Wholesale Markets Quarterly

Q1 2021

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AUSTRALIAN ENERGY REGULATOR

Australian Government

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Electricity markets

Volume weighted average (VWA) prices in all regions were lower than expected in Q1 2021, ranging from $27/MWh in Victoria up to $53/MWh in South Australia. While prices are typically higher in the first quarter due to summer demand, this did not happen due to mild weather, low demand and increased low cost generation. This was the first time any region has had a Q1 price this low since 2012.

Low demand from the grid was driven by an unusually mild summer and high levels of rooftop solar generation. As a result, there were a high number of negatively priced trading intervals in Q1 2021, especially in Victoria and South Australia, as well as the lowest number of prices above $300/MWh in a Q1 since 2012. Demand fell to such low levels in South Australia there were concerns for system security. Our first focus story looks at the events of 14 March when rooftop solar in South Australia was curtailed for the first time.

Reduced output and cheaper prices resulted in very low National Electricity Market (NEM) turnover in Q1 2021. These prices are expected to continue, with contract prices for the next 2 to 3 years sitting below $60/MWh in all regions.[1] Lower prices have been putting pressure on ageing thermal plant. On 10 March, EnergyAustralia announced it was bringing forward to mid-2028, the expected closure year of the Yallourn power station in Victoria.

Increased brown coal, wind and solar generation coupled with low demand meant less high priced capacity was needed, reducing the amount of gas and black coal generation dispatched. As a result, black coal generation fell to its lowest ever Q1 level, and gas generation fell to its lowest Q1 level since 2005.[2] Despite higher international coal prices, coal generators offered the majority of their capacity at low prices. Hydro generation also offered its capacity at prices comparable to black coal. Our second focus story looks at how gas offers have changed in the NEM over the last few years.

Gas markets

Average quarterly east coast gas spot prices ranged from $5.50/GJ to $6.40/GJ in Q1 2021, increasing marginally from last quarter. Domestic gas spot prices remain relatively subdued compared to Asian LNG spot prices which increased dramatically in this quarter, following severe winter conditions, and logistical and supply constraints. Asian LNG spot prices experienced an unprecedented rise, peaking in January at an average of $25/GJ over that month.

On the east coast, gas flowed strongly from southern markets to Queensland, to supply elevated levels of LNG demand at high prices. The Day Ahead Auction helped unlock unused transportation capacity to allow more shipments from the southern markets.

Gas demand for electricity generation continued to fall, reaching levels not seen since 2005, with generators in Victoria and NSW consuming less than 1 PJ of gas in each state.

1 As at 31 March 2021.

2 In Q1 2021 gas fell to its lowest quarterly level since 2005 which was also its lowest Q1 level since 2005.

Electricity markets at a glance

Q1 2021

Spot prices

Q1 2021 prices low, ranging from $27/MWh to $53/MWh, first time since 2012 a Q1 price has been so low

Demand

Demand was very low, due to a mild summer and increased rooftop solar

Offers

Coal continued to offer capacity at low prices despite rising international coal prices

Generation

Total generation has been trending down for 2 years, showing impact of rooftop solar

NEM turnover

Low prices and low output reduced National Electricity Market turnover, especially in Victoria

Outlook

Based on contract market outcomes, future price expectations have fallen

Gas markets at a glance

Q1 2021

Spot prices

Prices rise 2.5%, ranging from $5.50/GJ to $6.40/GJ, with Queensland prices the highest

International prices and LNG exports

Significant rise in Asian prices and high LNG demand

Gas production and flows

Queensland gas production close to record set in previous quarter, averaging close to 4,200 TJ/day

Day Ahead Auction

The Day Ahead Auction unlocked unused pipeline capacity so shippers could send gas north to Queensland

Common measurements and abbreviations

ELECTRICITY		GAS	
MW	megawatt	GJ	gigajoule
MWh	megawatt hour	PJ	petajoule
TW	terawatt	TJ	terrajoule
FCAS	Frequency control ancillary services	STTM	Short Term Trading Market
NEM	National Electricity Market	DWGM	Declared Wholesale Gas Market
VWA	Volume weighted average	WGSH	Wallumbilla Gas Supply Hub
AEMO	Australian Energy Market Operator	DAA	Day Ahead Auction
		BWP	Berwyndale to Wallumbilla Pipeline
		EGP	Eastern Gas Pipeline
		MAPS	Moomba to Adelaide Pipeline System
		MSP	Moomba to Sydney Pipeline
		PCA	Port Campbell to Adelaide Pipeline
		PCI	Port Campbell to Iona Pipeline
		QGP	Queensland Gas Pipeline
		RBP	Roma to Brisbane Pipeline
		SWQP	South West Queensland Pipeline
		TGP	Tasmanian Gas Pipeline

1. Electricity

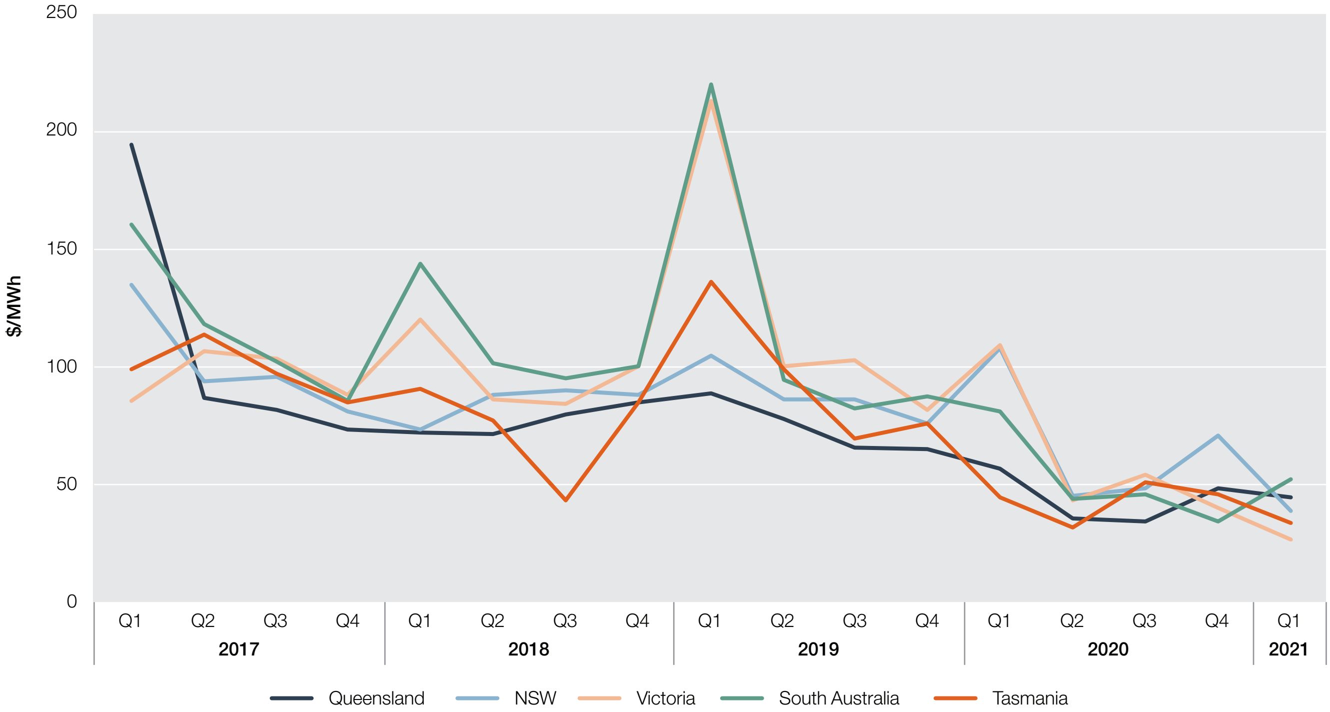
1.1 Wholesale spot prices lower than expected

Volume weighted average (VWA) prices in all regions were low this quarter, ranging from $27/MWh in Victoria up to $53/MWh in South Australia (Figure 1.1). While prices are typically higher in the first quarter due to summer demand, this did not eventuate this quarter. This was the first time any region had a Q1 price below $27/MWh since 2012. It was also the first time Victoria had the lowest average quarterly price in the NEM since the Hazelwood power station closed at the end of Q1 2017.

Prices fell by between 22% and 75% this quarter compared to Q1 2020, with the largest drops occurring in Victoria and NSW. Prices fell as less energy was needed from the grid than a year ago due to an unusually mild summer and because customers sourced more of their energy from rooftop solar. On the supply side, low priced wind and grid scale solar generation continue to put downward pressure on prices.

Q1 2021 prices were also lower than Q4 2020 prices in every region except South Australia. This fall in prices from Q4 to Q1 is unusual – the last time prices fell from Q4 to Q1 in as many regions was in 2006.

Figure 1.1 Average quarterly spot prices (VWA)

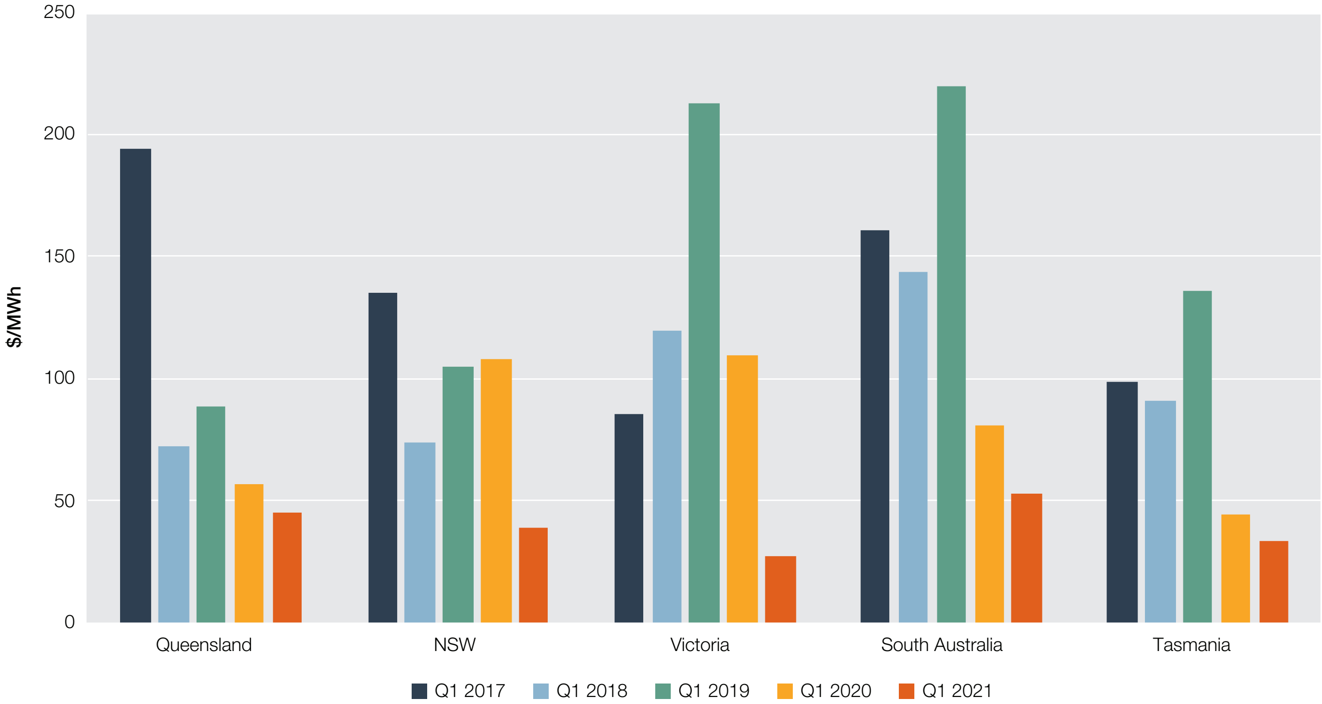


Source: AER analysis using NEM data.

Note: Volume weighted average price is weighted against native demand in each region. AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Comparing Q1 prices over a longer time series shows how low Q1 2021 prices were in all regions compared to recent summers (Figure 1.2). Victoria, South Australia and Tasmania in particular have seen dramatic falls in Q1 prices over the last 2 years, driven by mild summers, falling demand and increased renewable generation. Q1 2021 prices in Queensland and NSW were also lower than those in recent years.

Figure 1.2 Spot prices (VWA) – Q1 comparisons



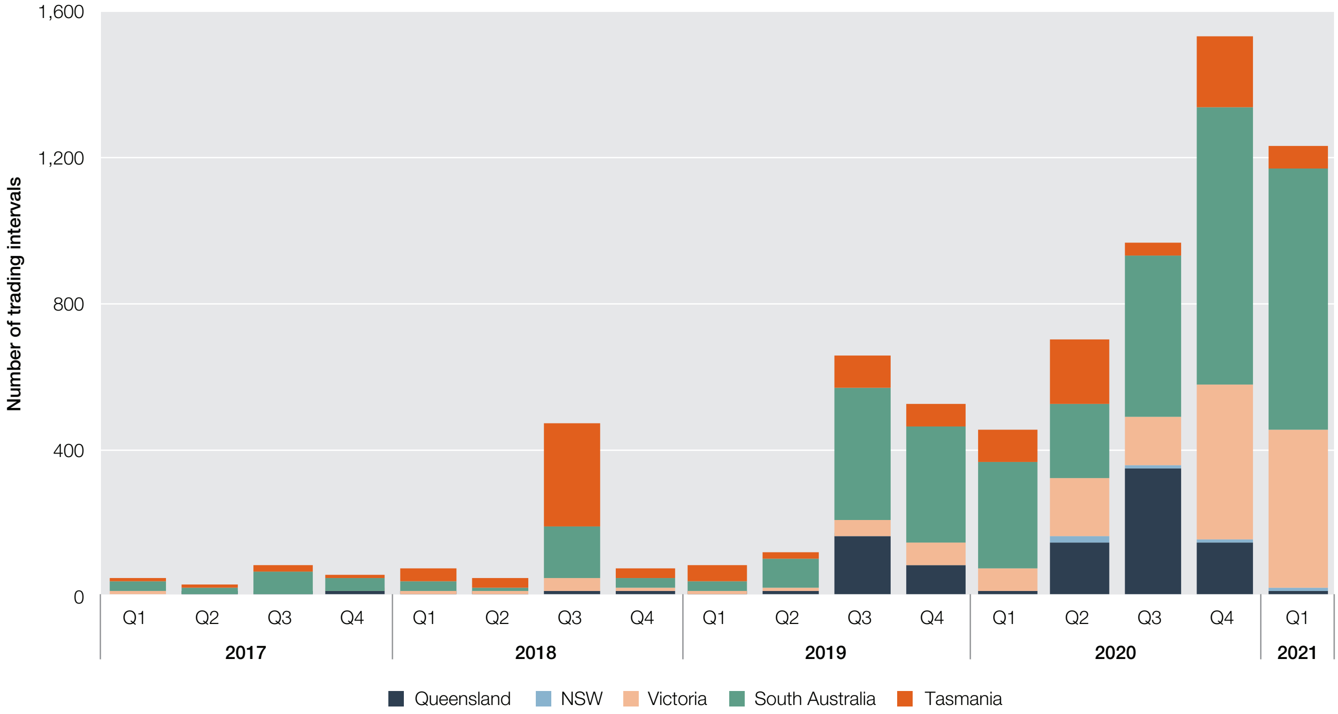
Source: AER analysis using NEM data.

Note: Volume weighted average price is weighted against native demand in each region. AER defines native demand as the sum of initial supply and total intermittent generation in a region.

There were the highest ever number of negatively priced trading intervals for a Q1 this quarter (Figure 1.3). Nearly all of these occurred in South Australia and Victoria, with Victoria hitting a new record. The incidence of negative prices reduced the average quarterly price in South Australia and Victoria by $6/MWh and $2/MWh respectively. There were very few negative prices in Queensland and NSW.

The quarter also saw the lowest number of prices above $300/MWh in a Q1 since Q1 2012. Those few that occurred were in Queensland, South Australia and Tasmania, with no prices above $300/MWh in NSW or Victoria. The only other time this has happened in a Q1 was in 2015.

Figure 1.3 Quarterly count of negative prices



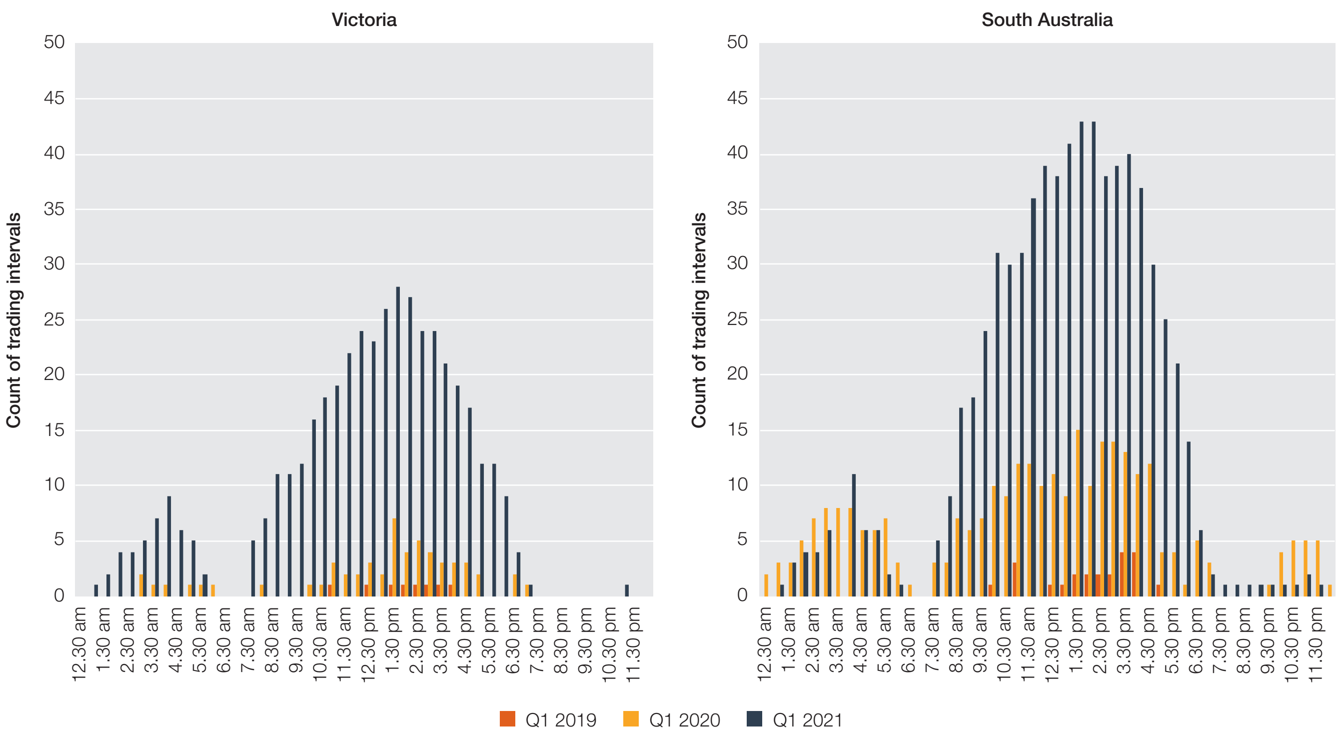
Source: AER analysis using NEM data.

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

By time of day, there was a large increase in the number of negative prices during daylight hours in Q1 2021 compared to Q1 in 2020 and 2019 (Figure 1.4).

Regular occurrences of negative prices have been a feature of the South Australian region for the past 18 months, but only emerged in Victoria in the last 6 months. With increased penetration of rooftop and large-scale solar we are likely to observe growing periods of negative prices. The increase in the number of negative prices is significant because it impacts market dynamics during the middle of the day, as well as contract markets and profitability.

Figure 1.4 Negative prices during the day, Victoria and South Australia



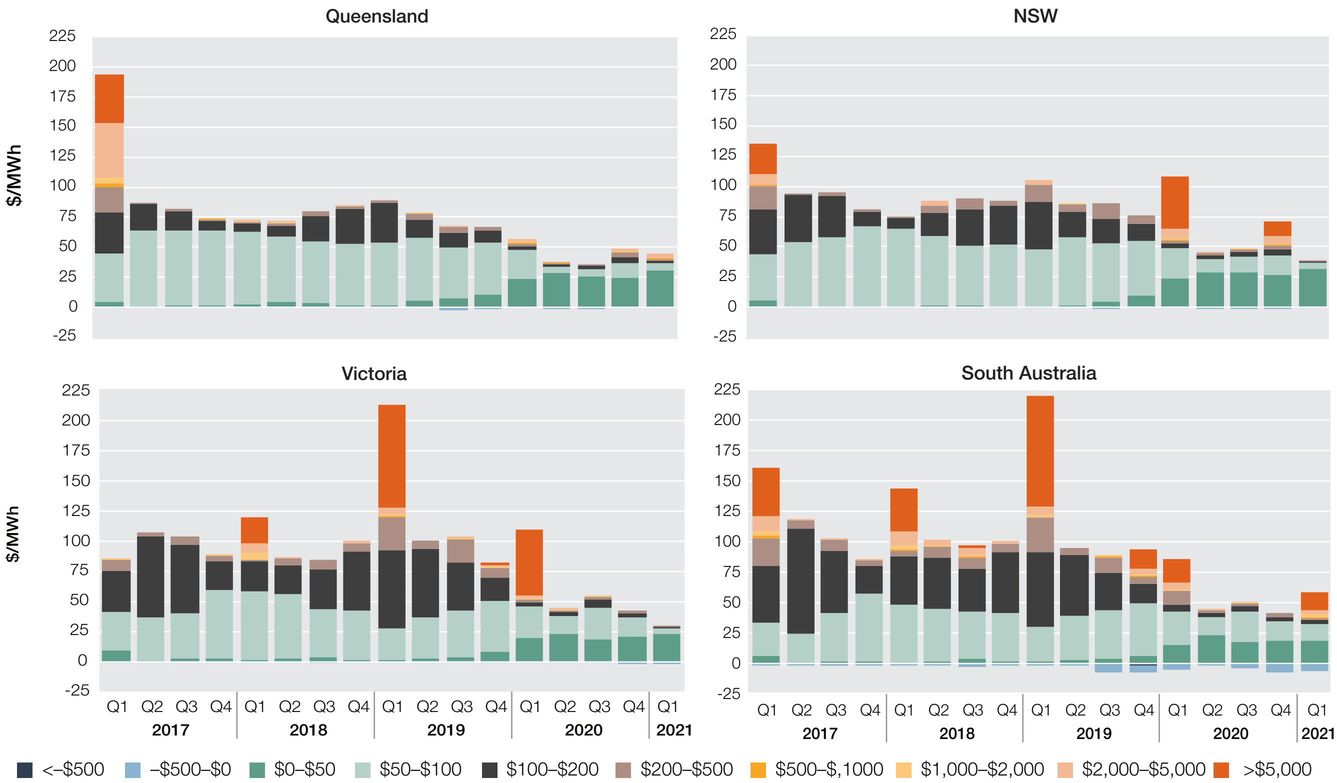
Source: AER analysis using NEM data.

Note: Count of negative prices by time of day.

The contribution of prices between $0/MWh and $50/MWh to average quarterly prices has been growing in every region since the latter half of 2019 (Figure 1.5). In Q1 2021, prices below $50/MWh made up over 80% of the NSW and Victorian quarterly prices compared to around 20% in Q1 2020. There were almost no prices above $100/MWh across the quarter in these 2 regions. This was very different to Q1 2020 when prices above $5,000/MWh contributed significantly to overall price outcomes in NSW and Victoria (Figure 1.5).

South Australia saw a larger spread of spot prices than other regions in Q1 2021. Prices below $50/MWh made up 36% of the South Australia quarterly average. This was less than in the other regions but more than in Q1 2020. And prices above $5,000/MWh made up another 30% of the quarterly average with spot prices exceeding $5,000/MWh on 2 occasions.[3]

Figure 1.5 Contribution of price bands to quarterly VWA price



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.

1.2 Future price expectations shift down

Base future contracts are the most commonly traded futures contract and their forward prices give an indication of the expected average wholesale spot price in each region. Coming into 2021, base future prices for Q1 were settling in the $58/MWh to $70/MWh range (Figure 1.6).

During the course of the quarter base future prices fell in all regions, with final Q1 base future prices ranging from $25/MWh to $43/MWh. Prices fell 62% in Victoria, 46% in NSW, 30% in South Australia and 28% in Queensland. The final contract prices were the lowest since 2015 in NSW and South Australia and since 2012 in Queensland and Victoria.

Queensland, which finished the quarter as the highest priced region, was initially expected to be one of the lowest priced regions. Victoria, initially expected to the second highest priced region behind NSW, turned out to be the lowest priced region, with final base future prices in Victoria at least $12/MWh lower than the other regions.

Sellers of base futures benefitted from outcomes this quarter. When the strike price for a future is higher than the average spot price for a quarter, the buyer of the base future makes a payment to the seller for the difference. As prices were lower than expected this quarter, a generator who sold base future contracts generally locked in a much higher strike price than they would have received on the spot market.

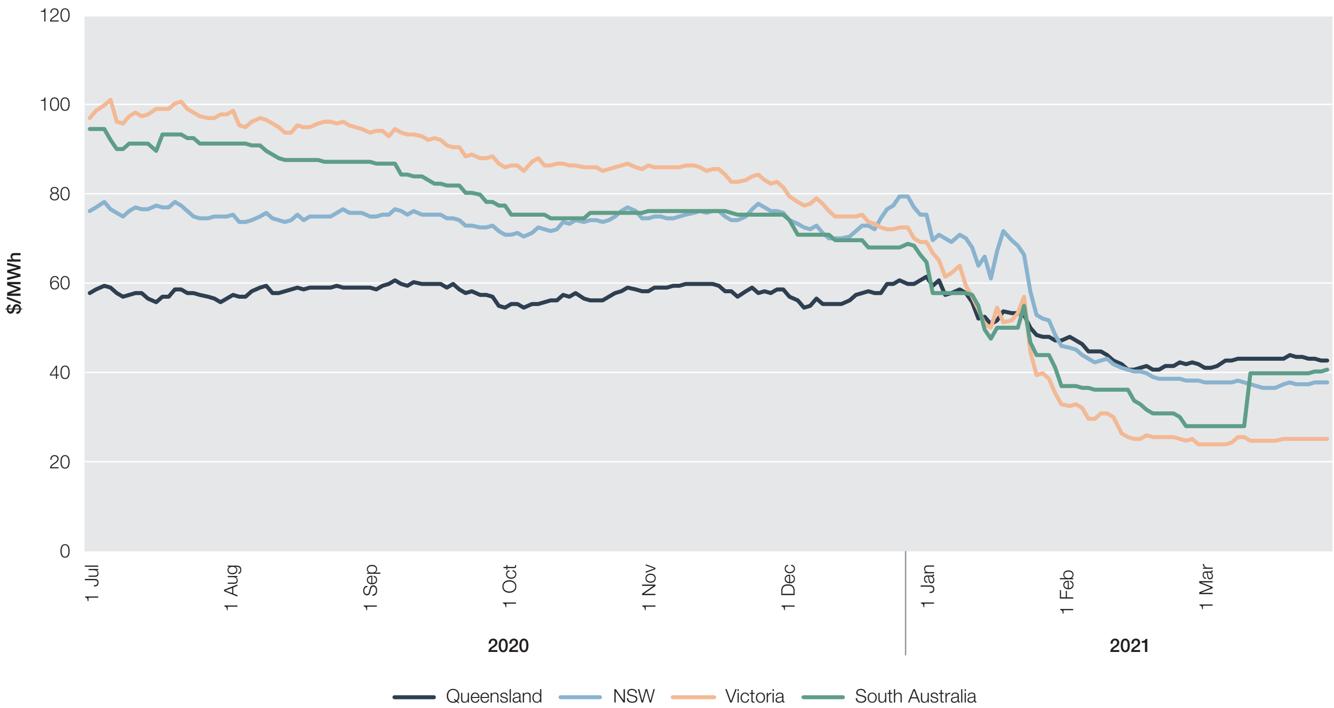
3 We have released reports on both these $5,000/MWh events.

At the start of the quarter, cap price expectations ranged from $10/MWh to $26/MWh but fell across the course of the quarter in all regions. The final cap prices in NSW and Victoria were $0/MWh, reflecting that there were no spot prices above $300/MWh in these regions this quarter. The final cap price in Queensland was $3.50/MWh due to a handful of 5 minute dispatch prices close to the market price cap of $15,000/MWh. These high prices were caused by ramping limitations over the evening peaks. South Australia had the highest final cap price at $16/MWh. The majority of the cap payout was the result of the high spot prices on 12 March.

On 22 March, the Australian Securities Exchange (ASX) launched a base load electricity 5 Minute Cap Futures Contract.[4] The new contract is designed to support the introduction of 5 minute settlement for the electricity market on 1 October 2021.

Also in March, FEX Global launched its futures exchange. Its products include base load, peak and cap contracts, as well as 5 Minute Cap products. In the first month of operation no trades occurred on this exchange.

Figure 1.6 Base future prices, Q1 2021



Source: AER analysis using ASX Energy data.

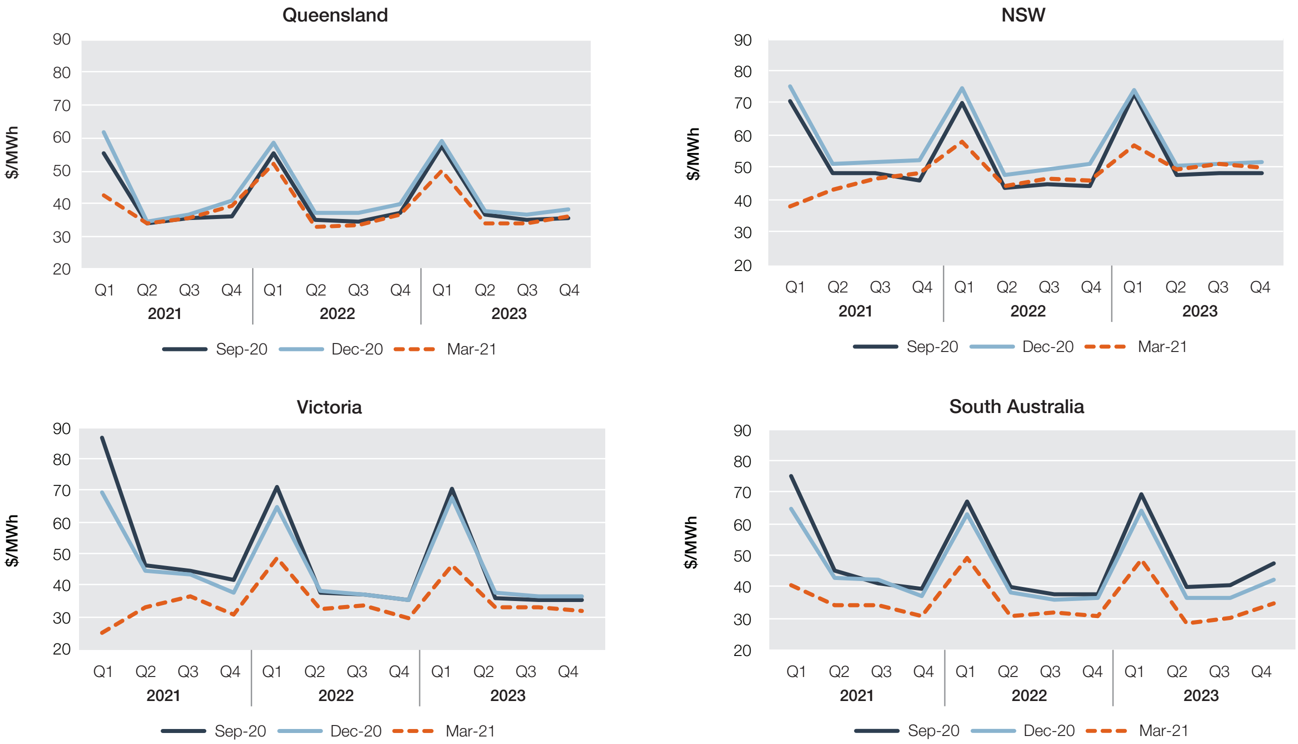
Note: Daily closing price for Q1 2021 quarterly base futures.

Looking forward, base future price expectations remain low for the remainder of 2021 and into 2022 and 2023 (Figure 1.7). At the end of Q1 2021, quarterly base future contracts in all regions across the next 2 to 3 years were settling at prices less than $60/MWh. Future price expectations have shifted downwards in recent months. The biggest falls have occurred in Victoria and South Australia with prices dropping approximately 25% on average in the past 6 months across the 3 year horizon.

Looking ahead, NSW is expected to be the highest priced region for the remainder of 2021 and into 2022 and 2023. The low Q1 prices this year have put downward pressure on Q1 prices for 2022 and 2023, with future Q1 prices falling more than the other quarters.

4 ASX energy derivatives market notice, February 2021.

Figure 1.7 Forward base future prices



Source: AER analysis using ASX Energy data.

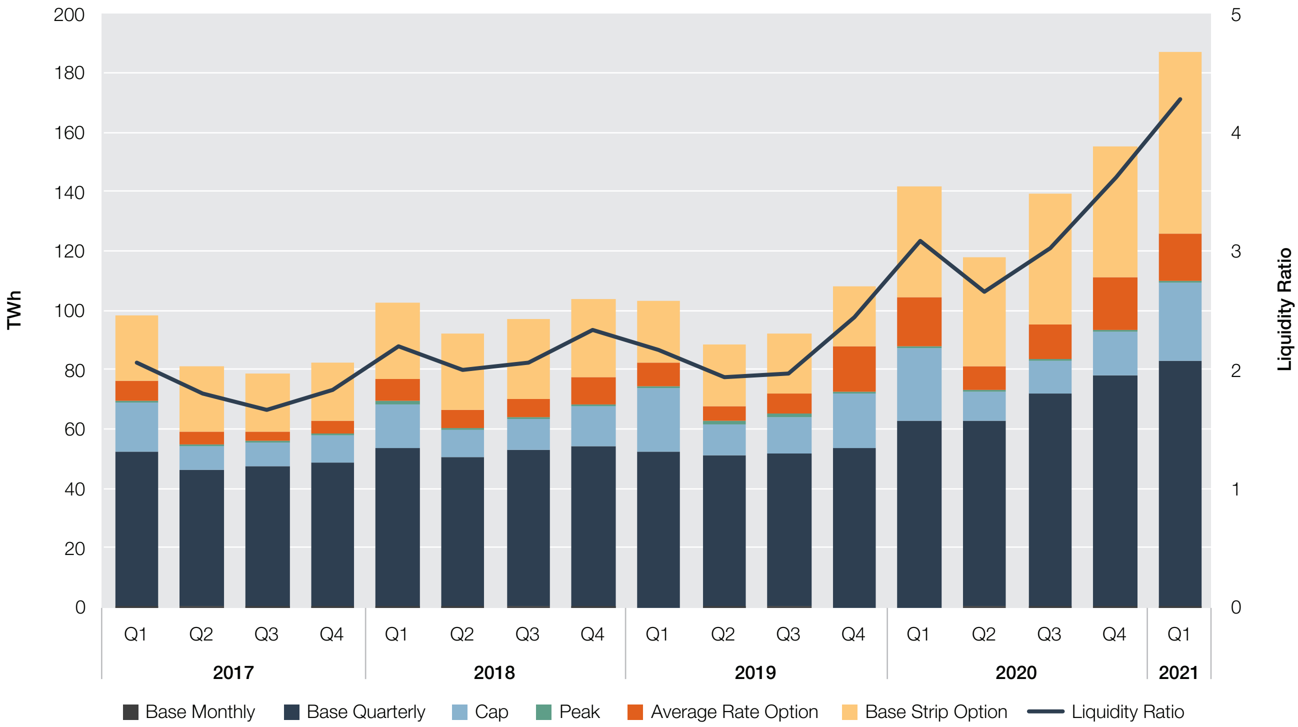
Note: Closing price of base futures contracts for Q1 2021 to Q4 2023 on the last trading day of Q3 2020 (30 September 2020), Q4 2020 (31 December 2020) and Q1 2021 (31 March 2021).

In the past 18 months, the volume of electricity derivatives being traded on the ASX has been steadily increasing (Figure 1.8). In Q1 2021, the traded volume of exchange traded futures and options hit record levels. This increase in volumes is being driven by an increase in the popularity of options, both base quarterly and base strip options.

The liquidity ratio in Q1 2021 was 4.3, the highest liquidity ratio recorded in any quarter. The liquidity ratio compares the total exchange traded volumes to the native demand (which was low this quarter) across the 4 combined regions. For every 1 MW of native demand in Q1 2021, more than 4 MW of contracts were traded.

Open interest volumes are also increasing, indicating that more contracts are being held by market participants.

Figure 1.8 Traded Volumes and Liquidity Ratio



Source: AER analysis using ASX Energy data and NEM data.

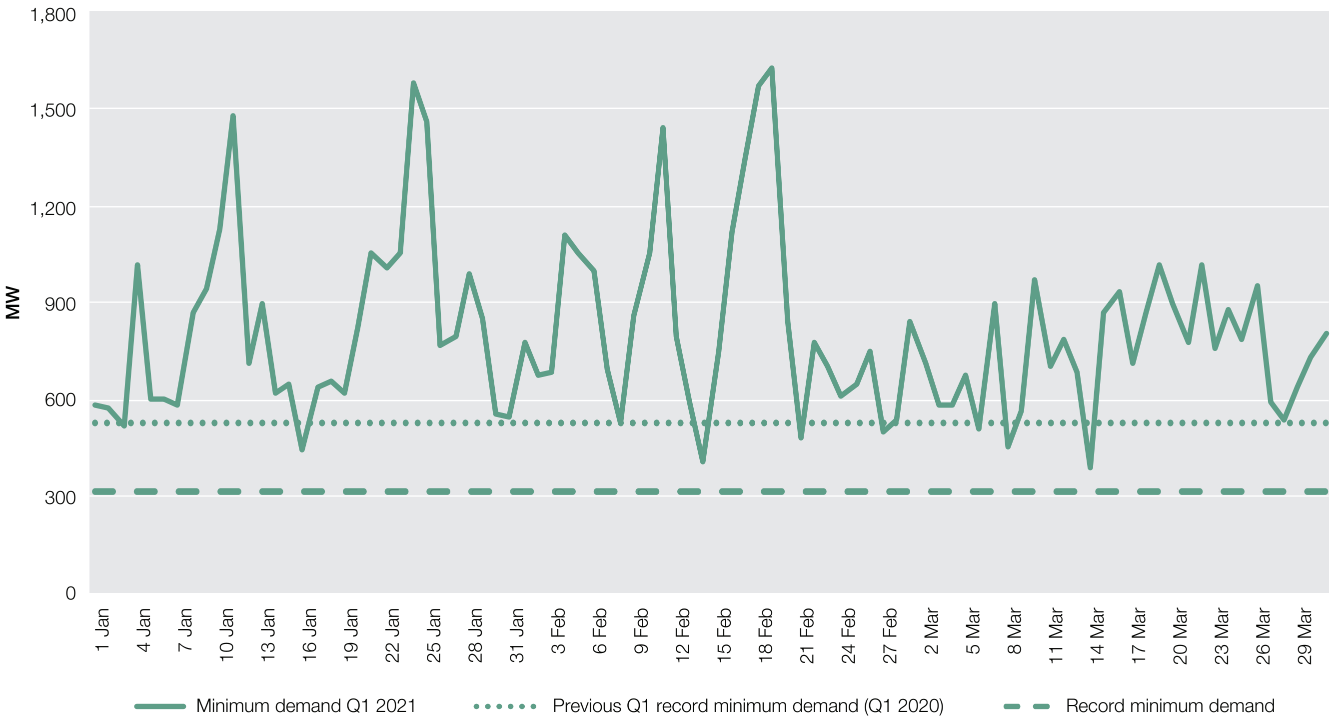
Note: Volumes of ASX trades that occurred for each quarter since 2016. Liquidity ratio uses total traded volumes and the total native demand in each region (excluding Tasmania where there are no ASX traded contracts).

1.3 Demand low with mild summer and increased rooftop solar

Demand was very low across all regions in Q1 2021 due to mild temperatures throughout the summer and increased rooftop solar generation. While we may not see such mild temperatures next summer, we will continue to see rooftop solar reducing demand.

Demand was particularly low in South Australia because of its high penetration of rooftop solar and its low industrial load (Figure 1.9). Back in Q1 2020, South Australian minimum demand fell as low as 526 MW which was a record Q1 minimum. However demand in Q1 2021 dipped below this record 8 times. At its lowest point in the quarter, on 14 March, native demand fell to just 391 MW. At this time, AEMO curtailed rooftop solar to address system security concerns (see focus story).

Figure 1.9 Daily minimum demand in South Australia, Q1 2021

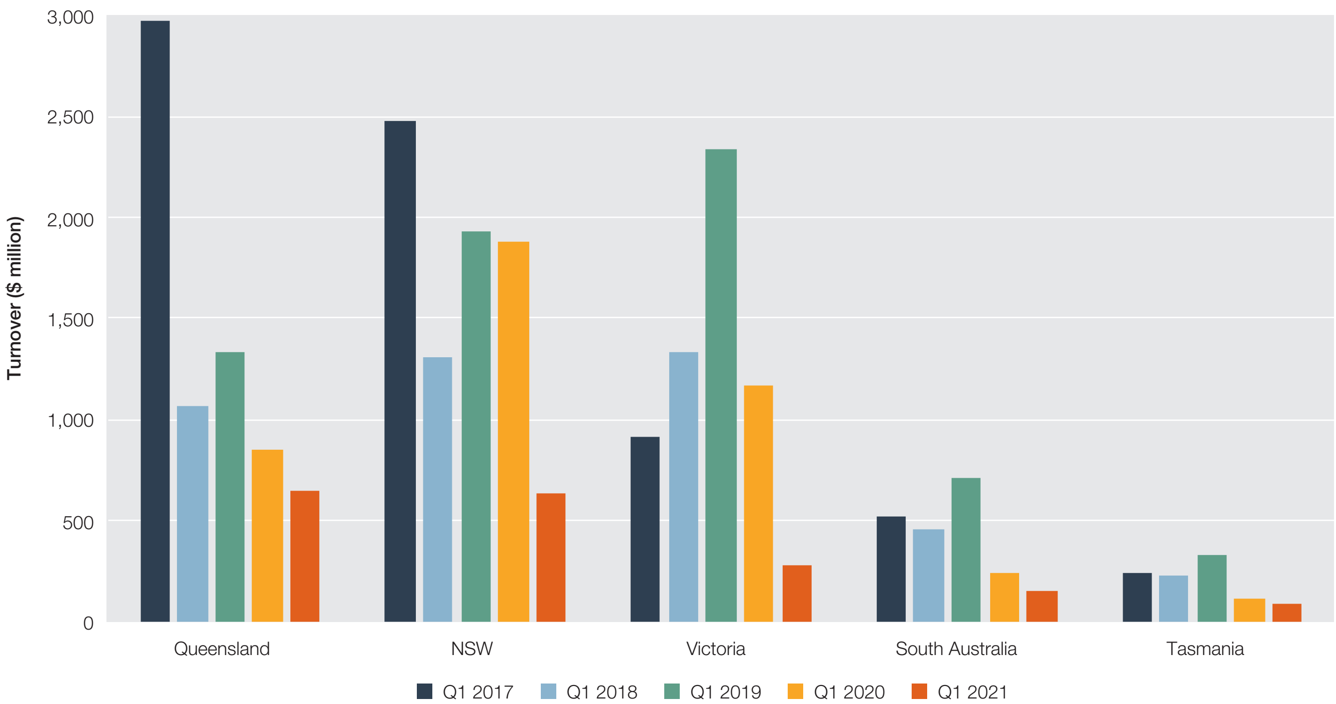


Source: AER analysis using NEM data.

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

Cheaper prices and reduced demand combined to reduce Q1 2021 NEM turnover to its lowest Q1 level since 2012. There were large year on year falls in turnover in all regions, but particularly in Victoria (Figure 1.10). Victorian turnover in Q1 2021 was just 12% of that in Q1 2019.[5]

Figure 1.10 NEM turnover, Q1 comparisons



Source: AER analysis of NEM data.

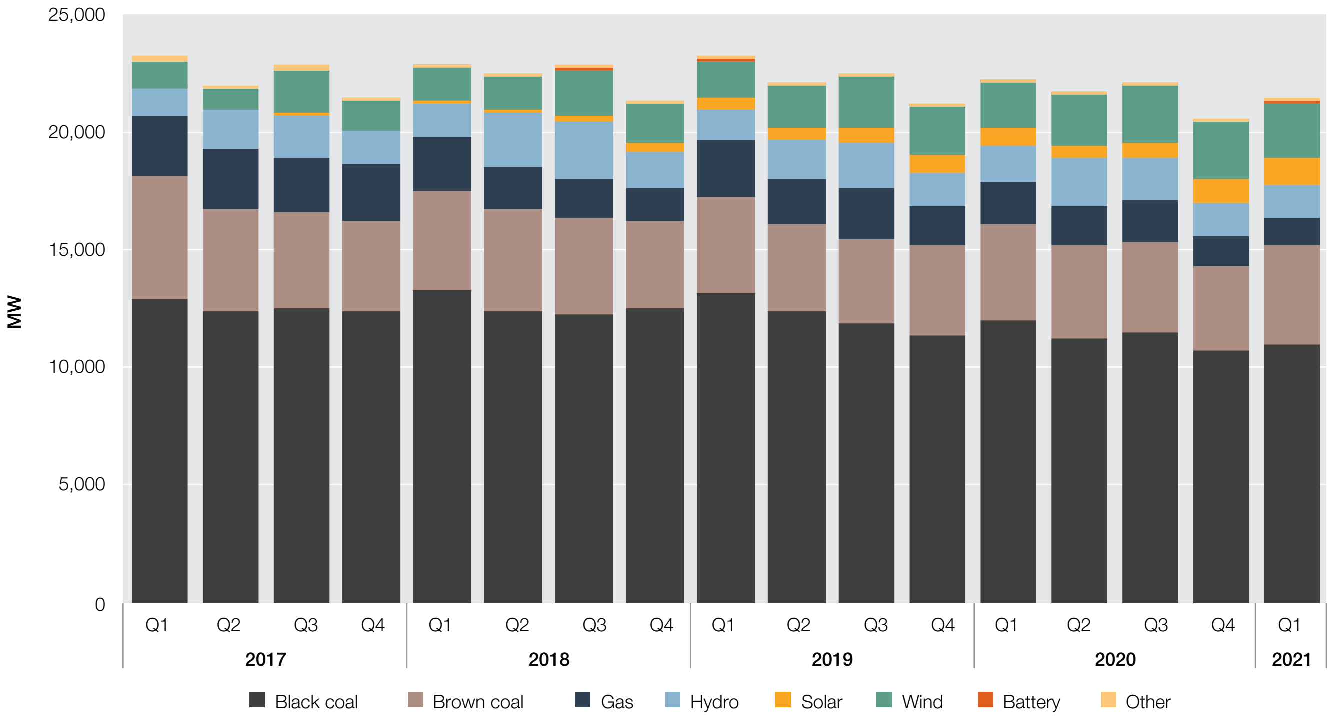
Note: We measure turnover by calculating spot market revenues.

5 We measure turnover by calculating spot market revenues. The actual revenues participants receive may depend more on revenues received through financial contracts. This calculation of turnover also doesn't include other revenue sources, such as revenue from FCAS markets.

1.4 Low demand and increased low cost generation reduce the need for black coal and gas

NEM output has been trending down since 2017 due to the dampening effect of rooftop solar on demand (Figure 1.11). At the same time, large-scale solar and wind generation has been steadily increasing as a proportion of total output. In Q1 2021, NEM output fell to its lowest Q1 average in the past decade, and wind and solar output was at near record levels. Combined, these factors displaced black coal and gas generation, with black coal output falling to its lowest ever Q1 level and gas falling to its lowest Q1 level since 2005. This quarter was the first time average large-scale solar generation exceeded gas generation in the NEM.

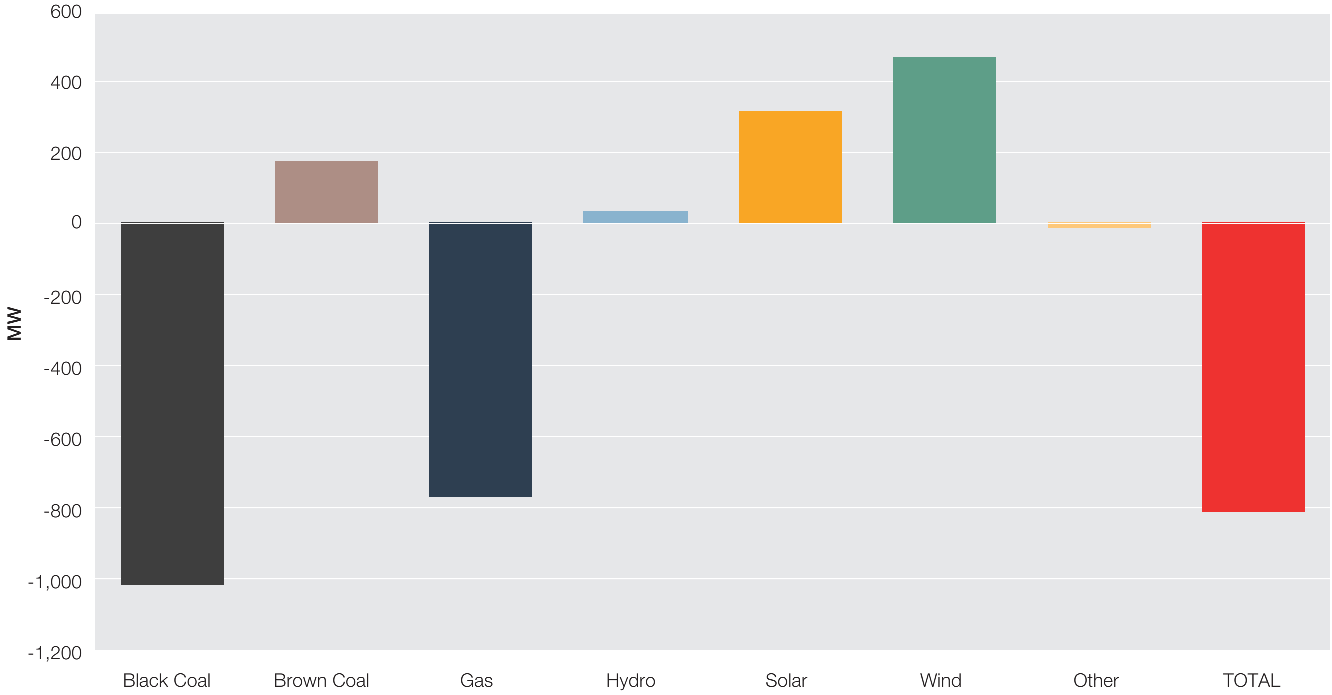
Figure 1.11 Average quarterly NEM generation



Source: AER analysis using NEM data.

Q1 2021 average generation was down 800 MW compared to Q1 2020 (Figure 1.12). There were significant falls in average black coal and gas generation (1,800 MW). These falls were not only driven by the fall in demand but also by an increase in generation from low cost brown coal, wind and solar (1,000 MW).

Figure 1.12 Change in average quarterly NEM generation, Q1 2020 to Q1 2021



Source: AER analysis using NEM data.

Note: Change in average quarterly metered generation output by fuel type from Q1 2020 to Q1 2021. Solar generation includes large scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

1.5 International coal costs increase but coal offers remain low, gas input costs remain steady

International coal costs rose in Q1 2021 but coal generators continued to offer capacity at low prices. Black coal set lower prices in Q1 2021 than in Q1 2020, even though coal proxy input costs are higher now than they were last year (Figure 1.13). Gas spot prices remained steady.

Coal generators can source their fuel from a range of sources including directly and relatively cheaply from an attached mine, or through short or long term fuel contracts which obtain coal from further afield. Because short term supply contracts and renegotiated long term contracts are often shaped by international coal prices, we use the price of coal at the Newcastle port as a reference point for NSW coal fuel costs. Although, the Newcastle coal price reflects a generator's theoretical maximum cost of some of its coal.[6]

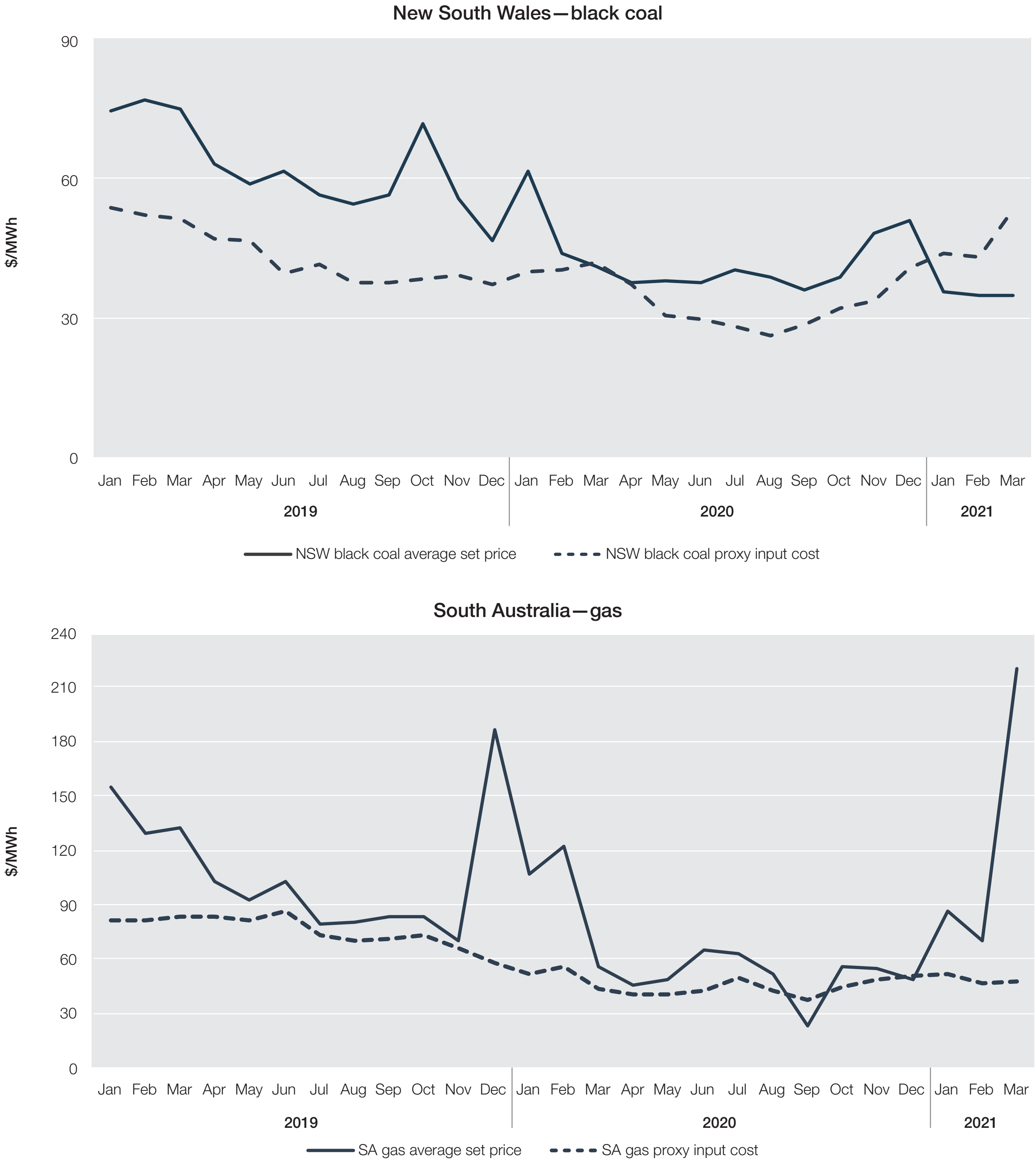
The price for Newcastle coal increased around 24% over the quarter. However, the average price set by NSW black coal generators fell, dropping below the proxy input cost for coal based on the Newcastle coal index. This may have been due to generators' contract positions, their lack of exposure to export coal prices, or because low demand reduced the need for higher priced coal capacity.

Gas input costs remained steady over the quarter. However, South Australia gas generators set a high average price in March 2021. The average price set was increased by the high price event on 12 March 2021 when peaking gas was needed to meet demand. This event was the subject of an AER $5,000/MWh report.[7]

6 For a more detailed explanation of coal input costs see AER, Wholesale electricity market performance report, 2020, p. 19.

7 Prices above $5,000/MWh – 12 March 2021 (SA), AER $5,000 reports.

Figure 1.13 Proxy input costs and the average price set by NSW black coal and South Australia gas



Source: AER analysis using the GlobalCOAL Newcastle coal index, the STTM price and NEM data.

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

1.6 Nearly all fuel types set lower prices and cheaper fuels set the price more often

There were 2 main drivers of generators setting lower prices in Q1 2021 compared to Q1 2020:

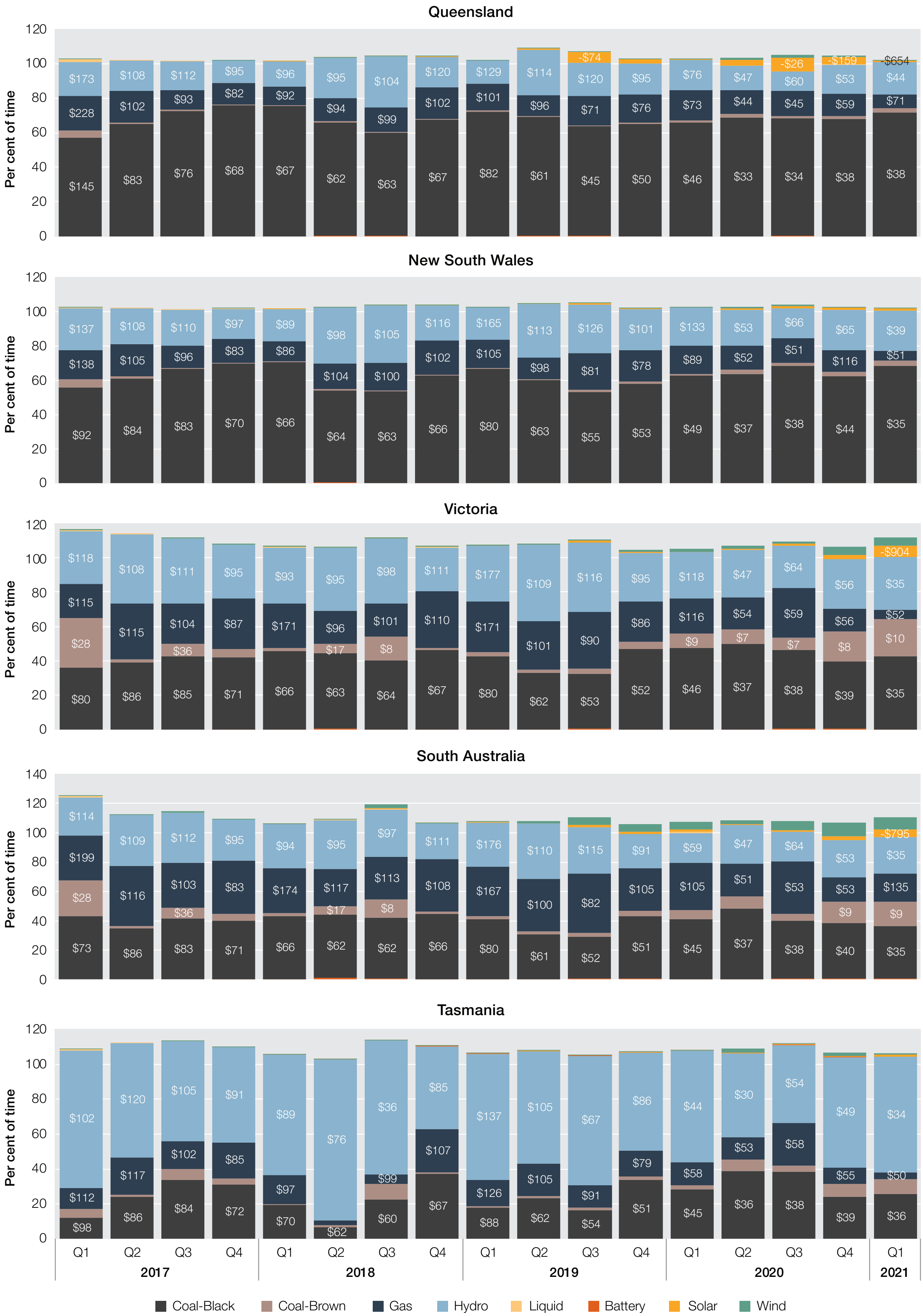
1. High cost generation such as gas was not needed to meet low demand. As a result gas set the price less often in every region, and black or brown coal, which is cheaper, set the price more often (Figure 1.14).
2. Black coal, hydro, wind, solar and gas (except in South Australia) generators set lower average prices.

In Victoria, gas only set the price 5% of the time. Instead, brown coal set the price more often at an average price of $10/MWh. Wind and solar also set the price a record 11% of the time, with solar setting an average price of -$904/MWh.

In all regions except Queensland, hydro set similar prices to black coal, between $35/MWh and $39/MWh. This is unusual, as hydro generators generally sets the price at higher prices than coal generation. In Queensland, black coal and hydro set slightly higher prices than in the other regions because higher average temperatures led to higher demand.

In South Australia, the average price setter outcomes would have been similar to other regions, except for the 2 high priced events that occurred in the quarter. During these events high priced peaking gas was needed to meet demand, increasing the average price set by gas to $135/MWh in Q1 2021.

Figure 1.14 Price setters by region



Source: AER analysis using NEM data.

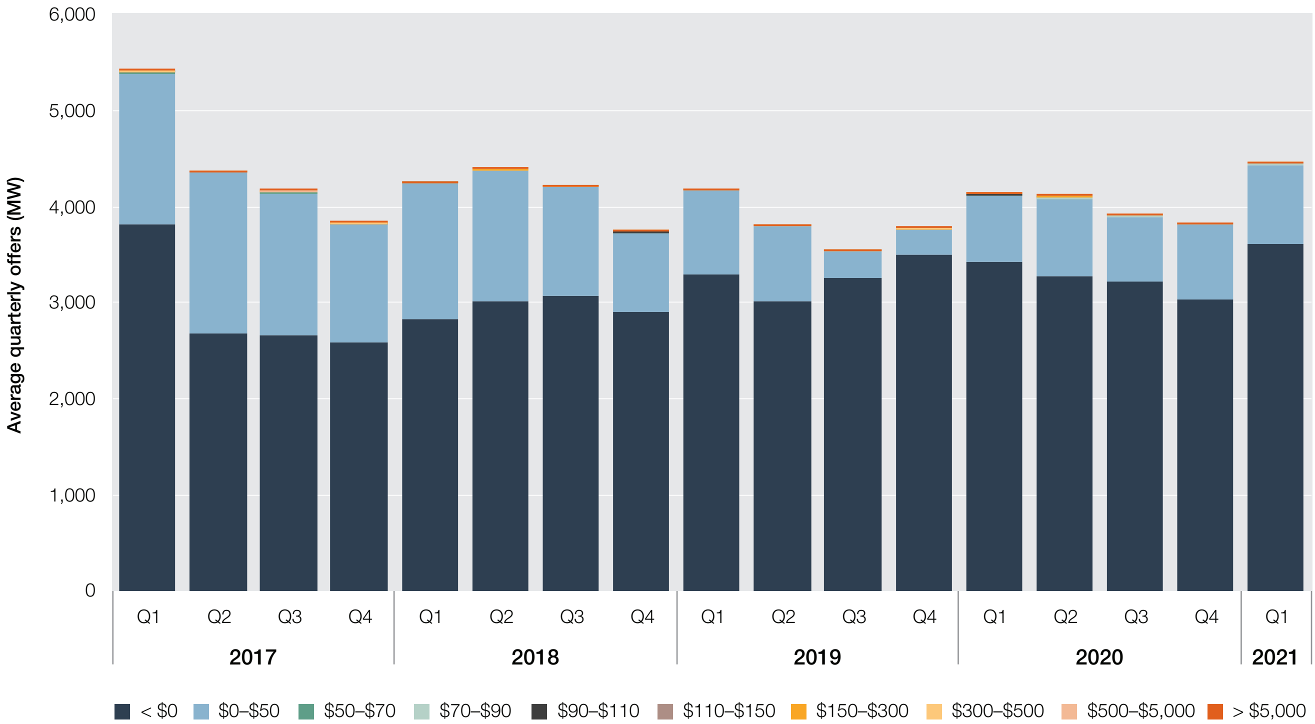
Note: The height of each bar is the percent of time each fuel type sets the price. And the numbers within each bar is the average price set by that fuel type when it is marginal (i.e. setting the price).

1.7 Brown coal, wind, solar and hydro offer more capacity at low prices

Cheaper fuel types such as brown coal and renewables set price more often, not only because of low demand, but also because they offered more capacity into the market at low prices.

Brown coal offered more capacity into the Victorian market in Q1 2021 than in any quarter since the Hazelwood power station closed, with total offers close to the volume generators reported to AEMO as their total summer operating capacity, which is around 4,500 MW (Figure 1.15).[8] Almost all of this capacity was offered below $50/MWh, and the majority of the increased capacity compared to the previous quarter was offered at prices below $0/MWh. This increase was mainly due to the low number of outage days. In Q1 2021 there were 66 cumulative outage days compared to 189 days in Q4 2020 and 94 days in Q1 2020 (see Appendix A).

Figure 1.15 Brown coal offers, Victoria



Source: AER analysis using NEM data.

Note: Average quarterly offered capacity by Victoria brown coal generators within price bands.

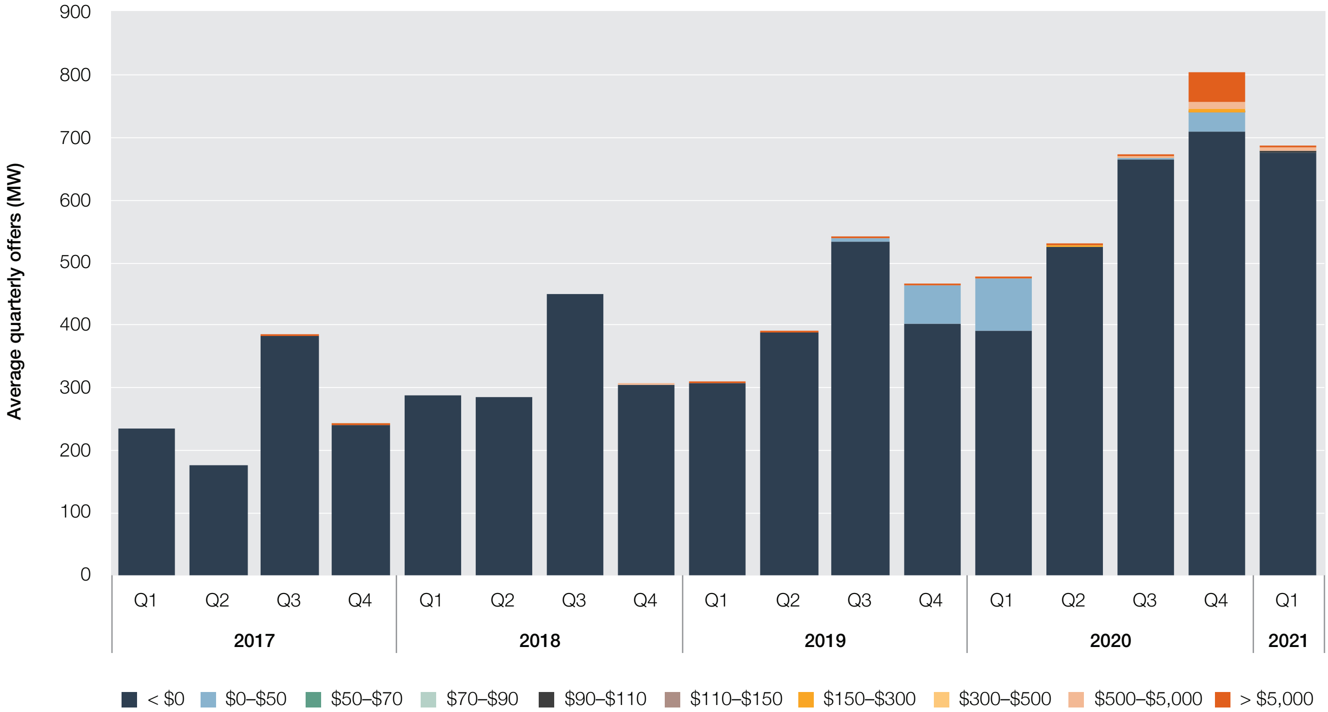
Total capacity offered by wind generators increased in all mainland regions compared to Q1 2020, but particularly in Victoria (around 200 MW), NSW (almost 100 MW) and Queensland (almost 90 MW). The approximate 30% increase in wind offers in Victoria was due to almost 1 GW of new entry over the year, with more wind capacity due to come online soon (Figure 1.16).

The increase in wind offers put downward pressure on prices because nearly all the capacity offered in Q1 2021 was offered at negative prices. The exception was NSW where around 25% was offered at prices between $0–$50/MWh.

There was very little wind capacity offered above $5,000/MWh in Victoria in Q1 2021 compared to Q4 2020, even though the count of negative prices was similar in both quarters. In Q4 2020 prices fell close to the floor (-$1,000/MWh) on 10 occasions, causing some wind generators to move capacity to high prices to avoid being dispatched. In Q1 2021, it appears prices weren't low enough to cause the same behaviour, reaching a minimum of only -$113/MWh.

8 Generators advise AEMO of their summer and winter capacity, NEM generator information.

Figure 1.16 Wind offers, Victoria

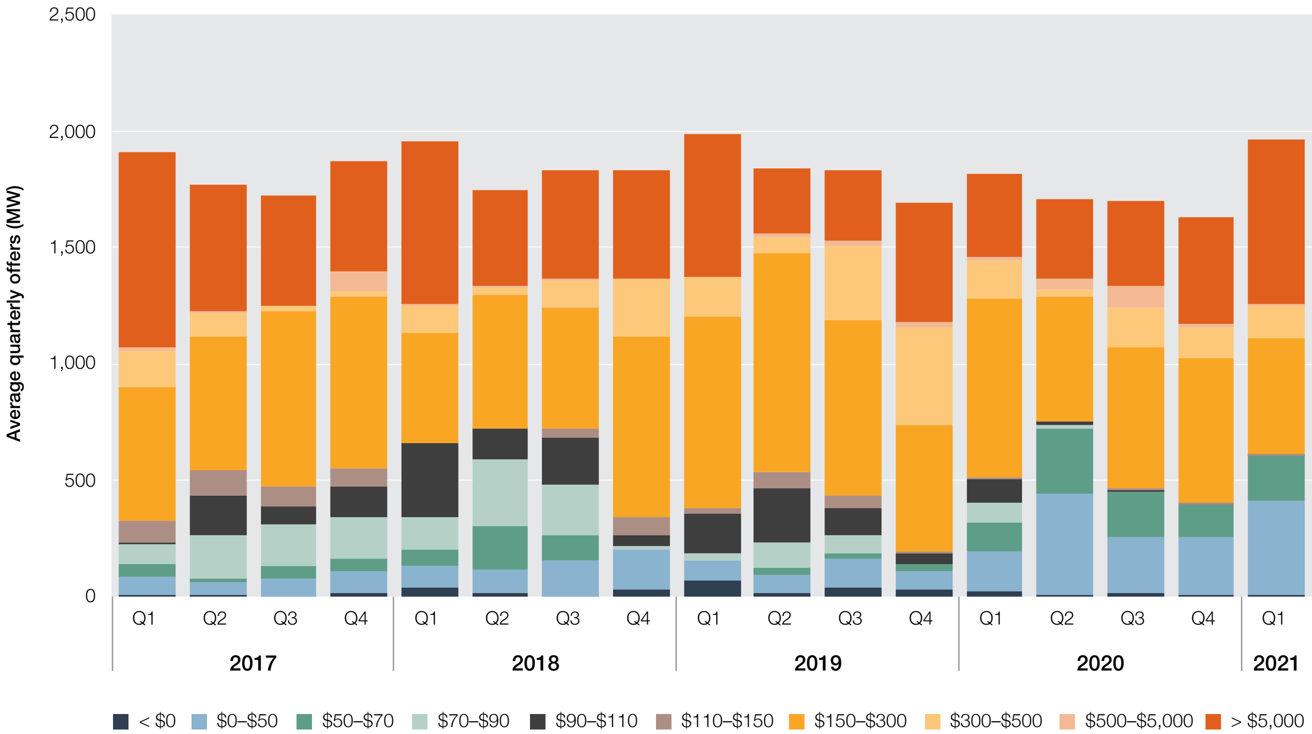


Source: AER analysis using NEM data.

Note: Average quarterly offered capacity by Victoria wind generators within price bands.

While hydro generators offered over 400 MW more capacity in Q1 2021 than in Q1 2020, this did not lead to an increase in the amount dispatched. In Victoria, Snowy Hydro shifted some capacity at Murray power station to prices below $50/MWh (Figure 1.17). By offering capacity at prices comparable with black coal, it was more likely to be dispatched, which likely reflects a need to cover contract positions, retail load and environmental requirements. In contrast, in NSW the majority of the increased hydro capacity was offered at prices between $150/MWh to $300/MWh.

Figure 1.17 Hydro offers, Victoria



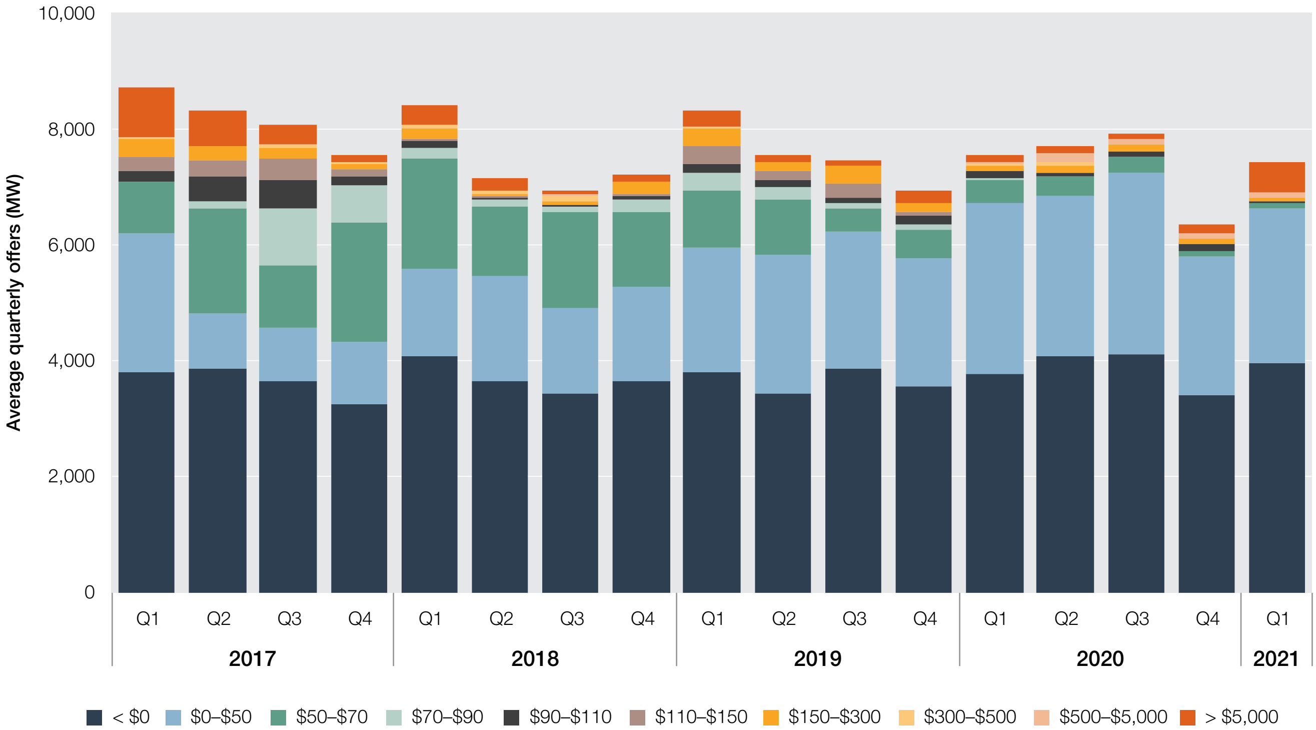
Source: AER analysis using NEM data.

Note: Average quarterly offered capacity by Victoria hydro generators within price bands.

Black coal generators offered slightly less capacity in Q1 2021 than in Q1 2020, down almost 300 MW in Queensland and 120 MW in NSW. However, despite increased coal costs, black coal generators still offered around 88% of their capacity at prices below $50/MWh. In contrast, there was very little capacity (4%) priced between $50/MWh and $5,000/MWh, as black coal generators shifted some of the capacity previously offered in this price band, to above $5,000/MWh.

After a high number of black coal outages in NSW in Q4 2020, black coal offers in NSW returned to previous levels (Figure 1.18).

Figure 1.18 Black coal offers, NSW



Source: AER analysis using NEM data.

Note: Average quarterly offered capacity by NSW black coal generators within price bands.

Gas generators in all regions offered less total capacity in Q1 2021, as well as less capacity priced below $50/MWh, than a year ago. But within these trends, offer profiles changed from region to region.

The different offer behaviour between regions reflected the different roles gas generation played in each region. Gas generators in Queensland and South Australia offered a larger share of capacity priced below $70/MWh (around 30%) than gas generators in NSW (6%) and Victoria (1%). Indeed, gas generators in NSW and Victoria offered more than 90% of their capacity at prices above $5,000/MWh.

In South Australia gas offers have dropped in the last 2 quarters because the 2 Torrens Island power station units that left the market were larger than Barker Inlet power station, which partially replaced them.

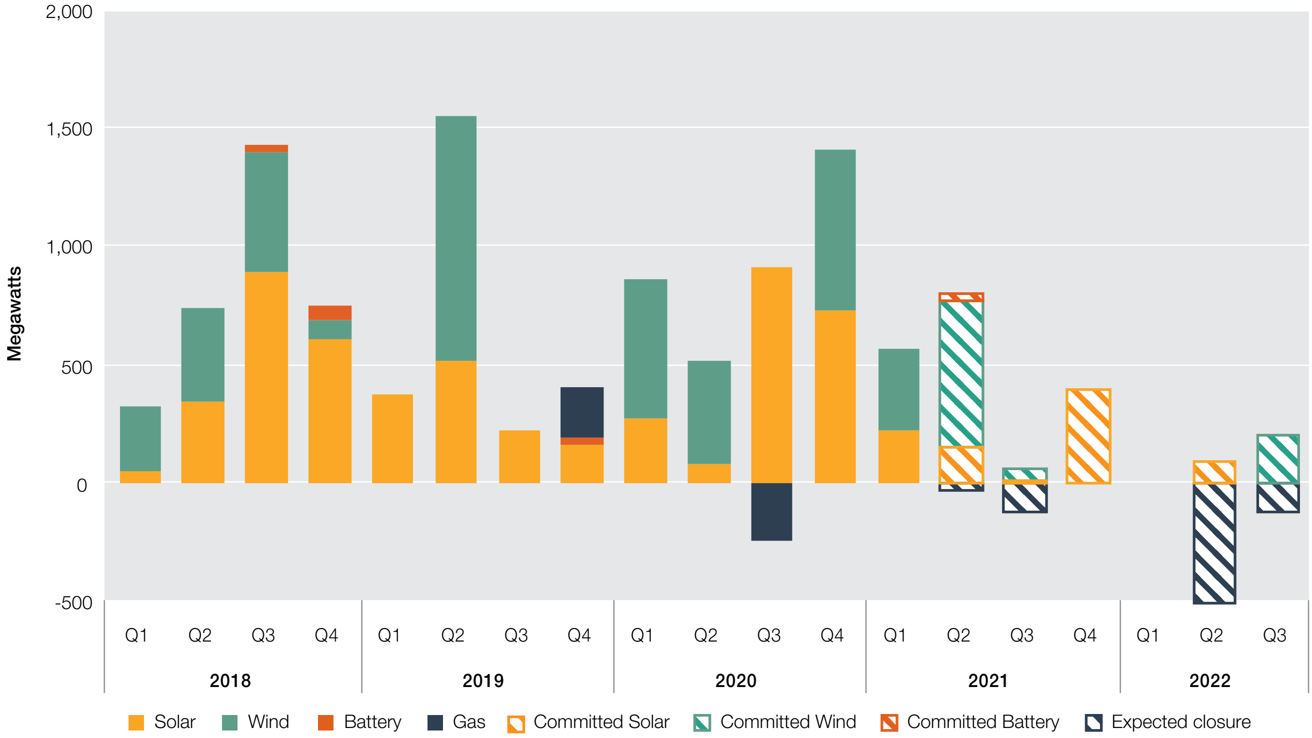
We analyse changing gas offers in more detail in our focus story.

1.8 New wind and solar farms ramp up to full capacity

New entry was 568 MW this quarter with 6 new wind and solar farms entering in NSW and Victoria (Figure 1.19 and Table 1.1). But more significantly, the 2.3 GW of wind and solar farms that entered the market in the second half of 2020 have been building up to full capacity over the quarter.

A further 1.5 GW of registered capacity is expected to enter in the remainder of 2021, including the delayed Stockyard Hill wind farm (532 MW) in Victoria.

Figure 1.19 New entry and exit



Source: AER analysis using NEM data.

Note: New entry is recorded using registered capacity of scheduled and semi-scheduled generators. Hashed areas reflect committed new entry and planned generator retirements according to the classification in AEMO Generator Information. The new entry date is taken as the first day the station produces energy. Closures are denoted below the line. Solar is large scale solar and does not include rooftop solar.

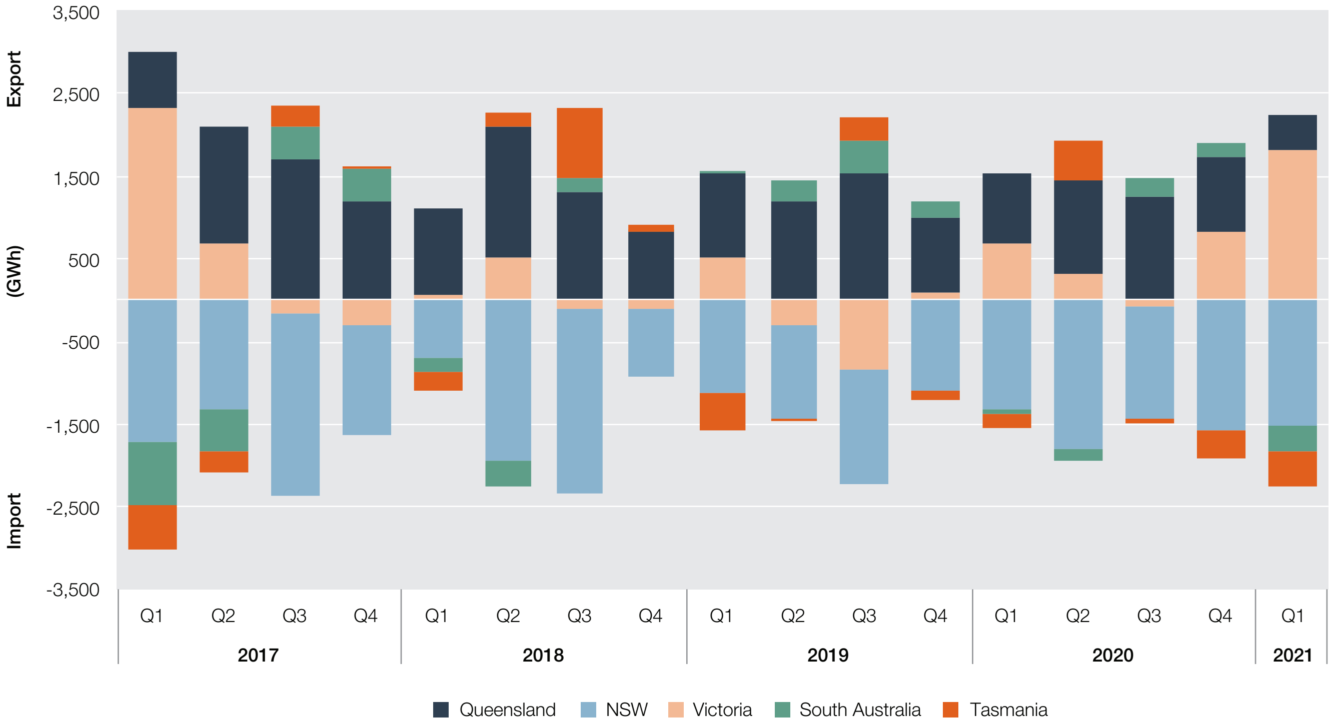
Table 1.1 New entry and exit during Q1 2021

REGION	STATION	FUEL TYPE	REGISTERED CAPACITY (MW)	HIGHEST CAPACITY OFFERED (MW)	COMMENCE DATE
NSW	Bango 973 wind farm	Wind	159	0.7	Jan–21
NSW	Jemalong solar farm	Solar	55	47	Feb–21
NSW	Corowa solar farm	Solar	36	0.5	Mar–21
Victoria	Berrybank wind farm	Wind	180	120	Feb–21
Victoria	Cohuna solar farm	Solar	31	6.4	Mar–21
Victoria	Winton solar farm	Solar	107	3.3	Mar–21
Total			**568**		

1.9 Lower priced generation from Victoria flows into NSW

Queensland and Victoria were net exporters this quarter while NSW, South Australia and Tasmania were net importers (Figure 1.20). Increased Victorian exports displaced Queensland exports into NSW. This change was largely due to lower priced generation from Victoria flowing into NSW, as well as to upgrades on the Queensland-NSW Interconnector (QNI), which limited Queensland's ability to export. The upgrades on QNI are due for completion in December 2021. Work on the Heywood interconnector also limited flows between South Australia and Victoria.

Figure 1.20 Regional interconnector flows



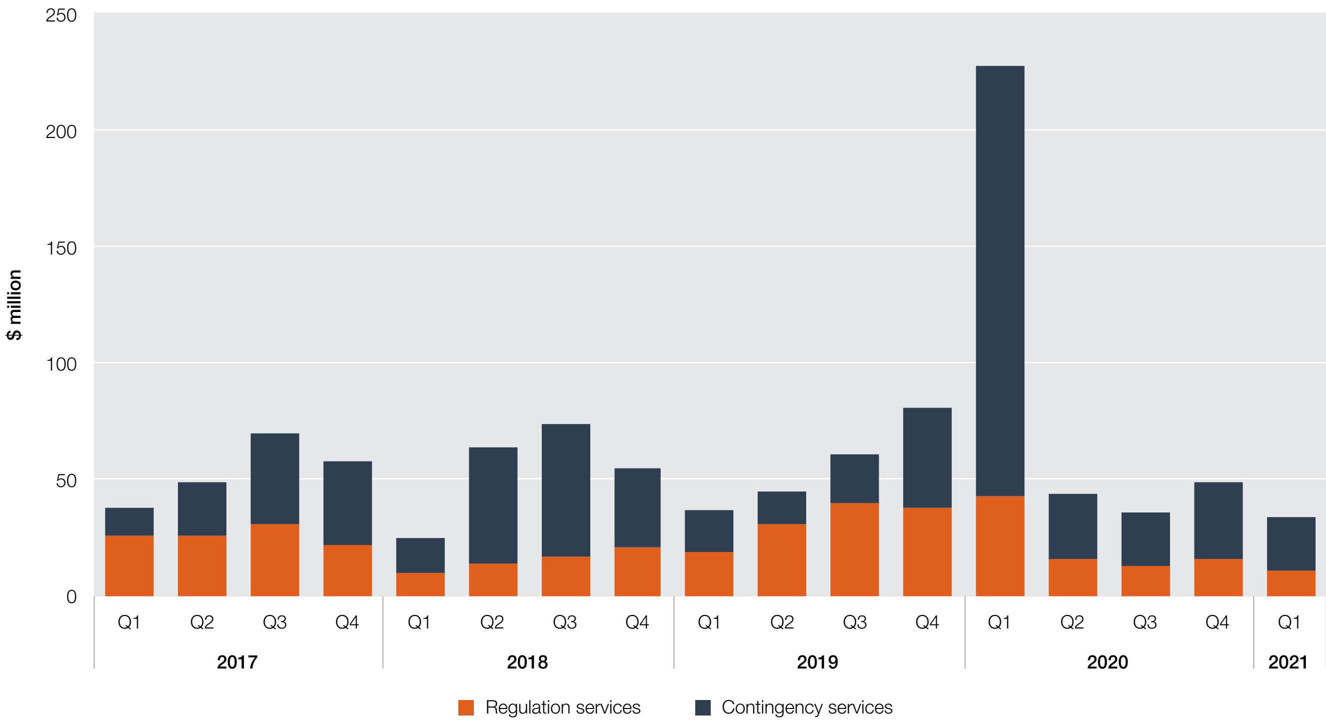
Source: AER analysis using NEM data.

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

1.10 FCAS costs remain relatively low

Total FCAS costs for Q1 2021 were around $33 million, the lowest level since Q1 2018 and about 85% ($194m) lower than Q1 2020 (Figure 1.21). However FCAS costs were a record $227 million in Q1 2020.[9] Compared to Q4 2020, total costs fell by 32% ($16m) mostly due to lower contingency costs but also lower regulation costs. The reduced costs were driven by lower prices.

Figure 1.21 Total NEM FCAS costs

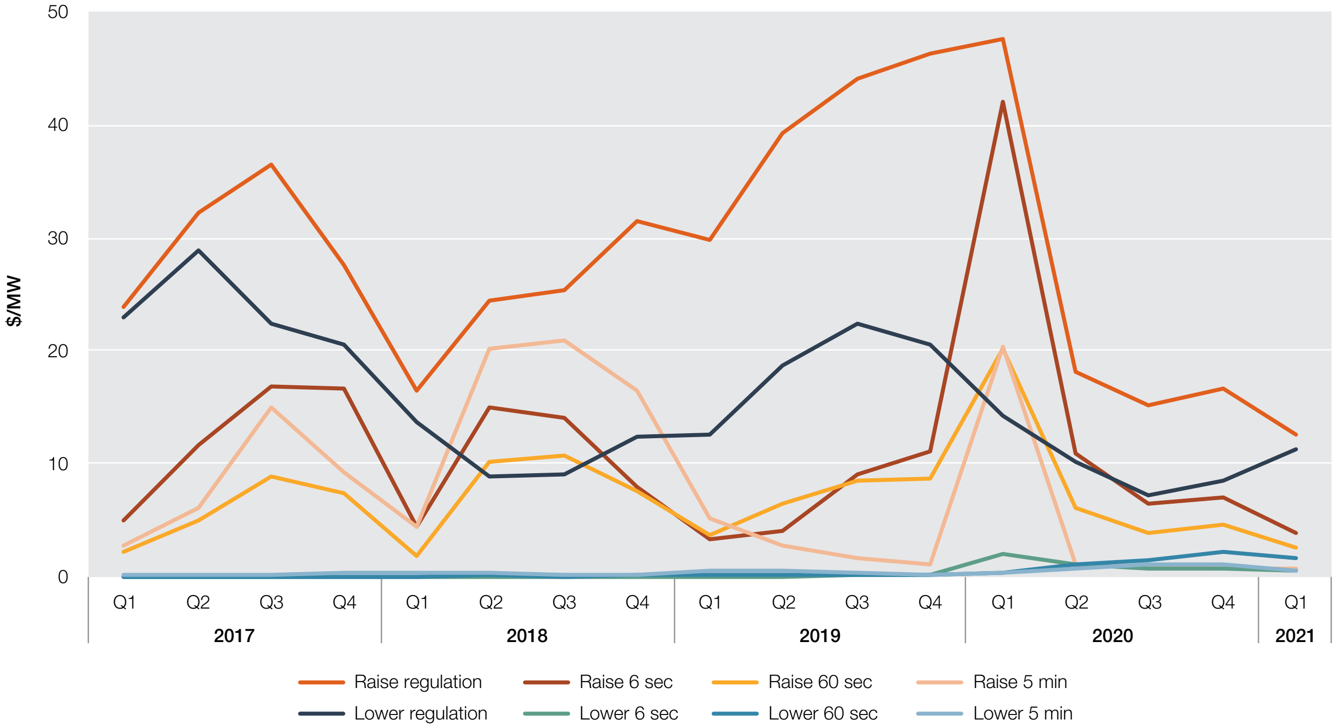


Source: AER analysis using NEM data.

After a slight kick up in prices last quarter, the average prices for all ancillary services fell again this quarter, except for lower regulation services which increased (Figure 1.22). Raise regulation prices were at their lowest level since Q1 2016 when the average price for raise regulation services was $2/MW.

9 See our Q1 2020 Wholesale Markets Quarterly for a detailed breakdown into the events that drove these record high costs.

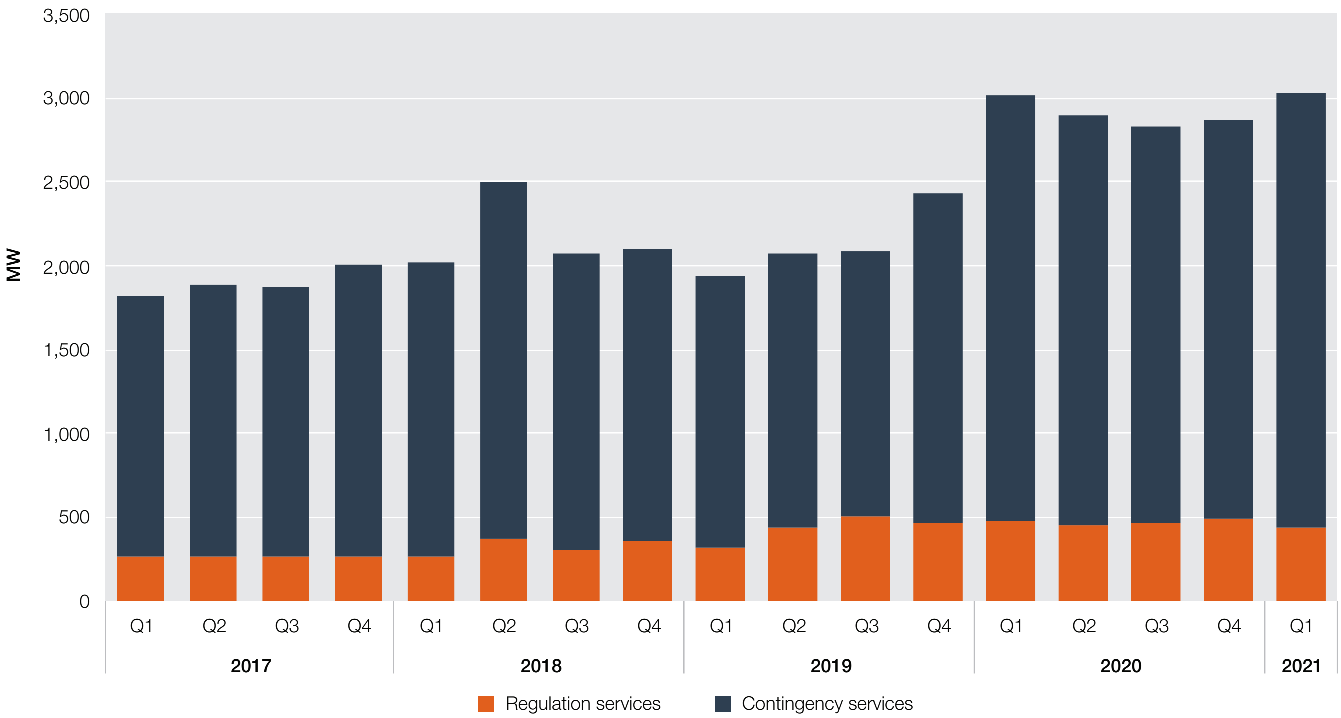
Figure 1.22 Quarterly FCAS prices, global



Source: AER analysis using NEM data.

After being fairly stable at around 2,800 MW through the last 3 quarters of 2020, FCAS enablement increased again in Q1 2021 (Figure 1.23). This was due to an increase in the contingency services required. We did not see the high costs observed in Q1 2020 even though the overall amount of FCAS required was similar.

Figure 1.23 Quarterly FCAS enabled



Source: AER analysis using NEM data.

In Q1 2021, no new participants registered to provide FCAS, but one of Quarantine power station's units started providing contingency services for the first time (Raise and Lower 5 minute and 60 second).

Focus 1 – Rooftop solar curtailed for first time in response to very low demand in South Australia

On 14 March, demand was so low in South Australia that AEMO instructed the distribution network operator to turn off some rooftop solar generation to increase demand. This focus story will explore why this happened and whether it is an evolving issue more broadly across the NEM.

It was a sunny Sunday in South Australia with temperatures around 21°C in Adelaide. Cool sunny days are ideal for rooftop solar, reducing individual household demand for electricity and potentially feeding power into the grid, reducing demand met by NEM generators (grid demand). The temperature also meant very little heating or cooling was required. Finally, much of the commercial load was reduced because it was the weekend. These factors combined to produce near record low levels of grid demand in South Australia.

Early that morning, AEMO announced that morning forecasts indicated demand would be below minimum operating levels and it may need to intervene to protect the security of the power system. The interventions could include curtailing non-scheduled wind and rooftop solar.

Minimum demand levels help to maintain a secure power system

Minimum demand levels in every region are important to help maintain a secure stable power system. Each region needs enough units generating that contribute to system security, to help manage minor voltage and frequency fluctuations. With technologies as they currently are, some thermal generation is required locally. When a region occasionally separates from the rest of the NEM, that region must have enough local generation online to respond to a separation event. These safeguards mean each region must supply a minimum amount of electricity that must be met by a minimum demand.

As more households rely on rooftop solar to meet their own electricity needs, demand from the grid falls. This means rooftop solar generation reduces grid demand and as the number of installations continues to increase every year the risk of minimum demand falling below levels AEMO considers safe is increasing.

Because South Australia's demand was considered to be at risk of falling below minimum demand levels, the South Australian government gave AEMO the power to temporarily increase demand, when necessary, by curtailing rooftop solar.[10]

What happened on 14 March?

When there is any maintenance work on the Heywood interconnector, AEMO sets the minimum demand level in South Australia to 400 MW. Planned repairs of the Heywood interconnector were underway from 12–19 March, setting the minimum threshold for demand to 400 MW. Local afternoon demand on 14 March was forecast to fall short of this safe operating level.

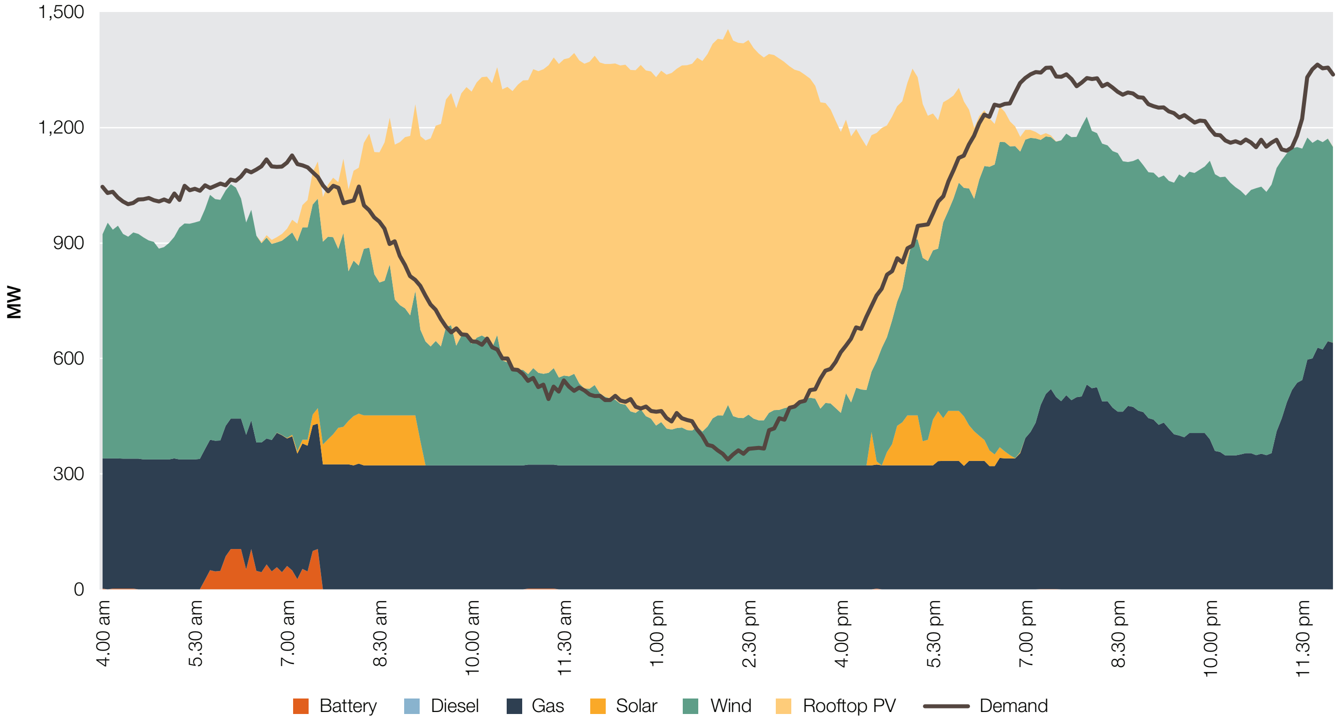
During the afternoon, network constraints on Heywood forced flows into South Australia. Not only did these constraints prevent excess generation from leaving the region but they actually increased supply into the region.

AEMO reduced renewable generation in South Australia and issued directions to thermal units to stay online. This ensured enough local thermal generation was online to maintain the security of the power system.

However as rooftop solar output continued to increase, and exports into Victoria were constrained, grid demand fell below safe operating levels. Grid demand continued to fall throughout the middle of day, but total demand for electricity, when including that met by rooftop solar, actually peaked around the same time (Figure 1.24).

10 The South Australian government granted powers to allow SA Power Networks (SAPN) to trip existing solar installations when directed by AEMO. The South Australian government also mandated a "Smart Homes" initiative. The initiative sets technical requirements for inverters and ensures all new rooftop solar installations in South Australia must register with an agent who can remotely disconnect and reconnect that system from the distribution network when instructed to do so.

Figure 1.24 Grid demand and local generation mix, South Australia



Source: AER analysis using NEM data.

At 2.30 pm AEMO instructed ElectraNet to require SA Power Networks (SAPN) to increase demand in the region to above 400 MW. ElectraNet manages the transmission of high voltage electricity in South Australia while SAPN manages the lower voltage distribution of power into consumers' homes and businesses. This was the first time AEMO exercised its new powers to increase grid demand. More than 50 MW of rooftop solar and 17 MW of commercial ground mounted solar was backed off through this instruction for about an hour.[11]

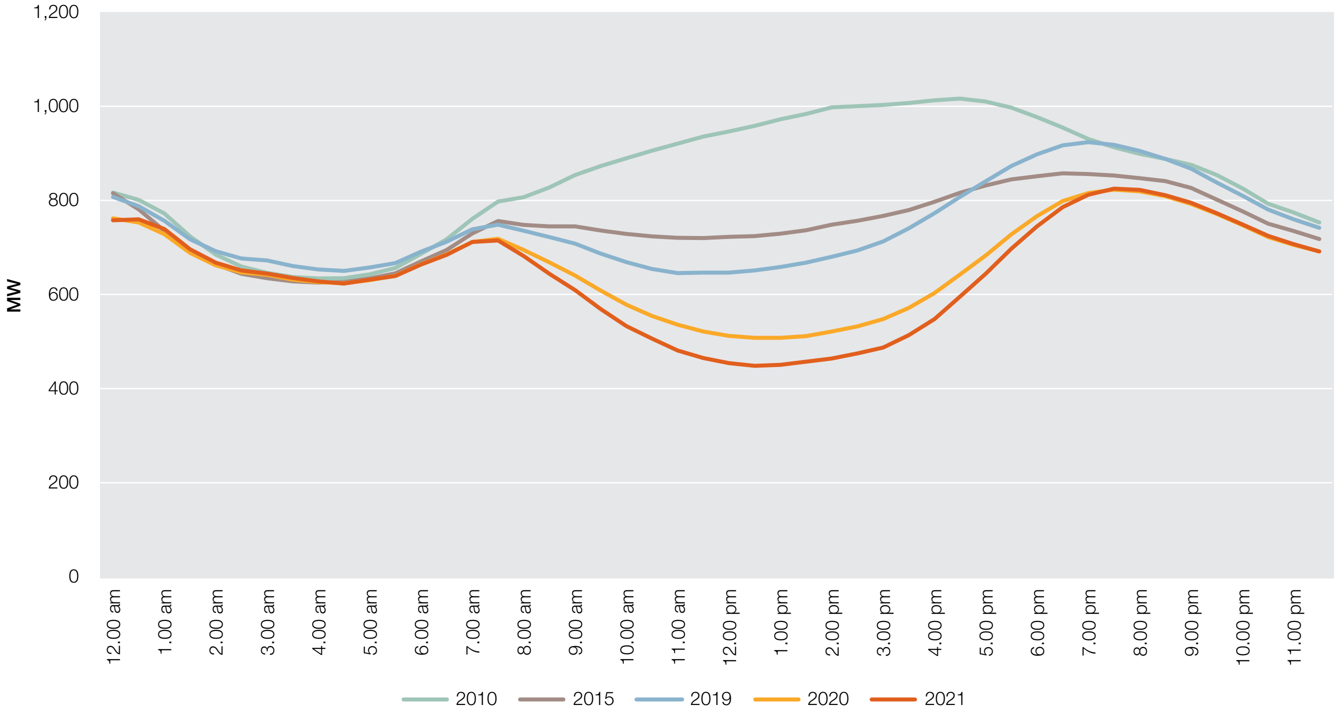
By backing off solar generation, consumers had to temporarily draw their power from the grid rather than their own rooftops. Grid demand increased above 400 MW and the risks associated with minimum demand passed.

Is this a one off problem?

The shape of the Q1 grid demand curve in South Australia has evolved over the past decade (Figure 1.25). In 2010, minimum demand occurred at around 4 am and started to steadily climb from around 5 am and typically peaked in the mid-afternoon. Since then, more than 1,480 MW of rooftop solar has been installed leading to a significant change in the shape of the demand curve. Minimum demand now occurs in the middle of the day when the sun is at its highest. The minimum demand level is also falling lower and lower each year.

11 https://aemo.com.au/newsroom/media-release/solar-pv-curtailment-initiative-by-sa-government-supports-the-nem. More than 10 MW was backed off as part of the Smarter Homes initiative, 40 MW was temporarily tripped by SAPN by slightly increasing the voltages at 7 substations, and 17 MW of ground-mounted commercial solar was backed off through SCADA control systems.

Figure 1.25 Average demand by time of day, Q1 comparisons, South Australia



Source: AER analysis using NEM data.

Note: Demand is native demand. Average demand by time of day, Q1 comparisons.

Conditions similar to 14 March, days with low business activity and mild sunny weather, occur multiple times throughout the year. Modelling undertaken by AEMO predicts that with increased uptake of rooftop solar, minimum demand in all regions will shift from the middle of the night to the middle of the day by 2025.[12] Compared to the other regions of the NEM, South Australia has a low industrial load so much of the demand in the region is driven by residential and business consumers. AEMO's modelling also predicts that South Australia may even have periods of negative demand, meaning all of the generation from rooftop solar would exceed all demand in the region and rooftop solar generation would be exported into Victoria.

Some of the effects of high rooftop solar could be mitigated using cost reflective tariffs to encourage consumers to switch demand to the middle of the day. From July 2020, new residential Time-of-Use tariffs were introduced in South Australia for customers with smart meters. These 'solar sponge' tariffs encourage households to run pool pumps, washing machines and dishwashers during the middle of the day to take better advantage of surplus solar generation.[13]

Other options to manage low demand include reduced export limits. South Australian households are currently limited to 5 kW of export capacity. But because some parts of the grid are overloaded, SAPN is trialling new rules which offers a choice between a 'flexible export' option with a limit of 10 kW (but allows SAPN to lower export limits when needed) or a 1.5 kW fixed limit.

Focus 2 – Gas offers respond to a changing market and mild summer

Since Q1 2017, there have been changes in how participants offer generation into the market. New entry of wind and solar generation has added capacity offered at low prices (section 1.8) but there has also been a shift of capacity priced between $50/MWh and $500/MWh to above $500/MWh, particularly by gas generators. This focus story explores the drivers of these changed gas offers and how these gas offers vary between regions.

The key drivers of changing gas offers include:

- increased rooftop solar output driving down demand needed to be met by the market
- new entry of low-priced renewable generation
- in Q1 2021, a mild summer leading to low demand.

12 AEMO, *2020 Electricity statement of opportunities*, August 2020, p45.

13 SA Power Networks time of use network tariffs. Between 10am–3pm this tariff is a quarter of the price of the normal network tariff. Distribution network charges make up about 30% of a retail bill in South Australia.

Gas offers have changed in different regions in different ways. In regions with significant coal generation, gas offers have largely shifted to above $5,000/MWh to avoid dispatch at low prices. However, in South Australia and Queensland where gas is used more often to cover retail and contract positions, gas offers still remain below $150/MWh.

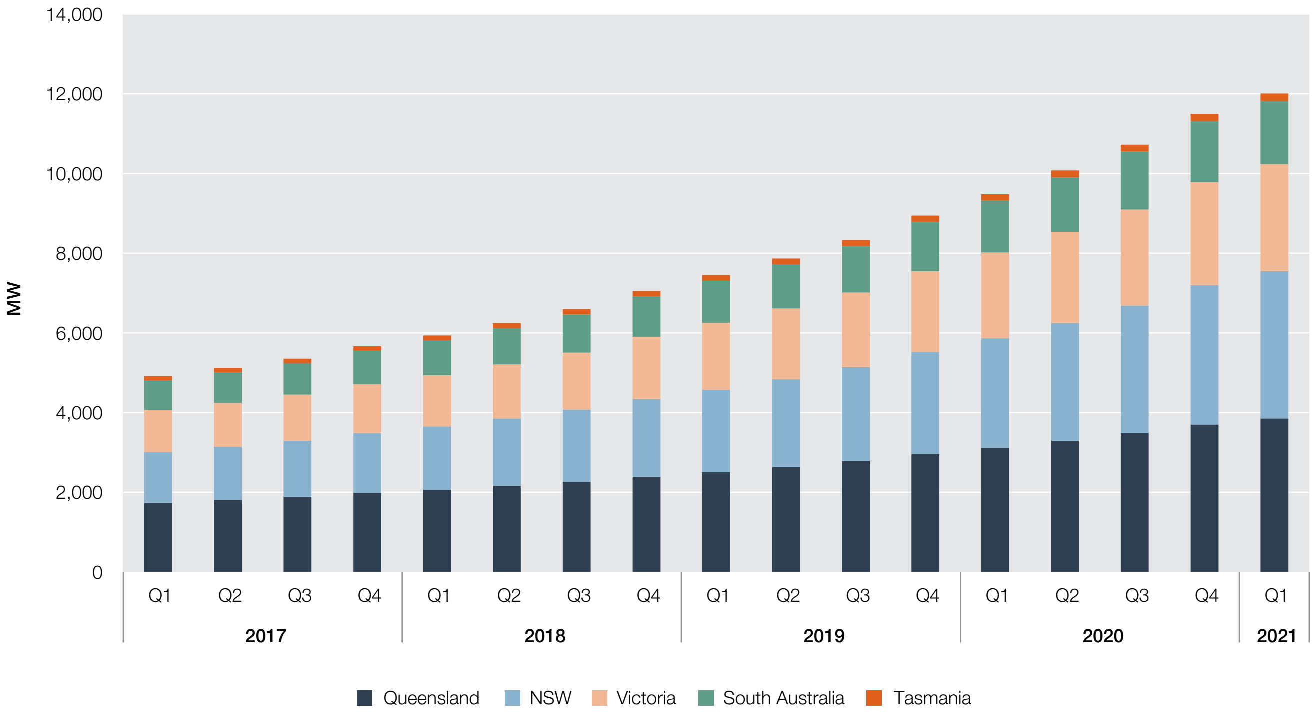
Box 1.1 Generator bidding in the NEM

As an 'energy only' market, in the NEM generators are only paid for the output they produce. Market participants will typically offer capacity across a range of different prices in order to be dispatched when and by how much they want to. Offers may be influenced by a variety of factors including type of generator, fuel costs, maintenance, start-up costs, competitive pressures and contract market positions.

Low demand and increased renewables impact gas offers

Since 2017, rooftop solar capacity has increased by around 7,000 MW, to 12,000 MW (Figure 1.26). In some regions, the increase was almost equal to its average demand and significantly reduced demand needed to be met by NEM generation during daylight hours. It also means that higher-cost generation like gas and hydro are being dispatched less during the day (section 1.4).

Figure 1.26 Installed capacity of rooftop solar



Source: AER analysis using CER data.

Notes: New rooftop solar PV installations have 12 months to register, so the most recent 12 months is not complete and may understate new installations.

There has also been a significant increase (2,200 MW) in wind and large scale solar generation in the past 4 years (section 1.8). These generators typically offer capacity at negative prices which has resulted in this new capacity getting dispatched ahead of higher priced generation like gas, hydro and in some instances coal.

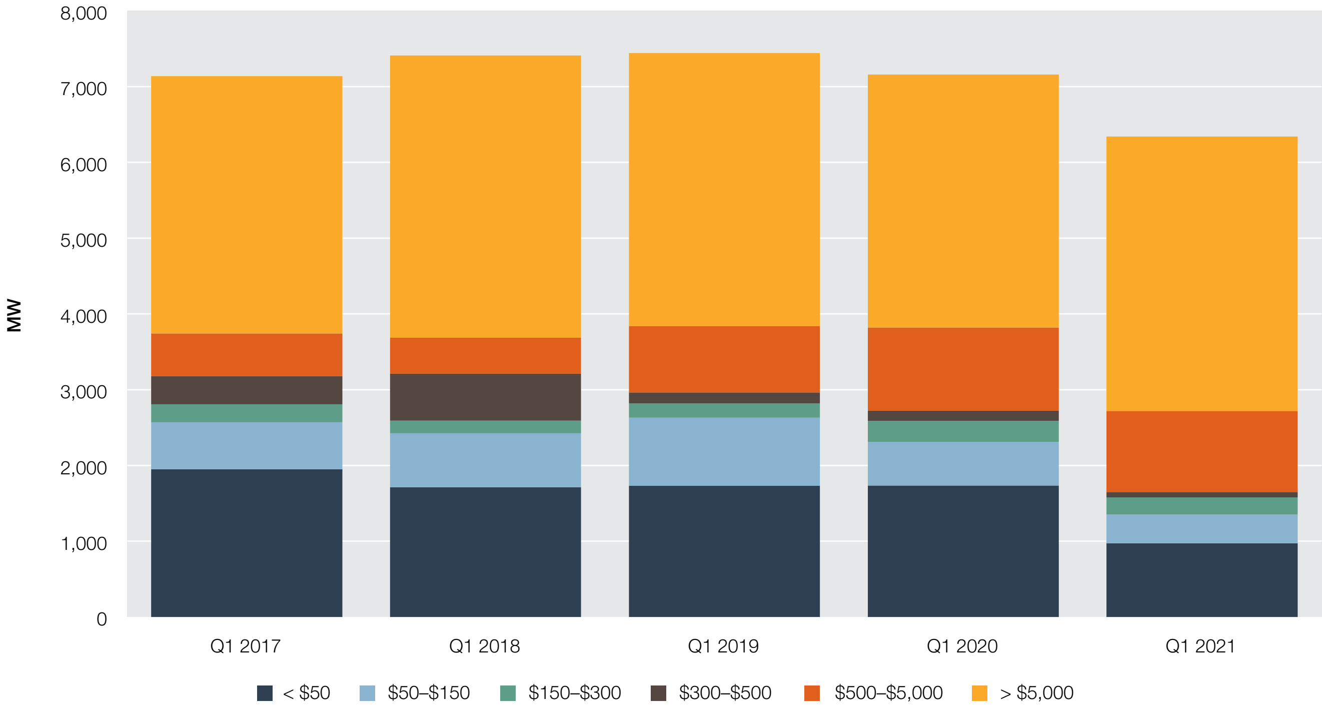
Falling daytime demand and increased renewable generation has changed the way some generators operate and offer. This was exacerbated in Q1 2021 by the mild summer that further lowered demand.

Changes in offers have been pronounced for gas generation, with (Figure 1.27):

- average capacity offered across the mainland falling over the last 2 summers
- capacity priced between $300/MWh and $500/MWh disappearing
- some capacity continuing to be offered below $50/MWh, mainly concentrated in South Australia and Queensland, to cover participants' retail and contract positions.

This shift in offers may be due to gas generation not being needed to meet participants' retail load or to avoid uneconomic dispatch (due to high start-up, running and maintenance costs) for short periods of high prices.

Figure 1.27 Mainland gas offers, Q1 comparisons



Source: AER analysis using NEM data.

Notes: Q1 average offers for all mainland gas generators.

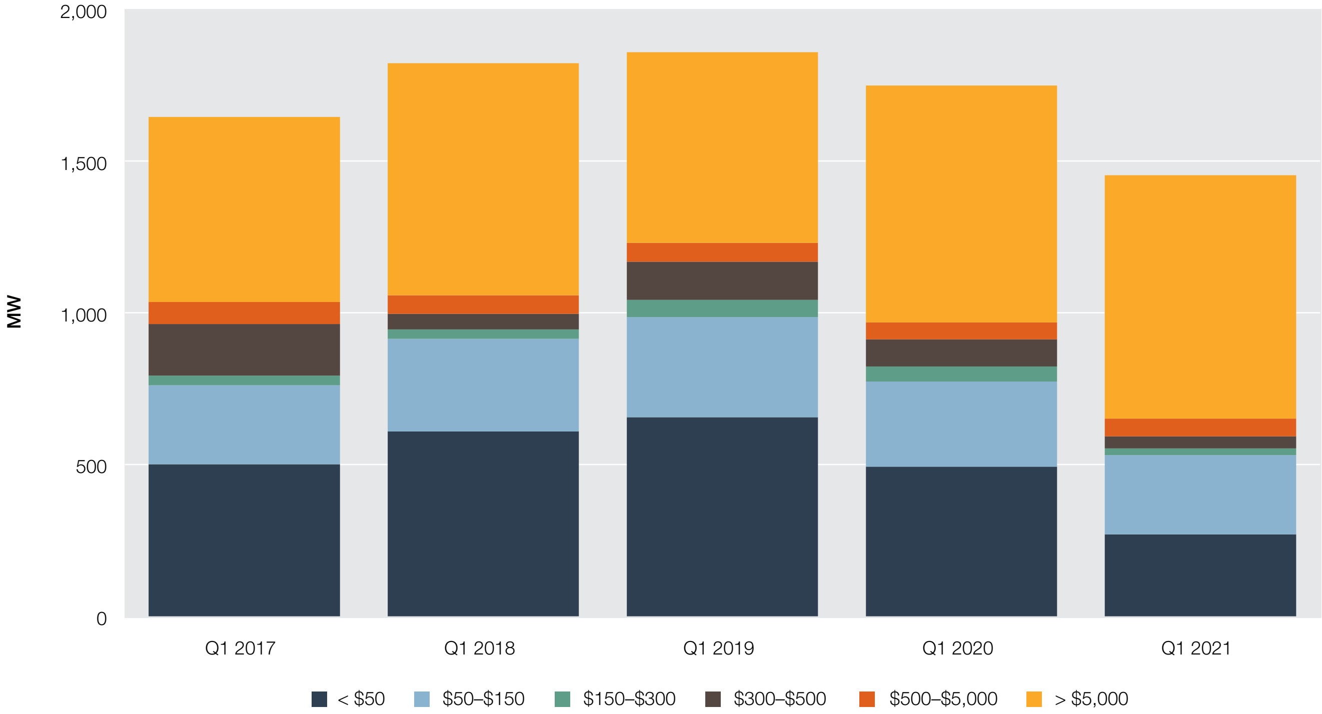
Regional gas offer profiles reflect regional differences

Gas offers have been influenced by the generation mix in each region. This may reflect the relative market share of participants with gas generation in different regions and their hedging strategies.

In South Australia, gas and wind are the main sources of generation, and accounted for more than 80% of the region's offers in Q1 2021. As gas is the only thermal generation in the region, it provides a constant 'base' source of generation, with a large amount of capacity priced below $150/MWh (Figure 1.28). This reflects participants using gas generation to cover their retail and contract load. However in Q1 2021, average gas offers were 320 MW lower than Q1 2020 with less capacity offered below $150/MWh. The decline in average offers below $50/MWh may have been in response to low demand.

Q1 2021 also saw an increase in capacity offered at prices above $5,000/MWh. This may be partly due to the significant increase in directions issued to gas generators (for around 70% of the time in Q1 2021). When gas generation was directed, generators offered the 'directed' capacity at prices above $5,000/MWh to indicate they would not normally have been running.

Figure 1.28 South Australia gas offers, Q1 comparisons



Source: AER analysis using NEM data.

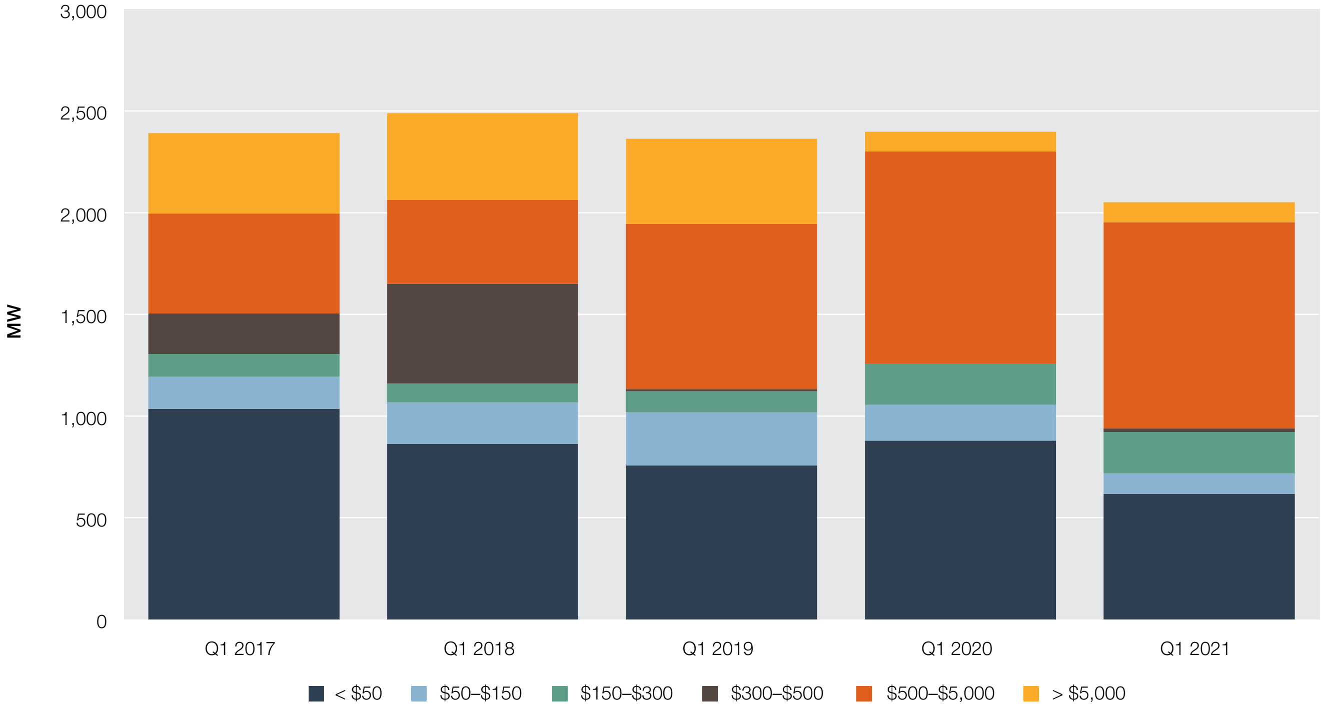
Notes: Q1 average offers for gas generators in South Australia.

In Queensland, black coal generation is the main source of generation and accounted for around 65% of regional offers in Q1 2021 with gas generation accounting for around 20% of offers.

While less gas capacity was offered in Queensland, offers generally remained below $5,000/MWh, rather than above $5,000/MWh as observed in other mainland regions (Figure 1.29). Queensland gas generators offered 600 MW of capacity priced below $50/MWh. Similar to South Australia, some gas generation is used to manage retail and contract positions and is offered at prices below $150/MWh.

Also similar to South Australia, in Queensland some gas continues to be offered at prices below $50/MWh. The majority of this is offered during morning and evening peaks by Origin Energy at Darling Downs power station. Darling Downs is Origin's main scheduled generator in Queensland used to cover its retail load in the region.

Figure 1.29 Queensland gas offers, Q1 comparisons



Source: AER analysis using NEM data.
Notes: Q1 average offers for gas generators in Queensland.

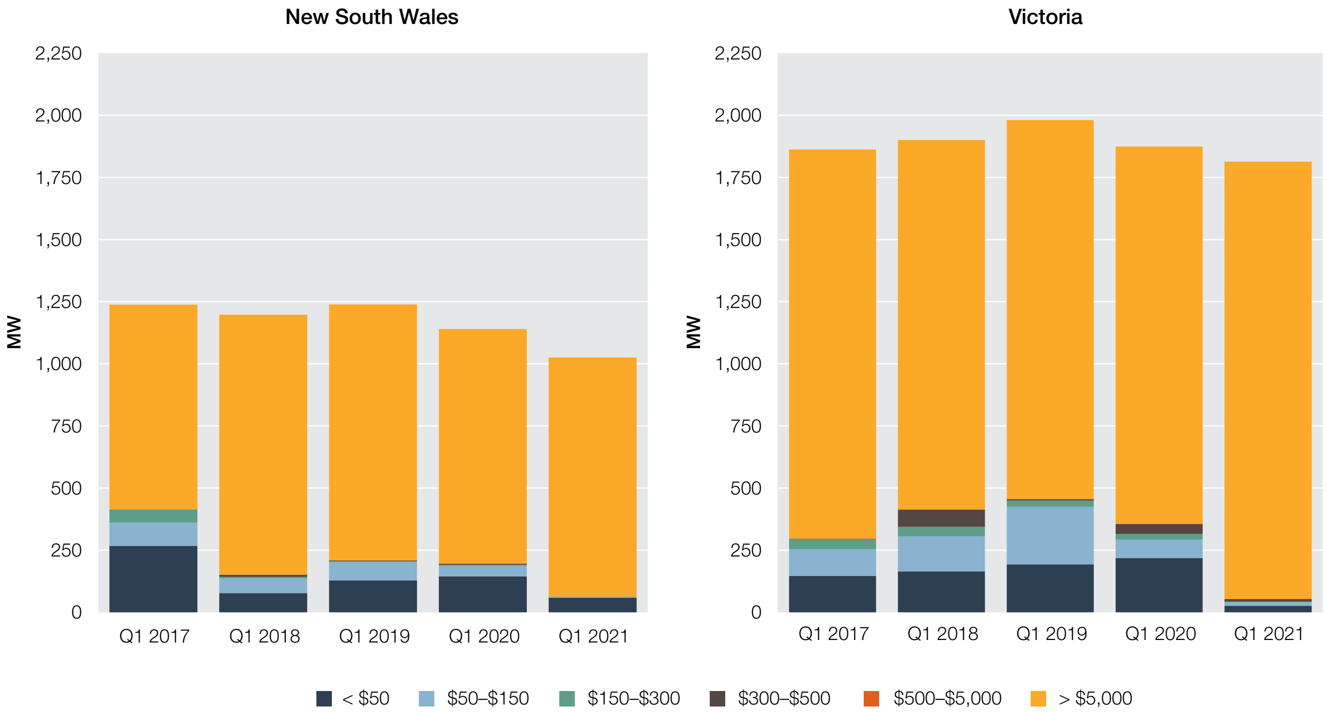
In NSW and Victoria, coal remains the primary source of baseload generation. As a result, periods of high demand or high prices are typically met with gas or hydro generation. This provides a gas offer profile more in line with traditional gas peaking plant, and different to that in South Australia and Queensland.

Nearly all gas capacity priced below $500/MWh in Q1 2020 was shifted into prices above $5,000/MWh in Q1 2021 (Figure 1.30). This reflects gas units avoiding an uneconomic start for a short period of time with low demand and low spot prices.

In addition, gas in both NSW and Victoria competes with hydro which has seen an increase in offers below $50/MWh since Q1 2018, displacing gas output.

Some market participants use gas generation as a backup if there are issues at their other generators or on interconnectors. However, there were fewer outages in Q1 2021 so this gas generation was not needed.

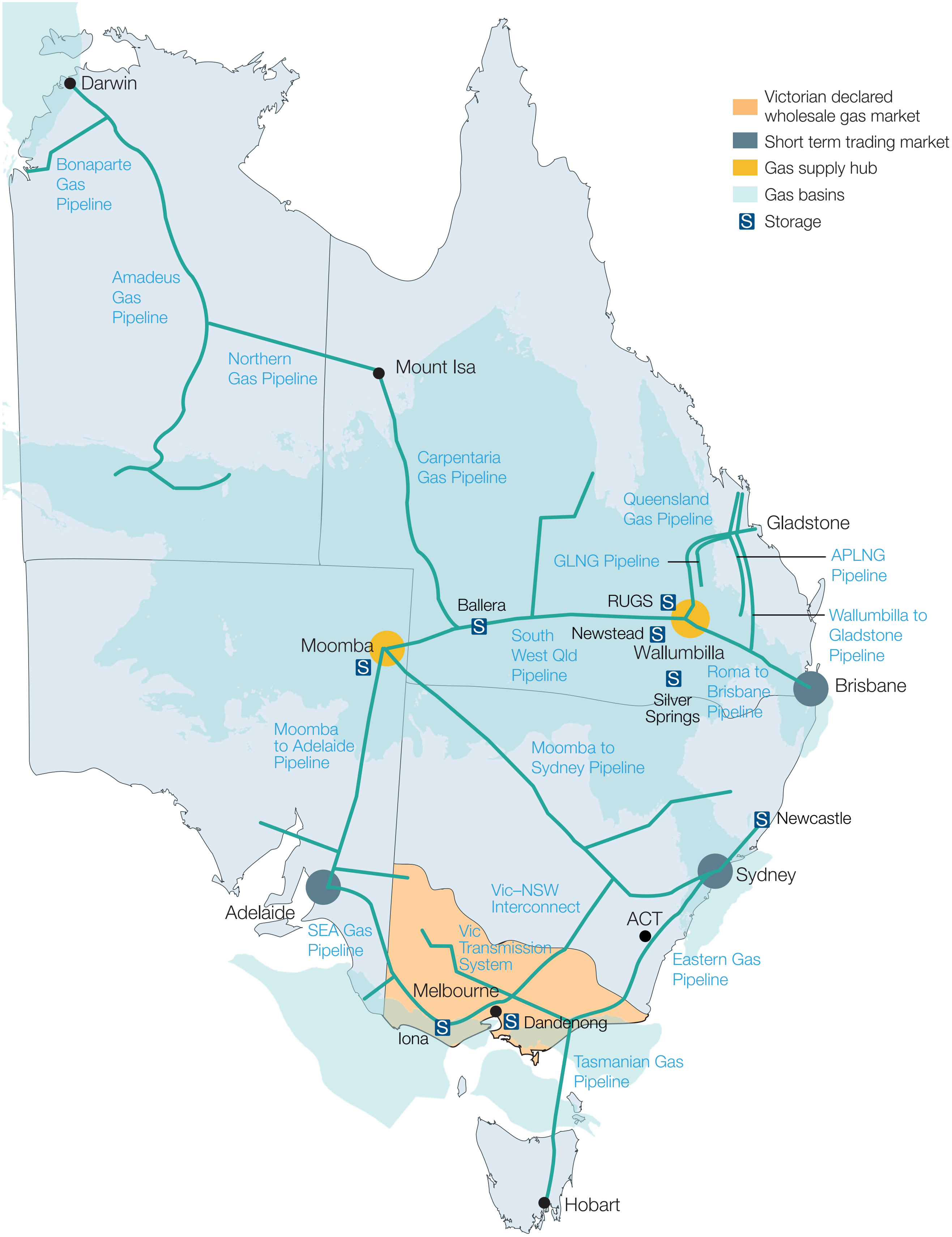
Figure 1.30 NSW and Victoria gas offers, Q1 comparisons



Source: AER analysis using NEM data.
Notes: Q1 average offers for gas generators in NSW and Victoria.

We will continue to monitor trends in offers and explore changes in offer behaviour.

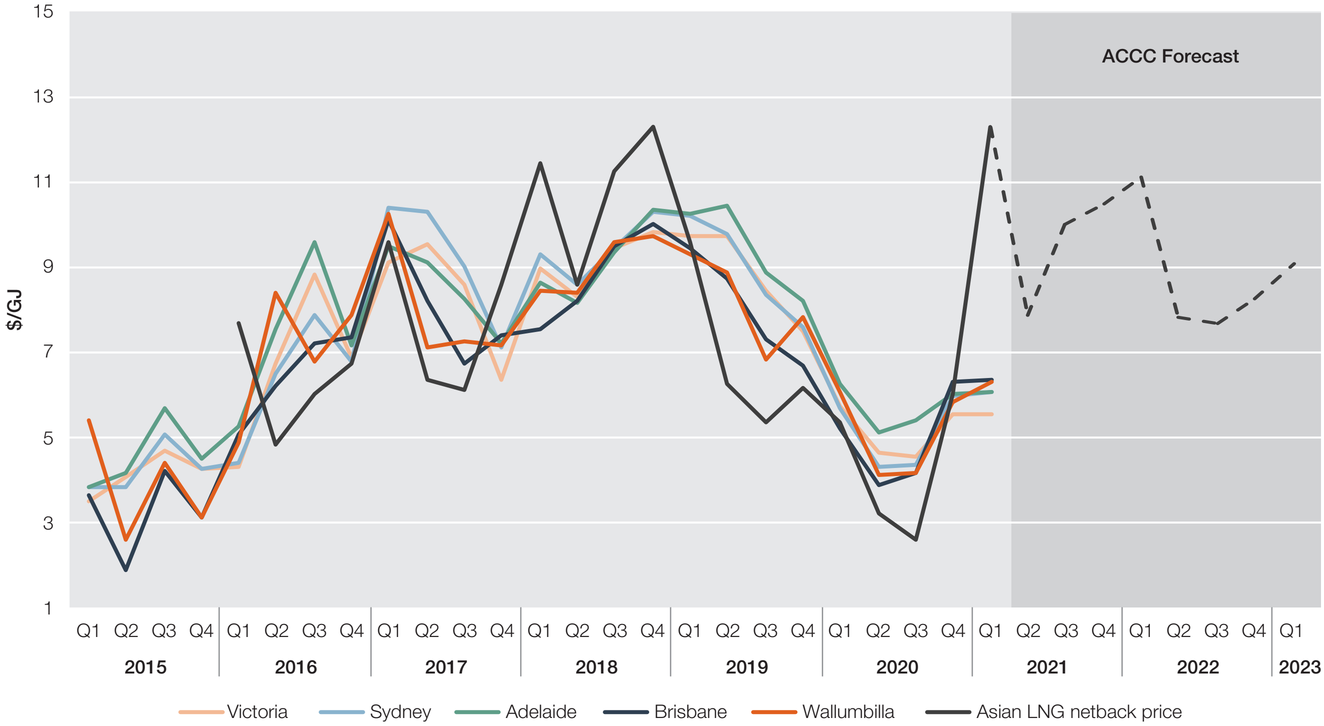
2. Gas



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
Wallumbilla to Gladstone Pipeline
Ballera
RUGS
Moomba
South West Qld Pipeline
Newstead
Wallumbilla
Roma to Brisbane Pipeline
Brisbane
Silver Springs
Moomba to Adelaide Pipeline
Moomba to Sydney Pipeline
Newcastle
Sydney
Vic–NSW Interconnect
ACT
Adelaide
SEA Gas Pipeline
Vic Transmission System
Eastern Gas Pipeline
Melbourne
Iona
Dandenong
Tasmanian Gas Pipeline
Hobart

2.1 Domestic prices subdued amid global volatility

Figure 2.1 Domestic spot prices and Asian LNG spot netback price



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

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

Domestic prices in Q1 2021 ranged from $5.50/GJ in Victoria to $6.40/GJ in Brisbane (Figure 2.1). Overall, east coast gas market prices increased marginally by 2.5% from Q4 2020. Notably, prices in northern markets were on average $0.46/GJ higher than southern markets in Q1, a growing price differential from $0.22/GJ last quarter. This is the second consecutive quarter that northern prices have exceeded southern prices, which has not happened since 2017. As noted in section 2.6, larger quantities of gas have been flowing north in Q1 from last quarter, indicating that higher northern market prices reflect the cost of sourcing gas from southern markets plus a cost for transportation.

Asian LNG spot prices spiked in Q1 2021, averaging $12/GJ on a netback basis to Wallumbilla, almost double the level of domestic spot prices (Figure 2.1). This is the first time domestic prices have separated significantly from Asian netback prices since late 2018.

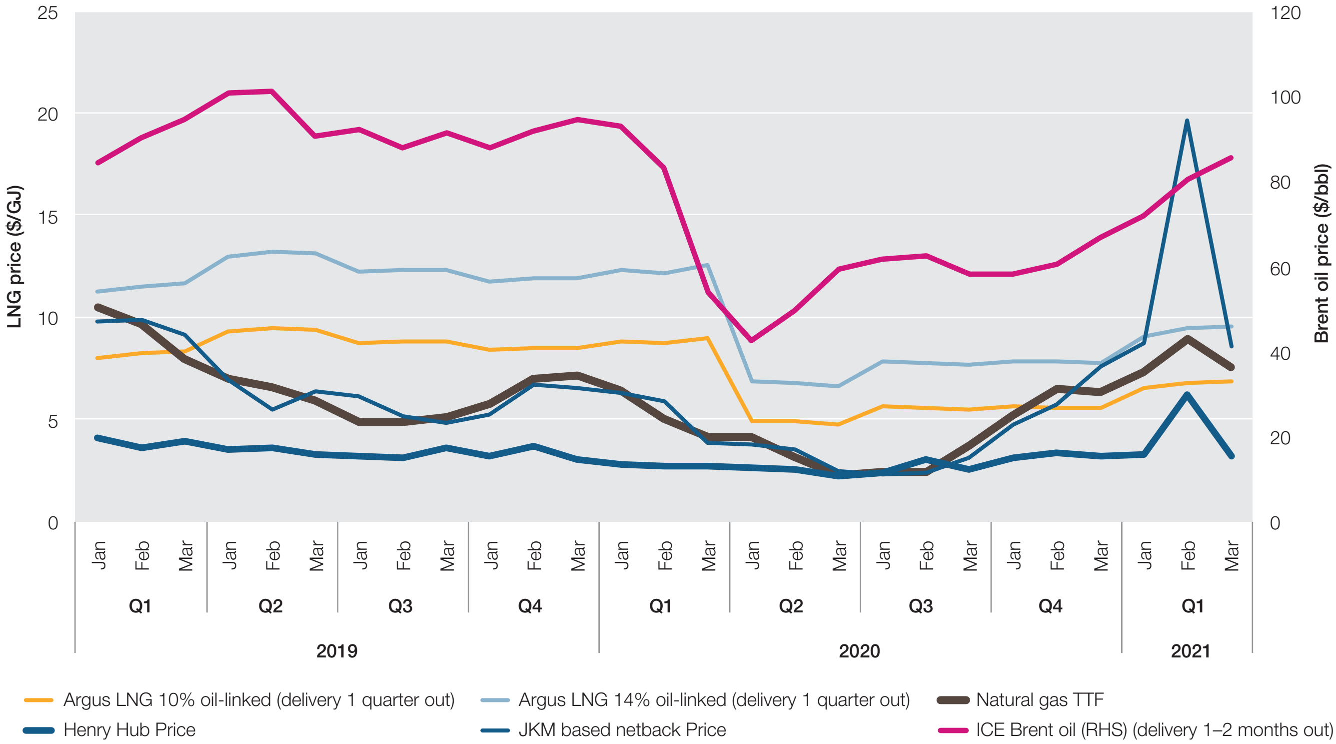
Gas prices increased across European (TTF) and American (Henry Hub) markets, as is expected during the Northern Hemisphere winter (Figure 2.2). However, the spot price increase in Asia was particularly acute, with Argus Media price assessments of north-east Asian prices rising to unprecedented levels. Asian LNG prices peaked in mid-January when we understand a few high-priced trades skewed prices higher for deliveries in February. Prices in January reached as high as $48/GJ based on Argus assessments. Our focus story assesses the liquidity and price formation of Asian prices in comparison to other international markets.

High prices in Asia were caused by the following factors which occurred simultaneously:[14]

- Severe winter conditions – raising the level of gas demand for heating.
- Shipping constraints – shortages of freighters available to deliver cargoes to Asia.
- LNG supply contraction – outages at major LNG export facilities Qatar, Western Australia and USA.

14 Argus Media, Asian spot LNG prices at record high on 'perfect storm', 7 January 2021, accessed 11 May 2021.

Figure 2.2 International gas and Brent oil prices



Source: AER analysis using Argus Media data and Bloomberg data.

Note: The ACCC Netback price is used as a proxy for the JKM physical spot price assessment representing cargoes delivered ex-ship (des) to Asia, trading in the month before the date of delivery.

The Argus LNG 14% oil linked contract prices are indicative of a 14% 3-month average Ice Brent crude futures slope.

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

The Henry Hub price is the average of end of day natural gas spot prices traded on the Henry Hub – sourced from Scoville via Bloomberg.

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Oil prices continued to increase over Q1 2021, settling at around $80/barrel by the end of the quarter. The price of oil has recovered from lows of around $40/barrel during Q2 2020, when fierce price competition, followed by reduced demand for travel, pushed prices down.[15] Since April 2020, Asian LNG prices have typically been less than $10/GJ for both cargoes sold on a spot basis or under a 14% oil linkage typical of pricing terms in longer term Queensland LNG export contracts. Export prices over 2020 were down from 2019 levels and this helps to explain recent ACCC information that that retailer domestic contract prices reviewed in 2020 declined to $6–8/GJ from $8–14/GJ.[16]

2.2 East coast production remains near record levels

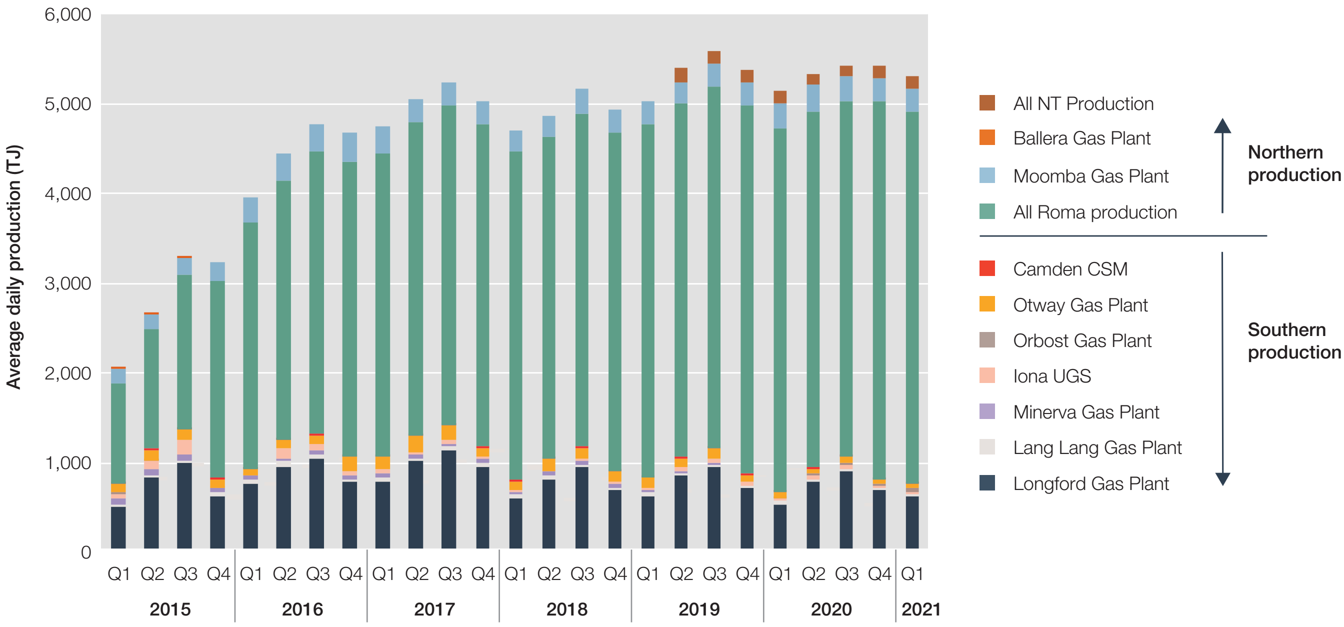
Production on the east coast remains at elevated levels, averaging 5,294 TJ/day in Q1 2021, declining slightly by 2% from 5,416 TJ/day in Q4 2020. The decline mostly reflects reductions at large production facilities in Queensland that are operated by LNG exporters, and the Longford gas plant in Victoria, which is the single largest source of gas supply in the southern markets.

Q1 gas production in Queensland (Roma) remained high at 4,170 TJ/day, declining from a record production level of 4,242 TJ/day in Q4 2020 (Figure 2.3). This coincides with a slight decline in LNG exports from Gladstone, as the Northern Hemisphere winter ends and gas demand declines. There were also a number of LNG maintenance days in Q1 2021 (Table 2.1).

15 AER, Wholesale market quarterly report Q2 2020, p. 37.

16 ACCC, Gas inquiry, January 2021, p. 54.

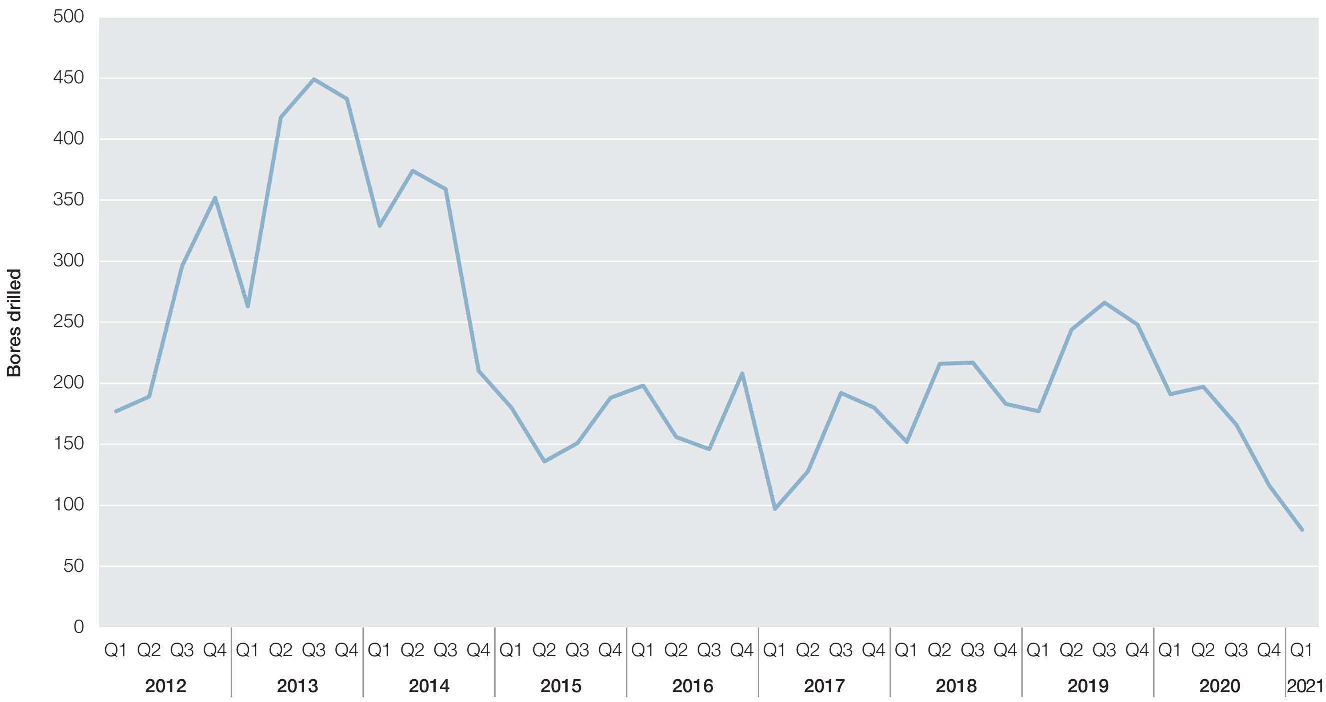
Figure 2.3 East coast production (including Northern Territory)[17]



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

There was a sharp decline in the number of new coal seam gas wells drilled in Queensland in Q1 2021, continuing a declining trend in drilling from 2020 (Figure 2.4). Production numbers do not appear to have been affected by the slowing trend in drilling. However, drilling numbers can be indicative of planned supply changes, as a procession of new wells is required to support ongoing production from coal seam gas resources such as those in Roma.

Figure 2.4 Queensland coal seam gas bores drilled



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

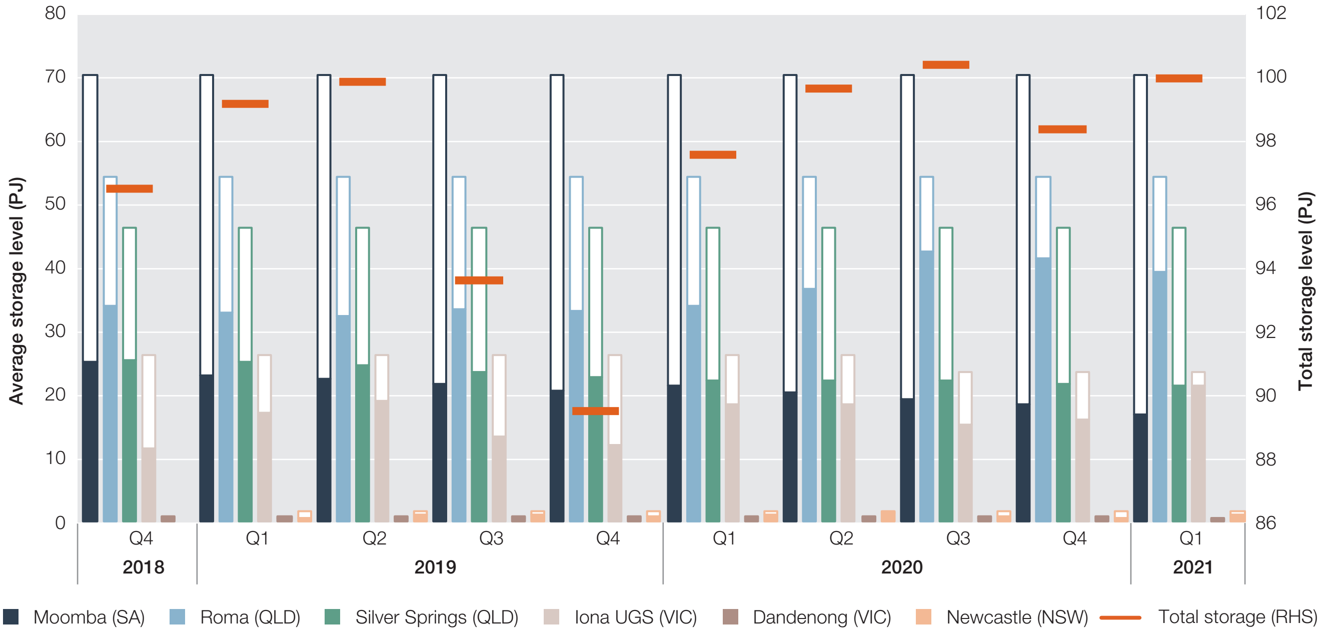
17 Production data includes BB data revisions from October 2018 and back-dated data for a number of facilities (showing quantities reported as pipeline receipts prior to the submission of production data). This provides additional historical information for Northern Territory production (back to the start of Q2 2019) and a number of Roma facilities.

In Victoria, the Longford gas plant decreased production from an average of 648 TJ/day in Q4 2020 to 580 TJ/day in Q1 2021. The decline in Longford's production followed subdued demand particularly from gas powered generators. This follows a typical seasonal production profile, whereby Longford reduces output in Q1 ahead of peak winter demand. AEMO recently highlighted the decline in gas field reserves as a supply risk and Longford's reduced maximum output leading to insufficient supply to meet peak winter demand of southern states from 2026.[18]

The Orbost gas plant in Victoria increased production to an average of 36 TJ/day in Q1 2021, from 18 TJ/day in Q4 2020. The plant continues to operate well below a nameplate capacity of 68 TJ/day due to ongoing delays to the commissioning of the plant.[19]

Q1 2021 average storage levels increased 1.6 PJ from last quarter, reflecting a large increase in the storage level at the Iona storage facility in Victoria, outweighing declines in storage levels at the Roma and Moomba storage facilities in and around Queensland (Figure 2.5). The Roma and Moomba storage level declines coincide with high international prices which may indicate this gas is supporting elevated levels of LNG exports.

Figure 2.5 Storage levels[20]



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

Note: Storage levels are averages across a quarter.

2.3 High LNG export volumes continue

Total Queensland LNG exports remained high at around 320 PJ during Q1 2021, down slightly from a record volume of 340 PJ in Q4 2020. Strong buying interest from Asian buyers continued, reflecting colder than normal winter conditions, a recovery in industrial activity and environmental policies promoting use of gas as a cleaner fuel of choice to reduce carbon emissions (Figure 2.6). The Chinese Government has indicated gas will play a key role in meeting their pledge to achieve carbon neutrality by 2060. The creation of the state-owned PipeChina company to operate gas infrastructure is expected to support growth of LNG imports and promote gas consumption. South Korea experienced a number of outages at coal and nuclear electricity generators that required more gas to supply electricity, and promoted use of gas by restricting output of coal generators over December–February.[21]

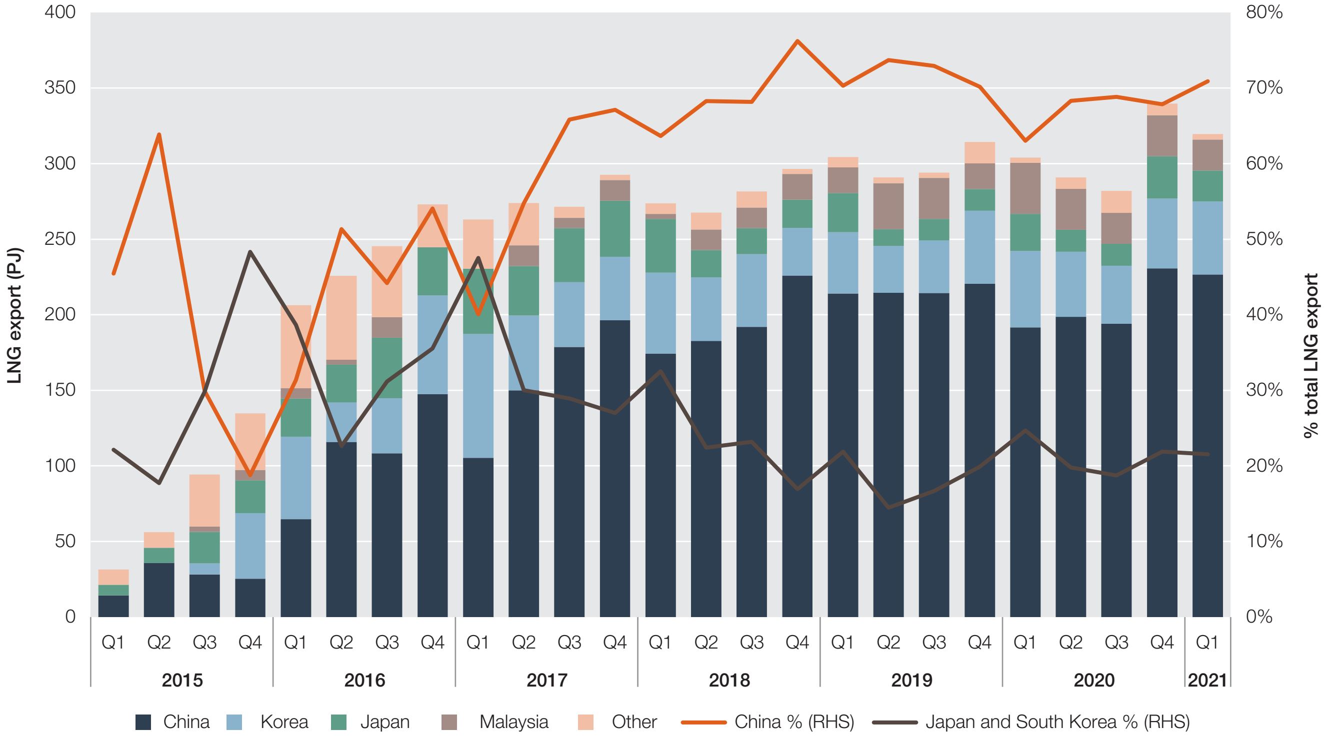
18 AEMO, *Gas Statement of Opportunities 2021*, March 2021, p. 3.

19 APA, Investor presentation, February 2021, p. 20.

20 Nameplate storage capacity at Iona reduced from 26 PJ to 23.5 PJ from May 2020.

21 Department of Industry Science Energy and Resources, March Resources Quarterly, pp. 69-70.

Figure 2.6 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Port Corporation data.

LNG exports remained high despite a number of planned maintenance outages across all LNG export facilities (Table 2.1).

Table 2.1 LNG plant outages

FACILITY	DATE RANGE	CAPACITY
APLNG	27–28 January	0.5 train outage
APLNG	2–3 March	0.5 train outage
GLNG	2–7 January	1 train outage
QCLNG	22–23 March	0.5–1 train outage
QCLNG	15–16 March	0.5–1 train outage

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

2.4 Trade at Wallumbilla recovers

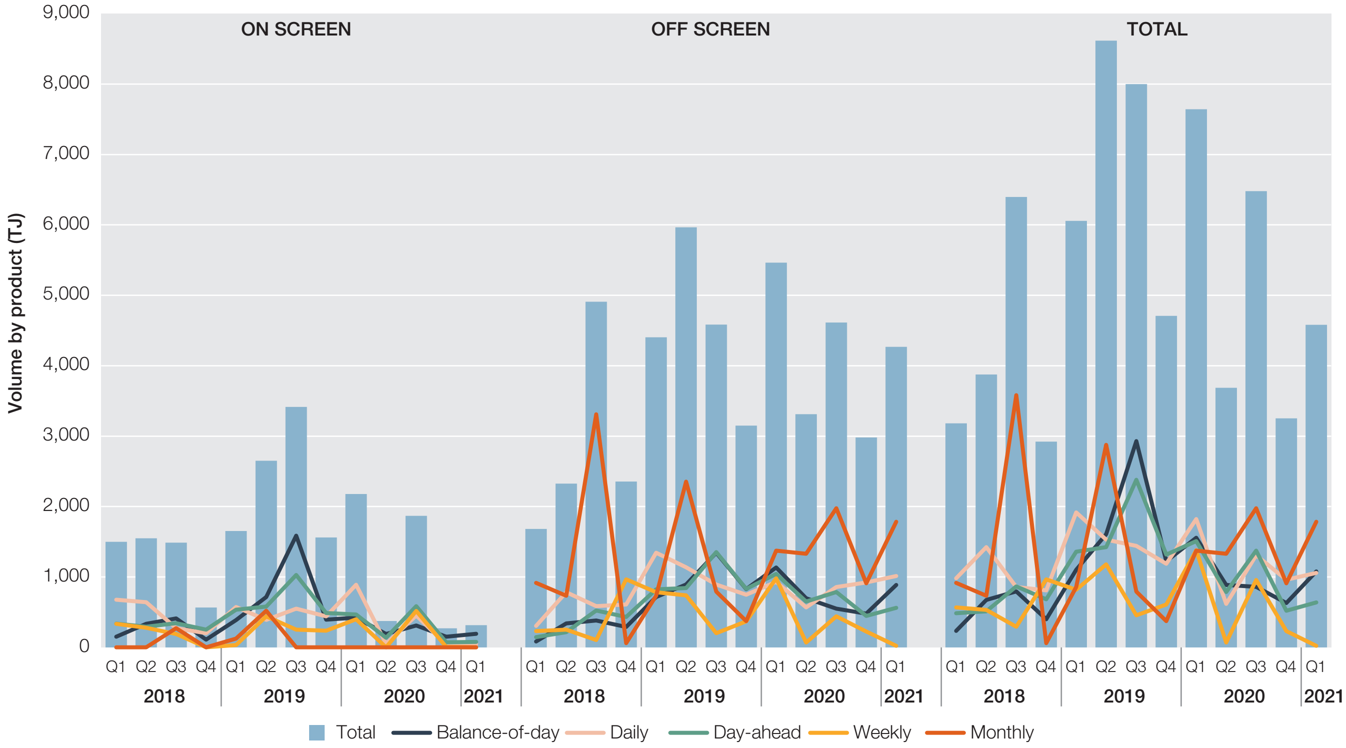
Trade at the Gas Supply Hub increased 41% to 4,582 TJ in Q1 2021 from 3,252 TJ in Q4 2020, driven by an increase in balance of day and monthly products (Figure 2.7).[22] Overall, trade volume at the Gas Supply Hub has been in a state of continuing decline since the high levels of trading volume in 2019. In Q1 2020, trading volumes at the hub reached 7,642 TJ versus trade volume of 4,582 TJ in Q1 2021.

Another notable trend is the increasing proportion of trade at the Gas Supply Hub that is occurring off screen since 2019.[23] This trend presents some level of concern as off screen trades provide less pricing information than on screen trades to participants on the trading day and undermines price discovery, which is one measure of a well-functioning market. In Q1 2021, 93% of the trade at the gas supply hub was off screen, with on screen trades being at historic lows.

22 There are 5 standard product lengths that participants can use when trading at the Gas Supply Hub: balance of day, daily, day ahead, weekly and monthly.

23 Participants using the Gas Supply Hubs can lodge trades either ‘on screen’ or ‘off screen’. On screen trades are matched anonymously through the Gas Supply Hub trading platform. Off screen trade 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 2.7 Gas Supply Hub – On screen, off screen and total trade volumes by product



Source: AER analysis using Gas Supply Hub trades data.

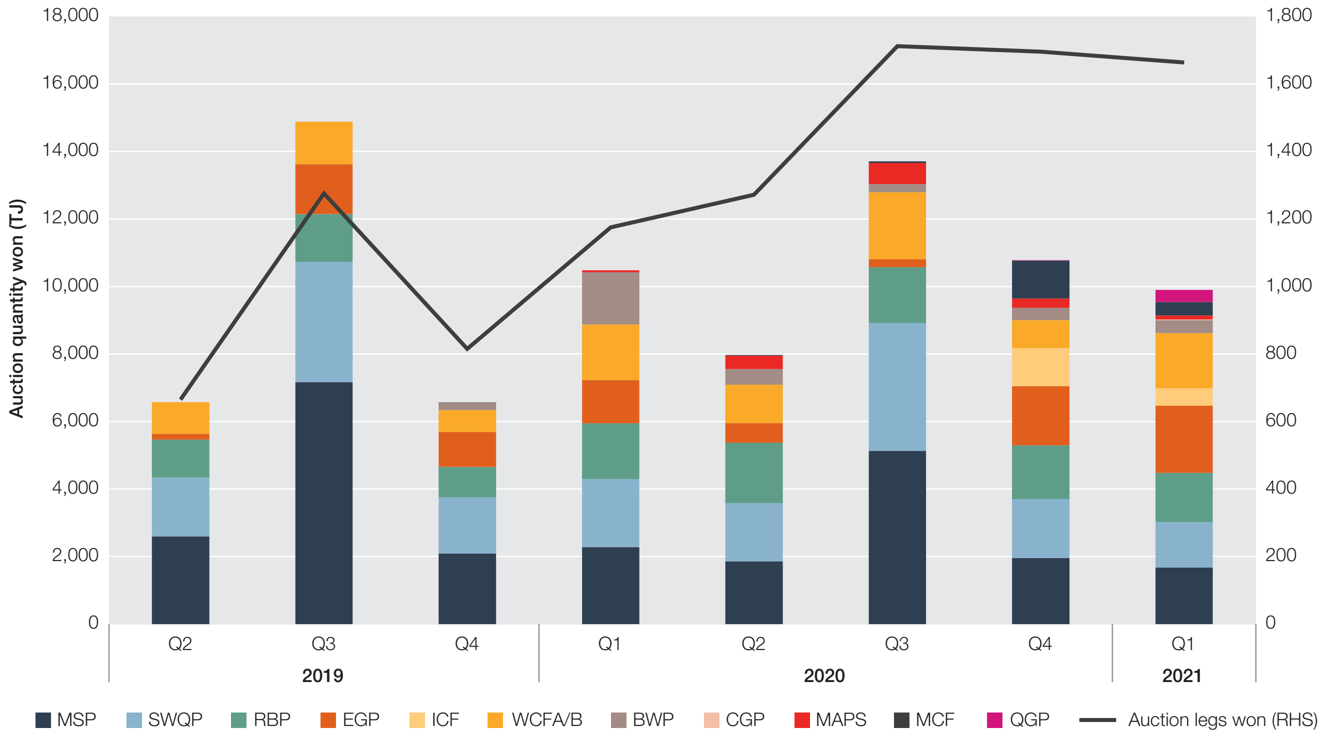
Traded volume was more concentrated among the top 3 participants, reaching 48% in Q1 2021, compared to an average of 37% across 2020.

On 28 January, AEMO expanded the boundary of the Gas Supply Hub to include delivery points at Wilton (NSW) and Culcairn (NSW-Victoria). Participants now have an ability to trade from Queensland to NSW and Victoria using the Gas Supply Hub. The new locations did not significantly boost trade, with 67 TJ and 70 TJ being delivered to Sydney and Victoria, respectively.

2.5 Day Ahead Auction participation increases

The quantity of auction transportation capacity won decreased from 10.8 PJ in Q4 2020 to 9.9 PJ in Q1 2021, a decrease of 8.2% (Figure 2.8). The auction is now operating across a wider range of facilities with the Carpentaria Gas Pipeline (CGP), Iona Compression Facility (ICF) and Queensland Gas Pipeline (QGP) starting to record auctioned capacity. As of Q1 2021, a total of 12 facilities now participate in the Day Ahead Auction (DAA), with 4 more facilities added since Q4 2020. The number of active participants also increased from 11 participants in Q1 2020 to 13 participants in Q1 2021. Notably, the QGP recorded 370 TJ of capacity auctioned in Q1 2021, increasing from just 12 TJ in Q4 2020.

Figure 2.8 Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using DAA auction results data.

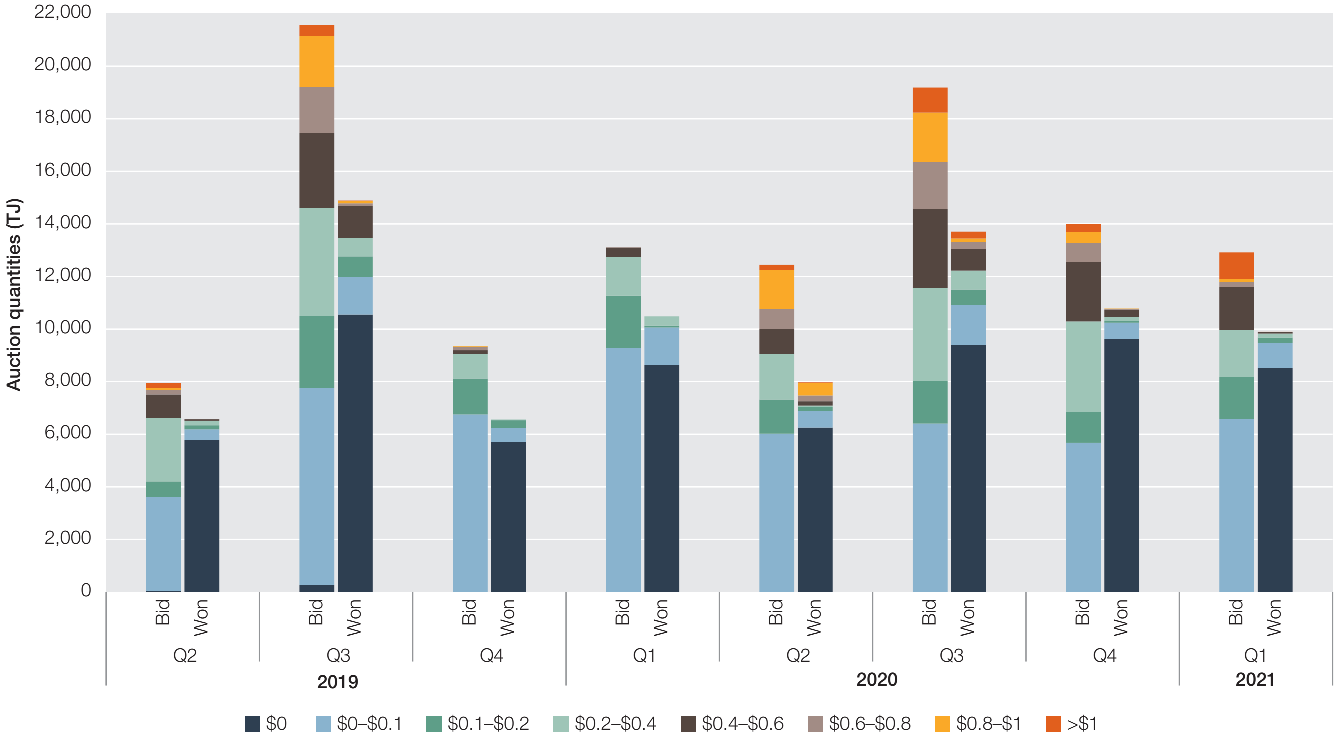
Note: Quantities shown are the monthly sum of auction products allocated on each pipeline and do not necessarily represent the physical volumes of gas that actually flowed for each gas day.

From this quarter reporting on the DAA was on a quarterly basis, whereas previously reporting was on a monthly basis. The above reporting excludes March 2019 when the auction commenced.

In Q1 2021, 86% of auctioned transportation capacity was won at $0/GJ but more competitive bidding on popular transport routes pushed capacity prices greater than $1/GJ in extreme cases, leading to auction constraints across a number of facilities (Figure 2.9). In Q1 2021, 8% of all bids were at prices greater than $1/GJ. This is the highest observed since the start of the auction – the previous highest was 5% in Q3 2020. This indicates that participants are willing to bid higher for auction capacity to ensure they lock in that capacity.

The Eastern Gas Pipeline (EGP) saw the highest auctioned capacity of any facility in Q1 2021, with 1,997 TJ auctioned over the quarter. It also recorded the highest cleared price of $1.4/GJ. The EGP auction was constrained for 7 days in January, when it reached its maximum cleared auction price under price competition. Auction capacity on the Moomba to Sydney Pipeline was predominantly used to flow gas south from Moomba and east towards Sydney, with 75% of capacity won used for this purpose.

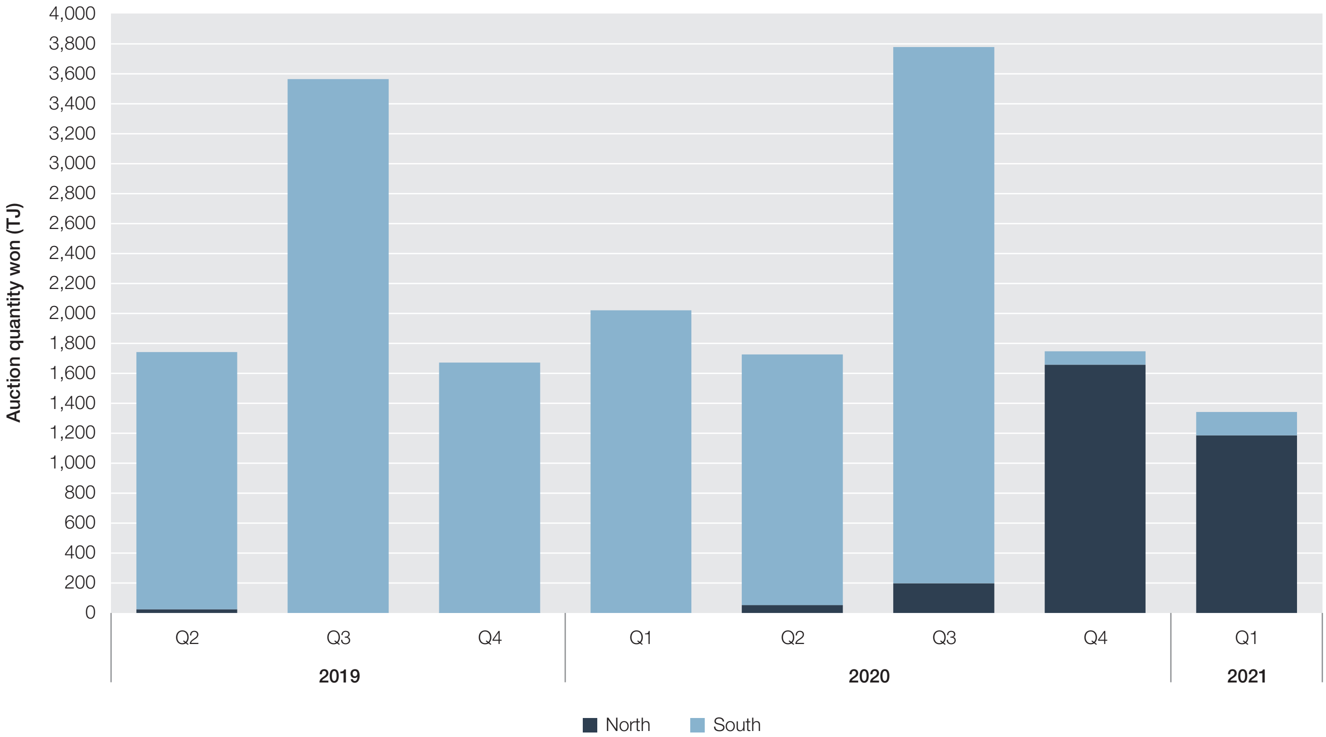
Figure 2.9 Day Ahead Auction bid stack



Source: AER analysis using DAA auction results data.

The DAA continues to facilitate gas flowing to its highest value use, with capacity being won in larger quantities to flow gas north of Moomba towards Wallumbilla on the South West Queensland Pipeline (SWQP – Figure 2.10).

Figure 2.10 Auction quantities won on South West Queensland Pipeline (SWQP) by route



Source: AER analysis using DAA auction results data.

Note: Quantities shown are the monthly sum of auction products allocated and grouped for different auction routes based on the direction of that auction route and does not necessarily represent the physical volumes of gas that actually flowed for each gas day.

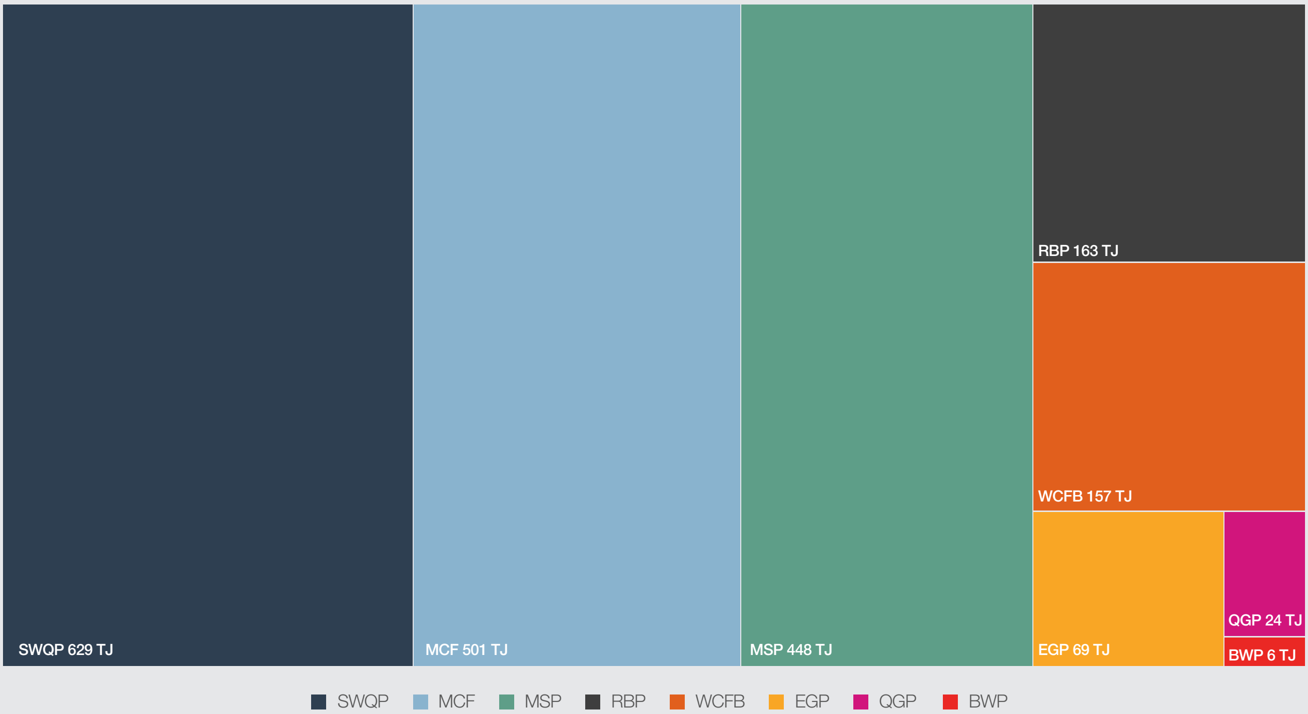
This may reflect gas being used to supply LNG exports, taking advantage of high Asian LNG spot prices. In Q1 2020, approximately 34% of all capacity won at the auction was won by Exporters and Producers, a record amount of capacity won for this participant group. The SWQP was the most constrained auction facility in Q1 2021, with more than 50% of auction results clearing above $0.01/GJ, with constraints on 62 out of the 90 days across the quarter. Overall on the SWQP there was 629 TJ of surplus demand.

Box 1.1. Surplus demand

Surplus demand indicates the volume of auction bids which were unsuccessful because the total bids at a point exceeded the available auction quantity, the Auction Quantity Limit (AQL), or a bid was unsuccessful due to a paired bid with another constrained facility. This surplus demand is only calculated on auction routes where auction capacity was actually won and does not reflect auction routes where no capacity was won. The AER discusses the level of surplus demand as well as the impact of auction constraints over 2019 and 2020 in its Pipeline Capacity Trading 2 Year Review.[24]

In Q1 2021 there was surplus demand on a number of facilities (Figure 2.11). Notably there was surplus demand on the QGP for the first time (as a result of auction bids above demand on that pipeline) and also surplus demand for usage of the Moomba Compression Facility as a result of participants looking to move gas north with paired bids on the constrained SWQP (this also occurred in Q4 2020 when LNG exports started to increase).

Figure 2.11 Day Ahead Auction surplus demand



Source: AER analysis using DAA auction results data.

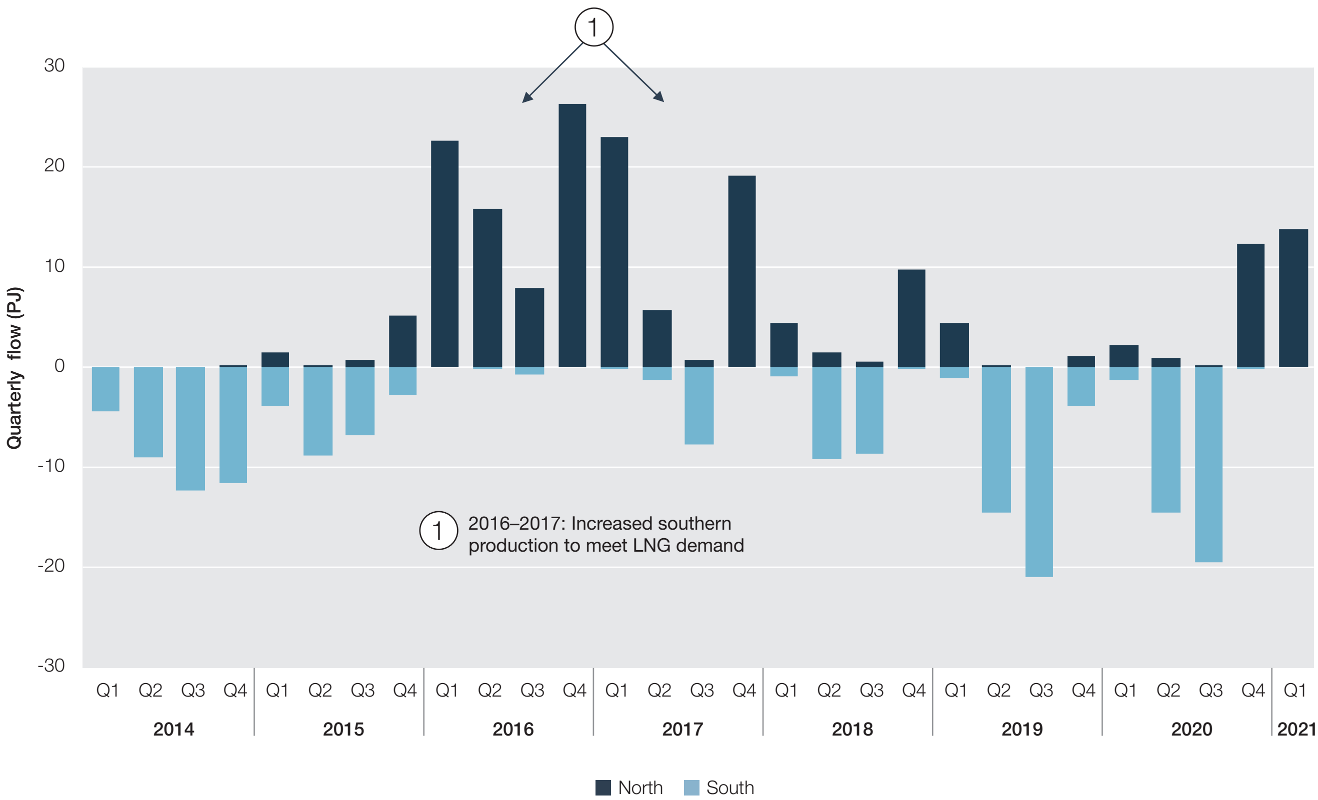
Note: Surplus demand is only calculated on routes where auction capacity was won.

24 AER, *Pipeline Capacity Trading 2 Year Review*, pp. 10-11.

2.6 Gas flows north

Gas continued to flow from southern markets to Queensland, with 13.9 PJ of gas moving north in Q1 2021, up from 12.4 PJ in Q4 2020 (Figure 2.12). More gas was directed to Queensland to support elevated levels of LNG exports to supply Asian LNG buyers at historically high spot prices. Gas has not flowed north to this extent since 2016–17, where large gas volumes were required to operate LNG export facilities at full capacity during commissioning tests.[25]

Figure 2.12 North-South gas flows

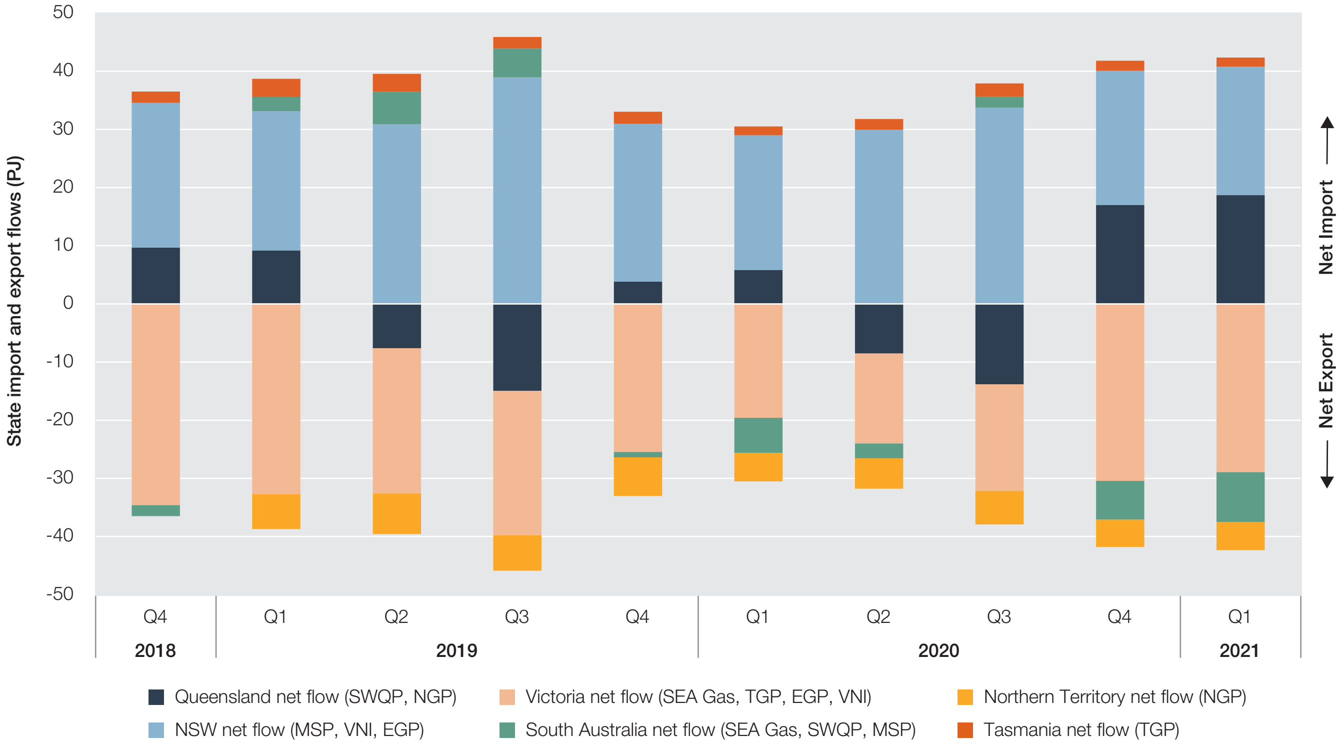


Source: AER analysis using the Natural Gas Services Bulletin Board.
Note: North-South flows depict net physical flows around Moomba – north or south.

Queensland net imports have increased over the last 2 quarters and NSW net imports have fallen as less gas is coming into NSW from the north (Figure 2.13).

25 Lewis Grey Advisory, Projections of gas and electricity used in LNG, December 2017, p. 56.

Figure 2.13 Interstate gas flows

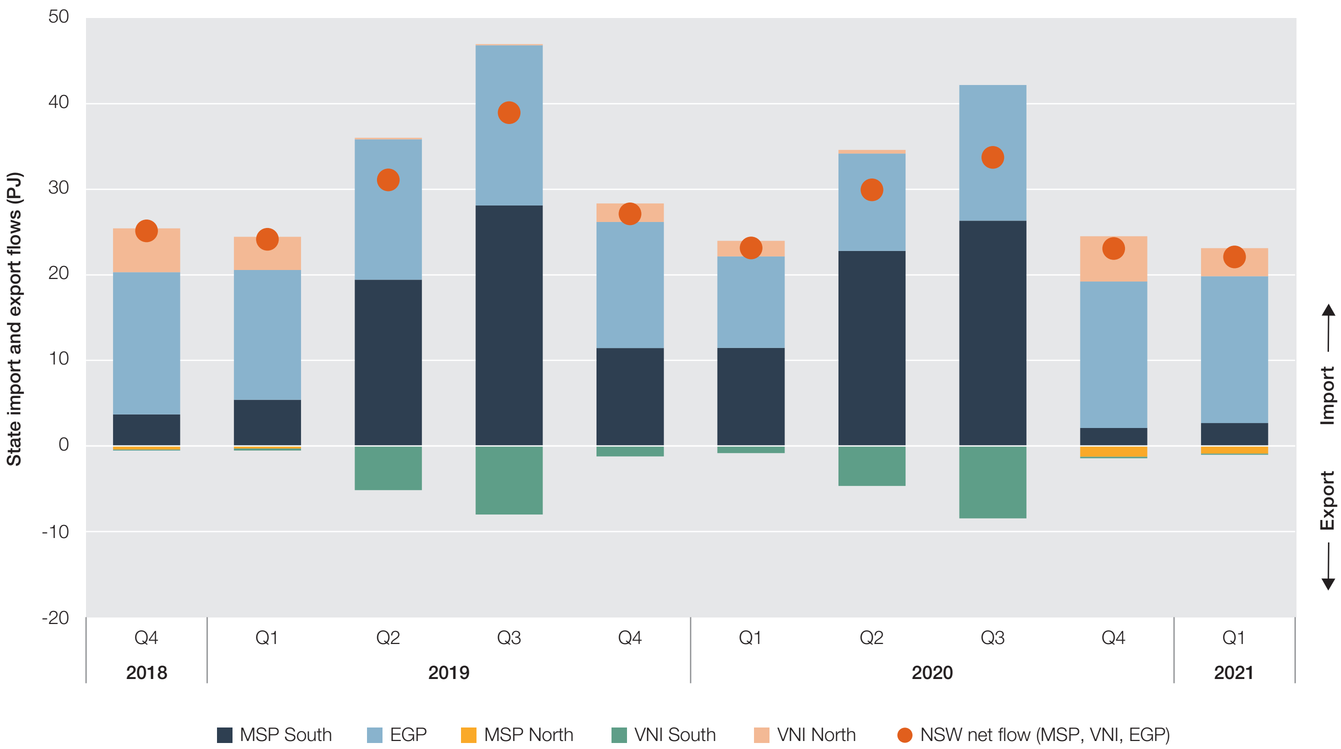


Source: AER analysis using the Natural Gas Services Bulletin Board.

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

NSW imported 17.2 PJ from Victoria via the Eastern Gas Pipeline in Q1 2021, the majority of Victoria's 21.9 PJ gas exports over the quarter (Figure 2.14). NSW only imported 2.7 PJ of gas via the Moomba to Sydney Pipeline, showing less reliance on gas supply from northern markets. This is much lower than the 15.7 PJ on average that flowed southwards from northern markets via the Moomba to Sydney Pipeline during 2020.

Figure 2.14 New South Wales import and export gas flows

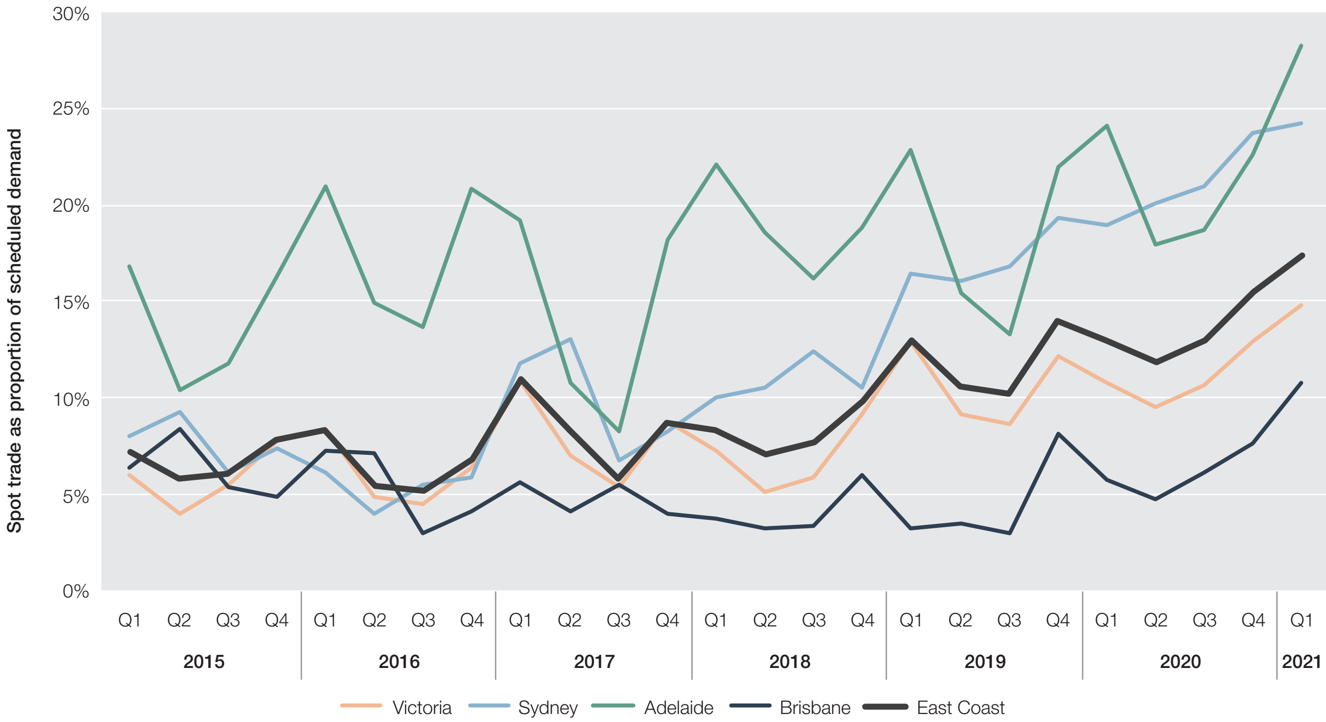


Source: AER analysis using the Natural Gas Services Bulletin Board.

2.7 Spot market trade increases

Spot market trade increased from 12.8 PJ in Q4 2020, to 13.8 PJ Q1 2021, largely driven by higher trade volumes in Brisbane and Sydney. Total spot trade as a percentage of demand rose to a record high 17%, showing encouraging signs that participants are using spot markets to source gas beyond balancing requirements (Figure 2.15). Competitive and liquid spot markets can provide 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.

Figure 2.15 Spot trade liquidity

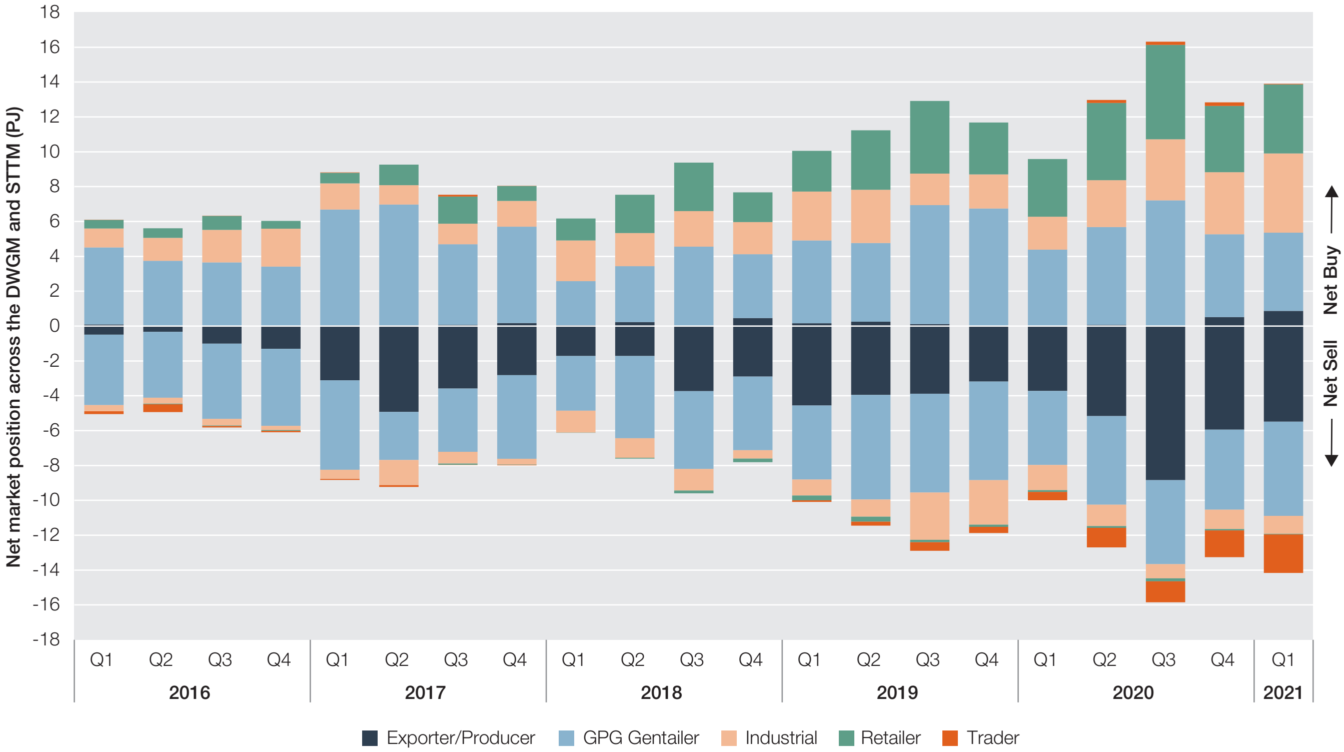


Source: AER analysis using DWGM and STTM data.

In Q1 2021, sales to spot markets increased from last quarter, as reduced sales volumes from Exporters and Producers was offset by higher sales by GPG Gentailers and Traders (Figure 2.16). Exporters and Producers sold 5.48 PJ in domestic spot markets, a decline from 5.94 PJ in Q4 2020, following high Asian LNG spot prices and demand for LNG exports from Asia. Amongst sellers, BHP was most prominent and publicly announced its intention to continue to offer gas into the spot markets at the Australian Domestic Gas Outlook Conference. GPG Gentailers and Traders collectively sold 7.6 PJ into spot markets in Q1 2021, compared to 6.1 PJ in Q4 2020.

Lower prices across spot markets were favourable for industrial buyers who increased purchases to 4.54 PJ in Q1 2021, an increase of around 1 PJ from last quarter. Notably, Exporters and Producers bought 0.9 PJ from spot markets, the highest ever recorded buying volume for these participants who are typically large sellers. Retailers did not significantly increase buying from spot markets, buying only 3.97 PJ, recording an increase of 0.2 PJ from last quarter.

Figure 2.16 Spot trade by participant



Source: AER analysis using DWGM and STTM data.

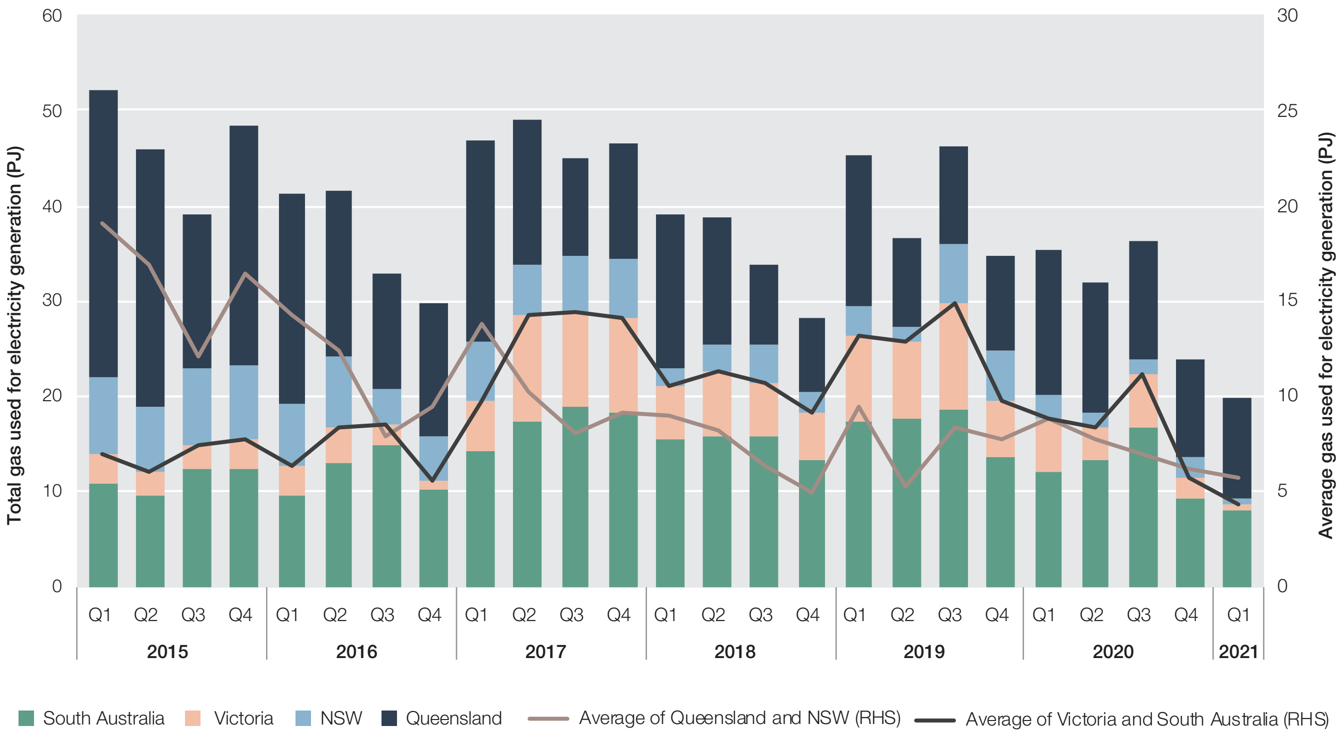
Note: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs has been estimated netting scheduled buy and sell quantities for each trading participant.

BlueScope, Tasmania Gas Retail and Tango joined the Victorian Declared Wholesale Gas Market as participants, CSR joined the Sydney Short Term Trading Market and APLNG and Senex registered on the Day Ahead Auction in Q1 2021 (Table 2.3 in Appendix B).

2.8 Gas powered generation continues to fall

Gas demand from electricity generators continued to fall, with a steep decline from 35.3 PJ in Q1 2020 to 19.9 PJ in Q1 2021, a level not seen since 2005. Lower demand for gas powered generation (GPG) occurred in all southern states, increasing only marginally in Queensland. Falls in GPG follow mild temperatures, a large increase in renewable generation capacity and a continuing trend of falling electricity demand in the NEM (Section 1.3).

Figure 2.17 Gas used for gas powered generation



Source: AER analysis using NEM data.

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

2.9 Gas futures trading subdued

The volume of trade in Victorian gas futures contracts remained subdued in Q4 2020 (Table 2.2). Total volumes traded were 668 TJ this quarter, reducing dramatically since Q2 2020.

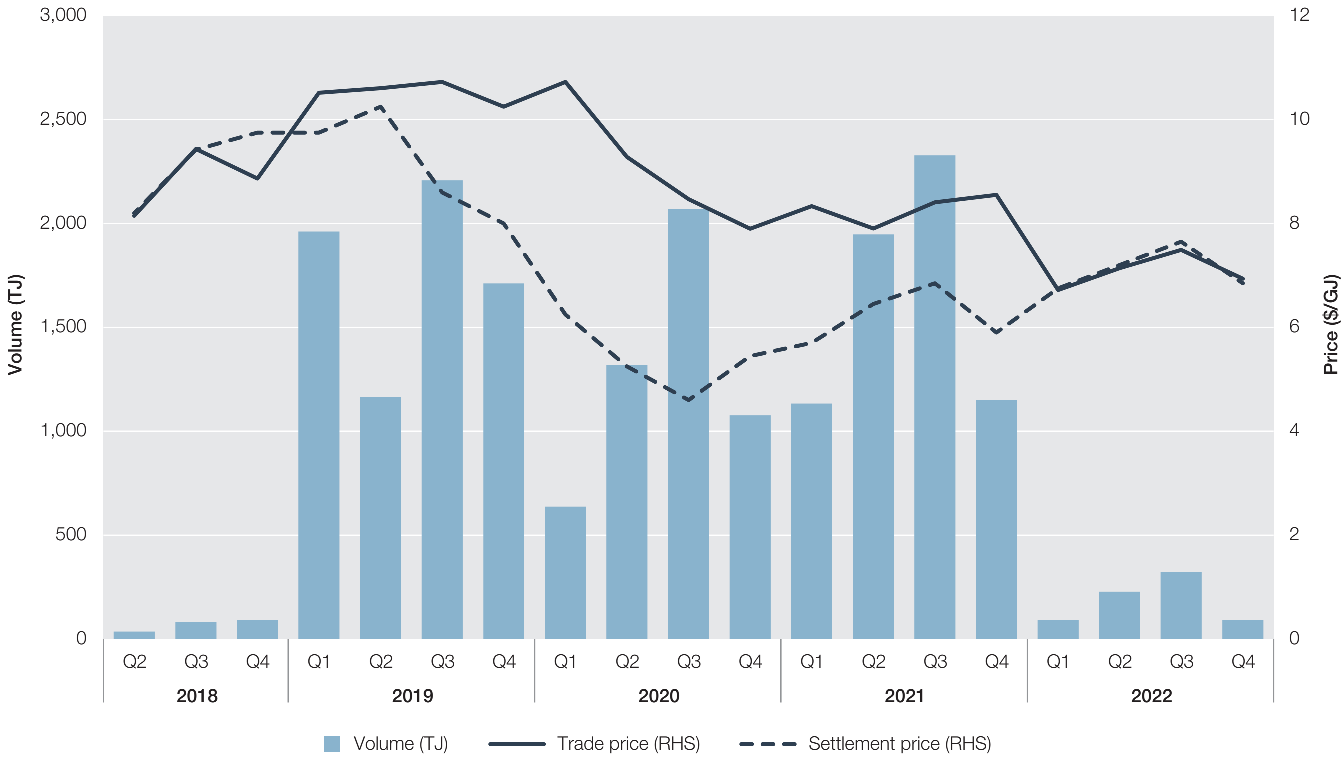
Table 2.2 Victorian gas futures trade summary

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
Q4 2020	741	81
Q1 2021	668	73

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

Settlement prices indicate expected gas prices between $5.9/GJ and $6.9/GJ over the remainder of 2021 (Figure 2.18). The difference between settlement and traded contract prices shows the divergence between actual prices and expectations from prior years. In Q1 2021, Victorian gas futures prices settled for $5.7/GJ, compared to an average traded price of $8.3/GJ.

Figure 2.18 ASX Victorian futures trade



Source: ASX Energy.

Note: Trading volumes are organised by contract expiry date.

Focus – International and domestic gas prices

Given recent media attention to the short-term volatility in the Asian LNG spot prices assessed by Argus Media and Platts, and also a recent short-lived price spike at the US Henry Hub, this focus story provides an overview and description of global gas price benchmarks. Below, we highlight recent trends, price formation and pricing outcomes, and the level of trade in various international markets.

Gas is exported by producers such as Australia, Qatar Russia and the United states. Much of this gas is sent to major importers in Europe and Asia using pipelines and ships. For example, most of the gas exported from the east coast of Australia is sent as LNG by ship to China. The use of LNG tankers allows an exporter to send gas anywhere in the world, this trade connects individual markets and means that the price of gas in one place can influence prices in markets thousands of kilometres away. The cost of importing LNG differs in different parts of the world because it is more expensive to ship gas to some regions than others but these differences are small and overall, global LNG prices are ultimately established by demand and supply fundamentals in LNG markets. At times, large price changes have been seen in individual regions that can continue for periods of weeks or months. However, the global nature of the LNG trade means that large differences in prices between different regions would not be expected to persist.

International price benchmarks can be a useful reference point to compare domestic gas supply prices and are often directly used in formulas to calculate gas prices under contracts.[26] Pricing of gas supply varies significantly across countries and can be linked to a range of benchmarks. The following benchmarks are commonly cited across a number of markets:

› Oil (Brent Crude, Japanese Crude Composite indexes).
› Gas spot markets (Henry Hub – USA, JKM – Asia, Transfer Title Facility – Europe).
› Ammonia (fertilizer input).

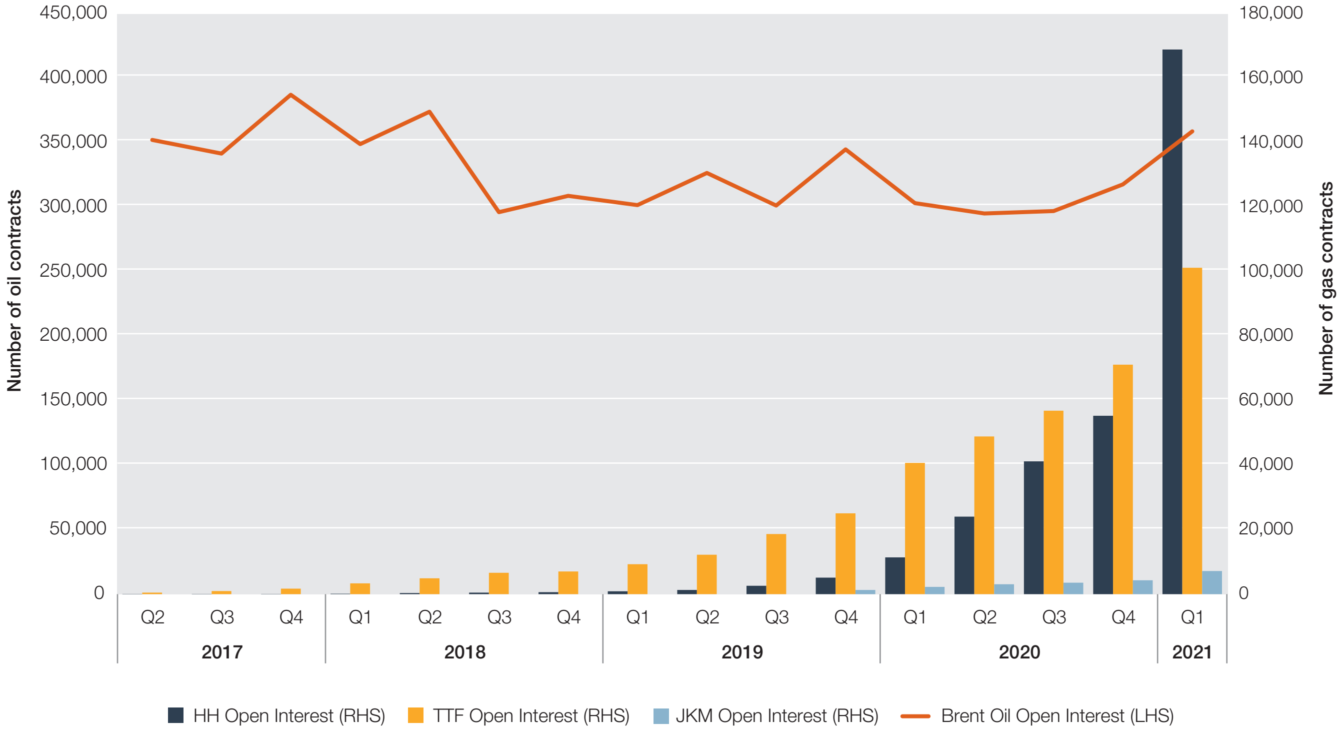
In Australia and overseas, gas contract prices have been linked to oil, and internationally, LNG trade prices have increasingly been linked to spot market benchmarks.[27] Oil markets are well established and are typically the most widely traded commodity markets with oil price benchmarks based on large trade volumes. Gas spot markets are relatively less mature with much lower volumes of trade. Figure 2.19 shows the Brent Crude May 2021 futures contract

26 The ACCC has discussed the usage of JKM in domestic pricing and domestic gas supply contracts in a number of its reports.

27 ACCC, Gas inquiry interim report, January 2021, p. 108.

trades over 3 times greater than the most traded gas contract (Figure 2.19). Liquidity can also vary widely across gas spot markets, with the more mature European and North American markets reporting higher liquidity compared to relatively less established Asian markets. Figure 2.19 depicts the liquidity across spot markets using futures contracts linked to various spot price benchmarks, showing the open interest of futures contracts expiring in May 2021. The most widely traded gas contract is related to the Henry Hub (HH) North American Benchmark; followed by the Transfer Title Facility (TTF) European benchmark, lastly the Japanese/Korea Marker (JKM) benchmark trades in volumes that are less than 1% of the trade volume of other North American and European benchmarks.[28]

Figure 2.19 Natural gas and LNG futures contract liquidity



Source: Bloomberg and ACCC.

Notes: HH = Henry Hub; TTF = Transfer title facility; JKM = Japan Korea Marker.
Figure compares number of contracts open for futures contracts expiring in May 2021. Each Henry Hub and JKM futures contract is for a quantity of 10,000 MMBtu (10.1 TJ). A monthly TTF contract is for a quantity of 1MW times the number of hours and days in the respective month (2.7 TJ for a 31 day month). Crude Oil futures are traded in lots of 1,000 barrels (6.1 TJ).
The quarterly average open interest in JKM futures is calculated from the ACCC JKM open interest data publish as part of its LNG netback price series.

This may, in part, reflect differences in the size of these markets. Additionally, Figure 2.20 below shows the size of the underlying physical trade recorded in each market over 2020. Generally, high trade volumes are considered a sign of a well-functioning market where prices reflect a wide range of buyers' and sellers' expectations.

28 For JKM contracts, similar to other gas or oil futures contracts, trades in the contract increase in the period closer to the contract close out, starting around 2 years before.

Figure 2.20 Physical gas trade liquidity across markets[29]

Source: Henry Hub volumes – IEA data and statistics[30], Title Transfer Facility volumes – Gasunie 2020 Report[31], Surveyable Asian spot LNG trades – Argus Media, Australian east coast spot market trade – AER analysis using DWGM, STTM and GSH data.

Note: The value of the LNG spot trade is calculated from the number of LNG cargoes that can be surveyed by a price reporting agency. The number of surveyable cargoes was estimated to have been 522 unique cargoes in 2020. The total number of LNG cargoes including those for the details of the sales are withheld from the market surveillance is larger.

Aside from differences in the relative liquidity underlying each benchmark, comparisons between benchmarks should also consider differences in methods of estimation and the form of physical markets being measured. The following outlines differences in the physical markets being estimated by each pricing benchmark.

Japanese Korea price marker (JKM) – Japan, China, South Korea, Taiwan

Figure 2.6 above highlights most east coast LNG exports are sold into export destinations used in this price marker, with China reflecting the majority of exports.

- Measures spot market prices for LNG cargoes delivered to Japan, Korea, China and Taiwan.
- Survey-based price informed by voluntary information reporting by LNG traders.[32]
- Measuring spot cargoes, no formal trading hub, platform or exchange.
- Includes transnational costs to ship LNG via large freight ships.
- Reflects a portion of LNG transactions, which can be lumpy and influenced by few participants.
- Reports the price of a cargo delivered to the customer, quoted by financial instruments, referenced to LNG trades.
- Limited number of daily trades, price assessment incorporates a degree of judgement, which may vary from the true market clearing price to some extent.[33]

Transfer Title Facility (TTF) – Netherlands

- Measures market prices for large quantities of natural gas flowing across European hubs in Netherlands, France, Germany, Austria, Czech Republic, Belgium and Luxembourg through interconnected pipelines.
- Reflects gas imported via vast European pipeline network and LNG import.
- Transparent price from formal reporting framework based on virtual trading platform that records change in ownership of gas.[34]
- Reported pricing, quoted by financial instruments, referenced in LNG trades.

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29 JKM, TTF and Henry Hub have specific characteristics that impact on the level of trade – the JKM is restricted to assessments of spot LNG cargoes sold into Japan, Korea, China and Taiwan whereas Henry Hub and TTF incorporate pipeline gas trades in the USA and Canada (Henry Hub) and in Europe extending to large Russian pipeline gas supplies (TTF). Furthermore Henry Hub and TTF are used in contracts for difference where gas at a different location is priced at a differential to the TTF and Henry Hub location.

30 International Energy Agency, Gas Market report Q1 2021 charts, accessed 30 April 2021.

31 Gasunie, 2020 Annual report, March 2021.

32 Two methods of collecting LNG transaction include a daily survey and market on close process recording bids and offers through an electronic platform. The market on close process was introduced in 2018 and typically does not reflect a large volume of total trade.

33 S&P Global Platts, JKM price assessment methodology, Accessed 30 April 2021.

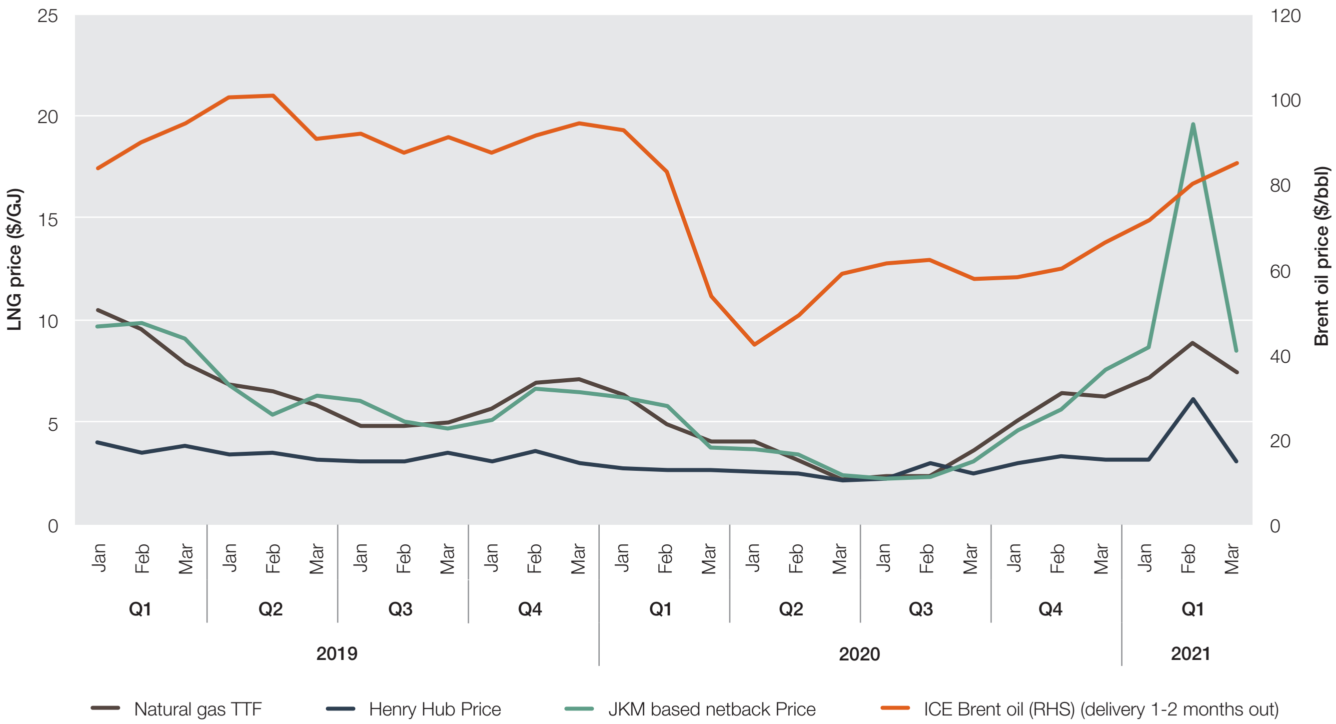
34 Title transfers of gas occur by electronic notification stating the particulars of the transfer.

- The TTF accounts for over 70% of European gas trading.[35]
- There are 144 publicly registered shippers on the TTF and additional shippers who are privately registered.[36]
- Gas trading in the Netherlands is regulated by the Netherlands Authority for Consumers and Markets, which is the equivalent of the ACCC.[37]

Henry hub – Louisiana

- Measures gas market prices for natural gas flowing in Louisiana and around the nearby US Gulf coast large gas production facilities.
- Transparent price reporting based on formalised reporting requirements.
- Regarded as most liquid physical market consisting of 9 interstate gas pipelines and 4 intrastate pipelines.
- Reported public pricing, quoted by financial instruments, referenced in LNG trades.
- Financial instruments project forward prices 10 years ahead.
- The price of gas at the Henry Hub is most influenced by the North American market because domestic US gas demand is approximately 100 times greater than US LNG exports.[38]
- The Henry Hub may exert more influence on international prices in the future if LNG exports from the US gulf coast increase but the expected expansion of gulf coast exports has reduced more recently.[39]

Figure 2.21 International price series



Source: AER analysis using Argus Media data and Bloomberg data.

Note: The ACCC Netback price is used as a proxy for the JKM physical spot price assessment representing cargoes delivered ex-ship (des) to Asia, trading in the month before the date of delivery.

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

The Henry Hub price is the average of end of day natural gas spot prices traded on the Henry Hub – sourced from Scoville via Bloomberg.

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35 Gasunie – 2020 Annual report – 4 March 2021.

36 Gasunie, Shipper list, Accessed 30 April 2021.

37 Authority for consumers and markets, Dutch office of Energy Regulation regulatory regime, Accessed 30 April 2021.

38 Energy Information Administration, Liquefied natural gas exports, Accessed 30 April 2021.

39 Natural gas intel, No U.S LNG export FIDs predicted in 2021, Accessed 30 April 2021.

Figure 2.21 shows the movement of the various spot price benchmarks from 2019. At times each price may vary independently of other benchmarks, reflecting factors including but not limited to localised weather conditions, transportation and supply constraints. The JKM price series has varied widely over 2020–21, reflecting colder than average ambient temperatures, shipping constraints and interruptions to the availability of gas supply (Figure 2.21). These factors culminated in 2 weeks of intense bidding for LNG spot cargoes in mid-January 2021, which caused prices to reach as high as $49/GJ.[40] At this time, a few transactions between a concentrated group of traders had skewed prices upwards for January, far in excess of other benchmarks.[41] This in part reflects the logistical challenges of importing LNG through shipping to Asia at this time, as transportation costs were 4–5 times higher than usual and peaked at the same time as Asian LNG spot prices. At this time, shipping from USA to Asia was close to $10/GJ, while the cost of shipping from Australia to Asia was $2.5/GJ.

The January price spike also reflects the cost of limited immediate supply from Australia, Qatar and USA due to LNG plant outages at the time. As Figure 2.21 shows, other benchmarks were not similarly affected as the underlying markets they reflect are not as dependent on LNG imports and global shipping, and have sufficient nearby production sources that can be accessed via pipelines. During the northern winter, the Henry Hub in the USA recorded a price spike of $16/GJ brought about by freezing temperatures, high demand for gas for heating and electricity generation. Additionally, infrastructure damaged by freezing temperatures was limiting gas supply at this time.

Recent developments in Australian Industrial Energy's proposed Port Kembla LNG import terminal in NSW has raised the possibility of a physically imported gas price derived from an LNG price, which may also alter price dynamics on the east coast.

As a result, the costs of importing LNG become a relevant consideration to importing gas from across Australia or overseas. Costs of LNG import can vary widely depending on the transaction model employed and the throughput of the facility. International experience has suggested total cost of between $0.8/GJ and 1.50/GJ for LNG import is possible.[42] Conversely, other studies suggest costs could reach as high as $3/GJ.[43]

40 This period was notable for how far the JKM price deviated from the TTF, whereas outside early 2021 the JKM and TTF prices had been tracking quite closely, something which appears to be returning in Q2 2021.

41 Argus Media, LNG daily 14 January 2021, January 2021, p. 9.

42 Argus Media, PipeChina outlines tariffs for LNG terminals, October 2020, accessed 11 May 2021.

43 Department of Industry Innovation and Science, Resources and Energy Quarterly – Special Topic: Asian LNG trade and Australian LNG imports, June 2018, p. 105.

Appendix A Electricity generator outages

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q1 2021	REASON FOR OUTAGE	RETURNED TO SERVICE
Queensland		**303**		
Callide B, CS Energy	Black Coal, 2 units, 350 MW each	Unit 1: 7 days	Unplanned – technical issues	Unknown
		Unit 2: 32 days	Unplanned – 'unit trip'	26 March 2021
Callide C, Callide Power Trading	Black Coal, 2 units, 420 MW each	Unit 3: 14 days	Unplanned – technical issues	10 March 2021
Gladstone, CS Energy	Black Coal, 6 units, 280 MW each	Unit 1: 18 days	Unplanned (9 days this quarter) – unit trip during Q4 2020	10 January 2021
			Planned (9 days)	18 February 2021
		Unit 2: 15 days	Unplanned – 'tube leak'	21 March 2021
		Unit 3: 44 days	Unplanned – technical issues	Unknown
		Unit 4: 30 days	Planned	7 February 2021
		Unit 5: 23 days	Planned	24 January 2021
		Unit 6: 22 days	Planned	17 February 2021
Millmerran, InterGen	Black Coal, 2 units, 306 MW each	Unit 1: 11 days	Planned	27 March 2021
		Unit 2: 4 days	Unplanned (4 days this quarter) – technical issues during Q4 2020	5 January 2021
Stanwell, Stanwell Corporation	Black Coal, 4 units, 365 MW each	Unit 2: 81 days	Unplanned (58 days this quarter) – 'unit trip' during Q4 2020	28 February 2021
			Unplanned (23 days) – technical issues	Unknown
Tarong North, Stanwell Corporation	Black Coal, 443 MW	2 days	Planned	3 January 2021
New South Wales		**255**		
Bayswater, AGL Energy	Black Coal, 4 units, 630 MW – 655 MW	Unit 2: 27 days	Planned	Unknown
		Unit 3: 5 days	Unplanned - 'plant failure'	18 January 2021
Eraring, Origin Energy	Black Coal, 4 units, 680 MW each	Unit 1: 37 days	Planned (1 day)	2 January 2021
			Planned (36 days)	Unknown
		Unit 2: 20 days	Planned (17 days)	22 February 2021
			Unplanned (3 days) – 'wet coal'	24 March 2021
		Unit 3: 5 days	Unplanned – 'unit trip'	31 March 2021

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q1 2021	REASON FOR OUTAGE	RETURNED TO SERVICE
Liddell, AGL Energy	Black Coal, 4 units, 450 MW each	Unit 1: 5 days	Unplanned – 'plant failure'	26 January 2021
		Unit 2: 17 days	Unplanned (10 days) – 'plant failure'	16 January 2021
			Unplanned (7 days) – 'unit trip'	21 February 2021
		Unit 3: 90 days	Unplanned – 'significant transformer incident'	Unknown
		Unit 4: 29 days	Planned (9 days)	13 January 2021
			Planned (8 days)	20 February 2021
			Unplanned (3 days) – 'tube leak'	5 March 2021
			Unplanned (9 days) – 'plant failure'	30 March 2021
Mt Piper, EnergyAustralia	Black Coal, 2 units, 675 MW each	Unit 1: 7 days	Unplanned – 'tube leak'	15 January 2021
		Unit 2: 8 days	Planned	23 January 2021
Vales Point, Delta Electricity	Black Coal, 2 units, 660 MW each	Unit 5: 3 days	Unplanned – 'tube leak'	19 February 2021
		Unit 6: 2 days	Unplanned – 'unit trip'	28 February 2021
Victoria		**66**		
Loy Yang A, AGL Energy	Brown Coal, 4 units, 500 MW – 540 MW	Unit 2: 2 days	Unplanned – 'plant failure'	19 January 2021
		Unit 3: 12 days	Unplanned (12 days this quarter) – plant failure from Q4 2020	13 January 2021
		Unit 4: 12 days	Planned	28 March 2021
Yallourn, EnergyAustralia	Brown Coal, 4 units, 355 MW each	Unit 1: 7 days	Unplanned – 'plant failure'	Unknown
		Unit 2: 15 days	Unplanned (1 day this quarter) – tube leak from Q4 2020	2 January 2021
			Unplanned (4 days) – 'tube leak'	2 February 2021
			Planned (10 days)	29 March 2021
		Unit 3: 12 days	Unplanned (3 days) ' tube leak'	2 January 2021
			Unplanned (6 days) – technical issues	9 February 2021
			Unplanned (3 days) – 'tube leak'	14 March 2021
		Unit 4: 6 days	Unplanned – technical issues	21 January 2021

Appendix B Gas snapshots

Table 2.3 Market participant list

	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	●	●				
	Cooper Energy	●					
	Esso	●	●				●
	GLNG					●	
	Lochard Energy	●					
	Santos	●	●	●	●	●	●
	Senex					●	●
	Shell		●				●
	Walloons Coal Seam Gas (QGC)					●	●
	Westside Corporation					●	●
Retailer	1st Energy	●					
	Click Energy	●	●				
	Covau	●	●		●		
	CPE Mascot		●				
	Delta Electricity		●				
	Discover Energy		●	●	●		
	Dodo	●	●				
	GloBird Energy	●	●	●	●		
	Powershop	●					
	Simply Energy		●	●			
	Sumo Gas	●					
	TasGas	●					
	Tango	●					
	Weston Energy	●	●	●	●		

PARTICIPANT LIST IN EASTERN GAS MARKET

	Market participant	Victoria	Sydney	Adelaide	Brisbane	GSHs	DAA
Industrial	Adelaide Brighton Cement			● Before 2017			
	Ampol				● Before 2017		
	BlueScope	● 2021	● Before 2017		● 2018		
	Boortmalt	● 2019	● 2018	● 2018			
	Brickworks	● 2020	● 2020	● 2020	● 2020		
	Commonwealth Steel		● 2017				
	Coopers			● 2017			
	CSR Building Products	● 2018	● 2021	● 2019	● 2018		
	Incitec Pivot				● Before 2017	● Before 2017	● 2019
	Infrabuild	● Before 2017	● Before 2017	● Before 2017			
	Master Butchers			● 2020			
	Michell Wool			● 2019			
	Mobil Oil	● 2018					
	Norske Skog	● 2018 ● Exit or inactive					
	Oceania Glass	● 2020					
	O-I International	● 2018	● 2018	● 2018	● 2019		
	Orica		● 2017				
	Orora		● 2020				
	Paper Australia	● 2018	● 2020				
	Qenos	● 2017	● Before 2017			● 2017 ● Exit or inactive	● 2019
	SA water			● Before 2017			
	Tarac Technologies		● 2017	● Before 2017			● 2019
	Visy	● Before 2017	● Before 2017	● Before 2017	● Before 2017		● 2020
	Viva Energy	● 2018					
Trader	Eastern Energy Supply	● 2020	● 2020	● 2020	● 2020	● 2020	● 2020
	Macquarie Bank	● 2019	● 2019			● 2018 ● Exit or inactive	● 2019
	Petro China	● 2020	● 2020			● 2019	● 2020
	Strategic Gas Market Trading	● 2019	● 2019		● 2020	● Before 2017	● 2019
	62	39	38	24	21	17	22

● Entered before 2017 ● Entered in 2017 ● Entered in 2018 ● Entered in 2019 ● Entered in 2020 ● Entered in 2021 ● Exit or inactive

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

* Arrow also operates the Braemar 2 power station

DAY AHEAD AUCTION SNAPSHOT

	2019				2020				2021	
	MAR	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Auction to date
number of active participants	1	4	6	6	11	12	14	15	13	17*
number of facilities	4	6	6	7	7	9	8	11	12	12
auction legs won	139	665	1,276	815	1,175	1,272	1,712	1,696	1,664	10,414
capacity won, TJ	2,513	6,577	14,891	6,563	10,482	7,976	13,709	10,782	9,901	83,392
maximum auction price, $/GJ	0.10	0.70	1.05	0.30	0.30	1.26	1.49	0.93	1.40	1.49
% won at $0/GJ	82%	88%	71%	87%	82%	78%	69%	89%	86%	80%
% won at ≥$0.10/GJ	0.4%	8%	20%	5%	4%	14%	23%	5%	6%	12%

GAS SUPPLY HUBS SNAPSHOT	2014	2015	2016	2017	2018	2019	2020	2021 YTD
number of trades	481	875	798	1,638	1,919	3,635	2,655	456
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%*	21.1 *40% : 53%*	4.6 *50% : 46%*
trade value, $million	5	24	57	89	148	219	98	29
volume weighted average price, $/GJ	2.01	3.66	7.20	7.68	9.02	7.98	4.68	6.3
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 *15:15*	16 *11:16*
% traded through exchange (sum bought divided by regional demand)	N/A	N/A	N/A	4.3%	6.1%	9.1%	7.1%	5.0%