Electricity Report

AUSTRALIAN ENERGY REGULATOR

29 July – 4 August 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 28 July – 4 August 2018.

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

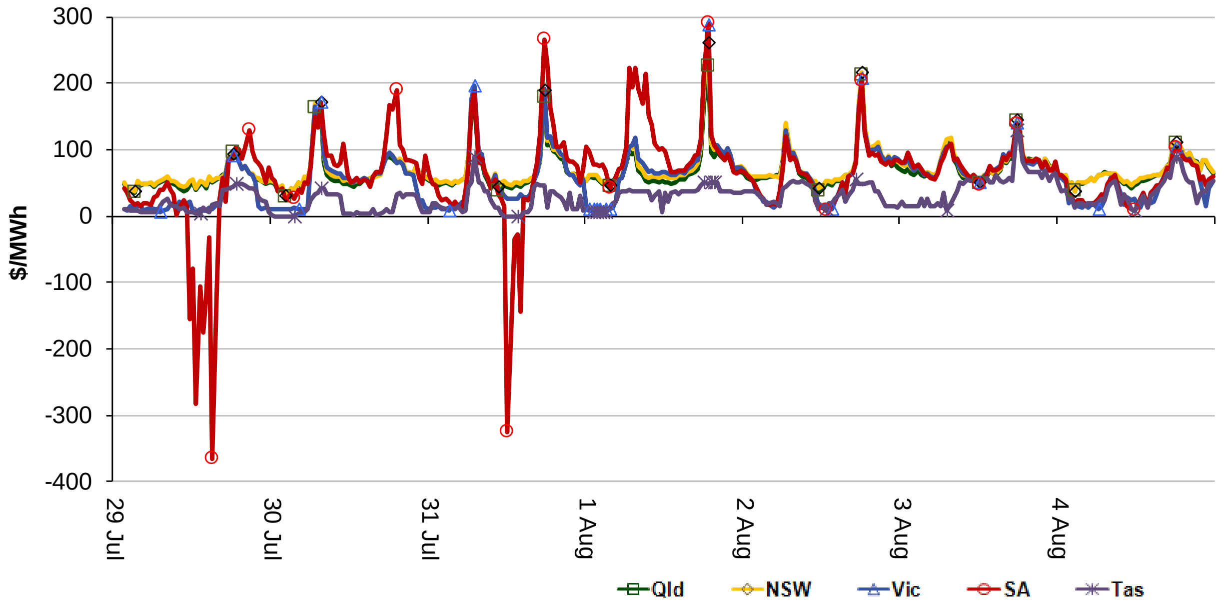


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

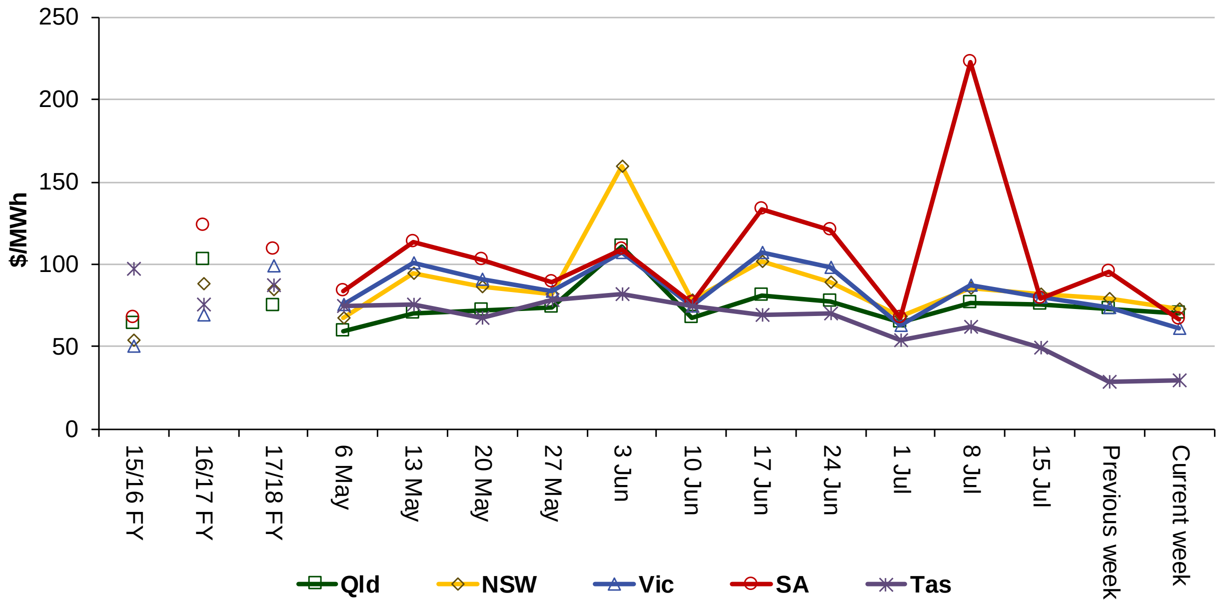


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	70	73	61	67	30
17-18 financial YTD	80	95	121	118	118
18-19 financial YTD	72	78	73	107	45

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 252 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	9	35	0	1
% of total below forecast	12	35	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

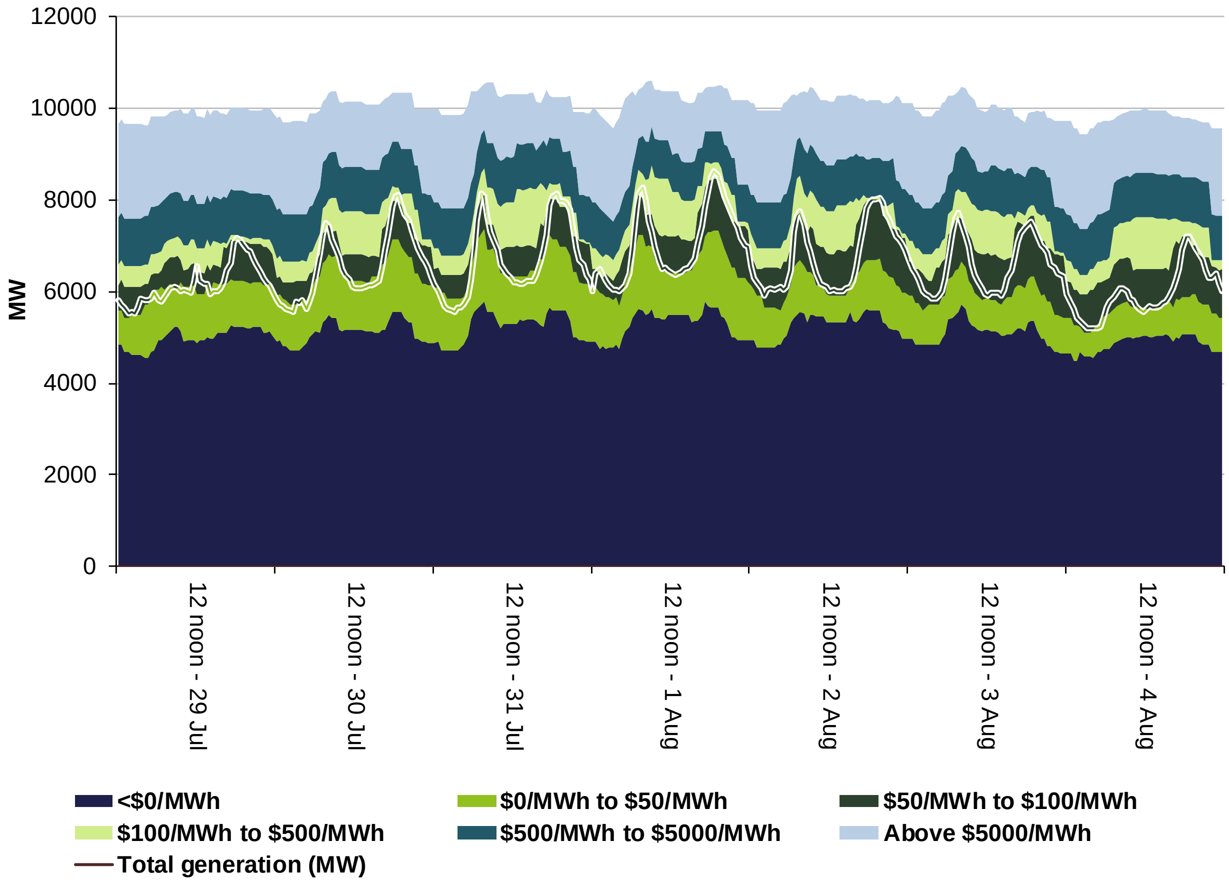


Figure 4: New South Wales generation and bidding patterns

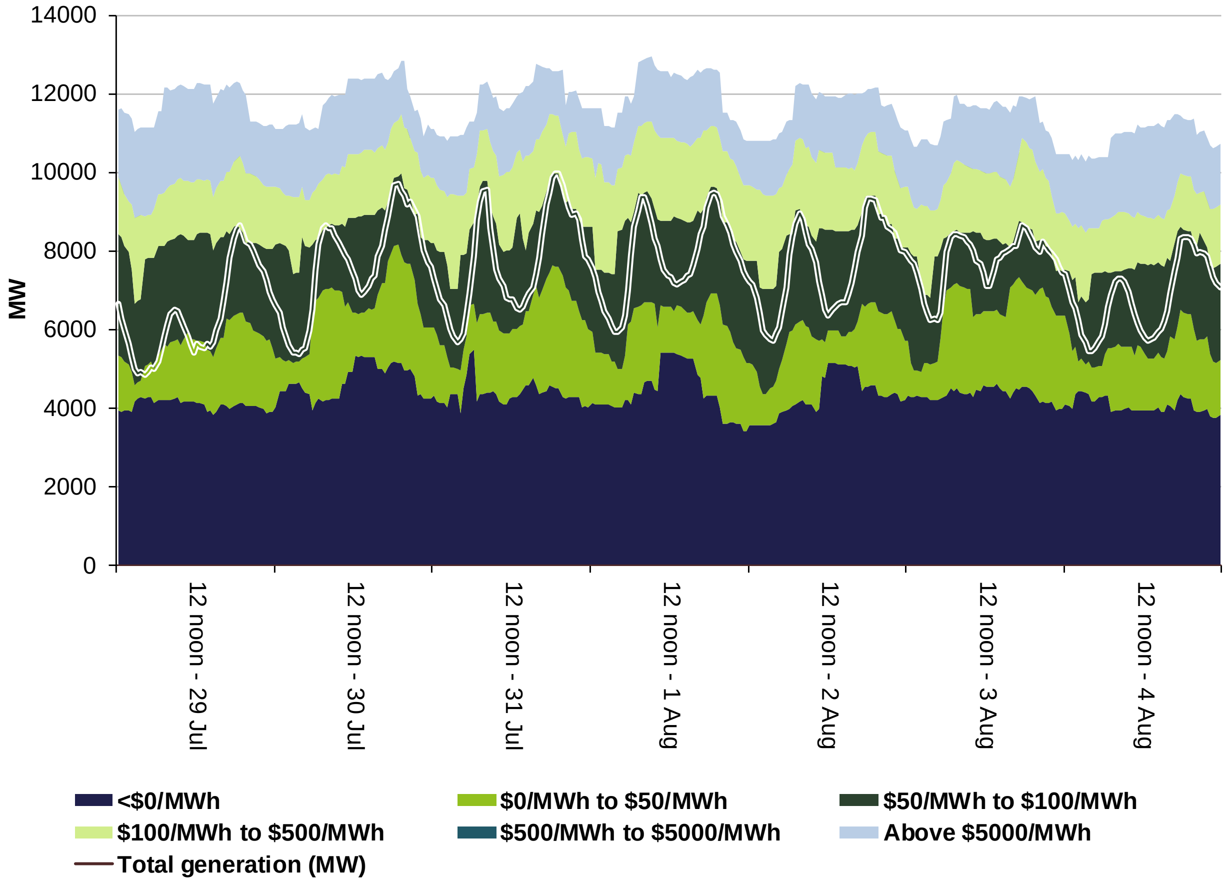


Figure 5: Victoria generation and bidding patterns

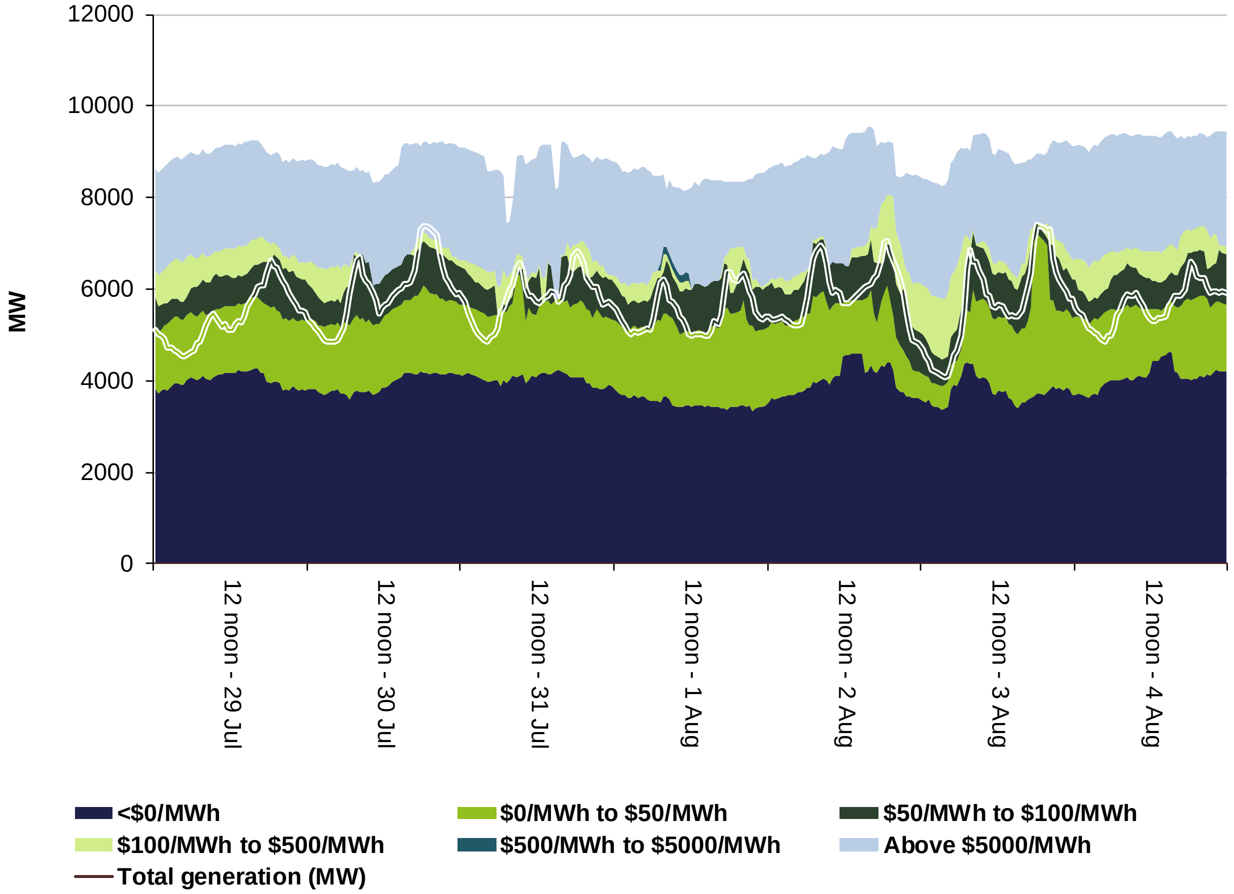


Figure 6: South Australia generation and bidding patterns

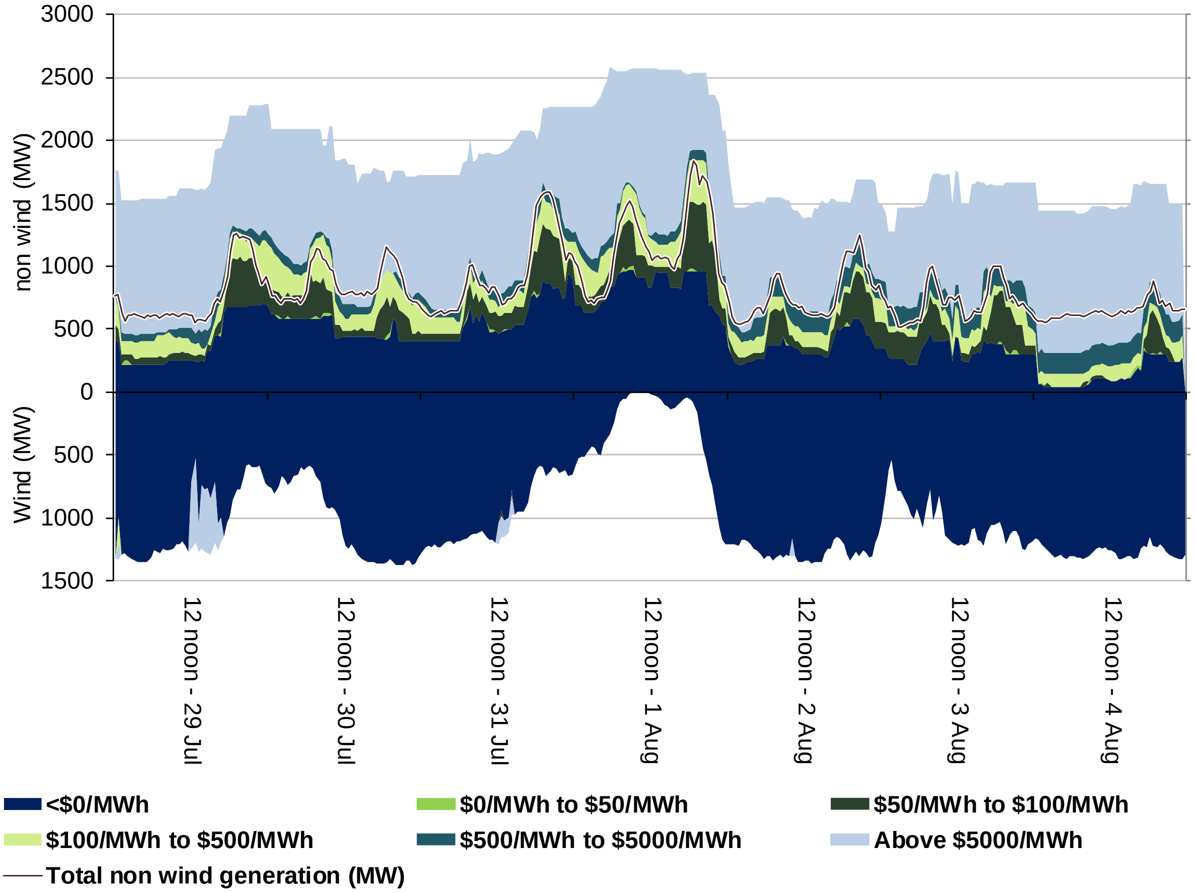
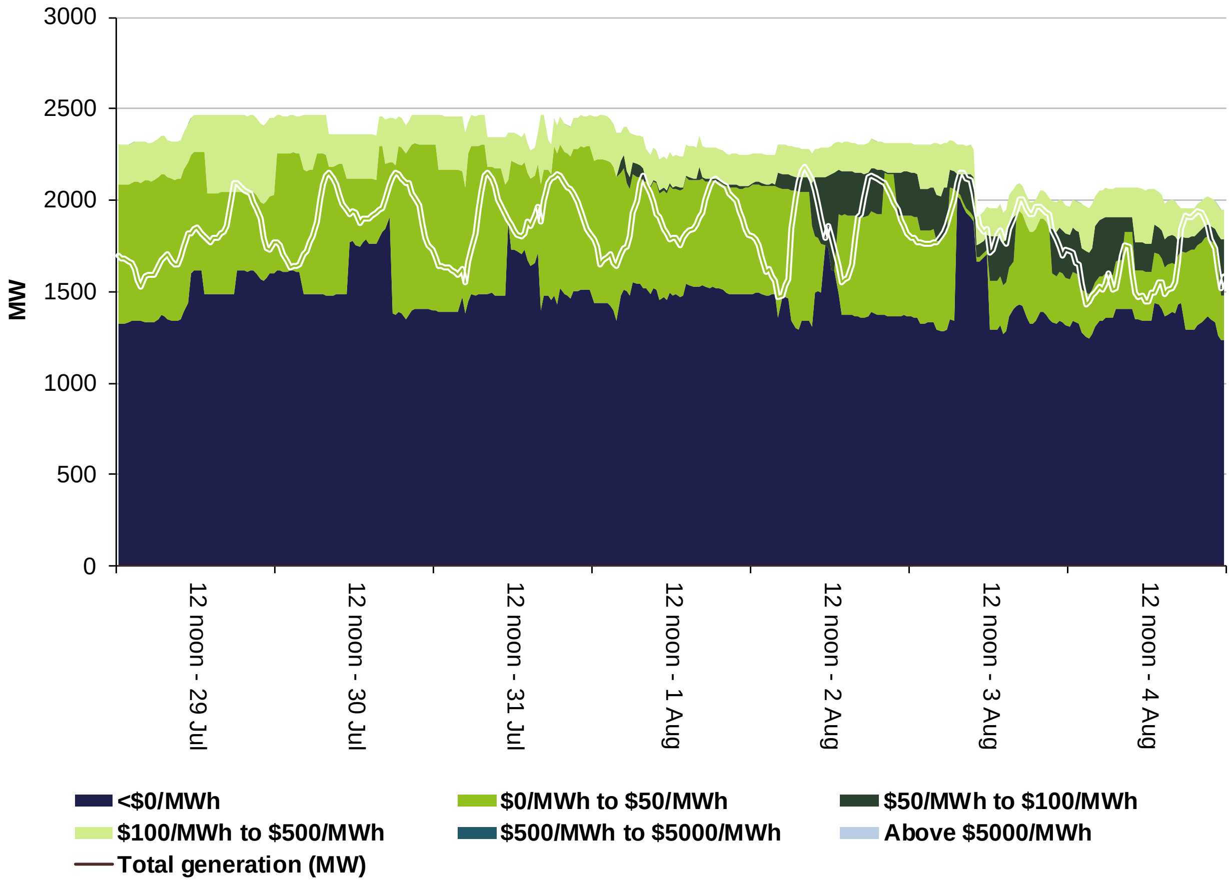


Figure 7: Tasmania generation and bidding patterns



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.

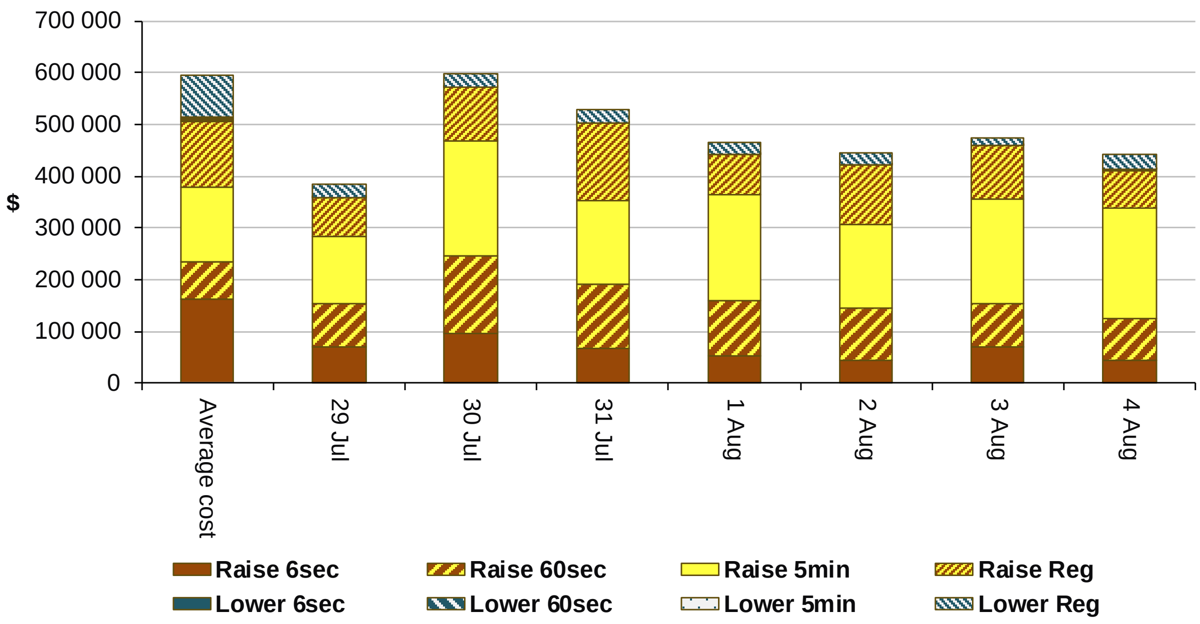
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 253 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $86 500 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



Detailed market analysis of significant price events

New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $73/MWh and above $250/MWh.

Wednesday, 1 August

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	260.91	127.82	299.60	10 220	10 286	10 410	12 417	12 474	12 166

The price was aligned with the Victorian and South Australian price. See the Victorian section for this analysis.

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $61/MWh and above $250/MWh.

Wednesday, 1 August

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
7 pm	287.44	138.34	348.81	6764	6777	6918	8252	8308	7836

The price in Victoria, New South Wales and South Australian were aligned for the 7 pm trading interval and is discussed collectively in this section.

Net demand across Victoria, South Australia and New South Wales was 63 MW lower than forecast and net availability was 234 MW lower than forecast, both four hours prior.

At 6.22 pm Snowy Hydro rebid 300 MW at Murray priced at $107/MWh to $290/MWh, it then set price at $290/MWh for the majority of the trading interval.

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 $67/MWh and above $250/MWh and there were eleven occasions where the spot price was below -$100/MWh.

Sunday, 29 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
1 am	-168.45	47.16	55.12	1328	1300	1321	3088	2898	2868
Midday	-156.02	15.83	7.74	899	886	852	2897	2699	2691
1 pm	-282.21	16.51	7.74	956	906	858	2803	2782	2779
1:30 pm	-106.68	16.50	15.77	947	907	872	2875	2778	2773
2 pm	-175.95	18.06	16.52	1027	951	892	2864	2771	2765
2:30 pm	-119.52	19.16	17.71	1076	960	904	2868	2746	2755
3:30 pm	-366.11	20.34	20.10	1095	1013	989	2953	2784	2800
4 pm	-117.48	20.52	19.36	1152	1139	1061	3091	2995	2804

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.

For the 1 am trading interval, demand was close to forecast and availability was 190 MW higher than that forecast four hours prior, mainly due to higher than forecast wind generation.

Demand dropped by around 50 MW at the start of the trading interval and again for the 12.50 am dispatch interval, this led to two negatively priced dispatch intervals and the lower than forecast price.

For the remainder of the lower than forecast trading intervals, demand (up to 116 MW) and availability (up to 198 MW) was higher than forecast four hours prior.

For the afternoon a constraint managing an outage on the Brinkworth to Templers West 275 kV line limited the output of a large amount of generators located in the north of the region. There was also an outage on one of the South East to Tailem Bend 275 kV lines which limited flows across the Heywood interconnector.

Across the afternoon, due to either constraints limiting higher priced generation setting price, the co-optimisation of energy and FCAS markets or constraints forcing flows on Heywood interconnector, the dispatch price decreased to between -$400/MWh and the floor 11 times, causing the lower than forecast prices.

Tuesday, 31 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
12:30 pm	-324.49	45.66	23.67	1078	1106	1107	3099	2852	2843
1 pm	-155.40	44.91	20.96	1124	1136	1112	3046	2864	2861
2:30 pm	-144.86	23.21	43.58	1103	1178	1166	2944	2878	2888
6 pm	266.35	148.00	379.95	1688	1604	1637	2719	2768	2848

For the 12.30 pm to 2.30 pm trading intervals demand was close to forecast while availability was up to 247 MW higher than forecast four hours ahead, mainly due to higher than forecast wind generation.

With only a small amount of generation priced between the forecast price and the floor, small changes in demand or supply within South Australia had large impacts on price.

At 12.25 pm constraints managing system security in South Australia, which limits wind generation, stopped binding. Wind generation then increased by around 110 MW, resulting in the dispatch price decreasing to -$990/MWh. It then decreased to the floor for the 12.30 pm dispatch interval after a large decrease in exports in to Victoria.

The negative dispatch prices continued into the 1 pm trading interval due to an increase in wind generation of around 50 MW. This resulted in the lower than forecast trading intervals for 12.30 pm and 1 pm.

At 2.05 pm, due to a decrease in demand, higher priced generation was ramp down constrained and unable to set price. The dispatch price decreased to -$993/MWh and caused the lower than forecast price for the 2.30 pm trading interval.

For the 6 pm trading interval demand was around 80 MW higher than forecast while availability was around 50 MW lower than forecast four hours prior.

Across the last 3 dispatch intervals demand increased by 83 MW while wind generation decreased by 54 MW, with no generation priced between $150/MWh and $270/MWh, the dispatch price increased from $148/MWh at 5.45 pm to $361/MWh and remained at the level for the remainder of the trading interval.

Wednesday, 1 August

Table 7: Price, Demand and Availability

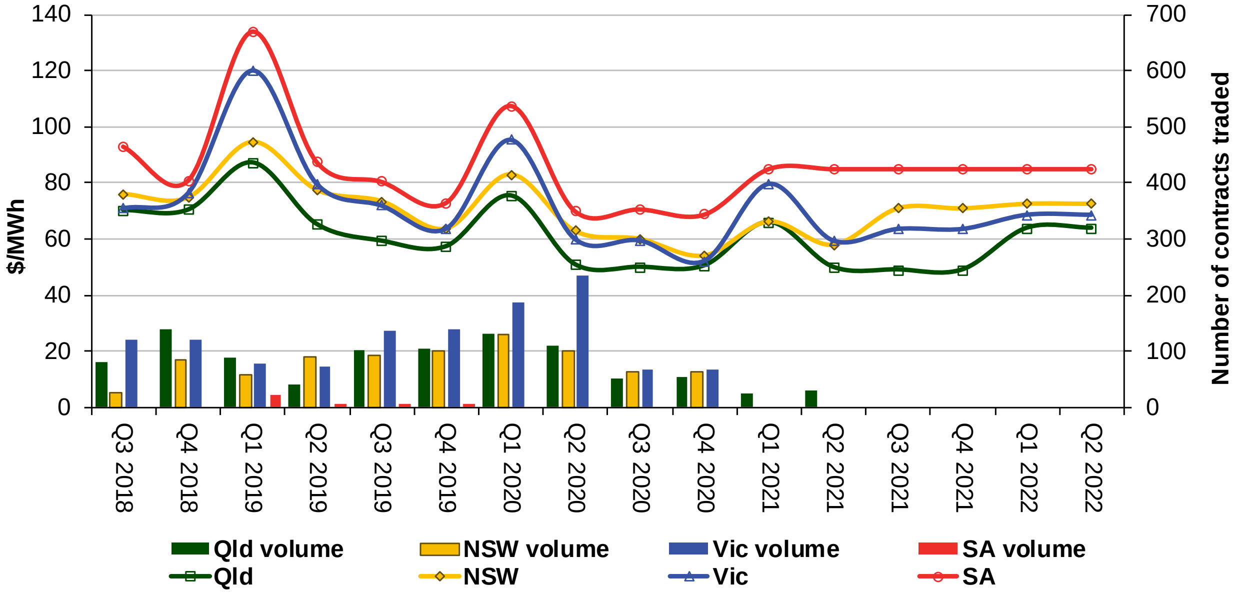
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 pm	289.87	145.50	349.35	1904	1888	1882	2613	2734	2737

The price was aligned with the Victorian and New South Wales price. See the Victorian section for analysis.

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.

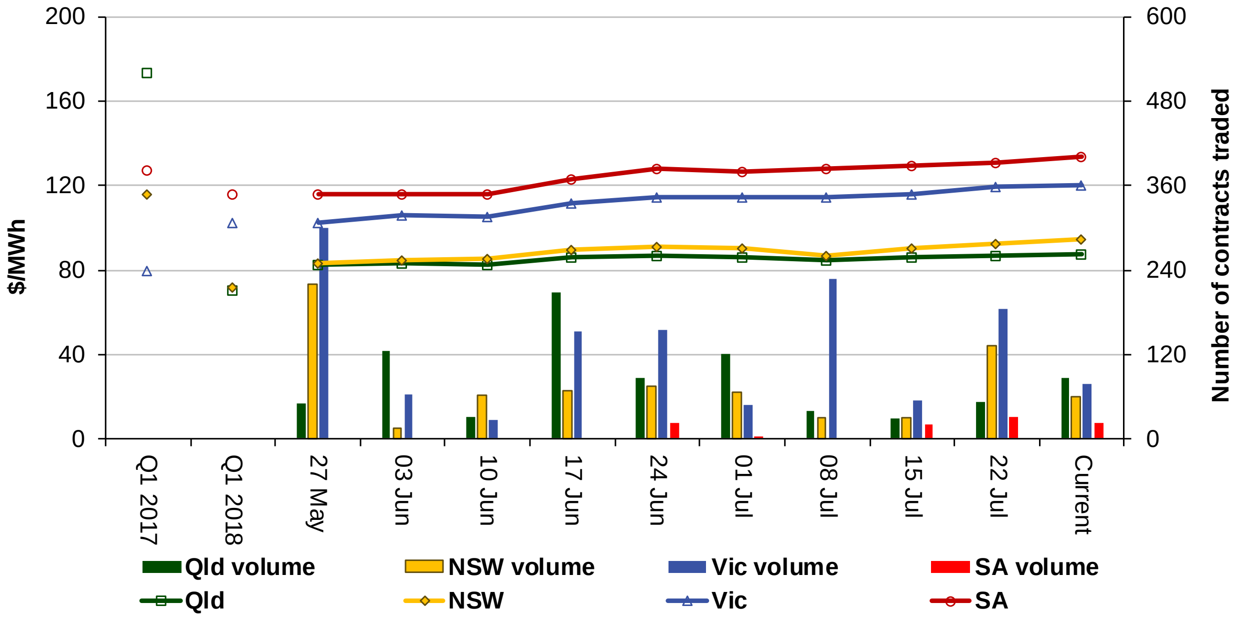
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



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)



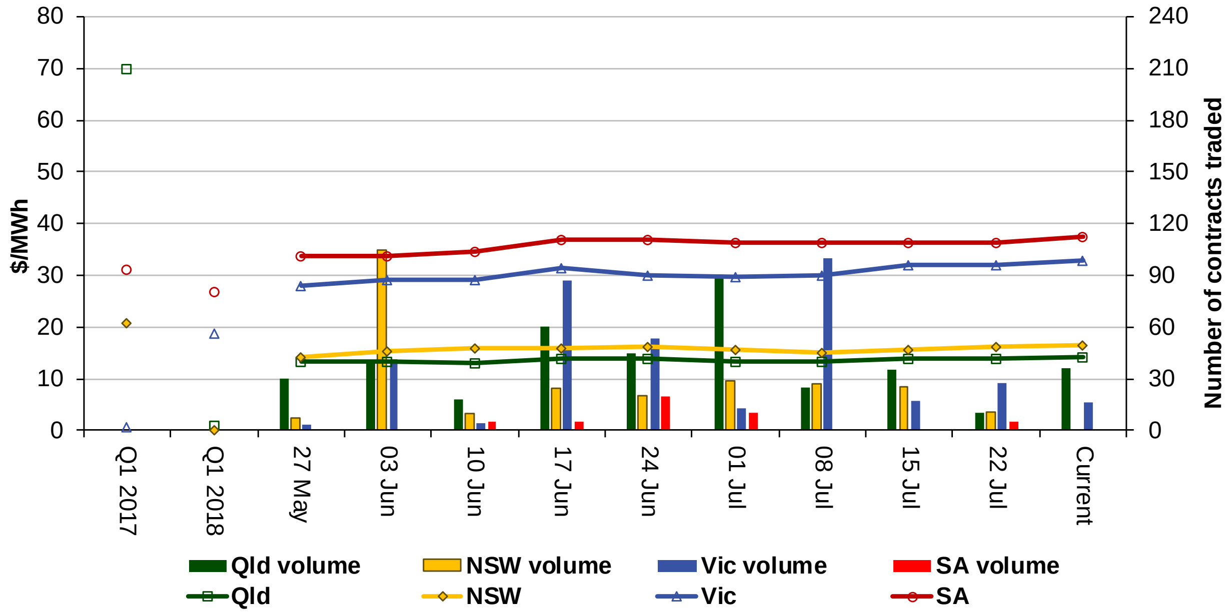
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
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