Electricity Report

AUSTRALIAN ENERGY REGULATOR

4 – 10 October 2020

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $23/MWh in Tasmania to $68/MWh in New South Wales. Q4 quarter to date prices were less than half the levels seen a year ago.

Significant planned maintenance was underway this week coinciding with a number of unplanned outages of baseload generating units. Notably from 4 October, close to 3100 MW of low-priced coal capacity was unavailable across New South Wales and Victoria due to ongoing planned maintenance, unit trips or tube leaks at several power stations, including Bayswater, Mt Piper, Liddell, Vales Point and Yallourn power stations. This drove relatively higher price outcomes for the week, especially in New South Wales and Victoria.

High levels of wind generation and mild demand in South Australia drove negative prices later in the week.

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 4 to 10 October 2020.

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

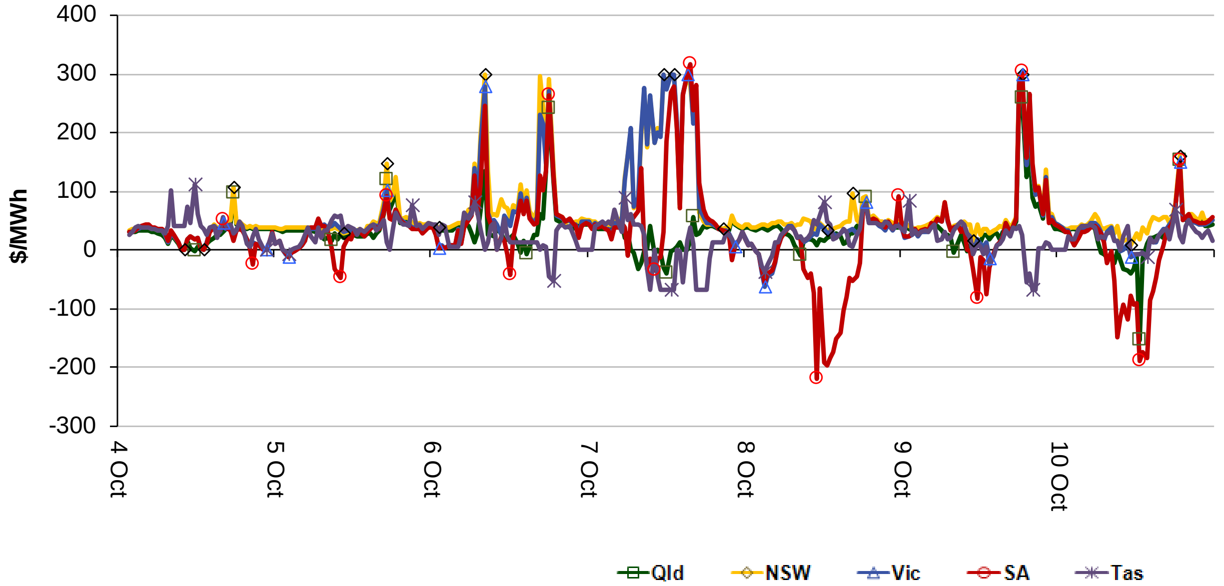


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous three financial years.

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

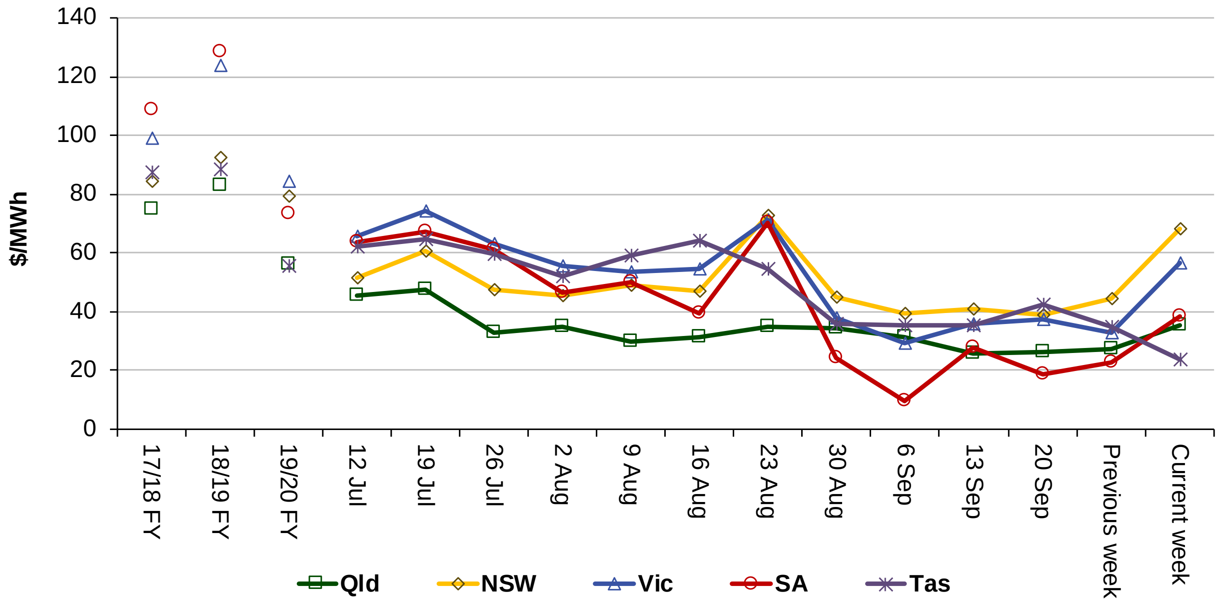


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	35	68	57	38	23
Q4 2019 QTD	61	114	117	68	113
Q4 2020 QTD	32	58	43	28	24
19-20 financial YTD	65	89	104	81	73
20-21 financial YTD	34	49	53	45	48

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 277 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	31	0	1
% of total below forecast	14	37	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

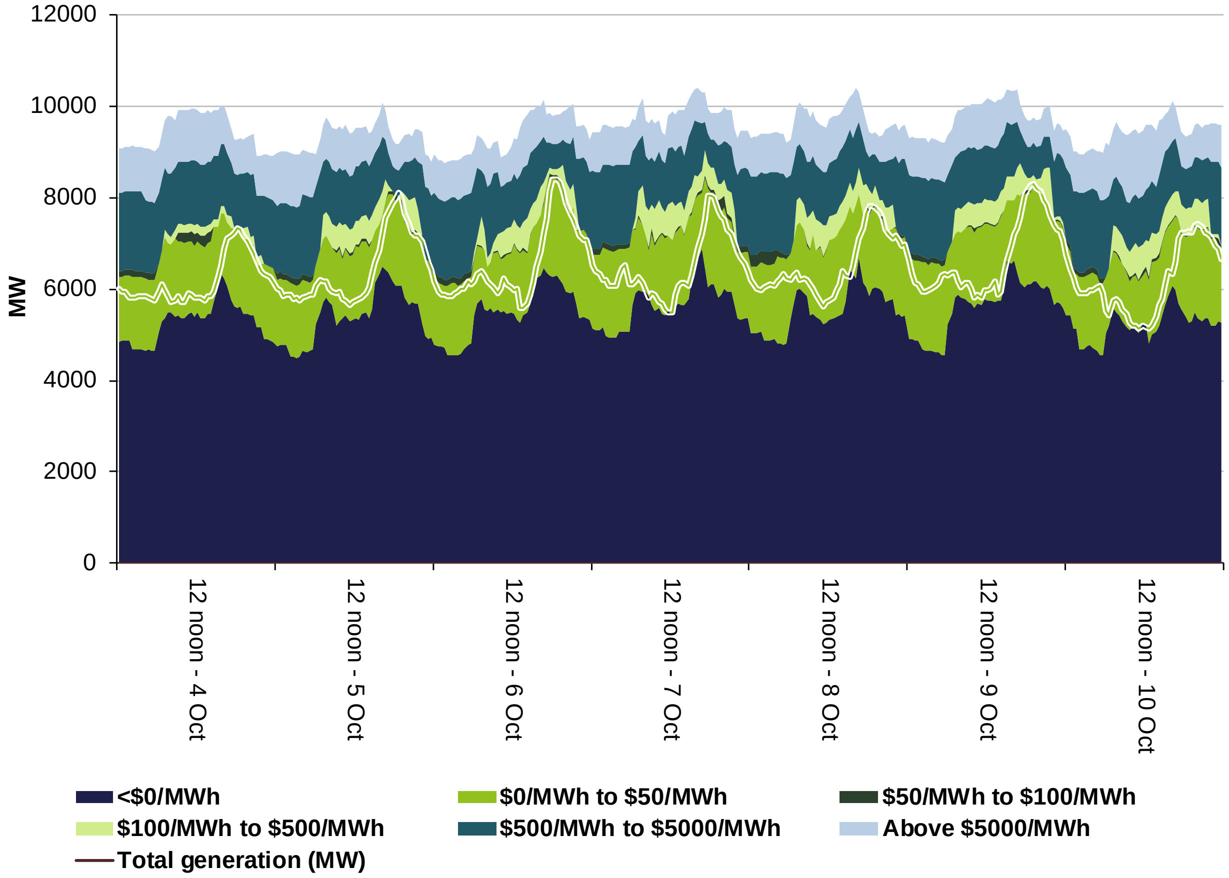


Figure 4: New South Wales generation and bidding patterns

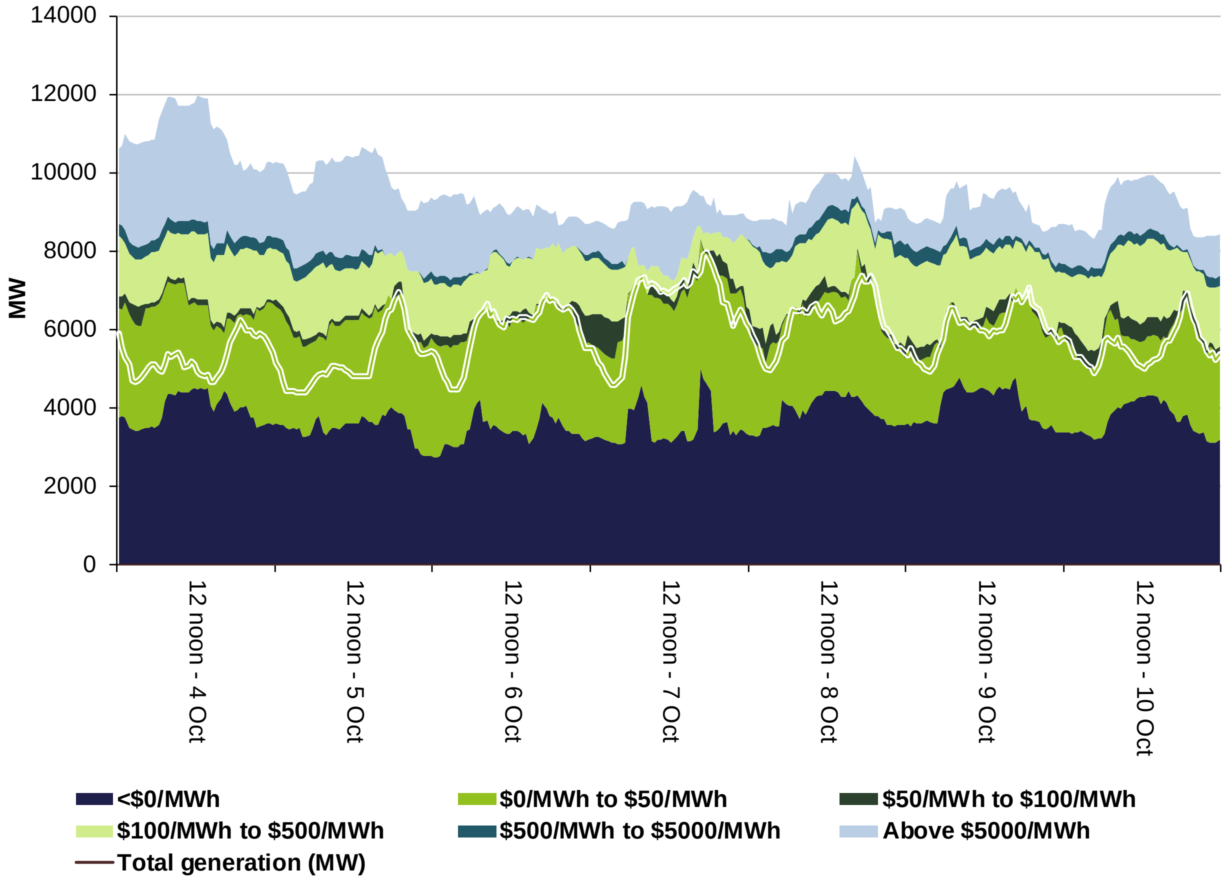


Figure 5: Victoria generation and bidding patterns

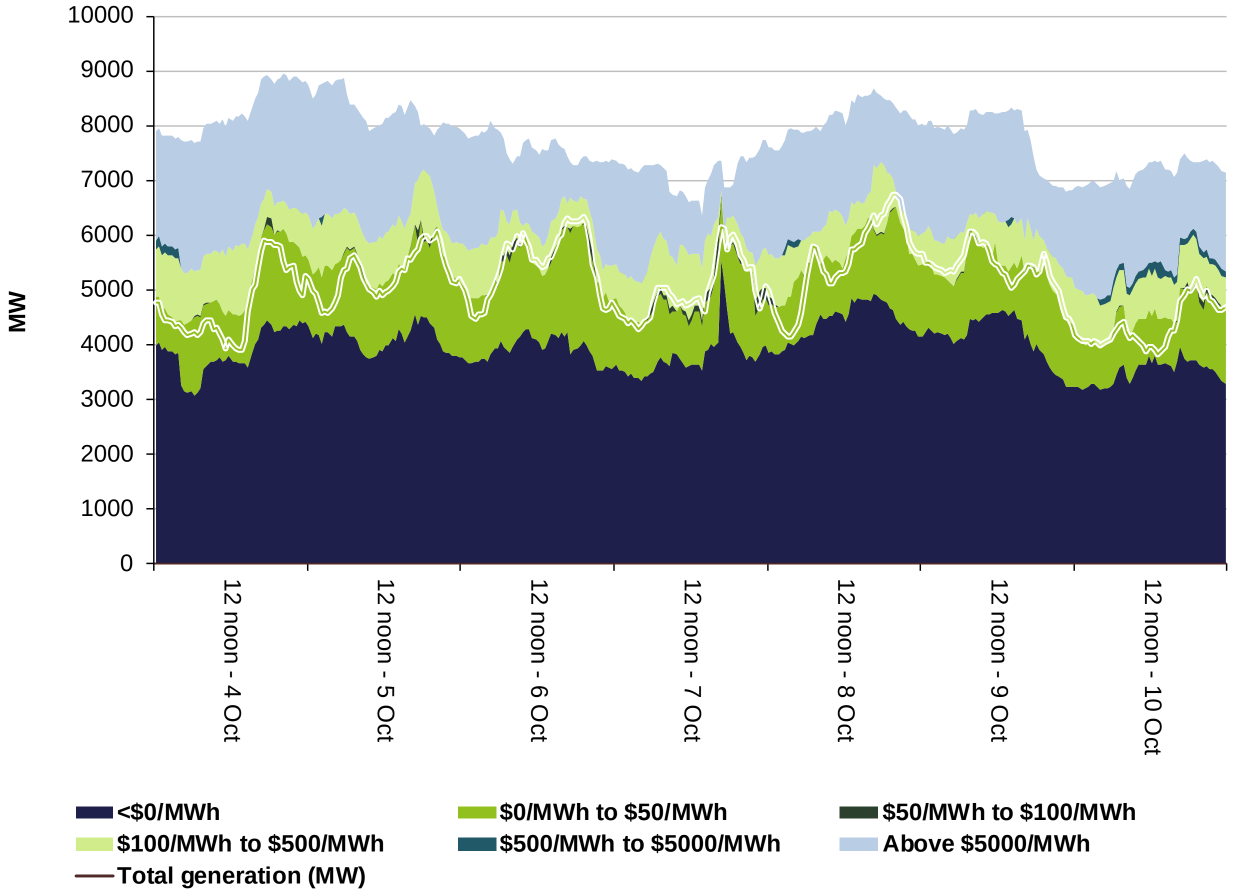


Figure 6: South Australia generation and bidding patterns

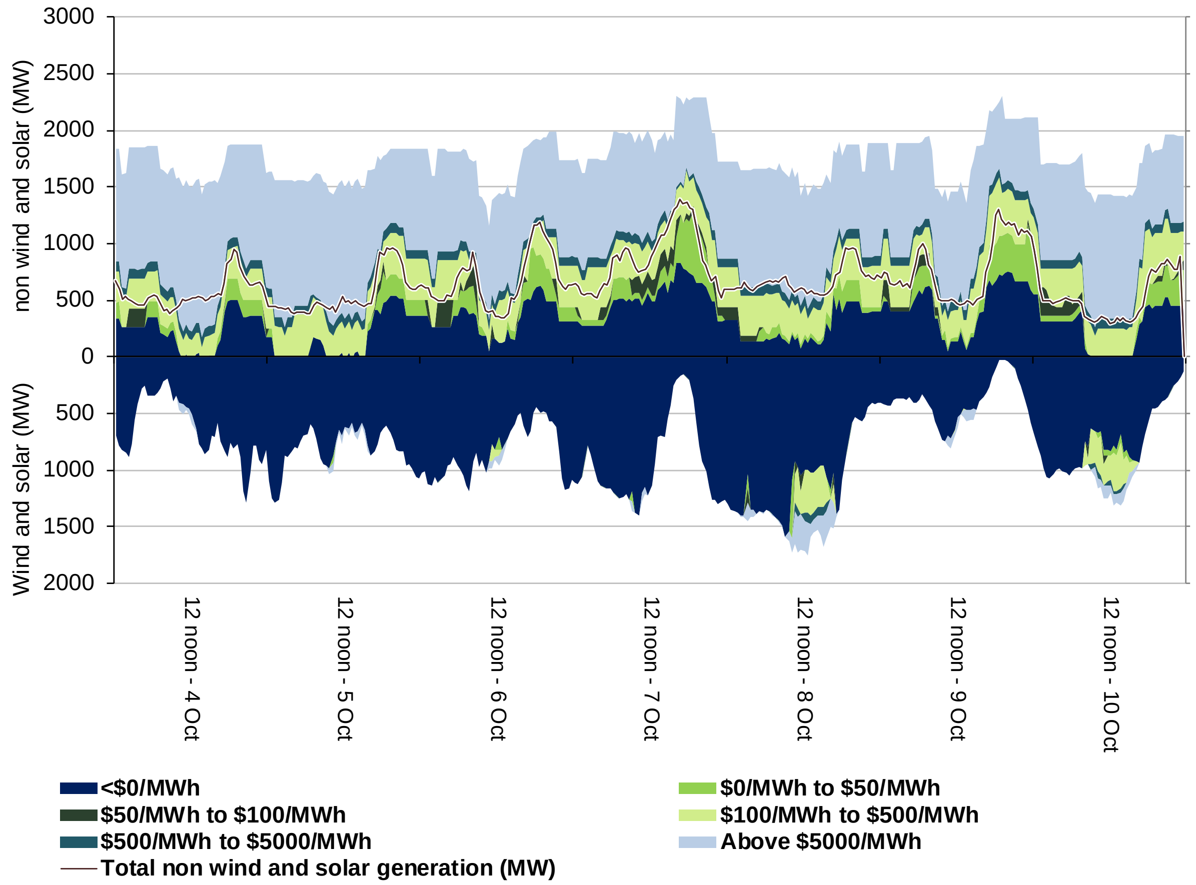
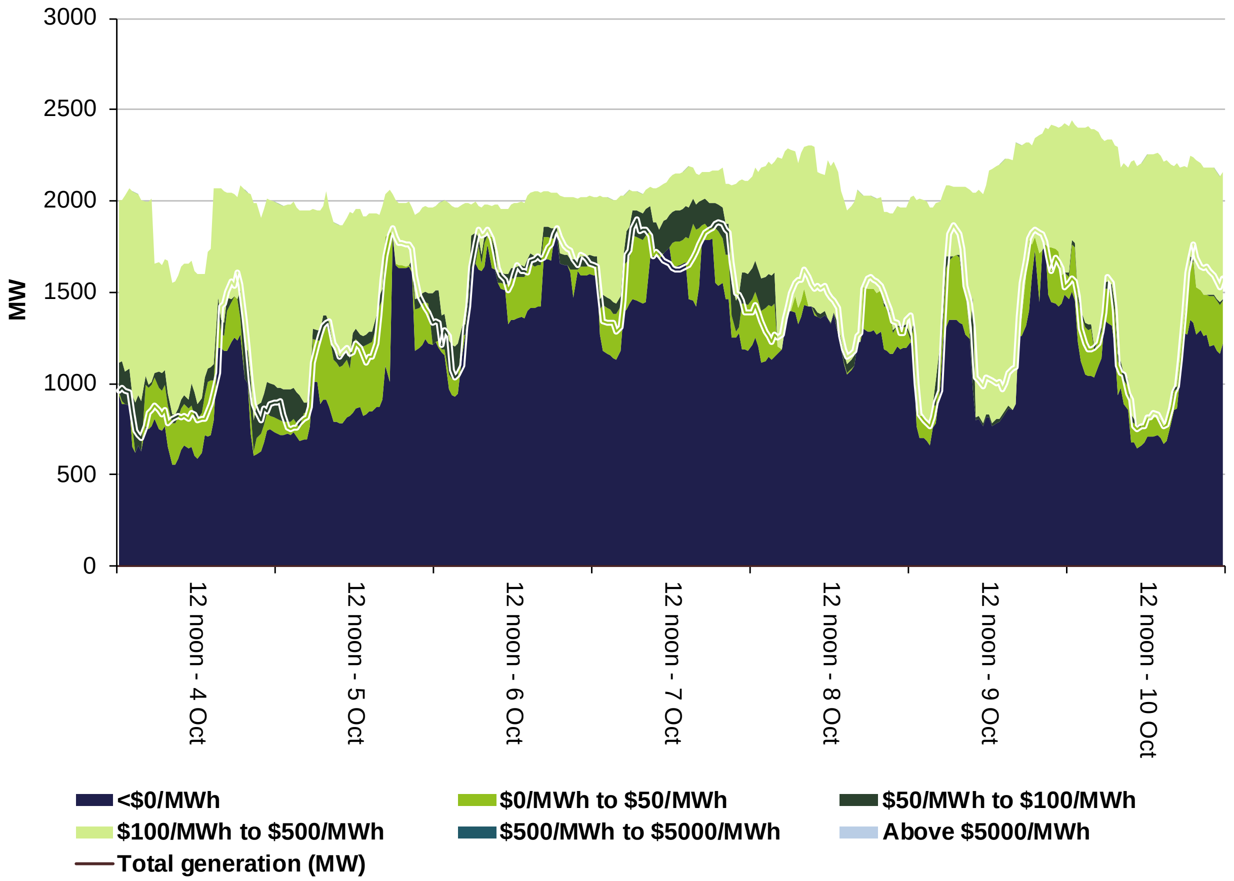


Figure 7: Tasmania generation and bidding patterns



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.

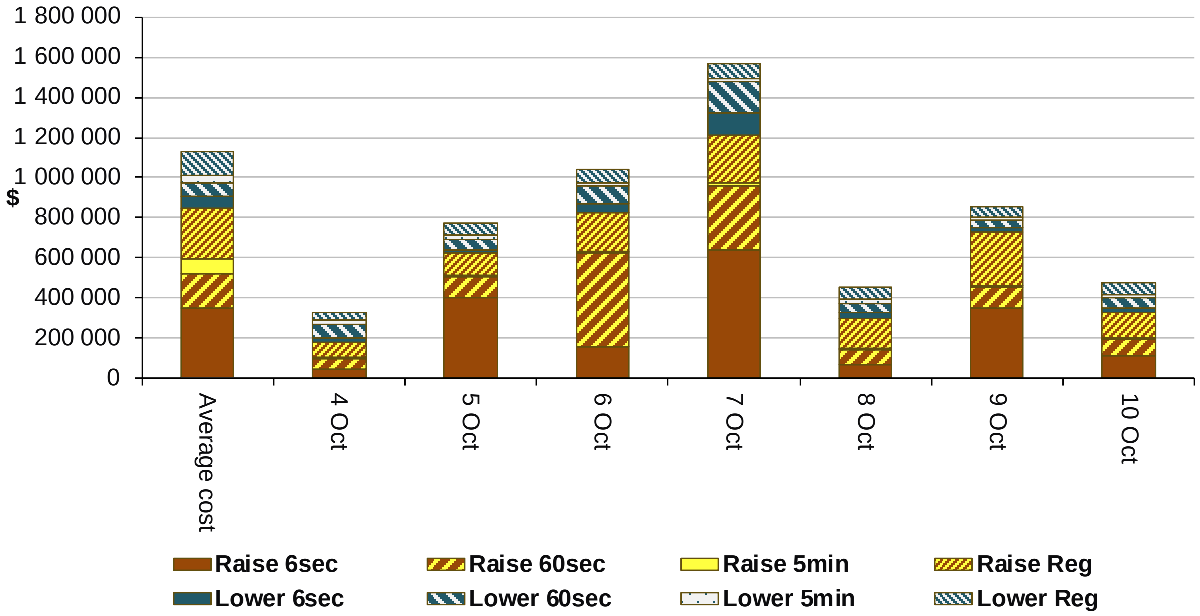
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4 857 500 or less than 3 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $638 000 or around 14 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



Higher FCAS costs on 7 October were driven by higher prices for global raise services of up to $340/MW for raise 6 second, $260/MW for raise regulation and $260/MW for raise 60 second services.

Detailed market analysis of significant price events

Mainland

There were two occasions where the spot price aligned across the mainland and the New South Wales price was greater than three times the New South Wales weekly average price of $68/MWh and above $250/MWh.

Friday, 9 October

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	296.22	186.41	299.60	21 543	21 550	21 581	28 244	29 339	29 063
7 pm	299.86	299.60	299.99	21 910	21 698	21 796	28 302	29 140	28 945

For 6.30 pm, demand was close to forecast while mainland availability was 1095 MW lower than forecast, four hours prior. Lower than forecast availability was due to rebids and plant withdrawals in the four hours prior to dispatch. In New South Wales, rebids by Bayswater and Eraring removed around 500 MW due to plant reasons, while in Victoria, unit trips at Yallourn and McKay removed close to 500 MW of capacity. As a result, the spot price settled higher than forecast.

For the 7 pm trading interval, prices were close to forecast four and 12 hours prior.

Queensland

There was one occasion where the spot price in Queensland was below -$100/MWh.

Saturday, 10 October

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
1 pm	-153.88	-31.62	-1000	4381	4285	4262	9845	9631	9864

Demand was 96 MW higher than forecast and availability was 214 MW higher than forecast, four hours prior. At 12.55 pm, demand fell by 57 MW and with the generation priced between $0/MWh and the price floor ramp-down constrained and unable to set price, the price fell to the floor for once dispatch interval. In response, participants rebid over 700 MW from the price floor to higher prices.

New South Wales and Victoria

There were five occasions where the spot price aligned across the New South Wales and Victoria and the New South Wales price was greater than three times the New South Wales weekly average price of $68/MWh and above $250/MWh.

Tuesday, 6 October

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
5 pm	297.56	299.6	299.99	14 132	13 445	13 015	16 512	16 710	17 086

Prices were close to forecast four and 12 hours prior.

Wednesday, 7 October

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
9 am	271.6	414.46	426.26	13 027	13 275	13 341	16 014	16 538	16 412
10 am	258.77	82.8	485.54	12 925	13 025	13 110	15 811	16 392	16 311
Midday	299.99	49.42	282.2	12 674	12 635	12 705	15 733	16 363	16 407
12.30 pm	276.53	43.89	253.46	12 731	12 708	12 700	15 644	16 592	16 602

For the 9 am trading interval, demand was 248 MW lower than forecast and availability was 524 MW lower than forecast, four hours prior. Lower than forecast availability was due to rebids that removed high priced generation for forecast constraint management and lower priced generation for plant reasons.

Lower than forecast demand resulted in prices between $150/MWh and $300/MWh for the trading interval.

For the remaining trading intervals, demand was close to forecast however availability was between 580 MW and 948 MW lower than forecast. Lower than forecast availability was mostly due to rebids that removed low priced capacity, notably at Yallourn unit 2 for a unit trip and Vales Point unit 5 for plant reasons. Snowy Hydro also shifted over 1500 MW of capacity from the floor to prices between $33/MWh and $450/MWh in response to changes in forecast price sensitivities. As a result, prices generally settled between $250/MWh to $300/MWh throughout each of the trading intervals.

New South Wales, Victoria and South Australia

There were eight occasions where the spot price aligned across the New South Wales, Victoria and South Australia and the New South Wales price was greater than three times the New South Wales weekly average price of $68/MWh and above $250/MWh.

Tuesday, 6 October

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	299.99	64.41	50.86	14516	13735	13800	19027	19479	19839
6.30 pm	292.18	299.99	282.23	15832	15684	15229	18625	18987	19231

For the 8.30 am trading interval, demand was 781 MW higher than forecast while availability was 452 MW lower than forecast, four hours prior. Lower than forecast availability was due to rebids by Eraring and Jeeralang A and B that removed over 240 MW of capacity for plant reasons, as well as lower than forecast wind generation. Lower availability combined with significantly higher than forecast demand caused prices to settle between $250/MWh to $300/MWh for the trading interval.

For the 6.30 pm trading interval, prices were close to forecast four and 12 hours prior.

Wednesday, 7 October

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 pm	299.94	65	280.61	14 286	14 048	13 967	18 576	19 349	19 387
1.30 pm	299.99	294.95	277.86	14 288	14 006	13 955	18 447	18 750	19 446
3 pm	265.26	69.6	272.91	14 481	14 253	14 046	18 739	19 091	19 293
3.30 pm	294.24	67.65	275.06	14 780	14 475	14 256	18 893	19 367	19 328
4 pm	280.46	65.01	279.65	15 127	14 717	14 502	18 982	19 295	19 342
5 pm	253.49	299.99	299.99	16 030	15 460	15 179	19 212	19 286	19 402

For the 1 pm, 3 pm, 3.30 pm and 4 pm trading intervals, demand was up to 410 MW higher than forecast while availability was up to 773 MW lower than forecast, four hours prior. Lower than forecast availability was driven by lower than forecast wind and solar generation, as well as rebids by Vales Point, Bayswater and Yallourn that removed capacity due to plant reasons. As a result, prices generally settled between $260/MWh to $301/MWh throughout each of the trading intervals.

For the 1.30 pm prices were close to forecast four and 12 hours prior.

The 5 pm trading interval was lower than forecast as Snowy Hydro rebid 1600 MW of capacity across its portfolio, for the last five minutes of the trading interval, from prices above $300/MWh to below $30/MWh due to forecast price changes. As a result, prices to fell to around $30/MWh.

South Australia

There were ten occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $38/MWh and above $250/MWh. There were fourteen occasions where the spot price in South Australia was below -$100/MWh.

Nine of these occurred when prices were aligned across at least one region and is detailed in the *Mainland* and *New South Wales, Victoria and South Australia* outcomes section. The one occasion was as forecast and is presented below.

Thursday, 8 October

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
11.30 am	-220.47	-649.33	-1000	900	767	757	3330	2968	3039
12.30 pm	-190.72	-1000	-1000	834	650	683	3228	2964	3032
1 pm	-196.89	-1000	-1000	778	630	681	3228	2956	3025
1.30 pm	-184.56	-1000	-1000	779	631	680	3024	2949	3024
2 pm	-174.64	-649.33	-1000	748	640	694	3065	2937	3015
2.30 pm	-152.54	-1000	-1000	729	626	687	3044	2945	3010
3 pm	-141.89	-1000	-1000	752	684	729	3085	2932	2998
3.30 pm	-103.03	-200	-1000	806	752	767	3198	2929	2987

For all trading intervals in Table 9, prices were higher than forecast four and 12 hours prior. In the lead up to the start of the trading intervals, market participants rebid up to 300 MW of capacity from the floor to higher prices due to technical and forecasting reasons. The combination of higher than forecast demand and rebids caused prices to settle above forecast.

Friday, 9 October

Table 10: 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 pm	265.64	249.00	299.46	1384	1449	1439	2126	2201	2194

Prices were close to forecast four hours prior.

Saturday, 10 October

Table 11: 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
9.30 am	-149.86	-200.00	7.74	670	736	750	2435	2436	2421
10 am	-114.96	-510.73	-190	596	630	640	2492	2468	2454
11 am	-118.38	-649.33	-900	460	444	464	2583	2510	2512
1 pm	-188.28	-1000	-1000	346	324	391	2745	2484	2581
1.30 pm	-174.72	-900	-1000	368	337	397	2717	2471	2567
2 pm	-185.39	-900	-1000	371	343	404	2746	2461	2534

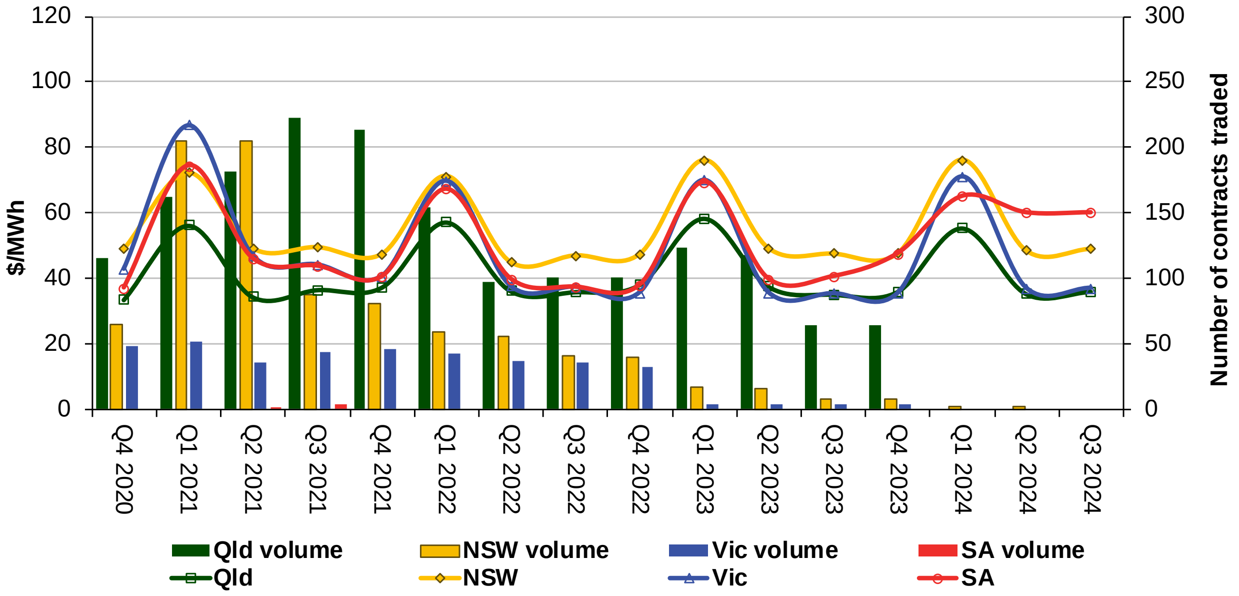
For the 9.30 am, 10 am and 11 am trading intervals demand and availability were close to forecast, four hours prior. Meanwhile, for the 1 pm, 1.30 pm and 2 pm trading intervals, demand was close to forecast while availability was greater than forecast, four hours prior. Higher than forecast availability was driven by higher than forecast wind generation, most of which was priced below $0/MWh.

In the four hours prior to the start of each trading interval, participants rebid up to 400 MW of capacity from the price floor to higher prices due to changes in forecasts and technical reasons. As a result, prices settled above forecast.

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.

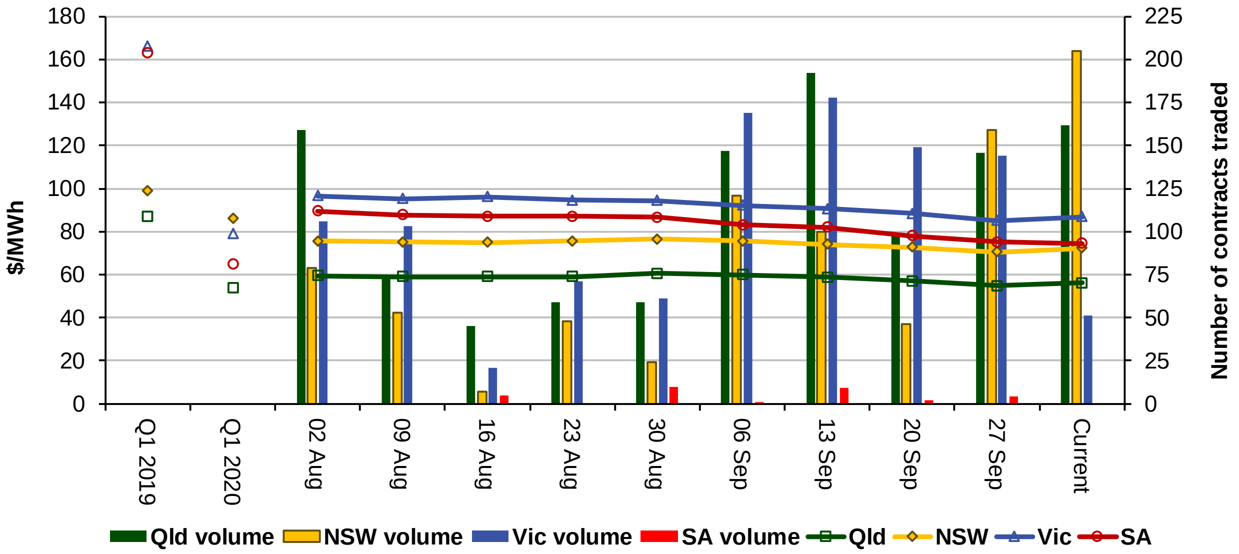
Figure 9: Quarterly base future prices Q4 2020 – Q3 2024



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 Q1 2020 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

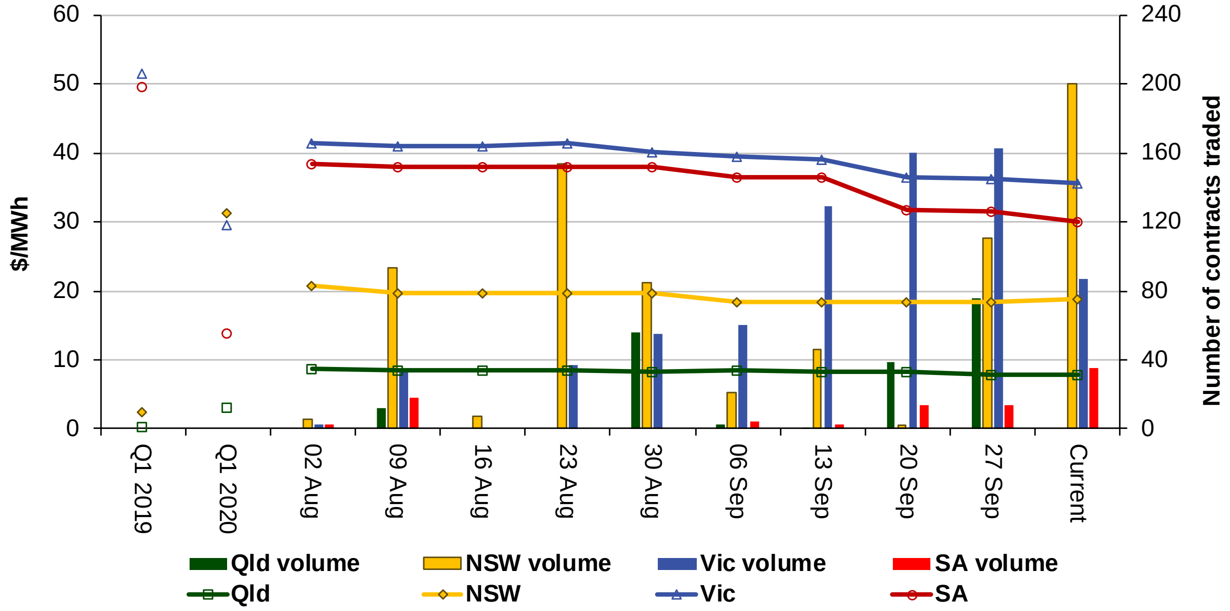
Figure 10: Price of Q1 2021 base contracts over the past 10 weeks (and the past 2 years)



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 2020 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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