Electricity Report

AUSTRALIAN ENERGY REGULATOR

21 - 27 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 21 - 27 January 2018.

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

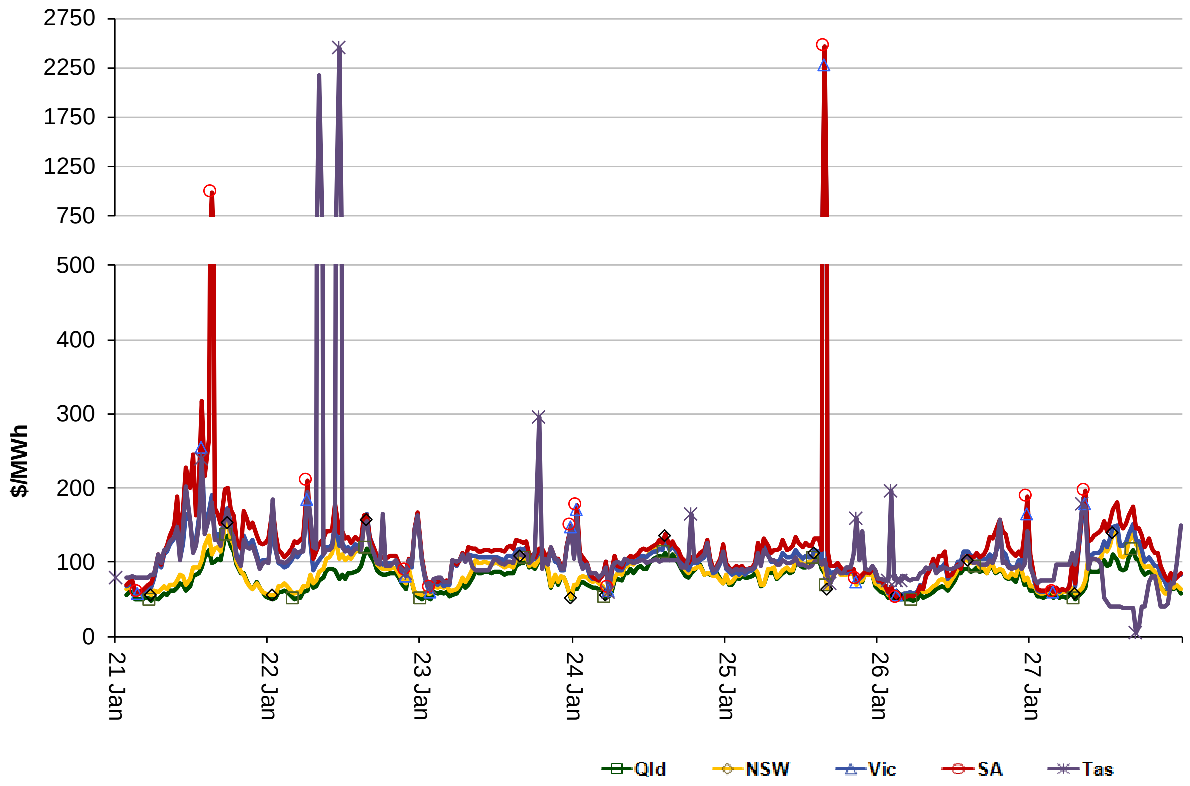


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

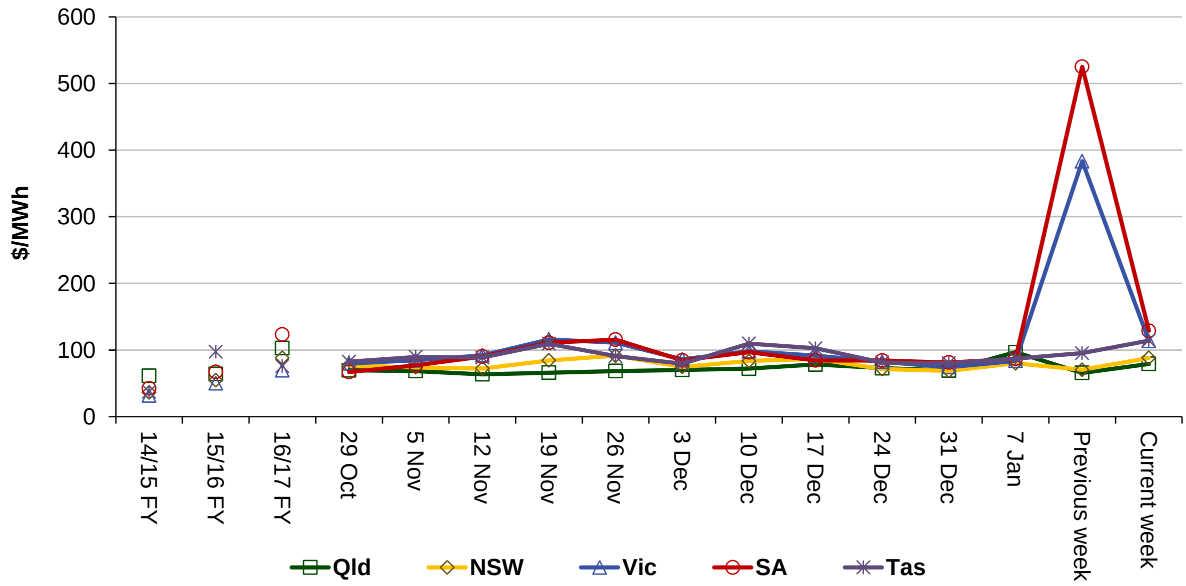


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	79	88	114	129	114
16-17 financial YTD	83	64	47	105	52
17-18 financial YTD	78	87	106	112	92

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 189 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	2	33	0	2
% of total below forecast	51	4	0	8

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

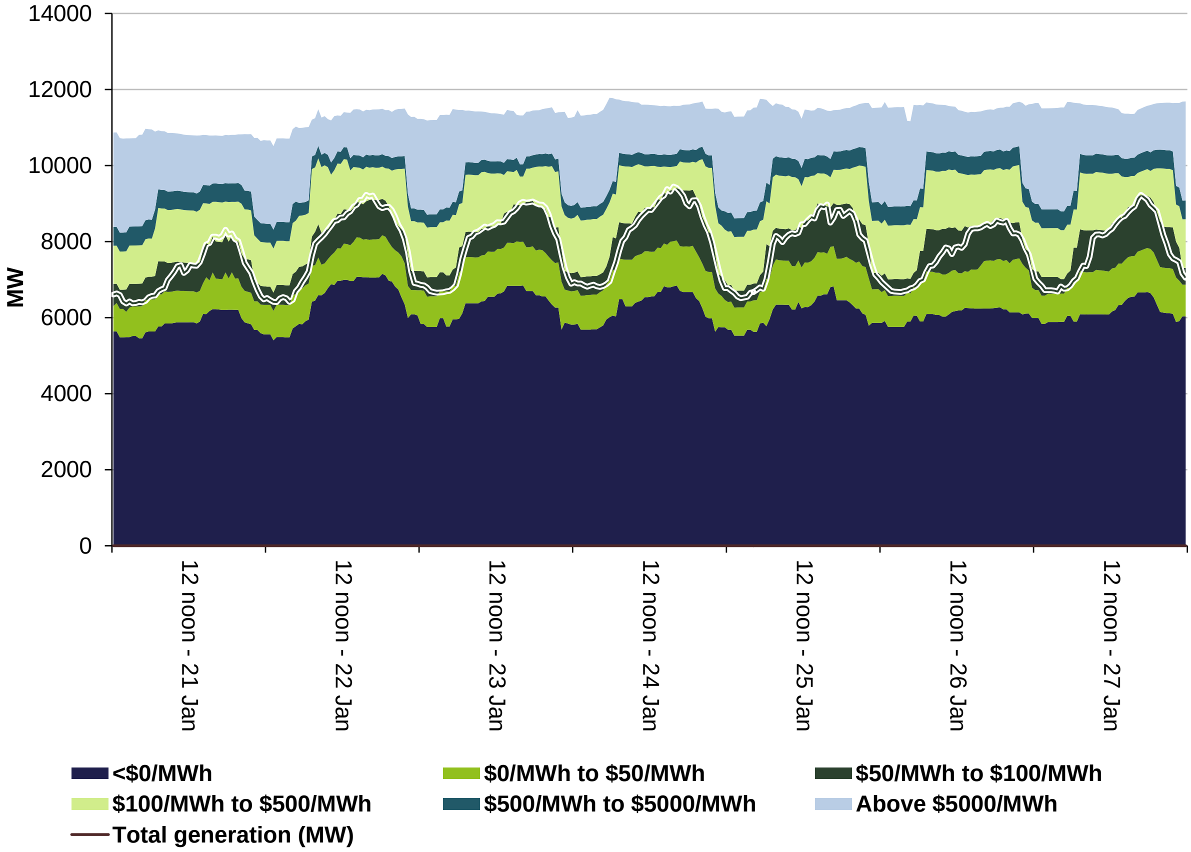


Figure 4: New South Wales generation and bidding patterns

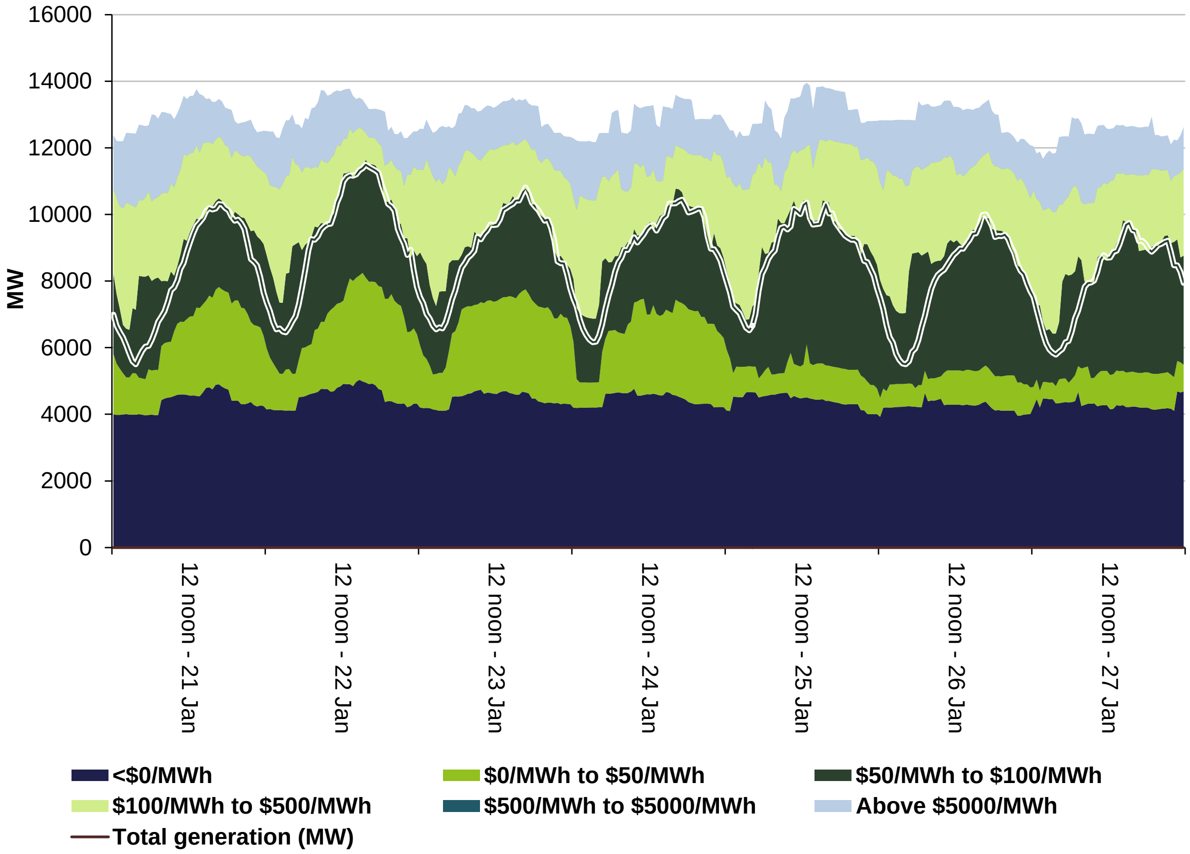


Figure 5: Victoria generation and bidding patterns

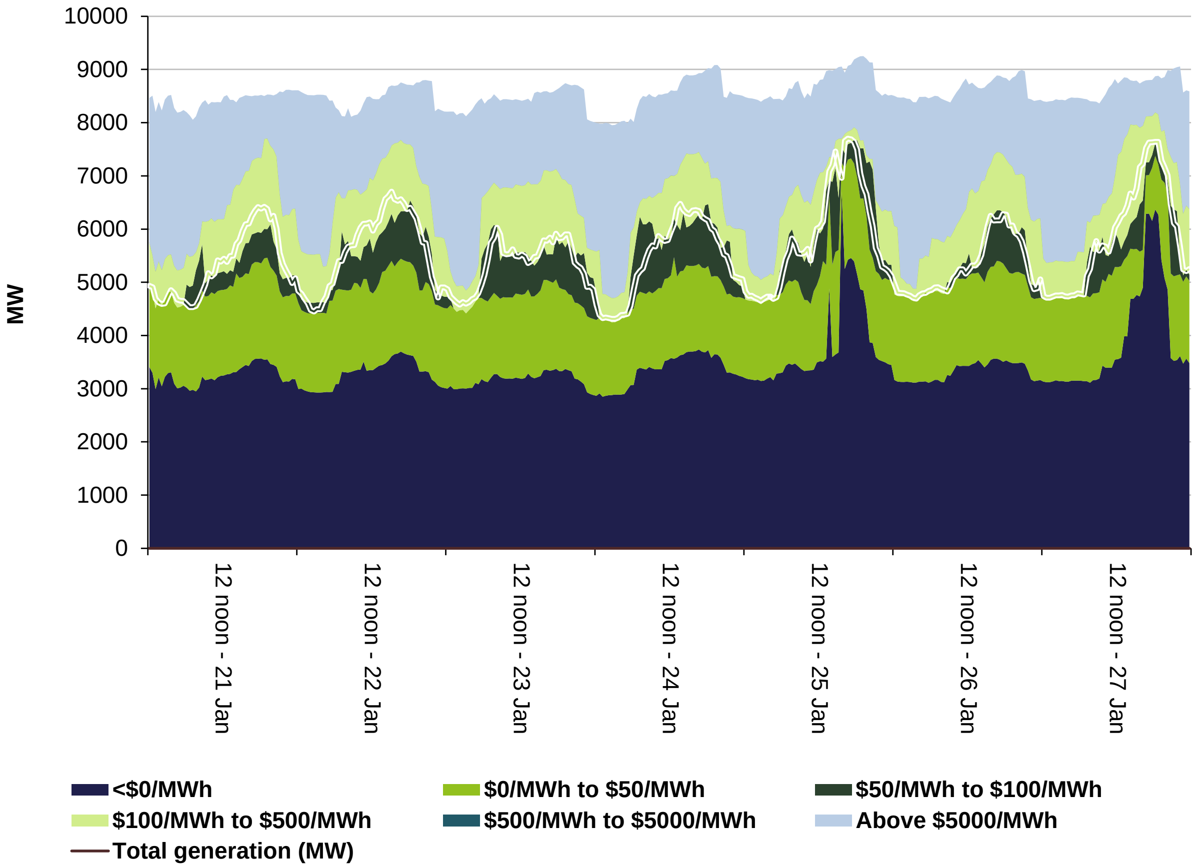


Figure 6: South Australia generation and bidding patterns

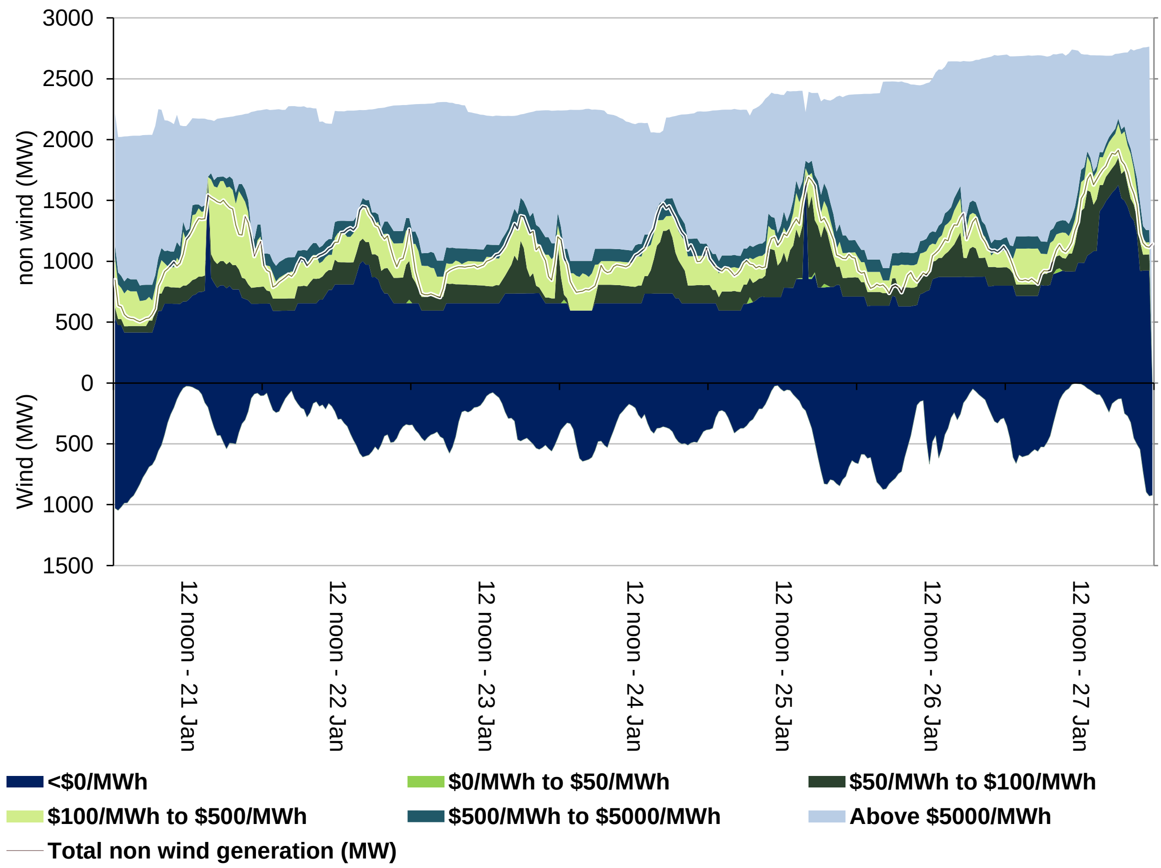
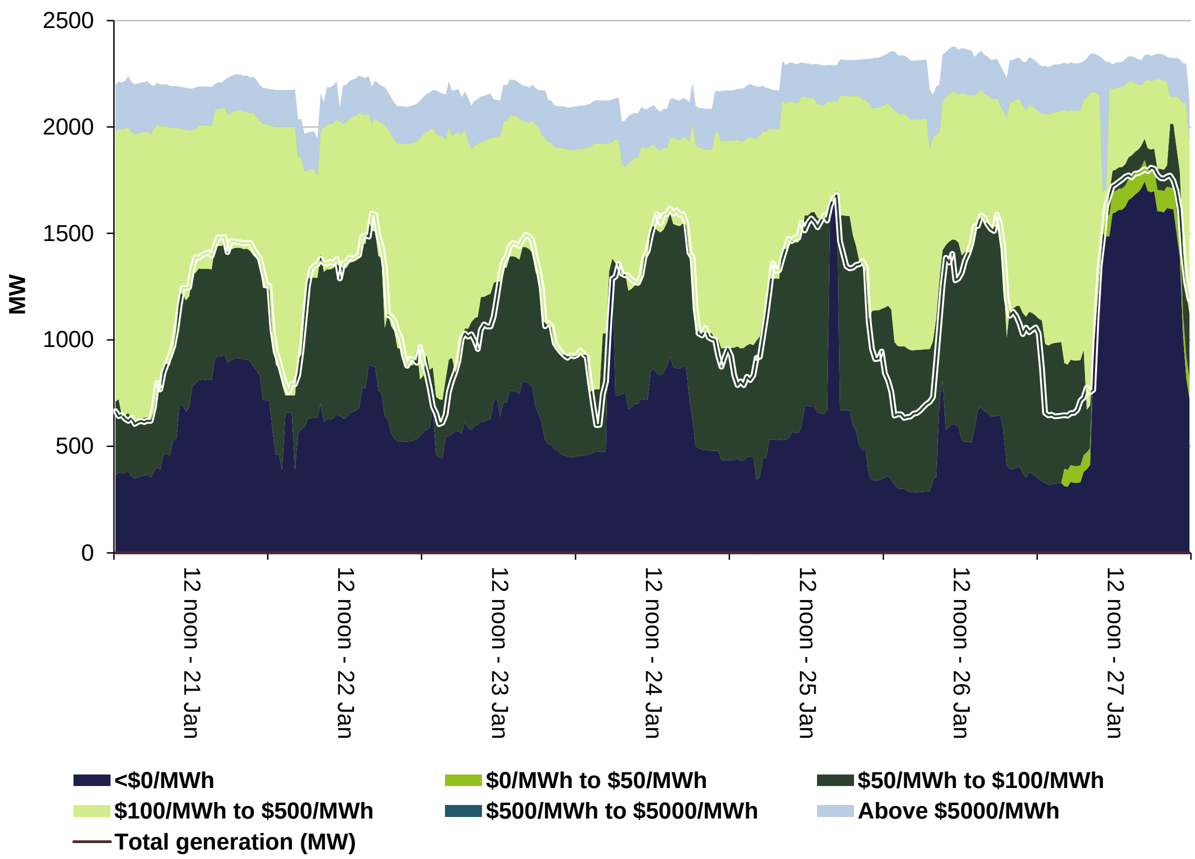


Figure 7: Tasmania generation and bidding patterns



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.

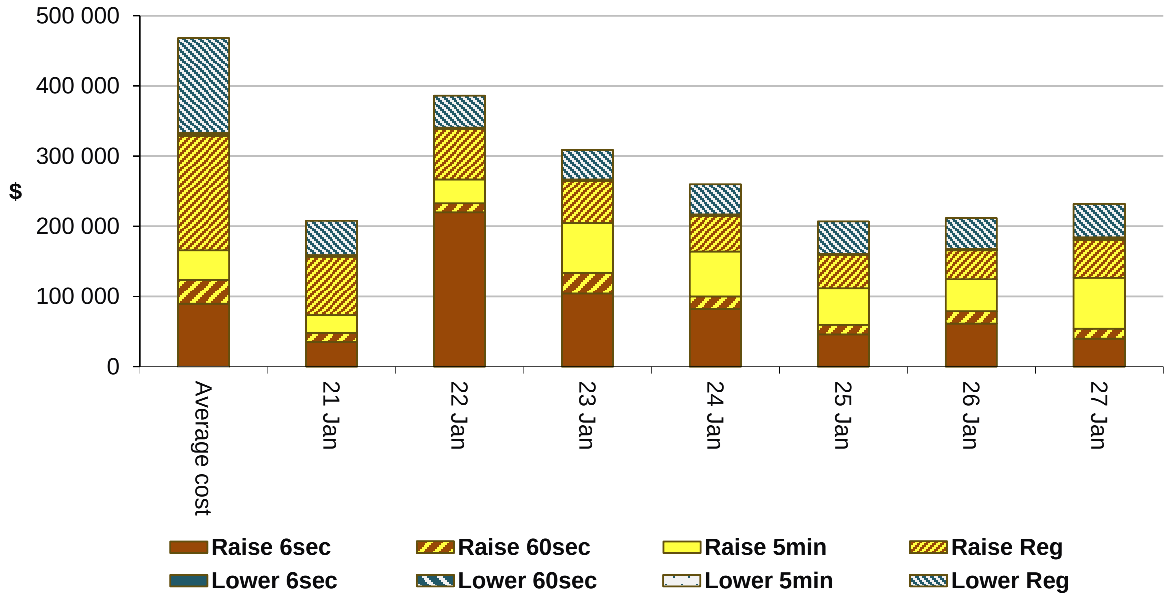
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 185 000 or around one third per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $627 500 or 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



Detailed market analysis of significant price events

Victoria

There was one occasion where the spot price in Victoria was greater than three times the Victoria weekly average price of $114/MWh and above $250/MWh.

Thursday, 25 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
4 pm	2273.73	290.00	290.00	7427	7266	7194	9048	8935	8947

Conditions at the time saw demand and availability higher than forecast. Prices were aligned with those in South Australia.

At 3.55 pm a system normal constraint managing the overload of the Dederang to Shepparton 220kV line violated. The constraint reduced low priced generation, particularly at Murray power station and flow was forced across the Vic - NSW interconnector into Victoria. This capacity was replaced by capacity priced at $13 086/MWh, which set price. At 4 pm Murray was no longer constrained down and the price fell to $87/MWh.

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 $129/MWh and above $250/MWh

Sunday, 21 January

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
3.30 pm	985.57	590.01	122.30	2261	1961	1723	2370	2323	2522

Conditions at the time saw demand 300 MW higher than forecast and availability was around 50 MW higher than that forecast four hours ahead.

At 3.05 pm demand increased by 34 MW and wind generation fell by 10 MW. The increase in demand and loss of low priced generation could not be fully offset by 10 MW of capacity offered between $350/MWh and $5077/MWh, and an increase of 28 MW of imports from Victoria. High priced generation was required to meet demand and the dispatch price increased from $350/MWh at 3 pm to $5114/MWh at 3.05 pm before returning to levels below $200/MWh for the remainder of the trading interval.

Thursday, 25 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
4 pm	2472.93	316.66	312.01	1905	1753	1773	2600	2576	2598

Conditions at the time saw demand and availability higher than forecast. The price was aligned with Victoria, see the Victorian section above.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $114/MWh and above $250/MWh.

Monday, 22 January

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
8.30 am	2171.87	136.00	109.05	1120	1153	1160	2159	2221	2229
11.30 am	2452.39	101.77	123.17	1077	1098	1103	2167	2268	2278

For the 8.30 am trading interval, demand was 33 MW lower than forecast and availability was 62 MW lower than forecast, both four hours ahead.

At 8.05 am, a constraint which manages system security and limits generation at Tamar Valley CCGT violated. The constraint decreased generation at Tamar Valley CCGT by 45 MW. Other constraints which managed frequency control services also violated and increased regulation requirements in Tasmania by 48 MW and increased forced exports across Basslink by 77 MW. With cheaper priced generation ramp rate limited the dispatch price reached $12 529/MWh.

The price then returned to less than $115/MWh for remainder of the trading interval as constraints were no longer binding and cheaper generation was no longer ramp rate limited and able to set price.

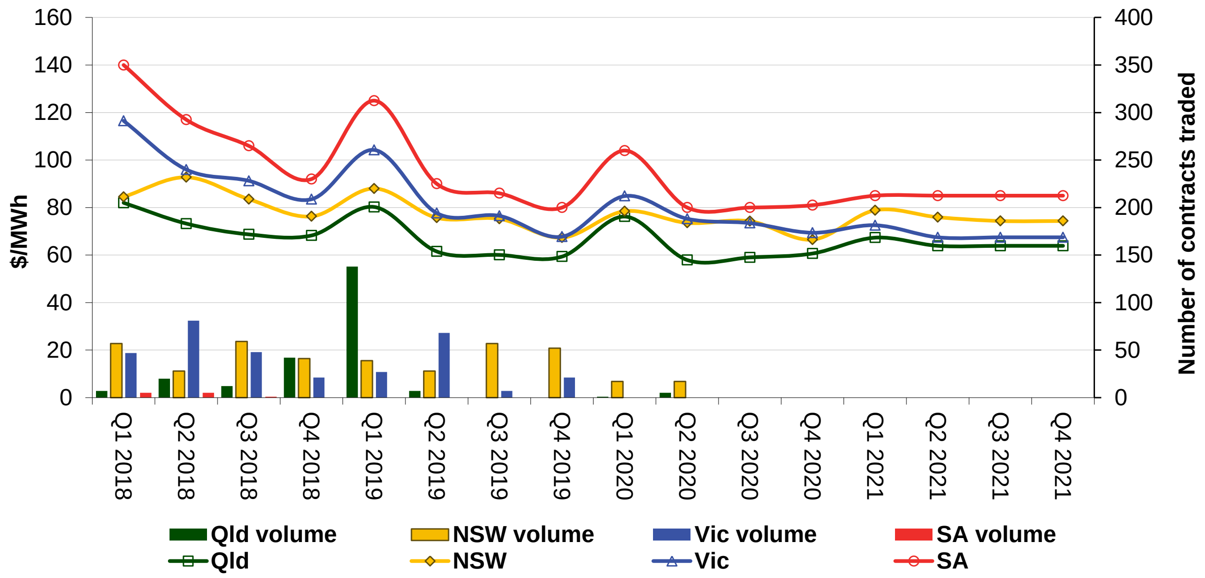
For the 11.30 am trading interval, demand was close to forecast and availability was around 100 MW lower than forecast.

According to AEMO, for the 11.15 am dispatch interval, erroneous SCADA data, caused by work being carried out at the Palmerston Substation, led to a system normal constraint binding which reduced the local generation target by 824 MW and caused flows on Basslink to change direction. The dispatch price reached the price cap for one dispatch interval. AEMO, are currently investigating the dispatch interval as a potential scheduling error and will report on the outcome once they have reached a conclusion.

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.

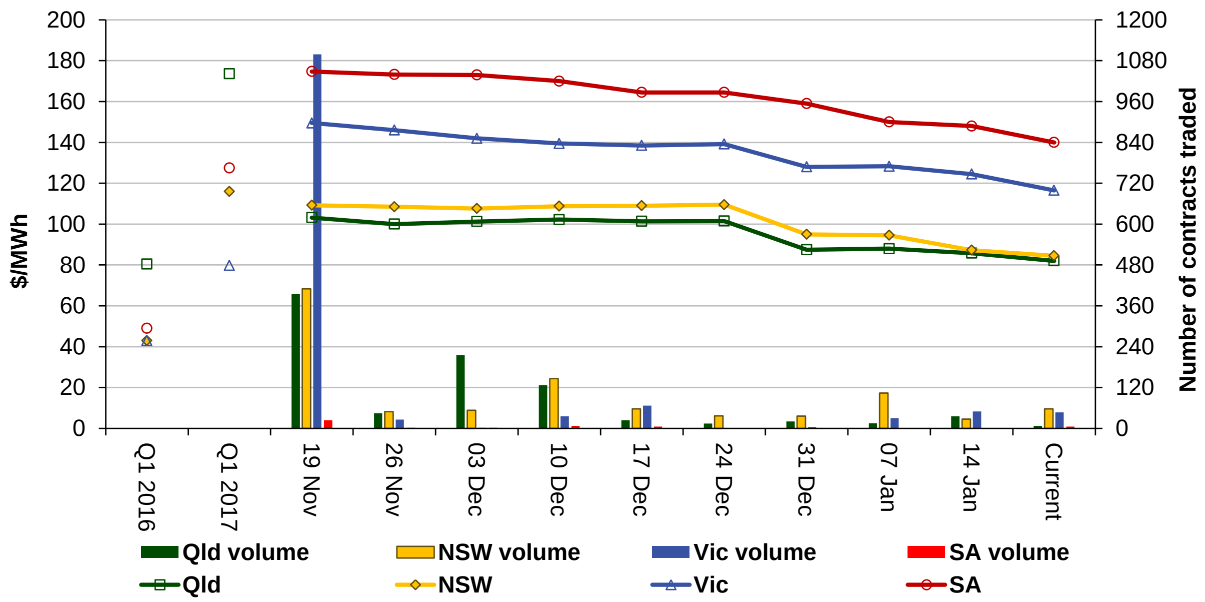
Figure 9: Quarterly base future prices Q1 2018 – Q4 2021



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)



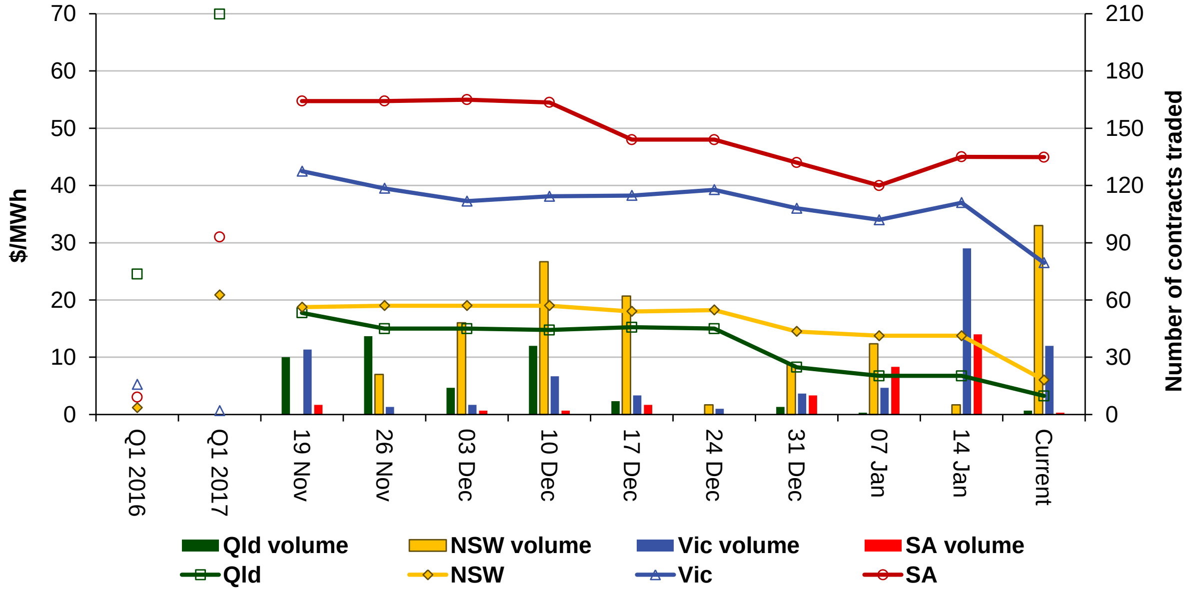
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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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