Electricity Report

28 December 2014 - 3 January 2015

AUSTRALIAN ENERGY REGULATOR

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 28 December 2014 to 3 January 2015.

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

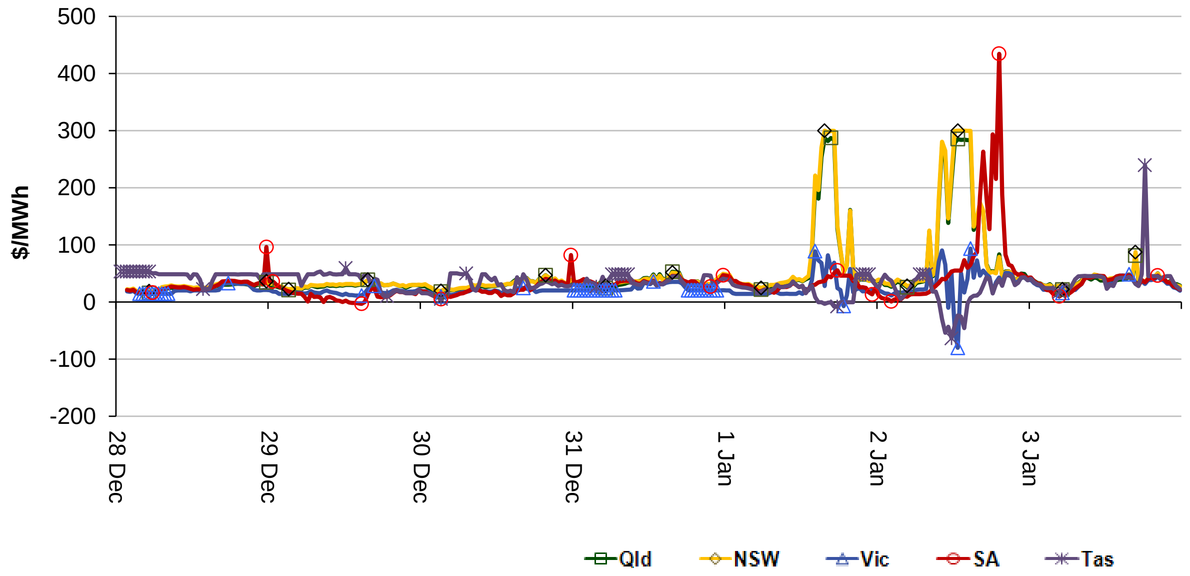


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years. The increases in spot prices across most states in the NEM reflected higher demand levels and relative supply scarcity with some strategic rebidding. While this did not result in prices at the market price cap there were extended periods of prices greater than $150/MWh. These are discussed in more detail in the later sections of this report.

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

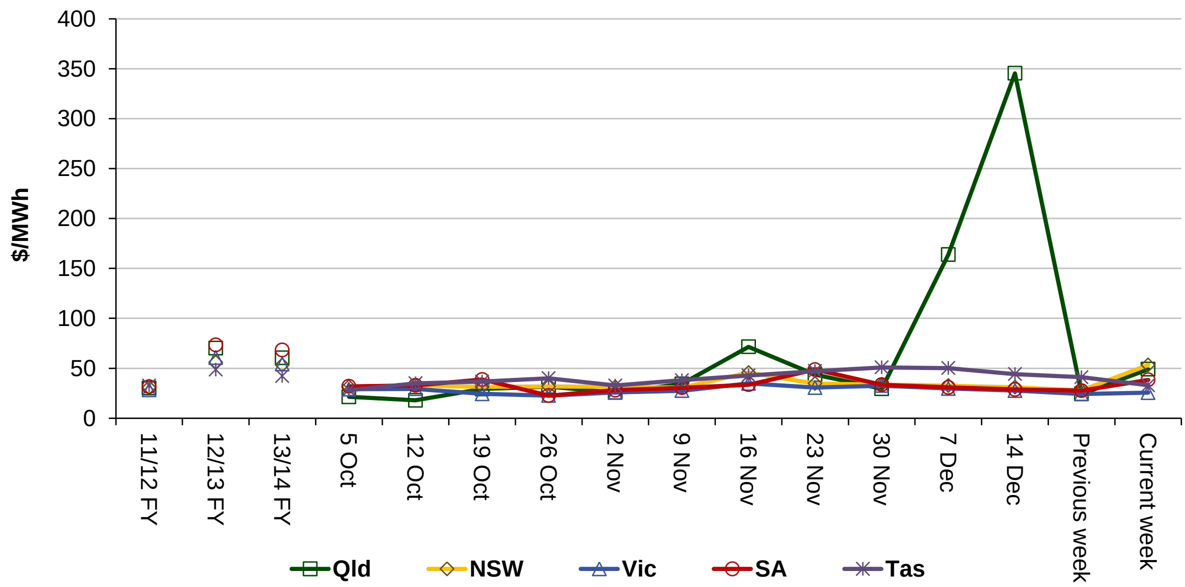


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	49	53	26	38	33
13-14 financial YTD	60	55	53	70	44
14-15 financial YTD	51	37	33	41	38

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 257 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2013 of 97 counts and the average in 2012 of 60. 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	29	0	2
% of total below forecast	56	9	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. Figures 3 to 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 ellipses highlight the rebidding that resulted in the high spot prices. A detailed analysis of the events relating to these periods is in the “Detailed market analysis of significant price events” below.

The red ellipse on Figure 1 for Queensland highlights periods on the 1 and 2 January 2015 where there was only a small amount of capacity available between $50/MWh and $5000/MWh.

The red ellipse on Figure 7 for Tasmania on 3 January 2015 shows that a rebids shifted capacity from low priced bands to higher price but this did not result in a price greater than $250/MWh.

Figure 3: Queensland generation and bidding patterns

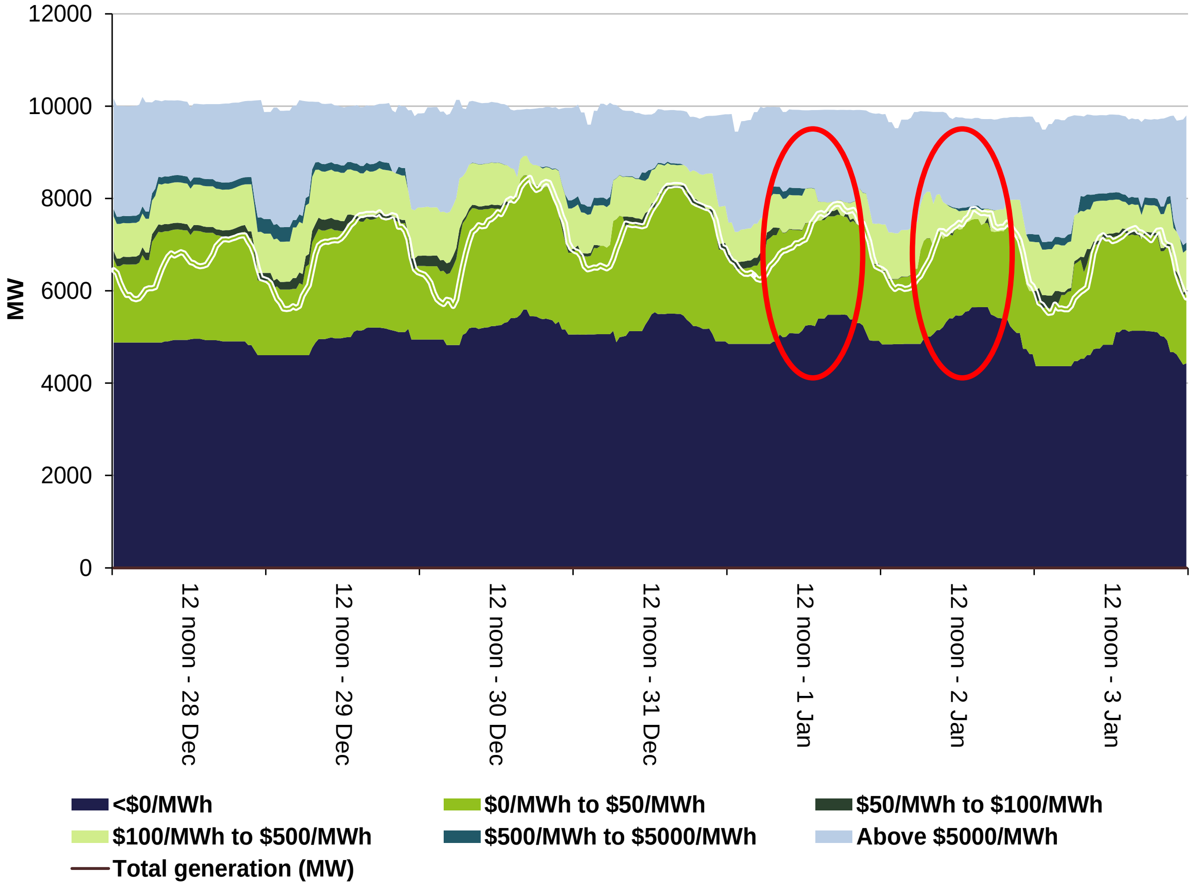


Figure 4: New South Wales generation and bidding patterns

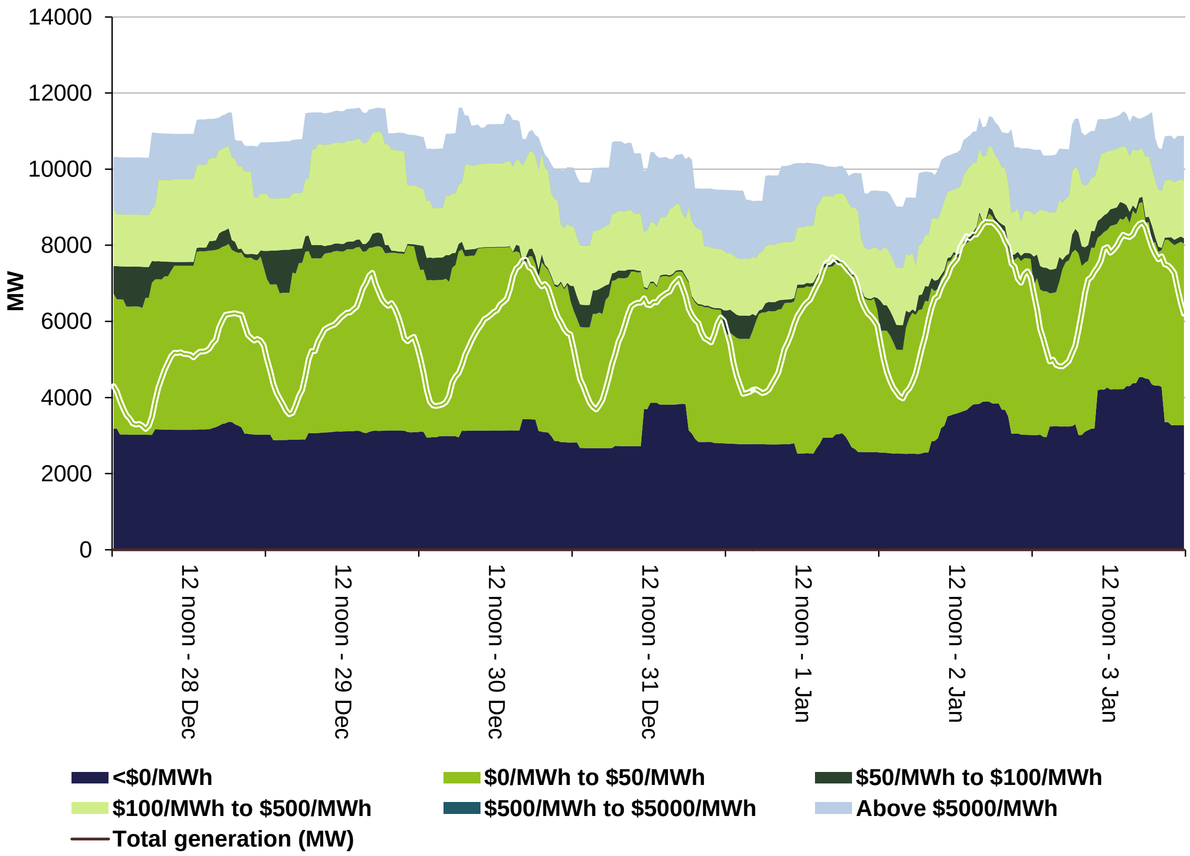


Figure 5: Victoria generation and bidding patterns

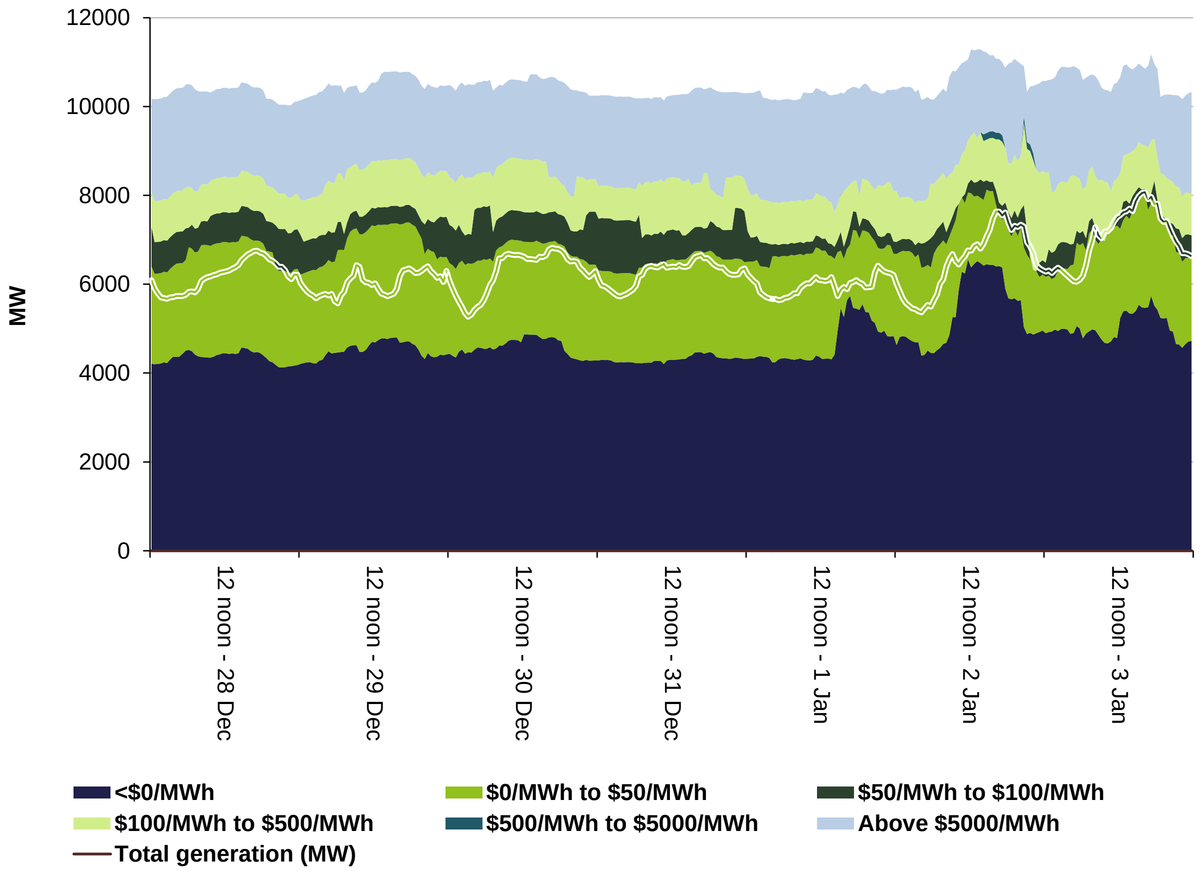


Figure 6: South Australia generation and bidding patterns

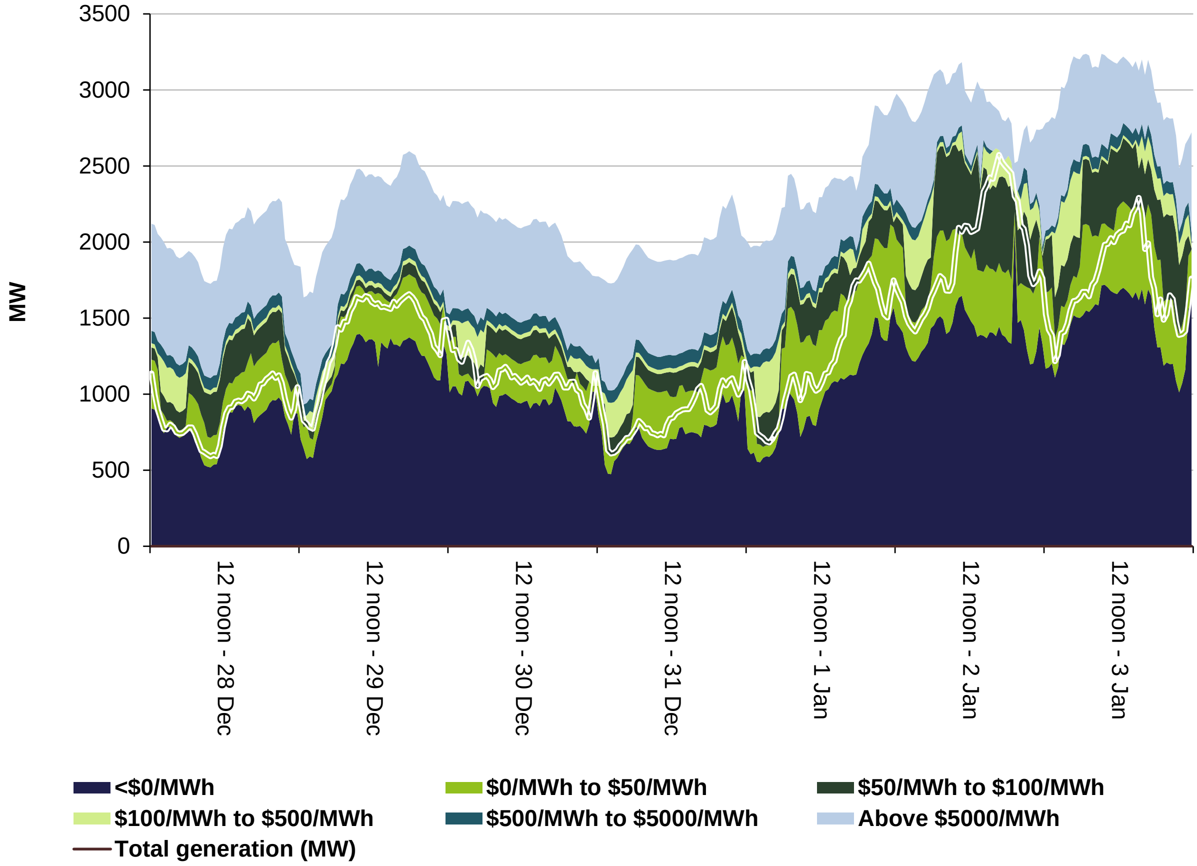
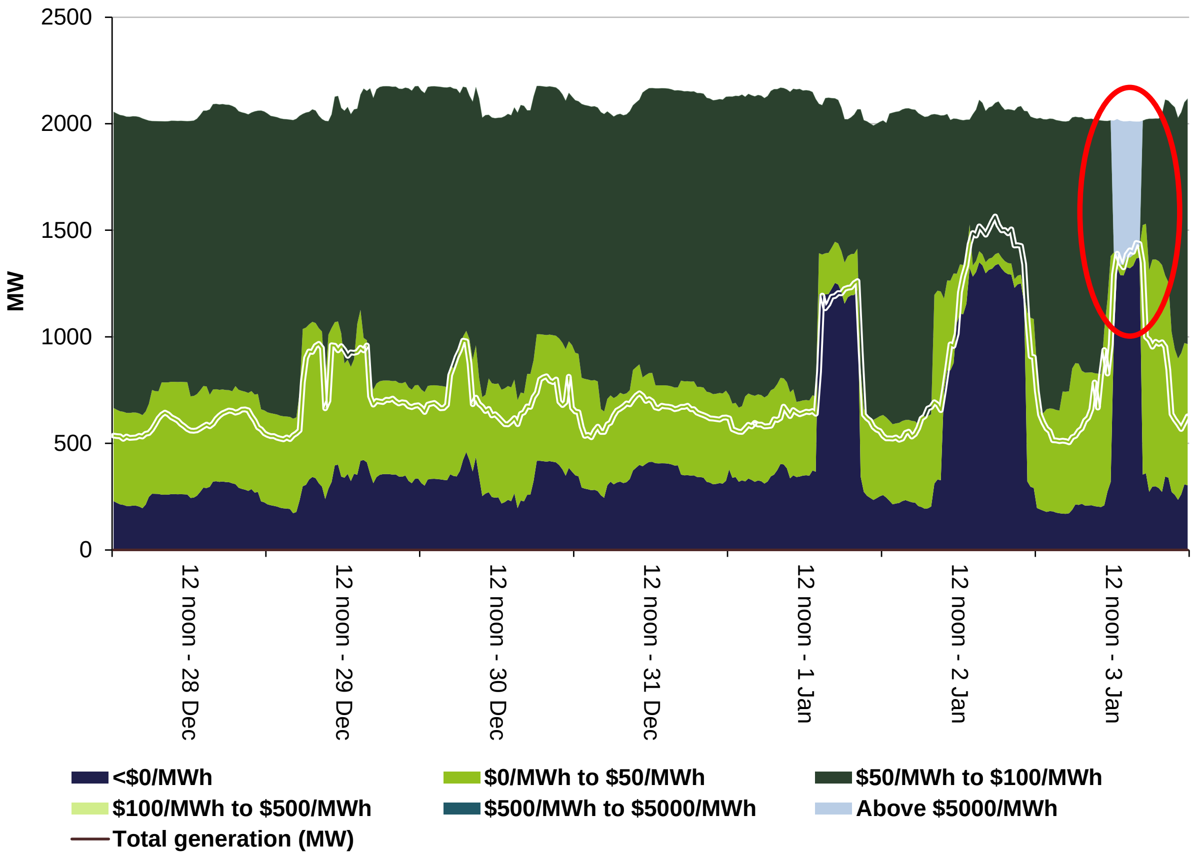


Figure 7: Tasmania generation and bidding patterns



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.

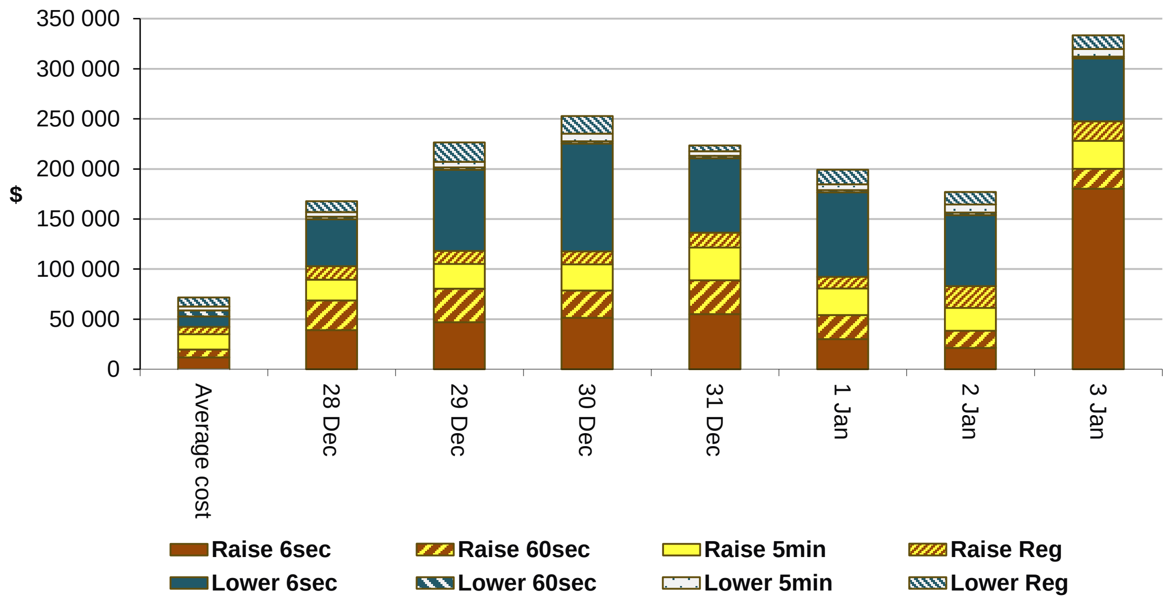
The total cost of FCAS on the mainland for the week was $706 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $873 000 or around 17 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. During the week a system normal constraint managing the requirement for lower 6 second service for the loss of two Comalco potlines was binding and Basslink was unable to transfer FCAS. This meant that all Tasmanian FCAS services had to be sourced locally. The requirement for lower 6 second services was around 230 MW and at prices approaching $50/MW. Over the week the cost of lower 6 second services was around $526 000.

At 5.50 pm, AEMO reclassified, along with a range of other lines, the loss of the Farrell to Sheffield No.1 and 2 220kV lines as a credible contingency due to lightning. Constraints were invoked to manage the requirement for raise 6 second services and violated at 6.10 pm to 6.30 pm. The price of raise 6 second services exceeded $1600/MW during this period at a cost of around $156 000.

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. There were 13 occasions in Queensland and New South Wales where prices aligned and they were separated from the rest of the market and there were three occasions in South Australia which breached the reporting threshold.

Queensland and New South Wales

Thursday, 1 January

For each trading interval between 3.30 pm and 5.30 pm, spot prices in Queensland and New South Wales were around $250—299/MWh. During the period, Queensland and New South Wales were separated from the other regions of the NEM, due to a binding constraint on the Vic-NSW interconnector for the entire period.

Queensland

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	252.94	62.02	35.50	6921	6811	6488	9919	9915	9941
4:00 PM	286.36	289.97	35.50	7074	6858	6564	9921	9915	9941
4:30 PM	281.80	61.74	39.90	7135	6910	6649	9920	9914	9940
5:00 PM	287.03	62.25	48.22	7203	6980	6717	9920	9914	9940
5:30 PM	284.10	46.36	51.66	7199	6784	6780	9918	9914	9948

New South Wales

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	270.47	64.14	36.36	9054	8366	7804	9934	9912	9881
4:00 PM	299.67	299.80	36.50	9168	8488	7905	9904	9908	9878
4:30 PM	296.95	64.31	41.96	9199	8596	7965	9933	9917	9891
5:00 PM	299.60	63.80	49.90	9324	8701	8091	9934	9924	9890
5:30 PM	299.60	49.90	53.00	9253	8661	8088	9935	9929	9882

Demand was particularly high on the day in New South Wales and Queensland and up to around 700 MW and 400 MW respectively higher than forecast fours ahead. Queensland demand was at its highest level since New Year’s Day 2009 and in New South Wales, since New Year’s Day 2011. Available capacity in both Queensland and New South Wales was close to forecast.

There was also little capacity priced between around $70/MWh and $250/MWh in both regions. These tight demand supply conditions meant that small changes in demand, rebidding or available capacity led to higher than forecast prices except for the 4 pm trading interval.

The significant rebids of 1 January are set out below, and are divided between Queensland and New South Wales.

Queensland

CS Energy rebidding at Gladstone to the price cap

TI Effective	Rebid submitted	Capacity shifted (MW)	Reason
3.30 pm	2.01 pm	60	1400A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	2.52 pm	210	1452A REVIEWED SENSITIVITIES-SL
4 pm	2.01 pm	60	1400A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	3.23 pm	210	1523A DISPATCH PRICE LOWER THAN 5MIN FORECAST-SL
4.30 pm	2.01 pm	60	1400A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	3.52 pm	210	1552A REVIEWED SENSITIVITIES-SL
5 pm	2.01 pm	60	1400A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	4.15 pm	210	1615A CHANGE IN QLD GENERATION - OAKEY-SL
5.30 pm	2.01 pm	60	1400A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	4.15 pm	210	1615A CHANGE IN QLD GENERATION - OAKEY-SL

New South Wales
Snowy Hydro rebidding at Upper Tumut to around $280/MWh

TI Effective	Rebid submitted	Capacity shifted (MW)	Reason
3.30 pm	11.51 pm	205	11:01 A NSW: 30MPD PRICE $7.94 LWR THN 30MPD 12:30@10:31-SL
4 pm	11.51 pm	235	11:01 A NSW: 30MPD PRICE $7.94 LWR THN 30MPD 12:30@10:31-SL
	3.49 pm	150	15:50 A UPPTUMUT: ACT DUID DISP 152 HGR THN 30MPD 15:50@15:32
4.30 pm	11.51 pm	245	11:01 A NSW: 30MPD PRICE $7.94 LWR THN 30MPD 12:30@10:31-SL
	3.49 pm	150	15:50 A UPPTUMUT: ACT DUID DISP 152 HGR THN 30MPD 15:50@15:32
5 pm	11.51 pm	245	11:01 A NSW: 30MPD PRICE $7.94 LWR THN 30MPD 12:30@10:31-SL
	3.49 pm	150	15:50 A UPPTUMUT: ACT DUID DISP 152 HGR THN 30MPD 15:50@15:32
5.30 pm	11.51 pm	245	11:01 A NSW: 30MPD PRICE $7.94 LWR THN 30MPD 12:30@10:31-SL
	3.49 pm	150	15:50 A UPPTUMUT: ACT DUID DISP 152 HGR THN 30MPD 15:50@15:32

Upper Tumut set the price for the majority of the time between 3.05 pm and 5.30 pm at around $280/MWh.

Friday, 2 January

Queensland and New South Wales were separated from the rest of the NEM during the high priced trading intervals for the same reasons as the day before (explained above). Supply and demand factors were also similar, although demand in each region did not reach the same record highs as the day before.

Queensland

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 AM	271.25	41.70	38.53	6660	6452	6350	9848	9838	10 036
11:00 AM	253.42	39.82	37.49	6667	6525	6434	9804	9858	10 014
12:30 PM	278.65	41.80	40.49	6687	6665	6633	9774	9913	9989
1:00 PM	285.06	35.50	42.13	6771	6719	6695	9753	9913	9989
1:30 PM	283.55	37.49	42.83	6857	6752	6771	9741	9873	9989

2:00 PM	283.99	39.25	42.85	6899	6833	6821	9725	9873	9949
2:30 PM	283.24	39.25	43.56	7038	6891	6902	9730	9878	9949
3:00 PM	283.79	42.23	51.07	7088	6955	6951	9745	9836	9949

New South Wales

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 AM	280.25	43.29	41.96	8511	8241	8225	10 098	9984	10 110
11:00 AM	264.50	41.96	40.16	8662	8277	8264	10 153	10 186	10 284
12:30 PM	299.63	41.96	41.96	9002	8333	8397	10 228	10 534	10 531
1:00 PM	299.80	34.96	43.29	9117	8339	8428	10 265	10 563	10 536
1:30 PM	299.77	39.12	43.29	9260	8608	8465	10 553	10 406	10 531
2:00 PM	299.73	40.92	43.29	9337	8649	8517	10 611	10 540	10 534
2:30 PM	299.60	39.32	43.29	9284	8626	8487	10 671	10 532	10 543
3:00 PM	299.63	41.96	49.93	9283	8834	8536	10 745	10 653	10 552

Conditions at the time saw demand up to around 780 MW higher than forecast fours ahead in New South Wales and close to forecast in Queensland. Demand was not as high as the day. Available capacity was close to that forecast in both regions.

Queensland
CS Energy rebidding at Gladstone to the price cap

TI Effective	Rebid submitted	Capacity shifted (MW)	Reason
10.30 am	8.09 am	40	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	9.52 am	190	0952A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
11 am	8.09 am	40	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	10.17 am	190	1016A CHANGE IN QLD GENERATION - BRAEMAR-SL
12.30 am	8.09 am	60	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	10.17 am	190	1016A CHANGE IN QLD GENERATION - BRAEMAR-SL
	11.52 am	20	1151A CHANGE IN QLD GENERATION - OAKEY-SL
1 am	8.09 am	40	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	10.17 am	190	1016A CHANGE IN QLD GENERATION - BRAEMAR-SL
	11.52 am	20	1151A CHANGE IN QLD GENERATION - OAKEY-SL
1.30 am	8.09 am	60	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	12.31 pm	210	1231A REVIEWED SENSITIVITIES-SL
2 pm	8.09 am	60	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	12.31 pm	210	1231A REVIEWED SENSITIVITIES-SL
2.30 pm	8.09 am	60	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	12.31 pm	210	1231A REVIEWED SENSITIVITIES-SL
3 pm	8.09 am	60	0809A DISPATCH PRICE HIGHER THAN 5MIN FORECAST-SL
	12.31 pm	210	1231A REVIEWED SENSITIVITIES-SL

There were also small reductions (30 MW to 60 MW) in low priced capacity at Condamine, Millmerran and Callide due to technical reason which had a minor effect on forecast prices.

New South Wales

Snowy Hydro rebidding at Upper Tumut or Tumut 3 to around $280/MWh

TI Effective	Rebid submitted	Capacity shifted (MW)	Reason
10.30 am	9.48 am	500	09:50 A NSW: ACT PRICE $36.92 HGR THN 5MPD 09:50@09:41
11 am	9.48 am	500	09:50 A NSW: ACT PRICE $36.92 HGR THN 5MPD 09:50@09:41
12.30 pm	9.48 am	250	09:50 A NSW: ACT PRICE $36.92 HGR THN 5MPD 09:50@09:41
1 pm	9.48 am	250	09:50 A NSW: ACT PRICE $36.92 HGR THN 5MPD 09:50@09:41
1.30 pm	12.48 pm	320	12:01 A VIC: 30MPD PRICE $117.69 LWR THN 30MPD 13:00@11:31
2 pm	12.48 pm	320	12:01 A VIC: 30MPD PRICE $117.69 LWR THN 30MPD 13:00@11:31
2.30 pm	1.17 pm	320	13:02 A NSW: 30MPD PRICE $257.64 HGR THN 30MPD 14:00@12:32
3 pm	1.17 pm	320	13:02 A NSW: 30MPD PRICE $257.64 HGR THN 30MPD 14:00@12:32

AGL reduced the available capacity of Bayswater unit two throughout the morning by up to 250 MW as it was experiencing slower than expected run up after returning to service. All this capacity was priced below $60/MWh.

Upper Tumut and Tumut 3 set the price for the majority of the time between 10.05 pm and 3 pm at around $280/MWh.

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 $38/MWh and above $250/MWh.

Friday, 2 January

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
5:00 PM	263.00	590.07	64.99	2422	2638	2544	2860	2925	2943
6:30 PM	293.58	215.80	64.98	2512	2643	2605	2822	2808	2874
7:30 PM	434.38	65.09	54.99	2442	2546	2507	2682	2781	2863

For the 5.00 pm and 6.30 pm trading intervals available capacity was close to forecast. Demand was slightly less than forecast 4 and 12 hours before but closer to the 12 hour forecast.

The high prices were primarily the result of tight supply and demand conditions.

5.00 pm

At 3.48 pm AGL rebid 60 MW of available capacity at Torrens B1, B2, B3 and B4 priced at $95/MWh to $351/MWh. The reason given was “1545~A~040 CHG in AEMO disp~44 price decrease VS 30PD SA $161.7”.

6.30 pm

At 5.58 pm, effective from 6.05 pm, AGL rebid 80 MW of available capacity at Torrens B1, B2, B3 and B4 priced at $95/MWh to $351/MWh. The reason given was “1755~A~040 CHG in AEMO DISP~44 price decrease VS 30PD”.

7.30 pm

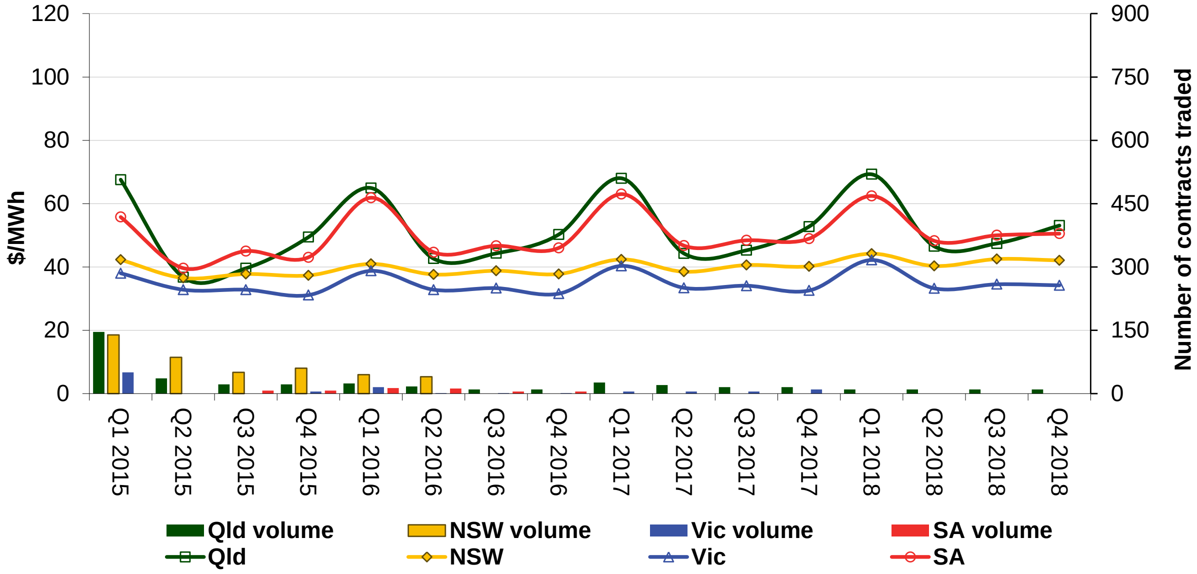
At 7.18 pm, Alinta reduced the available capacity at Northern 2 by 260 MW priced below $54/MWh. The reason given was “1918P unit trip@ 19:18”.

Origin’s Ladbroke generators were backed off for the 7.20 pm dispatch interval due to a network constraint on the Keith—Tailem Bend line. This caused a price spike to $2283.32/MWh before rebidding drove the price back down.

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.

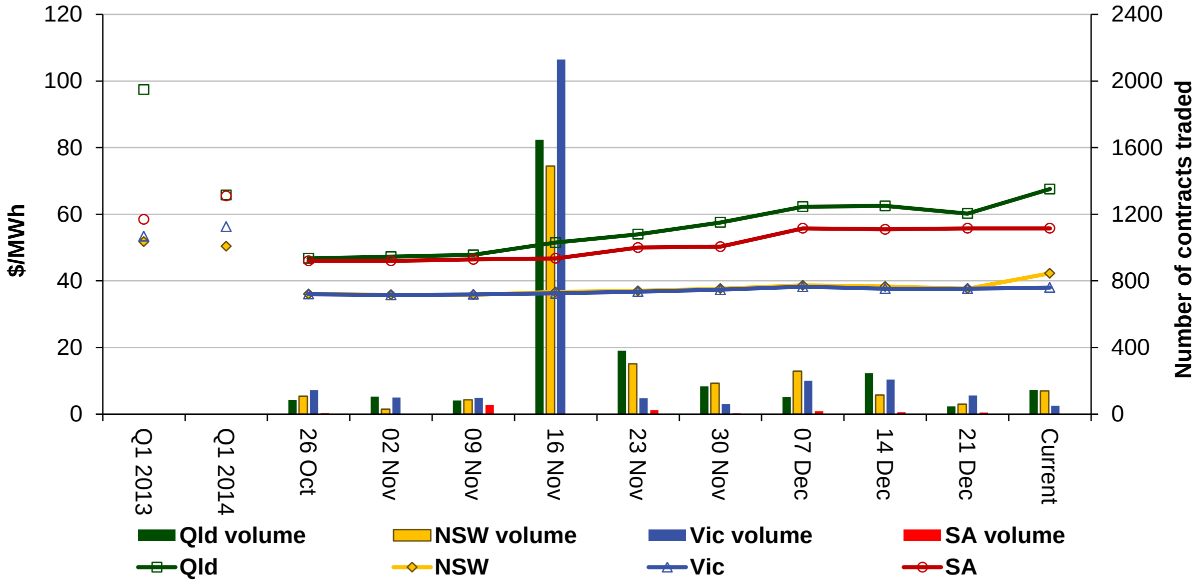
Figure 9: Quarterly base future prices Q1 2015 – Q4 2018



Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2015 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2013 and quarter 1 2014 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 2015 base contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

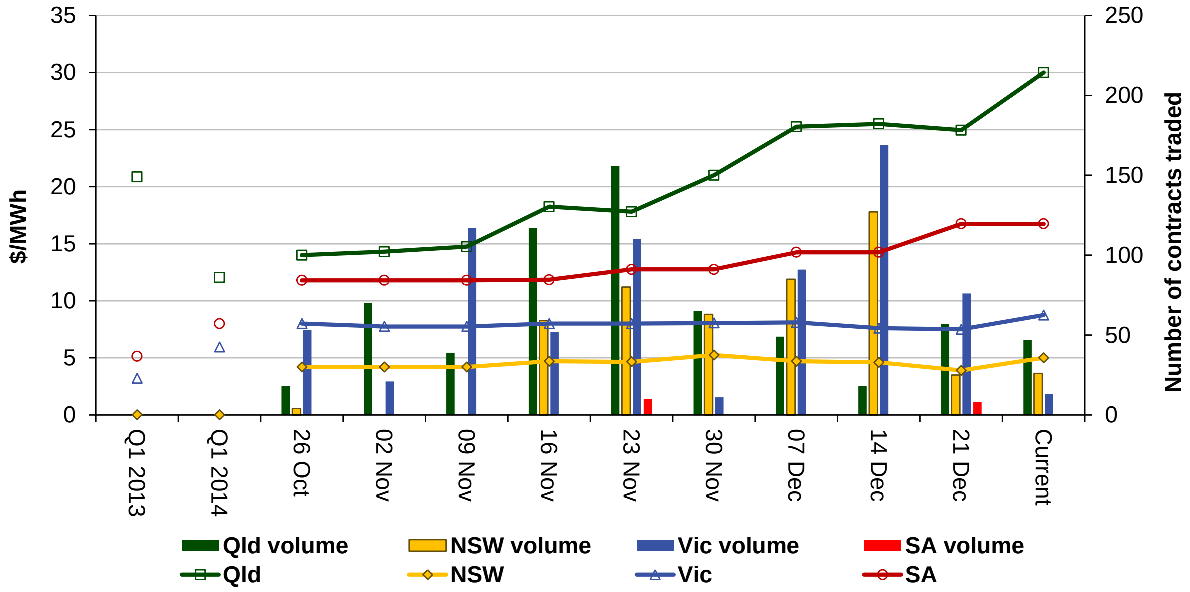
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

The high volume of trades in Figure 10 for the week commencing 16 November 2014 is due to options on calendar year base load contracts expiring on Wednesday 19 November.

Prices of other financial products (including longer-term price trends) are available in the Performance of the Energy Sector section of our website.

Figure 11 shows how the price for each regional Quarter 1 2015 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2013 and quarter 1 2014 prices are also shown. The increase in Queensland price and volatility is reflected in an increase in the price of cap and base contracts for that region. Cap and base contract prices have returned to an increasing trend. Cap contract volumes are slightly lower but those for base have increased.

Figure 11: Price of Q1 2015 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

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