Wholesale Markets Quarterly

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Summary

This report highlights wholesale electricity and gas market outcomes for Q4 2021.

Electricity markets

Volume weighted average (VWA) annual prices in the NEM in 2021 ranged from $34/MWh in Tasmania to $96/MWh in Queensland. The average annual price in Queensland in 2021 was over double the level of 2020 and was the second highest average annual price in Queensland on record. Year on year average wholesale prices also rose in NSW and South Australia, but fell in Victoria and Tasmania.

Quarterly price outcomes displayed similar overall trends. The average Q4 2021 prices in Queensland of $111/MWh were the highest Q4 prices in record. These Queensland prices were almost double the levels of Q4 prices of any other region.

There were 17 half hours of prices over $5,000/MWh in Queensland for the year. All of these high half hourly prices came after the Callide C power station incident on 25 May 2021. While thermal generator outages were a key driver of the high prices, other factors contributed, including periods of high demand and network constraints which limited the ability to import electricity from NSW.

Market outcomes also highlighted the ongoing transition from a market dominated by large coal-fired generators to one that incorporates an increasing volume of dispersed renewable generators and where rooftop solar is playing a more significant role.

Minimum daily demands in Victoria and South Australia fell below previous record levels in December, reflecting mild temperatures and the impact of rooftop solar output (which offsets the demand that must be met by grid supplied electricity). Across the NEM, rooftop solar output was 24% higher in 2021 than 2020. On 14 December 2021, generation from rooftop solar reached 10 GW across the NEM, a level of generation which is just below the record maximum demand ever recorded in Queensland.

As rooftop solar generation continues to break records in every region, demand for energy from the grid continues to decline. NEM output fell for the fifth year in a row in 2021, with average annual generation dropping by 200 MW in 2021 compared to 2020, falling to its lowest levels since Tasmania joined the market in 2005.

While total output fell, average renewable generation reached a record 5,430 MW in 2021 – 25% of total output. This was driven by increased wind and solar installations, and good rainfall. Reduced demand, fuel costs, and increased competition from renewable generation, significantly impacted black coal and gas-fired generation with both falling to record low annual levels.

Some participants are changing their offer behaviour. Black goal generators are changing offers to avoid low prices in the middle of the day when demand is low and solar output is high. Following the shift to five minute settlement we have also observed less rebidding of capacity from high to low prices following a price spike by participants seeking to share in a high average 30 minute price.

Frequency control ancillary services (FCAS) were at an all-time high of $438 million in 2021, with high local FCAS costs in Queensland in Q2 to Q4 2021 being a significant driver. Queensland FCAS costs are the subject of our focus.

Gas markets

East coast spot market prices increased over 2021 with average prices ranging between $8.24/GJ and $10.64/GJ, an increase of 81% from 2020 average prices which ranged between $4.83/GJ and $5.70/GJ. Average annual prices in Queensland locations at Brisbane and Wallumbilla exceeded previous annual records set in 2018, with the Wallumbilla price of $10.64/GJ over $1.50/GJ higher than the previous record.

International gas prices were significantly higher and diverged from east coast prices over 2021, with the Asian spot LNG netback price at Wallumbilla averaging $16.56/GJ for the year. The contrast in prices was most prominent over this most recent quarter, with Asian netback prices increasing to average around $32.35/GJ, whereas as east coast prices declined slightly from the previous quarter to around $10/GJ. Our focus story highlights a decline in correlation between international spot prices and east coast spot prices for 2021 compared to previous years.

Strong international demand saw record LNG exports from Gladstone in 2021, with exports exceeding the previous year's record by about 5%. Production increased in Queensland to match export levels, increasing again in Q4 2021. However, exports were also facilitated by use of the northern storage facilities, where levels dropped over the quarter, and by strong flows of gas from the south to the north including flows facilitated by the day ahead auction of pipeline capacity.

Southern markets over the quarter were delinked from northern gas supply, with gas not flowing south through the QSN Link from Queensland. However, the southern and northern markets did continue to interact. Victorian gas flowing north contributed to southern demand being met intermittently by southern storage. As a result, Iona storage levels ended the year lower than any previous year since reporting of data began in 2017.

Future reports will monitor international conditions as well as storage levels as we approach higher demand over the east coast in winter when there is potential for international pricing to bear more strongly on east coast spot gas prices.

Electricity markets at a glance

Q4 2021

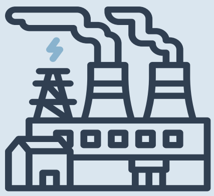
30-minute prices

Queensland's average 2021 and Q4 prices more than doubled compared to 2020.

Demand

Victoria and SA hit record low demand multiple times in Q4 2021 due to mild weather and record rooftop solar.

Generation



Low demand led to lowest annual and quarterly generation since Tasmania joined the NEM in 2005.

Interconnectors

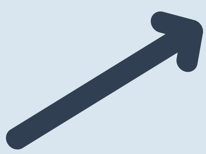
Planned outages led to high energy and FCAS prices in Queensland.

FCAS

50 Hz

Record annual total FCAS costs in 2021 largely driven by record Q4 Queensland costs of $89 million.

Outlook



Price expectations for 2022 increased in all regions, especially Queensland and NSW.

Gas markets at a glance
Q4 2021

Spot prices

Annual prices increase by 80% in 2021. Domestic Q4 prices $10.5/GJ lower than Asian netback prices $32/GJ.

Spot Trade Downstream

Record trade of 66.6PJ in 2021, while Q4 spot trade declines from Q3.

Gas storage

Storage continues to decline and provide critical market supply.

International markets

Unprecedented LNG prices in Q4, record LNG exports from QLD in 2021.

Gas production and flows

Gas production reaches record levels in 2021 but declines in Q4.

Day Ahead Auction

Auction usage changed to support south and north flows across Q4.

About this report

This report describes wholesale electricity and gas market outcomes in Q4 2021.

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

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

We also have obligations to report quarterly on outcomes in the frequency control ancillary services (FCAS) markets and report on prices over $5,000/MW in ancillary services markets. We fulfil both of these obligations in this report.

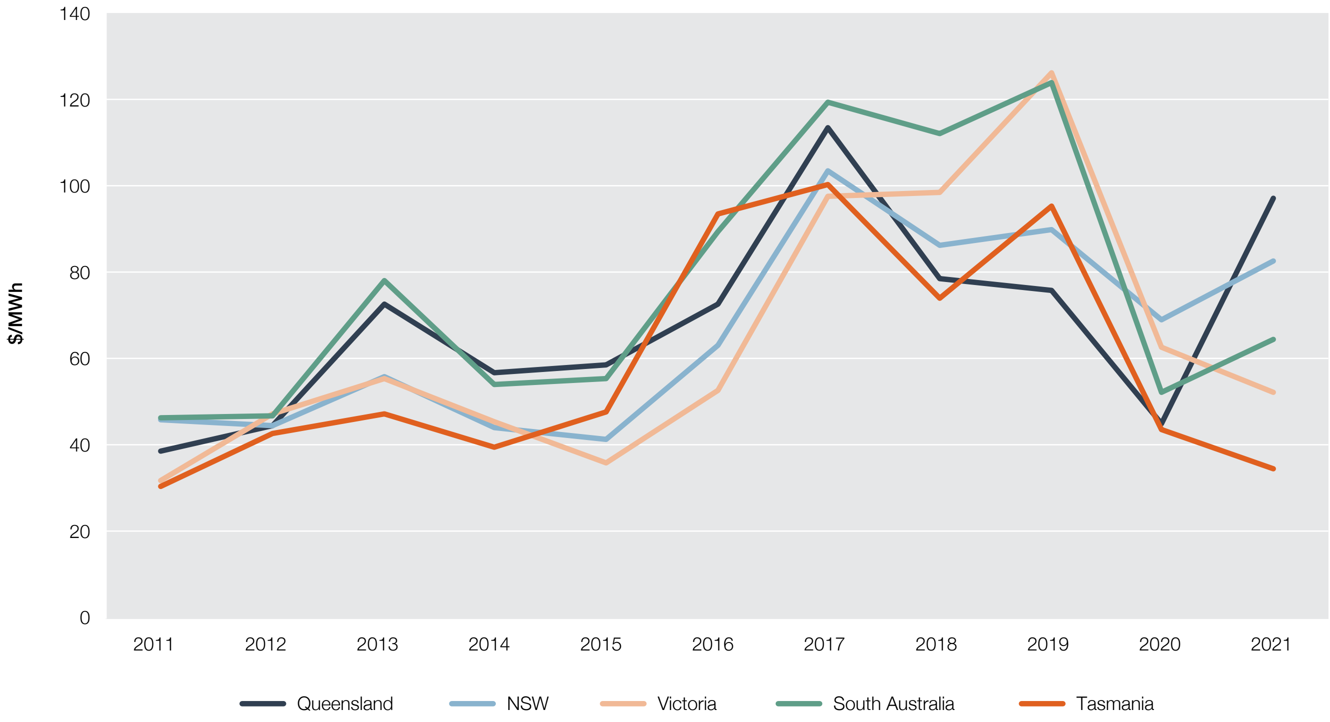
1. Electricity

1.1 Wholesale prices diverge between the regions

In 2021, annual volume weighted average (VWA) prices increased from 2020 levels in Queensland, NSW and South Australia, while average prices in Victoria and Tasmania fell compared to 2020 (Figure 1.1). Prices ranged from $34/MWh in Tasmania to $96/MWh in Queensland.

Queensland was the most expensive region on average for 2021 and recorded its second highest average price, behind the record set in 2017. Queensland was the highest priced region for 3 of the 4 quarters for 2021, largely due to the ongoing network upgrades and significant generator outages that occurred during the year.

Figure 1.1 Average annual prices (VWA)

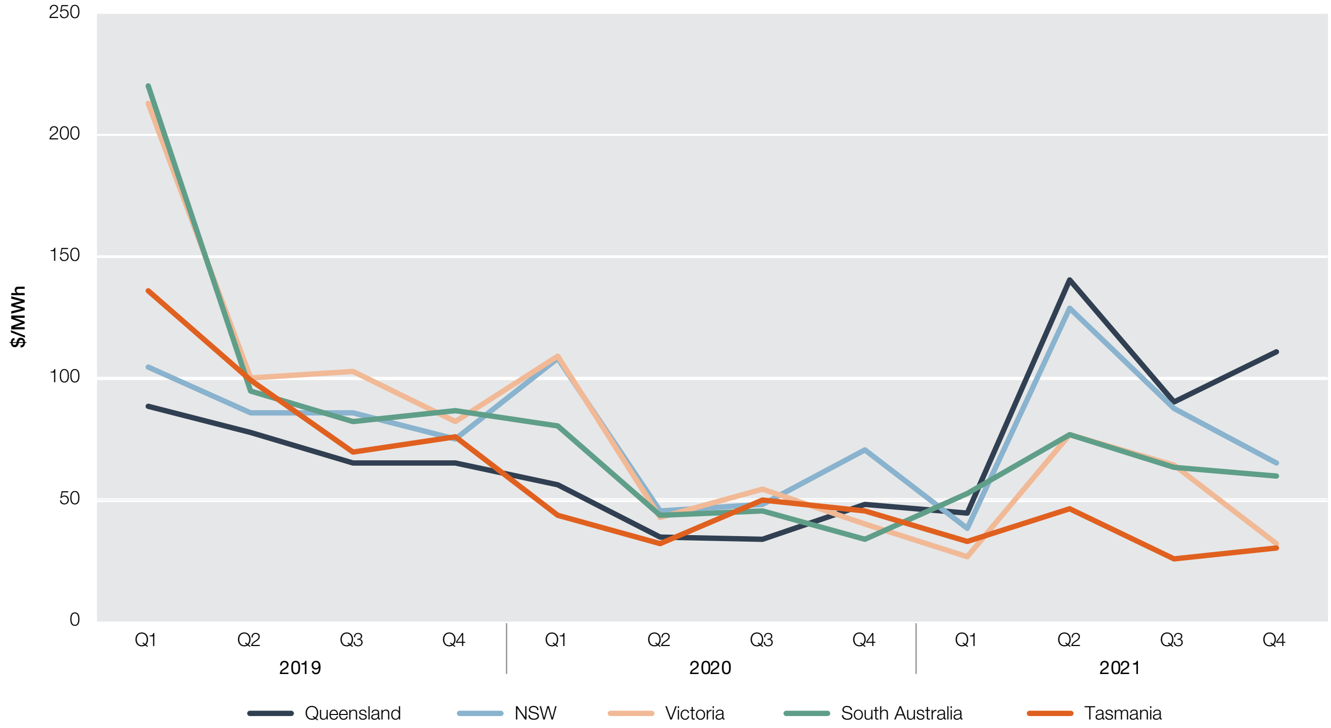


Source: AER analysis using NEM data.

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.

Quarterly prices rose in Queensland and South Australia compared to Q4 2020 and fell in Tasmania, Victoria and NSW (Figure 1.2). Prices ranged from $30/MWh in Tasmania to $111/MWh in Queensland. Queensland's price was a Q4 record for the region at $111/MWh, up 130% from the same time last year.

Figure 1.2 Average quarterly 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.

High priced events contributed to the increased quarterly prices in Queensland and South Australia. There were 7 30-minute prices above $5,000/MWh in Queensland and 4 in South Australia during the quarter.

The reasons for these high priced events in Queensland included:

- limited access to low priced capacity due to generator outages and reduced generator availability
- rebidding of capacity from low to high prices
- interaction with FCAS markets, with FCAS prices high at the time of the high price event
- high demand
- reduced imports due to network constraints.

The reasons for high priced events in South Australia included:

- high demand
- low wind generation (or a sudden unforecast drop in wind generation)
- rebidding capacity from low to high prices
- reduced imports.

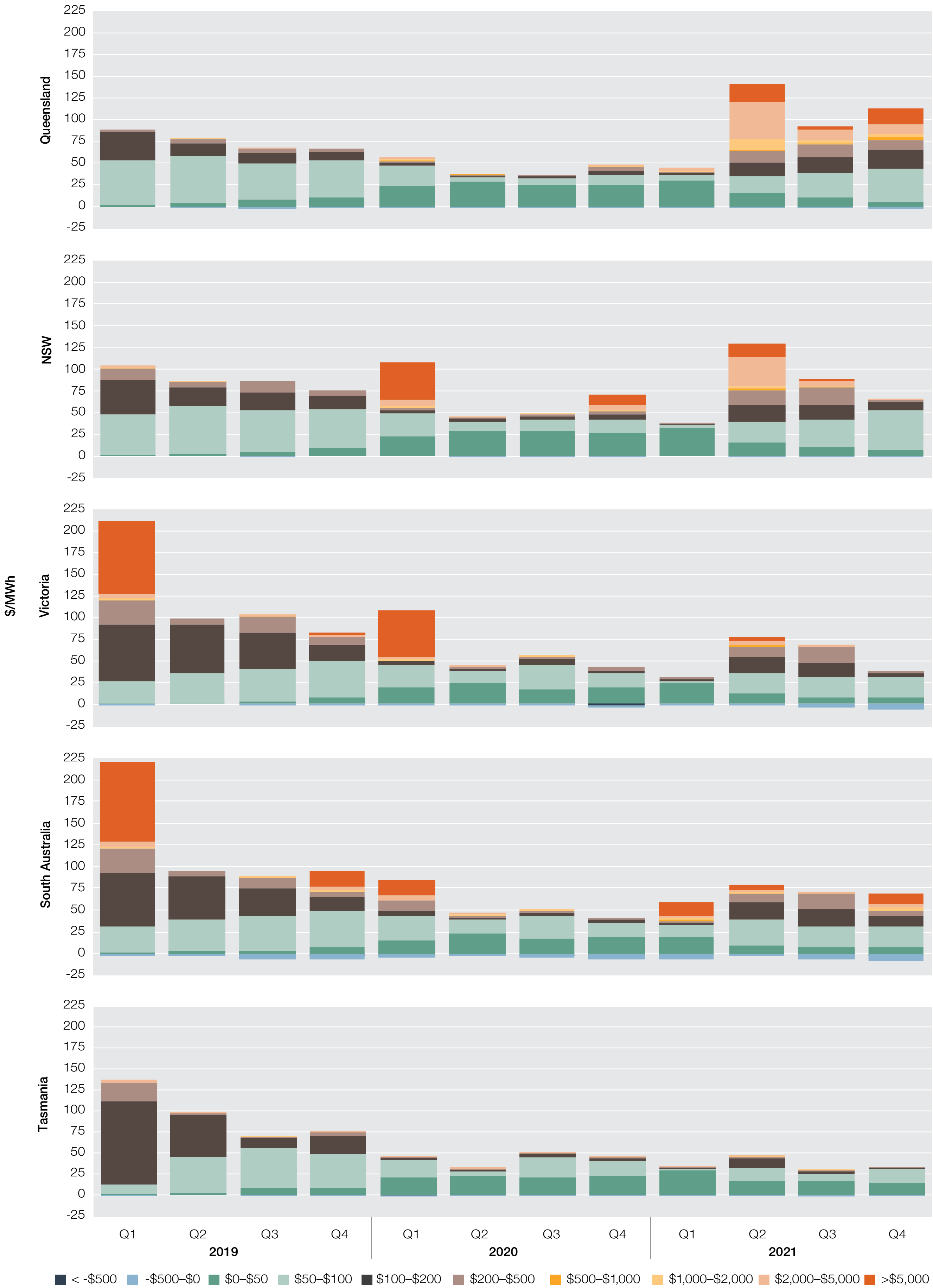
We publish detailed analysis of these events on our website.

The high quarterly prices in Queensland in Q2, Q3 and Q4 led to that region experiencing the highest 2021 annual price across the NEM. Prices above $5,000/MWh contributed $19 to the average price of $111/MWh in Queensland and $12 to the $60/MWh average price in South Australia (Figure 1.3).

Prices between $0/MWh and $50/MWh continued to make a smaller contribution to the average price in Queensland, and instead prices were set above $50/MWh for most of the quarter. High Queensland prices often occurred during the evening peak. The average price for the 6.30 pm and 7 pm 30-minute intervals was over $300/MWh for the quarter, while the average 5-minute price for the 6.40 pm dispatch interval was $800/MWh.

We explore the drivers behind the high Queensland prices this quarter, such as network upgrades (section 1.7), generator outages (section 1.4) and fuel costs and supply issues (section 1.6), later in the report.

Figure 1.3 Contribution of different price bands to average quarterly prices



Source: AER analysis using NEM data.

Are negative prices affecting average prices?

We had a close-to-record number of negative 5 minute prices this quarter, just 628 fewer across the NEM than the record set in Q3 2021 of 20,909 intervals (Figure 1.4).

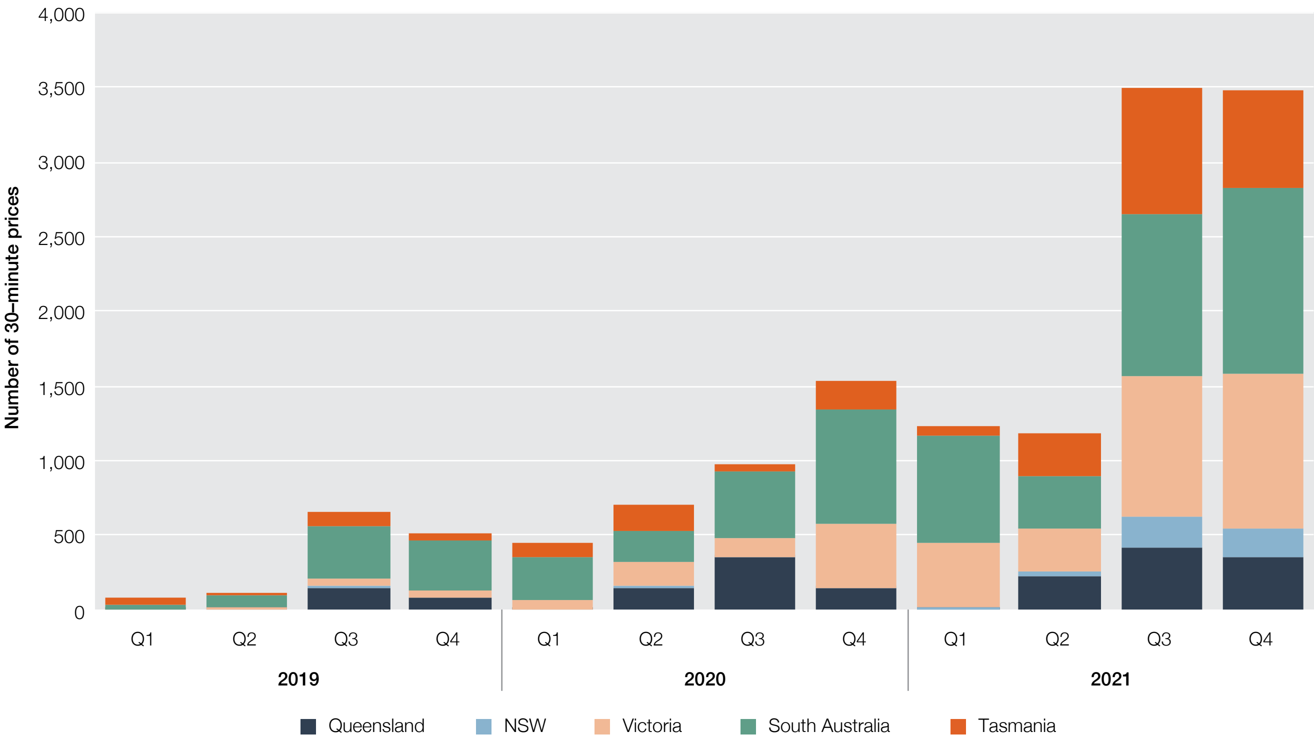
South Australia and Victoria each had a record number of negative priced intervals in Q4 2021, with 7,123 and 5,873 negative prices respectively (27% and 22% of all 5-minute prices during the quarter). Coincidentally, these regions each recorded record minimum demand this quarter (section 1.3).

However, although there were a large number of negative priced intervals, most of these were closer to $0/MWh rather than the floor of -$1,000/MWh. The average negative price this quarter ranged from -$12/MWh in Tasmania to -$60/MWh in Queensland. These prices often occurred during the day when demand was low, so the impact to VWA pricing was reduced. In contrast, average negative prices in Q1 2021 ranged from -$14/MWh in NSW to -$220/MWh in Queensland.

Since then, the semi-scheduled generator dispatch obligations rule change was introduced. The rule change was introduced to prevent semi-scheduled generators from rapidly removing their generation (without a dispatch target) during times of negative prices. The sudden loss of generation was leading to system security concerns. Now with the new rules in place, a participant must wait for a target from AEMO before they can change their output, meaning they could be exposed to 1 or 2 negative dispatch prices before they can adjust their output. Following the rule change, our expectation was semi-scheduled generation would adjust their offers to limit their exposure to low negative prices rather than withdrawing their generation.[1]

Renewable generation offered capacity closer to the negative value of Renewable Energy Certificates (RECs) than they did previously. Renewable generation receives the price of a REC for every megawatt hour they generate. This means they can still generate at a negative price, close to the value of a REC, without making a loss.[2]

Figure 1.4 Quarterly count of negative prices



Source: AER analysis using NEM data.

Note: 30-minute prices calculated to allow comparison to pre-5 minute settlement.

1 https://www.aemc.gov.au/rule-changes/semi-scheduled-generator-dispatch-obligations.

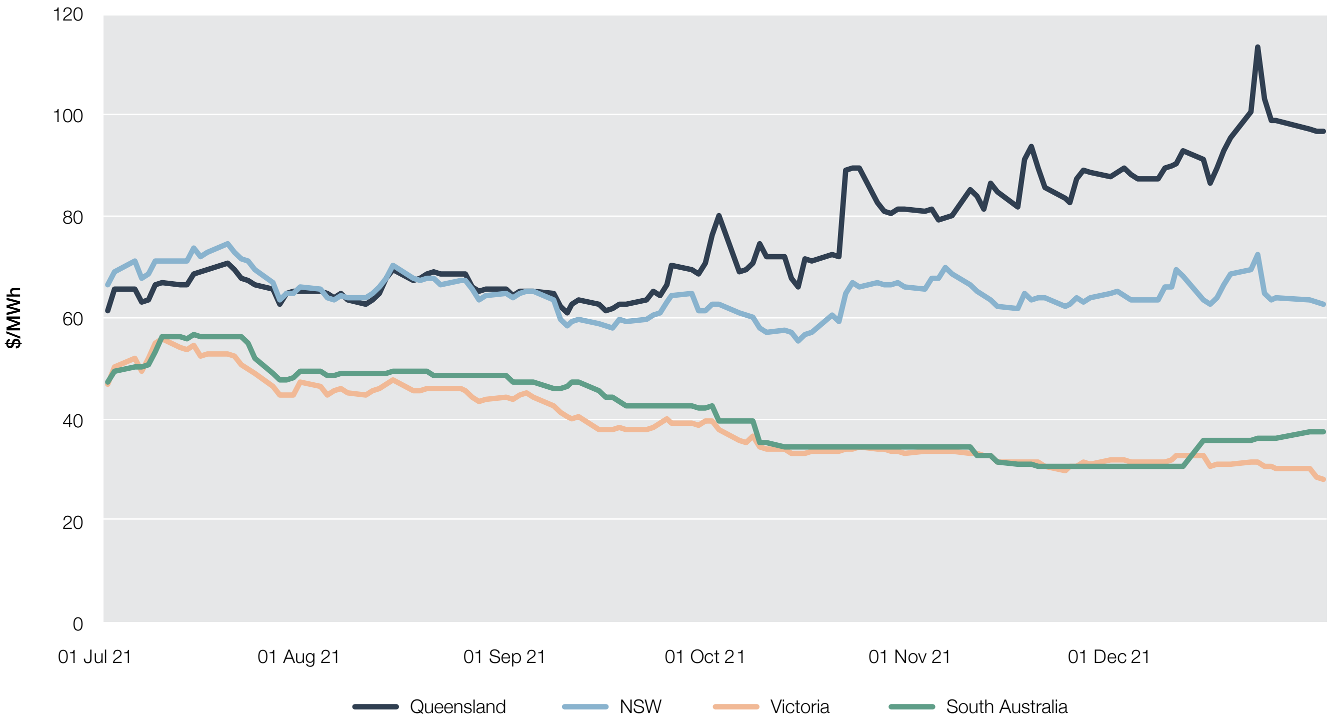
2 Renewable energy certificates (cleanenergyregulator.gov.au).

1.2 Contract prices high in Queensland relative to other regions

Queensland experienced the highest contract prices during Q4 2021 as price outcomes were higher than anticipated. Queensland base future prices increased from $76/MWh at the start of the quarter, to a final price of $97/MWh, an increase of 27% (Figure 1.5). This is the highest final Q4 price ever recorded in Queensland, replacing the previous record of $82/MWh set in 2018.

In contrast, base future prices fell in Victoria and South Australia during the quarter. Final prices in these regions were less than half that of the Queensland price, at $28/MWh and $38/MWh respectively.

Figure 1.5 Base future prices, Q4 2021

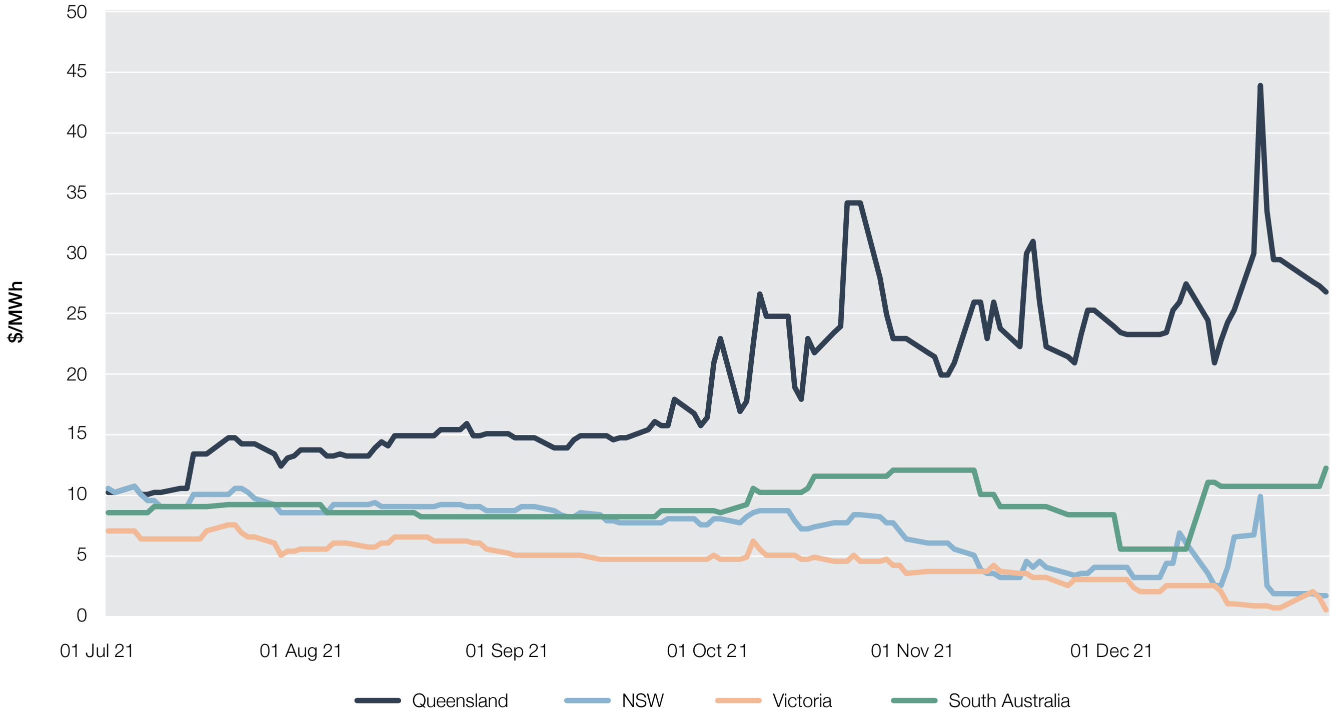


Source: AER analysis using ASX Energy data.

Note: Daily settled price for Q4 2021 quarterly base futures.

Cap contract prices also increased in Queensland, from an initial price of $23/MWh to a final cap price of $26/MWh (Figure 1.6). The high final cap price was driven by a large number of 5-minute prices that exceeded $10,000/MWh. The 5-minute price exceeded $10,000/MWh on 48 occasions this quarter on 15 separate days. The final cap price of $27/MWh was the second highest Q4 cap price ever recorded in Queensland, less than $1/MWh shy of the record set in 2014.

Figure 1.6 Cap prices, Q4 2021



Source: AER analysis using ASX Energy data.

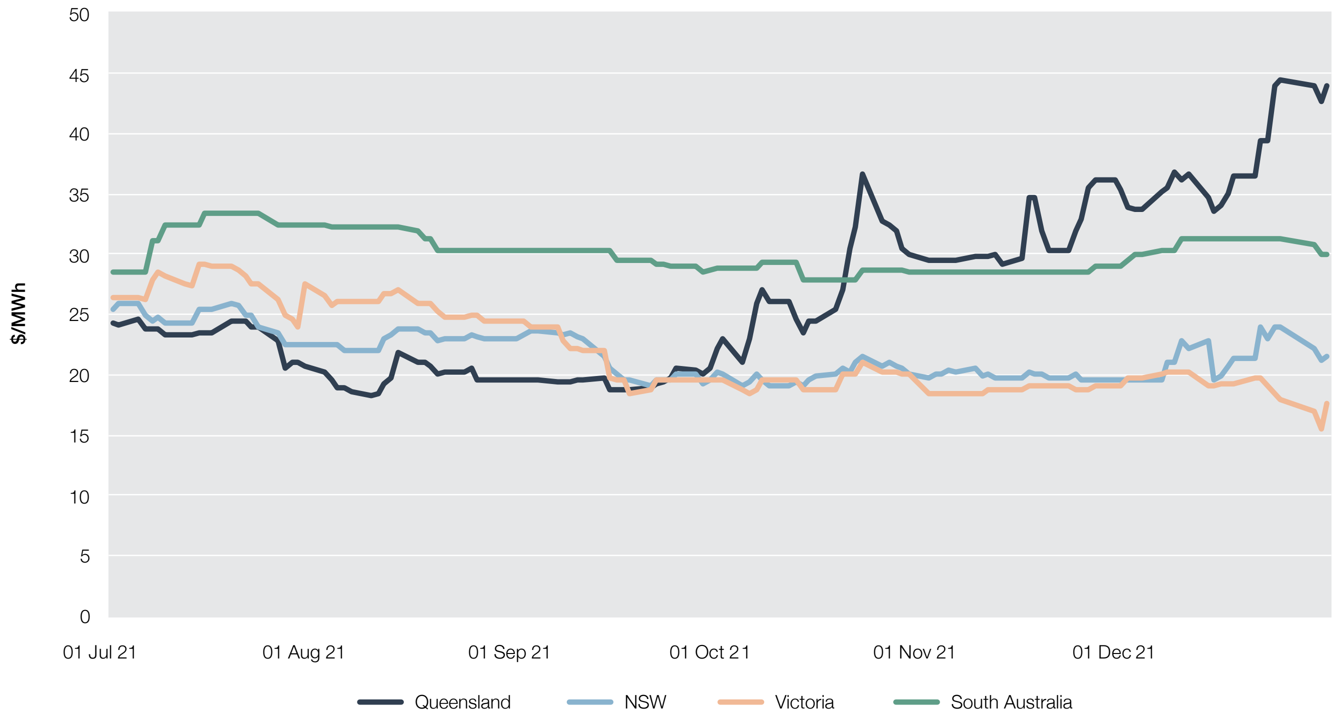
Note: Daily settled price for Q4 2021 quarterly caps.

Future price expectations

Forward base future price expectations for Q1 2022 have increased significantly in Queensland, up from $78/MWh at the start of the quarter to $132/MWh by the end of December, an increase of 70%. Queensland base future prices for this summer are now $40/MWh to $75/MWh higher than the other regions. The elevated contract prices are being driven by high underlying energy prices due to the ongoing transmission constraints relating to the QNI upgrade, combined with high coal prices and generator outages.

Like base futures, cap future prices are highest in Queensland for Q1 2022 (Figure 1.7). By the end of December cap prices for Q1 2022 in Queensland had jumped to $44/MWh, doubling over the past 3 months. The risk of high prices this summer is present in all regions, with cap prices in the other regions ranging from $18/MWh in Victoria to $30/MWh in South Australia.

Figure 1.7 Forward cap futures at 31 December 2021

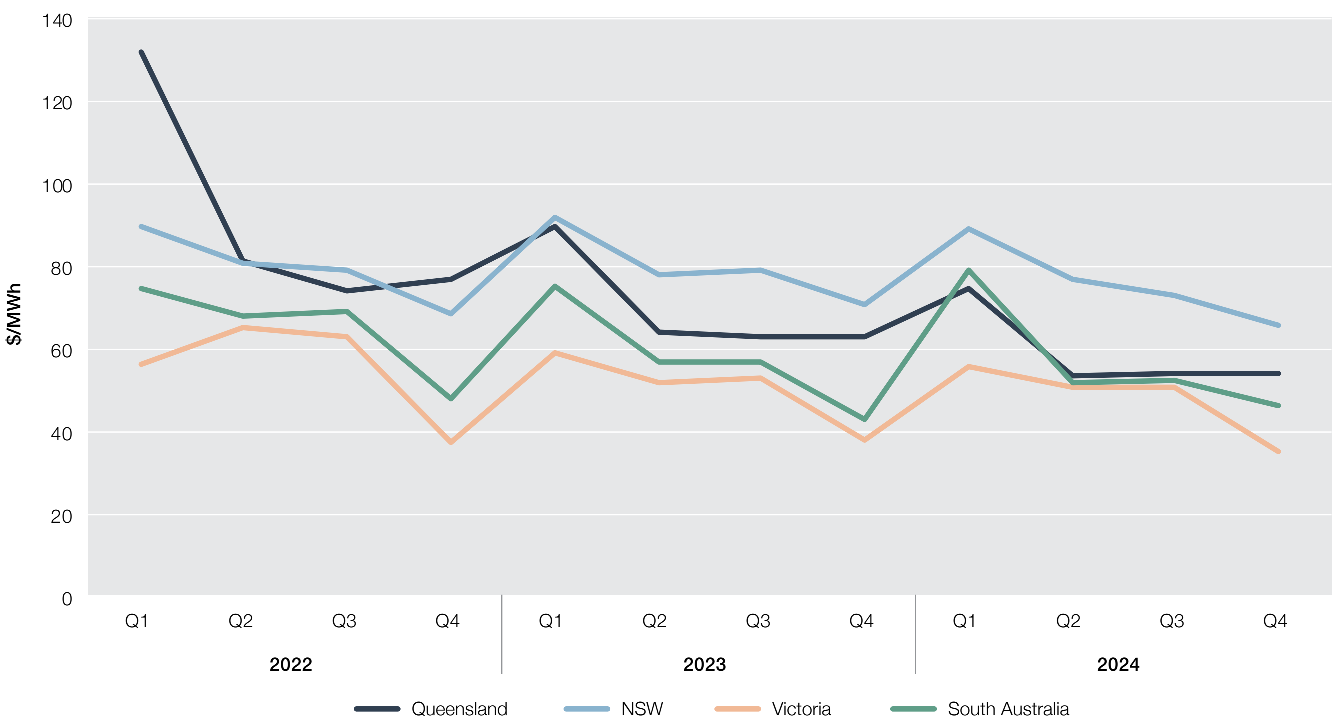


Source: AER analysis using ASX Energy data.

Note: Daily settle price for Q1 2022 cap contracts on 31 December 2021.

Looking further ahead, base futures indicate the market expects Queensland to be the highest priced region in 2022 but NSW prices are higher from 2023 onwards (Figure 1.8). Victoria is currently expected to remain the lowest priced region until at least 2024.

Figure 1.8 Forward base future prices at 31 December 2021



Source: AER analysis using ASX Energy data.

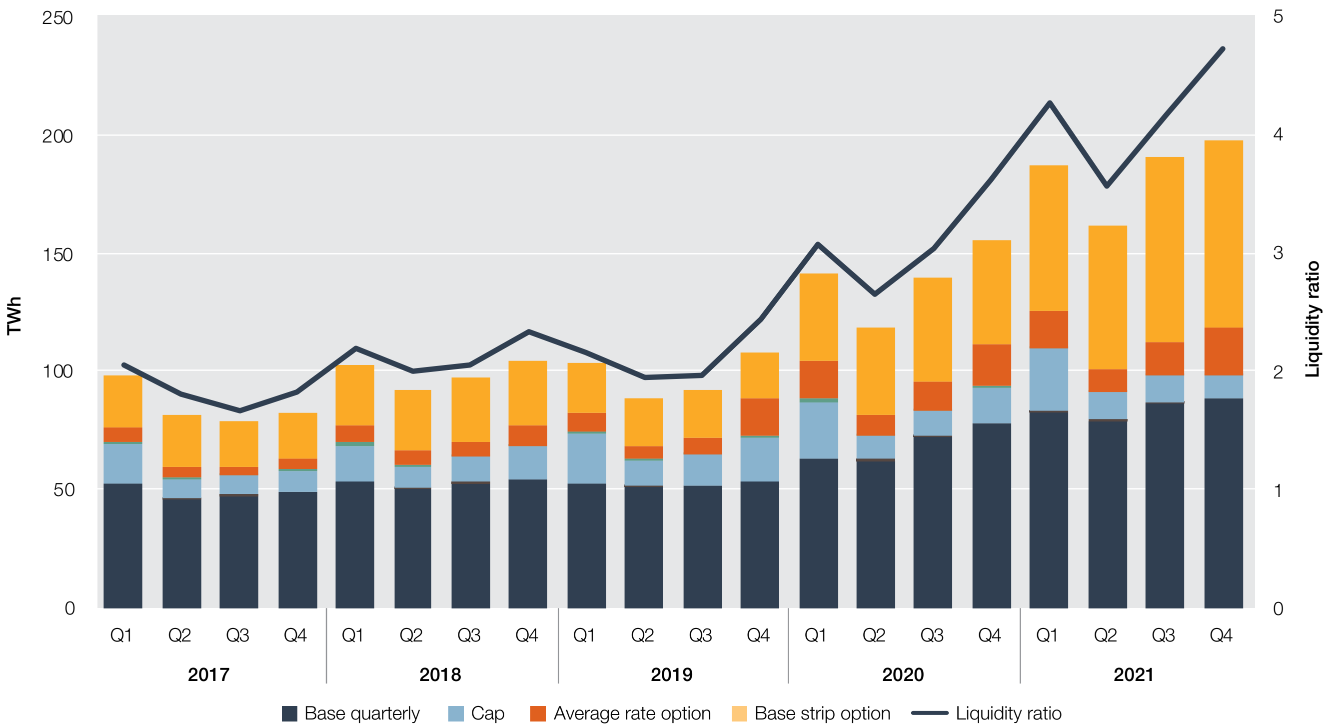
Note: Daily settled price for Q1 2022 base contracts on 31 December 2021.

Liquidity continues to improve

In the past 2 years, the volume of electricity derivatives traded on the ASX has steadily increased (Figure 1.9). In Q4 2021, exchange trading of futures and options hit record volumes. This is being driven by increased trading of base future and options (both base quarterly and calendar year base strip options).

The liquidity ratio in Q4 2021 was 4.7, the highest liquidity ratio recorded in any quarter. The liquidity ratio compares the total exchange traded volumes to the native demand across the mainland regions. For every 1 MW of native demand in Q4 2021, almost 5 MW of contracts were traded. Liquidity is strongest in Victoria, with a liquidity ratio of 7.8 in Q4 2021. Victoria had the largest volume of contracts traded despite having the only the third highest demand. South Australia continues to lack liquidity, recording a liquidity ratio of 0.7 this quarter.

Figure 1.9 Traded volumes and liquidity ratio



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

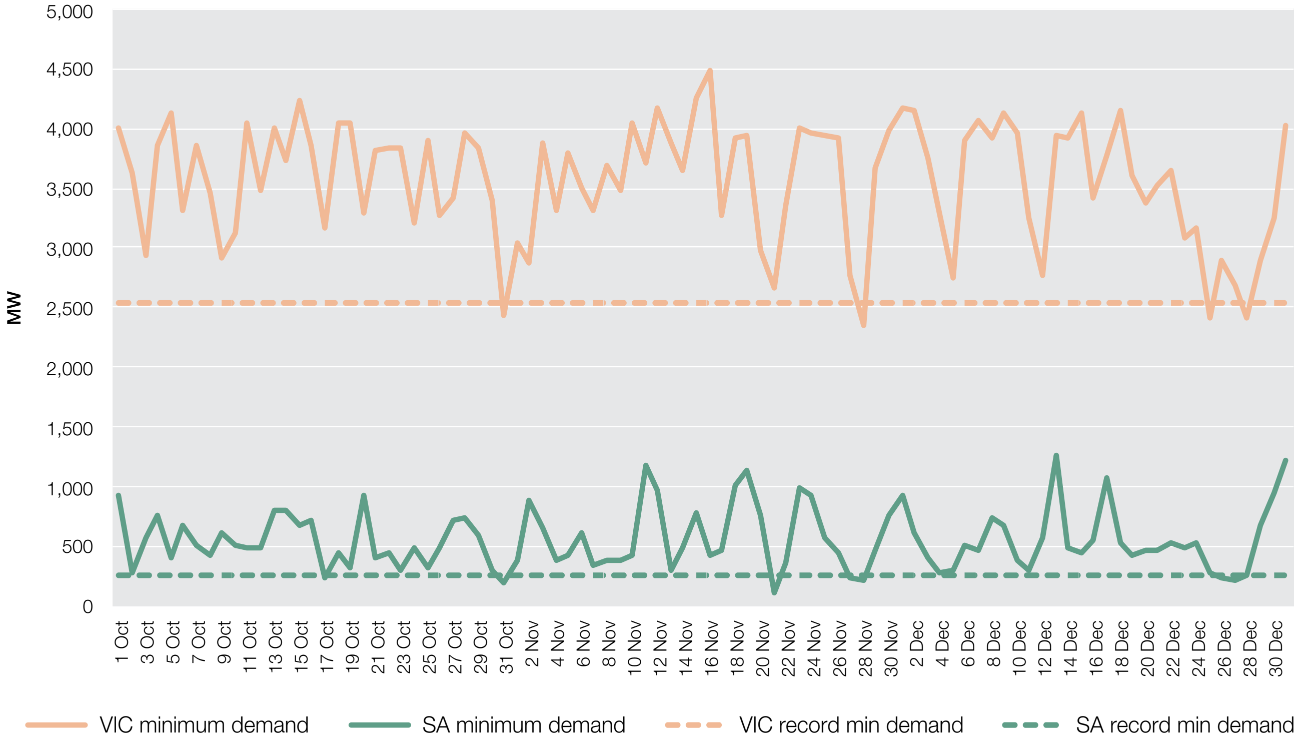
Note: Volumes of ASX trades that occurred for each quarter since 2017. Liquidity ratio uses total traded volumes and the total native demand in each region (excluding Tasmania where there are no ASX traded contracts).[3]

1.3 Demand generally down across the NEM

Demand was down in all regions except for Queensland, compared to last year. Q4 normally experiences high summer temperatures driving high demand, especially late in the quarter. However, in December both Victoria and South Australia's minimum daily demands fell below previous record levels (Figure 1.10). In South Australia daily minimum demand fell below the previous record on 8 occasions throughout the quarter, all of these occurring between noon and 1.30 pm. This reflects the impact that mild temperatures and rooftop solar output has on demand as it offsets the demand that must be met by grid supplied electricity.

3 https://www.asx.com.au/documents/products/ASX_AustralianElectricityFuturesandOptions_ContractSpecifications_July2015.pdf

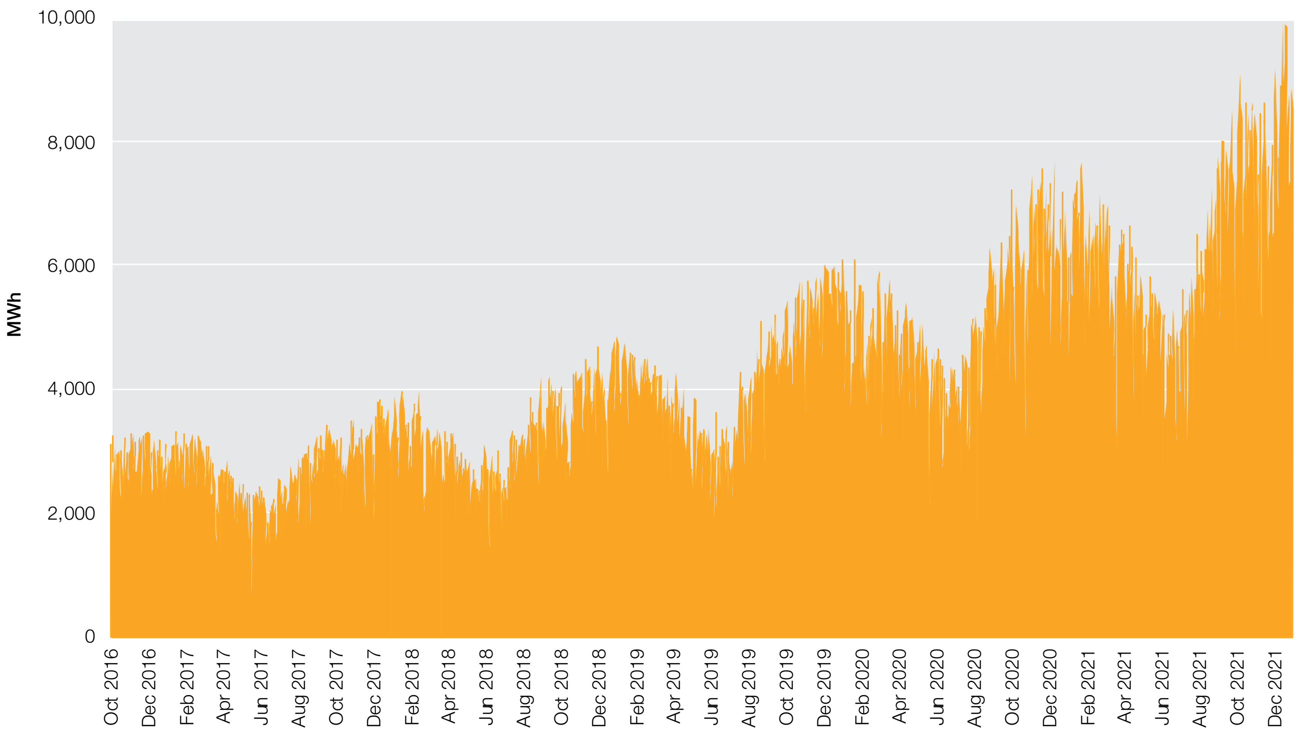
Figure 1.10 Daily minimum demands in Victoria and South Australia



Source: AER analysis using NEM data.

Low demand in the middle of the day was driven by record rooftop solar output in all regions (with rooftop output across the NEM in 2021 up 24% compared to 2020).[4] To put it in perspective, on 14 December generation from rooftop solar reached 10 GW across the NEM which is just below record the maximum demand ever recorded in Queensland (Figure 1.11).

Figure 1.11 Daily maximum rooftop solar generation in the NEM



Source: AER analysis using NEM data.

4 For further analysis of demand throughout Q4 2021, see AEMO's Quarterly Energy Dynamics, https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed, p. 6.

The NEM has also experienced mild temperatures due to the La Niña weather pattern. Fewer hot days means lower demand and a reduced need for NEM generation.[5]

1.4 NEM generation falls for the fifth consecutive year

As rooftop solar generation continues to break records in every region, demand for energy from the grid continues to decline. NEM output fell for the fifth year in a row in 2021, with average annual generation dropping by 200 MW in 2021 compared to 2020, falling to its lowest levels since Tasmania joined the market in 2005 (Figure 1.12).

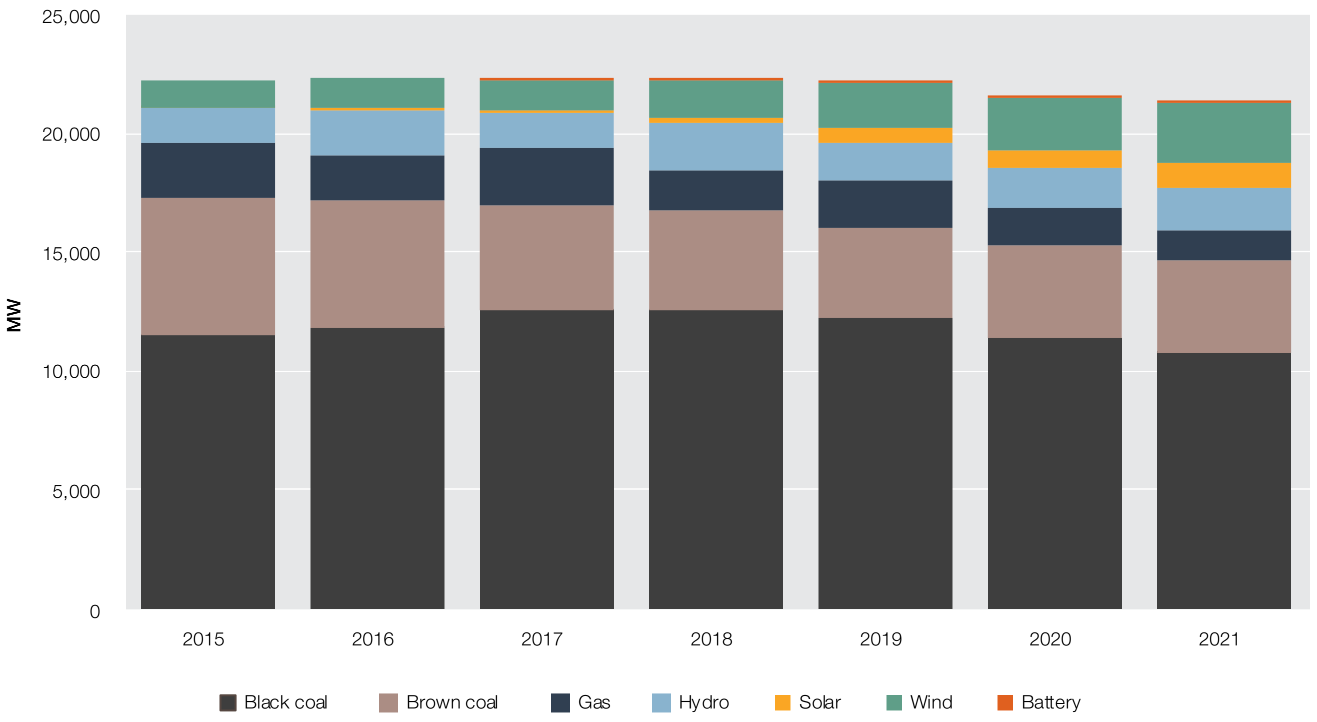
While total output fell, average renewable generation reached a record 5,430 MW in 2021. This was driven by increased wind and solar installations, and good rainfall.

Wind output increased more in 2021 than in any previous year, with average annual output increasing 380 MW, and wind farms producing twice as much energy as gas-fired generators. Average grid solar output increased by 240 MW and average hydro output increased by 170 MW.

Reduced demand, fuel costs and increased competition from renewable generation, significantly impacted black coal and gas-fired generation with both falling to record low annual levels.

Average annual black coal generation fell for the third year in a row, with average black coal output in 2021 dropping by 560 MW compared to 2020. Similarly, average annual gas-fired generation fell for the second year in a row, with average gas output in 2021 dropping by 375 MW from the previous year.

Figure 1.12 Average annual generation in the NEM



Source: AER analysis using NEM data.

While NEM generation is typically low early in a Q4, mild weather and record rooftop solar (section 1.3) led to even lower levels of quarterly output in Q4 2021. Black coal, brown coal and gas-fired generation all fell to their lowest quarterly levels since at least 2005. Together, average quarterly thermal generation in Q4 2021 fell by well over 1 GW compared to the same quarter a year earlier, with average black coal generation dropping by almost 700 MW.

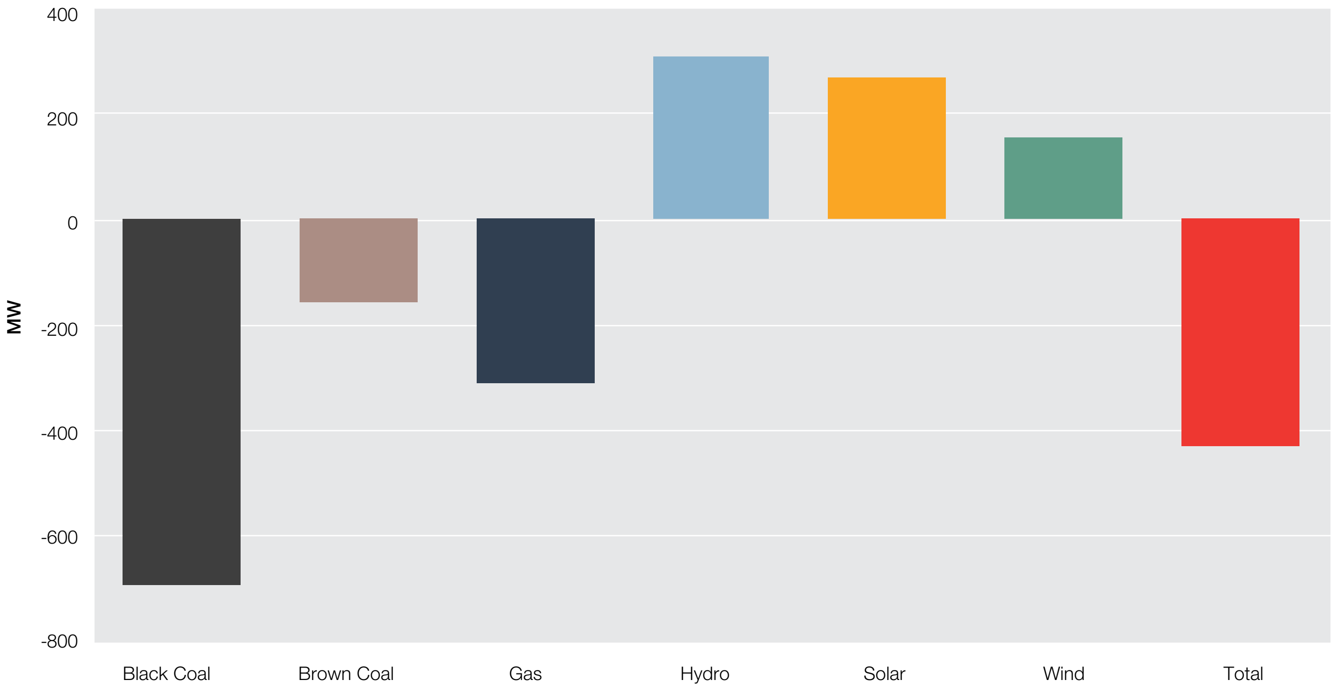
At the same time, quarterly solar generation hit record high levels and wind generation rose to its second highest quarterly level after hitting record levels in Q3 2021. Hydro generation increased 300 MW or 25% in Q4 2021 compared to Q4 2020.

5 See AEMO's Quarterly Energy Dynamics, https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed, p. 7.

Quarterly output fell most in Queensland (415 MW) due to a large fall in black coal and gas generation. The local drivers were limited exports due to QNI upgrade, outages, fuel costs and supply. South Australian output fell by 208 MW, largely due to the fall in gas-fired generation as directions to thermal generators by AEMO were reduced.[6]

The increase in solar generation was most marked in NSW, the increase in wind generation came mostly from Victoria and the increase in hydro generation came mostly from Tasmania.

Figure 1.13 Change in average quarterly generation, Q4 2021 compared to Q4 2020



Source: AER analysis using NEM data.

1.5 Generator offer behaviour varied between NEM regions

Quarterly prices reflected changes to offers in regions.

In Queensland, the average total capacity offered decreased by around 730 MW in Q4 2021 compared to Q4 2020. Most of this decrease came from prices between $0/MWh and $50/MWh and between $500/MWh and $5,000/MWh, with some capacity being shifted to over $5,000/MWh. As looked at in our report for Q3 2021, the increase in capacity offered above $5,000/MWh came from thermal generators shifting capacity to higher price bands to avoid low demand periods during the middle of the day.[7]

While average total offers in NSW increased over 1,200 MW in Q4 2021 compared to the previous Q4, prices between $0/MWh and $50/MWh decreased just over 1,600 MW. This was mostly due to changes in offers made by thermal generators. Black coal and gas offers in the NEM are explored further below.

In contrast, total offers in Victoria increased around 430 MW in Q4 2021 compared to the same time last year. There were increases in almost all price bands, except for between $150/MWh and $300/MWh. Brown coal offers increased, mainly in prices between $0/MWh and $50/MWh, though some of this was shifted from below $0/MWh.

Total offers in South Australia in Q4 2021 dropped by almost 440 MW compared to the same time last year and almost 490 MW compared to Q3 2021. This was driven by lower demand and the continuing closure of AGL's Torrens Island gas generators.

Black coal in the NEM

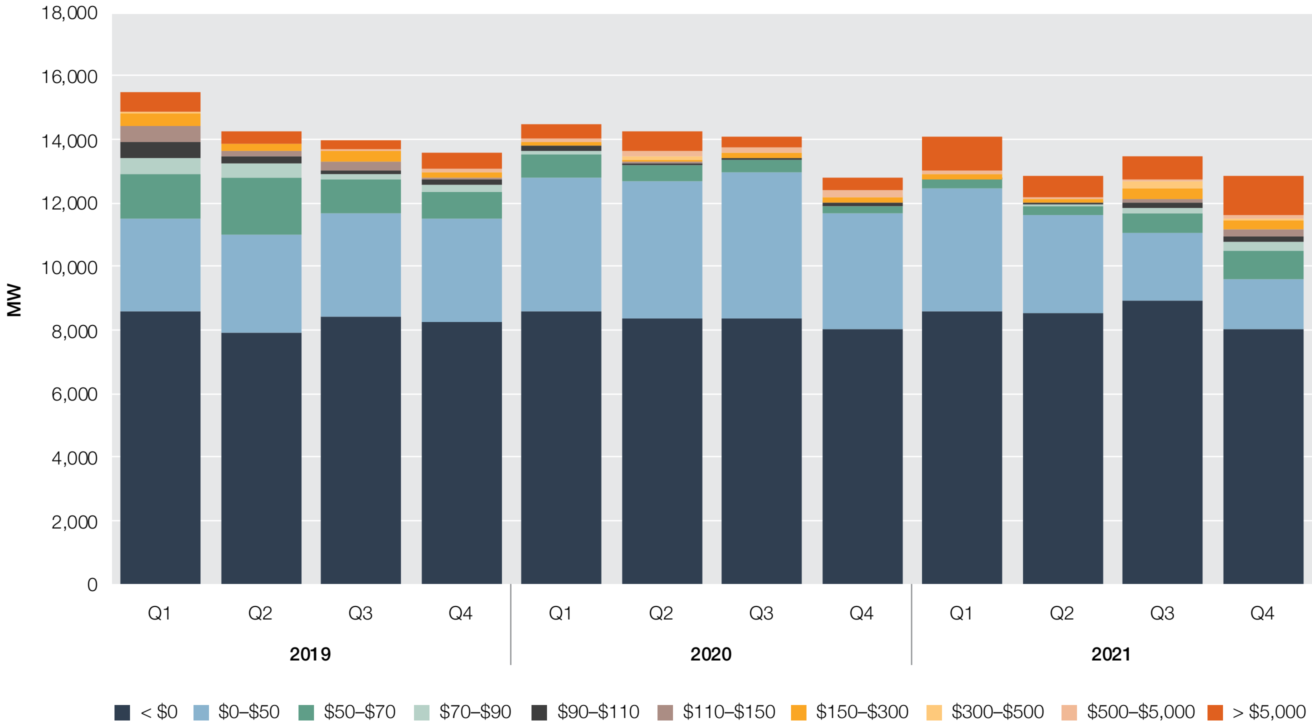
Across the NEM, black coal offers priced below $50/MWh fell by over 2,000 MW in Q4 2021 compared to Q4 2020 (Figure 1.14). Around 1,750 MW of this capacity was shifted to prices between $50/MWh to $90/MWh and above

6 See AEMO Quarterly Energy Dynamics on the commissioning of the synchronous condensers in South Australia, https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en&hash=CD6B71C8573830867349B6A9570E9D22, p. 23.

7 Wholesale Markets Quarterly Q3 2021, https://www.aer.gov.au/wholesale-markets/performance-reporting/wholesale-markets-quarterly-q3-2021, p. 23.

$5,000/MWh. A further 250 MW was no longer offered in any price band. This shifting or removal of capacity was largely due changes in offer strategies to avoid low prices in the middle of the day when demand was low and solar output was high. Coal costs and supply issues may have also been drivers.

Figure 1.14 NEM black coal offers, quarterly

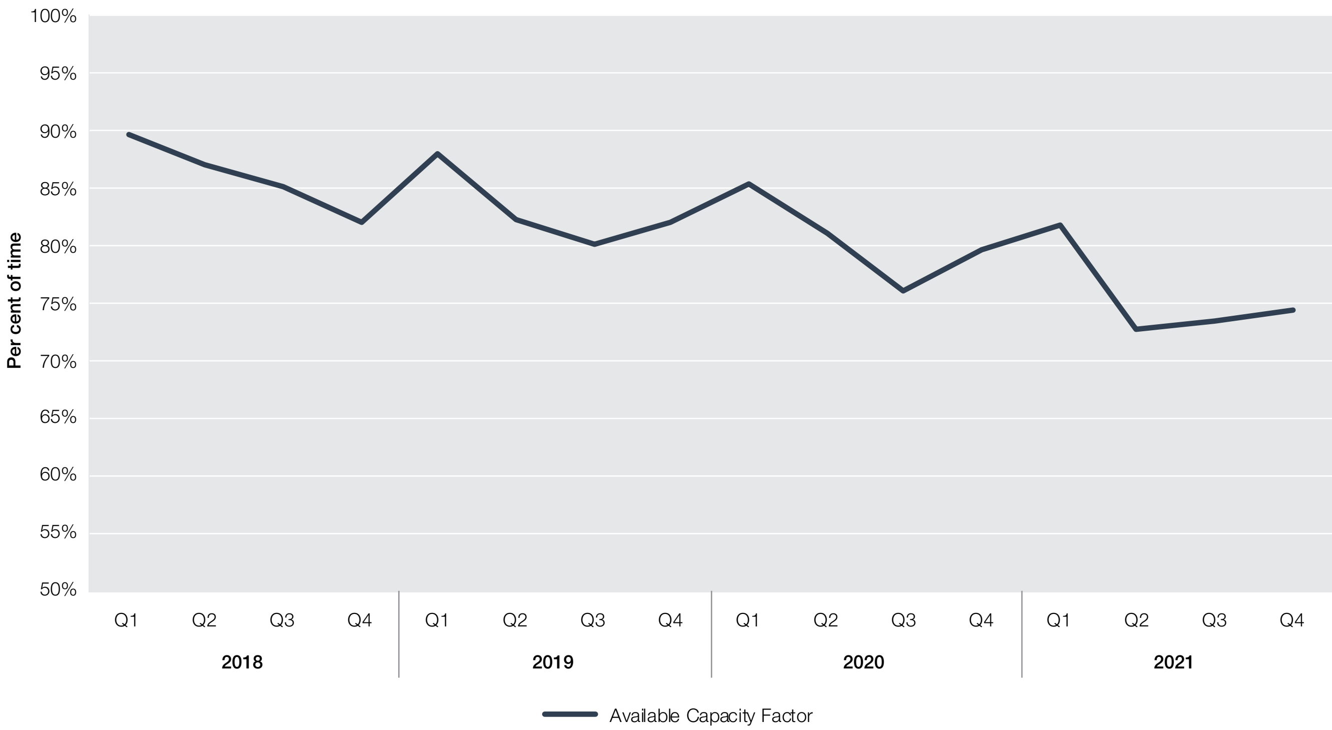


Source: AER analysis using NEM data.

Fewer outages in Queensland but less offered

There were 38 fewer days of black coal outages in Queensland compared to the same quarter last year, a reduction of 11% (Figure 1.15). Although the number of outage days fell, the amount of MW available on average dropped. On average coal availability as a proportion of registered capacity dropped from 80% to 75% compared to Q4 2020, meaning less was offered to the market.

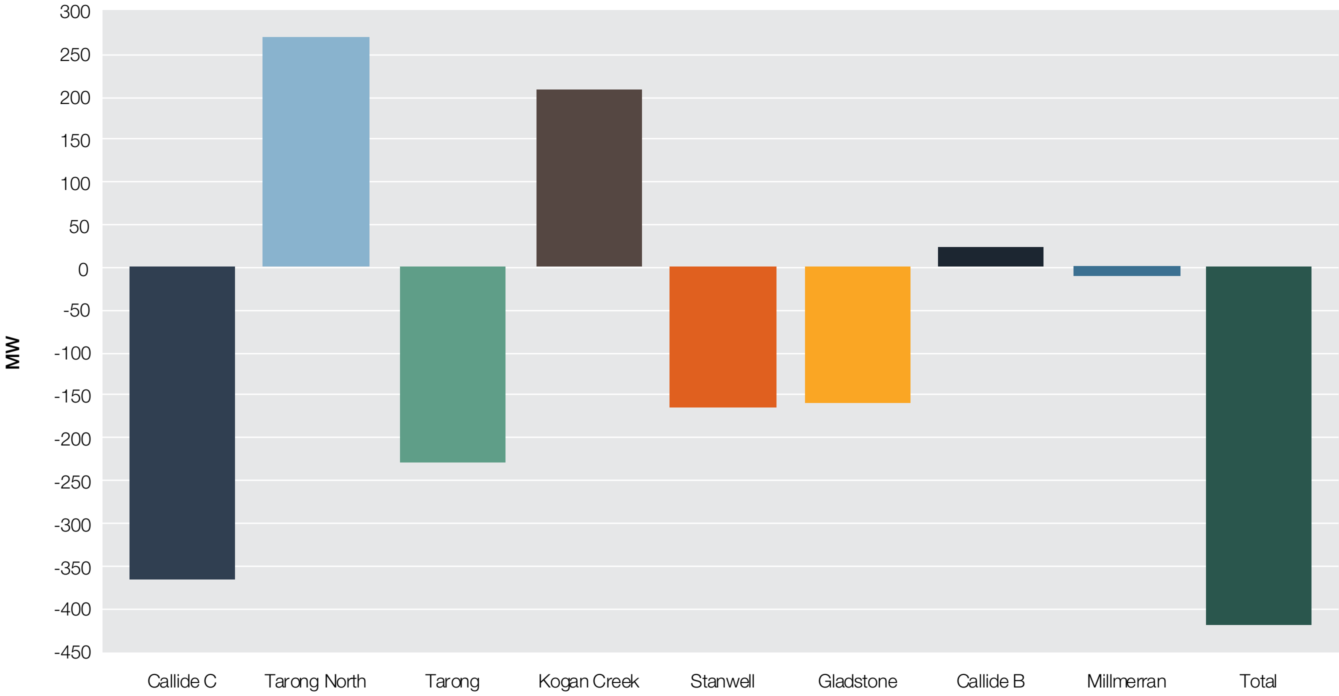
Figure 1.15 Available capacity factor for black coal in Queensland



Source: AER analysis using NEM data.

Using each station's availability capacity factors as a weighting against its registered capacity, overall around 420 MW less coal generation was available across the quarter in Q4 2021 compared to Q4 2020 (Figure 1.16). This is equivalent to the Callide C power station unit that is currently out of service.

Figure 1.16 Change in average quarterly generation available, Q4 2021 to Q4 2020



Source: AER analysis using NEM data.

In Queensland, Stanwell Corporation reduced capacity offered at Tarong power station due to coal management issues from October.[8] CS Energy continued to experience an outage at Callide C unit 4 and Gladstone unit 1 remained offline all quarter.[9] In addition, CS Energy experienced a cyber-security incident in late November which impacted offers across their portfolio including FCAS.[10]

NSW offered more but changed its offer strategy

Overall coal offers in NSW were up by around 450 MW despite significant outages at Liddell, Mt Piper and Eraring power stations (Appendix A). However black coal participants removed almost 1,400 MW of capacity priced between $0/MWh and $50/MWh. Participants shifted 200 MW to below $0/MWh, 800 MW was offered between $50/MWh and $90/MWh and the majority of the remaining capacity was offered above $5,000/MWh.

Gas in the NEM

There was also a drop in total average gas offered across the NEM, compared to both Q4 2020 (-850 MW) and Q3 2021 (-670 MW) (Figure 1.17). This reduction was mainly from South Australia which saw almost 400 MW removed due to low demand, the closure of the Torrens A gas generators and the introduction of the synchronous condensers reducing the need for gas generators to be directed on for system security purposes.[11]

A further 107 MW on average was removed from Victorian gas offers due to the low demand levels in Q4 2021 (section 1.3).

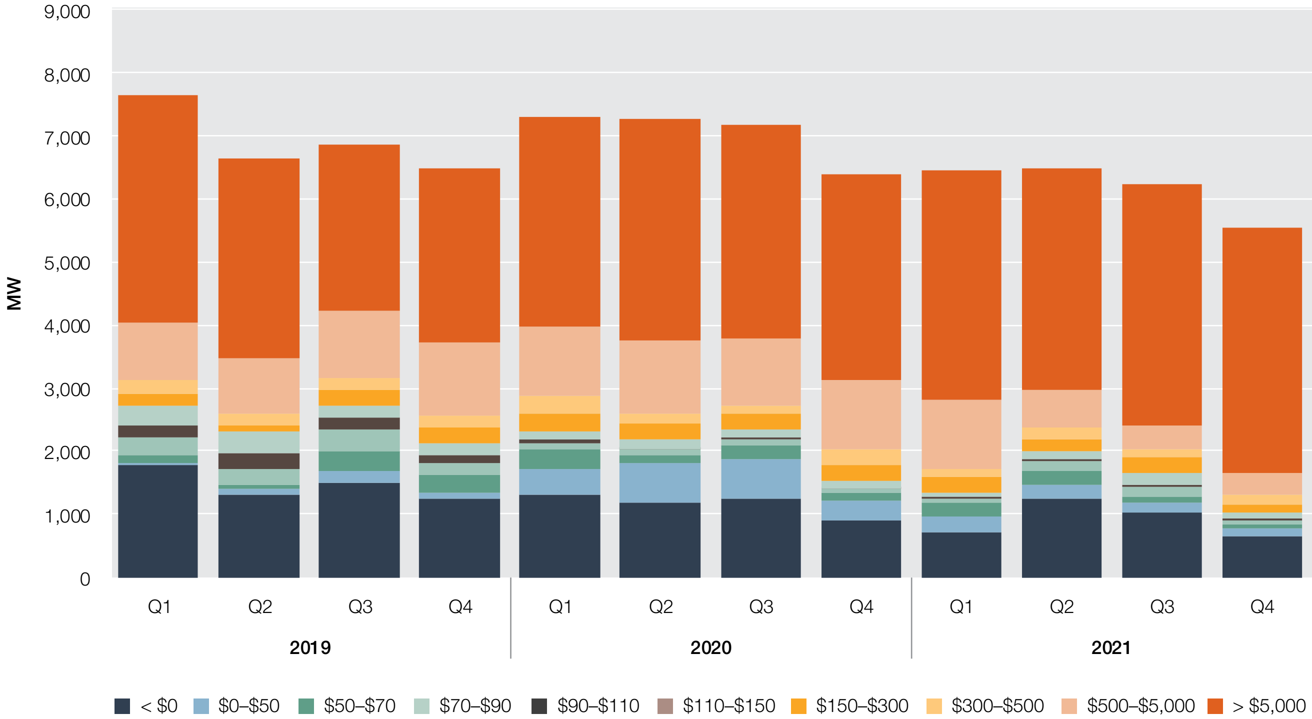
8 See AEMO Quarterly Energy Dynamics for further detail https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en&hash=CD6B71C8573830867349B6A9570E9D22.

9 See our $5,000/MWh price report for 25 May 2021 https://www.aer.gov.au/wholesale-markets/performance-reporting/prices-above-5000-mwh-25-may-2021-queensland-and-nsw.

10 https://www.csenergy.com.au/news/cs-energy-responds-to-cyber-security-incident.

11 See AEMO Quarterly Energy Dynamics https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en&hash=CD6B71C8573830867349B6A9570E9D22.

Figure 1.17 NEM gas offers, quarterly



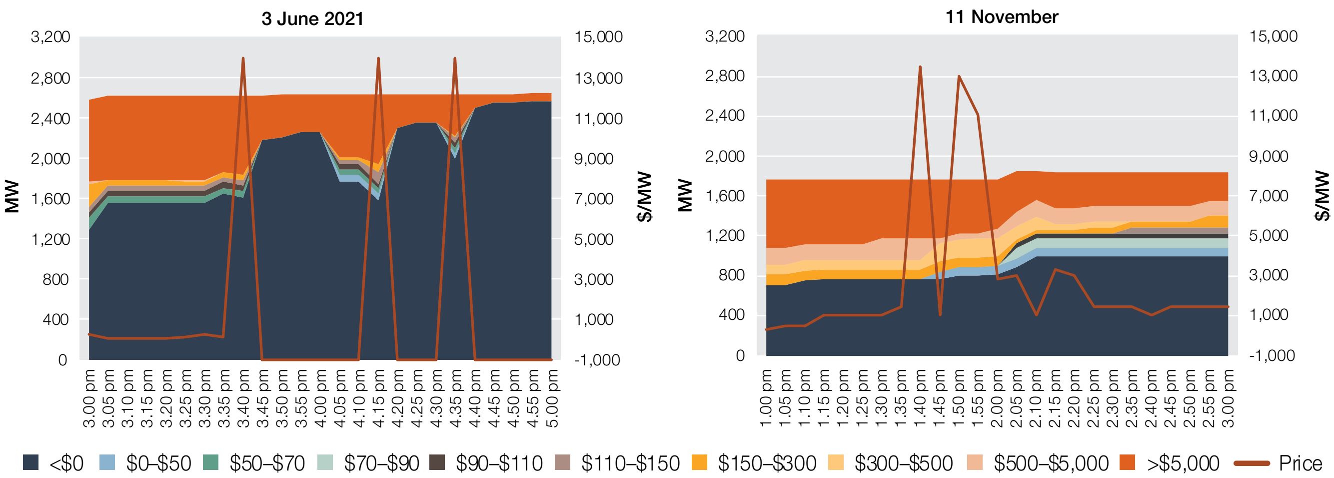
Source: AER analysis using NEM data.

Comparing gas offers in Q4 2021 to Q4 2020, offers priced above $5,000/MWh increased mainly in Queensland (590 MW).

While higher fuel costs and lower demand played a role, the introduction of 5 minute settlement has also changed participant offer behaviour.[12]

For example, gas generators in Queensland responded differently to high prices on 11 November 2021 after the start of 5 minute settlement compared to 3 June 2021. On 3 June, participants offered more capacity throughout the day and responded to price spikes by shifting capacity from above $5,000/MWh to below $0/MWh. In contrast, on 11 November participants offered less capacity overall throughout the day and did not respond significantly to price spikes (Figure 1.18).

Figure 1.18 Queensland gas offers on 3 June and 11 November 2021



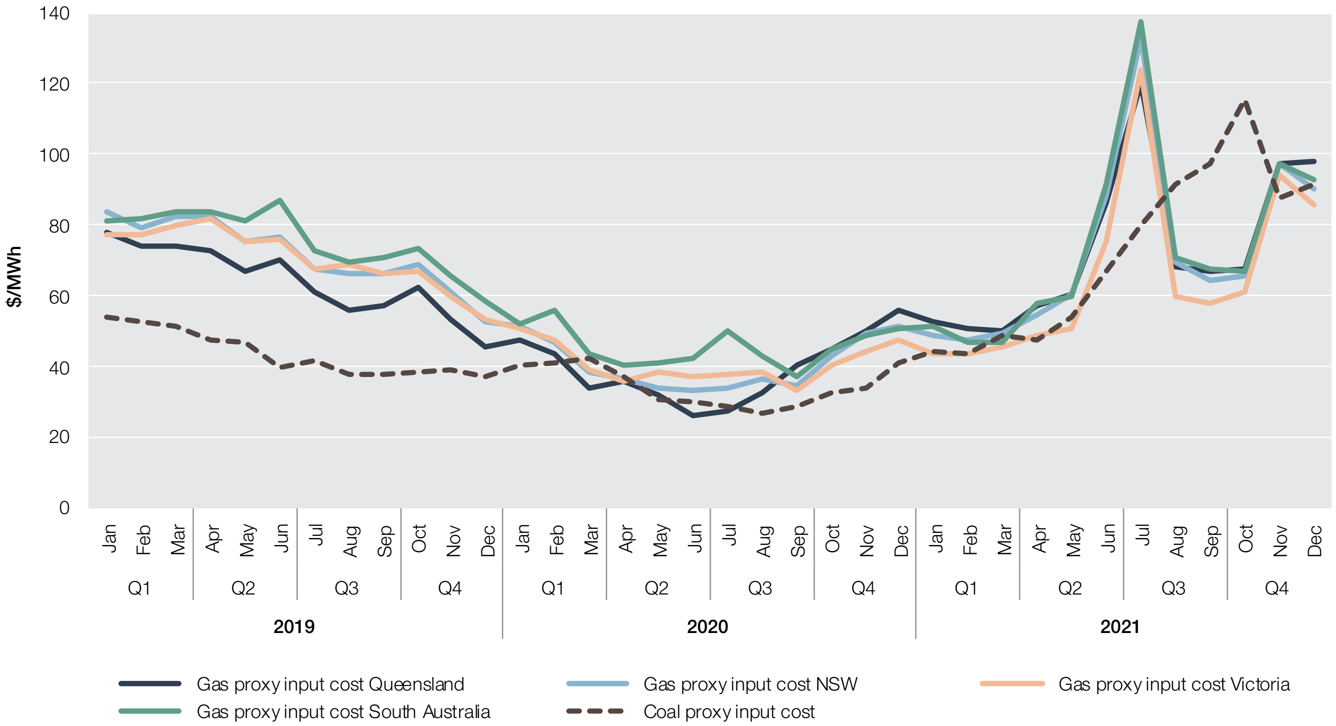
Source: AER analysis using NEM data.

12 Further information on how participants prepared for the introduction of 5 minute settlement is in the Wholesale Markets Quarterly Q3 2021, p25 https://www.aer.gov.au/system/files/Wholesale%20markets%20quarterly%20Q3%202021_2.pdf.

Fuel costs have been high

Newcastle coal and spot market gas prices have risen considerably since mid-2020 (Figure 1.19). Participants exposed to these short term prices will be far more affected than those who are securely hedged with fuel contracts or access to coal mines. While we do not have data on the extent to which participants are exposed to short term fuel costs, they can provide an upper bound to represent participant input costs. The increases in coal costs to around $90/MWh in Q4 may have contributed to the change in coal offers from between $0/MWh and $50/MWh to between $50/MWh and $90/MWh mentioned above. The gas cost increased almost $40/MWh across the quarter in all markets and is considerably higher than in Q4 2020. This partly explains the increased price at which gas is being offered, however supply issues may also have been a factor (see 2.1).

Figure 1.19 Proxy input costs for gas in all regions and for NSW coal



Source: AER analysis using globalCOAL data.

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

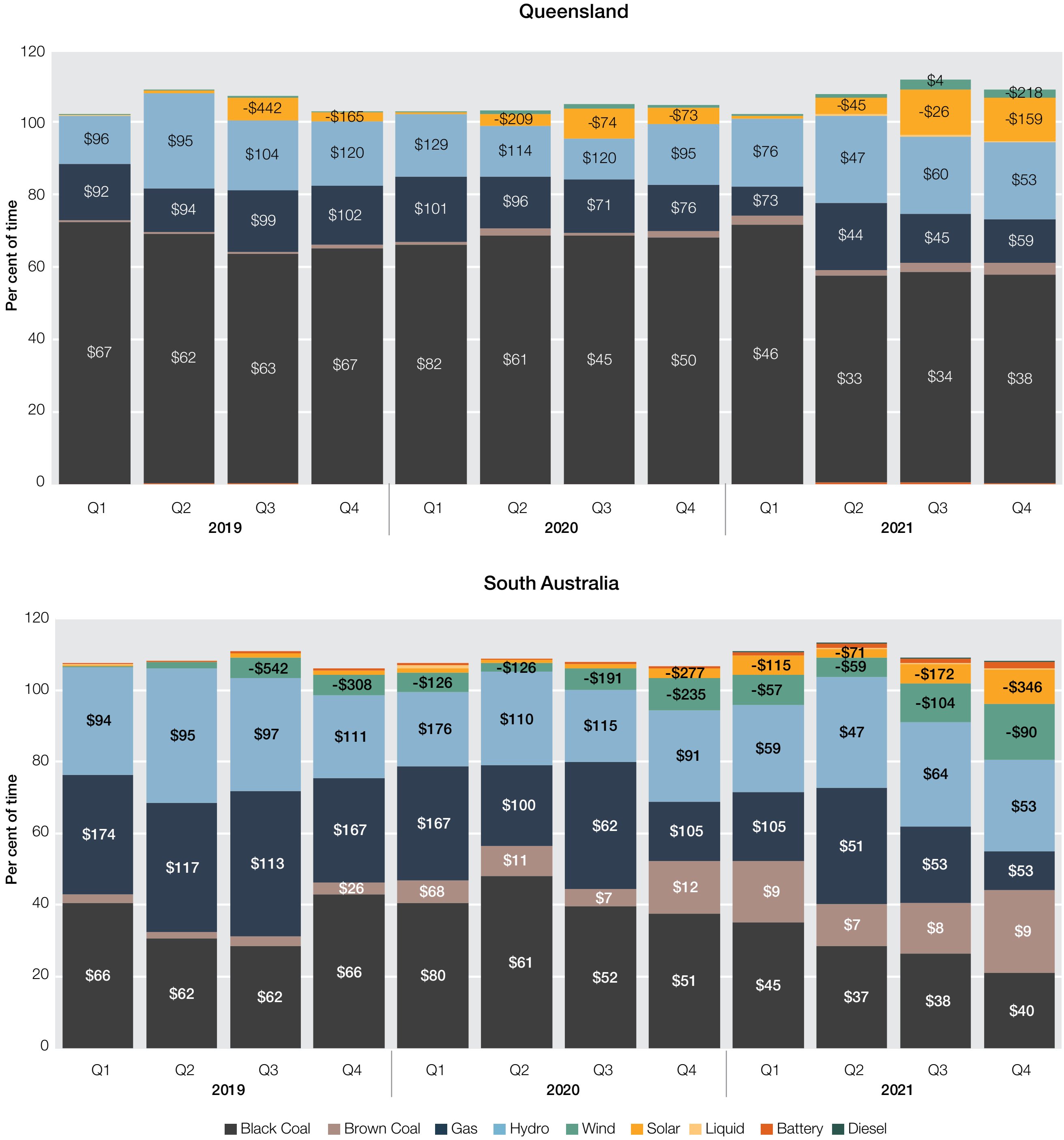
1.6 Higher prices set by black coal and gas in Queensland

Black coal, gas and hydro set much higher prices in Q4 2021 compared to Q4 2020 in Queensland (Figure 1.20). This was driven by interconnector outages limiting the import of cheaper generation, high demand and increased fuel costs. These factors contributed to a higher average quarterly price in the region.

In Queensland:

- black coal set an average price of $64/MWh (up from $38/MWh)
- gas set an average price of $237/MWh (up from $59/MWh)
- hydro set an average price of $80/MWh (up from $53/MWh).

Figure 1.20 Price setter by region, Queensland and South Australia



Source: AER analysis using NEM data.

The price set by black coal increased in all regions. This is significant because black coal sets the price a significant amount of the time, especially in Queensland and NSW where it sets the price over half of the time.

A significant increase in the price set by gas, particularly in Queensland, reflects the impact of high-priced events when very expensive gas generation was needed to meet peak demand. More expensive hydro generation was also needed to meet demand in these periods, with hydro setting higher prices more often compared to a year earlier.

These increases were partly offset by wind and solar setting lower average prices than a year ago. In Queensland, solar set an average price of -$305/MWh and wind set an average price of -$425/MWh. The offset was only partial because wind and solar set the price a lot less frequently than the other fuel types, especially in Queensland and NSW.

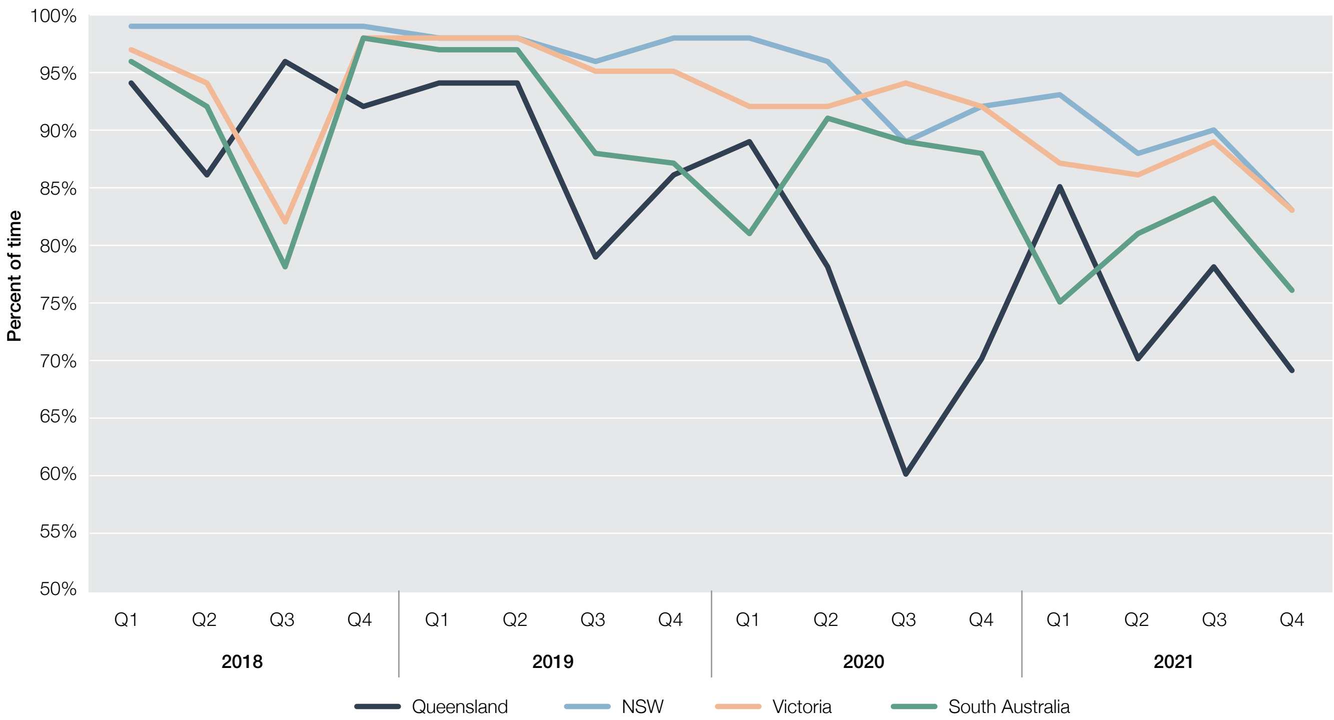
Like Queensland, South Australia experienced a number of high-priced events in the quarter, with very expensive gas generation needed to meet peak demand. However, the impact on average quarterly prices was more muted because black coal, gas and hydro set prices only 53% of the time in South Australia, whereas they set prices 83% of the time in Queensland.

1.7 Constrained interconnectors lead to price separation

Price alignment measures how often a region has access to generation from at least one other region, through unconstrained interconnectors. When price alignment occurs, the generation capacity in the exporting regions (usually priced cheaper) sets price in the importing region to achieve most economic dispatch of electricity. As alignment falls there is reduced access to cheaper generation from neighbouring regions.

Prices were less aligned across the mainland regions this quarter by between -6% and -9% compared to the previous quarter (Figure 1.21). Queensland prices were the least aligned at 68% followed by South Australia at 76% and were two of the highest priced regions for the quarter. Queensland and South Australia are at the ends of the network and only connected to one neighbouring region limiting access to cheaper generation in other regions if the interconnectors joining them are constrained.

Figure 1.21 Region price alignment



Source: AER analysis using NEM data.

Note: Price alignment each quarter by region.

Queensland price separation was the greatest due to constraints managing the upgrade of QNI and system normal constraints. These constraints reduced the ability of Queensland to import cheaper electricity from NSW contributing to high prices.

South Australia had reduced price alignment due to equipment outages impacting Heywood and voltage control issues in Victoria impacting Murraylink. This reduced the amount of imports into South Australia from the cheapest region on the mainland, Victoria.

NSW had reduced price alignment due to constraints on both QNI and the Vic–NSW interconnector during Q4. Constraints invoked to manage outages in the Canberra region restricted flows across the Vic–NSW interconnector 53% of the time compared to 32% a year ago, limiting access to cheaper generation from Victoria.[13]

13 See AEMO Quarterly Energy Dynamics https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en&hash=CD6B71C8573830867349B6A9570E9D22.

Constraints on QNI

Interconnector constraints restricted Queensland's ability to access cheaper generation from NSW, especially during the evening peak. This meant that Queensland demand often had to be met by more expensive Queensland generation.

QNI was constrained 32% of the quarter mainly due to the upgrade to QNI which commenced May 2020 and is due for completion April 2022. System normal constraints contributed around a third of these binding constraints (Box 1).

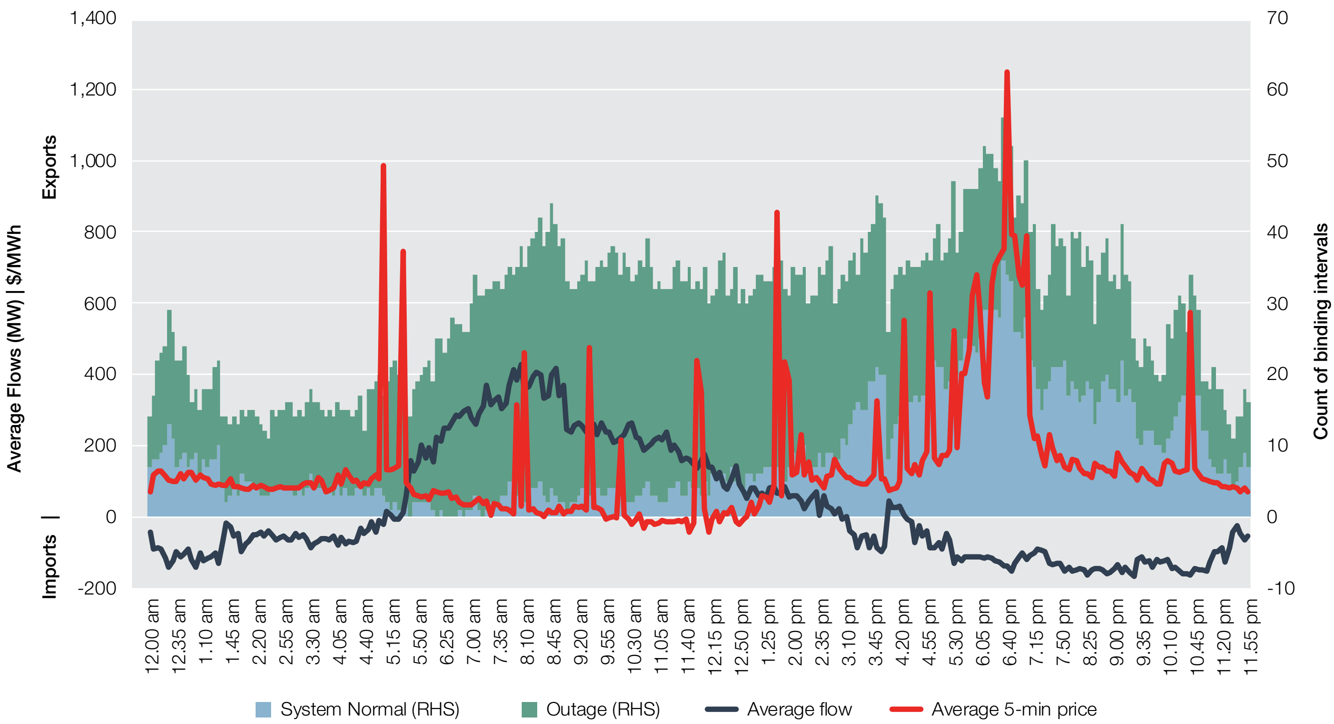
> ### Box 1: What are system normal and outage constraints?
>
> System normal constraints are always invoked to reflect network limits when there are no outages. Outage constraints are used to manage network outages and can be planned or unplanned. For example, the upgrade to QNI requires certain network lines to be taken out of service for a period of time. AEMO temporarily puts constraints in place to manage this. Network constraints are referred to as "binding" when flow on a line is at the limit set by the constraint and cannot increase further.

The outage constraints bound most often during daylight hours when work was undertaken to upgrade QNI (Figure 1.22). This is also when solar generation is at its highest and prices are generally at their lowest. During most of this time Queensland was exporting to NSW even though there were occasions where the Queensland price was higher than the NSW price. This was done to keep the system secure, explained in detail in our Focus.

System normal constraints mainly bound during the evening when demand is highest, local solar generation is not contributing to supply and network limits are being approached. The average import amount during the evening was around 180 MW, well below its nominal limit of 300 to 600 MW. As a result, prices were at their highest during this time meaning system normal constraints had a bigger impact on price than outage constraints, despite occurring less often. The average price when system normal constraints bound was $294/MWh compared to $107/MWh when outage constraints bound.

Once the upgrade on QNI is complete, these system normal constraints may be re-evaluated to reflect the change of network infrastructure.

Figure 1.22 Queensland Import Limit – Time of Day



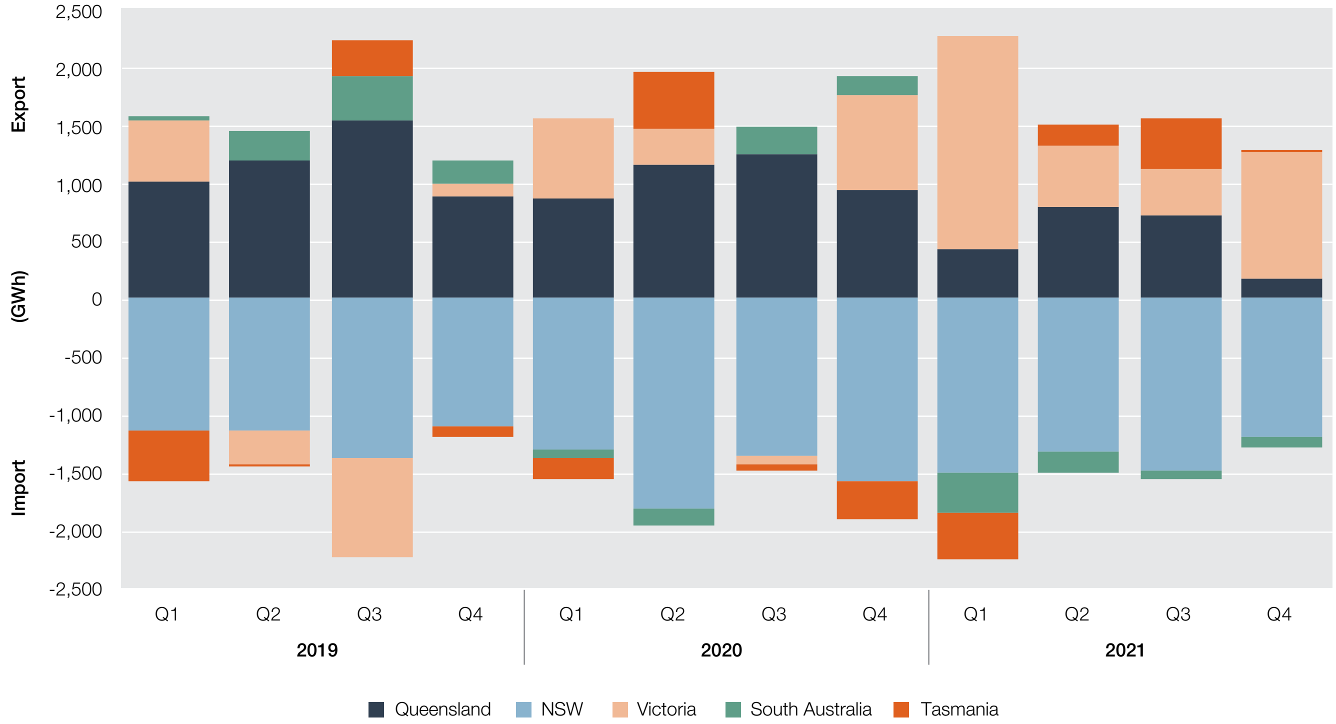
Source: AER analysis using NEM data.

Note: Queensland import limit and constraints by time of day for quarter 4.

Source of exports changes

NSW continues to be a net importer this quarter but the source of its imports has changed (Figure 1.23). Historically Queensland was a heavy net exporter into NSW, but for Q4 2021 we can see that Victoria was the biggest net exporter and Queensland has fallen back. Higher demand and network upgrades on QNI limited Queensland's export ability. Victoria had abundant low priced renewable generation and lower demand allowing it to export to neighbouring regions.

Figure 1.23 Net flows between regions (exports – imports)



Source: AER analysis using NEM data.
Note: Net amount of energy either imported or exported each quarter by region.

1.8 Over 3 GW of new capacity entered the NEM in 2021

Over 3 GW of new capacity entered the NEM in 2021, comprising (Table 1.1):

› 1.5 GW of solar capacity which was located mostly in NSW and Queensland
› 1 GW of wind capacity which was located mostly in Victoria
› 0.5 GW of battery capacity (2 batteries in Victoria, 1 in Queensland and 1 in NSW).

This was less capacity than entered in 2020 but more than in 2019. The total was boosted by the entry of the NEM's largest wind farm (Stockyard Hill), largest solar farm (Western Downs Green Power Hub) and largest battery (the Victorian Big Battery).

150 MW of plant exited the NEM in 2021. This included the Mackay Gas Turbine (30 MW) in Queensland and the third unit (120 MW) at Torrens Island Power Station in South Australia. Coming exits include the first black coal unit (500 MW) at Liddell Power Station in April 2022 and the final Torrens Island unit (120 MW) in September 2022 (Figure 1.24).

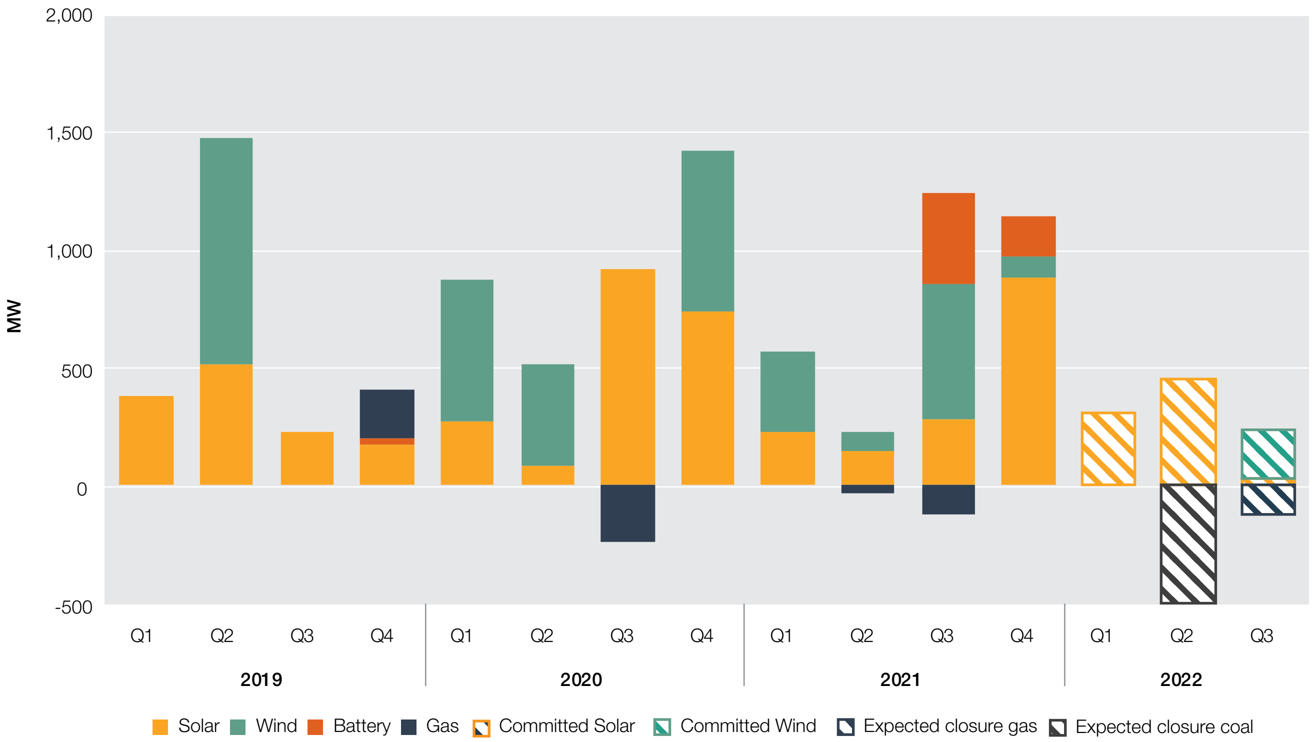
Table 1.1 New entry and exit in 2021

REGION	SOLAR (MW)	WIND (MW)	BATTERY (MW)	GAS EXITS (MW)	REGIONAL NEW ENTRY LESS EXITS (MW)
Queensland	679	43	123	-30	815
NSW	721	243	50	0	1,014
Victoria	138	711	384	0	1,233
South Australia	0	86	0	-120	-34
Tasmania	0	0	0	0	0
Total by fuel type	**1,538**	**1,083**	**557**	**-150**	**3,028**

In Q4 2021, over 1 GW of new capacity entered the market, mostly solar (Table 1.2). The Western Downs Green Power Hub (500 MW) in Queensland accounted for almost half of it. When fully operational, it will become Australia's largest solar farm. It has a power purchase agreement with CleanCo and is expected to be co-located with a 200 MW battery.

The wholesale demand response mechanism commenced in Q4 2021. Demand response service providers (a new category of market participant) can aggregate demand response capability and offer it directly into the wholesale energy market in the same way generators currently offer to supply energy. By helping reduce peak demand, particularly at times of high electricity prices and electricity supply scarcity, the mechanism is designed to reduce the need for expensive peaking generation. In Q4 2021, Enel X Australia registered 3 units, one able to provide 10 MW of demand response in NSW and 2 in Victoria totalling 10 MW.[14]

Figure 1.24 New entry and exit



Source: AER analysis using AEMO generator information (October 2021) and 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.

14 See AEMO's Quarterly Energy Dynamics section on Wholesale Demand Response units, https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en&hash=CD6B71C8573830867349B6A9570E9D22, p. 30.

Table 1.2 New entry in Q4 2021

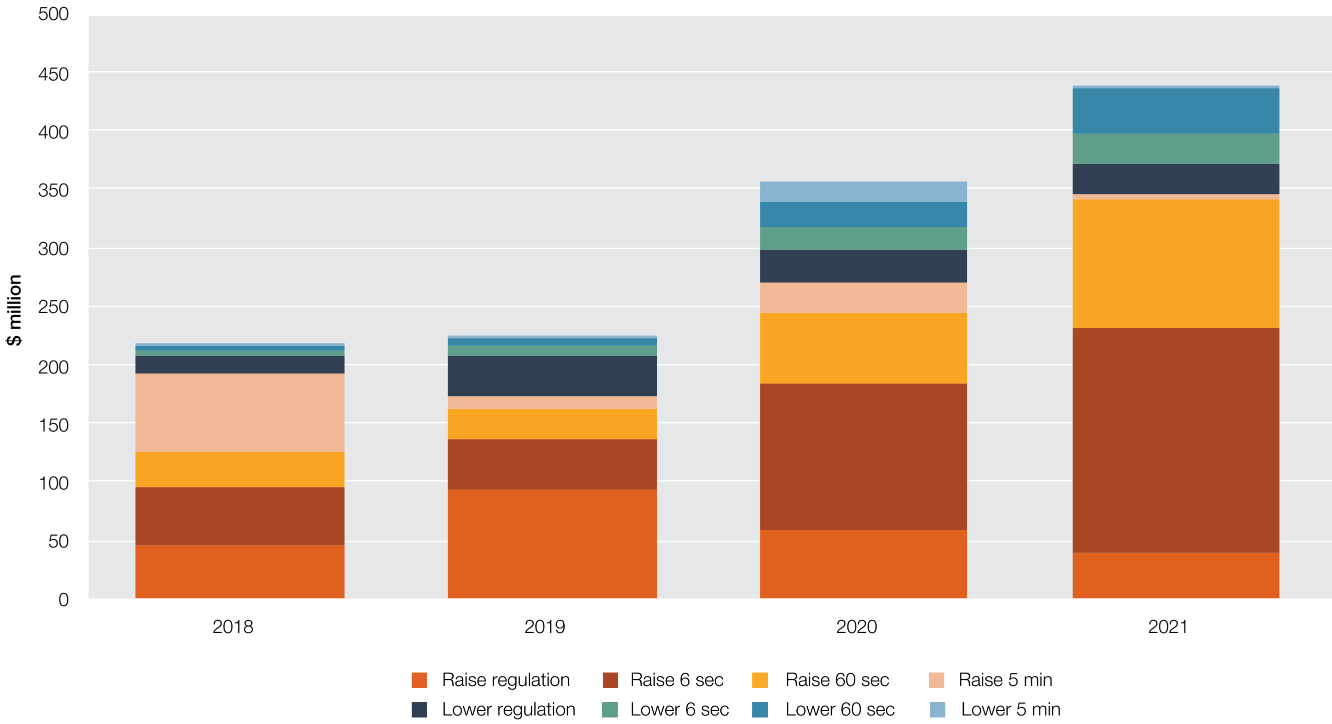
REGION	STATION	FUEL TYPE	HIGHEST CAPACITY OFFERED IN Q4 2021 (MW)	REGISTERED CAPACITY (MW)
Queensland	Wandoan BESS	Battery	5	123
Queensland	Gangarri Solar Farm	Solar	9	162
Queensland	Western Downs Green Power Hub	Solar	0	501
NSW	Hillston Sun Farm	Solar	30	110
NSW	Wallgrove BESS 1	Battery	50	50
NSW	Sebastopol Solar Farm	Solar	30	110
South Australia	Lincoln Gap Wind Farm – stage 2	Wind	50	86
Total				**1,142**

1.9 Record high FCAS costs

Total costs for frequency control ancillary services (FCAS) were an all-time high in 2021, totalling $438 million, and were influenced by local FCAS costs in Queensland increasing to $234 million.

Local FCAS costs in Queensland were mainly driven by contingency services. These were greatest for raise 6 second (R6) and raise 60 second (R60) services, which accounted for $182 million, while lower 6 second (L6) and lower 60 second (L60) services cost $45 million. Consequently, total FCAS costs were largely attributed to these ancillary services as well (Figure 1.25).

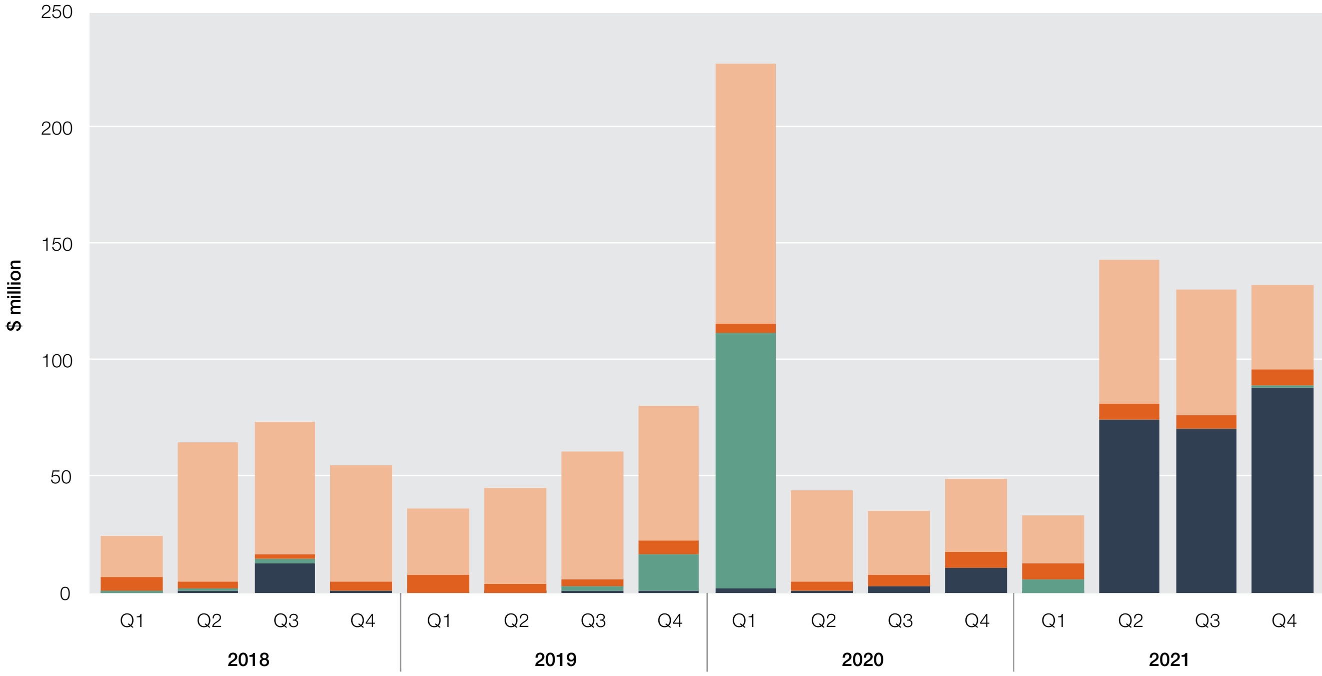
Figure 1.25 Annual total FCAS cost by ancillary service



Source: AER analysis using NEM data.
Note: Annual FCAS costs in the NEM, by ancillary service.

In Q4 2021, FCAS costs came to $132 million. High local FCAS costs in Queensland were the main cause of the annual and quarter outcome, reaching a record $89 million this quarter. On the other hand, global FCAS costs fell to $36.7 million (Figure 1.26).

Figure 1.26 Quarterly total FCAS costs by local and global costs



Source: AER analysis using NEM data.
Note: Global and local FCAS costs, by quarter.

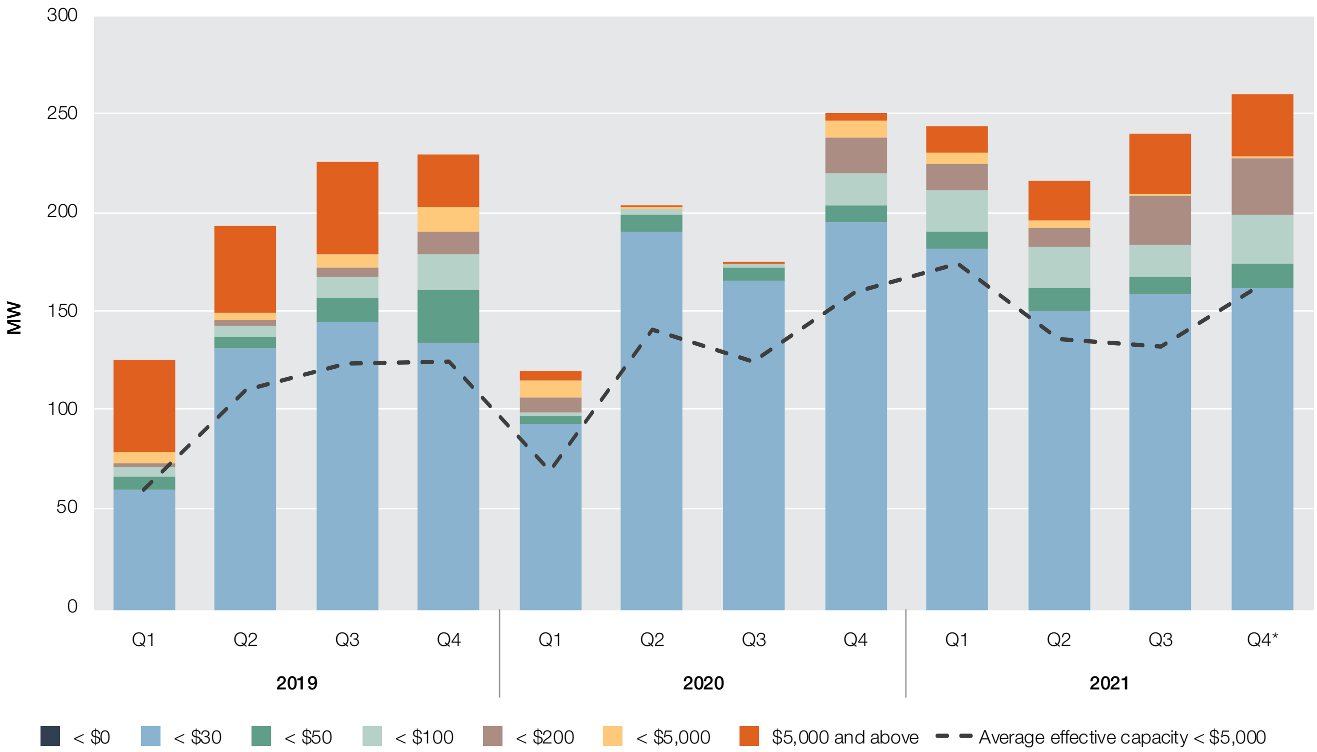
High local FCAS costs in Queensland were due to a combination of factors, which are expanded on in our Focus. In particular, the ongoing upgrade to QNI triggered local requirements for FCAS. This created a local market, meaning FCAS requirements in Queensland had to be met exclusively by local supply. As a result, it was necessary to dispatch more expensive local capacity in some circumstances, as FCAS supply from other regions was limited.

Overall, the high costs were not driven by a change in participant behaviour, but rather a high requirement for these services. On average FCAS offers by Queensland participants were the highest since 2013. For example, R6 offers exceeded 250 MW over the quarter (Figure 1.27).[15] Even though the amount offered was high, the average R6 requirement was 276 MW when the price was above $5,000/MW, meaning there were times of tight supply.

An increase of offers led to the effective capacity priced less than $5,000/MW increase from Q3 by 32 MW (on average), but the increased requirement meant more high priced capacity was also needed at times.

15 Up until 28/11/2021 inclusive. There were no local requirements for Queensland to supply its own FCAS in December, so average offers were analysed for 1/10/2021 – 28/11/2021 when they could affect local FCAS prices in Queensland.

Figure 1.27 Maximum capacity offered for raise 6 second services in Queensland by price



Source: AER analysis using NEM data.

Note: Average maximum capacity offered for raise 6 second ancillary services in Queensland by price. *Q4 2021 includes 1/10/2021 – 28/11/2021 inclusive. Prices referenced are in $/MW. 'Effective capacity' is the maximum capacity of ancillary services offered to the market, adjusted by amount of energy dispatched.

On the other hand, market participants shifted roughly 25 MW of capacity for L6 and L60 second services each. Capacity offered below $30/MW was reallocated to higher price thresholds, predominately above $200/MW.

Focus – Queensland FCAS costs

This focus story explains the drivers of the high local FCAS costs in Queensland which hit a record for Q4 in 2021. It also explains how high local FCAS prices in Queensland impacted the energy market.

There were 51 FCAS prices (30-minute prices) over 4 days in Queensland that exceeded $5,000/MW and triggered our reporting requirements in Q4 2021.[16] High prices and high local demand in Queensland led to record Q4 costs for FCAS of $89 million. The high prices were in the contingency service markets R6, R60, L6 and L60.

While not necessarily common to all events, the principal drivers of these high FCAS prices were:

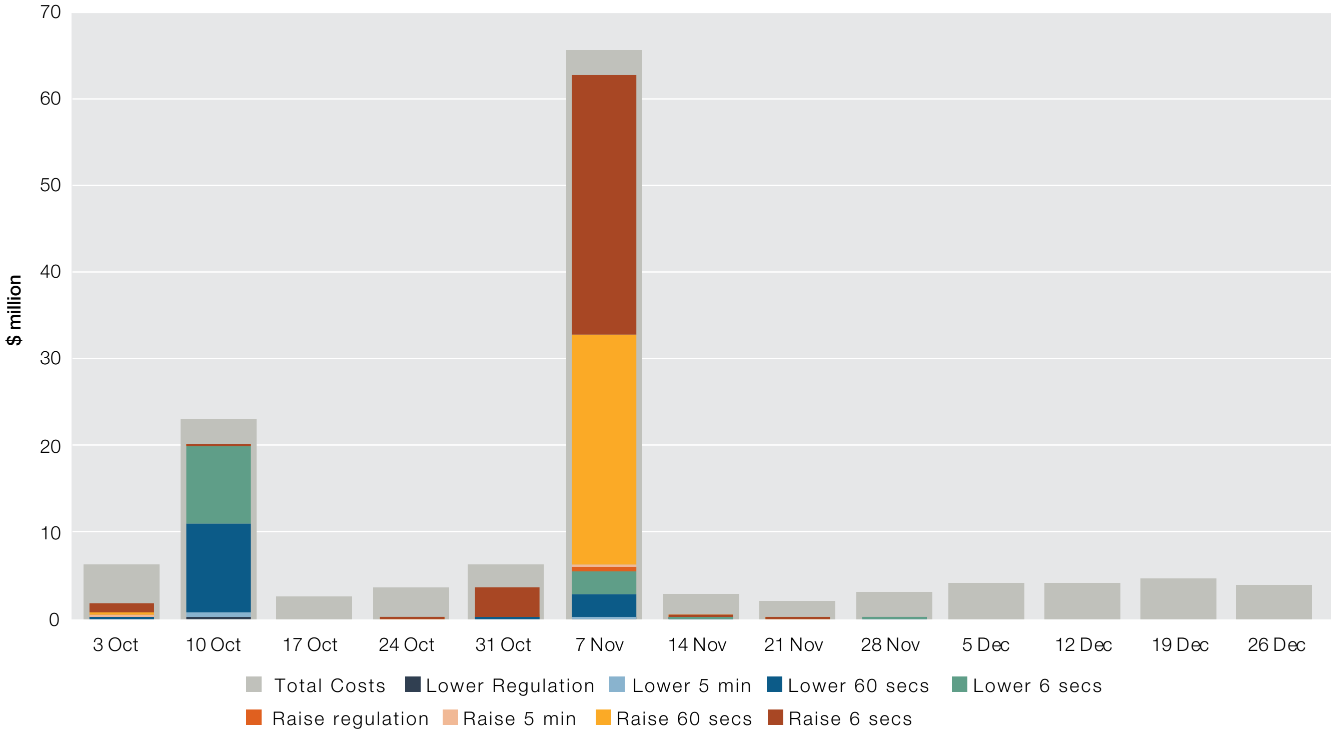
- network outages, as part of the Queensland–NSW Interconnector (QNI) upgrade triggered the requirement for all FCAS for the Queensland market to be sourced within that region
- the interaction of energy and FCAS markets which reduced the amount of FCAS effectively available to the market
- at times high priced capacity was needed to meet the local requirements
- participants rebid some low priced FCAS capacity out of the market or to higher price bands.

Each of these drivers is explained below.

Local costs in Queensland contributed to the majority of the FCAS costs across the quarter (Figure 1.28). The events on 16 October and 11 November had the greatest impact on overall costs.

16 The details of all the 30-minute periods where FCAS prices were above $5,000/MW is at Appendix B.

Figure 1.28 Queensland's contribution to total FCAS costs over the quarter



Source: AER analysis using NEM data.

Upgrades on QNI meant Queensland had to provide its own FCAS

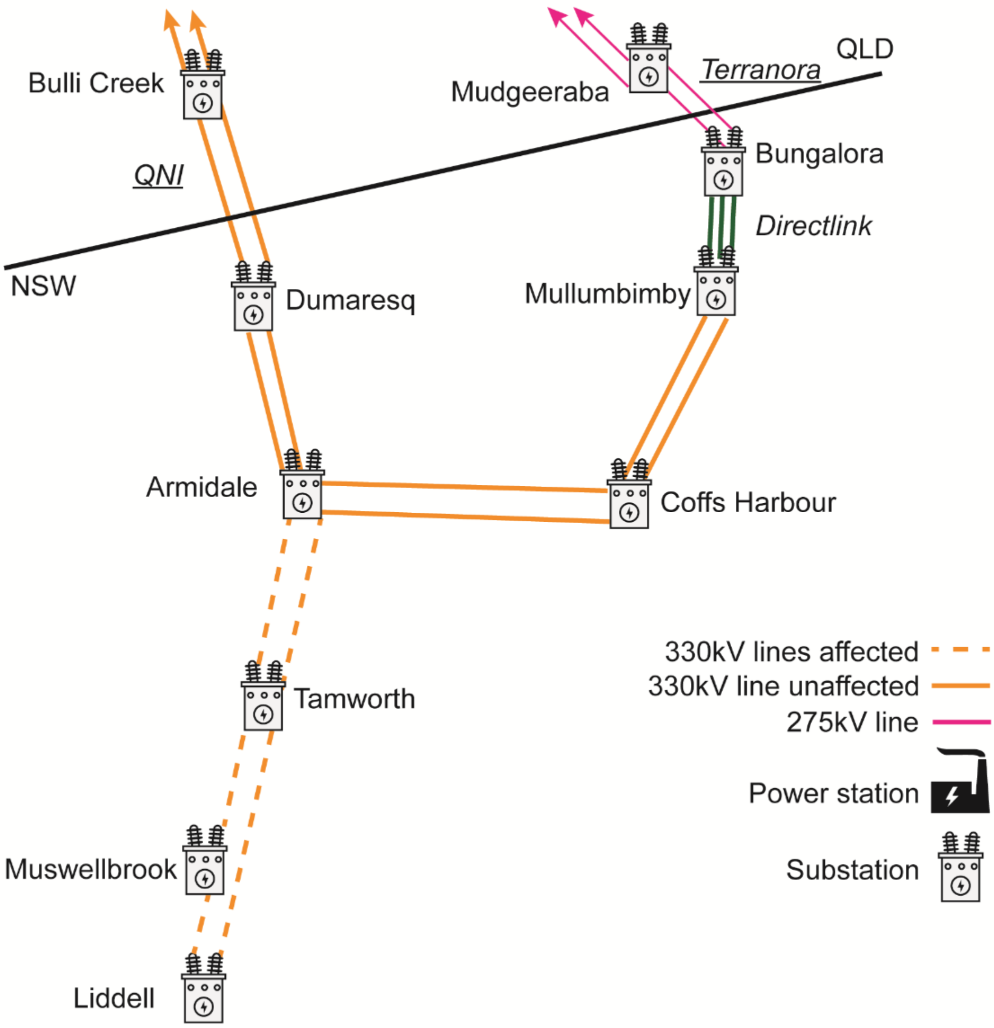
As upgrades on QNI continue, a series of high voltage transmission lines are systematically taken out of service to safely install new equipment. These lines form part of the QNI interconnector. If, in addition to a planned outage, another line tripped then Queensland would be electrically islanded meaning the region would be unable to access any ancillary services from the rest of the NEM.[17] To manage this risk, AEMO invokes constraints to ensure Queensland sources its own FCAS requirements locally. These local requirements were the main driver behind the high Queensland FCAS prices in Q4 2021 (Table 1.3 and Figure 1.29).

Table 1.3 Line outages and high priced contingency services

DATE	LINE OUTAGE	FCAS MARKETS WHERE PRICES > $5,000/MW
16 October	Armidale to Tamworth	L6, L60
4 November	Liddell to Muswellbrook	R6
8 November	Armidale to Tamworth	L6, L60
11 November	Liddell to Tamworth	R6, R60

17 The second interconnector between Queensland and NSW, Terranora, is a DC interconnector and unable to transfer FCAS.

Figure 1.29 Simplified network chart



Interactions between the energy and FCAS markets

Upgrades on QNI meant at times Queensland had to provide more of its own energy

The QNI upgrade limited Queensland's access to low priced energy from NSW. This meant at times Queensland had to also provide more of its own energy.

If some units are providing more energy, their ability to provide raise services is reduced. For example, a generator that is operating at its maximum capacity in energy cannot increase its output any further to provide raise services. To provide additional raise services a generator would need its energy target reduced to provide it the headroom necessary for it to provide raise services.

We often see the energy price co-optimised with FCAS during times of limited raise and energy availability. When the requirement increases, higher priced FCAS raise services are co-optimised with energy prices which also increases the price of energy.

FCAS requirements forced flow out of Queensland

QNI upgrades led to counter-price flows between Queensland and NSW. Counter-price flows occur when electricity is exported from a high price region into a lower priced region in order to manage congestion. This occurs when the market dispatch engine determines that the optimal outcome to manage congestion located in one region is to force the flow of electricity into an adjoining region.

During times of limited supply of raise services in Queensland, the dispatch engine will tend to force flow counter-price into NSW to reduce the local requirement for raise services. While forcing flows south will reduce the local requirement it will also reduce the effective availability of raise services in Queensland, as more energy is being dispatched. This can lead to higher energy and FCAS prices.

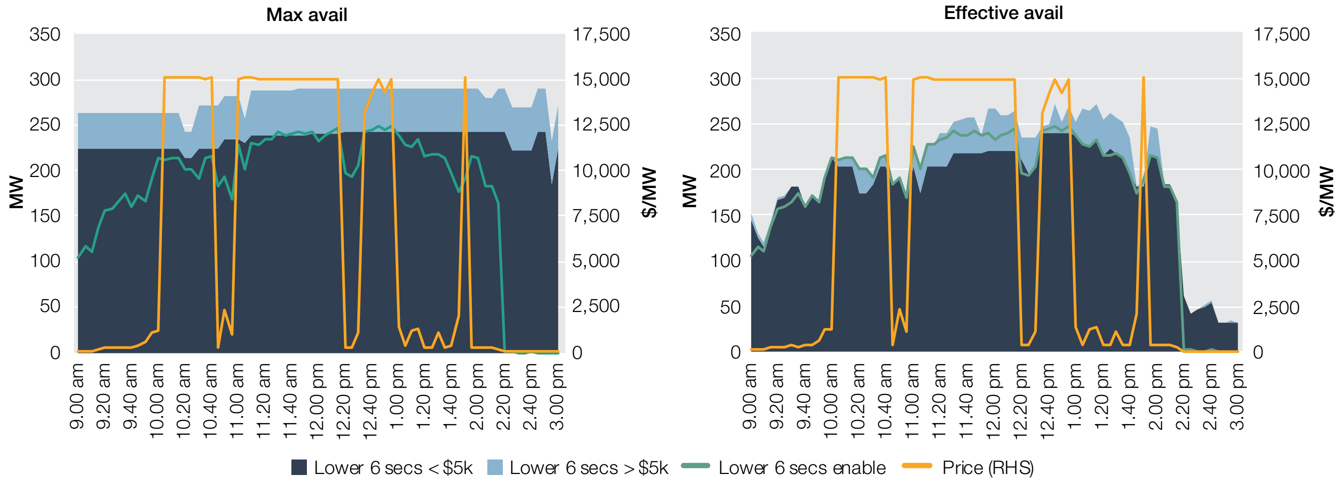
Counter-price flows trigger the negative settlement residue constraint to bind, which tries to limit the amount of electricity flowing from a higher priced region to a lower priced region. This constraint forces flow back into Queensland which in turn increases the local requirement for raise services.

Low levels of demand for energy reduce FCAS availability for lower services

Demand on 16 October was between 3,790 MW and 4,278 MW during the time of the L6 and L60 FCAS high prices. This is a relatively low level of demand for Queensland so many of the thermal units that were generating were at their minimum load. The units generating could not safely reduce their electricity output any further to lower system frequency, so the effective availability of lower services was reduced.

On 16 October, the total availability of L6 services was reduced by up to 40% compared to its maximum level (Figure 1.30). This illustrates how the interactions between the energy and FCAS markets can reduce the availability of FCAS. On this occasion, the L6 price was set by co-optimisation between energy and the other FCAS markets during 5 of the 6 30-minute periods.

Figure 1.30 16 October availability

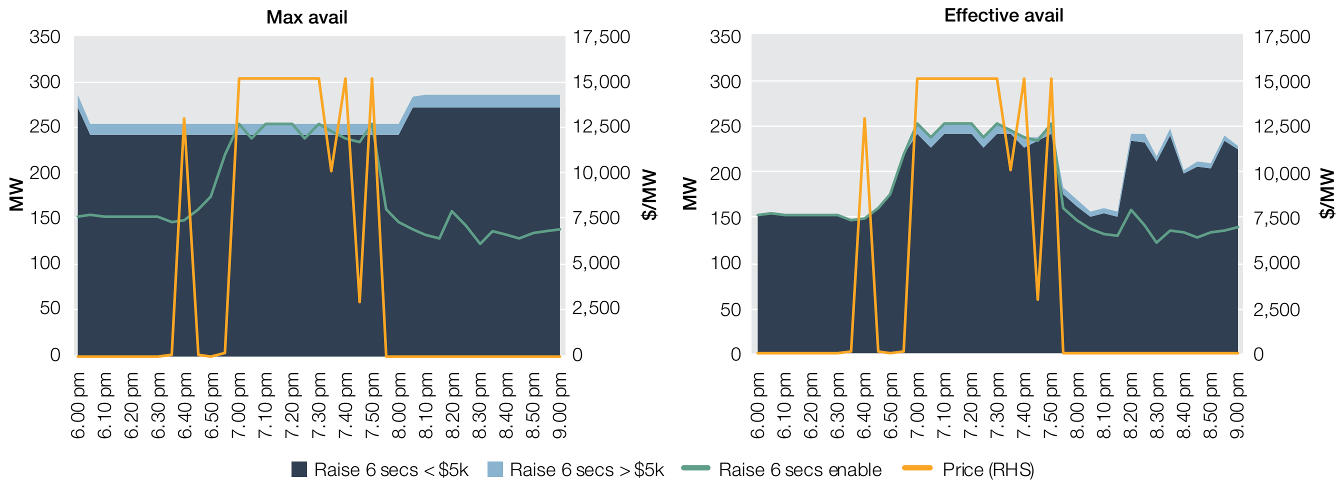


Source: AER analysis using NEM data.

Some high priced capacity was needed to meet the local FCAS requirement

As highlighted on 4 November, sharp increase in the requirement for R6 services around 7 pm meant there was no more low-priced capacity available to meet the requirement (Figure 1.31). The requirement increased when a negative settlement residue constraint reduced forced exports from Queensland, as discussed earlier.

Figure 1.31 4 November availability



Source: AER analysis using NEM data.

Table 1.4 shows the percentage of capacity offered during each high-priced period below $5,000/MW and the cost of those services during the high prices.

Table 1.4 Per cent of FCAS services offered below $5,000/MW and costs

DATE	SERVICE	# 30 MIN INTERVALS	% OFFERED <$5K	COST OF HP INTERVALS
16 October	L6, L60	7	~85% ~55%	L6 ($8,746,281.93) L60 ($9,790,766.56)
4 November	R6	2	~95%	R6 ($2,754,943.78)
8 November	L6, L60	3	~62% ~45%	L6 ($2,340,192.72) L60 ($2,554,938.81)
11 November	R6, R60	15	~59% ~48%	R6 ($29,024,447.08) R60 ($25,964,508.05)

Price setter

On 11 November we also observed a negative settlement residue constraint contributing to the high prices. As discussed above, flow was sometimes forced out of Queensland counter-price, triggering the negative settlement residue constraint to bind and then violate. The cost of violating the constraint contributed to the price that was set.

On 8 November there were 8 occasions the high price was set by units who rebid their capacity into higher price bands.

Rebidding

On a number of occasions, rebidding of capacity from low to high prices contributed to the high FCAS price.

8 November

On this day, 5 minutes before the start of the 11.20 am dispatch interval, CS Energy rebid 75 MW of L6 services at Gladstone and Callide power stations from prices below $7/MW to $15,000/MW. At the same time, CS Energy also rebid 60 MW of L60 services from prices below $7/MW to $15,000/MW. The reasons given related to price forecasts. Stanwell also removed 35 MW of L60 services from Tarong 3 due to mill limits. While some 5 minute prices greater than $5,000 may still have occurred in the L6 and L60 services, these rebids contributed to the number of dispatch prices close to the cap.

On the other days some generators provided an additional 10 to 50 MW of capacity for one or more service, with many also moving capacity from high price bands to lower price bands. Demand response aggregators also made additional FCAS capacity available.

Participants rebid their enablement points across most of the dispatch intervals meaning a unit could begin to provide lower services at a lower level in energy.[18] The reasons for these rebids given related to mill, technical or emission limits.

FCAS costs can affect participant behaviour in energy

Record FCAS costs caused some participants to change how they offer their energy. The allocation of raise contingency costs puts an extra burden on generators who are not able to provide these services (Box 2).

Box 2: What is Contingency FCAS and who pays?

Contingency services manage risk. Generators pay for raise and customers pay for lower services. These services must be available to raise or lower the frequency of the power system if there is a major loss of generation or load. The costs are split between suppliers and consumers of electricity. Generators and small generation aggregators pay for raise services because if a generator trips, raise services will be needed to increase the frequency of the power system. Market customers pay for lower services because if a large load trips off the system, lower services will be needed to reduce the frequency into safe operating bands once again.

Solar and wind generators typically don't provide raise services or earn raise revenue, but they are apportioned a share of local raise FCAS costs based on their share of total generation. This means during a time of high contingency raise prices and low energy prices it may be uneconomic for these units to continue generating electricity because

18 Enablement points are the technical limits for a unit to provide FCAS and form part of an FCAS offer. For a detailed explanation see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/guide-to-ancillary-services-in-the-national-electricity-market.pdf.

the contingency raise costs outweigh the revenue from generating electricity. As a result wind and solar generators may have an incentive to rebid their energy offers to high prices to reduce their exposure to raise FCAS costs. A sudden reduction in the supply of cheap generation can in turn cause energy prices to jump. This occurred on 11 November in Queensland when 7 solar farms rebid around 500 MW of capacity to the cap.[19]

Going forward

The upgrades on QNI have been the principal driver of record FCAS costs in Q4 and across the 2021 calendar year. The upgrades are currently 90% complete with the next set of system outages expected in March and April 2022, following summer peak demand.[20] Once the equipment installation is complete and fully tested we would expect to see FCAS costs return toward levels seen before May 2020, when the upgrade started.

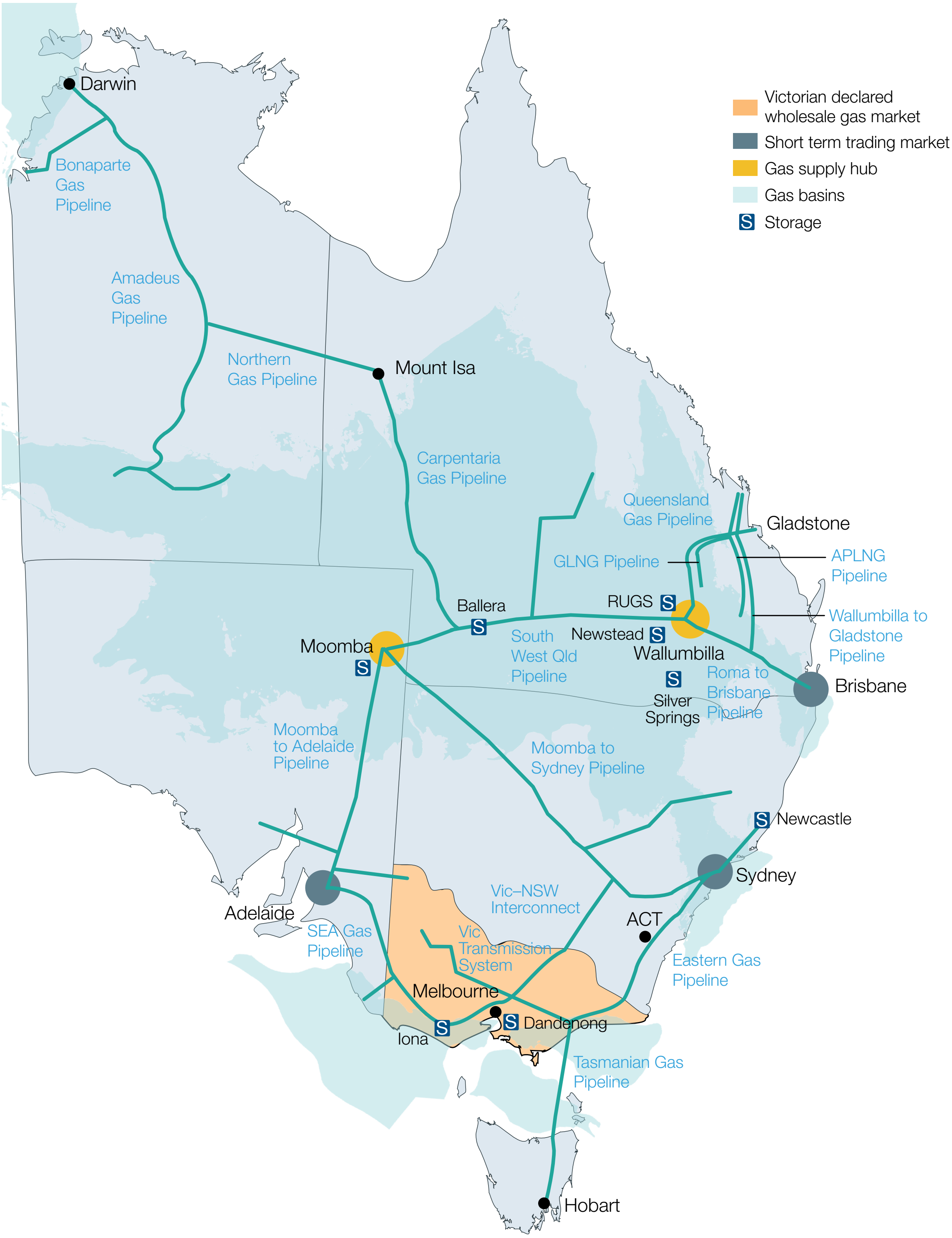
19 https://www.aer.gov.au/wholesale-markets/performance-reporting/prices-above-5000-mwh-11-november-2021-queensland.

20 QNI upgrade nears completion as ninth capacitor bank installed – Energy Source & Distribution (esdnews.com.au).

2. Gas

The gas section commences with a discussion of domestic pricing and global pricing/shipping in section 2.1 and 2.2 before reporting on outcomes from the upstream to downstream following the flow of gas:

- Section 2.3, 2.4 – Upstream production, storage trends and trade at gas supply hubs.
- Section 2.5, 2.6 – Transportation of gas including trade through capacity platforms.
- Section 2.7, 2.8 – Downstream markets and gas usage by gas-powered generators.
- Section 2.9 – Financial markets attached to the Victorian gas market.



2.1 Moderate domestic prices de-link from high international prices

Domestic gas prices increased significantly over 2021 with average prices ranging between $8.24/GJ and $10.64/GJ, an increase of 81% from 2020 average prices which ranged between $4.83/GJ and $5.70/GJ (Table 2.1). This coincided with even larger increases in Asian LNG netback prices ($16.56/GJ) which are now materially higher than domestic market prices, driven by price spikes which occurred during the latter part of 2021.

Both international and domestic prices experienced intense periods of price spikes during summer and winter periods. The high price events were generally associated with high demand for gas and supply outages at gas production facilities.

Table 2.1 Calendar year gas spot price outcomes

		AVERAGE SPOT PRICES				
		2017	2018	2019	2020	2021
Price, $/GJ	VIC	8.39	9.12	8.84	5.11	8.24
	ADL	8.50	9.13	9.44	5.70	9.25
	BRI	8.09	8.81	8.02	4.89	9.12
	SYD	9.20	9.40	8.97	5.08	9.07
	WAL	8.52	8.96	7.84	4.83	10.64
	Asian LNG Netback price at Wallumbilla	7.65	10.88	6.83	4.29	16.56

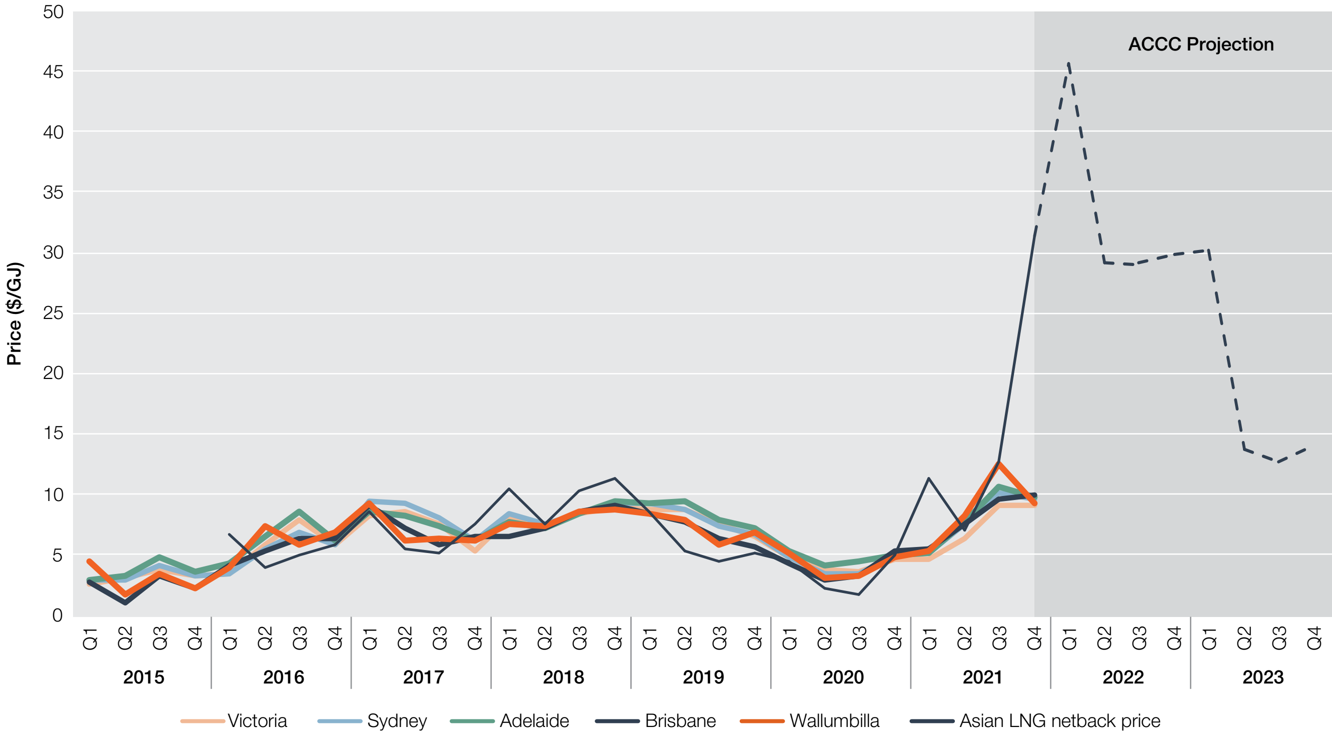
Source: AER analysis using Argus media, DWGM, STTM, WGSH data and ACCC netback price series.

Domestic prices decreased slightly this quarter, on average ranging between $10.00/GJ and $10.91/GJ in Q4, compared to Q3 prices which ranged between $10.10/GJ and $13.42/GJ (Figure 2.1). This followed the end of winter and reduced demand for gas with lower gas heating requirements. There were some daily price spikes, ranging between $12/GJ and 15/GJ across mid-November to mid-December, coinciding with reduced supply from the Longford production plant in Victoria. During this period, the Iona storage facility was offering relatively more expensive supply, bearing on higher market prices.

International market prices rose significantly over Q4, with the Asian LNG netback price more than doubling to $32.35/GJ in Q4 2021 from $13.65/GJ in Q3 2021 (Figure 2.1). This represented a significant deviation from domestic market prices, reflecting the following range of factors:

- Heavy buying of LNG for heating on expectations of a cold northern hemisphere winter.
- Competitive bidding for LNG cargoes between Asian and European customers.
- Shipping constraints affecting supply chains.
- Outages at production facilities in Malaysia, USA and Australia (NT).
- European supply constraints affecting gas supplies from Russia.

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.

2.2 Gas production high reaches record levels

Gas production levels rose to record levels on the east coast, increasing from 1948 PJ in 2020 to 1,991 PJ in 2021 (Table 2.2). The increase in gas production over the last year has been driven by increases mostly by the large fields in Queensland around Roma (28 PJ) and in Victoria at the Longford (24 PJ) and Orbost production plants (7 PJ). The rise in production levels in 2021 coincides with a sharp increase in domestic and international spot prices over the same period.

Table 2.2 Calendar year gas production and storage outcomes

		PRODUCTION AND STORAGE VOLUMES				
		2017	2018	2019	2020	2021
Production, PJ	Northern	1385	1442	1604	1639	1657
	Southern	441	348	347	308	334
	Total	1826	1789	1951	1948	1991
Average gas storage level, PJ		N/A	N/A	95.4	98.9	99.8

Source: AER analysis using Natural Gas Services Bulletin Board data which requires facilities producing greater than 10TJ per day to report.
Notes: Data for storage is not continuous, as new storage facility reporting has been added since 2016/17.

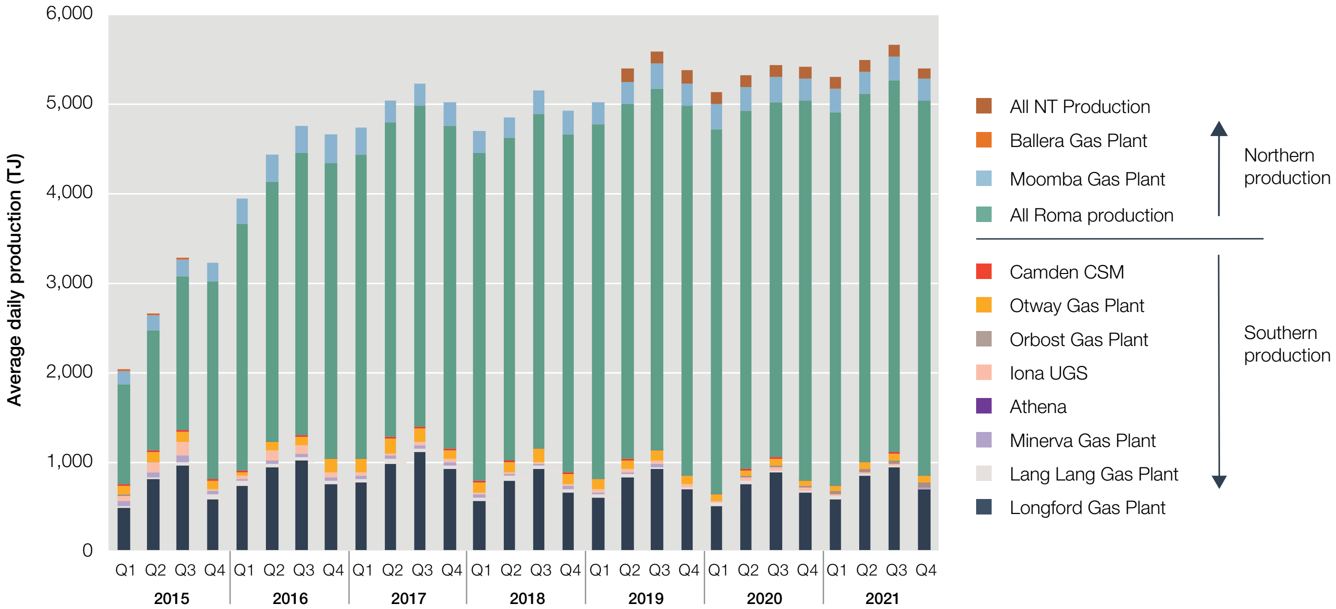
Gas production over the quarter declined from 5,649 TJ/day in Q3 2021 to 5,391 TJ/day in Q4 2021 as expected given lower east coast gas heating demand. The reduction in production over Q4 was mainly attributable to reduced supply at the Longford gas plant in Victoria which reached 697 TJ/day output in Q4, down from a maximum of 928 TJ/day in Q3 (Figure 2.2). Longford's reduction was due to planned maintenance which typically occurs at this time of year (Table 2.3). The reduced production capacity of Longford during December coincided with higher prices up to $16/GJ in southern markets across a number of days. The Athena gas plant in Victoria commenced production in Q4 2021, supplying 13 TJ/day over the quarter, sourcing gas from the Casino, Henry and Netherby gas fields.[21]

Production increased at gas fields in Queensland around Roma from 4,162 TJ/day in Q3 to 4,202 TJ/day in Q4 2021, slightly lower than the record quarterly production level of 4,242 TJ/day in Q4 2020 (Figure 2.2). There were limited

21 Cooper Energy, ASX announcement, accessed 7 February 2022.

outages at a number of gas production facilities around Roma which allowed these fields to produce with less constraints (Table 2.3). These fields are operated by the Queensland LNG exporters and support higher LNG export volumes for customers needing gas during the northern hemisphere winter.

Figure 2.2 East coast production (including Northern Territory)



Source: AER analysis using Natural Gas Bulletin Board data.

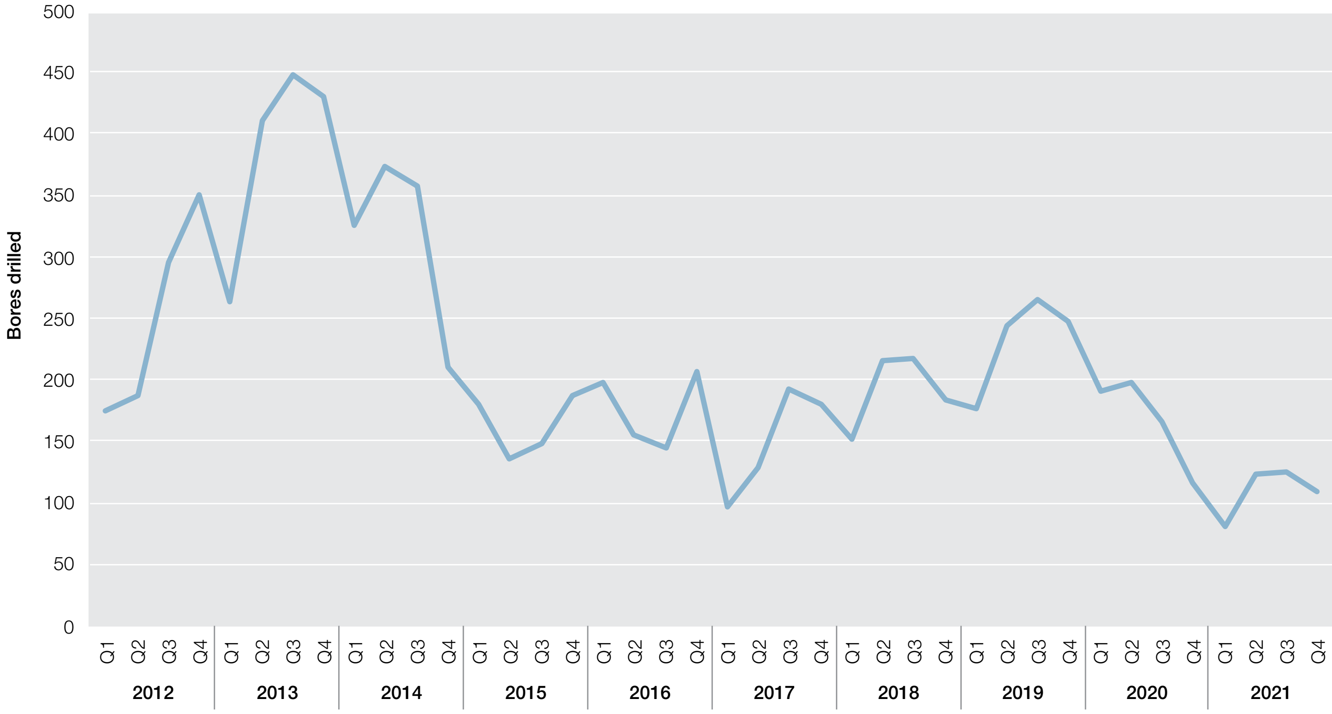
Table 2.3 Major gas production facility outages

DATE	FACILITY	OPERATOR	NAMEPLATE CAPACITY (TJ/DAY)	MAXIMUM CAPACITY DURING MAINTENANCE (TJ/DAY)
1 Oct–31 Dec	Longford	Esso	1,115	505–980
14–18 Oct	Berwyndale South	QGC	144	35–80
5–20 Oct	Moomba	Santos	310	175–240

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

There was a decrease in the number of new coal seam gas wells drilled in Queensland, reaching 109 in Q4 2021, falling from 126 in Q3 2021, amid rising gas production volumes. Drilling numbers can be indicative of potential supply changes, as a procession of new wells is required to support ongoing production from coal seam gas resources such as those in Roma. During 2021, only 439 bores were drilled, compared to 671 bores drilled in 2020, despite a rise in international and domestic gas prices during 2021 (Figure 2.3).

Figure 2.3 Queensland coal seam gas bores drilled

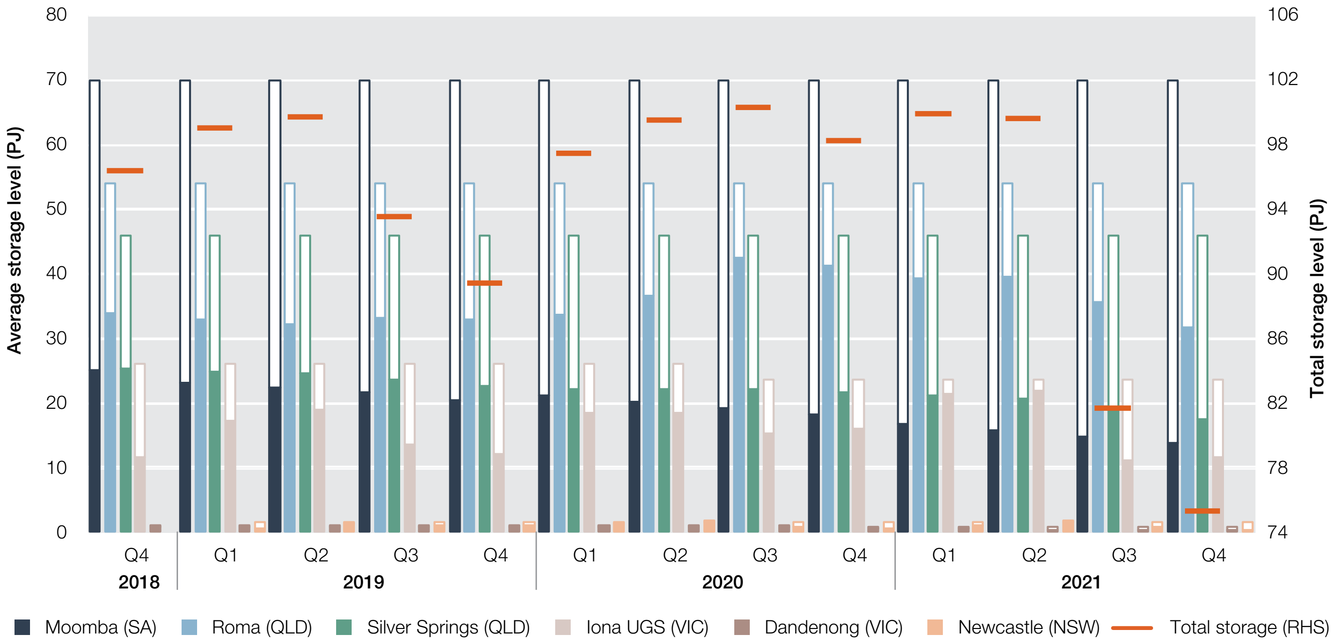


Source: AER analysis using Queensland Department of Natural Resources, Mines and Energy.

Storage volumes continued to decline from the previous quarter from 81.7 PJ in Q3 2021 to 75.2 PJ in Q4 2021 (Figure 2.4). The fall of storage volumes were driven by declines in the Roma and Silver Springs storage facilities in Queensland, which coincided with higher international and domestic market quarterly prices.

The Iona storage facility in Victoria maintained at a similar storage volume from Q3 2021, at around 11 PJ in Q4 and remains around 40% full. At times during Q4, the Iona facility critically injected significant volumes, in excess of 200 TJ/day into the Victorian gas market – supplying over a third of the markets needs as gas supply was constrained at the Longford gas plant.[22] The Iona storage levels at the end of 2021 were lower compared to any other year since 2017, indicating the increasing reliance on gas supply from storage to meet demand.[23]

Figure 2.4 Storage volumes



Source: AER analysis using Natural Gas Bulletin Board data.

22 Injections from Iona reached 42% of total Victorian gas injections on 8 November 2021 during unplanned maintenance at Longford.

23 AEMO, *Quarterly Energy Dynamics Q4 2021, January 2021*, p. 45.

2.3 QLD LNG exports still strong

Queensland LNG exports increased 4.9% to a record high of 1,277 PJ in 2021, from 1,217 PJ in 2020, as international prices increased dramatically and overseas gas use for power generation and industrial activity grew. Most of the increase in LNG exports can be attributed to higher buying volumes from China and South Korea (Table 2.4).

Table 2.4 Calendar year QLD LNG export outcomes

		QLD LNG EXPORT VOLUMES				
		2017	2018	2019	2020	2021
Exports, PJ	Total	1,101	1,119	1,204	1,217	1,277
Exports by country, PJ	China	631	775	863	815	851
	Korea	216	175	155	178	198
	Japan	149	89	65	82	77
	Malaysia	34	48	92	108	101
	Other	72	32	28	33	49

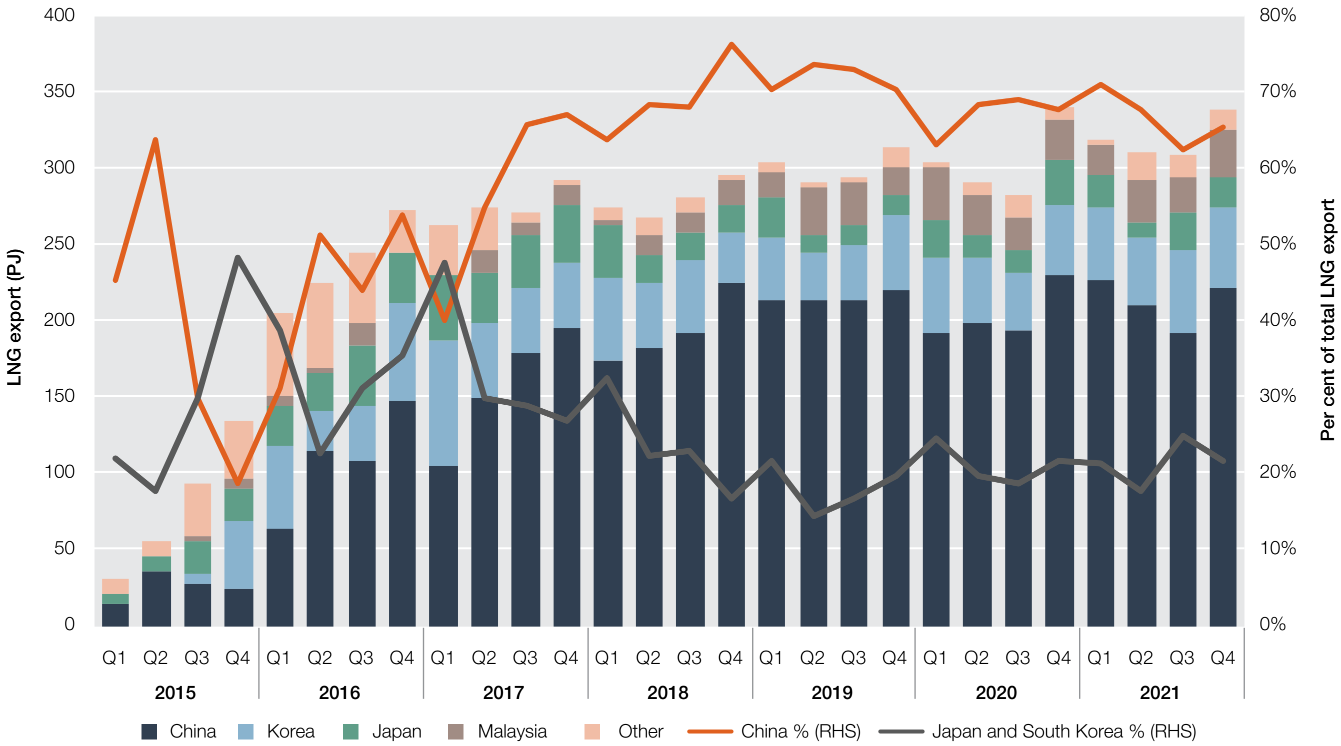
Source: AER analysis using Gladstone Port Corporation data.

Asian buyers showed strong demand for LNG in Q4 2021, importing 338 PJ in Q4 2021, slightly less than the record amount in Q4 2020 of 340 PJ (Figure 2.5). Strong northern hemisphere buying volumes are typical at this time of year as the northern winter commences. Weather forecasts indicated a strong possibility of a La Nina system, typically associated with colder than average temperatures, driving particularly strong demand for LNG this quarter.

Overall, a number of key structural factors appear to be supporting ongoing year-round gas use in Asia, including switching from coal and nuclear powered electricity generation to gas. China and South Korea have enacted energy plans to increase gas use for electricity generation to achieve carbon neutrality, promoting gas as a relatively lower emitting fuel source.[24] Both China and South Korea have increased importing LNG volumes in 2021 compared to previous years.

24 Department of Industry, Science, Energy and Resources, Resources and Energy Quarterly, December 2021, pp. 73–75.

Figure 2.5 LNG shipped from Gladstone Port by destination



Source: AER analysis using Gladstone Port Corporation data.

The Queensland LNG plants undertook limited maintenance during Q4 2021, which is typical for this time of year when LNG exports are at their highest during the northern hemisphere winter (Table 2.5).

Table 2.5 LNG plant outages

FACILITY	PERIOD	CAPACITY OFFLINE
APLNG	5–13 October	0.5 train
GLNG	19 October–6 November	0.5 train
QCLNG	15–17 October	0.5 train

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

2.4 Gas supply hub trade increases slightly

Gas supply hub prices increased dramatically last year, from $4.83/GJ in 2020 to $10.64/GJ in 2021 (Table 2.6). Participation increased from last year as gas traded through the gas supply hubs in 2021 reached 24.3 PJ an increase from 21.1 PJ in 2020 but still below record trade levels of 27.4 PJ in 2019. Increasingly, trade is occurring off-screen providing less transparency on the bidding process to market participants, compared to trade where bids appear on-screen and more trading data is available in real time.[25] In 2021, on screen trade was 15% of total trade, compared to previous years where on screen trade has been close to 60% of total trade. Participation has grown in the gas supply hubs over time with a record level of 20 active participants trading in 2021, including a greater diversity of participants across industrial, gentailer, producer and trader groups.

25 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 trades are agreed to by participants separately and then lodged through the hub for settlement. 'Off market' trades do not use the Gas Supply Hub platform at all.

Table 2.6 Calendar year gas supply hub outcomes

GAS SUPPLY HUB TRADE PRICES, VOLUMES AND PARTICIPATION	2017	2018	2019	2020	2021
Volume Traded	11.61	16.38	27.38	21.06	24.36
Off screen	4.85	11.27	18.10	16.37	20.65
On screen	6.76	5.11	9.28	4.69	3.72
Average price	$8.52	$8.96	$7.84	$4.83	$10.64
Active participants	13	12	16	19	20

Source: AER analysis using Gas Supply Hub trades data.

Note: Total of all products traded at all locations. We consider a participant “active” in the GSH on a yearly basis if it won capacity in the auction at least 12 times.

While yearly average prices were up, gas supply hub prices declined by 23% in the last quarter. Prices were volatile during Q4, ranging between $7/GJ and $16.50/GJ, starting low in October and peaking from mid-November to mid-December when southern markets and international prices similarly peaked.

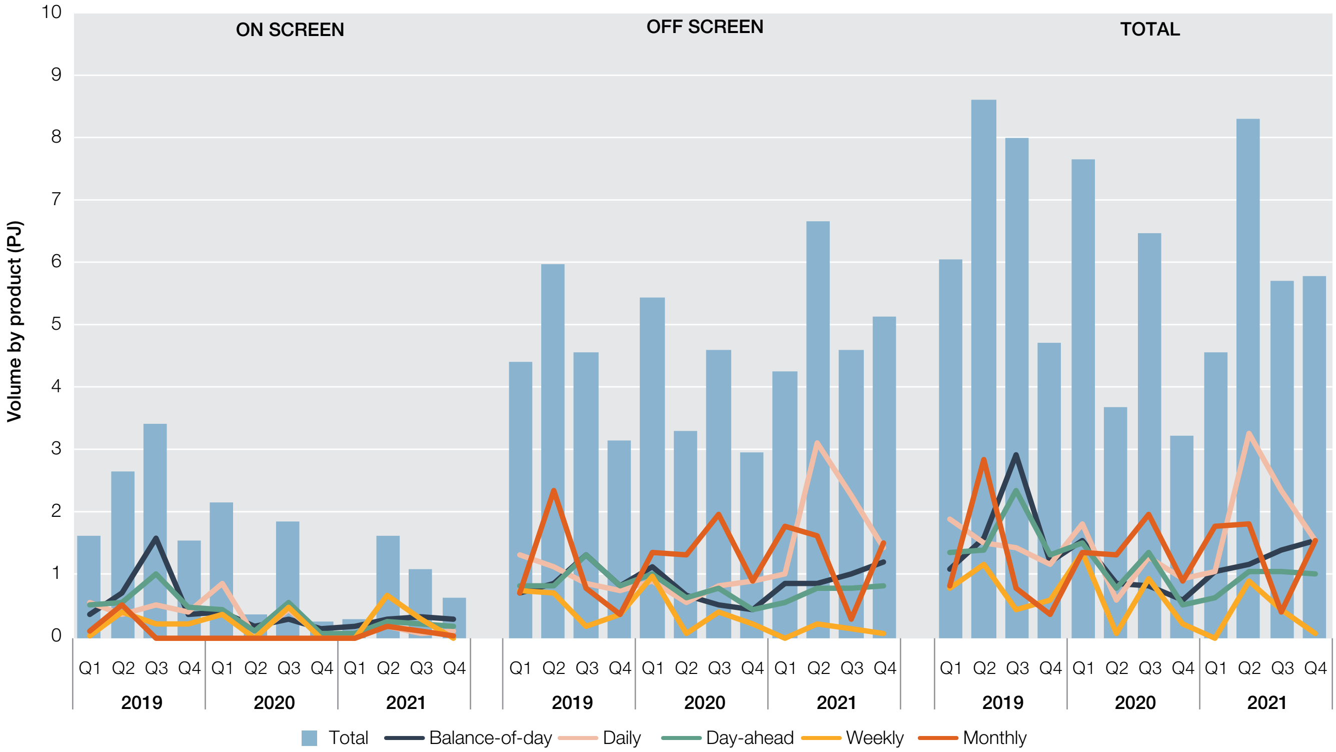
Gas trading volumes increased slightly over the quarter, reaching 5.8 PJ in Q4 2021, increasing from 5.7 PJ in Q3 2021 (Figure 2.6). An increase in trade of longer dated monthly products occurred in Q4, increasing from 0.4 PJ in Q3 to 1.6 PJ in Q4. Daily and balance of day products were also popular in Q4, trading at volumes of around 1.5 PJ each over the quarter.

Trading volumes were more dispersed across locations than previous quarters with material trades at delivery points at Moomba (0.24 PJ), Sydney (0.41 PJ) and Culcairn–Victoria (0.115 PJ).[26] This information provides transparency of trade volumes and prices between Queensland and southern markets, which hasn’t existed to date as trades have been organised bilaterally with no public disclosure. It is anticipated that further transparency will be provided through the requirement to report short-term and swap trades through the new Gas Market Transparency Measures legislative package currently tabled in the South Australian parliament.

Trading amongst participant groups has changed significantly since Q3 2021, with producer and exporter trades dropping from 54% of total trade in Q3 2021 to 23% in Q4 2021. This may reflect larger volumes of gas being converted into LNG for export to capitalise on relatively higher international LNG prices. Gentailers participated in 50% of total trade in Q4 2021 up from 35% in Q3 2021.

26 In 2021, the boundary of the gas supply hubs was expanded to include Sydney and Victoria but to date these locations have only traded immaterial quantities of gas.

Figure 2.6 Gas Supply Hub – On screen, off screen and total trade volumes by product



Source: AER analysis using Gas Supply Hub trades data.

2.5 Use of day ahead auction continues to grow

Last year, the day ahead auction for pipeline capacity continued to grow with 27% higher volume of trade from 43 PJ in 2020 to 54.7 PJ in 2021 (Table 2.7). The auction continues to provide relatively cheap short-term access to pipeline capacity compared to contract market rates with 83% of auctioned capacity won at $0/GJ in 2021. Importantly, this capacity has led to significant transport of gas between markets like Queensland with large gas supplies to other states via multiple pipeline routes that are heavily contracted.

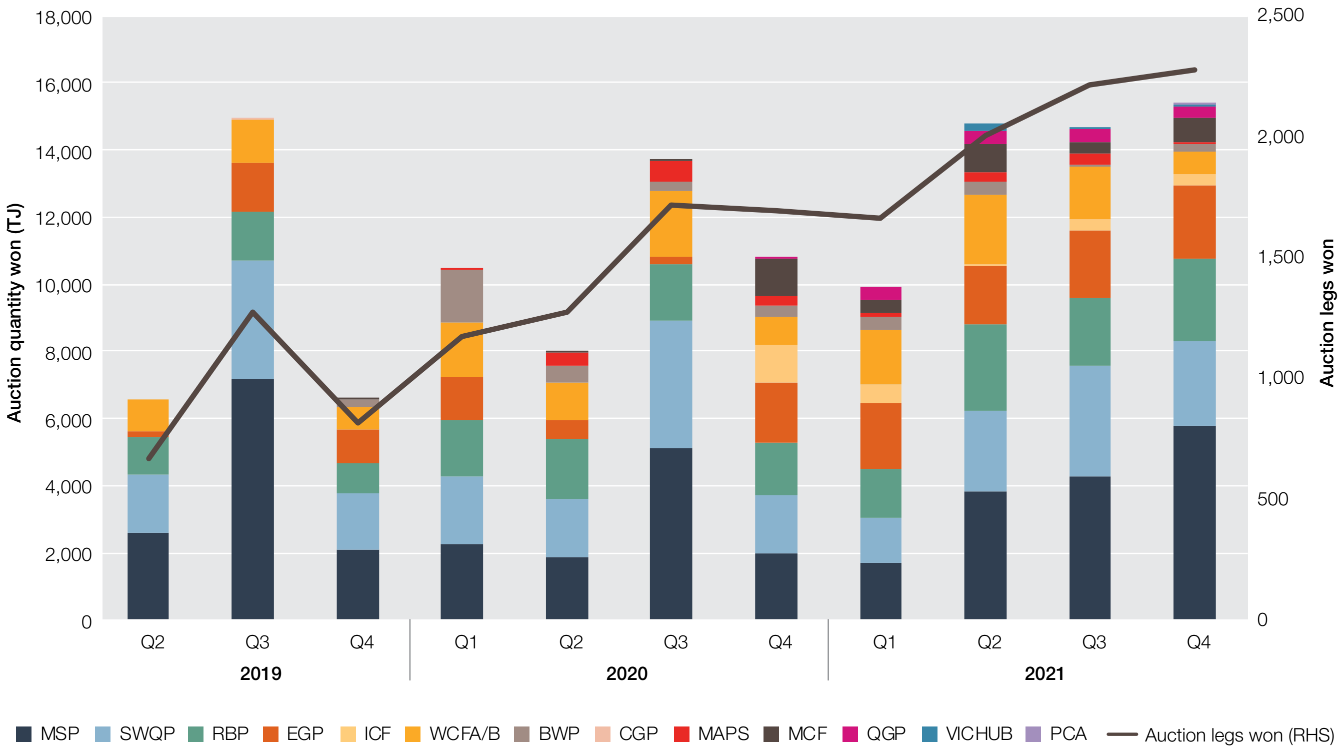
Table 2.7 Calendar year day ahead auction outcomes

DAY AHEAD AUCTION TRADING PRICES, VOLUMES AND PARTICIPATION			
	2019	2020	2021
Capacity won, PJ	30.5	43	54.7
Total auction volume bid, PJ	41.6	58.7	69
Auction legs won	2756	5855	8158
Won at $0/GJ clearing price, %	79	79	83
Active participants	8	16	22
Number of auction facilities traded	9	11	14

Source: AER analysis using DAA auction results data.

In Q4 2021, 83% of total pipeline capacity was auctioned at $0/GJ, and average auction prices reached $0.14/GJ for Q4, a decrease from $0.28/GJ in Q3 2021. The volume of pipeline capacity auctioned grew last quarter, from 14.7 PJ in Q3 2021 to the highest level ever of 15.4 PJ in Q4 2021 (Figure 2.7).

Figure 2.7 Pipeline capacity won on the Day Ahead Auction

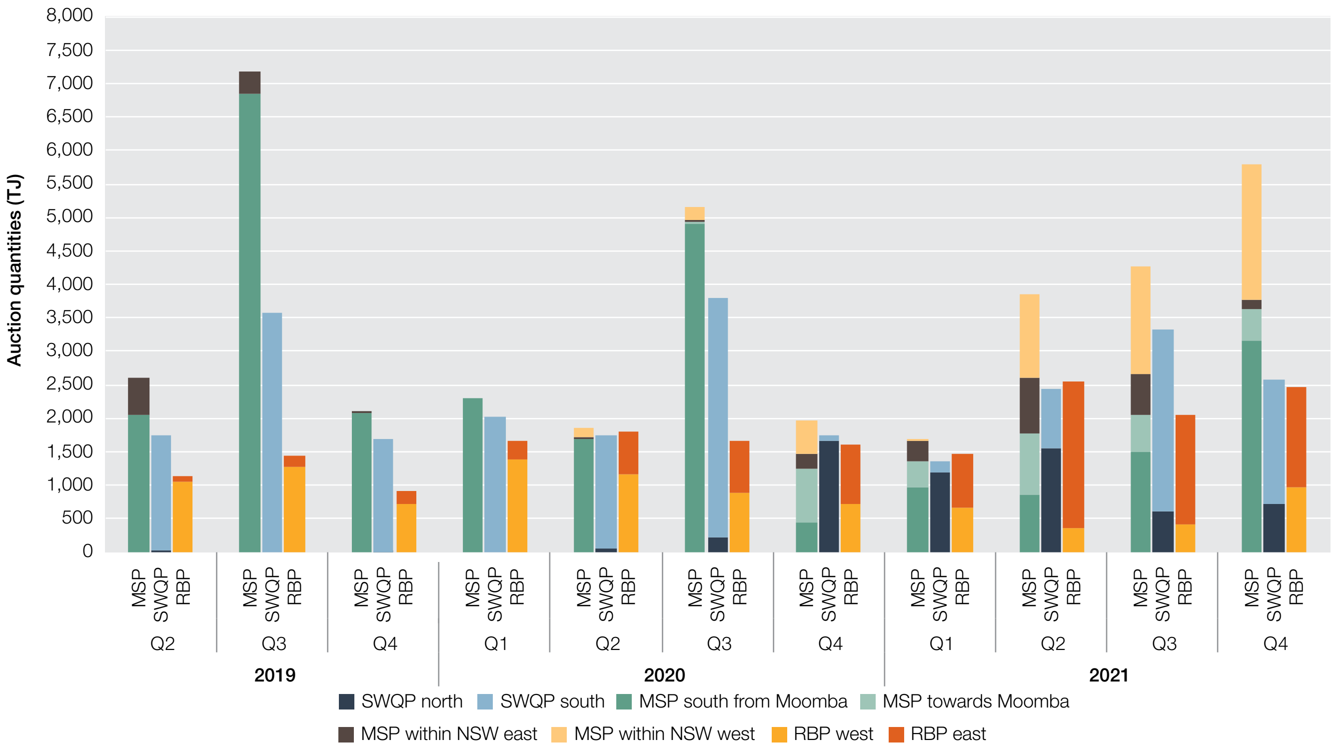


Source: AER analysis using DAA auction results data.

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.

The majority of the capacity was won on routes into and out of Queensland on the Moomba to Sydney Pipeline (5.8 PJ) and South West Queensland Pipeline (2.6 PJ) (Figure 2.8). This capacity was mostly supporting the flow of gas south from Queensland but to a lesser extent also sending gas from southern states to Queensland. The Moomba to Sydney Pipeline transported 3.1 PJ south from Moomba and 0.5 PJ north toward Queensland during Q4 2021. Approximately 1.9 PJ of auctioned capacity was won on routes flowing south on the South West Queensland Pipeline away from Queensland, and 0.7 PJ north to Queensland during Q4 2021. In Q4, producers and exporters won 53% of the capacity auctioned pipeline capacity, the highest level since the auction began.

Figure 2.8 Day Ahead Auction quantities won on the MSP, SWQP and RBP

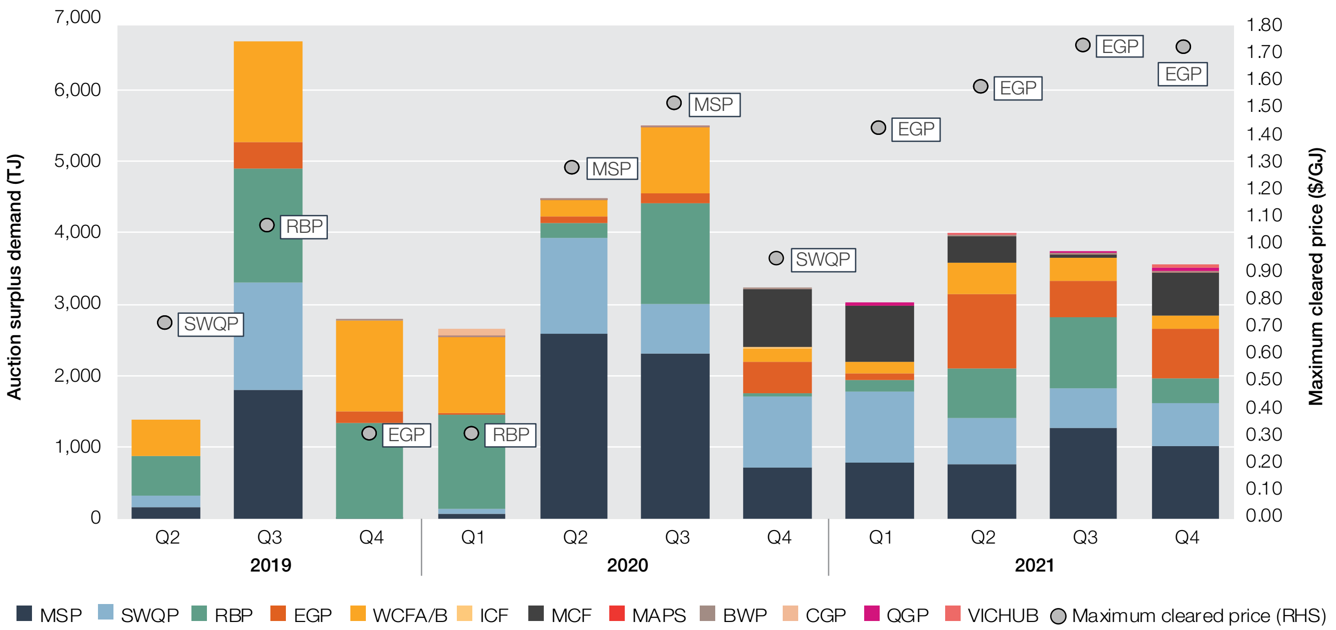


Source: AER analysis using DAA auction results data.

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

The auction was also used to transport material quantities of gas from Victoria to NSW via the Eastern Gas Pipeline (2.2 PJ) in Q4 2021 (Figure 2.8). The Eastern Gas Pipeline experienced a surplus auction demand of 0.62 PJ and recorded the highest auction price of $1.69/GJ for Q4 2021 (Figure 2.9). Although surplus auction demand was higher on the Moomba to Sydney Pipeline at 1.02 PJ it did not result in a higher maximum auction price.

Figure 2.9 Day Ahead Auction surplus demand and maximum clearing prices



Source: AER analysis using DAA auction results data.

Note: Constraints can be caused by individual pipeline segments, delivery or receipt zones, physical receipt or delivery points, or a combination thereof. The constraint percentage reflects the frequency in a given month where the auction demand exceeded the auction capacity or where auction demand matched the auction capacity resulting in an auction clearing price greater than $0/GJ.

The high maximum auction price recorded on the Eastern Gas Pipeline may be explained by a consistent frequency of constraints throughout the quarter between 55% and 71% of the time (Figure 2.10). Auction constraints mean auction demand exceeds supply, leading to increased auction prices. The number of active auction participants on the Eastern Gas Pipeline has grown to 6 in 2021 from 2 in 2019 and 2020, increasing the competition for auctioned pipeline capacity and putting upward pressure on auction prices. This increased competition explains the rise in weighted average auction clearing prices on the Eastern Gas Pipeline from $0.03/GJ in 2019 and 2020, to $0.34/GJ in 2021. Although the Moomba to Sydney Pipeline was the most used auction facility this quarter, it was relatively less constrained, between only 3% and 23% of the time.

Figure 2.10 Frequency of Day Ahead Auction constraints quarter on quarter comparison

		Q4 2019			Q4 2020			Q4 2021		
PIPELINE	DIRECTION	OCT	NOV	DEC	OCT	NOV	DEC	OCT	NOV	DEC
BWP			3%		26%	37%		3%	3%	
EGP		32%			10%	20%	10%	71%	60%	55%
MSP	Towards Moomba								17%	26%
	Within NSW East							3%	7%	
	Within NSW West							3%	20%	23%
QGP	Towards Wallumbilla								3%	100%
RBP	East							23%	10%	
	West	90%	67%	36%				52%	7%	13%
SWQP	North SWQP					70%	94%	23%	17%	29%

Not constrained	<20%	20–40%	40–60%	60–80%	>80%

Source: AER analysis using DAA auction results data.

Note: Surplus demand indicates the volume of auction bids which were unsuccessful because the total bids exceeded the available auction quantity, the Auction Quantity Limit (AQL), or a bid was unsuccessful due to a paired bid with another constrained facility. Surplus demand is calculated on auction routes where auction capacity was bid on.

2.6 Gas flows to markets of highest value

Gas continues to flow dynamically across the east coast. In 2021 Queensland imported 36.4 PJ of gas, a significant increase from the 0.5 PJ the state imported during 2020 (Table 2.8). This coincides with record levels of LNG exports from Queensland in 2021 and high LNG prices which may have incentivised producers and exporters to move higher volumes of gas from the south to the north than in previous years.

Table 2.8 Calendar year interstate gas flow outcomes

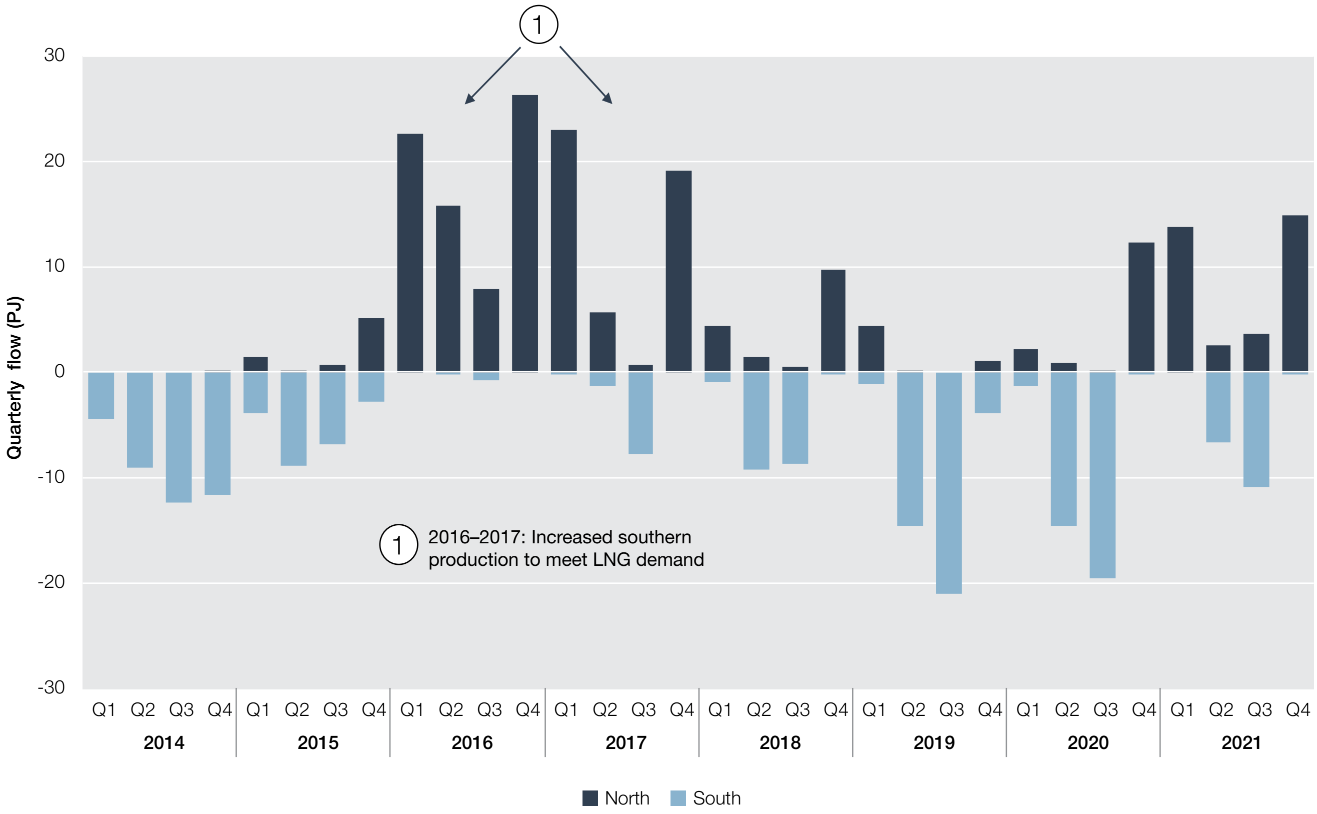
		INTERSTATE GAS FLOW VOLUMES							
		TAS	VIC	NSW	NT	SA		QLD	
		Import	Export	Import	Export	Import	Export	Import	Export
Gas flows, PJ	2019	10.2	107.9	120.8	25.7	12.1			9.6
	2020	7.4	83.9	109.8	20.5		13.2	0.5	
	2021	7.1	121.8	113.4	19.1		15.9	36.4	

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

Gas predominantly flowed from southern to northern markets in 2021, with significant volumes of gas, in excess of 10 PJ, flowing north for both Q1 and Q4. The last time more gas moved north from southern markets across a year, was during the commissioning phase of LNG export plants in Queensland in 2016 and then 2017 (Figure 2.11). At this time the plants needed to run at full capacity and were supplied by gas from southern states while Queensland production was still ramping up. Since 2018, LNG plants have operated at lower capacity than during the commissioning phase and been less reliant on gas supply from southern states.

During the winter months in 2021, less gas flowed south compared to 2019 and 2020. Additionally, there was some movement of gas north during these winter months. Gas production in Victoria was high over 2021, particularly during the winter months, which may have alleviated the need to import as much gas from northern markets compared to recent years.

Figure 2.11 North–South gas flows

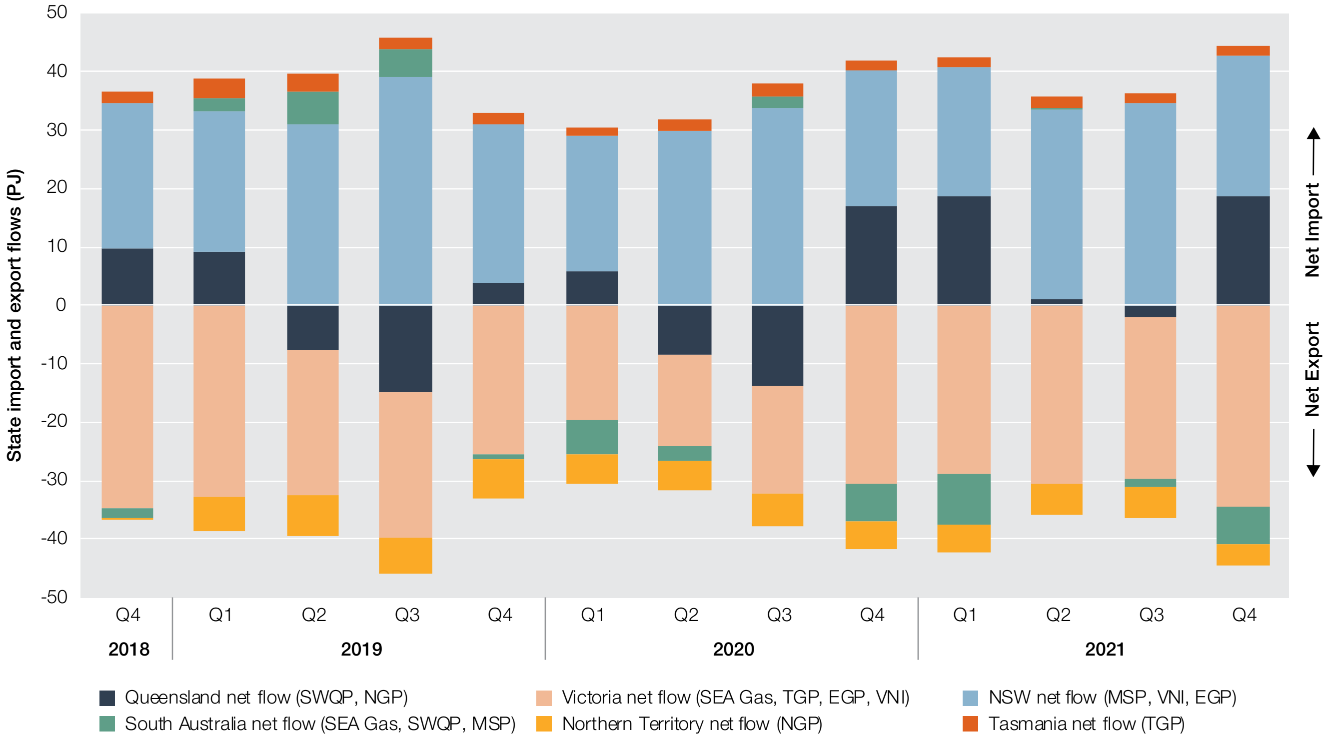


Source: AER analysis using the Natural Gas Services Bulletin Board.

Note: North–South flows depict net physical flows around Moomba – north or south.

Victoria is the largest exporter of gas of all the southern markets and in Q4 exported 34.47 PJ, a level not reached since Q4 2018 (Figure 2.12). A record quarterly quantity of gas was exported from Victoria via the Eastern Gas Pipeline to NSW (19.4 PJ) with smaller export flows via Culcairn on the Moomba to Sydney Pipeline into NSW too (6.5 PJ). Queensland, in turn, imported gas originating from southern fields, receiving 18.61 PJ during Q4 2021, a relatively high level than over recent years (Figure 2.12).

Figure 2.12 Net interstate gas flows



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

2.7 Producers drive record spot market trade in 2021

Trading volumes increased across spot markets and reached a record 66.6 PJ in 2021, a rise of 29% since 2020. The rise in liquidity was mostly driven by higher trading volumes in the Victorian markets and, to a lesser extent, increased trading in Sydney and Brisbane markets. The relative size of trade continues to grow as a percentage of demand, particularly in the Sydney market where trade was a notably high 24% of demand in 2021. Gas spot trade as a percentage of demand has increased in all states in 2021, except South Australia which remained flat from 2020 (Table 2.9).

The trade in spot markets has been estimated by netting participants' positions to determine the volume of gas that is exposed to spot market prices. Higher trade across spot markets in recent years has been driven by greater participation by large gas producers, in particular Santos, BHP and Esso selling more into Victorian and Sydney markets.

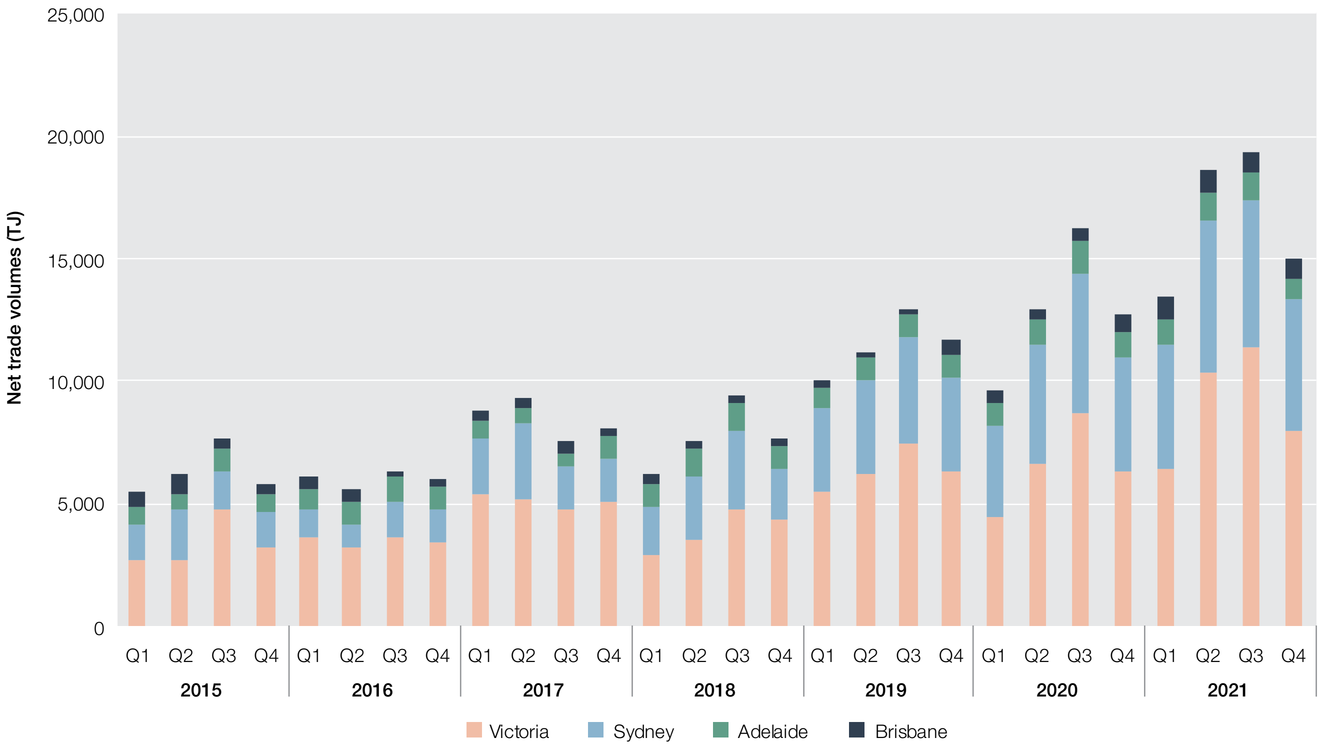
Table 2.9 Calendar year spot market trading outcomes

		SPOT MARKET TRADING VOLUMES				
		2017	2018	2019	2020	2021
Trade Volumes (PJ)	VIC	20.4	15.5	25.5	26.0	36.1
	SYD	8.8	10.0	15.3	19.0	22.6
	ADL	2.9	4.0	3.6	4.3	4.3
	BRI	1.5	1.3	1.5	2.2	3.6
	TOTAL	33.6	30.7	45.9	51.6	66.6
Trade volume as a proportion of demand (%)	VIC	8%	7%	10%	11%	14%
	SYD	10%	11%	17%	21%	24%
	ADL	13%	18%	17%	20%	20%
	BRI	5%	4%	4%	6%	10%

Source: AER analysis using DWGM and STTM data.

Spot market trade declined from 19.4 PJ in Q3 2021 to 15.1 PJ in Q4 2021, with the largest reduction in trade occurring in Victoria and Sydney markets (Figure 2.13). Trade in Q4 generally exhibits lower spot trading compared to Q2 and Q3, as domestic gas consumption reduces in Q4 and gas is converted to LNG and exported overseas is higher during Q4.

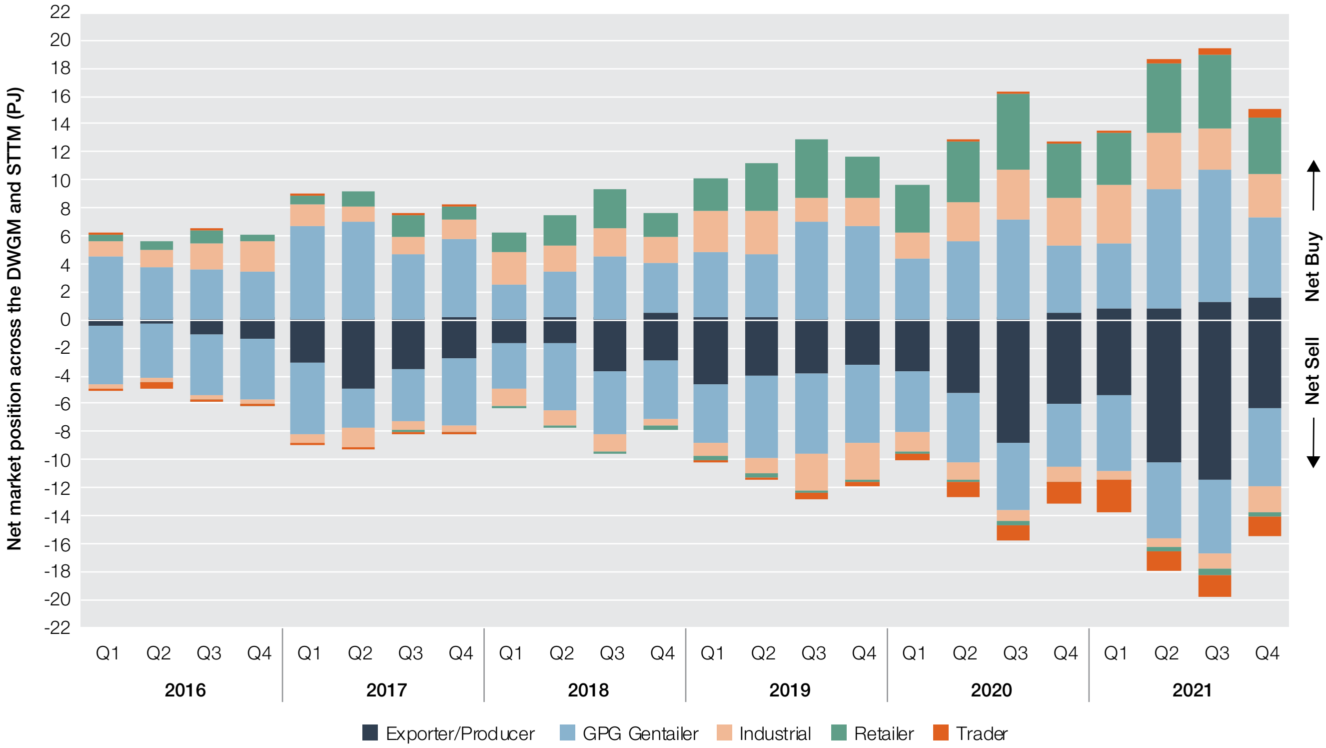
Figure 2.13 Spot trade liquidity



Source: AER analysis using DWGM and STTM data.

The volume of trade for Q4 was the highest Q4 in record. Producers and exporters sold 6.4 PJ in Q4 2021 higher than the 5.9 PJ sold in Q4 2020. Producer and exporters also bought 1.5 PJ in Q4 2021, the highest amount in any quarter since 2016. This is likely to be consistent with the movement of gas from the south to the north for export with domestic spot prices around $10/GJ compared to $30/GJ in Asia (Figure 2.14).

Figure 2.14 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.

2.8 Gas use by electricity generators continues to decline

Gas use by electricity generators continued to fall and in 2021 reached 101 PJ across all east coast mainland states, the lowest level since 2017. Gas consumption by generators fell 20% from 2020 levels and fell in every state except NSW (Table 2.10). This is due to large quantities of lower cost renewable generation displacing gas in the market.

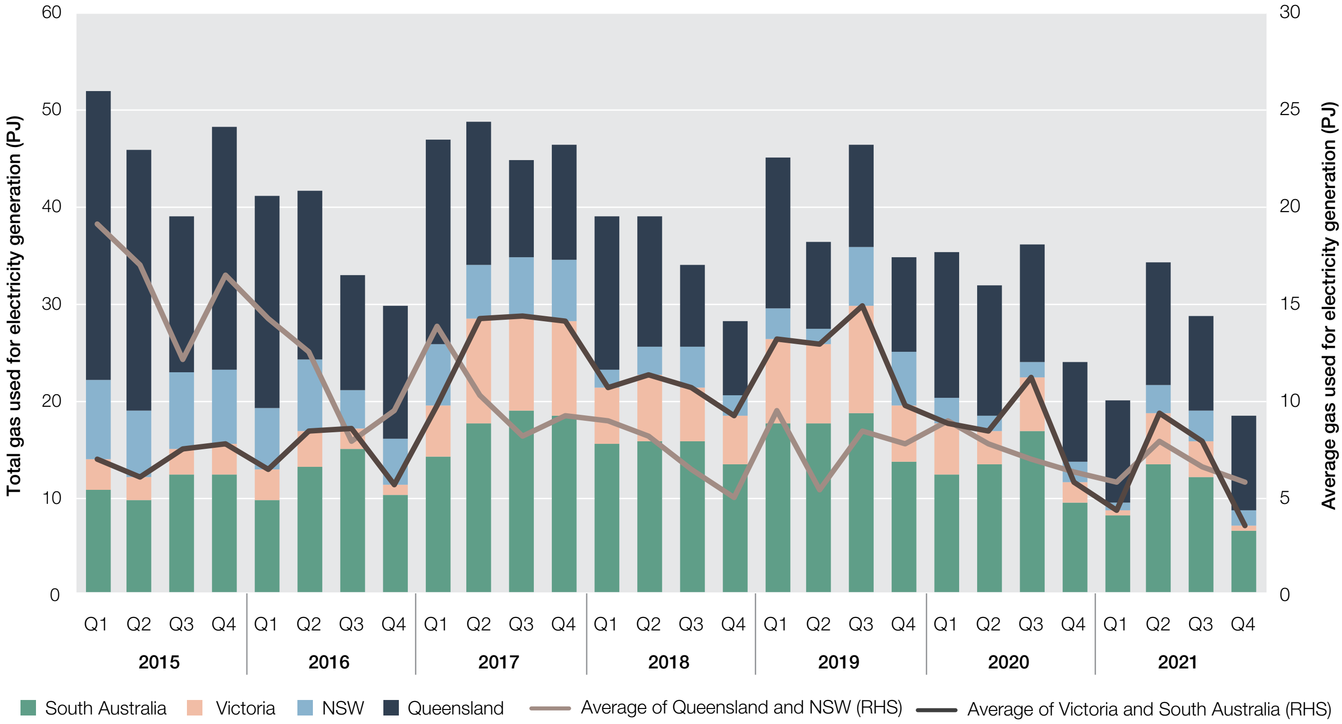
Table 2.10 Gas powered generator gas usage

		GAS POWERED GENERATION CONSUMPTION VOLUMES				
		2017	2018	2019	2020	2021
Total GPG, PJ	QLD	58	46	45	51	43
	NSW	24	11	16	8	8
	VIC	36	23	34	16	10
	SA	69	60	67	51	40
	TOTAL	187	140	163	127	101

Source: AER analysis using NEM data.

Gas generators reduced consumption from Q3 2021 at 28.7 PJ to 18.4 PJ in Q4 2021, following a return to service of coal powered generators and high renewable generation output (Figure 2.15). This represents the lowest quarterly consumption by gas powered generators since 2015 and marks a continuing trend of declining gas use for electricity generation. The role of gas powered generators is discussed further in sections 1.5 and 1.6 of this report.

Figure 2.15 Gas used for electricity generation



Source: AER analysis using NEM data.
Note: Gas use estimates are conversion of electricity generation output using average heat rates (GJ/MWh).

2.9 Victorian gas futures trading increases

Trade in the Victorian gas futures contracts grew over 2021 to 7.5 PJ, an increase from 6.4 PJ in 2020 (Table 2.11). Although the growth in contracts is encouraging, the total trade in futures contracts represents a small proportion, less than 5% of physical gas demand in Victoria. Increased trade in futures contracts is important to establish confidence in expectations of future gas prices and provide a price signal for investments in the energy sector.

Table 2.11 Victorian gas futures contract trade outcomes

	GAS FUTURES TRADE VOLUMES		
	2019	2020	2021
Trade (PJ)	7.2	6.4	7.5
Trade (# contracts)	791	696	821

Source: ASX Energy.

The volume of trade increased by 11% to 3.2 PJ in Q4 2021 from 2.8 PJ in Q3 2021 (Table 2.12). The total volume of contracts traded in Q4 2021 reached 346 and is the largest quantity of trade since Q4 2018. From mid-2020, trading in the Victorian gas futures contract declined significantly, recovering in the second half of 2021.

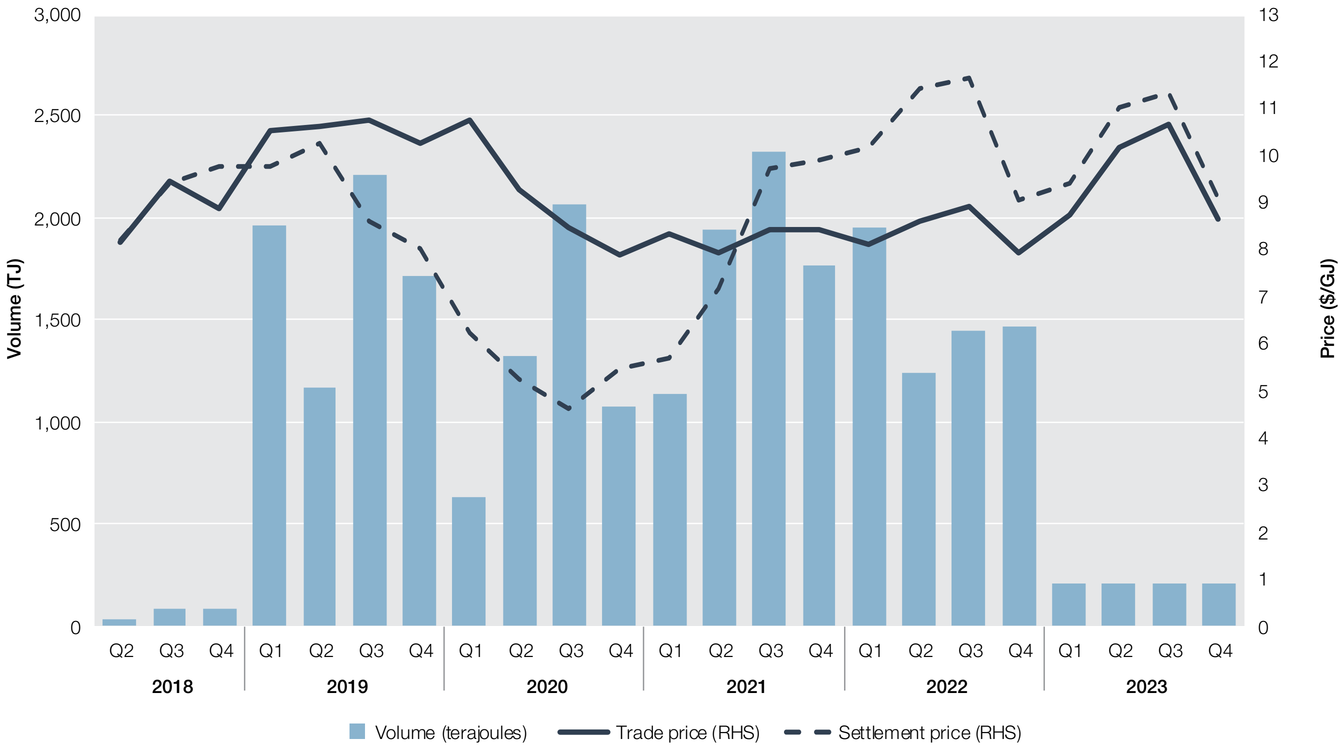
Table 2.12 Victorian gas futures trade summary

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	1,303	143
Q4 2018	3,294	361
Q1 2019	1,661	182
Q2 2019	2528	276
Q3 2019	989	108
Q4 2019	2,058	225
Q1 2020	2,051	224
Q2 2020	2,842	310
Q3 2020	743	81
Q4 2020	741	81
Q1 2021	668	73
Q2 2021	842	92
Q3 2021	2839	310
Q4 2021	3164	346

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

Settlement prices indicate expected gas prices between $9.1/GJ and $11.7/GJ over 2022, and between $9.1/GJ and $11.3/GJ throughout 2023. The difference between settlement and traded contract prices shows the divergence between actual prices and expectations from previous years. In Q4 2021, Victorian gas futures prices settled for $9.9/GJ, compared to an average traded price of $8.4/GJ (Figure 2.16).

Figure 2.16 ASX Victorian futures contract trade



Source: ASX Energy.

Note: Trading volumes are organised by contract expiry date.

Focus – East coast and global spot price trends

Since 2015 there have been physical linkages between international and east coast gas markets. Australia is now a leading global exporter of LNG. This physical connection between east coast and international markets means that prices could be expected to converge. As observed in section 2.6, gas flows to the market of highest value. History shows there is a general price link, reflected in netback prices which calculates the export parity price for gas at the Wallumbilla gas supply hub. This calculation takes the LNG price and subtracts the costs of liquefaction and transport required to produce and deliver LNG to international customers.

This focus explores the extent to which that connection remains consistent over time. We offer some analysis on market correlation and some factors that may be influencing this.

Factors driving prices – observations of local markets in 2021

Seasonal factors are generally strong drivers of demand and prices for gas. The northern hemisphere winter drives high global demand for gas for heating. During the southern hemisphere winter, Queensland production centres are meeting higher east coast demand as well as supplying the international market.

In addition, policy measures that incentivise gas use and broader economic factors contribute to demand for gas globally.

During 2021, these general trends unfolded as follows:

- Quarter 1 – northern hemisphere winter – Asian netback prices were well above domestic prices due to:
  - Severe winter conditions in Asia – 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 in Qatar, Western Australia and USA.
- Quarters 2 and 3 – Australian winter – domestic prices well aligned with, and at times exceeded, international prices due to:
  - Outages at coal fired electricity generators in Queensland, NSW and Victoria – increasing demand from gas-powered generators
  - Competitive bidding for gas by gentailers to supply electricity, incentivised by high NEM prices

- Gas supply constraints at Iona storage and Longford production facilities in Victoria
- Periods of low wind generation in Victoria, NSW and South Australia, requiring gas powered electricity generation.

› Quarter 4 – northern hemisphere winter – Asian netback prices began to significantly exceed domestic market prices due to:
  - Competition between buyers in Asia, Europe and South America
  - Higher gas demand to replenish gas storage volumes in Europe since Winter 2020–21
  - Constrained gas supplies from Russia.

This trend in 2021 suggests that southern production, southern constraints and at times NEM-wide influences on gas prices, may have had a stronger role in setting the marginal price of gas than international markets for most of the year, despite some very strong upward pressure on global prices.

Potential reasons for this are explored in further detail below.

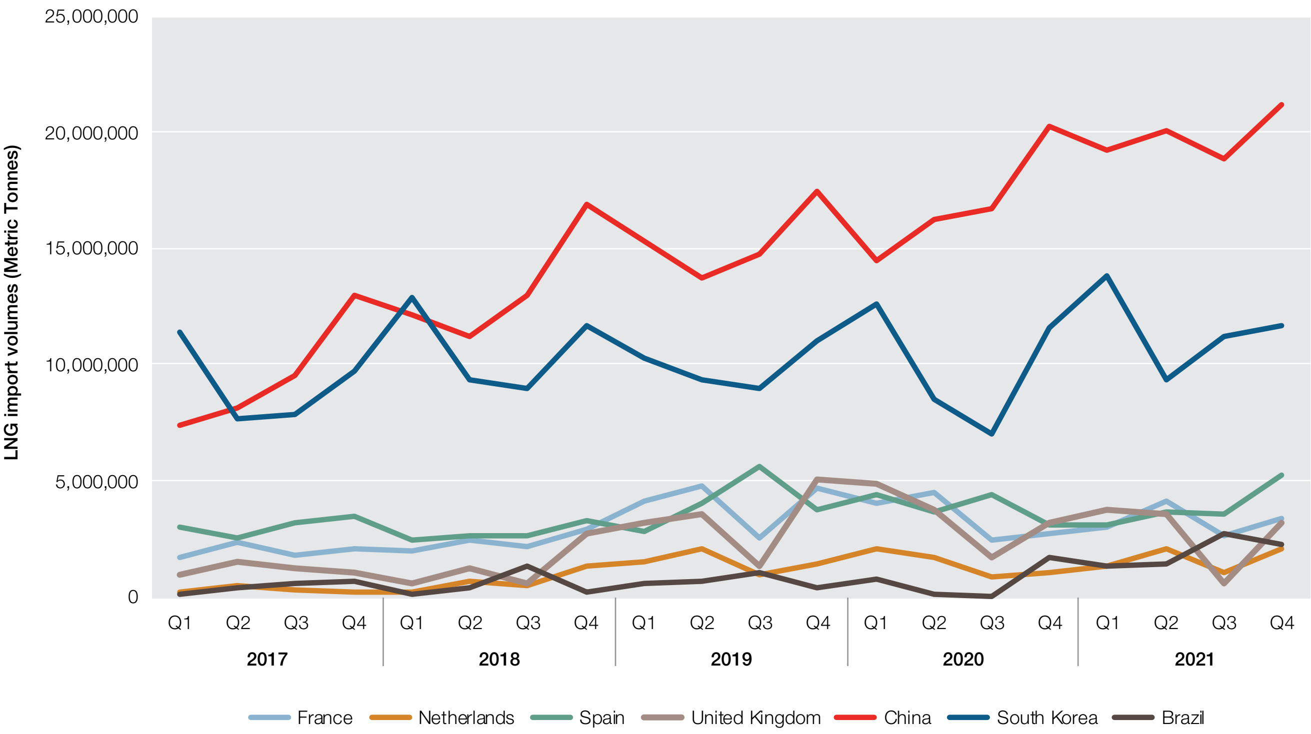
Factors driving prices – observations of international markets over time

Asian and European markets are primarily made up of gas buyers with insufficient production to meet their own gas demand and whose market outcomes may be more correlated to international prices than markets that predominantly export, such as Australia. The retailer failure events which have recently occurred in some European and Asian markets as a result of high prices for imported gas support this proposition.

Consistent with the high netback prices noted above, the rise in gas spot prices occurred dramatically across both Asian and European markets from September 2021. Buyers in both markets competed to bid for LNG cargoes ahead of the Northern hemisphere winter.

In addition, as noted in section 2.3, fuel switching towards gas in the Chinese and South Korean electricity sectors drove overall higher demand for imported gas as 2021 progressed (Figure 2.17). Demand from Spain also grew in 2021 while UK demand approached recent historic highs. In addition, Brazil emerged as a significant buyer of gas in 2021 to support electricity generation, as it experienced a drought which reduced hydro electricity generation capacity.[27] Buyers there were competing with Asian and European buyers for gas and supply chain infrastructure.

Figure 2.17 LNG imports by country



Source: Bloomberg.

27 Argus media, Brazil's LNG consumption surges in first half, November 2021, accessed 7 February 2022.

Looking at how price correlation moves over time

In our Q1 2020 report we explored correlations between the Asian spot price netback and domestic prices. We have now extended our analysis to correlations between Asian and European gas markets to explore global dynamics in more depth. We use the Argus Media ANEA price to assess Asian markets and the TTF price to understand European markets as they are available through the same data provider. We use the Wallumbilla and SEQ gas hub regions to test correlation with these international markets to east coast Australian markets.

Using a Pearson correlation for all periods the coefficient was positive, confirming the prices moved in the same direction, either increasing or decreasing across periods.[28]

Our analysis showed a moderate positive correlation between prices in all 4 of these market in 2018 (Table 2.13). At the beginning of 2018 international prices were high due to a cold northern winter. Buyers overstocked in expectation of cold whether at the end of 2018 which did not eventuate leading to a subsequent price decline.

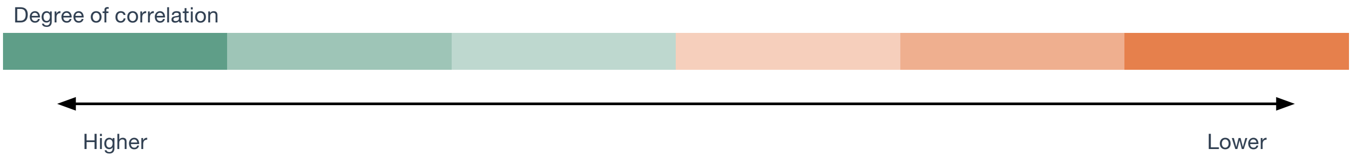
In 2019 there was a low positive correlation between domestic prices and the international markets. However, the European and Asian market prices were highly correlated. 2019 saw LNG prices decline after a mild northern winter and continuing robust supply.

In 2020 global gas demand and prices reached record lows. Global reductions in demand due in part to the economic effects of the COVID pandemic combined with strong energy supplies to accelerate the downward trend in prices to levels below the cost of production. Prices in all 4 markets were highly correlated but that linkage saw low prices, rather than high, trending globally.

Recovery in demand in 2021 saw a return to a moderate positive correlation between domestic prices and international prices but a very high correlation between European and Asian prices.

Table 2.13 Yearly correlations between SEQ, Wallumbilla, Asian (TTF) and European (ANEA) daily spot prices

CORRELATION COEFFICIENT	2018		2019		2020		2021	
	ANEA	TTF	ANEA	TTF	ANEA	TTF	ANEA	TTF
SEQ	0.664	0.626	0.440	0.601	0.818	0.862	0.529	0.612
Wallumbilla	0.657	0.628	0.345	0.496	0.773	0.834	0.565	0.627
ANEA		0.521		0.892		0.909		0.926



Source: AER analysis, Argus ANEA and TTF price series.

Notes: WAL and SEQ are separate trading points in the Wallumbilla/Roma gas production region.
Image depicts strength of correlation between international and domestic prices with correlation coefficients listed on a scale of -1 to 1.
0.9 – 1: very high positive correlation
0.7–0.9: high positive correlation
0.5–0.7: moderate positive correlation
0.3–0.5: low positive correlation
0–0.3: no or negligible correlation.

These observations of the last 4 years of data show that price linkages between markets weaken and strengthen.

There are a number of reasons, which may overlap, as to why east coast spot prices may not rise as high, or in as sustained a way, as international prices. For example, when considering 2021 global gas prices:

- Exporters may decide not to pass large global spot price increases on to domestic users at all times and may in effect have a domestic price ceiling

28 Correlation measures the degree to which two prices change relative to one another, either negative or positive and the magnitude of change. The strength of correlation increases as the correlation coefficient approaches one and becomes weaker as the coefficient approaches zero. We used a Pearson correlation coefficient (r value) which is a measure of the linear correlation between two variables. It gives indication of the degree of correlation and the direction of the relationship between two variables. Pearson coefficient lies in the range from -1 to +1. The absolute r value indicates the relationship strength. The larger the number, the stronger the relationship. In this report, we interpret r values as below (cited from Hinkle DE, Wiersma W, Jurs SG (2003). Applied Statistics for the Behavioral Sciences 5th ed. Boston: Houghton Mifflin).

- Over Q1 and Q4 when large international price increases occurred, the southern markets were not reliant on exporter gas – so southern buyers would be unlikely to compete to purchase gas from SEQ/WAL and drive up prices
- The AER has observed that in some periods of high LNG shipments, exporters were only willing to moderately price gas from the Wallumbilla exchange indicating that their own production was enough to fulfill their export needs.

There are also reasons why prices may not fall in as sustained a way during period of lower global prices. For example, when considering 2019 and 2020 global gas prices

- These prices on a netback basis fell close to, and at times below, costs of production near SEQ/WAL and producers may not have been willing to sell gas below cost.
- SEQ/WAL prices are also influenced by purchases from NEM participants which may support prices and prevent them falling as far as global gas prices.

One of the caveats on this analysis is that it reflects movements in the spot markets only. The extent to which this flows through to underlying contract gas prices will depend on how long price trends are sustained for, where prices are at when contract negotiations occur and the extent to which they influence production. However, contract market prices are not independent of spot market prices over time. The gas market is evolving to become more globally interlinked and homogenous and as such spot market prices are becoming increasing relevant.

We will continue to examine these trends to enable further consideration of the conditions under which domestic gas users need to secure supplies. In particular, correlations between gas markets can elucidate the relevance of different comparators of market performance, such as LNG netback pricing, to the efficiency and fairness of domestic market price outcomes.

Appendix A Baseload Outages

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q4 2021	REASON FOR OUTAGE	RETURNED TO SERVICE
Queensland		**345**		
Callide C, Callide Power Trading	Black coal, 2 units, 420 MW each	Unit 3: 3 days	Unplanned (3 days) – Technical issue	19/10/2021
		Unit 4: 92 days	Unplanned – significant failure on 25 May	Unknown
Callide B, CS Energy	Black coal, 2 units, 350 MW each	Unit 1: 22 days	Unplanned (17 days) – Unit trip	8/11/2021
			Planned (5 days)	22/12/2021
Gladstone, CS Energy	Black coal, 6 units, 280 MW each	Unit 1: 92 days	Unplanned (92 days) – Unit trip	Unknown
		Unit 2: 36 days	Planned (7 days)	17/10/2021
			Planned (22 days)	14/11/2021
			Unplanned (7 days) – turbine vibration issues	Unknown
		Unit 3: 24 days	Planned (24 days)	14/12/2021
		Unit 4: 21 days	Unplanned (21 days) – Tube leak	22/10/2021
		Unit 6: 4 days	Planned (2 days)	3/10/2021
			Planned (2 days)	8/10/2021
Kogan Creek, CS Energy	Black coal, 1 unit, 713 MW	Unit 1: 7 days	Planned (7 days)	21/11/2021
Stanwell, Stanwell Corporation	Black coal, 4 units, 365 MW each	Unit 3: 35 days	Planned (22 days)	23/10/2021
			Unplanned (13 days) – Unit trip	10/11/2021
Millmerran, Intergen	Black coal, 2 units, 306 MW each	Unit 1: 7 days	Unplanned (7 days) – Tube/ Steam Leak Limitation	27/10/2021
		Unit 2: 4 days	Unplanned (4 days) – Unit outage	13/12/2021
NSW		**354**		
Bayswater, AGL Energy	Black coal, 4 units, 630 MW – 655 MW	Unit 1: 43 days	Planned (37 days)	21/11/2021
			Unplanned (1 day) – Tube issues	25/11/2021
			Unplanned (5 day)	13/12/2021
		Unit 2: 5 days	Planned (4 days)	5/10/2021
			Planned (1 day)	Unknown
		Unit 3: 8 days	Unplanned (8 days) – Plant failure	23/12/2021
		Unit 4: 14 days	Unplanned (14 days) – Plant failure	28/10/2021
Liddell, AGL Energy	Black coal, 4 units, 450 MW each	Unit 2: 25 days	Unplanned (12 days) – Unit trip	23/10/2021
			Unplanned (13 days) – Plant failure	4/12/2021
		Unit 3: 17 days	Unplanned (17 days) – Plant failure	19/11/2021

STATION, COMPANY	FUEL TYPE, CAPACITY (SUMMER RATING)	NUMBER OF DAYS OFFLINE IN Q4 2021	REASON FOR OUTAGE	RETURNED TO SERVICE
		Unit 4: 42 days	Unplanned (19 days) – Unexpected plant limit	20/10/2021
			Unplanned (23 days) – Plant failure	19/12/2021
Vales Point, Delta Electricity	Black coal, 2 units, 660 MW each	Unit 5: 32 days	Planned (9 days)	Unknown
			Planned (2 days)	4/10/2021
			Planned (17 days)	8/11/2021
			Unplanned (4 days) – BTL repairs	9/12/2021
		Unit 6: 5 days	Planned (5 days)	Unknown
Eraring, Origin Energy	Black coal, 4 units, 680 MW each	Unit 1: 2 days	Planned (2 days)	29/11/2021
		Unit 4: 78 days	Unplanned (18 days)	21/11/2021
			Planned (30 days)	Unknown
			Unplanned (30 days)	31/10/2021
Mt Piper, Energy Australia	Black coal, 2 units, 675 MW each	Unit 1: 19 days	Planned (10 days)	2/11/2021
			Planned (9 days)	12/12/2021
		Unit 2: 64 days	Planned (16 days)	17/10/2021
			Planned (26 days)	1/12/2021
			Unplanned (22 days)	Unknown
Victoria		**171**		
Loy Yang A, AGL Energy	Brown coal, 4 units, 500 MW – 540 MW	Unit 1: 10 days	Planned (5 days)	31/10/2021
			Unplanned (5 days) – Tube leak	28/11/2021
		Unit 2: 30 days	Unplanned (22 days) – Tube leak	22/11/2021
			Unplanned (5 days) – Plant failure	2/12/2021
			Unplanned (3 days) – Plant failure	24/12/2021
		Unit 4: 1 day	Unplanned (1 day) – Unexpected ambient temperature effects	Unknown
Yallourn, Energy Australia	Brown coal, 4 units, 355 MW each	Unit 1: 24 days	Planned (16 days)	8/11/2021
			Unplanned (8 days) – Mill issue	14/12/2021
		Unit 2: 91 days	Unplanned (3 days) – Unit trip	Unknown
			Planned (88 days)	28/12/2021
		Unit 3: 15 days	Unplanned (11 days)	2/12/2021
			Unplanned (4 days) – Superheater spray line leak	12/10/2021

Appendix B 30-minute FCAS prices greater than $5,000/MW

		$/MW				$/MWH	
DATE	30-MINUTE INTERVAL	RAISE 6 PRICE $/MW	RAISE 60 PRICE $/MW	LOWER 6 $/MW	LOWER 60$/MW	ENERGY PRICE $/MWH	CO-OPTIMISED# OF DI'S
16-Oct	10.30 am			15,100	15,100	-1,000	L6 (1) L60 (4)
	11.00 am			8,119	10,313	-1,000	L6 (3) L60 (4)
	11.30 am			15,033	15,083	-1,000	L6 (1) L60 (3)
	12.00 pm			15,000	15,017	-863	L60 (4)
	12.30 pm			7,772	7,573	-998	L6 (1)
	1.00 pm			12,176	15,000	-1,000	L6 (3) L60 (3)
	2.00 pm				5,107	-107	L60 (5)
4-Nov	7.30 pm	15,100				336	R6 (5)
	8.00 pm	7,215				205	R6 (4)
8-Nov	11.30 am			10,031	10,088	113	
	12.00 pm			12,602	15,069	18	L60 (2)
	12.30 pm			5,054	5,163	-25	
11-Nov	12.30 pm	14,600	14,800			894	
	1.00 pm	9,717	10,348			406	R60 (2)
	1.30 pm	15,100	14,900			835	R6 (2)
	2.00 pm	14,900	13,817			7,149	R6 (4)
	2.30 pm	14,220	12,066			2,210	R6 (4)
	3.00 pm	15,100	14,500			1,390	R6 (3)
	3.30 pm	14,917	14,500			894	R6 (6)
	4.00 pm	9,877	9,012			473	R6 (4) R60 (3)
	4.30 pm	9,886	9,635			322	R6 (4)
	5.00 pm	10,309	9,540			519	R6 (6) R60 (1)
	5.30 pm	12,431	11,847			655	R6 (6) R60 (4)
	6.00 pm	15,049	12,666			815	R6 (5)
	6.30 pm	14,785	13,494			539	R6 (6) R60 (4)
	7.00 pm	14,981	10,768			839	R6 (6) R60 (1)
	7.30 pm	14,765	7,441			604	R6 (6)

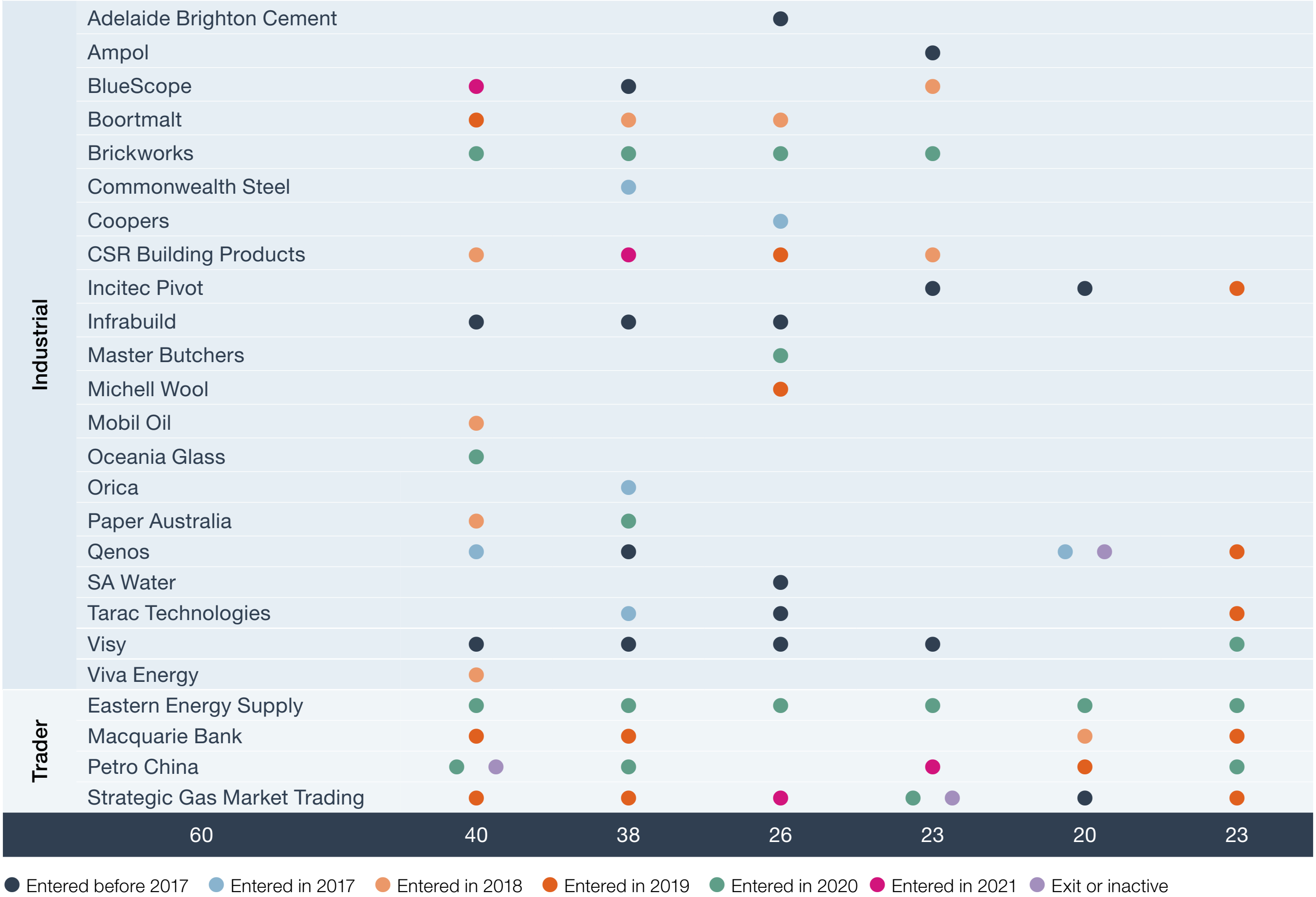
Appendix C Day Ahead Auction routes grouped by direction

FACILITY	DIRECTION	DAA ROUTE RECEIPT POINT NAME TO DELIVERY POINT NAME	RECEIPT POINT ID TO DELIVERY POINT ID
MSP	South from Moomba	MSP Inlet >>> Bathurst	1502045–1202022
		MSP Inlet >>> Canberra	1502045–1202027
		MSP Inlet >>> Dubbo	1502045–1202062
		MSP Inlet >>> MAPS Exit	1502045–1502039
		MSP Inlet >>> Uranquinty Power Station	1502045–1202047
		MSP Inlet >>> Culcairn South	1502045–1202026
		MSP Inlet >>> Culcairn Trade Point	1502045–1290016
		MSP Inlet >>> Griffith	1502045–1202063
		MSP Inlet >>> Wilton	1502045–1202052
		MSP Inlet >>> Wilton Trade Point	1502045–1290019
	Towards Moomba	Culcairn North >>> MAPS Exit	1202025–1502039
		Culcairn North >>> SWQP Exit	1202025–1502057
		Culcairn Trade Point >>> MAPS Exit	1290015–1502039
		Culcairn Trade Point >>> SWQP Exit	1290015–1502057
		EGP Entry >>> MAPS Exit	1202038–1502039
		EGP Entry >>> SWQP Exit	1202038–1502057
		Wilton Trade Point >>> MAPS Exit	1290018–1502039
		Wilton Trade Point >>> SWQP Exit	1290018–1502057
	Within NSW East	Culcairn North >>> Wilton	1202025–1202052
		Culcairn North >>> Wilton Trade Point	1202025–1290019
		Culcairn Trade Point >>> Culcairn South	1290015–1202026
		Culcairn Trade Point >>> Culcairn Trade Point	1290015–1290016
		Culcairn Trade Point >>> Wilton	1290015–1202052
		Culcairn Trade Point >>> Wilton Trade Point	1290015–1290019
		Wilton Trade Point >>> Wilton	1290018–1202052
	Within NSW West	Culcairn North >>> Culcairn Trade Point	1202025–1290016
		EGP Entry >>> Culcairn Trade Point	1202038–1290016
		Wilton Trade Point >>> Culcairn South	1290018–1202026
		Wilton Trade Point >>> Culcairn Trade Point	1290018–1290016

RBP	East	Condamine >>> Ellen Grove	1404086–1404089
		RBP Trade Point (IPT) >>> Condamine	1490022–1404085
		RBP Trade Point (IPT) >>> Ellen Grove	1490022–1404089
		RBP Trade Point (IPT) >>> Murarrie	1490022–1404093
		RBP Trade Point (IPT) >>> Oakey PS	1490022–1404095
		RBP Trade Point (IPT) >>> RBP Trade Point (IPT)	1490022–1490021
		RBP Trade Point (IPT) >>> Swanbank PS	1490022–1404104
		RBP Trade Point (IPT) >>> Tingalpa	1490022–1404105
		RBP Trade Point (IPT) >>> Wambo	1490022–1404261
		Scotia >>> RBP Trade Point (IPT)	1404102–1490021
		Wallumbilla Run 3 >>> Condamine	1404109–1404085
		Wallumbilla Run 3 >>> Ellen Grove	1404109–1404089
		Wallumbilla Run 3 >>> Murarrie	1404109–1404093
		Wallumbilla Run 3 >>> RBP Trade Point (IPT)	1404109–1490021
		Wallumbilla Run 7 >>> Tingalpa	1404111–1404105
	West	Argyle >>> Wallumbilla delivery	1404082–1404097
		Condamine >>> Wallumbilla delivery	1404086–1404097
		RBP Trade Point (IPT) >>> Wallumbilla delivery	1490022–1404097
		Scotia >>> Wallumbilla delivery	1404102–1404097
		Wallumbilla Run 2 >>> Wallumbilla delivery	1404108–1404097
		Woodroyd >>> Wallumbilla delivery	1404112–1404097
SWQP	North	Ballera Entry >>> Wallumbilla LP Trade Point	1404114–1490026
		SWQP Entry from MCF >>> GLNG Delivery Stream	1590026–1404129
		SWQP Entry from MCF >>> Wallumbilla LP Trade Point	1590026–1490026
		SWQP MSP Entry >>> Ballera Exit	1590027–1404115
		SWQP MSP Entry >>> SWQP to MCF Exit	1590027–1590025
		SWQP MSP Entry >>> Wallumbilla LP Trade Point	1590027–1490026
		Wallumbilla HP Trade Point >>> GLNG Delivery Stream	1490025–1404129
		Wallumbilla HP Trade Point >>> Wallumbilla LP Trade Point	1490025–1490026
	South	Ballera Entry >>> SWQP to MCF Exit	1404114–1590025
		Wallumbilla HP Trade Point >>> Cheepie	1490025–1404116
		Wallumbilla HP Trade Point >>> Ballera Exit	1490025–1404115
		Wallumbilla HP Trade Point >>> SWQP to MCF Exit	1490025–1590025

Appendix D Gas participant list

PARTICIPANT LIST IN EASTERN GAS MARKET							
	Market participant	Victoria	Sydney	Adelaide	Brisbane	GSHs	DAA
GPG Gentailer	AGL*	●	●	●	●	●	●
	Alinta Energy	●	●	●	●	●	●
	CleanCo				●	●	●
	EnergyAustralia	●	●	●		●	●
	Engie	●					●
	Hydro Tasmania	●	●				
	Origin	●	●	●	●	●	●
	Shell Retail	●	●	●	●	●	●
	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	●					
	Covau	●	●	●	●		
	CPE Mascot		●				
	Delta Electricity		●				
	Discover Energy	●	●	●	●		
	Dodo	●	●				
	GloBird Energy	●	●	●	●		
	OVO Energy	●					
	Powershop	●	●				
	Simply Energy*		●	●			
	Sumo Gas	●	●				
	TasGas	●					
	Tango	●					
	Weston Energy	●	●	●	●		



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.

* Click Energy was aquired by AGL, ERM was aquired by Shell (Shell Retail), O-I International was aquired by Visy.

* Arrow also operates the Braemar 2 power station.

* Simply Energy is the retail arm of Engie, who own and operate gas generation assets in South Australia.

* ICAP Brokers is also active in the GSH, but does not trade gas commodities (trade facilitator).

Common measurements and abbreviations

ELECTRICITY		GAS	
MW	Megawatt	GJ	Gigajoule
MWh	Megawatt hour	PJ	Petajoule
TW	Terawatt	TJ	Terajoule
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
QNI	Queensland New South Wales Interconnector	BWP	Berwyndale to Wallumbilla Pipeline
VNI	Victoria to New South Wales Interconnector	CGP	Carpentaria Gas Pipeline
V-SA	Heywood Interconnector	EGP	Eastern Gas Pipeline
V-S-MNSP1	Murraylink Interconnector	ICF	Iona Compression Facility
T-V-MNSP1	Basslink Interconnector	MAPS	Moomba to Adelaide Pipeline System
N-Q-MNSP1	Terranora Interconnector	MCF	Moomba Compression Facility
		MSP	Moomba to Sydney Pipeline
		NGP	Northern Gas 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
		WCFA	Wallumbilla Compression Facility A
		WCFB	Wallumbilla Compression Facility B

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