

Electricity Report

20 to 26 October 2013



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 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 1: Volume weighted average spot price by region (\$/MWh)

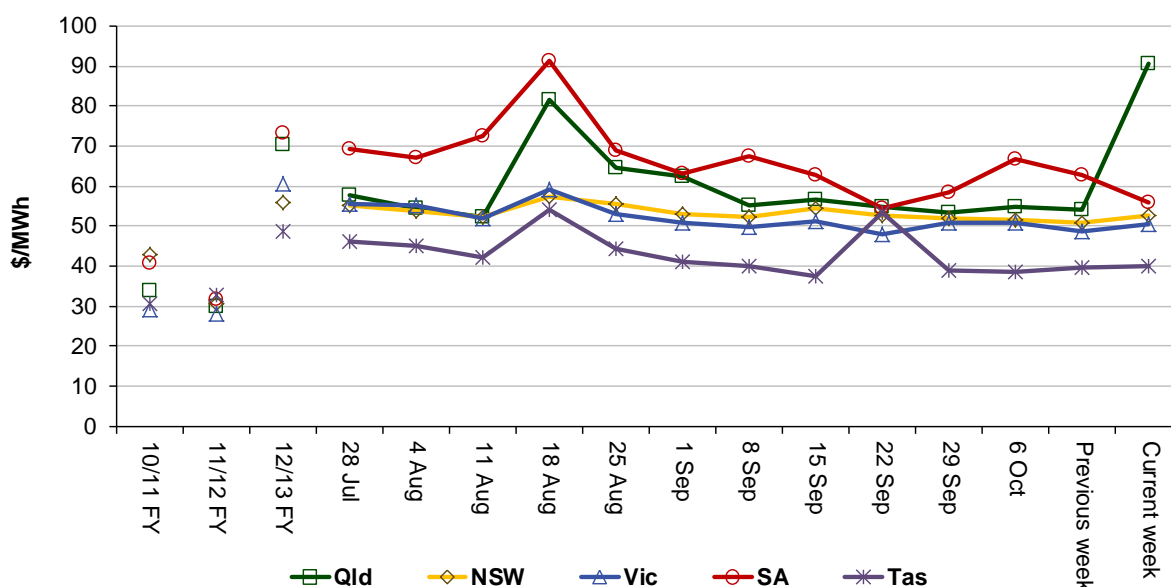


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	90	53	51	56	40
12-13 financial YTD	57	60	60	64	48
13-14 financial YTD	61	55	54	68	45

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 101 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2012 of 60 counts and the average in 2011 of 78. 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

Reason for variation	Availability	Demand	Network	Combination
% of total above forecast	16	12	0	5
% of total below forecast	6	55	0	6

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 2: Queensland generation and bidding patterns

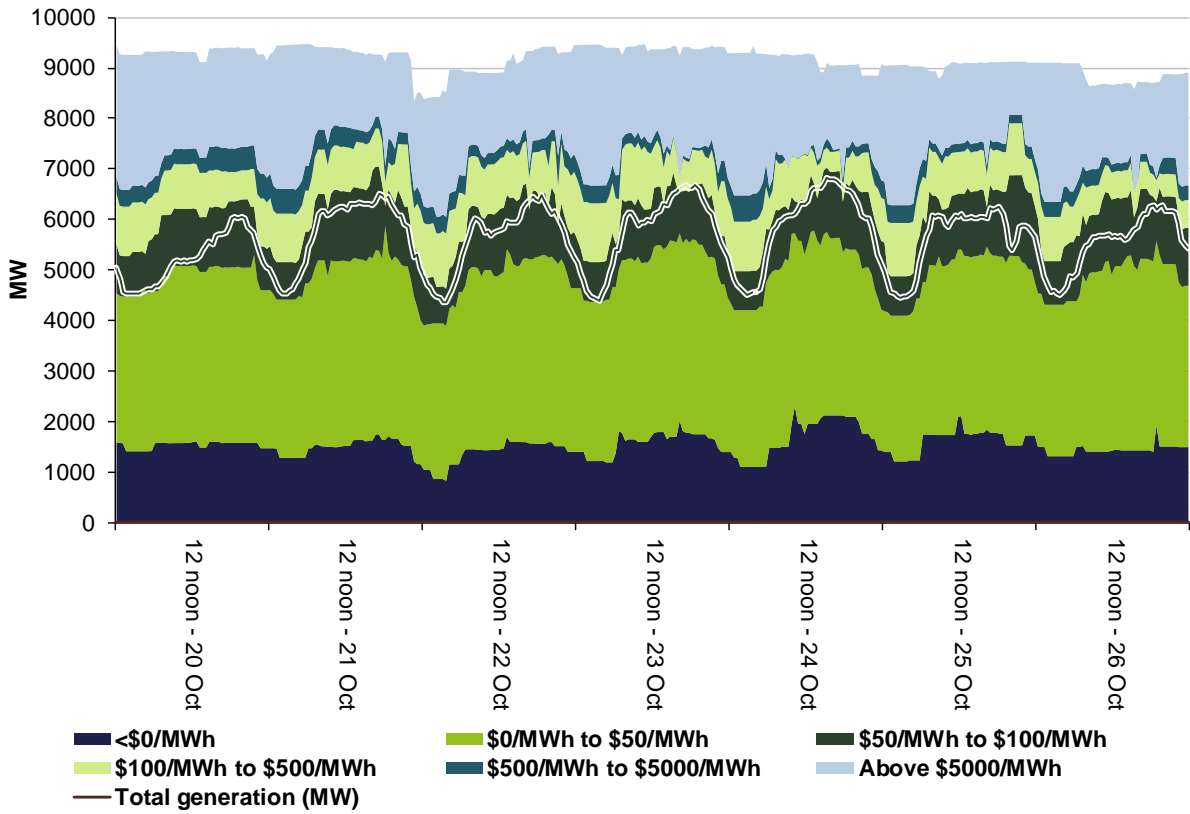


Figure 3: New South Wales generation and bidding patterns

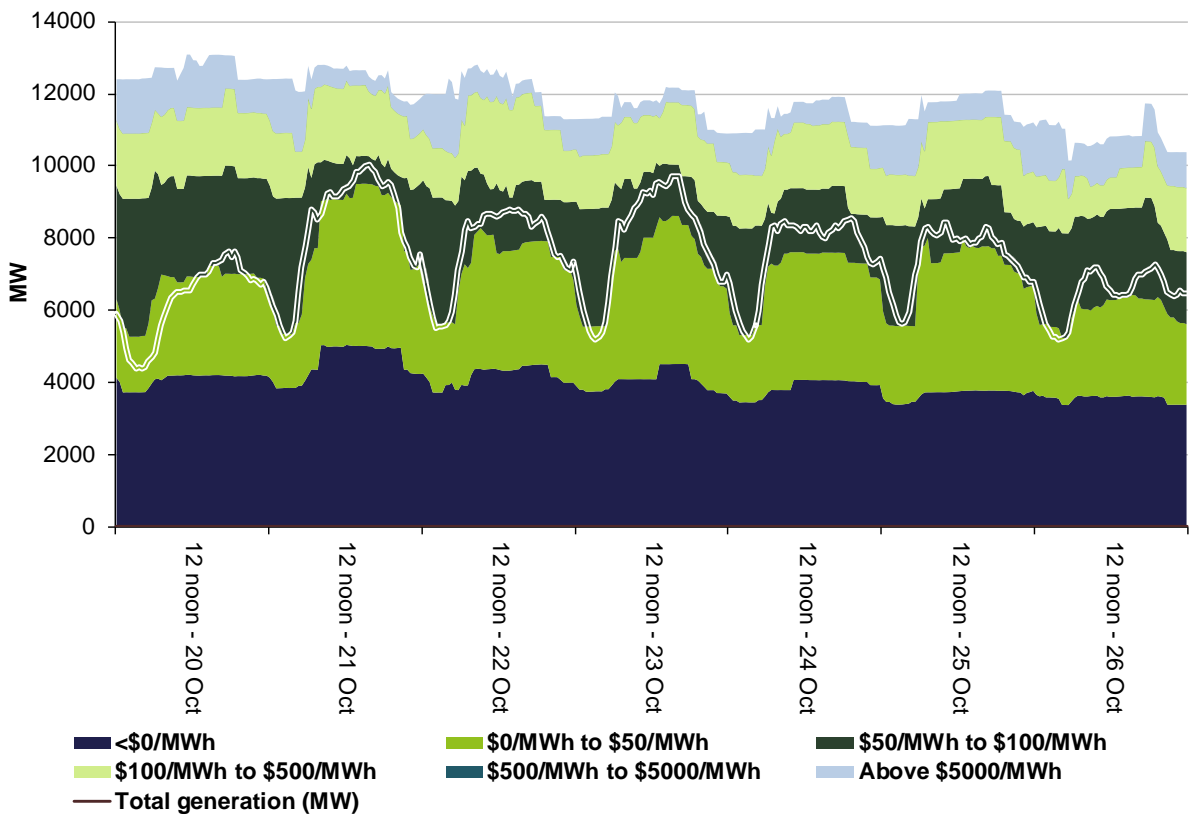


Figure 4: Victoria generation and bidding patterns

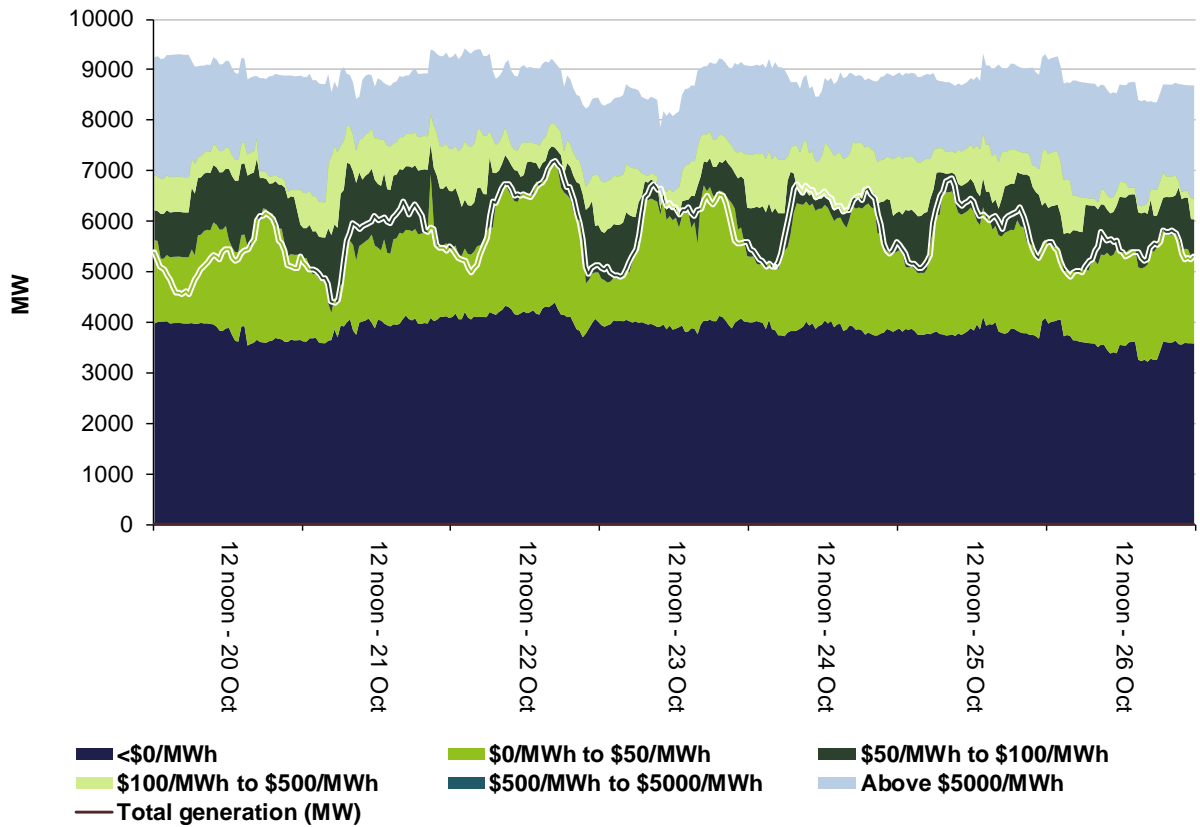


Figure 5: South Australia generation and bidding patterns

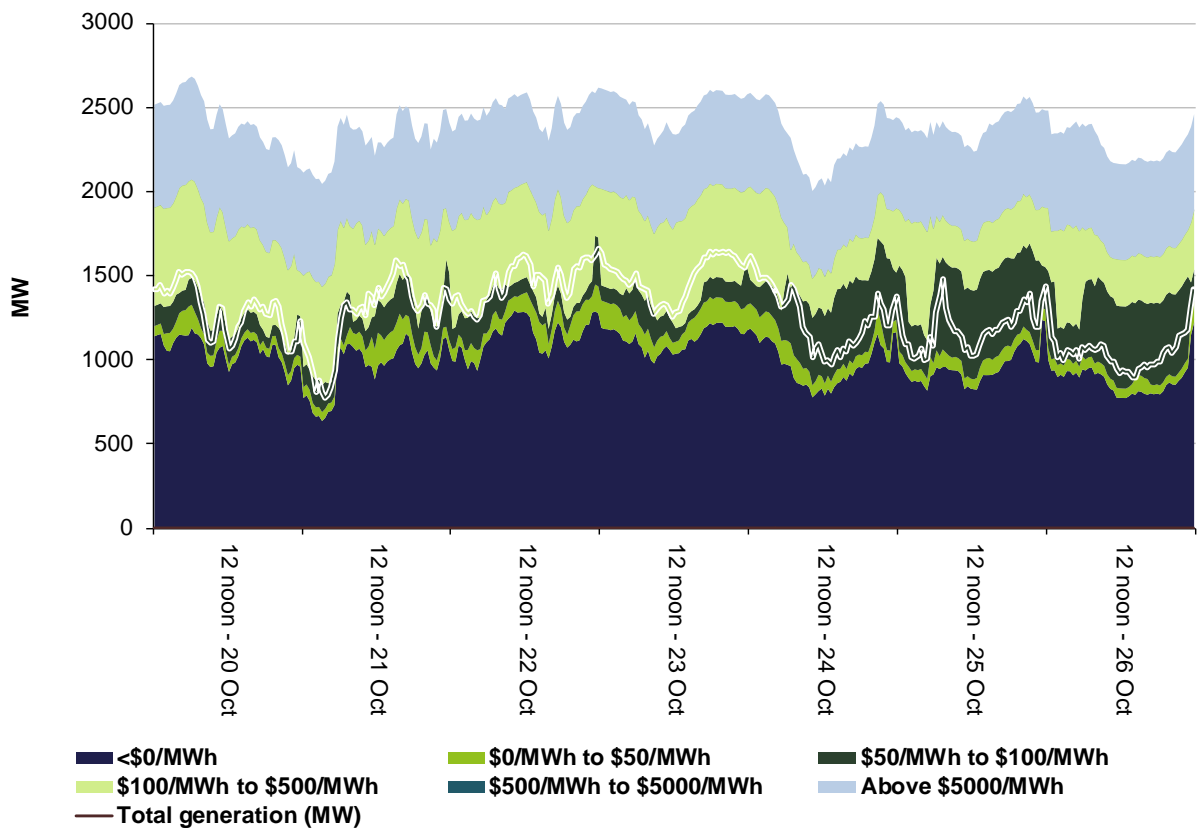
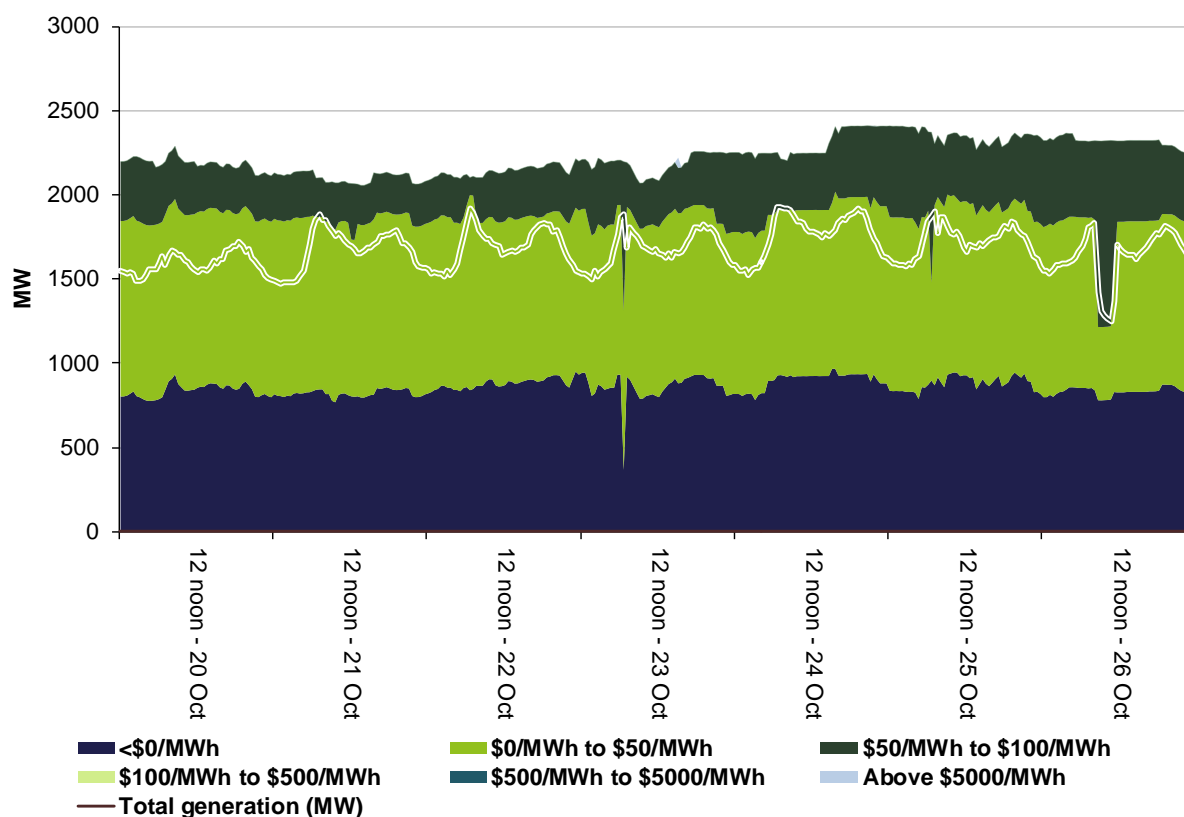


Figure 6: Tasmania generation and bidding patterns



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:

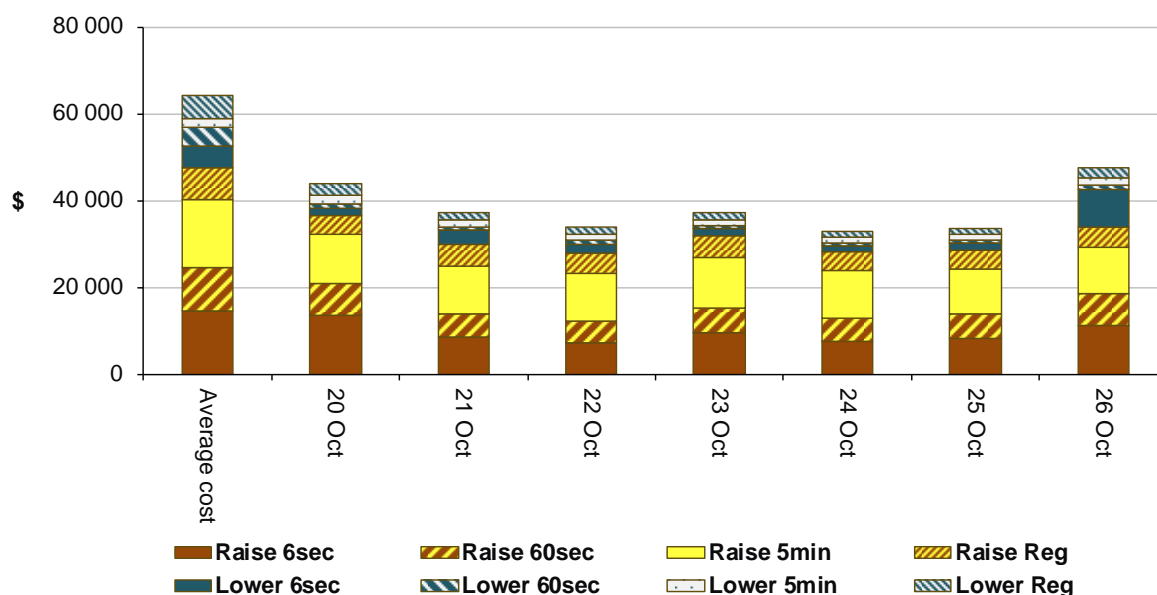
- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- *delayed services*, which return the frequency to the 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 \$225 000 or less than 1 per cent of energy turnover on the mainland. In Tasmania (which requires dedicated services for much of the time) the total cost for the week was \$41 500 or less than 1 per cent of energy turnover in Tasmania.

Figure 7 shows the daily breakdown of costs for each service, as well as the average daily costs for the previous financial year.

Figure 7: 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 were six occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of \$90/MWh and above \$250/MWh.

Monday, 21 October

6:30 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	376.51	84.99	85.00
Demand (MW)	6627	6541	6580
Available capacity (MW)	9243	9374	9443

Demand and available capacity were close to forecast.

The Terranora interconnector was still unavailable (since 8 August) and voltage collapse constraints from the loss of the Kogan Creek Power Station limited QNI to around 320 MW.

At 6.12 pm, effective from 6.20 pm, Stanwell rebid a total of 745 MW of available capacity at Stanwell and Swanbank E power stations from prices between \$52/MWh and \$282/MWh to between \$1 461/MWh and the price cap. The reason given was “1805A change in QLD price PD price”.

Demand increased by 88 MW between the 6.15 pm and 6.25 pm dispatch intervals.

The step change in demand was unable to be satisfied by low-priced generation which was either constrained, ramp rate limited or trapped in FCAS. This saw the dispatch of high priced generation and the 5-minute price increased from \$195/MWh at 6.20 pm to \$1500/MWh at 6.25 pm set by Stanwell’s Swanbank E.

There was no other significant rebidding.

11 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	301.86	84.99	65.00
Demand (MW)	5541	5569	5558
Available capacity (MW)	8591	9433	9463

Demand was close to forecast. Available capacity was around 840 MW lower than forecast both four and 12 hours before.

The Terranora interconnector was still unavailable (since 8 August) and voltage collapse constraints from the loss of the Kogan Creek Power Station limited QNI to around 390 MW.

At around 10.13 pm, Callide C units 3 and 4 tripped at a combined output of 392 MW. The subsequent rebids, effective from 10.40 pm and 10.45 pm, reduced the total capacity from 812 MW to zero (a majority of which was priced at the price floor).

At 10.21 pm, effective from 10.30 pm, Stanwell rebid a total of 90 MW of available capacity at Stanwell units 1, 3, and 4 from \$83/MWh to the price cap. The reason given was “2221A change DLD 5min PD 22:15 22:30-SL”.

At 10.38 pm, effective from 10.45 pm, AGL reduced the availability of Oakey unit 1 by 150 MW, all of which was priced at \$235/MWh. The reason given was “22:35F unit triggered by market::avoid uneconomical start”.

Between 10.35 pm and 10.40 pm demand increased by 82 MW. The step change in demand and generation was unable to be met by low-priced generation which was either constrained, ramp rate limited or trapped in FCAS. This saw the dispatch of high priced generation and the 5-minute price increased from \$91/MWh at 10.35 pm to \$1500/MWh at 10.40 pm.

There was no other significant rebidding.

Wednesday, 23 October

7 AM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	548.10	84.99	57.42
Demand (MW)	5583	5697	5705
Available capacity (MW)	9398	9430	9430

Demand was over 100 MW lower than forecast both four and 12 hours before. Available capacity was close to forecast.

The Terranora interconnector was still unavailable (since 8 August) and voltage collapse constraints from the loss of the Kogan Creek Power Station limited QNI to around 240 MW.

At 6.22 am, effective from 6.30 am, Stanwell Corporation rebid up to a total of 535 MW of available capacity across its portfolio from prices below \$584/MWh to \$1500/MWh and above (a majority was at the price cap). The reason given was “0622A change 5 min QLD PD-price-SL”.

At 6.38 am, effective from 6.45 am, Alinta Energy rebid 57 MW of available capacity at Braemar 2 from prices below \$155/MWh to above \$430/MWh (a majority at the price cap). The reason given was “0640A QLD price \$1500- much greater than PD@6.38”.

At 6.47 am, effective from 6.55 am, Origin Energy rebid 30 MW of available capacity at Darling Downs from \$0/MWh to \$11 836/MWh. The reason given was “0643A CHNG FCAST-DEC QLD DEM 5PD 5743MW@0705<30PD 5941MW@0730 SL”.

Demand increased by 38 MW for the 6.40 am dispatch interval and 144 MW for the 7 am dispatch interval.

Both step changes in demand were unable to be satisfied by low priced generation, as it was either constrained, ramp rate limited or trapped in FCAS. This saw the dispatch of high priced generation for the 6.40 am and the 7 am dispatch intervals.

There was no other significant rebidding.

4:30 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	2463.61	99.85	277.98
Demand (MW)	6763	6750	6891
Available capacity (MW)	9387	9440	9420

Demand was close to forecast four hours before, but was 128 MW lower than forecast 12 hours before. The high demand forecast 12 hours before contributed to the forecast price of \$277.98/MWh. Available capacity was close to forecast.

The Terranora interconnector was still unavailable (since 8 August) and voltage collapse constraints from the loss of the Kogan Creek Power Station limited QNI to around 240 MW.

At 4.16 pm, effective from 4.25 pm, Stanwell Corporation rebid a total of 856 MW of available capacity across its portfolio, from prices between -\$1/MWh and \$1500/MWh to prices above \$12 000/MWh. The reason given was “1615A change in QNI limit dispatch greater than predispatch”.

At 4.22 pm, effective from 4.30 pm, Arrow Energy reduced the available capacity of Braemar 7 by 173 MW, all of which was priced at \$434/MWh. The reason given was “1621A QLD price higher than FCAST SL”. This resulted in the dispatch of high priced generation and the 5-minute price increased from \$95/MWh at 4.20 pm to \$7200/MWh at 4.25 pm and 4.30 pm as low-priced generators were either ramp rate up limited or stranded in FCAS.

There was no other significant rebidding.

Friday, 25 October

4:30 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	2233.31	55.19	55.19
Demand (MW)	6263	6233	6265
Available capacity (MW)	9100	9138	9258

Demand and available capacity were close to forecast.

The Terranora interconnector was still unavailable (since 8 August) and voltage collapse constraints from the loss of the Liddell to Muswellbrook line limited QNI to around 3700 MW.

At 4.15 pm, effective from 4.25 pm, Stanwell Corporation rebid a total of 723 MW of available capacity across its portfolio, from prices between \$45/MWh and \$282/MWh to over \$12 000/MWh (a majority at the price cap). The reason given was “1610A change in QLD predispatch price”.

This resulted in the 5 minute price at 4.25 pm reaching the price cap as low-priced generation was either ramp rate up limited, constrained, or trapped in FCAS, and capacity priced at the cap at Stanwell’s Swanbank E power station was dispatched in its place.

There was no other significant rebidding.

Saturday, 26 October

7 PM	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	2231.69	55.19	84.98
Demand (MW)	6170	6110	6117
Available capacity (MW)	8712	8711	8569

Demand and available capacity were close to forecast.

The Terranora interconnector was still unavailable (since 8 August) and voltage collapse constraints from the loss of the Kogan Creek Power Station limited QNI to around 220 MW.

At 6.28 pm, effective from 6.35 pm, Stanwell rebid a total of 488 MW of available capacity at Stanwell power station, Tarong unit 1 and Tarong North, from prices between \$52/MWh and \$12 093 (a majority under \$100/MWh) to the price cap. The reason given was “1828A material change in QNI flow”.

At 6.41 pm, effective from 6.50 pm, Stanwell rebid a total of 160 MW of available capacity at Swanbank E and Tarong North, the majority of which was priced at \$45/MWh, to the price cap. The reason given was “1840A material change in QLD generation: Gladstone PS”.

At 6.41 pm, effective at 6.50 pm, CS Energy rebid a total of 75 MW of available capacity at Gladstone power station, from \$52/MWh to the price cap. The reason given was “1840A intra regional constraint-BI_FB-SL”.

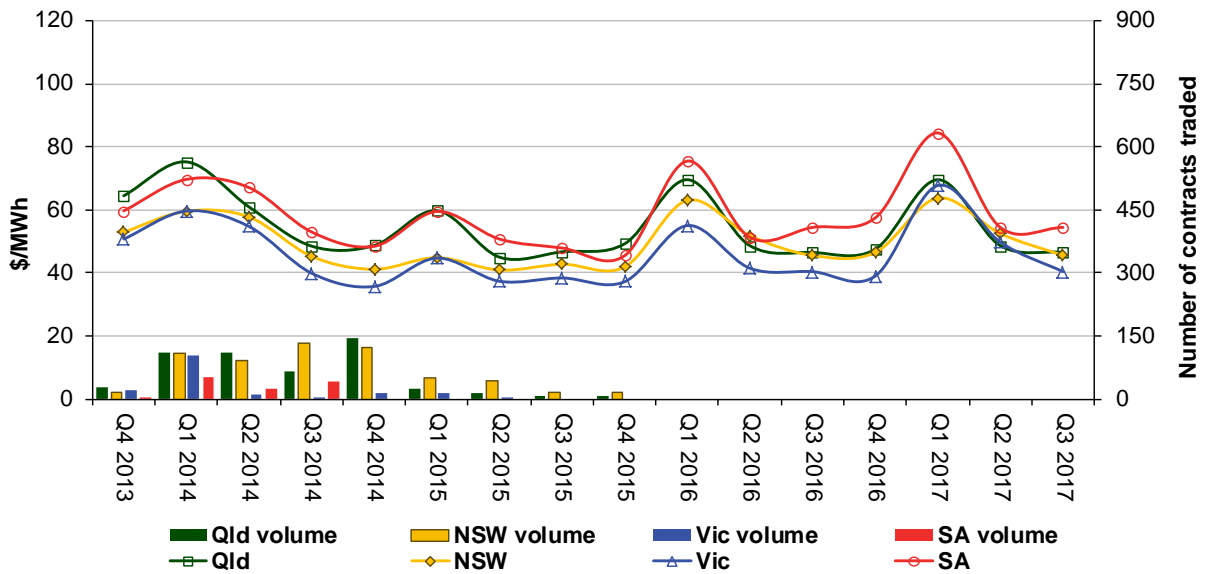
This resulted in the 5 minute price at 6.50 pm reaching the price cap as low-priced generation was either ramp rate up limited, constrained, or stranded in FCAS, and capacity priced at the cap at Stanwell’s power stations was dispatched in its place.

There was no other significant rebidding.

Financial markets

Figure 8 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.

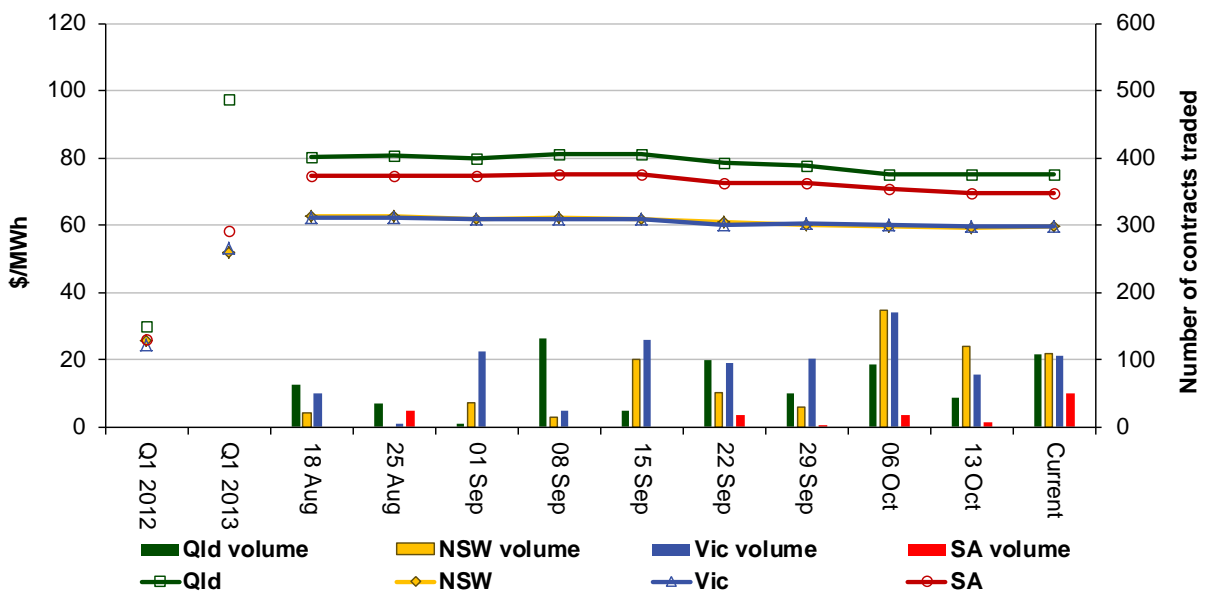
Figure 8: Quarterly base future prices Q4 2013 – Q3 2017



Source: ASXEnergy.com.au

Figure 9 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.

Figure 9: 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

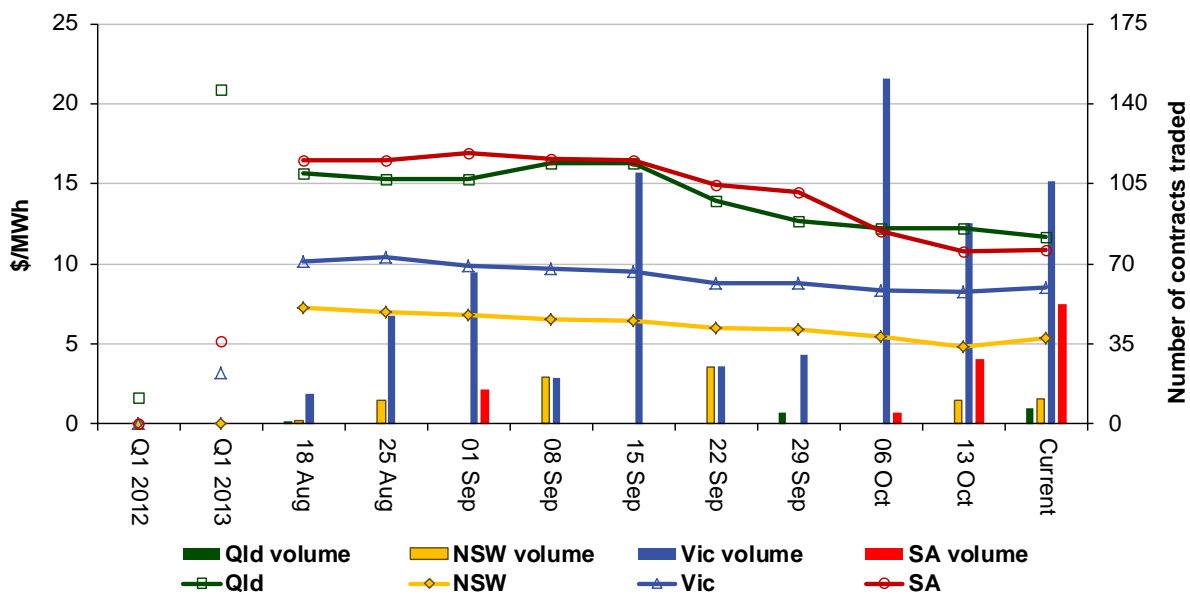
Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics](#) section of our website.

Figure 10 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. The cap contracts limit exposure to extreme spot prices (above \$300/MWh) and is an indicator of the cost of risk management.

Figure 10: 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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