

6 – 12 September 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 6 to 12 September 2015. There were two occasions in South Australia where the spot price exceeded the AER reporting threshold. These are discussed later in this report.

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

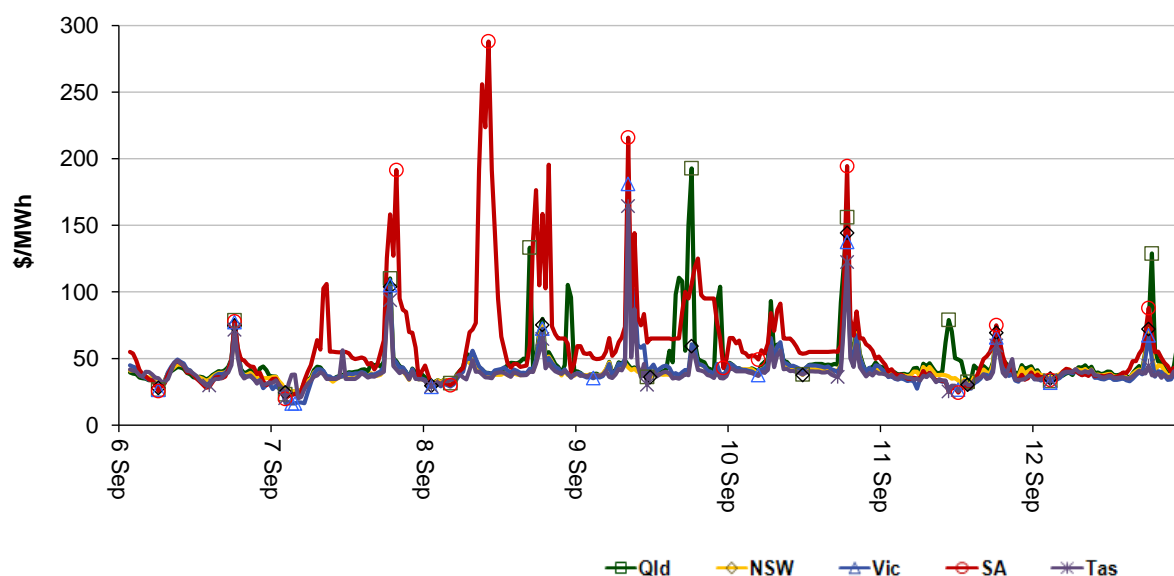


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

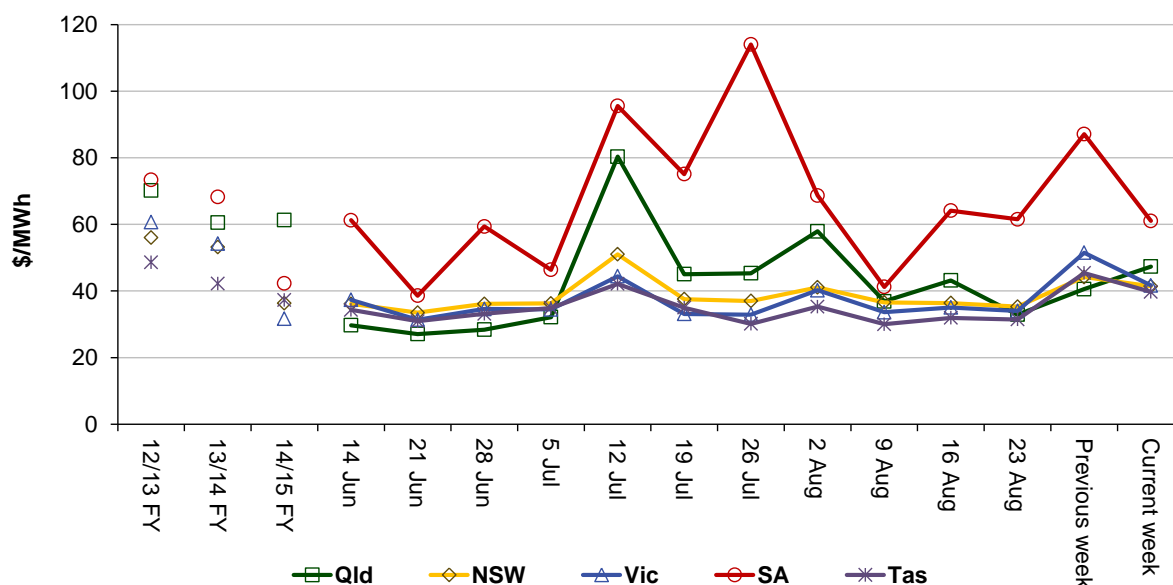


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	47	41	42	61	40
14-15 financial YTD	32	41	38	50	37
15-16 financial YTD	45	40	38	72	35

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 120 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	9	39	0	5
% of total below forecast	25	16	0	6

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

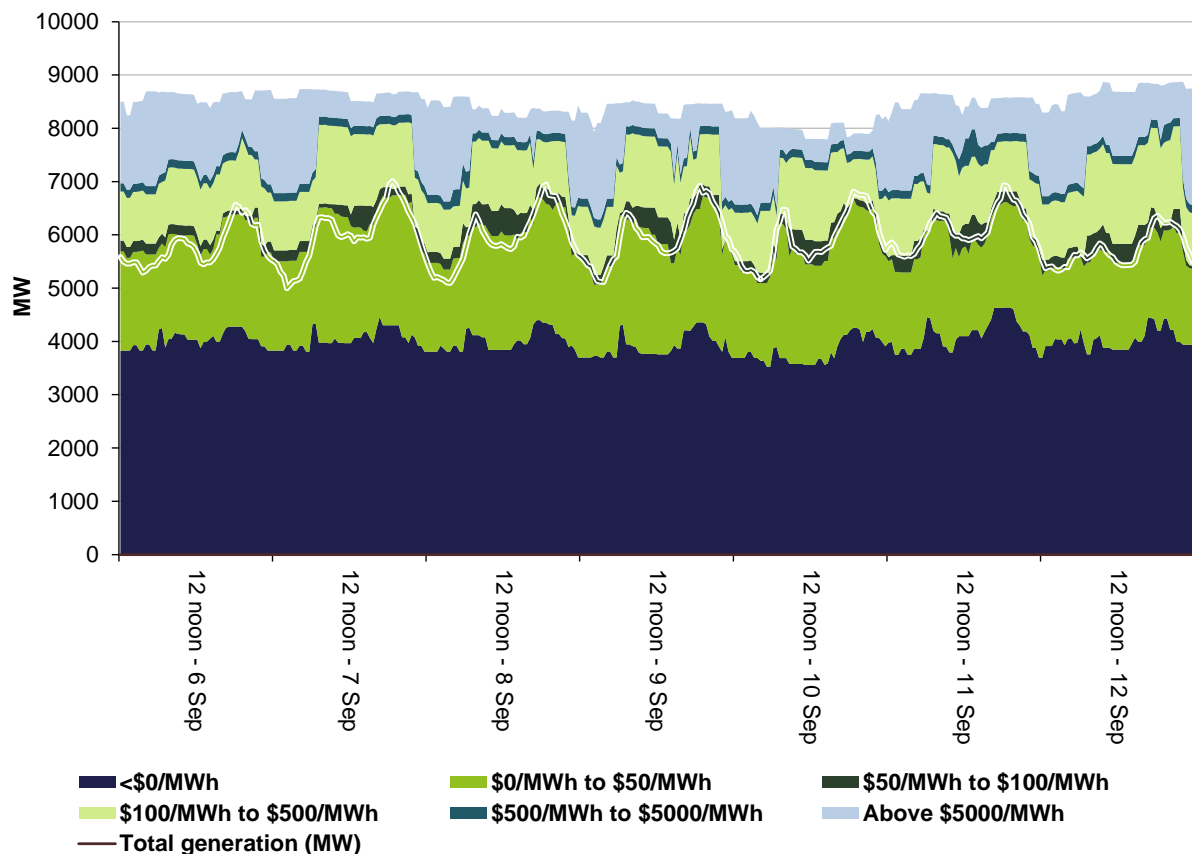


Figure 4: New South Wales generation and bidding patterns

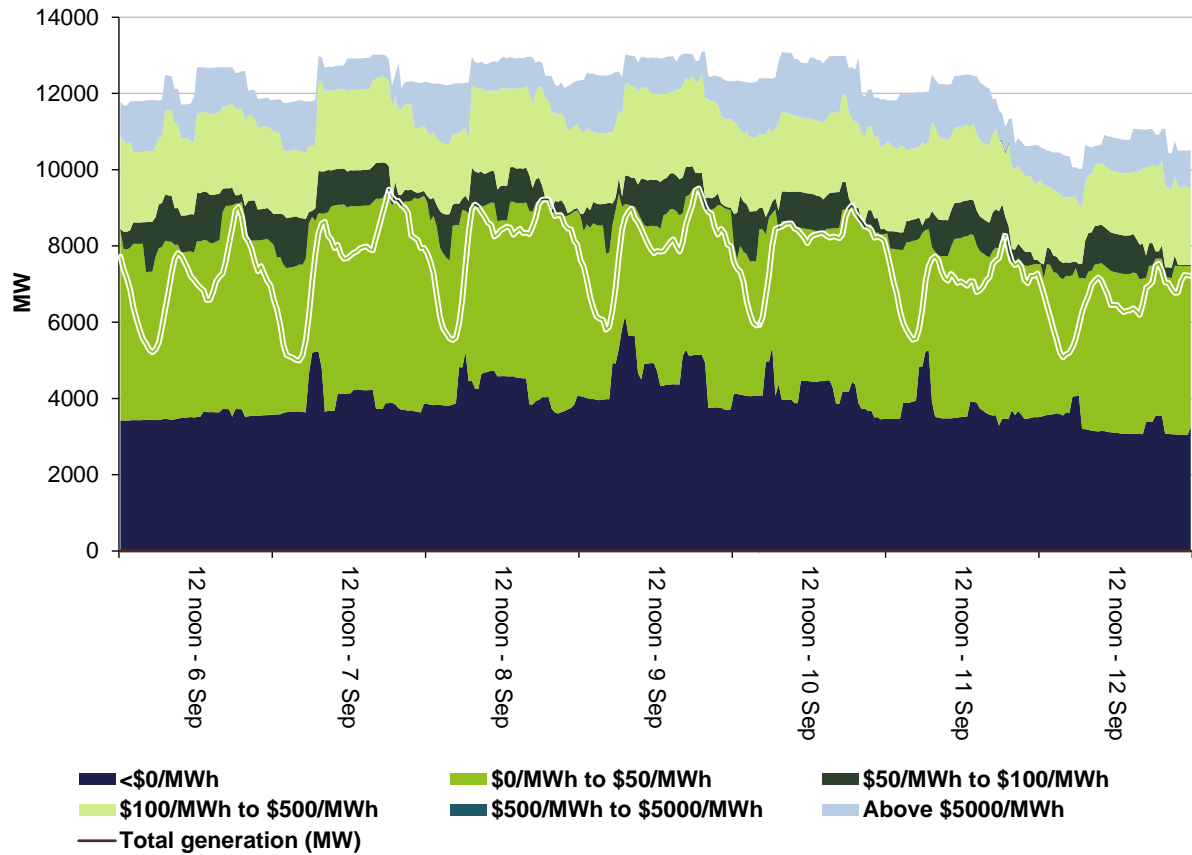


Figure 5: Victoria generation and bidding patterns

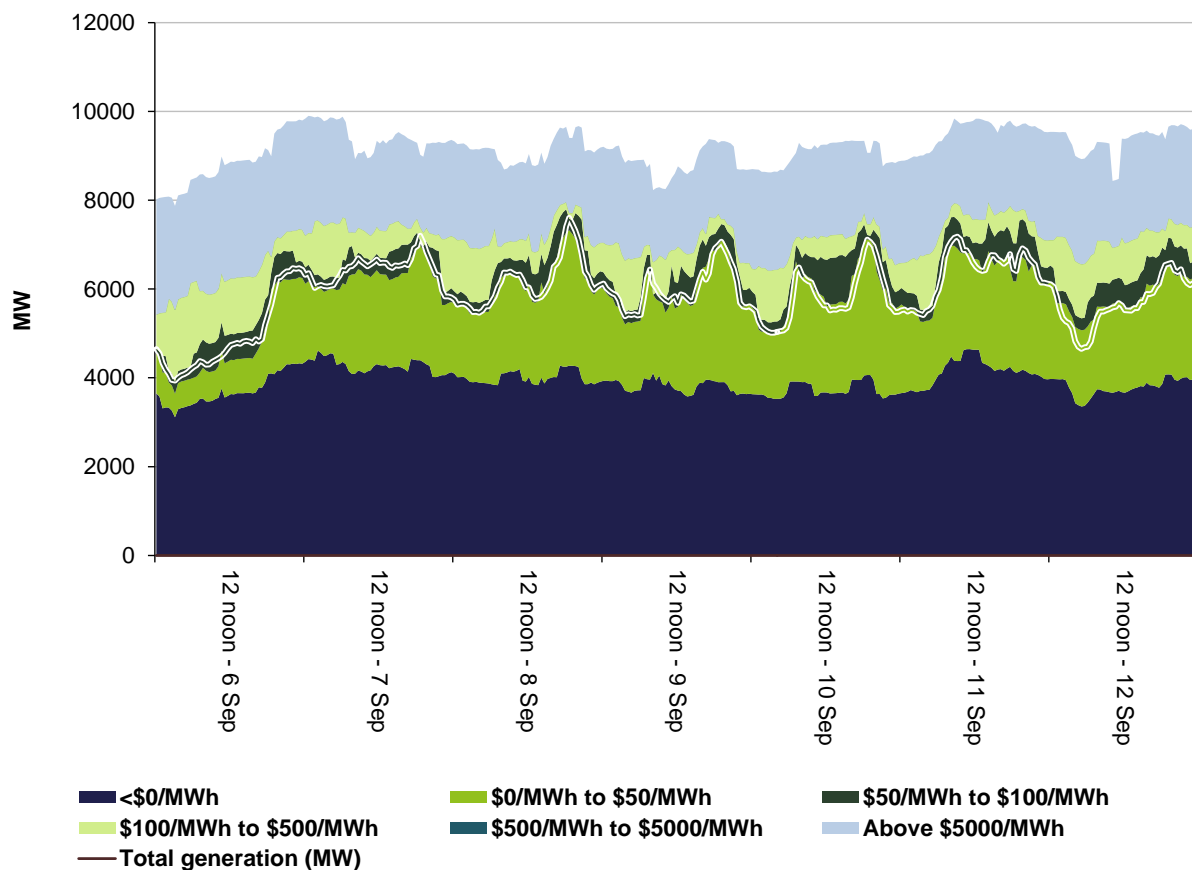


Figure 6: South Australia generation and bidding patterns

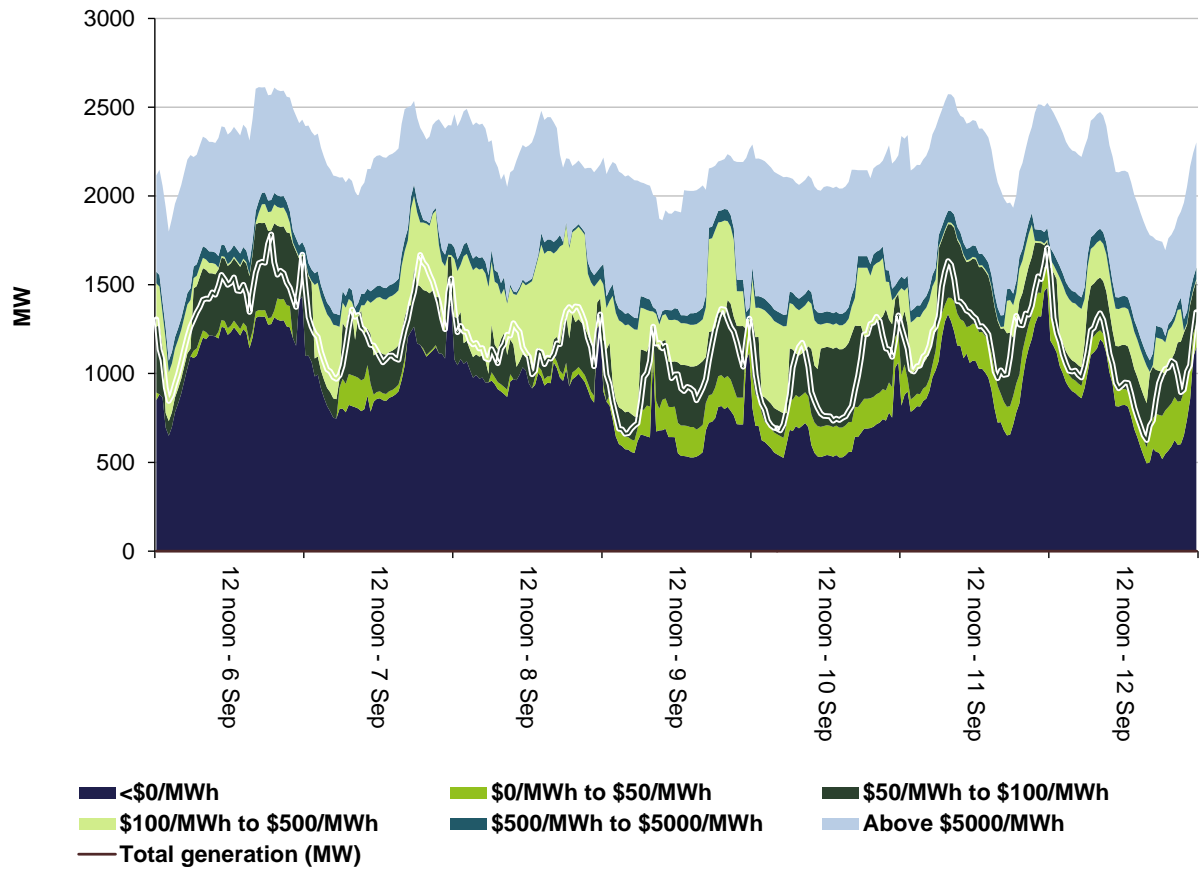
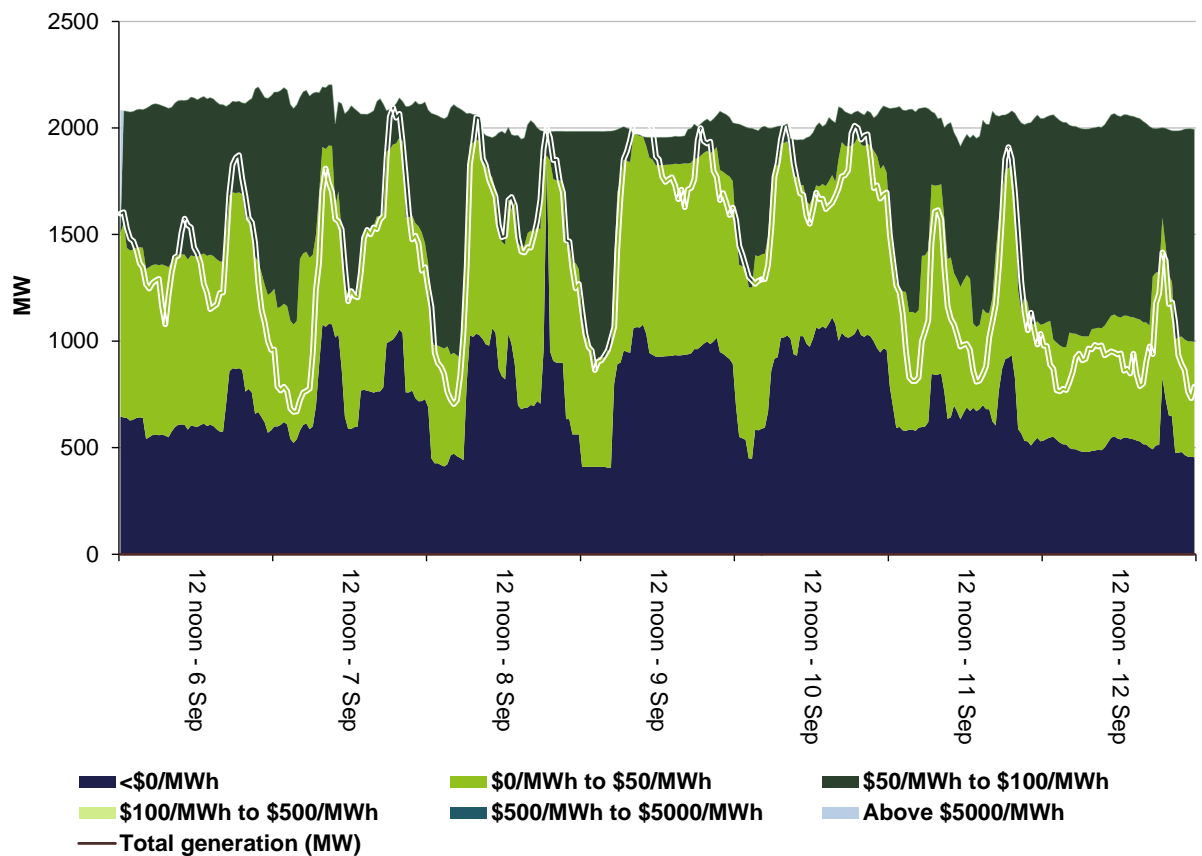


Figure 7: Tasmania generation and bidding patterns



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.

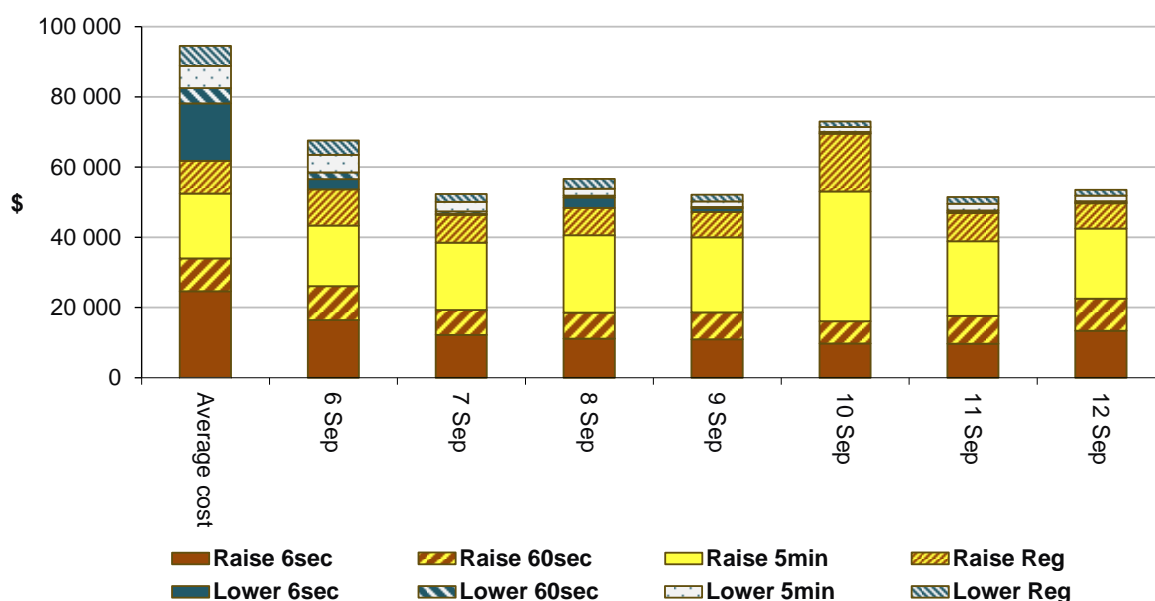
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$345500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$61000 or less than 1 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.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$61/MWh and above \$250/MWh.

Tuesday, 8 September

Table 3: 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
9:30 AM	255.82	64.99	64.99	1585	1518	1528	2133	2355	2307
10:30 AM	287.99	94.99	94.99	1517	1477	1484	2201	2300	2269

Demand was close to forecast and available capacity was lower than forecast four hours ahead.

Table 4: Rebids for the 9.30 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
8.27 am		Origin Energy	Quarantine	-48	95	N/A	0825A AVOID UNECONOMIC START SL
8.39 am		EnergyAustralia	Hallett	10	>361	-1000	08:37 A ADJ BAND DUE TO SA PRICE ABOVE 5PD
8.40 am		AGL Energy	Torrens Island	60	95	288	0835~A~040 CHG IN AEMO DISP~45 PRICE INCREASE VS PD SA +\$223
9.12 am	9.20 am	EnergyAustralia	Hallett	15	13482	-1000	09:12 A ADJ BANDS DUE TO SA PRICE>FCST @ 0915 287.99>94.99

Table 5: Rebids for the 10.30 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
9.40 am		Origin Energy	Osborne	42	37	10759	0938A CONSTRAINT MANAGEMENT - S>V_CB6033+6225_TX2 SL
9.51 am		AGL Energy	Torrens Island	180	<125	288	0931~A~050 CHG IN AEMO PD~55 PD PRICE INCREASE SA +\$30 [1100]

Interconnectors were supplying generation to South Australia at their limit, with flows affected by constraints managing the planned outage of the two Keith to Taillem Bend 132 kV lines.¹

¹ The constraints managing the planned outage of the Keith to Taillem Bend parallel lines from 2 – 11 September prevent a post contingent overload on one of the South East to Taillem Bend 275 kV lines in the event of a trip on the parallel line.

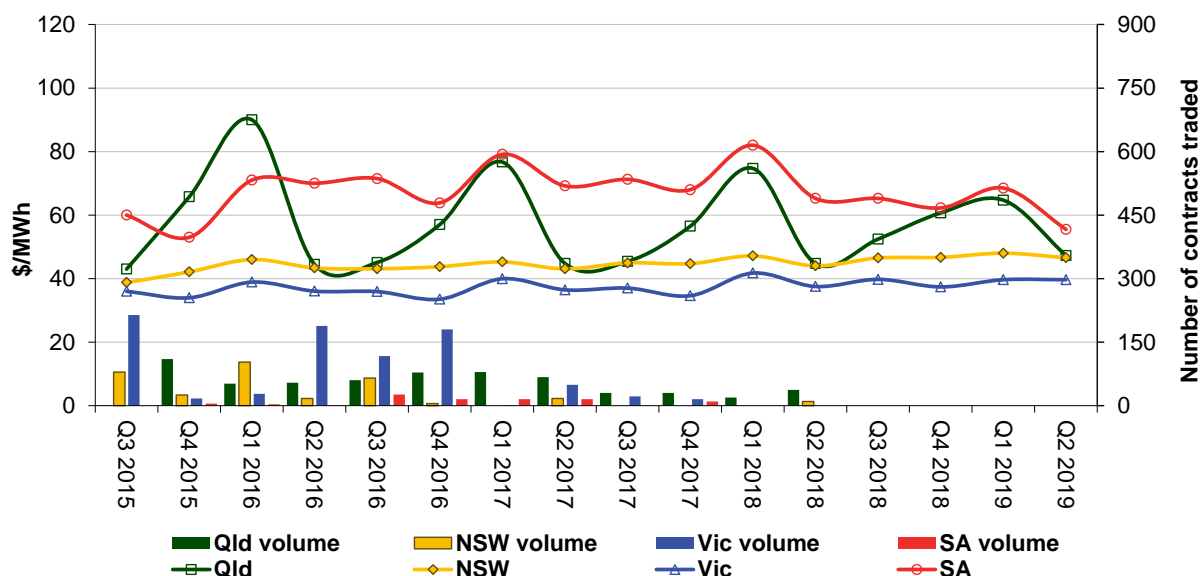
As a result of tight supply conditions, for much of the 9 am to 11.30 am trading intervals, following small variations in demand, dispatch prices fluctuated between \$95/MWh to the next highest priced capacity of around \$290/MWh.

For the 9.30 am and 10.30 am trading intervals, the above rebids contributed to creating a steep supply curve. Consequently, the dispatch price remained at \$288/MWh for the majority of these trading intervals.

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.

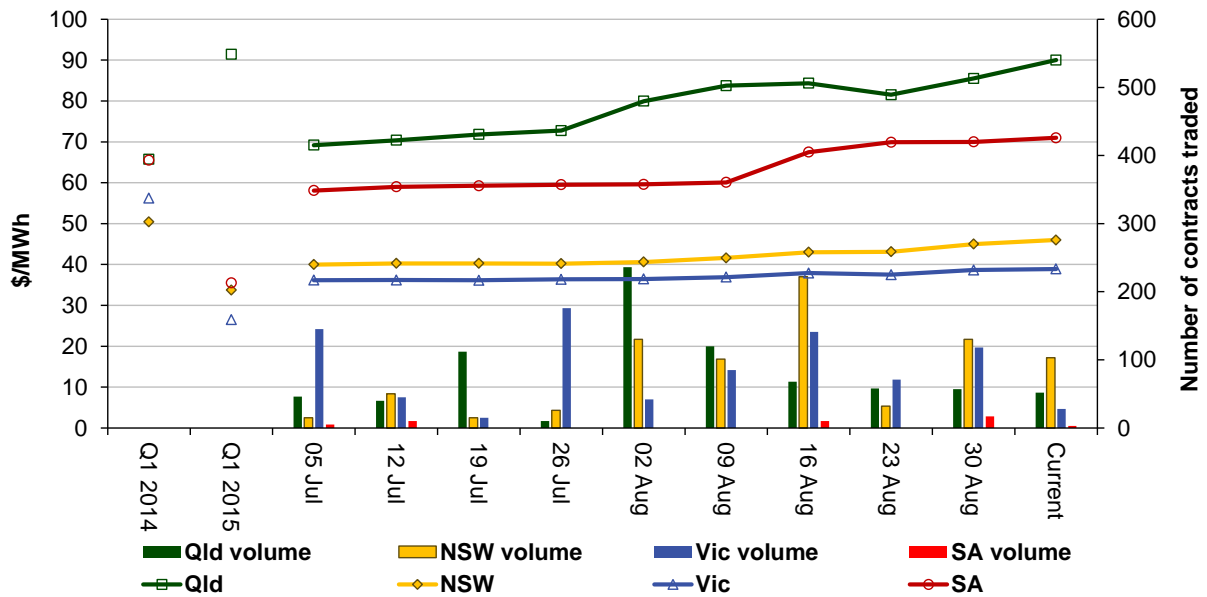
Figure 9: Quarterly base future prices Q3 2015 – Q2 2019



Source: ASXEnergy.com.au

Figure 10 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.

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



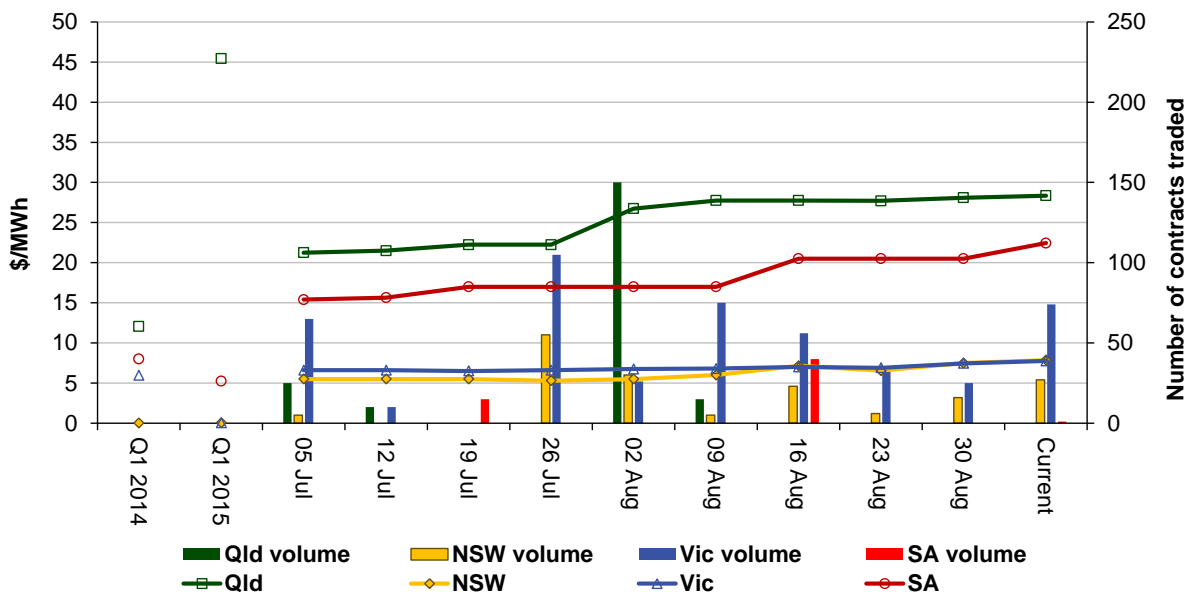
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

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

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



Source. ASXEnergy.com.au