9 - 15 September 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 9 – 15 September 2018.

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

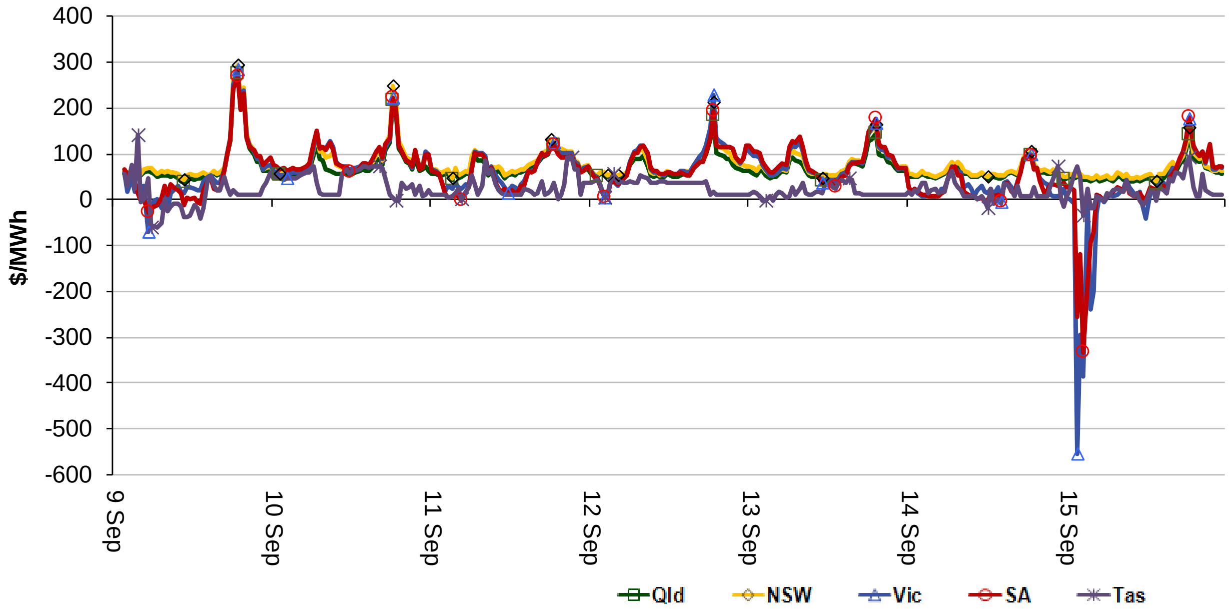


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

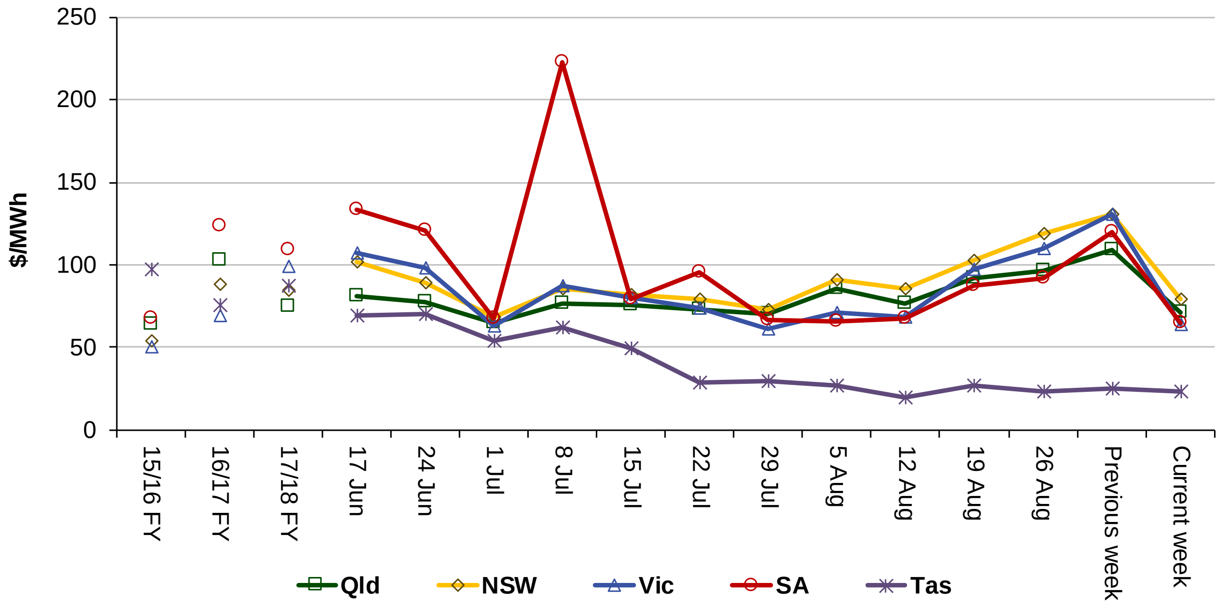


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	71	79	63	65	24
17-18 financial YTD	82	98	109	108	104
18-19 financial YTD	81	91	82	94	34

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 258 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	3	19	0	2
% of total below forecast	13	52	0	11

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

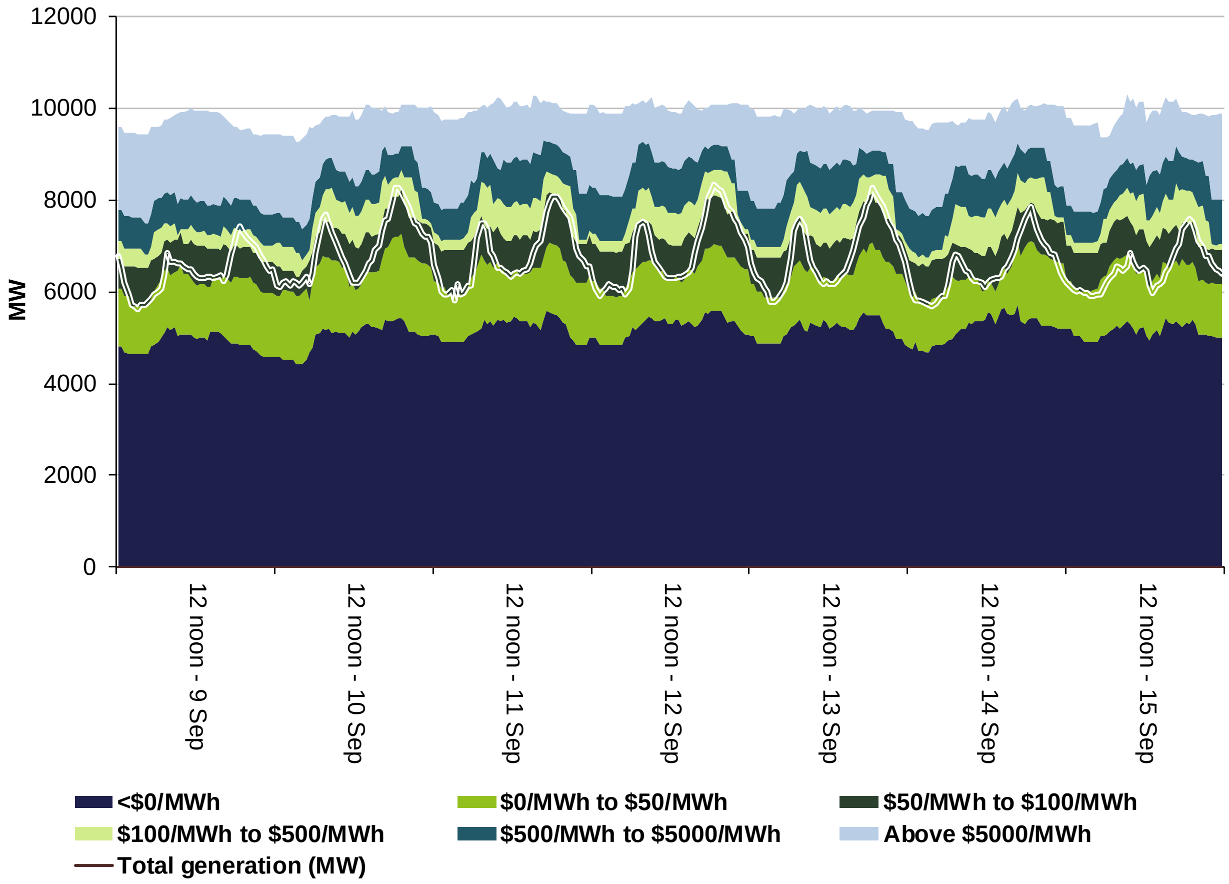


Figure 4: New South Wales generation and bidding patterns

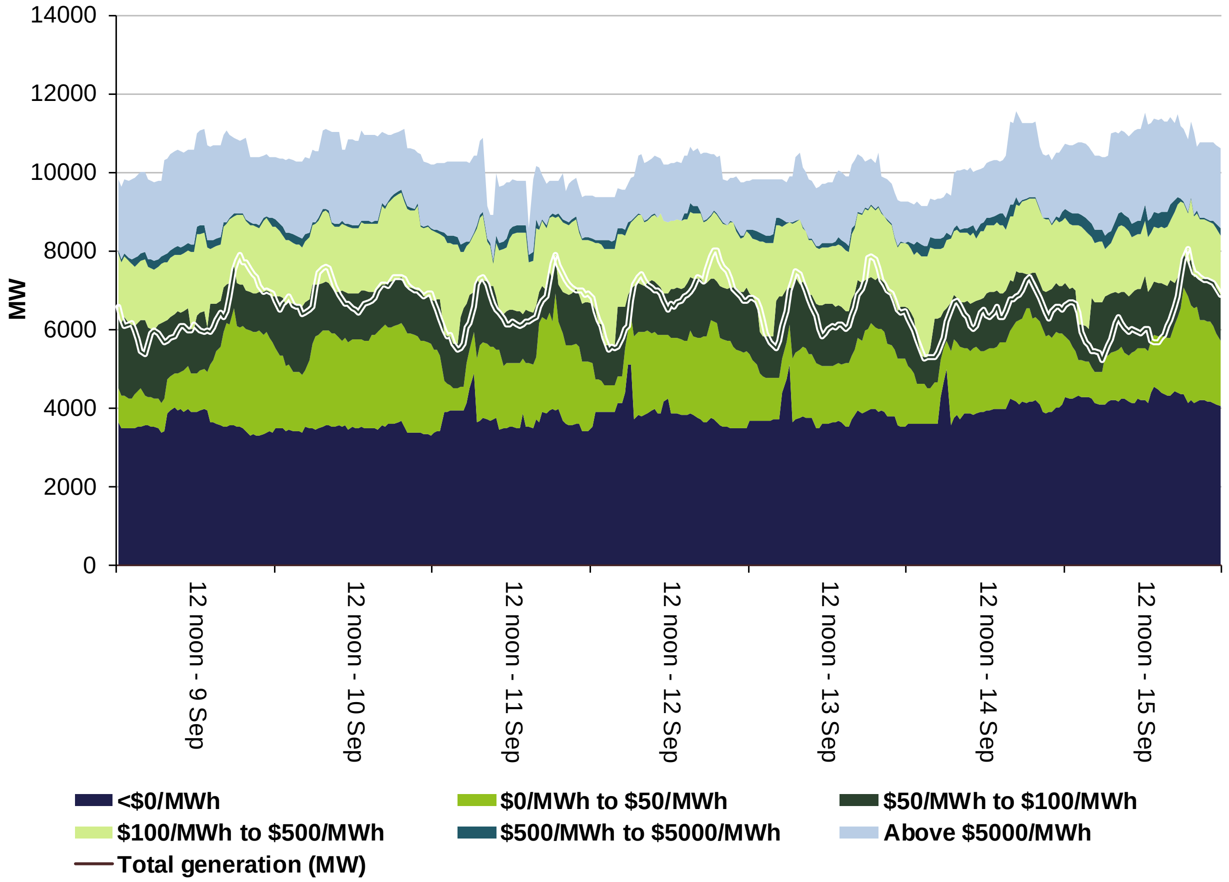


Figure 5: Victoria generation and bidding patterns

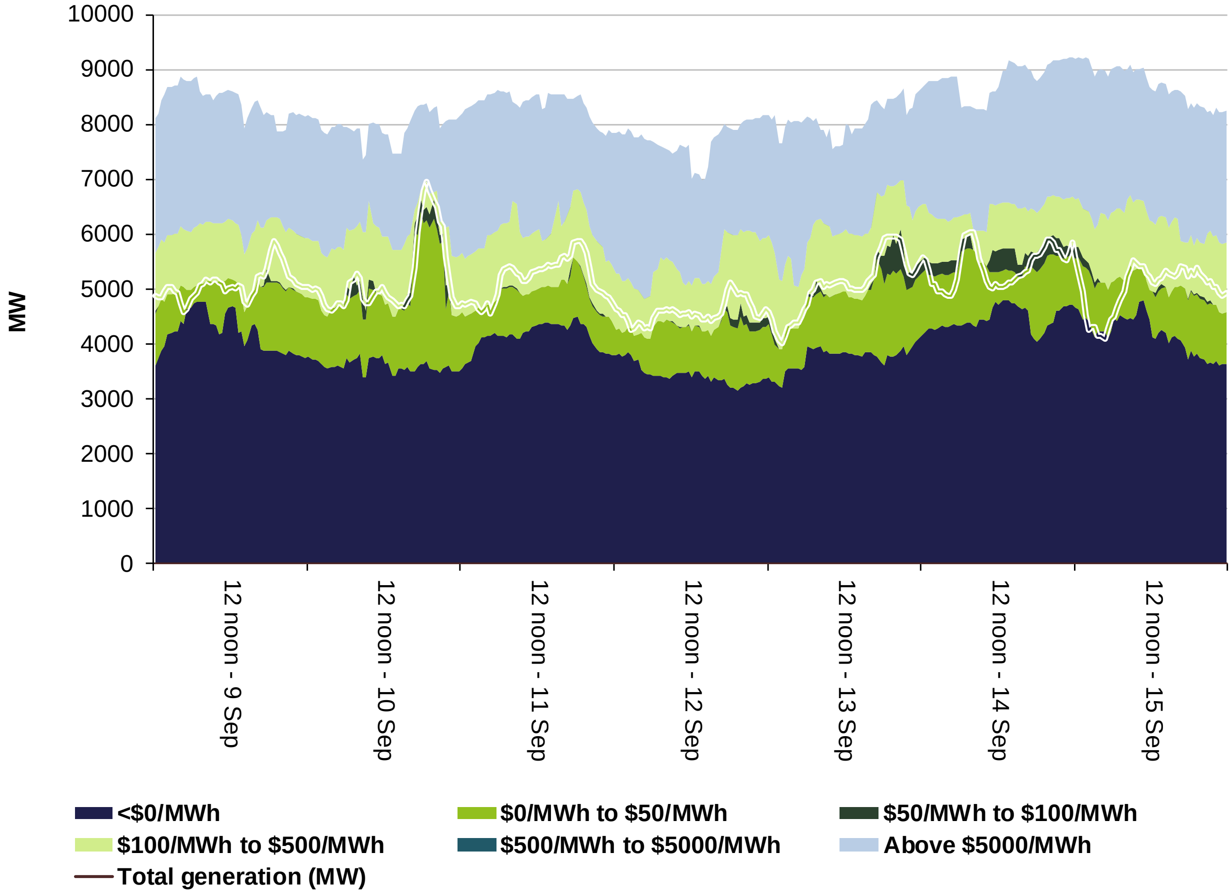


Figure 6: South Australia generation and bidding patterns

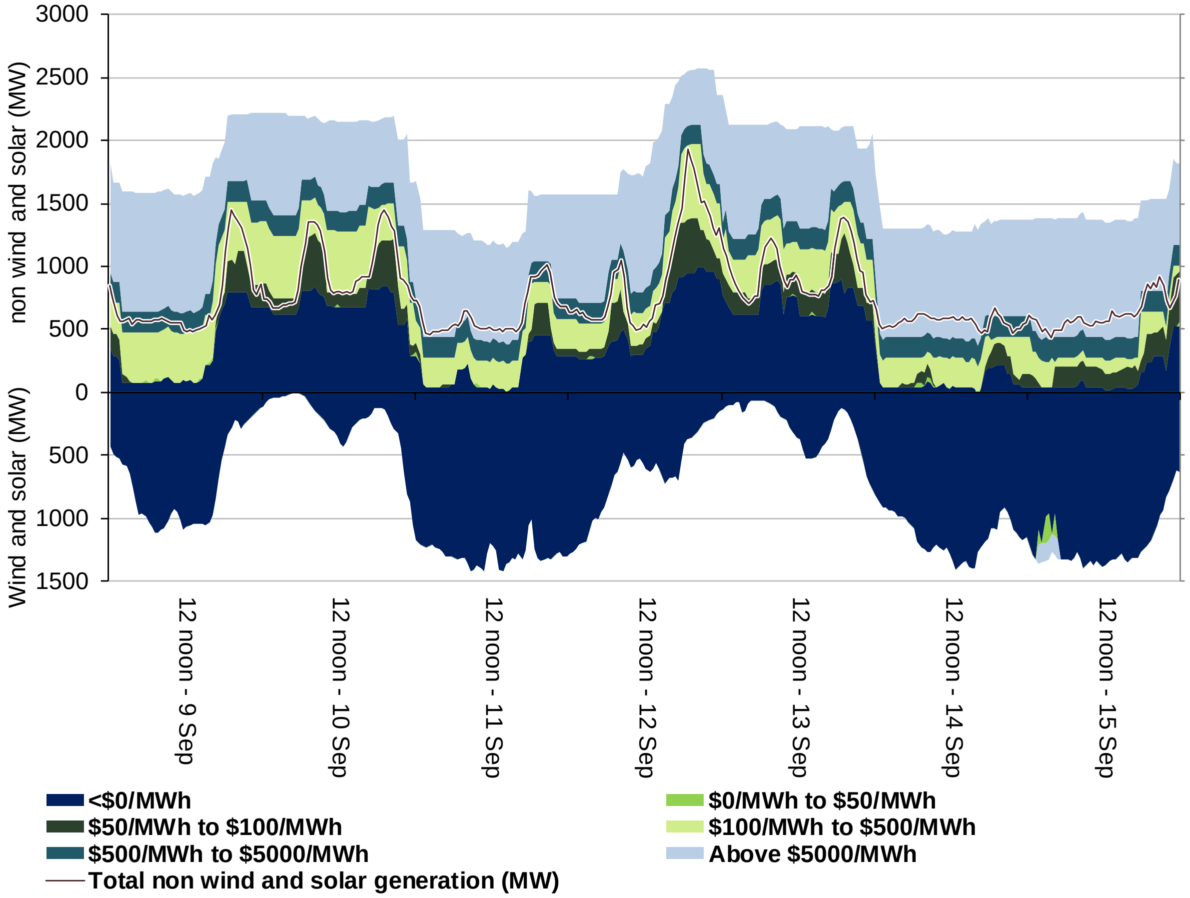
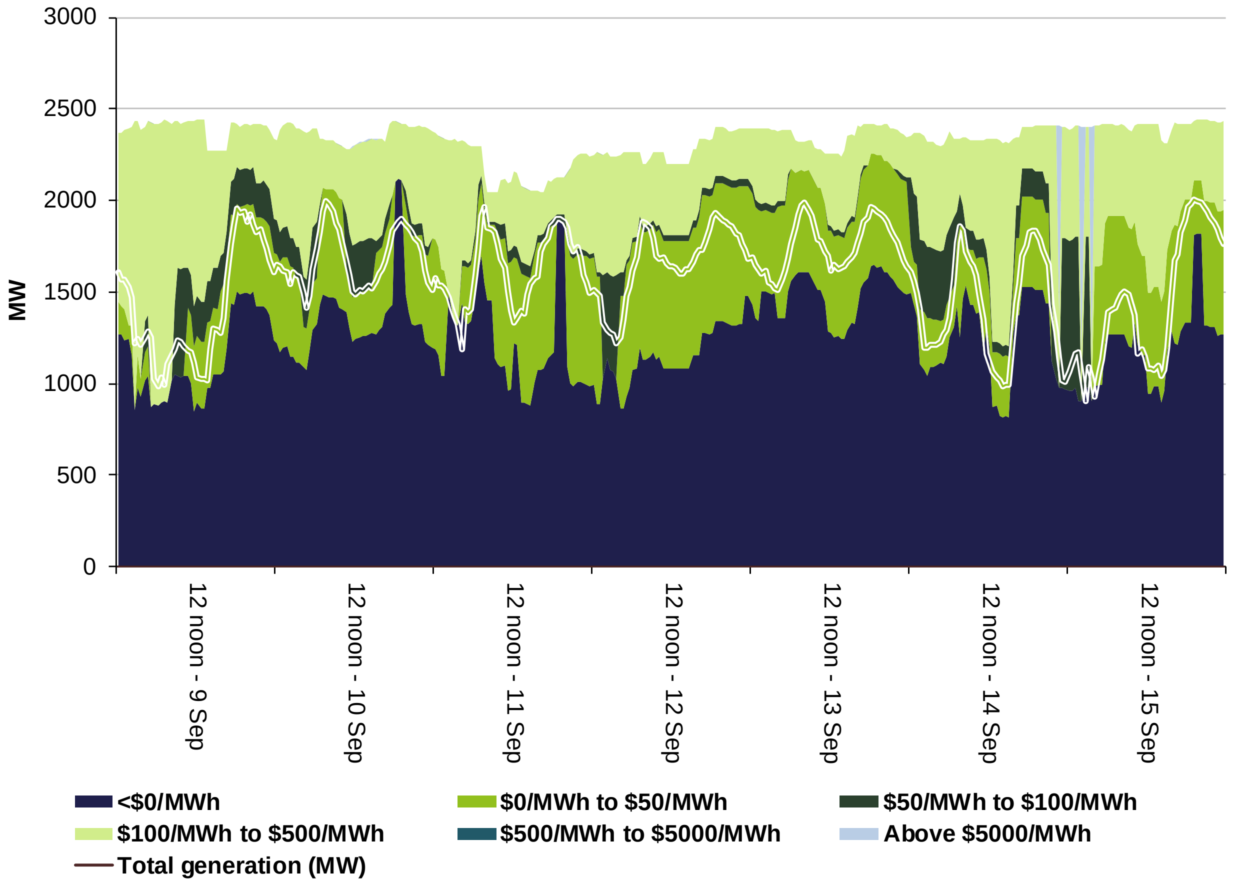


Figure 7: Tasmania generation and bidding patterns



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.

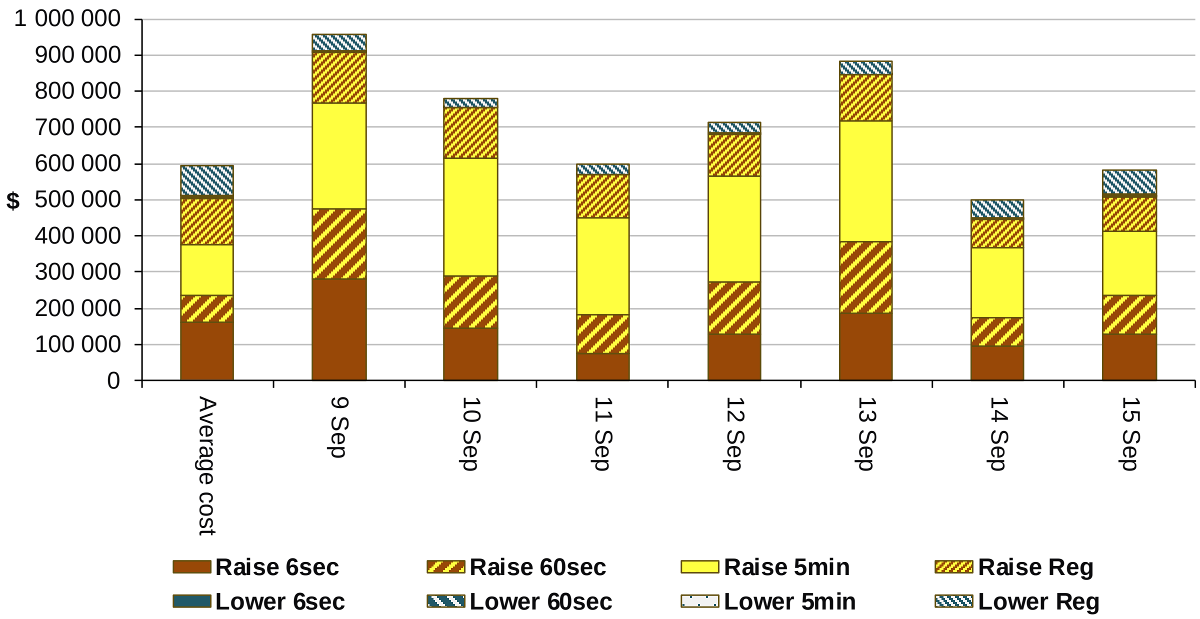
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $4 592 000 or around two per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $424 000 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



Detailed market analysis of significant price events

Queensland

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

Sunday, 9 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
7 pm	273.64	204.38	240.73	6770	6636	6832	9547	9664	9519

Please see the New South Wales 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 $79/MWh and above $250/MWh.

Sunday, 9 September

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
6:30 pm	261.47	153.87	148.98	8732	8371	8568	10 856	10 941	11 329
7 pm	292.89	225.00	262.78	8848	8442	8632	10 826	10 922	11 299

For the 6.30 pm trading interval prices were aligned with Victoria and will be discussed as one region.

Across both regions, demand was around 370 MW higher than forecast and availability was around 225 MW lower than forecast, both four hours prior.

In the four hours leading up to the start of the trading interval, EnergyAustralia removed 420 MW of capacity at Tallawara power station, priced between the floor and $81/MWh due to plant issues. Although Origin shifted 245 MW of capacity at Uranquinty and Shoalhaven power stations from the price cap to $69/MWh and below, higher priced capacity was still needed to meet the higher than forecast demand. Effective for the 6.10 pm dispatch interval, Wivenhoe power station shifted 25 MW from $160/MWh to $241/MWh and set price at this level for the 6.10 pm and 6.15 pm dispatch intervals.

For the 7 pm trading interval prices were aligned across all the mainland regions of the NEM so will be discussed as a single region.

Net demand was 542 MW greater than forecast and availability was 329 MW lower than forecast four hours ahead. The majority of the demand forecast error occurred in New South Wales. The removal of 420 MW at Tallawara power station and the rebid from Wivenhoe, outlined above in the 6.30 pm trading interval, were still in effect leading to the lower than forecast availability of low priced generation.

The higher than forecast demand and lower than forecast availability meant higher priced capacity was required to meet demand across all regions of the NEM.

Victoria

There were two occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $63/MWh and above $250/MWh and there were five occasions where the spot price was below -$100/MWh.

Sunday, 9 September

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
6:30 pm	250.74	152.00	147.75	5486	5476	5426	8179	8318	8320
7 pm	282.98	224.75	267.19	5610	5626	5610	8167	8290	8301

The 6.30 pm price was aligned with New South Wales and is discussed above.

For the 7 pm trading interval, prices were aligned across all mainland regions of the NEM. Please see the New South Wales section for this analysis.

Saturday, 15 September

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
2 am	-554.62	23.28	25.44	3836	3955	3951	9226	9169	9157
2:30 am	-296.45	23.09	25.24	3708	3795	3760	9197	9151	9149
3 am	-387.56	20.70	25.21	3606	3657	3647	9047	9133	9137
4 am	-239.87	20.90	14.08	3518	3640	3596	8976	8956	9044
4:30 am	-201.66	14.32	7.60	3523	3577	3533	8997	8983	9137

Demand was between 51 MW and 122 MW lower than forecast and availability was close to forecast, both four hours ahead.

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO issued a direction to a participant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions of the NEM following an intervention in the market.

Exports from Victoria into New South Wales were between 280 MW and 414 MW lower than that forecast four hours prior. This was due to an unforecast system normal constraint which prevents transient instability if the Heywood – South Morang 500 kV line trips. This constraint reduced the export limit on the Vic-NSW interconnector.

The reduction in exports and lower than forecast demand meant lower priced generation was required to set price. Multiple times during the morning demand dropped or low priced wind generation increased. Even though higher priced generation was dispatched it could not set price. This led to negatively priced dispatch intervals, resulting in the spot price being lower than forecast for the morning.

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 $65/MWh and above $250/MWh and there were four occasions where the spot price was below -$100/MWh

Sunday, 9 September

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
7 pm	268.80	215.89	265.53	1530	1512	1499	2548	2541	2450

For the 7 pm trading interval, prices were aligned across all mainland regions of the NEM. Please see the New South Wales section for this analysis.

Saturday, 15 September

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
2 am	-257.30	.38	9.75	1051	996	994	2738	2452	2445
2:30 am	-119.30	.00	9.40	1042	947	939	2731	2464	2450
3 am	-332.36	-.75	9.06	990	913	905	2720	2463	2490
3:30 am	-180.87	-.92	2.39	977	885	871	2702	2464	2493

Demand was between 55 MW and 95 MW higher than forecast and availability was up to 286 MW higher than forecast, both four hours ahead.

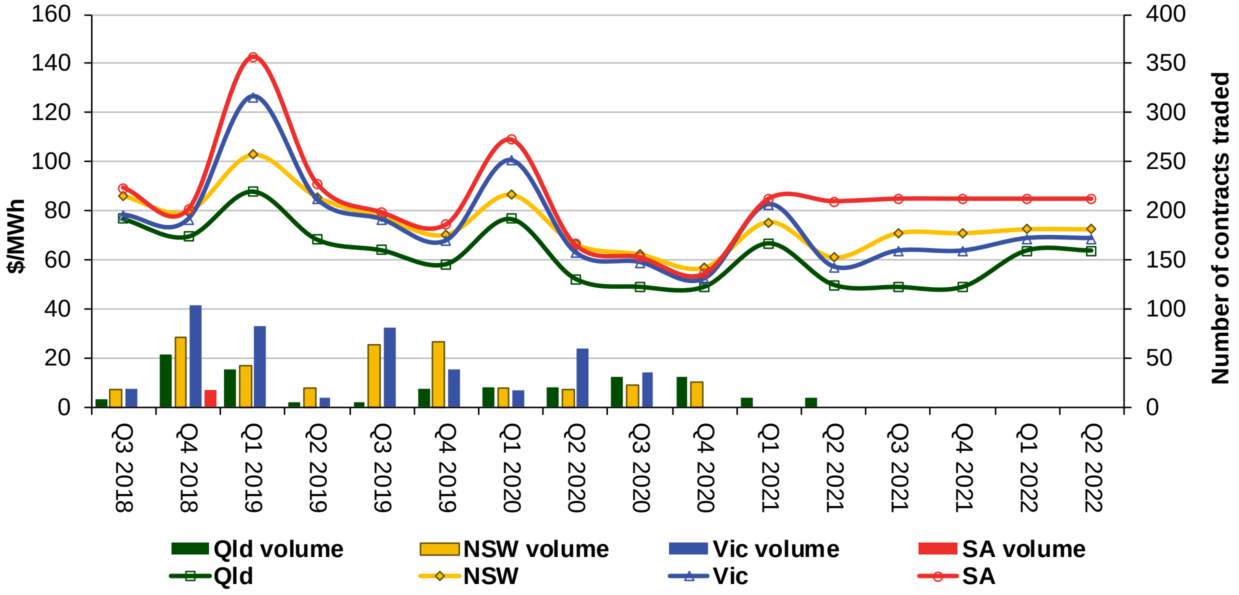
At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO issued a direction to a participant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions of the NEM following an intervention in the market.

Although exports were forecast into Victoria for the early morning, an unforecast import constraint forced flows into Victoria, counter price. Local wind generation was often either constrained or at max available, so could not set price. During these times, negatively priced generation in other regions set the price in South Australia. For the 3 am and 3.10 am dispatch intervals, local wind generation priced at the floor in South Australia set price when there was an increase in wind or drop 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.

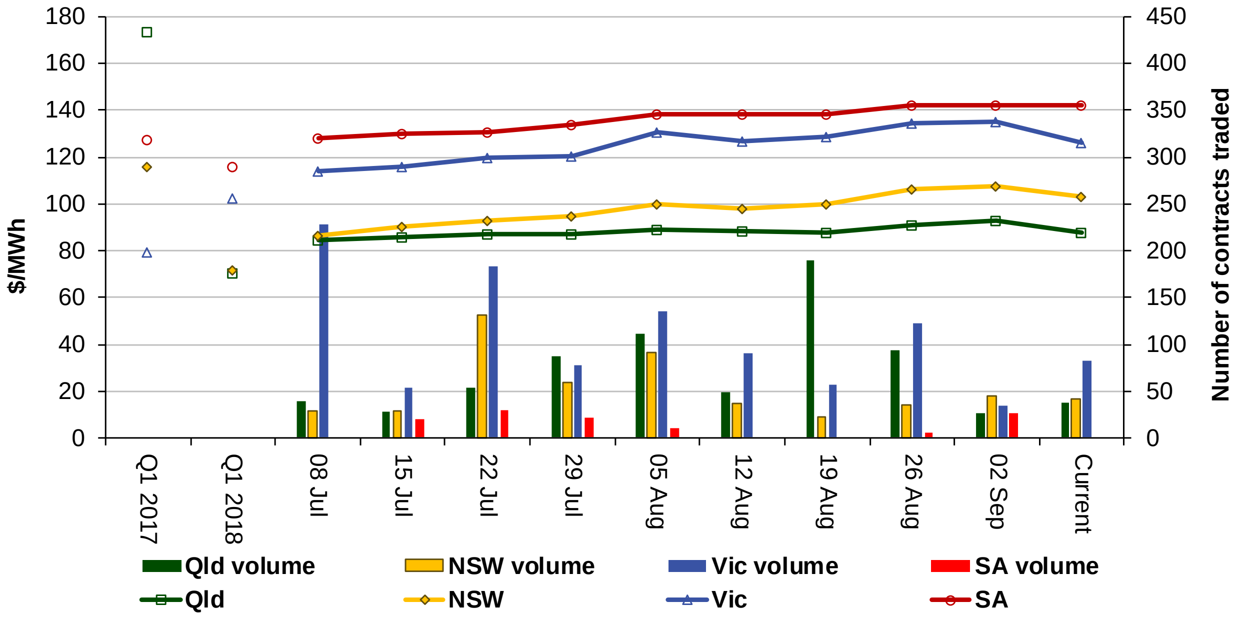
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



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)



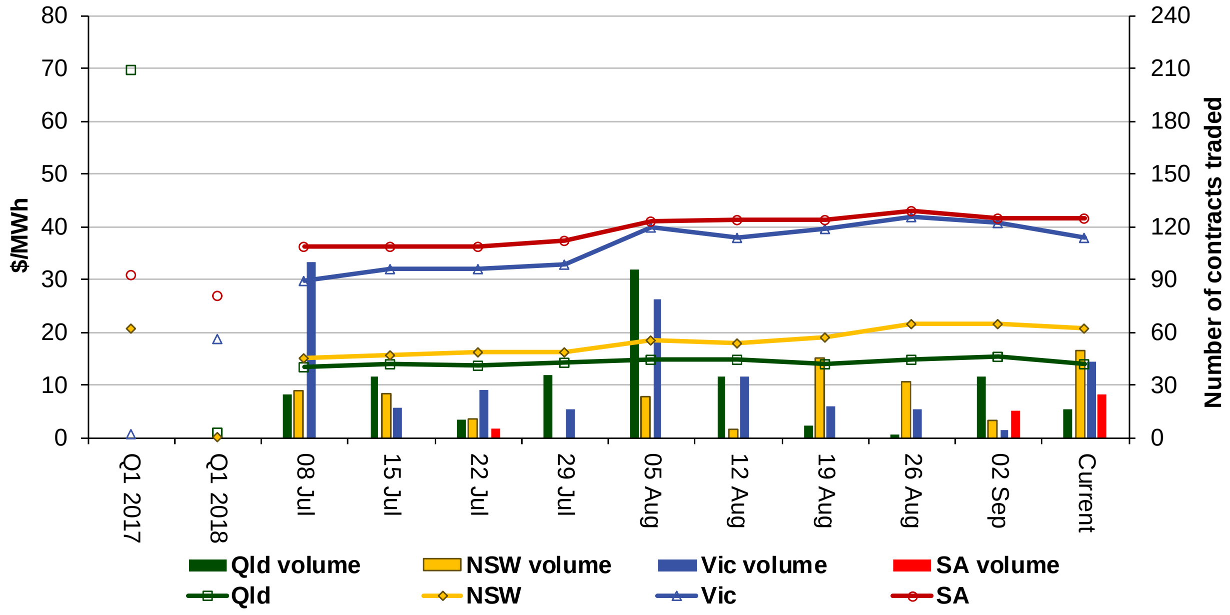
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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
November 2018