Electricity Report

AUSTRALIAN ENERGY REGULATOR

17 – 23 May 2020

Weekly Summary

Volume weighted average prices for the week ranged from $41/MWh in Tasmania and Queensland to $50/MWh in New South Wales.

Quarterly base future contracts trades for Q1 2021 continued to increase as more than 2800 regional contracts were traded this week, following 820 trades in the previous week.

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 17 to 23 May 2020.

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

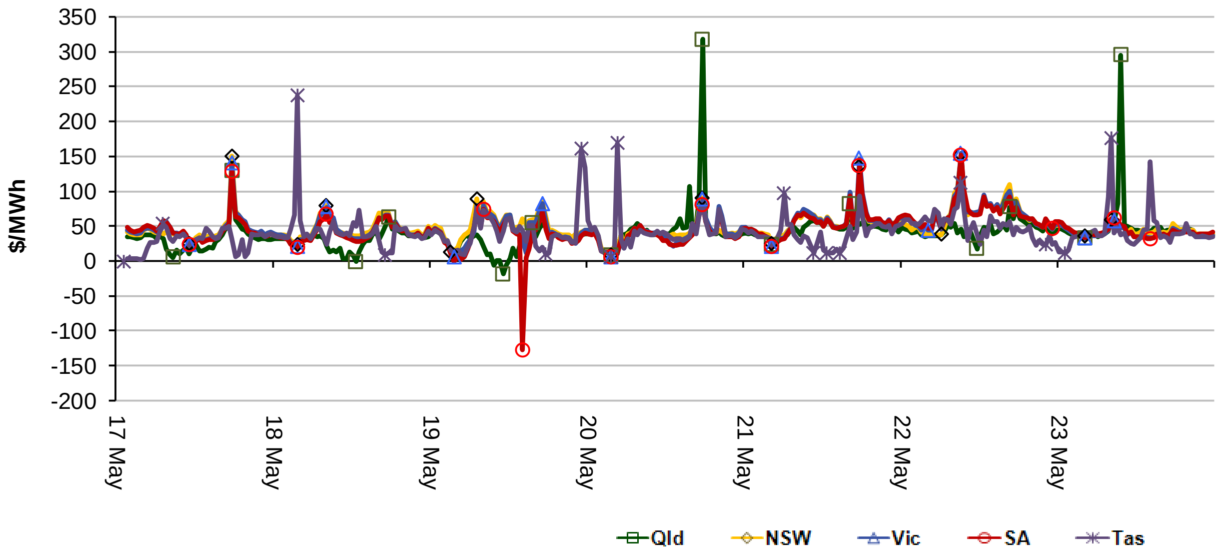


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

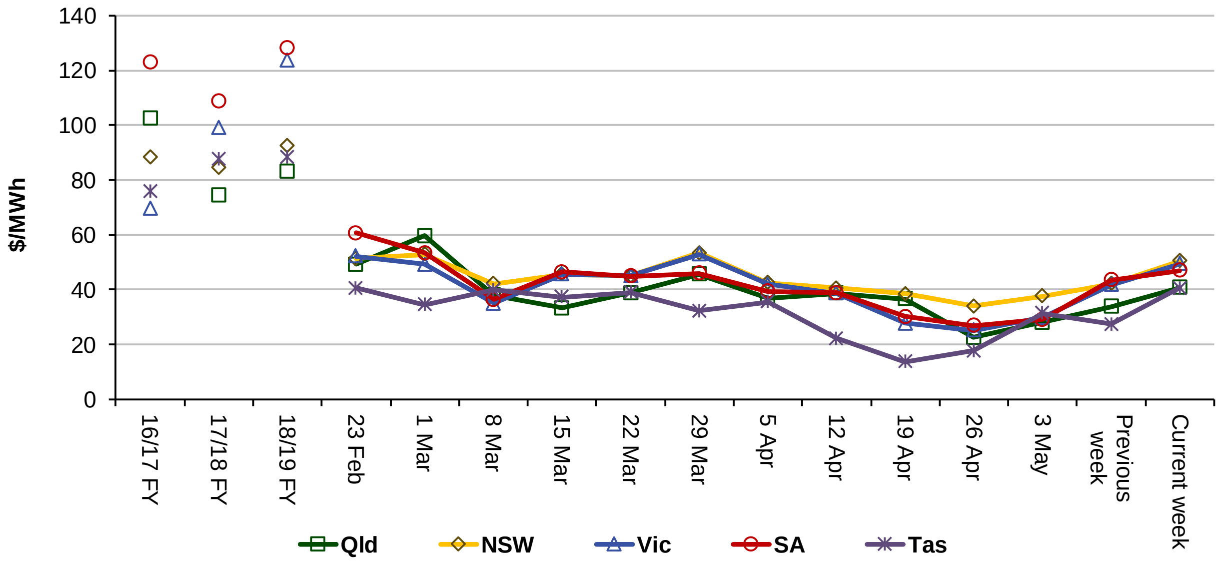


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	41	50	49	47	41
Q2 2019 (QTD)	72	81	99	93	101
Q2 2020 (QTD)	35	42	38	37	27
18-19 financial YTD	83	92	126	132	87
19-20 financial YTD	58	83	89	76	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 194 trading intervals throughout the week where actual prices varied significantly from forecasts. 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	7	32	0	2
% of total below forecast	10	29	0	19

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

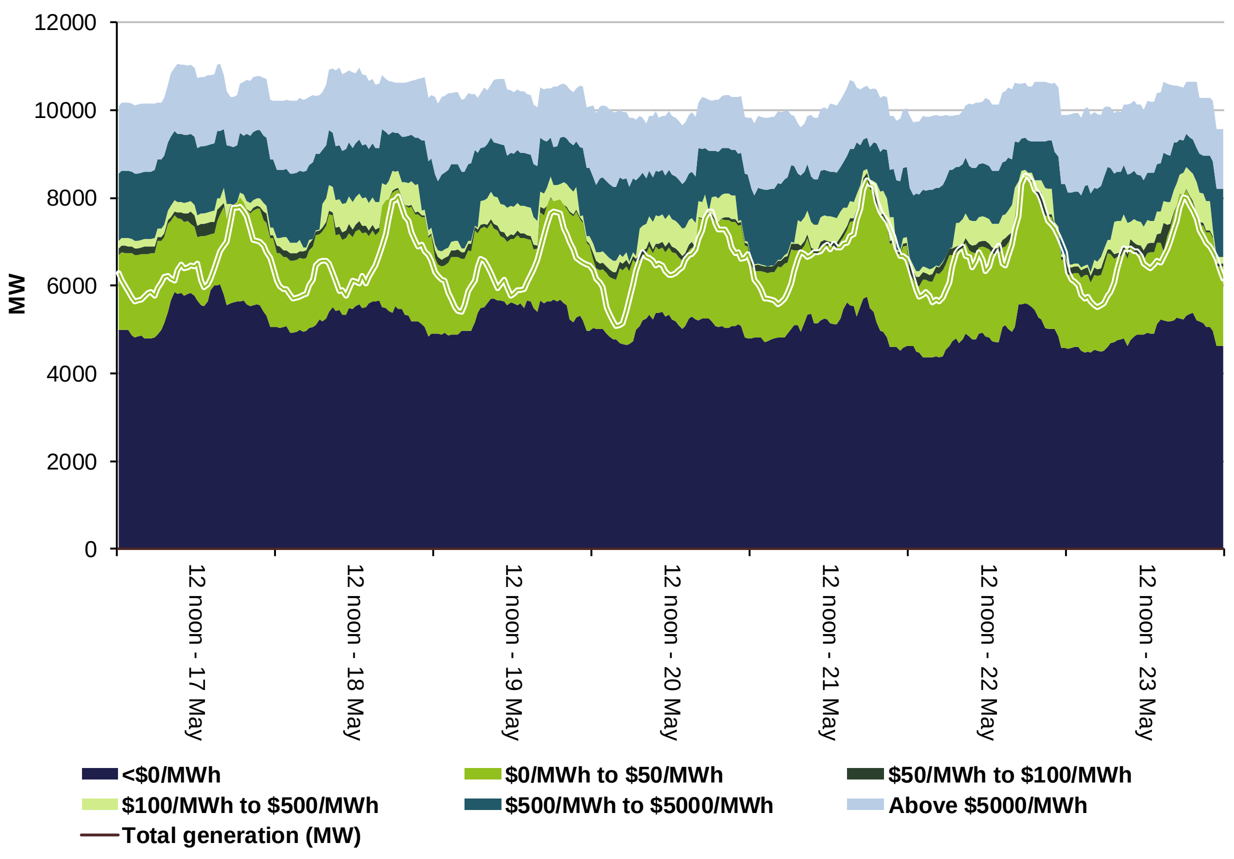


Figure 4: New South Wales generation and bidding patterns

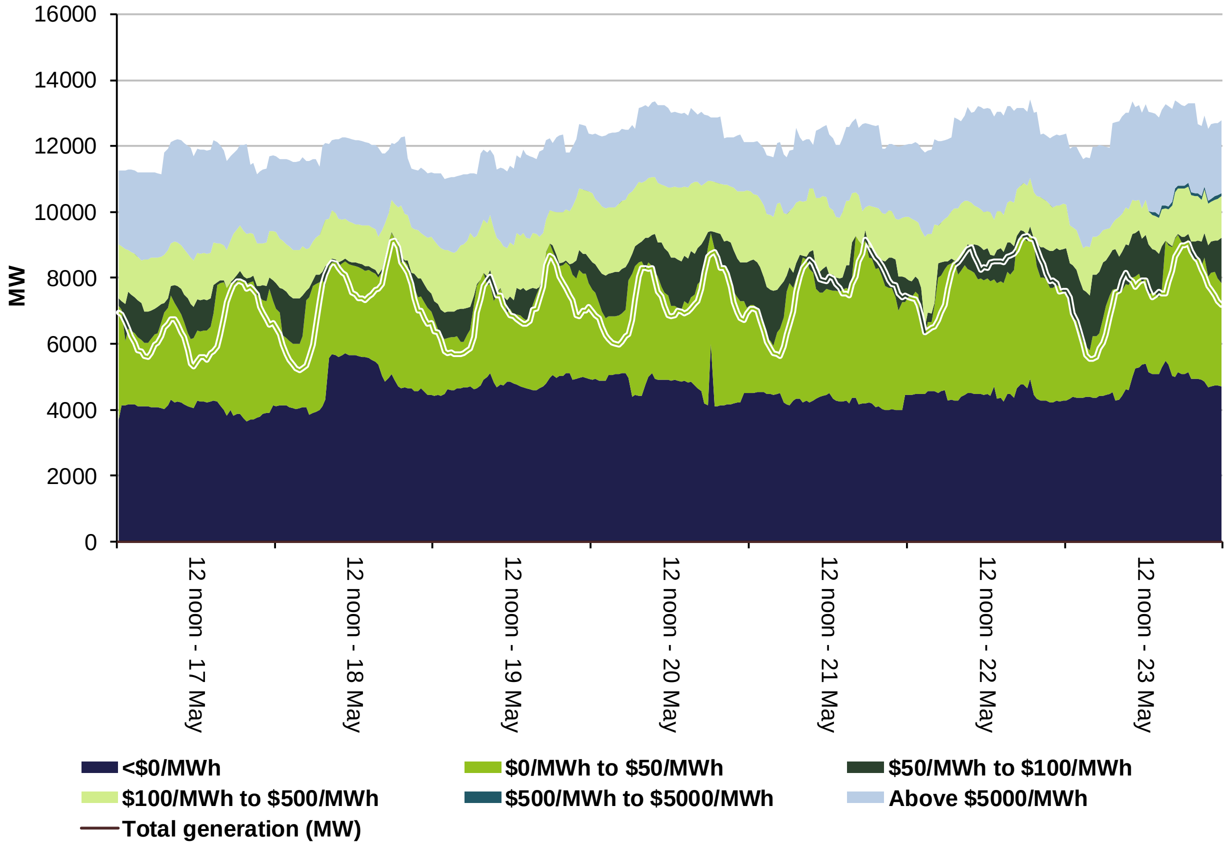


Figure 5: Victoria generation and bidding patterns

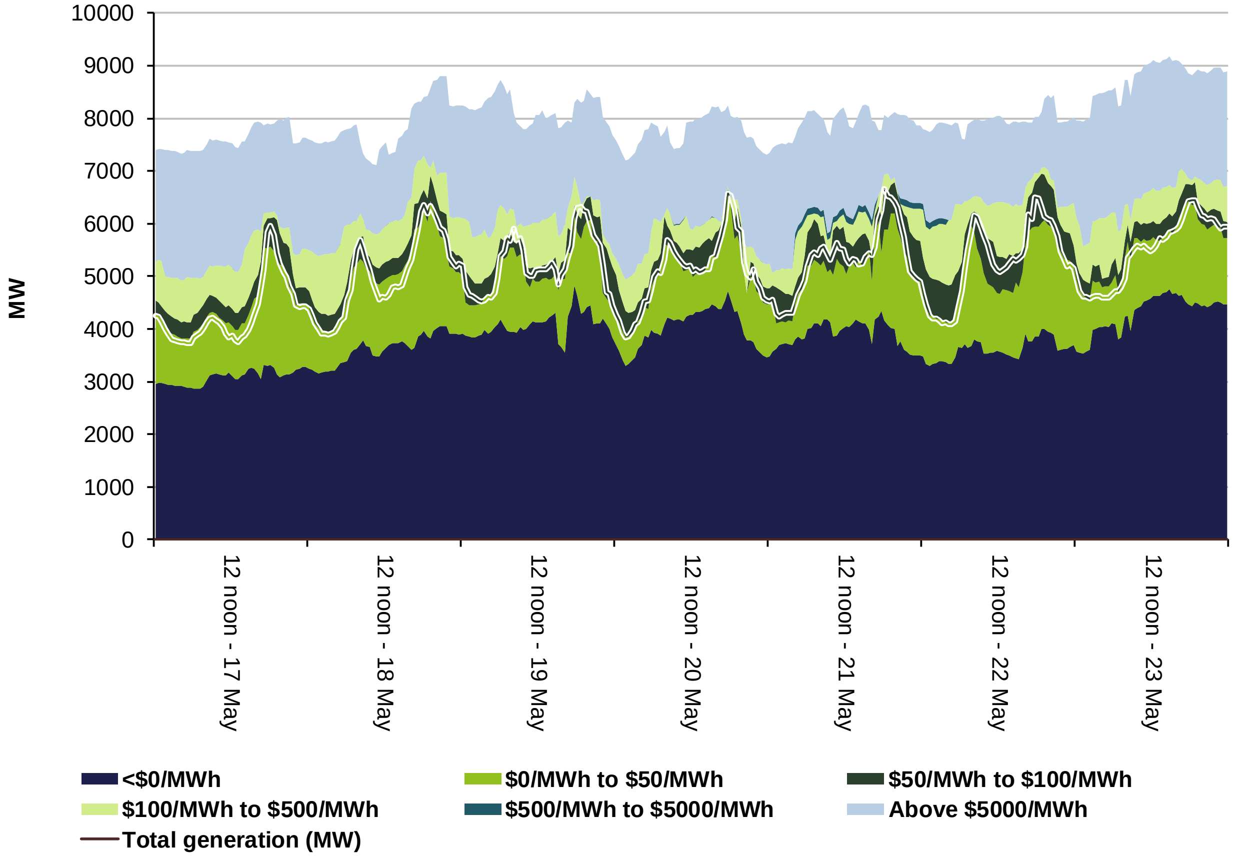


Figure 6: South Australia generation and bidding patterns

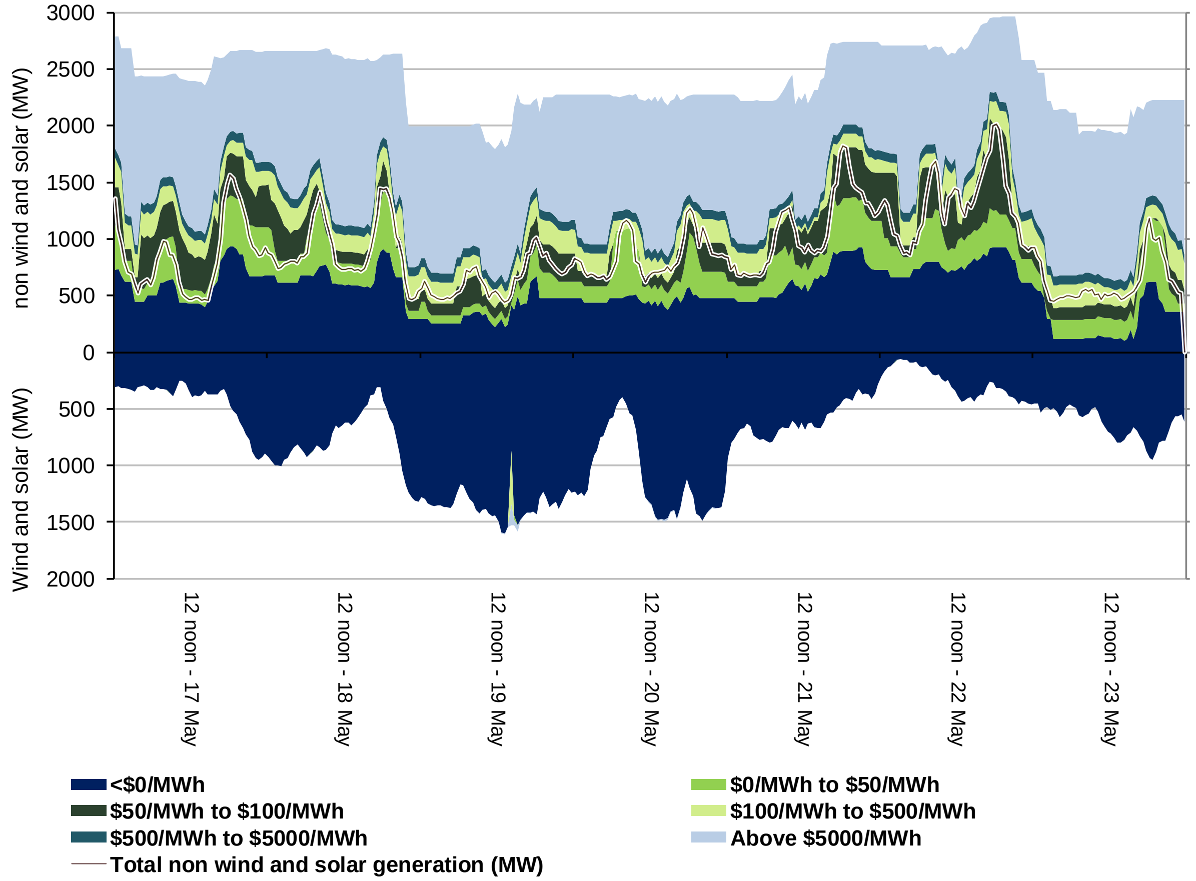
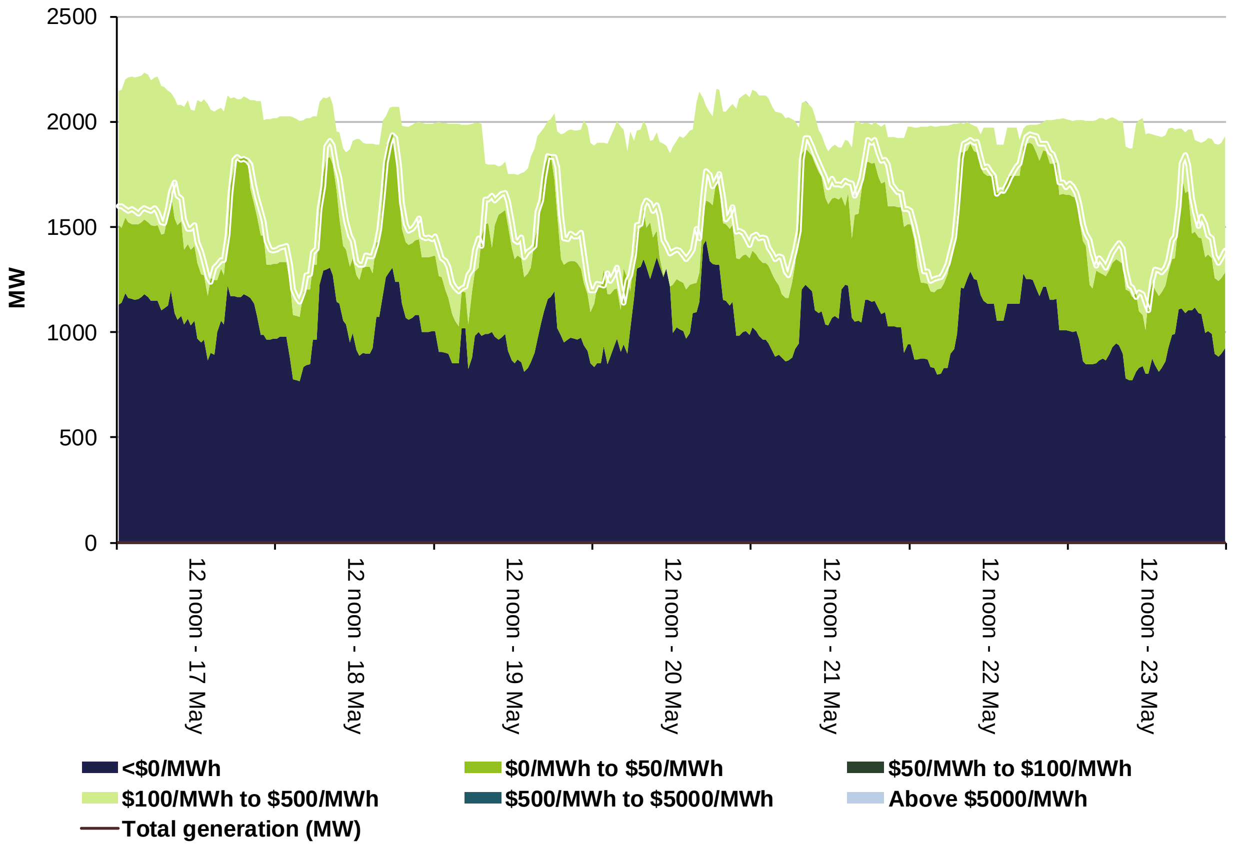


Figure 7: Tasmania generation and bidding patterns



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.

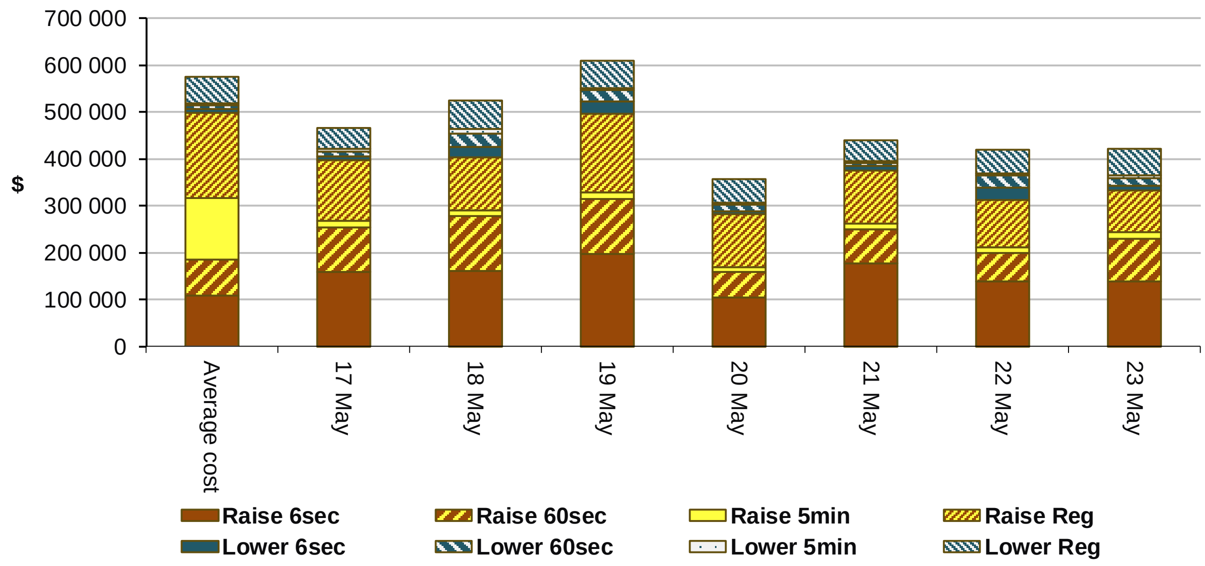
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 949 500 or less than 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $286 500 or less than 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 greater than three times the Queensland weekly average price of $41/MWh and above $250/MWh.

Wednesday, 20 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
6 pm	317.47	115.11	48.45	7289	7207	7230	10 226	10 382	10 594

Demand was 82 MW higher than forecast while availability was 156 MW lower than forecast, four hours prior. Lower than forecast availability was due to the unavailability of cheap-priced capacity.

Leading up to the 6 pm trading interval, rebids by Gladstone and CleanCo due to technical reasons shifted 310 MW from below $115/MWh either above $3500/MWh or out of the market. At 5.55 pm, demand increased by 95 MW, and with several generators either turned off or at maximum capacity, the price rose to $1419/MWh for one dispatch interval.

Saturday, 23 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
10 am	294.96	37.73	44.56	6537	5960	6066	10 145	10 376	10 323

Demand was 577 MW higher than forecast while availability was 231 MW less than forecast, four hours prior. Lower than forecast availability was due to lower than forecast solar generation.

The combination of higher than forecast demand and lower than forecast availability resulted in price being set above forecast, four hours prior.

South Australia

There was one occasion where the spot price in South Australia was below -$100/MWh.

Tuesday, 19 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
2.30 pm	-128	35.93	26.72	938	895	859	3488	3209	3226

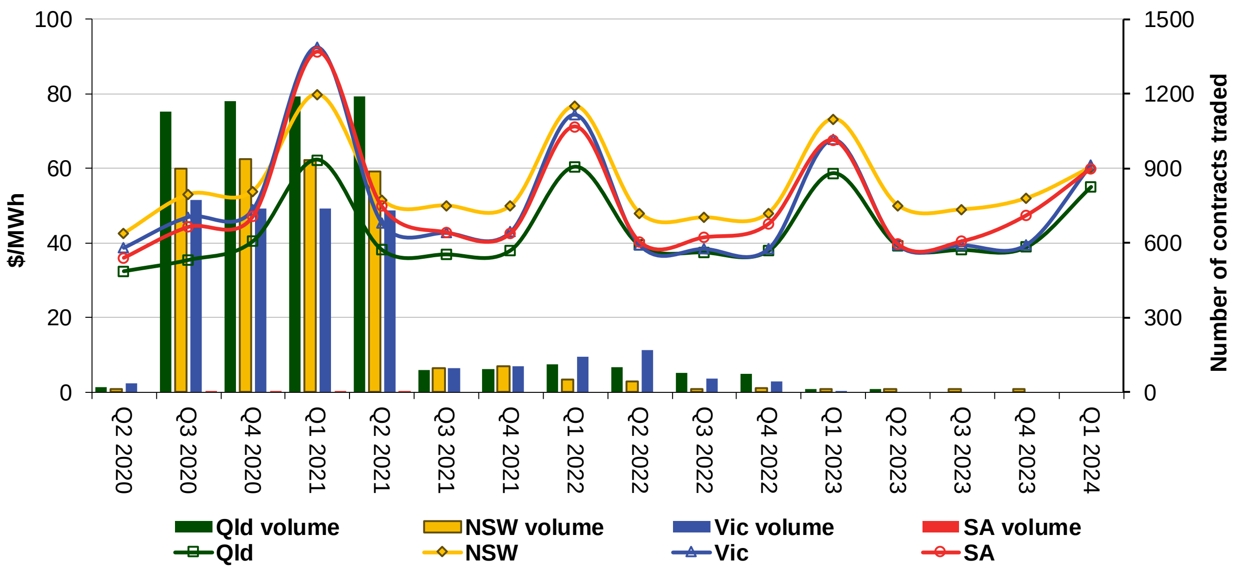
Demand was close to forecast while availability was 279 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation and rebids by Pelican Point adding 116 MW due to changes in forecast prices, priced at the floor.

During the first two dispatch intervals, 270 MW was rebid to the floor by Trustpower from prices above $-39/MWh in response to binding constraints on its generators. With higher than forecast low-priced generation, the price fell to the floor for one dispatch interval. In response, participants rebid 740 MW into higher price bands.

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.

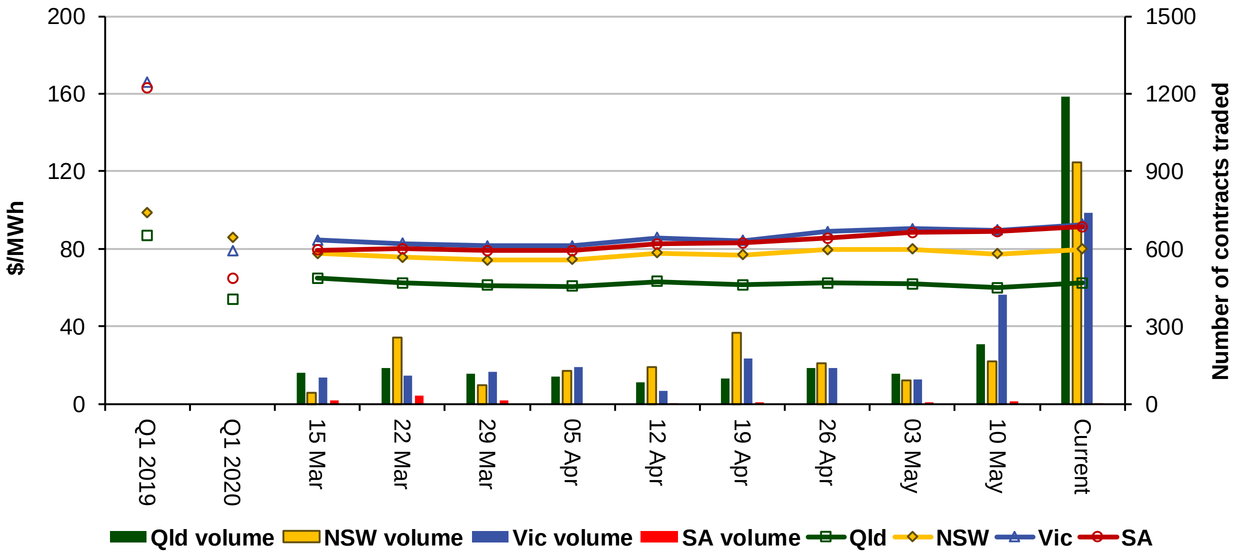
Figure 9: Quarterly base future prices Q2 2020 – Q1 2024



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 Q1 2020 and Q 1 2019 prices are also shown. The high volume of trades in Figure 10 is the result of the conversion of base load options to base future contracts on 19 May. 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)

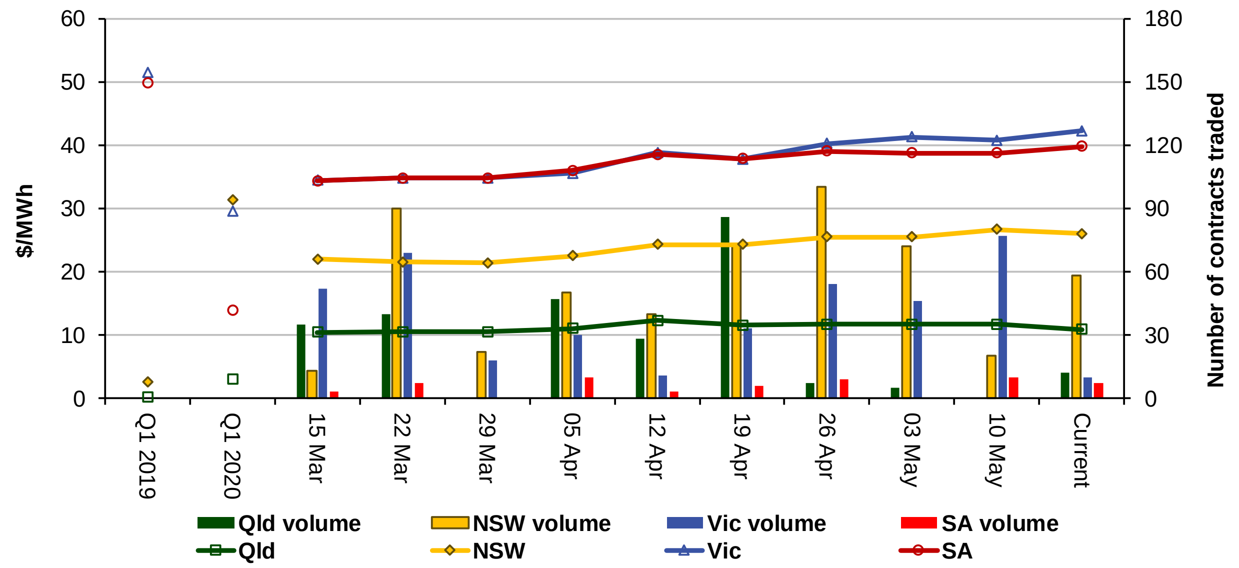


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2020 and Q1 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
June 2020