10 – 16 September 2017

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 10 - 16 September 2017.

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

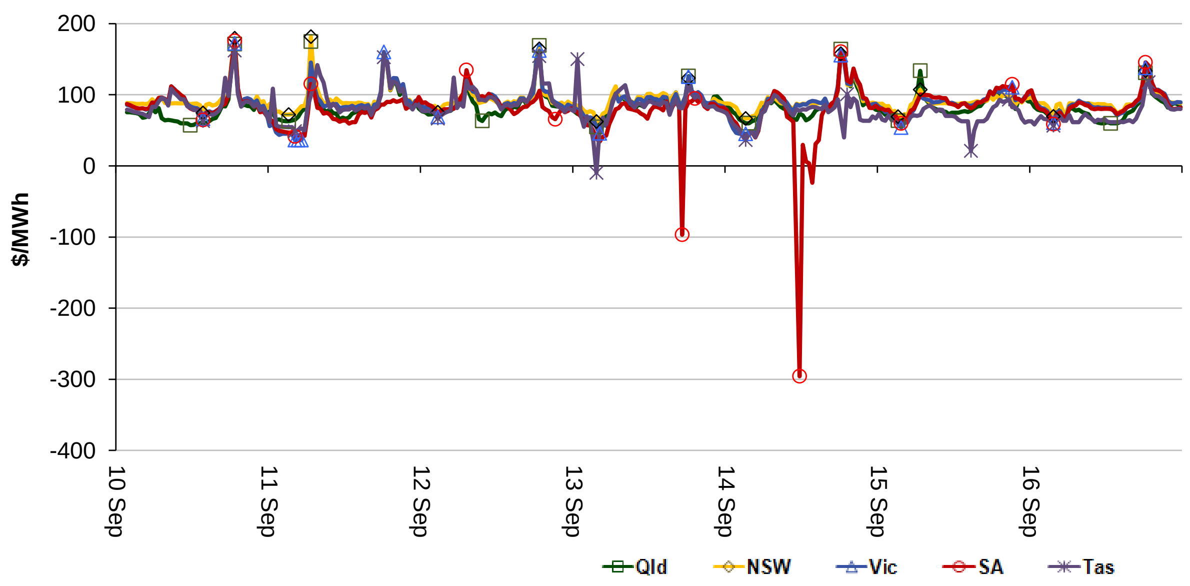


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

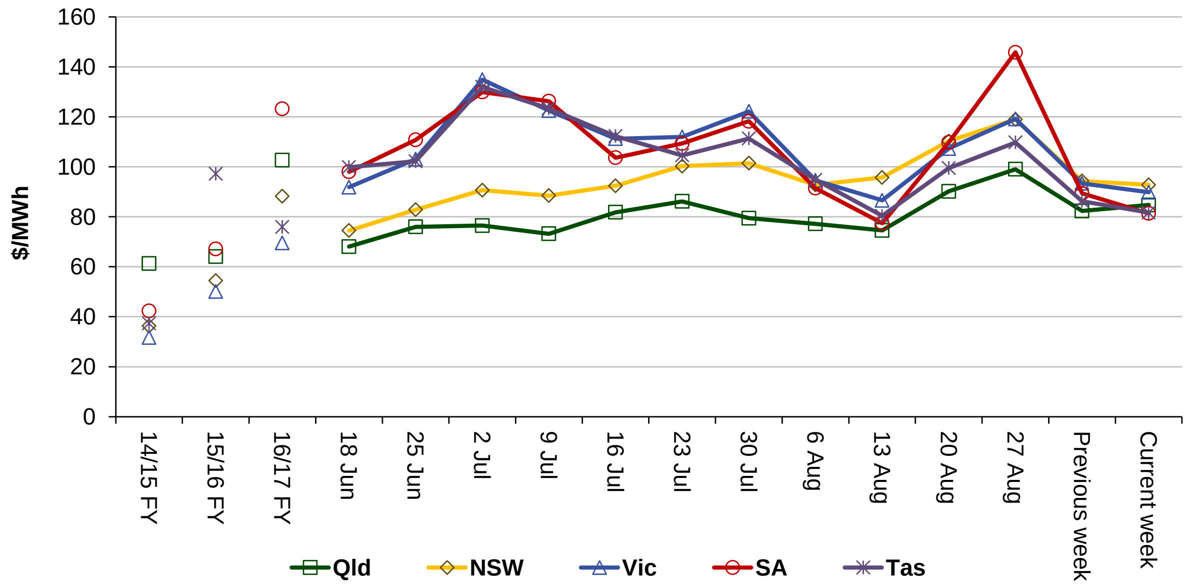


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	85	93	90	81	82
16-17 financial YTD	55	58	54	145	57
17-18 financial YTD	82	98	109	108	103

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 89 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2016 of 273 counts and the average in 2015 of 133. 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	3	37	0	2
% of total below forecast	46	9	0	3

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

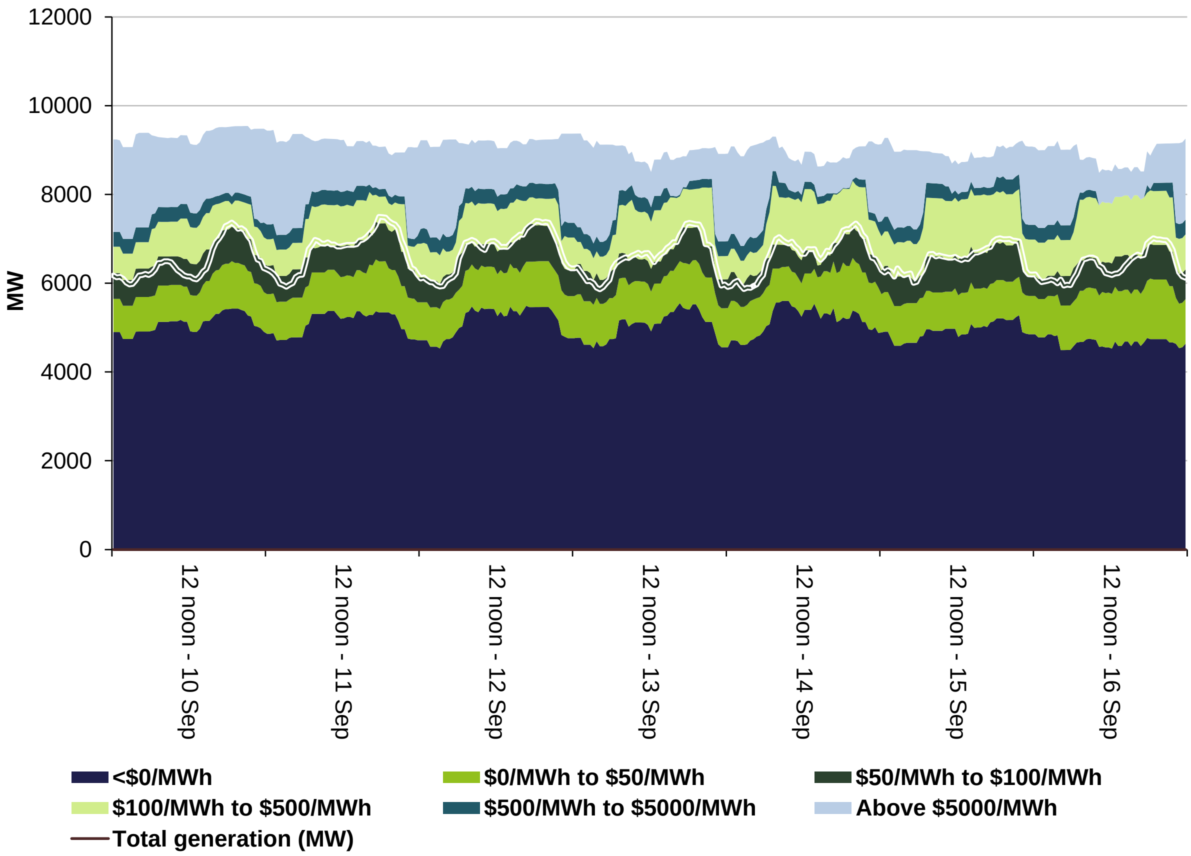


Figure 4: New South Wales generation and bidding patterns

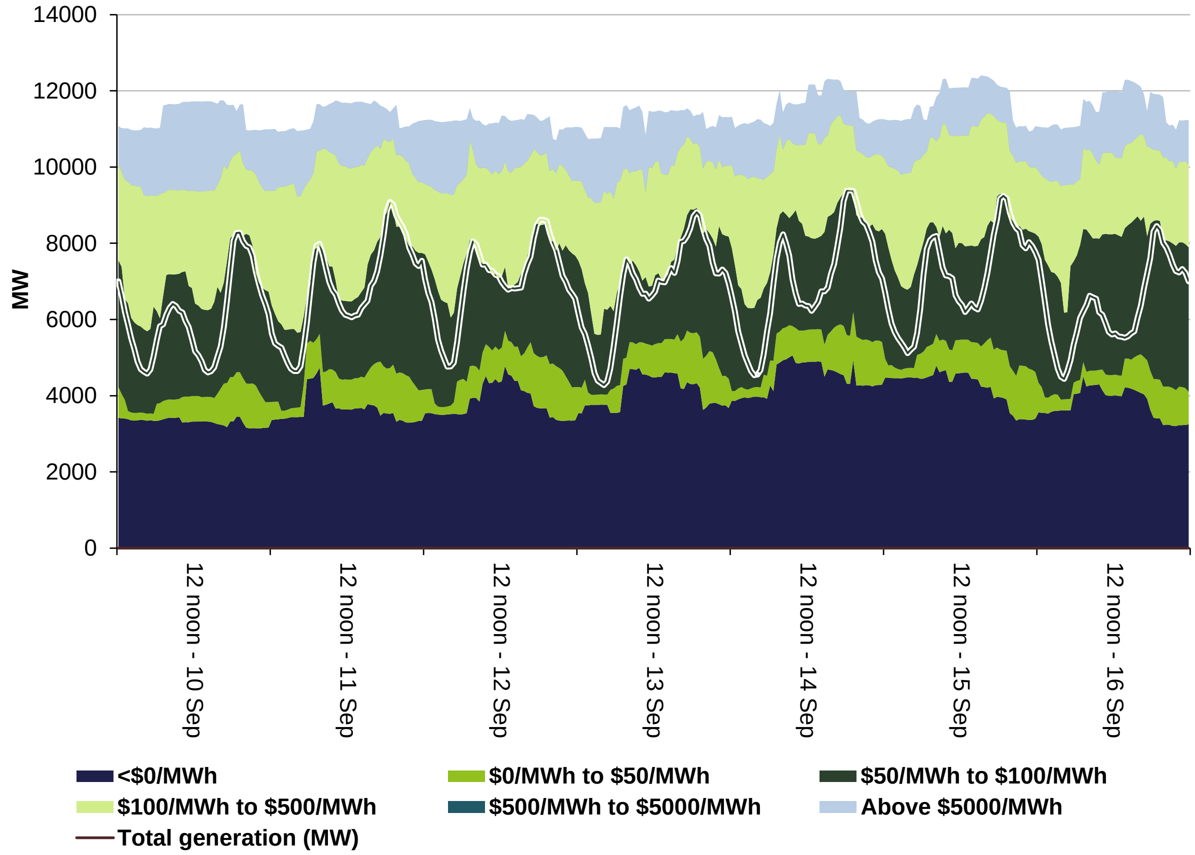


Figure 5: Victoria generation and bidding patterns

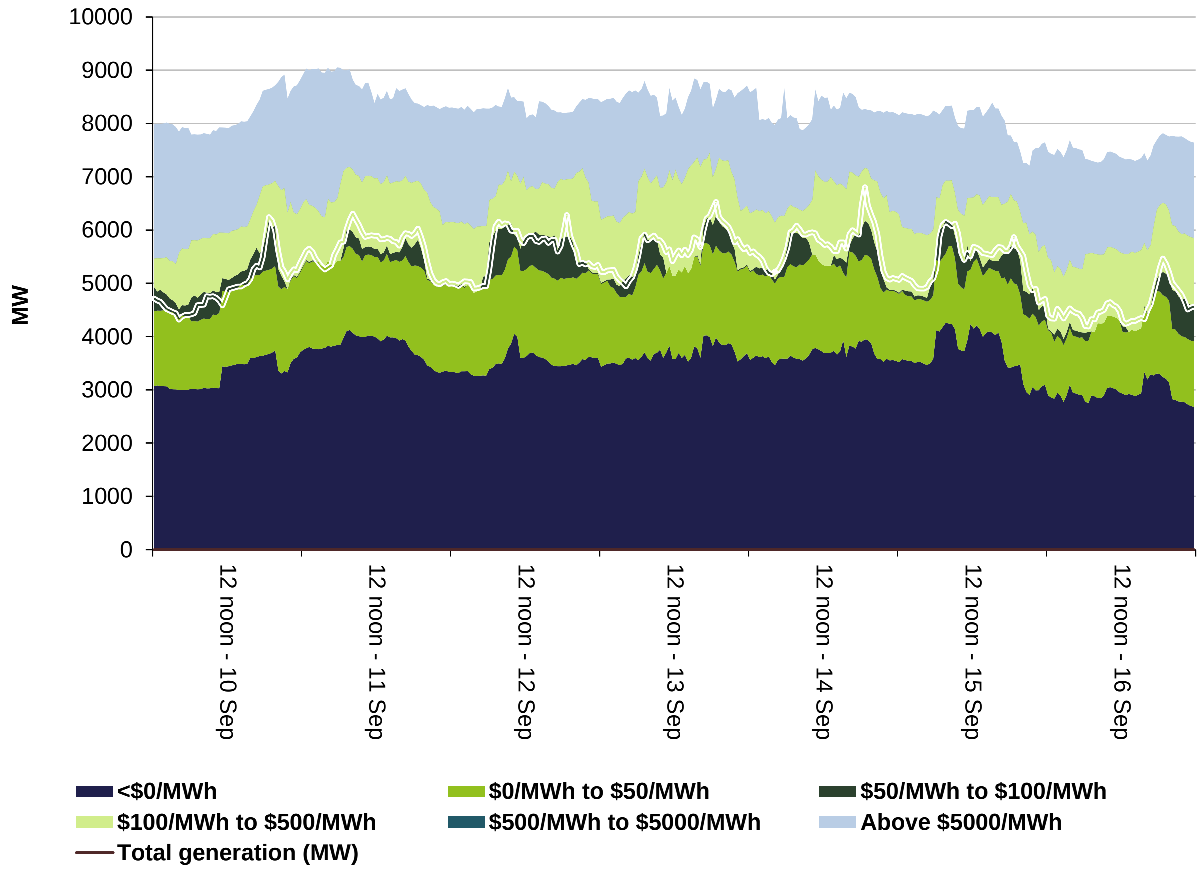


Figure 6: South Australia generation and bidding patterns

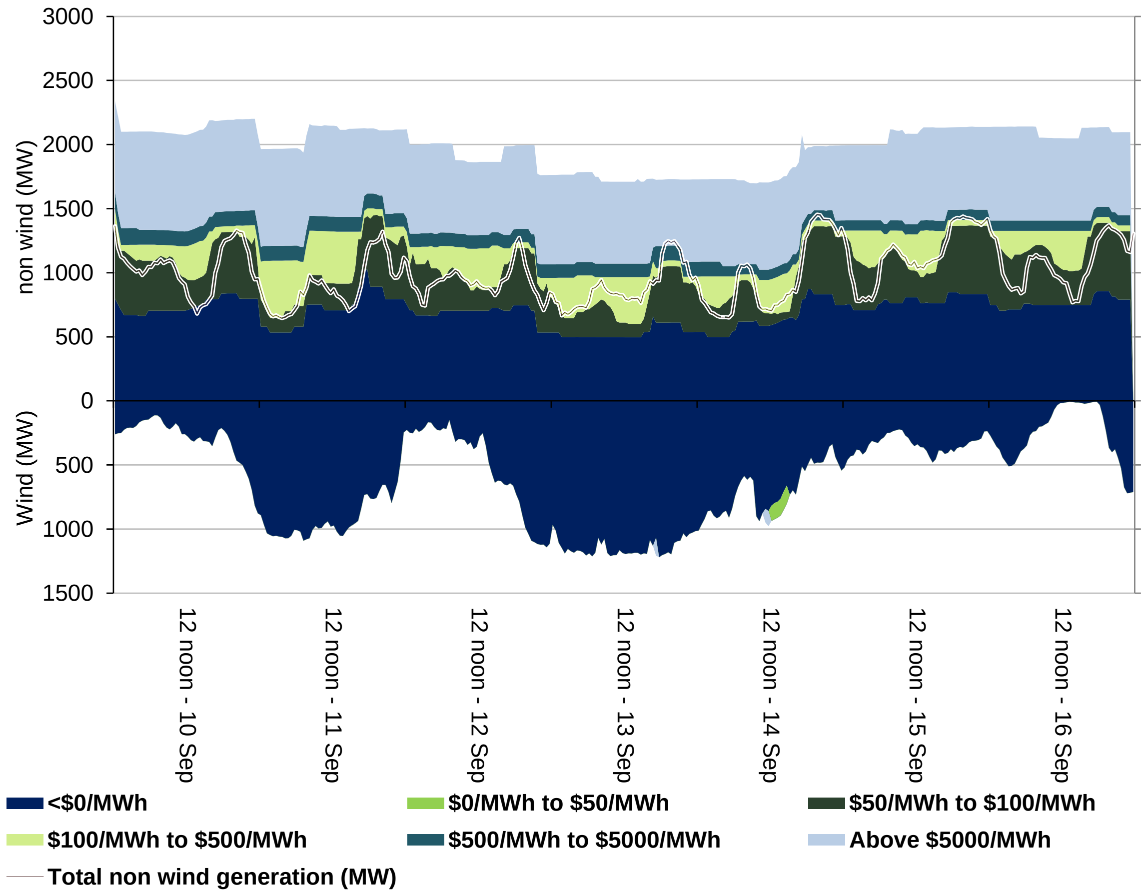
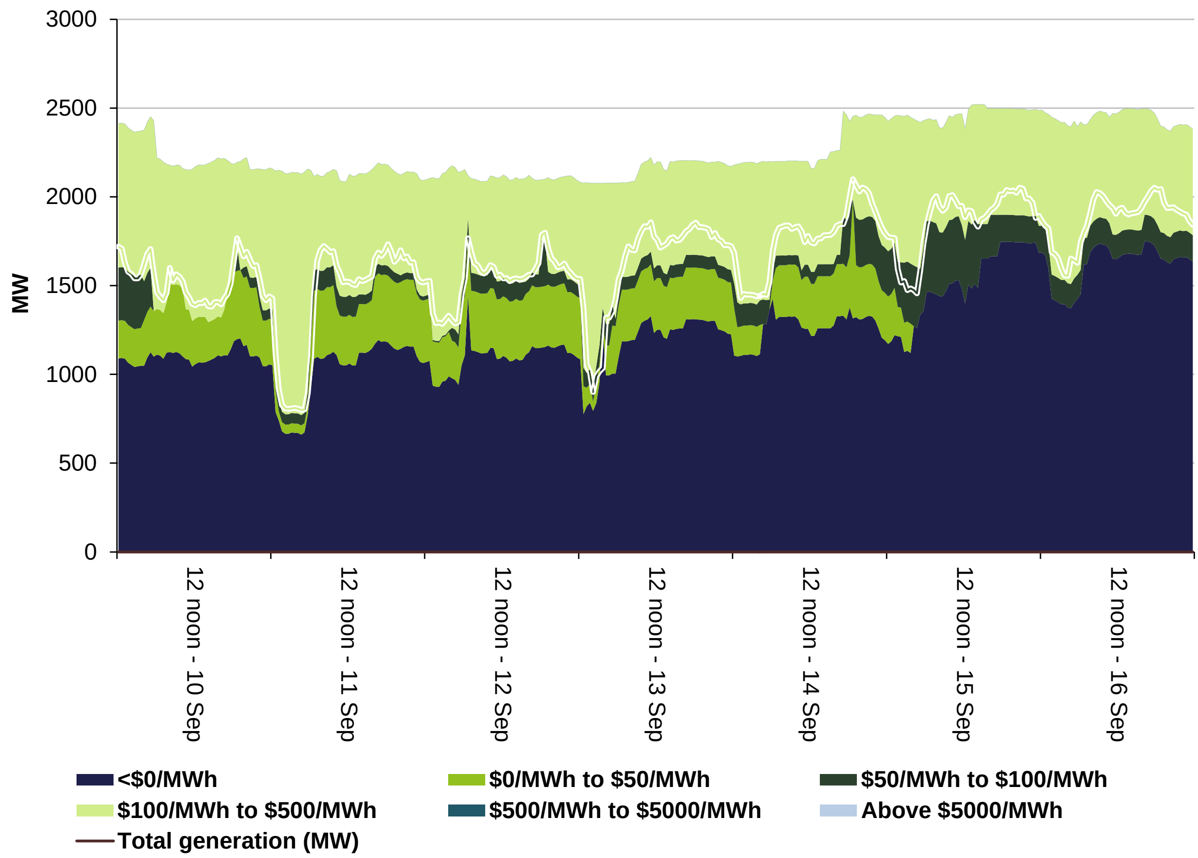


Figure 7: Tasmania generation and bidding patterns



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.

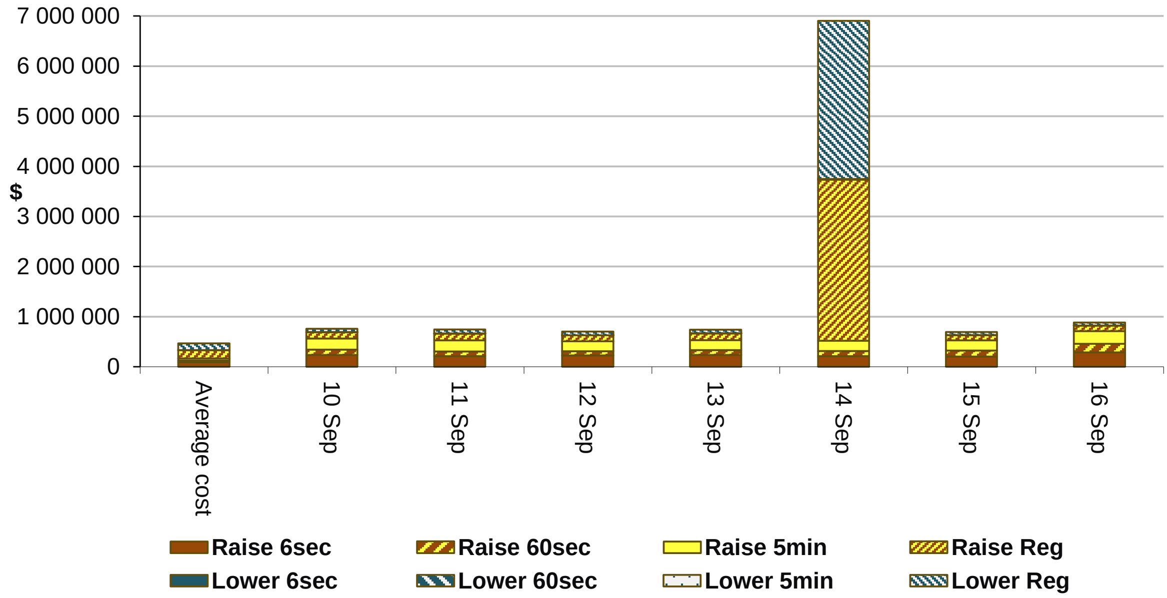
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $10 695 500 or around four per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $722 000 or around four 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



On 14 September, an outage in South Australia put the Heywood interconnector on a single contingency. This created the risk of South Australia becoming electrically isolated from the rest of the National Electricity Market. AEMO invoked constraints requiring 35 MW of local regulation services. The price of regulation services in South Australia exceeded $5000/MW for 16 trading intervals in both services. The total cost was around $6 million.

As required under the Electricity Rules, staff will prepare a FCAS Prices above $5000/MW report into the reasons for the high prices.

Detailed market analysis of significant price events

South Australia

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

Thursday, 14 September

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
11.30 am	-122.61	50.03	67.73	1216	1147	1217	2594	2487	2510
Midday	-295.82	57.88	68.10	1214	1128	1200	2623	2473	2499

Conditions at the time saw demand up to 86 MW higher than forecast and availability up to 150 MW higher than that forecast four hours ahead, this was partly because wind generation was between 50 and 70 MW higher than forecast.

In the four hours leading up to the start of the 11.30 am and 12 pm trading intervals, up to 221 MW of capacity was rebid from prices between $79/MWh and -$150/MWh to the price floor. This meant that small decreases in demand or increases in wind generation could lead to negative prices.

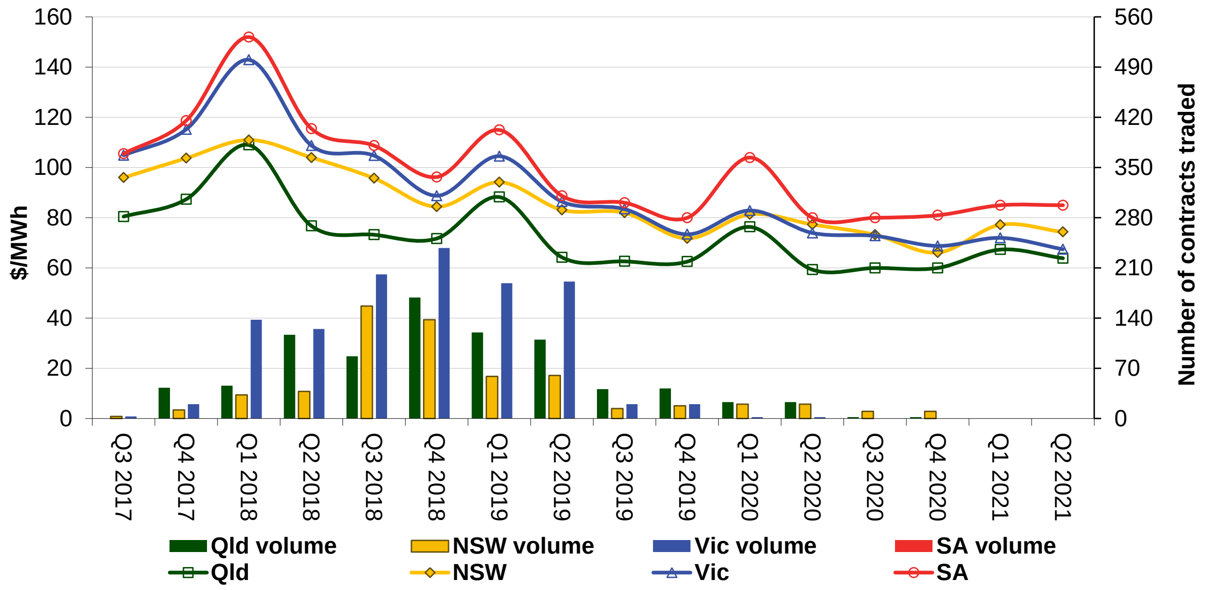
Between 11 am and 11.10 am, wind generation increased by 106 MW. For the 11.15 am dispatch interval demand decreased by 18 MW, as a result, the dispatch price fell to the floor. At 11.12 am, effective from 11.20 am, Infigen rebid 159 MW of capacity at Lake Bonney priced at -$3/MWh to $13 100/MWh. The reason related to the price being lower than forecast. At 11.20 am demand increased by 72 MW and the dispatch price increased to $70/MWh and stayed between $64/MWh and $80/MWh for the remainder of the trading interval.

For the midday trading interval, the dispatch price fell to the price floor twice, once at 11.50 am and once at 12 pm. Similarly to the start of the 11.30 am trading interval, wind generation increased by around 190 MW between 11.30 am and 11.50 am. For the 11.50 am dispatch interval, demand decreased by 57 MW and the price fell to the floor. At 11.48 pm, effective from 11.55 am, Infigen rebid 39 MW of capacity at Lake Bonney priced from -$152/MWh to the floor. The reason related to the price being lower than forecast. At midday wind generation increased by 86 MW and the dispatch price fell to the floor.

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.

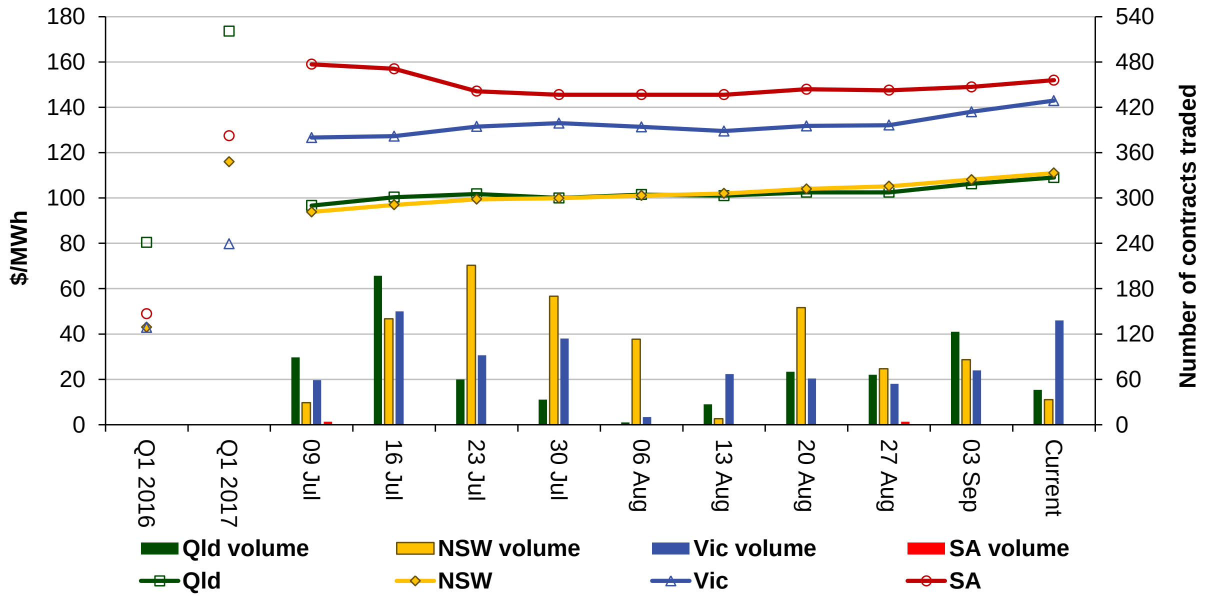
Figure 9: Quarterly base future prices Q3 2017 – Q2 2021



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



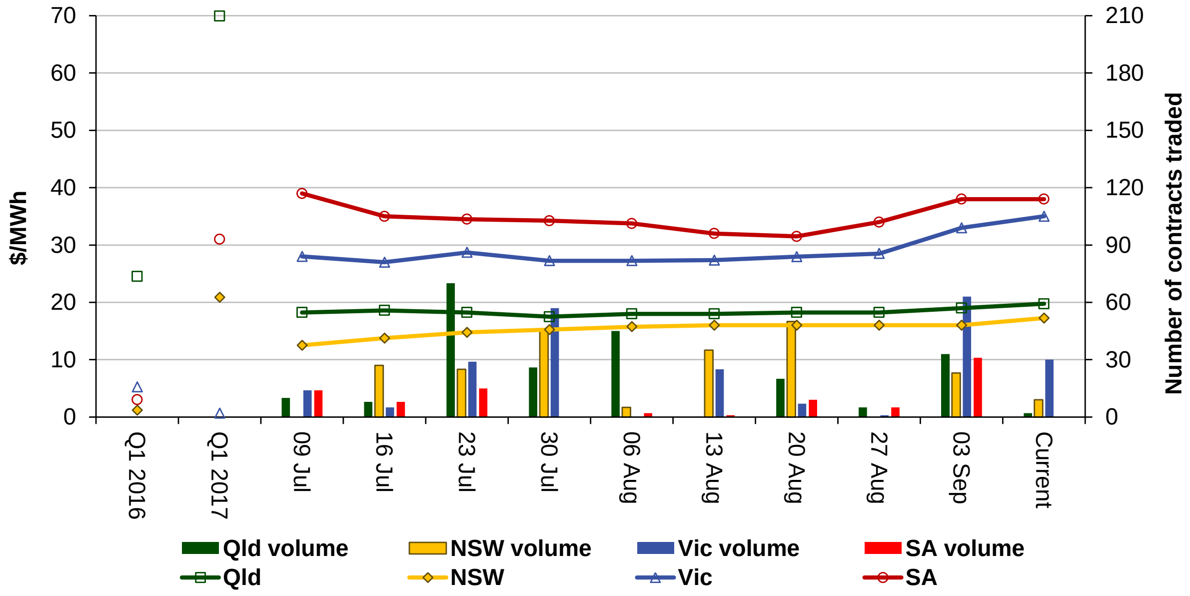
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
September 2017