Electricity Report

AUSTRALIAN ENERGY REGULATOR

21 – 27 February 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $22/MWh in Victoria to $52/MWh in Queensland. 2020-21 financial year to date prices ranged from $40/MWh in South Australia to $54/MWh in New South Wales, down from $65/MWh in Queensland to $105/MWh in Victoria a year ago.

The Heywood interconnector between Victoria and South Australia was taken offline to undergo maintenance on 25 February 2021. This resulted in more volatile prices in South Australia for the second half of the week as the region needed to source generation locally.

Despite 3 spot prices above $300/MWh in Queensland, cap contract trades for the region remained low.

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 21 to 27 February 2021.

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

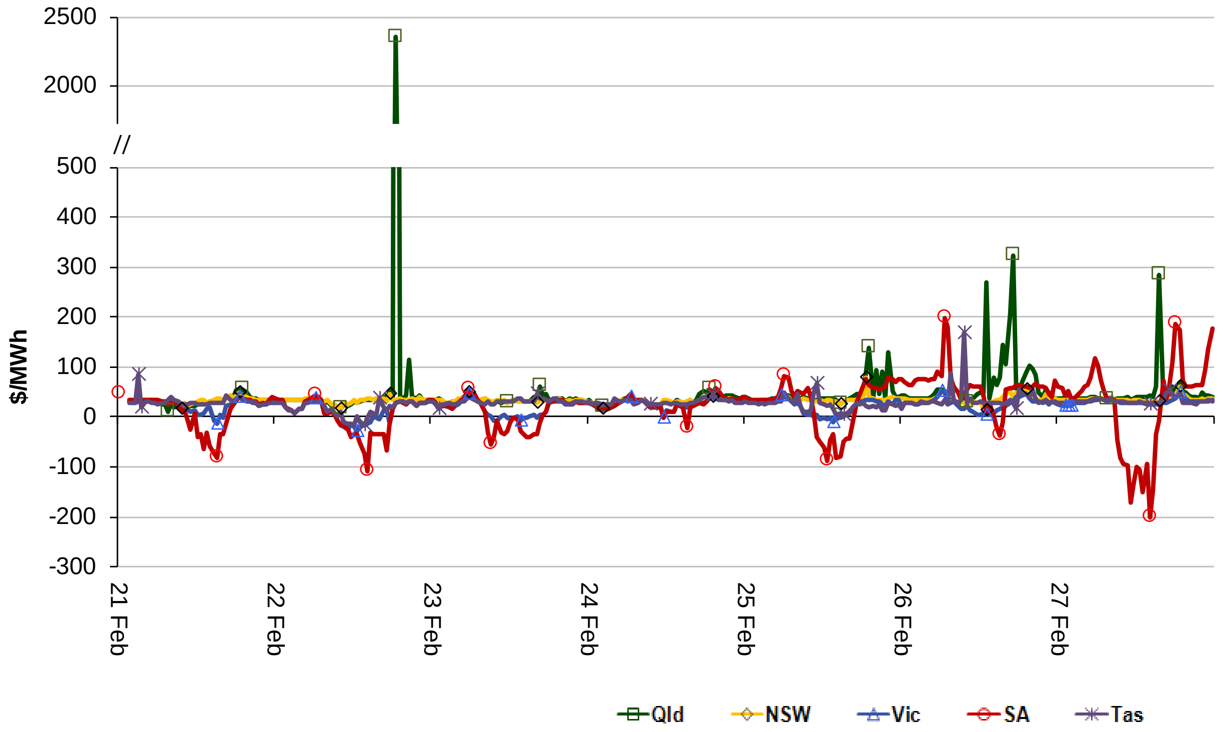


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in

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)

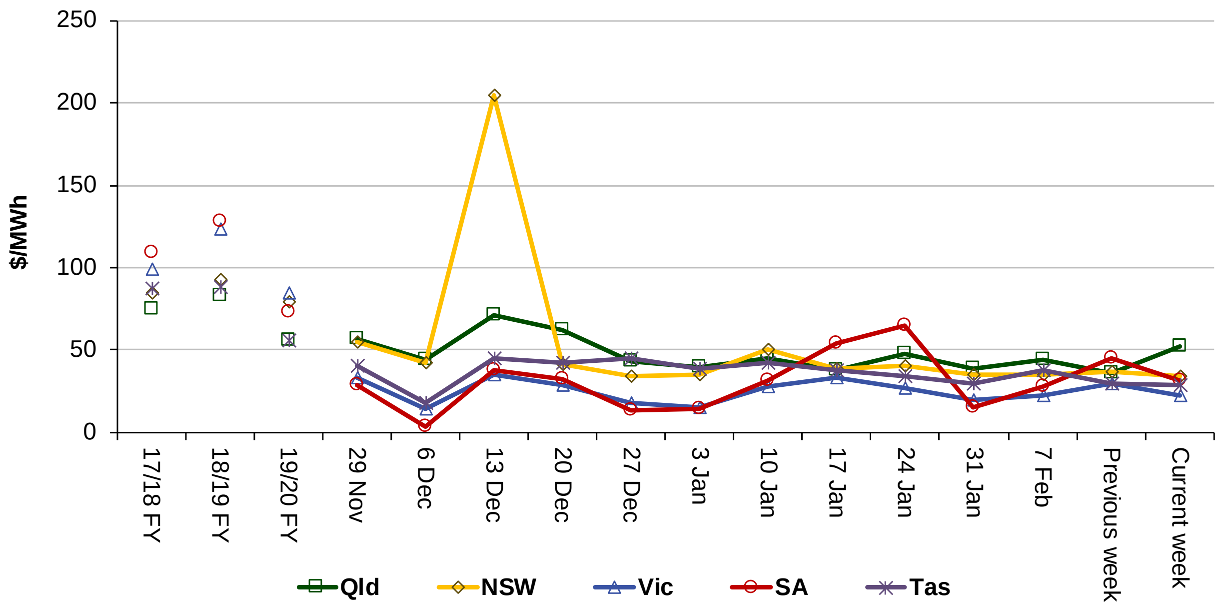


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	52	34	22	31	29
Q1 2020 (QTD)	64	138	142	98	48
Q1 2021 (QTD)	42	38	24	36	35
19-20 financial YTD	65	95	105	88	67
20-21 financial YTD	42	54	42	40	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 241 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2020 of 233 counts and the average in 2019 of 204. 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	18	0	0
% of total below forecast	7	52	0	16

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

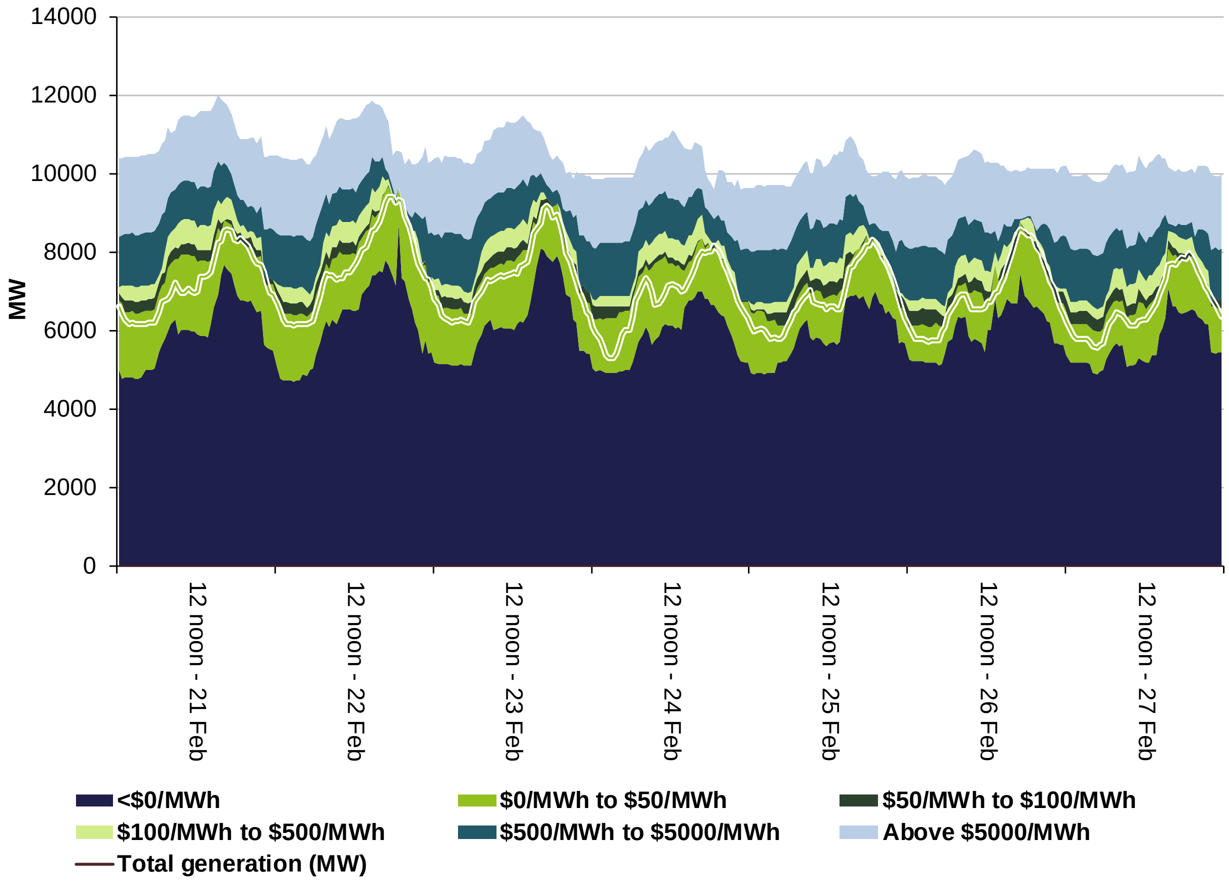


Figure 4: New South Wales generation and bidding patterns

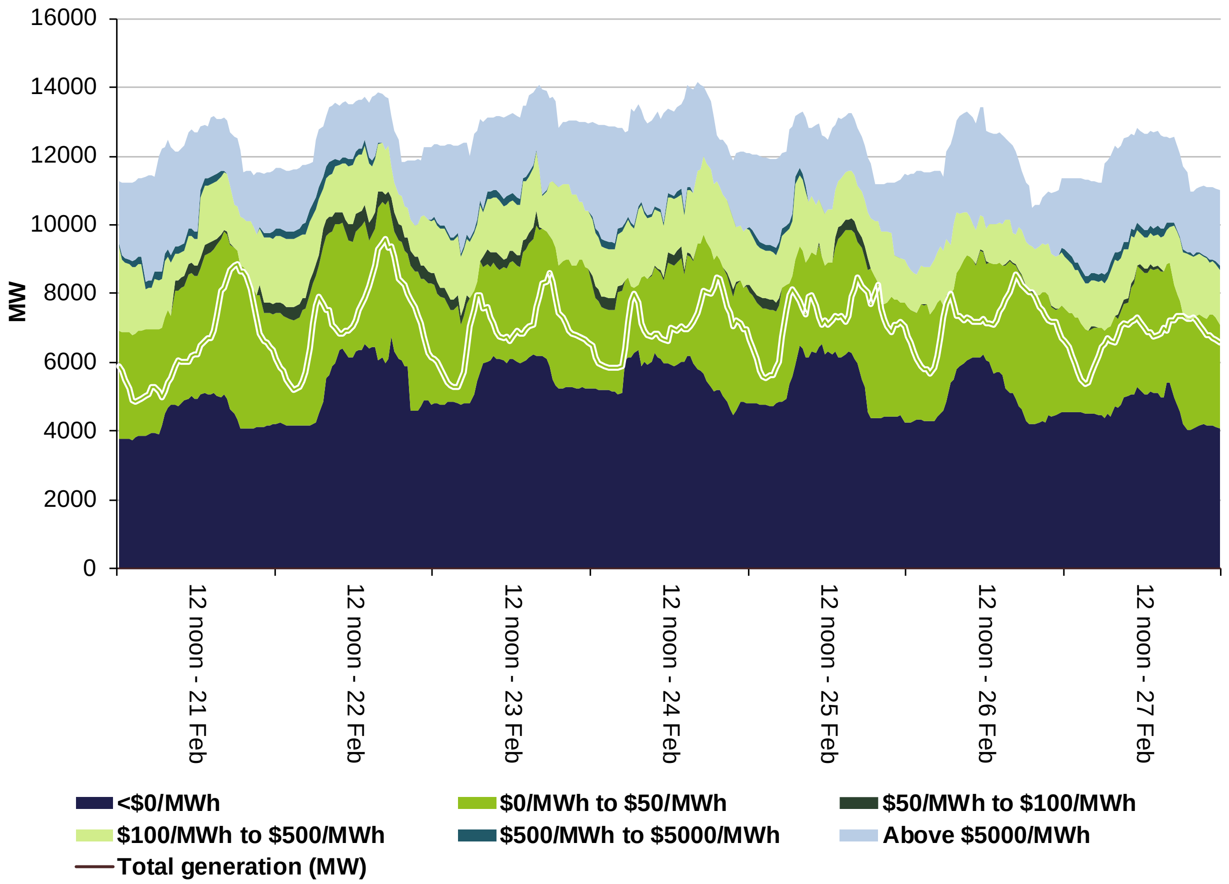


Figure 5: Victoria generation and bidding patterns

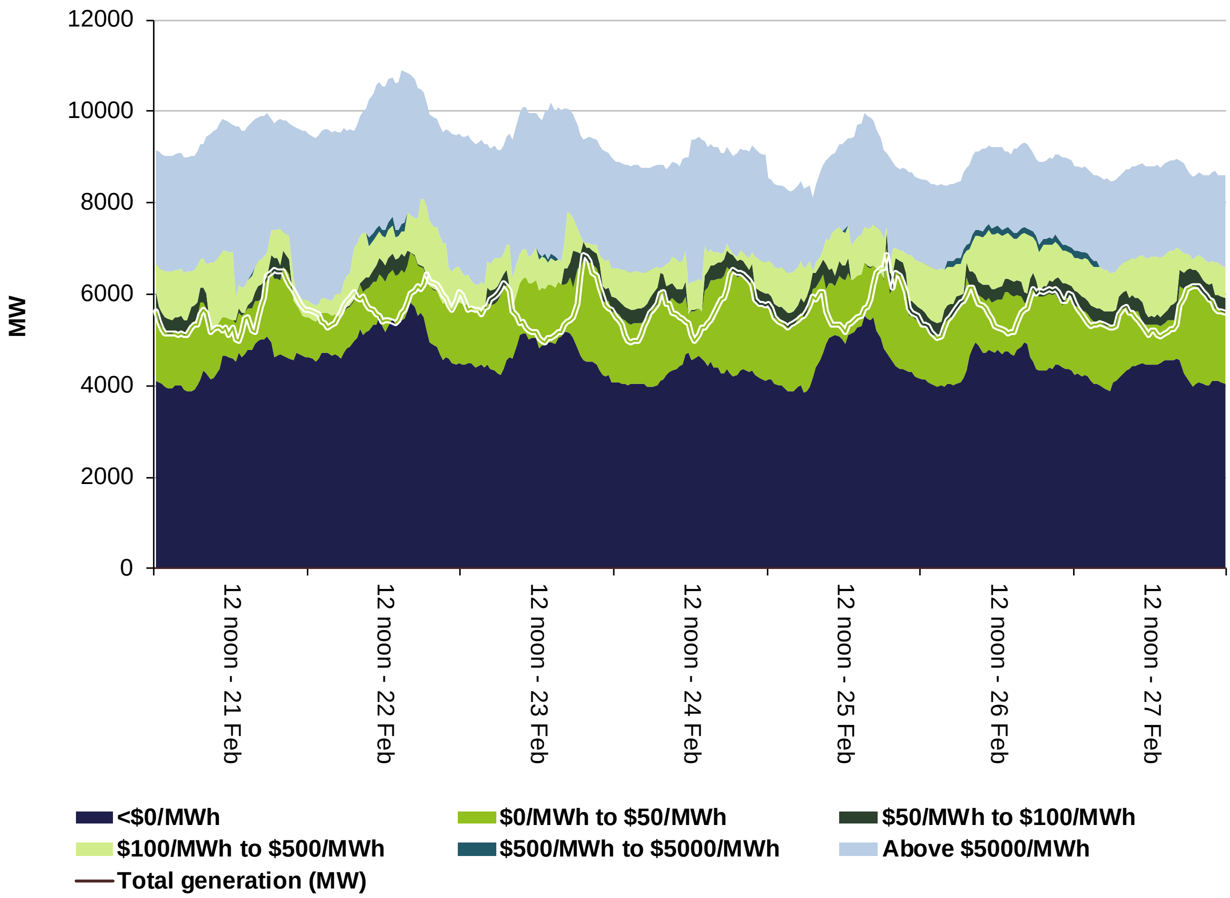


Figure 6: South Australia generation and bidding patterns

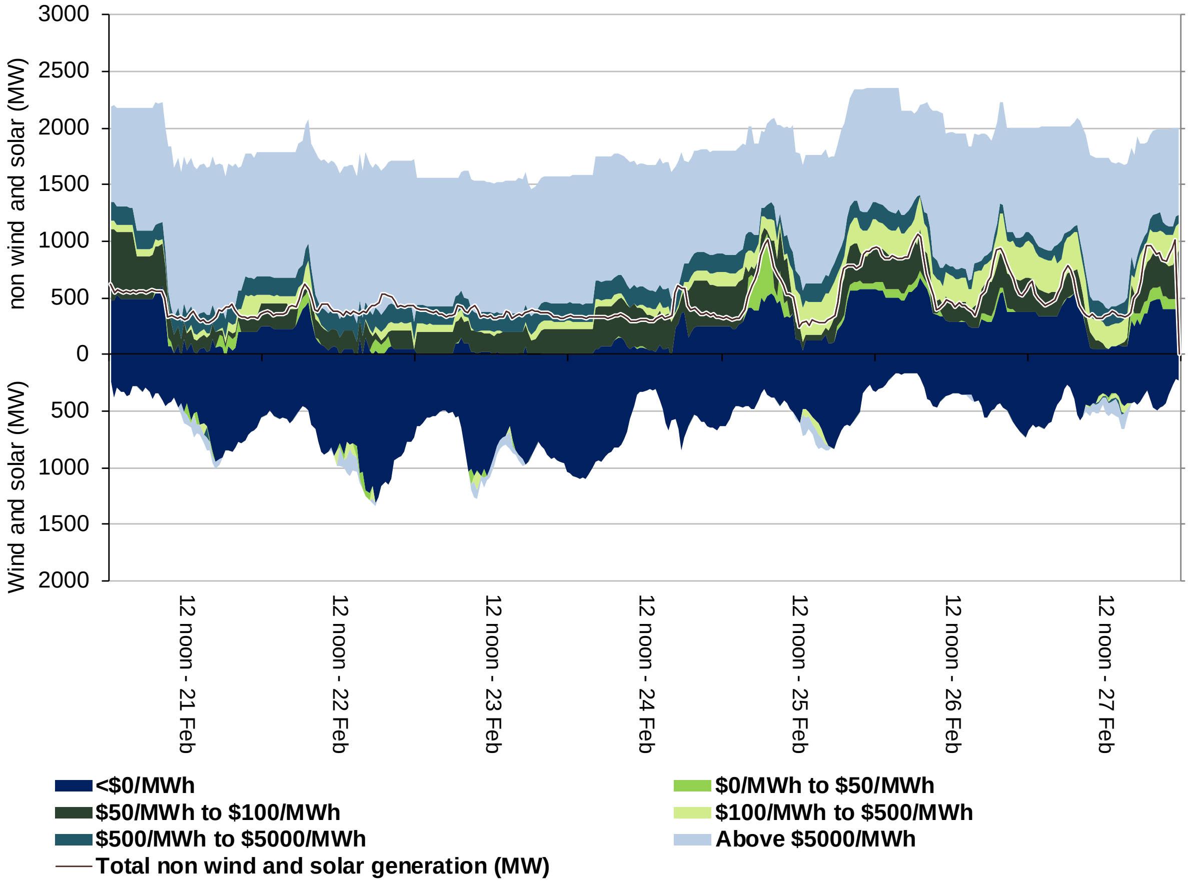
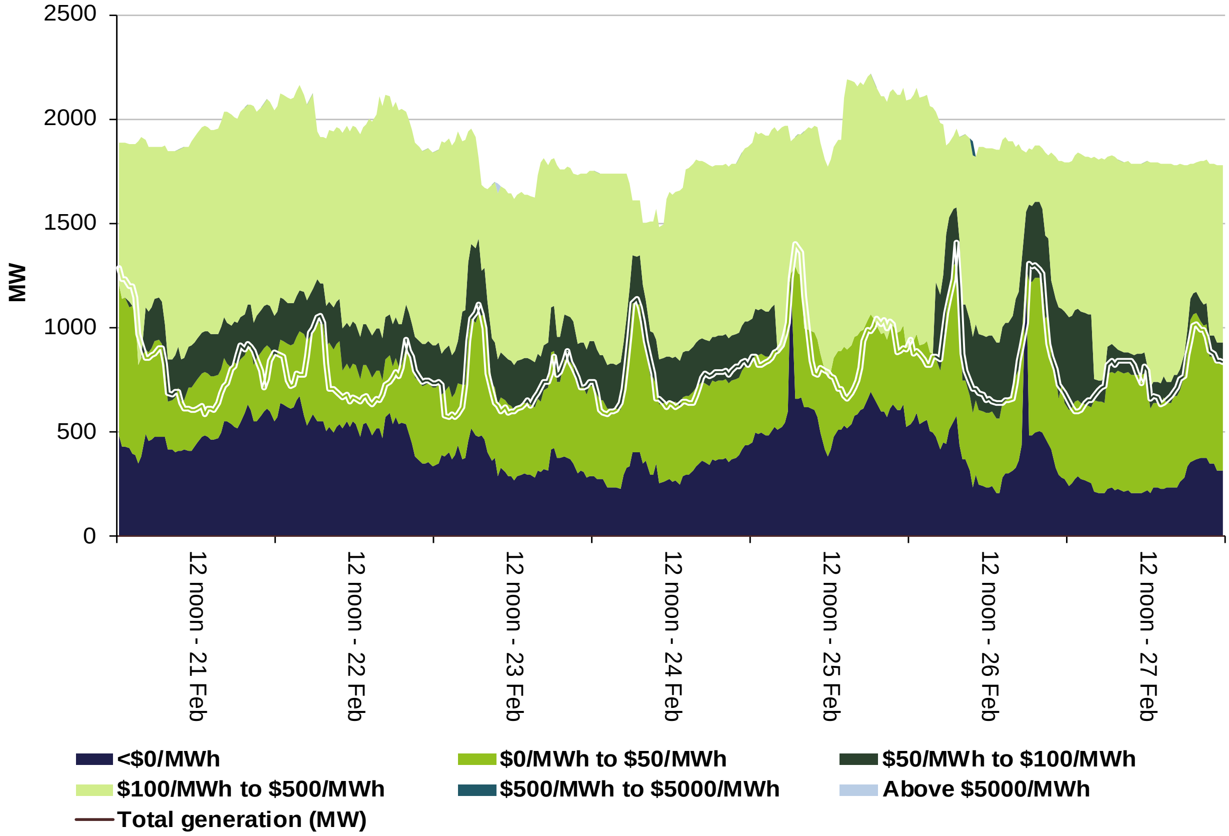


Figure 7: Tasmania generation and bidding patterns



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.

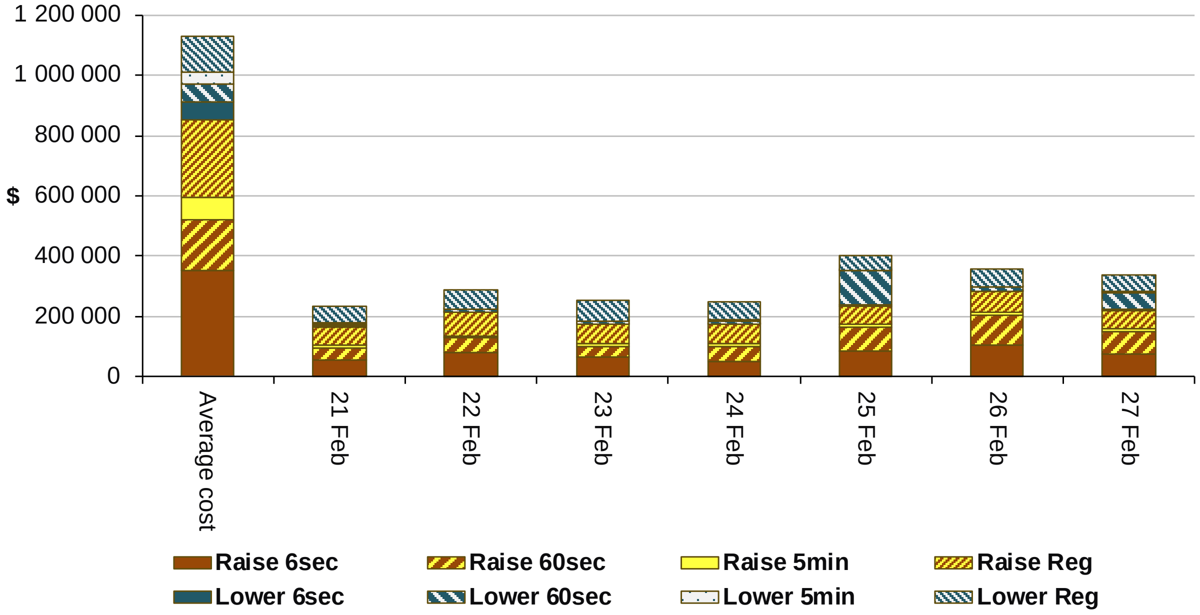
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1,602,000 or around 1% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $518,500 or around 10% 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 four occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $52/MWh and above $250/MWh.

Monday, 22 February

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	2,360.18	1,553	301.11	9,267	9,351	9,290	10,558	10,729	11,009

Demand was 84 MW lower than forecast and availability was 171 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind and rebids that removed capacity for plant reasons, including 36 MW at Millmerran and 60 MW at Gladstone. Forecast prices had increased earlier that morning following a unit trip at Callide B unit 2 that removed 320 MW of mostly low priced capacity.

There was only one generator with capacity offered at prices between $200/MWh and $13,000/MWh so small changes in market conditions could result in large changes in price. At 6.35 pm, demand increased by 85 MW and with cheaper priced generation ramp up-constrained, the price increased to $13,990/MWh for 5 minutes. In response to the high price, effective 6.40 pm around 360 MW of capacity was rebid from prices above $1,553/MWh to the price floor and cheaper priced generation was no longer ramp up-constrained. As a result, the dispatch price returned to around $35/MWh for the remainder of the trading interval.

Friday, 26 February

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
1.30 pm	269.87	38.90	43.73	7,113	6,986	6,956	10,292	10,567	10,665
5.30 pm	322.65	301.11	299.10	8,666	8,498	8,479	10,090	10,209	10,363

For the 1.30 pm trading interval, demand was 127 MW higher than forecast and availability was 275 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind and solar generation and rebids that removed 156 MW of low priced capacity at Callide C due to plant reasons.

At 1.05 pm, demand increased by 79 MW and with cheaper priced generation ramp constrained or unable to start up in 5 minutes, the price increased to $1,553/MWh. In response to the high price, effective 1.10 pm rebids shifted more than 200 MW of capacity from prices above $1552/MWh to the price floor and cheaper priced generation was no longer ramp up-constrained. As a result, the dispatch price was $13/MWh for the remainder of the trading interval.

For the 5.30 pm trading interval, prices were close to forecast, 4 hours prior.

Saturday, 27 February

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
4 pm	285.55	43.73	43.73	7,660	7,412	7,404	10,227	10,422	10,458

For the 4 pm trading interval, demand was 248 MW higher than forecast and availability was 195 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind and solar generation and rebids at Oakey that removed 155 MW of higher priced capacity during the trading interval in response to volatile prices.

At 3.35 pm, demand increased by 48 MW and solar generation fell by 38 MW. With cheaper priced generation ramp constrained or unable to start up in 5 minutes, the price increased to $1,553/MWh. In response to the high price, effective 3.40 pm, rebids shifted net 375 MW of capacity from prices above $43/MWh to below. As a result, the dispatch price was around $33/MWh for the remainder of the trading interval.

South Australia

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

Monday, 22 February

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
2.30 pm	-109.46	-100.77	-931.43	632	610	588	2,680	2,736	2,732

Prices were close to forecast, 4 hours prior.

Saturday, 27 February

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
11.30 am	-172.66	-363.97	-33.11	510	566	575	2,254	2,178	2,140
Midday	-131.60	-481.61	-354.87	482	517	537	2,174	2,176	2,128
12.30 pm	-100.08	-346.89	-343.18	451	506	522	2,255	2,222	2,174
1 pm	-107.13	-342.05	-352.67	469	481	504	2,266	2,235	2,191
1.30 pm	-151.05	-338.44	-350.91	447	476	512	2,212	2,240	2,208
2.30 pm	-200.19	-362.59	-333.34	507	521	547	2,242	2,233	2,261
3 pm	-144.71	-33.11	-335.31	548	573	587	2,342	2,242	2,279

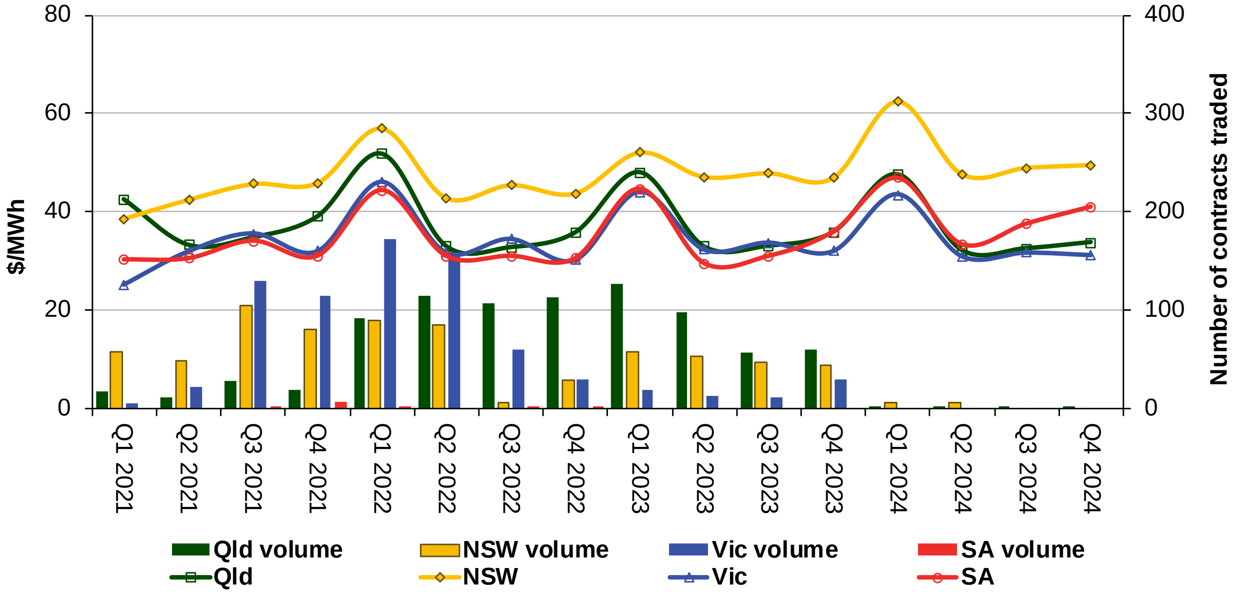
For the 11.30 am, midday, 12.30 pm, 1 pm, 1.30 pm and 2.30 pm trading intervals, demand was up to 56 MW lower than forecast and availability was between 26 MW lower to 76 MW higher than forecast, 4 hours prior. In the 4 hours to each trading interval, rebids in response to changes in forecast prices shifted at least 180 MW of capacity to higher prices. Across all trading intervals, only a few generators had capacity offered at prices between -$33/MWh and the price floor. As a result, small changes in supply or demand could result in large changes in price and dispatch prices generally ranged from around -$200/MWh to -$50/MWh.

For the 3 pm trading interval, demand was close to forecast and availability was 100 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind and solar generation, most of which priced below $0/MWh. With little generation offered at prices between -$33/MWh and -$300/MWh, small changes in supply or demand could result in large changes in price. As a result, dispatch prices were below forecast for the majority of the trading interval.

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.

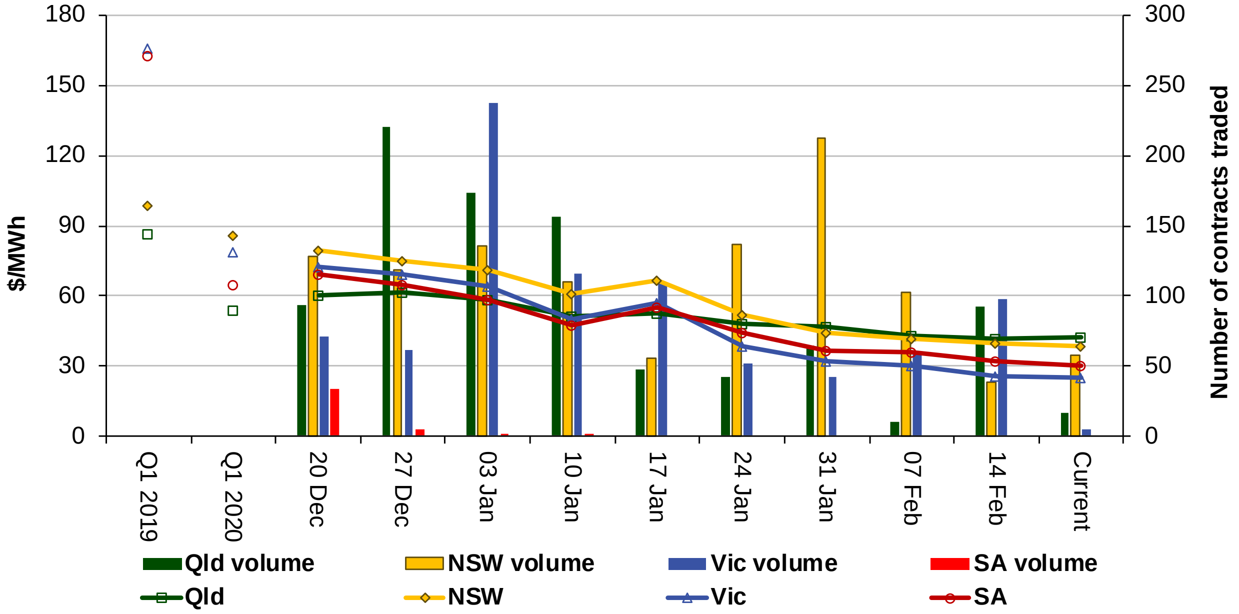
Figure 9: Quarterly base future prices Q1 2021 – Q4 2024



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 Q1 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)

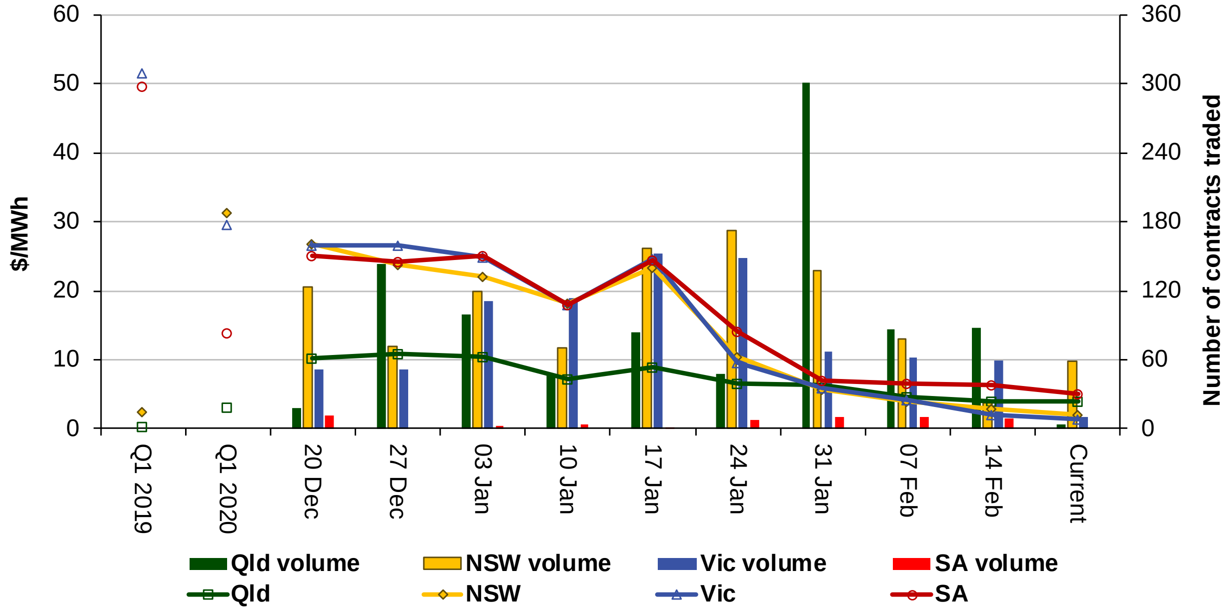


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional 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
March 2021