Electricity Report

AUSTRALIAN ENERGY REGULATOR

22 – 28 August 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $34/MWh in Tasmania to $73/MWh in New South Wales. Prices throughout the week peaked at $359/MWh in Queensland on 25 August while high wind generation in South Australia at the start of the week drove negative prices that breached our reporting thresholds. See detailed analysis section for more information.

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 22 to 28 August 2021.

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

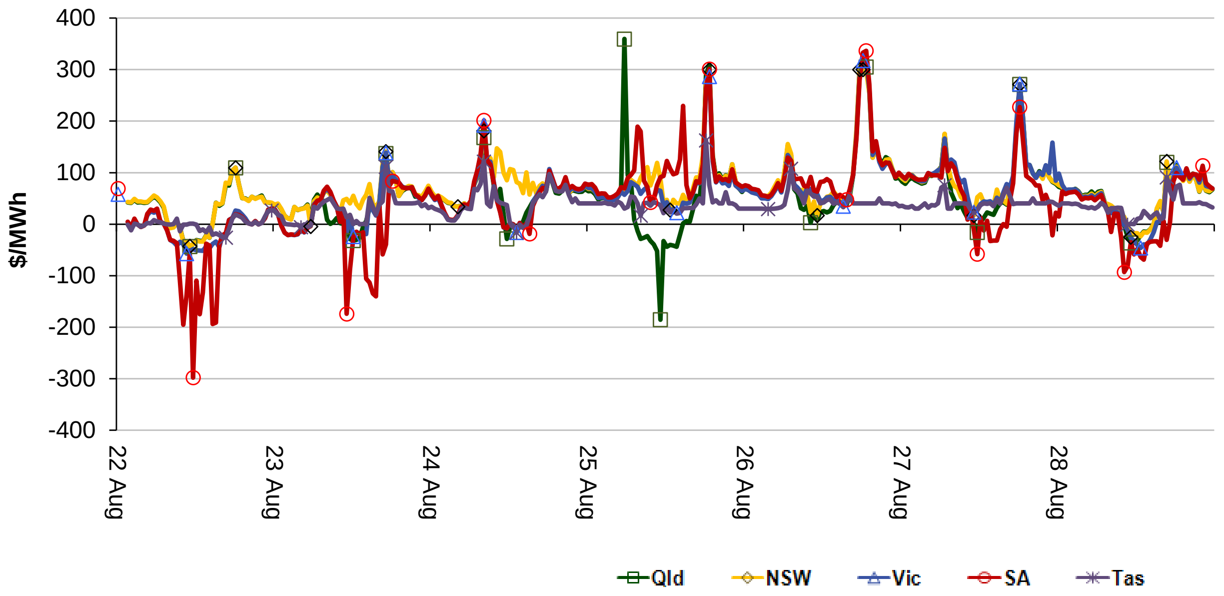


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

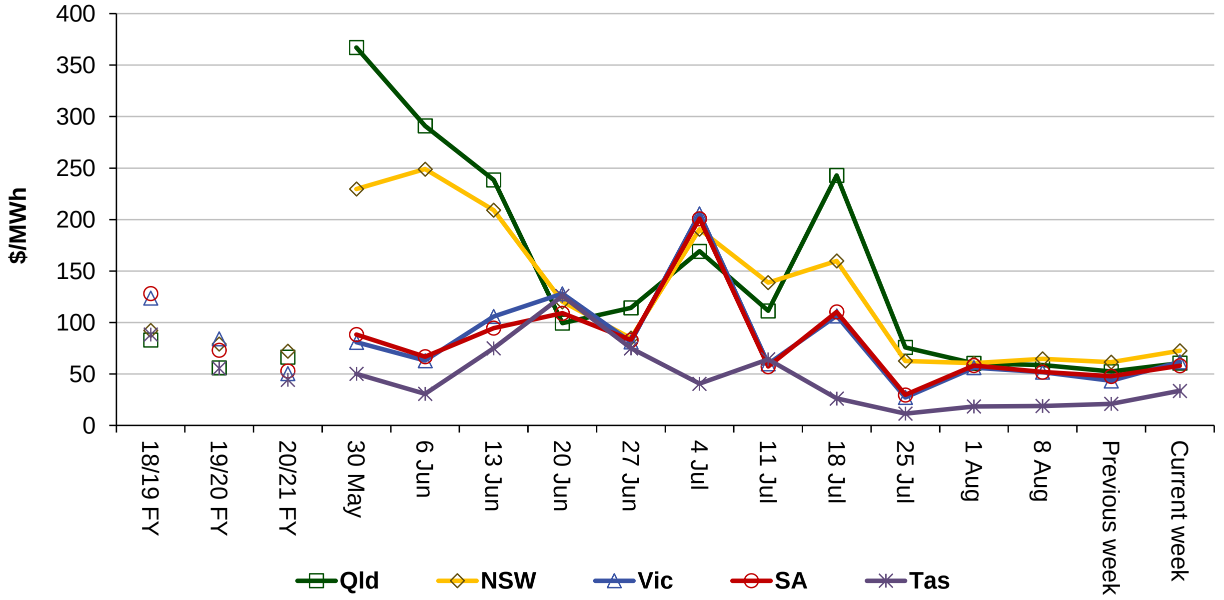


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	61	73	62	58	34
Q3 2020 QTD	37	52	63	58	58
Q3 2021 QTD	108	104	79	79	31
20-21 financial YTD	37	52	63	58	58
21-22 financial YTD	108	104	79	79	31

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 280 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	20	0	0
% of total below forecast	14	50	0	12

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

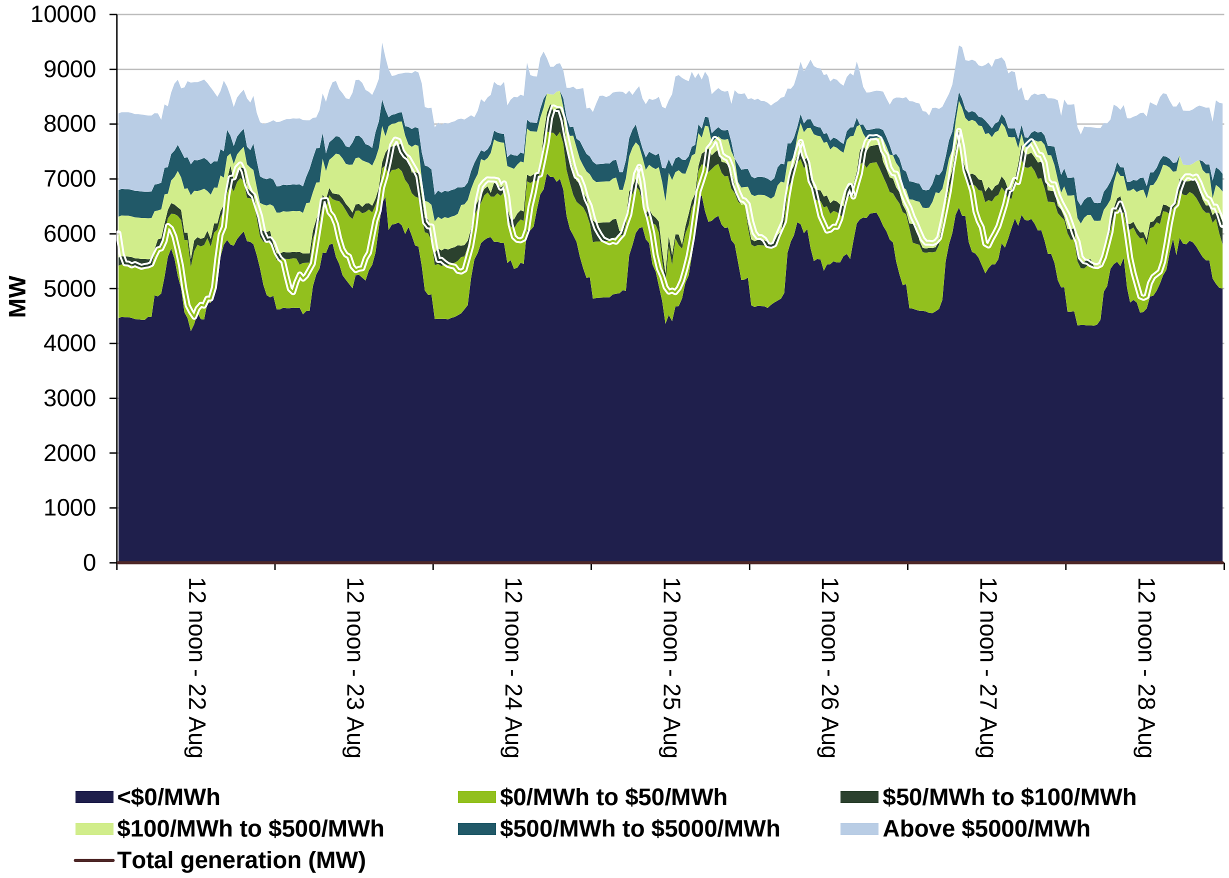


Figure 4: New South Wales generation and bidding patterns

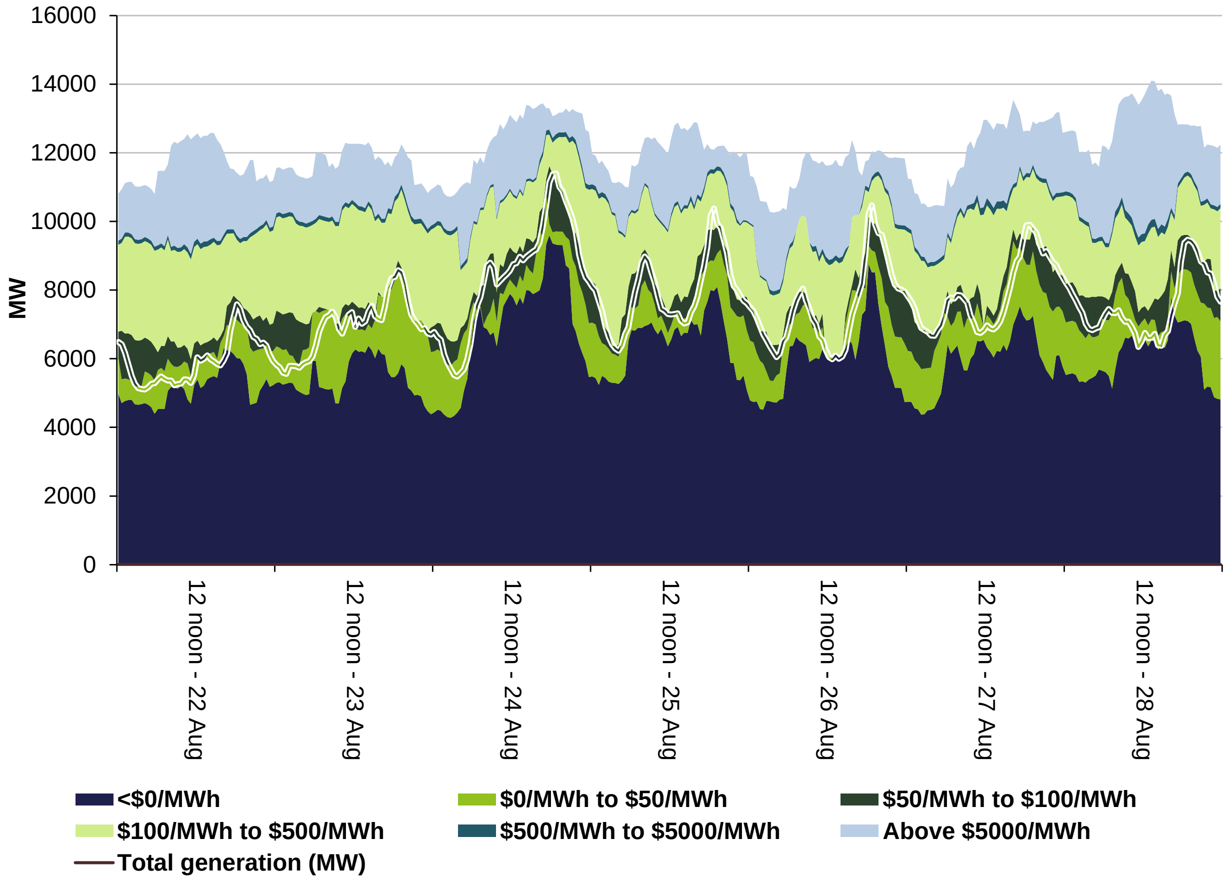


Figure 5: Victoria generation and bidding patterns

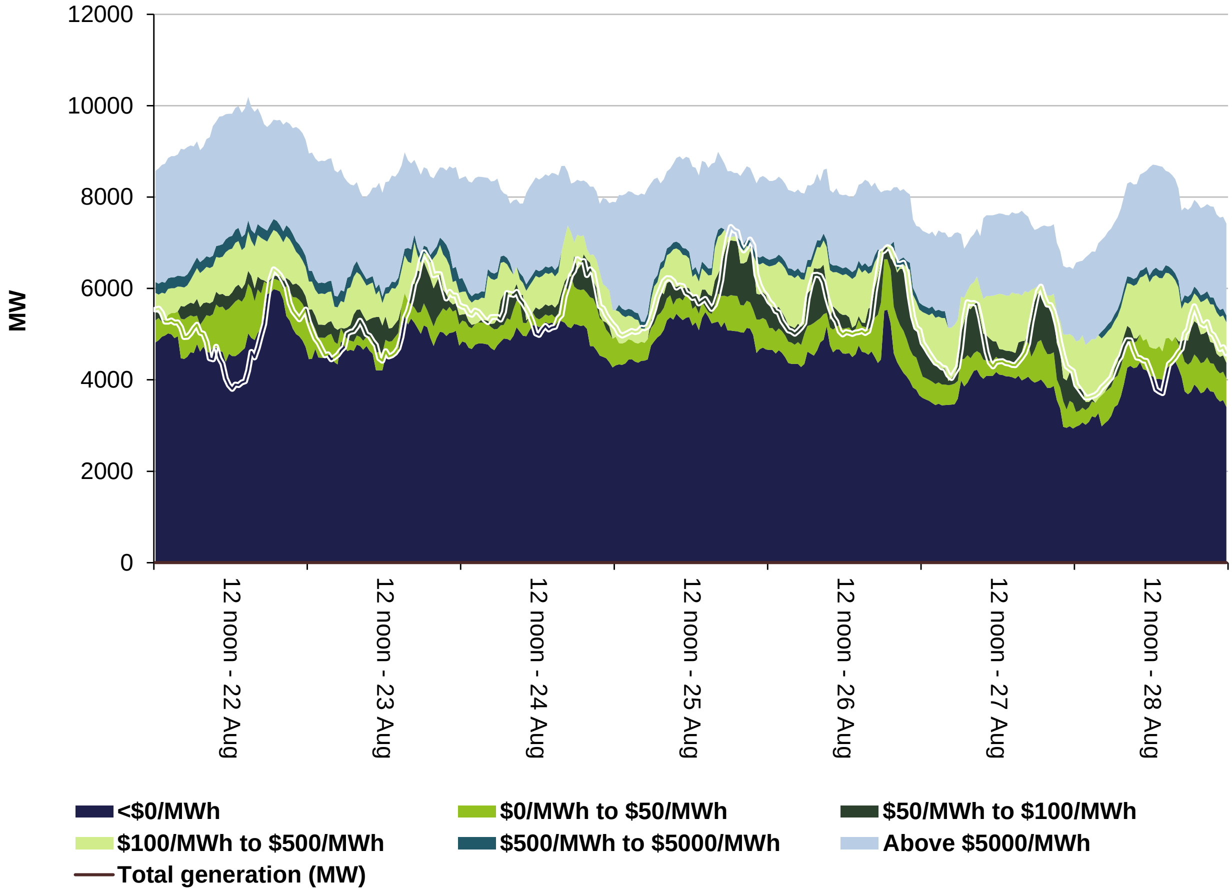


Figure 6: South Australia generation and bidding patterns

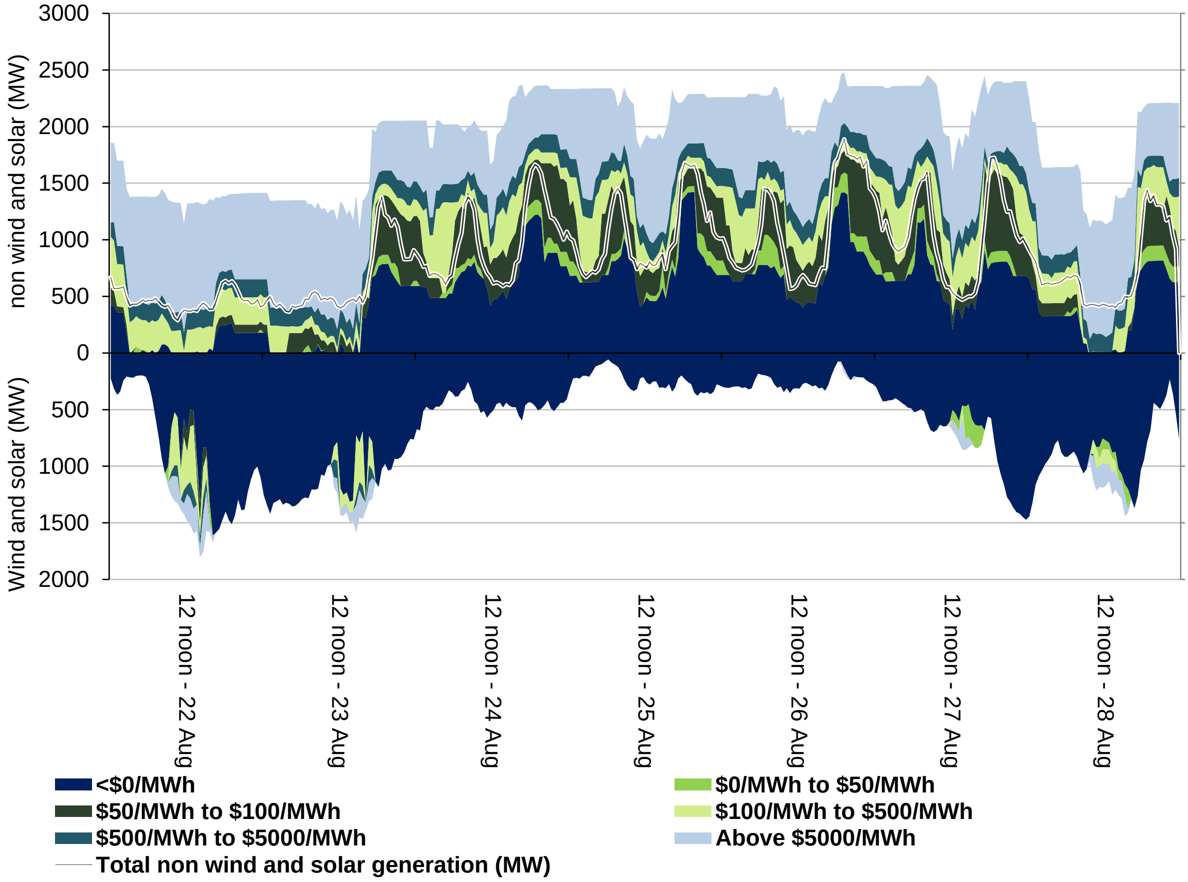
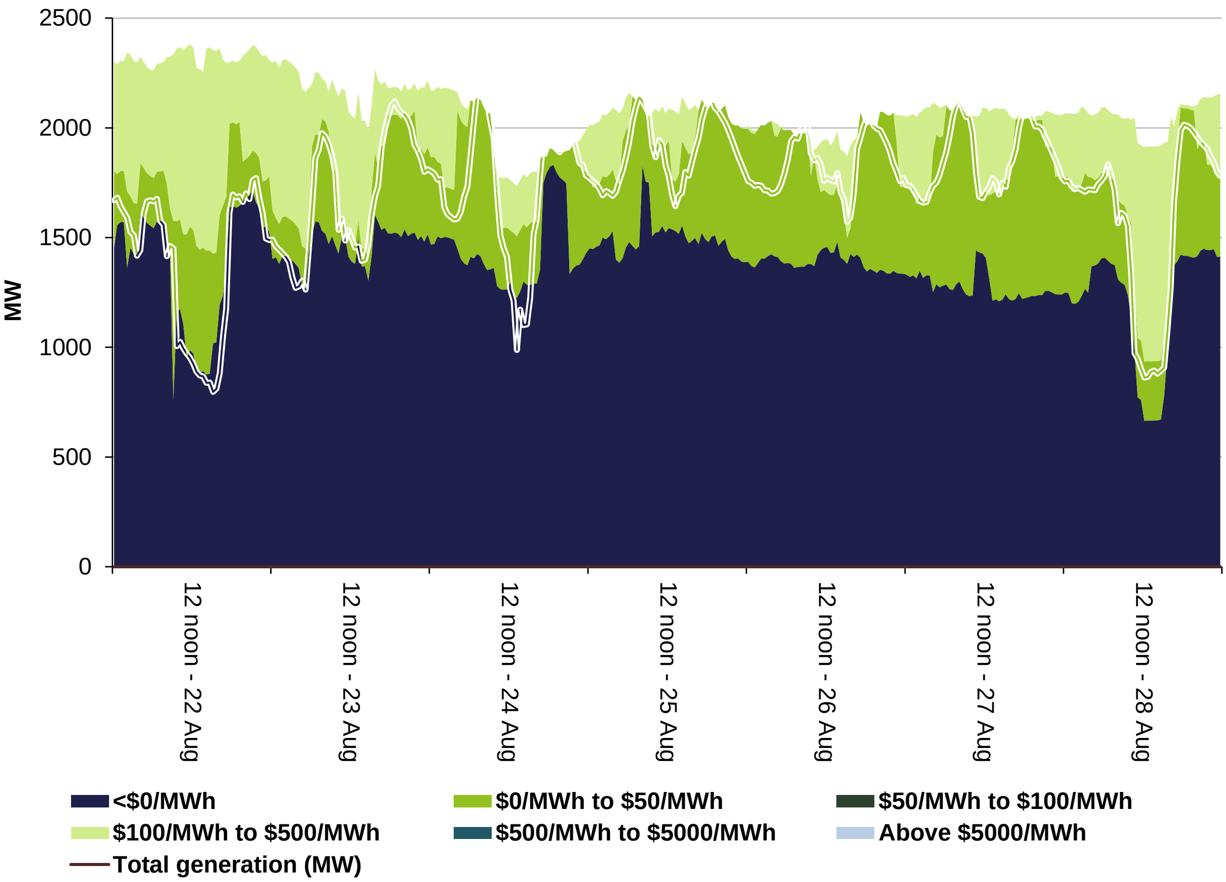


Figure 7: Tasmania generation and bidding patterns



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.

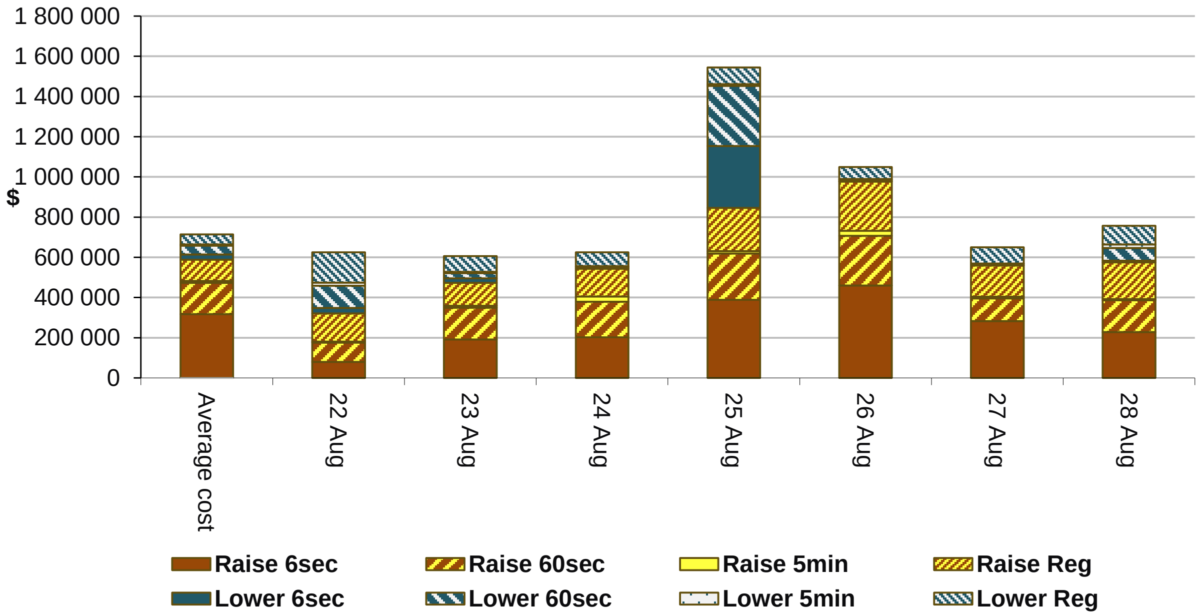
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $5,519,500 or around 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $335,500 or less than 5% 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



High FCAS prices on 25 August were driven by a high requirement in Queensland for lower 6 second (L6) and lower 60 second (L60) services due to a planned outage to the Armidale to Tamworth line in New South Wales. L6 and L60 prices reached the price cap at 1.10 pm.

Detailed market analysis of significant price events

Mainland

There were 7 occasions where prices across the mainland were greater than 3 times the New South Wales weekly average price of $73/MWh and above $250/MWh. The New South Wales price is used a proxy for the NEM.

Wednesday, 25 August

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
6.30 pm	274.31	299.99	299.98	27,006	27,099	27,102	31,929	31,993	32,042
7 pm	299.98	299.99	299.99	27,191	27,358	27,421	31,788	31,977	31,972

Prices were close to forecast.

Thursday, 26 August

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
6 pm	299.98	299.98	299.98	25,774	26,212	26,247	30,773	31,014	31,954
6.30 pm	299.98	699.75	299.99	26,958	27,392	27,424	31,019	31,449	32,201
7 pm	297.74	739.5	299.99	27,261	27,687	27,692	31,169	31,607	32,356
7.30 pm	254.77	310.19	299.98	26,718	27,303	27,297	31,409	31,343	32,439

For the 6 pm trading interval, prices were close to forecast.

For the 6.30 pm to 7.30 pm trading intervals, demand was between 426 MW and 585 MW lower than forecast 4 hours prior. Availability was around 430 MW lower than forecast 4 hours prior for the 6.30 pm and 7 pm trading intervals and close to forecast at 7.30 pm. Lower than forecast availability was due participants removing capacity at various prices due to plant reasons and forecast prices.

From 2 pm participants rebid at least 900 MW of capacity from high prices to the price floor due to plant reasons and forecast prices. Participant rebidding and lower than forecast demand saw prices below forecast throughout each trading interval.

Friday, 27 August

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	271.29	299.98	299.98	25,884	25,781	25,942	31,352	31,704	31,522

Prices were close to forecast

Queensland

There were 2 occasions where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $61/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Wednesday, 25 August

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 am	359.35	41.91	34.49	6,064	6,026	6,101	8,610	8,639	8,567
11.30 am	-185.36	-415.01	-1,000	4,220	4,341	4,415	8,287	8,117	8,436

For the 6 am trading interval, demand and availability were close to forecast 4 hours prior. In preparation for a planned outage of the Armidale to Tamworth line in New South Wales, a ramping constraint reduced the output of Kogan Creek, which had all of its capacity priced at the price floor. This combined with a 124 MW increase in demand at 6 am saw the dispatch price reach $1,877/MWh.

For the 11.30 am trading interval, demand was 121 MW lower than forecast, and availability was 170 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation which mostly offers below $0/MWh. From around 7.30 am onwards, participants shifted nearly 1000 MW from the price floor to prices above $109/MWh due to forecast prices. As a result prices remained higher than forecast throughout most of the trading interval.

South Australia

There were 14 occasions where the spot price was below -$100/MWh.

Sunday, 22 August

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
10 am	-110.27	-118.68	-554.19	795	690	721	2,600	2,371	2,542
10.30 am	-195.06	-594.45	-1,000	722	568	596	2,638	2,424	2,568
11 am	-136.46	-590.80	-1,000	623	480	507	2,655	2,521	2,617
Midday	-297.81	-1,000	-1,000	503	328	402	2,751	2,649	2,674
12.30 pm	-109.62	-1,000	-1,000	545	266	353	2,809	2,717	2,675
1 pm	-174.63	-1,000	-1,000	496	246	340	2,842	2,665	2,653
1.30 pm	-132.86	-1,000	-1,000	491	223	329	2,918	2,664	2,646
3 pm	-193.85	-621.34	-1,000	694	389	428	3,081	2,585	2,629
3.30 pm	-191.17	-300	-1,000	669	463	488	2,896	2,567	2,622

For the 10 am trading interval, prices were close to forecast 4 hours prior.

For the remaining trading intervals, demand was between 143 MW and 305 MW higher than forecast, and availability was between 92 MW and 496 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation which mostly offers below $0/MWh.

At the start of each trading interval prices were close to the low prices forecast. In response participants rebid capacity from the price floor to higher prices and to manage binding constraints. Prices remained higher than forecast for the remainder of each trading interval.

Monday, 23 August

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
11.30 am	-173.96	0.01	0	915	962	997	2,444	2,567	2,591
2.30 pm	-105.74	-180.54	-1,000	990	779	811	2,737	2,584	2,634
3 pm	-113.11	-142.14	-1,000	965	787	827	2,855	2,598	2,653
3.30 pm	-134.77	-3.10	-229.92	967	858	878	2,640	2,639	2,654

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	-139.93	24.60	.57	1083	965	950	2,726	2,751	2,736

For the 11.30 am trading interval, demand was 47 MW lower than forecast and availability was 123 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast renewable generation which mostly offers below $0/MWh.

At 11.20 am demand fell by 23 MW while wind generation increased by 36 MW. With no capacity offered between -$35/MWh and the price floor the price fell to the price floor for 5 minutes. In response, participants rebid over 500 MW of capacity from the price floor to higher prices.

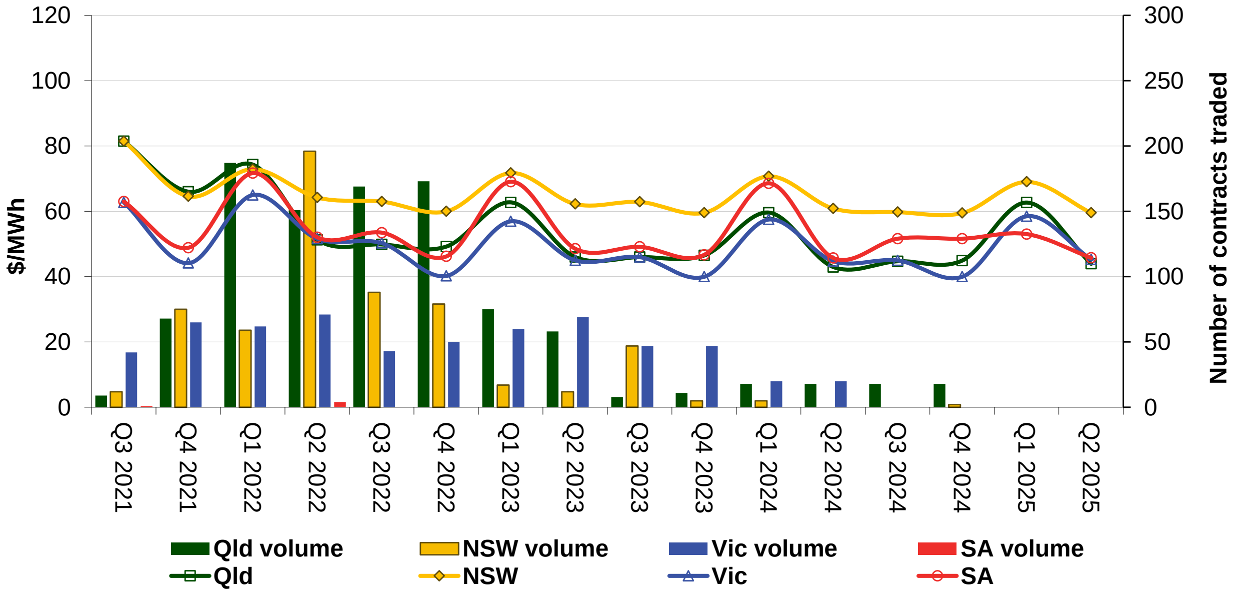
For the 2.30 pm and 3 pm trading intervals, prices were close to forecast 4 hours prior.

For the 3.30 pm and 4 pm trading intervals, demand was between 109 MW and 118 MW higher than forecast while availability was close to forecast, 4 hours prior. Rebids effective at the start of each trading interval shifted at least 300 MW of capacity to the price floor due to forecast prices and managing binding constraints. Prices were set at the price floor at the start of both trading intervals, resulting in lower than forecast spot 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.

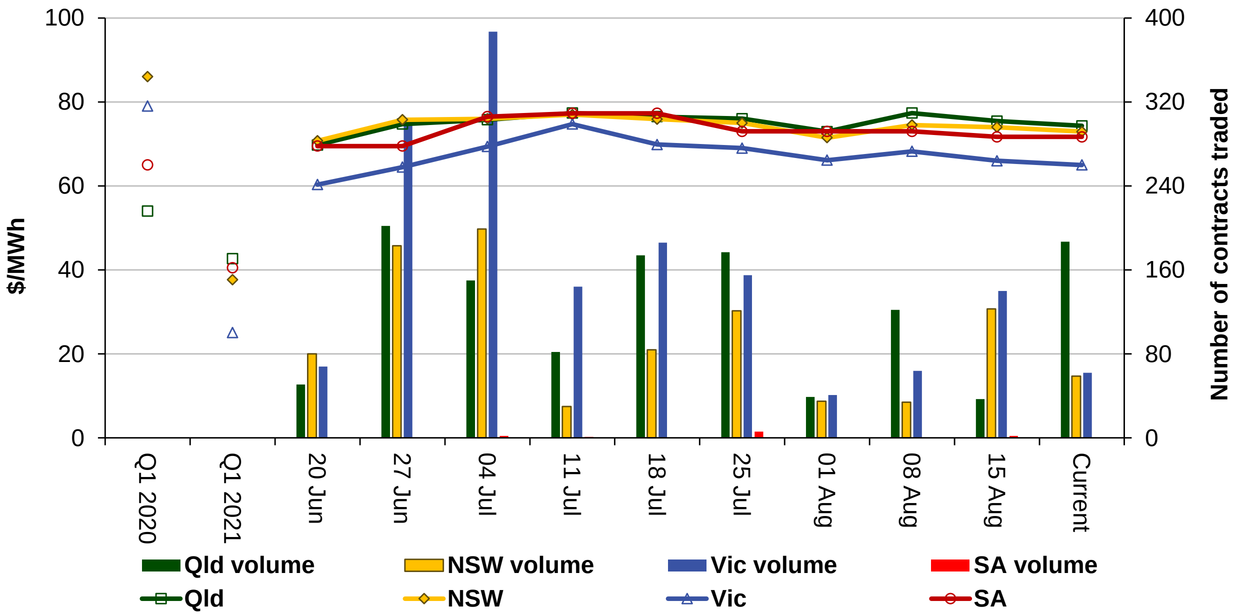
Figure 9: Quarterly base future prices Q3 2021 – Q2 2025



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)

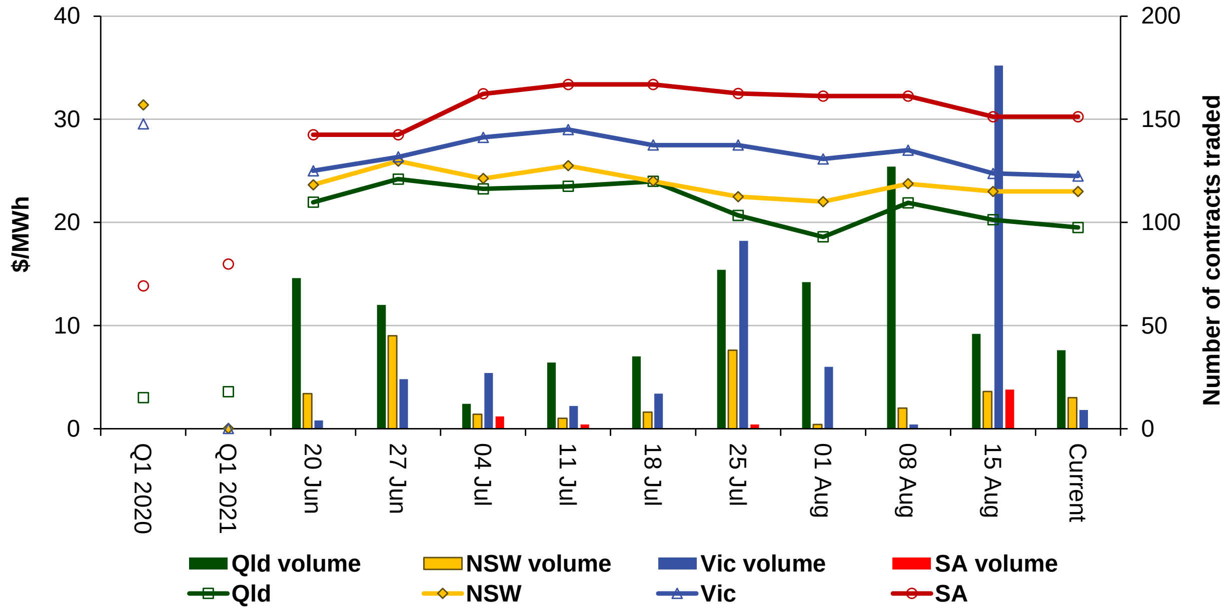


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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.

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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