WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

2 October - 8 October 2011

Summary

Weekly average spot prices ranged from $26/MWh in Victoria to $66/MWh in South Australia.

On 4 October the price for lower frequency control ancillary services (FCAS) in South Australia exceeded $5000/MW for several dispatch intervals, significantly higher than the energy price in that region. In accordance with clause 3.13.7(e) of the National Electricity Rules, the AER is required to publish a report into the circumstances that led to the FCAS prices exceeding $5000/MW.

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 2 October to 8 October and the 11/12 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 2 Oct - 8 Oct 2011	28	30	26	66	29
% change from previous week*	2	3	6	111	17
11/12 financial YTD	29	30	30	39	30
% change from 10/11 financial YTD **	33	3	15	44	-24

*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 Monday 10 October 2011. Figure 2 shows the base futures

[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 -> Monitoring, reporting and enforcement -> Electricity market reports -> Long-term analysis.

[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.

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.

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

	QLD		NSW		VIC		SA	
Calendar Year 2012	41	2%	47	1%	42	0%	52	1%
Calendar Year 2013	51*	-1%	56	0%	52*	3%	58	0%
Calendar Year 2014	56	0%	59	0%	60	0%	69	0%
Three year average	49	0%	54	0%	51	1%	60	0%

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

* denotes trades in the product.

Figure 3 shows the $300 cap contract price for Q1 2012 and calendar year 2012 and the percentage change[4] from the previous week.

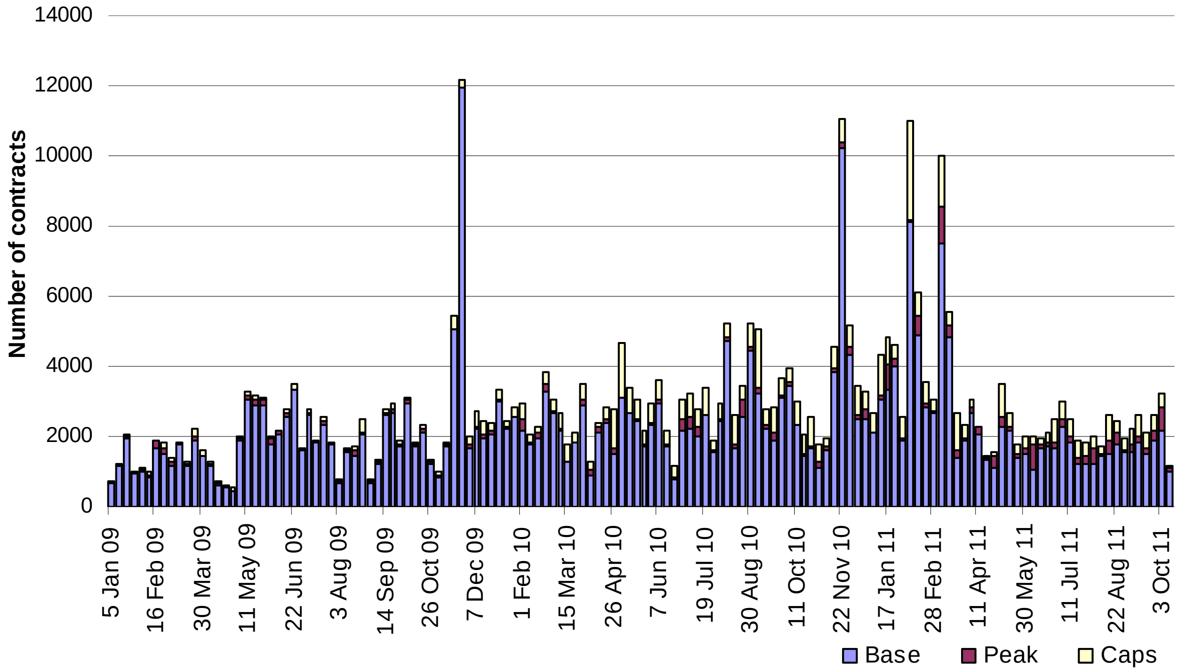
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2012 (% change)	13	0%	15	2%	16*	1%	34	0%
2012 (% change)	6	0%	9	0%	6	1%	12	0%

Source: d-cyphaTrade www.d-cyphatrade.com.au
* denotes trades in the product.

Figure 4 shows 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

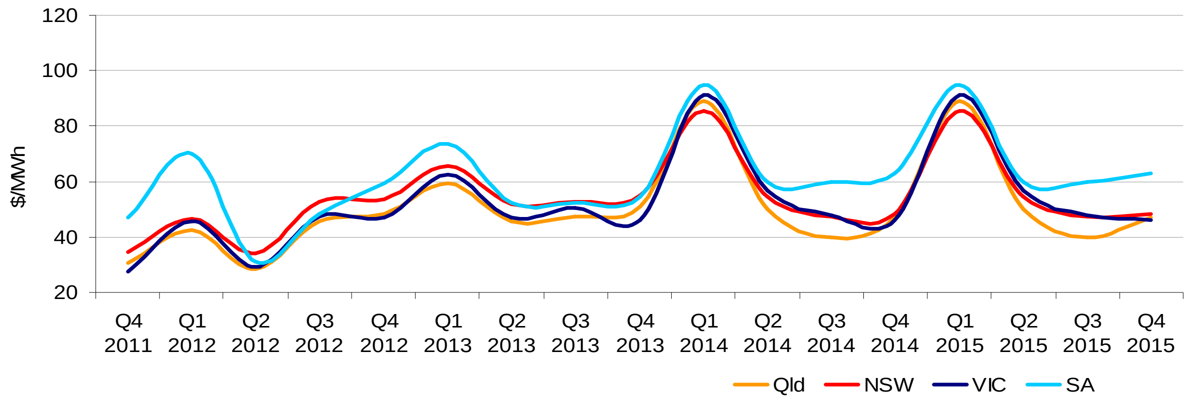


Source: d-cyphaTrade www.d-cyphatrade.com.au

[3] Calculated on prices prior to rounding.
[4] Calculated on prices prior to rounding.

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

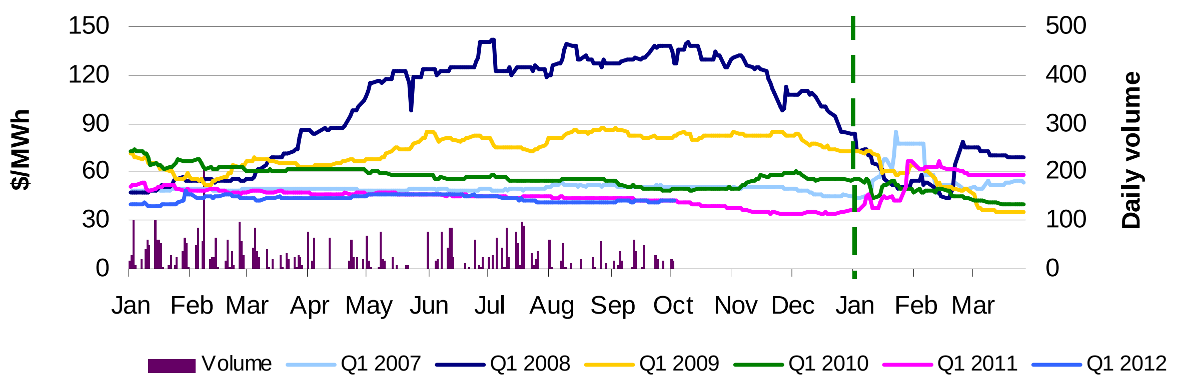
Figure 5: Quarterly base future prices Q4 2011 – Q4 2015



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

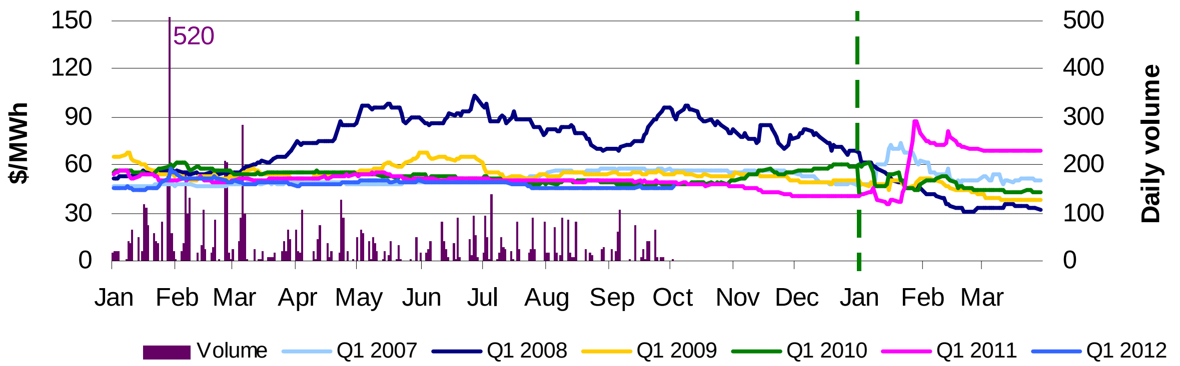
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2007, 2008, 2009, 2010, 2011 and 2012. Also shown is the daily volume of Q1 2012 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased. To understand the diagrams, the dark-blue line in figure 6 demonstrates that throughout the middle of 2007, the market had an expectation of very high spot prices in the first quarter of 2008.

Figure 6: Queensland Q1 2007, 2008, 2009, 2010, 2011 and 2012



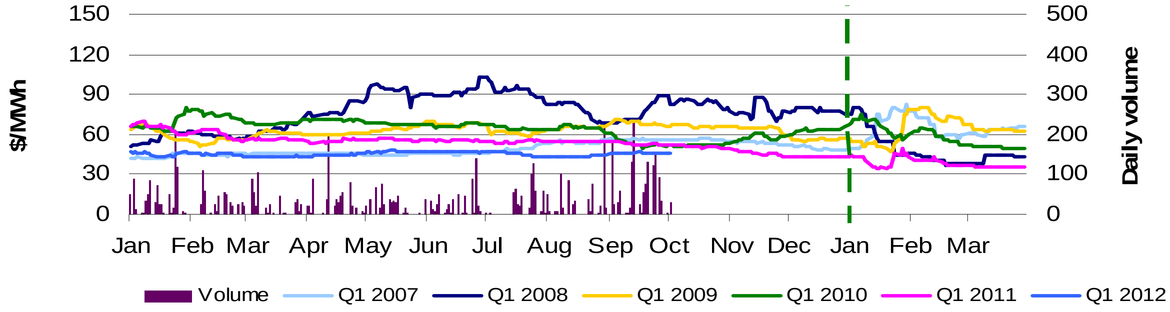
Source: d-cyphaTrade www.d-cyphatrade.com.au

Figure 7: New South Wales Q1 2007, 2008, 2009, 2010, 2011 and 2012



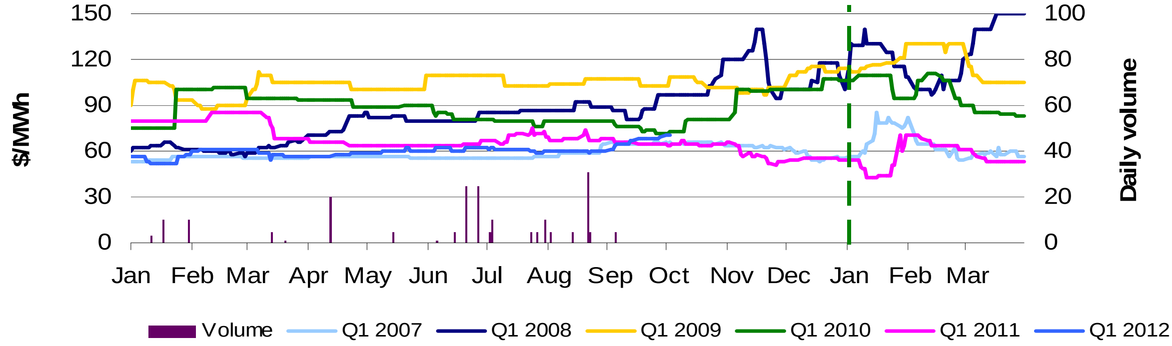
Source: d-cyphaTrade www.d-cyphatrade.com.au

Figure 8: Victoria Q1 2007, 2008, 2009, 2010, 2011 and 2012



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

Figure 9: South Australia Q1 2007, 2008, 2009, 2010, 2011 and 2012



Source: d-cyphaTrade 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 114 trading intervals throughout the week where actual prices varied significantly from forecasts[5]. This compares to the weekly average in 2010 of 57 counts and the average in 2009 of 103. 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	3	8	2	3
% of total below forecast	82	1	0	1

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

[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.

weekly change in total available capacity at various price levels during peak periods[7]. For example, in Queensland 24 MW less 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	-24	22	51	-13
NSW	176	-347	-54	-207
VIC	444	-193	434	-8
SA	157	-16	156	-78
TAS	-353	98	-117	14
TOTAL	400	-436	470	-292

Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $4.3 million or around four per cent of energy turnover on the mainland.

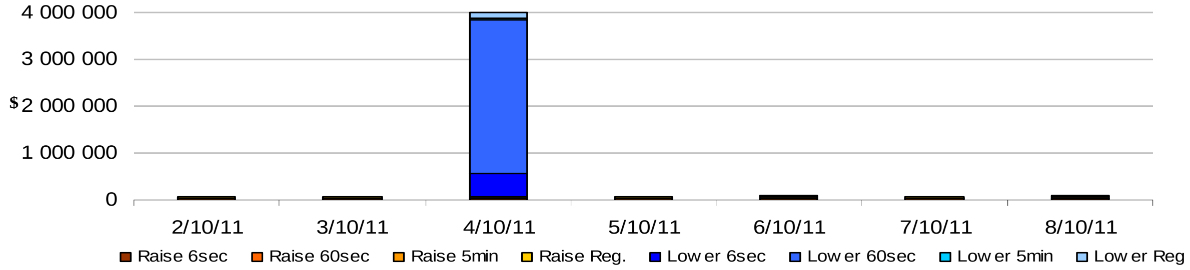
On Tuesday 4 October, the costs of lower 6 second and lower 60 second services were $506 000 and $3.3 million, respectively. Almost all of these costs were accrued in South Australia where the price of lower FCAS exceeded $5000/MW for multiple trading intervals (with lower 60 second services reaching the price cap for 35 consecutive dispatch intervals), significantly higher than the energy price in that region. In accordance with clause 3.13.7(e) of the National Electricity Rules, the AER is required to publish a report into the circumstances that led to the FCAS prices exceeding $5000/MW.

The high FCAS prices were associated with planned network outages in Victoria on the Heywood interconnector. These outages were in the vicinity of the new Mortlake Power Station, which was undergoing commissioning testing at the same time. The energy price reached $2113/MWh during this period (discussed in more detail in Appendix A).

The total cost of FCAS in Tasmania for the week was $156 000 or around three 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
November 2011

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

Detailed Market Analysis

AUSTRALIAN ENERGY REGULATOR

2 October – 8 October 2011

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 $66/MWh and above $250/MWh.

Tuesday, 4 October

10:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2112.86	33.88	31.31
Demand (MW)	1421	1469	1511
Available capacity (MW)	2305	2376	2440
11 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	995.61	30.66	32.16
Demand (MW)	1454	1474	1514
Available capacity (MW)	2264	2406	2435

The previous day the Alcoa-Portland to Heywood No. 2 line, the Heywood to Mortlake No.2 line and a Heywood transformer were taken out of service due to a planned outage.

Mortlake was undergoing commissioning testing at the time. The commissioning program Origin Energy submitted to AEMO for its Mortlake Power Station showed the station was to commence generation at a fixed level of 180 MW from 10 am. However, Origin Energy only submitted its offer at 10.03 am (effective from 10.10 am). Up until that time, the effects of Mortlake generating were not taken into account in predispatch.

This, combined with the outage of the Heywood to Mortlake line saw the Heywood interconnector change from importing 190 MW into South Australia at 10.10 am to exporting 123 MW to Victoria by 10.15 am. At the same time, imports into South Australia across Murraylink increased by 166 MW to 238 MW.

The above conditions led to an increase in the requirement for lower FCAS in South Australia.

As a result of the step change in generation in South Australia and the increase in requirements for lower FCAS, the five minute energy price reached the price cap at 10.15 am.

At 10.42 am, effective from 10.50 am, AGL rebid 140 MW out of 400 MW of capacity at Torrens Island from the price floor to the price cap. The reason given was "10:31A Unfcast network constraint :: V_HYMO2_1”. This saw the five-minute price reach $5753/MWh for one dispatch interval at 10.50 am.

At 10.52 am, effective from 11 am, Origin Energy reduced the available capacity at Mortlake by 90 MW. The reason given was “1050P Commissioning- AEMO system security request”. As a result the Heywood interconnector reduced exports and the five-minute price fell to $40/MWh at 11 am.

There was no other significant rebidding.

Wednesday, 5 October

7:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2210.90	35.00	35.00
Demand (MW)	1555	1543	1559
Available capacity (MW)	2119	2417	2435
9:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2134.75	34.99	34.23
Demand (MW)	1690	1539	1551
Available capacity (MW)	2100	2438	2464
10 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2148.79	34.99	33.81
Demand (MW)	1631	1537	1549
Available capacity (MW)	2122	2480	2462

Conditions at the time saw demand up to 150 MW greater than that forecast four hours ahead. Available capacity was up to 358 MW below that forecast four hours ahead. Reductions in output from semi-scheduled wind generation as a result of drop in wind speed translate to a reduction in regional available capacity.

A constraint used to manage the continuing planned outage of the Alcoa-Portland to Heywood No. 2 line, limited imports into South Australia across the Heywood interconnector to around 190 MW from 6.30 am. Imports across Murraylink into South Australia were at the nominal limit of 220 MW.

At 6.58 am, effective for the 7.30 am trading interval, AGL rebid 200 MW out of 400 MW of capacity at Torrens Island from prices below $45/MWh to the price cap. The reason given was “07:55A Chg in dispatch::price increase vs PD SA $20”. At the same time, AGL rebid a further 50 MW of capacity at Angaston from prices below $250/MWh to above $11 000/MWh, with the same reason.

The five-minute price reached the price cap at 7.20 am following a 90 MW increase in five-minute demand from 7.15 am to 7.20 am, which saw the dispatch of high priced generation offers at Torrens Island.

At 9.13 am, first effective at 9.20 am, AGL rebid 240 MW out of 413 MW of capacity at Torrens Island from prices below $45/MWh to the price cap. The reason given was "09:05A Chg in dispatch::price increase vs PD SA $7". The five-minute price reached $12 498/MWh at 9.20 am and $12 499/MWh at 9.35 am..

At 9.36 am, first effective 9.45 am, AGL rebid 240 MW of capacity at Torrens Island from the price cap to the price floor. The reason given was "10.30A Chg in dispatch price:: price increase vs pd SA $12,000+ 30/5". This saw prices fall below $30/MWh by 9.45 am.

There was no other significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
2 October - 8 October 2011

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

Financial year	QLD	NSW	VIC	SA	TAS
2011-12 ($/MWh) YTD	29	30	30	39	30
2010-11 ($/MWh) YTD	22	29	26	27	40
Change*	33%	3%	15%	44%	-24%
2010-11 ($/MWh)	34	43	29	42	31

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2011-12 (YTD)	$1.686	56
2010-11	$7.445	204
2009-10	$9.643	206

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)
Jun-11	26	28	29	33	30	0.447
Jul-11	27	32	31	36	34	0.508
Aug-11	29	31	31	36	29	0.483
Sep-11	29	29	28	40	27	0.427
Oct-11 (MTD)	28	30	25	61	29	0.115
Q1 2011	65	90	41	83	27	3.484
Q1 2010	46	52	67	134	27	3.014
Change*	41%	74%	-38%	-38%	2%	15.57%

Table 4: ASX energy futures contract prices at end of 10 October

	QLD		NSW		VIC		SA	
Q1 2012	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 03 Oct ($/MW)	42	65	45	71	45	74	69	120
Price on 10 Oct ($/MW)	43	65	46	71	46	75	70	120
Open interest on 10 Oct	1317	115	1865	500	2343	296	170	5
Traded in the last week (MW)	50	0	21	35	165	0	0	0
Traded since 1 Jan 11 (MW)	4954	151	7415	938	6239	492	220	5
Settled price for Q1 11($/MW)	57	96	68	118	35	51	53	93

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
August 11 with August 10						
MW Priced <$20/MWh	-1212	-877	10	-152	-198	-2429
MW Priced $20 to $50/MWh	96	656	-241	57	-43	524
September 11 with September 10						
MW Priced <$20/MWh	-856	-1281	-424	-614	-345	-3520
MW Priced $20 to $50/MWh	-376	1085	148	175	161	1191
October 11 with October 10 (MTD)						
MW Priced <$20/MWh	-696	-1029	-305	-316	-790	-3136
MW Priced $20 to $50/MWh	-476	1363	454	114	481	1936

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