Electricity Report

3 January – 9 January 2016

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 3 to 9 January 2016. There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $46/MWh and above $250/MWh. There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $42/MWh and above $250/MWh

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

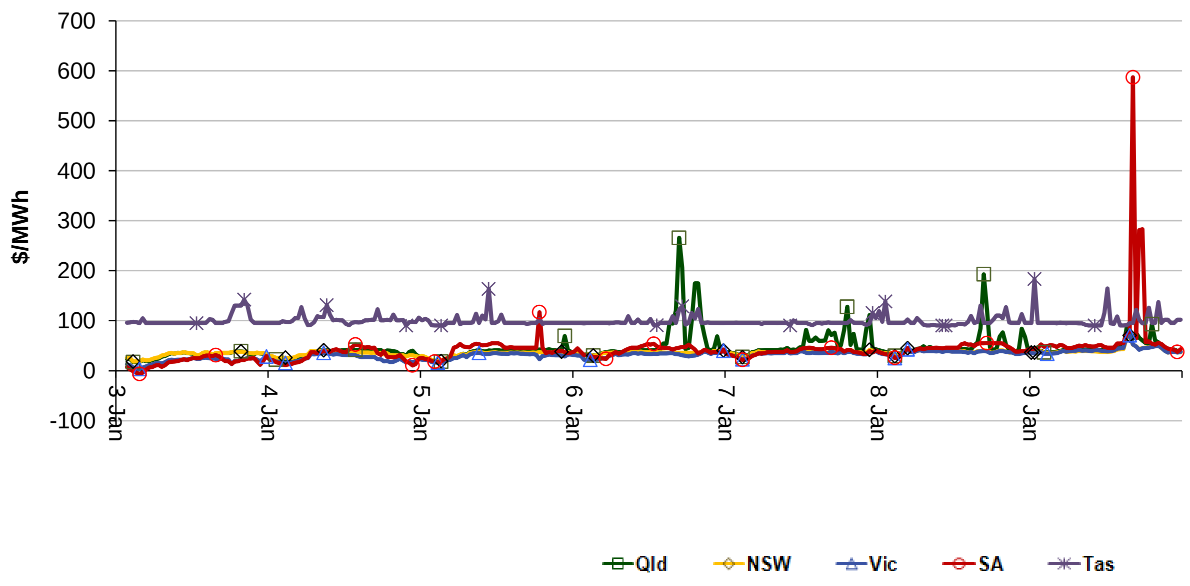


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

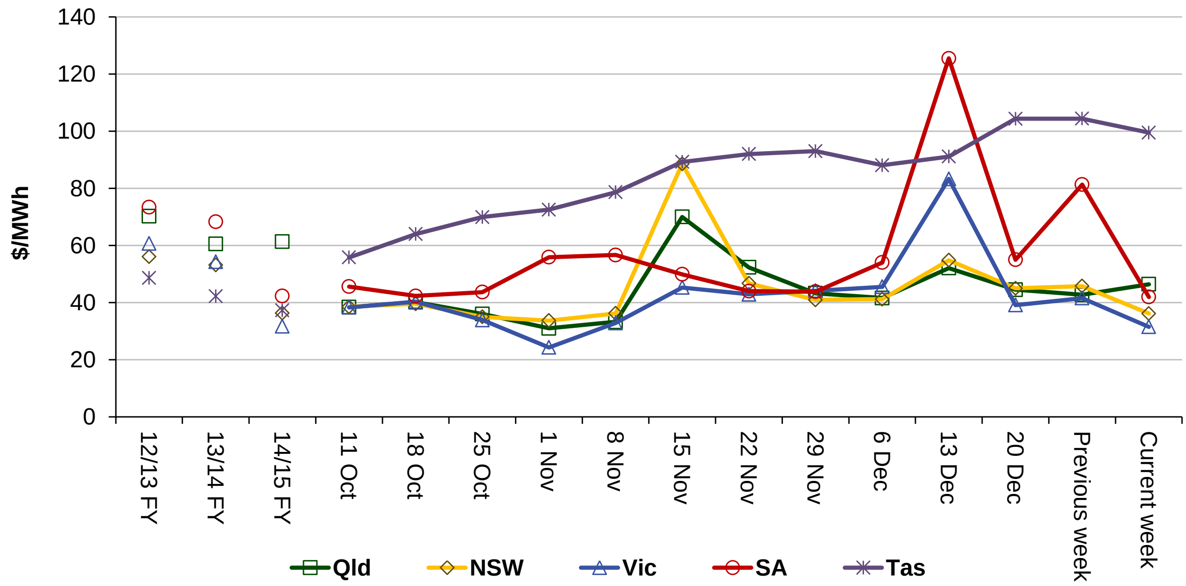


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	46	36	32	42	99
14-15 financial YTD	52	38	33	42	38
15-16 financial YTD	44	45	40	63	59

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 310 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. 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	9	0	0
% of total below forecast	87	2	0	0

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

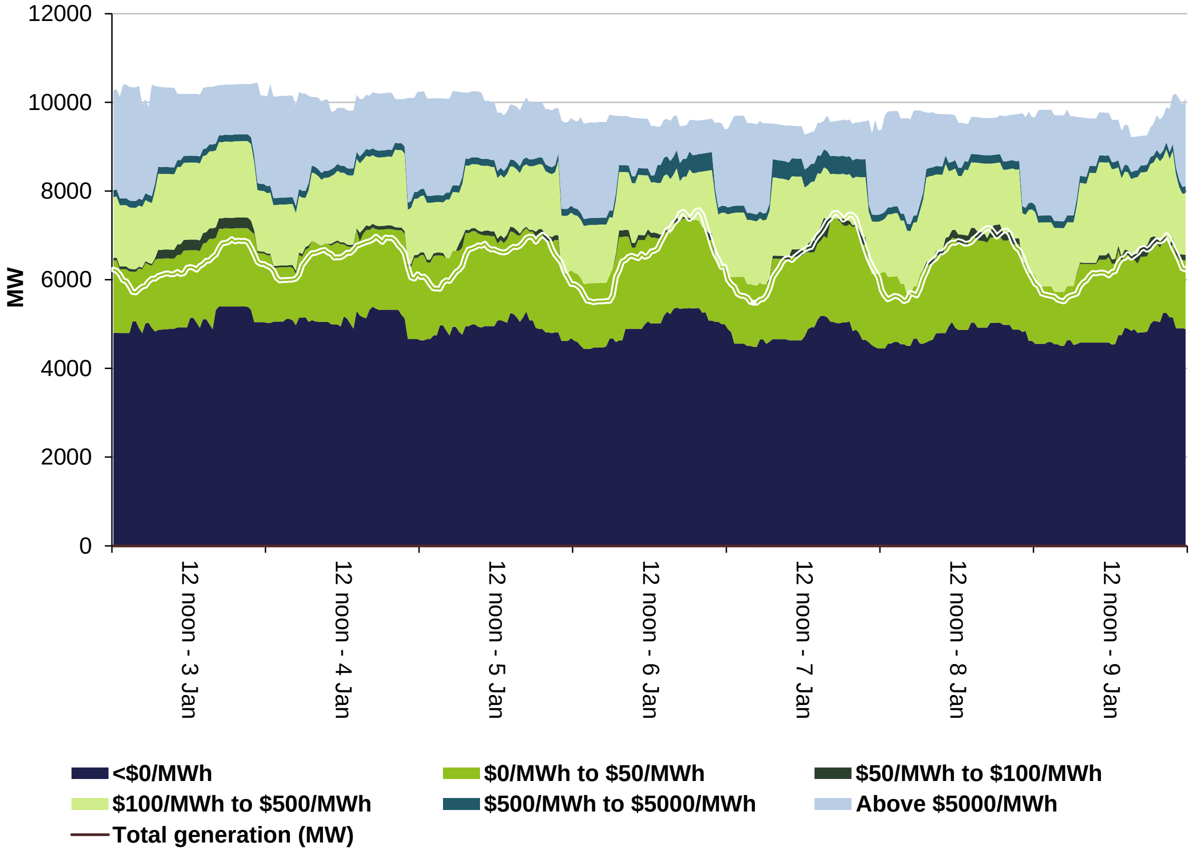


Figure 4: New South Wales generation and bidding patterns

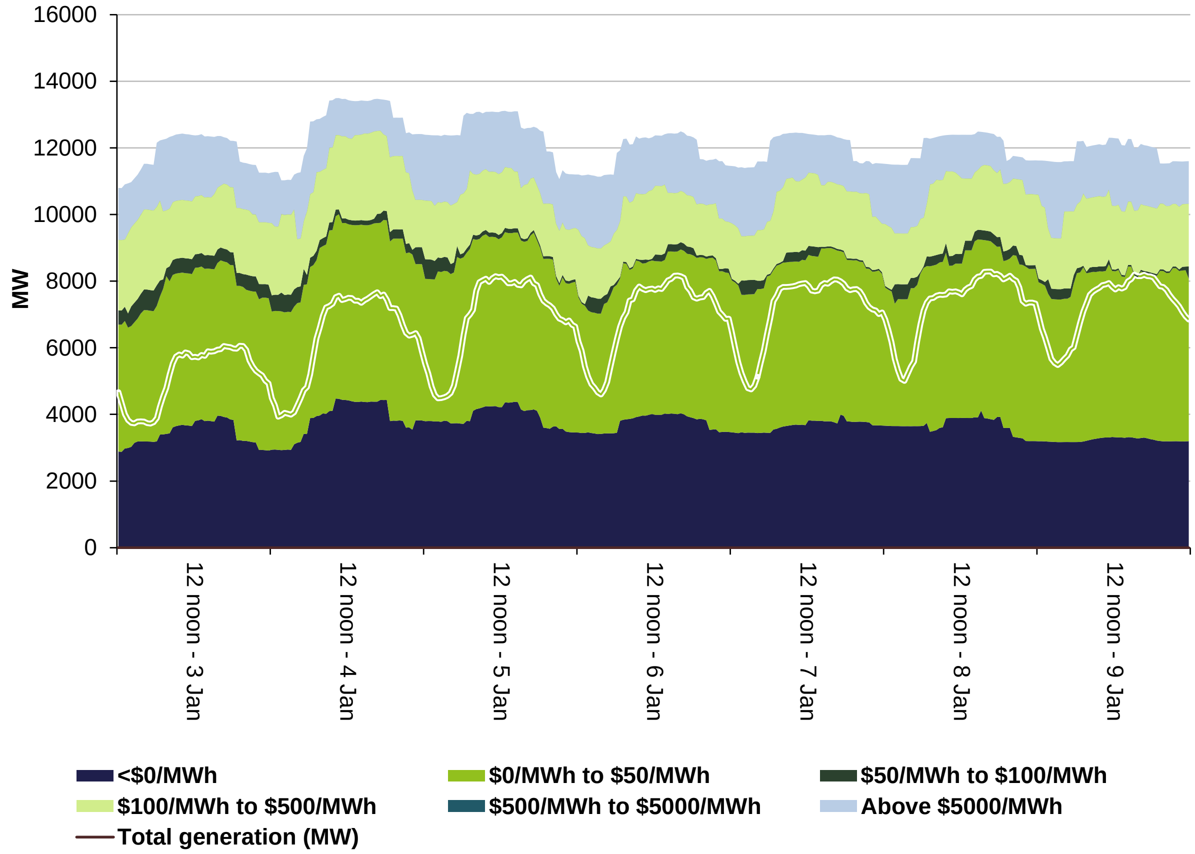


Figure 5: Victoria generation and bidding patterns

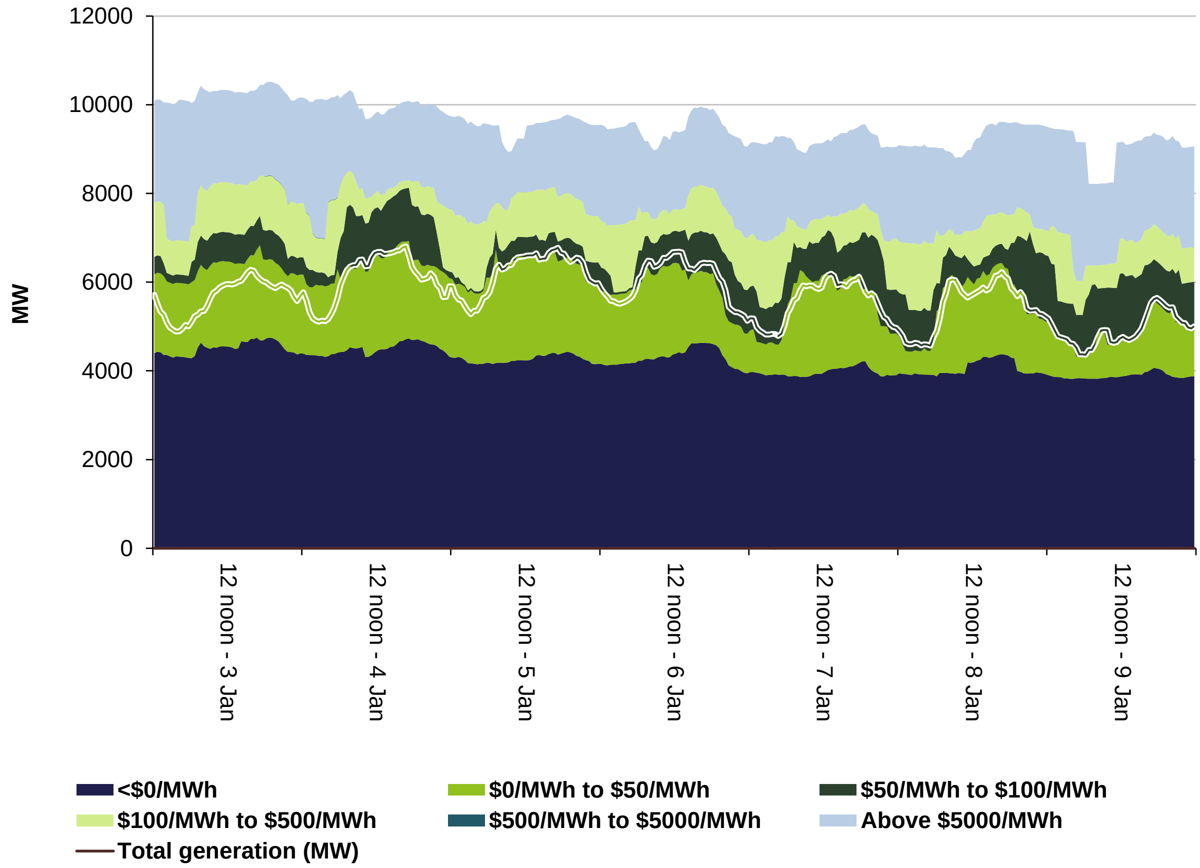


Figure 6: South Australia generation and bidding patterns

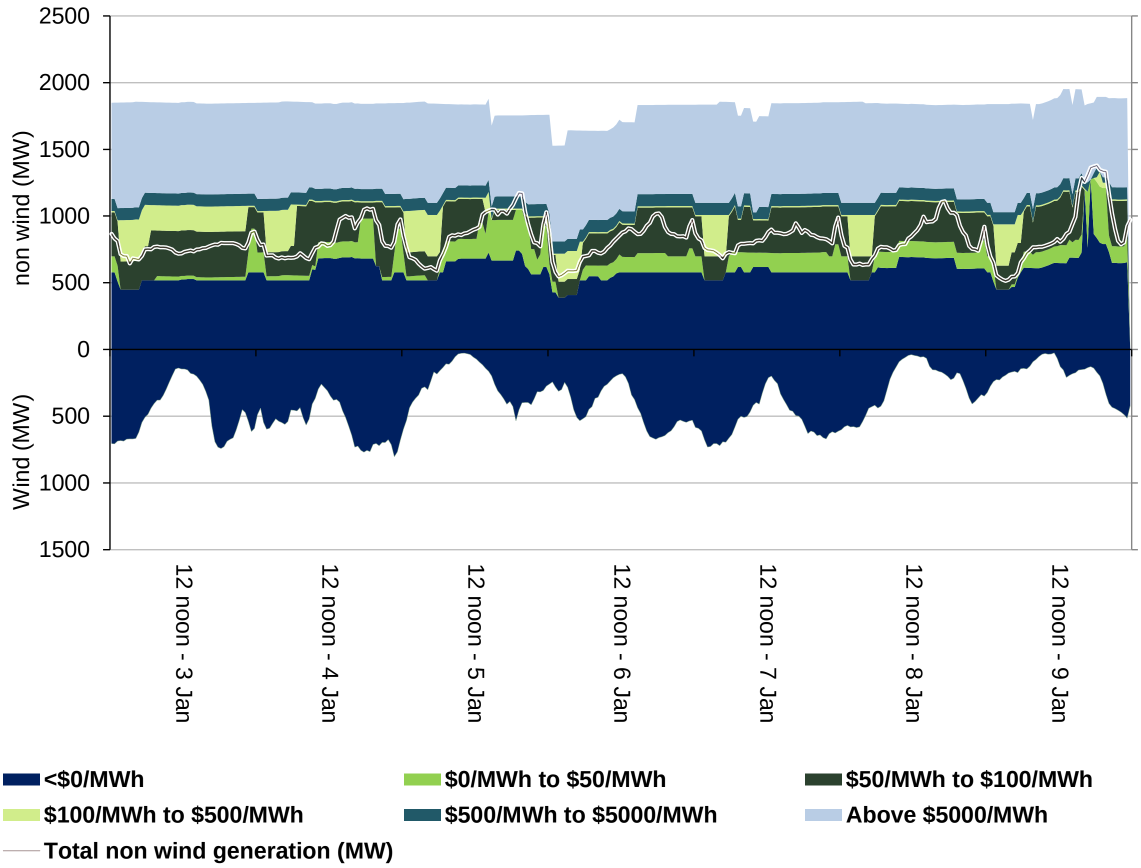
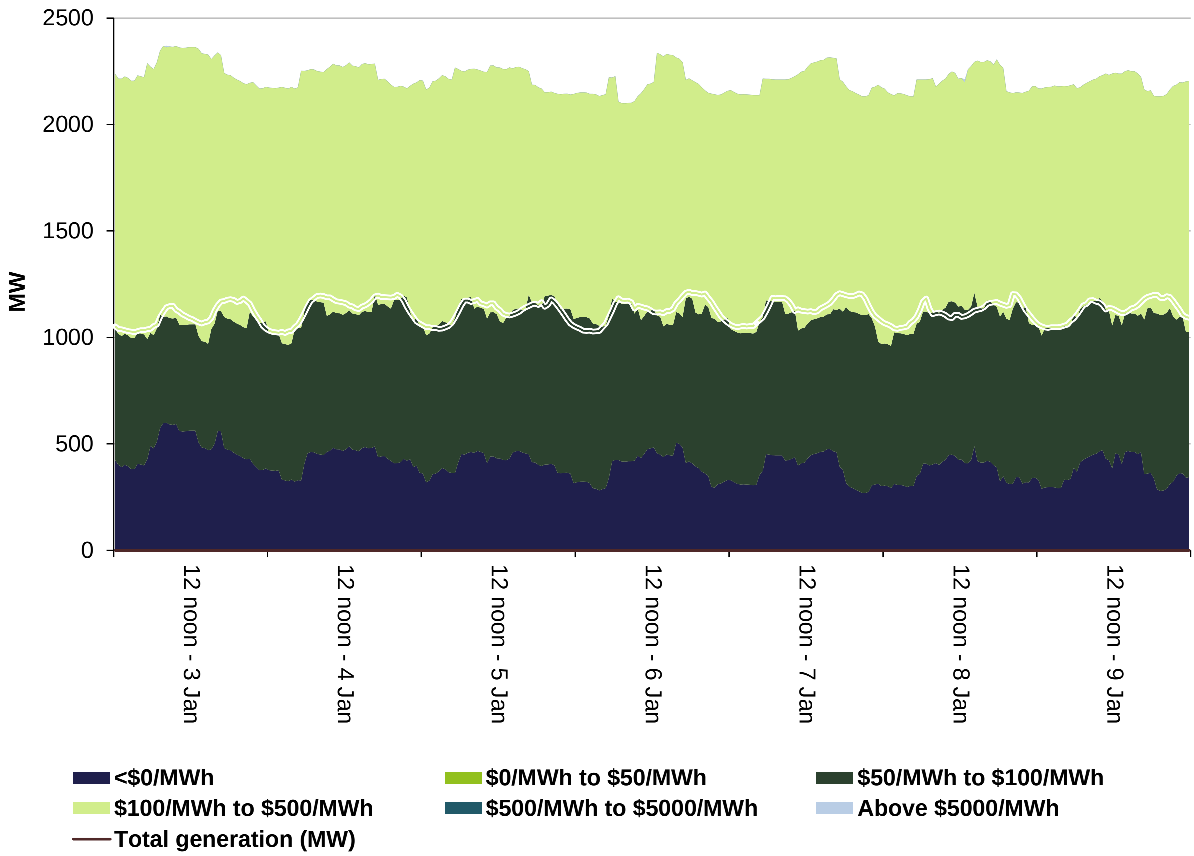


Figure 7: Tasmania generation and bidding patterns



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.

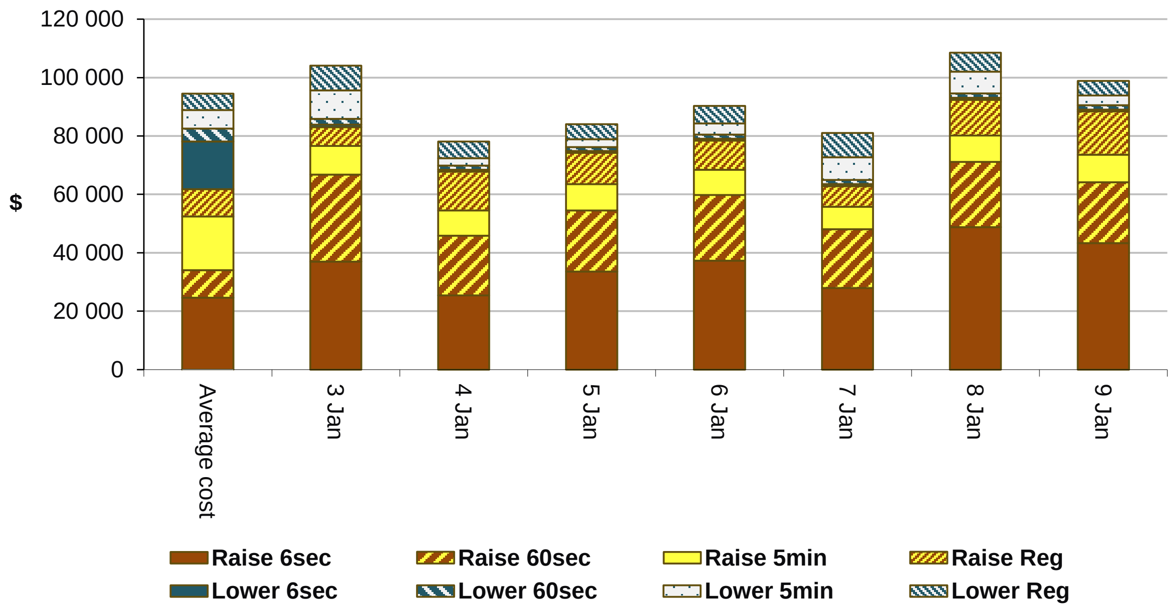
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $459 500 or less than 0.5 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $185 500 or around 1 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

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above $250/MWh or was below -$100/MWh.

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $46/MWh and above $250/MWh.

Wednesday, 6 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
5 pm	265.66	99.00	299.91	7647	7606	7784	9615	9740	9765

Conditions at the time saw demand close to the forecast fours ahead. Available capacity was 125 MW below forecast.

Table 4: Rebids for the 5 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.16 pm	-	Callide Power Trading	Callide C	-26	14	N/A	1614P FABRIC FILTER BLINDING ALARM
4.22 pm	-	CS Energy	Gladstone	80	<99	13 800	1619A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
4.32 pm	4.40 pm	CS Energy	Gladstone	40	200	13 800	1631A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL

In the previous trading interval, the dispatch price increased from $41/MWh at 4.20 pm to $200/MWh at 4.25 pm as a result of tight supply conditions, with little available generation priced between $41/MWh and $200/MWh, and generator rebidding. The dispatch price remained at $200/MWh as similar conditions prevailed for the remainder of the 4.30 pm trading interval and into the 5 pm trading interval.

As a result of the above rebidding and a 47 MW increase in demand at 4.45 pm, the dispatch price increased from $200/MWh at 4.40 pm to $298/MWh at 4.45 pm (there was no generation priced between $200/MWh and $290/MWh). The dispatch price remained at a similar level for the remainder of the trading interval.

South Australia

There were three occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $42/MWh and above $250/MWh.

Saturday, 9 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
4.30 pm	586.79	64.50	64.97	1640	1594	1636	2037	2077	2077
5.30 pm	281.31	64.97	64.99	1673	1678	1722	1972	2103	2098
6 pm	282.77	64.99	64.99	1716	1725	1751	1984	2125	2121

Conditions at the time saw demand close to the four hour forecast and availability up to 141 MW below the four hour forecast. Flows into South Australia from Victoria across the Heywood interconnector were up to 144 MW less than forecast.

Table 6: Rebids for the 4.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.12 pm	4.20 pm	AGL Energy	Torrens Island	-120	<65	NA	1610~P~020 REDUCTION IN AVAIL CAP~204 UNIT TRIP 120MW

At around 4.10 pm, Torrens Island A Unit 4 tripped removing 120 MW of available capacity, all of which was priced below $65/MWh. With all other available non-wind units either fully dispatched, trapped/stranded or unable to start in time, the dispatch price increased from $65/MWh at 4.15 pm to $3231/MWh at 4.20 pm. The dispatch price fell to around $50/MWh for the next dispatch interval due to an increase in non-scheduled generation and generator rebidding of capacity to the price floor.

The trip of Torrens Island A Unit 4 exacerbated tight supply demand conditions. Consequently, small changes in demand, interconnectors and availability could result in large changes in price.

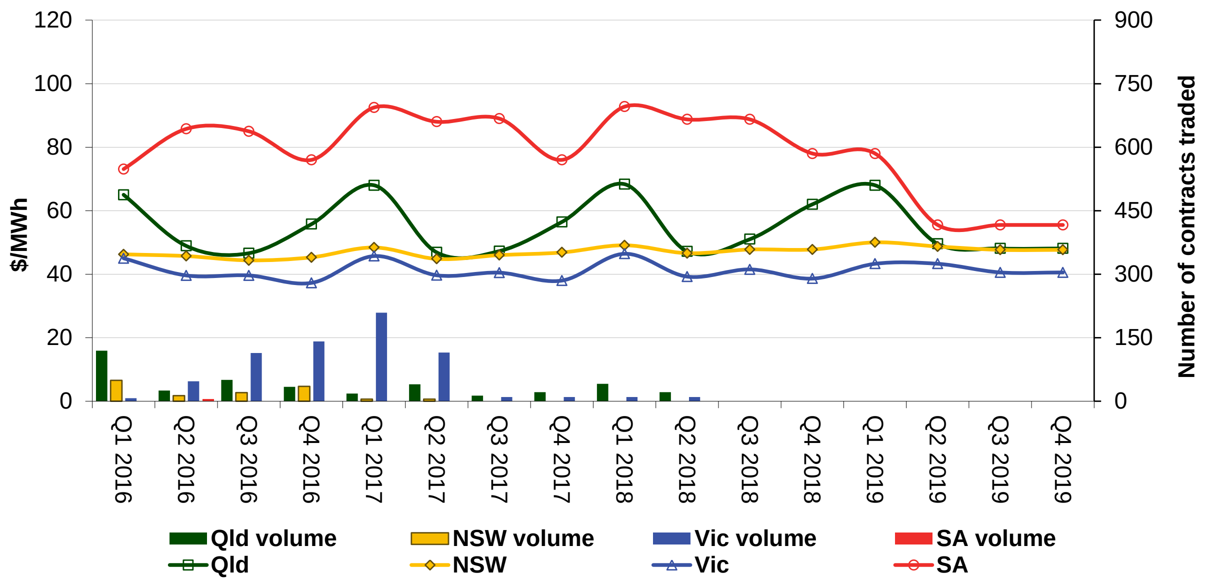
At the start of the 5.30 pm trading interval, demand increased by 73 MW between 5 pm and 5.05 pm. With lower priced generation either fully dispatched or stranded, higher priced generation had to be dispatched to meet demand. As a result, the dispatch price rose from $66/MWh at 5 pm to $1450/MWh at 5.05 pm. In the next dispatch interval, the dispatch price fell to $37/MWh following a 143 MW decrease in demand (mostly due to an increase in non-scheduled generation) and generators rebidding 87 MW of available capacity to the price floor.

At the start of the 6 pm trading interval, the dispatch price spiked again, increasing from $66/MWh at 5.30 pm to $1450/MWh at 5.35 pm due to a 32 MW increase in demand at 5.35 pm. With low priced generation fully dispatched and both interconnectors operating at limit, higher priced generation was dispatched to meet demand. In the following dispatch interval, the dispatch price fell to $71/MWh as a result of generator rebidding and fell further to $46/MWh at 5.45 pm following a 133 MW decrease in demand (mostly due to an increase in non-scheduled generation).

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.

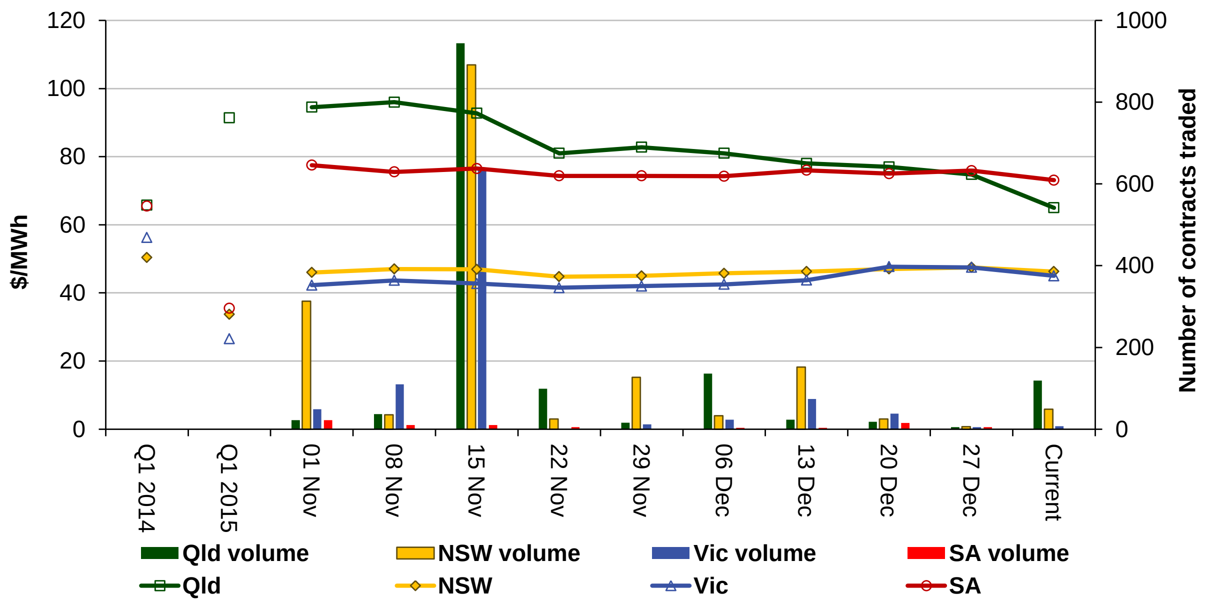
Figure 9: Quarterly base future prices Q1 2016 – Q4 2019



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades. The high volume of trades in Figure 9, 10, and 11 are due to options on calendar year base load expiring on Thursday 19 November.

Figure 10: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



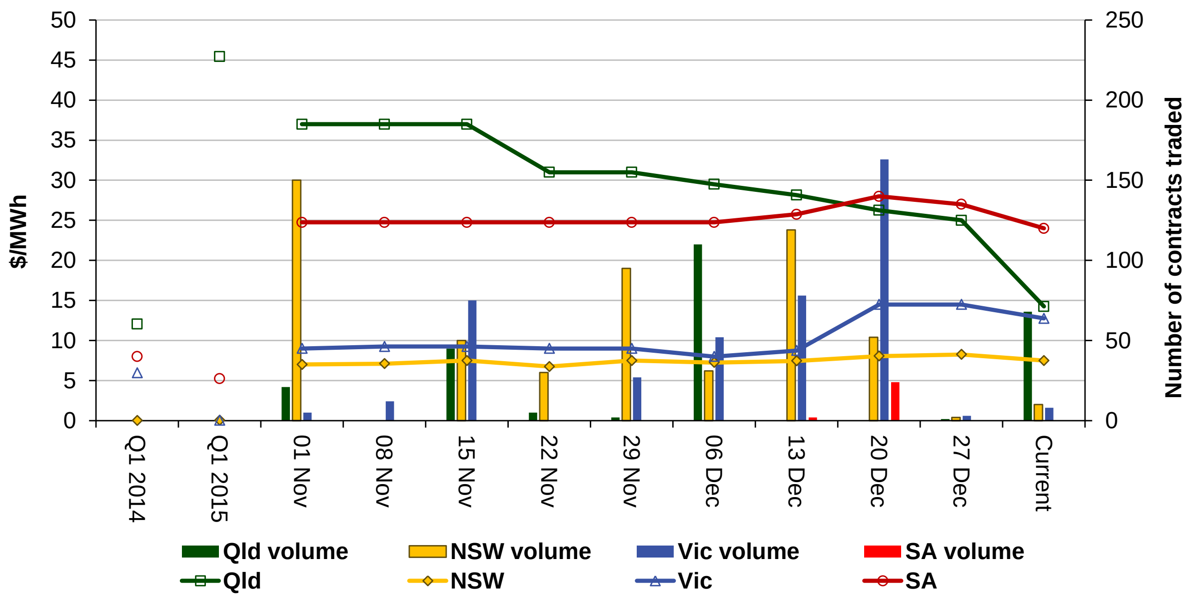
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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