Electricity Report

11 - 17 June 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 11 – 17 June 2017.

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

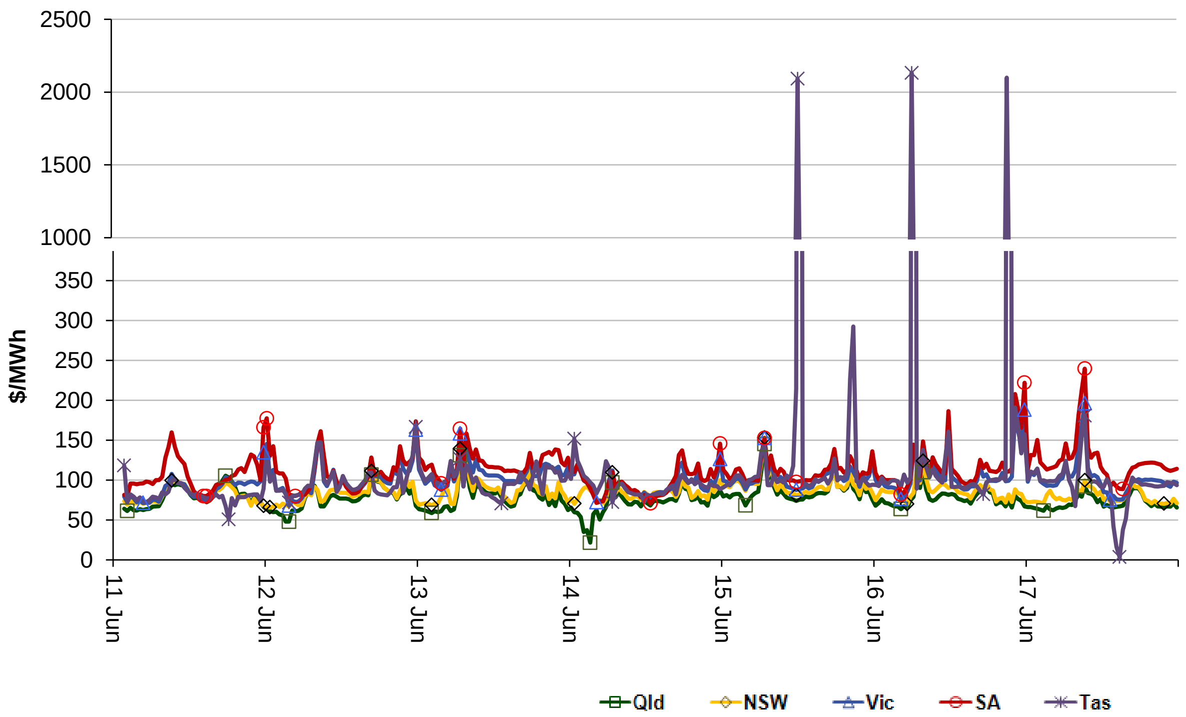


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

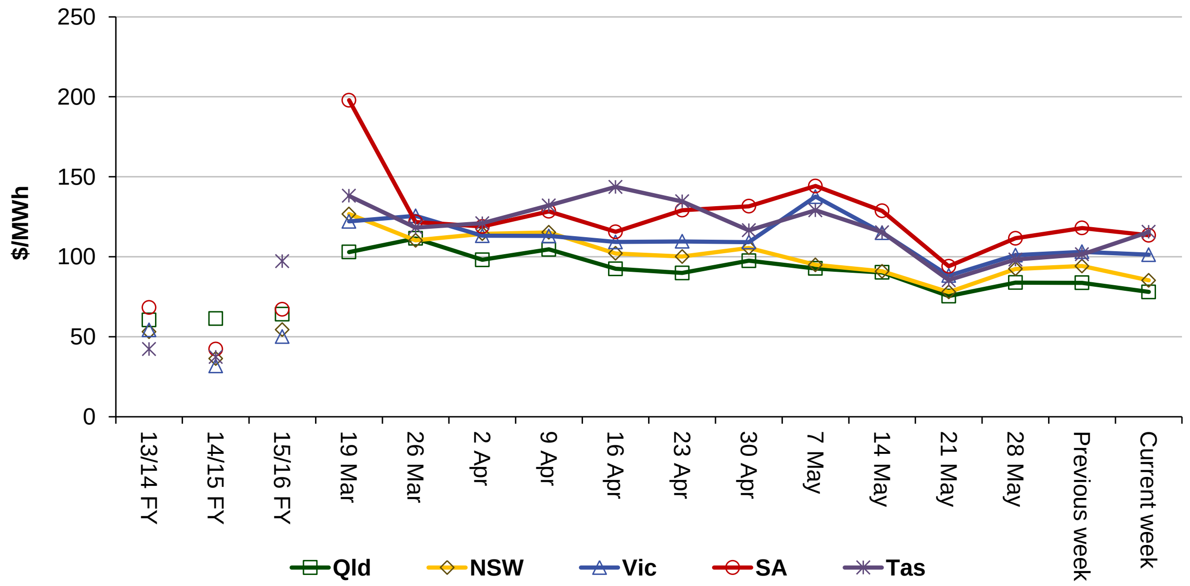


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	78	85	101	113	116
15-16 financial YTD	63	53	48	64	97
16-17 financial YTD	104	89	68	124	75

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 161 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	21	0	2
% of total below forecast	51	10	0	14

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

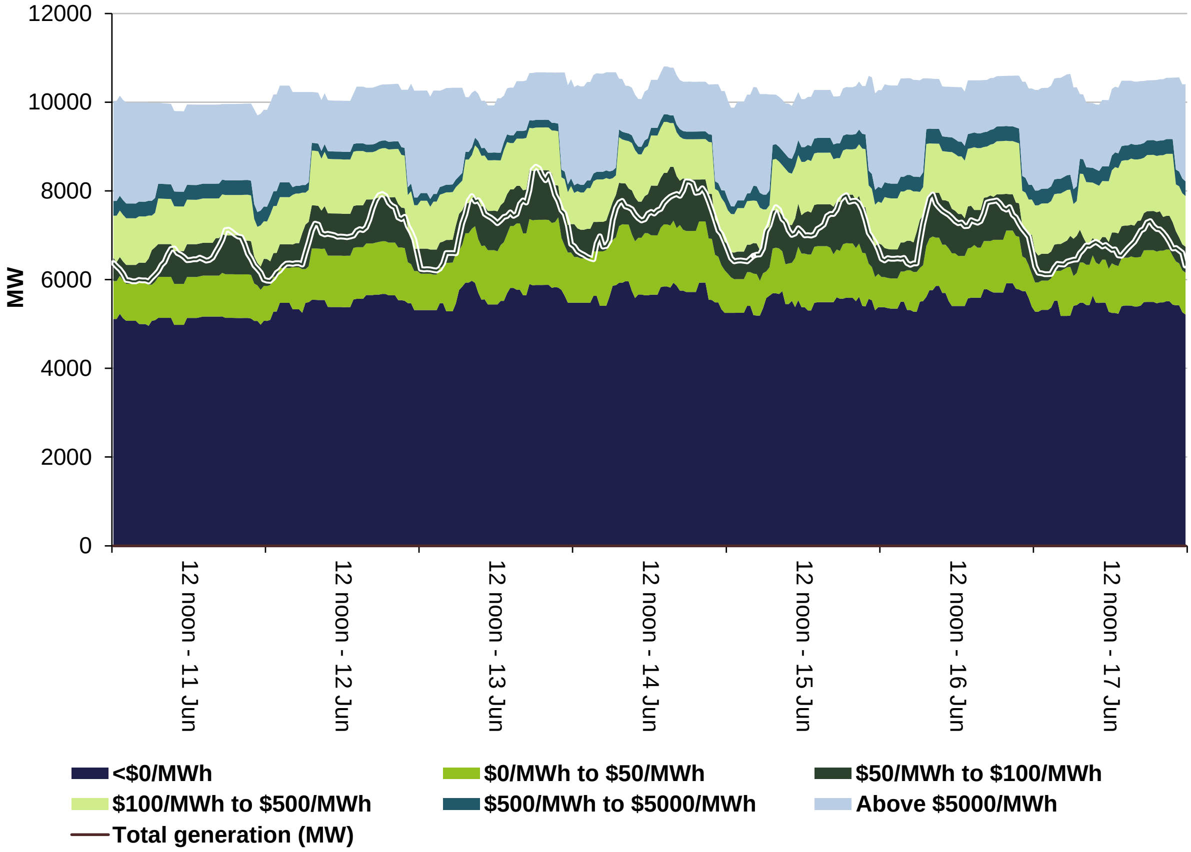


Figure 4: New South Wales generation and bidding patterns

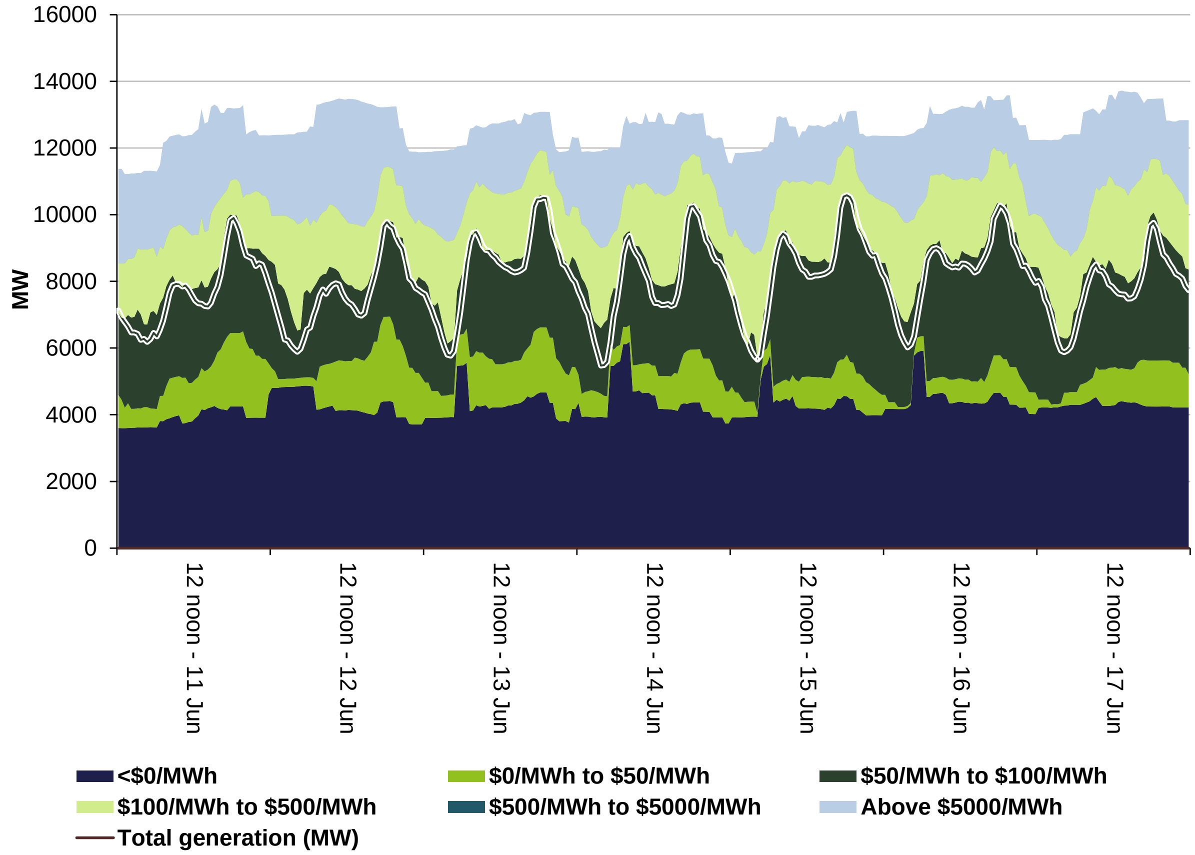


Figure 5: Victoria generation and bidding patterns

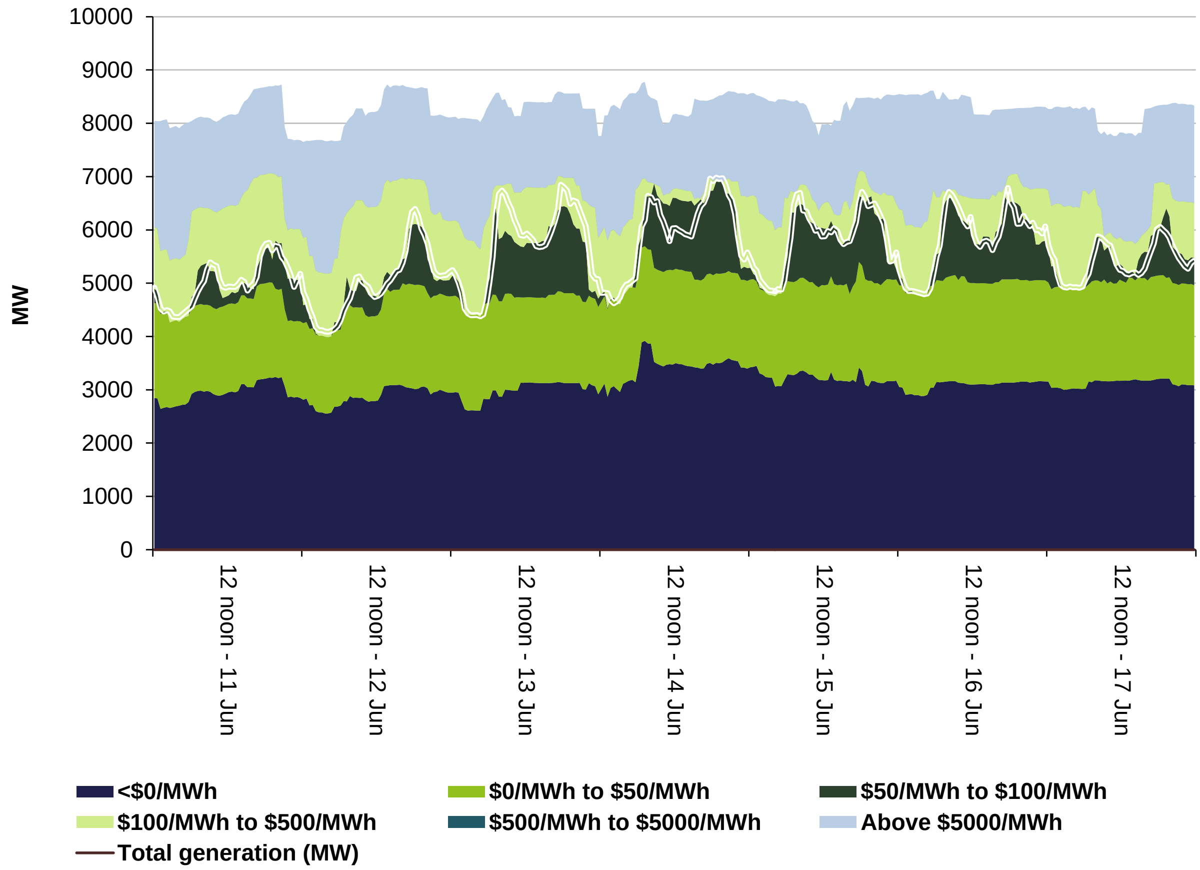


Figure 6: South Australia generation and bidding patterns

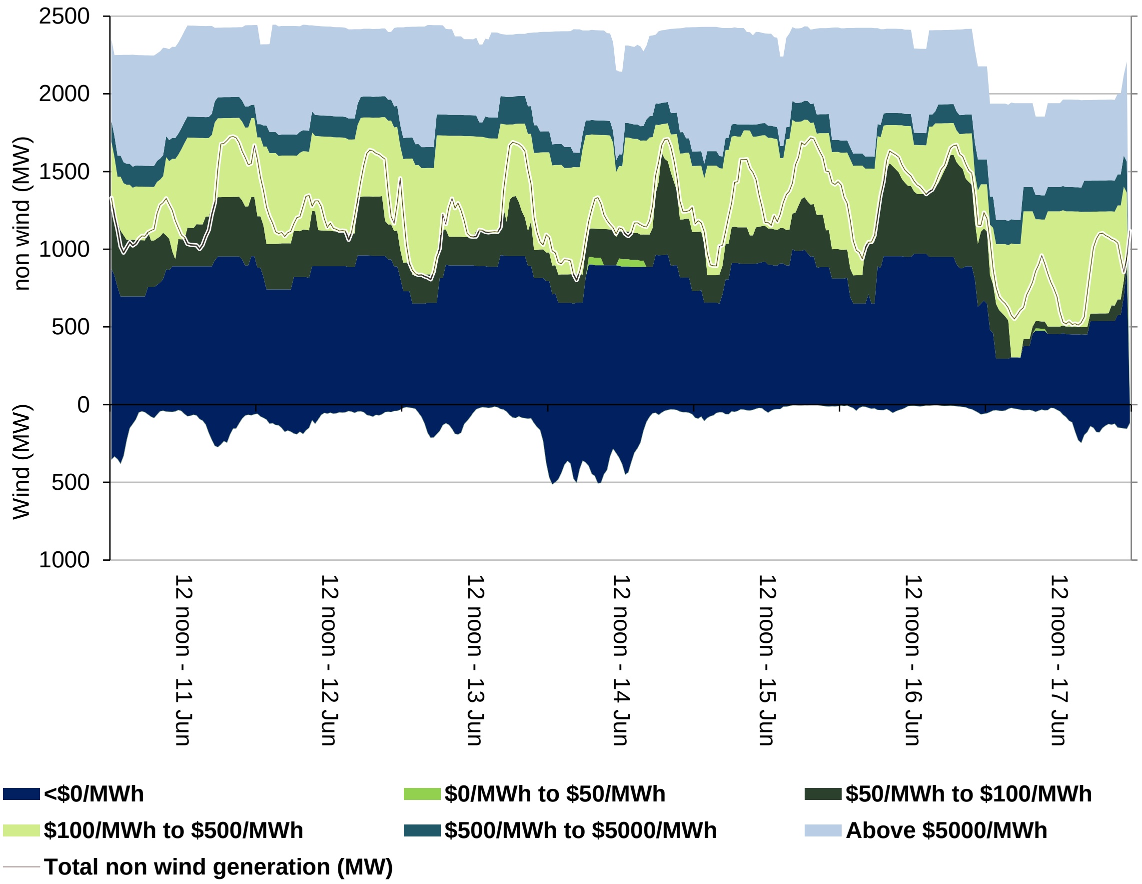
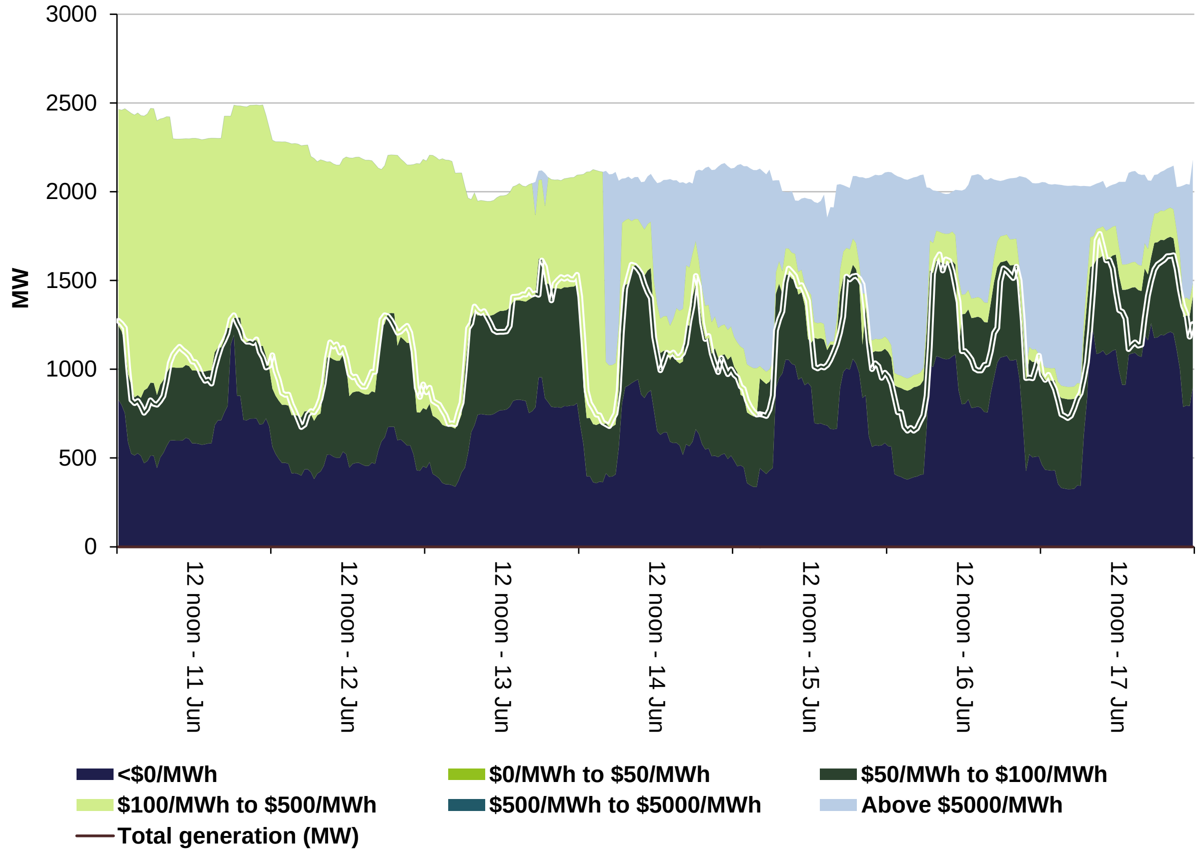


Figure 7: Tasmania generation and bidding patterns



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.

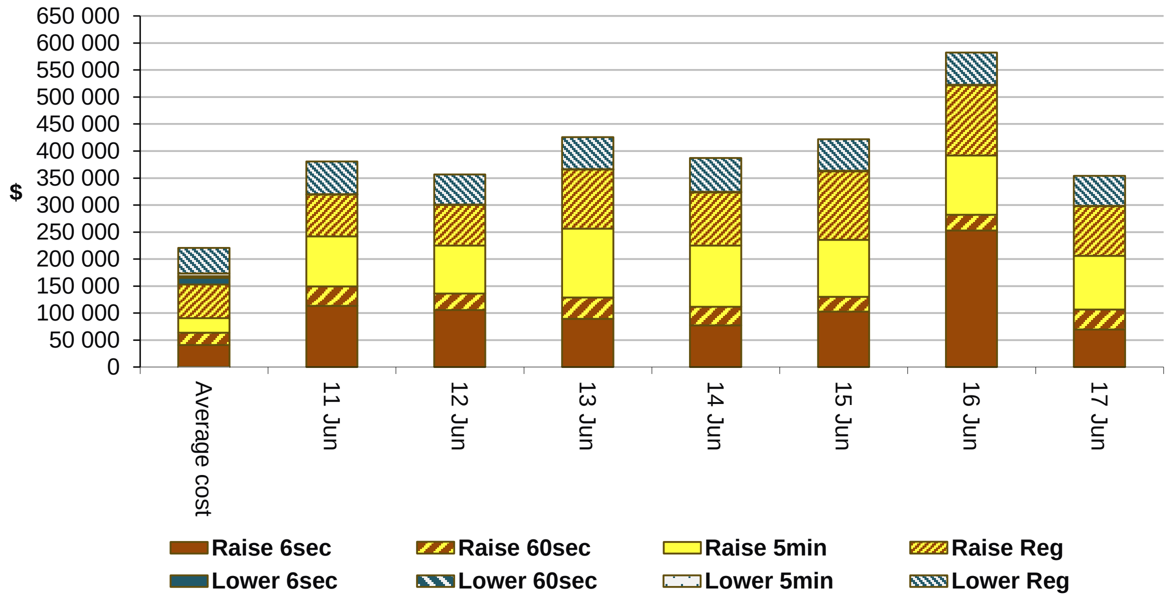
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 089 000 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $817 500 or around three per cent of energy turnover in Tasmania.of the previous financial year.

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



Since 5 May, AEMO limited the contribution of regulation services from Tasmania to the mainland to 50 MW. This has seen prices rise in the mainland and has led to the daily cost being higher than the previous financial year’s average.

The higher than average raise 6 second cost on 16 June was a result of co-optimisation of energy and raise 6 second markets in Tasmania, leading to a dispatch price at the cap at 6.20 am.

Detailed market analysis of significant price events

Tasmania

There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $116/MWh and above $250/MWh.

Thursday, 15 June

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
12.30 pm	2092.15	97.88	96.95	1200	1247	1221	1957	2025	2028

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

At 11.08 am HydroTas rebid around 150 MW of capacity priced less than $10/MWh to prices above $12 000/MWh at its Reece and John Butters power stations. The reason given was “1107P fcas requirement different to forecast”. At 12.05 pm there was a step change in the amount of low priced capacity available which resulted in the price increasing to $12 114/MWh for one dispatch interval.

Tasmanian participants rebid over 210 MW of capacity priced above $12 000/MWh to less than $0/MWh for the remainder of the trading interval. This resulted in the dispatch price remaining below $100/MWh for the rest of the trading interval.

Friday, 16 June

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	2132.69	113.39	12 114.40	1190	1175	1180	2024	2006	2007
9.30 pm	2100.28	98.92	96.27	1240	1266	1283	2084	2049	2111

For both trading intervals, demand and availability were close to that forecast four hours ahead.

For the 6.30 am trading interval, there was no capacity priced between $108/MWh and $12 114/MWh. Over two rebids from 6.02 am, Hydro Tasmania rebid 33 MW of capacity at Liap, Cata, Waya power station from -$75/MWh to $12 114/MWh. The reasons given were “0601P lk lvl < fcast” and “0606P plant late to start”.

The rebids coupled with the increases in morning peak demand resulted in the price increasing to $12 114/MWh at 6.20 am.

Rebidding 336 MW of capacity priced above $12 114/MWh to less than $0/MWh caused the price to remain below $100/MWh for the remainder of the trading interval.

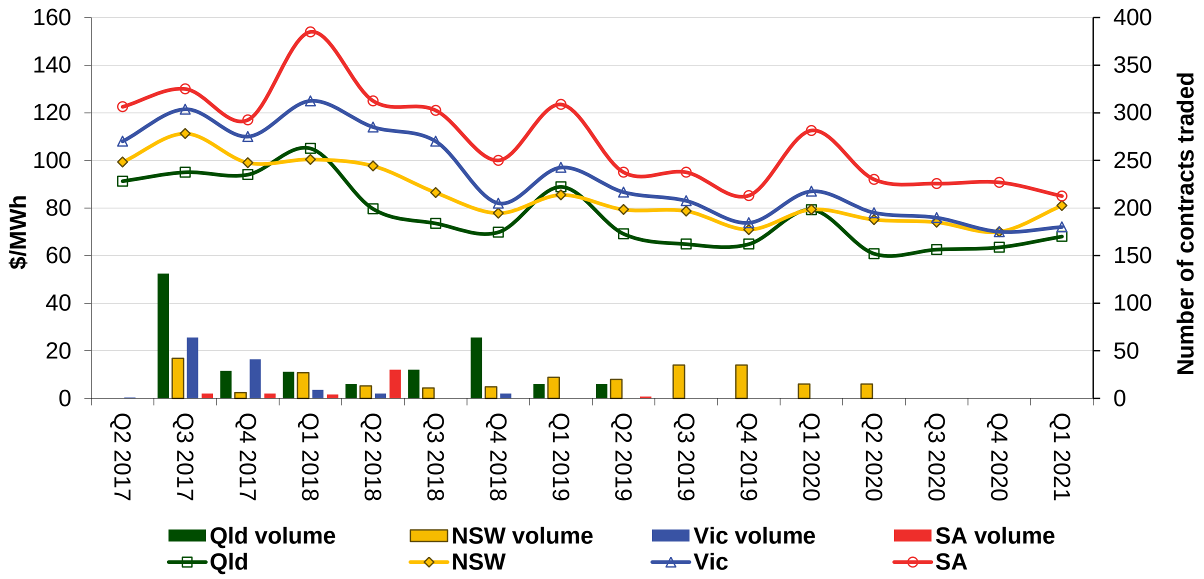
Leading up to the 9.30 pm trading interval: At 7.24 pm, Hydro Tasmania rebid 132 MW of capacity from -$1/MWh to $12 115/MWh at its John Butters and Tungatin power stations, with the reason “1922P machine target different to expectation”. At 9.05 pm there was a step change in the amount of low priced capacity available which resulted in the price increasing to $12 115/MWh for one dispatch interval.

The price then dropped to around $100/MWh for the remainder of the trading interval due to a 80 MW decrease in demand.

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.

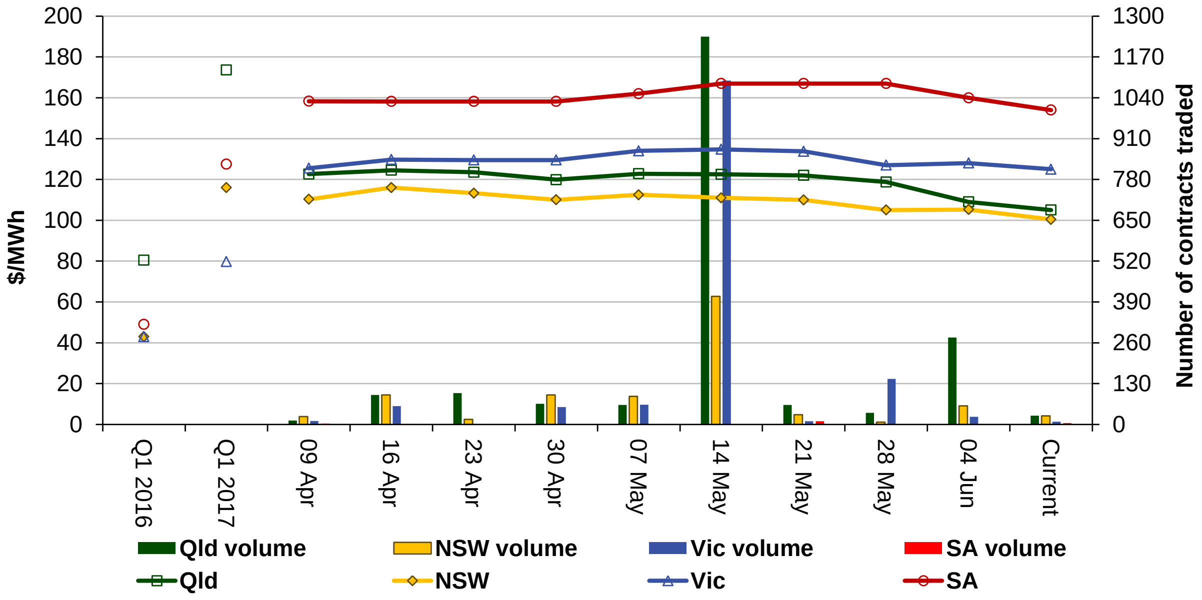
Figure 9: Quarterly base future prices Q2 2017 – Q1 2021



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. The high volumes for the week staring 14 May were a result of the conversion of 2017/18 financial year base load options to base future contracts.

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



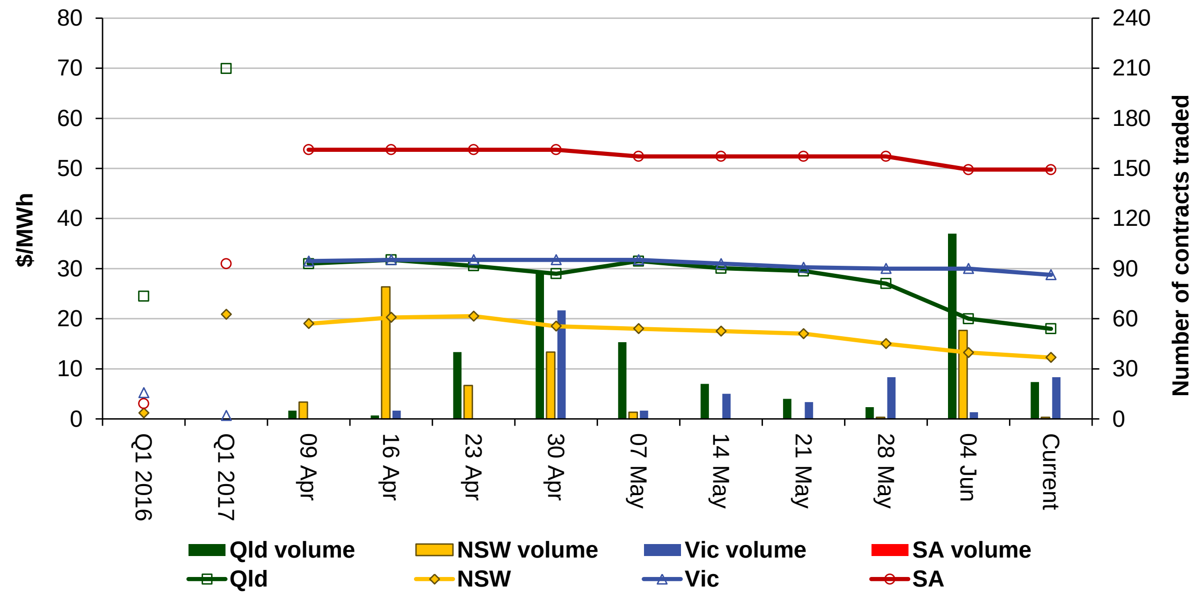
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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