Electricity Report

AUSTRALIAN ENERGY REGULATOR

22 – 28 October 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 22 - 28 October 2017.

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

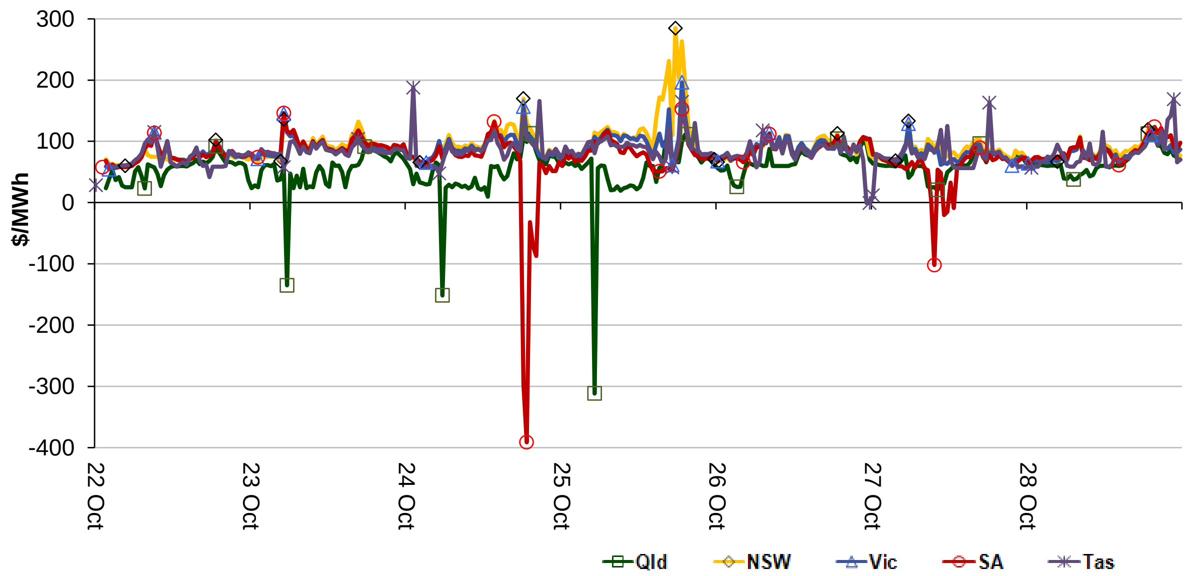


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

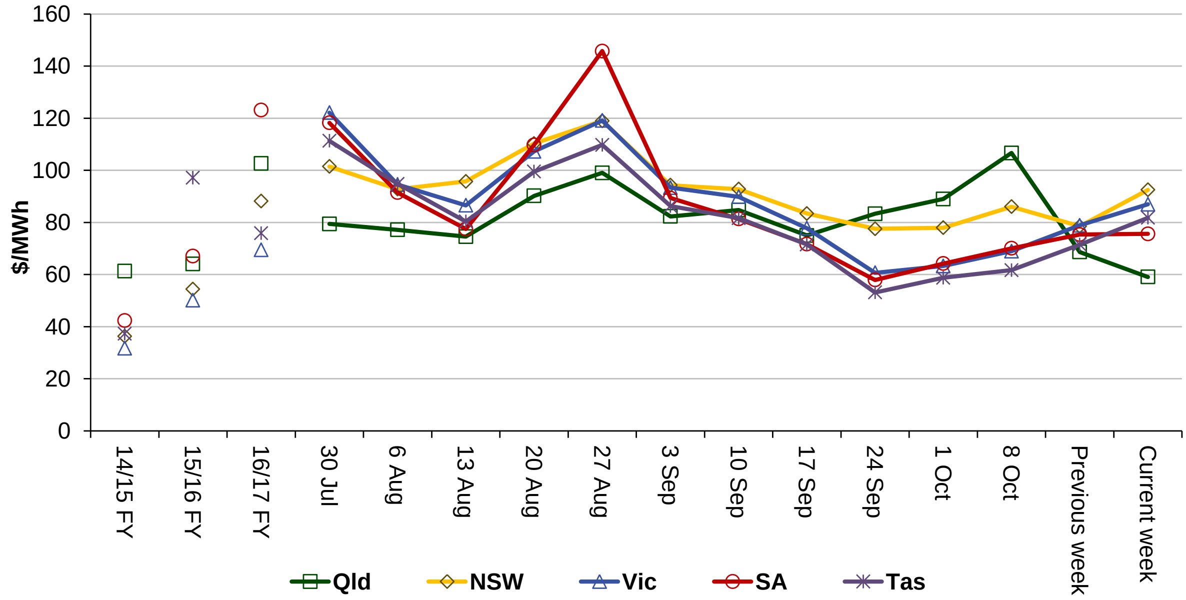


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	59	93	87	76	82
16-17 financial YTD	54	56	49	120	51
17-18 financial YTD	82	93	97	96	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 211 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	3	22	0	0
% of total below forecast	64	7	2	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

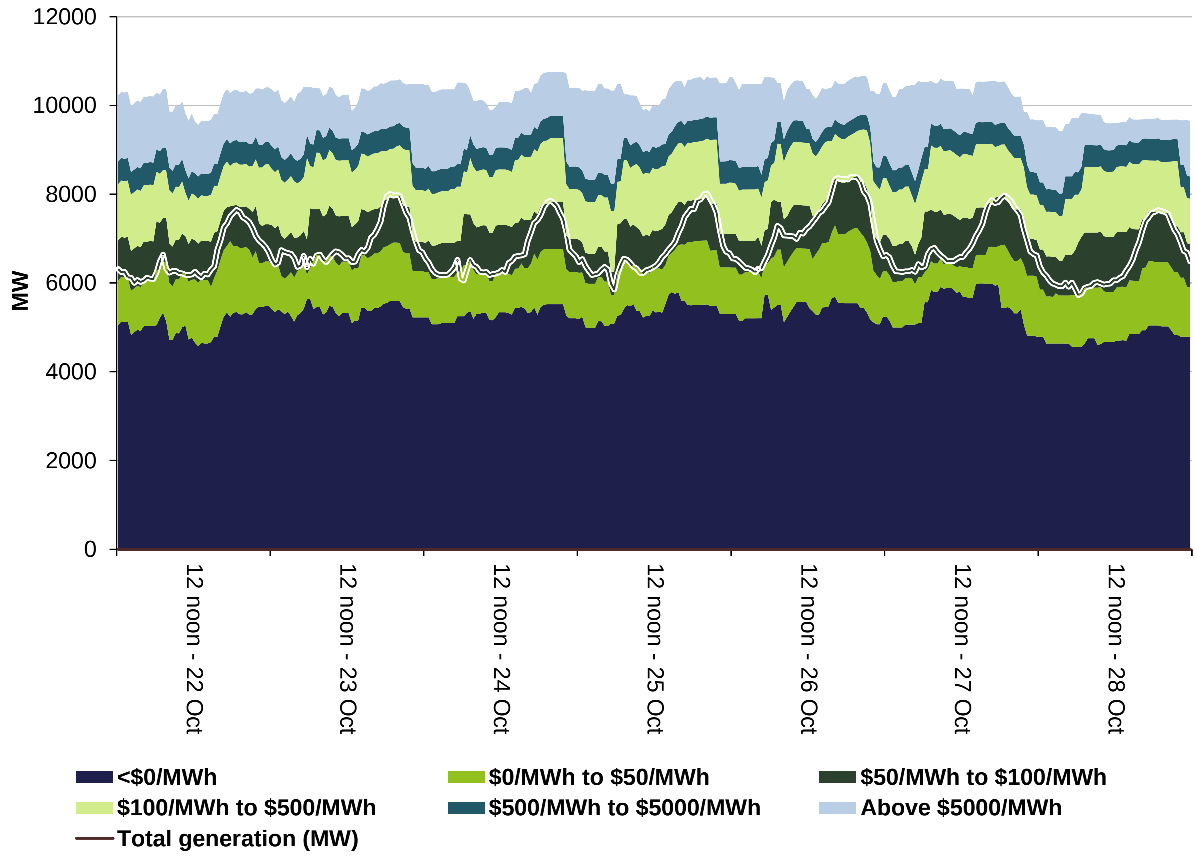


Figure 4: New South Wales generation and bidding patterns

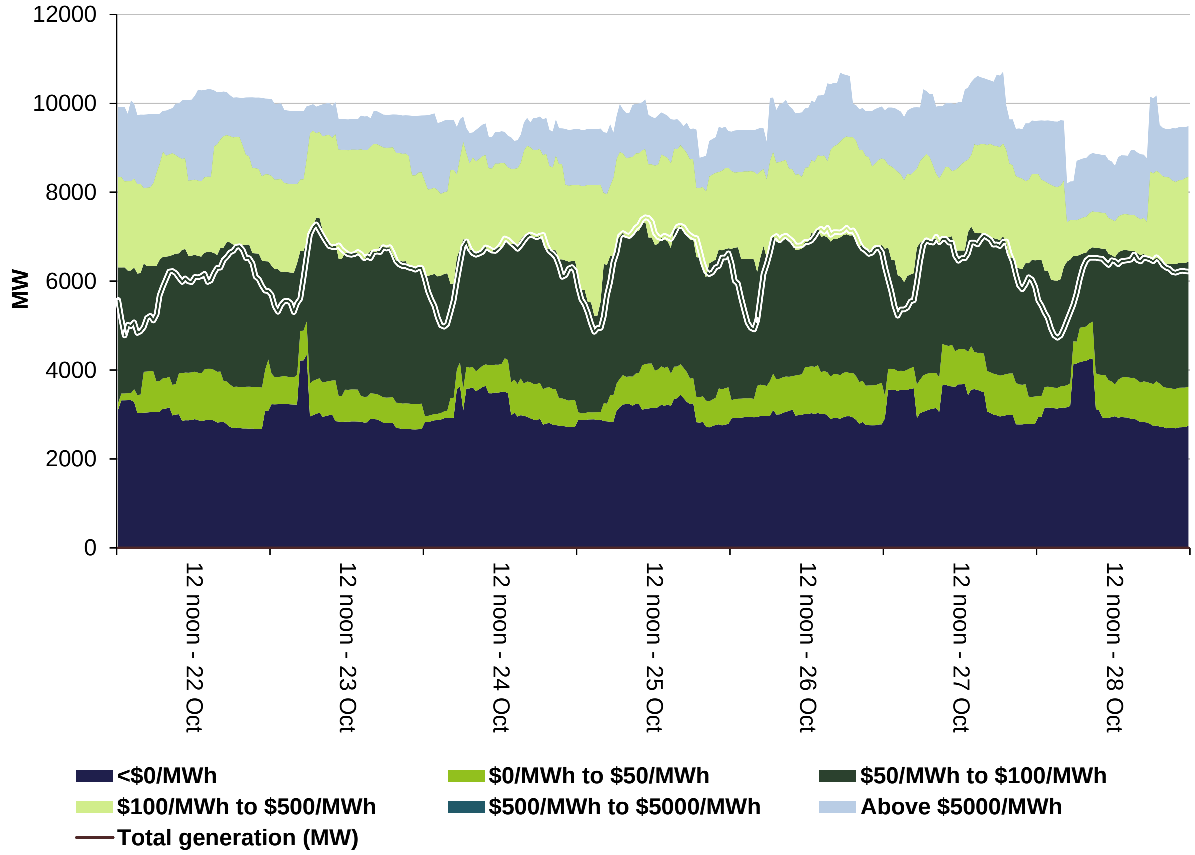


Figure 5: Victoria generation and bidding patterns

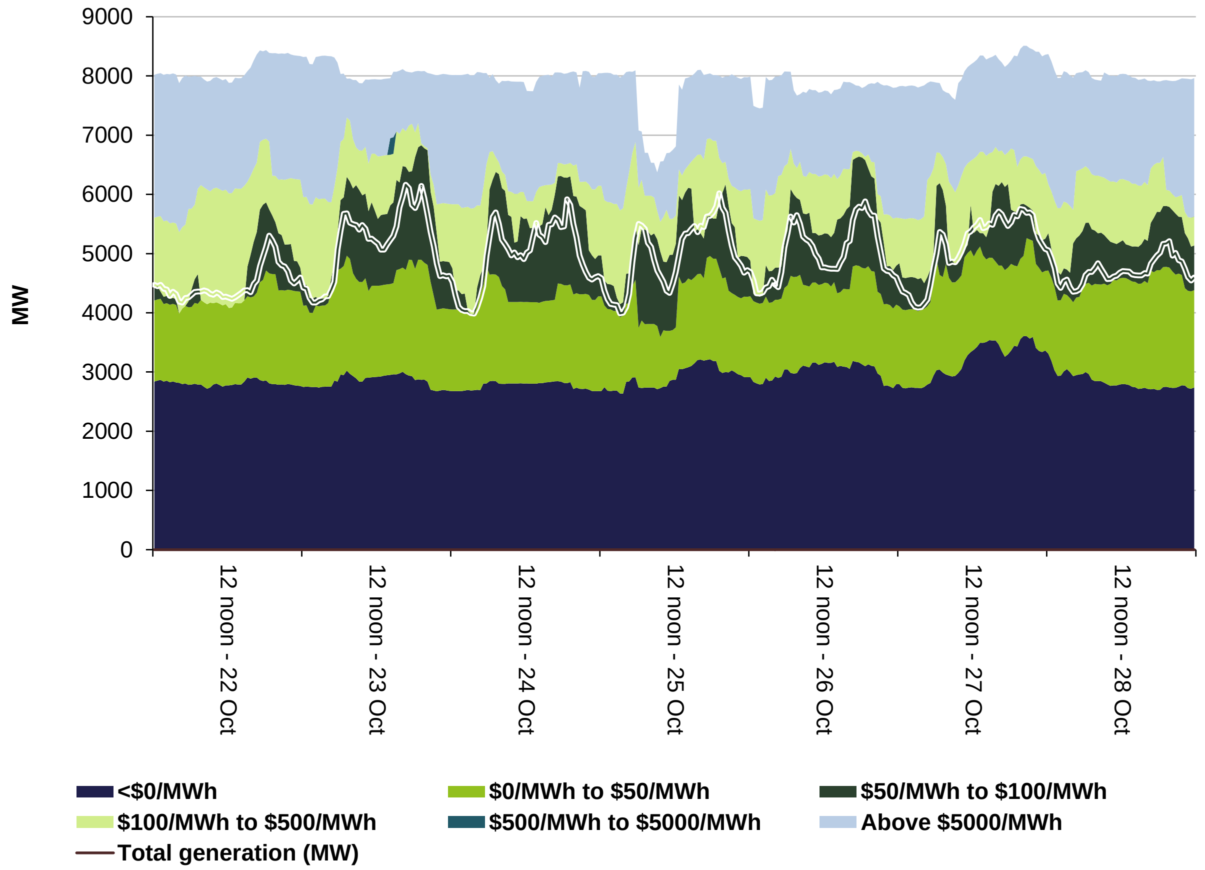


Figure 6: South Australia generation and bidding patterns

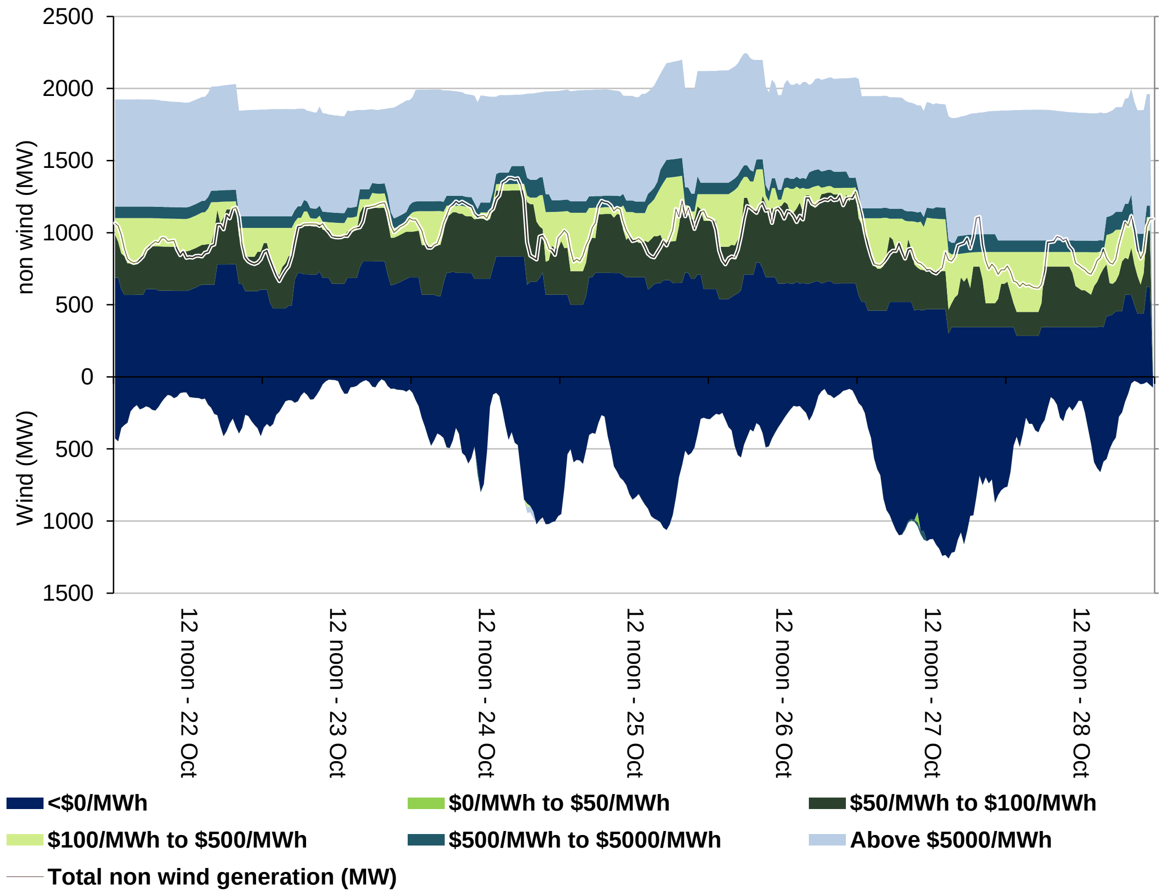
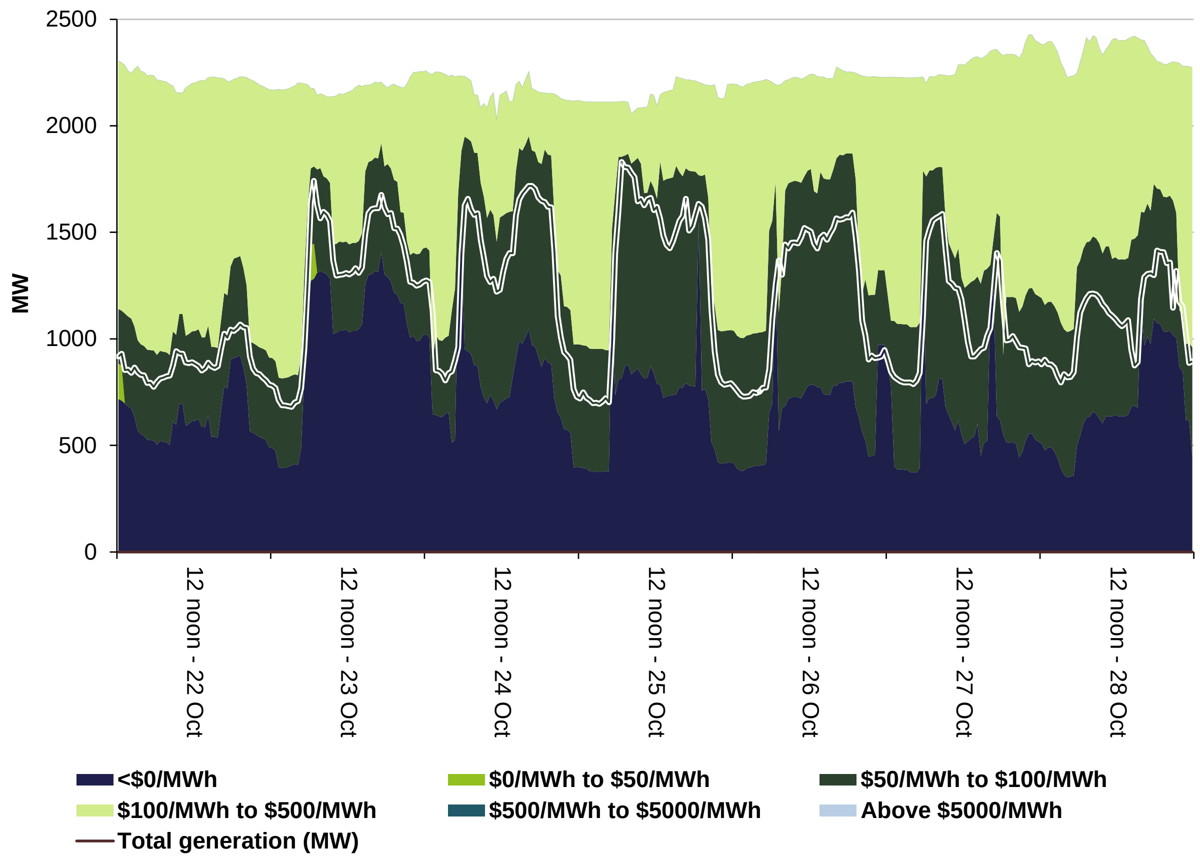


Figure 7: Tasmania generation and bidding patterns



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.

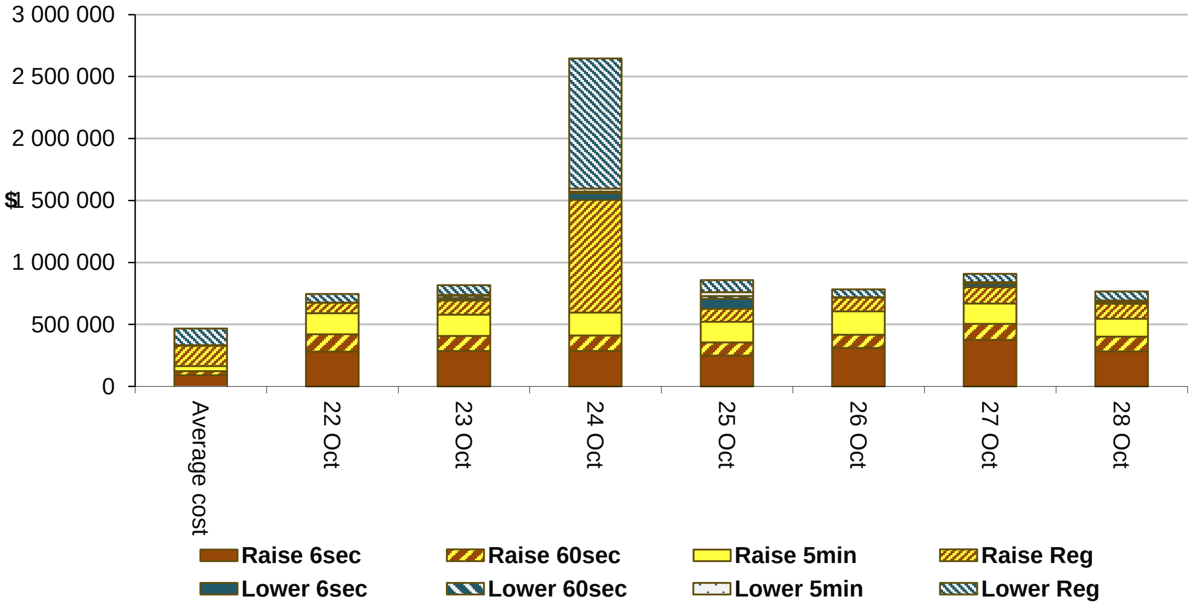
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $6 497 000 or around three per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $1 028 500 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



On 24 October, an outage in Victoria put the Heywood interconnector on a single contingency. This created the risk of South Australia becoming electrically isolated from the rest of the National Electricity Market. AEMO invoked constraints requiring 35 MW of local regulation services. The price of regulation services in South Australia exceeded $5000/MW for 26 dispatch intervals in lower and 23 dispatch intervals in raise services. The total cost

was around $1.7 million. As required under the Electricity Rules, staff will prepare a FCAS Prices above $5000/MW report into the reasons for the high prices.

Detailed market analysis of significant price events

Queensland

There were three occasions where the spot price in Queensland was below -$100/MWh.

Monday, 23 October

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
6 am	-135.10	24.88	59.78	5415	5328	5327	10 419	10 504	10 515

Conditions at the time saw demand around 90 MW greater than forecast and availability 85 MW lower than forecast four hours prior.

From 5.30 am, in preparation for an outage between Armidale to Bulli Creek, a ramping constraint reduced exports from Queensland to New South Wales.. For the 5.35 am dispatch interval, exports on QNI reduced by around 140 MW. With excess generation being ramped down and unable to set price the price fell to -$918/MWh for one dispatch interval.

Tuesday, 24 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
6 am	-151.57	65.13	67.23	5405	5361	5417	10 513	10 513	10 513

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

From 5.30 am, in preparation for an outage between Armidale to Bulli Creek, a ramping constraint reduced exports from Queensland to New South Wales. For the 5.40 am dispatch interval, exports on QNI reduced by around 200 MW. With excess generation being ramped down and unable to set price the price fell to -$918/MWh for one dispatch interval.

Wednesday, 25 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
5.30 am	-311.64	67.61	73.74	5215	5230	5273	10 364	10 358	10 358

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

From 5.05 am, in preparation for an outage between Armidale to Bulli Creek, a ramping constraint reduced exports from Queensland to New South Wales. For the 5.15 am dispatch interval, exports on QNI reduced by 206 MW. With excess generation being ramped down and unable to set price the price fell to -$1000/MWh at 5.15 am and -$918/MWh at 5.20 am.

New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $93/MWh and above $250/MWh.

Wednesday, 25 October

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
6 pm	284.60	106.96	109.14	8609	8322	8201	9409	9943	10 972

Conditions at the time saw demand around 290 MW higher than forecast and availability around 530 MW lower than that forecast four hours prior.

While the reduction in available capacity was priced low it was offset by participants rebidding around 560 MW of capacity from high to low prices.

At 5.25 pm, effective from the 5.35 pm dispatch interval, AGL removed 100 MW of capacity priced at $0/MWh from Liddell with the reason given “1720~P~010 unexpected/plant limits~104 coal conservation low bunker levels“. This coupled with demand being higher than forecast resulted in the dispatch price hovering around $285/MWh for the entire trading interval.

South Australia

There were three occasions where the spot price in South Australia was greater than three times the Tasmania weekly average price of $71/MWh and above $250/MWh.

Tuesday, 24 October

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
6.30 pm	-297.39	86.79	93.30	1248	1453	1384	2811	2420	2583
7 pm	-391.30	105.35	105.32	1305	1402	1356	2908	2422	2629

Conditions at the time saw demand between 100 MW and 200 MW lower than forecast four hours ahead. Availability was up to 486 MW greater than forecast four hours prior, this was because semi-scheduled wind generation was up to 336 MW greater than forecast.

An unplanned outage of the Heywood – Mortlake – APD line occurred at 6.25 pm, this led to AEMO invoking FCAS constraints and limiting flows to Victoria on the Heywood interconnector. For the 6.25 pm and 6.30 pm dispatch intervals, FCAS constraints bound, which reduced exports to Victoria on the Heywood interconnector by 400 MW. With excess generation being ramped down and unable to set price the price fell to the floor from 6.25 pm until 6.40 pm, leading to two negatively priced trading intervals.

Friday, 27 October

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	-101.97	57.78	71.11	833	949	920	2944	2740	2732

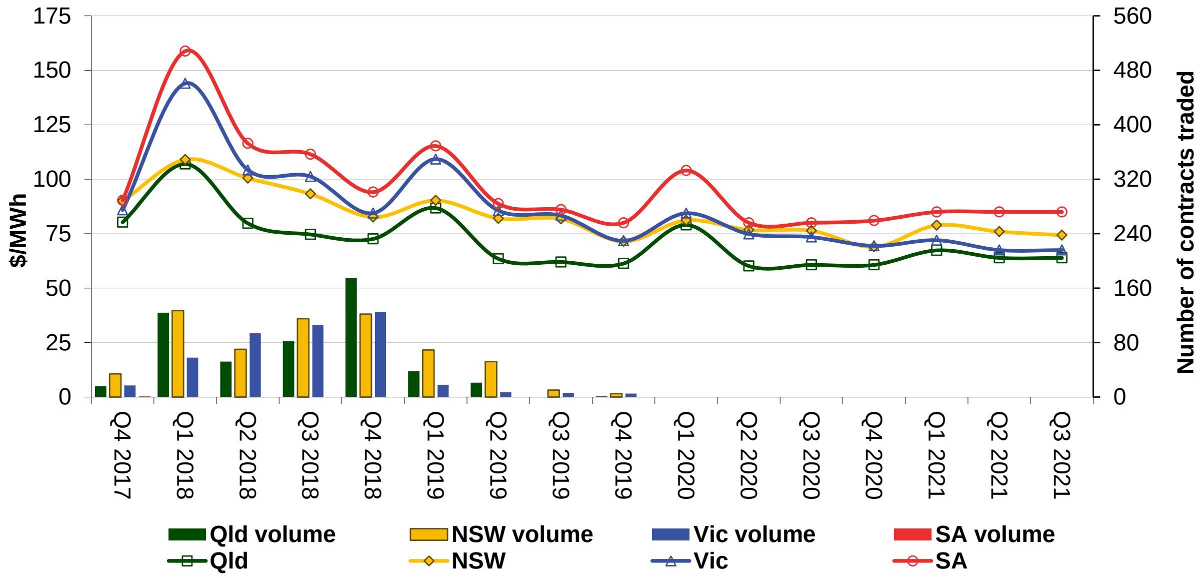
Conditions at the time saw demand around 120 MW lower than forecast and availability around 200 MW greater than forecast four hours prior, this was partly because semi-scheduled wind generation was 115 MW greater than forecast.

For this trading there was little available capacity priced between $50/MWh and the price floor, this meant small change in demand could lead to negative prices. At 9.40 am, demand dropped by 10 MW and exports decreased by 30 MW, as a result the dispatch price dropped to -$41/MWh. For the 9.45 am dispatch interval, demand dropped a further 27 MW and the dispatch price fell to -$500/MWh. The dispatch price stayed negative for the remainder 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.

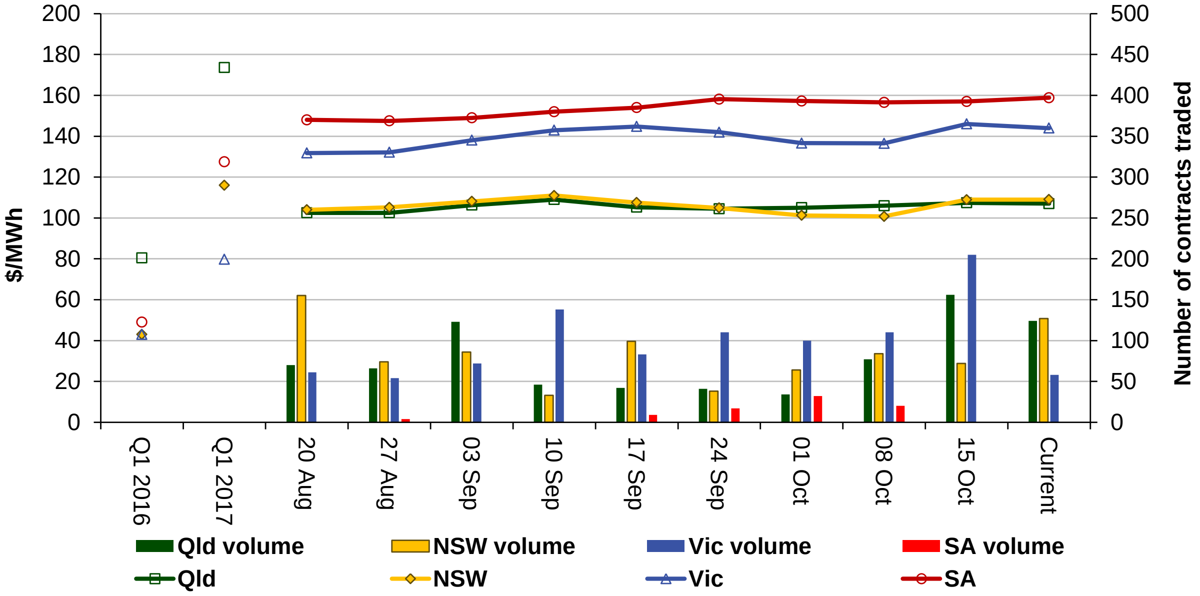
Figure 9: Quarterly base future prices Q4 2017 – Q3 2021



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)



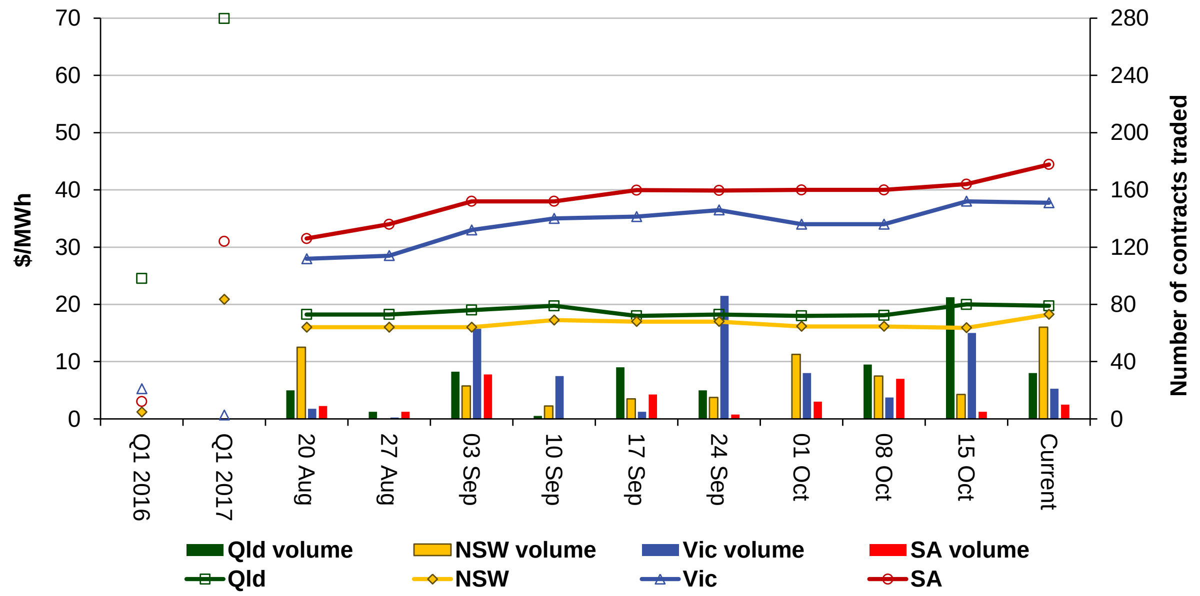
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
November 2017