Electricity Report

AUSTRALIAN ENERGY REGULATOR

29 November – 5 December 2020

Weekly Summary

Weekly volume weighted average (VWA) prices were between $29/MWh in South Australia and $57/MWh in Queensland. Q4 quarter to date VWA prices are at least $21/MWh less than the same time last year.

Higher temperatures during the week contributed to some high prices in Queensland and New South Wales. There were a number of forecast and actual Lack of Reserve level 1 in New South Wales. In contrast, high wind generation at the start and end of the week drove a number of negative prices in South Australia. These are all detailed in our 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 29 November to 5 December 2020.

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

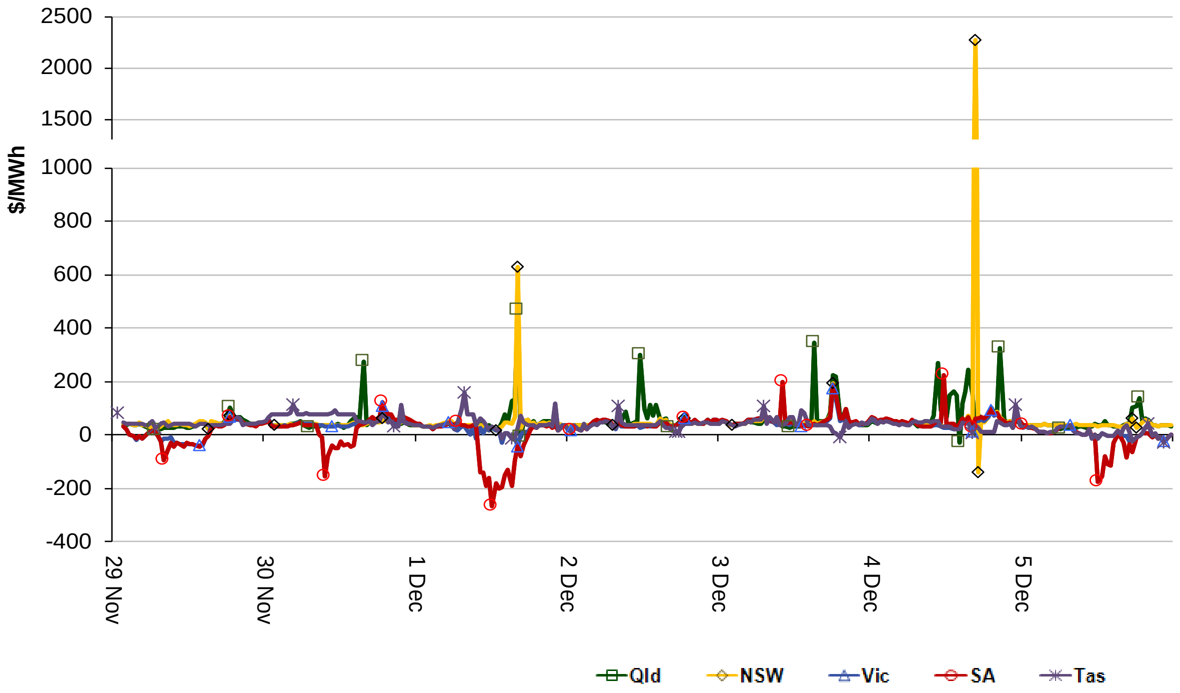


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

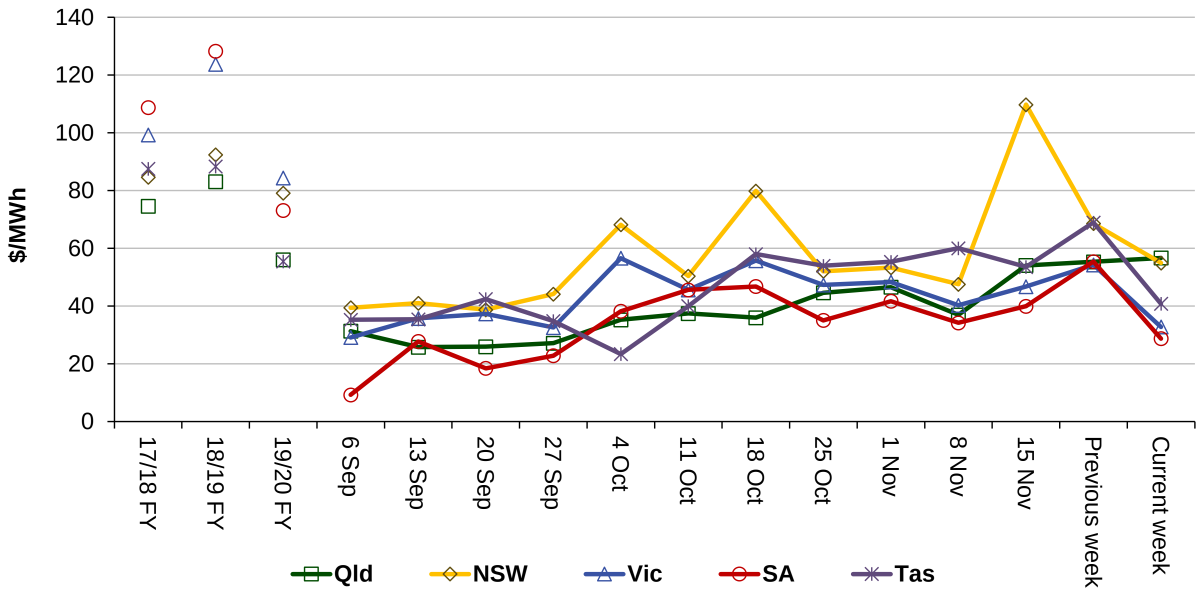


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	57	55	33	29	41
Q4 2019 QTD	69	85	83	63	84
Q4 2020 QTD	44	64	46	39	49
19-20 financial YTD	67	86	95	75	75
20-21 financial YTD	39	55	51	44	50

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 282 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	6	24	0	1
% of total below forecast	15	49	0	6

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

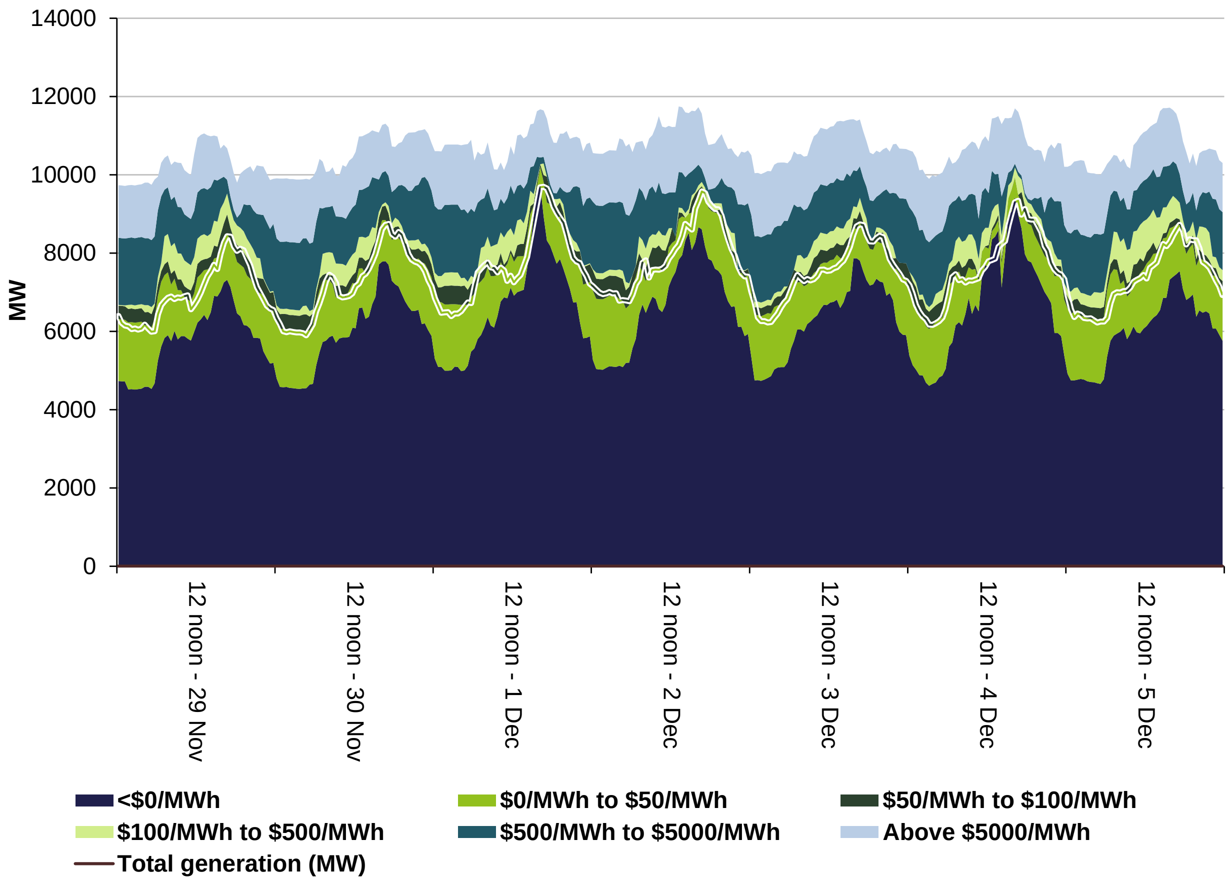


Figure 4: New South Wales generation and bidding patterns

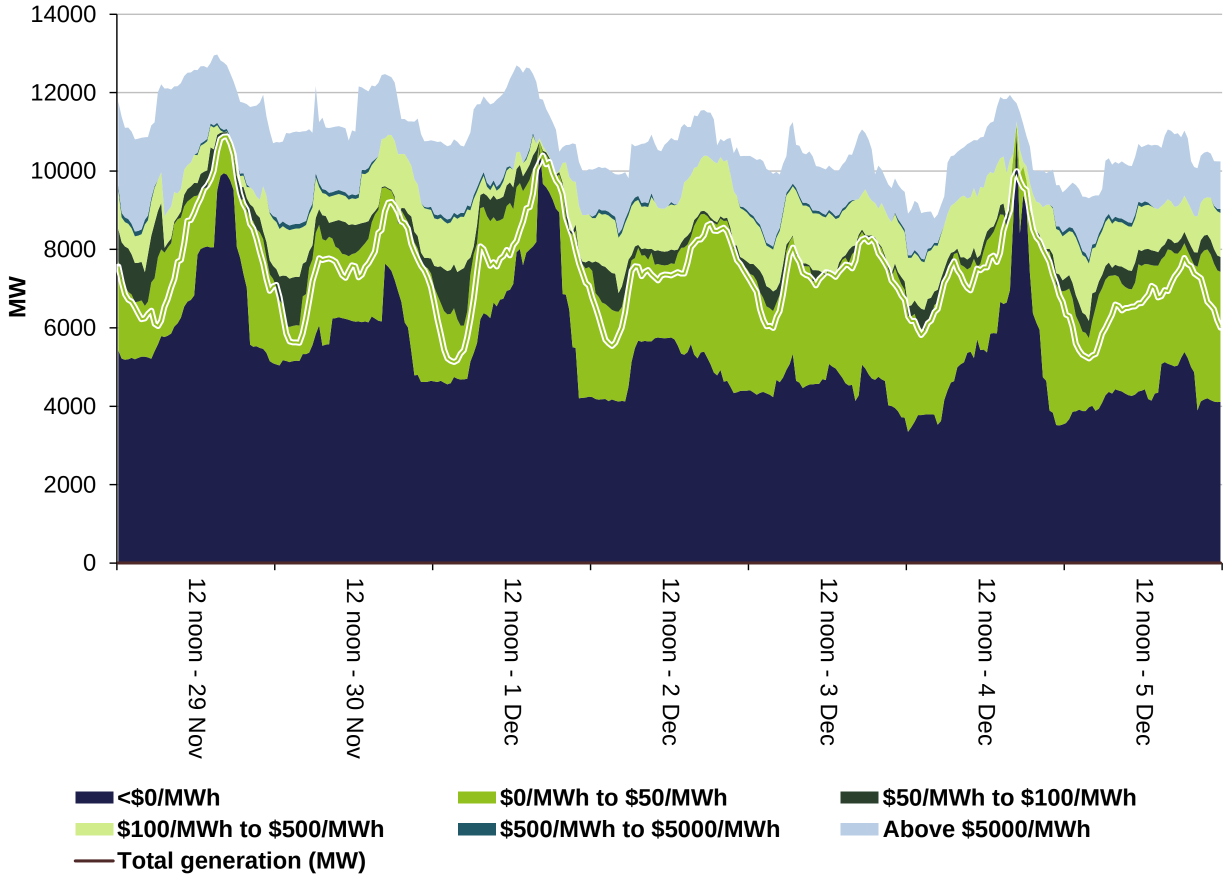


Figure 5: Victoria generation and bidding patterns

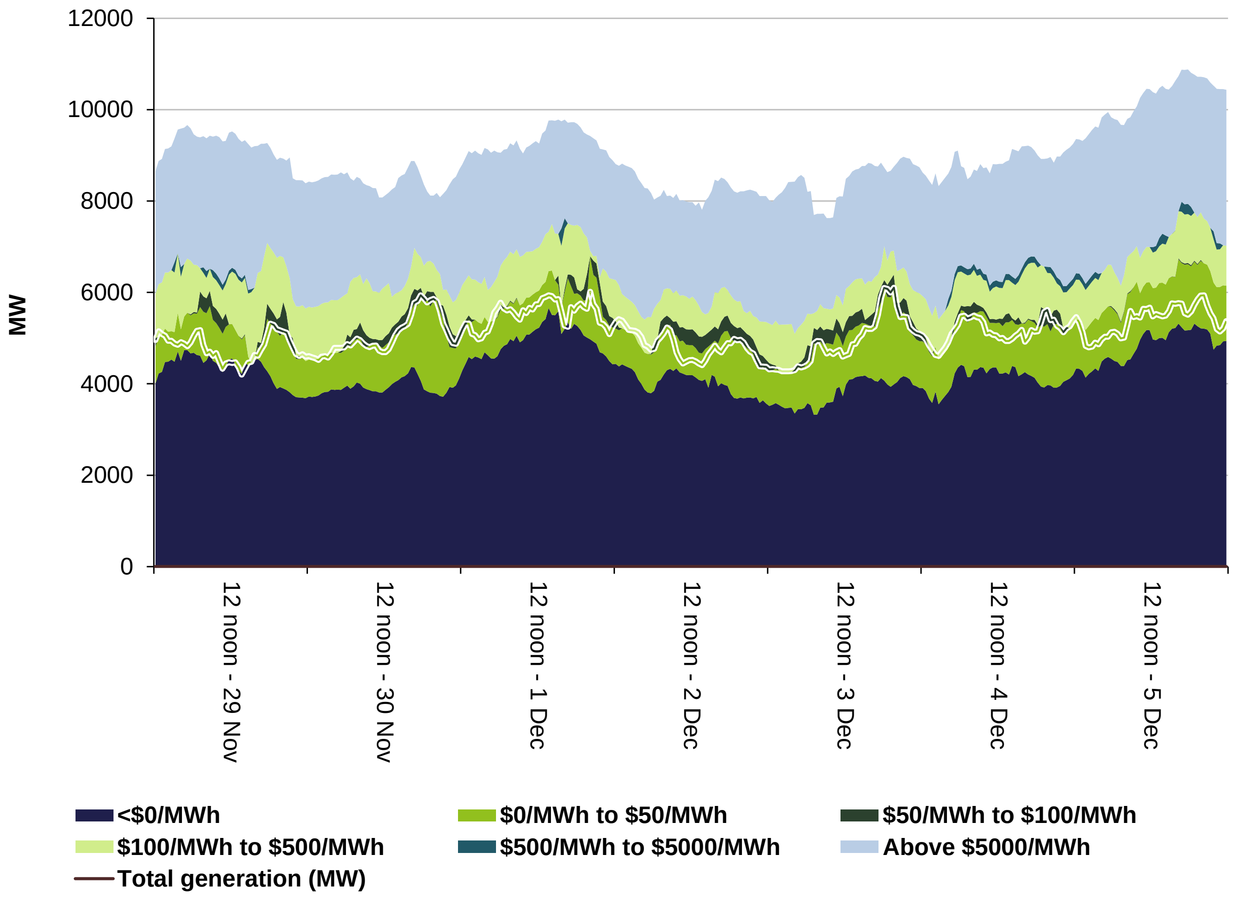


Figure 6: South Australia generation and bidding patterns

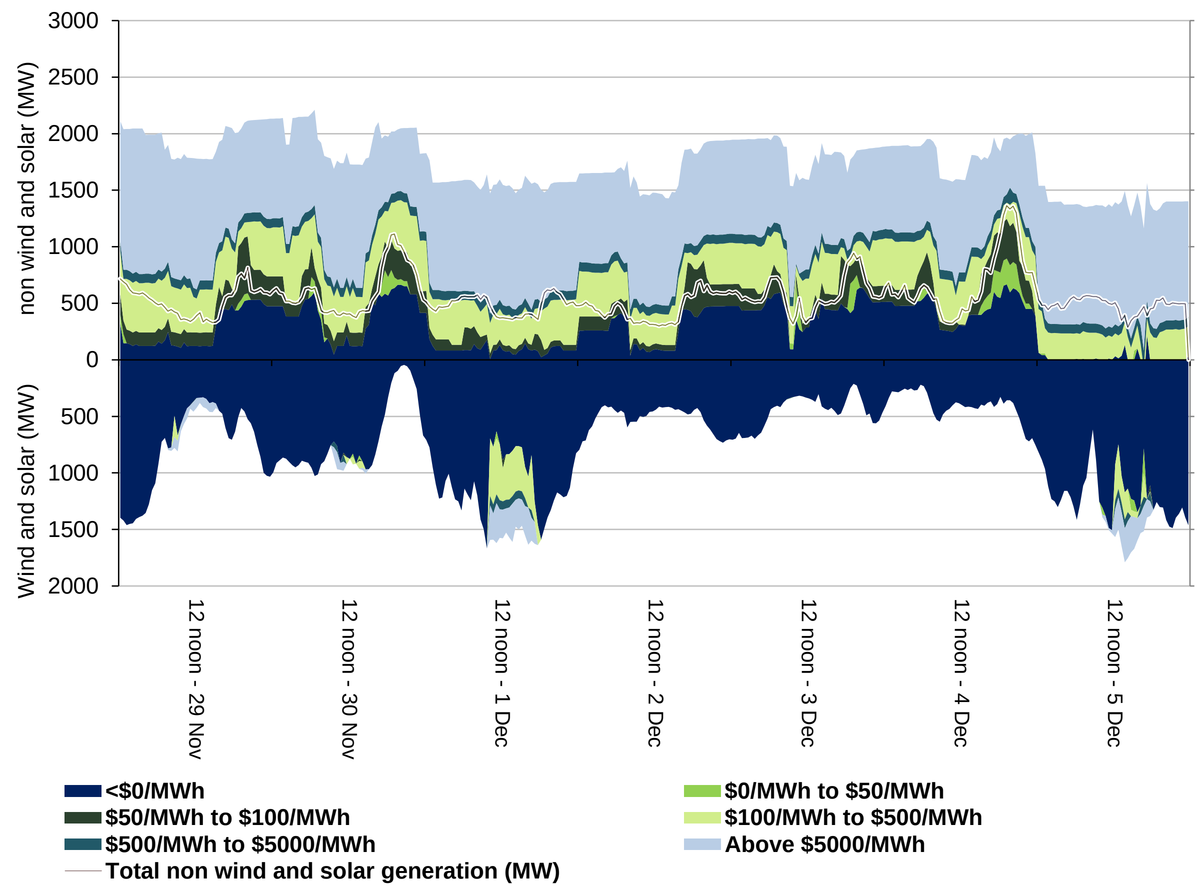
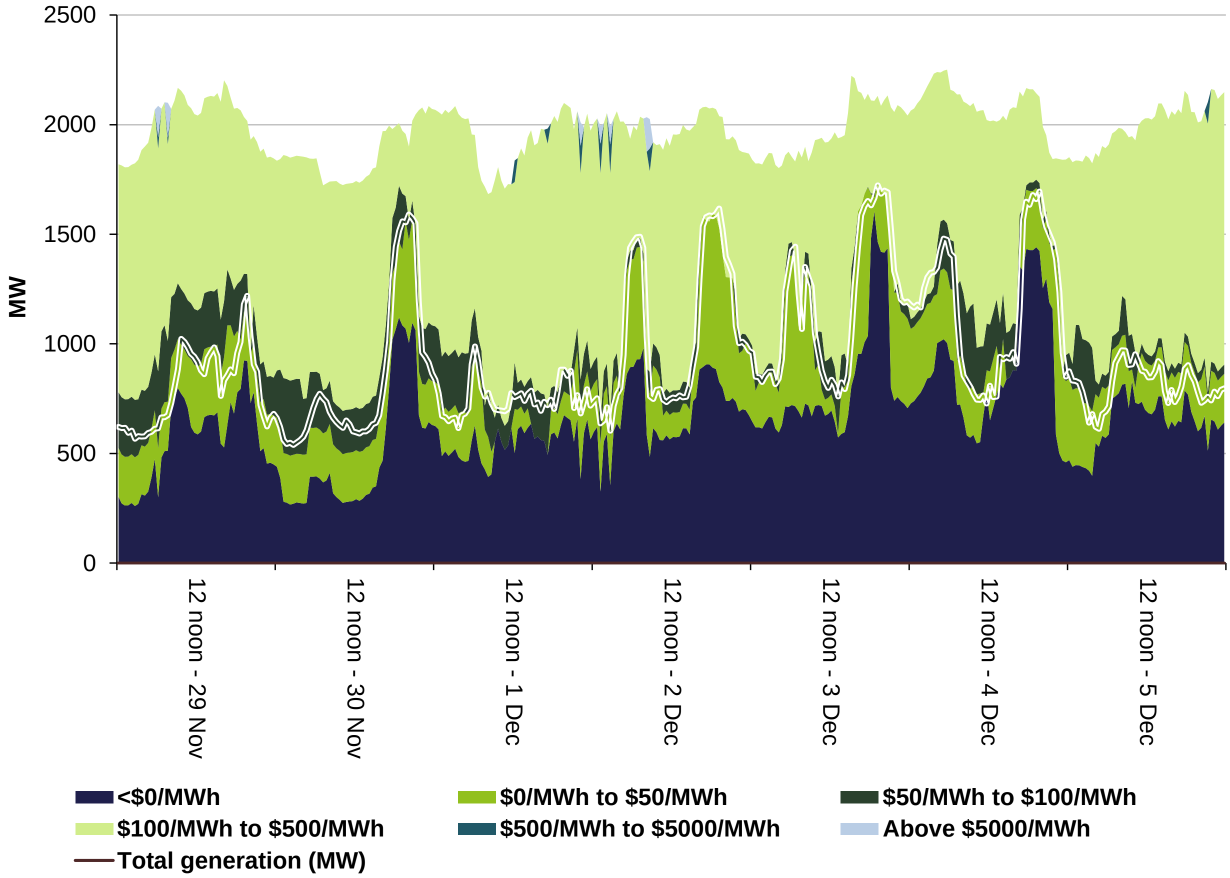


Figure 7: Tasmania generation and bidding patterns



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.

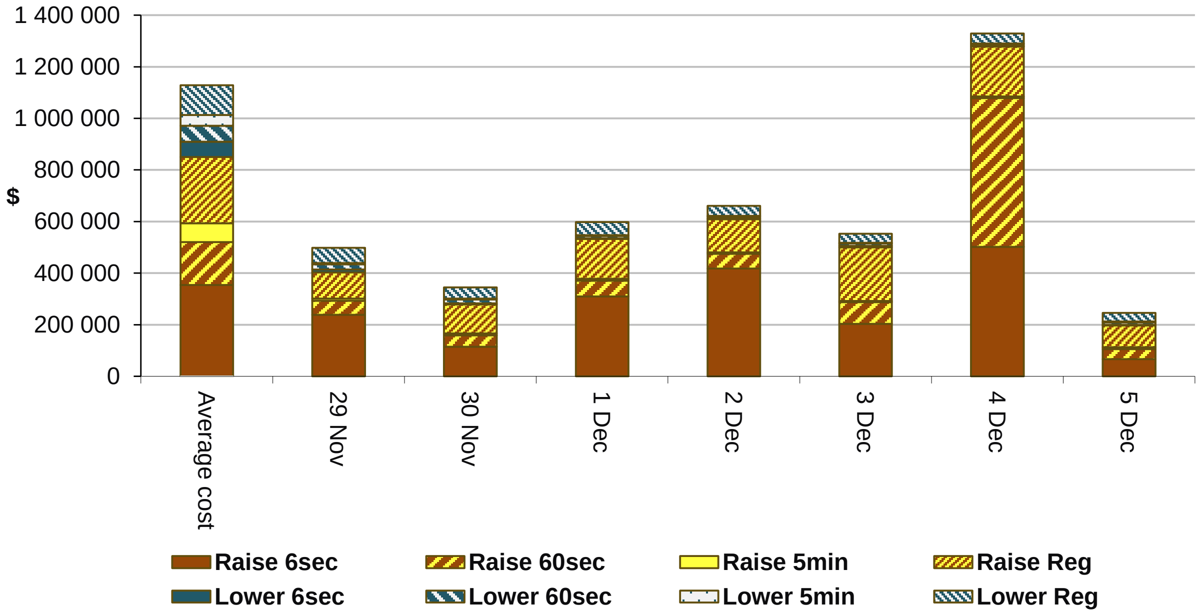
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3,058,500 or less than 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1,169,500 or less than 17% 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

Queensland

There were six occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $57/MWh and above $250/MWh.

Monday, 30 November

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
4 pm	276.03	72.70	46.53	8006	7974	7985	11,255	11,191	11,669

Demand and availability were both close to forecast, four hours prior.

At 3.55 pm, demand increased by almost 80 MW and with lower priced generation already at maximum availability, unable to come on in five minutes or trapped/stranded in FCAS, the dispatch price increased to $1306/MWh from $89/MWh.

Tuesday, 1 December

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
4.30 pm	466.89	63.97	171.10	8718	8637	8564	11,693	11,820	11,826

Price was aligned across Queensland and New South Wales and will be treated as one region. Demand was collectively close to forecast and availability was collectively almost 600 MW lower than forecast, 4 hours prior. Lower than forecast availability was primarily due to removal of capacity by -

- AGL at Bayswater (180 MW priced at the floor) and Liddell (380 MW priced at the floor) due to plant failure
- QGC Sales at Condamine Power Station (39 MW priced below $54/MWh) for technical reasons
- CS Energy at Gladstone (190 MW priced up to the cap) for technical reasons

At 4.15 pm a system normal constraint used to avoid the overload of the Raglan to Larcom Creek line resulted in generation priced at the floor being constrained off and as a result the price reached $3000/MWh for one dispatch interval. In response participants rebid capacity to the price floor and price went negative for the rest of the trading interval.

Wednesday, 2 December

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
Midday	301.98	36.85	56.95	7544	7414	7678	11,428	11,748	11,796

Demand was 130 MW higher than forecast and availability was 320 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to removal of capacity by Callide Power at Callide C (250 MW priced below $30/MWh).

At 11.45 am, demand increased by 91 MW and with no capacity available between $72/MWh and $1550/MWh, the dispatch price increased to $1550/MWh for one dispatch interval.

Thursday, 3 December

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
3.30 pm	346.31	56.95	72.73	7904	7770	7830	11,541	11,374	11,658

Demand was 134 MW higher than forecast and availability was 167 MW higher than forecast, 4 hours prior. Higher than forecast availability was primarily due to higher than forecast solar generation, all of which was priced below $0/MWh.

Effective 3.25 pm, rebids by InterGen at Millmerran and by Callide Power at Callide C shifted 95 MW from -$1000/MWh to $15000/MWh. At 3.25 pm, demand increased by 65 MW and the requirement for raise services increased by around 80 MW. This resulted in price co-optimising between the energy and FCAS markets and price increased to $409/MWh from $55/MWh.

At 3.30 pm, demand further increased by 68 MW and in combination with the rebids price increased to $1460/MWh from $409/MWh.

Friday, 4 December

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
11 am	272.00	27.62	26.51	7208	6920	6862	10,949	11,380	11,394
9 pm	325.93	195.11	72.66	8216	8193	8024	10,326	10,703	10,770

For the 11 am trading interval, demand was 288 MW higher than forecast and availability was 431 MW lower forecast, 4 hours prior. Lower than forecast availability was due to removal of capacity by CleanCo at Swanbank E (350 MW priced below $1260/MWh) and Callide Power at Callide C (156 MW priced below $30/MWh). At 10.55 am, demand increased by almost 50 MW and with lower priced generation ramp constrained and unable to set price, price was set at $1296/MWh for one dispatch interval.

For the 9 pm trading interval, demand was close to forecast and availability was 377 MW lower than forecast, 4 hours prior. Lower than forecast availability was primarily due to removal of capacity by Origin at Mt Stuart (276 MW priced at the cap), InterGen at Millmerran (30 MW priced at the floor), and lower than forecast wind generation (mostly priced below $0/MWh). At 8.27 pm, ERM Power rebid 140 MW from prices below $147/MWh to $1550/MWh. At 8.45 pm, demand increased by almost 80 MW and with lower priced capacity ramp constrained and unable to set price or trapped/stranded in FCAS, price was set at $1550/MWh for one dispatch interval.

New South Wales

There were two occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $55/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Tuesday, 1 December

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
4.30 pm	628.30	56.52	159.31	11 224	11 250	11 968	11 885	12 356	12 118

Price was aligned across Queensland and New South Wales – see Queensland section for analysis.

Friday, 4 December

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
5 pm	2286.40	14,998.89	1613.22	9761	10,204	10,189	11,565	11,574	11,726
5.30 pm	-139.93	14,316.84	1666.73	9551	10,058	10,230	11,365	11,376	11,536

For the 5 pm trading interval, demand was 443 MW lower than forecast and availability was close to forecast, 4 hours prior. The price at 4.40 pm was $15000/MWh as forecast. In response to the high price, a total of over 550 MW of capacity was rebid by Snowy Hydro at Colongra and by EnergyAustralia at Tallawarra from the cap to the floor effective 4.50 pm. This resulted in price settling lower than forecast 4 hours prior.

For the 5.30 pm trading interval, demand was 507 MW lower than forecast and availability was close to forecast, 4 hours prior. From 3.30 pm, Origin rebid 200 MW of capacity in response to forecast demand and Snowy Hydro rebid 360 MW at Colongra and Tumut in response to forecast dispatch at Upper Tumut, all from the cap to the floor. This resulted in price being set lower than forecast for the entire trading interval.

South Australia

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

Monday, 30 November

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
10 am	-154.78	-303.53	-282.92	729	767	763	2623	2792	2707

Demand was close to forecast and availability was almost 170 MW lower than forecast, 4 hours prior. The lower than forecast availability was due to lower than forecast renewable generation, most of which was priced below $0/MWh.

Throughout the trading interval, participants rebid over 300 MW of capacity up and down from prices below $-649/MWh to prices above $-285/MWh in response to the forecast price. This resulted in price settling above that forecast 4 hours prior.

Tuesday, 1 December

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
10.30 am	-137.28	31.73	-200.00	762	897	887	3139	2869	2887
11 am	-140.45	28.10	-348.49	849	812	815	3137	2882	2920
11.30 am	-191.71	-281.91	-335.20	779	761	751	3166	2894	2945
Midday	-161.93	-266.34	-1000.00	700	643	615	3122	2916	2967
12.30 pm	-265.06	-277.39	-1000.00	664	604	573	3125	2894	3027
1 pm	-179.94	-993.02	-1000.00	599	536	545	3075	2916	3035
1.30 pm	-199.29	-489.89	-1000.00	618	521	524	3119	2936	3039
2 pm	-196.67	-999.00	-1000.00	593	509	528	3158	2933	3039
2.30 pm	-149.81	-999.13	-1000.00	586	498	519	2991	2984	3042
3 pm	-129.17	-993.27	-1000.00	602	477	509	3011	2975	3048
3.30 pm	-191.16	-1000.00	-1000.00	627	476	566	2980	2965	3042

For the 10.30 am to 2 pm trading intervals, availability was between 159 MW to 272 MW higher than forecast. Higher than forecast availability was driven by higher than forecast renewable generation, most of which was priced below $0/MWh. For the 2.30 pm to 3.30 pm trading intervals, availability was close to forecast.

For the 10.30 am trading interval, demand was 135 MW lower than forecast 4 hours prior. There was little capacity offered between the floor and $85/MWh, so small changes in availability or demand could cause large fluctuations in price. The price dropped to the floor at 10.10 am. In response to the low price, participants rebid over 1000 MW of capacity from the floor to prices above $138/MWh. This resulted in price being set close to forecast for the remainder of the trading interval.

For the 11 am to midday trading intervals, demand was close to forecast 4 hours prior. From 10.27 am, rebids by Trustpower at Snowtown, Snowtown North, and Snowtown South Wind Farms, and by Lincoln Gap Wind Farm shifted over 270 MW of capacity to the price floor for each trading interval. The price dropped to the floor at the start of each trading interval, in response participants rebid over 380 MW of capacity from the floor to prices to higher prices. This resulted in price being set higher than forecast 4 hours prior.

For the 12.30 pm trading interval, price was close to the 4 hour forecast.

For the 1 pm to 3.30 pm trading intervals, demand was 63 MW to 151 MW higher than forecast, 4 hours prior. From 9 am, participants withdrew and rebid at least 350 MW of capacity from the price floor to higher prices in response to forecast prices for each trading interval. This resulted in prices settling higher than forecast 4 hours prior for each trading interval.

Saturday, 5 December

Table 12: 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
12.30 pm	-173.81	-43.74	-200	836	792	729	2929	2499	2639
1 pm	-157.05	-39.27	-1000	704	724	674	2861	2504	2668
2 pm	-109.67	-190.00	-1000	705	669	659	3155	2693	2750
2.30 pm	-112.17	-649.33	-1000	704	634	642	3124	2756	2800

Demand was close to forecast and availability was between 357 MW to 462 MW higher than forecast. Higher than forecast availability was due to higher than forecast renewable generation, most of which was priced below $0/MWh.

For the 12.30 pm and 1 pm trading intervals, there was little capacity offered between the floor and $300/MWh so small changes in demand or availability could cause large fluctuations in price. Rebids by participants during each trading interval shifted between 30 MW to almost 200 MW of capacity from prices above $-200/MWh to the floor. This resulted in price dropping to the floor once in each trading interval. In response to the low price, participants rebid over 520 MW in each trading interval from the floor price to higher price bands.

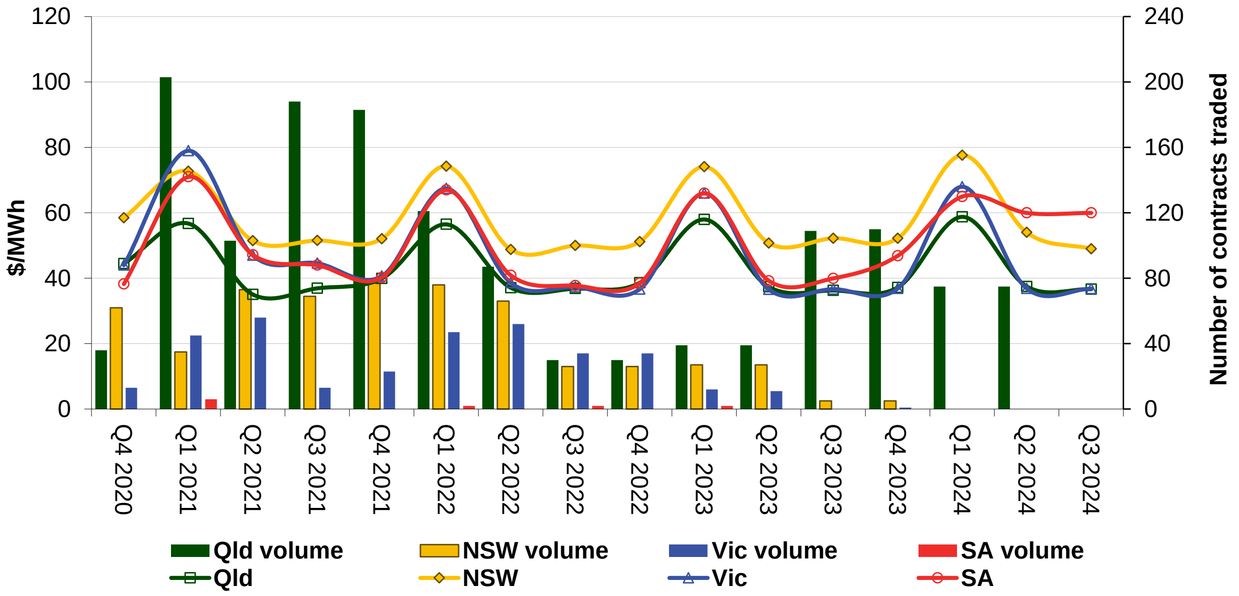
For the 2 pm trading interval, from 12.22 pm participants rebid over 500 MW from the price floor to prices above $-99/MWh. Rebids by Trustpower at Snowtown North and South Wind Farms shifted over 130 MW of capacity priced below $-190/MWh to prices above $-39/MWh, effective. 1.40 pm. This resulted in price being set between $-99/MWh to $-40/MWh for the majority of the trading interval.

For the 2.30 pm trading interval, participants rebid over 360 MW from the floor to higher prices from 10.30 am. This resulted in price settling above forecast for the entire 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 Q1 2021 – Q3 2024



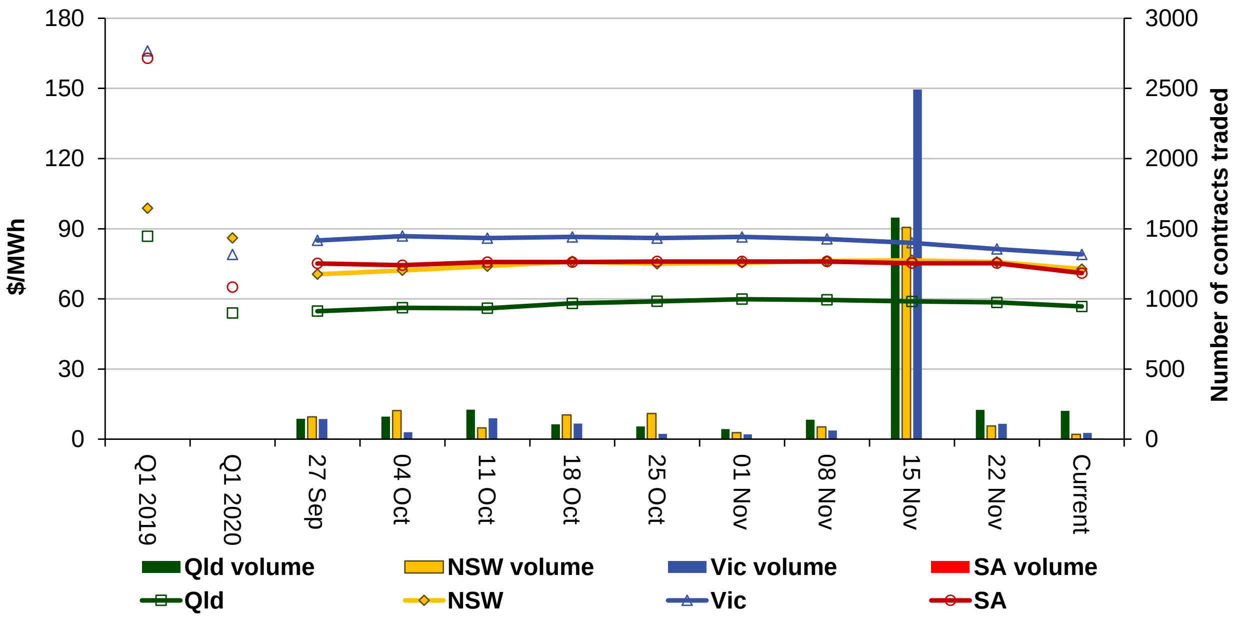
Source. ASXEnergy.com.au

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2020.

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.

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2020.

Figure 10: Price of Q1 2020 base contracts over the past 10 weeks (and the past 2 years)

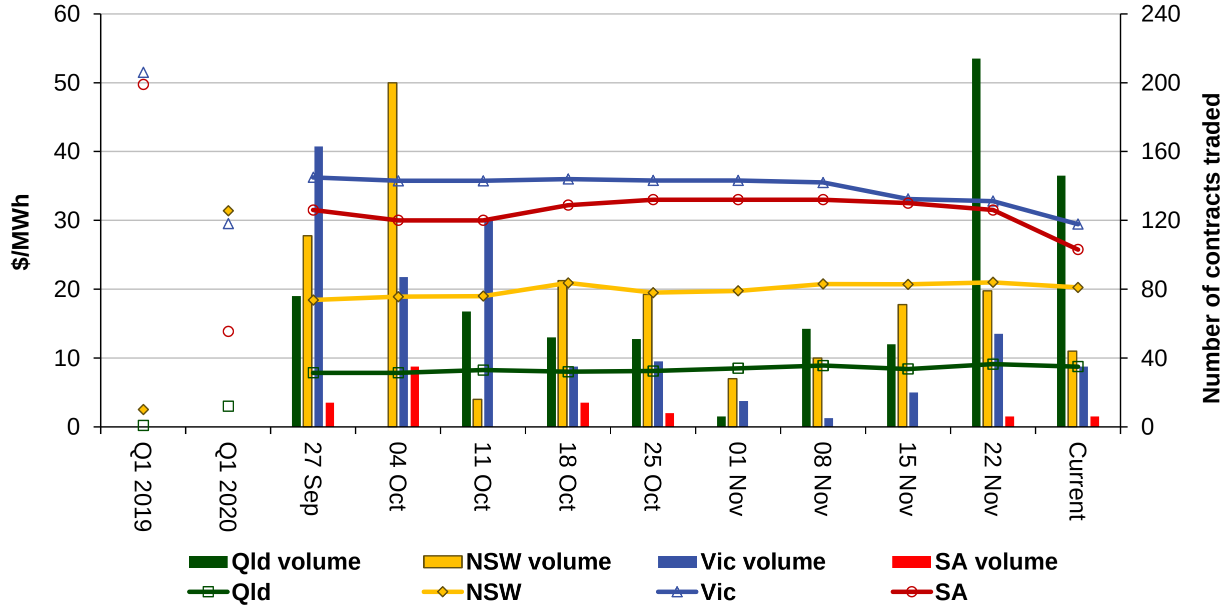


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
December 2020