Electricity Report

22 to 28 September 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)

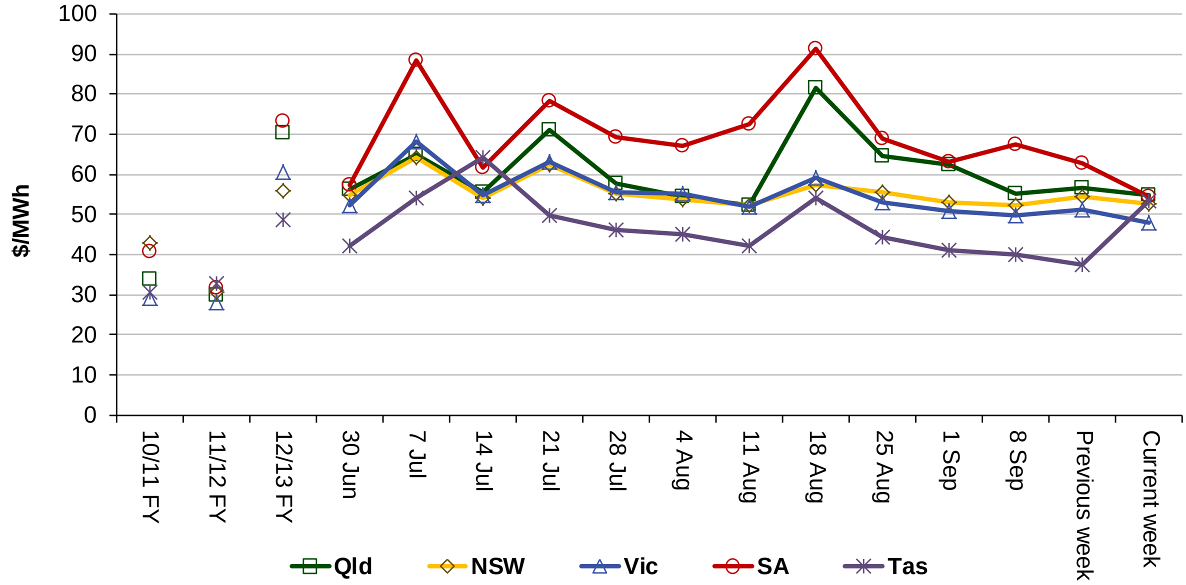


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	55	53	48	54	53
12-13 financial YTD	58	60	63	68	50
13-14 financial YTD	61	56	55	70	47

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 49 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	1	0	6	7
% of total below forecast	47	30	0	9

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

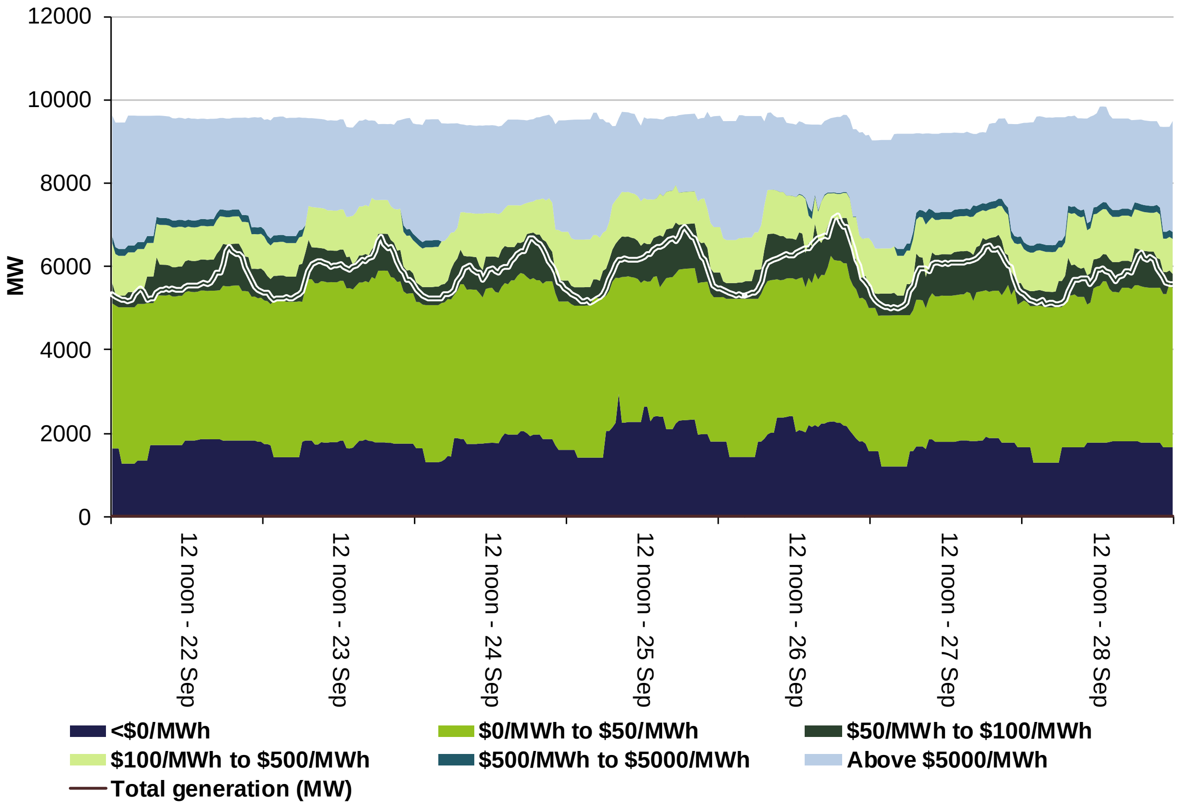


Figure 3: New South Wales generation and bidding patterns

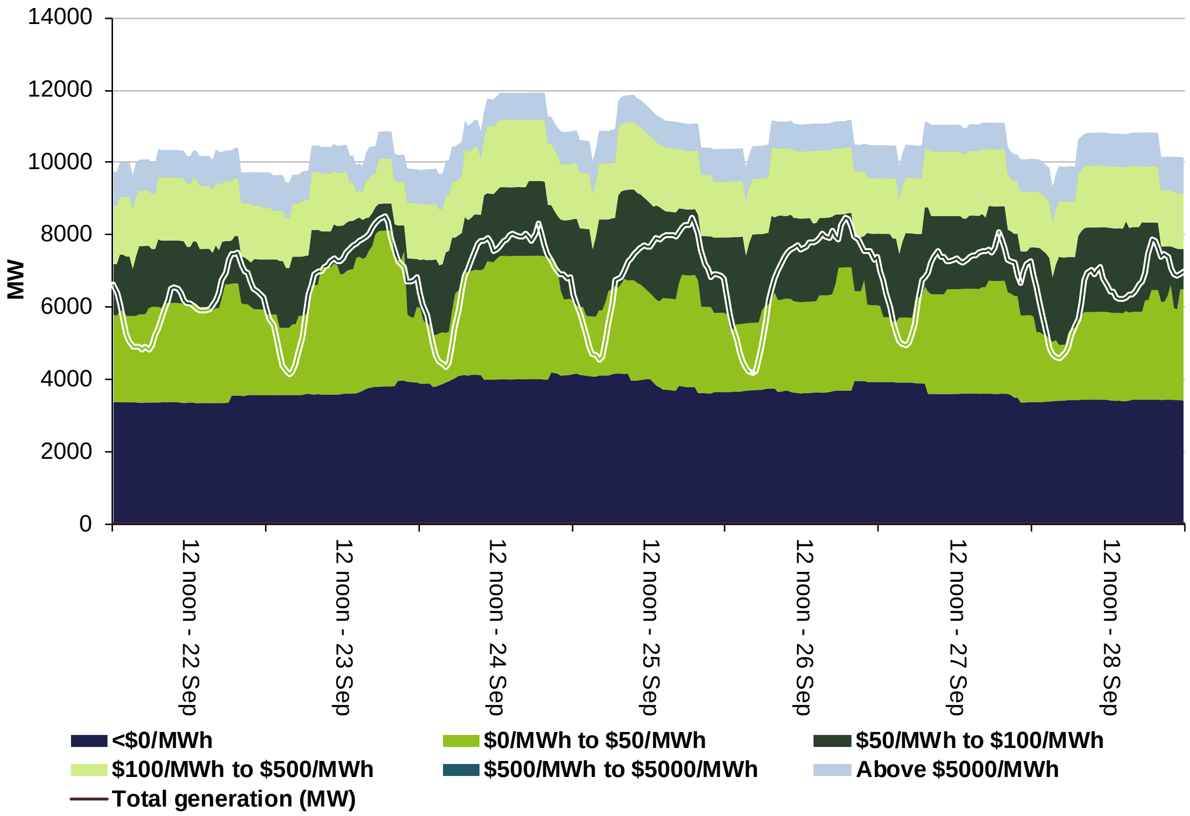


Figure 4: Victoria generation and bidding patterns

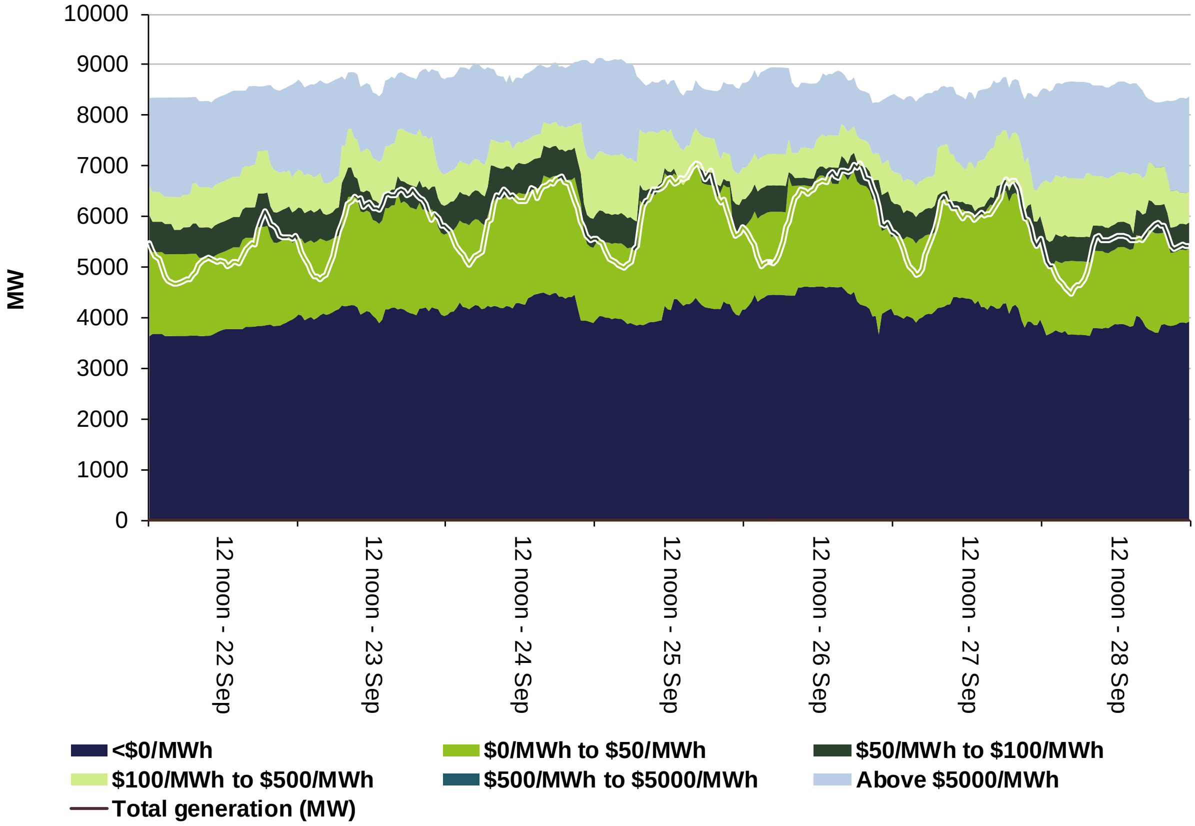


Figure 5: South Australia generation and bidding patterns

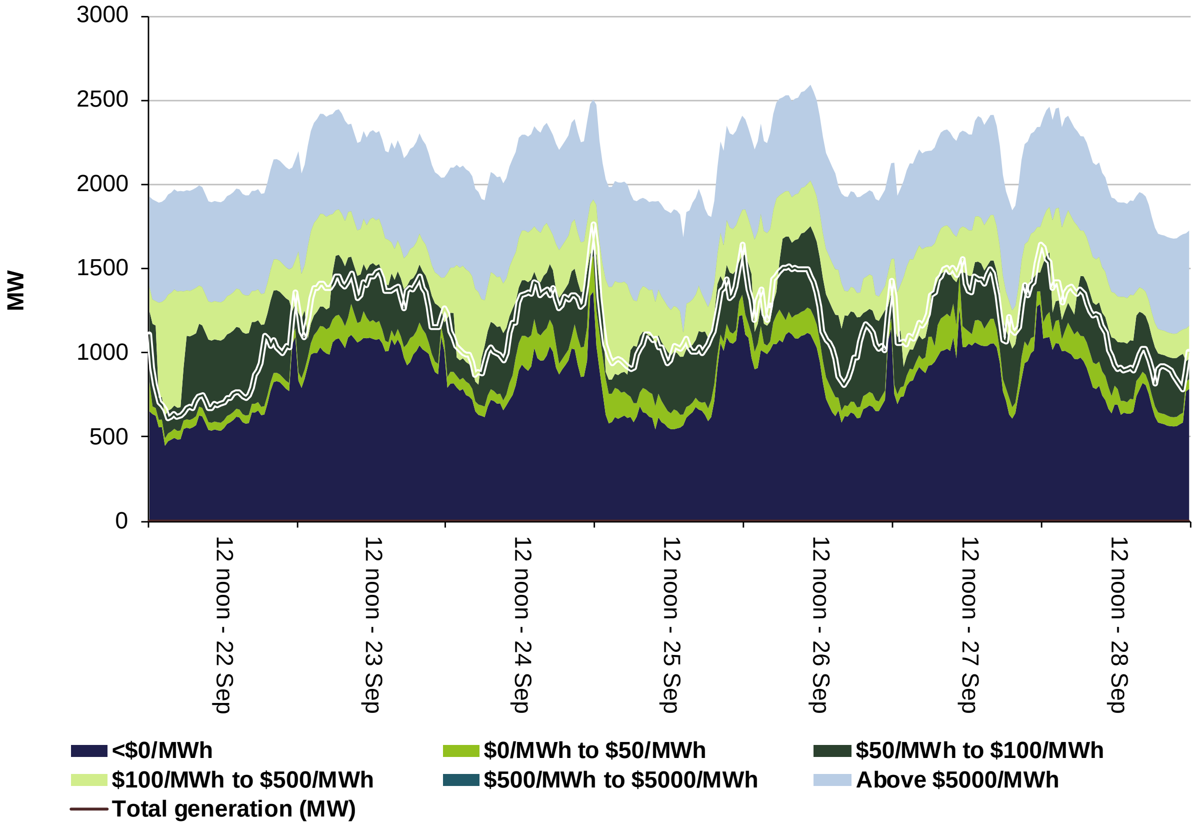
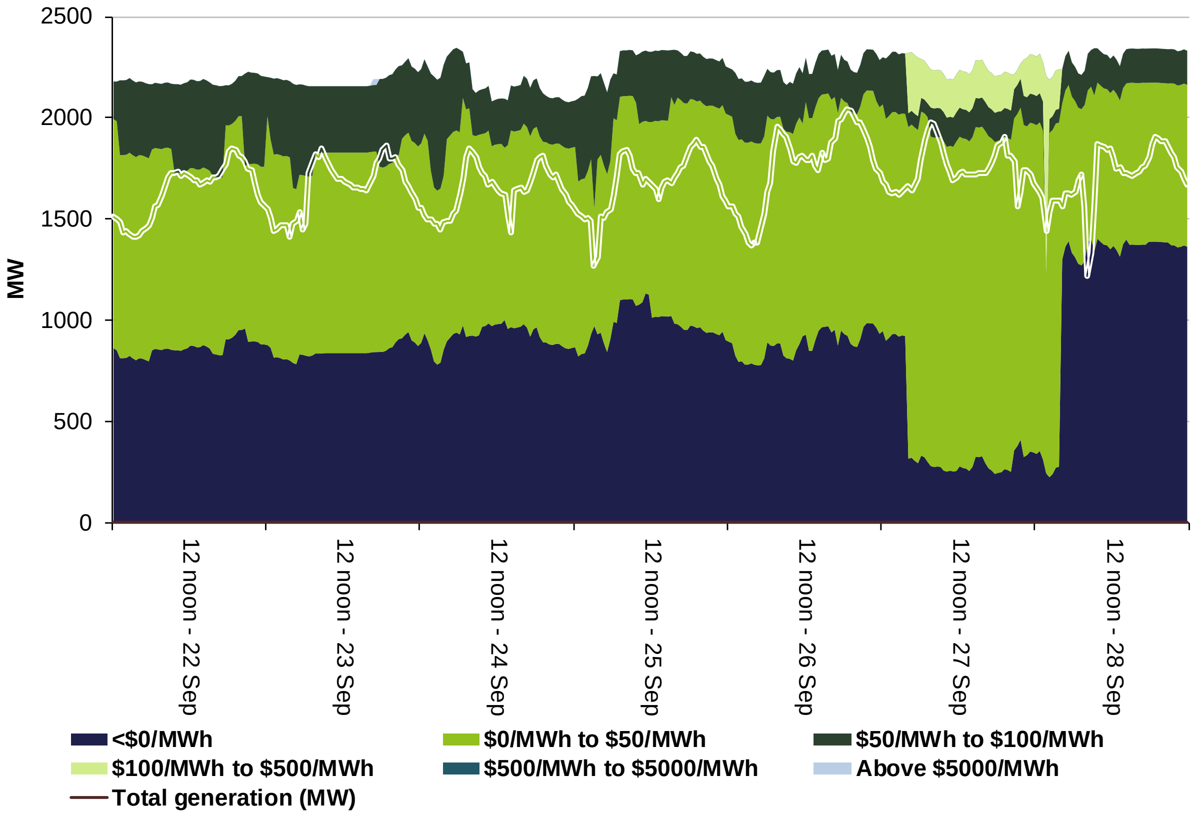


Figure 6: Tasmania generation and bidding patterns



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:

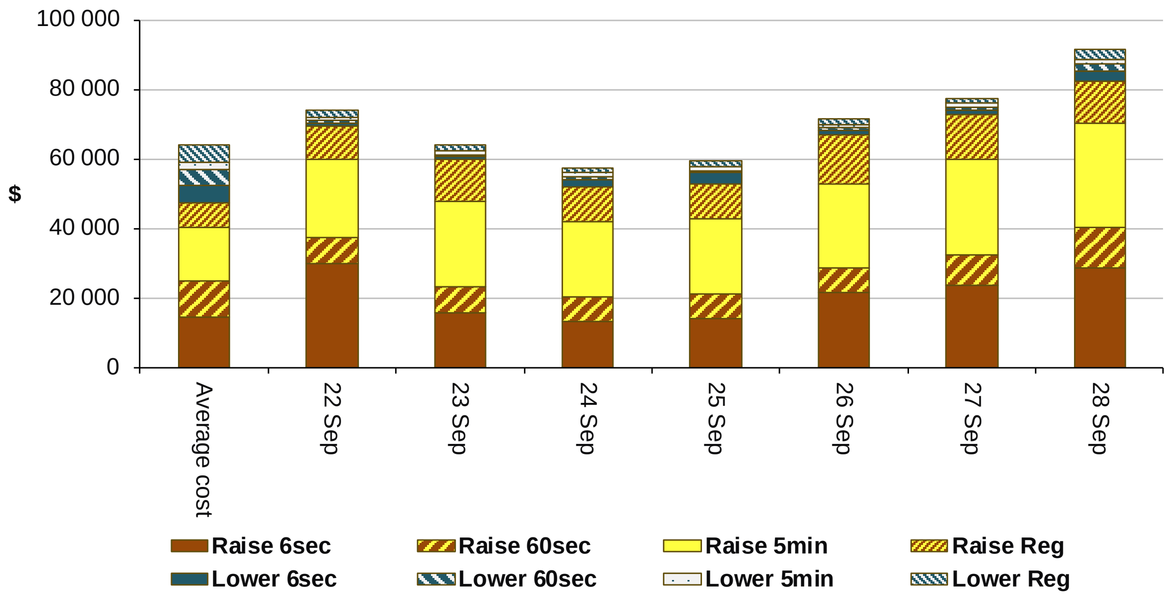
- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- *delayed services*, which return the frequency to the 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 $419 500 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 $76 000 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 two such occasions this week, where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $53/MWh and above $250/MWh.

Table 3: Tasmania, Friday 27 September 9 PM

9 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2521.89	39.32	39.32
Demand (MW)	1210	1219	1200
Available capacity (MW)	2216	2254	2246

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

At 8.45 pm, AEMO declared the simultaneous loss of the Sheffield to George Town 220 kV parallel lines as a credible contingency, due to lightning in the area, and a number of additional constraints were invoked. One of the constraints invoked affects all generation in Tasmania, with the exception of the Tamar Valley generation (Tamar Valley was offline at the time).

At the same time, simultaneous loss of the Farrell to Sheffield 220 kV lines was declared as a credible contingency in response to lighting in the Farrell area and constraints managing the raise FCAS requirement in the region were invoked.

From 8.45 pm to 8.50 pm the constraints invoked to manage the reclassification of the Sheffield to George Town lines reduced a number of the local generating units by around 250 MW and ramped up other generators. However, the changes were insufficient to meet the constraint requirements, causing two constraints to violate for the 8.50 pm and 8.55 pm dispatch intervals. The reduction in generation led to flows to Victoria on Basslink reducing from 456 MW down to 266 MW in one dispatch interval at 8.50 pm.

Consequently the five minute price increased to the cap at 8.50 pm and reduced to $1866/MWh at 8.55 pm before returning to below $50/MWh. At the same time, the reduction in flows to Victoria on Basslink resulted in an increase in the requirement for local raise FCAS. A number of constraints managing the second credible contingency violated for one dispatch interval at 8.50 pm, leading to the price for raise 6 second services increase to $969/MW at a cost of $2987.

Prices reduced to below $50/MWh when constraints ceased binding/violating following a 75 MW demand side response by NYRSTAR (smelter in Tasmania) from 8.50 pm.

There was no significant rebidding.

Table 4: Tasmania, Saturday 28 September

8 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2498.72	38.28	42.14
Demand (MW)	1066	1076	1046
Available capacity (MW)	2234	2246	2253

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

At 7.35 am, AEMO declared the simultaneous loss of the Sheffield to George Town 220 kV parallel lines as a credible contingency event, due to lightning in the area. The T-GTSH_N-2 constraint set was invoked to manage the event. Ten minutes later, at 7.45 am, the George Town to Hadspen 220 kV lines and the George Town to Palmerston 220 kV lines were also reclassified as credible contingencies due to lighting. One of the constraints invoked to manage the George Town to Hadspen line affects all generation in Tasmania (with the exception of Tamar Valley generation, which was offline at the time).

At 7.45 am, a system normal constraint managing the load on one of the George Town to Hadspen lines (in the event of a trip on the parallel line) violated when the generation requirements were unable to be met, seeing a number of generators trapped or stranded in FCAS.

From 7.35 am to 7.45 am the constraints invoked to manage the reclassification of the Sheffield to George Town lines reduced a number of the local generating units by around 256 MW and ramped up other generators. The reduction in generation led to flows to Victoria on Basslink reducing from 450 MW down at 7.35 am to 236 MW at 7.45 pm.

The Tasmanian dispatch price reached $1655/MWh at 7.45 am before increasing to the cap for the following trading interval, resulting in a $2499/MWh spot price.

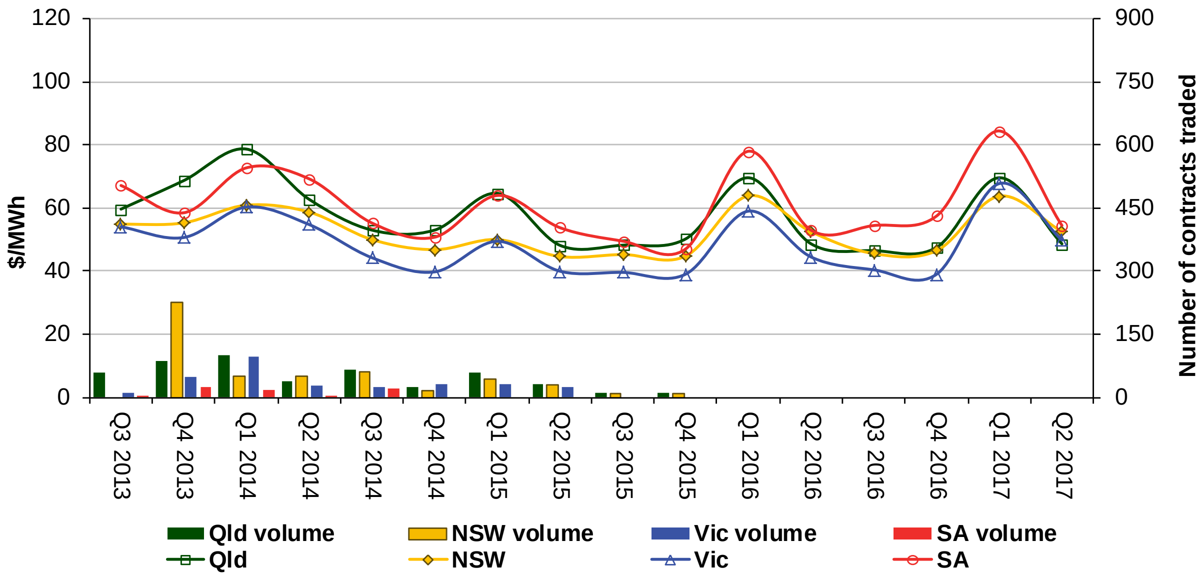
Prices returned to normal when constraints ceased violating at 7.55 am, after an 83 MW demand side response by NYRSTAR (smelter in Tasmania) from 8 am.

There was no 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.

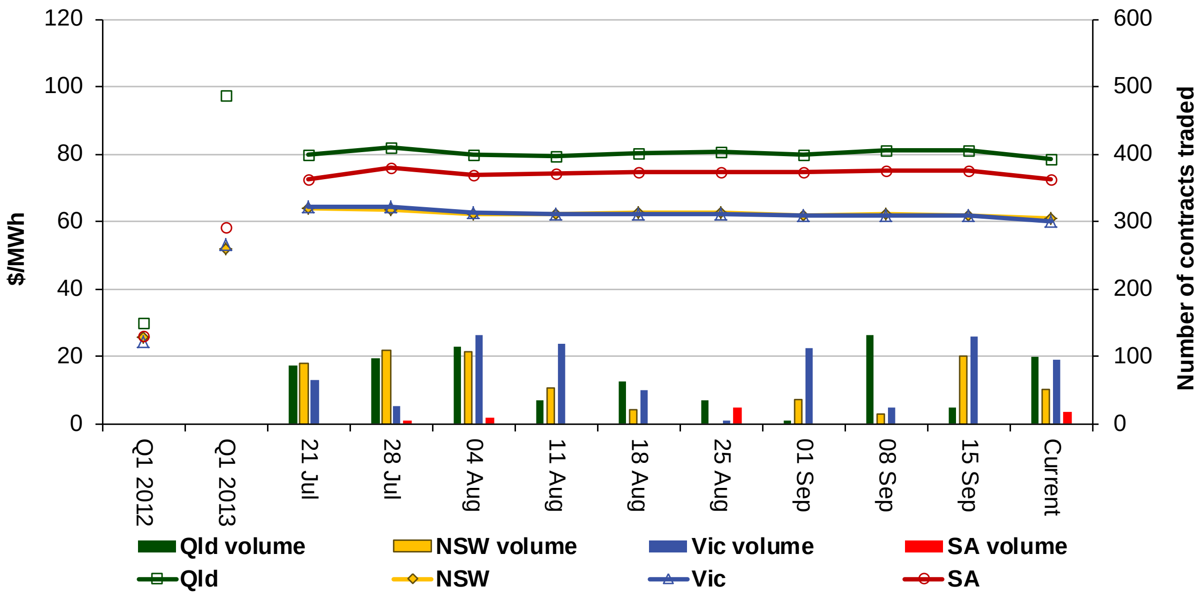
Figure 8: Quarterly base future prices Q3 2013 – Q2 2017



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

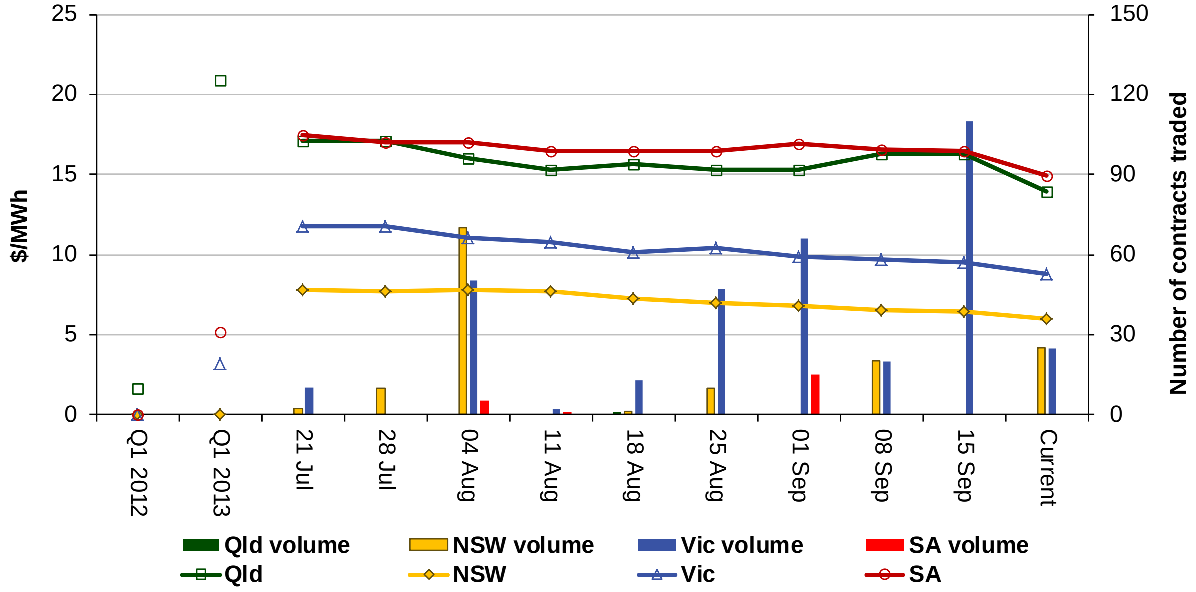
Source: ASXEnergy.com.au

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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