Electricity Report

AUSTRALIAN ENERGY REGULATOR

25 – 31 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 25 to 31 August 2019.

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

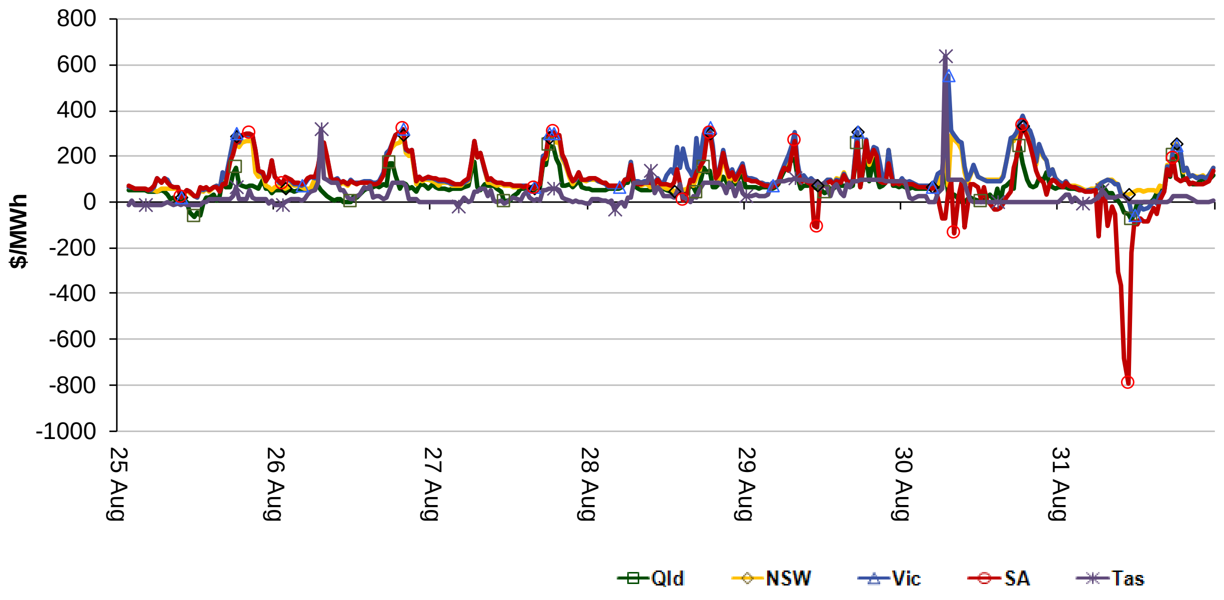


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

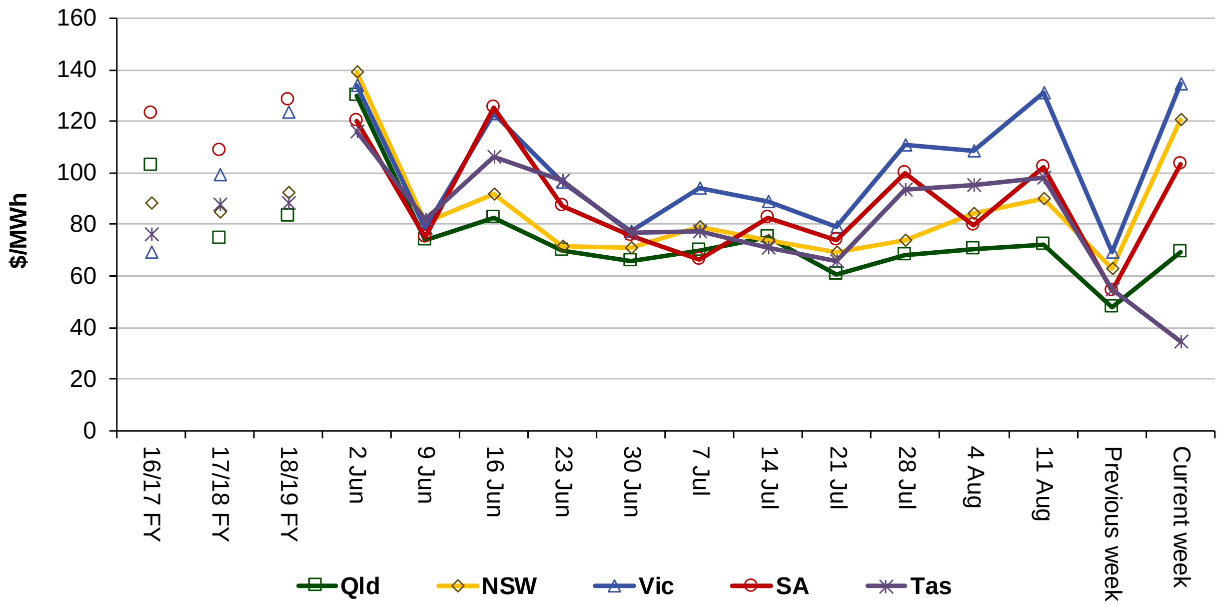


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	69	121	134	103	35
18-19 financial YTD	79	87	79	94	36
19-20 financial YTD	67	81	100	83	75

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 301 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	5	24	0	2
% of total below forecast	17	44	0	9

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

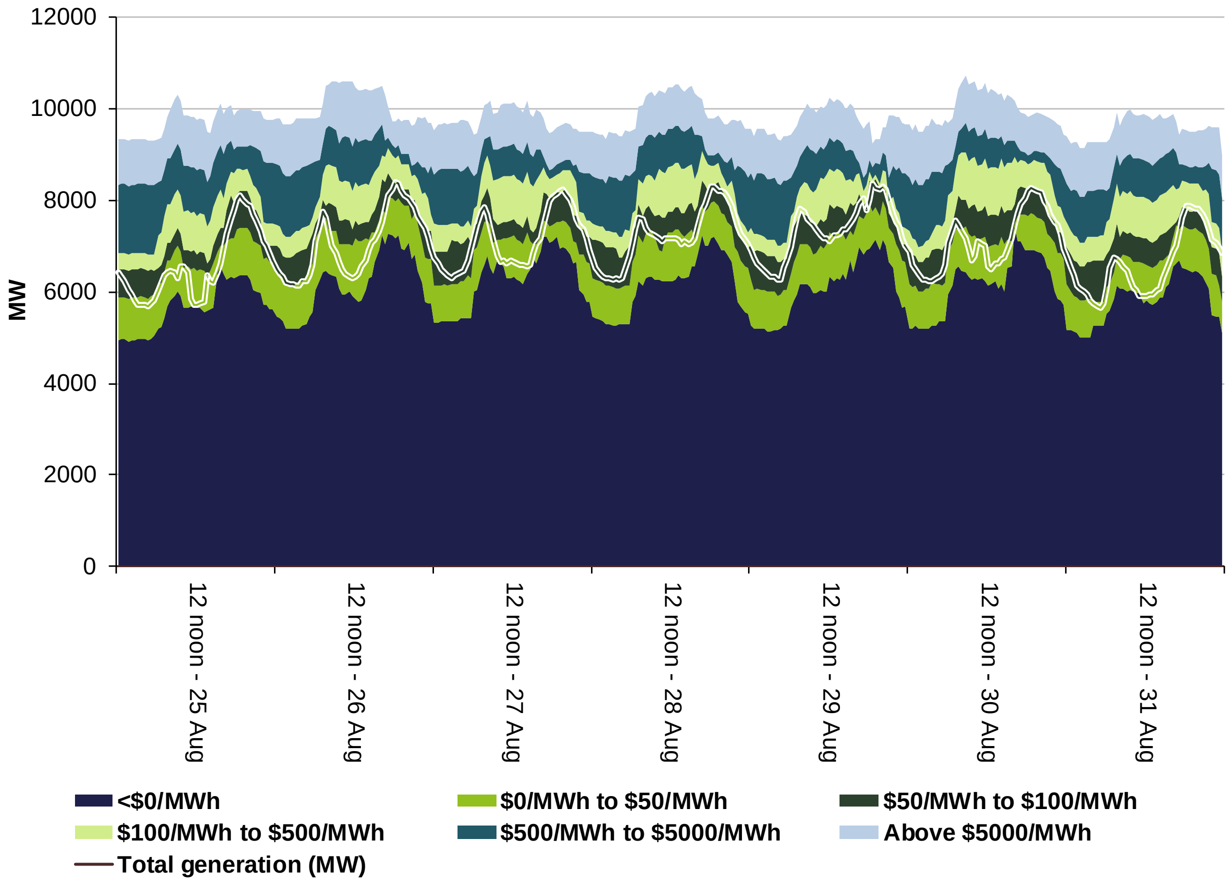


Figure 4: New South Wales generation and bidding patterns

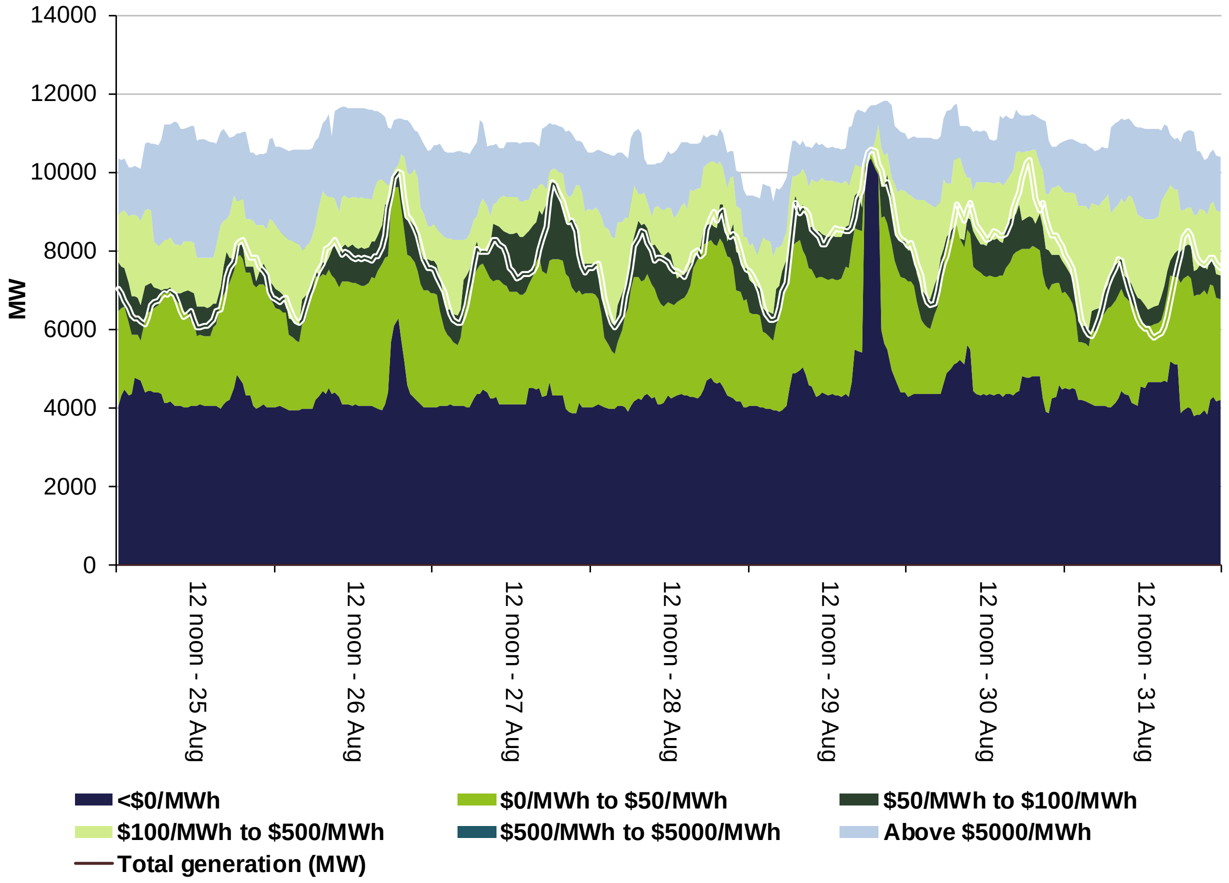


Figure 5: Victoria generation and bidding patterns

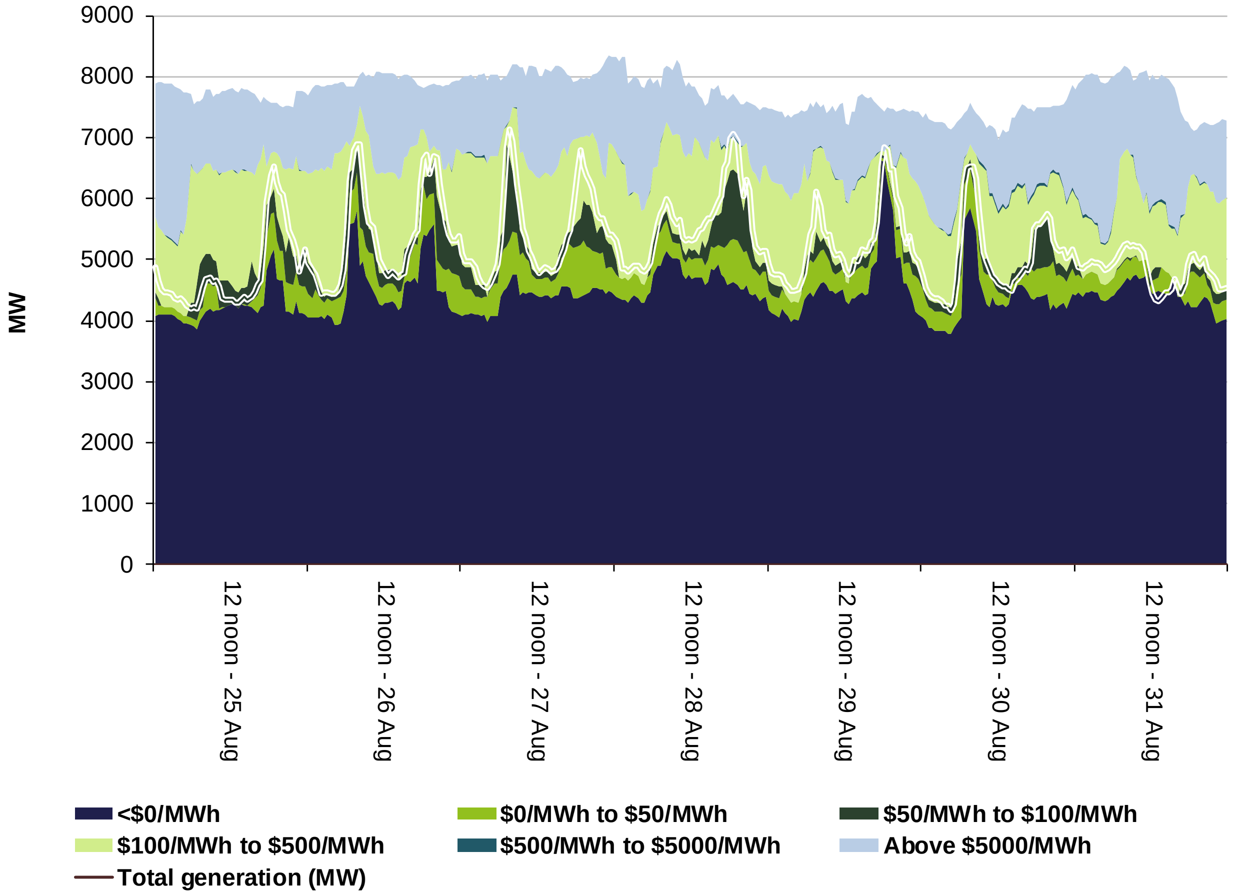
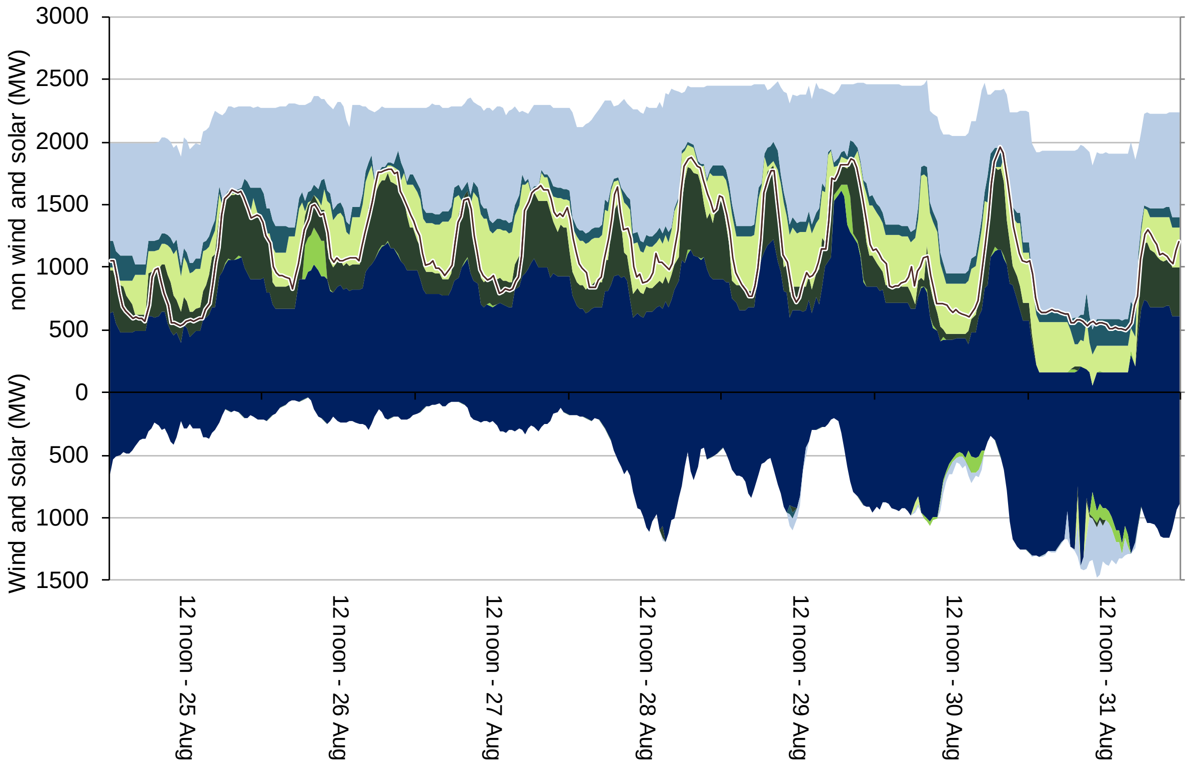
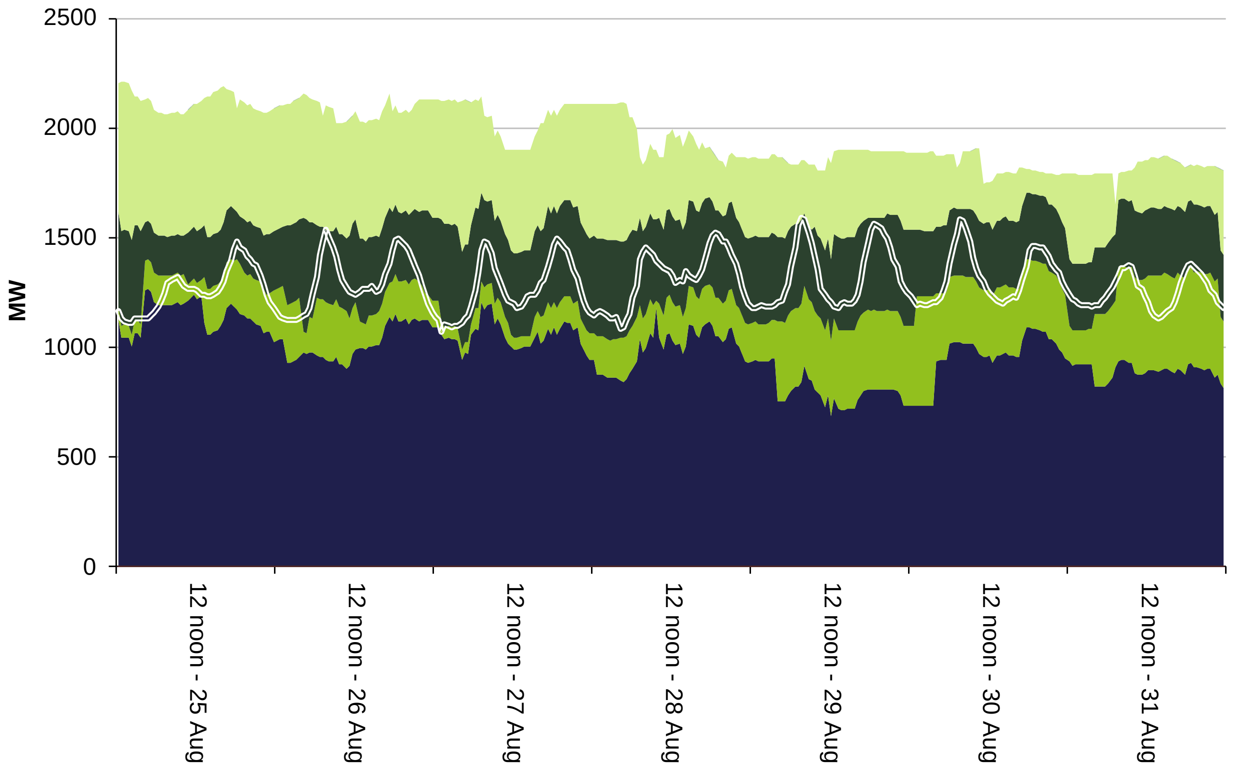


Figure 6: South Australia generation and bidding patterns



<$0/MWh
$0/MWh to $50/MWh
$50/MWh to $100/MWh
$100/MWh to $500/MWh
$500/MWh to $5000/MWh
Above $5000/MWh
Total non wind and solar generation (MW)

Figure 7: Tasmania generation and bidding patterns



<$0/MWh
$0/MWh to $50/MWh
$50/MWh to $100/MWh
$100/MWh to $500/MWh
$500/MWh to $5000/MWh
Above $5000/MWh
Total generation (MW)

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.

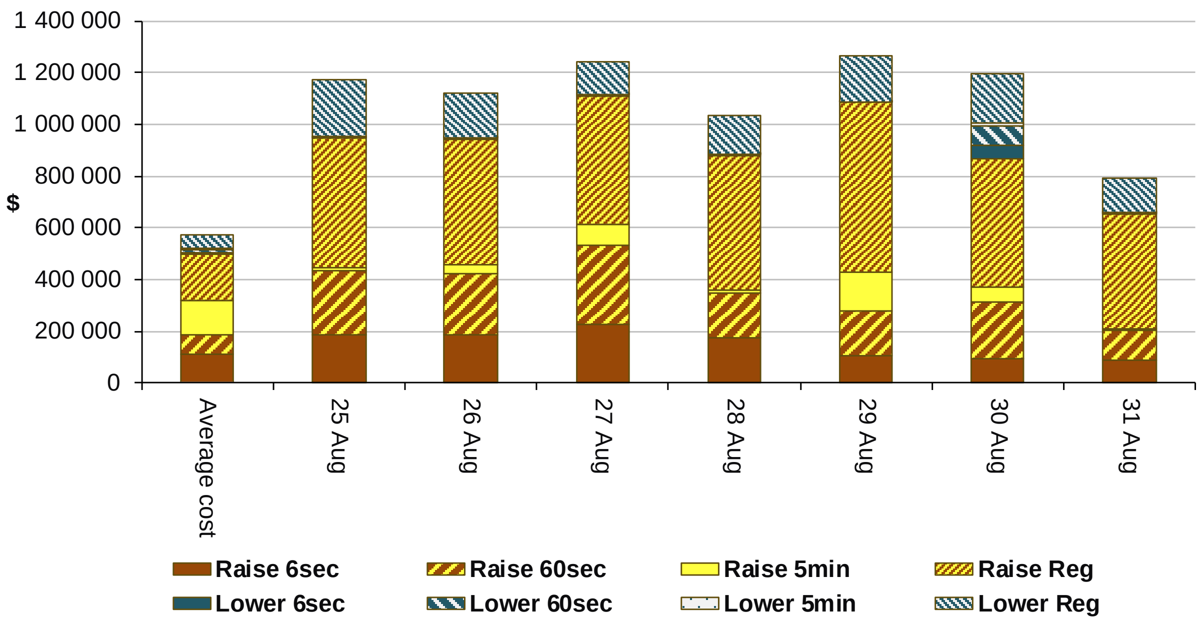
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $7 178 500 or less than 2 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $649 000 or around 10 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



There has been a general increase in global prices since the Basslink outage because the mainland has not had access to FCAS from Tasmania. As a result, the average global raise FCAS service prices more than doubled for the week 25 – 31 August 2019 compared to the week prior. Global raise regulation prices and global raise 60 second prices notably increased from $38/MWh to $74/MWh and $5/MWh to $24/MWh respectively.

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 $69/MWh and above $250/MWh.

Thursday, 29 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
5.30 pm	252.24	60.73	60.73	6800	6835	6717	9566	10 113	10 090

Demand was close to forecast while availability was around 550 MW lower than forecast four hours ahead. The reduced availability was all below $50/MWh.

At 1.49 pm, Origin rebid capacity out of the market and capacity from low to high prices which saw the forecast price increase to around $250/MWh. Shortly after Origin added back 105 MW of capacity at -$1000/MWh but this was offset by other participants reducing capacity, the relevant rebids are shown in Table 4.

Table 4: Significant rebids for 5.30 pm

Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.49 pm	Origin Energy	Darling Downs	-159	<54	N/A	1347A constraint management - Q^^NIL_QNI_SRAR SL
1.49 pm	Origin Energy	Darling Downs	206	>54	14 700	1347A constraint management - Q^^NIL_QNI_SRAR SL
2.22 pm	Origin Energy	Darling Downs	105	N/A	-1000	1421A material change in Qld dem sl
3.02 pm	ERM Power	Oakey	110	1413	<0	A 1457 1431 decrease in Qld availability for 1530: 9,949mw pd30@1431 vs 10,288mw pd30@1301
3.33 pm	Callide Power Trading	Callide C	-40	-1000	N/A	1533P C3 generator testing
4.13 pm	AGL Energy	Yabulu	-75	<50	N/A	1610~P~020 reduction in avail cap~208 rts 00:30 later than exp
4.33 pm	Callide Power Trading	Callide C	-100	-1000	N/A	1632P C3 generator testing runup
4.33 pm	Alinta Energy	Braemar A	160	305	<0	1630~A~change in price 5pd~
4.39 pm	Callide Power Trading	Callide C	-30	-1000	N/A	1638P C3 generator testing runup
4.42 pm	AGL Energy	Yabulu	-62	0	N/A	1620~P~020 reduction in avail cap~208 rts 00:30 later than exp - st

Submitted time	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.45 pm	Callide Power Trading	Callide C	-30	-1000	N/A	1644P boiler steam max alarm

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $134/MWh and above $250/MWh.

Friday, 30 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
7.30 am	550.81	776.24	310.35	6620	6384	6388	7451	7382	7367

Demand and availability were both higher than forecast four hours ahead.

An outage of the Bunonga to Balranald to Darlington Point line saw forecast flows forced out of Victoria into New South Wales at around 450 MW, four hours ahead. Actual flows into New South Wales across the Victoria to New South Wales interconnector ended up averaging 61 MW, which resulted less generation dispatched in Victoria and the price was lower than forecast.

South Australia

There were two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $103/MWh and above $250/MWh and there were eleven occasions where the spot price was below -$100/MWh.

Monday, 26 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 pm	318.69	108.24	439.38	2078	2121	2143	2490	2401	2433

Prices were aligned with those in Victoria and New South Wales but neither of these regions breached our reporting threshold.

From 4.42 pm onwards, Snowy Hydro rebid 476 MW of capacity mainly from the price floor to above $450/MWh over several rebids at Murray, before rebidding 100 MW back down late in the trading interval (see Table 7 for details). This resulted in dispatch prices between $291/MWh and $346/MWh for the trading interval.

Table 7: Significant rebids for 8 pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.42 pm		Snowy Hydro	Murray	6	-1000	14700	15:05:00 A Vic 30min pd +1000 sensitivity $12,804.28 lower than 30min pd 18:00@14:35 ($744.03)
6.16 pm		Snowy Hydro	Murray	137	-1000	450	18:05:00 A NSW 30min pd +1000 sensitivity $11,969.73 lower than 30min pd 19:30@17:35 ($1,786.61)
6.31 pm		Snowy Hydro	Murray	133	-1000	>450	18:30:19 P redistribute generation to improve plant efficiency
7.16 pm		Snowy Hydro	Murray	200	290	14700	19:11:00 A Vic-NSW 5min pd price separation $33.85 higher than 5min pd 19:30@19:06 ($51.56)
7.41 pm	7.50 pm	Snowy Hydro	Murray	100	>450	-1000	19:35:03 A Vic 5MIN actual price $9.82 higher than 30min pd 19:40@19:32 ($336.03)

Thursday, 29 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
11 am	-103.74	128.25	102.41	1281	1280	1280	3446	2843	2853
11.30 am	-112.85	97.74	77.50	1212	1201	1199	3483	2860	2827

For both the 11 am and 11.30 am trading intervals, demand was close to forecast and availability was between 600 MW and 623 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, the majority of which was priced at the floor. With little or no capacity priced between $70/MWh and the price floor, the dispatch price dropped to the price floor once during these trading intervals when there was a small reduction in demand or change in generation availability.

Friday, 30 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
8.30 am	-138.78	78.00	78.00	1690	1644	1638	3468	3325	3305
10 am	-110.31	77.50	77.50	1367	1319	1321	3192	3049	3099
7 pm	332.41	318.91	318.90	1710	1657	1665	2801	2899	2922

For both the 8.30 am and 10 am trading intervals, demand was around 50 MW higher than forecast and availability was 143 MW higher than forecast, four hours prior. The higher than forecast availability was due to higher than forecast wind generation, the majority of which was priced at the floor.

At 8.30 am, a 36 MW drop in demand led to co-optimisation between the FCAS and energy markets. This resulted in the dispatch price falling to almost -$900/MWh.

At 10 am, demand dropped by 71 MW. With less than 30 MW priced between the forecast price of $70/MWh and the price floor, the dispatch price dropped to the price floor for one dispatch interval.

For the 7 pm trading interval, prices were close to forecast both four and 12 hours prior.

Saturday, 31 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
6.30 am	-148.53	48.45	46.03	1025	946	957	3105	3090	3063
8 am	-101.92	47.93	38.54	1145	1055	1050	3241	3099	3083
9.30 am	-304.24	-50.85	-50.85	982	962	947	3335	3112	3169
10 am	-367.23	-50.85	-50.85	882	869	855	3261	3082	3139
10.30 am	-683.62	-151.85	-151.85	760	756	730	3244	3095	3164

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.

For the 6.30 am trading interval, demand was 79 MW higher and availability was 15 MW higher than forecast, four hours prior. A network constraint resulted in lower than forecast flows into Victoria across the Heywood interconnector. As a result, less generation was required to meet demand and the price fell to -$1000/MWh at 6.15 am.

For the 8 am trading interval, demand was 90 MW higher and availability was 142 MW higher than forecast, four hours prior. Additional availability was due to higher than forecast wind generation, the majority of which was priced below $0/MWh. At 7.45 am, demand in South Australia decreased by 40 MW. With only a small amount of generation priced between $100/MWh and the price floor, this resulted in the price falling to -$1000/MWh for one dispatch interval.

For the 9.30 am and 10 am trading intervals, demand was close to forecast and availability was between 179 MW to 223 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, the majority of which was priced below $0/MWh. From 8.30 am to 9 am, Neoen rebid 109 MW of capacity at Hornsdale Wind Farm 3 from the price cap to the price floor, due to a change plant conditions or change in availability. The rebids were effective for both the 9.30 am and 10 am trading intervals and resulted in the dispatch price falling to the price floor twice in both trading intervals.

For the 10.30 am trading interval, demand was close to forecast and availability was around 150 MW higher than forecast, four hours prior. Higher than forecast availability was due to higher than forecast wind generation, the majority of which was priced below $0/MWh. As a result, price went to the price floor for four dispatch intervals.

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
11 am	-794.58	-1000	-1000	670	689	662	3393	3125	3193
11.30 am	-222.49	-1000	-1000	655	629	628	3367	3161	3201

For the 11 am trading interval, demand was 19 MW lower than forecast and availability was 268 MW higher than forecast due to wind generation, four hours prior. From 10.14 am, around 220 MW of capacity priced at -$1000/MWh was rebid to more than -$100/MWh (see Table 12). These rebids saw the dispatch price increase to -$667/MWh and -$100/MWh for the first two dispatch intervals.

Table 12: Significant rebids for 11 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.14 am		Willogoleche Power Pty Ltd	Willogoleche Wind Farm	119	-1000	-100	1005~A~response to sa forecast prices: -$1000 in 30mpd: SL~
10.18 am		Origin Energy Uranquinty Power Pty Ltd	Bungala One Solar Farm	110	-1000	0	1010A constraint management - v_sv_mlmo_nett SL

For the 11.30 am trading interval, demand was 26 MW higher than forecast and availability was 206 MW higher than forecast due to wind generation, four hours prior. Rebidding saw around 450 MW of capacity shifted from -$1000/MWh to above -$100/MWh, see Table 13 for details. This led to dispatch prices between -$93/MWh and -$51/MWh for four dispatch intervals.

Table 13: Significant rebids for 11.30 am

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.14 am		Willogoleche Power Pty Ltd	Willogoleche Wind Farm	119	-1000	-100	1005~A~response to sa forecast prices: -$1000 in 30mpd: sl~
10.18 am		Origin Energy Uranquinty Power Pty Ltd	Bungala One Solar Farm	110	-1000	0	1010A constraint management - v_sv_mlmo_nett sl
11.02 am	11.10 am	EnergyAustralia	Waterloo WF	130	-1000	100	11:02 ~ A ~ band adj to 5min negative dp ~ sl

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.03 am	11.10 am	Trustpower	Snowtown WF	99	-1000	14 700	1100 A SA1 5min pd rrp for 1110 ($-50.85) published at 1100 is 94.91% higher than 5min pd rrp published at 1045 ($-1000.0) - time of alert: 1103

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $35/MWh and above $250/MWh.

Monday, 26 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
7.30 am	317.35	102.44	102.47	1358	1364	1378	2105	2129	2132

Demand and availability were both close to forecast, four hours prior. The continued Basslink outage meant that Tasmania had to source its FCAS locally. At 7.15 am, there was a 50 MW increase in local raise regulation service requirements. This resulted in co-optimisation between the FCAS and energy markets resulting in the energy price increasing to over $1400/MWh for one dispatch interval.

Friday, 30 August

Table 15: Price, Demand and Availability

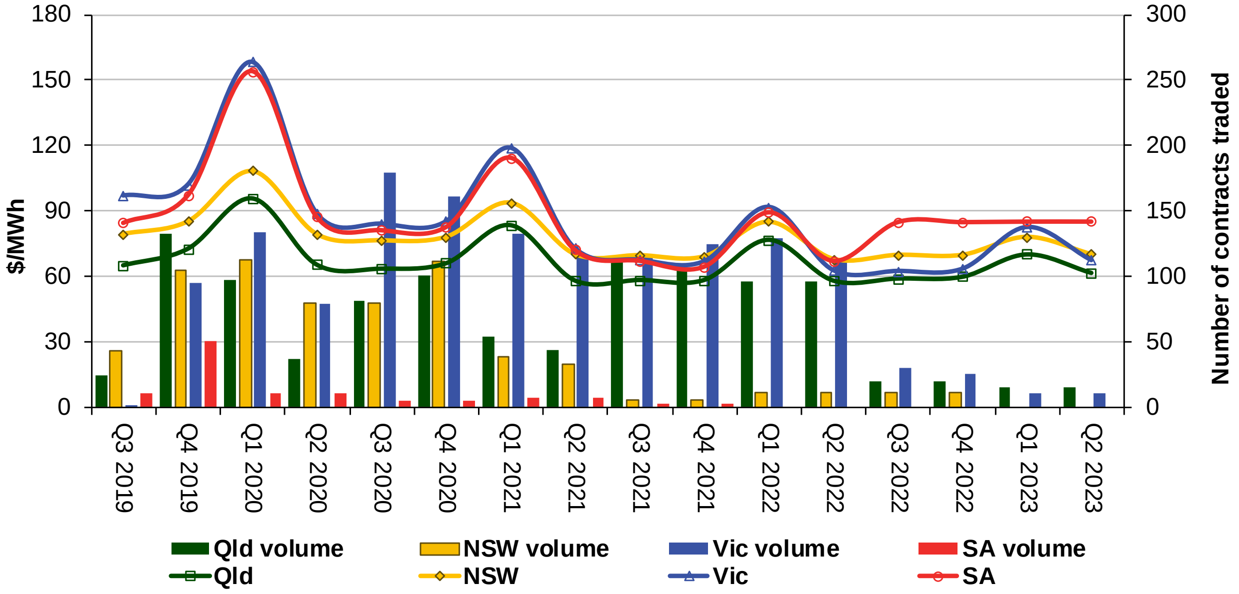
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 am	635.72	100.33	100.34	1382	1387	1397	1879	1870	1873

Demand and availability were close to forecast, four hours prior. The continued Basslink outage meant that Tasmania had to source its FCAS locally. At 6.55 am, there was a total of 174 MW increase across local raise FCAS services requirements. This resulted in co-optimisation between the raise FCAS markets and the energy market and the energy price increasing to over $3300/MWh for one dispatch 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.

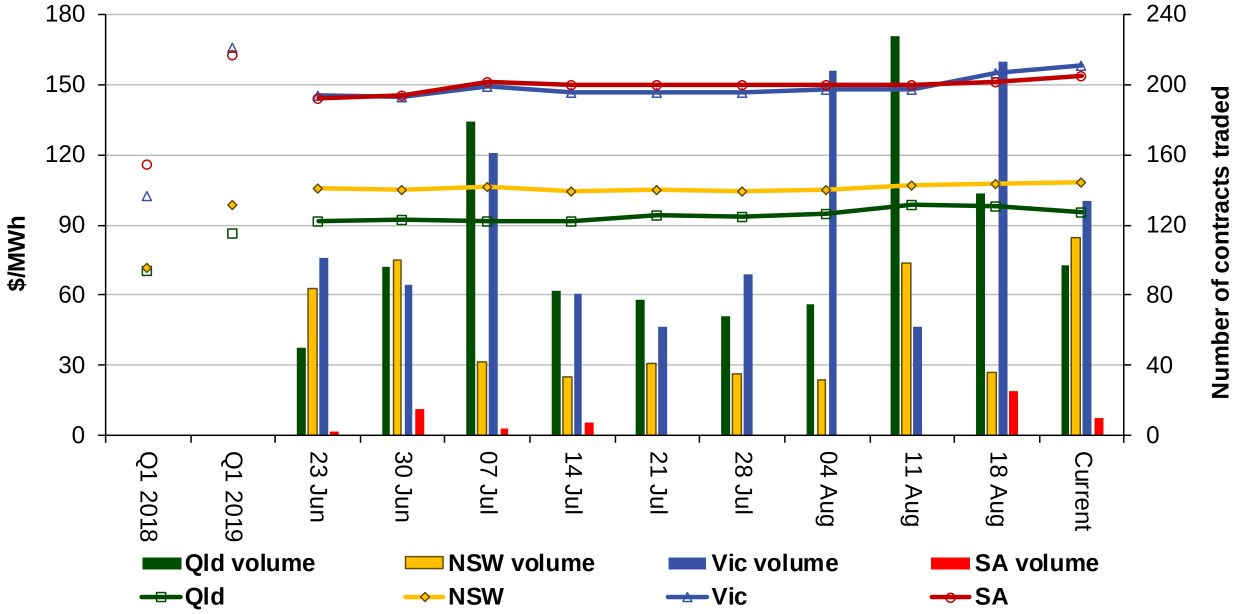
Figure 9: Quarterly base future prices Q3 2019 – Q2 2023



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)



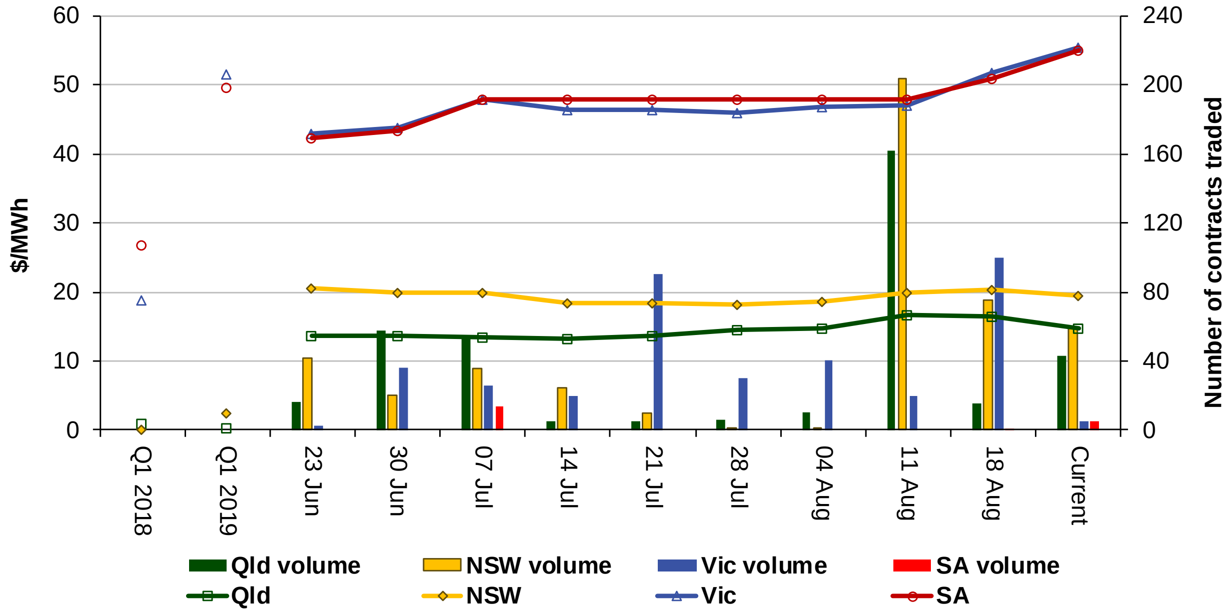
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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

Australian Energy Regulator
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