Electricity Report

25 to 31 August 2013

AUSTRALIAN ENERGY REGULATOR

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.

Weekly spotlight

As discussed in the *Detailed market analysis of significant price events* section below, the spot price in Queensland reached $2223/MWh at 7 am on Wednesday 28 August, as a result of a single five-minute price at 6.40 am at the market price cap (MPC, $13 100/MWh). This is the fourth occasion recently where the spot price has reached around $2200/MWh in Queensland for the 7 am trading interval. The other occasions were on 18, 22 and 23 August. These three other high prices were also driven by single five-minute dispatch interval price spikes at the MPC during the 7 am trading interval (and are discussed in previous weekly reports). None of these prices were forecast.

Given the regularity of these events, the AER considers it appropriate to explore the events in more detail as part of this weekly spotlight.

Analysis shows that the high prices have been driven by relatively small increases in five-minute demand which is unable to be met by low-price generation in Queensland or imports in the relevant five minutes, requiring the dispatch of generation priced at or close to the price cap. These spikes in dispatch price occurred at levels of demand of around 6000 MW, which is relatively low when compared to peak demand for the 2012/13 summer of 8606 MW and installed capacity in Queensland around 11 000 MW.[1]

Other contributing factors common to each event are as follows:

- A total of 800 MW of capacity at Millmerran Power Station and CS Energy’s Callide Power Station came offline in mid-August. A significant proportion of this capacity is usually offered at low prices when available.

- The Directlink interconnector has been out of service since 6 August (expected to return on 30 September).

- During the times of high prices the ability to import energy into Queensland across the QNI interconnector has been limited to around 180 MW (compared to its nominal limit of 480 MW) by a network constraint. During the times of high prices, QNI has usually been importing into Queensland at close to its limit, meaning that Queensland generation has been dispatched to meet any increase in demand.

[1] Note that this figure excludes generation that is currently mothballed such as 700 MW at Stanwell’s Tarong Power Station (unit 2 was mothballed in October 2012 and unit 4 was mothballed in December 2012).

- Due to technical limitations (including plant being ramp rate limited, or trapped or stranded in frequency control ancillary services (FCAS)) available low-price generation has been unable to be dispatched to meet small increases in demand, resulting in the dispatch of high-price generation. This is explained further in the following example below (which is indicative only, and not based on a specific event).

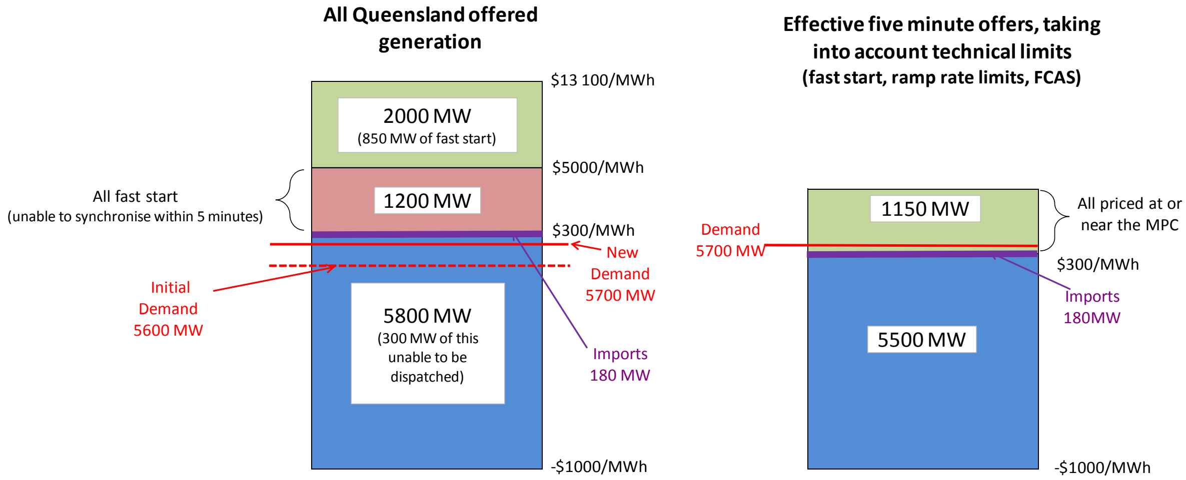
Example to illustrate causes of Queensland 7 am price spikes

Assume the initial level of demand to be 5600 MW, as shown by the red dotted line in the column marked *All Queensland offered generation* (in the left hand pane of the figure) in the chart below. This can be met by a combination of 5500 MW of low-price generation capacity and 180 MW of imports, resulting in a price below $300/MWh. As mentioned above, common to all of these days was a small increase in five-minute demand (ranging from about 70 MW to about 140 MW). Assume that after a small increase in demand of 100 MW, the new level of demand is 5700 MW. It would appear that this level of demand could still be met comfortably by a combination of low-price Queensland generation and imports.

However, our analysis shows that during each of the events, on average around 5 per cent of low-price generation capacity in Queensland (300 MW out of 5800 MW) was unable to be dispatched because certain generators were either trapped or stranded in FCAS (meaning they could not vary their energy output for that five minutes), or ramp up rate limited.

In addition, common to all of the events was that a significant proportion of fast start plant (i.e. plant that is able to synchronise and reach minimum loading within 30 minutes) was offline prior to the time of the high prices. In the left hand column, we show 1200 MW of fast start plant bid in at between $300/MWh and $5000/MWh, and 850 MW of fast start plant bid in at between $5000/MWh and $13 100/MWh. However, much of this capacity takes more than five minutes to start generating, which means that it is unable to be dispatched in a dispatch interval to meet the increase in five-minute demand for that dispatch interval.

Spotlight figure: Offers within price bands – comparison of total offers and effective offers



The right hand pane illustrates the impact of removing the generation capacity that is unable to start or increase energy output due to technical considerations (i.e. it is the amount of capacity that is effectively offered in the dispatch interval). It shows that the only way the new level of demand can be met is by dispatching on-line high-price generation, thus setting the dispatch price at the price cap.

Spot market prices

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

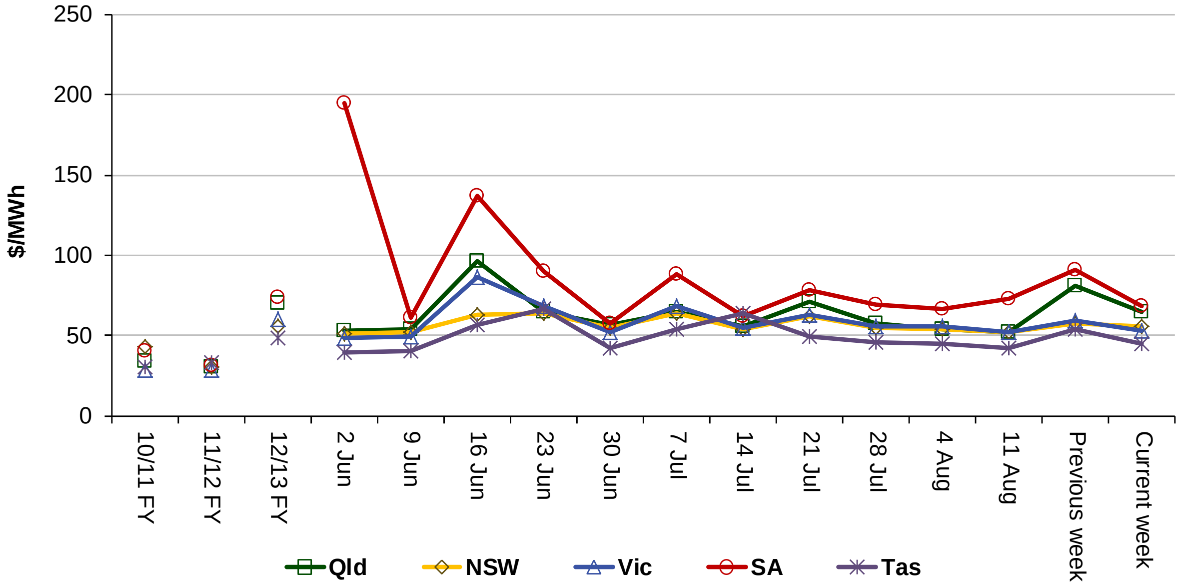


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	64	55	53	69	44
12-13 financial YTD	60	63	66	73	54
13-14 financial YTD	62	57	57	73	49

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 133 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2012 of 60 counts and the average in 2011 of 78. 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

Reason for variation	Availability	Demand	Network	Combination
% of total above forecast	0	14	0	0
% of total below forecast	55	27	0	4

Note: Due to rounding, the total may not be exactly 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. Figures 2 to 6 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 2: Queensland generation and bidding patterns

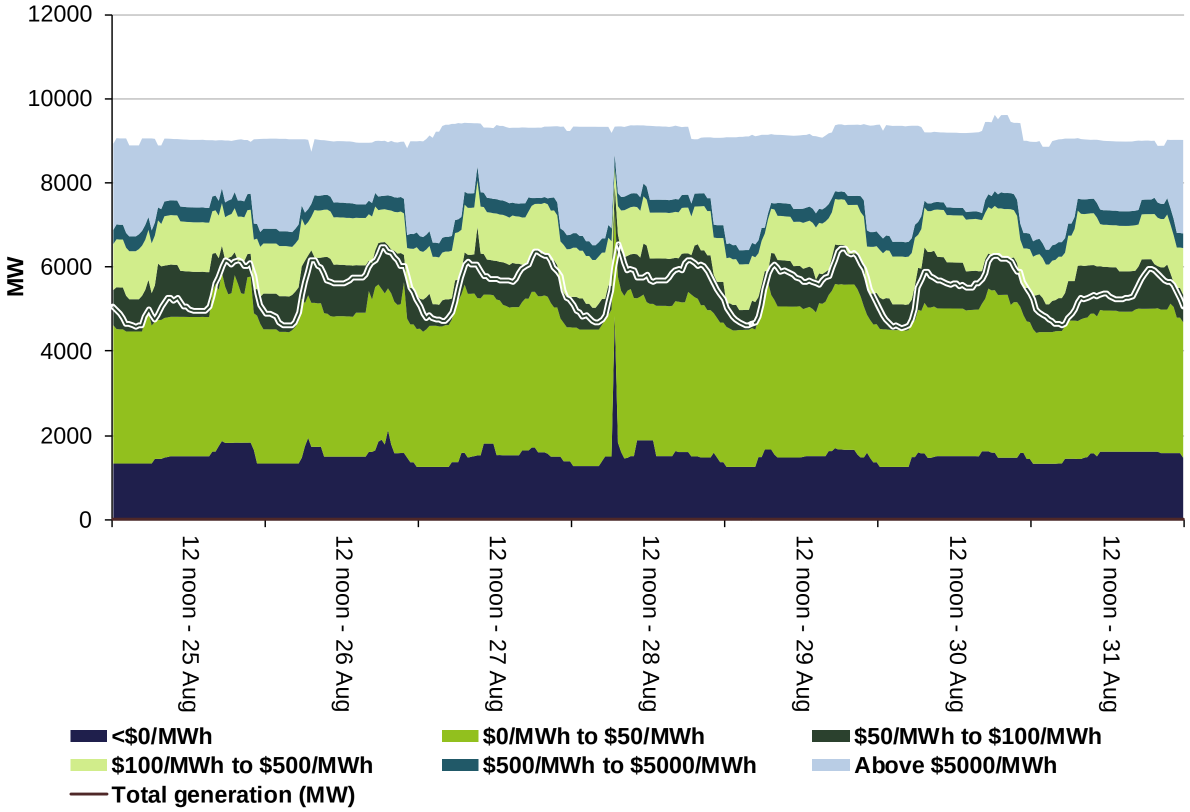


Figure 3: New South Wales generation and bidding patterns

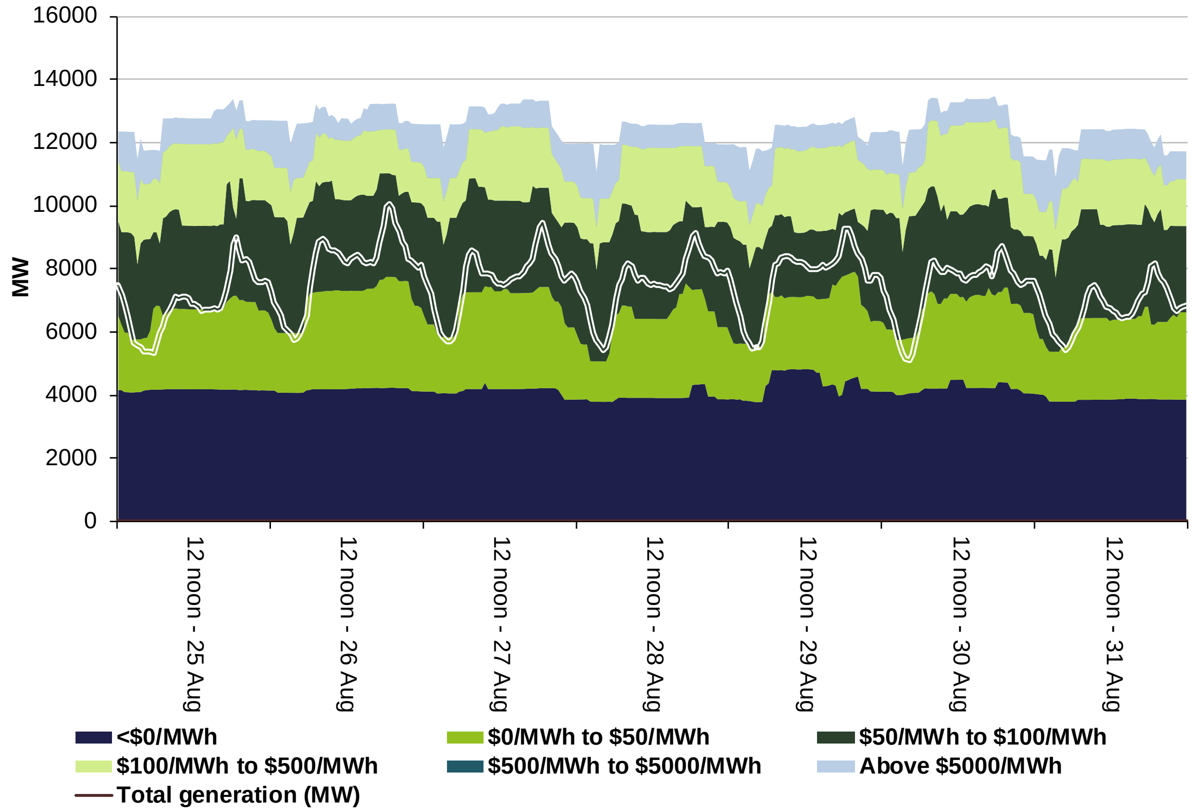


Figure 4: Victoria generation and bidding patterns

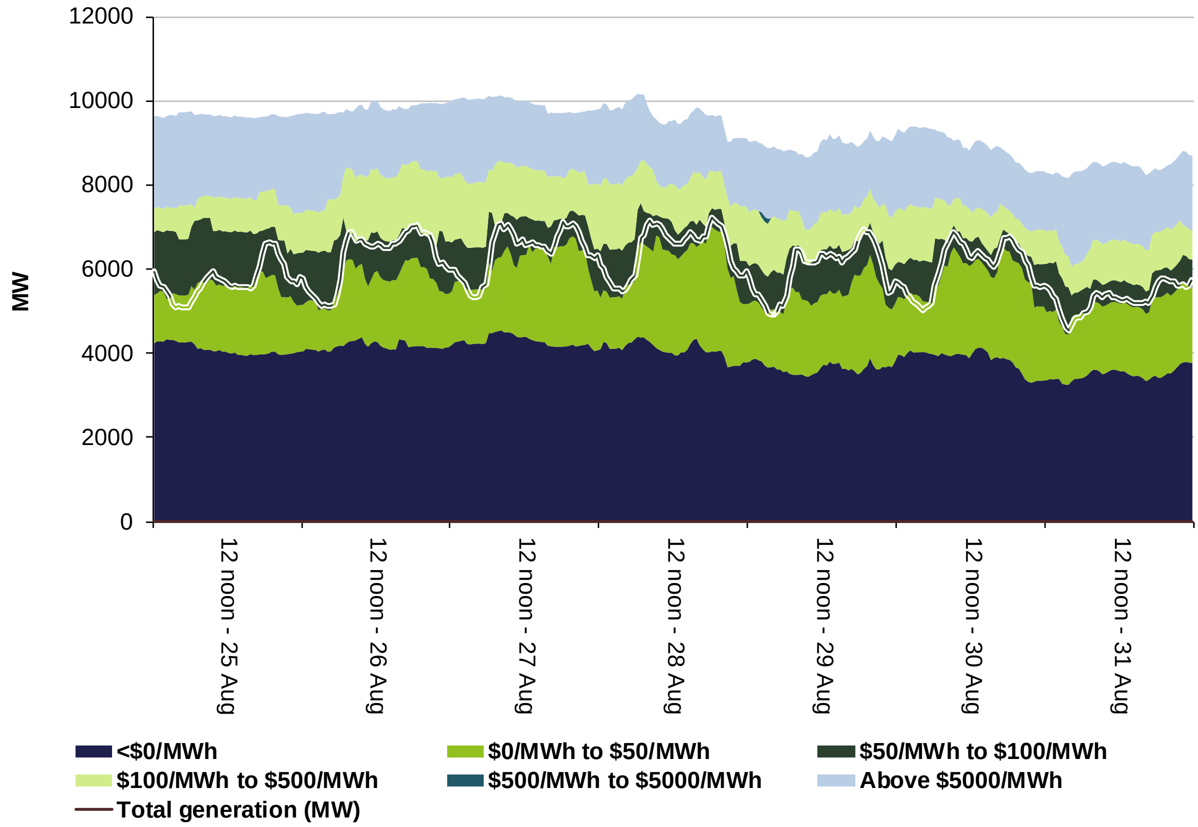


Figure 5: South Australia generation and bidding patterns

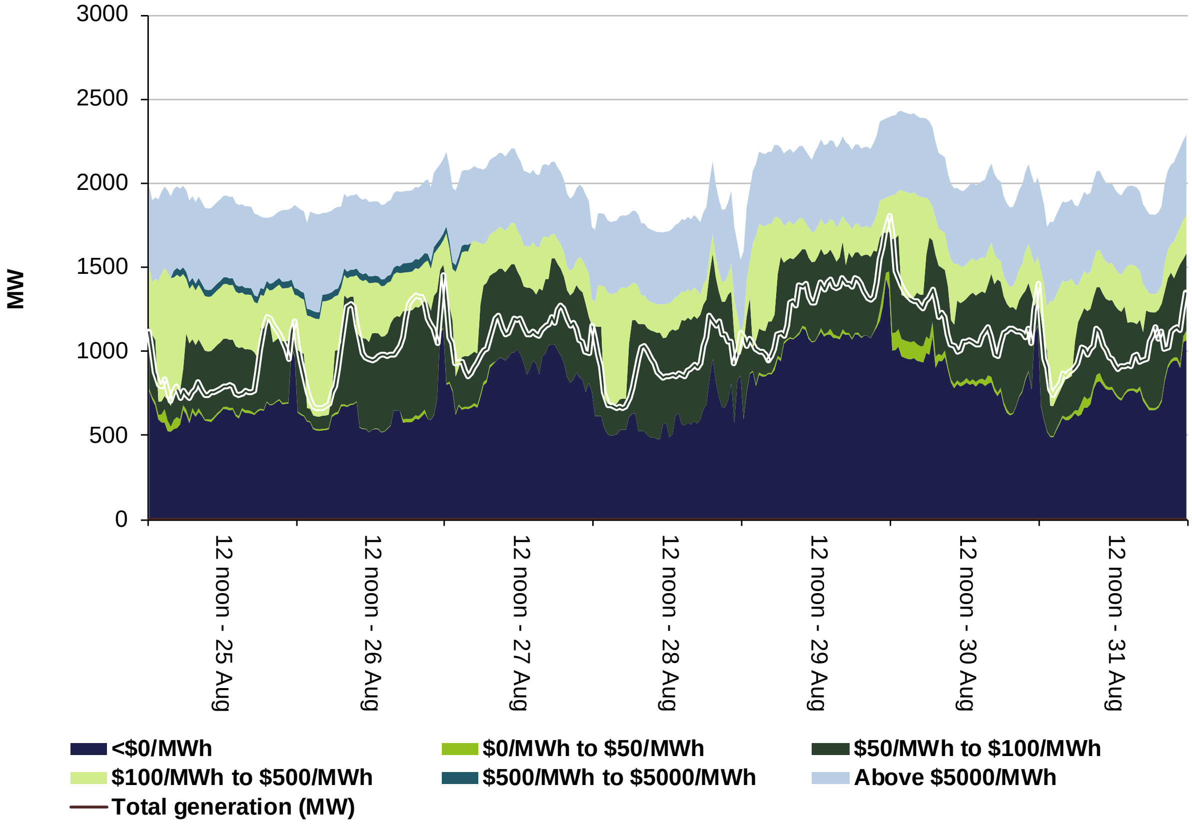
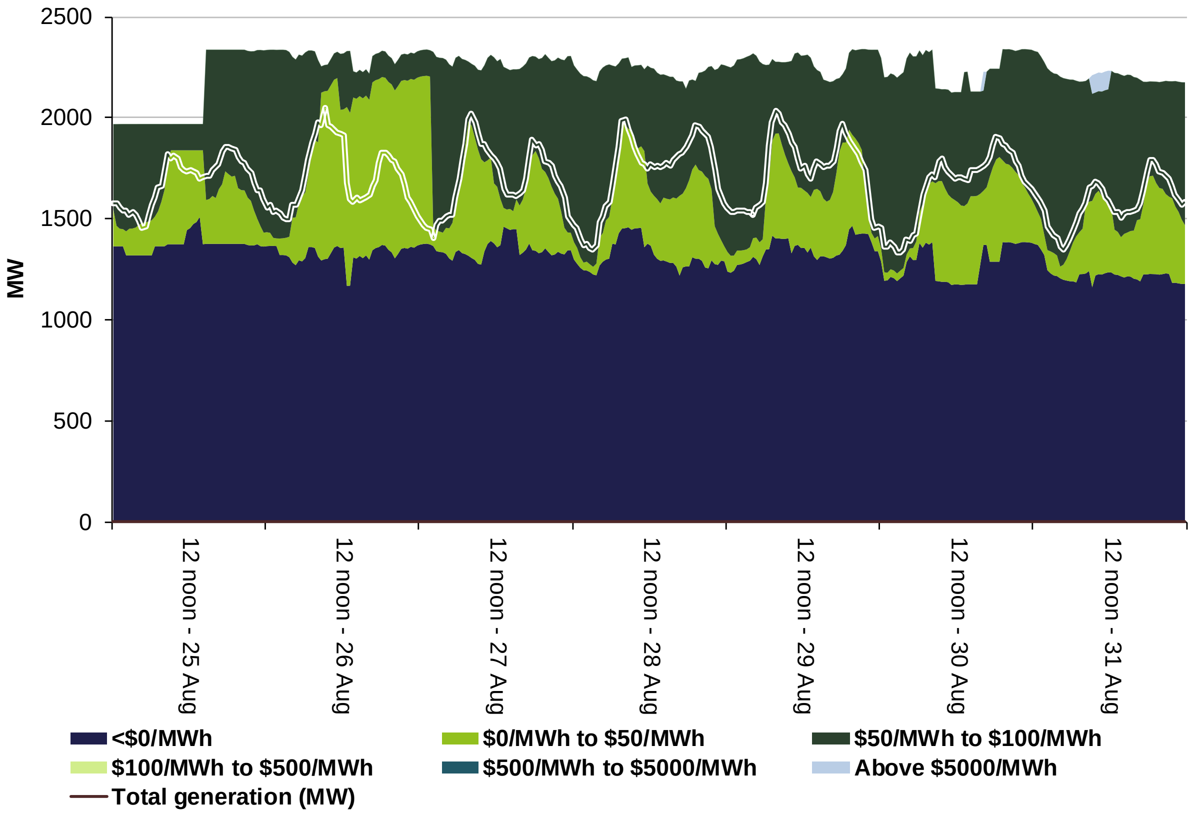


Figure 6: Tasmania generation and bidding patterns



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:

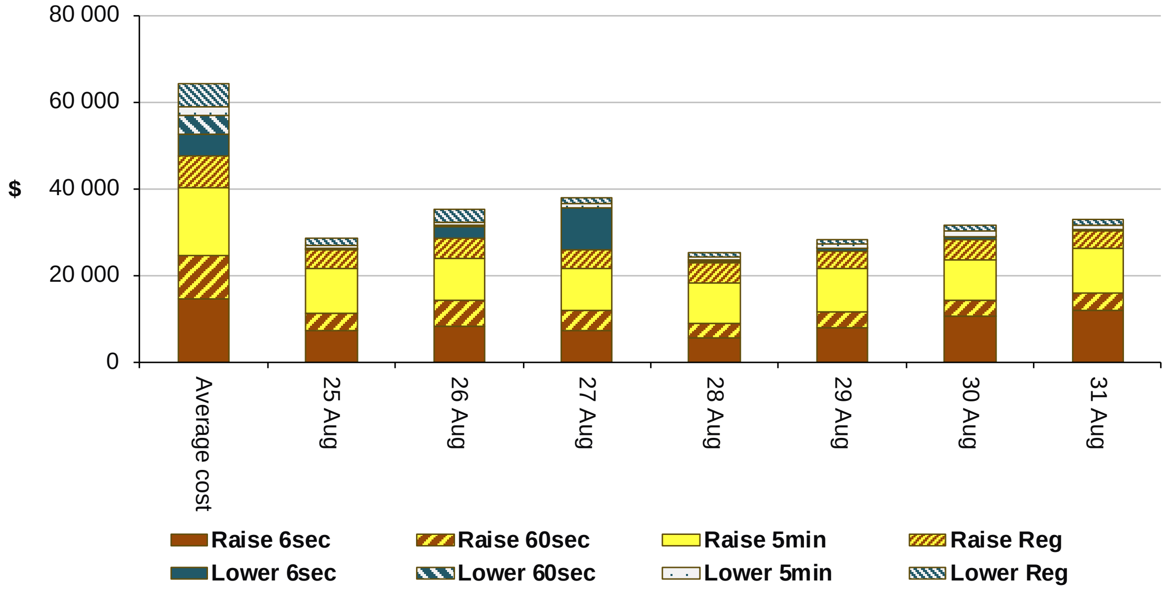
- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- *delayed services*, which return the frequency to the 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 $181 000 or less than 1 per cent of energy turnover on the mainland. In Tasmania (which requires dedicated services for much of the time) the total cost for the week was $38 000 or less than 1 per cent of energy turnover in Tasmania.

Figure 7 shows the daily breakdown of costs for each service, as well as the average daily costs for the previous financial year.

Figure 7: 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. There was one such occasion this week, as set out below.

Table 3: Queensland, Wednesday 28 August

7:00 AM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2223.36	60.08	60.00
Demand (MW)	5624	5665	5693
Available capacity (MW)	9236	9322	9407

Demand and available capacity were slightly lower than forecast four and 12 hours ahead.

At 6.08 am, effective from 6.20 am, CS Energy reduced the available capacity of Gladstone unit 2 by 150 MW, 140 MW of which was priced below $300/MWh. The reason given was “0607P technical issues-feedwater pump issue-SL”. At 6.10 am, effective from 6.20 am, CS Energy rebid 50 MW of capacity at the remaining Gladstone units from the price cap to $52/MWh. The reason given was “0608P Portfolio rearrangement due to G2 feedwater pump issue-SL”. At 6.45 am, effective from 6.55 am, CS Energy reversed the previous Gladstone unit 2 rebid, with the same reason.

At 6.33 am, effective from 6.40 am, Origin Energy reduced the available capacity of Darling Downs by 10 MW, all of which was priced at zero. The reason given was “Plant conditions – ambient temps SL”.

Demand increased from 5473 MW at 6.30 am to 5595 MW at 6.35 am and then to 5662 MW at 6.40 am (189 MW in total). Over the same period, scheduled flows across the QNI interconnector into Queensland increased by 113 MW to the limit of 188 MW (the Directlink interconnector was out of service). The remaining increase in demand of around 76 MW was unable to be satisfied by local low-price generation, because:

- 2280 MW of fast start plant (1200 MW of which was priced at or below $2100/MWh) was unable to come online in time.
- There was also 125 MW of capacity at Gladstone priced at less than $290/MWh that was not dispatched to meet this increase in demand as the units were either ramp rate limited, trapped or stranded in FCAS (such that energy output could not be varied).

As a result high-price generation at Stanwell’s Swanbank and Tarong power stations was dispatched, which saw the 5-minute price increase from $66/MWh at 6.35 am to the price cap at 6.40 am.

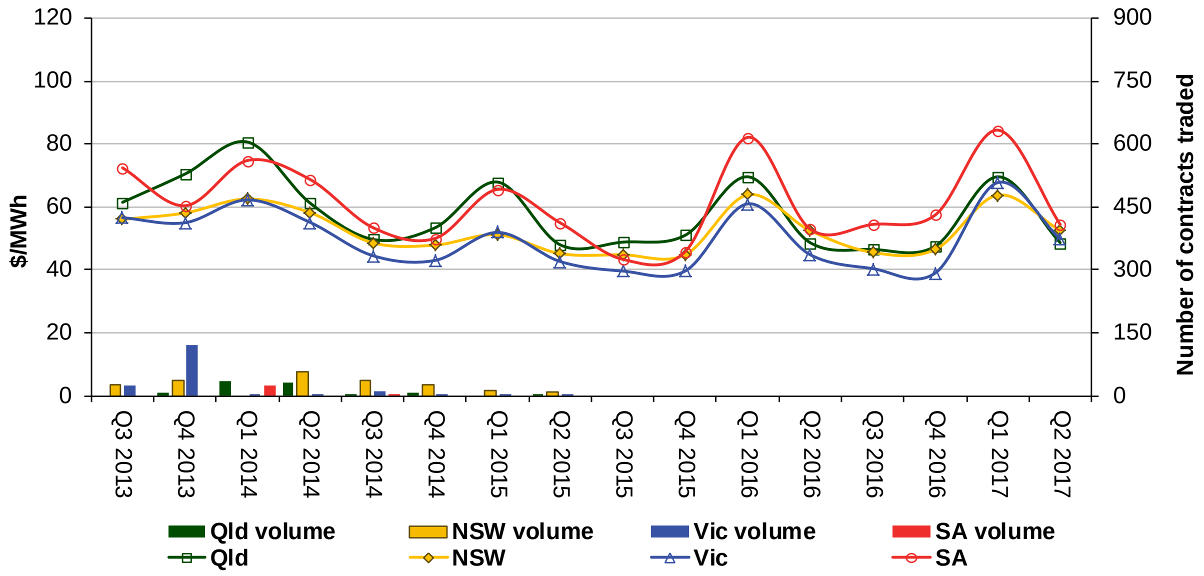
At 6.45 am Queensland generators rebid around 450 MW of capacity from the price cap to zero or below, and, according to AEMO, at the same time there was an apparent demand side response from a refinery in Northern Queensland. This saw the 5-minute price fall to around $50/MWh for the remainder of the trading interval.

There was no other significant rebidding.

Financial markets

Figure 8 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.

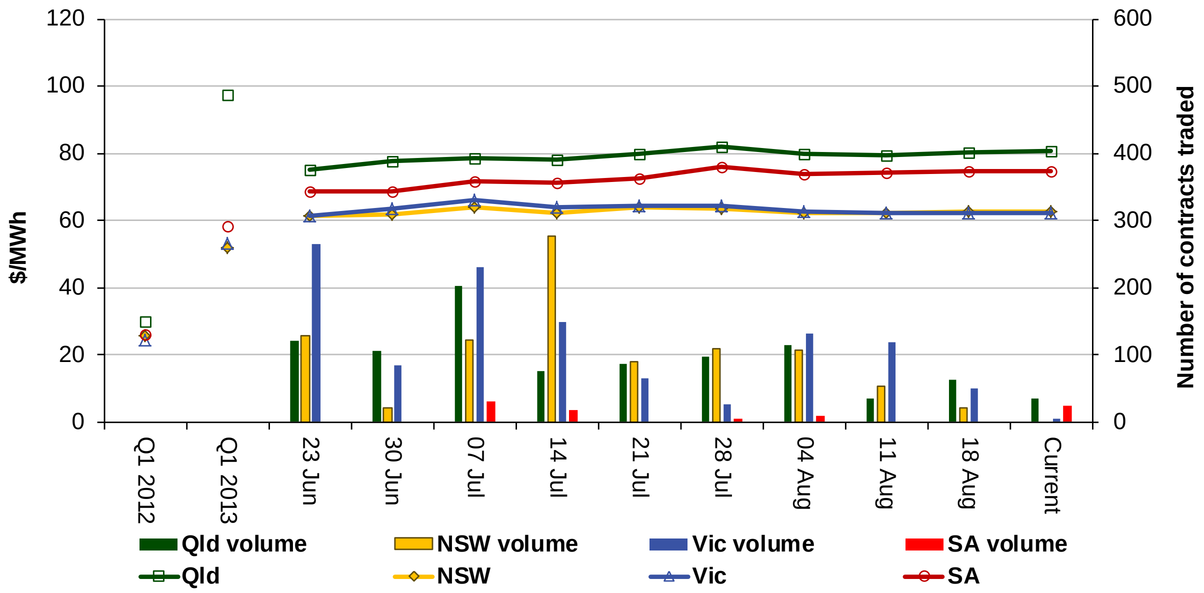
Figure 8: Quarterly base future prices Q3 2013 – Q2 2017



Source: ASXEnergy.com.au

Figure 9 shows how the price for each regional Quarter 1 2014 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Quarter 1 2012 and Quarter 1 2013 prices are also shown.

Figure 9: Price of Q1 2014 base contracts over the past 10 weeks (and the past 2 years)



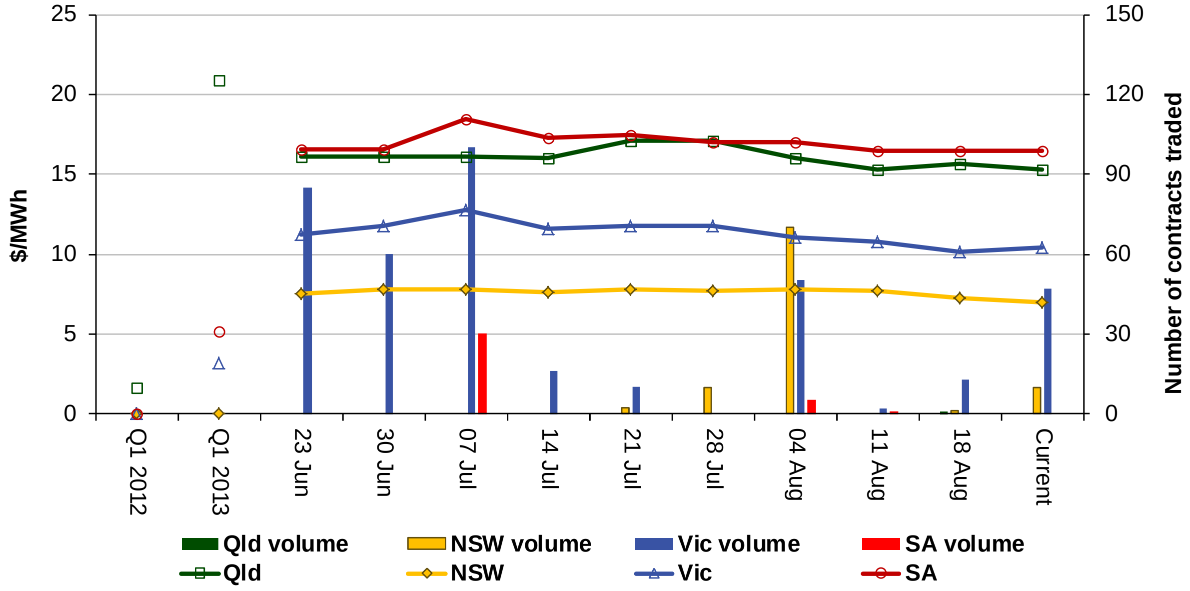
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: ASXEnergy.com.au

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

Figure 10 shows how the price for each regional Quarter 1 2014 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Quarter 1 2012 and Quarter 1 2013 prices are also shown. The cap contracts limit exposure to extreme spot prices (above $300/MWh) and is an indicator of the cost of risk management.

Figure 10: Price of Q1 2014 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

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