# 25 – 31 October 2020

## Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $35/MWh in South Australia to $54/MWh in Tasmania. Q4 2020 quarter to date prices ranged from $37/MWh to $60/MWh, down from $73/MWh to $109/MWh at the same time last year.

In Victoria, low wind generation later in the week and outages saw generation availability dip as low as 6000 MW. However, this didn't result in any high prices in the region.

## Purpose

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

## Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 25 to 31 October 2020.

### Figure 1: Spot price by region ($/MWh)

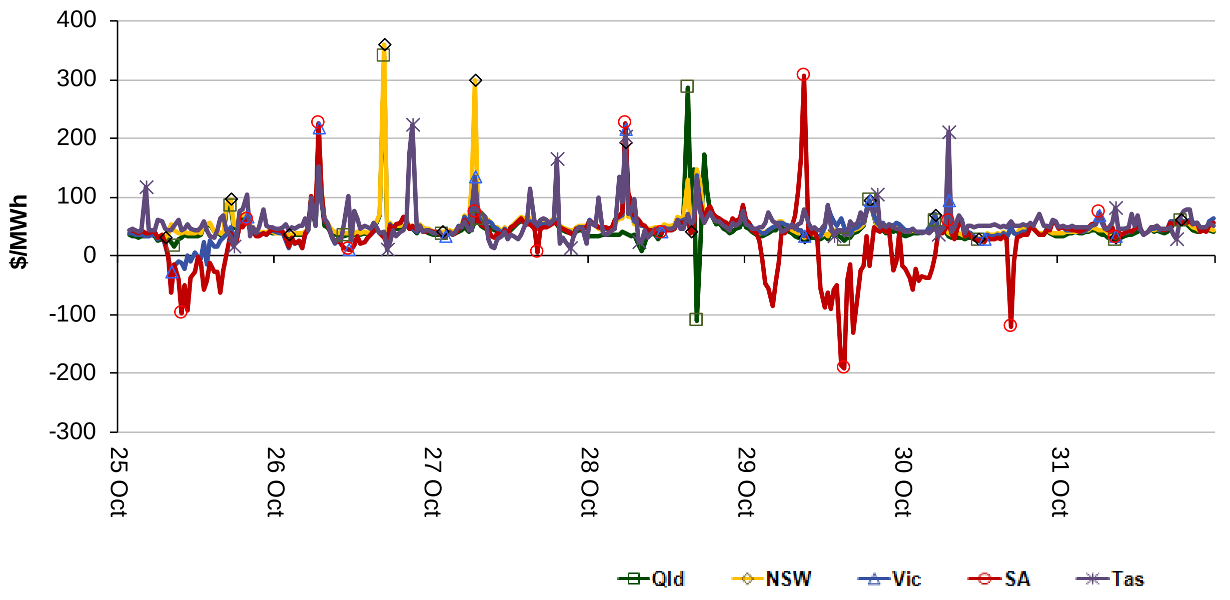
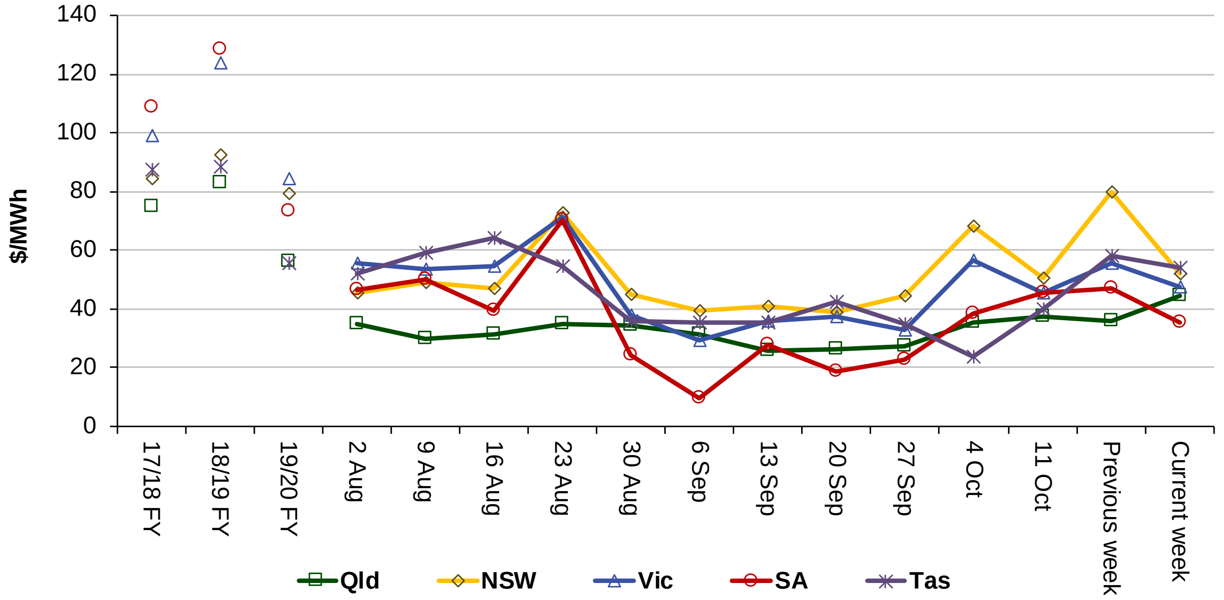


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

### Figure 2: Volume weighted average spot price by region ($/MWh)




### Table 1: Volume weighted average spot prices by region ($/MWh)

| Region | Qld | NSW | Vic | SA | Tas |
|---|---|---|---|---|---|
| Current week | 45 | 52 | 47 | 35 | 54 |
| Q4 2019 QTD | 77 | 104 | 104 | 73 | 109 |
| Q4 2020 QTD | 37 | 60 | 47 | 38 | 42 |
| 19-20 financial YTD | 68 | 90 | 103 | 80 | 78 |
| 20-21 financial YTD | 35 | 51 | 53 | 44 | 49 |

Longer-term statistics tracking average spot market prices are available on the AER website.

## Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 247 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2019 of 204 counts and the average in 2018 of 199. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

### Table 2: Reasons for variations between forecast and actual prices

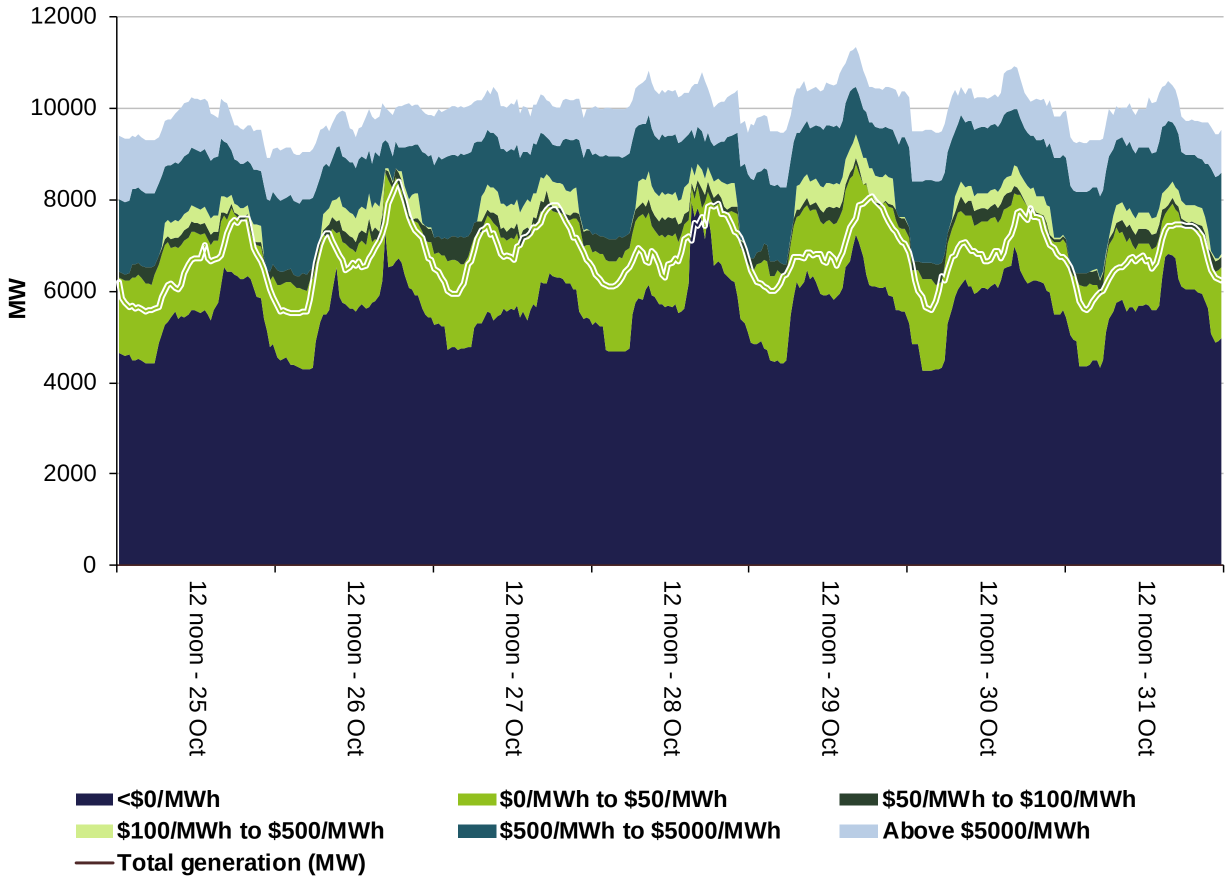
| | Availability | Demand | Network | Combination |
|---|---|---|---|---|
| % of total above forecast | 5 | 33 | 0 | 2 |
| % of total below forecast | 13 | 41 | 0 | 7 |

Note: Due to rounding, the total may not be 100 per cent.

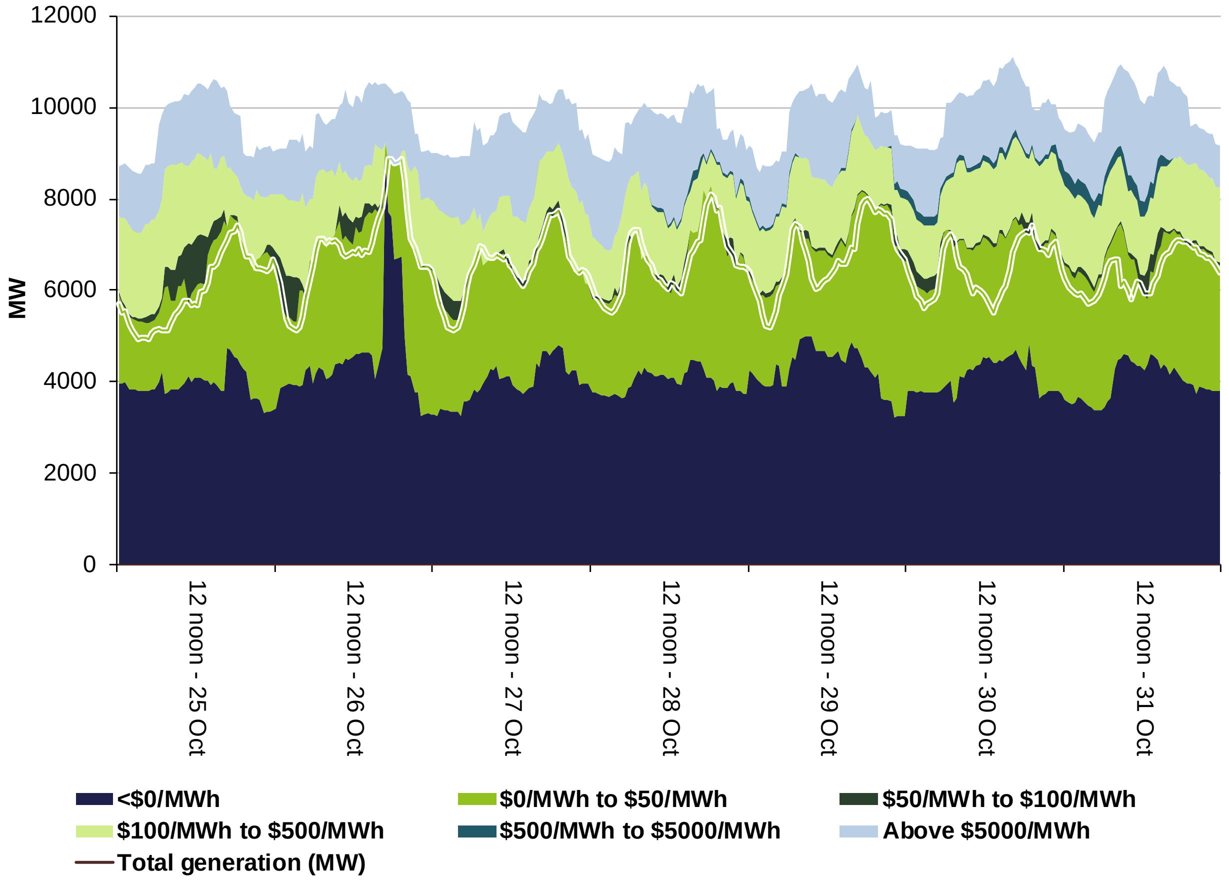
## Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

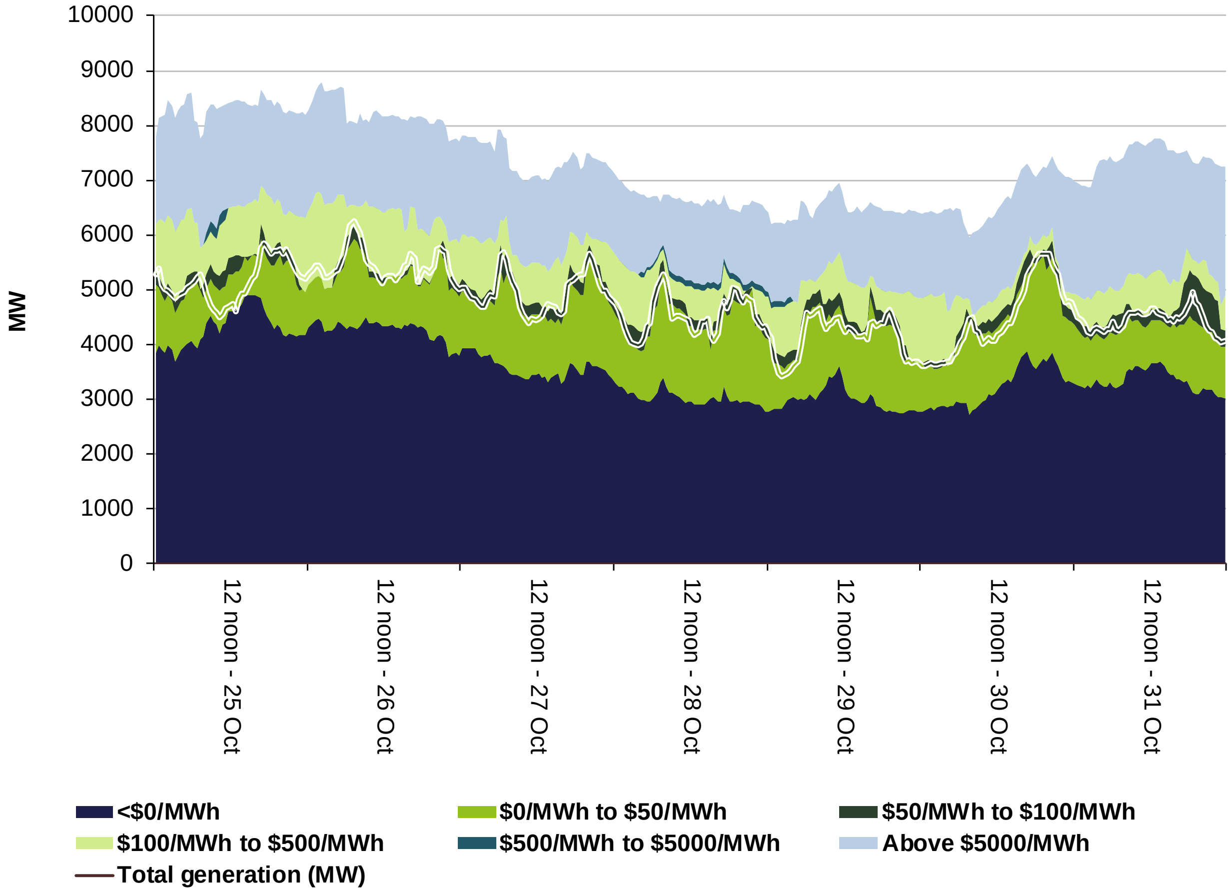
### Figure 3: Queensland generation and bidding patterns



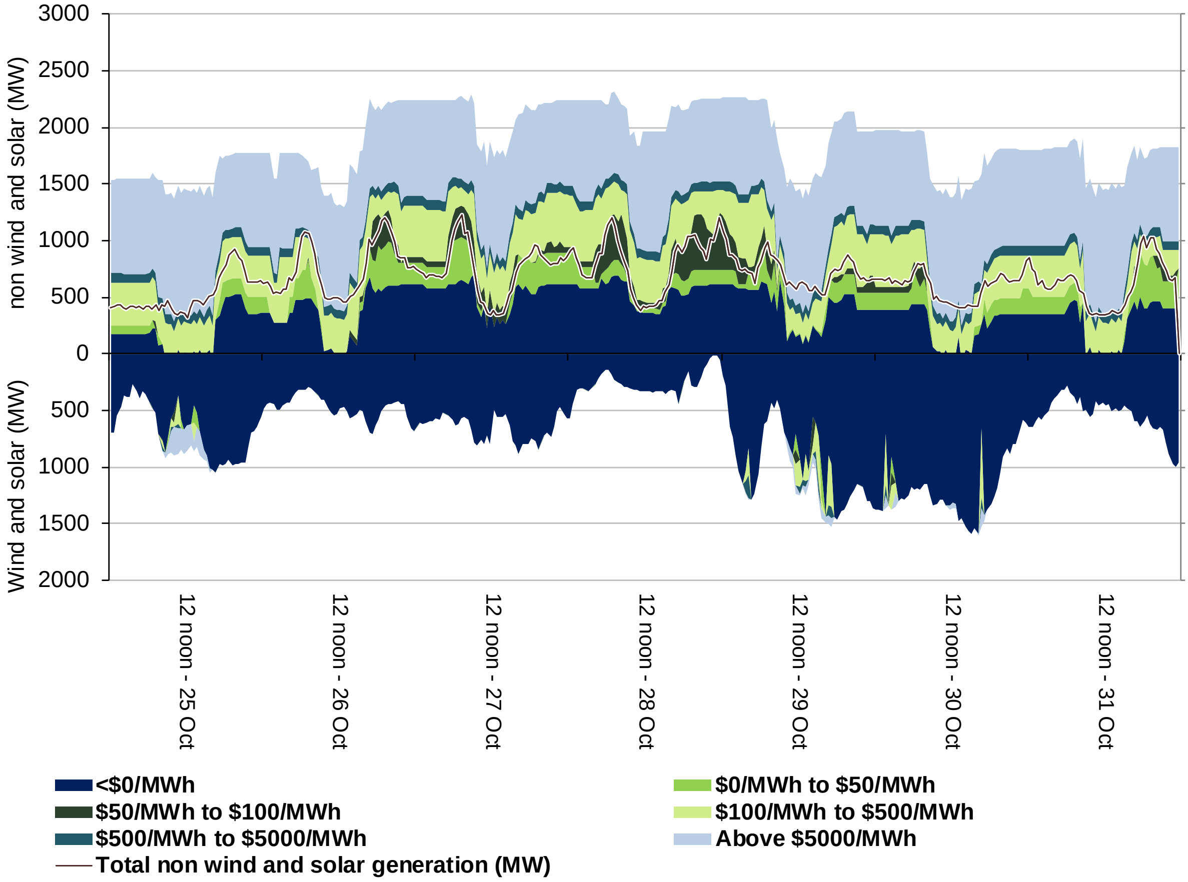
## Figure 4: New South Wales generation and bidding patterns



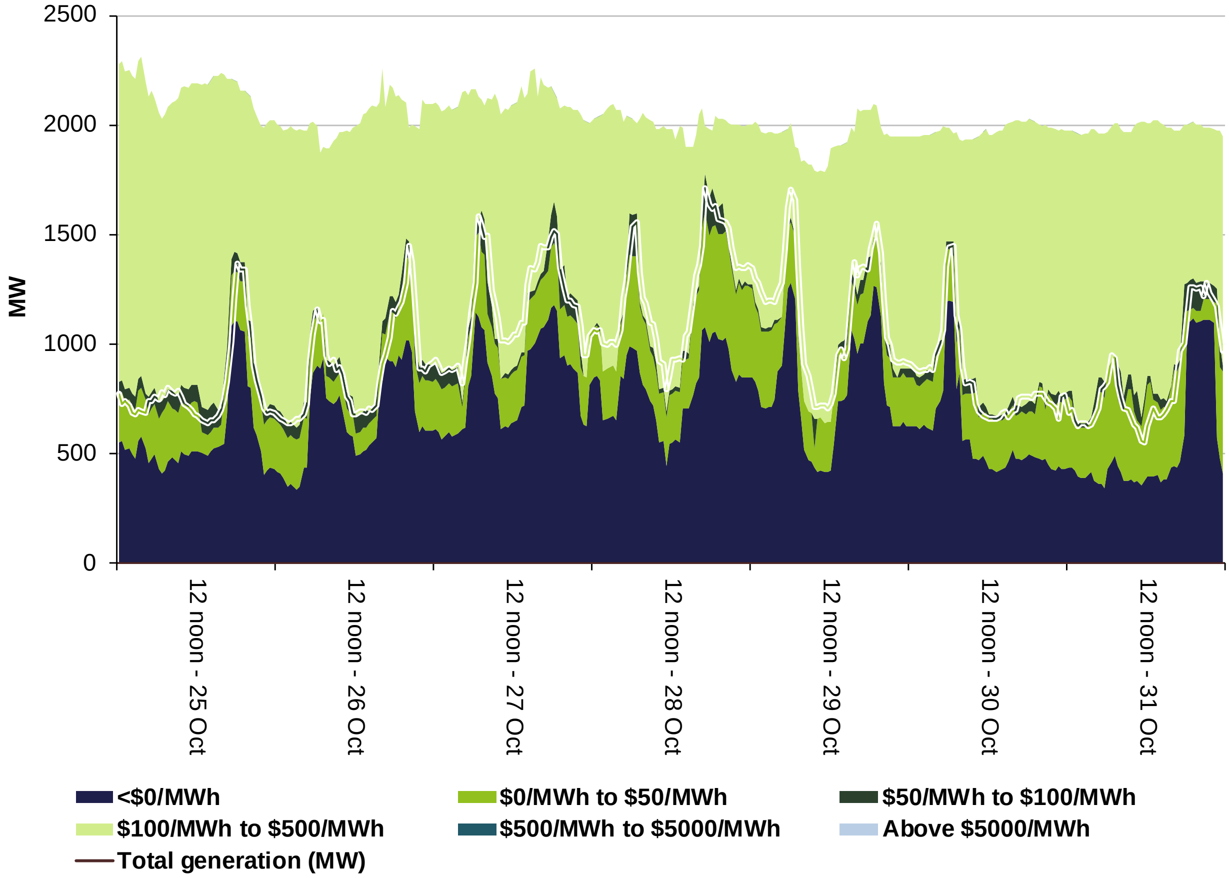

## Figure 5: Victoria generation and bidding patterns



## Figure 6: South Australia generation and bidding patterns




## Figure 7: Tasmania generation and bidding patterns



## Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

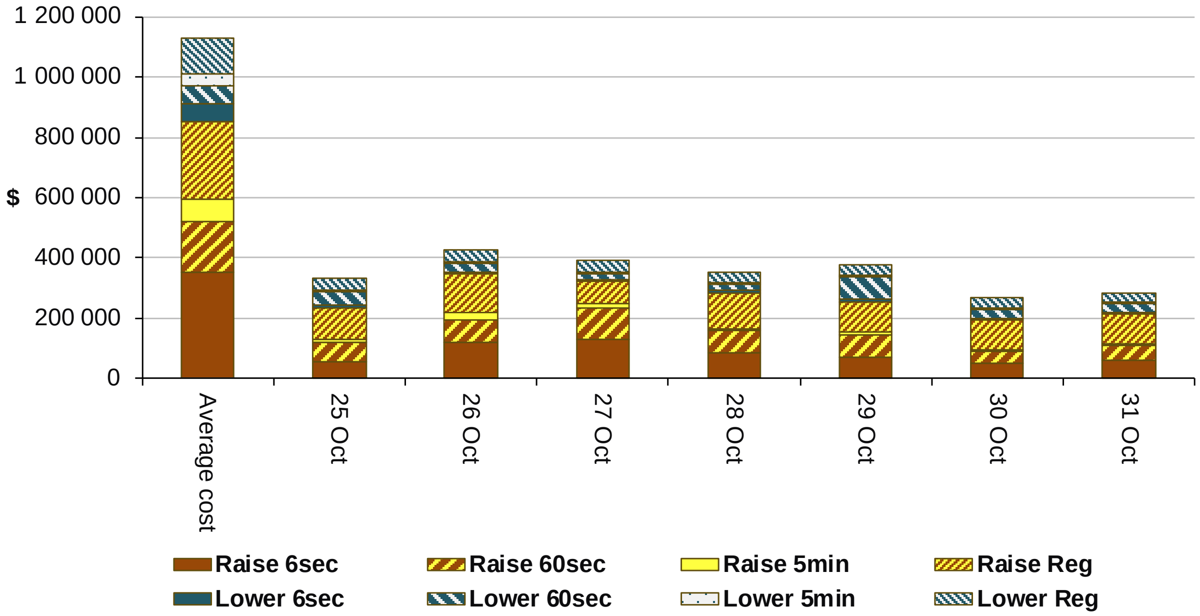
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 068 500 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $355 500 or less than 4 per cent of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

### Figure 8: Daily frequency control ancillary service cost



# Detailed market analysis of significant price events

## Queensland and New South Wales

There was one occasion where the spot price was aligned across Queensland and New South Wales and was more than three times the weekly average price in New South Wales of $52/MWh and above $250/MWh.

**Monday, 26 October**

### Table 3: Price, Demand and Availability

| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 5 pm | 360.87 | 56.07 | 66.37 | 16 160 | 15 888 | 15 594 | 20 564 | 20 494 | 20 350 |

Collectively, demand was 272 MW higher than forecast and availability was 70 MW higher than forecast, four hours prior. At 4.50 pm, unplanned line outages in NSW and Queensland limited the ability for low priced generation to be dispatched at Tumut, Upper Tumut stations and Gladstone power stations. At the same time demand increased by 92 MW and with no other generation capacity available between the forecast price and $1500/MWh, the price increased to more than $1500/MWh for 5 minutes.

## Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $45/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

**Wednesday, 28 October**

### Table 4: Price, Demand and Availability

| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 3.30 pm | 285.97 | 49.70 | 34.95 | 6736 | 6335 | 6146 | 10 339 | 10 348 | 10 847 |
| 5 pm | -111.65 | 53.97 | 44.85 | 6839 | 6873 | 6812 | 10 805 | 10 415 | 10 844 |

For the 3.30 pm trading interval, demand was 401 MW higher than forecast and availability was close to forecast, four hours prior. Higher than forecast demand resulted in prices between $155/MWh and $502/MWh throughout the trading interval.

For the 5 pm trading interval, demand was 34 MW lower than forecast and availability was 390 MW higher than forecast, four hours prior. Higher than forecast availability was mostly due to higher than forecast wind and solar generation, all of which was priced below $0/MWh. Effective 4.50 pm, rebids shifted or added more than 400 MW of capacity at the price floor in response to constraint management, plant conditions and changes in forecast prices. Also, at 4.50 pm, the amount of generation able to flow across QNI from Queensland to NSW fell by more 130 MW With higher priced generation ramp-down constrained, the price fell to -$1000/MWh for 5 minutes.

## New South Wales

There were two occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $52/MWh and above $250/MWh.

**Tuesday, 27 October**

### Table 5: Price, Demand and Availability

| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 7 am | 299.60 | 89.34 | 73.96 | 8280 | 7856 | 7921 | 9468 | 9617 | 9736 |

Demand was 424 MW higher than forecast and availability was 149 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower solar and wind generation and rebids by AGL Energy that removed 90 MW of capacity at Bayswater due to plant reasons. The combination of higher than forecast demand and lower than forecast low-priced generation saw prices settle at $299.60/MWh for the entire trading interval.

## South Australia

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of $35/MWh and above $250/MWh and there were four occasions where the spot price was below -$100/MWh.

**Thursday, 29 October**

### Table 6: Price, Demand and Availability

| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 9.30 am | 305.43 | 0 | 48.44 | 1165 | 1113 | 1162 | 2268 | 2863 | 2673 |
| 3 pm | -186.53 | -1000 | -1000 | 725 | 711 | 693 | 2512 | 2813 | 2988 |
| 3.30 pm | -192.39 | -1000 | -1000 | 748 | 778 | 739 | 2833 | 2828 | 3002 |
| 5 pm | -131.64 | -35.00 | -200 | 1135 | 1046 | 973 | 3317 | 3037 | 3103 |

For the 9.30 am trading interval, demand was 52 MW higher than forecast and availability was 595 MW lower than forecast, four hours prior. Lower than forecast availability was due to lower than forecast wind generation. As a result, the prices settled above $300/MWh for most of the trading interval.

For the 3 pm and 3.30 pm trading intervals, demand was close to forecast while availability was up to 301 MW lower than forecast, four hours prior. Lower than forecast availability was mostly due to rebids at Barker Inlet and Ladbroke Grove that removed capacity for plant reasons. Prior to the start of each trading interval, rebids shifted nearly 400 MW of capacity priced at -$1000/MWh either out of the market or to higher prices. As a result prices settled above -$695/MWh throughout each of the trading intervals.

For the 5 pm trading interval, demand was 89 MW higher than forecast and availability was 280 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast solar generation, most of which was priced below $0/MWh. Effective 4.35 pm, over 400 MW was rebid by participants from higher prices to the price floor in response to changes in forecast prices or to manage binding constraints. As a result, the price fell to the floor once in the trading interval. In response, participants rebid over 900 MW from the price floor to higher prices and the price settled between $37/MWh and $54/MWh for the rest of the trading interval.

### Friday, 30 October

### Table 7: Price, Demand and Availability

| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 5 pm | -121.56 | 25.23 | -72.76 | 1288 | 926 | 909 | 3155 | 2855 | 2835 |

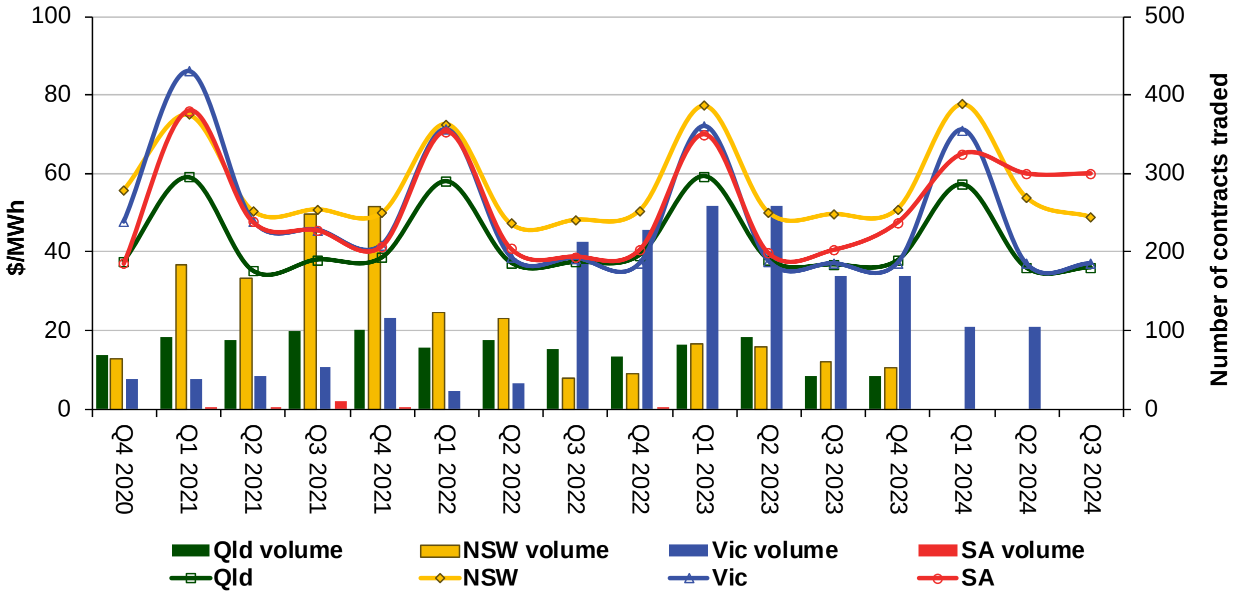
Demand was 362 MW higher than forecast and availability was 300 MW higher than forecast, four hours prior. Higher than forecast availability was mostly due to higher than forecast solar generation, all of which was priced below $0/MWh.

At 4.35 pm, a step change in offers at Pelican Point added 122 MW of capacity at the price floor. At the same time rebids by EnergyAustralia and Trustpower shifted 400 MW of capacity to the price floor. As a result, the price fell to -$1000/MWh for 5 minutes. In response, participants rebid net over 1000 MW from the price floor to higher prices and the price settled between $30/MWh and $64/MWh for the rest of the trading interval.

## Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

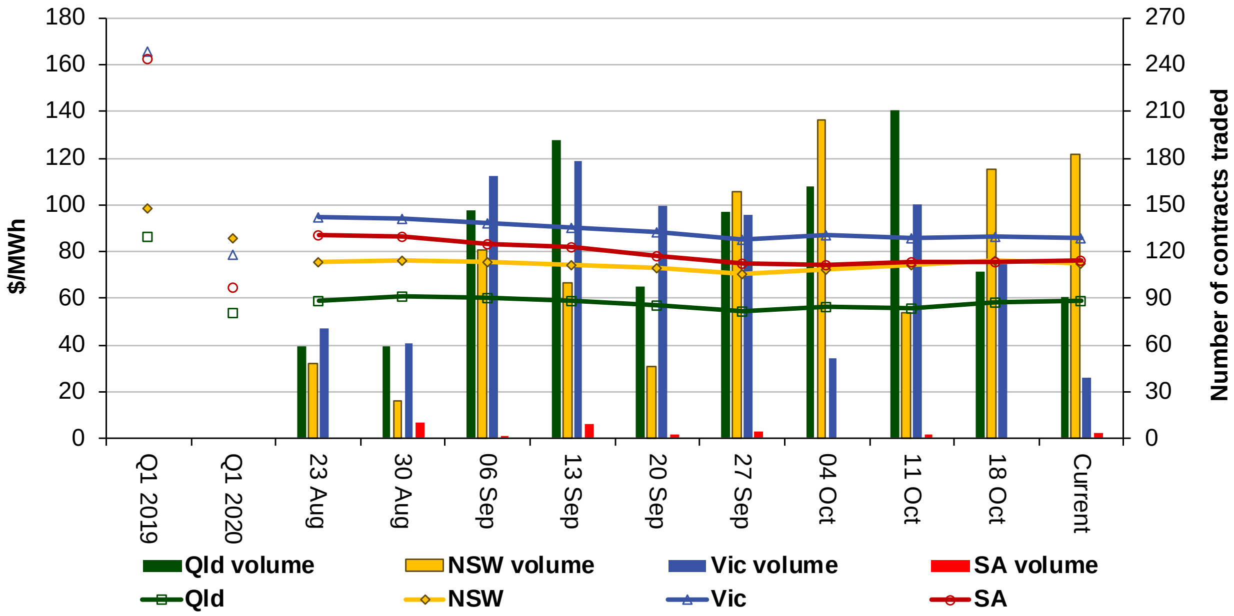
### Figure 9: Quarterly base future prices Q4 2020 – Q3 2024




Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2021 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q1 2020 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

### Figure 10: Price of Q1 2021 base contracts over the past 10 weeks (and the past 2 years)

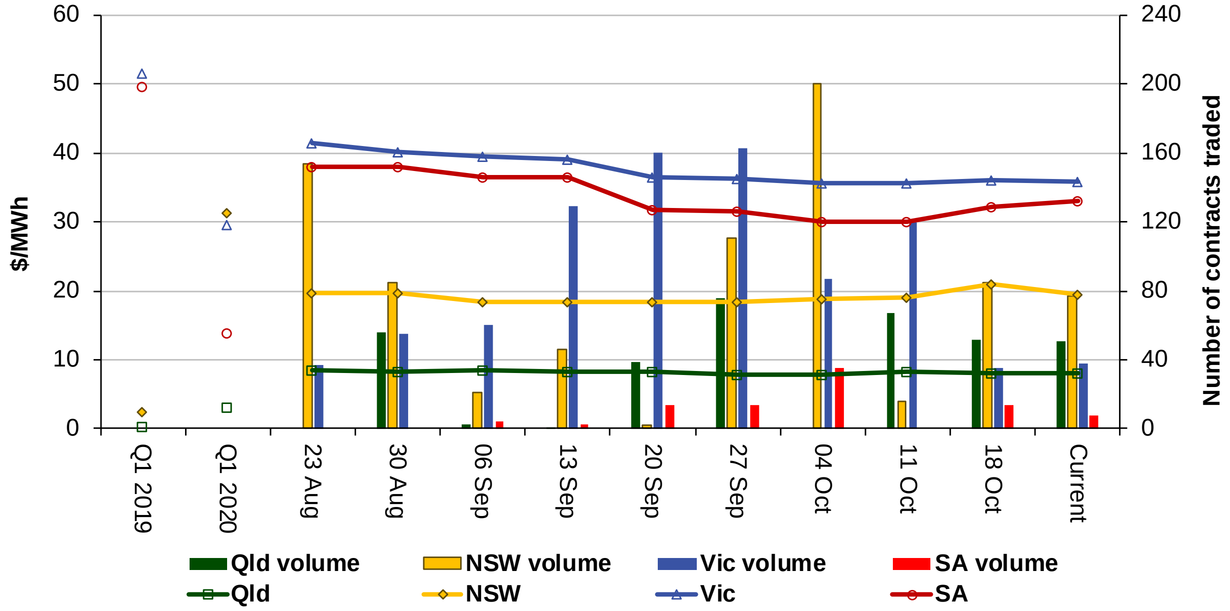



Source: ASXEnergy.com.au

Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q1 2020 prices are also shown.

## Figure 11: Price of Q1 2021 cap contracts over the past 10 weeks (and the past 2 years)




Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics](#) section of our website.

**Australian Energy Regulator**
**November 2020**