Electricity Report
24 – 30 May 2015

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 24 to 30 May 2015. There was three occasions where the spot was greater than three times the weekly average price and above $250/MWh, one in Tasmania, one in New South Wales and one in South Australia. These are discussed in the *Detailed market analysis of significant price events* section.

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

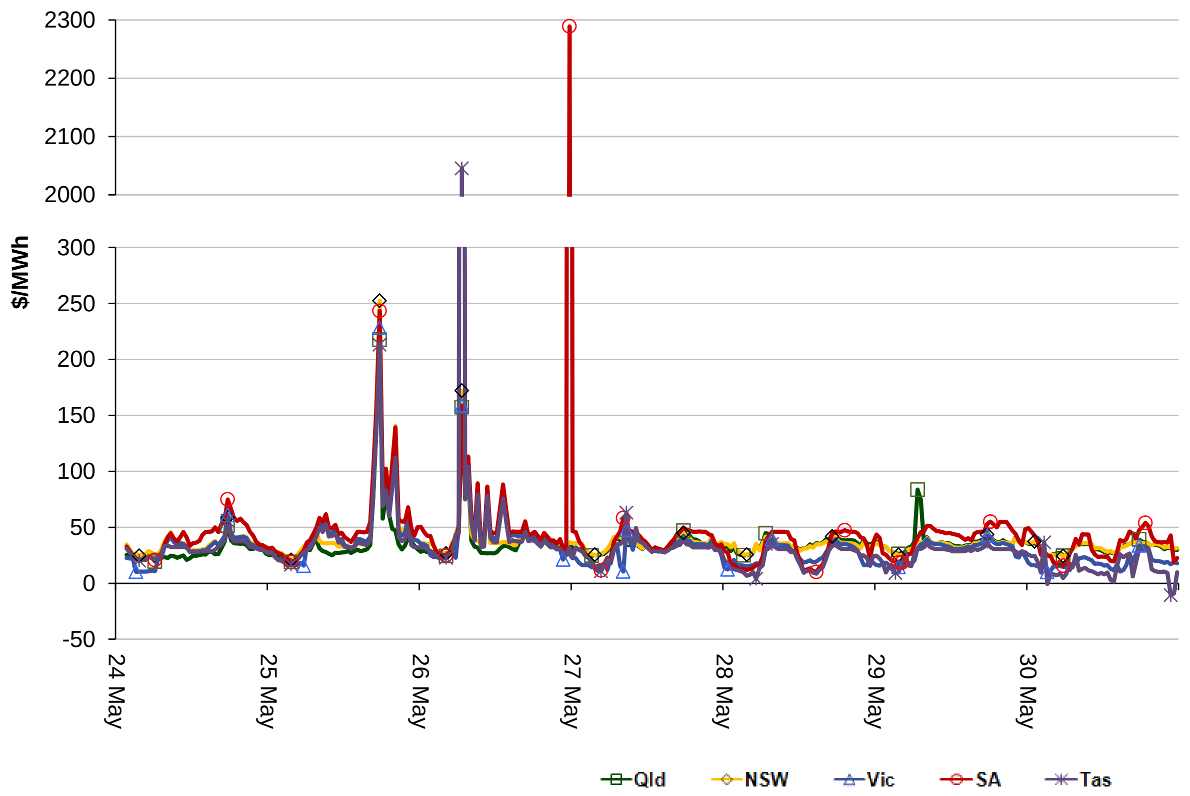


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

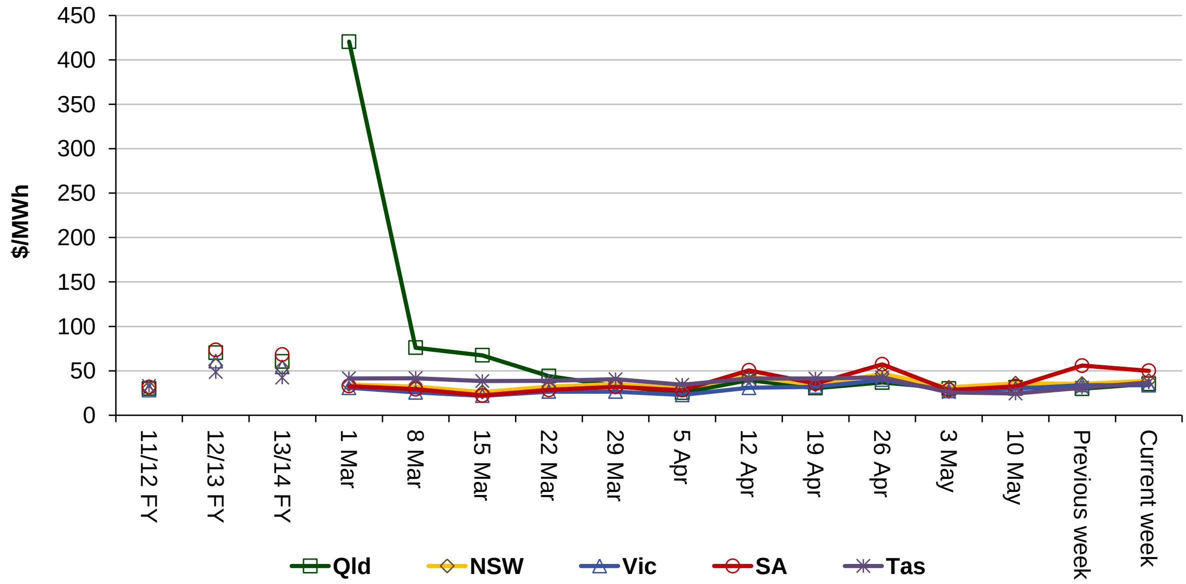


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	35	39	34	50	37
13-14 financial YTD	61	53	55	69	42
14-15 financial YTD	64	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 80 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	8	65	0	1
% of total below forecast	22	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

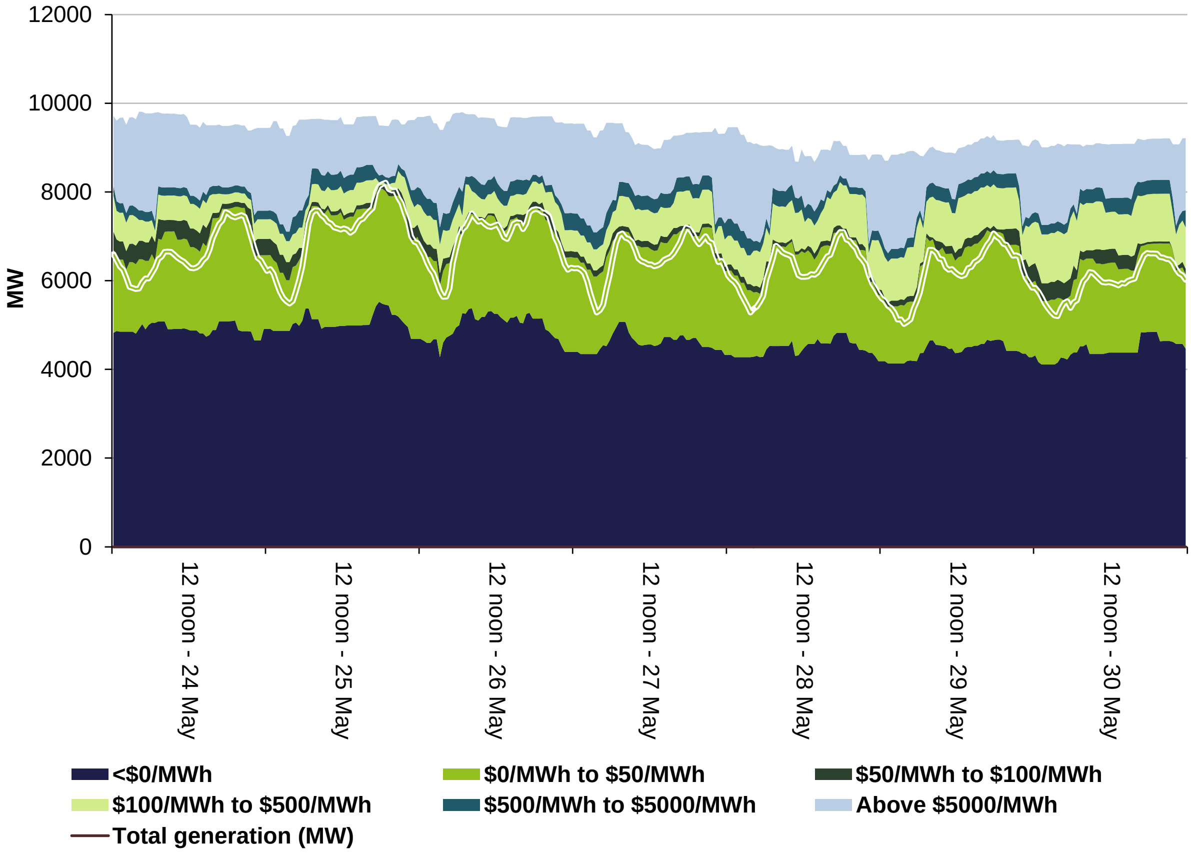


Figure 4: New South Wales generation and bidding patterns

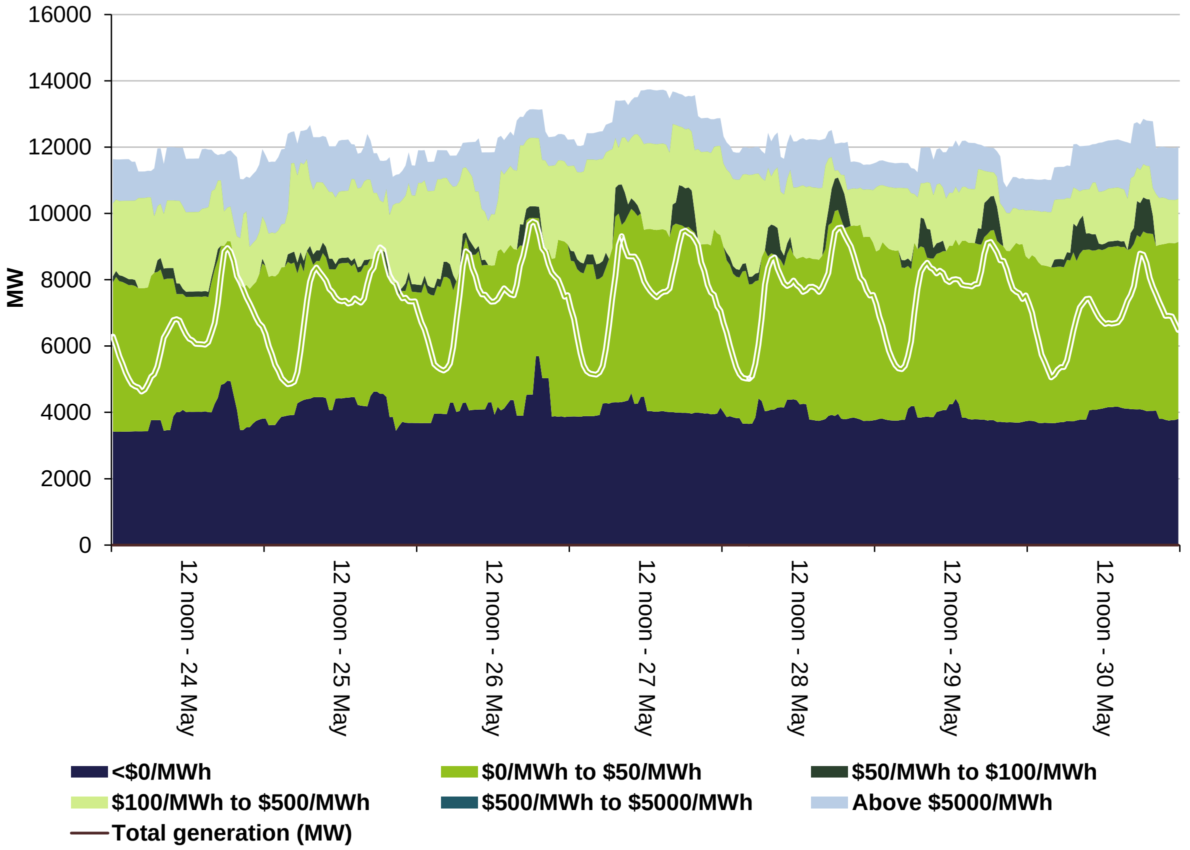


Figure 5: Victoria generation and bidding patterns

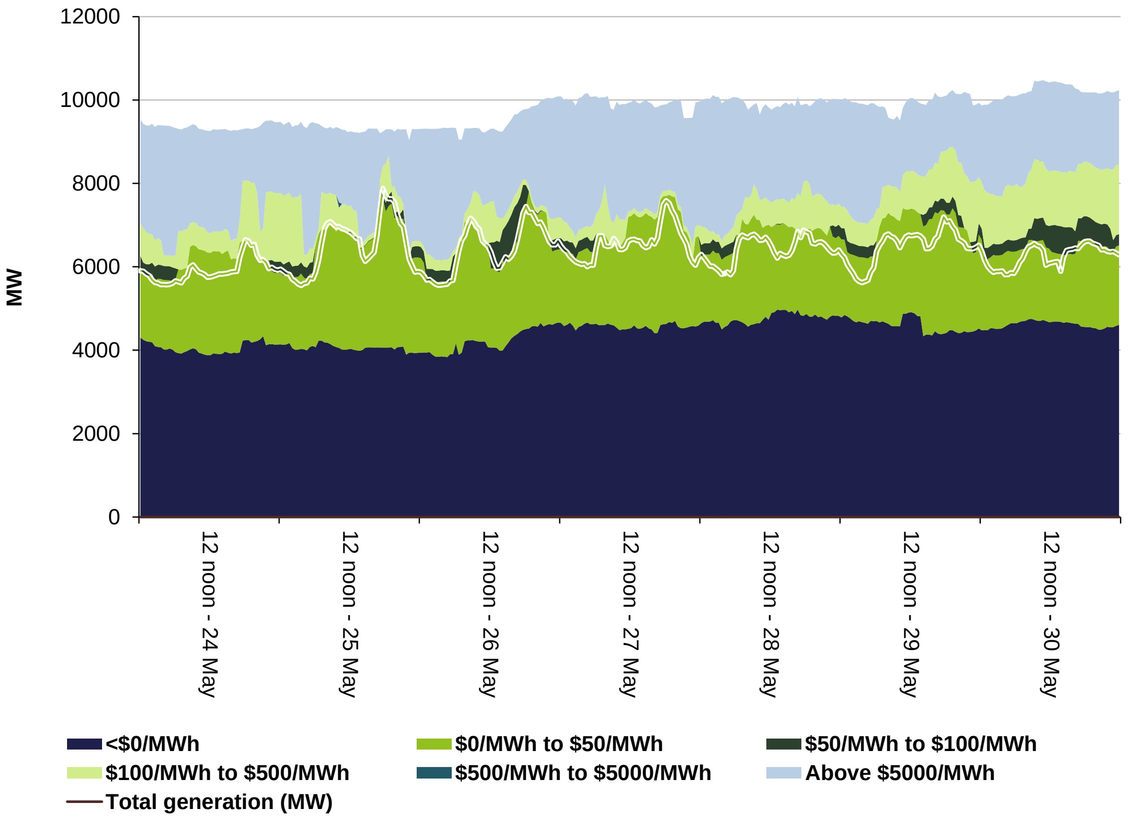


Figure 6: South Australia generation and bidding patterns

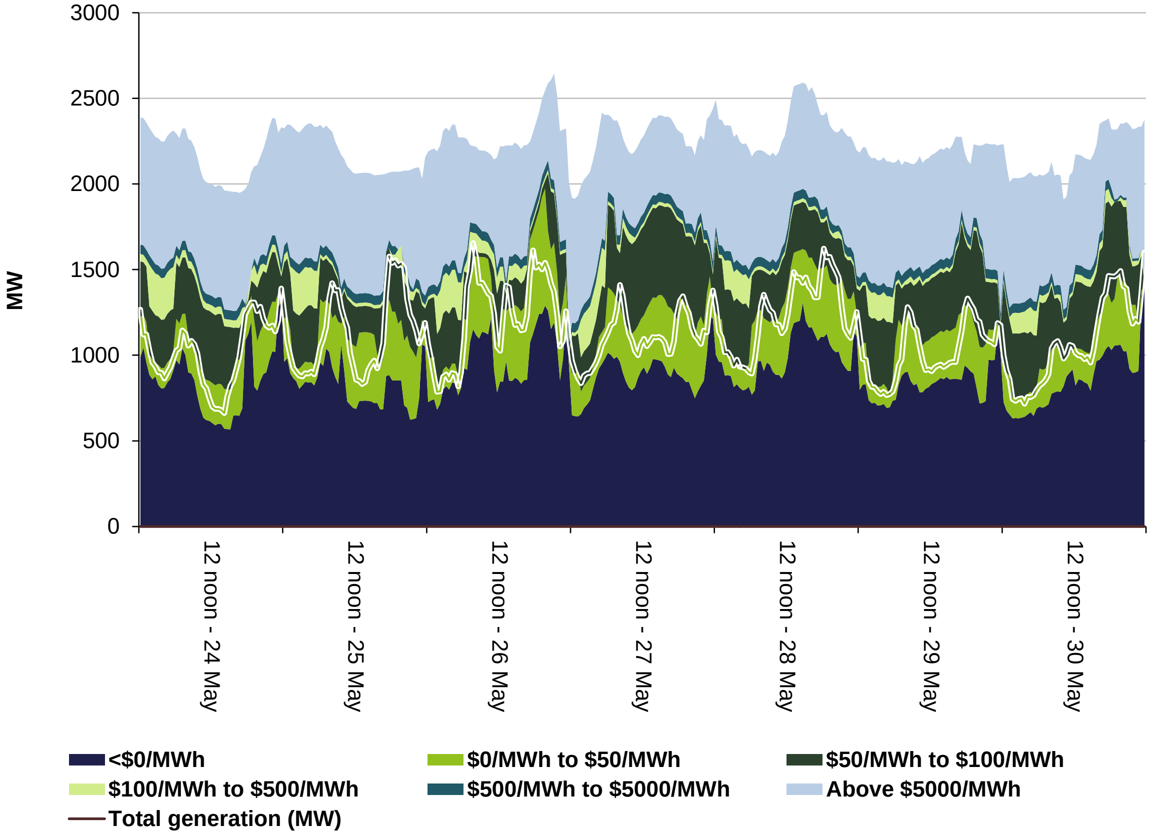
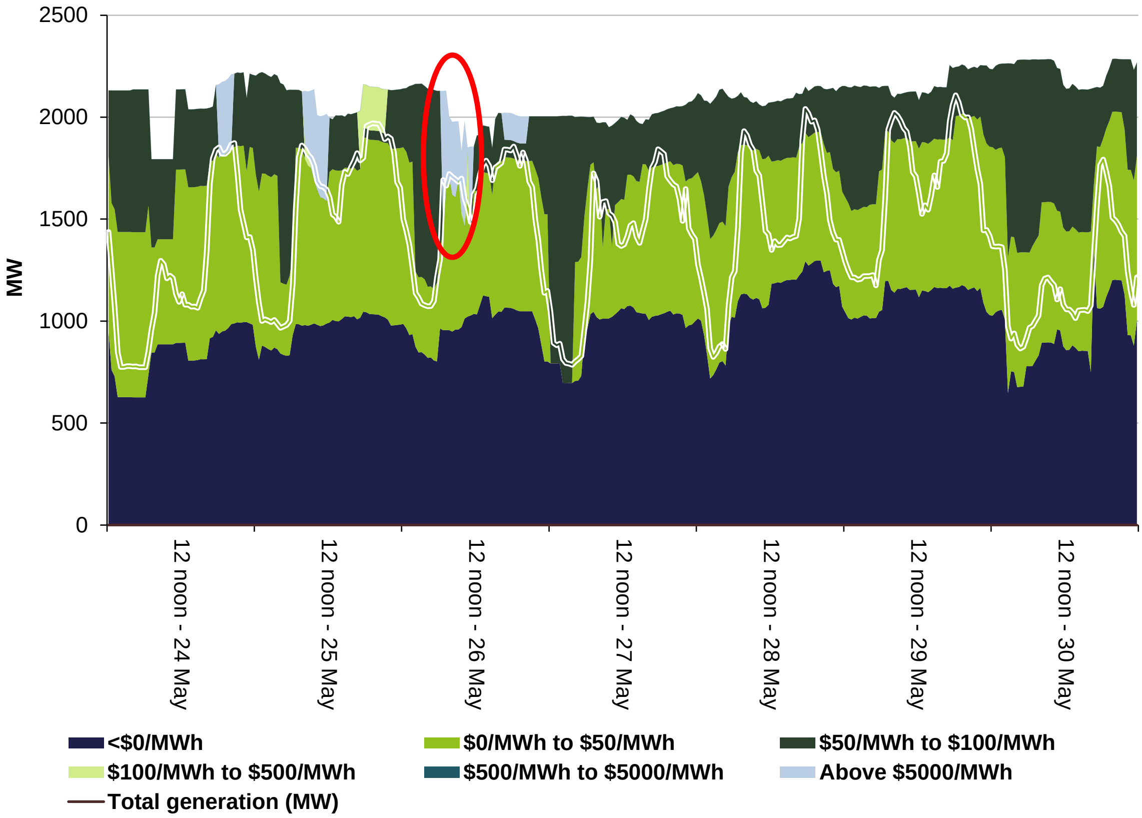


Figure 7: Tasmania generation and bidding patterns



The red ellipse shows where Hydro Tasmania rebid capacity to high prices leading to a high spot price as detailed in the “Detailed market analysis of significant price events”.

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.

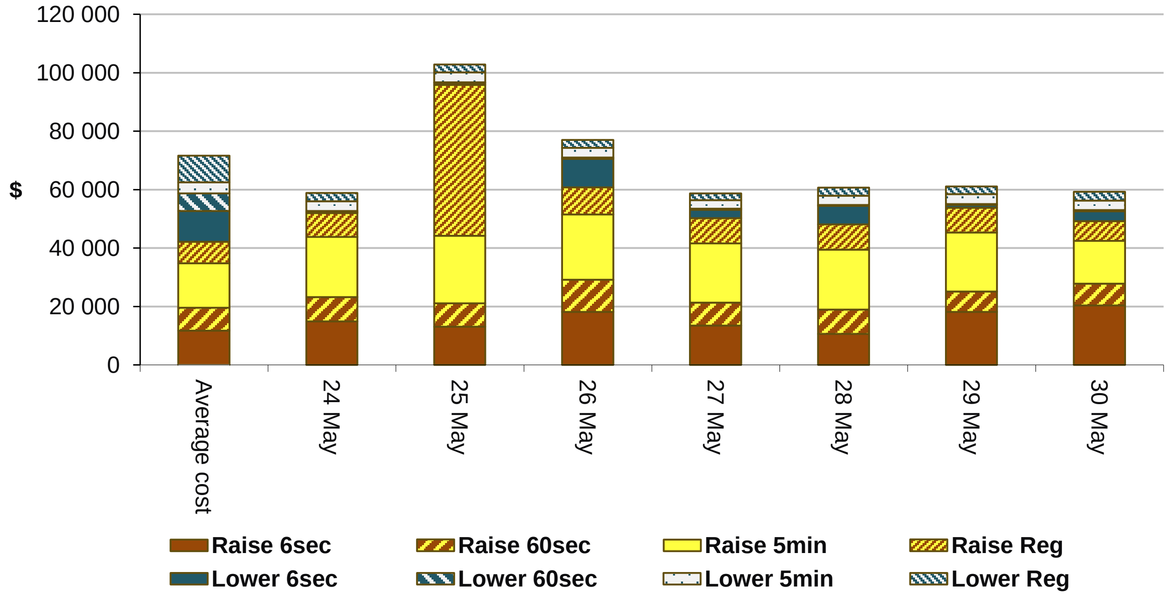
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $382 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $96 500 or around 1.3 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.

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 and above $250/MWh.

Monday 25 May

Table 3: Price, Demand and Availability for 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	252.51	61.95	48.74	10 760	10 689	10 500	11 787	13 208	13 785
VIC	228.07	61.50	48.17	6961	6743	6737	9244	9250	9689
QLD	217.71	57.52	46.35	7018	7041	7052	9628	9702	9687
SA	243.45	66.64	54.99	1761	1667	1704	2067	2065	2141
TAS	212.99	58.13	45.52	1534	1526	1511	2077	2042	2037

All interconnectors were unconstrained for all of the 6 pm trading interval and price alignment occurred across the NEM.[1] However, only the New South Wales trading interval price breached the reporting threshold of $250/MWh.

Conditions at the time saw demand close to forecast levels in all regions except Victoria, which was over 200 MW higher than that forecast four hours ahead. Available capacity in New South Wales was more than 1400 MW lower than that forecast four hours ahead and most of this capacity was priced below $50/MWh.

Table 4: Rebids for 6 pm

Submit Time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason	Region
3.06 pm		Origin	Eraring	-100	36	N/A	1504P change in avail - coal feeder issues ongoing SL	NSW
3.40 pm		AGL	Liddell	-450	<36	N/A	1535~P~010 unexpected/plant limits~RTS following trip	NSW
3.48 pm		Origin	Eraring	-50	36	N/A	1545P change in avail - coal issues revised SL	NSW

1 Slight variation in prices across regions occurs as a result of transmission losses.

Submit Time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason	Region
3.53 pm		Alinta	Northern	58	<65	13 334	1545~A~5PD $54.94 V 30PD $46.32~	SA
4.58 pm		Delta	Vales Point	-60	<280	N/A	1657P milling/feeder limit	NSW
5.08 pm		Energy Australia	Mount Piper unit 1	-680	<50	N/A	17:07 P avail adj due to unit trip et unknown	NSW
5.15 pm		Ecogen Energy	Jeeralang A	-54	1	N/A	17:14 P adj avail due to main lube pump fault	VIC
5.31 pm	5.40 pm	Alinta	Northern	40	55	13 334	1730~P~oil turned off ~	SA
5.35 pm	5.45 pm	Delta	Vales Point	-130	<50	N/A	1734P milling/feeder limit - additional mill out	NSW
5.40 pm	5.50 pm	Millmerran	Millmerran	-75	7	N/A	17:39 P: mill trip	QLD

The above rebids reduced the amount of low-priced capacity creating a steeper supply curve across the NEM. As the evening peak demand increased the dispatch price increased. At 5.40 pm there was a 330 MW increase in demand across the NEM which saw the dispatch price in New South Wales increase from $116/MWh at 5.35 pm to $300/MWh at 5.40 pm. The dispatch price remained above $200/MWh for the rest of the trading interval.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price and above $250/MWh.

Tuesday 26 May

Table 5: 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
7 am	2045.46	36.93	32.05	1309	1292	1323	2129	2166	2159

Demand and available capacity were close to forecast levels.

At 6.48 pm, effective from 6.55 pm, Hydro Tasmania rebid 686 MW of capacity across its portfolio[2] from prices less than $98/MWh to $11 677/MWh. The reasons given were “0640A

2 For all available generators except Bastyan, Poatina and Reece.

P5 VIC price higher than forecast." and "0640A P5 VIC price higher than forecast.+unmanned". This saw the dispatch price increase from $81/MWh at 6.50 am to $11 678/MWh at 6.55 am.

A decrease in demand of 77 MW at 7 pm saw the dispatch price drop to $270/MWh before returning to lower levels.

South Australia

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price and above $250/MWh.

Wednesday 27 May

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
Midnight	2289.00	31.83	29.54	1552	1577	1586	2140	2473	2512

Conditions saw demand close to forecast four hours ahead and available capacity was over 300 MW lower than forecast four hours ahead. Most of this capacity was due to the trip of Northern Unit 2 which was 273 MW price below $65/MWh.

Demand in the region increased by 200 MW from 1353 MW at 11.30 pm to 1553 MW at 11.35 pm. Demand in the following intervals remained above this level until 11.55 pm. This was related to off peak hot water load.

Table 7: Rebids for the midnight trading interval

Submit Time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.38 pm	11.45 pm	AGL	Torrens Island	200	<55	13 500	2335~A~040 chg in aemo disp~45 price increase VS PD SA $51.98 VS
11.39 pm	11.50 pm	Alinta	Northern	-273	<65	N/A	2335~P~NPS2 unit trip

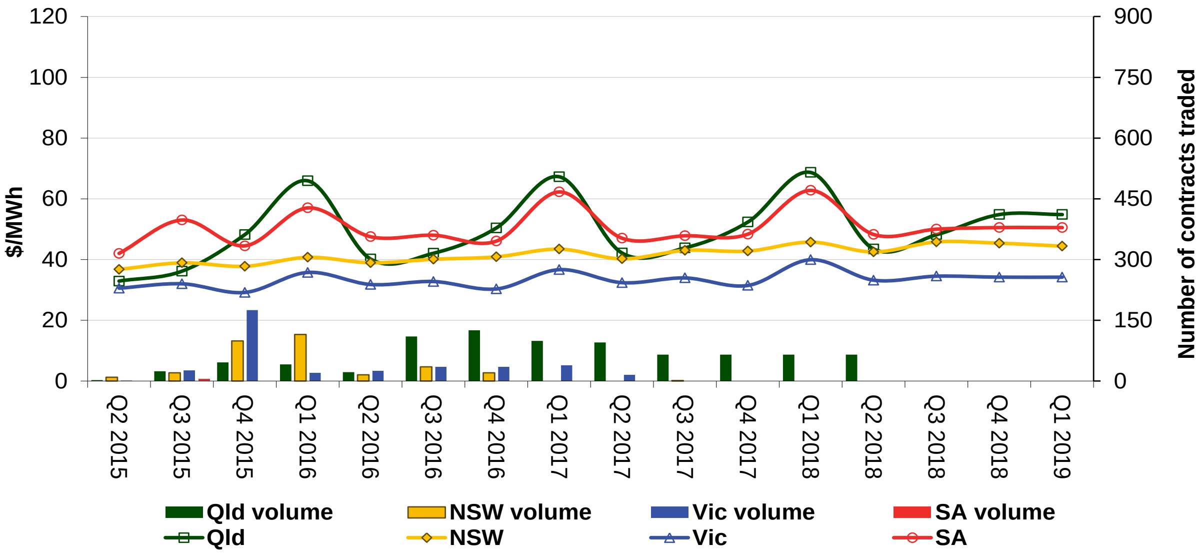
At 11.45 pm when AGL's rebid became effective, the dispatch price was $47/MWh as the units rebid were ramp down limited and unable to set price. At 11.55 pm, low priced capacity was either ramp up limited or trapped in FCAS, and AGL's Torrens units that were rebid were no longer ramp down limited and were able to set price at the cap.

At midnight the price fell to $32/MWh when non-scheduled generation output increased, reducing demand.

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.

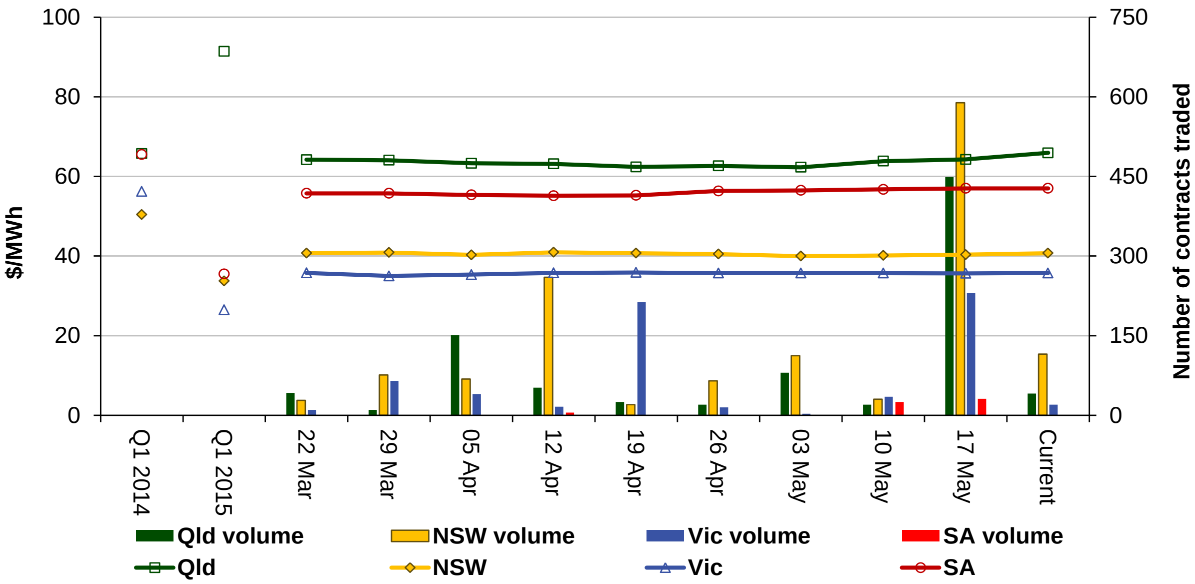
Figure 9: Quarterly base future prices Q2 2015 – Q4 2018



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

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



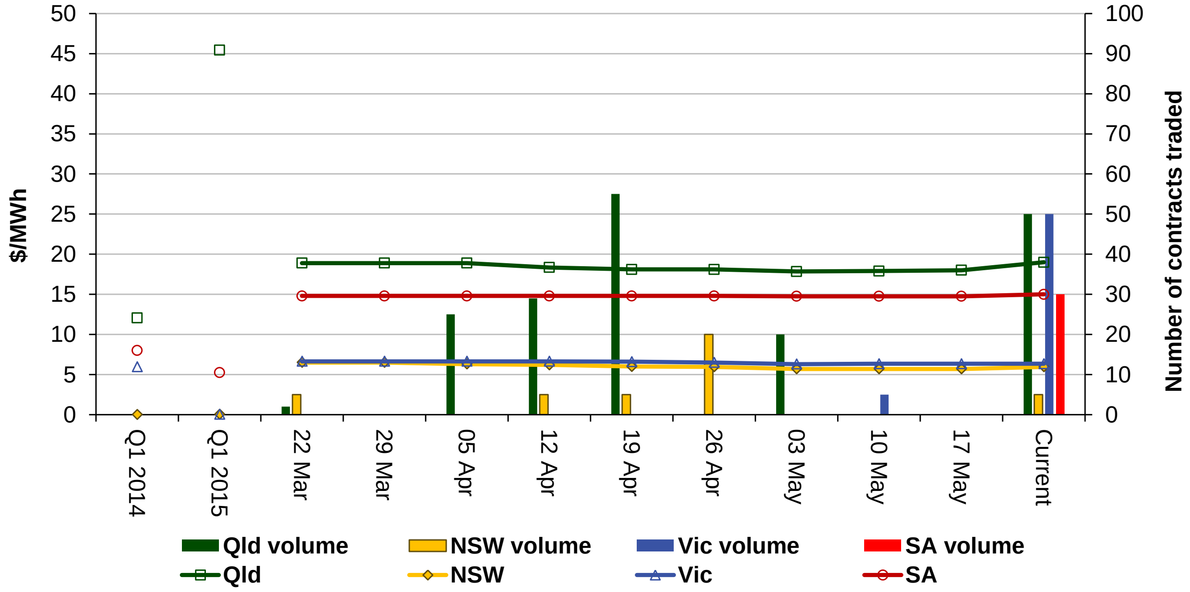
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics 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. Despite being close to the end of the quarter, prices in Queensland remain elevated and volumes are still being traded.

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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