# Electricity Report

# 14 – 20 July 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.

## Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 14 to 20 July 2019.

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

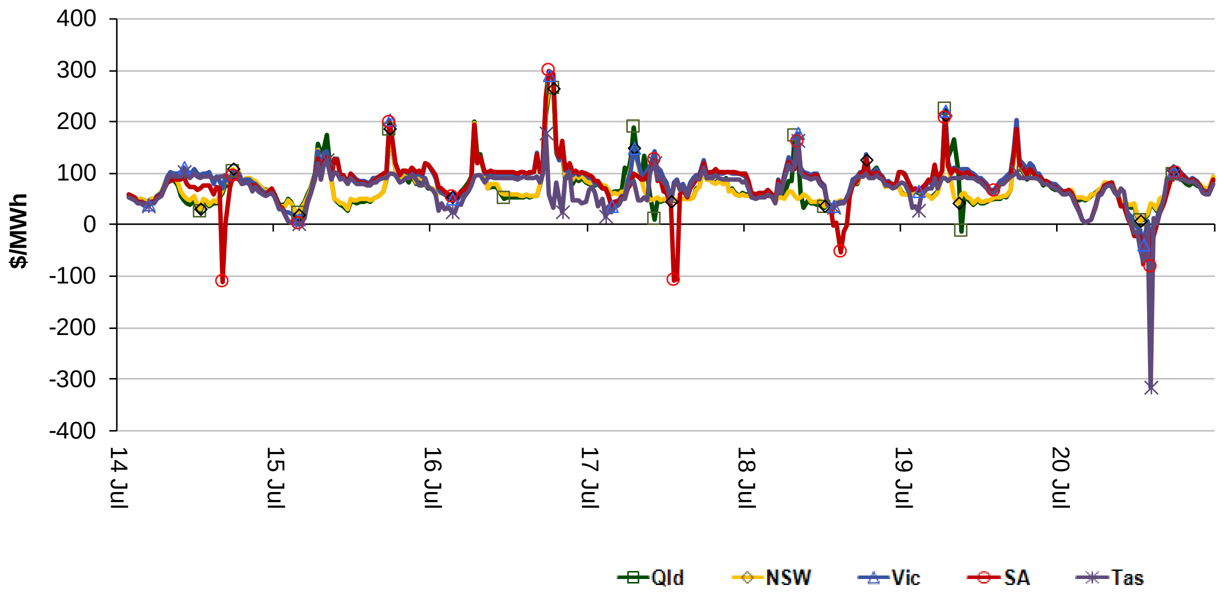
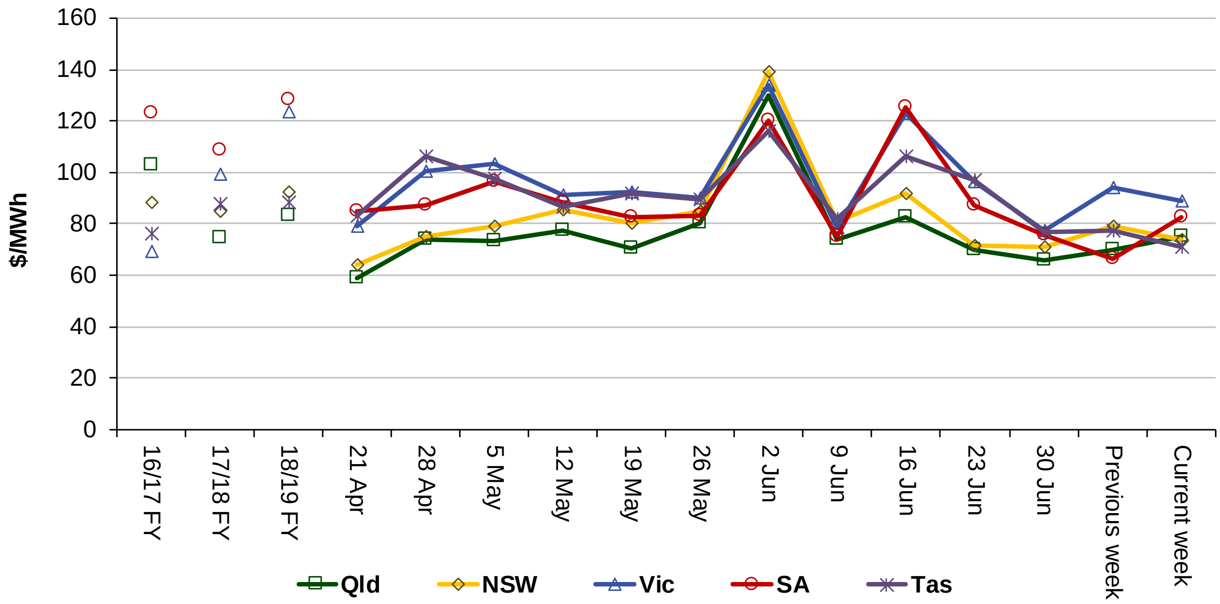



Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

### 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 | 75 | 74 | 89 | 83 | 71 |
| 18-19 financial YTD | 72 | 79 | 76 | 125 | 56 |
| 19-20 financial YTD | 71 | 76 | 89 | 76 | 75 |

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 187 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

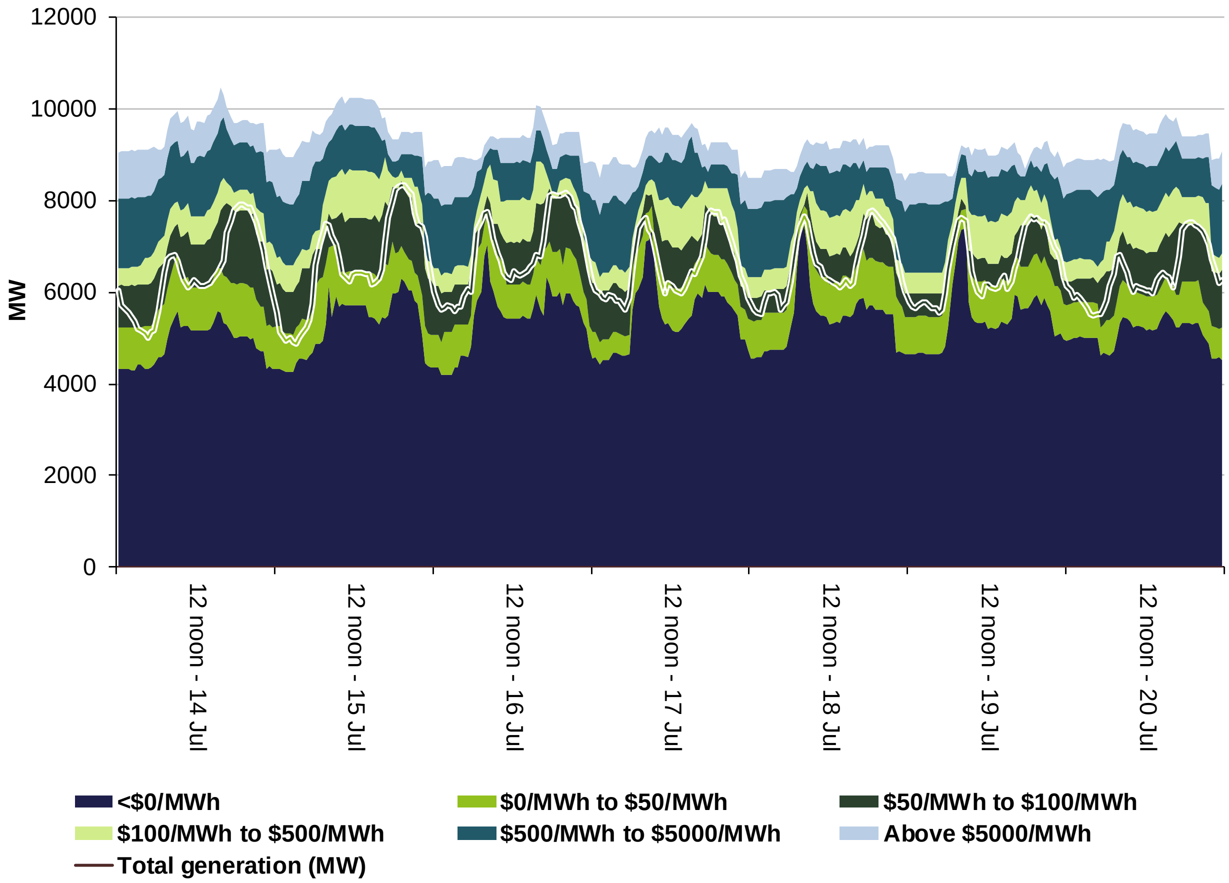
| | Availability | Demand | Network | Combination |
|---|---|---|---|---|
| % of total above forecast | 7 | 30 | 0 | 1 |
| % of total below forecast | 8 | 41 | 0 | 13 |

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

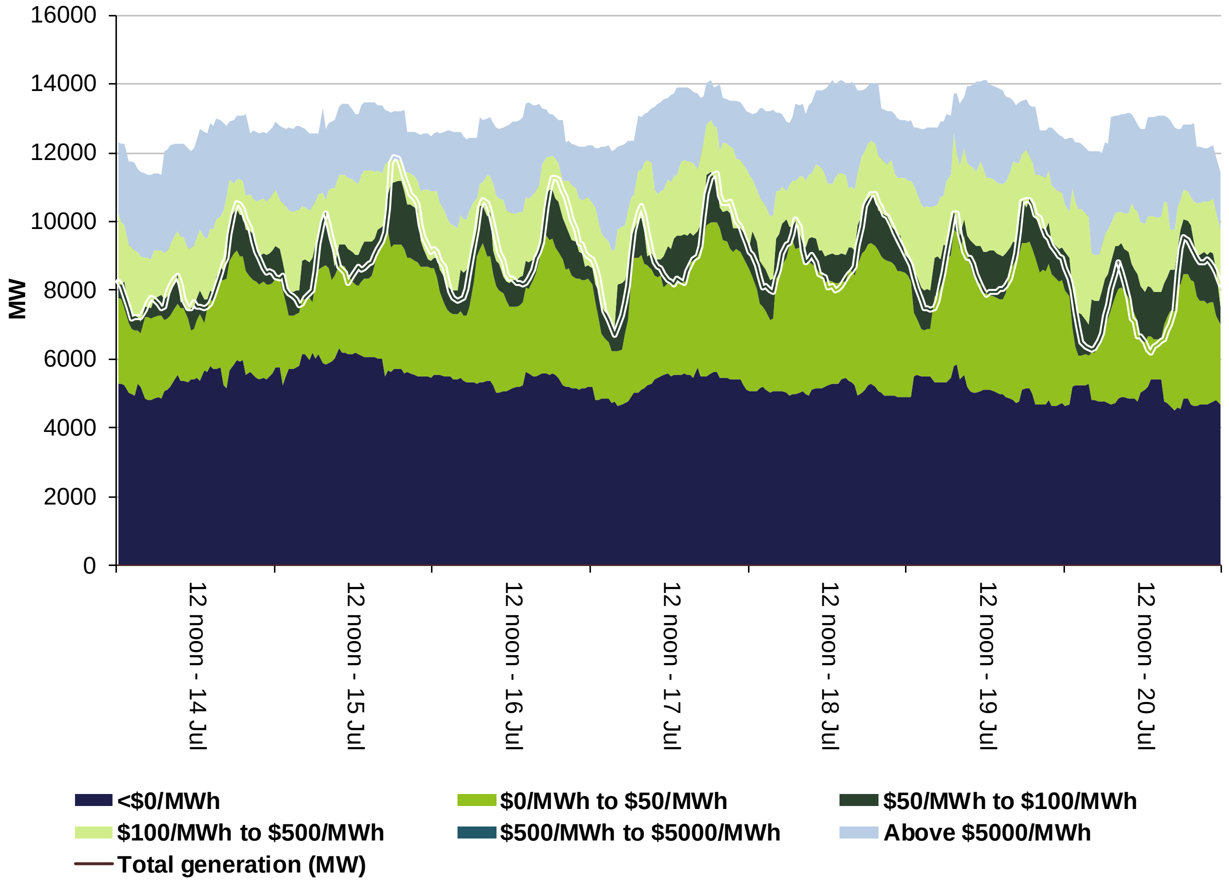
## Generation and bidding patterns

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.

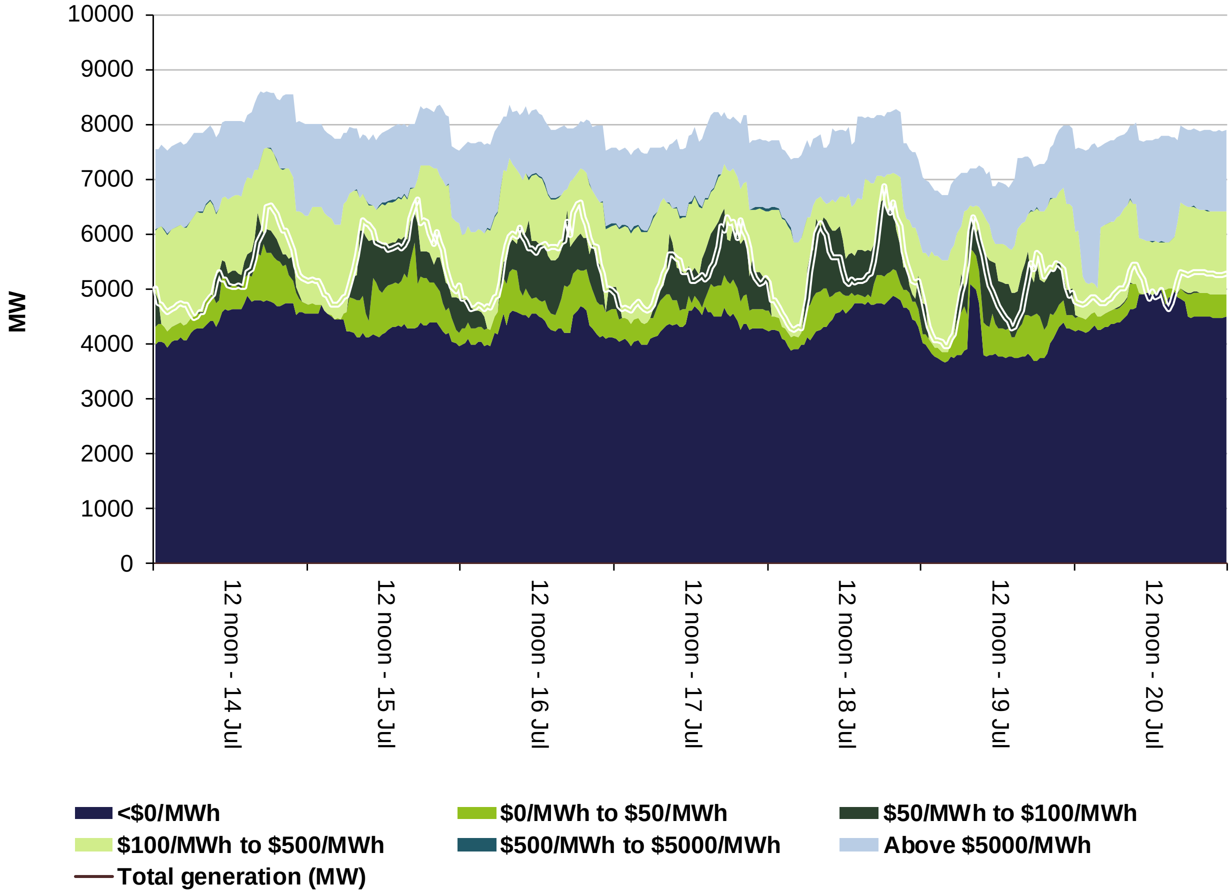
### Figure 3: Queensland generation and bidding patterns



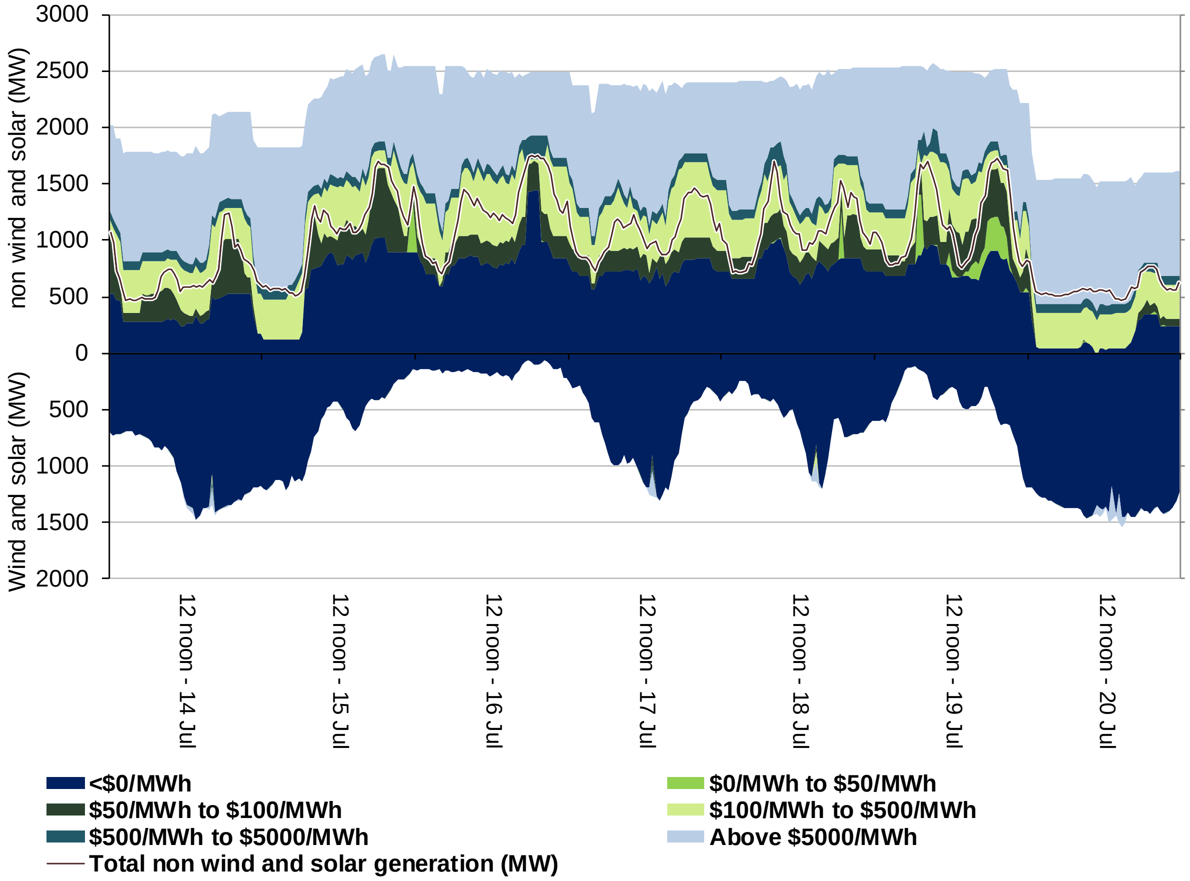
## Figure 4: New South Wales generation and bidding patterns



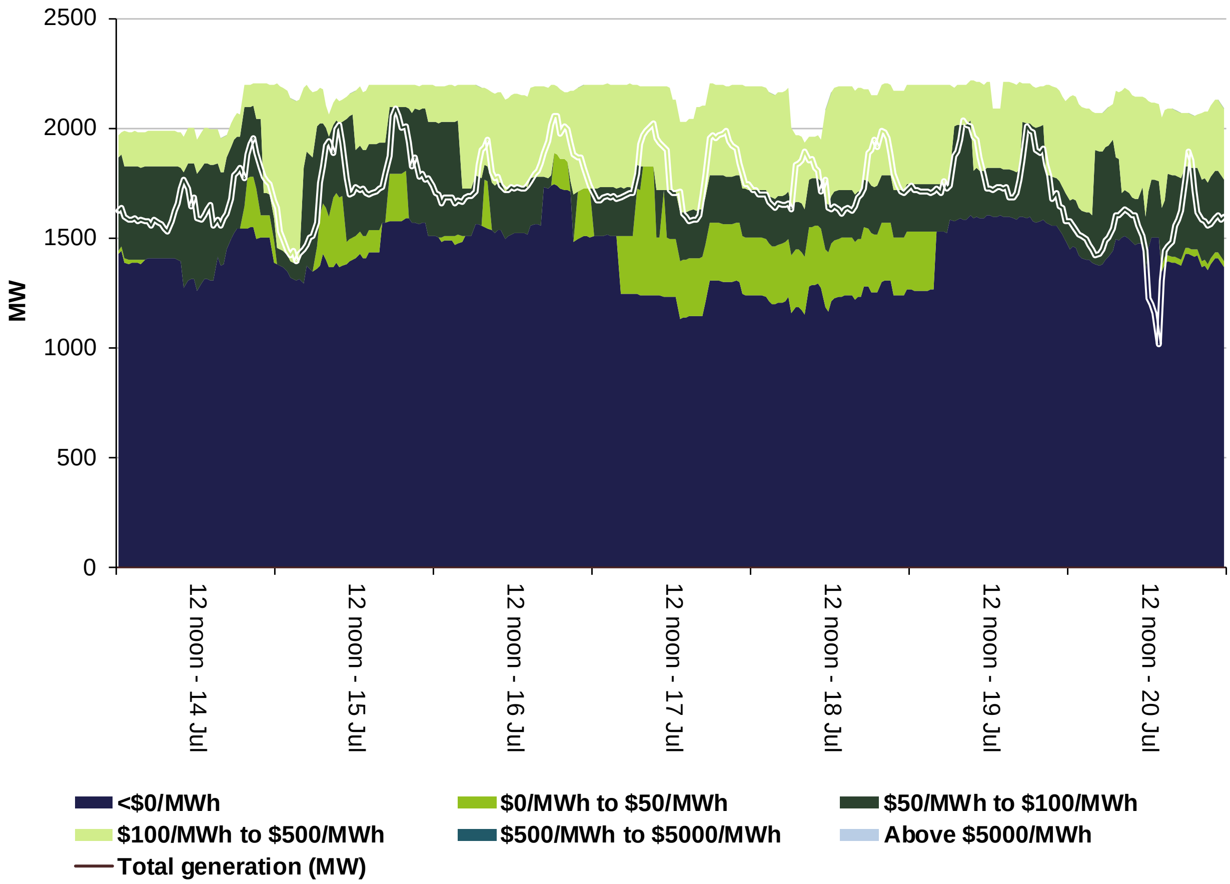

## Figure 5: Victoria generation and bidding patterns



## 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.

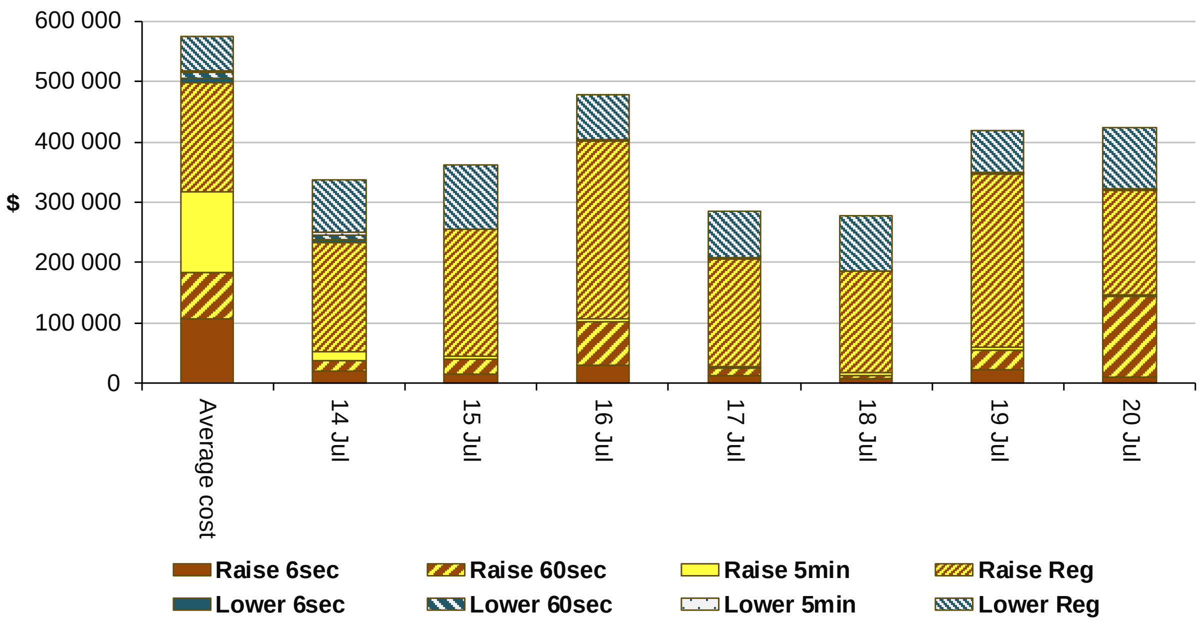
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 295 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $285 500 or around 2 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 were two occasions where the spot price aligned nationally and the New South Wales price was greater than three times the New South Wales weekly average price of $74/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

**Tuesday, 16 July**

### 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 |
| 6.30 pm | 265.31 | 236.34 | 277.63 | 27 353 | 27 241 | 27 470 | 32 966 | 33 539 | 33 849 |
| 7 pm | 265.46 | 299.50 | 279.78 | 27 291 | 27 216 | 27 505 | 32 928 | 33 446 | 33 913 |

For 6.30 pm and 7 pm trading intervals, prices across all mainland regions were close to forecast, four and 12 hours prior.

## South Australia

There were three occasions where the spot price in South Australia was below -$100/MWh.

**Sunday, 14 July**

### 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 |
| 4.30 pm | -111.12 | 41.71 | -1000 | 1459 | 1282 | 1238 | 3436 | 3163 | 3137 |

Demand was 177 MW higher than forecast while availability was 273 MW higher than forecast, mostly due to higher than forecast wind generation, four hours prior.

A step change in offers by Engie at Pelican Point set up a day ahead added around 170 MW of capacity at -$1000/MWh at 4.05 pm and caused the price to fall to the floor. In immediate response to the price falling to the floor, around 430 MW of generation was rebid from -$1000/MWh to more than $300/MWh. See Table 5 for relevant rebids.

### Table 5: Significant rebids effective 4.10 pm

| Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
|---|---|---|---|---|---|
| Infigen | Lake Bonney 2 WF | 159 | -1000 | 12 879 | 1600~A~unforecast floor sl~ |
| Hornsdale Power Reserve Pty Ltd | Hornsdale Power Reserve | 40 | -1000 | 305 | 1601 P change in forecast soc |
| EnergyAustralia | Waterloo WF | 130 | -1000 | 400 | 16:01 A manage 5 min negative price ~ sl |
| Trustpower | Snowtown WF | 99 | -1000 | 5000 | 1600 A SA1 5min PD RRP for 1610 ($-1000.0) published at 1600 is 2082.87% lower than 5min PD RRP published at 1540 ($45.81) - time of alert: 1603 |

**Wednesday, 17 July**

### 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 |
| 1.30 pm | -107.62 | 44.75 | 40.66 | 1293 | 1330 | 1314 | 3625 | 3464 | 3599 |
| 2 pm | -104.91 | 45.54 | 40.72 | 1407 | 1353 | 1330 | 3530 | 3424 | 3587 |

For both the 1.30 pm and 2 pm trading intervals, availability was between 105 MW and 160 MW higher than forecast availability, four hours prior. This was due to higher than forecast wind generation but was partially offset by rebids at Hornsdale Power Reserve and Tailem Bend Solar Project that removed around 105 MW of low priced capacity due to “change in forecast prices” in the four hours to dispatch.

For 1.30 pm trading interval, demand was around 40 MW lower than forecast, four hours prior. At 1.05 pm Engie rebid 110 MW of capacity at Pelican Point from $77/MWh to the price floor and at 1.10 pm there was an increase of almost 70 MW in renewable generation priced at -$1000/MWh and the price fell to the floor. In response almost 390 MW of capacity at Waterloo, Snowtown and Lake Bonney 2 wind farms was rebid from low to high prices which caused the dispatch price to increase to $131/MWh over the rest of the trading interval.

Effective 2 pm, Engie offered an additional 120 MW of capacity at Pelican Point at -$1000/MWh for plant testing reasons and the price fell to the floor.

## Tasmania

There was one occasion where the spot price in Tasmania was below -$100/MWh.

**Saturday, 20 July**

### 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 |
| 2.30 pm | -316.79 | -0.68 | -0.60 | 1190 | 1154 | 1100 | 2046 | 2137 | 2142 |

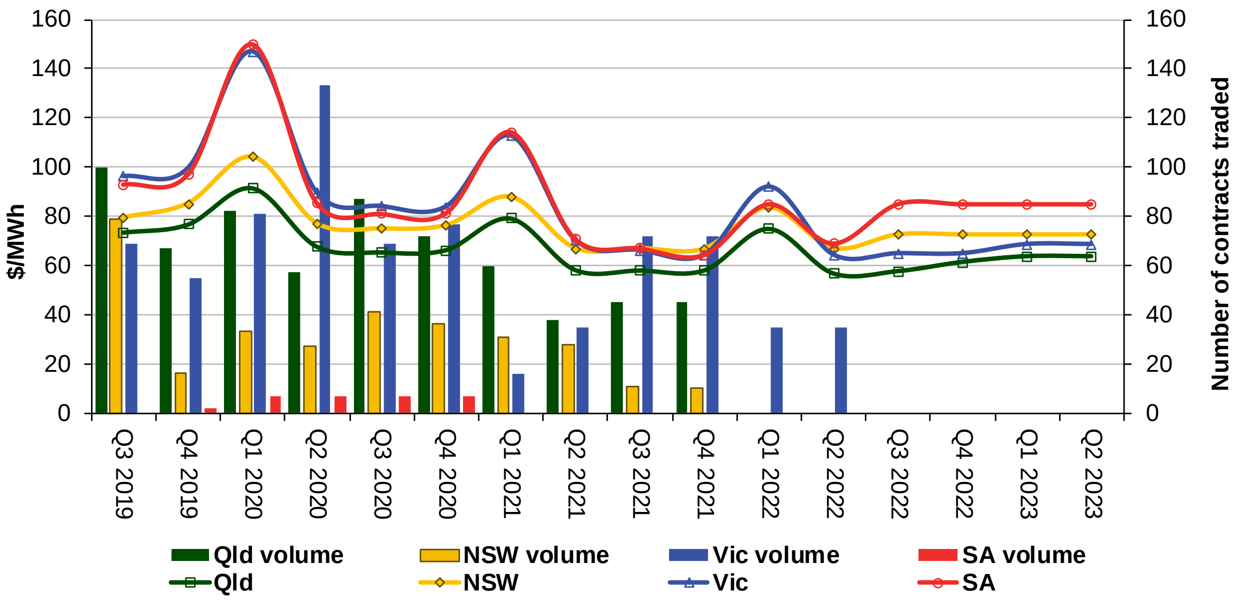
Demand was around 35 MW higher than forecast and availability was around 90 MW lower than forecast, four hours prior.

Effective from 2.05 pm, Hydro Tasmania rebid 646 MW of capacity across its portfolio from the forecast price of around -$1/MWh to -$1000/MWh with the rebid reason being "FCAS cooptimisation impact greater than expected" and the price fell to the floor for two dispatch intervals. Effective 2.20 pm, Hydro Tasmania rebid 127 MW of capacity at Gordon and Poatina from the price floor to $91/MWh due to "Tas price different to forecast". As a result the price increased to $91/MWh for the remainder 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 Q3 2019 – Q2 2023

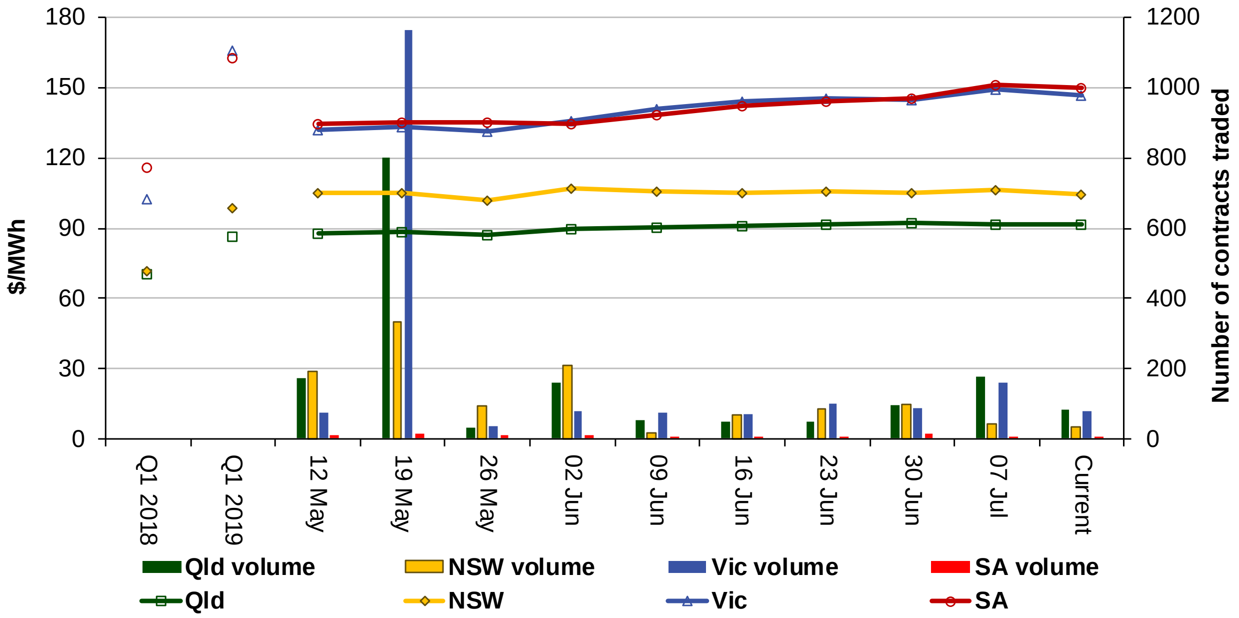



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 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.

The high volume of trades for the week beginning 19 May is a result of the conversion of base load options to base future contracts on Monday 20 May 2019.

## Figure 10: Price of Q1 2020 base contracts over the past 10 weeks (and the past 2 years)



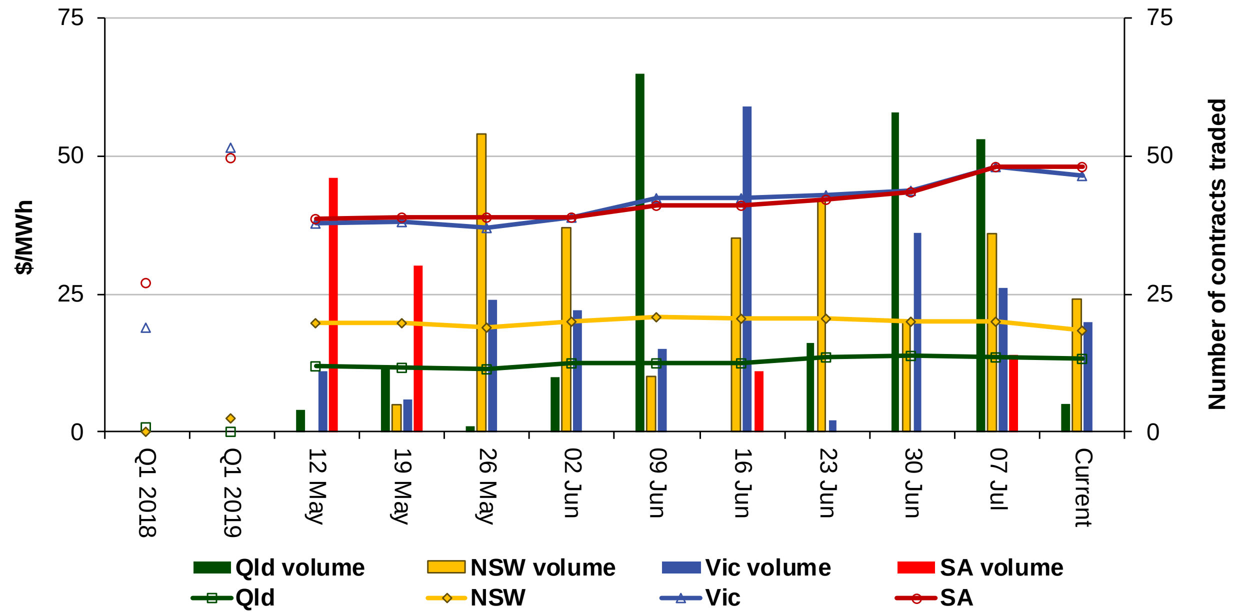

Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

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

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

**Australian Energy Regulator**
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