

Electricity Report

26 July – 1 August 2015



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 spot prices that occurred in each region during the week 26 July to 1 August 2015. There were five occasions in South Australia and one occasion in Queensland where the spot price exceeded the AER reporting threshold. These are discussed later in this report.

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

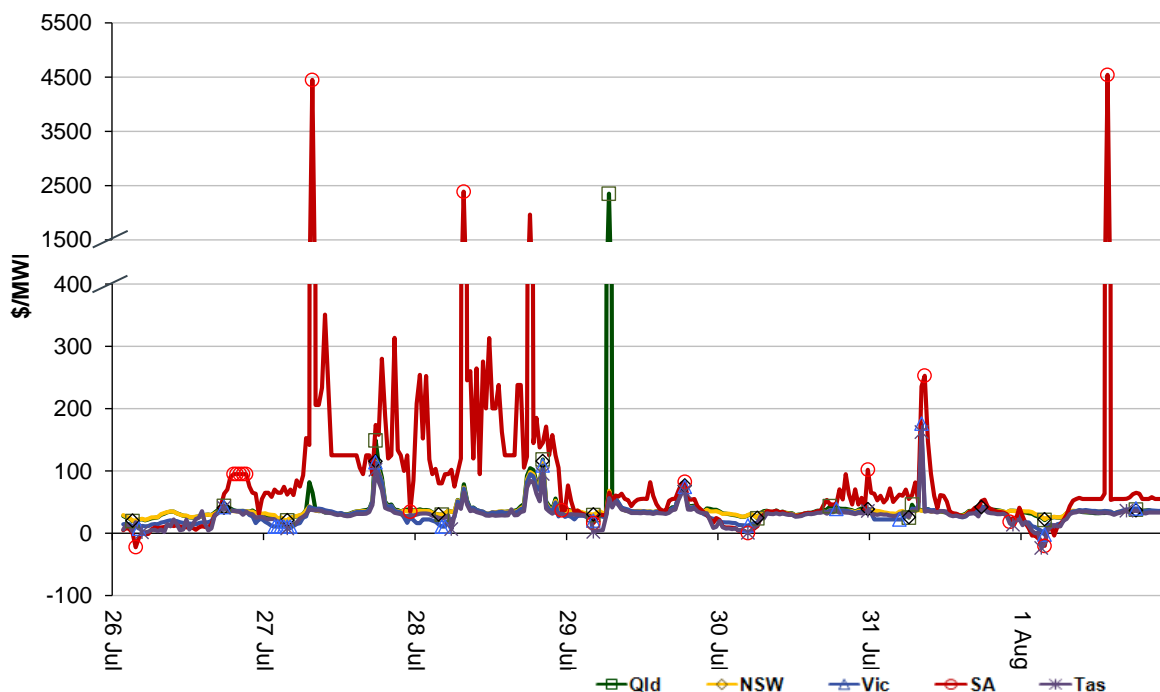


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

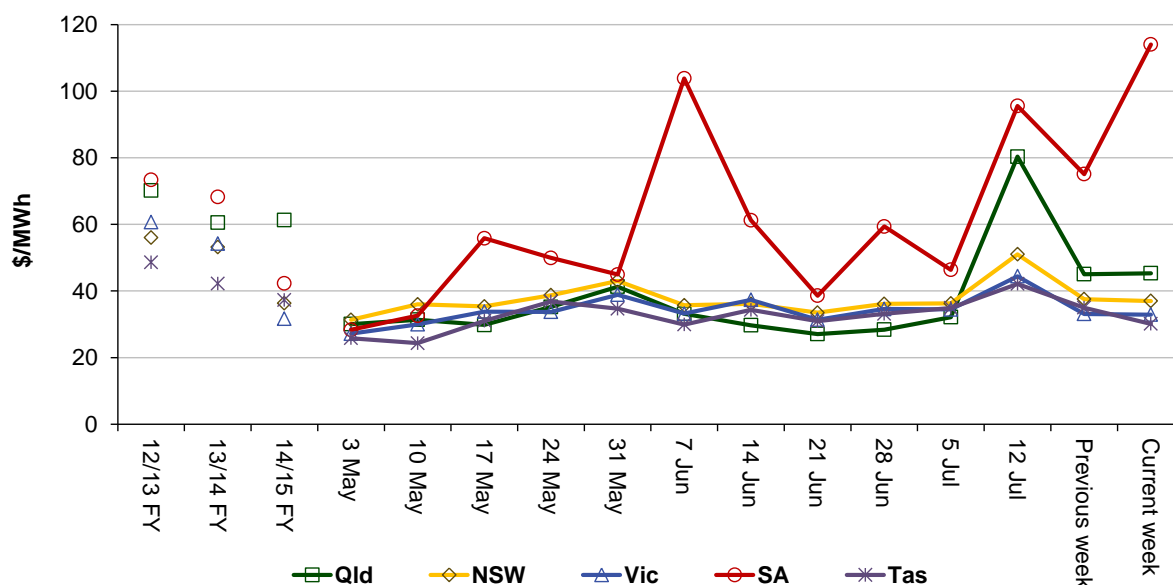


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	45	37	33	114	30
14-15 financial YTD	34	42	40	55	34
15-16 financial YTD	48	40	36	81	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 195 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

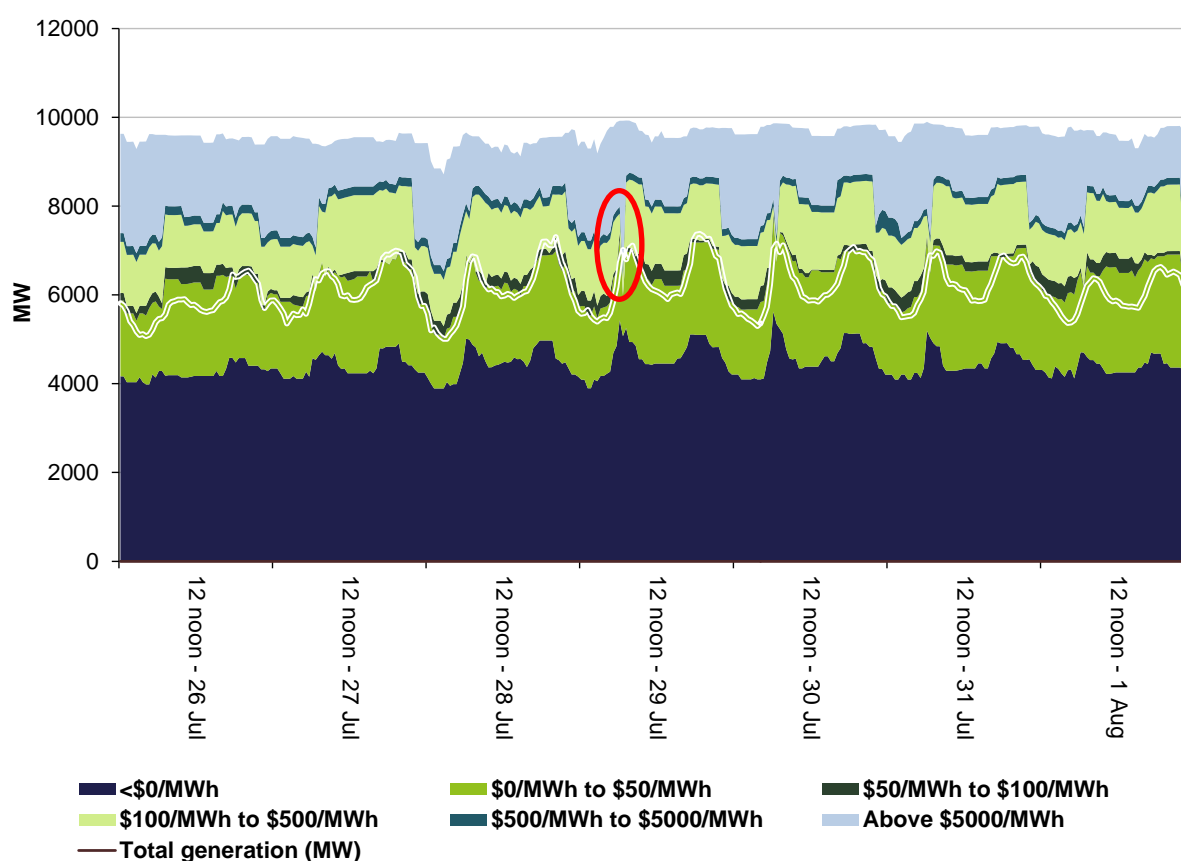
	Availability	Demand	Network	Combination
% of total above forecast	13	42	0	5
% of total below forecast	19	19	0	3

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



The red ellipse on Figure 3 highlights where rebidding created a price event in Queensland, discussed later in this report.

Figure 4: New South Wales generation and bidding patterns

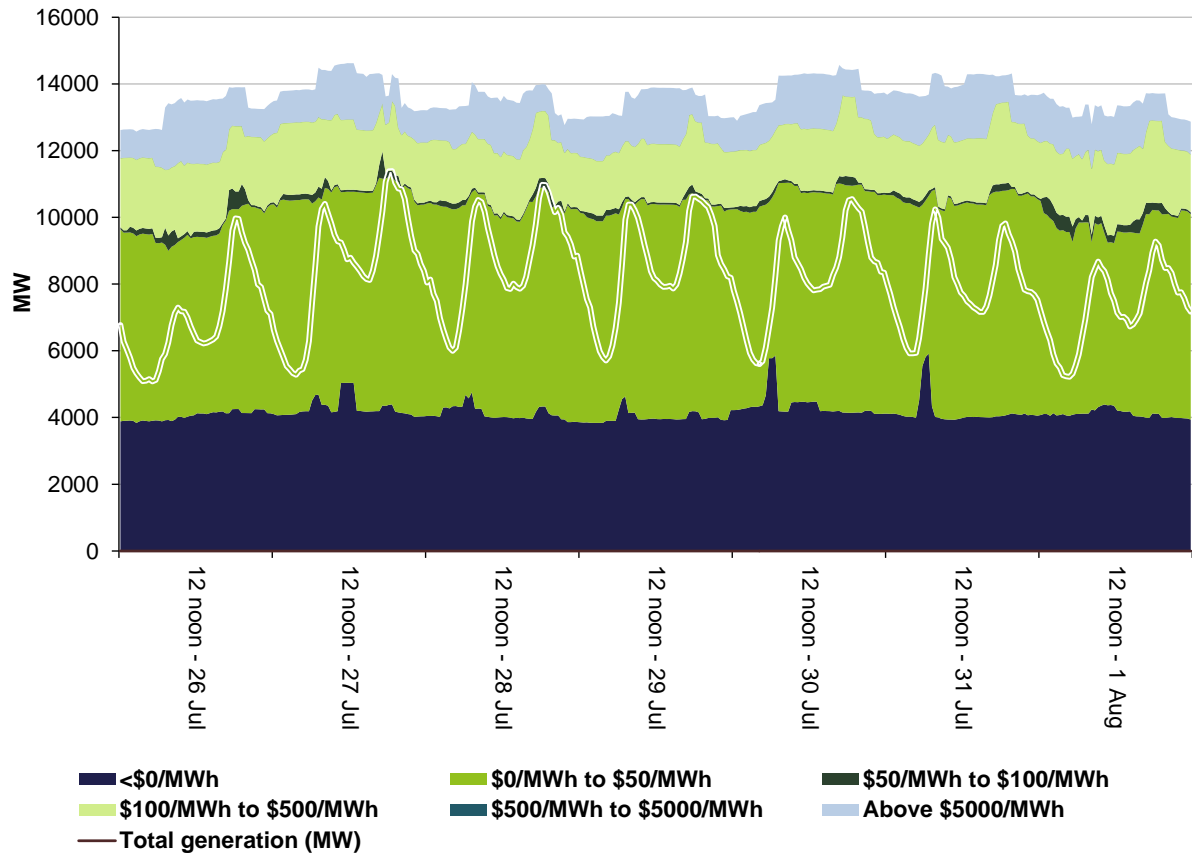


Figure 5: Victoria generation and bidding patterns

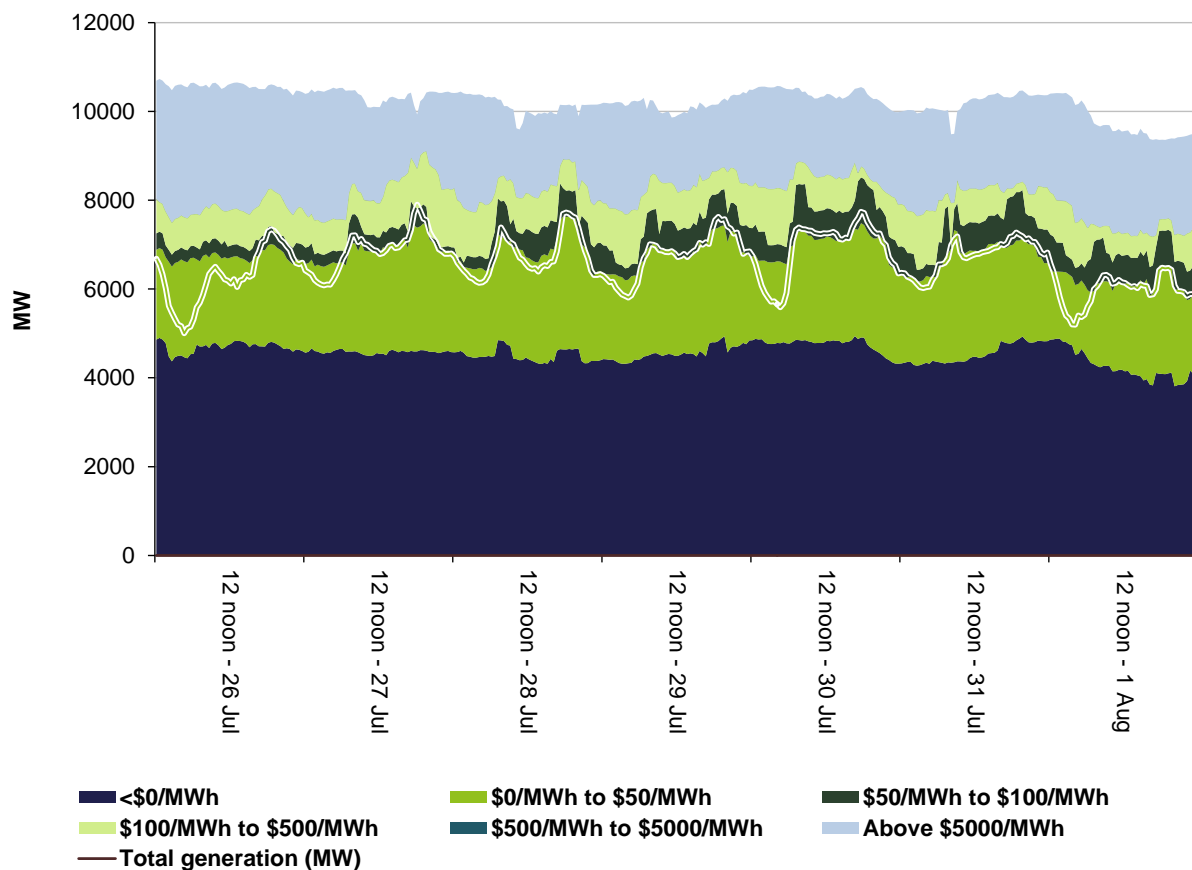
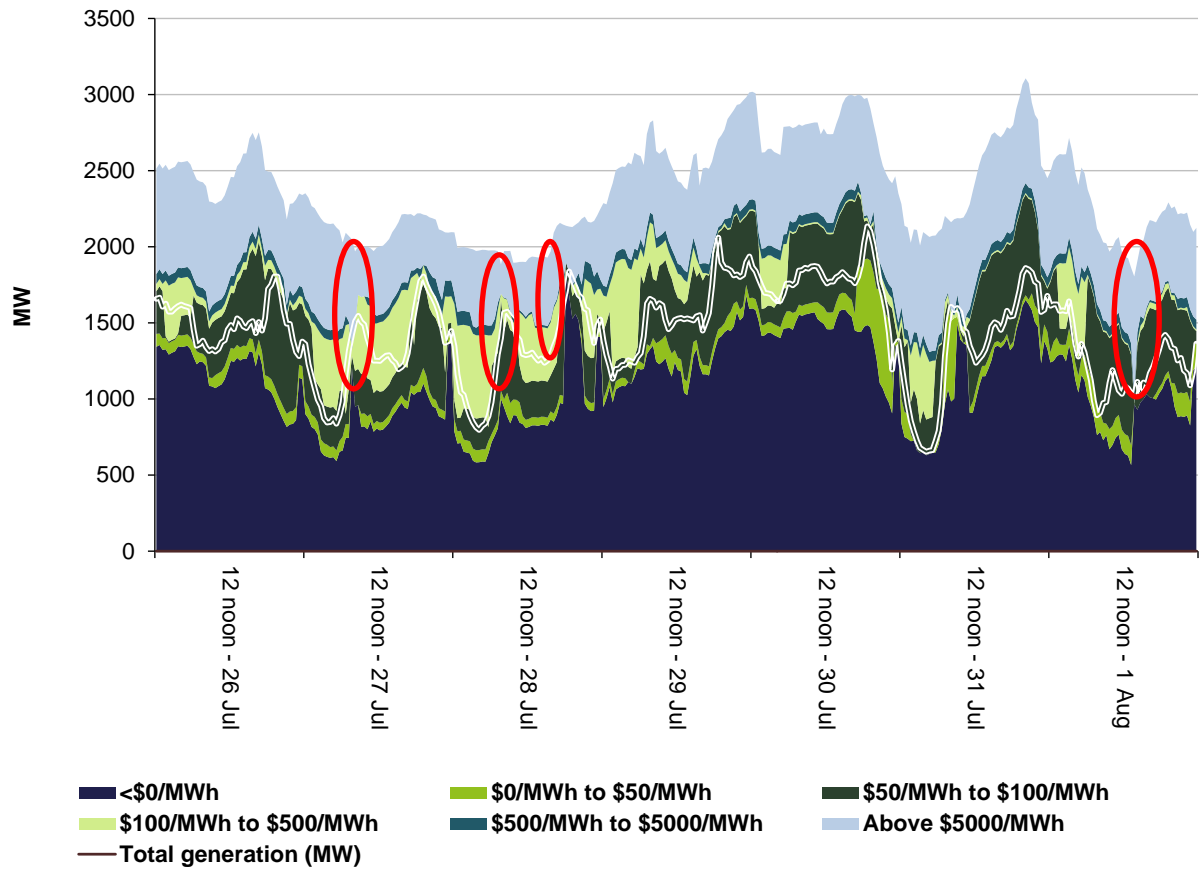
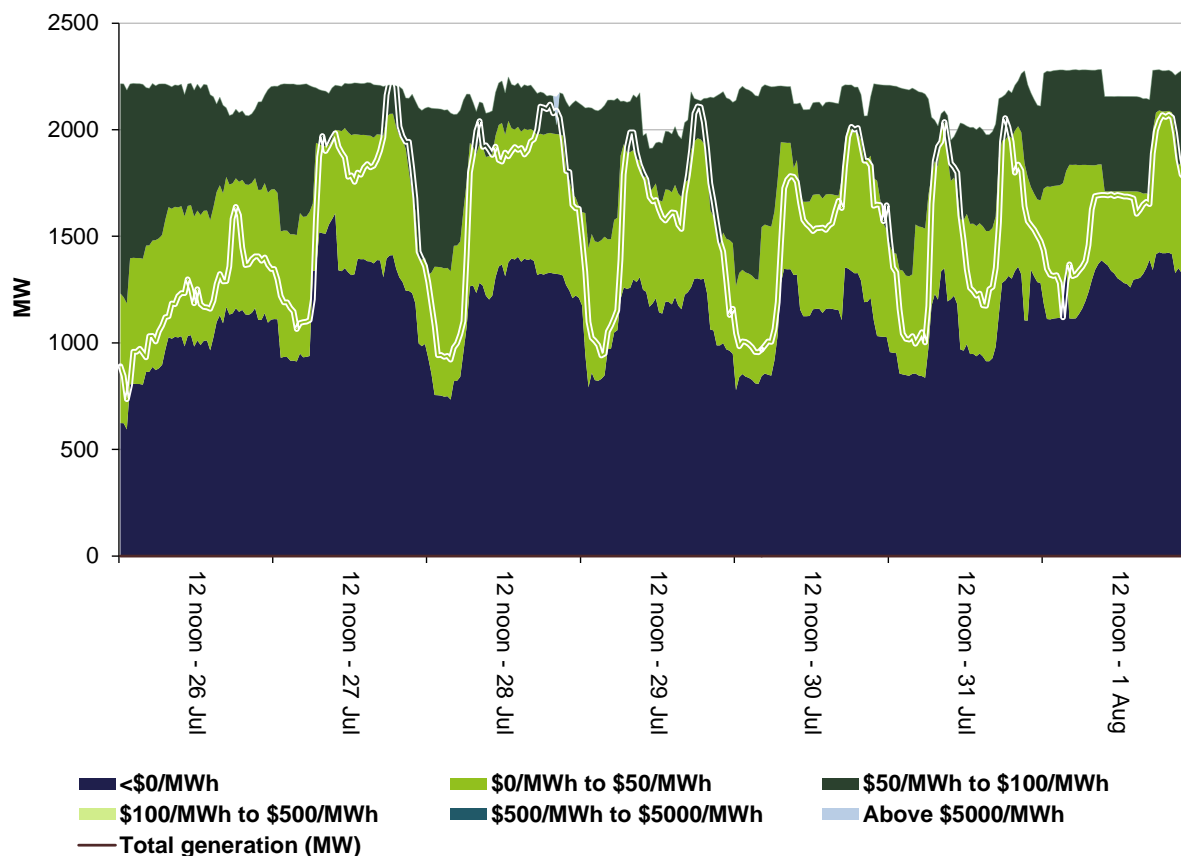


Figure 6: South Australia generation and bidding patterns



The red ellipses on Figure 6 highlight where rebidding created a price event in South Australia, as discussed later in this report.

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.

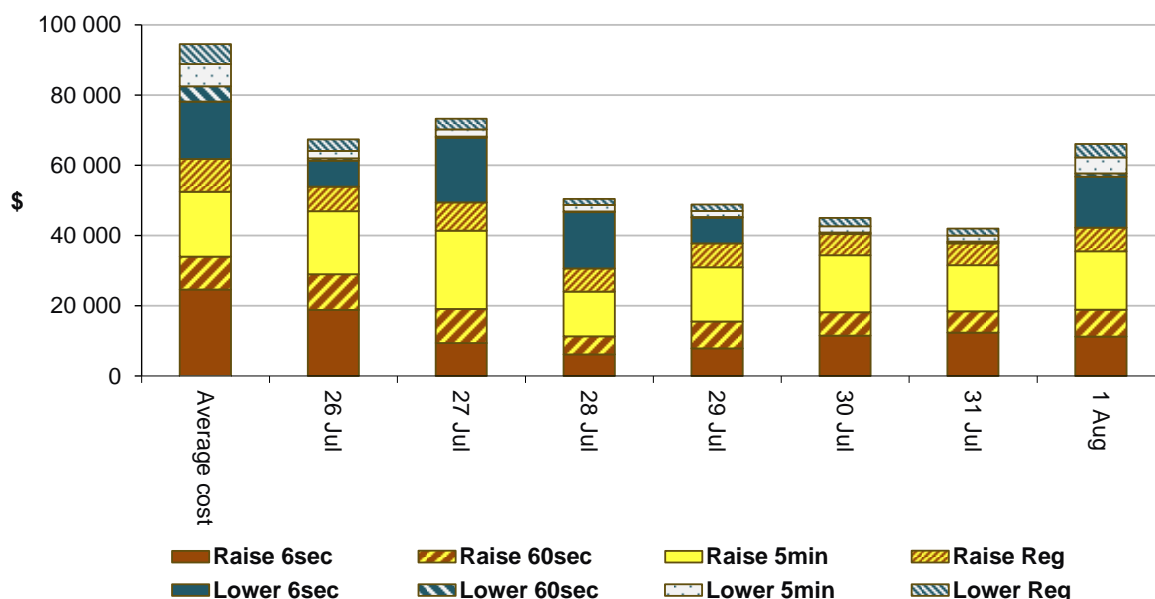
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$273 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$119 500 or around 2 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.

Queensland

There was occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of \$45/MWh and above \$250/MWh.

Wednesday, 29 July

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
7 am	2352	36	38	6506	6346	6383	9922	9892	9892

Demand and available capacity were 160 MW and 30 MW higher than forecast four hours ahead, respectively.

Table 4. Rebids for 7 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
6.35 am	6.45 am	Callide Power Trading	Callide C	160	-1000	13 800	0634A change in QNI pd - sl
6.39 am	6.50 am	Millmerran Energy Trader	Millmerran	230	7	13 800	06:38 A change in QNI pd flow sl
6.48 am	6.55 am	CS Energy	Gladstone	280	<44	13 800	0646A interconnector constraint-binding in pd-sl
6.48 am	6.55 am	CS Energy	Wivenhoe	250	309	13 800	0646A interconnector constraint-binding in pd-sl
6.51 am	7 am	ERM Power	Oakey	129	<341	13 351	0651A change in QLD price 5m pd vs 30mpd 0651A change in QLD demand 5m pd vs 30mpd

The above rebids contributed to a steep supply curve. At 7 am, when ERM Power’s rebid became effective, the dispatch price increased from \$106/MWh at 6.55 am to the price cap. With lower priced generation either fully dispatched or ramp rate limited, high-priced generation in Queensland was dispatched.

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$58/MWh and above \$250/MWh.

Monday, 27 July

Table 5. 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
8 am	4449	175	125	1804	1803	1790	2059	2077	2251
10 am	351	175	125	1859	1837	1847	1997	2048	2340

For the 8 am trading interval, demand and available generation was close to forecast four hours ahead.

At 7.47 am, effective at 7.55 am, AGL Energy rebid 200 MW of capacity at Torrens Island priced at less than \$175/MWh to the price cap. The reason given was “0731~a~050 chg in AEMO pd~54 pd price decrease SA \$415”. This coincided with a demand increase of 69 MW and with low-priced generation either fully dispatched, ramp rate limited or trapped in FCAS, higher priced generation at Torrens Island had to be dispatched to meet demand. This resulted in the dispatch price increasing from \$175/MWh at 7.50 am to the price cap at 7.55 am. At 8 am, demand decreased by 46 MW and with generation priced slightly under

the price cap no longer ramp rate limited or trapped in FCAS, the dispatch price fell to \$12 195/MWh.

For the 10 am trading interval, demand was slightly higher than forecast and available capacity was 51 MW less than forecast four hours ahead.

At 9.18 am, effective from 9.25 am, AGL Energy rebid 160 MW of available capacity at Torrens Island priced at less than \$175/MWh to \$351/MWh. The dispatch price increased from \$175/MWh at 9.20 am to \$351/MWh at 9.25 am and remained there for the 10 am trading interval set by Torrens Island.

Tuesday, 28 July

Table 6. 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
8 am	2390	125	126	1873	1855	1907	1943	1997	2026

Demand and availability was close to forecast four hours ahead.

At 7.41 am, effective from 7.50 am, AGL Energy rebid 160 MW of capacity at Torrens Island from prices less than \$125/MWh to the price cap. The reason given was “0731~A~050 chg in AEMOP pd~54 pd price decrease SA -\$10169 0900”. With low priced generation either ramp rate limited or fully dispatched, higher priced generation had to be dispatched to meet demand. This resulted in the dispatch price increasing from \$126/MWh at 7.45 am to the price cap at 7.50 am. The dispatch price fell to \$109 at 7.55 pm following a 77 MW demand decrease (mainly due to an increase in South Australian non-scheduled generation) and rebidding by generators into lower price bands.

Table 7. 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
6.30 pm	1968	590	10 759	2133	2222	2213	2138	2152	2148

Demand and availability was close to forecast.

A steep supply curve was forecast 12 hours ahead, with 15 MW of available capacity between \$591/MWh and \$10 779/MWh. Consequently, small changes in demand and availability caused the forecast twelve hour price to decrease from \$10 759/MWh to \$590/MWh four hours ahead.

Imports from Victoria into South Australia across the Heywood Interconnector were limited by the constraint managing an outage of the Keith to Tailem Bend 132 kV line. The constraint bound for longer than forecast, limiting imports from Victoria into South Australia to 405 MW (40 MW less than forecast four hours ahead).

Table 8: Rebids for 6.30 pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
5.23 pm		EnergyAustralia	Hallett	40	361	>590	17:22 A band adj due to material change in demand sl
6.12 pm	6.20 pm	Alinta Energy	Northern	23	46	13 334	18:10~A~dispatch \$590 v 5pd \$351.50~
6.12 pm	6.20 pm	EnergyAustralia	Hallett	15	590	13 482	18:12 A band adj due to change in SA prices!

The above rebids contributed to an already steep supply curve, with only 29 MW of available capacity priced between \$591/MWh and \$10 779/MWh. Consequently, small changes in demand, interconnectors and availability led to large changes in price.

At 6.20 pm, demand increased by 50 MW. With lower priced generation either ramp rate limited, fully dispatched, stranded or trapped in FCAS, higher priced generation had to be dispatched to meet demand. This resulted in the dispatch price increasing from \$590/MWh at 6.15 pm to \$10 579/MWh at 6.20 pm. In response to the high price participants rebid around 100 MW to the price floor which saw the dispatch price fall to \$104/MWh at 6.25 pm.

Saturday, 1 August

Table 9. 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
2 pm	4542	55	55	1653	1507	1553	1844	1916	1931

Demand was 146 MW higher than forecast and available generation was 72 MW less than forecast four hours ahead (wind generation was 92 MW less than forecast four hours ahead).

Table 10: Rebids for 10 am

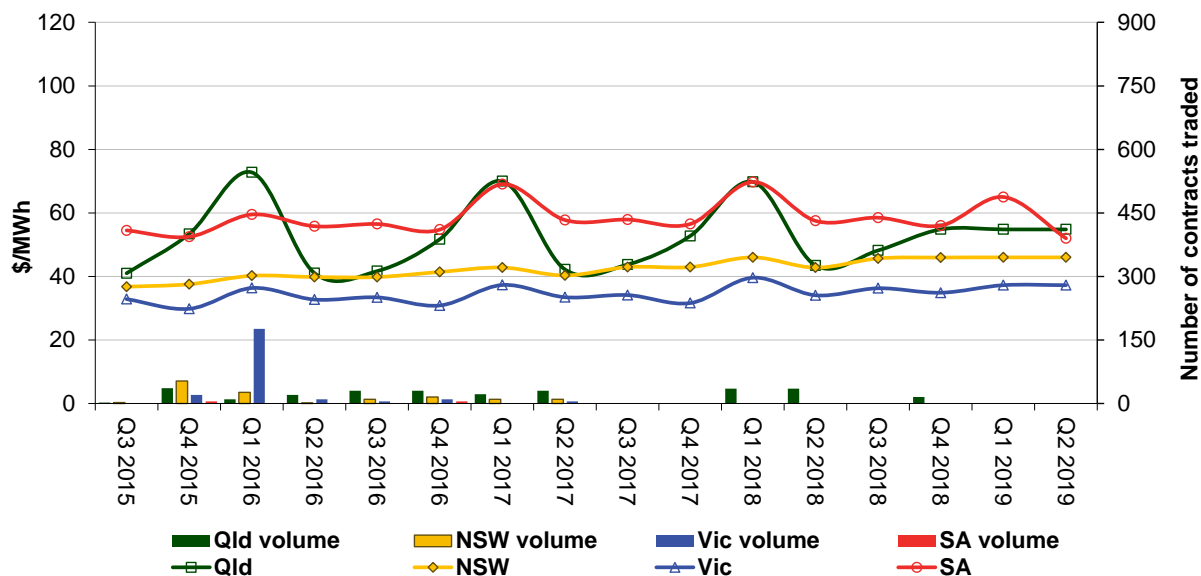
Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
1.46 pm	1.55 pm	AGL Energy	Torrens Island	270	<65	13 500	1331~A~050 chg in AEMO pd~decr wind forecast SA -99MW [1400]
1.53 pm	2 pm	Origin Energy	Quarantine	-48	95	N/A	1350A avoid uneconomic start - avoid short run sl

With lower priced generation trapped in FCAS or ramp rate limited, the rebid by AGL resulted in the dispatch price increasing from \$65/MWh at 1.50 pm to \$13 500/MWh at 1.55 pm. At 2 pm, the dispatch price remained at \$13 500/MWh as low price generators were either trapped in FCAS, ramp rate limited or fully dispatched, and there was no step change in demand.

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.

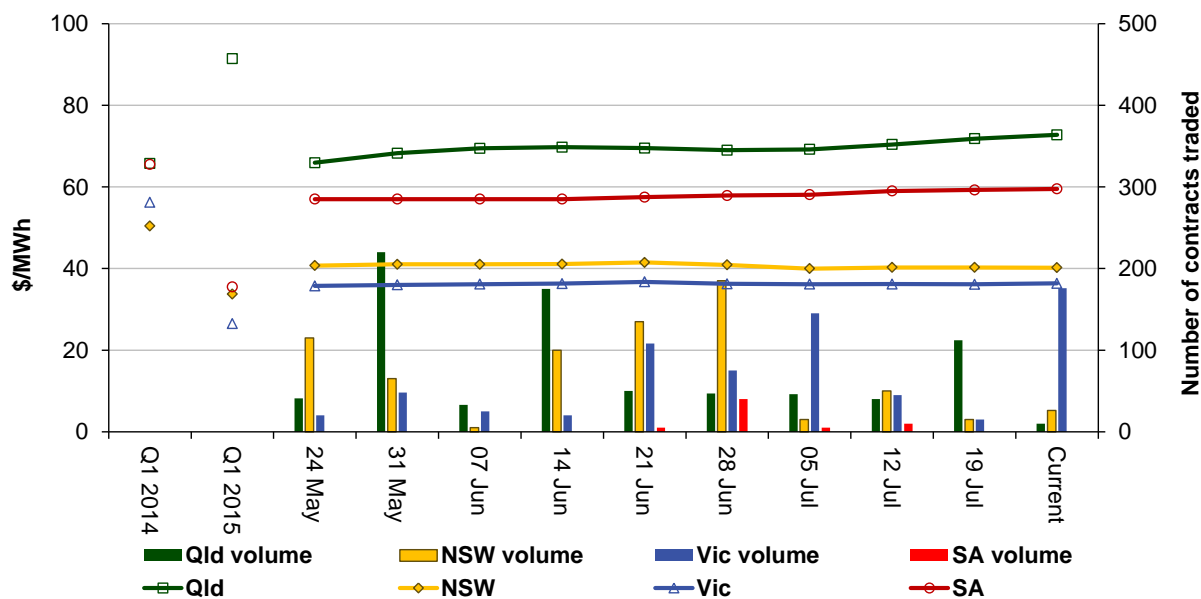
Figure 9: Quarterly base future prices Q3 2015 – Q2 2019



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)



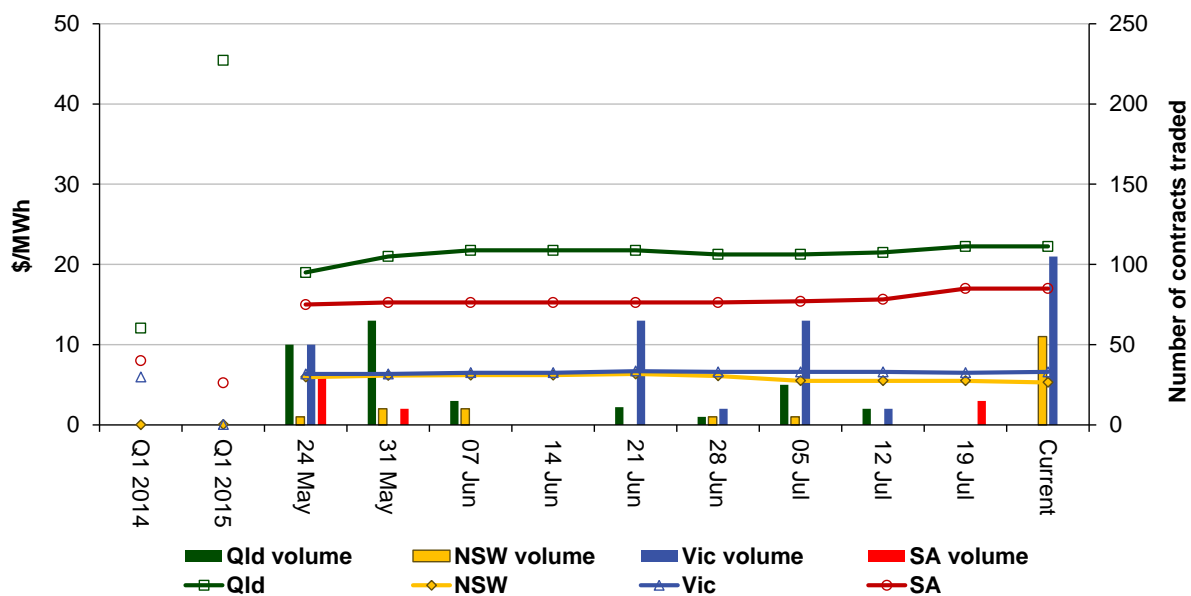
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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

Australian Energy Regulator

August 2015