

7 – 13 February 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from \$22/MWh in Victoria to \$44/MWh in Queensland. Q1 2020 quarter to date prices are lower in all regions compared to the same time last year (Table 1). The largest decreases are in Victoria and New South Wales and the difference is largely driven by a number of high priced events in Q1 2020 rather than low prices in Q1 2021.

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 7 to 13 February 2021.

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

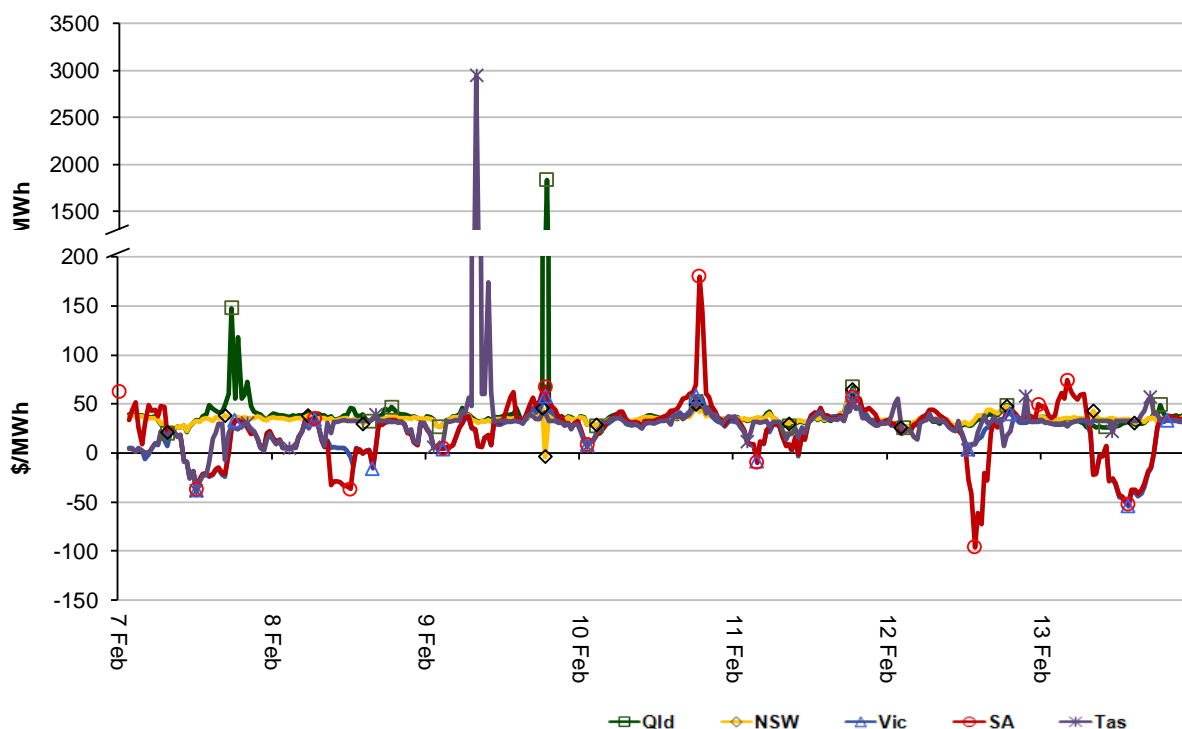


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in

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)

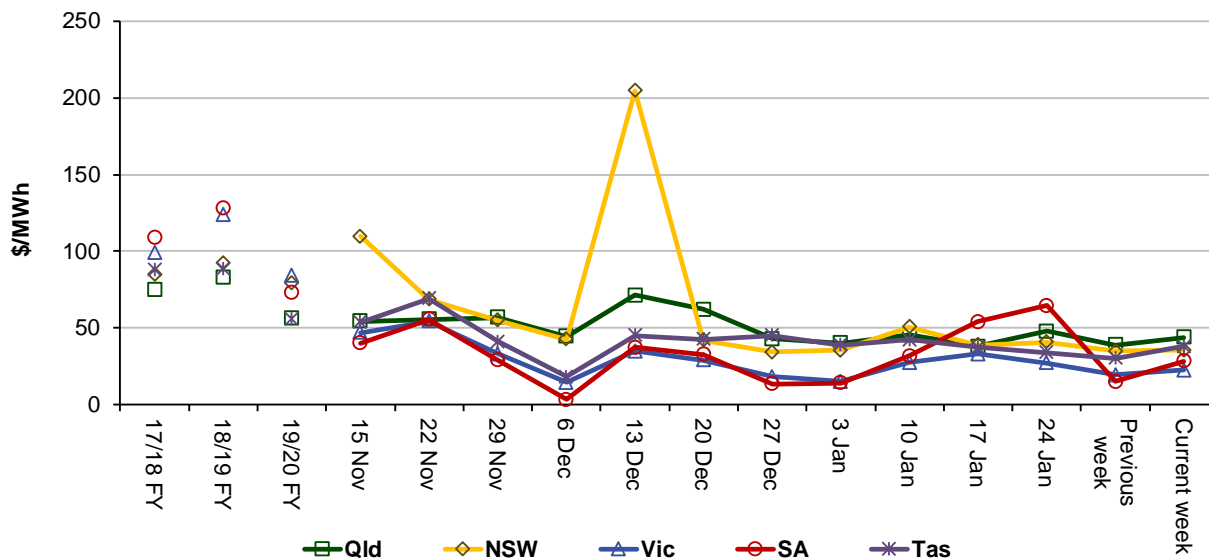


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	44	35	22	28	38
Q1 2020 (QTD)	66	163	172	106	51
Q1 2021 (QTD)	42	39	24	35	37
18-19 financial YTD	65	98	108	89	69
19-20 financial YTD	42	55	43	40	46

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 186 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	10	22	0	2
% of total below forecast	14	44	0	8

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

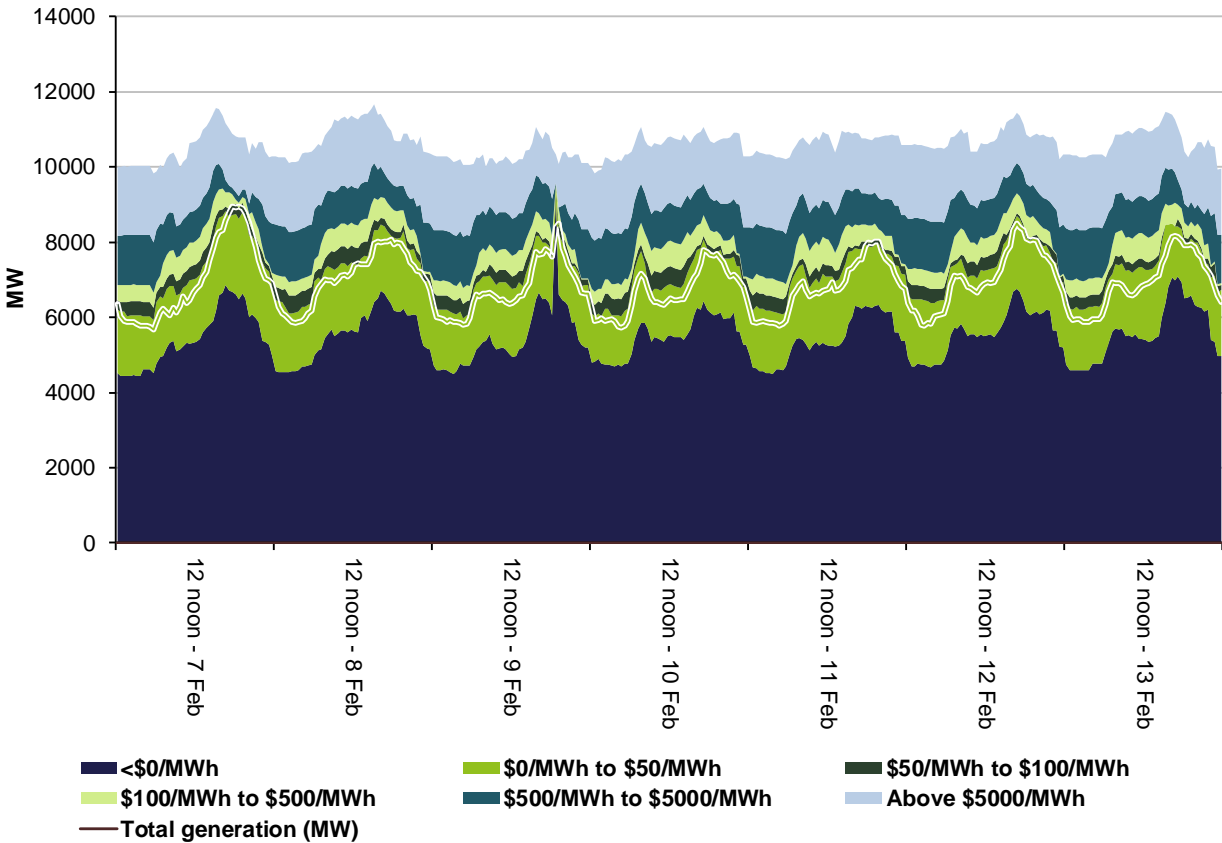


Figure 4: New South Wales generation and bidding patterns

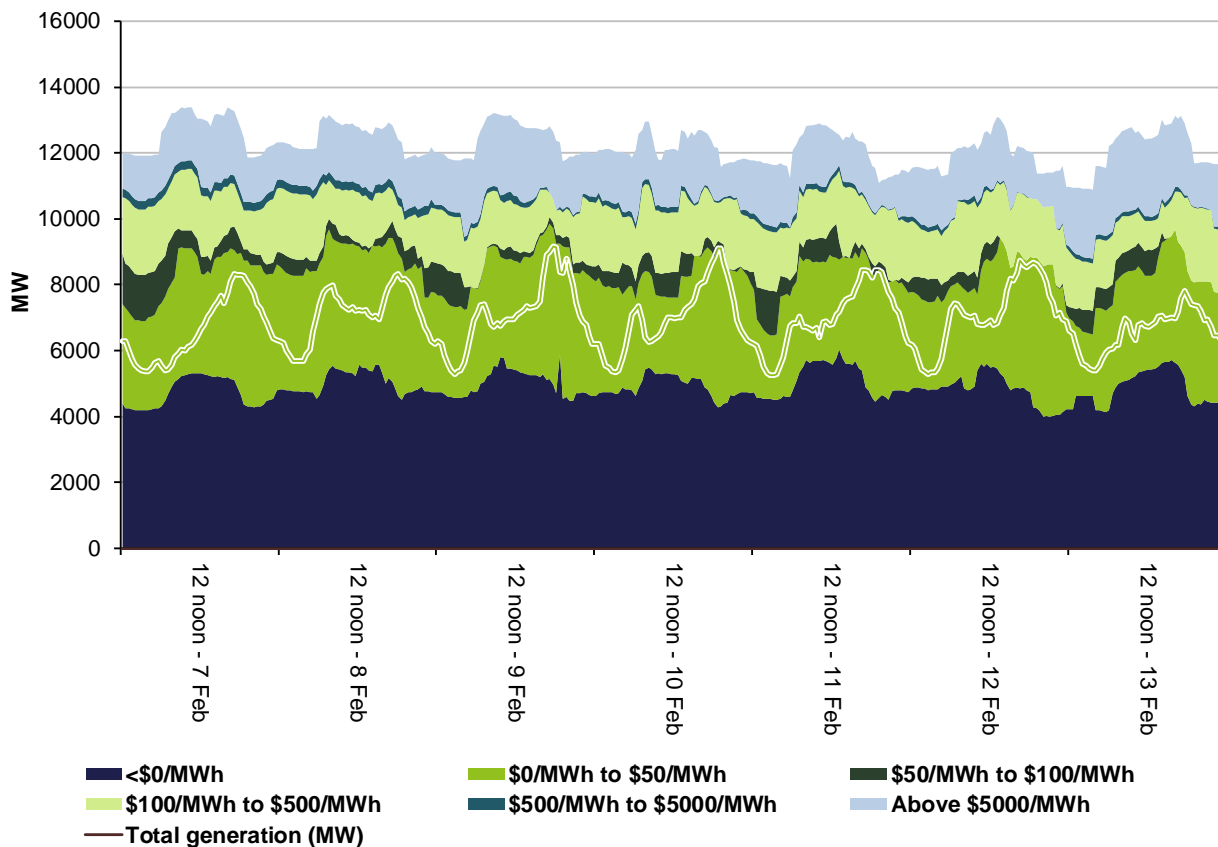


Figure 5: Victoria generation and bidding patterns

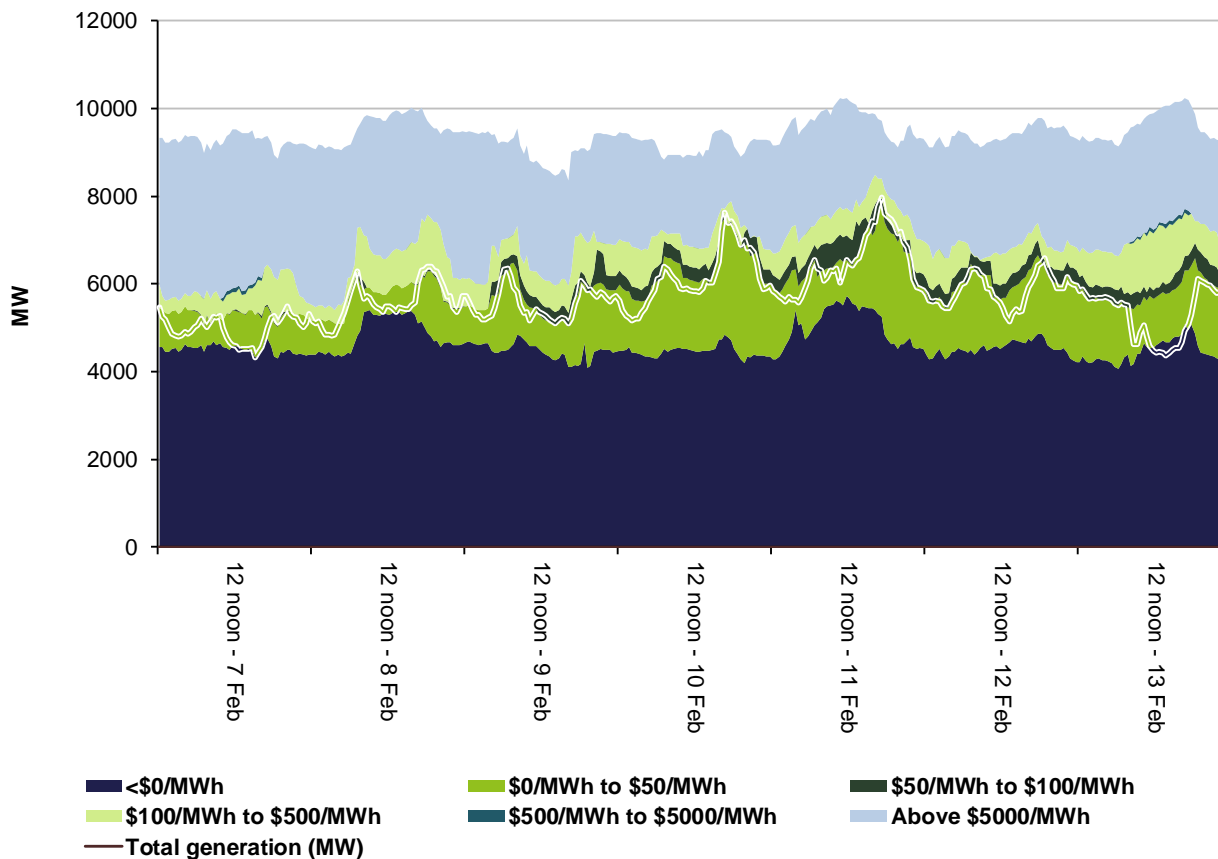


Figure 6: South Australia generation and bidding patterns

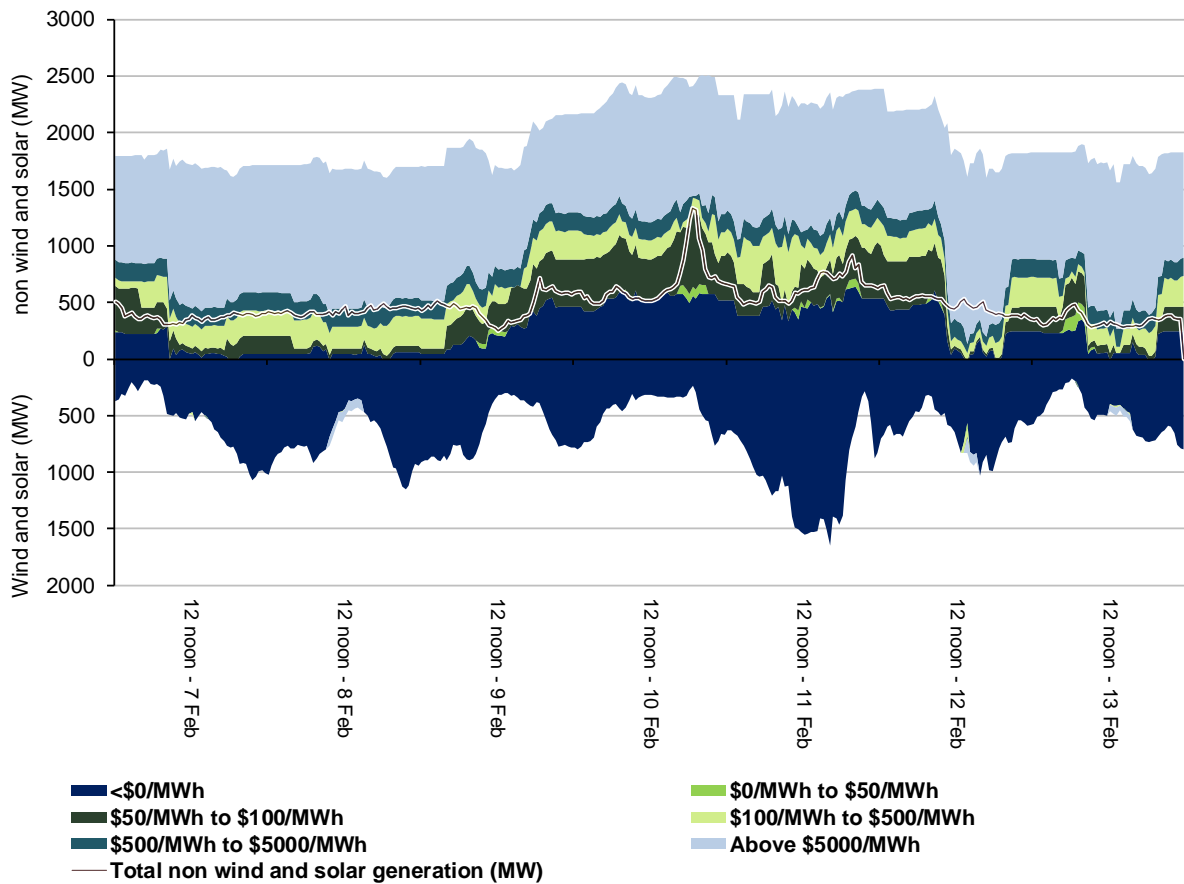
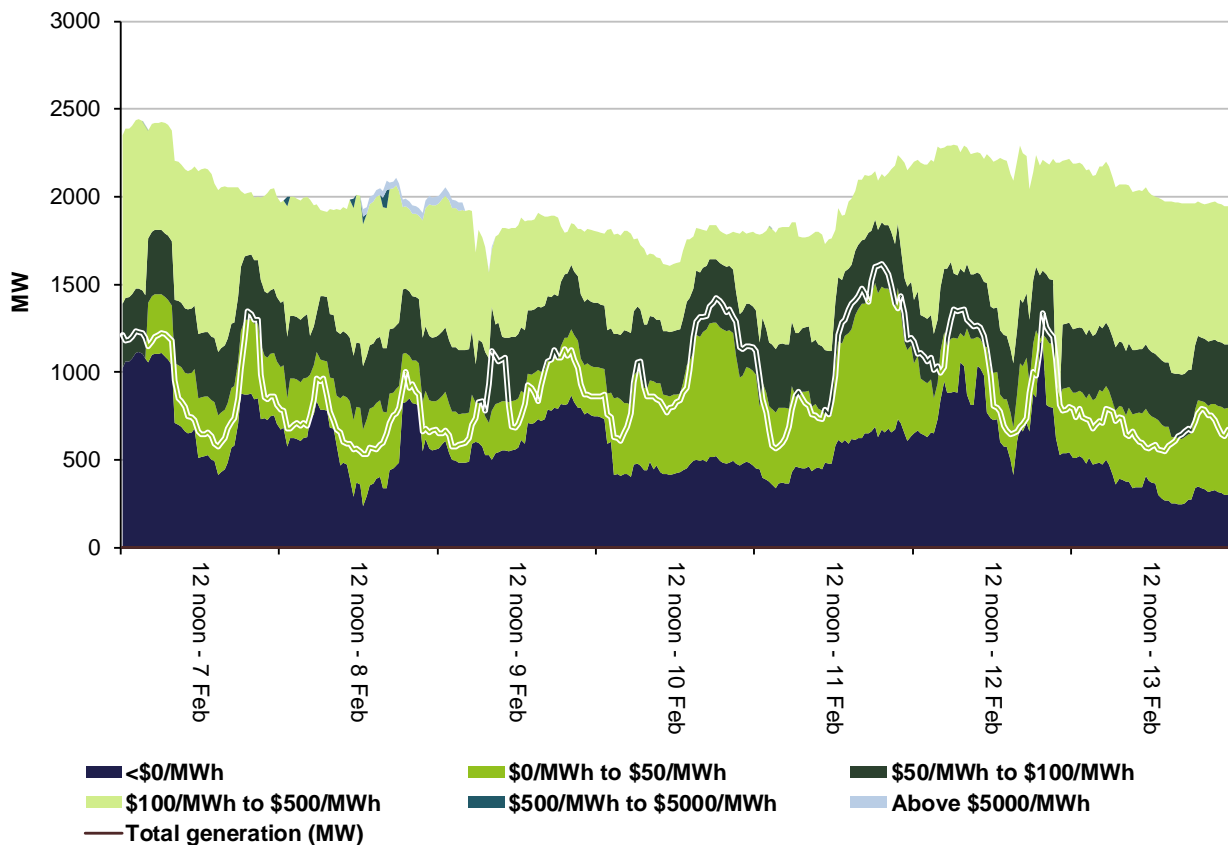


Figure 7: Tasmania generation and bidding patterns



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.

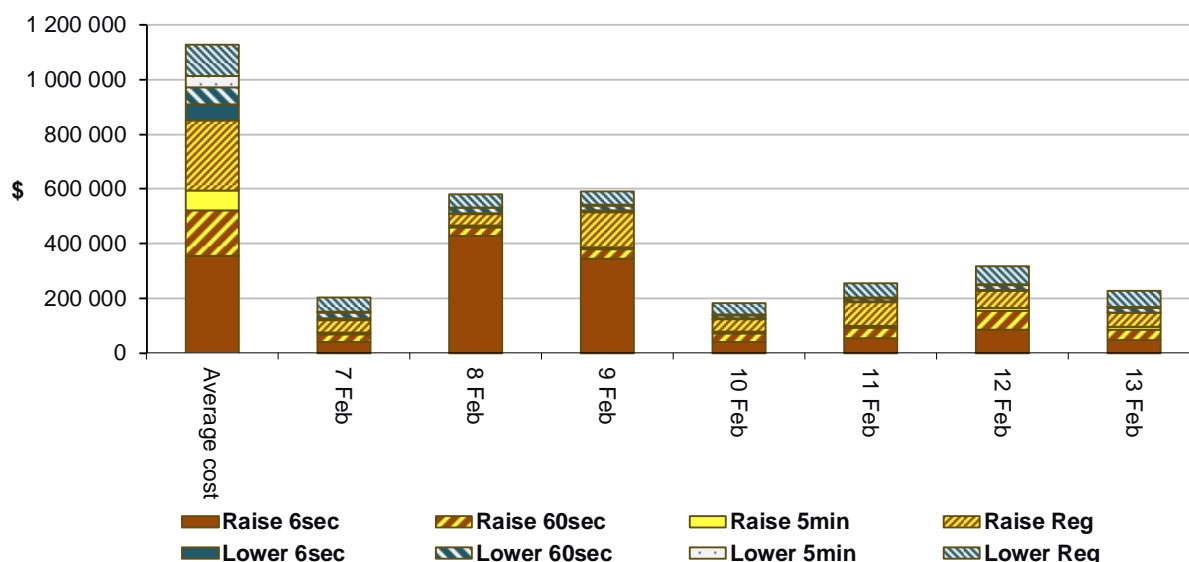
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$1,206,000 or around 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$1,151,500 or around 18 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 was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of \$44/MWh and above \$250/MWh.

Tuesday, 9 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	1,836.24	49.61	47.73	7,849	8,058	8,083	10,382	10,742	10,936

Demand was 209 MW lower and availability was 360 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to rebids by CS Energy at Gladstone which removed 295 MW of capacity (215 MW below \$48/MWh and the remaining priced above \$71/MWh) due to technical issues, and lower than forecast wind generation most of which was priced below \$0/MWh.

At 6.35 pm, demand increased by 93 MW. Effective from 6.35 pm, Callide Power Trading rebid 45 MW of capacity at Callide C from the price floor to \$14,892/MWh due to forecast prices. With several generators either ramp constrained, already at max avail, unable to come on in 5 minutes, or trapped / stranded in FCAS and unable to set price the dispatch price reached \$15,000/MWh. In response, participants rebid over 2,600 MW to the price floor. Dispatch prices remained below \$3/MWh for the remainder of the trading interval.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of \$38/MWh and above \$250/MWh.

Tuesday, 9 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
8 am	2,945.45	35.00	36.36	964	1,207	1,195	1,611	1,773	1,814
8.30 am	675.47	33.04	33.83	1,087	1,174	1,159	1,691	1,771	1,812

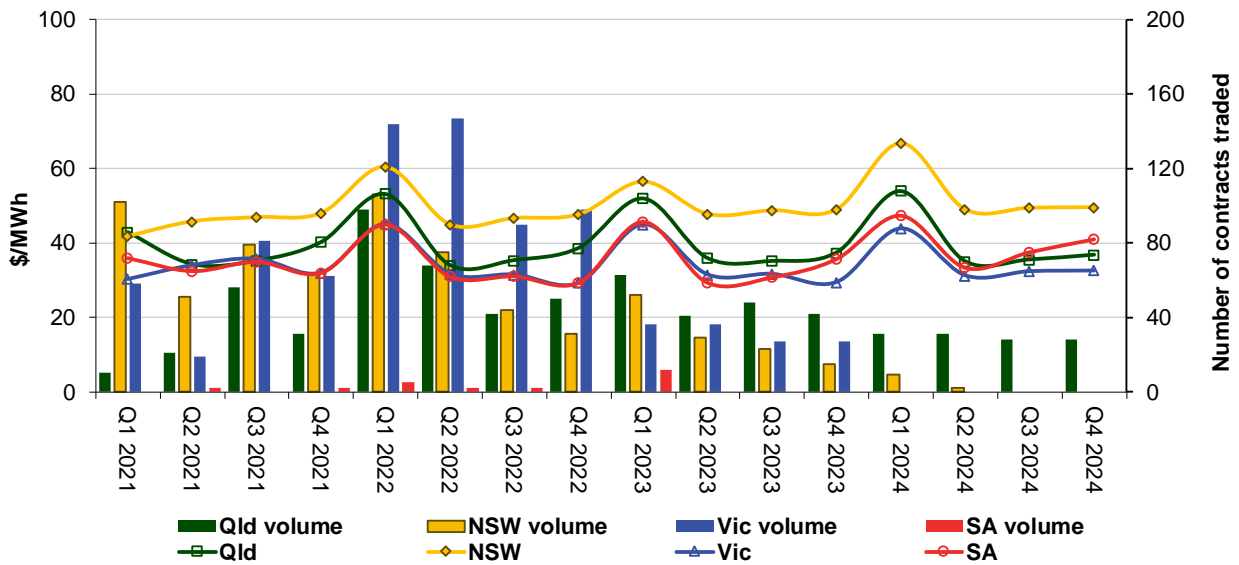
Demand was between 87 MW and 243 MW lower than forecast, while availability was between 80 MW and 162 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast renewable generation, most of which was priced below \$0/MWh, and rebids by Hydro Tasmania at Tamar Valley GT and Tungatinah which removed capacity at \$398/MWh due to targets differing from forecast.

During each trading interval, constraints related to a network control special protection scheme and potential loss of the non-scheduled Woolnorth power station violated which saw FCAS and energy markets co-optimize. As a result, dispatch prices reached over \$14,000/MWh at 7.50 am, and over \$3,400/MWh at 8.05 am.

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.

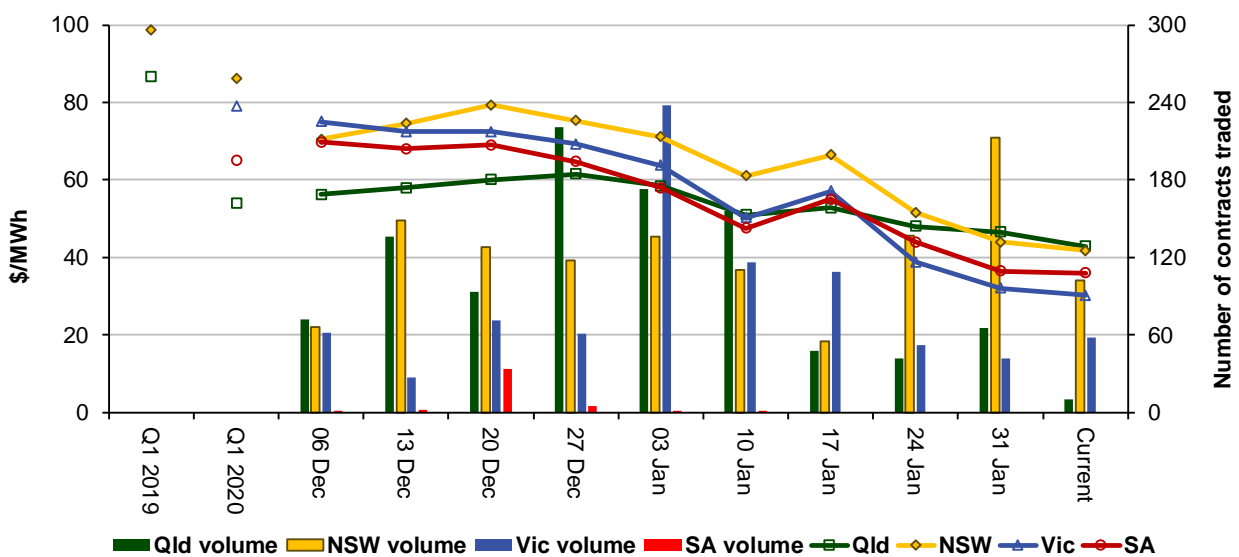
Figure 9: Quarterly base future prices Q1 2021 – Q4 2024



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)

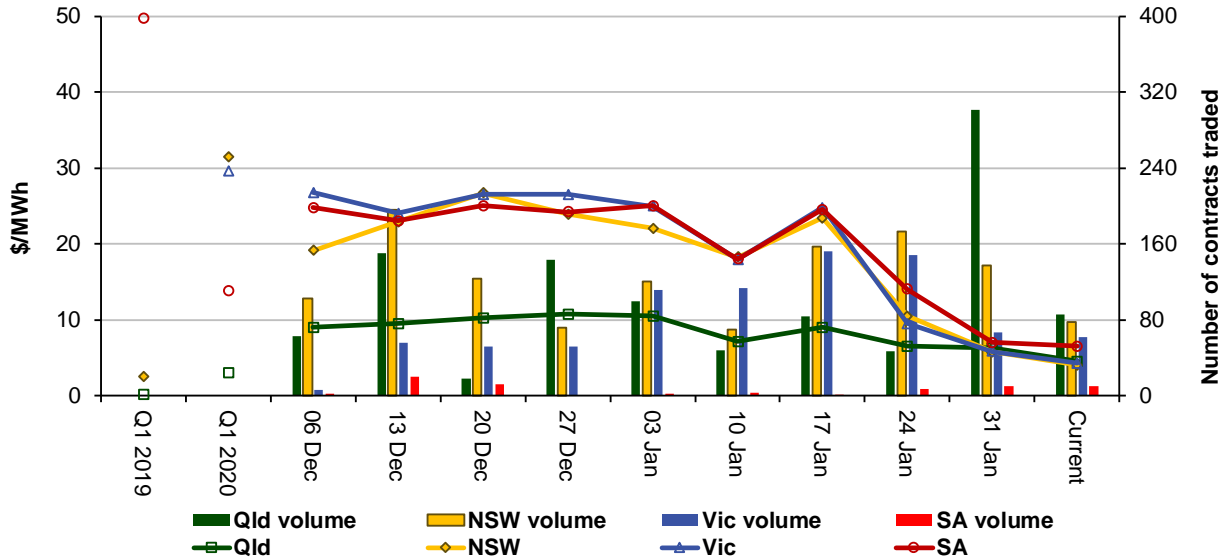


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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**