Electricity Report

AUSTRALIAN ENERGY REGULATOR

3 – 9 November 2019

Introduction

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 3 to 9 November 2019.

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

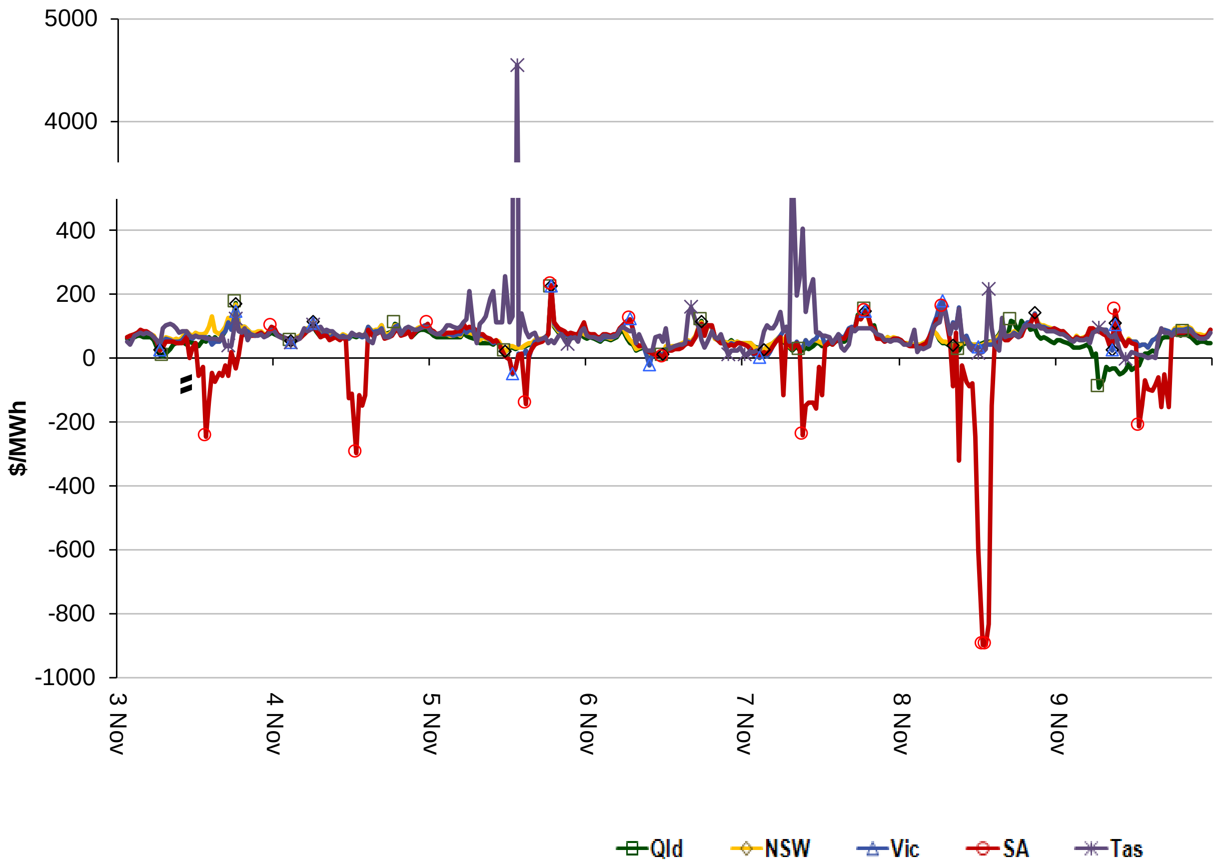


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

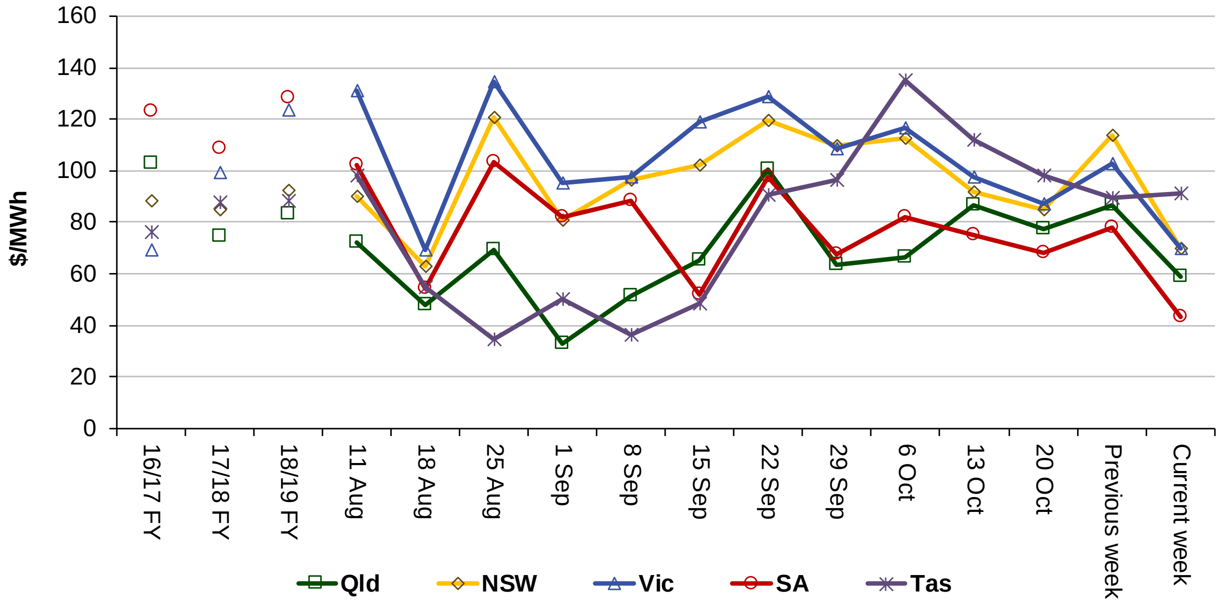


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	59	70	70	43	91
18-19 financial YTD	82	90	89	96	57
19-20 financial YTD	68	89	101	78	79

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 214 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2018 of 199 counts and the average in 2017 of 185. 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	38	0	3
% of total below forecast	9	33	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

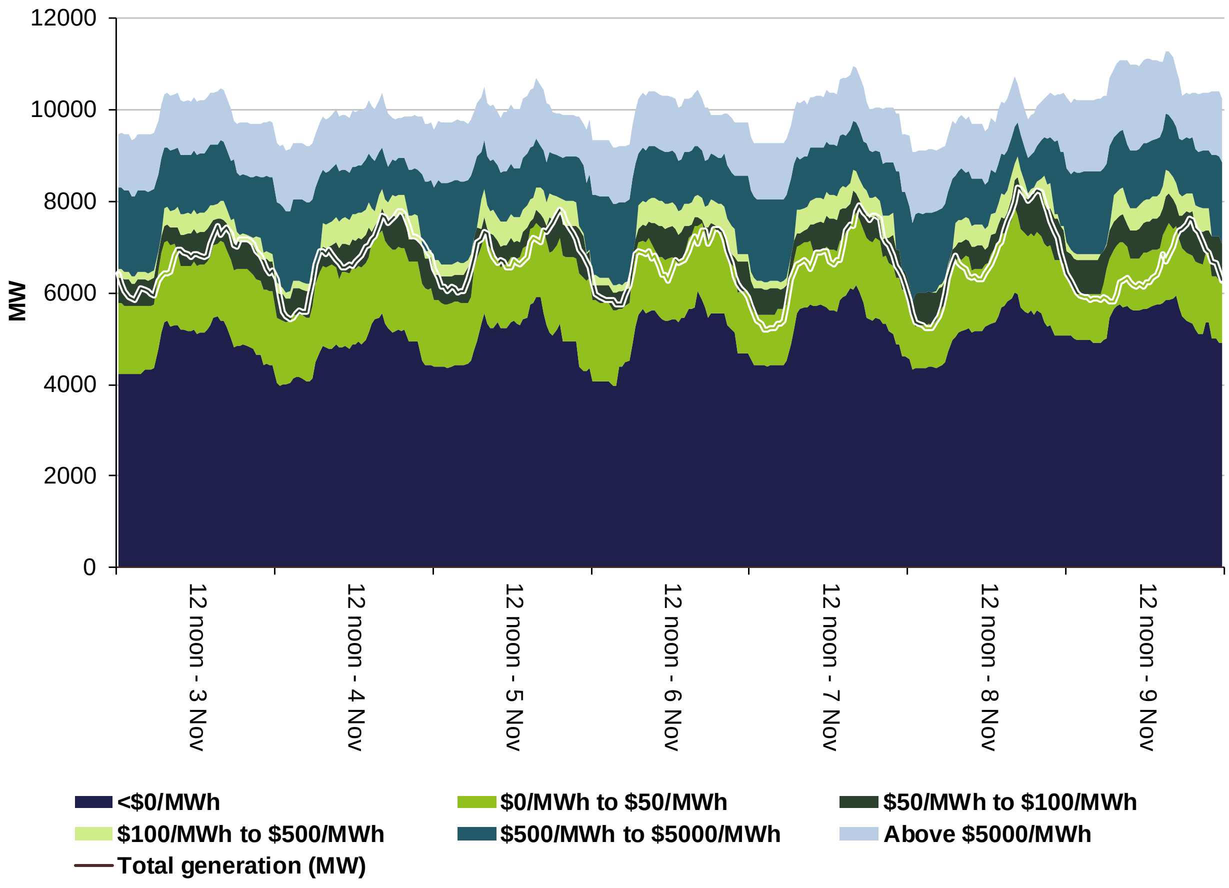


Figure 4: New South Wales generation and bidding patterns

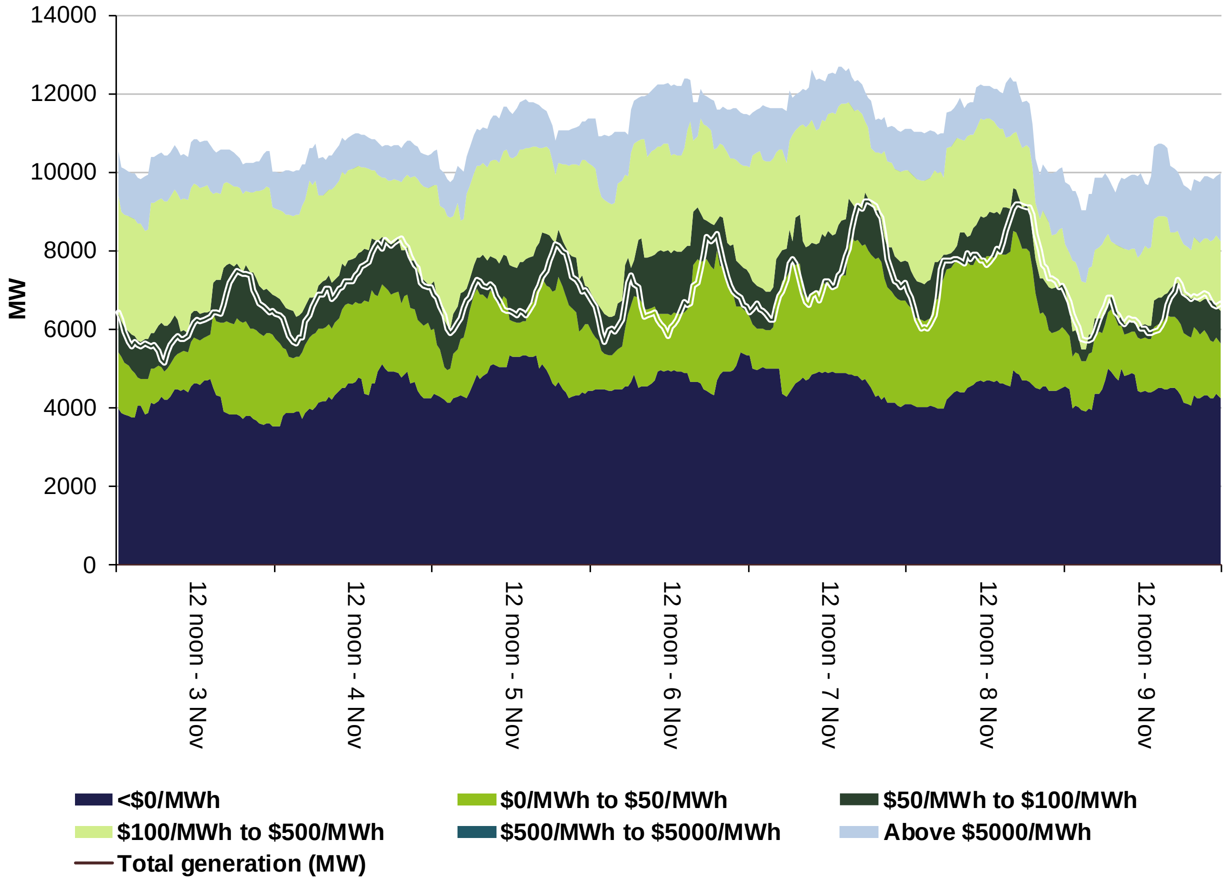


Figure 5: Victoria generation and bidding patterns

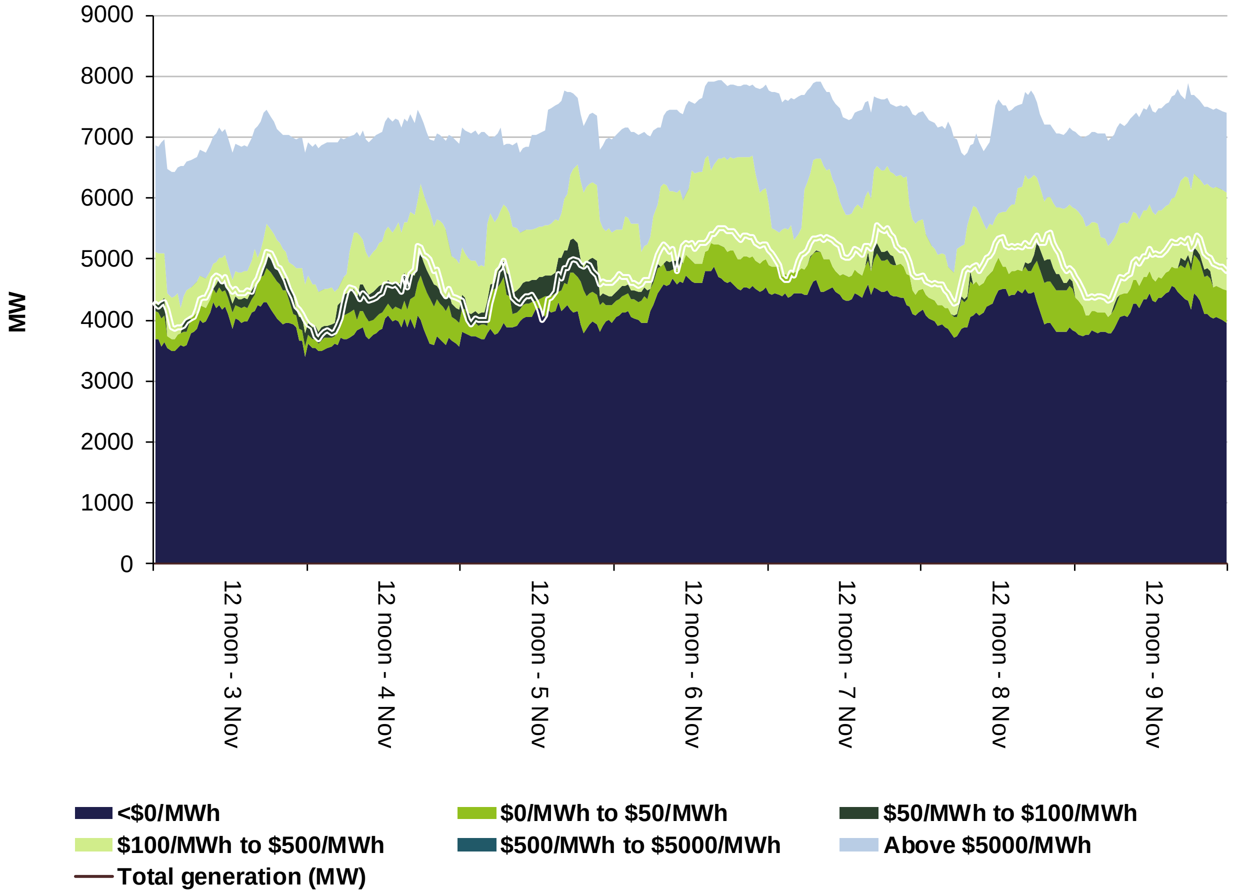


Figure 6: South Australia generation and bidding patterns

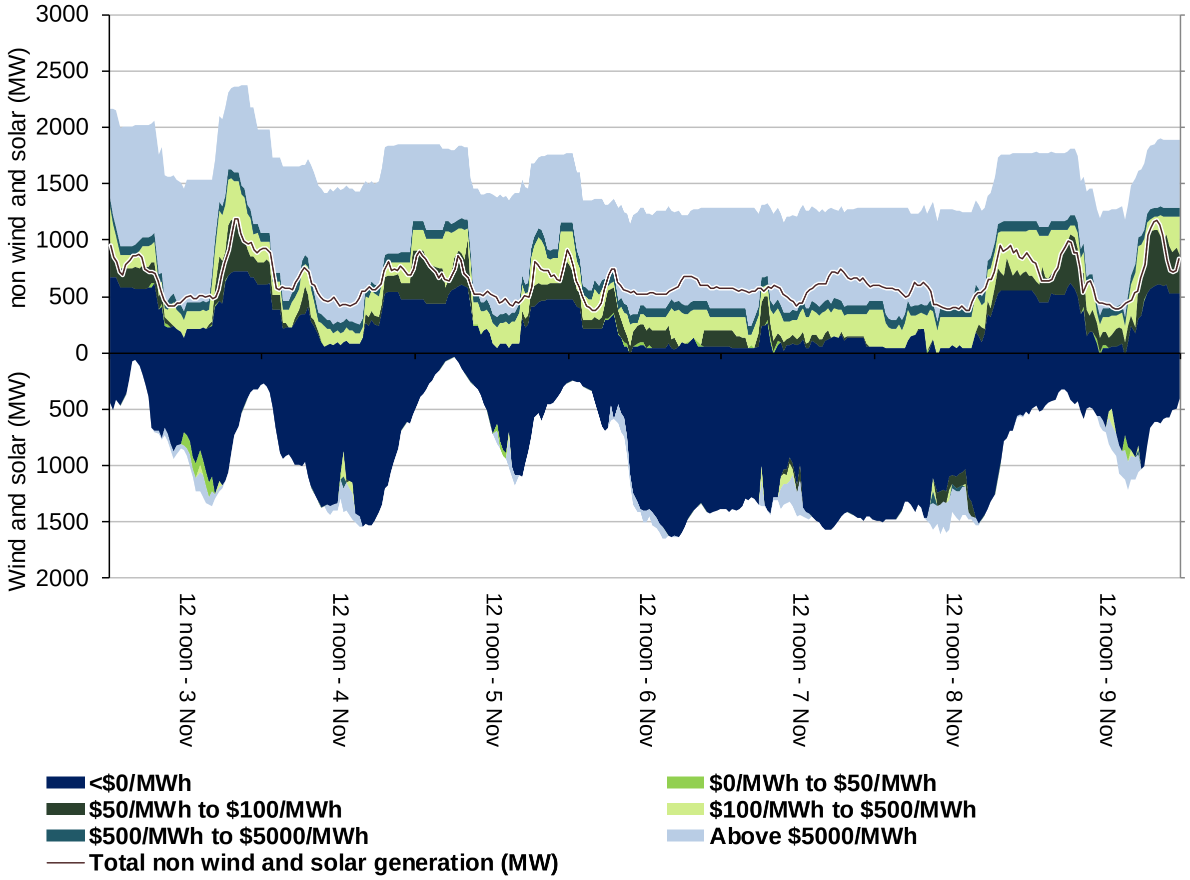
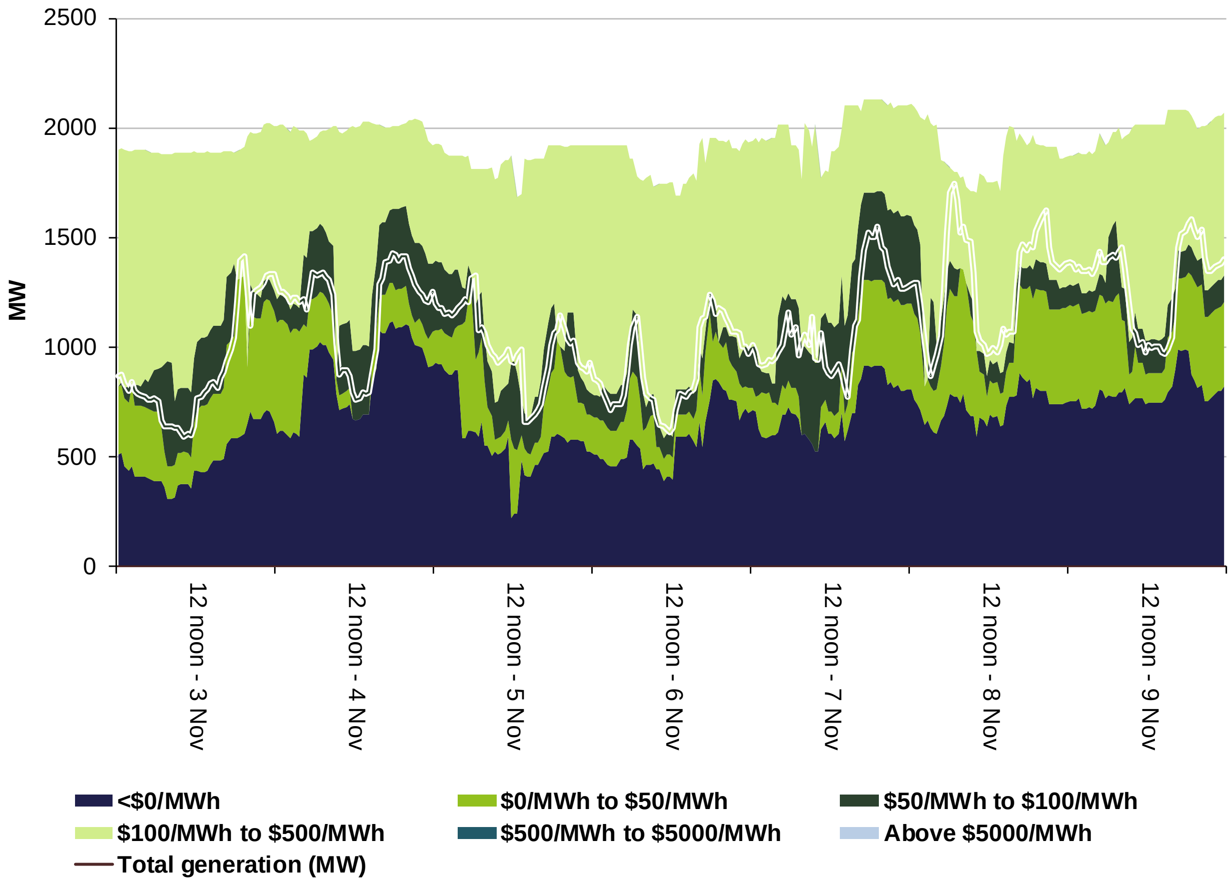


Figure 7: Tasmania generation and bidding patterns



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.

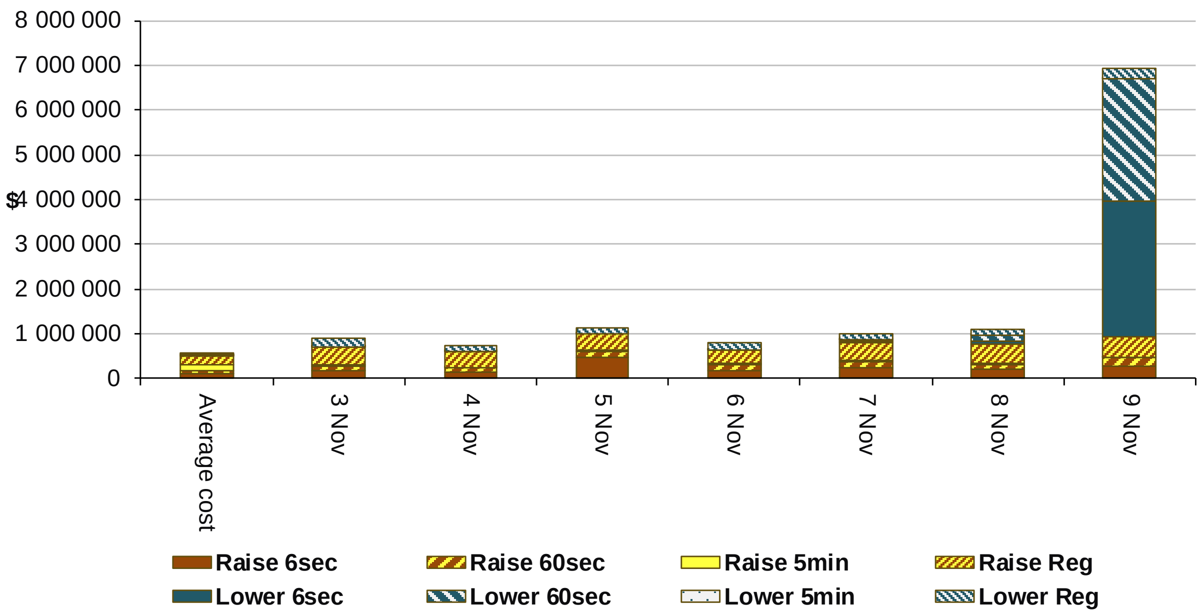
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $11 332 000 or around 5 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 226 000 or less than 8 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



On Saturday 9 November, local prices for Lower 6 second and lower 60 second contingency services in South Australia were above $5000/MW during the 6 am to 7.30 am trading intervals. Analysis of this pricing event will be covered in our FCAS prices above $5000/MW 9 November 2019 report which will be released at a later date.

Detailed market analysis of significant price events

South Australia

There were 27 occasions where the spot price in South Australia was below -$100/MWh.

Sunday, 3 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
2 pm	-248.25	-151.85	-1000	473	380	403	2755	2659	2666
2.30 pm	-136.26	-151.85	-1000	517	408	429	2754	2653	2656

For the 2 pm trading interval, demand was 93 MW higher than forecast and availability was 96 MW higher than forecast, four hours prior. Higher availability was due to higher than forecast wind generation, most of which was offered at prices below $0/MWh. There was little capacity priced between -$100/MWh and the price floor at -$1000/MWh, which meant that small changes in demand or availability could cause large changes in price. A rebid by EnergyAustralia for Waterloo Wind Farm became effective at 2 pm and shifted 130 MW priced at -$35/MWh to the price floor. This resulted in the dispatch price settling at the floor for one dispatch interval.

Conditions for the 2.30 pm trading interval saw prices close to forecast four hours ahead.

Monday, 4 November

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
Midday	-123.90	40.35	-1000	656	667	657	2847	2647	2678
12.30 pm	-111.52	-1000	-1000	725	601	627	2744	2676	2709
1 pm	-298.06	-50.86	-1000	704	585	605	2864	2743	2722
1.30 pm	-115.25	-1000	-1000	716	575	593	2859	2753	2726
2 pm	-147.06	-1000	-1000	697	576	601	2884	2748	2729
2.30 pm	-116.13	-1000	-1000	701	576	619	2928	2765	2753

Higher than forecast availability for all these trading intervals was due to higher than forecast wind generation, most of which was offered below $0/MWh.

For the midday trading interval, demand was close to forecast, four hours prior. At midday, wind generation fell by 20 MW and demand dropped by 40 MW and with only 45 MW of capacity priced between the $381/MWh and the price floor, the dispatch price fell to the price floor for one dispatch interval.

For the 12.30 pm trading interval, demand was 124 MW higher than forecast, four hours prior. At 12.05 pm, the dispatch price was as forecast at -$1000/MWh. Rebids effective 12.10 pm, shifted 270 MW of capacity from -$1000/MWh to more than $40/MWh in response to the negative price (see Table 5) which resulted in the dispatch price settling between $61/MWh and $72/MWh for the remainder of the trading interval.

Table 5: Significant rebids, 12.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
12.01 pm	12.10 pm	Neoen	Hornsdale Power Reserve	40	-1000	51	1201 A CHANGE IN FORECAST PRICES
12.03 pm	12.10 pm	Energy Australia	Waterloo WF	130	-1000	85	1203 A BAND ADJ TO MANAGE 5MIN NEGATIVE DP SL
12.03 pm	12.10 pm	Trustpower	Snowtown WF	99	-1000	14700	1200 A SA1 5MIN PD RRP FOR 1210 ($-1000.0) PUBLISHED AT 1200 IS 1891.33% LOWER THAN 5MIN PD RRP PUBLISHED AT 1155 ($50.22) - TIME OF ALERT: 1203
12.03 pm	12.10 pm	Greentricity Pty Ltd	Dalrymple North Battery Energy Storage System	-1	-1000	N/A	1203~P~SOC/MW CHANGE

For the 1 pm trading interval, demand was 120 MW higher than forecast, four hours prior. Only a small amount of generation was offered at prices between $50/MWh and the price so small changes in demand or availability could cause large fluctuations in price. Between 12.45 pm and 12.50 pm, generation in SA dropped by around 60 MW due to a decrease in demand and reduced exports to Victoria. As a result, the price fell to the floor for two dispatch intervals.

For the 1.30 pm, demand was 121 MW higher than forecast, four hours prior. Rebids effective 1.10 pm shifted 415 MW of capacity from -$1000/MWh to more than $85/MWh in response to the negative dispatch price at 1.05 pm (see Table 6). This resulted in the spot price settling between $52/MWh and $68/MWh for the rest of the trading interval.

Table 6: Significant rebids, 1.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.01 pm	1.10 pm	Neoen	Hornsdale Power Reserve	40	-1000	>102	1301 A CHANGE IN FORECAST PRICES
1.01 pm	1.10 pm	Neoen	Hornsdale Power Reserve Unit 1	30	0	406	1301 A CHANGE IN FORECAST PRICES
1.02 pm	1.10 pm	Infigen	Lake Bonney 2 WF	146	-1000	12879	1300~A~SA PRICE DP@1305 1057.2 LWR THN 5PD@1300 FOR 1305 SL ~
1.03 pm	1.10 pm	Energy Australia	Waterloo WF	130	-1000	85	1303 A BAND ADJ TO MANAGE 5MIN NEGATIVE DP SL

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.03 pm	1.10 pm	Trustpower	Snowtown WF	99	-1000	14700	1300 A SA1 5MIN PD RRP FOR 1330 ($0.0) PUBLISHED AT 1300 IS 100.0% LOWER THAN 30MIN PD RRP PUBLISHED AT 1231 ($49.1) - TIME OF ALERT: 1303
1.03 pm	1.10 pm	Greentricity Pty Ltd	Dalrymple North Battery Energy Storage System	-1	-1000	N/A	1303~P~SOC/MW CHANGE

For the 2 pm trading interval, demand was 141 MW higher than forecast, four hours prior. Rebids effective 1.50 pm in response to the dispatch price falling to the price floor saw 525 MW of capacity rebid from -$1000/MWh to more than -$100/MWh (see Table 7). This resulted in the dispatch price increasing to $56/MWh by the end of the trading interval.

Table 7: Significant rebids, 2 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.41 pm	1.50 pm	Neoen	Hornsdale Power Reserve	40	-1000	>102	1341 A CHANGE IN FORECAST PRICES
1.42 pm	1.50 pm	Engie	Willogoleche Wind Farm	110	-1000	-100	1340~A~RESPOND TO 5MIN PD -$1000MWH IN DI 13:40~
1.42 pm	1.50 pm	Infigen	Lake Bonney 2 WF	146	-1000	12879	1345~A~SA PRICE DP@1345 FOR 1345 1058 LWR THN 5PD@1340 SL~
1.43 pm	1.50 pm	EnergyAustralia	Waterloo WF	130	-1000	85	1343 A BAND ADJ TO MANAGE 5MIN NEGATIVE DP SL
1.43 pm	1.50 pm	Trustpower	Snowtown WF	99	-1000	14700	1340 A SA1 5MIN PD RRP FOR 1400 ($52.42) PUBLISHED AT 1340 IS 94.76% HIGHER THAN 30MIN PD RRP PUBLISHED AT 1231 ($-1000.0) - TIME OF ALERT: 1343
1.41 pm	1.50 pm	Neoen	Hornsdale Power Reserve	40	-1000	>102	1341 A CHANGE IN FORECAST PRICES

For the 2.30 pm trading interval, demand was 125 MW higher than forecast, four hours prior. With higher than forecast demand, the dispatch price settled between $52/MWh to $77/MWh for the majority of the trading interval.

Tuesday, 5 November

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
3 pm	-142.43	34.38	-3.09	601	673	692	2412	2243	2412

Demand was 72 MW lower than forecast and availability was 169 MW higher than forecast, both four hours prior. The higher availability was due to higher than forecast wind generation, most of which was offered at prices below $0/MWh.

Effective 2.40 pm, Infigen rebid 136 MW of capacity at Lake Bonney 2 Wind Farm from -$152/MWh to the price floor. At 2.40 pm, there was less than 10 MW of capacity priced between the floor and $248/MWh which meant that small changes in demand or availability could cause large fluctuations in price. In conjunction with the rebid, a 24 MW drop in demand at 2.40 pm saw the dispatch price settle at the floor for one dispatch interval.

Thursday, 7 November

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
6.30 am	-116.72	43.10	48.23	1146	1123	1176	2668	2417	2415
9.30 am	-242.59	39.28	30.04	964	940	931	2597	2375	2251

For the 6.30 am and 9.30 am trading intervals, demand was approximately 24 MW higher than forecast and availability was between 220 MW and 250 MW higher than forecast, both four hours prior. Higher availability was due to higher than forecast wind generation, most of which was offered below $0/MWh.

For both trading intervals, the dispatch price dropped to prices below -$900/MWh for one dispatch interval due to higher than forecast availability of low priced wind generation.

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	-150.42	-625.24	-96.00	1006	887	876	2542	2372	2249
10.30 am	-141.02	-1000	-1000	1043	859	839	2548	2377	2441
11 am	-138.18	-1000	-1000	927	833	810	2535	2394	2441
11.30 am	-156.16	-1000	-1000	955	822	801	2587	2458	2495
12.30 pm	-113.38	-1000	-1000	961	816	780	2666	2489	2483

Demand was 94-184 MW higher than forecast and availability was 129-177 MW higher than forecast, four hours prior. Between 437 and 708 MW of capacity was rebid, mainly by renewable generators, from prices below $-900/MWh to prices above $-100/MWh before and during the trading intervals. Rebidding was in response to forecast negative prices and constraint management.

Friday, 8 November

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	-320.36	-1000	-900	986	801	779	2833	2476	2568
Midday	-247.08	-1000	-1000	791	605	578	2842	2571	2648
12.30 pm	-607.30	-1000	-1000	764	558	552	2686	2615	2647
1 pm	-900	-1000	-1000	762	534	533	2733	2611	2645
1.30 pm	-900	-1000	-1000	728	515	526	2752	2627	2637
2 pm	-832.30	-1000	-1000	742	537	527	2695	2633	2632
2.30 pm	-149.10	-1000	-1000	763	549	541	2686	2636	2625

At times AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply for all significant price events on 8 November in all regions following an intervention in the market.

For all trading intervals in Table 11, between 500 MW and 900 MW of capacity was rebid by renewable energy participants from the price floor to more than -$900/MWh before and during the trading interval. The rebid reasons given were in relation to forecast prices and constraint management. This resulted in the spot price settling above the price floor for all trading intervals.

Saturday, 9 November

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
1 pm	-213.17	-1000	-1000	489	537	519	2069	2000	2103
1.30 pm	-148.51	-1000	-1000	517	514	502	2130	2046	2138

At times AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO had directed a gas plant in South Australia, triggering an intervention event. Special pricing arrangements apply for all significant price events on 9 November in all regions following an intervention in the market. Higher availability on this day was due to higher than forecast gas generation, most of which was offered above $12 500/MWh.

For the 1 pm trading interval, demand was 48 MW lower than forecast and availability was 69 MW higher than forecast, four hours prior. A number of constraints for lower FCAS requirements were violated, and the price was co-optimised between the FCAS and energy markets for the majority of the trading interval.

For the 1.30 pm trading interval, demand was close to forecast and availability was 84 MW higher than forecast, four hours prior. Before and during the trading interval, around 800 MW of capacity was rebid by renewable energy participants from the price floor to prices greater than -$100/MWh.

Table 13: 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	-151.59	74.62	-1000	786	676	676	2463	2152	2284
5.30 pm	-152.31	78.00	67.50	972	926	914	2673	2392	2402

Demand was between 46 MW and 110 MW higher than forecast and availability was between 281 MW and 311 MW higher than forecast, four hours prior. Higher availability was due to higher than forecast gas generation, most of which was offered at prices above $12 500/MWh. There was little capacity priced between the price floor and $78/MWh, which meant that small changes could cause large fluctuations in price. With generation offered above $0/MWh either under direction or trapped/stranded in FCAS and unable to set price, the dispatch price dropped to the floor for the first dispatch interval in both trading intervals.

Tasmania

There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $91/MWh and above $250/MWh.

Tuesday, 5 November

Table 14: 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
1.30 pm	4551.39	74.70	84.39	999	865	950	1700	1809	1836

Demand was 134 MW higher than forecast and availability was 109 MW lower than forecast, both four hours prior. Lower availability was mainly due to the removal of 158 MW of capacity from Tamar Valley GT earlier in the day, all of which was priced at $403/MWh. In addition there was an outage of a 220 kV line near Hadspen in the north of Tasmania.

Constraints used to manage these outages were binding and the FCAS and Energy markets became co-optimised. Across the 1.15 pm and 1.20 pm dispatch intervals, the requirement for raise services increased by a total of approximately 12 MW and the dispatch price for energy reached $12 882/MWh.

Thursday, 7 November

Table 15: 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 am	627.13	95.91	95.91	1111	1134	1115	1854	2023	2023
9.30 am	405.73	95.91	97.55	1063	1023	1011	1943	1969	1969

A constraint managing the loss of Farrell and Sheffield lines as a credible contingency due to lightning was invoked from 7.35 am. This constraint backs off generation in the west of Tasmania, most of which was priced below $3/MWh.

For the 8 am trading interval, demand was 23 MW lower than forecast and availability was 169 MW lower than forecast, four hours prior. Lower availability was due to removal of approximately 160 MW of capacity at Tamar Valley GT power station (priced up to $403/MWh). Combined with the network limitations, as a result the dispatch price was $2622/MWh for one dispatch interval.

For the 9.30 am trading interval, demand was 40 MW higher than forecast and availability was 26 MW lower than forecast, four hours prior. From 7.09 am, Hydro Tasmania rebid approximately 210 MW of capacity across a number of generators from prices below $3/MWh to $402/MWh (see Table 16). The reason related to the constraint managing the loss of Farrell and Sheffield lines as a credible contingency. With little capacity offered priced between $95/MWh and $400/MWh, the dispatch price was around $400/MWh for the whole trading interval.

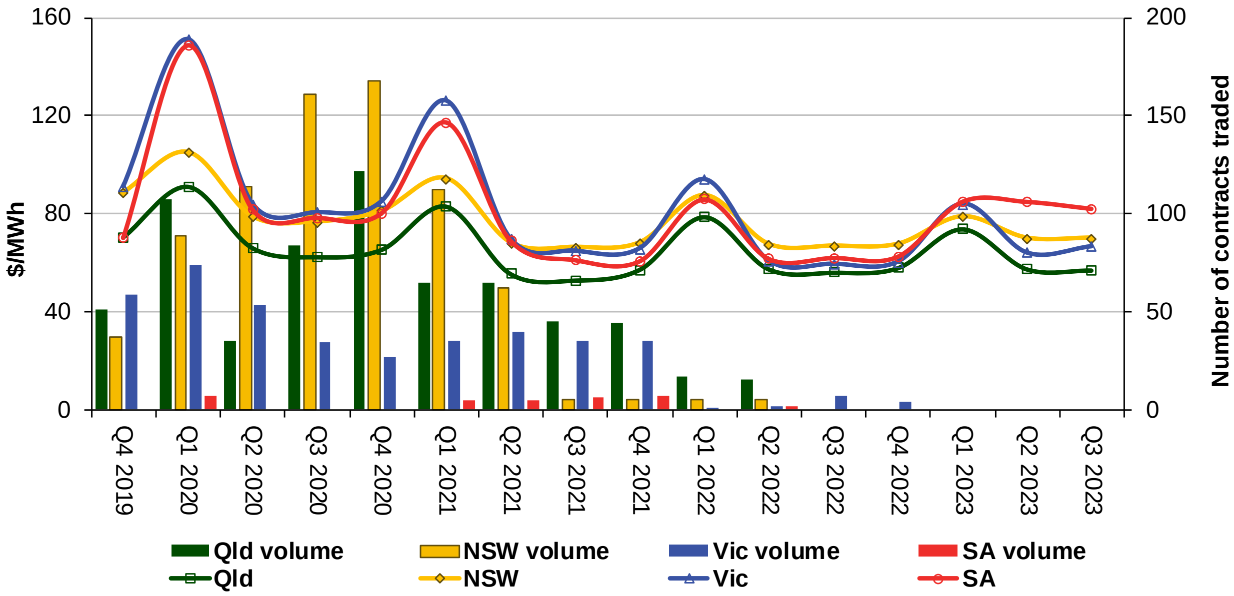
Table 16: Significant rebids, 9.30 am trading interval

Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.09 am	Hydro Tasmania	John Butters	102	402	3	0709A price different from forecast: Vic
7.42 am	Hydro Tasmania	Fisher	27	-70	402	0742A T_FASH_N-2 invoked
8.28 am	Hydro Tasmania	Bastyan	70	-70	402	0827A T_FASH_N-2 extended
8.28 am	Hydro Tasmania	John Butters	112	<3	402	0827A T_FASH_N-2 extended
8.28 am	Hydro Tasmania	Reece	101	-70	402	0827A T_FASH_N-2 extended

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.

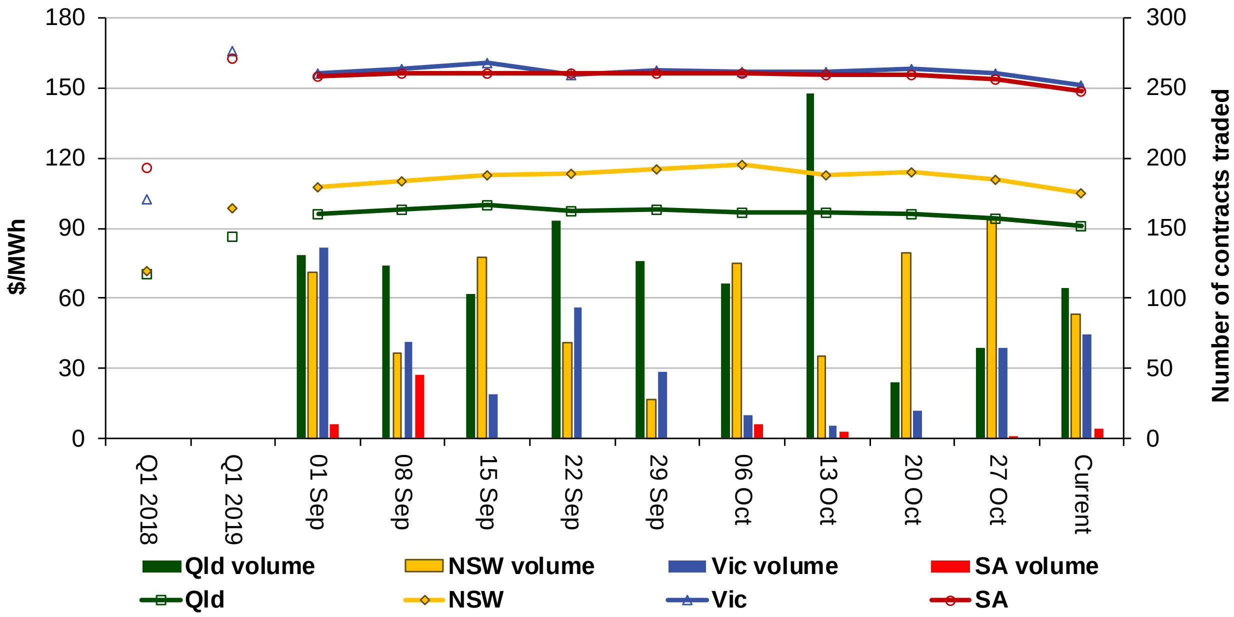
Figure 9: Quarterly base future prices Q4 2019 – Q3 2023



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)

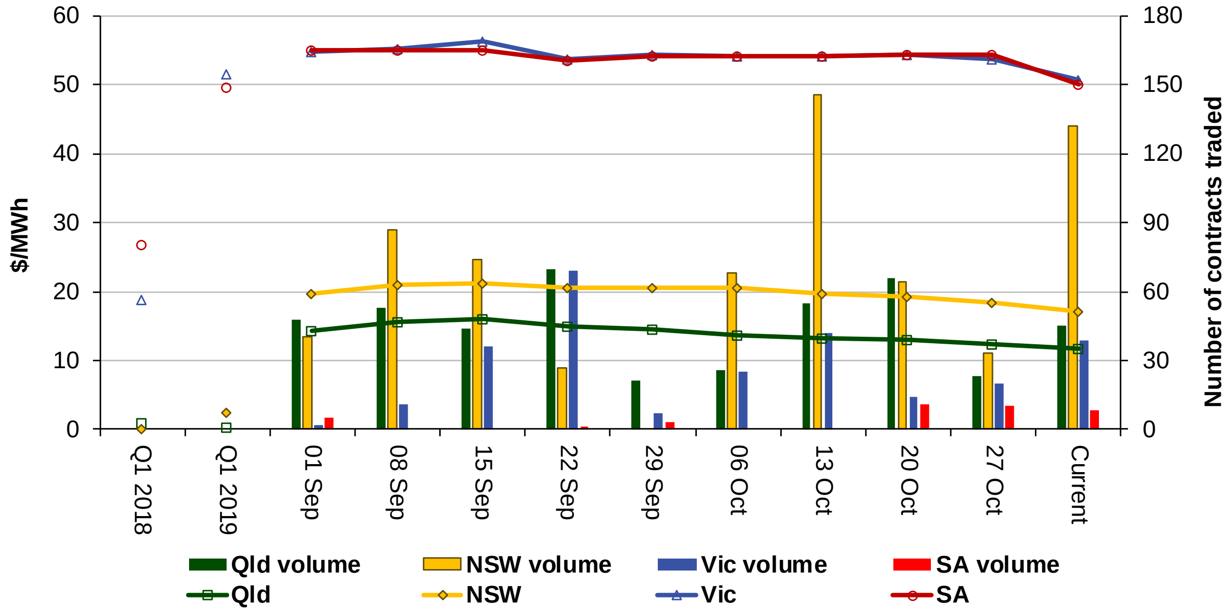


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
November 2019