WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

12 – 18 May 2013

Spot market prices

There were seven spot prices of around $2000/MWh in South Australia on Friday 17 May. None of these prices were forecast with some much higher than forecast and some much lower than forecast. There were also long periods of prices close to $200/MWh later in the week, with 28 spot prices at $201/MWh on Saturday 18 May.

Figure 1 sets out the volume weighted average (VWA) prices for 12 May to 18 May 2013 and the 12/13 financial year to date (YTD) across the NEM. It compares these prices with price outcomes from the previous week and year to date respectively.

Figure 1: Volume weighted average spot price by region ($/MWh)

	QLD	NSW	VIC	SA	TAS
Average price for 12 May - 18 May 2013	56	55	54	151	42
% change from previous week*	-1	-2	4	81	-19
12-13 financial YTD	71	56	61	68	49
% change from 11-12 financial YTD**	139	87	121	111	48

*The percentage change between last week's average spot price and the average price for the previous week. Calculated on VWA prices prior to rounding.

**The percentage change between the average spot price for the current financial year and the average spot price for the previous financial year. Percentage changes are calculated on VWA prices prior to rounding.

Further information is provided in Appendix A when the spot price exceeds three times the weekly average and is above $250/MWh or less than -$100/MWh. Longer term market trends are attached in Appendix B.[1]

Financial markets

Figures 2 to 9 show futures contract[2] prices traded on the Australian Securities Exchange (ASX) as at close of trade on Friday 17 May 2013. Figure 2 shows the base futures contract prices for the next three calendar years, and the average over these three years. Also shown are percentage changes[3] from the previous week.

[1] Monitoring the performance of the wholesale market is a key part of the AER's role and an overview of the market's performance in the long term is provided on the AER website. Long-term statistics can be found there on, amongst other things, demand, spot prices, contract prices and frequency control ancillary services prices. To access this information go to www.aer.gov.au -> Australian energy industry -> Performance of the energy sector

[2] Futures contracts traded on the ASX are listed by d-cyphaTrade (www.d-cyphatrade.com.au). A futures contract is typically for one MW of electrical energy per hour based on a fixed load profile. A base load profile is defined as the base load period from midnight to midnight Monday to Sunday over the duration of the contract quarter. A peak load profile is defined as the peak-period from 7 am to 10 pm Monday to Friday (excluding Public holidays) over the duration of the contract quarter.

[3] Calculated on prices prior to rounding.

Figure 2: Base calendar year futures contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Calendar Year 2014	55 (5)	-1%	52 (32)	-2%	48 (5)	-1%	56	-1%
Calendar Year 2015	47	-1%	45	-1%	41	-2%	48	0%
Calendar Year 2016	51	0%	52	0%	50	0%	63	0%
Three year average	51	-1%	50	-1%	46	-1%	55	0%

Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
A number in brackets denotes the number of trades in the product.

Figure 3 shows the $300 cap contract price for Q1 2014 and calendar year 2014 and the percentage change[4] from the previous week.

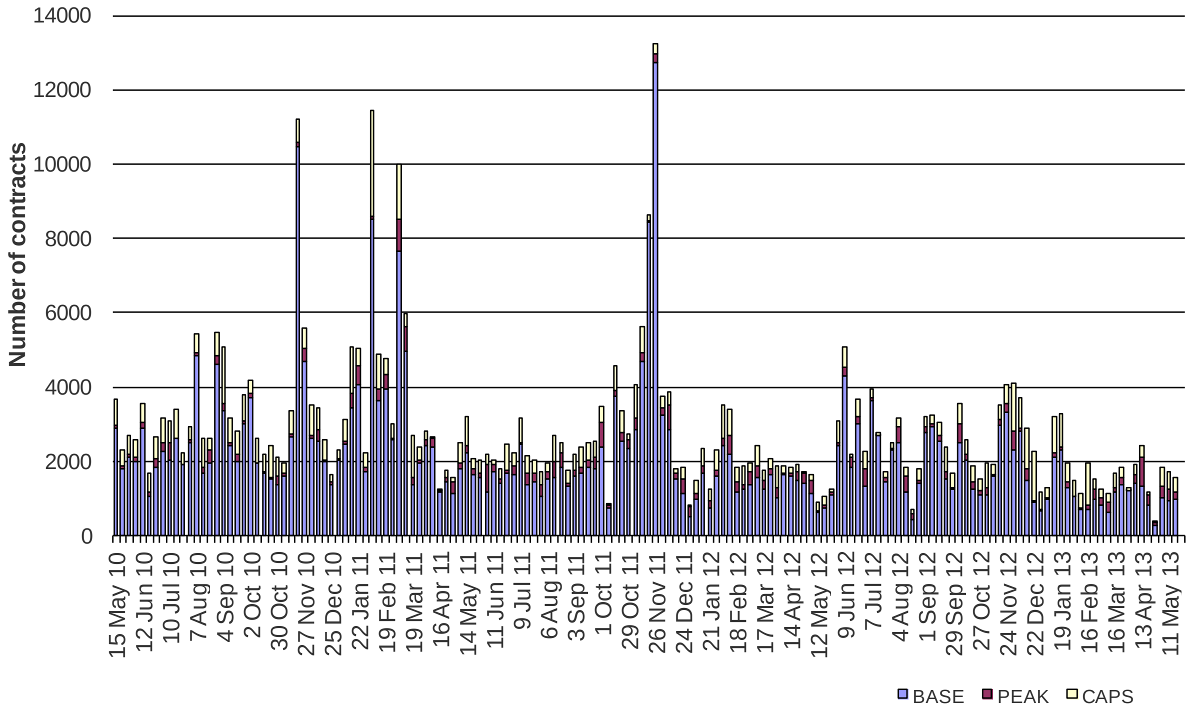
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2014	12	0%	8	-1%	10 (40)	-2%	16 (30)	2%
2014	6	0%	4	-2%	4	0%	8	1%

Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
A number in brackets denotes the number of trades in the product.

Figure 4 shows for the last three years the weekly trading volumes for base, peak and cap contracts. The date represents the end of the trading week.

Figure 4: Number of exchange traded contracts per week

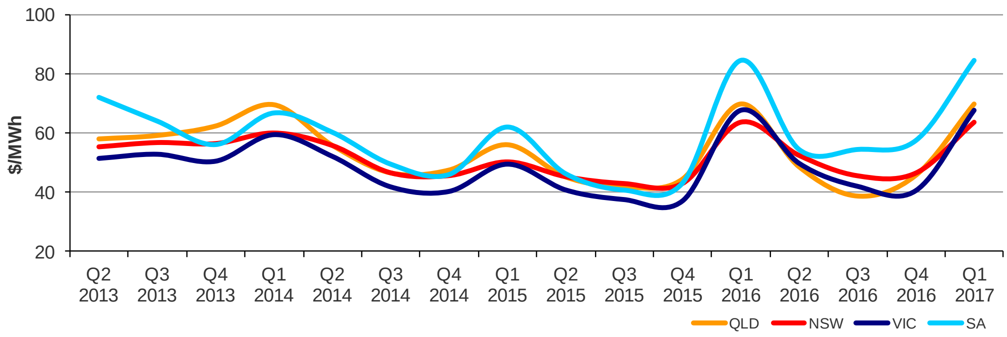


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 5 shows the prices for base contracts for each quarter for the next four financial years.

[4] Calculated on prices prior to rounding.

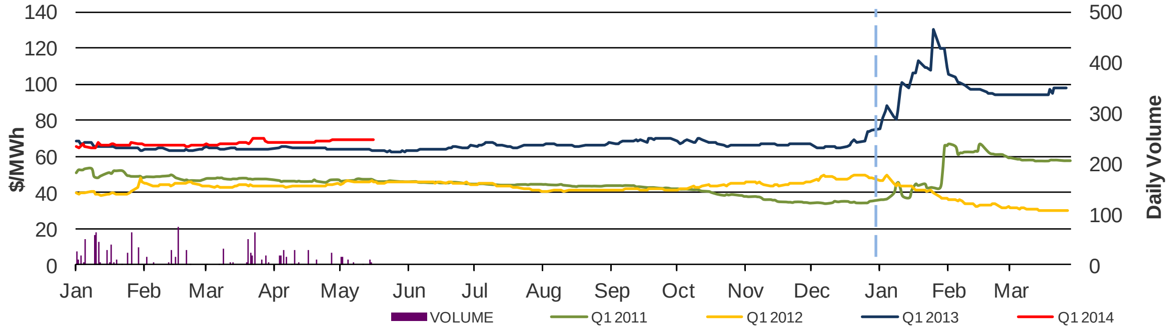
Figure 5: Quarterly base future prices Q2 2013 – Q1 2017



Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

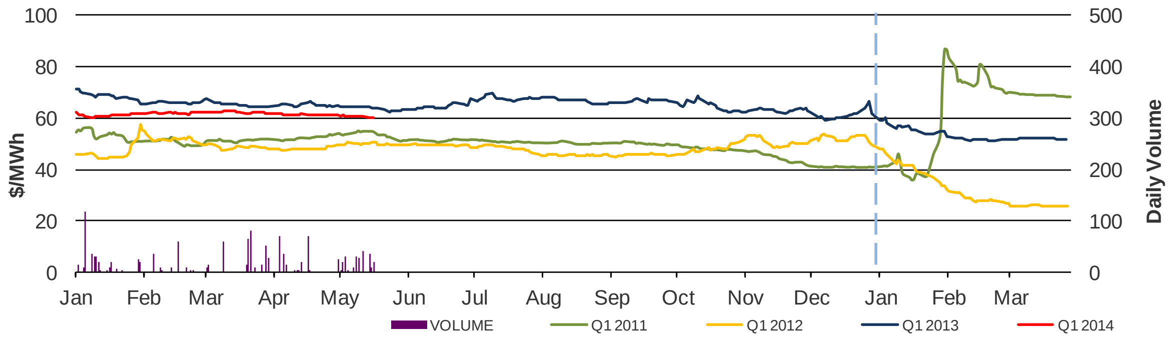
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2011, 2012, 2013 and 2014. Also shown is the daily volume of Q1 2014 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

Figure 6: Queensland Q1 2011, 2012, 2013 and 2014



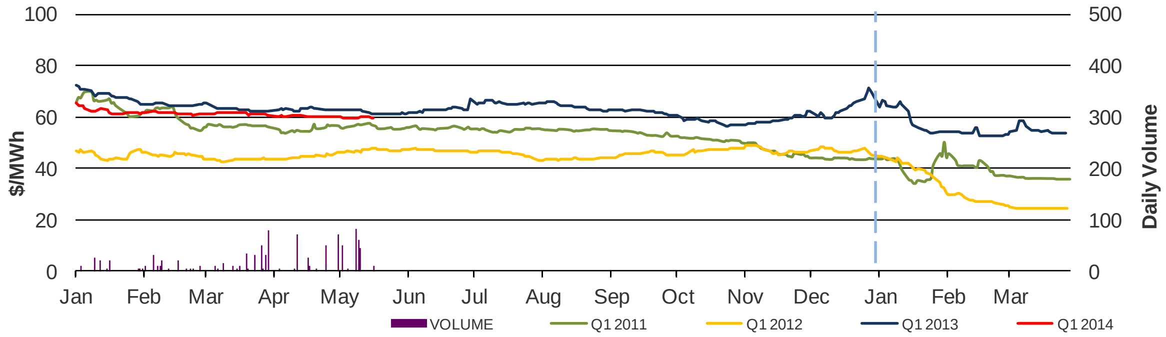
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 7: New South Wales Q1 2011, 2012, 2013 and 2014



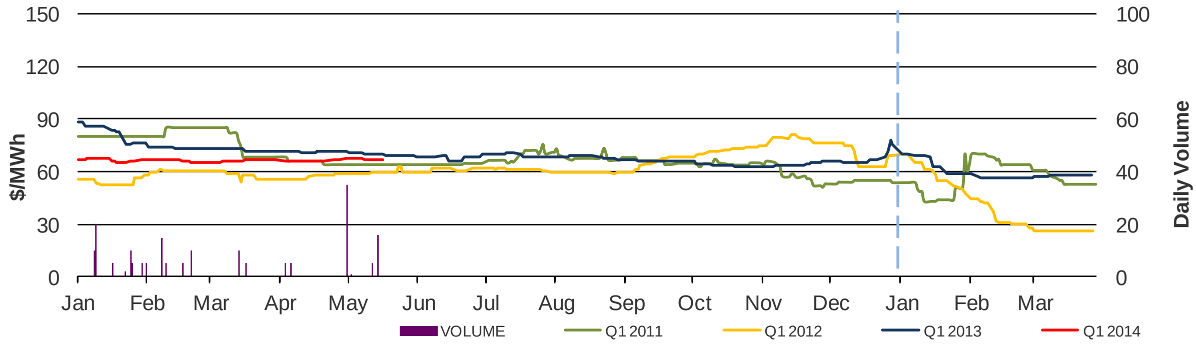
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 8: Victoria Q1 2011, 2012, 2013 and 2014



Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 9: South Australia Q1 2011, 2012, 2013 and 2014



Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au
The daily volume scale for South Australia is smaller than for other regions to reflect the lower liquidity in the market in South Australia.

Spot market forecasting 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 as participants react to changing market conditions. There were 152 trading intervals throughout the week where actual prices varied significantly from forecasts.[5] This compares to the weekly average in 2012 of 60 counts and the average in 2011 of 78. Reasons for these variances are summarised in Figure 10.[6]

Figure 10: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	13	19	0	4
% of total below forecast	8	44	1	11

The total may not equal 100% due to rounding

[5] A trading interval is counted as having a variation if the actual price differs significantly from the forecast price either four or 12 hours ahead.

[6] 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.

Demand and bidding patterns

The AER reviews demand, network limitations and generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 11 shows the weekly change in total available capacity at various price levels during peak periods[7]. For example, in Queensland 102 MW more capacity was offered at prices under $20/MWh this week compared to the previous week. Also included is the change in average demand during peak periods, for comparison.

Figure 11: Changes in available generation and average demand compared to the previous week during peak periods

MW	<$20/MWh	Between $20 and $50/MWh	Total availability	Change in average demand
QLD	102	-47	595	28
NSW	164	200	643	105
VIC	-592	162	-362	174
SA	37	16	67	0
TAS	57	86	75	19
TOTAL	-232	417	1018	326

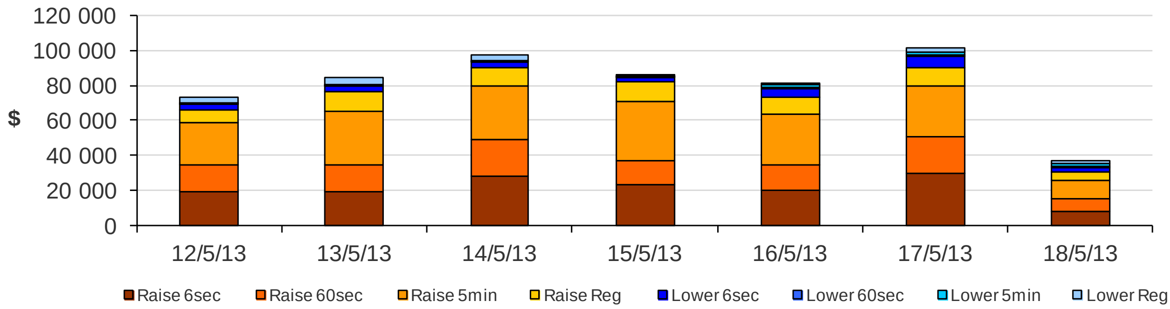
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $513 000 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $50 500 or less than one per cent of energy turnover in Tasmania.

Figure 12 shows the daily breakdown of cost for each FCAS for the NEM.

Figure 12: Daily frequency control ancillary service cost



Australian Energy Regulator
June 2013

[7] A peak period is defined as between 7 am and 10 pm on weekdays.

12 – 18 May 2013

South Australia:

There were seven occasions on Friday where the spot price in South Australia was greater than three times the South Australia weekly average price of $150/MWh and above $250/MWh.

Friday, 17 May

8:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2034.0	200.8	200.8
Demand (MW)	1578	1583	1562
Available capacity (MW)	1739	1868	1895
8:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2018.81	300.07	200.8
Demand (MW)	1593	1651	1620
Available capacity (MW)	1729	1858	1895
9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2082.9	300.07	200.8
Demand (MW)	1550	1620	1586
Available capacity (MW)	1732	1864	1887

Demand was lower than that forecast four hours ahead due to increases in non-scheduled generation output (including 35 MW at Angaston, which is treated as a reduction in demand) and a demand reduction in response to a high 5-minute price in each trading interval. Available capacity was around 130 MW lower than forecast four hours ahead.

At 6.56 am, Origin Energy reduced the availability of its offline Quarantine unit 5 by 80 MW, which was priced at $111/MWh, for the 8 am and 8.30 am trading intervals and 120 MW for the 9.30 am trading interval. The reason given was “0655P change in avail – unit failed start SL”.

At 7.48 am, effective from 7.55 am, AGL rebid a total of 95 MW of capacity at Torrens Island across A2, A3, B1 and B2 from around $200/MWh to $11 290/MWh. The reason given was “07:45A chg in forecast::5MPD price decrease SA approx $12000”.

This led to the 5-minute price increasing from $201/MWh at 7.50 am to $11 290/MWh at 7.55 am, set by the AGL units.

Demand increased by around 40 MW for the 8.30 am dispatch interval while available capacity and wind generation remained unchanged. At the same time, the import limit set by the constraint managing post contingent load on the Heywood 275/500 kV transformer reduced by 29 MW. The step change in supply and demand was unable to be satisfied by low priced generation with limited ramp up rate. This led to high priced generation being dispatched and the 5-minute price increasing from $201/MWh at 8.25 am to $11 290/MWh at 8.30 am.

Demand increased by around 60 MW for the 9.05 am dispatch interval while available capacity fell by 20 MW. At the same time, the import limit set by the constraint managing post contingent load on the Heywood 275/500 kV transformer reduced by 50 MW. The step change in supply and demand was unable to be satisfied by low priced generation with limited ramp up rate. This led to high priced generation being dispatched and the 5-minute price increasing from $200.80/MWh at 9 am to $12 195/MWh at 9.05 am.

There was no other significant rebidding.

6:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1922.7	12 190.80	12 190.80
Demand (MW)	1701	1916	1860
Available capacity (MW)	2095	2072	2076

Demand was around 215 MW lower than forecast four hours ahead. Available capacity was close to forecast. Wind generation was around 35 MW, which was 30 MW higher than forecast four hours before. This led to the actual price being lower than forecast for the majority of the trading interval.

There was a step increase in demand of around 140 MW for the 6.15 pm dispatch interval. At the same time, the import limit set by the constraint managing post contingent load on the Heywood 275/500 kV transformer reduced by 50 MW. The step change in supply and demand was unable to be satisfied by low priced generation with limited ramp up rate. This led to high priced generation being dispatched and the 5-minute price increasing from $61/MWh at 6.10 pm to $11 108/MWh at 6.15 am.

There was no significant rebidding.

8:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2099.8	12 190.80	12 190.80
Demand (MW)	1676	1861	1831
Available capacity (MW)	2006	2080	1952

Demand was 185 MW lower than forecast four hours before. Available capacity was around 70 MW lower than forecast four hours before. This led to the actual price being lower than forecast for the majority of the trading interval.

At 8.10 pm the import limit set by the constraint managing post contingent load on the Heywood 275/500 kV transformer reduced by 26 MW. The step change in supply was unable to be satisfied by low priced generation with limited ramp up rate. This led to high priced generation being dispatched and the 5-minute price increasing from $201/MWh at 8.05 pm to $12 191/MWh at 8.10 pm.

There was no significant rebidding.

10:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1893.8	300.07	12 190.80
Demand (MW)	1528	1632	1662
Available capacity (MW)	1998	2092	2091

Demand was around 100 MW lower than forecast four hours before. Available capacity was around 100 MW lower than forecast four hours before. Wind generation was very low (around 2 MW) which was around 20 MW lower than forecast four hours before.

The four hour forecast price reduced compared to the 12 hour forecast due to a 30 MW drop in demand.

At 9.51 pm, effective at 10.05 pm International Power rebid 30 MW of capacity at Pelican Point from $51/MWh to $12 887/MWh. The reason given was "2147A constraint MGT V>S_NIL_HYTX".

This led to high priced generation being dispatched and the 5-minute price increasing from $201/MWh at 10 pm to $11 108/MWh at 10.05 pm.

There was no other significant rebidding.

Midnight	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2075.4	60.0	64.05
Demand (MW)	1692	1621	1664
Available capacity (MW)	1997	2032	2102

Demand was around 70 MW higher than forecast four hours ahead. Available capacity was around 30 MW lower than forecast four hours ahead. Actual wind generation, at 0 MW, was lower than the 32 MW forecast at 8 pm.

There was a step change in demand increasing from 1637 MW at 11.30 pm to 1857 MW at 11.35 pm. This sharp increase in scheduled demand was related to off peak hot water load. Limited ramp up rates from low priced capacity led high-priced capacity to be dispatched to meet the increase in demand. As a result, the 5-minute price increased from $64/MW at 11.30 pm to $12 191/MW at 11.35 pm.

There were no significant rebids.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
12 May - 18 May 2013

AUSTRALIAN ENERGY REGULATOR

Table 1: Financial year to date spot market volume weighted average price

Financial year	QLD	NSW	VIC	SA	TAS
2012-13 ($/MWh) YTD	71	56	61	68	49
2011-12 ($/MWh) YTD	30	30	27	32	33
Change*	139%	87%	121%	111%	48%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	10.496	171
2011-12	5.987	199
2010-11	7.445	204

Table 3: Recent monthly and quarterly spot market volume weighted average price and turnover

Volume weighted average ($/MWh)	QLD	NSW	VIC	SA	TAS	Turnover ($, billion)
January-13	170	51	60	68	57	1.489
February-13	60	53	56	63	46	0.855
March-13	76	53	55	62	50	0.986
April-13	56	55	51	80	45	0.836
May-13 MTD	57	56	53	107	46	0.544
Q2 2013 QTD	57	55	52	90	45	1.380
Q2 2012 QTD	28	32	31	30	36	0.782
Change*	100%	72%	66%	198%	25%	0.765

Table 4: ASX energy futures contract prices at end of 17 May 2013

	QLD		NSW		VIC		SA	
Q1 2014	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 10 May ($/MWh)	69	88	61	73	60	77	67	92
Price on 17 May ($/MWh)	69	88	60	72	60	77	67	92
Open Interest on 17 May ($/MWh)	763	95	1333	260	742	245	103	35
Traded in the last week (MW)	17	0	107	45	55	5	21	0
Traded since 1 Jan 13 (MW)	1180	66	1328	475	1010	305	179	35
Settled price for Q1 13 ($/MWh)	97	110	52	54	53	62	58	69

Table 5: Changes to availability of low priced generation capacity offered to the market

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
March 13 with March 12						
MW Priced $20/MWh	-4598	-1294	-810	99	-386	-6989
MW Priced $20/MWh to $50/MWh	2509	-548	1060	-290	353	3084
April 13 with April 12						
MW Priced $20/MWh	-4017	-164	-415	-348	-316	-5259
MW Priced $20/MWh to $50/MWh	2269	-1179	951	-513	284	1811
May 13 with May 12 MTD						
MW Priced $20/MWh	-3998	-803	-715	-526	-138	-6180
MW Priced $20/MWh to $50/MWh	2284	-1606	142	-620	362	562

*Note: These percentage changes are calculated on VWA prices prior to rounding

** Estimated value