Electricity Report 26 April – 2 May 2015

Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 26 April to 2 May 2015. There were four occasions in South Australia and one occasion in New South Wales, Victoria and Tasmania respectively where the spot price was above \$250/MWh and greater than three times the regional weekly average price. There was one occasion where the spot price was below -\$100/MWh in Tasmania. These price events will be discussed in the detailed analysis section of this report.



Figure 1 : Spot price by region (\$/MWh)

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Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.



Figure 2 : Volume weighted average spot price by region (\$/MWh)

Table 1 : Volume weighted average spot prices by region (\$/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	37	47	40	57	43
13-14 financial YTD	62	54	55	71	43
14-15 financial YTD	67	36	31	40	39

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast 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 participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 87 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2014 of 71 counts and the average in 2013 of 97. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, 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.

	Availability	Demand	Network	Combination
% of total above forecast	2	49	0	2
% of total below forecast	40	4	0	4

Table 2 : Reasons for variations between forecast and actual prices

Note: Due to rounding, the total may not be 100 per cent.

Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region. The red ellipses on the following charts highlight bidding patterns during the high price period.



Figure 3 : Queensland generation and bidding patterns











Figure 6: South Australia generation and bidding patterns





Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was \$478 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was \$246 000 or 3 per cent of energy turnover in Tasmania.



Figure 8 : Daily frequency control ancillary service cost

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year. The costs in Tasmania were largely caused by high Raise 60 second and Raise Reg prices on 1 May. At 8.39 am, effective from 8.50 am, Hydro Tasmania rebid all available capacity for Raise 60 second and Raise Regulation services (1452 MW and 386 MW respectively) from below \$3/MWh to

\$13 100/MWh. The reason given was "0840A vic prices > forecast, increased price risk". This resulted in the Raise 60 second and Raise Reg prices reaching \$13 100/MWh at 8.50 am.

Detailed market analysis of significant price events

We provide more detailed analysis of events where the spot price was greater than three times the weekly average price in a region and above \$250/MWh or was below -\$100/MWh.

South Australia

There were four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of \$57/MWh and above \$250/MWh.

Monday, 27 April

Table 3: Price, Demand and Availability, Midnight

Time	Р	Price (\$/MWh)		C	Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	
Midnight	2289.40	43.18	37.02	1493	1591	1593	1671	2023	2142	

Demand was around 100 MW below forecast while availability was 350 MW below that forecast four hours ahead. The reduction in available capacity was a result of lower than forecast wind generation and a delay in the return to service of unit one at Northern Power station. There was only around 114 MW of wind generation and the Heywood and Murraylink interconnectors were importing into South Australia at 435 MW and 188 MW respectively.

At 11.35 pm demand increased by 196 MW, related to off peak hot water load. In response, non-scheduled generation started reducing demand at 11.40 pm by 76 MW, neither resulting in significant changes in dispatch price. Demand increased from 1477 MW at 11.40 pm to 1605 MW at 11.45 pm, an increase of 128 MW as a result of the non-scheduled demand reducing its dispatch. All low priced capacity was either ramp rate limited, trapped, stranded or fully dispatched. This resulted in the dispatch price increasing from \$58/MWh at 11.40 pm to \$13 500/MWh at 11.45 am.

Prices dropped below \$70/MWh at 11.50 pm when demand fell by 148 MW as a result of the dispatch of non-scheduled generation.

Tuesday, 28 April

Time	Price (\$/MWh)			D	emand (MV	V)	Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9 AM	552.39	126.74	327.66	1543	1555	1626	1924	1921	1917

Table 4: Price, Demand and Availability, 9 am

Forecast demand and availability were both close to the four hour ahead forecasts.

In preparation for a planned outage of the Keith-Tailem Bend no 1 132 kV transmission line, a ramping constraint applied during much of the 9 am trading interval. This constraint reduced generation in the South East of South Australia and reduced imports into South Australia across Heywood interconnector to 398 MW at 8.55 am.

Table 5: Rebids for 9 am

Submit Time	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
8.37 am (effective 8.45 am)	AGL Energy	Torrens A and B	210	<65	13 500	0801~A~050 chg in AEMO PD~51 PD demand increase SA +76MW 0900
8.43 am (effective 8.50 am)	Energy Australia	Hallet	50	>10 782	<300	08:42 A BAND t1 adj due to change 5 min PD price

At 8.55 am the ramping constraint led to the Ladbroke Grove and Lake Bonney 2 and 3 being constrained off. At the same time demand increased by 42 MW.

With low priced capacity either ramp rate limited or fully dispatched, the dispatch price increased from \$70/MWh at 8.50 am to \$2960/MWh at 8.55 am. Prices reduced to \$64/MWh 9 am, when demand reduced by 142 MW.

Wednesday, 29 April

Table 6: Price, Demand and Availability

Time	Price (\$/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
9 AM	502.77	199.95	589.20	1548	1554	1625	1910	1949	1968
3.30 PM	566.66	45.99	45.99	1370	1336	1331	2039	2043	2105

Demand and availability were close to forecast four hours ahead.

9 am Trading Interval

During the 9 am trading interval Murraylink imported less than 10 MW due to an outage constraint which avoids overloading the Buronga to Red Cliffs 220 kV line during the planned outage of the Ballarat to Horsham 220kV line.

In preparation for a planned outage of the Keith-Tailem Bend no 1 132 kV transmission line, a ramping constraint applied during much of the 9 am trading interval. This constraint reduced generation in the South East of South Australia and reduced imports into South Australia across Heywood interconnector to 399 MW at 8.45 am.

Table 7: Rebids for 9 am

Submit Time	Particip ant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
8.38 am (effective from 8.45 am)	AGL Energy	Torrens A and B	120	<65	13 500	0836~A~040 chg in AEMO disp~45 price increase VS PD [SA] 292.20

With low priced capacity either ramp rate limited, fully dispatched or constrained-off, the dispatch price increased from \$292/MWh at 8.40 am to \$2525/MWh at 8.45 am when the rebid by AGL took effect. Prices returned to \$44/MWh at 8.50 pm, when demand reduced by 142 MW.

3.30 pm Trading Interval

The outage constraint for the Keith to Tailem Bend line bound for most of the trading interval. This constraint had the effect of constraining off generation and increasing flows towards South Australia on the Heywood interconnector. Flows on the Murraylink interconnector were limited to zero from 2.30 pm.

At 3.12 pm, effective 3.20 pm, AGL Energy rebid 335 MW of available capacity from below \$65/MWh to the price cap for Torrens A and B units. The reason given was "1505~A~040 chg in AEMO disp~44 price decrease VS PD [SA] 45.99 V".

With low priced capacity either ramp rate limited or fully dispatched, the dispatch price increased from \$55/MWh at 3.15 pm to \$3167/MWh at 3.20 pm when the rebid by AGL took effect. Prices reduced to \$42/MWh at 3.25 pm, when demand reduced by 111 MW and 157 MW of available capacity was rebid to lower price bands.

Tasmania – Wednesday 29 April

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of \$43/MWh and above \$250/MWh.

Table 8: Price, Demand and Availability 1 pm

Time	Price (\$/MWh)			C	Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	
1 PM	1009.16	37.55	37.83	1072	1167	1144	1853	1826	1826	

Availability was close to forecast and demand was 95 MW below forecast four hours ahead.

Table 9: Rebids for 1 pm

Submit Time	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
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Submit Time	Participant	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
12.41 pm (effective from 12.50 pm)	Hydro Tasmania	Gordon, Reece	291	<200	11 678	1240A P5 vic prices < forecast+env cnst

With no capacity priced between \$200/MWh and \$11 678/MWh and low priced capacity either ramp rate limited, trapped, stranded or fully dispatched, the dispatch price increased from \$35/MWh at 12.45 pm to \$5868/MWh at 12.50 pm. The price was set by the Reece unit. Prices returned to \$40/MWh at 12.55 pm, when Hydro Tasmania reversed 115 MW of its previous rebid from \$11 678/MWh to lower price bands.

New South Wales, Victoria and Tasmania – Friday 1 May

There was one occasion where the spot price in Victoria and New South Wales was greater than three times the respective weekly average price and above \$250/MWh. At the same time the spot price in Tasmania was below -\$1000/MWh.

Table 10: New South Wales, Victoria and Tasmania; Price, Demand andAvailability 9 am

Region	Price (\$/MWh)			D	Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	
NSW	1792.03	45.40	44.10	8790	8668	8676	10 188	10 357	10 357	
Vic	505.44	41.97	41.15	5870	6011	6039	10 208	9644	9759	
Tas	-137.27	38.06	37.55	1355	1318	1320	2110	2110	2110	

Actual prices were not forecast until around 8.40 am when AEMO invoked ramping constraints in preparation for planned works on the Kemps Creek no.3 500/330 kV transformer. These constraints assist in reducing the loading on the transformer and affect a majority of generators in New South Wales. These constraints violated for the majority of the 9 am trading interval resulting in number of generators being constraining off.

From 8.40 am a number of system normal constraints started to bind. One constraint is used to avoid the post contingent overload Murray to Upper Tumut no.65 330kV line for the loss of Murray to Lower Tumut no 66 330kV line and led to a number of New South Wales generators being further constrained. Another system normal constraint, to avoid the overloading the South Morang F2 500/330 kV transformer, led to a number of Victorian generators being constrained off.

These constraints led to rapid changes in the flow of QNI, Terranorra and the Vic-NSW interconnectors. QNI flows went from importing 266 MW into New South Wales at 8.35 am to exporting196 MW to Queensland at 8.50 am. Terranora went from importing 57 MW into New South Wales at 8.35 am to exporting 5 MW to Queensland at 8.50 am.

The VIC-NSW interconnector also rapidly increased flows into New South Wales from 1053 MW at 8.35 am to 1705 MW by 8.45 am (counter price). These flows were reduced at 8.50 am when a constraint to manage the negative settlement residues bound.

These changes saw the price in New South Wales increase to \$205/MWh at 8.40 am. As a result participants in New South Wales rebid capacity to the price floor.

Table 11: New South Wales, Victoria and Tasmania - dispatch prices during 9am trading interval

Region			Price (\$	5/MWh)		
	8.35 am	8.40 am	8.45 am	8.50 am	8.55 am	9 am
NSW	47	205	-1000	-1000	-1000	13 500
Victoria	41	138	453	0	0	2401
Tasmania	38	38	32	-963	0	32

Table 12: NSW rebids for 9 am

Submit Time	Participa nt	Station	Capacity rebid (MW)	Price from (\$/MWh)	Price to (\$/MWh)	Rebid reason
8.34 am (effective 8.45am)	Energy Australia	Mt Piper	400	>32	-1000	08:33 A band adj due to change in PD5 price SL
8.38 am (effective 8.45am)	Snowy Hydro	Tumut 3	250	300	>42	08:40 A NSW: act price \$157.01 hgr thn 5MPD 08:40@08:31
8.42 am (effective 8.50 am)	Origin Energy	Eraring and Shoal Haven	1210	<13 500	-1000	0837A constraint management - CA_SPS_445534C8_01 SL
8.45 am (effective 8.55 am)	Snowy Hydro	Tumut 3 and Upper Tumut	730	<450	-1000	08:45 A NSW: act price \$1,044.99 lwr thn 30MPD 08:45@08:32
8.45 am (effective 8.55 am)	AGL Energy	Liddell	345	N/A	<296	0840~P~030 increase in avail cap~301 plant limit lifted 345MW -
8.53 am (effective 9 am)	Snowy Hydro	Upper Tumut	181	<300	N/A	08:55 A NSW: act price \$1,044.99 lwr thn 30MPD 08:55@08: 3 2
8.53 am (effective 9 am)	Snowy Hydro	Tumut 3	887	300	N/A	08:55 A NSW: act price \$1,044.99 lwr thn 30MPD 08:55@08:32

As a result of the rebidding up until 8.45 am the dispatch price reached the floor price from 8.45 am to 8.55 am.

Subsequent rebids by Snowy at 8.53 am, effective 9 am, withdrew around 1000 MW of capacity priced at \$300/MWh or less (150 MW at the price floor). With low priced capacity either ramp rate limited, stranded, constrained off or fully dispatched, the dispatch price increased from \$-1000/MWh at 8.55 am to \$13 500/MWh at 9 am.

At 9 am increased generation in Victoria to meet New South Wales requirements was either ramp rate limited, stranded, constrained off or fully dispatched. Flow into New South Wales across the NSW-Vic interconnector increased and the dispatch price in Victoria increased from \$0/MWh at 8.55 am to \$2401/MWh at 9 am.

In Tasmania, at 8.43 am, effective 8.50 am, Hydro Tasmania rebid 1504 MW of available capacity from prices below \$35/MWh to the floor price across the generation portfolio. The reason provided was "0845A vic price > forecast, basslink flow < forecast". As a result, the dispatch price reduced from \$32/MWh at 8.45 am to \$ -963/MWh at 8.50 am. Prices increased to \$0/MWh when Hydro Tasmania reversed their previous rebid.

Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.



Figure 9: Quarterly base future prices Q2 2015 – Q1 2019

Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2016 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2016 base contracts over the past 10 weeks (and the past 2 years)



Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the <u>Performance of the Energy Sector</u> section of our website.

Figure 11 shows how the price for each regional Quarter 1 2016 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2014 and quarter 1 2015 prices are also shown.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

Australian Energy Regulator

May 2015