3 - 9 June 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 3 – 9 June 2018.

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

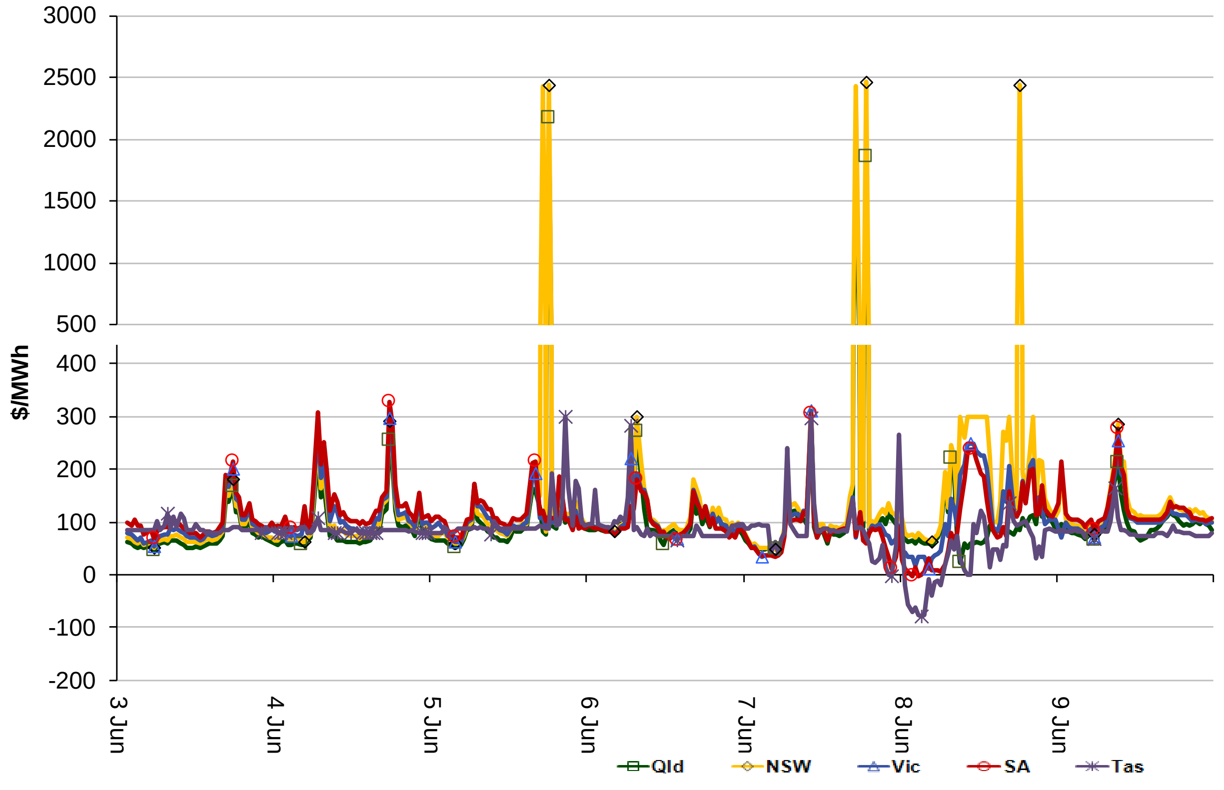


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

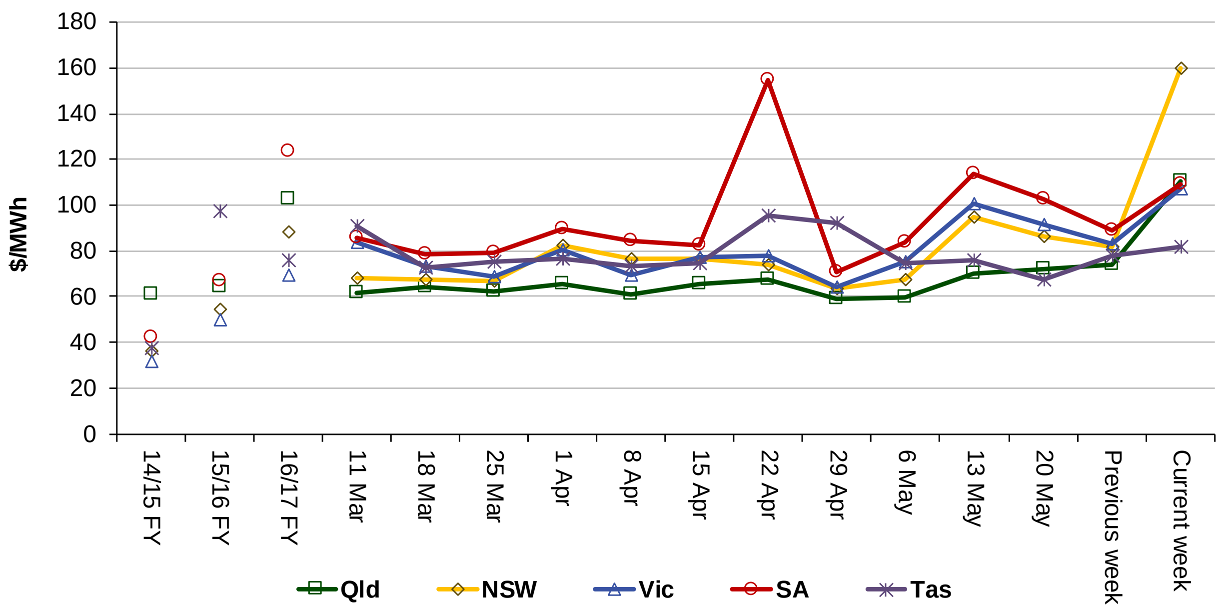


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	111	160	107	109	82
16-17 financial YTD	104	89	68	124	74
17-18 financial YTD	75	84	100	109	89

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 225 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	10	25	0	0
% of total below forecast	3	51	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

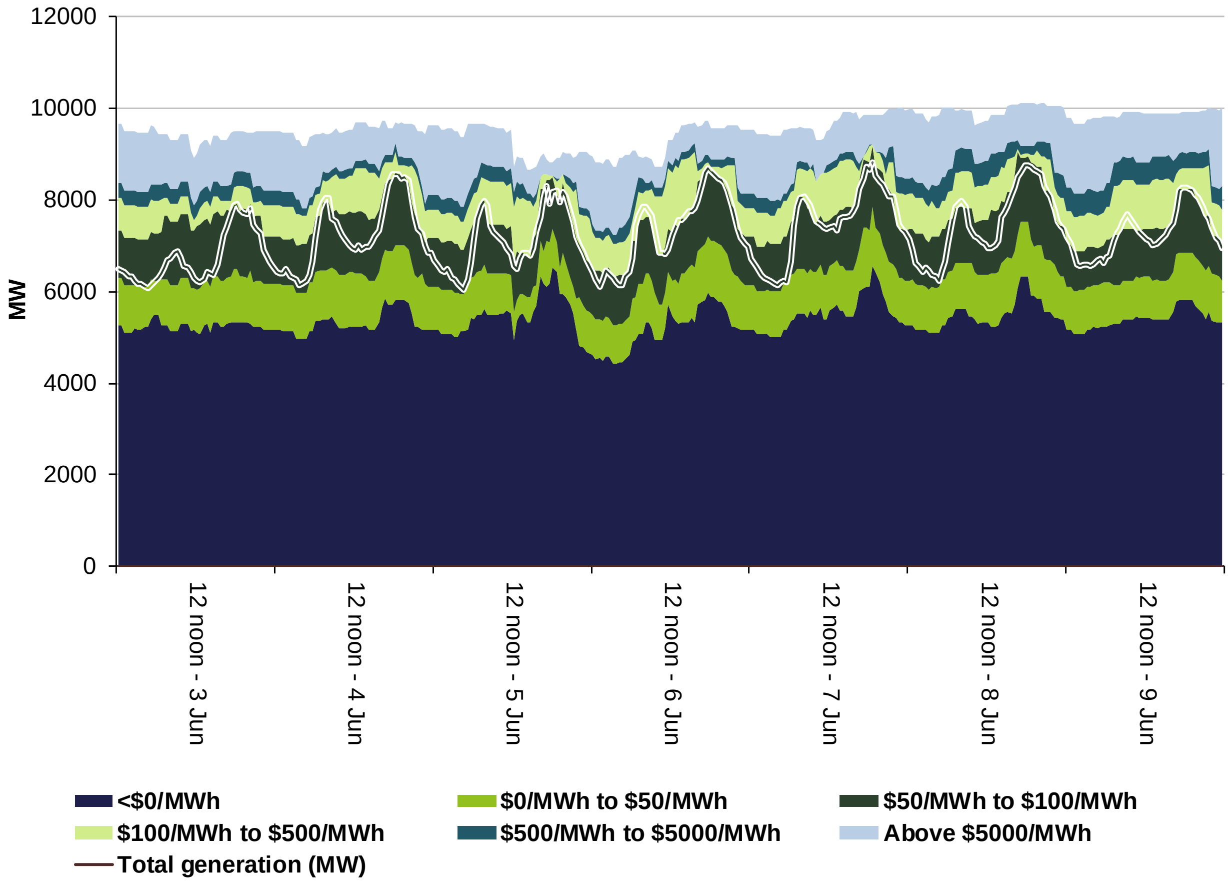


Figure 4: New South Wales generation and bidding patterns

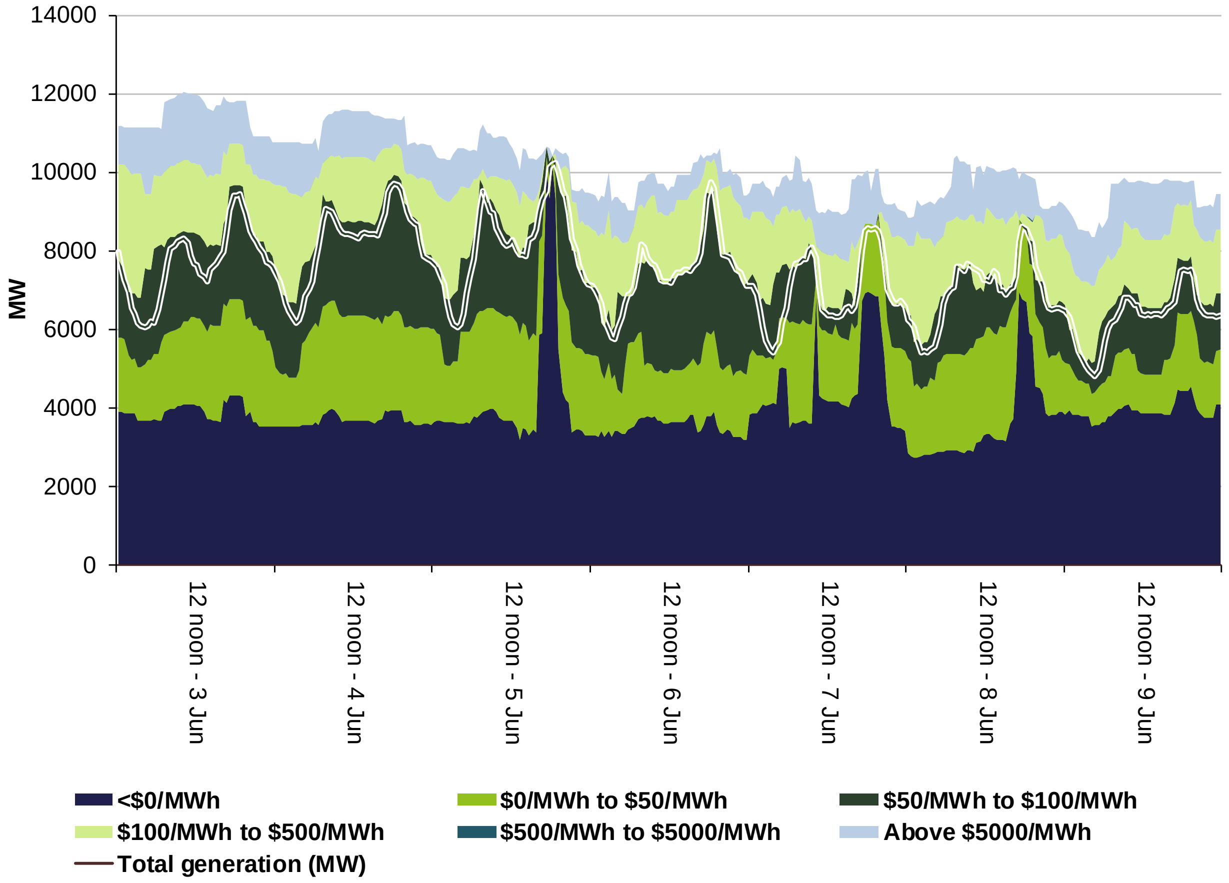


Figure 5: Victoria generation and bidding patterns

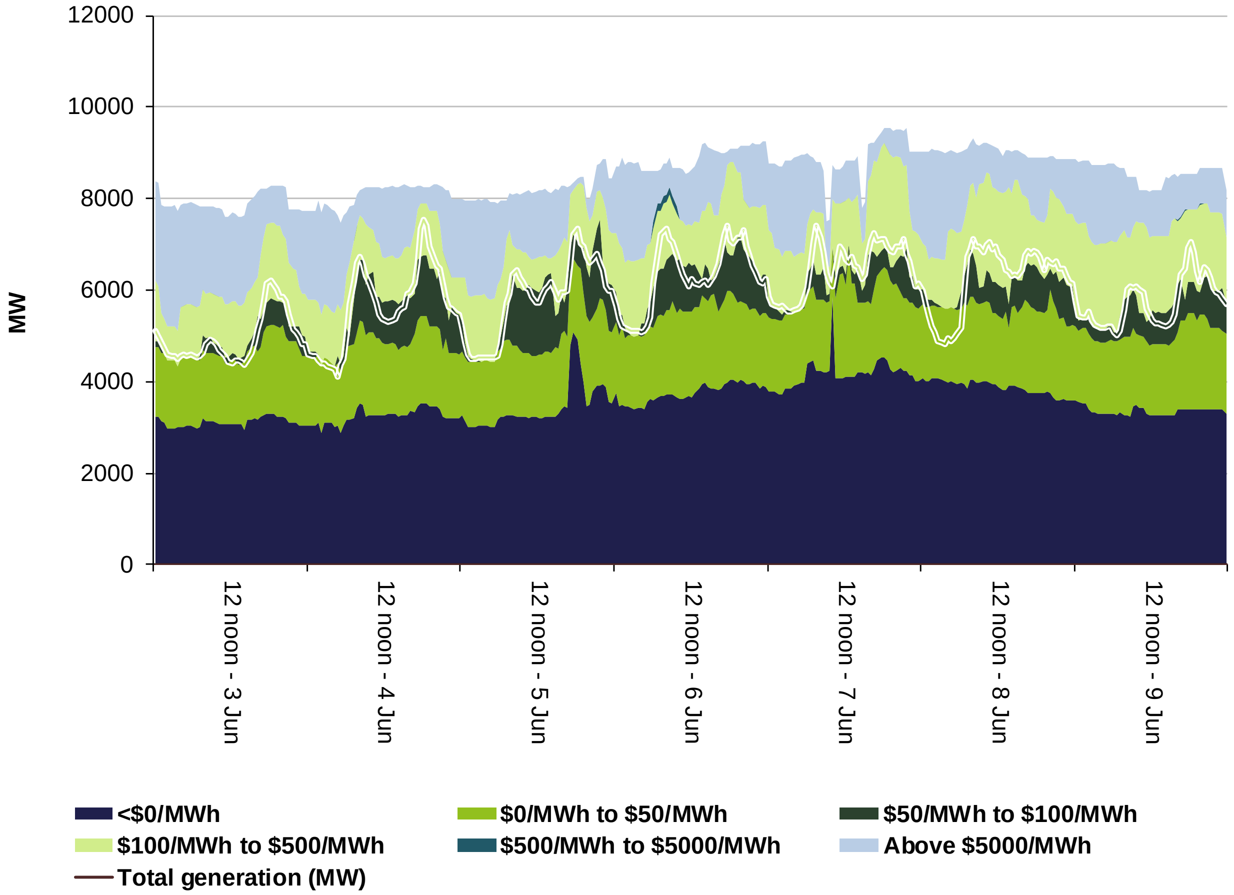


Figure 6: South Australia generation and bidding patterns

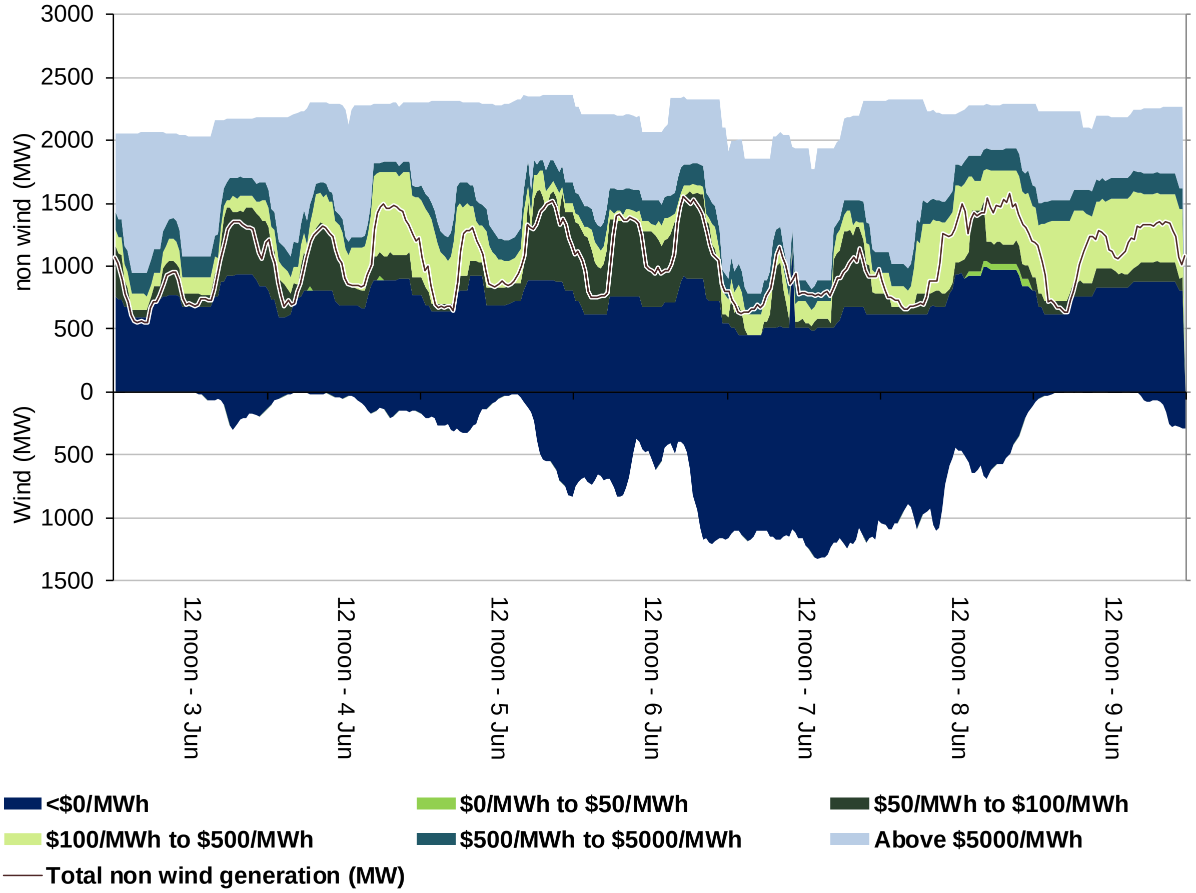
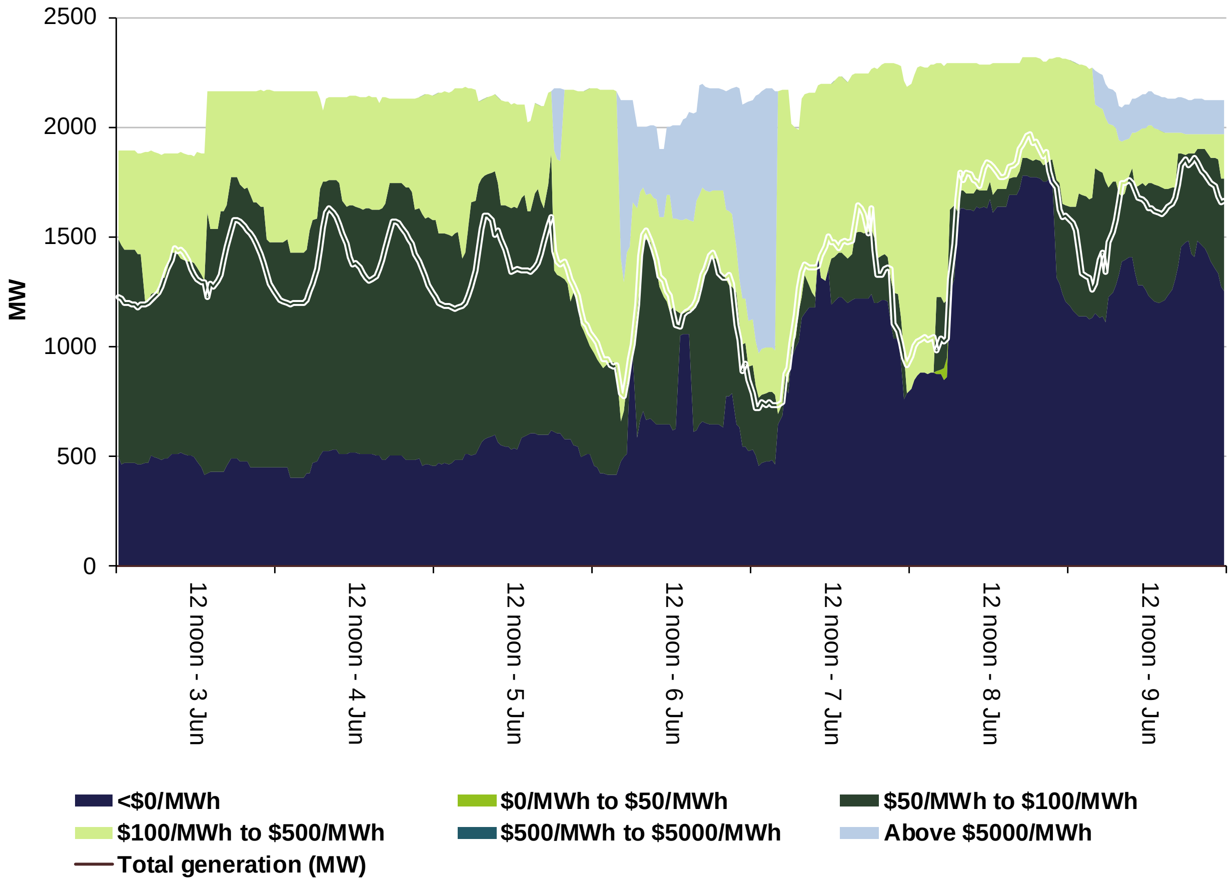


Figure 7: Tasmania generation and bidding patterns



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.

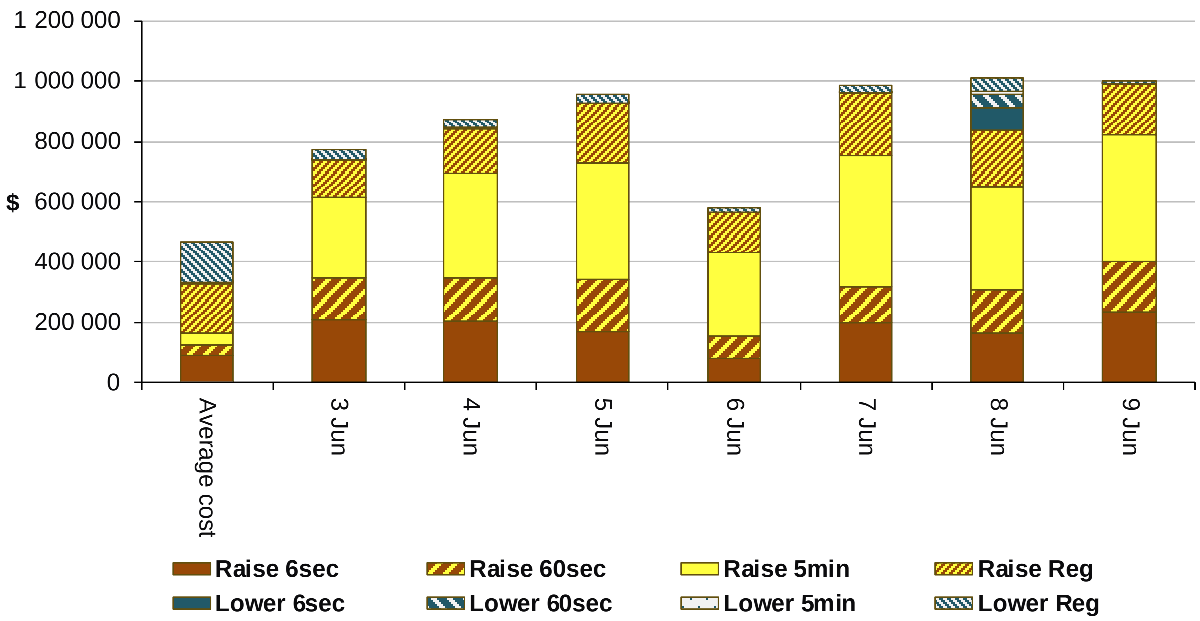
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $5 579 000 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $596 000 or around three 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



Higher than average FCAS costs, particularly in Raise 5 minute and Raise 60 second services, are attributed to outages of baseload generation in New South Wales, leading to a reduced supply of these services.

Detailed market analysis of significant price events

Queensland

There were three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $111/MWh and above $250/MWh.

Tuesday, 5 June

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	2175.39	106.79	223.37	7336	7348	7526	8821	9902	9858

The price was aligned with the New South Wales price. See the New South Wales section for this analysis.

Thursday, 7 June

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
5.30 pm	1759.10	98.78	92.24	7328	7299	7273	9847	9975	9975
7 pm	1868.50	115.08	127.94	7526	7541	7573	9854	9934	9969

Prices were aligned with the New South Wales region. See the New South Wales section for this analysis.

New South Wales

There were five occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $160/MWh and above $250/MWh.

Tuesday, 5 June

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
5.30 pm	2428.77	284.92	145.65	10 501	10 441	10 175	10 425	10 872	11 308
6.30 pm	2447.89	331.89	267.15	10 855	11 049	10 780	10 425	10 617	11 383

For the 5.30 pm trading interval, demand was close to forecast while availability was around 450 MW lower than forecast, both four hours prior.

The lower than forecast availability can mainly be attributed to EnergyAustralia removing 350 MW of capacity from its Mt Piper power station, priced at the floor at 1.20 pm, due to plant issues.

A planned network outage on the Bannaby to Gullen Range line which was originally scheduled to finish at 5 pm was extended to 7 pm. The outage limited generation from southern New South Wales flowing to the north of the state.

Across a number of rebids from 3 pm, Origin Energy rebid around 650 MW from higher prices to less than $70/MWh at its Uranquinty power station, mainly due to changes in forecast demand. This increased generation at the power station which is located in the south of New South Wales.

For the 5.15 pm dispatch interval, demand increased by 256 MW, net imports increased by around 200 MW resulting in all interconnectors importing or exporting at their limits. Lower priced capacity was limited at Uranquinty which was ramp down constrained by the network outage and at Eraring which was trapped in FCAS, therefore could not set price, resulting in the dispatch price increasing to $14 000/MWh for one dispatch interval.

For the 6.30 pm trading interval, cumulatively across Queensland and New South Wales, demand was around 200 MW lower than forecast and availability was around 1270 MW lower than forecast, both four hours prior.

The decrease in availability in Queensland can be attributed to CS Energy removing 750 MW of capacity at Kogan Creek, priced between the floor and $14/MWh, due to a revised return to service schedule and Callide Power Trading removing 206 MW of capacity at Callide C, priced at the floor, due to plant issues. In New South Wales Origin removed 200 MW of capacity at Eraring, priced below $45/MWh, due to a delayed in returning to service.

For the 6.20 pm dispatch interval, net demand increased by 336 MW. With cheaper priced capacity in Queensland ramp up constrained, the price increased to $14 000/MWh in New South Wales and $12 431/MWh in Queensland for one dispatch interval and led to the higher than forecast spot price.

Thursday, 7 June

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
5.30 pm	2438.00	117.51	114.43	9915	9796	9885	9841	10 624	10 807
7 pm	2464.52	129.29	144.65	10 077	10 153	10 142	9586	10 771	10 761

For the 5.30 pm trading interval, across Queensland and New South Wales net demand was around 150 MW higher than forecast while availability was around 900 MW lower than forecast.

In the fours leading up to the start of the trading interval, in New South Wales, Delta Energy withdrew 630 MW of capacity priced below $86/MWh at Vales Point because the unit tripped and had a return to service delay. In Queensland, 175 MW was withdrawn at Millmerran power station priced below $10/MWh due to plant issues.

For the 5.30 pm dispatch interval, net demand increased by around 300 MW. With cheaper priced generation ramp up constrained, the dispatch price reached the cap in New South Wales and $10 189/MWh in Queensland and led to a higher than forecast spot price.

For the 7 pm trading interval, net demand was around 100 MW lower than forecast and availability was 1265 MW lower than forecast four hours prior.

The rebids for Vales Point and Millmerran that are outlined above were still in effect for the 7 pm trading interval. For the 6.40 pm dispatch interval, net demand increased by 128 MW and with cheaper priced generation trapped in FCAS in Queensland the price reached the cap for in New South Wales and $10 716/MWh in Queensland and led to the higher than forecast spot price.

Friday, 8 June

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	2444.49	313.71	299.60	10 387	10 615	10 072	9719	9986	10 081

Conditions at the time saw availability around 270 MW and demand around 230 MW less than that forecast four hour ahead.

On the day, New South Wales had a steep supply curve with no capacity priced between $300/MWh and $14 000/MWh. This meant that small changes in offers could lead to significant changes in price.

Over four rebids between 3.48 pm and 6.02 pm, Energy Australia reduced the availability at Mount Piper unit 2 by 250 MW due to coal quality and coal limits, the majority of which was priced below $0/MWh.

For the 6.30 pm dispatch interval demand increased by 112 MW and a system normal constraint managing voltage stability limited cheaper priced generation. This saw the dispatch price increased from $142/MWh at 6.25 pm to $14 200/MWh.

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 $109/MWh and above $250/MWh.

Monday, 4 June

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
6 pm	328.72	472.00	383.56	1837	1886	1848	2308	2344	2322

Demand and availability were both close to forecast four hours prior.

Across two rebids between 4 pm and 4.30 pm, Origin shifted 170 MW of capacity at Quarantine priced at the cap to less than $64/MWh. Because of these rebids, lower priced capacity than what was forecast was required to meet demand.

Tasmania

There were four occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $82/MWh and above $250/MWh.

Tuesday, 5 June

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
9 pm	300.11	299.98	293.45	1472	1393	1401	2170	2173	2172

The price was close to that forecast four hours prior.

Wednesday, 6 June

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
7 am	283.46	215.81	293.45	1417	1345	1295	1992	1997	1997

Demand was 72 MW greater than forecast and availability was close to forecast, both fours prior.

Slightly lower than forecast imports, combined with higher than forecast demand led to the dispatch price being set between $270/MWh and $300/MWh for the entire trading interval.

Thursday, 7 June

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
10.30 am	296.92	99.98	73.32	1239	1274	1264	2188	2154	2132

Demand and availability were close to that forecast four hours ahead.

Prices were aligned across the NEM, but only the Tasmanian price is discussed as it is the only region that exceeded our reporting threshold, due to its lower weekly average price.

At around 10.15 am Vales Point power station in New South Wales tripped, removing 660 MW of low priced capacity from the market. This resulted in a step change in supply that could not be met by low priced generation and caused prices across the NEM to increase to around $1550/MWh for the 10.20 am dispatch interval.

Friday, 8 June

Table 12: Price, Demand and Availability

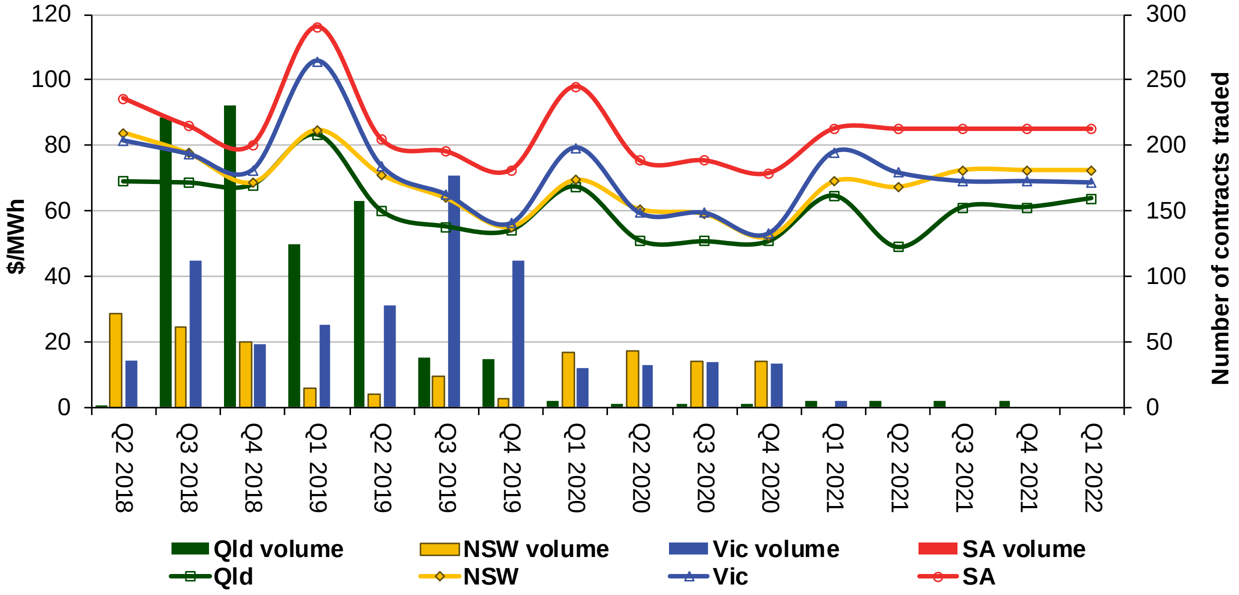
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
Midnight	266.27	265.91	265.91	1042	1043	1019	2183	2265	2289

The actual spot price was close to that 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.

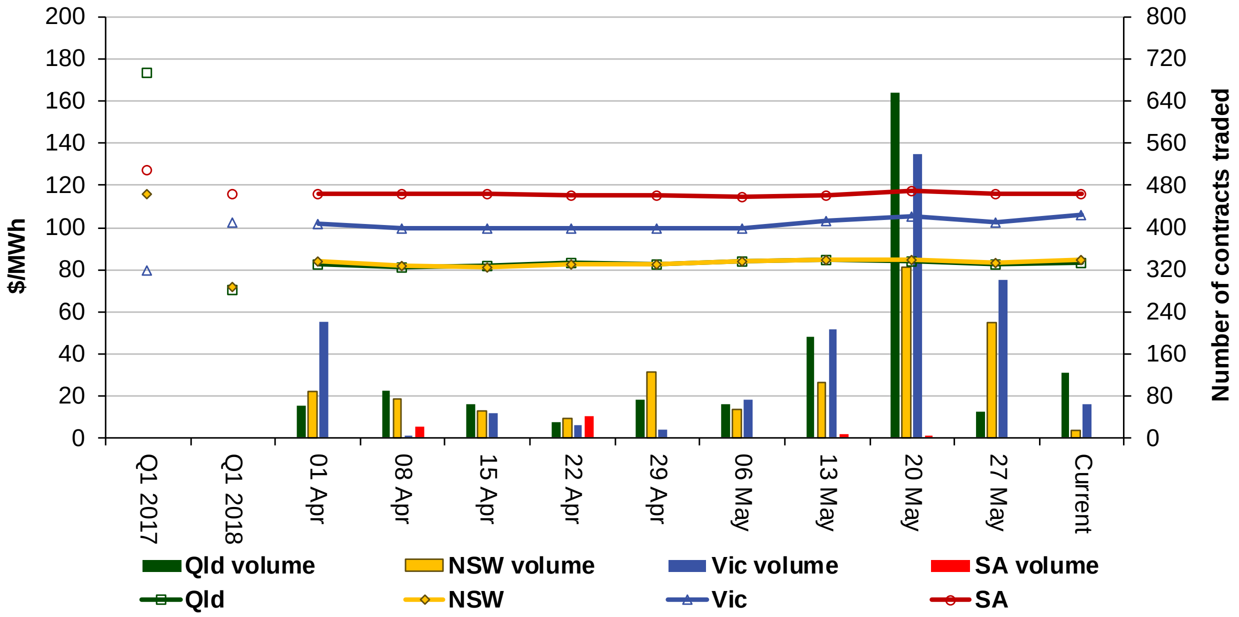
Figure 9: Quarterly base future prices Q2 2018 – Q1 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

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



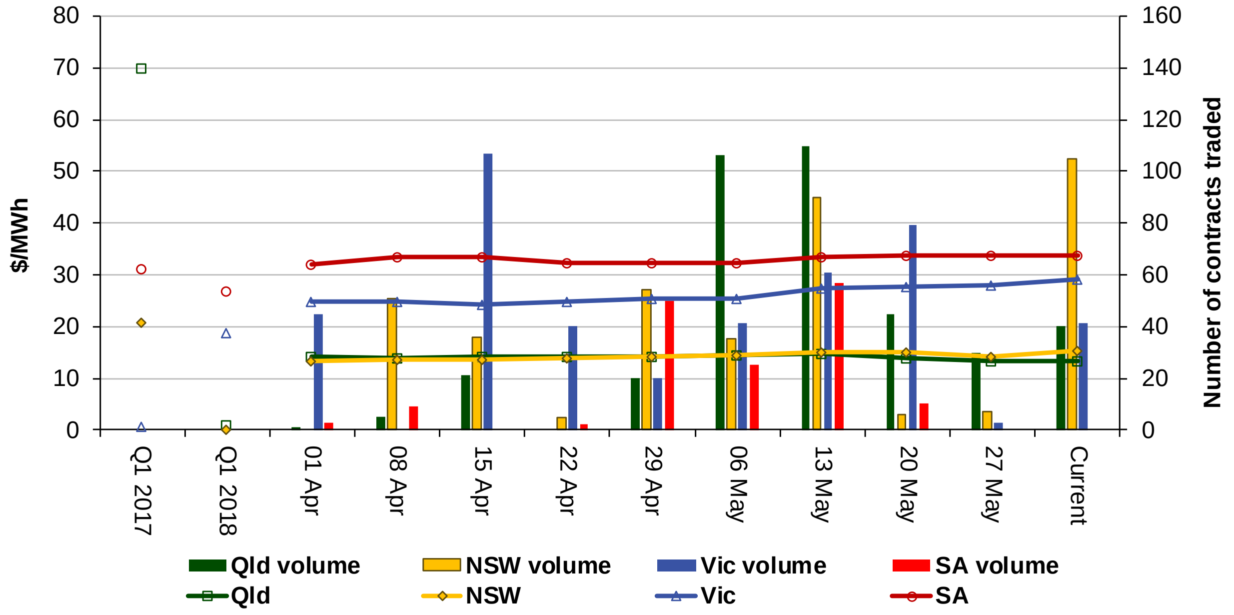
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry Statistics section of our website.

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

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



Source. ASXEnergy.com.au

Australian Energy Regulator
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