12 - 18 March 2017

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 12 – 18 March 2017.

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

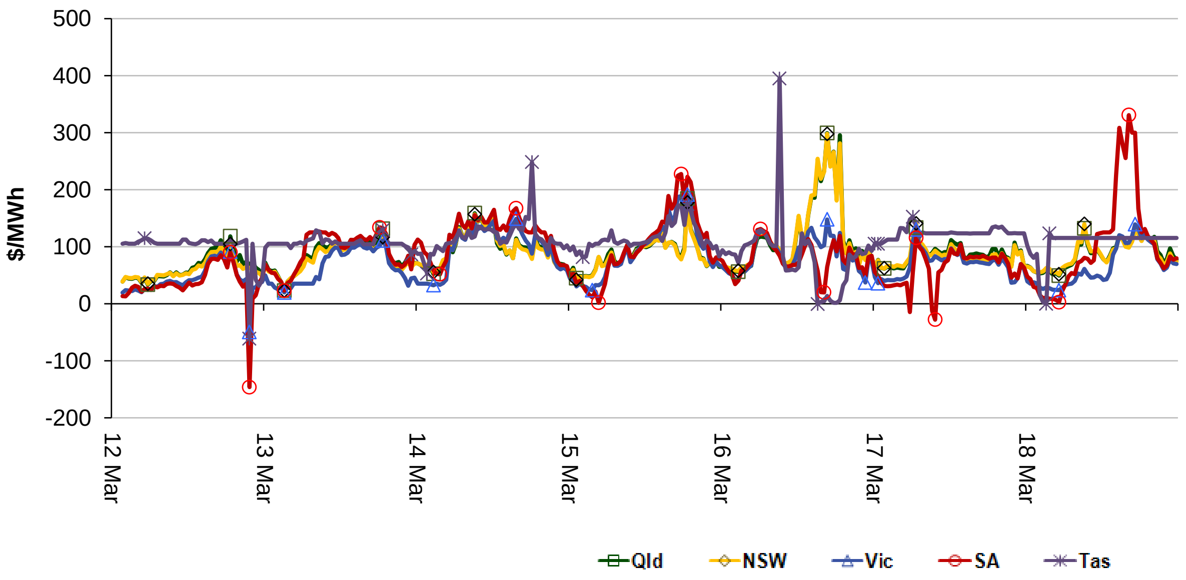


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

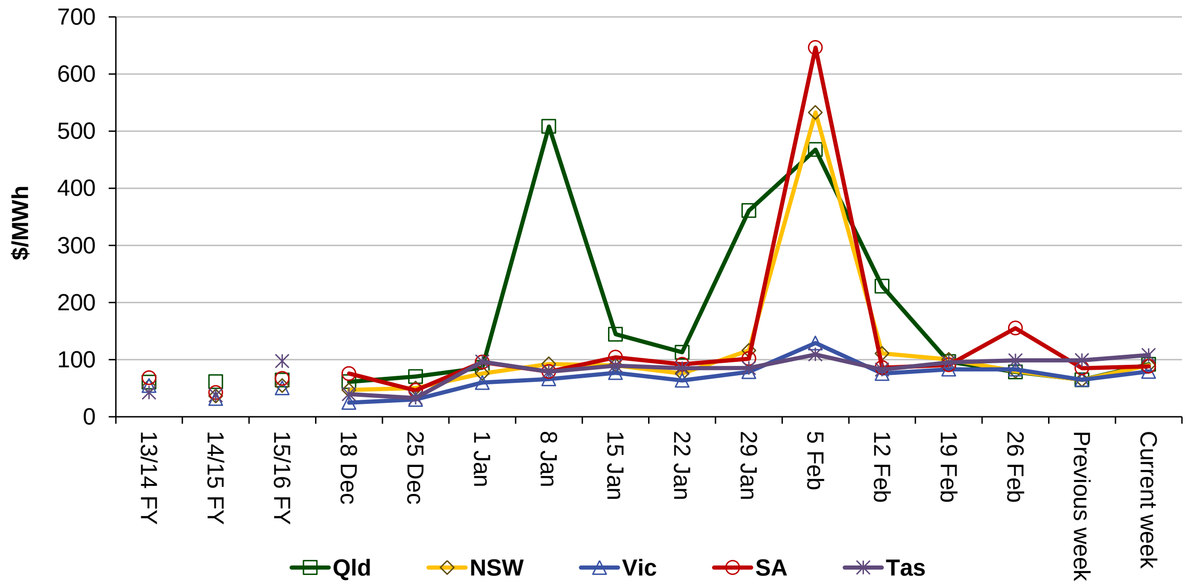


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	92	90	79	88	108
15-16 financial YTD	60	46	44	61	85
16-17 financial YTD	107	85	54	123	60

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 281 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2016 of 273 counts and the average in 2015 of 133. 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	21	0	1
% of total below forecast	54	16	0	1

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

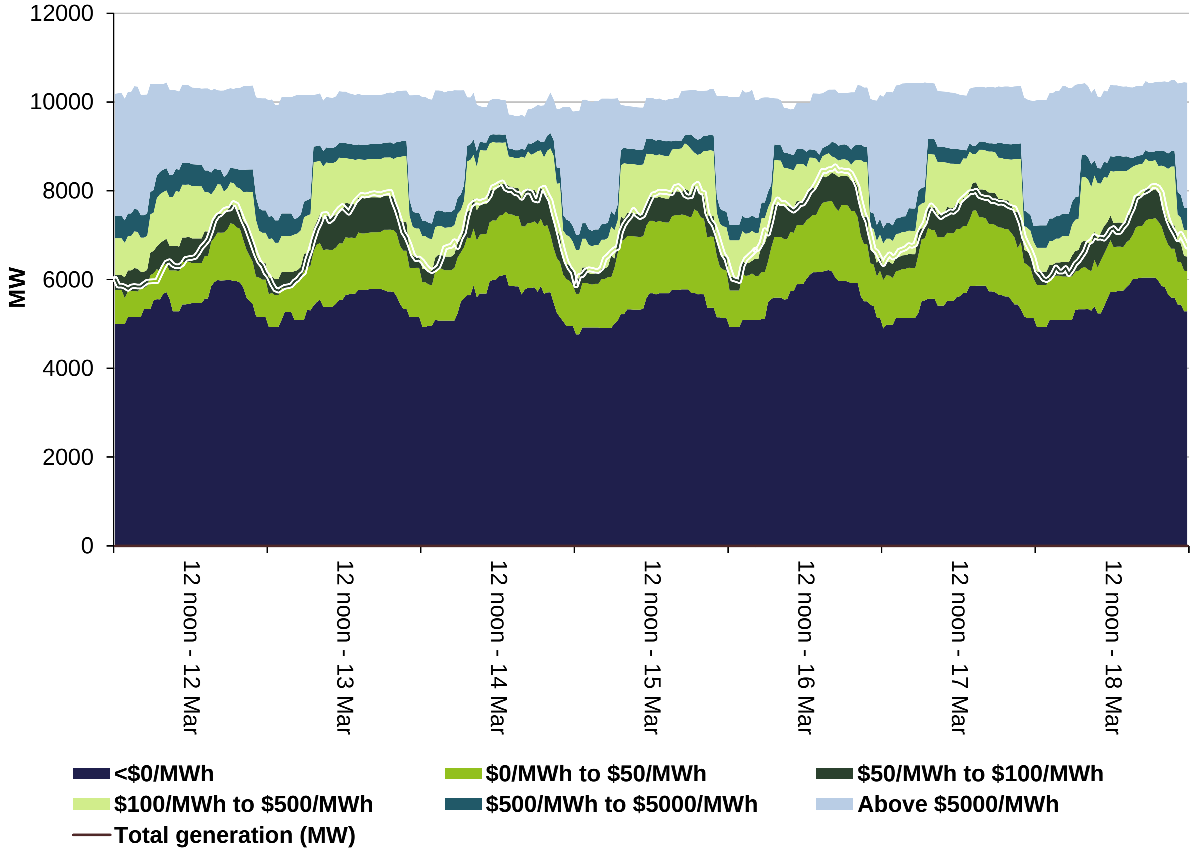


Figure 4: New South Wales generation and bidding patterns

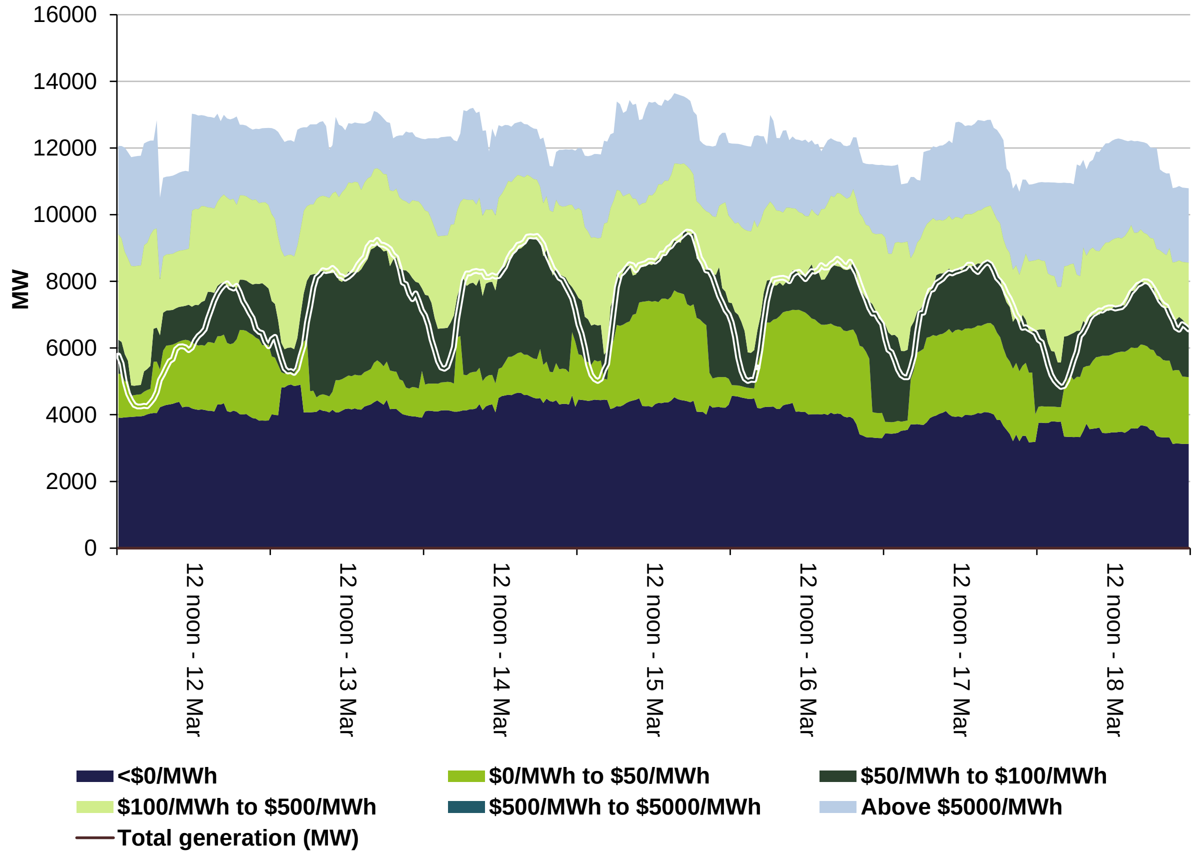


Figure 5: Victoria generation and bidding patterns

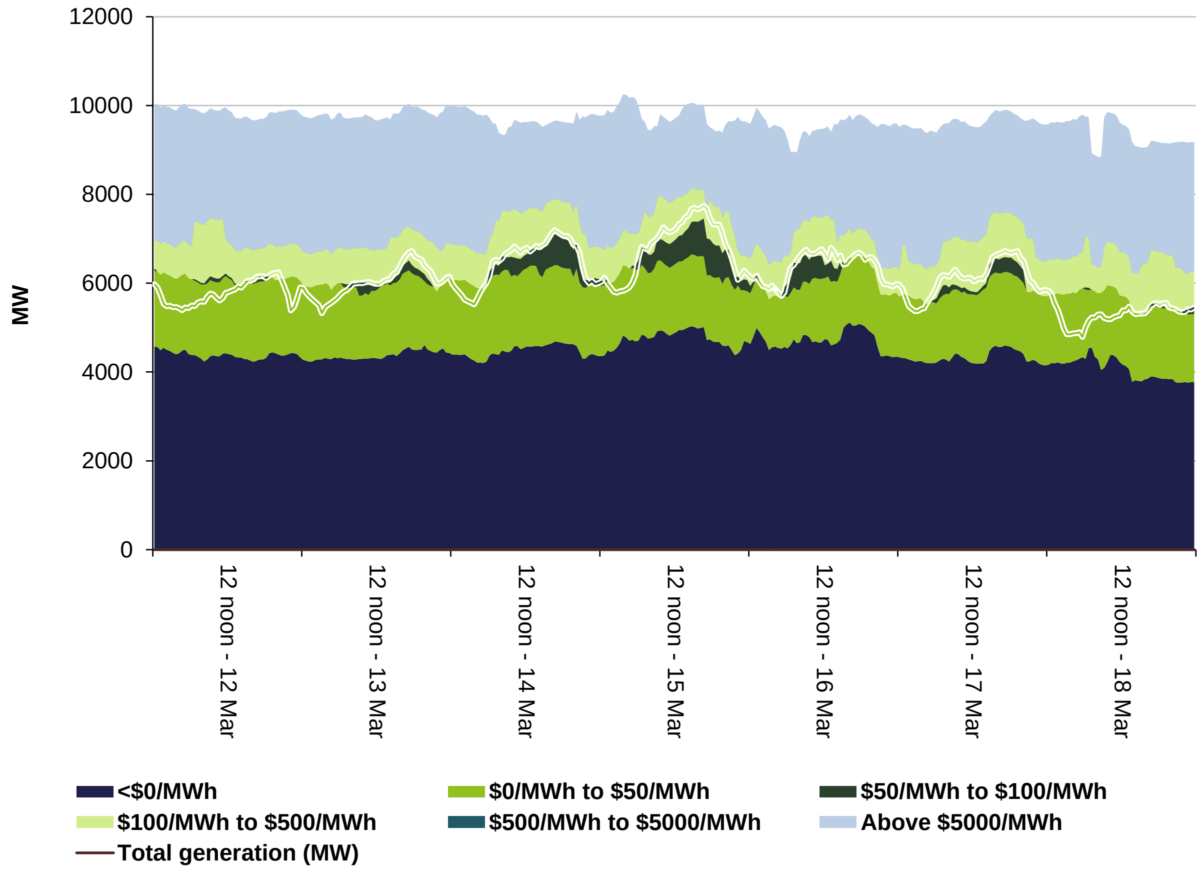


Figure 6: South Australia generation and bidding patterns

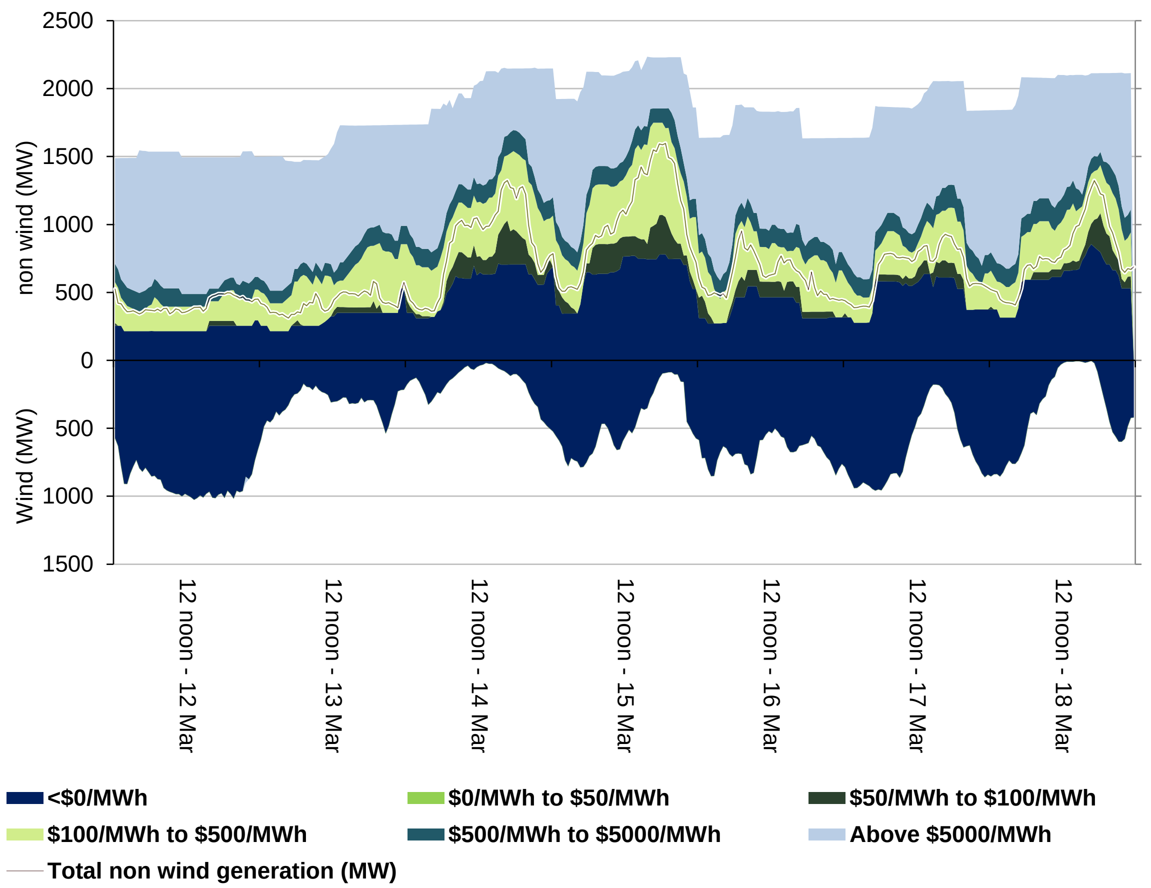
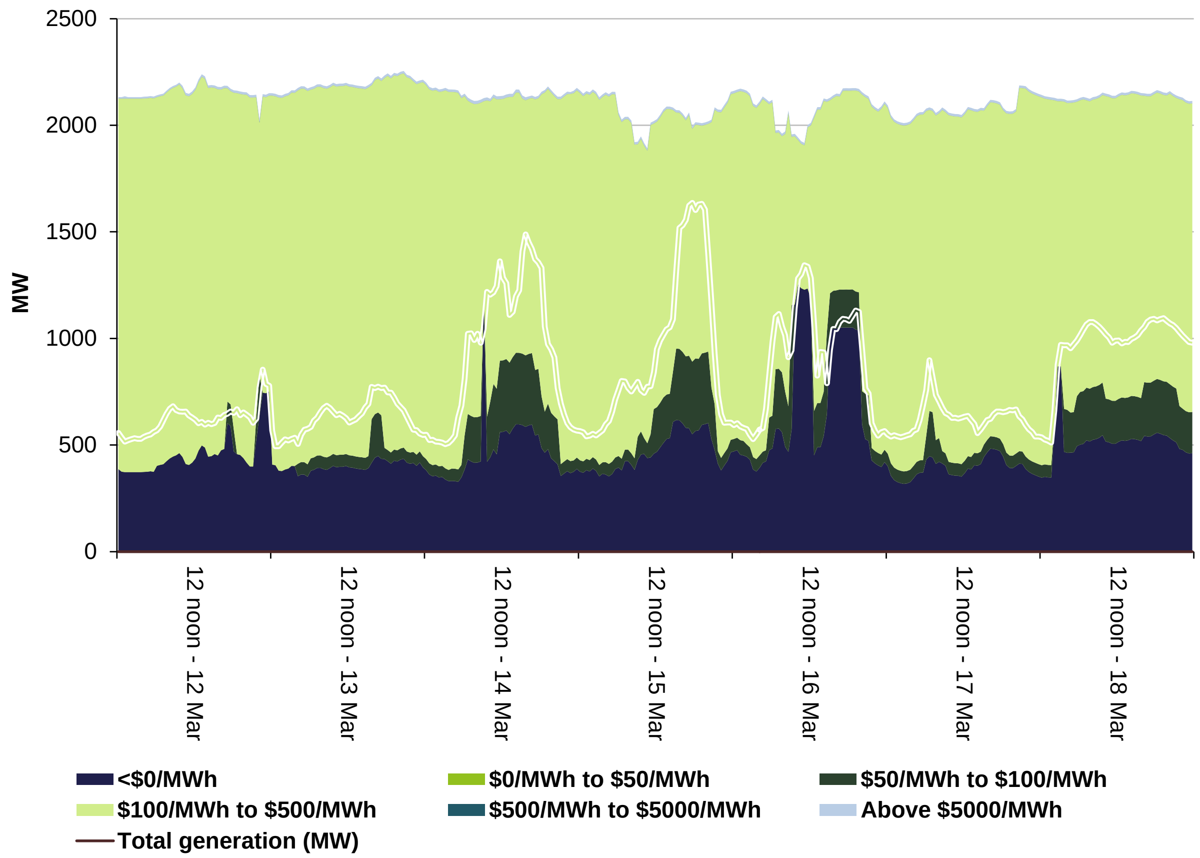


Figure 7: Tasmania generation and bidding patterns



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.

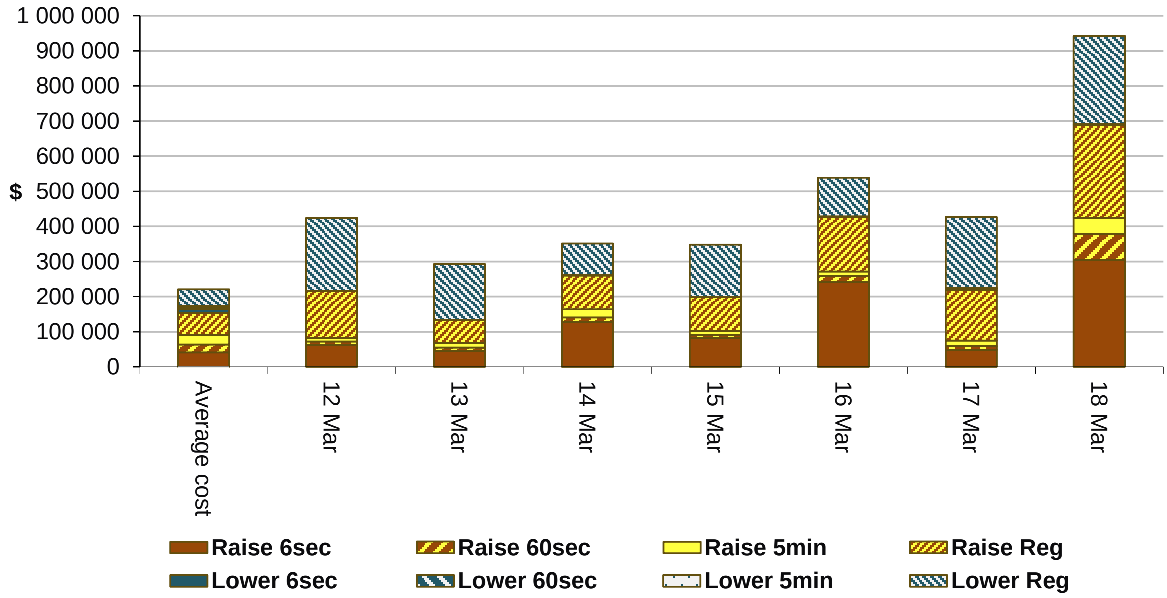
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $2 475 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $847 500 or around five per cent of energy turnover in Tasmania.of the previous financial year.

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



On 18 March an outage on the Keilor transformer in Victoria resulted in AEMO invoking a 35 MW requirement of local regulation services in South Australia. The requirement resulted in price spikes of around $11 500/MW.

On the same day there was a raise 6 second requirement in Tasmania due to system normal constraint on loss of largest generator in Tasmania. Both of these requirements resulted in the higher than average ancillary service costs.

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 $92/MWh and above $250/MWh.

Thursday, 16 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
5 pm	299.11	198.00	198.00	8041	7996	8198	10 285	10 340	10 488
7 pm	295.29	319.01	167.61	8197	8213	8303	10 208	10 201	10 539

For the 5 pm trading interval demand was 45 MW higher than forecast while availability was 55 MW lower than forecast four hours ahead.

Due to a system normal constraint affecting the Vic-NSW interconnector, New South Wales and Queensland were separated from the rest of the NEM and acting as one region.

In New South Wales around 220 MW of low priced capacity was removed from the market in the four hours leading up to the 5 pm trading interval. This reduction combined with higher than forecast demand (around 450 MW) resulted in the higher than forecast price in both regions.

The 7 pm trading interval was close to that forecast four hours prior.

New South Wales

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

Thursday, 16 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
5 pm	297.67	183.02	180.14	9632	9184	9501	12 174	12 393	13 236
7 pm	281.27	299.80	150.04	9371	8985	9243	12 088	12 234	13 115

Prices in New South Wales were aligned with those in Queensland. See the Queensland section for details on the higher than forecast prices.

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $88/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Sunday, 12 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
10 pm	-146.29	38.78	26.42	1147	1124	1106	2440	2437	2414

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

At 9.50 pm flows from Victoria to Tasmania decreased by around 345 MW due to the Basslink interconnector tripping. This resulted in excess generation in Victoria which flowed into South Australia across the Heywood interconnector. The dispatch price then decreased to the floor for five minutes.

Saturday, 18 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
3 pm	308.32	350.69	589.99	1224	1355	1653	2107	2132	2172
3.30 pm	279.05	484.99	590.01	1283	1406	1702	2112	2129	2185
4.30 pm	330.77	350.69	13 100.02	1444	1402	1827	2110	2118	2168
5 pm	299.99	299.99	468.09	1486	1457	1884	2117	2135	2189
5.30 pm	299.99	325.45	487.07	1546	1525	1907	2133	2151	2197

The 3 pm, 4.30 pm, 5 pm and 5.30 pm trading intervals were close to that forecast four hours ahead.

Conditions for the 3.30 pm trading interval saw demand around 120 MW lower than forecast while availability was close to that forecast hours ahead. This combined with some minor rebidding of capacity from high to low prices resulted in the lower than forecast price.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $108/MWh and above $250/MWh.

Thursday, 16 March

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
9.30 am	394.88	150.59	158.67	1077	1133	1166	1983	2064	2057

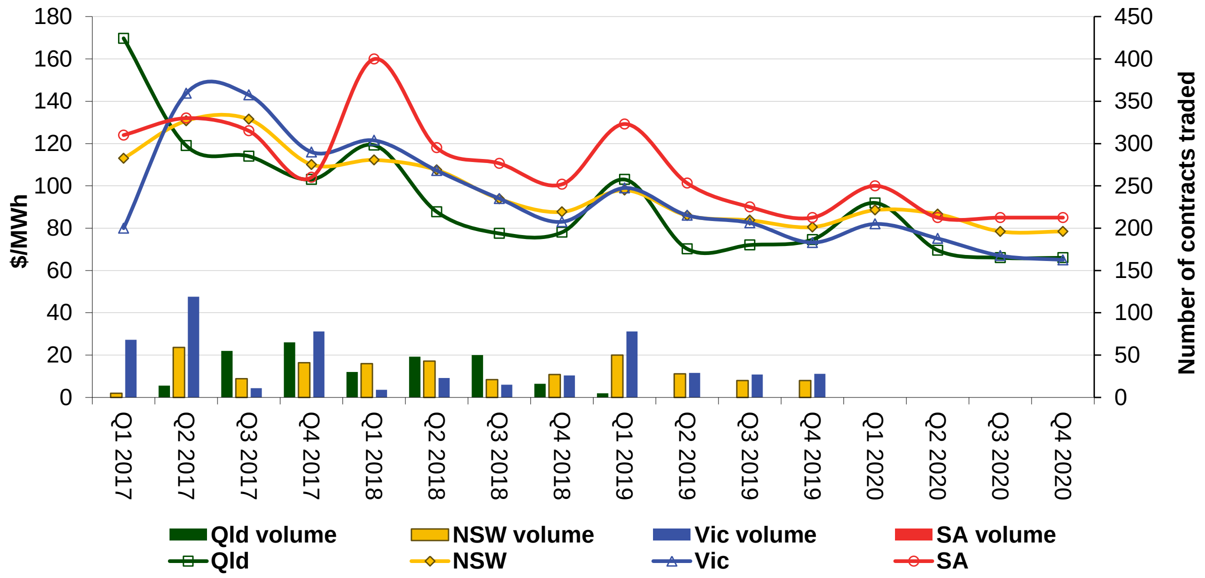
Conditions at the time saw demand around 60 MW lower than forecast and availability around 80 MW lower than forecast four hours ahead.

At 9.15 am flows from Victoria to Tasmania across the Basslink interconnector decreased by around 110 MW. The decrease was due to a constraint binding which manages frequency control in Tasmania. As a result higher priced generation in Tasmania was required and the price increased to $1802/MWh for five minutes before returning to previous levels.

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.

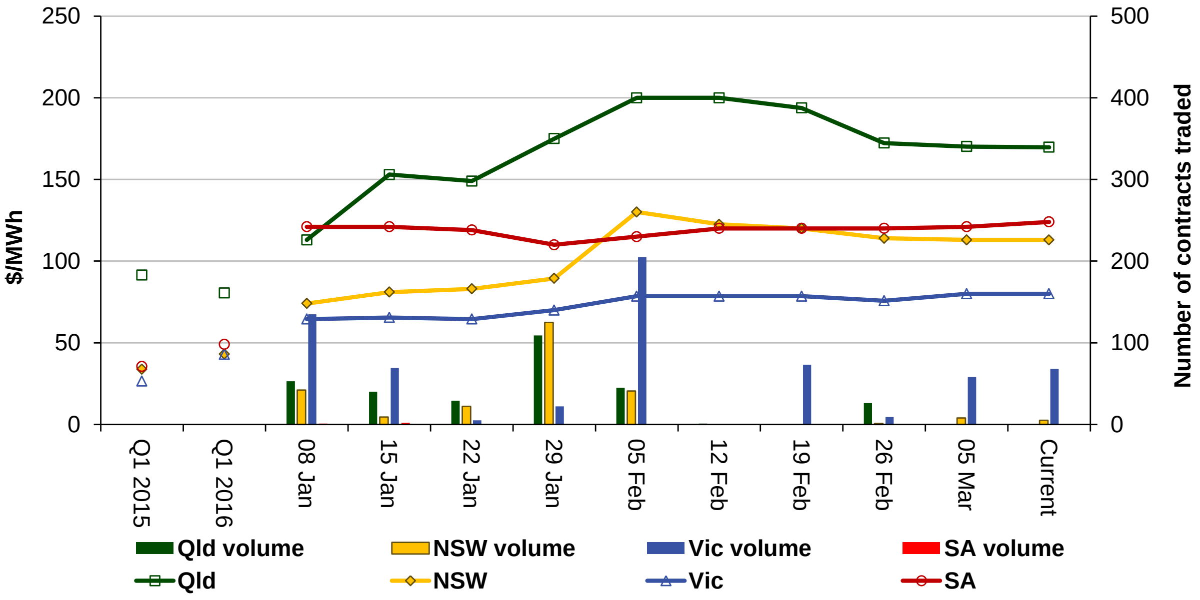
Figure 9: Quarterly base future prices Q1 2017 – Q4 2020



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 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 2017 base contracts over the past 10 weeks (and the past 2 years)



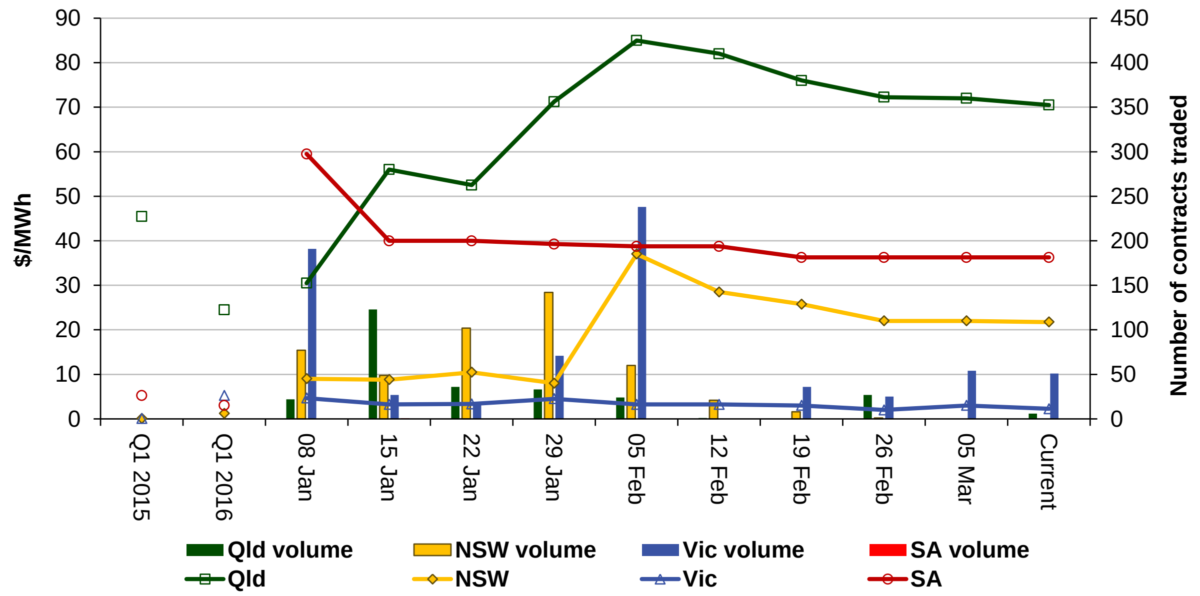
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au