Electricity Report

AUSTRALIAN ENERGY REGULATOR

25 – 31 October 2015

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 25 to 31 October 2015. There were two occasions where the spot price exceeded the AER reporting threshold, both in Tasmania.

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

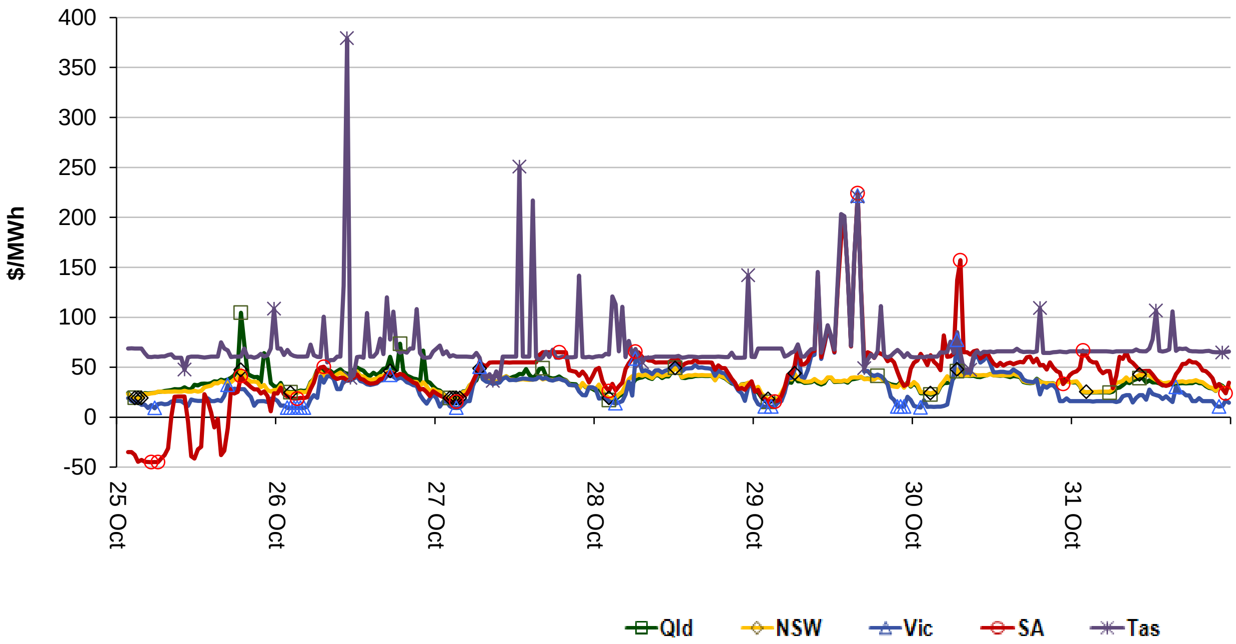


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

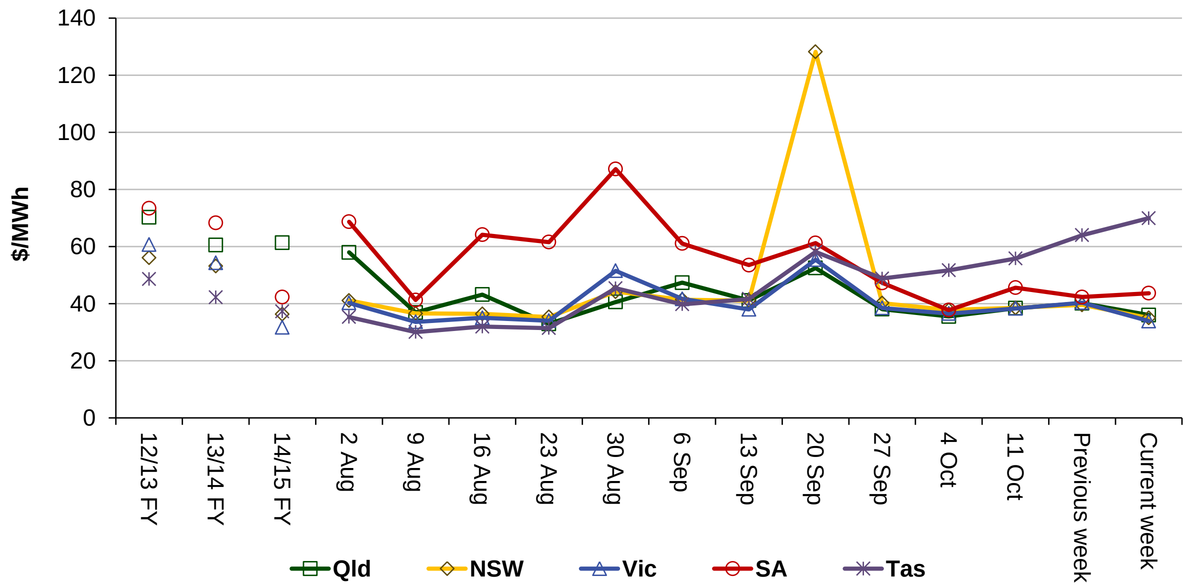


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	36	35	34	44	70
14-15 financial YTD	30	38	35	44	36
15-16 financial YTD	43	44	39	63	43

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 273 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	7	17	0	1
% of total below forecast	72	2	0	1

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. Figure 3 to

Figure 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

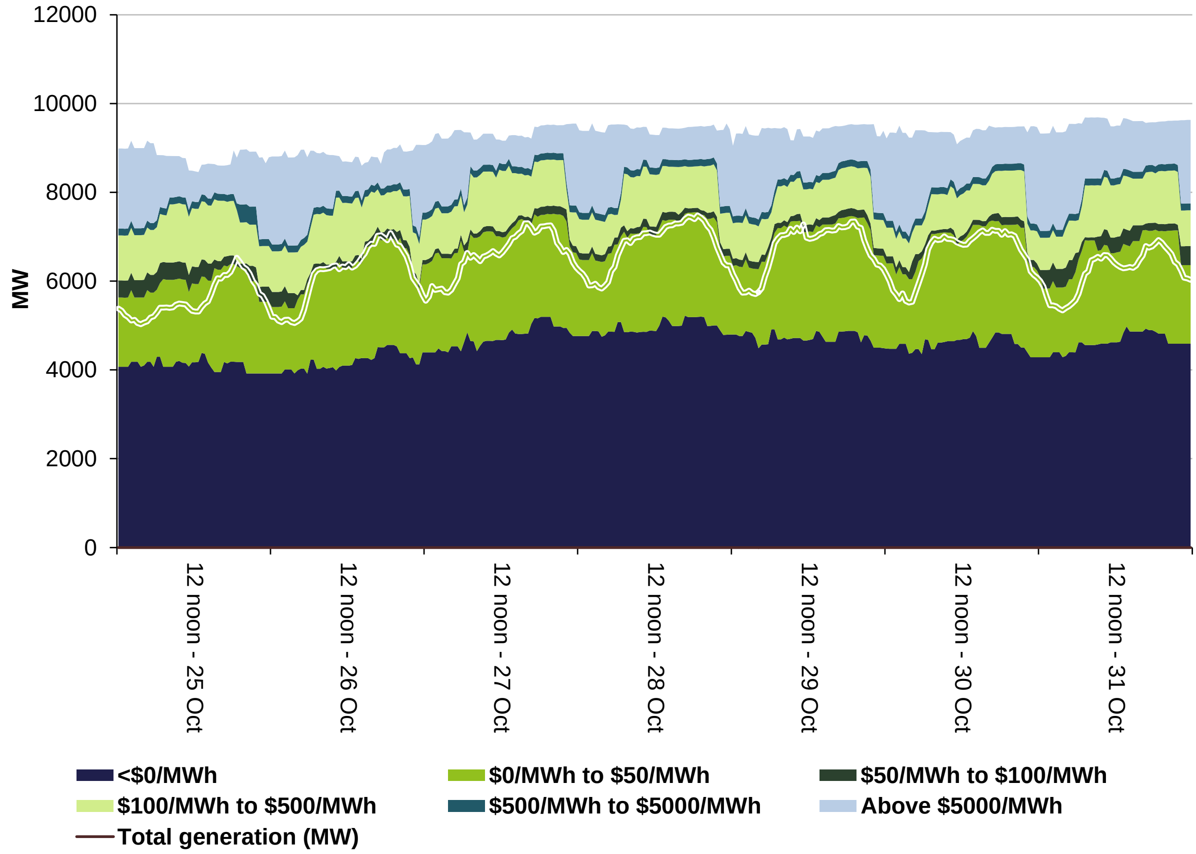


Figure 4: New South Wales generation and bidding patterns

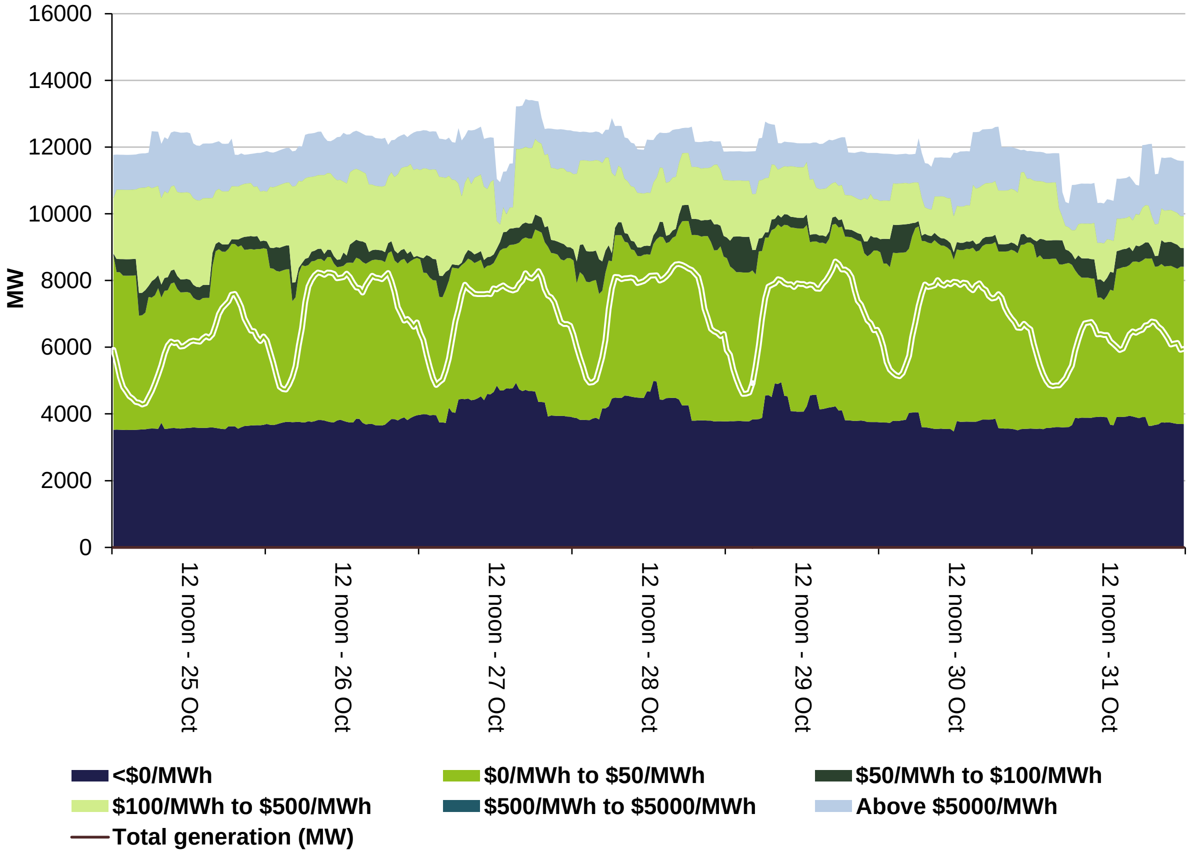


Figure 5: Victoria generation and bidding patterns

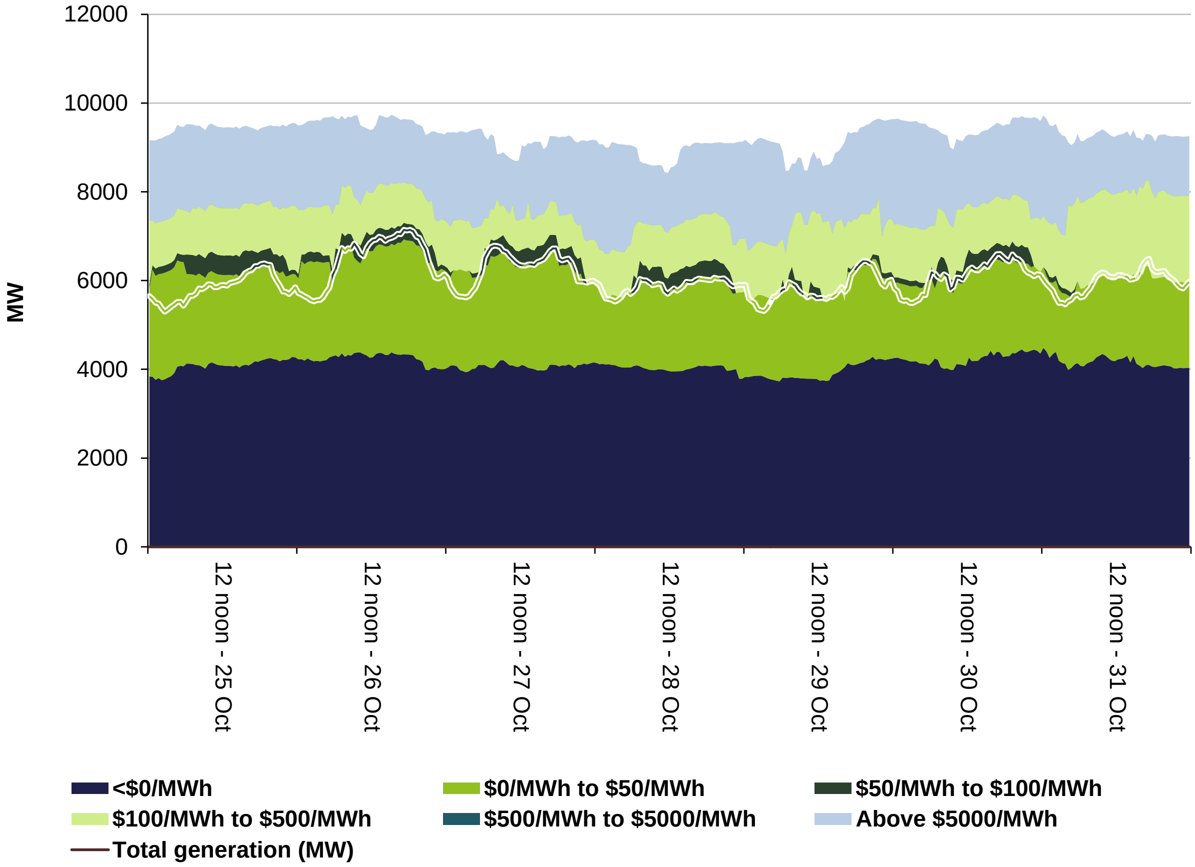


Figure 6: South Australia generation and bidding patterns

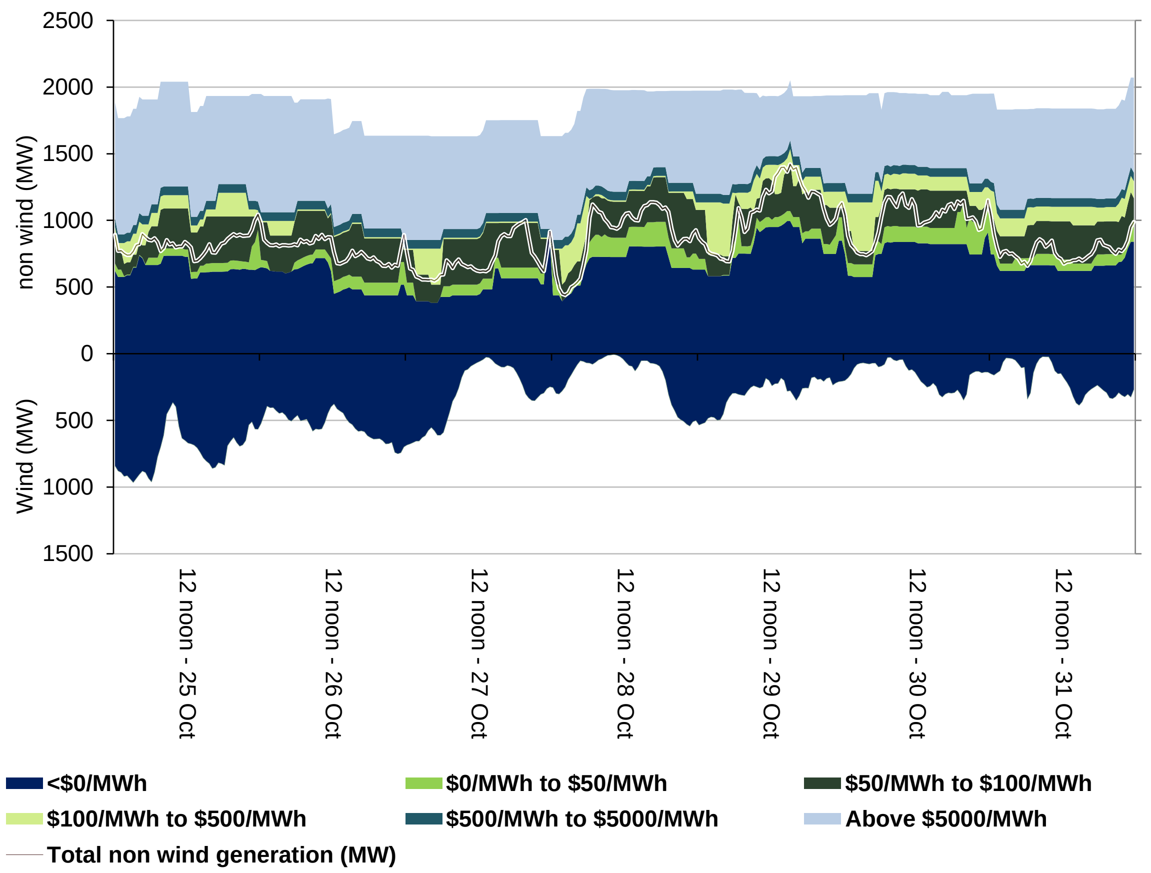
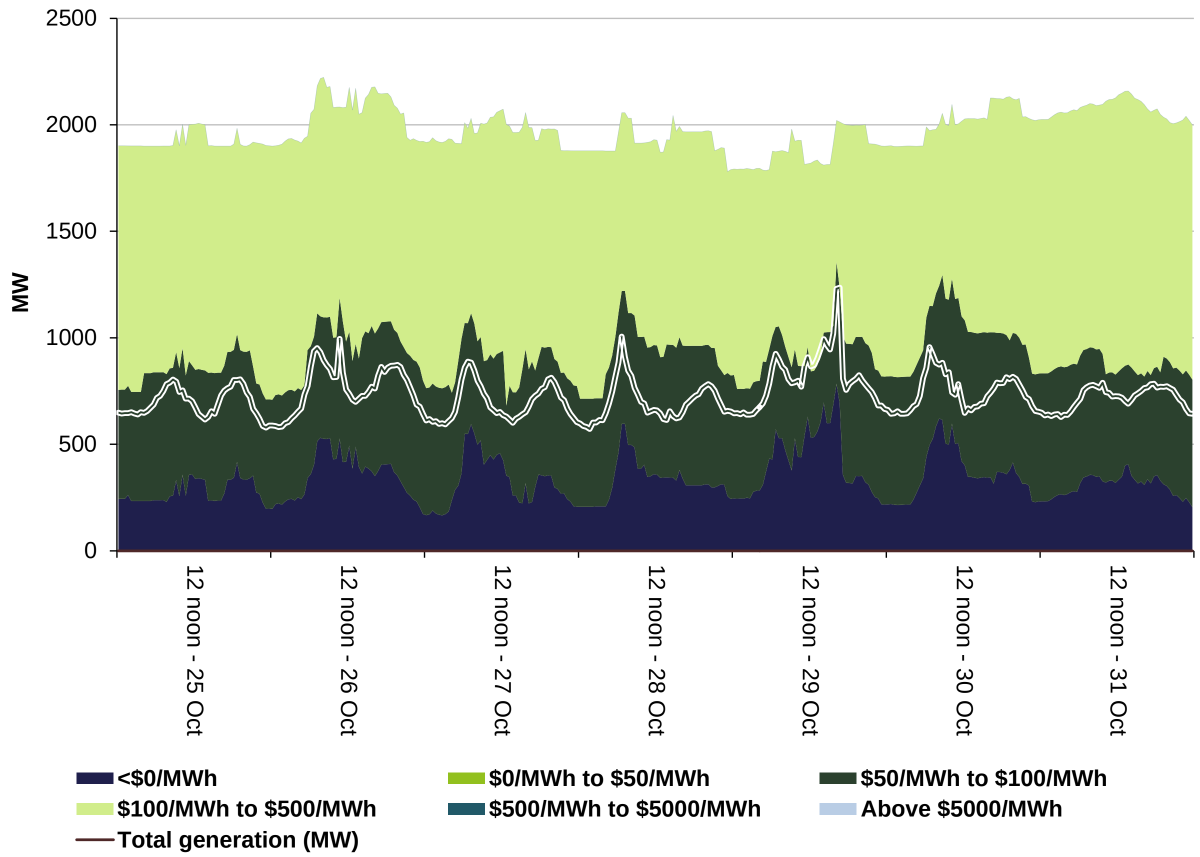


Figure 7: Tasmania generation and bidding patterns



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.

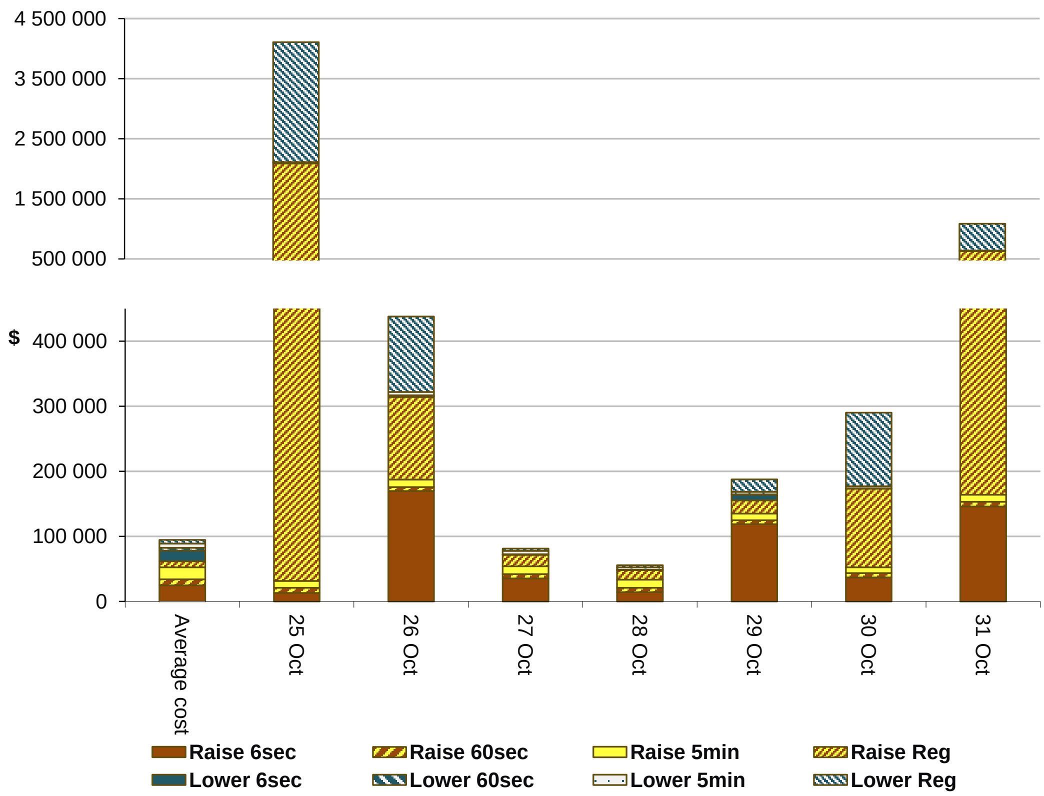
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $5 679 500 or around 5 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $569 500 or around 4.5 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



The 35 MW requirement for local raise and lower regulation services in South Australia, that was imposed for the duration of network outages needed for the Heywood upgrade commencing 11 October, continued this week.

The price for regulation services exceeded $5000/MW for a significant period on 25 October resulting in a breach of the Cumulative Price Threshold for both lower and raise regulation services. Consequently AEMO issued an administered price declaration notice and the price for these services was capped at $300/MW.

As required under clause 3.8.17 of the National Electricity Rules, the AER will publish a separate report into the events on that day.

The completion of a network outage Monday 26 October removed the 35 MW requirement for regulation services in South Australia until the next outage commenced on the morning of 29 October. Price administration continued until the 27 October when prices were again unconstrained.

From 4 am on 31 October, regulation service prices in the region increased to just over $600/MW with occasional prices around $1400/MW.

The total cost for regulation services in South Australia for the week was around $5.5million.

In Tasmania, significant costs accrued for raise 6 second services over a number of days, $162 468 on Monday 26 October, $112 849 on Thursday 29 October and $138 241 on Saturday 31 October. These costs arose due to high prices which occurred as a result of the interaction between the energy and FCAS markets, when a system normal constraint was either binding or violated.

The constraint manages the raise 6 second FCAS requirement in Tasmania for the loss of a Smithton to Woolnorth 110 kV line, or Norwood to Scotsdale to Derby 110 kV lines. While the constraint was binding or violating Basslink was unable to transfer FCAS and the region had to source the service locally.

On 26 October, increased raise 6 second requirements saw prices spike to $4684/MW at 10.35 am, $1331/MW at 5 pm and $4702/MW at 6 pm. On 29 October, prices spiked to $4341/MW four times from 2.55 am. On 31 October, prices were set at $1341/MW, $1329/MW and $1341/MW for three consecutive dispatch intervals from 1 pm.

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 occasions in Tasmania that exceeded this threshold.

Tasmania

Monday, 26 October

Table 3: 11 am Price, Demand and Availability

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 am	378.97	60.63	59.52	1059	1036	1074	2084	2065	2177

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

At 10.35 am, the price of the raise 6 second ancillary service increased to $4684/MW following the violation of a constraint managing the service requirement. At the same time, the energy dispatch price rose to $2030/MWh as a result of the interaction of the FCAS and Energy markets (described in the previous section), before falling to $69/MWh at 10.40 am.

Tuesday, 27 October

Table 4: 1 pm Price, Demand and Availability

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 pm	250.56	81.30	98.20	1027	1037	1080	2013	1953	1950

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

Table 5: Rebids the 1 pm trading interval

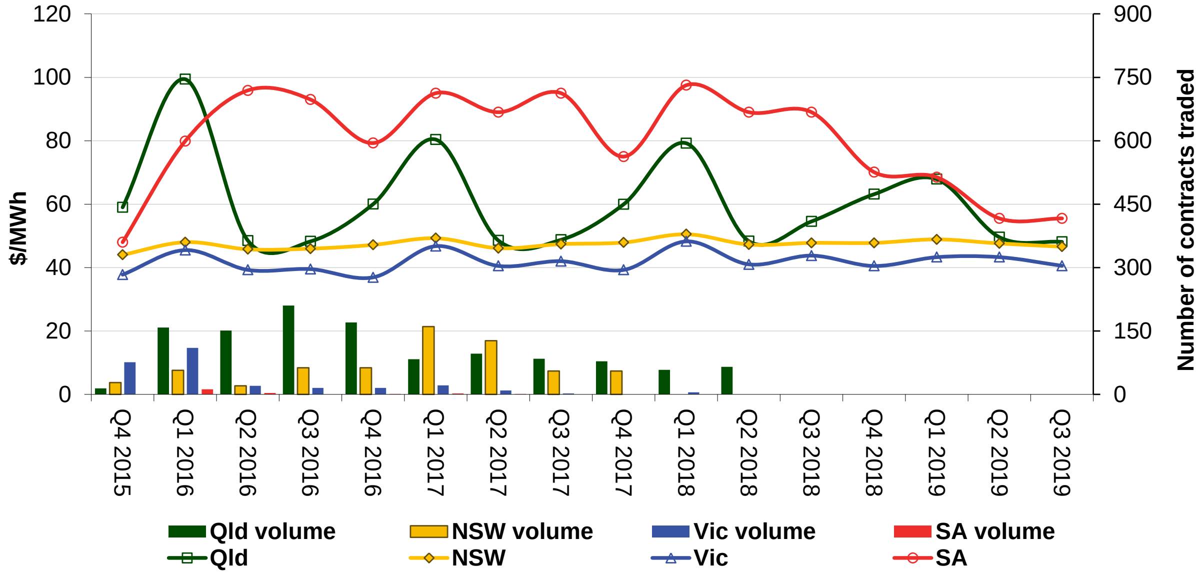
Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
12.30 pm	12.40 pm	Hydro Tasmania	Cethena	70	-1	N/A	1230P CHANGE IN OUTAGE SCHEDULE : CETHANA
12.43 pm	12.50 pm	Hydro Tasmania	Gordon	188	61	306	1230A DEMAND LOWER THAN FORECAST: TAS+ENV CNST

The 12.50 pm the dispatch price increased to $306/MWh following a rebid by Hydro Tasmania. The dispatch price then rose to $709/MWh at 12.55 pm, as a result of the interaction of Energy and FCAS markets, before falling to $306/MWh at 1 pm.

Financial markets

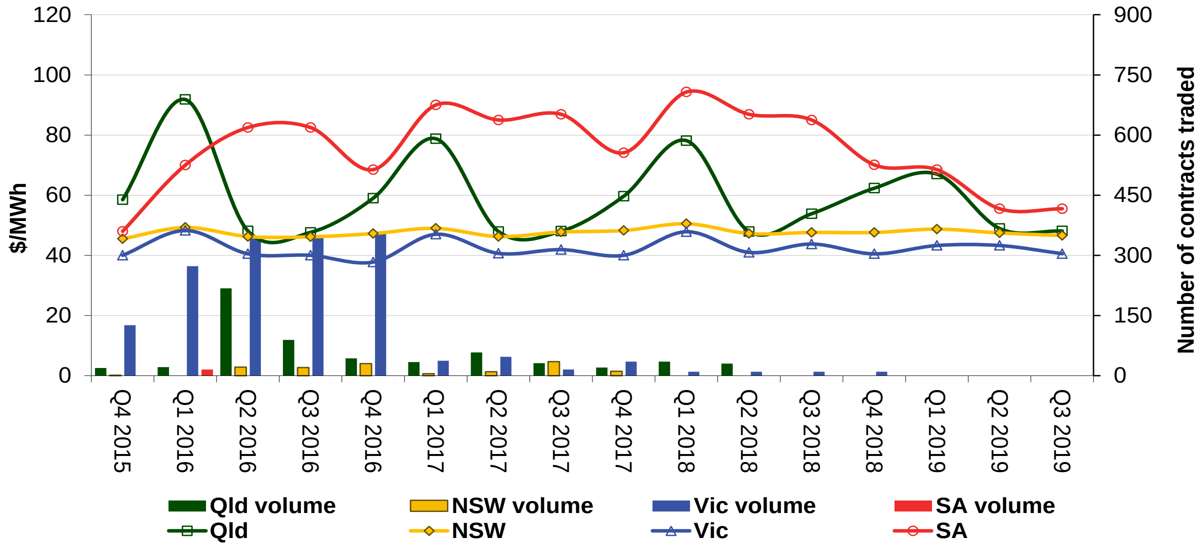
Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years. Figure 10 shows the quarterly base contract prices for the preceding week (18 - 24 October). The increase in contract prices out to Q4 2016 is quite dramatic, increasing in most cases between \$10/MWh and \$15/MWh on the back of a small number of trades. These graphs highlight the relative paucity of trade in contracts in South Australia to that of the other NEM states.

Figure 9: Quarterly base future prices Q4 2015 – Q3 2019 (current week)



Source. ASXEnergy.com.au

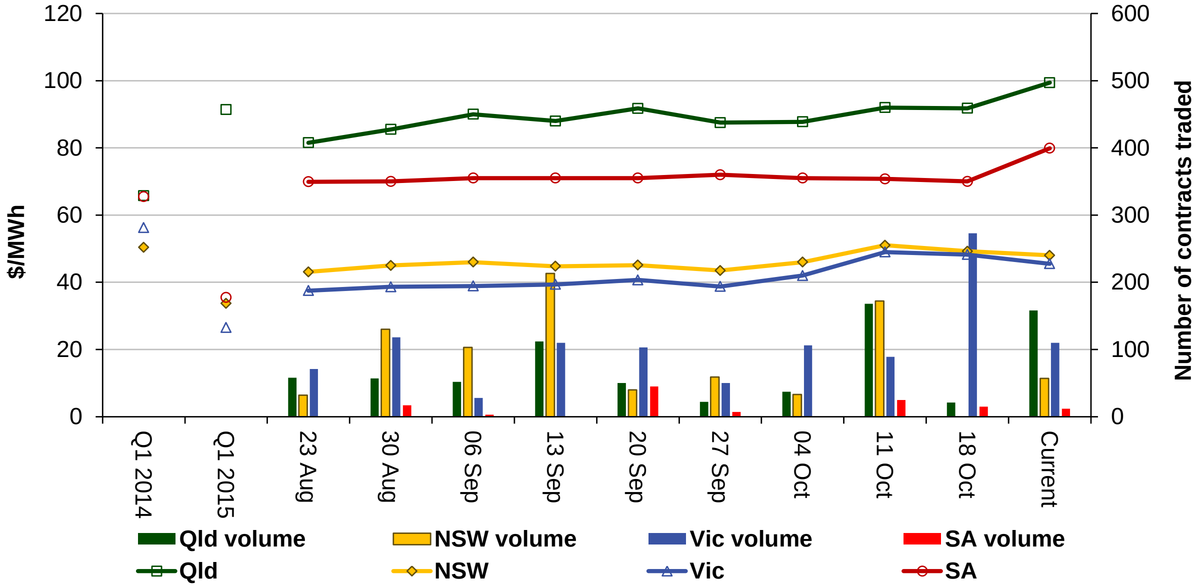
Figure 10: Quarterly base future prices Q4 2015 – Q3 2019 (18 - 24 October)



Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades but this week there were trades in South Australian contracts and the increase in price over previous weeks is clearly evident.

Figure 11: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



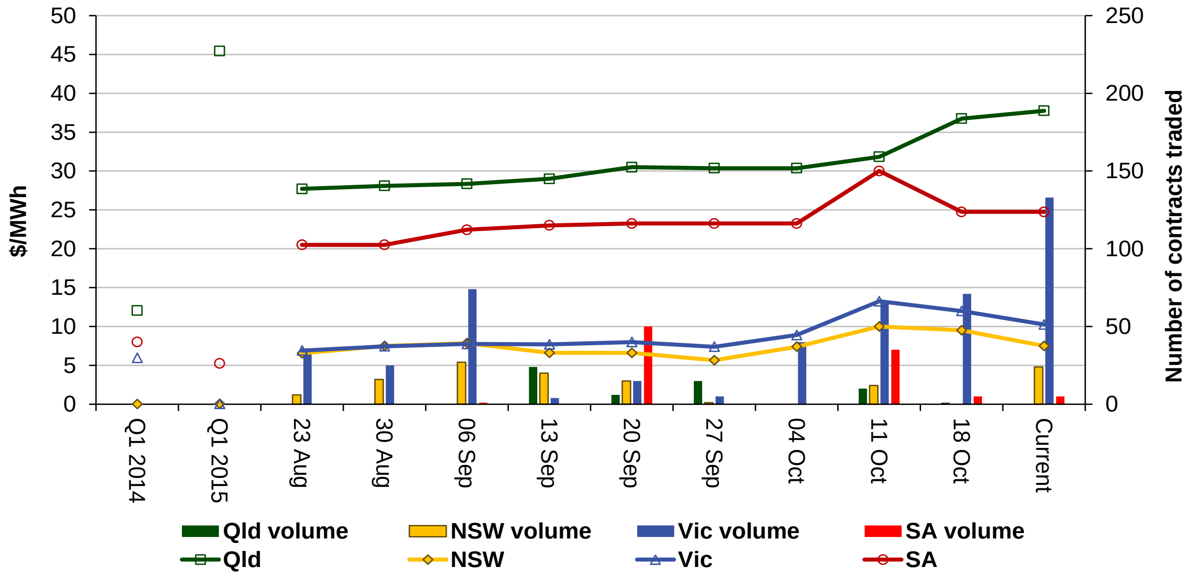
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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 12 shows how the price for each regional Quarter 1 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 12: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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