Electricity Report

AUSTRALIAN ENERGY REGULATOR

29 October – 4 November 2017

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 29 October - 4 November 2017.

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

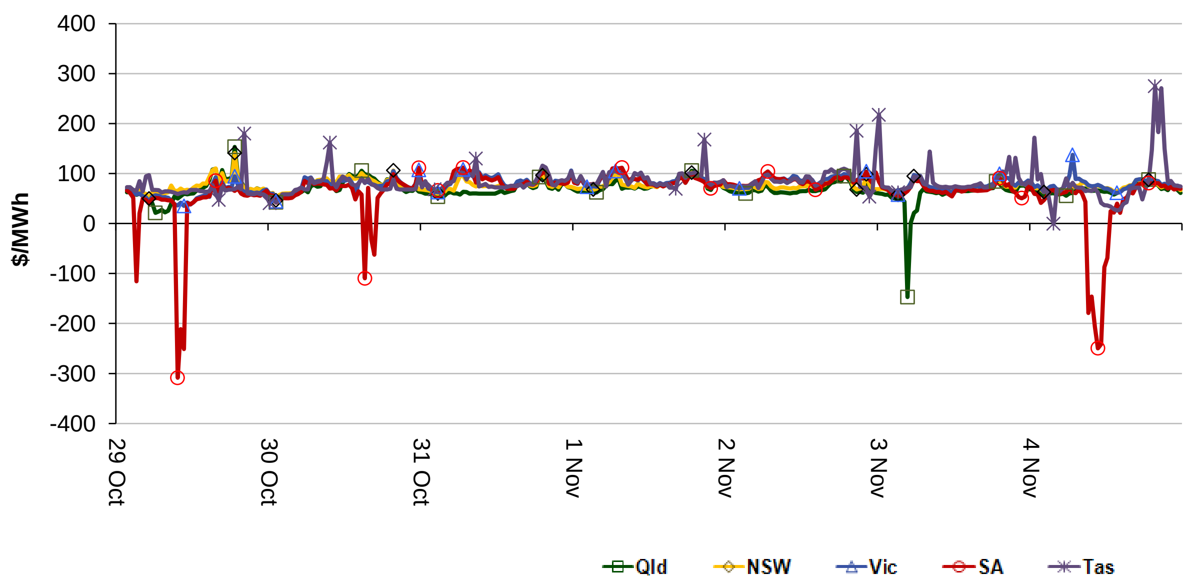


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

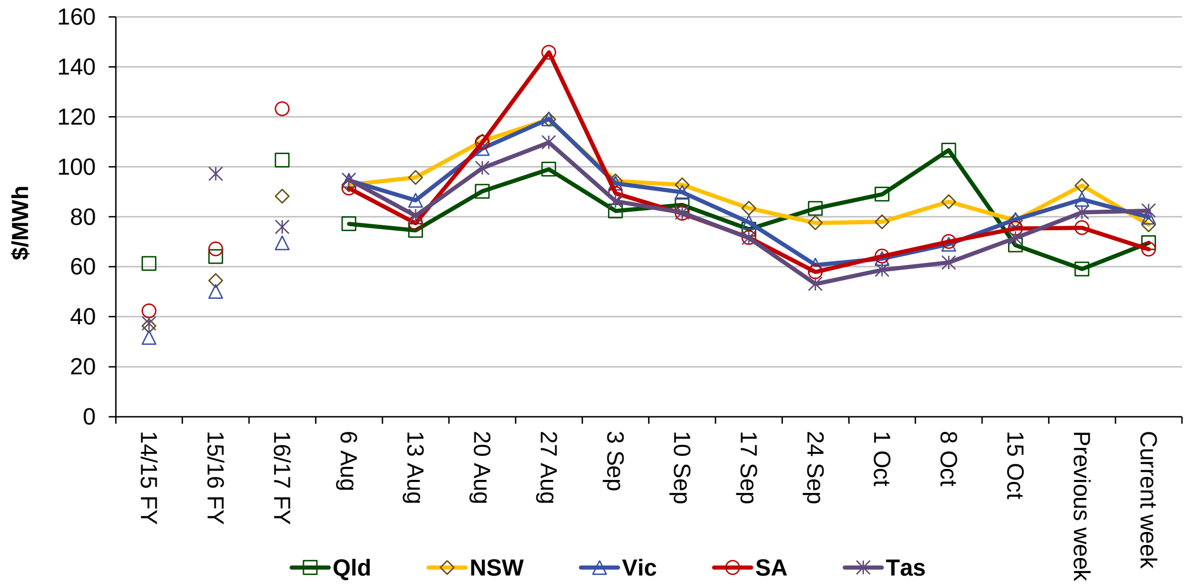


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	70	77	80	67	82
16-17 financial YTD	54	56	48	117	50
17-18 financial YTD	81	92	96	95	91

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 150 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2016 of 273 counts and the average in 2015 of 133. 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	0	18	0	0
% of total below forecast	58	13	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

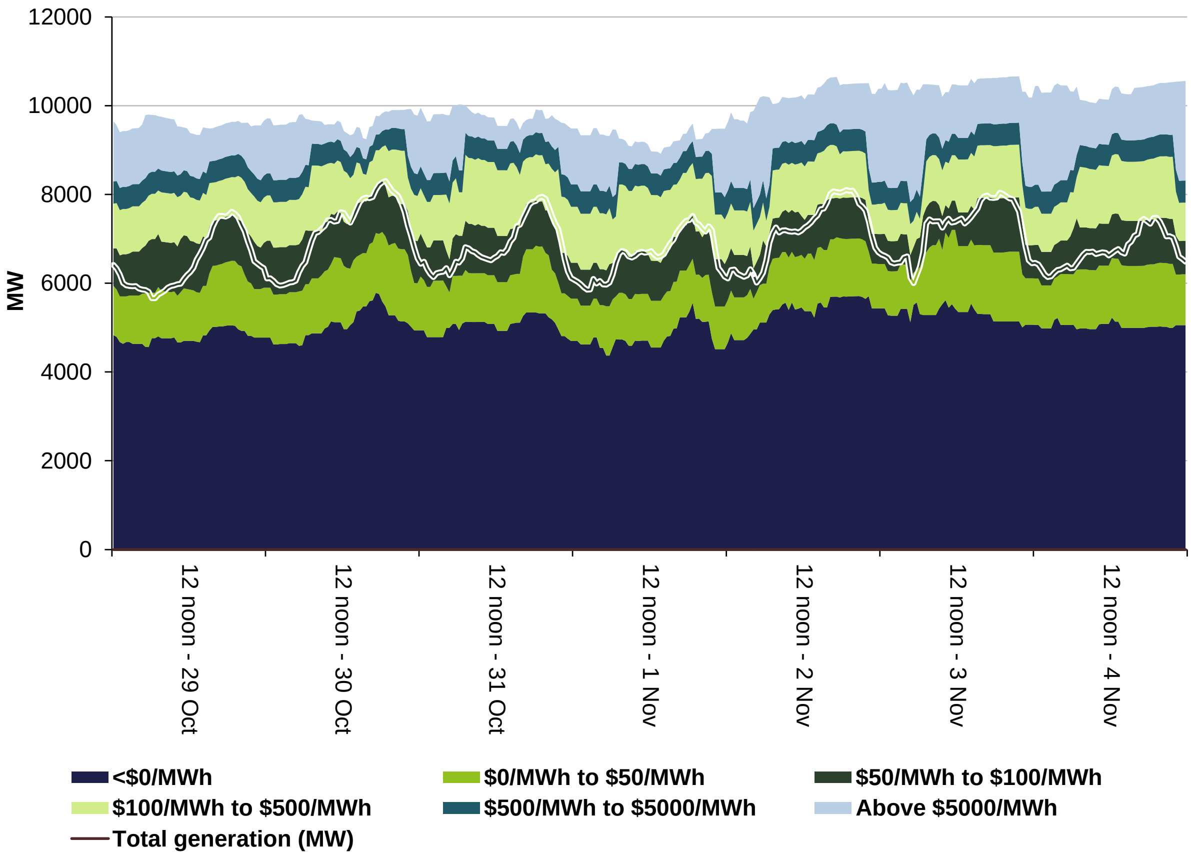


Figure 4: New South Wales generation and bidding patterns

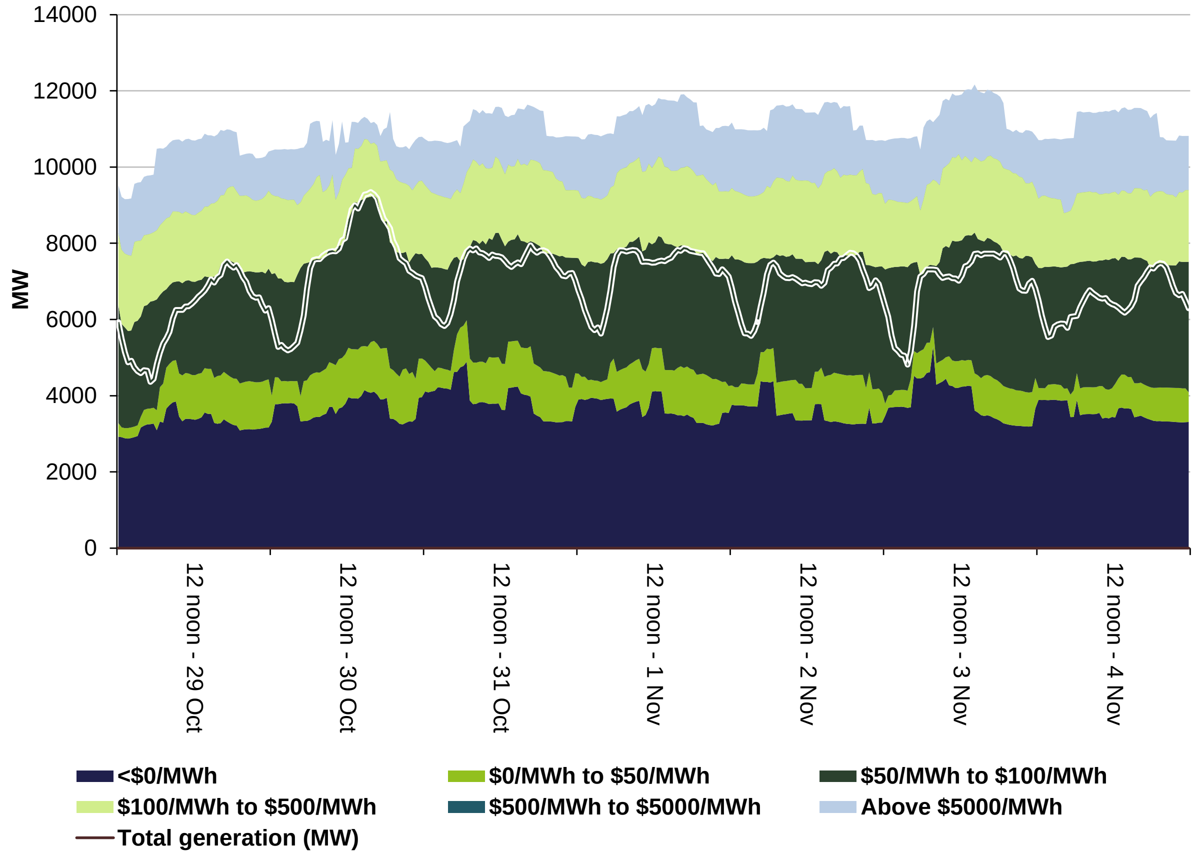


Figure 5: Victoria generation and bidding patterns

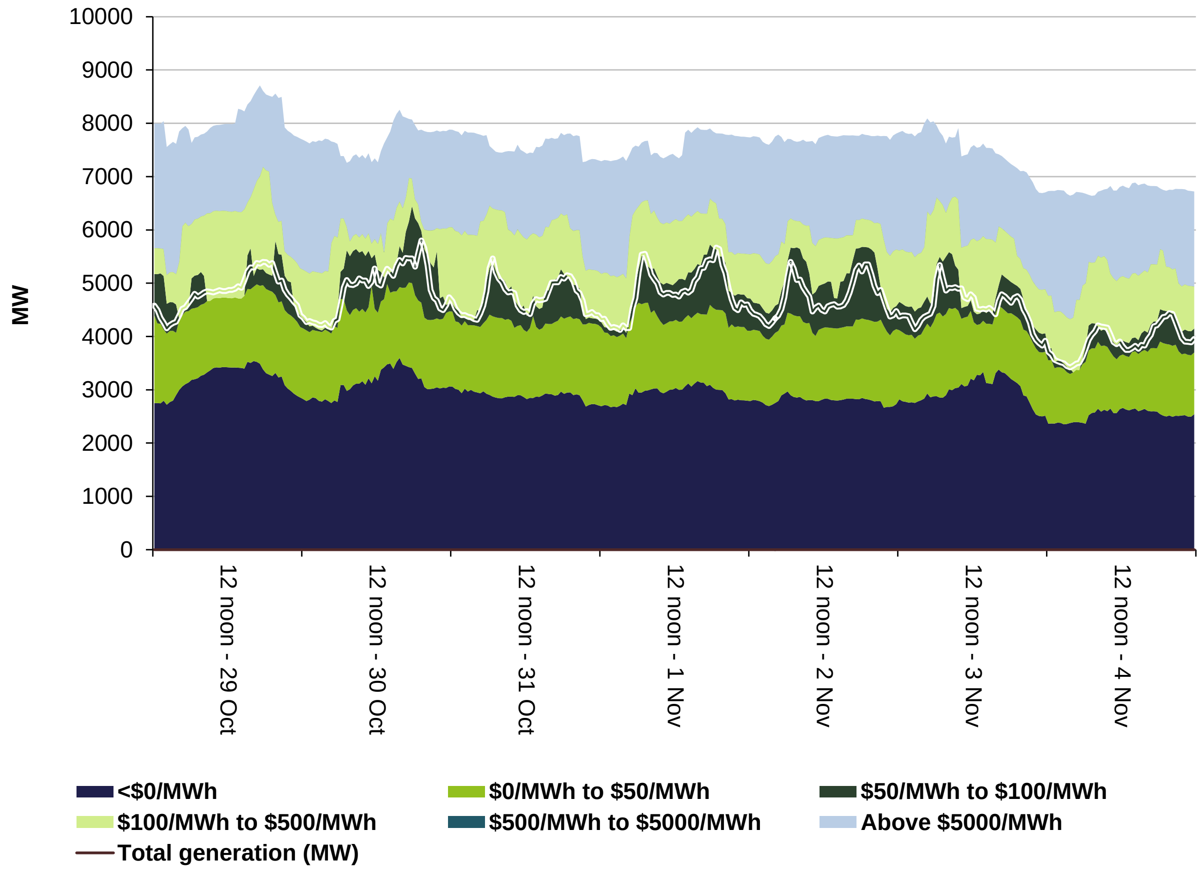


Figure 6: South Australia generation and bidding patterns

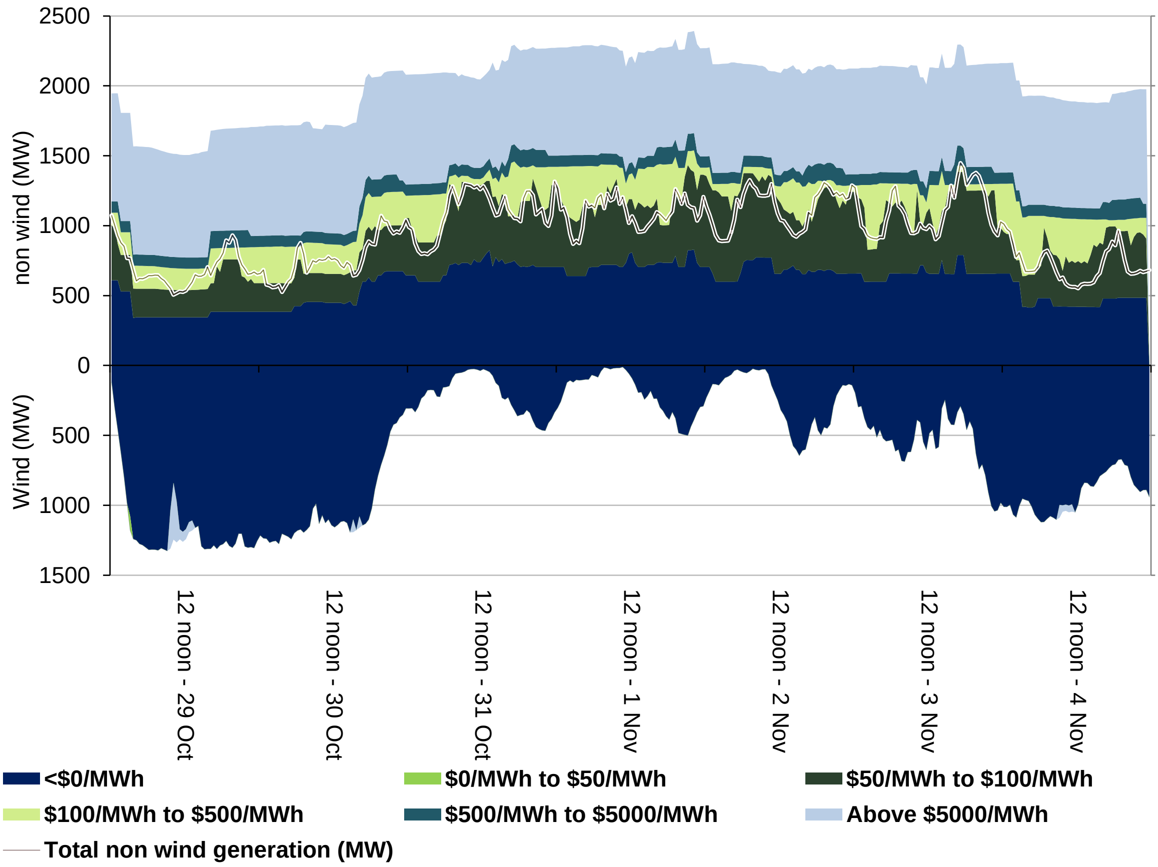
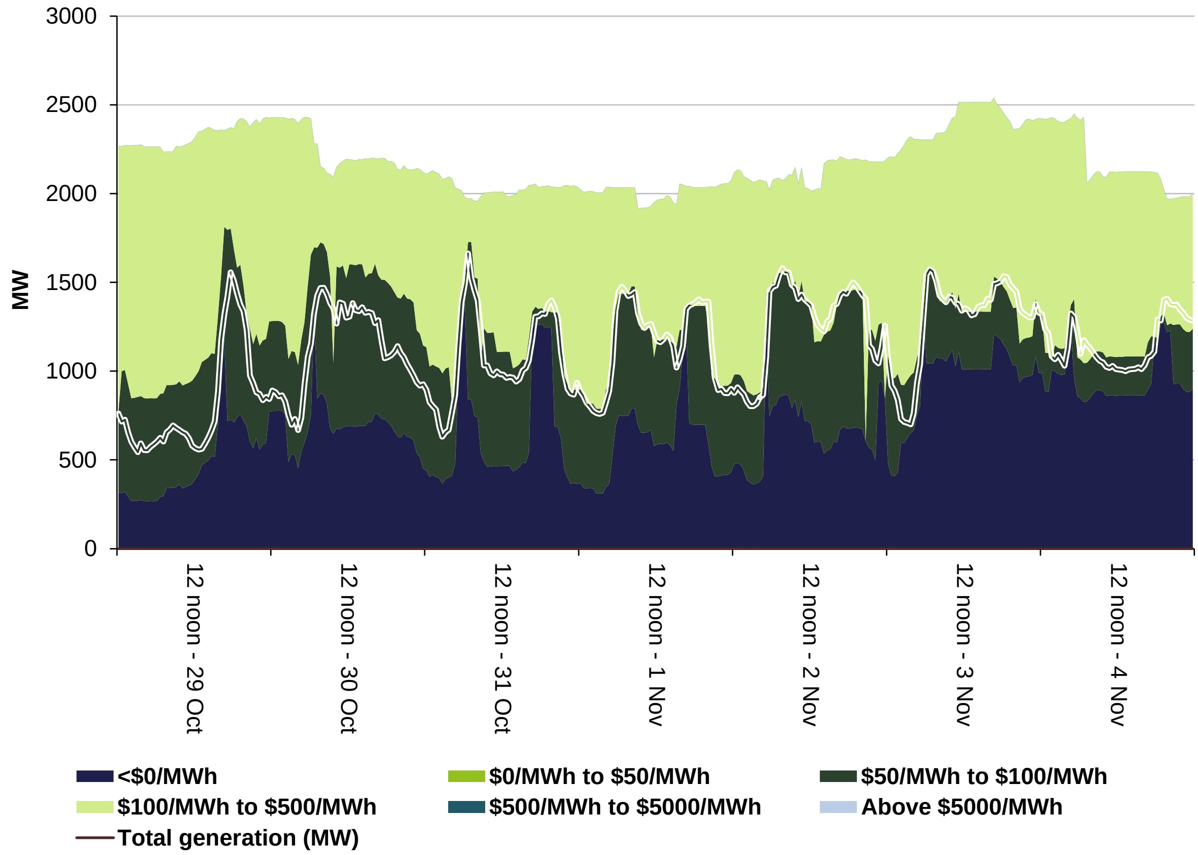


Figure 7: Tasmania generation and bidding patterns



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.

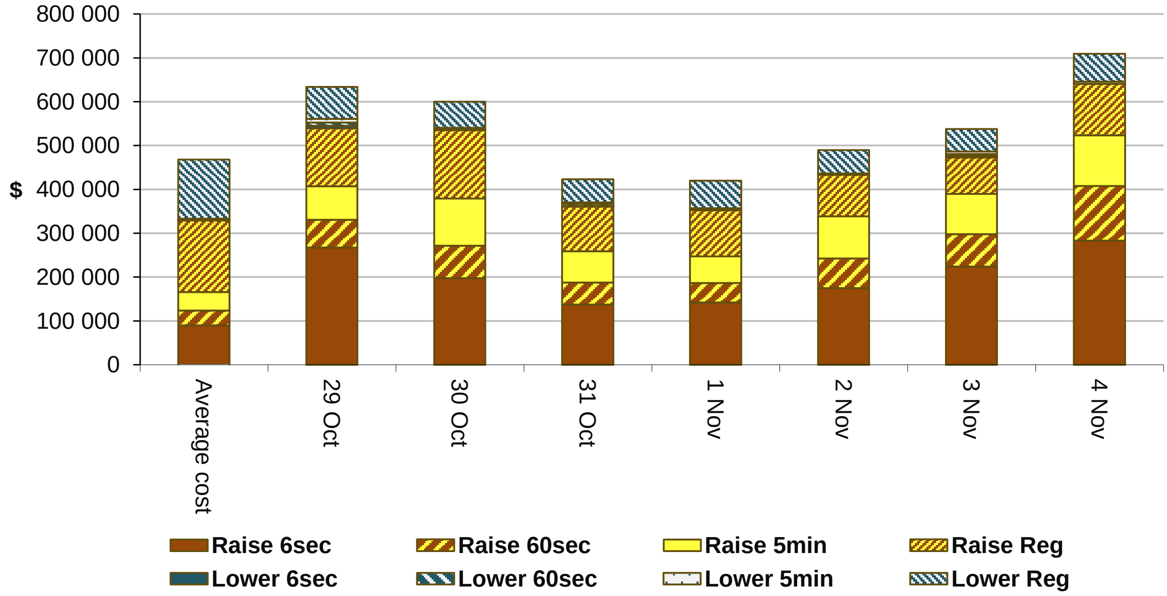
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 919 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $892 500 or around six 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

Queensland

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

Friday, 3 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
5 am	-147.12	61.30	58.71	5316	5305	5363	10 362	10 387	10 605

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

From 4.30 am, in preparation for an outage between Armidale to Bulli Creek, a ramping constraint reduced exports from Queensland to New South Wales. For the 4.35 am and 4.40 am dispatch intervals, exports on QNI reduced by a total of 268 MW and local demand also decreased by around 80 MW. With excess generation being constrained in ramp down and unable to set price, the price fell to -$11.01/MWh and -$918/MWh.

South Australia

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

Sunday, 29 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
3.30 am	-115.41	55.43	55.32	890	826	789	2987	2569	2614
10 am	-308.72	37.54	-103.60	697	583	548	2828	2597	2520
10.30 am	-211.29	-186.64	-103.52	763	534	509	2760	2590	2520
11 am	-251.34	-327.12	-187.30	723	517	494	2779	2606	2548

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply following an intervention in the market.

Conditions at the time saw demand between 64 MW and 229 MW higher than forecast while availability was between 170 MW and 418 MW higher than forecast four hours ahead, mainly due to higher amounts of wind availability.

For the 3.30 am trading interval, the higher than forecast wind resulted in negative dispatch prices between $-1/MWh and $-337/MWh.

For the 10 am trading interval Hornsdale wind farm rebid around 210 MW of capacity to the floor in the four hours leading up to the start of the trading interval. This combined with the higher than forecast wind generation resulted in two dispatch prices at the floor at 9.50 am and 9.55 am.

The 10.30 am and 11 am trading intervals were close to that forecast four hours prior.

Monday, 30 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
3.30 pm	-109.64	67.42	80.00	884	908	904	2928	2756	2743

Conditions at the time saw demand close to forecast while availability was around 170 MW higher than forecast four hours ahead.

For the 3.05 pm dispatch interval demand decreased by 24 MW and net exports into Victoria decreased by 13 MW. With no capacity priced between $50/MWh and -$950/MWh and higher priced generation ramp down constrained and unable to set price, the dispatch price decreased to the floor.

The price increased to around $65/MWh for the remainder of the trading interval as demand increased and higher priced generation was no longer constrained and able to set price.

Saturday, 4 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	-179.19	65.63	63.94	827	841	804	2995	2797	2775
10 am	-145.95	55.00	55.35	789	788	752	2944	2781	2747
10.30 am	-206.29	50.69	55.00	731	738	705	2935	2746	2700
11 am	-249.59	52.32	55.00	702	697	659	2942	2721	2663
11.30 am	-241.46	51.68	53.60	688	653	629	2934	2696	2658

Conditions at the time saw demand close to forecast while availability was between 160 MW to 240 MW higher than forecast, mainly due to higher than forecast wind generation.

From 9.30 am to 11.30 am there was limited capacity priced between $50/MWh and -$150/MWh. This meant that small changes to demand and supply (in this case wind generation) caused large variations in price.

For all five trading intervals there was one dispatch interval at the floor, due to either an increase in wind generation or decrease in demand, or both. During these times higher priced generation was dispatched however was unable to set price due to being either ramp down constrained or trapped in FCAS. In response to the lower than forecast prices, participants rebid capacity priced at the floor to greater than $12 500/MWh and the price increased to higher levels for the remainder of the trading intervals.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $82/MWh and above $250/MWh.

Sunday, 4 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
8 pm	274.66	84.90	86.27	1220	1200	1184	1969	2012	1992
9 pm	270.61	79.79	81.06	1181	1163	1159	1973	2005	1986

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

Conditions at the time saw demand around 20 MW higher than forecast while availability was around 35 MW lower than forecast four hours ahead.

For the 8 pm trading interval there was only around 20 MW of capacity priced between $80/MWh and $350/MWh. This meant small changes in demand or interconnector flows caused large variations in price.

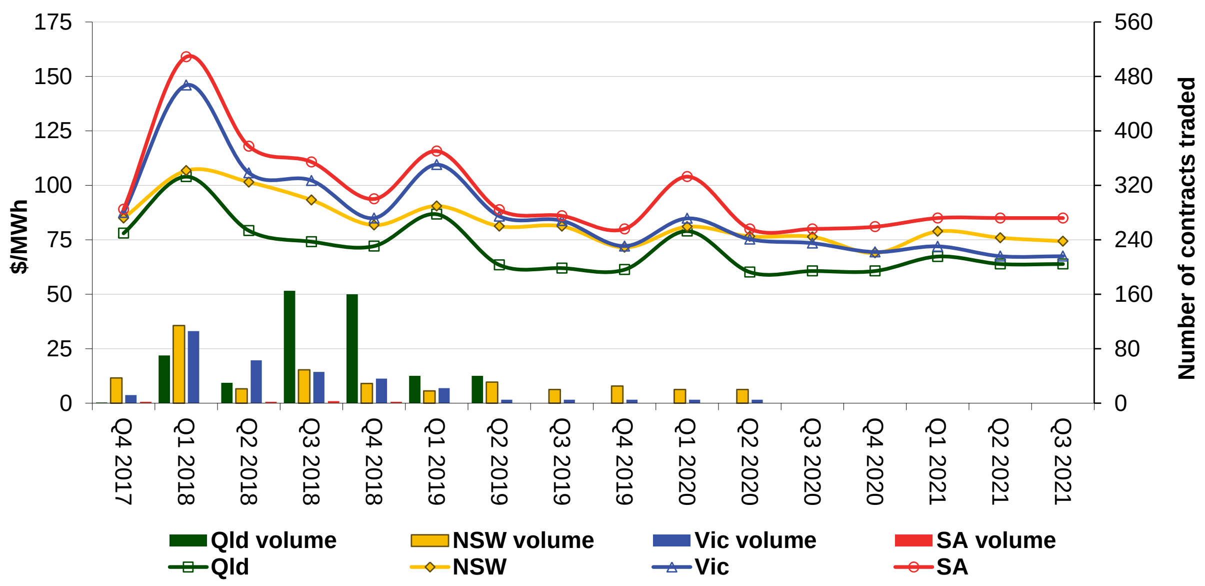
For the entire trading interval, system normal constraints were forcing flows across Basslink into Victoria, slightly higher than forecast. The forced exports and slightly higher demand resulted in prices ranging from $83/MWh to $349/MWh across the trading interval.

For the 9 pm trading interval, a series of FCAS constraints were forcing exports into Victoria across Basslink. This combined with local requirements for FCAS saw the price co-optimised for all dispatch intervals and remain around $270/MWh for the entire 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.

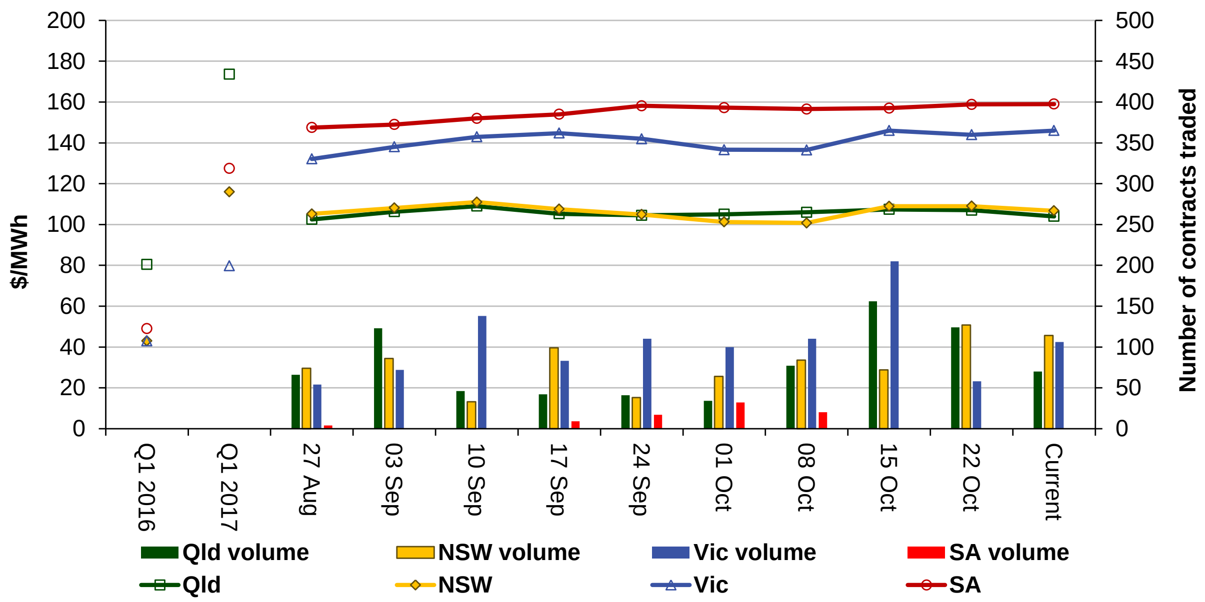
Figure 9: Quarterly base future prices Q4 2017 – Q3 2021



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



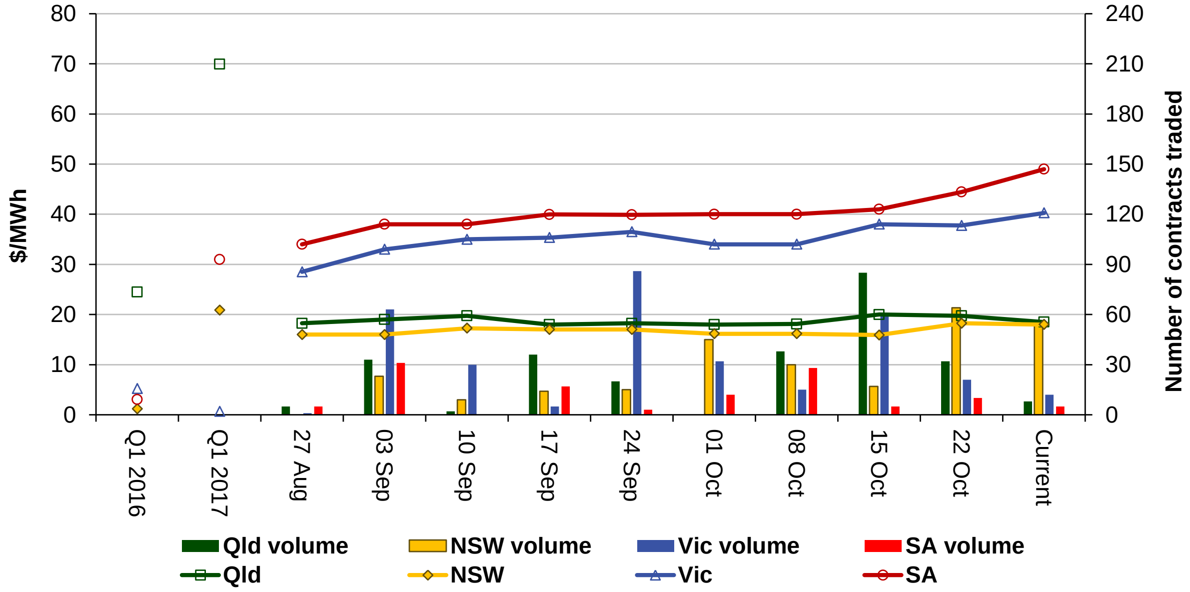
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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