

Electricity Report

18 to 24 May 2014



AUSTRALIAN ENERGY
REGULATOR

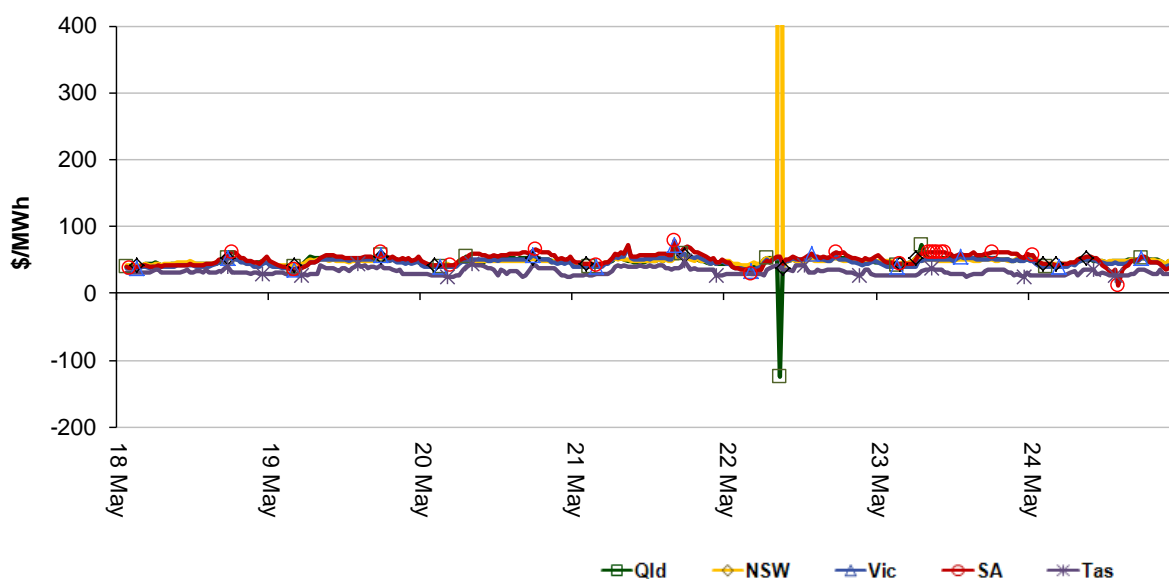
Introduction

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 18 to 24 May 2014. The New South Wales price spike on 22 May reached \$2225/MWh.

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



The high price in New South Wales and the corresponding low price in Queensland were caused by an automated constraint invoked by AEMO to manage a planned transmission outage. This is discussed in detail in the analysis section.

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)

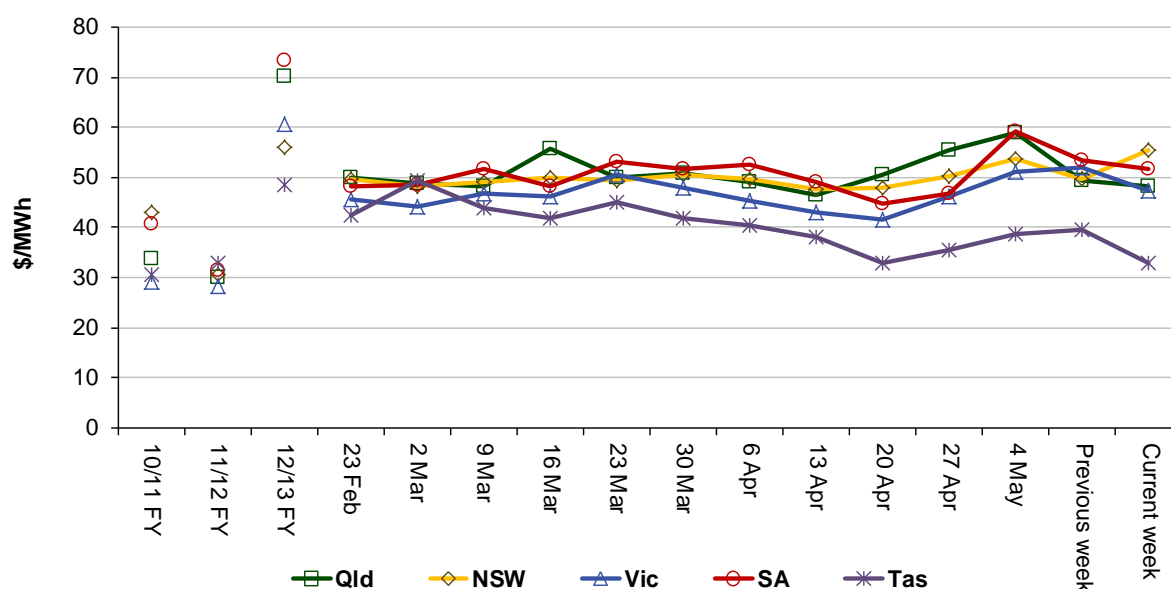


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	48	55	47	52	33
12-13 financial YTD	70	56	61	73	49
13-14 financial YTD	61	53	55	70	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 6 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	0	0	18	0
% of total below forecast	45	18	18	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. The red oval on Figure 3 corresponds to rebidding in Queensland corresponding to the planned and forced outages in the TransGrid network afternoon in New South Wales. The red oval on Figure 4 corresponds to rebidding in New South Wales as a result of planned outage in the TransGrid network and high prices that occurred in that region as a result of an automated constraint.

Figure 3: Queensland generation and bidding patterns

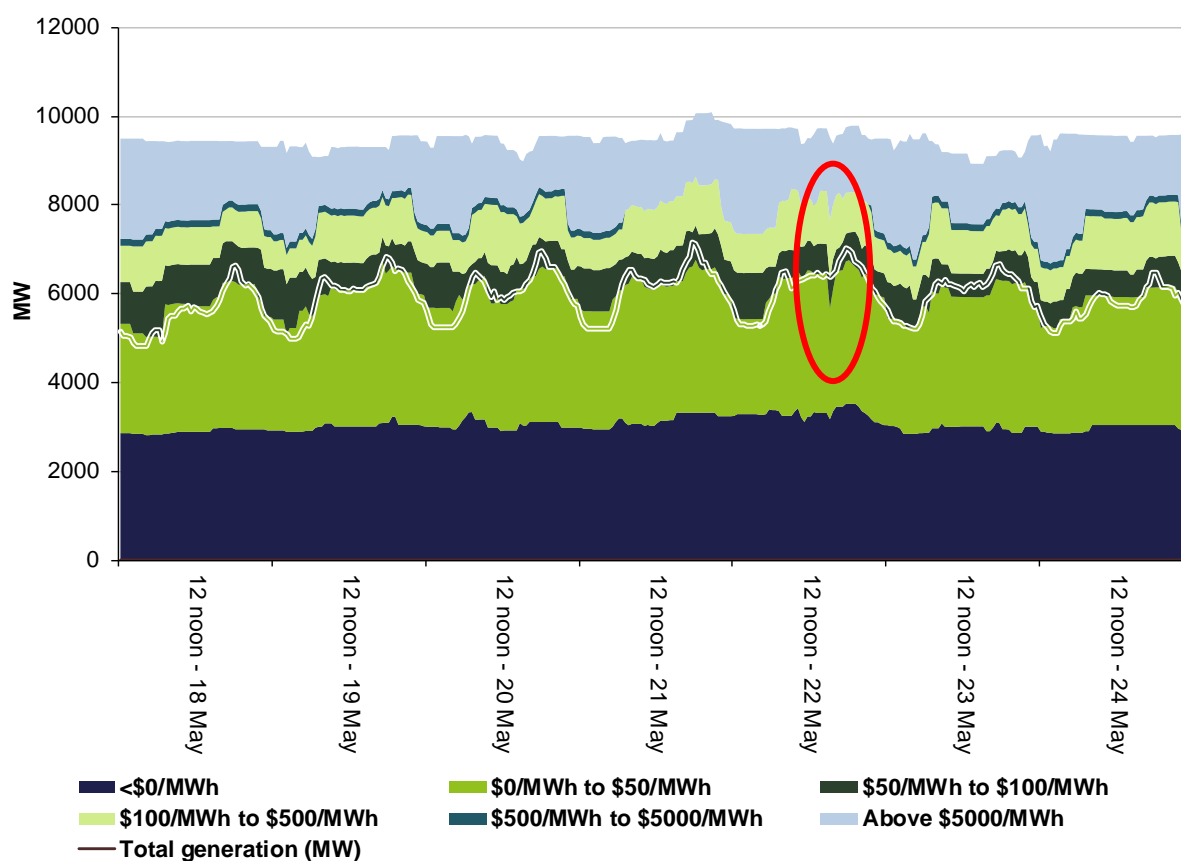


Figure 4: New South Wales generation and bidding patterns

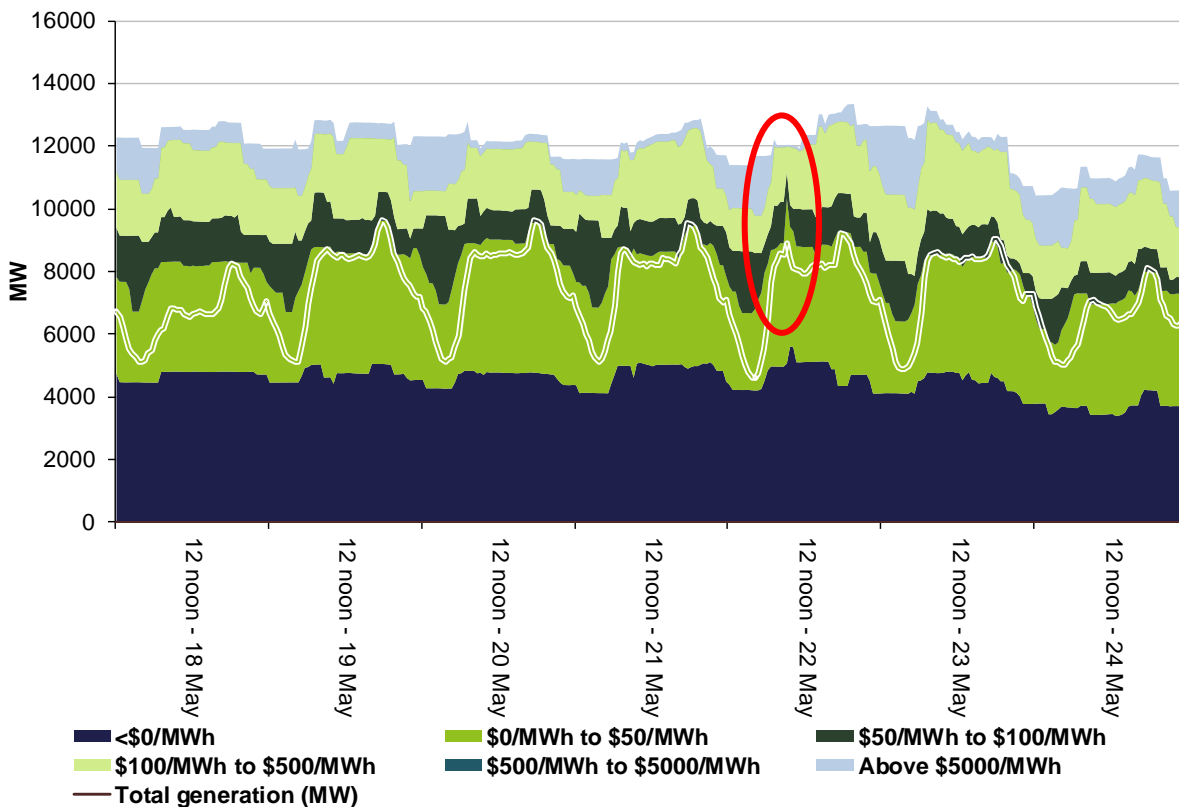


Figure 5: Victoria generation and bidding patterns

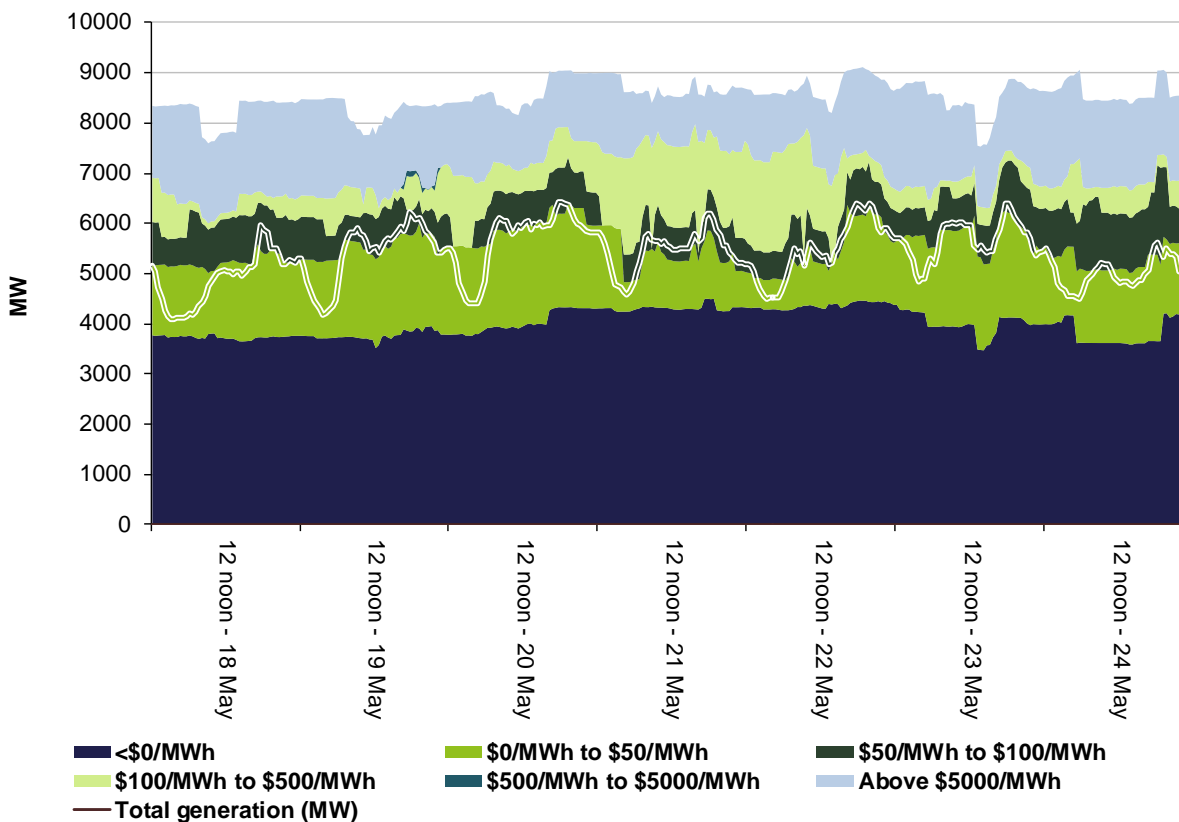


Figure 6: South Australia generation and bidding patterns

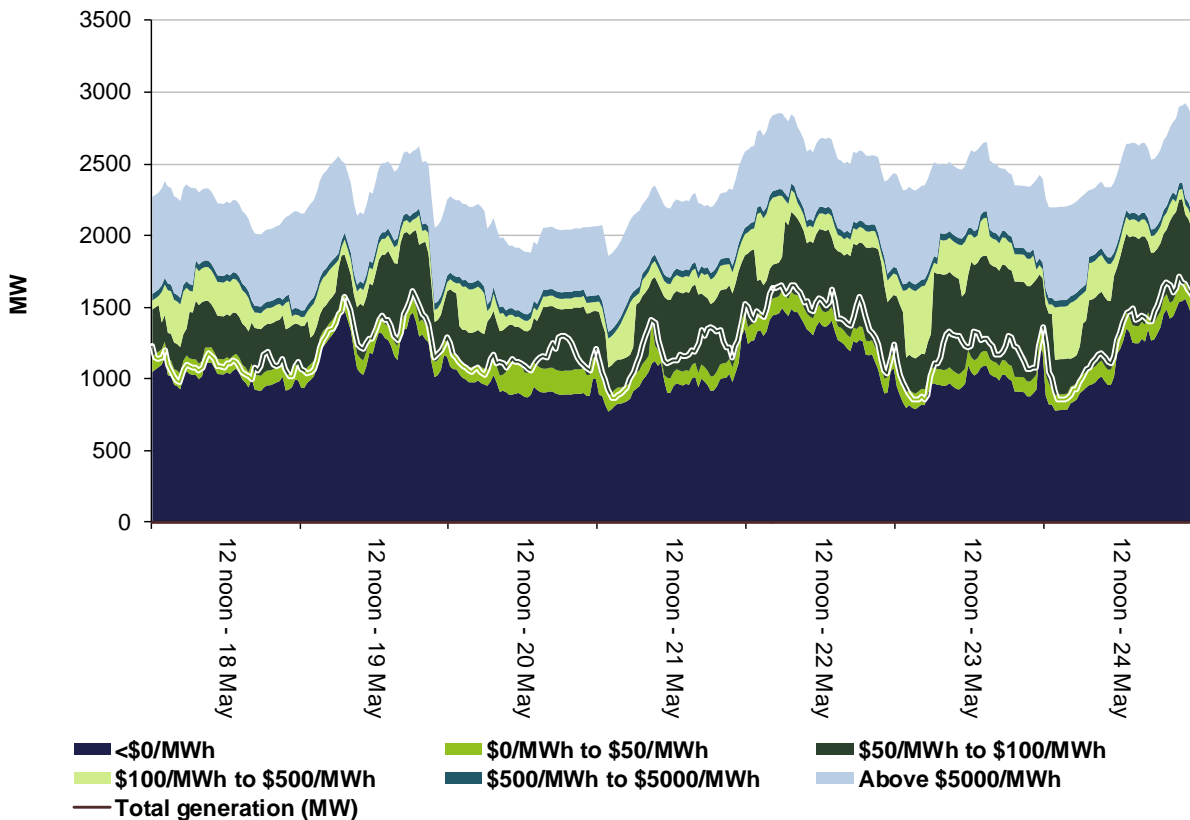
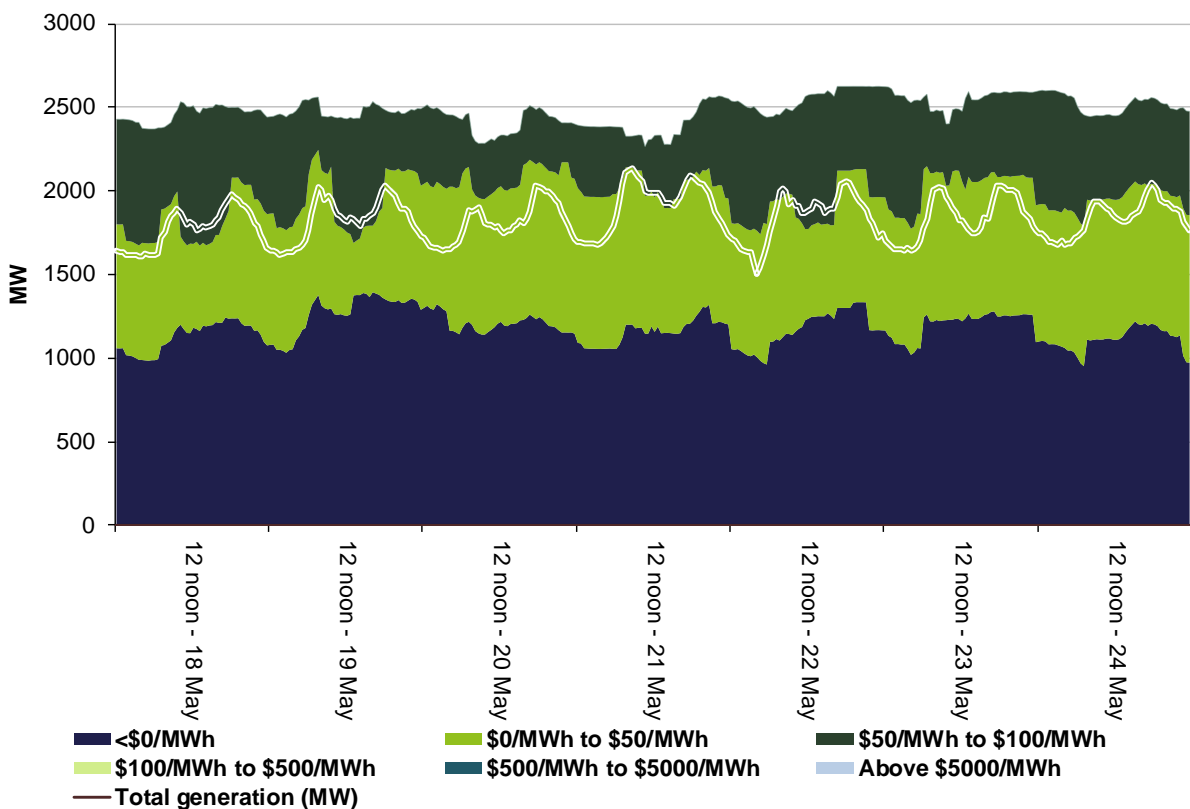


Figure 7: Tasmania generation and bidding patterns



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.

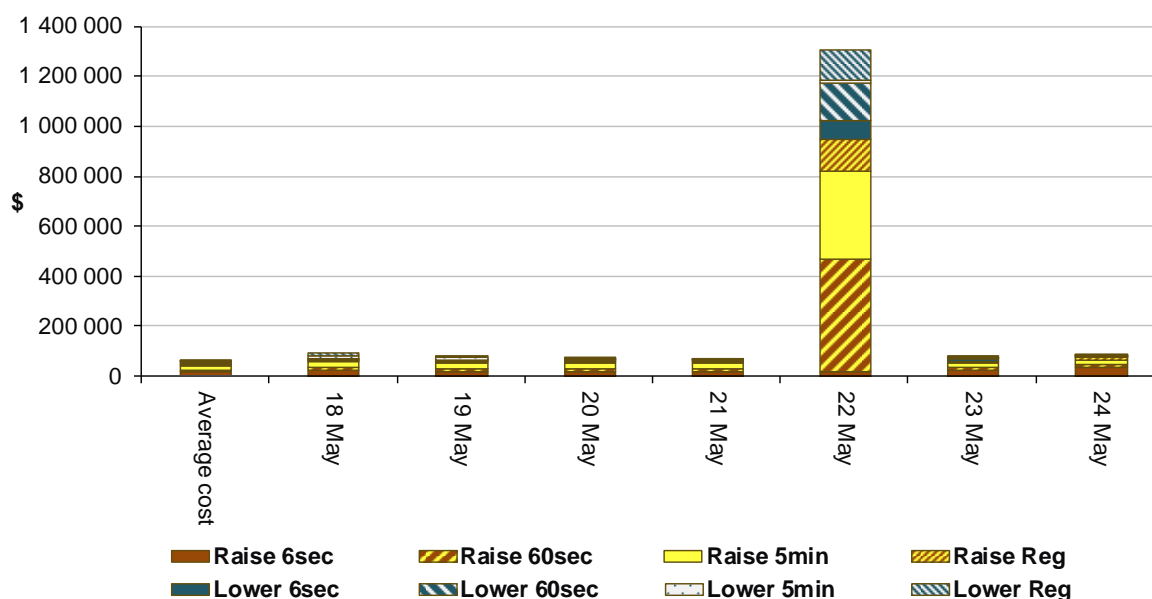
The total cost of FCAS on the mainland for the week was \$1 693 000 or around 1 per cent of energy turnover on the mainland. A majority of this cost (\$1.3 million) accrued on 22 May at 3.05 pm when Queensland was separated from the rest of the Market and had to source FCAS locally. There was a planned outage of the Armidale no. 1 330kV bus to commence at 2.50 pm which required the Armidale to Dumeresq no.8C 330kV line and the Armidale to Tamworth no.86 330kV line to be taken out of service. While taking these lines out of service the remaining Armidale to Tamworth no.85 330kV line was accidentally tripped, isolating Queensland from the rest of the market. At 3.05 pm AEMO invoked constraints to manage the separation. Requirements for both local lower and raise services were significantly increased by between 12 MW and 403 MW. This led to a shortage of local services in Queensland with all but Lower 5 minute and Raise 6 second prices reaching the price cap at 3.05 pm.

Prices at 3.10 pm returned to previous levels when the Armidale to Tamworth no.85 330kV line was returned to service.

The total cost of FCAS in Tasmania for the week was \$79 500 or around 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.

Queensland

There was occasion where the spot price in Queensland was less than -\$100/MWh.

Table 3: Queensland, Thursday 22 May

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
9.00 AM	-124.56	50.95	47.80	6043	5997	5917	9746	9755	9815

Both demand and available generation were close to forecast.

There was a planned outage of the Mt Piper to Wallerawang no.71 330kV line, which was to commence at 8 am. AEMO invoked a constraint at 8 am to manage the outage but it did not have the desired effect and failed to bind. At 9 am AEMO invoked an automated constraint to manage the possible overload of the Mt Piper to Wallerawang no. 94E 132kV line on the loss of the remaining Mt Piper to Wallerawang no.72 330kV line, which immediately violated. This constraint forced QNI flows from New South Wales into Queensland at 264 MW at 9 am from 163 MW into New South Wales at 8.55 am. This change caused an excess of supply in Queensland, with the dispatch price falling to the price floor. Changes in generation in New South Wales could not meet the constraint requirements and the dispatch price in New South Wales reached the price cap at 9 am.

The automated constraint was revoked at 9.05 am when the Mt Piper to Wallerawang no.71 330kV line returned to service and prices returned to previous levels.

There was no other significant rebidding.

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 \$55/MWh and above \$250/MWh.

Table 4: New South Wales, Thursday 22 May

Time	Price (\$/MWh) ¹			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
9.00 AM	2224.54	53.48	48.82	8691	8680	8639	11 970	11 983	11 990

Both demand and available generation were close to forecast. The dispatch price reached the price cap at 9 am as detailed in the Queensland section above

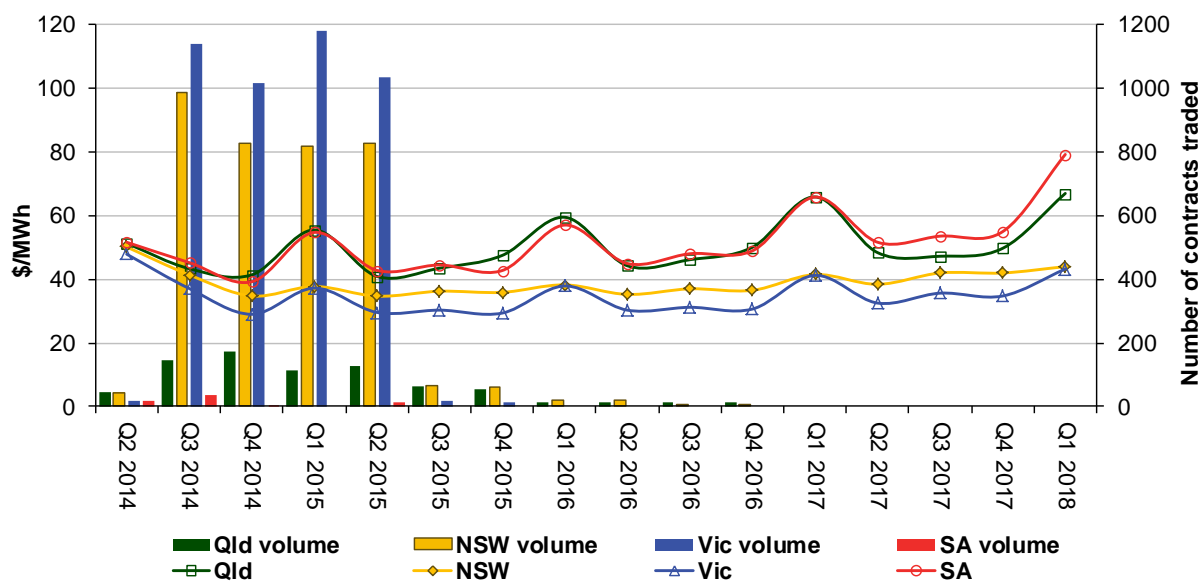
There was no other significant rebidding.

Financial markets

The high volume in trades this week was a result of the 2014/15 financial year options being converted into quarterly base future contracts on 19 May.

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

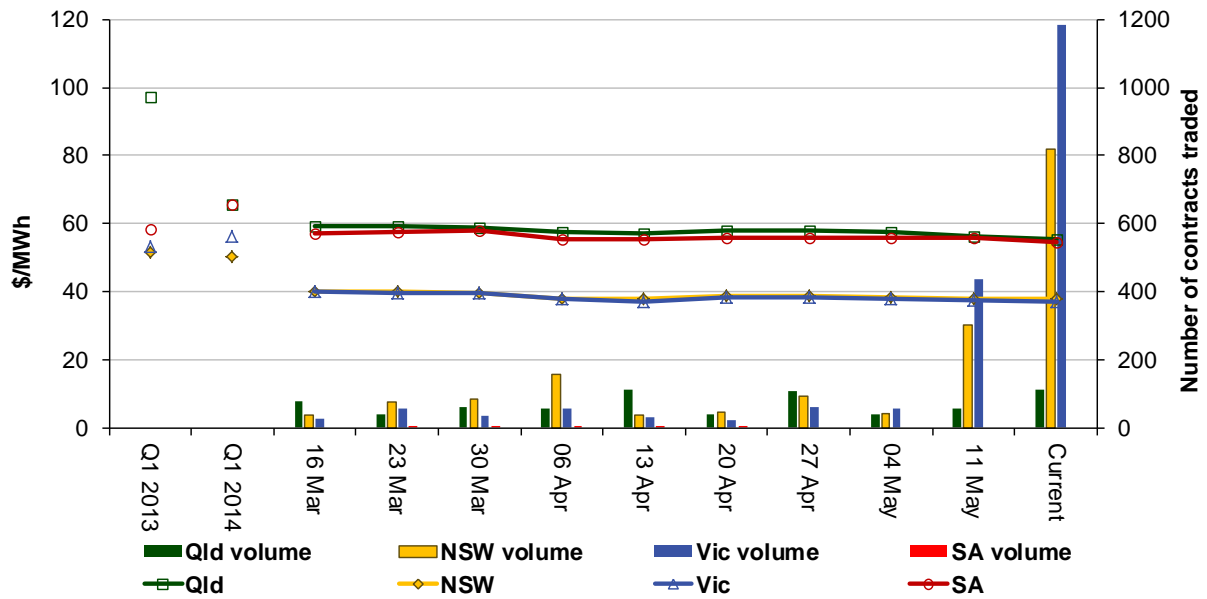


Source: ASXEnergy.com.au

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.

¹ The prices listed are for New South Wales. The prices in Queensland, Victoria, and Adelaide were similar.

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



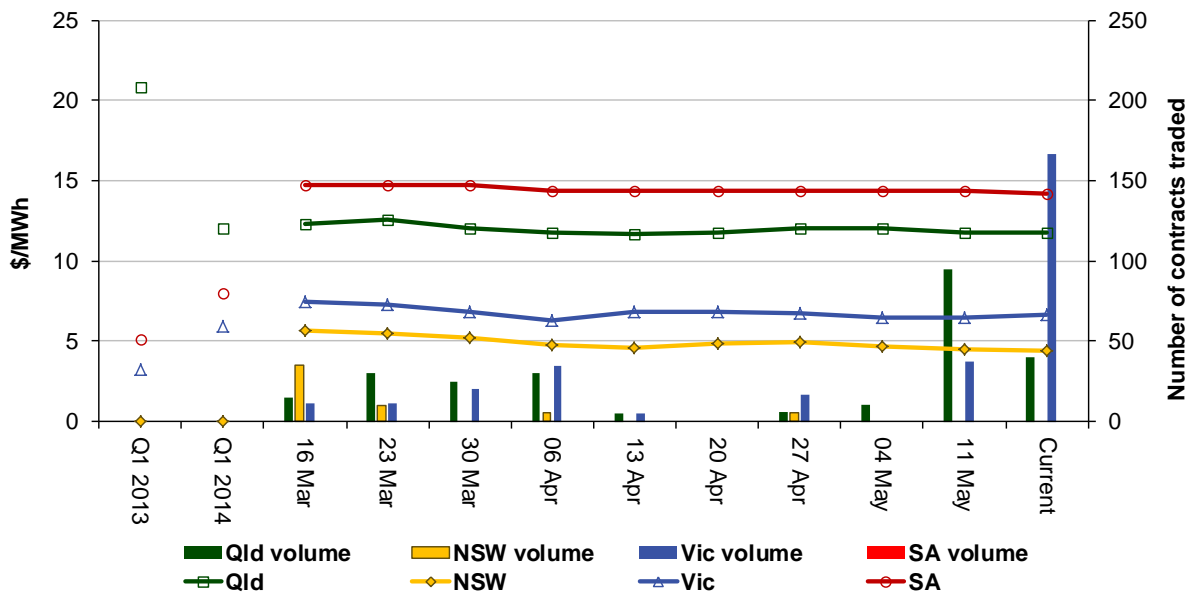
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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

Australian Energy Regulator
May 2014