Electricity Report

AUSTRALIAN ENERGY REGULATOR

18 – 24 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 18 – 24 December 2016.

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

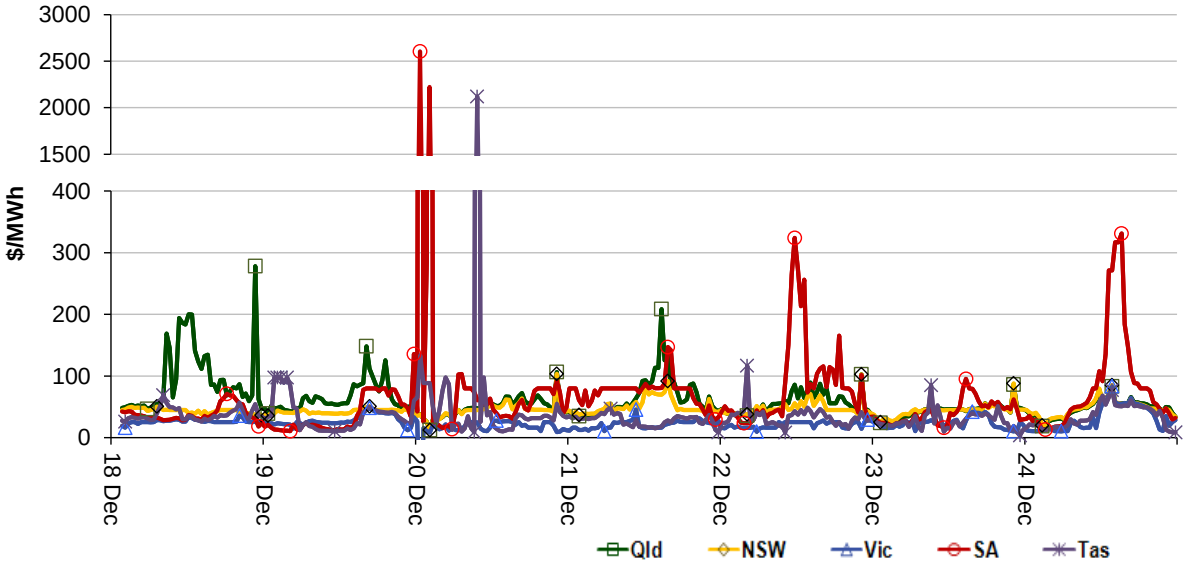


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

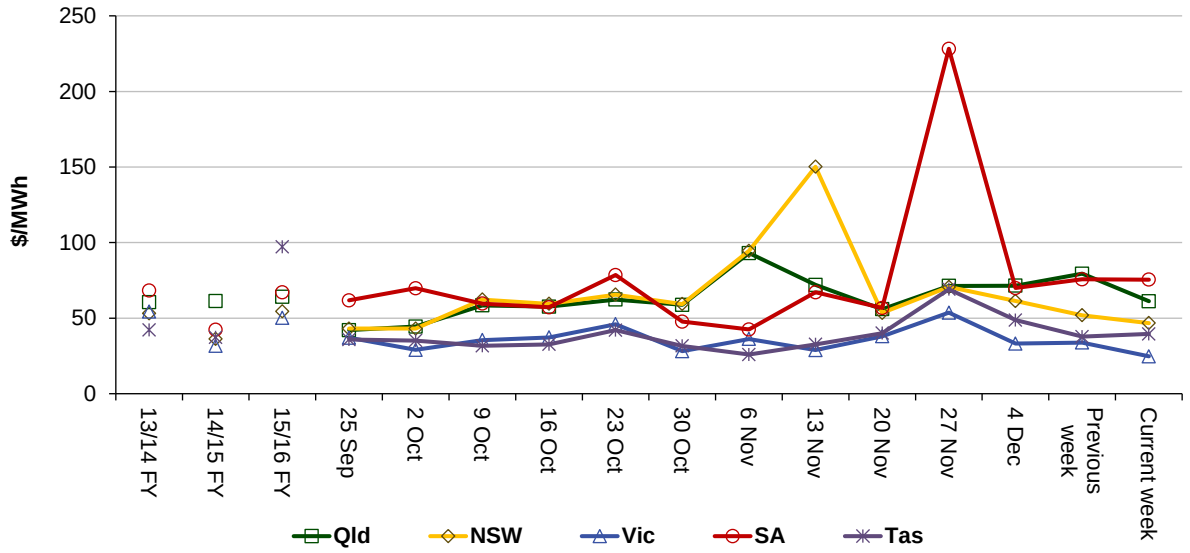


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	61	47	25	75	40
15-16 financial YTD	44	46	41	63	56
16-17 financial YTD	60	62	45	109	47

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	3	33	1	2
% of total below forecast	28	30	0	4

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

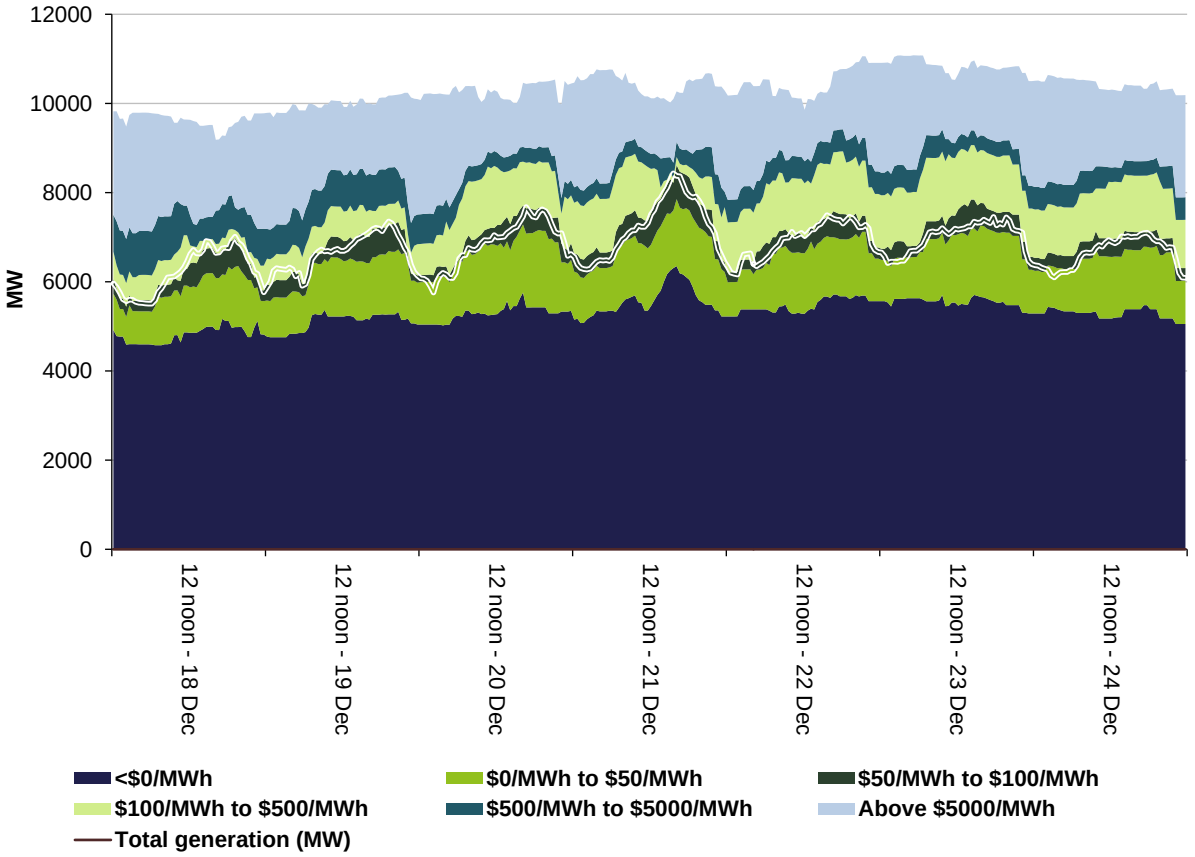


Figure 4: New South Wales generation and bidding patterns

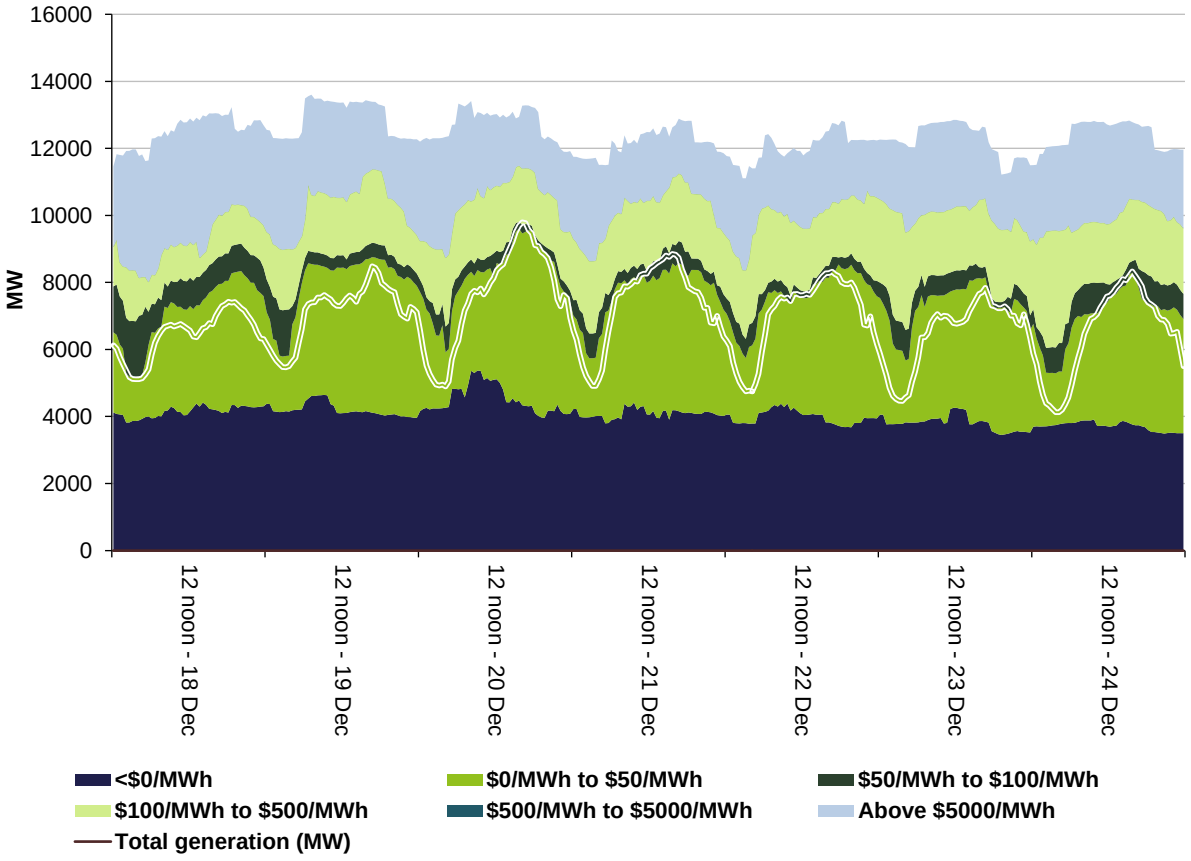


Figure 5: Victoria generation and bidding patterns

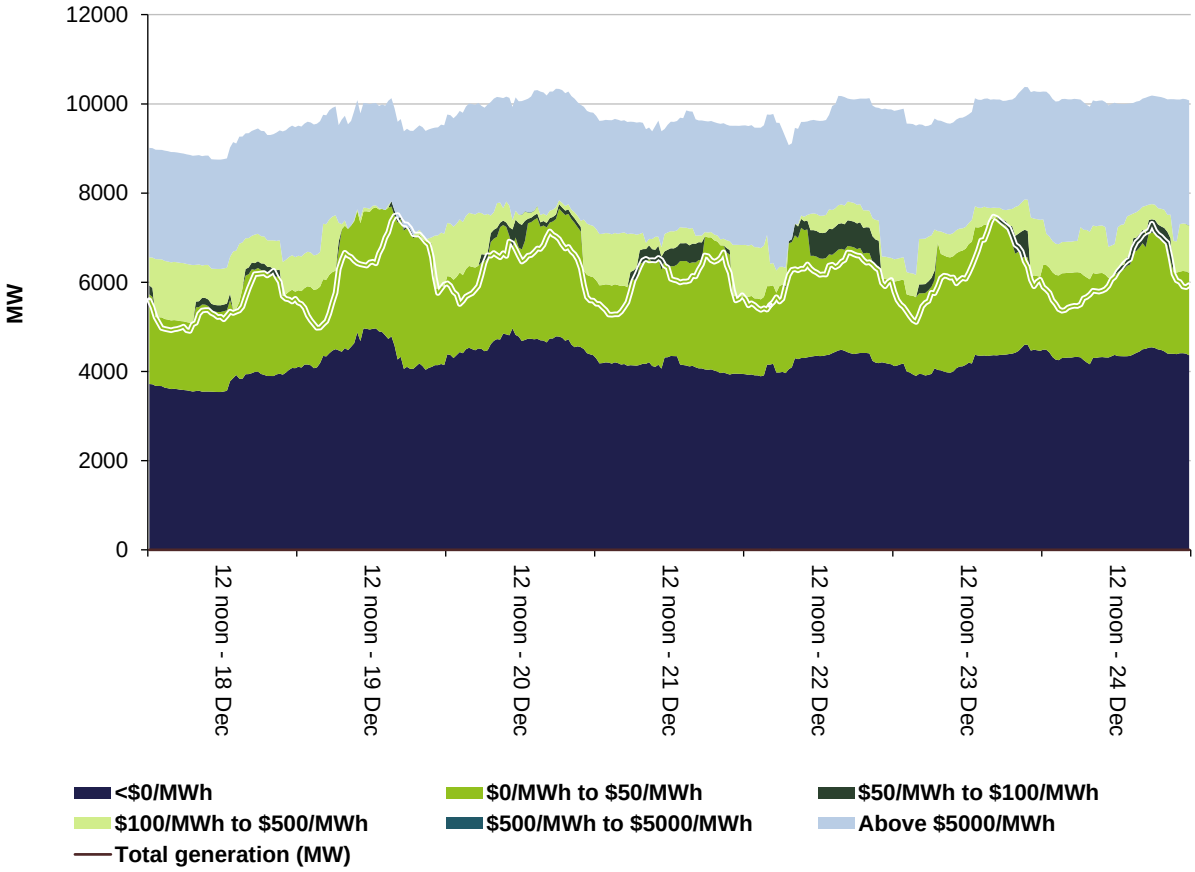


Figure 6: South Australia generation and bidding patterns

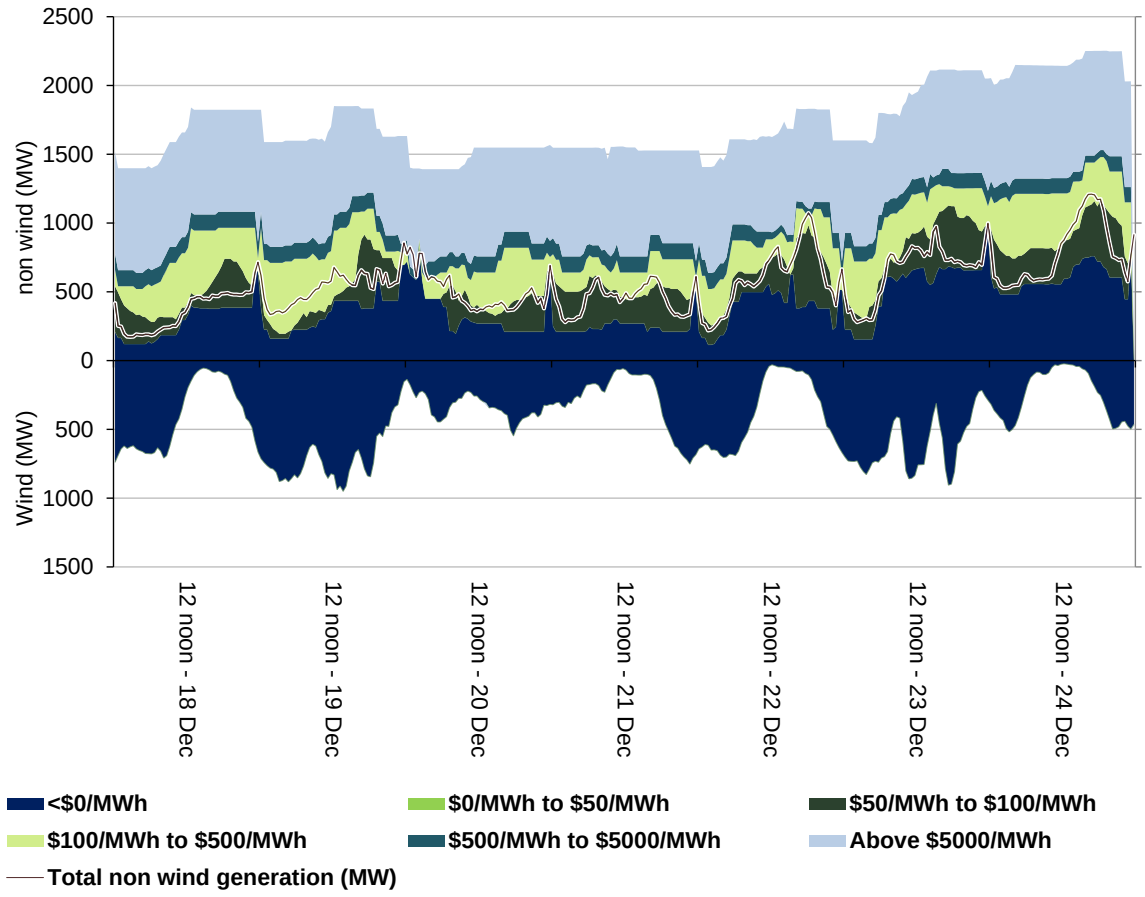
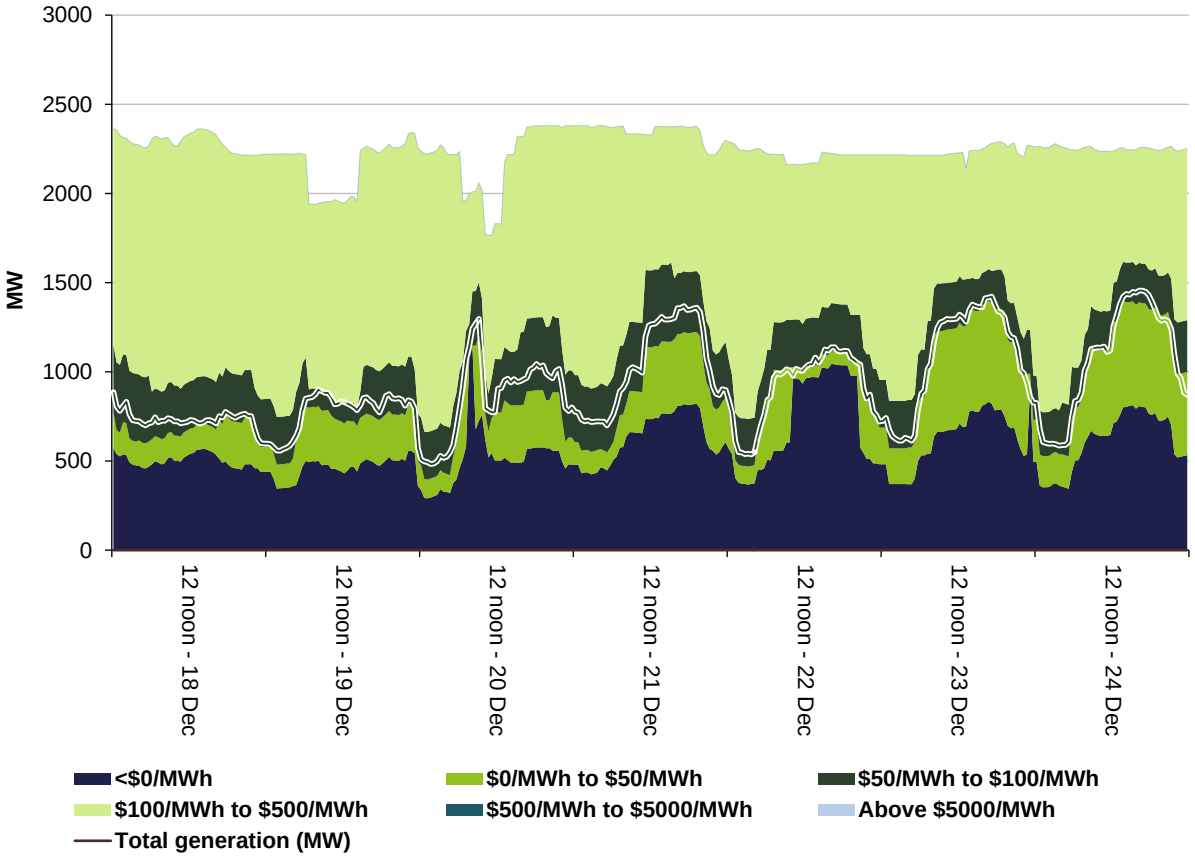


Figure 7: Tasmania generation and bidding patterns



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.

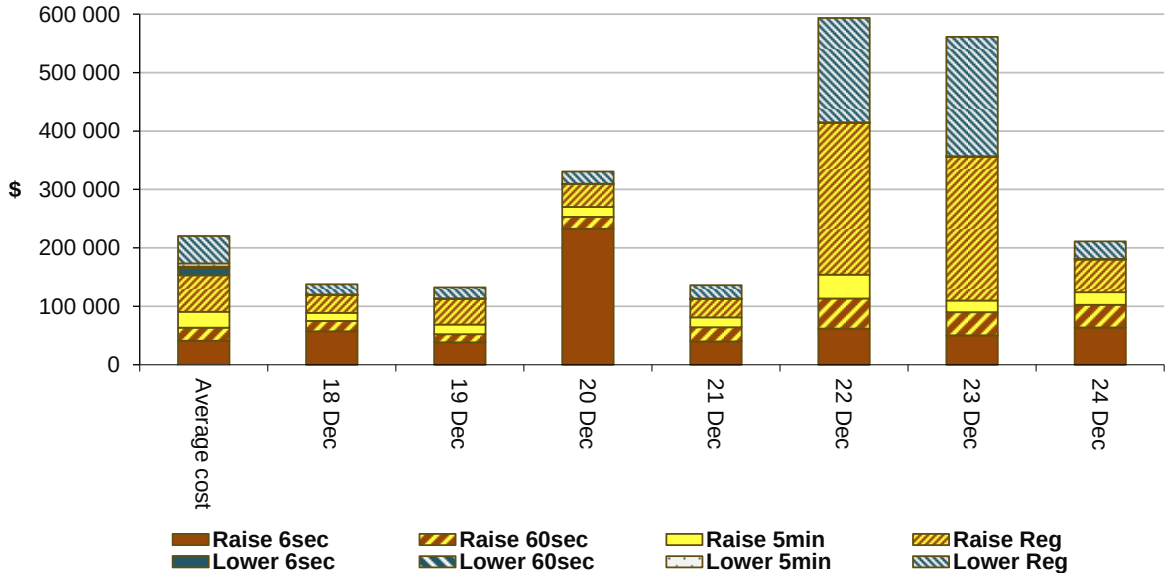
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 633 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $469 500 or around seven 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



Two unplanned outages in Victoria on the Heywood to Tarrone 500 kV line on 22 December and the Moorabool to Mortlake 500 kV line on 23 December created a single contingency which if occurs separates South Australia from the rest of the NEM. AEMO invoked a requirement for 35 MW of local raise and lower regulation services in South Australia on both days which resulted in high priced regulation services on both days.

Detailed market analysis of significant price events

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $61/MWh and above $250/MWh.

Sunday, 18 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
11 pm	278.04	423.12	423.13	6284	6252	6414	9776	9746	9911

Conditions at the time saw demand and availability close to forecast four hours prior.

The lower than forecast price was a result of rebidding, by several Queensland participants, of around 450 MW of capacity from high to low prices within four hours of the trading interval commencing.

Victoria

There was one occasion where the spot price in Victoria was below -$100/MWh.

Tuesday, 20 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
1 am	-150.11	25.2	16.2	4084	4205	4139	9746	9629	9910

Conditions at the time saw demand 121 MW below forecast and availability 117 MW above forecast four hours ahead. At 12.55 am a system normal constraint designed to manage system security in South Australia on the loss of the Heywood interconnector violated. The constraint reduced exports from Victoria to South Australia by around 170 MW, this in turn led to a reduction in local Victorian generation. As a result the price fell to the floor at 12.55 am.

South Australia

There were twelve occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $75/MWh and above $250/MWh.

Tuesday, 20 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
1 am	2604.47	62.49	79.99	1278	1322	1298	1579	1705	1695
2 am	285.95	79.99	79.99	1129	1176	1192	1667	1751	1761
2.30 am	2223.87	79.99	79.99	1123	1148	1177	1628	1763	1789

Conditions at the time saw demand close to forecast and availability up to 135 MW below that forecast four hours ahead.

As discussed above in the Victoria section, at 12.55 am a system normal constraint violated and exports from Victoria into South Australia decreased. This resulted in high priced generation required to meet demand for the last two dispatch intervals of the 1 am trading interval.

At 1.47 am there was an unplanned outage on the Murraylink interconnector reducing imports into South Australia by 122 MW by 2 am. With low-priced generation ramp rate limited the reduction in imports and an increase in demand at 1.55 am resulted in the dispatch of high priced capacity and the dispatch price reaching $1498/MWh.

At 2.05 am demand increased by around 30 MW while wind generation decreased by around 25 MW. With low-priced capacity ramp rate limited, fully dispatched or trapped in FCAS the price increased to $13 300/MWh.

The price decreased to previous levels at 2.10 am after participants rebid capacity from high to low prices and demand decreased by around 35 MW.

Thursday, 22 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
11.30 am	264.22	79.99	79.99	1204	1174	1162	1710	1813	1753
Midday	323.81	79.99	79.99	1196	1182	1178	1670	1771	1728
12.30 pm	272.5	79.99	81.49	1222	1189	1204	1656	1754	1710
1.30 pm	256.07	81.48	84.3	1278	1264	1251	1698	1773	1732

Conditions at the time saw demand slightly higher than forecast, while available capacity was up to 103 MW below that forecast four hours ahead.

Actual wind generation was between 80 MW and 100 MW lower than that forecast four hours ahead, leading to the dispatch of higher priced capacity in its place.

Saturday, 24 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
1.30 pm	271.07	59.99	59.99	1707	1381	1380	2181	2271	2283
2 pm	271.32	62.64	61.59	1749	1424	1394	2199	2295	2311
2.30 pm	316.91	79.99	49.26	1775	1461	1431	2231	2298	2350
3 pm	316.77	79.99	64.01	1824	1545	1478	2230	2307	2373
3.30 pm	331	79.99	65.03	1870	1607	1506	2252	2388	2465

Conditions at the time saw demand up to 326 MW higher than forecast. Available capacity was up to 136 MW lower than forecast four hours ahead mainly due to lower than forecast wind generation (between 70 MW and 100 MW).

Due to the higher than forecast demand and lower than forecast availability, higher priced generation was required to meet demand.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $40/MWh and above $250/MWh.

Tuesday, 20 December

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
10 am	2120.26	8.66	10.27	958	920	949	2075	2072	2074

Conditions at the time saw demand and available capacity close to forecast levels.

The high price was driven by network constraints on the Hadspen to Georgetown No. 1 220 kV line. The constraint affects all Tasmanian generation except for generation at Tamar Valley.

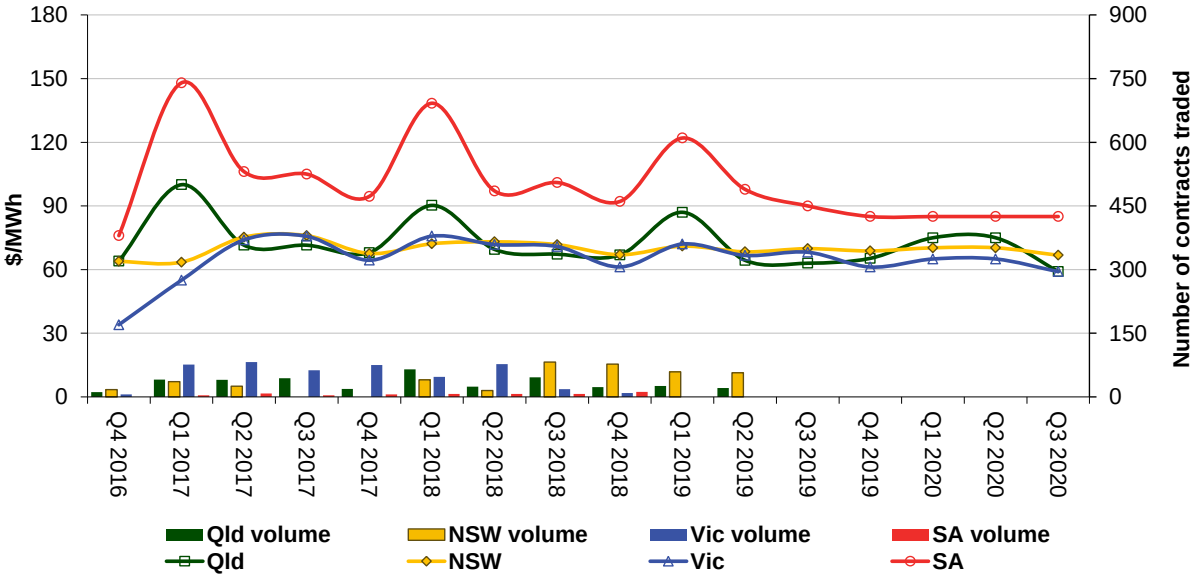
At 9.45 am the constraint bound and reduced local generation and flows across Basslink switched from exporting 122 MW into Victoria at 9.40 am to importing 154 MW at 9.45 pm. With cheaply priced generation constrained off or ramp rate limited, the price reached $12 678/MWh.

The price returned to previous levels for the remainder of the trading interval as the constraint was no longer binding.

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.

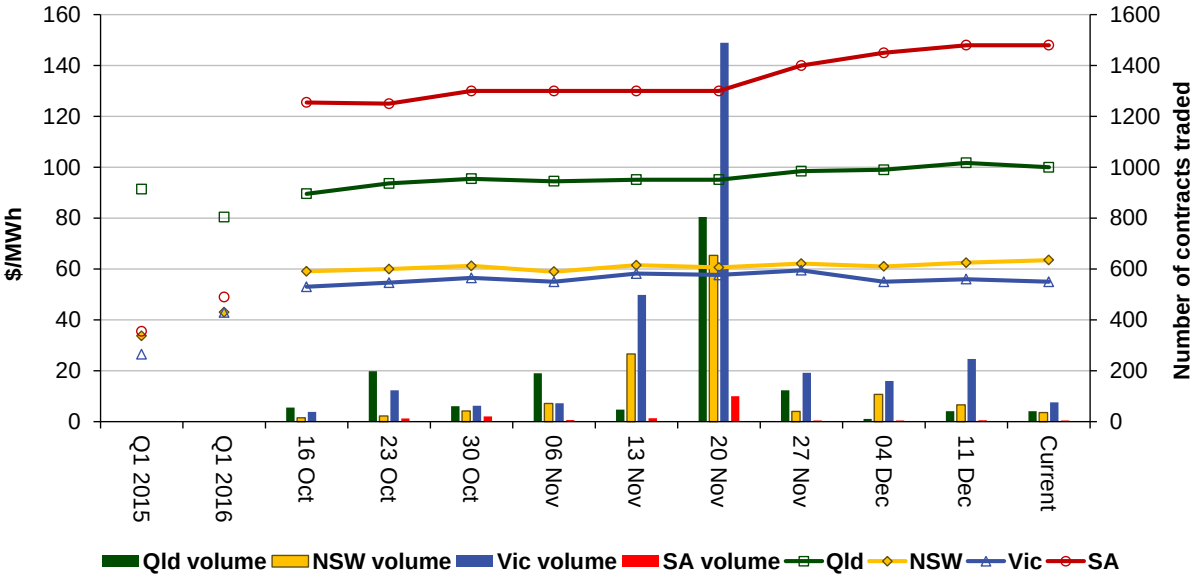
Figure 9: Quarterly base future prices Q4 2016 – Q3 2020



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)



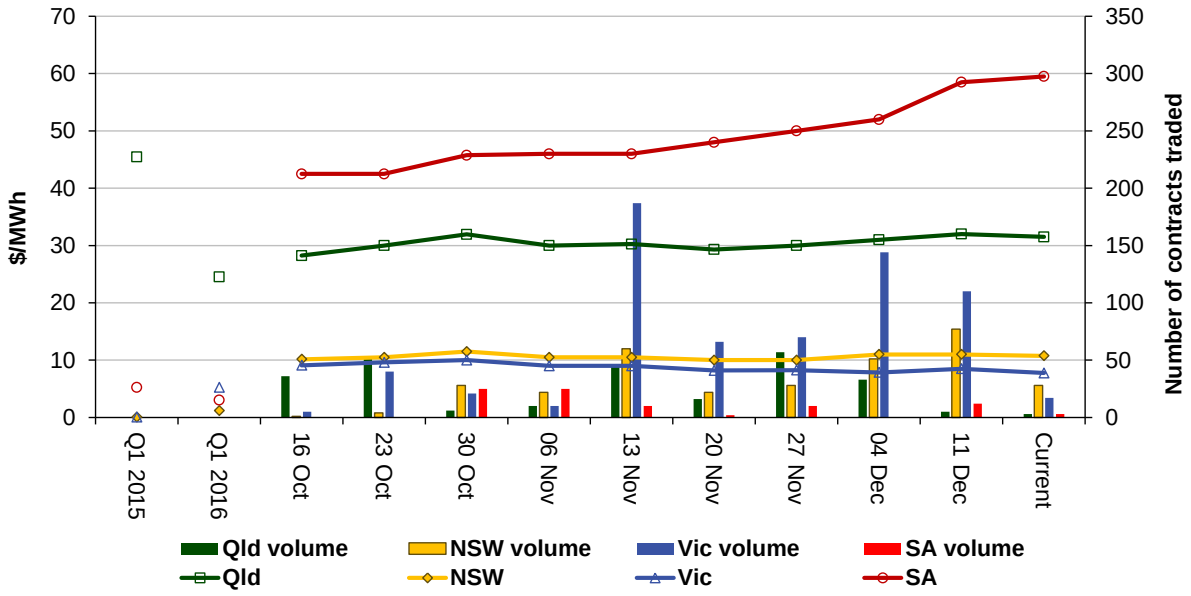
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
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