Electricity Report

22 to 28 December 2013

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 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)

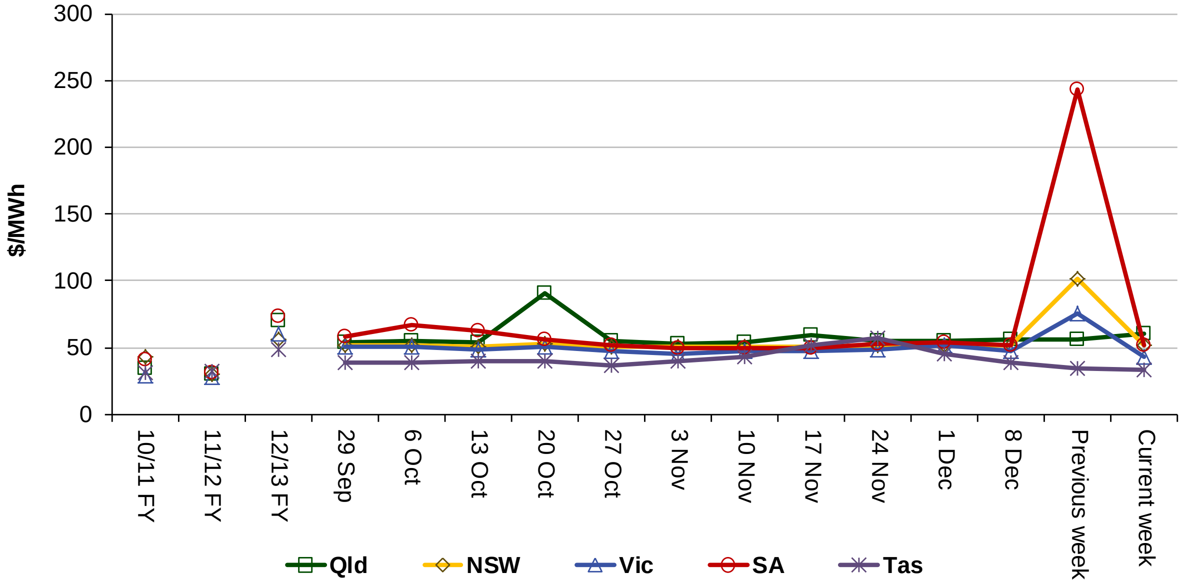


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	60	52	43	52	33
12-13 financial YTD	57	58	65	64	48
13-14 financial YTD	59	56	53	71	44

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 72 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	15	24	0	5
% of total below forecast	28	26	0	1

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

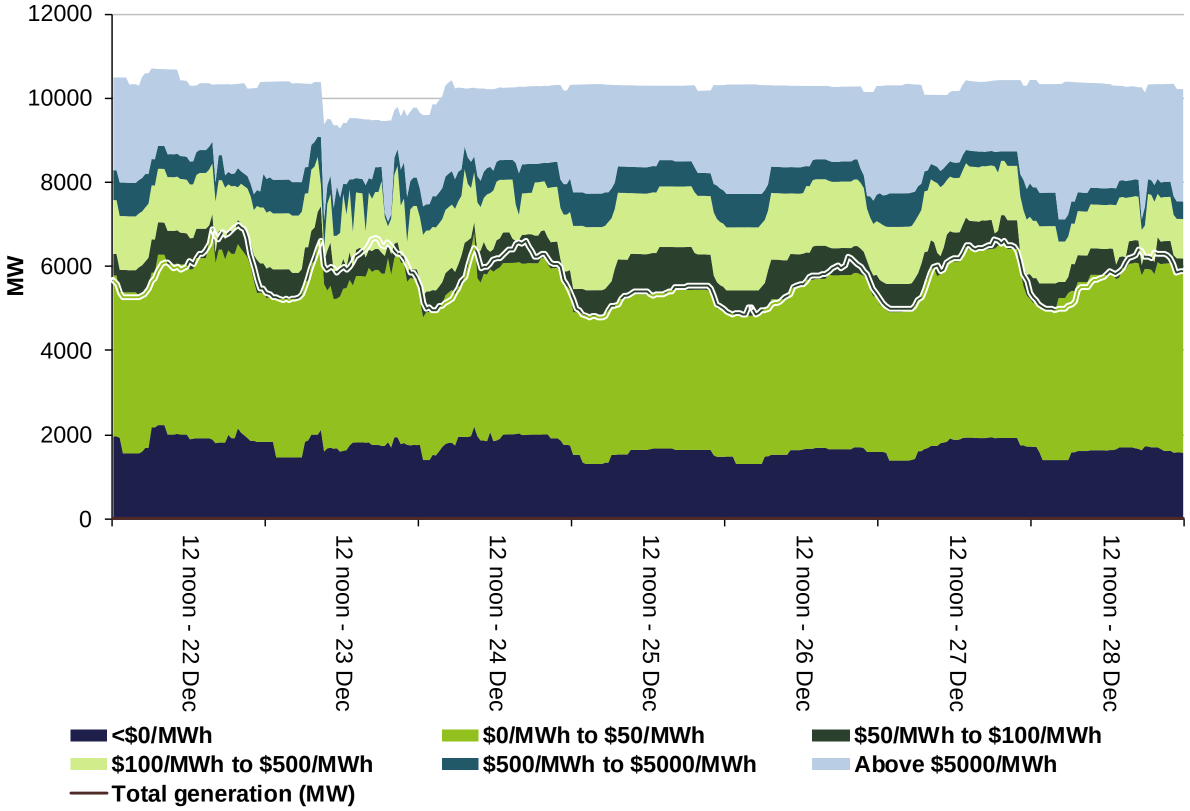


Figure 3: New South Wales generation and bidding patterns

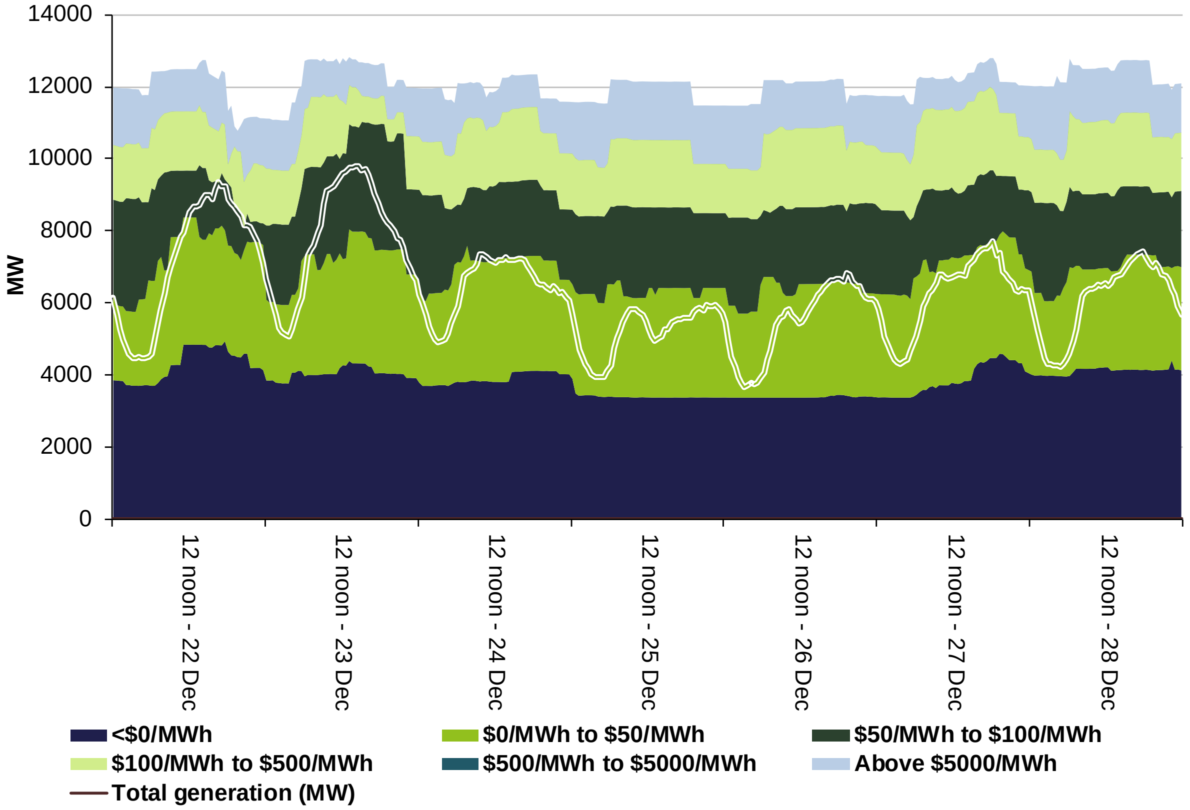


Figure 4: Victoria generation and bidding patterns

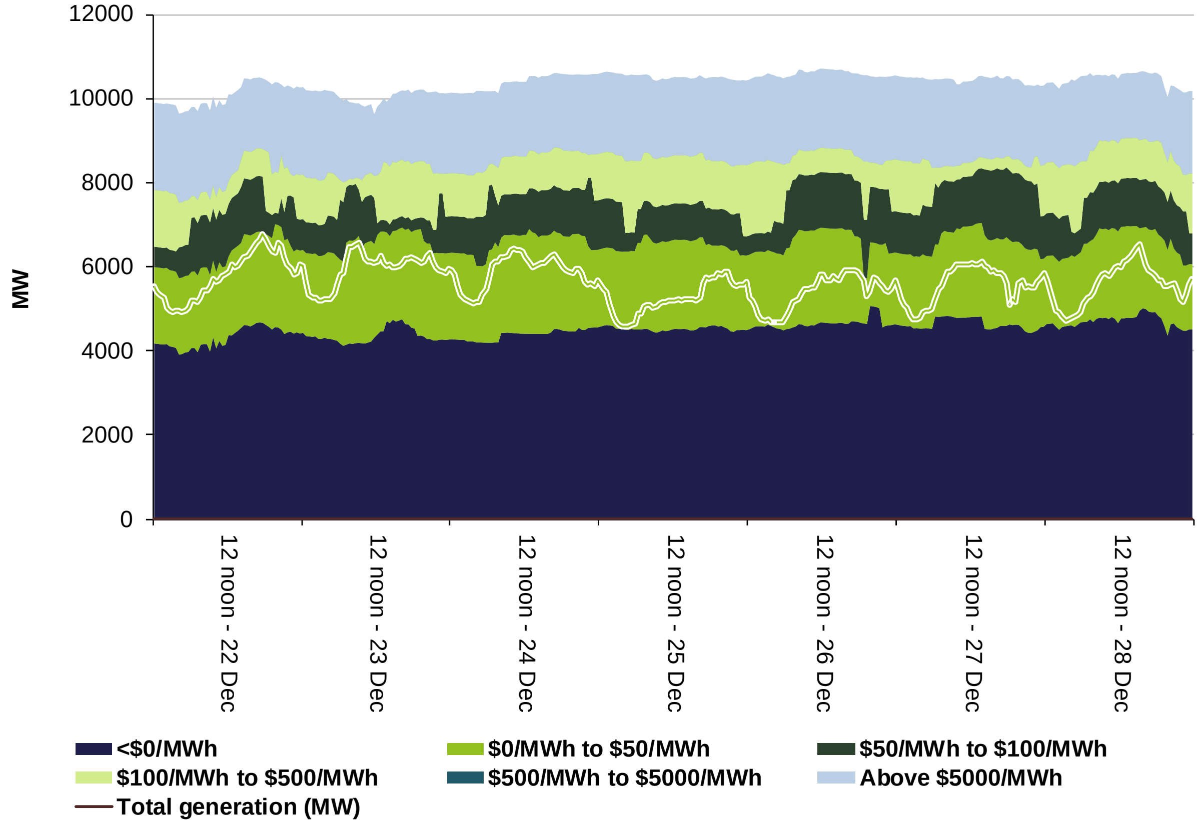


Figure 5: South Australia generation and bidding patterns

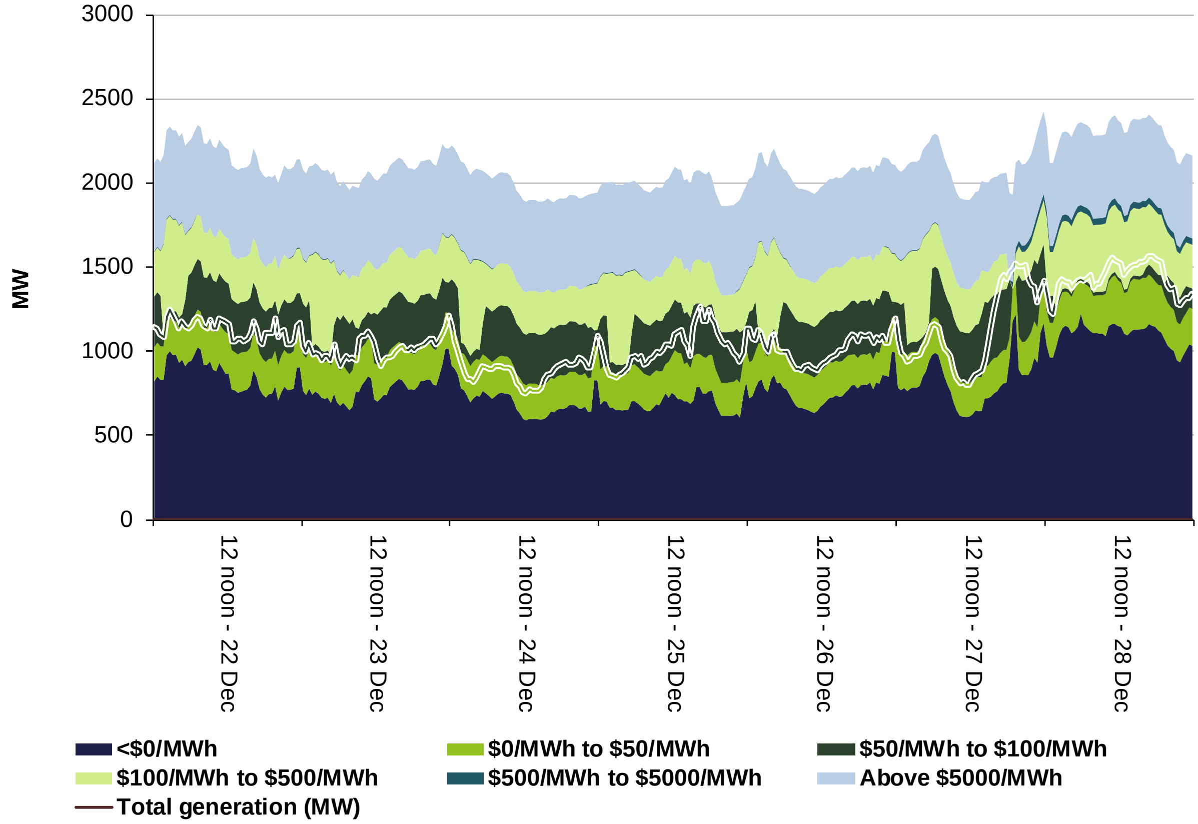
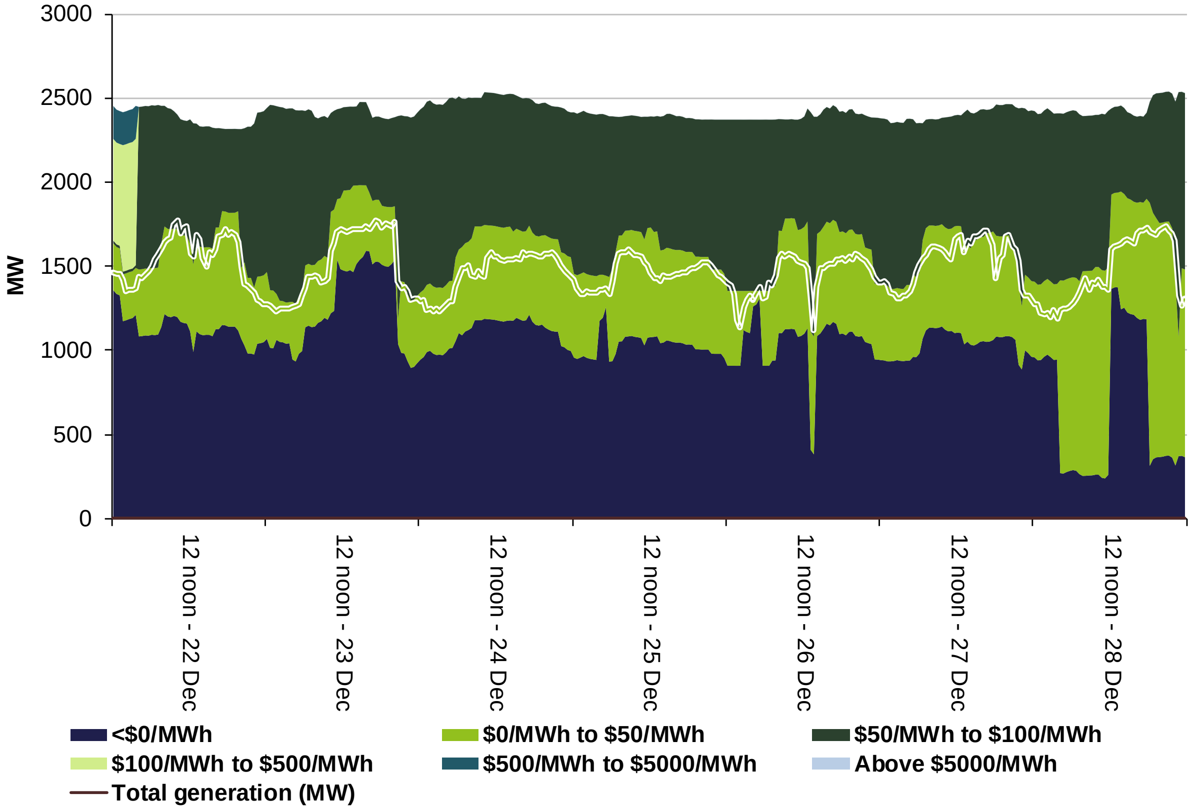


Figure 6: Tasmania generation and bidding patterns



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.

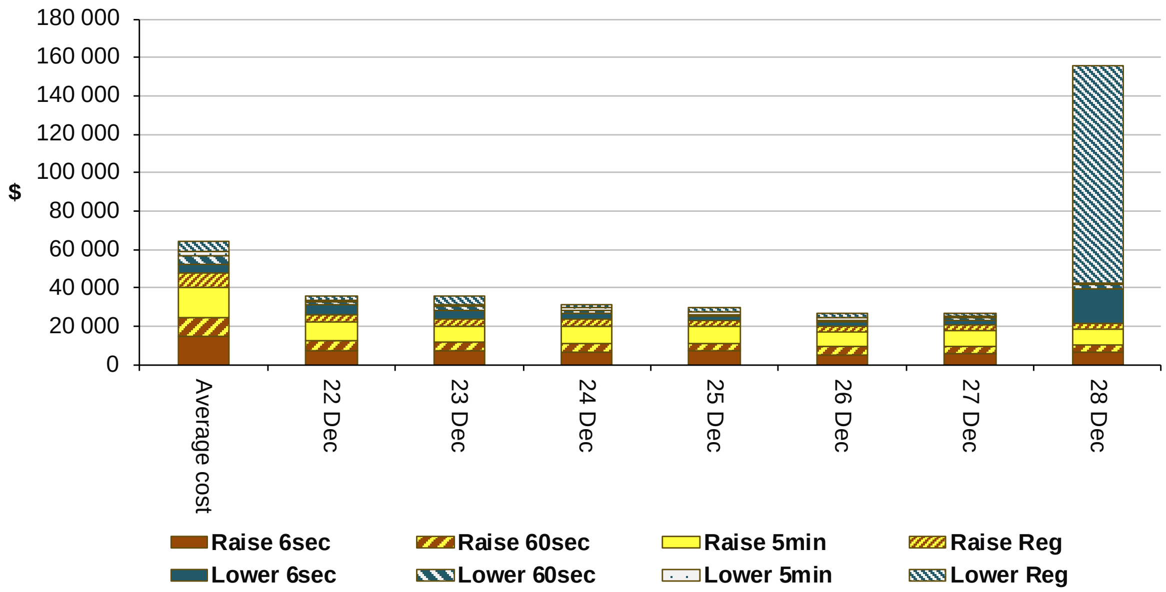
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $174 000 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 $167 500 or around 3 per cent of energy turnover in Tasmania. A majority of this ($113 000) occurred on 28 December in the lower regulation service. At around 6.15 pm Basslink Pty. Ltd. rebid the availability of Basslink from 594 MW to 571 MW. The reason given was “Scenerio 1”, which after correspondence with the participant means that Basslink was operating outside its envelope and needed to be reduced. This resulted in the target and the maximum availability of Basslink being the same at 6.35 pm and 6.40 pm. This means that there is no headroom on Basslink to transfer lower services from the mainland (they have to be sourced locally). The requirement for local lower regulation increased from 26 MW at 6.30 pm to 50 MW at 6.35 pm and 6.40 pm. With only 26 MW available at less than the price cap the price at 6.35 pm and 6.40 pm reached the price cap.

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 was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $60/MWh and above $250/MWh. There two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $52/MWh and $250/MWh.

Table 3: Queensland, Monday 23 December

7:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	392.81	56.89	60.00
Demand (MW)	6629	6655	6968
Available capacity (MW)	9396	9957	10 563

Conditions at the time saw demand close to that forecast and available capacity up to around 1200 MW lower than that forecast 12 hours ahead and 560 MW lower than that forecast four hours ahead.

With the Terranora interconnector still unavailable (on a planned outage since 8 August) and voltage collapse constraints from the loss of Kogan Creek limiting QNI to around 250 MW, there was reduced import capability into Queensland.

At 9.05 am Millmerran Energy Trader reduced the availability capacity of Millmerran from 870 MW to zero because of a station trip. All this capacity was priced at the price floor.

At 5.21 pm Callide Power Traders reduced the availability of Callide unit 4 by 240 MW (127 MW of which was priced at the price floor) and bid the unit inflexible at 166 MW. The reason given was "SFPT on mandatory barring schedule". Enquiries show that this was related to the mechanical balancing of the steam feed pump at the station.

At 6.59 pm, effective from 7.10 pm, CS Energy rebid 860 MW of capacity across its portfolio, the majority from prices below $160/MWh to above $12 700/MWh. The reason given was "Interconnector constraint-QNI binding in 30min Pd-SL".

At 7.07 pm, effective from 7.15 pm, Alinta Energy rebid 161 MW of available capacity at Braemar unit 3 from $430/MWh to above $11 500/MWh. The reason given was "Uneconomic start based on PD SL@19:07".

The rebids, combined with generators being ramp up limited at the time saw an increase in the five minute price from $160/MWh at 7.05 pm to $291/MWh at 7.10 pm and then to $1500/MWh at 7.15 pm. Prices returned to below $60/MWh at 7.25 pm following a number of Queensland generators rebidding of capacity from high prices to low prices, and a coincidental reduction in regional demand of 95 MW.

There was no other significant rebidding.

Table 4: South Australia, Friday 27 December

6:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	380.34	70.80	70.80
Demand (MW)	1660	1594	1602
Available capacity (MW)	2000	2031	2042
7 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	321.11	70.80	70.80
Demand (MW)	1716	1589	1572
Available capacity (MW)	2030	2028	2049

Actual demand at the time was 127 MW higher than that forecast four hours ahead and available capacity close to that forecast.

Imports into South Australia across Heywood were limited to around 200 MW by a system normal constraint managing flow across the Snuggery to Keith 132kV line. A dynamic line rating process that operates in response to temperature reduced the rating of the Snuggery to Keith 132kV line from 71 MW at 6.05 pm to 60 MW at 6.10 pm resulting in a step change in the right hand side of the constraint. This led to low priced generation being constrained-off and the five minute price reached $1208/MWh at 6.10 pm.

At 6.36 pm, effective from 6.45 pm, GDF Suez rebid 33 MW of capacity at Dry Creek unit 3 from the price floor to $589/MWh. The reason given was “constraint management V>>S_NIL_PWKN_SGKH”.

At 6.51 pm, effective from 7 pm, Alinta Energy rebid 25 MW of capacity at NPS1 from prices under $56/MWh to $10 330/MWh. The reason given was “1848A SA spot price higher than forecast $589 V $176@18:51”.

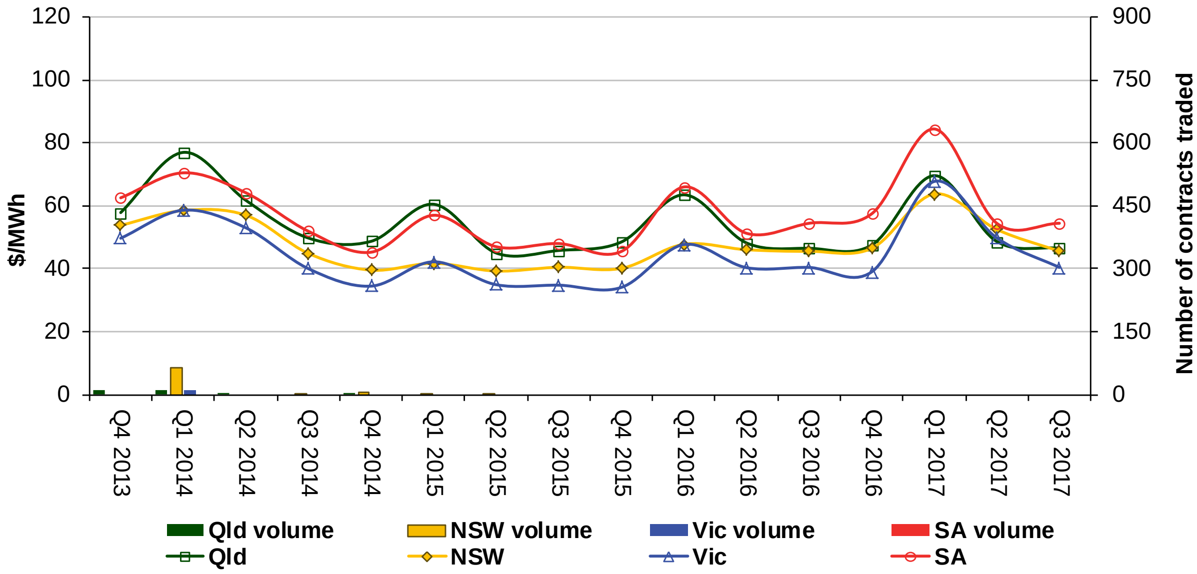
At 6.45 pm demand increased by 107 MW and the five minute price alternated between $292/MWh and $589/MWh (set by Dry Creek unit 3) for the rest of the trading interval.

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.

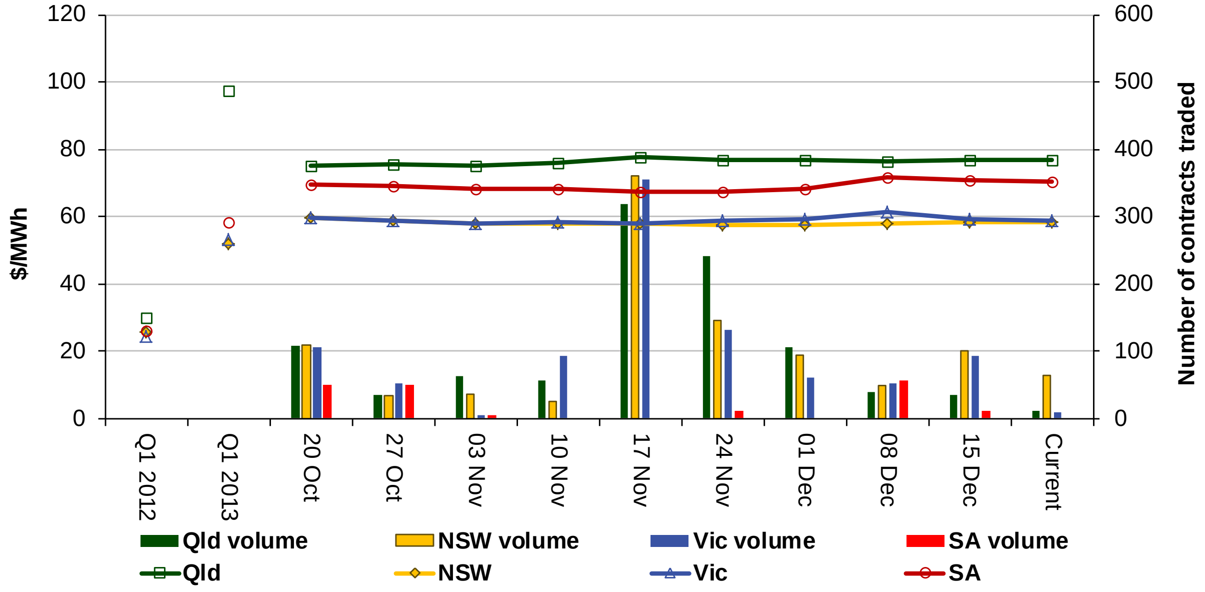
Figure 8: Quarterly base future prices Q4 2013 – Q3 2017



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)



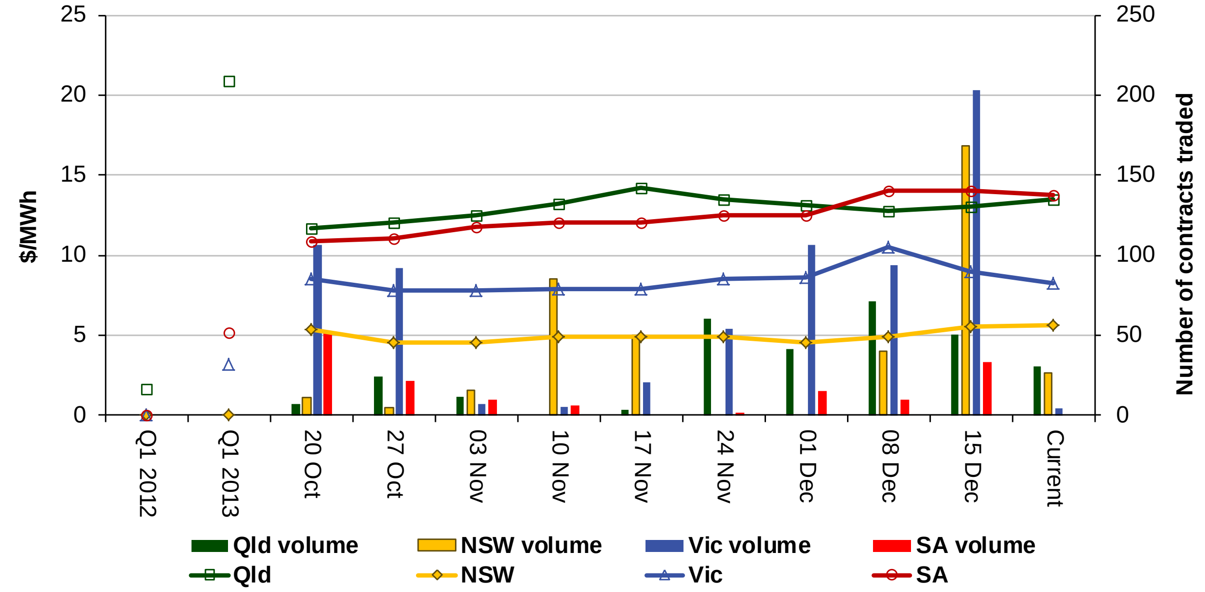
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

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

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January 2014