Electricity Report

AUSTRALIAN ENERGY REGULATOR

24 – 30 November 2019

Weekly Summary

Average prices for the week ranged from $51/MWh in South Australia to $72/MWh in Tasmania. During the week, there was one significant spike in spot prices of $2200/MWh in Tasmania, which coincided with a local raise regulation price over $10 000/MW. There were also a number of prices between -$100/MWh and -$200/MWh in South Australia.

There was one significant unplanned generation outage during the week. At 11.50 am on 28 November, Loy Yang B unit 2 in Victoria tripped. It had been generating at around 520 MW prior to the trip and that capacity was priced at the price floor. Despite the loss of this capacity, the market impacts were minor with dispatch prices in Victoria increasing by around $30/MWh for 15 minutes. The unit resumed normal generation at around 3 pm on the same day.

There were numerous instances where AEMO reclassified the loss of network elements as reasonably possible, mostly in Queensland due to lightning and in New South Wales due to bushfire conditions. This can reduce flow on those network elements and lead to reduction in generation or interconnector capability. Despite the amount of reclassifications this week, they did not lead to any significant increase in spot prices except for one instance in Tasmania.

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 24 to 30 November 2019.

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

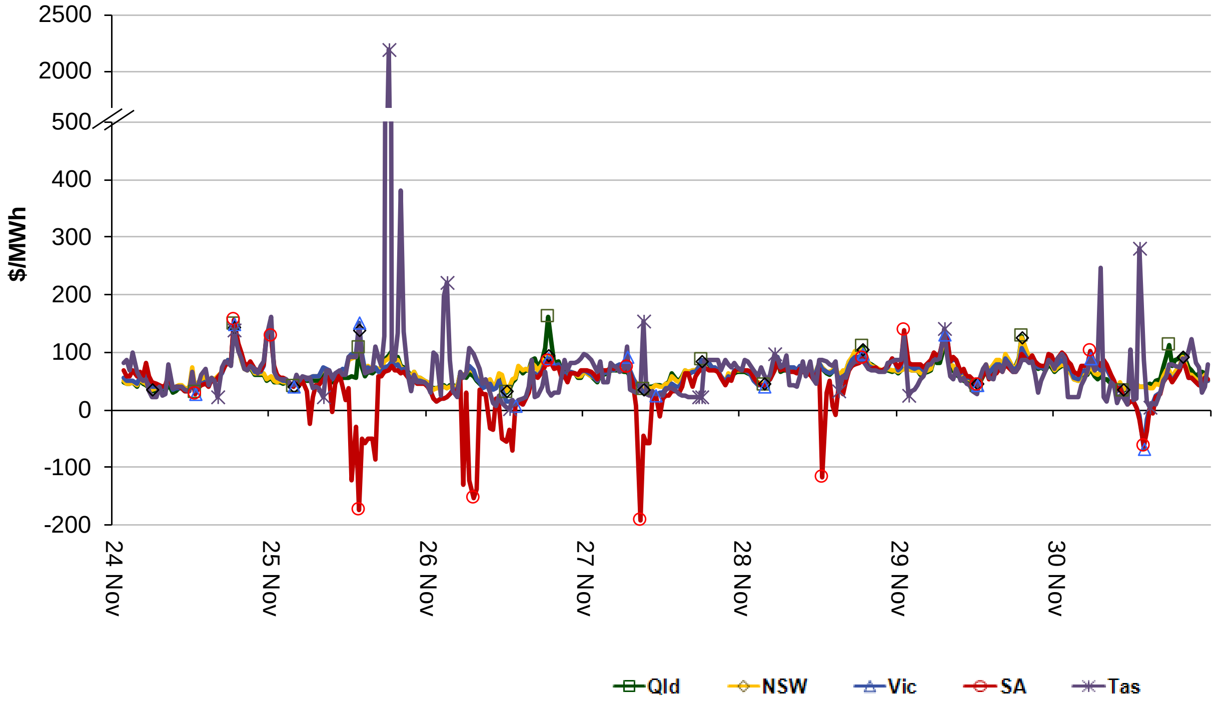


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

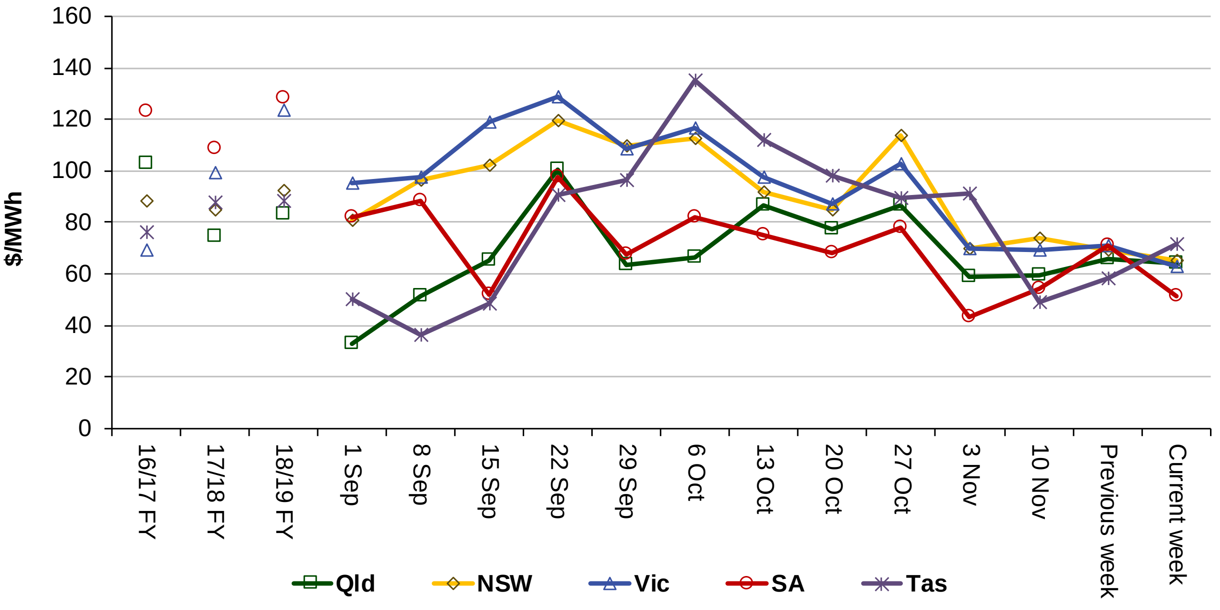


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	64	65	63	51	72
18-19 financial YTD	83	90	90	97	61
19-20 financial YTD	67	87	97	76	76

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 238 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	14	38	0	2
% of total below forecast	9	28	0	10

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

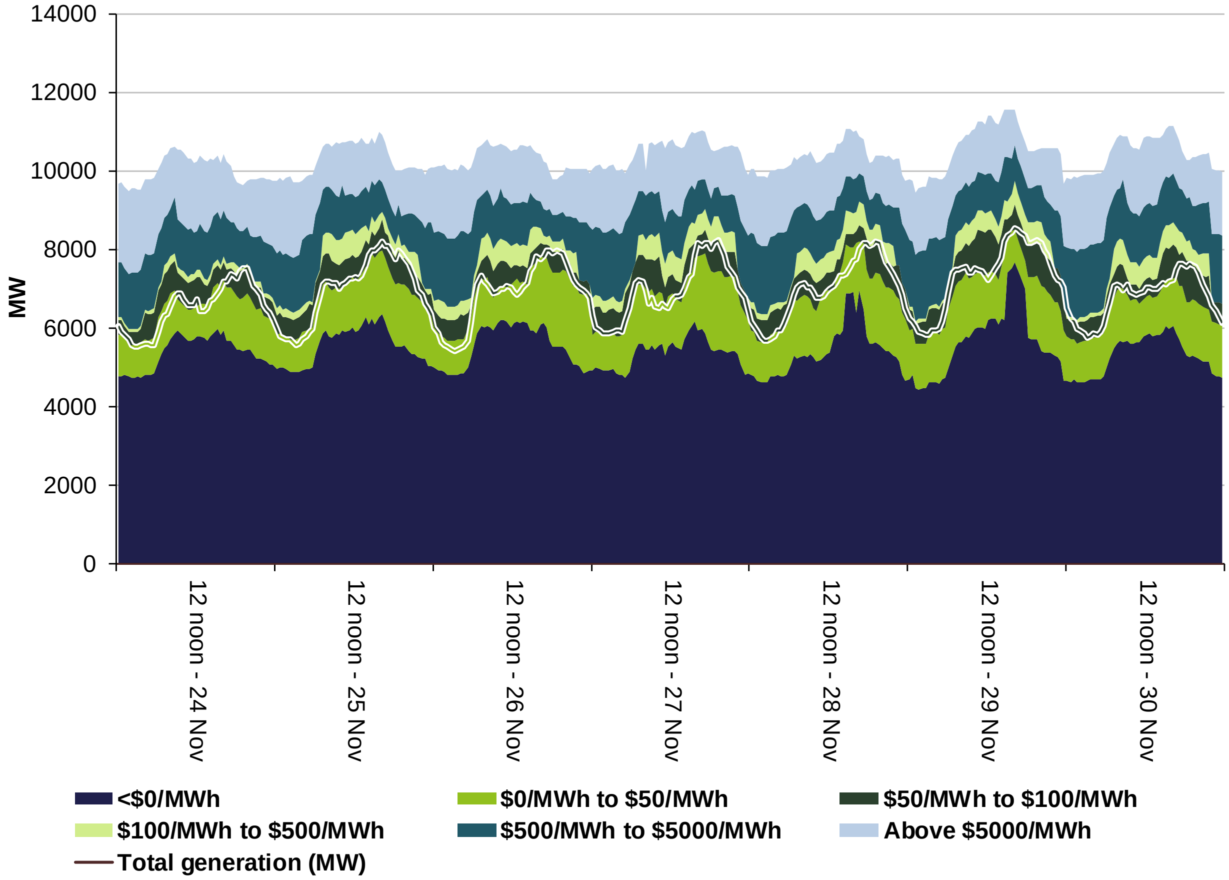


Figure 4: New South Wales generation and bidding patterns

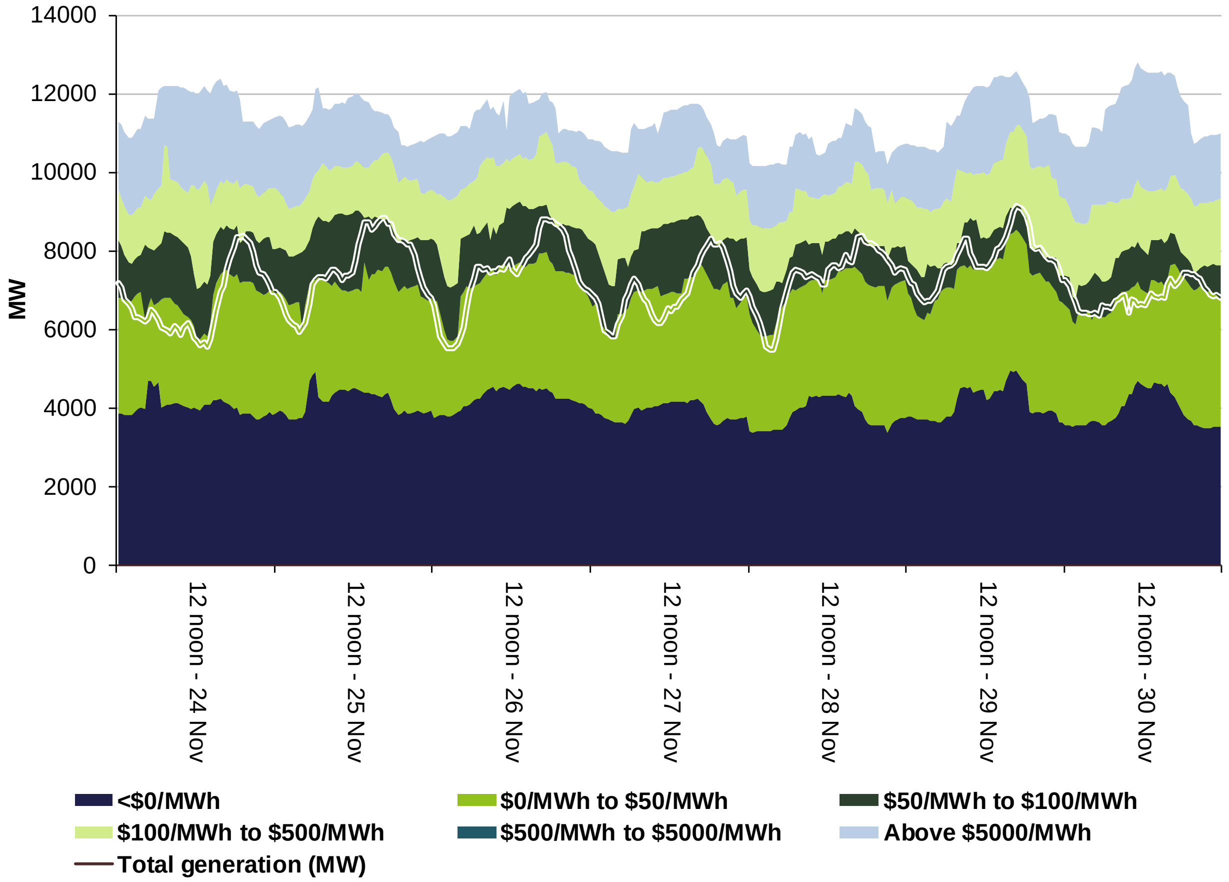


Figure 5: Victoria generation and bidding patterns

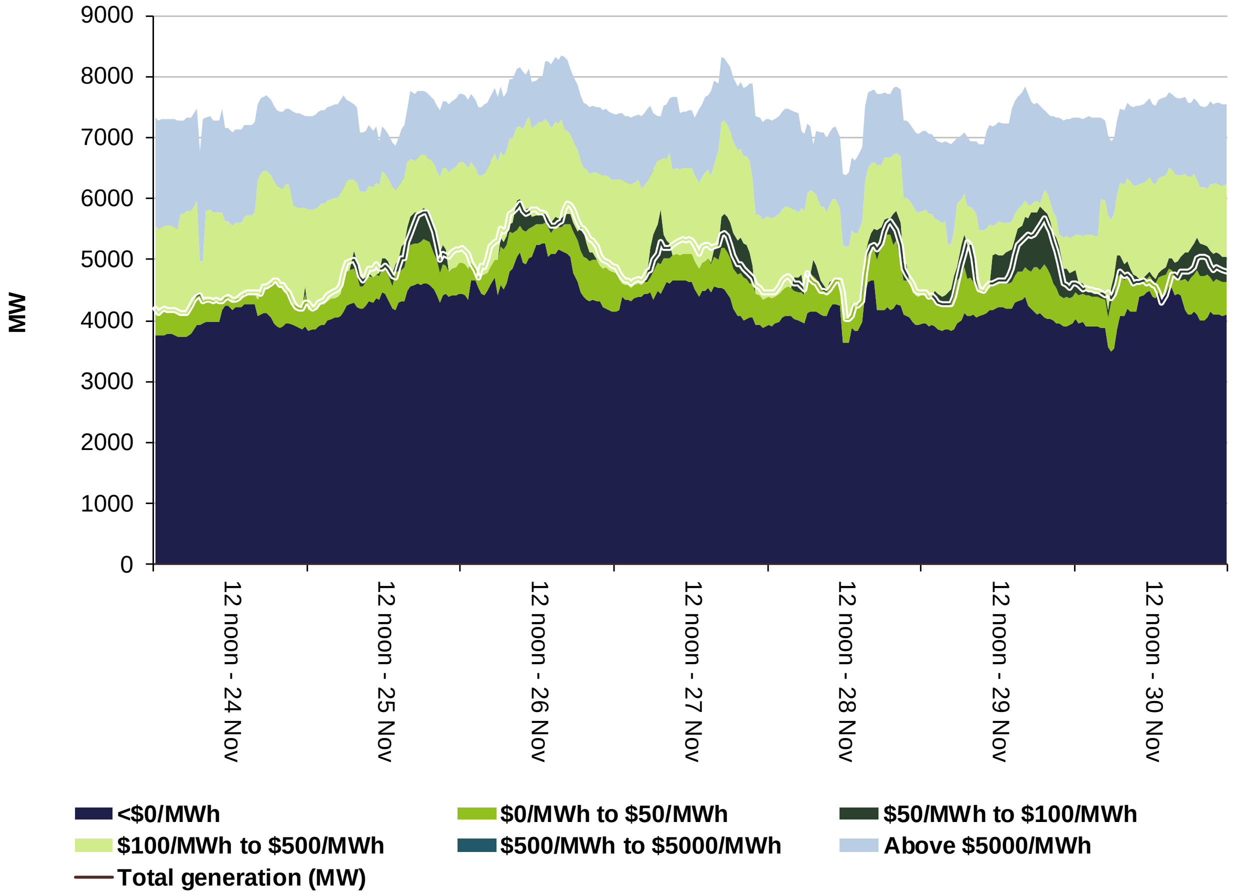


Figure 6: South Australia generation and bidding patterns

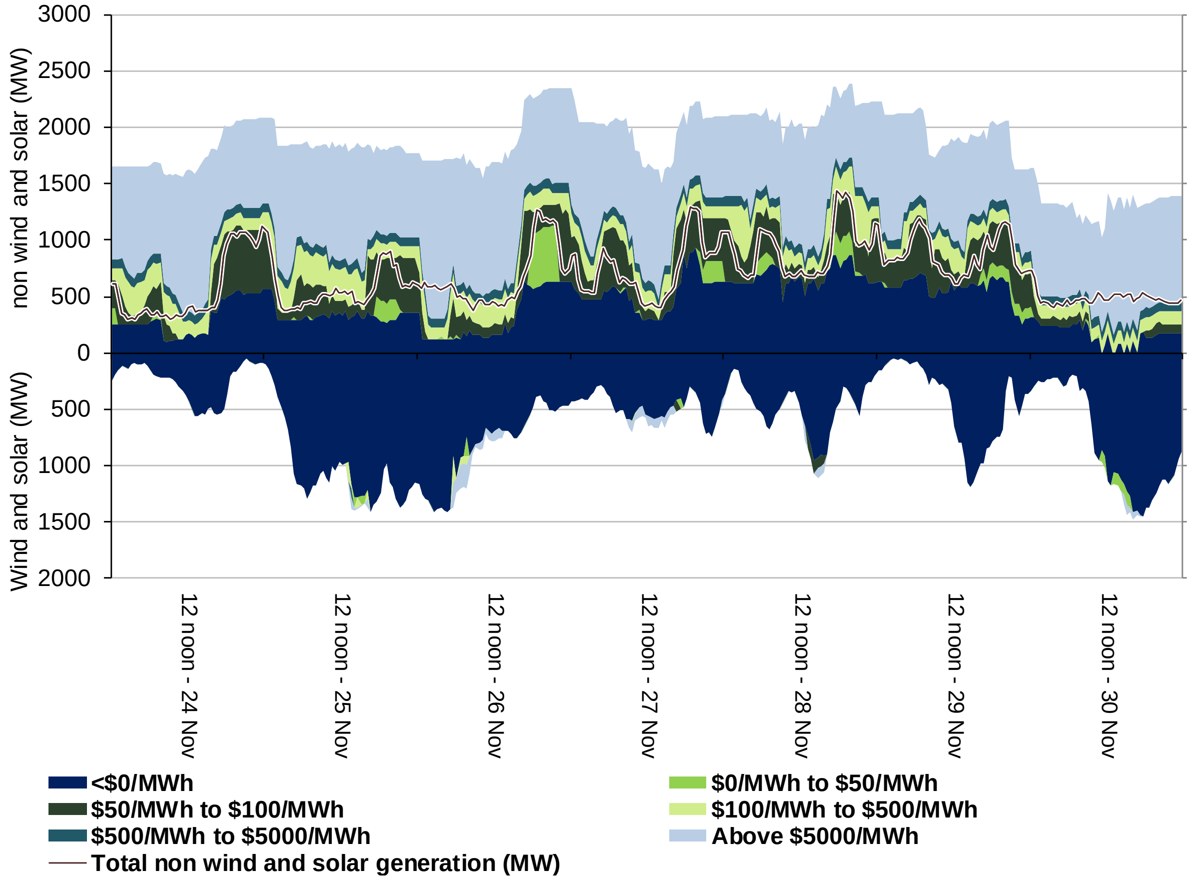
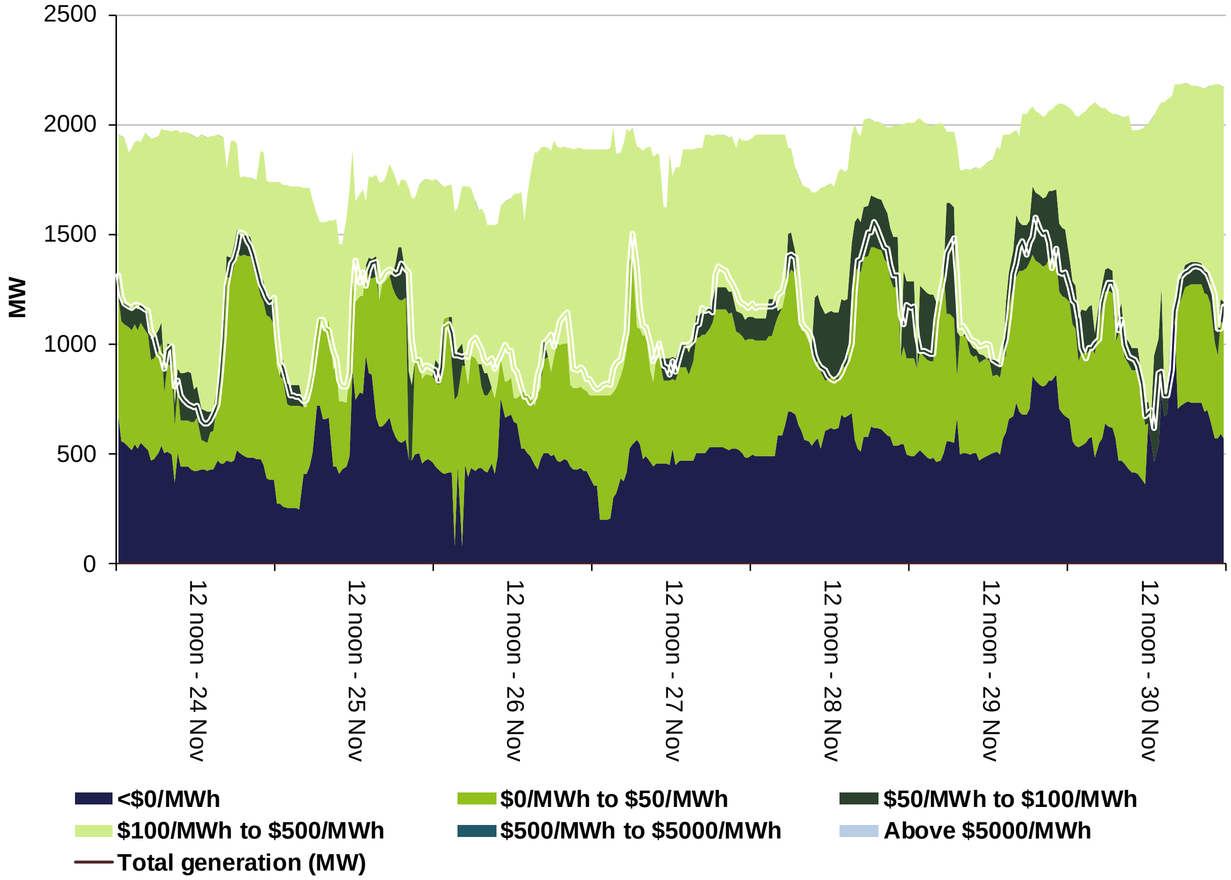


Figure 7: Tasmania generation and bidding patterns



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.

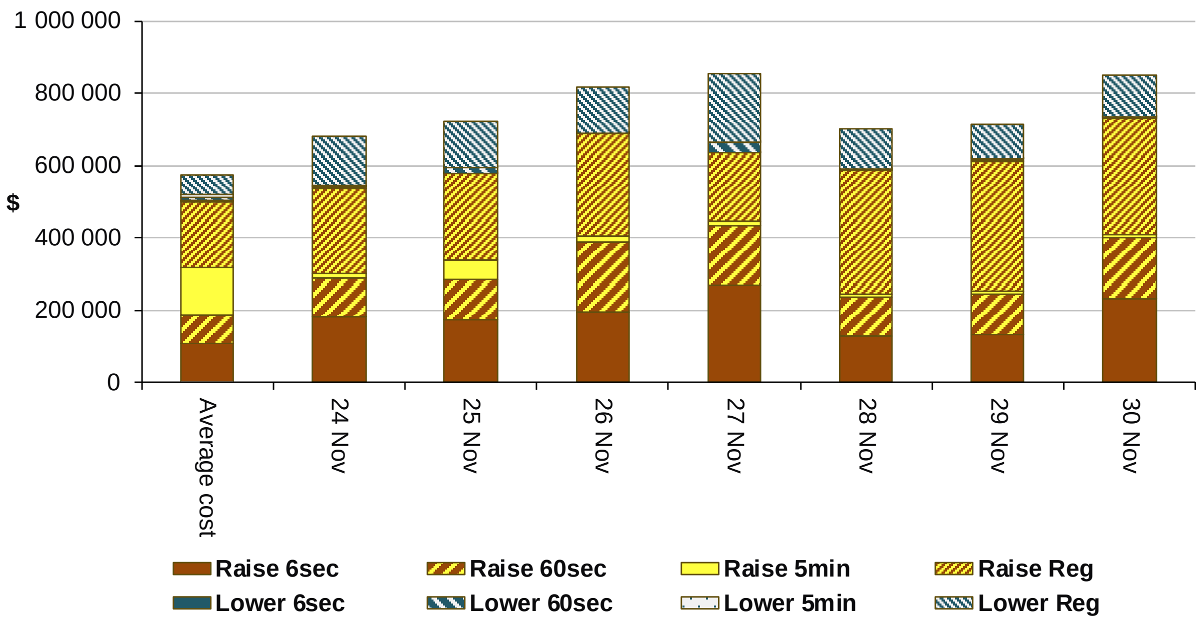
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4 266 500 or around 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 080 500 or around 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



Detailed market analysis of significant price events

South Australia

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

Monday, 25 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
1 pm	-123.12	53.22	60.46	1355	1127	1159	2825	2651	2679
2 pm	-173.20	43.12	46.92	1348	1155	1153	3206	2809	2861

Demand was between 193 MW and 228 MW higher than forecast and availability was between 174 MW and 397 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 negative prices.

There was little capacity priced between the price floor and the forecast price, which meant that small changes in demand or availability could cause large fluctuations in price. Consequently, small changes in demand and higher than forecast availability resulted in dispatch price falling to the price floor once during each of the above trading intervals. For the 2 pm trading interval, a few participants in South Australia rebid wind farm capacity from the price floor to higher prices to avoid uneconomic dispatch. The price rose to $54/MWh for the last dispatch interval after the rebids came into effect.

Tuesday, 26 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
6 am	-130.85	61.81	42.15	1096	1091	1102	3093	2857	2849
7 am	-121.28	48.00	45.90	1257	1201	1211	2922	2875	2878
7.30 am	-154.46	43.52	43.35	1226	1190	1210	2926	2890	2894
8 am	-138.26	-1000	-1000	1156	1101	1119	2934	2896	2900

Demand was no more than 60 MW higher than forecast and availability was between 36 MW and 236 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 negative prices.

There was little capacity priced between the price floor and the forecast price, which meant that small changes could cause large fluctuations in price. As a result, small changes in demand or consumption of battery loads, coupled with higher priced generators either ramp down-constrained or trapped/stranded in FCAS, caused dispatch price to fall to price floor once during each of the above trading intervals. A number of participants in South Australia rebid capacity from the price floor to higher prices, at solar farms and wind farms, to avoid uneconomic dispatch. The price stayed above $30/MWh for the remainder of the intervals after the rebids came into effect.

Wednesday, 27 November

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
9 am	-191.40	43.68	30.30	921	978	997	2636	2518	2584

Demand was 57 MW less than forecast and availability was 118 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 negative prices.

From 8.50 am to 9 am, demand in South Australia reduced by a total of 55 MW over the space of 10 minutes. With only Lake Bonney 2 and 3 wind farms having capacity priced between the forecast price and the price floor at the time, the small reduction in demand caused both of these generators to be ramp down-constrained and unable to set price at 9 am. As a result, price fell to the price floor for one dispatch interval.

Thursday, 28 November

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
1 pm	-117.56	36.03	32.52	812	747	748	2820	2616	2641

Demand was 65 MW higher than forecast and availability was 204 MW higher than forecast, four hours prior. The higher availability was due to higher than forecast wind generation, most of which was offered at negative prices, and AGL rebidding at Barker Inlet to introduce 51 MW at the price floor due to requirement testing.

As a result there was little capacity priced between the price floor and the forecast price, which meant that small changes could cause large fluctuations in price. Consequently, small changes in demand and wind generation caused the dispatch price to fall to the price floor at 12.50 pm. A number of participants in South Australia rebid capacity from the price floor to higher prices, mainly at solar farms and wind farms, in response to this negative price event. The price stayed around $60/MWh for the remainder of the interval after the rebids came into effect.

Tasmania

There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $72/MWh and above $250/MWh.

Monday, 25 November

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
6.30 pm	2193.88	91.62	77.37	1195	1157	1162	1760	1863	1870
8.30 pm	380.15	67.65	76.89	1209	1141	1161	1722	1821	1858

Starting at 6.25 pm, there was an increase in local requirement for raise 5 minute and raise regulation services in Tasmania, triggered by a reclassification of Tasmania generation event. With insufficient local raise 5 minute and raise regulation availability in Tasmania at the time, these ancillary markets were co-optimised with the energy market and price rose to around $12 000/MWh for one dispatch interval.

At the start of 8.30 pm trading interval, there was a step change in availability set up a day in advance. As a result, lower priced generation became ramp up-constrained and price was set by generation units with offers over $400/MWh for most of the trading interval.

Saturday, 30 November

Table 8: Price, Demand and Availability

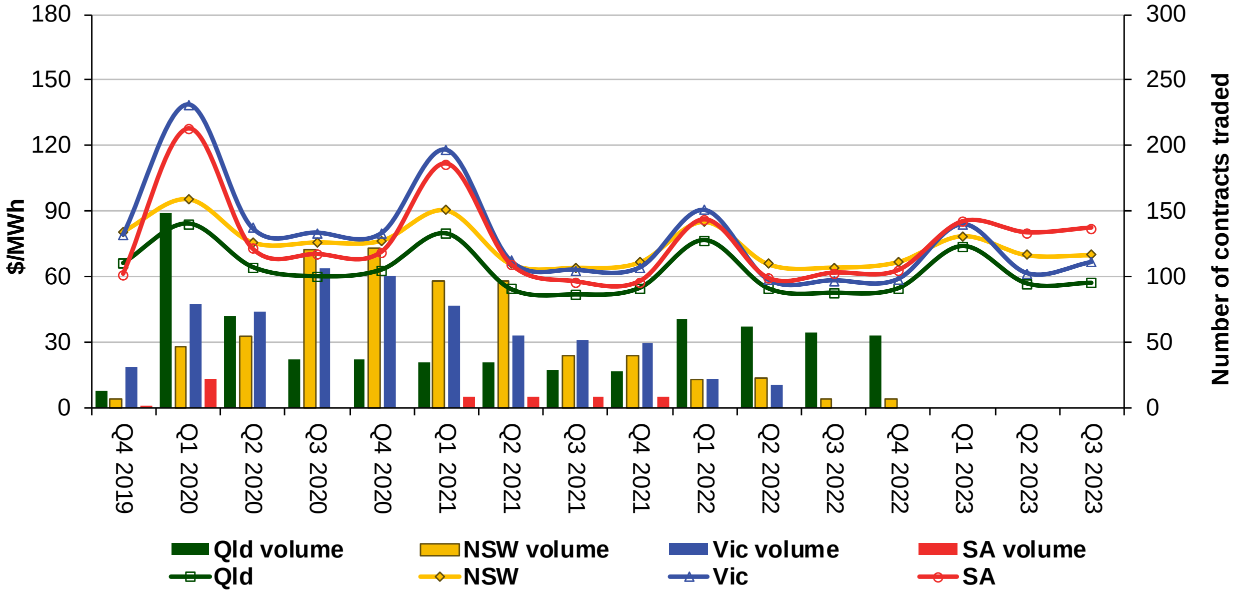
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1.30 pm	281.65	1.55	48.54	979	983	991	2043	2055	2061

Starting 1.10 pm, AEMO issued a reclassification of Farrell to Sheffield lines due to lightning which reduced combined generation at John Butters and Bastyan stations from over 200 MW to 0 MW. As a result, more expensive generation units were dispatch and price increased to over $400/MWh for three dispatch 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 Q4 2019 – Q3 2023

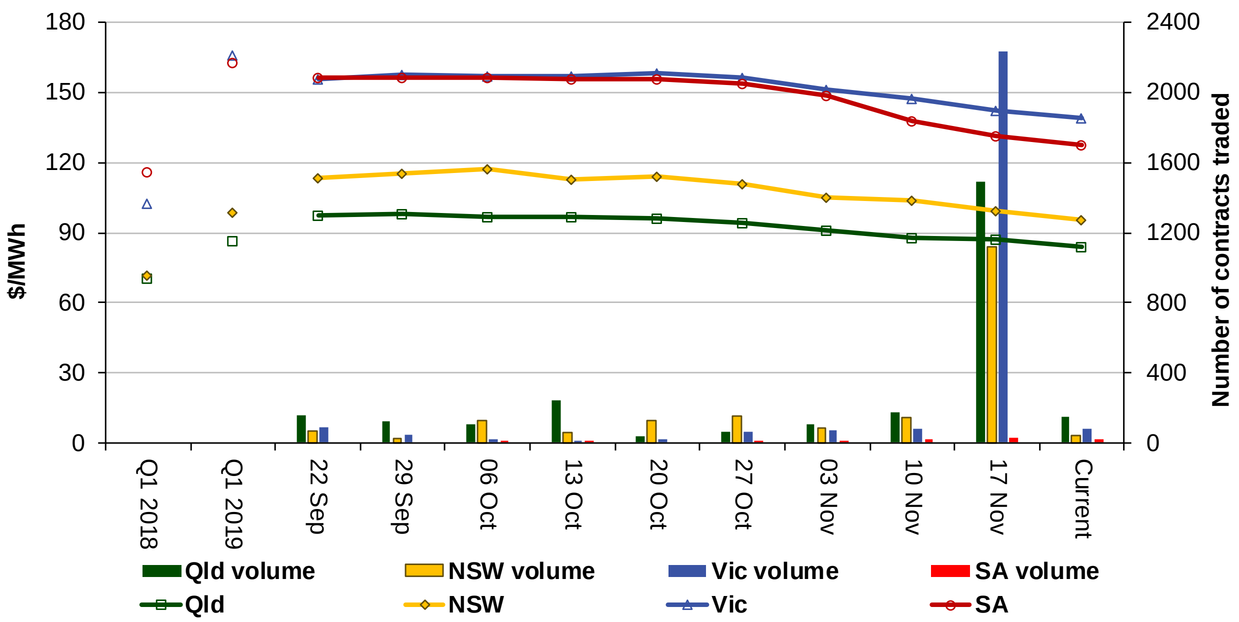


Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 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.

The high volumes for the week starting 17 November were a result of the conversion of base load options to base future contracts.

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

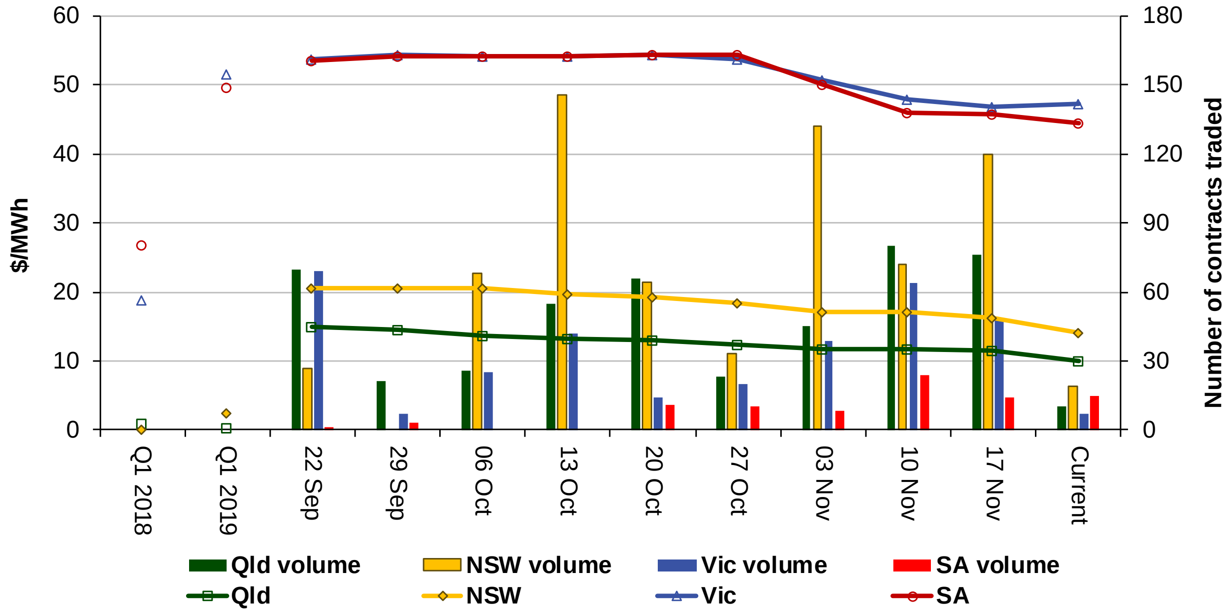


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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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