

13 – 19 January 2019

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 13 to 19 January 2019.

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

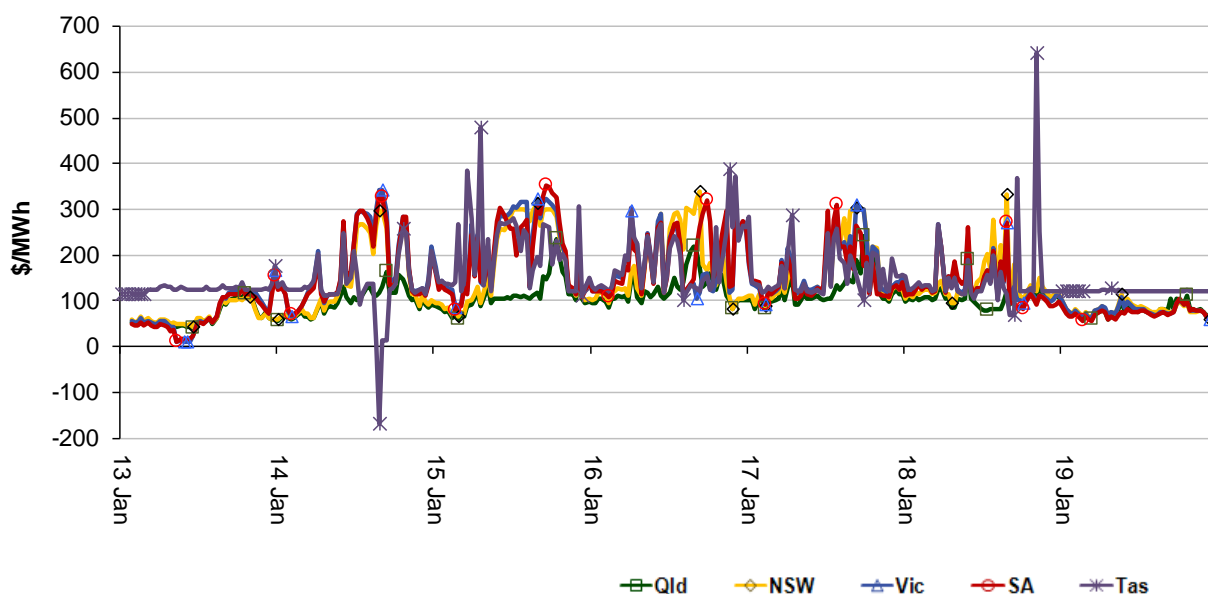


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in

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)

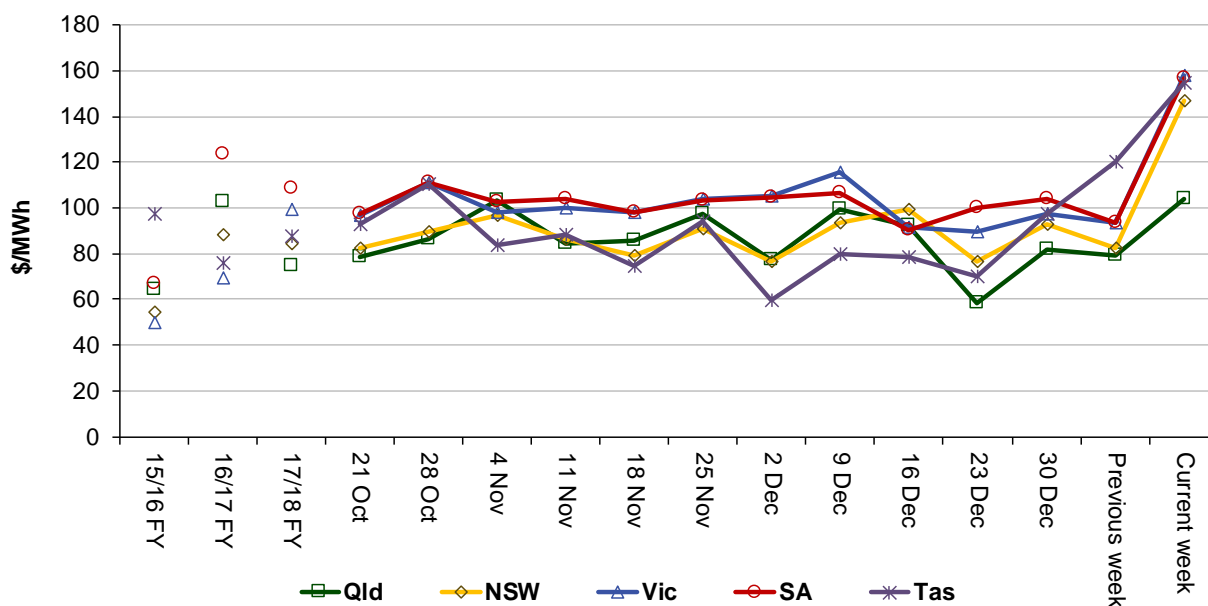


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	104	147	158	157	155
17-18 financial YTD	78	87	106	112	91
18-19 financial YTD	83	92	94	100	68

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 239 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2018 of 199 counts and the average in 2017 of 185. 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	12	31	0	3
% of total below forecast	0	44	0	10

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

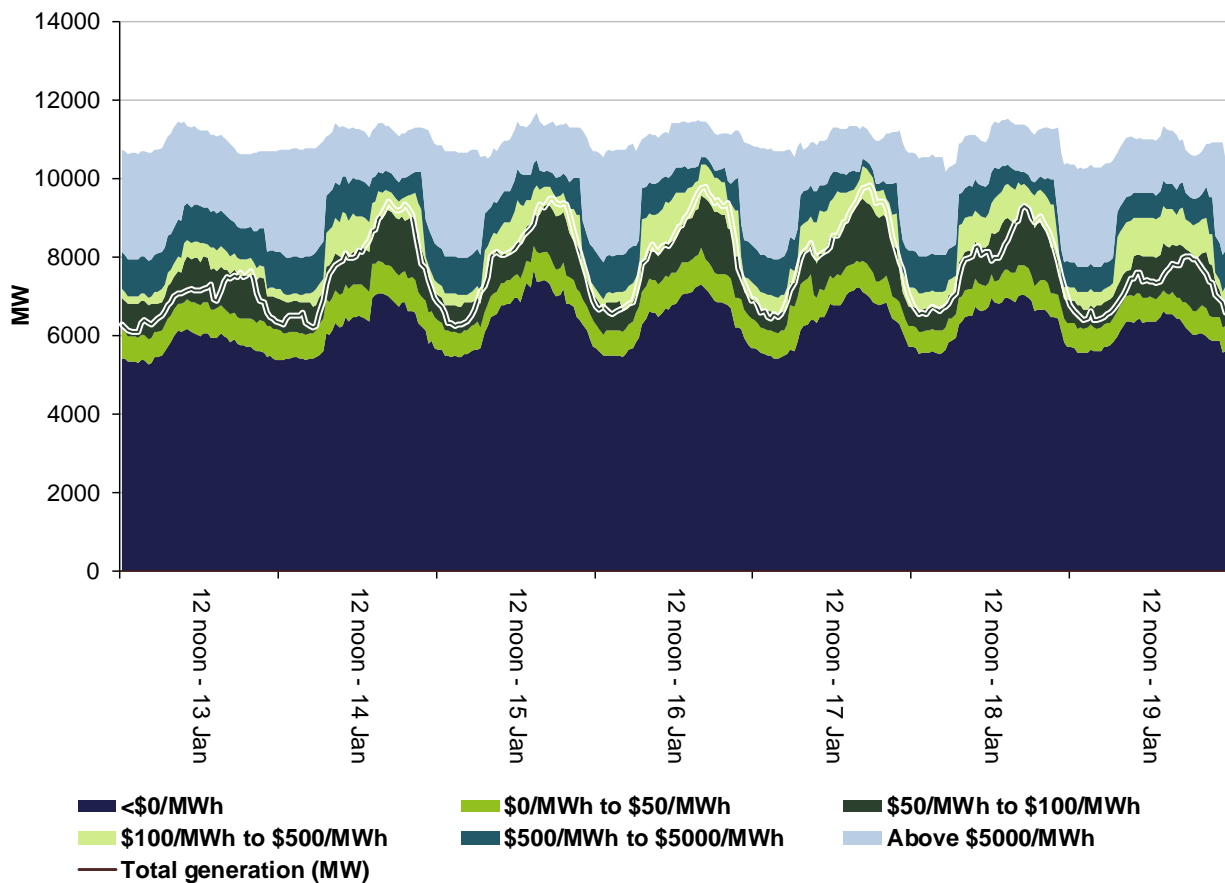


Figure 4: New South Wales generation and bidding patterns

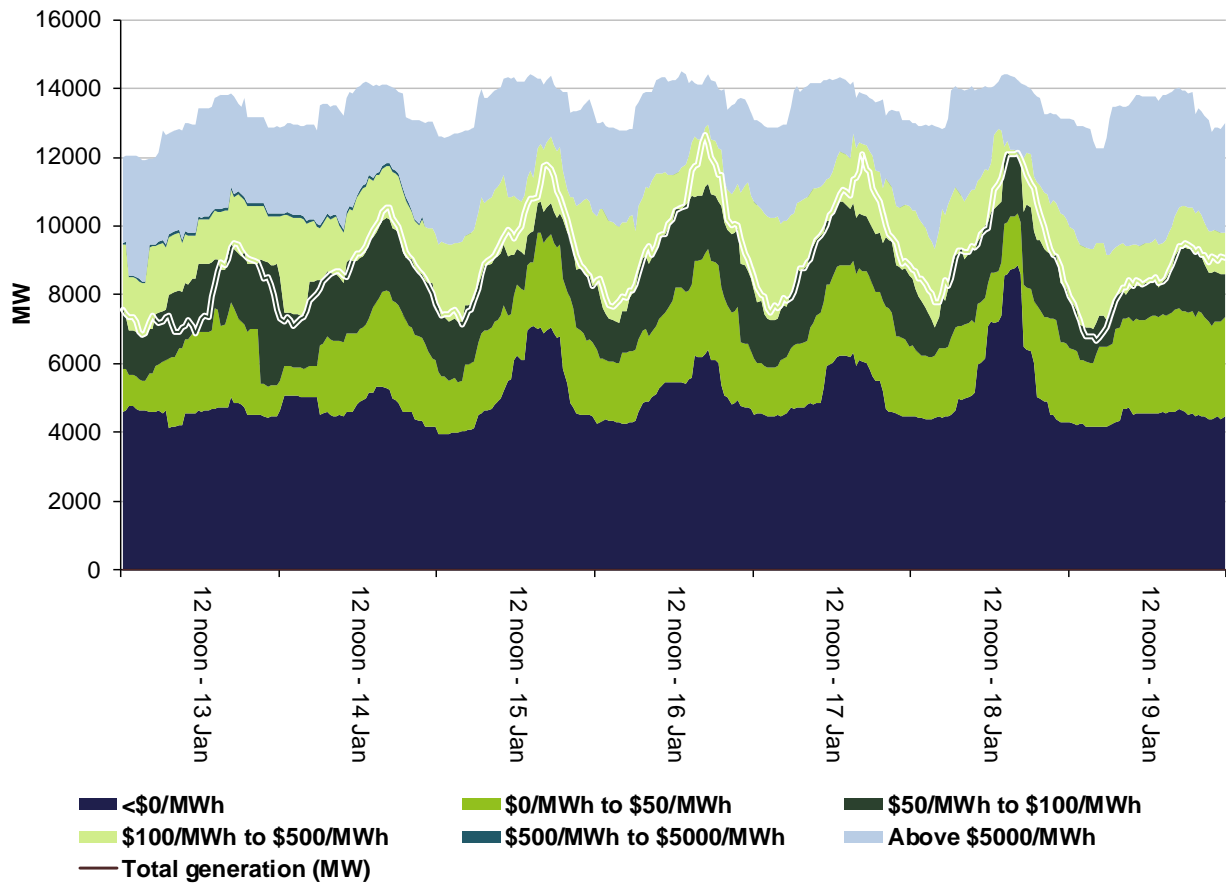


Figure 5: Victoria generation and bidding patterns

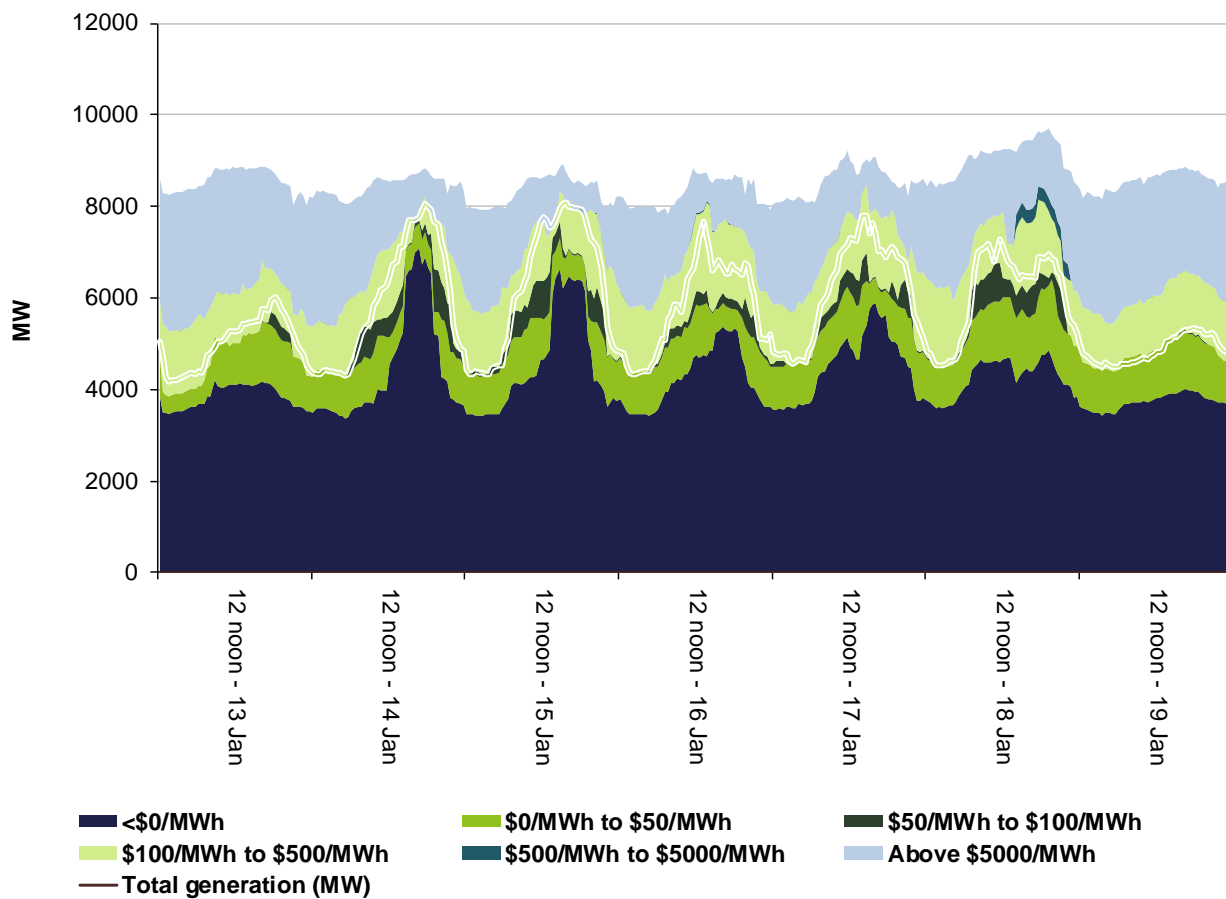


Figure 6: South Australia generation and bidding patterns

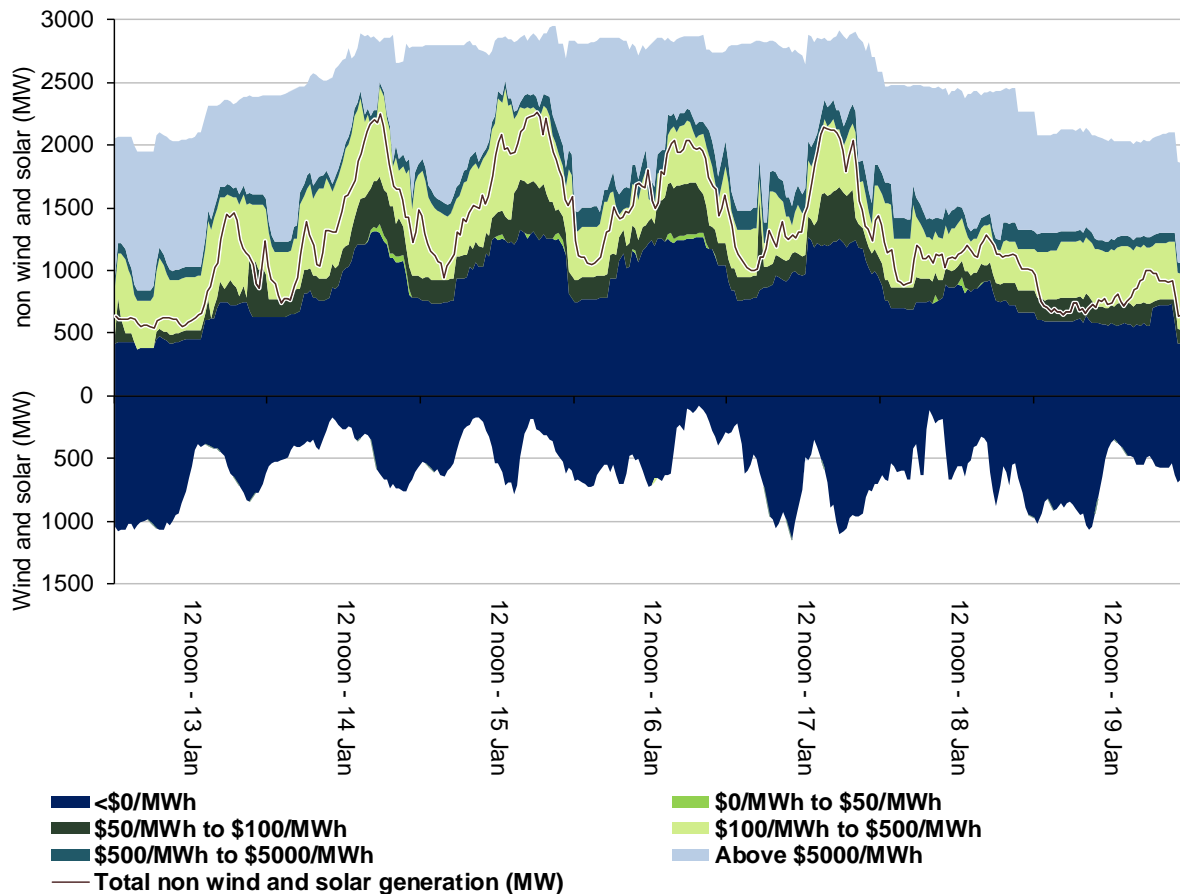
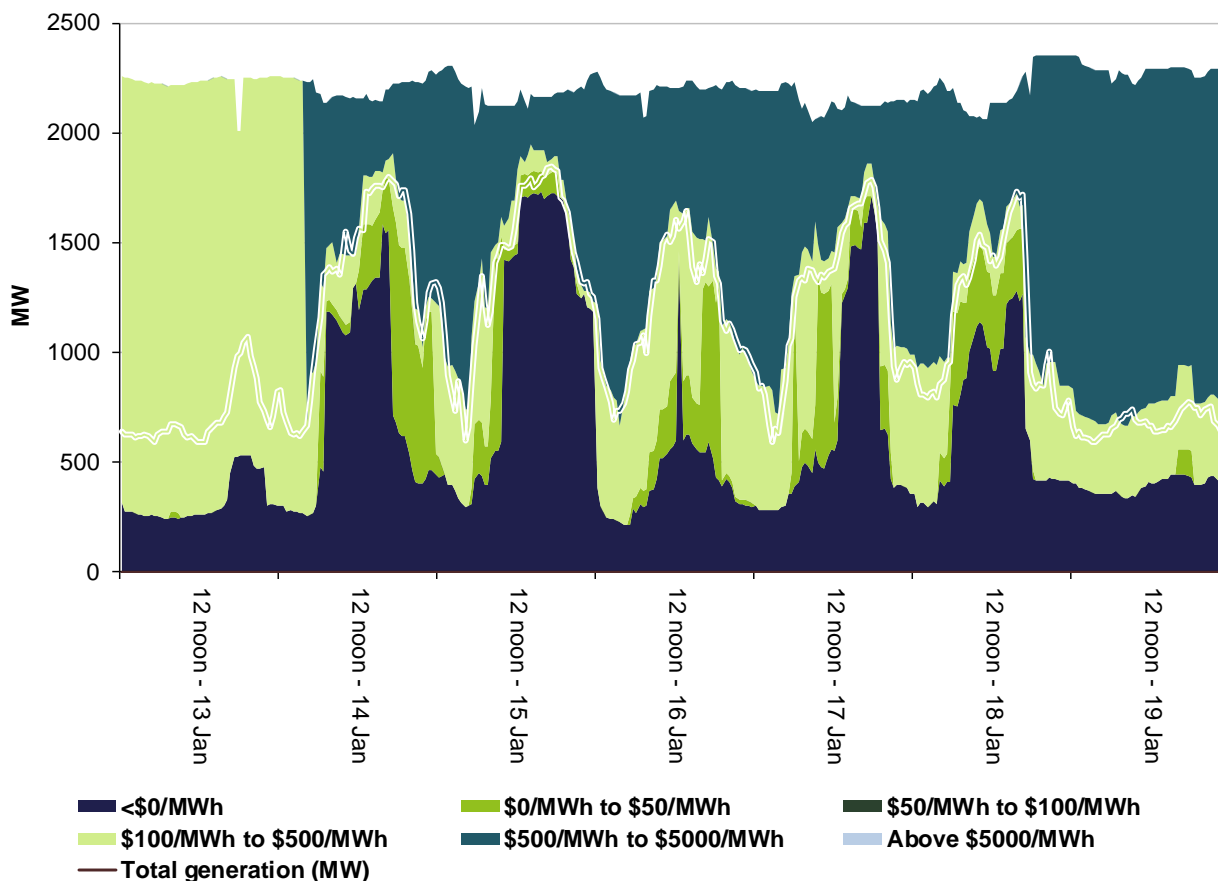


Figure 7: Tasmania generation and bidding patterns



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.

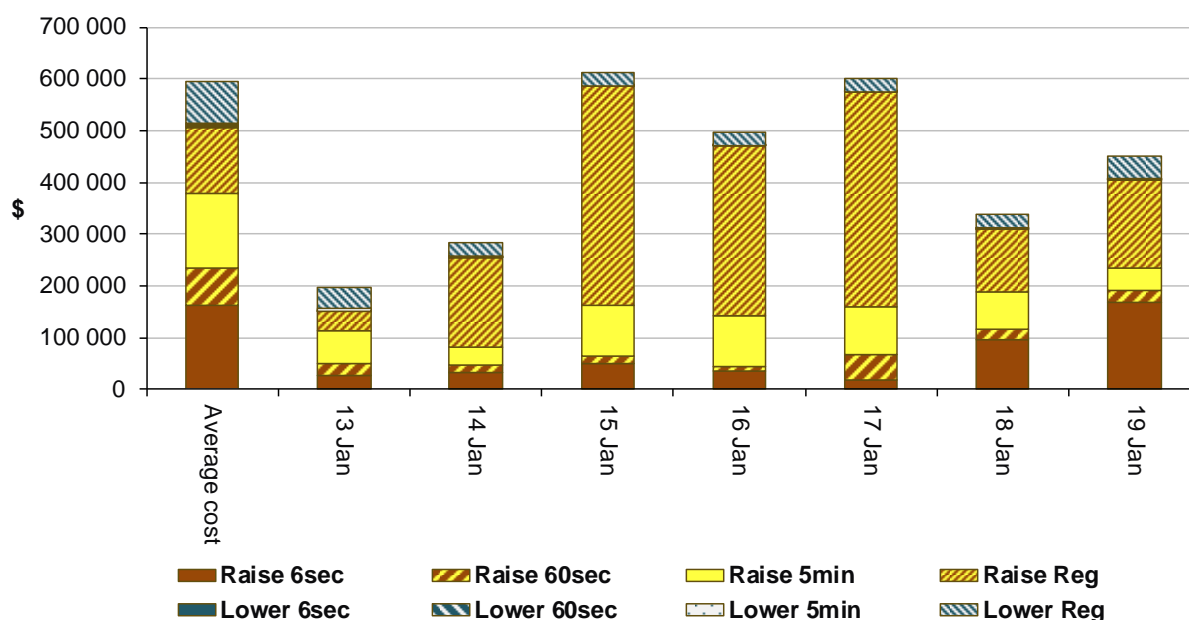
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$2,403,000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$576,500 or less than 3 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

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of \$155/MWh and above \$250/MWh and there was one occasion where the spot price was below -\$100/MWh.

Monday, 14 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	-169.34	13.26	898.64	1114	1126	1112	2141	2176	2176

Demand and availability were close to forecast, four hours prior. There was little capacity priced between \$13/MWh and the price floor so small changes in demand, interconnectors or generator availability could have a large effect on prices.

At 3.35 pm, there was a 35 MW decrease in demand. The only station with capacity between \$13/MWh and the price floor, Gordon, was down-constrained and the price fell to the floor. Effective 3.40 pm, in response to the lower than forecast price, Hydro Tasmania rebid 133 MW of capacity at Gordon from the price floor to more than -\$1/MWh. This led to the price increasing to -\$70/MWh and then to the forecast price for the rest of the trading interval.

Tuesday, 15 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
7.30 am	477.87	141.11	120.70	1151	1149	1158	2127	2157	2150

Demand and availability were close to forecast both four and 12 hours prior.

In the four hours leading up to the trading interval, Hydro Tasmania rebid 131 MW of capacity at Tribute and Fisher stations, most of which was priced below \$140/MWh, to \$898/MWh in response to prices differing from forecast which.

At 7.05 am, following a step change in capacity at Tungatina and Poatina, most of which was priced below \$130/MWh, the price increased to \$898/MWh for two dispatch intervals. From 7.15 am, flows on the Basslink interconnector changed so Tasmania was importing from Victoria and the price dropped back to around \$270/MWh for the rest of the trading interval.

Table 5: Price, demand and availability

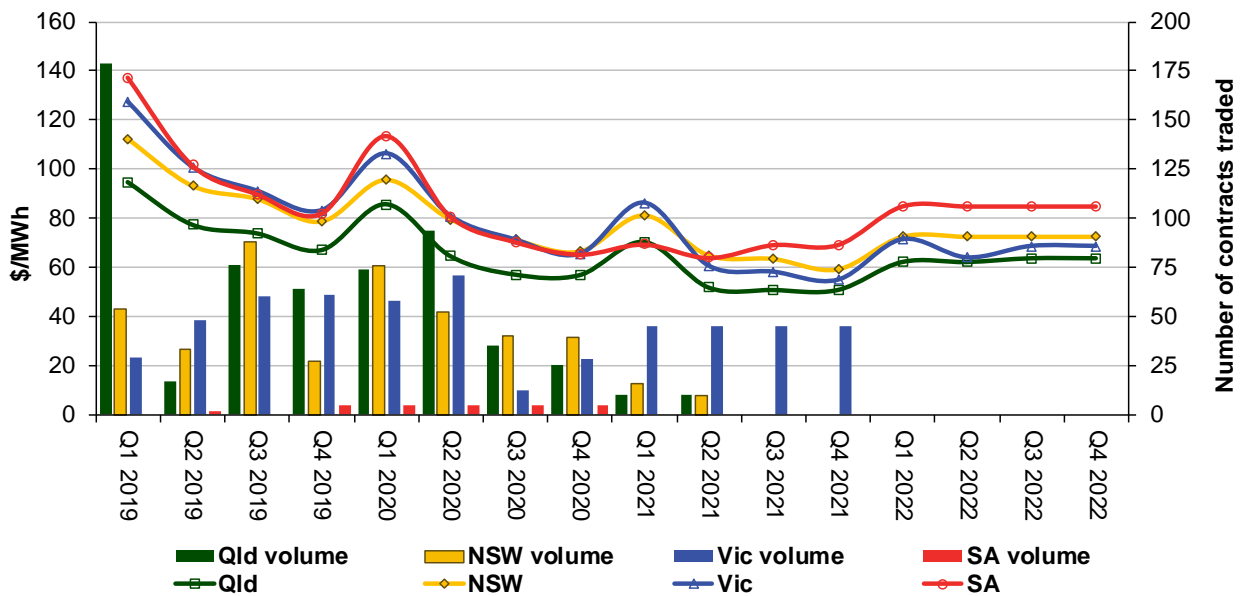
Time	Price (\$/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
8.30 pm	641.74	119.86	120.95	1081	1076	1057	2350	2334	2343

Demand and availability were both close to forecast, four hours prior. Throughout the trading interval, imports into the Tasmania were limited by the frequency control special protection scheme, a network constraint on the Basslink interconnector. As a result, imports were reduced from 423 MW at 8 pm to 136 MW by 8.30 pm, and FCAS services provided by Basslink were restricted. The reduction in imports needed to be met by an increase in generation and FCAS within the state, which led to increased prices. As a result, for four dispatch intervals the price rose to \$898/MWh.

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.

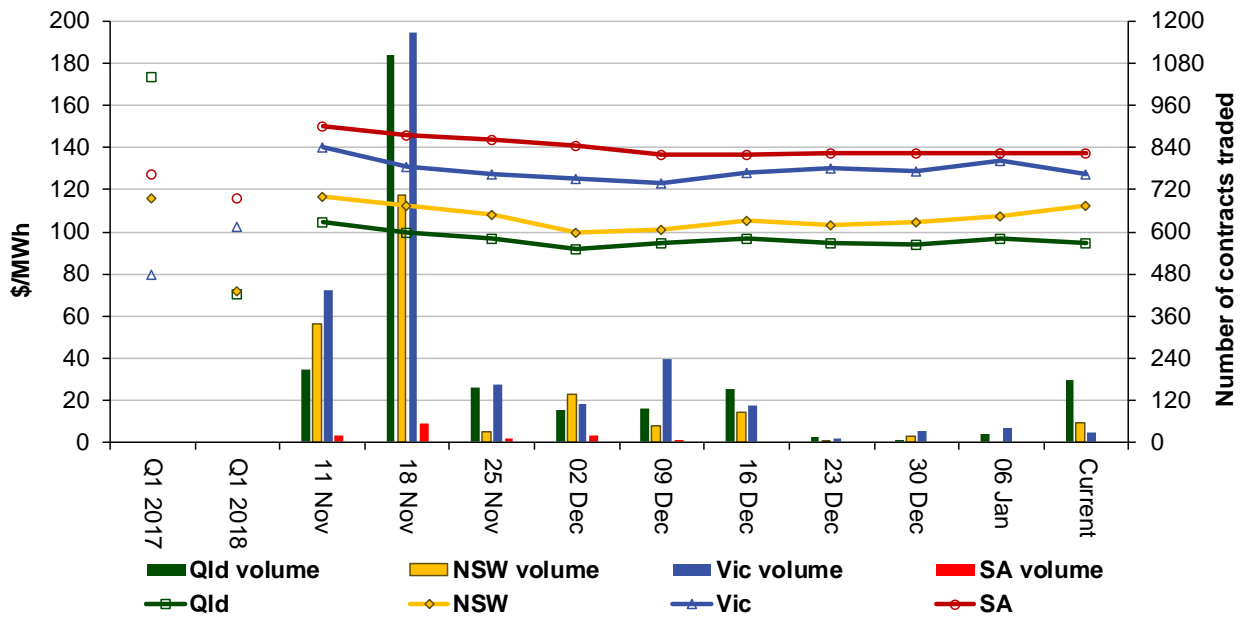
Figure 9: Quarterly base future prices Q1 2019 – Q4 2022



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)



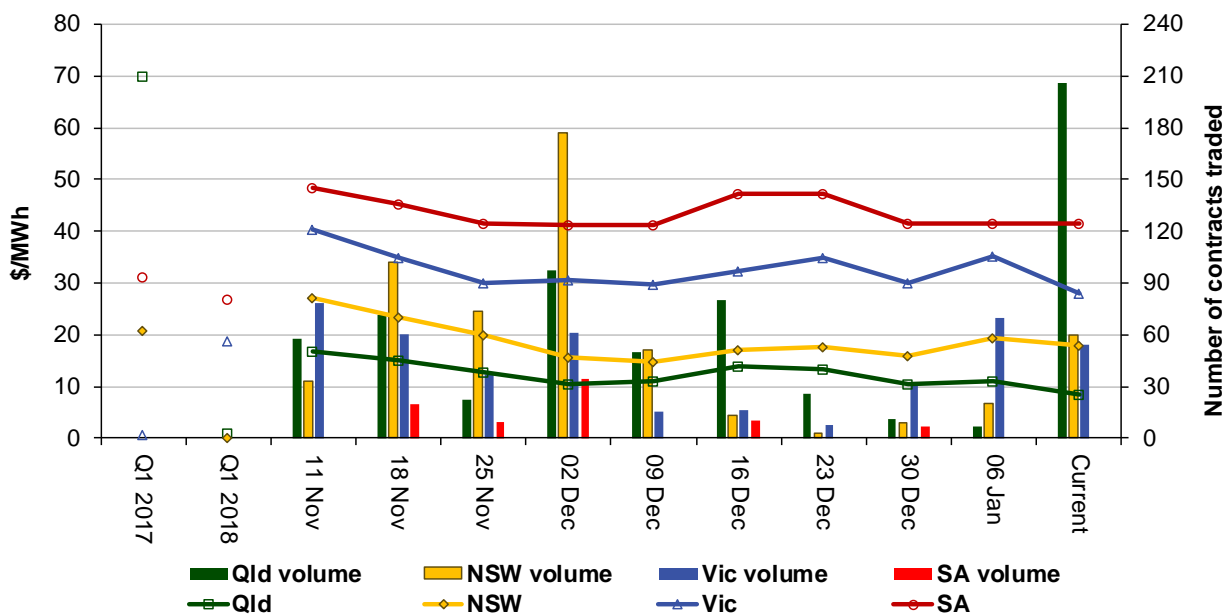
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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