

20 – 26 December 2015

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 20 to 26 December 2015. There were six occasions, five in South Australia and one in Tasmania, where the spot price exceeded the AER reporting threshold.

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

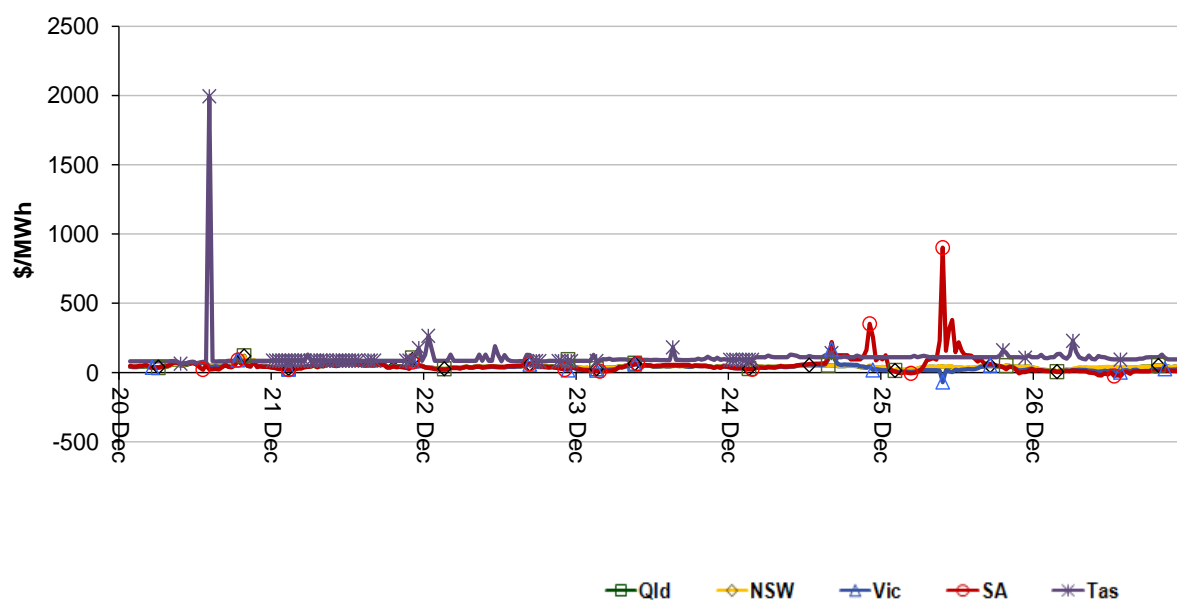


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

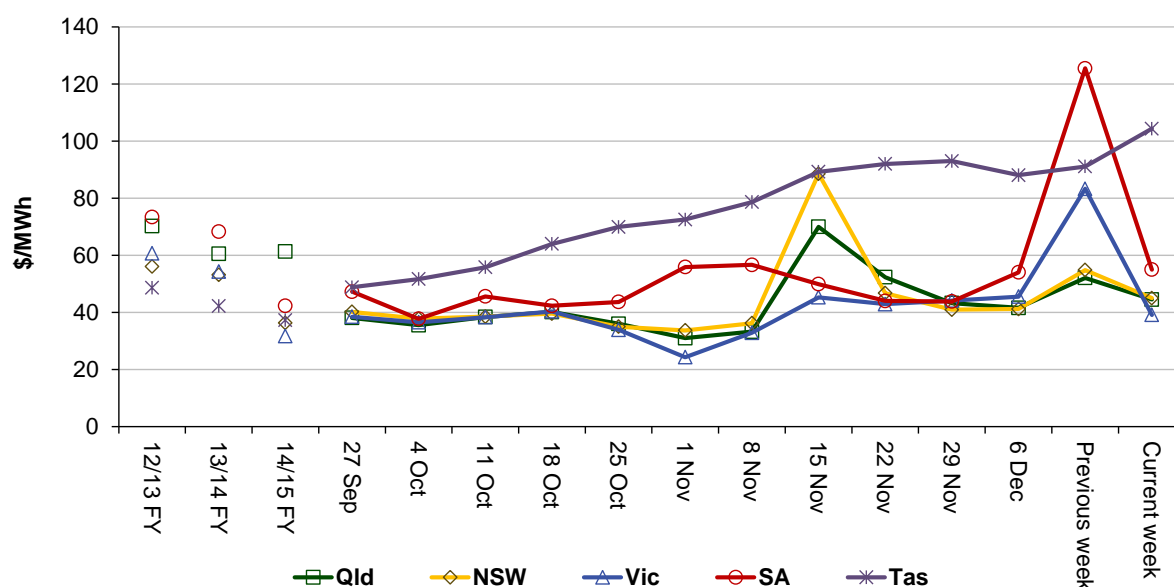


Table 1: Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	45	45	39	55	104
14-15 financial YTD	51	37	33	41	38
15-16 financial YTD	44	46	41	63	56

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 263 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2014 of 71 counts and the average in 2013 of 97. 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	9	47	0	2
% of total below forecast	35	5	0	2

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

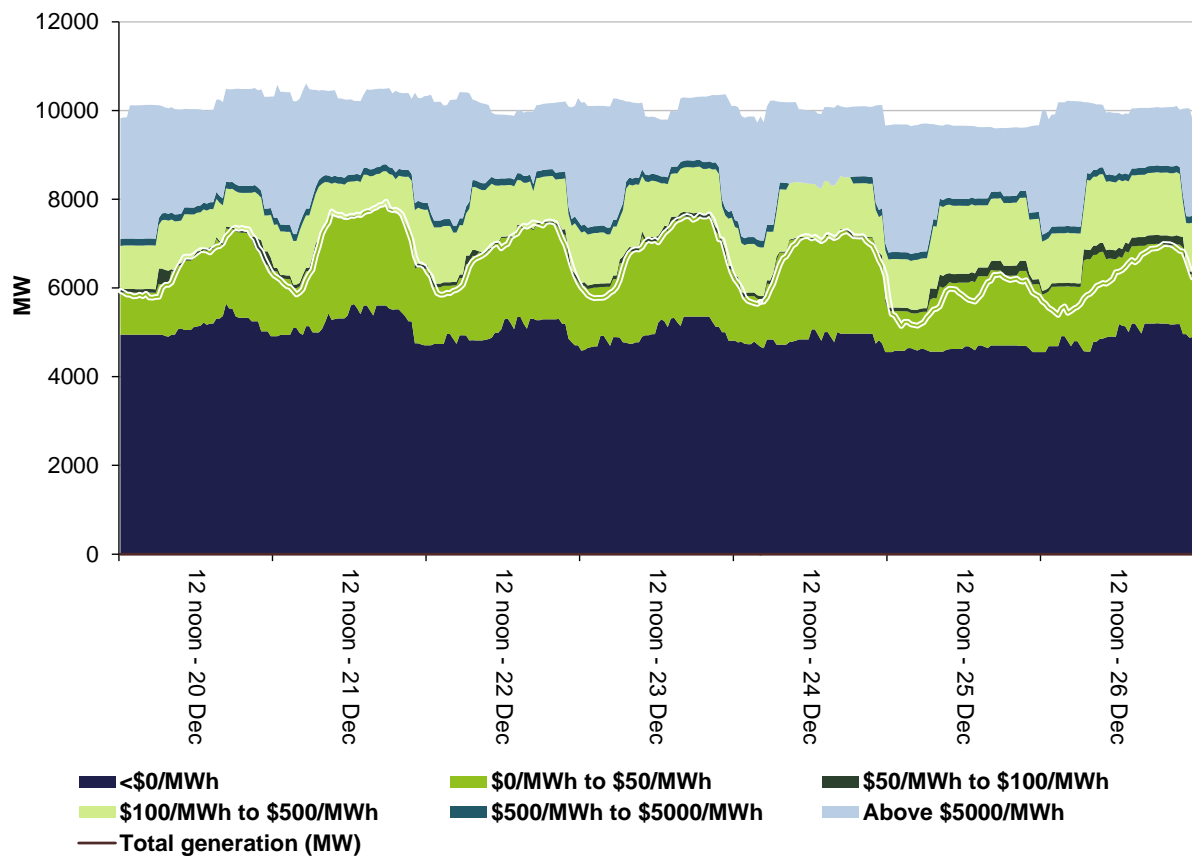


Figure 4: New South Wales generation and bidding patterns

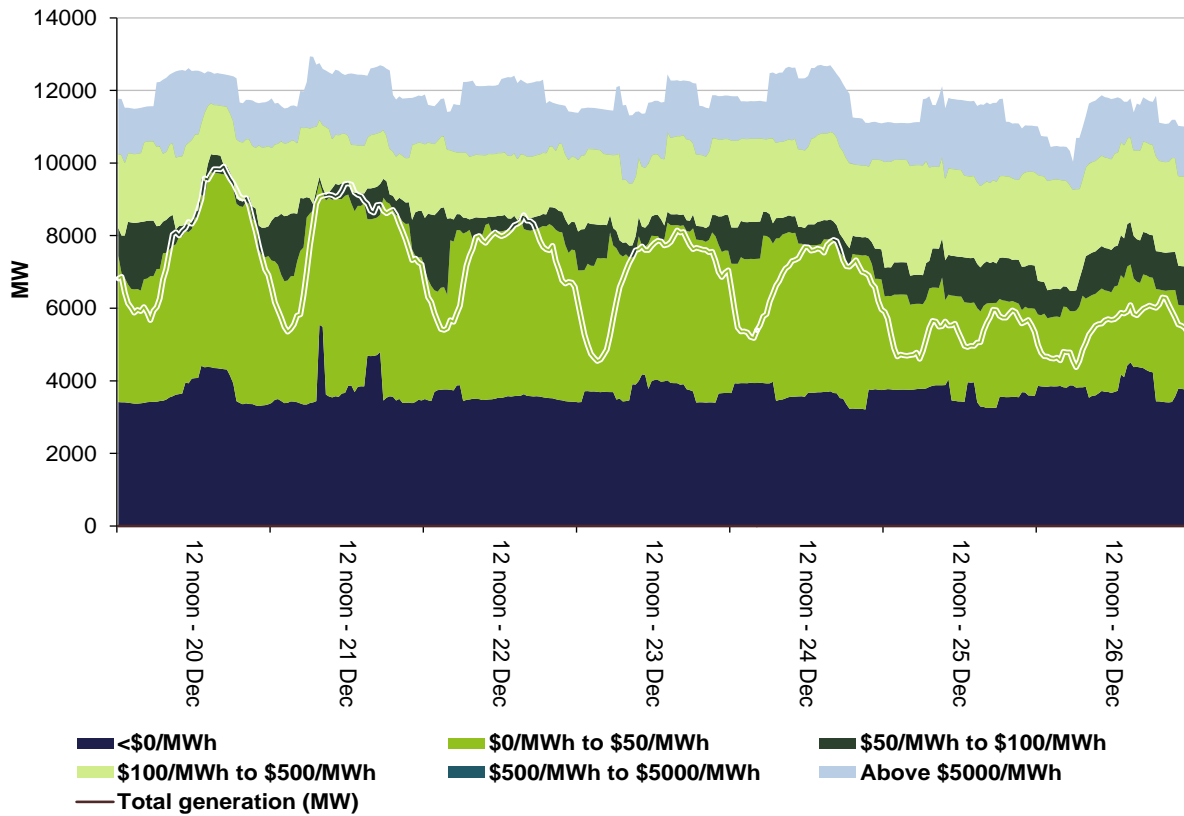
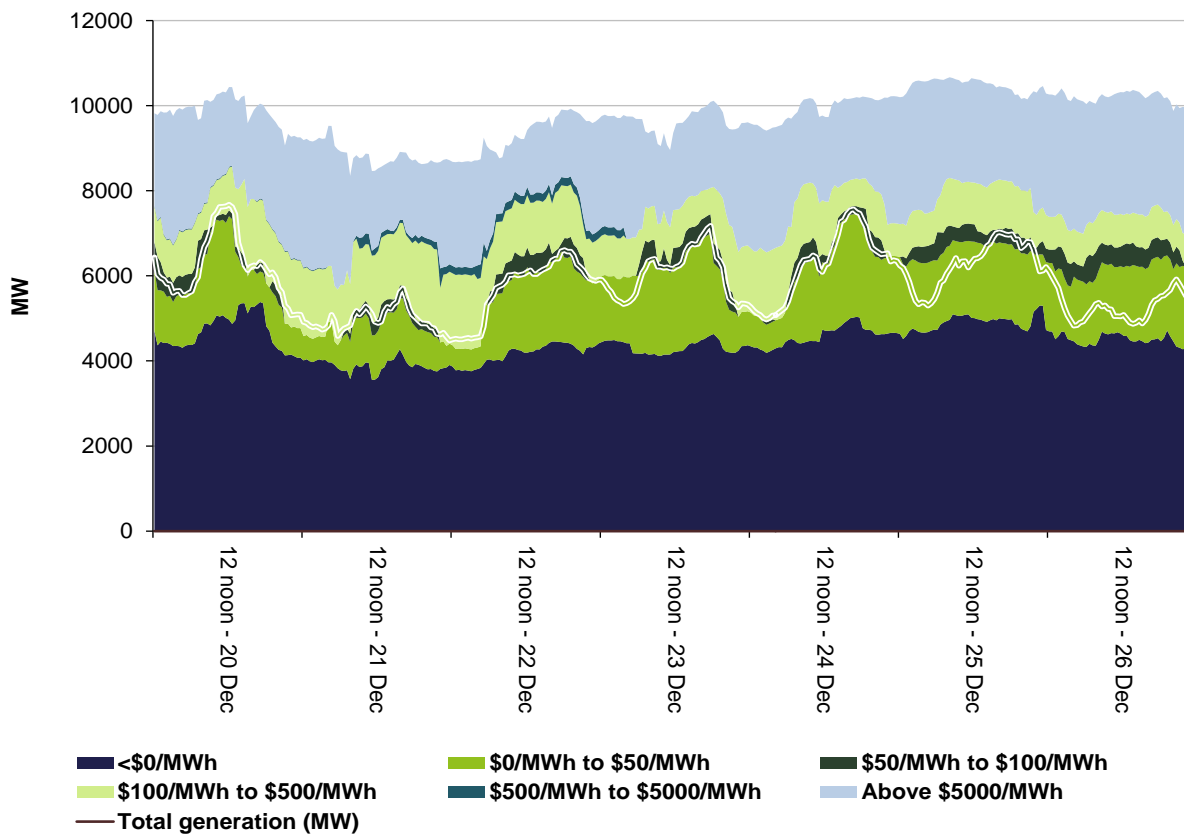
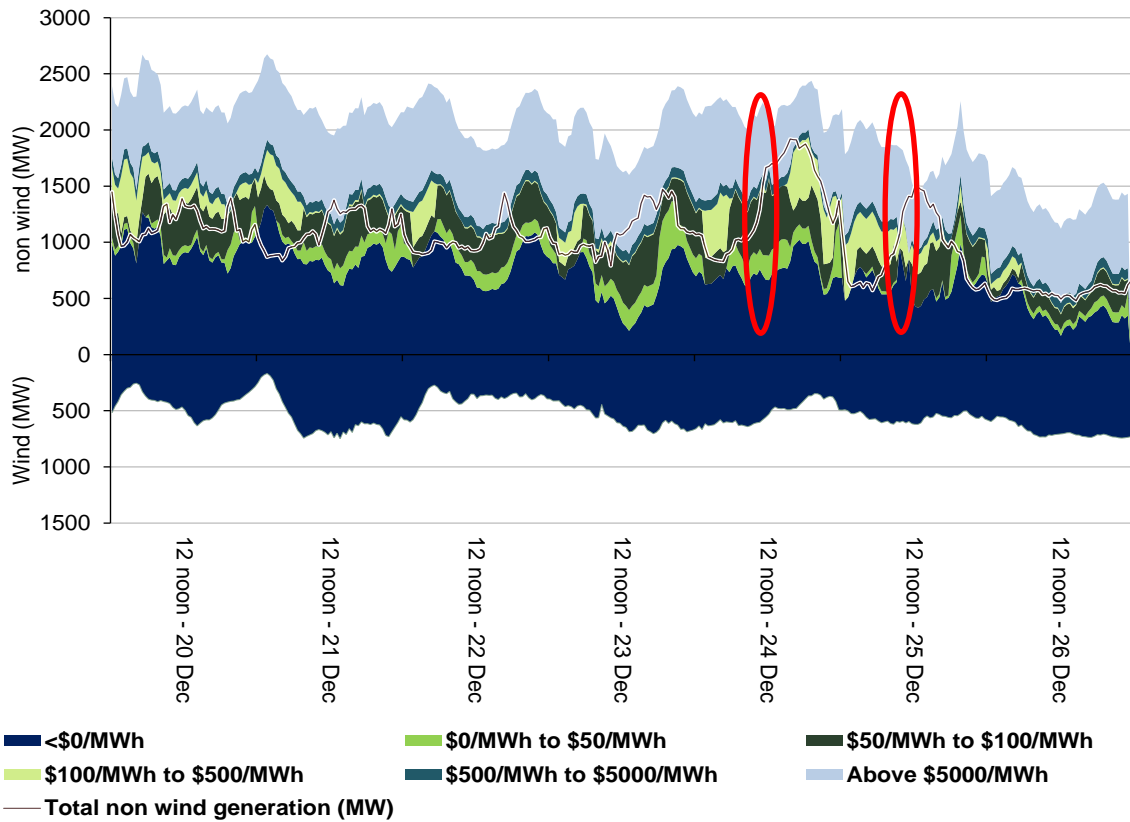


Figure 5: Victoria generation and bidding patterns



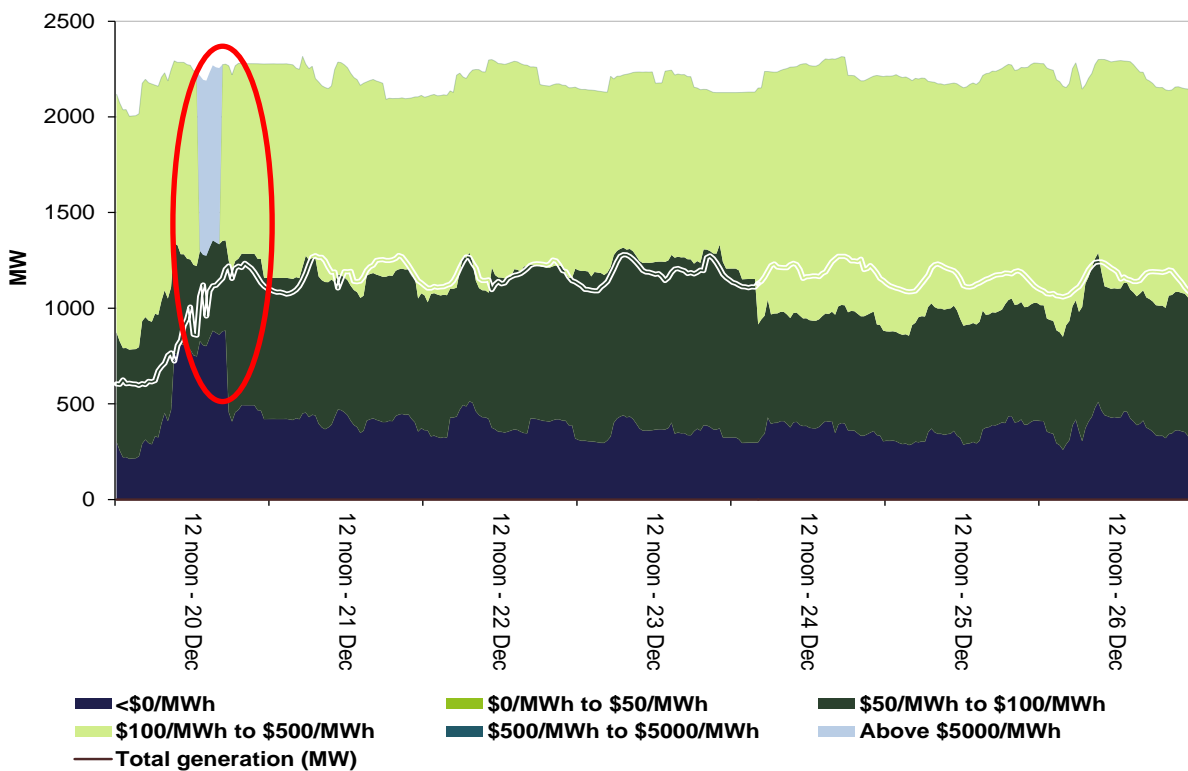
The red ellipses on Figure 6, following, highlight periods where high prices occurred in South Australia. Demand on these days was high and, as can be seen from the figure, there was limited capacity available between low prices and prices greater than \$5000/MWh.

Figure 6: South Australia generation and bidding patterns



The red ellipses on Figure 7, following, highlight the period where the high price occurred in Tasmania. As can be seen from the figure, there was limited capacity available between low prices and prices greater than \$5000/MWh.

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.

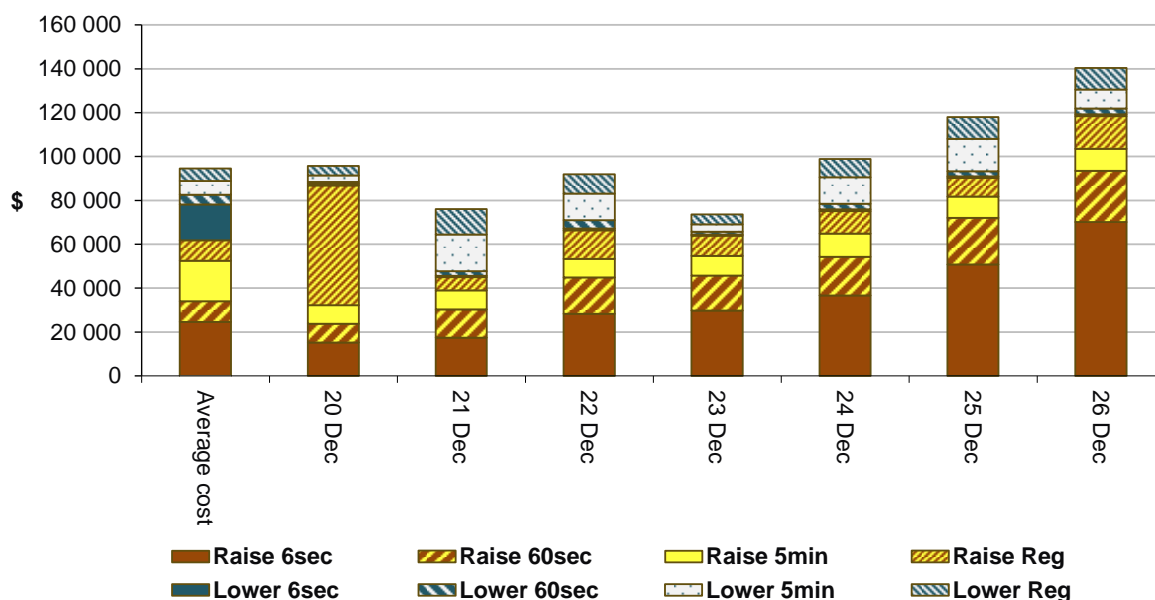
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$452 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$242 000 or around 1.5 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 the 20 December, the price of raise regulation services in Tasmania reached \$11 711/MW at 2.25 pm. An analysis of this event is included in the detailed market analysis of significant price events section below.

On the 26 December, the price of raise six second services in Tasmania reached \$1363/MW at 6.25 pm. This was a result of increased local raise six second service requirements

associated with managing a generation event in Tasmania where Basslink is unable to transfer FCAS.

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.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of \$104/MWh and above \$250/MWh.

Sunday, 20 December

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
2:30 pm	1993.58	84.77	81.03	894	1019	1028	2189	2286	2287

Conditions at the time saw demand 125 MW less than forecast four hours ahead and available capacity less than 97 MW less than forecast four hours ahead.

At around 2.25 pm, a fault occurred on the Basslink interconnector, separating Tasmania from the National Electricity Market. At the same time, demand increased by 132 MW. The loss of Basslink meant that all of Tasmania's energy and FCAS requirements had to be sourced locally. With cheaper generation either rate ramp limited or stranded, higher priced generation had to be dispatched to meet demand and FCAS requirements. Consequently the dispatch price increased from \$40/MWh at 2.20 pm to \$11 707/MWh and at 2.25 pm the raise regulation service price increased from \$2/MW at 2.20 pm to \$11 711/MW. All other FCAS prices remained low.

The energy and raise regulation services fell in the following dispatch interval as local generators were no longer ramp rate limited or stranded.

The AER understands that this fault may make Basslink unavailable for around 60 days.

South Australia

There were five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$55/MWh and above \$250/MWh.

Thursday, 24 December

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
10.30 pm	350.99	44.07	37.05	1891	1877	1855	2405	2758	2842
11 pm	255.66	42.09	35.82	1746	1811	1808	2504	2751	2829

Conditions at the time saw demand close to forecast four hours head and available capacity up to 353 MW less than forecast four hours ahead.

Table 5: Rebids for 10.30 pm and 11 pm trading intervals

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
9.04 pm		AGL Energy	Torrens Island	120	95	351	2031~p~080 chg in pipeline cond~801 change in imbal pos seagas
9.06 pm		AGL Energy	Torrens Island	40	95	>351	2101~p~050 chg in unit operation~min load required for unit shutdown
9.06 pm		Origin Energy	Ladbroke Grove	40	65	13 800	2105a avoid uneconomic start sl
9.08 pm		Origin Energy	Ladbroke Grove	40	65	13 800	2105a ensure stop sl
9.52 pm		AGL Energy	Torrens Island	240	125	351	2131~f~080 chg in pipeline cond~82 change in imbal pos seagas - conserve gas
10.19 pm	10.30 pm	AGL Energy	Torrens Island	80	65	351	2201~p~080 chg in pipeline cond~801 change in imbal pos seagas - conserve gas

Northern Power Station unit 2 suffered a tube leak and started reducing its output from 8 pm and was off line after 9.40 pm. As a result of rebidding and the reduction in available generation the dispatch interval price from 10.05 pm to 10.45 pm was set by Torrens Island at around \$350/MWh. At 10.50 pm demand decreased by around 107 MW (in part due to an increase in non-scheduled generation) and the dispatch fell to \$65/MWh.

Friday, 25 December

Table 6: Price, Demand and Availability for 10 am

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 am	901.11	22.08	14.87	1524	1431	1438	2445	2536	2535

Conditions at the time saw demand 92 MW more than forecast four hours ahead and available capacity 91 MW less than forecast.

At 9.27 am, effective from 9.35 am, AGL Energy rebid 300 MW of available capacity at Torrens Island from under \$125/MW to the price cap. The reason for the rebid was '0925~a~050 chg in aemo pd~56 price increase \$102 5mpd'.

As a result of the rebidding, the dispatch interval price increased from \$351/MWh at 9.30 am to \$5236/MWh at 9.35 am. In the following dispatch interval a 139 MW decrease in demand (mostly due to an increase in non-scheduled generation) and rebids for 80 MW of capacity priced above \$10 000/MWh to the price floor reduced the price to \$23/MWh.

Table 7: Price, Demand and Availability for 11 am and 11.30 am

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
11 am	317.40	30.17	20.47	1569	1494	1450	2343	2490	2458
11.30 am	379.43	37.09	19.82	1547	1561	1453	2265	2461	2423

Conditions at the time saw demand close to forecast but available capacity up to 196 MW less than forecast four hours ahead (mostly attributed to lower wind generation).

Table 8: Rebids for 11 am and 11.30 am trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
8.15 am		AGL Energy	Torrens Island	300	>55	>95	0956a sa act price \$21.89 < \$403.81 30 mpd hhe 10:00
10.08 am		EnergyAustralia	Hallett	30	>361	>12 195	10:07 a adj bands due to sa price>fcst 381.74>124.99
10.11 am		AGL Energy	Torrens Island	120	<95	351	1001~a~050 chg in aemo pd~55 pd price increase 63mw sa
10.18 am		EnergyAustralia	Hallett	10	-1000	12 195	10:18 a adj bands due to mat change in sa wind gen waterloo
10.33 am	10.40 am	EnergyAustralia	Hallett	10	-1000	12 195	10:32 a adj bands mat change sa wind generation waterloo sl
11.05 am	11.15 am	GDF Suez	Dry Creek	26	371	590	1104a constraint management: v>>s_nil_khtb2_khtb1

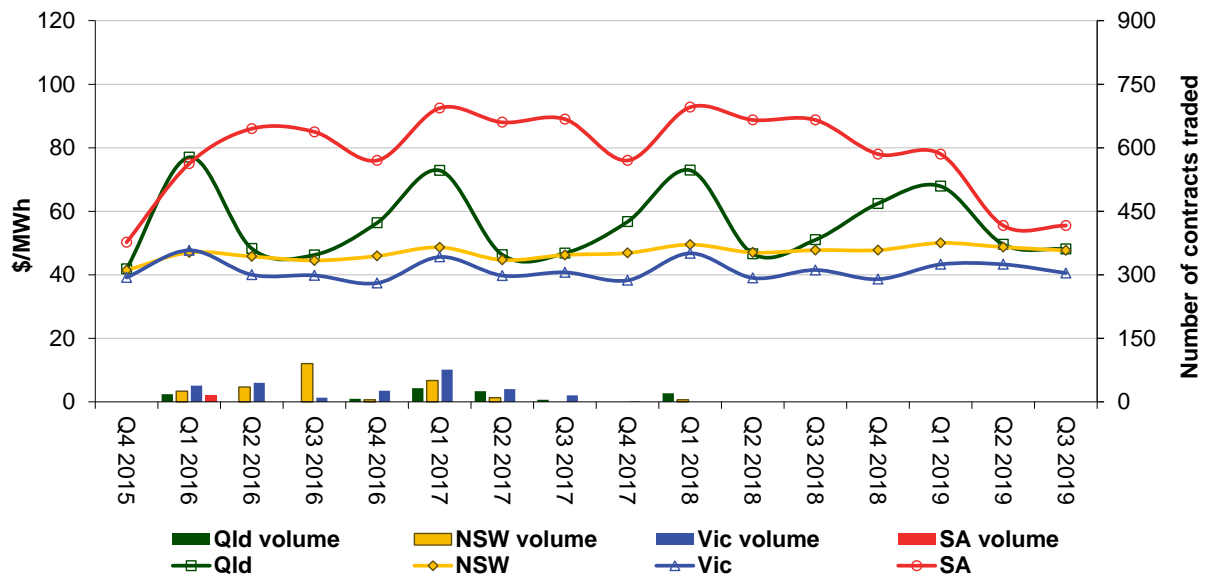
Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
11.09 am	11.20 am	AGL Energy	Torrens Island	240	<125	13 800	1110~a~050 chg in aemo pd~56 price increase \$725 sa

As a result of the above rebidding, the dispatch price stayed at around \$350/MWh for a majority of the two trading intervals.

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.

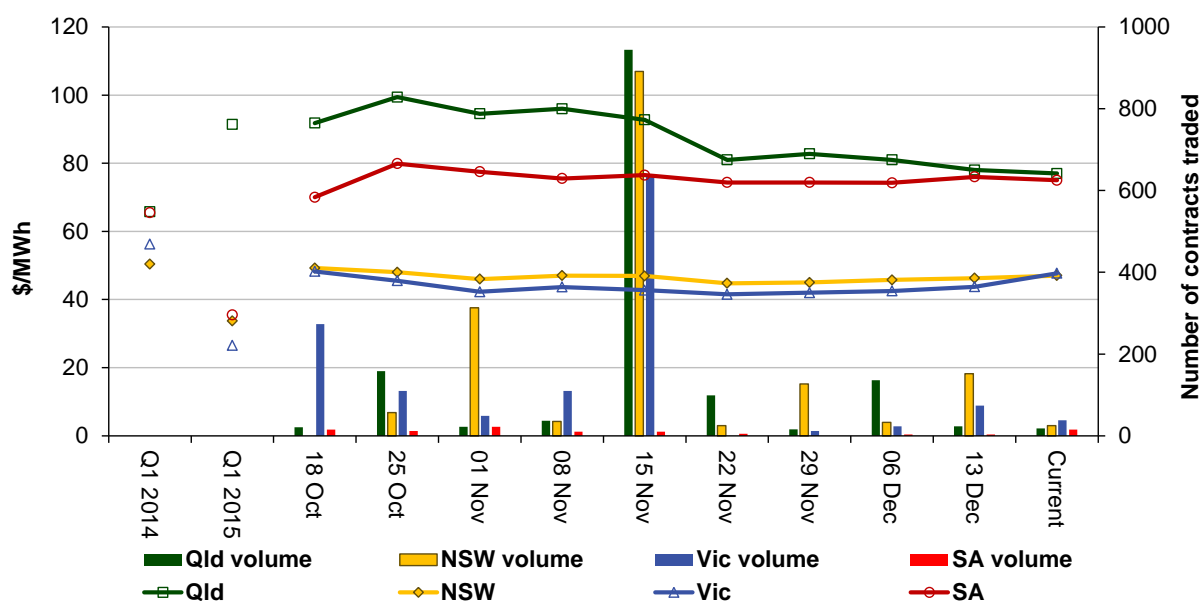
Figure 9: Quarterly base future prices Q4 2015 – Q3 2019



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)



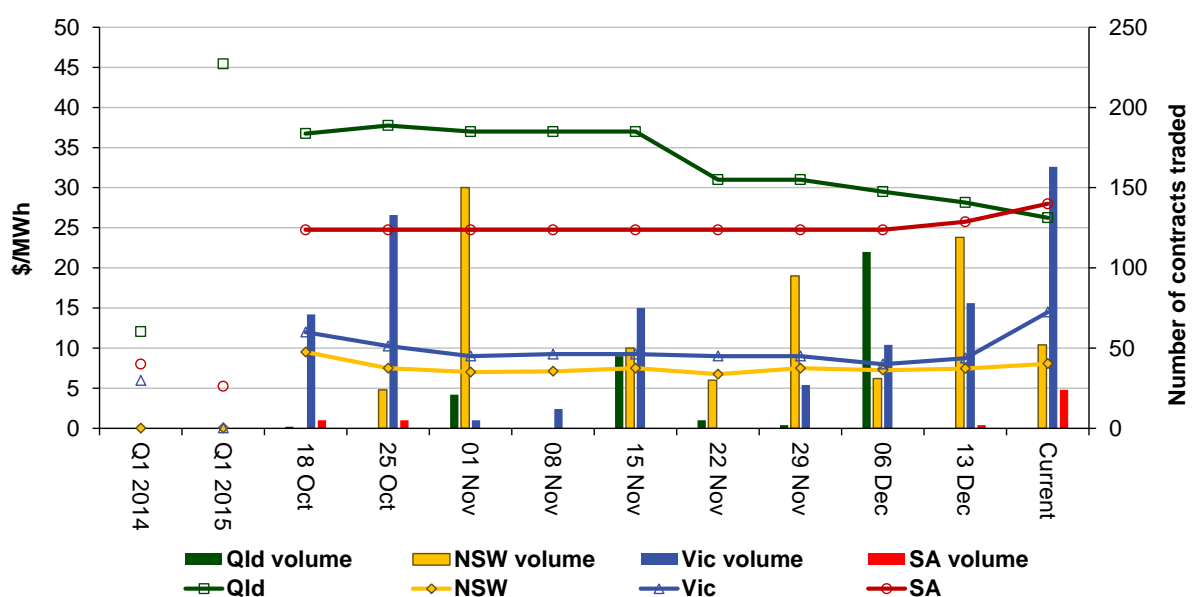
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

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

