Electricity Report

AUSTRALIAN ENERGY REGULATOR

7 - 13 January 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 7 – 13 January 2018.

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

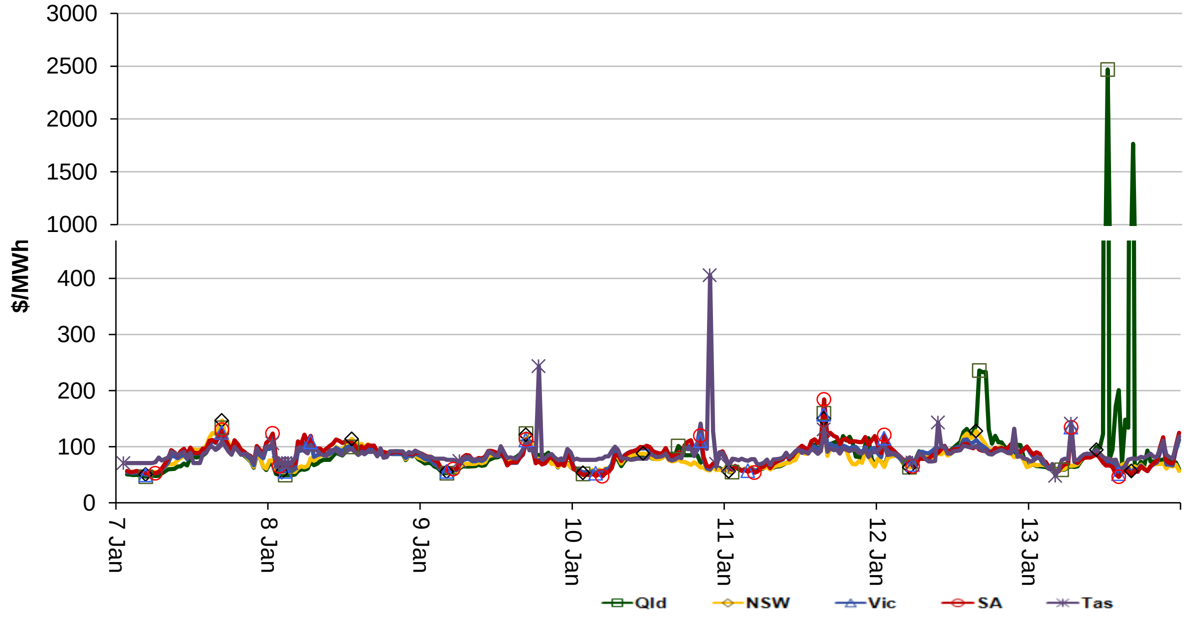


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

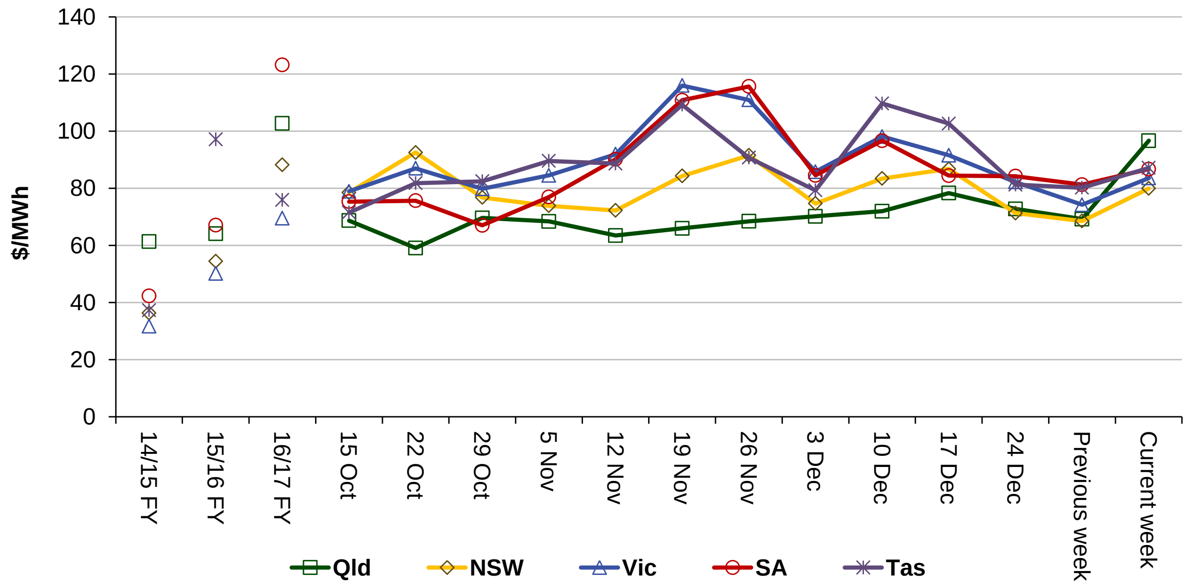


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	97	80	84	87	87
16-17 financial YTD	69	63	45	105	49
17-18 financial YTD	78	87	95	94	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 176 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	26	0	1
% of total below forecast	62	7	0	3

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

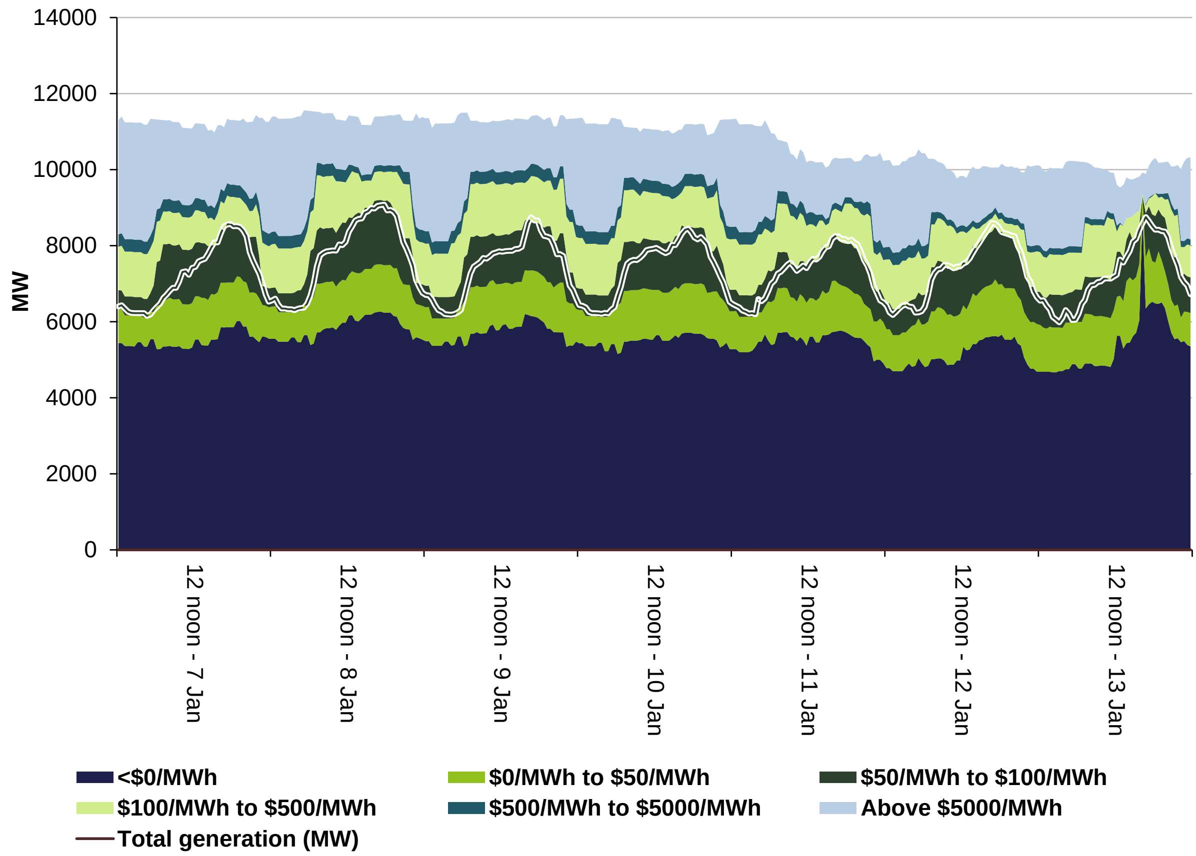


Figure 4: New South Wales generation and bidding patterns

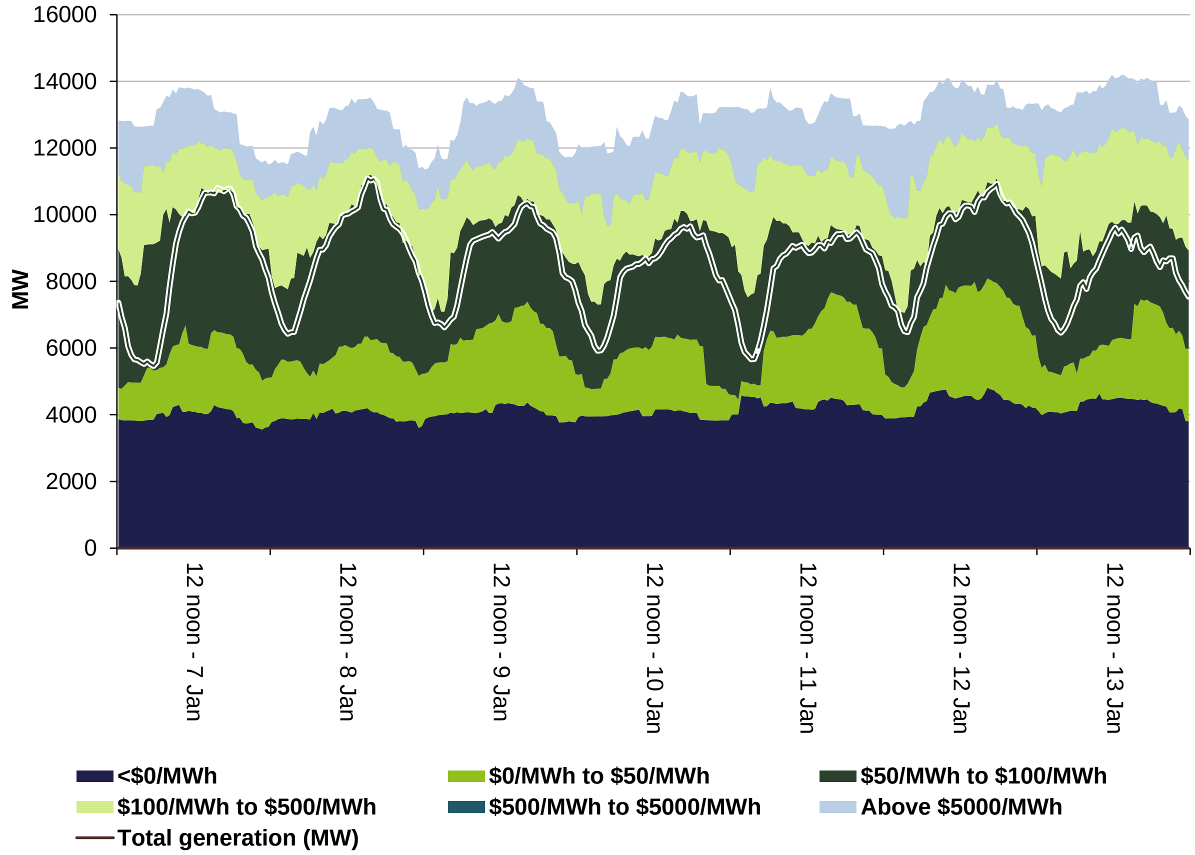


Figure 5: Victoria generation and bidding patterns

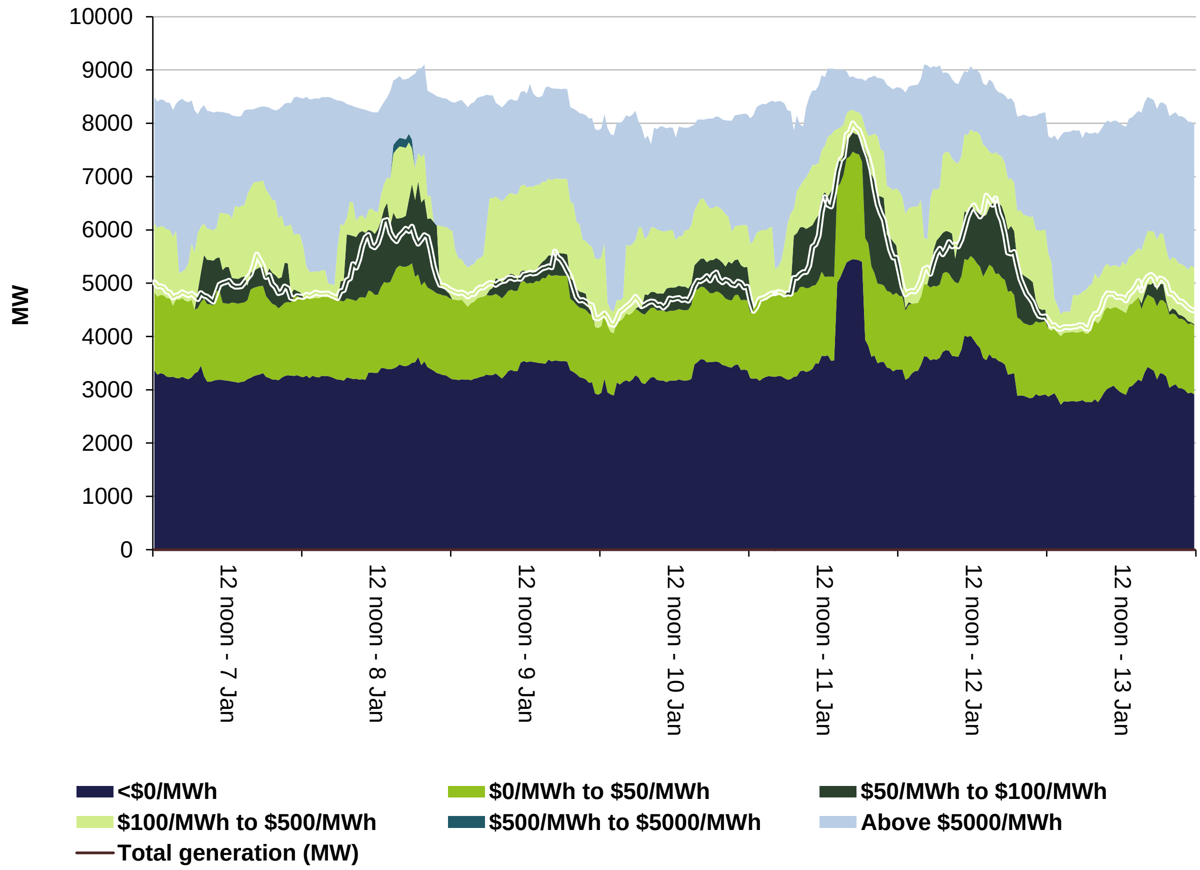


Figure 6: South Australia generation and bidding patterns

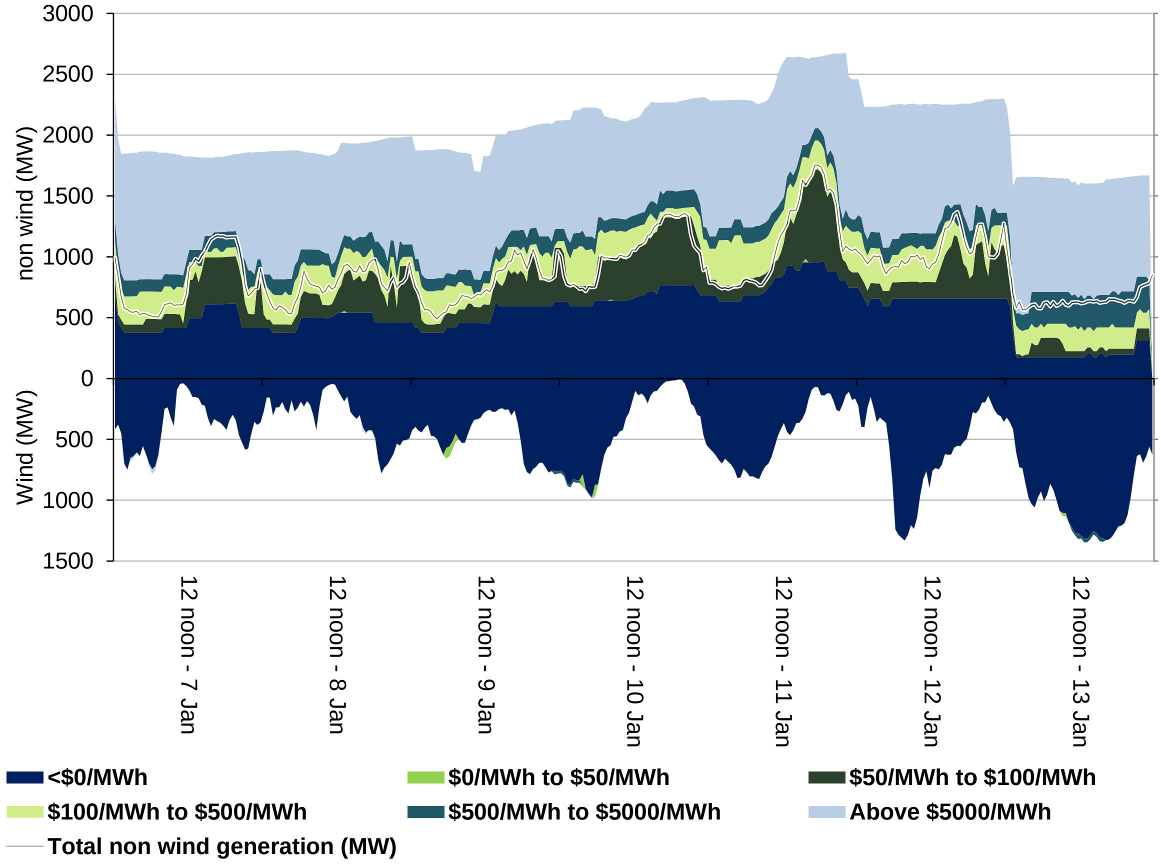
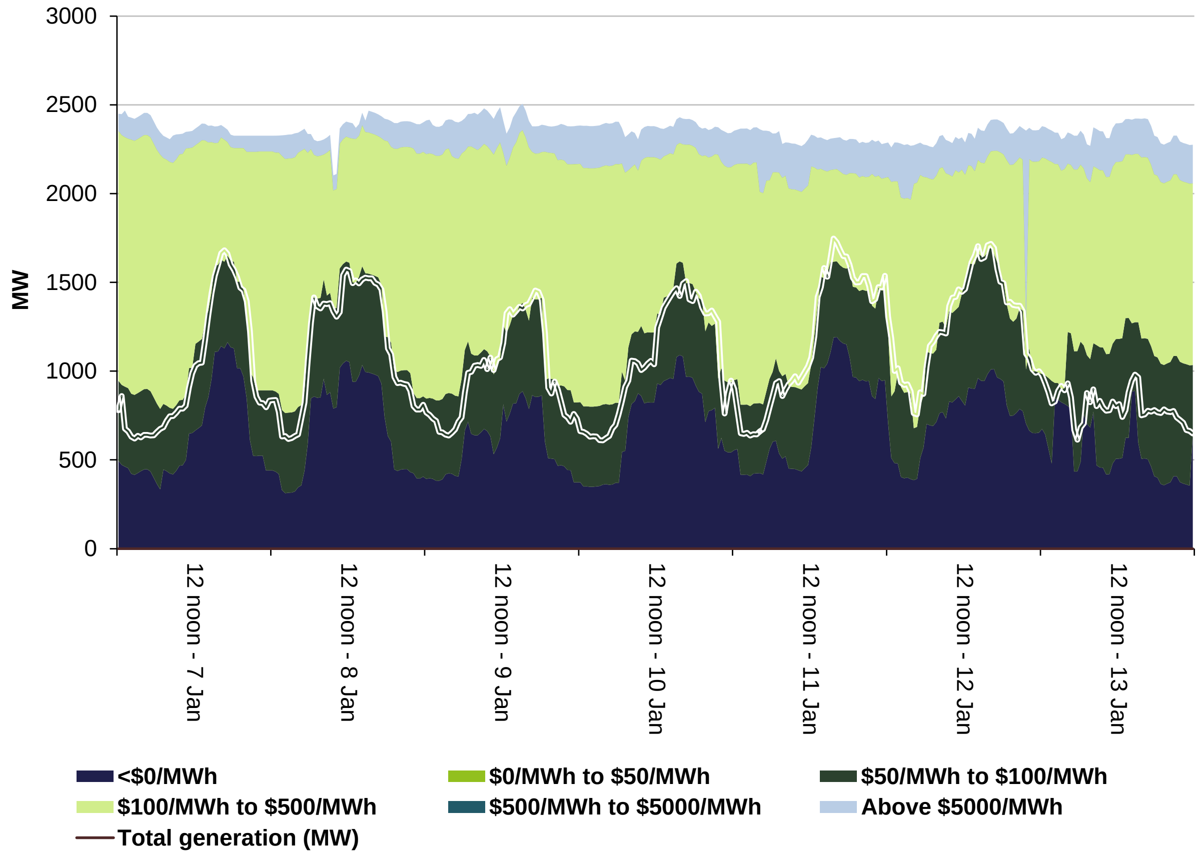


Figure 7: Tasmania generation and bidding patterns



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.

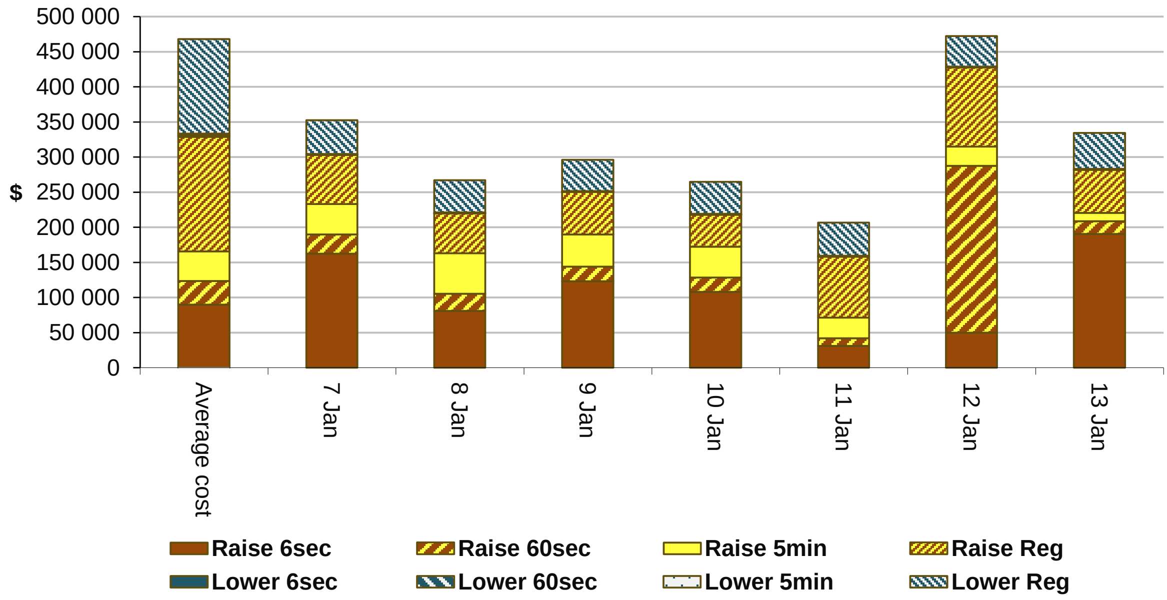
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 284 000 or around a half per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $909 000 or around six 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

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $97/MWh and above $250/MWh.

Sunday, 13 January

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
12.30 pm	2467.64	74.94	88.94	7494	7479	7500	9639	10 055	9898
4.30 pm	1765.12	150.00	200.01	8583	8584	8546	9855	10 064	10 231

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.

For the 12.30 pm trading interval demand was close to forecast while availability was around 415 MW lower than forecast.

In the four hours leading up to the start of the trading interval across a number of power stations, around 180 MW of capacity priced less than $90/MWh was removed. Across two rebids effective from 12.10 pm and 12.15 pm respectively, CS Energy and Origin removed a further 340 MW from the Gladstone and Darling downs power stations. These rebids are shown in Table 4 below.

As a result the dispatch price reached the cap at 12.25 pm.

Table 4: Rebidding

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
Midday	12.10 pm	CS Energy	Gladstone	-240	<0	N/A	1200P Technical issues-unit tripped-sl
12.05 pm	12.15 pm	Origin Energy	Darling Downs	-100	120	N/A	1205P Change in avail – GT2 rts revised load sl

For the 4.30 pm trading interval demand was close to forecast while availability was around 210 MW lower than forecast.

At 4.07 pm, effective from 4.15 pm, CS Energy rebid 250 MW of capacity at its Wivenhoe power station price below $450/MWh to the price floor. The reason given was "1606P Technical issues-avoid partial target received-sl". At the same time imports across QNI decreased by 90 MW. With other low priced generation ramp down constrained or trapped in FCAS the dispatch price increased to $9814/MWh at 4.15 pm before falling to $58/MWh at 4.20 pm.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $87/MWh and above $250/MWh.

Wednesday, 10 January

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	405.75	95.75	82.83	1116	1085	1058	2374	2368	2398

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

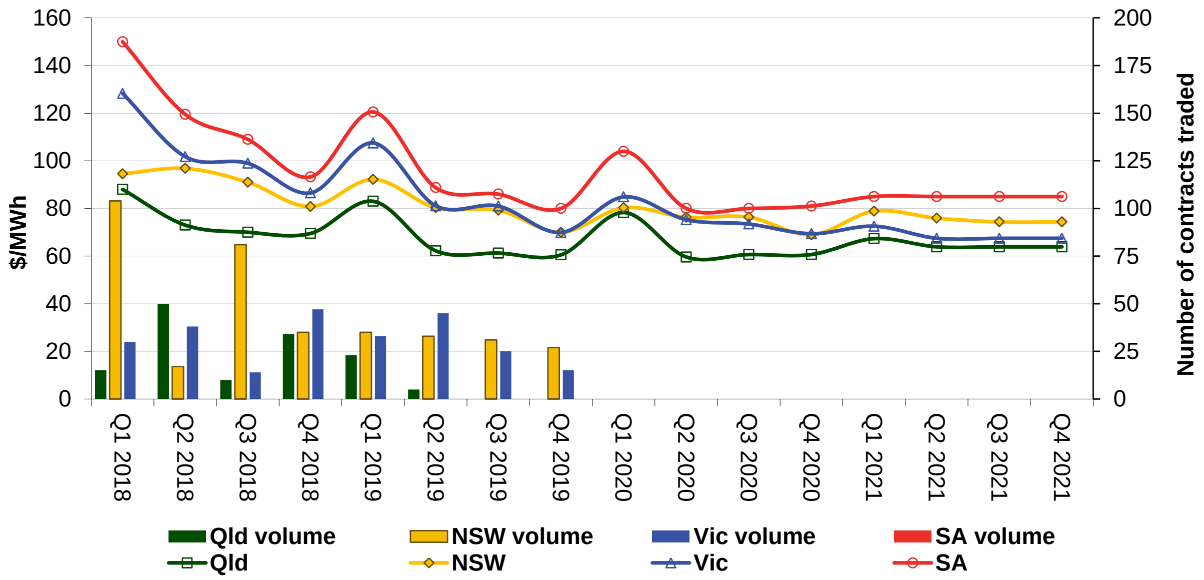
For the entire trading interval FCAS constraints forced exports across Basslink into Victoria, this was not forecast. Flows were also around 410 MW higher than forecast four hours prior.

The only capacity available priced between $96/MWh and $406/MWh was limited and unable to set price. As a result the price was $406/MWh for the entire trading 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.

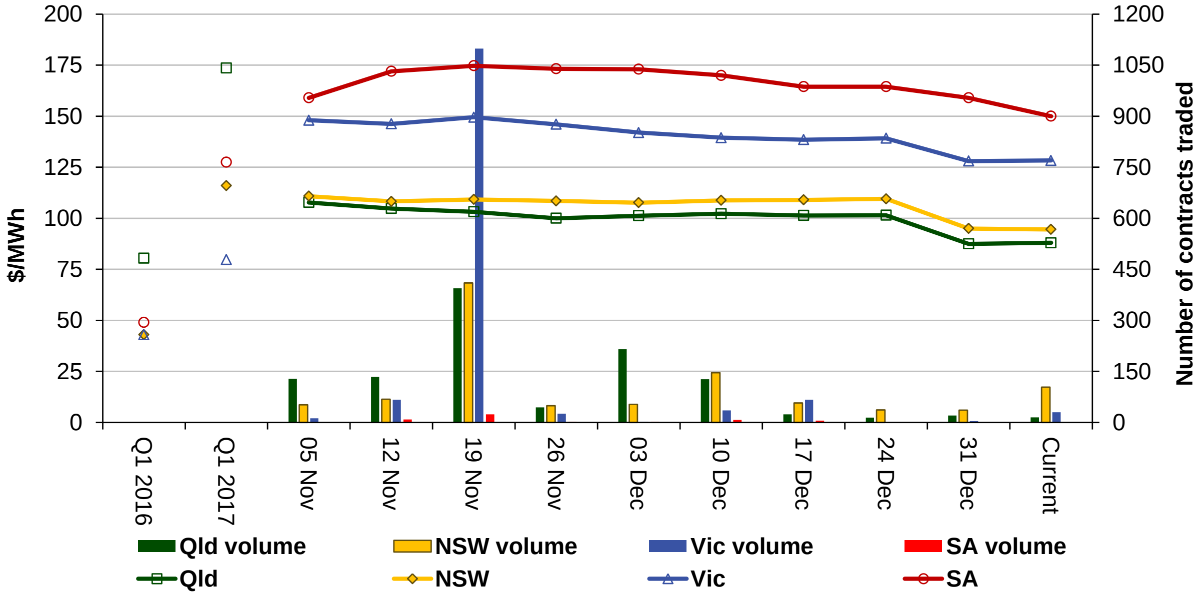
Figure 9: Quarterly base future prices Q1 2018 – Q4 2021



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)



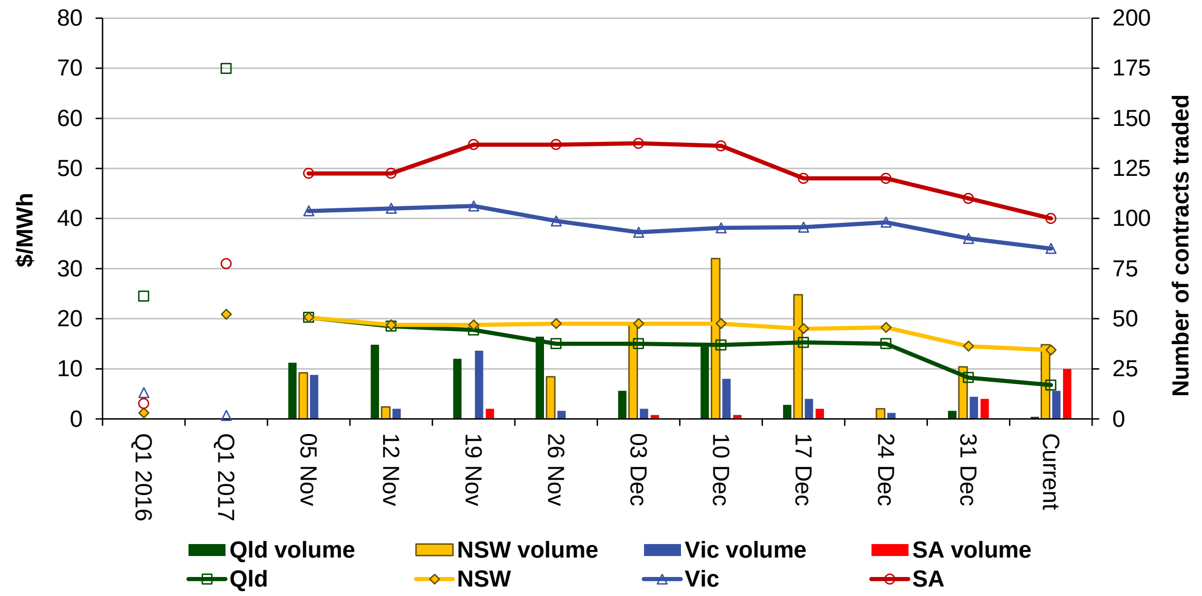
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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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