Electricity Report

AUSTRALIAN ENERGY REGULATOR

29 September – 5 October 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 29 September to 5 October 2019.

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

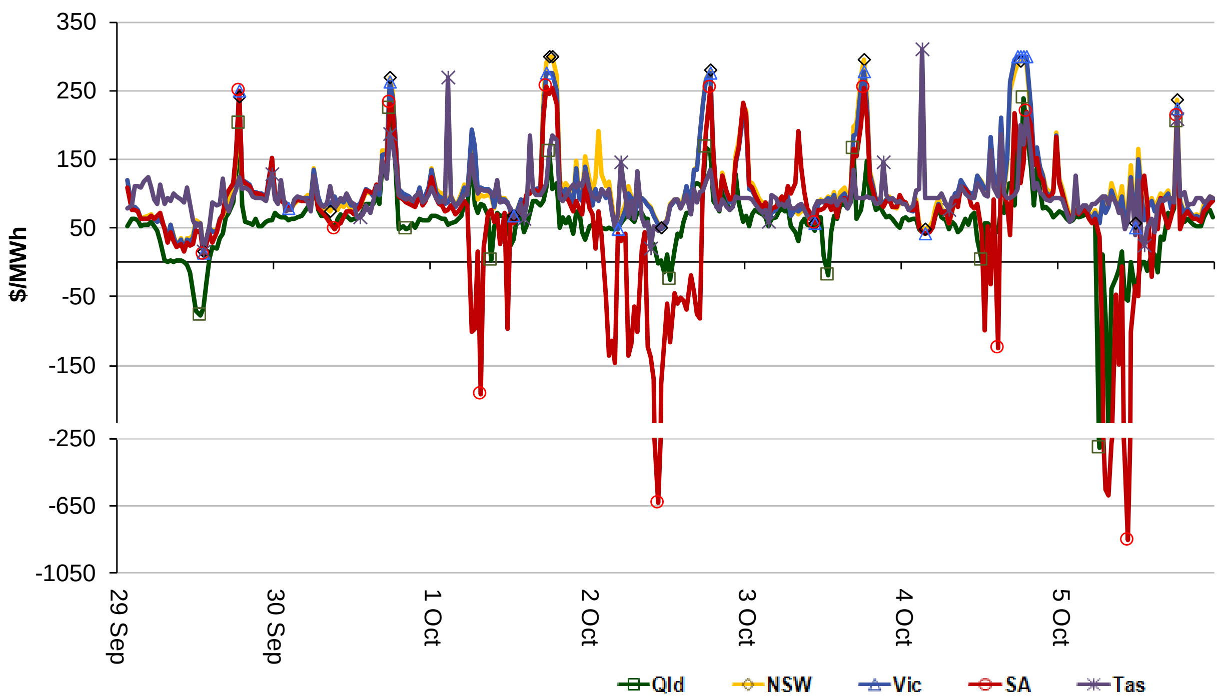


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

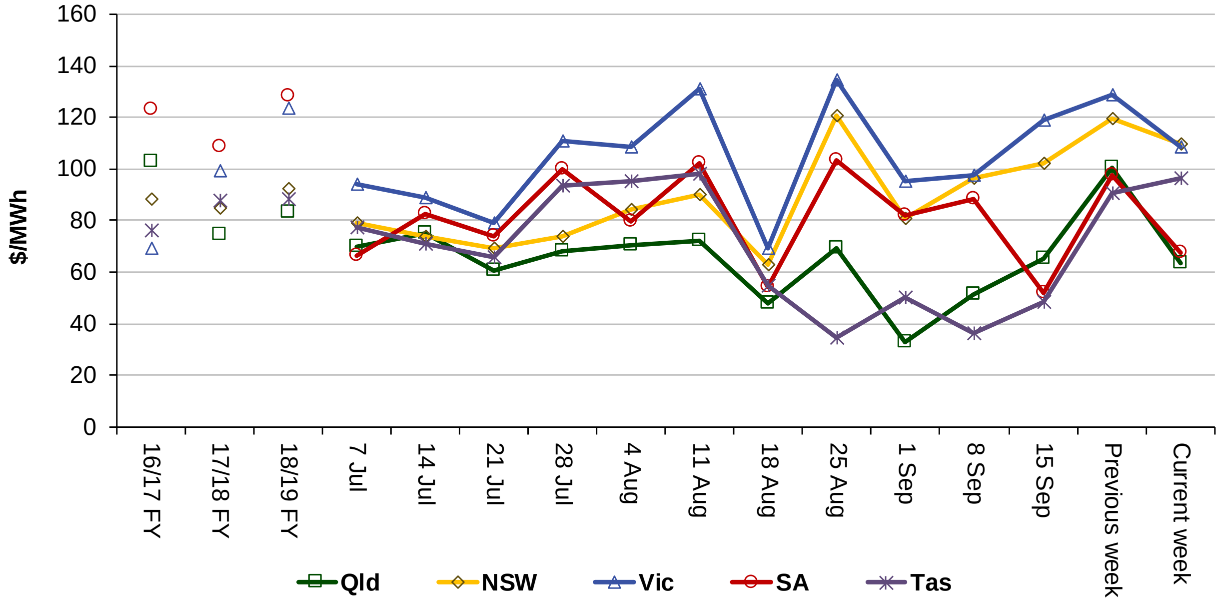


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	63	110	108	68	96
18-19 financial YTD	80	90	85	95	46
19-20 financial YTD	65	88	103	81	71

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 274 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	6	20	0	1
% of total below forecast	17	51	0	5

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

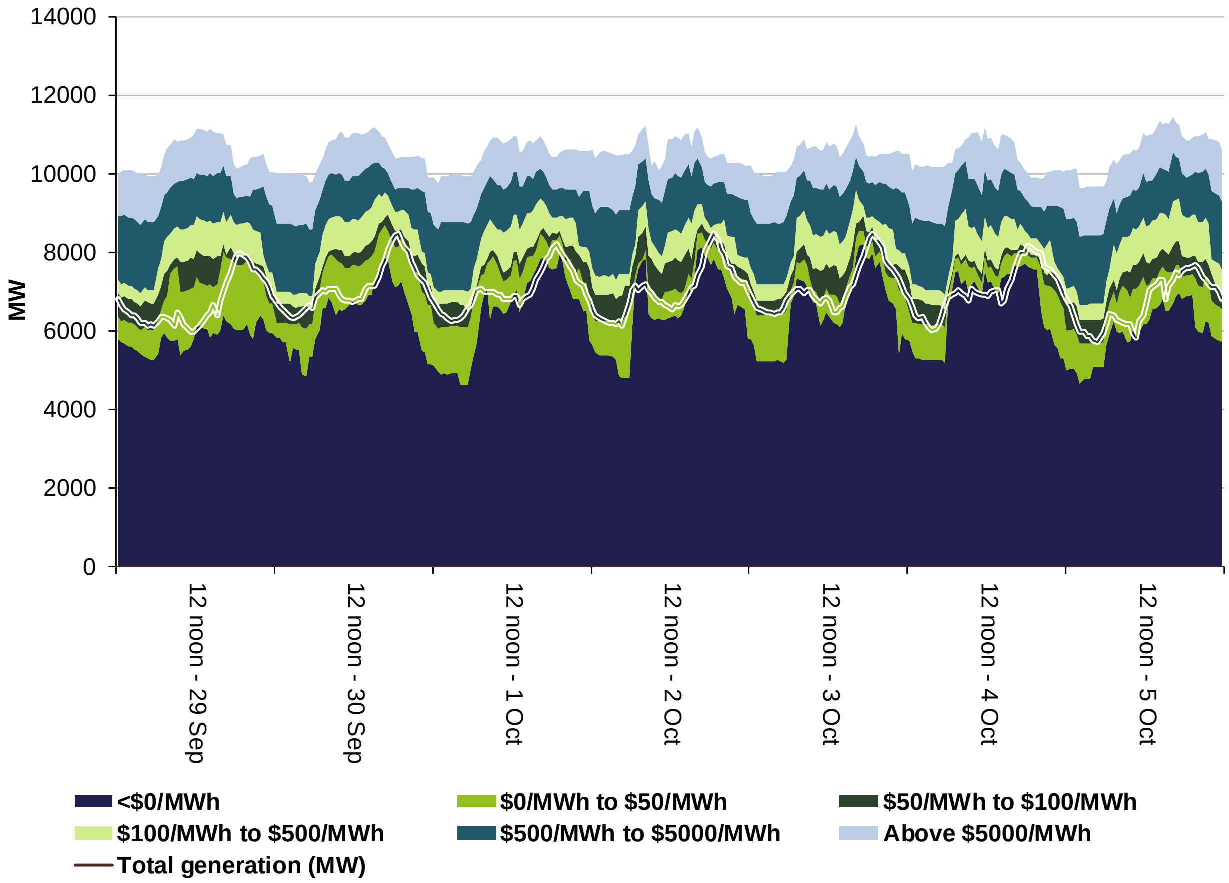


Figure 4: New South Wales generation and bidding patterns

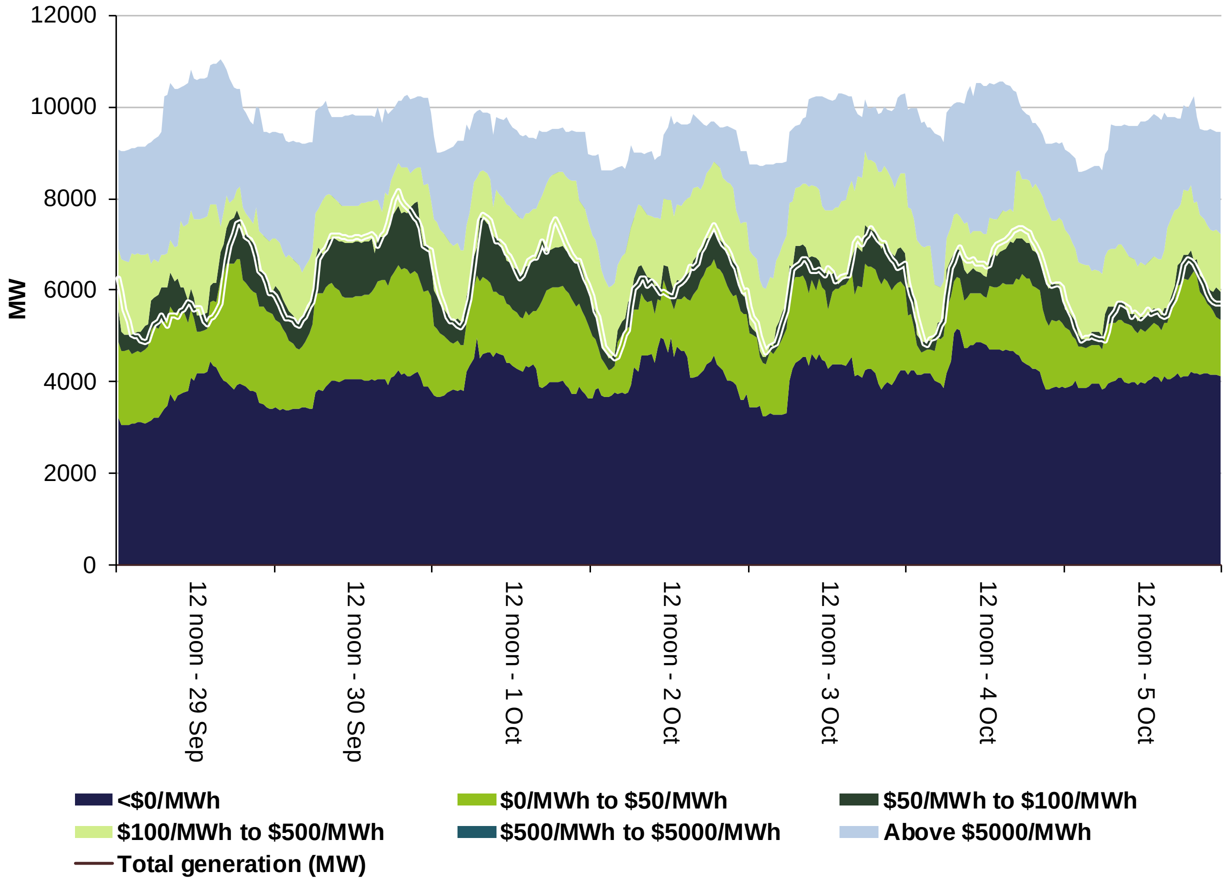


Figure 5: Victoria generation and bidding patterns

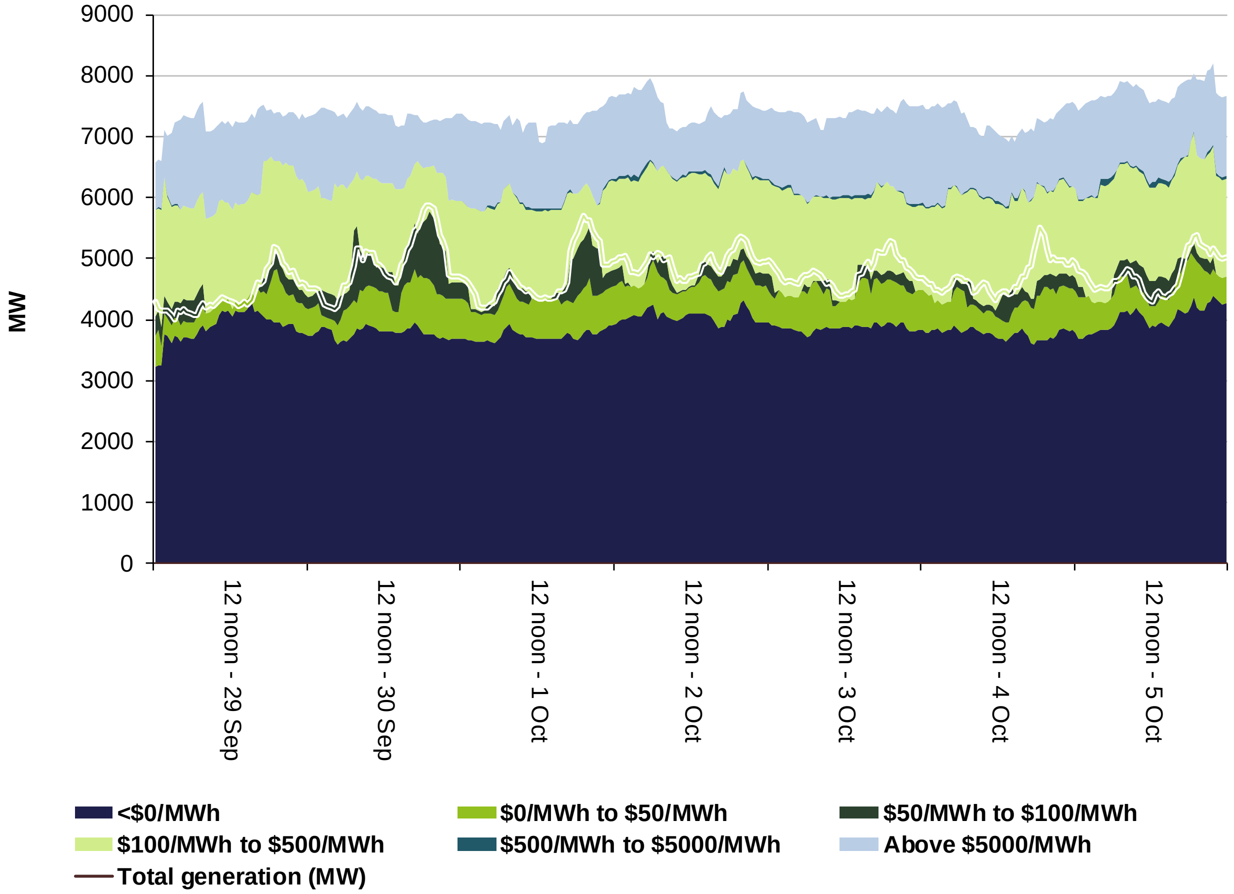


Figure 6: South Australia generation and bidding patterns

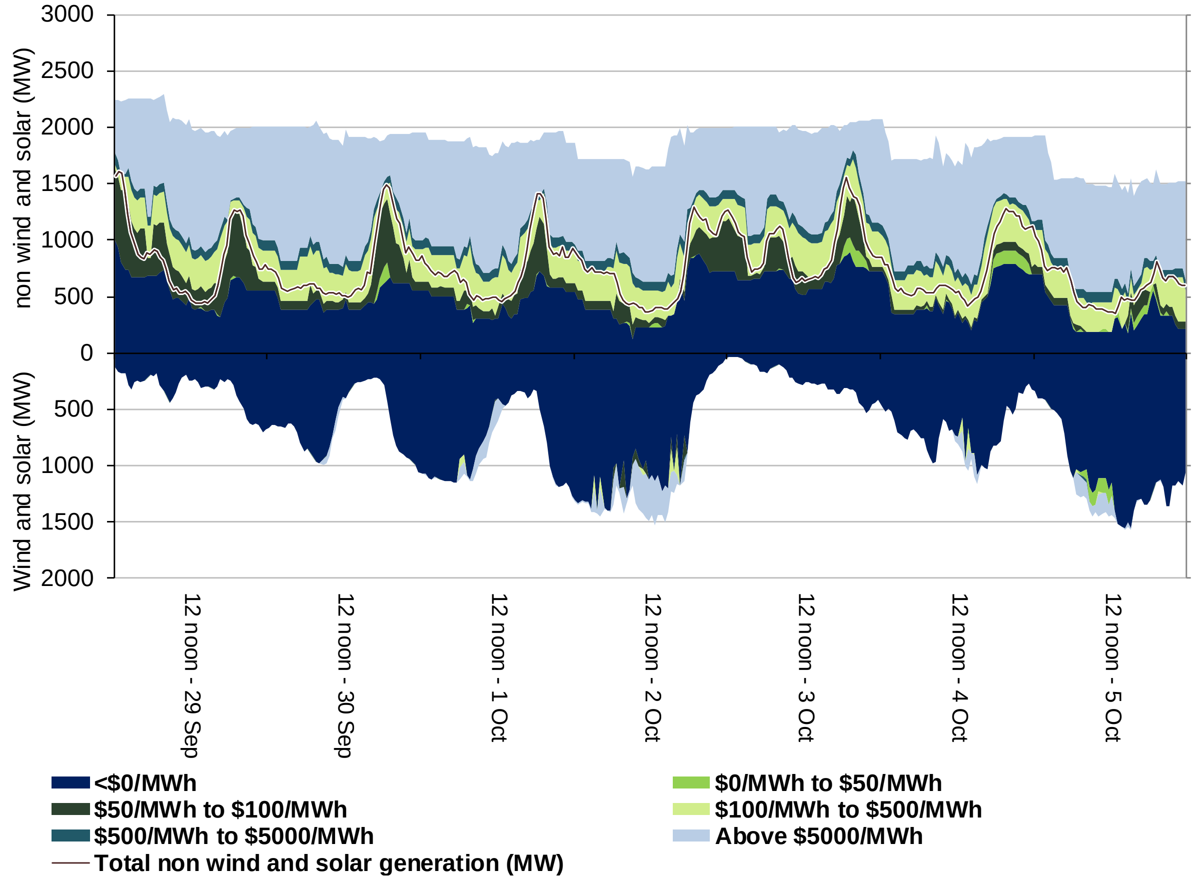
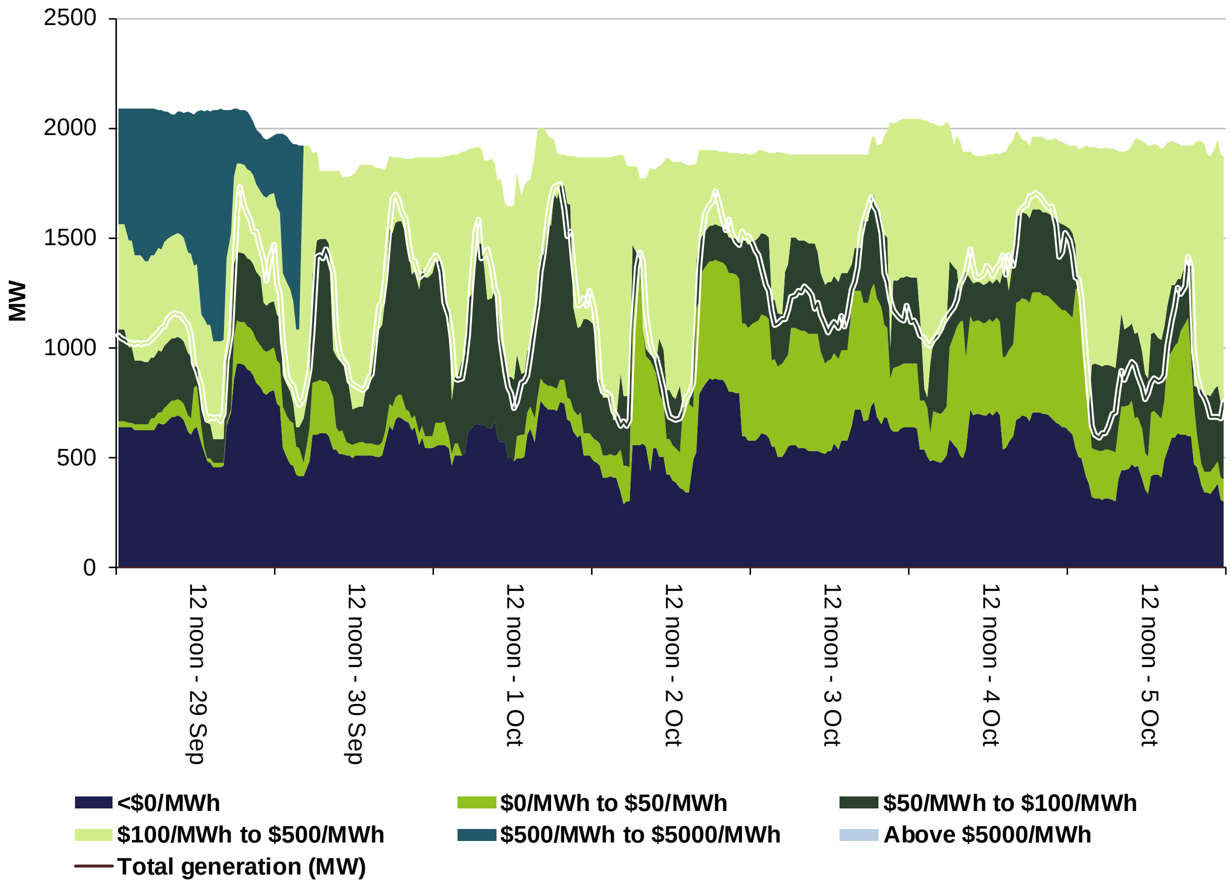


Figure 7: Tasmania generation and bidding patterns



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.

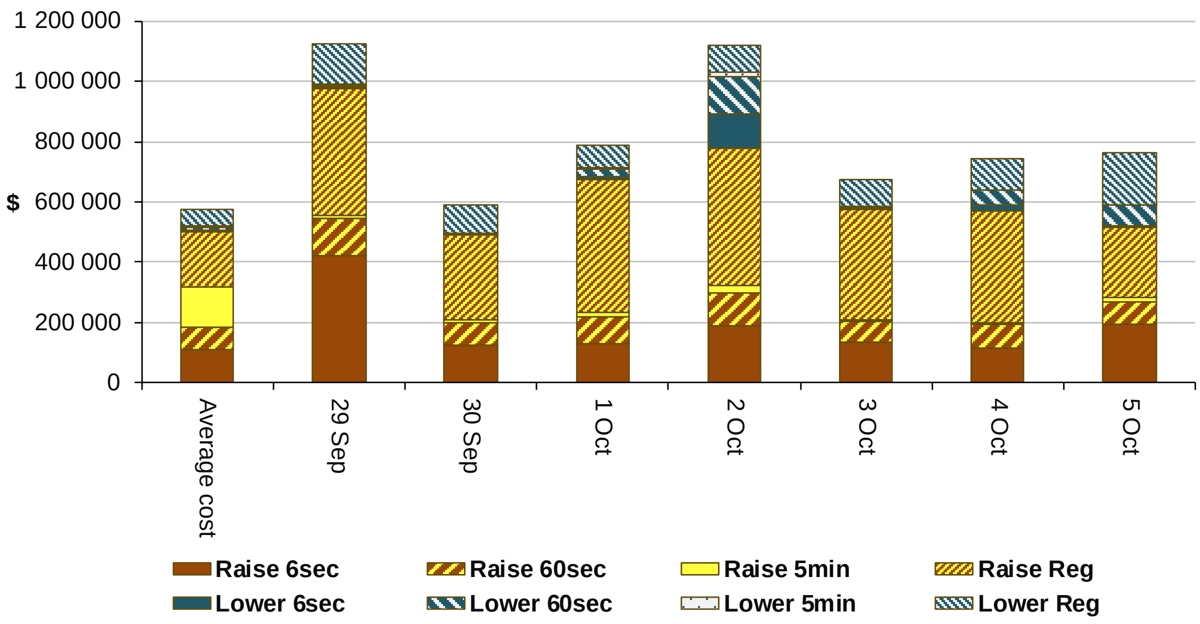
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $5 094 000 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $710 000 or around 4 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

Queensland

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

Saturday, 5 October

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 am	-303.52	76.64	63.73	5028	5120	5139	9823	9537	9852
8 am	-235.70	24.55	0	4853	5032	5058	10 350	10 227	10 690

Conditions at the time saw demand was up to 179 MW lower than forecast and availability was up to 286 MW higher than forecast, both four hours prior. Availability increased around 4 am, when CS Energy returned Kogan Creek to service, adding 300 MW of capacity priced at the floor.

For the 6.30 am trading interval: Effective at 6.20 am, CS Energy rebid 610 MW of capacity at Gladstone power station from between $1/MWh and $115/MWh to the price floor, the reason related to portfolio rearrangement. This led to two dispatch intervals priced between -$959/MWh and the floor and a lower than forecast spot price.

At the start of the 8 am trading interval demand fell by 41 MW. Both interconnectors were already exporting at their limits, so any excess low priced generation in Queensland could not reach other regions. As a result of falling demand, increased low priced generation from Kogan Creek and constrained exports, the price for the first dispatch interval fell to -$984/MWh. In response to the negative dispatch price participants shifted some capacity into higher price bands but the dispatch price remained between -$155/MWh and -$59/MWh for the rest of the trading interval.

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $68/MWh and above $250/MWh and there were twenty-three occasions where the spot price was below -$100/MWh.

Sunday, 29 September

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	250.13	166.61	311.04	1490	1464	1470	2277	2342	2389

Demand was close to forecast. The spot price was aligned across all mainland regions of the NEM, however the reporting threshold was only triggered in South Australia. Across the mainland, availability was around 530 MW lower than forecast meaning slightly more expensive generation was required to meet demand.

Tuesday, 1 October

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
6.30 am	-101.63	105.57	145.53	1168	1136	1127	2998	2915	2834
8 am	-192.20	53.61	68.00	1233	1170	1157	3010	2940	2882
6 pm	255.92	264.43	273.74	1327	1322	1307	2251	2328	2324
7 pm	254.37	272.28	276.74	1458	1450	1439	2440	2448	2438

There was little capacity priced between $100/MWh and the price floor so small changes in demand or generator availability could lead to fluctuations in price outcomes. Demand and availability were reasonably close to forecast for all trading intervals.

For the 6.30 am trading interval a ramping constraint on the Heywood interconnector reduced exports meaning excess low priced generation in South Australia could not reach other regions. As a result one dispatch interval was priced at the floor and led to a negative priced trading interval.

For the 8 am trading interval, all dispatch intervals were priced lower than forecast as low priced wind generation was higher than forecast. The last dispatch interval was priced at the floor when demand fell by 5 MW and low priced wind generation increased by 28 MW.

The 6 pm and 7 pm trading intervals were priced close to forecast.

Wednesday, 2 October

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
3.30 am	-136.54	86.82	28.42	1083	992	966	3131	2857	2800
4 am	-113.01	52.98	29.92	1040	964	947	3143	2861	2798
4.30 am	-145.86	53.48	39.69	1033	957	930	3173	2939	2903
6.30 am	-135.26	75.33	101.53	1071	1053	1041	3071	2959	2896
7 am	-118.82	-1000	55.43	1144	1090	1079	2892	2966	2889
8 am	-101.67	115	69.54	1226	1098	1069	3102	2878	2802
9.30 am	-122.02	58.84	-1000	1069	988	932	2847	2826	2895
10 am	-137.36	-1000	-1000	1032	933	864	2991	2826	2922
10.30 am	-170.47	-1000	-1000	994	869	806	3031	2873	2898

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 am	-633.33	-1000	-1000	944	793	804	3067	2910	2924
11.30 am	-176.9	-1000	-1000	917	772	783	3095	3071	2935
Midday	-117.65	-1000	-1000	899	772	794	3120	3082	2941
1 pm	-116.98	-1000	-1000	884	766	781	3183	3073	2924
7 pm	255.29	236.27	290.81	1483	1523	1496	2424	2616	2435

Demand was between 18 MW and 151 MW greater than forecast. Availability was between 21 MW and 282 MW greater than forecast, except for the 7 am trading intervals when availability was 74 MW lower than forecast. Higher than forecast availability was mostly due to higher than forecast wind generation.

Little or no capacity was initially offered to the market priced between the floor and $100/MWh. This meant minor fluctuations in demand, generator availability or rebidding could lead to significant fluctuations in price. Planned maintenance on the Heywood interconnector between 6 am and 6.40 pm reduced exports into Victoria to around 100 MW. Exports across Heywood into Victoria were at or close to the export limit for the day, which meant any excess low priced generation in South Australia could not reach neighbouring regions.

The first four trading intervals above all had one dispatch interval priced at the floor due to spread of offers discussed above. As a result, these spot prices were lower than forecast.

For the 7 am and 8 am trading intervals, as forecast, the first dispatch intervals were priced at the floor. However, in response to the negative prices, participants shifted capacity into higher price bands and the dispatch prices settled between $68/MWh and $78 /MWh.

The trading intervals between 9.30 am and 1 pm followed similar patterns of one or more negative priced dispatch intervals followed by participants responding and shifting capacity into higher bands.

The 7 pm trading interval was close to forecast.

Thursday, 3 October

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
6.30 am	255.46	274.20	318.91	1454	1384	1363	2361	2227	2201

Price was close to the forecast.

Friday, 4 October

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
3 pm	-125.75	-508.60	80.59	1044	1000	1113	2897	2818	2621

Demand was 44 MW greater than forecast and availability was 79 MW greater than forecast, both four hours prior. Higher than forecast availability was mostly due to higher than forecast wind generation.

In the four hours leading up to the start of the trading interval participants shifted capacity from the floor into higher price bands due to forecast prices. Also Engie removed 70 MW of capacity priced at the floor at Pelican Point as its return to service was delayed.

The removal or rebidding of low priced capacity led to the dispatch price being set between -$1/MWh and $80/MWh. However one dispatch price hit the floor when low priced generation that was previously constrained was able to set price.

Saturday, 5 October

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
7 am	-127.16	81.62	86.06	1043	994	978	2815	2400	2407
7.30 am	-551.45	76.13	-1.25	1026	1003	995	2840	2440	2503
8 am	-592.75	21.01	-552.25	1020	1020	1002	2815	2540	2562
8.30 am	-276.96	-521.28	-552.19	1039	1011	991	2795	2529	2492
9.30 am	-148.37	101.00	-541.59	1005	968	954	2935	2599	2590
10.30 am	-391.88	-588.82	-577.38	921	923	887	2934	2737	2760
11 am	-850.00	-593.13	-583.18	844	921	889	2907	2812	2800

Demand was close to forecast while availability was between 95 MW and 415 MW greater than forecast, both four hours prior. Higher than forecast availability was mostly due to higher than forecast wind generation.

Planned maintenance on the Heywood interconnector continued between 6 am and 6.40 pm which reduced exports into Victoria to around 75 MW. Exports across Heywood into Victoria were at the export limit for the day, which meant any excess low priced generation in South Australia could not reach neighbouring regions.

With little capacity offered between the floor and $80/MWh, small changes in demand, generator availability or rebidding could lead to volatile price outcomes.

All the trading intervals above other than the 8.30 am trading interval had one or more dispatch intervals priced lower than forecast because there was higher than forecast low priced wind generation, constrained exports and a sensitive supply curve due to the spread of offers.

The 8.30 am trading interval was higher than forecast due to participants rebidding capacity into higher price bands throughout the trading interval.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $96/MWh and above $250/MWh.

Friday, 4 October

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
3.30 am	310.41	94.39	94.31	775	769	803	2024	2027	1977

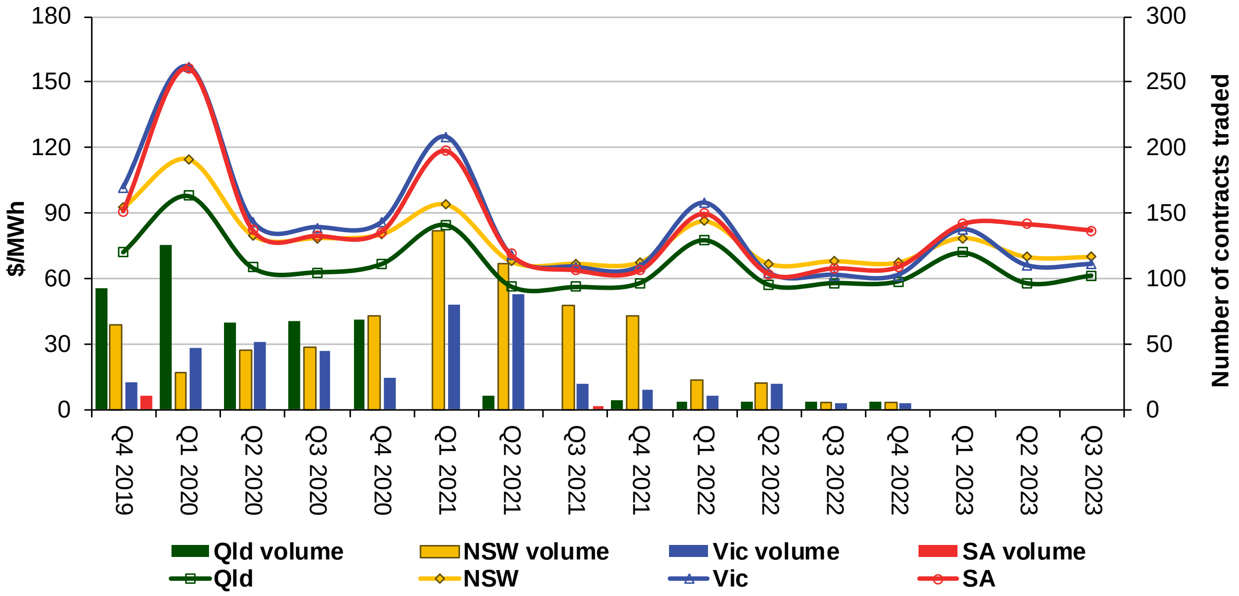
Conditions at the time saw demand and availability close to forecast.

Higher priced generation was necessary to meet demand because other low priced generation was either trapped in FCAS or ramp constrained and unable to set 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.

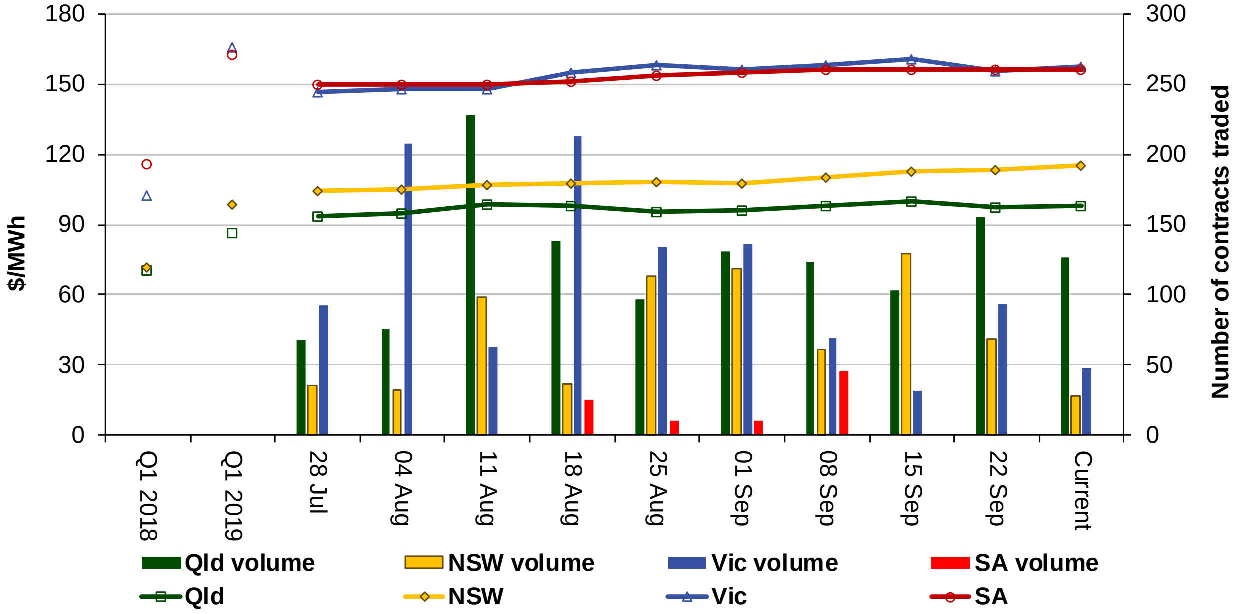
Figure 9: Quarterly base future prices Q4 2019 – Q3 2023



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 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.

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



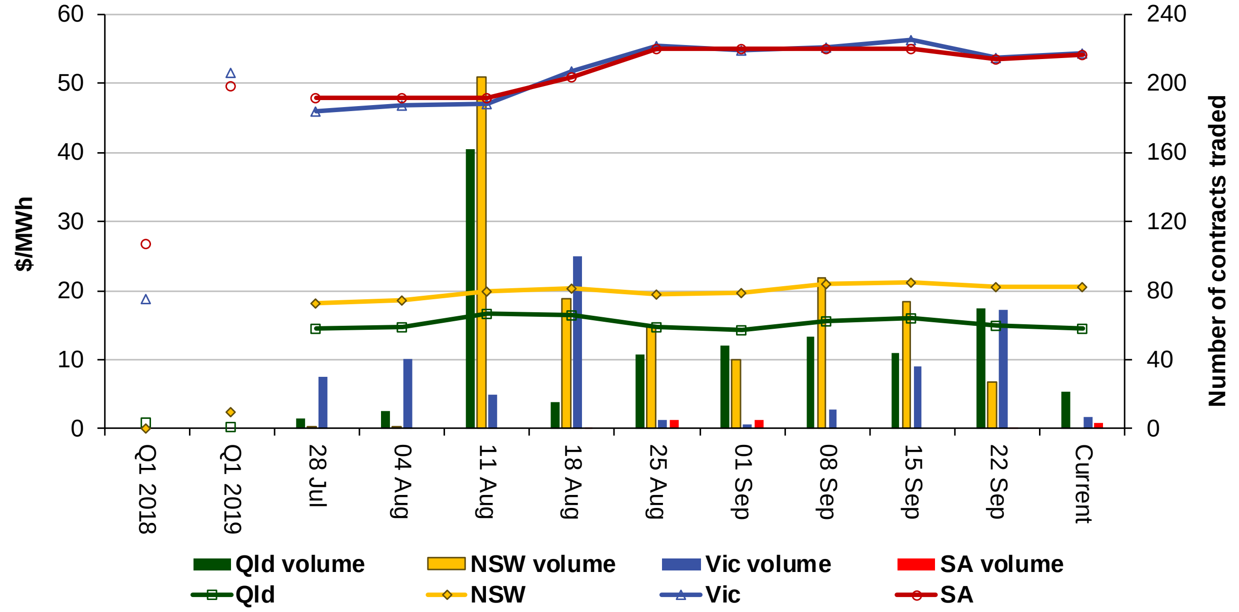
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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