Electricity Report

AUSTRALIAN ENERGY REGULATOR

11 – 17 August 2019

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 11 to 17 August 2019.

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

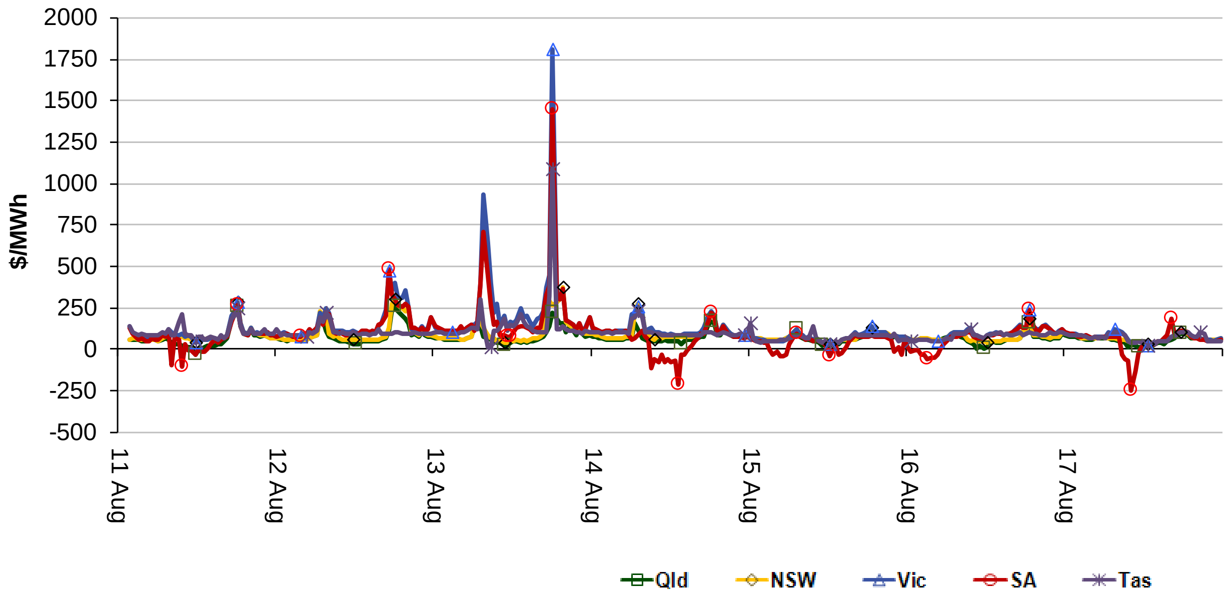


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

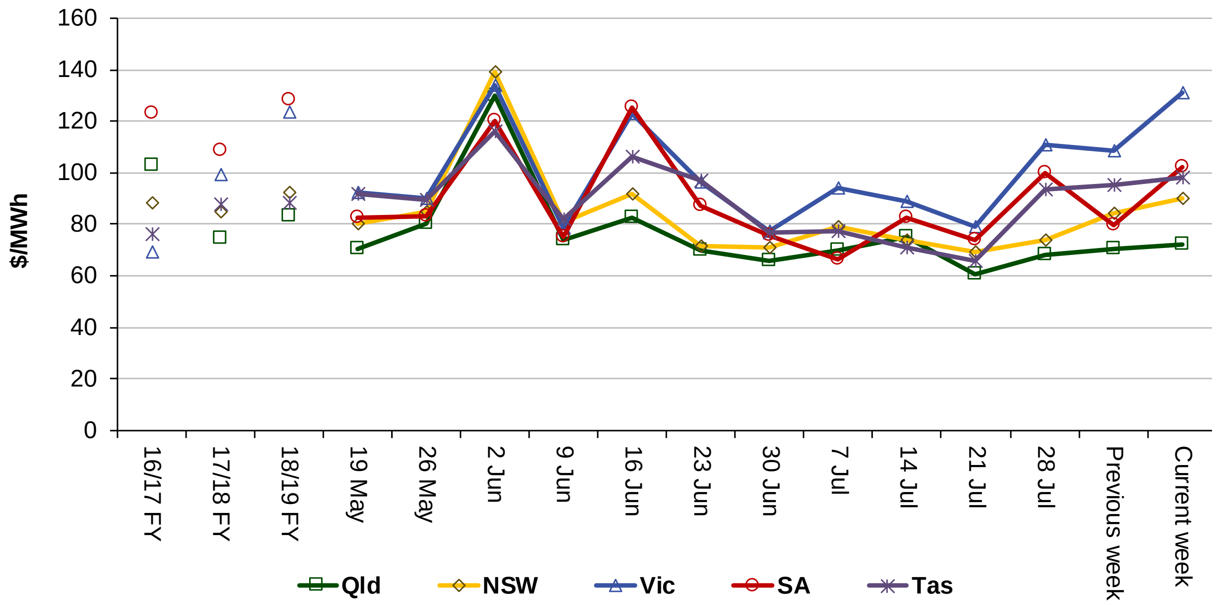


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	72	90	131	102	98
18-19 financial YTD	75	81	73	97	39
19-20 financial YTD	69	78	100	84	83

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 220 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2018 of 199 counts and the average in 2017 of 185. 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	25	0	2
% of total below forecast	10	48	0	8

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

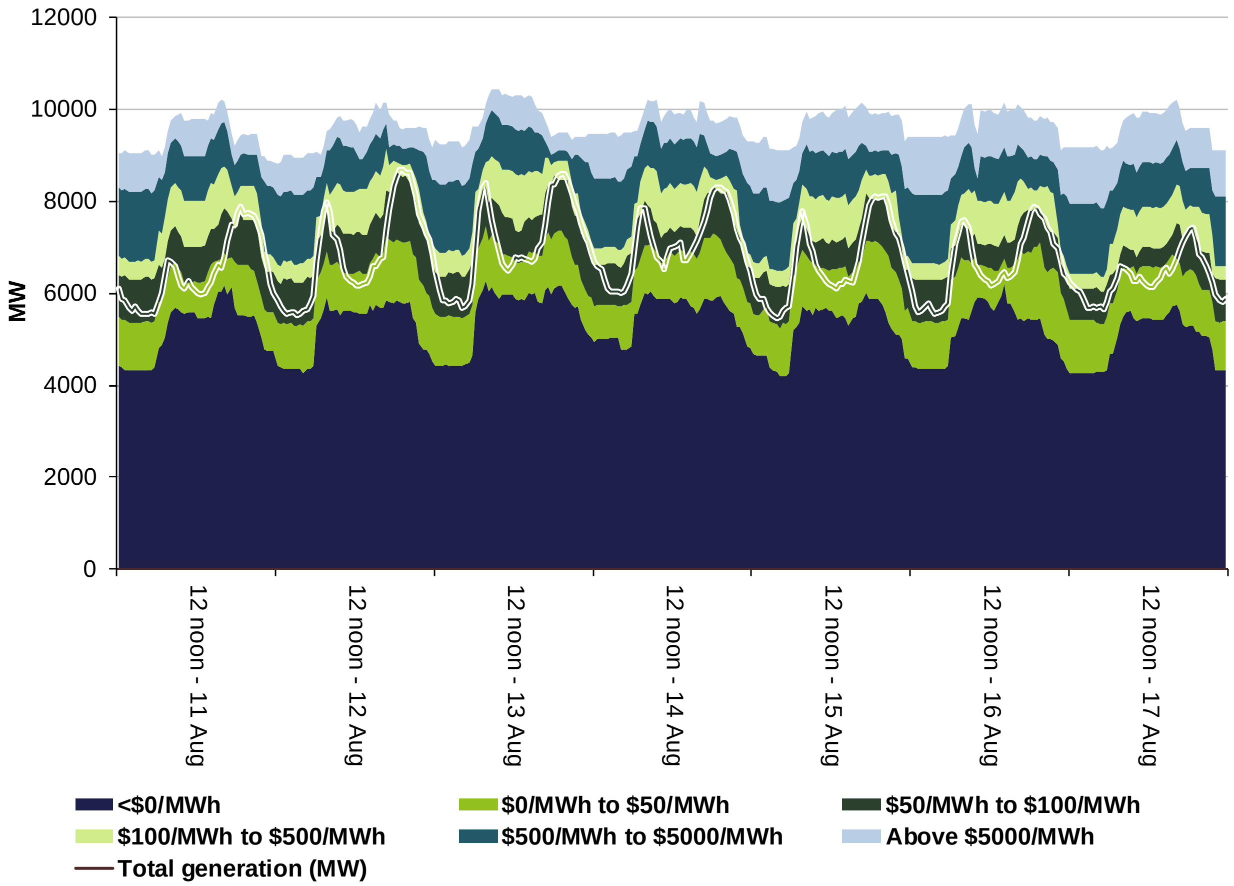


Figure 4: New South Wales generation and bidding patterns

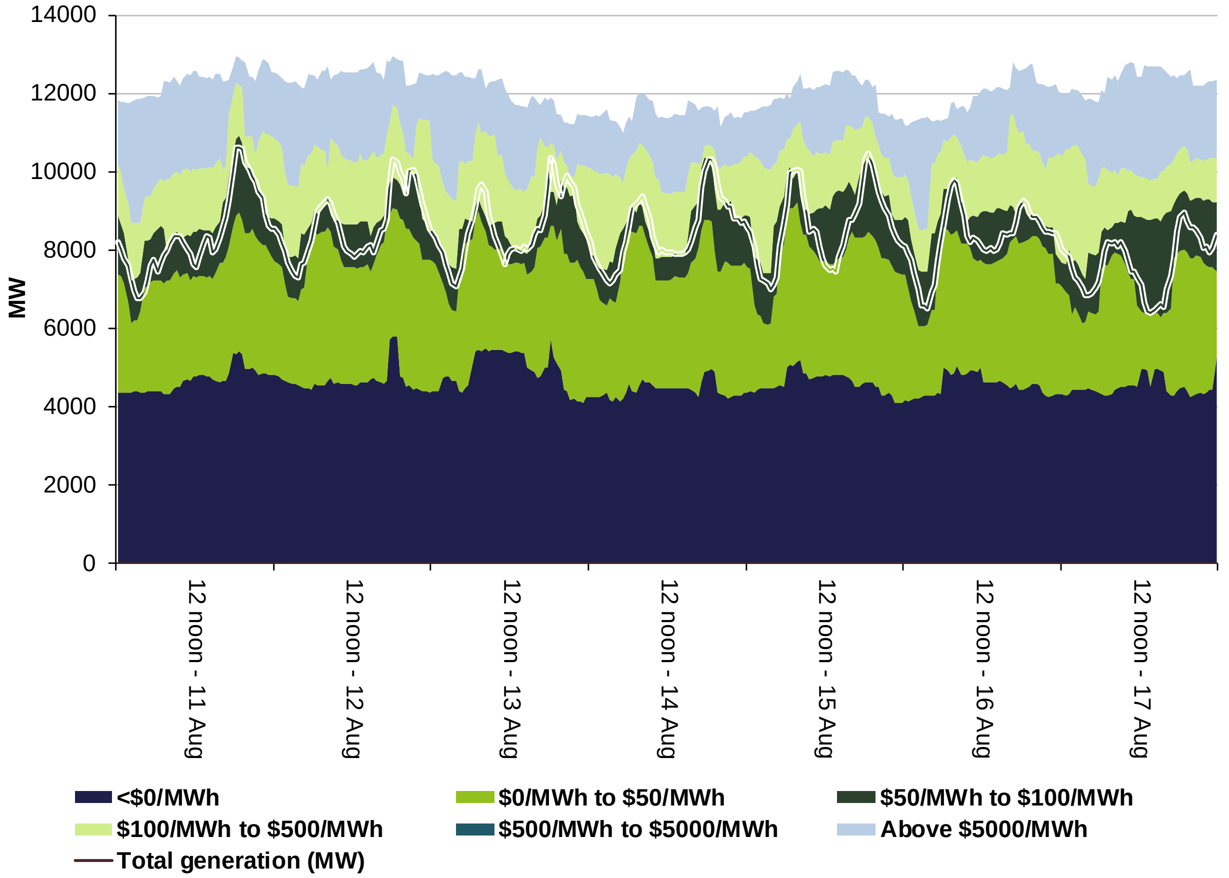


Figure 5: Victoria generation and bidding patterns

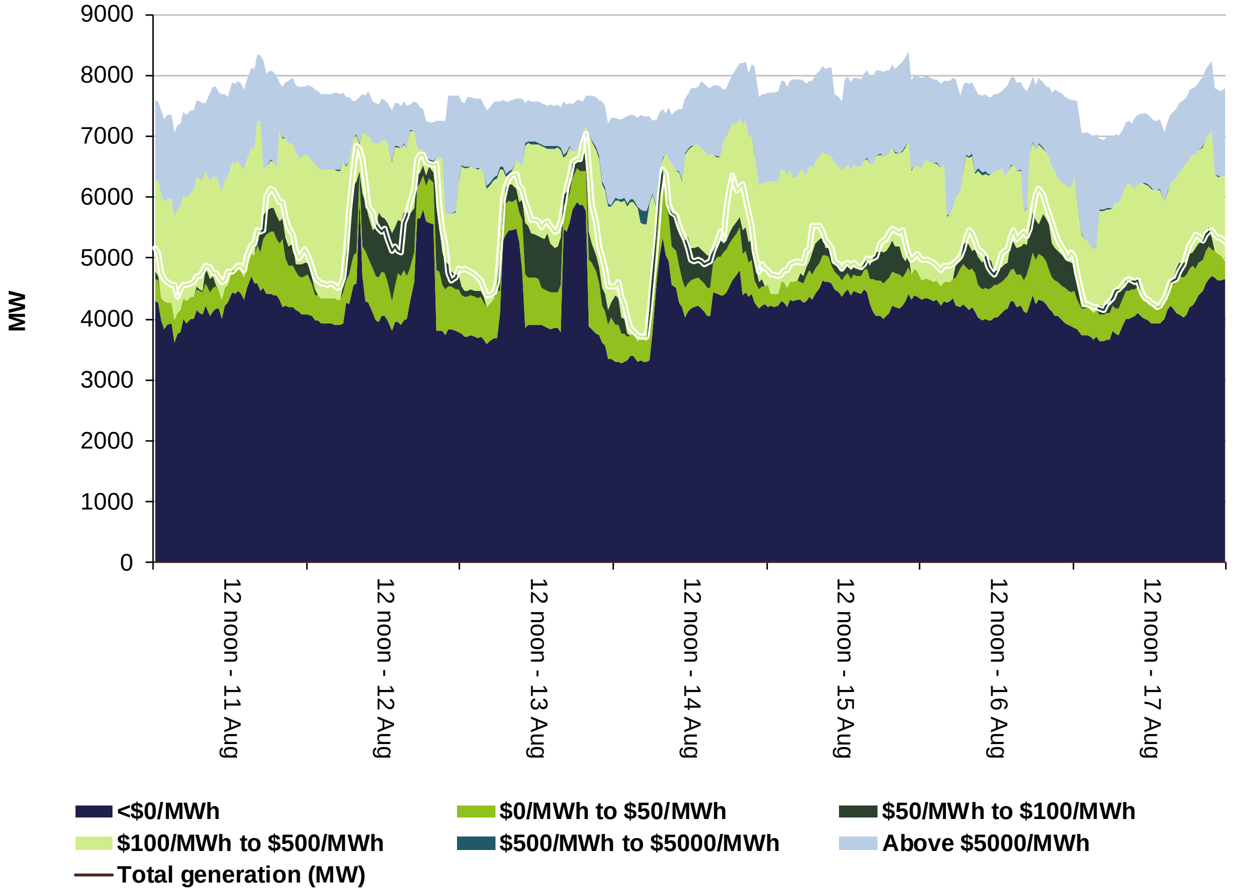


Figure 6: South Australia generation and bidding patterns

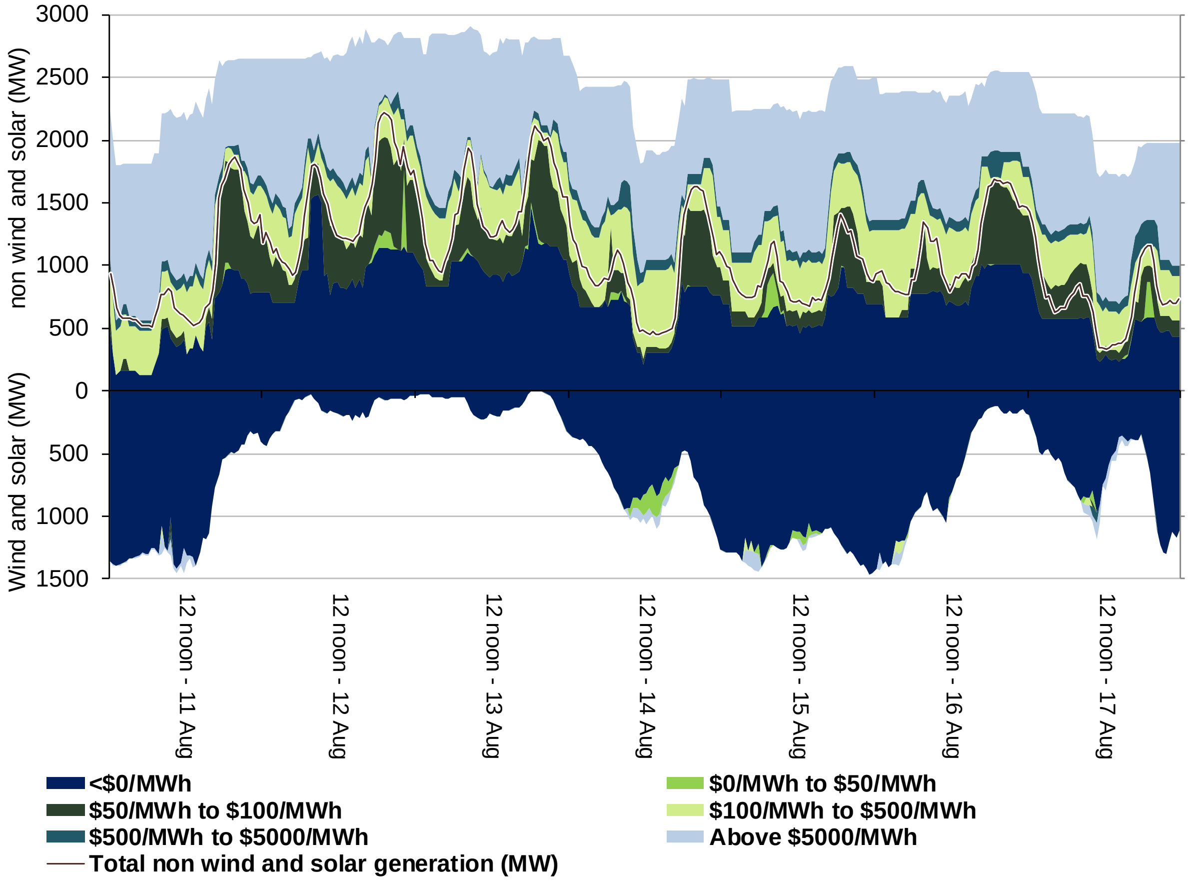
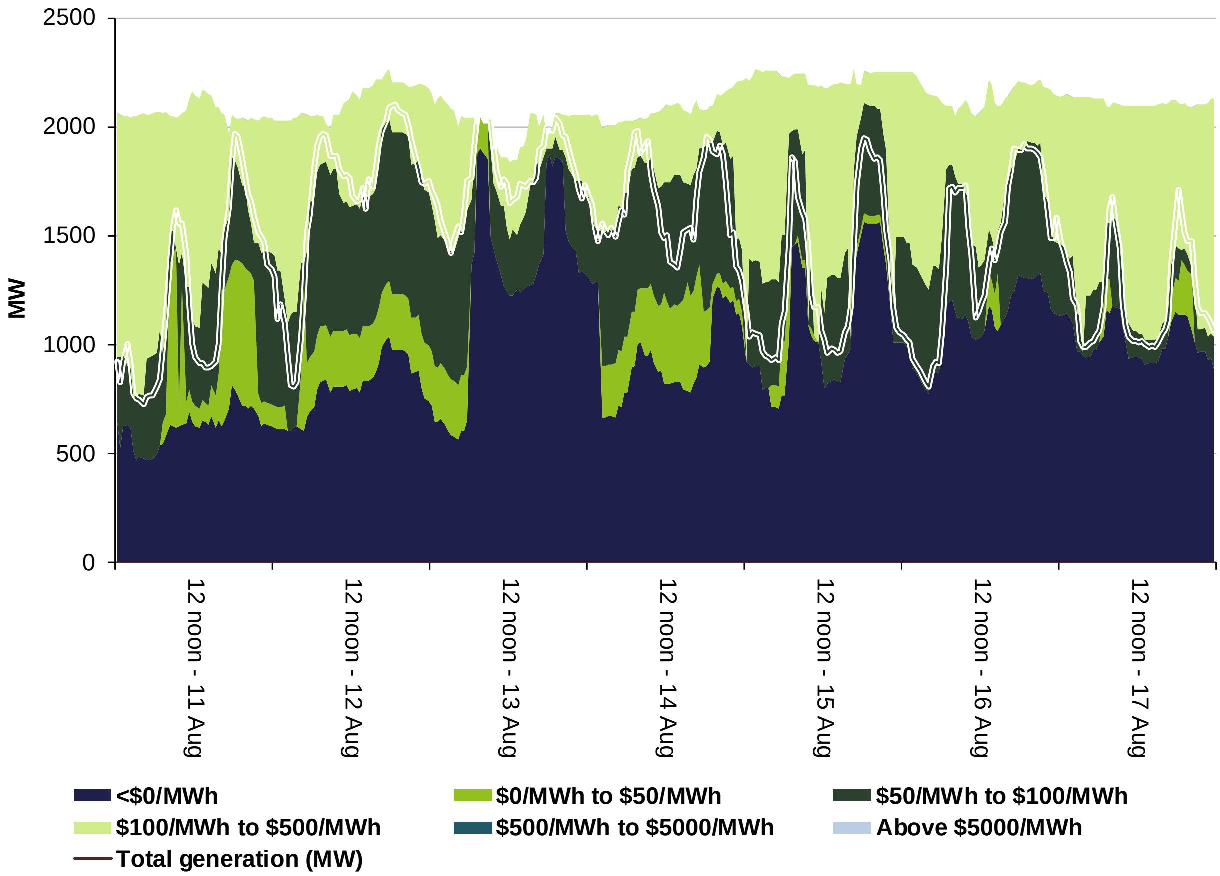


Figure 7: Tasmania generation and bidding patterns



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.

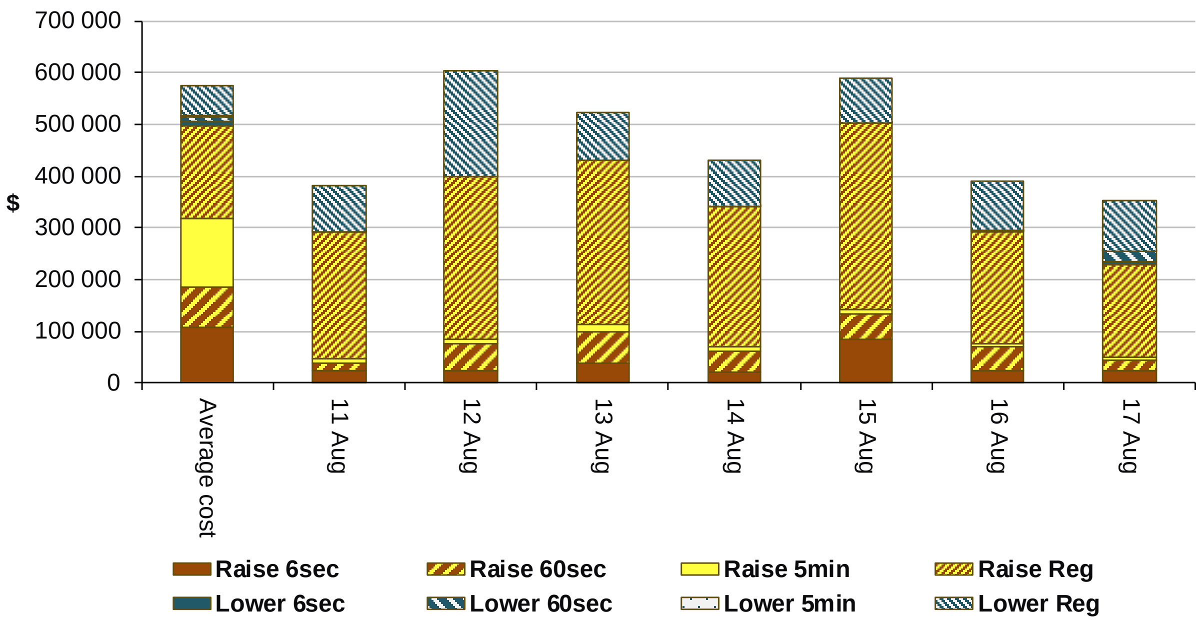
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 754 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $517 000 or around 3 per cent of energy turnover.

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 were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $72/MWh and above $250/MWh.

Sunday, 11 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
6.30 pm	259.62	192.73	201.00	7051	7112	7100	9242	9495	9555

Prices across Queensland and New South Wales were aligned and will be discussed as one region.

At 5.57 pm, Origin removed 244 MW of capacity priced below $84/MWh from Darling Downs Power Station due to a change in its return to service profile. As there was approximately only 20 MW of capacity between $140/MWh and $300/MWh for the majority of the trading interval, the dispatch price settled around $270/MWh for the first five intervals.

Monday, 12 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
6.30 pm	254.99	162.00	151.50	7437	7589	7581	9763	9991	9880

Prices were aligned across Queensland and New South Wales. See New South Wales section for analysis.

New South Wales

There were eight occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $90/MWh and above $250/MWh.

Sunday, 11 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
6.30 pm	282.38	206.43	219.72	11 128	10 946	11 144	12 969	13 492	13 710

Prices across Queensland and New South Wales were aligned. Analysis of the event will be discussed as one. See Queensland section for analysis.

Monday, 12 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
6 pm	278.17	105.01	98.09	10 667	10 521	10 618	12 799	13 108	12 925
6.30 pm	297.17	186.00	161.50	11 062	10 880	10 962	12 902	13 153	13 007

Prices were aligned across New South Wales and Queensland and will be discussed as one. A system normal constraint which manages voltage collapse at Darlington Point was allowing exports into Victoria, four hours ahead it was forecasted to force flows from Victoria into New South Wales. This meant higher priced generation was required from New South Wales, resulting in the dispatch prices settling between $187/MWh and $354/MWh for these two trading intervals.

Tuesday, 13 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
6 pm	295.63	89.24	87.37	10 785	10 441	10 415	11 845	12 078	12 055
7 pm	280.40	115.81	220.36	11 221	10 895	10 868	11 849	11 853	12 082
7.30 pm	299.60	105.01	166.28	11 119	10 820	10 762	11 640	11 853	12 108
8 pm	369.86	136.77	282.58	10 932	10 660	10 608	11 480	11 842	12 130

In each of the above trading intervals, demand was approximately 270 MW to 340 MW higher than forecast and availability was 4 MW to 630 MW lower than forecast, both four hours prior.

There was little capacity priced between $115/MWh and $449/MWh so small changes in demand could result in large changes in the dispatch price. In each trading interval, there were small changes in demand causing the dispatch price to settle around $449/MWh for one or two dispatch intervals.

Wednesday, 14 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
7.30 am	274.65	187.22	278.77	10 605	10 481	10 456	11 883	12 134	12 194

Demand was 124 MW higher than forecast and availability was 251 MW lower than forecast, both four hours ahead. The reduced availability was mainly due to Origin and EnergyAustralia reducing capacity at Eraring and Mount Piper respectively. Both reasons related to mill issues and all capacity was priced below $116/MWh.

There was little capacity priced between $115/MWh and $299/MWh so small changes in demand could result in large changes in the dispatch price. At 7.15 am, demand increased by 167 MW and caused the dispatch price to settle at $299/MWh for the remainder of the trading interval.

Victoria

There were eight occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $131/MWh and above $250/MWh.

Monday, 12 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
5.30 pm	470.41	470.36	499.20	6689	6605	6750	7521	7710	7911

Prices across Victoria and South Australia were aligned with prices in Victoria close to forecast.

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
6.30 pm	399.48	562.52	615.51	7140	7048	7176	7461	7692	7863

Demand was slightly higher and availability around 230 MW lower than forecast four hours ahead.

At 6 pm a system normal constraint which manages voltage collapse at Darlington Point was allowing more imports from New South Wales than was forecasted which saw four dispatch intervals priced below $400/MWh during the trading interval.

Tuesday, 13 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
7.30 am	393.37	1204.18	199.86	6361	6263	6253	7565	7579	7601
8 am	932.46	11 053.06	1174.32	6670	6613	6579	7574	7593	7619
8.30 am	640.87	11 053.06	828.05	6732	6723	6716	7585	7612	7649
9 am	404.55	11 053.06	833.04	6661	6660	6676	7645	7634	7656

Prices were aligned across Victoria and South Australia and will be discussed as one. From 6.44 am, rebids across both regions shifted a maximum of 285 MW of capacity from the prices above $13 000/MWh to below $148/MWh. This resulted in lower than forecast prices four hours ahead. See Table 12 below for the maximum capacity rebid and details of rebids effective for the above trading intervals.

Table 12: Significant rebids

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.44 am		AGL Energy	Torrens Island	120	14 700	<305	0631~A~050 chg in AEMO pd~51 pd demand increase NEM wide by avg 251MW from pe 0700 until 0930 in the 0501-0631 pds
6.58 am	7.05 am	Snowy Hydro	Murray	60	14 700	-1000	06:56:00 A VIC 5min pd price $395.80 higher than 5min pd 07:30@06:51 ($1,036.10)
7.03 am	7.10 am	Snowy Hydro	Murray	60	14 700	-1000	07:00:04 A VIC-NSW 5min actual price separation $299.51 higher than 5min pd 07:05@06:56 ($286.75)
7.15 am	7.25 am	AGL Energy	Torrens Island	25	14 700	<148	0700~A~050 chg in AEMO pd~50 pd VIC1-NSW1 export limit decrease by avg 1005MW from pe 0730-0800 in the 0700pd
7.21 am	7.30 am	Engie	Dry Creek	40	13 100	<300	0715~A~respond to 5min pd >$300MWH~

Table 13: 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 pm	443.44	1297.22	11 053.06	6955	6971	6997	7514	7493	7613
6.30 pm	1807.74	1224.50	11 053.06	7153	7063	7106	7573	7493	7619

For the 6 pm and 6.30 pm trading intervals, prices aligned across Victoria, Tasmania and South Australia and will be discussed as one. See analysis in South Australian section.

South Australia

There were ten occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $102/MWh and above $250/MWh and there were five occasions where the spot price was below -$100/MWh.

Sunday, 11 August

Table 14: 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
10 am	-102.98	75.65	99.19	1139	1151	1183	3515	3229	2997

Conditions at the time saw demand close to forecast and availability 286 MW higher than forecast, both four hours prior. Increased availability was due to higher than forecast wind generation, the majority of which was priced lower than -$150/MWh.

There was only two generation units offering capacity priced between -$150/MWh and $68/MWh so small drops in demand or generation could lead to large changes in price. At 9.50 am, demand dropped by 33 MW causing these two units to be ramp-down constrained. As a result, the dispatch price dropped to the price floor for one dispatch interval. In response to the negative dispatch price, generators rebid capacity to above $100/MWh for the remainder of the trading interval to avoid being dispatched. See Table 15 for details.

Table 15: Significant rebids

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
9.46 am	9.55 am	Hornsdale Power Reserve Pty Ltd	Hornsdale Power Reserve	40	51	305	0946 A change in forecast prices
9.47 am	9.55 am	Infigen	Lake Bonney 2 WF	159	-3	12879	0945~A~SA price DP@0950 for 0950 1053 lwr thn 5PD@0945
9.47 am	9.55 am	Energy Australia	Waterloo WF	130	-1000	100	09:46 ~ A ~ managed negative 5 min dispatch price
9.48 am	9.55 am	Trustpower	Snowtown WF	99	-1000	5000	0945 A SA1 5min pd rrp for 0955 ($-1000.0) published at 0945 IS 2064.04% lower than 5min pd rrp published at 0925 ($46.21) - time of alert: 0948

Monday, 12 August

Table 16: 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
5.30 pm	484.97	382.62	512.94	1950	1899	1951	2995	2987	2990

For the 5.30 pm trading interval, prices aligned across South Australia and Victoria. In Victoria, prices were close to forecast.

At 4.45 pm, effective from 5.05 pm, AGL rebid 185 MW of capacity at Torrens Island from prices below $305/MWh to the price cap. The reason given was “1631~A~050 chg in aemo pd~50 pd available generation decrease SA/VIC by avg 125MW from pe 1700-2030 in the 1601-1631”. As a result, the dispatch price increased to above $460/MWh for the trading interval.

Table 17: 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 pm	324.80	456.95	770.76	2082	2049	2083	2906	2974	2951

Demand was slightly higher and availability slightly lower than forecast four hours ahead.

From 4.40 pm participants rebid around 260 MW of capacity from prices above $390/MWh to below $300/MWh, with almost half to the price floor. As a result the dispatch price stayed around $300/MWh for the trading interval. See Table 18 below for relevant rebids.

Table 18: Significant rebids

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.40 pm		Origin Energy	Quarantine	74	14 700	-1000	1639a constraint management - n^^v_nil_1
5.07 pm		Engie	Dry Creek	35	13 100	<300	1650~a~response to 5min pd $>500~
5.07 pm		Energy Australia	Hallett	60	579	<0	1700~a~band adj redistribute portfolio jla to hal
5.38 pm	5.45 pm	Engie	Dry Creek	47	>390	<300	1715~a~response to 5min pd $>1000~
5.45 pm	5.55 pm	Origin Energy	Quarantine	48	14 700	-1000	1745a inc sa dem 5pd 2171mw > 30pd 2033mw @hhe1800

Tuesday, 13 August

Table 19: 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	393.87	1242.89	223.24	1798	1769	1768	2903	2912	2989
8 am	705.38	10 511.37	1173.45	1948	1906	1901	2905	2913	2985
8.30 am	449.99	10 511.37	800.67	2015	1983	1976	2947	2946	3009

For the above trading intervals, prices were aligned across South Australia and Victoria and will be discussed as one. See Victoria section for analysis.

Table 20: 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
5.30 pm	332.86	1353.75	925.97	1802	1813	1856	2895	2897	2906
6 pm	380.57	1471.60	9485.10	1949	1978	2005	2856	2854	2864
6.30 pm	1452.64	1328.15	11 408.38	2077	2145	2151	2835	2848	2856
7 pm	326.72	11 606.23	11 618.32	2207	2245	2244	2833	2831	2875
8 pm	364.36	1261.19	902.42	2170	2217	2225	2812	2832	2904

Prices were aligned across South Australia, Victoria and Tasmania so will be discussed as one.

From 3.41 pm onwards, Snowy Hydro shifted between 300 MW and 430 MW of capacity several times between the price ceiling and the price floor. This resulted in the dispatch price across these trading intervals settling lower than forecast, four hours prior. In addition to the rebids by Snowy Hydro, there was approximately 775 MW of capacity in South Australia and Victoria that contributed to a lower than forecast dispatch price by either bringing on capacity at the price floor or rebidding capacity from prices greater than $5000/MWh to prices lower than $152/MWh, the majority of which was at the price floor. See Table 21 for maximum capacity and rebid detail.

Table 21: Significant rebids – maximum capacity rebid between 5.30 pm to 8 pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.57 pm		Energy Australia	Yallourn	16	N/A	-1000	1455~P~adj avail mill limit lifted
3.41 pm		Snowy Hydro	Murray	430	14 700	-1000	15:32:00 A VIC 30min pd price $5,087.04 higher than 30min pd 18:00@15:02 ($10,121.01)
4.10 pm		Engie	Mintaro	30	14 700	-1000	1555~A~response to 5min > 30min pd~
4.24 pm		Snowy Hydro	Murray	300	-1000	450	16:21:00 A VIC 5min pd price $356.38 lower than 30MIN PD 16:35@16:02 ($112.20)
4.33 pm	6.35 pm	Trustpower	Snowtown WF	99	5000	-1000	1601 A SA1 30min pd total demand for 1900 (2217.03MW) published at 1601 IS 0.54% lower than 30min pd total demand published at 1531 (2229.17MW) - time of alert: 1633
4.53 pm		Origin Energy	Quarantine	24	14 700	-1000	1649P plant conditions - QPS5 failed start
4.56 pm	5.05 pm	Origin Energy	Quarantine	125	N/A	<115	1656P change in avail - unit RTS

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.58 pm	5.05 pm	Energy Australia	Hallett	24	13 999	-1000	1655~P~adj avail due to GPS testing
5.01 pm	5.10 pm	Origin Energy	Osborne	4	N/A	77	1700P change in avail - peaking enabled
5.06 pm	5.15 pm	Origin Energy	Quarantine	48	14 700	-1000	1705A inc SA dem 5pd 1806MW > 30pd 1744MW @HHE1830
5.35 pm	5.45 pm	Energy Australia	Yallourn	5	N/A	-1000	1730~P~adj avail due to mill exit temps
6.29 pm	6.40 pm	Engie	Pelican Point	23	N/A	-1000	1825~P~updateavail: match actual levels: MCL operation~
6.44 pm	7.05 pm	Energy Australia	Newport	210	11 053	<146	1840~A~band adj due to change in pd price 464 VS 1075 @ 1930 VIC
6.46 pm	6.55 pm	AGL Energy	Torrens Island	65	14 700	78	1801~F~040 chg in contract pos~40 callable contract triggered
6.54 pm	7.00 pm	Energy Australia	Jeeralang A	48	13 050	152	1850~A~band adj due to change in 5min pd price 145 vs 295 @ 1930 VIC
6.54 pm	7.00 pm	Energy Australia	Jeeralang B	54	10 579	129	1850~A~band adj due to change in 5min pd price 145 vs 295 @ 1930 VIC
7.52 pm	8.00 pm	Snowy Hydro	Murray	37	14 700	-1000	19:45:04 A NSW 5min actual price $93.90 higher than 5min pd 19:50@19:41 ($393.40)
7.53 pm	8.00 pm	Snowy Hydro	Murray	58	N/A	-1000	19:53:30 P update capability parameters for change to outage plan/plant conditions

Wednesday, 14 August

Table 22: 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	-112.23	78.00	77.50	1556	1578	1597	3384	3135	3268

Demand was close to forecast and availability was 249 MW higher than forecast, both four hours prior. Increased availability was due to higher than forecast wind generation, the majority of which was priced lower than -$150/MWh.

There was only two generation units offering capacity priced between the price floor and $77/MWh and so small drops in demand or generation could lead to large changes in price. At 9.15 am, demand dropped by 40 MW causing these two units to be ramp-down constrained. As a result, the dispatch price dropped to the price floor for one dispatch interval. In response to the negative dispatch price, generators rebid capacity to above $100/MWh for the remainder of the trading interval to avoid being dispatched. See Table 23 for details.

Table 23: Significant rebids

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
9.11 am	9.20 am	Infigen	Lake Bonney 2 WF	159	-3	12879	0910~a~SA price dp@0915 for 0915 1077 lwr thn 5pd@0910
9.13 am	9.20 am	Trustpower	Snowtown WF	99	-1000	5000	0910 a SA1 5min pd rrp for 0920 ($-1000.0) published at 0910 is 9899.98% lower than 5min pd rrp published at 0905 ($-3.09) - time of alert: 0913

Table 24: 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
1.30 pm	-216.81	-1000.00	-1000.00	897	840	855	2902	2997	2989

Demand was 57 MW higher and availability 95 MW lower than forecast four hours ahead. At 10.19 am Vena Energy Services rebid 95 MW of capacity at Tailem Bend solar farm from the price floor to the price cap as there were expected negative prices. As a result the dispatch price increased to above -$152/MWh for all but one dispatch interval.

Saturday, 17 August

Table 25: 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
10.30 am	-247.36	77.50	77.50	972	1039	1061	3062	2643	2637
11 am	-133.33	78.79	78.00	903	958	973	2916	2353	2357

For the 10.30 am and 11 am trading intervals, demand was 67 MW and 55 MW lower than forecast and availability was 420 MW and 560 MW higher than forecast respectively. Higher availability was due to higher than forecast wind generation, most of which was priced below $0/MWh.

At the start of the 10.30 am trading interval, there no capacity priced between the price floor and $77/MWh and so small drops in demand or generation could lead to large changes in price. At 10.05 am, demand dropped by 65 MW and resulted in the dispatch price dropping to the price floor for one dispatch interval.

The continued high availability and lower demand resulted in the dispatch price settling around -$150/MWh to -$100/MWh for the remainder of the 10.30 am trading interval and into the 11 am trading interval.

Tasmania

There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $98/MWh and above $250/MWh.

Tuesday, 13 August

Table 26: 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	298.77	133.50	129.68	1457	1404	1407	2031	2054	2059

Demand was 53 MW higher than forecast and availability was 23 MW lower than forecast four hours ahead. With no capacity price between $129/MWh and $382/MWh the forecast errors were enough to see the dispatch price increase to as much as $668/MWh during the trading interval.

Table 27: Price, Demand and Availability

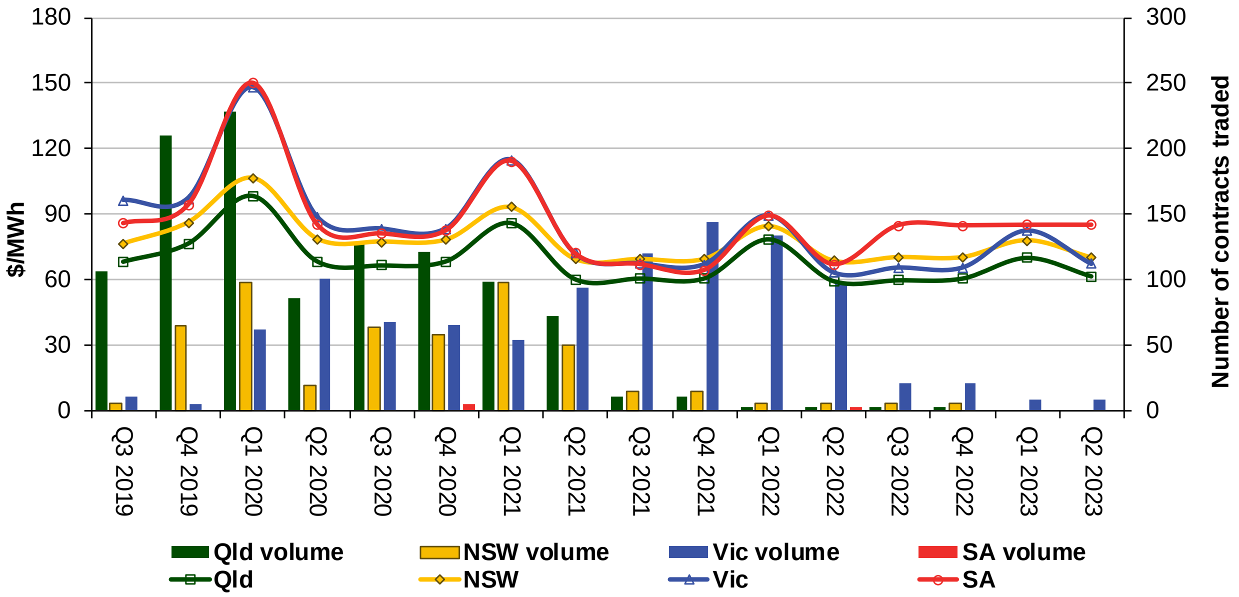
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6 pm	320.86	133.43	400.04	1417	1381	1414	1995	2054	2065
6.30 pm	1084.27	133.50	400.06	1408	1415	1446	1980	2054	2065

Prices were aligned with those in Victoria and South Australia, see South Australian section for analysis.

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.

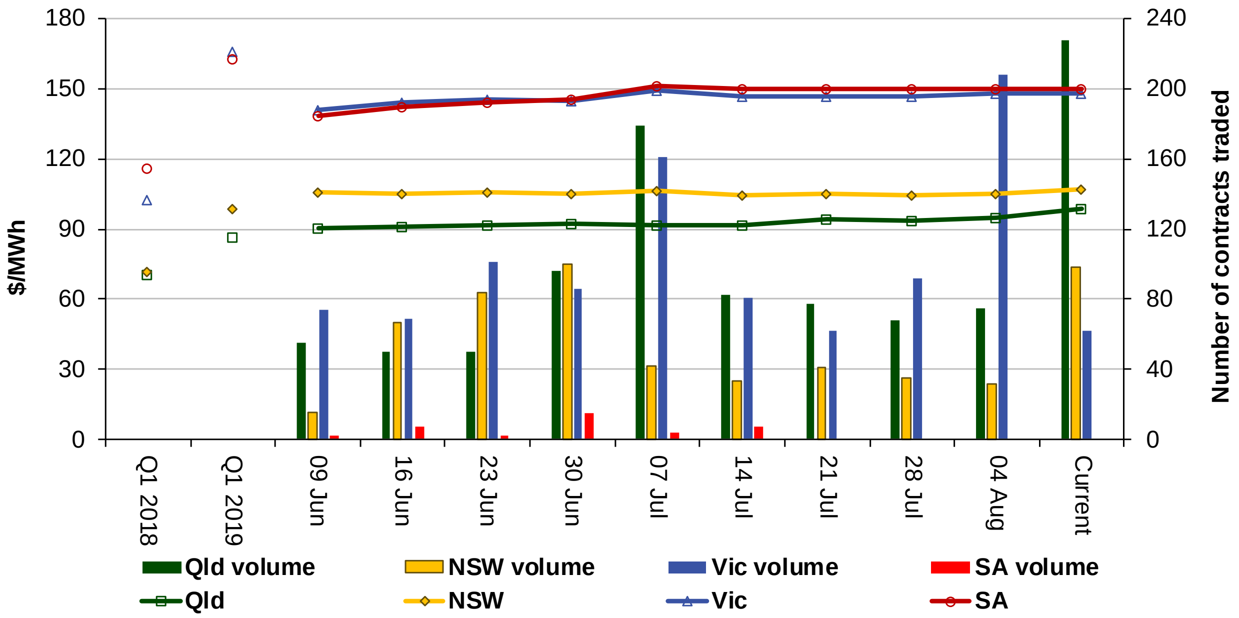
Figure 9: Quarterly base future prices Q3 2019 – Q2 2023



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2020 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2018 and quarter 1 2019 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 2020 base contracts over the past 10 weeks (and the past 2 years)



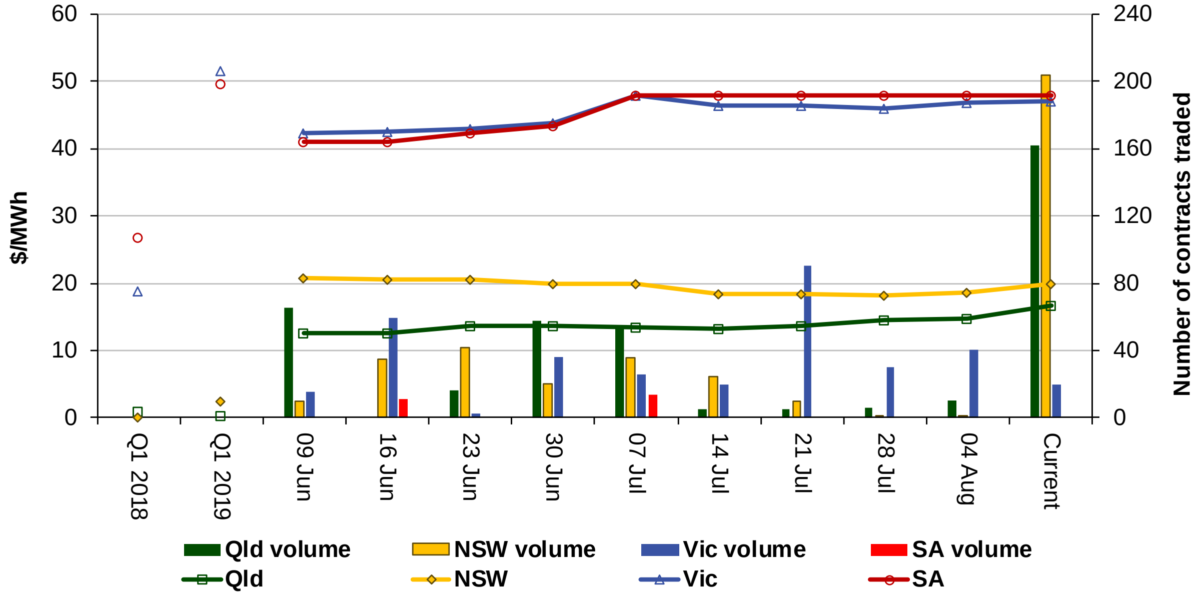
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2020 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
September 2019