Electricity Report

AUSTRALIAN ENERGY REGULATOR

13 – 19 December 2015

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 13 to 19 December 2015. There were nine occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $83/MWh and above $250/MWh. There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $125/MWh and above $250/MWh. There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $91/MWh and above $250/MWh and one occasion where the spot price was below $-100/MWh.

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

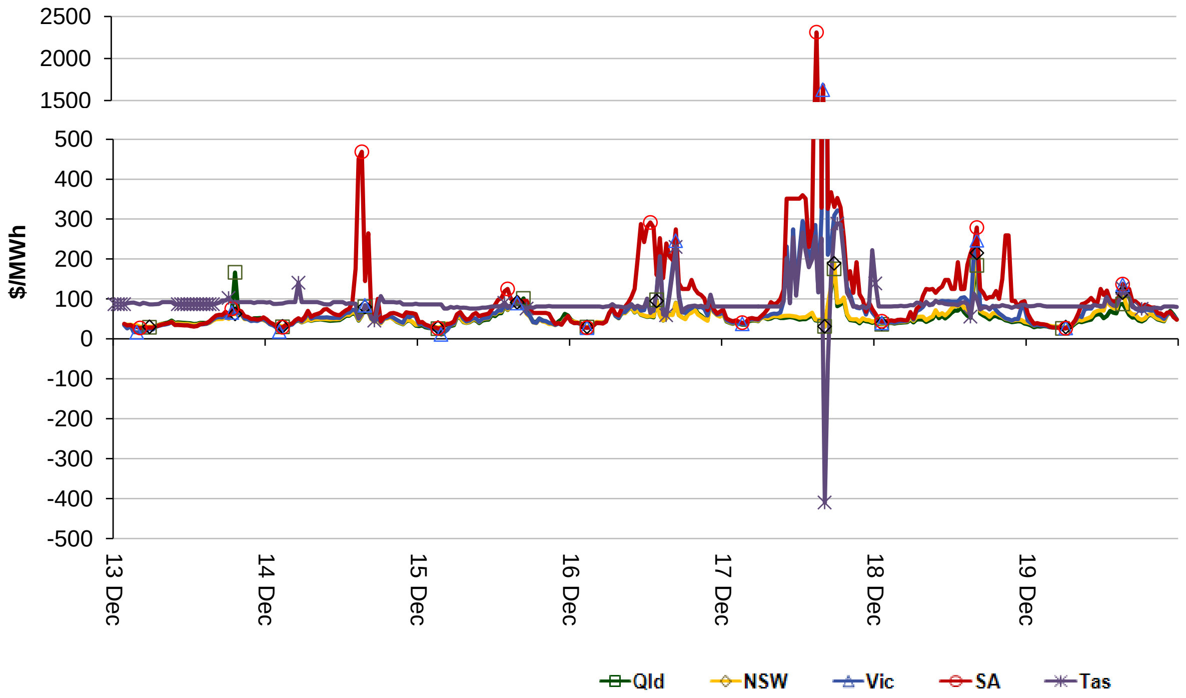


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

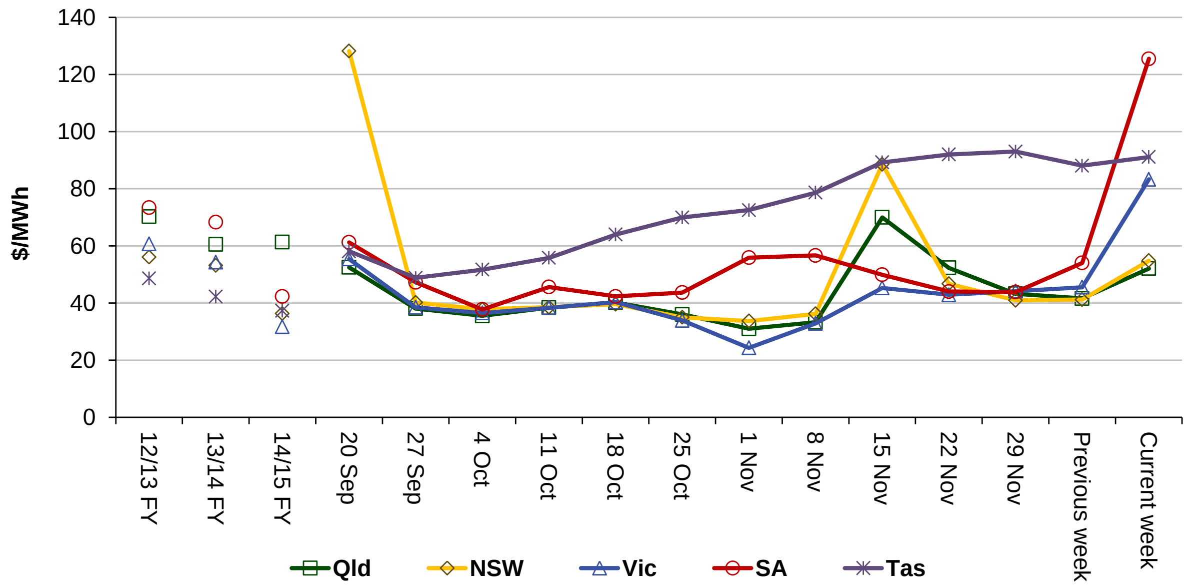


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	52	55	83	125	91
14-15 financial YTD	53	37	34	41	38
15-16 financial YTD	44	46	41	63	54

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 190 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2014 of 71 counts and the average in 2013 of 97. 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	5	57	0	2
% of total below forecast	26	6	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.

The red ellipses in Figures 5, 6 and 7 show where rebidding to the price floor led to dispatch prices close to or at the floor.

Figure 3: Queensland generation and bidding patterns

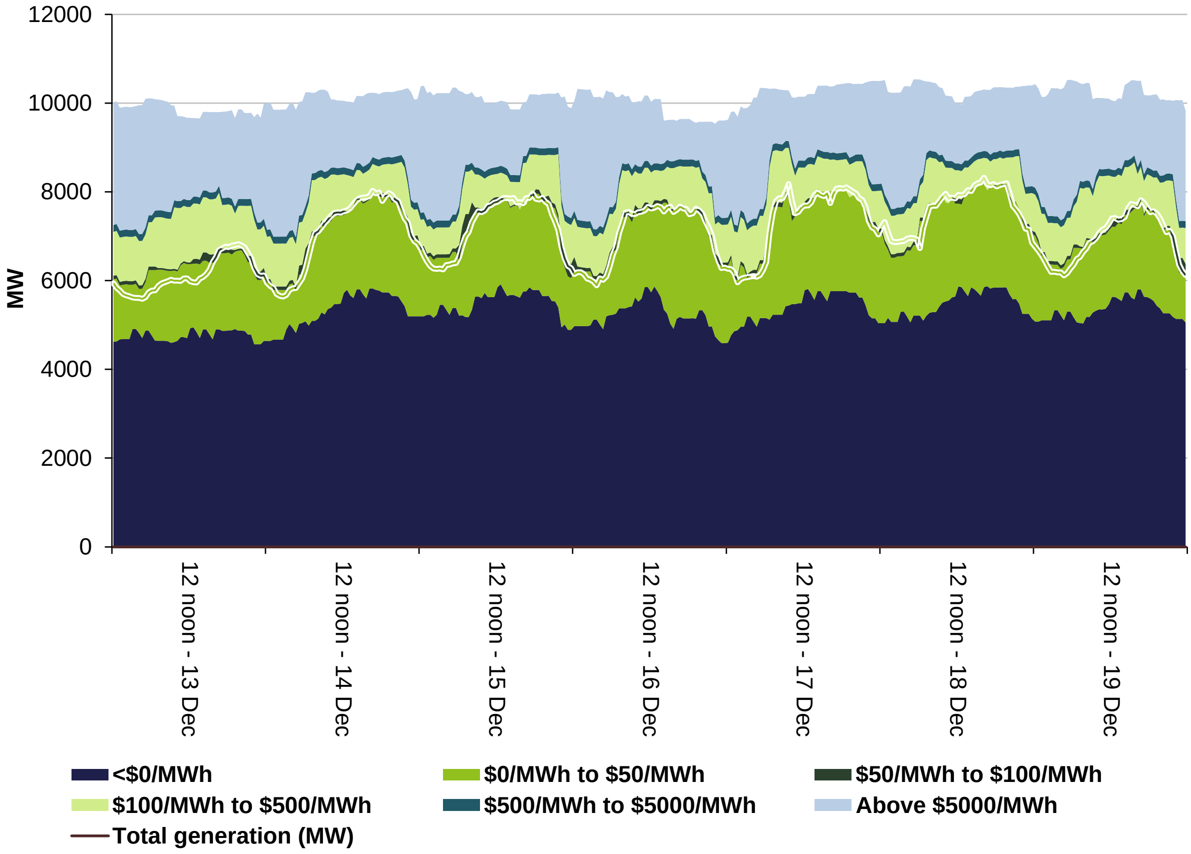


Figure 4: New South Wales generation and bidding patterns

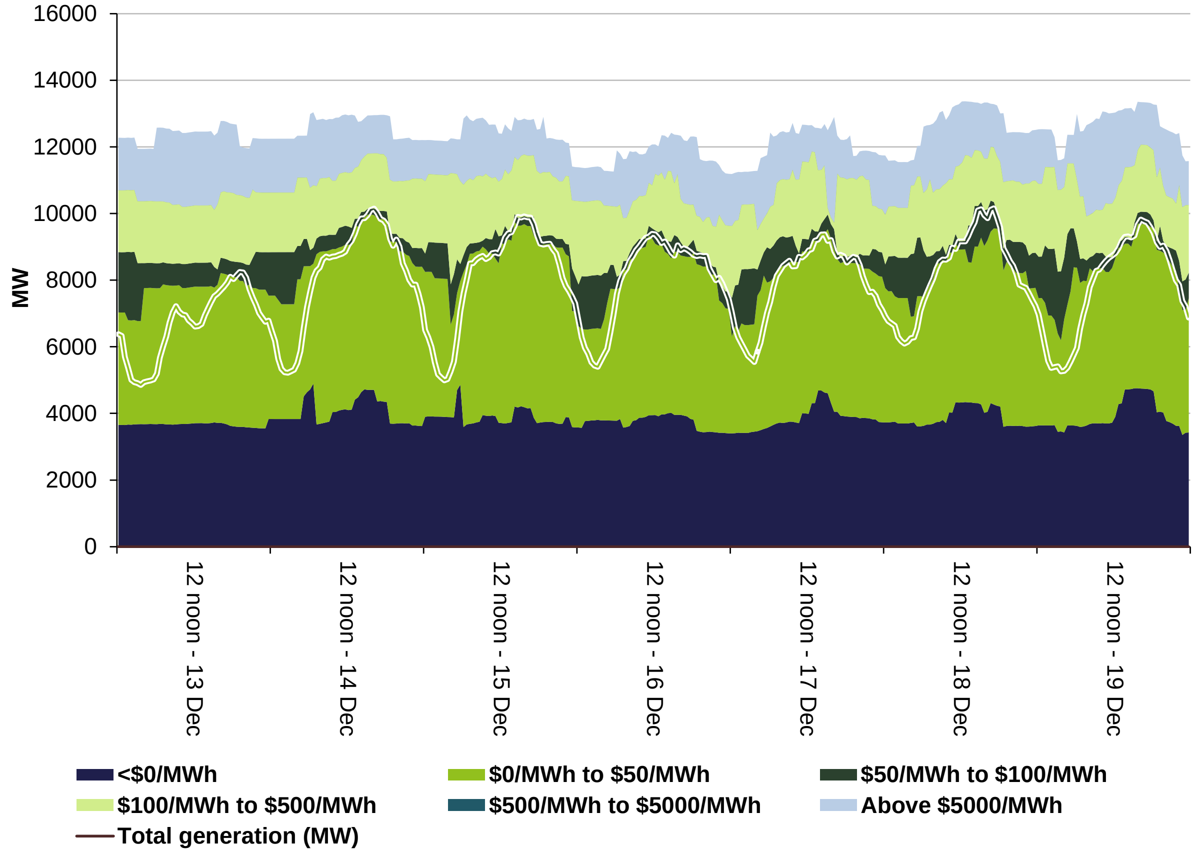


Figure 5: Victoria generation and bidding patterns

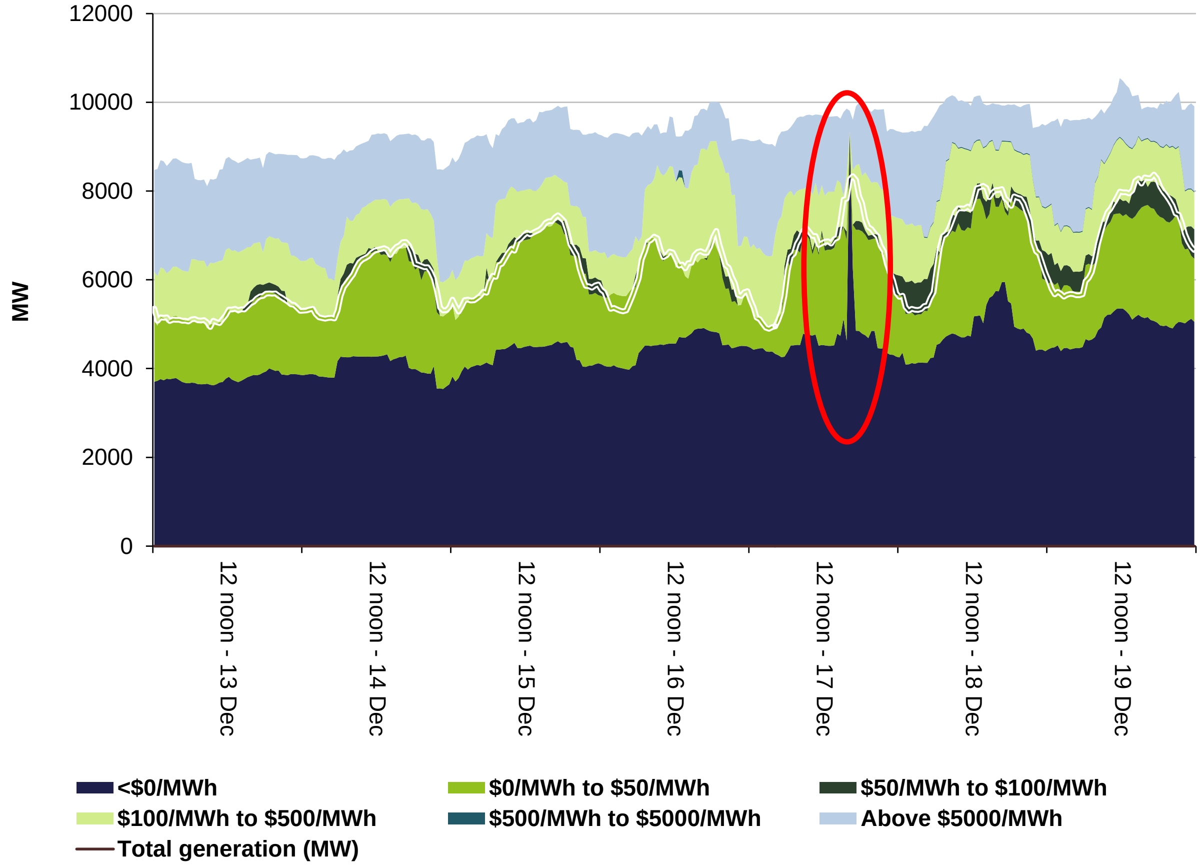


Figure 6: South Australia generation and bidding patterns

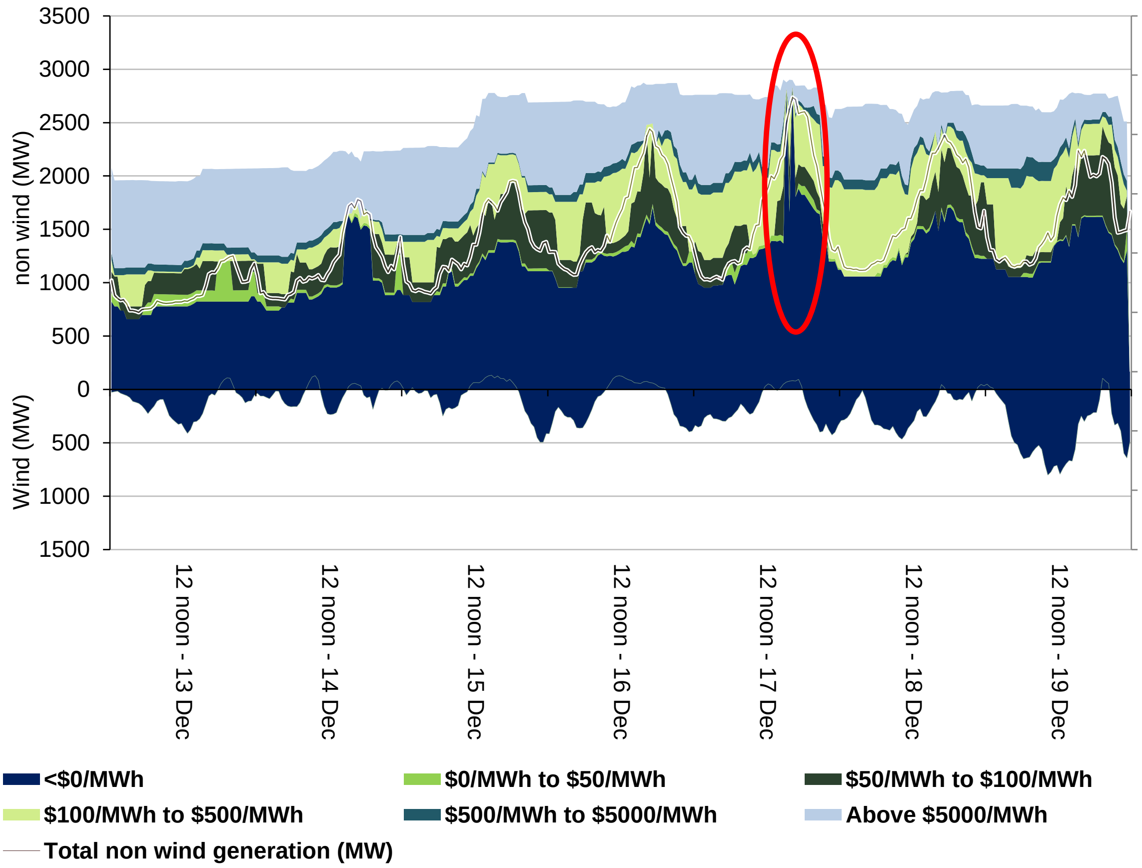
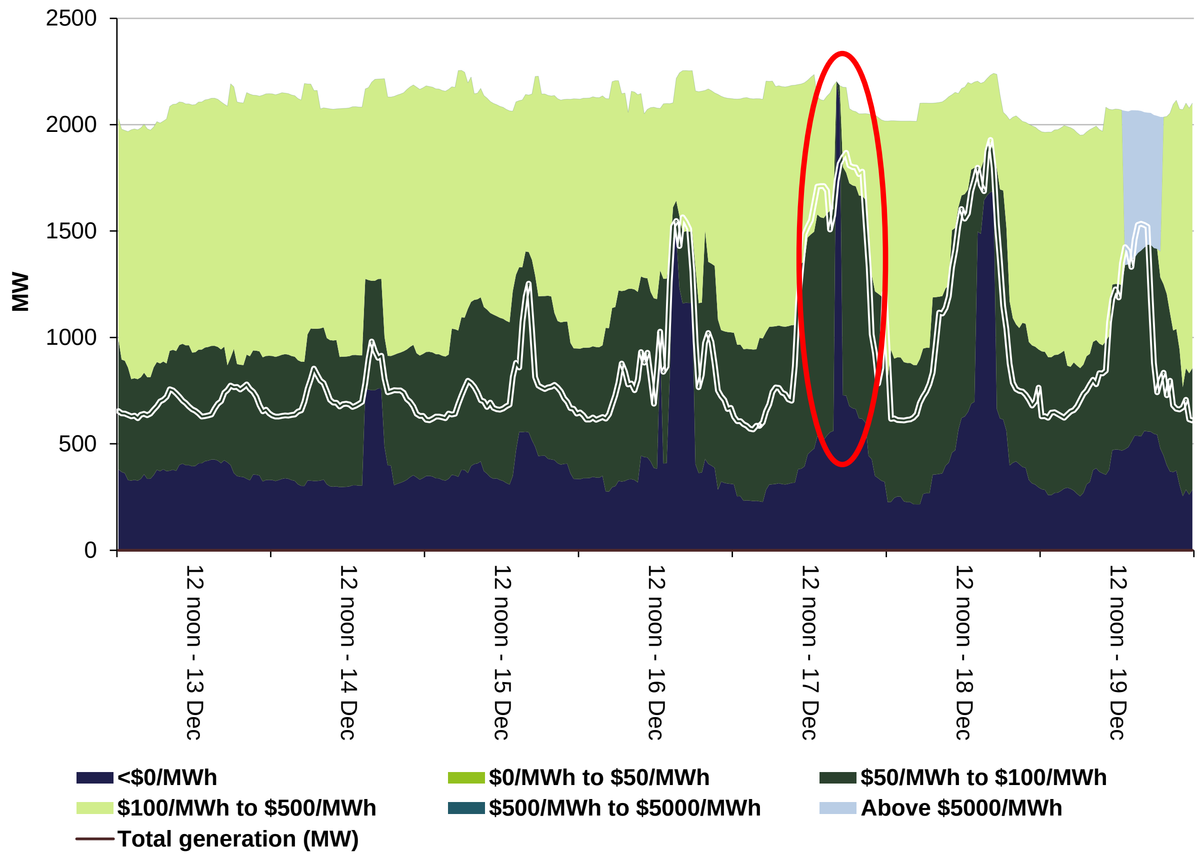


Figure 7: Tasmania generation and bidding patterns



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.

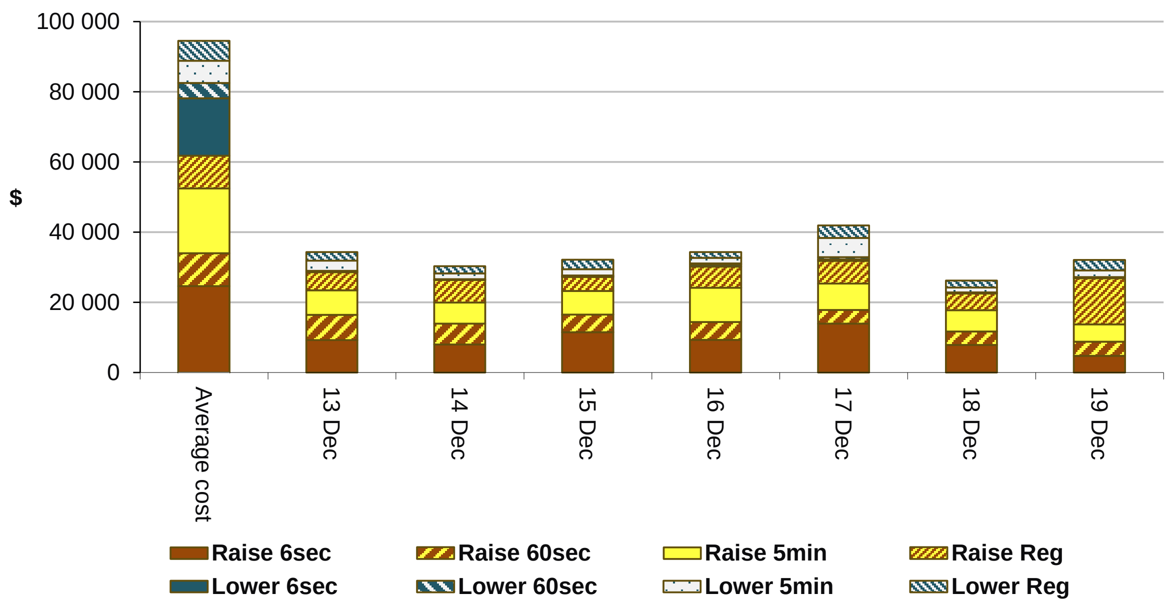
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $160 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $71 000 or less than 1 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

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above $250/MWh or was below -$100/MWh.

Victoria

There were nine occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $83/MWh and above $250/MWh.

Thursday, 17 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
11.30 am	273.96	82.05	80.81	6887	6686	6938	9719	9645	9856
1 pm	295.12	94.69	93.36	7430	7276	7344	9678	9777	9546
1.30 pm	271.87	85.71	83.00	7559	7392	7501	9672	9774	9552
3 pm	285.21	74.85	82.47	8010	7772	7825	9648	9887	9880
4 pm	312.49	82.25	95.46	8407	8023	8174	9829	9907	9886
4.30 pm	1626.30	90.47	95.46	8415	8078	8176	9847	9928	9889
6 pm	309.47	83.93	102.85	8271	7731	7683	9975	9950	9923
6.30 pm	321.64	279.59	100.75	8115	7480	7405	10 026	9970	9941
7 pm	321.11	81.01	81.84	7955	7301	7207	9949	9973	9941

Available capacity was close to forecast. Across the high priced trading intervals, demand was between 154 MW and 654 MW higher than forecast four hours ahead. Forecasts half an hour and one hour ahead also varied materially. Wind generation in Victoria increased gradually from about 55 MW at 11 am to 250 MW by 5 pm and remained at about that level until 7 pm.

Table 4: Rebids

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.59 am	11.05 am	Ecogen Energy	Newport	50	59	13 051	10:58 P ADJ BANDS DUE TO DWGM DEV POSN - WUGS ISSUES SL
11.01 am	11.10 am	Origin Energy	Mortlake	248	-1000	13 800	1100P MANAGEMENT OF FUEL AND LINEPACK SL

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
12.16 pm		AGL Energy	Loy Yang A	120	32	500	1210~A~040 CHG IN AEMO DISP~45 PRICE INCREASE VS PD VIC $249.05 VS $90.70
12.41 pm		Origin Energy	Mortlake	248	-1000	13 800	1240P MANAGEMENT OF FUEL AND LINEPACK SL
1.47 pm		Snowy Hydro	Murray	1229	-1000	>300	13:46 A VIC: 5MPD PRICE $34.21 LWR THN 30MPD 14:35@13:32
3.49 pm	4.00 pm	Origin Energy	Mortlake	248	-1000	13800	1549P MANAGEMENT OF FUEL AND LINEPACK SL
3.57 pm	4.05 pm	Snowy Hydro	Murray	532	300	13794	15:56 A VIC: 5MPD PRICE $52.04 LWR THN 30MPD 16:05@15:32
4.06 pm	4.15 pm	Snowy Hydro	Murray	1532	>35	-1000	16:05 A VIC: ACT PRICE $13,173.23 HGR THN 5MPD 16:05@15:56
4.06 pm	4.15 pm	Origin Energy	Mortlake	248	13800	-1000	1605A UNFORECAST MPC EVENT SL
4.09 pm	4.20 pm	Snowy Hydro	Valley Power	285	13800	-1000	16:05 A VIC: ACT PRICE $13,173.23 HGR THN 5MPD 16:05@15:56

The combination of the demand forecast error and the above rebidding saw the dispatch price at around $300/MWh for a majority of the high price periods.

At 4.05 pm, following Snowy Hydro's rebid at Murray, the dispatch price reached the price cap. Generators immediately responded by rebidding capacity into lower prices. This caused the price to fall to $55/MWh at the 4.10 pm dispatch interval. The price continued to decline and reached the price floor (-$1000/MWh) for the final three dispatch intervals. This low price was replicated in Tasmania

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $125/MWh and above $250/MWh.

Monday, 14 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
3 pm	450.35	76.50	80.30	2040	1915	1813	2420	2620	2702
3.30 pm	468.27	94.99	94.99	2063	1949	1849	2350	2636	2682

Conditions at the time saw demand over 100 MW higher than forecast four hours ahead. Available capacity was over 200 MW lower than forecast four hours ahead.

A system normal constraint avoiding the overload of the Keith to Tailem Bend No.1 line was binding, which constrained off low-priced generation in the South East of South Australia and limited exports into South Australia across Heywood to around 300 MW.

At 2.35 pm, demand increased by 70 MW largely due to a reduction in non-scheduled generation. With other low-priced generation either ramp rate limited or trapped in FCAS the dispatch price reached to $2384/MWh. The dispatch price fell to $56/MWh at 2.40 pm following rebidding by GDF Suez from high prices to low prices and a reduction in demand of 97 MW (largely due to an increase in non-scheduled generation).

At 3.10 pm, demand increased by 152 MW, again largely due to a reduction in non-scheduled generation, resulting in a dispatch price of $2410/MWh.

The dispatch price fell to $55/MWh following rebidding by multiple participants and a 153 MW decrease in demand (largely due to an increase in non-scheduled generation). The dispatch price remained below $91/MWh for the remainder of the trading interval.

Thursday, 17 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
3 pm	863.88	124.99	97.54	2681	2676	2555	2962	3031	2997
3.30 pm	2310.06	124.99	124.99	2700	2739	2621	2978	3092	3038
4.30 pm	1682.40	260.69	124.99	2840	2817	2707	2980	3082	3070

Demand and available capacity were close to that forecast four hours ahead. Wind generation was low at around 150 MW. Demand on the day exceeded 3000 MW for the first time since February 2014.

Prices were generally aligned with those in Victoria (analysis of Victoria's high prices on this day is earlier in this report) except for the 3 pm and 3.05 pm dispatch intervals.

At 3 pm a system normal constraint avoiding the overload of the Keith to Tailem Bend No.1 line was constraining off low-priced generation in the South East of South Australia. There was also a 96 MW increase in demand (largely due to a reduction in non-scheduled generation). This resulted in the dispatch price reaching $3458/MWh at 3 pm.

At 2.56 pm, effective from 3.05 pm, Alinta rebid 120 MW of capacity at Northern from prices below zero to $13 330/MWh. The reason given was "1455~A~dispatch $3458 v $357.47~". This resulted in Northern setting the price at $13 330/MWh at 3.05 pm.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $91/MWh and above $250/MWh and one occasion where the spot price was below -$100/MWh.

Thursday, 17 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
4.30 pm	-410.38	84.77	88.31	1090	1141	1148	2203	2267	2261
6.30 pm	288.12	287.37	99.54	1208	1127	1169	2076	2057	2161
7 pm	286.93	84.77	84.77	1194	1130	1170	2066	2054	2157

Conditions at the time saw demand and available capacity close to forecast four hours ahead during all three trading intervals.

During the 4.05 pm dispatch interval, the dispatch price in Victoria reached the price cap. At 4.05 pm, flows on the Basslink interconnector increased by 101 MW (to 515 MW) towards Victoria and the Tasmanian dispatch price reached $1197/MWh. Prices in Tasmania and Victoria were effectively aligned from 4.10 pm.

At 4.08 pm, effective from 4.15 pm, Hydro Tasmania rebid 1380 MW of available capacity across its portfolio from prices above -$75/MWh to the price floor (reason: "1610A Bassllink export flow less than forecast.") and the dispatch price dropped to -$709/MWh for the 4.15 pm dispatch interval.

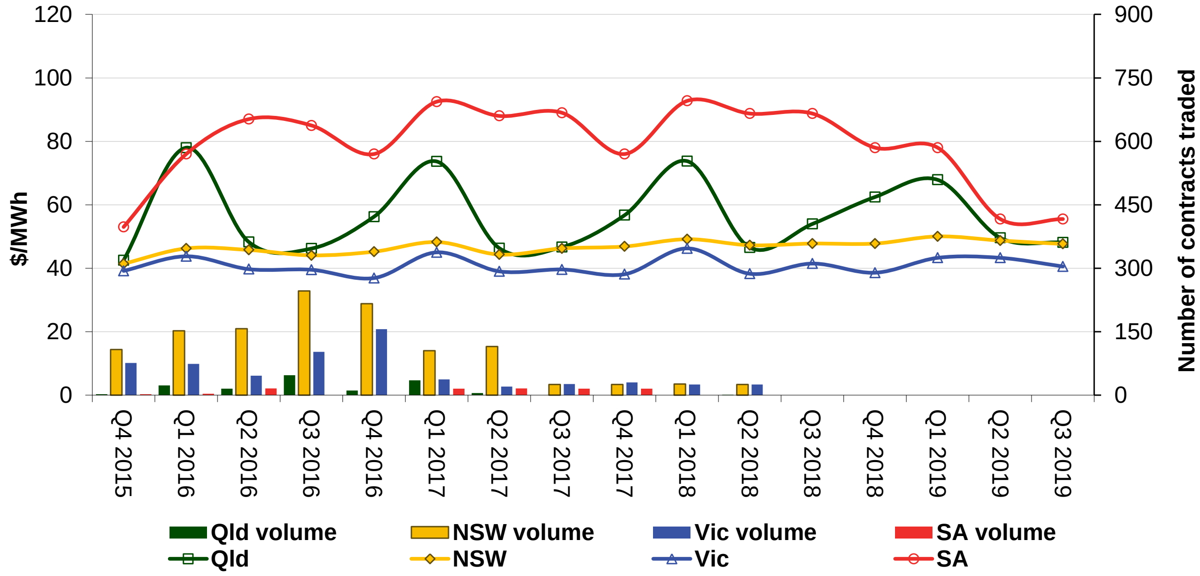
At 4.13 pm, effective from 4.20 pm, Hydro Tasmania rebid 365 MW of available capacity at Gordon, John Butters, and Poatina from prices above -$75/MWh to the price floor (reason:"1615A Basslink export flow less than forecast.") and the dispatch price effectively hit the price floor for the rest of the trading interval. Prices in Tasmania increased to -$62/MWh for the 5 pm trading interval when these rebids expired.

Prices were aligned between Victoria and Tasmania for the 6.30 pm and 7 pm trading intervals and Basslink was flowing into Victoria at between 450 MW and 502 MW (four hours ahead it was forecast to be flowing from Victoria).

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.

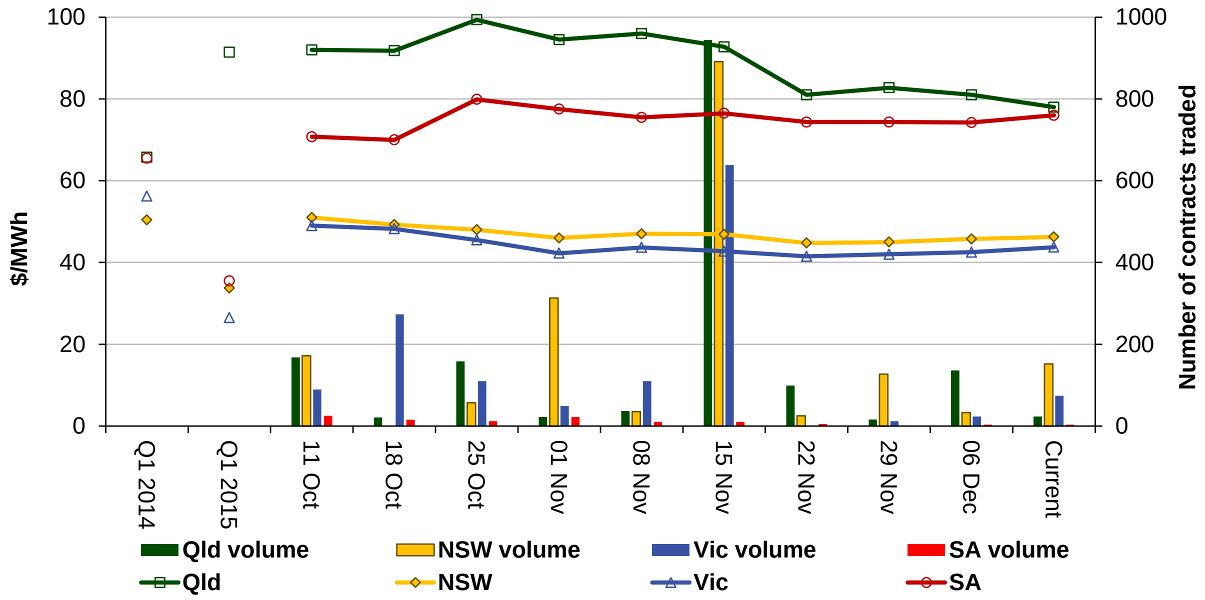
Figure 9: Quarterly base future prices Q4 2015 – Q3 2019



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades. The high volume of trades in Figure 9, 10, and 11 are due to options on calendar year base load expiring on Thursday 19 November.

Figure 10: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



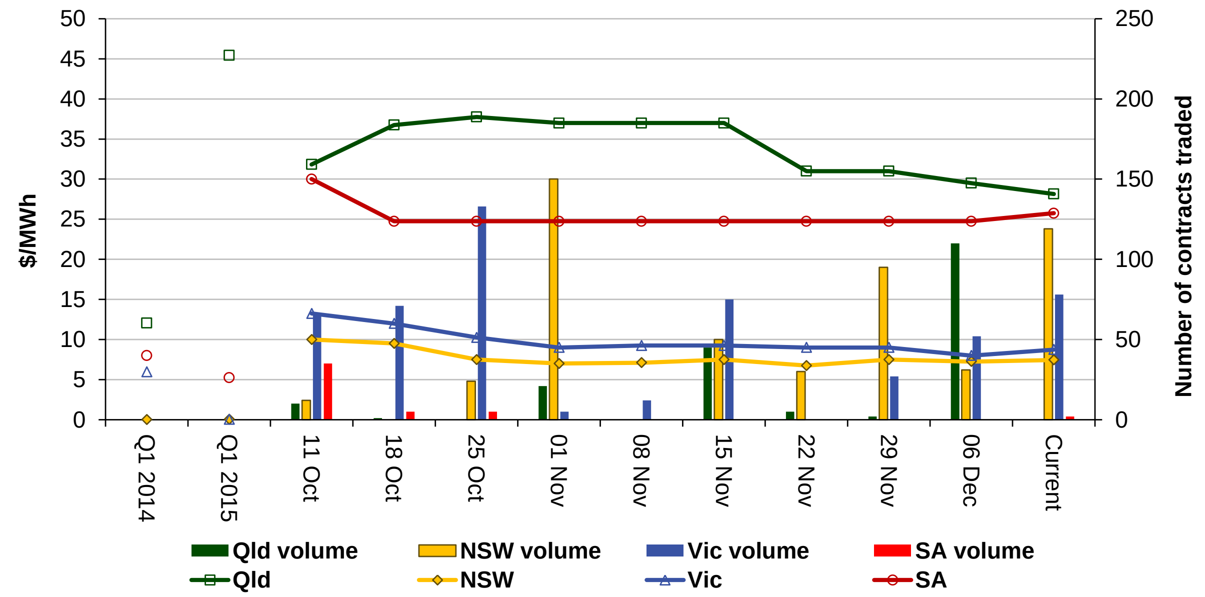
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au