Electricity Report
12 – 18 April 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 12 to 18 April 2015. There were three occasions in New South Wales, one occasion in Queensland and two in South Australia where spot prices were above $250/MWh and greater than three times the regional weekly average price.

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

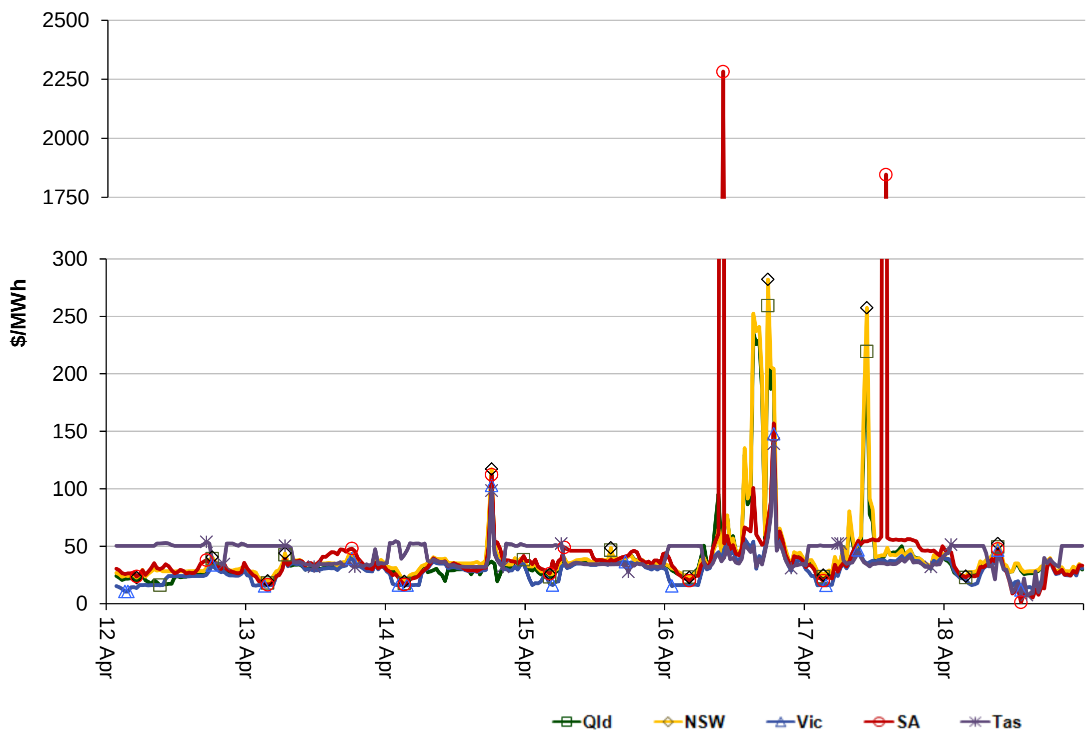


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

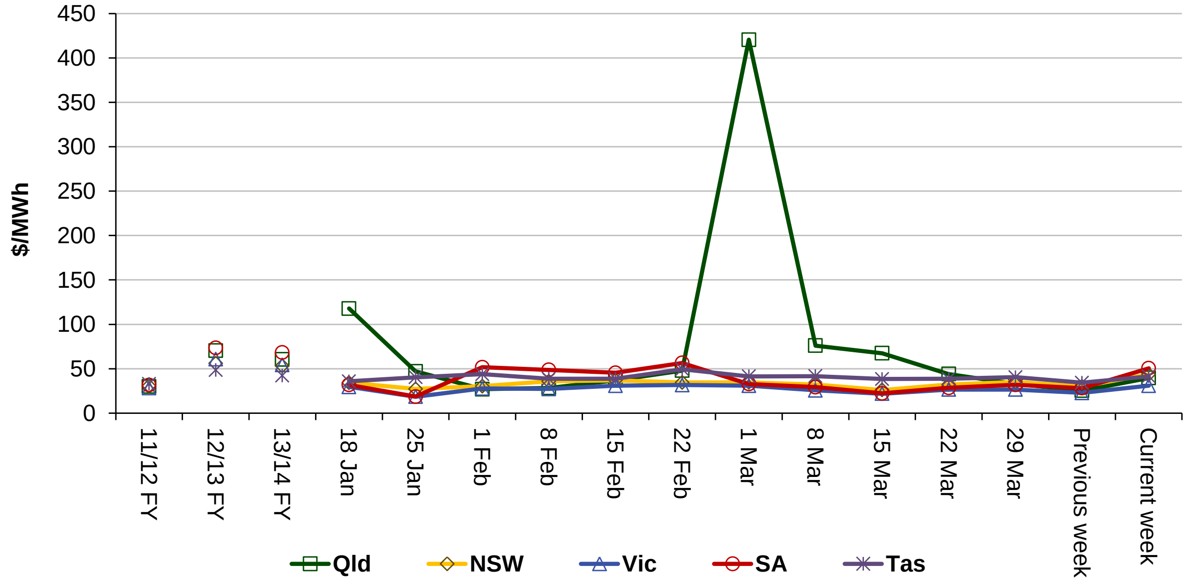


Table 1 : Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	40	44	31	50	41
13-14 financial YTD	63	54	56	72	43
14-15 financial YTD	68	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 114 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	5	28	0	3
% of total below forecast	45	7	0	12

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

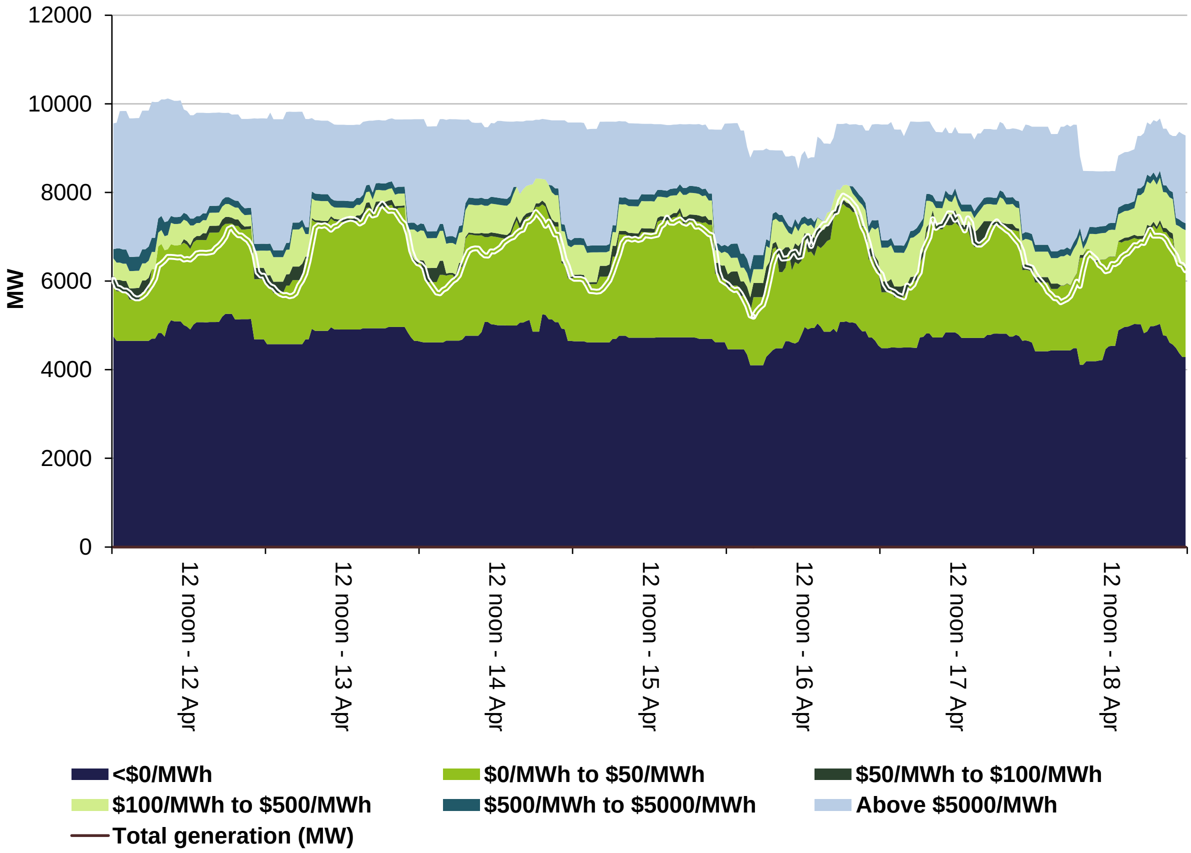


Figure 4 : New South Wales generation and bidding patterns

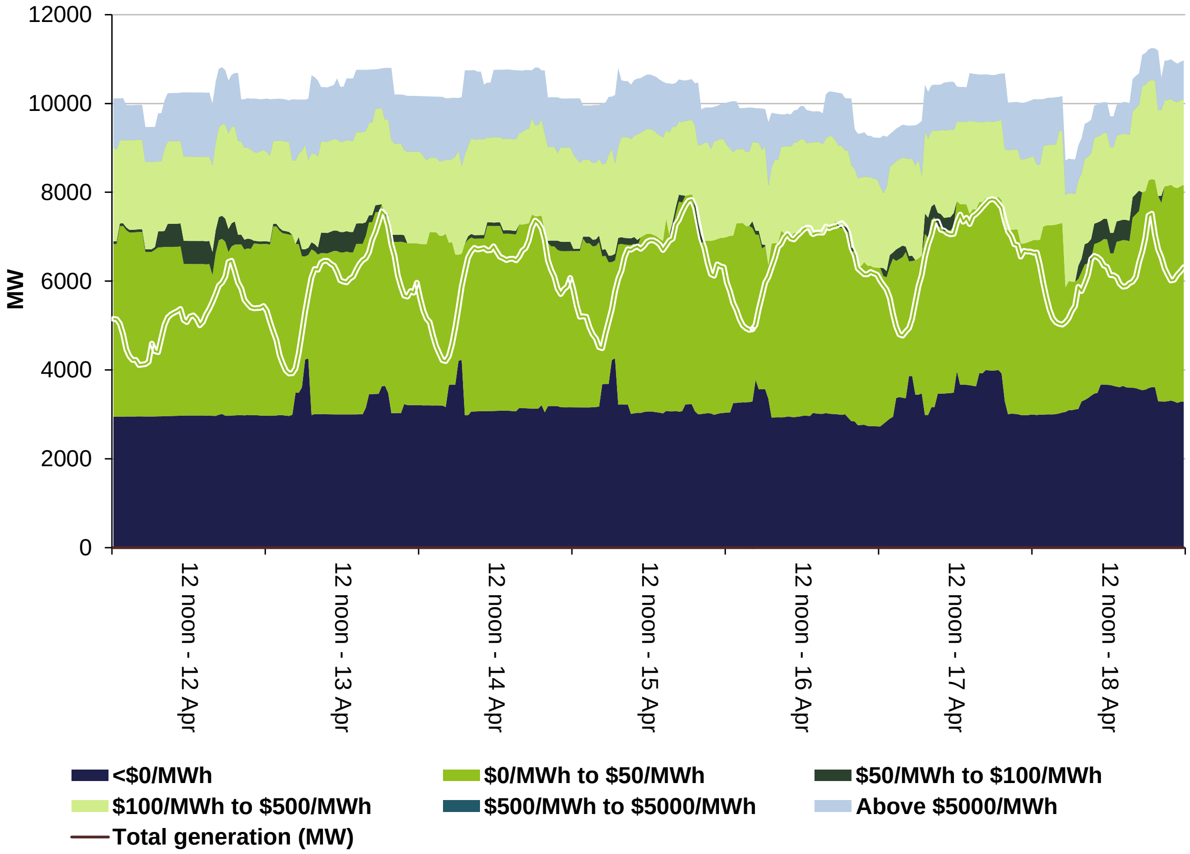


Figure 5 : Victoria generation and bidding patterns

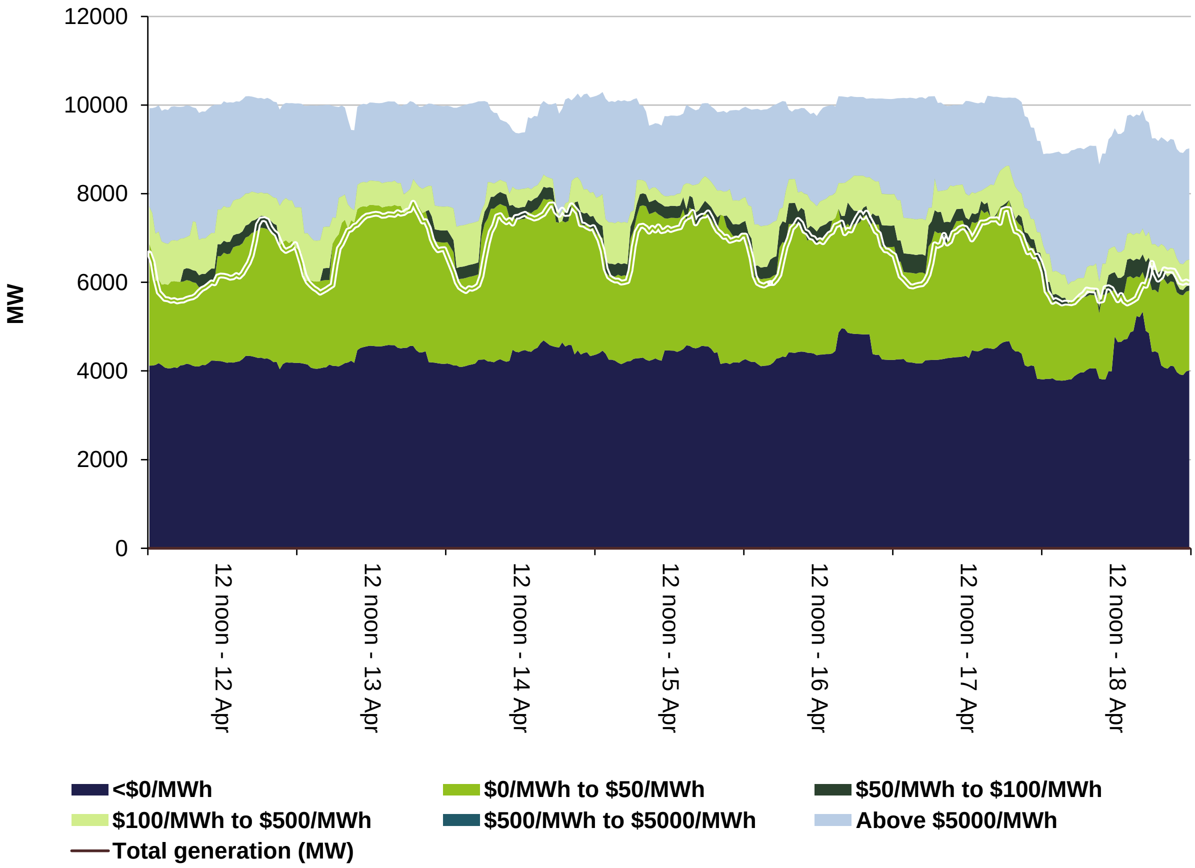


Figure 6: South Australia generation and bidding patterns

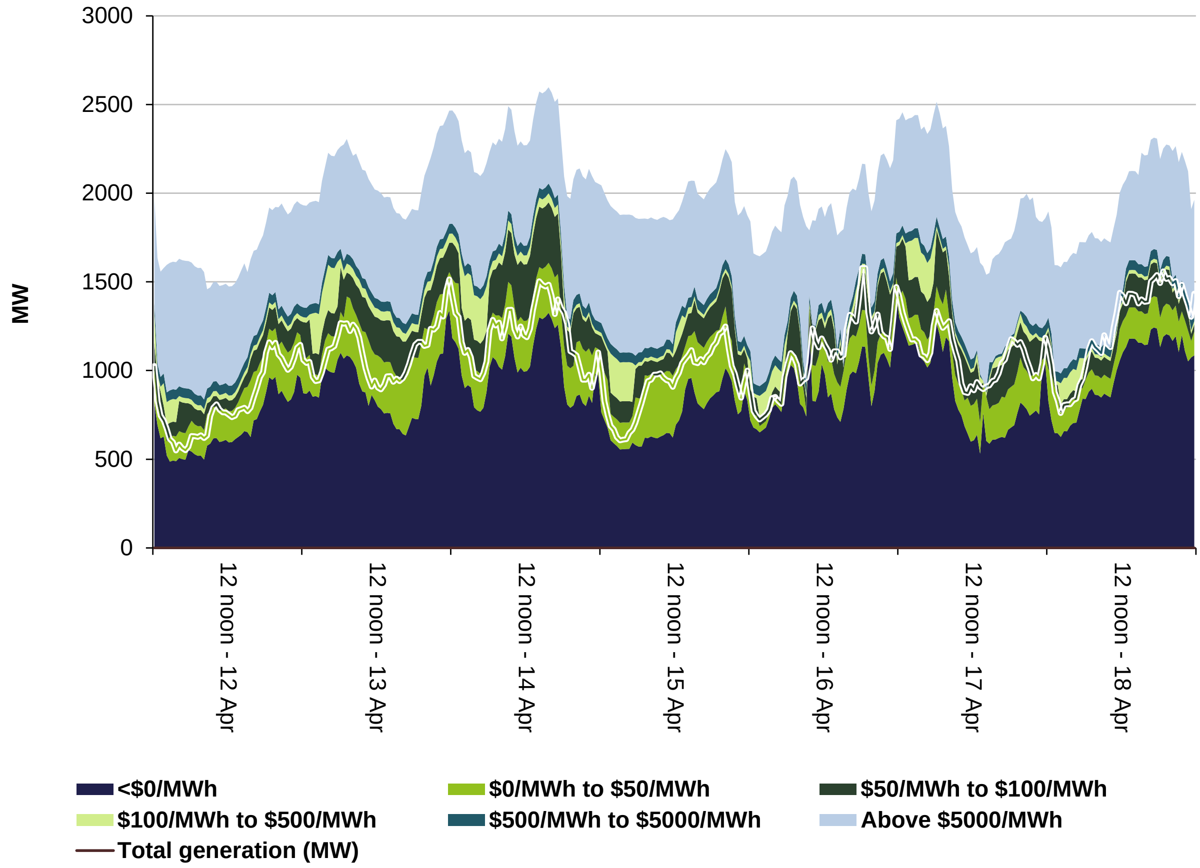
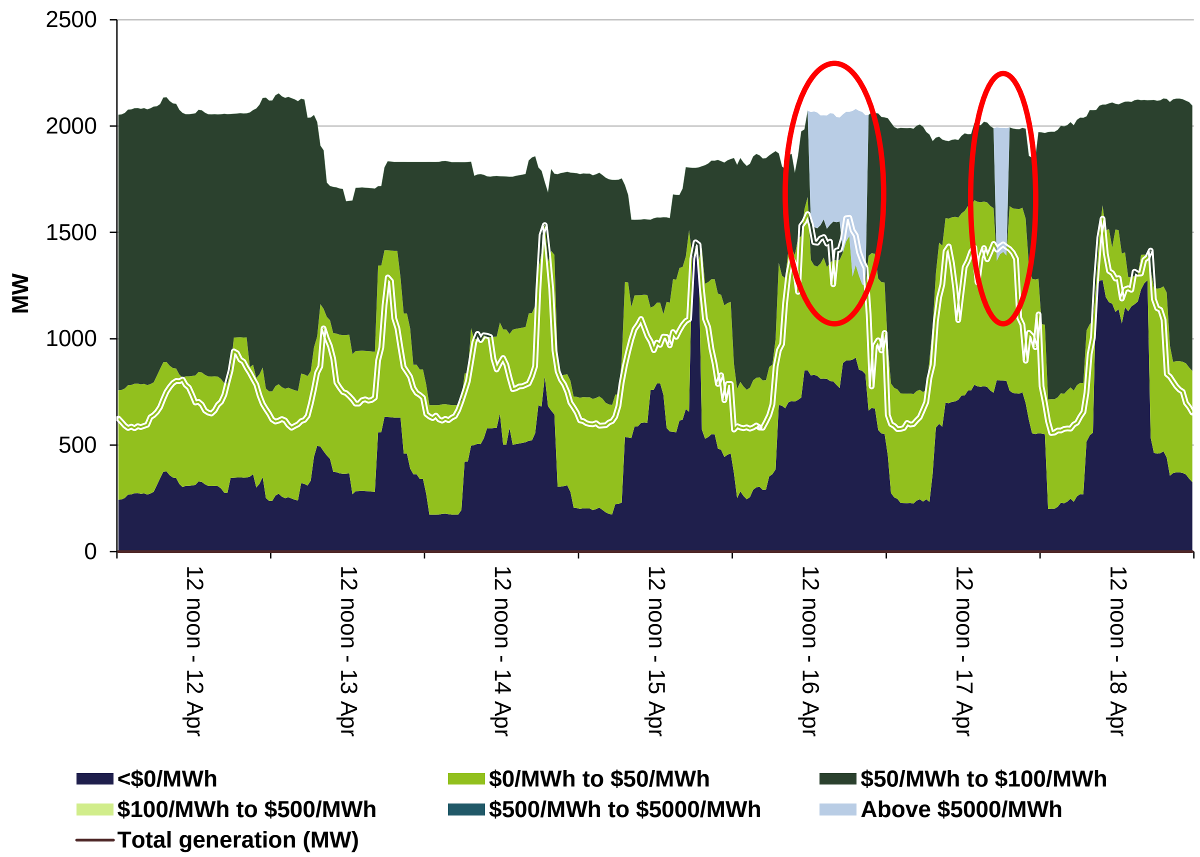


Figure 7: Tasmania generation and bidding patterns



The red ellipses show where Hydro Tasmania had little or no capacity priced between $0/MWh and $10 500/MWh. This bidding did not lead to prices above our reporting threshold.

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 $471 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $103 500 or around 1.3 per cent of energy turnover in Tasmania.

Figure 8 : Daily frequency control ancillary service cost

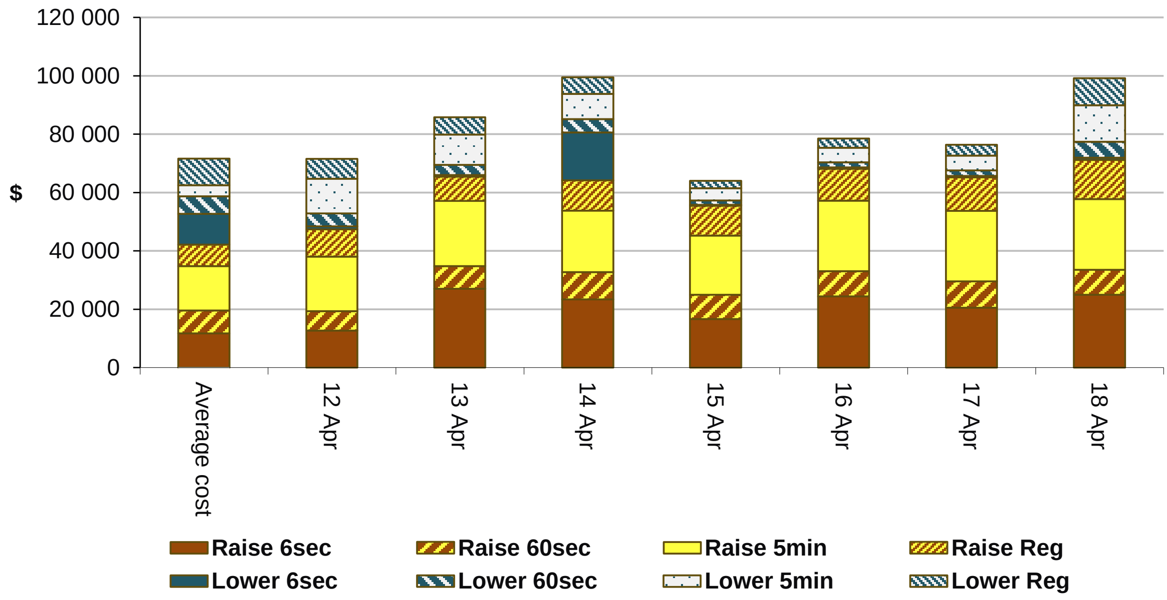


Figure 8shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

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.

New South Wales and Queensland

There were three occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $44/MWh and above $250/MWh. On one of these occasions the price in Queensland also reached the reporting threshold.

New South Wales and Queensland – Thursday 16 April

Table 3: Price, Demand and Availability 3.30 pm

Region	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
NSW	252.33	58.84	48.31	8848	8726	8408	9671	9628	10 085
QLD	236	55	47	6587	6540	6539	9219	9543	9602

Queensland and New South Wales were isolated from the rest of the NEM because the Victoria-New South Wales interconnector was constrained to its limit into New South Wales of around 1200 MW. QNI remained unconstrained and prices in New South Wales and Queensland roughly aligned.

Demand in New South Wales was 122 MW higher than forecast four hours ahead. Available capacity in Queensland was 324 MW lower than forecast four hours ahead.

There was little capacity across the two regions priced between $70/MWh and $280/MWh. This meant that small changes in demand, availability and rebidding could lead to large changes in price.

Table 4: Rebids for 3.30 pm

Submit Time	Partici pant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason	Region
10.28 am	AGL Energy	Liddell	460	<50	N/A	0935~P~010 unexpected/plant limits~ delay in unit rts	NSW
12.15 pm	Stanwell	Stanwell	55	30	13 499	1214P V	QLD
1.18 pm	Delta	Vales Point	180	<42	280	1314P managing internconnector flows SL	NSW
1.28 pm	Origin	Darling Downs	290	<19	N/A	1327P change in avail - rts profile revised SL	QLD

Submit Time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason	Region
1.40 pm	CS Energy	Gladstone	160	30	13 500	1339P portfolio rearrangement due to-w/hoe testing delayed-SL	QLD
2.15 pm	CS Energy	Gladstone	100	<39	13 500	1414P portfolio rearrangement due to-gps 1 return to full availa	QLD
2.32 pm	CS Energy	Callide	75	0	N\A	1431P mill trip-SL	QLD
3.03 pm (effective from 3.10 pm)	Origin	Darling Downs	60	-1000	N/A	1501P change in avail – rts profile revised SL	QLD
3.23 pm (effective from 3.30 pm)	CS Energy	Gladstone	70	<53	N/A	1523P condenser backflush-SL	QLD

At 3.10 pm Queensland demand increased by 45 MW and 17 MW in New South Wales. This coincided with Origin Energy's rebid at Darling Downs, reducing capacity by 60 MW. Consequently the dispatch price increased to $262/MWh in Queensland and $285/MWh in New South Wales and stayed at this level for the rest of the trading interval.

New South Wales and Queensland – Thursday 16 April

Table 5: New South Wales Price, Demand and Availability 6 pm

Region	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
NSW	282	285	208	9187	9158	8855	10 098	9919	10 346
QLD	259	261	199	6988	6895	6951	9548	9552	9589

Prices in both Queensland and New South Wales were close to those forecast four hours ahead.

New South Wales – Friday 17 April

Table 6: 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
11 am	257.41	59.96	39.77	8888	8617	8498	10 396	10 354	10 346

Conditions at the time saw demand 271 MW higher than forecast four hours ahead. Available capacity was close to that forecast. Wind generation was around 25 MW.

Table 7: Rebids for 11 am

Submit Time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.39 am	Delta	Vales Point	160	<280	N/A	0737P fabric filter pass o/s capacity limit
8.11 am	Delta	Vales Point	160	N/A	280	0811P fabric filter pass o/s capacity limit alter, ramp rate cha
9.52 am	Delta	Vales Point	40	35	280	0951P VP6 fabric filter issue resolved – portfolio balance - SL
10.08 am	AGL	Bayswater	90	<29	296	1000~A~040 chg in AEMO disp~44 price decrease vs PD NSW $62.76 v

With no capacity priced between $65/MWh and $275/MWh small changes in demand and the above rebidding saw the dispatch price at around $280/MWh for all but one dispatch interval during the 11 am trading interval.

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 $50/MWh and above $250/MWh.

South Australia– Thursday 16 April

Table 8: 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
10 am	2282.19	54.99	54.99	1364	1400	1436	1787	1789	1709

Conditions at the time saw demand and available capacity close to forecast four hours ahead. Wind generation was only around 220 MW at the time of the high price.

At 9.14 am, effective from 9.25 am, AGL rebid 200 MW of capacity at Torrens Island from prices below $66/MWh to the price cap. The reason given was “0910~F~070 chg in ic operation~70 unexpected effect of ir constr”.

With one other thermal unit available to increase output (ramp up rate of 3 MW/min), and both interconnectors into South Australia at their limits, the dispatch price reached the price cap at 9.35 am, as set by the Torrens Island rebid.

South Australia – Friday 17 April

Table 9: 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
2 pm	1845.63	54.99	40.70	1467	1495	1347	1604	1782	2022

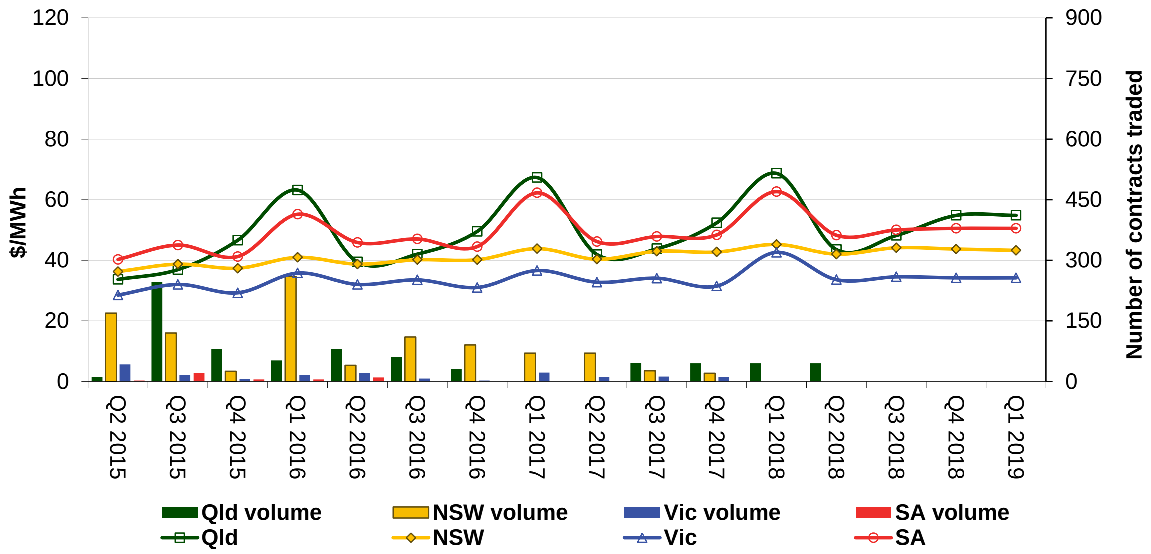
Conditions at the time saw demand close to forecast and available capacity 178 MW lower than forecast four hours ahead.

At 1.43 pm, effective from 1.50 pm, AGL rebid 160 MW of capacity at Torrens Island from prices below $66/MWh to the price cap. The reason given was “1331~A~050 chg in AEMO PD~50 PD avail decrease SA 103MW 14:00”. With low-priced capacity either fully dispatched or trapped in FCAS the dispatch reached $10 782/MWh at 1.50 pm.

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.

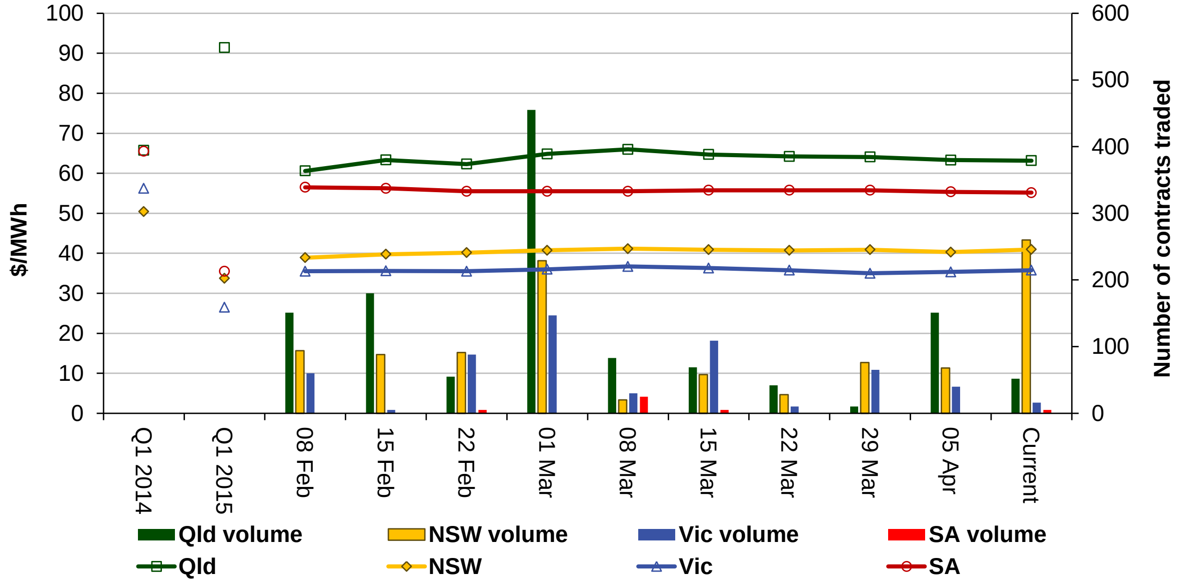
Figure 9: Quarterly base future prices Q2 2015 – Q1 2019



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.

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



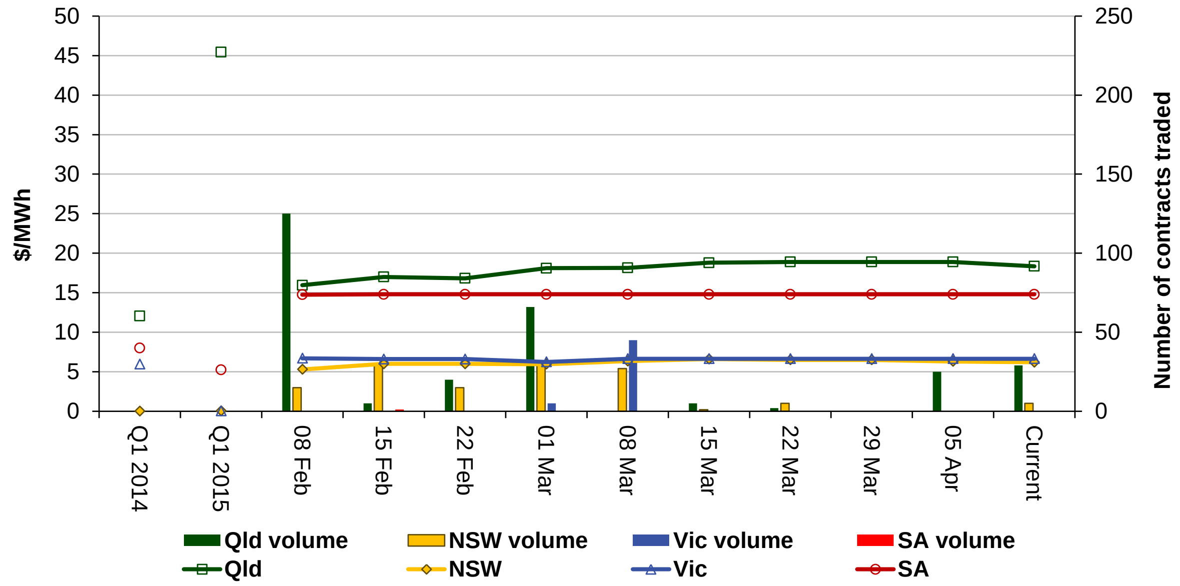
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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 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

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May 2015