Electricity Report

1 – 7 August 2021

Weekly Summary

Weekly volume weighted average prices ranged from $19/MWh in Tasmania to $61/MWh in New South Wales.

VWA quarter to date prices for Q3 2021 are tracking between $28/MWh and $96/MWh higher across the mainland, compared to the same time last year. This increase has been driven by high prices in preceding weeks.

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 1 to 7 August 2021.

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

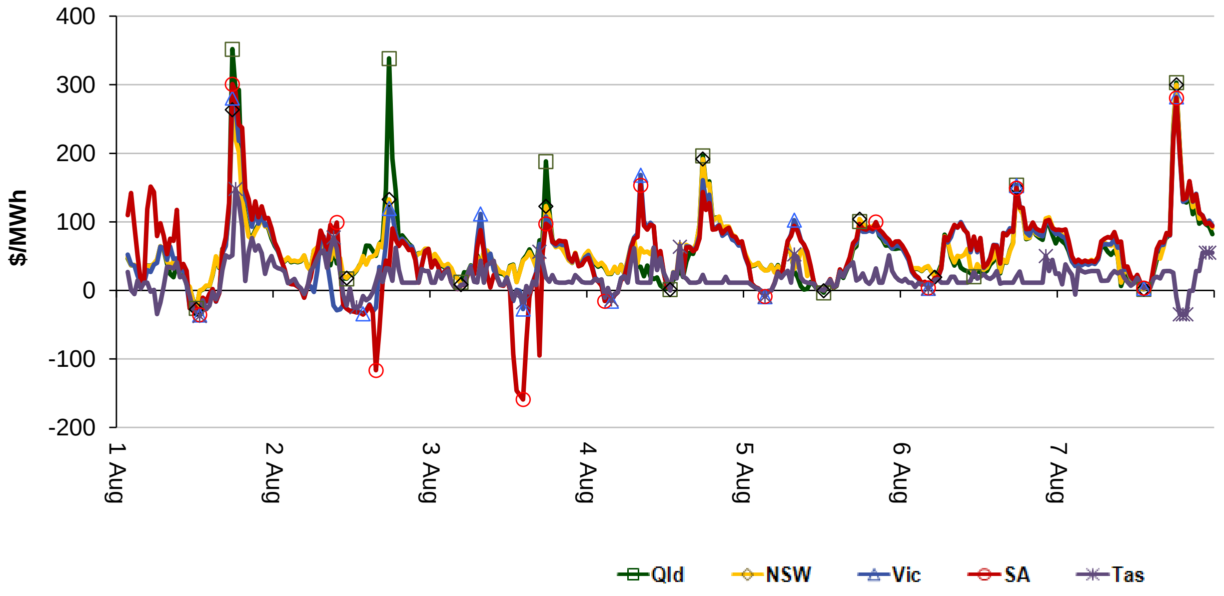


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

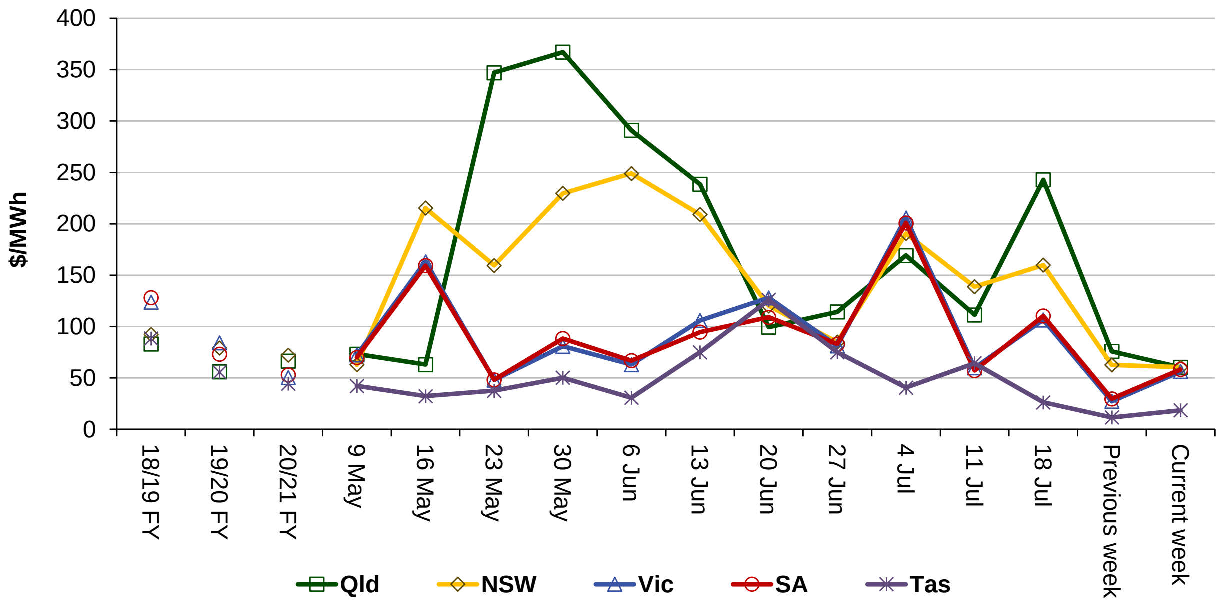


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	60	61	56	58	19
Q3 2020 QTD	39	49	64	59	56
Q3 2021 QTD	135	123	92	91	35
20-21 financial YTD	39	49	64	59	56
21-22 financial YTD	135	123	92	91	35

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 303 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	5	13	0	1
% of total below forecast	10	61	0	10

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

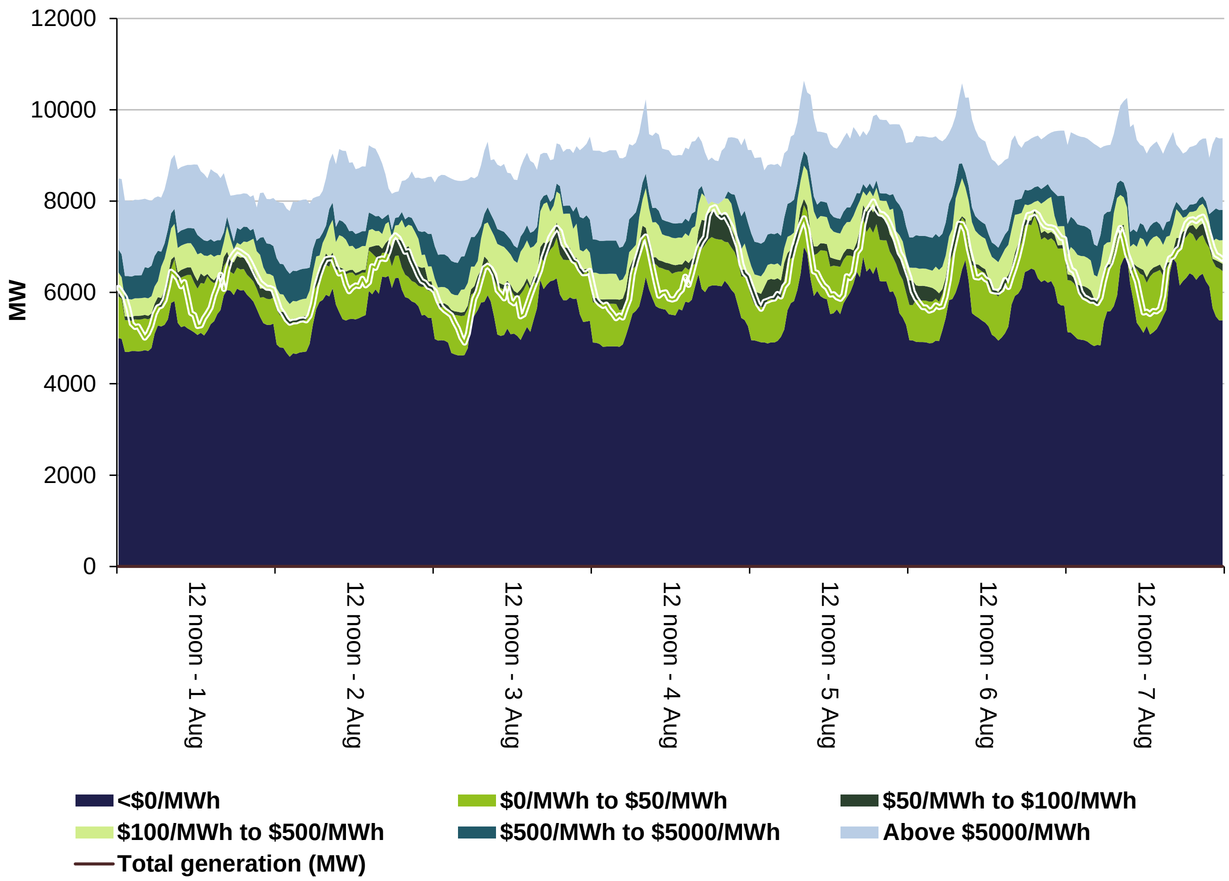


Figure 4: New South Wales generation and bidding patterns

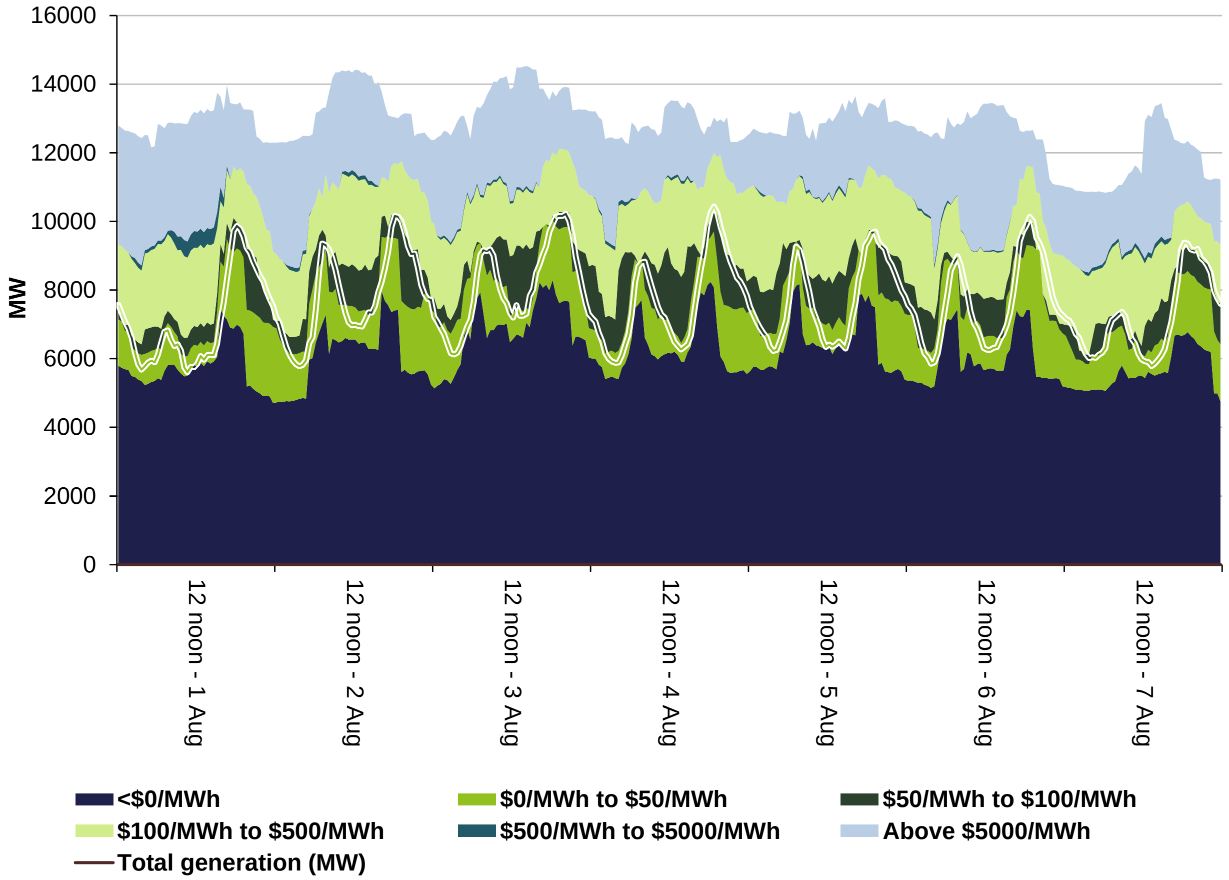


Figure 5: Victoria generation and bidding patterns

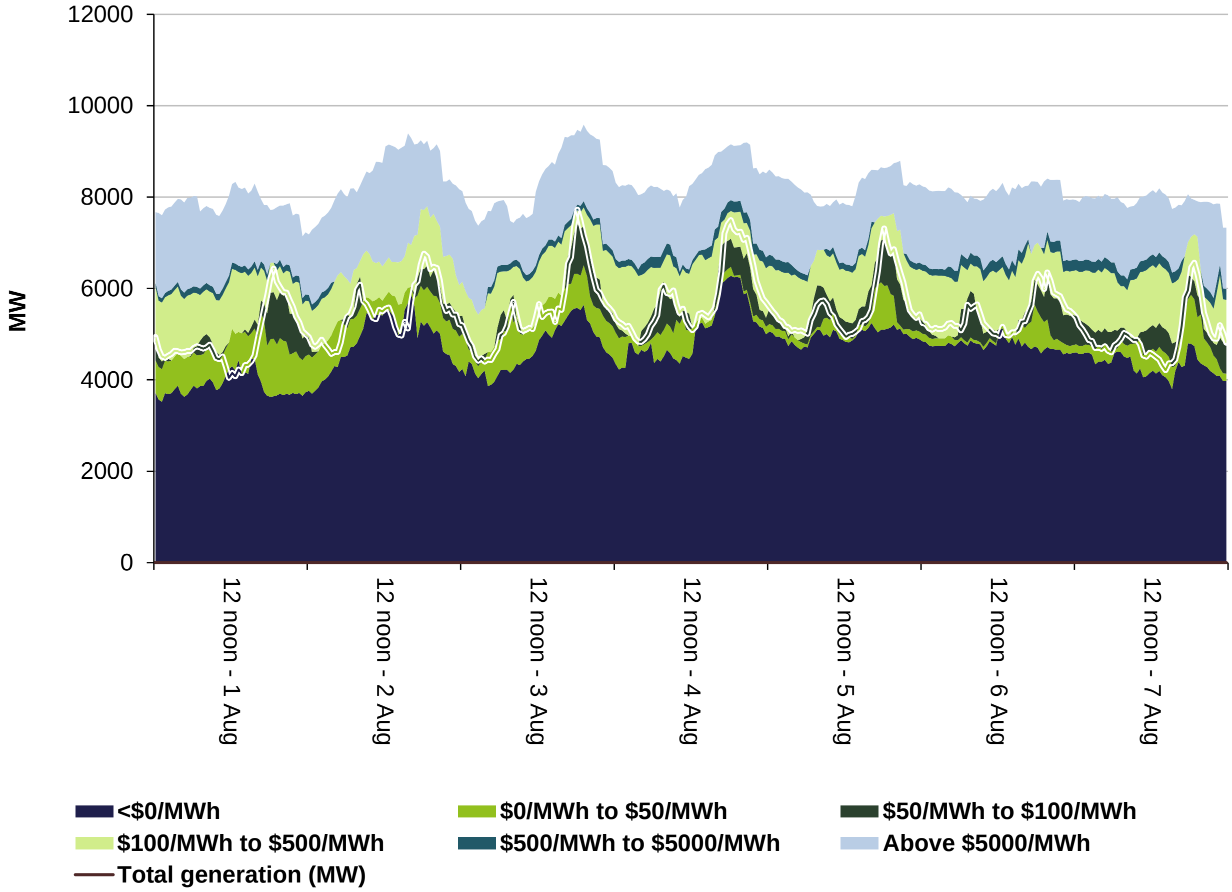


Figure 6: South Australia generation and bidding patterns

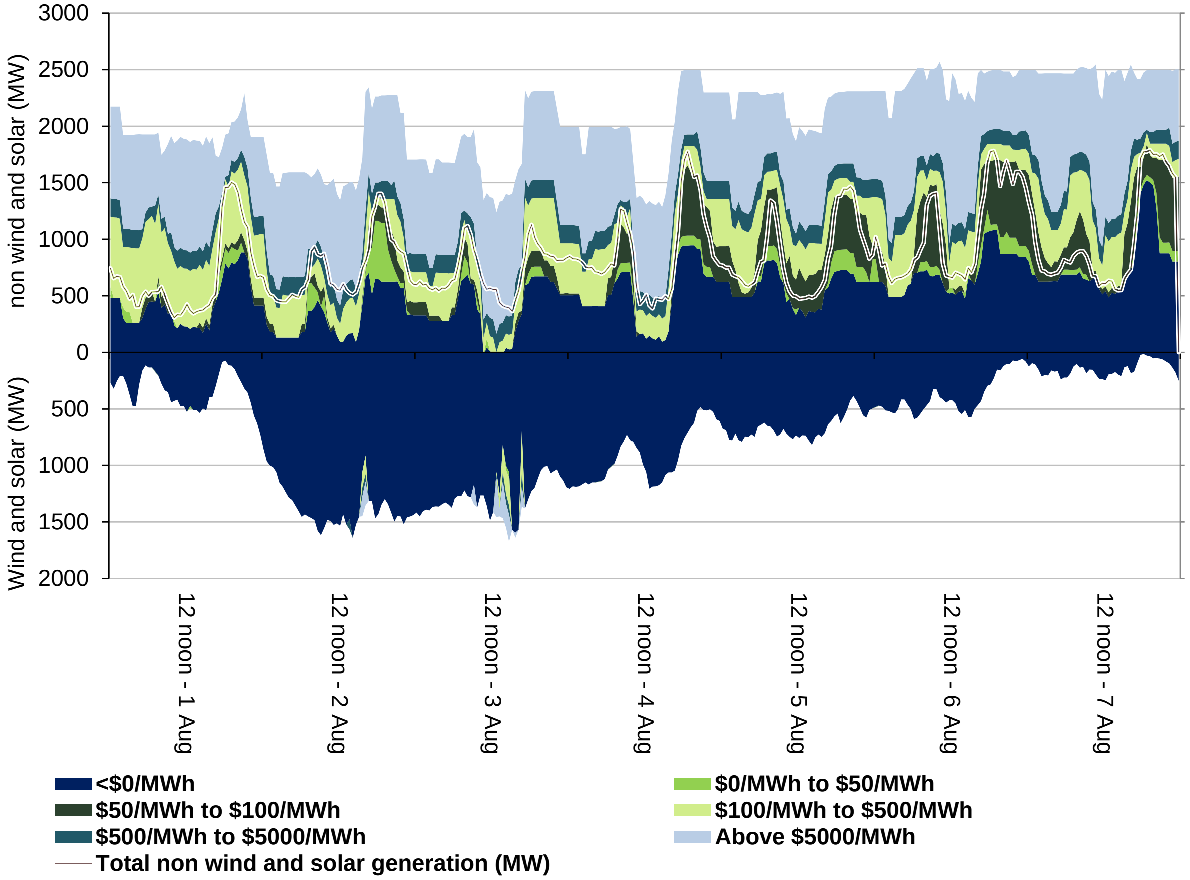
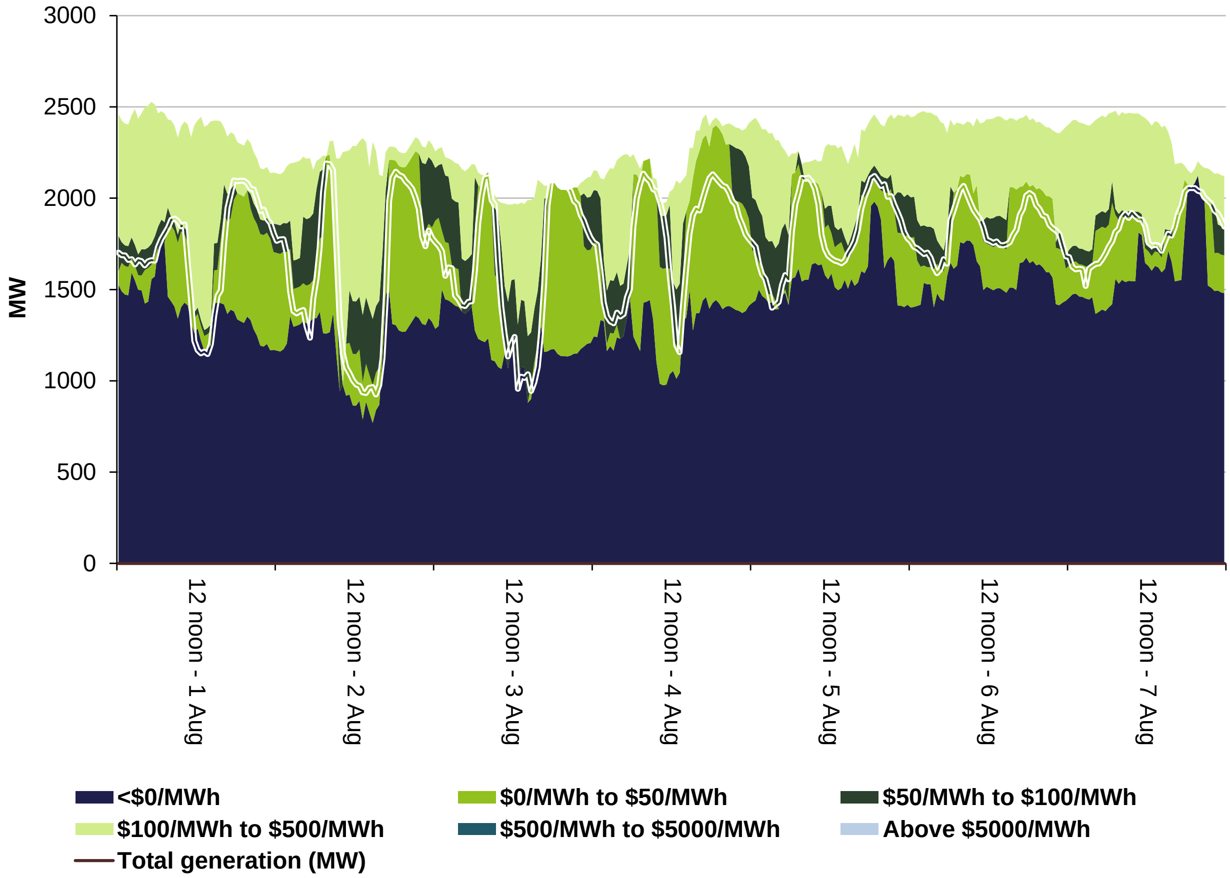


Figure 7: Tasmania generation and bidding patterns



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.

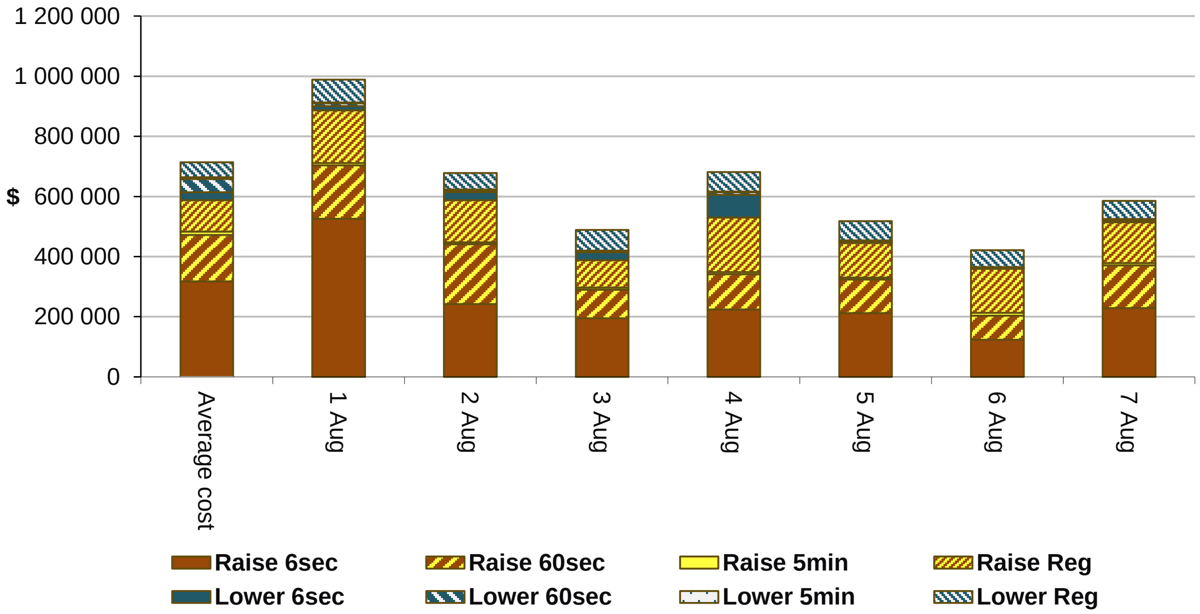
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3,939,000 or around 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $423,000 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

Mainland

There were 3 occasions where prices across the mainland were greater than 3 times the New South Wales weekly average price of $61/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Sunday, 1 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 pm	264	78	78	24,253	23,814	23,744	31,282	31,826	31,960
6.30 pm	221	139	127	24,820	24,567	24,545	31,284	31,952	31,851

Prices were aligned across the mainland and will be analysed as 1 region. Demand was between 253 MW to 439 MW higher than forecast, and availability was 544 MW to 668 MW lower than forecast. Lower than forecast availability was mainly due to removal of capacity by AGL Energy at Bayswater due to technical issues and lower than forecast wind generation which usually offers at prices below $0/MWh.

Rebids at 5.17 pm by Snowy Hydro at Murray shifted around 300 MW of capacity from prices below $70/MWh to the price cap due to forecast prices. The combination of higher than forecast demand, lower than forecast availability and rebids resulted in dispatch prices between $150/MWh and $450/MWh throughout each trading interval.

Saturday, 7 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
6.30 pm	299.98	299.98	221.14	25,437	25,156	24,954	31,853	32,413	32,753

Price was as forecast 4 hours prior.

Queensland

There were 2 occasions where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $60/MWh and above $250/MWh.

Sunday, 1 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
7 pm	292.82	265.69	134.73	7,029	7,007	6,981	8,151	7,972	8,573

Price was close to forecast, 4 hours prior.

Monday, 2 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 pm	338.28	239.44	235.73	7,225	7,244	7,181	8,203	8,448	8,402

Demand was close to forecast and availability was 245 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to CleanCo removing 220 MW of capacity at Swanbank priced below $300/MWh. It was rebid at 5.31 pm, effective from 5.40 pm, to manage unit thermal stress.

Demand increased 88 MW at 5.50 pm, with no capacity offered between $235/MWh and $449/MWh and some lower-priced plant either ramp-constrained or trapped/stranded in FCAS the price was set at $449/MWh for the remainder of the trading interval.

South Australia

There were 4 occasions where the spot price was below -$100/MWh.

Monday, 2 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
4 pm	-116.46	27.69	9.40	1634	1,335	1,271	3,209	2,893	2,646

Demand was 299 MW higher than forecast and availability was 316 MW higher than forecast, 4 hours prior. Constraints related to system strength requirements which limit wind generation were eased leading up to the trading interval, resulting in higher than forecast wind generation, which mostly offers at prices below $0/MWh. Prices were set lower than forecast throughout the trading interval.

Tuesday, 3 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
1.30 pm	-146.27	8.98	-450	1,037	972	990	2,816	2,581	2,653
2 pm	-152.37	8.03	-450	1,043	980	997	2,830	2,579	2,660
2.30 pm	-159.06	8.01	-450	1,060	1005	1030	2,913	2,555	2,656

Demand was between 55 MW to 65 MW higher than forecast and availability was between 235 MW to 358 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, which offered most capacity below $0/MWh.

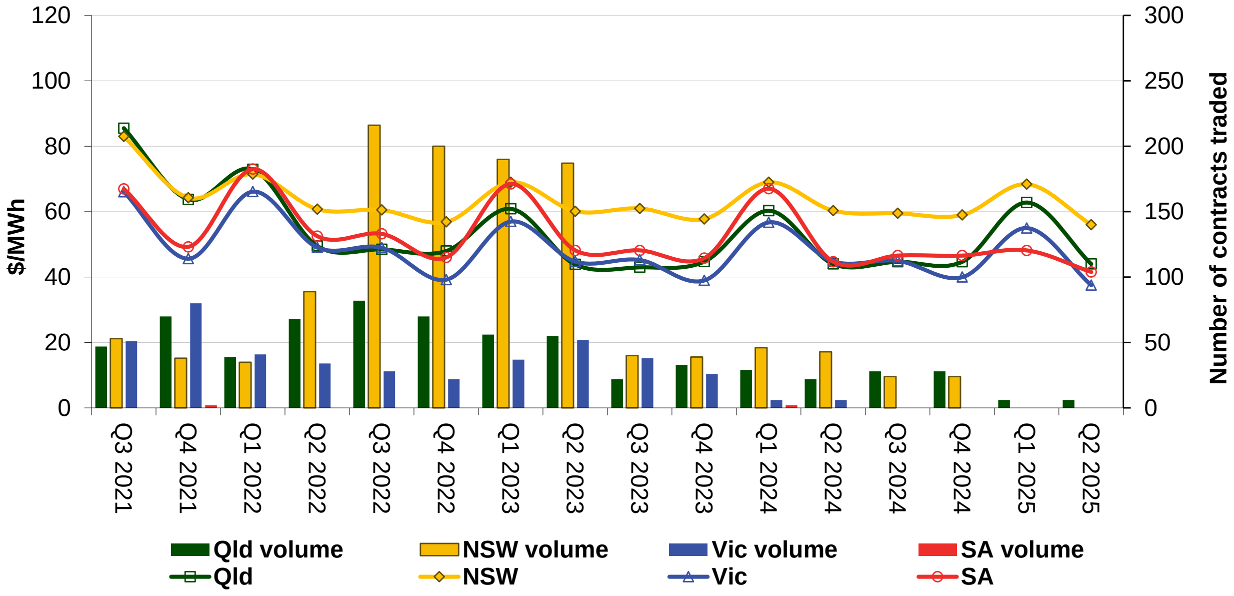
For the 1.30 pm and 2 pm trading intervals, there was little capacity offered between the floor and $247/MWh, so small changes in demand or availability could cause large fluctuations in price. Price dropped to below $-915/MWh once in each trading interval. In response to the low prices, participants rebid at least 250 MW from the price floor to prices above $138/MWh.

For the 2.30 pm trading interval, the higher than forecast availability resulted in prices below forecast for the whole 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.

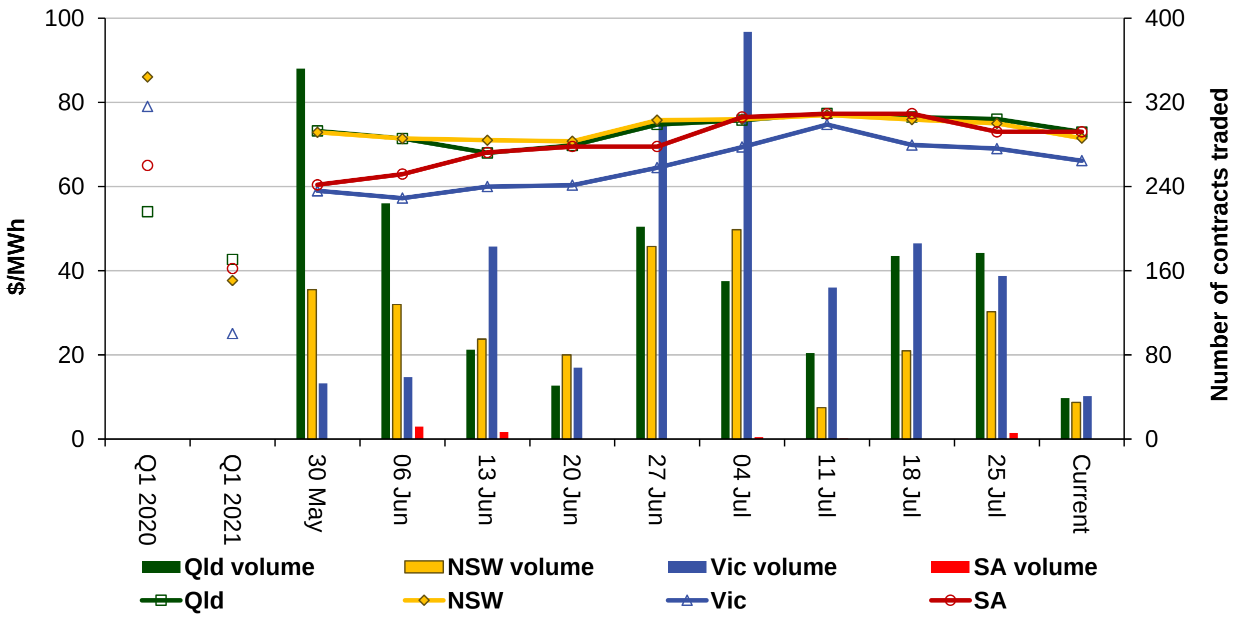
Figure 9: Quarterly base future prices Q3 2021 – Q2 2025



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)

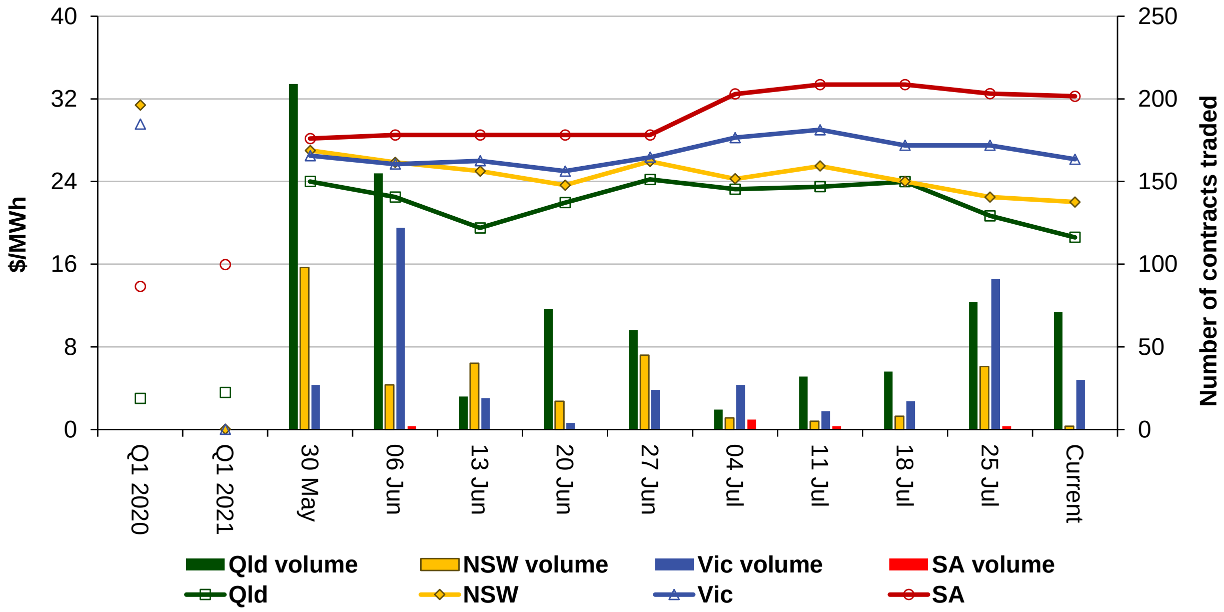


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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.

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
August 2021