Electricity Report

AUSTRALIAN ENERGY REGULATOR

5 - 11 August 2018

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 5 - 11 August 2018.

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

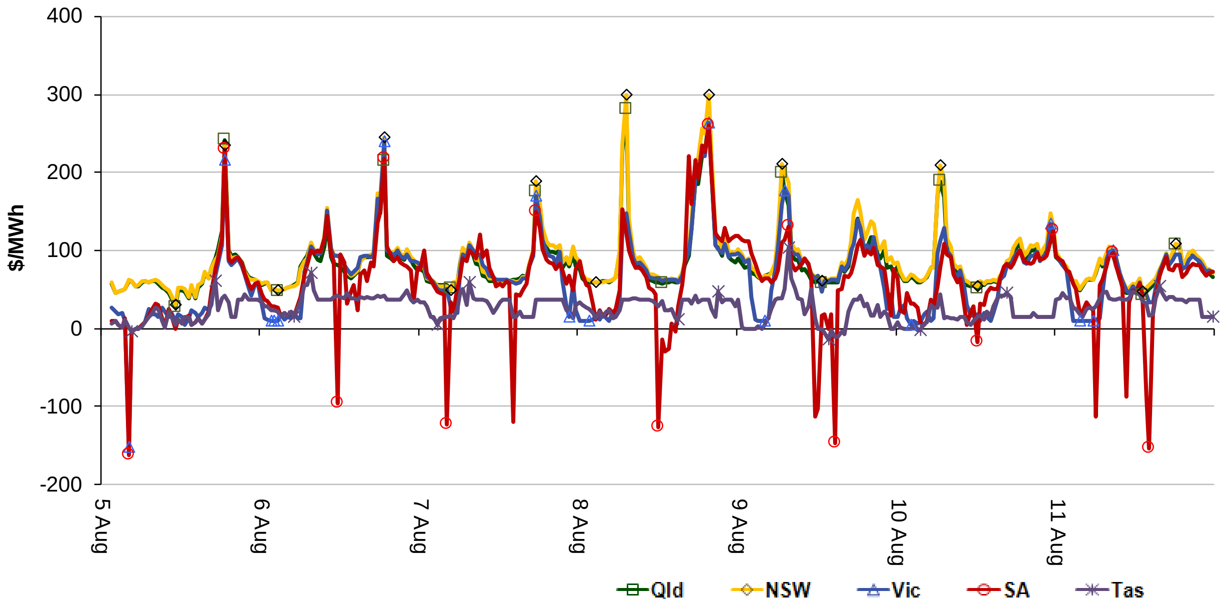


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

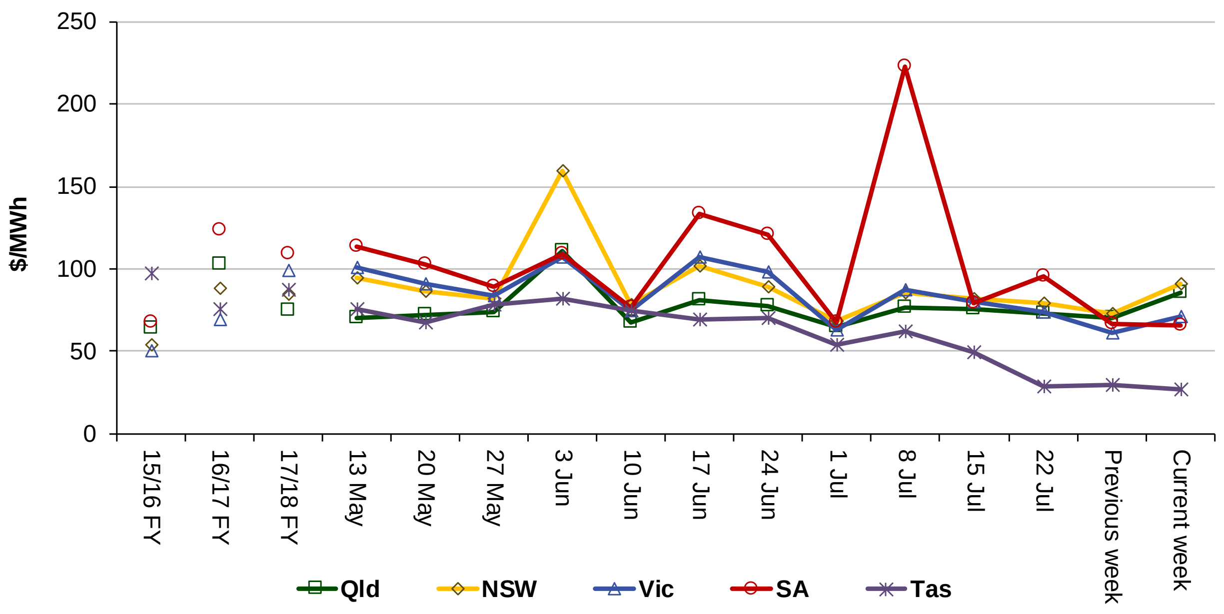


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	85	91	71	66	27
16-17 financial YTD	79	94	117	114	114
17-18 financial YTD	74	80	73	100	42

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 267 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. 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	6	21	0	3
% of total below forecast	10	44	0	16

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

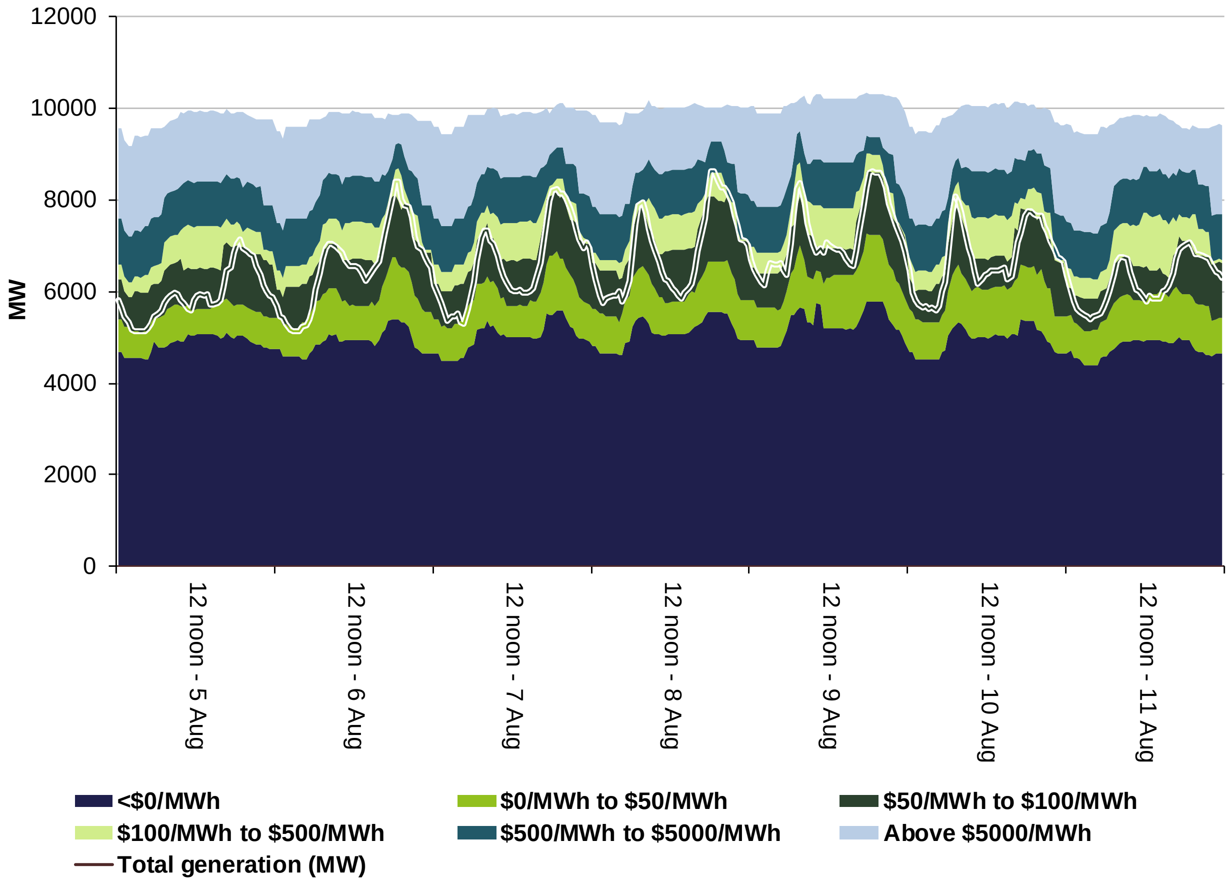


Figure 4: New South Wales generation and bidding patterns

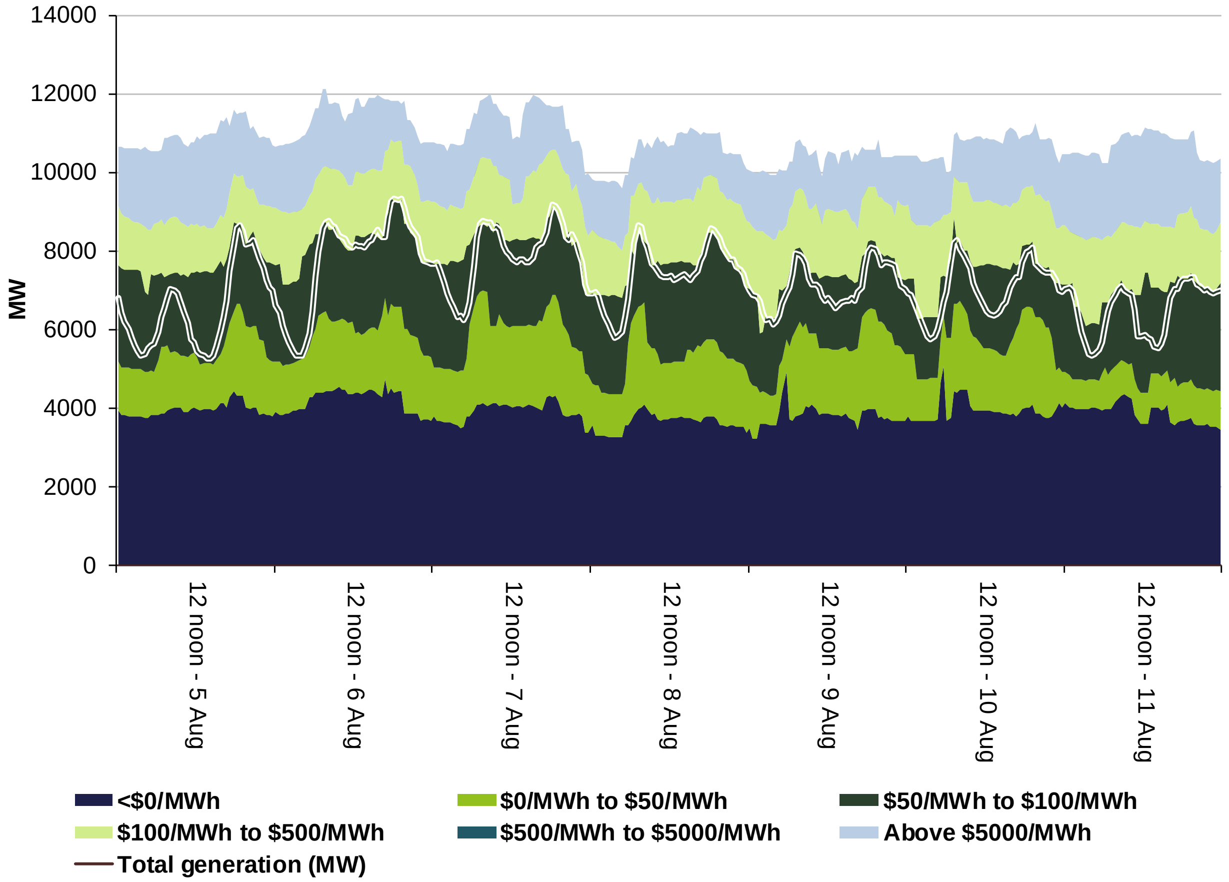


Figure 5: Victoria generation and bidding patterns

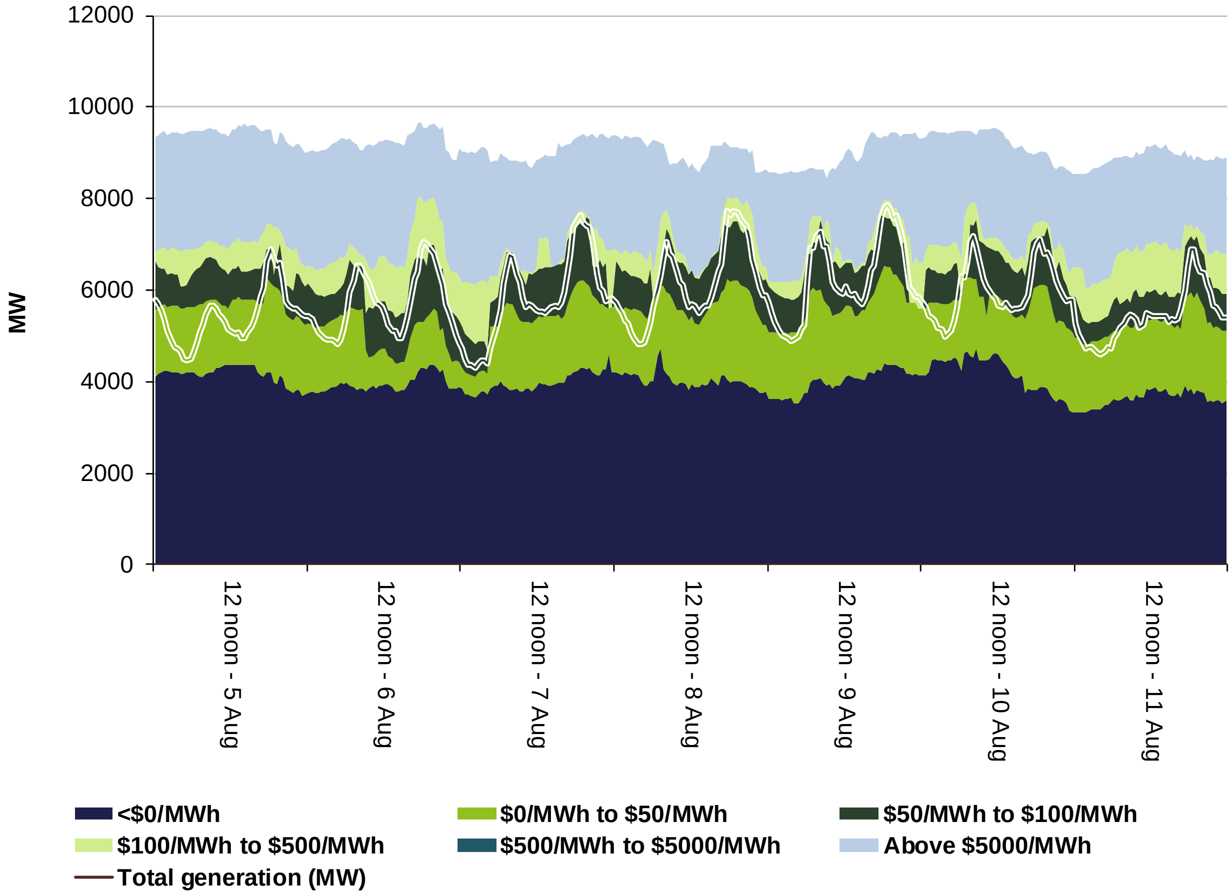


Figure 6: South Australia generation and bidding patterns

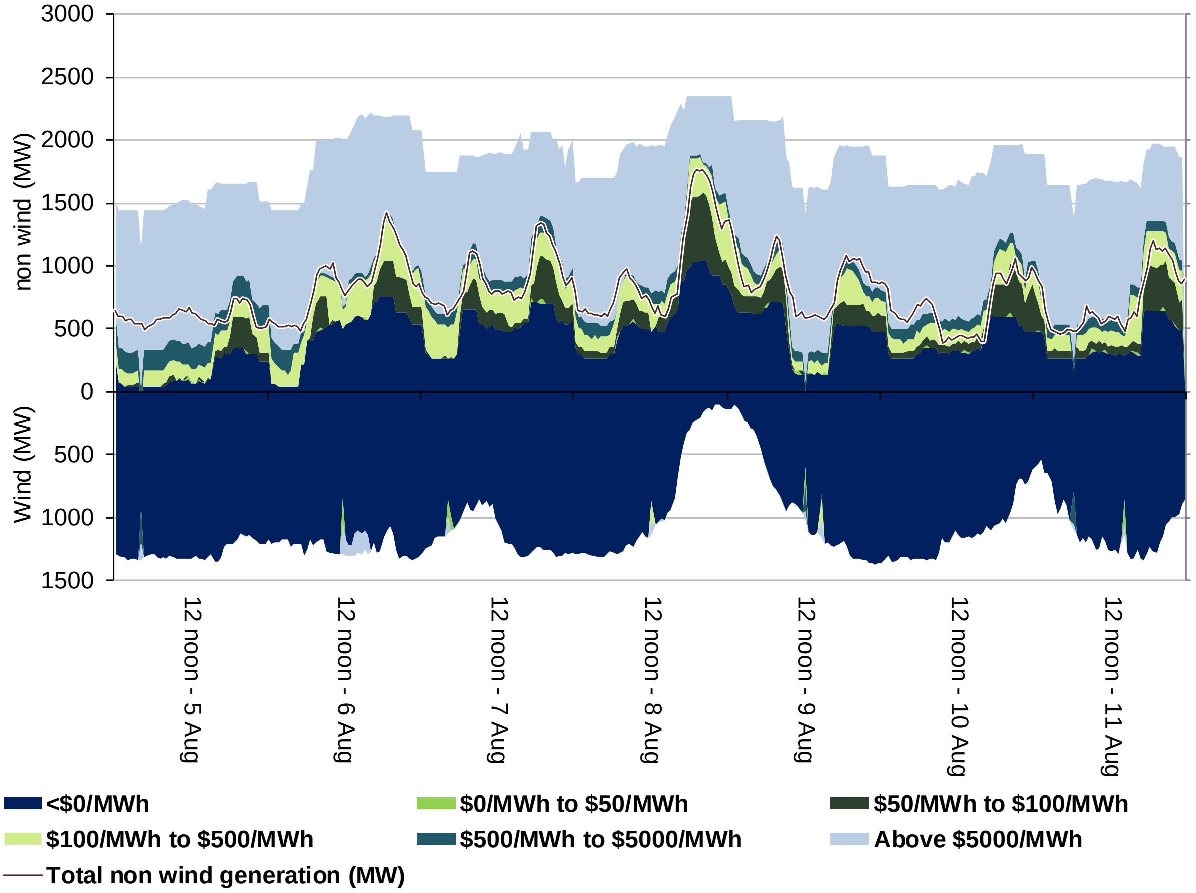
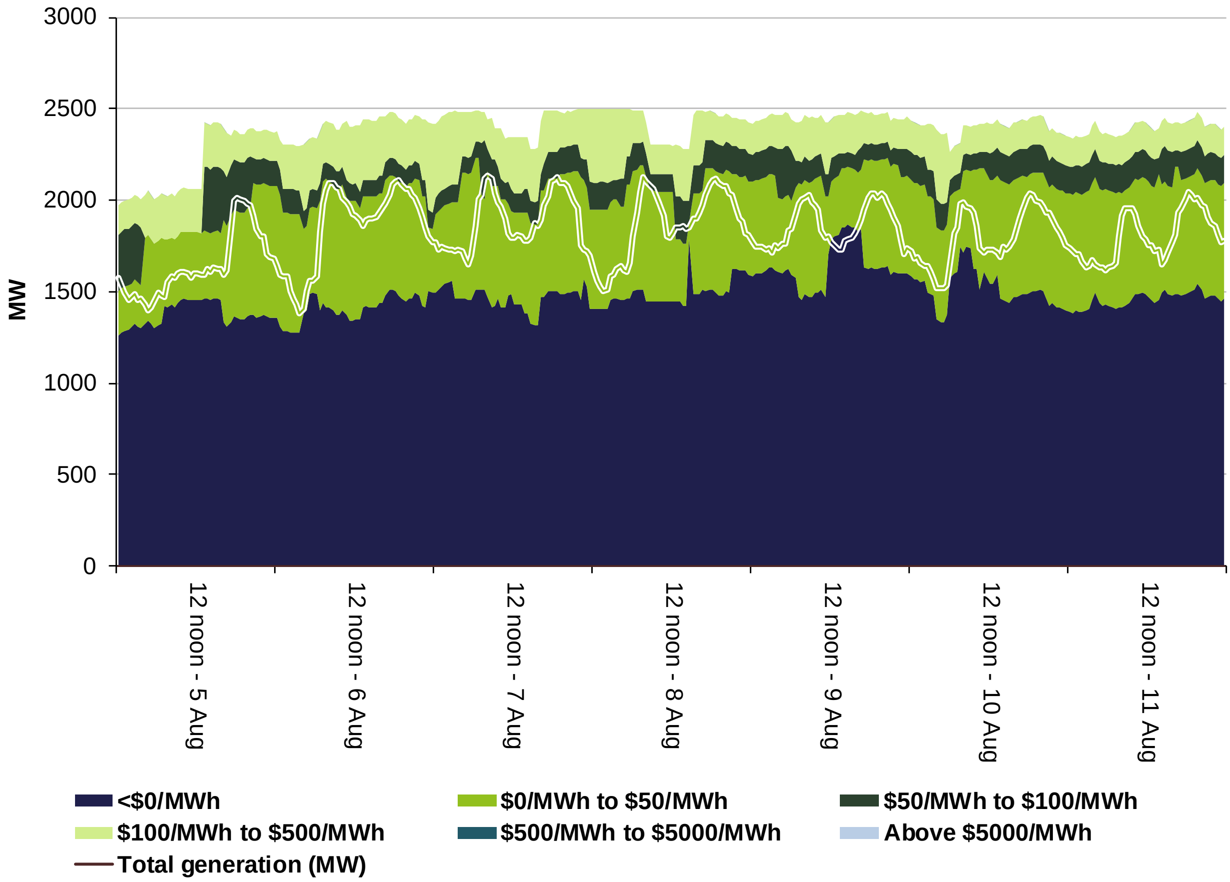


Figure 7: Tasmania generation and bidding patterns



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.

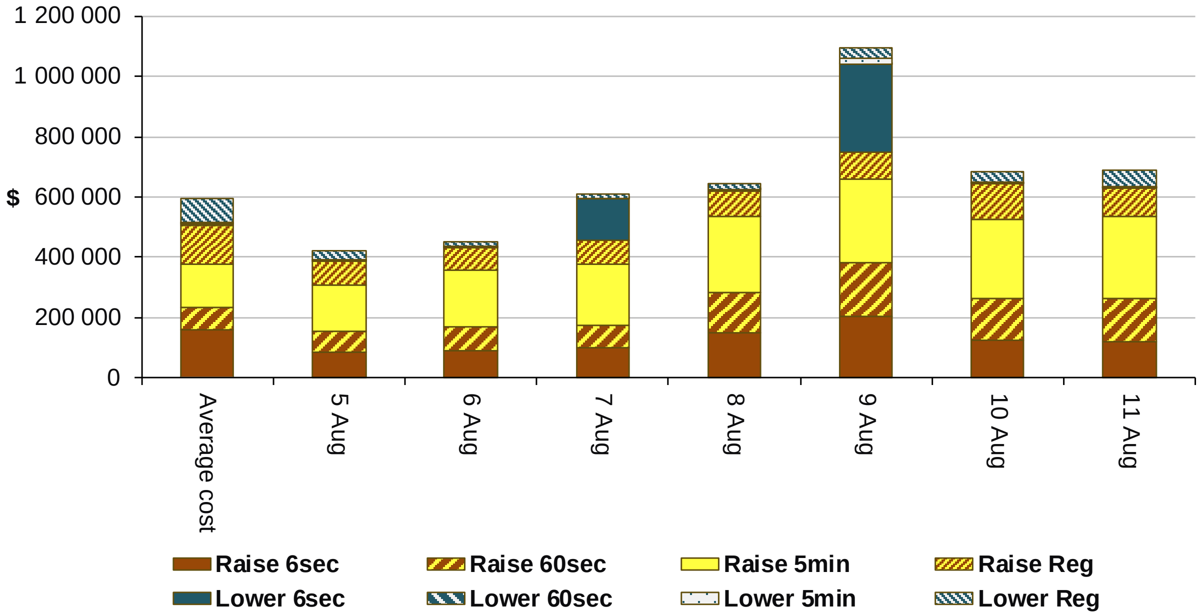
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4 078 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $517 500 or around nine 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



Due to a planned outage on 7 and 9 August on one Comalco to George Town line in Tasmania, local requirements for lower services were in place for multiple hours on both days. During the outage there were multiple prices above $100/MW and price spikes in lower 6 second services of around $900/MW on 7 August and $1650/MW on 9 August caused the higher than average prices.

Detailed market analysis of significant price events

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $85/MWh and above $250/MWh.

Wednesday, 8 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
7.30 am	280.89	121.00	135.64	7305	7011	7086	9864	9918	9934
8 pm	268.05	229.93	251.50	7303	7204	7370	9981	10 029	9951

Prices across New South Wales and Queensland were aligned for the 7.30 am trading interval and will be discussed as one region. Net demand was around 400 MW higher than forecast and availability was around 370 MW lower than forecast, both four hours ahead.

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

An unforecast ramping constraint meant imports from Victoria across the Vic-NSW interconnector were around 780 MW lower than forecast. The constraint was invoked in preparation of an outage on the Ararat to Horsham 220 kV line.

The combination of the reduction in imports from Victoria, higher than forecast demand and lower than forecast availability resulted in the higher than forecast price.

Prices across New South Wales, Queensland, Victoria and South Australia were aligned for the 8 pm trading interval and will be discussed as one region. Please see the South Australian section for this analysis.

New South Wales

There were two occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $91/MWh and above $250/MWh.

Wednesday, 8 August

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
7.30 am	299.60	130.43	137.69	9996	9888	9914	10 592	10 909	11 502
8 pm	299.60	299.60	299.60	10 318	10 151	10 055	10 895	10 846	11 536

Prices in New South Wales were aligned with Queensland for the 7.30 am trading interval, see Queensland section for this analysis.

Prices across New South Wales, Queensland, Victoria and South Australia were aligned for the 8 pm trading interval and will be discussed as one region. See the South Australian section for this analysis.

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $71/MWh and above $250/MWh.

Sunday, 5 August

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
4.30 am	-152.36	24.11	24.54	3603	3624	3633	9343	9395	9346

Prices across Victoria and South Australia were aligned. See Table 7 for further analysis.

Wednesday, 8 August

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
8.00 pm	264.06	280.80	306.30	6479	6519	6510	9029	9108	8721

Prices across New South Wales, Queensland, Victoria and South Australia were aligned for the 8 pm trading interval and will be discussed as one region. See Table 9 for further analysis.

South Australia

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of $66/MWh and above $250/MWh.

Sunday, 5 August

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
4.30 am	-163.04	8.05	9.19	982	881	871	2782	2526	2515

Prices across South Australia and Victoria were aligned for this trading interval and will be discussed as one region.

Net demand was 80 MW higher than forecast and availability was around 200 MW higher than forecast, both four hours prior.

The higher than forecast availability was due to the additional megawatts directed on by AEMO.

For the 4.20 am dispatch interval net demand decreased by 35 MW. With more expensive generation ramped down limited or trapped in FCAS and unable to set price, the dispatch price dropped to the floor and caused the lower than forecast trading interval.

Tuesday, 7 August

Table 8: 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
4.30 am	-122.45	44.48	46.11	1124	1070	1079	2875	2770	2644
2.30 pm	-119.70	50.31	57.49	1187	1286	1355	3101	3036	3052

For the 4.30 am trading interval demand was 54 MW higher than forecast and availability was 105 MW higher than forecast four hours prior.

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

The higher than forecast availability was due to the additional megawatts directed on by AEMO.

At 4.05 am demand decreased by 38 MW. With no capacity priced between $90/MWh and the floor, the dispatch price fell to the floor and led to the negatively priced trading interval.

For the 2.30 pm trading interval demand was around 100 MW lower than forecast while availability was 65 MW higher than forecast.

At 2.30 pm a system normal constraint which limits wind generation in the region stopped binding. This led to low priced wind generation increasing by 135 MW. As a result the dispatch price decreased to the floor and caused the lower than forecast price.

Wednesday, 8 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
12:30 pm	-126.77	35.61	39.52	1151	1110	1163	3097	2954	2956
8 pm	260.83	480.55	13 100.02	1905	1922	2001	2553	2594	2546

For the 12.30 pm trading interval demand was 41 MW higher than forecast while availability was 143 MW higher than forecast four hours prior.

With no capacity offered between $80/MWh and the price floor, small changes in demand or availability could lead to negative prices.

For the 12.10 pm dispatch interval wind generation (priced at the floor) increased by 29 MW while demand decreased by 38 MW. This led to the dispatch price fall to the floor during the negatively priced trading interval.

Prices were aligned across South Australia, Victoria, New South Wales and Queensland for the 8 pm trading interval so will be discussed here as one region.

Net demand was around 210 MW higher than forecast while availability was around 120 MW lower than forecast, four hours prior.

The price in New South Wales, Queensland and Victoria was close to that forecast four hours ahead while the South Australian price was lower than forecast. Rebids by Origin Energy and AGL in South Australia of around 300 MW of capacity from prices above $10 000/MWh to between $115/MWh and the floor led to the lower than forecast price.

Thursday, 9 August

Table 10: 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
Midday	-113.06	49.08	44.06	850	963	969	2579	2554	2574
12.30 pm	-103.37	29.93	52.39	853	927	929	2650	2587	2613
3 pm	-146.97	44.96	20.29	905	854	922	2778	2669	2656

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

For the midday and 12.30 pm trading intervals demand was between 113 – 74 MW lower than forecast while availability was between 25 – 63 MW higher than forecast four hours prior.

For the 12 pm dispatch interval, wind generation increased by 31 MW. With no capacity priced between $185/MWh and the floor, the dispatch price reached the floor and led to the negatively priced trading interval.

The 12.05 pm dispatch interval remained at the floor after exports into Victoria decreased by 55 MW. Prices then increased to between $65/MWh to $92/MWh for the remainder of the trading interval after a number of wind farms rebid capacity from the floor to higher prices.

These two dispatch prices at the floor caused the lower than forecast trading intervals.

For the 3 pm trading interval demand was 51 MW higher than forecast and availability was 109 MW higher than forecast four hours prior.

At 2.35 pm wind generation increased by 39 MW and the dispatch price fell to the floor. In response to the negative price a number of wind farms rebid capacity from the floor to prices $60/MWh and above and dispatch prices increased to between -$1/MWh and $63/MWh for the remainder of the trading interval.

Saturday, 11 August

Table 11: 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 am	-112.80	44.15	45.94	1041	970	1068	2748	2586	2606
2.30 pm	-153.92	20.12	40.59	1091	906	950	2802	2727	2702

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

For the 6.30 am trading interval demand was around 70 MW higher than forecast and availability was around 160 MW higher than forecast four hours prior.

With no capacity priced between $70/MWh and -$1000/MWh small changes in demand and availability could cause large movements in price.

At 6.05 am demand decreased by 49 MW and the dispatch price fell to the floor. In response to the negative price a number of wind farms rebid capacity from the floor to $1000/MWh and above and dispatch price remained between $51/MWh and $79/MWh for the remainder of the trading interval.

For the 2.30 pm trading interval demand was 185 MW higher than forecast and availability was 75 MW higher than forecast four hours prior.

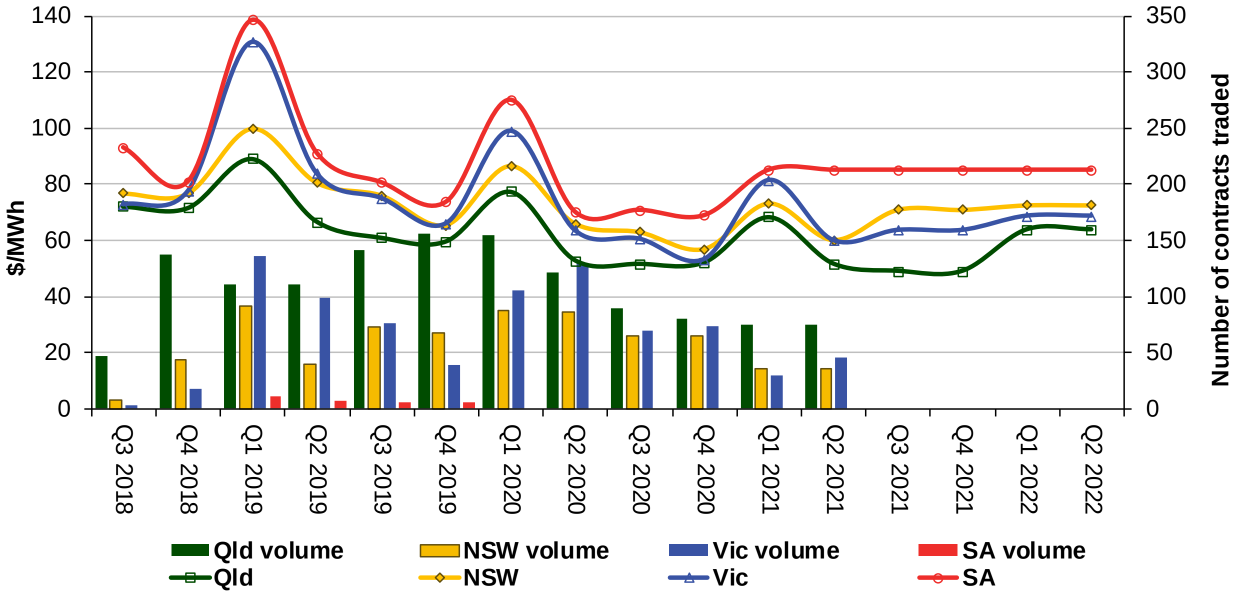
With no capacity priced between $70/MWh and -$1000/MWh small changes in demand and availability could cause large movements in price.

At 2.05 pm demand decreased by 28 MW and wind generation increased by 37 MW which led to the dispatch price at the floor. In response to the negative price a number of wind farms rebid capacity from the floor to $0/MWh and above. The dispatch price was between $0/MWh and $31/MWh for the remainder of the trading interval.

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.

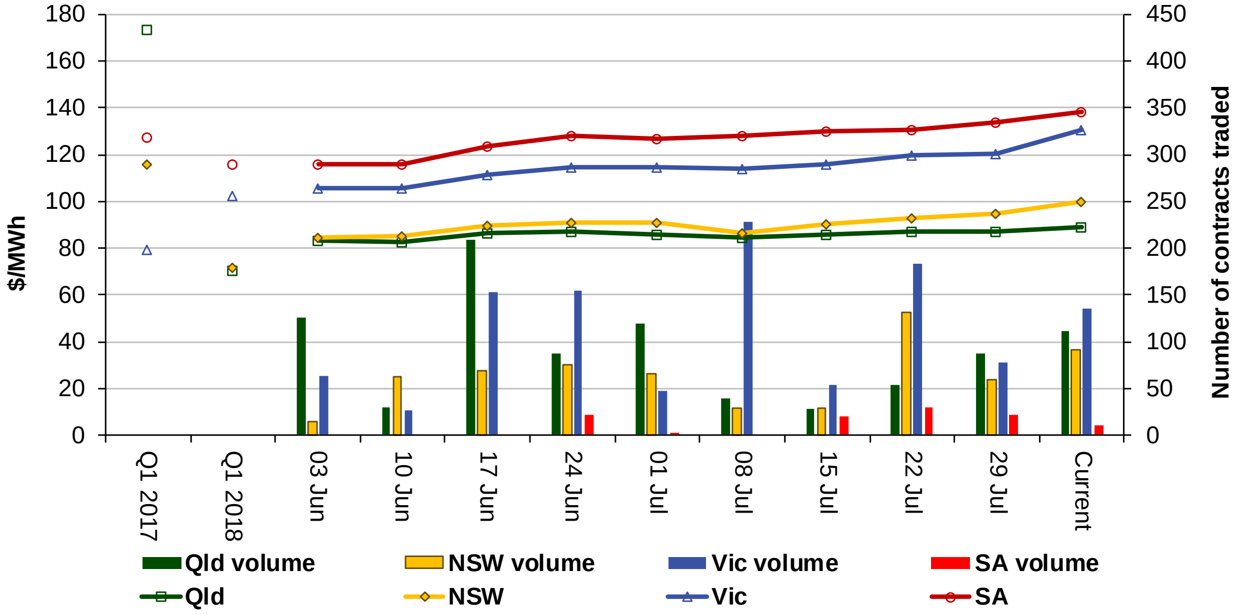
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 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 2019 base contracts over the past 10 weeks (and the past 2 years)



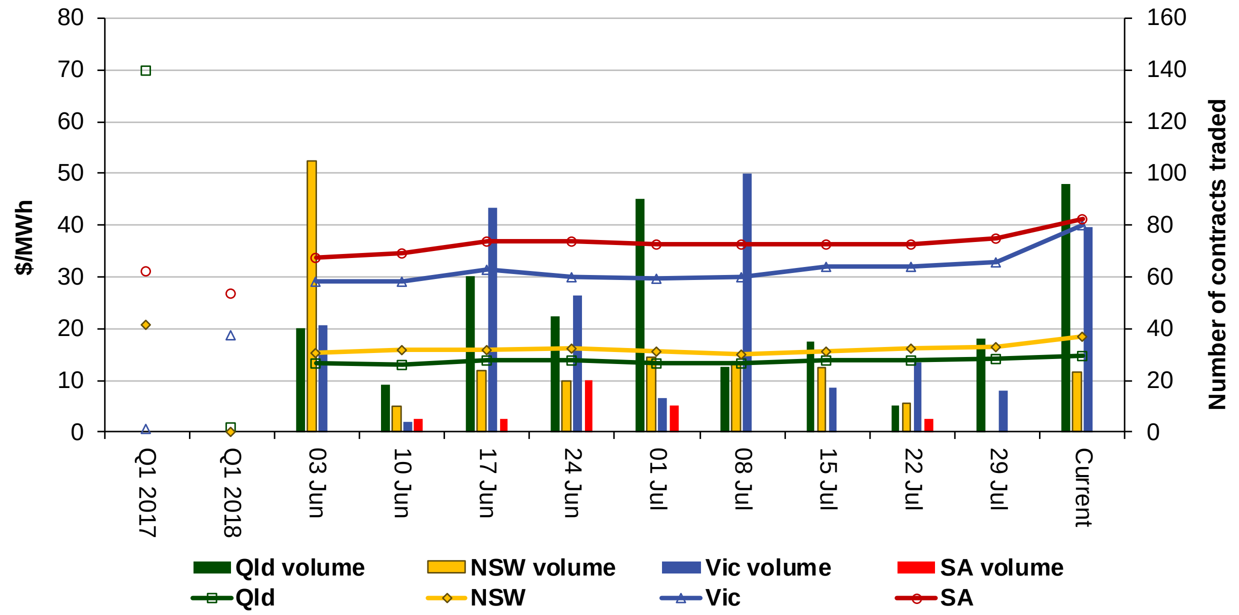
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 11 shows how the price for each regional quarter 1 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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