

# Electricity Report

## 4 – 10 January 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 4 to 11 January 2015. There were fourteen occasions where the spot price was above \$250/MWh and greater than three times the regional weekly average price, and one occasion where the price was less than -\$100/MWh.

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

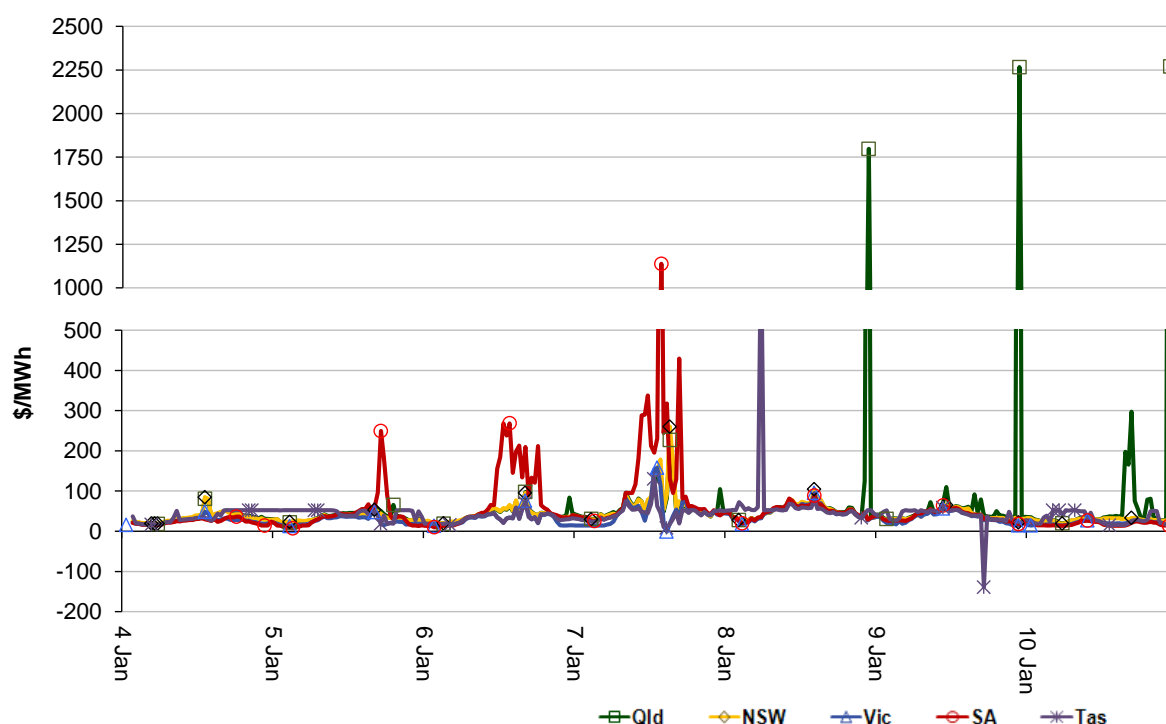
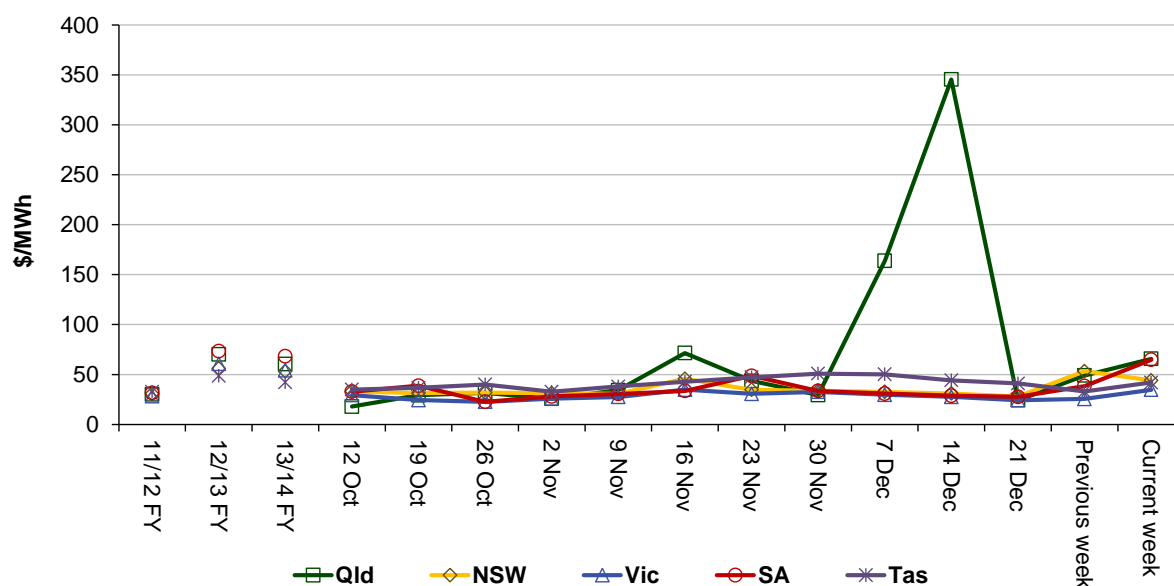


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years. The high prices in Queensland over the past three weeks has doubled the year to date volume weighted spot price in that region from \$33/MWh to \$66/MWh.

**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
<b>Current week</b>	66	44	35	65	42
<b>13-14 financial YTD</b>	61	53	54	68	42
<b>14-15 financial YTD</b>	66	37	33	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 246 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**

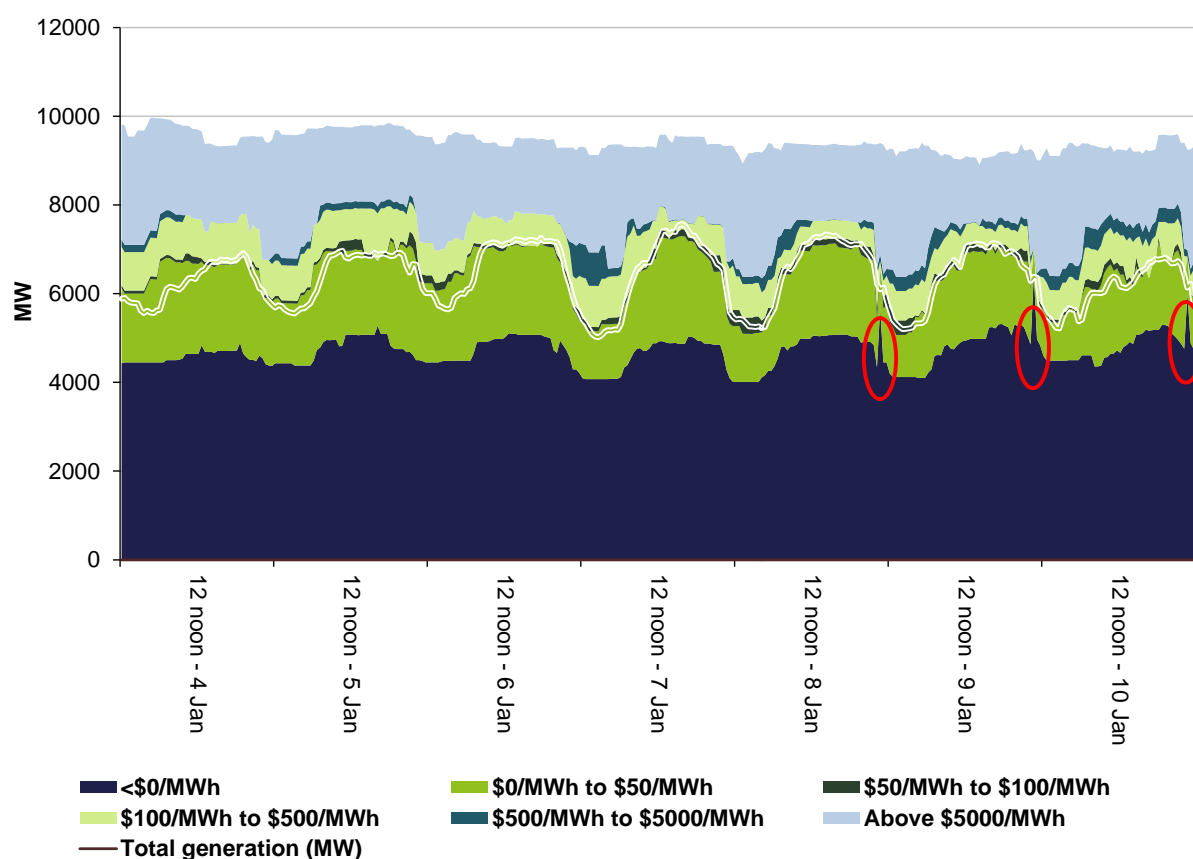
	Availability	Demand	Network	Combination
% of total above forecast	3	35	0	3
% of total below forecast	49	9	0	2

Note: Due to rounding, the total may not be 100 per cent.

## Generation and bidding patterns

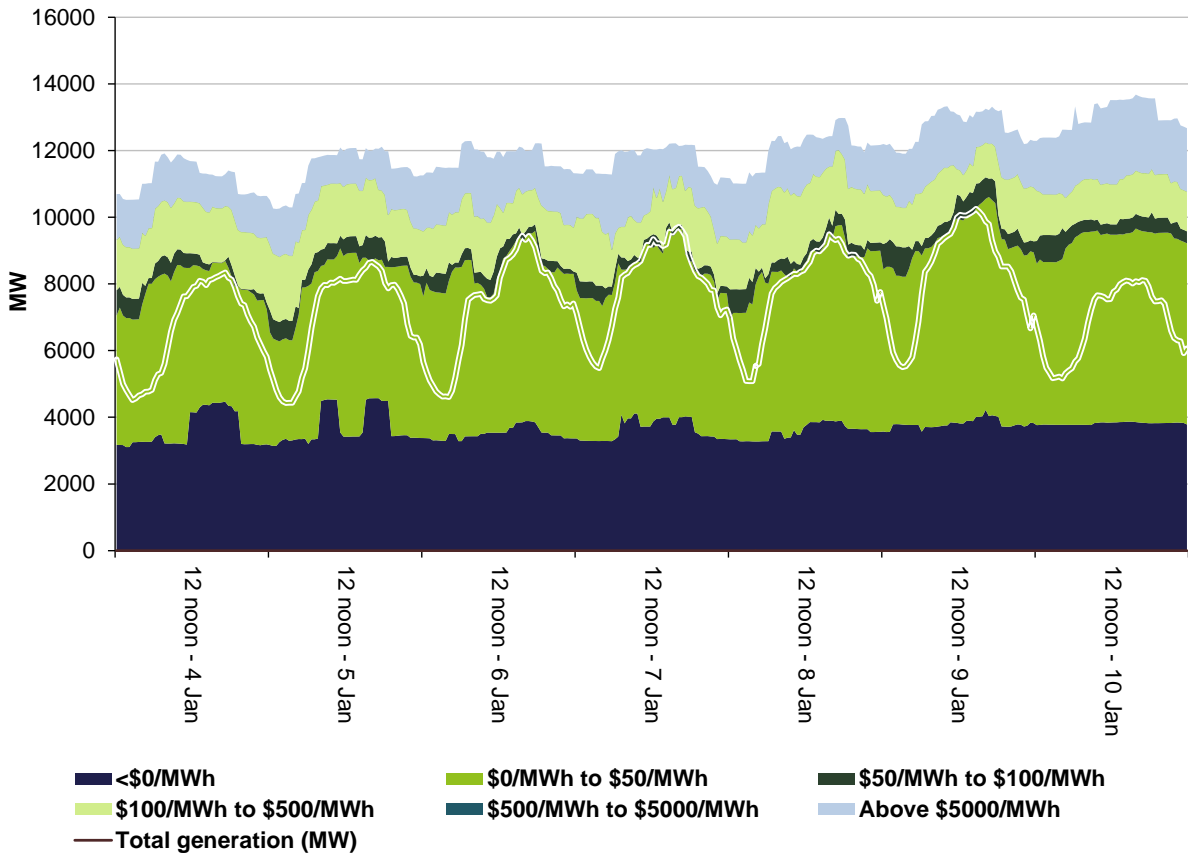
The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figures 3 to 7 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

**Figure 3: Queensland generation and bidding patterns**

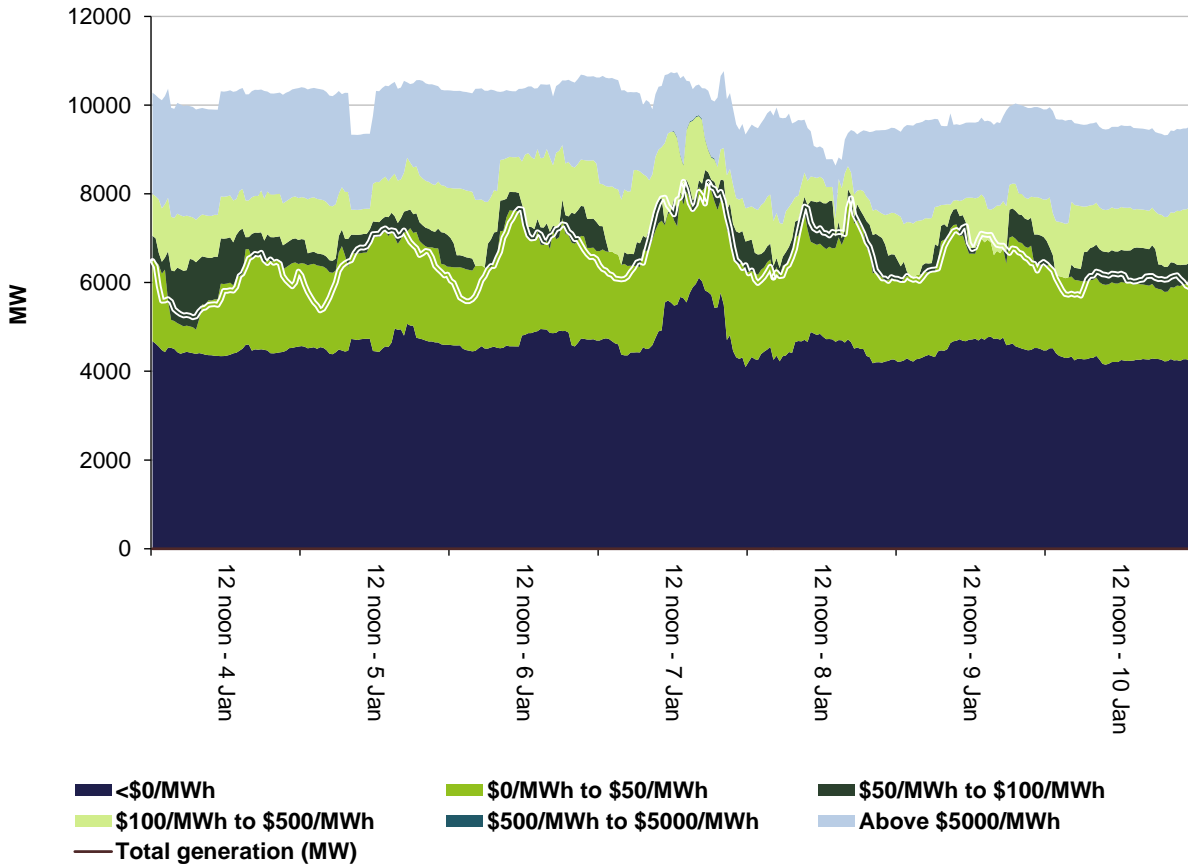


The increase in capacity priced less than zero, as highlighted in the red ellipse, is a result of Queensland participants rebidding capacity to low prices in response to high prices. These prices are discussed below under the detailed market analysis section.

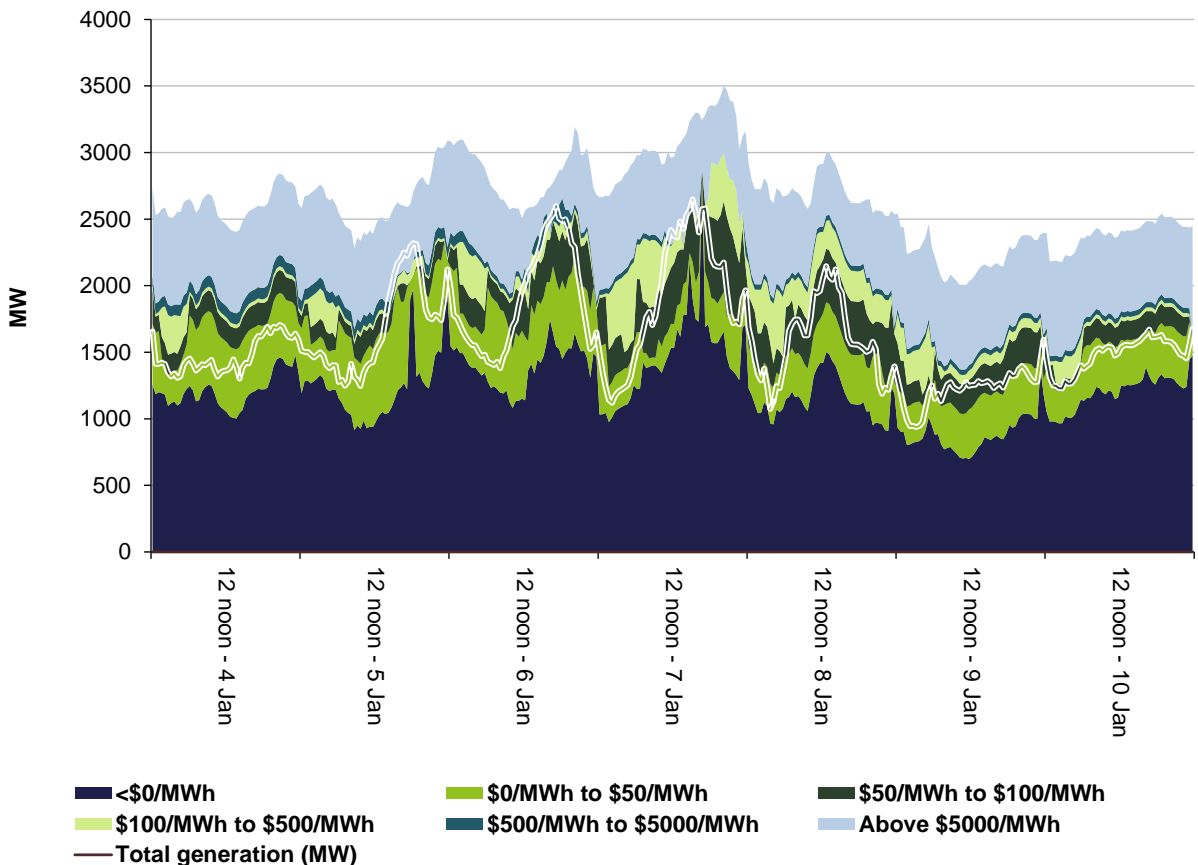
**Figure 4: New South Wales generation and bidding patterns**



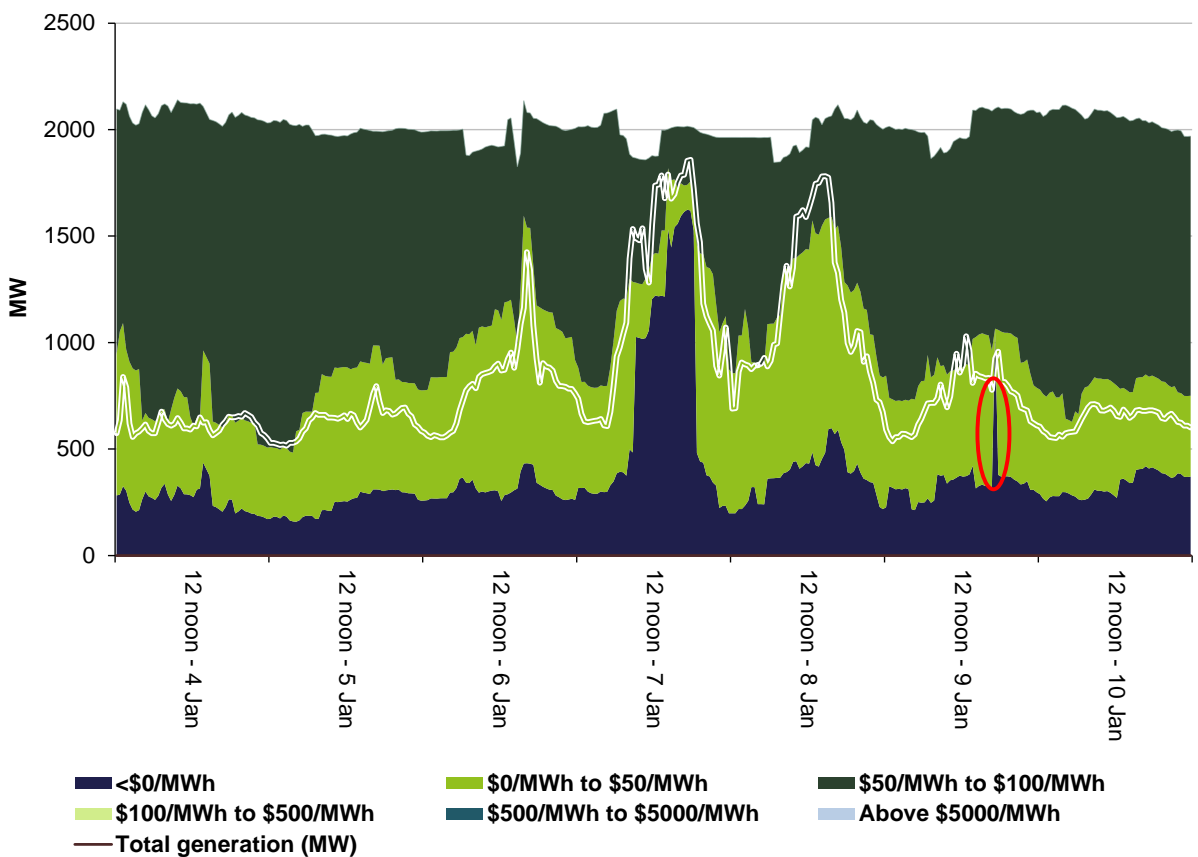
**Figure 5: Victoria generation and bidding patterns**



**Figure 6: South Australia generation and bidding patterns**



**Figure 7: Tasmania generation and bidding patterns**



The red ellipse in Figure 7 highlights the rebidding that resulted in the negative spot price in Tasmania.

## 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 \$654 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$1 105 500 or around 16 per cent of energy turnover in Tasmania. The high FCAS cost in Tasmania was mainly driven by the events on 8 January.

**Figure 8: Daily frequency control ancillary service cost**

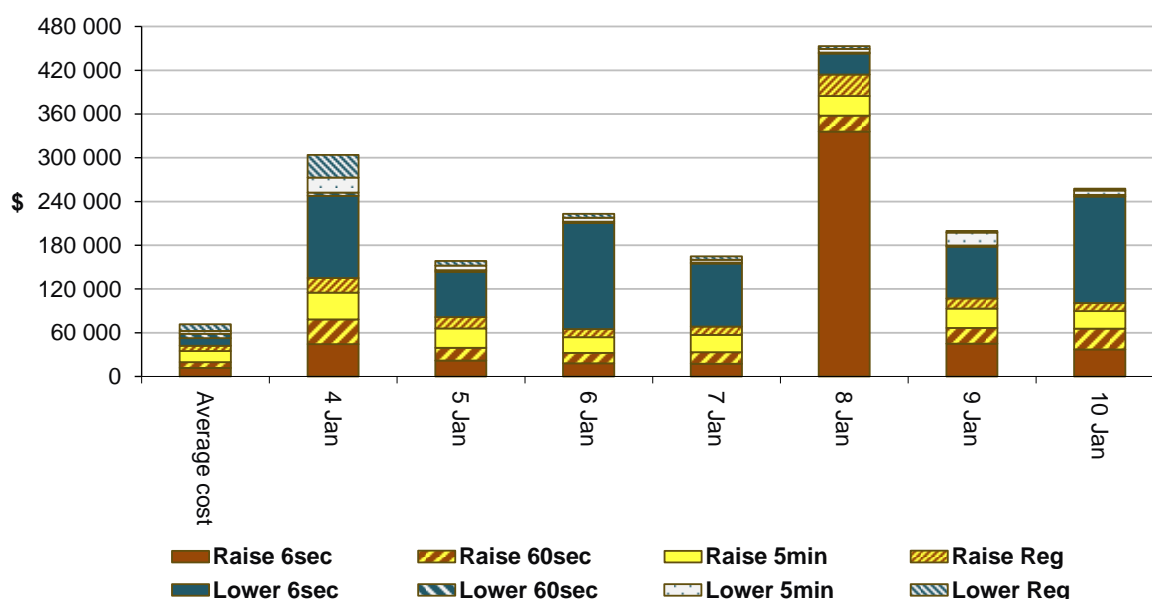


Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year. The figure shows FCAS costs were high on 8 January (the majority of which was accumulated in Tasmania).

On 8 January at 5.20 am, AEMO reclassified a non-credible contingency event on the Farrell–Sheffield No.1 and No.2 220 kV lines in Tasmania due to lightning. This limited the imports from Victoria into Tasmania on the Basslink interconnector. This meant that all Tasmanian FCAS services had to be sourced locally and consequently the requirement for these services increased.

The requirement for raise 6 second services increased from 67 MW at 5.25 am to 177 MW at 5.45 am. A constraint managing raise 6 second requirements for the post-contingent loss of both Farrell to Sheffield parallel lines violated from 5.35 am and saw the respective FCAS price increase from \$107.95/MWh to \$13 500/MWh at 5.35 am, \$6 408.09/MWh at 5.40 am, and \$6 403.65/MWh at 5.45 am.

On several occasions during the week a system normal constraint managing the requirement for lower 6 second service for the loss of two Bell Bay Aluminium potlines violated and Basslink was unable to transfer FCAS. This meant that all Tasmanian FCAS services had to be sourced locally.

Lower 6 second services were required consistently throughout the week, usually between 200 MW and 250 MW. For most of the week prices for lower 6 second services ranged between \$0.18/MW to \$50/MW, however there were some price spikes reaching around \$335/MW and one that reached \$546.93/MW.

Over the week the cost of lower 6 second services was around \$660 000.

## 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.

### Queensland

There were four occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of \$66/MWh and above \$250/MWh.

### Thursday, 8 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
11:00 PM	1797.48	34.74	30.46	5955	5821	5851	9385	9426	9551

Demand was 134 MW higher than forecast four hours before. Available capacity was close to forecast four hours before.

At 9.24 pm, Origin rebid 66 MW of available capacity at Roma priced at \$64/MWh to the price cap. The reason given was “2120A avoid uneconomic start SL”.

Over two rebids at 8.36 pm and 9.25 pm, Callide reduced the available capacity at Callide C4 by 76 MW priced at \$13/MWh. The reasons given were “2035P emissions almost at licence limit” and “2124P emission average to hi”.

Over two rebids at 9.43 pm and 10.13 pm, CS Energy rebid 160 MW of available capacity at Gladstone from \$22/MWh to the price cap. The reasons given were “2141A interconnector constraint-QNI binding in predispach-SL” and “2212A interconnector constraint-QNI binding north-SL”.

At 8.57 pm, Stanwell rebid 105 MW of available capacity across its portfolio priced at \$19/MWh to the price cap. The reason given was “2053A demand greater than forecast SL”.

A constraint to avoid the voltage collapse of the loss of Kogan Creek bound at 10.35 pm which limited imports into Queensland on the QNI and Directlink interconnectors. At the same time, demand increased by 46 MW.

With low priced generation either fully dispatched, ramp rate limited, or trapped in FCAS, the dispatch price increased from \$47/MWh at 10.30 pm to \$10 499/MWh at 10.35 pm.

## Friday, 9 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
11:00 PM	2265.96	30.77	30.86	6071	6048	5902	9258	9420	9470

Demand was close to forecast four hours before. Available generation was 162 MW lower than forecast four hours before.

Over two rebids at 8.55 pm and 10.13 pm, Callide reduced the available capacity at Callide C4 by a total of 106 MW priced under \$13/MWh. The reasons given were “2054P HI emission coal CV low” and “2211P coal CV has improved, klinker indicator are very low”.

At 10.20 pm, CS Energy rebid a total of 120 MW of available capacity at Gladstone priced at \$22/MWh to the price cap. The reason given was “2219A intra regional constraint-QNI almost binding north-SL”.

Constraints managing voltage stability for the loss of Kogan Creek and overload for the loss of a Lismore to Dunoon parallel line limited imports into Queensland, as demand increased by around 40 TJ.

With low priced generation either fully dispatched, ramp rate limited, or inflexible, the dispatch price increased from \$37/MWh at 10.30 pm to \$13 499/MWh at 10.35 pm.



## Saturday, 10 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
<b>5:00 PM</b>	297.44	39.25	36.69	6811	6685	6687	9268	9418	9523
<b>11:00 PM</b>	2269.81	29.49	29.42	6036	6016	6031	9351	9642	9539

### 5.00 pm

Demand was 126 MW higher than forecast four hours before. Available generation was 150 MW lower than forecast four hours before.

The high prices started during the 4.30 pm trading interval, when the price increased from \$35.94/MWh at 4.15 pm to \$295.93/MWh at 4.20 pm. There were no significant rebids during this period. However, at 4.20 pm, demand increased by 53 MW. Constraints managing post-contingent outages at Kogan Creek and on a Lismore to Dunoon parallel line were binding throughout the high priced intervals, limiting imports into Queensland on the interconnectors.

Over three rebids at 2.23 pm, 3.35 pm, and 4.45 pm<sup>1</sup>, Callide reduced the available capacity at Callide C3 by 140 MW priced at the price floor. The reasons given were “1422P emissions increasing”, “1534P taking a FAB. FILT pass out of service”, and “1643P CC4 – attempting to take “A” filter out for PTW”.

At 4.19 pm, CS Energy rebid 335 MW of available capacity at Gladstone priced below \$95/MWh to \$290/MWh. The reason given was “1619A interconnector constraint – QNI binding – SL”.

At 4.42 pm, effective from 4.50 pm, Stanwell rebid 165 MW of available capacity across its portfolio from prices at or below \$26/MWh to the price cap. The reason given was “1641A change in QLD generation – ROMA”.

With low priced generation either fully dispatched, ramp rate limited, or inflexible, limited imports from New South Wales and sustained high demand, the dispatch price remained around \$295/MWh for the 5 pm trading interval.

### 11.00 pm

Demand was close to forecast four hours before. Available generation was 291 MW lower than forecast four hours before.

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<sup>1</sup> 20 MW effective from 4.55 pm

At 10.22 pm, CS Energy rebid 30 MW of available capacity at Gladstone priced at \$22/MWh to the price cap. The reason given was “2221A interconnector constraint-almost binding in next trading I”.

Over a further two rebids at 10.26 pm (effective from 10.35 pm) and 10.37 pm (effective from 10.45 pm) a total of 210 MW of available capacity at Gladstone was rebid from \$22/MWh to the price cap. The reasons given were “2221A interconnector constraint – almost binding in next trading I” and “2236A interconnector constraint – QNI binding north-SL”.

Constraints managing post-contingent outages at Kogan Creek and on a Lismore to Dunoon parallel line were binding, limiting interconnector imports to Queensland at 10.45 pm. With low priced generation either fully dispatched, ramp rate limited, or inflexible, the dispatch price increased from \$39/MWh at 10.40 pm to \$13 499/MWh at 10.45 pm.

## 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 \$44/MWh and above \$250/MWh.

### Wednesday, 7 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
3.30 PM	259.99	299.80	69.80	10 352	10 341	9746	12 140	12 001	12 098

The price was close to forecast four hours before but higher than the 12 hour ahead price. This was caused by significantly lower forecast demand, around 600 MW lower than the actual and 4 hour ahead demand.

## South Australia

There were eight occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$65/MWh and above \$250/MWh.

### Tuesday, 6 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
1.00 PM	268.08	45.99	45.99	2003	1961	1927	2587	2777	2795
2.00 PM	268.20	54.49	45.99	2121	2044	2012	2600	2803	2851

Conditions at the time saw demand higher than forecast and available capacity lower than forecast. On the day the temperature in Adelaide reached a high of around 40 degrees, which contributed to the high demand on the day.

A constraint to avoid the oversupply on the Keith–Taillem Bend #1 line if one of the South East Taillem Bend lines trips had been binding since the morning. This limited imports into South Australia on the Heywood interconnector to around 65 MW. A binding constraint designed to avoid the overload of the Ballarat North to Buangor 66kV line for the loss of the Ballarat to Waubra to Horsham 220 kV line was forcing flow out of South Australia across Murraylink at around 50 MW.

There was limited capacity priced between \$95/MWh and \$220/MWh. These tight supply conditions meant that small changes in demand, rebidding, or available capacity led to higher than forecast prices for both the 1 pm and 2 pm trading intervals.

Available capacity was up to 190 MW lower than forecast four hours before as wind generation was up to 188 MW lower than forecast four hours ahead.

At 12.25 pm, effective at 12.35 pm, Origin rebid a total of 48 MW of available capacity at Quarantine units 3 and 4 priced at \$54/MWh to the price cap. The reason given was “1222A constraint management – S>>KHTB2\_SETB\_KHTB1”. At 1.21 pm, Origin extended this rebid for the 2 pm trading interval.

At 12.40 pm, effective from 12.50 pm, Alinta rebid 153 MW of capacity at Northern units 1 and 2 from prices under \$60/MWh to the price cap. The reason given was “1239A ANGAS started@12:40”.

This saw the 5 minute price range between \$100/MWh and \$600/MWh for the 1 pm and 2 pm trading intervals.

### Wednesday, 7 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
<b>11.00 AM</b>	288.06	54.99	53.56	2401	2051	1971	2919	3202	3184
<b>11.30 AM</b>	290.02	55.22	54.99	2424	2157	2037	3006	3215	3189
<b>Midday</b>	337.56	63.93	54.99	2465	2237	2100	2972	3218	3197

Conditions at the time saw demand up to 350 MW higher than forecast four hours ahead and available capacity up to 283 MW lower than forecast four hours ahead. On the day the temperature in Adelaide reached a high of around 42 degrees, which contributed to the high demand on the day. Wind generation was up to 168 MW lower than forecast four hours ahead

## Relevant rebidding for 7 January

Time submitted	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
8.42 am	9.05 am	GDF Suez	Pelican Point	-55	<220		1013P coal quality@10:14
10.14 am	10.25 am	Alinta	Northern	-50	<156		0841P updated RTS profile SL
10.48 am	11.05 am	AGL	Torrens B	160	228	13 500	1031~A~050 CHG in AEMO PD~55 PD price increase SA \$190
11.02 am	11.10 am	EA	Hallett	50	296	582	11:01 P band ADJ to match fuel profile
11.10 am	11.20 am	Alinta	Northern	30	<156	9744	1109P coal quality issues SL@11:10
<b>Total capacity rebid from low to high prices</b>				<b>240</b>			

These above factors led to consistent prices around \$250/MWh to \$300/MWh for most of the dispatch intervals.

## Wednesday, 7 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
<b>2.00 PM</b>	1138.18	159.98	55.89	2609	2560	2304	3109	3158	3216
<b>3.00 PM</b>	317.67	325.78	94.99	2621	2664	2384	3234	3194	3265
<b>5.00 PM</b>	429.30	328.67	94.99	2588	2801	2567	3243	3229	3295

Conditions at the time saw demand close to that forecast four hours ahead but up to 305 MW higher than forecast 12 hours ahead. Available capacity was close to that forecast.

There was limited capacity offered between \$95/MWh and \$287/MWh. These tight supply conditions meant that small changes in demand, rebidding, or available capacity led to higher than forecast prices

At 1.47 pm, effective at 1.55 pm, AGL rebid a total of 213 MW of available capacity across its portfolio priced below \$288/MWh (the majority of which was priced around \$95/MWh) to the price cap. The reason given was "1345~A~050 CHG in AEMO PD~30PD NEM wide demand has increased by".

At 1.53 pm, effective at 2 pm, Alinta rebid a total of 30 MW of available capacity at Northern units 1 and 2 priced under \$53/MWh to the price cap. The reason given was “1352A price above PD price \$3913@13:53”.

Origin’s Ladbroke generators were backed off for the 1.55 pm and 2 pm dispatch intervals due to a network constraint on the Keith—Tailem Bend line. This caused a price spike to \$3912.65/MWh and \$2285.64/MWh respectively before rebidding drove the price back down. This also occurred at 2.35 pm and 4.35 pm and the 5 minute price went to \$1487.75/MWh and \$2432.33/MWh respectively.

## Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of \$42/MWh and above \$250/MWh.

### Thursday, 8 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
6:00 AM	714.69	98.00	52.26	1011	1026	1050	1963	1966	1976

There were several reclassifications of transmission lines in Tasmania due to lightning which meant that Basslink was unable to provide raise FCAS (as discussed in the FCAS section above which in turn led to high FCAS prices). The interaction of the energy and FCAS markets set the price at \$3929.83/MWh at 5.35 am.

There was no significant rebidding.

There was one occasion where the spot price in Tasmania was less than \$-100/MWh.

### Friday, 9 January

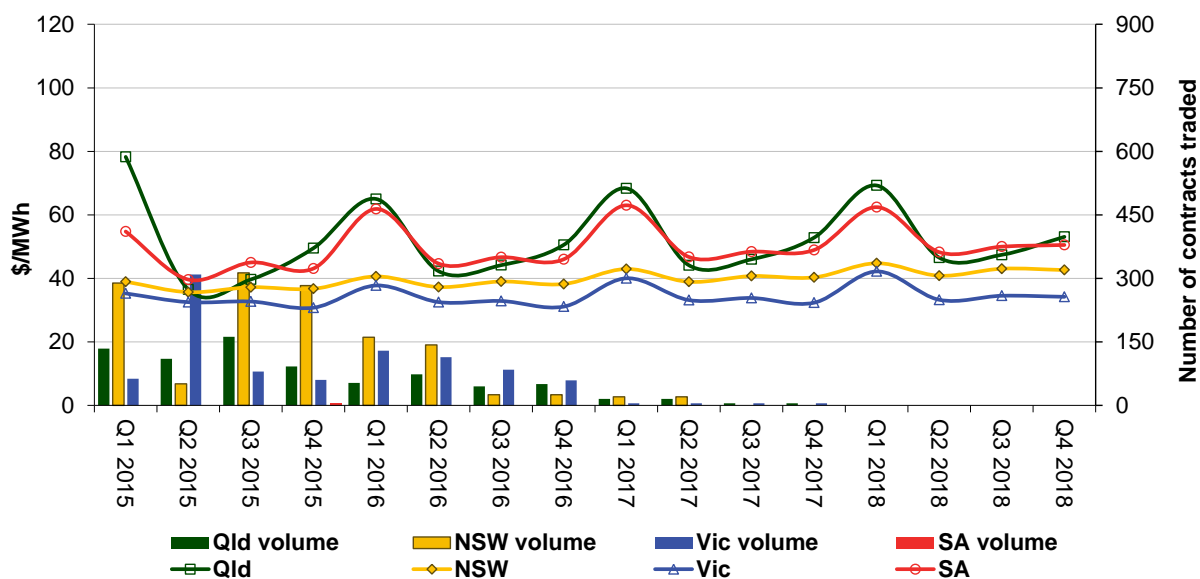
Time	Price (\$/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5:30 PM	-139.08	51.19	51.19	1101	1043	1043	2099	2060	2037

At 5.08 pm, effective at 5.15 pm, Hydro Tasmania rebid a total of 1023 MW across its portfolio, the majority of which was priced around \$50/MWh, to the price floor. The reason given was “1710A increased transmission risk”. This resulted in the dispatch price increasing from \$32.17/MWh at 5.10 pm to \$-964.30/MWh at 5.15 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.

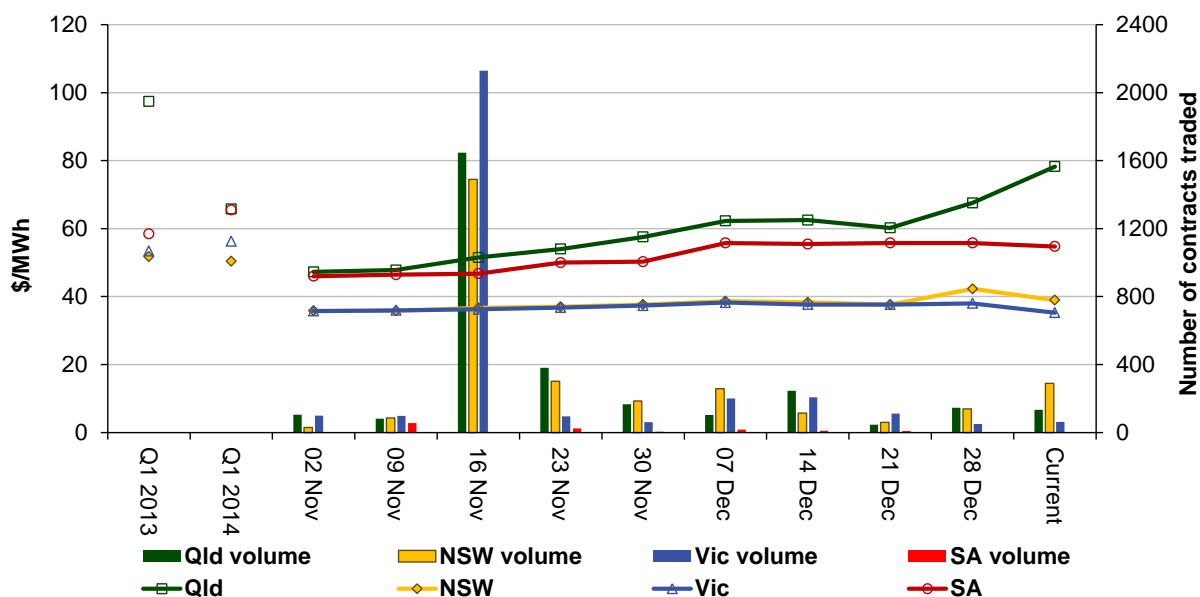
**Figure 9: Quarterly base future prices Q4 2014 – Q3 2018**



Source: [ASXEnergy.com.au](http://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)**



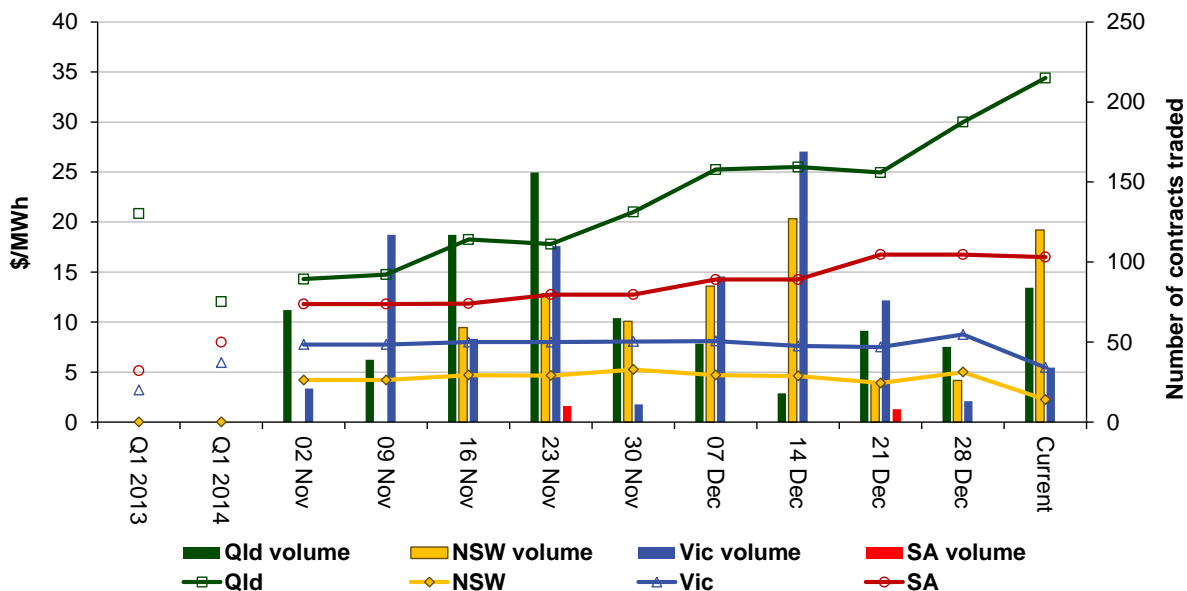
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: [ASXEnergy.com.au](http://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 2105 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](http://ASXEnergy.com.au)

**Australian Energy Regulator**  
**January 2015**