WEEKLY ELECTRICITY MARKET ANALYSIS

AUSTRALIAN ENERGY REGULATOR

13 January – 19 January 2013

Spot market prices

Figure 1 sets out the volume weighted average (VWA) prices for the week 6 January to 12 January 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.

Queensland experienced periods of high spot prices. These price events were driven by hot weather that saw high demand and reduced network capability leading to congestion in central Queensland. Generator rebidding exacerbated the congestion issues and created significant price volatility. The AER's *"Special report - The impact of congestion on bidding and inter-regional trade in the NEM"* provides further detail of the congestion issues in Queensland.

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

	QLD	NSW	VIC	SA	TAS
Average price for 13 Jan - 19 Jan 2013	223	54	47	51	46
% change from previous week*	3	4	-1	-25	-6
12-13 financial YTD	70	57	65	66	49
% change from 11-12 financial YTD**	134	88	140	93	60

*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 11 January 2013. Figure 2 shows the base futures contract prices for the next three calendar years, and the average over these three years. Also shown are percentage changes[3] from the previous week.

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

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

[3] Calculated on prices prior to rounding.

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

	QLD		NSW		VIC		SA	
Calendar Year 2013	68 (70)	9%	55	-1%	53	-3%	59	-3%
Calendar Year 2014	57 (25)	1%	56	0%	54 (5)	-1%	57	0%
Calendar Year 2015	51	0%	52	0%	48	0%	50	0%
Three year average	59	3%	55	0%	52	-1%	56	-1%

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

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

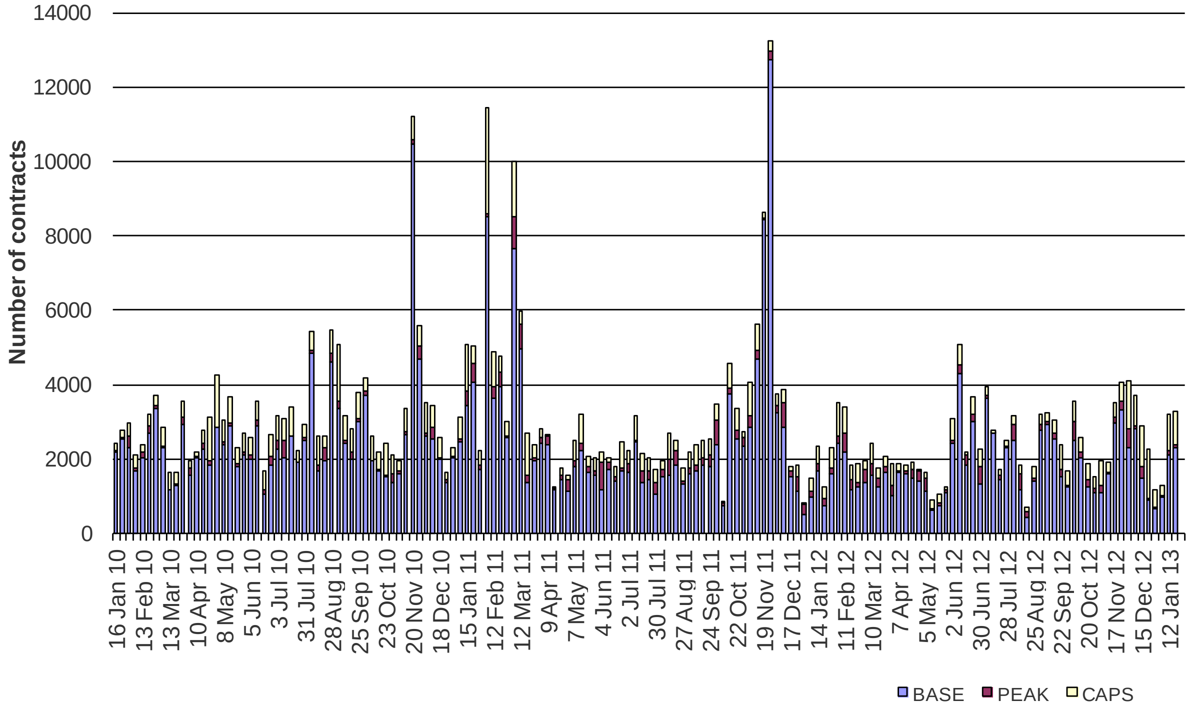
Figure 3: $300 cap contract prices ($/MWh)

	QLD		NSW		VIC		SA	
Q1 2013	34(255)	57%	4 (230)	-23%	8 (122)	-48%	15 (5)	-9%
2013	11	44%	4	-6%	4	-32%	7	-6%

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

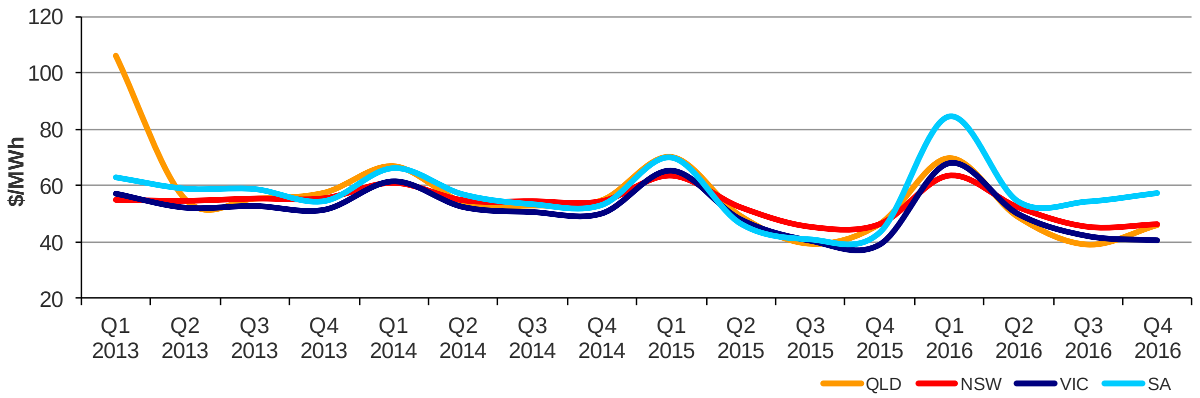


Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

[4] Calculated on prices prior to rounding.

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

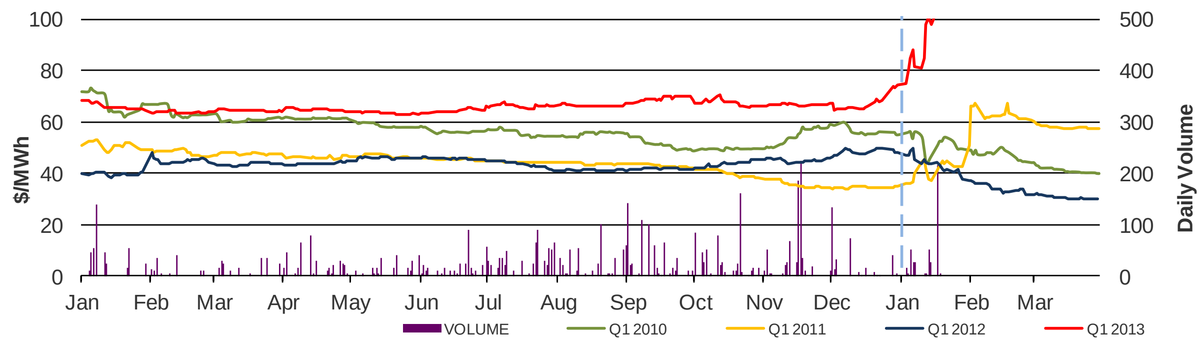
Figure 5: Quarterly base future prices Q1 2013 – Q4 2016



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

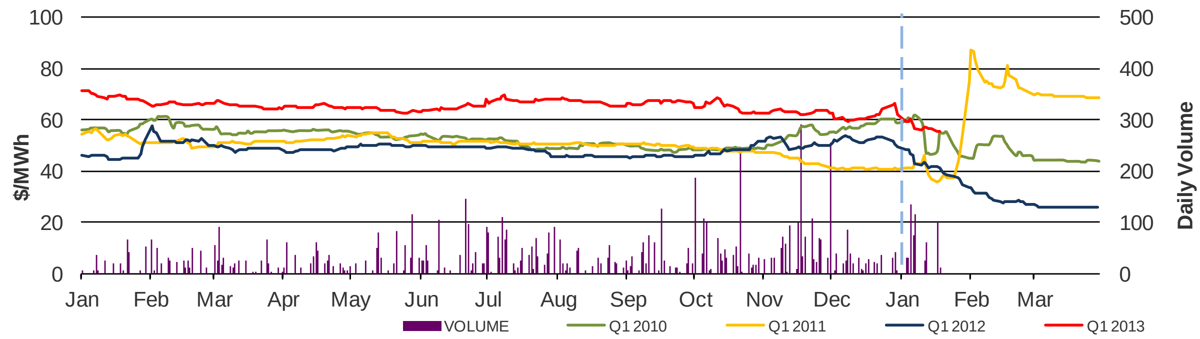
Figures 6-9 compare for each region the closing daily base contract prices for the first quarter of 2010, 2011, 2012 and 2013. Also shown is the daily volume of Q1 2013 base contracts traded. The vertical dashed line signifies the start of the Q1 period for which the contracts are being purchased.

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



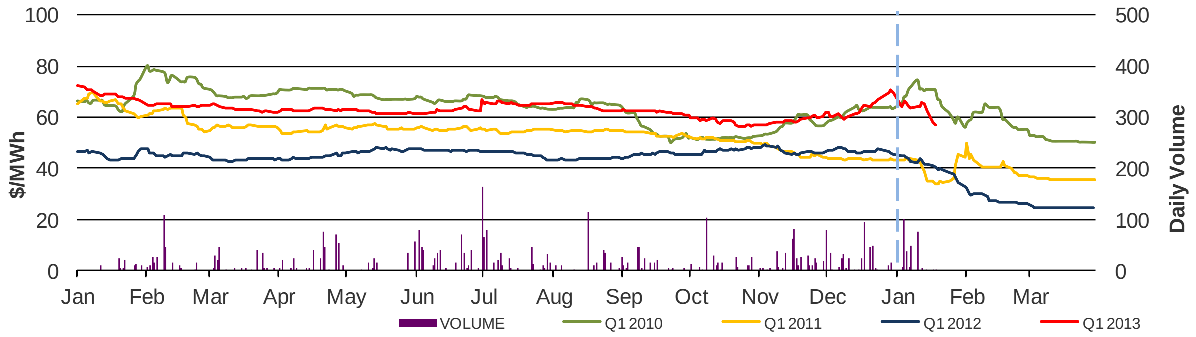
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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



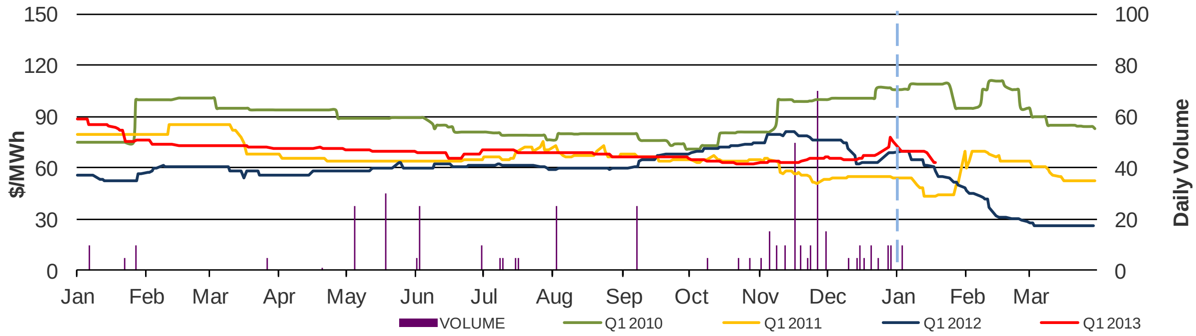
Source: d-cyphaTrade/ASX www.d-cyphatrade.com.au

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 196 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].

[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	7	43	4	12
% of total below forecast	22	10	0	3

The total may not equal 100% due to rounding

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 42 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	42	-125	-90	-225
NSW	-30	290	-211	-147
VIC	152	-128	82	235
SA	23	49	96	21
TAS	12	-11	-71	0
Total	199	75	-194	-116

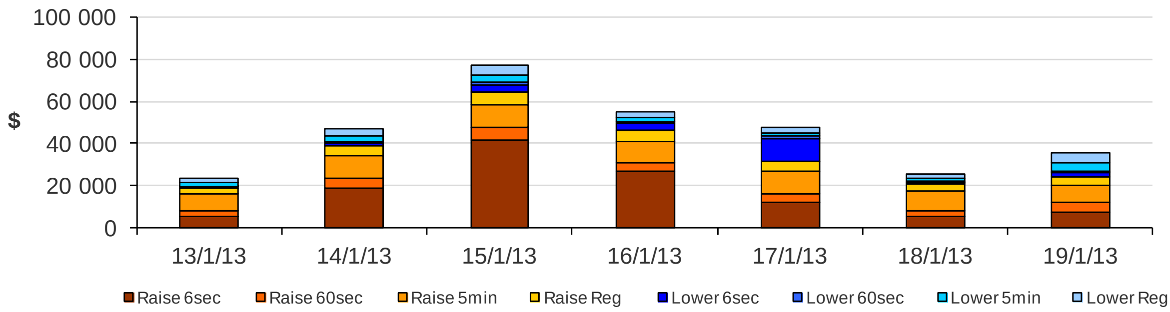
Ancillary services market

The total cost of frequency control ancillary services (FCAS) on the mainland for the week was $169 500 or less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $144 500 or 1.7 per cent of energy turnover in Tasmania. The majority of FCAS costs in Tasmania were for local raise 6 second services, with frequent occurrences where the price of these services reached around $200/MW for extended periods of time. This was driven by network constraints which prevented the transfer of FCAS on BassLink.

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 2013

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

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Queensland:

There were fifteen occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $223/MWh and above $250/MWh.

A number of these high prices were caused by congestion around Gladstone 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.

Sunday, 13 January

11:00 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2486.67	172.16	327.33
Demand (MW)	6856	6757	6761
Available capacity (MW)	8999	9453	9453

Conditions at the time saw demand close to forecast and available capacity around 450MW below that forecast.

Rebidding by Origin Energy, effective for the 11 am trading interval, reduced available capacity by a total of 470 MW to zero at the offline Mt Stuart and Roma power stations to avoid uneconomic unit start.

At 10.36 am, first effective at 10.45 am, CS Energy rebid 120 MW of capacity at Gladstone power station priced around $51/MWh to the price cap. The reason given was “1031A Dispatch price lower than 5min forecast-SL”. With imports into the region on both QNI and Directlink at their limit and a number of generators required to increase their output to continue to meet demand ramp rate limited, the high priced generation offered at Gladstone was dispatched and contributed to setting the five minute dispatch price to the price cap. The five minute dispatch price fell to $1062.93/MWh at 10.50 am once lower priced generation was no longer ramp rate limited. The price fell below $300/MWh in the next dispatch interval as fast start plant that had rebid capacity into lower prices in response to the price spike received targets to start.

There was no other significant rebidding.

12:30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2290.05	208.39	499.83
Demand (MW)	7150	6942	7086
Available capacity (MW)	9278	9517	9520

Conditions at the time saw available capacity below forecast.

At 11.45 am, effective from 12.05 pm, Stanwell Corporation rebid 140 MW of capacity at Stanwell power station priced between $300/MWh and $1600/MWh to prices around $2000/MWh and the price cap. The reason given was “1143A Mnge binding q>>nil_855_871 constraint sl”.

At 12.03 pm, effective at 12.10 pm, AGL Energy rebid 60 MW of capacity at Oakey unit 1 to the price floor and an additional 85 MW to prices above $450/MWh. All of this capacity was previously priced around $430/MWh. The reason given was “12:05A Chg in dispatch:: price increase vs pd qld [>200] 5mpd”.

At 12.04 pm, effective at 12.15 pm, CS Energy reduced the available capacity at Callide B unit 2 by 90 MW, all of which was priced at the price floor. The reason given was “1203P unit back end temps high-sl”.

By the 12.15 pm dispatch interval, available capacity was reduced by a further 175 MW following rebidding by Origin Energy to reduce the available capacity at the offline Mt Stuart unit 2 and Roma unit 8 to zero to avoid uneconomic unit starts. All of this capacity was priced below $1000/MWh.

The reduced availability of lower priced capacity, combined with an incremental increase in demand and limited ramp rate, saw the higher priced generation at Stanwell dispatched and setting the five minute dispatch price to $2001/MWh at 12.15 pm.

At 12.11 pm, CS Energy rebid 120 MW of capacity at Gladstone units 3, 4 and 6 to the price cap and 15 MW of capacity to below $50/MWh. All of this capacity was previously priced around $50/MWh. The reason given was “1210A dispatch price higher than 30 min forecast-sl”. This rebid was not used in dispatch as a further rebid was submitted at 12.12 pm, effective at 12.20 pm, with these same parameters. The only additional change was an increase in the down ramp rate of each unit from 5MW/minute to 12MW/minute. The reason given was “1211E Correct error in previous bid-sl”.

Also at 12.11 pm, effective at 12.20 pm, Alinta Energy rebid 46 MW of capacity at Braemar A unit 1 from the price floor to above $9500/MWh. The reason given was “1211A Br1 qld dispatch price at $2001 v $644.83@12:11”.

Limited ramp rate again saw the higher priced generation at Gladstone and Braemar A dispatched and setting the five minute dispatch price to $10 450/MWh at 12.20 pm.

There was no other significant rebidding.

3:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2918.26	274.52	503.90
Demand (MW)	7552	7598	7588
Available capacity (MW)	9277	9590	9550

3:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2613.32	503.04	543.02
Demand (MW)	7635	7695	7649
Available capacity (MW)	9298	9585	9545

4:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1179.99	503.04	543.02
Demand (MW)	7688	7761	7707
Available capacity (MW)	9306	9580	9550
4:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	870.81	503.04	543.00
Demand (MW)	7751	7732	7693
Available capacity (MW)	9314	9550	9570

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

From most of this period, both the constraint managing voltage stability for the loss of Kogan Creek and the constraint to avoid overloading the Calvale to Wurdong 871 line for the loss of the Calvale to Stanwell 855 line, the "Calvale to Wurdong" constraint, were binding, which restricted imports across the QNI interconnector.

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 reducing northerly flow on the QNI interconnector.

With imports into Queensland across both interconnectors limited to around 170 MW by constraints, demand had to be mostly met by Queensland generation. Queensland demand was between 7500 MW to 7600 MW for the majority of the trading interval and with all capacity above 7200 MW in the region priced above $400/MW, higher priced generation was dispatched and contributed to setting the five minute dispatch price to above $600/MWh from 2.35 pm to 2.50 pm.

At 2.46 pm, effective at 2.55 pm and only until the end of the trading interval, CS Energy rebid 30 MW of capacity at Gladstone power station priced around $50/MWh to the price cap. The reason given was "1446A Dispatch price higher than 30min forecast-sl".

With limited imports and ramp rate limitations on a number of generators, an increase in demand of around 80 MW saw generation priced at the price cap dispatched and setting the five minute dispatch price to the price cap at 2.55 pm.

At 2.44 pm, effective at 3.05 pm, Stanwell Corporation rebid 40 MW of capacity at Stanwell priced below $1600/MWh to around $2000/MWh. The reason given was "1442A Mnge Q>>NIL_855_871 constraint; dispatch out of merit sl".

At 3.05 pm, effective at 3.15 pm, CS Energy rebid 150 MW of capacity at Callide B power station priced at the price floor to the price cap and 500 MW of capacity from the price floor to $0/MWh. In the same rebid, 120 MW of capacity at Gladstone was shifted from the price cap to around $50/MWh. The reason given was "1502A Rearrangement due to 855-871 constraint-sl".

Higher priced generation at Stanwell set the five minute dispatch price at 3.20 pm to $2001/MWh.

At 3.18 pm, effective at 3.25 pm, Alinta Energy rebid 44 MW of capacity at Braemar A unit 1 from the price floor to around $10 000/MWh. The reason given was "1517A Br1 QLD dispatch price at $2001 V $644@15:18". An increase in demand of around 60 MW and ramp rate limitations saw higher priced generation at Braemar A dispatched and setting the five minute dispatch price at 3.25 pm to $10 100/MWh.

At 3.20 pm, effective at 3.30 pm, Alinta Energy reversed the earlier rebid at Braemar A unit 1. The reason given was “1520a Br1 QLD dispatch at $10100 v $2001@15:20”. This rebid combined with a small reduction in demand saw generators no longer ramp rate limited and the five minute dispatch price at 3.30 pm fell to $2001/MWh and remained there for the 3.35 pm dispatch interval.

The five minute dispatch price fell below $500/MWh at 3.40 pm as fast start plant came online and received dispatch targets.

Between 3.40 pm and 3.55 pm, an increase in demand of around 80 MW combined with ramp rate limitations for lower priced generation saw the five minute dispatch price again reach $2001/MWh at 3.55 pm and 4 pm.

At 4.14 pm, effective at 4.20 pm, CS Energy rebid 75 MW of capacity at Gladstone from prices around $50/MWh to around $10 000/MWh. The reason given was “1613A Dispatch price higher than 30min forecast-sl”.

This reduction in lower priced capacity combined with an increase in demand at 4.25 pm, again resulted in higher priced generation dispatched and setting price to $2001/MWh at 4.25 pm and 4.30 pm.

There was no other significant rebidding.

8:00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1567.00	150.34	321.00
Demand (MW)	7590	7468	7408
Available capacity (MW)	9258	9565	9667
9:30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	860.66	455.23	109.57
Demand (MW)	7178	7164	7114
Available capacity (MW)	9366	9573	9652

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

Earlier rebidding saw the majority of capacity above 7200 MW offered at prices above $1000/MWh. With imports into Queensland limited to around 200 MW for the majority of the period due to interconnector constraints, the five minute dispatch price reached above $1000/MWh for the duration of the 8 pm trading interval.

Continuing tight supply conditions saw the five minute dispatch price exceed $500/MWh at 9.05 pm and 9.10 pm.

At 9.06 pm, effective at 9.15 pm, Alinta Energy rebid 31 MW of capacity at Braemar A unit 1 priced around $550/MWh to around $10 000/MWh. The reason given was “2105A Br1 QLD dispatch price at $578 V $358.60@21:05”.

This reduction in moderately priced capacity combined with ramp rate limited generation saw higher priced offers dispatched and setting the price to $1017/MWh at 9.15 pm.

At 9.20 pm, Queensland demand increased by around 30 MW and this saw the five minute dispatch price reach $2000/MWh.

There was no other significant rebidding

11:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	763.79	70.98	57.27
Demand (MW)	6406	6341	6354
Available capacity (MW)	8949	9411	9647

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

At 10.01 pm, effective at 10.10 pm, CS Energy rebid 60 MW of capacity at Gladstone unit 3 priced around $50/MWh to the price cap. The reason given was “2201A Dispatch price higher than 5min forecast-sl”. At 10.07 pm, effective at 10.15 pm, CS Energy rebid 120 MW of capacity at Gladstone units 4 and 6 priced around $50/MWh to the price cap. The reason given was “2206A Dispatch price higher than 5min forecast-sl”.

From 10.30 pm, the Calvale to Wurdong constraint bound. 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.

To manage the constraint, lower priced generation at Callide was constrained off and imports into Queensland on QNI were reduced. Ramp rate limitations saw higher priced generation at Gladstone dispatched and contributing to setting the five minute dispatch price to $1568 at 10.30 pm. .

Conditions were largely unchanged for the next two dispatch intervals, with the five minute dispatch price set to $1573/MWh at 10.35 pm and $1587/MWh at 10.40 pm. An increase in imports into Queensland saw lower priced generation no longer ramp rate limited and the five minute dispatch price fall to $1044/MWh at 10.45 pm.

There was no other significant rebidding.

Monday, 14 January

6:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1469.65	56.06	54.81
Demand (MW)	5776	5920	5817
Available capacity (MW)	9225	9515	9515

7:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2498.67	55.10	53.30
Demand (MW)	6415	6641	6557
Available capacity (MW)	9000	9464	9484

Conditions at the time saw demand and available capacity below forecast. From 6.05 am, the Calvale to Wurdong constraint bound and this saw a step change in the export limit on QNI of around 325 MW, forcing exports from Queensland to New South Wales.

At 6.20 am, a step change in the right hand side of the constraint saw generation south of Calvale reduced and generation at Gladstone (offered at the price cap) dispatched and contributing to setting the price to $1541/MWh.

At 6.23 am, effective at 6.30 am, Alinta Energy rebid 48 MW of capacity at Braemar A unit 1 priced around $5/MWh to around $10 000/MWh. The reason given was “0621A Change in QLD dispatch price $1540 v $208@6:23”. At 6.30 am, Queensland demand increased by around 84 MW. With fast start and intermediate plant offline or no longer available following earlier rebidding during the trading interval, and other generators ramp rate limited, generation at Stanwell priced at the price cap was dispatched and contributed to setting the five minute dispatch price to $6619/MWh.

At 6.48 am, effective at 6.55 am, CS Energy reduced the available capacity of Gladstone unit 3 by 135 MW to 145 MW. The reason given was “0647P Condenser backflush – sl”.

At 7.05 am, a step change in the right hand side of the Calvale to Wurdong constraint saw a step change in the dispatch of Queensland generation. To manage the constraint, generation south of Calvale was reduced. Demand in Queensland also increased by around 80 MW. Ramp rate limitations and generation trapped in FCAS led to the constraint violating. The 7.05 am five minute dispatch price reached the price cap. The five minute dispatch price fell below $200/MWh at 7.10 am following rebidding to low prices in response to the price spike and as generators became no longer ramp rate limited.

At 7.20 am, demand in Queensland increased by around 100 MW and at the same time, forced exports to New South Wales increased by around 285 MW. The Calvale to Wurdong constraint was still binding at this time and constraining down generation at Callide while constraining up generation at Gladstone and Stanwell. With fast start plant still in the process of starting, ramp rate limitations and some generators trapped in FCAS, higher priced generation from peaking plant contributed to setting the five minute dispatch price to $1833/MWh at 7.20 pm.

There was no other significant rebidding.

10:30 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1740.03	275.28	500.00
Demand (MW)	7481	7621	7642
Available capacity (MW)	9413	9523	9373

11:00 AM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	956.79	275.28	499.94
Demand (MW)	7563	7714	7723
Available capacity (MW)	9269	9521	9366

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

At 9.59 am, effective at 10.05 am, CS Energy rebid 240 MW of capacity at Gladstone priced around $50/MWh to the price cap. The reason given was “0958A 855_871 constraint-SL”.

At 10.09 am, effective at 10.15 am, CS Energy rebid 60 MW of capacity at Callide B priced at the price floor to the price cap. The reason given was “1007A 855_871 constraint-Ssl”.

At 10.17 am, effective at 10.25 am, Arrow Energy rebid 160 MW of capacity at Braemar unit 5 priced around $300/MWh to around $12 000/MWh. The reason given was “1010A QLD price higher than fcast: avoid uneconomic start Ssl”.

At 10.25 am, there was a step change in the right hand side of the Calvale to Wurdong constraint and an increase in Queensland demand of around 30 MW. Ramp rate limitations and generators stranded in FCAS saw higher priced generation contributing to setting the five minute dispatch price to $6601/MWh.

At 10.30 am, there was a further step change in the right hand side of the constraint that saw generators at Callide ramp rate down constrained and Stanwell ramp rate up constrained with generation priced at the price cap at Gladstone dispatched and contributing to setting the five minute dispatch price to $1644/MWh.

At 10.26 am, effective from 10.35 am, CS Energy extended the earlier rebid of 240 MW of capacity at Gladstone priced around $50/MWh to the price cap. The reason given was “1025A 855_871 constraint-sl”.

At 10.35 am there was a further step change in the right hand side of the Calvale to Wurdong constraint. With generators at Callide and Stanwell still ramp rate limited, higher priced generation again contributed to setting the five minute dispatch price at 10.35 am and 10.40 am to $1644/MWh.

With imports into Queensland limited to around 150 MW by constraints, demand had to be mostly met by Queensland generation. With Queensland demand increasing steadily from around 7500MW to more than 7600 MW for the remainder of the trading interval and with all capacity above 7500 MW priced above $600/MWh, higher priced generation was dispatched and contributed to setting the five minute dispatch price above $600/MWh from 10.50 am to 11.00 am.

Around $860 000 of negative settlement residues accrued on the day, primarily as a result of congestion around Gladstone leading to counter price flows into New South Wales.

There was no other significant rebidding.

Friday, 18 January

8:30 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1972.02	53.24	51.68
Demand (MW)	6706	6786	6716
Available capacity (MW)	9373	9662	9634

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

At 8.30 am there was a step change in the right hand side of the Calvale to Wurdong constraint. At the time, there were forced exports to New South Wales on QNI. Ramp rate limitations and generators trapped in FCAS meant that the constraint equation could not be satisfied causing the constraint to violate. The 8.30 am five minute dispatch price reached $11 566/MWh.

There was no significant rebidding.

5:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1989.07	206.88	306.44
Demand (MW)	7964	7698	7705
Available capacity (MW)	9724	9821	9836

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

At 4.42 pm, CS Energy rebid 120 MW of capacity at Gladstone priced around $50/MWh to the price cap. The reason given was “1641A interconnector constraint-sl”. This rebid was not used in dispatch as a further rebid was submitted at 4.43 pm, effective at 4.50 pm, with these same parameters. The only additional change was an increase in the up and down ramp rates of each unit from

5MW/minute to 12MW/minute. The reason given was “1642P Ramp rate change to match output-sl”.

The Calvale to Wurdong constraint bound from 4.50 pm as Gladstone received targets to reduce output by around 120 MW. Ramp rate limitations for generators required to increase their output saw the five minute dispatch price set to $816/MWh at 4.50 pm.

At 4.49 pm, effective at 5 pm, Alinta Energy rebid 76 MW of capacity at Braemar A priced at the price floor to around $10 000/MWh.The reason given was “1648A B1 B2 ds price higher than pd $816 vs $340@16:49”.

At 5 pm, Queensland demand increased by around 46 MW. With limited import capability on QNI and ramp rate limitations, higher priced generation at Braemar A was dispatched and set the five minute dispatch price to $10 100/MWh.

There was no other significant rebidding.

Tasmania:

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $46/MWh and above $250/MWh.

Sunday, 13 January

11:00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	1279.73	40.06	40.94
Demand (MW)	953	928	944
Available capacity (MW)	2214	2214	2214

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

At 11 pm increased flows across the Hadspen-George Town 220kV lines saw the network control scheme (NCSPS) constraint become active. The NCSPS constraint is used to manage the post-contingent loading on one of the Hadspen-George Town lines.

With Basslink exporting to Victoria, the constraint required a reduction in output from generators in eastern and southern Tasmania and an increase in output from generators in western and southern Tasmania.

However, the output of a number of generators was unable to be changed sufficiently to satisfy the constraint due to ramp rate limitations and exports to Victoria fell short of the requirement, with the constraint violating for the 11 pm dispatch interval. The five minute dispatch price spiked to $7469/MWh at 11 pm.

A demand side response of around 66 MW saw the price fall to $42/MWh at 11.05 pm and the constraint no longer violated with exports to Victoria on Basslink increasing from around 74 MW to around 213 MW.

There was no significant rebidding.

Detailed NEM Price and Demand Trends

for Weekly Market Analysis

13 January - 19 January 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 ($/MWh) YTD	70	57	65	66	49
2011-12 ($/MWh) YTD	30	30	27	34	31
Change*	134%	88%	140%	93%	60%
2011-12 ($/MWh)	30	31	28	32	33

Table 2: NEM turnover

Financial year	NEM Turnover** ($, billion)	Energy (TWh)
2012-13 YTD	6.772	108
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)
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	62	50	55	57	47	0.881
January-13 MTD	182	52	68	78	56	0.986
Q1 2013 QTD	182	52	68	78	56	0.986
Q1 2012 QTD	37	24	24	26	37	0.291
Change*	395%	116%	187%	200%	51%	2.387

Table 4: ASX energy futures contract prices at end of 18 January 2013

	QLD		NSW		VIC		SA	
Q1 2013	Base	Peak	Base	Peak	Base	Peak	Base	Peak
Price on 11 Jan ($/MWh)	85	118	57	67	64	93	70	85
Price on 18 Jan ($/MWh)	106	136	55	63	57	77	63	87
Open Interest on 18 Jan ($/MWh)	1550	317	2462	690	1303	175	270	0
Traded in the last week (MW)	305	11	174	2	8	3	0	0
Traded since 1 Jan 12 (MW)	5564	585	8434	1059	4096	288	481	0
Settled price for Q1 12 ($/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
November 12 with November 11						
MW Priced $20/MWh	-3407	78	-1859	-61	-283	-5533
MW Priced $20/MWh to $50/MWh	2797	-1617	452	-242	77	1467
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 MTD						
MW Priced $20/MWh	-2923	-2621	-1167	60	-208	-6860
MW Priced $20/MWh to $50/MWh	2173	1426	1170	-349	340	4760

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

** Estimated value