WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

9 December – 15 December 2012

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 9 December to 15 December 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.

Spot prices in Victoria and South Australia were higher than in the other regions as a result of unplanned transmission line outages in New South Wales and Victoria that reduced interconnector capability for energy imports into Victoria on 12 and 13 December, and high demand driven by hot weather in both regions on those days. These events are described further in Appendix A.

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

	Qld	NSW	VIC	SA	Tas
Average price for 9 - 15 December 2012	50	51	76	78	51
% change from previous week*	-25	-3	46	48	0
12/13 financial YTD	56	59	66	66	49
% change from 11/12 financial YTD **	91	86	138	83	63

*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 17 December 2012. 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 2013	57*	0%	57*	1%	55	2%	59	0%
Calendar Year 2014	55	0%	57*	1%	53	0%	57	0%
Calendar Year 2015	51	1%	52*	0%	48*	0%	53	0%
Three year average	54	0%	55	0%	52	1%	56	0%

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

Figure 3 shows the $300 cap contract price for Q1 2013 and calendar year 2013 and the percentage change[4] from the previous week.

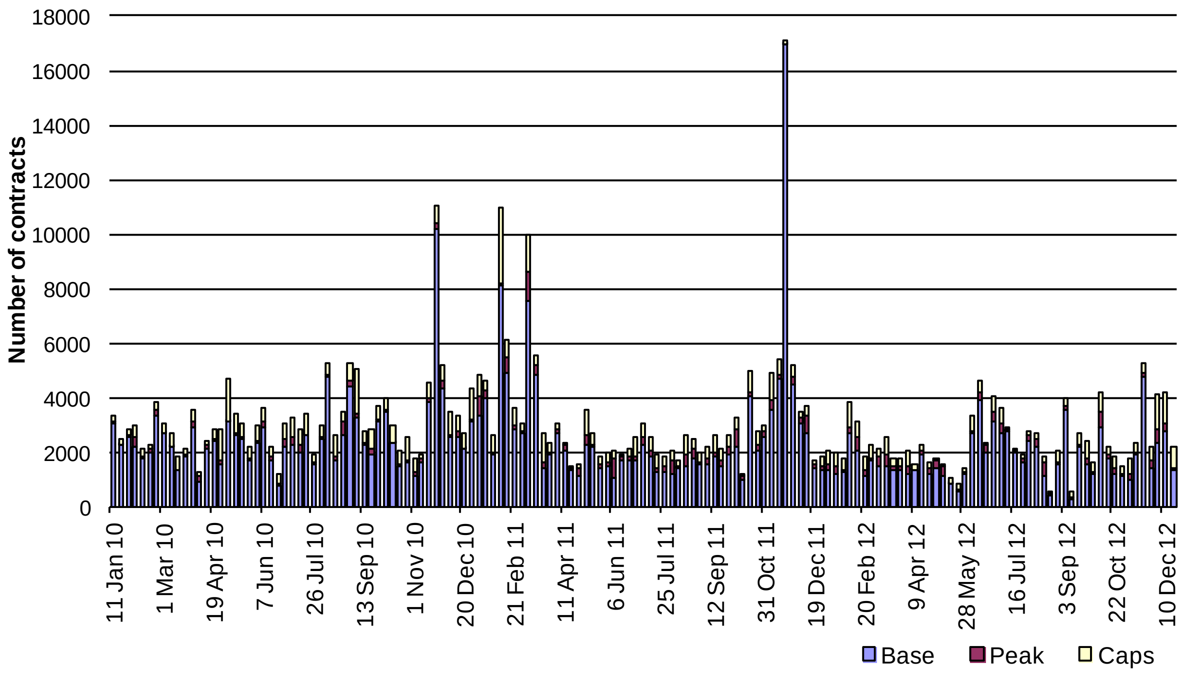
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2013 (% change)	11*	1%	8*	10%	12*	23%	14*	0%
2013 (% change)	5	-1%	5	3%	5	18%	7	-3%

Source: d-cyphaTrade/ASX 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

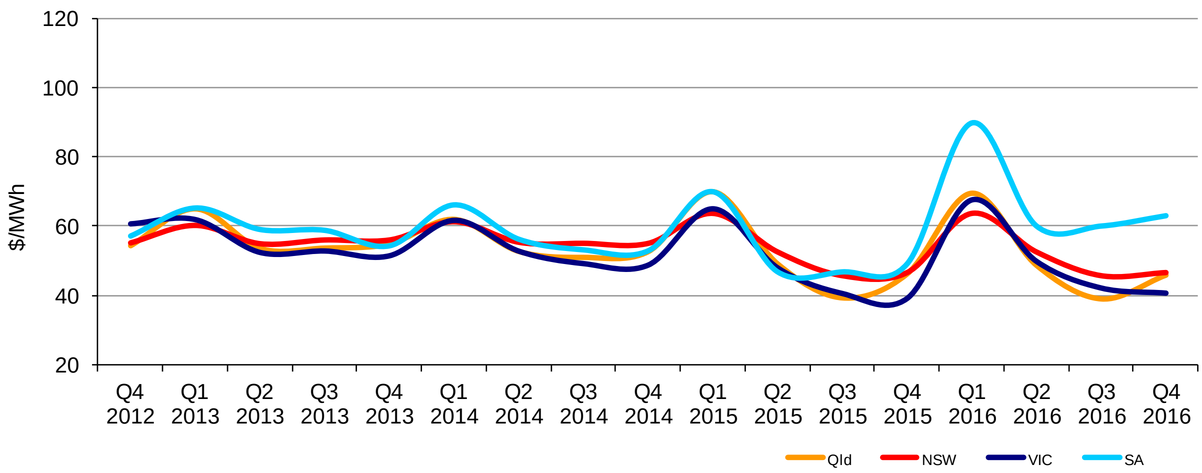


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

4 Calculated on prices prior to rounding.

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

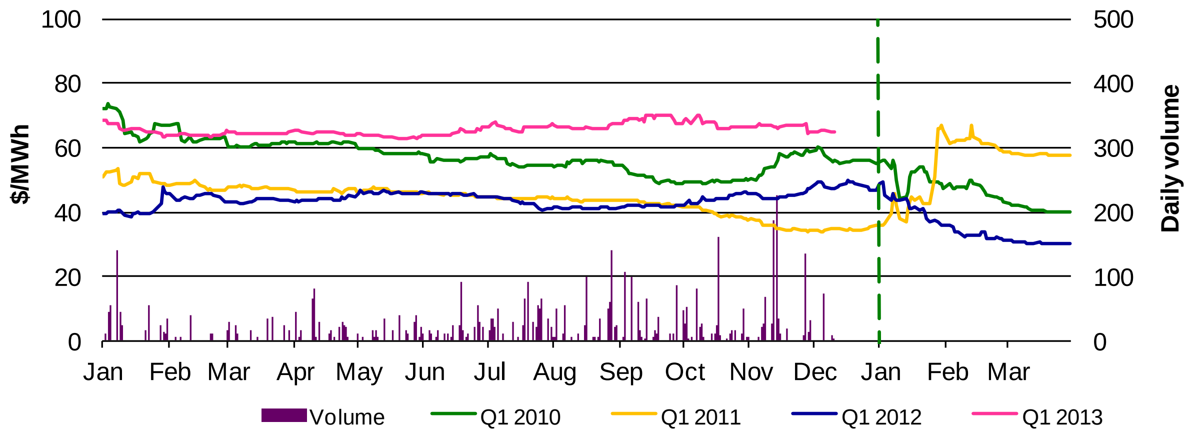
Figure 5: Quarterly base future prices Q4 2012 – Q4 2016



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

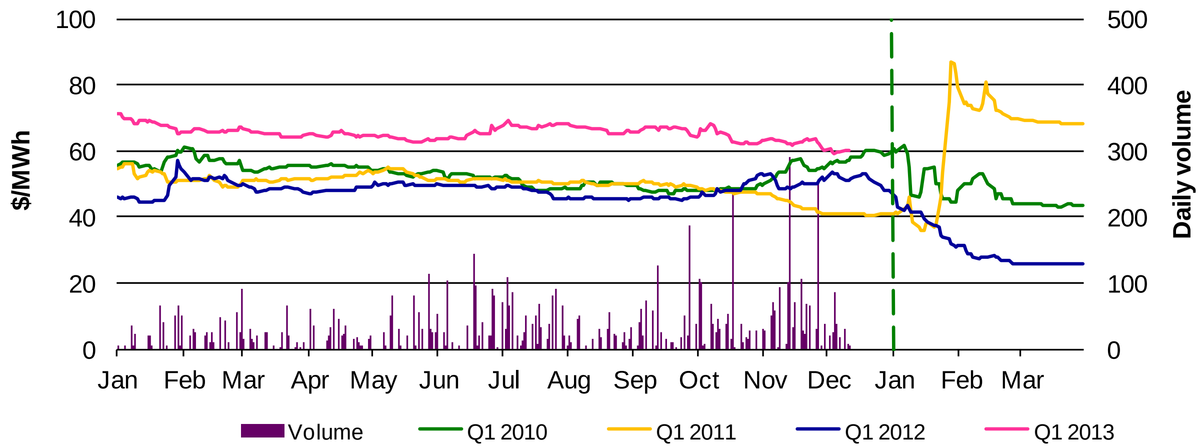
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2010, 2011, 2012 and 2013. Also shown is the daily volume of Q1 2013 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

Figure 6: Queensland Q1 2010, 2011, 2012 and 2013



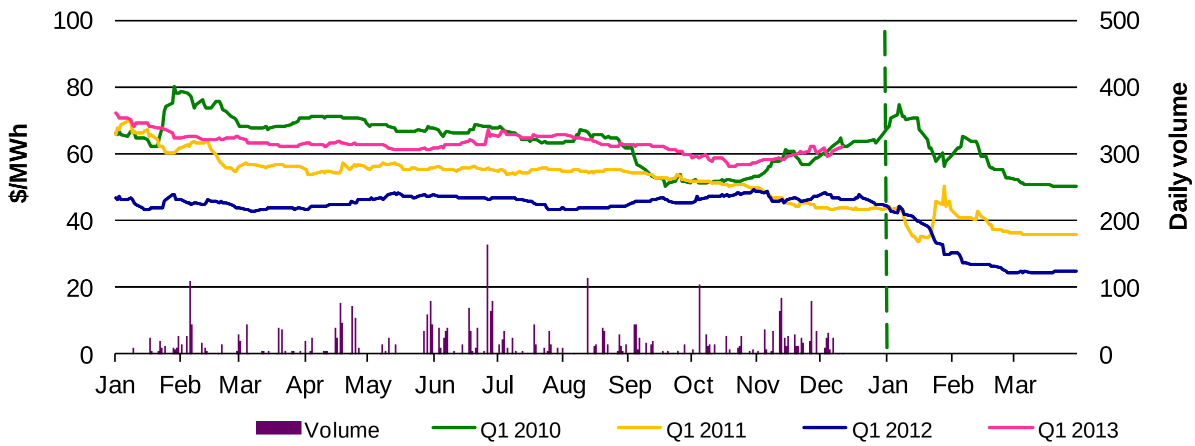
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 7: New South Wales Q1 2010, 2011, 2012 and 2013



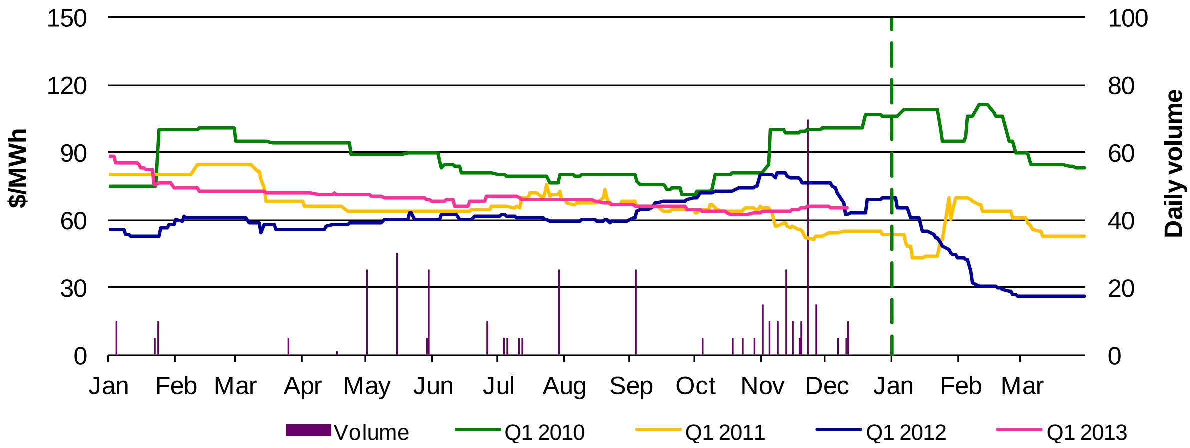
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

Figure 8: Victoria Q1 2010, 2011, 2012 and 2013



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

Figure 9: South Australia Q1 2010, 2011, 2012 and 2013



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 49 trading intervals throughout the week where actual prices varied significantly from forecasts[5]. This compares to the weekly average in 2011 of 78 counts and the average in 2010 of 57. Reasons for these variances are summarised in Figure 10[6].

[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.

Figure 10: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	5	40	1	22
% of total below forecast	11	16	0	5

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 986 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	-986	544	-236	-625
NSW	-393	968	-420	234
VIC	171	-83	46	703
SA	210	25	262	438
TAS	11	264	140	35
TOTAL	-987	1718	-208	785

Ancillary services market

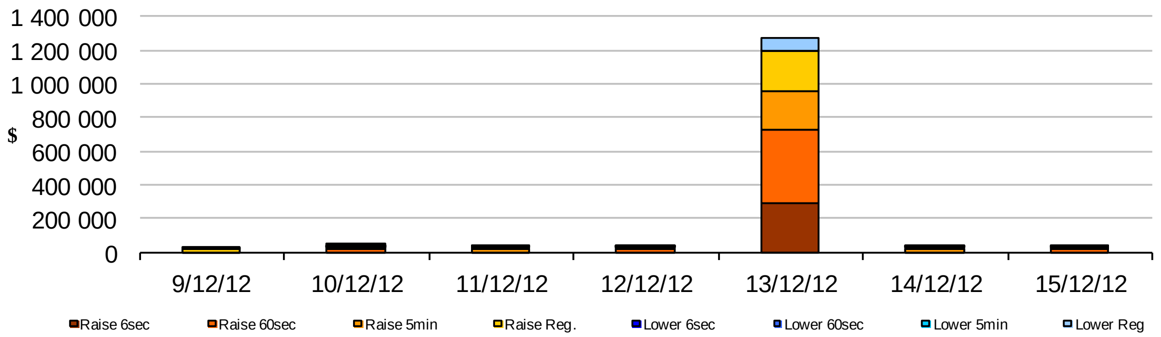
The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $1.4 million or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $36 000 or less than one per cent of energy turnover in Tasmania.

The high FCAS costs on 13 December were incurred primarily in South Australia. Details of the events that led to this outcome are described further in Appendix A.

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
February 2013

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

Victoria:

There were six occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $76/MWh and above $250/MWh.

Wednesday, 12 December

4:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	337.92	82.72	86.00
Demand (MW)	8259	7932	7571
Available capacity (MW)	8992	9297	9373
4:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	372.39	82.74	86.00
Demand (MW)	8254	7880	7526
Available capacity (MW)	9003	9234	9375

Conditions at the time saw demand up to 375 MW higher than that forecast four hours ahead. Available capacity was up to 305 MW lower than that forecast 4 hours ahead.

Hot weather contributed to increased demand, with the temperature in Melbourne reaching around 34 degrees following much milder weather.

From around 1 pm, an unplanned outage of the Buronga to Balranald to Darlington Point X5 220 kV transmission line in New South Wales saw constraints invoked that limited flows on the Murraylink and VIC-NSW interconnectors. With reduced capability for imports into Victoria and little capacity priced between $100/MWh and $200/MWh, any rebidding of capacity into high price bands or increases in demand, had the potential to result in a significant increase in the spot price.

Throughout the 4 pm trading interval, the five-minute price was between $245/MWh and $290/MWh before increasing during the last dispatch interval.

In two rebids, effective at 3.55 pm and 4 pm respectively, Snowy Hydro shifted a total of 140 MW of capacity at Murray priced at zero to $455/MWh. The reasons given were “15:41 A Vic: 5mpd price $178.49 lwr thn 30mpd 16:05@15:32” and “15:36 A Vic: 5mpd price $356.36 lwr thn 5mpd 16:00@15:31”.

At 4 pm, demand peaked at 8300 MW. Imports into Victoria from New South Wales were limited to around 720 MW at the time, around 450 MW less than that forecast four hours ahead. A system normal constraint binding on the Murraylink interconnector, together with a violation of one of the constraints managing the unplanned transmission outage in New South Wales, saw imports into Victoria from South Australia on Murraylink limited to around 90 MW. With no other available generation in Victoria priced below $250/MWh and limited import capability, the higher priced generation offered at Murray was dispatched and contributed to setting the five minute price to around $719/MWh at 4 pm.

A reduction in demand of around 70 MW by 4.10 pm saw the five minute price fall below $300/MWh for the start of the 4.30 pm trading interval. At 4.15 pm, a small increase in demand and an increase in imports from New South Wales saw higher priced generation from New South Wales set the five minute price to around $440/MWh. A reduction in imports from New South Wales of around 170 MW, combined with a 40 MW increase in demand saw the five minute price reach around $729/MWh.

In two rebids, effective at 4.25 pm and 4.30 pm respectively, Snowy Hydro shifted a total of 480 MW of capacity at Murray priced at $455/MWh to zero. The reasons given were “16:20 A vic: act price $441.09 hgr thn 30mpd 16:20@15:32” and “16:22 A mng 5/30 min sett risk sl”. This increase in lower priced generation in Victoria saw the five minute price fall below $250/MWh for the 4.25 pm and 4.30 pm dispatch intervals.

There was no other significant rebidding.

Thursday, 13 December

12:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	250.45	96.86	96.86
Demand (MW)	8256	8075	7900
Available capacity (MW)	9440	9520	9539
12:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	334.94	117.48	104.04
Demand (MW)	8416	8156	8046
Available capacity (MW)	9371	9498	9537
1:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	405.90	125.86	125.86
Demand (MW)	8588	8249	8144
Available capacity (MW)	9352	9483	9535

Conditions at the time saw demand up to around 340 MW greater than that forecast four hours ahead. Available capacity was close to that forecast.

Continuing hot weather contributed to increased demand, with the temperature in Melbourne reaching around 35 degrees after a warmer than average night. Demand increased by around 530 MW from 11.35 am to the end of the 1 pm trading interval.

The continuing outage of the Buronga to Balranald to Darlington Point X5 220kV transmission line in New South Wales led to reduced interconnector capability for imports into Victoria on the

Murraylink and VIC-NSW interconnectors. With South Australia also experiencing hot weather, higher priced generation offers were dispatched in order to meet the higher demand in both regions for the majority of the time until the end of the 1 pm trading interval.

At 9.16 am, AGL Energy rebid 280 MW of capacity at its Mckay Power Station from below $130/MWh to above $240/MWh, with 120 MW priced close to the cap. At 11.33 am, effective at 11.40 am, 80 MW of capacity at its Somerton Power Station was rebid from zero to above $12 700/MWh. The reason given was “11:31P reduction in avail cap::3rd gt run up slwr than exp”.

At around 12.43 pm, effective at 12.50 pm until the end of the 1 pm trading interval, Snowy Hydro rebid 704 MW of capacity at Murray priced around $450/MWh to the price cap. The ramp down rate of the unit was also increased from 50 to 150 MW/minute. The reason given was “12:43 A Avoid Murray being constrained on sl”.

This significant reduction of available capacity priced below $500/MWh, together with reduced capability for further imports into Victoria from adjoining regions, saw higher priced generation offers dispatched. The five minute price reached around $805/MWh at 12.50 pm and $1064/MWh at 1 pm, as demand increased to its highest level of the day at that point.

An apparent demand side response saw demand fall by around 200 MW over two dispatch intervals from 1.05 pm. An increase in wind generation in South Australia resulted in an increase in the availability of lower priced capacity that led to the five minute price falling to around $110/MWh at 1.05 pm.

There was no other significant rebidding.

3:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2184.61	543.28	135.44
Demand (MW)	8606	8541	8246
Available capacity (MW)	9186	9386	9475

Conditions at the time saw demand and available capacity close to that forecast four hours ahead.

At around 2.22 pm, effective only for the 2.30 pm dispatch interval, Snowy Hydro rebid 300 MW of capacity at Murray priced between $150/MWh and the price cap to $0/MWh. The reason given was “14:25 A nsw: act price $102.05 hgr thn 5mpd 14:25@14:16”. In the same rebid, 315 MW of capacity at Upper Tumut in New South Wales priced around $12 000/MWh was shifted to $0/MWh.

This increase in low priced capacity led to an increase in generation at Murray of 300 MW and at Upper Tumut of 315 MW for the 2.30 pm dispatch interval.

At 2.35 pm (the next trading interval), the rebid ceased to be effective and both Murray and Upper Tumut reduced their output. This caused a constraint to bind, managing voltage stability for the loss of the Dederang to Murray 330kV line (during the planned outage of the Buronga to Darlington Point 220kV line in New South Wales). A decrease in generation at Murray or an increase in generation at Upper Tumut helps alleviate the constraint, as does a reduction in imports into Victoria from New South Wales (on the VIC-NSW interconnector), as this reduces flows on the Dederang to Murray line. As both generators now had their remaining available capacity priced at close to the price cap, imports into Victoria from New South Wales reduced by around 260 MW. This coincided with a 145 MW increase in demand, with demand for the dispatch interval reaching the peak for the day of 8745 MW. At the time, import from Tasmania over BassLink was at its maximum of 478 MW and from South Australia on the Heywood and Murraylink interconnectors were also at the maximum of around 430 MW and 30 MW respectively.

With lower priced generation either at maximum output, ramp rate limited or trapped in frequency control ancillary services, higher priced generation in Victoria was required to be dispatched to meet the sudden increase in demand. This saw the five minute price reach the price cap for the 2.35 pm dispatch interval.

At around 2.31 pm, first effective at 2.40 pm, Snowy Hydro rebid 1200 MW at Murray priced at $0/MWh and the price cap to the price floor. The ramp down rate of the unit was also decreased from 50 MW/minute to 3 MW/minute. The reason given was "14:31 A Vic price $12500 hghr than prev 5pd".

This increase in availability of low priced capacity, together with a reduction in demand saw the five minute price fall to around $32/MWh at 2.40 pm.

South Australia:

There were seven occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $78/MWh and above $250/MWh.

Wednesday, 12 December

1:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	258.23	71.00	70.80
Demand (MW)	2479	2330	2244
Available capacity (MW)	2623	2795	2788
2:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	274.36	93.94	72.00
Demand (MW)	2536	2408	2334
Available capacity (MW)	2667	2788	2750

Conditions at the time saw demand greater and available capacity lower than forecast.

Reductions in output from semi-scheduled wind generation are reported as a reduction in regional available capacity. For the 1 pm trading interval, output from semi-scheduled wind generators was around 111 MW, around half of that forecast four hours ahead.

In three rebids between 9.53 am and 11.45 am, AGL reduced the available capacity of Torrens Island B unit 3 by a total of 76 MW, all of which was priced below $75/MWh due to delays in returning to service following a trip of the unit earlier in the day.

With reduced availability of lower priced capacity, lower than forecast wind generation and increasing demand, the five minute price was around $300/MWh for the majority of the 1 pm trading interval.

At 12.32 pm, first effective from 12.45 pm, Origin Energy rebid 115 MW of capacity at its Quarantine Power Station unit 5 priced below $50/MWh to prices above $11 500/MWh. The reason given was "1230P MW redistribution – mange fuel and linepack".

At 12.32 pm and 1.48 pm, effective at 12:40 pm and 1.55 pm respectively, Alinta Energy rebid up to 100 MW of capacity at Northern units 1 and 2 priced below $50/MWh to prices above

$11 500/MWh. The reasons given were "1226A NPS1 NPS2 change in SA PD $299 V $125@12:31" and "1340A NPS1 & NPS2 inc SA price $250 vs $60@13:48".

At 1.55 pm, an increase in demand of around 40 MW, combined with lower priced generation either ramp rate limited, trapped in frequency control ancillary services or at maximum output, saw higher priced generation from Victoria contribute to setting the five minute price in South Australia to around $555/MWh, and to $544/MWh at 2 pm.

There was no other significant rebidding.

4:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	350.03	102.66	99.25
Demand (MW)	2473	2588	2488
Available capacity (MW)	2725	2700	2646

4:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	385.02	109.18	105.23
Demand (MW)	2497	2632	2536
Available capacity (MW)	2763	2705	2659

Conditions at the time saw demand and available capacity close to forecast.

The outcomes in South Australia were driven by the events described in Victoria (see above).

Thursday, 13 December

7:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2128.66	59.98	60.05
Demand (MW)	1990	1969	1982
Available capacity (MW)	3181	3282	3211

Conditions at the time saw demand close to forecast and available capacity around 100 MW less than forecast four hours ahead.

Reductions in output from semi-scheduled wind generation are reported as a reduction in regional available capacity. For the 7.30 am trading interval, output from semi-scheduled wind generators was 405 MW, around 100 MW lower than that forecast four hours ahead.

At 7 am, a planned outage of the APD to Heywood 500kV No. 2 line commenced. A single circuit connection on the Heywood interconnector requires local lower frequency control ancillary services (FCAS) to be sourced from South Australia, which were sourced from 7 am when constraints were invoked to manage the FCAS requirements during the outage. At around 7.04 am, the Heywood-Mortlake 500kV line in Victoria tripped during the outage switching sequence, resulting in the separation of the Victoria and South Australia regions at the Heywood Terminal Station. At the time, there were imports into South Australia from Victoria on the Heywood interconnector of around 170 MW. The loss of the interconnector saw a minor fall in the frequency in South Australia. The electrical separation led to a requirement (for the 7.20 am dispatch interval onwards) for local raise

FCAS, in addition to the requirement for local lower FCAS as these services could no longer be sourced from other regions.

For the 7.20 am dispatch interval, the requirement for raise FCAS in South Australia increased to around 560 MW, from 0 MW in the previous five minutes. This saw raise FCAS offers priced at or close to the price cap dispatched and contributing to setting the price for all raise FCAS at the price cap for the 7.20 am and 7.25 am dispatch intervals. The price for lower regulation FCAS also reached $12 390/MW at 7.20 am. The large increase in FCAS led to a number of generators being backed off in the provision of energy, which saw the five minute price for energy reach $12 458/MWh at 7.25 am.

For the 7.20 am and 7.25 am dispatch intervals, the total cost of all raise FCAS was around $1.175 million and the total cost of all lower FCAS was around $72 000.

The Victoria and South Australia regions were resynchronised at around 7.20 am. This meant that constraints invoked to manage the FCAS requirements in South Australia during the event were revoked. For the 7.30 am dispatch interval, there was no longer a requirement for raise FCAS in South Australia and the energy price fell to around $50/MWh.

At 7.18 am, effective at 7.25 am, Alinta Energy rebid 100 MW of capacity at its Northern Power Station from below $60/MWh to above $11 500/MWh. The reason given was 0715A Heywood i/c at 0mw sl@7:18"

There was no other significant rebidding.

12:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	315.64	115.99	104.66
Demand (MW)	2420	2447	2483
Available capacity (MW)	3284	3244	3277
1:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	283.47	125.01	124.58
Demand (MW)	2413	2476	2495
Available capacity (MW)	3300	3243	3265

The outcomes in South Australia were driven by the events described in Victoria (above).

At 12.40 pm, effective at 12.50 pm, AGL Energy rebid 180 MW of capacity at its Torrens Island B Power Station from below $115/MWh to $300/MWh. A further rebid at 12.51 pm, effective at 1 pm, moved 150 MW of capacity from $300/MWh into prices around the price cap. The reasons given for the rebids were "12:31A chg in forecast::pd price decrease 13:30 [SA] [$50]" and "12:45chg in ic operation::unforecast i/r constraint" respectively.

There was no other significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
9 December - 15 December 2012

AUSTRALIAN ENERGY REGULATOR

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

Financial year	QLD	NSW	VIC	SA	TAS
2012-13 ($/MWh) YTD	56	59	66	66	49
2011-12 ($/MWh) YTD	30	32	28	36	30
Change*	91%	86%	138%	83%	63%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 (YTD)	$5.362	89
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)
August-12	55	58	57	65	48	0.971
September-12	53	53	55	56	40	0.812
October-12	53	58	52	52	44	0.848
November-12	55	58	94	72	51	1.045
December-12 (MTD)	58	52	64	65	51	0.458
Q4 2012 (QTD)	55	57	71	62	48	2.351
Q4 2011 (QTD)	30	33	25	35	30	1.227
Change*	81%	73%	180%	81%	60%	0.916

Table 4: ASX energy futures contract prices at end of 17 December 2012

	QLD		NSW		VIC		SA	
Q1 2013	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 10 Dec ($/MWh)	66	85	59	72	59	78	65	85
Price on 17 Dec ($/MWh)	65	86	60	73	62	81	65	85
Open interest on 17 Dec	1340	311	2122	681	1234	130	244	0
Traded in the last week (MW)	85	20	101	5	33	1	20	0
Traded since 1 Jan 12 (MW)	5061	539	7649	1022	3561	208	431	0
Settled price for Q1 12($/MWh)	30	37	26	28	25	29	26	30

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
October 12 with October 11						
MW Priced <$20/MWh	-3085	-908	-2042	-48	98	-5985
MW Priced $20 to $50/MWh	2830	-1652	857	-175	148	2008
November 12 with November 11						
MW Priced <$20/MWh	-3407	78	-1859	-61	-283	-5533
MW Priced $20 to $50/MWh	2797	-1617	452	-242	77	1467
December 12 with December 11 (MTD)						
MW Priced <$20/MWh	-2662	477	-1831	-169	-271	-4455
MW Priced $20 to $50/MWh	2461	-1357	368	-225	-248	998

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