Electricity Report
14 – 20 June 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 14 to 20 June 2015. There were 2 occasions in South Australia where the spot price exceeded the AER reporting threshold. These are discussed later in this report.

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

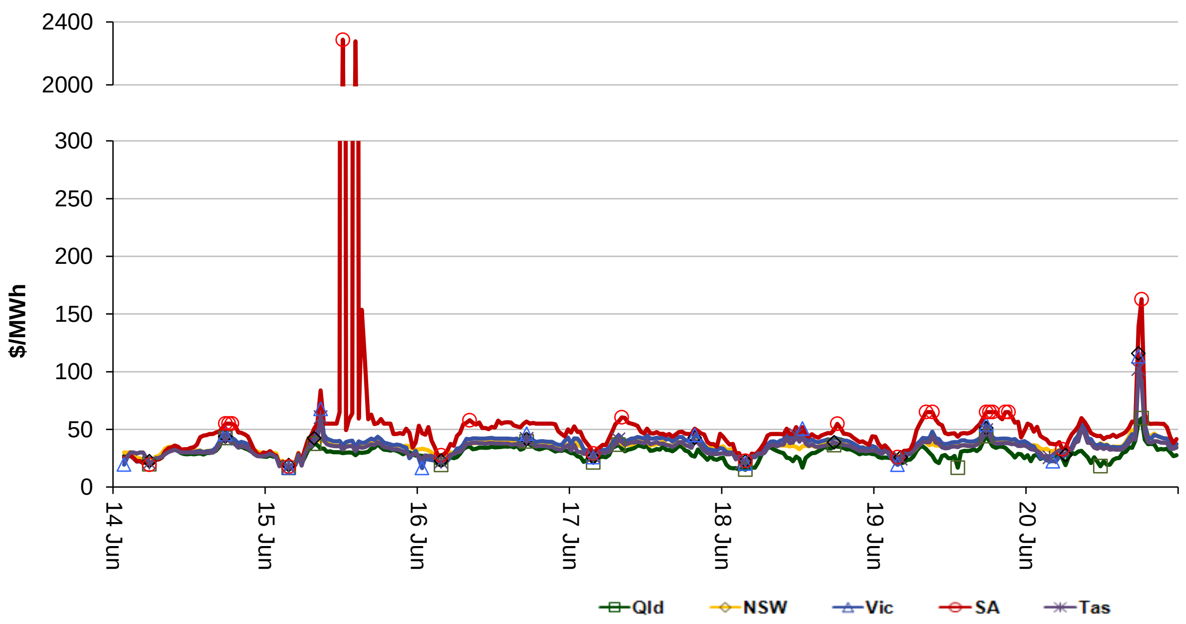


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

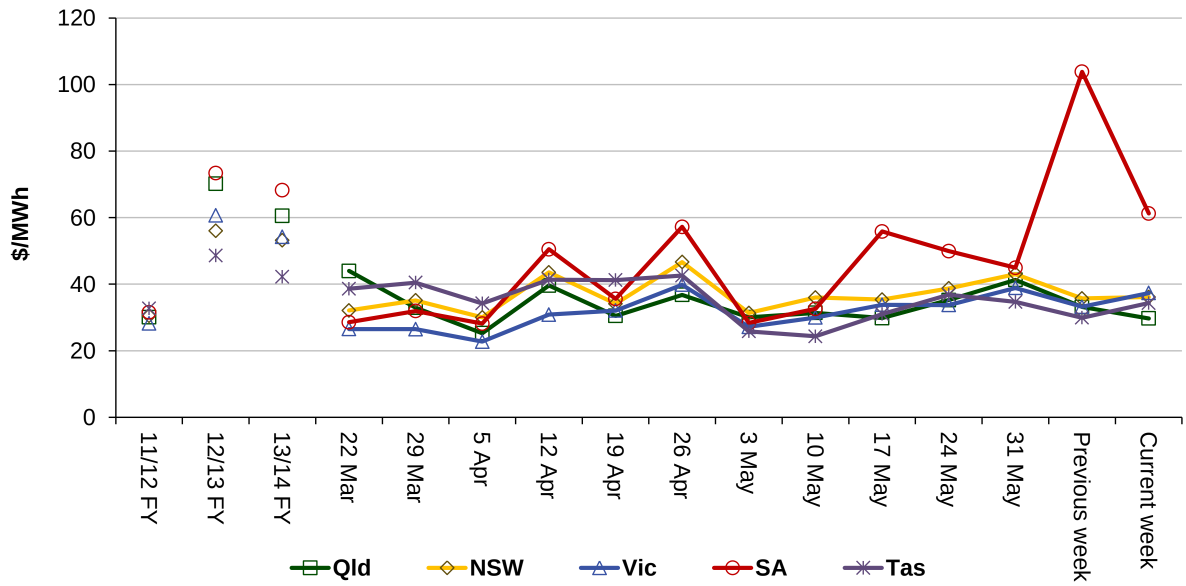


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	30	36	37	61	34
13-14 financial YTD	61	53	55	69	42
14-15 financial YTD	62	36	32	42	37

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 51 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	3	40	0	0
% of total below forecast	54	2	0	0

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

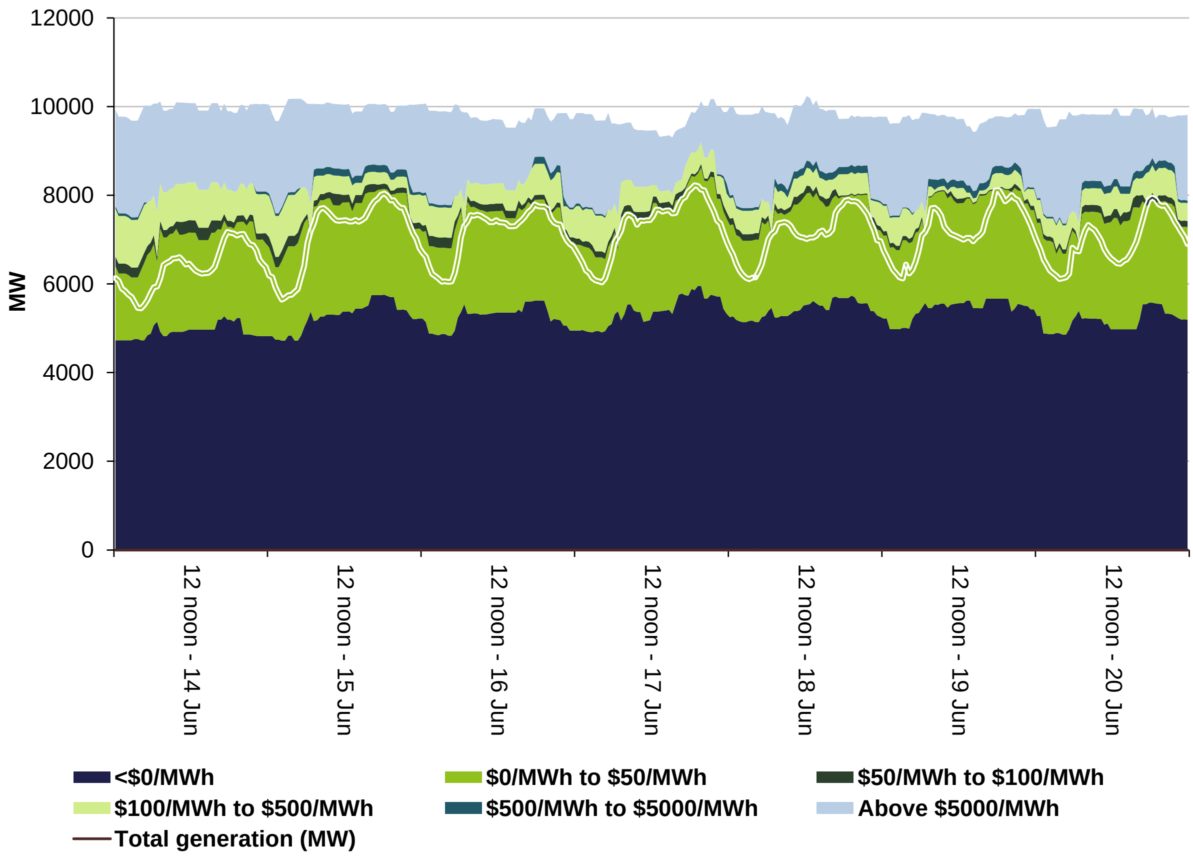


Figure 4: New South Wales generation and bidding patterns

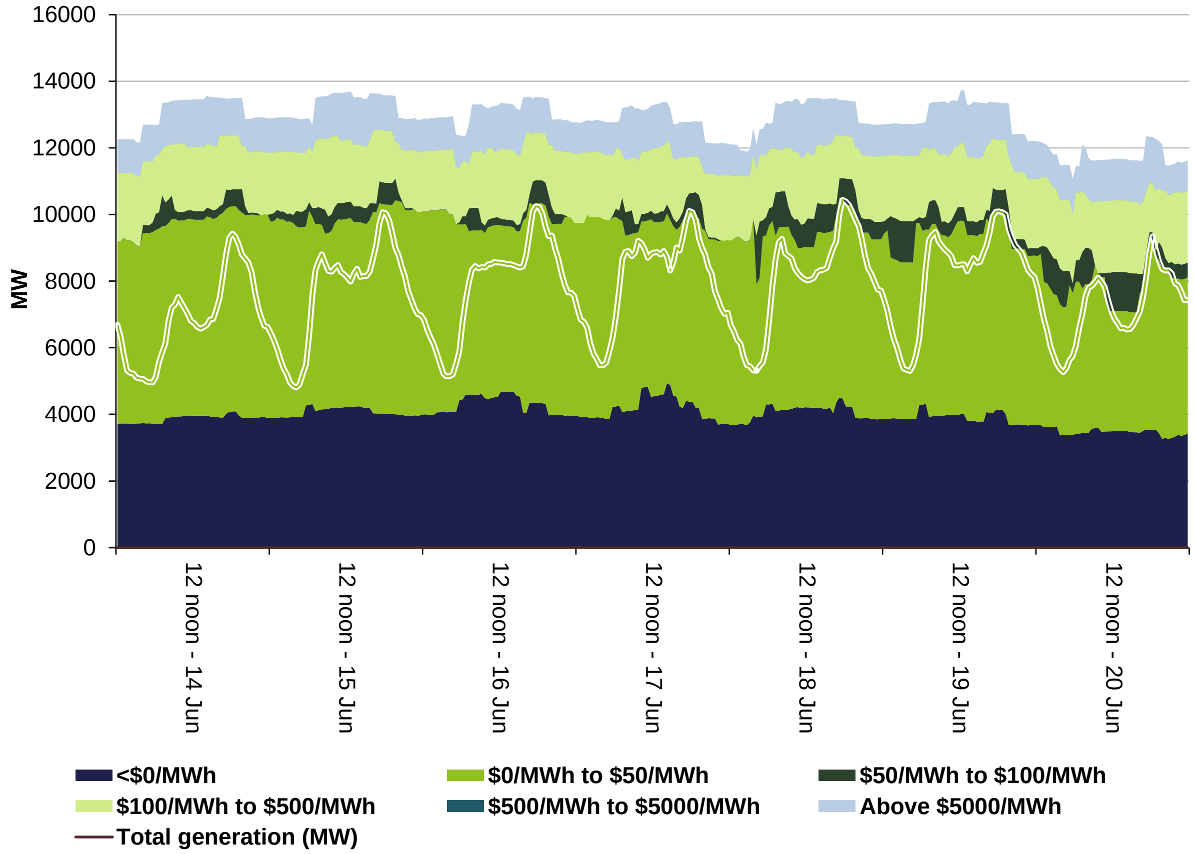


Figure 5: Victoria generation and bidding patterns

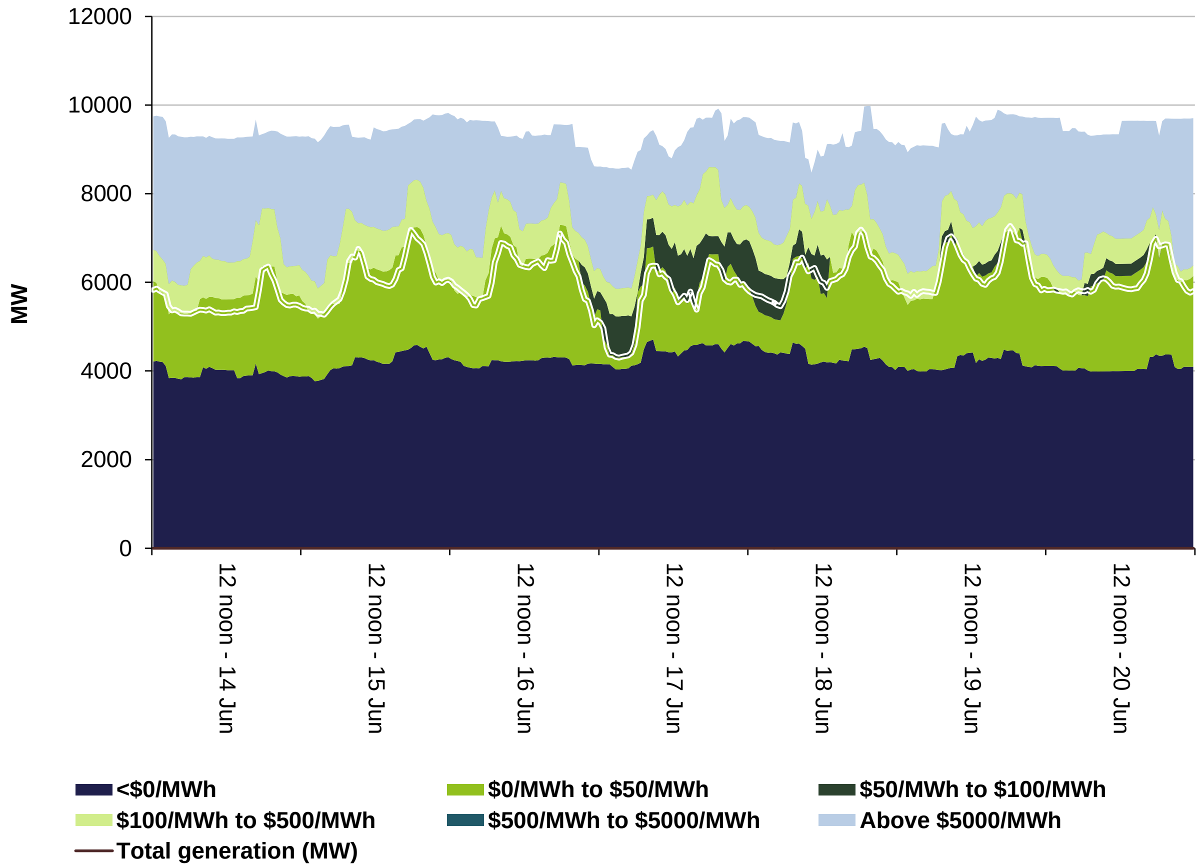


Figure 6: South Australia generation and bidding patterns

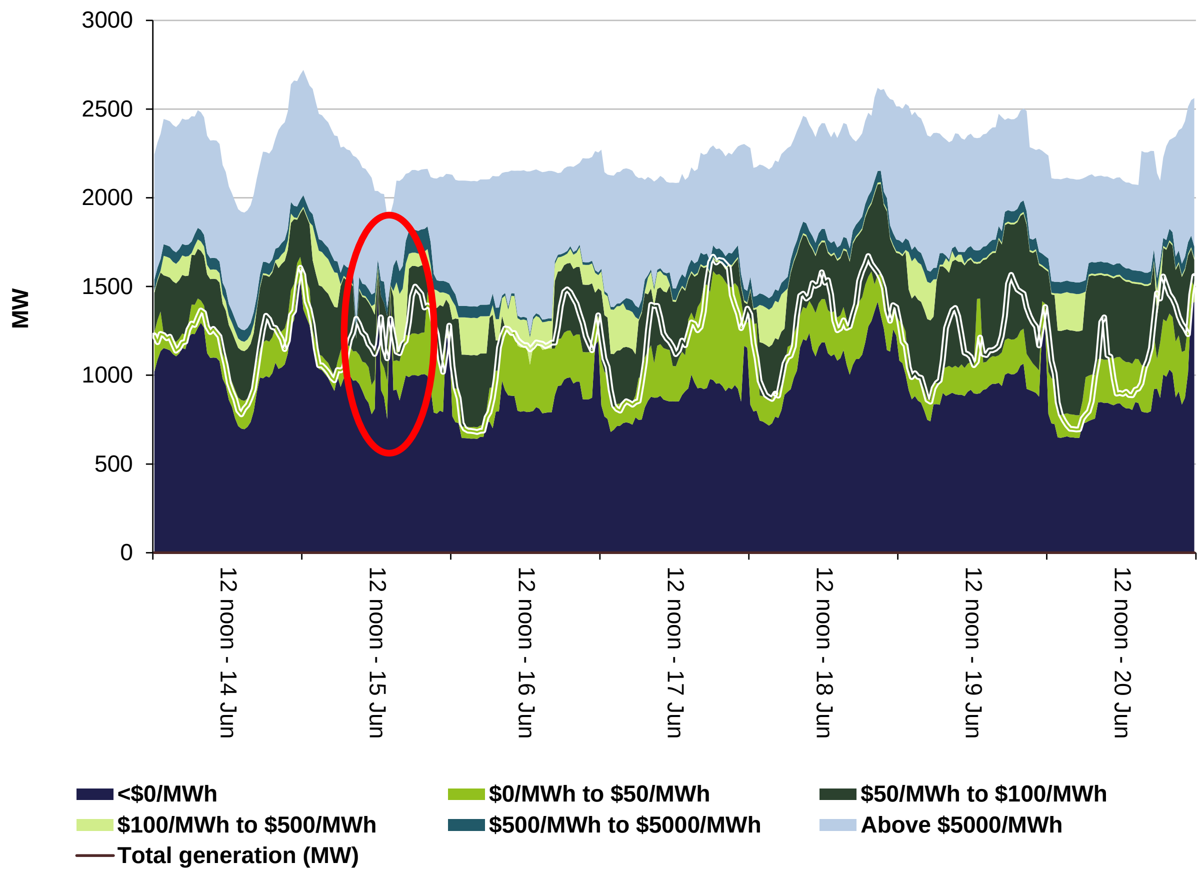
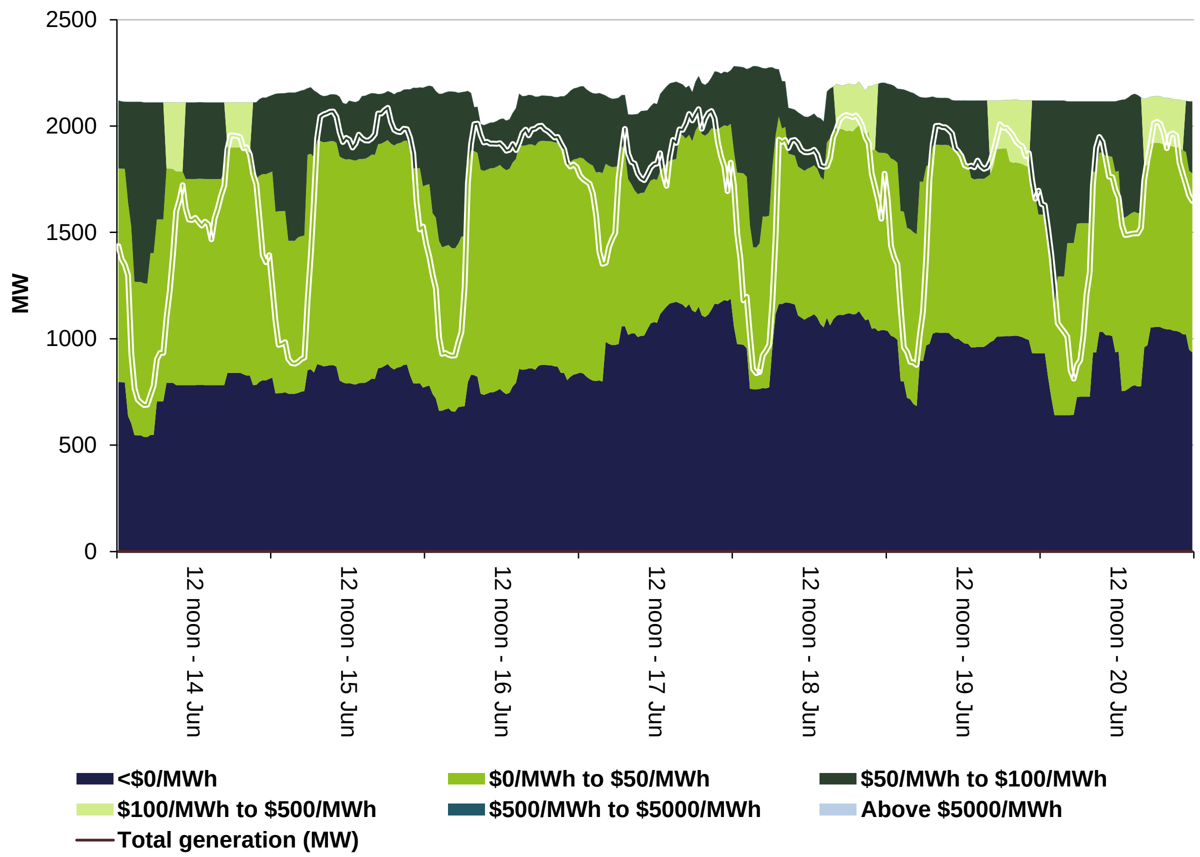


Figure 7: Tasmania generation and bidding patterns



The red ellipse on Figure 6 highlights the period in South Australia where there was significant market activity that resulted in volatile prices away from forecast.

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.

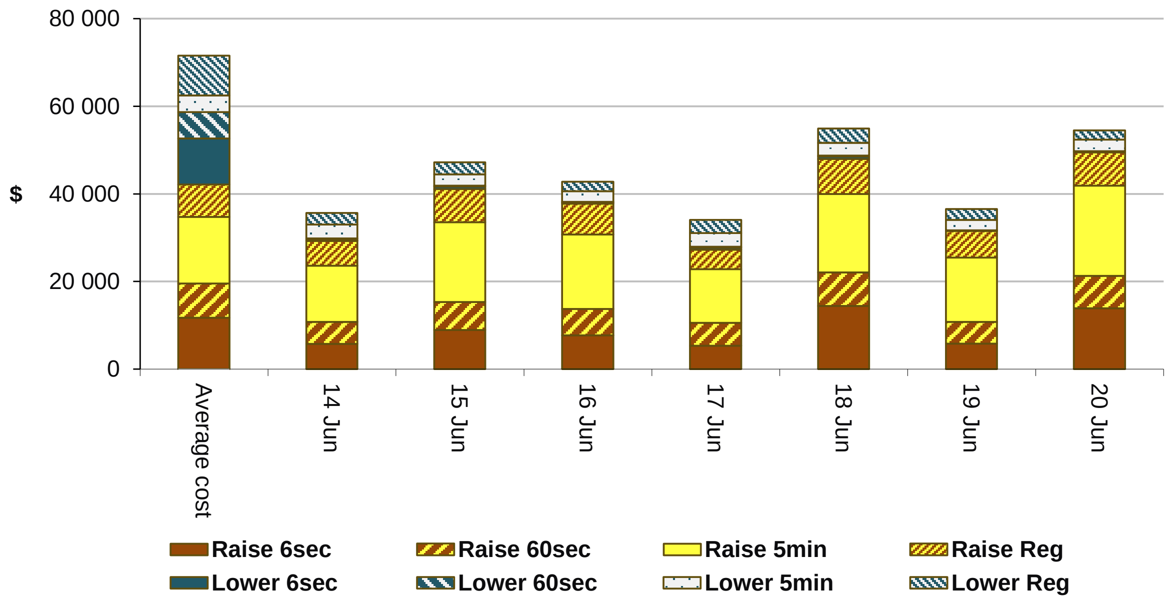
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $278 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $27 000 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.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $61/MWh and above $250/MWh.

Monday, 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	2287.03	54.99	46.10	1626	1578	1535	2049	2108	2135
2:30 pm	2276.71	54.99	50.72	1638	1630	1545	1919	2079	2100

For the 12.30 pm trading interval, demand was 48 MW higher, and available capacity was 59 MW lower, than forecast four hours before.

For the 2.30 pm trading interval, demand was close to forecast. Available capacity was 160 MW lower than forecast four hours before as a result of a unit trip at Northern Power Station.[1]

At 12.03 pm, effective from 12.10 pm, AGL rebid 380 MW of capacity at Torrens Island from prices below $95/MWh to the price cap. The reason given was “1200~A~040 CHG in AEMO DISP~increase in generation QPS1 start SA”.

This saw the dispatch price increase from $65/MWh at the 12.05 pm dispatch interval to the price cap for the 12.10 pm dispatch interval.[2]

A 127 MW decrease in demand saw the price decrease to $52/MWh for the 12.15 pm interval. The price remained around this level for the remainder of the trading interval. The decrease in demand corresponds to the operation of the non-scheduled generation at Lonsdale, Port Stanvac and Angaston in South Australia.

At 1.55 pm, effective from 2.05 pm, AGL rebid 365 MW of capacity at Torrens Island from prices below $95/MWh to the price cap. The reason given was “1355~A~030 CHG in AEMO AVAIL CAP~30 DECREASEN SA -130MW”.

This saw the dispatch price increase from $65/MWh at the 2 pm dispatch interval to $13 482/MWh for the 2.05 pm dispatch interval.[3]

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1 Available capacity at Northern Power Station had been priced at $46/MWh or lower prior to the trip.

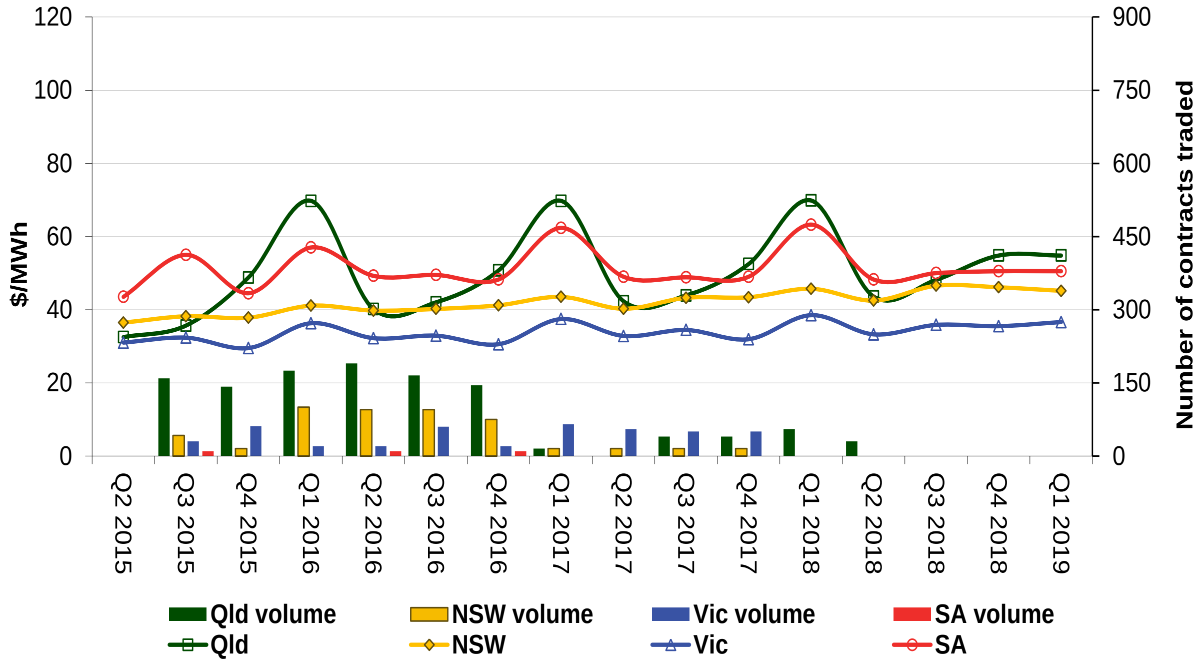
2 Required supply from Torrens Island units set the price at the cap at 2.10 pm. Other lower priced generation at Hallett was ramp up constrained at the time and all other non-wind output was bid as inflexible or dispatched at its maximum availability. Wind output was below 14 MW at the time.

At 2.02 pm, effective from 2.10 pm, another rebid by AGL at Torrens Island saw 365 MW of capacity priced at the cap and an additional 125 MW of capacity priced at $46/MWh shifted to the price floor. This, combined with a 131 MW decrease in demand, resulted in the 2.10 pm dispatch price decreasing to $38/MWh. The price remained around this level for the remainder of the dispatch interval. The decrease in demand corresponds to the operation of the non-scheduled generation at Lonsdale, Port Stanvac and Angaston in South Australia.

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 2015 – Q1 2019

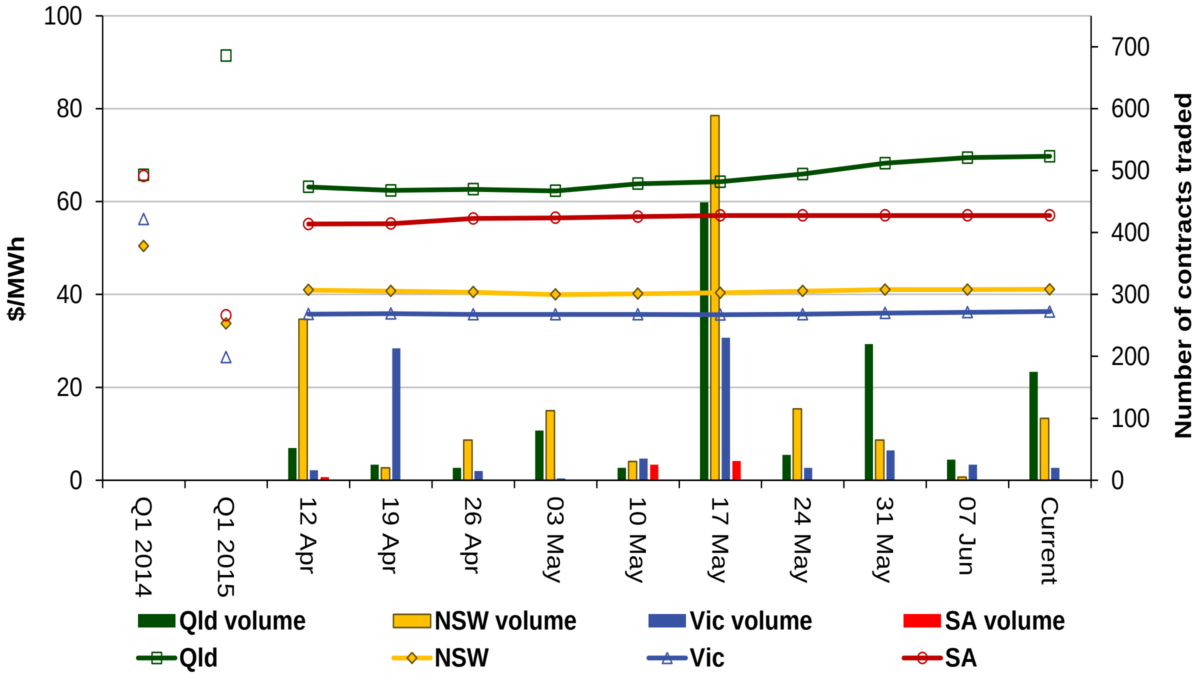


Source: ASXEnergy.com.au

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.

[3] Other lower priced capacity was either ramp up constrained or at maximum availability, while two fast start units at Dry Creek required one dispatch interval to synchronise before generating 40 MW in the following interval. There was no wind output at the time.

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



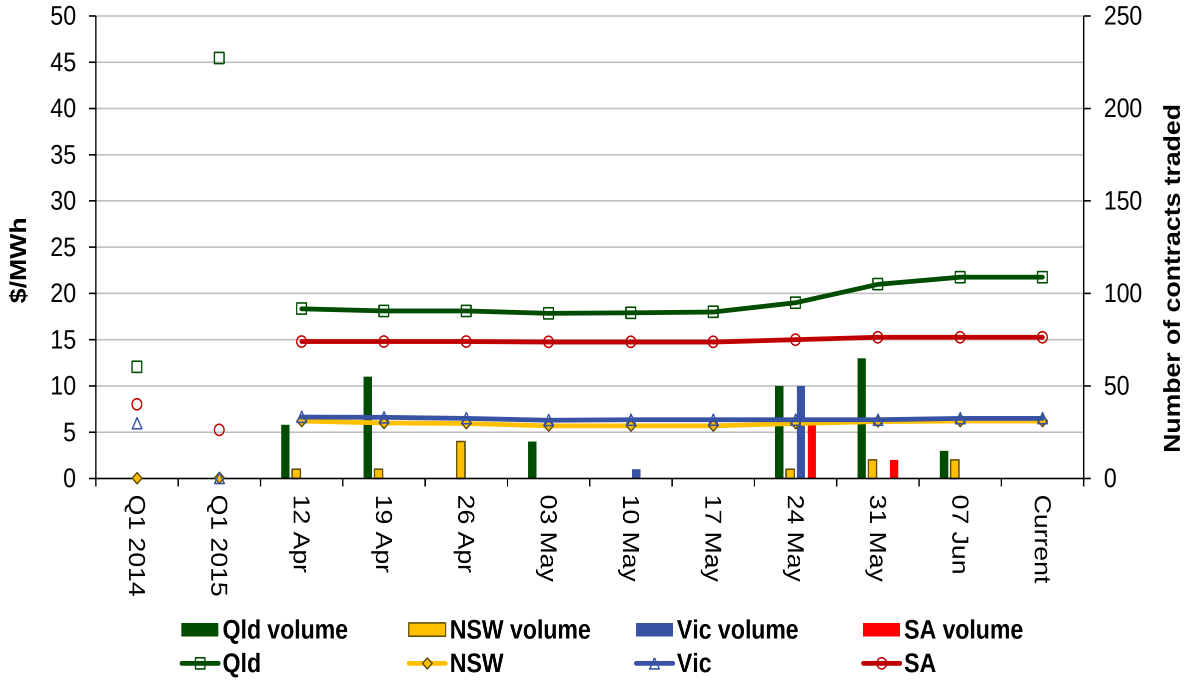
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Performance of the Energy Sector] section of our website.

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

Australian Energy Regulator

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