WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

3 – 9 February 2013

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 3 February to 9 February 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 3 Feb - 9 Feb 2013	52	51	50	53	44
% change from previous week*	-73	1	11	14	-19
12-13 financial YTD	74	57	63	65	49
% change from 11-12 financial YTD**	147	88	134	91	57

*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 8 February 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.

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

	QLD		NSW		VIC		SA	
Calendar Year 2013	67	-7%	55	-1%	53	0%	57	-1%
Calendar Year 2014	56 (6)	-1%	56	-1%	54	0%	58	0%
Calendar Year 2015	52	0%	52	0%	48	0%	50	0%
Three year average	58	-3%	54	-1%	51	0%	55	0%

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

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

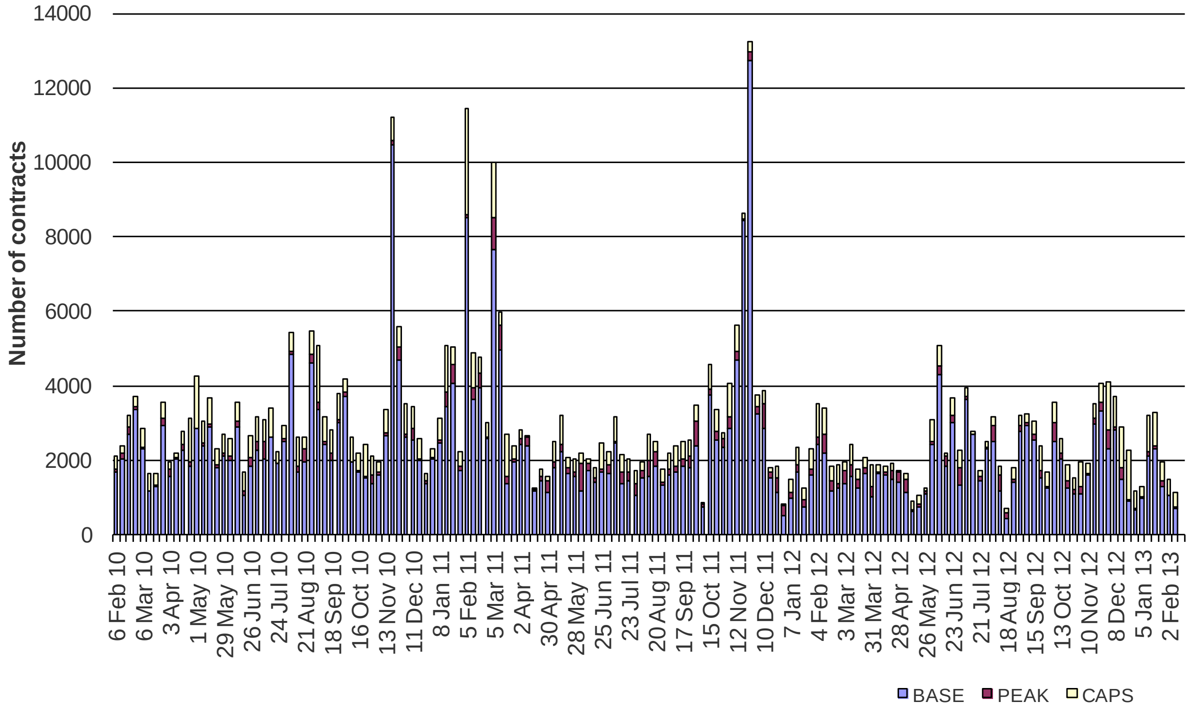
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2013	26 (71)	-16%	2 (2)	-57%	5 (1)	-20%	7	-10%
2013	9	-13%	3	-15%	3	-9%	5	-4%

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

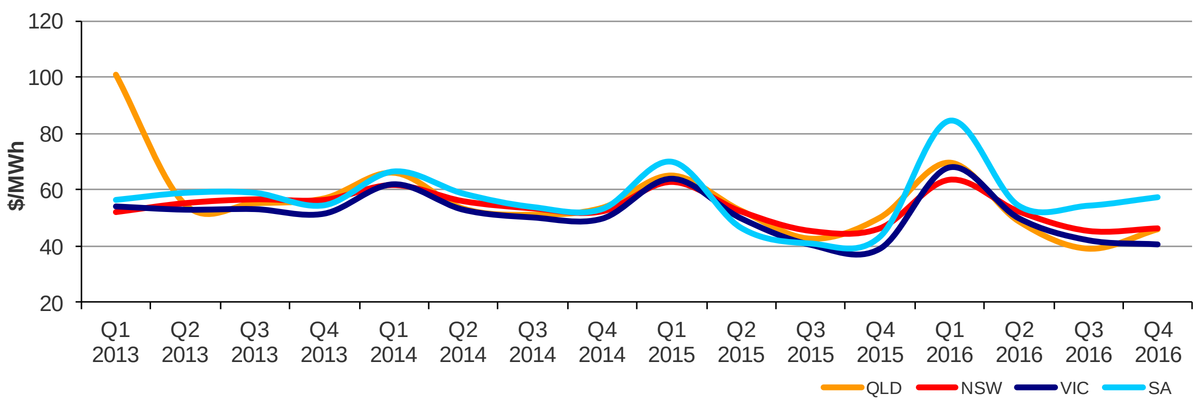
Figure 4: Number of exchange traded contracts per week



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

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

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

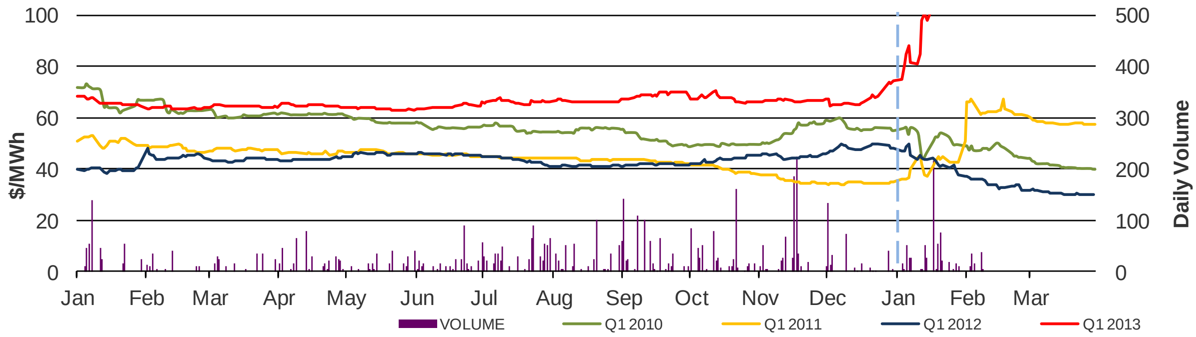


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

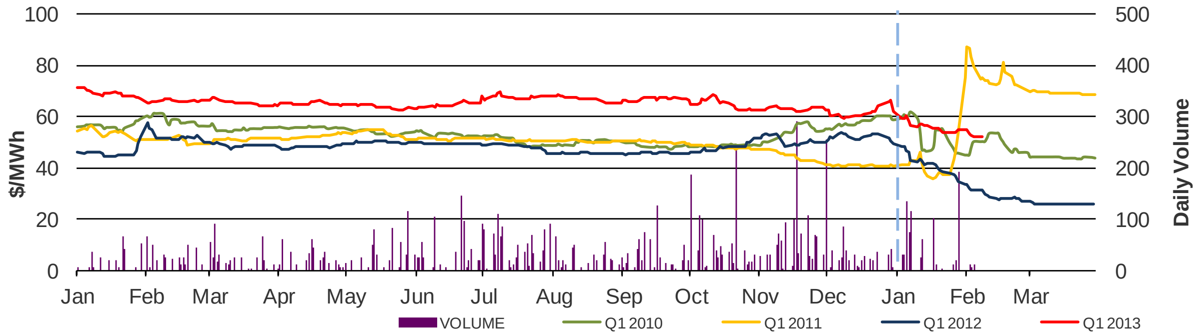
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2010, 2011, 2012 and 2013. Also shown is the daily volume of Q1 2013 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

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



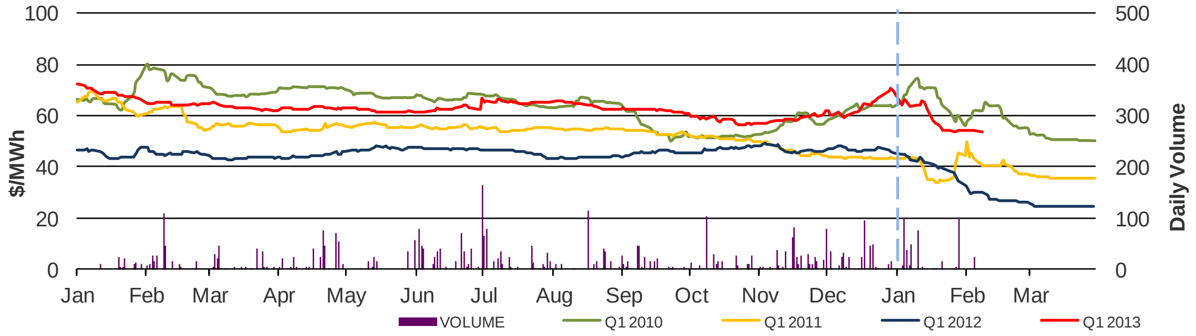
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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



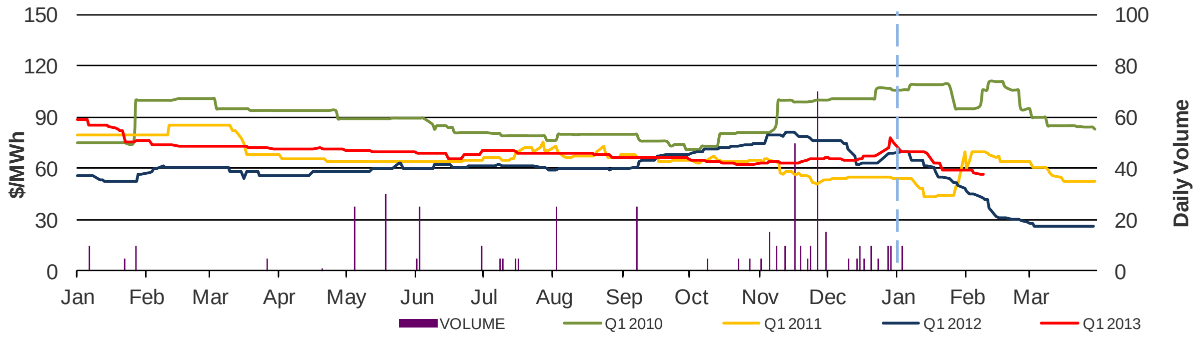
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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 50 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	8	22	17	8
% of total below forecast	25	12	9	0

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 66 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	-66	518	1623	-318
NSW	-64	-195	-62	157
VIC	137	-177	-456	988
SA	118	-2	249	377
TAS	67	48	97	39
TOTAL	192	192	1451	1243

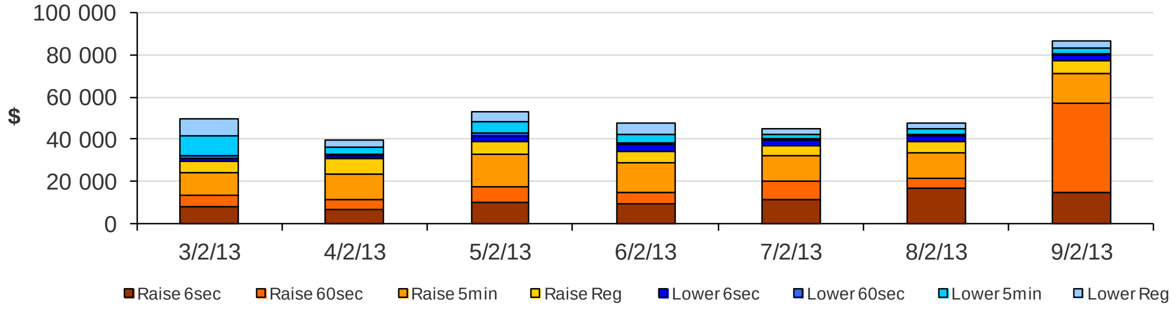
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $252 000 or less than one per cent of energy turnover on the mainland. On Sunday, a network outage in New South Wales led to local requirements in Queensland at a cost of around $13 500, this is discussed in Appendix A.

The total cost of FCAS in Tasmania for the week was $118 500 or one and a half 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
March 2013

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

3 – 9 February 2013

Queensland:

There were three occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $52/MWh and above $250/MWh, and two occasions where the spot price was less than -$100/MWh.

Sunday, 3 February

6:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	-153.28	29.99	29.99
Demand (MW)	4721	4907	4851
Available capacity (MW)	9845	9956	9987
7:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	-826.14	0.00	30.01
Demand (MW)	4676	4751	4967
Available capacity (MW)	9836	9882	9989

Conditions at the time saw demand and available capacity below that forecast.

A planned outage on the Tamworth to Liddell (84) 330 kV line in New South Wales (that forms part of the QNI interconnector), originally scheduled to occur from 5.30 am[8], was delayed and rescheduled to commence at 6.30 am. In preparation for the outage, flows on QNI from Queensland to New South Wales were required to be reduced from 6.10 am. At the time, there were around 690 MW of exports from Queensland. By the end of the 6.15 am dispatch interval, the ramping constraint invoked to prepare for the outage set the limit for exports to New South Wales on QNI to around 550 MW, a step change of around 140 MW from the previous five minutes. This saw a rapid reduction in Queensland generation dispatch and with generators either ramp rate limited or trapped or stranded in frequency control ancillary services (FCAS), low priced capacity saw the five minute dispatch price reduce from $40/MWh to $0/MWh at 6.15 am.

At 6.14 am, effective from 6.20 am, CS Energy reduced the bid maximum consumption of Wivenhoe Pump 2 by 245 MW to zero[9]. The reason given was “0613P Water management-sl”. The pump was operating at around 240 MW at the time. This unforecast reduction in scheduled load, at the same time that exports to New South Wales were limited as a result of the QNI outage, saw a reduction in Queensland generation of around 250 MW (previously satisfying the pump load) within five minutes.

8 The interconnector was ramped down from 4.30 am in preparation for the original outage start time but then the normal limits were restored at 5.35 am.

9 Wivenhoe Pump 2 is a normally off scheduled load. It places bids into dispatch to indicate at what price levels it is willing to consume.

This resulted in the five minute dispatch price falling to the price floor as several generators were ramp rate limited or trapped in FCAS and offers at the price floor were dispatched and setting the price.

For the 6.35 am dispatch interval, once the network outage commenced, further constraints were invoked that saw exports from Queensland on QNI reduced by a further 145 MW from the previous five minutes. The outage also led to requirements for local lower FCAS, as these services could only be sourced locally in the event of electrical separation from New South Wales. At the same time, demand in the region was around 100 MW below forecast.

The combination of reduced export limits, lower than forecast demand and local FCAS requirements saw Queensland generation reduce by around 230 MW from the previous five minutes. With several generators ramp rate limited or enabled for contingency FCAS, the five minute dispatch price fell to the price floor and remained there for the 6.40 am dispatch interval. At 6.34 am, effective from 6.45 am, Stanwell Corporation rebid 1485 MW of capacity across its portfolio from prices around $30/MWh to the price floor. The reason given was “0633F Avoid uneconomic outage”.

At 6.35 am, effective from 6.45 am, CS Energy rebid 660 MW of capacity at its Gladstone Power Station priced at zero to the price floor. The reason given was “0634A Pool price negative-sl”.

This rebidding saw around 4300 MW of available capacity priced below zero during a time of low demand in the region. This saw the five minute dispatch price continue to be set at the price floor from 6.45 am to 7 am.

The increased local lower FCAS requirements resulted in the cost of all lower FCAS accruing to around $11 200, with the price of lower 5-minute and lower regulation services increasing to around $1000/MW for the 7 am trading interval.

Tuesday, 5 February

The high prices at 4 pm (and at 12.30 pm and 4.30 pm on 8 February) were caused by congestion around Gladstone (on the Calvale to Wurdong and Calvale to Stanwell lines) and were similar to the circumstances explained in the “*Special report - The impact of congestion on bidding and inter-regional trade in the NEM”* published by the AER in December 2012. The report is available at http://www.aer.gov.au/node/18855.

Congestion on the Calvale to Wurdong and Calvale to Stanwell lines can be alleviated through a combination of increasing output from generators north of Calvale (e.g. Gladstone and Stanwell Power Stations), reducing generation south of Calvale and/or increasing the flow on the QNI interconnector towards New South Wales. A number of low priced or constrained generators were ramp rate limited or trapped in FCAS at the relevant times, contributing to the dispatch of high priced generation. Forced exports from Queensland to New South Wales, counter-priced, saw negative settlement residues accrue on the QNI interconnector.

4:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	333.26	57.33	63.66
Demand (MW)	6721	6845	7038
Available capacity (MW)	10 144	10 207	10 359

Conditions at the time saw demand and available capacity below forecast.

The Calvale to Wurdong constraint bound on the QNI interconnector from the 3.45 pm dispatch interval, forcing exports to New South Wales from Queensland (counter priced).

At 3.43 pm, effective from 3.50 pm, CS Energy rebid 120 MW of capacity at its Gladstone power station from prices around $50/MWh to the price cap. The reason given was “1542A 855_871 constraint-sl”.

At 3.50 pm, effective at 4 pm, Stanwell Corporation rebid 320 MW at its Stanwell power station from prices between $300/MWh and $500/MWh to around $1000/MWh. In the same rebid, 575 MW of capacity was rebid at Tarong power station to the price floor, the majority of which was priced around $30/MWh and 83 MW of capacity at Kareeya power station was shifted from prices below zero to the price cap. The reason given was “1549A Transmission constraint: 855_871 binding”.

Following this rebidding, ramp rate limitations for lower priced generation saw the higher priced generation at Gladstone dispatched, contributing to setting the five minute dispatch price at 4 pm to $1635/MWh.

Rebidding into lower prices in response to the price spike and generators no longer ramp rate limited saw the five minute dispatch price fell below $50/MWh by 4.10 pm.

There was no other significant rebidding.

Friday, 8 February

12:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	278.31	54.59	55.44
Demand (MW)	6706	6760	6849
Available capacity (MW)	10 558	10 663	10 683

4:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	273.40	72.52	62.50
Demand (MW)	6698	6956	6999
Available capacity (MW)	10 569	10 540	10 658

Conditions at the time saw demand up to 258 MW below that forecast four hours ahead, while available capacity was up to 105 MW below that forecast four hours ahead.

The Calvale to Wurdong constraint bound for the majority of the day, leading to volatile five minute dispatch prices in Queensland from 12.25 pm until around 6 pm. Rebidding by a number of generators combined with ramp rate limitations at times led to higher priced generation being dispatched to meet demand and satisfy the constraint . The five minute dispatch price reached $1476/MWh at 12.25 pm and $1441/MWh at 4.20 pm as a result.

Contributing rebids are set out below:

- At 12.17 pm, effective from 12.25 pm and only for the remainder of the 12.30 pm trading interval, CS Energy rebid 150 MW of capacity at Gladstone priced around $50/MWh to the price cap. The reason given was “1216A 855_871 constraint-sl”.
- At 4.13 pm, effective from 4.20 pm and only for the remainder of the 4.30 pm trading interval, CS Energy rebid 200 MW of capacity at Gladstone priced around $50/MWh to the price cap. The reason given was “1613A 855_871 constraint-sl”.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis

3 February - 9 February 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 ($/MWh) YTD	74	57	63	65	49
2011-12 ($/MWh) YTD	30	30	27	34	31
Change*	147%	88%	134%	91%	57%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	7.519	119
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)
October-12	53	58	52	52	44	0.848
November-12	55	58	94	72	51	1.045
December-12	62	50	55	57	47	0.881
January-13	170	51	60	68	57	1.489
February-13 (MTD)	55	50	48	51	44	0.244
Q1 2013 QTD	145	51	57	64	54	1.733
Q1 2012 QTD	33	26	25	28	38	0.628
Change*	337%	97%	124%	130%	41%	1.760

Table 4: ASX energy futures contract prices at end of 8 February 2013

	QLD		NSW		VIC		SA	
Q1 2013	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 1 Feb ($/MWh)	120	153	55	62	54	66	59	79
Price on 8 Feb ($/MWh)	101	125	52	59	54	65	57	74
Open Interest on 8 Feb ($/MWh)	1523	324	2451	692	1245	178	270	0
Traded in the last week (MW)	105	1	25	1	25	1	0	0
Traded since 1 Jan 12 (MW)	5869	601	8681	1069	4243	291	481	0
Settled price for Q1 12 ($/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
December 12 with December 11						
MW Priced $20/MWh	-2990	273	-1725	-115	-219	-4777
MW Priced $20/MWh to $50/MWh	2632	-867	605	-235	33	2168
January 13 with January 12						
MW Priced $20/MWh	-2772	-2217	-1360	-41	-235	-6625
MW Priced $20/MWh to $50/MWh	1812	1269	1255	-346	339	4330
February 13 with February 12 (MTD)						
MW Priced $20/MWh	-2824	-1694	-974	-52	-364	-5909
MW Priced $20/MWh to $50/MWh	1589	650	645	-264	398	3019

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

** Estimated value