

# Electricity Report

23 to 29 November 2014



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 23 to 29 November 2014.

Date and time	Region	Spot Price (\$/MWh)
24/11/2014 4.30 pm	QLD	1156.28
25/11/2014 3.00 pm	QLD	2296.88
29/11/2014 3.00 pm	SA	280.00
29/11/2014 3.30 pm	SA	2365.96
29/11/2014 4.30 pm	SA	2279.32

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

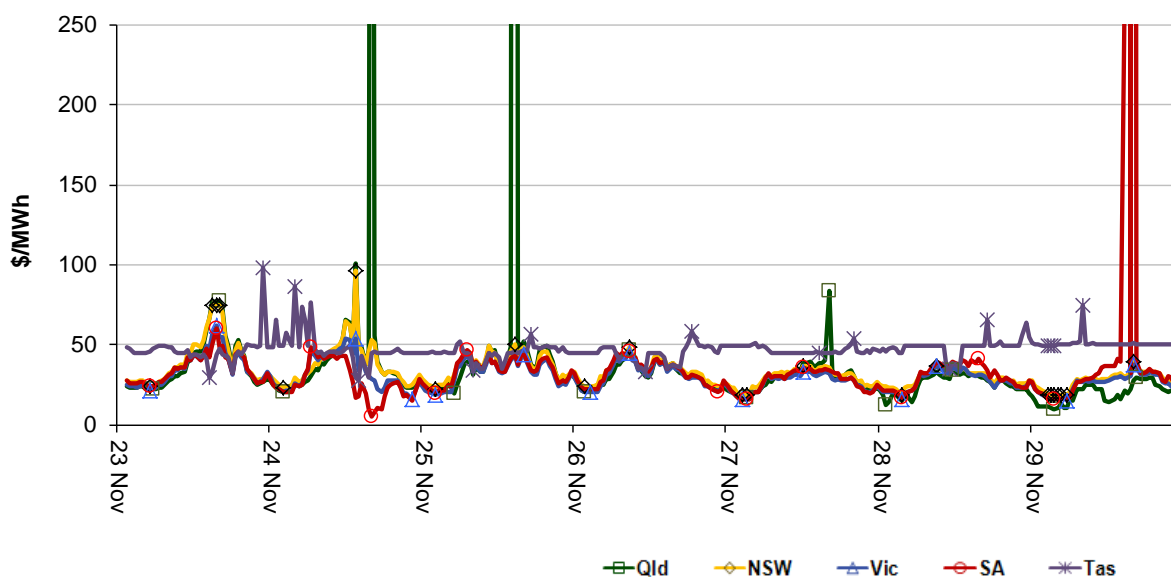
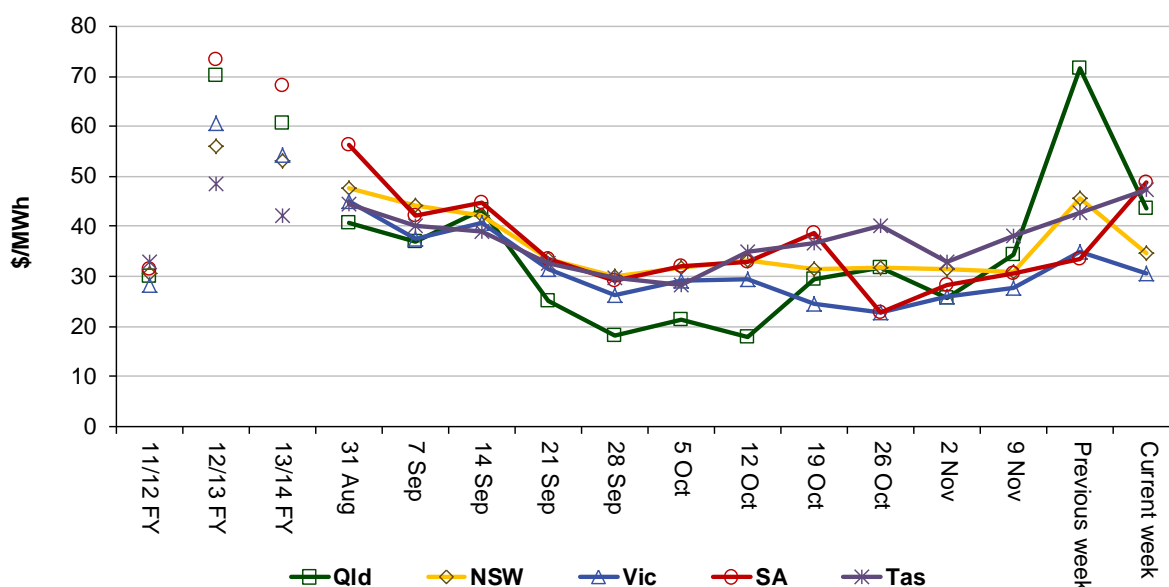


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years. The volume weighted average prices in Queensland have been materially higher over the last few

weeks; up from the \$20/MWh levels experienced in the late September and early October. This increase has been driven by increased spot price volatility in that region from late rebidding. Both high price events in Queensland this week were driven by participants rebidding substantial volumes of capacity from low prices up to prices at or near the price cap.

**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	44	35	31	49	47
13-14 financial YTD	60	54	53	64	45
14-15 financial YTD	33	38	34	42	37

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 111 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**

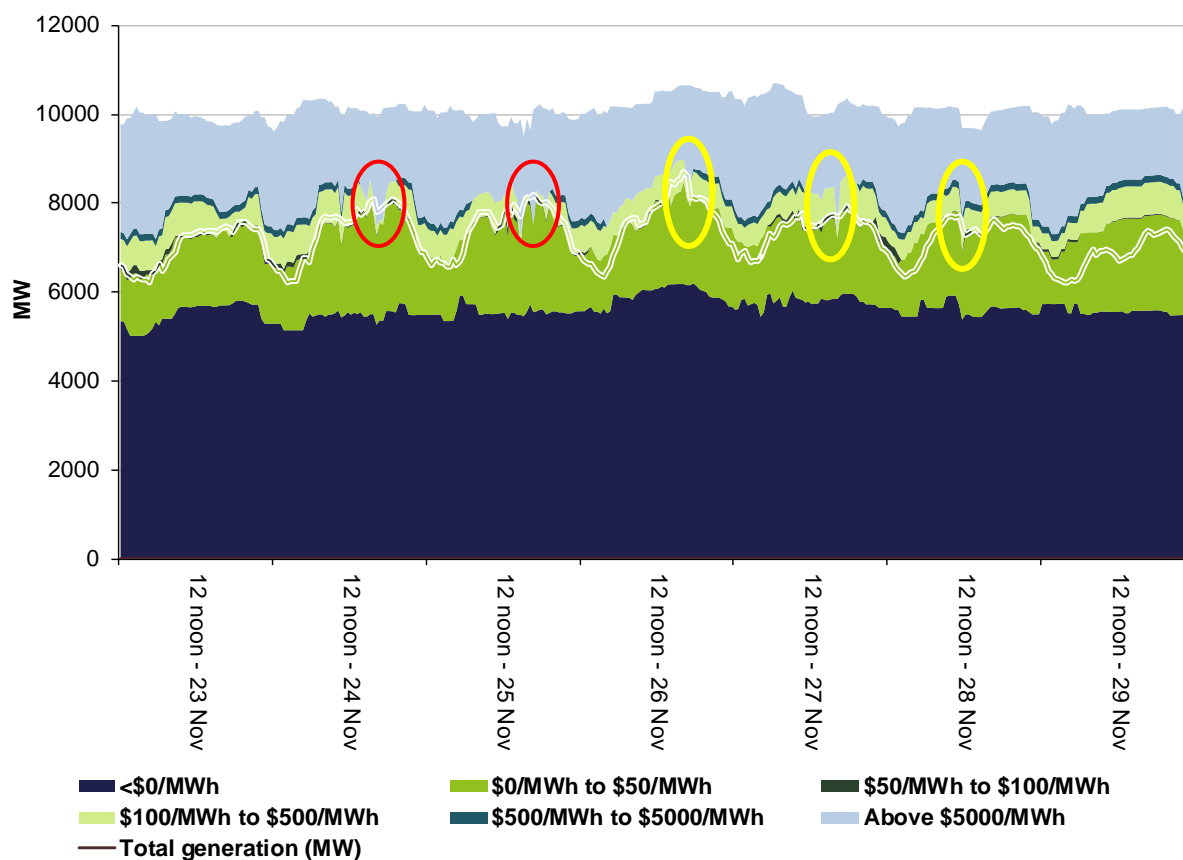
	Availability	Demand	Network	Combination
% of total above forecast	1	30	0	1
% of total below forecast	62	6	0	0

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

## Generation and bidding patterns

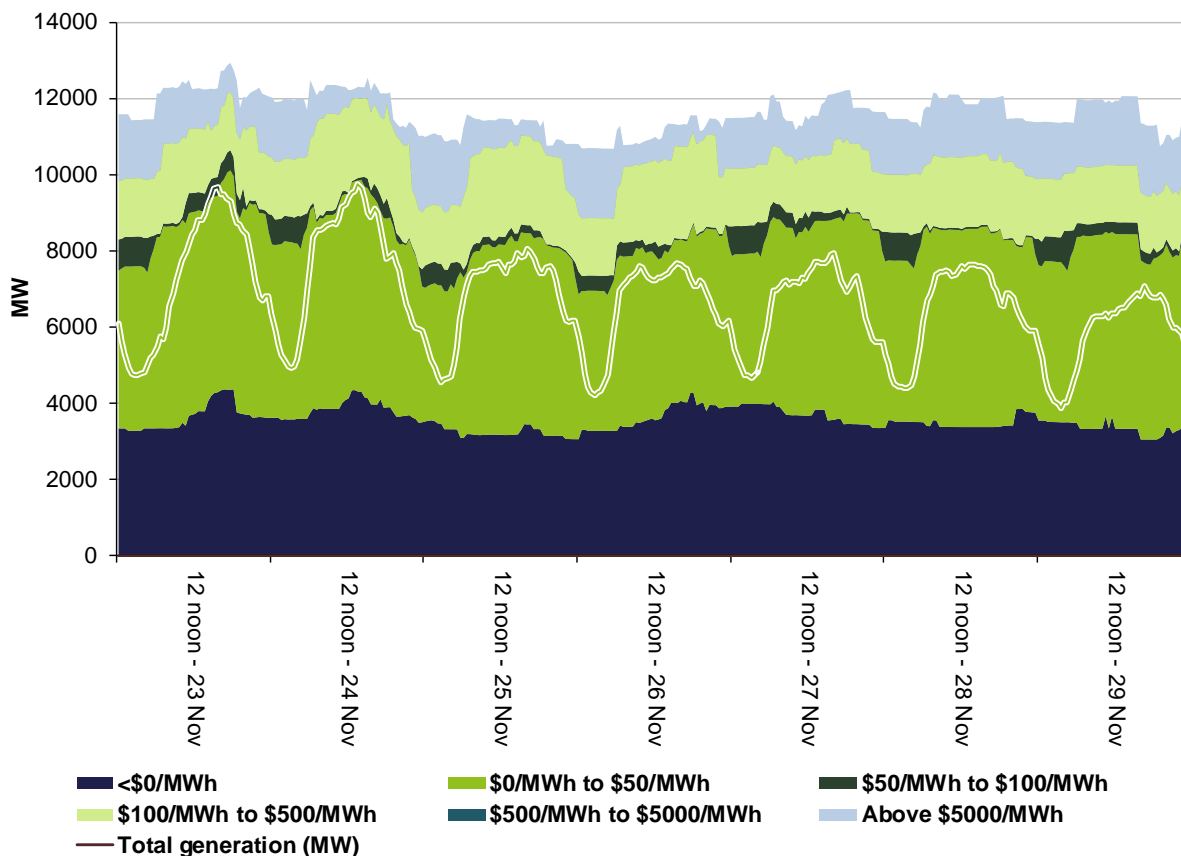
The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figures 3 to 7 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

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

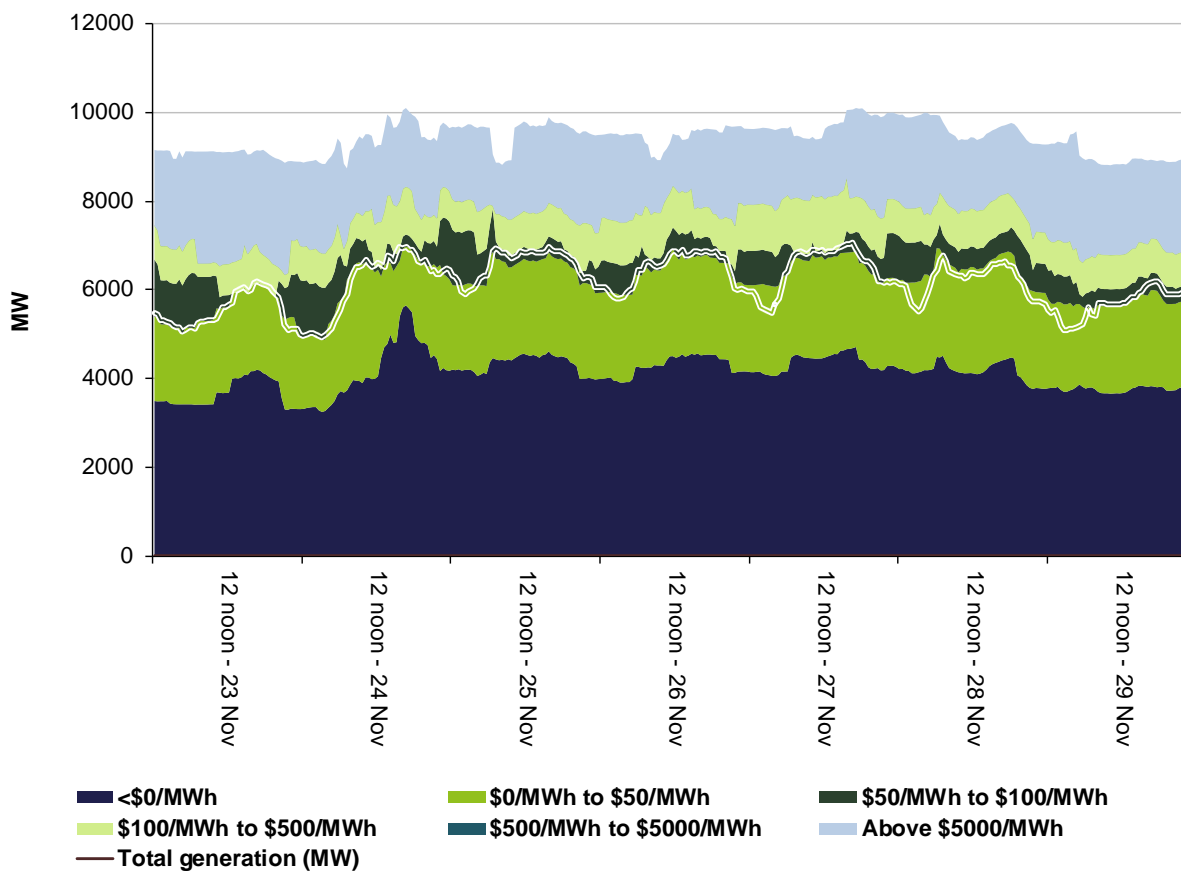


The red ellipses highlight the rebidding that resulted in the high spot prices. A detailed analysis of the events relating to these periods is in the “Detailed market analysis of significant price events” below. The yellow ellipses highlight other periods where material volumes of low priced capacity were suddenly rebid to prices near the price cap.

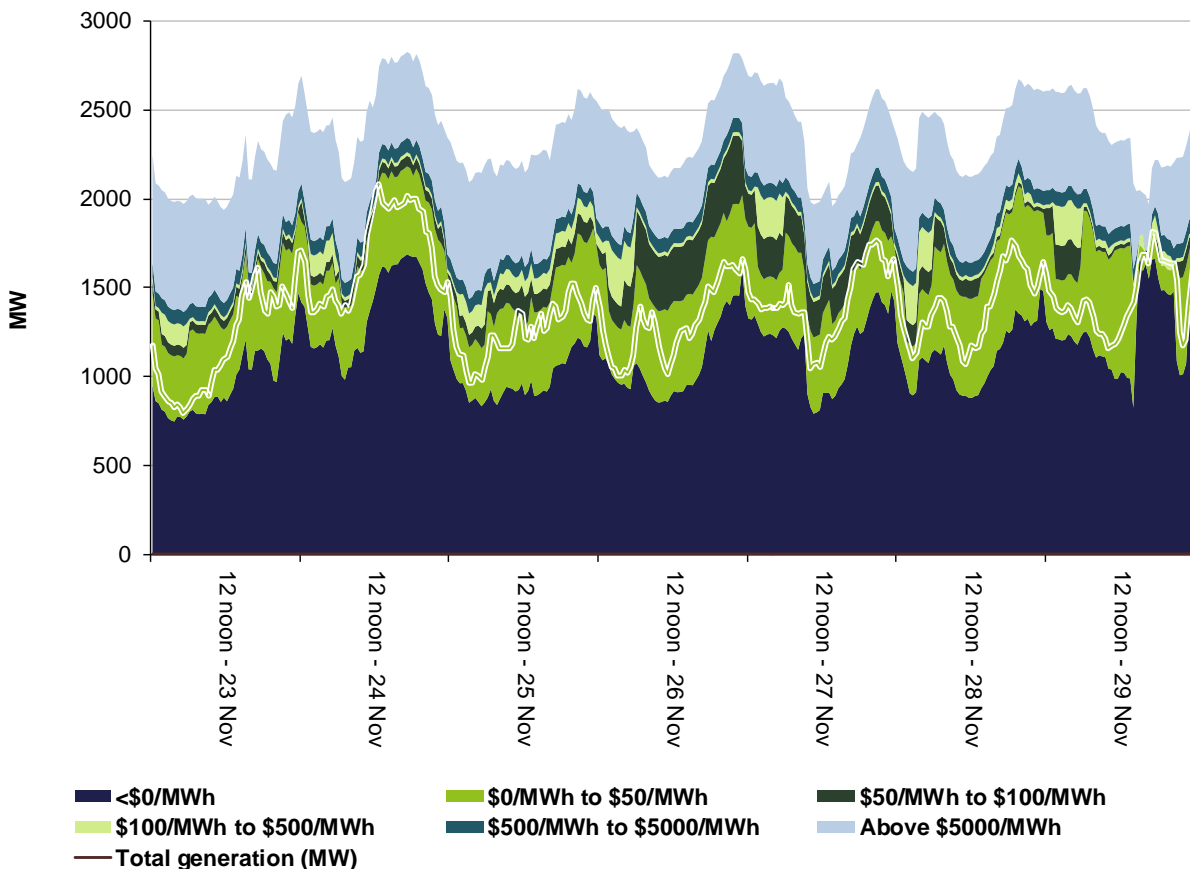
**Figure 4: New South Wales generation and bidding patterns**



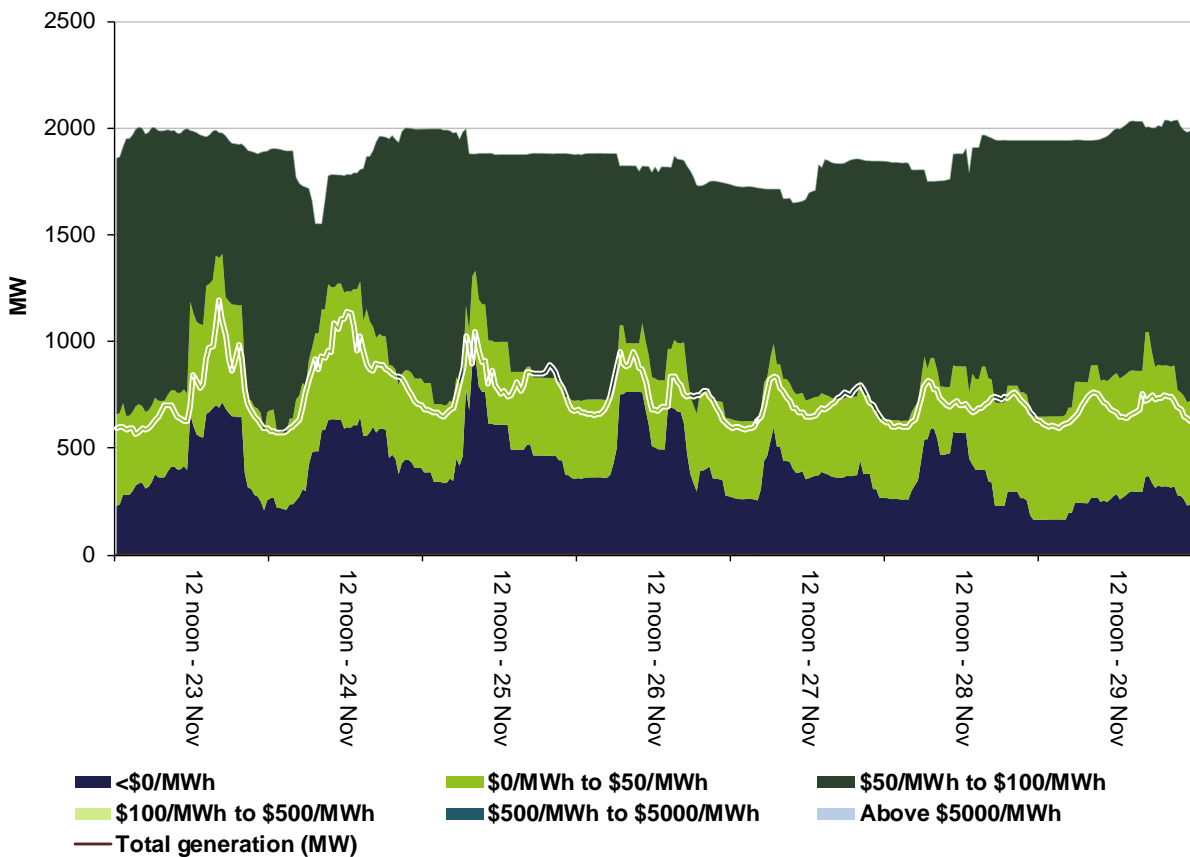
**Figure 5: Victoria generation and bidding patterns**



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



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



## 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.

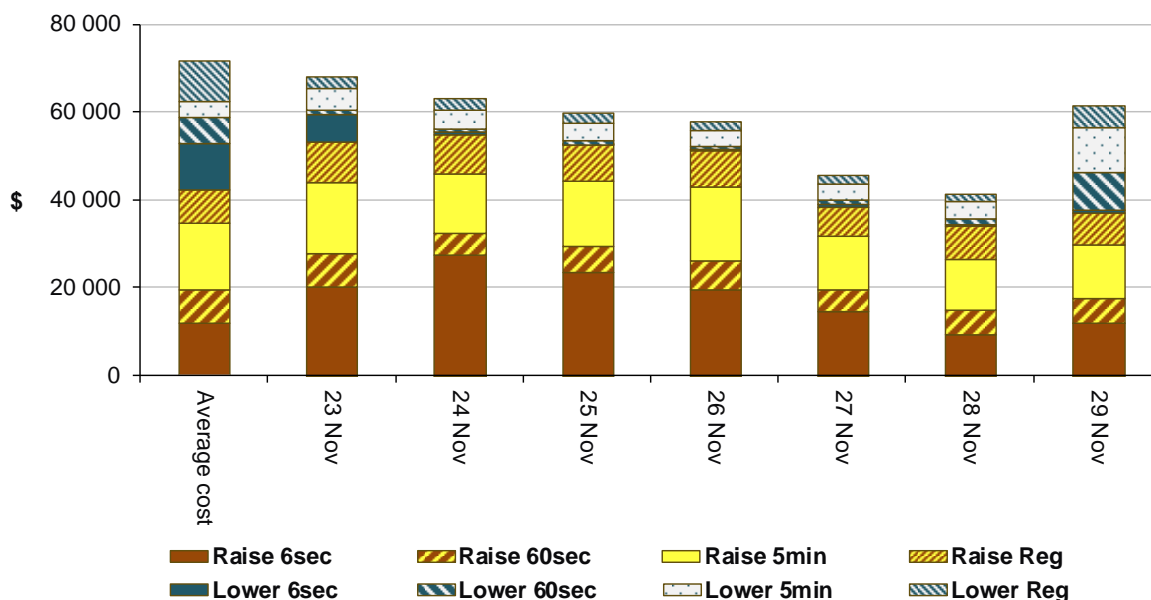
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$257 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$139 500 or around 2 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.

### Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of \$44/MWh and above \$250/MWh.

#### Monday, 24 November

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
4:30 PM	1156.28	34.87	46.76	7694	7570	7688	9976	10 333	10 180

Conditions at the time saw demand 124 MW higher than forecast four hours ahead. Available capacity was 357 MW lower. 12 hours ahead, 4 hours ahead and at the start of the trading interval, QNI was forecast to be within 200 MW of its export limit.

At 1.57 pm, Arrow Energy reduced the available capacity at Braemar 6 by 55 MW, priced under \$285/MWh. The reason given was “1356P unit maintenance: max output limited by bearing temperatur”.

At 3.32 pm, Stanwell reduced the available capacity at Stanwell 3 by 160 MW, 70 MW of which was priced under \$300/MWh. The reason given was “1532P FD fan issue”. At 4.07 pm, Stanwell again reduced the available capacity at Stanwell 3, this time by 75 MW, priced at the price floor. The reason given was “1406P FD fan issue”.

At 4.11 pm, effective from 4.30 pm, CS Energy rebid 80 MW of available capacity at Gladstone 1, 3, and 6 from below \$30/MWh to the price cap. The reason given was “1622A interconnector constraint-QNI changed limit-SL”.

At 4.19 pm, effective from 4.30 pm, Stanwell rebid 336 MW of available capacity from Kareeya, Stanwell, Swanbank E, and Tarong 1 from below \$21/MWh. 275 MW was rebid to around \$6500/MWh, with the remaining 61 MW rebid at the price cap. The reason given was “1620A material change in QNI flow: DI1540”.

At 4.21 pm, effective from 4.30 pm, Callide Power Trading rebid 23 MW of available capacity at Callide C from \$13/MWh to the price cap. The reason given was “1620A QLD RRP higher than PD-SL”.

Low priced generation was either ramp rate limited or fully dispatch resulting in the dispatch price increasing from \$56.40/MWh at 4.25 pm to \$6666.66/MWh at 4.30 pm, with Stanwell setting the price.

## Tuesday, 25 November

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
3:00 PM	2296.88	34.74	46.11	7624	7503	7577	9838	9973	10 111

Conditions at the time saw demand 121 MW higher than forecast four hours ahead. Available capacity was 135 MW lower than forecast four hours ahead. 12 hours ahead, 4 hours ahead and at the start of the trading interval, QNI was forecast to be within 200 MW of its export limit.

At 2.30 pm, effective from 2.40 pm, CS Energy rebid 80 MW of available capacity at Gladstone 1 and 3 from \$22/MWh to the price cap. The reason given was "1428A change in QNI flow-SL".

At 2.38 pm, effective from 2.45 pm, CS Energy rebid 50 MW of available capacity at Wivenhoe 2 from \$15/MWh to the price cap. The reason given was "1438P technical issues-high tempos-SL".

At 2.50 pm, effective from 3.00 pm, CS Energy rebid 200 MW of available capacity at Wivenhoe 2 from \$15/MWh to the price cap. The reason given was "1449P commissioning-shut unit down-high winding temps-SL".

At 2.48 pm, effective from 2.55 pm, Stanwell rebid 445 MW of capacity across its portfolio from prices of \$21/MWh and \$290/MWh to the price cap. The reason given was "1445A change QLD GEN Wivenhoe".

At 2.50 pm, effective from 3.00 pm, Millmerran rebid a total of 100 MW of available capacity across its portfolio from \$7/MWh to the price cap. The reason given was "14:46 a change in 5min PD QNI flow-SL".

Low priced generation was either ramp rate limited or fully dispatch resulting in the dispatch price increasing from \$57.36/MWh at 2.55 pm to the price cap at 3.00 pm with CS Energy setting the price.

### South Australia

There were three occasions 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.

## Saturday, 29 November

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
3:00 PM	280.91	36.99	36.99	1616	1543	1530	2083	2481	2450
3:30 PM	2365.96	36.99	36.99	1700	1575	1574	2056	2447	2472
4:30 PM	2279.32	40.50	41.50	1785	1702	1677	1998	2447	2476

### 3 pm

For the 3 pm price, conditions at the time saw demand 73 MW higher than forecast four hours before. Available capacity was 398 MW lower than forecast four hours before.



For the 3 pm trading interval, wind generation was 72 MW lower than forecast four hours before (177 MW – 105 MW). Notably the SA-Vic interconnector was constrained at, or close to, its import limits into South Australia.

At 2.04 pm Alinta Energy reduced the available capacity at Northern 2 from 273 MW to 0 MW due to a tube leak. The unit had been operating at approximately 180 MW immediately prior to its outage and its dispatched capacity was priced at or under \$53/MWh. Flow on the SA-Vic interconnector increased to around 350MW into South Australia, approximately 80MW above its limit. Non-scheduled generation units in South Australia started at this time reducing the flow on the interconnector back below the import limit.

Demand increased by 114 MW for the 2.45 pm dispatch interval. A contributing factor to the increase in demand was decreased output from non-scheduled in South Australia. The step change in demand was unable to be met by low priced generation as generators were either ramp rate limited or fully dispatched and the flow on the SA-Vic interconnector once again exceeded its import limits into South Australia. Consequently the dispatch price increased from \$40.50/MWh at 2.40 pm to \$1500.20/MWh at 2.45 pm.

### **3.30 pm**

For the 3.30 pm price, conditions at the time saw demand 125 MW higher than forecast four hours before. Available capacity was 391 MW lower than forecast four hours before. The SA-Vic interconnector was operating closer to its import limits into South Australia.

For the 3.30 pm trading interval, wind generation was 49 MW lower than forecast four hours before. Alinta's Northern 2 generator remained offline.

At 2.39 pm, GDF Suez reduced the available capacity at Dry Creek 2 from 41 MW to 0 MW due to the unit tripping on start up. The capacity was priced at or under \$1504/MWh.

At 2.45 pm, GDF Suez reduced the available capacity at Dry Creek 1 from 41 MW to 0 MW due to the unit tripping on run up. The capacity was priced at or under \$293/MWh.

At 3.13 pm, effective from 3.20 pm, GDF Suez reduced the capacity at Port Lincoln 1 from 42 MW to 0 MW. The capacity was priced at the price cap. The reason given was "1511P Mintaro unit starting-decommit PL1 from start SL".

At 3.07 pm, effective at 3.15 pm, Origin Energy rebid 66 MW of capacity Ladbroke Grove 1 and 2 from the price floor to the price cap. The reason given was "1506A change in SA Gen – Northern unit trip SL".

Demand increased by 128 MW for the 3.20 pm dispatch interval. A contributing factor to the increase in demand was un-forecast decreased output from non-scheduled in South Australia and the reduced capacity of the SA-Vic interconnector. The step change in demand was unable to be met by low priced generation as generators were either ramp rate limited, trapped in FCAS or fully dispatched. SA-Vic Interconnector flows exceeded the South Australian import limits and consequently the dispatch price increased from increased from \$300.07/MWh at 3.15 pm to the price cap at 3.20 pm with Origin's Ladbroke Grove units setting the price.

### 4.30 pm

For the 4.30 pm price, conditions at the time saw demand 83 MW higher than forecast. Available capacity was 449 MW lower than forecast four hours before.

For the 4.30 pm trading interval, wind generation was 119 MW lower than forecast four hours before.

Alinta's Northern 2 generator, and GDF's Dry Creek 1 and 2 generators remained offline.

At 4.13 pm, effective from 4.20 pm, Origin rebid 66 MW of capacity Ladbroke Grove 1 and 2 from the price floor to the price cap. The reason given was "1612A dec SA dem 5 PD 1806 < 30PD 1896 @ 16010 SL".

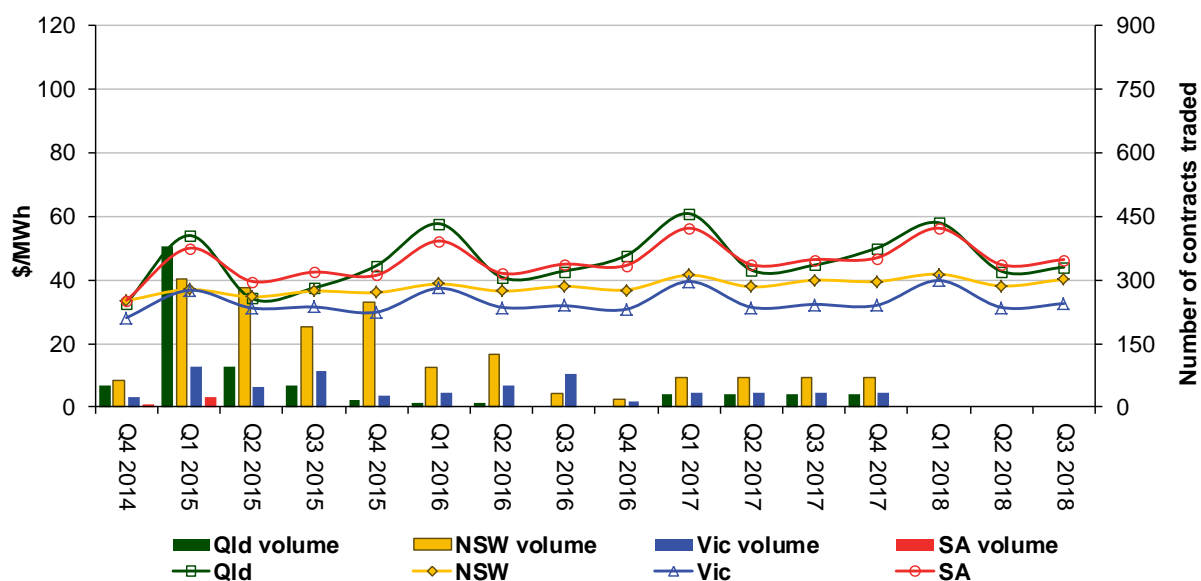
Non-scheduled generation was not operating at this time and the SA-Vic interconnector was operating at it import limit (~180MW) into the region.

Low priced generation was either ramp rate limited, trapped in FCAS or fully dispatched resulting in the dispatch price increasing from \$51.37/MWh at 4.15 pm to \$13481.81/MWh at 4.20 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.

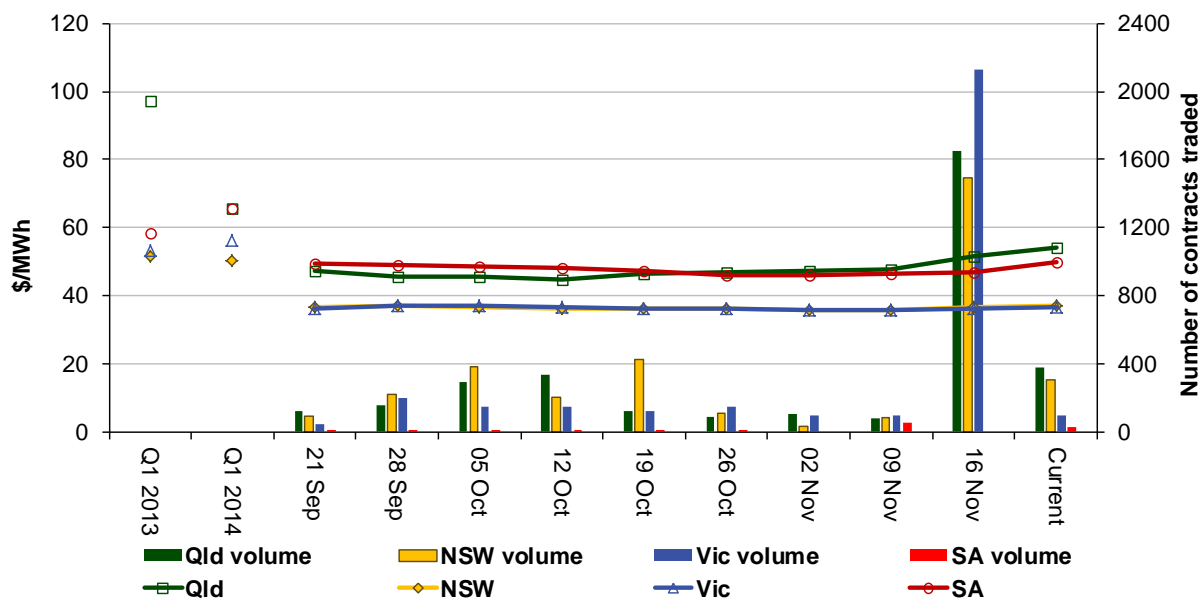
**Figure 9: Quarterly base future prices Q4 2014 – Q3 2018**



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.

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



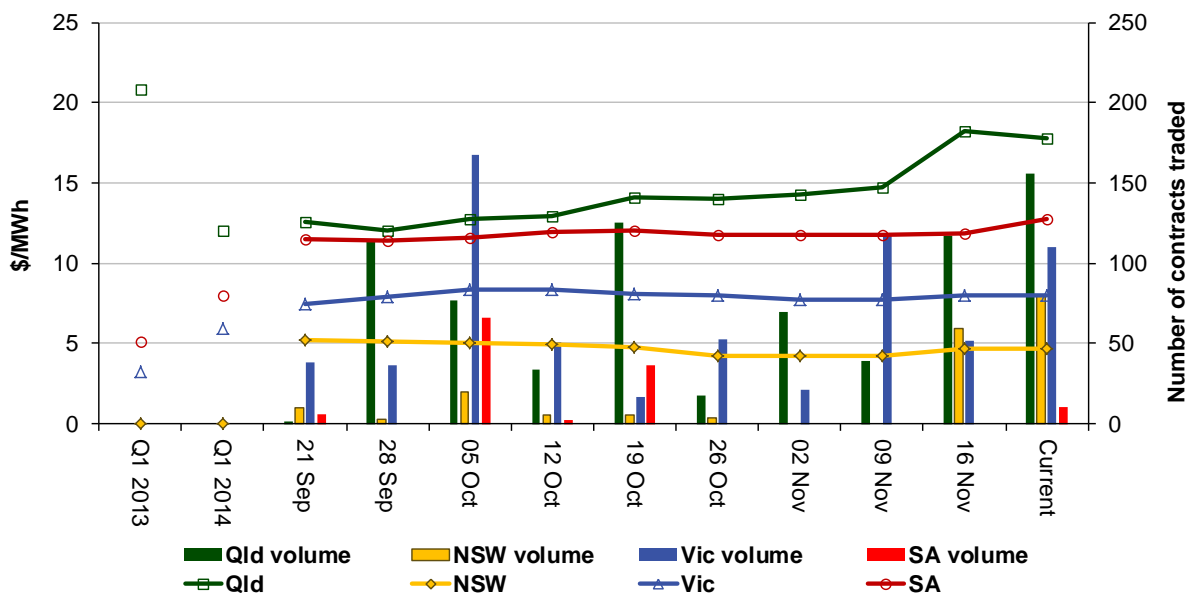
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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 increase in Queensland price and volatility is reflected in an increase in the price of cap contracts and volumes traded for that region.

**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)