Electricity Report 30 August – 5 September 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 30 August to 5 September 2015. There were eight occasions where the spot price exceeded the AER reporting threshold in South Australia. These are discussed later in this report.

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

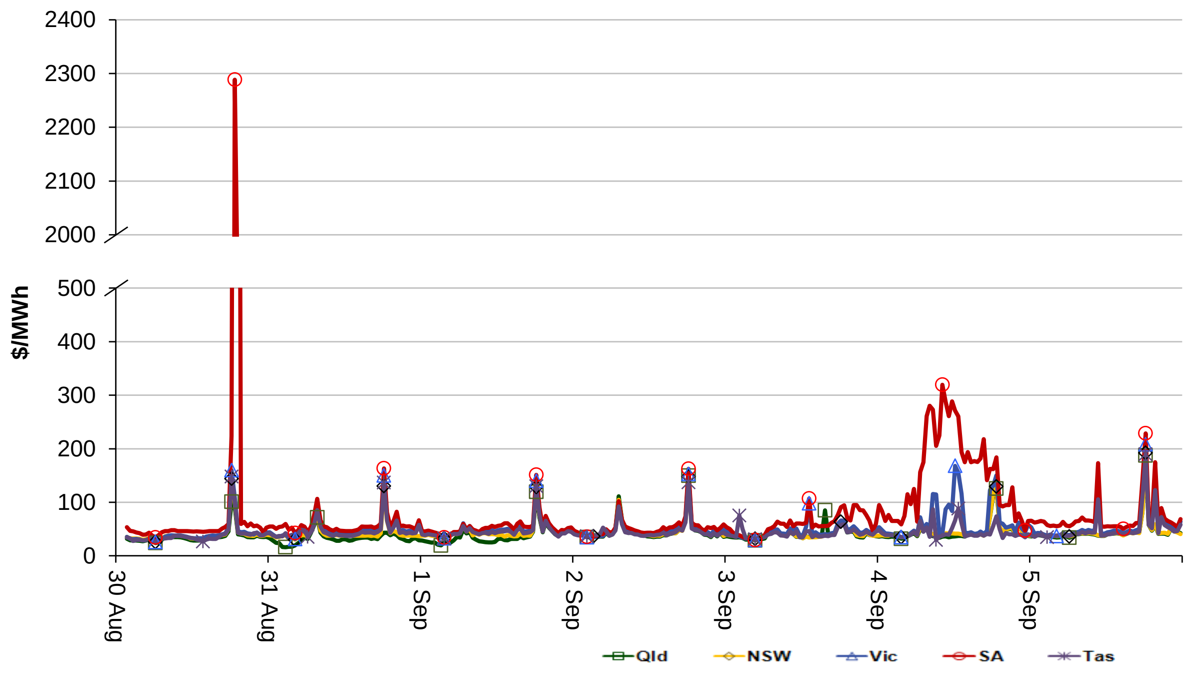


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

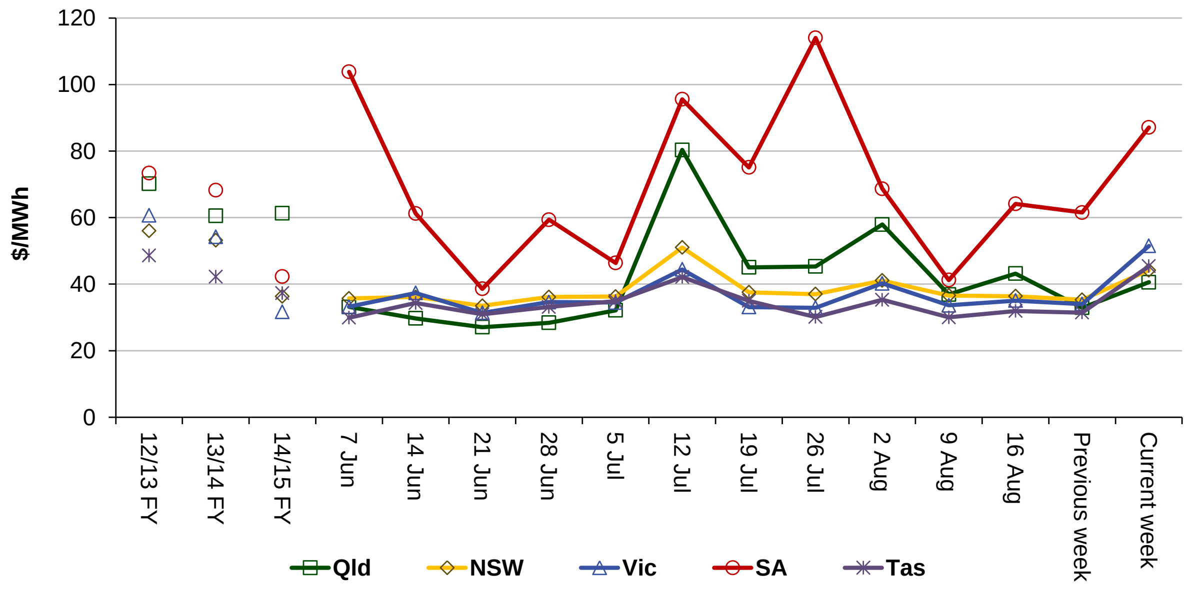


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	41	44	52	87	45
14-15 financial YTD	31	40	39	51	36
15-16 financial YTD	45	39	37	73	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 96 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	10	36	0	1
% of total below forecast	35	16	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

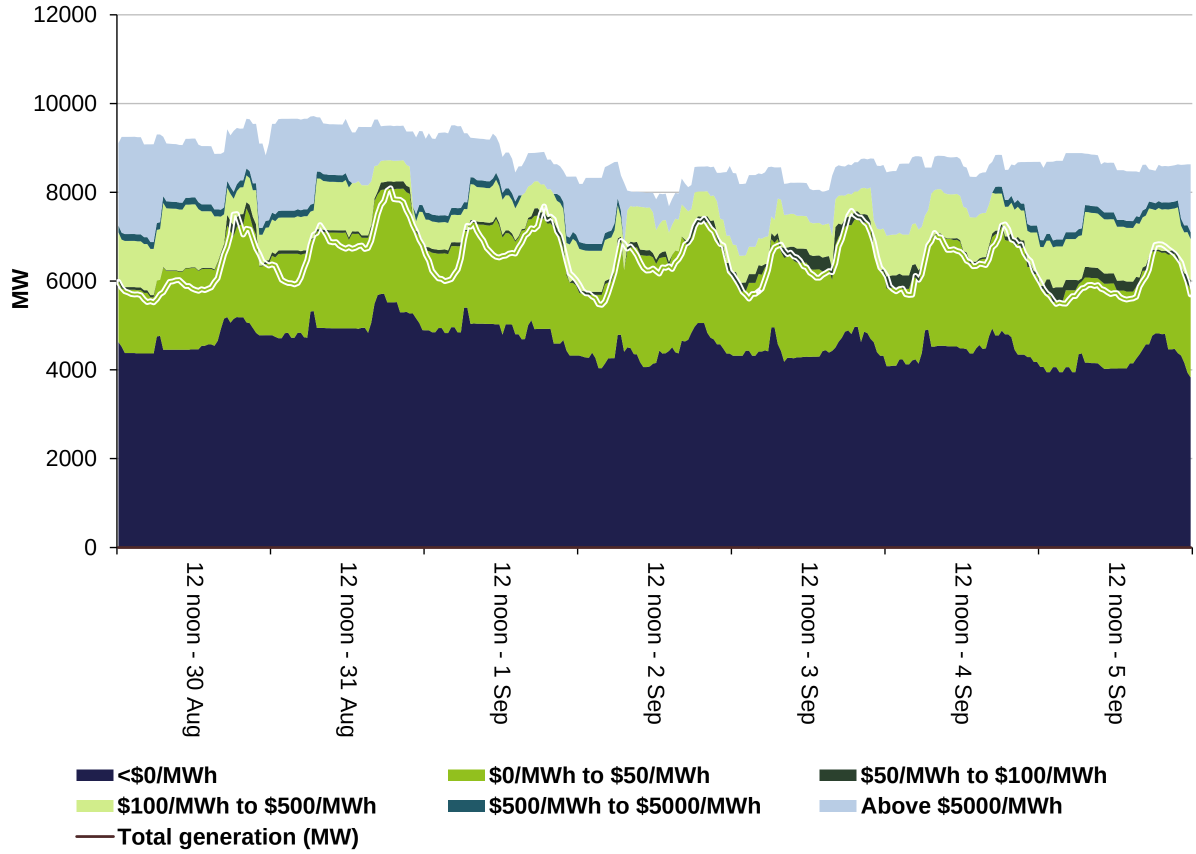


Figure 4: New South Wales generation and bidding patterns

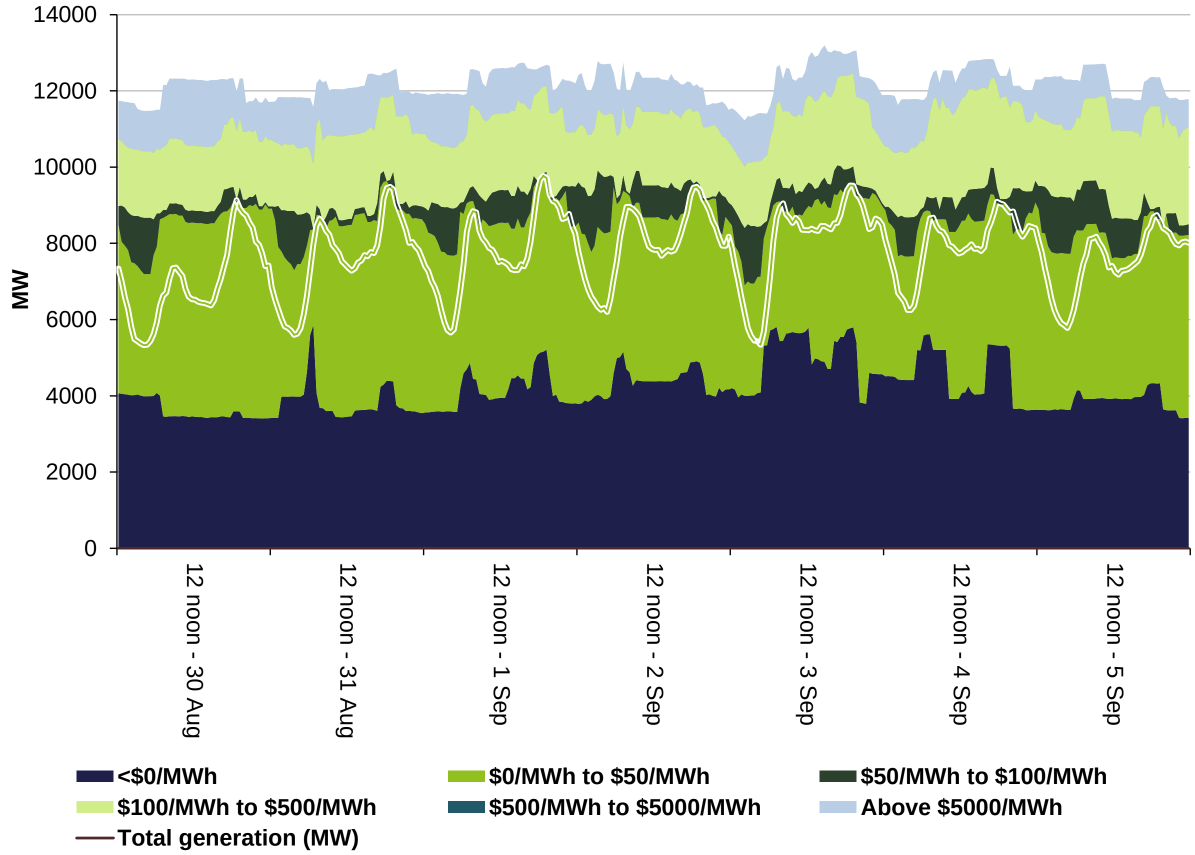


Figure 5: Victoria generation and bidding patterns

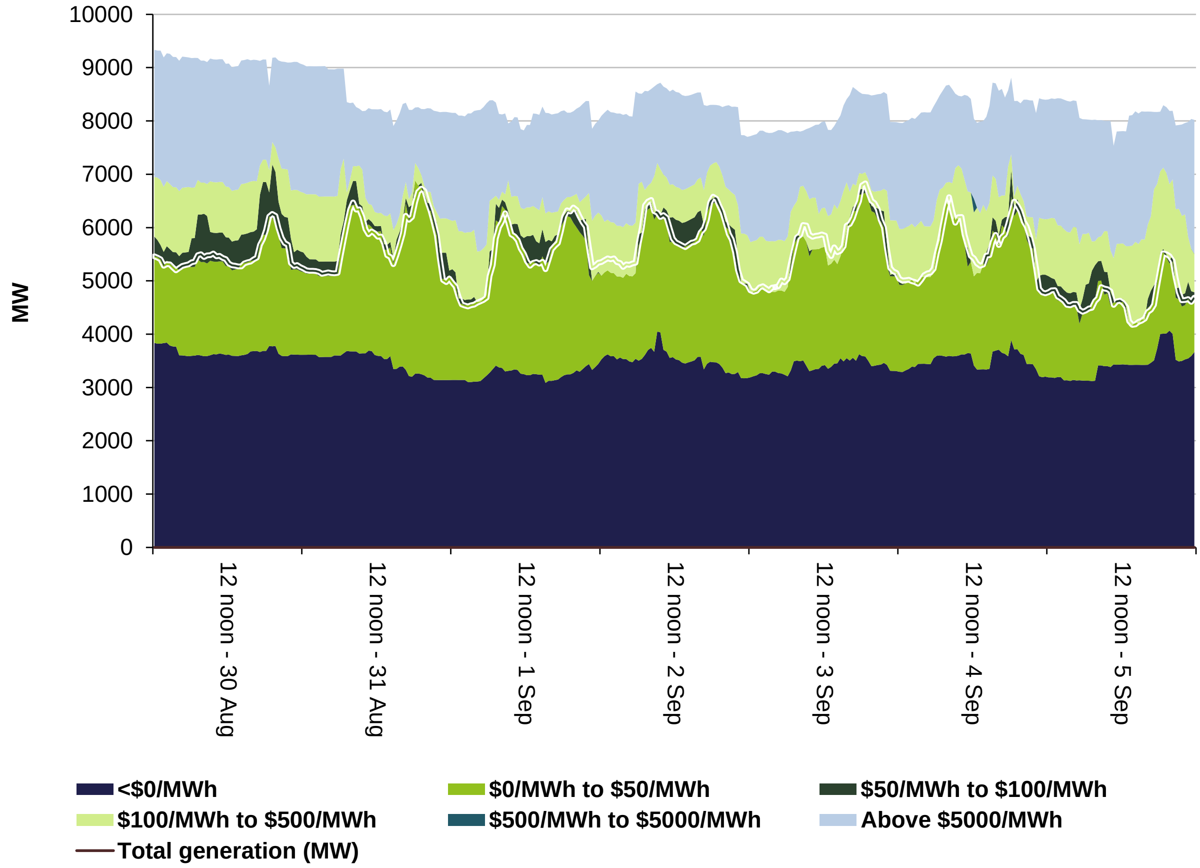


Figure 6: South Australia generation and bidding patterns

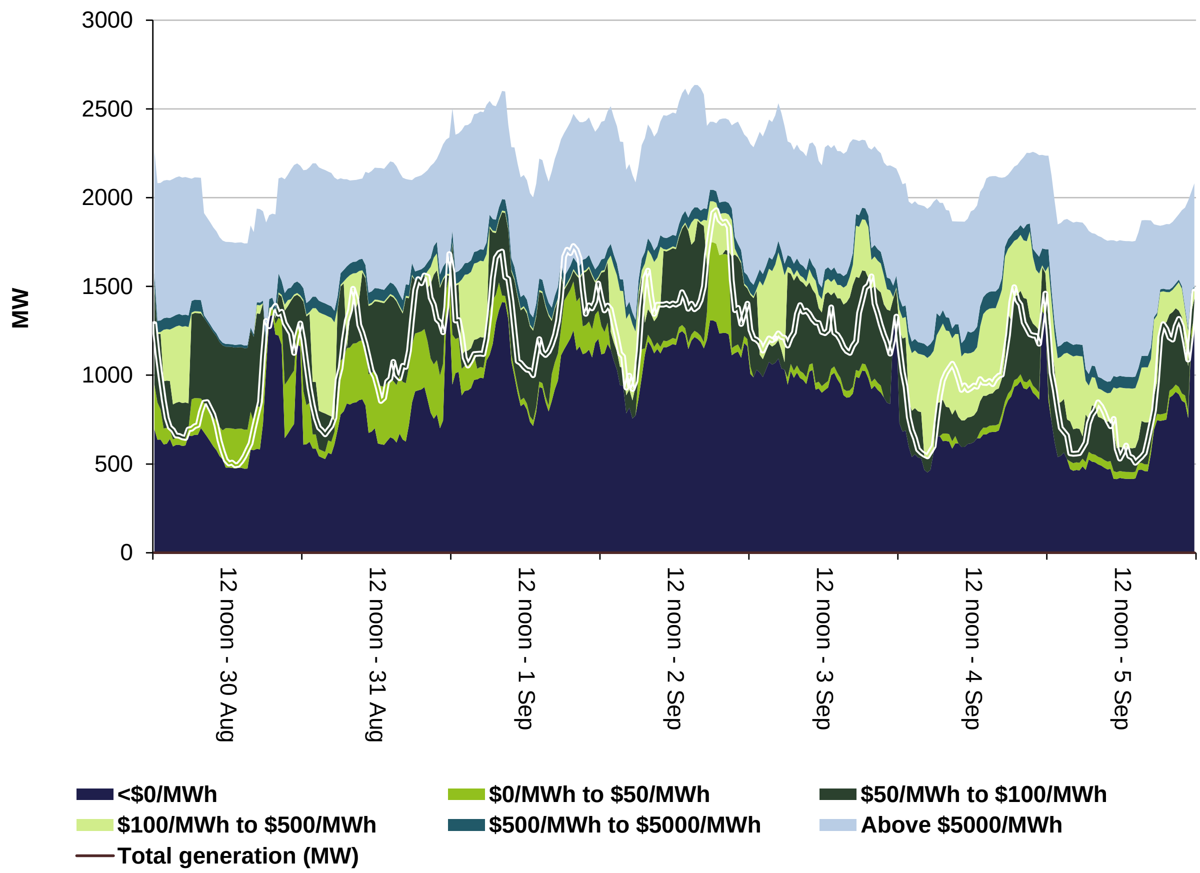
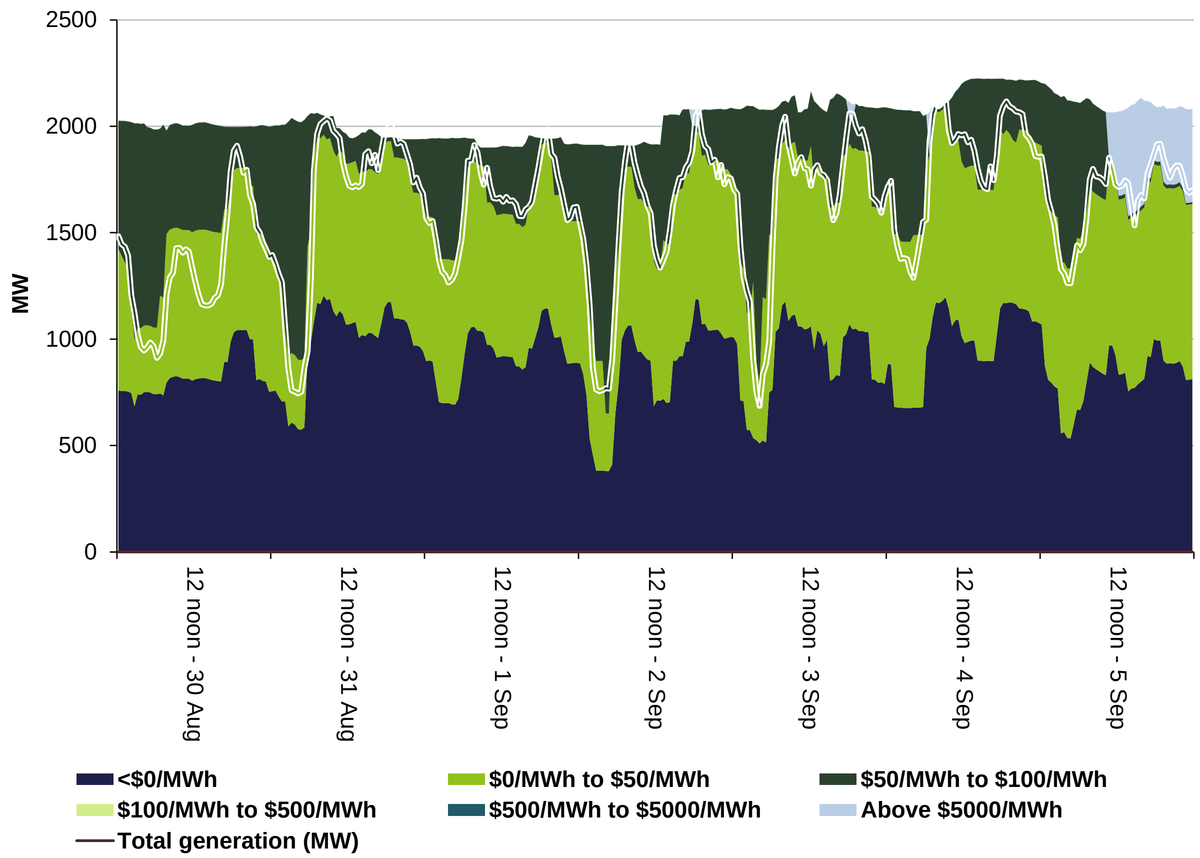


Figure 7: Tasmania generation and bidding patterns



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.

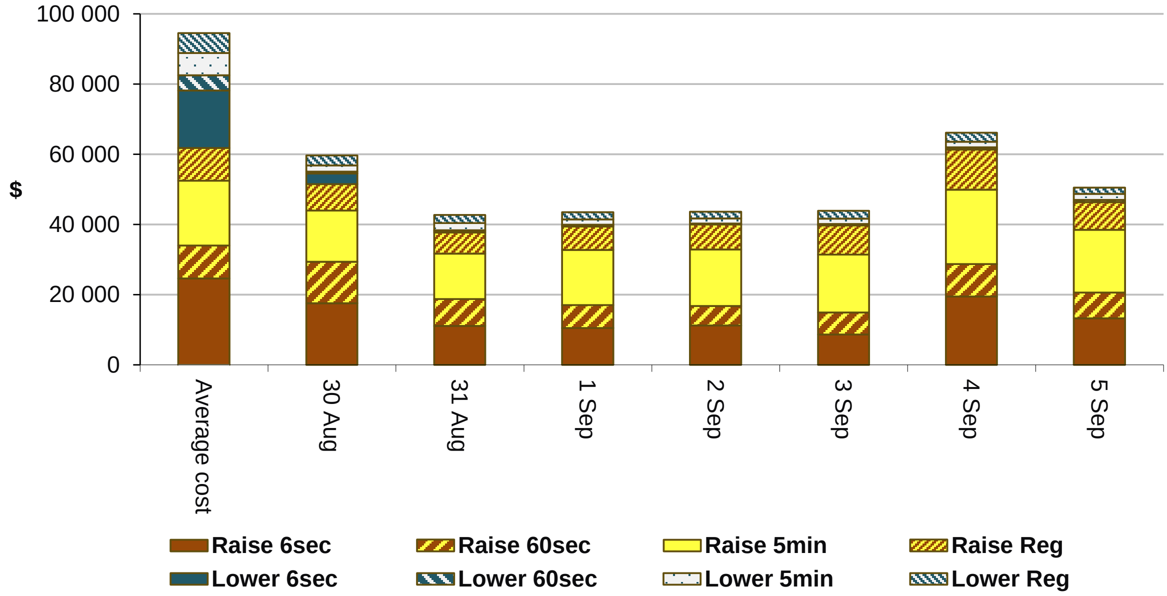
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $315 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $35 000 or around 3.5 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



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 eight occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $87/MWh and above $250/MWh.

Sunday, 30 August

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 pm	2288.47	85.20	88.46	1745	1763	1786	1899	2116	2139
7.30 pm	1846.35	72.29	85.51	1818	1812	1831	1910	2118	2152

Conditions at the time saw demand close to forecast, while available capacity was up to 217 MW below that forecast four hours ahead. In the lead up to the first price spike, AGL's Torrens Island unit B4 tripped, removing 200 MW of available capacity priced at $65/MWh or lower in the region. From 7.16 pm, an actual lack of reserve level 1 (LOR1) market notice was published by AEMO for the period from 7 pm to 7.30 pm, with a subsequent LOR1 notice published from the 7.40 pm dispatch interval until 8.10 pm.

At 6.40 pm, demand increased by 97 MW, largely as a result of a significant decrease in non-scheduled generation output.[1] With other lower priced available generation being dispatched at maximum availability, ramp rate limited (Northern unit 1), or requiring additional time to synchronise (Dry Creek unit 3) the dispatch price spiked to $13 331/MWh for that interval. The price returned to $75/MWh for the next dispatch interval following rebidding to lower prices[2] and a decrease in demand of 120 MW (mostly due to an increase in output from the non-scheduled generating units).

At 6.40 pm, Alinta Energy rebid 43 MW of available capacity at its Northern Power Station unit 1 from below $95/MWh to $13 330/MWh, resulting in its generation output being reduced.[3] While lower priced generation was either dispatched at its maximum availability or ramp rate limited (Dry Creek unit 2), Dry Creek unit 3 set the dispatch price at $13 331/MWh. The price returned to $46/MWh for the next dispatch interval following rebidding to lower prices[4] and a decrease in demand of 116 MW (mostly due to an increase in non-scheduled generation).

Friday, 4 September

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1 Non-scheduled units at Angaston, Port Stanvac and Lonsdale significantly decreased output for the dispatch interval. The resulting change in flows toward South Australia on the Heywood interconnector saw the constraint managing the thermal loading on the 275/500 kV transformer violated when flows exceeded the transformer rating threshold.

2 540 MW of generation was rebid to the price floor effective from 7.45 pm.

3 Northern Power Station unit 2 was taken offline from 27 August and has remained unavailable.

4 270 MW of generation was rebid to the price floor effective from 7.25 pm.

Table 4: 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
8.30 am	280.12	287.99	288.09	1634	1701	1731	1927	2107	2126
9 am	273.04	287.99	287.99	1637	1680	1714	1917	2101	2122
10.30 am	319.54	174.99	174.99	1545	1534	1554	1865	2083	2099
11 am	288.17	174.99	174.99	1516	1481	1501	1865	2075	2093
Midday	288.49	174.99	174.99	1487	1442	1439	1923	2075	2090
12.30 am	271.38	174.99	174.99	1461	1450	1419	1921	2085	2098

Conditions at the time saw demand close to forecast, while available capacity ranged from 152 MW to 218 MW below that forecast four hours ahead for the affected trading intervals. While prices were close to those forecast for the 8.30 am and 9 am trading intervals, the remaining intervals were forecast to increase above $250/MWh in the hours leading up to dispatch.

The lower than forecast capacity was largely a result of AGL gradually reducing the availability at its Torrens Island unit B3, reporting "unexpected/plant limits~106 AUX/plant failure" in its rebidding reasons. However, rebidding leading up to dispatch saw AGL and other participants shifting available generation into lower price bands.

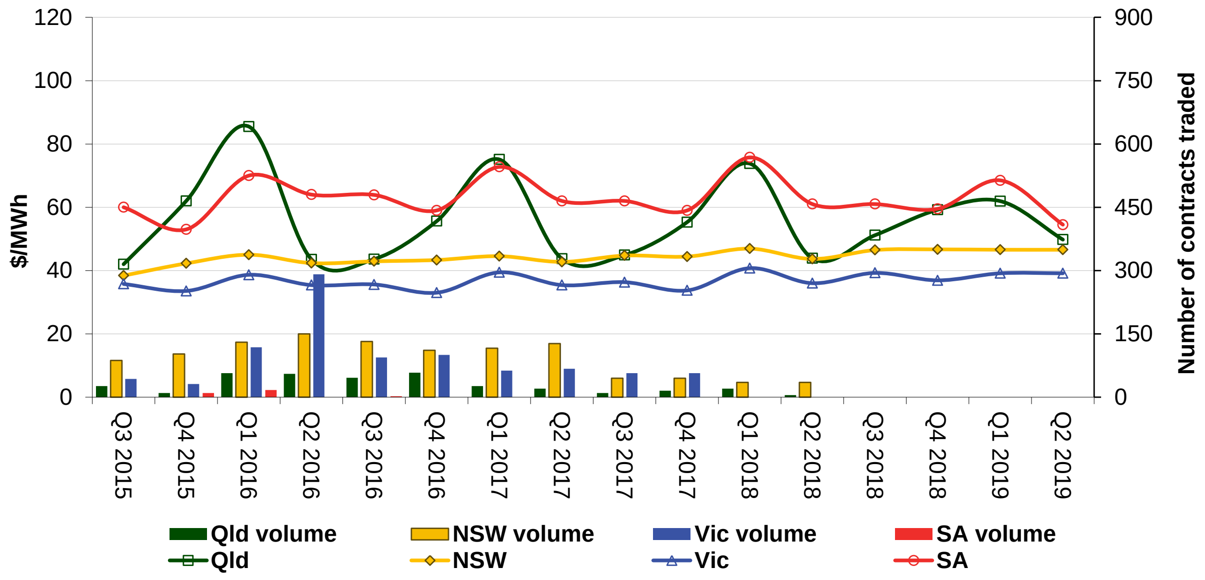
Dispatch prices generally increased from $175/MWh, to the next highest offered bands around $290/MWh and $350/MWh throughout the period following small variations in demand. Interconnectors were supplying generation to South Australia at their limit, with flows affected by constraints managing the planned outage of the two Keith to Tailem Bend 132 kV lines.[5]

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

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.

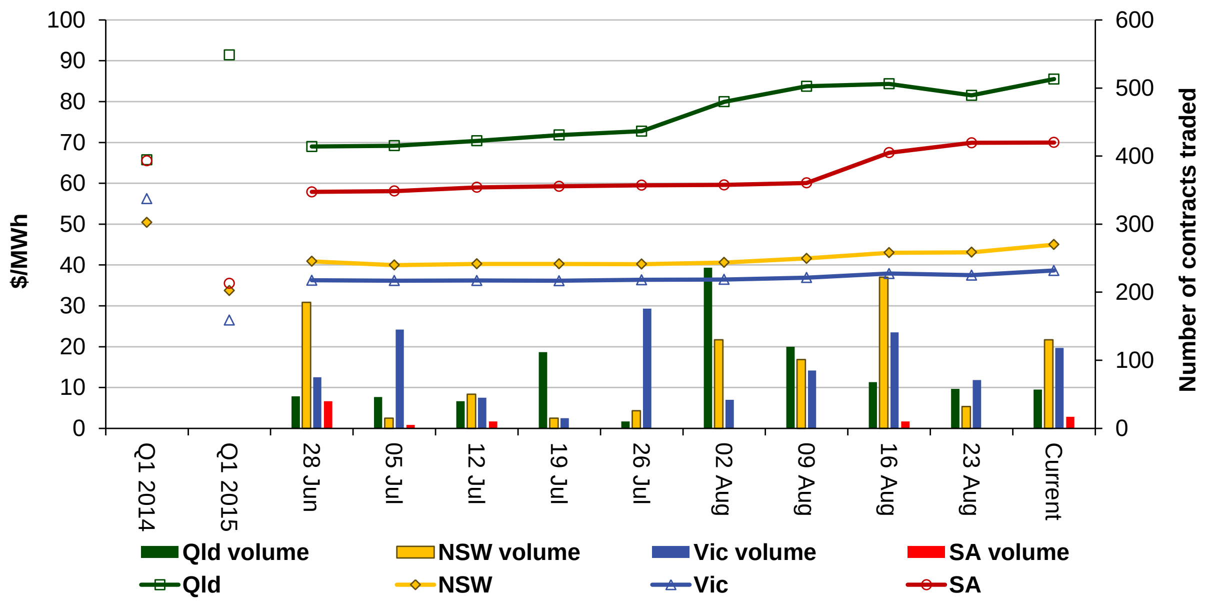
Figure 9: Quarterly base future prices Q3 2015 – Q2 2019



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)



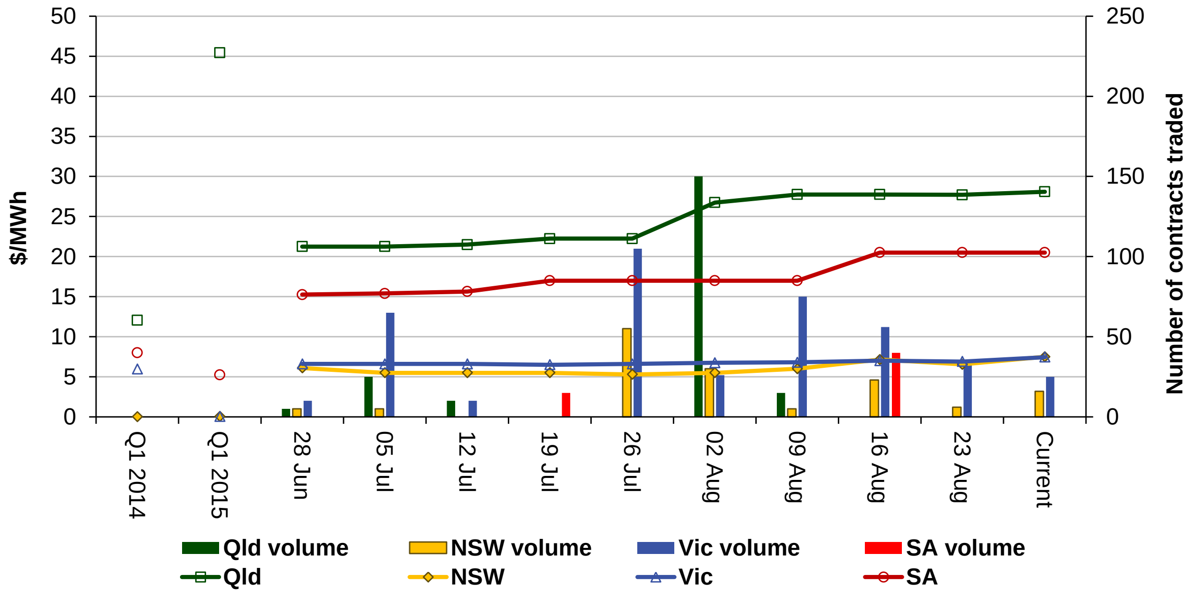
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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

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