Electricity Report

AUSTRALIAN ENERGY REGULATOR

8 - 14 July 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 8 - 14 July 2018.

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

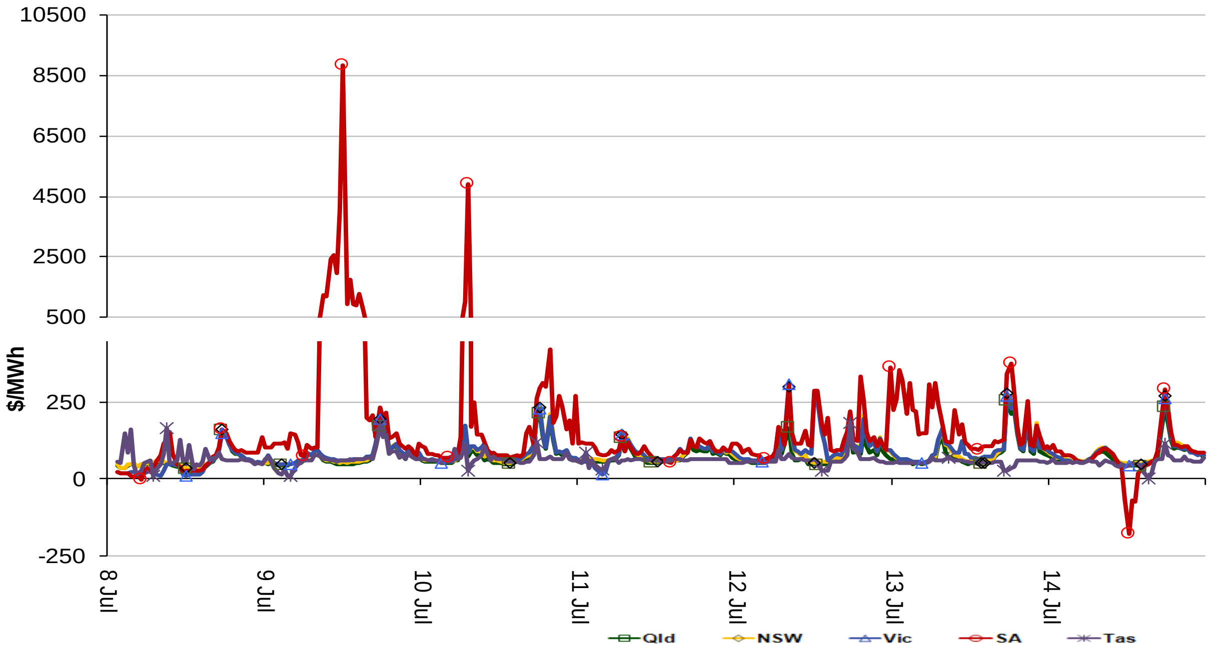


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

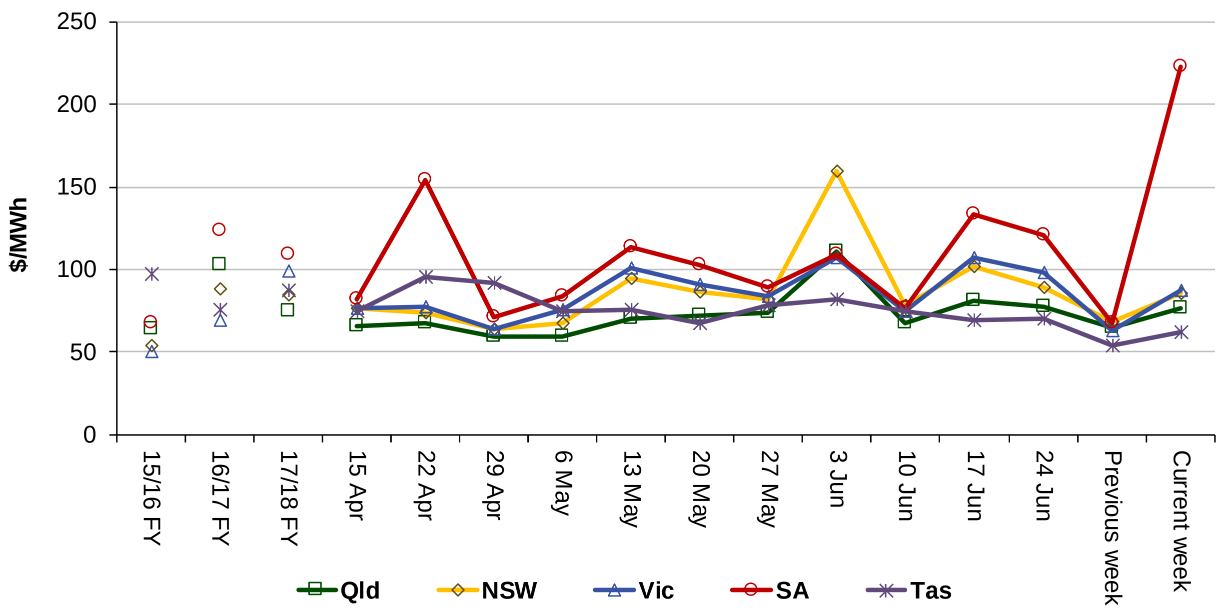


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	76	86	87	223	62
17-18 financial YTD	75	90	127	126	127
18-19 financial YTD	71	77	75	145	58

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 256 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	11	22	0	1
% of total below forecast	4	53	0	9

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

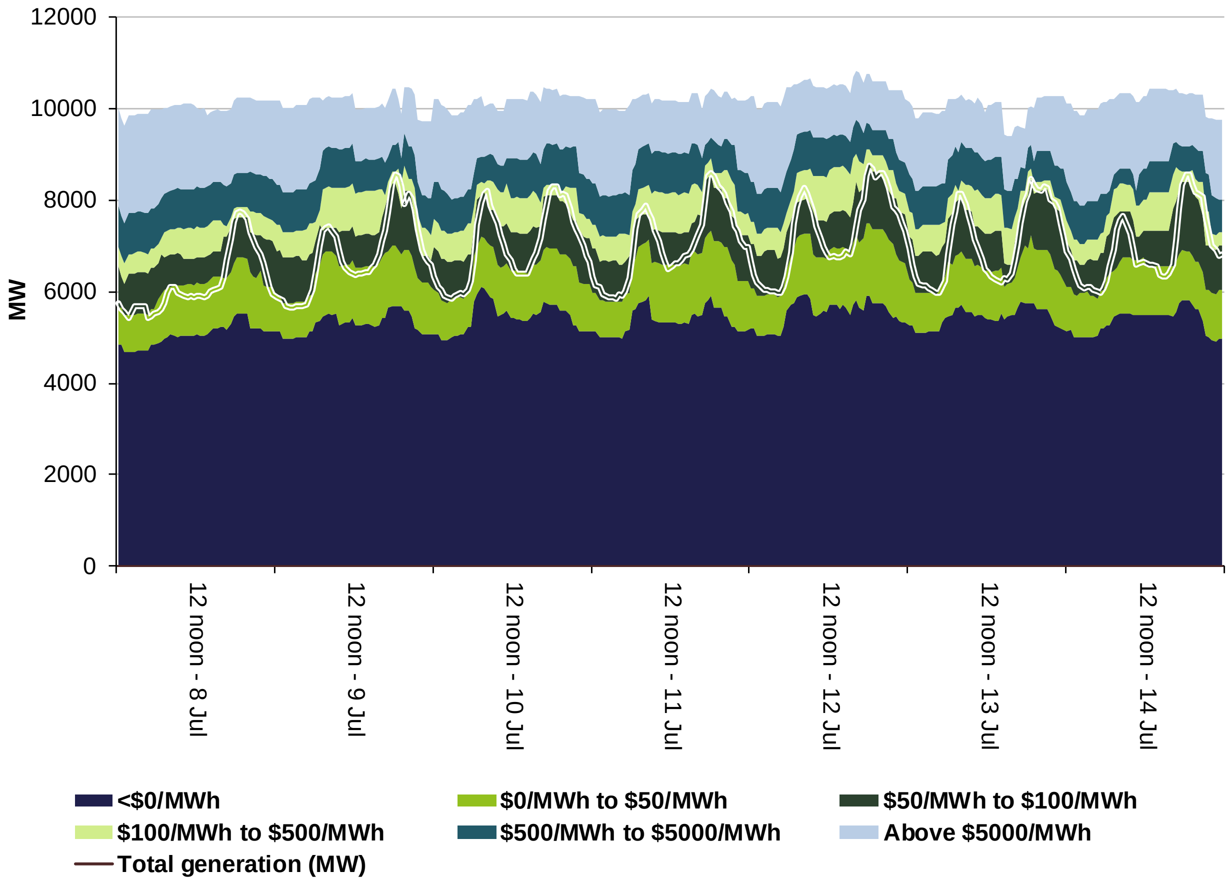


Figure 4: New South Wales generation and bidding patterns

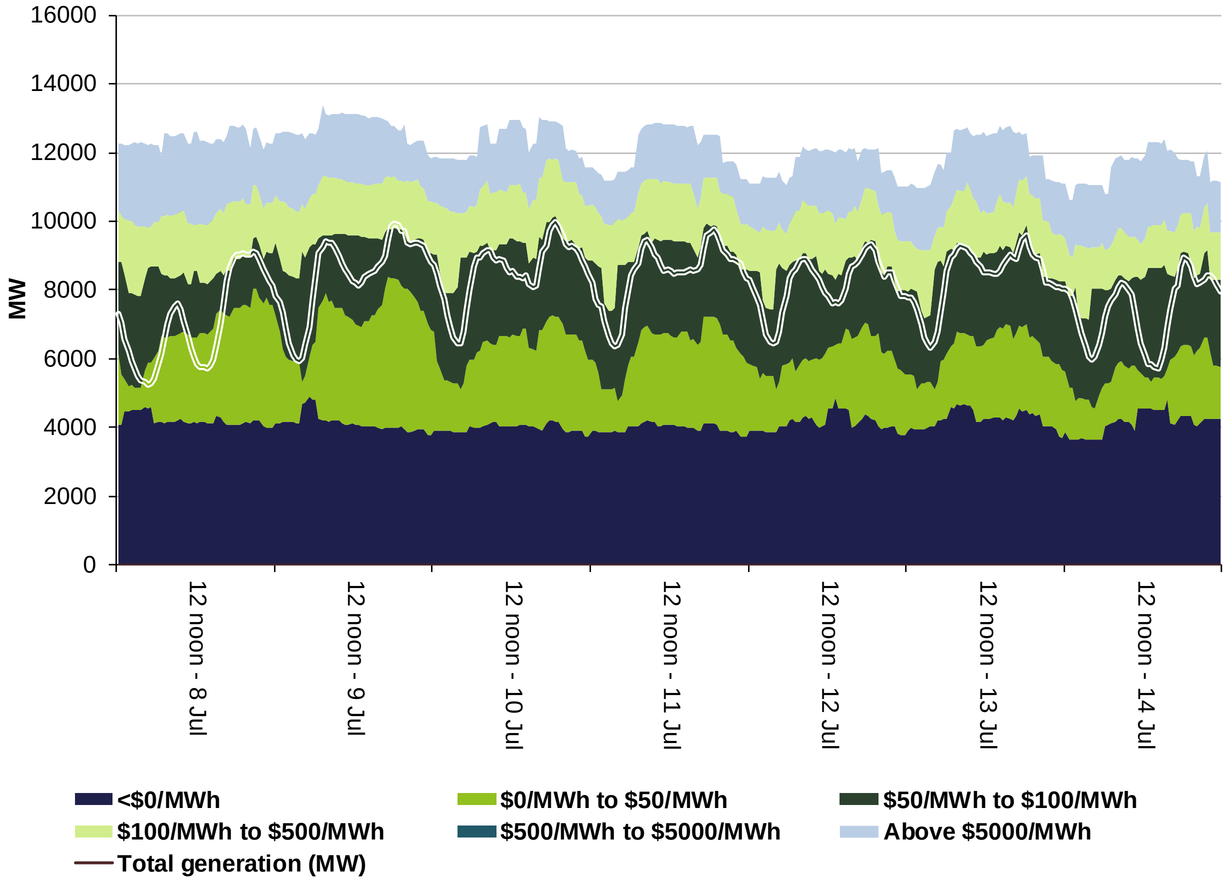


Figure 5: Victoria generation and bidding patterns

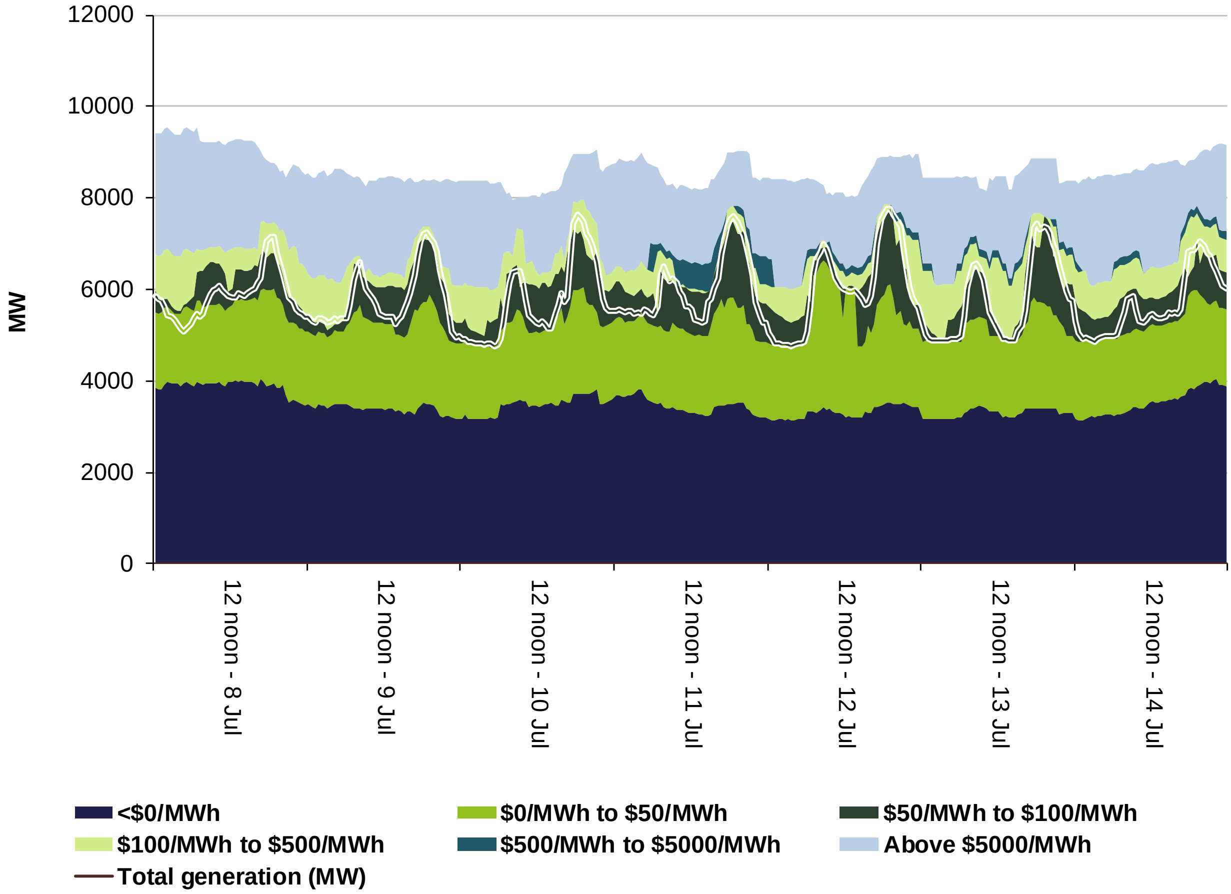


Figure 6: South Australia generation and bidding patterns

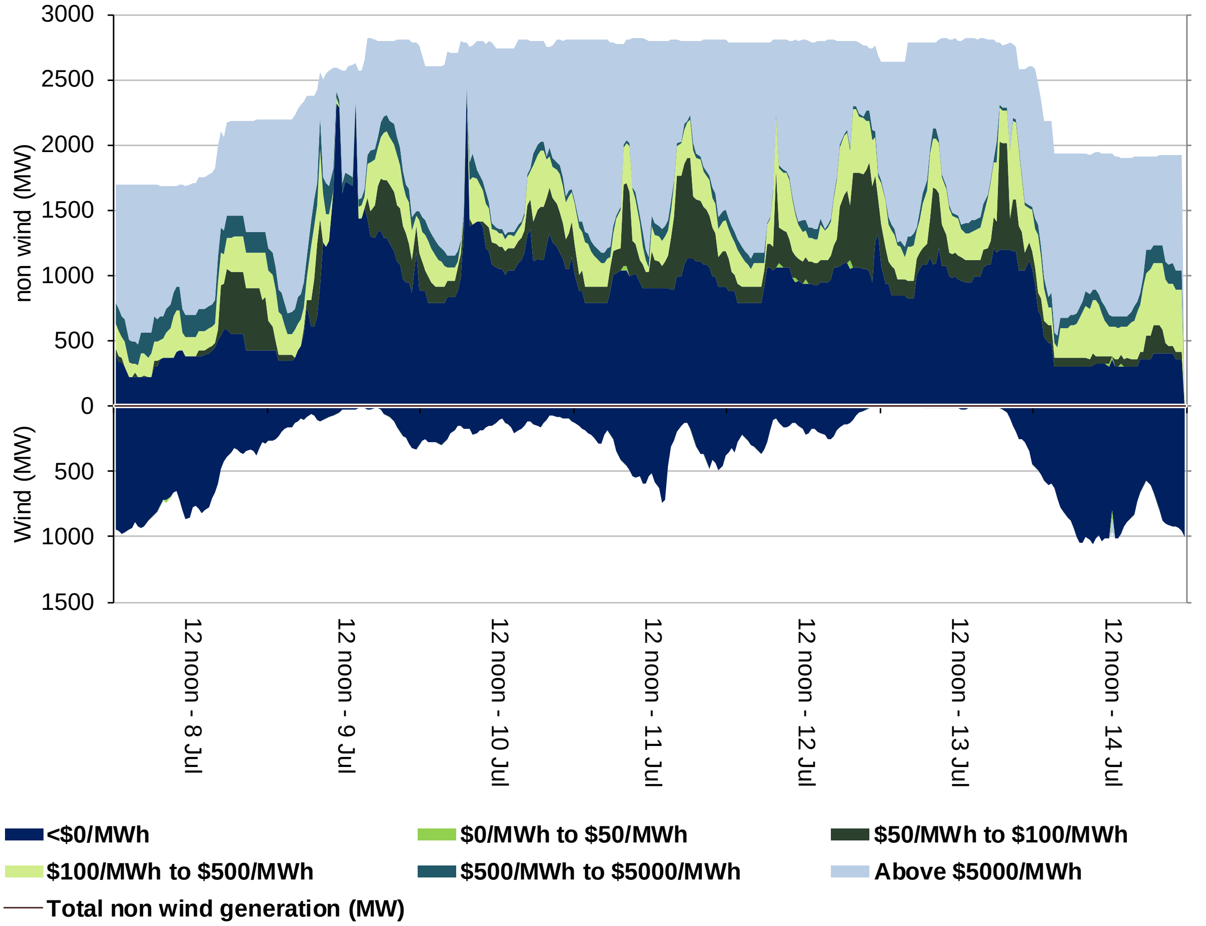
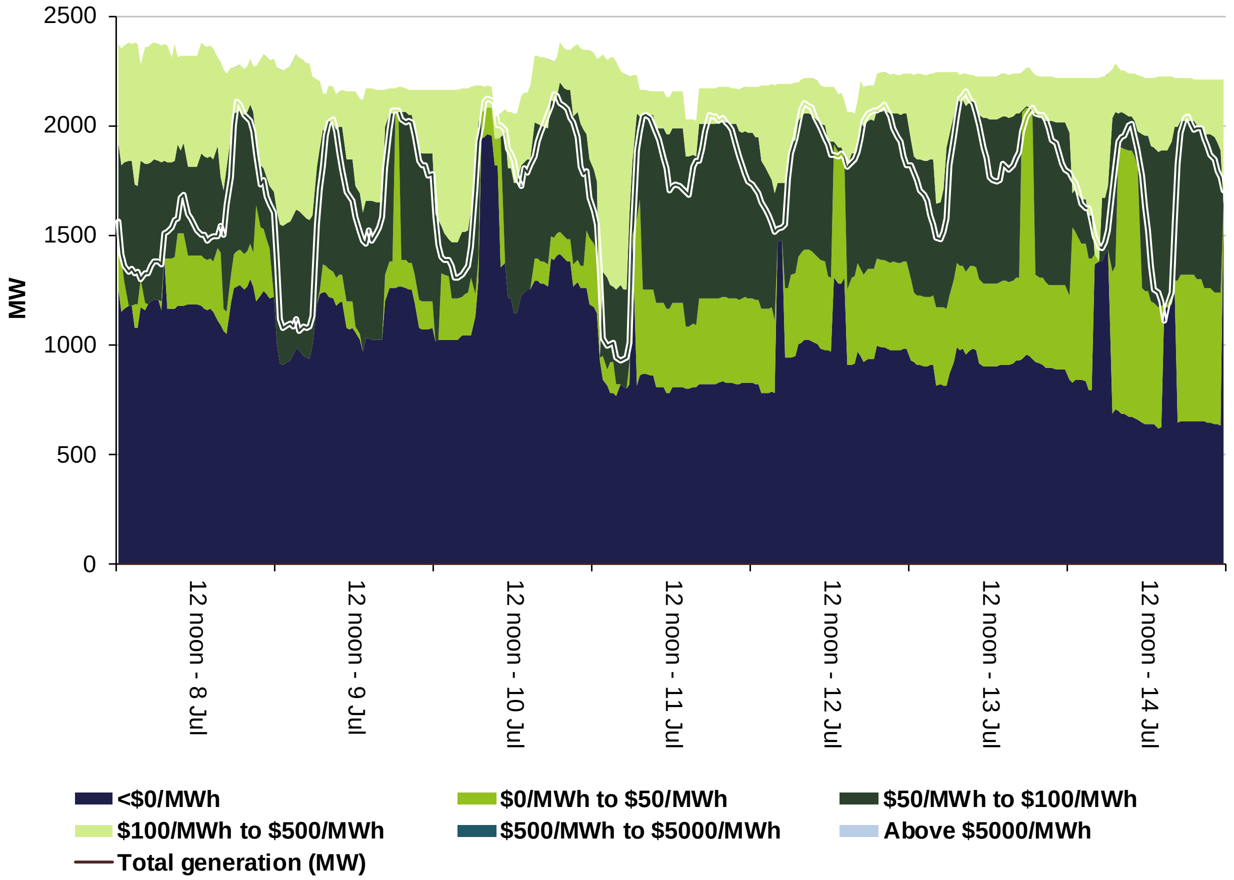


Figure 7: Tasmania generation and bidding patterns



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.

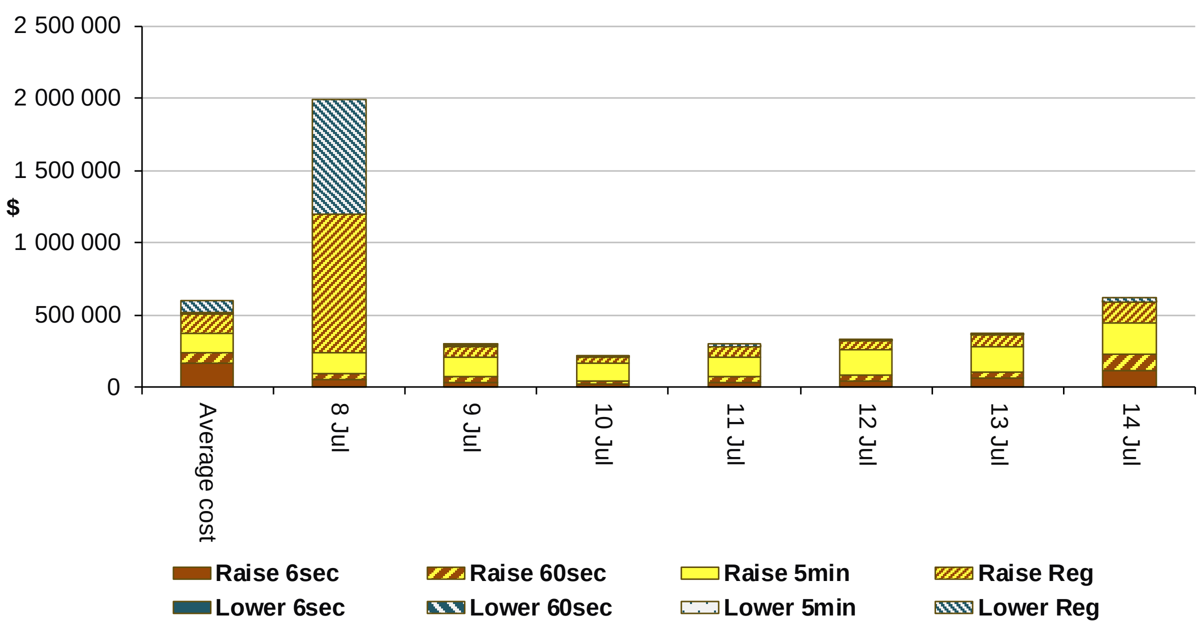
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 991 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $151 000 or around one 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



Analysis of the high costs will be covered in our FCAS prices above $5000/MW – 8 July 2018 report which will be released at a later date.

Detailed market analysis of significant price events

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $76/MWh and above $250/MWh.

Friday, 13 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 pm	253.04	88.00	85.10	7216	7133	7181	9570	10 327	10 504

The prices in Queensland, New South Wales and Victoria were aligned and will be discussed as one region.

For all regions combined conditions at the time saw demand around 380 MW higher than forecast while availability was around 1600 MW lower than forecast four hours ahead.

The reduction in availability can mainly be attributed to CS Energy removing 710 MW at its Gladstone power station at 4 pm due to coal management issues, EnergyAustralia removing 670 MW at its Mt Piper power station at 2 pm due to mill issues and Delta Electricity removing 110 MW of capacity at Vales Point priced less than $86/MWh at 3.30 pm due to milling and feeder limits. Around 1300 MW of this capacity was priced less than $86/MWh.

The reduction in low priced capacity resulted in the higher than forecast price.

New South Wales

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

Thursday, 12 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
8:30 am	299.60	68.89	144.63	10 482	10 400	10 280	11 983	12 427	12 464

The prices in New South Wales and Victoria were aligned and will be discussed as one region.

Conditions at the time saw demand close to forecast in New South Wales and Victoria, while availability was around 450 MW lower than forecast in New South Wales and around 140 MW higher than forecast in Victoria, four hours ahead.

The reduction in availability in New South Wales was mainly due to EnergyAustralia removing 400 MW of capacity at 7.07 am at its Mt Piper power station due to mill issues. 300 MW was priced less than $65/MWh. The increase in Victoria was due to Snowy Hydro adding in 171 MW at 6.13 am at Laverton North, this was priced at the cap, hence had no impact on price.

At 5.38 am in Victoria Origin Energy rebid 285 MW from the cap to prices less than $85/MWh at its Mortlake power station with the rebid reason ‘0535A INC VIC DEM 5PD 5784 MW > 30PD 5611 MW @0630 SL’.

At 7.50 am in New South Wales Snowy Hydro rebid 330 MW from prices less than $105/MWh to $300/MWh at Tumut. The rebid reason given was ‘07:45:05 A VIC 5MIN ACTUAL PRICE $1.59 HIGHER THAN 5MIN PD 07:50@07:41 ($106.19)’.

The combination of the changes in availability and available low priced capacity resulted in increased exports from Victoria to New South Wales (around 470 MW higher than forecast) and aligning the prices across both regions.

Friday, 13 July

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
6 pm	276.99	101.82	107.12	10 877	10 709	11 023	12 390	13 159	13 043

The price is discussed under Table 3 above.

Saturday, 14 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
6 pm	271.85	118.27	153.40	10 412	10 193	10 471	11 659	12 246	12 215

Prices in New South Wales and Victoria were aligned and will be discussed as one region.

Conditions across both regions saw demand around 450 MW higher than forecast while availability was 570 MW lower than forecast four hours ahead.

The reduction in availability in New South Wales was mainly due to Delta Electricity removing 140 MW of capacity at 3.30 pm at its Vales Point power station due to mill issues and EnergyAustralia removing 400 MW of capacity over two rebids at 5 pm and 5.50 pm at its Mount Piper power station due to mill issues. 310 MW of this capacity was priced less than $65/MWh.

At 5.25 pm, over a number of rebids, Snowy Hydro rebid 400 MW of capacity across its portfolio from prices below $110/MWh to $290/MWh. This resulted in around $300/MWh priced generation at Murray or Tumut being dispatched from 5.40 pm onwards for the remainder of the trading interval.

Victoria

There were four occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $87/MWh and above $250/MWh.

Thursday, 12 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
8:30 am	308.95	837.52	163.60	6945	6933	6968	8325	8186	8239
12:30 pm	277.98	77.70	95.31	6276	6333	6368	8037	8127	8129

Analysis of the 8.30 am trading interval is discussed under Table 4 above.

For the 12.30 pm trading interval demand was around 60 MW lower than forecast while availability was 90 MW lower than forecast four hours ahead.

Effective from 12.05 pm, there was a step change in offers at Snowy Hydro's Mortlake power station, who had rebid 125 MW to the floor for the previous trading interval. EnergyAustralia also withdrew 60 MW (priced less than $30/MWh) at its Yallourn power station due to mill maintenance. A system normal constraint which manages voltage collapse at Darlington Point was also binding and limited cheaper priced generation in Victoria. The combination of factors saw the price increase to $380/MWh at 12.05 pm then remain between $90/MWh and $380/MWh for the remainder of the trading interval.

Friday, 13 July

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	269.09	104.40	107.00	6901	6771	6883	8872	8925	8941

The price is discussed under Table 3Table 4 above.

Saturday, 14 July

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
6 pm	263.30	109.87	142.11	6105	5873	6071	8794	8777	8706

The price is discussed under Table 6 above.

South Australia

There were fourteen occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $223/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Monday, 9 July

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
9.30 am	1253	1200	13 999	1739	1731	1753	2614	2600	2497
10 am	1200	14 500	14 500	1714	1699	1711	2644	2593	2547
10.30 am	2424	14 000	14 500	1657	1614	1653	2655	2595	2603
11 am	2558	14 000	14 500	1611	1559	1576	2655	2596	2606
11.30 am	1949	13 999	14 000	1599	1505	1521	2633	2599	2606
Midday	4064	14 000	14 000	1595	1488	1493	2597	2608	2610
12.30 pm	8824	13 999	14 000	1599	1441	1472	2613	2621	2621
1 pm	920	1196	14 000	1544	1427	1473	2615	2622	2622
1.30 pm	1750	1196	14 000	1546	1430	1475	2636	2595	2644
2 pm	945	1023	14 000	1546	1433	1489	2647	2693	2687
2.30 pm	889	10 670	14 000	1538	1458	1498	2592	2706	2684
3 pm	1276	1750	14 000	1561	1484	1513	2586	2713	2682

Analysis of the high prices will be covered in our Prices above $5000/MWh – 9 July 2018 report which will be released at a later date.

Tuesday, 10 July

Table 11: 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	1006.05	92.63	134.89	1488	1417	1446	2969	3091	3080
7.30 am	4928.64	145.50	145.50	1597	1560	1557	2887	3064	3050

For both trading intervals demand was close to forecast while availability was between 120 – 170 MW lower than forecast four hours ahead.

For the 7 am trading interval the lower than forecast availability was due to lower than forecast wind generation.

At 6.55 am, ramping constraints on the MurrayLink interconnector bound limiting imports from Victoria to 53 MW. There was only 31 MW of available capacity priced between $79/MWh and $5000/MWh, hence a small change in demand of 46 MW and limited imports saw the 5 minute price increase from $107/MWh to $5117/MWh. The price then decreased to $79/MWh at 7 am, as participants in South Australia rebid around 100 MW from the cap to prices less than zero.

For the 7.30 am trading interval the reduction in availability is due to lower than forecast wind and a rebid by EnergyAustralia at 6.57 am, effective from 7.05 am, which removed 129 MW of capacity at its Hallett power station due to transformer issues. 35 MW of this capacity was priced at the price floor.

At 7.05 am a planned outage on the Ararat to Horsham 220 kV line began limiting imports into South Australia across the MurrayLink interconnector. With only 31 MW of available capacity priced between $145/MWh and $10 491/MWh, a 47 MW increase in demand combined with the reduction in capacity at Hallett, the price increased to $10 500/MWh.

In response to the high price, over the next two dispatch intervals participants rebid around 300 MW from prices above $13 000/MWh to the floor, however the price remained at $10 500/MWh as the participants took longer than five minutes to start and could not set price. Once they were able to set price at 7.20 pm, the price decreased to less than $100/MWh.

Saturday, 14 July

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
12.30 pm	-179.53	42.59	41.75	929	959	921	2905	2738	2685

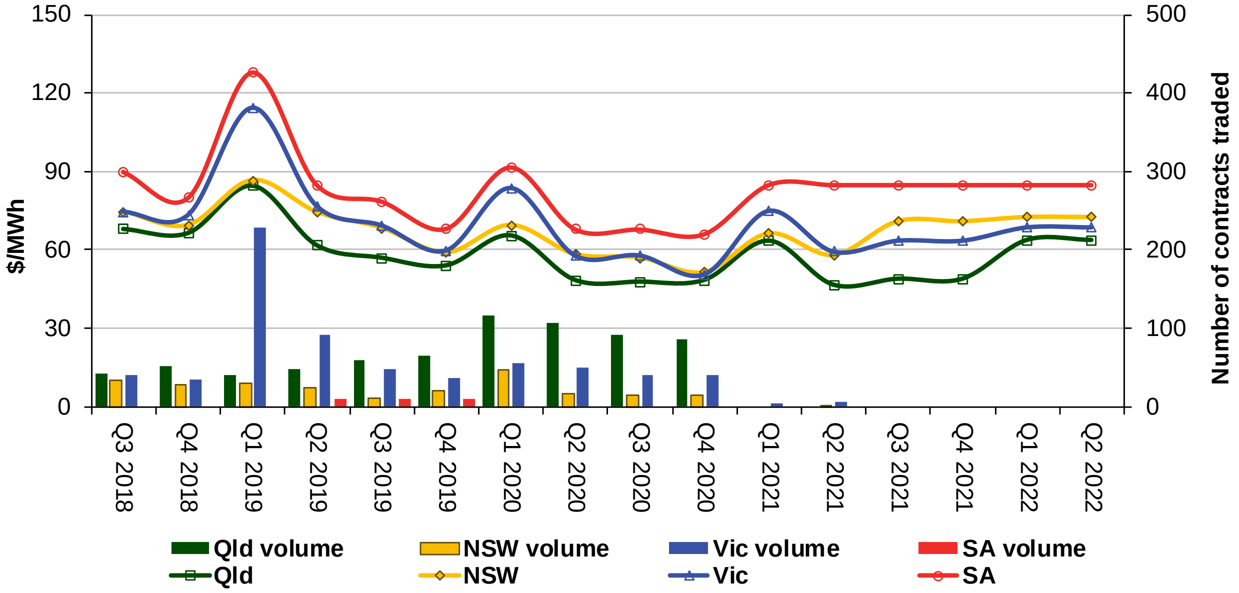
Conditions on the day saw demand 30 MW less than that forecast four hours ahead and availability 160 MW more than that forecast.

At 12 noon, 5 minute demand decreased by 21 MW, (from 939 MW to 917 MW). This small decrease, combine with higher than forecast wind saw the five minute price reduce to -$705/MWh at 12.05 pm. Prices remained below zero for the rest of the trading interval, resulting in a -$179/MWh spot price.

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. Of note is the lack of trades in the later years. Anecdotally, most participants don't trade beyond two and one half years and hence the prices shown here for those periods are unreliable as they may be the average of the buy and sell prices or, if there have been no offers for that period, the last valid offer.

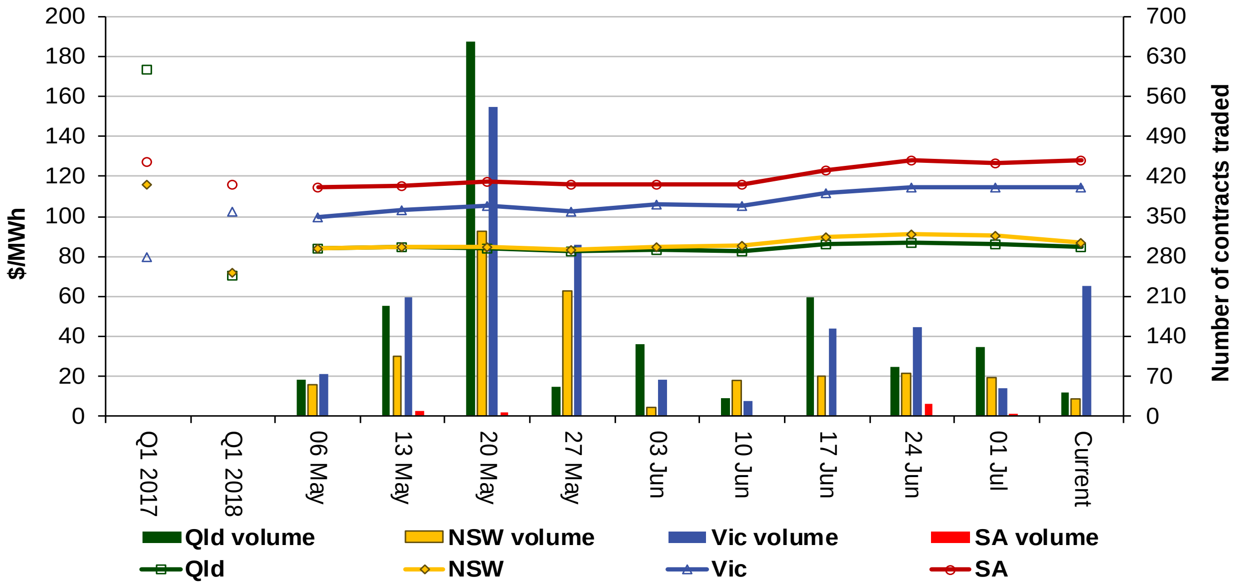
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



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)



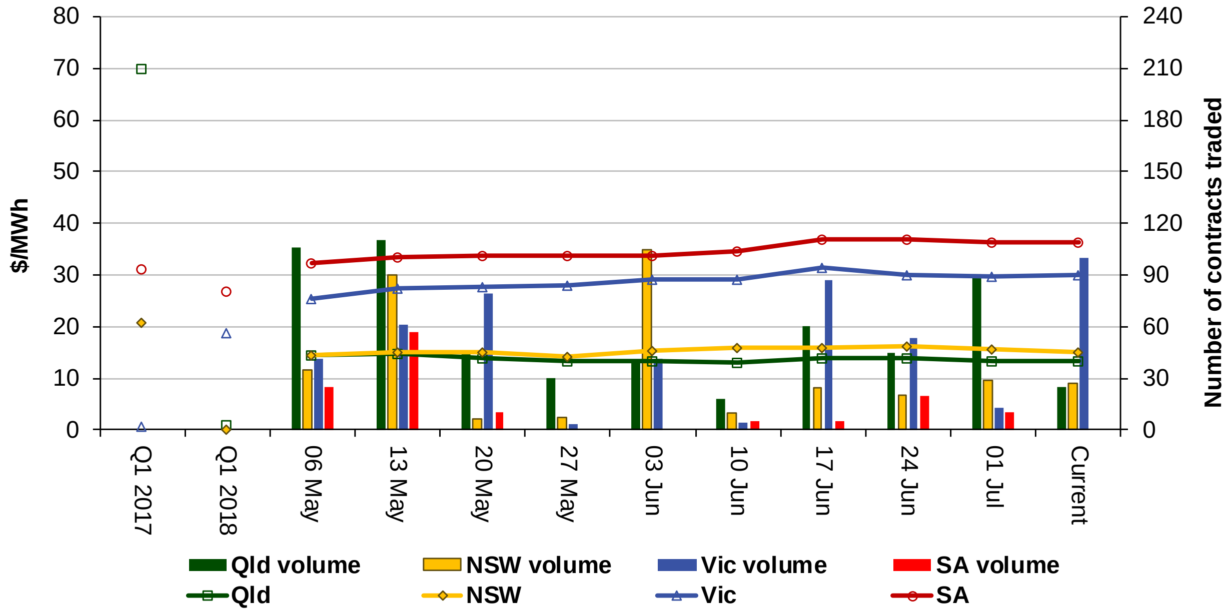
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
July 2018