Electricity Report

6 – 12 May 2018

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 6 – 12 May 2018.

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

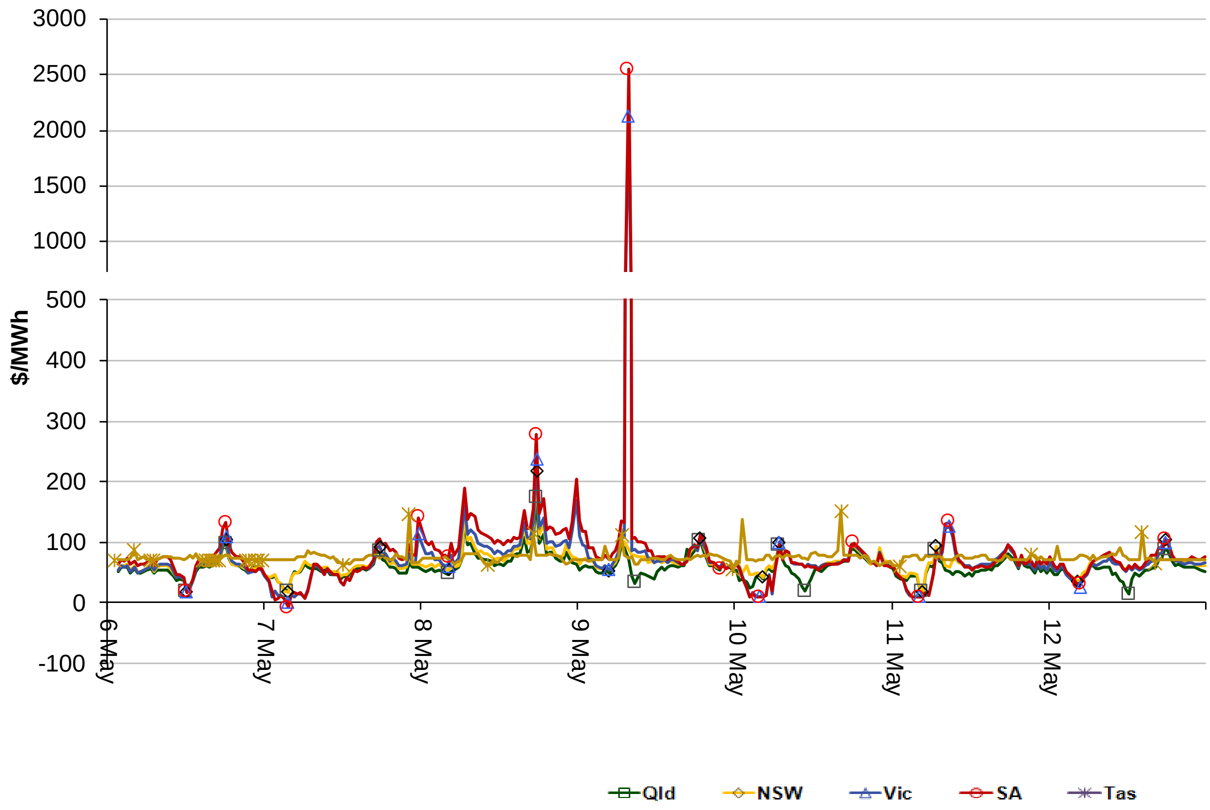


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

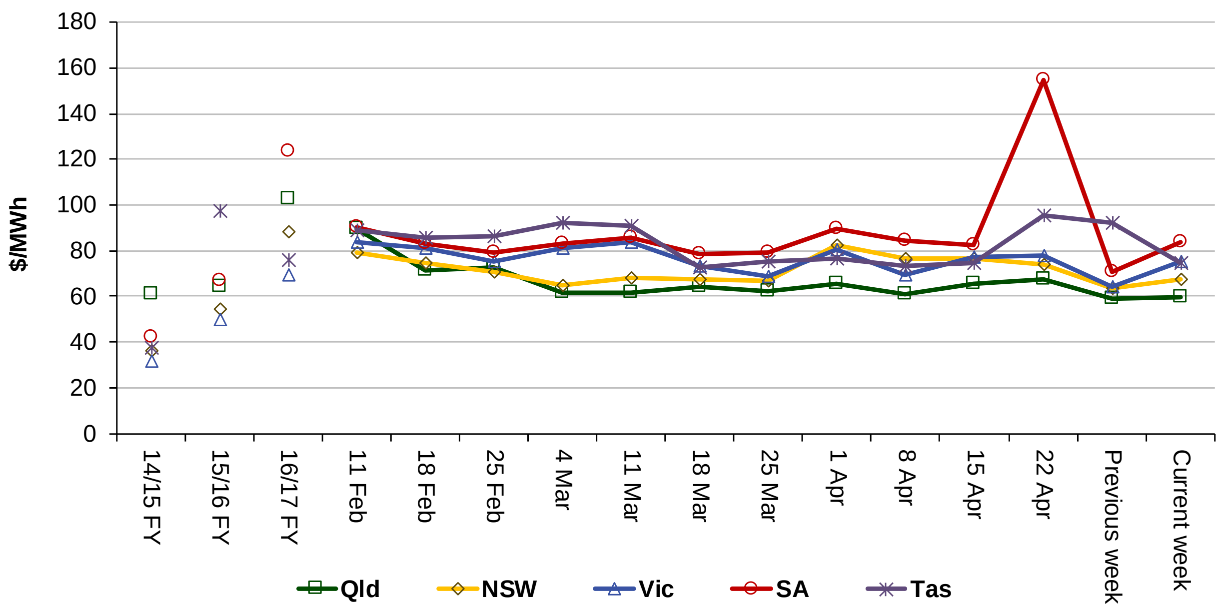


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	60	68	75	84	75
16-17 financial YTD	106	89	64	125	71
17-18 financial YTD	74	82	100	109	90

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 140 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	8	11	0	0
% of total below forecast	1	73	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

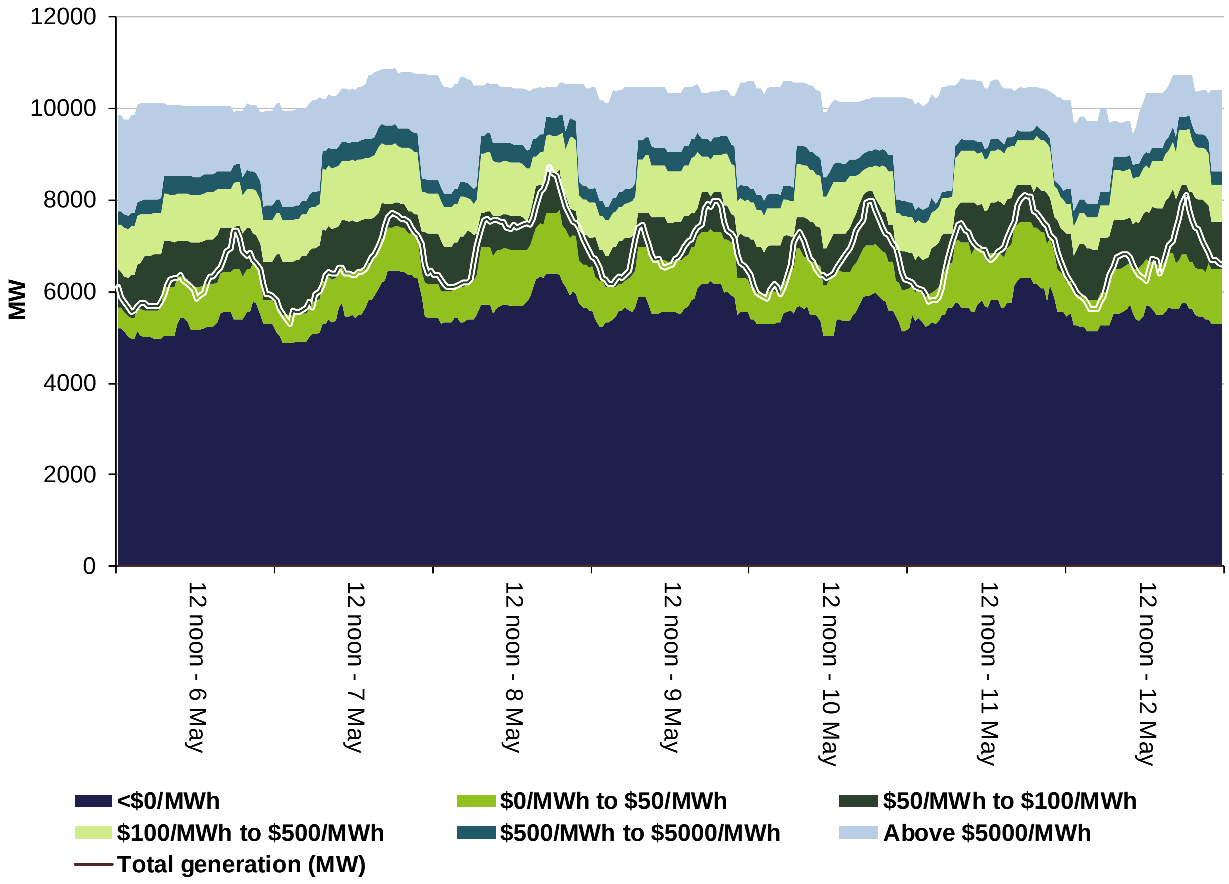


Figure 4: New South Wales generation and bidding patterns

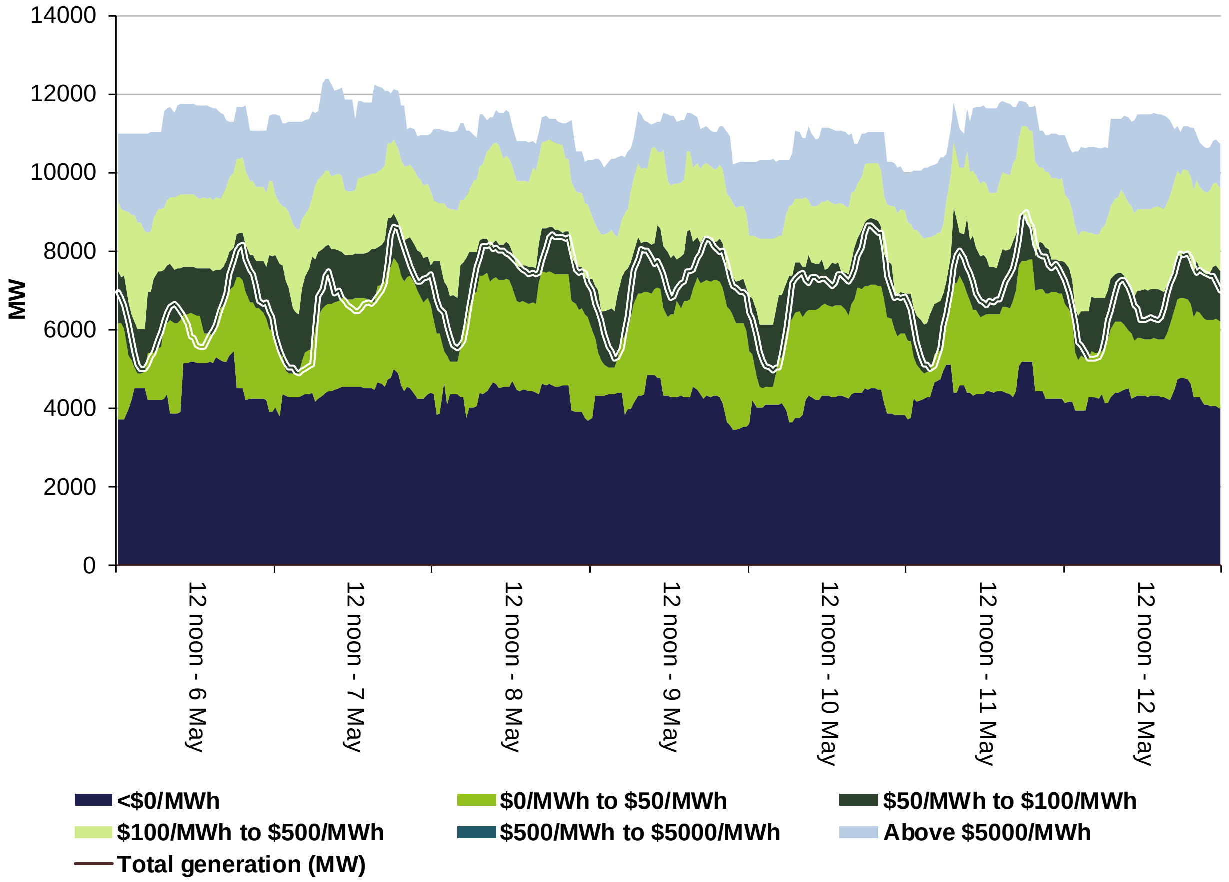


Figure 5: Victoria generation and bidding patterns

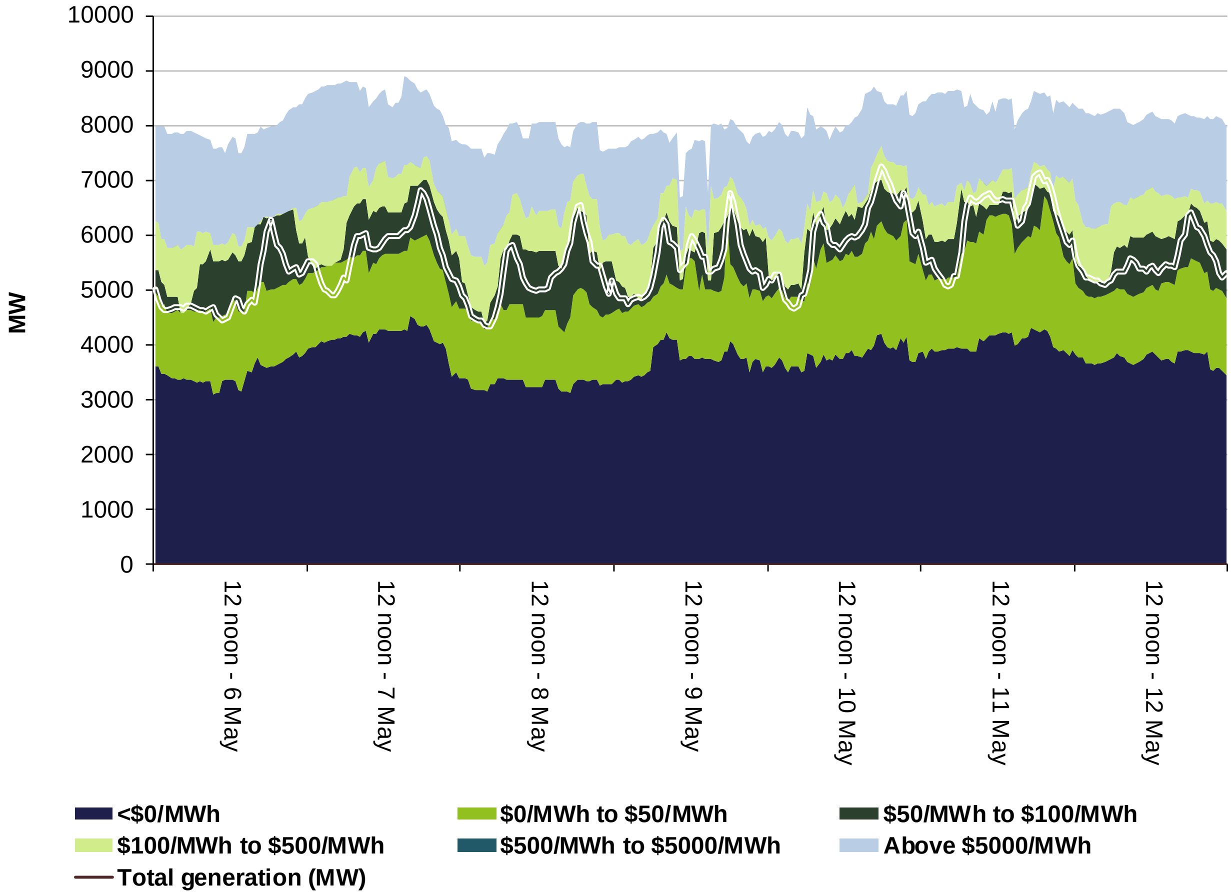


Figure 6: South Australia generation and bidding patterns

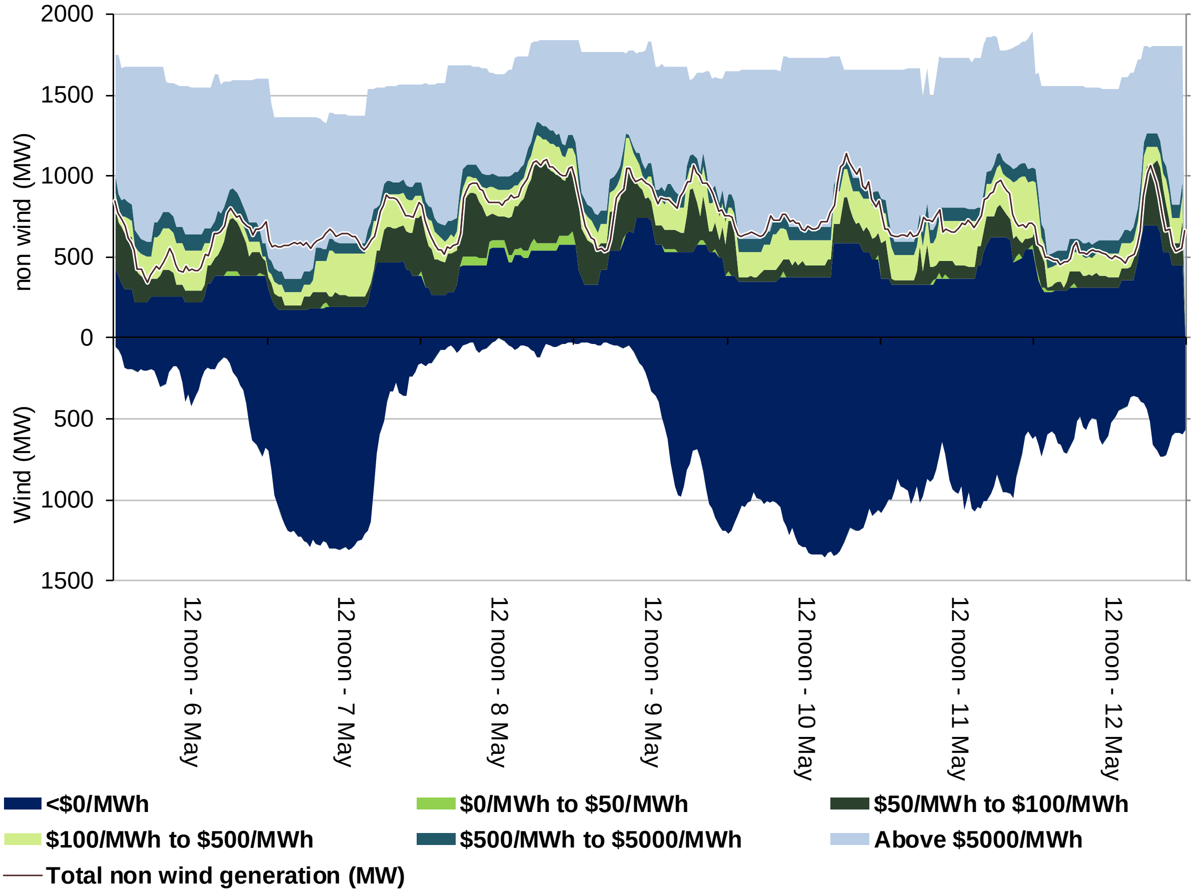
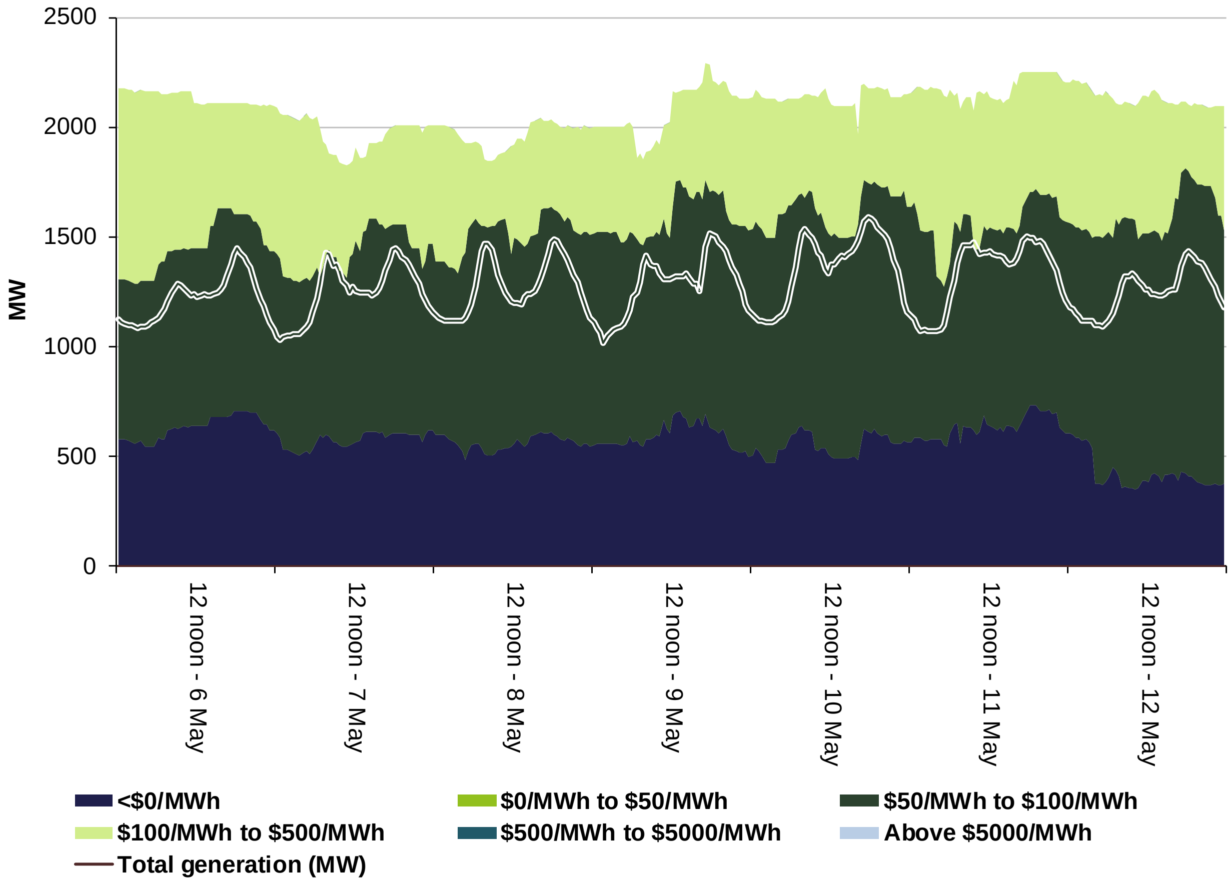


Figure 7: Tasmania generation and bidding patterns



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.

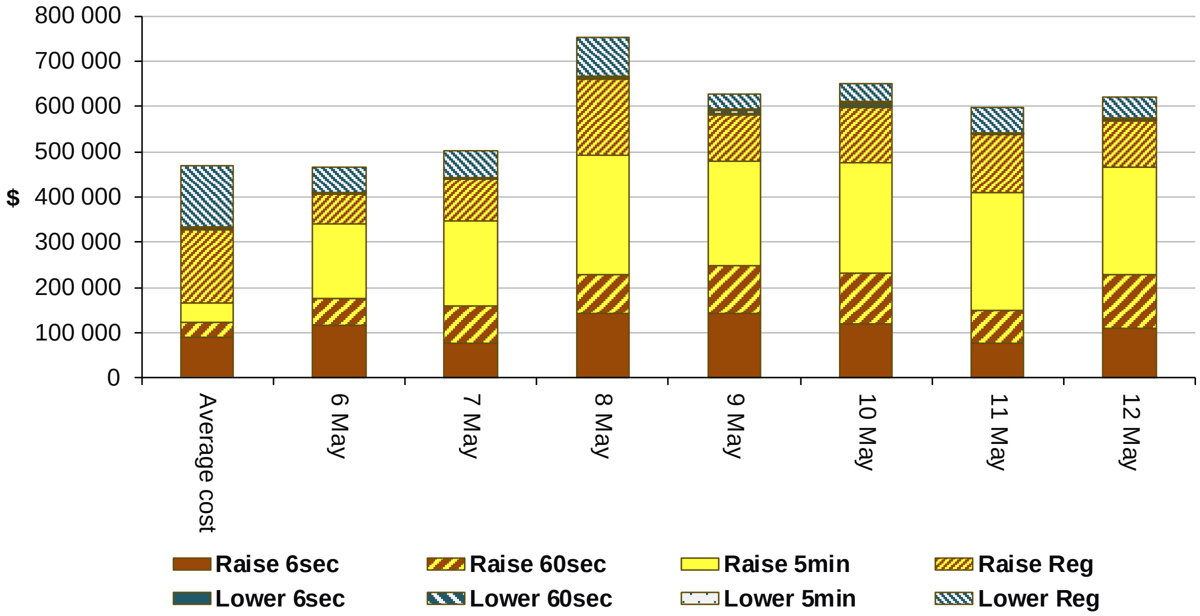
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 744 000 or less than two per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $474 500 or around three 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

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $75/MWh and above $250/MWh.

Wednesday, 9 May

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
8 am	2126.21	447.56	262.15	5827	5918	5783	7874	7921	7968

Conditions at the time saw demand and availability close to forecast.

Prices in Victoria were aligned with South Australia and will be discussed as one region. See South Australia section for more information.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $84/MWh and above $250/MWh.

Tuesday, 8 May

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
6 pm	277.26	389.60	397.30	1548	1677	1596	1804	1763	1757

Conditions at the time saw demand around 130 MW lower than forecast while availability was slightly above forecast, mainly due to higher than forecast wind generation.

At 4.47 pm, effective for the 6 pm trading interval, AGL rebid 40 MW from the cap to around to $71/MWh at its Torrens Island power station. This rebid combined with the lower than forecast demand and higher than forecast wind generation resulted in the lower than forecast price.

Wednesday, 9 May

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
8 am	2544.49	578.81	349.95	1469	1504	1458	1720	1774	1812

Prices in Victoria were aligned with South Australia and will be discussed as one region.

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

At 7.42 am, effective 7.50 am, Hornsdale Power Reserve reduced the availability at Hornsdale unit one by 80 MW, the reason given was “07:40 P new SOC forecast differs from previous SOC forecast”.

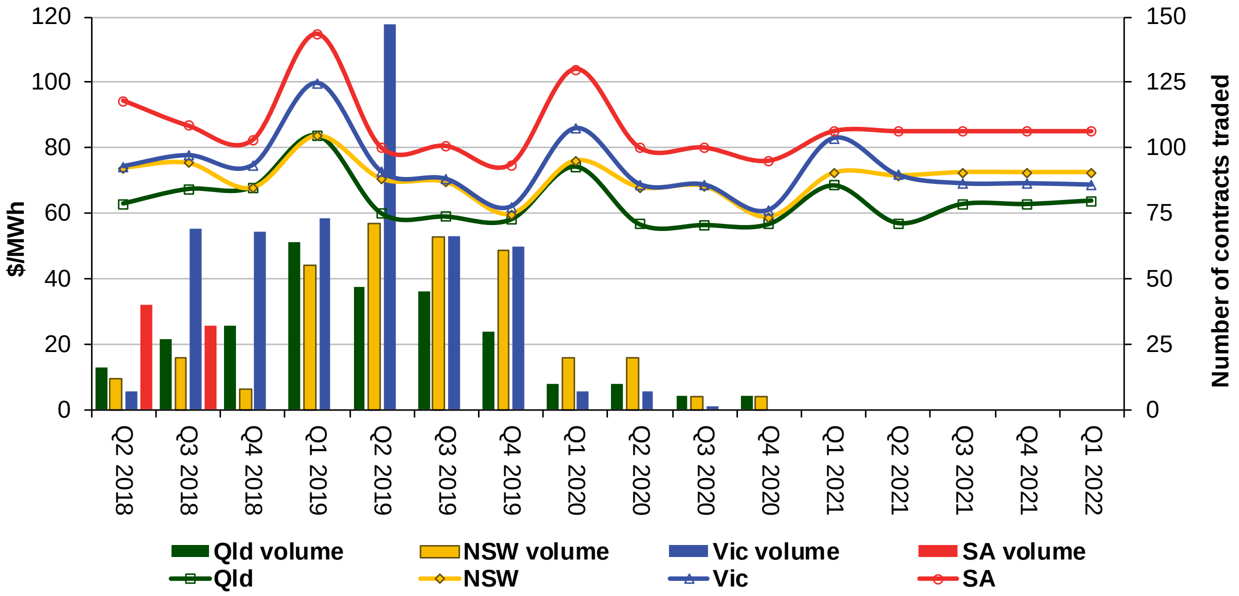
At 7.51 am, effective at 8 am, Snowy Hydro reduced the availability of raise frequency services at the Jindabyne pump (35 MW raise 5 minutes, 70 MW raise 60 seconds, 50 MW raise 6 seconds). The reason given was “07:51:05P match bid to pump operation”. For generators in New South Wales to replace these services exports from New South Wales to Victoria were reduced by 266 MW.

With only 20 MW of available capacity priced between $600/MWh and $10 000/MWh in South Australia and Victoria an 80 MW increase in demand and the reduced imports saw the dispatch price reached $14 000/MWh in South Australia and $11 710/MWh in Victoria at 8 am.

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.

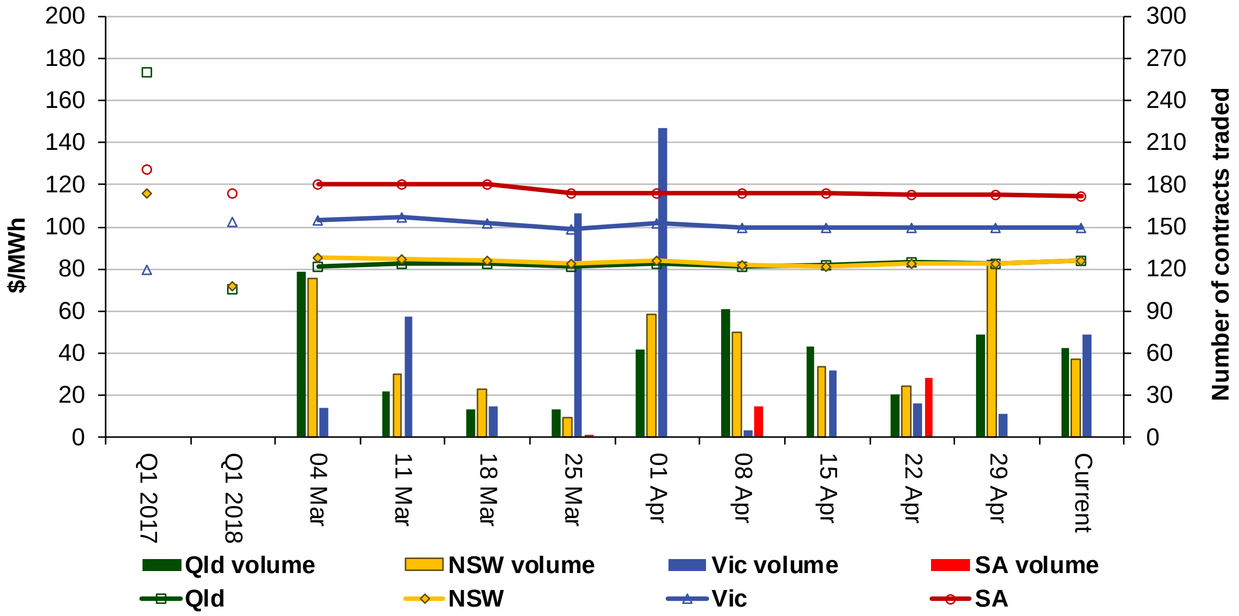
Figure 9: Quarterly base future prices Q2 2018 – Q1 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



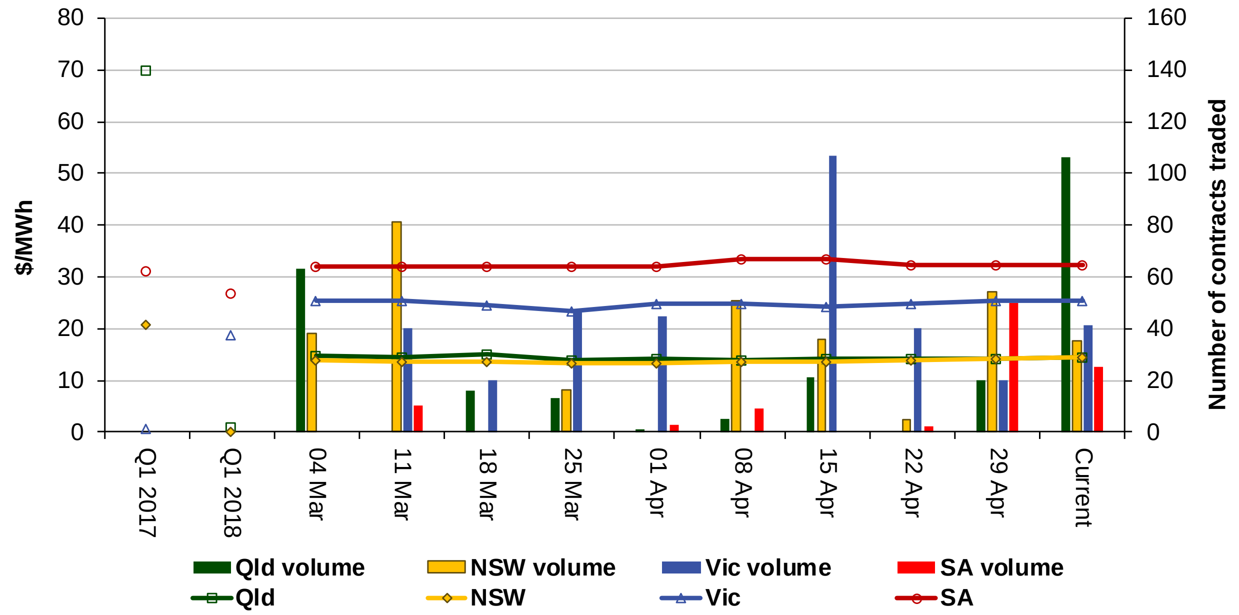
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
May 2018