Electricity Report

1 to 7 June 2014

AUSTRALIAN ENERGY REGULATOR

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 1 to 7 June 2014. The Tasmanian price spike on 5 June reached $2235/MWh.

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

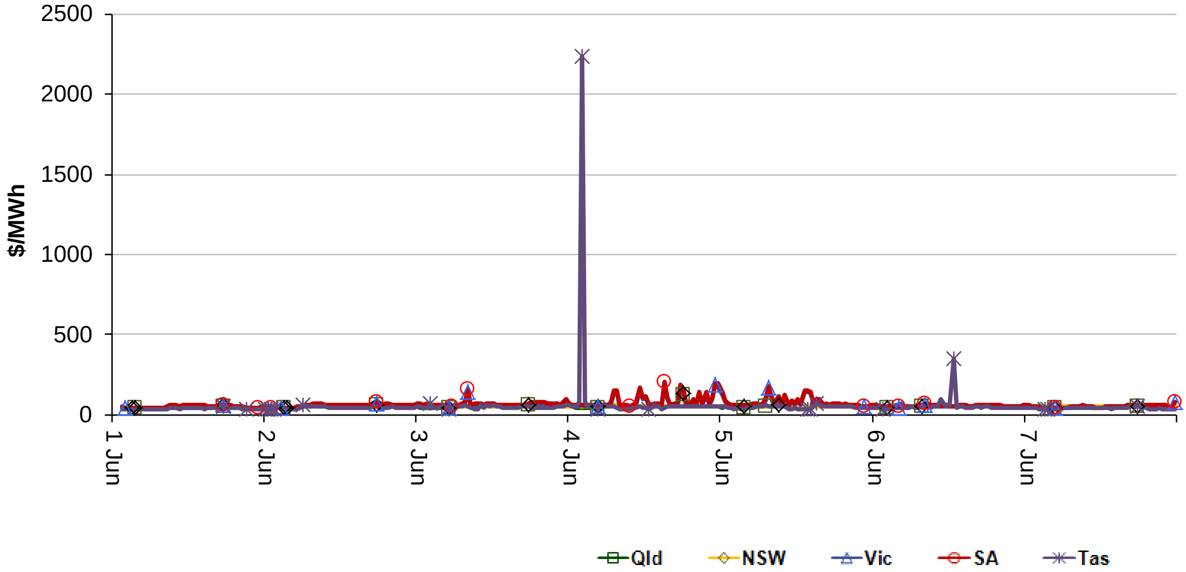


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

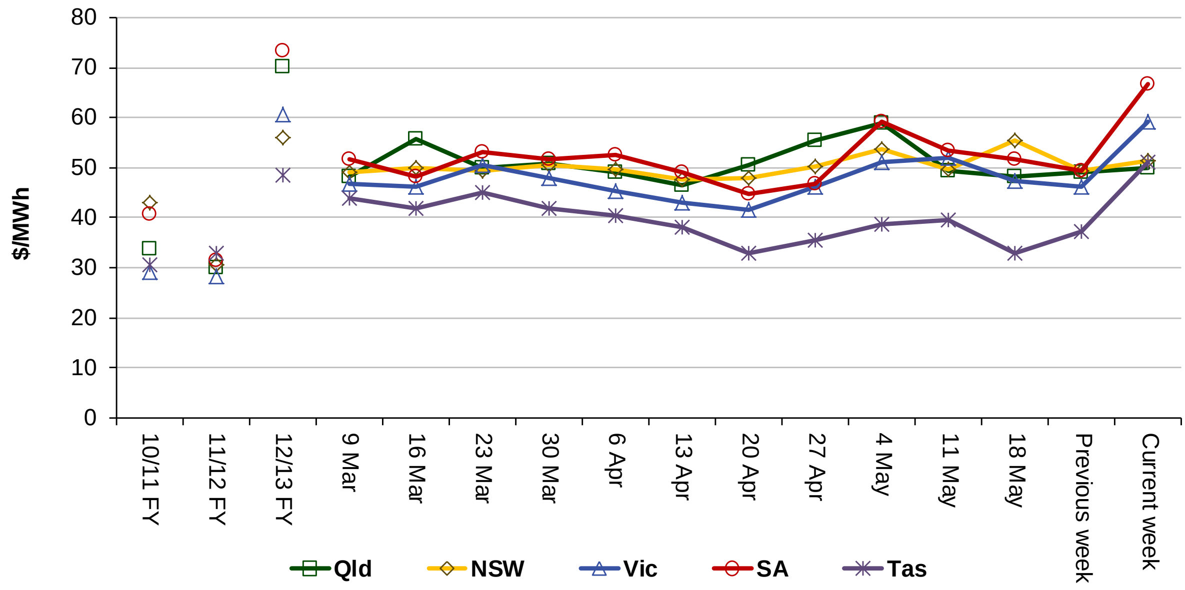


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	50	51	59	67	51
12-13 financial YTD	70	56	61	73	49
13-14 financial YTD	61	53	55	69	42

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 80 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2013 of 97 counts and the average in 2012 of 60. 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	23	24	2	16
% of total below forecast	10	22	0	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. Figures 3 to 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

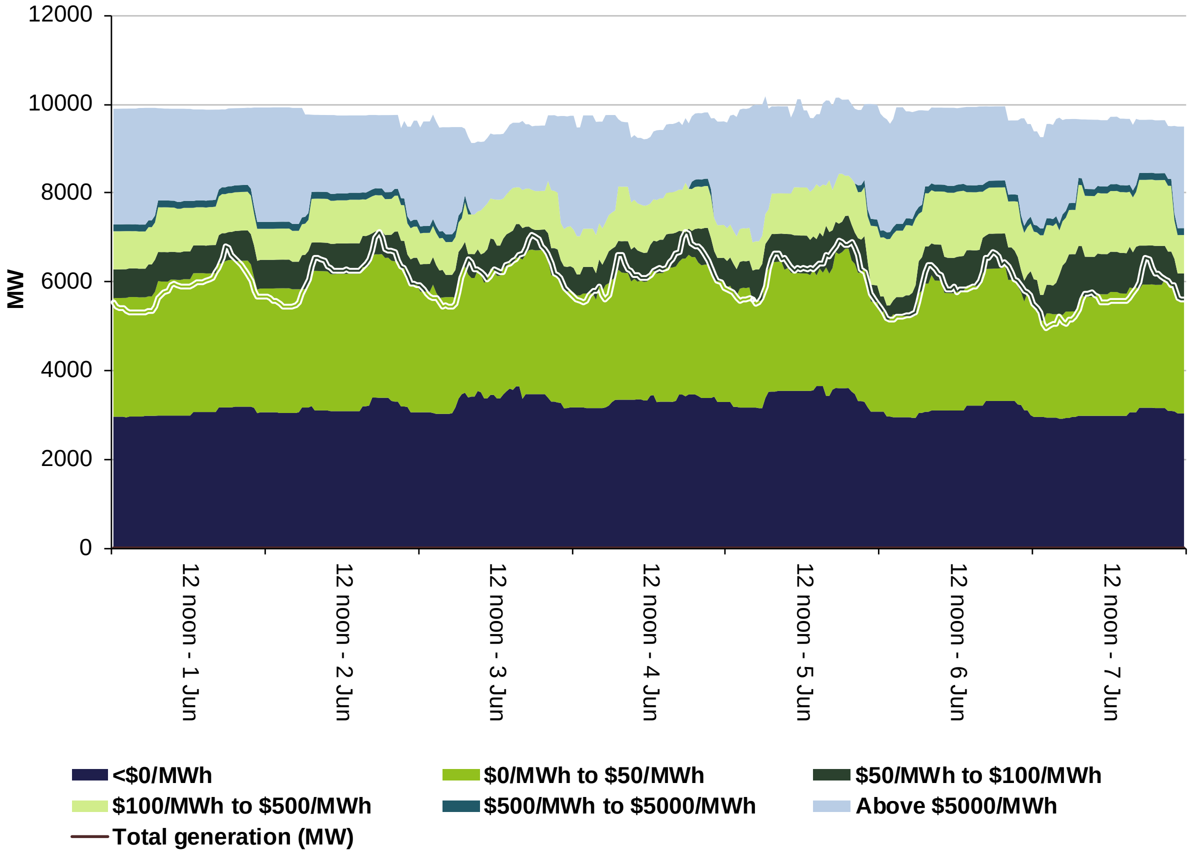


Figure 4: New South Wales generation and bidding patterns

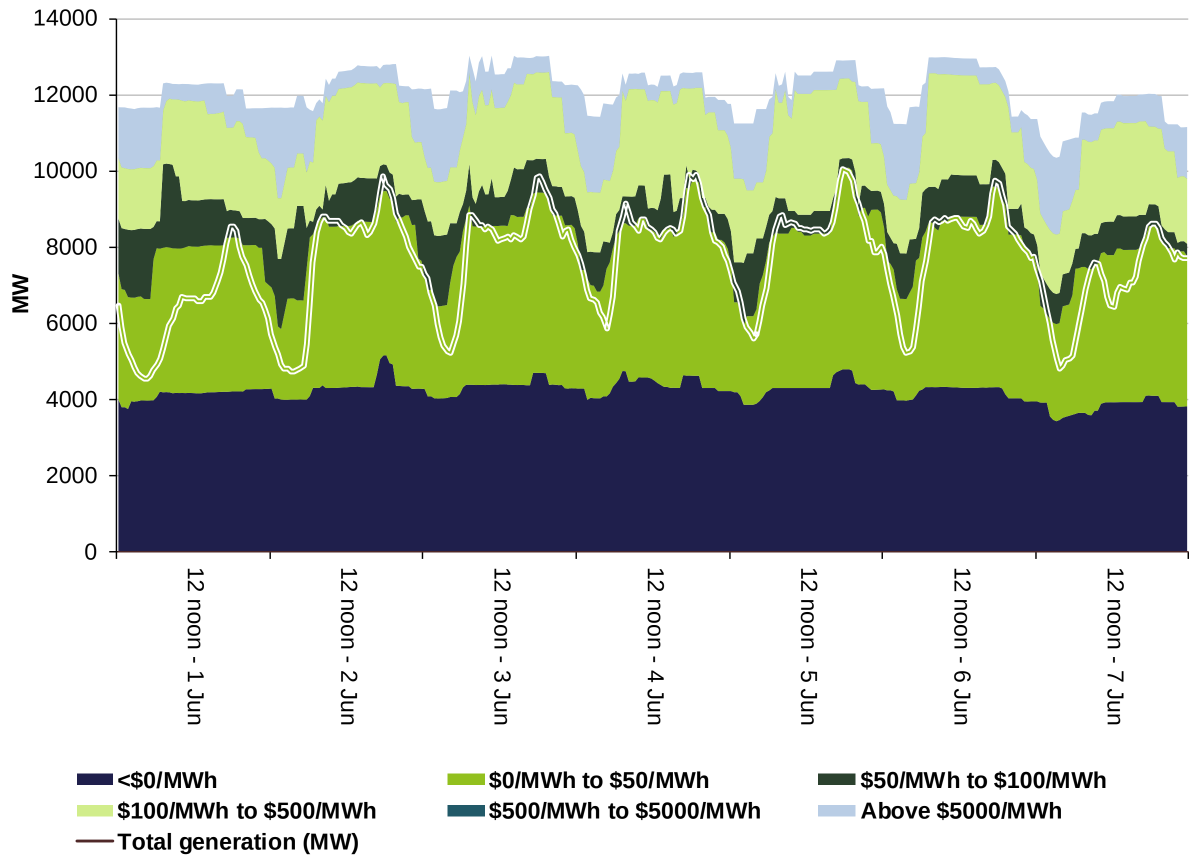
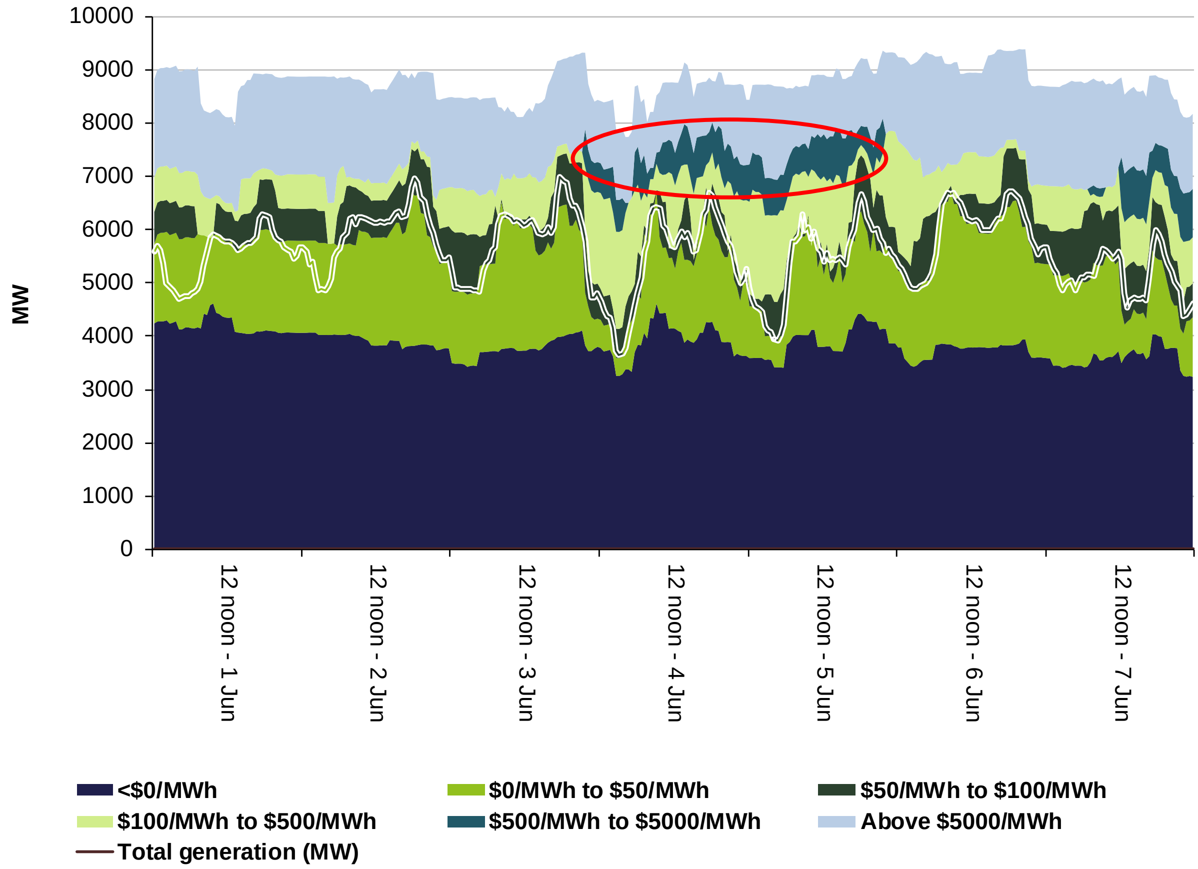


Figure 5: Victoria generation and bidding patterns



Rebidding at Loy Yang A power station saw available capacity reduced or rebid from below $50/MWh to just over $500/MWh across the day on 4 and 5 June. The reasons given for the rebids indicated issues with coal causing plant limitations.

Figure 6: South Australia generation and bidding patterns

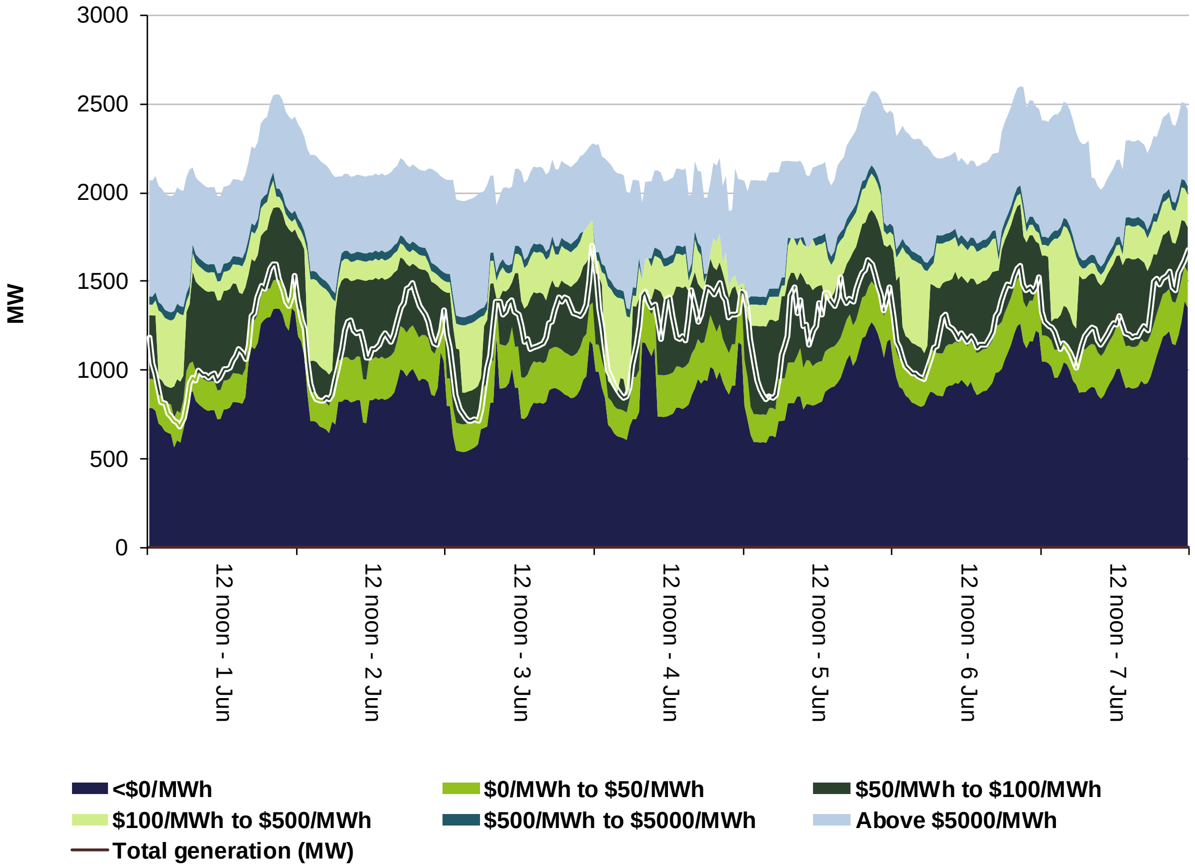
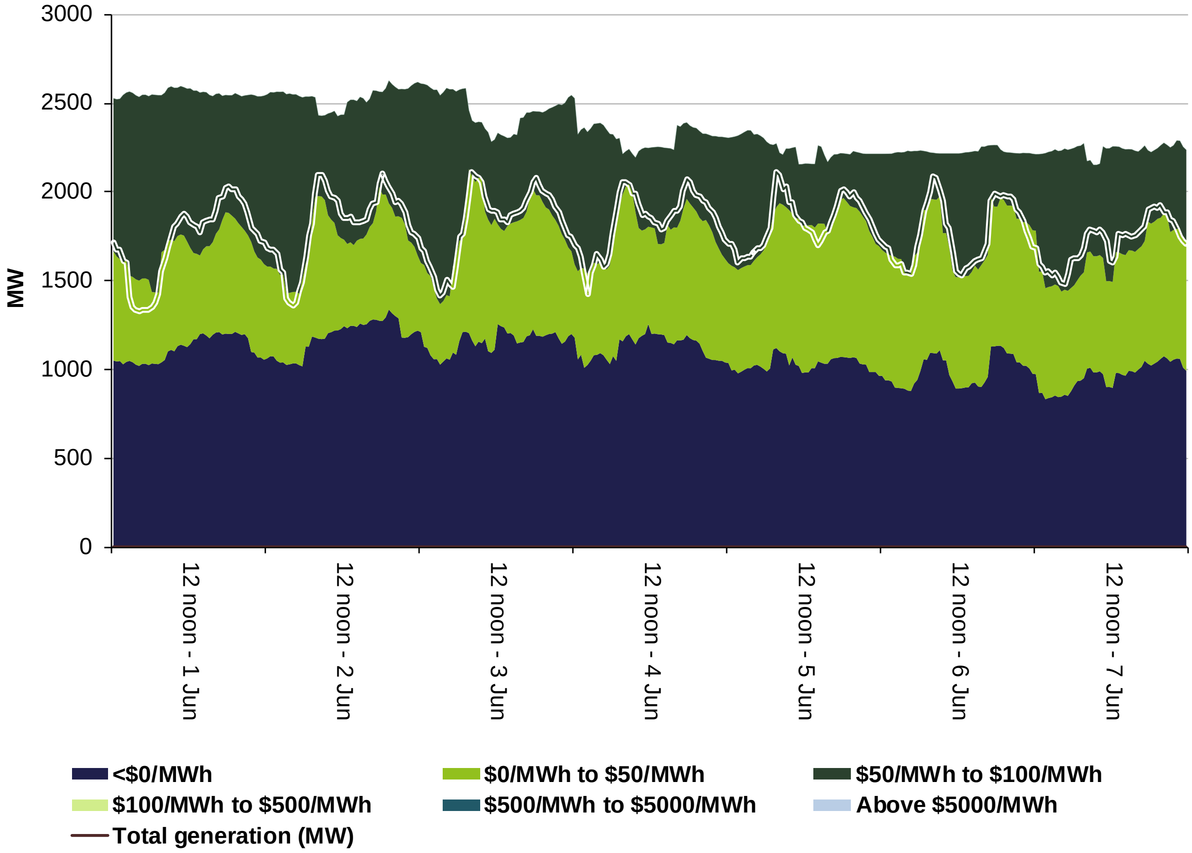


Figure 7: Tasmania generation and bidding patterns



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.

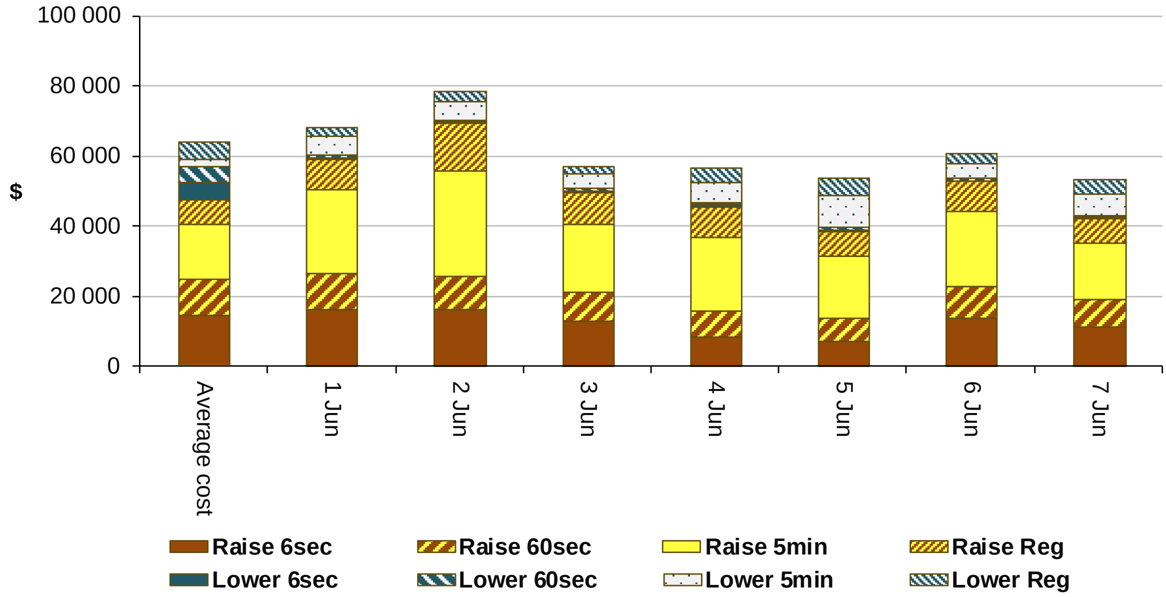
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $391 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $36 000 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.

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $51/MWh and above $250/MWh. In both cases, prices were generally aligned across all regions of the NEM.

Table 3: Tasmania, Wednesday 4 June

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
2.30 AM	2235.2	36.34	36.34	964	985	985	2338	2370	2422

Conditions at the time saw demand and available capacity close to that forecast.

The high price was driven by network constraints in Tasmania. The constraint T>>T_NIL_BL_EXP_5F manages post contingent flows on the Hadspen to Georgetown 220 kV lines. The constraint affects all Tasmanian generation except for generation at Tamar Valley and affects flows to Victoria on Basslink.

An increase in flows across the Hadspen to Georgetown 220 kV lines from 2.05 am caused the constraint to violate, reducing local generation at a number of units by around 270 MW and reducing total exports to Victoria by around 240 MW.

Limited ramp rate capability (and generators trapped in FCAS or fully dispatched) contributed to the five minute price reaching $13 100/MWh.

There was an apparent 37 MW demand side response from a Tasmanian industrial load and prices returned to previous levels as ramp rate restrictions diminished.

There was no significant rebidding.

Table 4: Tasmania, Friday 6 June

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
1.00 PM	351.14	47.74	45.95	1180	1259	1248	2219	2270	2270

Demand and generation in Tasmania were both below forecast, by 79 MW and 51 MW respectively.

The high price was again driven by the same network constraint in Tasmania managing post contingent flows on the Hadspen to Georgetown 220 kV lines.

An increase in flows across the Hadspen to Georgetown 220 kV lines from 12.50 pm caused the constraint to bind, and reduced exports to Victoria by around 180 MW.

Limited ramp rate capability (and generators trapped in FCAS or fully dispatched) resulted in the five minute price reaching $1878/MWh.

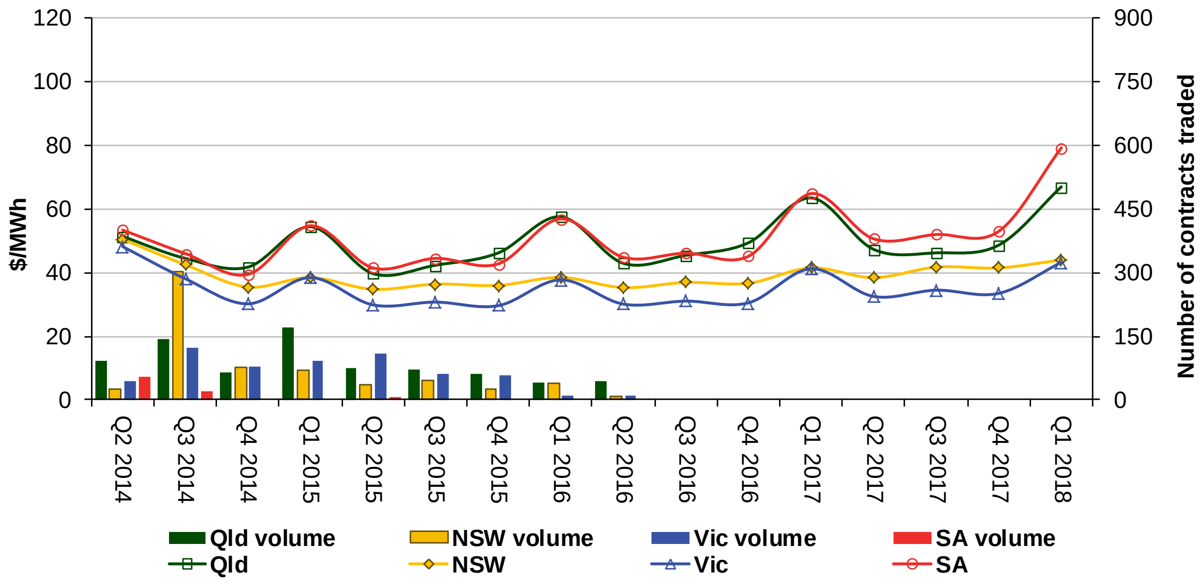
Prices returned to previous levels in the following interval when flows on the affected line reduced.

There was no significant rebidding.

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.

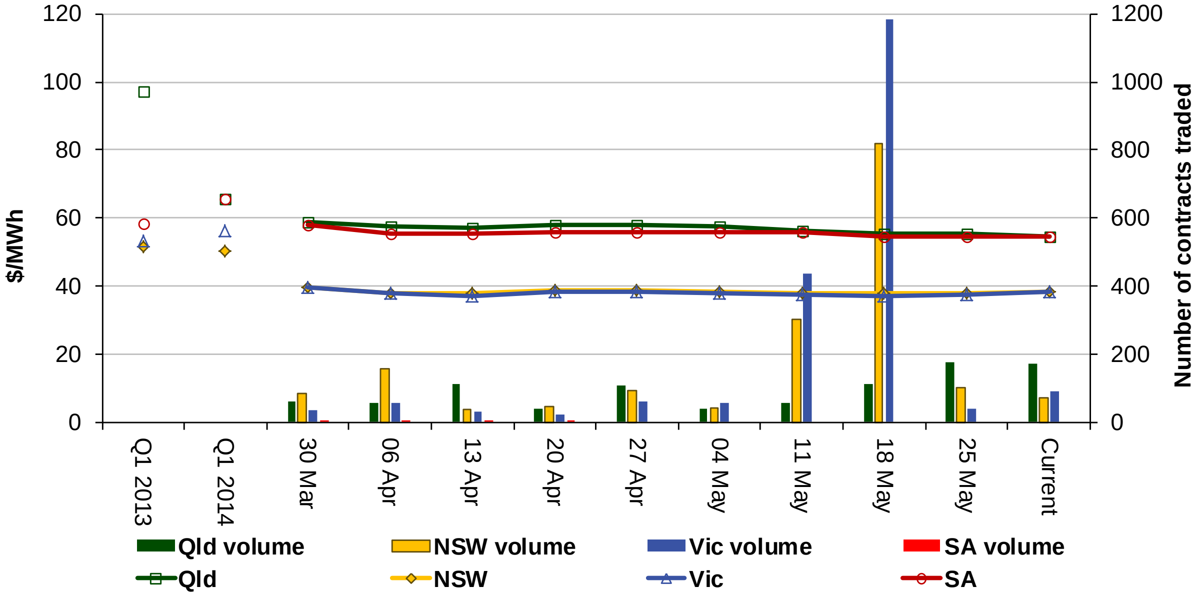
Figure 9: Quarterly base future prices Q2 2014 – Q1 2018



Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2015 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2013 and quarter 1 2014 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 2015 base contracts over the past 10 weeks (and the past 2 years)



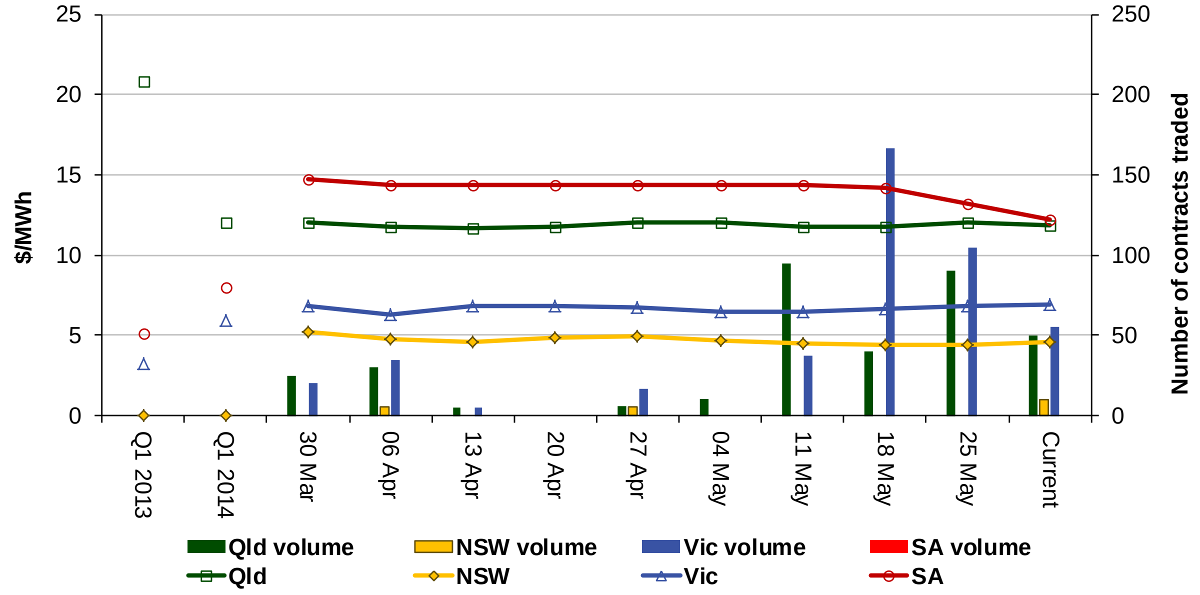
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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 shows how the price for each regional Quarter 1 2015 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2013 and quarter 1 2014 prices are also shown.

Figure 11: Price of Q1 2015 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

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