

Electricity Report

12 – 18 July 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 12 to 18 July 2015. There were five occasions in South Australia and five occasions in Queensland where the spot price exceeded the AER reporting threshold. These are discussed later in this report. Nine negative spot prices were also recorded in South Australia on 14 July but these were not less than the -$100/MWh reporting threshold.

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



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 | 80 | 51 | 44 | 96 | 42 |
| 13-14 financial YTD | 37 | 48 | 42 | 59 | 35 |
| 14-15 financial YTD | 51 | 42 | 38 | 71 | 37 |

Longer-term statistics tracking average spot market prices are available on the [AER website](http://www.aer.gov.au/australian-energy-industry/performance-of-the-energy-sector).

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 194 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.

Table 2: Reasons for variations between forecast and actual prices

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | Availability | Demand | Network | Combination |
| % of total above forecast | 2 | 52 | 0 | 1 |
| % of total below forecast | 27 | 12 | 0 | 5 |

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.

Figure 3: Queensland generation and bidding patterns



The red ellipses on Figure 3 highlight periods where rebidding created pricing events in Queensland that are discussed later in this report.

Figure 4: New South Wales generation and bidding patterns



Figure 5: Victoria generation and bidding patterns



Figure 6: South Australia generation and bidding patterns



Figure 7: Tasmania 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 $357 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $73 000 or less than 1 per cent of energy turnover in Tasmania.

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.

Figure 8: Daily frequency control ancillary service cost



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 five occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $96/MWh and above $250/MWh.

Thursday, 16 July

Table 3: 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 | 288 | 288 | 288 | 1745 | 1803 | 1862 | 2292 | 2221 | 2267 |
| 2.30 pm | 288 | 95 | 95 | 1628 | 1484 | 1516 | 2183 | 2211 | 2286 |

The 9 am spot price reached $288/MWh as forecast both four and twelve hours before.

For the 2.30 pm trading interval, demand was 144 MW higher and capacity was close to forecast four hours ahead. At 2 pm there was an increase in demand of 78 MW. With cheaper generation trapped in FCAS or ramp rate limited, higher price generation was dispatched, resulting in the 2 pm dispatch price reaching $288/MWh. Similar conditions prevailed throughout the 2.30 pm trading interval and the dispatch price remained at $288/MWh.

Table 4: 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 |
| 6.30 pm | 4428 | 590 | 590 | 2073 | 2163 | 2139 | 2431 | 2545 | 2490 |
| 9 pm  | 2142 | 95 | 95 | 1941 | 2082 | 2110 | 2521 | 2495 | 2390 |

For the 6.30 pm trading interval, demand was around 90 MW less and capacity was 114 MW less than forecast four hours before (around 100 MW of which was as a result of wind generation being lower than forecast).

At 6.18 pm, effective from 6.25 pm, AGL rebid 445 MW of available capacity at Torrens Island from below $10 760/MWh (365 MW of which was below $288/MWh) to $13 500/MWh. The reason given was “1800~a~030 chg in AEMO avail cap~30 decrease SA 100MW due to change in non-scheduled generation”.

When AGL’s rebid became effective, the dispatch price increased from $288/MWh to $13 500/MWh, set by Torrens Island. The price fell to $12 301/MWh at 6.30 pm following a 106 MW decrease in demand (mostly due to an increase in South Australian non‑scheduled generation). The dispatch price fell to $66/MWh at 6.35 pm, the start of the next trading interval, following further a decrease in demand and AGL’s rebid no longer being effective.

For the 9 pm trading interval, demand was around 141 MW less and capacity close to forecast four hours ahead. At the start of the trading interval there was a steep supply curve, with only around 34 MW priced between $590/MWh and $10 770/MWh.

At 8.35 pm there was an increase in demand of around 142 MW (mostly due to a decrease in South Australian non-scheduled generation). With low priced generators either ramp rate limited or fully dispatched, high price generation had to be dispatched. This resulted in the dispatch price increasing from $65/MWh at 8.30 pm to $13 482/MWh at 8.35 pm. The dispatch price fell to $35/MWh at 8.40 pm following a decrease in demand of around 142 MW (mostly due to an increase in South Australian non-scheduled generation) and rebidding, by AGL, of 545 MW of capacity at Torrens Island to the price floor.

Saturday, 18 July

Table 5: 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 |
| Midnight | 2256.25 | 64.99 | 64.99 | 1896 | 1928 | 1939 | 2428 | 2429 | 2414 |

Demand and capacity were close to forecast four hours ahead.

**Table 6: Rebids for midnight**

| Submit time | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
| --- | --- | --- | --- | --- | --- | --- |
| 10.58 pm | AGL | Torrens Island | 100 | <95 | 13 500 | 2250~A~050 chg in AEMO pd~56 price increase SA $524.21 5mpd vs pd |
| 11.08 pm  | Alinta Energy | Northern  | 150 | <287 | 13 334 | 2307~A~spot price 5pd higher than 30pd~SA 5pd$100.77 vs 30pd $48.92 |

The above rebids removed some mid-priced capacity, making the supply curve steeper and leaving only a small amount of capacity priced between $100/MWh and $10 770/MWh. Consequently, small changes in demand, interconnectors and availability led to large changes in price.

Over the 11.35 pm and 11.40 pm dispatch intervals, demand increased by 181 MW and 70 MW respectively. The increase in demand was related to off peak hot water load. With lower priced generation fully dispatched, the demand increase resulted in the dispatch price increasing from $58/MWh at 11.35 pm to $13 334/MWh at 11.40 pm, with Northern setting the price. At 11.45 pm the dispatch price fell to $47/MWh when 206 MW of available capacity at close to the price cap was rebid into lower price bands and demand decreased by around 120 MW (mostly due to an increase in South Australian non-scheduled generation).

Queensland

There were five occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $80/MWh and above $250/MWh.

Monday, 13 July

Table 7: 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 |
| 7 am | 2325.28 | 37.18 | 45.14 | 6686 | 6532 | 6424 | 9892 | 10 034 | 9795 |

Demand was 154 MW higher than forecast and available capacity was 142 MW less than forecast four hours ahead.

As would be expected there was a substantial increase in demand from 6.35 am to 7 am, driven by the morning peak, with demand increasing by 388 MW over the 30 minute trading period.

**Table 8: Rebids for the 7 am**

| Submit time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 6.07 am |  | CS Energy | Callide | -125 | <17 | N/A | 0606P technical issues-fd fan-sl |
| 6.24 am  | 6.35 am | Millmerran  | Millmerran | 170 | 7 | 13 388 | 06:23 A change in 5 min QNI pd flow |
| 6.46 am | 6.55 am | Callide Power Trading | Callide  | 86 | -1000 | 13 800 | 0644a change in 5min QNI pd flow  |
| 6.53 am  | 7 am | CS Energy | Gladstone | 160 | <55 | 13 800 | 0652A interconnector constraint-QNL binding-sl |
| 6.53 am  | 7 am  | Millmerran  | Millmerran | 30 | -1000 | 13 388 | 06:52 A rrp above pd  |

The above rebids contributed to a steep supply curve with only 180 MW of available capacity priced between $570/MWh and $2221/MWh, and 13 MW of available capacity priced between $2221/MWh and $12 387/MWh. Consequently, small changes in demand, interconnectors and availability led to large changes in price.

At 7 am, five minute demand increased by 113 MW. With lower priced generators either fully dispatched, ramp rate limited or unable to start in time, higher priced generation at Millmerran was dispatched. This resulted in an increase in the dispatch price from $331/MWh at 6.55 am to $13 387/MWh at 7 am.

Wednesday, 15 July

Table 9: 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 |
| 7 pm | 292.62 | 110.36 | 110.17 | 7570 | 7471 | 7548 | 9884 | 10 296 | 10 272 |

Demand was 99 MW higher than forecast and available capacity was 412 MW less than forecast four hours ahead.

**Table 10: Rebids for 7 pm**

| Submit time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 3.48 pm |  | Origin Energy | Darling Downs | -70 | <46 | N/A | 1546P change in avail – gt rts profile revised |
| 4.19 pm  |  | CS Energy | Gladstone | -210 | <13 800 | N/A | 1617P unit offline revised-unit offline for post |
| 5.05 pm |  | Origin Energy | Darling Downs | -80 | -1 000 | N/A | 1703P change in avail – gt rts delayed sl  |
| 6.02 pm  |  | CS Energy | Gladstone | 40 | N/A | 0 | 1801P unit offline revised-updated ramp down schedule-sl |
| 6.22 pm |  | CS Energy | Gladstone  | -110 | 0 | N/A | 1821P unit trip-sl  |
| 6.25 pm  | 6.35 pm | Millmerran | Millmerran | 220 | 7 | 13 388 | 18:21 A change in pd QNI flow – sl |
| 6.35 pm  | 6.45 pm  | Callide Power Trading  | Callide | 173 | -1000 | 13 800 | 1831 A change in QNI pd – sl  |
| 6.52 pm | 7 pm | CS Energy | Gladstone | 90 | <55 | 13 800 | 1847A interconnector constraint-QNI binding-sl  |
| 6.52 pm | 7 pm | Alinta Energy | Braemar | -167 | 332 | N/A | 1850~F~avoid uneconomic start~  |

As a result of the above rebidding the dispatch price was between $200/MWh and $331/MWh for the trading interval despite demand decreasing by 169 MW during the trading interval.

Thursday, 16 July

Table 11: 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 |
| 7 am | 2399.71 | 45.90 | 45.90 | 6799 | 6751 | 6793 | 10 049 | 10 135 | 10 415 |

Demand and available capacity were both close to forecast four hours ahead.

There was a substantial increase in demand from 6.35 am to 7 am, driven by the morning peak, with demand increasing by 295 MW over the 30 minute trading period.

**Table 12: Rebids for 7 am**

| Submit time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 6.13 am |  | CS Energy | Gladstone | 40 | 13 800 | 100 | 0610P technical issues-turbine vibrations-sl |
| 6.19 am |  | QGC sales | Condamine  | -63 | 0 | N/A | 6:19 am P change in plant capabilities  |
| 6.28 am  | 6.35 am | Millmerran | Millmerran | 230 | 7 | 13 388 | 06:25 A change in QNI pd flow – sl |
| 6.35 am | 6.45 am | Callide Power Trading | Callide | 160 | -1000 | 13 800 | 0630A change in QNI pd – sl |
| 6.38 am  | 6.45 am  | CS Energy | Gladstone | 250 | <46 | 13 800 | 0636A 5min pd price higher than 30min pd-sl |
| 6.43 am | 6.50 am | CS Energy  | Gladstone | 30 | 13 800 | 35 | 0642E correct error in previous bid-sl |
| 6.44 am | 6.55 am | Stanwell | Stanwell | 80 | 17 | 13 800 | 0643A change in QLD 5 min price 0640 v 0645 |
| 6.48 am | 6.55 am  | Origin Energy | Roma | -38 | 90 | N/A | 0645A avoid uneconomic start |
| 6.49 am  | 7 am  | Alinta | Braemar | 52 | 14 | 13 377 | 0645~A~spot price 5pd higher than 30pd |

The above rebids contributed to a steep supply curve with only 155 MW of available capacity priced between $570/MWh and $2221/MWh, and 13 MW of available capacity priced between $2221/MWh and $12 387/MWh. Consequently, small changes in demand, interconnectors and availability led to large changes in price.

At 7 am, five minute demand increased by 100 MW. With lower priced generators either fully dispatched, ramp rate limited or unable to start in time, higher priced generation was dispatched. This resulted in an increase the dispatch price from $331/MWh at 6.55 am to the price cap at 7 am.

Friday, 17 July

Table 13: 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 |
| 7 am | 2351.49 | 43.40 | 37.40 | 6827 | 6897 | 6889 | 9942 | 10 011 | 10 317 |

Demand was 70 MW less than forecast and available capacity was close to forecast four hours ahead.

There was a substantial increase in demand from 6.35 am to 7 am, driven by the morning peak, with demand increasing by 345 MW over the 30 minute trading period.

**Table 14: Rebids for 7 am**

| Submit time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 5.13 am |  | Callide Power Trading | Callide | -56 | <14 | N/A | 0511P poor coal |
| 5.24 am |  | Callide Power Trading | Callide | -30  | <14 | N/A | 0524P poor coal |
| 6.18 am |  | CS Energy | Gladstone | 160 | <46 | 13 800 | 0615A dispatch price higher than 30 min forecast-sl |
| 6.35 am | 6.45 am | Millmerran | Millmerran | 185 | 7 | 13 800 | 06:34 A change in dispatch gen 5min pd for di 0700 – sl |
| 6.36 am | 6.45 am | Alinta Energy | Braemar | 170 | 13 800 | <14 | 0636~A~change in interconnector flow 5pd~  |
| 6.42 am | 6.50 am | Callide Power Trading | Callide | 128 | -1 000 | 13 800 | 0620A change in dispatch gen 5min pd for di 0700 – sl |
| 6.49 am  | 7 am | Stanwell | Stanwell, Tarong | 110 | <25 | 13 800 | 0648A change qld 5 min price pd 0645 v 0650  |
| 6.52 am | 7 am | CS Energy | Gladstone | 60 | 35 | 13 800 | 0615A interconnector constraint-qnl binding-sl |

The above rebids contributed to a steep supply curve with little capacity priced between $300/MWh and $12 387/MWh. Consequently, small changes in demand, interconnectors and availability led to large changes in price.

At 7 am, when Stanwell and CS Energy’s bids became effective and the five minute demand increased by 93 MW, lower priced generators were either fully dispatched, ramp rate limited or trapped in FCAS, higher priced generation was dispatched. This resulted in an increase the dispatch price from $107/MWh at 6.55 am to the price cap at 7 am.

Saturday, 18 July

Table 15: 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 |
| 10.30 pm | 2458.63 | 54.91 | 54.90 | 6362 | 6172 | 6132 | 9565 | 9900 | 9999 |

Demand was close to 190 MW more than forecast and available capacity was 335 MW less than forecast four hours ahead.

**Table 16: Rebids for 10.30 pm**

| Submit time | Time effective | Participant | Station | Capacity rebid (MW) | Price from ($/MWh) | Price to ($/MWh) | Rebid reason |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 9.57 pm | 10.05 pm | Millmerran | Millmerran | 190 | 7 | 13 800 | 21.53 A rrp above pd |
| 10.06 pm | 10.15 pm | Stanwell | Stanwell | 210 | 17 | 13 800 | 2205A material change in QNI flow di2205 |
| 10.11 pm | 10.20 pm | Callide Power Trading | Callide | 88 | <25 | 13 800 | 2204A RRP above pd |
| 10.12 pm | 10.20 pm | Arrow Energy | Braemar | -173 | <12 947 | N/A | 2211A qld price higher than forecast: avoid uneconomic start |
| 10.12 pm | 10.20 pm | CS Energy | Gladstone | 120  | 35 | 13 800 | 2212A interconnector constraint-QNI binding-sl |
| 10.14 pm | 10.25 pm | Alinta Energy | Braemar | 58 | 14 | 13 377 | 2215~A spot price higher than pd~ qld $332.04 vs $54.91 |
| 10.16 pm | 10.25 pm | Arrow Energy | Braemar | -173 | <12 948 | N/A | 2216A qld price higher than forecast : avoid uneconomic start sl |
| 10.20 pm | 10.30 pm  | Origin Energy | Darling Downs | 255 | 55 | 13 800 | 2218P plant conditions – avoid short duct burner usage sl |
| 10.23 pm | 10.30 pm | CS Energy | Gladstone | 200 | <42 | 13 800 | 2222A interconnector constraint-QNI binding sl |

As a result of the generator rebidding set out in the table above at 10.30 pm, with lower price generation either ramp rate limited or fully dispatched, high priced generation at Braemar had to be dispatched to meet. This led to the dispatch price increasing from $601/MWh at 10.25 pm to $13 377/MWh at 10.30 pm.

## 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 Q3 2015 – Q1 2019



Source: [ASXEnergy.com.au](https://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](https://asxenergy.com.au/)

Prices of other financial products (including longer-term price trends) are available in the [Performance of the Energy Sector](http://www.aer.gov.au/australian-energy-industry/performance-of-the-energy-sector) section of our website.

Figure 11: Price of Q1 2016 cap contracts over the past 10 weeks (and the past 2 years) 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](https://asxenergy.com.au/)

Australian Energy Regulator

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