28 October – 3 November 2018

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 28 October – 3 November 2018.

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

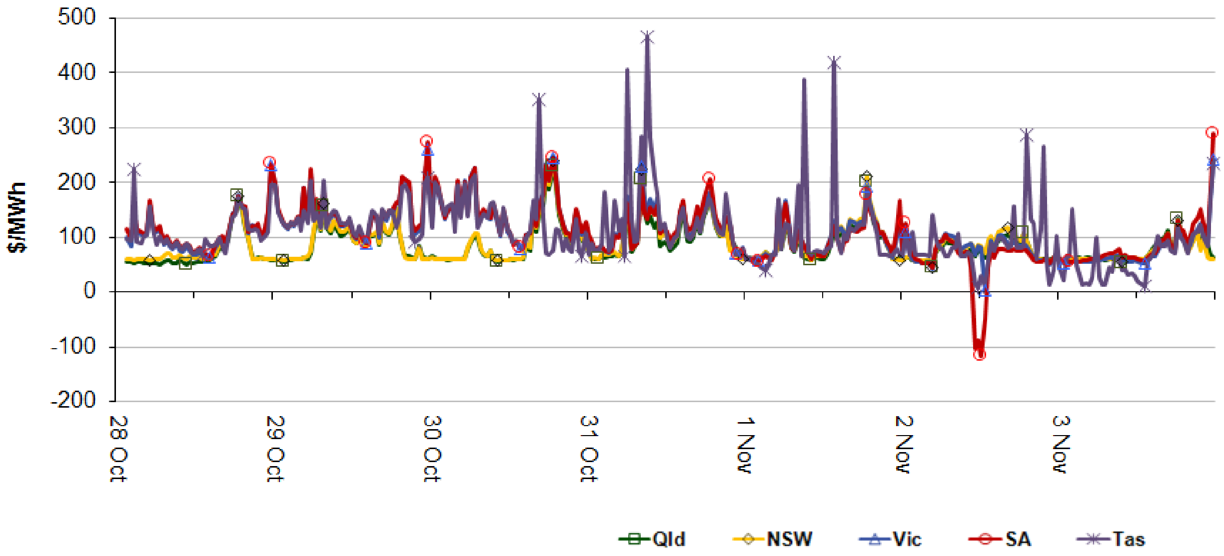


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

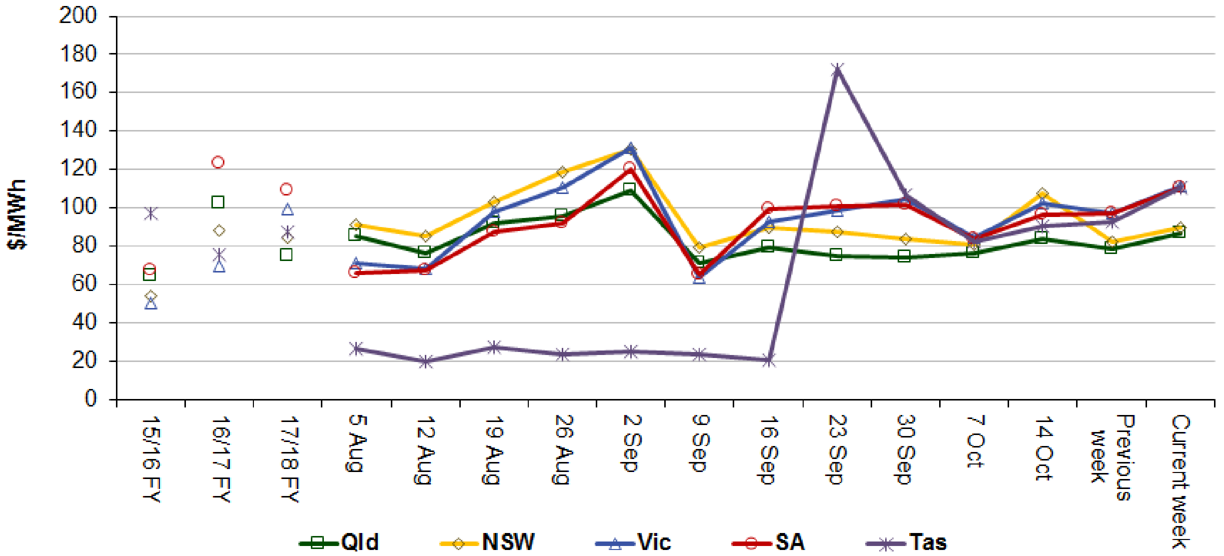


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	87	90	111	111	111
17-18 financial YTD	81	92	96	95	91
18-19 financial YTD	80	90	88	96	56

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 2017 of 185 counts and the average in 2016 of 273. 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	14	0	3
% of total below forecast	14	52	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

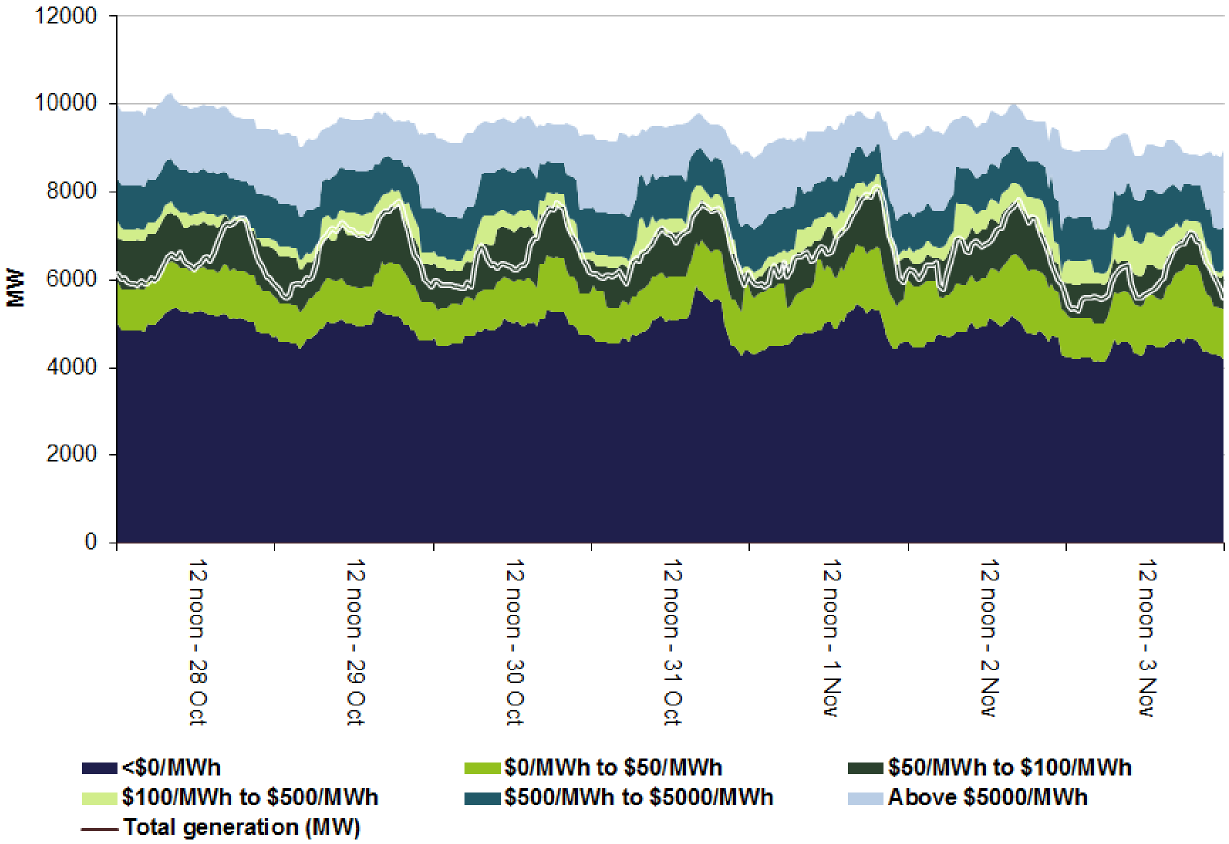


Figure 4: New South Wales generation and bidding patterns

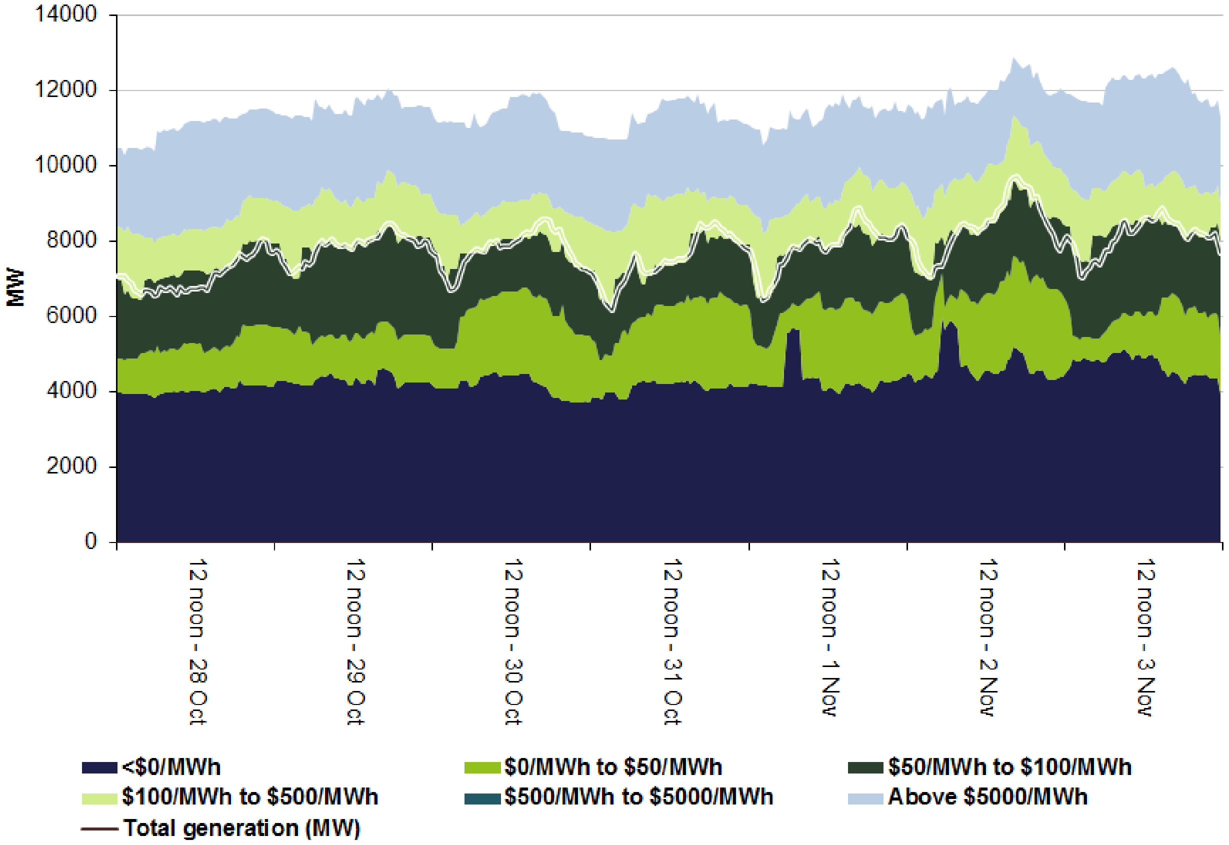


Figure 5: Victoria generation and bidding patterns

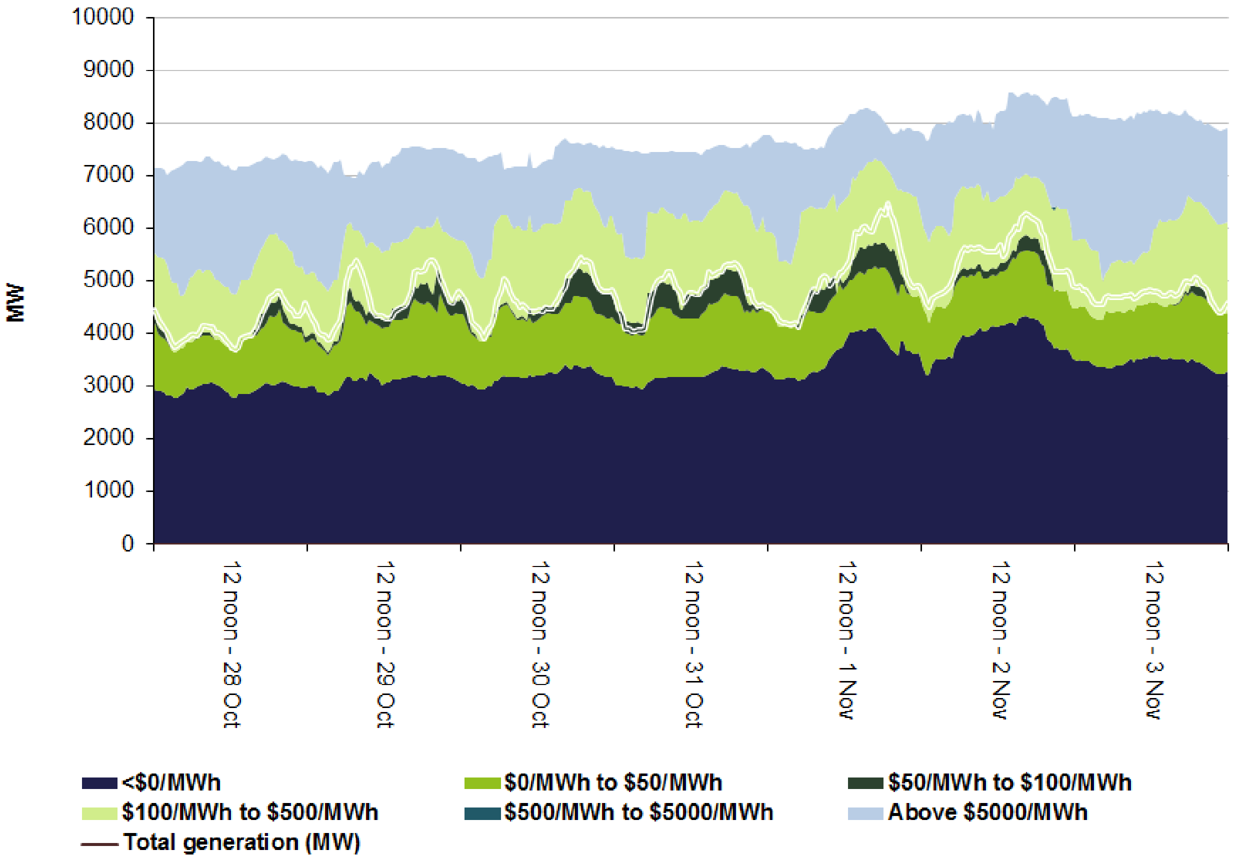


Figure 6: South Australia generation and bidding patterns

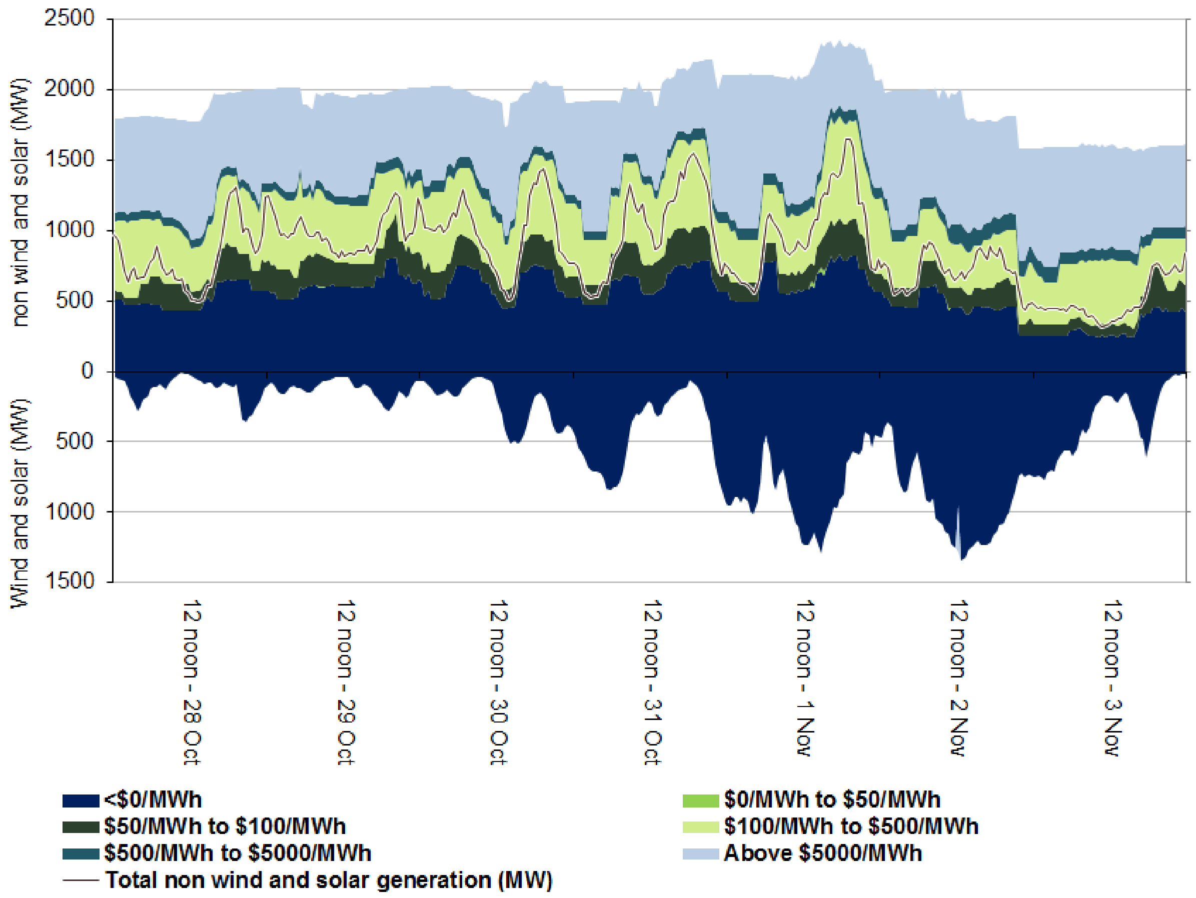
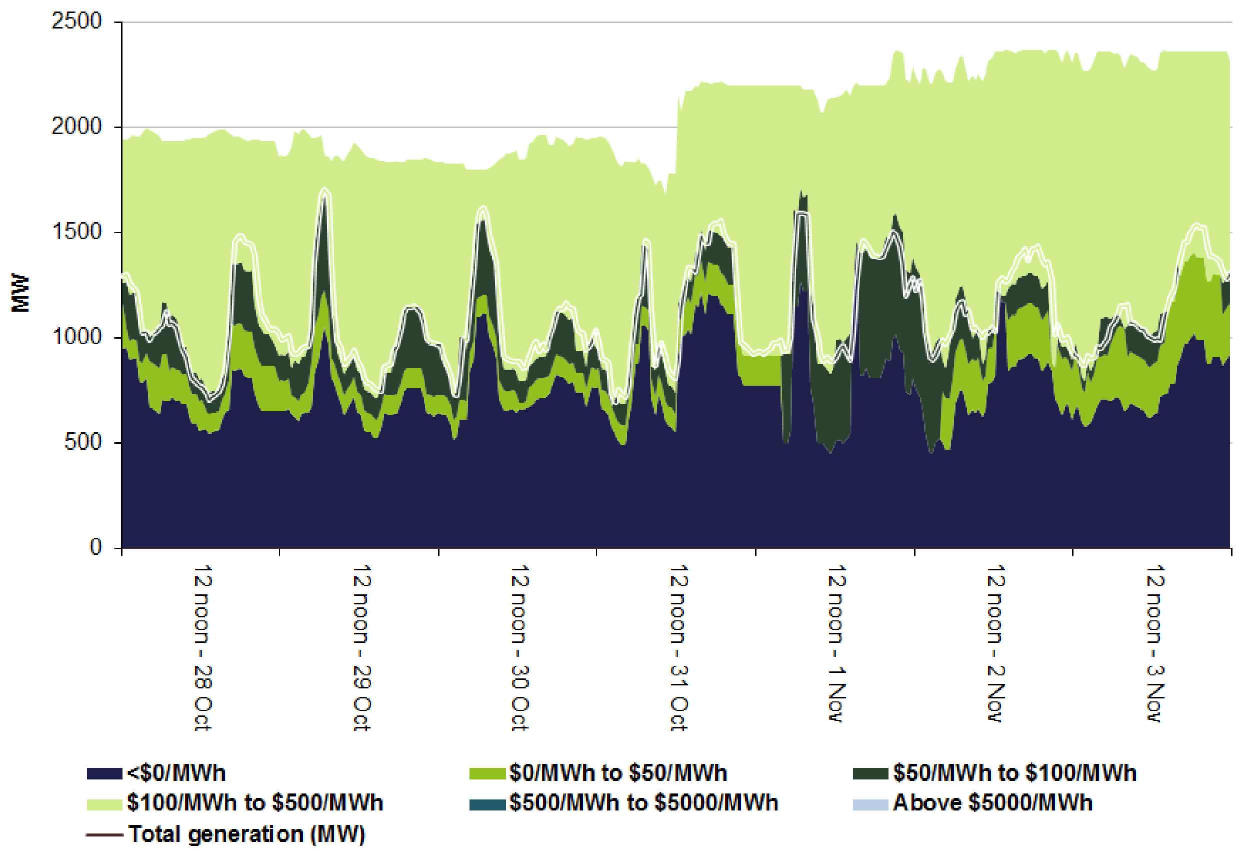


Figure 7: Tasmania generation and bidding patterns



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.

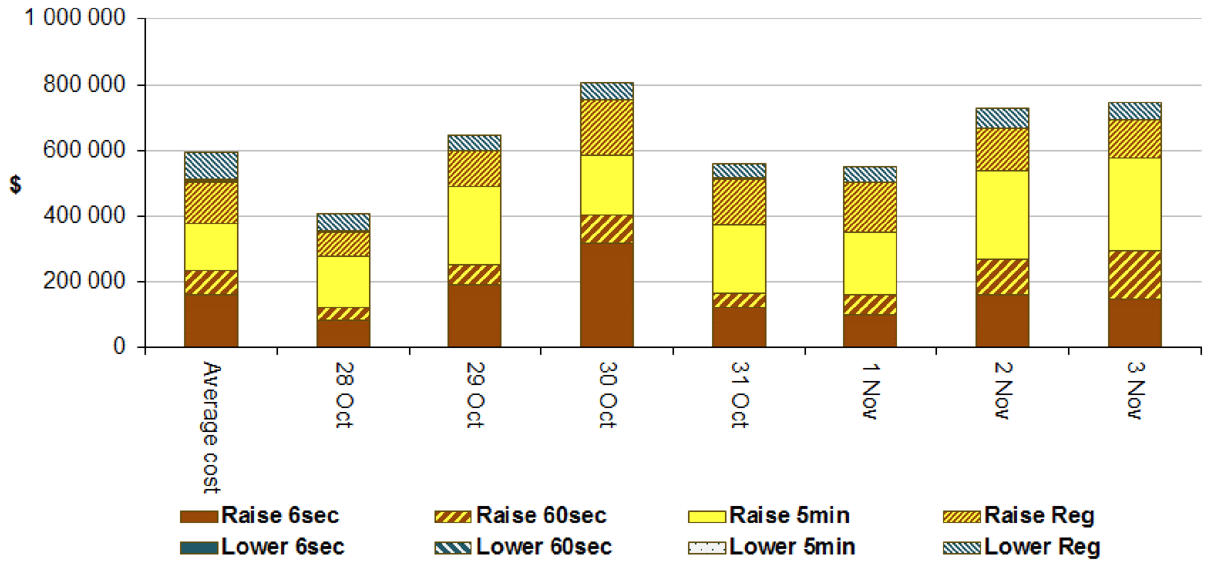
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 448 000 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $995 000 or around five 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 two occasions where the spot price in South Australia was below -$100/MWh.

Friday, 2 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
11.30 am	-104.28	122.06	102.00	1020	1080	1141	3188	2948	2970
12.30 pm	-115.28	25.14	94.08	999	909	1067	3274	3045	3036

For the 11.30 am trading interval demand was 60 MW lower than forecast and availability was 240 MW higher than forecast four hours prior.

The lower than forecast demand and higher than forecast wind generation meant the price for the first two dispatch intervals was set around $36/MWh. At 11.15 am, demand decreased by 26 MW. With higher priced generation trapped in FCAS and unable to set price, the dispatch price decreased to -$3/MWh. The dispatch price then decreased to -$152/MWh at 11.20 am and -$576/MWh at 11.25 am as wind generation increased by 78 MW and higher priced generation was ramp down limited or trapped in FCAS and unable to set price, resulting in the lower than forecast spot price.

For the 12.30 pm trading interval demand was 90 MW higher than forecast and availability was 229 MW higher than forecast, both four hours prior.

The higher than forecast low priced wind generation meant the price for the first five dispatch intervals was set between -$3/MWh and -$573/MWh, which resulted in the lower than forecast spot price.

Tasmania

There were five occasions where the spot price in Tasmania was greater than three times the Tasmanian weekly average price of $111/MWh and above $250/MWh.

Tuesday, 30 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
5 pm	352.85	92.24	65.35	1121	1115	1112	1944	1943	1934

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

Over multiple rebids in the four hours leading up to the start of the trading interval HydroTas rebid around 500 MW of capacity from prices less than $65/MWh to $420/MWh and above. The rebid reasons related to prices being different from forecast in the Victorian region.

The rebids were offset by forecast exports being around 550 MW lower than forecast four hours ahead.

At 4.36 pm, effective from 4.40 pm, Hydro Tasmania rebid a further 60 MW at John Butters from prices below $65/MWh to $422/MWh. The reason for the rebid was “1632A FCAS availability < Forecast: TAS R6”. With a constraint managing a line outage on one Hadspen to Palmerston 220 kV line limiting cheaper priced generation in Tasmania, the dispatch price increased to $400/MWh. The dispatch price ranged from $300/MWh to $438/MWh for the rest of the trading interval as cheaper priced generation was either limited by the constraint, ramp rate limited or trapped in FCAS so unable to set price.

Wednesday, 31 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
6.30 am	406.53	204.24	290.32	1316	1297	1284	1838	1847	1831
9.30 am	465.56	182.24	185.11	1107	1149	1159	1773	1757	1768

Demand and availability were close to that forecast four hours prior for both trading intervals.

For the 6.30 am trading interval, there was no capacity priced between $66/MWh and $200/MWh. Hydro Tasmania rebid around 100 MW of capacity from prices greater than $290/MWh to -$21/MWh which led to the first five dispatch prices being set at around $75/MWh.

However, at 6.30 am, constraints invoked to manage a planned outage on a Hadspen to Palmerston 220 kV line violated and caused imports into Tasmania to increase by around 200 MW. The increase in imports meant cheaper priced local generation was ramp down constrained, while other generation was trapped in FCAS and unable to set price. As a result the dispatch price increased to $2075/MWh and caused the higher than forecast spot price.

For the 9.30 am trading interval, constraints managing the line outage mentioned above bound at 9.10 am causing imports to increase by 110 MW. With cheaper priced generation limited by the constraint or ramp rate limited, the dispatch price increased to $2175/MWh and caused the higher than forecast price.

Thursday, 1 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
9.30 am	388.88	126.73	422.56	1036	1101	1122	2130	2132	2130
2 pm	418.28	73.91	1866.88	981	1006	1043	2180	2145	2146

Demand and availability were close to that forecast four hours prior for both trading intervals.

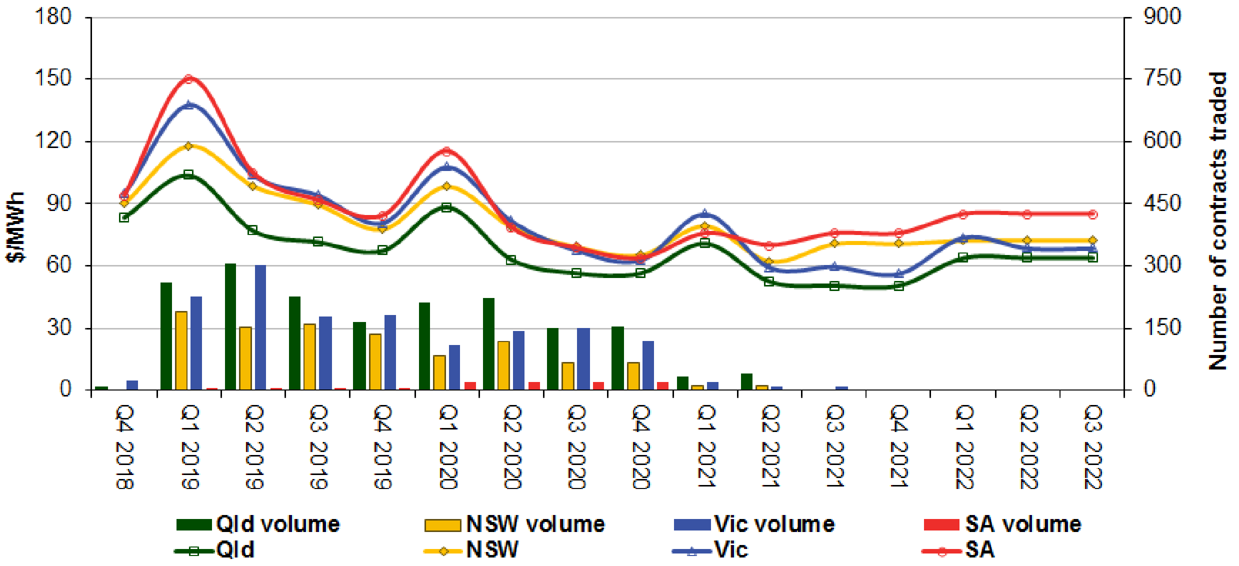
At 9.25 am a constraint managing the planned outage on one Hadspen to Palmerston 220 kV line violated and imports into Tasmania increased by 88 MW. With cheaper priced generation limited by the constraint, ramp rate limited or stranded in FCAS, the dispatch price increased to $1820/MWh and caused the higher than forecast price for the 9.30 am trading interval.

At 2 pm the constraint managing the outage bound and imports into Tasmania increased by 20 MW. With cheaper priced generation limited by the constraint or ramp down constrained the dispatch price increased to $1873/MWh and caused the higher than forecast price for the 2 pm 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.

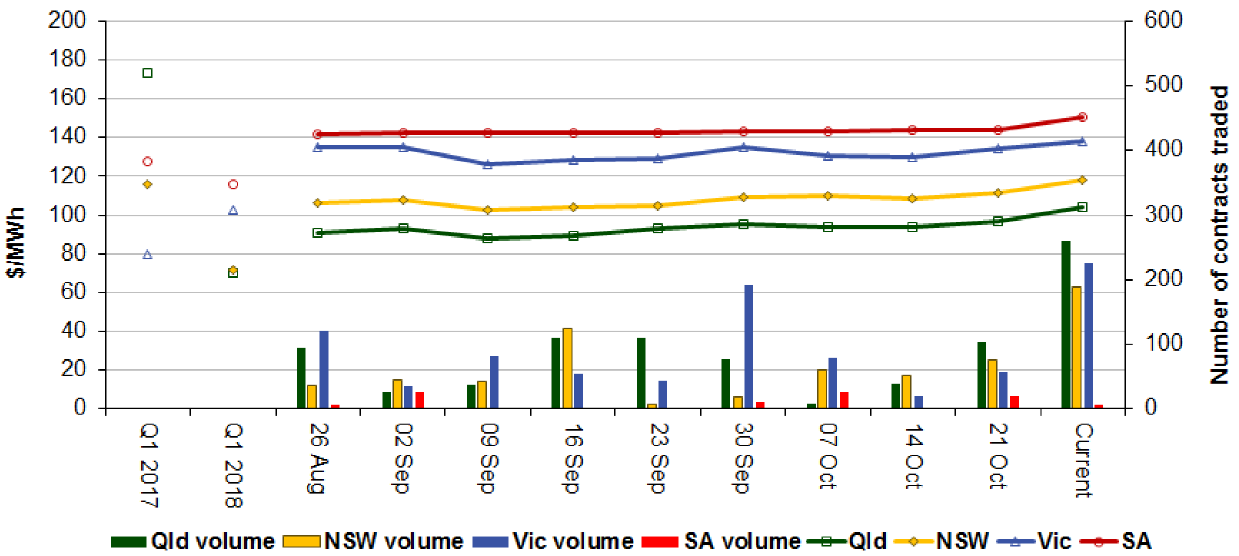
Figure 9: Quarterly base future prices Q4 2018 – Q3 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



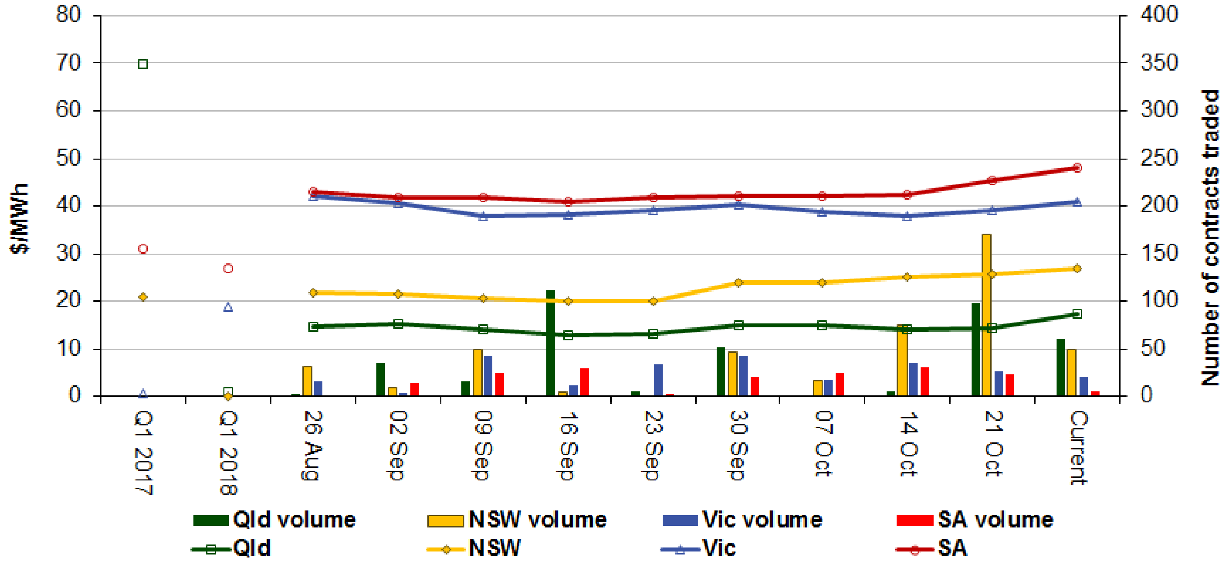
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

Figure 11 shows how the price for each regional quarter 1 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
December 2018