Electricity Report

AUSTRALIAN ENERGY REGULATOR

25 - 31 March 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 25 – 31 March 2018.

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

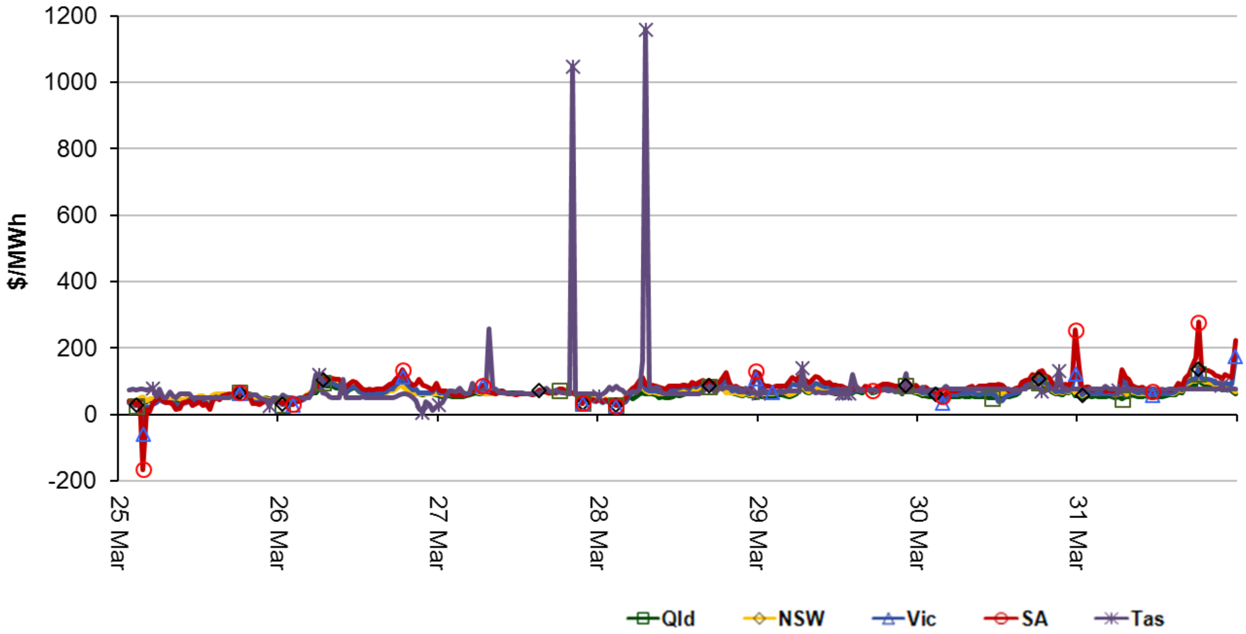


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

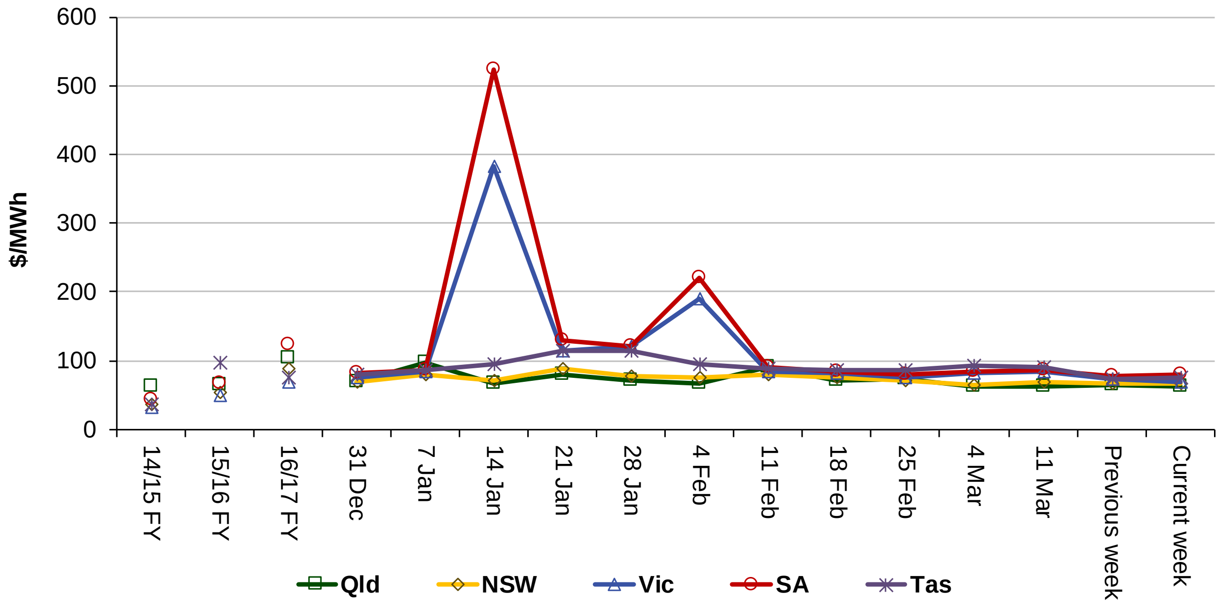


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	62	67	69	79	76
16-17 financial YTD	107	86	57	125	63
17-18 financial YTD	76	83	104	111	91

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 179 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	1	44	0	5
% of total below forecast	43	3	0	4

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

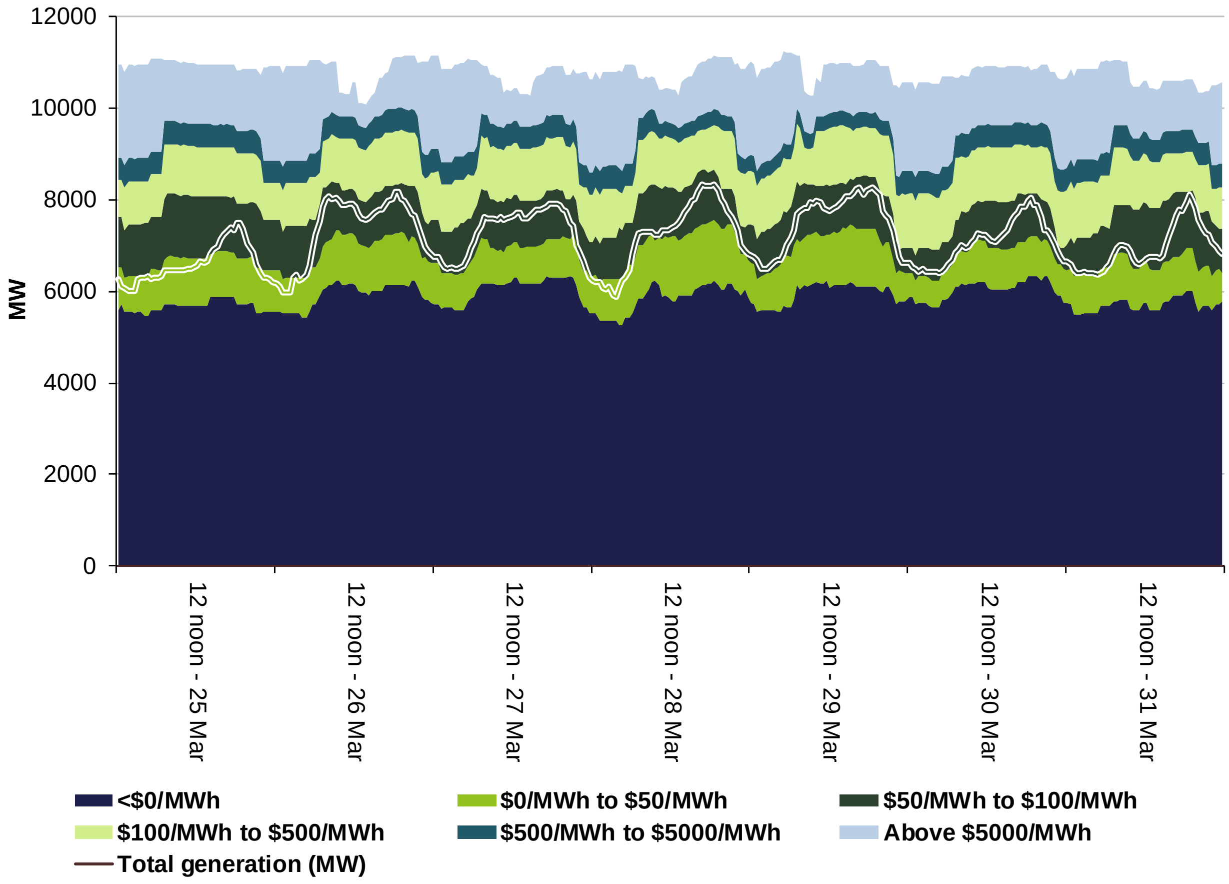


Figure 4: New South Wales generation and bidding patterns

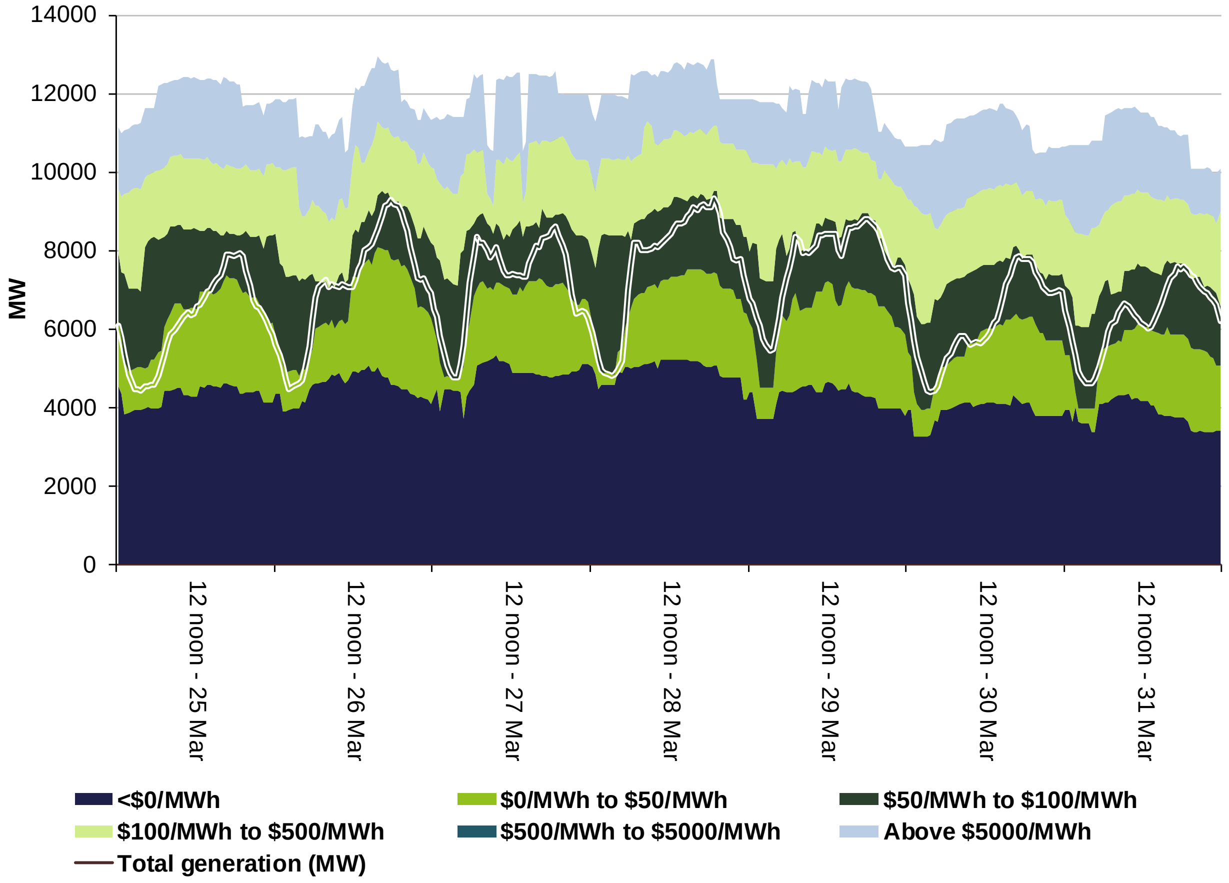


Figure 5: Victoria generation and bidding patterns

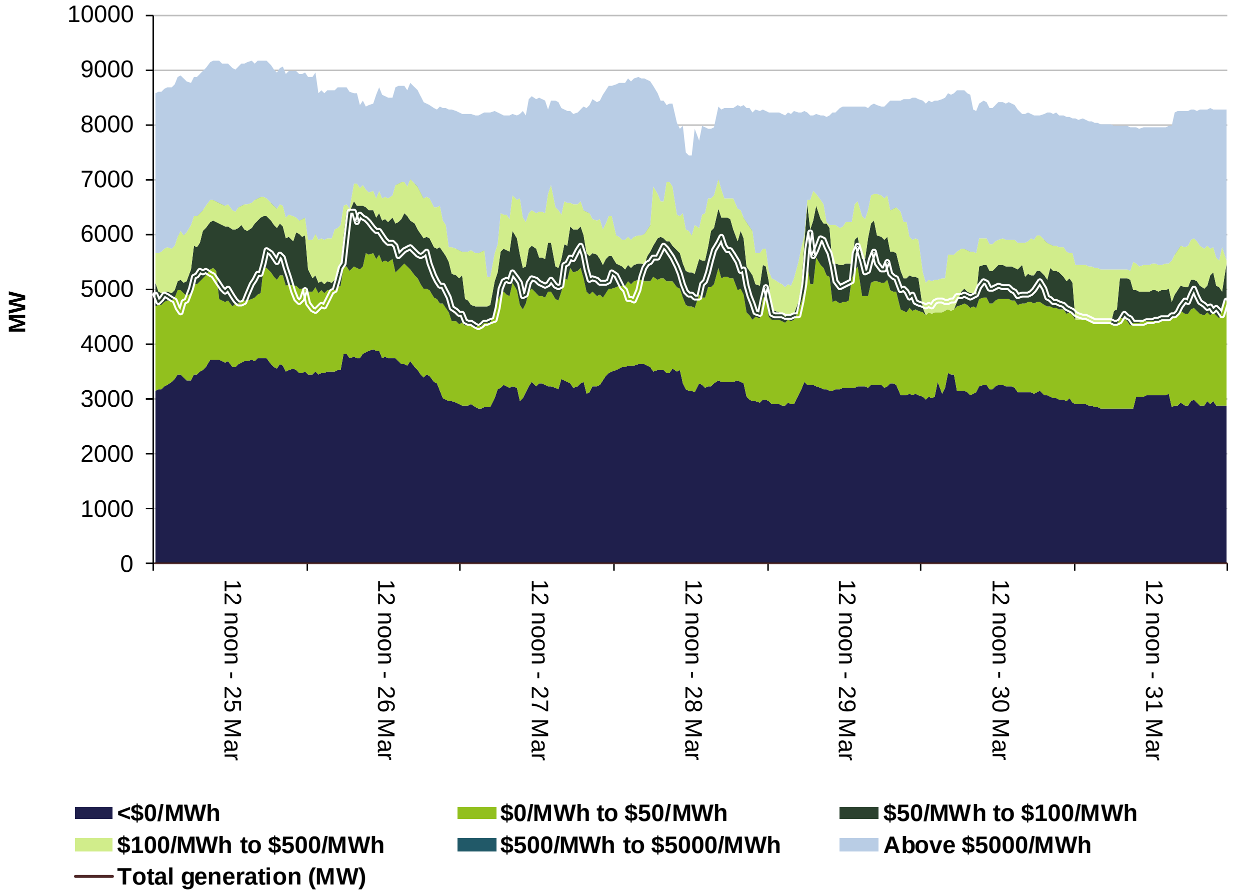


Figure 6: South Australia generation and bidding patterns

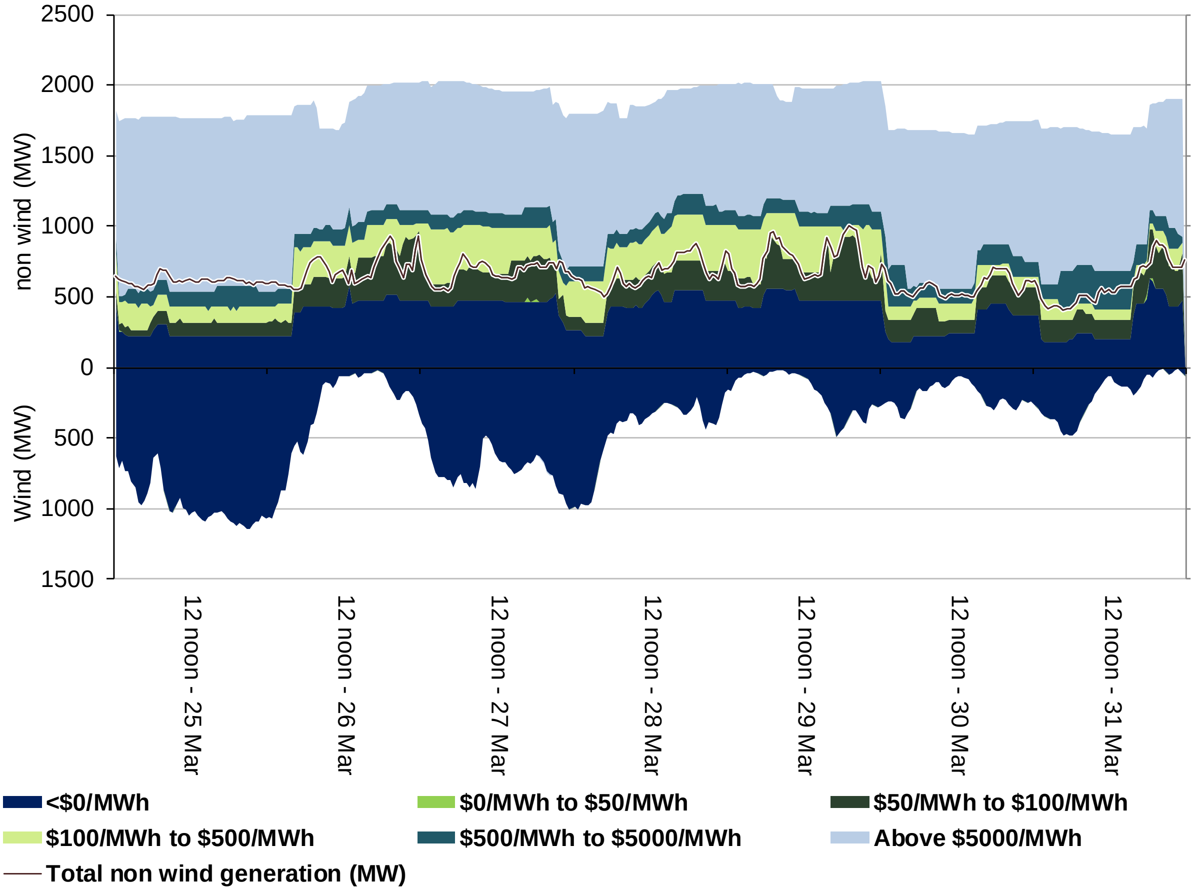
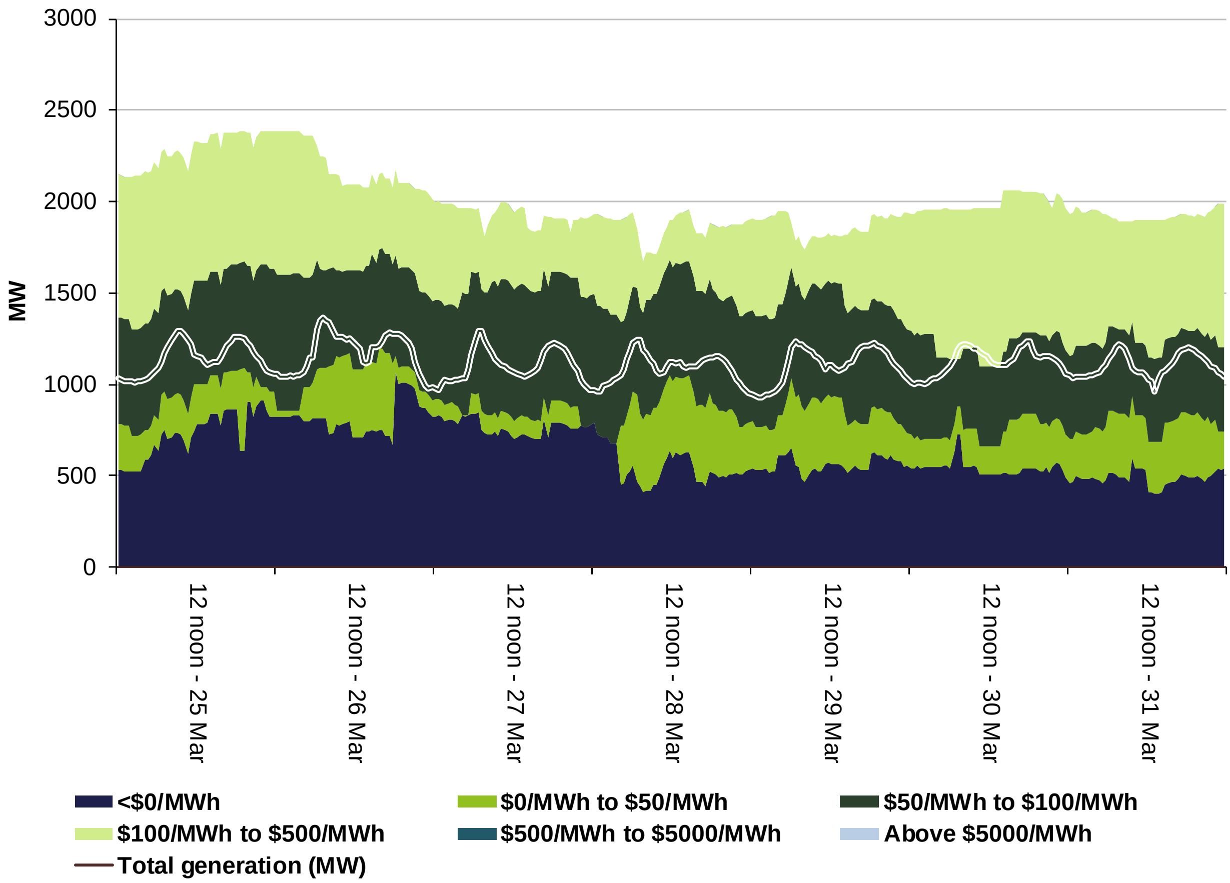


Figure 7: Tasmania generation and bidding patterns



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.

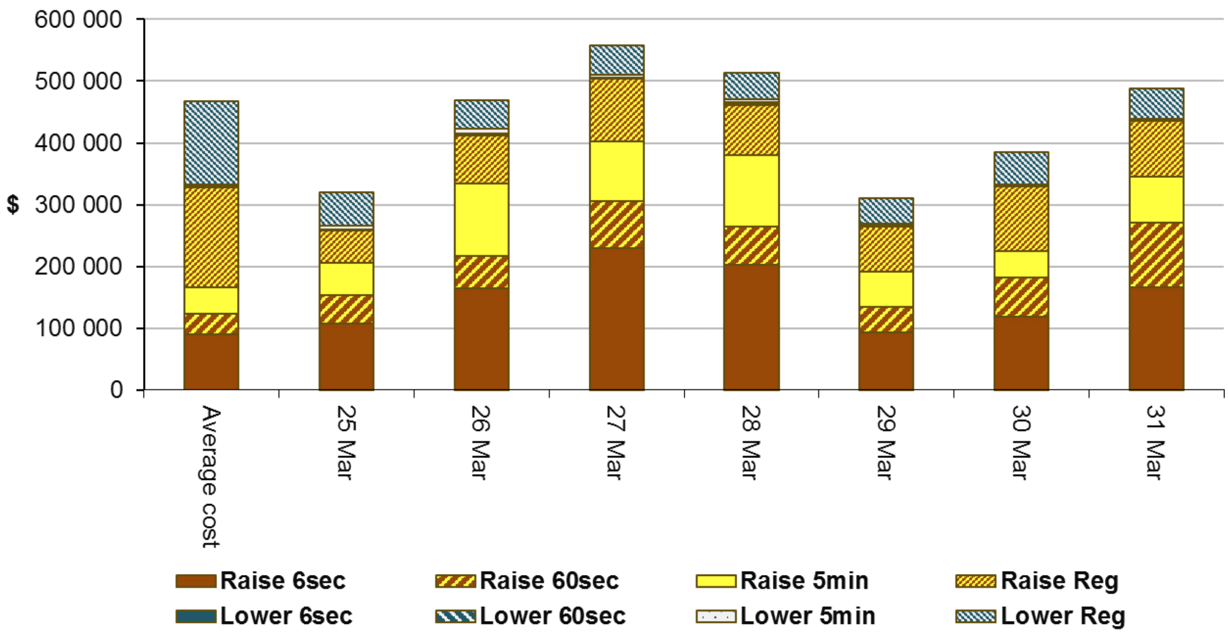
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 417 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $624 500 or around five 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

South Australia

There was two occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $79/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Sunday, 25 March

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
4 am	-165.25	37.11	37.52	1048	1003	1064	2726	2651	2326

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

Conditions at the time saw demand and availability close to that forecast four hours prior.

With only a small amount of capacity priced between the floor and around $90/MWh, increases in wind generation or decreases in demand can cause large decreases in price.

At 3.35 am wind generation increased by 51 MW and there was a small decrease in demand. With higher priced generation ramp down constrained the price fell to the floor for the 3.35 am dispatch interval.

Saturday, 31 March

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
Midnight	253.87	119.71	107.14	1403	1367	1333	1990	2056	2049
6.30 pm	278.17	349.95	349.95	1352	1253	1243	1807	1836	1843

At times, AEMO may need to override the normal dispatch process to maintain system security. On this day AEMO directed gas plant in South Australia triggering an intervention event. Special pricing arrangements apply in all regions following an intervention in the market.

At 11.35 pm demand increased by 119 MW (probably related to hot water load) and the dispatch price increased from $124/MWh at 11.30 pm to $203/MWh at 11.35 pm. At 11.40 pm demand increased by a further 31 MW which saw the dispatch price increase to $299/MWh. The price stayed at $299/MWh until midnight when there was a 49 MW decrease in demand and the dispatch price fell to $124/MWh.

The 6.30 pm trading interval was close to forecast four hours ahead.

Tasmania

There were three occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $76/MWh and above $250/MWh.

Tuesday, 27 March

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
8 am	257.07	77.02	65.57	1220	1280	1292	1844	1995	2013
8.30 pm	1048.18	65.57	65.57	1092	1115	1155	1898	1917	1966

Conditions at the time saw demand up to 60 MW lower than forecast and availability was up to 150 MW lower than forecast.

With Basslink out and unable to transfer FCAS to or from the mainland, generators in Tasmania had to provide all FCAS services locally.

At 7.40 am, the local requirement for raise 6 second services increased. Price co-optimisation of the FCAS and energy markets saw the dispatch price reach $1149/MWh at 7.40 am. The price then decreased to around $80/MWh as the local requirement for raise 6 second services fell and the energy and FCAS markets were no longer co-optimised.

At 8.15 pm, the local requirement for raise regulation services increased. Price co-optimisation of the FCAS and energy markets saw the dispatch price reach $5978/MWh at 8.15 pm. The price then decreased to around $60/MWh as the local requirement for raise regulation services fell and the energy and FCAS markets were no longer co-optimised.

Wednesday, 28 March

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
7.30 am	1158.55	81.93	81.96	1215	1262	1275	1758	1828	1826

Conditions at the time saw demand and availability slightly lower than forecast four hours ahead.

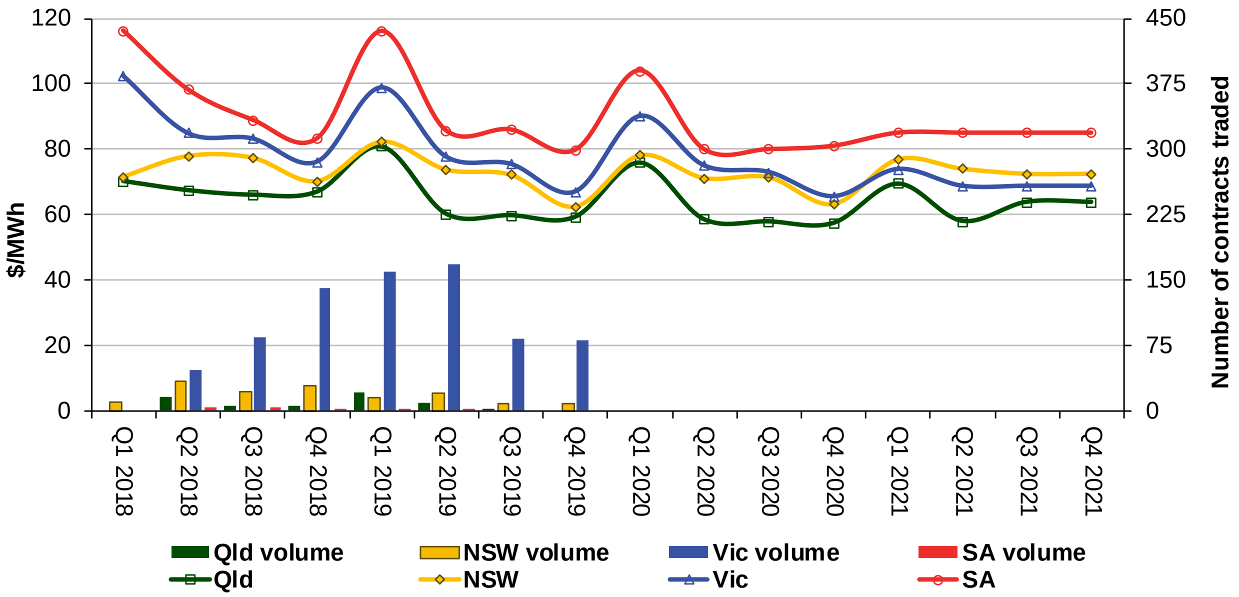
With Basslink out and unable to transfer FCAS to or from the mainland, generators in Tasmania had to provide all FCAS services locally.

At 7.05 am, the effective availability of local raise regulation services fell to 1 MW which was priced at $4300/MWh. This was a result of Cethana shutting down as forecast which was providing around 20 MW of regulation services and other generators increasing output in energy therefore reducing their effective availability of raise regulation services. Price co-optimisation of the FCAS and energy markets saw the dispatch price reach $5878/MWh at 7.05 pm. The dispatch price fell in the following dispatch intervals as energy and FCAS markets were no longer co-optimised.

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.

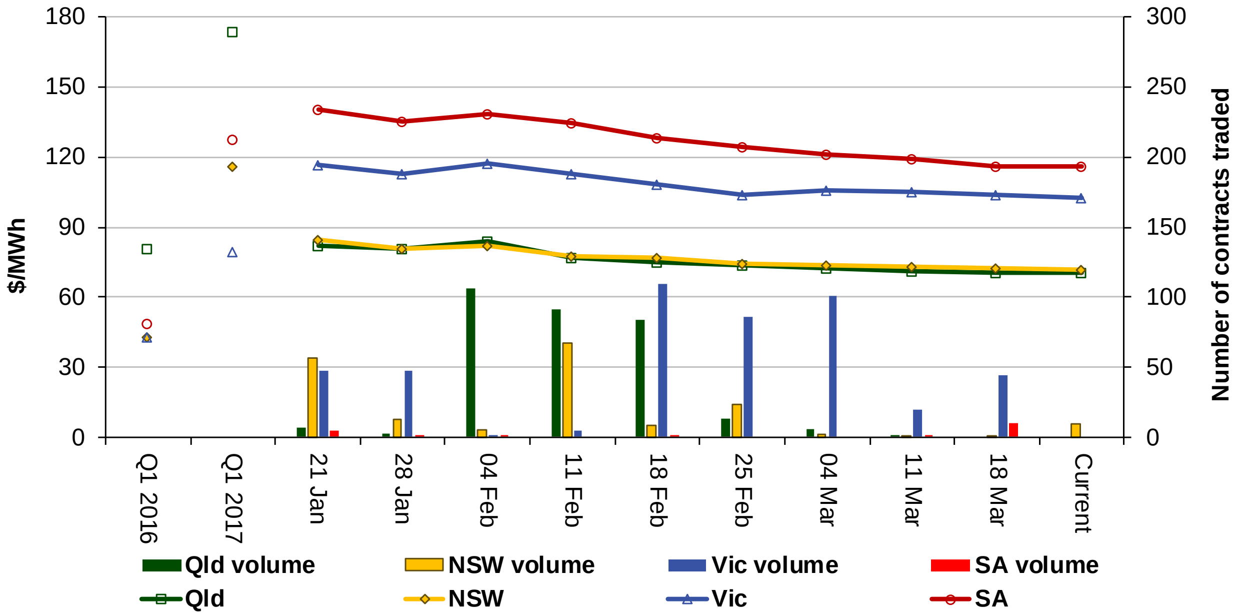
Figure 9: Quarterly base future prices Q1 2018 – Q4 2021



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2018 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 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 2018 base contracts over the past 10 weeks (and the past 2 years)



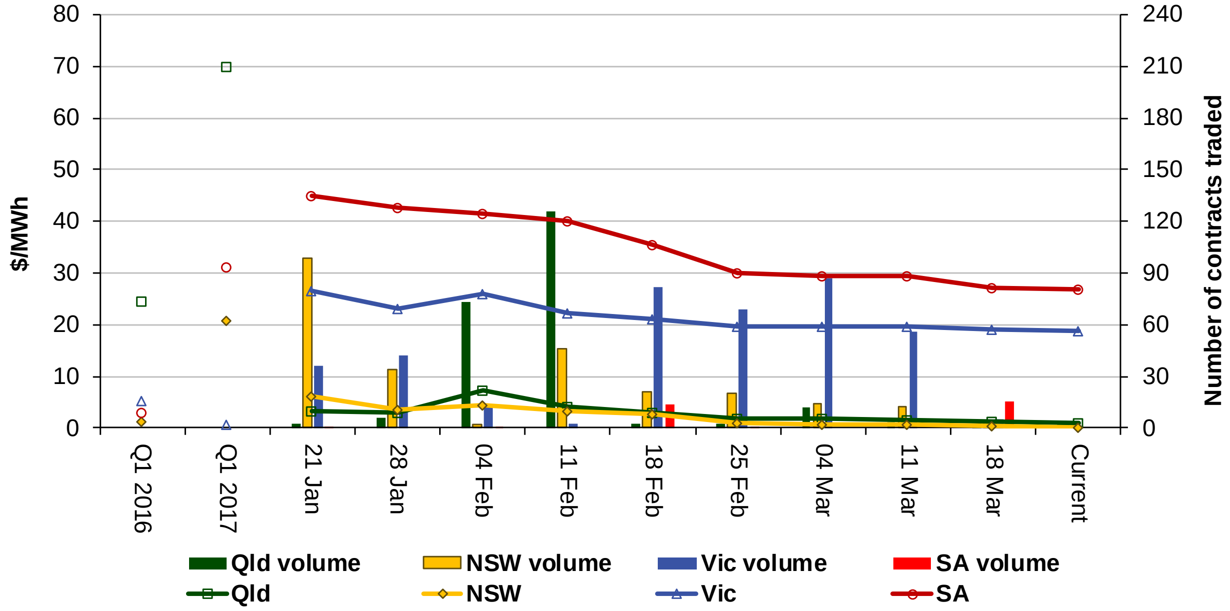
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2018 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2016 and quarter 1 2017 prices are also shown.

Figure 11: Price of Q1 2018 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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