Electricity Report

11 – 17 December 2016

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 11 – 17 December 2016.

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

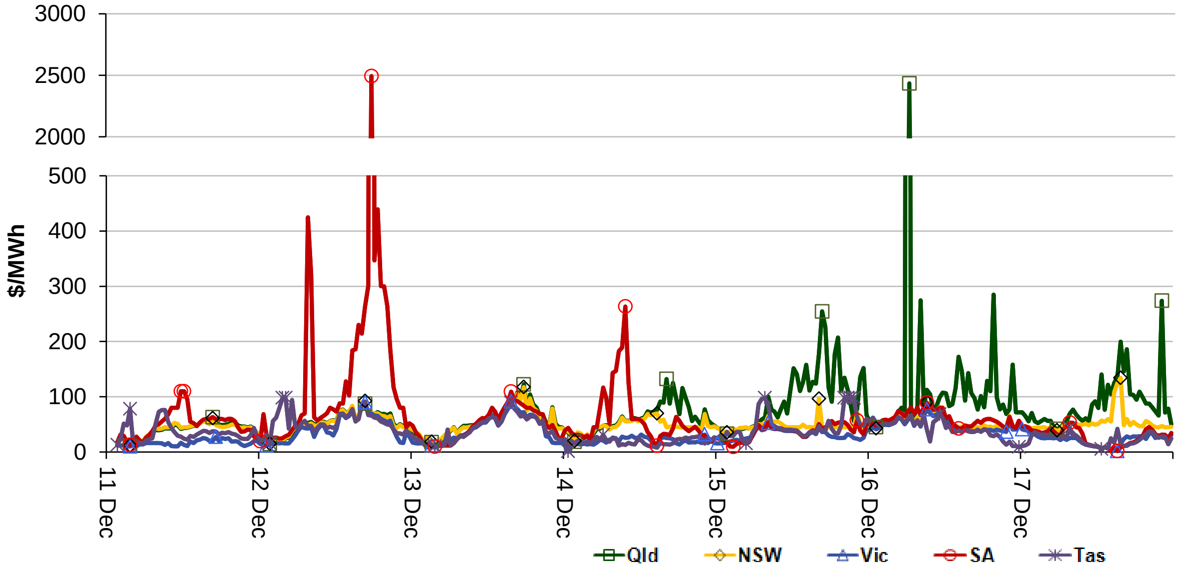


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

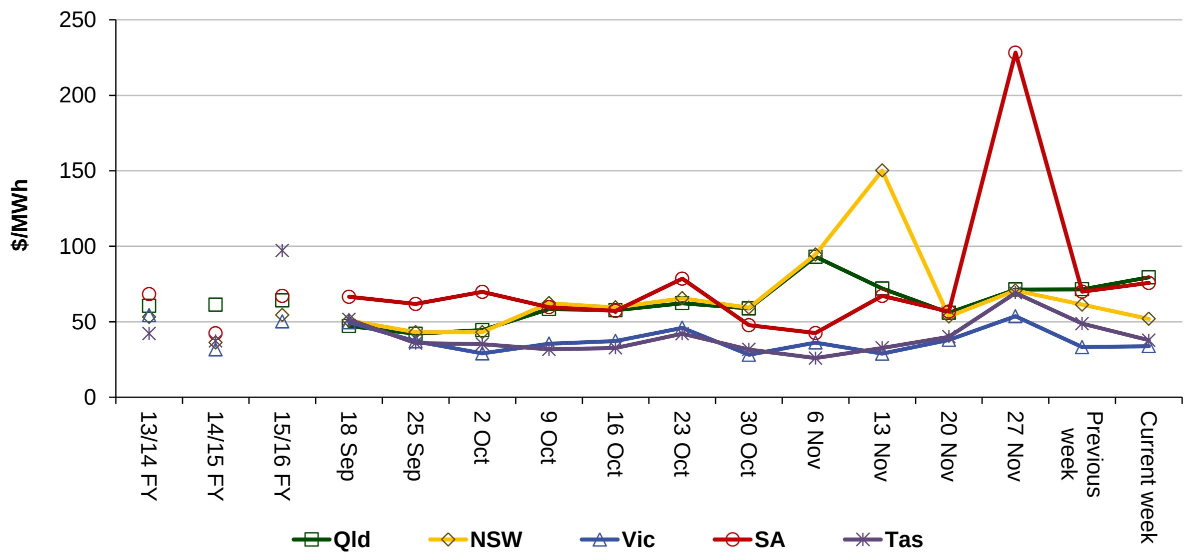


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	79	52	34	76	38
15-16 financial YTD	44	45	40	63	54
16-17 financial YTD	59	62	45	110	48

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 288 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. 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	22	0	3
% of total below forecast	45	23	0	3

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

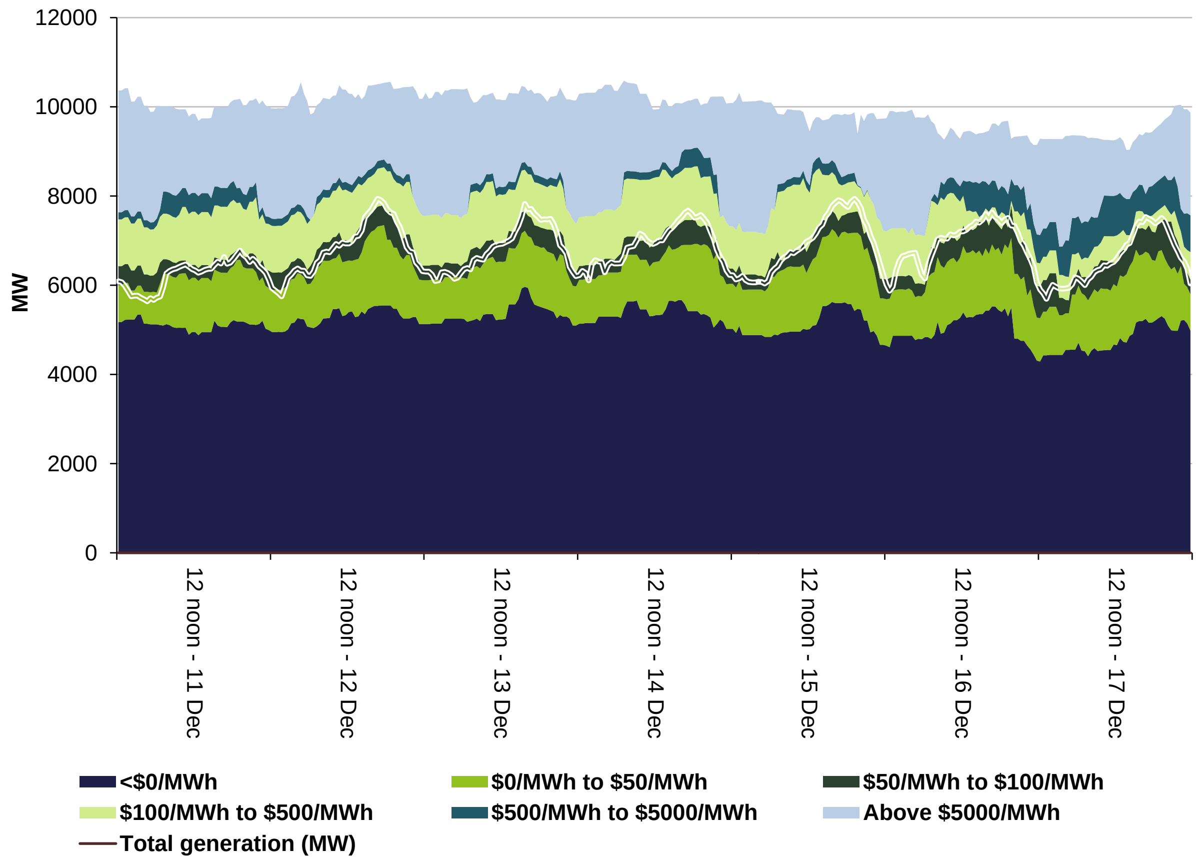


Figure 4: New South Wales generation and bidding patterns

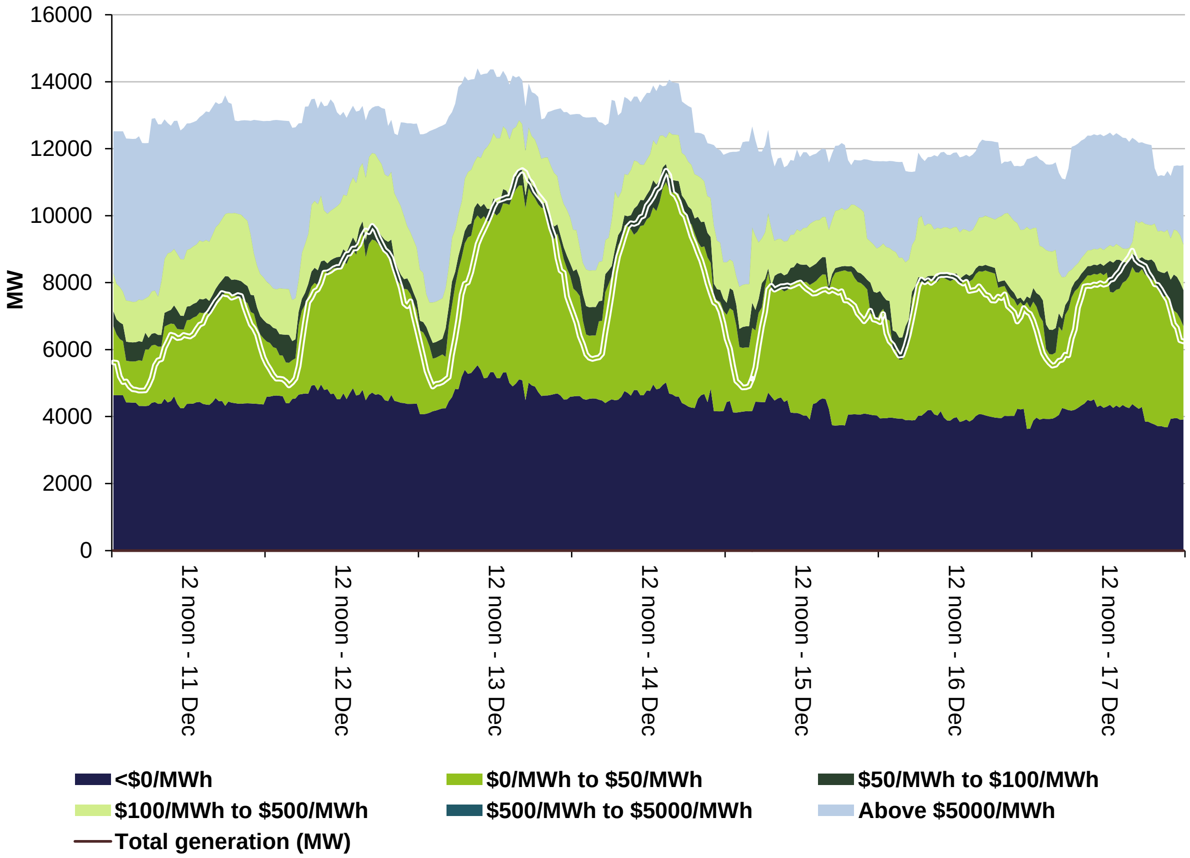


Figure 5: Victoria generation and bidding patterns

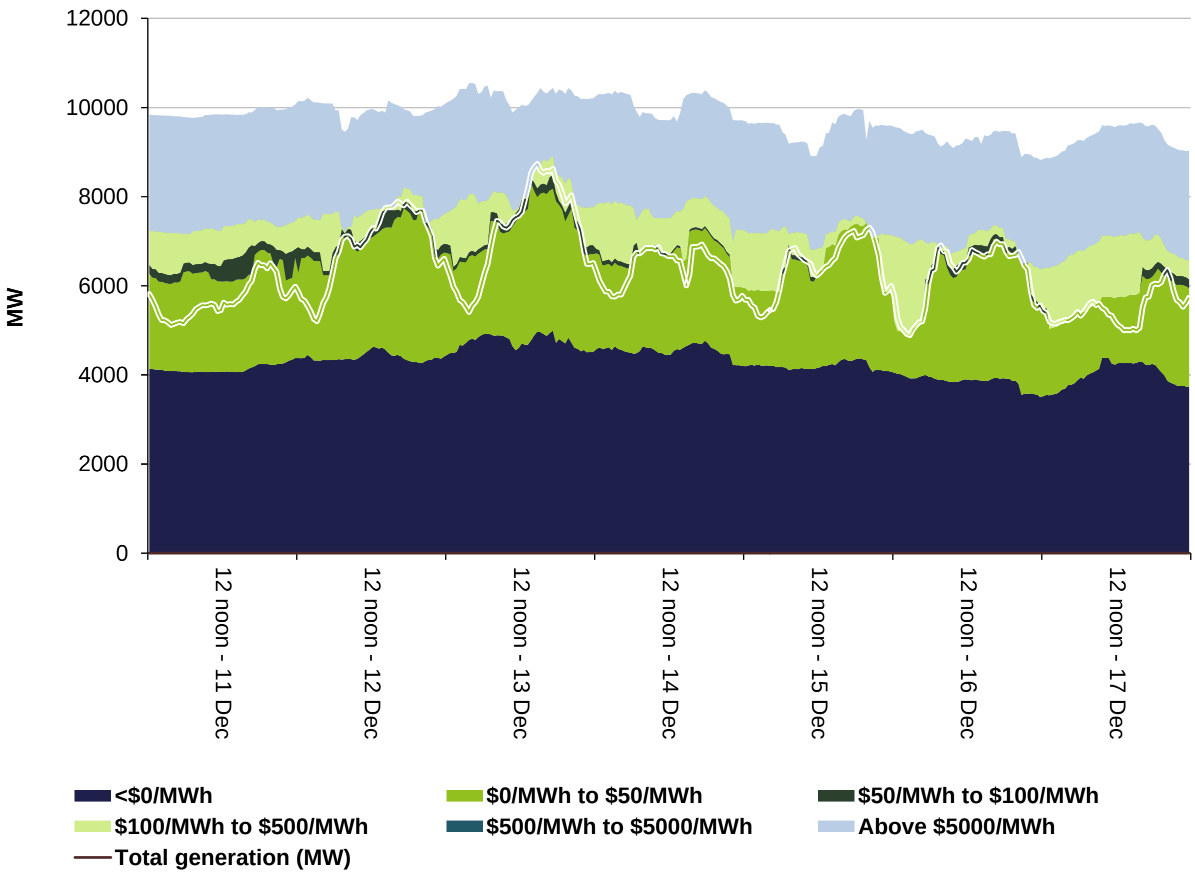


Figure 6: South Australia generation and bidding patterns

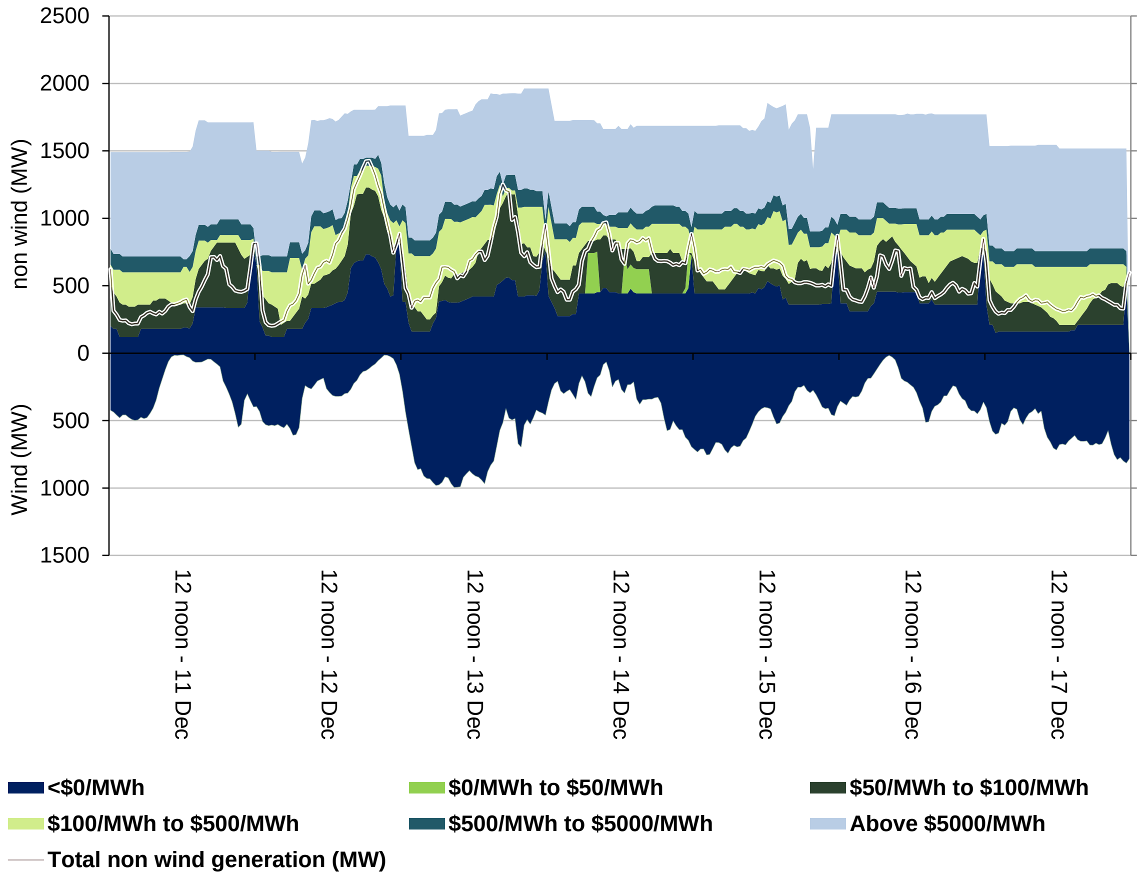
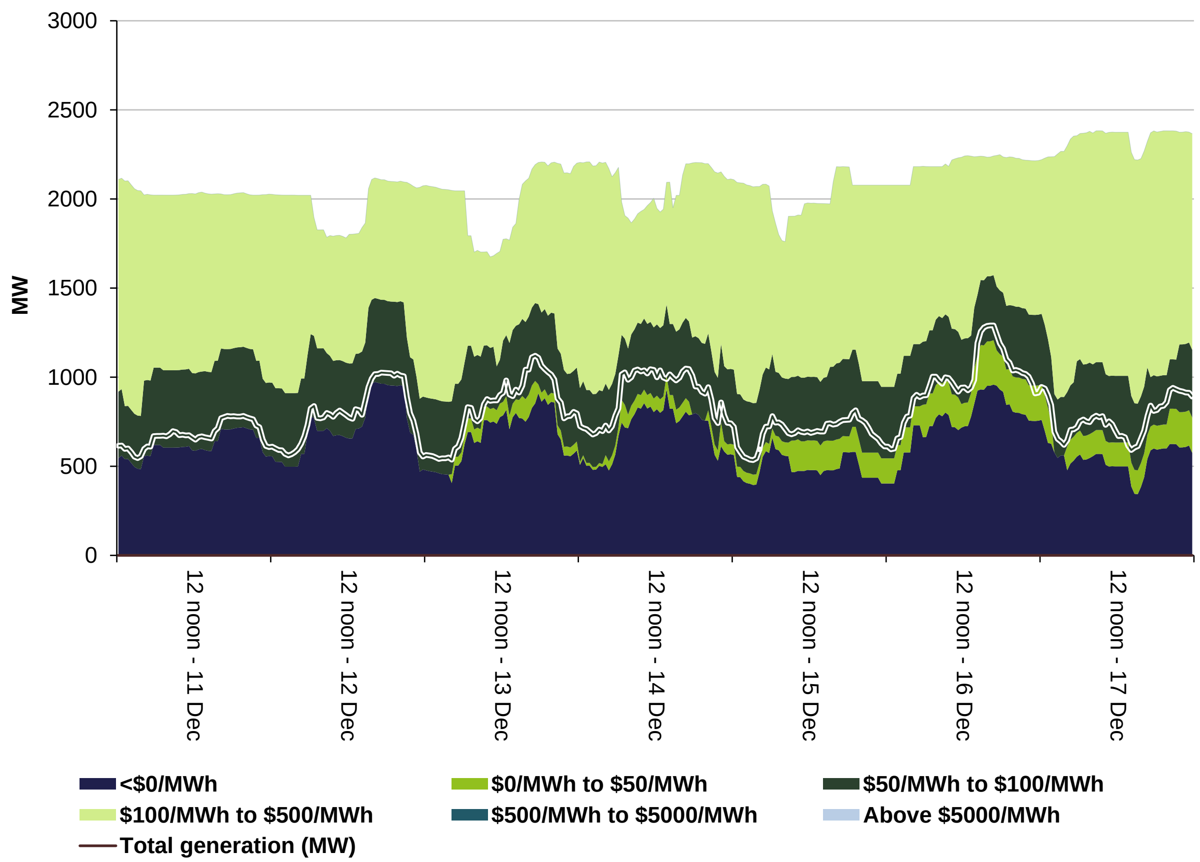


Figure 7: Tasmania generation and bidding patterns



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.

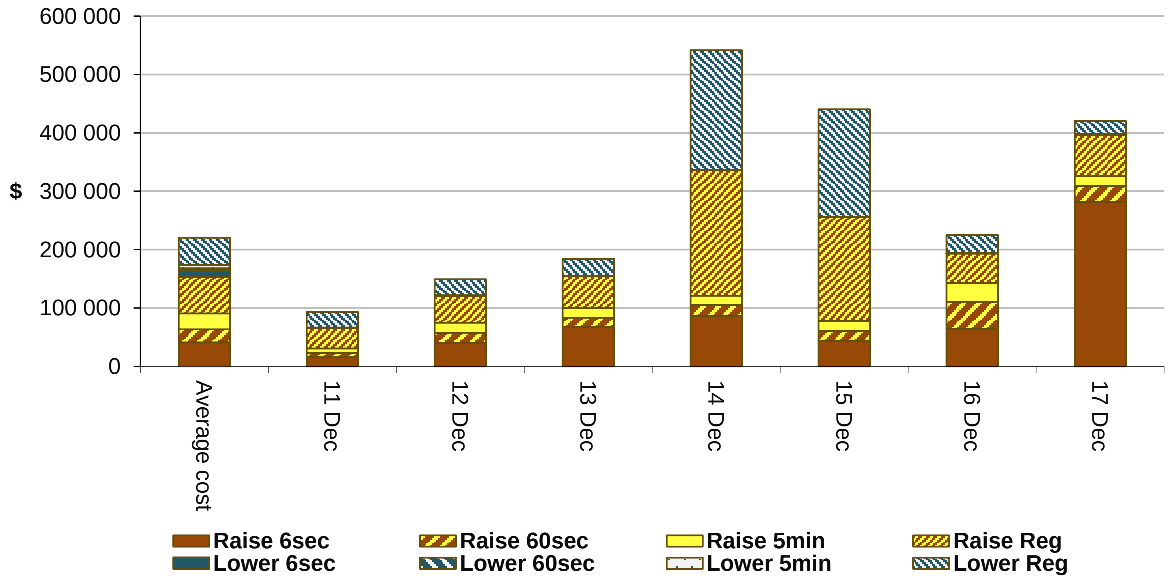
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 525 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $528 500 or around eight 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 14 December a two day planned outage of the Heywood No.1 busbar commenced putting the Heywood interconnector on a single contingency. AEMO invoked a 35 MW requirement for raise and lower regulation services in South Australia. This led to increased FCAS costs during these days.

Detailed market analysis of significant price events

Queensland

There were five occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $79/MWh and above $250/MWh.

Thursday, 15 December

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
5 pm	254.46	266.03	200.01	8028	7903	7704	9834	9950	10 421

Conditions at the time saw the price close to forecast.

Friday, 16 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
6.30 am	2434.05	61.12	75.91	6255	6182	6091	9757	9965	9965
8.30 am	274.56	262.00	149.99	6823	7033	6851	9482	9734	9759
8 pm	285.07	96.66	265.71	7398	7425	7514	9628	9725	10 044

Conditions on the day saw demand higher than forecast for the 6.30 pm trading interval but lower than forecast for the 8.30 am and 8 pm trading intervals. Available capacity was lower than forecast for all three trading intervals.

The 6.30 am spot price was significantly higher than forecast. At 5.11 am CS Energy reduced the availability of Gladstone unit 2 by 149 MW, the majority of this capacity was priced below $32/MWh. The reason given was “0511P technical issues-id fan limit –sl”. At 6.30 am there was a 120 MW increase in demand. With low priced capacity ramp rate limited or taking more than five minutes to start the dispatch price went to the price cap.

The 8.30 am spot price was close to forecast.

The 8 pm spot price was higher than forecast because at 7.50 pm, Tarong North tripped and 340 MW of capacity priced at the floor was lost. Higher priced capacity was then dispatched resulting in the dispatch prices reaching $1400/MWh.

Saturday, 17 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
10.30 pm	273.89	423.12	423.13	6582	6804	6831	10 046	10 011	10 016

The spot price was lower than forecast as demand was around 200 MW lower than forecast.

South Australia

There was eleven occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $76/MWh and above $250/MWh.

Monday, 12 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
8 am	424.99	79.99	67.15	1334	1315	1296	1771	1978	2002
8.30 am	321.04	79.99	79.99	1323	1289	1301	1697	1916	1941
5 pm	262.86	344.44	299.95	2118	1978	1822	2007	1939	2003
5.30 pm	300.17	578.81	299.97	2155	2047	1866	1966	1928	1989
6 pm	2493.61	349.98	299.97	2177	2066	1891	1941	1916	2001
6.30 pm	346.72	578.81	299.97	2213	2064	1909	1935	1903	2003
7 pm	439.54	349.98	299.97	2216	2055	1902	1919	1899	1977
7.30 pm	300.18	300.00	299.95	2156	2002	1838	1900	1920	1996
8 pm	300.03	349.95	80.19	2060	1950	1778	1886	1929	2019
8.30 pm	263.66	300.00	79.99	1982	1896	1755	1889	1984	2046

For the 8 am and 8.30 am, demand was close to forecast while available capacity was 200 MW lower than that forecast four and 12 hours ahead. Wind generation decreased by around 211 MW within the 8 am trading interval, and a further 96 MW within the 8.30 am trading interval. This resulted in higher priced gas generation being dispatched.

The 5 pm and 5.30 pm spot prices were close to what was forecast 12 hours ahead. Rebidding from high to low prices contributed to the lower than forecast price four hours prior.

The 6 pm trading interval price was a result of the dispatch price for 6 pm reaching over $13 000/MWh. This occurred due to a combination of a decrease in imports into South Australia across the Heywood interconnector (56 MW) and an increase of demand (28 MW).

The 6.30 pm to 8.30 pm trading intervals were close to forecast.

Wednesday, 14 December

Table 7: Price, Demand and Availability

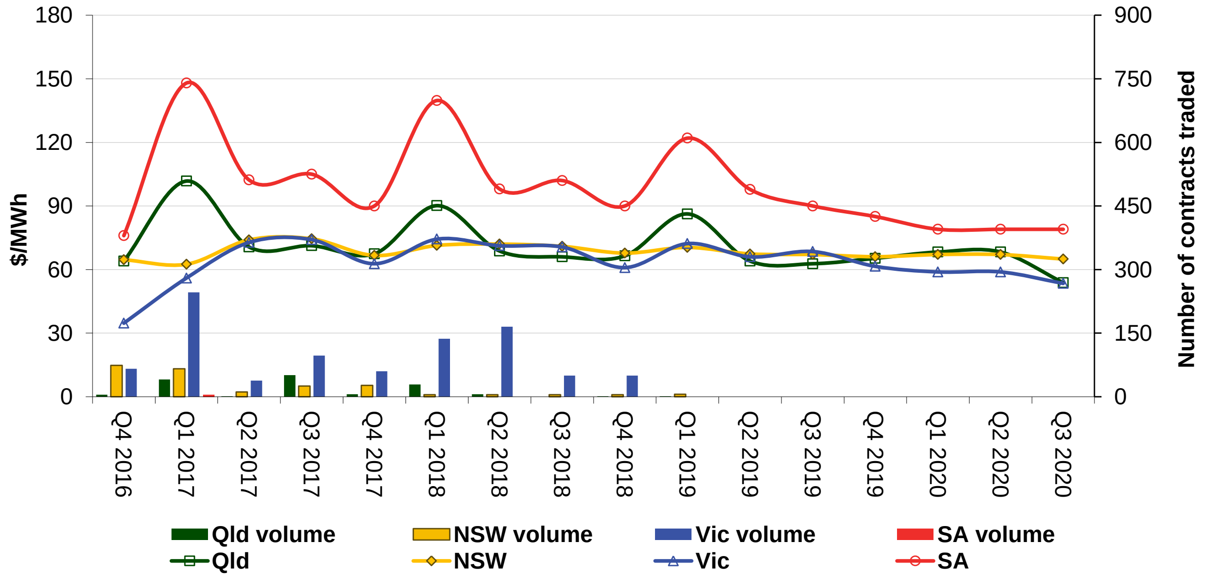
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
10 am	263.33	79.99	79.99	1400	1399	1322	1728	1850	2023

Conditions at the time saw demand close to forecast and available capacity around 120 MW lower than forecast four hours ahead. There was no capacity priced between $80/MWh and $300/MWh. At 9.35 am demand increased by around 28 MW, imports from Victoria decreased by around 13 MW and the price went to $300/MWh for the majority of the 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.

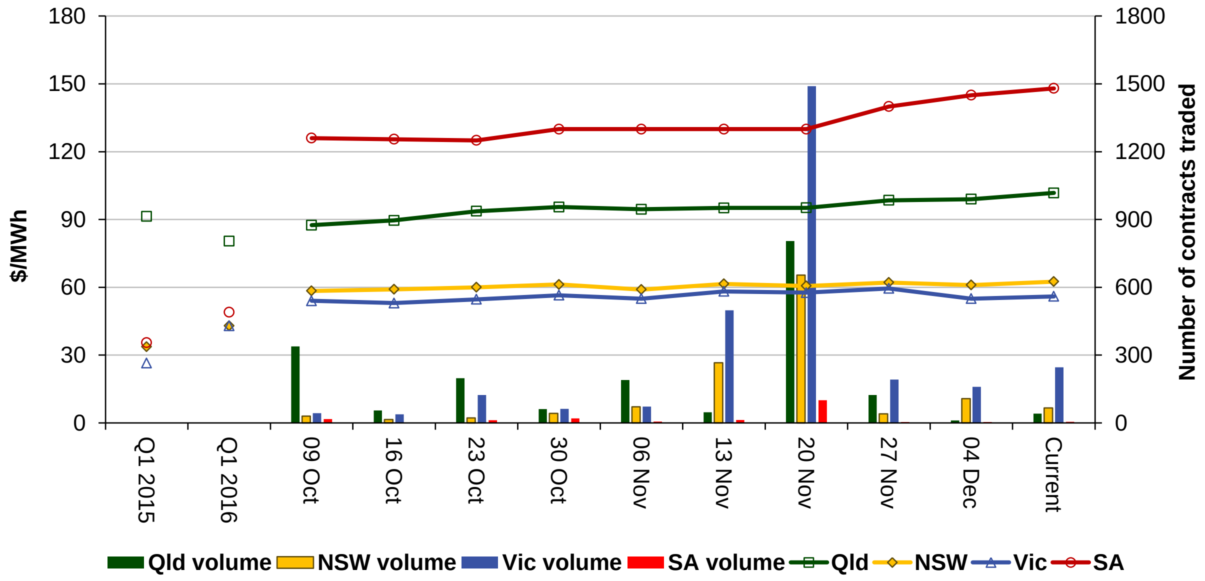
Figure 9: Quarterly base future prices Q4 2016 – Q3 2020



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional quarter 1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 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 2017 base contracts over the past 10 weeks (and the past 2 years)



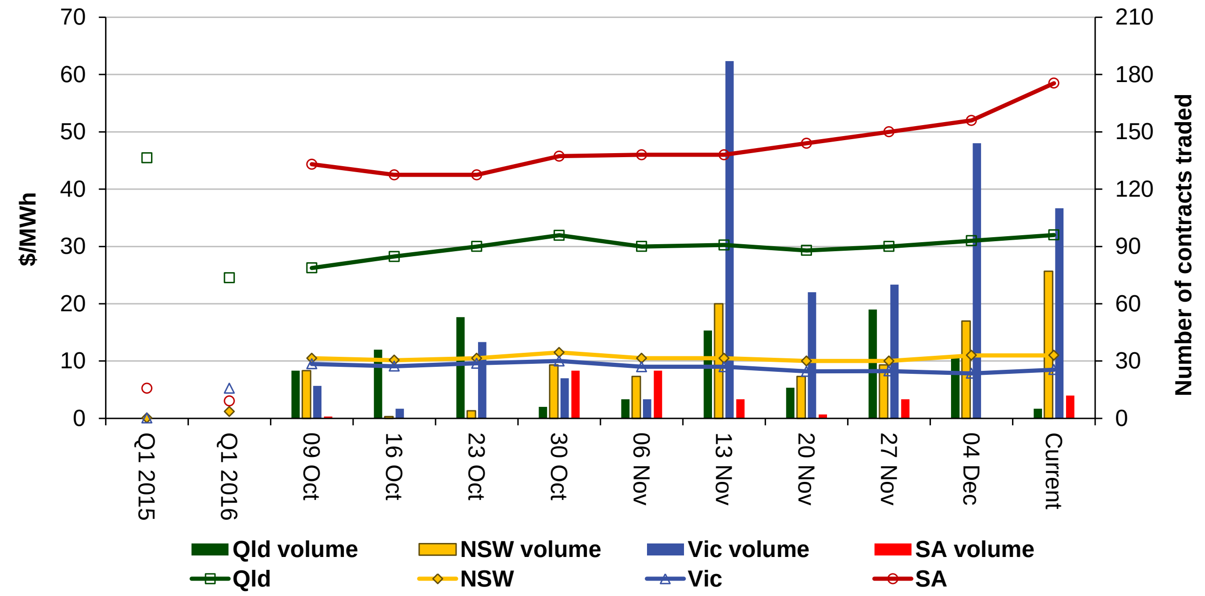
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
May 2017