Electricity Report

AUSTRALIAN ENERGY REGULATOR

25 – 31 July 2021

Weekly Summary

Weekly volume weighted average (VWA) prices were between $12/MWh in Tasmania to $76/MWh in Queensland. The high VWA Queensland price was driven by the spot price on 26 July reaching over $2,500/MWh (detailed analysis section).

High wind generation in South Australia in the first half of the wind (Figure 6) drove a number of prices below -$100/MWh (see detailed analysis 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 25 to 31 July 2021.

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

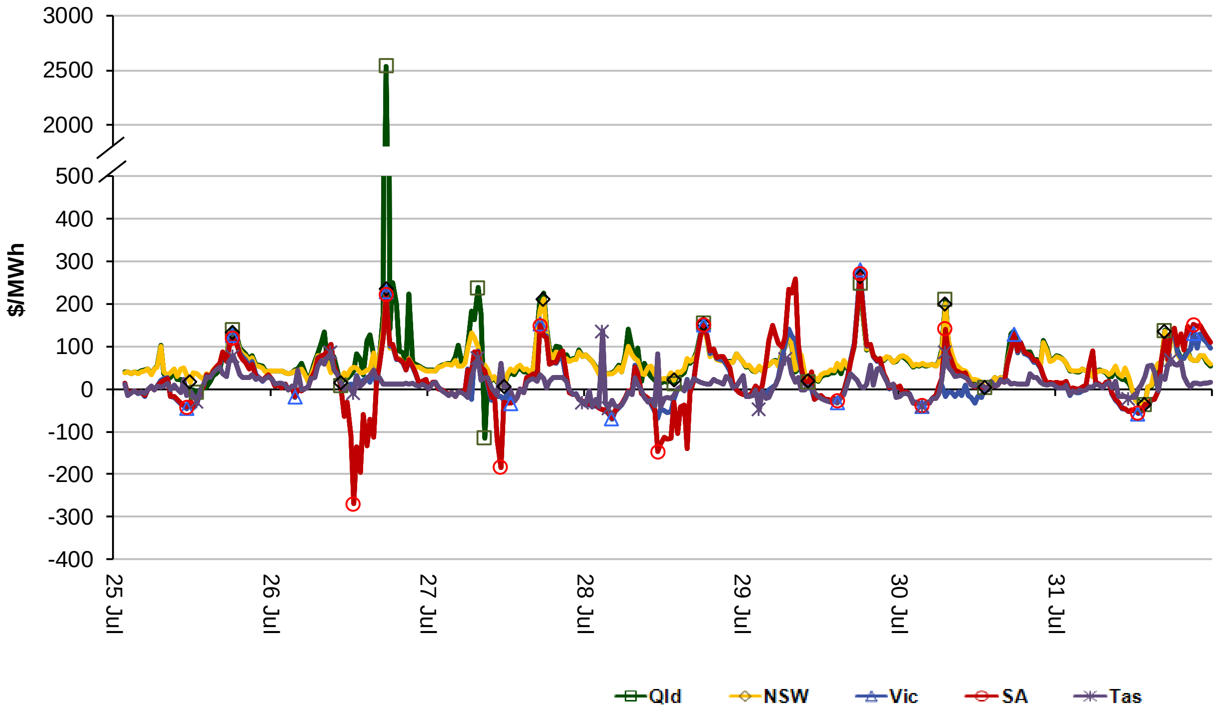


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

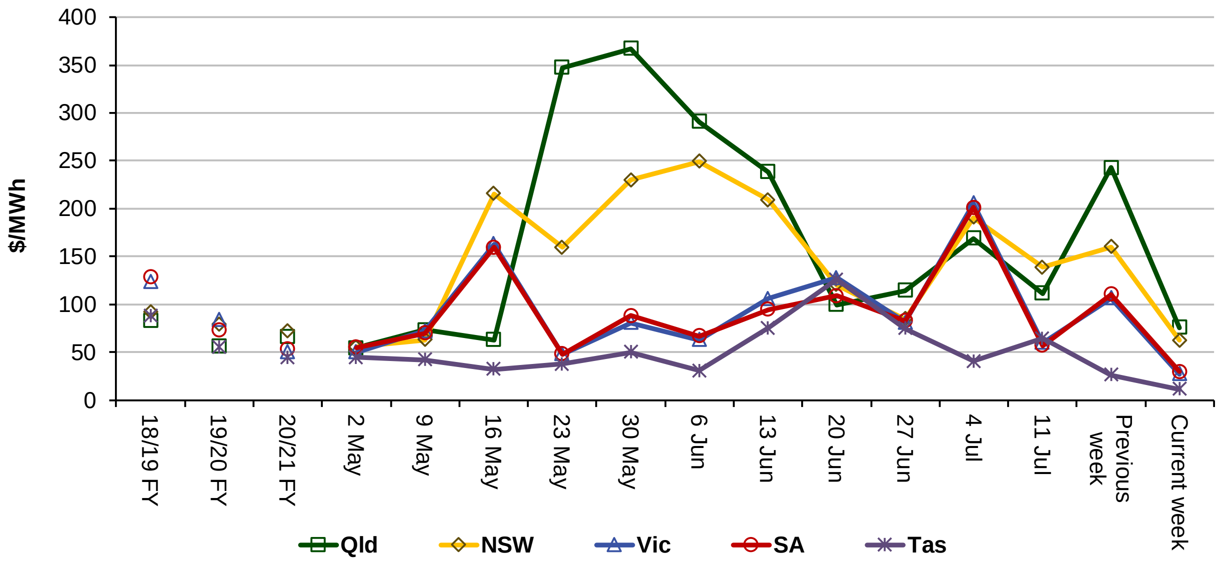


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	76	63	27	30	12
Q3 2020 (QTD)	40	50	66	62	57
Q3 2021 (QTD)	151	136	100	99	39
20-21 financial YTD	40	50	66	62	57
21-22 financial YTD	151	136	100	99	39

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 315 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	3	25	0	2
% of total below forecast	16	46	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

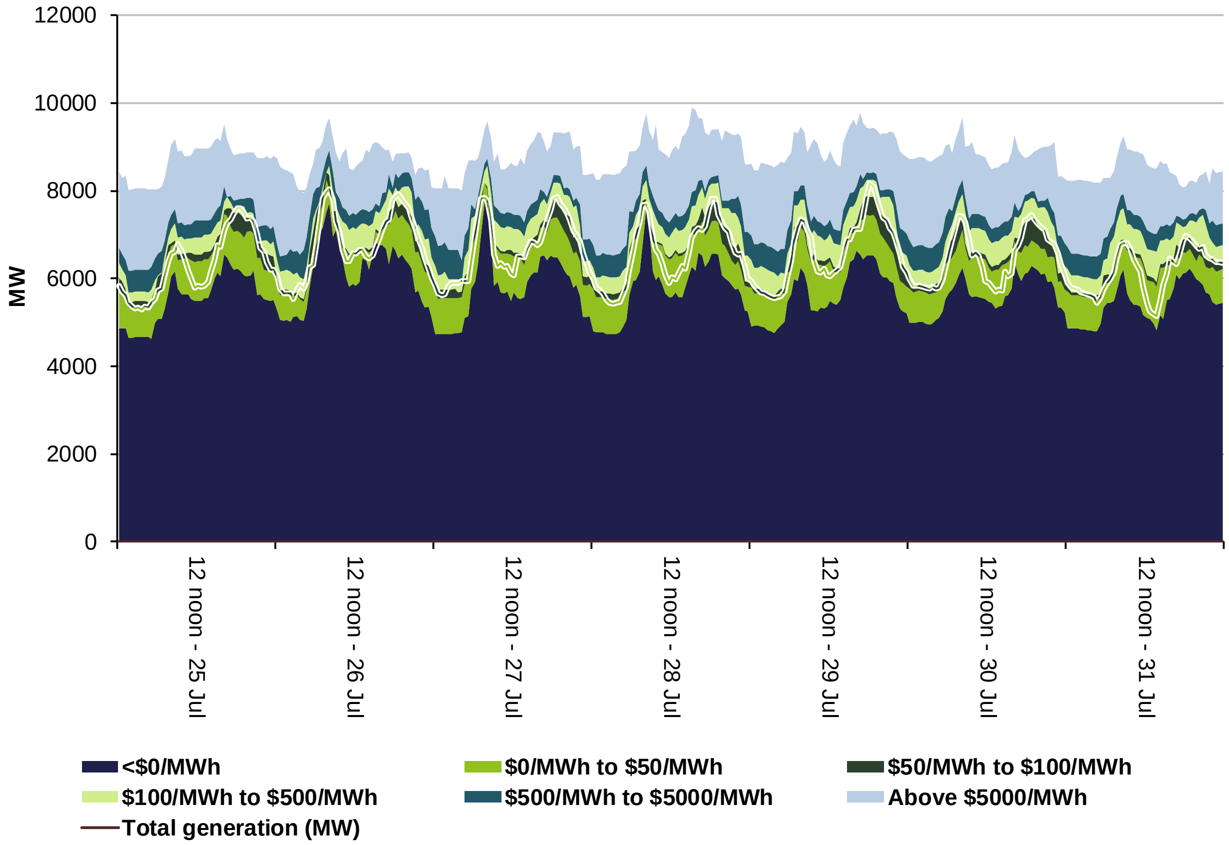


Figure 4: New South Wales generation and bidding patterns

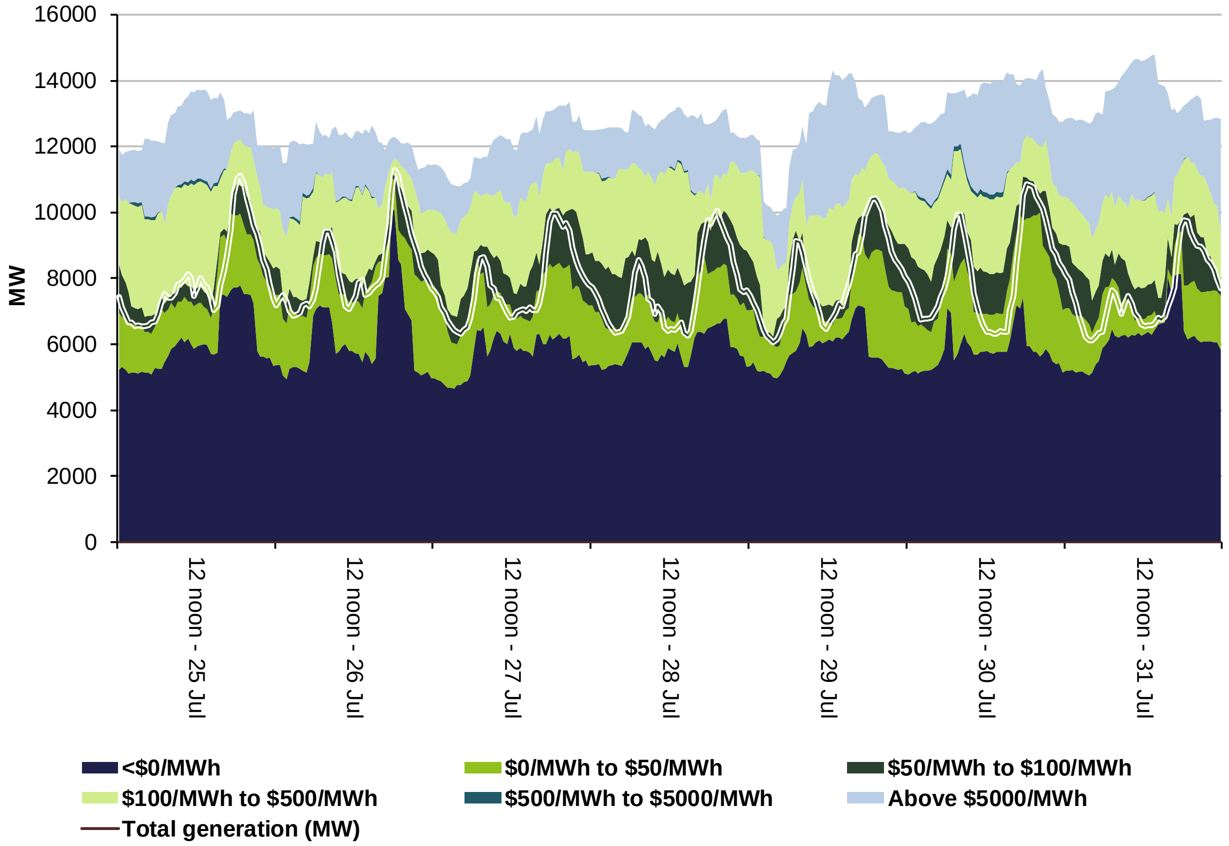


Figure 5: Victoria generation and bidding patterns

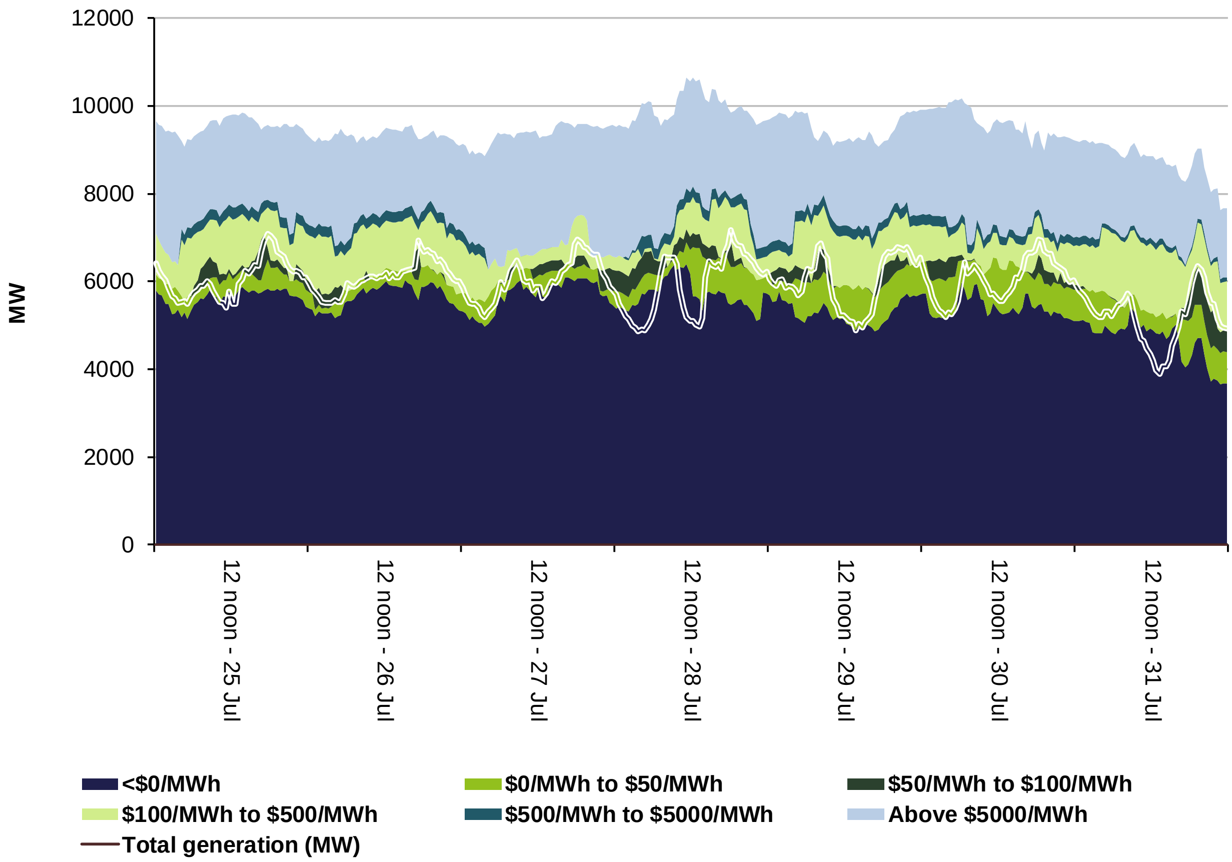


Figure 6: South Australia generation and bidding patterns

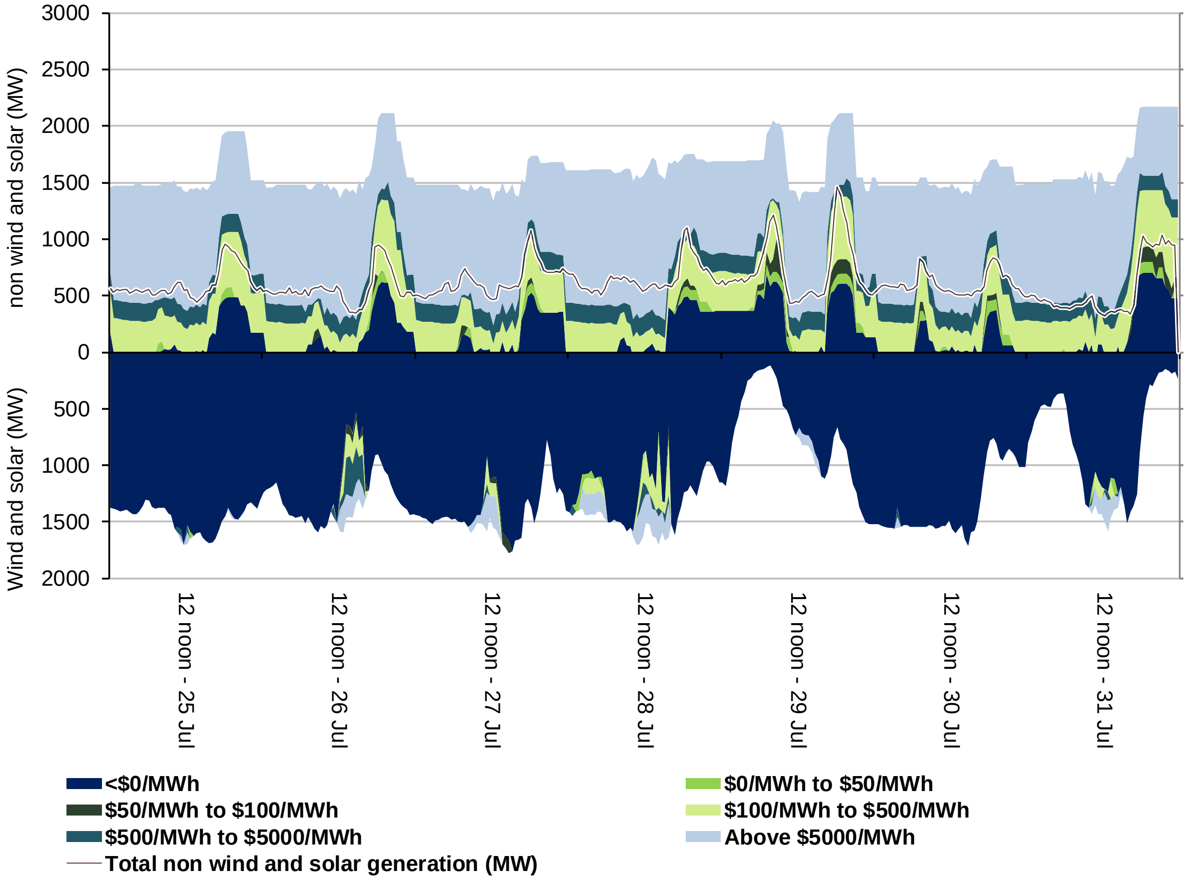
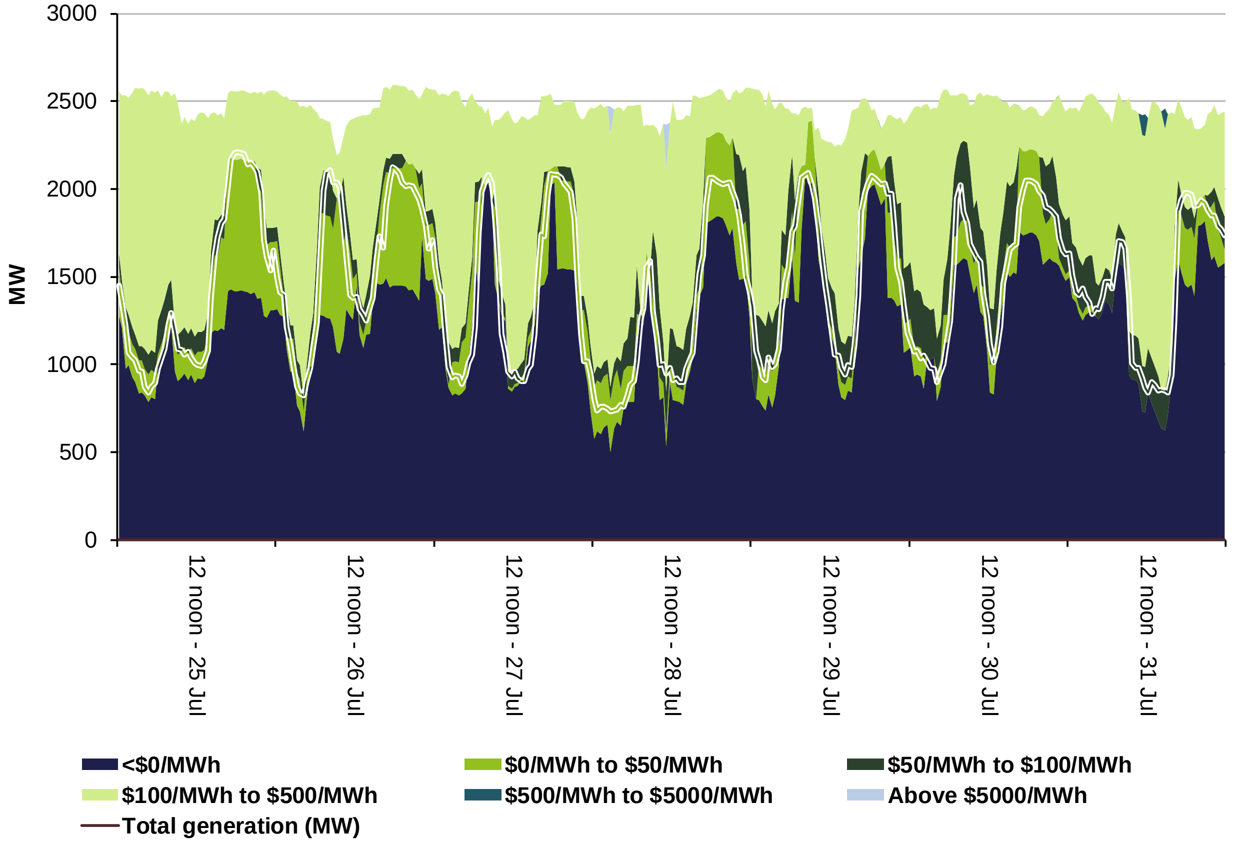


Figure 7: Tasmania generation and bidding patterns



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.

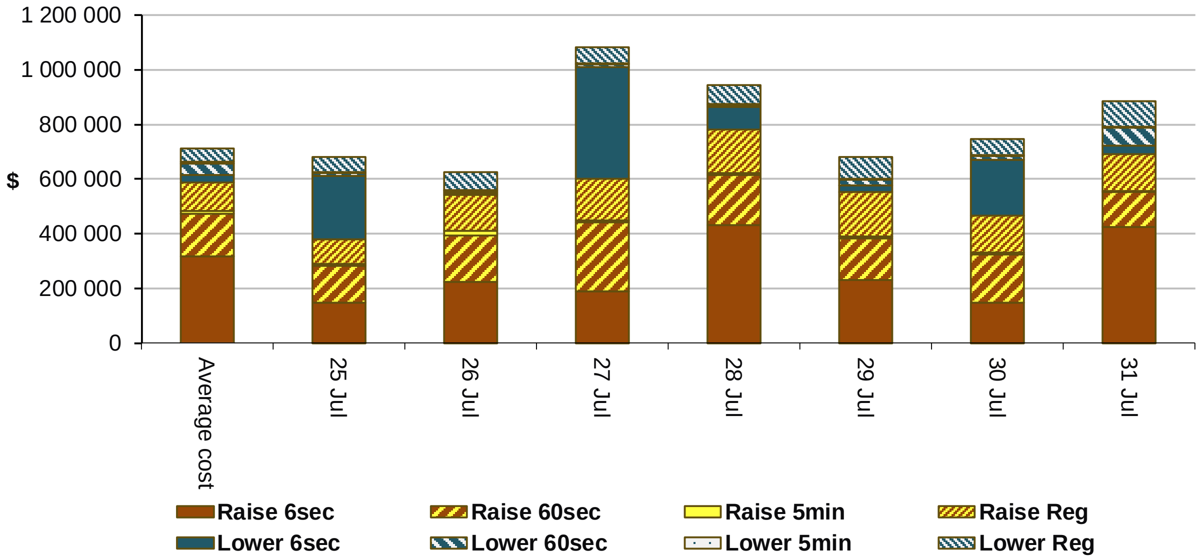
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3,636,500 or less than 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $2,012,500 or around 80% of energy turnover in Tasmania. The high percentage is a result of a few high FCAS prices and a low VWA Tasmanian spot price.

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 $76/MWh and above $250/MWh and there was 1 occasion where the spot price was below -$100/MWh.

Monday, 26 July

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	2,540.26	175.87	301.01	7,859	7,751	7,730	8,806	8,821	8,764

Demand was 108 MW higher than forecast and availability was close to forecast, 4 hours prior.

Rebids effective at 5.40 pm by Callide Power Trading at Callide and at 5.45 pm by Intergen at Millmerran shifted a combined 142 MW of capacity from the price floor to above $15,000/MWh due to forecast prices. At 5.55 pm demand increased by nearly 70 MW while a rebid at Millmerran shifted 20 MW of capacity from the price floor to price cap due to forecast prices. As a result, dispatch prices increased to $13,800/MWh at 5.55 pm.

Tuesday, 27 July

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
9 am	-114.39	68.03	68.35	6,398	6,395	6,407	9,211	9,096	9,090

Demand was close to forecast while availability was 115 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to a rebid by Origin Energy at Mt Stuart which added 138 MW of capacity below $301/MWh in response to a constraint managing line outages between New South Wales and Queensland.

At 9 am demand fell by nearly 90 MW while wind generation increased by over 90 MW, most of which was offered at the price floor. A constraint managing negative residues across the New South Wales to Queensland interconnectors saw several generators ramp constrained and unable to set price, resulting in the 9 am dispatch price being set at the price floor.

New South Wales

There was 1 occasion where the spot price in New South Wales was greater than 3 times the New South Wales weekly average price of $63/MWh and above $250/MWh.

Thursday, 29 July

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
6.30 pm	265.33	265.17	265.66	10,680	10,797	10,965	13,338	13,609	13,854

Prices were close to forecast.

Victoria

There was 1 occasion where the spot price in Victoria was greater than 3 times the Victoria weekly average price of $27/MWh and above $250/MWh.

Thursday, 29 July

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
6.30 pm	280.58	299.50	299.50	6,990	6,809	6,832	9,205	9,519	9,598

Prices were close to forecast.

South Australia

There were 2 occasions where the spot price in South Australia was greater than 3 times the South Australia weekly average price of $30/MWh and above $250/MWh and there were 15 occasions where the spot price was below -$100/MWh.

Monday, 26 July

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
12.30 pm	-108.97	12.04	11.16	863	866	782	3,023	2,718	2,722
1 pm	-269.95	8.42	-450	903	847	762	3,028	2,715	2,713
1.30 pm	-136.28	12.18	-939.87	864	845	755	2,906	2,734	2,744

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 pm	-194.89	-2.12	-205.30	897	863	766	2,898	2,754	2,735
3 pm	-132.97	17.88	10.16	910	872	824	2,772	2,743	2,762
4 pm	-112.47	24.77	25.47	1065	976	948	2,891	2,764	2,786

Demand was either close to forecast or up to 89 MW higher than forecast, 4 hours prior. Availability was between 29 MW and 313 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind.

Higher than forecast availability saw prices lower than forecast at the start of each trading interval after which participants rebid capacity to higher prices in response.

For the 2 pm trading interval, a rebid by EnergyAustralia at Waterloo Wind Farm shifted 65 MW from prices above -$32/MWh to the price floor due to forecast prices, resulting in the dispatch price falling close to the price floor for 5 minutes.

Tuesday, 27 July

Table 8: 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 am	-118.85	9.20	9	880	1,123	1,128	2,964	2,736	2,766
11.30 am	-183.93	-30.22	-29.50	901	1,019	1,067	3,015	2,750	2,770

Demand was between 118 MW and 243 MW lower than forecast while availability was between 228 MW and 265 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

Due to a combination of lower than forecast demand, higher than forecast availability and prices fell up to -$400/MWh on several occasions in each trading interval, leading to lower than forecast spot prices.

Wednesday, 28 July

Table 9: 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	-147.24	-450	-42.75	1,303	940	943	3,271	2,813	2,847
Midday	-128.20	-450	-895.19	1,142	889	877	3,227	2,862	2,859
12.30 pm	-113.95	-464.25	-867.03	1,177	850	846	3,127	2,890	2,863
1 pm	-117.45	-1,000	-869.73	1,207	821	841	3,169	2,913	2,866

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	-114.69	-450	-866.17	1,196	826	825	3,308	2,959	2,867
2.30 pm	-103.21	-190	-874.00	1,148	822	828	3,267	2,799	2,829
4 pm	-139.48	4.36	-597.49	1,211	958	919	3,287	2,908	2,867

Demand was between 253 MW and 386 MW higher than forecast and availability was between 237 MW and 468 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

Rebids by Lincoln Gap Wind Farm at 8 am and by Infigen Energy at Lake Bonney at 9 am and 10.46 am shifted a combined 364 MW of capacity from the price floor to higher prices due to low forecast prices. For the 11.30 am, 1 pm, 1.30 pm, and 2.30 pm trading intervals, prices were set above forecast for most of each trading interval.

For the midday and 12.30 pm trading intervals, prices were set close to forecast at the start of each trading interval. In response, participants rebid up to 390 MW of capacity from the price floor to higher prices, resulting in prices being set above forecast for the remainder of each trading interval.

For the 4 pm trading interval, there was around a 100 MW increase in renewable offers, most of which was at the price floor. Prices were set at -$1000/MWh at the start of the trading interval, causing the spot price to be set lower than forecast. In response to low prices, participants rebid over 660 MW from the price floor to higher prices.

Thursday, 29 July

Table 10: 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
8.30 am	258.07	578.81	578.81	1,782	1,723	1,744	2,185	2,123	2,208
6.30 pm	271.09	379.95	329.90	1,837	1,839	1,816	2,775	2,958	2,454

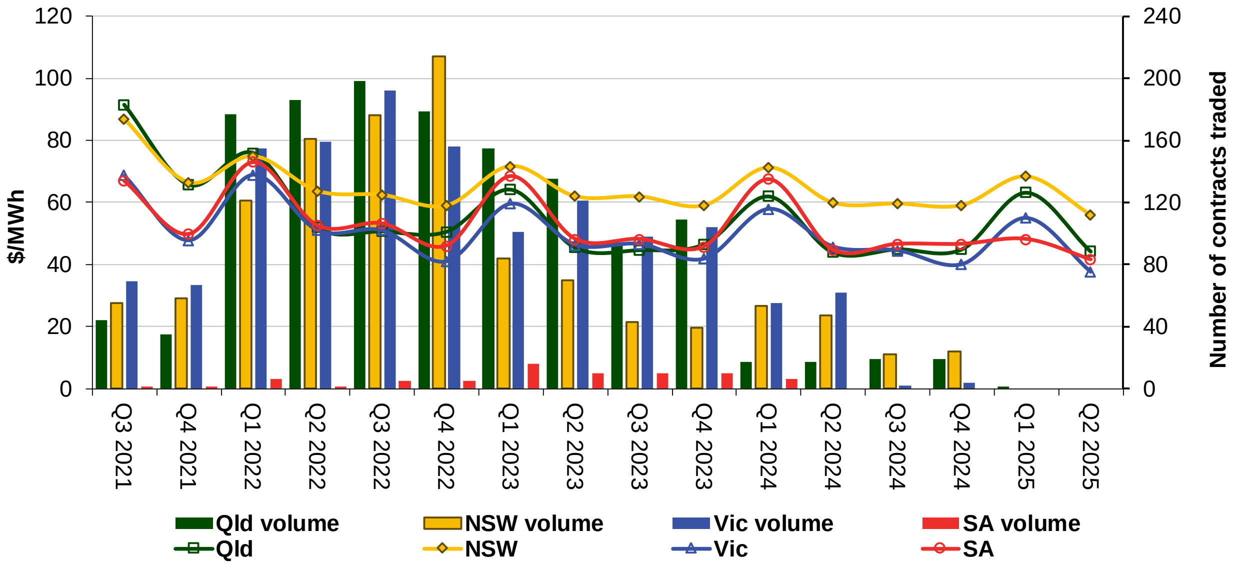
For the 8.30 am trading interval, demand was 59 MW higher than forecast while availability was 62 MW higher than forecast, 4 hours prior. Participants added nearly 200 MW of capacity at low prices and rebid nearly 300 MW of capacity from prices above $579/MWh to low prices due to forecast prices, directions and constraint management. As a result, prices remained below $281/MWh throughout the trading interval.

For the 6.30 pm trading interval, at 5 pm Origin rebid 151 MW of capacity at Quarantine from the price cap to below $71/MWh due to demand forecasts. A constraint used to manage system security in South Australia was forecast to limit imports to 420 MW but did not bind during 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.

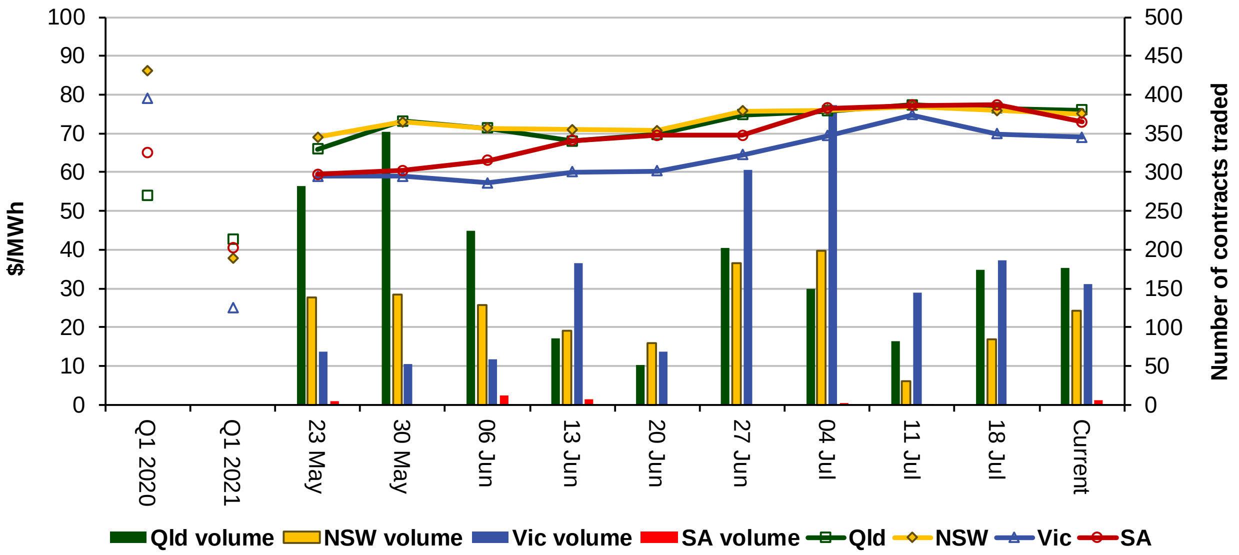
Figure 9: Quarterly base future prices Q3 2021 – Q2 2025



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)



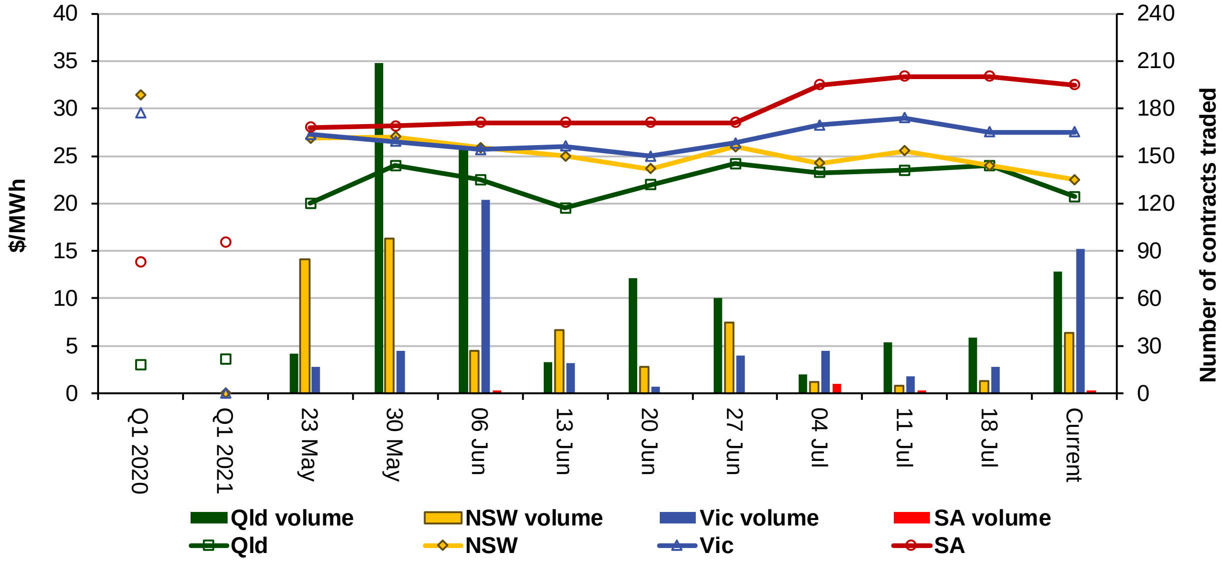
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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.

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
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