Electricity Report

26 January to 1 February 2014

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 26 January to 1 February 2014.

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

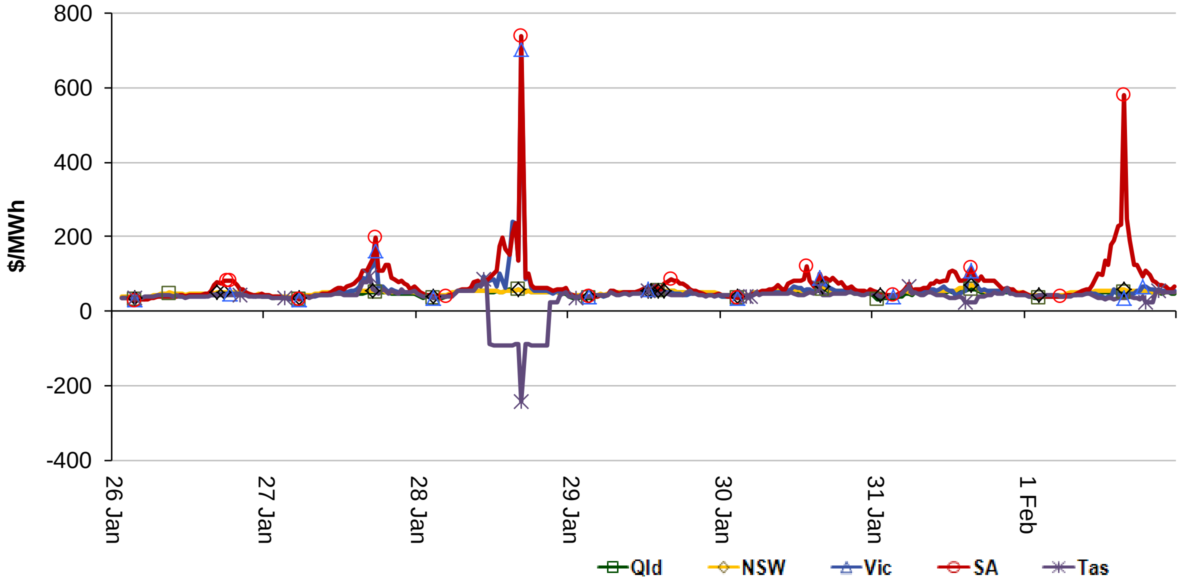


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

 AER reference: 39220 – D14/18636

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

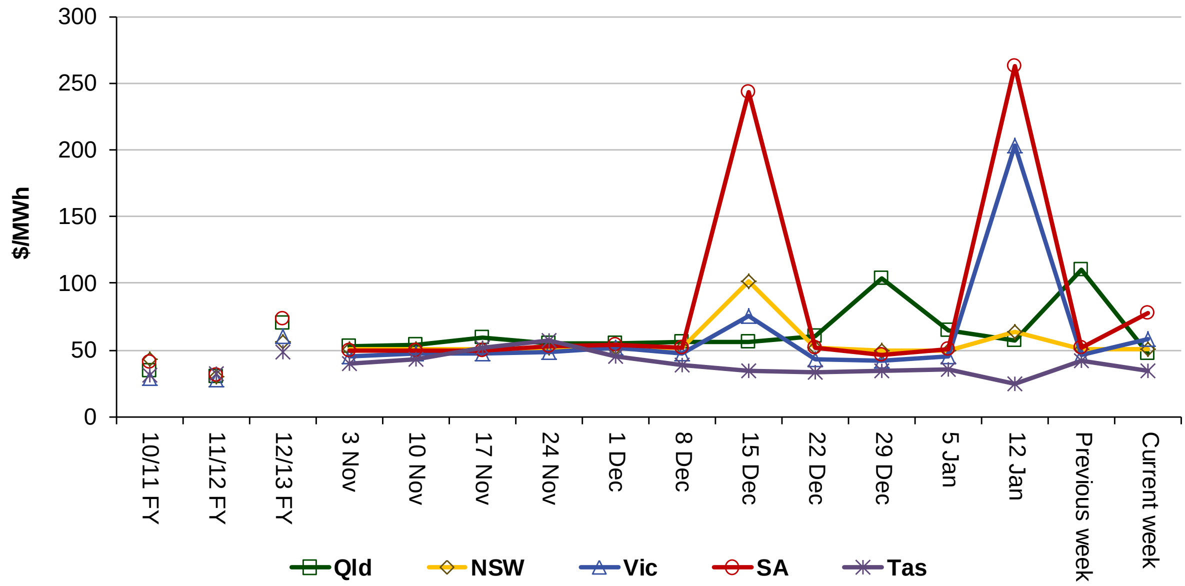


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	64	50	46	51	36
12-13 financial YTD	70	56	61	73	49
13-14 financial YTD	61	55	59	79	43

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 75 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	4	72	0	0
% of total below forecast	51	28	0	10

Note: Due to rounding, the total may not be exactly 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 2 to 6 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 shows that generators have not offered capacity between $500/MWh and $5000/MWh on the 29 and 30 January and Figure 4 shows a similar situation for the whole week in New South Wales.

Figure 3: Queensland generation and bidding patterns

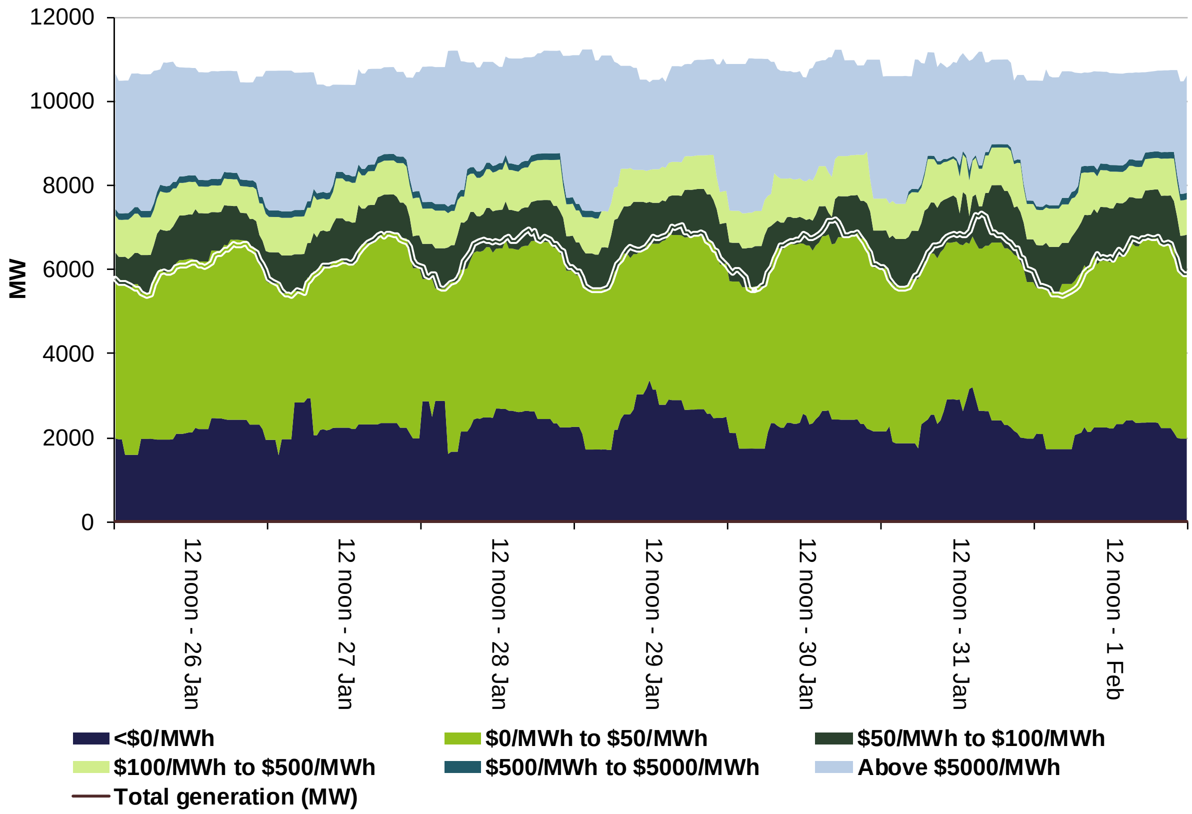


Figure 4: New South Wales generation and bidding patterns

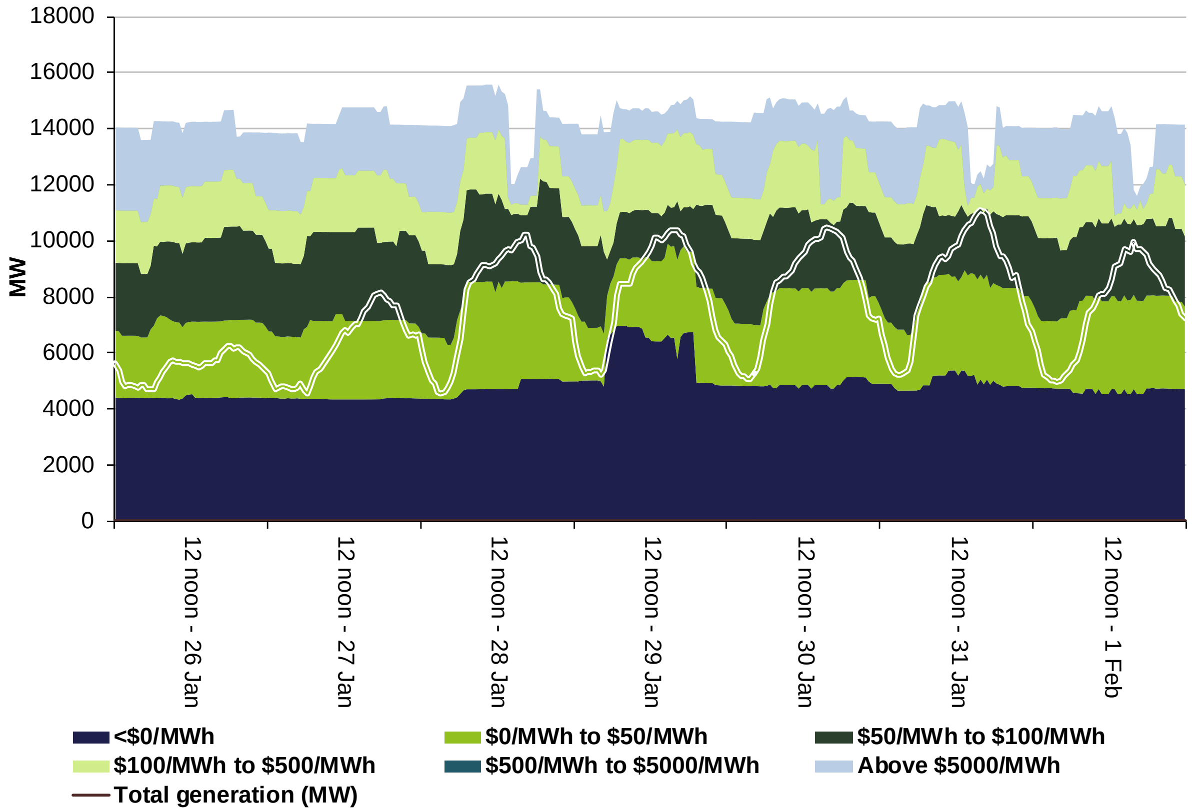


Figure 5: Victoria generation and bidding patterns

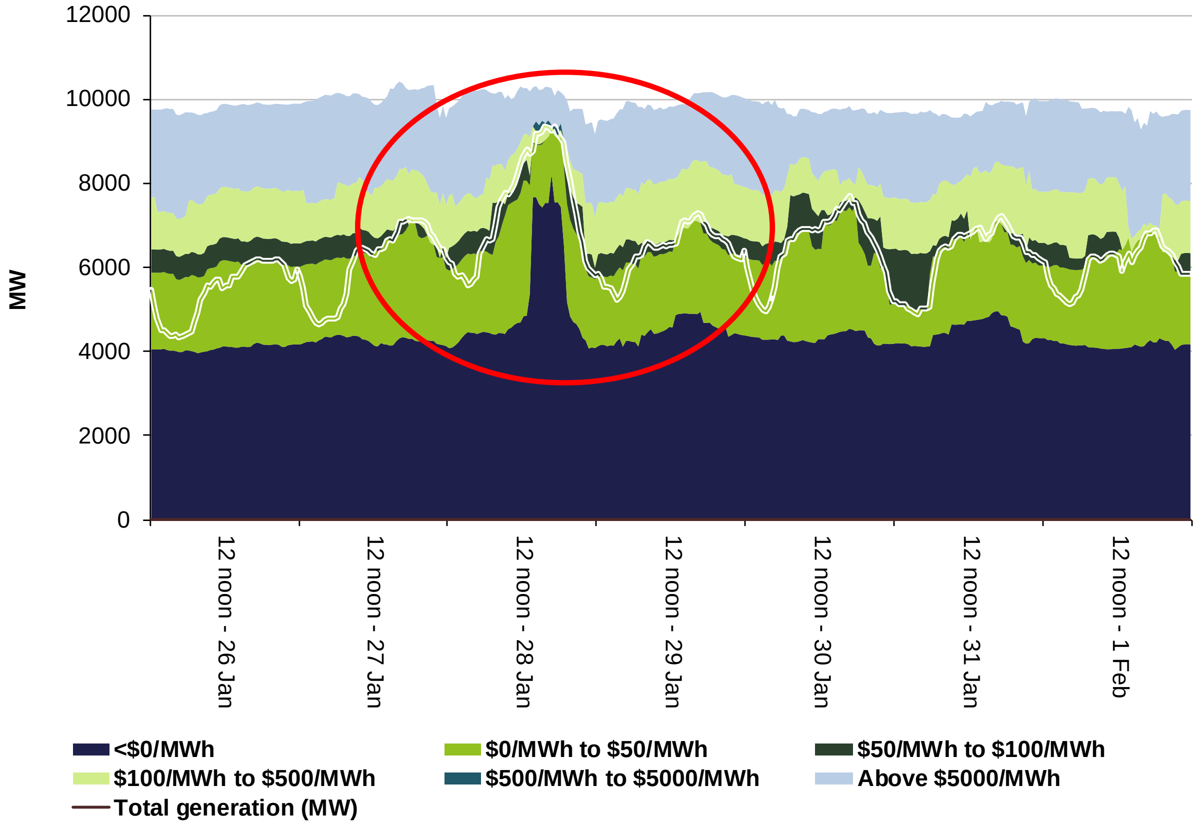


Figure 6: South Australia generation and bidding patterns

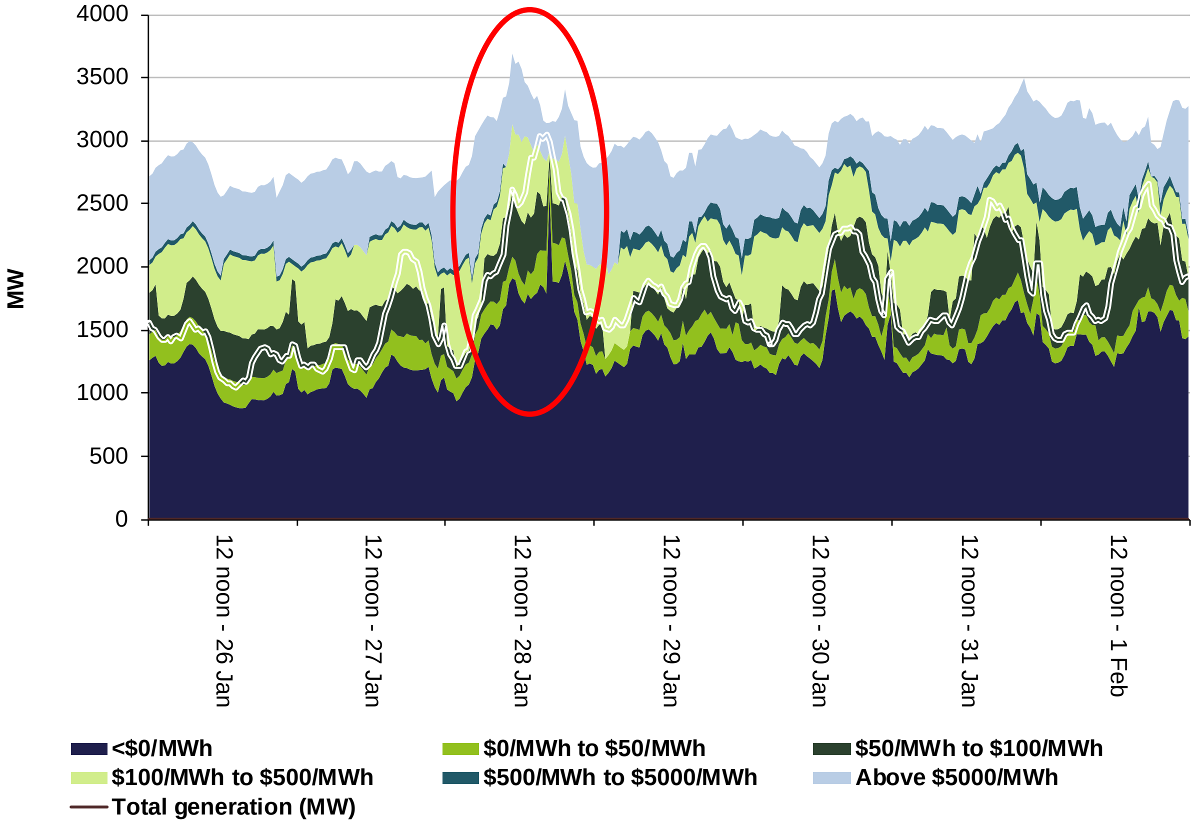
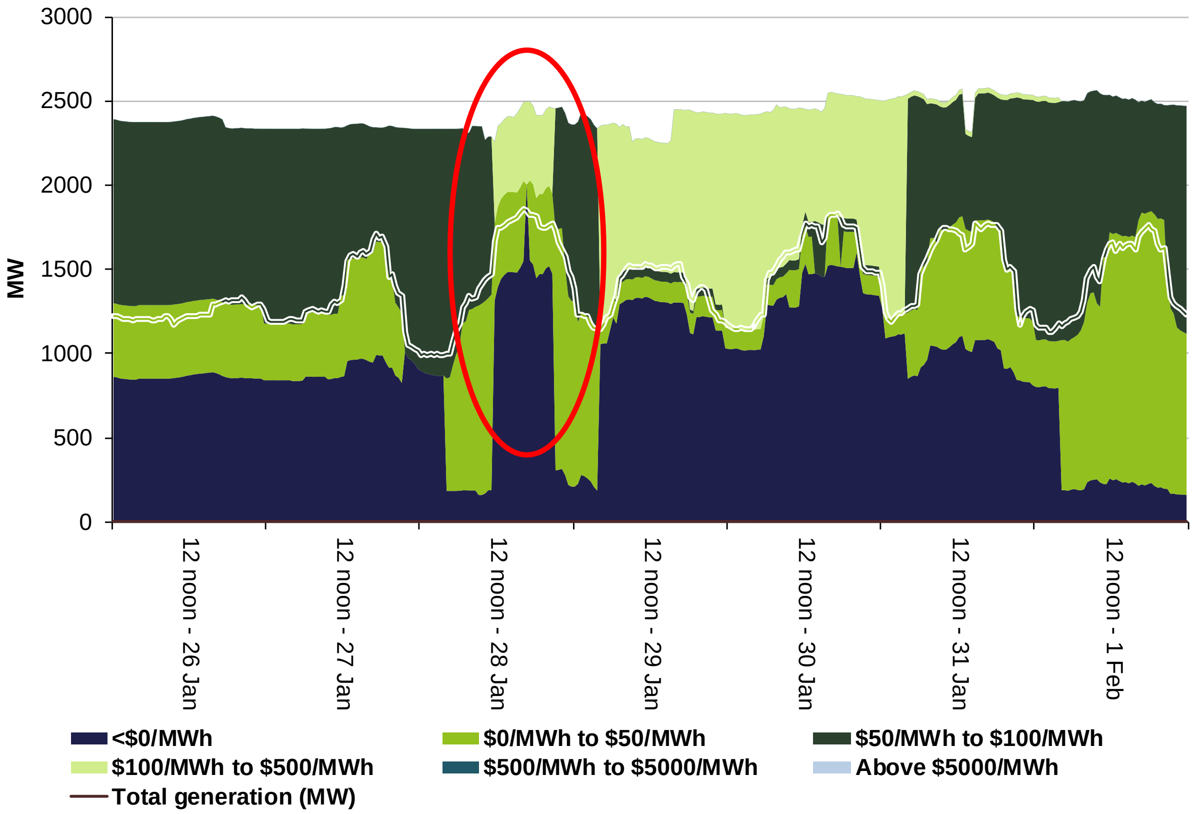


Figure 7: Tasmania generation and bidding patterns



The red circles in figures 5, 6 and 7 coincide with the prices explained in the *Detailed market analysis of significant price events* section below.

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 $223 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $460 000 or around 8 per cent of energy turnover in Tasmania. The majority of this cost accrued on 28 and 31 January and 1 February.

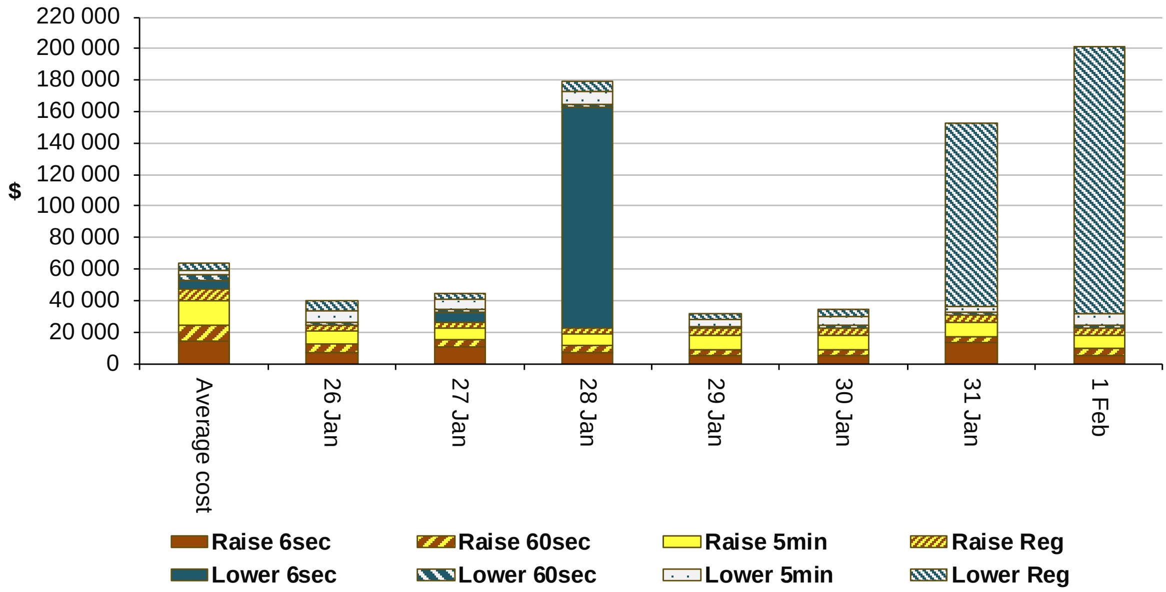
On 28 January at 4.50 pm the lower 6 sec service price in Tasmania was being co-optimised with energy in Victoria. At 4.55 pm the energy price in Victoria reached $3552/MWh (described in the *Detailed market analysis of significant price events* section). As the remaining lower 6 sec service available in Tasmania was priced at the cap Lower 6 services continued to be co-optimised and the price reached $3538/MW at 4.55 pm and $1152/MW at 5 pm for a cost of around $139 000.

On 31 January at 9.20 pm Basslink entered the no-go zone and stayed there until 9.30 pm. This saw the local requirement for lower regulation services increase from zero at 9.15 pm to around 50 MW at 9.20 pm. With only around 26 MW of lower regulation services available at prices less than price cap, high-price capacity was dispatched which saw the price reach the cap at 9.20 pm and 9.25 pm. The total cost of the local lower regulation services for the 10 minute period from 9.20 pm reached $113 502.

At 6.52 pm, effective from 7.05 pm, Basslink Pty. Ltd. rebid the availability of Basslink from 594 MW down to 478 MW. The reason given was “Temperature alarm”, which means that Basslink was operating outside its envelope and therefore needed to be reduced. As a result, the target and maximum availability of Basslink converged at 7.05 pm. With no headroom on Basslink to transfer lower services from the mainland, they had to be sourced locally. The requirement for local lower regulation services increased from 26 MW at 7 pm to 50 MW at 7.05 pm. With only 26 MW of local lower regulation services available at prices below the price cap, high price capacity was dispatched which saw the 5-minute price reach the price cap at 7.05 pm and 7.10 pm. At 7.05 pm, effective from 7.15 pm, Hydro Tasmania rebid all the high priced capacity to low prices and the price fell to previous levels. Then at 7.48 pm, effective from 8.05 pm, Hydro Tasmania reversed the above bid and the price reach the price cap at 8.05 pm. At 8.10 pm Basslink flow was reduced from the maximum available and the requirement for local regulation services reduced to zero.

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. There was one such occasion in Victoria, two in South Australia and one in Tasmania as shown below.

Table 3: Victoria, Tuesday 28 January

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
5 PM	704.68	52.70	60.65	9951	9542	8865	10 254	10 381	10 474

Conditions at the time saw demand around 1100 MW higher than forecast 12 hours ahead and around 400 MW higher than that forecast four hours ahead. Available capacity was close to forecast. Prices in South Australia were aligned with those in Victoria.

Flows into Victoria across the Vic-NSW and Basslink interconnectors were at their limits and were higher than forecast.

At 3.33 pm, effective from 3.40 pm, GDF Suez rebid 135 MW of capacity at Loy Yang B from prices around $290/MWh to above $11 600/MWh. The reason given was “Chg in fcast – inc Vic dem 5M 9861MW>30MPD 9795MW”.

At 4.45 pm, effective from 4.55 pm, AGL Energy rebid a total of 297 MW of capacity at Dartmouth, Eildon and McKay from zero to close to the price cap. The reason given was “Chg in contract pos::callable contract triggered”.

This saw the price 5-minute reach $3552/MWh in Victoria and $3757/MWh in South Australia at 4.55 pm, with McKay contributing to the price being set.

Table 4: South Australia, Tuesday 28 January

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
5 PM	739.89	213.54	90.80	2781	2894	2770	3130	3380	3357

This event coincided with the high price event in Victoria. This event is explained in the Victorian section.

Table 5: South Australia, Saturday 1 February

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	580.72	109.80	148.49	2643	2603	2529	3044	3062	3068

Conditions at the time saw demand and available capacity close to that forecast.

At around 11 am a system normal constraint managing the loss of the Keith to Tailem Bend No.1 132kV line on the trip of the South East to Tailem Bend 275 kV line was binding. This constraint limited flow into South Australia to around 260 MW from 3 pm. Another system normal constraint was binding on Murraylink. This constraint manages the loss of the Ballarat to Bendigo 22 kV line on the loss of the Shepparton to Bendigo line and was forcing flows out of South Australia into Victoria at around 50 MW.

At 4 pm there was an increase in demand in South Australia of 93 MW. This increase in demand could not be met by low priced capacity in South Australia and the 5-minute price increased from $200/MWh at 3.55 pm to $2384/MWh at 4 pm. At 4.05 pm there was a 114 MW reduction in demand which saw the 5-minute price fall to previous levels.

Table 6: Tasmania, Tuesday 28 January

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
5 PM	-241.50	-89.84	-92.66	1268	1192	1134	2498	2400	2380

Conditions at the time saw demand and available capacity close to that forecast.

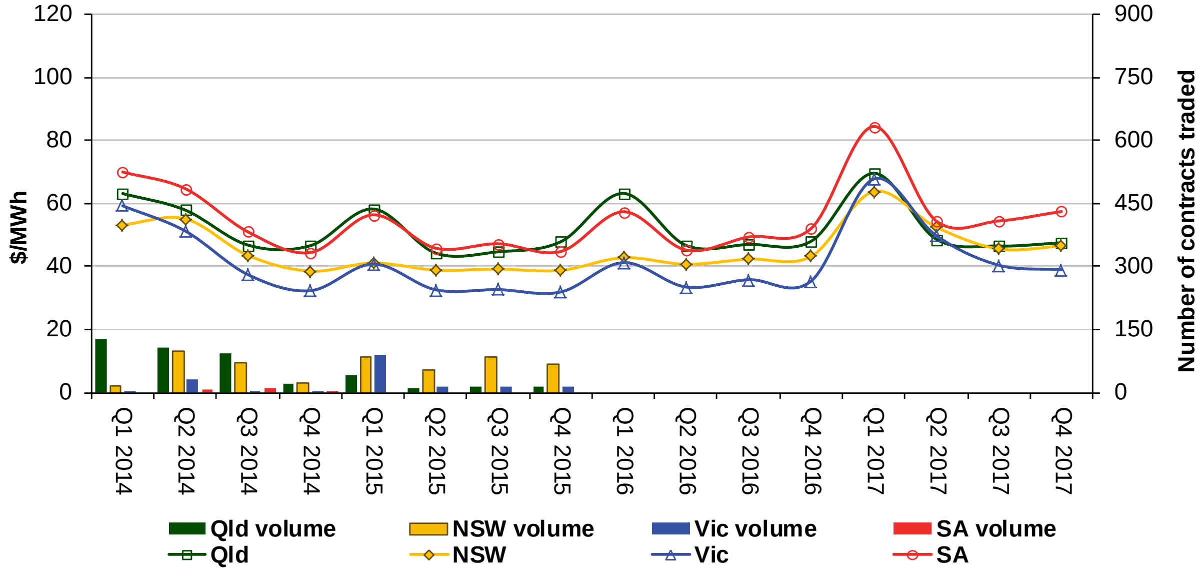
From 11.35 am the 5-minute price was around -$90/MWh, trying to ensure Tasmanian generation was exported to Victoria where the price was higher than that in Tasmania.

At 2.51 pm Hydro Tasmania rebid 1025 MW of capacity across its portfolio from prices above -$305/MWh (48 MW at $634/MWh) to the price floor or close to it. The reason given was “1450A vic price higher than forecast.”. Then at 4.51 pm, for 5 pm dispatch interval only, they rebid a further 542 MW across their portfolio from prices below $25/MWh to the price floor or close to it. The reason given was “1651A price different from forecast: Vic”. This resulted in the 5-minute price reach the price floor at 5 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.

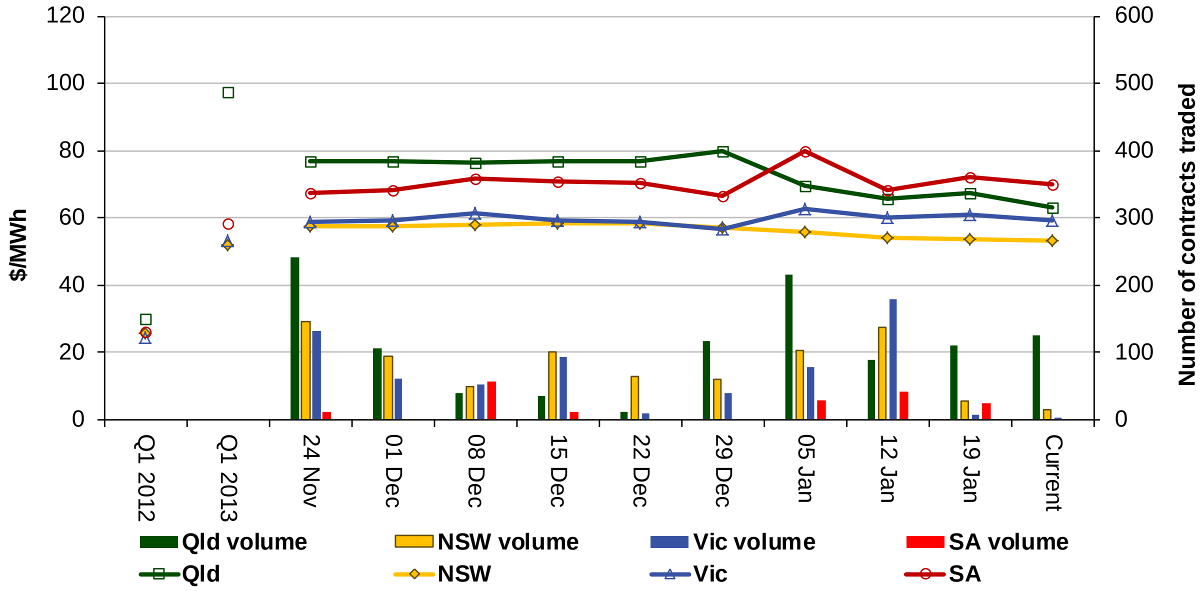
Figure 9: Quarterly base future prices Q1 2014 – Q4 2017



Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2014 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2012 and quarter 1 2013 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 2014 base contracts over the past 10 weeks (and the past 2 years)



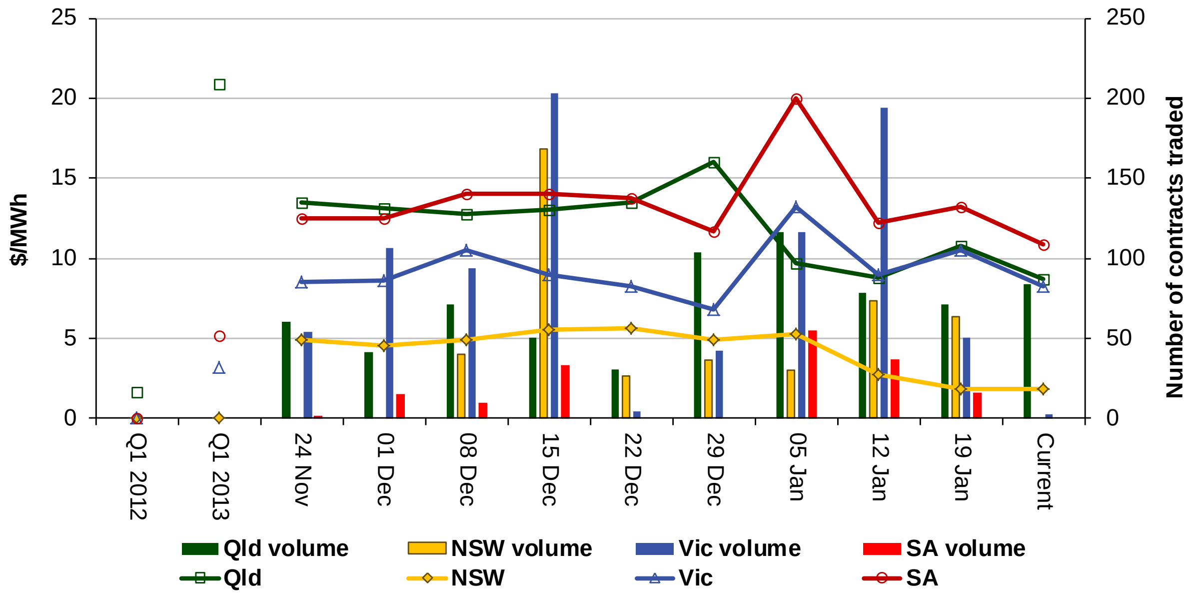
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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 2014 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2012 and quarter 1 2013 prices are also shown.

Figure 11: Price of Q1 2014 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

Australian Energy Regulator

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