Wholesale Markets Quarterly

Q3 2020

July—September

November 2020

AUSTRALIAN
ENERGY
REGULATOR

Australian Government

Requests and inquiries concerning reproduction and rights should be addressed to:

Director, Content & Digital Services
Australian Competition and Consumer Commission
GPO Box 3131
Canberra ACT 2601

or publishing.unit@accc.gov.au

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Tel: 1300 585 165

Email: marketperformance@aer.gov.au

Contents

Summary **iv**
Electricity markets iv
Gas markets iv
About this report **3**
1. Electricity **4**
1.1 Wholesale spot prices remain low 4
1.2 Record number of negative prices 5
1.3 Interconnector limits contribute to negative prices in Queensland and South Australia 10
1.4 Forward markets expect prices below $90 per MWh this summer 12
1.5 Demand very low during the day in Victoria and South Australia 15
1.6 Black coal, gas and hydro generation down 16
1.7 Black coal offers more capacity priced below $50 per MWh 17
1.8 While gas prices remain low, gas offers vary 18
1.9 Low winter rainfall in Tasmania leads to higher priced hydro offers 20
1.10 Price set by black coal and gas continues to track lower fuel prices 21
1.11 Black coal, gas and hydro set lower prices than a year ago 23
1.12 Over 900 MW of new solar capacity enters the market, while two gas units exit 25
1.13 FCAS costs fall 26
1.14 Focus–Links between the wholesale gas and electricity markets 28
1.15 Focus–The role of load in the NEM 32
2. Gas **37**
2.1 International and domestic prices starting to recover from multi-year lows 38
2.2 Production remains strong on the east coast 41
2.3 LNG exports continue to fall 43
2.4 Trade at Wallumbilla up from last quarter 44
2.5 Day Ahead Auction participation continues to rise 46
2.6 Record daily gas flows south on the South West Queensland Pipeline and Moomba to Sydney Pipeline 51
2.7 Trade through spot markets jumps in Q3 2020 52
2.8 Gas powered generation significantly lower than Q3 2019 53
2.9 ASX gas futures prices rising in 2021 54
2.10 Focus—Competition in spot markets 55
Appendix A Electricity generator outages **66**
Appendix B Gas snapshots **68**

Summary

Electricity markets

Average wholesale electricity prices in Q3 2020 ranged from $34 per MWh in Queensland to $54 per MWh in Victoria. This is the first time since 2014 that Q3 prices were below $55 per MWh in all regions.

Quarter three is typically a low demand quarter due to milder weather and good rooftop solar generating conditions. This quarter, some regions saw instances of extremely low daytime demand, supported by an unusually warm September. In particular, South Australia experienced record low demand and Victoria experienced its lowest ever minimum demand for quarter three. These low demand conditions combined with transfer limits on the Queensland and South Australian interconnectors resulted in a record number of negative prices. These negative prices were a factor in lower average prices this quarter, including an average weekly price in South Australia of just $9 per MWh for the week of 6 September 2020.

For generation, the low demand conditions in September resulted in a fall in total NEM output compared to the same quarter last year. Queensland black coal generation in particular was lower than in Q3 2019 as a number of generators experienced both planned and unplanned outages. And, with the exception of Queensland, gas generation was also lower in all mainland regions. Meanwhile, solar and wind generation continues to rise as more capacity comes online.

Looking forward, falls in base future and cap prices for Q1 2021 over this quarter suggest an expectation that the market is well placed to deal with summer conditions. While prices generally increase over summer, current expectations are that prices will remain below $90 per MWh in every region, and AEMO is not forecasting any major generation issues.

Gas markets

In most markets, gas prices increased slightly from last quarter, but remained at levels last seen in early 2016 of between $4 and $5.50 per GJ. Remarkably, prices decreased for the seventh quarter in a row in Victoria to $4.56 per GJ.

After continued falls, international netback gas prices bottomed out this quarter at $2.29 per GJ in July, bouncing back in the following months.

LNG exporter maintenance over winter was higher than in 2019. The associated changes in Queensland production has led to reduced LNG export cargoes and some gas diverted to storage, however gas flows south did not notably decline from Q3 2019 levels.

Our focus story highlights competition outcomes across the upstream Gas Supply Hubs, Day Ahead Auction and downstream spot markets. A significant increase in trade occurred in Adelaide, Brisbane, Sydney and Victoria with predominately producers and traders selling gas to a mix of mostly industrial, and small and large gas retailers.

A record number of trades occurred through the Day Ahead Auction this quarter. Our report highlights some key pinch points on the network where demand exceeded available capacity—this quarter one constraint on the Moomba to Sydney Pipeline led to record auction prices of $1.49 per GJ. Participants vied for limited capacity to bring gas south during this quarter's peak demand period to address threats to system security in Victoria. These outcomes further support the design intent of the Day Ahead Auction to facilitate gas transfers across the markets to balance supply and demand.

Electricity markets at a glance

Q3 2020

Spot prices

Prices (VWA) remain low ranging from $34 in Queensland to $54 per MWh in Victoria. Record number negative prices

Demand

Record low demand in SA and record low Q3 demand in Victoria

Offers

Coal generators offer more low priced capacity in line with low fuel costs

Generation

Record wind and high solar output help displace black coal, gas and hydro output

FCAS

50 Hz

Fall in FCAS prices lead to lower FCAS costs

Outlook

Moderate summer prices expected with Q1 2021 base future prices below $90 per MWh in all regions

Gas markets at a glance

Q3 2020

Spot prices

Small price increases in most markets, Victoria has the seventh straight quarter of price decline

Spot trade downstream

Increasing spot trade particularly in Sydney

Wallumbilla trade

Exchange trade still down on record 2019 levels

International prices and LNG exports

Prices stopped falling and started to increase, LNG cargoes rose in September

Gas production and flows

Southward flows just below Q3 2019 record, East Coast production less than Q3 2019

Day Ahead Auction

Record participation and new maximum auction price of $1.49 per GJ

About this report

The AER has a range of obligations to monitor and report regularly on the performance of the national wholesale electricity and gas commodity and capacity markets. Quarterly reporting on performance issues, including on some longer term trends, is a fundamental part of fulfilling these obligations. It bridges the gap between our shorter term high price event reports and our longer-term biennial *Wholesale electricity markets performance report*.

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

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

1. Electricity

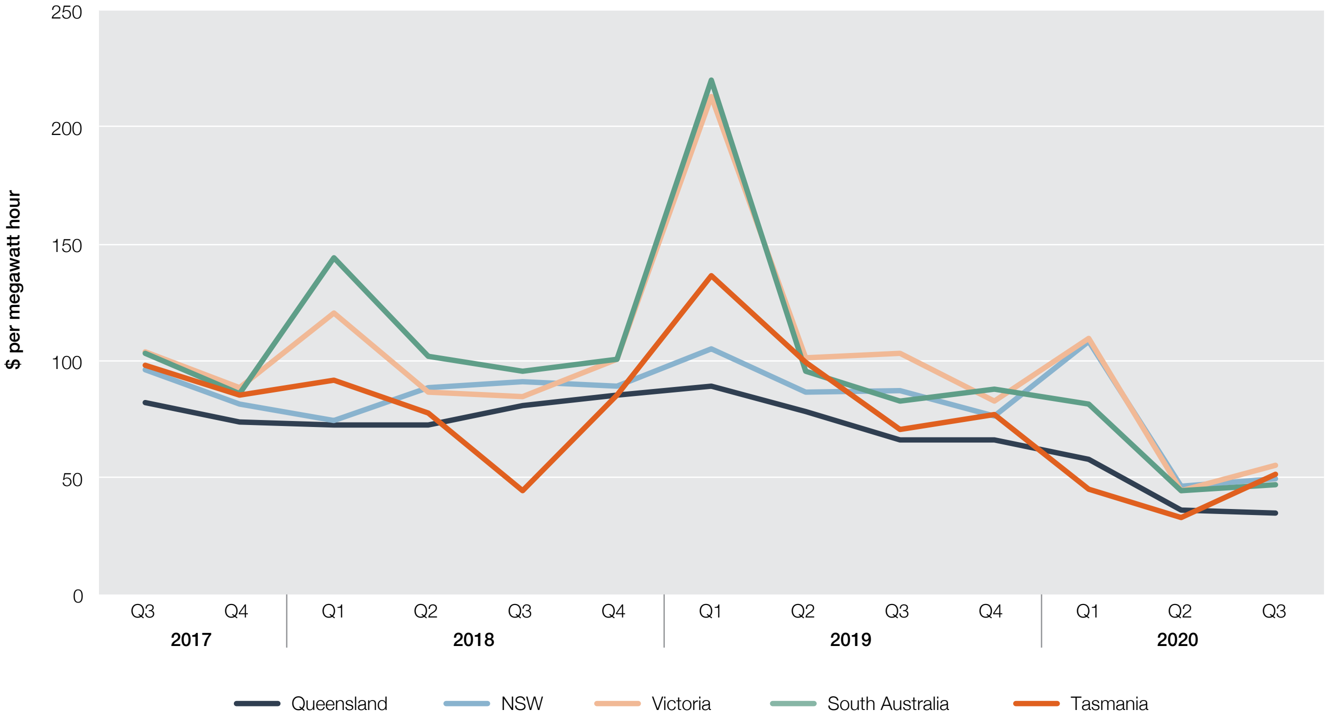
1.1 Wholesale spot prices remain low

Quarterly volume weighted average (VWA) spot prices across all National Electricity Market (NEM) regions remained low in the third quarter of 2020 (Q3 2020). Quarterly prices ranged from $34 per MWh in Queensland to $54 per MWh in Victoria (figure 1.1).

Average prices were up slightly on the Q2 2020 levels in most regions. In Tasmania average prices were up $19 per MWh on Q2 2020 levels, driven by hydro plant rationing water as a result of low rainfall.

Prices were, however, significantly lower than comparable Q3 prices in recent years. Across the NEM as a whole, Q3 2020 marked the first time since 2014 that Q3 prices were below $55 per MWh in all regions. Individually, prices this quarter were the lowest Q3 prices observed since 2011 in South Australia, 2014 in Queensland, 2015 in NSW, 2016 in Victoria and 2018 in Tasmania.

Figure 1.1 Average quarterly prices (VWA)



Source: AER analysis using NEM data.

Note: The volume weighted average price is weighted using native demand in each region.

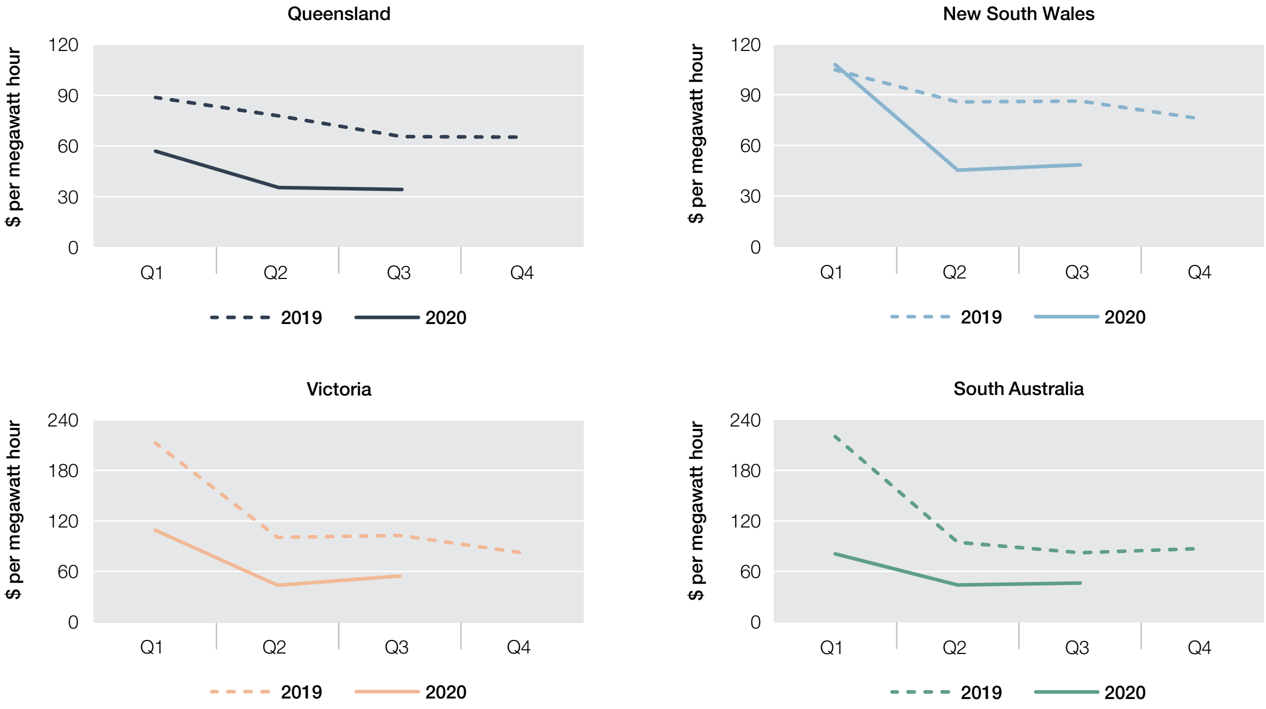
These prices were significantly lower than those a year earlier (figure 1.2). In all mainland regions, average Q3 prices in 2020 were between 44 and 48 per cent lower than in 2019. This continued a trend reported in our *Wholesale markets quarterly Q2 2020* of quarterly prices across all regions generally being significantly lower than their 2019 levels.[1]

Breaking down this trend further, there were some extremely low average weekly prices in the quarter. In particular, for the week commencing 6 September, average prices in South Australia were $9 per MWh—the lowest weekly price in any region since 2012. This in part reflected the record number of negative prices in South Australia in that week (section 1.2). These negative prices lowered average prices for the week by almost $15 per MWh.

---

[1] Average Q1 prices in 2020 in NSW were slightly higher than levels in 2019. As highlighted in our *Wholesale markets quarterly Q1 2020*, the average price in NSW in Q1 2020 was driven by short periods of high prices during extreme weather and bushfires.

Figure 1.2 Average prices by quarter (VWA) 2019 and 2020



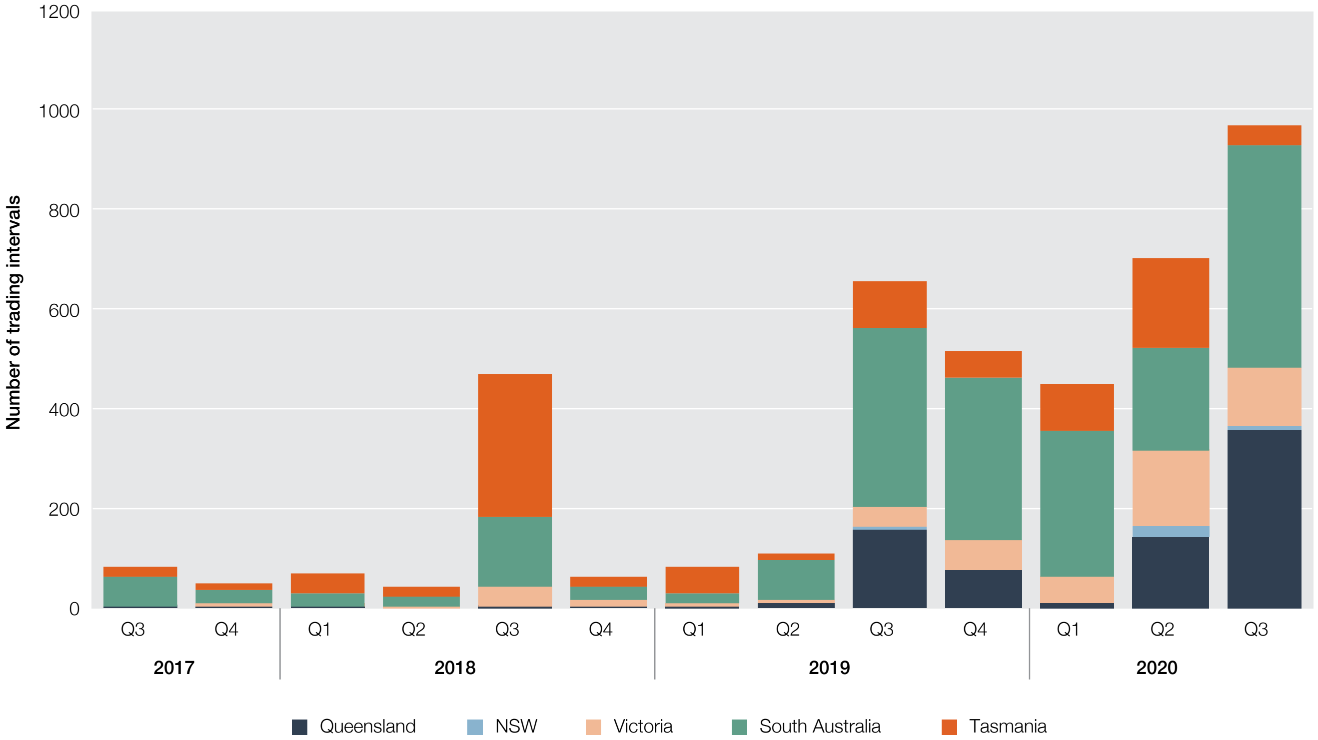
Source: AER analysis using NEM data.

Note: Compares average quarterly spot prices (VWA) in 2020 with the same quarter in 2019.

1.2 Record number of negative prices

The recent trend of increasing numbers of negative spot prices continued in Q3 2020, with a record number of negative prices across the NEM (figure 1.3). There were 47 per cent more negative prices in Q3 2020 than for the same period last year. The number of negative prices in Queensland and South Australia for the quarter also reached new highs. In South Australia, spot prices were negative for more than 10 per cent of the time, the highest count ever in any region.

Figure 1.3 Quarterly count of negative prices

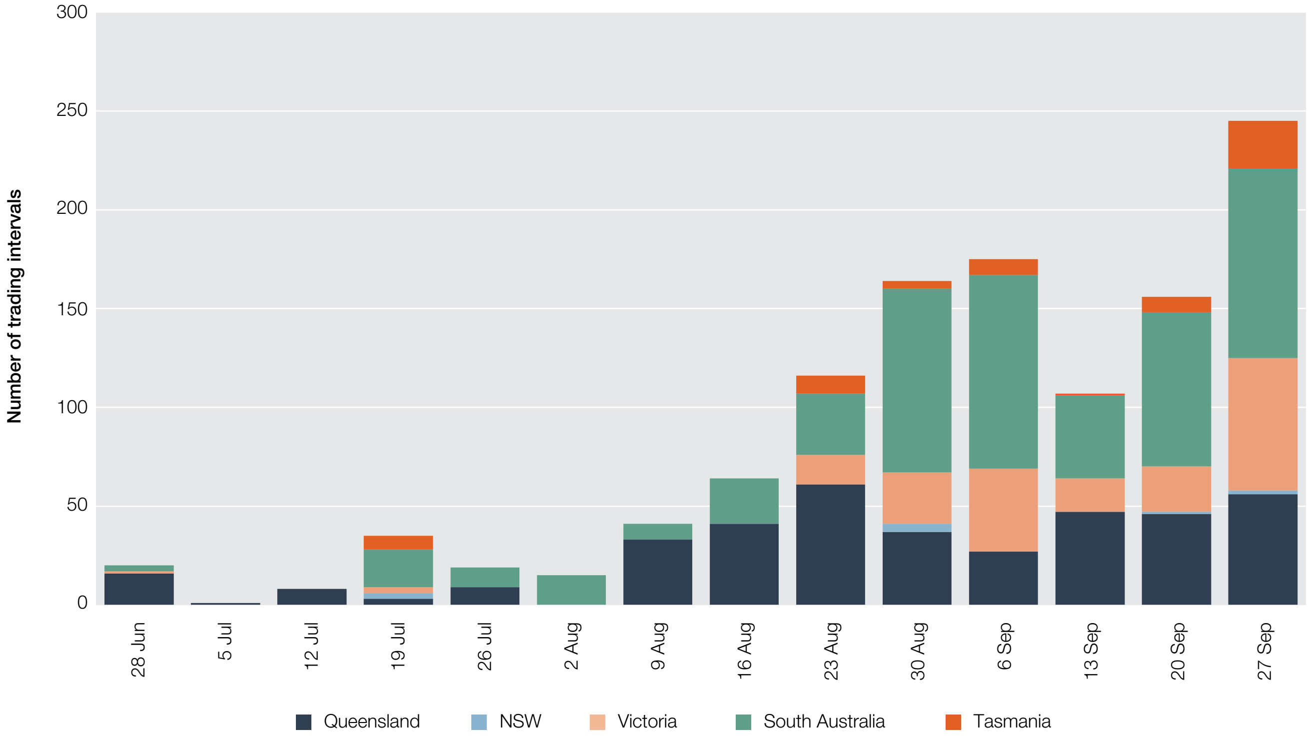


Source: AER analysis using NEM data.

Note: Count of spot prices below $0 per MWh in each quarter.

Breaking this down further, the number of negative prices across the NEM increased later in the quarter (figure 1.4). Indeed, the week commencing 27 September had the highest weekly count of negative prices since the start of the NEM. In part, this trend reflected low wind at the start of the quarter and an increase in solar output and fall in demand as temperatures rose.

Figure 1.4 Weekly count of negative prices, Q3 2020

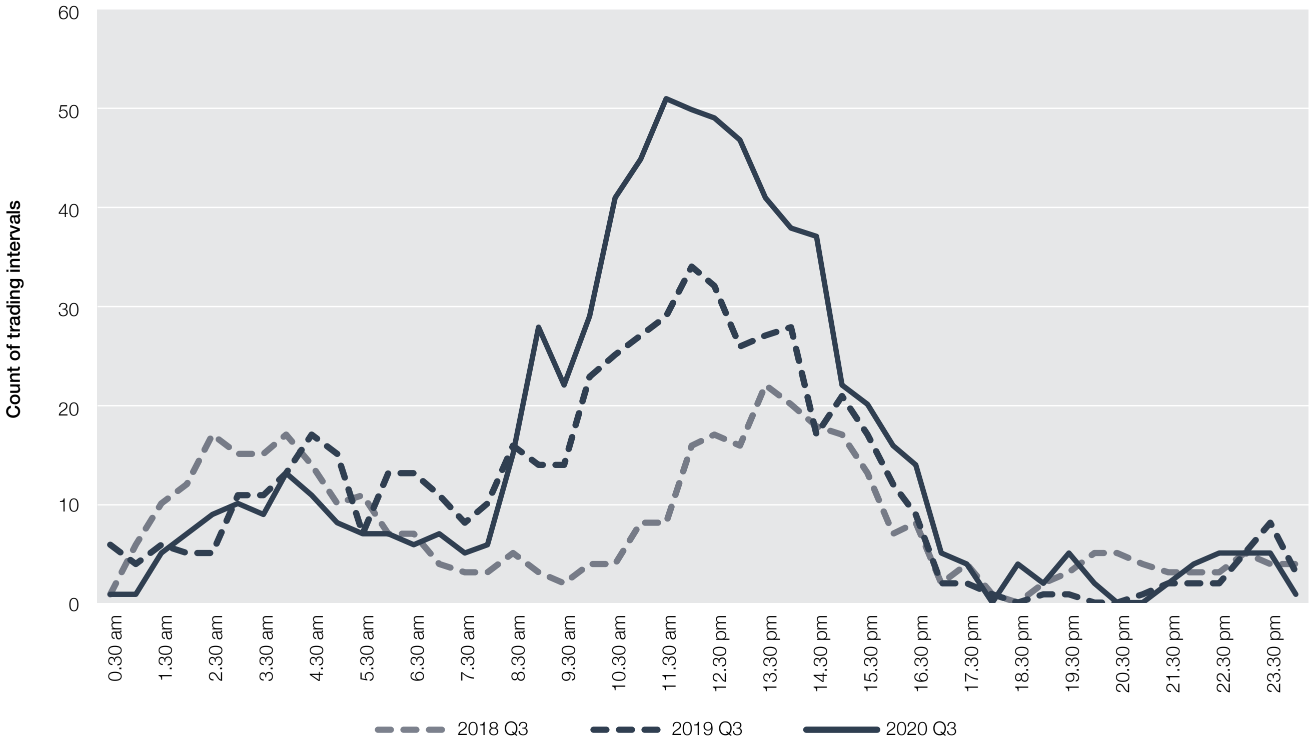


Source: AER analysis using NEM data.

Note: Count of spot prices below $0 per MWh in each week of Q3 2020. Weeks run Sunday to Saturday and include full weeks at the start and the end of the quarter.

The distribution of negative prices throughout the day continues to evolve. While the number of negative prices was lower in the evening and morning peaks compared to previous third quarters, the number of negative prices has grown significantly in daylight hours (figure 1.5). In Q3 2020, there were negative prices in at least one region 50 per cent of the time in the 10.30 am to 1.30 pm trading intervals. For September 2020, this figure was over 80 per cent. A key driver of this is the growth of solar generation including increased household solar PV which has reduced demand and large scale solar which has increased the amount of low priced capacity availability during daylight hours.

Figure 1.5 Count of negative prices by time of day in Q3



Source: AER analysis using NEM data.

Note: Count of spot prices below $0 per MWh by time of day in Q3 2020.

Sustained periods of negative prices will impact the operational and investment decisions of generators and has potential to have significant impacts on the market. We examined negative prices in detail in a focus story in our *Wholesale markets quarterly Q3 2019*. We will further analyse trends in negative prices and the impact they are having on participant behaviour in more detail in our *Wholesale electricity market performance report 2020*, due to be released in December.[2]

Influences on lower average prices throughout the quarter were not confined to the emergence of negative prices. There were more low priced trading intervals in the range $0 to $50 per MWh compared to previous quarters and these played a significant role in driving overall price outcomes (table 1.1).

Table 1.1 Share of prices between $0 to $50 per MWh, Q3 2019 and Q3 2020

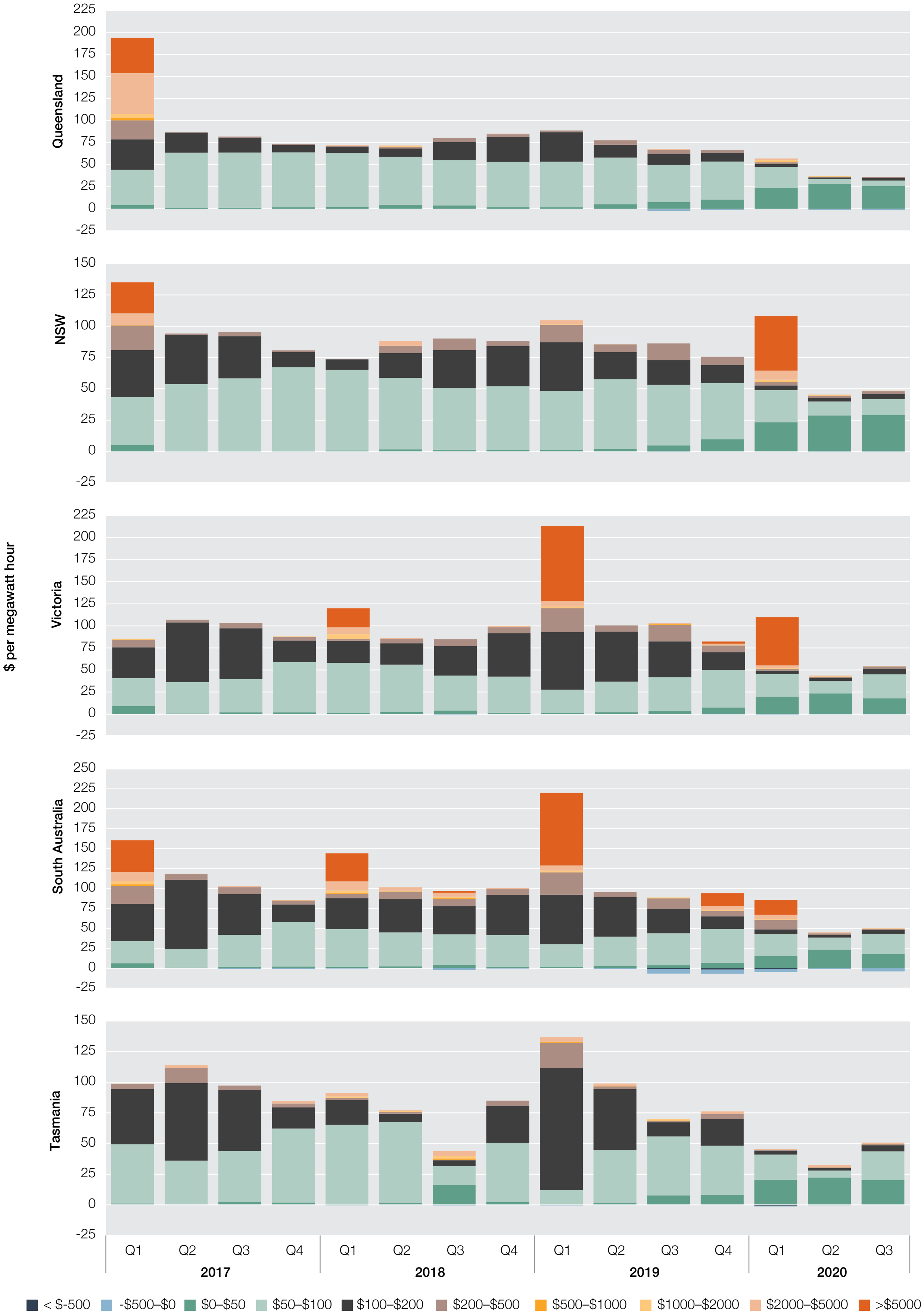
	Q3 2019 (%)	Q3 2020 (%)
Queensland	25	82
NSW	14	79
Victoria	12	55
South Australia	13	52
Tasmania	31	60

Further, while there has generally been an increase in the contribution from prices in the $50 to $100 per MWh price range from Q2 2020 to Q3 2020, the contribution of these prices is still significantly lower than in Q3 2019 (figure 1.6).

---

[2] AER, *Wholesale markets quarterly Q3 2019*, November 2019; AER, *Wholesale electricity markets performance report 2020*, December 2020.

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



Source: AER analysis using NEM data.

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

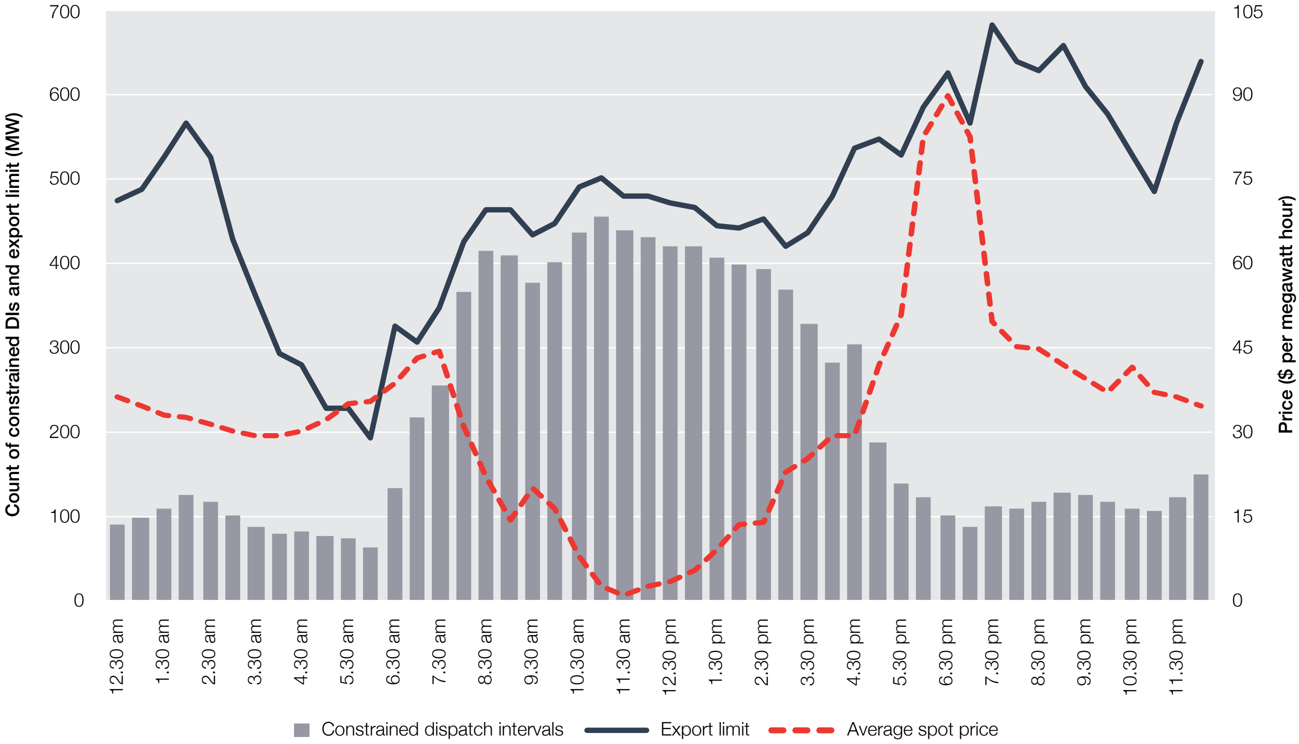
1.3 Interconnector limits contribute to negative prices in Queensland and South Australia

Work to upgrade the transfer capacity of the Queensland-NSW interconnector (QNI), which started in May 2020, continued to limit flows from Queensland into NSW over Q3 2020. As a result of outages related to the upgrade, around a third of the time flows from Queensland into NSW were limited to below 500 MW. This is half the typical limit of around 1000 MW.

When interconnectors are unconstrained and generation flows freely between regions, prices between the regions align. While there were still significant exports from Queensland into NSW, the lower limits on the QNI interconnector meant that in Q3 2020 prices between Queensland and NSW were aligned only around 60 per cent of the time. This was their lowest level of price alignment since the start of the NEM.

Instances where no further generation could flow from Queensland into NSW occurred most often during the middle of the day (figure 1.7). This meant there was low priced solar generation in Queensland that could not flow to NSW. This excess of generation put downward pressure on the Queensland spot price during daylight hours, and instances of negative prices in Queensland increased. Once completed in mid-2022, the upgrade will increase the southwards capacity of the interconnector by 190 MW and the northwards capacity by 460 MW, however in the meantime the work will likely continue to affect market outcomes.

Figure 1.7 Queensland-New South Wales Interconnector, export limit from Queensland

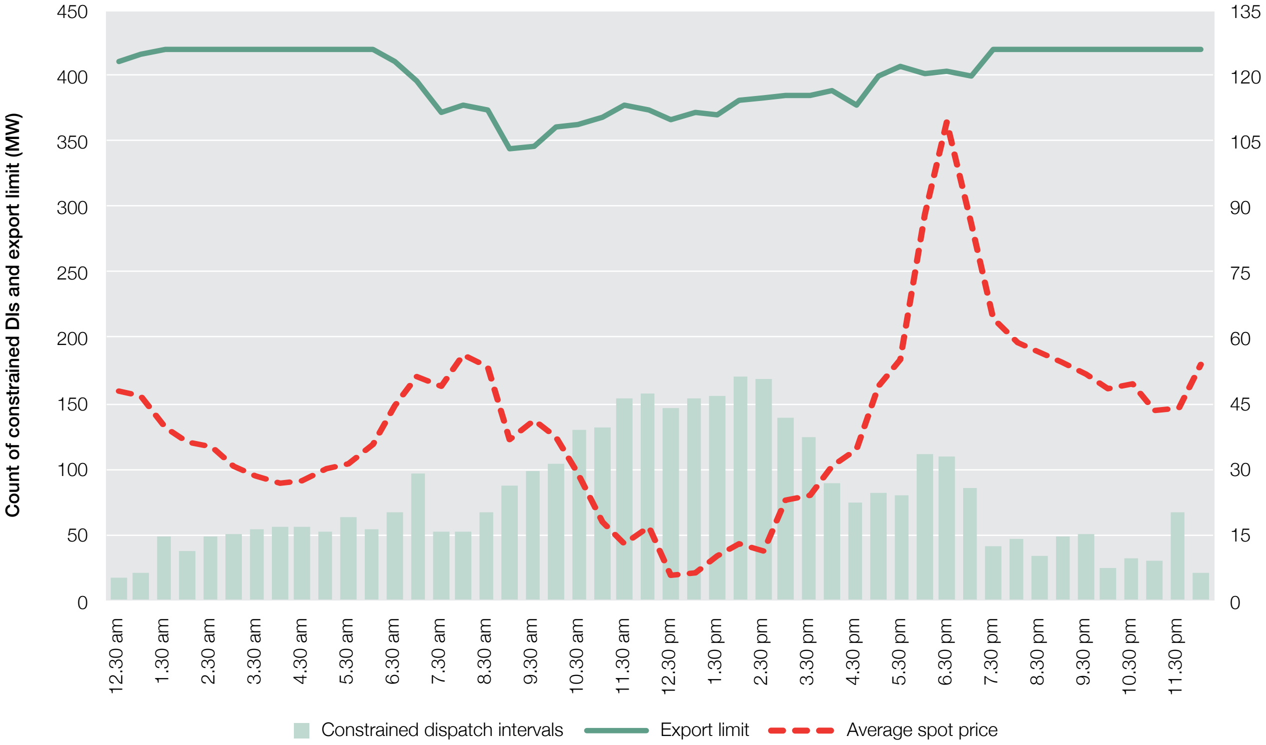


Source: AER analysis using NEM data.

Note: The bars show a count of the dispatch intervals (DIs) when the interconnector was constrained, i.e. could not export anymore into NSW. The limit of each dispatch interval is the average limit only when the dispatch interval was constrained. The average spot price is the average spot price for that dispatch interval across the quarter (including constrained and unconstrained).

There were also reduced limits on flows over the Heywood interconnector in Q3 2020. In mid-July, failure of network equipment at the Para substation in South Australia led AEMO to place a 420 MW limit on flows from South Australia into Victoria where the limit is normally around 600 MW. Like Queensland, this lower limit capped the amount of low-priced renewable generation that was able to flow out of South Australia. This occurred most often during the middle of the day when demand was low due to rooftop solar generation, especially during periods of high wind generation (figure 1.8). Again like Queensland, this put downward pressure on spot prices in South Australia and contributed to the record number of negative prices in the region. The export limit is expected to stay in place until July 2021 and is likely to affect market outcomes until then.

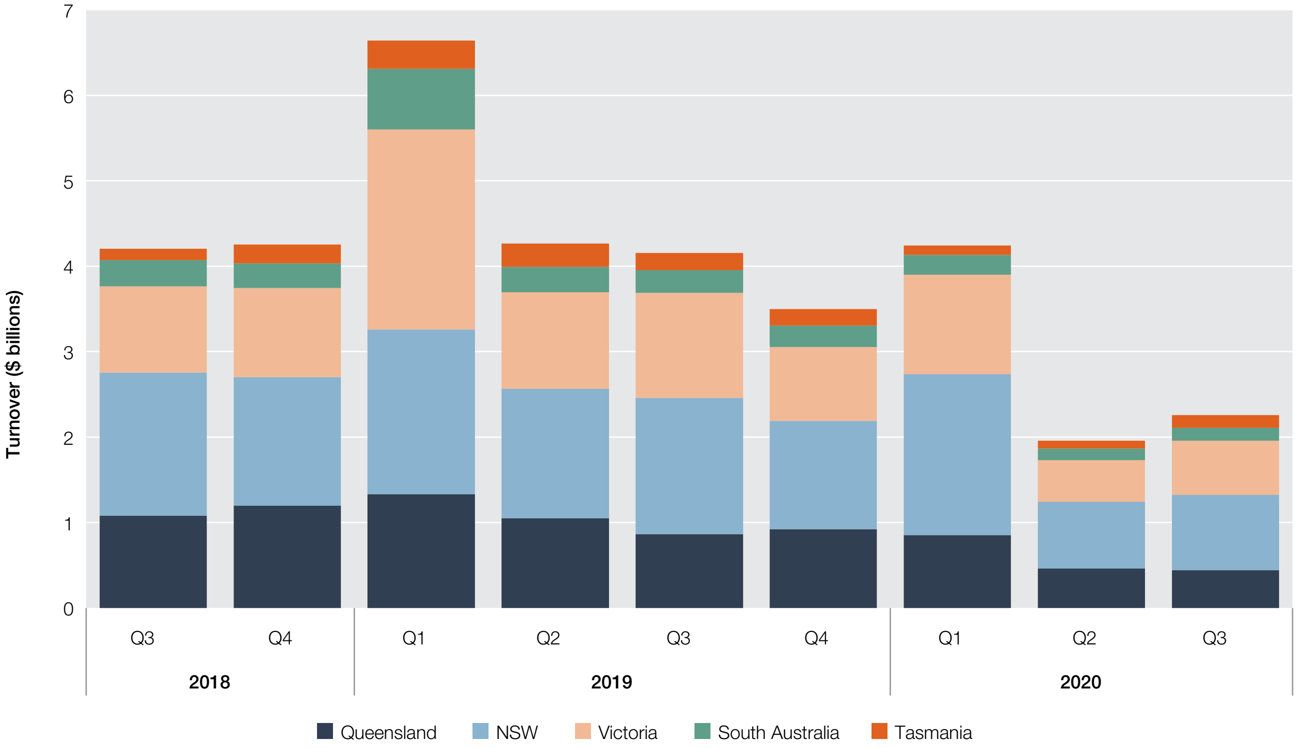
Figure 1.8 **Heywood interconnector, export limit from South Australia**



Source:	AER analysis using NEM data.
Note:	The bars show a count of the dispatch intervals when the interconnector was constrained, i.e. could not export anymore into Victoria. The limit of each dispatch interval is the average limit only when the dispatch interval was constrained. The spot price is the average spot price for that dispatch interval across the quarter (including constrained and unconstrained).

Low quarterly prices and seasonally low average quarterly demand resulted in low spot market turnover in Q3 2020 of around $2.2 billion, slightly more than half the level of Q3 2019 (figure 1.9). In the first three quarters of 2020, NEM turnover was around $8.5 billion compared to around $15 billion in the same period in 2019.

Figure 1.9 NEM turnover



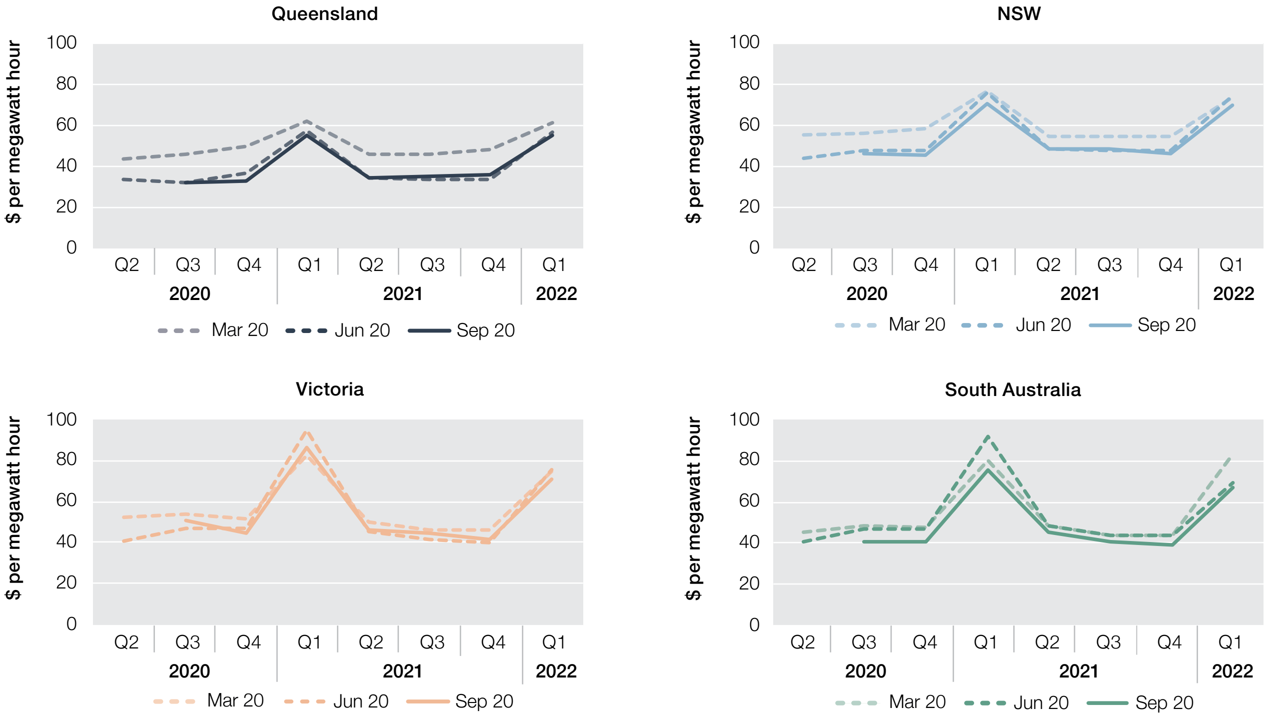
Source: AER analysis using NEM data.

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

1.4 Forward markets expect prices below $90 per MWh this summer

Prices are expected to be low and stable across the NEM for the remainder of 2020, with quarter four prices expected to remain below $50 per MWh in all regions (Figure 1.10). With the exception of the fall in base future prices for Q1 2021 in Victoria and South Australia, prices for forward quarters have remained the same since the start of June.

Figure 1.10 Forward base future prices



Source: AER analysis using ASX Energy data.

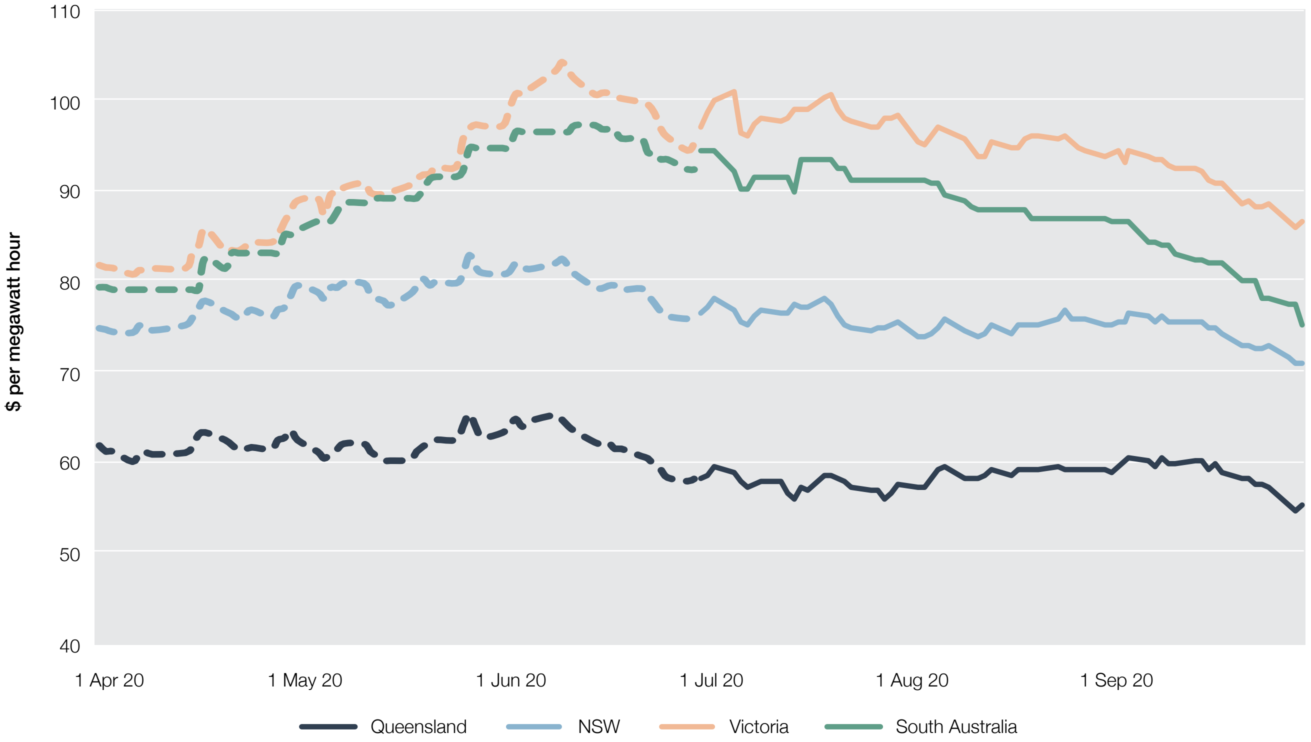
Note: Closing price of base futures contracts for Q2 2020 to Q1 2022 on the last trading day of Q1 2020 (31 March), Q2 2020 (30 June) and Q3 2020 (30 September).

Prices are expected to be higher for Q1 2021 than for other quarters, reflecting the typical impacts of summer conditions on demand. Q1 2021 base futures prices were below $90 per MWh in all regions by the end of September, which is moderate compared to recent Q1 outcomes. By the end of the quarter, they ranged from $55 per MWh in Queensland up to $86 per MWh in Victoria.

Price expectations for Q1 2021 base futures in Victoria and South Australia fell over this quarter, reversing the trend seen earlier in the year (figure 1.11). There were more moderate falls in Q1 2021 base futures prices in NSW and Queensland over quarter three.

Similarly Q1 2021 cap prices fell in Victoria and South Australia over this quarter (figure 1.12). Quarter 1 2021 cap prices ranged from $8 per MWh in Queensland to $36 per MWh in Victoria at the end of September. These are moderate by recent standards—comparable Q1 2020 cap prices at the end of September 2019 were $54 per MWh in Victoria and South Australia.

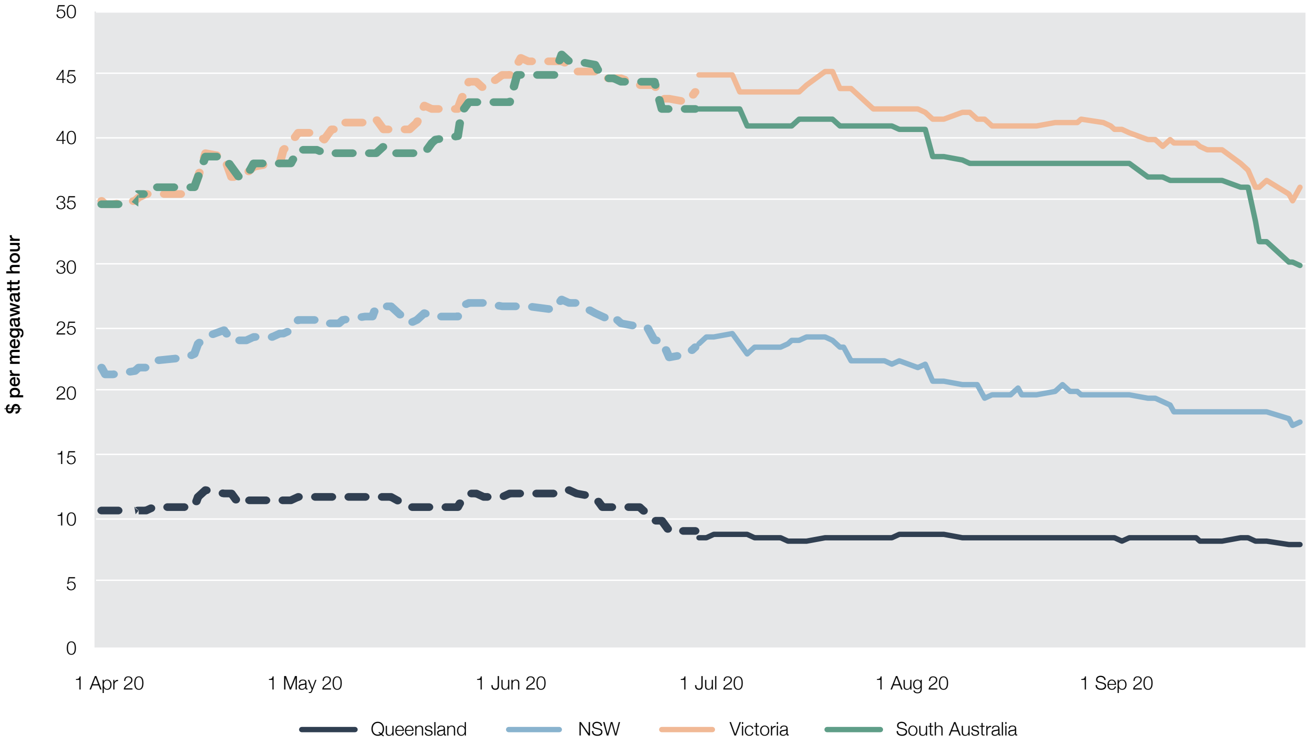
Figure 1.11 Q1 2021 base future prices



Source: AER analysis using ASX data.

Note: Daily closing price for Q1 2021 base futures from 1 April 2020 to 30 September 2020.

Figure 1.12 Q1 2021 cap prices



Source: AER analysis using ASX data.

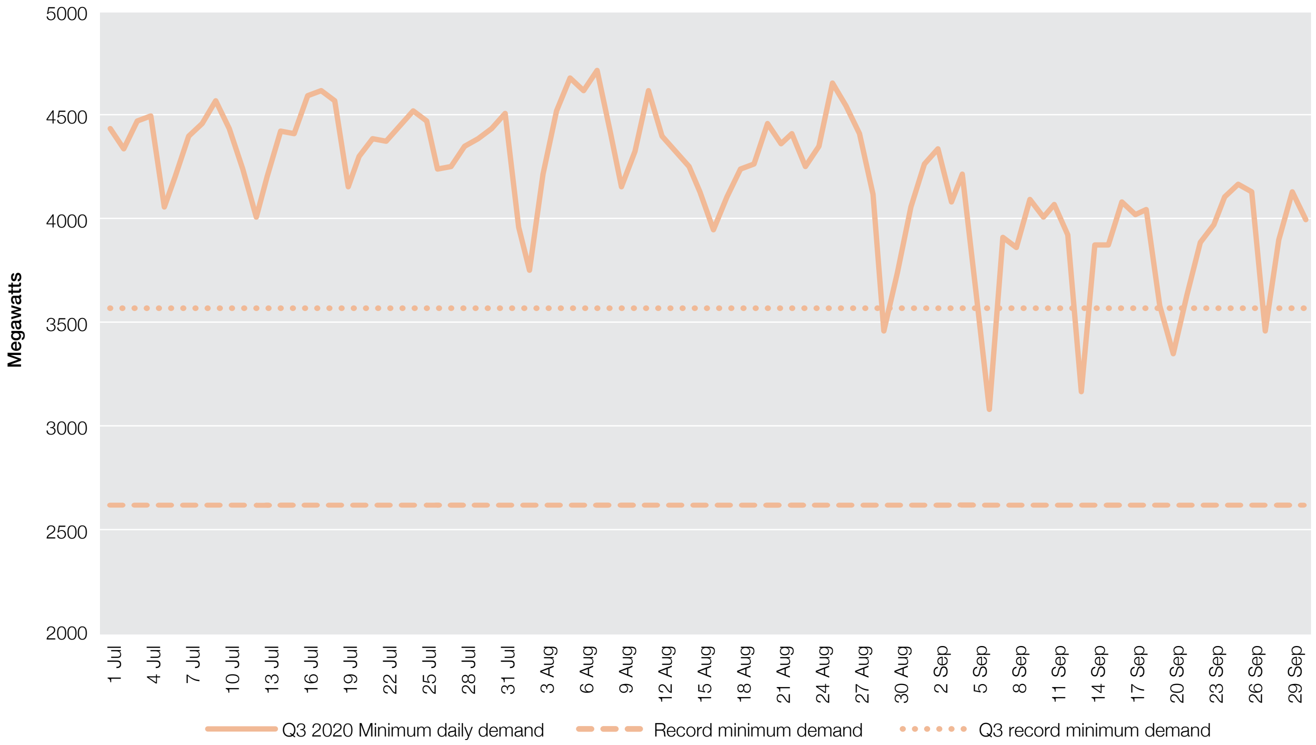
Note: Daily closing price for Q1 2021 caps from 1 April 2020 to 30 September 2020.

1.5 Demand very low during the day in Victoria and South Australia

There were increasing instances of demand from the grid reaching low levels in the middle of the day in September. Quarter three is typically a quarter of low demand, characterised by mild temperatures and good rooftop solar generating conditions. These conditions were further enhanced by a warmer than usual September to create days of very low daytime demand.

Demand in Victoria fell below the previous Q3 record on five separate days, while demand in South Australia fell to an all-time low of just 426 MW (figure 1.13 and figure 1.14).[3] While low demand in South Australia has been a trend for some time, such low demand in Victoria is relatively new. There has been a surge in rooftop solar installations in the past 12 months in response to Victorian state government rebates.[4] This and low heating requirements meant even less electricity was needed from the grid than usual this quarter. COVID-19 also had an impact on Victorian demand, although AEMO found the Victorian shutdown reduced demand during the morning peak but did not reduce demand during the middle of the day.[5]

Figure 1.13 Minimum daily demand, Victoria



Source: AER analysis using NEM data.

Note: Uses daily minimum native demand. Record refers to the lowest record native demand that has occurred in the region since market start. Q3 record refers to the lowest record native demand that has occurred in the region in quarter three since market start.

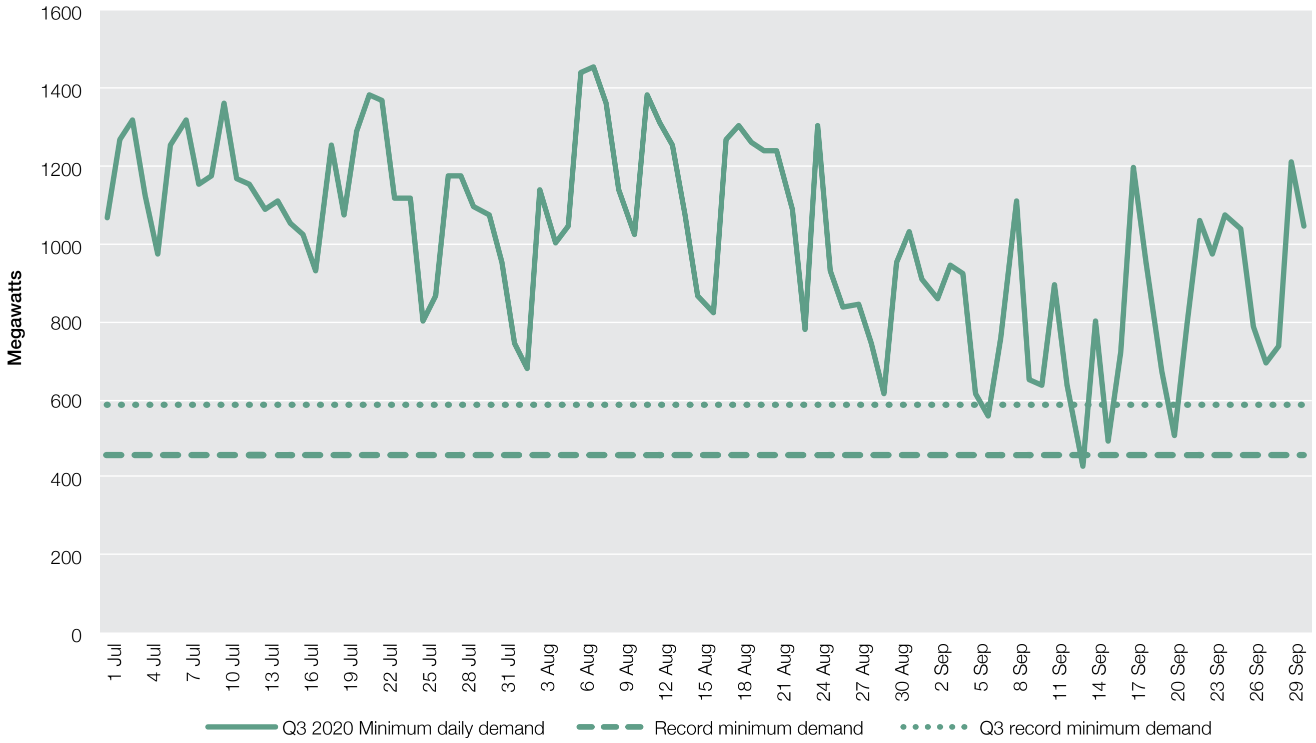
---

[3] Demand from the grid excludes demand met by rooftop solar.

[4] https://www.solar.vic.gov.au/solar-homes-rebate-1888-1-january-2020.

[5] AEMO analyse the impact of COVID-19 on demand in Victoria in *Quarterly energy dynamics—Q3 2020*, October 2020.

Figure 1.14 Minimum daily demand, South Australia



Source: AER analysis using NEM data.

Note: Uses daily minimum native demand. Record refers to the lowest record native demand that has occurred in South Australia since market start. Q3 record refers to the lowest record native demand that has occurred in the region in quarter three since market start.

Exceptionally low demand has implications for system security. In South Australia, demand fell below 650 MW on at least nine days. Where South Australia is at risk of islanding, a minimum of around 600 MW of synchronous generation is required to provide sufficient system strength to withstand a credible fault and loss of a synchronous unit.

High maximum demand periods are still expected across most regions, despite the increasing solar uptake.[6] This is because maximum demand from the grid now typically occurs closer to sunset, when rooftop solar contributes less to meeting household consumption.

1.6 Black coal, gas and hydro generation down

Lower than usual demand in September meant average quarterly generation in Q3 2020 was down nearly 400 MW compared to the same period last year (figure 1.15). Meanwhile, solar and wind generation continued to rise as more capacity came online. As a result, less black coal, gas and hydro generation was dispatched, especially in the middle of the day.

The average output of black coal and gas were both down by over 420 MW compared to Q3 2019. At a regional level, Queensland black coal generation was lower than in Q3 2019 as a number of generators experienced both planned and unplanned outages. And, with the exception of Queensland, gas generation was also lower in all mainland regions. Average hydro output was down by close to 200 MW compared to Q3 2019, which largely reflected unseasonably low rainfall in Tasmania.

This quarter saw record average wind output of almost 2500 MW, an increase of around 250MW on the previous high set in Q3 2019. July to September is typically the windiest quarter of the year and over 1000 MW of new wind capacity has entered the market over the last 12 months. Wind output increased the most in Victoria where the majority of the new wind farms are located. It also increased in Queensland where Coopers Gap wind farm (450 MW) has been ramping up.[7]

---

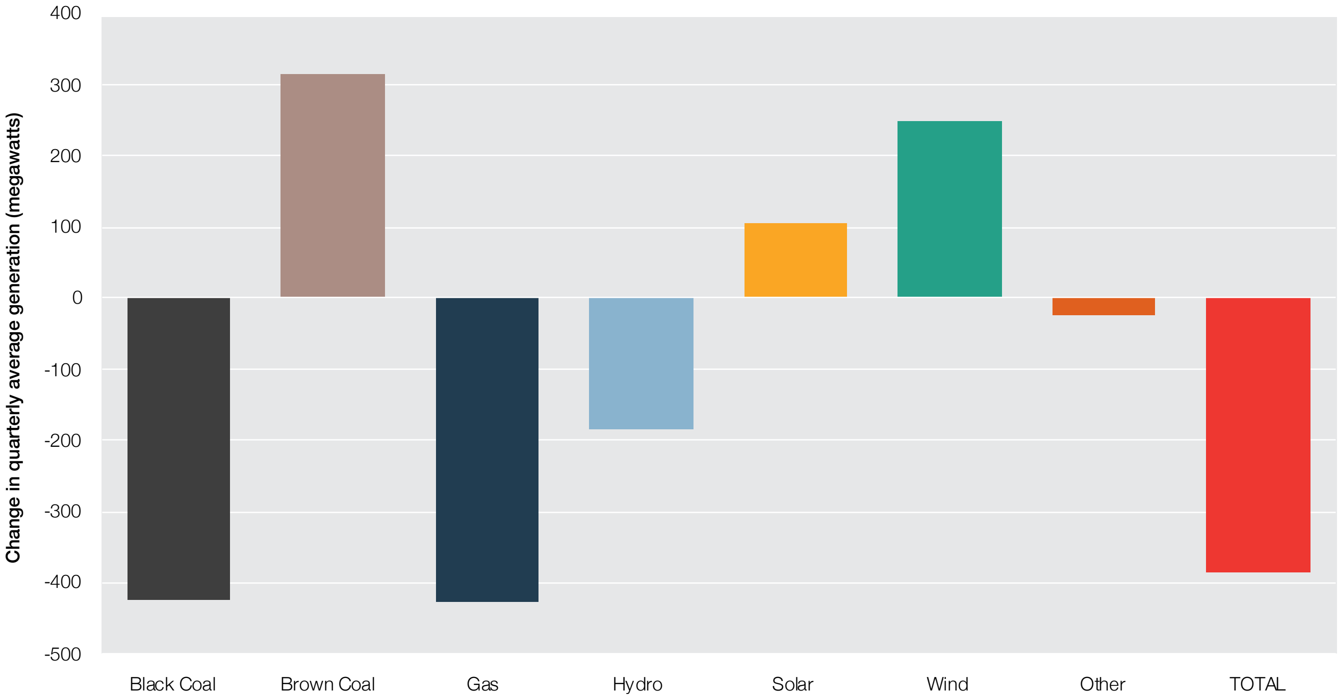
[6] AEMO, *2020 Electricity statement of opportunities (ESOO)*, August 2020.

[7] On 4 November 2020, AGL announced the blades of one of the new wind turbines at Coopers Gap will have to be replaced as well as a number of generators. The wind farm remains operational.

Average solar production was also up from levels a year earlier, with 750 MW of grid connected solar entering the market. The full impact of this new solar plant is expected to materialise next quarter, with the quarter four being the best quarter of the year for solar generation. In summary, average wind and solar output combined was up by over 350 MW in Q3 2020 compared to Q3 2019 with wind and solar output up in every region, except South Australia where there has been no new grid-scale renewable entry over the past 12 months.

Average brown coal output was also up by over 300 MW but from a low base in Q3 2019 due to brown coal outages last year. In our Q3 2019 report, we reported significant brown coal outages in Victoria at Loy Yang A (552 MW out for 92 days), Loy Yang B (535 MW out for 14 days) and Yallourn (382 MW out for a total of 85 days). In comparison, this year there were far fewer unplanned brown coal outages. Appendix A lists the major planned and unplanned outages across the NEM during the quarter.

Figure 1.15 Change in average quarterly generation, Q3 2019 to Q3 2020



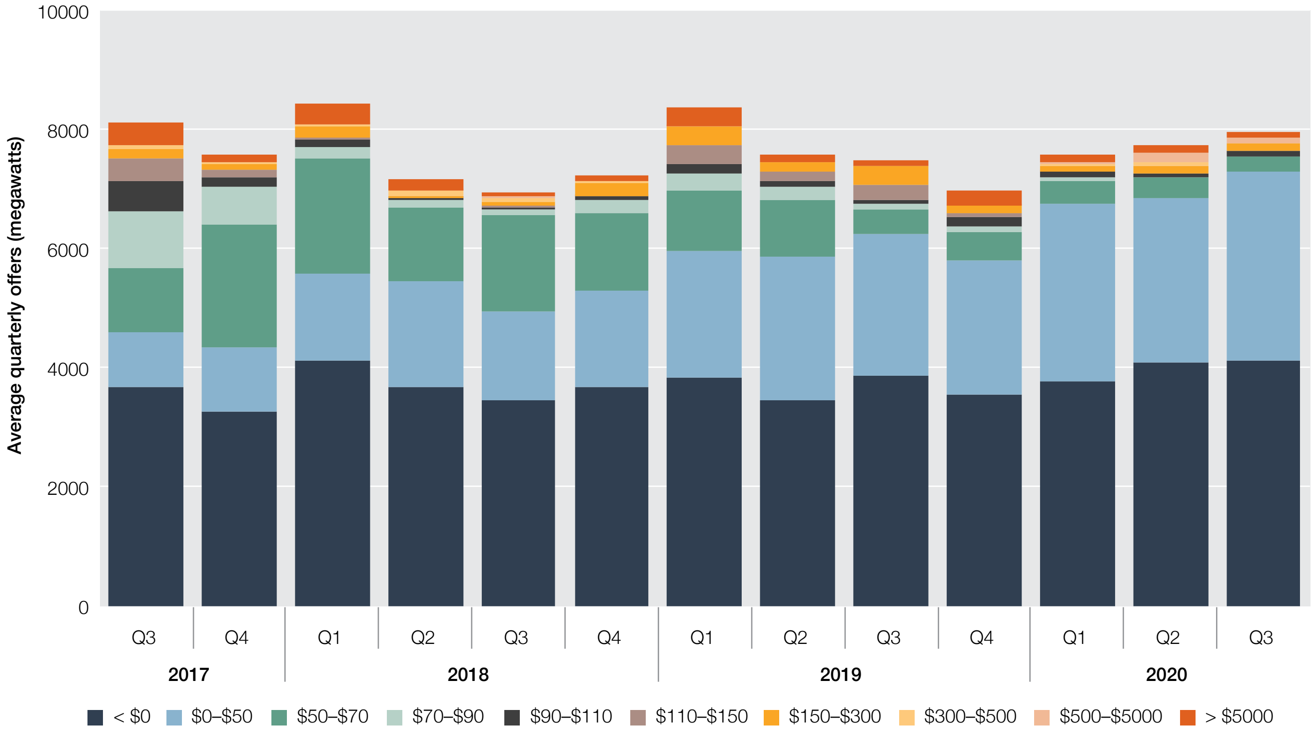
Source: AER analysis using NEM data.

Note: Change in quarterly average metered generation output by fuel type from Q3 2019 to Q3 2020. Solar generation includes large scale generation only. Rooftop solar PV is not included as it affects demand not grid-supplied generation output.

1.7 Black coal offers more capacity priced below $50 per MWh

Black coal generators continued to offer capacity at low prices. NSW black coal generators offered over 1000 MW more capacity into the market priced below $50 per MWh than they did in Q3 2019 (figure 1.16). This was the highest amount offered below $50 per MWh since Q3 2016, and represented more than 90 per cent of black coal offers.

Figure 1.16 Average quarterly offers by price bands, New South Wales black coal



Source: AER analysis using NEM data.
Note: Quarterly average offered capacity by NSW black coal generators within price bands.

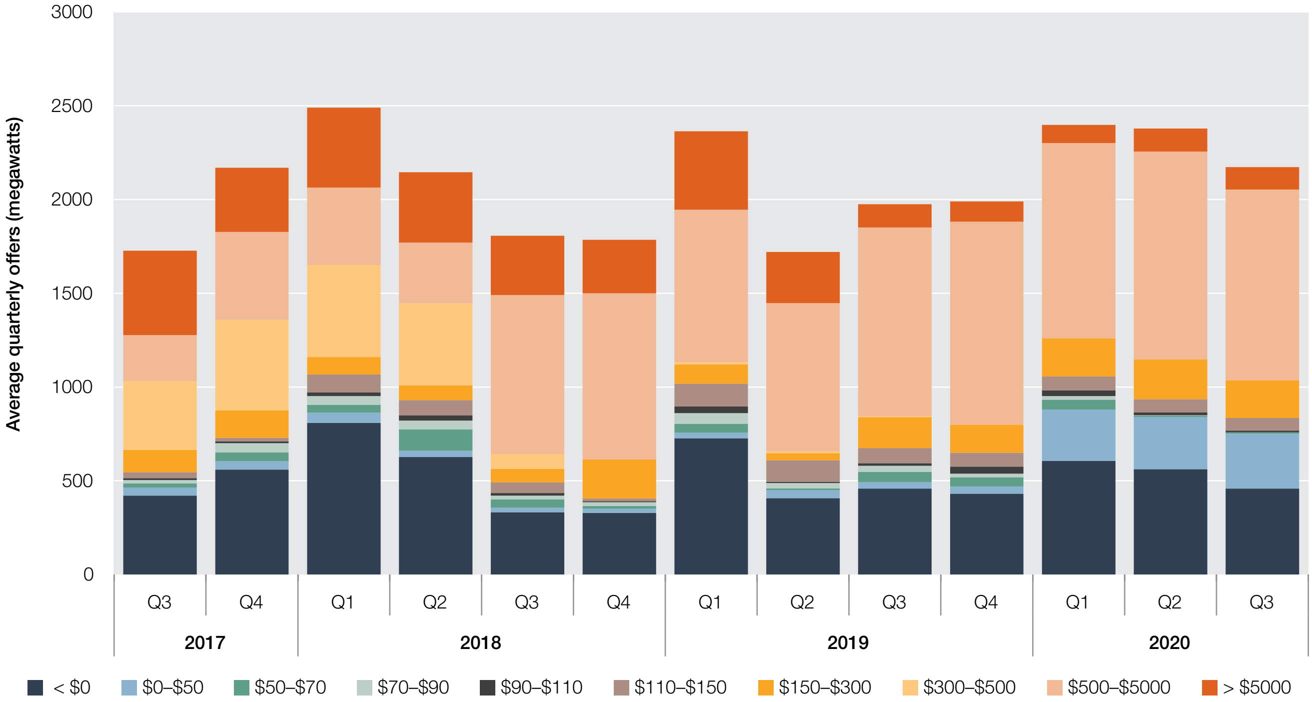
In Queensland, despite outages, black coal generators offered around 240 MW more capacity priced below $50 per MWh in Q3 2020 than in Q3 2019. Scheduled outages at Callide power station and Stanwell power station and unplanned outages at Gladstone power station meant Queensland black coal generators offered 350 MW less total capacity in Q3 2020 than in Q3 2019. This was the lowest amount of total capacity offered since Q4 2013. However, because generators offered a greater share of their capacity at lower prices, these outages did not increase the spot price.

1.8 While gas prices remain low, gas offers vary

With the exception of NSW, gas generators offered more capacity in Q3 2020 than in Q3 2019. However, offers varied between regions.

In Queensland nearly 260 MW more capacity was offered into the market priced below $50 per MWh than in Q3 2019 (figure 1.17). Most of this was offered by Swanbank E power station, which didn't offer capacity into the market in Q3 2019. In South Australia, gas generators offered 160 MW more capacity overall, and 170 MW more capacity priced less than $50 per MWh in Q3 2020 than in Q3 2019. The increase in lower priced gas offers mostly came from AGL Energy's Barker Inlet power station entering the market in Q4 2019.

Figure 1.17 Average quarterly offers by price bands, Queensland gas



Source: AER analysis using NEM data.

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

Overall, less gas was offered in NSW and Victoria in Q3 2020 compared to last year, as Q3 2019 was a quarter of high gas generation due to coal outages.

NSW gas generators offered 135 MW less capacity priced below $50 per MWh and 260 MW less capacity in total in Q3 2020 than in Q3 2019 (figure 1.18). The decrease in offers below $50 per MWh was mostly driven by less offers from EnergyAustralia's Tallawarra and Origin Energy's Uranquinty power stations. Last year EnergyAustralia offered output from Tallawarra power station in order to offset the reduced output from its Mt Piper power station due to coal supply issues. We also observed that the composition of NSW gas offers changed. This quarter 99 per cent of NSW gas offers were either below $50 per MWh or above $5000 per MWh, with hardly anything in between.[8]

In Victoria, gas generators offered 187 MW more capacity in Q3 2020 than in Q3 2019. However, participants shifted offers into the highest price band, with over 500 MW more capacity offered above $5000 per MWh than in Q3 2019. Similar to NSW, gas generators offered nearly all of their capacity into the market priced either below $50 per MWh or above $5000 per MWh.[9] The decrease in offers below $50 per MWh in Victoria was partly due to less offers from EnergyAustralia's Newport power station which ran hard in 2019.[10]

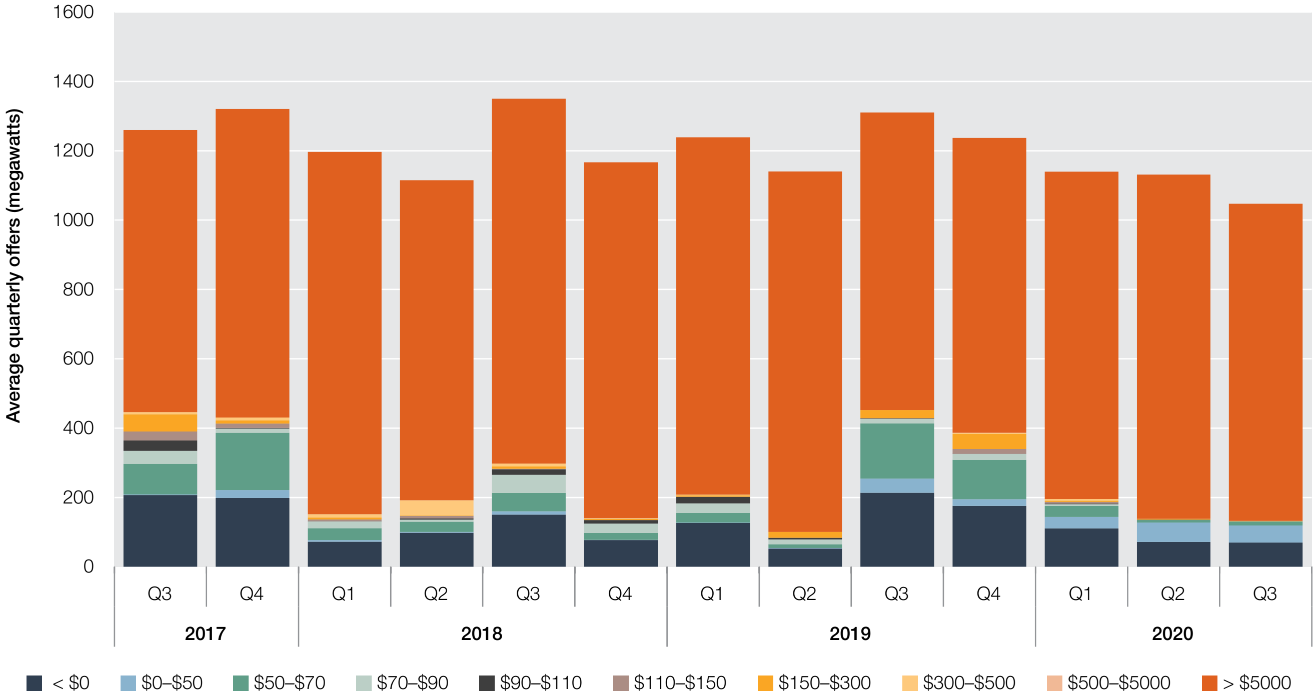
---

[8] The corresponding figure in Q3 2019 was 85 per cent.

[9] The corresponding figure in Q3 2019 was 80 per cent.

[10] Newport power station offered an average of 27 MW in Q3 2018, 126 MW in Q3 2019 and 36 MW in Q3 2020, priced below $50 per MWh.

Figure 1.18 Average quarterly offers by price bands, New South Wales gas



Source: AER analysis using NEM data.

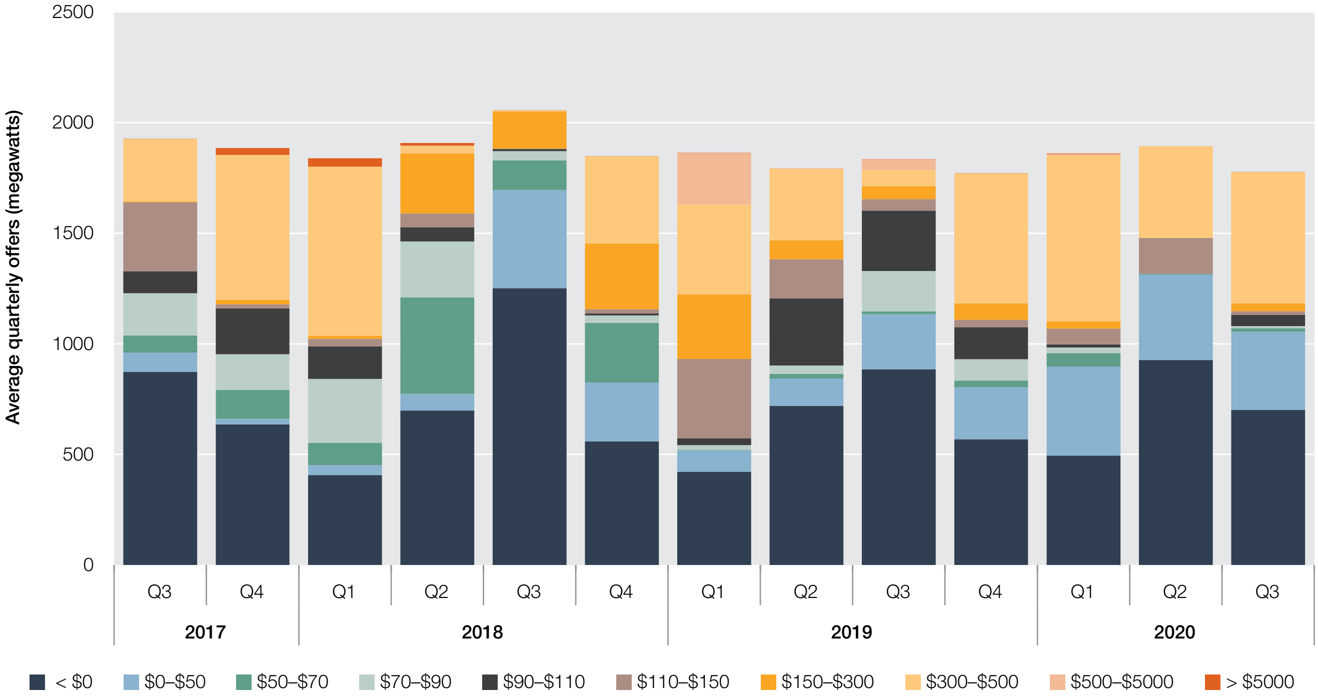
Note: Quarterly average offered capacity by NSW gas generators within price bands.

1.9 Low winter rainfall in Tasmania leads to higher priced hydro offers

Offers from hydro generators varied from region to region with the most significant change in offers occurring in Tasmania.

This year Tasmania had about two-thirds of its typical winter rainfall and July was the second driest July on record in the region. Hydro Tasmania shifted over 500 MW previously priced below $150 per MWh in Q3 2019 to above $300 per MWh in Q3 2020 (figure 1.19). Shifting offers into higher price bands like this is consistent with the need to conserve water. As a result hydro set the price at $54 per MWh in Q3 2020 compared to $30 in Q2 2020 which contributed to the $19 per MWh increase in average quarterly prices in Tasmania.

Figure 1.19 Average quarterly offers by price bands, Tasmania hydro



Source: AER analysis using NEM data.

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

Hydro generators in Queensland offered nearly 80 MW less total capacity in Q3 2020 than in Q3 2019, driven primarily by offers from CleanCo's Wivenhoe power station. While the amount of capacity offered below $50 per MWh didn't change, similar to Tasmania, generators shifted an average of 230 MW previously offered between $150 and $300 per MWh into higher price bands.

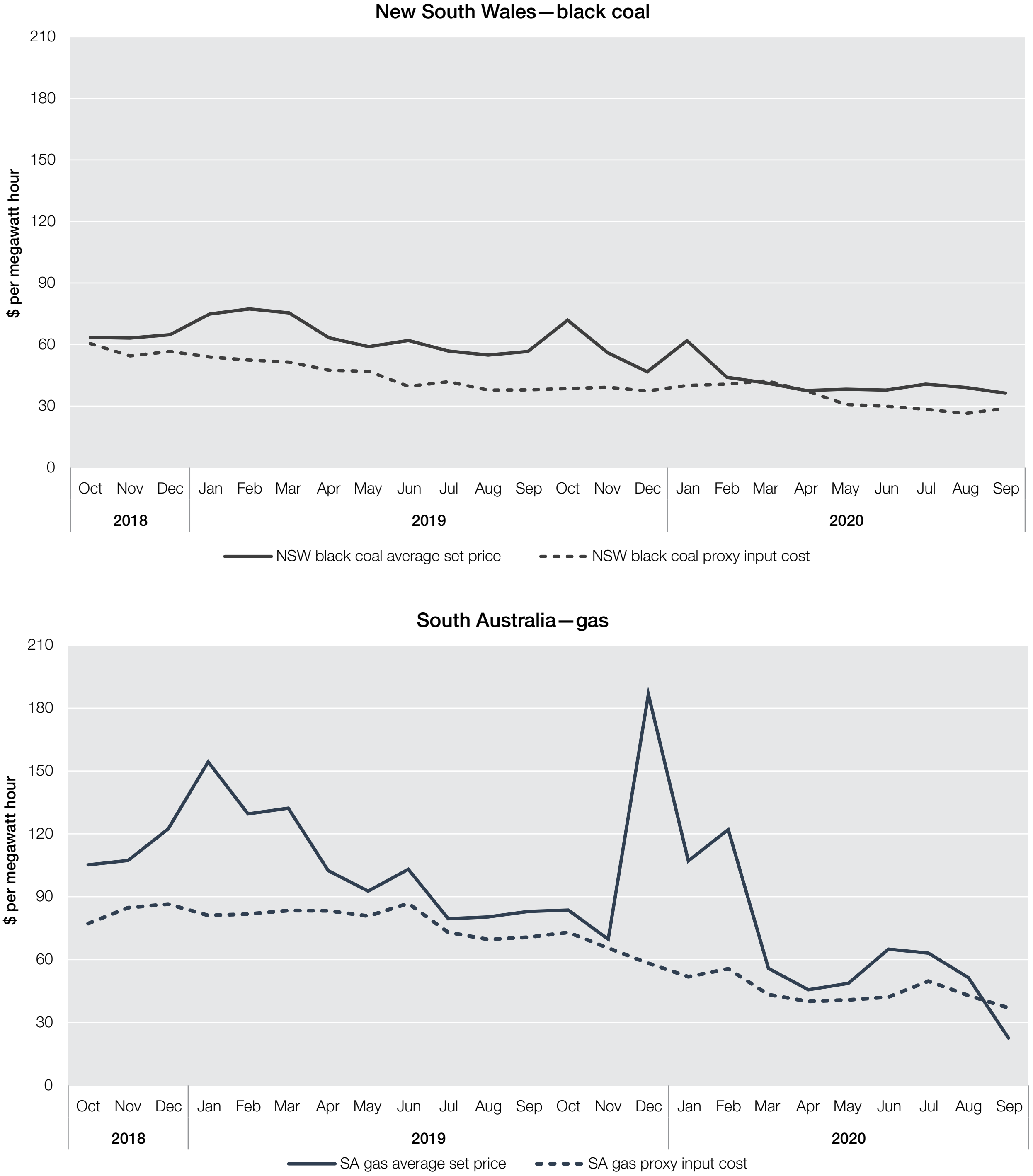
In contrast to Tasmania and Queensland, hydro generators in NSW offered over 220 MW more capacity priced below $50 per MWh in Q3 2020 than in Q3 2019. That said, they also shifted nearly 150 MW previously priced below $150 per MWh to above $150 per MWh.

While hydro generators in Victoria offered 140 MW less capacity in Q3 2020 than in Q3 2019, they offered more capacity priced below $50 per MWh and below $70 per MWh. In total, over 260 MW was shifted down from higher price bands to below $70 per MWh.

1.10 Price set by black coal and gas continues to track lower fuel prices

On the whole, wholesale electricity prices set by black coal and gas tend to track input costs. The price set by NSW black coal generators continued to track the NSW black coal proxy input costs, which remained relatively steady over the quarter (figure 1.20). The average price set by NSW black coal generators increased slightly in July, then fell in August and September to just $36 per MWh. Likewise the price set by South Australian gas generators continued to track the South Australia gas proxy input cost. Notably, in September the average price set by gas generators in South Australia halved to just $22 per MWh, falling below our proxy input cost. Gas fired generators may offer capacity below the proxy input cost to cover contract commitments or retail loads.

Figure 1.20 Average price set and proxy input cost



Source: AER analysis using NEM data.

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

1.11 Black coal, gas and hydro set lower prices than a year ago

Lower spot prices in Q3 2020 compared to Q3 2019 were driven by black coal, gas and hydro generators setting lower prices this year, with the cheapest of these fuel types, black coal, setting the price more often (figure 1.21).

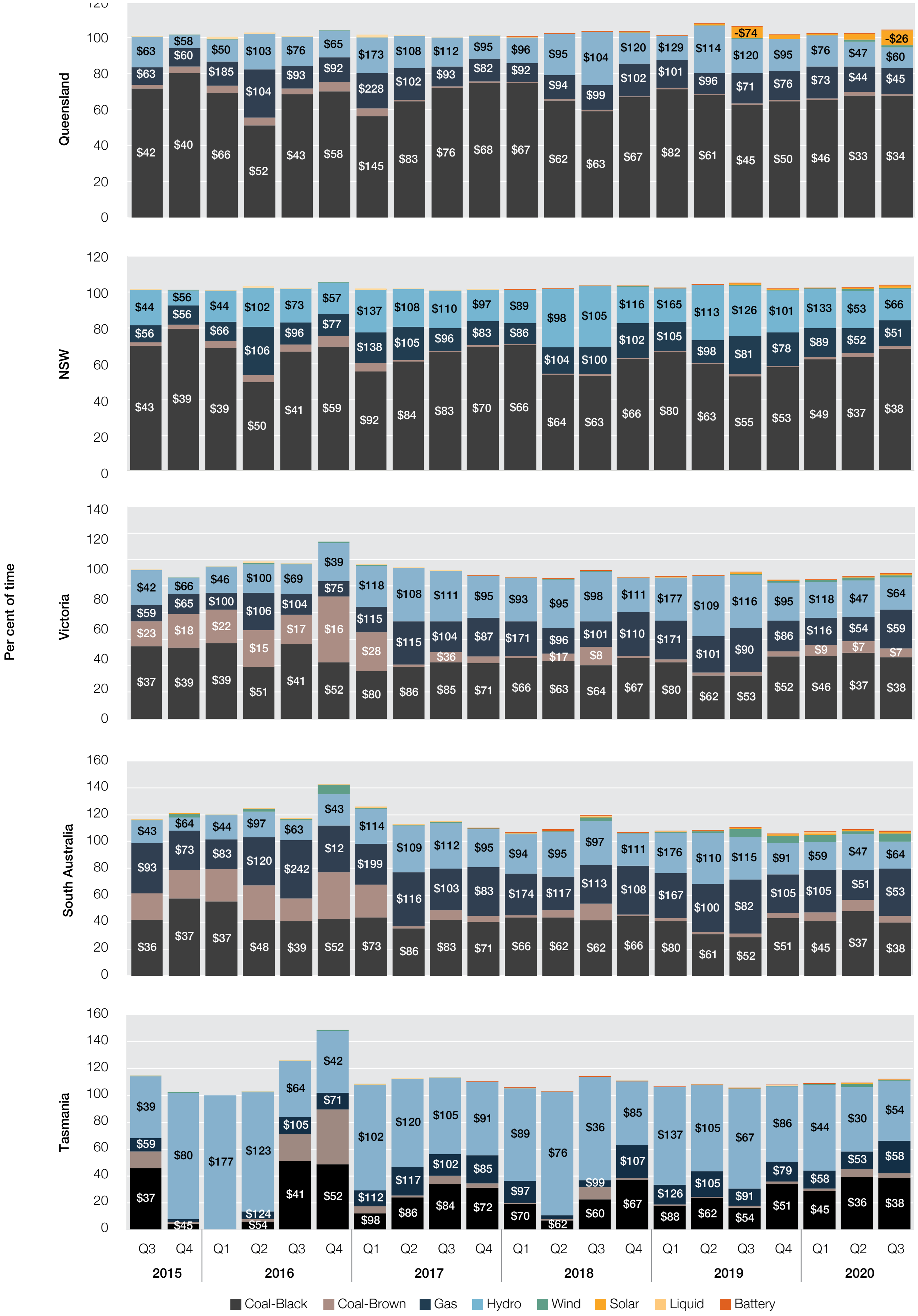
The price set by black coal generators in NSW fell from $55 per MWh in Q3 2019 to just $38 per MWh in Q3 2020 with similar falls of around 30 per cent being mirrored in other regions. Black coal also set the price significantly more often than a year ago, while gas and hydro set the price less often. The amount of time black coal set the price increased from 53 per cent of the time in Q3 2019 up to 68 per cent of the time in Q3 2020 in NSW. Because black coal is typically a cheaper fuel than gas or hydro, this outcome contributed to lower average quarterly prices and occurred not just in NSW but in all regions.

The price set by gas generators fell by an even bigger margin. In NSW for example, the price set by gas generators in that region fell from $81 per MWh in Q3 2019 to $51 per MWh in Q3 2020, a fall of 37 per cent. However, the amount of time gas fired generators set the price in NSW fell from 22 per cent of the time in Q3 2019 to 15 per cent in Q3 2020. With gas being a relatively more expensive fuel, if it sets the price less often, this also contributes to lower average quarterly prices.

Hydro outcomes in Tasmania are worth noting. While hydro typically sets lower prices in Tasmania than in any other region at $54 per MWh in Q3 2020, the amount of time hydro set the price in Tasmania dropped compared to the same quarter last year—falling from 74 per cent of the time last year, to just 45 per cent in Q3 2020. In other states, hydro outcomes for Q3 2020 tended to follow the same trends as gas—setting the price at lower levels on average than in Q3 2019 and setting the price less often.

Solar and wind continued to set negative prices during the middle of the day in all regions but set prices higher than a year ago. The price when set by Queensland solar generators increased from -$74 per MWh in Q3 2019 to -$26 per MWh in Q3 2020. Over the same period, the price set by South Australia wind generators increased from -$191 per MWh to -$104 per MWh. In what is likely to be a continuing trend for similar periods of the year, solar and wind set the price more often, with Queensland solar and South Australia wind generators setting the price 8 per cent and 6 per cent of the time respectively.

Figure 1.21 Price setter by fuel type and region



Source: AER analysis using NEM data.

Note: More than one generator or fuel type may set the price, leading to totals of greater than 100 per cent. The height of the bars is the per cent of the time each fuel type set the price in the region. The price is the quarterly average price set by that fuel type.

1.12 Over 900 MW of new solar capacity enters the market, while two gas units exit

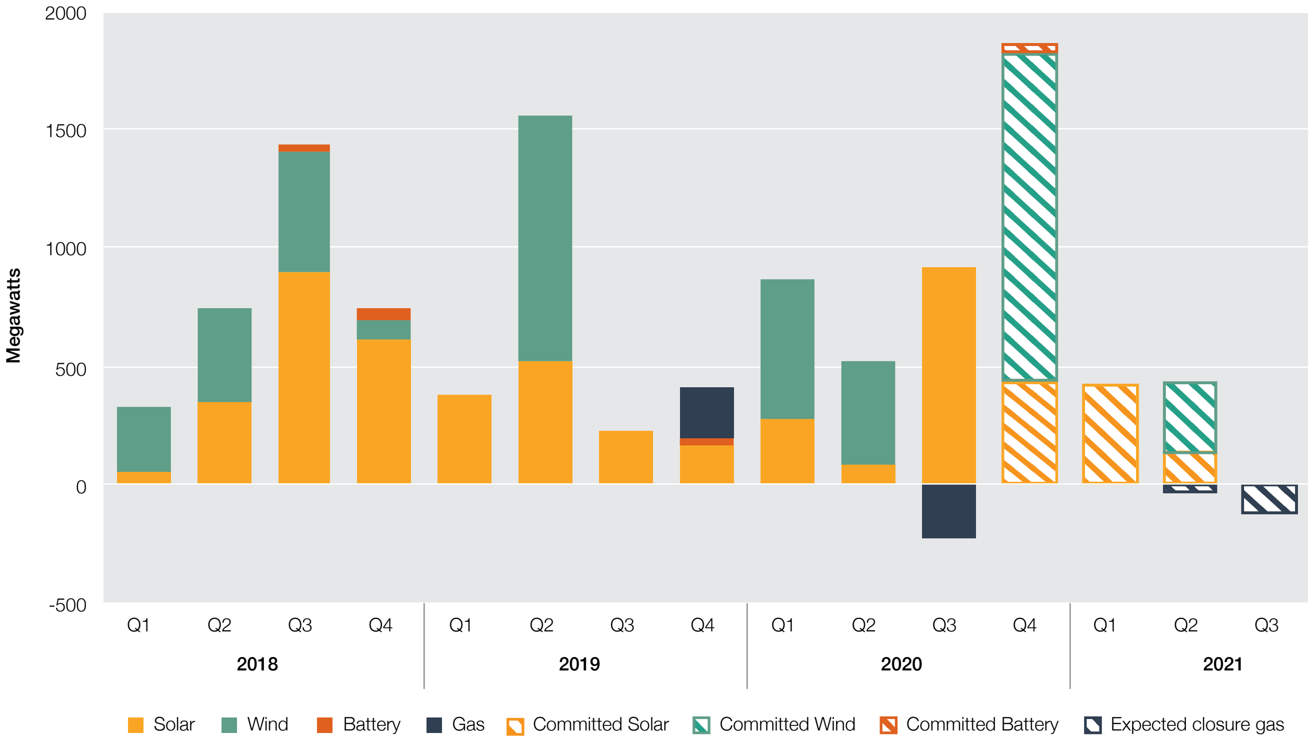
Four solar farms entered the market in Q3 2020 with a combined registered capacity of almost 916 MW (table 1.2).[11] At 324 MW, Darlington Point Solar Farm is the largest solar farm to be connected to the NEM.

Limondale and Darlington Point solar farms are located in the West Murray Zone (WMZ) where last financial year, system strength issues caused AEMO to delay connections and curtail five solar farms to half of their output for seven months. To allow more capacity to be connected AEMO is using control software to coordinate the output of solar farms in the zone. The Darlington Point project also included two synchronous condensers to improve system strength in the region.

Torrens Island A power station units 2 and 4, which were more than 50 years old, officially closed on 30 September 2020. Unit 1 is scheduled to close in September 2021 and the final unit, unit 3, in September 2022. AGL Energy constructed the fast start 205 MW gas-fired Barker Inlet power station alongside the AGL Torrens Island power station site. Since it and the Lake Bonney battery came on line in late 2019, there has been no new entry in South Australia.[12]

Over 1900 MW of new wind, solar and battery capacity is expected to enter the market in the remainder of 2020 (figure 1.22). Over half are wind farms in Victoria, including the Stockyard Hill Wind Farm (530 MW), which will be the largest wind farm in the NEM.

Figure 1.22 New entry and exits by fuel type



Source: AER analysis using NEM data.

Note: New entry is recorded using registered capacity. New entry is allocated to a particular year based on the first day the station produces energy. Closures are denoted below the line.

---

[11] Registered capacity of solar farms is typically between 15 and 25 per cent higher than maximum capacity due to the conversion of energy from DC to AC.

[12] Also the Hornsdale Power Reserve was expanded from 100 KW to 150 KW, but we did not count it as new entry.

Table 1.2 New entry, Q3 2020

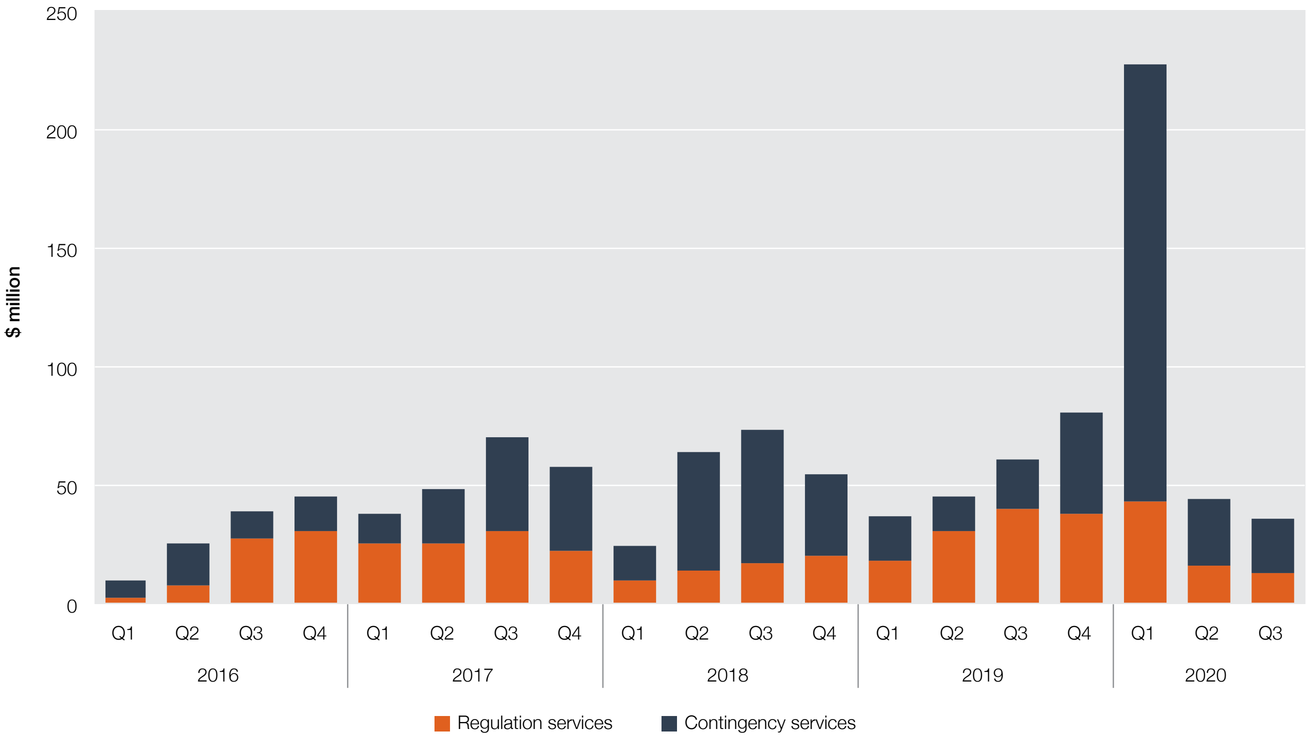
REGION	STATION	FUEL TYPE	COMMENCED OPERATIONS	HIGHEST CAPACITY OFFERED Q3 2020 (MW)	REGISTERED CAPACITY (MW)
NSW	Limondale Solar Farm 1	Solar	July 2020	6	275
NSW	Darlington Point Solar Farm	Solar	September 2020	80	324
Victoria	Kiamal Solar Farm – stage 1	Solar	September 2020	40	239
Queensland	Warwick Solar Farm	Solar	September 2020	8	78
Total					**916**

Note: Registered capacity of solar farms is typically between 15 and 25 per cent higher than maximum capacity due to the conversion of energy from DC to AC.

1.13 FCAS costs fall

Total frequency control ancillary services (FCAS) costs in Q3 2020 were around $36 million, down $25 million compared to Q3 2019 and down $8 million compared to last quarter (figure 1.23).[13] This fall was driven by declining regulation costs, which were $27 million lower than the same time last year. While a small portion of total costs, the cumulative costs for the three lower contingency services increased by around $2 million compared to last quarter and last year.

Figure 1.23 Total FCAS costs by quarter



Source: AER analysis using NEM data.

Average quarterly prices for most FCAS services continued to fall after peaking in Q1 2020 (figure 1.24). Compared to Q3 2019, average regulation prices were down by over 65 per cent with the average quarterly price for raise regulation services down by $29 per MW and for lower regulation services down by $15 per MW.

---

[13] FCAS is used to maintain the frequency of the system. There are eight FCAS markets, two for regulation services and six for contingency services. Regulation services continuously balance small changes in frequency, while contingency services are called upon to respond to major changes in frequency. There are raise and lower services for each category of FCAS. Contingency services are categorised by the time they take to respond – 6 second, 60 second and 5 minute.

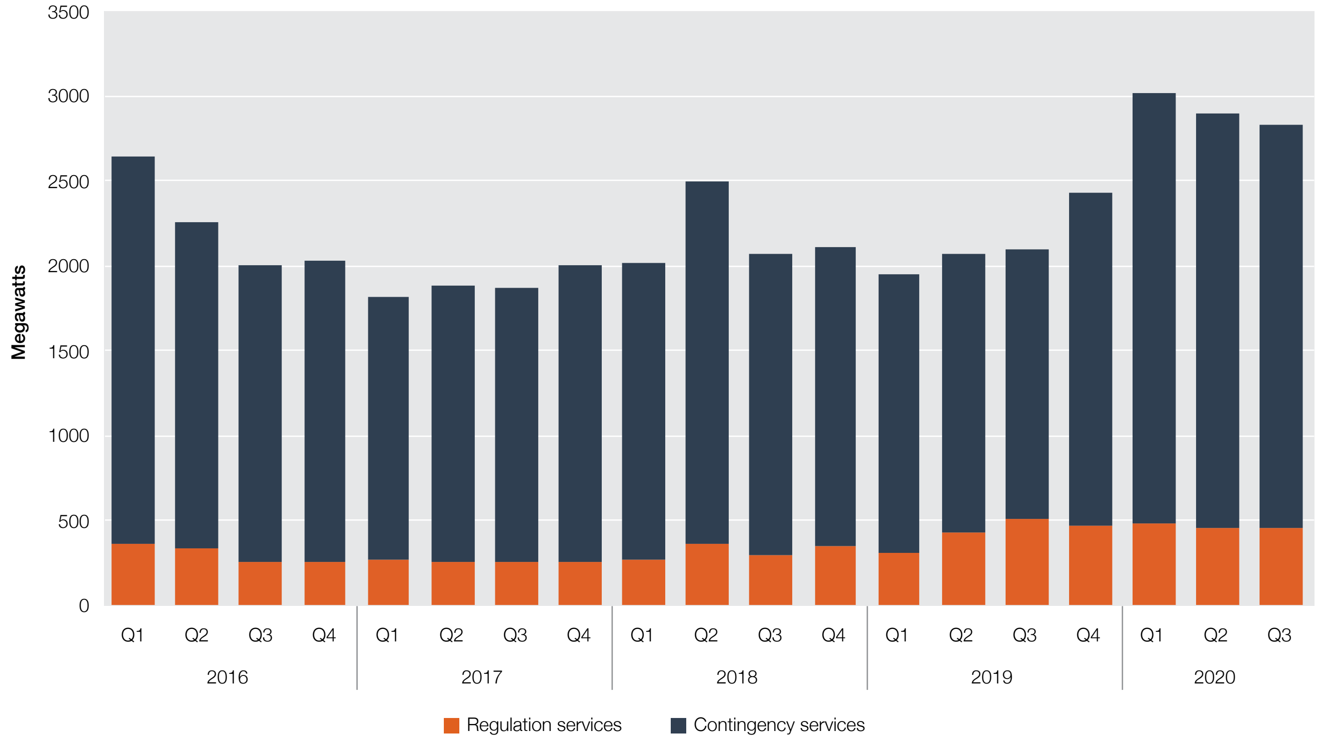
Prices outcomes varied for contingency services. The average quarterly price for raise contingency prices fell by between $0.71 per MW and $4.60 per MW while the average quarterly price for lower contingency services increased by between $0.71 per MW and $1.28 per MW.

Figure 1.24 FCAS prices by quarter, global services only

Source: AER analysis using NEM data.

There was very little change between the amount of FCAS enabled this quarter and last quarter (figure 1.25). However, compared to Q3 2019, total contingency enablement increased by 783 MW (or 49 per cent). This increase aligns with AEMO's announcements to changes in contingency requirements in Q3 and Q4 last year. Over the same period, total regulation enablement fell by 43 MW (or 9 per cent).

Figure 1.25 FCAS enabled by quarter



Source: AER analysis using NEM data.

1.14 Focus–Links between the wholesale gas and electricity markets

There are strong links between the wholesale gas and electricity markets. There is 9500 MW of gas fired generation capacity in the NEM, which contributes around 9 per cent of total output.[14] The share of gas generation varies significantly from region to region. For example, South Australia has no coal or hydro generation so is more reliant on gas fired generation than other regions. There are also a significant number of participants that operate in both markets. Some electricity market participants have interests in gas production or storage facilities, while others participate in gas markets to secure gas for electricity generation. Participants that operate in both markets will price arbitrage between the two when deciding whether to supply gas to generate electricity or sell back into the gas markets.

The price of gas impacts the wholesale electricity market

Changing gas prices impact not only the cost of producing electricity, but also the generation mix and wholesale electricity prices.

The price of domestic gas impacts how gas fired generators offer into the electricity market. To cover rising gas costs, gas fired generators offer more of their capacity into the market at higher prices. If they are needed to meet demand they will set the price at higher levels and this contributes to higher average prices. In Q3 2020, gas fired generators set the price 15 per cent of the time in Queensland and NSW, 30 per cent of the time in Victoria, and 36 per cent of the time in South Australia. Gas tends to be the marginal generator towards the end of the evening peak, from around 7pm onwards.

Domestic gas prices have changed several times in the past six years:

- 2015—The start of liquid natural gas (LNG) exports from Queensland linked domestic gas prices with international oil and gas prices driving prices higher in 2016 and 2017.
- 2017—The Australian Government proposed limiting LNG exports by introducing the Australian Domestic Gas Security Mechanism. In response, gas offers from LNG exporters increased and domestic gas prices fell from Q1 2017 peaks.
- 2018—Domestic prices rose again in line with international prices.
- 2019—International gas prices fell and this had a strong bearing on domestic gas prices. By Q2 2020 domestic gas prices had fallen to pre-LNG export levels. Other factors contributing to lower domestic prices included high levels of Queensland gas production, competition in spot gas markets and the introduction of pipeline capacity auctions reducing shipping costs from north to south.[15]

Owners of gas fired power stations generally enter into long term (one to two years) gas supply contracts but may be able to source from the spot market when needed. Interestingly, since Q4 2019 spot markets have offered a cheaper source of gas than contract markets. When deciding whether to use gas for electricity generation, market participants will often value their gas at the price they could sell it on the spot market, including the Short Term Trading Markets in Adelaide, Brisbane and Sydney, the Declared Wholesale Gas Market in Victoria or the Gas Supply Hubs.

Gas powered electricity generation impacts demand for domestic gas

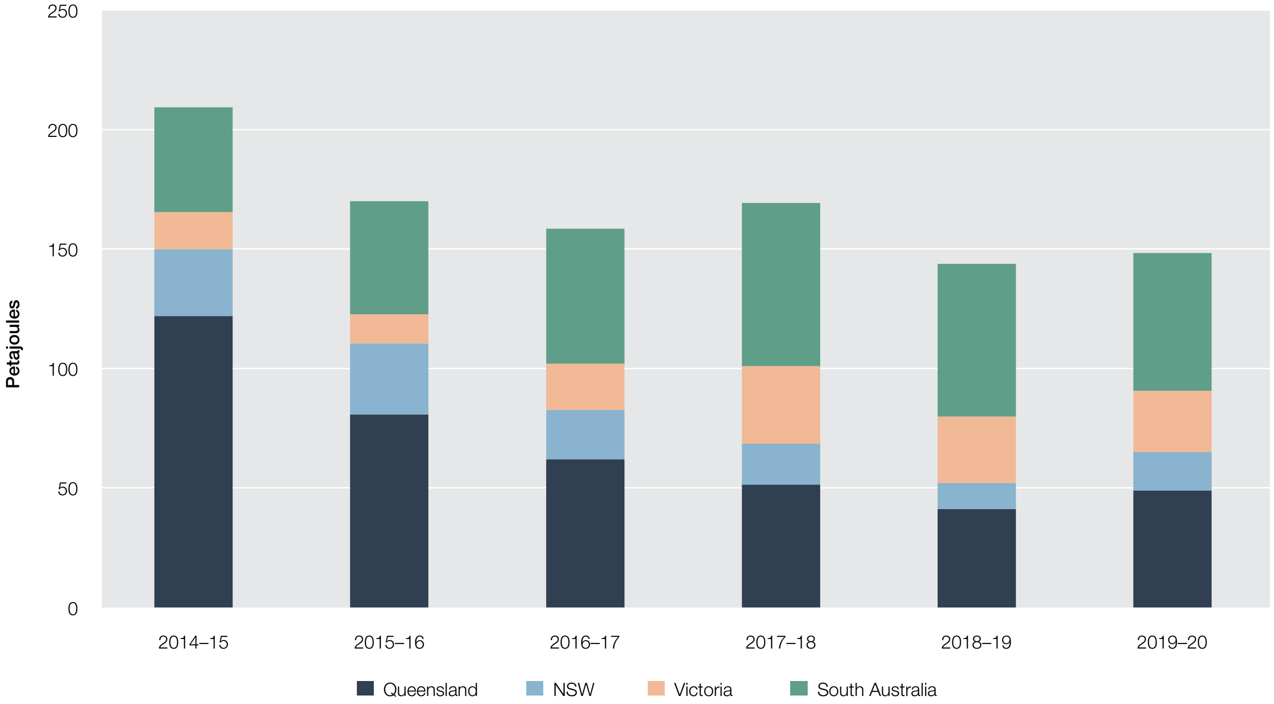
While the majority (around 70 per cent) of gas produced in eastern Australia is exported as LNG, the electricity sector is still a major consumer of gas. In 2019–20, almost 150 petajoules (PJ) of gas was used to produce electricity in the NEM (figure 1.26). While this is down from the 200 PJ used to produce electricity in 2014–15, it still accounts for around 26 per cent of domestic gas use.

---

[14] The share of gas fired generation varies, ranging from as low as 2 to 4 per cent in NSW and Victoria up to around 50 per cent in South Australia for the 12 months ending 30 September 2020.

[15] AER, *State of the energy market 2020*, July 2020, p. 200.

Figure 1.26 Gas used for electricity generation



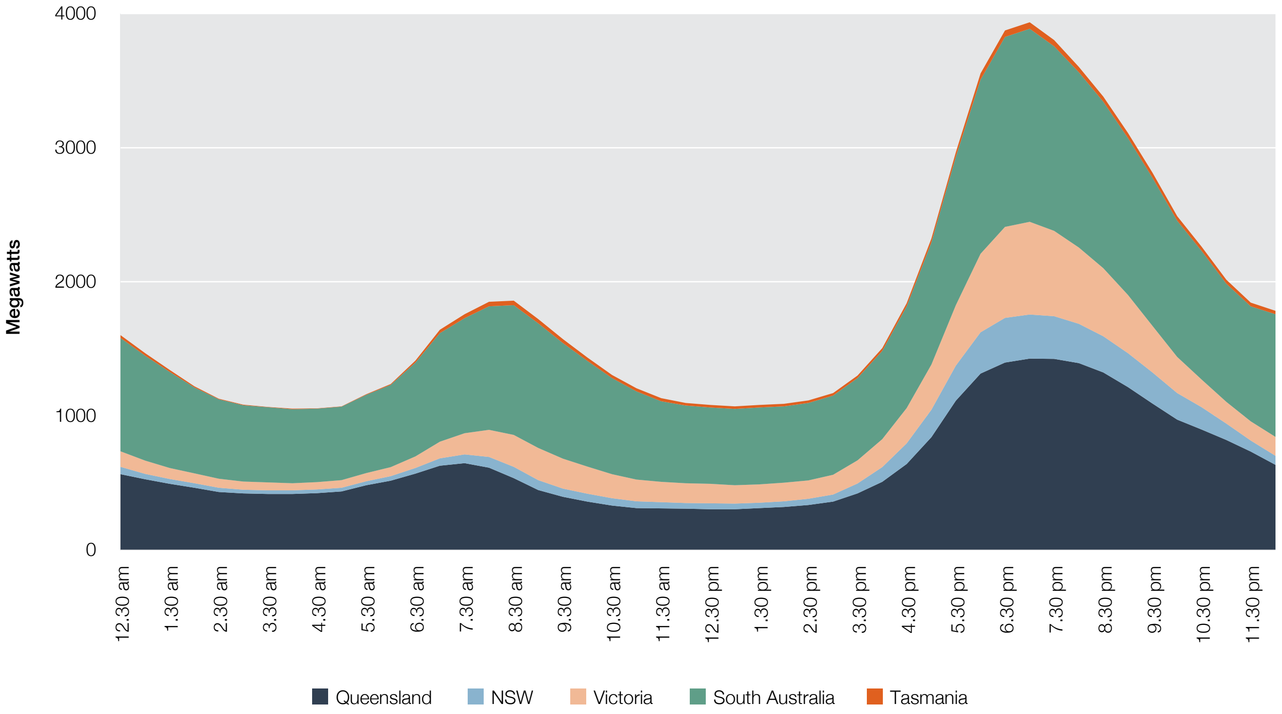
Source: NEM data, ACIL Allen data.

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

Gas fired generators typically operate as ‘flexible’ or ‘peaking’ plants that operate at times of high demand or prices in the electricity market. In summer, high demand for gas to generate electricity may push up domestic spot prices at the same time Asian demand for LNG peaks for the northern hemisphere winter. Gas usage for electricity generation also varies with plant outages and renewable generation output.

While increasing solar generation is helping to displace gas fired generation during the middle of the day, gas generation continues to play an important role providing generation during the evening peak. Looking at gas generation by time of day in Q3 in 2020, average gas fired generation increases from around 1000 MW during the middle of the day to around 4000 MW during the evening peak when solar generation is unable to contribute (figure 1.27). In South Australia, on Sunday 11 October solar generation was enough to meet regional demand for an hour between 12 noon and 1 pm, however by 6.30 pm 1300 MW of gas fired generation was dispatched to meet the evening peak. As a consequence of this transition, gas generators may re-structure their bids to recover fixed costs over a shorter period of the day.

Figure 1.27 Average gas generation in the NEM by time of day, Q3 2020



Source: AER analysis using NEM data.

Note: Average gas generation for that trading interval across the quarter.

Reforms in the gas market impact the electricity market—Case study 24 August 2020

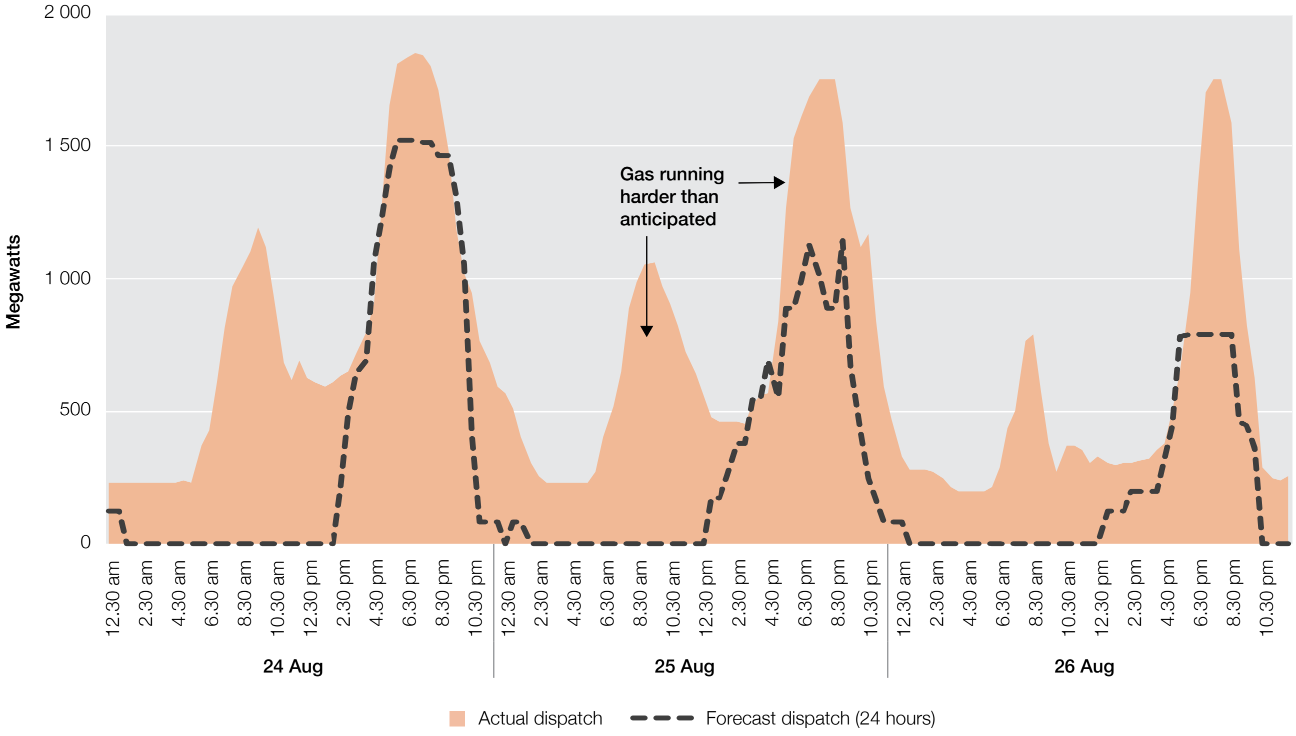
Policy reforms in the gas market have made it easier for gas fired generators to respond to changes in demand the electricity market. The introduction of the Day Ahead Auction in 2019 frees up contracted pipeline capacity that is not being fully used. This has allowed gas fired generators to transport gas at lower cost to where it is needed. This year we have observed high electricity spot prices, particularly where they are not forecast, not only effecting gas spot markets but also the Day Ahead Auction for gas pipeline capacity.

There have been two notable episodes this year where high prices in the electricity spot market drove high gas fired generation and impacted the Day Ahead Auction:

- On 30 and 31 January where electricity prices went to the cap and gas fired generation peaked at 2260 MW on 30 January.
- On 24, 25 and 26 August when electricity spot prices were high and gas fired generation peaked at 1856 MW on 24 August.

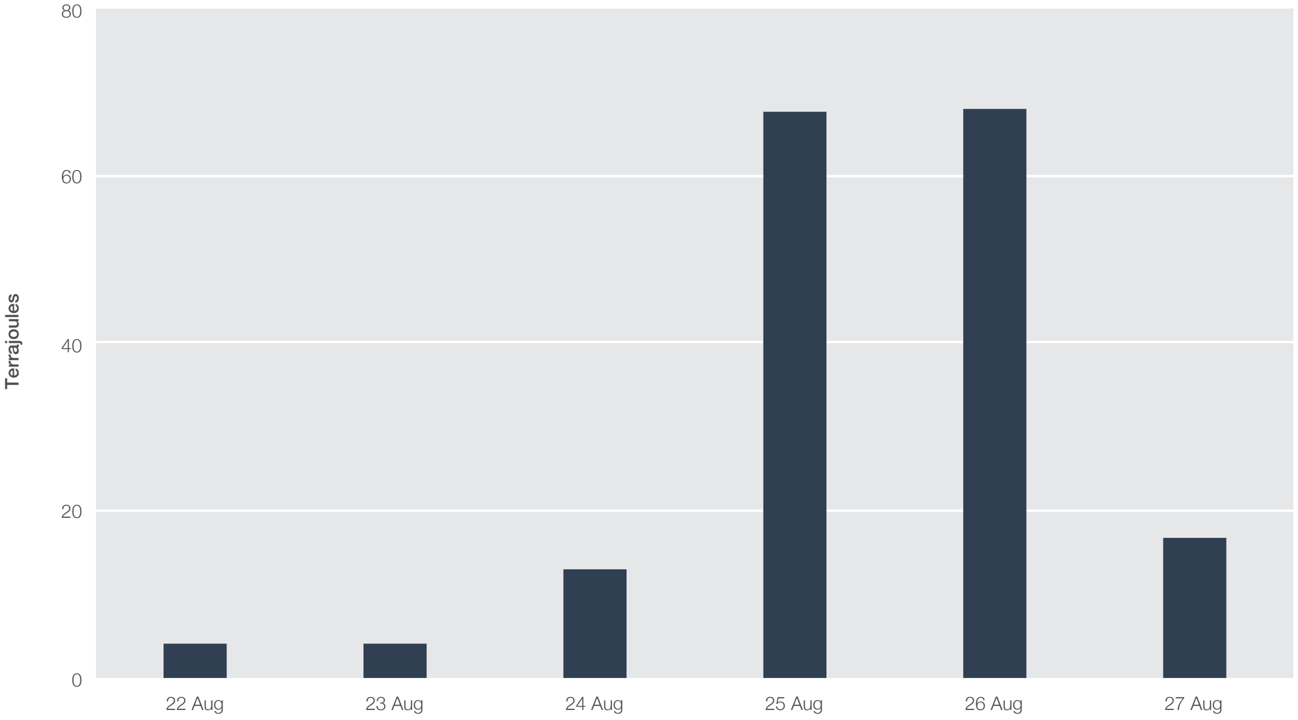
Spot prices peaked on 24 August in Victoria with lower than forecast wind generation and outages at Mt Piper power station and Yallourn power station. Gas generators, such as Mortlake power station in Victoria, rebid capacity into lower price bands to be dispatched to capture the higher prices. Gas generators in Victoria ran harder than anticipated on 24, 25 and 26 August (figure 1.28). As a result they needed to source more gas resulting in increased Day Ahead Auction activity on the South West Queensland Pipeline (SWQP). The SWQP is the pipeline that links the northern and southern gas markets and is used to move gas from Queensland markets to southern markets. Capacity sold at auction on the SWQP increased from 4 terrajoules (TJ) in the days leading up to the high prices on 24 August to 68 TJ on 25 and 26 August (figure 1.29).

Figure 1.28 Forecast (24 hours) and actual dispatch, gas Victoria, 24 to 26 August



Source: AER analysis using NEM data.

Figure 1.29 South West Queensland Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using Day Ahead Auction data.

Note: Quantities shown are the auction products allocated on the South West Queensland Pipeline (SWQP) and do not necessarily represent the physical volumes of gas that flowed on the day. The SWQP is used to move gas from Queensland markets to southern markets.

There are links between physical spot markets and contract markets

There are also strong links between the physical spot gas and electricity markets and the contract markets. Most wholesale electricity and gas market participants will participate in both spot and contract markets to manage their gas and electricity portfolios:

- Electricity market participants will trade electricity derivatives products in two ways: on the Australian Securities Exchange (ASX) or directly with a counterparty (often with the assistance of a broker) known as over-the-counter transactions.
- Gas market participants will often enter into 'off market' contracts to buy and sell gas in addition to participating in the Victoria, Sydney, Adelaide, Brisbane, Moomba and Wallumbilla markets. There are also a number of gas derivatives products available on the ASX which are starting to trade.

The degree to which participants have entered into contract arrangements will affect behaviour in gas and electricity spot markets. This is because entering into long term contracts can affect a participant's incentives to offer capacity in the short term spot markets. The links between the markets can also provide opportunities for cross market manipulation. For example, off market contracts in gas markets may be settled by reference to prices on the Wallumbilla Gas Supply Hub.[16] In some circumstances, a participant may have an incentive to influence prices on the hub in order to gain benefit under an off market contract.

In electricity, public information is available on ASX traded products (primarily prices and volumes traded), but not on the parties to those transaction. Information on OTC transactions is limited to voluntary participant surveys conducted by the Australian Financial Markets Association. For gas markets, the AER has routine access to all public and confidential market trade data. However, a lack of access to off-market bilateral contracts for the purchase and sale of gas presents challenges in monitoring compliance with the market manipulation provisions in the National Gas Rules.

1.15 Focus–The role of load in the NEM

What is a load?

Loads are consumers of electricity, rather than generators of electricity. Scheduled loads offer into the energy and FCAS markets in the same way as generators and are dispatched by AEMO. They are typically large storage units (greater than 30 MW) and include:

- pumped hydro
- grid-scale batteries.

Non-scheduled loads don't offer into the energy market but some non-scheduled loads offer FCAS. Non-scheduled loads are generally smaller in scale and include:

- demand response
- virtual power plants (VPPs).

The exception to this is the Portland Aluminium Smelter which is a large non-scheduled load, able to provide up to 450 MW of raise contingency FCAS.[17]

Generally speaking, demand response changes the pattern of demand by controlling demand side energy resources like smelters. Whereas VPPs provide functions on the supply side, similar to that of a power station, by controlling distributed energy resources like rooftop solar and behind-the-meter batteries.

Loads, including the Portland aluminium smelter, demand response and VPPs can turn off (or consume less energy) to provide raise FCAS services, or consume more energy to provide lower services. Loads can also provide other non-market services that help stabilise the power system.[18]

---

[16] Participants using the Gas Supply Hubs can lodge trades either 'on screen' or 'off screen' via the market's trading platform. 'Off market' trades are settled purely over the counter and do not go through the market at all.

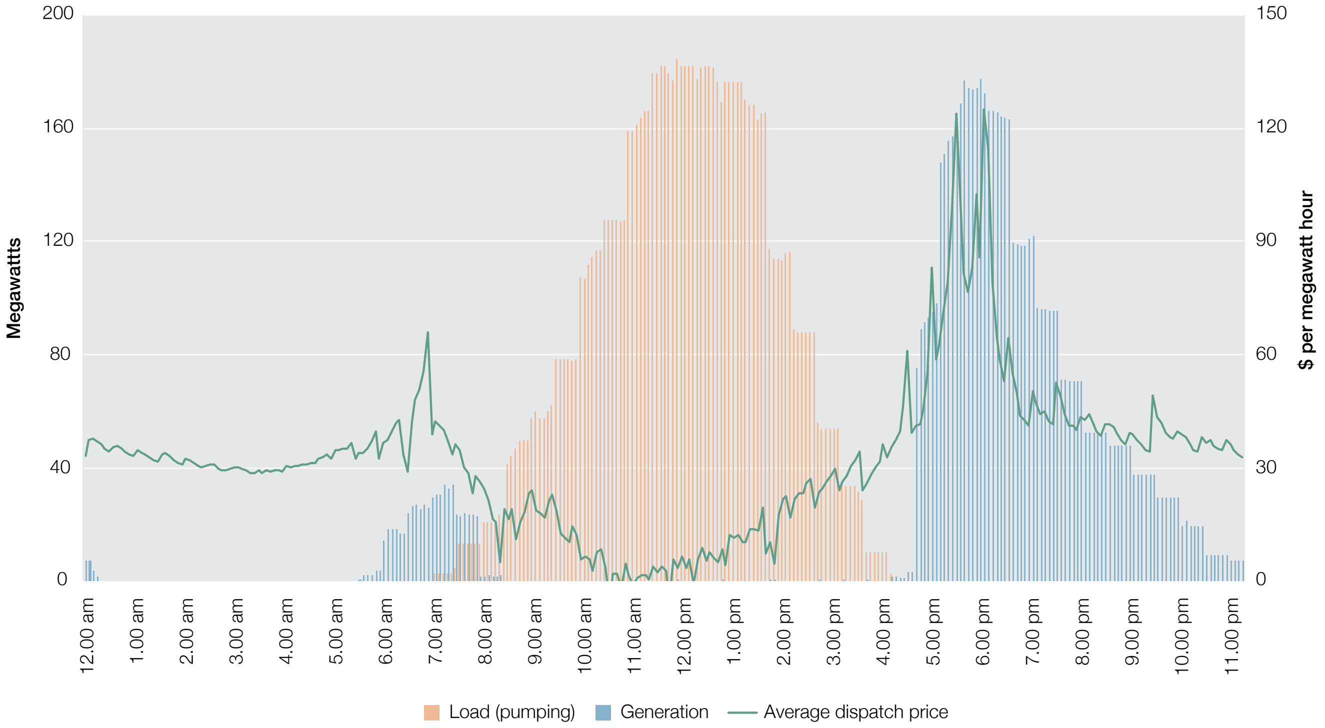
[17] The Portland Smelter was initially registered as a scheduled load but converted to a non-scheduled load in April 1999 soon after market start.

[18] These include synthetic inertia, voltage and reactive power control and black start services.

How storage loads typically work

Energy storage systems, such as batteries and pumped hydro take advantage of variations in the spot price, typically charging or pumping when prices are low, which is often in the middle of the day, and discharging or generating electricity when prices are high, often in the morning and evening when demand is high (Figure 1.30). The greater the difference between these two prices determines how much revenue the load will make in the energy market. With the increase in negative spot prices this makes storage loads an attractive option.

Figure 1.30 Pumped hydro (Wivenhoe), load and generation by time of day, Q3 2020



Source: AER analysis of NEM data.

Note: Wivenhoe load dispatched and generation dispatched averaged by trading interval in Q3 2020. Average dispatch price is the Queensland dispatch price averaged by trading interval in Q3 2020.

Different load technologies provide different benefits to the market and carry different efficiencies.

Pumped hydro

The benefits provided by pumped hydro include:

- the capability to quickly produce or consume large amounts of energy over a long duration, though there are limitations to how quickly it can switch between generating and pumping
- the provision of FCAS—if a plant is pumping and gets a target in a lower service in FCAS, it can provide this by increasing consumption.

Depending on their scale, however, pumped hydro systems can be expensive to build and require the right geography and environmental conditions. The price difference between pumping and generating also needs to cover a loss rate of around 25 per cent. The increase in negative spot prices over the last year means pumped hydro can earn revenue while pumping and offer generation at lower prices than previously. There are three pumped hydro power stations in the NEM (table 1.3).

Table 1.3 Existing pumped hydro

STATION NAME	REGION	OWNER	SIZE (MW)	OFFERS IN ENERGY	OFFERS IN FCAS
Shoalhaven	NSW	Origin Energy	340 generating 240 pumping	✓	✗
Tumut 3	NSW	Snowy Hydro	1800 generating 600 pumping	✓	✓
Wivenhoe	Queensland	CleanCo	570 generating 480 pumping	✓	✓

Batteries

Batteries provide a different set of benefits to the market:

- They have fast response times which enable them to help maintain the power system in a secure state faster than other technologies (although they cannot provide sustained generation).
- They can be co-located with renewable resources to firm output or with gas plant to provide instant energy while the gas plant starts up.

The Hornsdale Power Reserve, connected in 2017, was the first utility-scale battery in the NEM. Since then, the market for large scale battery storage has continued to increase with four more lithium-ion batteries connected, with storage capacities ranging from 15 minutes to 2 hours (table 1.4).

Table 1.4 Existing batteries in the NEM

STATION NAME	REGION	OWNER	SIZE (MW)	OFFERS ENERGY	OFFERS FCAS	OTHER SERVICES	CO-LOCATED
Ballarat Battery	Victoria	EnergyAustralia	30	✓	✓	✗	✗
Dalrymple North	South Australia	AGL	30	✓	✓	✓	✗
Gannawarra	Victoria	EnergyAustralia	25	✓	✓	✗	✓
Hornsdale Power Reserve	South Australia	Neoen	150	✓	✓	✓	✓
Lake Bonney	South Australia	Infigen	25	✓	✓	✗	✓

Note: Owner refers to the participant trading the capacity. For example, the Gannawarra Energy Storage System's capacity is traded by EnergyAustralia, but owned by Wirsol and Edify. Other services include fast frequency response, synthetic inertia, voltage stability and other services not cleared through a market. This indicates if the service is currently provided by the battery, not if the battery has the technical ability to provide the service. The registered capacity for the load at the Hornsdale Power Reserve is 120 MW, which is different to the generator portion of the Hornsdale Power Reserve.

Demand response

Wholesale demand response is when electricity users offer to reduce their demand in the NEM, and is a small portion of overall demand response. Demand response participants do not yet offer into the energy market, and only provide FCAS (table 1.5).

Table 1.5 Existing demand response participants in the NEM

OWNER	REGION	MAX CAPACITY (MW)	OFFERS ENERGY	OFFERS FCAS
Alcoa (Portland Smelter)	Victoria	450	✗	✓
Amalgamated Energy Services	NSW	8	✗	✓
Enel X Australia	Queensland	39	✗	✓
Enel X Australia	NSW	180	✗	✓
Enel X Australia	Victoria	69	✗	✓
Enel X Australia	South Australia	26	✗	✓
HydroTasmania	Tasmania	105	✗	✓

There is also non-market demand response:

- Reliability Emergency Reserve Trader (RERT), where AEMO pays consumers to reduce demand
- demand response, including retailers who can control customer appliances such as pool pumps and air-conditioners in return for a discount or cash bonus
- large energy users who are exposed to the spot price and vary consumption accordingly.

With limited transparency, it is difficult to assess how much non-market demand response is actually occurring. New rules commencing in October 2021 will allow large customers, who previously did not participate in the market to bid their demand response into the market on a daily basis. These consumers will participate under a new participant category—demand response service providers.

Virtual power plants

A virtual power plant (VPP) is a collection of energy storage systems working together, such as a network of homes with solar and battery systems. An aggregator uses a central control system to charge and/or discharge the energy storage systems like one single power plant in response to high prices and FCAS events. There are currently three VPPs in the NEM (Table 1.6).

Table 1.6: Existing VPPs in the NEM

STATION NAME	REGION	OWNER	SIZE	OFFERS ENERGY	OFFERS FCAS
AGL VPP	SA	AGL	3 MW	✗	✓
Energy Locals SA VPP	SA	Energy Locals	10 MW	✗	✓
Simply Energy VPP	SA	Simply Energy (Engie)	3 MW	✗	✓

Load is a small but growing part of the market

Loads only make up a small proportion of the NEM but this has grown and is expected to continue to grow due to:

- increases in FCAS requirements providing the opportunity for supplementary revenue streams
- a large fall in the cost of batteries
- the upcoming shift from thirty-minute to five-minute settlement which was introduced to incentivise fast-response generation such as batteries to participate in the NEM[19]
- reforms to the market design to allow for further integration of VPPs
- Australia's household storage capacity passing 1 GWh for the first time, increasing the potential for VPPs.[20]

---

[19] Five minute settlement will commence on 1 October 2021.

[20] https://www.cleanenergycouncil.org.au/resources/technologies/energy-storage.

AEMO’s long term forecast shows just over 2000 MW of mature or committed capacity and almost 11 000 MW of announced storage projects in the pipeline (table 1.7).[21] While a number of these projects may not be realised, a large number will be successfully commissioned and significantly impact the market.

Table 1.7 Future storage projects in the NEM, generation capacity

LOAD TYPE	MATURING AND COMMITTED (MW)	ANNOUNCED (MW)	TOTAL (MW)
Pumped hydro	2040	4620	6660
Snowy 2.0	*2040*		
Battery of the Nation		*3150*	
Kidston		*250*	
Battery	47	6090	6137
Virtual power plant	6	5	11
Total	**2093**	**10 715**	**12 808**

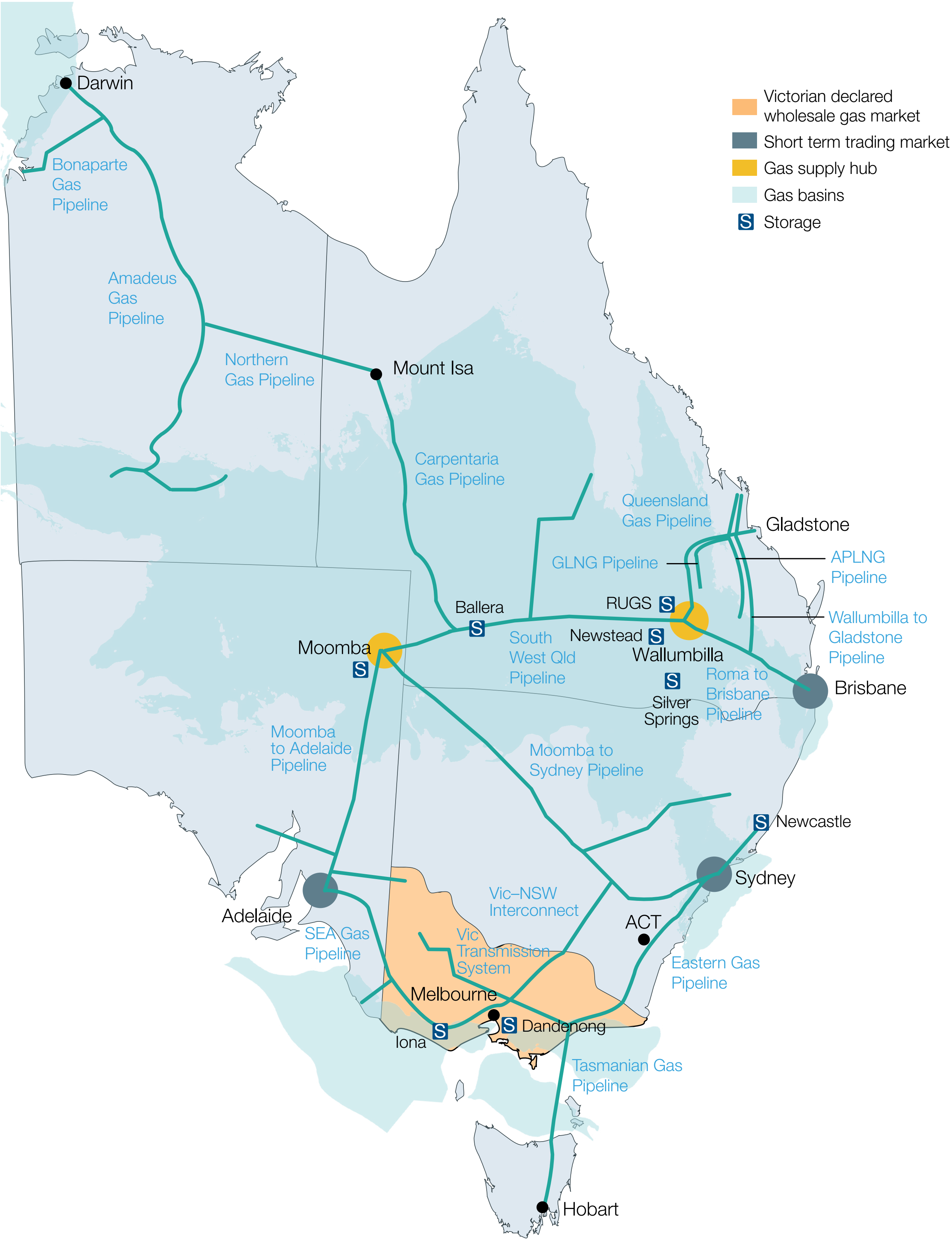
Source: AEMO, July 2020 NEM Generation Information page.

Note: Measured by MW of generating capacity. Proposed projects are categorised as announced, maturing or committed, in order of advancement. Publically announced projects have been announced publicly, but do not have finance arrangements in place. Committed projects are those where construction has started, maturing projects are less advanced.

---

[21] AEMO, July 2020 NEM Generation Information page. AEMO forecast 16 000 MW of storage will be installed in the NEM by 2042. AEMO, *2020 Integrated System Plan*, 30 July 2020, p. 40.

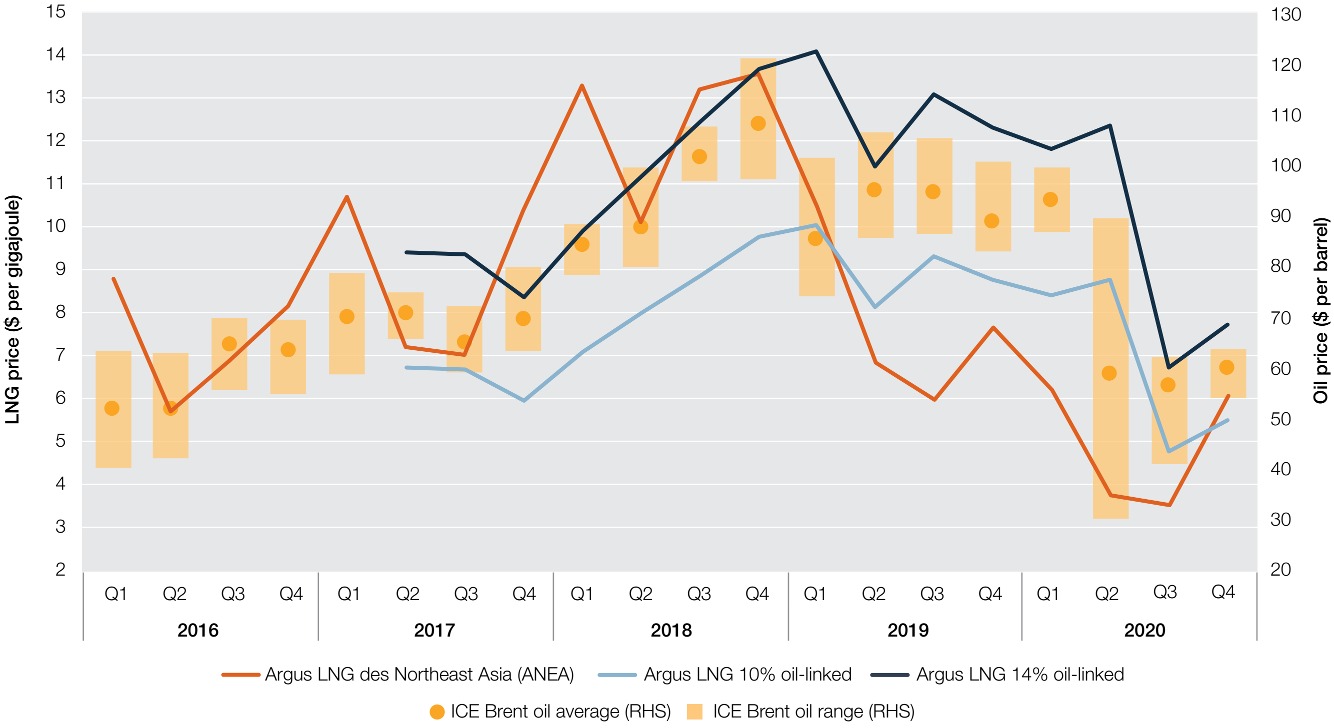
2. Gas


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

2.1 International and domestic prices starting to recover from multi-year lows

Asian LNG spot prices started to increase as the global economy continued to show signs of recovering from the COVID-19 pandemic over the quarter. The Argus Media Northeast Asia (ANEA) LNG spot price assessments increased towards the end of Q3 2020 to $6.09 per gigajoule (GJ) for Q4 deliveries in October (figure 2.1). The average ANEA price has now increased 116 per cent from its multi-year low of $2.82 per GJ for June deliveries.

Figure 2.1 Delivered Asian LNG spot price and Brent oil price



Source: AER analysis using Argus media data.

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

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

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

The Q4 2020 price data represents delivery dates in October 2020 for the ANEA price and delivery dates up to November 2020 for the ICE Brent oil price.

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

As the northern hemisphere winter approaches, the expected increase in seasonal consumer demand for LNG is providing some support to Asian LNG spot prices. Price spreads to lower priced European and USA markets could provide arbitrage opportunities for LNG cargoes to flow to Asia in the coming months and limit price increases. In particular, the USA Henry Hub gas continues to play a swing gas role in the global gas market. LNG cargo loading cancellations from the USA peaked in August with around 40 to 45 cargoes cancelled.[22] Since then, cargo cancellations have edged lower every month with 16 to 26 cargo loadings cancelled in September, up to 10 cargo loadings cancelled in October and up to 5 cargo loadings cancelled in November.[23]

The oil price is continuing to recover from the lows seen in the first half of the year with oil prices for delivery in Q4 2020 trading in a narrower range of between $54 per barrel (bbl) and $64 per bbl (figure 2.1). The volatility experienced in the oil price over the year is evident in the spread between the minimum and maximum oil price for delivery between Q2 2020 and Q4 2020 of almost $60 per bbl, even though the average oil price for this period differs by less than $1 per bbl. The oil price in Q3 2020 was 40 per cent lower compared to the same period a year earlier.

---

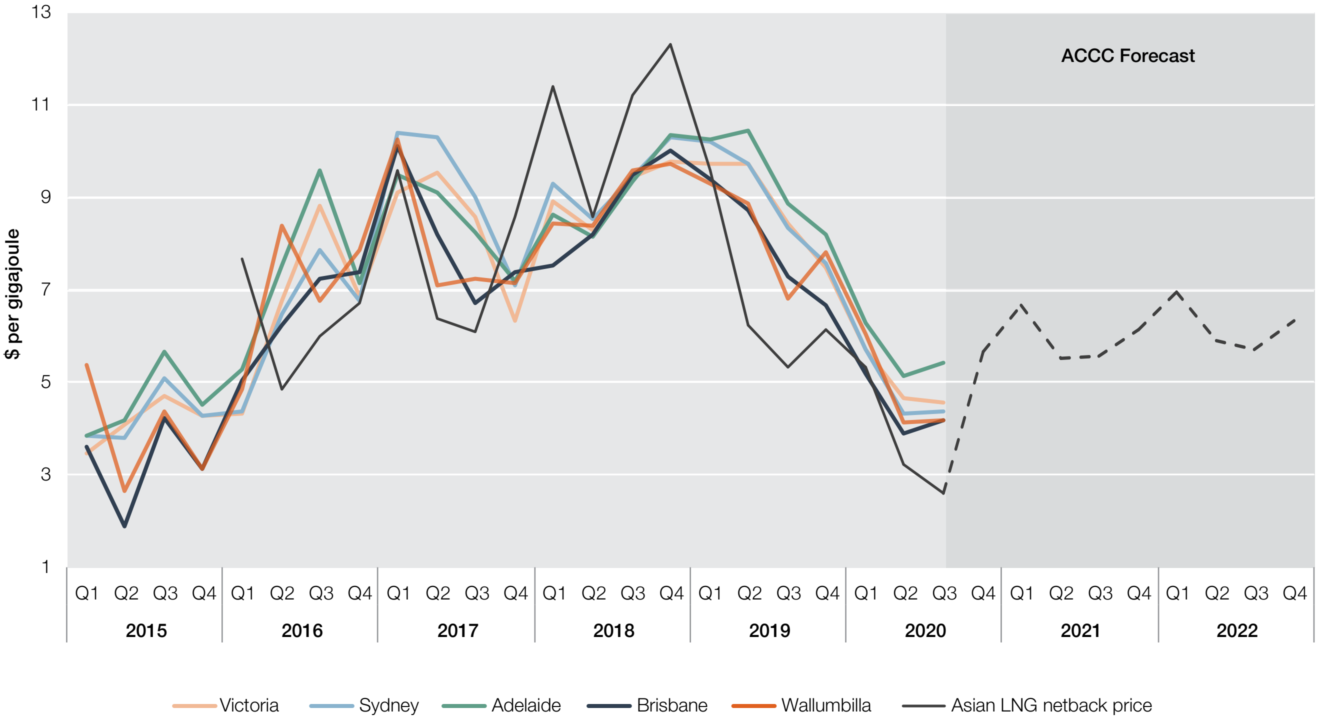
[22] Argus Media, *Asia-Pacific LNG: More supplies emerge*, Argus LNG Daily, Issue 20–141, 20 July 2020.

[23] Argus Media, *Asia Pacific: TTF prices, US cargo cancellations eyed*, Argus LNG Daily, Issue 20–186, 21 September 2020. We understand that USA cargo loadings can be cancelled up to two months before shipping.

LNG spot prices have been below both 'lower' and 'higher' range LNG oil-linked contract pricing since 2019 with the higher range 14 per cent oil linked pricing more indicative of historic LNG export gas contracts from Queensland (figure 2.1). However, recent sharp falls in oil prices have narrowed the gap—Q3 2020 saw the lowest point for oil-linked LNG prices with the Argus Media three month average, 10 per cent and 14 per cent oil-linked contracts bottoming at $4.81 per GJ and $6.74 per GJ, respectively.[24] With the majority of Australian east coast LNG export contracts indexed to oil with a 3 to 6 month lag, it is to be expected that Q3 2020 would see the largest impact on the bottom line of LNG exporters, with their margins improving in Q4 as international oil prices continue to recover.[25] However, in the longer term if spot prices continue to trade at a significant discount to higher percentage oil-linked contracts, downward pressure on pricing could be expected. Argus Media reported in September on some early signs of lower term contracts being negotiated, with Sinopec closing a tender for 1 million tons of LNG to be supplied over 10 years by Qatargas, starting in 2022, with a price indexed around 10 to 10.2 per cent of a Brent oil price, according to market participants.[26]

In the domestic market, prices remained low, trading slightly upwards across the Short Term Trading Markets and marginally lower in Victoria (figure 2.2).[27] From Q3 2019 to Q3 2020 spot prices have declined 48 per cent in Sydney, 46 per cent in Victoria, 43 per cent in Brisbane and 39 per cent in Adelaide. With Q2 2020 seeing the lowest spot prices across the east coast in years, this downward price trend reversed slightly in Q3 as prices started to follow the LNG netback price movements upwards.

Figure 2.2 Domestic spot prices and Asian LNG spot netback price



Source: AER analysis using DWGM, STTM and Gas Supply Hub price data, and ACCC netback price series.

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

During the first week of August, cold weather affected most of southern Australia with some areas experiencing their lowest winter minimum or maximum temperatures on record.[28] This caused AEMO to declare a Threat to System Security on 4 August and 7 August resulting in emergency gas injections from the Dandenong LNG storage facility being scheduled out-of-merit (as opposed to scheduling gas on a least cost basis). Although the impact of the weather event on the Victorian gas prices was not significant, it coincided in record demand of 382 terajoules (TJ) in the Sydney market on 6 August, passing the previous record of 377 TJ set on 9 June 2011. Market participants

---

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

[25] Santos, *2020 Third Quarter Activities Report*, 22 October 2020, accessed 23 October 2020.

[26] Argus Media, *Sinopec awards more cargoes than sought in LNG tender*, Argus LNG Daily, Issue 20–179, 10 September 2020.

[27] Three separate types of markets for gas operate in eastern Australia. The Gas Supply Hubs at Wallumbilla and Moomba are "upstream" exchanges for the wholesale trading of natural gas. The STTMs in Brisbane, Sydney and Adelaide, and the DWGM in Victoria as "downstream" markets for managing the imbalance of gas consumption and demand.

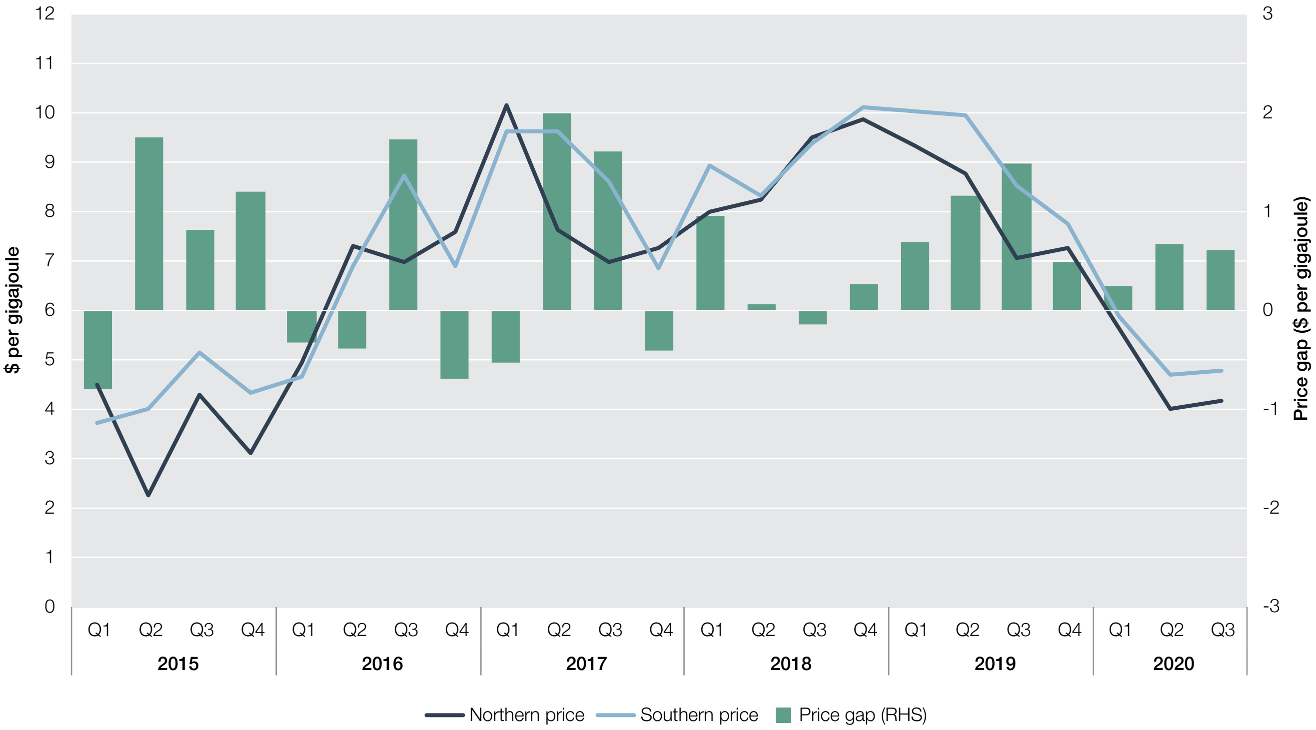
[28] Bureau of Meteorology, *Australia in winter 2020*, 1 September 2020, accessed 23 October 2020.

appeared to withdraw large volumes of gas from the Sydney market to inject into Victoria via the Eastern Gas Pipeline (EPG) given there was a $1.41 per GJ price difference between the markets. This is discussed in more detail in our weekly *Gas market report 2 – 8 August 2020.*[29]

In Brisbane, the ex ante prices reached $10 per GJ due on 31 August, 2 September, 3 September and 8 September. These high prices were the result of an unplanned outage at the Dalby compressor station on the Roma to Brisbane Pipeline (RBP), which is located just upstream of the Brisbane Short Term Trading Market. The capacity constraints were reached on each of these occasions during days of higher gas generation and industrial demand in the market. If the days the capacity constraints did not occur are excluded from the average ex ante calculation, the quarterly ex ante price for Brisbane is $3.91 per GJ compared to $4.17 per GJ, indicative of a $0.26 per GJ impact over the quarter. This is discussed in more detail in our weekly *Gas market report 30 August—5 September 2020* and *Gas market report 6 September—12 September 2020.*[30]

The average southern market prices have now remained consistently higher than the average northern market prices for eight quarters in a row, continuing to provide arbitrage opportunities to move gas from northern production fields to southern markets (figure 2.3).[31]

Figure 2.3 North-South commodity price gap



Source: AER analysis using DWGM, STTM and Gas Supply Hub price data.

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

The price gap in Q3 2020 was $0.61 per GJ, almost 60 per cent lower compared to a year earlier. This continued the downward trend observed in the previous quarter. It is also in line with increased gas production in Moomba and increased participation in the Day Ahead Auction over 2020 compared to 2019.[32]

---

[29] AER, Gas market report 2-8 August 2020, 13 August 2020, accessed 23 October 2020.

[30] AER, Gas market report 31 August-5 September 2020, 13 August 2020, accessed 23 October 2020.
AER, Gas market report 6-12 September 2020, 13 August 2020, accessed 23 October 2020.

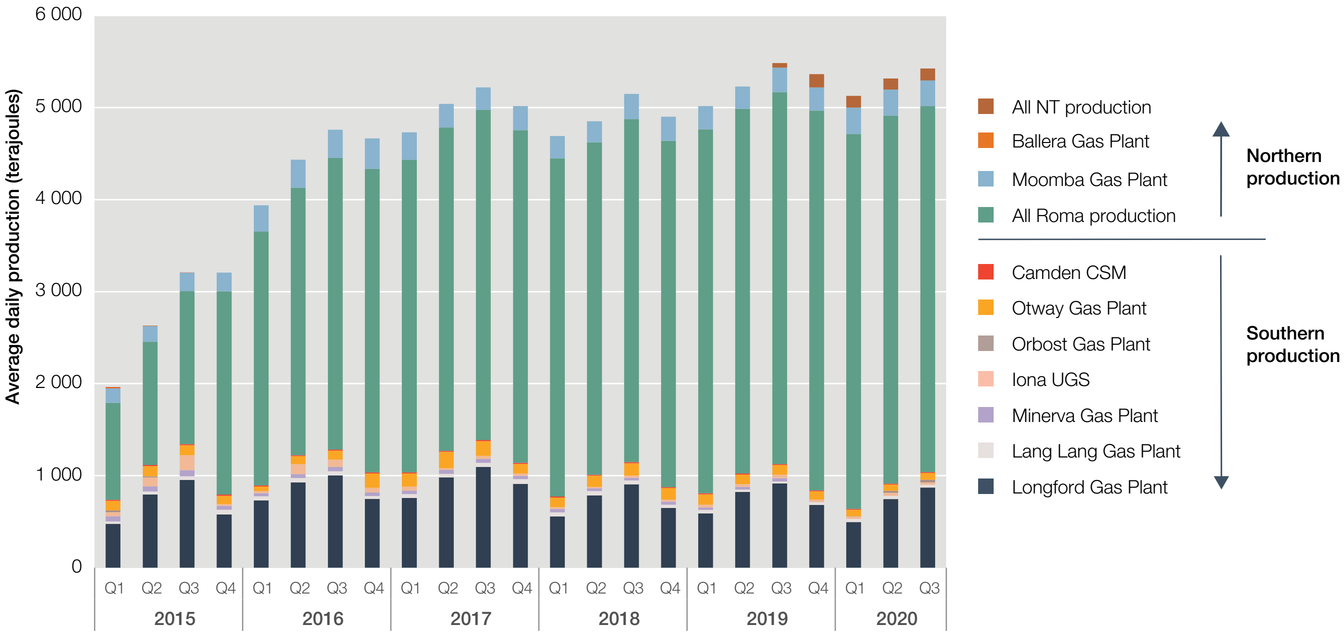
[31] Northern markets refers to the Wallumbilla (QLD) Gas Supply Hub and Moomba (SA) Gas Supply Hub Exchanges and the Brisbane STTM. Southern markets refers to the Sydney and Adelaide STTMs, and the Victorian DWGM. There is only one transmission pipeline for gas connecting the northern and southern markets,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

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

2.2 Production remains strong on the east coast

Total east coast gas production remained strong, reaching an average of 5512 TJ per day for Q3 2020, only slightly lower than a peak of 5561 TJ per day Q3 in 2019 (figure 2.4). East coast gas production is mostly supported by the Roma region in Queensland of approximately 4000 TJ per day, with gas fields in this area located close to large LNG export projects.

Figure 2.4 East coast production



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

Notes: Production levels are average daily figures.

Gas production typically peaks in Q3, as the Longford gas plant in Victoria increases output to serve southern markets' winter demand. The Longford plant varies gas production around timing of maintenance and seasonal peak consumption periods. Since 2017, peak production from Longford during Q3 has consistently declined from an average of over 1000 TJ per day to 870 TJ per day. This follows a consistent fall in offshore gas reserves in the Gippsland basin which has accelerated in recent years.[33] Esso, the operator of the Longford plant, announced extensive maintenance this quarter, which meant the facility operated below the nameplate capacity of 1115 TJ per day over the entire quarter. These outages were most pronounced during September but aligned with milder weather conditions. The new Orbost production facility in Victoria has experienced a delayed commissioning period with its gas production level below nameplate capacity throughout the quarter.[34]

Production from the Roma gas fields tends to be less sensitive to seasonal consumption patterns than Longford, maintaining around 4000 TJ per day since Q1 2019, with production dominated by the Queensland LNG exporters. In Q3 2020, Roma production declined to 3978 TJ per day from a record high of 4126 TJ per day in Q4 2019. This followed a number of outages at large facilities, which aligned with maintenance at LNG export facilities (table 2.1). Notably, Kenya, Orana and Bellevue production facilities.

---

[33] AEMO, *Victorian gas planning report update*, March 2018, p. 5.

[34] APA, ASX announcement, 20 August 2020, accessed 28 October 2020.

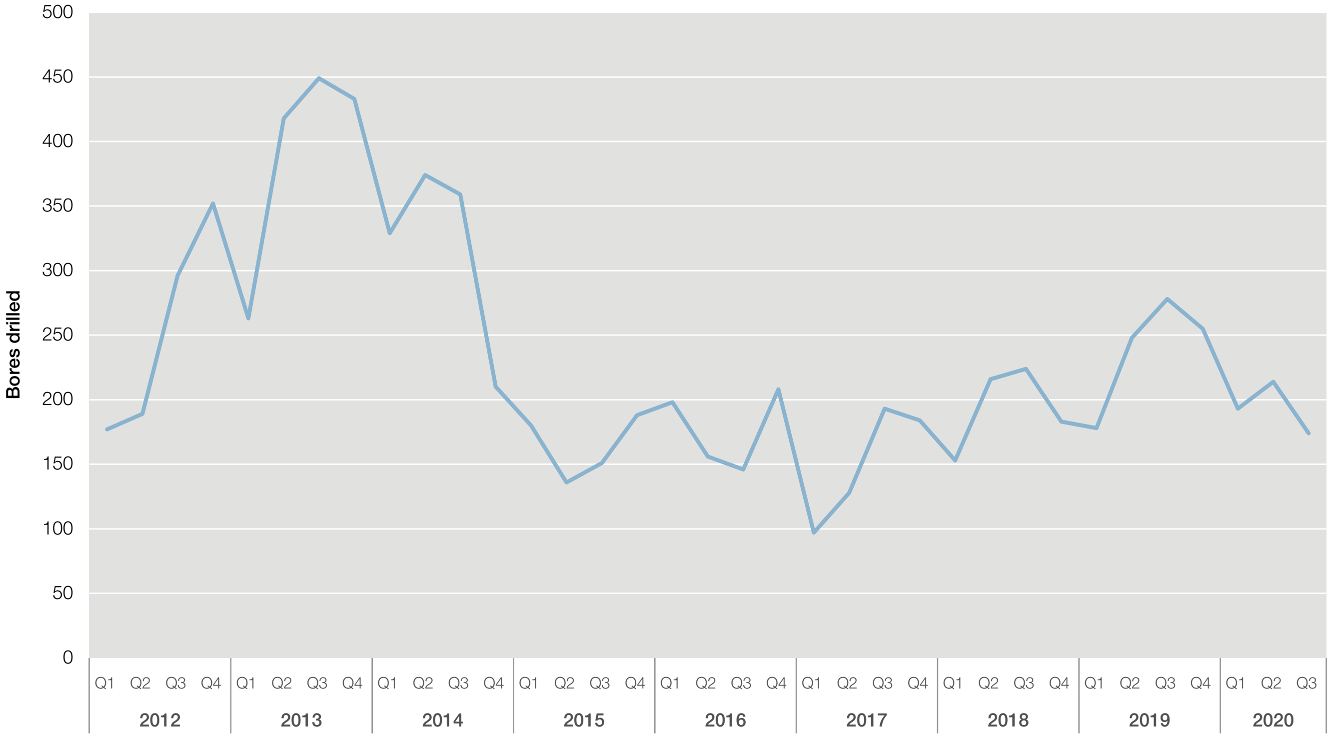
Table 2.1 Production facility outages

DATE	FACILITY	OPERATOR	NAMEPLATE CAPACITY (TJ/DAY)	MAXIMUM CAPACITY DURING MAINTENANCE (TJ/DAY)
7–20 Aug	Bellevue (QLD)	QGC	243	0
3–15 Sep	Orana (QLD)	APLNG	195	91
18–30 Sep	Orana (QLD)	APLNG	195	90
1–10 Sep	Longford (VIC)	Esso	1115	815
11–30 Sep	Longford (VIC)	Esso	1115	910
28 Aug–3 Sep	Kenya (QLD)	QGC	180	10
1 Jul–30 Sep	Orbost (VIC)	APA	65	0–48

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

The number of new coal seam gas wells drilled in Queensland declined to 174 this quarter, following a continued slowdown in drilling activity since Q3 2019 (figure 2.5). This follows a number of announcements of large gas producers of asset impairments associated with sharp declines in oil prices and reduced LNG demand due to the outbreak of COVID-19.[35] Drilling numbers can be indicative of planned supply changes, noting that a procession of new wells is required to support ongoing production from coal seam gas resources, particularly for the LNG exporters to keep up with export demand from their own production. AEMO's *Quarterly Energy Dynamics—Q3 2020* explores in more detail trends in the LNG exporter's gas production.

Figure 2.5 Queensland coal seam gas bores drilled



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

A number of public announcements were made during Q3 2020 in relation to large gas production projects, which may contribute significantly to the future availability of gas on the east coast. Notably, Origin Energy confirmed that it will resume exploration in the Northern Territory within the Beetaloo Basin and will update on drilling results in Q1 2021. This is significant because the Beetaloo Basin has estimated resources of 7000 PJ.[36] Additionally, Santos announced a milestone in gaining environmental approval to develop the Narrabri gas project by the NSW environment Minister and awaits further approval from the Australian environment Minister. The Narrabri project is

---

[35] Origin Energy, Media announcement, 15 July 2020, accessed 28 October 2020; Santos, Media announcement, 21 July 2020, accessed 28 October 2020.

[36] Core Energy, *Gas reserves and resources and cost estimates*, November 2019, p. 10.

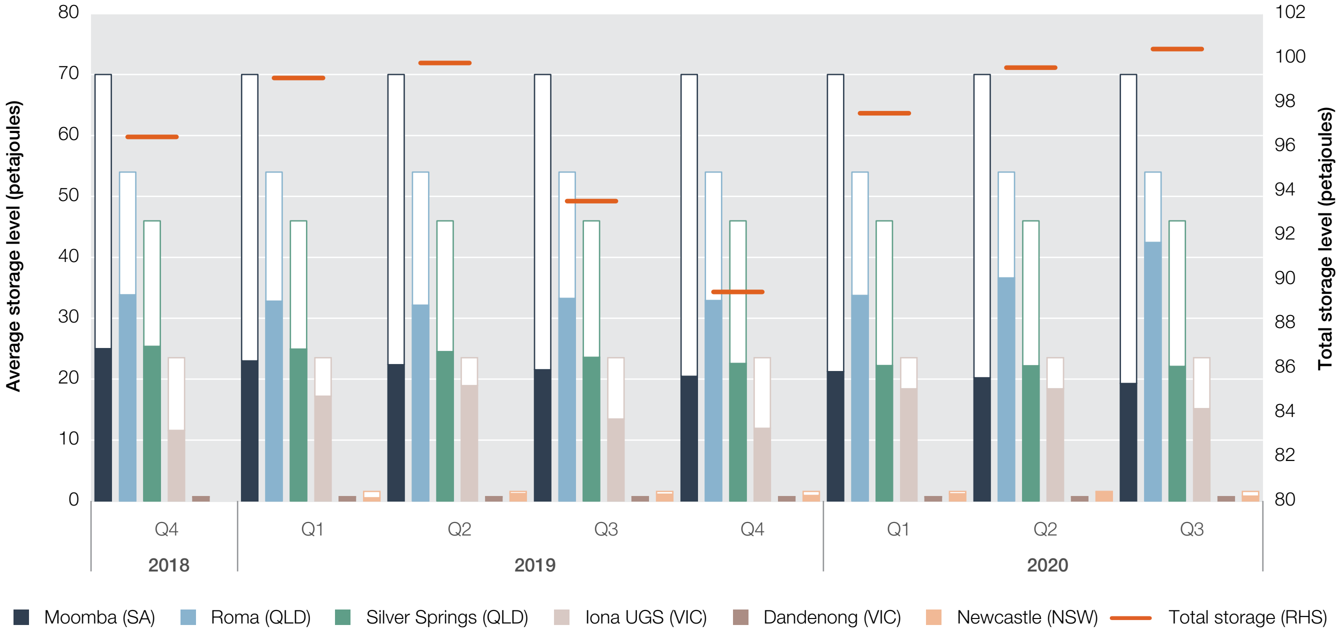
estimated to be capable of producing 70 PJ per year and is expected to commence operations no earlier than 2023, pending government approvals and construction of an interconnecting pipeline.[37]

Total average storage levels remained steady at 100.4 PJ compared to the previous quarter, with increases in volumes at the Roma storage facility (Queensland) slightly outweighing declines at Moomba (South Australia) and Iona (Victoria).

Gladstone LNG's Roma storage facility, which is located near large production fields, increased storage volumes by 5.9 PJ since Q2 2020 following a consistent trend of filling since Q1 2020 (figure 2.6). This indicates an oversupply of gas in Queensland and may also reflect commercial decisions to store gas with lower prices across the east coast, and falling trade volumes at the Wallumbilla Gas Supply Hub. The facility filled during July and began depleting over September, as trading increased at Wallumbilla.

The Iona facility in Victoria operates more dynamically than other storage facilities, with a larger capacity to inject and withdraw gas on any given day. Iona plays an important supply role in Victoria, particularly during peak winter periods and at times represented 20 per cent of the supply into the Victorian market. AEMO's *Quarterly Energy Dynamics—Q3 2020* explores in more detail trends in storage levels against trends over Q3 2019.[38]

Figure 2.6 Storage levels



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

Notes: Storage levels are averages across a quarter.

2.3 LNG exports continue to fall

Queensland LNG exports declined for the third quarter in a row to 282 PJ in Q3 2020, reflecting subdued LNG demand in Asia and plant maintenance in Queensland. However, this volume represents only a 4 per cent decline from Q3 2019 export volumes. Queensland LNG exports tend to peak in Q4 coinciding with peak Asian demand during the Northern Hemisphere winter. Noting this, cargoes shipped increased in September 2020 to 28 cargoes from 25 cargoes in July and August.

The decline is primarily driven by China, South Korea and Malaysia taking less LNG, as a result of the ongoing impact of COVID-19 (figure 2.7). The COVID-19 pandemic has caused declining demand of gas used for power generation and industrial processes. In addition, South Korea announced a number of nuclear generation units returning from maintenance, reducing the need for gas powered generation. More generally, South Korea and China have pursued environmental policies to use more gas instead of coal for electricity generation to reduce carbon emissions. There is some uncertainty of the Chinese Government's continuation of current environmental priorities given the immediacy of dealing with COVID-19 impacts, which may have some bearing on China's future LNG demand.[39]

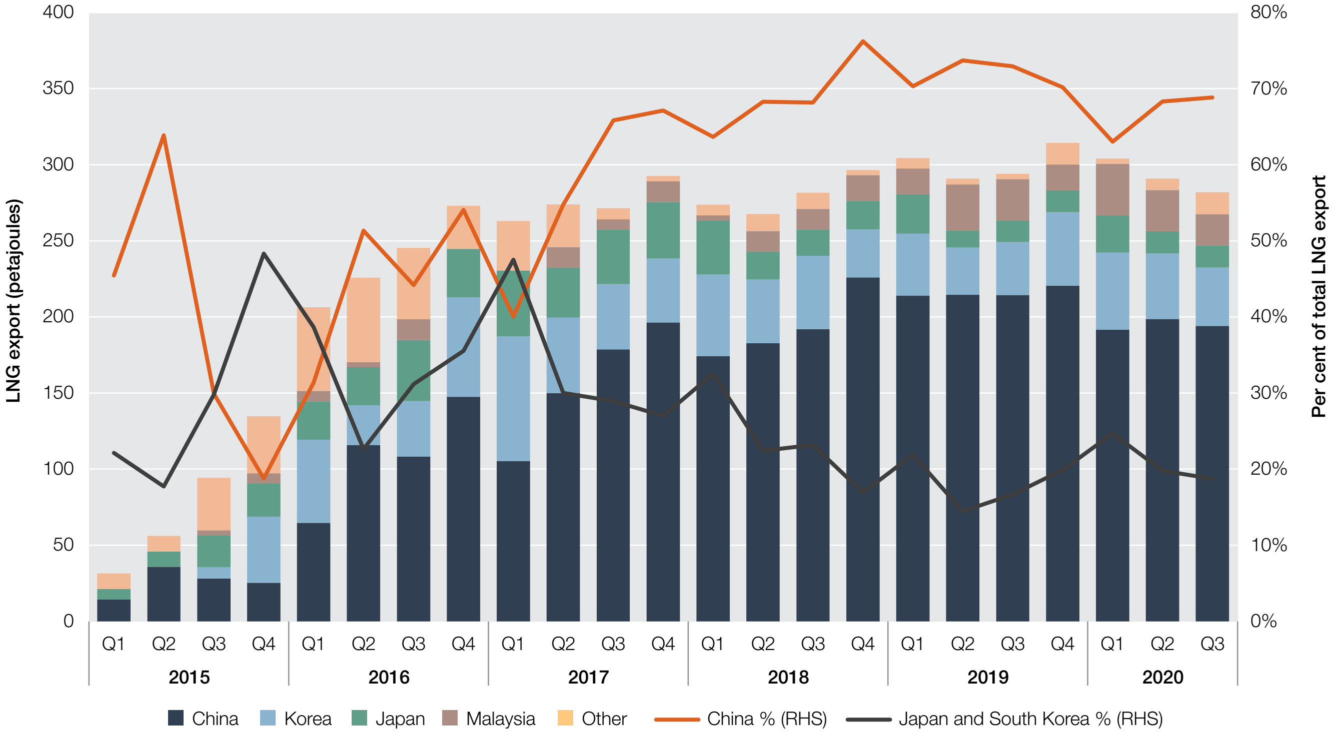
---

[37] AEMO, *Victorian gas planning report*, March 2020, p. 41.

[38] AEMO, *Quarterly Energy Dynamics—Q3 2020*, 21 October 2020, p. 34.

[39] Department of Industry and Energy, *Energy resources quarterly*, September 2020, pp. 69–70.

Figure 2.7 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Port Corporation data.

The decline in Queensland LNG exports coincided with a number of extensive maintenance outages across all Queensland LNG export facilities over Q3 2020, likely to be aligned to periods of low pricing in global markets. The impact of outages is summarised below (table 2.2), noting start and end date and magnitude of outages. Notably, this maintenance coincided with some of the lowest pricing which would have been received for exports under oil-linked contracts or from spot cargo sales (figure 2.1).

Table 2.2 LNG export facility outage history

DATE	OPERATOR	CAPACITY AFFECTED
4–12 Aug	APLNG	0.5 train
1–9 Sep	APLNG	0.5 train
10–30 Aug	QCLNG	0.5-1 train
16 Jul–16 Aug	GLNG	1 train

Source: AER analysis using AEMO LNG maintenance program data.

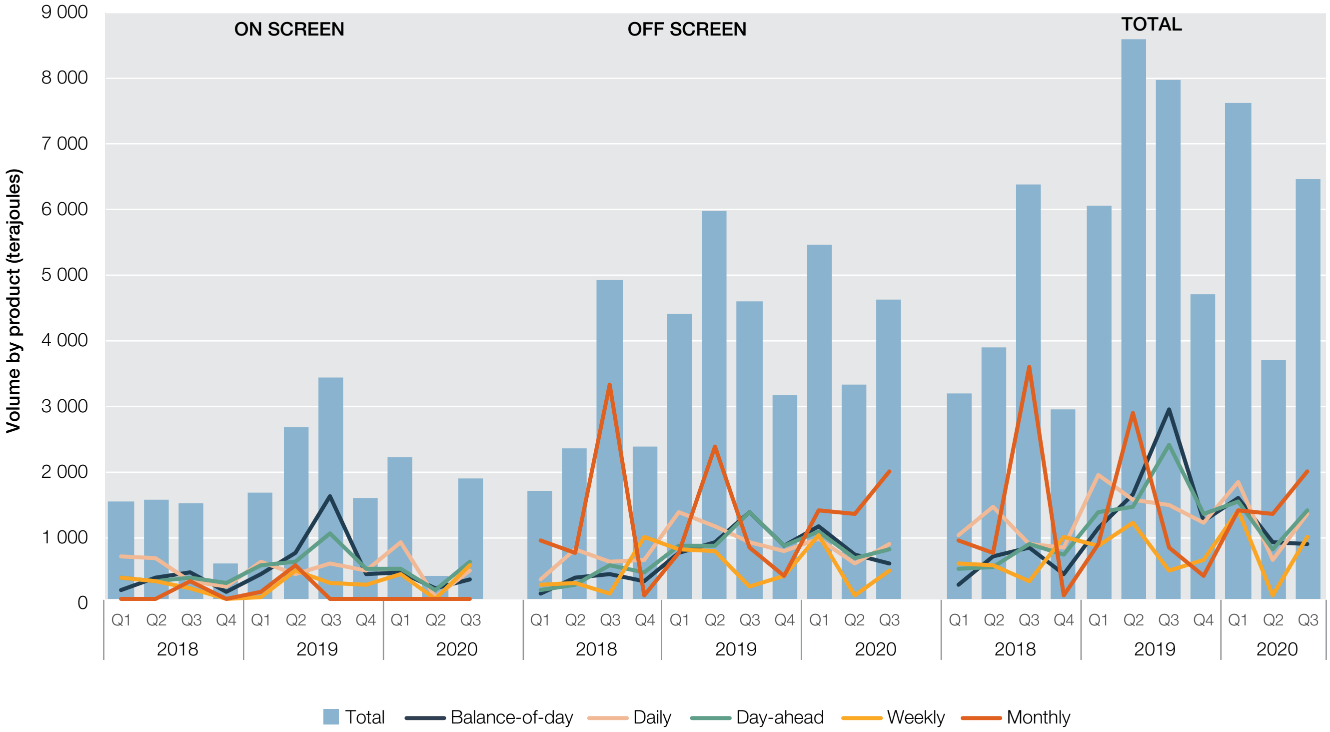
2.4 Trade at Wallumbilla up from last quarter

Traded volume at the Gas Supply Hubs rebounded from the slump last quarter, but remained down compared to Q3 2019 last year (figure 2.8). In total, there was almost 6500 TJ of gas traded this quarter across 774 transactions. This growth from Q2 2020 in the number of trades struck is the result of more on screen trades, which were significantly lower last quarter.[40]

---

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

Figure 2.8 Gas Supply Hub—On screen, off screen and total trade volumes by product



Source: AER analysis using Gas Supply Hub trades data.

Compared to Q3 2019, the volume of gas traded on screen fell by about half, while off screen trades remained steady. This was primarily due to unusually high trade in balance of day products in Q3 last year.[41] In other products, both daily and day ahead products traded less volume than Q3 2019, with the latter falling by almost half. On the other hand, weekly products more than doubled in volume from the same quarter last year.

Off screen, there was significant growth in volume traded for weekly and monthly products, with both more than doubling since Q3 2020. Non-netted monthly products in particular traded at their highest ever level. But we may see further increases in trade into the future after AEMO expanded the trading window on 22 September 2020 to allow participants to trade those products up to 12 months in advance.[42] The remaining products were down compared to the same time last year, with balance of day and day ahead products falling from unusual highs.

This quarter 17 participants traded, of which two were new participants. Continuing the trend from previous quarters, more participants were active off screen than on.[43] Generally, many participants traded less than the same time last year, including a number of large participants. With some larger participants trading significantly less, there is now less concentration amongst buyers and sellers, with the top three participants accounting for about 42 per cent of trade this quarter, compared to more than half in Q3 2019.

The Gas Supply Hub facilitates trade across a number of pipelines, which we group into three locations: Moomba, South Australia; Wallumbilla, Queensland (WAL); and a separate south east Queensland (SEQ) product traded at the Wallumbilla hub, which provides virtual delivery into the RBP (figure 2.9). This separation is valuable as it allows several large, closely clustered gas production facilities to connect easily into the Wallumbilla hub via the RBP. This makes it a popular trading location.

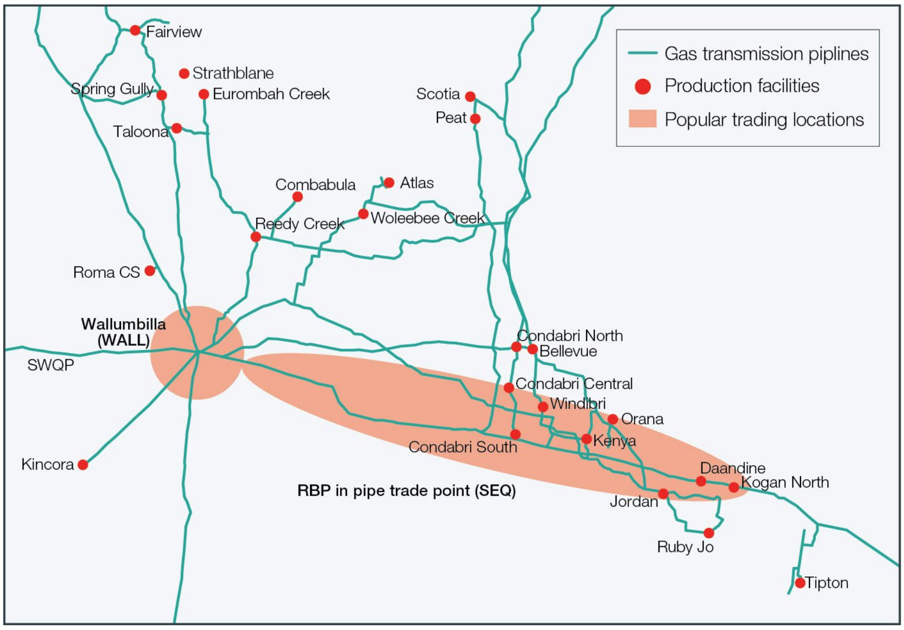
---

[41] There are five standard product lengths that participants can use when trading at the Gas Supply Hub: balance of day, daily, day ahead, weekly and monthly.

[42] This change took effect from 22 September 2020.

[43] We consider a participant “active” if it makes at least a number of trades equal to the number of months in the quarter (three) or year (12).

Figure 2.9 Wallumbilla hub and notional trading points



Source: AER analysis of GEOScience Australia data.

By participant type, Exporter/Producers remain the major sellers of gas, at both Wallumbilla locations. At SEQ in particular, concentration among the different seller participant type has diminished from the same time last year with Exporter/Producer, and Gentailer participant types together now accounting for 83 per cent of gas sold, down from 91 per cent. Traders have increased activity at this location, nearly doubling trade.

Traders have also increased selling activity at WAL, however a sharp decline in Gentailer sales has meant that Exporters/Producers now account for 68 per cent of WAL sales this quarter, up from 63 per cent in Q3 2019.

Gentailers and Traders remain the majority buyers at SEQ, despite buying less there this quarter than Q3 2019. At WAL, the buying market is more balanced across the participant categories, however declining purchases by traders has resulted in Gentailers now buying 45 per cent of gas, up from 37 per cent in Q3 2019. While Trader participants have reduced the volume of gas purchased, demand from Exporter/Producer participants has remained steady. The effect of this is those participants are now responsible for buying more of the gas on offer at both locations.

The churn rate for Q3 2020 fell to 7.1 per cent at Wallumbilla from the record 13.6 per cent achieved the same time last year.[44] Similarly, the churn rate at the Moomba hub declined from 0.9 per cent in Q3 2019 to 0.4 per cent this quarter.

Finally, this quarter the volume-weighted average price for on screen trades fell to \$3.71 per GJ.[45] This was marginally cheaper than the off screen price of \$3.75 per GJ. Our Q1 2020 report examined the emergence of higher priced on screen products since Q4 2019. The reversal of this trend is due in part to the significant increase in monthly products this quarter, which were all traded off screen and for a higher price than Q2 2020.

2.5 Day Ahead Auction participation continues to rise

Participation in the Day Ahead Auction continued to rise with an additional participant winning auction capacity for the first time this quarter, bringing the total number of participants who have won capacity since the commencement of the auction to 17.

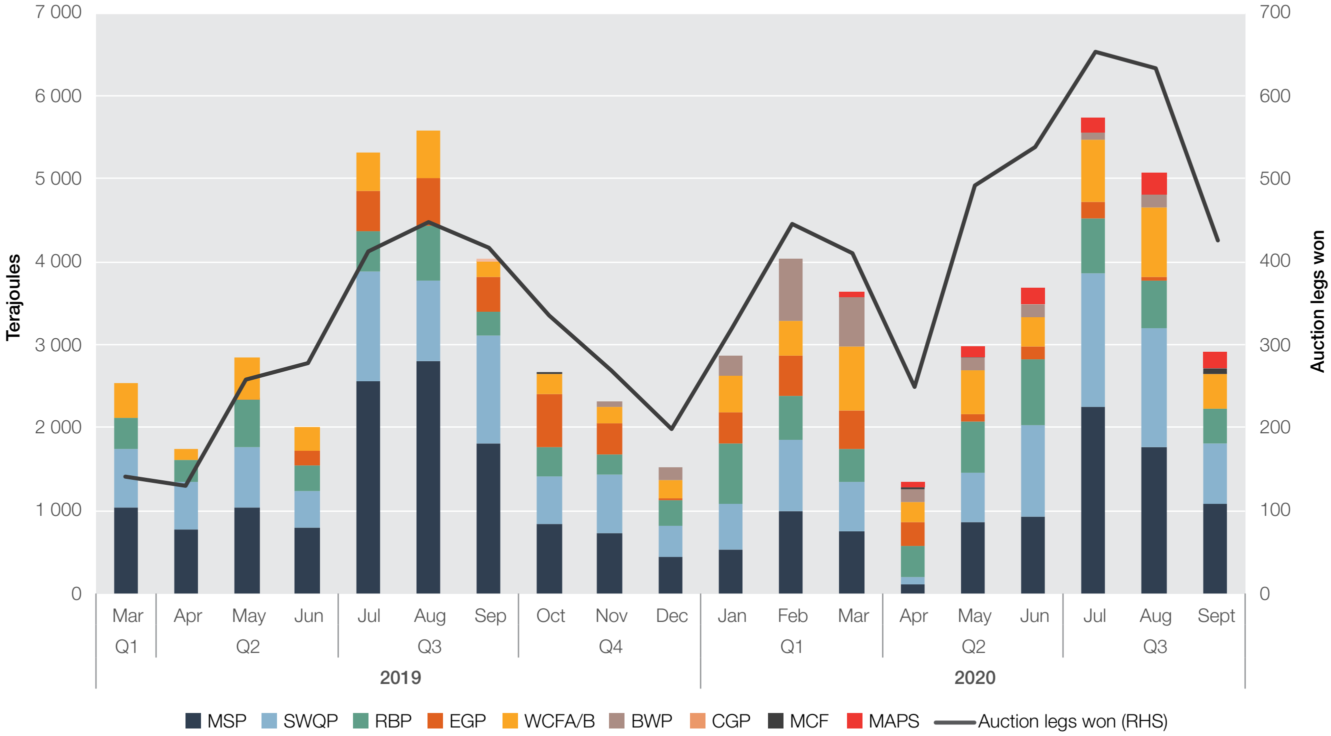
A total of 13.7 PJ of unused contracted pipeline capacity was won across eight facilities in the quarter, with July recording the highest monthly volume of capacity and auction legs won. This was slightly lower than Q3 2019, when 14.9 PJ was won across six facilities with only six participants winning capacity (figure 2.10).

---

[44] The churn rate refers to the total trade through the Gas Supply Hub as a proportion of regional bulletin board gas flows.

[45] Averaged across all prices, products and locations.

Figure 2.10 Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using Day Ahead Auction 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.

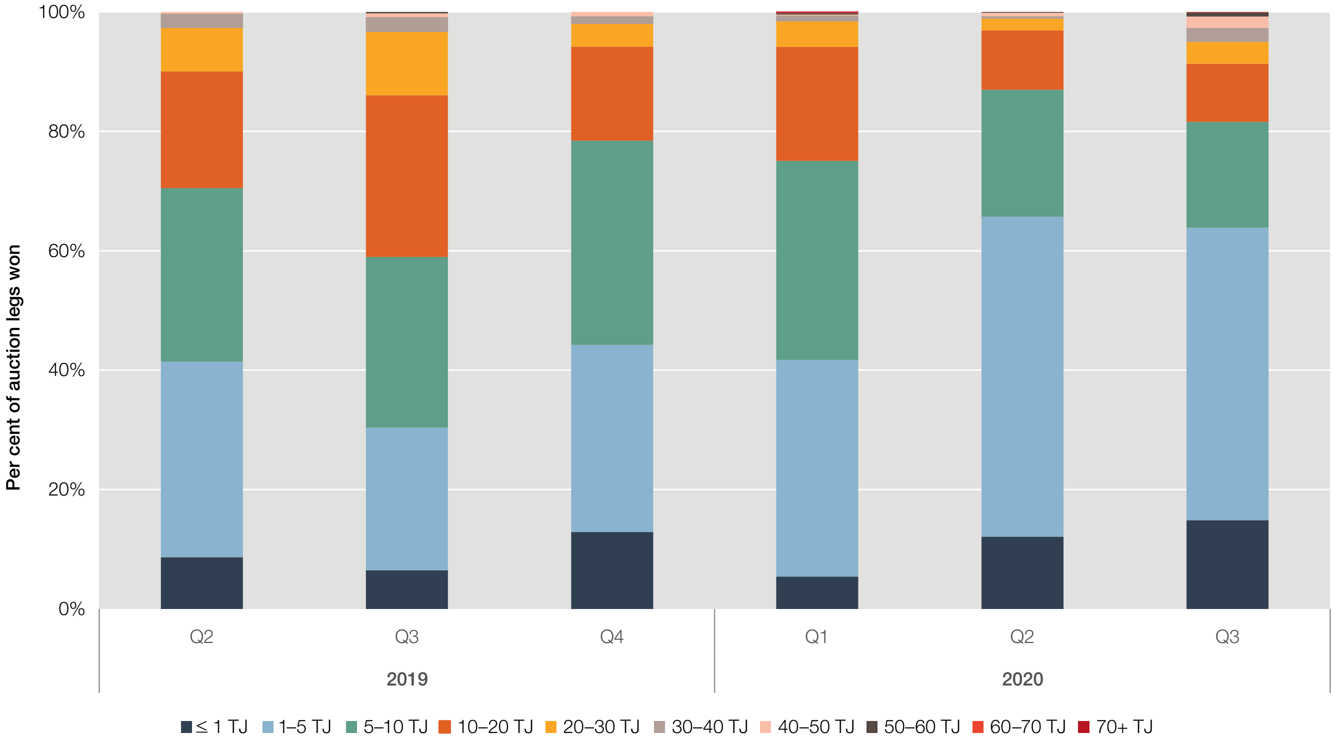
Capacity won on the Moomba to Adelaide Pipeline System (MAPS) increased by over 55 per cent compared to Q2 2020. However, for the first time since the commencement of the auction, pipeline curtailments were observed (24 days across July and August 2020), resulting in participants not being able to use all of the auction capacity won on those days. Curtailments were a result of shippers renominating up on the gas day.

Record quarterly volumes were won for the Wallumbilla Compression Facility B (WCFB) (over 2 PJ) and South West Queensland Pipeline (SWQP) (over 3.7 PJ). Although the quantities won on the SWQP in Q3 2020 were comparable to those won in Q3 2019, there was almost twice the amount of auction capacity available in Q3 2020 resulting in lower clearing prices ($0.25 per GJ compared to $1.00 per GJ) and considerably less days where the Auction Quantity Limit was reached (table 2.3).

After only small quantities of capacity were won for the Moomba Compression Facility (MCF) in previous quarters, Q3 2020 saw a considerable increase. This is of interest as the MCF moves gas from low to high pressure, allowing for the transport of gas through Moomba from southern pipelines, eastwards along the SWQP towards Wallumbilla.

Although quantities won in Q3 2019 were higher than the same quarter this year, Q3 2020 saw a record 1716 auction legs won. The higher number of legs won can be attributed to more than 60 per cent of auction legs won being less than 5 TJ (figure 2.11).

Figure 2.11 Volume of auction legs won



Source: AER analysis using Day Ahead Auction 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.

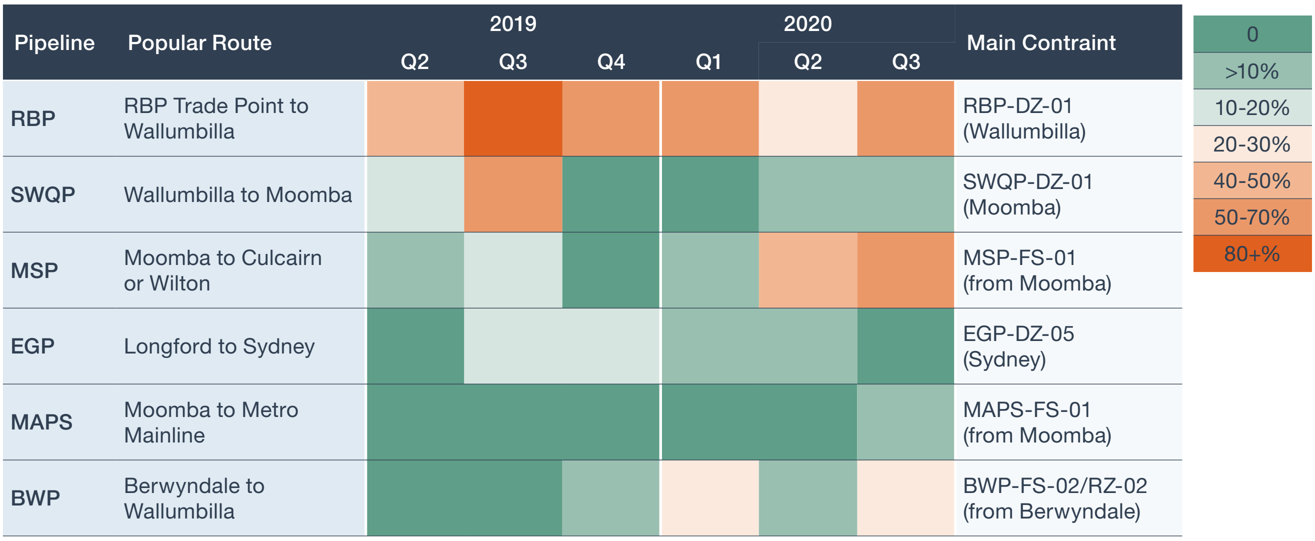
Auction results for gas day 7 August 2020 saw a record clearing price of $1.49 per GJ for capacity to transport gas south on the Moomba to Sydney Pipeline (MSP). This was a result of the Auction Quantity Limit being set quite low at 11 TJ and auction demand being considerably higher at 123 TJ. This high priced auction day coincides with the peak demand period in Victoria, noted in section 2.1, where there were threats to system security in Victoria—the auction pricing outcomes appear consistent with the high value likely to be placed on gas at that time given the peak pricing condition in the south.

Six auction facilities involved in the Day Ahead Auction have had days where the Auction Quantity Limit has been reached. This has resulted in clearing prices above the auction reserve of $0 per GJ and excess demand for auction capacity. These Auction Quantity Limits are set by either physical limits or contracted capacity constraints at either an individual or combination of receipt zone, delivery zone, pipeline segments or service points (figure 2.12). Further details about auction service points can be found in the Transportation Service Point Register.[46]

---

[46] AEMO, *Transportation Service Point Register*, August 2020.

Table 2.3 Day Ahead Auction constraints on popular pipeline routes and proportion of time Auction Quantity Limits were reached



Pipeline	Popular Route	2019			2020			Main Contraint
		Q2	Q3	Q4	Q1	Q2	Q3	
RBP	RBP Trade Point to Wallumbilla	40-50%	80+%	50-70%	50-70%	20-30%	50-70%	RBP-DZ-01 (Wallumbilla)
SWQP	Wallumbilla to Moomba	10-20%	50-70%	0	0	>10%	>10%	SWQP-DZ-01 (Moomba)
MSP	Moomba to Culcairn or Wilton	>10%	10-20%	0	>10%	40-50%	50-70%	MSP-FS-01 (from Moomba)
EGP	Longford to Sydney	0	10-20%	10-20%	>10%	>10%	0	EGP-DZ-05 (Sydney)
MAPS	Moomba to Metro Mainline	0	0	0	0	0	>10%	MAPS-FS-01 (from Moomba)
BWP	Berwyndale to Wallumbilla	0	0	>10%	20-30%	>10%	20-30%	BWP-FS-02/RZ-02 (from Berwyndale)

0
>10%
10-20%
20-30%
40-50%
50-70%
80+%

Source: AER analysis using Day Ahead Auction data.

Notes: MAPS also has a number of other limits that are always set at zero (i.e. Loopline), therefore capacity is never available to be won on some routes. Curtailments have not been included in this table if they did not coincide with days on which the Auction Quantity Limit was reached.

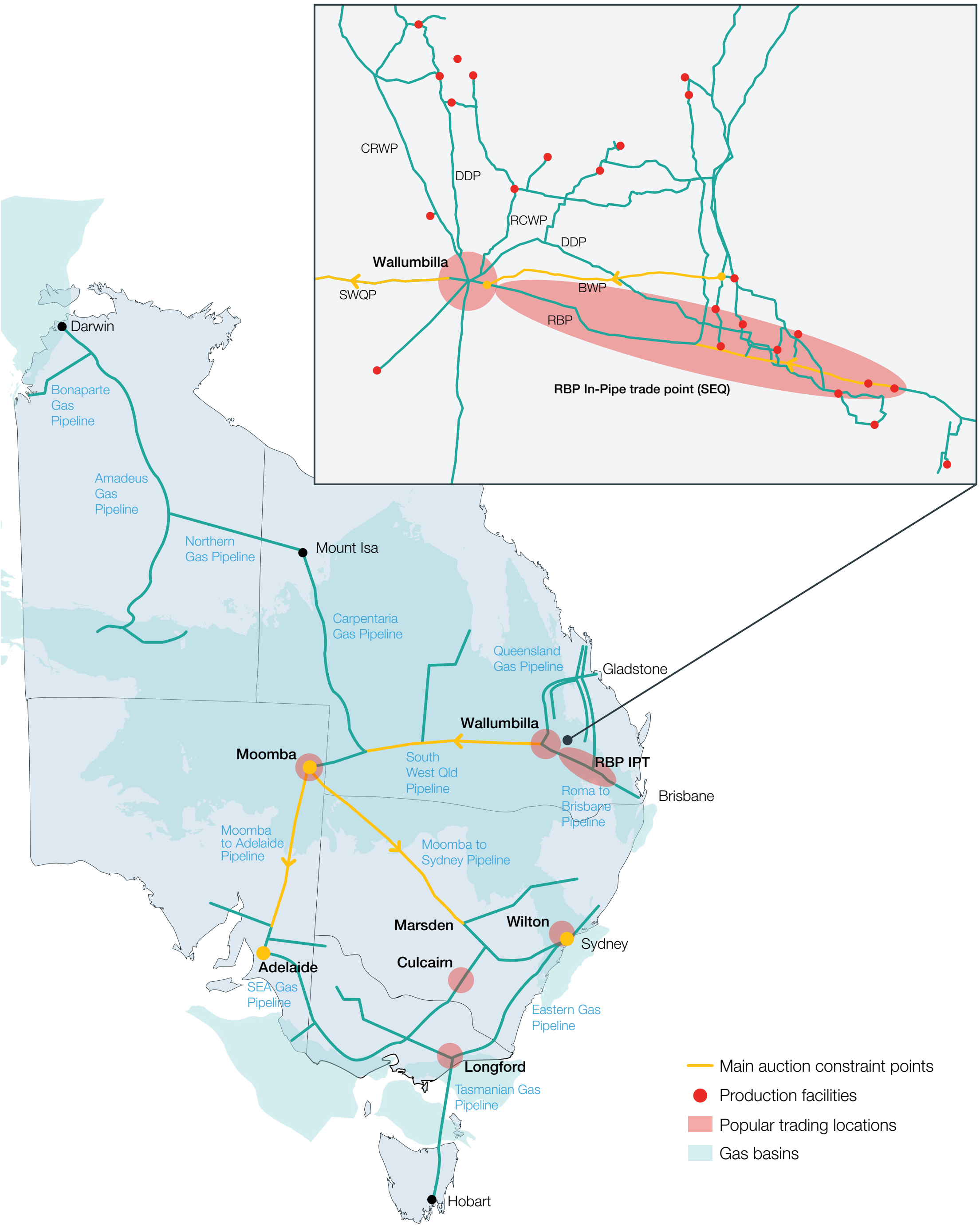
The major constraints appear to be at the main delivery zones at Wallumbilla (RBP), Moomba (SWQP) and Sydney (EPG), and the first pipeline segments south of Moomba on both the MSP and MAPS. Constraints on the Berwyndale to Wallumbilla Pipeline (BWP) appear at the Berwyndale receipt point and the pipeline segment that links to Wallumbilla.

Q3 2020 saw Auction Quantity Limits reached on over 50 per cent of days on the RBP and MSP, with Auction Quantity Limits on the BWP reached between 20 and 30 per cent during the quarter. The RBP is a heavily contracted pipeline with transport capacity during some periods throughout the year contracted at 100 per cent.[47] This is reflected in the Day Ahead Auction results where the Auction Quantity Limit has been reached most frequently (table 2.3).

---

[47] ACCC, *Gas Inquiry 2017-25 Interim report,* July 2020, p. 96.

Figure 2.12 Constraints on popular Day Ahead Auction transport routes



Source: AER analysis of GEOScience Australia data.

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

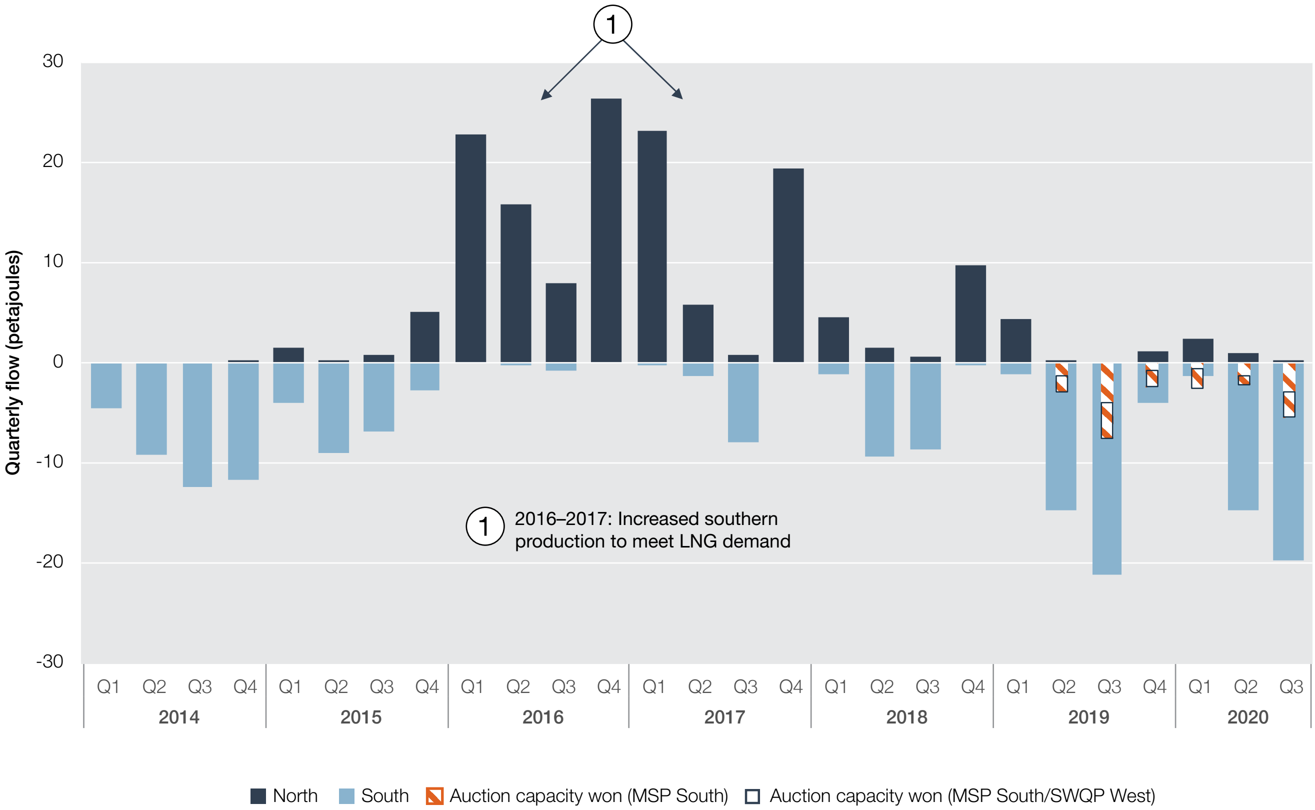
2.6 Record daily gas flows south on the South West Queensland Pipeline and Moomba to Sydney Pipeline

The net gas flow from north to south increased to 19.6 PJ this quarter compared to 13.8 PJ in Q2 2020 in line with increased winter demand in the southern markets, but was slightly lower than the net flow of 21.6 PJ in Q3 2019 (figure 2.13). When comparing the period June to August, when gas flow to the south typically peaks, this year saw 44 gas days during this period with flow rates of 300 TJ per day or more compared to only 10 days during the same period in 2019.

Gas transport via the Day Ahead Auction made up 26 per cent of the total flow south, which is slightly lower compared to Q3 2019 when the auction accounted for 34 per cent of the gas flow south.

On 31 July, 389 TJ of gas flowed south following the previous record set in June of 386 TJ. With record flows south on the SWQP and increased production at Moomba, the flow rate south on the MSP also hit a record daily rate in this quarter of 404 TJ on 18 July.

Figure 2.13 North-South gas flows



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

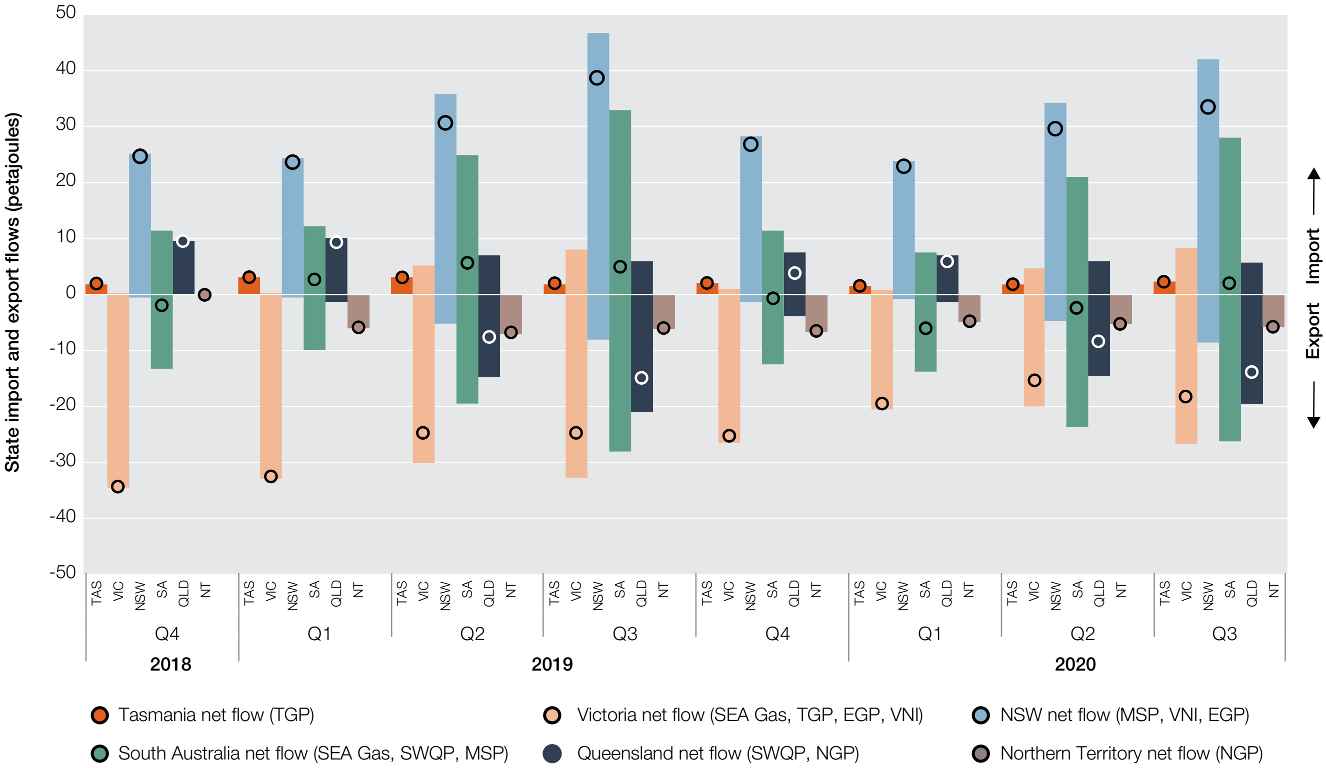
Notes: North-South flows depict net physical flows around Moomba—north or south. MSP South/SWQP West is a subset of MSP South auction quantities showing auction volumes linked to longer haulage from Wallumbilla.

When comparing net gas flow rates by states for Q3 2019 to Q3 2020, Victoria and Queensland are net exporters of gas, and NSW and South Australia are net importers of gas, with all four states seeing a decrease in their net gas flowrates compared to Q3 2019 (figure 2.14).[48]

---

[48] The net gas flow rate of a state is the difference between the amount of gas imported into the state and the amount of gas exported from the state. If a state is a net exporter of gas it means it exports more gas than it imports and vice versa when it is a net importer of gas.

Figure 2.14 Interstate gas flows



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

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

Victoria continued to see a downward trend in gas being exported from the state declining from 32.8 PJ in Q3 2019 to 26.8 PJ in Q3 2020. More gas continues to flow south through the Victoria-NSW interconnector reaching a total of 8.5 PJ for this quarter with a record flow on 16 July of 152 TJ. Queensland remained a net exporter of 13.8 PJ of gas, while gas imported from the Northern Territory increased slightly from last quarter to 5.7 PJ. NSW imported 42.2 PJ this quarter compared 47 PJ in Q3 2019, a decline of 4.8 PJ quarter on quarter.

2.7 Trade through spot markets jumps in Q3 2020

The Short Term Trading Markets are markets for trading natural gas at the wholesale level between pipelines and distribution systems at defined hubs in Sydney, Brisbane and Adelaide. They operate under slightly different rules to the more frequently traded Victorian Gas Market. These mandatory markets appear to be transitioning from balancing markets where Retailers and Gentailers have traditionally traded small supply-demand imbalances, to markets where there are a number of largely seller and buyer only participants on each side of the market.

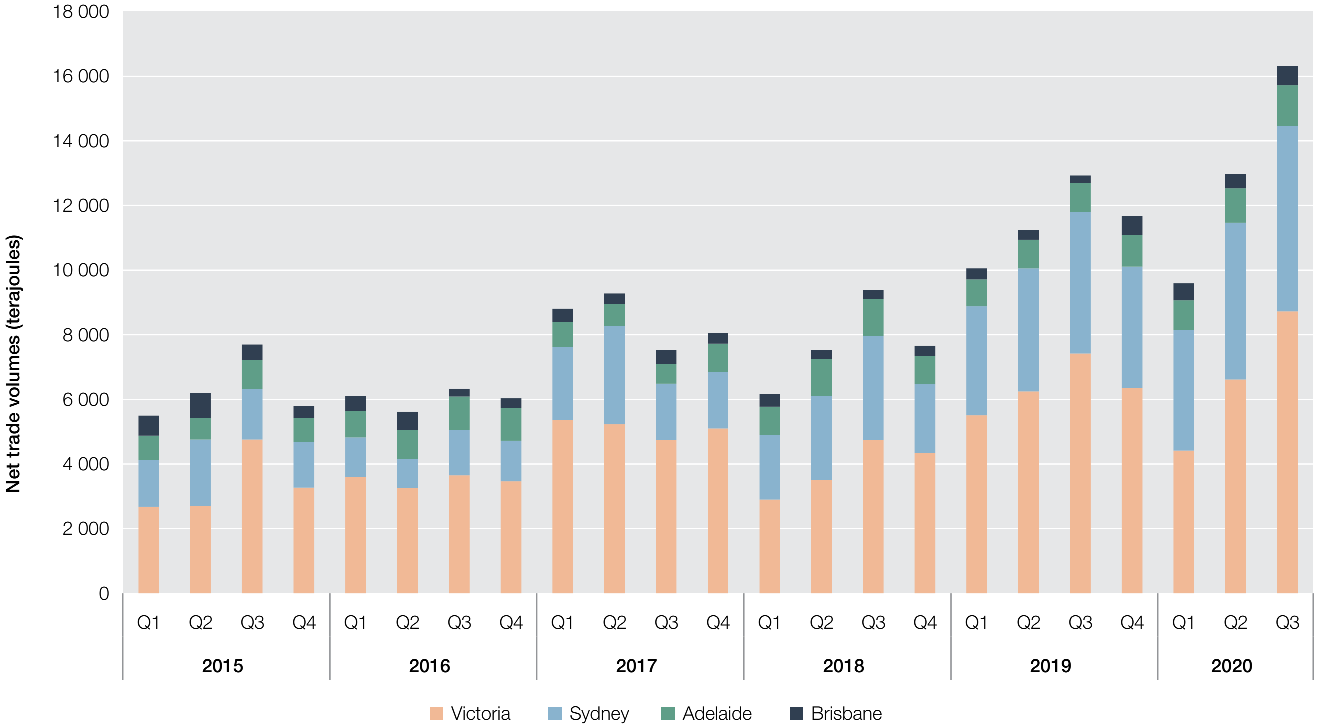
Liquidity in these east coast gas markets improved slightly again this quarter, with significant rises in Victoria and Sydney where producers continued to be amongst the top sellers in those markets, accounting for more than half the net trade volumes in Victoria and close to 40 per cent in Sydney (figure 2.15).[49] Record trade quantities have now been recorded for a second consecutive quarter, with in excess of 16.3 PJ supplied for the period.[50]

---

[49] Both quantities traded and the proportion of total trades were up from the previous quarter. Gentailers also supplied significant quantities in Sydney over the quarter.

[50] Previous records across the markets were 12,931 TJ over Q3 2019 and 12,976 TJ over Q2 2020, compared to 16,311 TJ over Q3 2020. Sydney also exceeded its previous record for the proportion of gas traded, reaching just under 21 per cent of total demand.

Figure 2.15 Spot trade liquidity



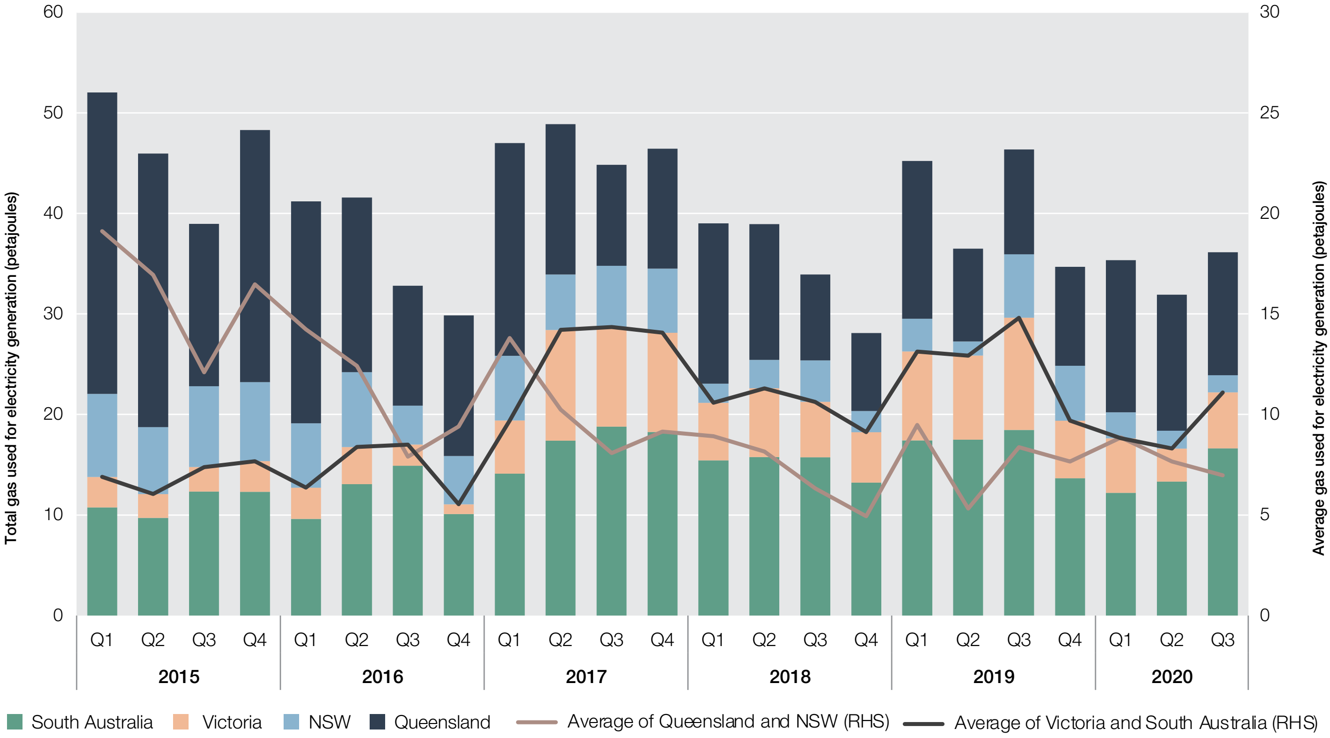
Source: AER analysis using DWGM and STTM data.

Further analysis of competition outcomes across the market is part of our Focus Story.

2.8 Gas powered generation significantly lower than Q3 2019

Gas demand for electricity generation was up in Victoria and South Australia from last quarter (figure 2.16). However mainland generation was significantly lower compared to Q3 2019, resulting from much lower gas generation in southern states (primarily in Victoria and NSW). Queensland has declined steadily since Q1 2020, yet usage remains higher in comparison to the same period last year.

Figure 2.16 Gas powered generation



Source: AER analysis using NEM data.

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

2.9 ASX gas futures prices rising in 2021

The quantity of trade in Victorian gas futures contracts that occurred in Q3 2020 reduced dramatically from 2842 TJ to 743 TJ in Q2 2020. Trade in Q3 2019 similarly fell dramatically from Q2 2019 and may be exhibiting a seasonal trade profile around the gas futures contracting cycle (table 2.4). The term of contracts have now extended to every quarter, through to Q4 2022, providing a longer-term price signal. It should be noted the quantity of gas traded under the Victorian contracts still represents less than 5 per cent of physical gas demand in the Victorian market.

Table 2.4 Victorian gas futures summary

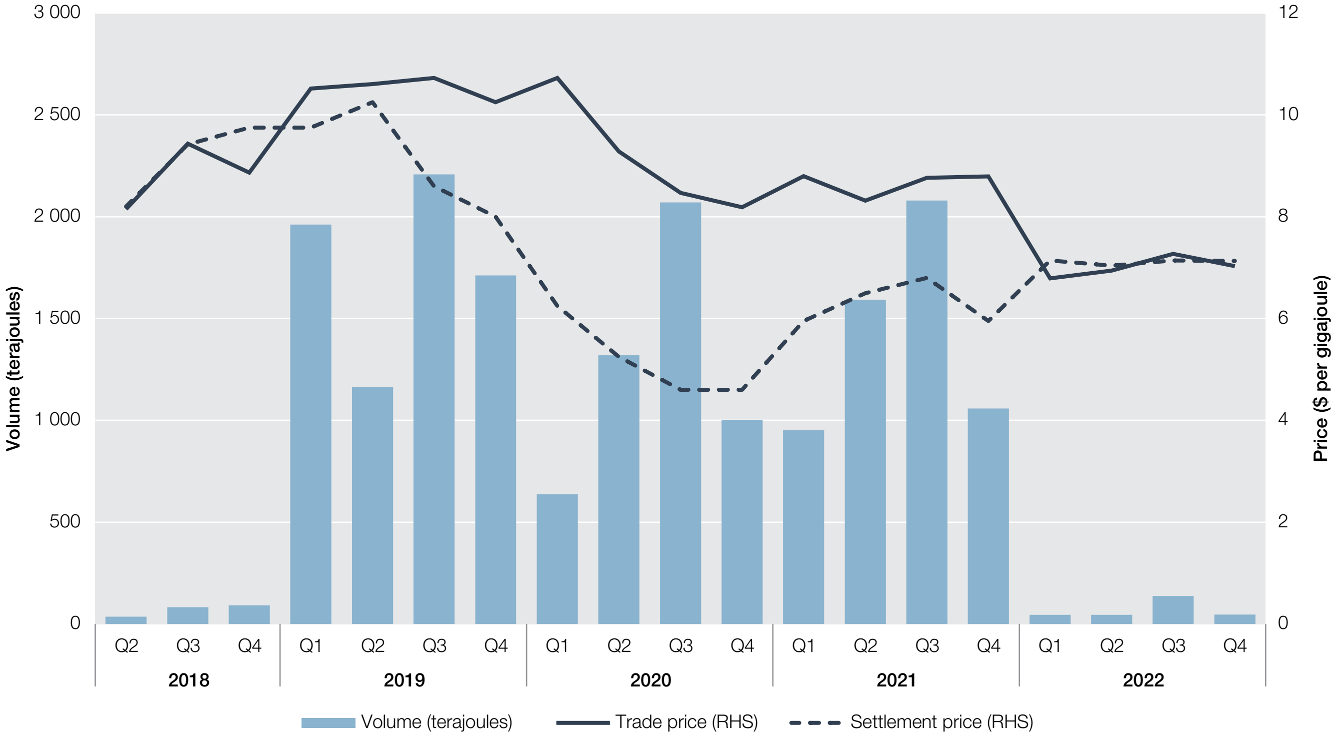
TRADE DATE	QUANTITY (TJ)	NUMBER OF CONTRACTS
Q2 2013	92	10
Q3 2016	92	10
Q4 2016	46	5
Q2 2018	777	85
Q3 2018	1303	143
Q4 2018	3294	361
Q1 2019	1661	182
Q2 2019	2528	276
Q3 2019	989	108
Q4 2019	2058	225
Q1 2020	2051	224
Q2 2020	2842	310
Q3 2020	743	81

Source: AER anaylsis using ASX data.

Notes: Trade date reflects the date of transactions not contract expiry date.

Settlement prices indicate expected prices between $4.60 in Q4 2020 to rise to between $6 and $6.80 per GJ over 2021 (figure 2.17). The difference between settlement and traded contract prices shows the divergence between actual prices realised and expectations in years prior in 2018 and 2019.

Figure 2.17 ASX Victorian futures trade



Source: AER anaylsis using ASX data.

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

2.10 Focus—Competition in spot markets

Changes in east coast dynamics

In recent years, east coast gas markets have undergone unprecedented change underscored by the start-up of the three large LNG export projects in Queensland. From 2015, Queensland began to overtake Victoria as the largest gas production region on the east coast. Additionally, pipeline expansions and the Day Ahead Auction have allowed gas to flow more dynamically between states, in greater quantities and distances than ever before. Over this period, spot markets have also changed, with higher volumes of trade and the increased presence of larger producers, retailers and traders participating.

Competitive and liquid spot markets are essential to establish a reliable and transparent price signal for investment. In particular, liquid spot markets can serve to develop trade in financial products, which provide a useful forward-looking price expectation around future investment needs. The importance of a gas forward price signal is of increasing importance as significant investment is currently being contemplated for generation and transmission in the National Electricity Market, along with proposals for new gas pipeline and production facilities, and LNG import terminals. The following analysis is intended to assess the liquidity and state of competition in these markets.

Both upstream and downstream markets across the east coast are experiencing increasing volumes of trade (table 2.5). These markets have different names and operating processes but essentially all function as a means to trade gas on a short term basis.[51]

---

[51] Three separate types of markets for gas operate in eastern Australia. The Gas Supply Hubs at Wallumbilla and Moomba are “upstream” exchanges for the wholesale trading of natural gas. The STTMs in Brisbane, Sydney and Adelaide, and the DWGM in Victoria are “downstream” markets for managing the imbalance of gas consumption and demand.

Table 2.5 East coast spot market trade (PJ)

YEAR	QUARTER	VIC	SYD	ADL	BRI	WALLUMBILLA
2016	Q1	3.6	1.2	0.8	0.5	1.6
	Q2	3.3	0.9	0.9	0.6	1.0
	Q3	3.6	1.4	1.0	0.2	4.0
	Q4	3.5	1.3	1.0	0.3	1.3
2017	Q1	5.4	2.3	0.8	0.4	1.2
	Q2	5.2	3.0	0.7	0.3	3.3
	Q3	4.7	1.7	0.6	0.4	3.1
	Q4	5.1	1.7	0.9	0.3	4.0
2018	Q1	2.9	2.0	0.9	0.4	3.2
	Q2	3.5	2.6	1.1	0.3	3.9
	Q3	4.7	3.2	1.2	0.3	6.4
	Q4	4.3	2.1	0.9	0.3	2.9
2019	Q1	5.5	3.4	0.8	0.3	6.1
	Q2	6.2	3.8	0.9	0.3	8.6
	Q3	7.4	4.4	0.9	0.2	8.0
	Q4	6.4	3.8	1.0	0.6	4.7
2020	Q1	4.4	3.7	0.9	0.5	7.6
	Q2	6.6	4.9	1.1	0.4	3.7
	Q3	8.7	5.7	1.3	0.6	6.5

Source: AER analysis using DWGM, STTM, and Gas Supply Hub trades data.

Notes: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs has been estimated netting scheduled buy and sell quantities for each trading participant.

In total, approximately 73.1 PJ has been traded over the last year in these markets, which is only 11 to 12 per cent of east coast demand that typically ranges between 600 to 650 PJ each year. However, it should be noted that there is a clear trend of increasing trade in spot markets at transparent market prices that offer an alternative to bilateral contractual transactions where prices are not published.

Competition in Victoria, Sydney, Brisbane and Adelaide markets

The Victorian Declared Wholesale Gas Market, and the Sydney, Adelaide and Brisbane Short Term Trading Markets have traditionally operated only as balancing markets where retailers and GPG Gentailers would buy or sell small volumes of gas to match receipt and delivery of gas into each market. It appears that these spot markets are now being used beyond this purpose to buy or sell larger volumes of gas at transparent market prices. We have estimated trade volumes in these markets by netting participants' sales and purchases from each market to calculate the extent that they are exposed to market prices. We have classified participants into five groupings for our analysis—GPG Gentailer, Retailer, Industrial, Trader or Exporter/Producer (see Appendix B for details of participant grouping).

The total volume of trade in the Victorian, Brisbane, Sydney and Adelaide markets is increasing across different market participant categories (figure 2.18). The increasing spot trade has been supported by higher sales volumes from large gas producers including LNG exporters, and to a lesser extent by traders. This trend of greater producer participation may be related to a combination of gas availability from excess production in Queensland, extensive outages across all LNG export projects and lower LNG exports more generally.

A number of structural changes have occurred in the market, such as Esso and BHP ceasing joint marketing of gas from its large reserves in Victoria since January 2019.[52] In 2019, BHP registered separately to Esso, and began trading as competitors in the Victoria and Sydney markets. Separately, Shell and Arrow Energy also registered in the Sydney Short Term Trading Market and Day Ahead Auction in 2019 and 2020 respectively.

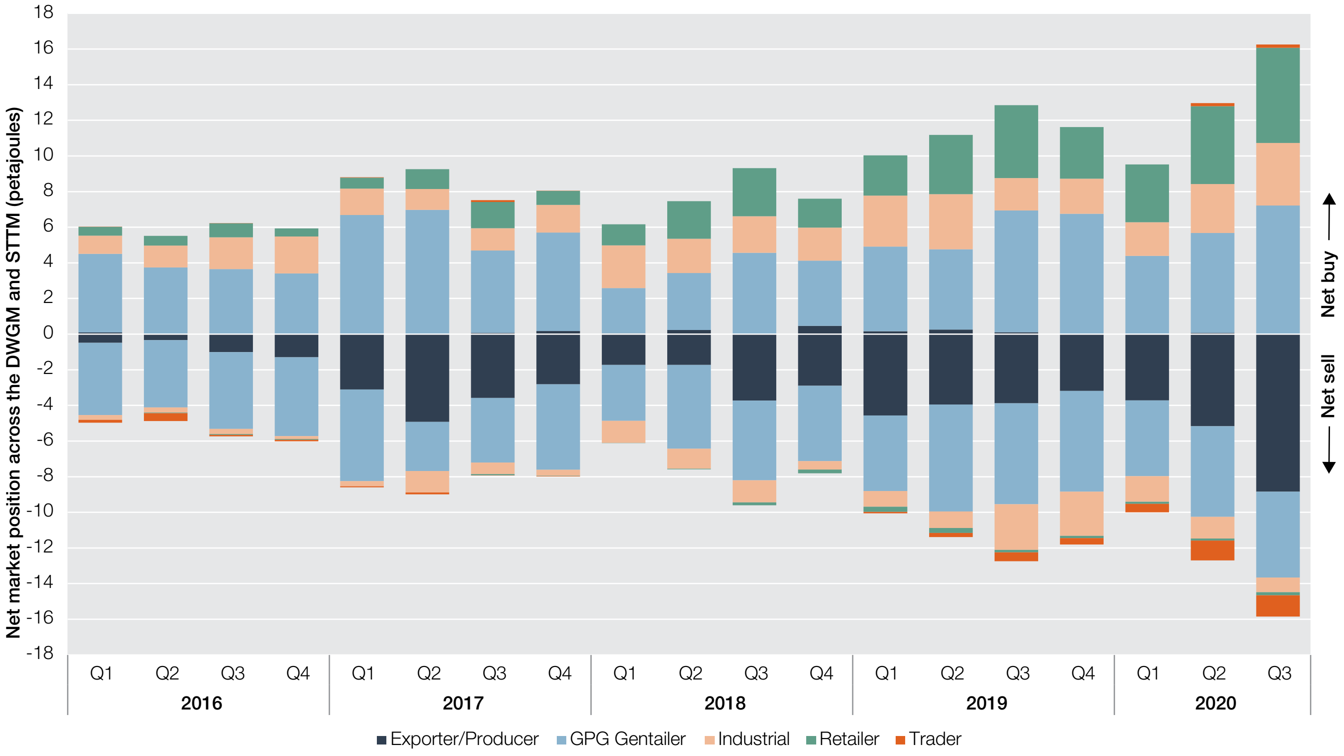
---

[52] ACCC, BHP and Esso to separately market Gippsland basin gas, 17 December 2017, accessed 27 October 2020.

Importantly, the diversity of large suppliers participating in spot markets is increasing, which acts as a greater competitive constraint on prices. Prior to 2017, only Esso and Santos participated in the Victorian and Sydney markets and did not offer significant sales volumes of gas. Since 2019, the net volume Exporter/Producers sold across markets have increased every quarter, with 8.8 PJ offered into the market this quarter compared to 5.1 PJ in Q2 2020. Santos and BHP combined represented 89 per cent of the Exporter/Producer net sell position this quarter. The Exporter/Producer group has access to the largest sources of gas on the east coast, and provide much of the gas supply to retailers, which in turn supply residential and industrial customers. Their continued participation is important to the ongoing development of liquid trade in the gas spot markets. To a lesser extent, Traders have also emerged as a participant group who have been actively engaged in arbitrage by securing cheap transportation services through the Day Ahead Auction. Since the auction commenced in Q1 2019, Traders have consistently held net sell positions in the market, reaching a record of 1 PJ in this quarter. Notable Trader participants include Strategic Gas Market Trading, Macquarie Bank and PetroChina.

Buying interest has similarly increased since 2017, particularly from retailers and industrial customers. This may be partly driven by a number of newer retail models that have emerged, which link offers to wholesale gas spot market prices. In addition, collective buyer groups have emerged and are sourcing cheaper gas from spot markets as an alternative to higher priced bilateral contract markets.[53] Since late 2019, spot prices have ranged between $4.50 and $6 per GJ, while contract offers for gas for 2020 and 2021 have been between $8 and $11 per GJ.[54] Industrial customers have also demonstrated an increasing interest in sourcing cheaper gas from spot markets, with more registrations across all markets since 2018 than any other participant type.

Figure 2.18 Spot trade by participant



Source: AER analysis using DWGM and STTM data.

Notes: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs has been estimated netting scheduled buy and sell quantities for each trading participant.

---

[53] Eastern Energy buyers group, Website About Us, accessed 28 October 2020; Western Energy, Website home, accessed 28 October 2020.

[54] ACCC, *Gas inquiry 2017–2025, July 2020 interim report*, 17 August 2020, p. 45.

Bidding analysis

We have analysed the bidding practices of different participants in each market and noted individual market characteristics, which may affect competitive outcomes. The following factors may explain differences in competitive dynamics across markets:

- Distance from large gas production facilities
- Access to pipeline infrastructure
- Presence of gas powered generation
- The number of participants in each market
- Diversity of participants making supply offers and price bidding.

The following is an analysis of competition in a number of key areas covering offer prices, competition of volumes of gas offered into markets, and ability of different market participants to affect price outcomes.

Offer prices

Brisbane prices have consistently been the lowest of any market since Q1 2016, while Adelaide prices have consistently been higher than any other market over the same period. Although Sydney and Victoria have the largest proportion of offers in the $0 to $2 per GJ price band, Brisbane has consistently the lowest priced marginal offers, which set the market price (figure 2.19). Adelaide has the lowest proportion of $0 to $2 offers and the highest priced marginal offers, which results in the price being set higher than any other market. In each of the four markets, the number of participants offering gas in the $0 to $2 price range has increased year on year since 2016. Only 21 participants offered gas across the four markets in this price range in 2016 compared to 41 participants in 2020. In 2020, Exporter/Producers started to offer gas into the Brisbane and Adelaide markets in the $0 to $2 price range for the first time. Albeit in small volumes, Traders have also started to offer gas in this price range into the Sydney and Victorian market since 2019 with volumes more than doubling in 2020 compared to 2019.

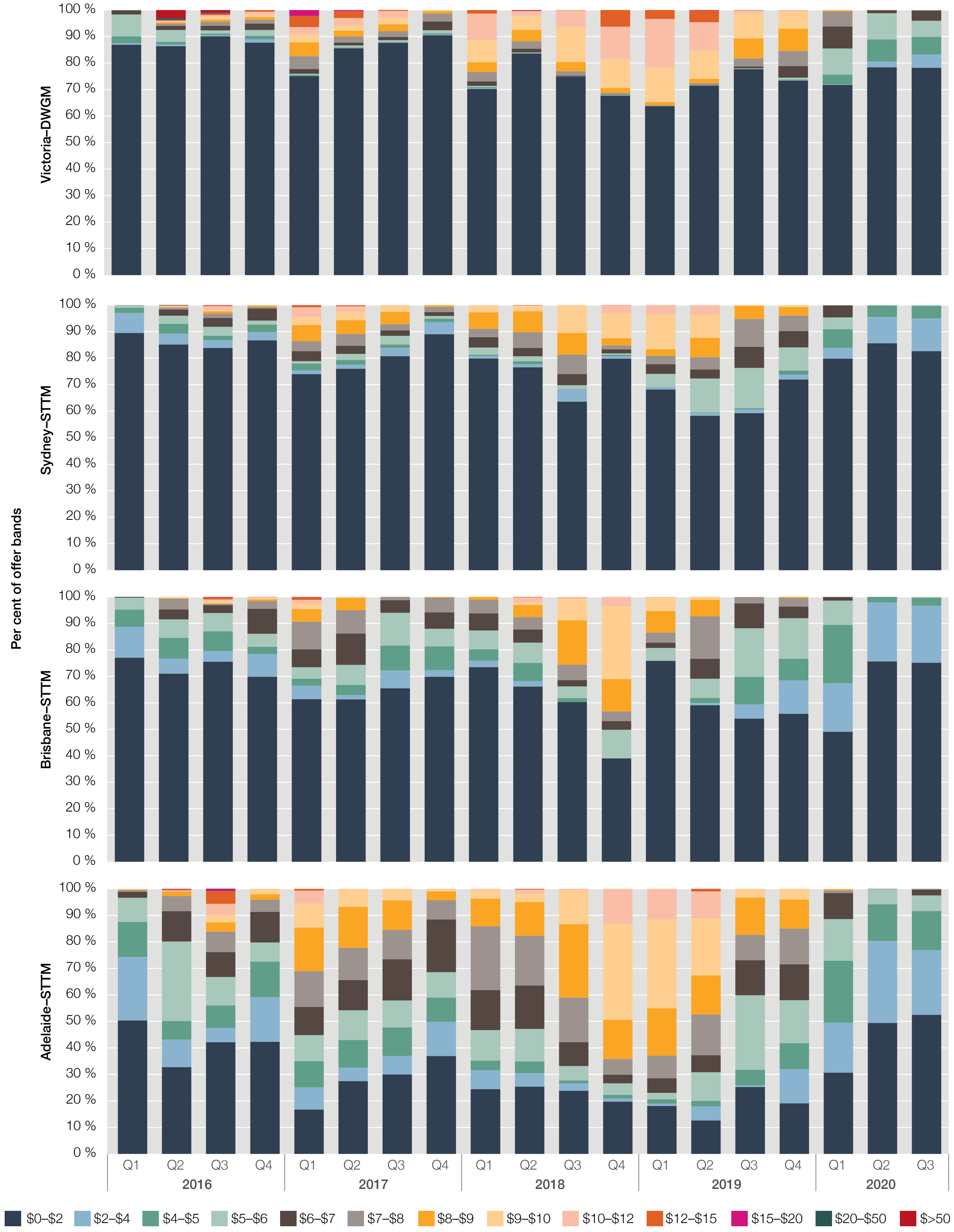
The Brisbane market is likely to benefit from relatively closer proximity to large gas fields at Roma, Queensland, which is by far the largest source of supply on the east coast. Since 2018, production from the Roma fields have increased materially and offer prices in Brisbane have consistently declined over the same period. In Q4 2018, 28 per cent of offers were in the $9 to $10 per GJ range, while in Q3 2020, 97 per cent of offers were $4 per GJ or less. While prices have moved to cheaper price bands in other markets they remain higher than Brisbane and likely reflect the cost of transportation of gas from Queensland to other markets.

By comparison, Victoria and Sydney have traditionally been supplied by the Longford gas plant, which is located in Victoria and has been the largest and cheapest source of gas supply on the east coast. In 2017, Longford produced a historically high output of gas but started to decline thereafter as legacy gas fields are deplete. This period of lower gas production in 2018 may explain the more expensive offers in the $9 to $10 and $10 to $12 per GJ price bands in Sydney and Victoria.

Since March 2019, the Day Ahead Auction has offered a cost effective means to transport gas large distances from cheaper markets in Queensland to the higher priced Victorian and Sydney markets. Throughout 2019, a higher portion of offers moved into cheaper price bands following the downward trend of domestic and international LNG prices. Notably, in Q1 2019 a large portion of offers were priced in the higher price bands in Victoria and in Sydney 13 per cent of offers were priced at $9 to $10 per GJ. By Q3 2020, offer prices had reduced significantly, with a large number of offers priced at less than $7 per GJ in Victoria and Adelaide, while all offers in Sydney and Brisbane were priced at less than $6 per GJ.

Since Q2 2019, Adelaide prices have been consistently higher than Sydney and Victoria by between $0.57 and $0.95 per GJ. This may reflect the lower activity on the Day Ahead Auction into the Adelaide market, which makes it harder and more expensive to arbitrage from cheaper markets to sell gas into Adelaide. However, it is important to note that Adelaide prices have tended to be higher than other market prices since before the Day Ahead Auction commenced, such as in 2015 when gas prices were low. Given the large relative consumption of gas by power generation in South Australia, electricity market prices may also bear more heavily on Adelaide gas prices and explain the price differences observed to other gas markets at times.

Figure 2.19 Scheduled offers by price band



Source: AER analysis using STTM and DWGM data.

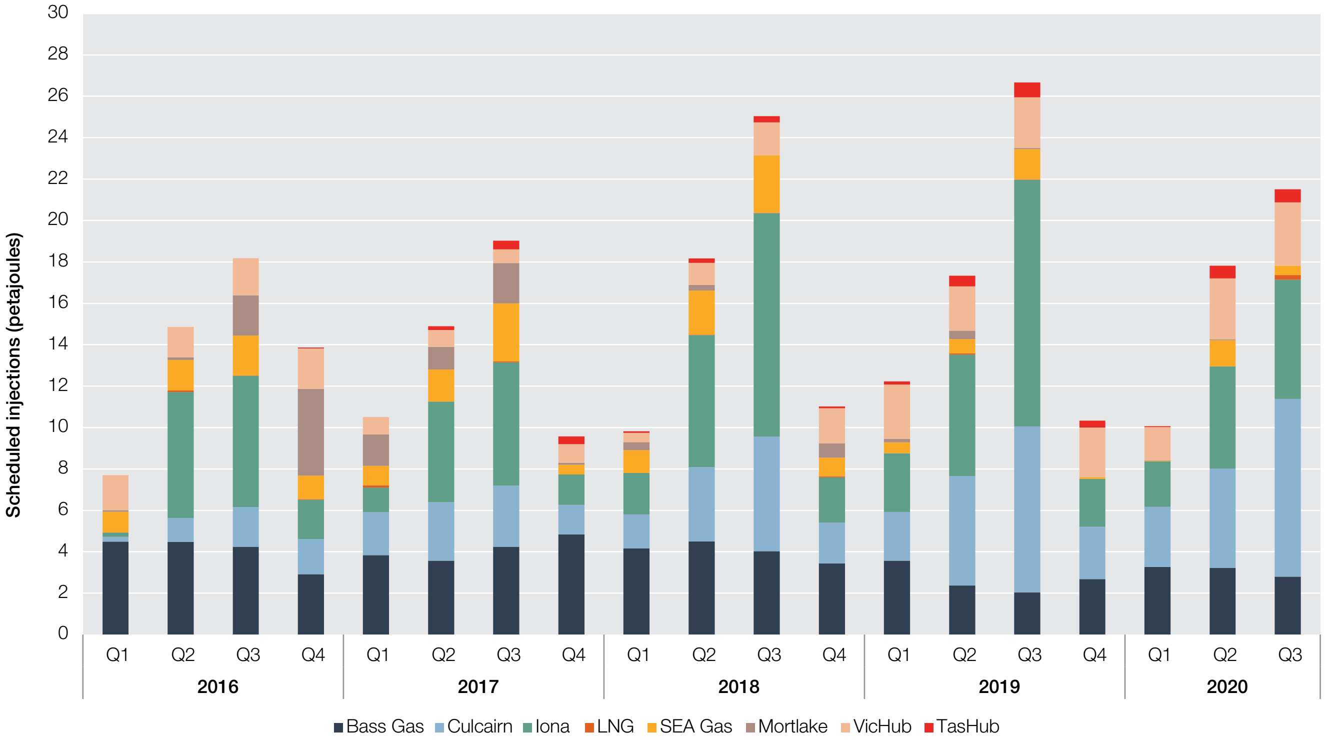
Notes: The DWGM price bands also includes the next price band on the offer stack that was not filled. For example if the price was set in band $7 to $8, the next band up namely $8 to $9 will also be included in the data – this approach recognises limitations in the current AER approach to account for physical system impacts in Victoria on the cleared offers. The STTM price bands are the actual price bands that were filled.

The DWGM price bands were calculated for the 6 AM market schedule. The STTM price bands were calculated for the D-1 schedule.

Offer volumes

Increasing quantities of gas are flowing from NSW into Victoria via the Culcairn injection point, which is the main entry point for gas moving from northern markets into Victoria (figure 2.20). Since Q2 2019, there has been a consistent increase in injections from Culcairn into Victoria. Although the majority of gas being moved through Culcairn into Victoria can be attributed to the GPG Gentailers, since 2019, Exporter/Producers and Traders have also started to inject more gas into Victoria through Culcairn. In Q3 2020, Exporter/Producers accounted for 13 per cent and Traders 6 per cent of the gas injected into the Victorian market through Culcairn. Culcairn has also been a particularly popular delivery point for transport services won in the Day Ahead Auction, with similar quantities linked to receipt points in south east Queensland. In Q3 2019, 25 per cent of the injections into Victoria through Culcairn were attributable to capacity won on the auction, while in Q3 2020 this was 11 per cent. The number of shippers using the Day Ahead Auction through Culcairn increased from four in 2019 to five in 2020.

Figure 2.20 Scheduled injections into Victoria by injection point excluding Longford

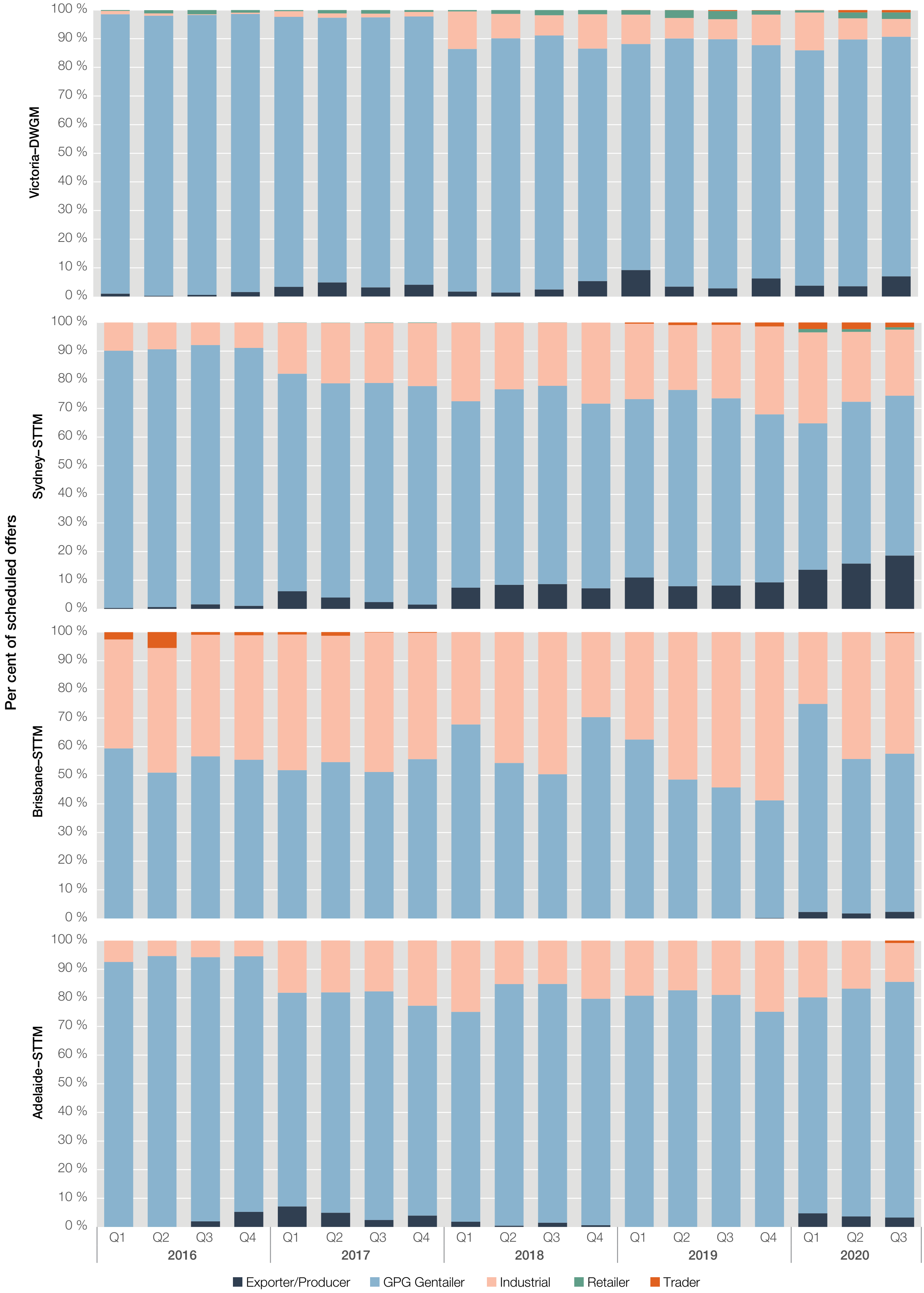


Source: AER analysis using DWGM data.

Note: The DWGM injections were calculated for the 6 AM market schedule.

There is evidence of increasing competition between participants driving lower prices, particularly in the Sydney and Victorian markets. Exporter/Producers such as Shell, Santos, Esso and BHP, and many new industrial customers are scheduling more gas into the market. As a result, they are winning market share away from the historically dominant GPG Gentailer participants, which include AGL Energy, Origin Energy and EnergyAustralia (figure 2.21). Since 2019 and the introduction of the Day Ahead Auction, this shift has accelerated and there has been a greater diversity of participants joining Victorian and Sydney markets. In Q3 2020, Sydney sourced a record 19 per cent of gas offers from Exporter/Producers, while in Victoria, Exporter/Producers offered in 7 per cent of scheduled gas. The Victorian market has seen less scheduled gas offers from Exporter/Producers with Shell notably not participating in Victoria but active in the Sydney market. Adelaide has seen a small increase in scheduled offers by Exporter/Producers since Q1 2020, reaching 3 per cent in Q3 2020. Over this time, participants have started winning auction capacity on the Moomba to Adelaide Pipeline System, which may give more participants access to the Adelaide market and the opportunity to arbitrage the price differential between the other markets.

Figure 2.21 Scheduled offers by participant group



Source: AER analysis using STTM and DWGM data.

Notes: The DWGM scheduled offers were calculated for the 6 AM market schedule. The STTM offers were calculated for the D-1 schedule.

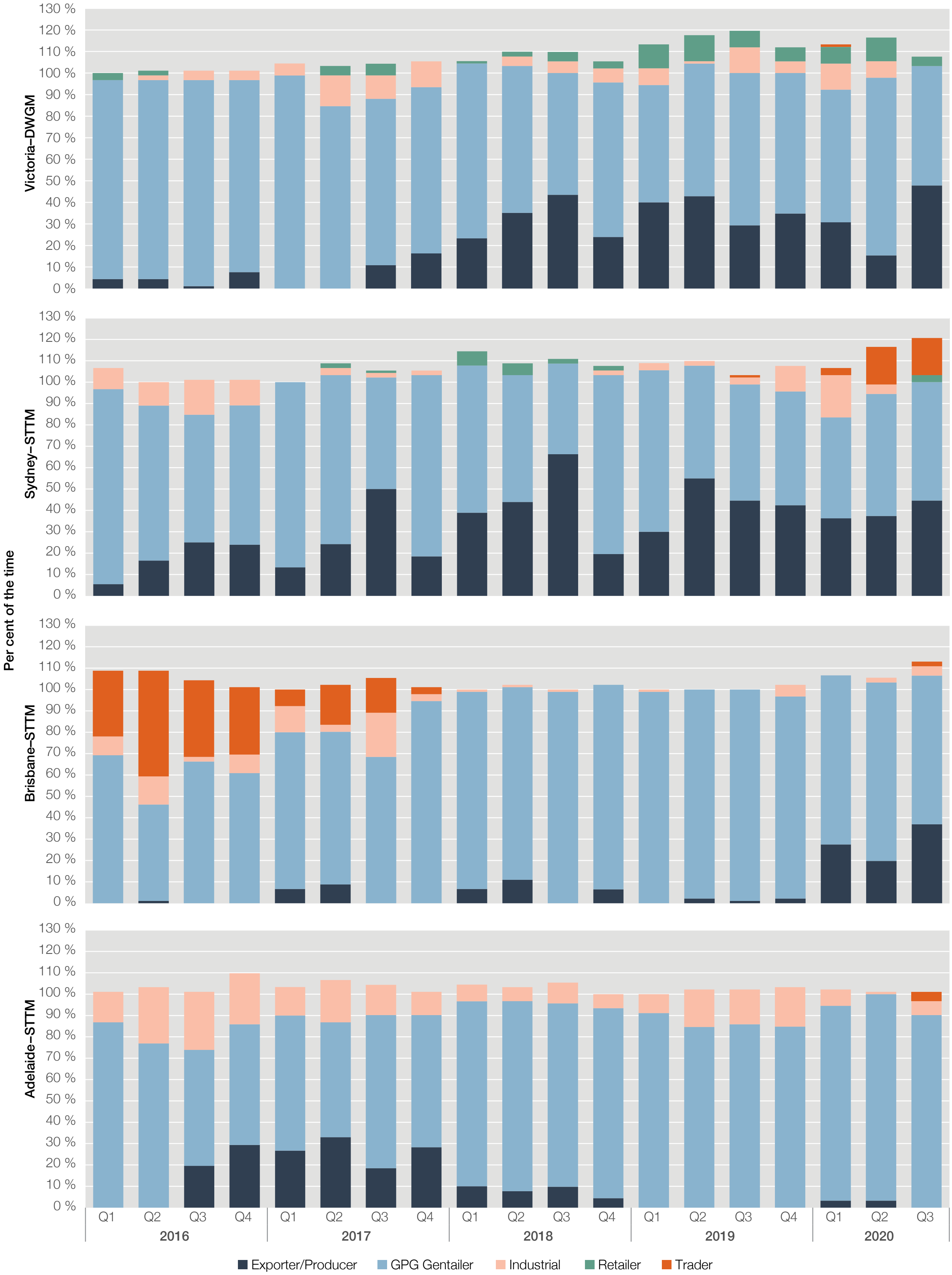
Price setting

Another key aspect of gas market competition is the extent that different participant groups are influencing market prices. Increasingly, Exporter/Producers and Traders have a significant bearing on market outcomes, setting the price more in Victoria and Sydney since 2017, and in Brisbane and Adelaide across 2020 (figure 2.22). With lower prices across markets this year, there has also been greater competition between participant groups in setting the price. In general, as markets have evolved to have a more diverse mix of participants, GPG Gentailers have been less influential in setting market prices. This increased competition in price bids has culminated in Exporter/Producers setting the price a higher proportion of the time, including between 40 and 50 per cent of the time in Victoria and Sydney in Q3 2020 and 37 per cent of the time in Brisbane. Traders have also been more influential in setting prices particularly in Sydney, where they set the price 17 per cent of the time in Q3 2020.

As Industrial and Retail participants have increased their participation in spot markets to source cheaper gas relative to contract offers, they have become more active in setting the price, particularly in the Victorian and Sydney markets. In Q1 2020, Industrials set the price at a notably high 12 per cent of the time in Victoria and 20 per cent of the time in Sydney. In Victoria, Retailers have also been setting the price more often since 2019.

This contrasts to the period from 2016 to 2018 when it was not uncommon for GPG Gentailers to set the price 80 to 90 per cent of the time in Victoria, Brisbane and Adelaide and 70 to 90 per cent of the time in Sydney. This more recent period of increased competition between participant groups has contributed to a prices being set at lows not seen since Queensland’s LNG export projects became fully operational in 2016. Consistently higher prices in the Adelaide market may reflect that GPG Gentailers are setting prices the vast majority of the time, given their willingness to pay higher prices to source gas for power generation when NEM prices are favourable. We explore the linkage between gas and electricity markets further in the electricity focus story.

Figure 2.22 Price setter by participant type



Source: AER analysis using STTM and DWGM data.

Notes: The DWGM price setter was calculated for the 6 AM market schedule. The STTM price setter was calculated for the D-1 schedule.

The large proportion of the Trader participants setting the price in Brisbane over 2016 and 2017 can be explained by Stanwell mothballing its Swanbank E power station and being classified as a Trader rather than a GPG Gentailer during this period.

Trade at the Wallumbilla hub

The Wallumbilla Gas Supply Hub is another major market that accounts for a significant volume of spot trades on the east coast. The hub is a major pipeline junction linking large gas production fields in Roma, LNG export trains, regional demand centres, nearby gas powered generation and the Brisbane market. As the upstream market for the wholesale trading of gas, the Wallumbilla hub has become a major source of gas for the other east coast markets. Since the Day Ahead Auction commenced in March 2019, yearly volumes flowing south have roughly doubled as shown in section 2.6. The hub gives participants an ability to trade physical gas, as well as the compression services necessary to move gas from low to high pressure pipelines.[55] There is also a Gas Supply Hub in Moomba, South Australia which does not see significant trade.

As an upstream market, the Wallumbilla hub trades on a different basis to the downstream Victorian, Sydney, Brisbane and Adelaide markets. Since Q2 2018, trade at Wallumbilla has mostly exceeded the other markets but is generally close to or less than trade volumes in Victoria. Peak trade occurred at the Wallumbilla hub in Q2 2019 at 8.6 PJ for the quarter, while Victorian trade peaked at 8.7 PJ in Q3 2020. Since Q3 2019, trade at Wallumbilla has been on a downward trajectory and well below Victorian trade, reflecting lower overall market prices.

The Wallumbilla hub facilitates trade across a number of pipelines, including between the SWQP and the RBP. We group trade at the hub into two locations: Wallumbilla (WAL), and a separate south east Queensland (SEQ) product, which provides virtual delivery into the RBP. WAL can further be divided into the low pressure and high pressure notional trade points, from which a number of pipelines and compressors are physically linked. Trade at SEQ consist of all trade on the RBP from Kogan North production facility to Wallumbilla (Figure 2.23). As section 2.4 notes, a large part of trade at Wallumbilla involves receiving gas from SEQ and compressing it to flow along the SWQP at higher pressure.

There are a large number of trades outside of the defined WAL and SEQ trade locations that are not recorded on the hub, close to and around Wallumbilla which includes bilateral trades under contract via the surrounding vast pipeline network. AEMO is currently undertaking a review to add reporting of prices at additional trading points to the Wallumbilla hub, as well as adding trading points in NSW.[56] We have estimated the hub trade as a proportion of total physical flows around Wallumbilla to be no more than 14 per cent since Q4 2016, and mostly less than 6 per cent from Q4 2016 to Q3 2020.[57] This suggests that a significant portion of trade at Wallumbilla is not being reported, and not reflected in the pricing signal. However, quantifying the value of these trades is difficult because not all physical flows around Wallumbilla are the result of trades of gas, but rather gas in transit flowing between markets e.g. Exporter/Producers may send their own gas south for sale or move gas production through Wallumbilla to Gladstone for export.

Over the last year to Q3 2020, LNG exports have totalled 1191 PJ from Gladstone, while production from Roma facilities has totalled 1480 PJ. Even after discounting for gas consumed in the process of converting gas to LNG, or electricity generation by exporters, this suggests that there is still significant quantities of gas available for domestic trade. Over the same period, only 22.5 PJ has traded at the Wallumbilla hub, and a total of 50 PJ was traded in Victoria, Sydney, Adelaide and Brisbane spot markets. This suggests large volumes of gas are being traded off market, and these trades are not reflected in the Wallumbilla market price. This was confirmed by the ACCC, which measured trade at Wallumbilla as representing a fraction of bilateral trade in Queensland.[58]

---

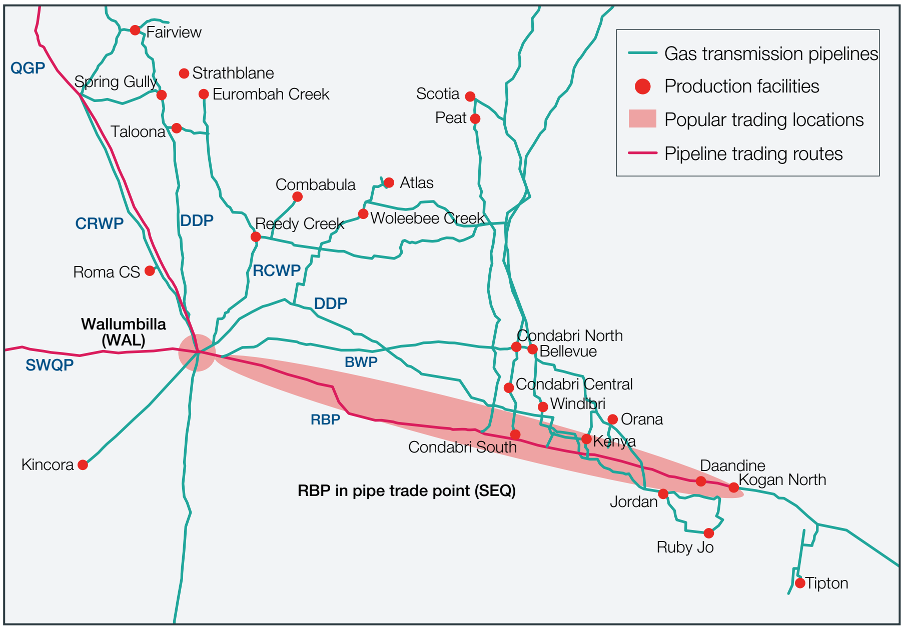
[55] AEMO, *Gas supply hub industry guide*, October 2019, p. 8.

[56] AEMO, Gas supply hub reference group, 13 May 2020.

[57] AER, Wholesale industry statistics: Gas liquidity churn rate, accessed 28 October 2020.

[58] ACCC, *Gas Inquiry 2017–2020, April 2019 interim report*, 30 May 2019, p. 47.

Figure 2.23 Wallumbilla hub schematic

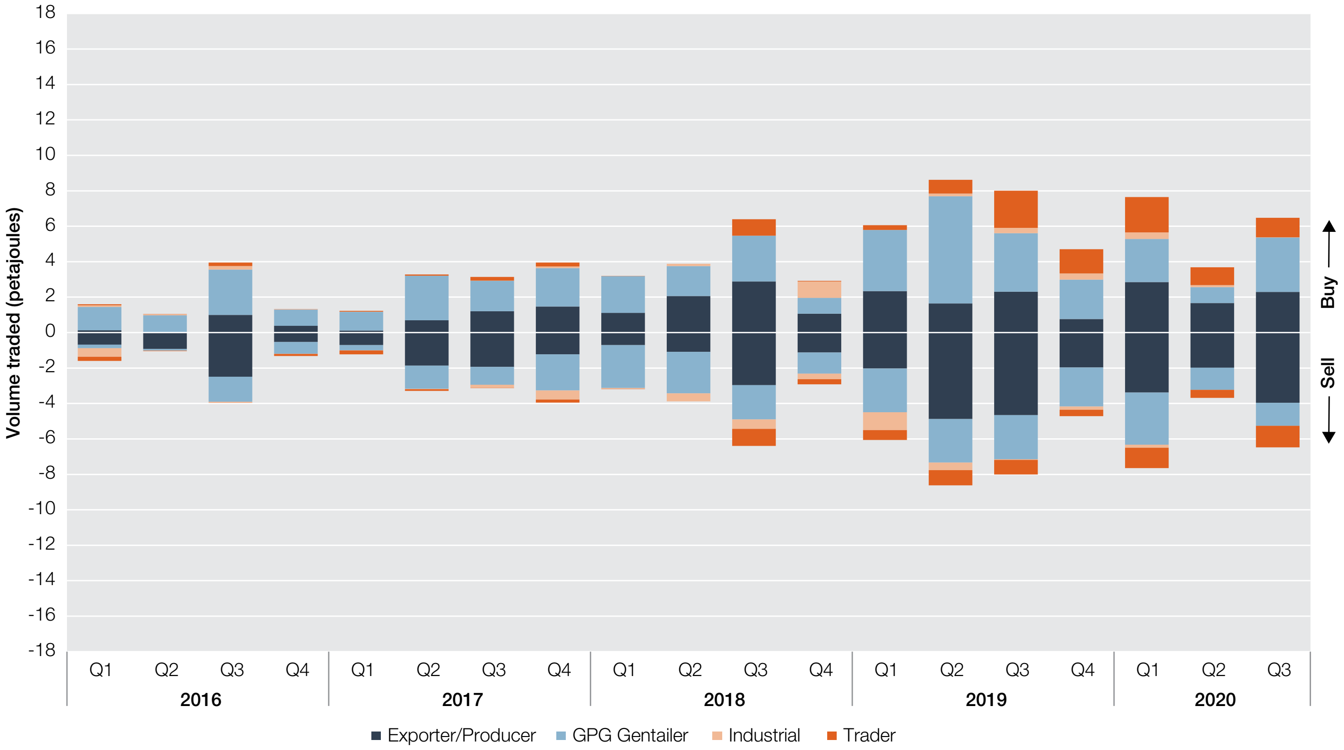


Source: AER analysis using GEOScience Australia data.

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

Exporter/Producers and GPG Gentailer participant groups have emerged as the most dominant users of the Wallumbilla hub. These participants have increased trade volumes at Wallumbilla since Q1 2016, with each type of participant typically both buying and selling throughout each quarter (figure 2.24). Exporter/Producers with large gas supplies, typically sell more than they buy in each quarter, while Traders and GPG Gentailers tend to buy more than they sell. Compared to other spot markets, Exporter/Producers and Traders at Wallumbilla are more significant participants, together accounting for around 60 to 70 per cent of the trade at the hub. Unlike other spot markets, the share of trade is more diverse among participant groups, and competition at the hub seems more balanced, with less influence of GPG Gentailers than in other markets.

Figure 2.24 Wallumbilla hub trade by participant



Source: AER analysis using Gas Supply Hub trades data.

Appendix A Electricity generator outages

Major generator outages Q3 2020

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q3 2020	REASON FOR OUTAGE	RETURNED TO SERVICE
Queensland				
Callide B, CS Energy	Black Coal, 2 units, 350 MW each	Unit 1: 91 days	Planned	Unknown
Callide C, Callide Power Trading	Black Coal, 2 units, 420 MW each	Unit 2: 52 days	Planned	28 September
Condamine, QGC Sales	Gas 133 MW	37 days	Unplanned (8 days) – 'change in ambient conditions'	21 August
			Unplanned (22 days) – 'market conditions'	21 September
			Unplanned (7 days) – 'change in ambient conditions'	Unknown
Gladstone, CS Energy	Black coal, 6 units, 280 MW each	Unit 1: 27 days	Unplanned – 'technical issues – fuel leak'	28 July
		Unit 2: 26 days	Unplanned – 'technical issues'	5 August
		Unit 3: 69 days	Unplanned (49 days) – 'portfolio rearrangement due to G1 outage and network'	19 August
			Unplanned (20 days) – 'mill limit'	9 September
		Unit 5: 71 days	Unplanned (10 days) – 'technical issues – FD fan'	11 July
			Unplanned (26 days) – 'unit offline revised'	24 August
			Unplanned (35 days) – 'unit trip'	Unknown
Millmerran, Millmerran Energy Trader	Black coal, 2 units, 306 MW each	Unit 1: 10 days	Unplanned – 'mill or feeder limitation'	18 July
Stanwell, Stanwell Corporation	Black coal, 4 units, 365 MW each	Unit 1: 17 days	Planned	6 August
		Unit 2: 71 days	Planned	14 September
Tarong, Stanwell Corporation	Black coal, 4 units, 350 MW each	Unit 1: 5 days	Unplanned – "technical issue – tube leak"	Unknown
		Unit 2: 18 days	Planned	Unknown

New South Wales				
Bayswater, AGL Energy	Black coal 4 units, 630 MW each	Unit 3: 40 days	Planned	Unknown
Eraring, Origin Energy	Black coal 4 units, 680 MW each	Unit 2: 25 days	Unplanned – ‘FD fan outage’	26 September
Liddell, AGL Energy	Black coal 4 units, 450 MW each	Unit 1: 20 days	Planned	Unknown
		Unit 2: 41 days	Unplanned - ‘plant failure’	31 August
		Unit 3: 20 days	Planned (19 days)	2 August
			Unplanned (1 day) – ‘unit trip’	12 August
		Unit 4: 45 days	Planned (37 days)	14 September
			Unplanned (8 days) - ‘tube leak’	Unknown
Vales Point, Delta Electricity	Black coal 2 units, 660 MW each	Unit 1: 24 days	Planned	8 September
Victoria				
Loy Yang A, AGL Energy	Brown coal, 4 units, 500 MW - 540 MW	Unit 1: 11 days	Unplanned - ‘steam leak’	16 September
		Unit 2: 9 days	Unplanned - ‘tube leak’	26 July
		Unit 4: 11 days	Unplanned - ‘plant failure’	14 July
Loy Yang B, Alinta Energy	Brown coal, 2 units, 520 MW each	Unit 1: 14 days	Unplanned (3 days) - ‘steam leak’	2 September
			Planned (11 days)	Unknown
Yallourn, EnergyAustralia	Brown coal, 4 units, 355 MW each	Unit 1: 91 days	Unplanned - ‘tube leak’	Unknown
		Unit 2: 18 days	Unplanned (6 days) - ‘tube leak’	9 August
			Unplanned (5 days) - ‘tube leak’	17 August
			Unplanned (7 days) - ‘tube leak’	27 August
		Unit 4: 10 days	Planned	28 September

Source: AER analysis using NEM data.

Note: The table outlines major generator outages throughout Q3 2020 and the reason for the outage. The table focuses primarily on larger coal and gas generators that operate most of the time. Outages under 10 days in duration have been included in the count of days offline in Q3 2020 but have been excluded from the ‘reason for outage’.

Appendix B Gas snapshots

PARTICIPANT LIST IN EASTERN GAS MARKET

	Market participant	Victoria	Sydney	Adelaide	Brisbane	GSHs	DAA
GPG Gentailer	AGL	●	●	●	●	●	🟠
	Alinta Energy	●	🔵	●	●	●	🟠
	CleanCo				🟠	🟠	🟠
	EnergyAustralia	●	●	●		🔵	🟠
	Engie	●					
	ERM	●	●	🟢	●	●	🟠
	Hydro Tasmania	●	●				
	Origin	●	●	●	●	●	🟠
	Snowy Hydro	●	●	🔵	🟡		
Exporter/Producer	Arrow		🟢		🟠	●	🟢
	APLNG					●	
	BHP Billiton	🟠	🟠				
	Esso	●	●				🟠
	GLNG					●	
	Lochard Energy	🔵					
	Santos	●	●	●	●	●	🟠
	Senex					🟢	
	Shell		🟠				🟠
	Walloons (QGC)					●	🟠
	Westside Corporation					●	🟠
Retailer	1st Energy	🟢					
	Click Energy	●	🔵				
	Covau	●	●		🟢		
	Delta Electricity		●				
	Dodo	●	●				
	GloBird Energy	🟡	🟢	🟢	🟢		
	GridX		●				
	Powershop	🔵					
	Simply Energy		🔵	●			
	Sumo Gas	🔵					
	Weston Energy	🔵	●	🔵	🟡		

Industrial	Adelaide Brighton Cement			⚫			
	BlueScope		⚫		🟠		
	Boortmalt	🔴	🟠	🟠			
	Brickworks	🟢	🟢	🟢	🟢		
	Caltex				⚫		
	Commonwealth Steel		🔵				
	Coopers			🔵			
	CSR Building Products	🟠		🔴	🟠		
	Incitec Pivot				⚫	⚫	🔴
	Infrabuild	⚫	⚫	⚫			
	Master Butchers			🟢			
	Michell Wool			🔴			
	Mobil Oil	🟠					
	Norske Skog	🟠					
	Oceania Glass	🟢					
	O-I International	🟠	🟠	🟠	🔴		
	Orica		🔵				
	Orora		🟢				
	Paper Australia	🟠	🟢				
	Qenos	🔵	⚫			🟣	🔴
	SA Water			⚫			
	Tarac Technologies		🔵	⚫			🔴
	Visy	⚫	⚫	⚫	⚫		🟢
	Viva Energy	🟠					
Trader	Eastern Energy Supply	🟢	🟢	🟢	🟢	🟢	🟢
	Macquarie Bank	🔴	🔴			🟠	🔴
	Petro China	🟢	🟢			🔴	🟢
	Strategic Gas Market Trading	🔴	🔴		🟢	🟢	🔴
	60	36	37	23	20	19	20

⚫ Entered before 2017 🔵 Entered in 2017 🟠 Entered in 2018 🔴 Entered in 2019 🟢 Entered in 2020 🟣 Exit or inactive

Note: For Victoria, Adelaide, Sydney, Brisbane and the Gas Supply Hub the year represents when participants commenced trading. For the Day Ahead Auction the year represents when participants registered.

* Arrow also operates the Braemar 2 power station.

GAS SUPPLY HUBS SNAPSHOT

	2014	2015	2016	2017	2018	2019	2020 YTD
number of trades	481	875	798	1 638	1 919	3 635	2 263
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%*	17.8 *40% : 56%*
trade value, $million	5	24	57	89	148	219	78
volume weighted average price, $/GJ	2.01	3.66	7.20	7.68	9.02	7.98	4.40
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*	19 *15:16*
% traded through exchange (sum bought divided by regional demand)	N/A	N/A	N/A	4.3%	6.1%	9.1%	7.2%

Source: AER analysis using Gas Supply Hub trades and National Gas Services Bulletin Board data.

DAY AHEAD AUCTION SNAPSHOT

	2019				2020			
	MAR	Q2	Q3	Q4	Q1	Q2	Q3	Total
number of active participants	1	4	6	6	11	12	14	17
number of facilities	4	6	6	7	7	9	8	10
auction legs won	142	671	1 281	807	1 179	1 282	1 716	7 078
capacity won, TJ	2 548	6 609	14 945	6 492	10 525	8 026	13 706	62 850
maximum auction price, $/GJ	0.10	0.61	1.05	0.30	0.30	1.26	1.49	1.49
% won at $0/GJ	82%	88%	71%	87%	82%	78%	69%	77%
% won at ≥$0.10/GJ	0.4%	8%	20%	5%	4%	14%	23%	14%

Source: AER analysis using Day Ahead Auction results data.

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