Electricity Report

AUSTRALIAN ENERGY REGULATOR

16 – 22 February 2020

Weekly Summary

Average prices for the week ranged from $44/MWh in Tasmania to $74/MWh in South Australia. There were two instances of higher spot prices that did not breach the $5000/MWh reporting threshold. The spot price reached $4227/MWh in South Australia and $2453/MWh in Tasmania due to rebidding and co-optimisation between energy and FCAS markets respectively.

On Monday 17 February, the Heywood interconnector was returned to service at limited capacity and South Australia was no longer electrically islanded. This led to lower FCAS costs on the mainland relative to the two weeks prior as South Australia no longer needed to provide its own FCAS services locally.

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 16 to 22 February 2020.

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

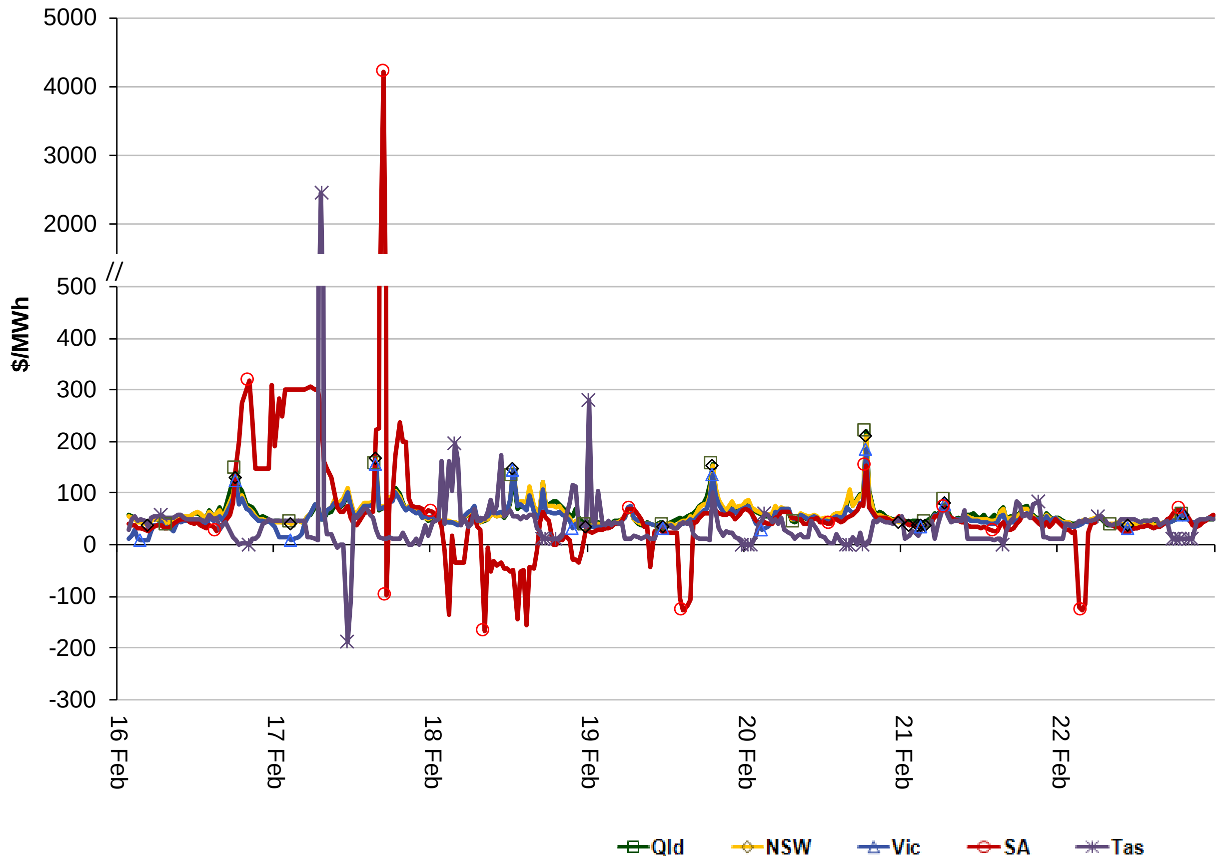


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

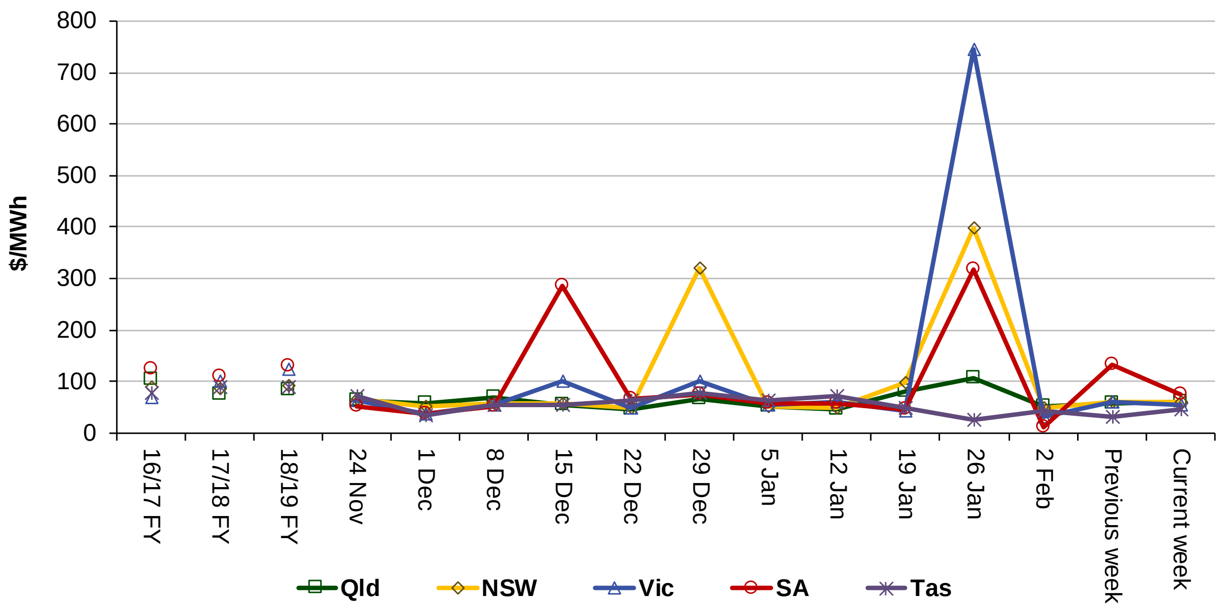


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	61	60	54	74	44
18-19 financial YTD	85	96	128	137	79
19-20 financial YTD	65	96	106	89	68

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 265 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	4	29	0	1
% of total below forecast	8	49	0	9

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

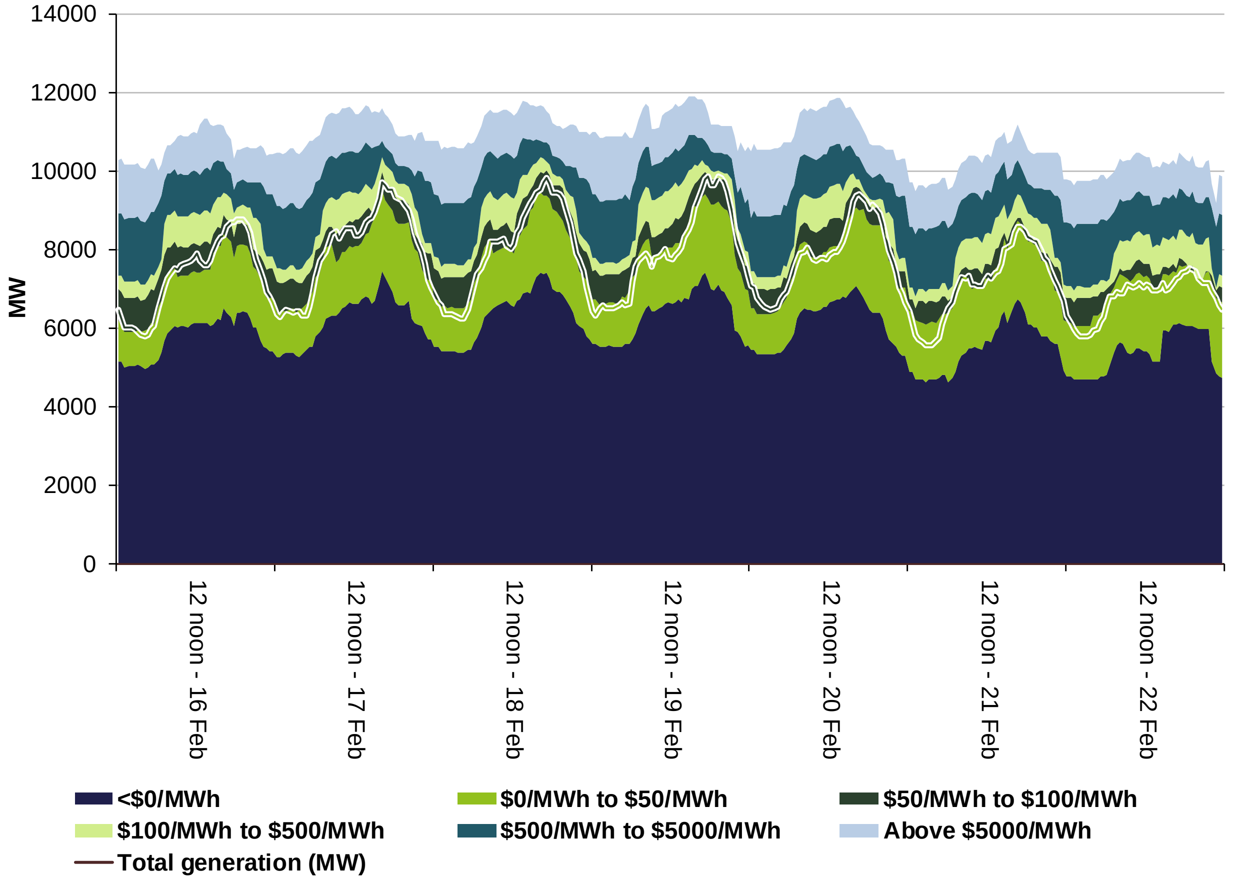


Figure 4: New South Wales generation and bidding patterns

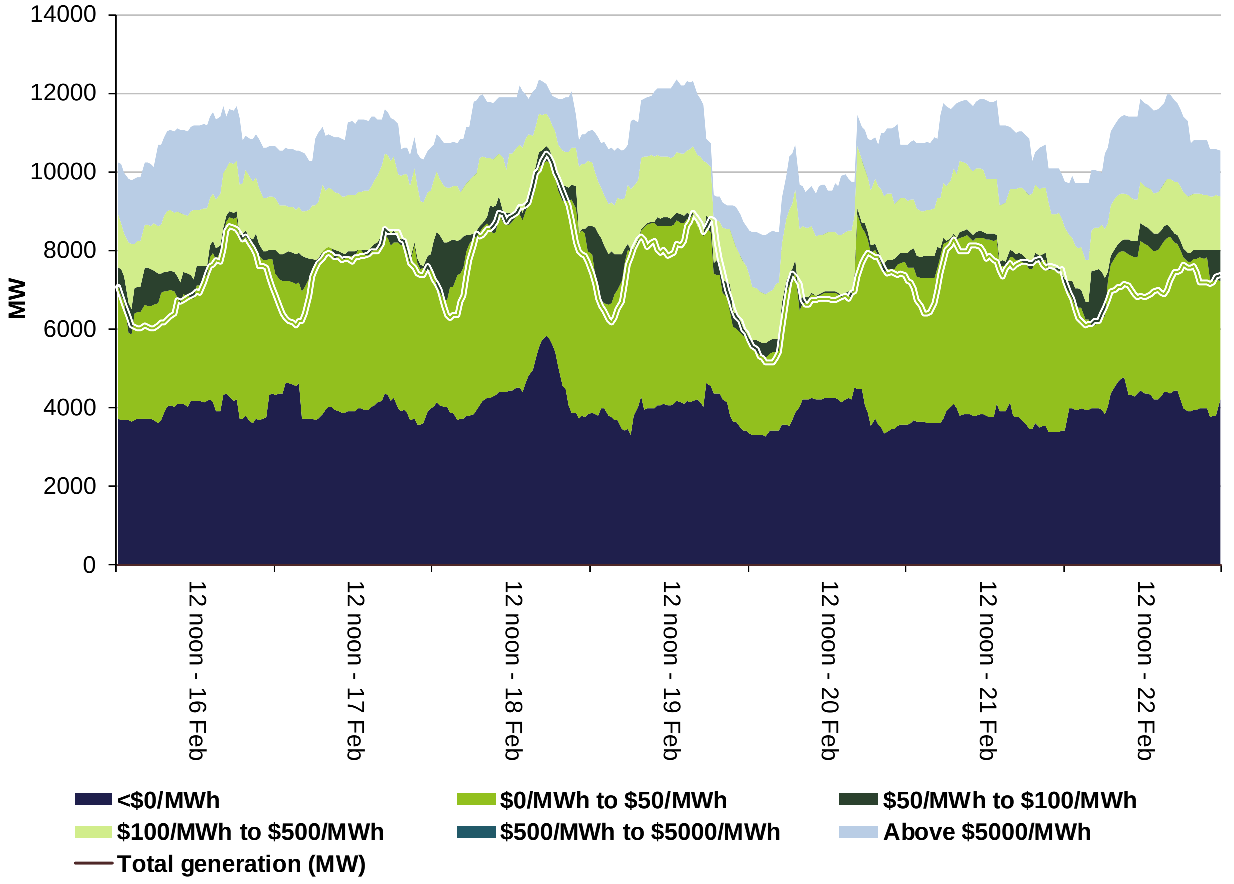


Figure 5: Victoria generation and bidding patterns

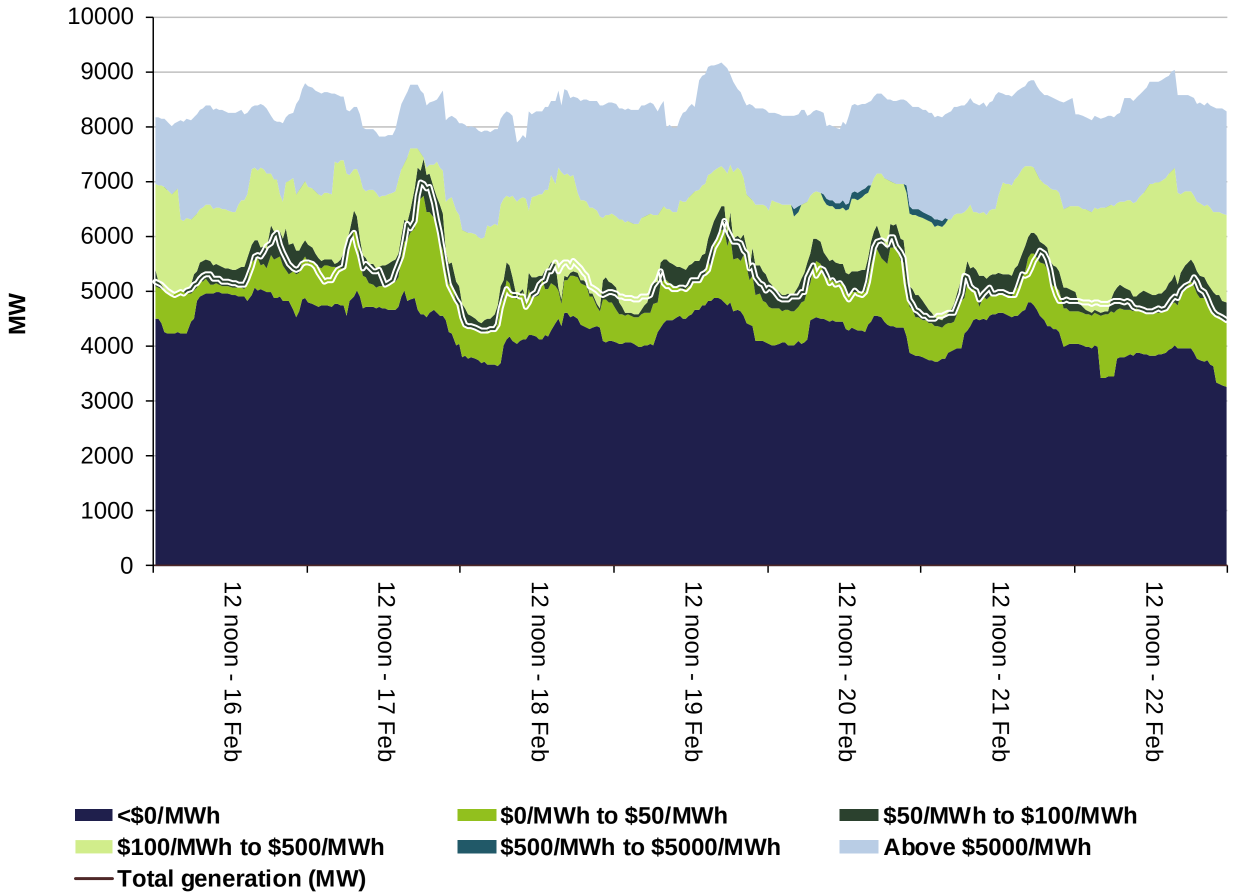


Figure 6: South Australia generation and bidding patterns

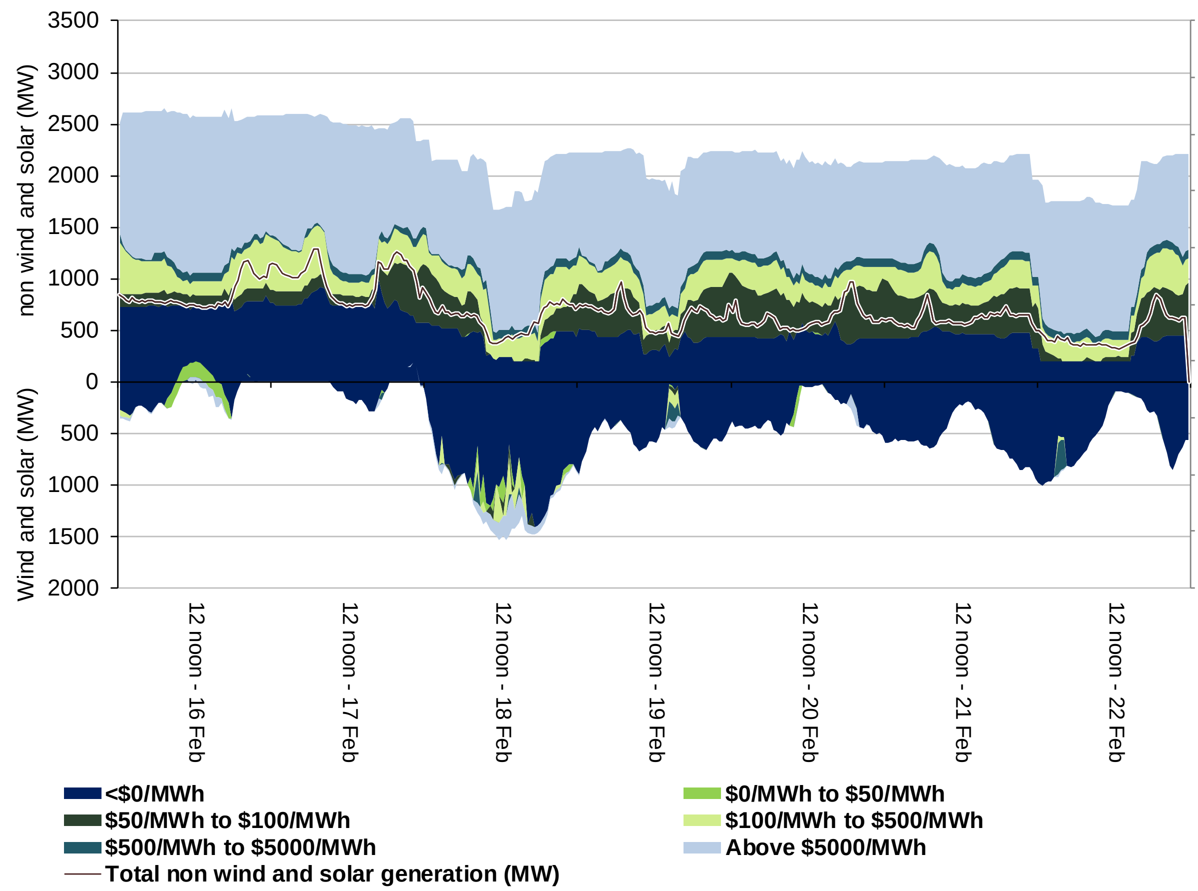
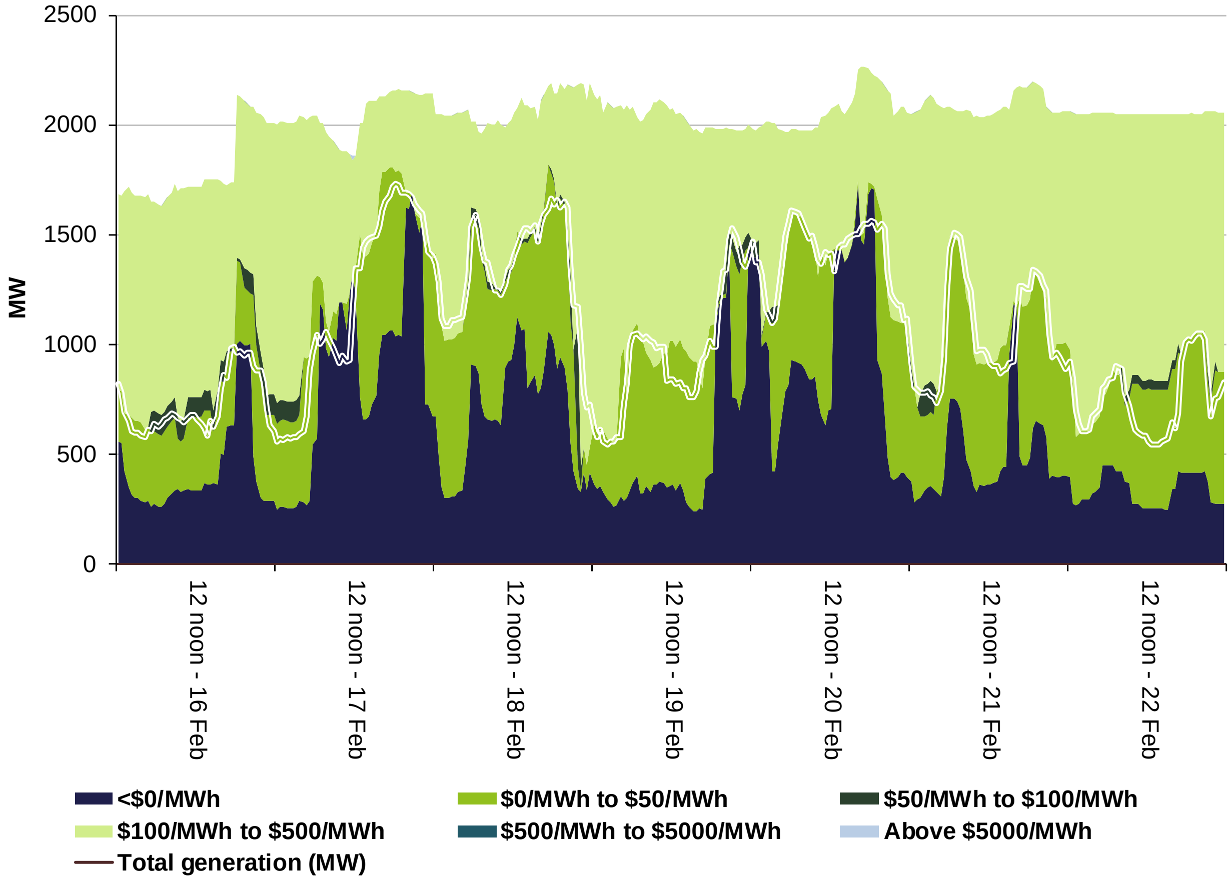


Figure 7: Tasmania generation and bidding patterns



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.

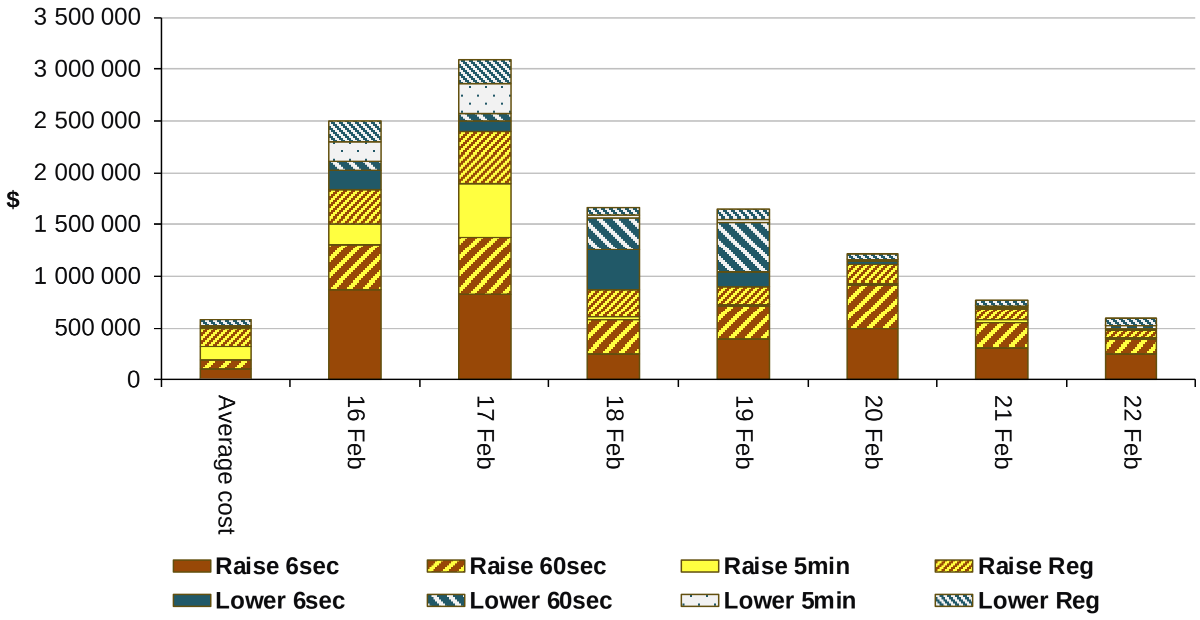
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $10 318 500 or around 5 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 167 000 or around 15 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



South Australia remained separated from the rest of the NEM and was required to provide its own FCAS services locally. This led to high FCAS prices in South Australia on 16 and 17 February. The Heywood interconnector returned to service at limited capacity on 18 February however some local requirements remained in place and resulted in the higher than average costs for the remainder of the week.

Detailed market analysis of significant price events

South Australia

There were eighteen occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $74/MWh and above $250/MWh and there were eleven occasions where the spot price was below -$100/MWh.

Sunday, 16 February

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
7.30 pm	274.90	301.00	301.00	1386	1406	1418	2776	2818	2833
8 pm	301.00	301.00	315.74	1406	1424	1425	2706	2792	2816
8.30 pm	317.42	301.00	301.00	1398	1413	1404	2689	2782	2811

Prices were close to forecast both four and twelve hours prior.

Monday, 17 February

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
Midnight	308.17	299.20	316.65	1406	1372	1363	2711	2717	2699
1 am	282.82	299.20	301.00	1323	1317	1326	2668	2662	2675
2 am	300.60	301.00	301.00	1217	1234	1219	2639	2644	2656
2.30 am	301.00	301.00	301.00	1189	1222	1193	2624	2635	2655
3 am	301.00	301.00	301.00	1182	1208	1189	2626	2627	2655
3.30 am	301.00	301.00	301.00	1176	1191	1176	2629	2618	2653
4 am	301.00	301.00	299.25	1167	1195	1171	2622	2615	2657
4.30 am	301.00	301.00	301.00	1172	1199	1179	2609	2610	2667
5 am	301.00	301.00	301.00	1204	1225	1207	2615	2608	2663
5.30 am	303.15	321.60	313.61	1237	1262	1247	2610	2607	2659
6 am	305.13	379.95	317.93	1324	1333	1335	2617	2609	2659
6.30 am	300.40	379.98	379.98	1397	1398	1404	2607	2604	2656
7 am	300.40	1365.56	379.98	1465	1452	1459	2582	2591	2616

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	254.74	379.98	379.98	1441	1444	1455	2611	2617	2630
5 pm	4226.99	301.00	301.00	1533	1406	1433	2872	2816	2784

For the trading intervals from midnight to 5.30 am, prices were close to forecast both four and twelve hours prior.

For the trading intervals from 6 am to 7.30 am, demand and availability were both close to forecast, four hours prior. Rebids in the four hours leading up to the trading interval shifted between 116 MW and 405 MW from more than $380/MWh to less than $200/MWh. As a result, prices settled between $250/MWh to $300/MWh for each trading interval.

For the 5 pm trading interval, demand was 127 MW higher than forecast and availability was 56 MW higher than forecast, four hours prior.

There was a steep supply curve which meant that small changes in supply or demand could result in large impacts on price. For the 4.40 pm and 4.45 pm dispatch intervals demand increased by 126 MW which saw the price increased to $11 450/MWh and $13 999/MWh respectively. Following the high prices participants rebid capacity from above $13 000/MWh to $300/MWh or less and the dispatch price decreased to less than $315/MWh for the remainder of the trading interval.

Tuesday, 18 February

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
3 am	-136.47	48.16	62.70	1164	1210	1210	3151	2633	2577
8.30 am	-168.12	-50.86	39.96	1313	1262	1296	3479	3092	3052
1.30 pm	-145.90	-1000.00	-1000.00	839	799	742	3219	3100	3180
3 pm	-155.41	-508.60	-1000.00	951	842	795	3276	2953	3185

For the 3 am and 8.30 am trading intervals, demand was close to forecast and availability was between 387 MW and 528 MW higher than forecast, four hours prior. Higher than forecast availability was mostly due to higher than forecast wind generation which saw the dispatch price fall to the floor once in each trading interval.

For the 1.30 pm and 3 pm trading intervals respectively, demand was 40 MW and 109 MW higher than forecast and availability was 119 MW and 323 MW higher than forecast, four hours prior. Higher than forecast availability was due to participants adding in capacity mostly at prices less than $0/MWh. The dispatch price fell to -$1000/MWh in the middle of each trading interval. In response capacity was rebid from the price floor to more than $149/MWh causing the higher than forecast prices.

Wednesday, 19 February

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
2.30 pm	-104.21	30.02	-999.99	719	713	725	2532	2501	2758
3 pm	-127.05	27.62	-1000.00	715	720	734	2543	2522	2783
3.30 pm	-119.23	28.83	-1000.00	765	760	768	2459	2551	2803
4 pm	-106.31	30.31	-78.42	803	816	818	2328	2575	2818

For each trading intervals from 2.30 pm to 4 pm, demand was close to forecast while availability was up to 247 MW lower than forecast, four hours prior.

For the 2.30 pm and 3 pm trading intervals rebidding prior to the start of the trading interval saw the first dispatch price set at the floor and result in the lower than forecast prices.

For the 3.30 pm and 4 pm trading intervals the lower than forecast availability was due to lower than forecast wind generation. However due to over 150 MW of capacity being rebid to the floor for each trading interval, the first dispatch interval was set at the floor and resulted in the lower than forecast prices.

Saturday, 22 February

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
3.30 am	-120.81	32.11	36.98	1079	1079	1046	2774	2633	2588
4 am	-126.05	32.35	36.85	1052	1073	1044	2718	2629	2595
4.30 am	-115.77	41.25	43.65	1082	1074	1050	2708	2654	2621

For the trading intervals from 3.30 am to 4.30 am, demand was close to forecast and availability was between 54 MW and 141 MW higher than forecast, four hours prior.

For each trading interval either an increase in cheaply priced wind generation or rebidding of capacity from high prices to the floor resulted in one dispatch interval at the floor which caused the lower than forecast prices.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $44/MWh and above $250/MWh and there were two occasions where the spot price was below -$100/MWh.

Monday, 17 February

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
7.30 am	2452.79	60.40	51.84	1165	1174	1146	2011	1999	2003
11.30 am	-189.41	67.14	47.92	1026	993	974	1866	1888	1878
Midday	-109.52	62.96	47.94	1101	968	961	1860	1881	1876

For the 7.30 am trading interval, demand and availability were close to forecast, four hours prior.

A system normal constraint which avoids overloading the Gordon to Chapel line and limits generation at Gordon bound at 7.30 am. At the same time there was a change in the requirement for raise services. With nearly all generation in the region either ramp constrained or trapped in FCAS, the price was co-optimised with FCAS markets and increased to $14 700/MWh.

For the 11.30 am and midday trading intervals, demand and availability was close to forecast, four hours prior. Rebids within each trading interval by Hydro Tasmania shifted over 800 MW of capacity from more than -$69/MWh to -$1000/MWh. As a result, the dispatch price fell to the floor once in each trading interval.

Wednesday, 19 February

Table 9: Price, Demand and Availability

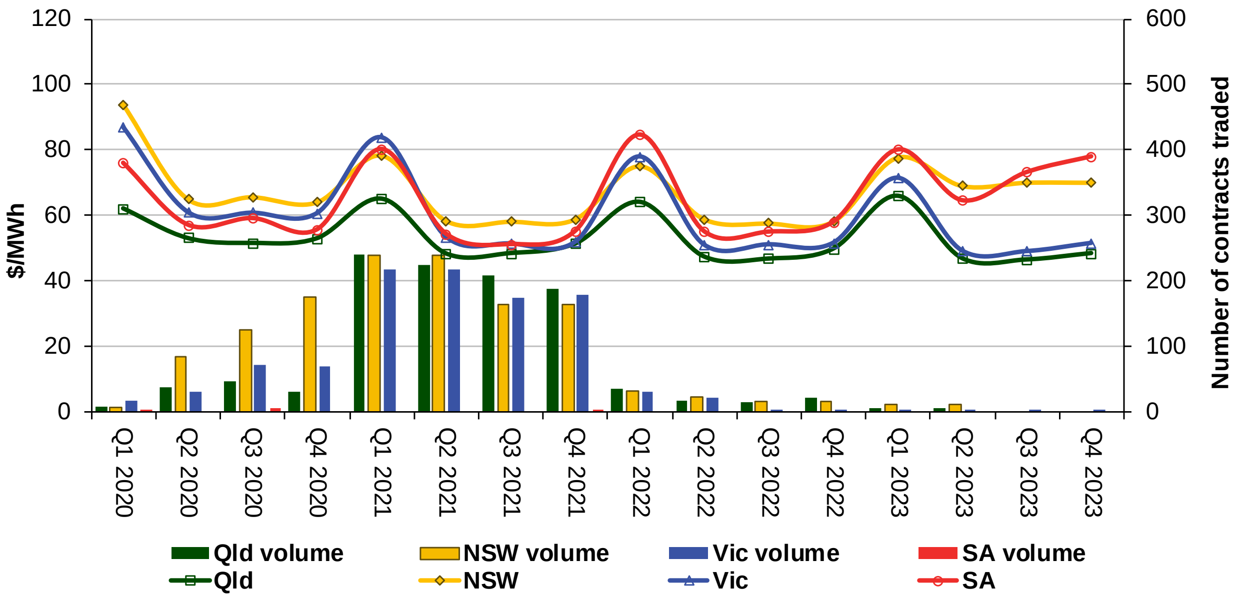
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
12.30 am	280.83	43.97	402.32	958	881	933	2137	2173	2157

Demand was 77 MW higher than forecast and availability was 36 MW lower than forecast, four hours prior. This led to the higher than forecast price for the 12.30 am 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.

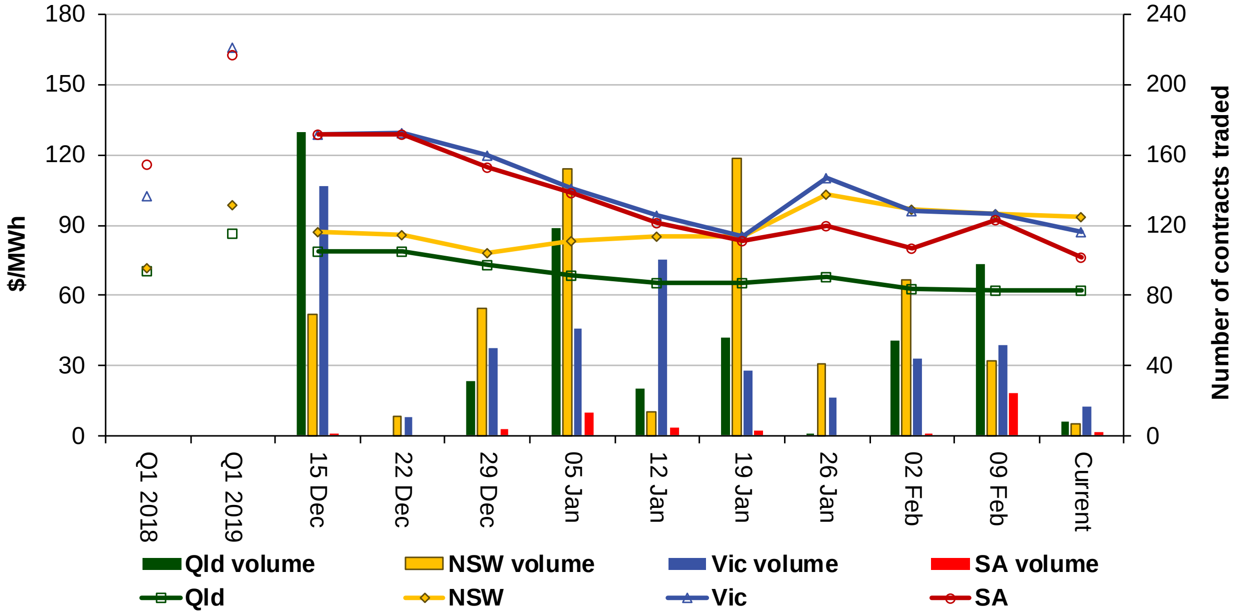
Figure 9: Quarterly base future prices Q1 2020 – Q4 2023



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2020 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 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 2020 base contracts over the past 10 weeks (and the past 2 years)

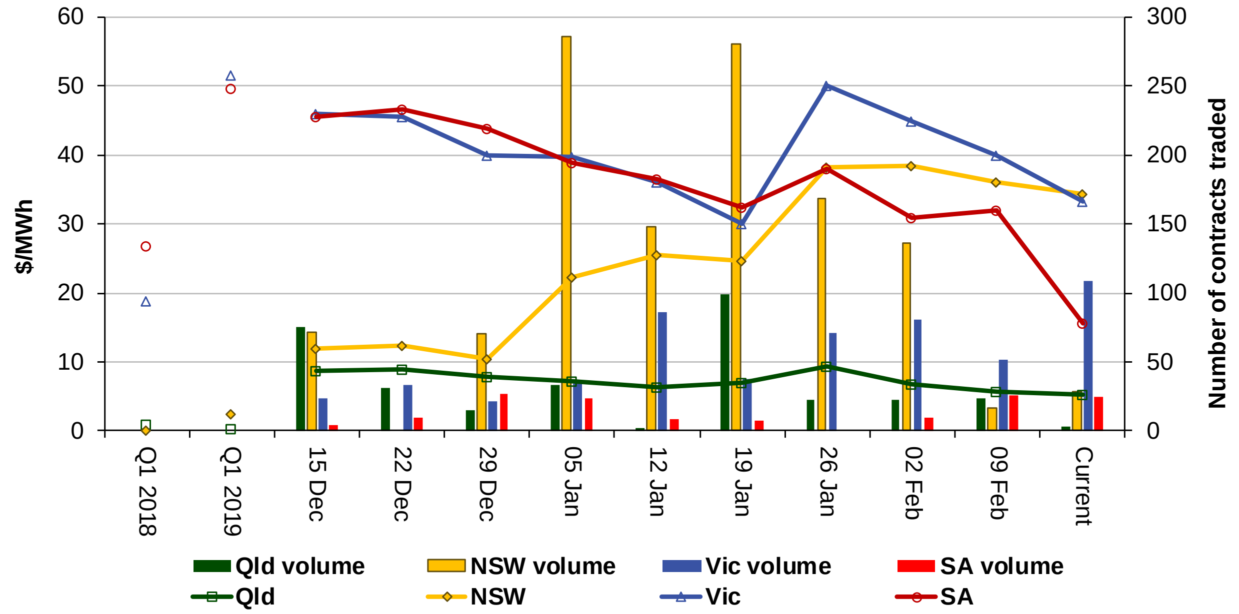


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional quarter 1 2020 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 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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