Electricity Report

AUSTRALIAN ENERGY REGULATOR

7– 13 March 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $31/MWh in Tasmania to $267/MWh in South Australia. The high weekly price in South Australia is due to a high price event on 12 March resulting from a fire in the Torrens Island substation. This reduced the output from the Torrens Island and Barkers Inlet power stations from 5 pm and for the rest of the evening. These prices will be the subject of an upcoming $5,000/MWh report. Despite the high prices, quarter to date VWA prices remain below $60/MWh across all regions.

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 7 to 13 March 2021.

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

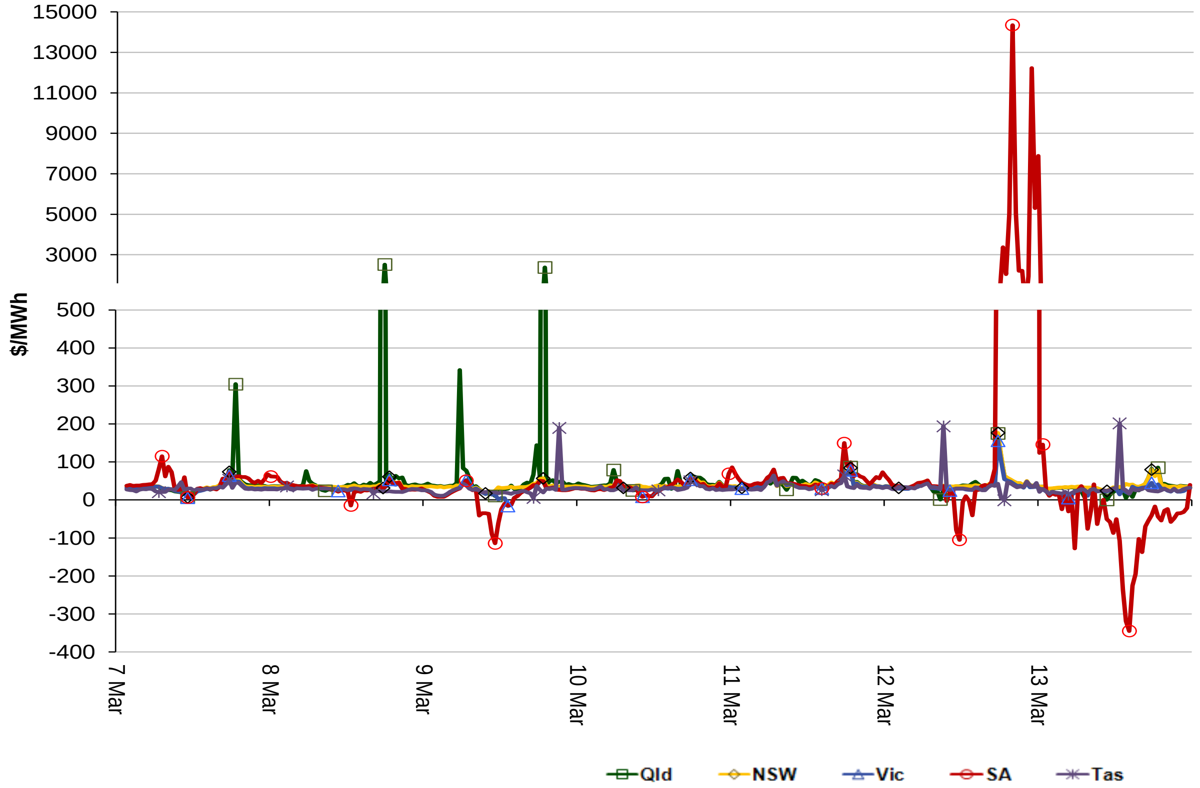


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

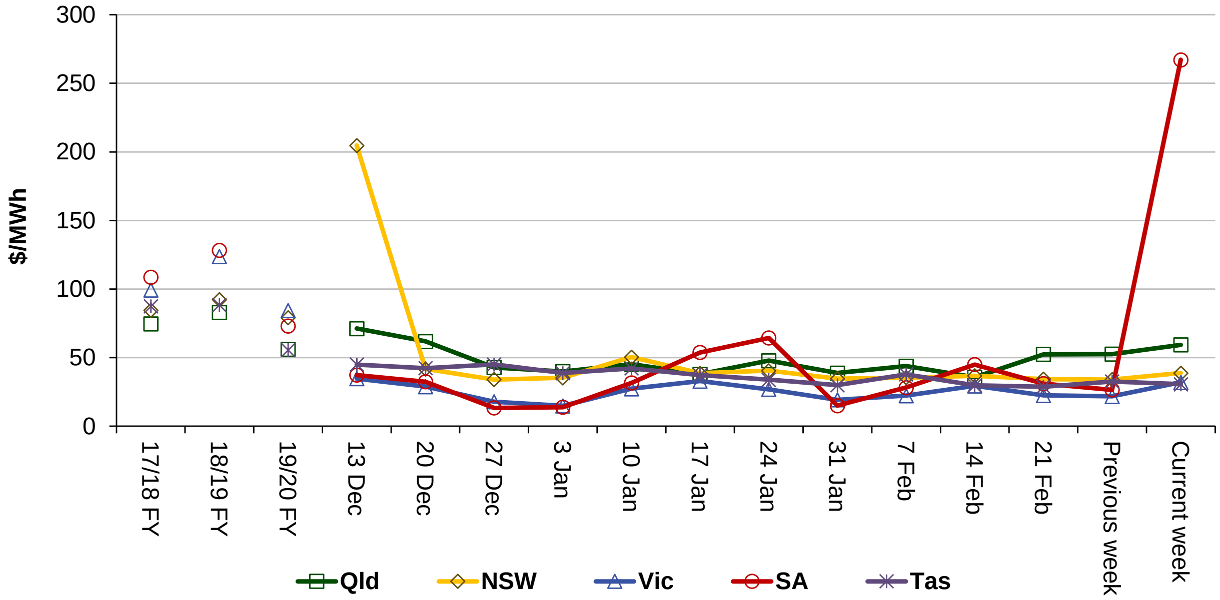


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	59	39	32	267	31
Q1 2020 QTD	61	122	124	90	46
Q1 2021 QTD	45	38	25	56	34
19-20 financial YTD	64	93	102	86	66
20-21 financial YTD	43	53	41	45	45

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 242 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	16	0	1
% of total below forecast	11	52	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

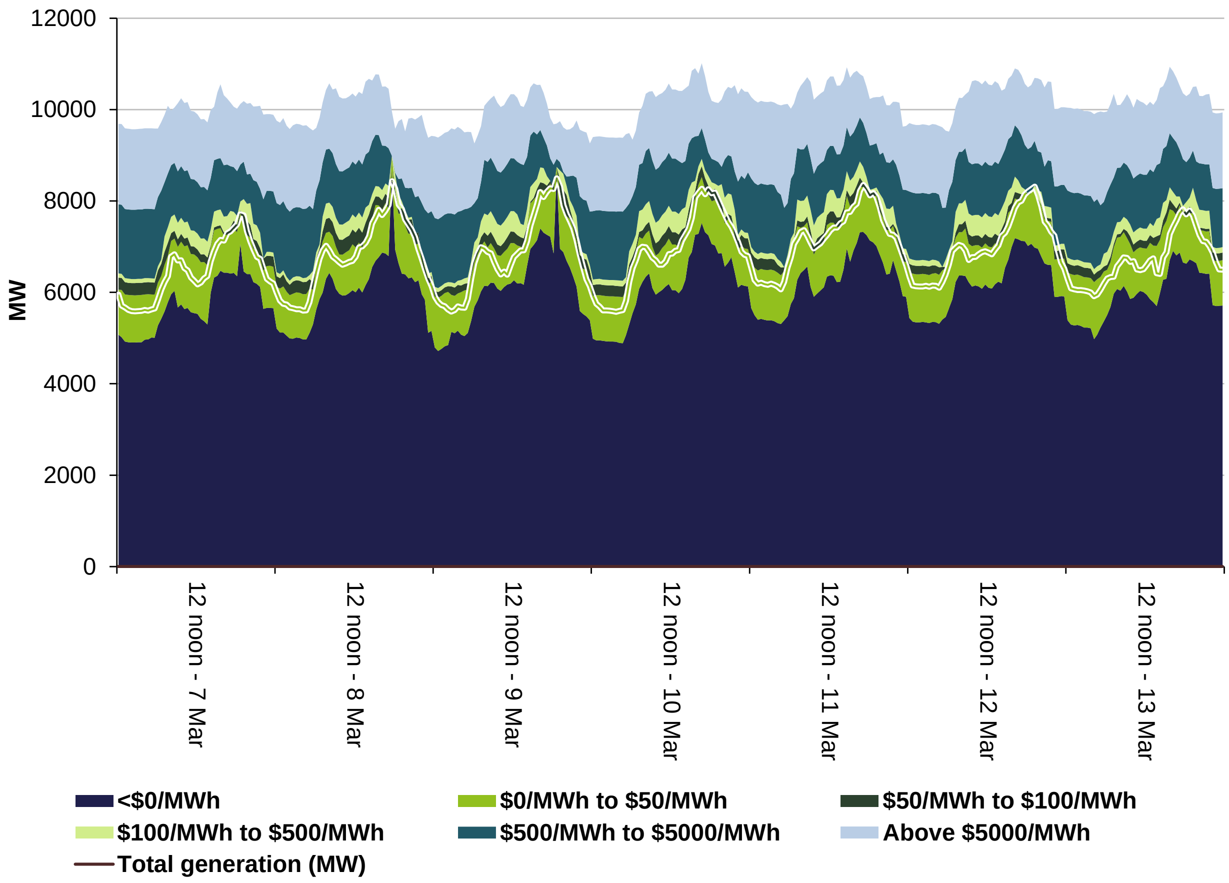


Figure 4: New South Wales generation and bidding patterns

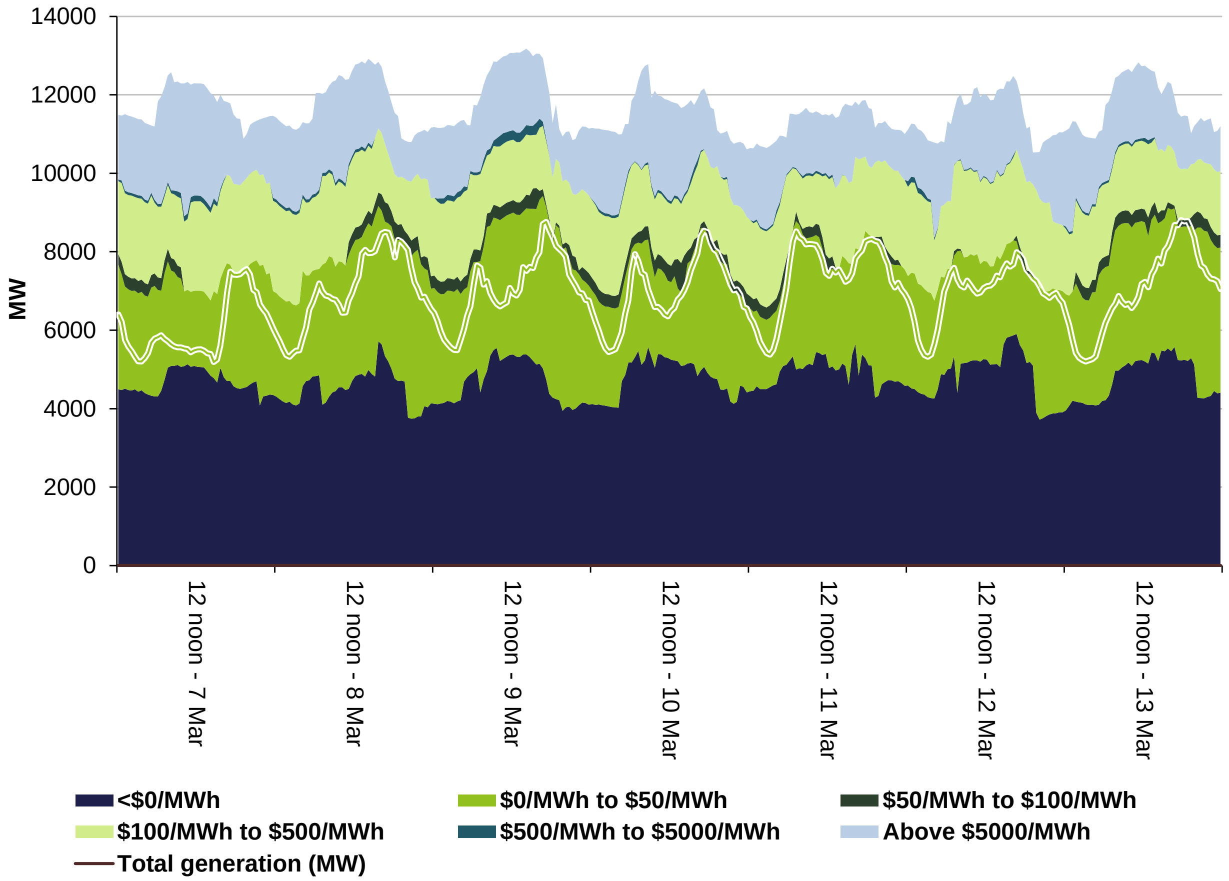


Figure 5: Victoria generation and bidding patterns

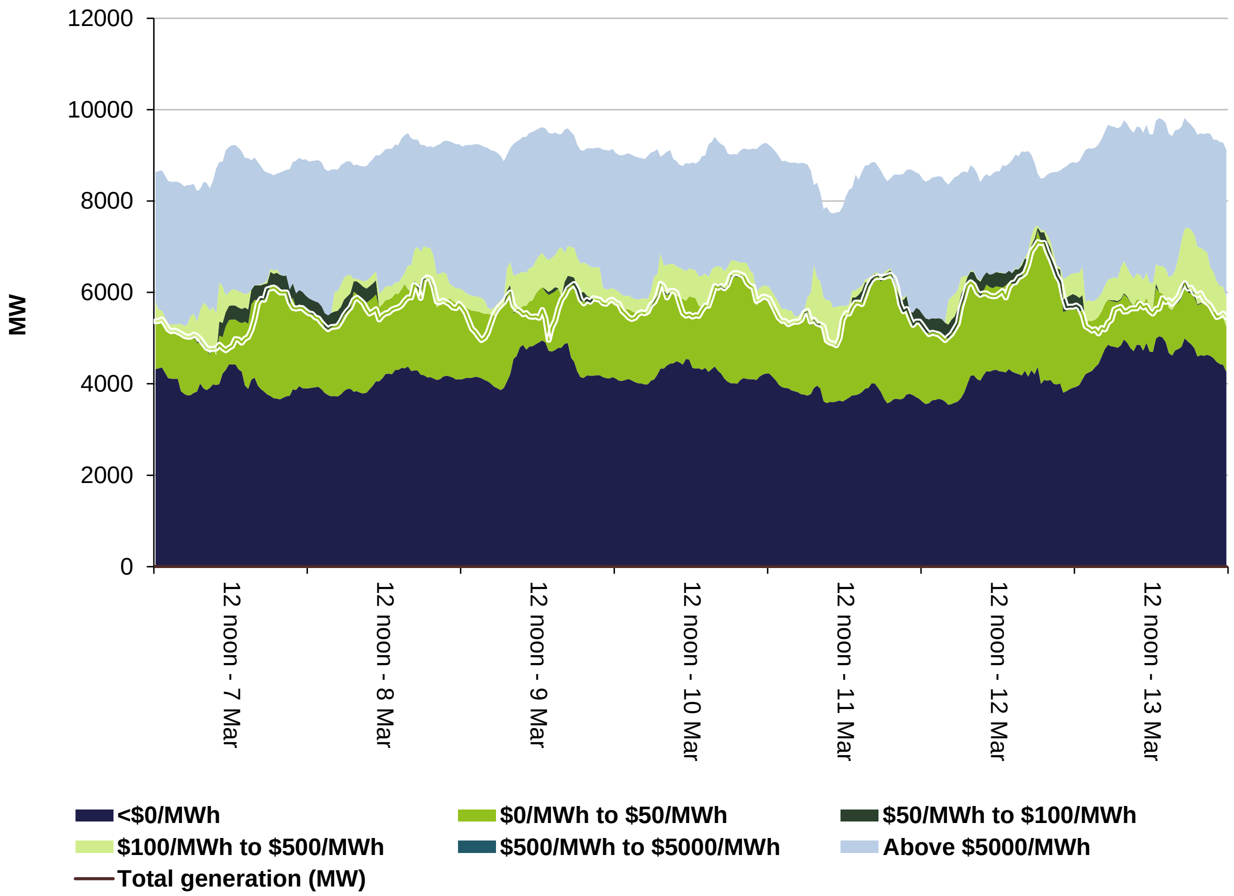


Figure 6: South Australia generation and bidding patterns

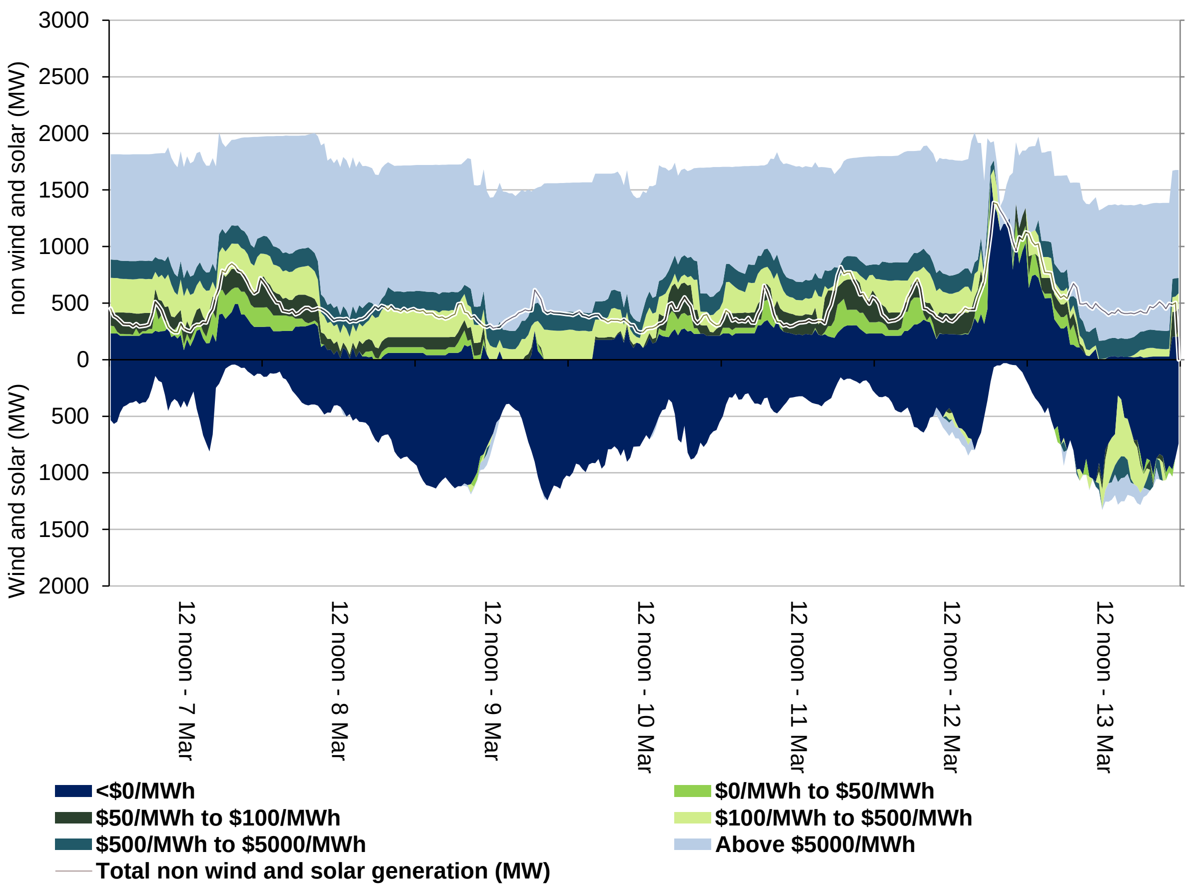
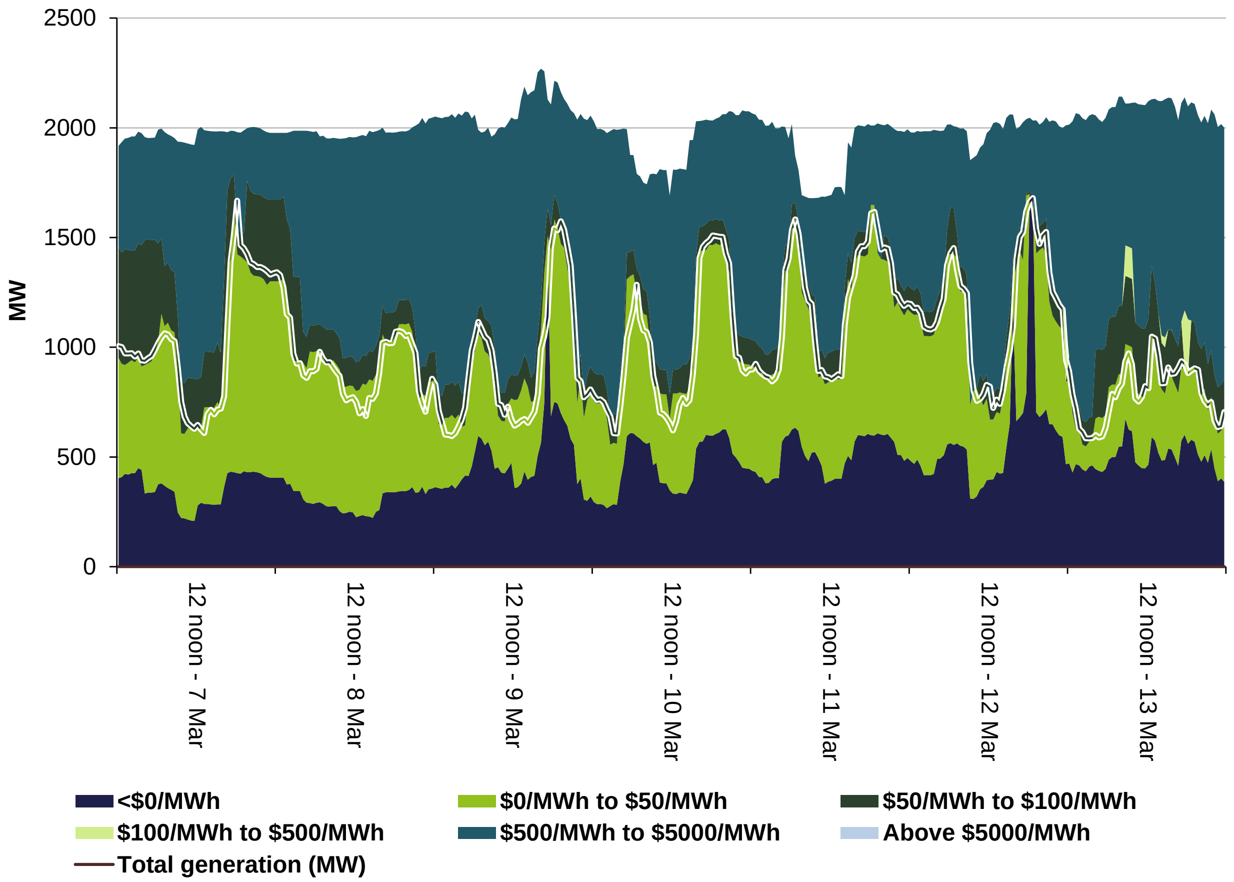


Figure 7: Tasmania generation and bidding patterns



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.

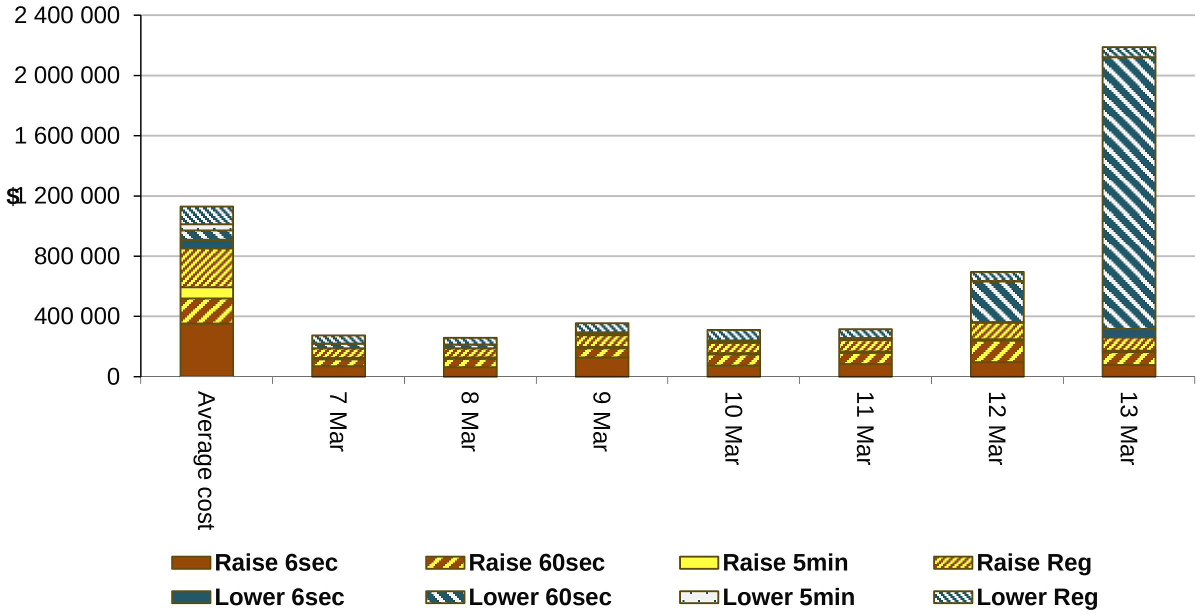
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3,874,500 or around 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $522,000 or less than 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



High costs on 13 March occured in South Australia due to a planned outage of lines in Victoria near the Heywood interconnector which required South Australia to provide its own FCAS. There was limited capacity of FCAS available and the price of lower 60 second services in South Australia was above $1,000/MW for the majority of the day.

Detailed market analysis of significant price events

Queensland

There were 4 occasions where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $59/MWh and above $250/MWh.

Sunday, 7 March

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	304.90	200.11	200.11	7,700	7,612	7,530	10,121	9,916	9,954

Demand was 88 MW higher than forecast and availability was 205 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to QGC Sales adding in 82 MW of capacity at Condamine at the floor in response to market conditions, Yarwun adding in 50 MW of capacity close to the floor due to gas supply limitations, and also higher than forecast wind generation all priced at the floor.

At 4.42 pm, CleanCo rebid 175 MW of capacity from $0/MWh to $668/MWh at Wivenhoe due to a fall in forecast prices. At 6.35 pm demand increased by over 150 MW, likely due to rooftop solar stopping production for the day. With several generators unable to come on in 5 minutes or ramp constrained and unable to set price, the price was set at $1,553/MWh for 5 minutes. In response, participants rebid over 200 MW of capacity from prices above $1,500/MWh to the price floor. Price was set below $60/MWh for the remainder of the trading interval.

Monday, 8 March

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	2,515.68	288.00	288.00	7,950	8,059	8,008	9,985	10,151	10,046

Demand was 109 MW lower than forecast and availability was 166 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to CS Energy removing 270 MW of capacity priced below $56/MWh at Gladstone due to a unit trip.

At 5.35 pm demand increased by almost 80 MW. With several generators unable to come on in 5 minutes, ramp constrained or trapped / stranded in FCAS and unable to set price, price was set at the cap for 5 minutes. At 5.40 pm demand dropped by 195 MW and with some generators no longer limited, price was below $20/MWh for the remainder of the trading interval.

Tuesday, 9 March

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 am	342.16	40.68	40.68	6,184	6,098	6,084	9,504	9,624	9,703
7 pm	2,371.43	593.42	1,553.00	8,398	8,376	8,412	9,690	9,717	9,435

For the 6 am trading interval, demand was 86 MW higher than forecast and availability was 120 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to removal of 50 MW of capacity priced at the floor by RTA Yarwun at Yarwun, and lower than forecast wind generation all of which was priced close to the floor.

At 2.30 am, CS Energy rebid 50 MW of capacity at Gladstone from prices below $56/MWh to the cap due to turbine vibrations. At 6 pm demand increased by over 75 MW and with several generators ramp constrained and unable to set price, price was at $1,553/MWh for the last dispatch interval.

For the 7 pm trading interval, demand and availability were both close to forecast 4 hours prior.

At 6.40 pm demand increased by almost 130 MW and with several generators unable to come on in 5 minutes or ramp constrained and unable to set price, price was set at $13,990/MWh for 5 minutes only. In response, participants rebid over 130 MW of capacity from prices above $13,990/MWh to the floor. At 6.45 pm demand dropped by over 125 MW and prices were below $33/MWh for the remainder of the trading interval.

South Australia

There were 12 occasions where the spot price in South Australia was greater than 3 times the South Australia weekly average price of $267/MWh and above $250/MWh and there were 11 occasions where the spot price was below -$100/MWh.

Tuesday, 9 March

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
11.30 am	-114.17	-181.02	-562.78	633	572	586	2,360	2,452	2,399

Demand was close to forecast and availability was 92 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to AGL making 200 MW at Torrens Island B2 unavailable. Most of this capacity was priced above $40/MWh due to an increase in forecast available generation in other regions.

At 8.55 am AGL rebid 300 MW of capacity from the price floor to prices above $-40/MWh at the Bluff, Hallet 1 and 2, and North Brown Hill Wind Farms in response to forecast price. There was little capacity between $-200/MWh and $-35/MWh so small changes in demand or availability could cause large fluctuations in price. Prices ranged between $-200/MWh and $-35/MWh as demand changed through the trading interval.

Friday, 12 March

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
Midday	-104.97	-338.59	-348.95	790	750	774	2,443	2,412	2,387
6 pm	1,087.16	100.11	278.81	1,607	1,626	1,643	2,243	2,379	2,264
6.30 pm	3,372.40	379.95	379.95	1,689	1,693	1,713	2,199	2,282	2,267
7 pm	2,041.92	1,500.00	1,152.56	1,770	1,731	1,735	2,057	2,188	2,181
7.30 pm	5,010.09	1,017.06	1,015.13	1,752	1,727	1,730	1,977	2,192	2,161
8 pm	14,348.15	1,500.00	1,015.13	1,680	1,775	1,693	1,404	2,199	2,171
8.30 pm	5,066.14	1,750.05	396.80	1,613	1,712	1,643	1,466	2,228	2,200
9 pm	2,207.63	1,500.00	379.98	1,545	1,646	1,581	1,570	2,230	2,214
9.30 pm	2,206.08	157.78	278.81	1,472	1,583	1,532	1,665	2,264	2,214
10.30 pm	1,938.67	62.00	66.77	1,339	1,467	1,452	1,851	2,341	2,184
11 pm	12,222.58	62.26	350.00	1,302	1,423	1,415	1,930	2,345	2,211
11.30 pm	5,308.74	62.00	379.98	1,261	1,408	1,405	1,929	2,399	2,229

For the midday trading interval, demand and availability were both close to forecast, 4 hours prior. From 7.30 am, participants rebid over 500 MW of capacity from prices below $-649/MWh to prices above $-40/MWh in response to forecast prices. This resulted in price being set between $-200/MWh and $36/MWh for the entire trading interval.

Just after 5 pm, a fire occurred at the Torrens Island substation. Prices for the 6 pm to 11.30 pm trading intervals were driven by the events that occurred and will be analysed in our upcoming $5,000/MWh report.

Saturday, 13 March

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
Midnight	7,885.34	15,000.00	578.81	1,374	1,517	1,510	2,021	1,976	2,313
6 am	-127.68	19.02	25.89	1,013	1,037	1,109	2,568	2,348	2,487
1 pm	-107.05	-1,000	-1,000	1,000	623	698	2,625	2,719	2,625
1.30 pm	-236.26	-1,000	-1,000	787	664	666	2,603	2,728	2,627
2 pm	-319.10	-1,000	-1,000	632	671	639	2,565	2,732	2,668
2.30 pm	-345.10	-1,000	-1,000	586	644	611	2,650	2,720	2,668
3 pm	-225.48	-1,000	-1,000	587	643	613	2,619	2,710	2,663
3.30 pm	-195.00	-1,000	-1,000	610	643	632	2,620	2,704	2,653
4 pm	-102.66	-1,000	-1,000	702	668	670	2,564	2,641	2,628
4.30 pm	-137.49	-459.65	-1,000	780	822	698	2,574	2,654	2,621

A planned outage of the Moorabool to Mortlake 500 kV line in Victoria and the fire at the Torrens Island substation the previous evening resulted in exports from South Australia into Victoria over the Heywood interconnector being limited to less than 140 MW (nominally 600 MW) for the entire day.

The price for the midnight trading interval was due to events that occurred at Torrens Island substation just after 5 pm on 12 March, and will be analysed in our upcoming $5,000/MWh report.

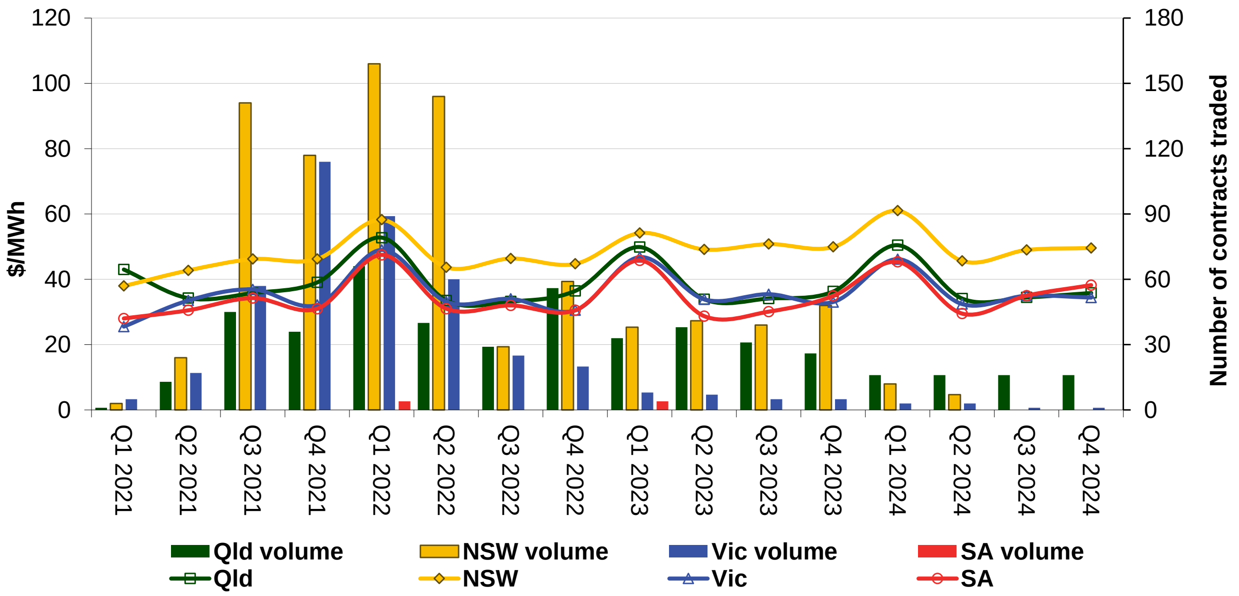
For the 6 am trading interval, demand was close to forecast and availability was 220 MW higher than forecast, 4 hours prior. Higher than forecast generation was due to higher than forecast wind generation, all of which was priced below $0/MWh. At 5.50 am, wind generation picked up by over 100 MW and with higher priced capacity ramp constrained and unable to set price, price fell to $-649/MWh for 5 minutes. In response to the low price, participants rebid over 530 MW of capacity from the floor to prices above $249/MWh.

For the 1 pm to 4.30 pm trading intervals, demand ranged between close to 377 MW higher than forecast and availability was between 70 MW to 167 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to higher than forecast renewable generation, mostly priced below $0/MWh. Due to forecast prices, from 4 hours before the start of each trading interval participants rebid at least 400 MW from the floor to higher prices. The combination of demand and availability conditions and the rebids resulted in price being set above forecast for all trading intervals.

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.

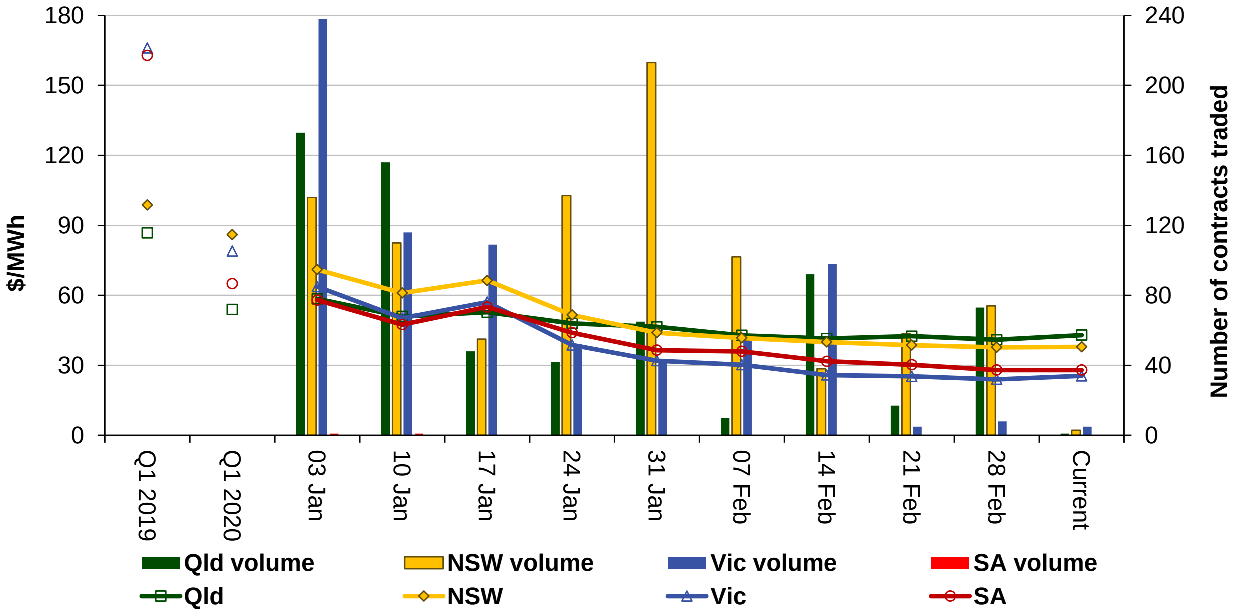
Figure 9: Quarterly base future prices Q1 2021 – Q4 2024



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 2020 and Q1 2019 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)

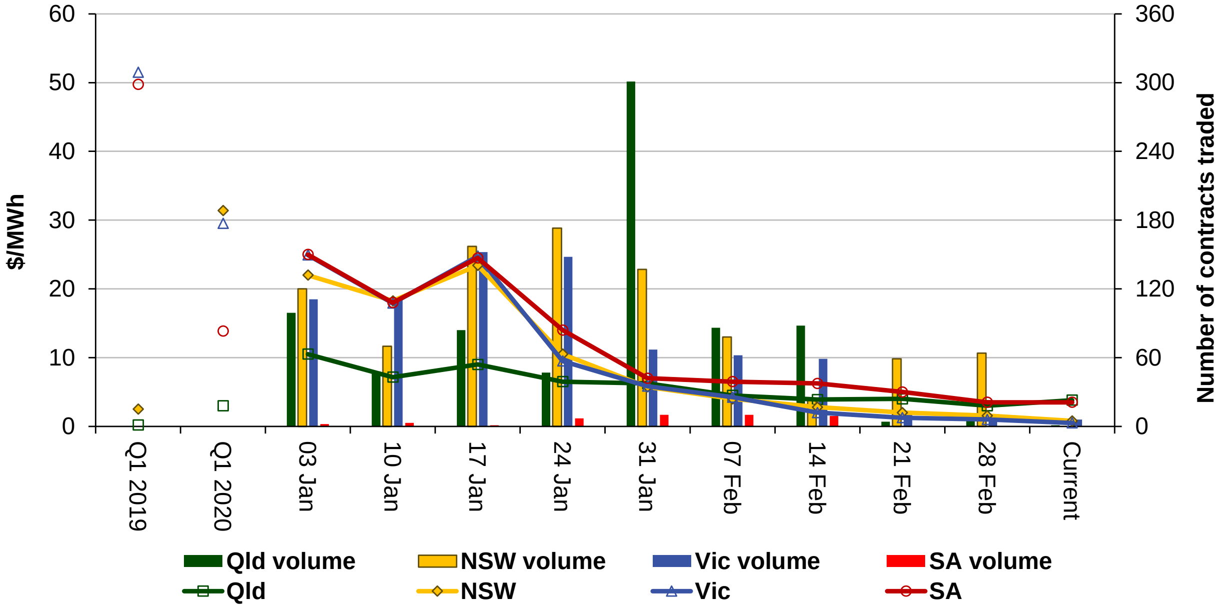


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2020 and Q1 2019 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
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