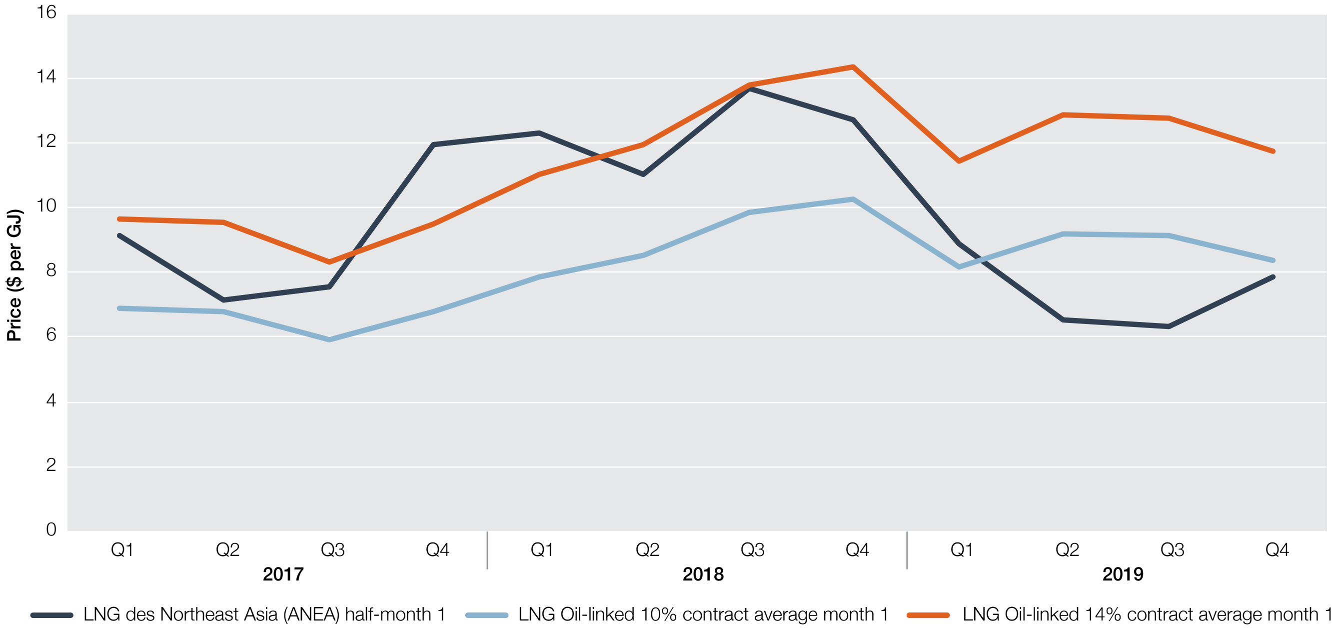
26 U.S Energy Information Administration: U.S Liquefaction Capacity, December 2019. U.S export capacity construction of a baseload nameplate capacity of 25 million tonnes per annum, this compares to the combined Gladstone projects' existing nameplate capacity of 25.3 million tonnes per annum.

27 Origin Energy, Origin 2019 investor briefing day presentation, https://www.originenergy.com.au/content/dam/origin/about/investors-media/origin_2019_ibd_final_asx.pdf, November 2019, accessed 9 January 2020.

Figure 2.19 Asian LNG (ANEA) spot price vs oil linked contract prices



Source: AER analysis using Argus Media data.

Note: The LNG oil linked contract price is indicative of either the 10 per cent or 14 per cent 1-month lagged Japan Customs-cleared crude oil price plus shipping.

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Across WA, NT and the East Coast, existing long term contracts are understood to be subject to pricing review points established under contracts, while in WA there are new potential LNG export projects nearing financial investment decisions. In the near term it appears that the decrease in Asian LNG spot prices relative to oil prices is likely to place significant pressure on LNG export term contract prices too. This outlook in turn implies that domestic buyers of gas should in general be competing for gas which has a lower export value when compared to recent years.

Moreover, the Asian LNG spot prices will likely remain an important reference, affecting LNG deliveries when buyers are looking to buy short term gas from LNG exporters. Exporters have signed a heads of agreement to first offer uncontracted gas to domestic users on competitive market terms, and are likely to be conscious of these prices when offering short-term gas to the domestic market.[28]

28 Australian Department of Industry Innovation and Science, Australian Domestic Gas Security Mechanism Heads of Agreement, p. 1.

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.[29]

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.[30] 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.[31] 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.[32] 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 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.

Up to the end of Q4 2019, there was negligible use of the CTP. However the DAA has been widely used with six participants in December 2019 buying spot capacity day ahead.

29 ACCC, Gas inquiry, April 2019 Interim Report, p. 41

30 ACCC, Gas inquiry, September 2017 Interim Report, p. 67.

31 ACCC, Gas Inquiry, April 2019 Interim, p. 15.

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