Electricity Report

11 – 17 April 2021

Weekly Summary

Weekly volume weighted average (VWA) prices were between $21/MWh in Tasmania and $47/MWh in New South Wales. The Queensland spot price reached nearly $2,200/MWh on 15 April, driven by a sharp increase in demand (Price events section).

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 11 to 17 April 2021.

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

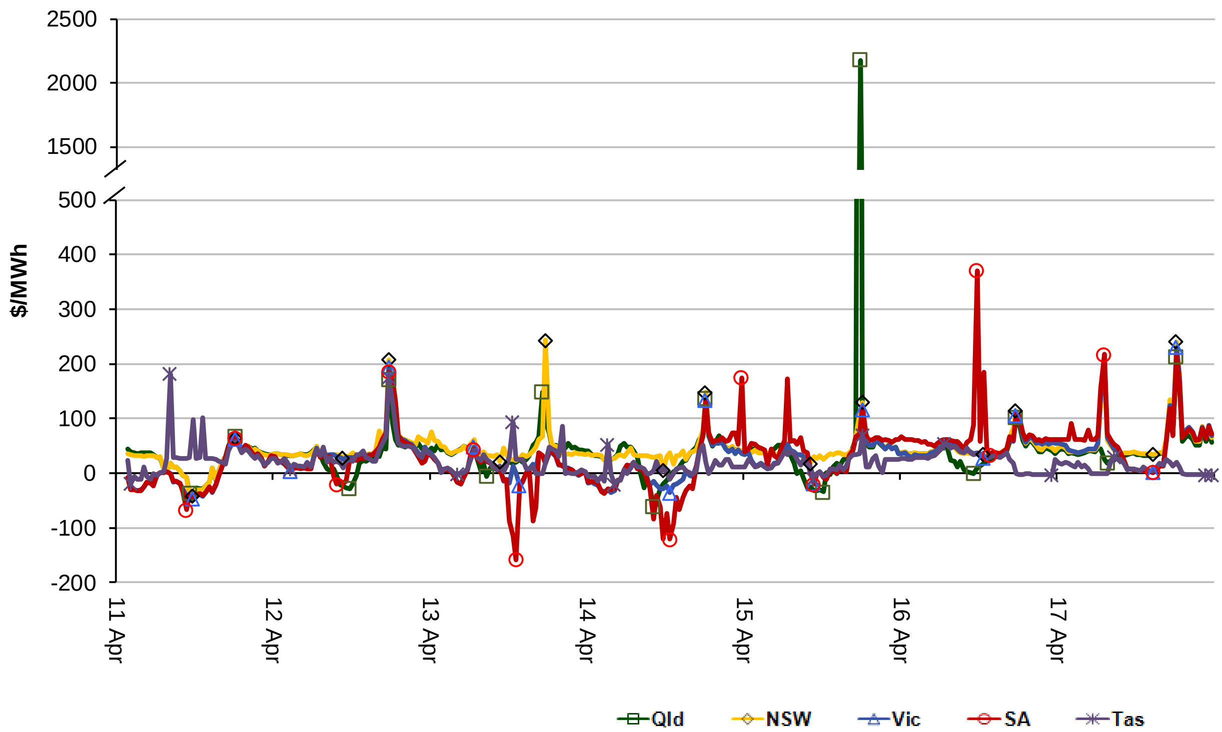


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

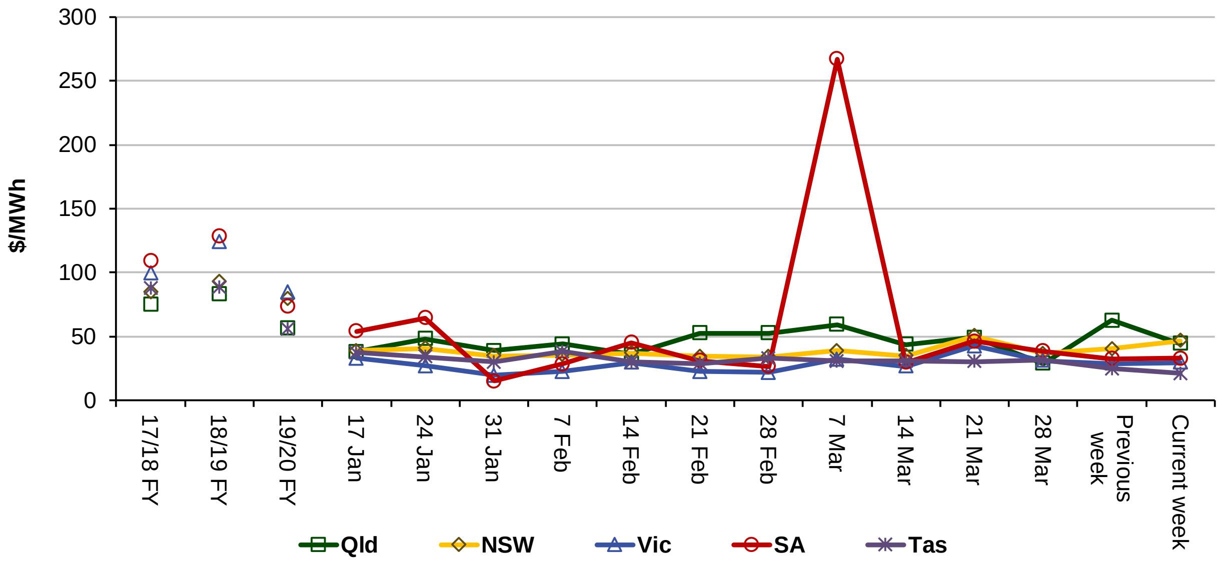


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	44	47	29	33	21
Q2 2020 (QTD)	40	44	43	40	29
Q2 2021 (QTD)	49	41	28	33	24
19-20 financial YTD	61	88	95	81	62
20-21 financial YTD	43	52	40	44	43

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 264 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	2	17	0	1
% of total below forecast	20	46	0	14

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

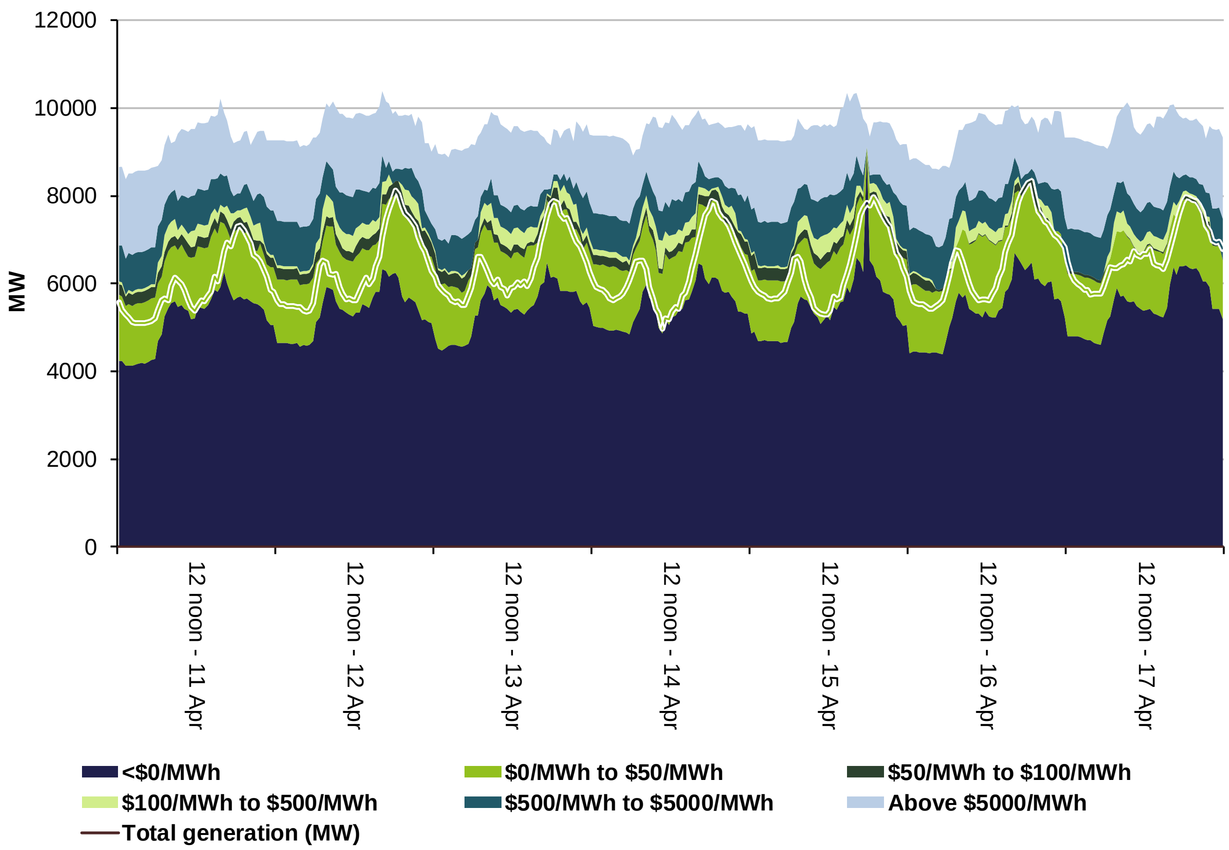


Figure 4: New South Wales generation and bidding patterns

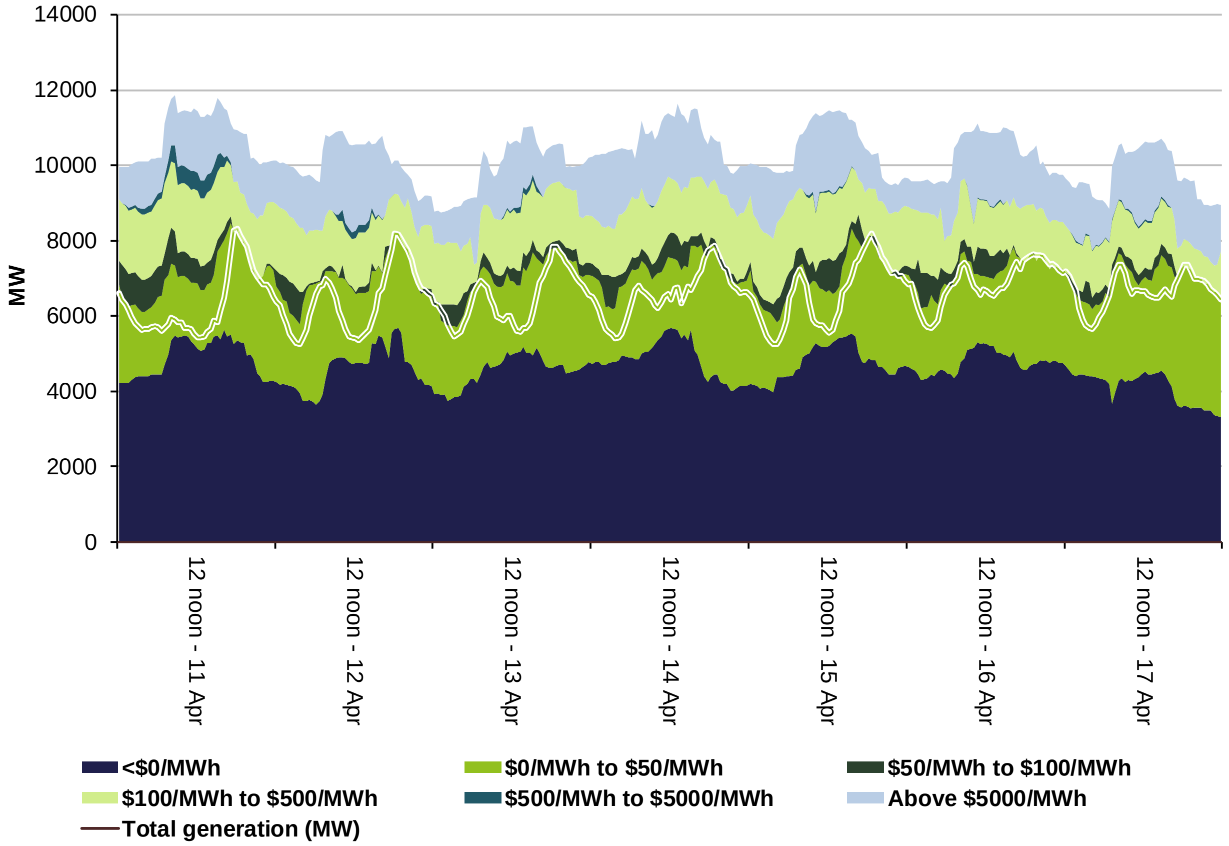


Figure 5: Victoria generation and bidding patterns

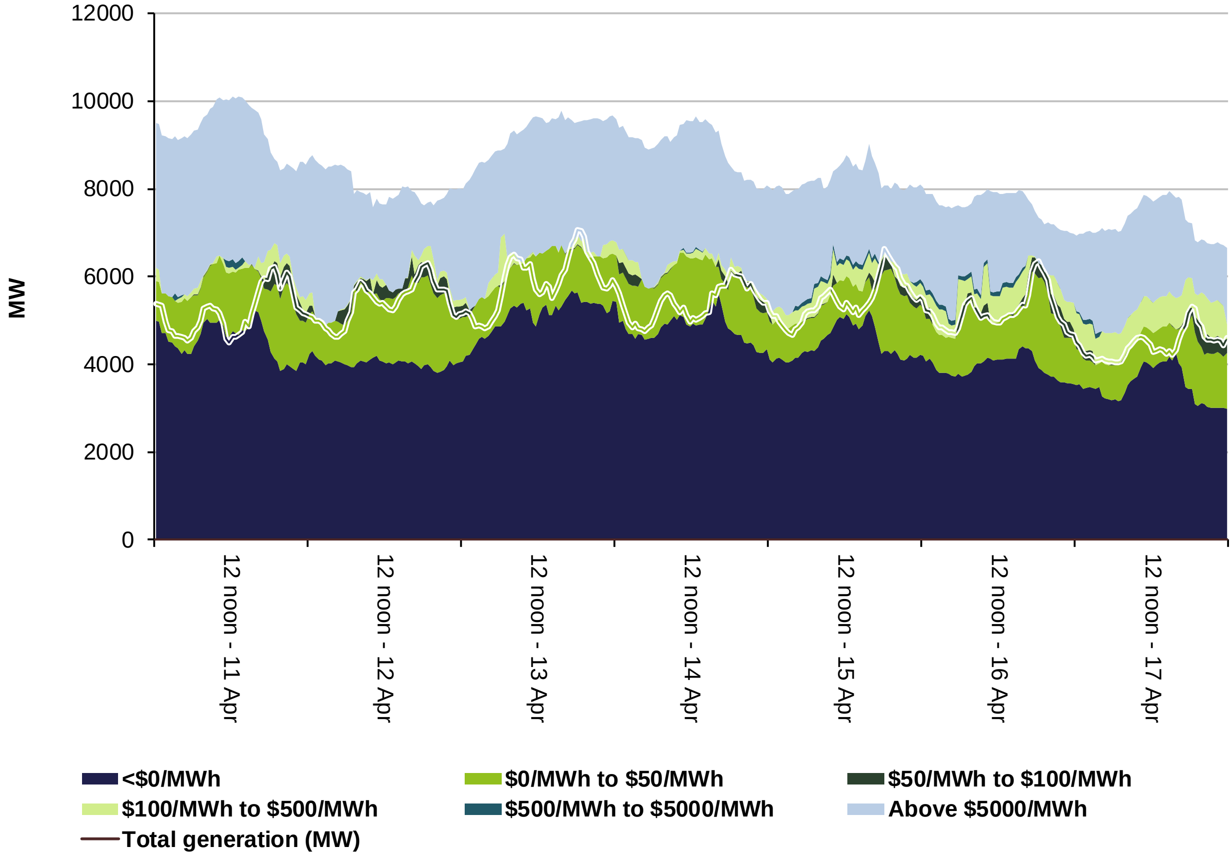


Figure 6: South Australia generation and bidding patterns

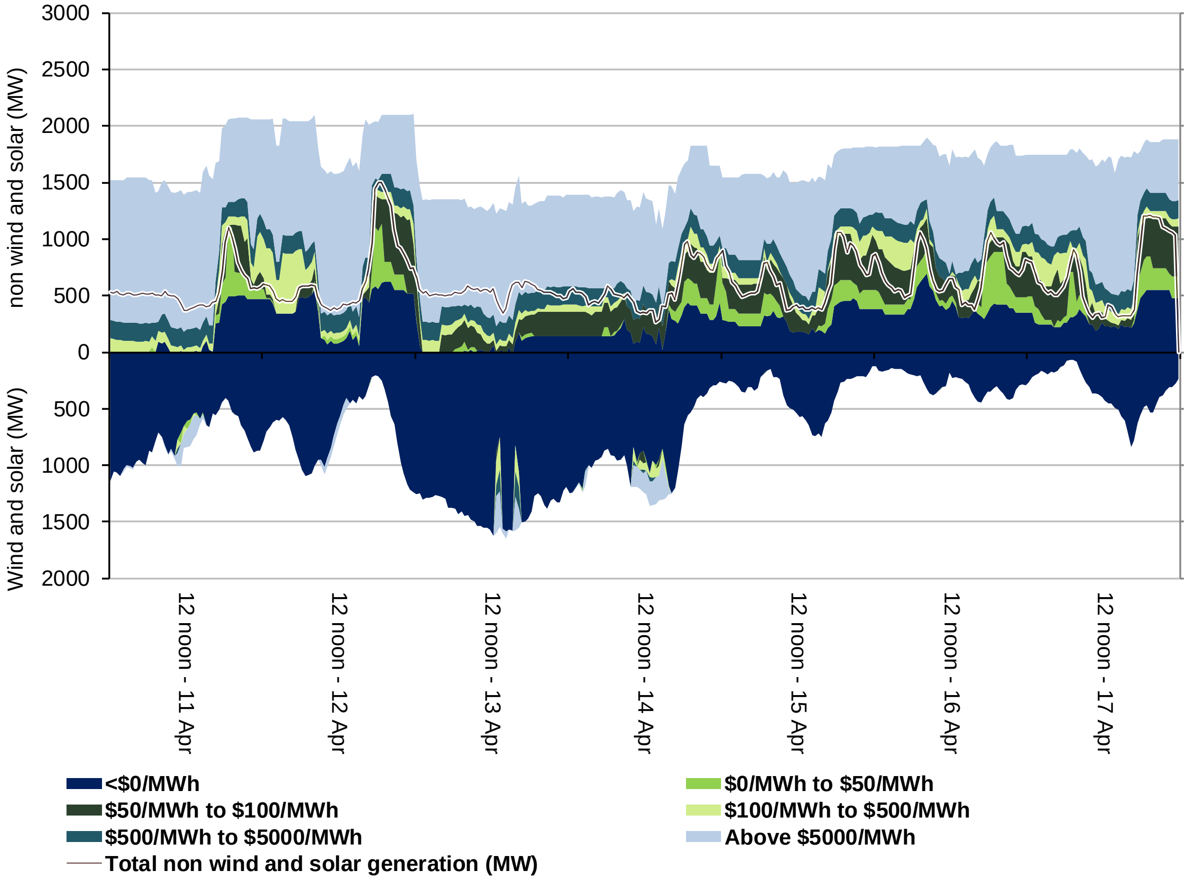
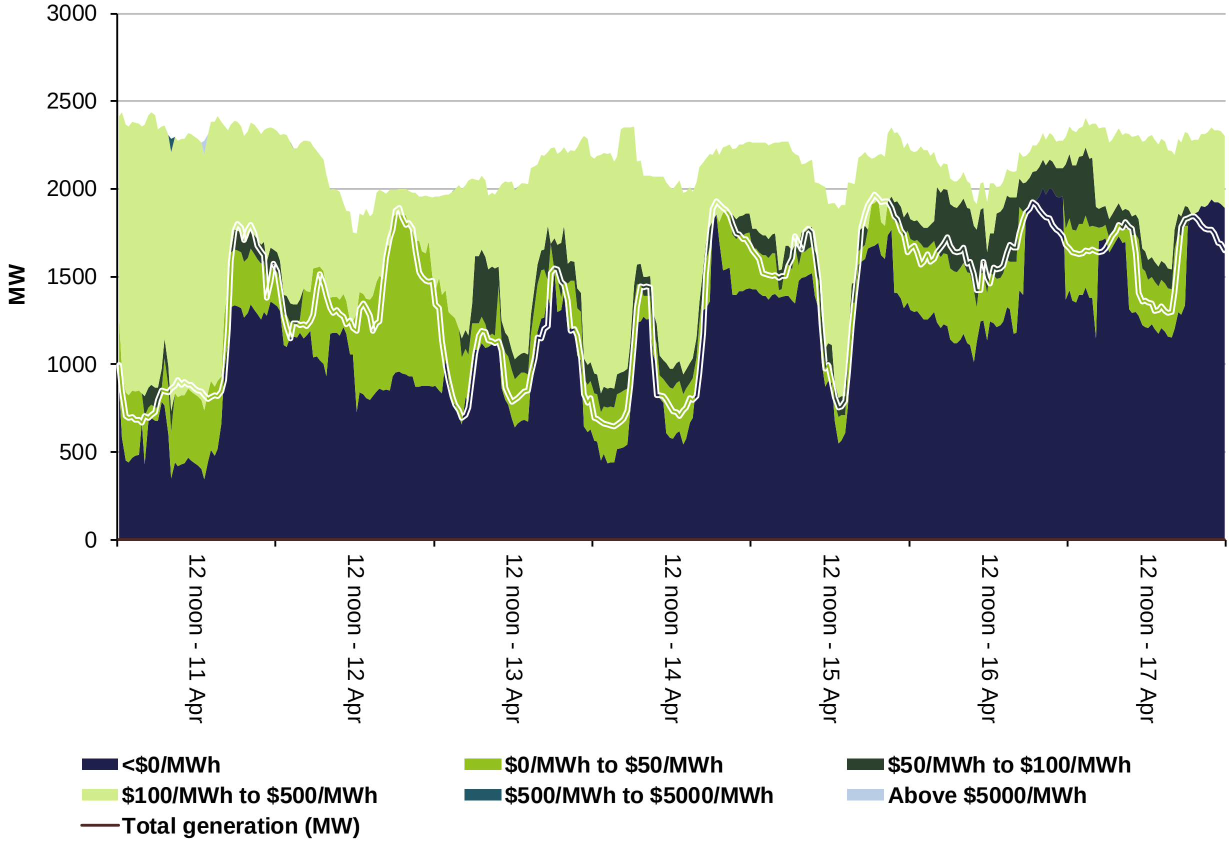


Figure 7: Tasmania generation and bidding patterns



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.

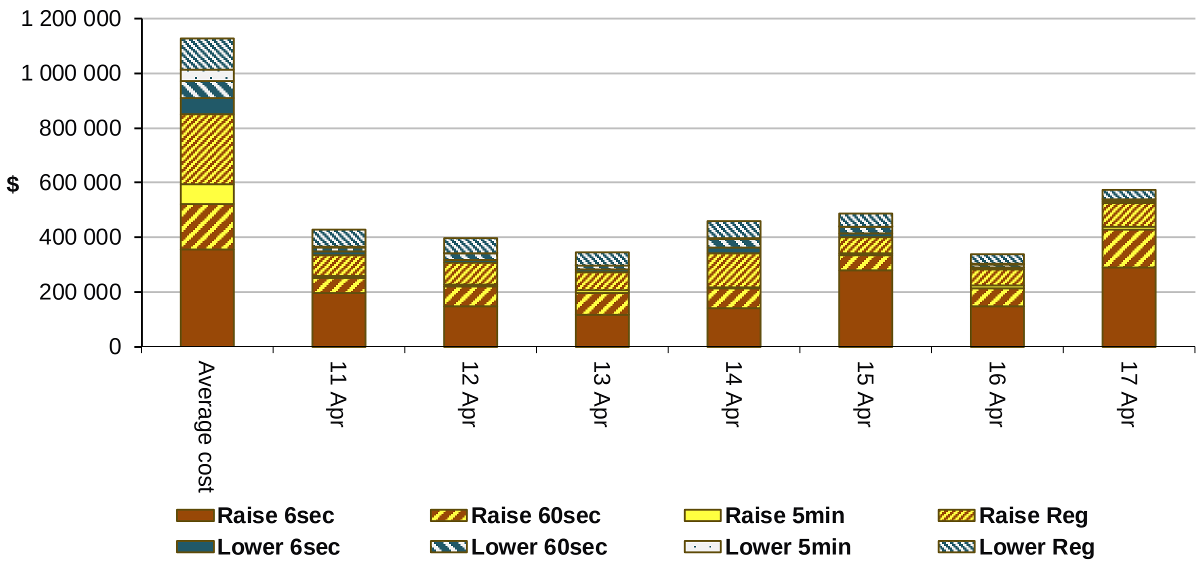
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2,507,500 or less than 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $520,000 or around less than 13% 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 1 occasion where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $44/MWh and above $250/MWh.

Thursday, 15 April

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	2180.65	61.55	70.73	7,377	7,313	7,270	9,619	9,724	9,728

Demand was 64 MW higher than forecast while availability was 105 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to a rebid by CS Energy at Kogan Creek at 3 pm which removed 120 MW of capacity below $12/MWh due to technical issues.

At 5.50 pm demand increased by nearly 150 MW. With several generators either trapped or stranded in FCAS or unable to start in 5 minutes, the price increased to $14,900/MWh. In response, participants rebid over 560 MW from above $14,900/MWh to the price floor. As a result, prices remained at the price floor for the remainder of the trading interval.

South Australia

There was 1 occasion where the spot price in South Australia was greater than 3 times the South Australia weekly average price of $33/MWh and above $250/MWh and there were 4 occasions where the spot price was below -$100/MWh.

Tuesday, 13 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
1 pm	-115.80	-30.92	-27.30	947	967	942	2,866	2,679	2,733
1.30 pm	-158.28	-130.84	-27.14	979	944	929	2,805	2,669	2,736

For the 1 pm trading interval, demand was close to forecast while availability was 187 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, about half of which was priced close to the floor. Due to the higher than forecast availability, the spot price was set below forecast.

For the 1.30 pm trading interval, prices were close to forecast 4 hours prior.

Wednesday, 14 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
Midday	-120.42	-605.78	-879.62	805	670	675	2,582	2,663	2,697
1 pm	-120.78	-770.51	-1,000	852	592	614	2,692	2,723	2,735

For the midday and 1 pm trading intervals, demand was 135 MW to 260 MW higher than forecast, while availability was up to 81 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast solar generation, about half of which was priced close to the floor.

Up to 4 hours prior to the start of each trading interval, participants rebid around 600 MW of capacity from the price floor to higher prices due to either forecast prices or plant reasons. The combination of participant rebids, higher than forecast demand and lower than forecast availability saw prices set higher than forecast throughout each trading interval. See Table 6 for details.

Table 6: Significant rebids for 14 April midday and 1 pm

Submitted time	Trading interval	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.28 am	Midday	Lincoln Gap Wind Farm	Lincoln Gap Wind Farm	192	-1,000	4,000	0701 A SA1 30MIN PD RRP for 1000 ($-190.0) published at 0701 is 392.89% lower than 30min PD RRP published at 0631 ($-38.55) - time of alert: 0728
8.28 am	1 pm	Lincoln Gap Wind Farm	Lincoln Gap Wind Farm	192	-1,000	4,000	0801 A SA1 30min PD RRP for 1030 ($-190.0) published at 0801 is 5.0% higher than 30min PD RRP published at 0701 ($-200.0) - time of alert: 0828
10.02 am	Midday, 1 pm	Vena Energy Services	Tailem Bend Solar Project 1	95	-1,000	15,000	1002 F change in contract position
10.15 am	Midday, 1 pm	AGL Energy	The Bluff WF	42	-1,000	-51	1010~A~040 chg in AEMO disp~44 price decrease vs PD SA -$459.65 10:15~
10.15 am	Midday, 1 pm	AGL Energy	Hallet 1 WF	80	-1,000	-51	1010~A~040 chg in AEMO disp~44 price decrease vs PD SA -$459.65 10:15~

Submitted time	Trading interval	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.15 am	Midday, 1 pm	AGL Energy	Hallet 2 WF	55	-1,000	-53	1010~A~040 chg in AEMO disp~44 price decrease VS PD SA -$459.65 10:15~
10.53 am	Midday, 1 pm	Lincoln Gap Wind Farm	Lincoln Gap Wind Farm	20	-1,000	123	1047 P minimum load adjustment SL
11.13 am	Midday	Pacific Hydro	Clements Gap WF	57	-1,000	-295	1110 A SA1 5min pd totaldemand for 1200 (848.02MW) published at 1110 is 20.13% higher than 30min PD totaldemand published at 1031 (705.91MW) - time of alert: 1113
11.23 am	Midday, 1 pm	AGL Energy	North Brown Hill WF	113	-1,000	-51	1120~A~040 chg in AEMO disp~44 price decrease vs PD SA -$190~

Friday, 16 April

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
Midday	371.01	-400.77	20.61	974	709	728	1,921	2,075	1,975

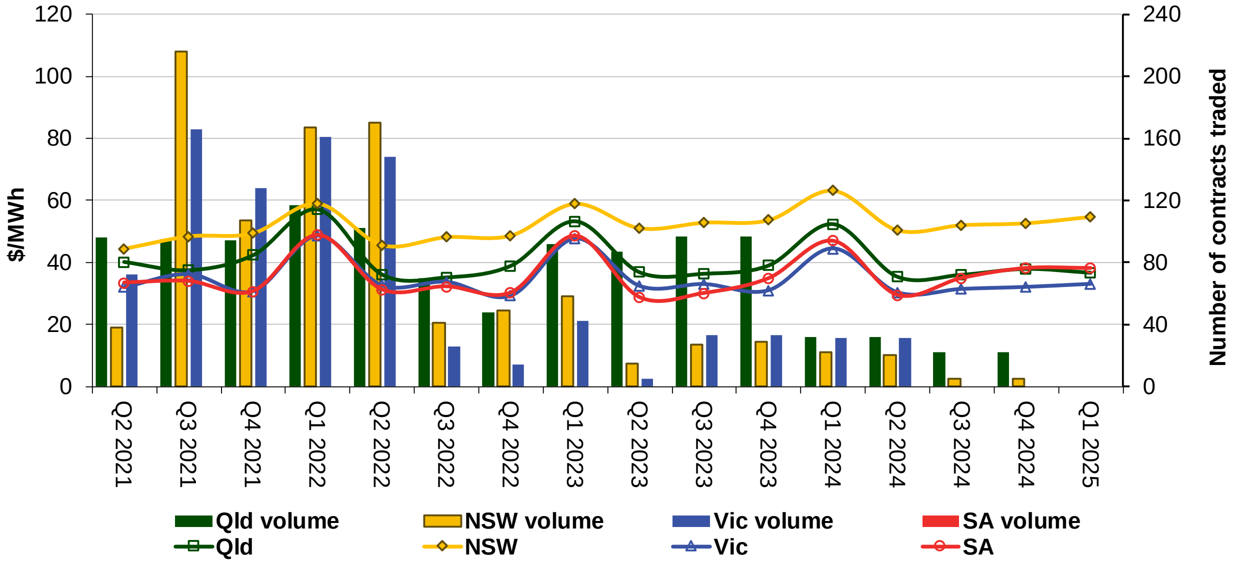
Demand was 265 MW higher than forecast while availability was 154 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast renewable generation.

The combination of little capacity offered between $62/MWh and $1,015/MWh, higher than forecast demand and lower than forecast availability saw prices set between $36/MWh and over $1,000/MWh throughout 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.

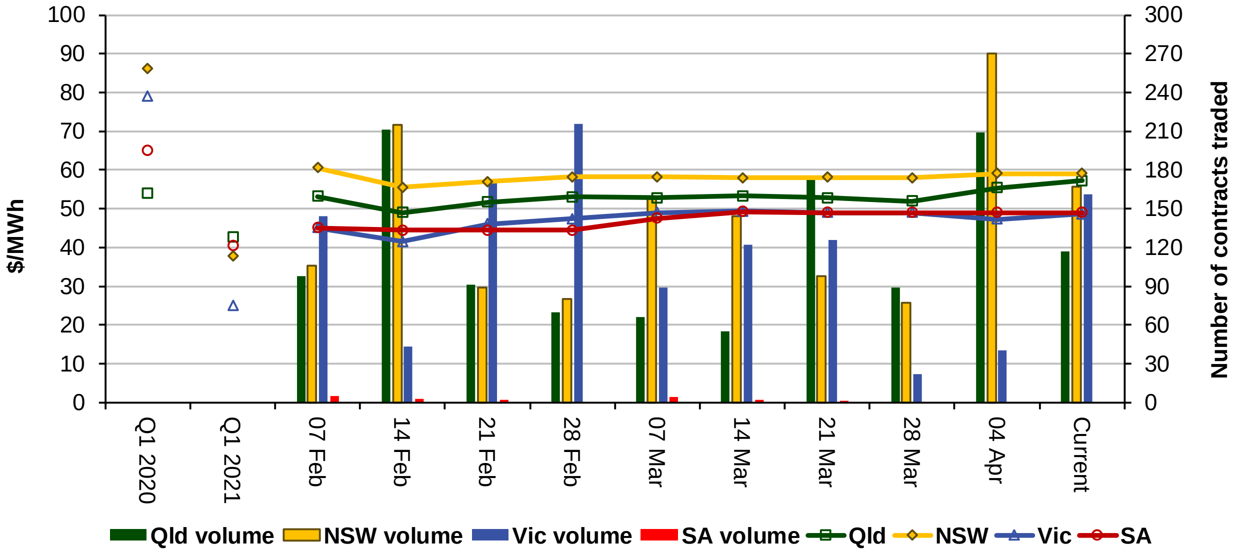
Figure 9: Quarterly base future prices Q2 2021 – Q1 2025



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2022 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 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 2022 base contracts over the past 10 weeks (and the past 2 years)



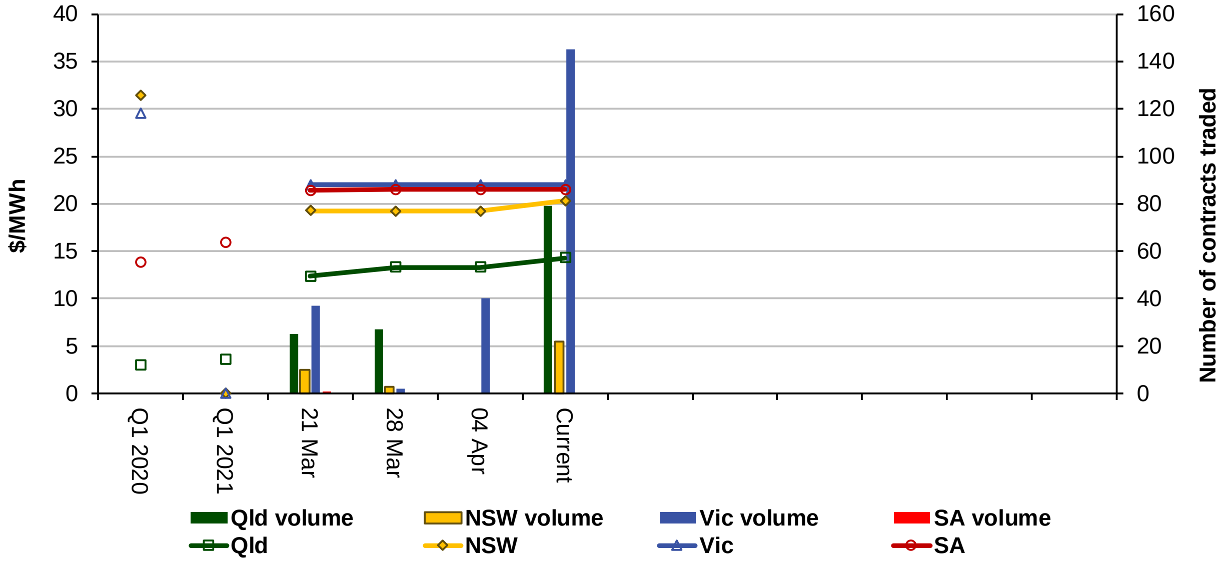
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2022 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 prices are also shown.

Cap contracts for 5 minute settlement (due to commence from Q4 2021) were listed on 22 March 2021. As a result, there's only been 4 weeks of Q1 2022 cap contract trading so far.

Figure 11: Price of Q1 2022 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 2021