Electricity Report

AUSTRALIAN ENERGY REGULATOR

2 – 8 May 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $45/MWh in Tasmania to $56/MWh in New South Wales. Quarter to date VWA prices across mainland regions were between $17/MWh and $23/MWh higher than the same time a year ago. Queensland and Tasmanian energy prices exceeded $2,000/MWh a few times during this week, driven by reduced generator availability and co-optimisation between energy and FCAS markets (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 2 to 8 May 2021.

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

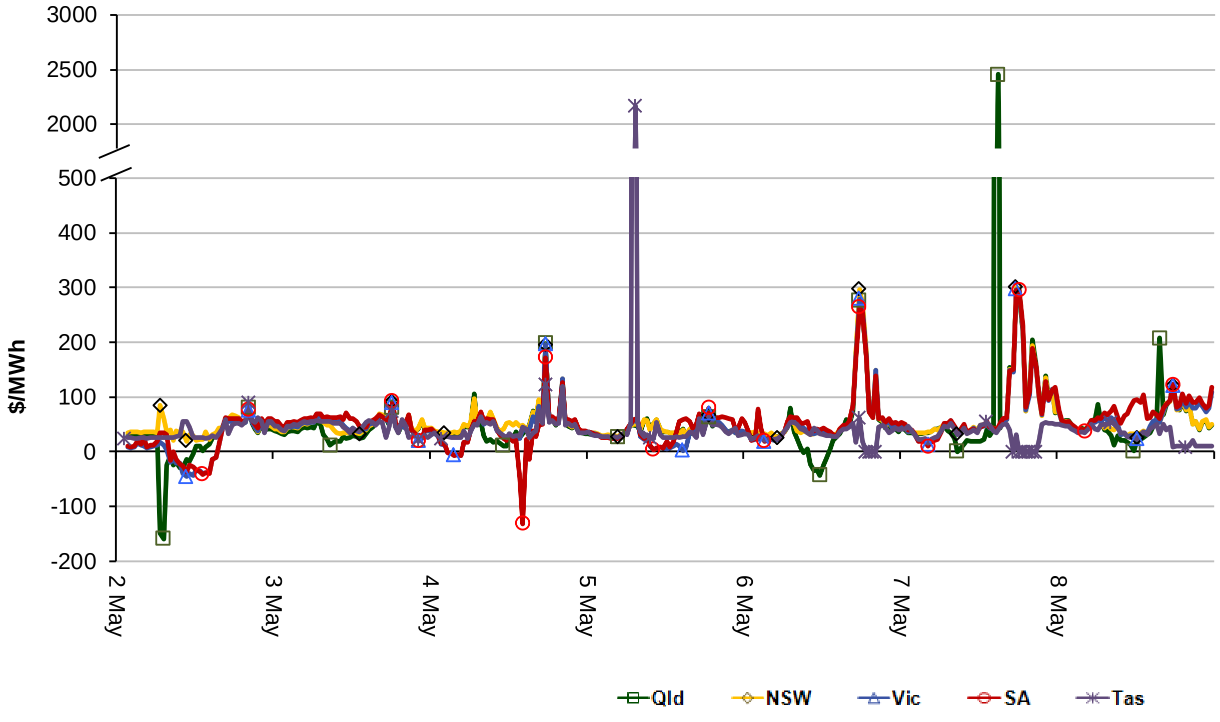


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

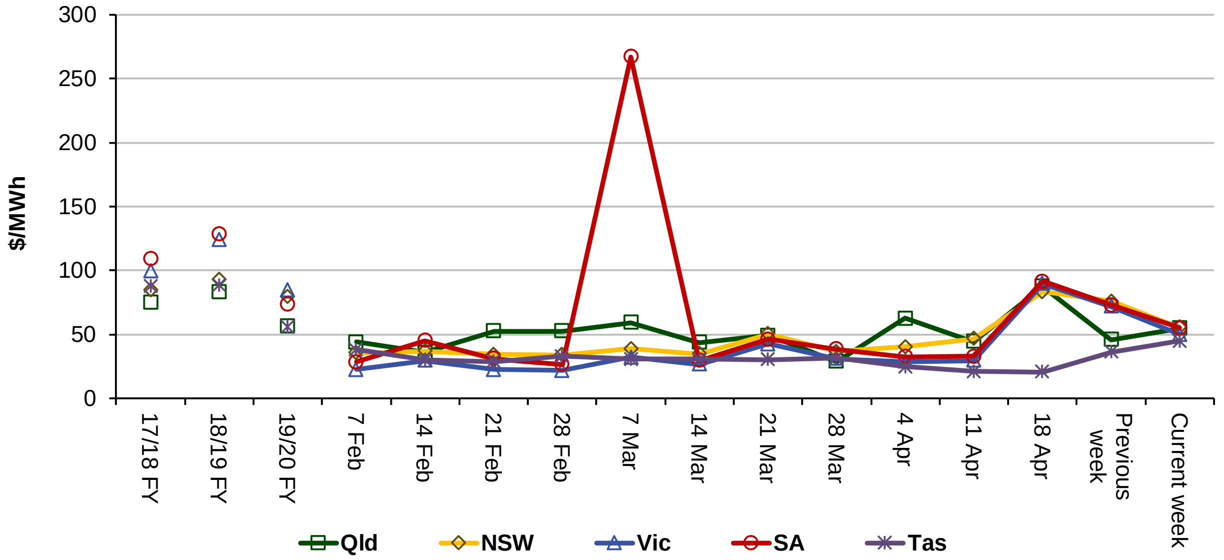


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	55	56	50	55	45
Q2 2020 (QTD)	34	40	35	34	25
Q2 2021 (QTD)	57	58	52	55	29
19-20 financial YTD	59	85	91	78	59
20-21 financial YTD	44	53	42	46	42

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 239 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	12	20	0	2
% of total below forecast	6	49	0	11

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

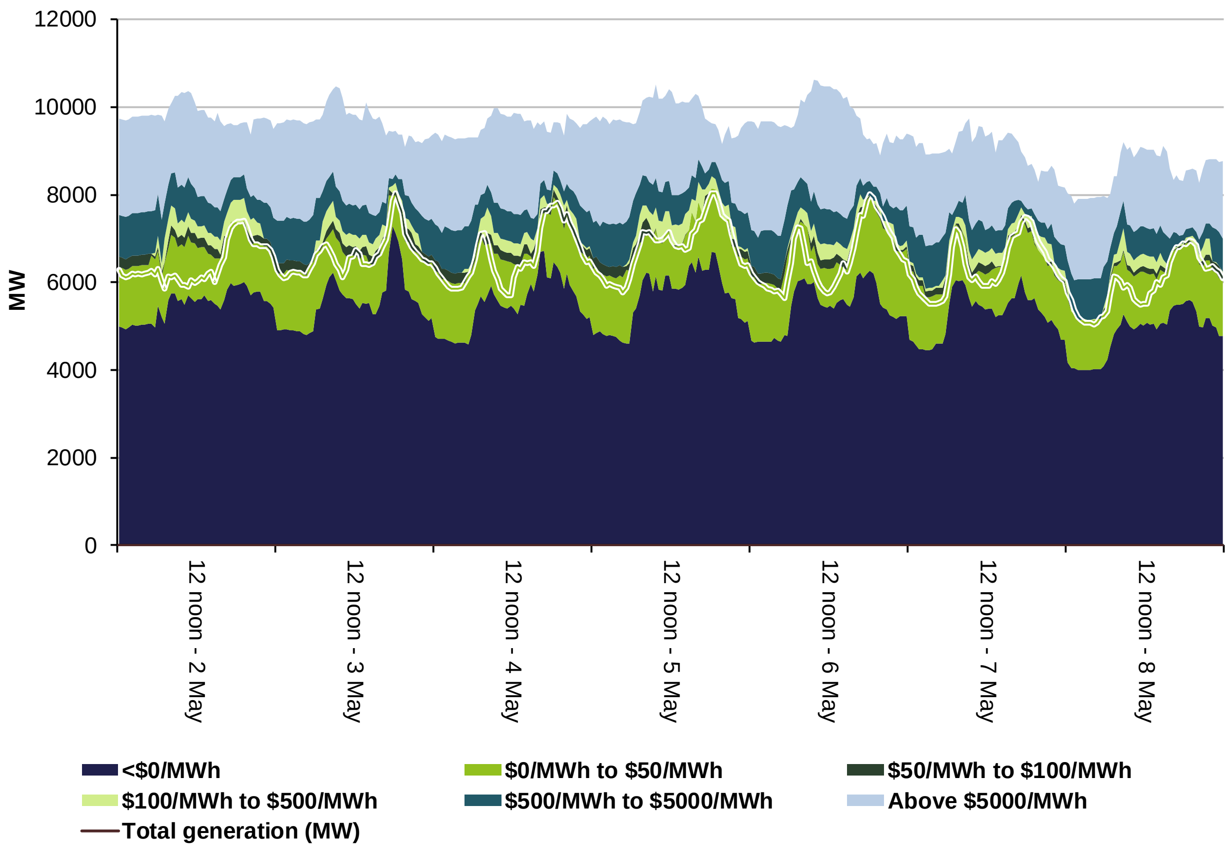


Figure 4: New South Wales generation and bidding patterns

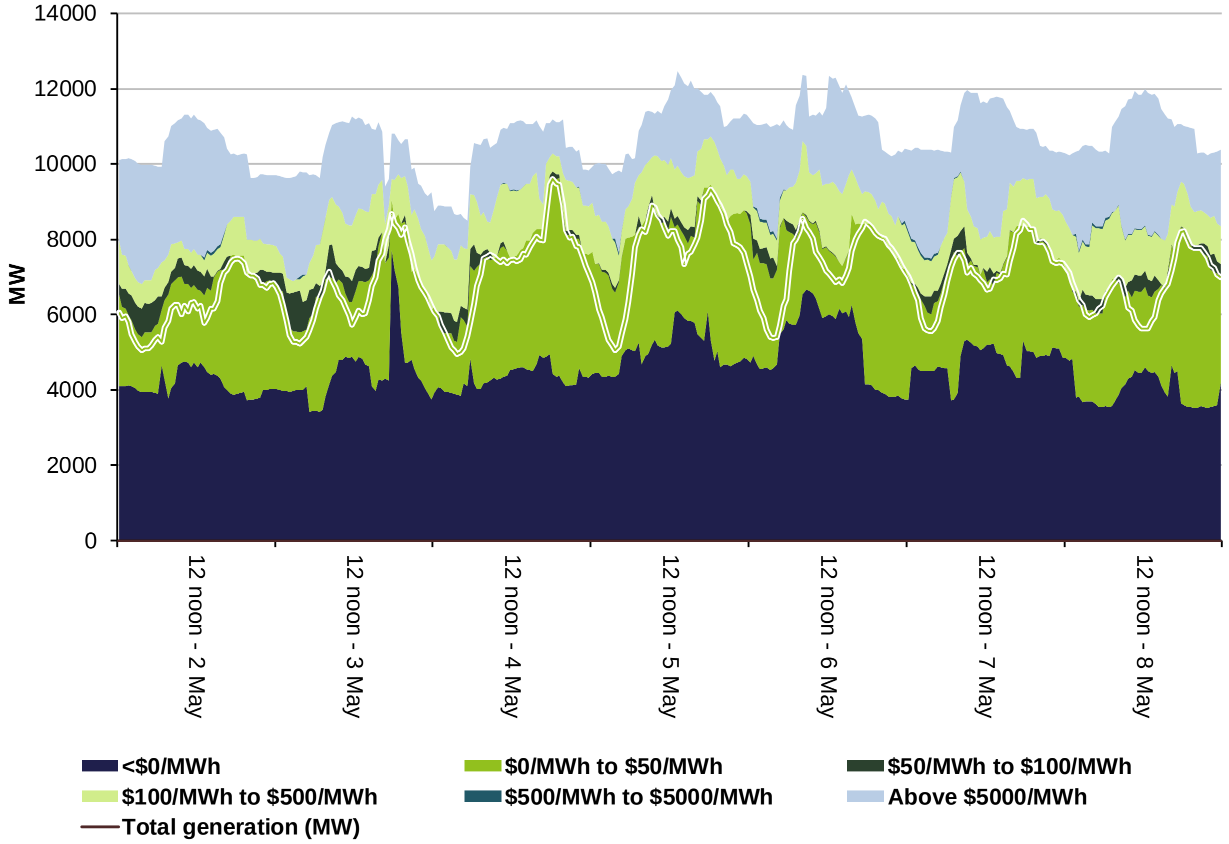


Figure 5: Victoria generation and bidding patterns

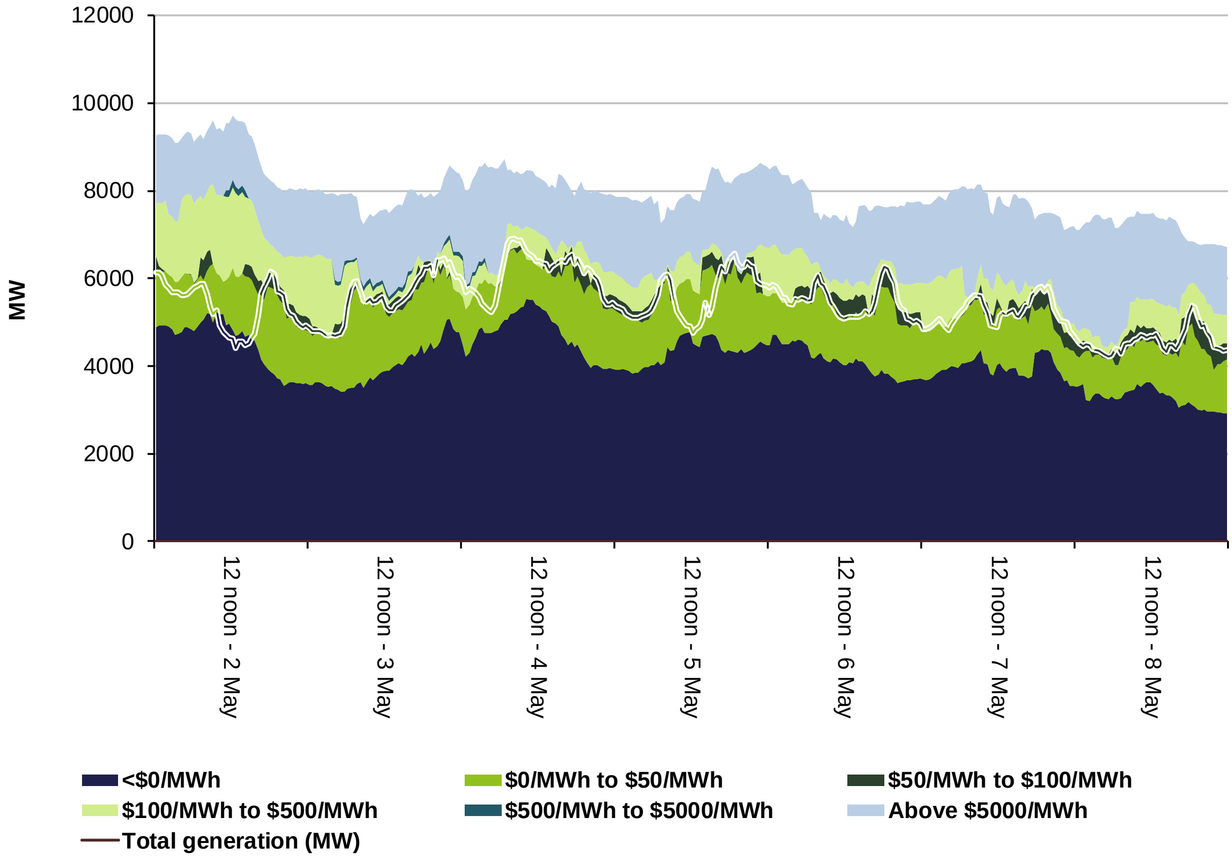


Figure 6: South Australia generation and bidding patterns

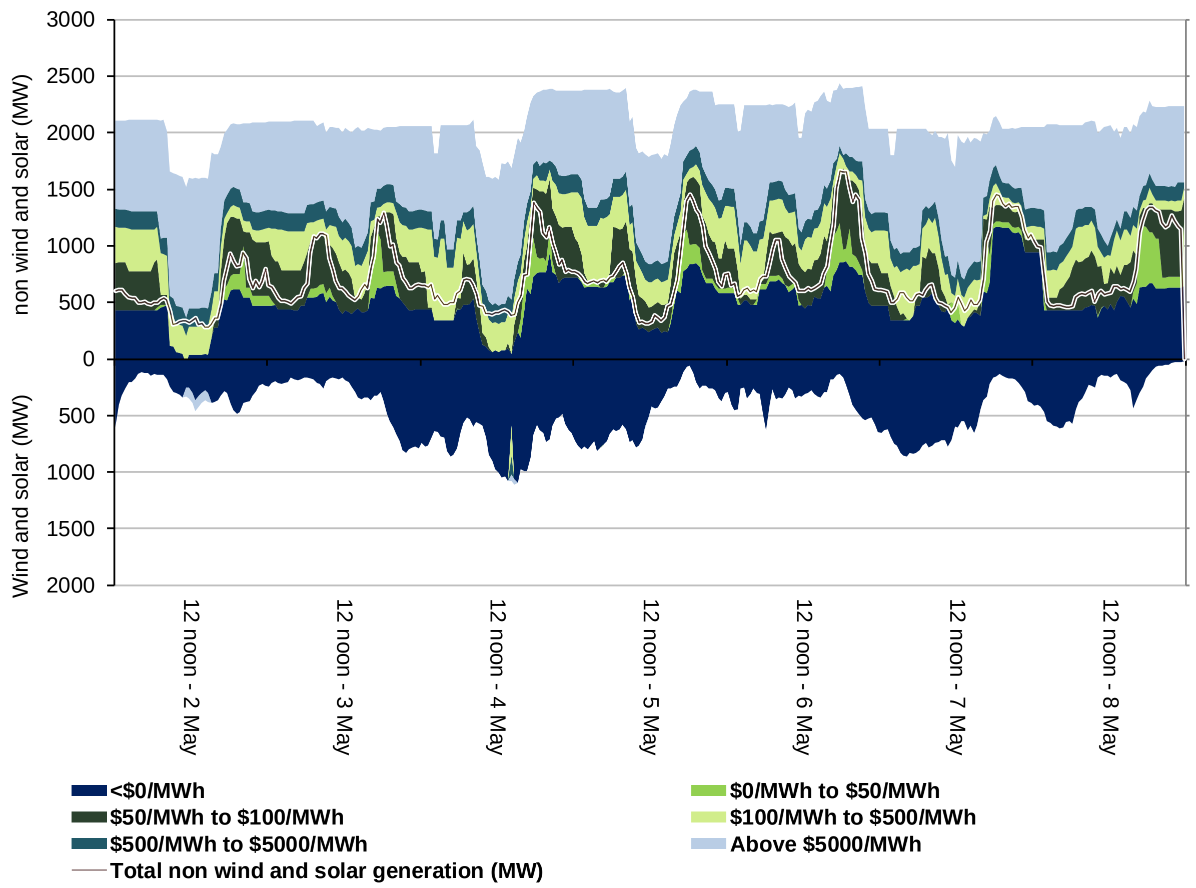
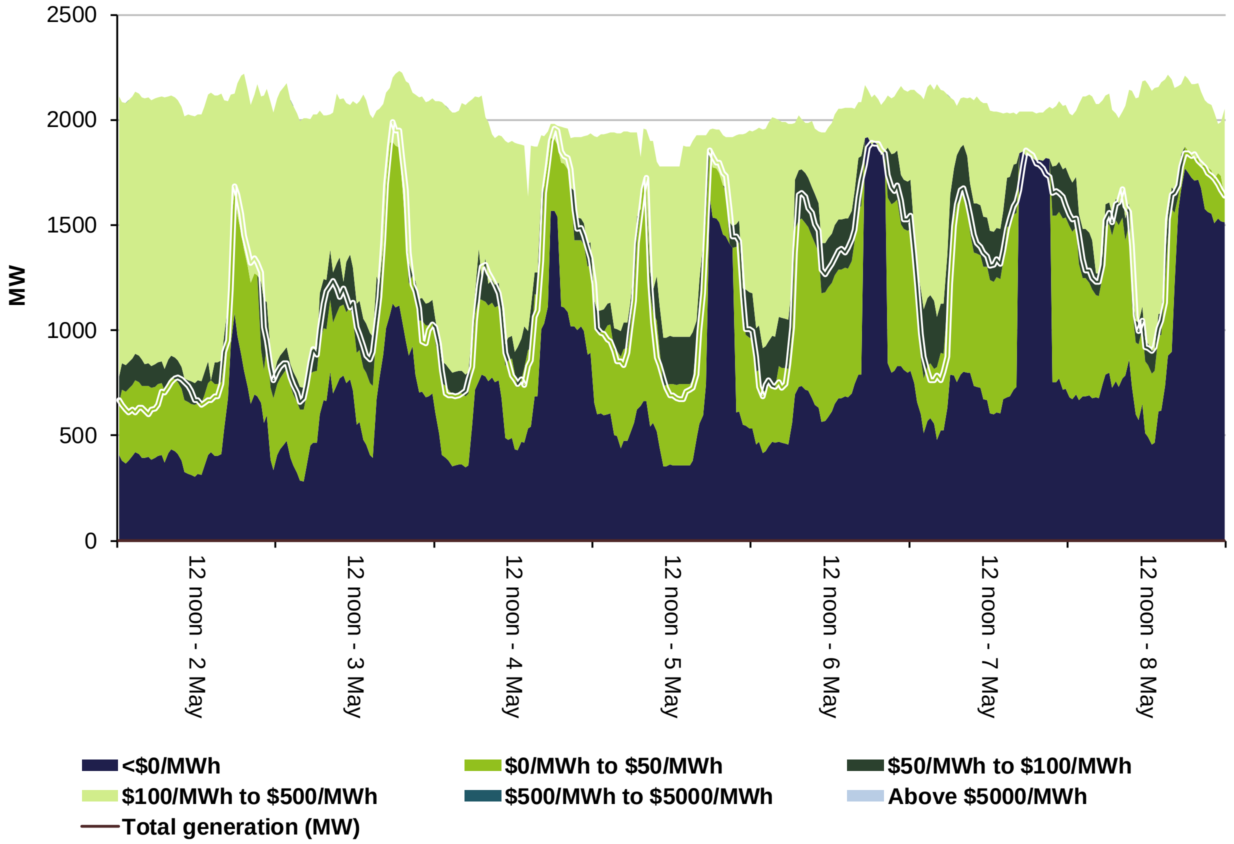


Figure 7: Tasmania generation and bidding patterns



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.

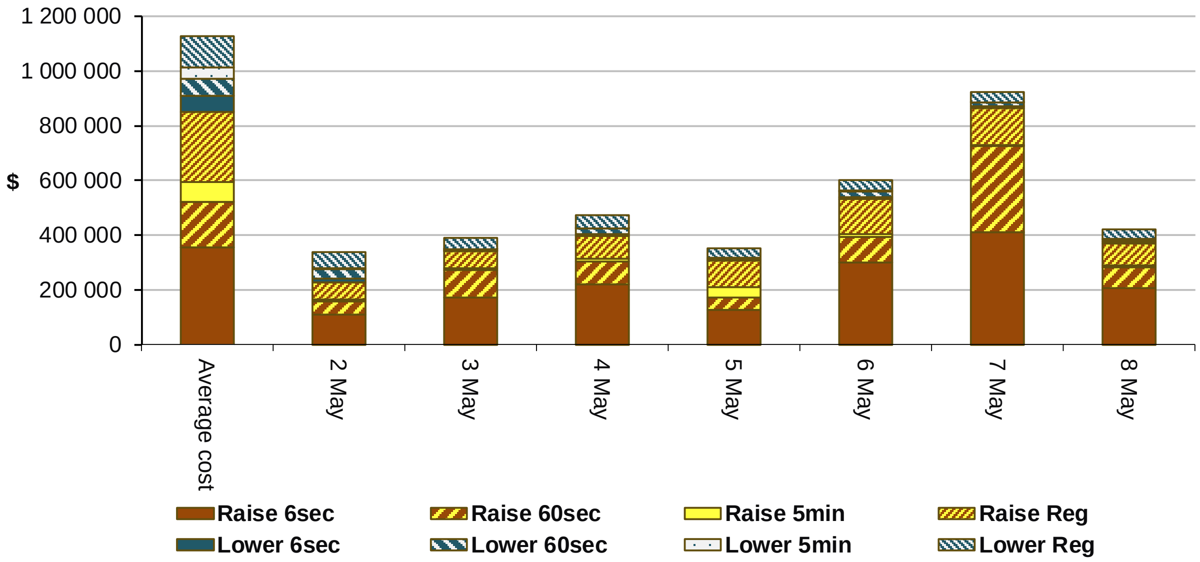
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3,067,500 or less than 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $432,500 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



Detailed market analysis of significant price events

Mainland

There were 4 occasions where the mainland region spot price was greater than 3 times the New South Wales weekly average price of $56/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Thursday, 6 May

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	296.59	314.57	113.95	24,679	24,249	24,276	30,822	31,137	31,447
6.30 pm	271.50	314.42	147.54	24,778	24,541	24,603	30,833	31,371	31,558

Prices were aligned across mainland regions and will be analysed as 1 region.

For the 6 pm trading interval, prices were close to forecast 4 hours prior.

For the 6.30 pm trading interval, demand was 237 MW higher than forecast, while availability was 538 MW lower than forecast, 4 hours prior. Lower than forecast availability was mostly due to rebids by participants that removed over 530 MW of capacity from prices below $300/MWh due to plant reasons. At 6.10 pm demand fell by over 200 MW, resulting in co-optimisation between the Energy and FCAS markets resulting in dispatch prices around $150/MWh.

Friday, 7 May

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	299.99	299.99	273.97	23,671	23,700	23,502	18,507	18,895	19,720
6.30 pm	297.97	299.99	292.35	23,596	23,852	23,623	18,505	18,928	19,784

Prices were aligned across mainland regions and were close to forecast.

Queensland

There were 1 occasion where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $55/MWh and above $250/MWh and there were 2 occasions where the spot price was below -$100/MWh.

Sunday, 2 May

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 am	-149.31	30.92	31.63	5,419	5,473	5,544	9,814	9,736	9,698
7.30 am	-159.46	11.84	19.20	5,459	5,555	5,656	9,766	9,774	9,732

Demand was up to 96 MW lower than forecast, while availability was close to or up to 78 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh.

In each trading interval, participants rebid more than 170 MW from higher prices to the price floor. With several generators down constrained or trapped / stranded in FCAS and unable to set price, dispatch prices were set at the price floor once in each trading interval.

Friday, 7 May

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
3 pm	2,454.92	32.25	26.25	6,063	5,772	5,861	9,346	9,896	10,124

Demand was 291 MW higher than forecast while availability was 550 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to rebids by participants which removed over 700 MW of capacity from various prices due to plant reasons. See Table 7 for details.

At 3 pm, a planned line outage of the Liddell to Tamworth 84 line in New South Wales saw an increase in local requirement for raise 6 second and raise 60 second services in Queensland. Energy and FCAS markets co-optimised, resulting in the dispatch price being set at $14,529/MWh.

Table 7: Significant rebids at 3 pm, 7 May 2021

Time	Time effective	Participant	Station	Amount (MW)	From ($/MWh)	To ($/MWh)	Reason
11.02 am		Arrow Energy	Yabulu	-62	0	N/A	1058~p~020 reduction in avail cap~206 run-up problems - steam turbine~

Time	Time effective	Participant	Station	Amount (MW)	From ($/MWh)	To ($/MWh)	Reason
1.15 pm		Stanwell Corporation	Tarong North	-420	<15	N/A	1314p tn unit trip mft
2.10 pm		Arrow Energy	Yabulu	-20	0	N/A	1355~p~010 unexpected/plant limits~108 load/ramp variation during rts - st delayed~
2.17 pm		CS Energy	Gladstone	-65	<71	N/A	1417p unit ramping rebid to match-sl
2.50 pm	3 pm	Alinta Energy	Braemar	-41	595	N/A	15:00:001445~p~plant condition sl~~

South Australia

The South Australia weekly average price was $55/MWh and there was 1 occasion where the spot price was below -$100/MWh.

Tuesday, 4 May

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
2.30 pm	-131.26	31.12	30.54	941	826	968	2,830	2,675	2,723

Demand was 115 MW higher than forecast and availability was 155 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.

At 2.15 pm, a rebid by Hornsdale Power Reserve shifted 80 MW of capacity from $1,015/MWh to the price floor due to plant reasons. As a result, the dispatch price fell to the price floor. In response, participants rebid nearly 850 MW of capacity from the price floor to prices above $300/MWh, resulting in prices being set above $55/MWh for the remainder of the trading interval.

Tasmania

There was 1 occasion where the spot price in Tasmania was greater than 3 times the Tasmania weekly average price of $45/MWh and above $250/MWh.

Wednesday, 5 May

Table 9: Price, Demand and Availability

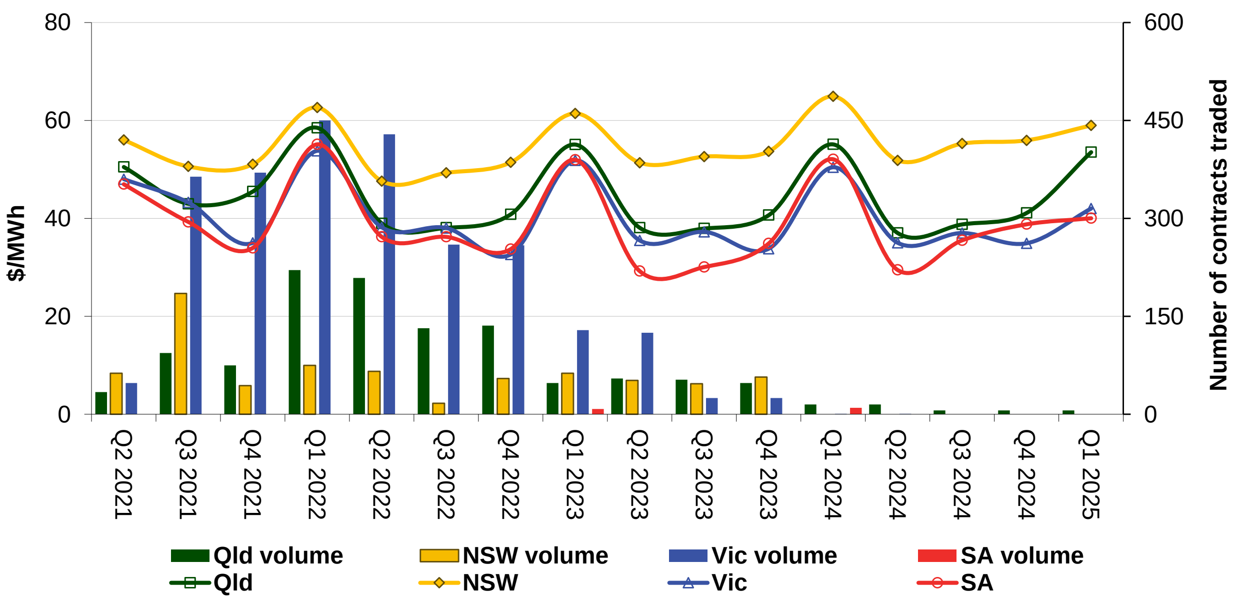
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7.30 am	2,165.37	34.66	54.06	1,447	1,416	1,413	1,859	1,943	1,944

Demand was 31 MW greater than forecast and availability was 84 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to a rebid at Gordon which removed 111 MW of capacity below $120/MWh due to failing to start. Constraints related to local FCAS increased the requirement in Tasmania for raise regulation and raise 5 minute services resulting in co-optimisation between energy and FCAS markets. Dispatch prices rose to $6,822/MWh at 7.20 am and $5,572/MWh at 7.25 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.

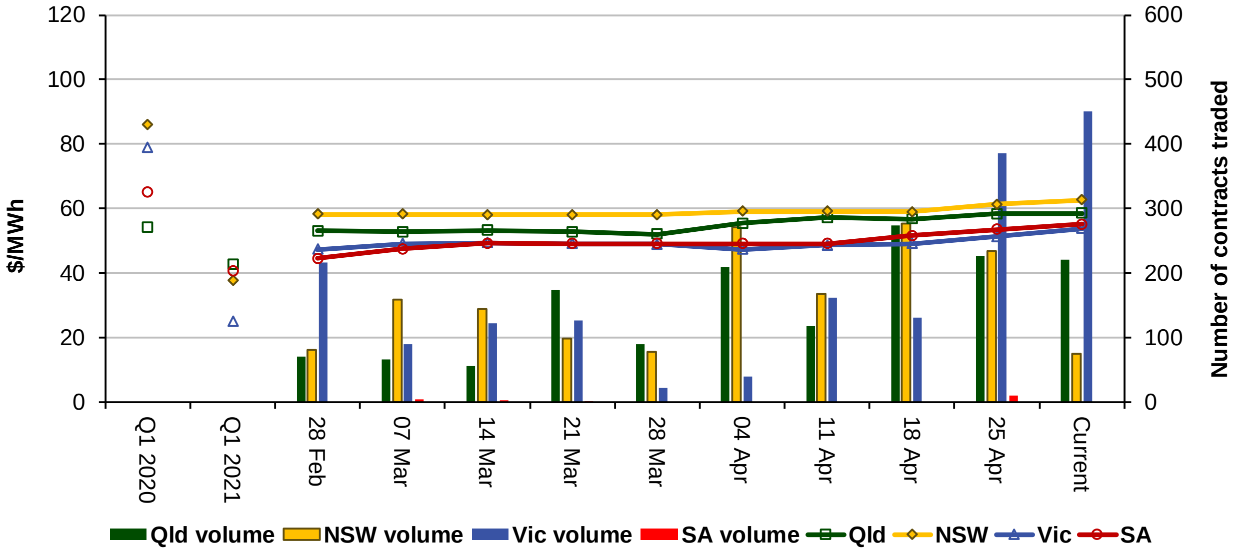
Figure 9: Quarterly base future prices Q2 2021 – Q1 2025



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)



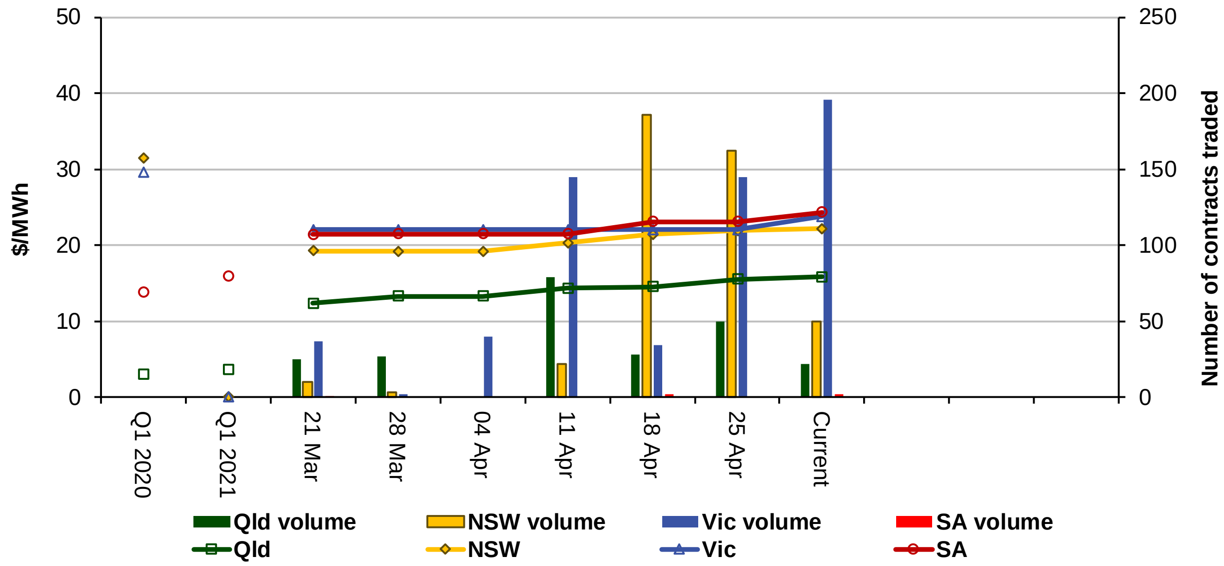
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 7 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
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