Electricity Report

29 March – 4 April 2020

Weekly Summary

Weekly average prices ranged from $32/MWh in Tasmania up to $53/MWh in New South Wales and Victoria. Windy conditions later in the week saw negative spot prices in South Australia.

Multiple lines were reclassified due to voltage control, unplanned outages and severe weather in Victoria and New South Wales, however these reclassifications did not significantly impact prices.

Purpose

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 March to 4 April 2020.

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

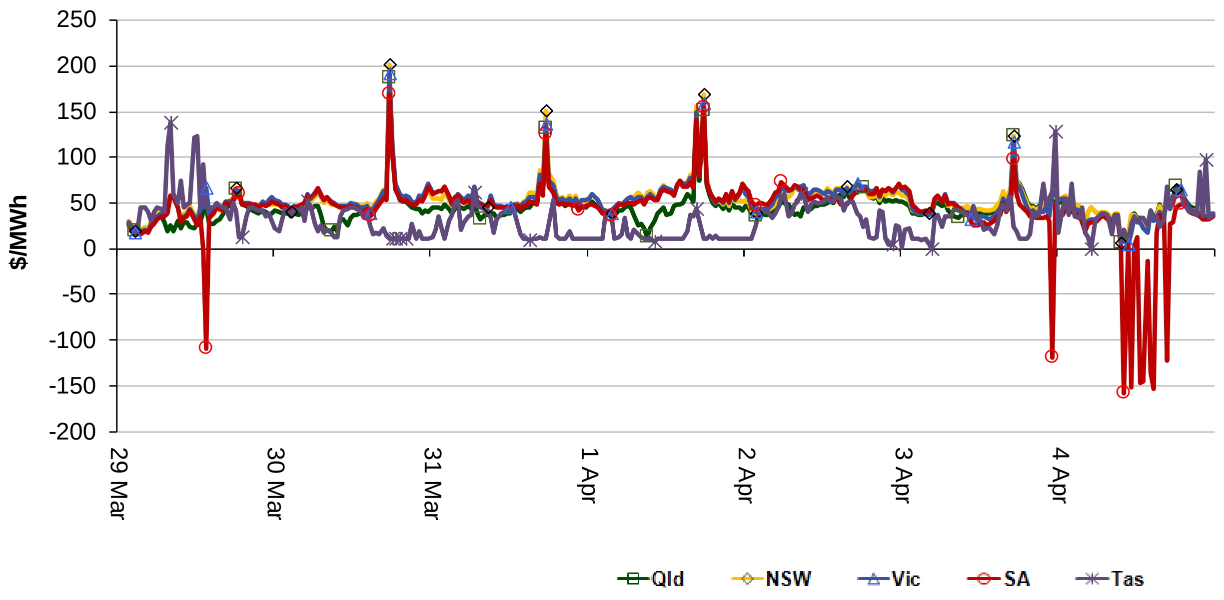


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

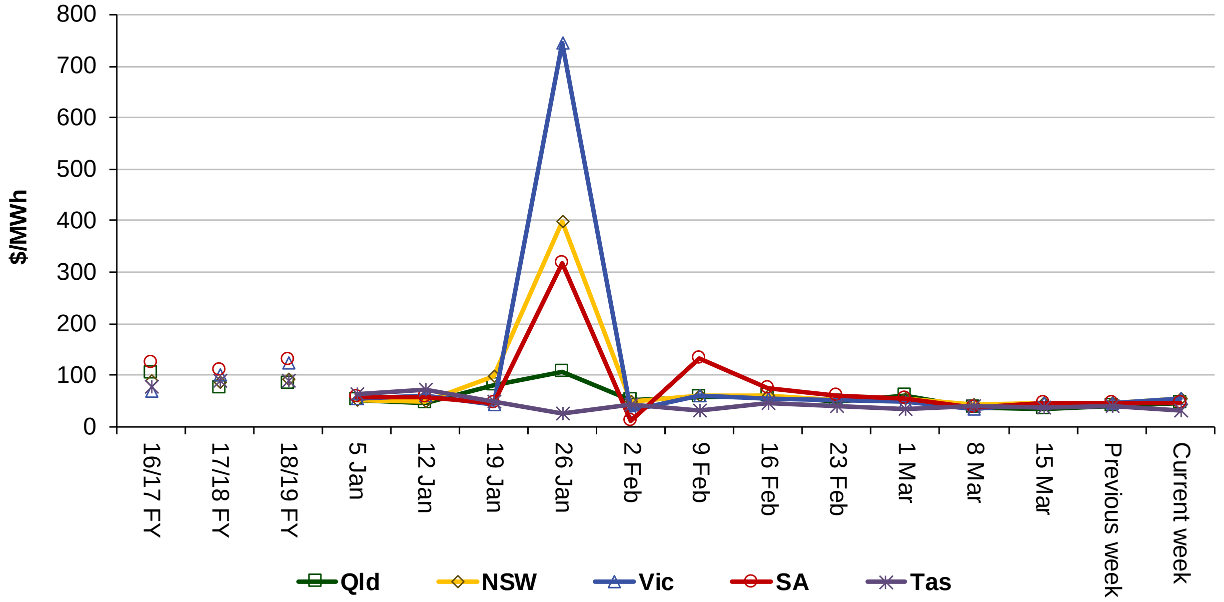


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	46	53	53	46	32
18-19 financial YTD	85	94	131	139	85
19-20 financial YTD	62	90	98	83	63

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 225 trading intervals throughout the week where actual prices varied significantly from forecast. This compares to the weekly average in 2019 of 204 counts and the average in 2018 of 199. 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	25	0	2
% of total below forecast	13	47	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

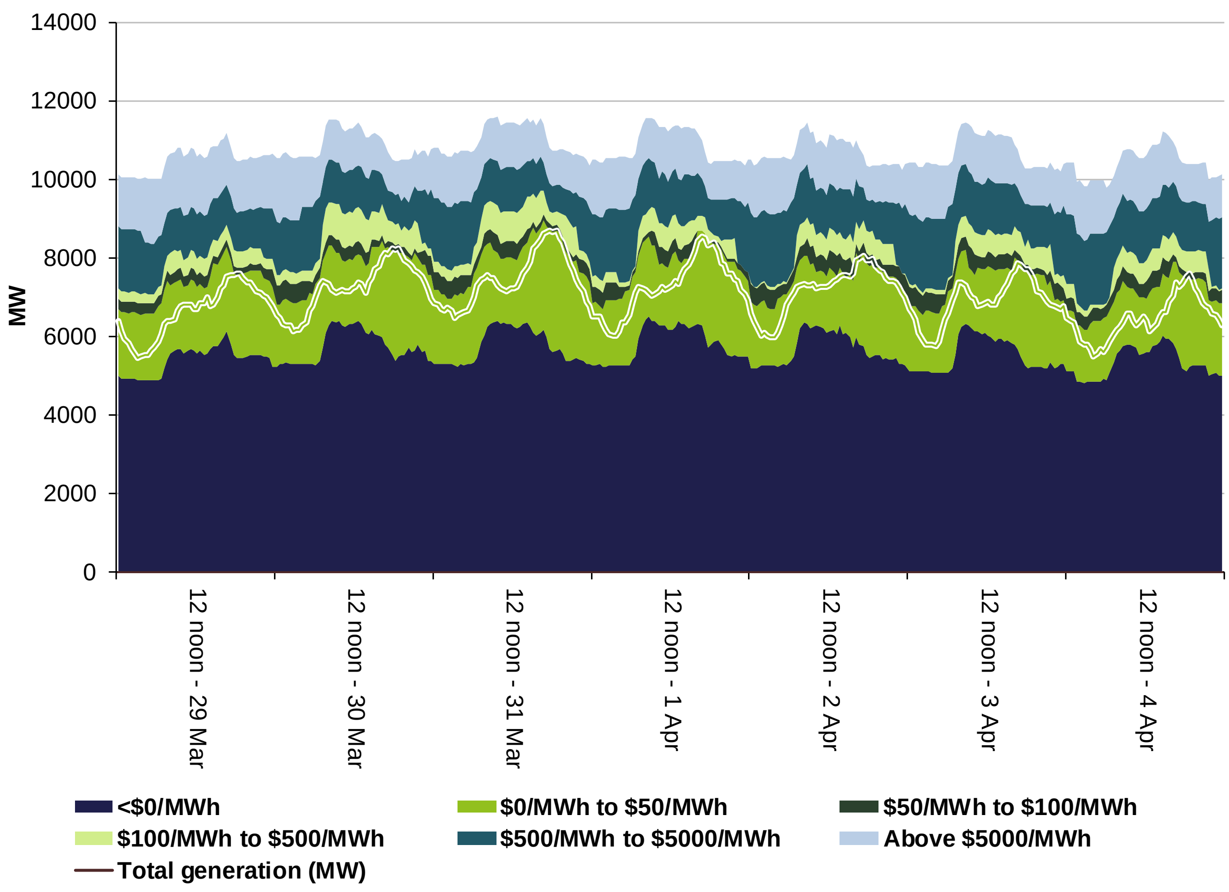


Figure 4: New South Wales generation and bidding patterns

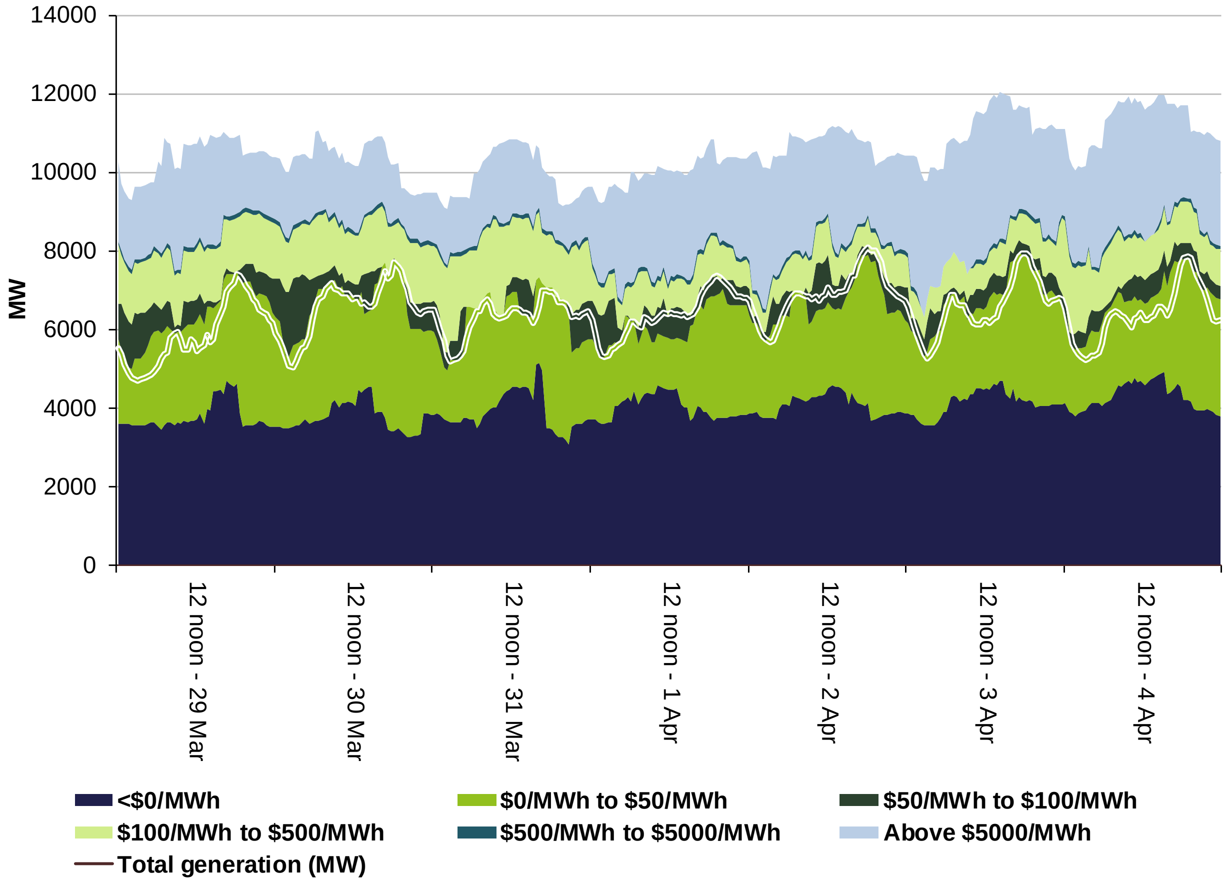


Figure 5: Victoria generation and bidding patterns

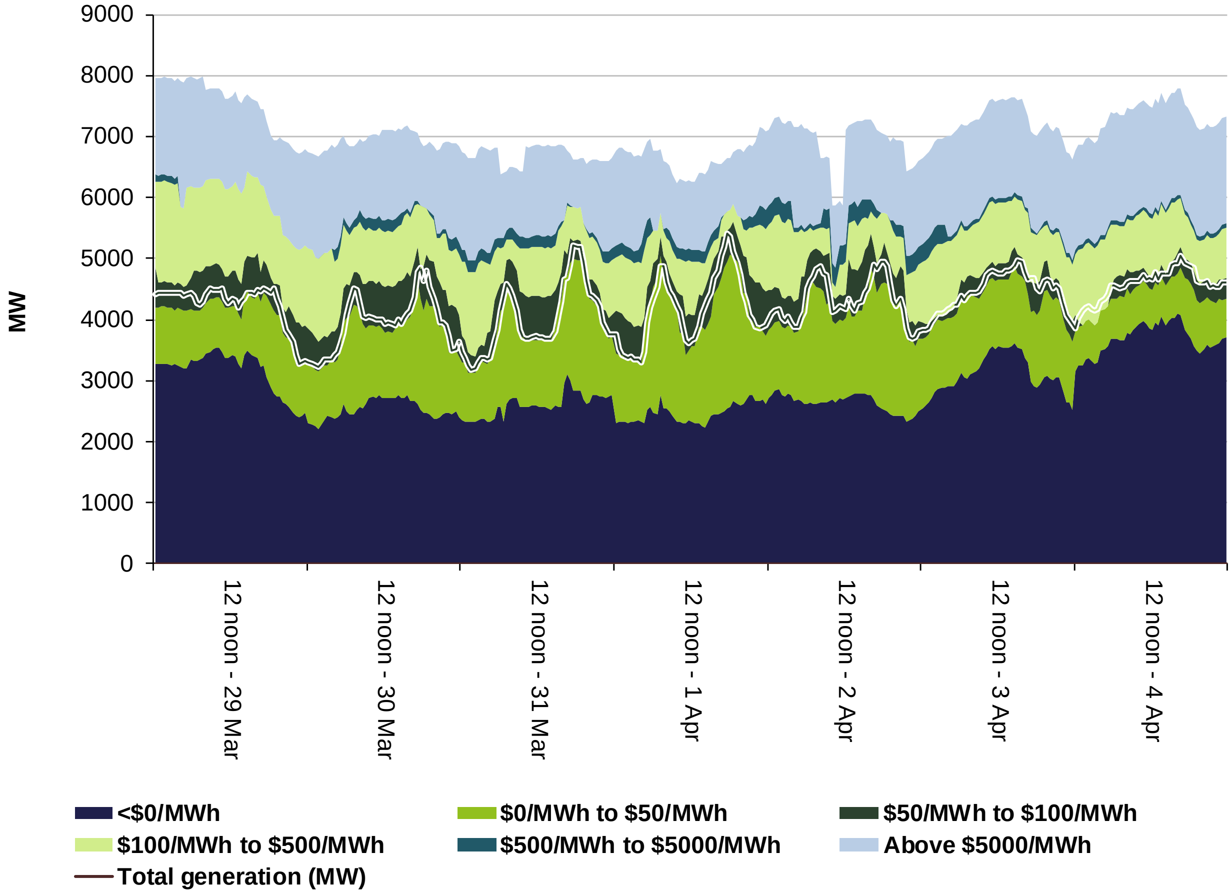


Figure 6: South Australia generation and bidding patterns

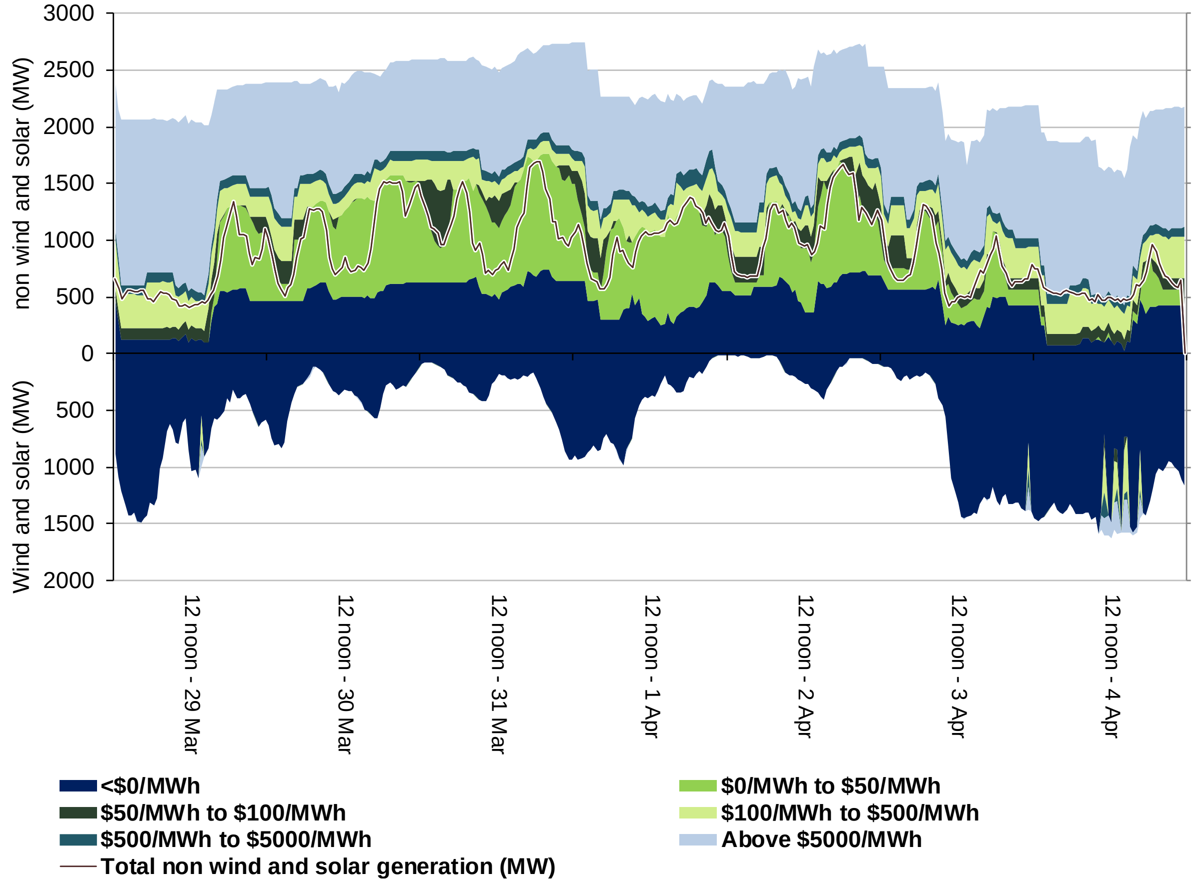
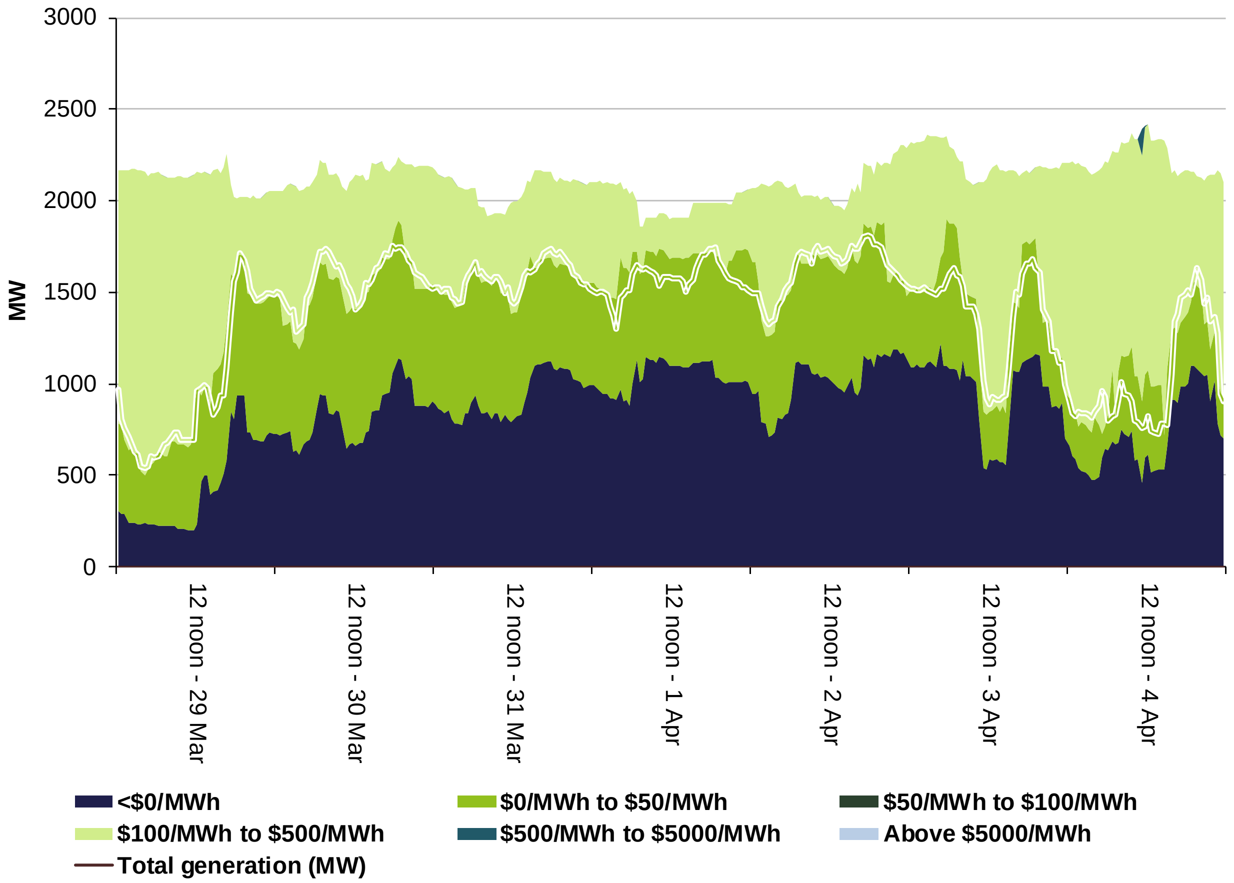


Figure 7: Tasmania generation and bidding patterns



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.

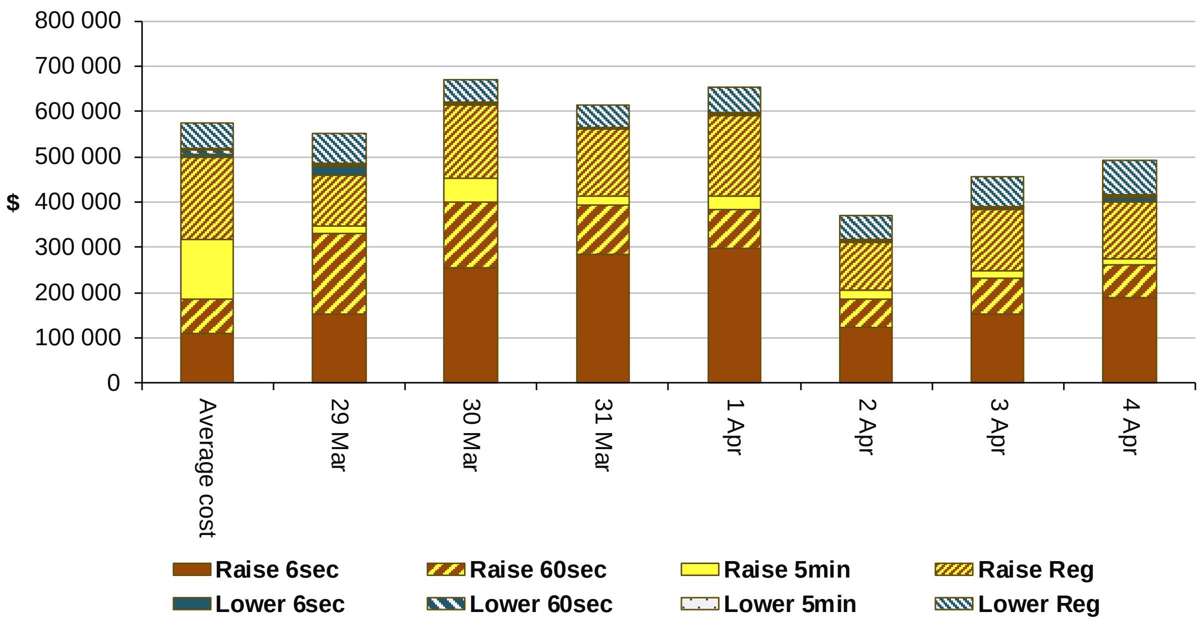
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 496 500 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $311 000 or around 5 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

South Australia

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

Sunday, 29 March

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
2 pm	-109.75	29.37	25.46	669	626	619	3047	3002	3028

Demand and availability were both higher forecast, four hours prior. At 1.35 pm, wind generation increased by 85 MW and with higher priced generation ramp down-constrained, the price fell to the floor for one dispatch interval.

Friday, 3 April

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
11.30 pm	-118.35	36.89	33.24	1159	1094	1079	3570	3396	3393

Demand and availability were both higher than forecast, four hours prior. Only two units were offering capacity at prices between $37/MWh and the price floor, small changes in demand could cause large changes in price. At 11.15 pm, demand fell by 41 MW and with higher priced generation either ramp constrained or trapped in FCAS and unable to set price, the dispatch price fell to the floor for one dispatch interval.

Saturday, 4 April

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
10.30 am	-157.50	30.21	7.96	671	782	798	3226	3216	3246
11.30 am	-151.35	12.87	7.89	713	682	687	3236	3237	3248
1 pm	-146.22	0.33	0	660	604	606	3185	3004	3227
1.30 pm	-145.99	-1000	0	712	585	599	3217	3013	3220
2.30 pm	-134.67	-1000	0	695	568	637	3210	3189	3198
3 pm	-152.71	-1000	0	696	628	678	3210	3181	3178

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
5 pm	-122.34	29.99	31.07	1068	965	995	3475	3245	3232

For the 10.30 am trading interval, demand was 111 MW lower than forecast while availability was close to forecast, four hours prior. Demand fell by over 200 MW throughout the trading interval and with little generation offered between $30/MWh and the price floor, the dispatch price fell to -$1000/MWh at 10.30 am.

For the 11.30 am trading interval, demand was 31 MW higher than forecast while availability was close to forecast, four hours prior. With only 10 MW of generation offered between $0/MWh and the price floor, small changes in demand or availability can lead to large changes in price. At 11.20 am, demand fell by 30 MW, resulting in the dispatch price falling to -$1000/MWh for one dispatch interval.

For the 1 pm trading interval, demand and availability were both higher than forecast, four hours prior. Effective 12.35 pm, Infigen rebid 132 MW of capacity at Lake Bonney wind farm from $12 879/MWh to the price floor causing the dispatch price to fall to -$1000/MWh once. In response to the price falling to the floor, participants then rebid capacity from low to high prices.

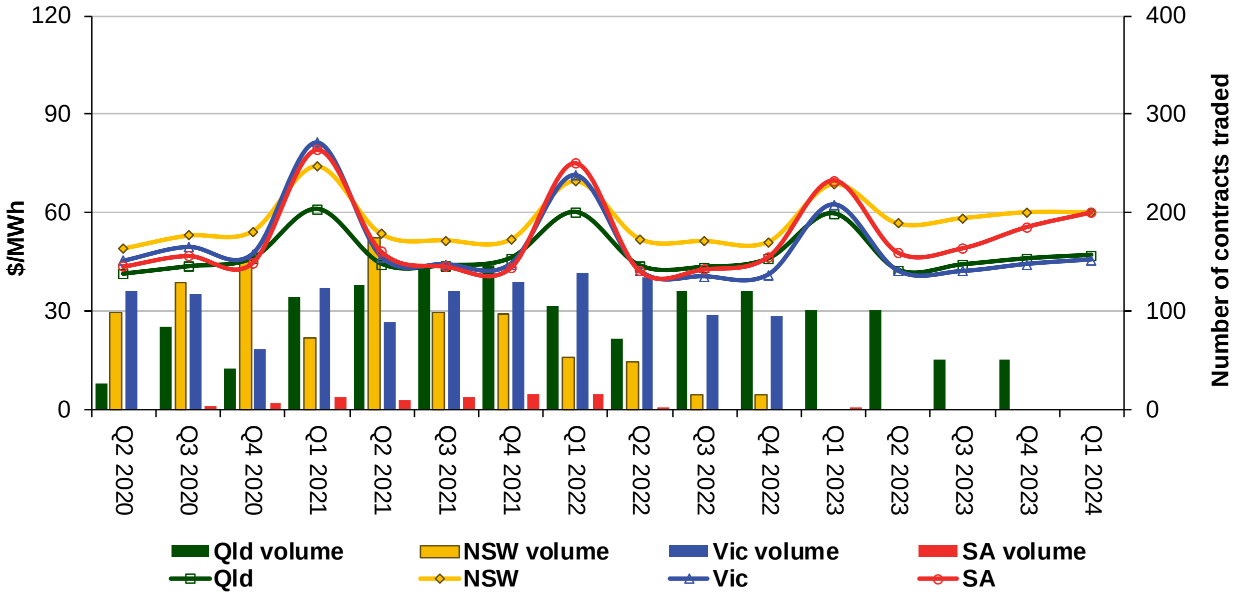
For the 1.30 pm, 2.30 pm and 3 pm trading intervals, demand and availability were both higher than forecast, four hours prior. The dispatch price fell to the price floor, as forecast, once in each trading interval. In response, participants rebids more than 1000 MW from -$1000/MWh to more than $50/MWh in each trading interval.

For the 5 pm trading interval, demand and availability were both higher than forecast, four hours prior. Higher than forecast availability was mostly due to higher than forecast wind. In the first dispatch interval, a sudden increase in wind generation caused the dispatch price to fall to -$1000/MWh once. In response to the price falling to the floor, participants then rebid capacity from low to high prices.

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.

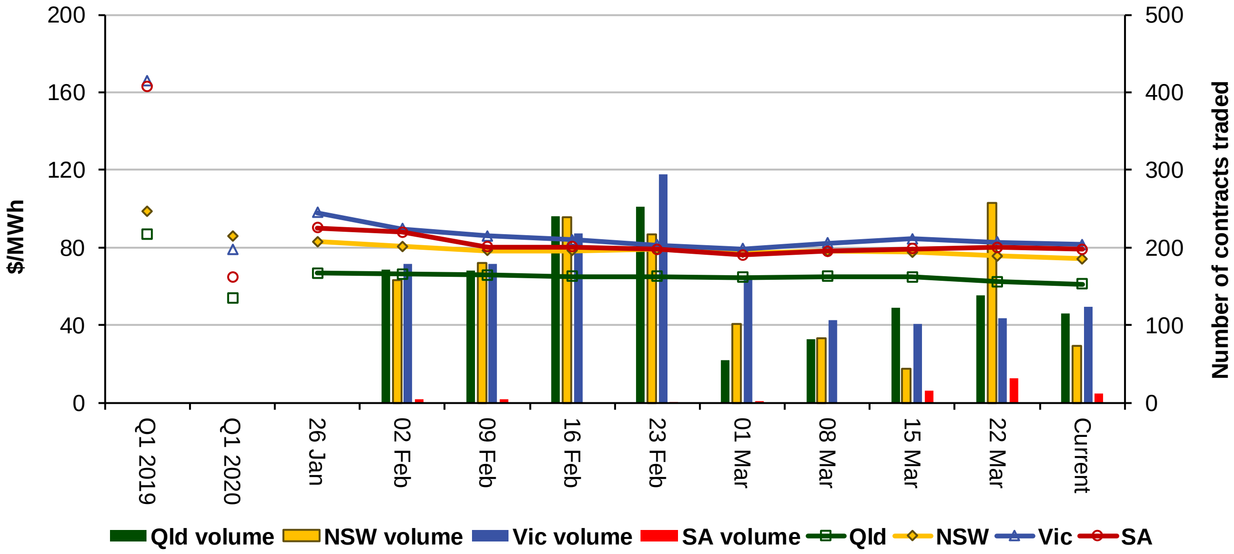
Figure 9: Quarterly base future prices Q2 2020 – Q1 2024



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2021 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 2021 base contracts over the past 10 weeks (and the past 2 years)

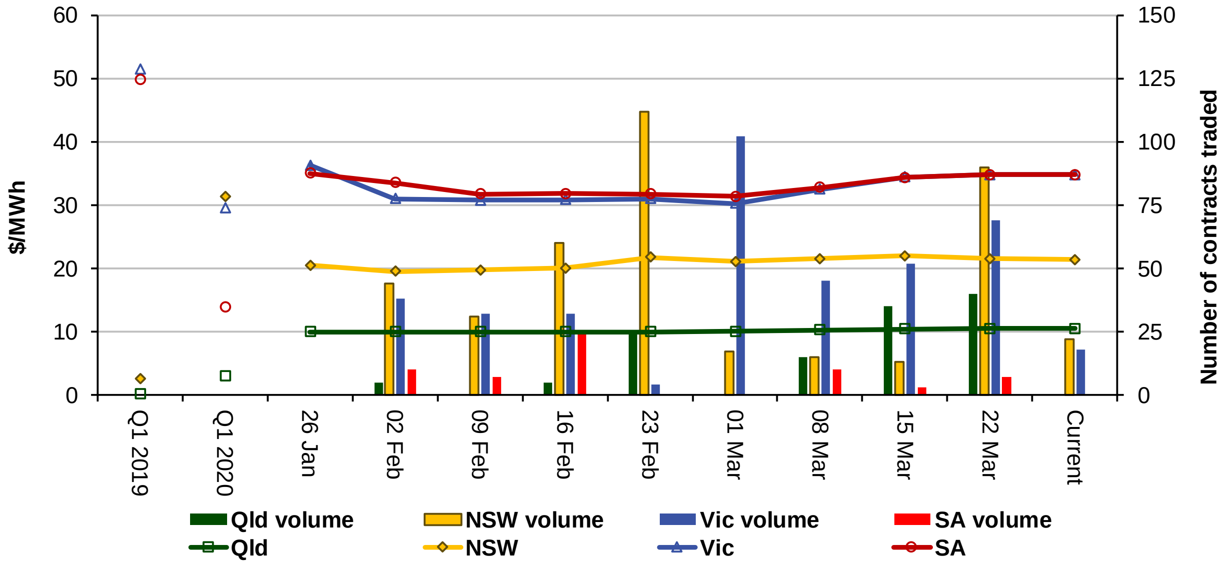


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional quarter 1 2021 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 2021 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the industry statistics section of our website.

Australian Energy Regulator
April 2020