Electricity Report

20 to 26 July 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 20 to 26 July 2014. In South Australia the spot price reached $2288/MWh and $2088/MWh on 20 July and $2412/MWh on 22 July.

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

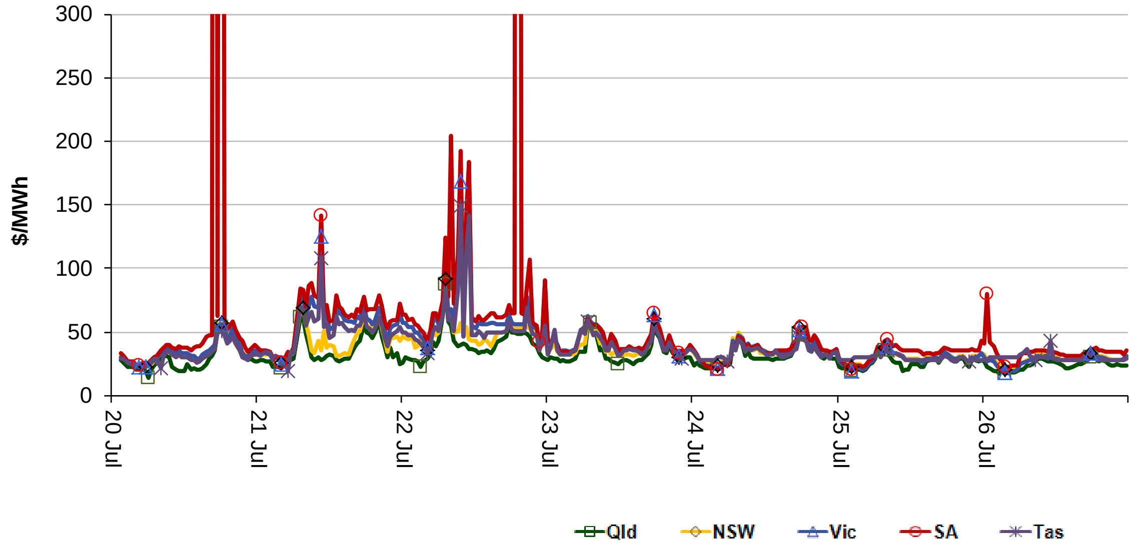


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

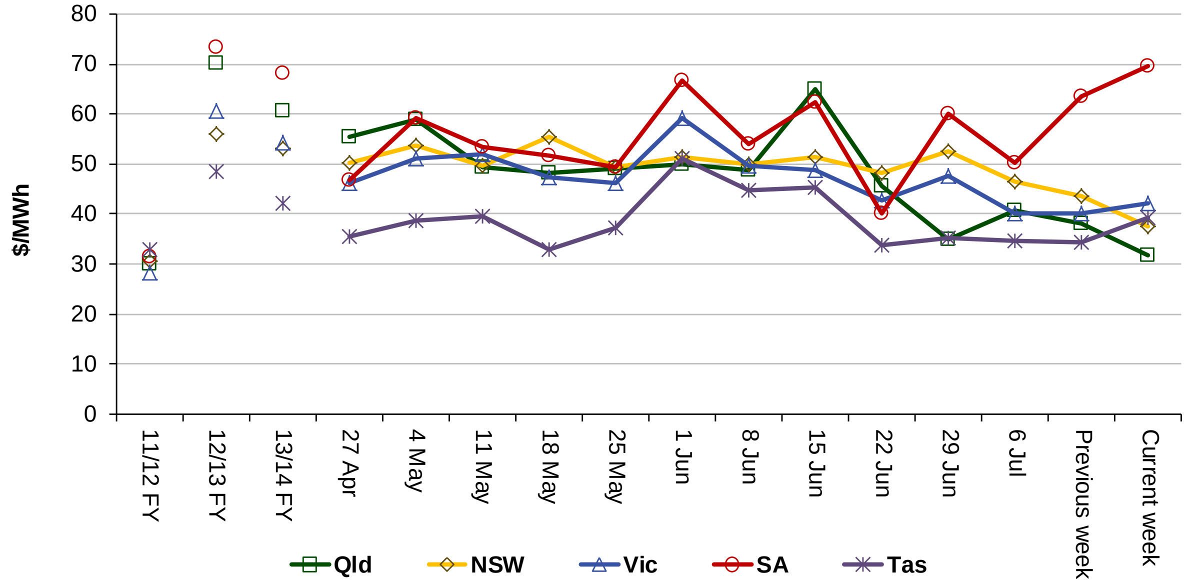


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	32	37	42	70	39
13-14 financial YTD	62	59	60	73	53
14-15 financial YTD	36	45	42	61	36

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 64 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	21	43	0	4
% of total below forecast	30	3	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. 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

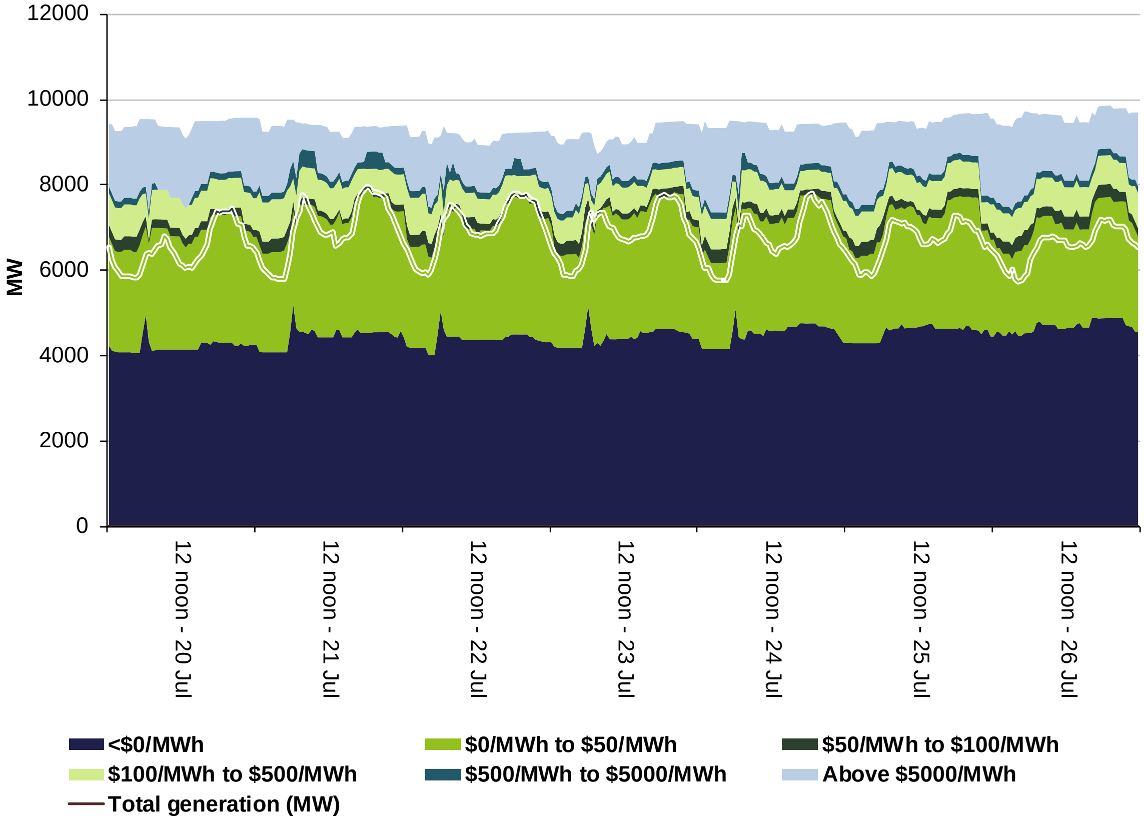


Figure 4: New South Wales generation and bidding patterns

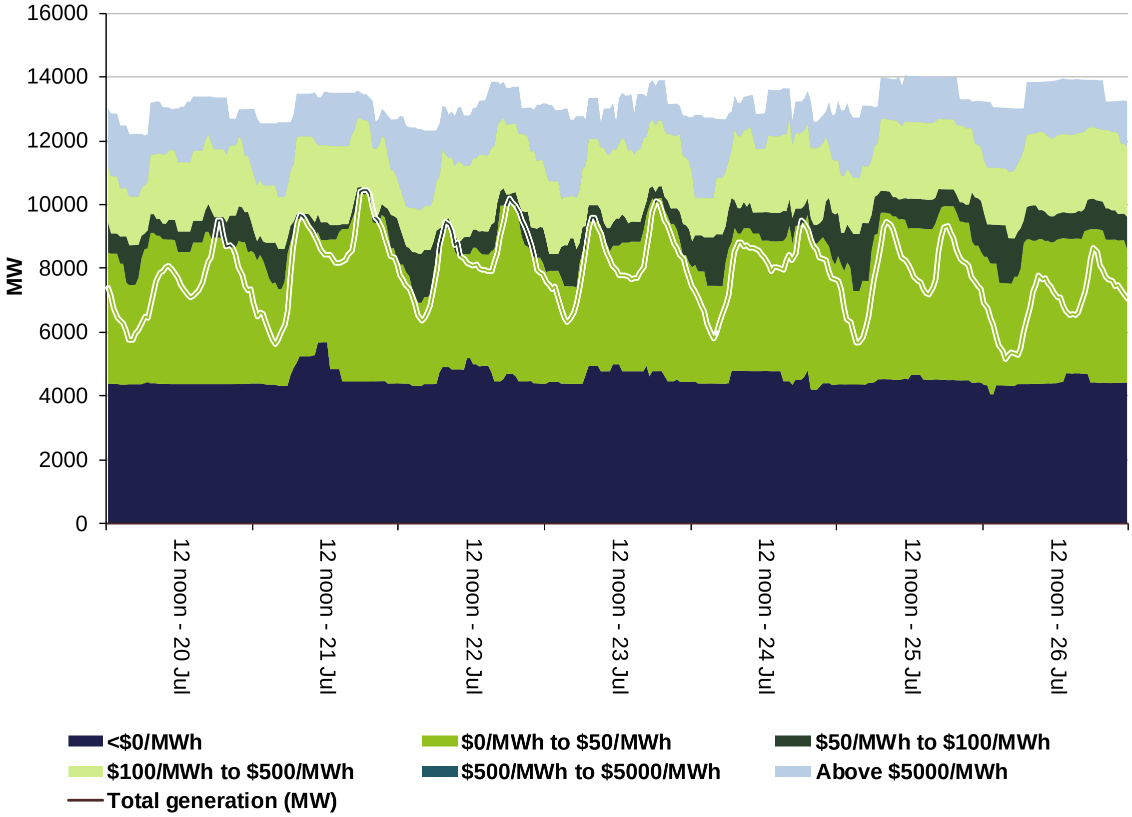
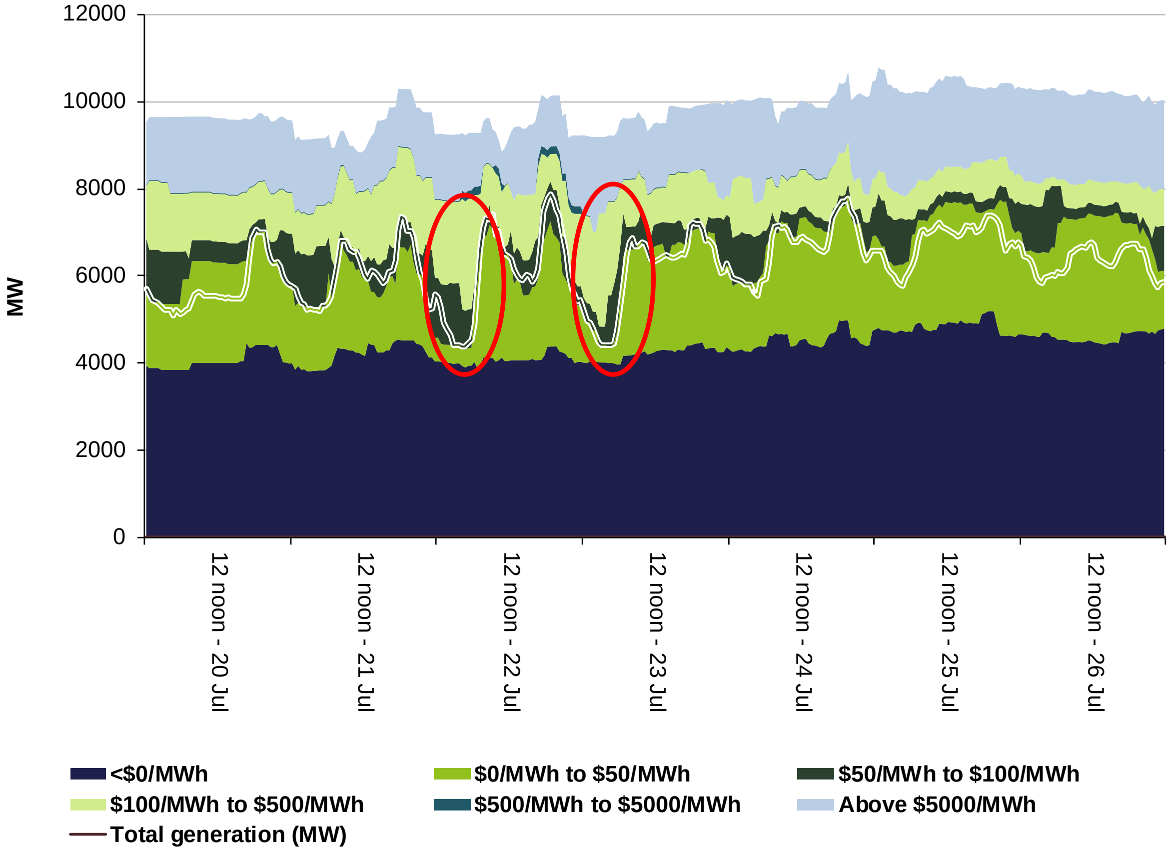


Figure 5: Victoria generation and bidding patterns



The red circles highlight periods where there was a significant shuffling of the capacity available between $0/MWh to $500/MWh. GDF Suez and Energy Australia reduced the available capacity of the Loy Yang B and Hazelwood power stations and AGL rebid Loy Yang A capacity into higher price bands. .

Figure 6: South Australia generation and bidding patterns

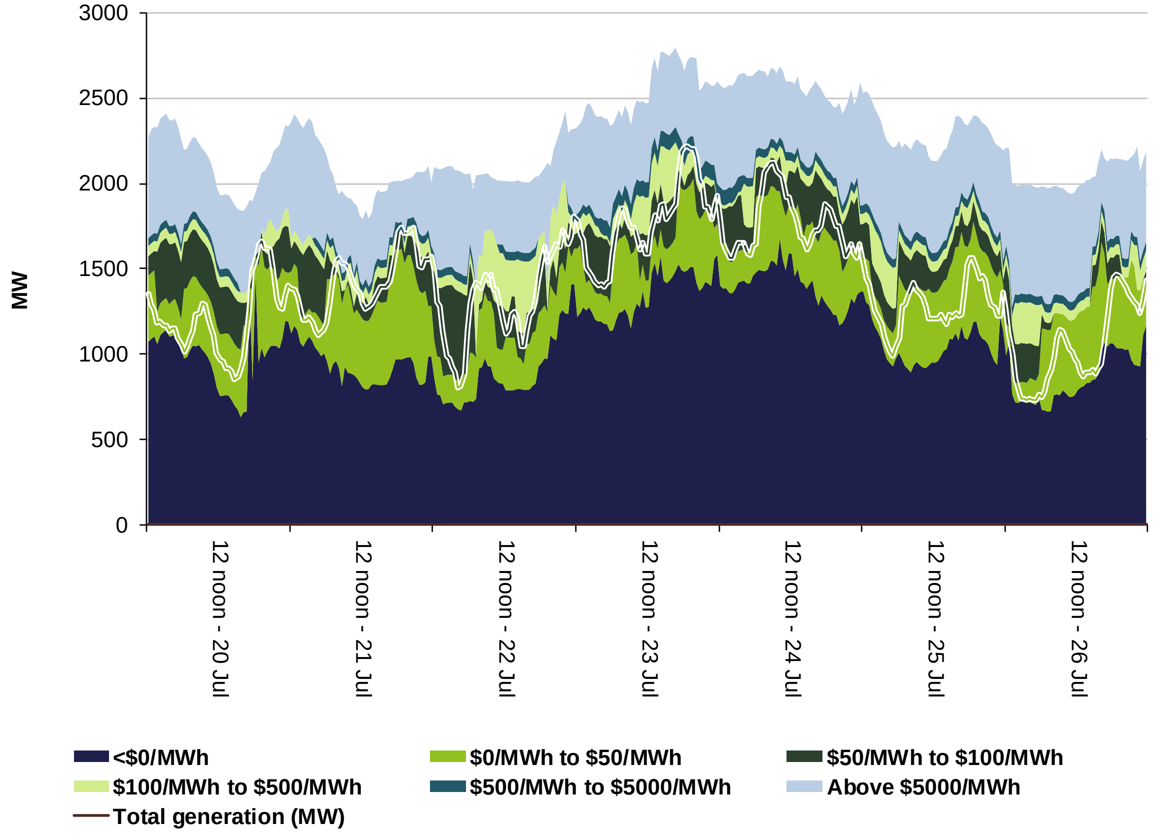
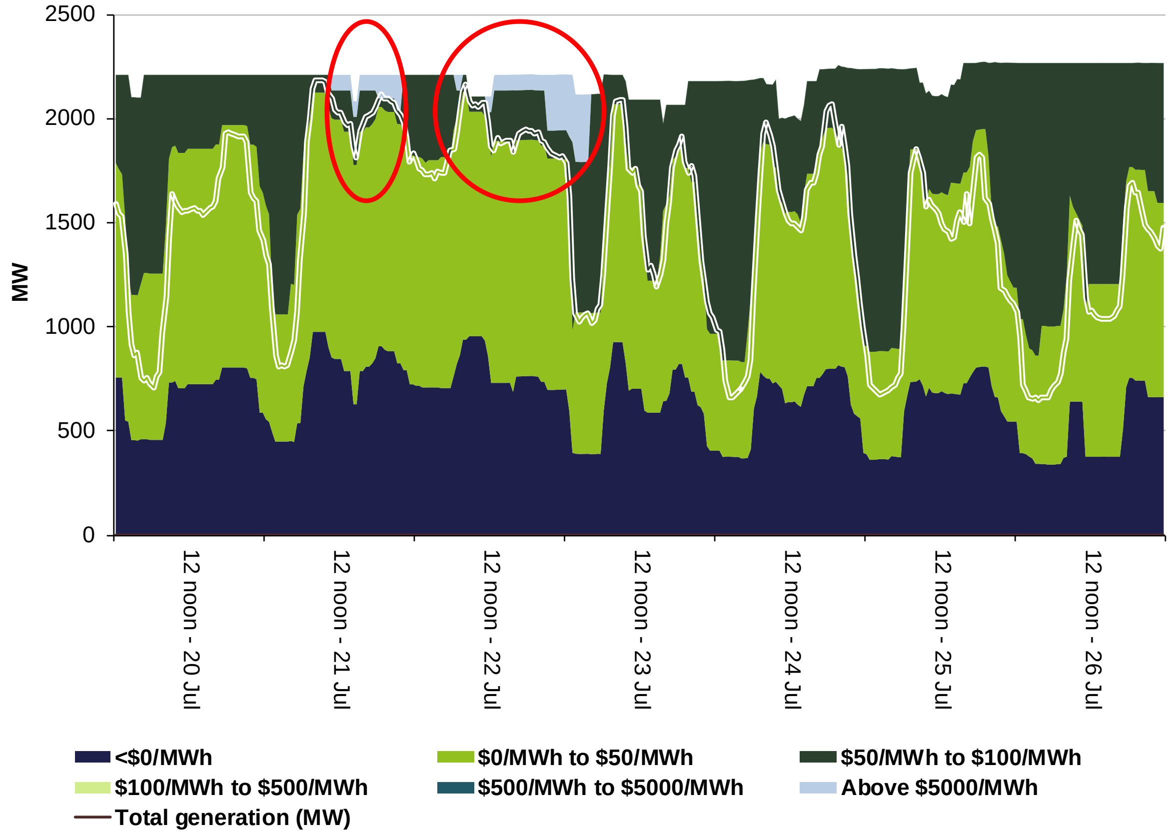


Figure 7: Tasmania generation and bidding patterns



The red circles show Hydro Tasmania rebidding capacity from the $50/MWh to $100/MWh price bands into price above $12 000/MWh.

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.

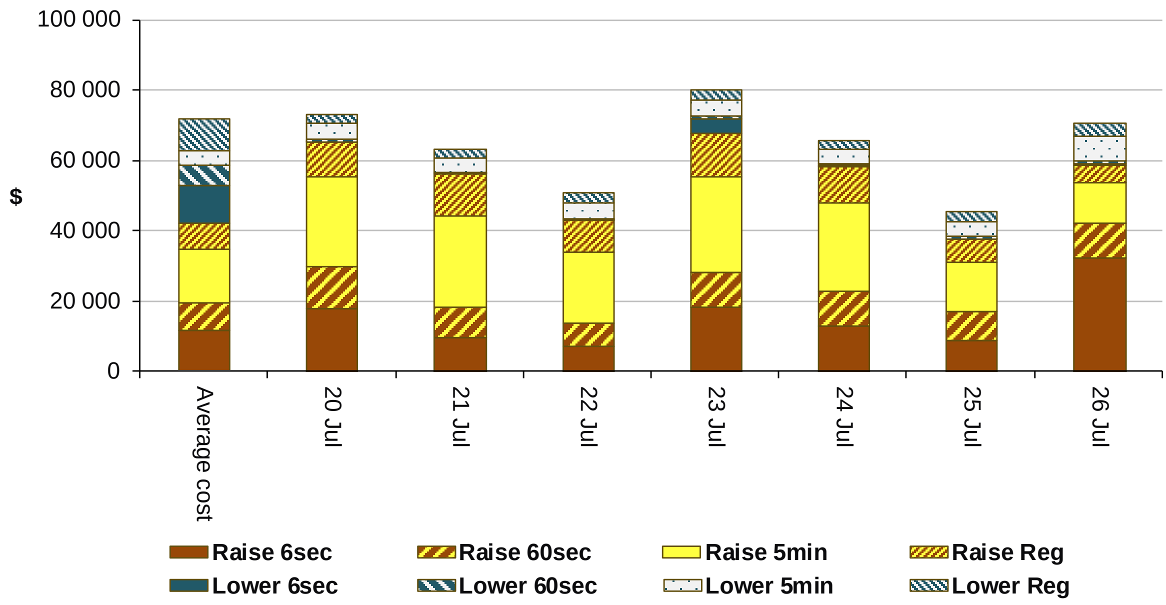
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $370 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $78 500 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 three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $70/MWh and above $250/MWh.

Table 3: South Australia, Sunday 20 July

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 PM	2288.13	54.06	46.98	1638	1711	1602	1895	1879	2038
6.30 PM	2088.28	300.07	70.49	2018	2032	1946	1929	1941	2115

At the time demand and available capacity close to forecasts and Wind generation was less than 20 MW.

Over several rebids from 3.36 pm, GDF Suez rebid 100 MW of available capacity at Dry Creek from between $500/MWh and $11 000/MWh to the price cap.

At 4.56 pm, effective from 5.05 pm, Origin Energy rebid a total of 147 MW of available capacity at Ladbroke and Quarantine power stations from $38/MWh to the price cap. The reason given was “1655A inc SA dem 5PD 1811 > 30PD 1682 @ 1730”. As a result the five minute price at 5.05 pm reached the price cap set by Quarantine and Ladbroke.

At 5.05 pm, both Heywood and Murraylink were importing into South Australia at their limits (approximately 460 MW and 185 MW respectively).

At 5.10 pm there was a 90 MW decrease in demand (mainly due to Angaston and Pt Stanvac increasing their output) which saw the five minute price return to previous levels.

For the second high price: at 6.16 pm, effective from 6.25 pm, Energy Australia rebid 60 MW of available capacity at Hallet power station from $296/MWh to $12 035/MWh. The reason given was “18:14 A band adj for mat change in sa sensitivities SL”.

At 6.18 pm, effective from the same dispatch interval, Origin Energy rebid a total 140 MW of available capacity at Ladbroke and Quarantine power stations from $38/MWh to the price cap. The reason given was “1815A constraint management - V^SML_NSWRB_2 SL”. As a result the 5 minute price at 6.25 pm was $12 195/MWh set by Hallett power station.

At 6.25 pm, both Heywood and Murraylink were importing into South Australia at their limits (approximately 460 MW and 142 MW respectively).

At 6.30 pm there was a 140 MW decrease in demand (mainly due to Angaston and Pt Stanvac increasing their output) which saw the five minute price return to previous levels.

Table 4: South Australia, Tuesday 22 July

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
7.30 PM	2412.12	300.07	61.58	1980	2048	2140	2121	2248	2412

Conditions at the time saw demand and available generation slightly below that forecast. Both the MurrayLink and Heywood interconnectors were importing at their limit.

At 6.55 pm, effective from 7.05 pm, AGL rebid 180 MW of available capacity at Torrens Island B from below $65/MWh to $351/MWh. The reason given was “18:31F chg in pipeline cond::change in imbal pos Seagas”.

At 7.03 pm, effective from 7.10 pm, Origin Energy rebid 143 MW at Ladbroke and Quarantine power stations from below $55/MWh to the price cap. The reason was “1902A constraint management - V^SML_NSWRB_2 SL”.

As a result of these two rebids the 5 minute prices were around $300/MWh for the 7.10 pm to 7.25 pm dispatch intervals.

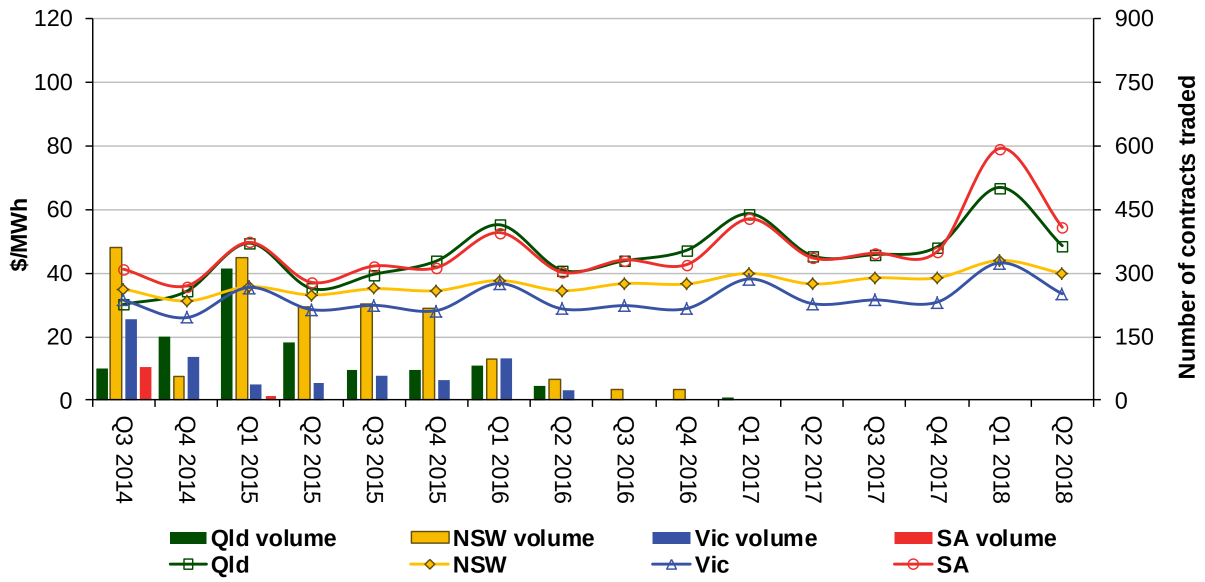
At 7.23 pm, effective from 7.30 pm, AGL rebid a total of 300 MW of available capacity at Torrens Island B from prices below $80/MWh to $13 301/MWh. The reason given was “19:15A chg in dispatch::price incr v PD SA 30/5 $350.98”. As a result the 5 minute price at 7.30 pm was $13 101/MWh set by Torrens Island B.

At 6.30 pm there was a 76 MW decrease in demand (mainly due to Angaston and Pt Stanvac increasing their output) which saw the five minute price return to previous levels.

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.

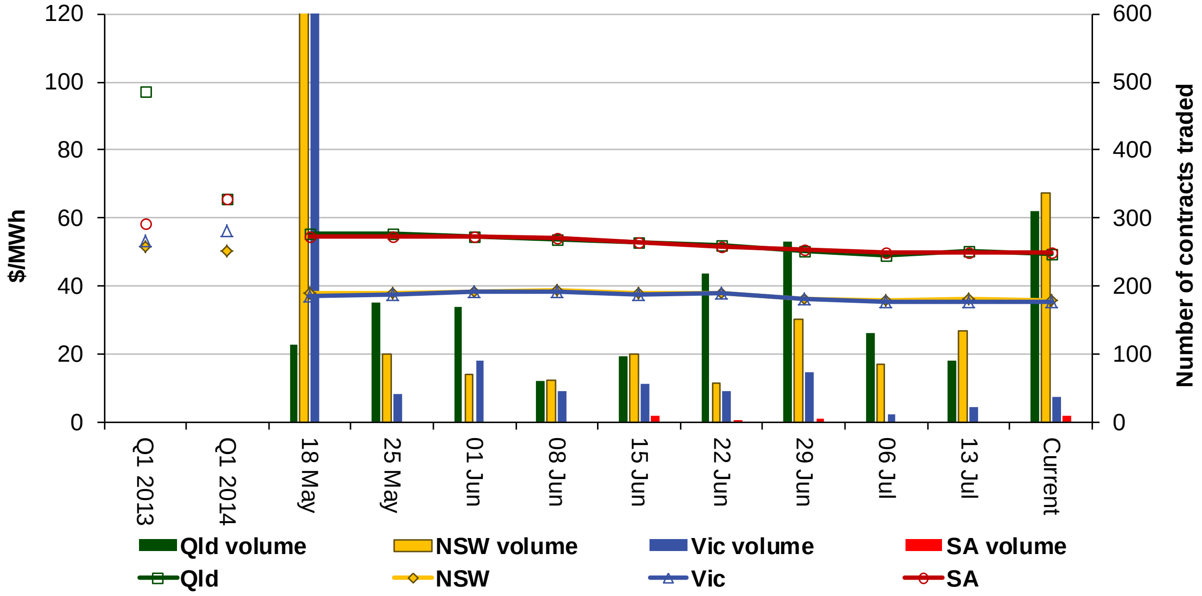
Figure 9: Quarterly base future prices Q3 2014 – Q2 2018



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)



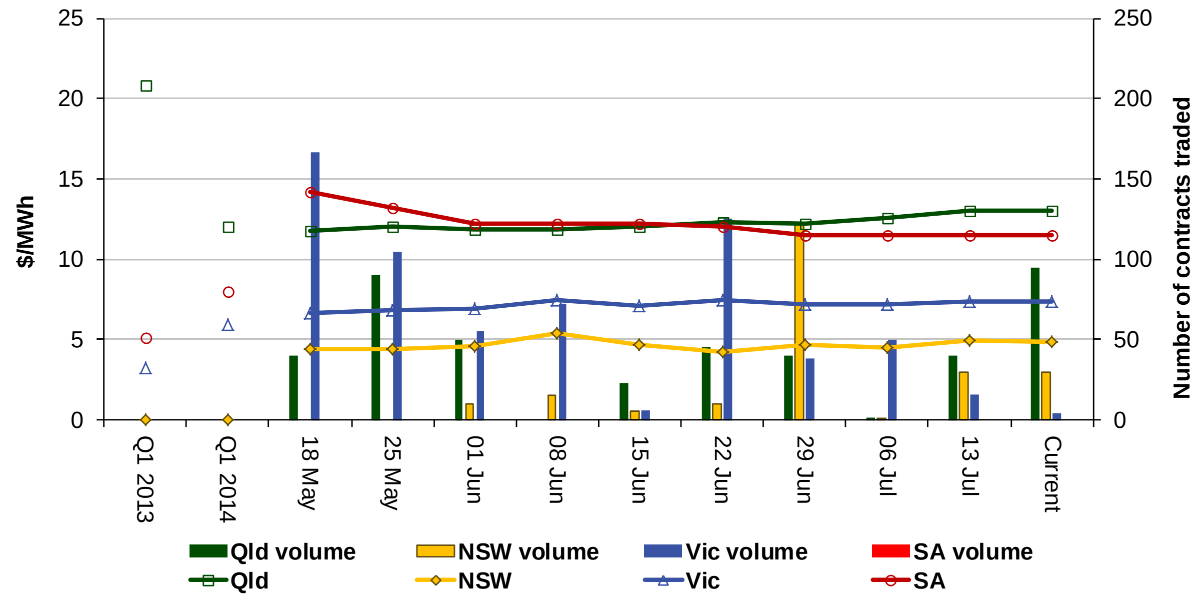
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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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