# Electricity Report

# 13 – 19 October 2019

## Introduction

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.

AGL Energy's new Barker Inlet Power Station commenced operations on 15 October 2019, with a maximum output for that week of 75 MWh on 19 October.

## Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 13 to 19 October 2019.

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

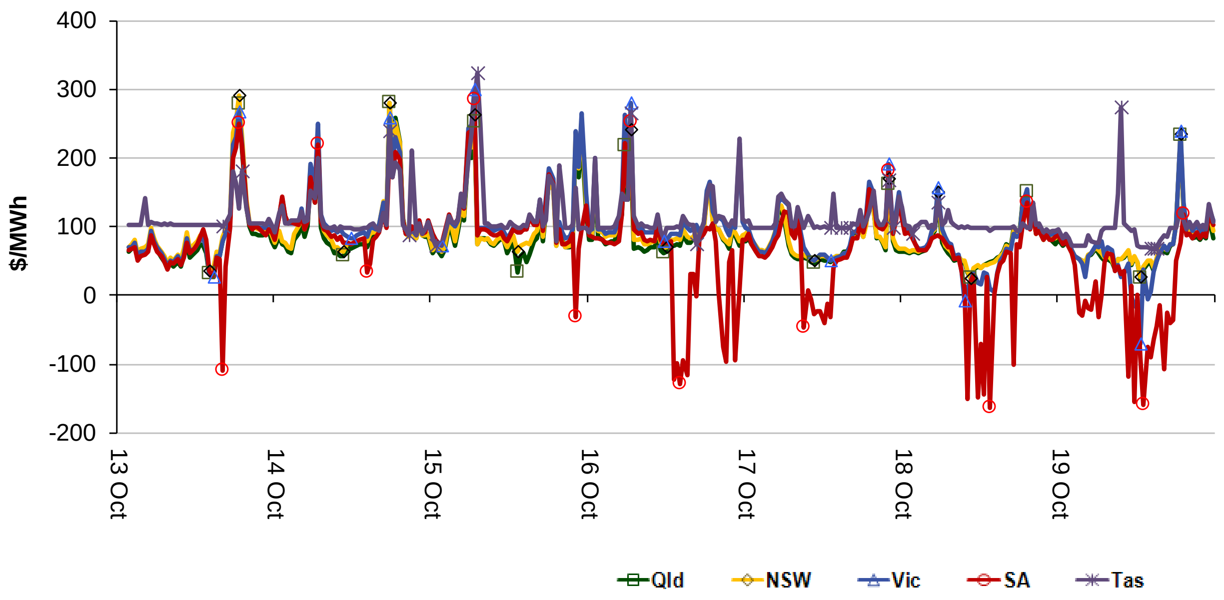
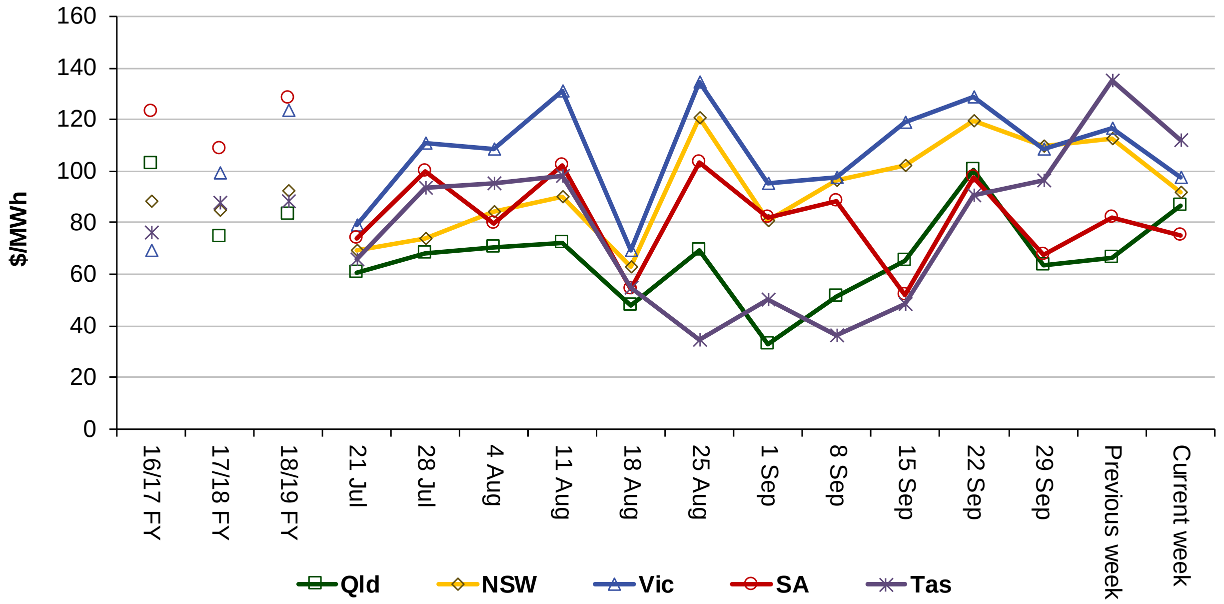



Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

## 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 | 86 | 92 | 98 | 75 | 112 |
| 18-19 financial YTD | 80 | 90 | 86 | 95 | 51 |
| 19-20 financial YTD | 67 | 89 | 104 | 81 | 77 |

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 234 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2018 of 199 counts and the average in 2017 of 185. 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

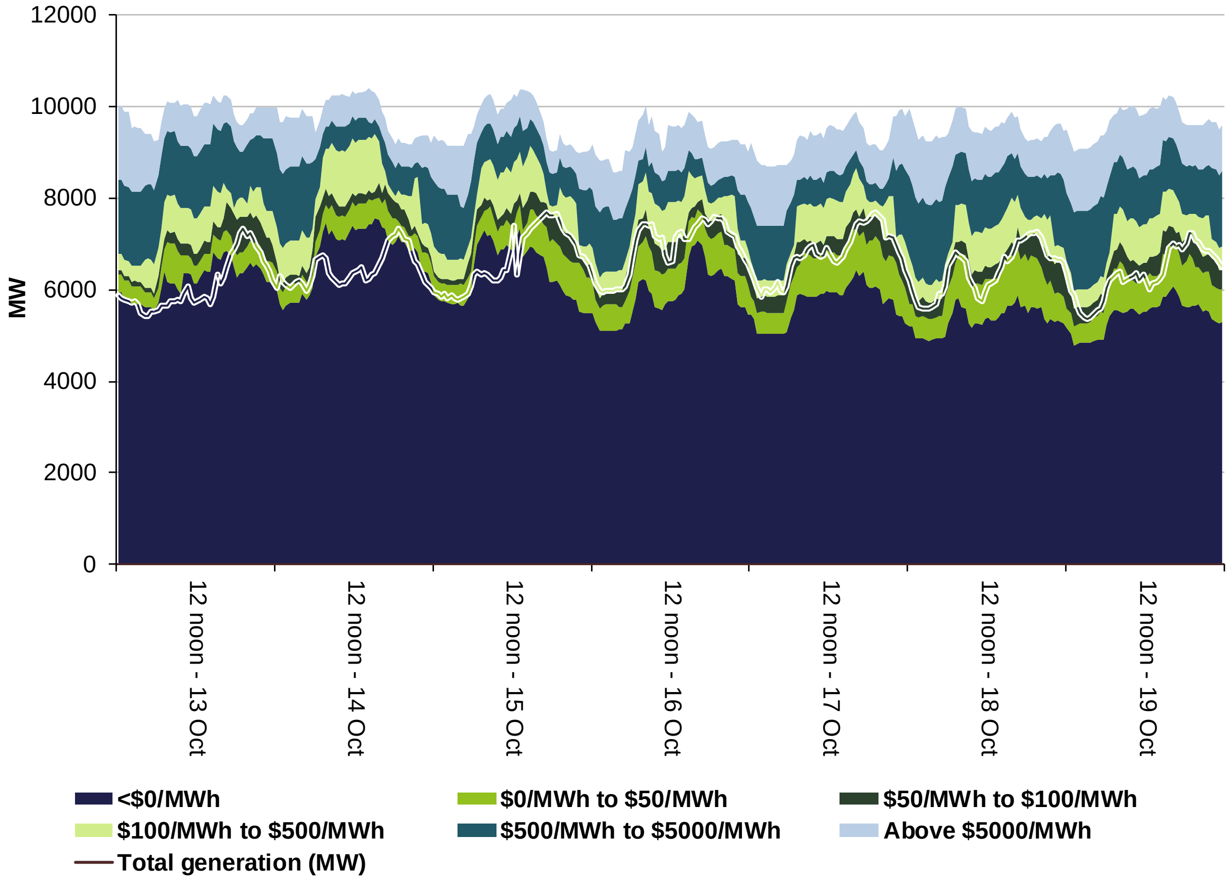
| | Availability | Demand | Network | Combination |
|---|---|---|---|---|
| % of total above forecast | 10 | 24 | 0 | 2 |
| % of total below forecast | 10 | 45 | 0 | 10 |

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

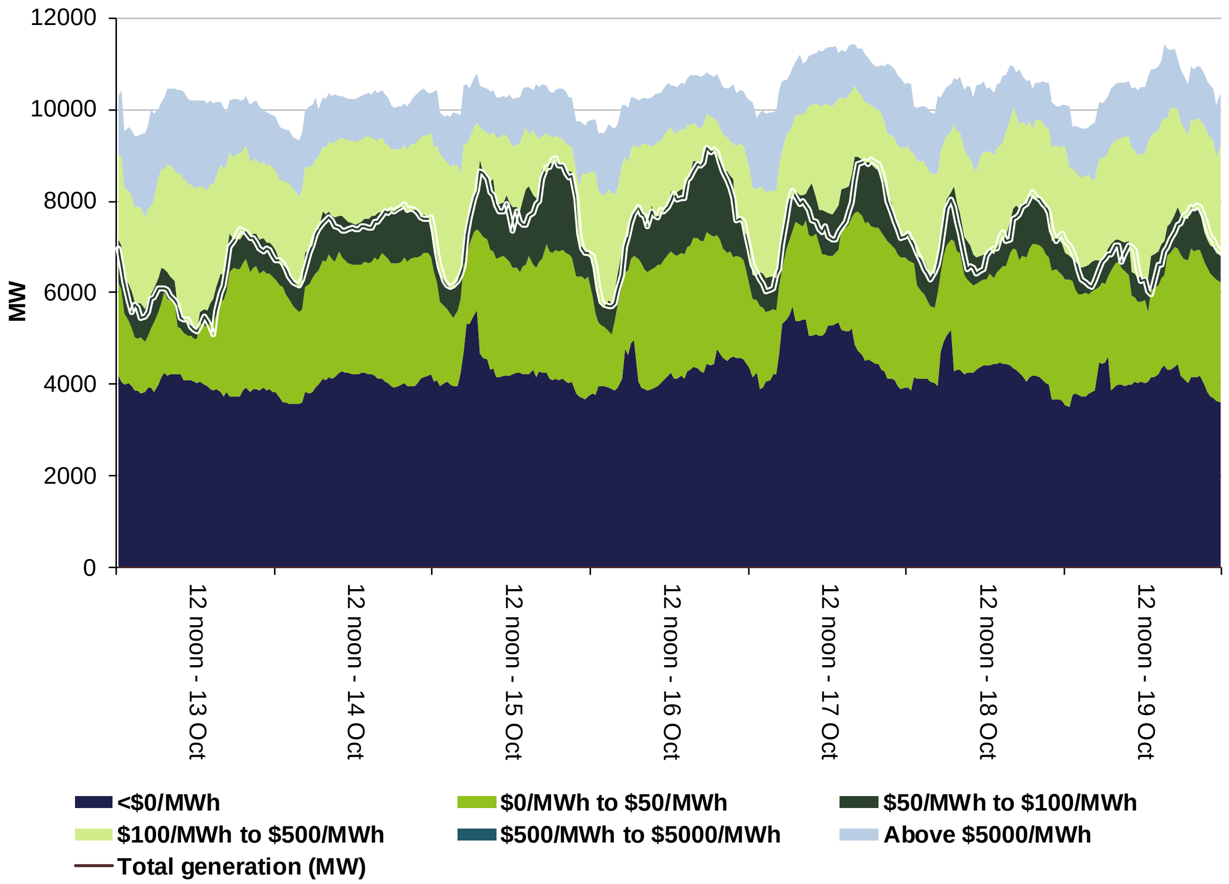
## Generation and bidding patterns

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.

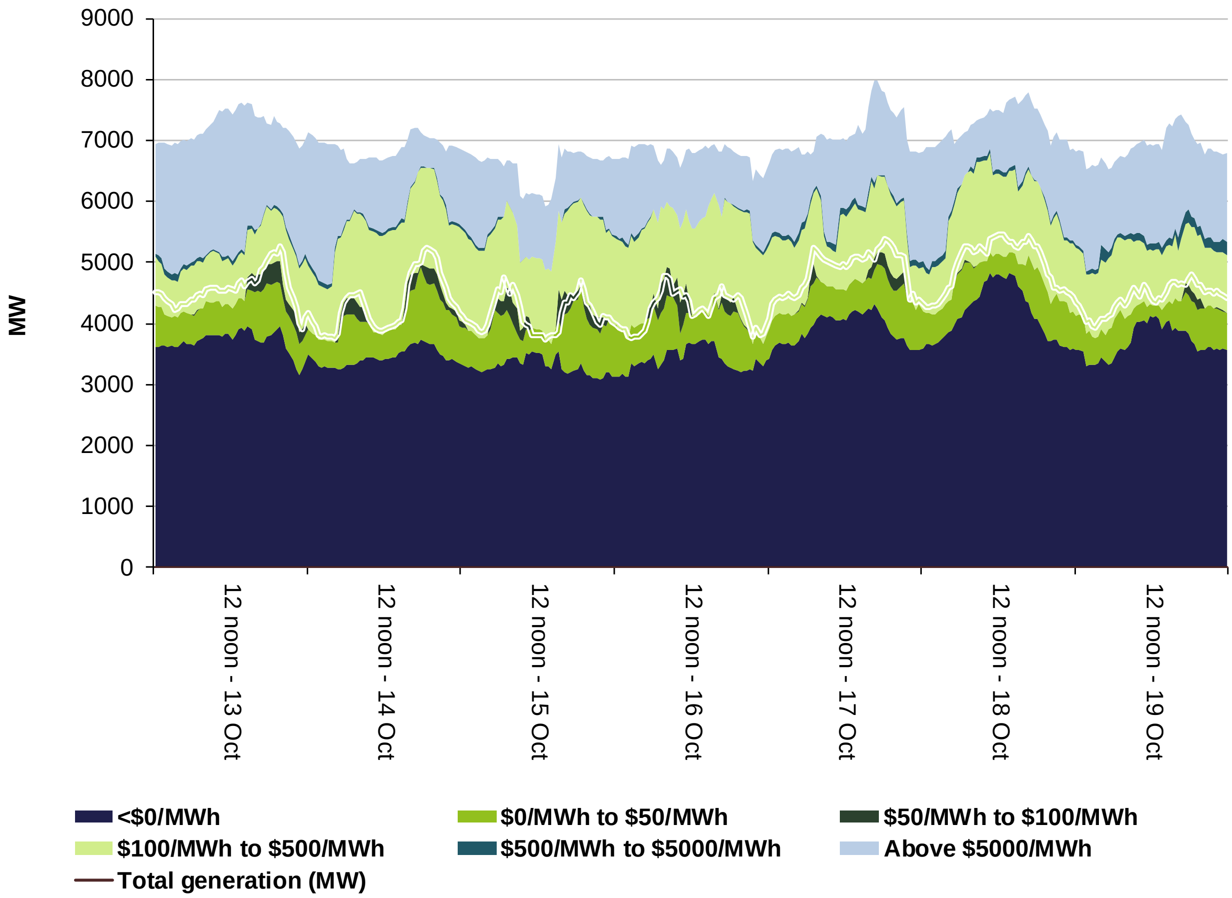
### Figure 3: Queensland generation and bidding patterns



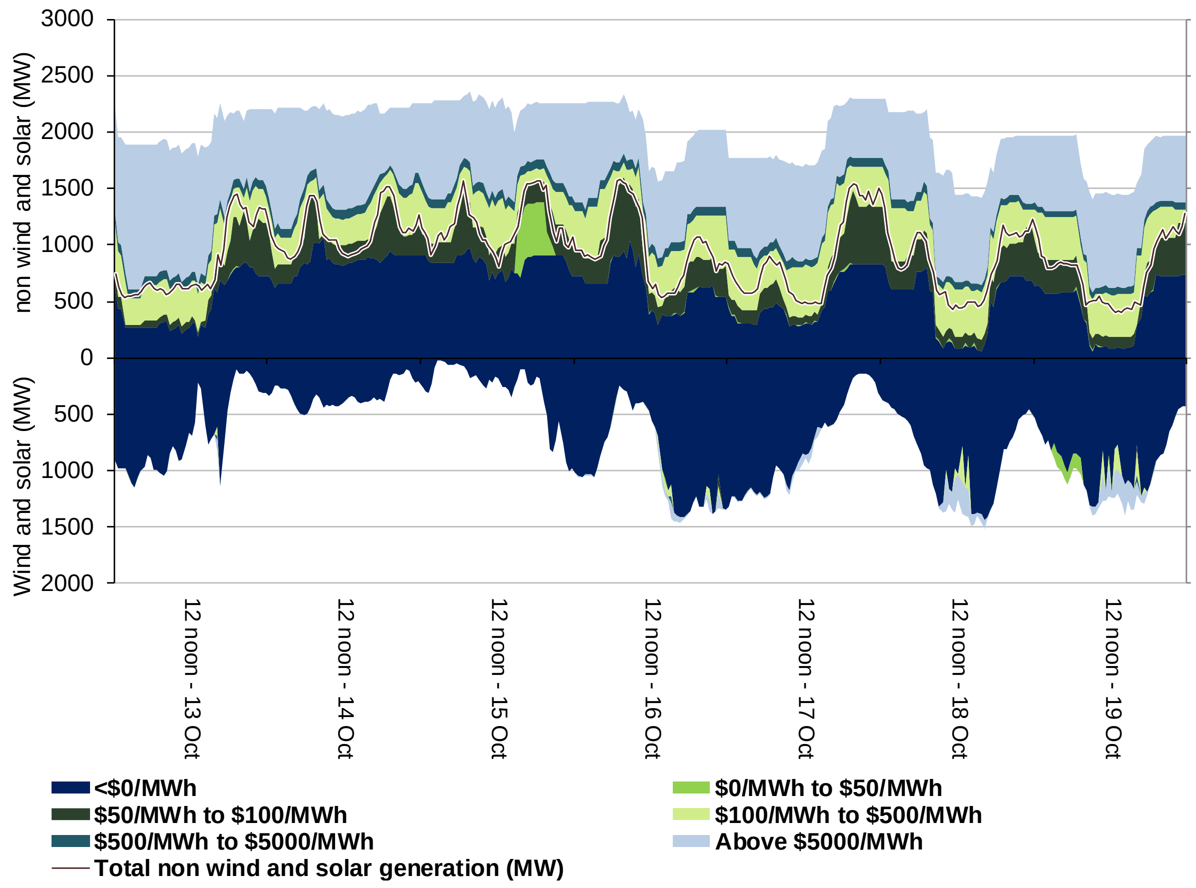
## Figure 4: New South Wales generation and bidding patterns



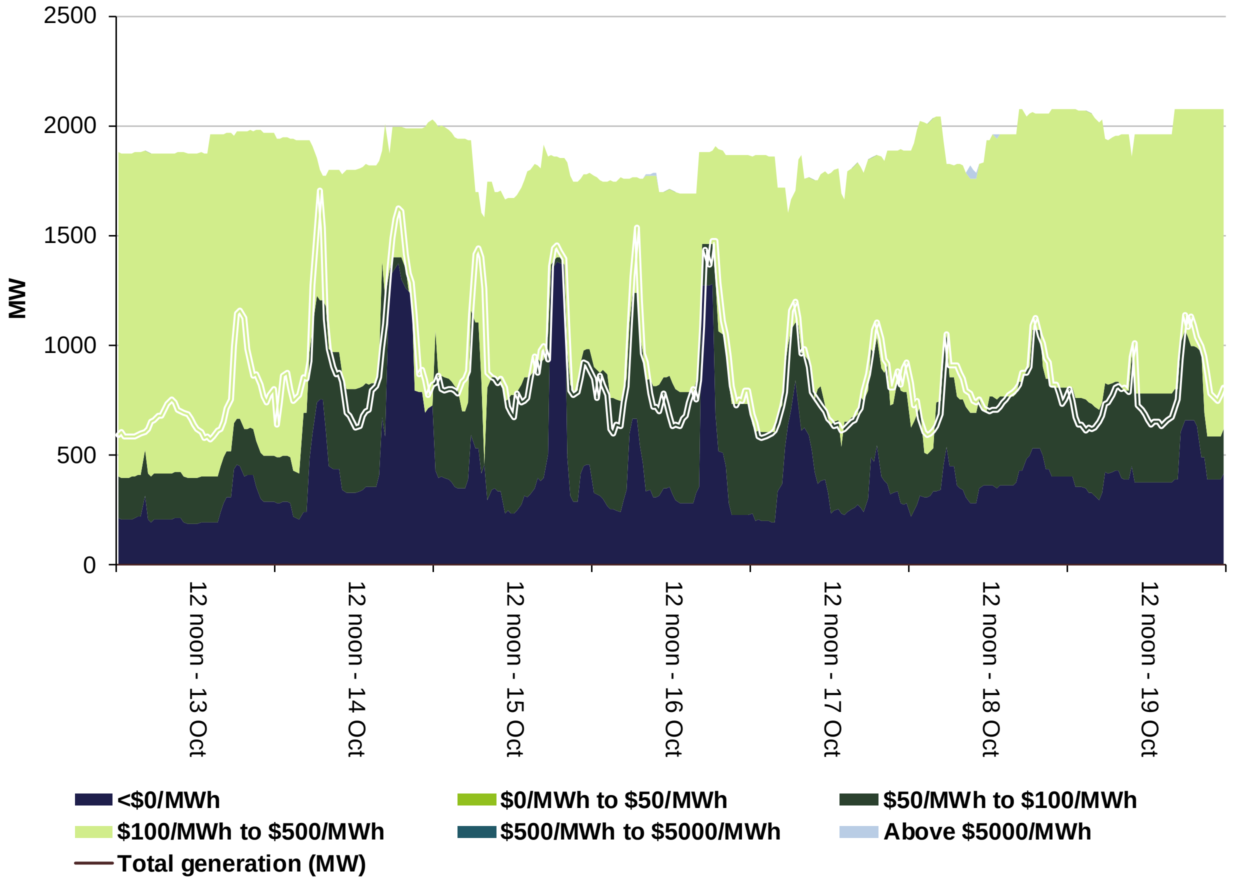

## Figure 5: Victoria generation and bidding patterns



## 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.

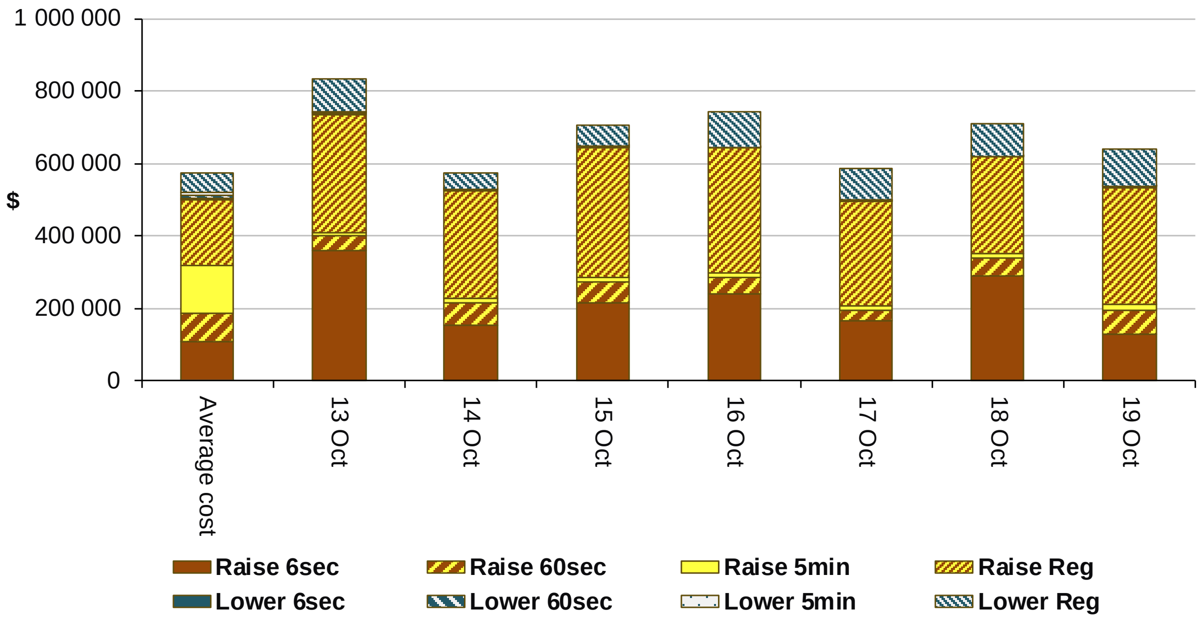
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 614 000 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 180 500 or around less than 6 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

## Mainland

There was one occasion where the spot price across the mainland was greater than three times the New South Wales weekly average price of $92/MWh and above $250/MWh. The New South Wales price is used a proxy for the mainland.

**Sunday, 13 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 |
| 7 pm | 290.81 | 185.79 | 244.68 | 20 853 | 20 627 | 20 749 | 29 456 | 30 138 | 30519 |

For the 7 pm trading interval, prices aligned across all mainland regions and will be treated as one. Conditions at the time saw net demand 226 MW higher than forecast and net availability 682 MW lower than forecast, both four hours prior. Lower availability was mostly due to the removal of approximately net 600 MW of capacity across Queensland, New South Wales and Victoria (most of which was priced below $48/MWh). With little capacity across the mainland regions offered between $148/MWh and $240/MWh, the spot price settled between $251/MWh and $290/MWh for the trading interval. See Table 4 for rebids removing capacity.

### Table 4: Significant rebids

| Submitted time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
|---|---|---|---|---|---|---|---|
| 4.46 pm | | Visy Power Generation | Smithfield | -120 | -984 | N/A | 1645~A~NSW price PD@1645 lwr thn 5PD@1500 for 1900 SL~ |
| 4.55 pm | | AGL Energy | Loy Yang A | -90 | <0 | N/A | 1650~P~010 unexpected/plant limits~101 milling limits |
| 5.34 pm | | AGL Energy | Bayswater | -20 | 38 | N/A | 1730~P~010 unexpected/plant limits~101 milling limits |
| 5.46 pm | | RTA Yarwun | Yarwun | -45 | -1000 | N/A | gas supply limitations |
| 5.52 pm | | EnergyAustralia | Jeeralang B | -84 | -1000 | N/A | 1750~P~B3 failed start SL~ |
| 5.55 pm | | EnergyAustralia | Jeeralang B | -84 | -1000 | N/A | 1755~P~B2 failed start SL~ |
| 6.23 pm | | CS Energy | Gladstone | -44 | -1000 | N/A | 1822P AVR testing-SL |
| 6.24 pm | 6.35 pm | CS Energy | Gladstone | -4 | -1000 | N/A | 1823P AVR testing-SL |
| 6.24 pm | 6.35 pm | CS Energy | Gladstone | -130 | <48 | N/A | 1824P condenser backflush-SL |

| Submitted time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
|---|---|---|---|---|---|---|---|
| 6.34 pm | 6.45 pm | CS Energy | Gladstone | 48 | N/A | -1000 | 1834P AVR testing-SL |
| 6.41 pm | 6.50 pm | AGL Energy | Loy Yang A | -10 | -1000 | N/A | 1840~P~020 reduction in avail cap~203 plant failure 10MW |

## Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $86/MWh and above $250/MWh.

### Sunday, 13 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 pm | 278.19 | 187.70 | 240.73 | 6806 | 6868 | 6890 | 9571 | 9786 | 9918 |

The price was aligned in all mainland regions and is discussed under Table 3.

### Monday, 14 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 |
| 6 pm | 281.61 | 299.73 | 299.73 | 7003 | 7044 | 7046 | 9303 | 9278 | 9507 |

Conditions at the time saw prices close to forecast.

## 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 $92/MWh and above $250/MWh.

### Sunday, 13 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 |
| 7 pm | 290.81 | 185.79 | 244.68 | 8152 | 8014 | 8164 | 10 213 | 10 529 | 10 739 |

The price was aligned in all mainland regions and is discussed under Table 3.

**Monday, 14 October**

### Table 8: 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 |
| 6 pm | 280.22 | 296.19 | 299.30 | 8387 | 8349 | 8425 | 10 118 | 10 164 | 10 272 |

Conditions at the time saw prices close to forecast.

## Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $98/MWh and above $250/MWh.

**Tuesday, 15 October**

### Table 9: 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 | 299.99 | 299.99 | 299.99 | 5495 | 5431 | 5540 | 6574 | 6586 | 6580 |

Conditions at the time saw prices as forecast.

## South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $75/MWh and above $250/MWh and there were thirteen occasions where the spot price was below -$100/MWh.

**Sunday, 13 October**

### Table 10: 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 |
| 4.30 pm | -109.68 | 43.62 | 68.50 | 1077 | 1100 | 1081 | 2971 | 3031 | 2561 |

Conditions at the time saw demand close to forecast and availability 60 MW less than forecast, both four hours prior.

At the time, there were only four plants offering capacity between $68/MWh and the price floor. This meant that small changes in demand or availability could result in large changes to the dispatch price. At 6.25 pm availability increased by 172 MW, mostly due to an increase in wind generation. This caused a number of generation plants to be ramp down constrained. This resulted in the dispatch price dropping to the price floor for one dispatch interval. In response to the negative price, a number of participants rebid a total of 289 MW of capacity from the price floor to above $101/MWh and the dispatch price increased to $80/MWh for the final dispatch interval. See Table 11 below.

### Table 11: Significant rebids

| Submitted time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
|---|---|---|---|---|---|---|---|
| 4.23 pm | 4.30 pm | Energy Australia | Waterloo WF | 130 | -1000 | 150 | 16:23 ~ A ~ band adj to 5min negataive DP ~ ABS1 |
| 4.23 pm | 4.30 pm | Trustpower | Snowtown WF | 99 | -1000 | 5000 | 1620 A SA1 5min PD RRP for 1630 ($-96.0) published at 1620 is 105.65% lower than 30min PD RRP published at 1531 ($46.68) - time of alert: 1623 |
| 4.23 pm | 4.30 pm | AGL Energy | Torrens Island | 60 | -1000 | 101 | 1620~A~040 chg in AEMO disp~44 price decrease VS PD SA - $1000 FOR 16:25 |

### Table 12: 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 pm | 251.45 | 150.18 | 213.46 | 1293 | 1264 | 1257 | 2377 | 2395 | 2304 |

The price was aligned in all mainland regions and is discussed under Table 3.

## Tuesday, 15 October

### Table 13: 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 | 286.23 | 273.13 | 273.16 | 1489 | 1445 | 1450 | 2366 | 2511 | 2522 |

Conditions at the time saw prices close to forecast.

## Wednesday, 16 October

### Table 14: 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 | 251.94 | 375.79 | 277.07 | 1466 | 1426 | 1431 | 2599 | 2480 | 2422 |
| 1.30 pm | -122.16 | 71.98 | -900.00 | 619 | 716 | 738 | 2482 | 2464 | 2806 |

For the 7 am trading interval conditions at the time saw demand 40 MW higher than forecast and availability 120 MW higher than forecast, both four hours prior.

Higher availability was due to higher than forecast wind generation, almost all of which was offered in at or below $0/MWh. This led to the price settling between $165/MWh to $274/MWh for the entire trading interval.

For the 1.30 pm trading interval, demand was 97 MW lower than forecast and availability was 18 MW higher than forecast, both four hours prior.

In the 4 hours leading up to the start of the trading interval, 240 MW of capacity was added in or rebid from prices above $105/MWh to prices below $0/MWh. From 1 pm to 1.10 pm demand dropped approximately 20 MW while wind generation increased by around 100 MW. With higher priced generation either ramp down constrained or unable to set price, the dispatch price dropped to $0/MWh and $-900/MWh for the first two dispatch intervals respectively. In response to the negative price, participants rebid approximately 350 MW of capacity from prices below $56/MWh to prices above $406/MWh and the dispatch price increased to between -$60/MWh and $81/MWh for the remainder of the trading interval. See Table 15 below for significant rebids.

### Table 15: Significant rebids

| Submitted time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
|---|---|---|---|---|---|---|---|
| 10.49 am | | Origin Energy | Ladbroke Grove | 83 | 105 | -1000 | 1045A ensure economic dispatch - avoid short shutdown SL |
| 11.34 am | | Engie | Pelican Point | 50 | N/A | -1000 | 0835~F~revised tolling nomination: #1575~ |
| 12.56 pm | 1.05 pm | Neoen | Hornsdale Power Reserve Unit 1 | 12 | N/A | <0 | 1256 A change in forecast prices |
| 12.57 pm | 1.05 pm | Vena Energy Services (Australia) Pty Ltd | Tailem Bend Solar Project 1 | 95 | 14700 | -1000 | 1257 A Predispatch showing positive prices |
| 1.04 pm | 1.15 pm | Vena Energy Services (Australia) Pty Ltd | Tailem Bend Solar Project 1 | 95 | -1000 | 14700 | 1304 A Negative prices again in predispatch |
| 1.06 pm | 1.15 pm | Neoen | Hornsdale Power Reserve Unit 1 | 6 | <56 | 406 | 1306 A change in forecast prices |
| 1.07 pm | 1.15 pm | Infigen | Lake Bonney 2 WF | 149 | -1000 | 12879 | 1250~A~SA PRICE DP@1310 for 1310 948 lwr thn 5PD@1305 SL~ |
| 1.08 pm | 1.15 pm | Trustpower | Snowtown WF | 99 | -1000 | 5000 | 1305 A SA1 5MIN PD RRP for 1330 ($-900.0) published at 1305 IS 1197.3% lower than 30MIN PD RRP published at 1231 ($69.37) - time of alert: 1308 |

### Table 16: 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 |
| 2.30 pm | -129.99 | -96.00 | -900.00 | 627 | 701 | 730 | 2882 | 2521 | 2869 |
| 3.30 pm | -116.27 | -333.98 | -900.00 | 744 | 752 | 783 | 3081 | 2633 | 2909 |

Prices were close to forecast for the 2.30 pm trading interval.

For the 3.30 pm trading interval, demand was close to forecast and availability was 448 MW higher than forecast, both four hours prior. The higher availability was mainly due to higher than forecast wind generation and Pelican Point adding in 122 MW of capacity in at the start of the trading interval (50 MW of which was priced at the floor).

There was no capacity priced between $-300/MWh and $-900/MWh so little changes in demand could cause large fluctuations in price. At 3.05 pm demand fell 30 MW and resulted in the dispatch price falling to $-900/MWh. In response to the negative price, EnergyAustralia and Trustpower collectively rebid approximately 230 MW at Snowtown Wind Farm and Waterloo Wind Farm priced less than $0/MWh to prices above $50/MWh. This caused the price to settle between $-50/MWh and $80/MWh for the remainder of the trading interval.

## Friday, 18 October

### Table 17: 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 |
| 10.30 am | -151.26 | -4.62 | -1000.00 | 635 | 701 | 700 | 3017 | 2633 | 2714 |
| Midday | -149.24 | -1000.00 | -1000.00 | 603 | 573 | 616 | 2982 | 2650 | 2677 |
| 1 pm | -143.39 | -554.58 | -1000.00 | 571 | 587 | 617 | 2825 | 2645 | 2651 |
| 2 pm | -163.26 | -494.10 | -1000.00 | 604 | 592 | 645 | 2864 | 2692 | 2668 |
| 5.30 pm | -101.27 | 77.50 | -16.13 | 1095 | 1060 | 1084 | 3013 | 2598 | 2622 |

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply for all significant price events on 18 October in all regions following an intervention in the market, with the exception of the 5.30 pm price event.

For the 10.30 am trading interval, demand was 66 MW lower than forecast and availability was 384 MW higher than forecast, both four hours ahead. Higher availability was due to higher than forecast wind generation, and 200 MW of capacity added in by AGL at Torrens Island (40 MW of which was offered at the price floor). There was little capacity offered between the price floor and $90/MWh. This meant that small changes in demand or availability could cause significant changes in price. The dispatch price dropped to the floor for one trading interval, causing the spot price to settle lower than forecast.

For the midday to 2 pm trading intervals, demand was close to forecast and availability was between 172 MW to 332 MW higher than forecast, four hours prior. Higher availability was due to higher than forecast wind generation, most of which was priced below $0/MWh. There was little capacity offered between the price floor and $-100/MWh. A minimum of net 136 MW capacity was moved from the price floor to prices above $-100/MWh before the start of each trading interval. In all trading intervals the price reached the floor for one dispatch interval. In response to the negative dispatch price, up to net 622 MW of capacity was moved from the price floor to prices above $-3/MWh. The combination of rebidding to higher prices before the trading interval and in response to price spikes at the floor saw all trading intervals higher than the forecast price 4 hours prior.

For the 5.30 pm trading interval, demand was close to forecast and availability was 415 MW higher than forecast, both four hours prior. Higher availability was mainly due to Origin Energy adding in 110 MW of capacity offered at the price floor and higher than forecast wind generation. At 5.04 pm (effective 5.15 pm) Origin Energy rebid 114 MW of energy from $115/MWh to the price floor, citing increased NEM demand as the reason. At 5.30 pm demand dropped by 77 MW and the dispatch price fell to the price floor for one dispatch interval.

### Saturday, 19 October

### Table 18: 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 |
| 11 am | -117.52 | 10.24 | -1000.00 | 641 | 636 | 660 | 2726 | 2602 | 2648 |
| Midday | -154.54 | -100.00 | -1000.00 | 673 | 547 | 592 | 2691 | 2595 | 2642 |
| 1.30 pm | -158.38 | -1000.00 | -1000.00 | 576 | 485 | 522 | 2653 | 2664 | 2627 |

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply for all significant price events on 19 October in all regions following an intervention in the market.

For the 11 am trading interval, demand was close to forecast and availability was 124 MW higher than forecast, four hours prior. The higher availability was due to higher than forecast wind generation, the majority of which was priced below $0/MWh. At 10.40 am a 66 MW increase in wind generation saw the dispatch price fall to the floor and result in the lower than forecast price.

Prices were close to forecast for the midday trading interval.

For the 1.30 pm trading interval, demand was 91 MW higher than forecast and availability was close to forecast. In response to the dispatch price dropping to the price floor at 1.10 pm, participants rebid approximately 480 MW of capacity from the price floor to prices above $150/MWh to avoid uneconomic dispatch, effective between 1.15 pm and 1.20 pm. This resulted in the dispatch price settling between $32/MWh to $41/MWh for the remainder of the trading interval. See Table 19 below.

## Table 19: Significant rebids

| Submitted time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
|---|---|---|---|---|---|---|---|
| 1.08 pm | 1.15 pm | Trustpower | Snowtown WF | 99 | -1000 | 14700 | 1305 A SA1 5MIN PD RRP for 1315 ($-1000.0) published at 1305 is 941.67% lower than 5min PD RRP published at 1300 ($-96.0) - time of alert: 1308 |
| 1.08 pm | 1.15 pm | EnergyAustralia | Waterloo WF | 130 | -1000 | 150 | 1308 A band adj to manage 5min negative DP SL |
| 1.11 pm | 1.20 pm | AGL Energy | Hallett 1 WF | 85 | -1000 | 300 | 1310~A~040 chg in AEMO disp~45 price increase VS PD SA $39.23 VS -$1000 |
| 1.11 pm | 1.20 pm | AGL Energy | Hallett 2 WF | 59 | -1000 | 300 | 1310~A~040 chg in AEMO disp~45 price increase VS PD SA $39.23 VS -$1000 |
| 1.11 pm | 1.20 pm | AGL Energy | North Brown Hill WF | 109 | -1000 | 300 | 1310~A~040 chg in AEMO DISP~45 price increase VS PD SA $39.23 VS -$1000 |

## Table 20: Price, Demand and Availability

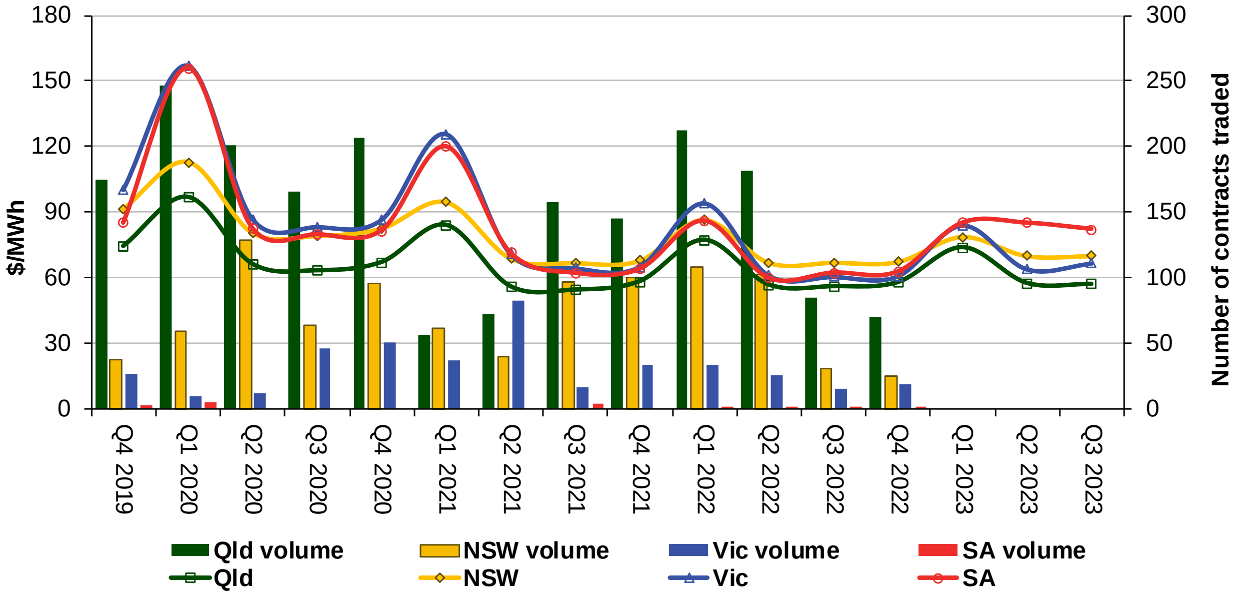
| Time | Price ($/MWh) | | | Demand (MW) | | | Availability (MW) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast | Actual | 4 hr forecast | 12 hr forecast |
| 4.30 pm | -107.28 | -96.00 | -1000.00 | 781 | 780 | 771 | 2758 | 2713 | 2652 |

Conditions at the time saw prices close to forecast.

## 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.

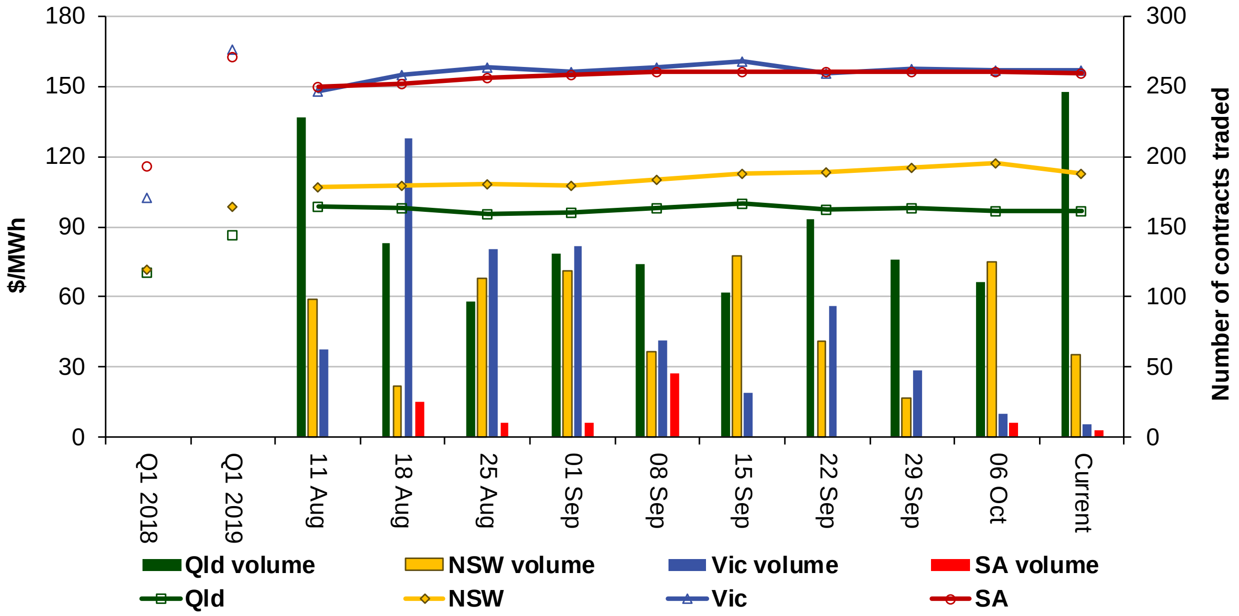
### Figure 9: Quarterly base future prices Q4 2018 – Q3 2022




Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2020 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 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 2020 base contracts over the past 10 weeks (and the past 2 years)

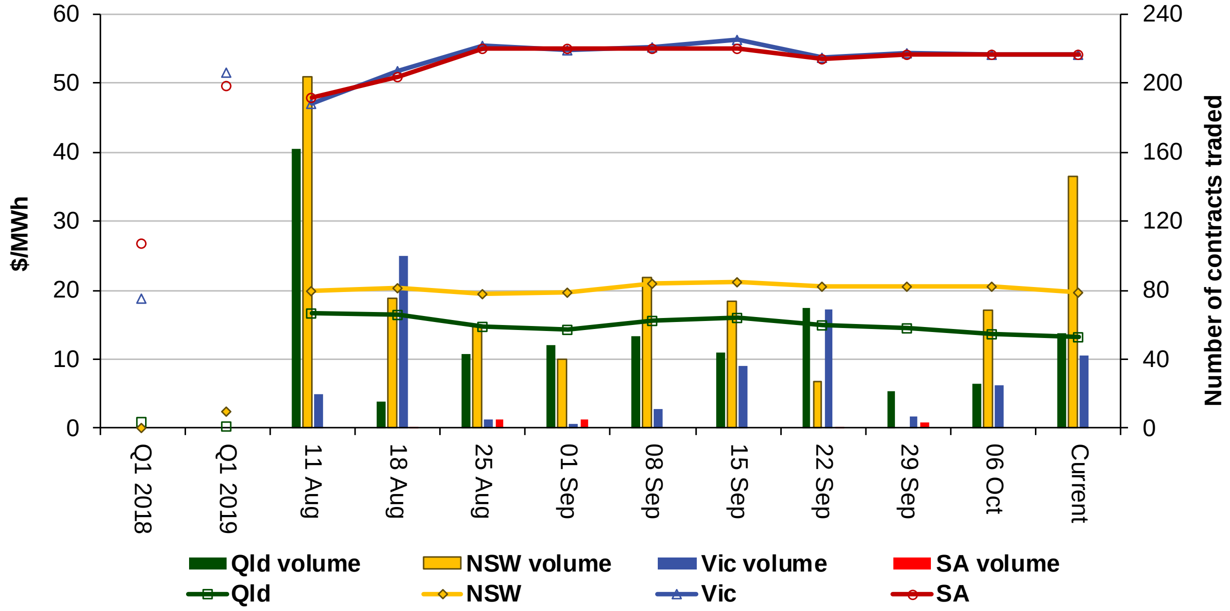



Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional quarter 1 2020 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 prices are also shown.

### Figure 11: Price of Q1 2020 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](Industry Statistics) section of our website.

**Australian Energy Regulator**
**November 2019**