Electricity Report

AUSTRALIAN ENERGY REGULATOR

26 April – 2 May 2020

Weekly Summary

Spot prices ranged from -$702/MWh in Queensland to $147/MWh in Tasmania.

On 30 April there was an unplanned outage of the Armidale to Tamworth line in New South Wales which reduced exports from Queensland to New South Wales. This resulted in a series of negative prices in Queensland on 1 and 2 May which are discussed in our detailed market analysis section below.

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 26 April to 2 May 2020.

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

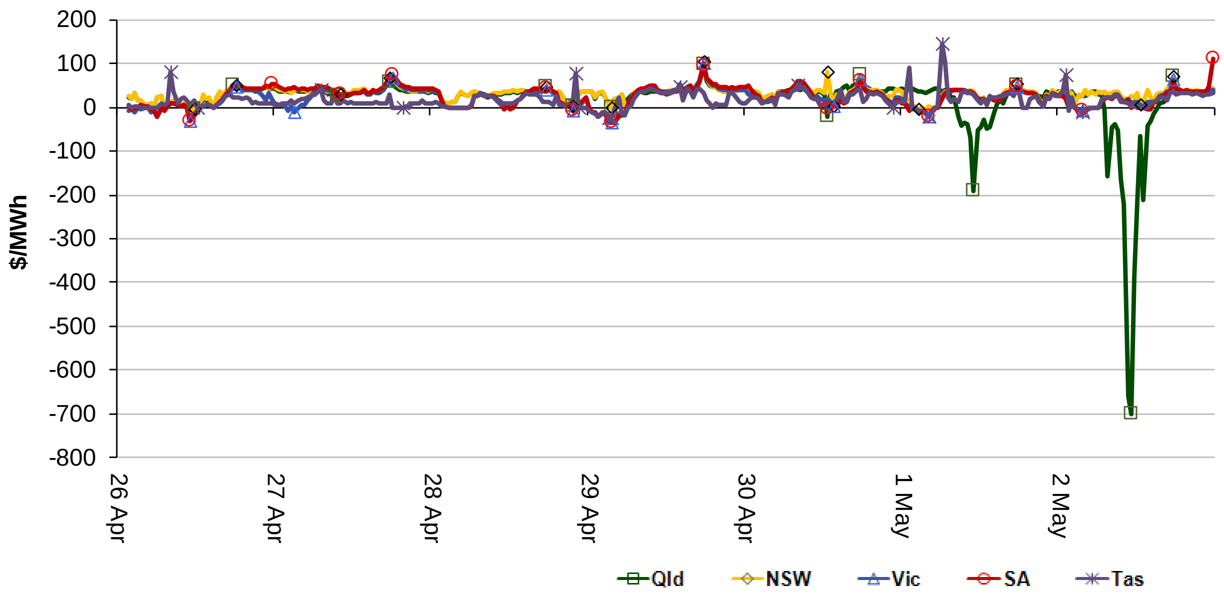


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

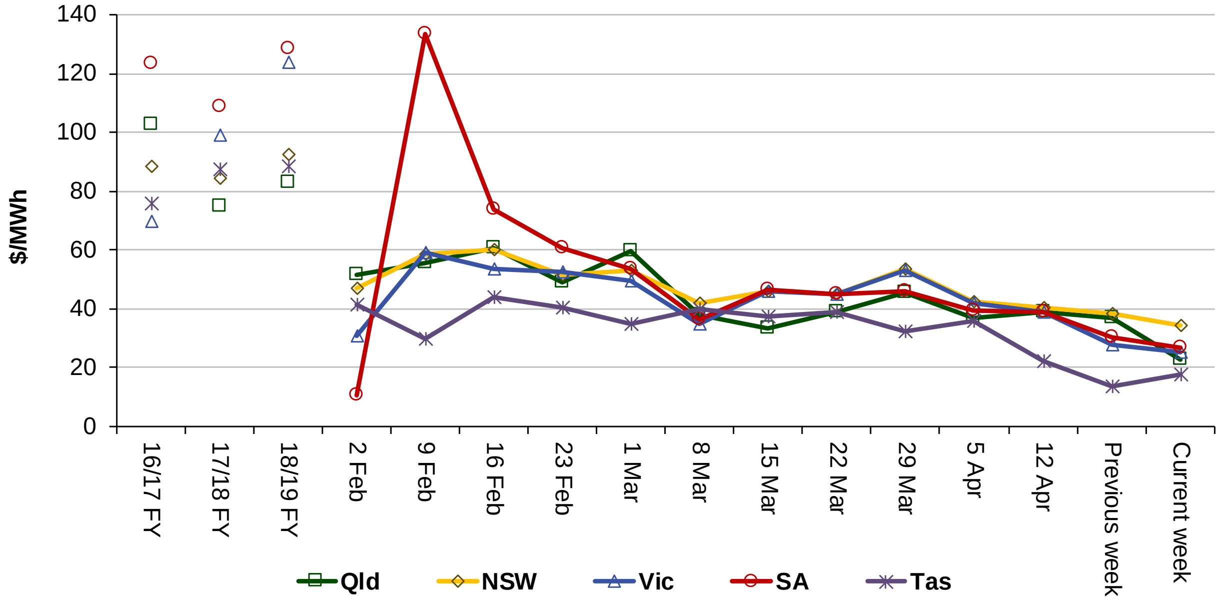


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	23	34	25	27	18
18-19 financial YTD	83	93	128	135	87
19-20 financial YTD	60	85	92	79	60

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 246 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	5	39	0	1
% of total below forecast	9	33	0	13

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

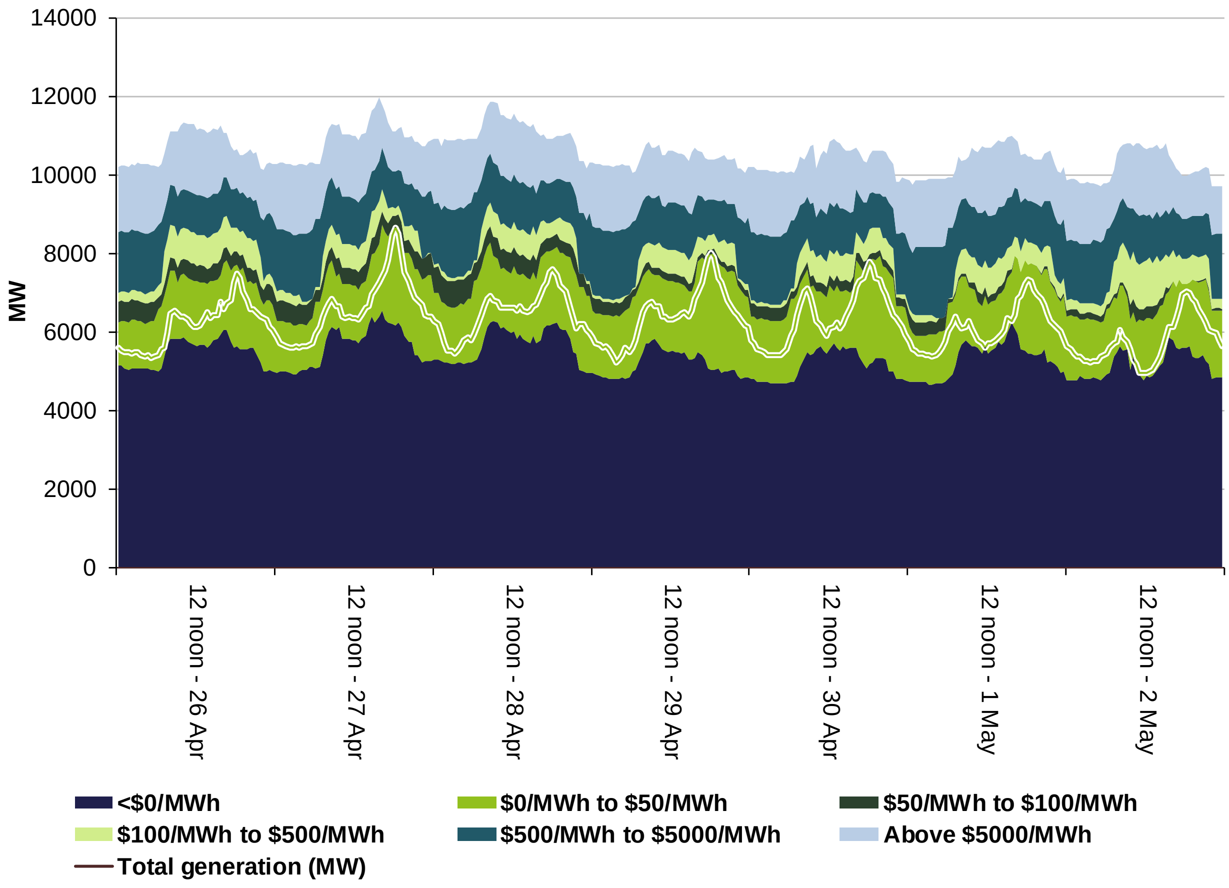


Figure 4: New South Wales generation and bidding patterns

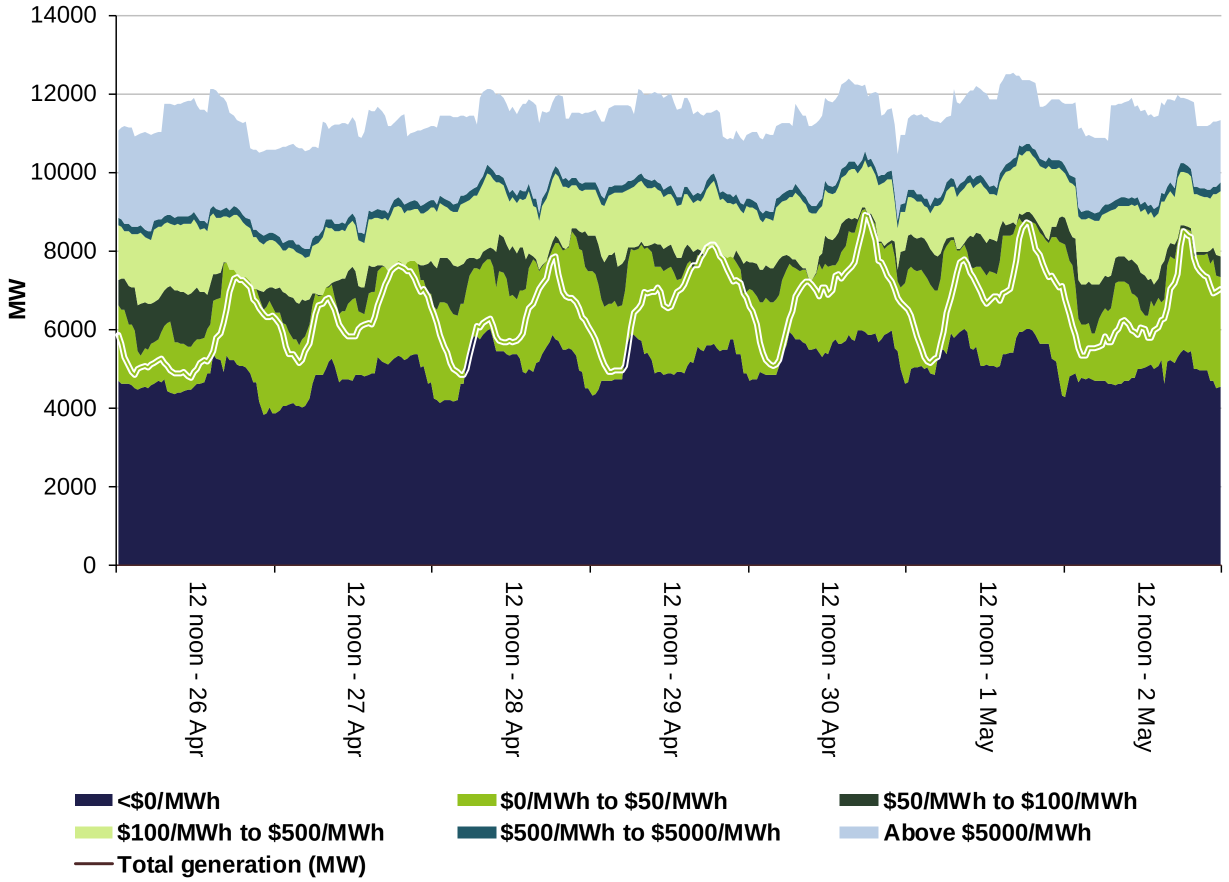


Figure 5: Victoria generation and bidding patterns

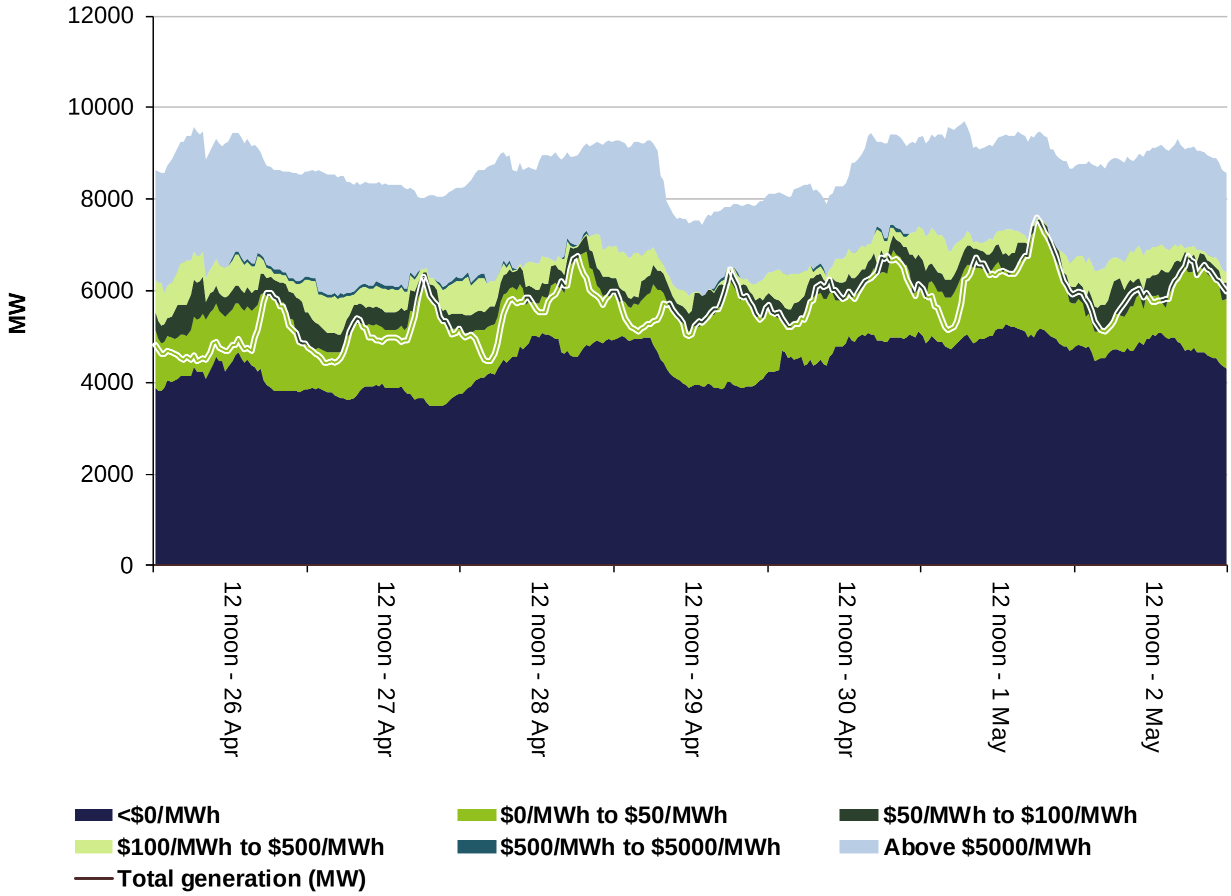


Figure 6: South Australia generation and bidding patterns

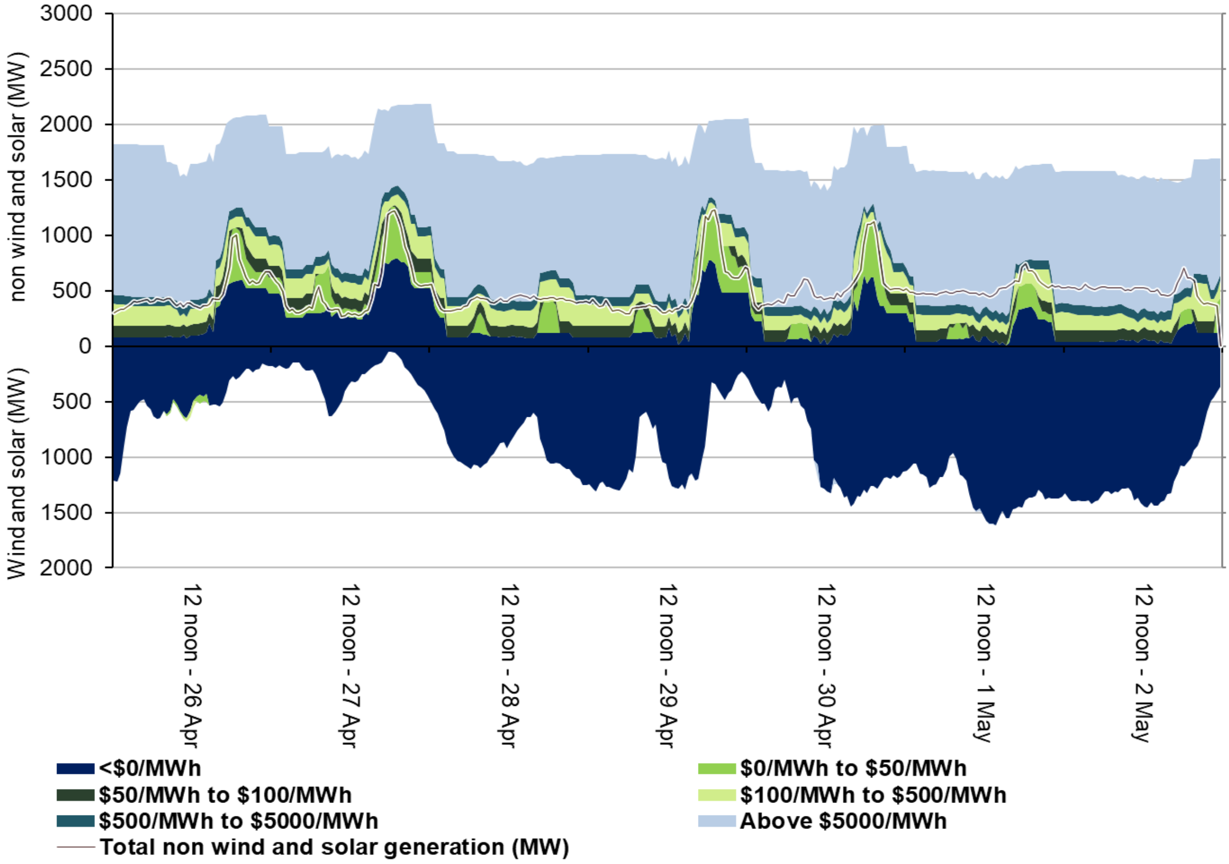
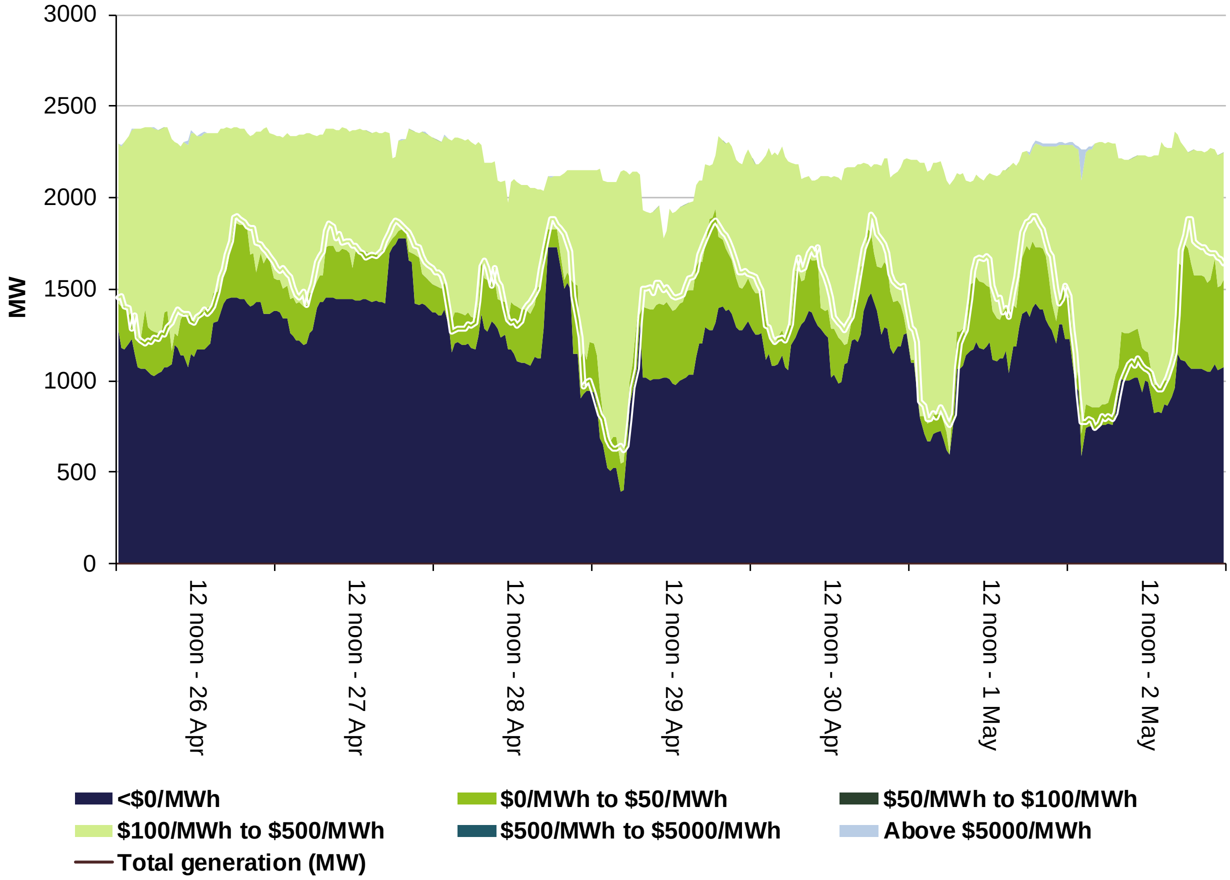


Figure 7: Tasmania generation and bidding patterns



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.

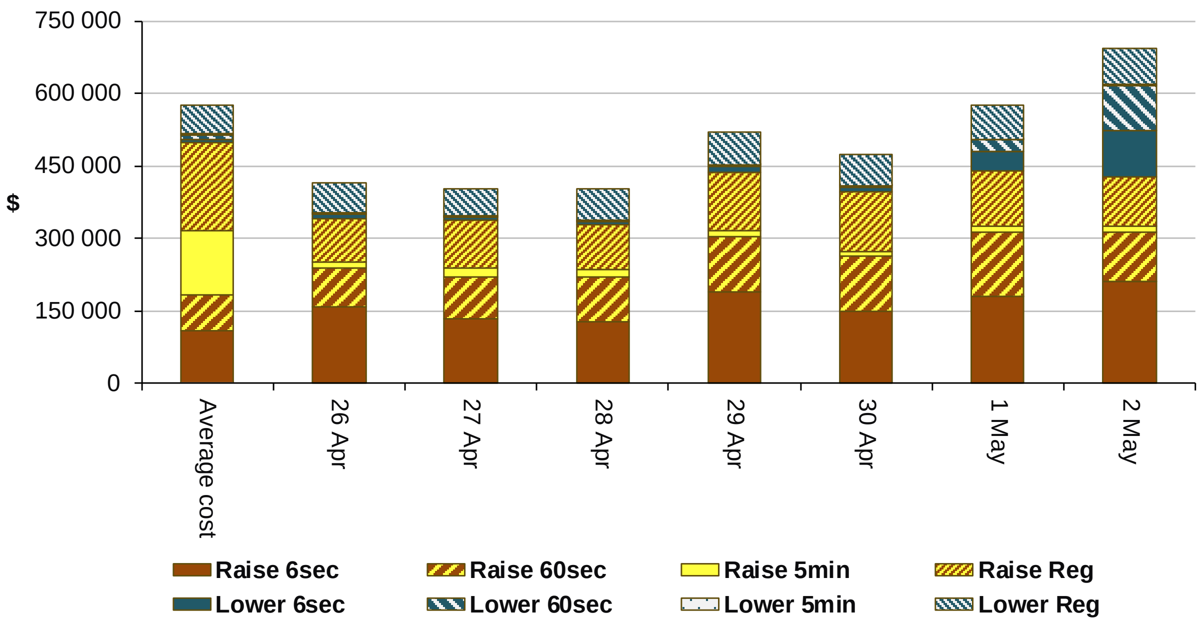
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 074 000 or around 3 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $408 500 or around 12 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 nine occasions where the spot price in Queensland was below -$100/MWh.

Friday, 1 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
11.30 am	-191.80	-31.56	-31.56	4925	5110	5116	10 754	10 844	10 826

Demand was 185 MW lower than forecast and availability was 90 MW lower than forecast, four hours prior. Reduced availability was due to removal of capacity at Condamine (84 MW priced at the floor due to market conditions) and Callide B (40 MW due to technical issues). On that day, an unplanned outage of the Armidale to Tamworth line in New South Wales limited exports from Queensland into New South Wales including during the 11.30 am trading interval.

From 8.24 am just under 200 MW of capacity was bid into the market and from prices above $12/MWh to prices below -$988/MWh, mostly in response to forecast market conditions or technical issues. These rebids combined with limited exports caused the dispatch price to be set at -$980/MWh in the first dispatch interval. In response, participants rebid almost 380 MW of capacity from prices below -$85/MWh to prices above -$1/MWh.

Saturday, 2 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
8 am	-157.82	18.75	18.75	5261	5409	5422	10 562	10 424	10 412
10 am	-163.56	-52.21	-31.56	4797	4831	4882	10 838	10 755	10 757
10.30 am	-222.84	-31.56	-23.27	4629	4731	4815	10 764	10 617	10 644
11 am	-661.87	-52.21	-31.56	4476	4642	4725	10 829	10 620	10 627
11.30 am	-701.65	-72.05	-52.21	4341	4555	4648	10 840	10 614	10 606
Midday	-389.50	-72.05	-52.21	4348	4493	4593	10 712	10 605	10 590
12.30 pm	-219.33	-975.55	-72.05	4353	4466	4573	10 742	10 758	10 742
1.30 pm	-210.65	-72.05	-52.21	4453	4531	4629	10 788	10 718	10 736

Demand was between 34 MW to 214 MW lower than forecast while availability was up to 226 MW higher than forecast, four hours prior. Higher availability was due to 170 MW of capacity added in by at Callide C between the floor and $41/MWh.

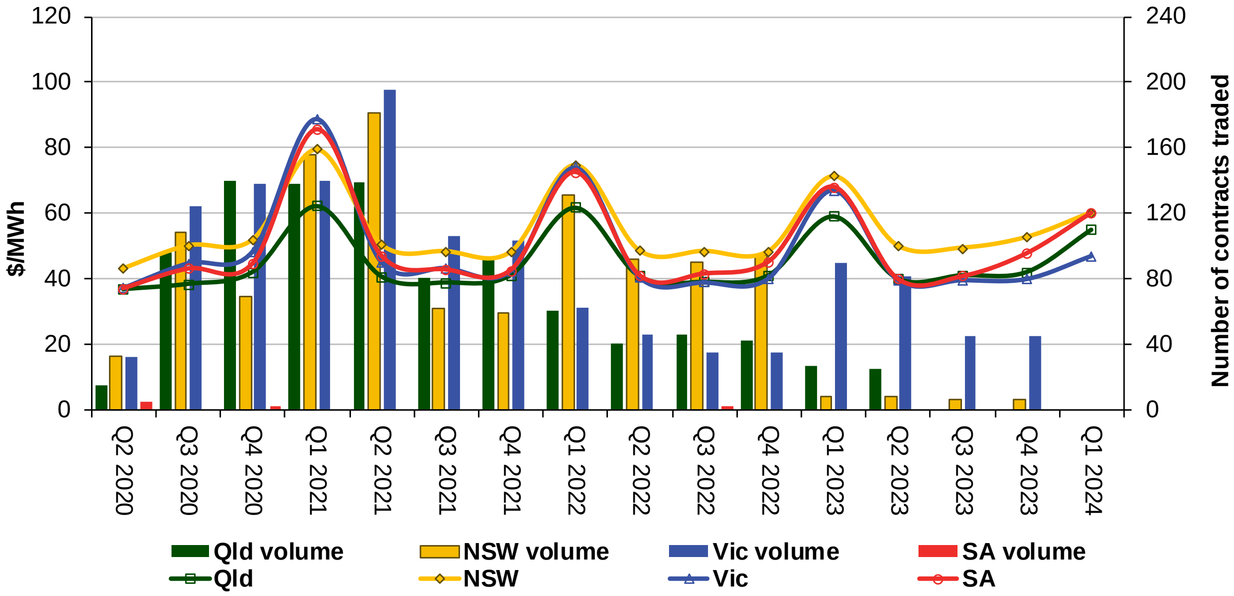
The continued outage of the Armidale to Tamworth line in New South Wales limited exports from Queensland into New South Wales. This resulted in flows being up to 270 MW lower than forecast.

These factors combined resulted in the price dropping to the floor for at least one dispatch interval in each of the above trading intervals as generators were either ramp down constrained or completely constrained off. In response, participants rebid upwards of 460 MW of capacity back to higher 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.

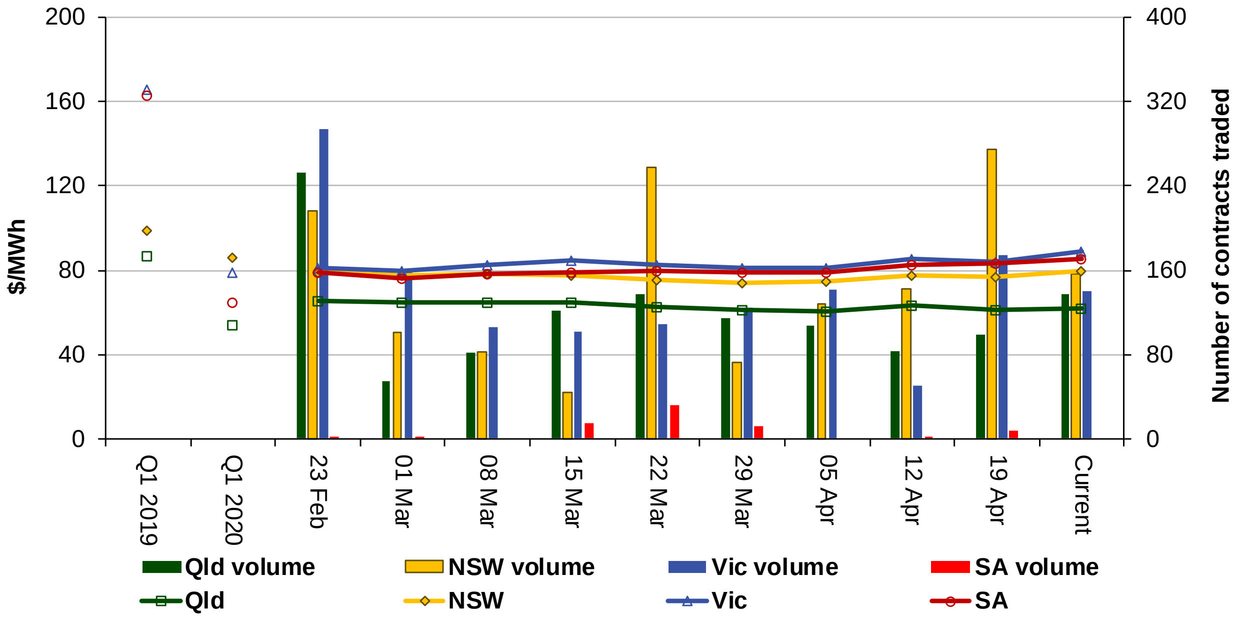
Figure 9: Quarterly base future prices Q2 2020 – Q1 2024



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 2019 and quarter 1 2020 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)

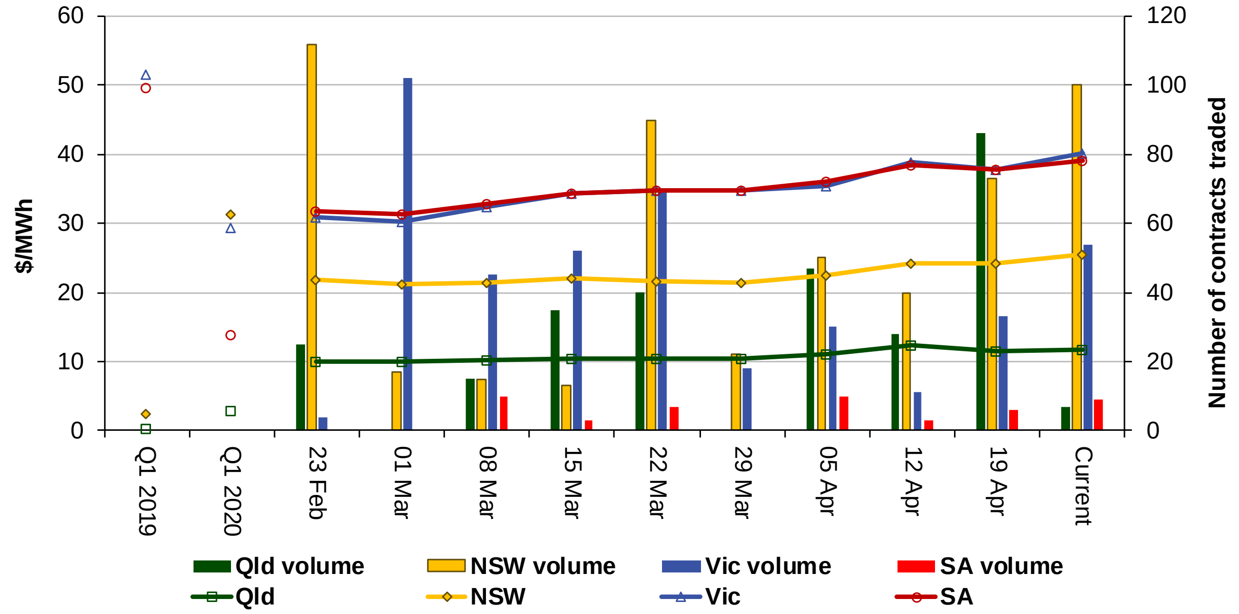


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2019 and quarter 1 2020 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
May 2020