WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

7 February – 13 February 2010

Summary

High temperatures and near record demand in both South Australia and Victoria on 8, 9 and 10 February saw multiple spot prices over $5000/MWh. The weekly averages in those states were $628/MWh and $206/MWh respectively. In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh.

In New South Wales the average spot price reached $98/MWh, primarily due to two periods of high prices over 11 and 12 February.

Average prices for the other regions were $35/MWh in Tasmania and $30/MWh in Queensland.

Spot market prices

Figure 1 sets out the volume weighted average prices for the week 7 February to 13 February 2010 and the financial year to date 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 7 – 13 February 2010	30	98	206	628	35
% change from previous week*	6	30	137	633	49246†
09/10 financial YTD	43	65	43	113	27
% change from 08/09 financial YTD**	10	34	-27	28	-45

*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 to date and the average spot price over the similar period for the previous financial year. Percentage changes are calculated on VWA prices prior to rounding.
†Of note is the very high percentage change in average prices in Tasmania for this week. This was due to the previous week being priced at an average close to $0/MWh.

The AER provides further information if the spot price exceeds three times the weekly average and is above $250/MWh. Details of these events are attached in Appendix A. Longer term market trends are attached in Appendix B[1].

[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.

Financial markets

Figures 2 to 9 show futures contract[2] prices traded on the Sydney Futures Exchange (SFE) as at close of trade on Monday 15 February 2010. Figure 2 shows the base futures contract prices for the next three calendar years, and the three year average. Also shown are percentage changes[3] compared to the previous week.

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

	QLD		NSW		VIC		SA	
Calendar Year 2010	37	2%	41	3%	41	1%	57	6%
Calendar Year 2011	38*	1%	42*	1%	42	2%	53*	-1%
Calendar Year 2012	46	0%	50	0%	53	0%	69	0%
Three year average	40	1%	45	1%	45	1%	60	2%

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

Figure 3 shows the $300 cap contract price for the first quarter of 2010 and the 2010 calendar year and the percentage change[4] from the previous week.

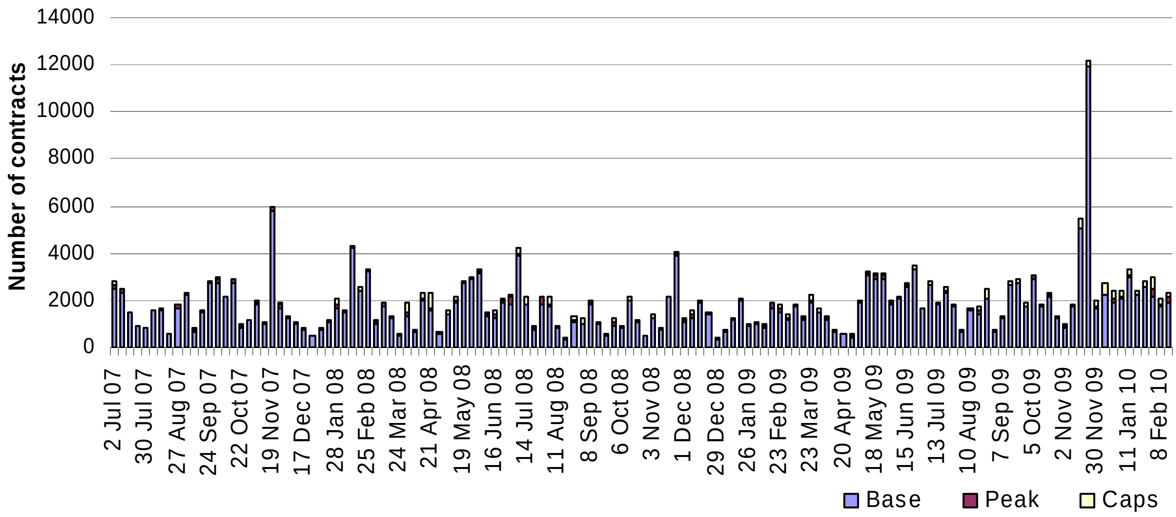
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2010 (% Change)	19	-10%	19*	3%	33*	6%	61	0%
2010 (% Change)	8	-5%	10	2%	11	5%	21	12%

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

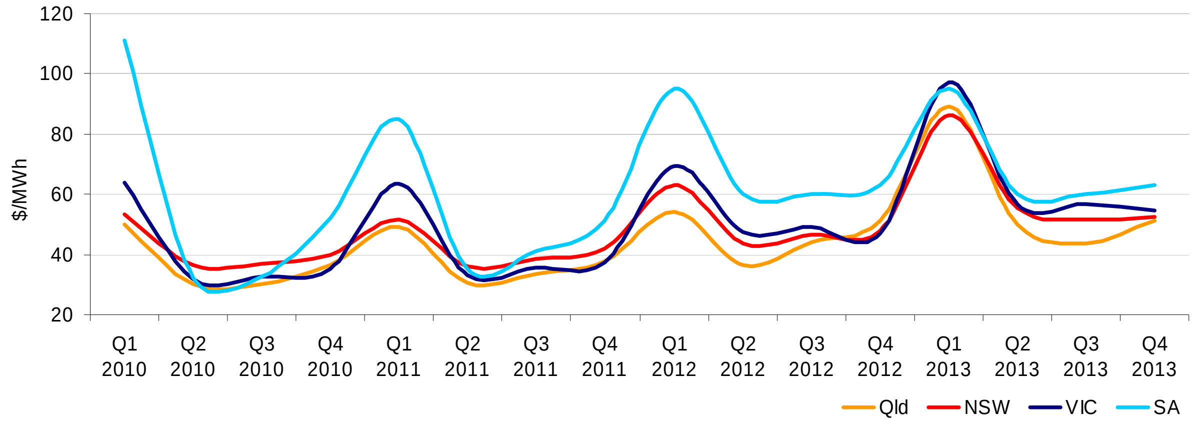


Source: d-cyphaTrade www.d-cyphatrade.com.au

[2] Futures contracts on the SFE 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.
[4] Calculated on prices prior to rounding.

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

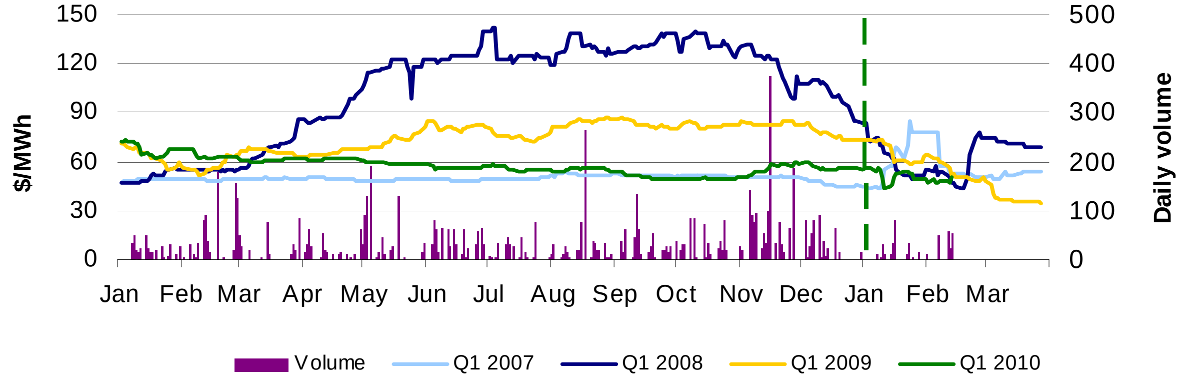
Figure 5: Quarterly base future prices Q4 2009 – Q3 2013



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

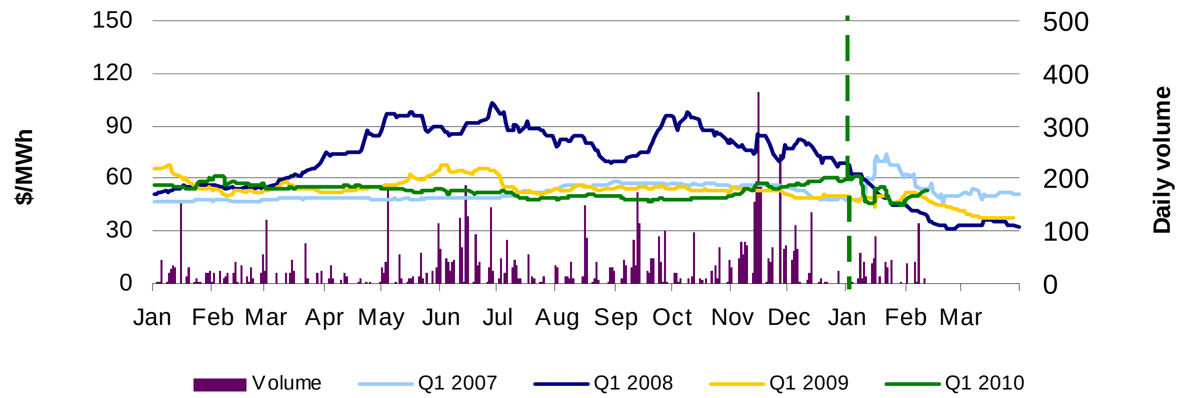
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2007, 2008, 2009 and 2010. Also shown is the daily volume of Q1 2010 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased. To understand the diagrams, the dark-blue line 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 and 2010



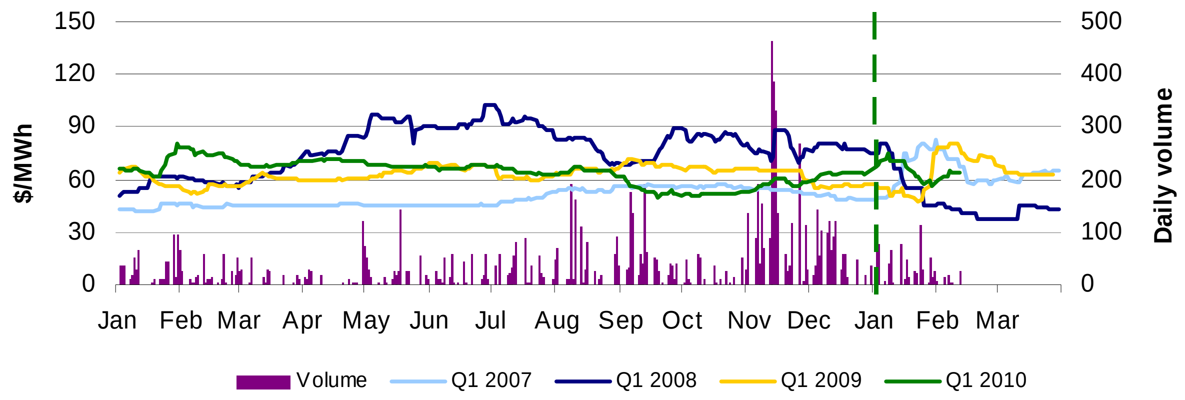
Source: d-cyphaTrade www.d-cyphatrade.com.au

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



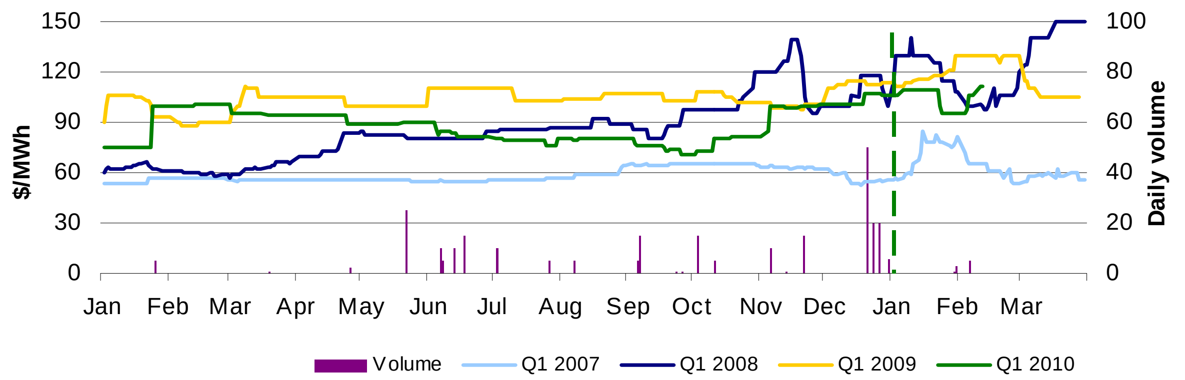
Source: d-cyphaTrade www.d-cyphatrade.com.au

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



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

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



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 391 trading intervals throughout the week where actual prices varied significantly from forecasts[5]. This compares to the weekly average in 2009 of 103 counts. 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	8	22	0	3
% of total below forecast	40	21	0	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.

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 389 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	389	-107	456	90
NSW	713	-104	739	737
VIC	381	-327	152	519
SA	108	134	171	491
TAS	169	166	-19	57
TOTAL	1760	-238	1,499	1894

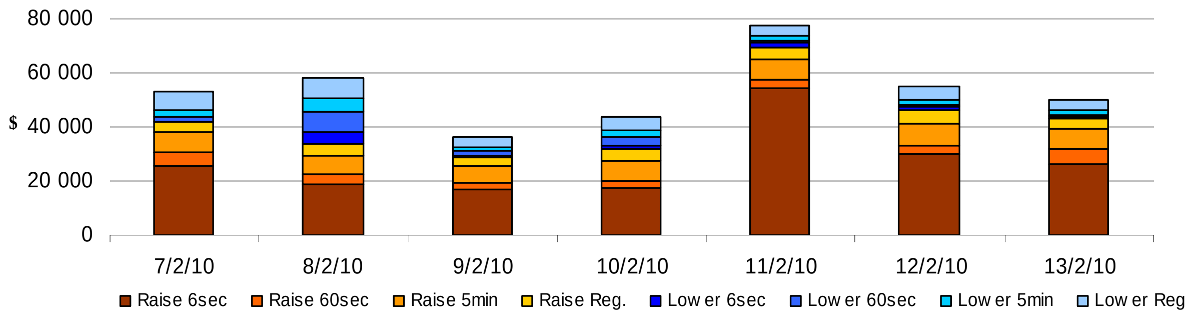
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $150 772 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $222 596 or approximately four 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
April 2010

[7] A peak period is defined as between 7 am and 10 pm on weekdays, which aligns with the SFE contract definition.

Detailed Market Analysis

AUSTRALIAN ENERGY REGULATOR

7 February – 13 February 2010

New South Wales: There were thirteen occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $98/MWh and above $250/MWh.

Thursday, 11 February

2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1997.96	50.24	120.59
Demand (MW)	12 526	12 570	12 463
Available capacity (MW)	14 210	14 269	14 289
3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1703.49	52.97	121.75
Demand (MW)	12 613	12 646	12 553
Available capacity (MW)	14 380	14 269	14 289

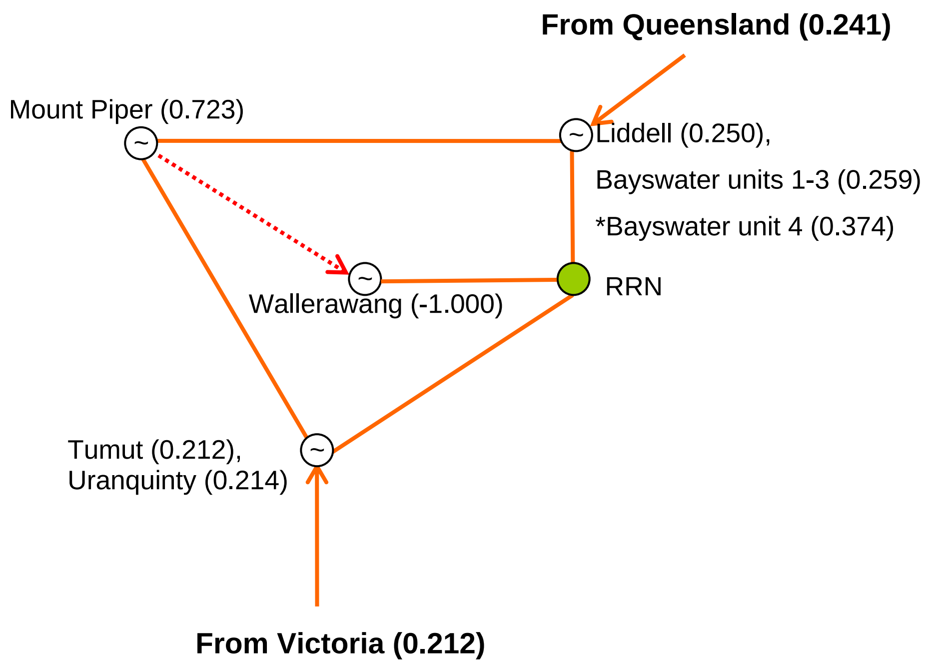
Conditions at the time saw demand and available capacity close to that forecast four hours ahead. During this time the system normal constraint N>>N-NIL__S was binding as a result of a rebid close to dispatch that reduced the availability at Wallerawang power station.

The system normal constraint N>>N-NIL__S[8] has repeatedly bound since December 2009[9]. This constraint manages flows across one of the Mt Piper to Wallerawang 330 kV lines in the event of the loss of the second Mt Piper to Wallerawang line. Figure 13 is a simplified representation of the transmission network in New South Wales, highlighting the flow paths into the regional reference node (RRN) at Sydney West, the interconnectors to Queensland and Victoria and significant generation stations. Also shown are the relevant coefficients for the stations according to the N>>N-NIL__S constraint.

[8] Constraint equations are mathematical expressions used in the dispatch engine to describe the physical limitations of the power system. System normal constraints are used when the network is operating in its normal network configuration. The N>>N-NIL__S constraint affects up to 11 700 MW of generation capacity (27 units) in New South Wales, and all three interconnectors into New South Wales.

[9] When a constraint binds it effects economic dispatch and causes generators to be constrained-on or off.

Figure 13: Simplified transmission network in New South Wales



* Bayswater unit four is connected to the 500 kV network. All other Bayswater units are connected to the 330 kV network, which explains the different coefficients.

The N>>N-NIL__S constraint is designed to prevent the Mt Piper to Wallerawang line (shown as a red dotted line) from overloading, which is consistent with Wallerawang and Mount Piper having the largest coefficients. In general, power flows from Mount Piper to Wallerawang. The direction of the power flow means that, to avoid overloading, it is necessary to increase or 'constrain-on' the Wallerawang units (with a -1.000 coefficient) and reduce or 'constrain-off' the Mount Piper units (with a 0.723 coefficient). Other generators can also influence flows across this line, but to a lesser extent (e.g. Bayswater unit four with a 0.374 coefficient is likely to be 'constrained-off' ahead of the other Bayswater units and the Liddell units with coefficients of 0.259 and 0.250 respectively, as it has a larger coefficient). The amount and rate at which a generator is 'constrained-on' or off is, however, limited by the availability and ramp rate offered by those generators. The interconnectors may also be 'constrained-off' in order to satisfy this constraint (with coefficients of 0.212 and 0.241), but unlike generators, there is no ramp rate for interconnectors.

The Mount Piper and Wallerawang units' coefficients are much greater than those for other generators or interconnectors, given their proximity to the network elements in question. If the ability to 'constrain-on' or 'constraint-off' these units is limited (for example, due to low ramp rates), then other generators and interconnectors will need to be constrained, but by a larger amount (three to four times more) to manage flows on the network.

The effects of this constraint on 11 February 2010 were twofold, firstly reducing and then forcing interconnector flows out of New South Wales, as well as constraining off significant quantities of low-priced generation within New South Wales.

Flows from Queensland into New South Wales across the QNI interconnector, were approximately 730 MW at 2.05 pm. However, flows began to run counter-price from around 2.30 pm until around 3.45 pm, reaching up to 293 MW from New South Wales into Queensland at 2.35 pm. Flows on the Terranora interconnector were also affected, with flows into New South Wales reduced by up to 80 MW.

AEMO invoked constraints across the Victoria to New South Wales interconnector to minimise counter-price flows that were also occurring on this interconnector. These constraints limited flows into Victoria to 0 MW between 2.45 pm and 3.20 pm.

Generation was also affected by the N>>N-NIL__S constraint, with up to 700 MW of capacity priced below $0/MWh constrained off. This capacity was constrained-off between 2.05 pm and 3.35 pm. A significant amount of this capacity (up to 375 MW) was constrained off at the Mt Piper power station. In addition, up to 120 MW at Liddell and 170 MW at Bayswater power stations was constrained-off.

At 1.38 pm, effective from 1.45 pm, Delta Electricity reduced available capacity at Wallerawang Unit seven by 280 MW to 220 MW (all of this capacity was previously bid as inflexible). The reason given was "Dust burden – ET2HRS::availabilty decreased". Following this rebid the unit was ramped down from 500 MW at 1.40 pm to 292 MW at 2.05 pm, at which point the N>>N-NIL__S constraint commenced binding.

At 2.12 pm, effective from 2.20 pm, Macquarie Generation rebid the ramp rates at all four units at Bayswater Power Station. The rebids increased the ramp up rates of each unit by 8 MW/min to 12 MW/min, and reduced the ramp down rates of each unit by 1 MW/min to 3 MW/min (the minimum allowable). The reasons given were "Management of unforecast transmission constraint" and "Nil change to unit bid".

At 2.40 pm, effective from 2.50 pm, Snowy Hydro reduced the ramp down rates of its Tumut 3 and Upper Tumut units. The ramp down rate at Tumut 3 was reduced from 250 MW/min to the minimum allowable of 3 MW/min. The reason given was "Unfcst NIL__S constrnt binding in disptch". The ramp down rate at Upper Tumut was reduced from 130 MW/min down to the minimum allowable of 3 MW/min, for the same reason.

Between 3 pm and 3.40 pm, 5-minute demand fluctuated significantly (by as much as 215 MW). As there was only approximately 150 MW of capacity priced between less than $0/MW and over $9000/MWh, the fluctuations in demand led to fluctuations in price. Some of this capacity was constrained-off or trapped in FCAS.

Although the 5-minute price was around $50/MWh from 2.30 pm to 2.55 pm inclusive, it reached the price cap again at 3 pm. However, coincident with the fluctuations in demand, the 5-minute price fell to close to the price floor of -$1000/MWh for the 3.05 pm, 3.15 pm and 3.35 pm dispatch intervals. The maximum 5-minute price between 3.05 pm and 3.40 pm was $300/MWh (at 3.10 pm).

Friday, 12 February

11 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	420.76	293.00	293.00
Demand (MW)	12 296	12 398	12 426
Available capacity (MW)	13 783	13 793	14 448
11:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2158.44	1797.95	584.62
Demand (MW)	12 470	12 687	12 707
Available capacity (MW)	13 991	13 873	14 448
12 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3162.01	1858.08	592.02
Demand (MW)	12 262	13 009	12 860
Available capacity (MW)	14 055	13 823	14 448
12:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	871.20	1858.08	1971.80
Demand (MW)	12 374	13 200	13 058
Available capacity (MW)	14 194	13 913	14 448
1 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2207.49	1827.78	1971.80
Demand (MW)	12 530	13 131	13 202
Available capacity (MW)	14 267	14 040	14 448
1:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2482.73	525.70	592.47
Demand (MW)	12 682	13 292	13 373
Available capacity (MW)	14 315	14 180	14 448
2 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	864.83	526.95	592.47
Demand (MW)	12 738	13 415	13 487
Available capacity (MW)	14 435	14 310	14 448
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	323.33	482.86	592.47
Demand (MW)	12 744	13 574	13 606
Available capacity (MW)	14 581	14 615	14 448
3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	596.59	3405.97	1971.80
Demand (MW)	12 991	13 690	13 695
Available capacity (MW)	14 526	13 990	14 448
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	504.32	3405.97	1978.18
Demand (MW)	13 026	13 767	13 771
Available capacity (MW)	14 629	14 128	14 448
4 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	539.77	1195.00	2134.82
Demand (MW)	13 121	13 745	13 754
Available capacity (MW)	14 683	14 563	14 448

Conditions at the time saw price generally lower and demand significantly lower than forecast, while available capacity was generally above that forecast four hours ahead. During this period the system normal constraint, N>>N-NIL__S, was binding.

The effects of this constraint on 12 February 2010 were twofold, firstly reducing imports and then forcing flows out of New South Wales, as well as constraining off significant quantities of low-priced generation within New South Wales.

Interconnector flows from Queensland into New South Wales across QNI, were reduced from approximately 750 MW at 10 am to zero by 11 am. The constraint had the effect of forcing flows counter-price into Queensland, by up to 240 MW, until after 6.30 pm.

Flows on the Terranora interconnector were also affected, with the limits on imports into New South Wales varying from over 120 MW at 11.30 am, down to around 50 MW through to after 4 pm.

AEMO invoked constraints across the Victoria to New South Wales interconnector to minimise counter-price flows on occasions down to zero.

Generation was also affected by the N>>N-NIL__S constraint, with up to 700 MW of negatively-priced capacity constrained off between 10 am and 4.30 pm. A significant amount of this capacity was constrained-off at Mt Piper (460 MW) and Bayswater Power Stations (400 MW).

On 12 February there were several rebids of significance. From 7.17 am, Macquarie Generation reduced the availability at Liddell Power Station by up to 120 MW for technical reasons including “Coal management” and “Milling limits”. Additionally, Macquarie Generation rebid the ramp rates at all 4 units at Bayswater Power Station prior to 10.05 am. These rebids increased the rate of change up by 8MW/min, and reduced the rate of change down by 1MW/min. The reasons stated were “Management of forecast constraints” and “Constraint management”.

At 10.27 am, effective from 10.35 pm, Eraring Energy rebid 480 MW of available capacity across its Eraring units one to four from prices below $50/MWh to above $9700/MWh. The reason given was “1022A Price changes in predis 1000 vs 1030”.

Set up from the previous day’s rebids, Snowy Hydro rebid both Tumut power stations rate of change down to lower rates. At Tumut 3 the rate of change down was decreased from 200 MW/min down to 3 MW/min (the minimum allowed) due to “NSW demand highr thn expctd”. At Upper Tumut the rate of change down was reduced from 130 MW/min down to 3 MW/min (the minimum allowed) for the same reason.

<u>Victoria:</u> There were eleven occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $206/MWh and above $250/MWh.

Monday, 8 February

3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1799.71	457.13	114.40
Demand (MW)	9258	8873	8613
Available capacity (MW)	9721	10 374	10 462
4 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	6481.89	2390.54	157.22
Demand (MW)	9506	9055	8772
Available capacity (MW)	9713	10 339	10 467
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	6368.41	1574.31	130.21
Demand (MW)	9330	9018	8733
Available capacity (MW)	9701	10 349	10 467

Tuesday, 9 February

2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1628.19	294.95	7828.22
Demand (MW)	9307	9109	8935
Available capacity (MW)	9943	10 226	9843
3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1668.65	287.72	8988.70
Demand (MW)	9255	9133	9009
Available capacity (MW)	9946	10 236	9843
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1650.10	130.06	9243.43
Demand (MW)	9383	9188	9053
Available capacity (MW)	9939	10 239	9843
4 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	6246.55	45.61	9331.12
Demand (MW)	9304	9191	9086
Available capacity (MW)	9936	10 214	9843

Tuesday, 9 February (cont)

4:30 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	7847.30	41.75	9366.27
Demand (MW)	9318	9122	9050
Available capacity (MW)	9920	10 191	9843
5 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1875.69	35.61	8975.80
Demand (MW)	9193	8978	8961
Available capacity (MW)	9939	10 130	9853

Wednesday, 10 February

2:30 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1489.18	524.67	9378.21
Demand (MW)	8705	9269	9252
Available capacity (MW)	10 029	10 096	10 129
3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1256.00	439.93	9551.43
Demand (MW)	8658	9306	9303
Available capacity (MW)	10 026	10 101	10 129

In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh on each of these occasions.

South Australia: There were fifteen occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $627/MWh and above $250/MWh.

Monday, 8 February

3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2083.51	1500.10	1500.10
Demand (MW)	2884	2830	2665
Available capacity (MW)	2891	2866	2866
4 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	8430.79	3829.91	1500.10
Demand (MW)	2962	2878	2703
Available capacity (MW)	2885	2863	2871
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	6719.05	2531.40	1500.10
Demand (MW)	2980	2900	2722
Available capacity (MW)	2898	2883	2928

Tuesday, 9 February

1:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	6833.20	9494.30	1000.00
Demand (MW)	2990	3013	2836
Available capacity (MW)	2986	2981	3011
2 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.76	9999.60	9000.20
Demand (MW)	3020	3167	2875
Available capacity (MW)	3006	2978	3020
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.77	9990.00	9494.30
Demand (MW)	3025	3148	2868
Available capacity (MW)	3017	2983	3023

Tuesday, 9 February (cont)

3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	8430.74	9800.00	9800.00
Demand (MW)	3037	3139	2872
Available capacity (MW)	2997	2990	3026
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.77	585.60	9990.00
Demand (MW)	3072	3125	2891
Available capacity (MW)	2984	3008	3034
4 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.77	590.00	9999.60
Demand (MW)	3111	3093	2933
Available capacity (MW)	2992	3018	3036
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.92	585.60	9999.50
Demand (MW)	3109	3082	2956
Available capacity (MW)	3012	3025	3088
5 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9705.76	39.06	9800.00
Demand (MW)	3070	2990	2956
Available capacity (MW)	3017	3033	3088
5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	8764.23	40.34	9000.10
Demand (MW)	3011	2943	2917
Available capacity (MW)	3039	3036	3101

Wednesday, 10 February

2:30 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	8823.77	1500.10	9999.77
Demand (MW)	2918	2889	2983
Available capacity (MW)	3081	2941	2960
3 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	6786.97	1500.10	9999.77
Demand (MW)	2883	2879	2964
Available capacity (MW)	3079	2950	2963
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4262.96	1500.10	9999.77
Demand (MW)	2918	2885	2970
Available capacity (MW)	3032	2944	2967

In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh on each of these occasions.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis
7 February - 13 February 2010

AUSTRALIAN ENERGY REGULATOR

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

Financial year	QLD	NSW	VIC	SA	TAS
2009-10 ($/MWh) (YTD)	43	65	43	113	27
2008-09 ($/MWh) (YTD)	40	49	59	88	49
Change*	10%	34%	-27%	28%	-45%
2008-09 ($/MWh)	36	43	49	69	62

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2009-10 (YTD)	$7.135	129
2008-09	$9.413	208
2007-08	$11.125	208

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)
Oct-09	27	28	26	30	26	0.459
Nov-09	99	138	36	325	34	1.924
Dec-09	34	130	25	26	32	1.066
Jan-10	67	63	88	160	30	1.336
Feb-10 (MTD)	29	91	156	404	17	0.867
Q4 2009	53	100	29	134	31	3.555
Q4 2008	39	51	34	32	44	2.133
Change*	35%	97%	-13%	312%	-30%	66.66%

Table 4: ASX energy futures contract prices at 15 February

	QLD		NSW		VIC		SA	
Q1 2010	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 08 Feb ($/MW)	47	81	50	70	62	110	97	185
Price on 15 Feb ($/MW)	50	81	53	73	64	110	111	185
Open interest on 15 Feb	2982	200	3624	177	4243	305	154	30
Traded in the last week (MW)	188	0	170	0	53	0	5	0
Traded since 1 Jan 09 (MW)	7826	350	8478	228	10065	612	266	20
Settled price for Q1 09($/MW)	35	48	38	48	62	114	102	200

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

Comparison:	QLD	NSW	VIC	SA	TAS	NEM
December 09 with December 08						
MW Priced <$20/MWh	872	-206	-165	503	-14	991
MW Priced $20 to $50/MWh	-423	-115	540	-68	441	375
January 10 with January 09						
MW Priced <$20/MWh	808	-25	168	179	-168	961
MW Priced $20 to $50/MWh	-603	47	-138	45	799	150
February 10 with February 09						
MW Priced <$20/MWh	583	-276	484	370	227	1389
MW Priced $20 to $50/MWh	-528	392	-309	211	581	346

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