Electricity Report
8 – 14 February 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 8 to 14 February 2015. The spot price exceeded $250/MWh and was greater than three times the regional weekly average price on one occasion in New South Wales and South Australia during this week. The spot price in Victoria was below -$100/MWh in Victoria during the same interval as the price exceeded the threshold in South Australia.

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

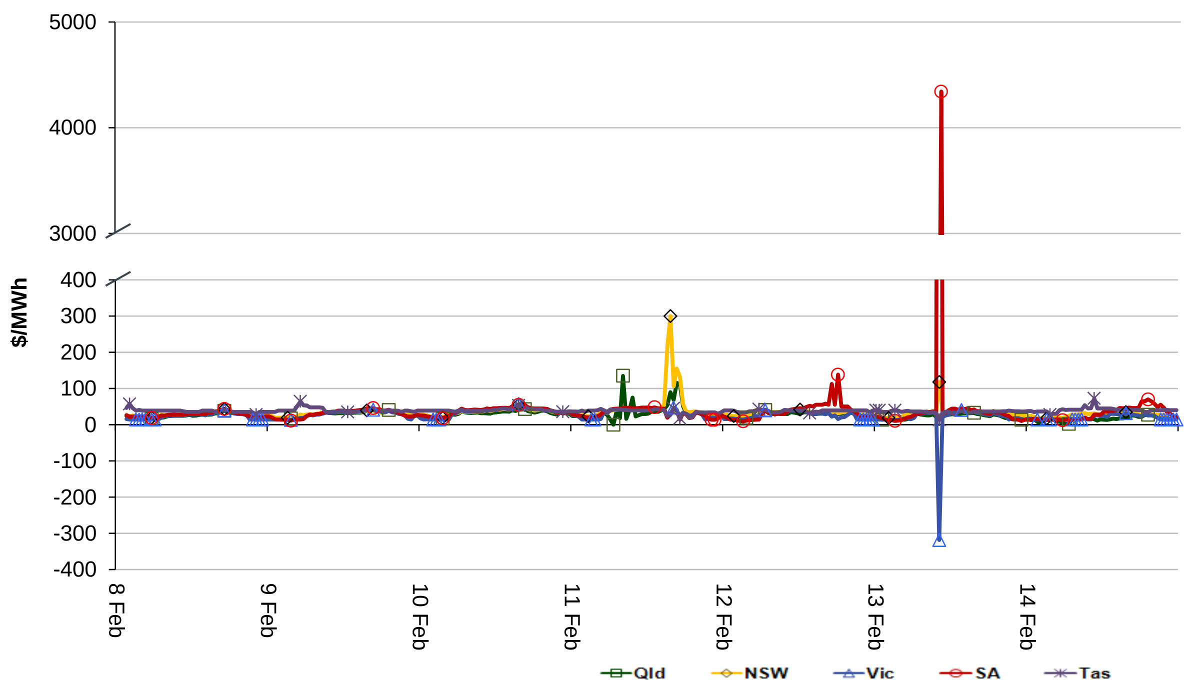


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

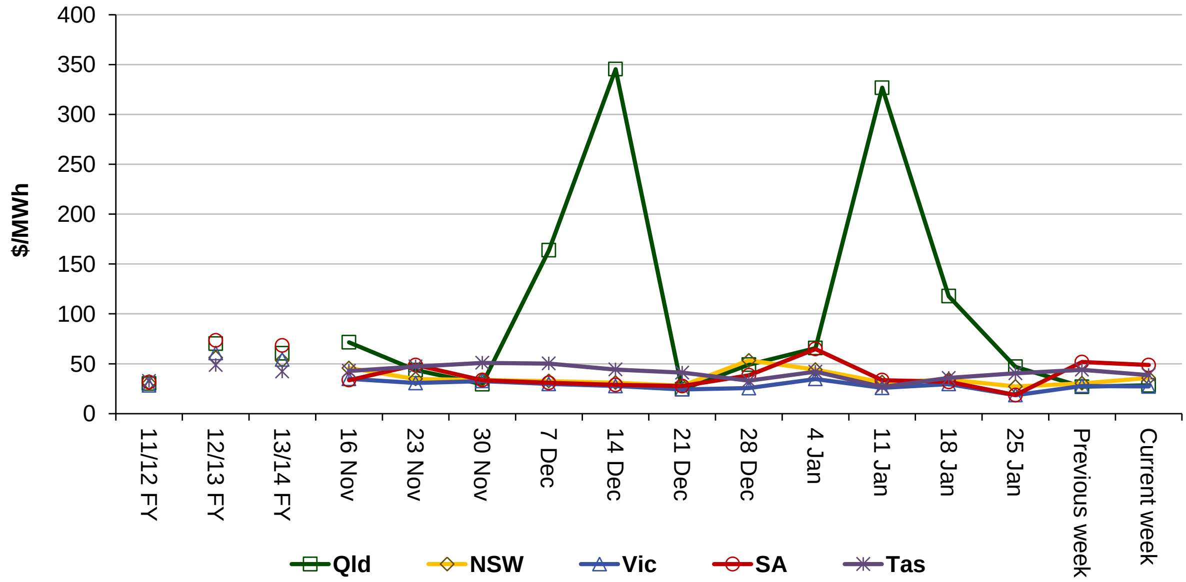


Table 1 : Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	28	36	27	49	39
13-14 financial YTD	61	53	54	68	42
14-15 financial YTD	62	37	32	41	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 98 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	7	23	1	3
% of total below forecast	32	32	0	2

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

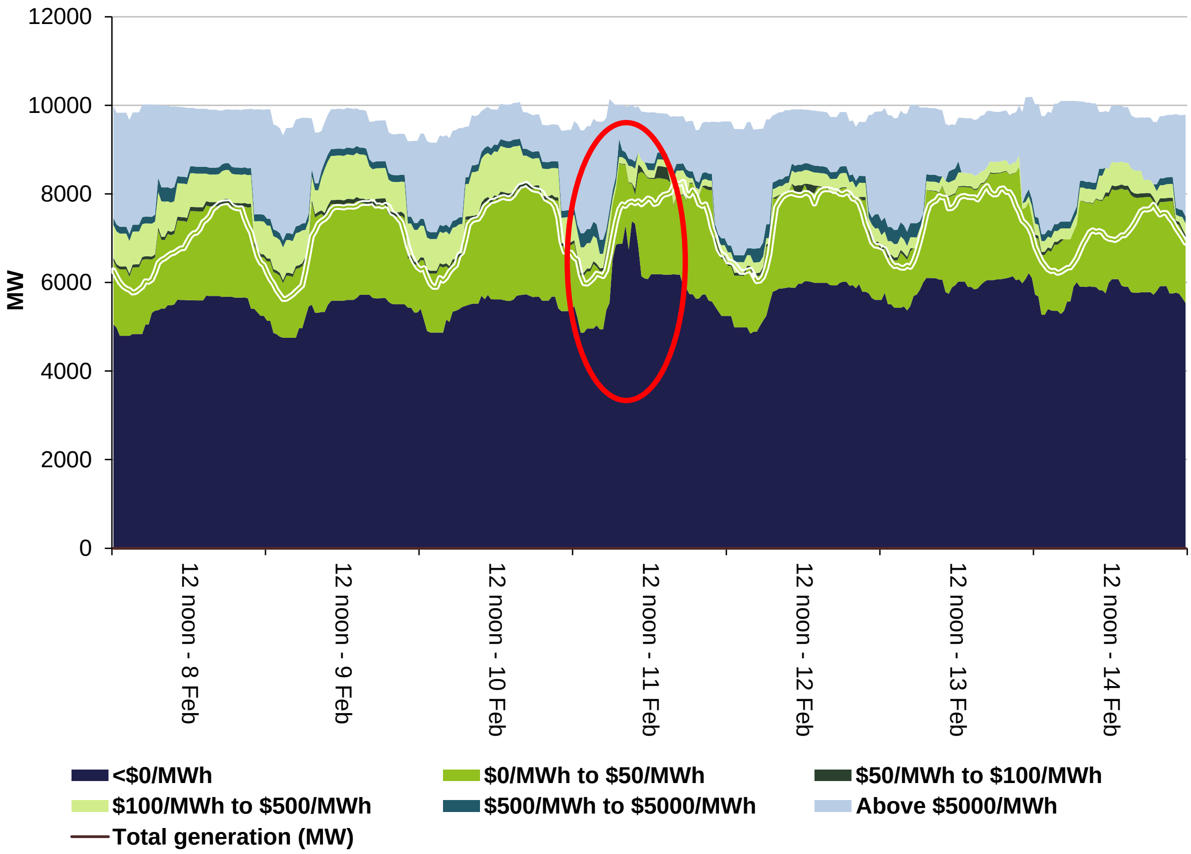


Figure 4 : New South Wales generation and bidding patterns

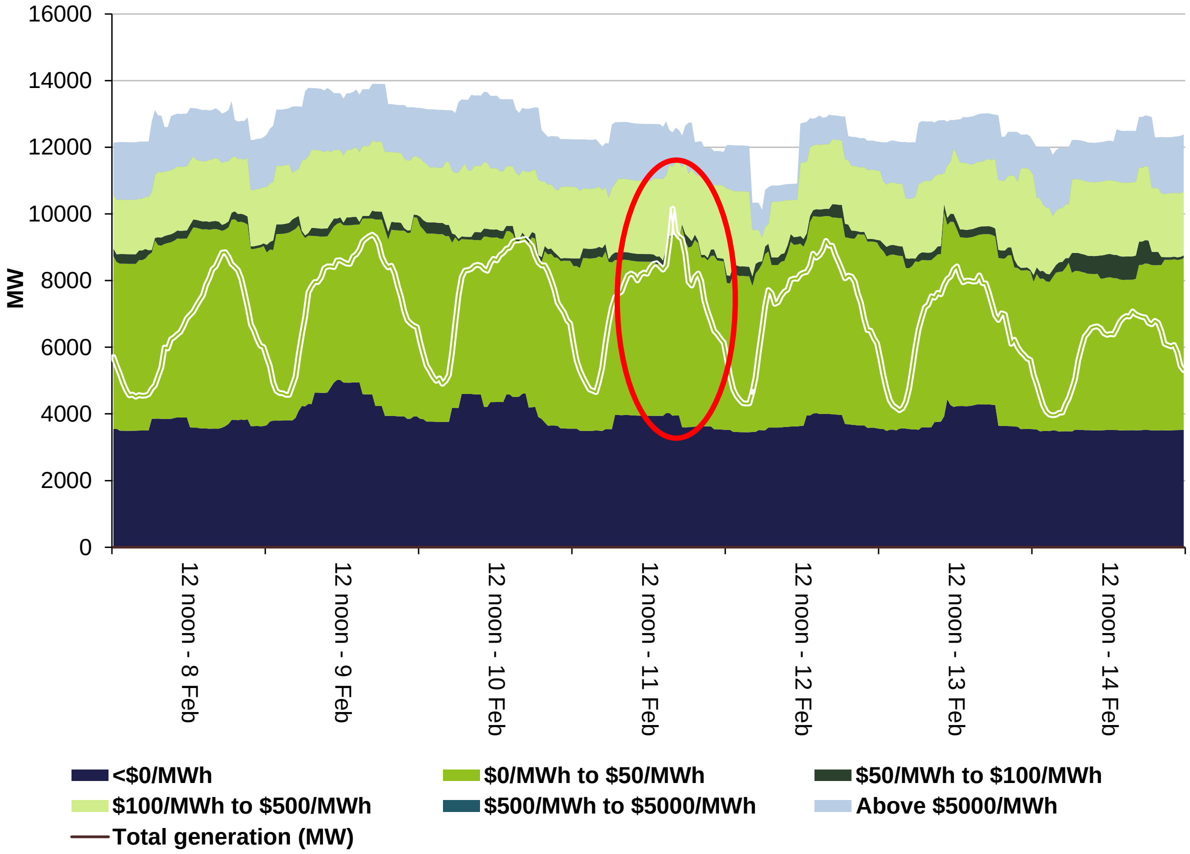


Figure 5 : Victoria generation and bidding patterns

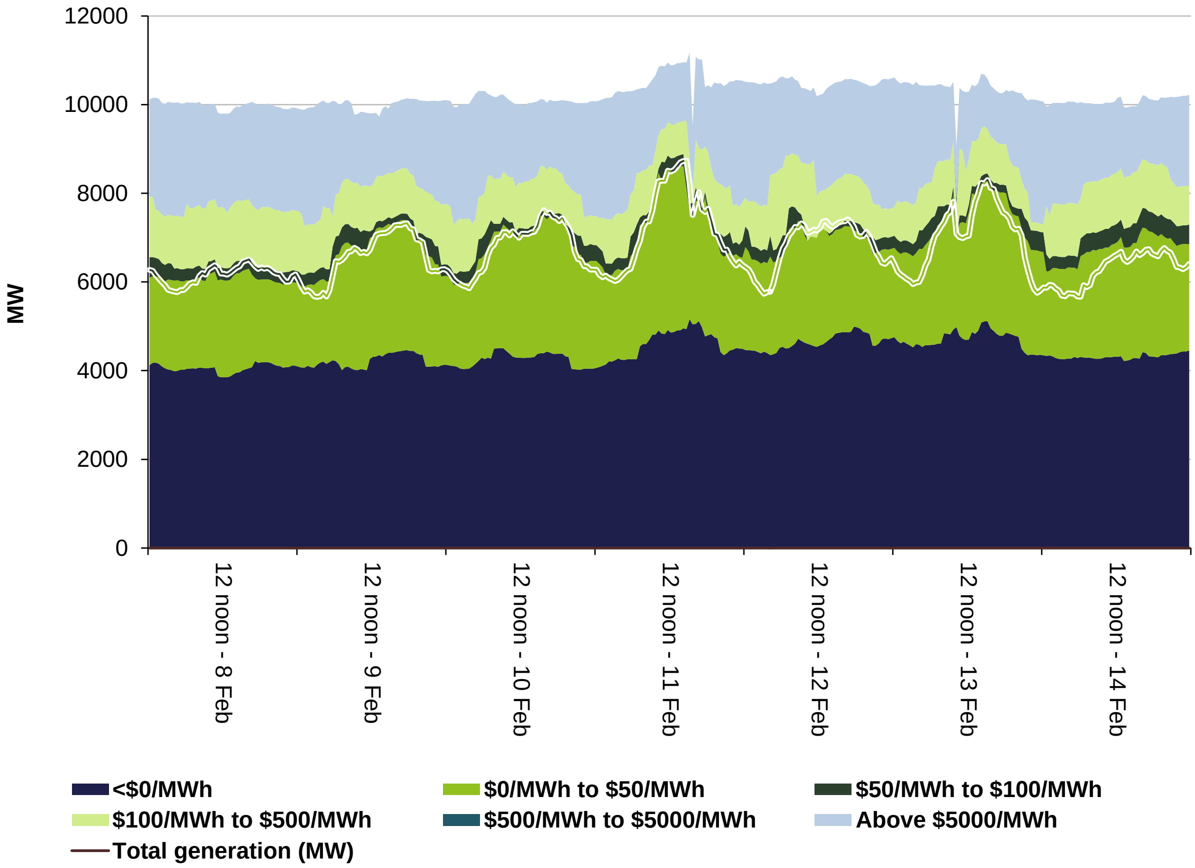


Figure 6: South Australia generation and bidding patterns

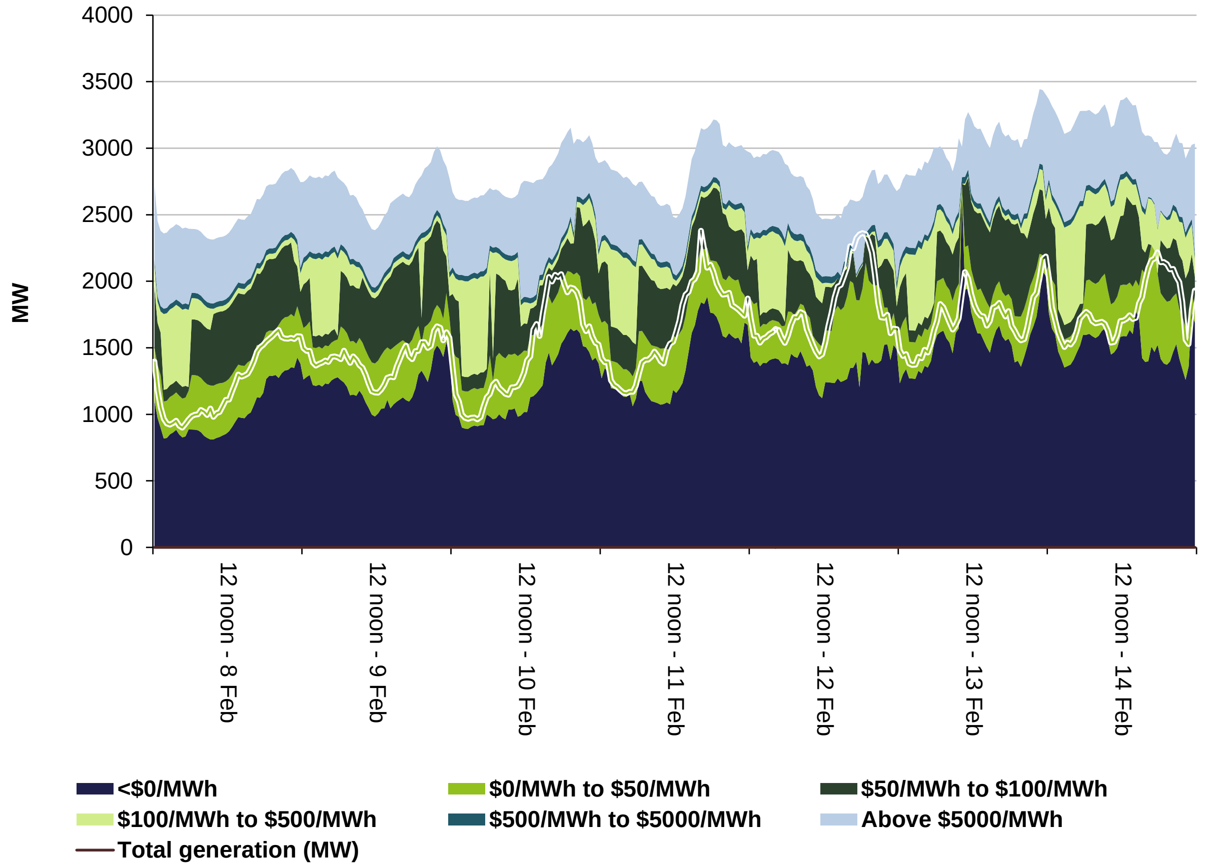
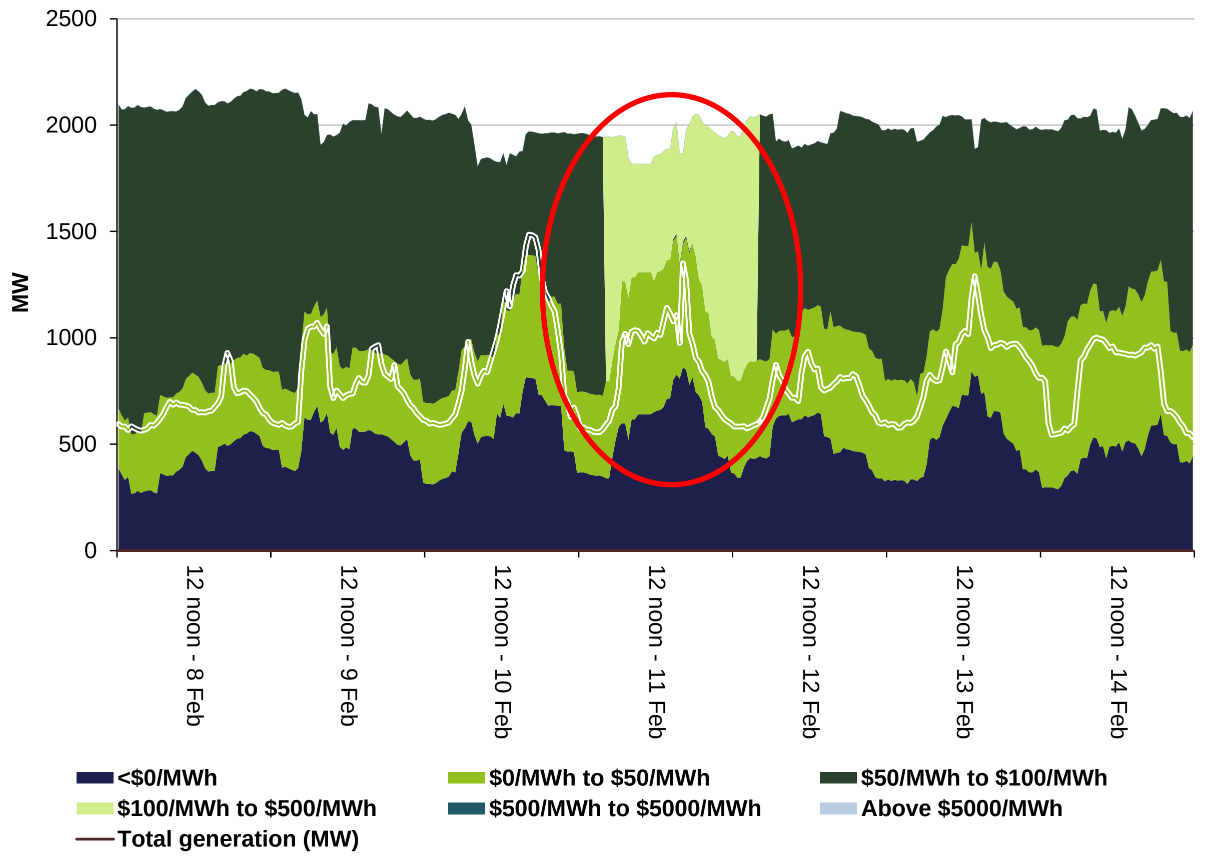


Figure 7: Tasmania generation and bidding patterns



The red ellipses highlight areas of particular interest.

The red ellipse on Figure 3 corresponds to rebidding by both CS energy and Stanwell shifting capacity from between $0/MWh and $50/MWh to less than $0/MWh.

The ellipse on Figure 4 highlights the period during which the prices exceeded the reporting threshold and are discussed in detail later in the 'Detailed market analysis of significant price events' section.

The ellipse on Figure 7 highlights 11 February where the initial bids for the generators in that region reallocated capacity normally priced between $50/MWh and $100/MWh into bands between 0/MWh and $50/MWh and between $100/MWh and $500/MWh for the whole of the trading day.

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 $1 563 500 or less than 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $69 500 or less than 2 per cent of energy turnover in Tasmania.

Figure 8 : Daily frequency control ancillary service cost

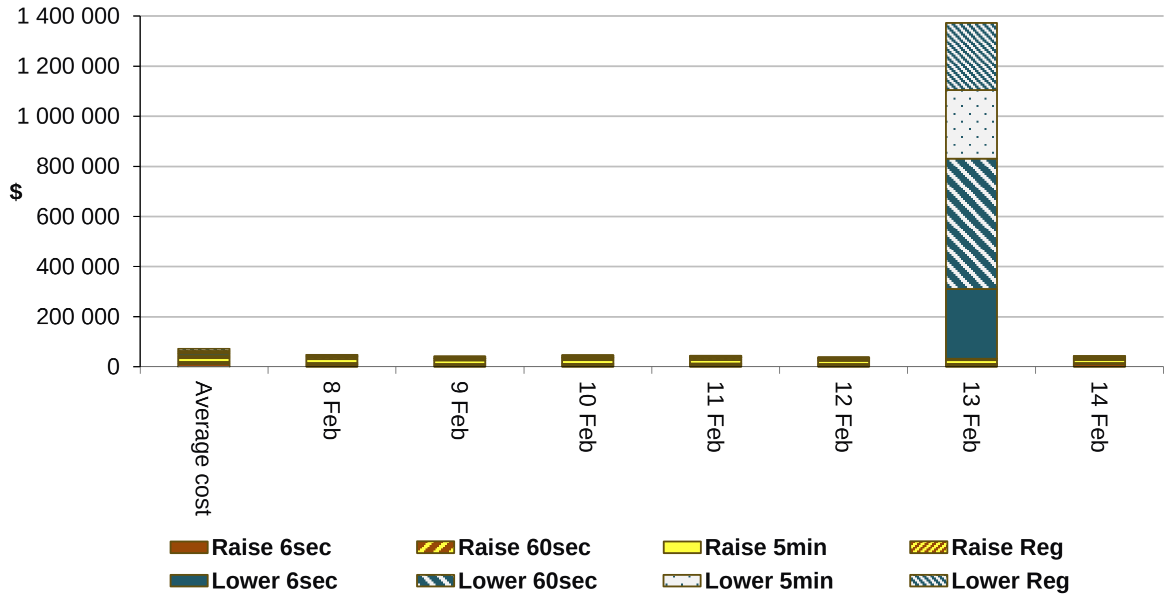


Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

On 13 February, lower FCAS requirements increased significantly in South Australia following the unplanned outage of the Alcoa Portland–Heywood–Tarrone no.1 500 kV transmission line, Moorabool –Tarrone no. 1 500kV transmission line and the 3 Alcoa Portland busses. The price for lower 60 second and lower 6 second services reached $13 100/MW at 10.20 am and 10.25 am. The price for the lower 5 minute and lower regulatory services reached $12 400/MW at 10.20 am and then reached $13 100/MW at 10.20 am. Overall the cost of lower FCAS in South Australia exceeded $1 300 000. This is described further in the 'Detailed market analysis of significant price events' section.

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 of $36/MWh and above $250/MWh.

Wednesday, 11 February

Table 3: 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
4 PM	299.77	42.14	52.64	10 519	10 357	10 445	12 408	12 706	12 829

Demand was 162 MW higher than forecast four hours before. Available generation was 298 MW lower than forecast four hours before.

For the duration of the 4pm trading interval, both the QNI and Terranora interconnector import targets were at the respective limits of approximately 1040 MW and 30 MW.

Between 3.15 pm and 4.05 pm a constraint to avoid the overload of the Ballarat North to Buangor 66kV line for the loss of the Ballarat to Waubra to Horsham 220kV line caused flows on the Vic-NSW interconnector to change direction. The interconnector went from importing 612 MW from Victoria into New South Wales at 3.10 pm to exporting 155 MW at 3.20 pm. During the 4 pm trading interval the Vic-NSW interconnector continued export flow targets, peaking at 845 MW at 3.35 pm

At 3.42 pm, effective from 3.40 pm, Origin Energy removed 300 MW of available capacity at the Uranquinty from below $235/MWh. The reason given was “1530A AVOID UNECONOMIC START SL.”

With low-priced capacity either ramp rate limited, fully dispatched or stranded in FCAS, the dispatch price reached approx. $300/MWh from 3.15 pm until 4.05 pm. Prices were therefore close to $300/MWh for the duration of the 4 pm trading interval.

Victoria and South Australia

There was one occasion where the spot price in Victoria was below -$100/MWh.

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of $49/MWh and above $250/MWh.

Friday, 13 February

Victoria

Table 4: 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
10:30 AM	-318.66	36.47	39.65	5984	6329	6612	9811	10 455	10 514

South Australia

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
10:30 AM	4342.64	39.97	43.97	1873	1884	1921	3116	3170	3099

In Victoria, demand and availability were below forecast. Demand was 345 MW below the four hour forecast. Availability was 644 MW below the four hour forecast.

In South Australia demand and availability were close to forecast.

At 9.58 am, the Alcoa Portland–Heywood–Tarrone no.1 500 kV transmission line, the Moorabool-Tarrone no.1 500 kV Transmission line, all 3 Alcoa Portland 500 kV Busses and the Macarthur Wind Farm tripped. AEMO invoked a number of constraints at 10.10 am to manage the outages. The constraints affected the Heywood and Murraylink interconnectors and lower FCAS requirements in South Australia.

At 10.10 am in response to these constraints, the Heywood interconnector switched from importing 335 MW into South Australia, to exporting 240 MW into Victoria (a 575 MW change). However, the step change across Heywood was not enough to meet the constraint requirements causing the constraints to violate from 10.10 am to 10.20 am.

At the same time Murraylink adjusted by changing directional flow from exporting 46 MW to importing 165 MW into South Australia, this in turn exceeded the export limit for the dispatch interval causing a system normal constraint which manages flow across Murraylink and the Vic to NSW interconnector to violate. This system normal constraint remained from 10.10 to 10.20 am.

Excess generation in Victoria was then constrained down or off and the price was set at the price floor for 10.15 am and 10.20 am dispatch intervals.

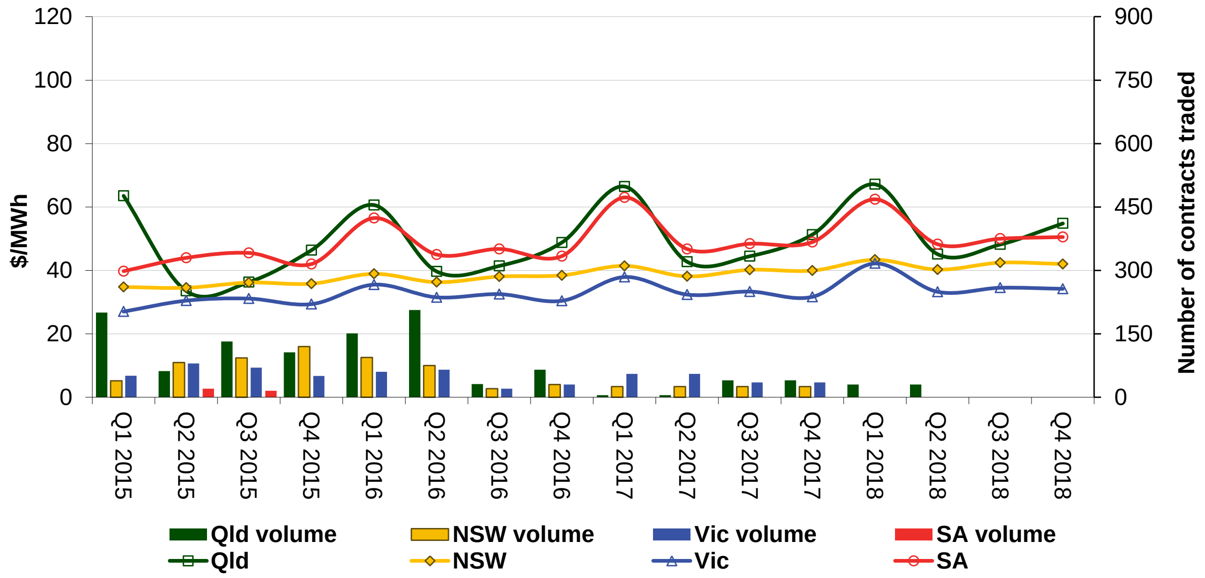
In South Australia, with low-priced capacity either ramp rate limited, fully dispatched or stranded in FCAS, the dispatch price reached the price cap at 10.15 am and 10.20 am. The above conditions led to an increase in the requirement for lower FCAS in South Australia. This resulted in high FCAS prices, as detailed in the ‘Frequency control ancillary services markets’ section.

There was no significant rebidding.

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.

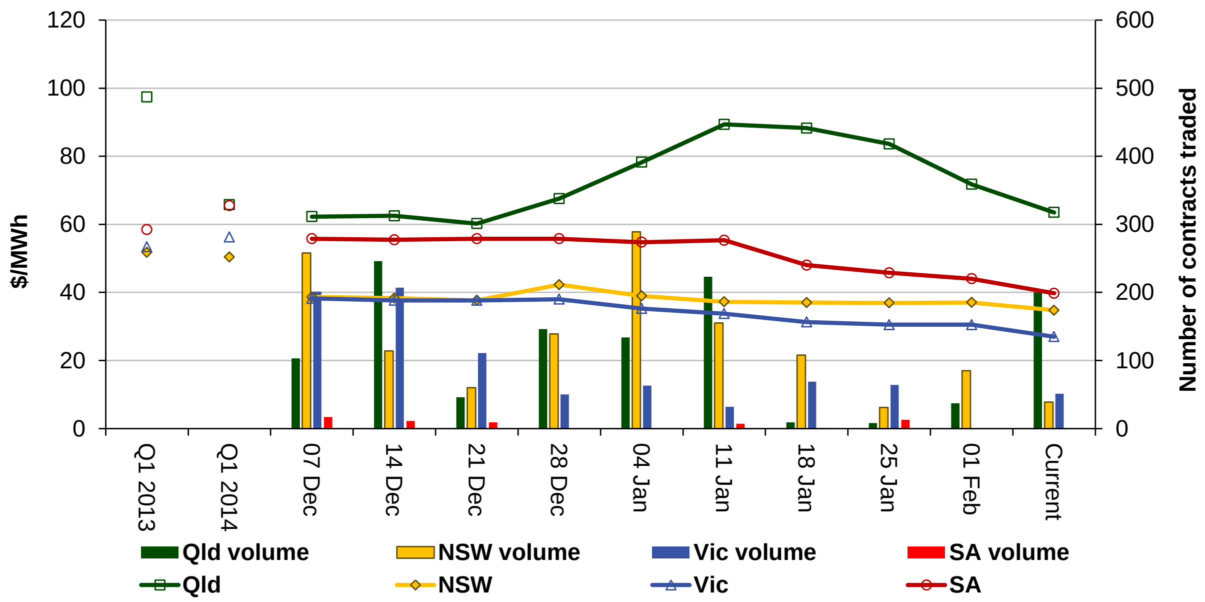
Figure 9 : Quarterly base future prices Q1 2015 – Q4 2018



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. The high volume of trades in Figure 10 is due to options on calendar year base load expiring on Wednesday 19 November.

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



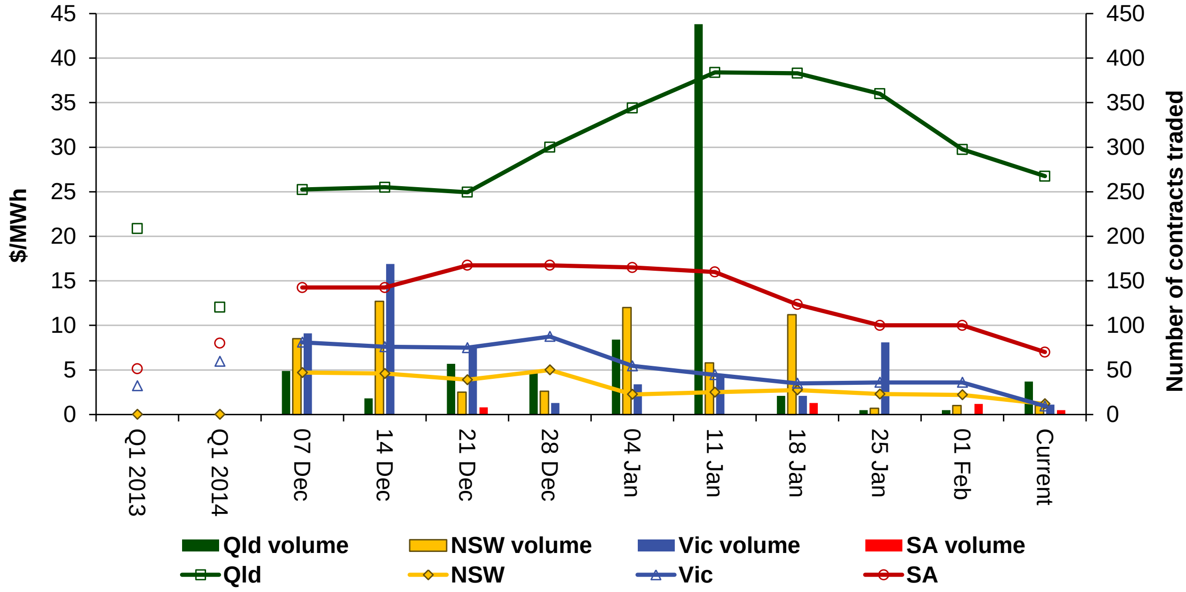
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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. The Queensland Q1 2015 cap contract price has now reached levels that were experienced in Q1 2013 when network capacity in central Queensland was providing opportunities for generation portfolios to raise prices.

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

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