Electricity Report
17 – 23 May 2015

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 17 to 23 May 2015. Two prices in South Australia, on 22 May and 23 May, triggered the AER reporting threshold. These are discussed later in this report.

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

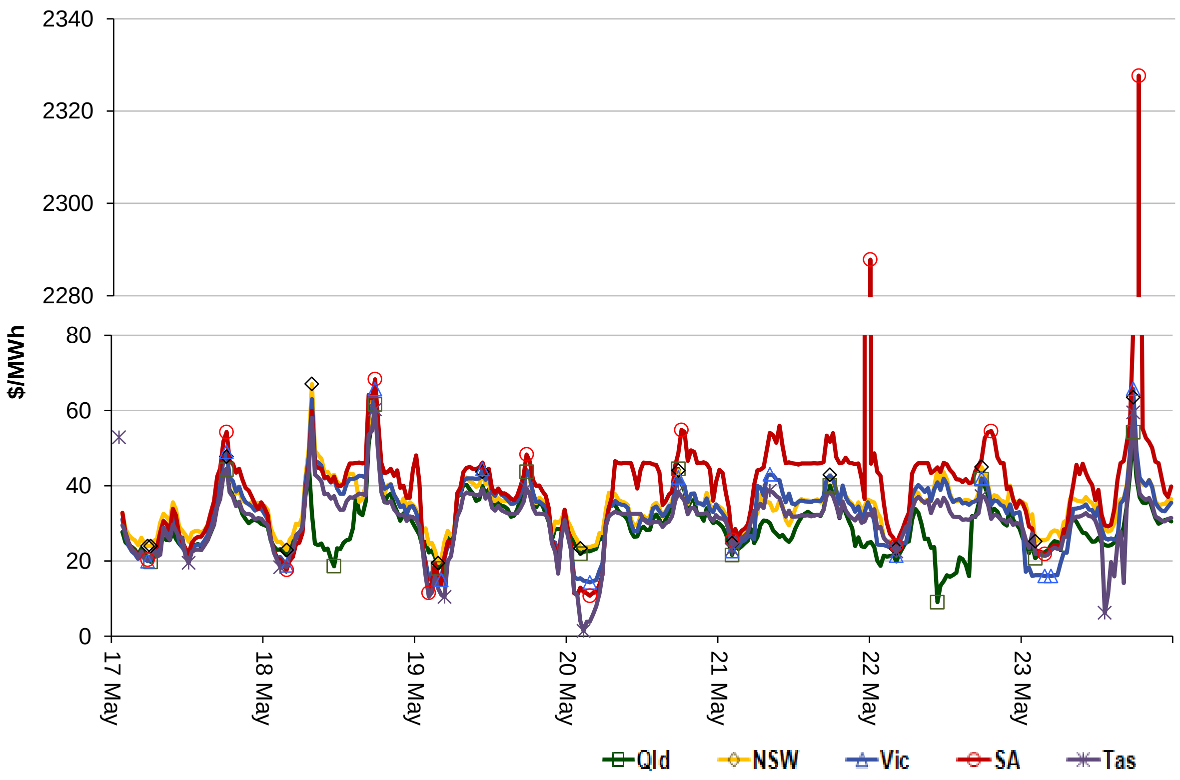


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

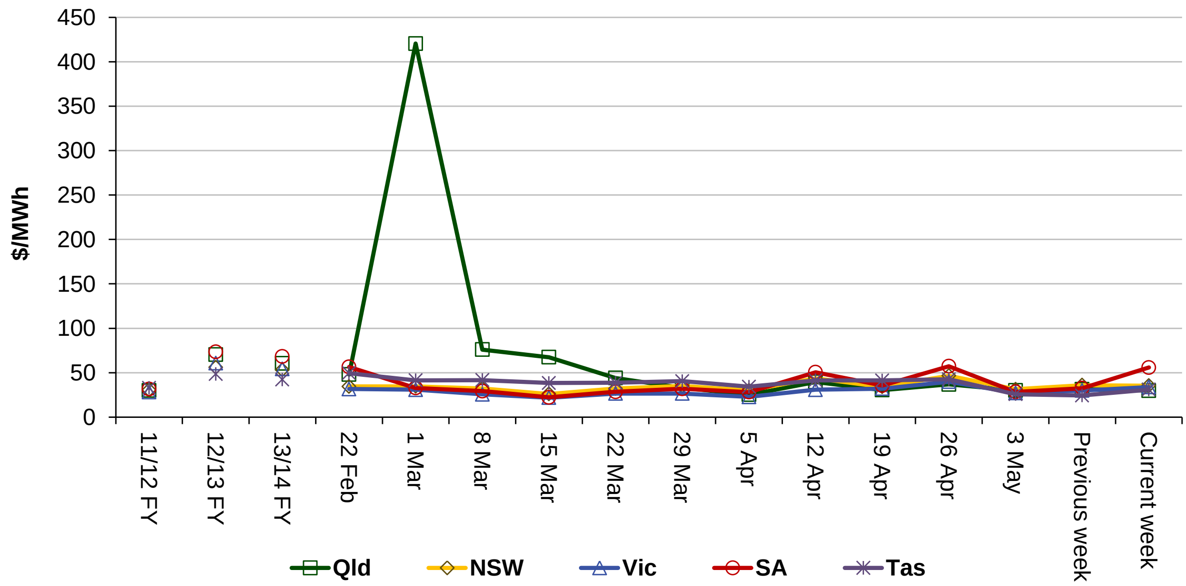


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	30	35	34	56	31
13-14 financial YTD	62	54	55	70	42
14-15 financial YTD	65	36	31	40	38

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 15 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	0	75	0	0
% of total below forecast	21	4	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

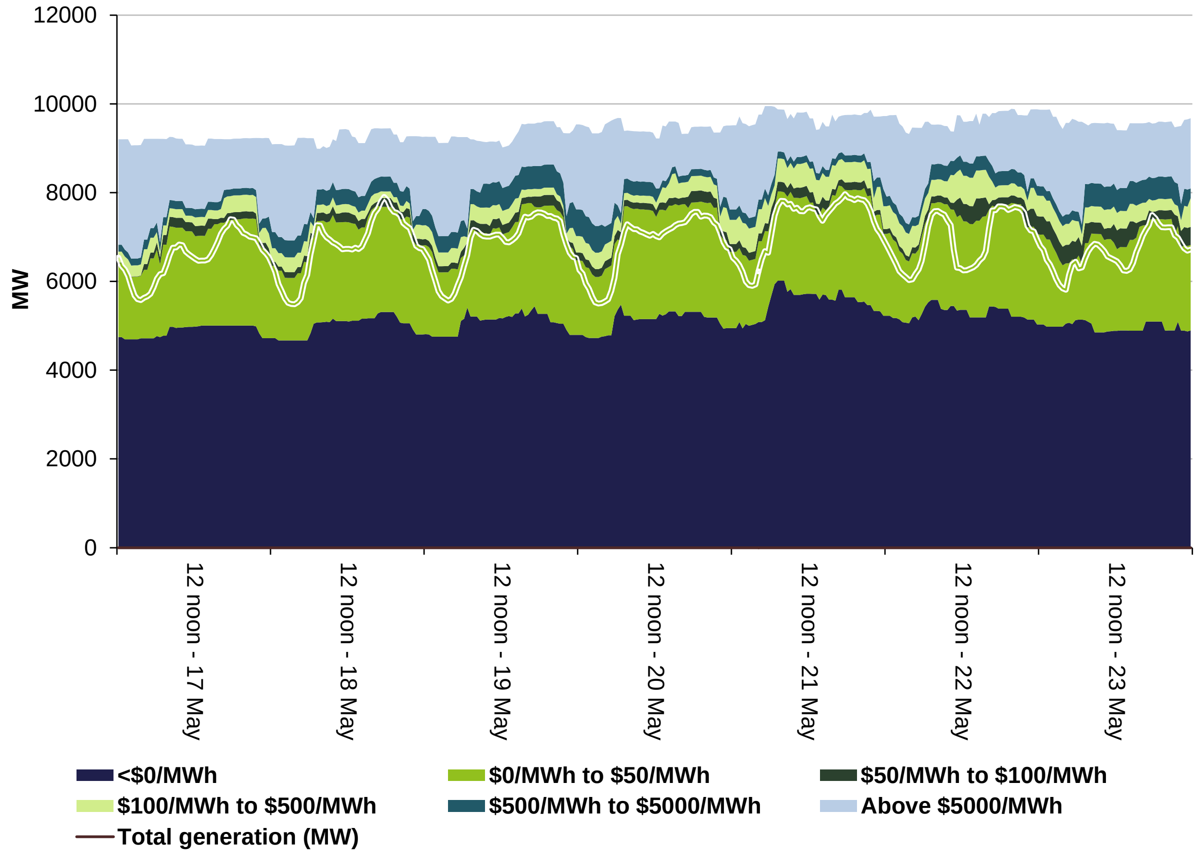


Figure 4: New South Wales generation and bidding patterns

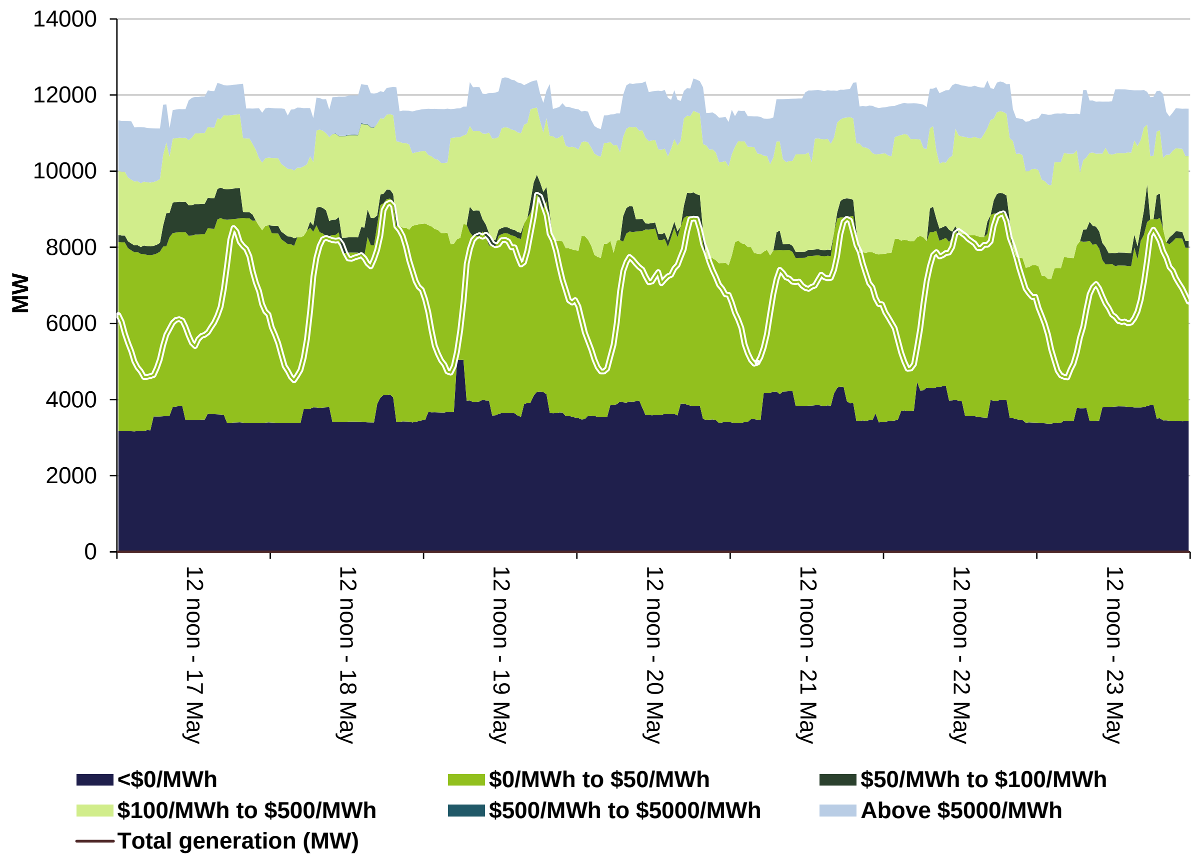


Figure 5: Victoria generation and bidding patterns

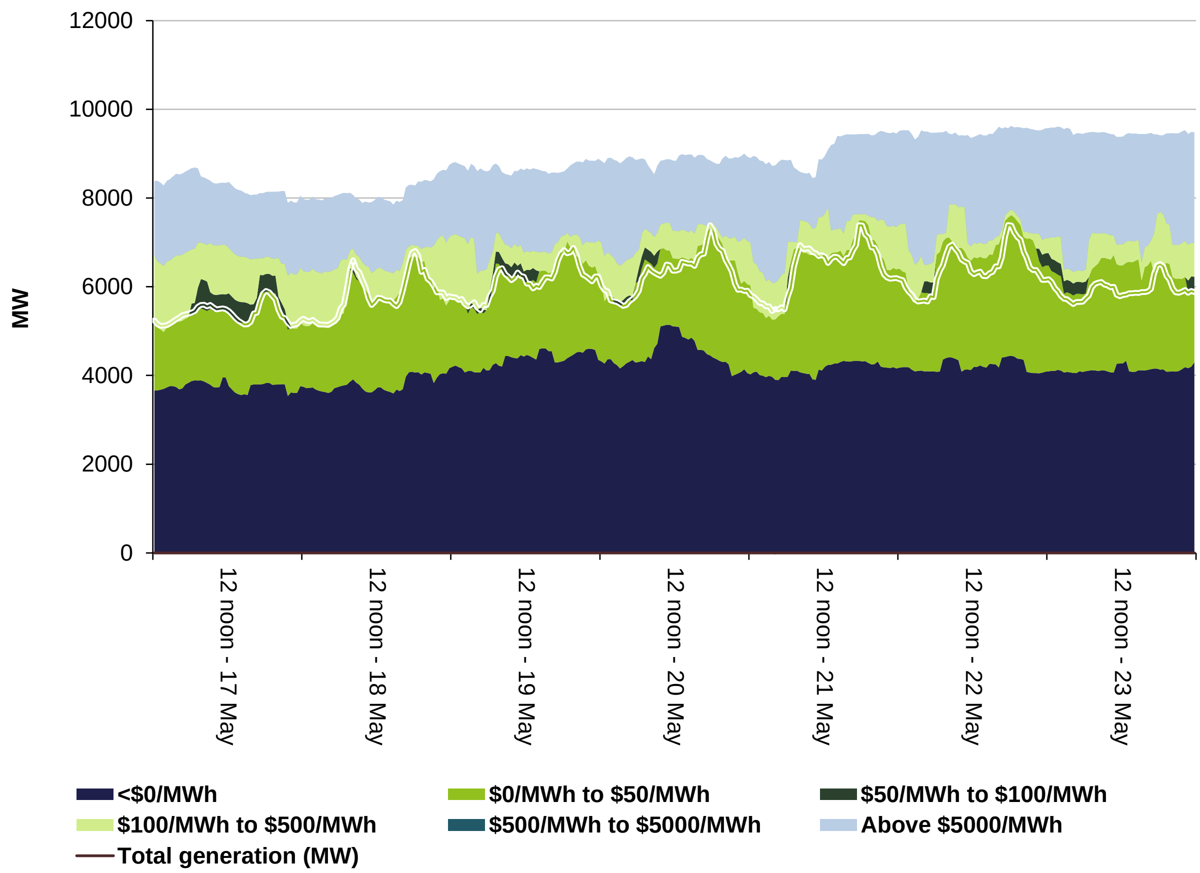


Figure 6: South Australia generation and bidding patterns

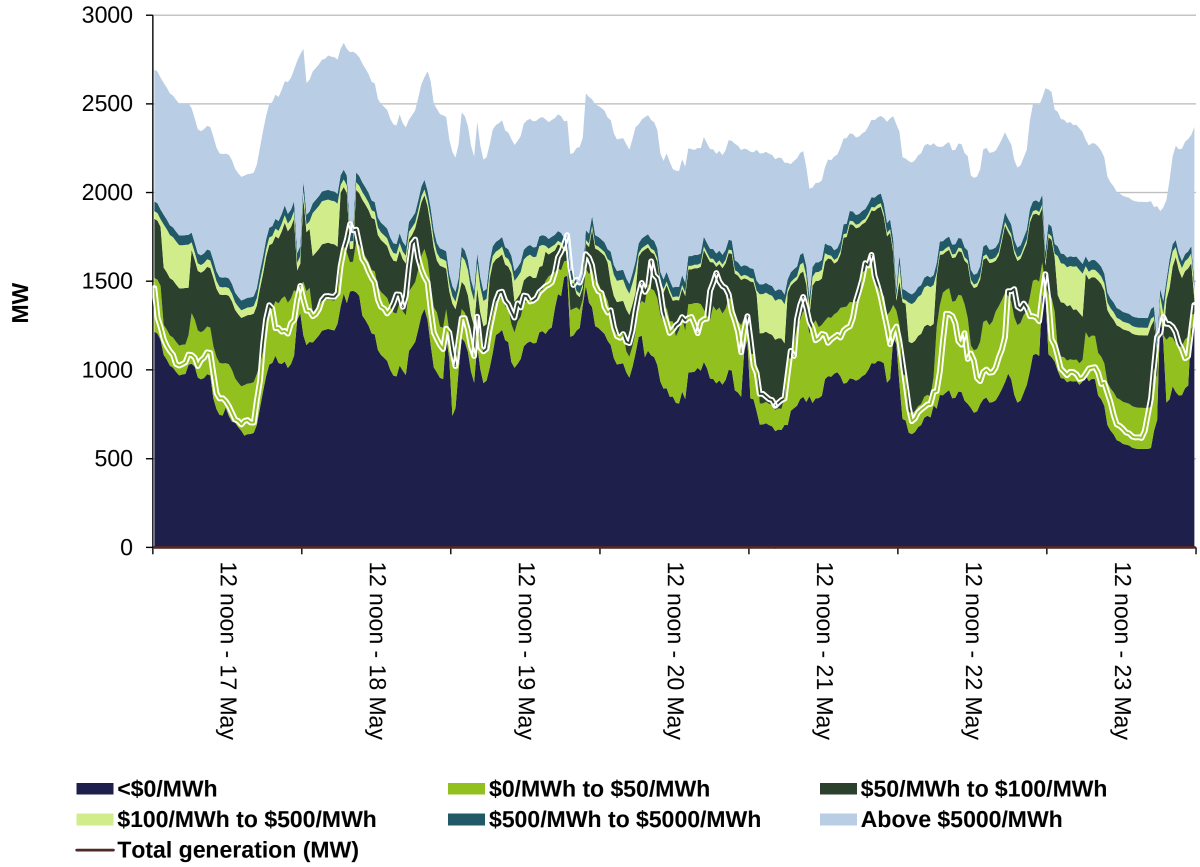
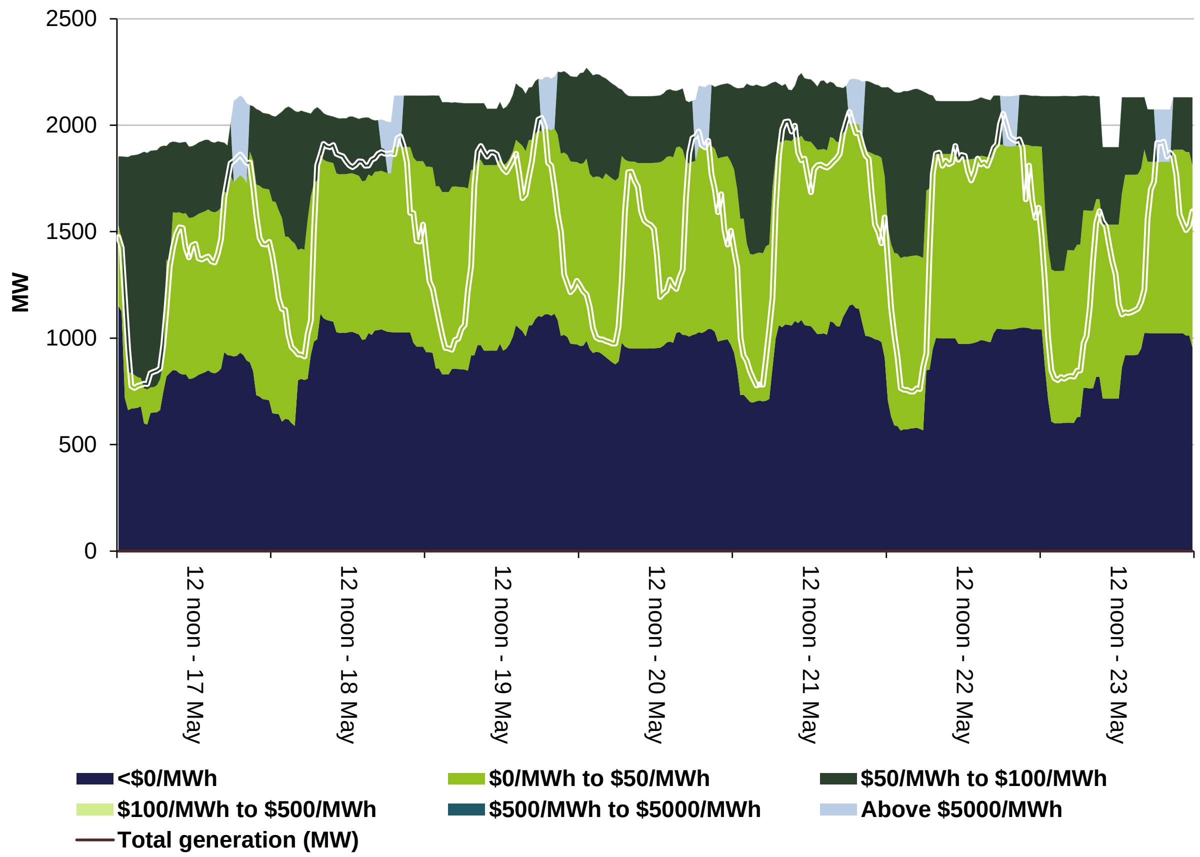


Figure 7: Tasmania generation and bidding patterns



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.

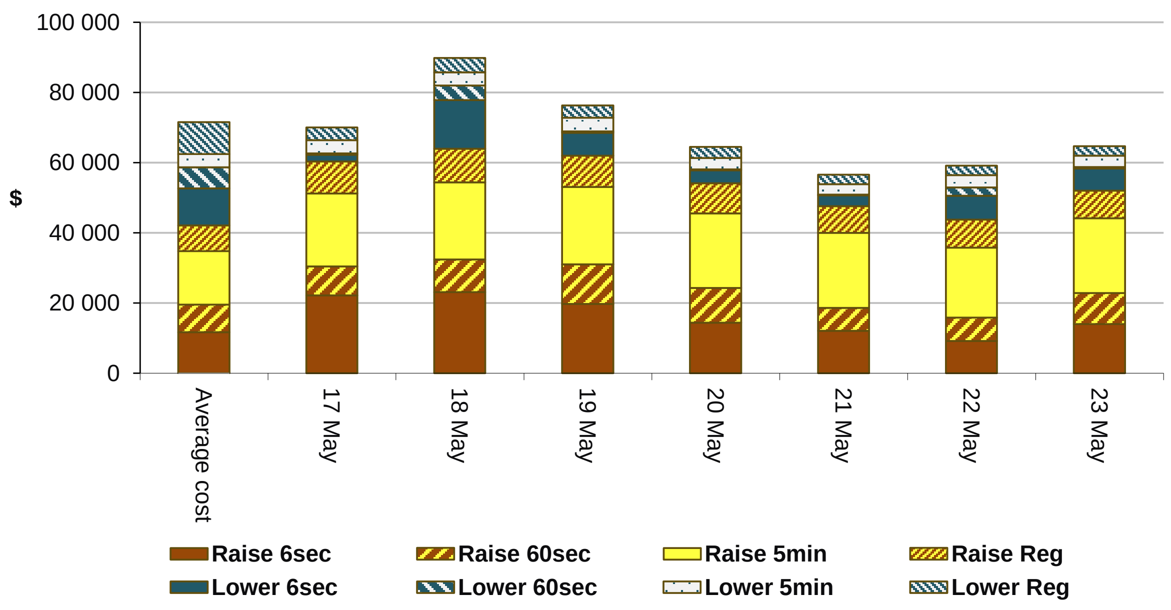
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $414 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $67 000 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.

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 $56/MWh and above $250/MWh.

Friday, 22 May

Table 3: Price, Demand and Availability, Midnight

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
Midnight	2287.83	45.94	45.94	1703	1787	1789	2384	2356	2348

Demand and availability were both close to forecast four hour ahead. Wind generation was around 230 MW (1475 MW is installed in South Australia).

At 11.35 pm on 21 May demand increased by 203 MW, related to off peak hot water load.

Both interconnectors were importing at their forecast limits.

At 11.37 pm, effective from 11.45 pm, AGL Energy rebid 350 MW of capacity at Torrens Island from prices less than $55/MWh to the price cap. The reason given was “2335~A~040 chg in AEMO disp~45 price increase vs pd SA $53.25 V”. All low priced capacity at the other two thermal stations was either ramp rate limited, stranded or fully dispatched. As a result the dispatch price reached the price cap at 11.45 pm, set by Torrens Island.

Subsequent rebidding saw the dispatch price return to lower levels for the remainder of the trading interval. Consequently the price for midnight 22 May (period ending 12 am 22 May) was $2288/MWh.

Saturday, 23 May

Table 4: Price, Demand and Availability, 6.30 pm

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 pm	2327.67	54.98	57.99	1773	1652	1752	1903	2088	2054

Conditions at the time saw demand 121 MW higher and available capacity 185 MW lower than forecast four hours ahead. Wind generation (41 MW) was around 100 MW lower than that forecast four hours ahead.

Interconnector flows were at their nominal limits importing at 680 MW.

Table 5: Rebids for the 6.30 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.01 pm	6.10 pm	Origin	Quarantine	46	95	N/A	1800A avoid uneconomic start SL
6.08 pm	6.15 pm	Alinta	Northern	43	55	200	1800~A~dispatch $87.33 V 5PD 82.56~
6.09 pm	6.20 pm	Origin	Ladbroke	75	-1000	13 500	1808A constraint management - V>S_NIL_HYTX_HYTX SL

With all low priced capacity either ramp rate limited or fully dispatched, the dispatch price increased to $200/MWh at 6.15 pm when Alinta's Northern rebid became effective, and then to the price cap at 6.20 pm when Origin's Ladbroke rebid became effective.

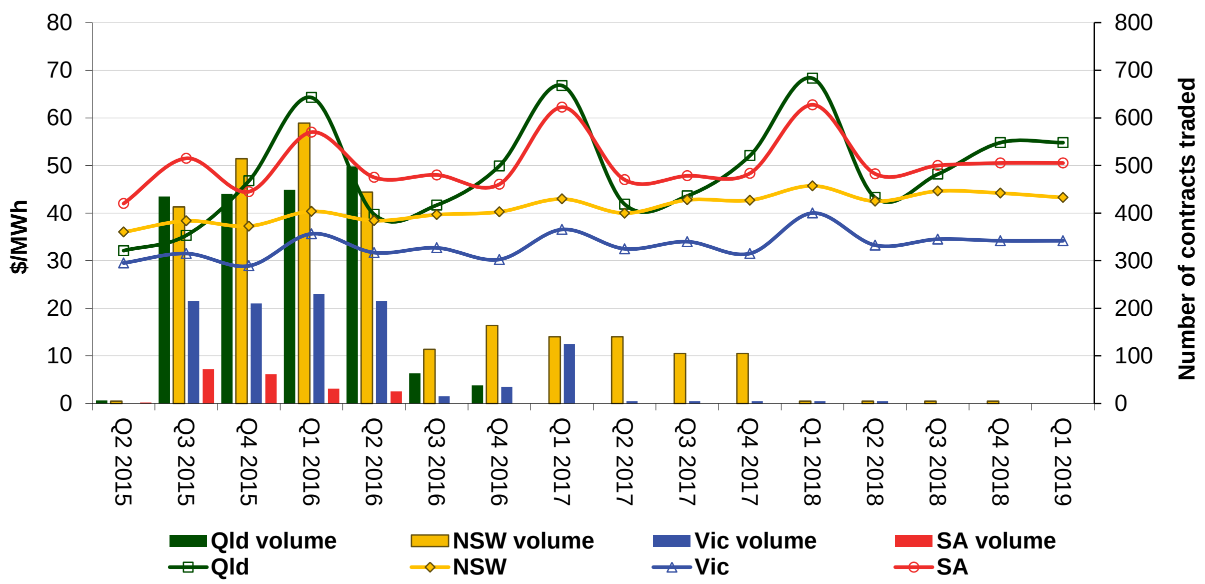
Subsequent rebidding saw the dispatch price return to lower levels for the remainder of the trading interval.

Financial markets

The high volume of contracts shown in Figure 9 and Figure 10 were the result of the exercising of financial year option contracts.

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.

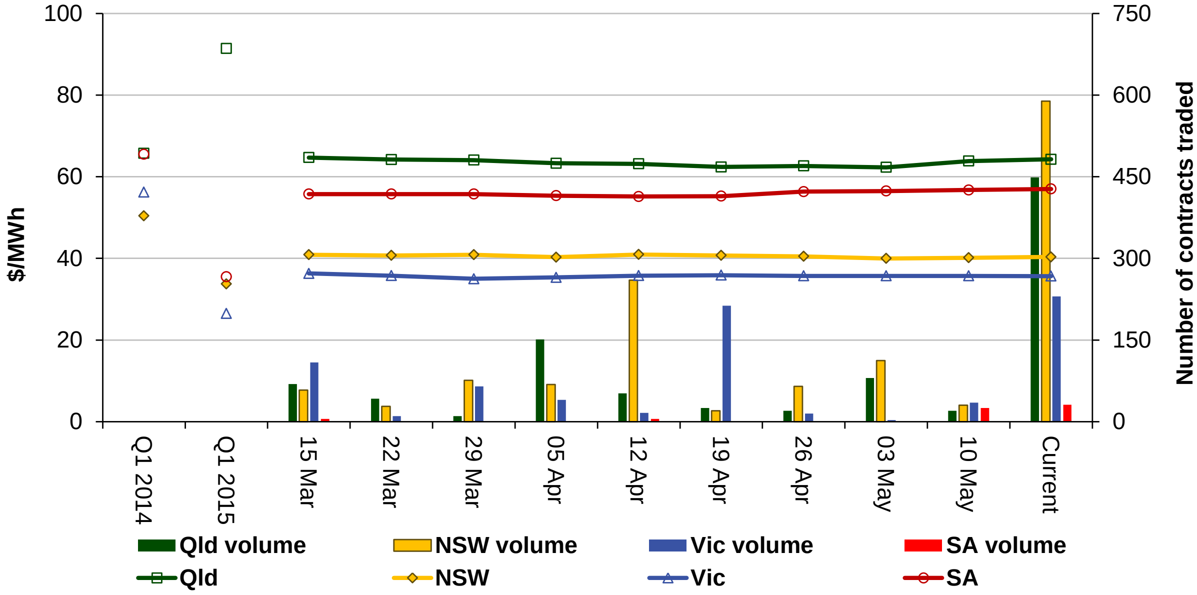
Figure 9: Quarterly base future prices Q2 2015 – Q1 2019



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.

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



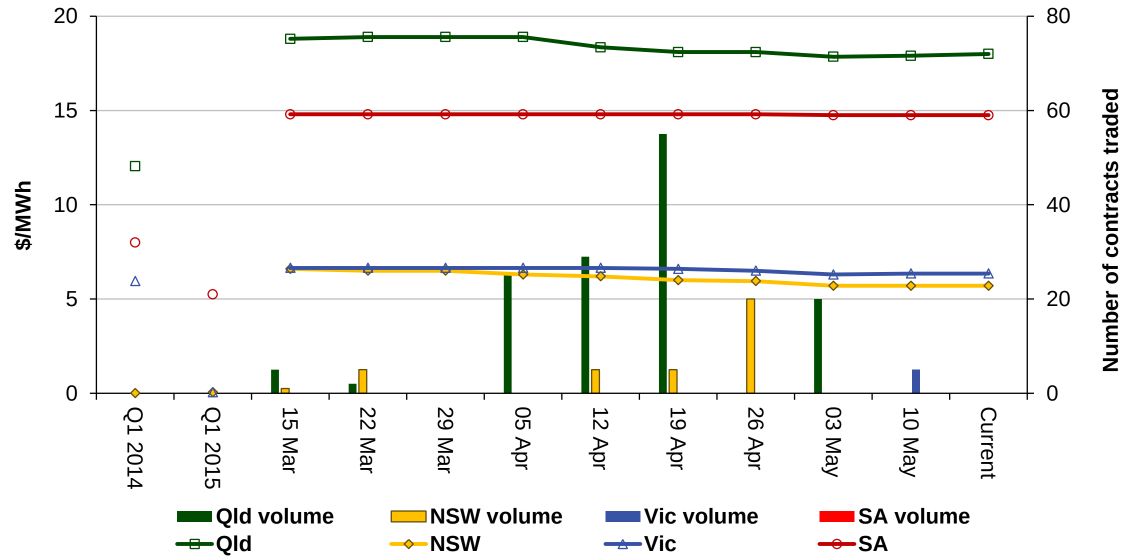
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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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