Electricity Report

AUSTRALIAN ENERGY REGULATOR

23 – 29 August 2020

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $35/MWh in Queensland to $73/MWh in New South Wales. Quarter to date VWA prices sit between $19/MWh to $37/MWh lower than the same time last year.

Outages or reduced capacity experienced by baseload generators and low wind generation contributed to prices up to $1900/MWh across the mainland on 24 August. These are detailed in our section on detailed market analysis of significant price events below.

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 23 to 29 August 2020.

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

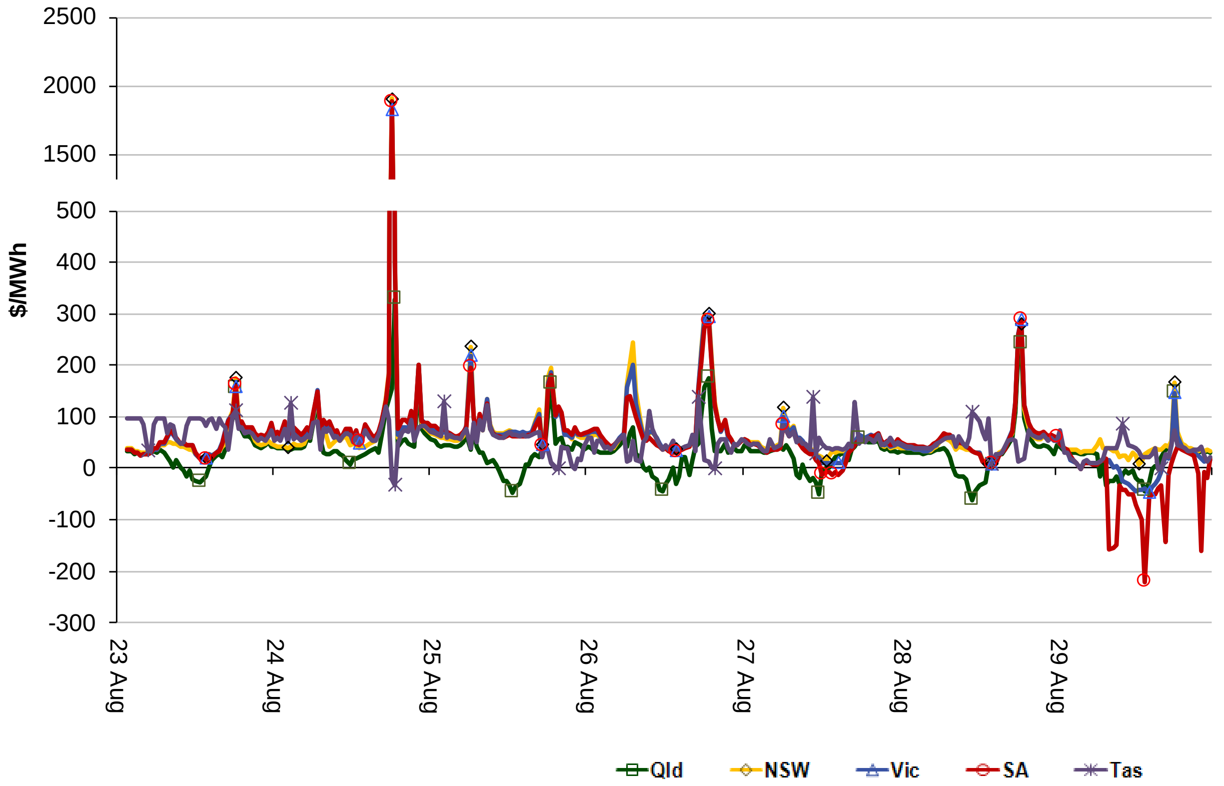


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

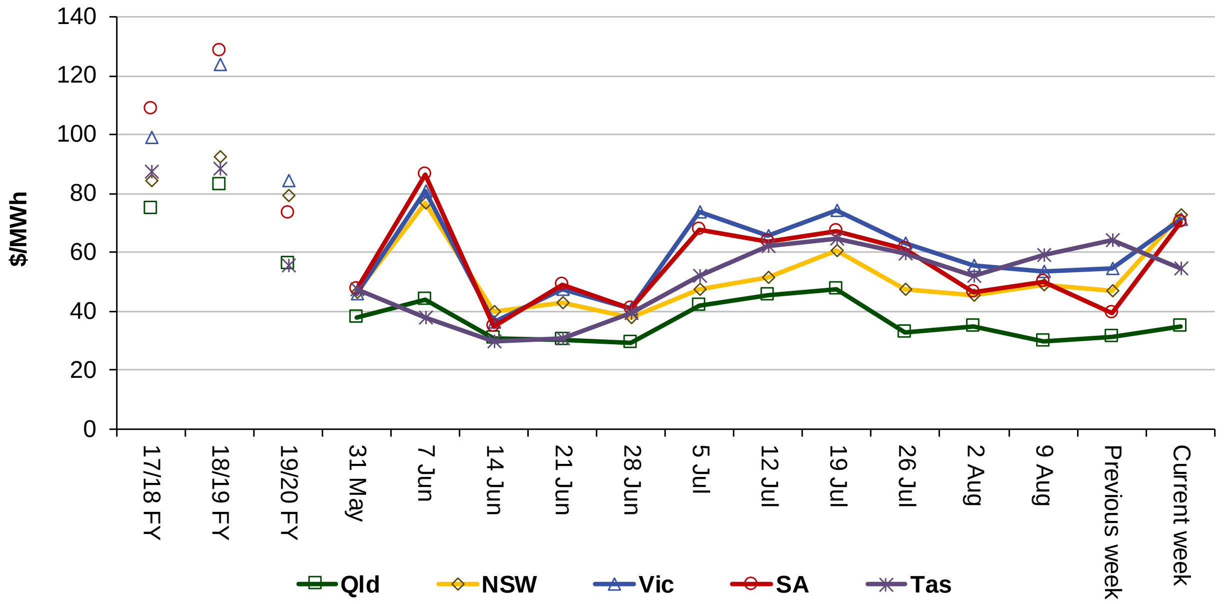


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	35	73	71	70	55
Q3 2019 QTD	67	79	99	84	76
Q3 2020 QTD	37	51	62	57	57
19-20 financial YTD	67	79	99	84	76
20-21 financial YTD	37	51	62	57	57

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 263 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2019 of 204 counts and the average in 2018 of 199. 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	8	17	0	1
% of total below forecast	8	58	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

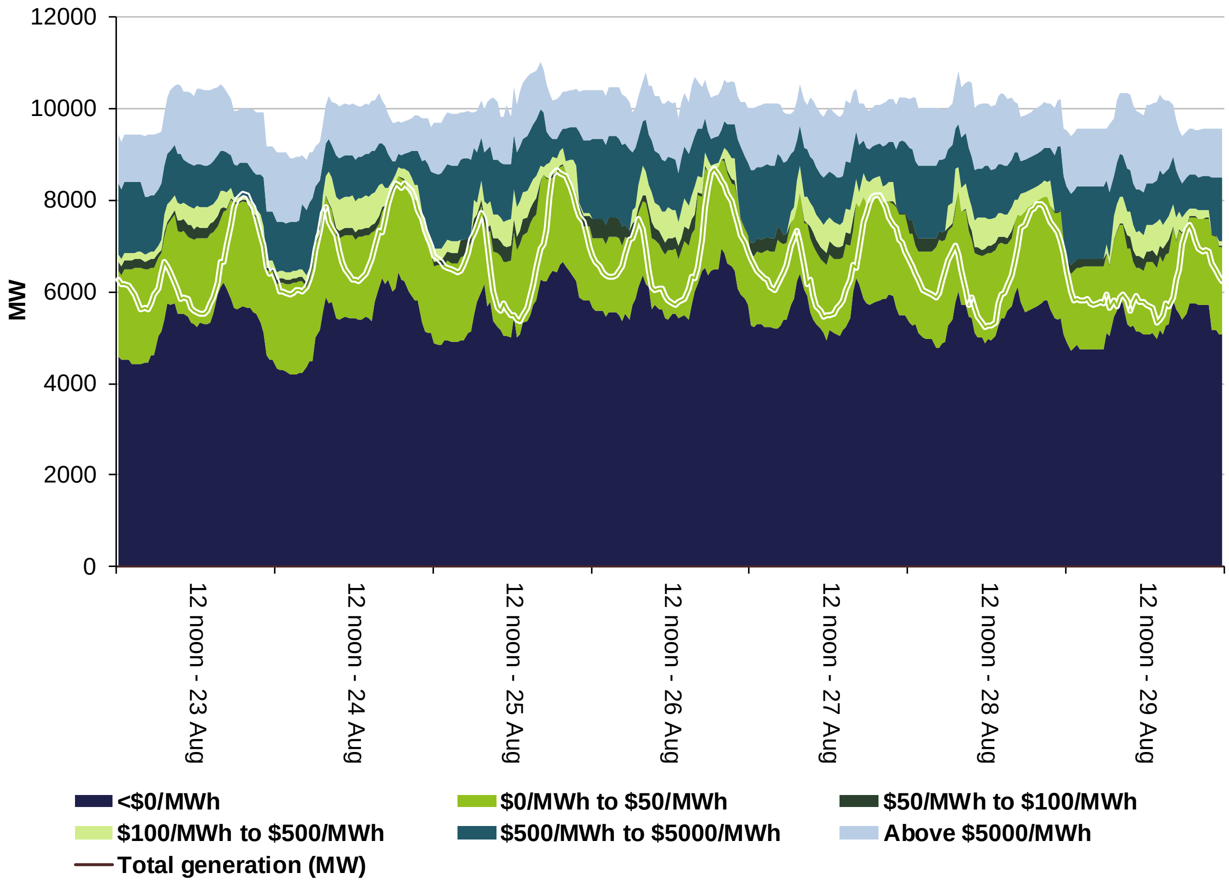


Figure 4: New South Wales generation and bidding patterns

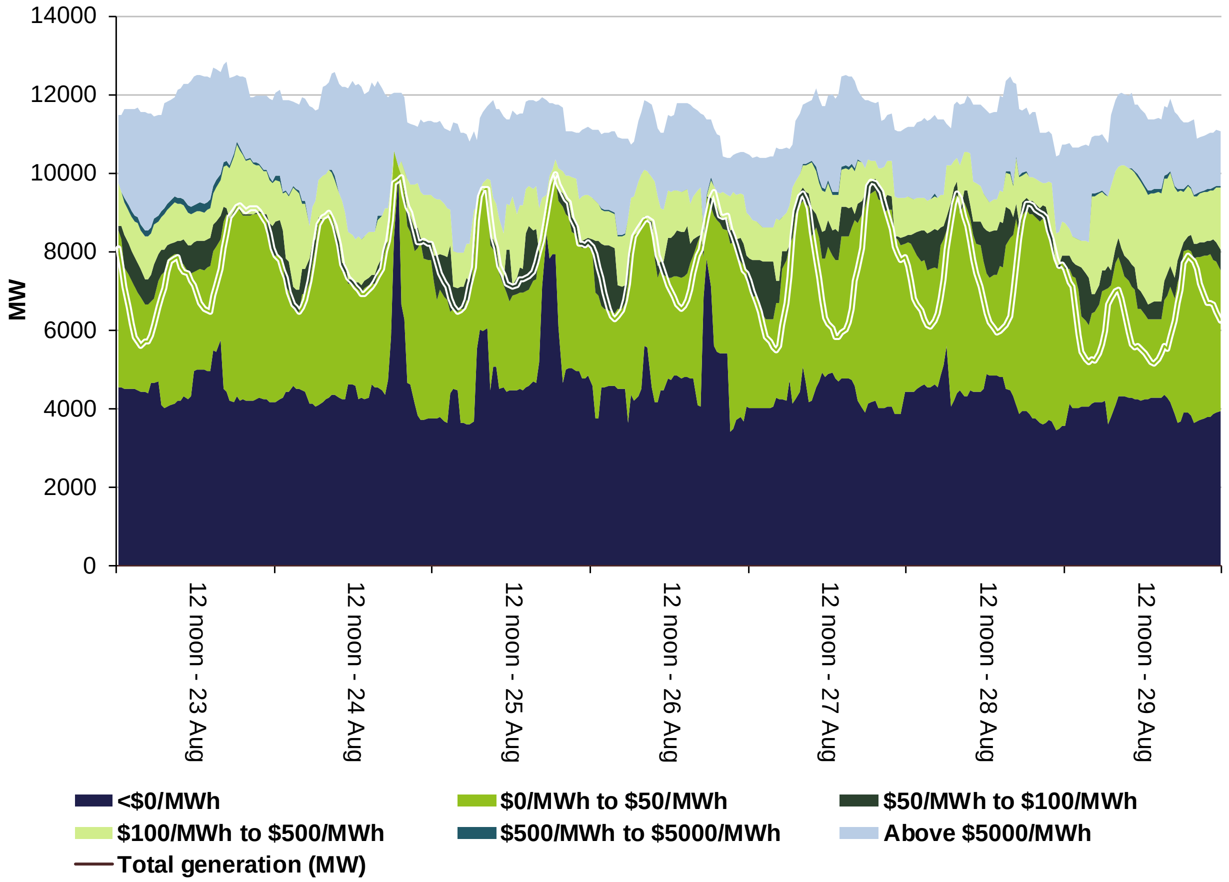


Figure 5: Victoria generation and bidding patterns

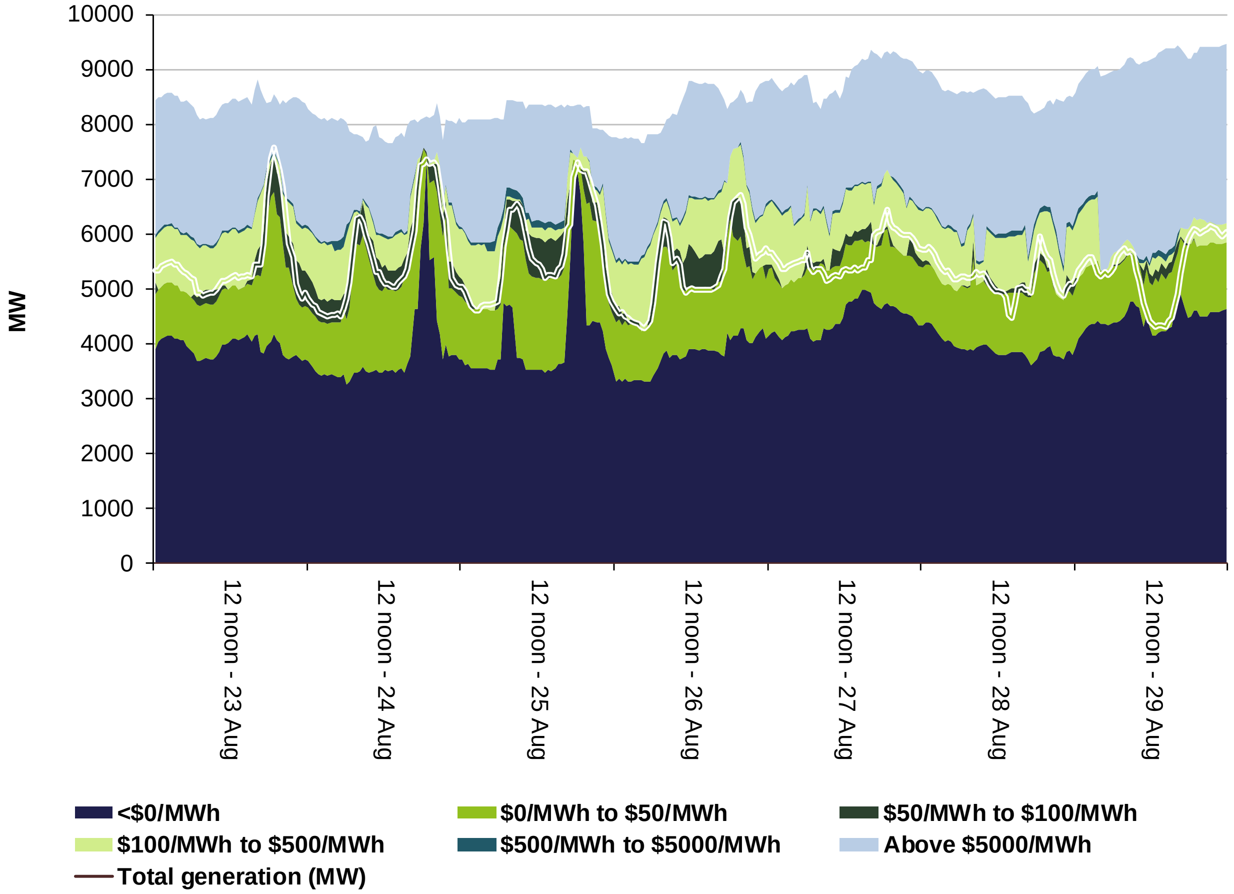


Figure 6: South Australia generation and bidding patterns

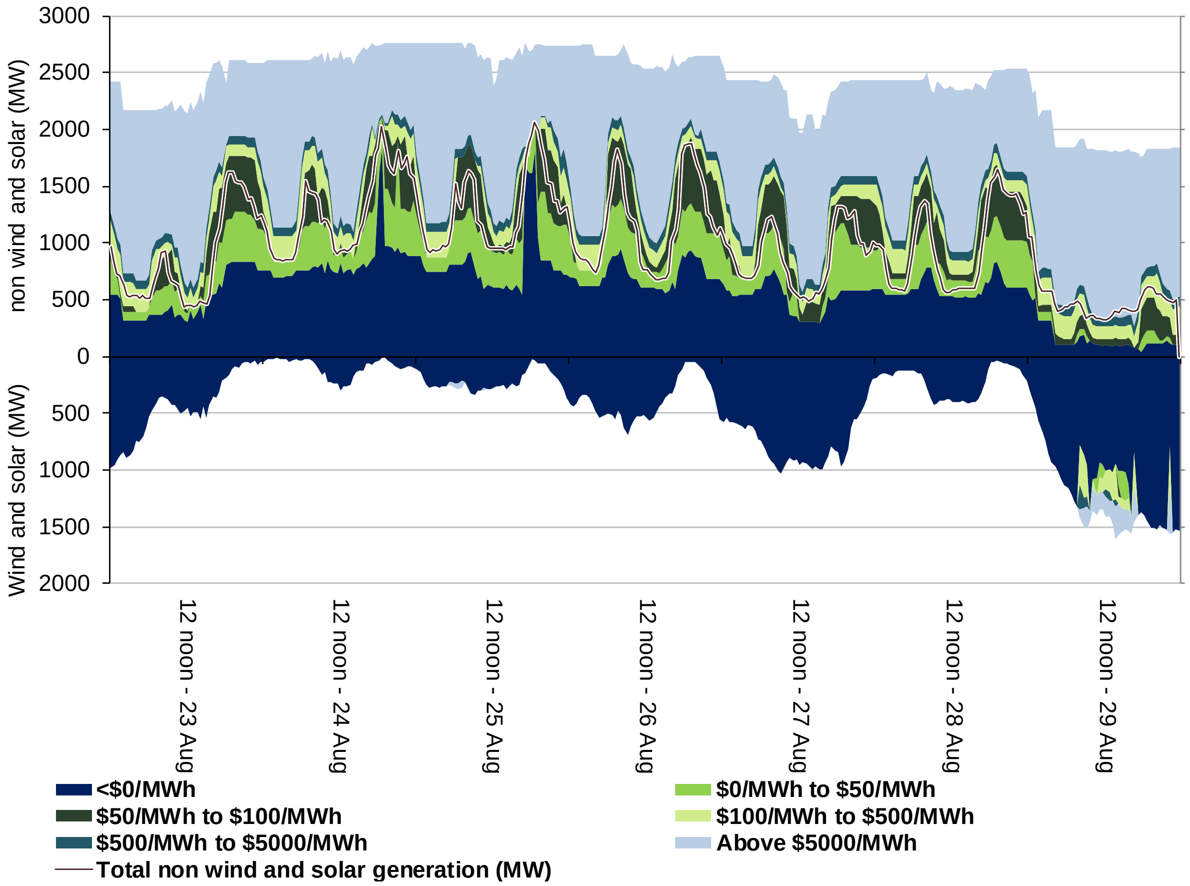
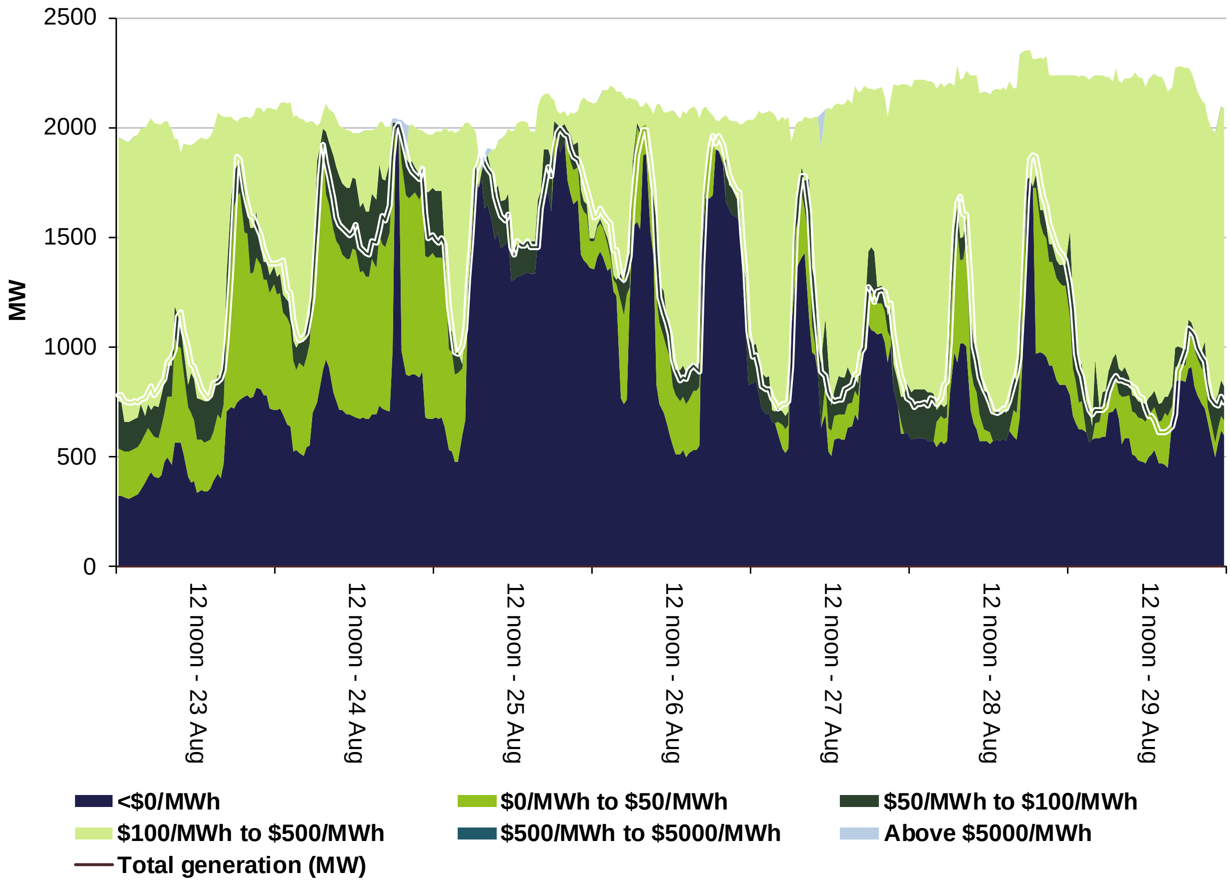


Figure 7: Tasmania generation and bidding patterns



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.

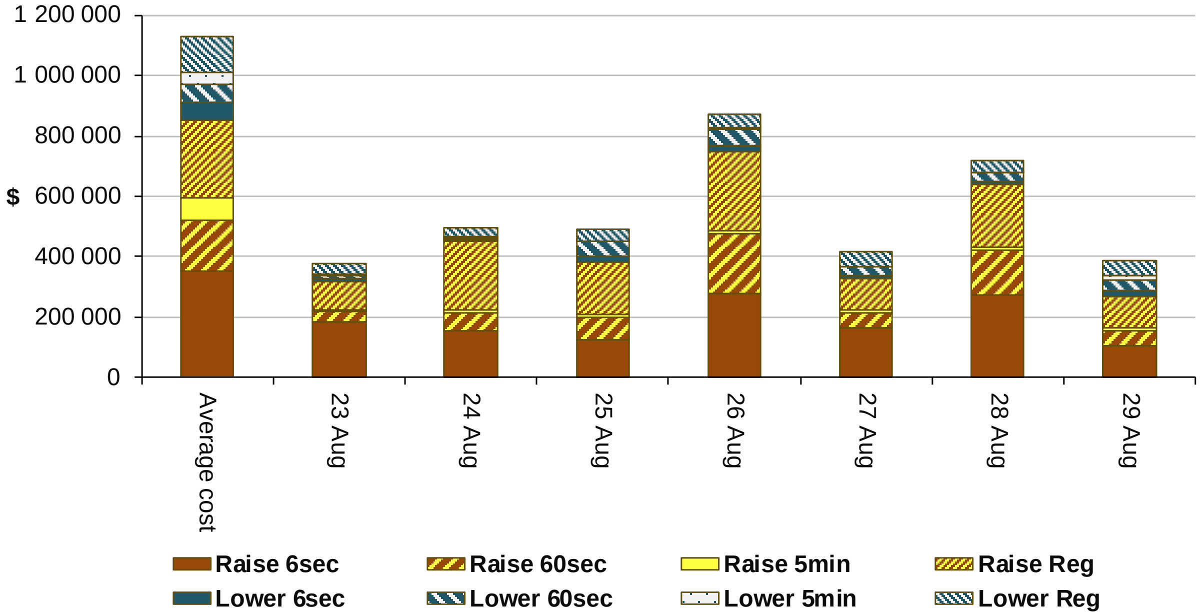
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 110 500 or around 1.5 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $644 500 or around 6 per cent 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 was one occasion where the spot price on the mainland was greater than three times the New South Wales weekly average price of $73/MWh and above $250/MWh. The New South Wales price is used as a proxy for the NEM.

Monday, 24 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
7 pm	402.67	1770.43	14 999.99	27 683	27 940	28 429	32 667	33 061	32 737

Prices were aligned across the mainland and will be treated as one region. Demand was collectively 257 MW lower than forecast and availability was collectively 394 MW lower than forecast, four hours prior. Lower than forecast availability was mainly due to removal of capacity at Mount Piper (100 MW priced below $515/MWh) and Yallourn (230 MW priced at the floor) and lower than forecast wind generation.

From 3 pm, over 630 MW of capacity was either added in at the floor or moved from prices above $13 100/MWh to prices below $37/MWh mainly in response to forecast prices. This led to dispatch prices around $60/MWh for the majority of the trading interval.

New South Wales, Victoria and South Australia

There were five occasions where prices were aligned across New South Wales, Victoria and South Australia and the spot price in New South Wales was greater than three times the New South Wales weekly average price of $73/MWh and above $250/MWh.

Monday, 24 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	1908.02	683.97	14 999.99	20 335	20 300	20 830	22 931	23 433	23 556

Demand was collectively 35 MW higher than forecast, while availability was collectively 502 MW lower than forecast, four hours prior. Lower availability was due to removal of capacity at Mount Piper (150 MW priced below $515/MWh), Yallourn (230 MW priced at the floor), Gannawarra Battery (25 MW priced below $100/MWh), and lower than forecast wind generation.

At 6.25 pm demand increased by 130 MW and, in addition to co-optimisation between the FCAS and energy markets, the price was set above $10 000/MWh for one dispatch interval. In response to the high price, around 930 MW was rebid by participants from prices above $10 000/MWh to prices below $42/MWh for the remainder of the trading interval.

Wednesday, 26 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	296.21	91.99	87.04	19 232	19 345	19 366	22 450	22 909	22 702
7 pm	299.60	95.35	229.10	19 512	19 584	19 628	22 324	22 911	22 699

For both trading intervals, demand was close to forecast and availability was 459 MW to 587 MW lower than forecast, four hours prior. Lower availability was due to removal of capacity at Mount Piper (net 200 MW priced below $515/MWh) and lower than forecast wind generation in Victoria.

At 5.41pm Snowy Hydro rebid 1330 MW of capacity from the floor to prices above $300/MWh in response to forecast prices. This resulted the price being set for all but one dispatch interval at just under $300/MWh by Snowy Hydro for both trading intervals.

Friday, 28 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
6.30 pm	256.98	93.58	270.76	17 543	17 681	17 983	22 432	22 949	22 979
7 pm	279.06	250.46	265.66	17 890	17 955	18 221	22 296	22 955	23 016

For both trading intervals, demand was close to forecast and availability was 517 MW lower than forecast, four hours prior. Lower availability was due to removal of capacity at Mount Piper (150 MW priced below $32/MWh over two rebids), Bayswater (net 100 MW priced below $38/MWh), and Smithfield (120 MW priced at the floor).

For the 6.30 pm trading interval, there was little capacity offered between $93/MWh and $290/MWh so small changes in demand or availability could cause large fluctuations in price. At 6.10 pm demand collectively rose by 150 MW and the price increased to over $290/MWh for the remainder of the trading interval.

For the 7 pm trading interval, prices were close to forecast.

South Australia

There were six occasions where the spot price in South Australia was below -$100/MWh.

Saturday, 29 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
8.30 am	-158.18	29.45	30.90	1112	1001	1008	3256	3026	2911
9 am	-154.15	-37.00	15.98	1059	932	930	3327	3108	2965
9.30 am	-150.27	-37.00	-37.00	1006	835	835	3341	3186	3007
2 pm	-221.12	-996.22	-1000.00	439	335	346	3432	3369	3345
5 pm	-142.43	-39.00	-1000.00	917	846	760	3285	3285	3229
10.30 pm	-161.02	15.10	15.33	1190	1161	1151	3400	3159	3153

Demand was between 29 MW to 171 MW higher than forecast and availability was up to 240 MW higher than forecast, four hours prior. Higher than forecast availability was due to an increase in lower-priced generation.

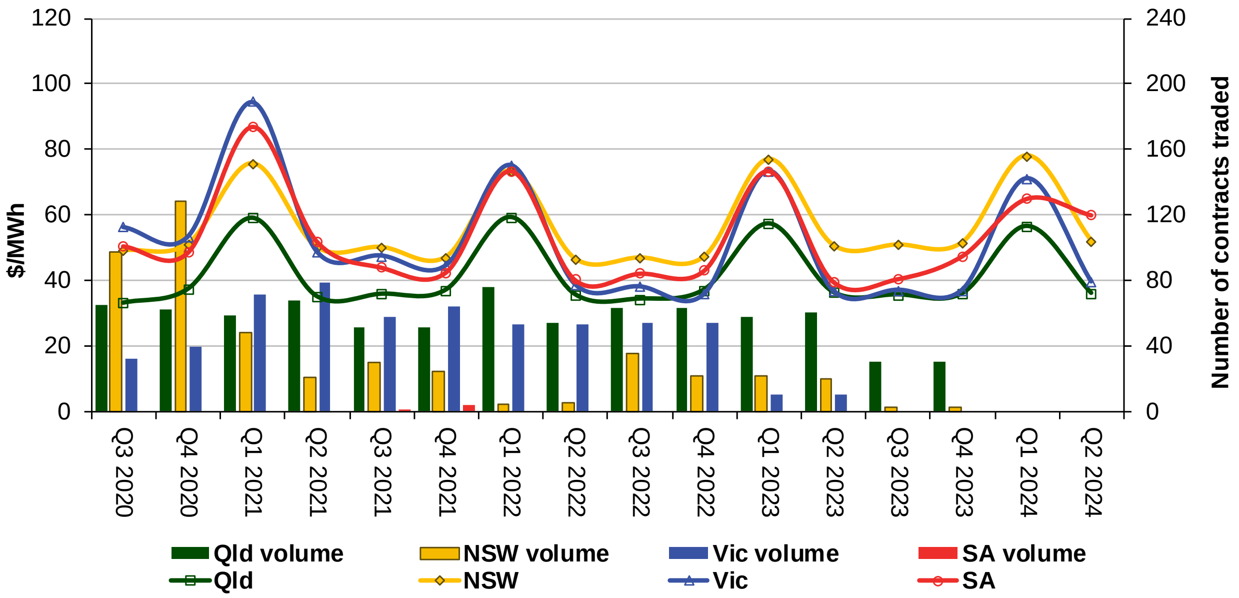
For all except the 2 pm trading interval participants rebid at least 270 MW of capacity to the price floor due to changes in forecast prices or constraint management. This resulted in the price dropping to the floor for one dispatch interval in each trading interval before participants rebid over 600 MW of capacity to higher prices.

For the 2 pm trading interval, demand was 104 MW higher than forecast and availability was 63 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation. In the four hours to the start of the trading interval, 85 MW was rebid from the price floor to prices greater than -$151/MWh. As a result, prices settled around -$100/MWh for most of 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.

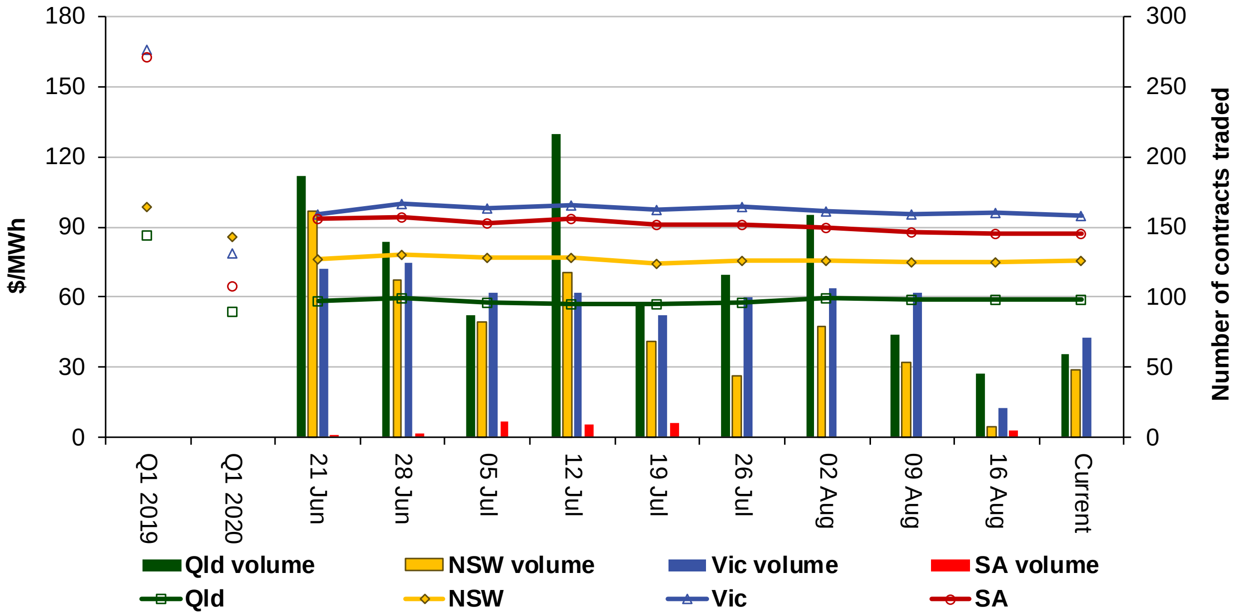
Figure 9: Quarterly base future prices Q3 2020 – Q2 2024



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2021 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q 1 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 2021 base contracts over the past 10 weeks (and the past 2 years)

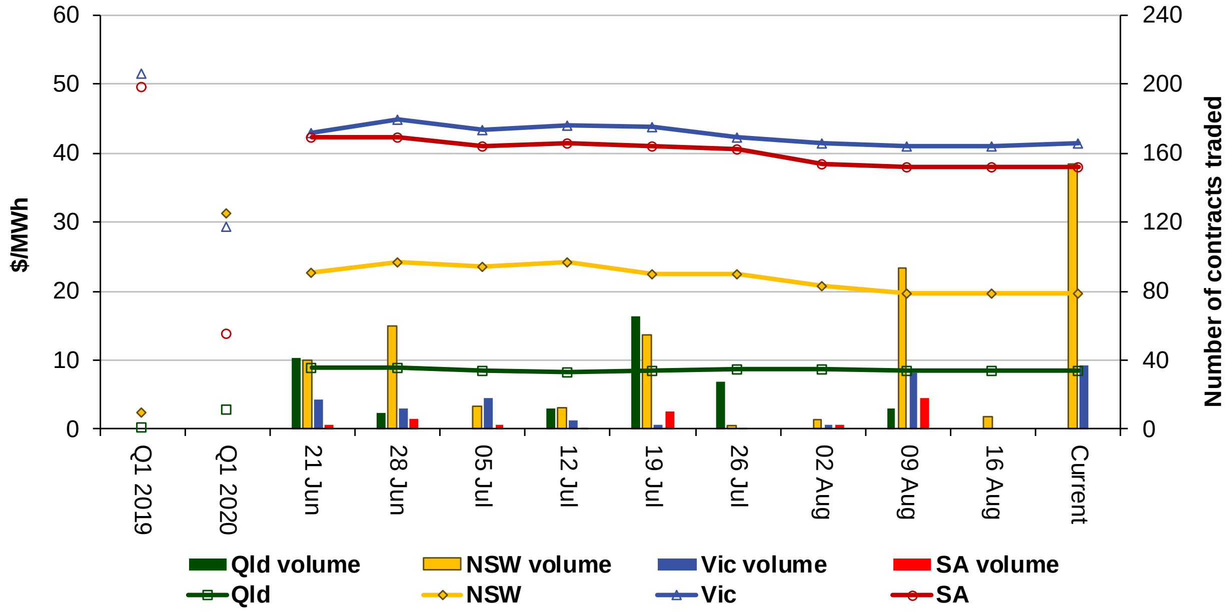


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2019 and Q1 2020 prices are also shown.

Figure 11: Price of Q1 2021 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
September 2020