Electricity Report

AUSTRALIAN ENERGY REGULATOR

4 – 10 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 4 to 10 August 2019.

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

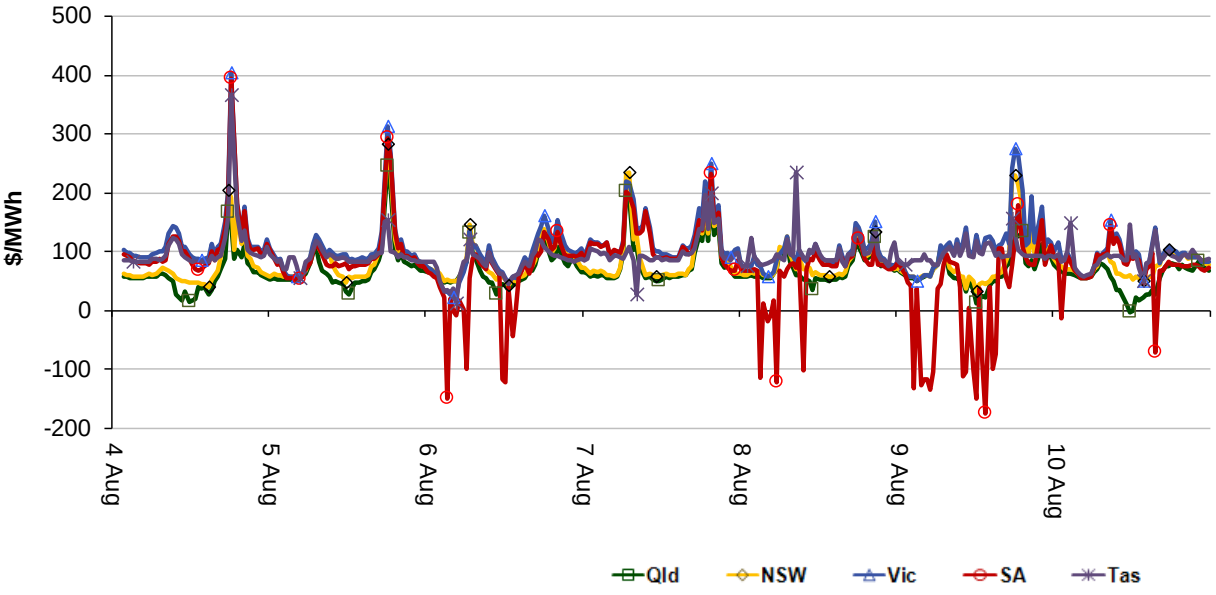


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

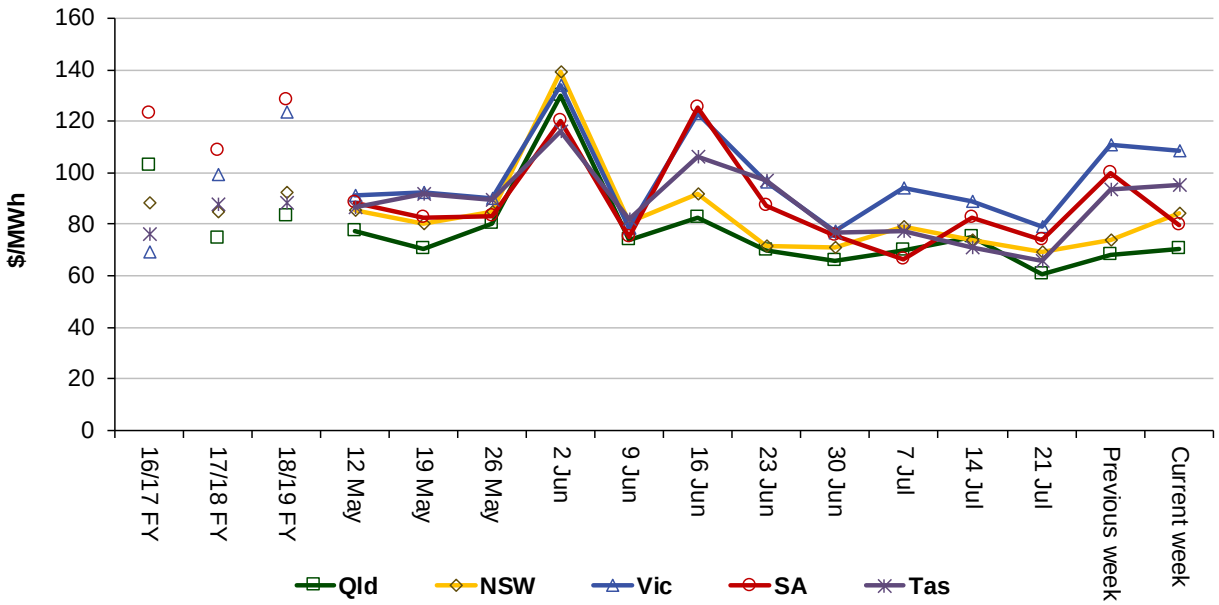


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	70	84	109	80	95
18-19 financial YTD	74	80	73	101	42
19-20 financial YTD	69	76	94	81	80

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 200 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	10	17	0	1
% of total below forecast	13	38	0	21

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

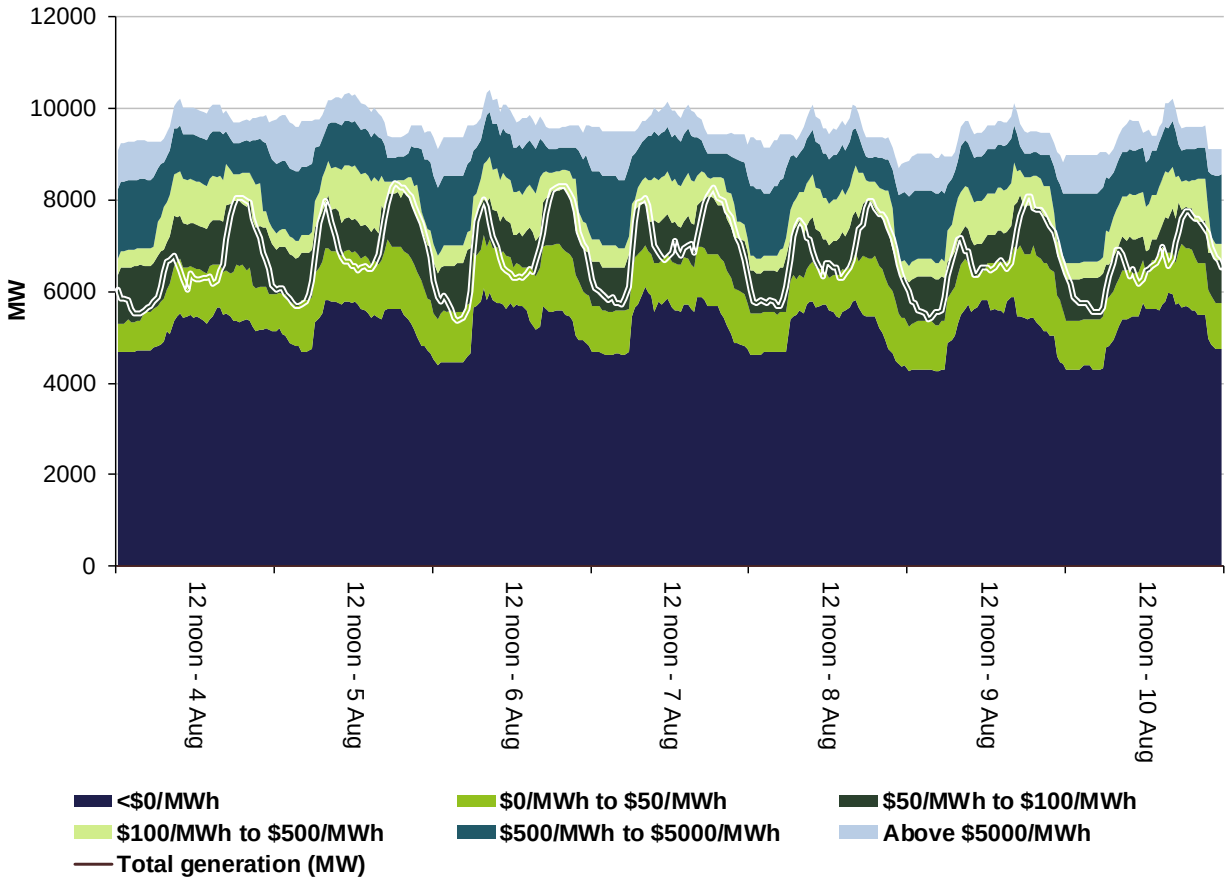


Figure 4: New South Wales generation and bidding patterns

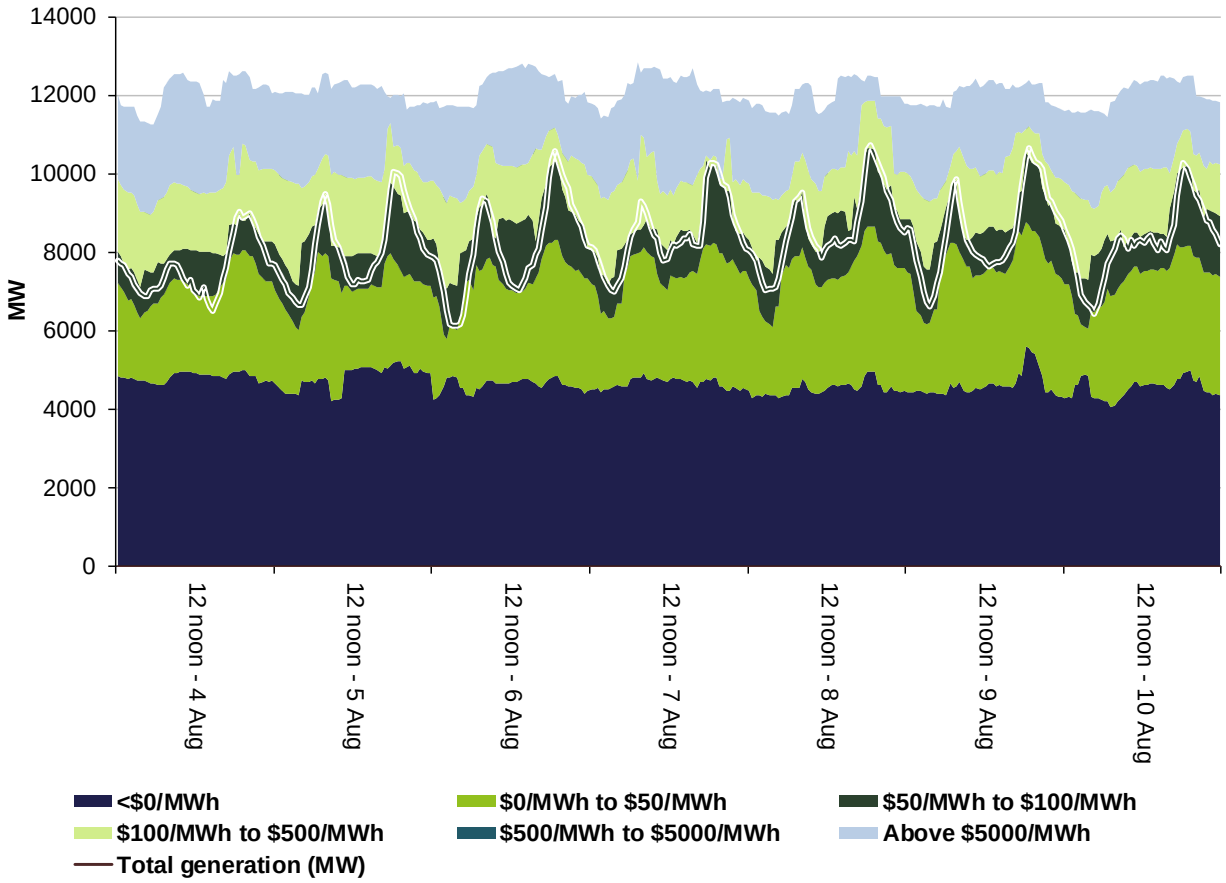


Figure 5: Victoria generation and bidding patterns

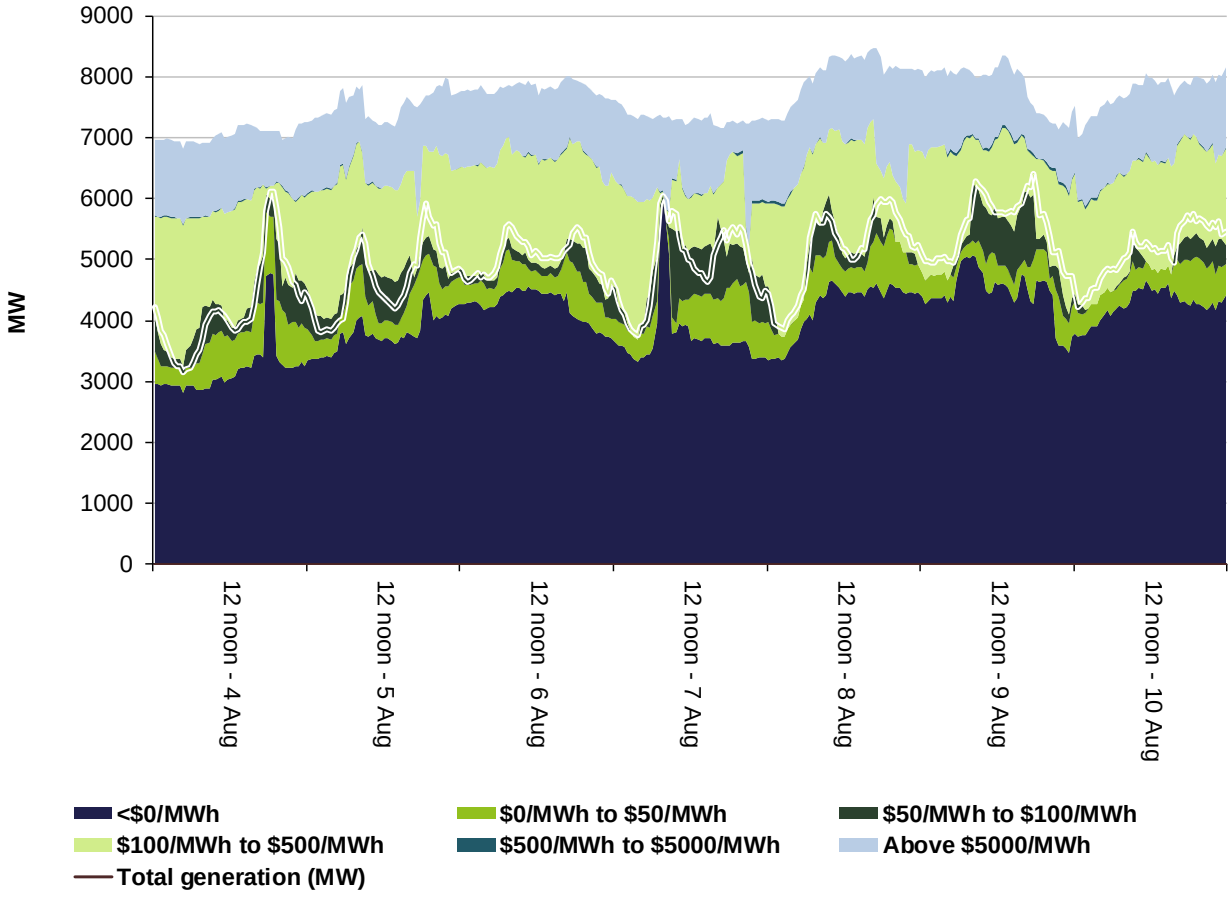


Figure 6: South Australia generation and bidding patterns

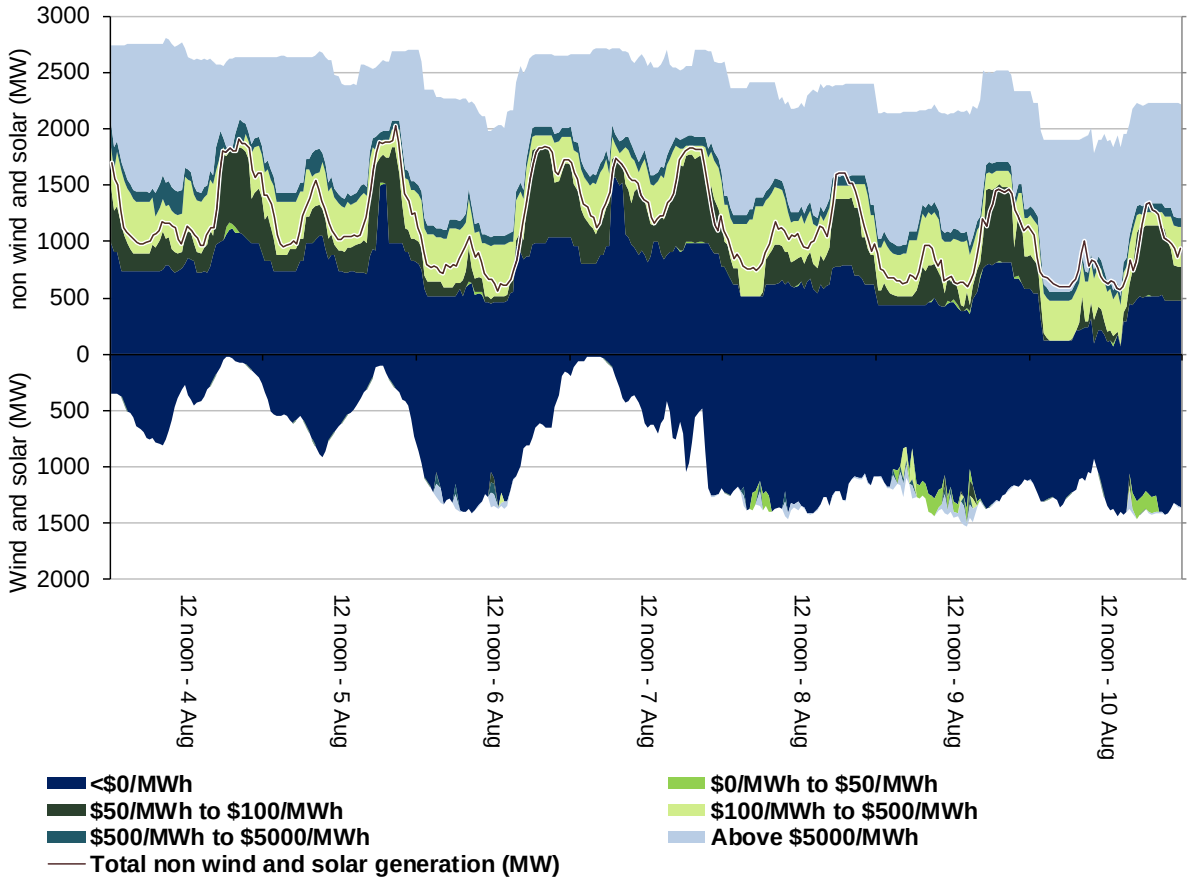
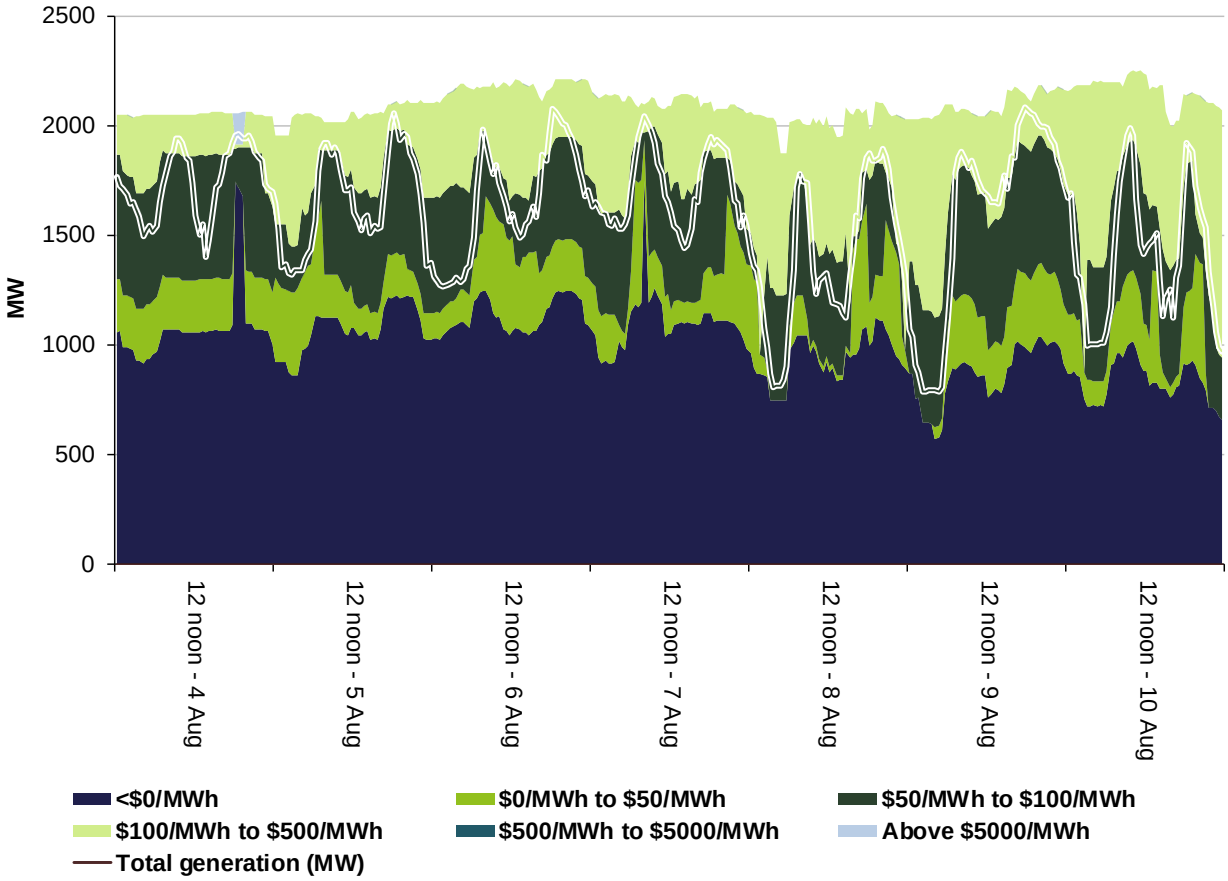


Figure 7: Tasmania generation and bidding patterns



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.

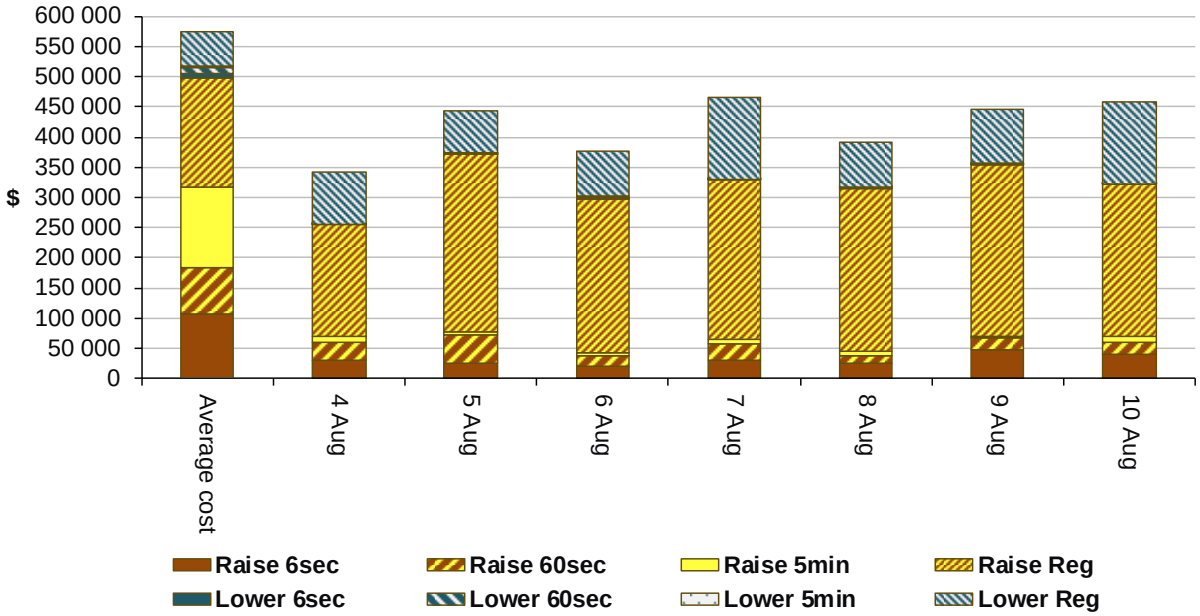
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 472 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $452 000 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

New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $84/MWh and above $250/MWh.

Monday, 5 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	282.69	266.66	260.70	10 432	10 219	10 355	11 987	12 105	12 717

Conditions at the time saw prices close to forecast.

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $109/MWh and above $250/MWh.

Sunday, 4 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	402.78	632.17	316.34	6381	6233	6175	7121	7117	7510

For the 6.30 pm and 7 pm trading intervals, prices aligned across Victoria and South Australia and will be discussed as one region. The spot price in Victoria did not breach our reporting thresholds for the 7 pm trading interval. See analysis in South Australia section.

South Australia

There were four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $80/MWh and above $250/MWh and there were nineteen occasions where the spot price was below -$100/MWh.

Sunday, 4 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	392.96	598.06	307.50	1761	1744	1735	2638	2746	2869
7 pm	291.51	578.81	318.91	1891	1846	1832	2650	2742	2855

Prices were aligned across Victoria and South Australia for the 6.30 pm and 7 pm trading intervals.

In South Australia demand was slightly higher than forecast while availability was lower than forecast.

Over several rebids from 3.35 pm, Origin rebid a total of around 280 MW of capacity at Ladbroke Grove and Quarantine from prices above $319/MWh to below $64/MWh, the majority of which was priced at the price floor (see Table 6 for the rebids). As a result prices were lower than forecast four hours ahead.

Table 6: Significant rebids for 6.30 pm and 7 pm

Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.35 pm	Origin Energy	Ladbroke Grove	42	319	-1000	1535A constraint management - N^^V_NIL_1 SL
4.20 pm	Origin Energy	Ladbroke Grove	43	319	-1000	1620A material change in SA dem @ 1700 SL
4.42 pm	Origin Energy	Quarantine	125	14 700	<64	1640A constraint management - N^^V_NIL_1 SL
4.50 pm	Origin Energy	Quarantine	24	14 700	-1000	1650A constraint management - N^^V_NIL_1 SL
5.13 pm	Origin Energy	Quarantine	24	14 700	-1000	1710A constraint management - N^^V_NIL_1 SL
5.28 pm	Origin Energy	Quarantine	24	14 700	-1000	1726A constraint management - N^^V_NIL_1 SL

Monday, 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
6.30 pm	293.77	276.99	269.55	1663	1734	1730	2701	2894	3036

Conditions at the time saw prices close to forecast, four hours prior.

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 pm	260.99	318.91	266.02	1819	1831	1832	2704	2899	3082

For the 7 pm trading interval, demand was close to forecast and availability was 200 MW lower than forecast, both four hours prior.

From 4.27 pm, approximately 210 MW of capacity was rebid from prices higher than $319/MWh to prices lower than $78/MWh, the majority of which was priced at the price floor. This resulted in the dispatch price settling lower than forecast for all but the first dispatch interval.

Table 9: Significant rebids for 7 pm

Submitted time	Region	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.27 pm	SA	Origin Energy	Ladbroke Grove	84	319	-1000	1625A inc NEM dem 5PD 23825MW > 30PD 23387MW @1700 SL
5.06 pm	SA	Origin Energy	Quarantine	124	14 700	<78	1704A inc NEM dem 5PD 26634MW > 30PD 26238MW @1800 SL

Tuesday, 6 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
3.30 am	-151.30	43.62	42.58	1116	1041	1065	3573	3285	3221
6.30 am	-100.43	49.68	60.17	1233	1124	1129	3641	3461	3338

For the 3.30 am and 6.30 am trading intervals, availability was 288 MW and 180 MW higher than forecast, four hours prior, respectively. Increased availability was due to higher than forecast wind generation, mostly priced below $0/MWh.

There were only two generation units offering capacity priced between $68/MWh and the price floor at the time. Small decreases in demand during these two intervals caused these units to be ramp-down constrained and unable to set price, leading to the dispatch price falling to the price floor for one dispatch period during each trading interval.

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
Midday	-116.19	-1000.00	44.46	1090	1039	1054	3385	3380	3489

Demand was 51 MW higher and availability was close to forecast, both four hours prior.

At 11.45 am, demand dropped by 45 MW. As there were only two generation units offering capacity priced between -$151/MWh and the price floor at the time, the dispatch price dropped to the price floor. In response, almost 440 MW of capacity was rebid from prices below -$3/MWh to above $100/MWh. This resulted in the dispatch price settling close to the 12 hour forecast price for the remainder of the trading interval. See Table 12 for details.

Table 12: Significant rebids

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.42 am	11.50 am	Infigen	Lake Bonney 2 WF	140	-3	12879	1140~A~SA price DP@1145 for 1145 1037 lwr thn 5PD@1140 SL ~
11.42 am	11.50 am	Energy Australia	Waterloo WF	105	-1000	100	11:40 ~ A ~ band adj to 5min negative DP ~ SL
11.42 am	11.50 am	Vena Energy Services (Australia) Pty Ltd	Tailem Bend Solar Project 1	95	-1000	14 700	11:42 A Negative prices
11.43 am	11.50 am	Trustpower	Snowtown WF	99	-1000	5000	1130 A SA1 30MIN PD RRP for 1200 ($54.74) published at 1130 is 447.43% higher than 30MIN PD RRP published at 0930 ($-3.09) - time of alert: 1143

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
12.30 pm	-122.42	-3.09	35.07	1050	996	1027	3352	3393	3494

Demand was 54 MW higher and availability was 41 MW lower than forecast, both four hours prior.

At 12.15 pm, wind generation increased by 31 MW as a semi-scheduled dispatch cap was lifted from a number of wind generators that had offered capacity at the price floor. With higher-priced generation constrained off, the dispatch price fell to the price floor for one dispatch interval.

Thursday, 8 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
3.30 am	-115.33	62.79	62.95	1122	1105	1098	3714	3436	3451
6 am	-123.22	52.86	54.10	1156	1079	1081	3757	3568	3546
10 am	-102.96	83.35	79.20	1560	1575	1559	3678	3537	3536

Availability was higher than forecast mainly due to wind generation being higher than forecast, the majority of which was priced below -$100/MWh.

The dispatch price dropped to the price floor once during each of the 3.30 am, 6 am, and 10 am trading intervals, each. There was little capacity priced between $100/MWh and -$140/MWh so small drops in demand or generation could lead to large changes in price. In each of the trading intervals there were small changes in demand and with higher priced generation either ramp down-constrained or trapped in FCAS and unable to set price caused the dispatch price to drop to the price floor. In response to the negative dispatch price, generators rebid capacity to above $5000/MWh for the remainder of the trading interval to avoid being dispatched. See Table 15 to Table 17 for details.

Table 15: Significant rebids for 3.30 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.03 am	3.10 am	Trustpower	Snowtown WF	99	-1000	5000	0300 A SA1 5MIN PD RRP for 0330 ($-3.09) published at 0300 IS 95.75% lower than 30min PD RRP published at 0231 ($72.62) - time of alert: 0303
3.05 am	3.15 am	Infigen	Lake Bonney 2 WF	159	-3	12 879	0300~A~SA price DP@0305 for 0305 1071 lwr thn 5PD@0300 SL~

Table 16: Significant rebids for 6 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.47 am	5.55 am	Infigen	Lake Bonney 2 WF	159	20	12 879	0545~A~SA price DP@0550 for 0550 1051 lwr thn 5PD@0545 SL~
5.48 am	5.55 am	Trustpower	Snowtown WF	99	-1000	5000	0545 A SA1 5MIN PD RRP for 0600 ($20.2) published at 0545 IS 79.73% lower than 30MIN PD RRP published at 0501 ($99.64) - time of alert: 0548

Table 17: Significant rebids for 10 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
9.41 am	9.50 am	Infigen	Lake Bonney 2 WF	159	-3	12 879	0940~A~SA price PD@940 lwr thn 5PD@ 935 for 945 SL~
9.47 am	9.55 am	Vena Energy Services (Australia) Pty Ltd	Tailem Bend Solar Project 1	95	-1000	14 700	09:47 A Negative prices
9.53 am	10.00 am	Trustpower	Snowtown WF	99	-1000	5000	0930 A SA1 30MIN PD RRP for 1000 ($87.93) published at 0930 is 28.36% higher than 30MIN PD RRP published at 0730 ($68.5) - time of alert: 0953

Friday, 9 August

Table 18: 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
3 am	-133.03	-3.09	45.20	1225	1118	1071	3334	3284	3353
4 am	-128.06	-3.09	30.05	1161	1059	1009	3303	3289	3340

During the evening the day before AEMO limited transfer across the Heywood interconnector at 250 MW due to severe weather across South Australia, Victoria and New South Wales. Conditions at the time saw higher than forecast wind generation, mostly priced below -$100/MWh.

The dispatch price dropped to the price floor for one dispatch interval each trading interval. There was around 100 MW of capacity priced between $68/MWh and -$150/MWh so small drops in demand or generation could lead to large changes in price. With generation either ramp-down constrained or trapped / stranded in FCAS, small drops in demand caused the dispatch price to drop to the price floor for one dispatch interval. In response to the negative dispatch price, generators rebid capacity to above $5000/MWh for the remainder of the trading interval to avoid being dispatched. See Table 19 and Table 20 for details.

Table 19: Significant rebids for 3 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.42 am	2.50 am	Infigen	Lake Bonney 2 WF	159	-3	12 879	0240~A~SA price DP@0245 for 0245 1036 lwr thn 5PD@0240 SL~

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.43 am	2.50 am	Trustpower	Snowtown WF	99	-1000	5000	0240 A SA1 5MIN PD RRP for 0300 ($-151.85) published at 0240 IS 1418.5% lower than 30MIN PD RRP published at 0201 ($-3.09) - time of alert: 0243

Table 20: Significant rebids for 4 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.42 am	3.50 am	Infigen	Lake Bonney 2 WF	159	20	12 879	0340~A~SA price DP@0345 for 0345 1036 lwr thn 5PD@0340 SL~
3.43 am	3.50 am	Trustpower	Snowtown WF	99	-1000	5000	0330 A SA1 30MIN PD RRP for 0400 ($20.2) published at 0330 IS 102.0% higher than 30MIN PD RRP published at 0231 ($-3.09) - time of alert: 0343

Table 21: 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	-116.61	-151.85	28.30	1160	1040	994	3422	3362	3409
5 am	-116.31	-151.85	-1000.00	1137	1043	990	3251	3347	3614
5.30 am	-134.88	-151.85	26.57	1107	1059	1008	3296	3360	3363

For the 4.30 am to 5.30 am trading intervals, conditions saw prices close to those forecast four hours prior.

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
6 am	-103.62	-3.09	35.87	1186	1102	1051	3435	3359	3369
10.30 am	-111.38	100.32	-3.09	1400	1487	1462	3527	3417	3449
11 am	-104.48	90.15	-3.09	1321	1433	1426	3549	3406	3457
Midday	-102.24	78.12	-3.09	1241	1358	1384	3554	3439	3461

The dispatch price dropped to the price floor for one dispatch interval each trading interval. There was around 100 MW of capacity priced between $68/MWh and -$150/MWh so small drops in demand or generation could lead to large changes in price. With generation either ramp-down constrained or trapped / stranded in FCAS, small drops in demand caused the dispatch price to drop to the price floor for one dispatch interval. In response to the negative

dispatch price, generators rebid capacity to above $5000/MWh for the remainder of the trading interval to avoid being dispatched. See Table 23 to Table 25 for details.

Table 23: Significant rebids for 6 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.31 am	5.40 am	Hornsdale Power Reserve Pty Ltd	Hornsdale Power Reserve	40	-1000	305	0531 A change in forecast prices
5.32 am	5.40 am	Infigen	Lake Bonney 2 WF	159	20	12 879	0525~A~SA price DP@0530 for 0530 1040 lwr thn 5PD@0525 SL~
5.33 am	5.40 am	AGL Energy	Hallett 1 WF	85	-1000	300	0530~A~040 chg in AEMO disp~44 price decrease VS PD SA -$1000 VS $43.15
5.33 am	5.40 am	AGL Energy	Hallett 2 WF	61	-1000	300	0530~A~040 chg in AEMO DISP~44 price decrease VS PD SA -$1000 VS $43.15
5.33 am	5.40 am	AGL Energy	North Brown Hill WF	109	-1000	300	0530~A~040 chg in AEMO disp~44 price decrease VS PD SA -$1000 VS $43.15
5.33 am	5.40 am	AGL Energy	The Bluff WF	43	-1000	300	0530~A~040 chg in AEMO DISP~44 price decrease VS PD SA -$1000 VS $43.15
5.33 am	5.40 am	Trustpower	Snowtown WF	99	-1000	5000	0500 A SA1 30MIN PD RRP for 0600 ($43.15) published at 0500 IS 113.6% higher than 30MIN PD RRP published at 0431 ($20.2) - time of alert: 0533

Table 24: Significant rebids for 11 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.29 am	10.40 am	Vena Energy Services (Australia) Pty Ltd	Tailem Bend Solar Project 1	93	-1000	14700	10:29 A delaying full return to service due to negative prices
10.47 am	10.55 am	Infigen	Lake Bonney 2 WF	159	20	12879	1045~A~SA price dp@1050 for 1050 848 lwr thn 5PD@1045 SL ~
10.48 am	10.55 am	Trustpower	Snowtown WF	99	-1000	5000	1045 A SA1 5min pd rrp for 1100 ($-151.85) published at 1045 IS 106.53% lower than 30MIN PD RRP published at 1000 ($73.52) - time of alert: 1048
10.48 am	10.55 am	AGL Energy	Torrens Island	225	<115	148	1045~A~040 chg in AEMO disp~46 price decrease V PD SA -$1,000 V $72.94

Table 25: Significant rebids for midday

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.32 am	11.40 am	EnergyAustralia	Waterloo WF	120	-1000	100	11:30 ~ A ~ band adj to 5MIN negative DP ~ SL
11.32 am	11.40 am	Infigen	Lake Bonney 2 WF	159	20	12 879	1130~A~SA price 5PD@1135 for 1140 835 lwr thn 5PD@1130 SL~
11.33 am	11.40 am	Trustpower	Snowtown WF	99	-1000	5000	1130 A SA1 5MIN PD RRP for 1140 ($-1000.0) published at 1130 is 4850.49% lower than 5MIN PD RRP published at 1120 ($20.2) - time of alert: 1133

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
12.30 pm	-149.83	-1000.00	-3.09	1289	1368	1380	3595	3412	3449

For the 12.30 pm trading interval, demand was 79 MW lower and availability was 183 MW higher than forecast, both four hours prior.

A planned outage of the Moorabool to Mortlake line was scheduled from 12 pm to 5 pm. This saw forecast exports into Victoria limited to 50 MW. However, this outage and its related constraints were revoked at 9.46 am and exports into Victoria ended up being 250 MW. This resulted in higher priced generation being dispatched in South Australia.

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
2 pm	-174.79	77.46	-3.09	1300	1345	1373	3662	3435	3405
3 pm	-100.40	77.50	64.91	1355	1350	1400	3601	3408	3382

The dispatch price dropped to the price floor for one dispatch interval each trading interval. There was around 100 MW of capacity priced between $68/MWh and -$150/MWh so small drops in demand or generation could lead to large changes in price. With generation either ramp-down constrained or trapped / stranded in FCAS, small drops in demand caused the dispatch price to drop to the price floor for one dispatch interval. In response to the negative dispatch price, generators rebid capacity to above $5000/MWh for the remainder of the trading interval to avoid being dispatched. See Table 28 and Table 29 for details.

Table 28: Significant rebids for 2 pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.52 pm	2.00 pm	Infigen	Lake Bonney 2 WF	159	20	12879	1350~A~SA PRICE DP@1355 for 1355 1020 lwr thn 5PD@1350 SL ~
1.53 pm	2.00 pm	Trustpower	Snowtown WF	99	-1000	5000	1350 A SA1 5MIN PD RRP for 1400 ($20.2) published at 1350 IS 77.89% lower than 5MIN PD RRP published at 1330 ($91.35) - time of alert: 1353

Table 29: Significant rebids for 3 pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.43 pm	2.50 pm	Trustpower	Snowtown WF	99	-1000	5000	1440 A SA1 5MIN PD RRP for 1450 ($74.99) published at 1440 IS 271.24% higher than 5MIN PD RRP published at 1415 ($20.2) - time of alert: 1443

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $95/MWh and above $250/MWh.

Sunday, 4 August

Table 30: Price, Demand and Availability

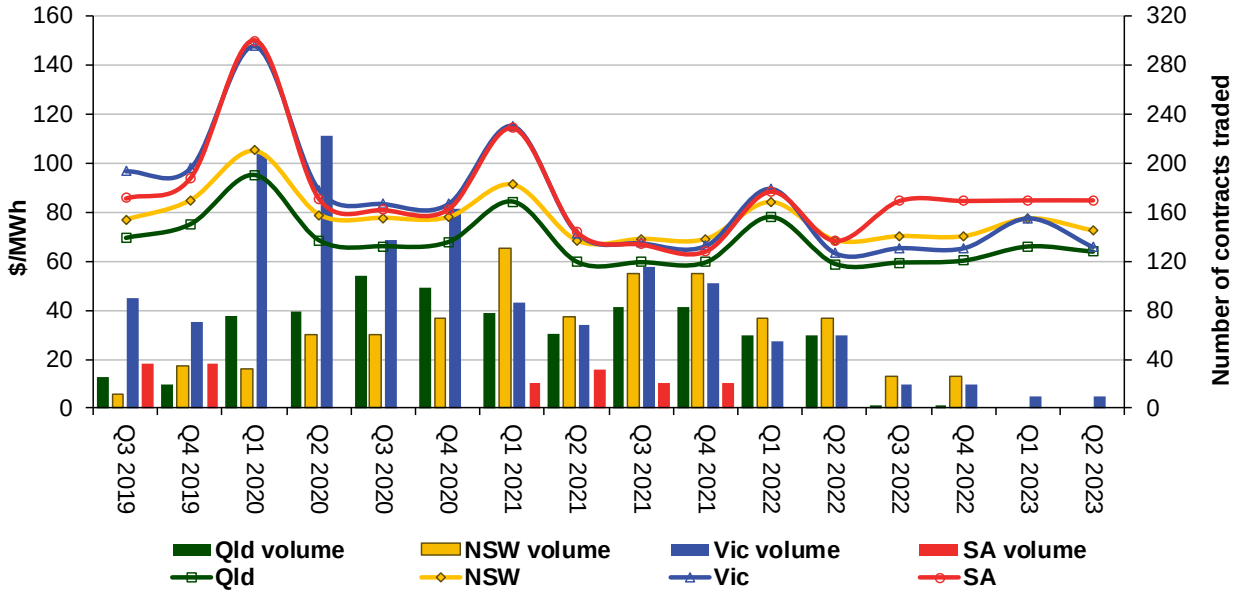
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6.30 pm	365.95	400.06	213.45	1537	1507	1493	2056	2068	2077

Conditions at the time saw prices close to forecast, four hours prior.

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.

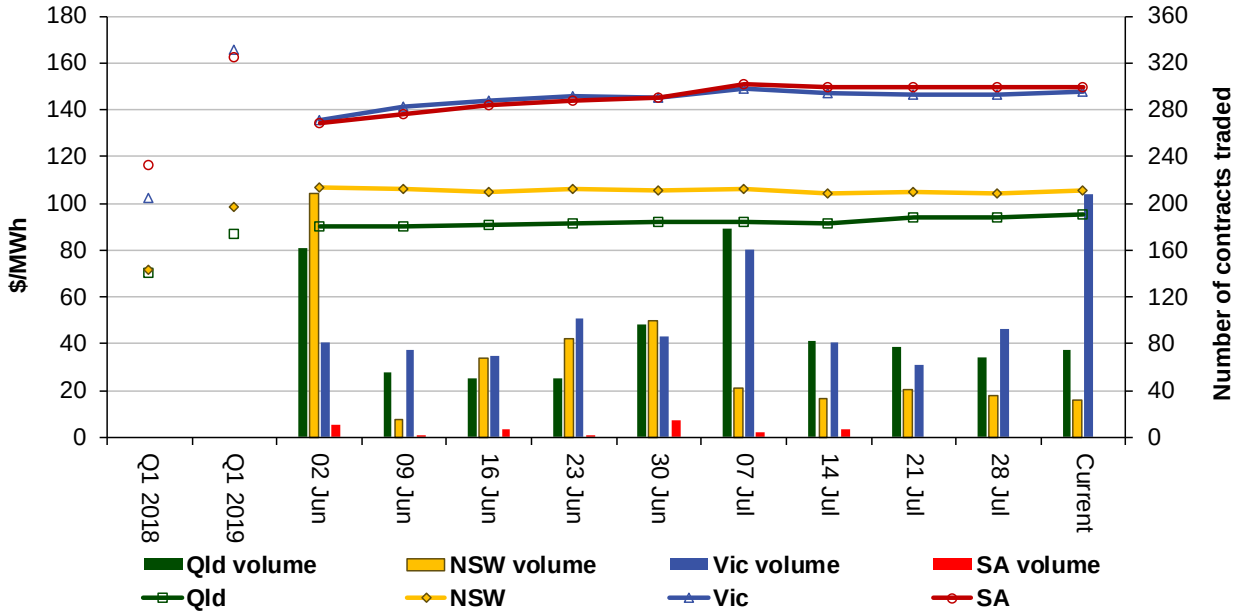
Figure 9: Quarterly base future prices Q3 2019 – Q2 2023



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)



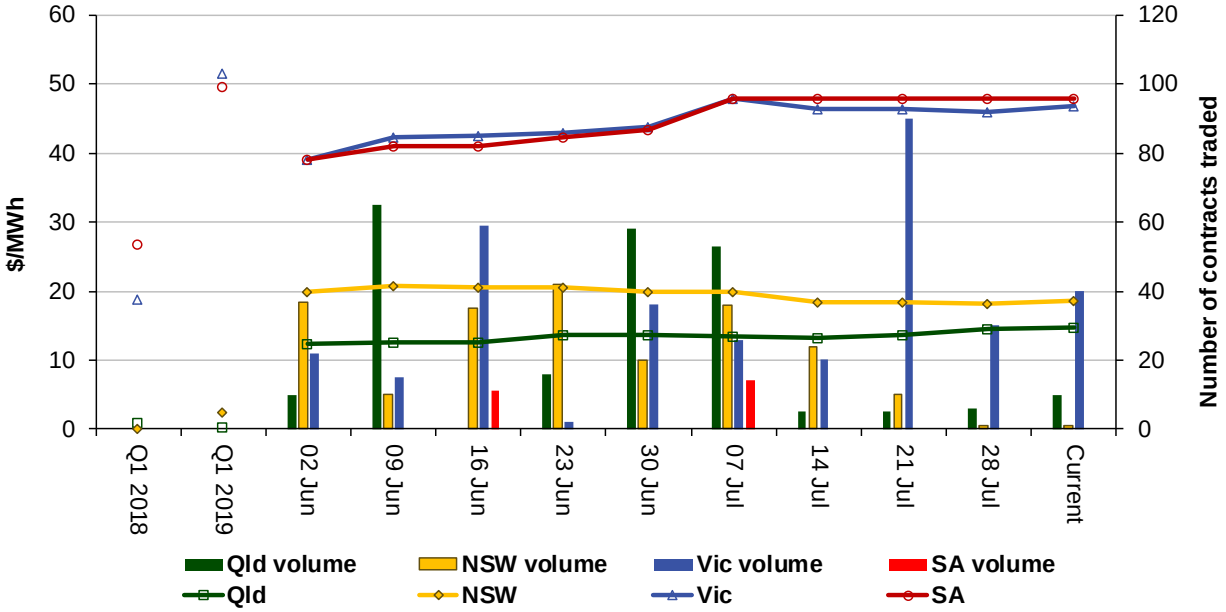
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2020 cap 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.

Figure 11: Price of Q1 2020 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au