Electricity Report

AUSTRALIAN ENERGY REGULATOR

24 January – 30 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 24 to 30 January 2016. There were three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $66/MWh and above $250/MWh

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

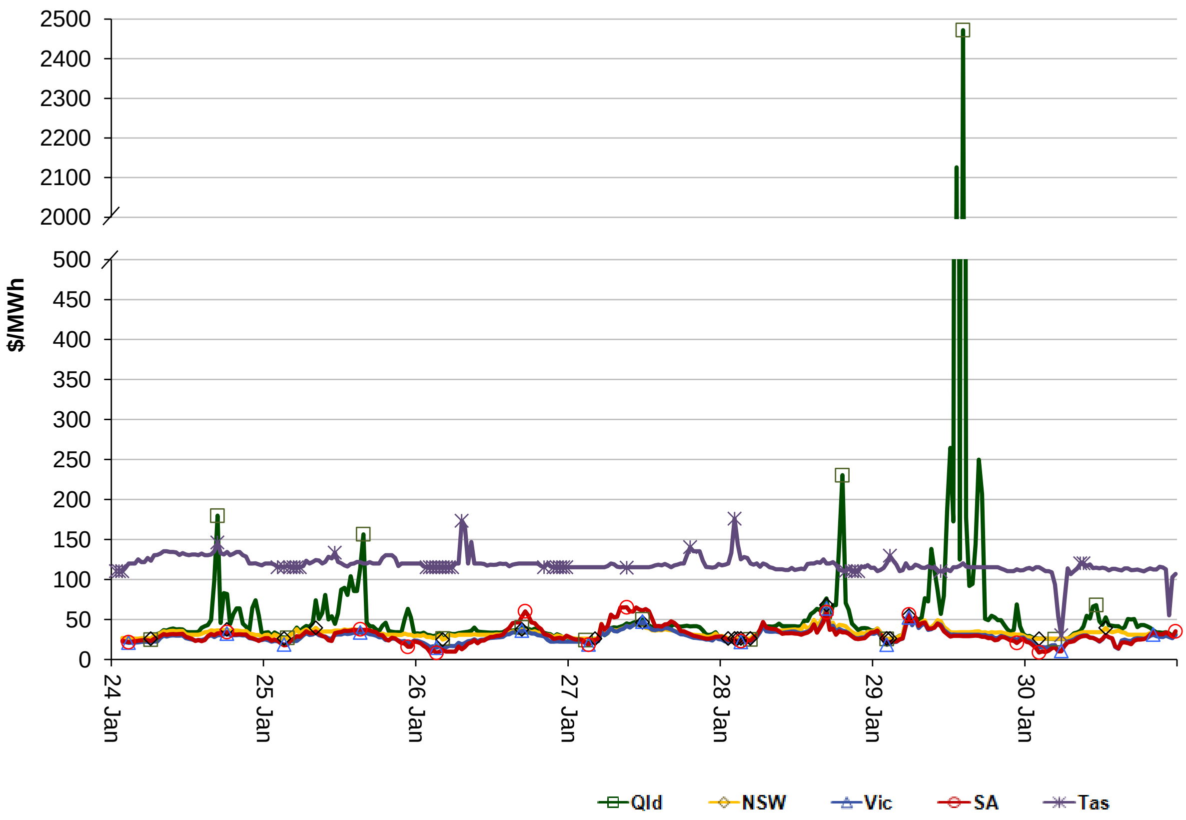


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

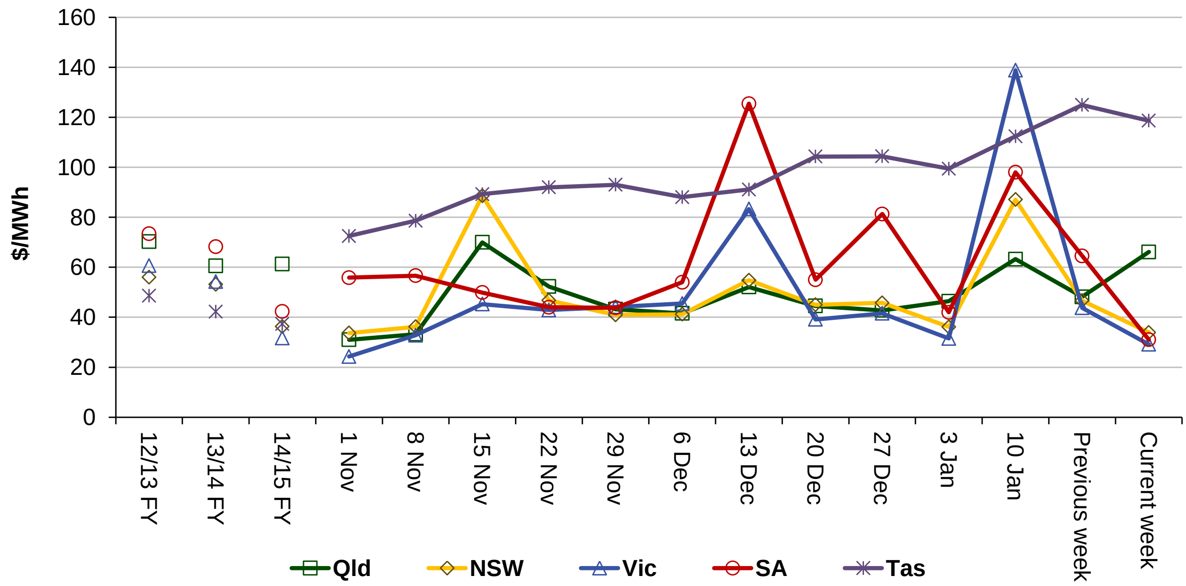


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	66	34	29	31	119
14-15 financial YTD	65	37	32	40	38
15-16 financial YTD	46	46	43	63	64

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 250 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	24	0	1
% of total below forecast	68	6	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.

The red ellipse in Figure 3 highlights when participants in Queensland rebid capacity from low to high prices. The effect on prices is detailed in the "Detailed market analysis of significant price events" section below.

Figure 3: Queensland generation and bidding patterns

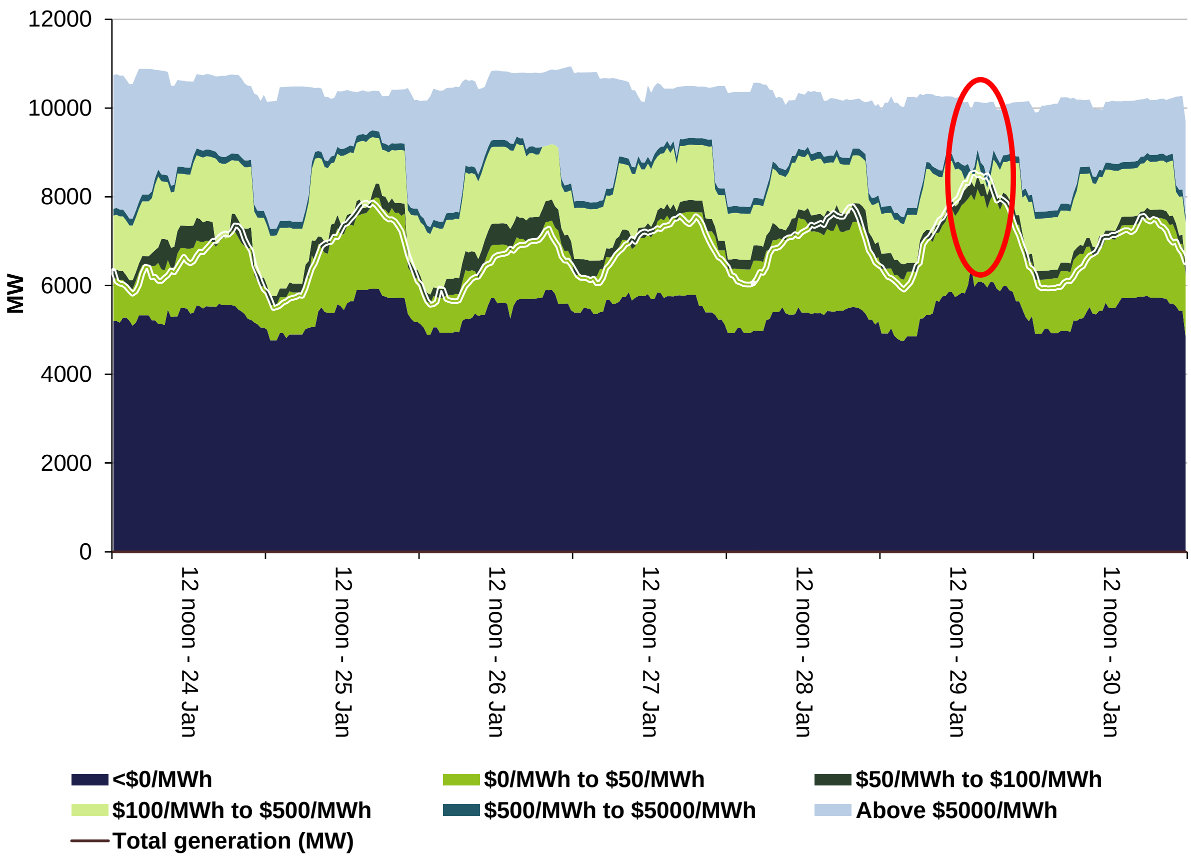


Figure 4: New South Wales generation and bidding patterns

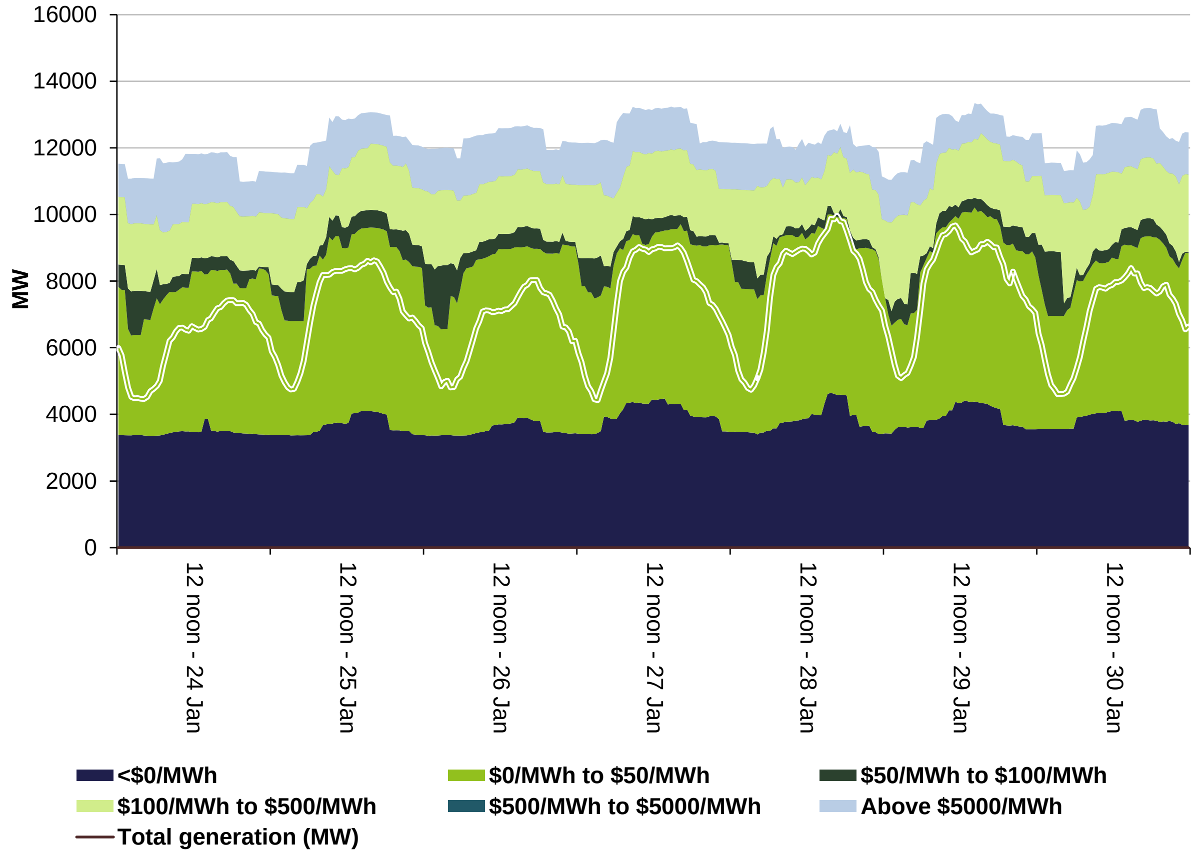


Figure 5: Victoria generation and bidding patterns

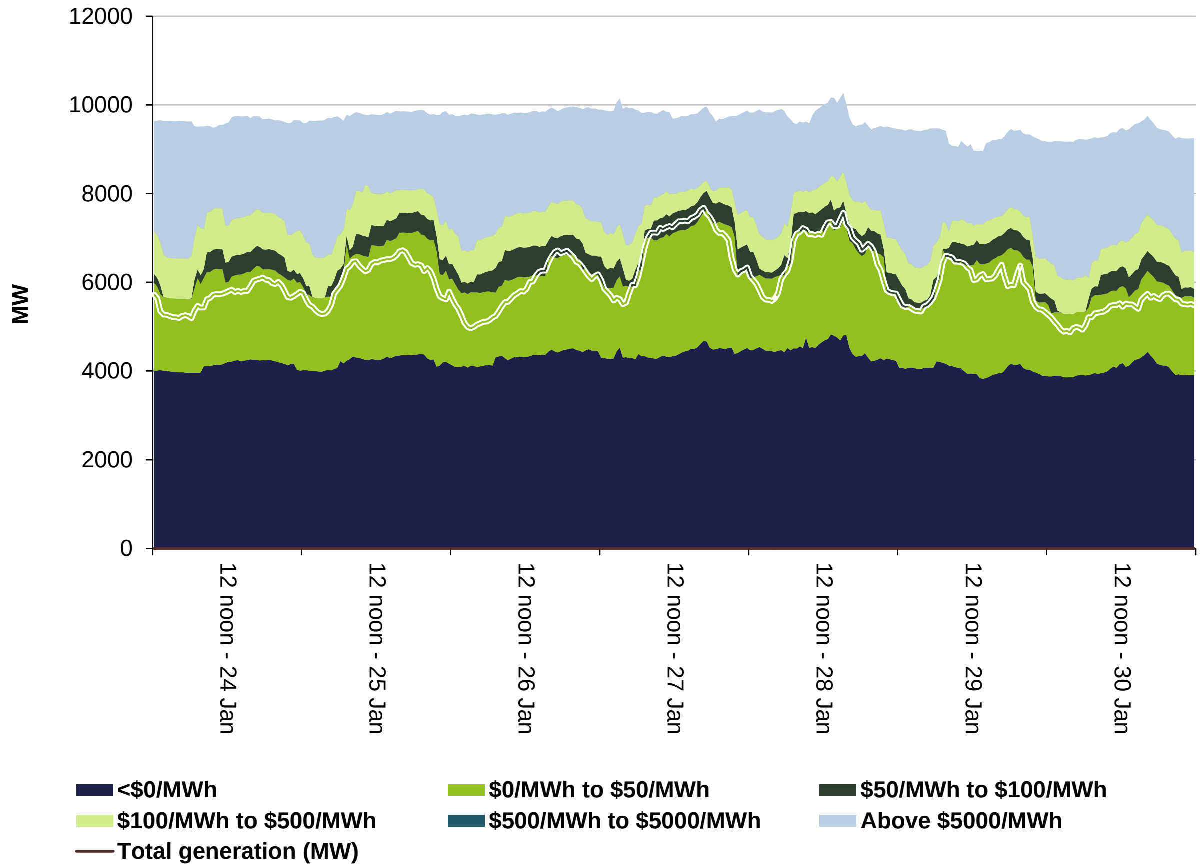


Figure 6: South Australia generation and bidding patterns

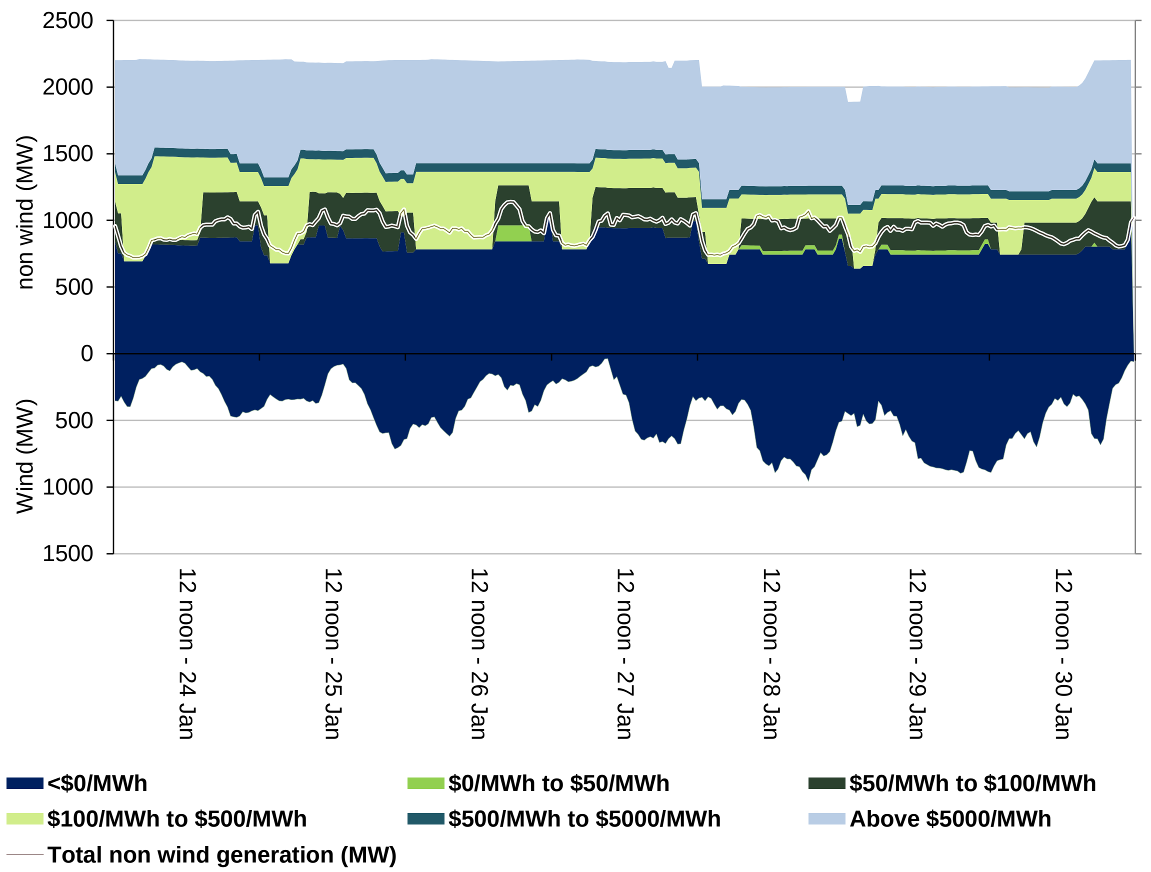
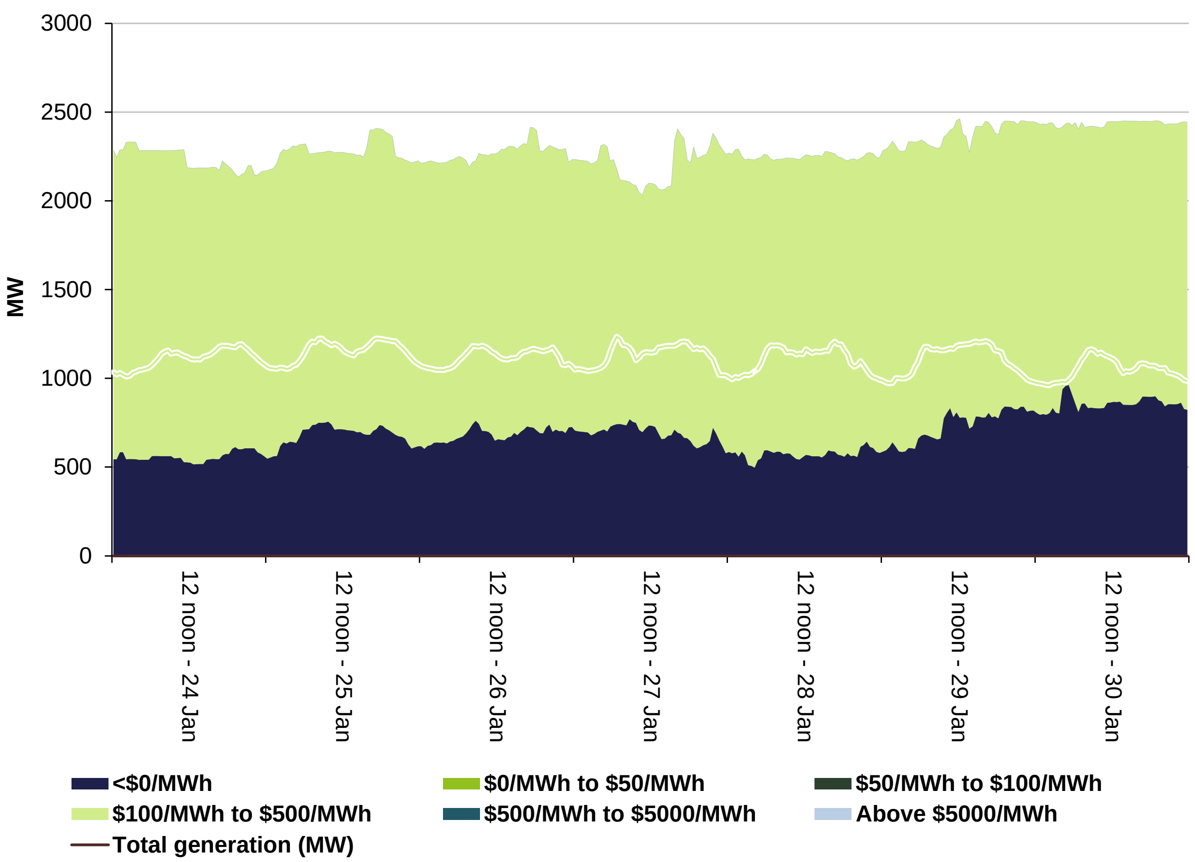


Figure 7: Tasmania generation and bidding patterns



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.

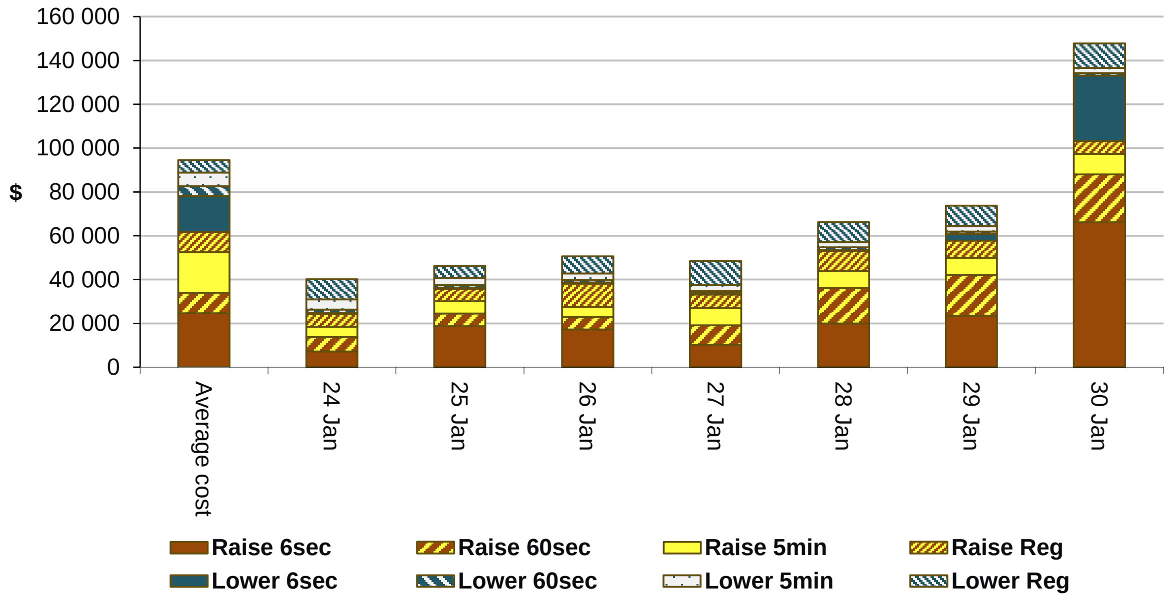
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $246 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $226 500 or just over 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



On Saturday 30 January at 6 am in Tasmania, a system normal constraint managing the raise 6 second ancillary service requirement violated. The constraint sets the requirement for the service in the event of a loss of one of the Smithton to Woolnorth or Norwood to Scotsdale to Derby 100 kV lines. The constraint was violated following the service requirement increasing from zero to 107.5 MW for that dispatch interval. This resulted in the price for the service increasing to $4476/MW at 6 am. The requirement decreased in the following dispatch interval, then increased to just below 100 MW setting higher prices as the service was co-optimised with energy and other services. This set prices of $305/MW and $508/MW at 6.10 am and 6.15 am respectively, before falling to $1/MW by 6.20 am.

On the same day, prices for the lower 6 second service in the region increased to levels between $62/MW to $84/MW over 15 dispatch intervals. This, combined with requirements above 165 MW across the day, led to the increased cost in Tasmania for the service.

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 were three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $66/MWh and above $250/MWh.

Friday, 29 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	264.50	49.00	46.87	8151	8010	7770	10 239	10 267	10 346
1.30 pm	2126.06	59.65	59.65	8642	8013	8015	10 109	10 258	10 343
2.30 pm	2472.01	99.00	200.10	8660	8213	8220	10 087	10 252	10 327

Conditions at the time saw demand up to 629 MW above the four hour ahead forecast and availability up to 165 MW below the four hour ahead forecast. The maximum demand of 8819 MW on the day was close to record levels in Queensland due to high temperatures.

Table 4: Rebids for the 12.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
12.00 pm	12.10 pm	CS Energy	Gladstone	160	<99	13 800	1159A INTERCONNECTOR CONSTRAINT-SL

The dispatch price increased from $99/MWh at 12.05 pm to $298/MWh at 12.10 pm following a rebid by CS Energy. With lower priced generation fully dispatched, higher priced offers were required to meet demand. Similar conditions prevailed for the remainder of the trading interval causing the dispatch price to remain at $298/MWh.

Table 5: Rebids for the 1.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.07 pm	1.15 pm	CS Energy	Gladstone	320	<300	13 800	1307A INTERCONNECTOR CONSTRAINT-SL
1.07 pm	1.15 pm	Callide Power Trading	Callide C	25	-1000	13 800	1306A CHANGE IN 5MIN PD DEMAND - SL
1.22 pm	1.30 pm	CS Energy	Callide B	30	17	13 800	1322A INTERCONNECTOR CONSTRAINT-SL

The dispatch price increased to from $69/MWh to $390/MWh for the 1.15 pm dispatch interval following a 144 MW increase in demand, and CS Energy and Callide rebidding capacity to the price cap. Dispatch prices stayed at around $300/MWh until 1.30 pm when the dispatch price rose to $11 531/MWh as demand increased by 60 MW and a CS Energy rebid became effective. Lower priced generation was unable to be dispatched due to units being fully dispatched, ramp rate limited or trapped/stranded in FCAS.

Table 6: Rebids for the 2.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.17 pm	2.25 pm	CS Energy	Gladstone	280	<300	13 800	1416A INTERCONNECTOR CONSTRAINT-SL
2.17 pm	2.25 pm	CS Energy	Callide B	30	17	13 800	1417A INTERCONNECTOR CONSTRAINT-SL
2.17 pm	2.25 pm	Millmerran Energy Trader	Millmerran	50	7	13 800	1417A CHANGE IN 5MIN PD DEMAND - SL
2.18 pm	2.25 pm	Callide Power Trading	Callide C	105	-1000	13 800	1417A 79 MW CHANGE IN 5MIN PD DEMAND FOR DI 14:30 RUNS 1410/1415
2.21 pm	2.30 pm	ERM Power	Oakey	20	>390	-1000	1420A RESPONSE TO UNFORECAST MARKET VOLATILITY
2.21 pm	2.30 pm	Arrow Energy	Braemar 2	135	>45	-1000	1420A QLD PRICE HIGHER THAN FORECAST SL

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.22 pm	2.30 pm	Callide Power Trading	Callide C	138	13 800	-1000	1421F RRP ABOVE PD AT 14:25 1421A RRP ABOVE PD AT 14:25

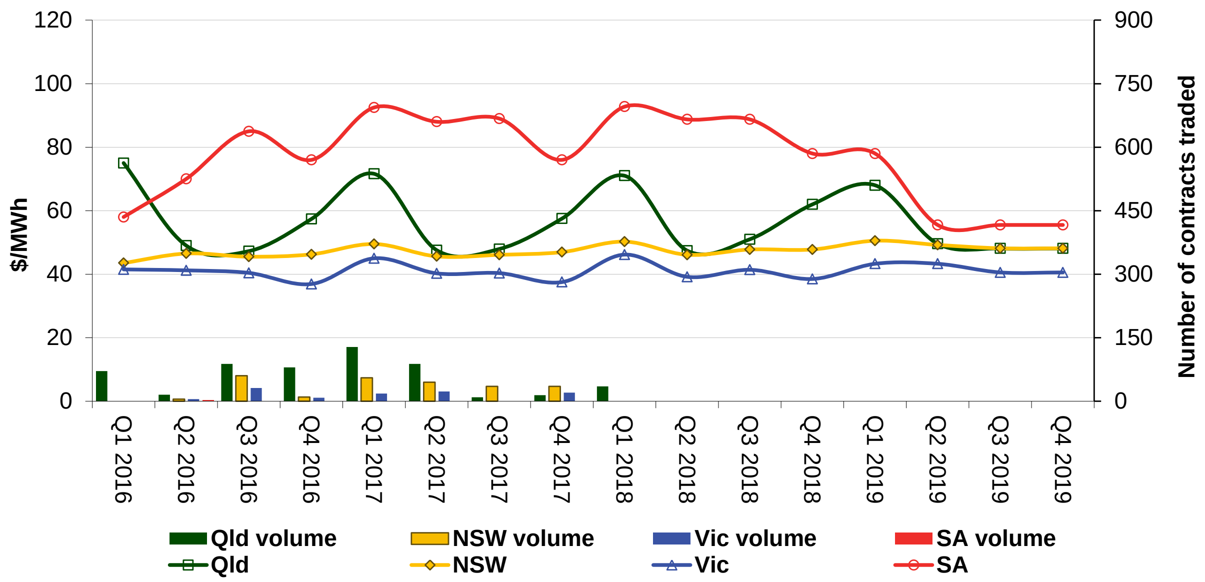
The dispatch price increased from $99/MWh to $298/MWh for the 2.10 pm dispatch interval following a 128 MW increase in demand. The price remained around that level for three dispatch intervals as demand increased, before finally reaching the price cap at 2.25 pm when the above rebids shifting capacity from low to high prices became effective.

At 2.30 pm, the dispatch price fell to $38/MWh following a drop in demand and capacity being rebid into low prices.

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.

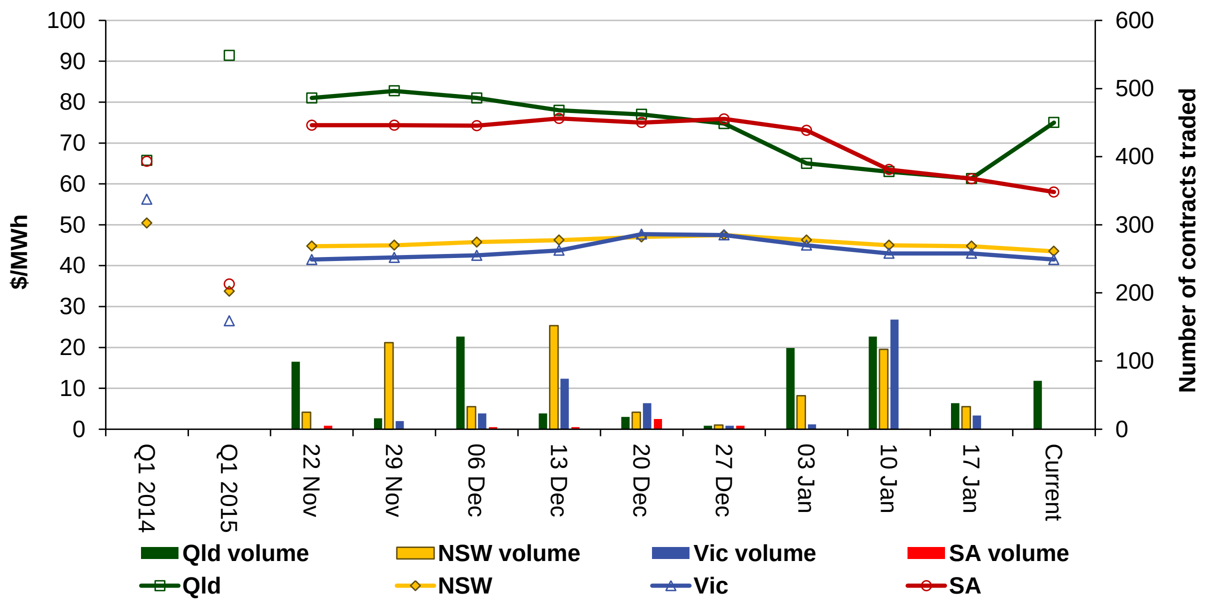
Figure 9: Quarterly base future prices Q1 2016 – Q4 2019



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. Queensland Q1 contract prices increased when the other regions decreased. This was driven by the volatility in Queensland as a result of high demand and late rebidding.

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



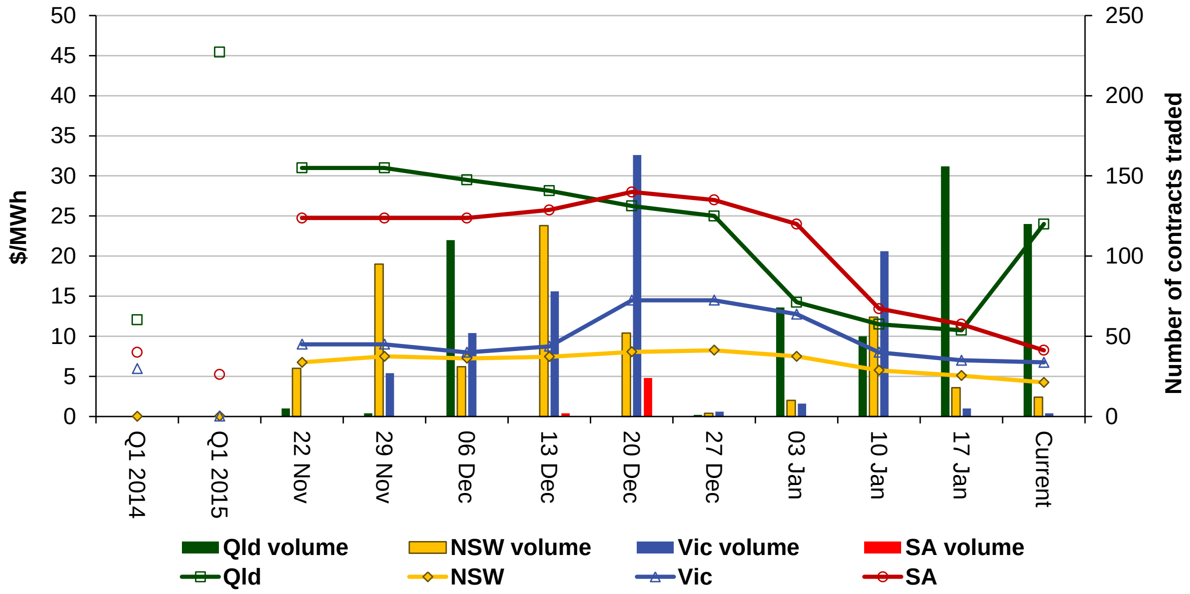
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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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