Electricity Report

29 Dec 2013 to 4 Jan 2014

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.

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)

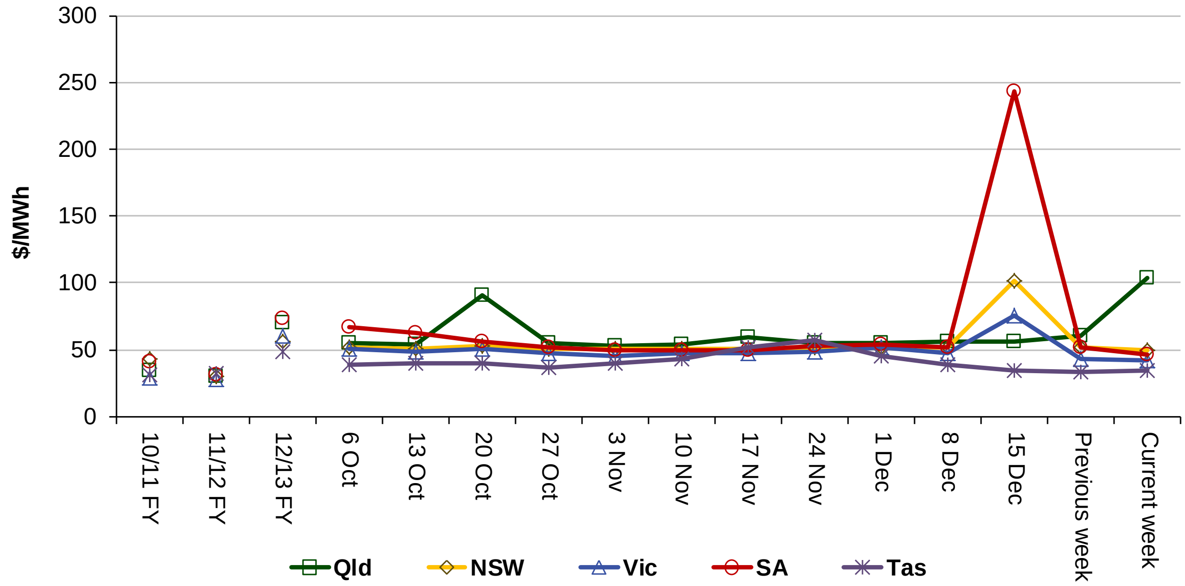


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	103	50	42	47	34
12-13 financial YTD	58	58	66	66	49
13-14 financial YTD	61	55	52	70	44

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 121 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	10	20	0	9
% of total below forecast	31	29	0	1

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.

The three situations identified in Figure 2 for Queensland resulted in prices above the AER's threshold for investigation and are discussed in greater detail later in the report.

Figure 2: Queensland generation and bidding patterns

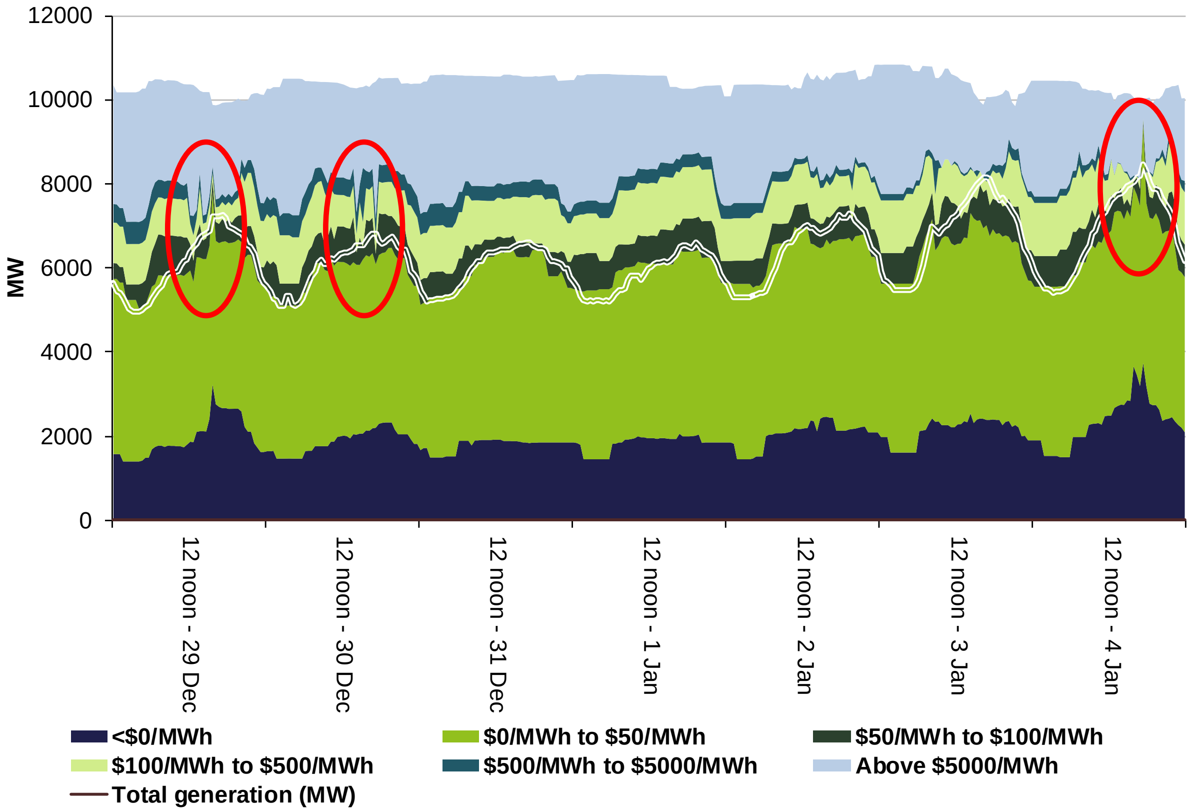


Figure 3: New South Wales generation and bidding patterns

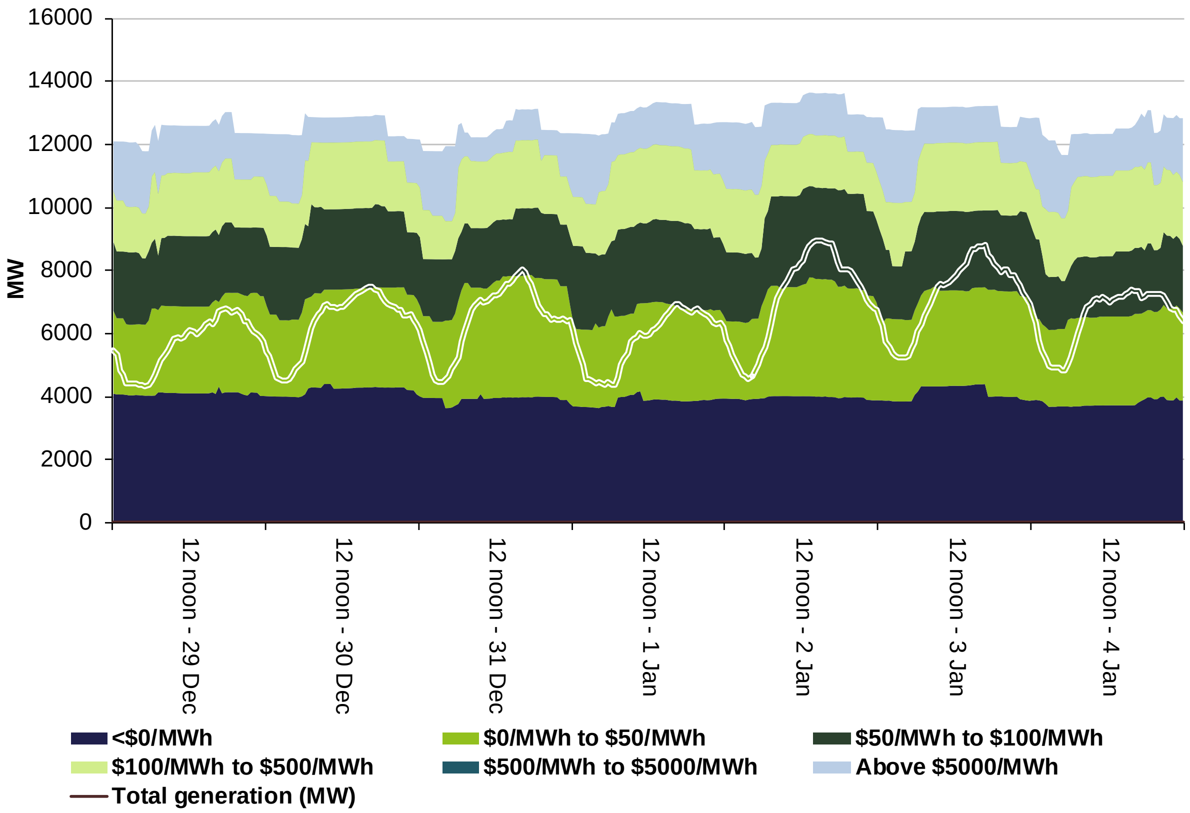


Figure 4: Victoria generation and bidding patterns

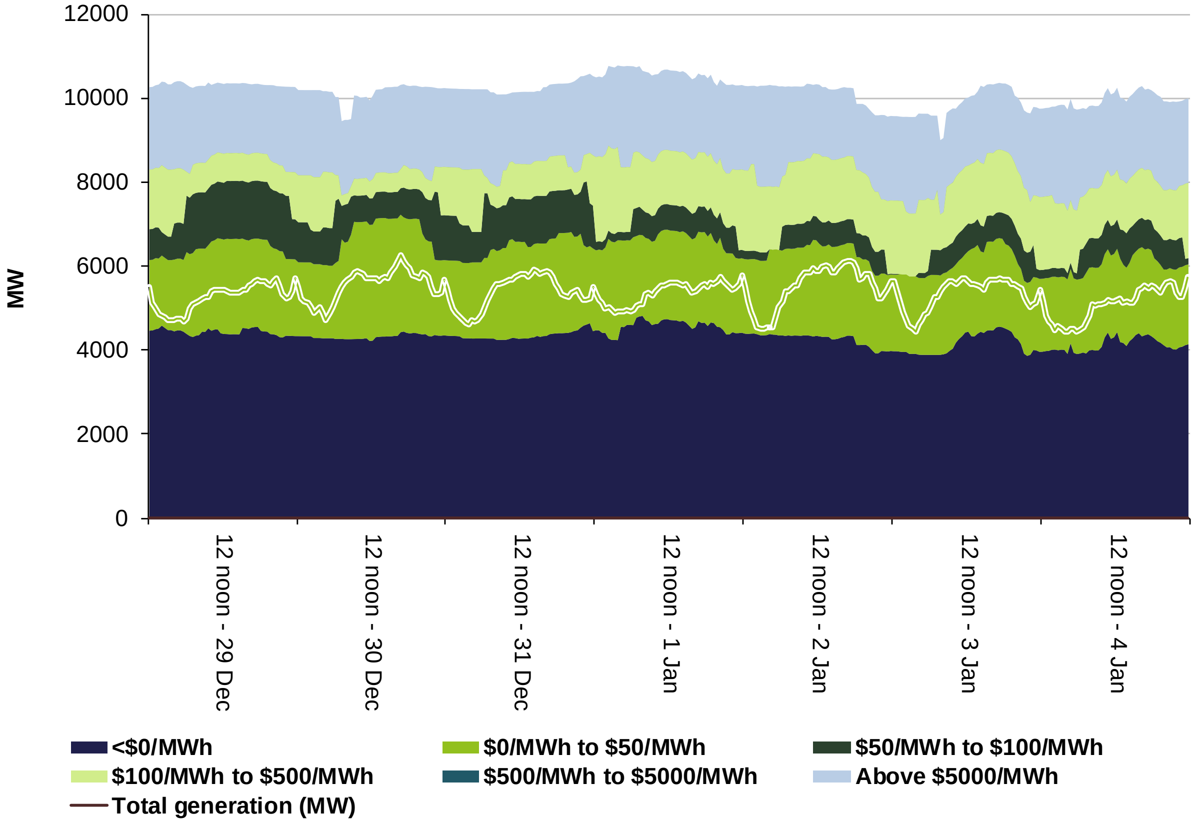


Figure 5: South Australia generation and bidding patterns

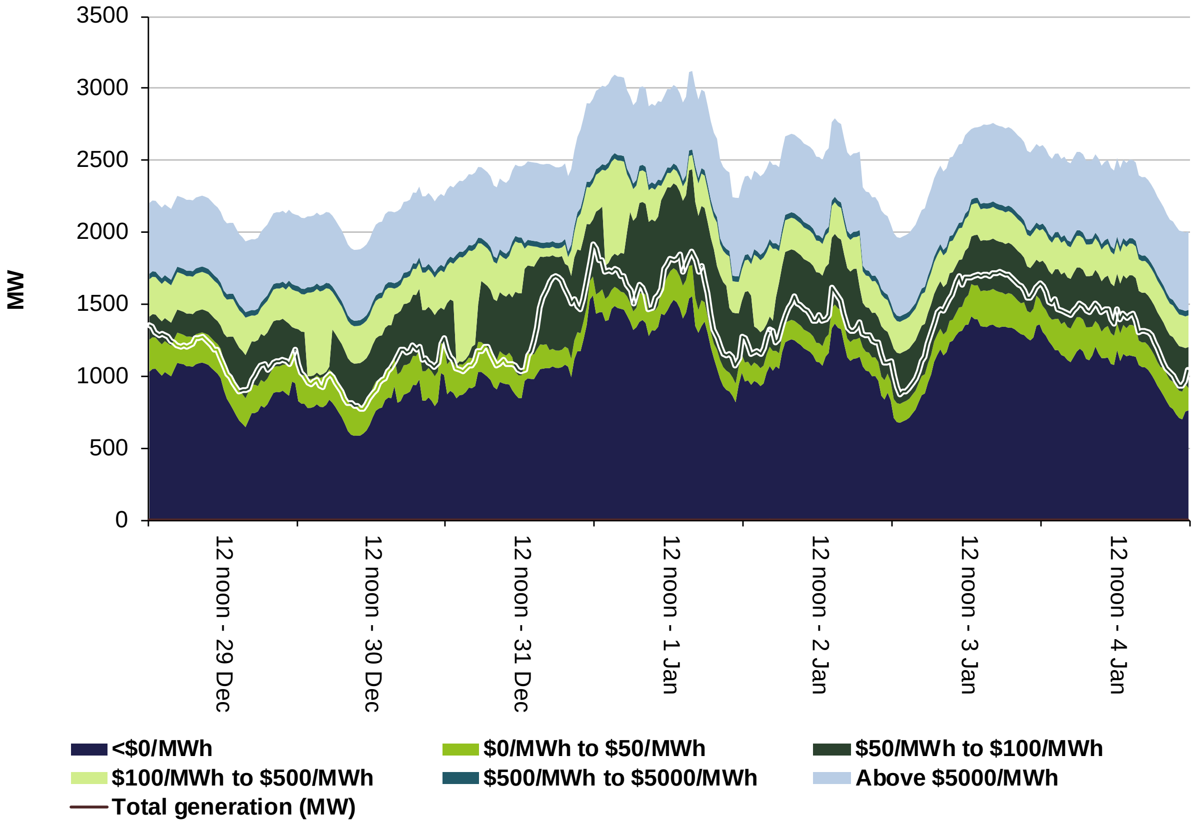
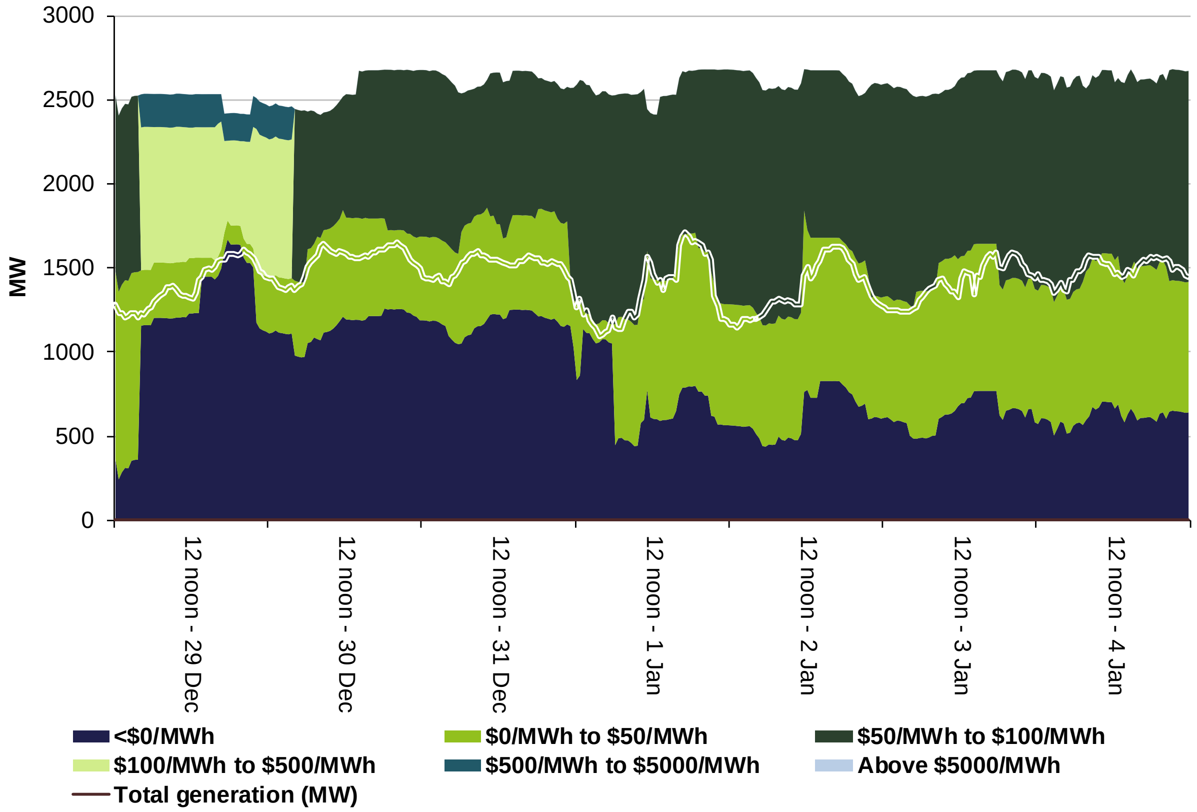


Figure 6: Tasmania generation and bidding patterns



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.

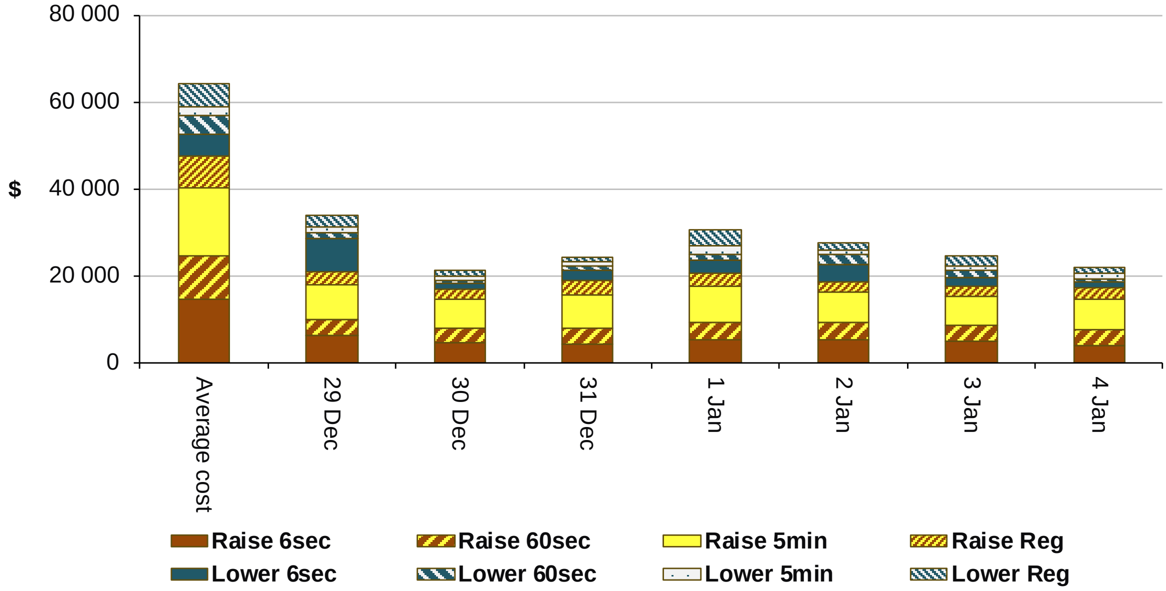
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $147 000 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 $365 000 or 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 were six occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $103/MWh and above $250/MWh.

Table 3: Queensland, Sunday 29 December

3.30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	575.58	56.89	77.55
Demand (MW)	7037	7058	7094
Available capacity (MW)	10 183	10 362	10 400
4.00 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2225.23	75.11	150.01
Demand (MW)	7163	7169	7174
Available capacity (MW)	9881	10 362	10 400

Conditions at the time saw demand close to forecast and available capacity up to 480 MW less than that forecast 4 hours ahead. Queensland import capability was reduced as a result of the long term outage of Directlink (due to a planned outage since 6 August 2013) and the voltage collapse constraints, from the loss of Kogan Creek, limited QNI to around 250 MW.

Two rebids by CS energy for Callide B unit 2 at 1.56 pm and 3.17 pm, effective from 2.05 pm and 3.25 pm respectively, shifted a total of 120 MW from prices below $60/MWh up to the price cap. The reason given for both rebids was ‘portfolio rearrangement due to-Callide coal management-SL’.

Almost an hour later, at 2.57 pm, effective from 3.05 pm for the 3.30 pm trading interval, CS Energy rebid 790 MW from across its portfolio from price bands between $52/MWh and $1375/MWh to the price cap. The reason for the rebid was ‘interconnector constaint -QNI binding-SL’. At 3.19 pm, the above rebid was extended for the 4 pm trading interval.

For the majority of the 3.30 pm trading interval, the 5-minute dispatch price was around $290/MWh. However at 3.21 pm, Swanbank E power station tripped from 300 MW and because low priced local generation either at maximum output, ramp rate limited or stranded high priced local generation was dispatched to meet demand and the 5-minute price increased from $290/MWh at 3.25 pm to $2004/MWh at 3.30 pm.

Similarly at 3.35 pm, when demand increased by 97 MW The low priced generation was either at maximum output or ramp rate limited and consequently high priced local generation was dispatched and the 5-minute price increased from $2004/MWh at 3.30 pm to the price cap at 3.35 pm.

The five minute price fell to $54/MWh at 3.40 pm when rebids by AGL Energy and Stanwell Corporation became effective, which moved around 260 MW from the price cap to under $100/MWh. The reasons for the rebids were ‘1530A chg in dispatch::price increase vs PD $13100 QLD’ and ‘1525F swan e trip portfolio rearrangement’.

There was no other significant rebidding.

Table 4: Queensland, Monday 30 December

5.30 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	509.11	56.15	56.15
Demand (MW)	6927	6635	6676
Available capacity (MW)	10 435	10 396	10 691

Conditions at the time saw demand around 300 MW greater than the four hours ahead forecast and around 260 MW less available capacity than that forecast 12 hours ahead.

Import capability into Queensland was limited by the unavailability of the Terranora interconnector(on a planned outage since 6 August) and voltage collapse constraints relating to the loss of Kogan Creek limiting QNI to around 250 MW, .

At 5.14 pm, effective from 5.20 pm, Stanwell rebid 443 MW from across its portfolio from prices below $60/MWh to the price cap. The reason for the rebid was ‘1703A change qld demand 1730ti pd1730vpd1630 sl’.

At 5.18 pm, effective from 5.25 pm, CS Energy rebid 600 MW of available capacity at Gladstone and Wivenhoe from prices below $250/MWh to bands above $1300/MWh, with the majority of this capacity priced around $12 800/MWh. The reason for the rebid was ‘1718A interconnector constraint-QNI binding-sl’.

Consequently the 5 minute price increased from $57/MWh at 5.15 pm to $84/MWh at 5.20 pm and $1400/MWh at 5.25 pm. Prices dropped to around $57/MWh by 5.40 pm

There was no other significant rebidding.

Table 5: Queensland, Saturday 4 January

4.00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	4376.90	1400.23	300.99
Demand (MW)	8205	8576	8581
Available capacity (MW)	10 076	10 250	10 363

Conditions at the time saw demand around 370 MW less than that forecast four hours ahead and available capacity around 180 MW less than forecast four hours ahead. High demand was driven by temperatures which reached a peak of 38.7 degrees in Brisbane.

Import capability into Queensland was reduced by the planned outage of the Terranora interconnector unavailable and voltage collapse constraints from the loss of Kogan Creek limiting QNI to around 250 MW.

At 3.19 pm, effective from 3.30 pm, CS Energy rebid 320 MW at Gladstone from prices below $60/MWh to the price cap. The reason given was "Interconnector constraint – QNI-SL". The rebid also saw all Gladstone units ramp rates increased from 5 MW/min to 8 MW/min. At 3.39 pm, effective from 3.50 pm, CS Energy further rebid 120 MW of capacity at Gladstone from prices below $60/MWh to the price cap. The reason given was 'Interconnector constraint-QNI-sl'. This was also when all Gladstone units became trapped in FCAS services.

At 3.52, effective from 4 pm, Callide Power Trading rebid 50 MW of capacity at Callide priced at the price floor to the price cap. The reason for the rebid was '1549A change in sens – sl'.

The above rebids and an increase in demand from 8190 MW at 3.50 pm to 8262 MW at 3.55 pm saw the 5-minute price increase from $301/MWh at 3.50 pm to $11990/MWh at 3.55 pm, then to the price cap at 4 pm.

There was no other significant rebidding.

Table 6: Queensland, Saturday 4 January

5.00 PM	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	413.65	460.50	300.99
Demand (MW)	8272	8586	8611
Available capacity (MW)	10 003	10 250	10 364
5.30 PM	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2040.92	82.66	162.59
Demand (MW)	8322	8462	8500
Available capacity (MW)	10 039	10 212	10 366

The 5 pm the market price was close to that forecast four hours ahead. Conditions for the 5.30 pm trading interval saw demand and available capacity up to 140 MW and 173 MW less than that forecast four hours ahead.

Queensland demand peaked at around 8300 MW during this time, which is the highest recorded Saturday demand and the highest demand since 17 December 2012.

Import capability into Queensland was reduced by the planned outage of the Terranora interconnector unavailable and voltage collapse constraints from the loss of Kogan Creek limiting QNI to around 250 MW.

At 4.45 pm, effective from 4.55 pm, CS Energy rebid 120 MW of capacity at Gladstone priced at $52/MWh to the price cap. The reason for the rebid was ‘1644A interconnector constraint-QNI-snl’.

This rebid combined with a 60 MW increase in demand, saw the 5-minute price increase from $120/MWh at 4.50 pm to $1501/MWh at 4.55 pm. The price fell in the next 5-minute interval to $451/MWh following a rebid by Arrow Energy which shifted 60 MW of capacity at Braemar priced above $1400/MWh to $54/MWh. The reason for the rebid was ‘1650A qld price higher than fcast SL’.

At 4.50 pm, effective 5.05 pm, Callide Power Trading rebid 126 MW of capacity at Callide from prices below $60/MWh, to the price cap. The reason for the rebid was ‘1646A change in Qld sens - 2014010423/25’.

At 4.56 pm, effective from 5.05 pm, Millmerran Energy Trader rebid 15 MW of capacity at Millmerran from the price floor to the price cap. The reason for the rebid was ‘1656A change in qld sens 2014010423/25’.

At 4.58 pm, effective from 5.05 pm, CS Energy rebid 240 MW of capacity at Gladstone priced under $56/MWh to the price cap. The reason for the rebid was ‘1657A interconnector constraint-QNI-in pd-sl’.

At 4.58 pm, effective from 5.05 pm, Alinta Energy rebid 27 MW of capacity at Braemar from less than $430/MWh to the price cap. The reason for the rebid was ‘1700A Qld dispatch $451.06 v 5pd $1500.99@16.58’.

There was an increase in demand from 8298 MW at 5 pm to 8364 MW at 5.05 pm. With lower priced generation either ramp rate limited, stranded or at maximum output, higher priced generation was dispatched to meet demand increasing the 5-minute price from $451/MWh at 5 pm to $12 000/MWh at 5.05 pm.

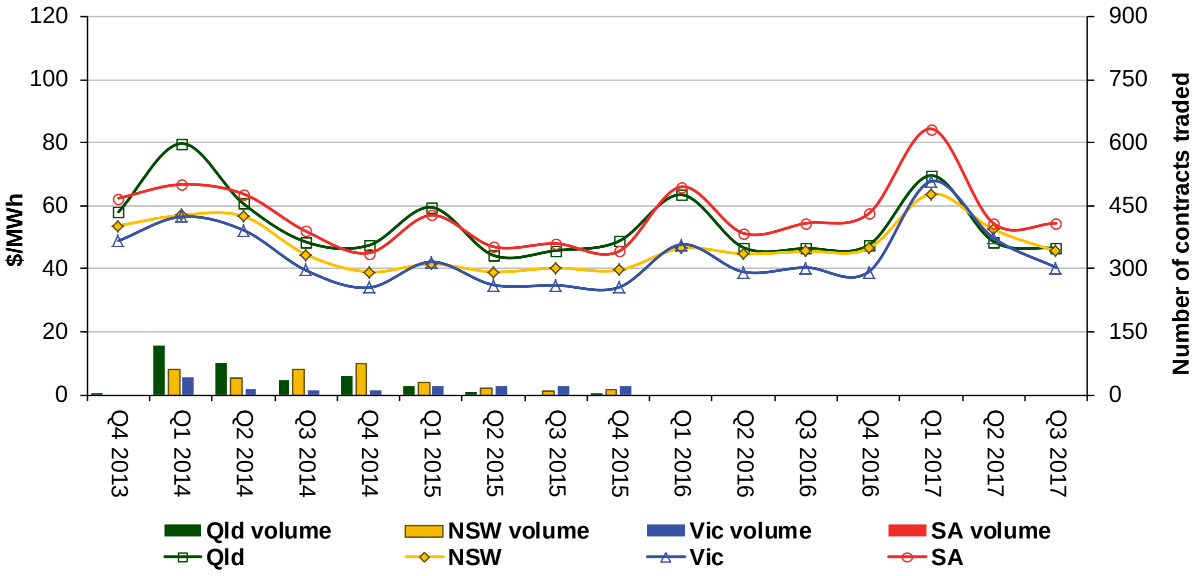
Prices fell in the 5.10 pm 5-minute trading interval to under $50/MWh at following a number of Queensland generators rebidding capacity from high to low prices, and a 100 MW reduction in regional demand.

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.

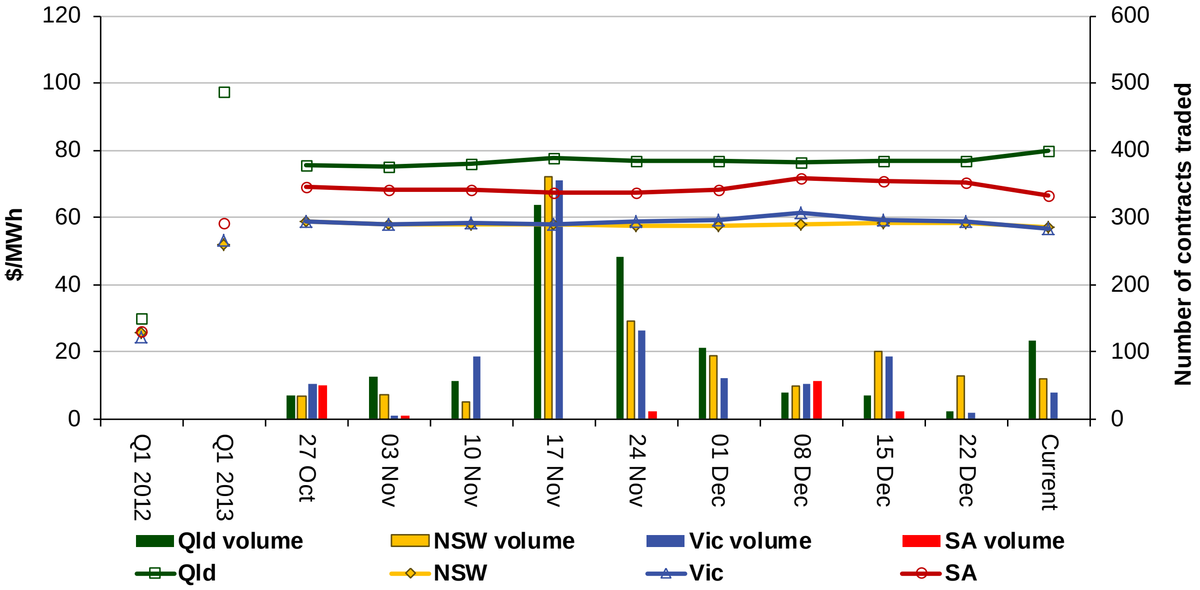
Figure 8: Quarterly base future prices Q4 2013 – Q3 2017



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)



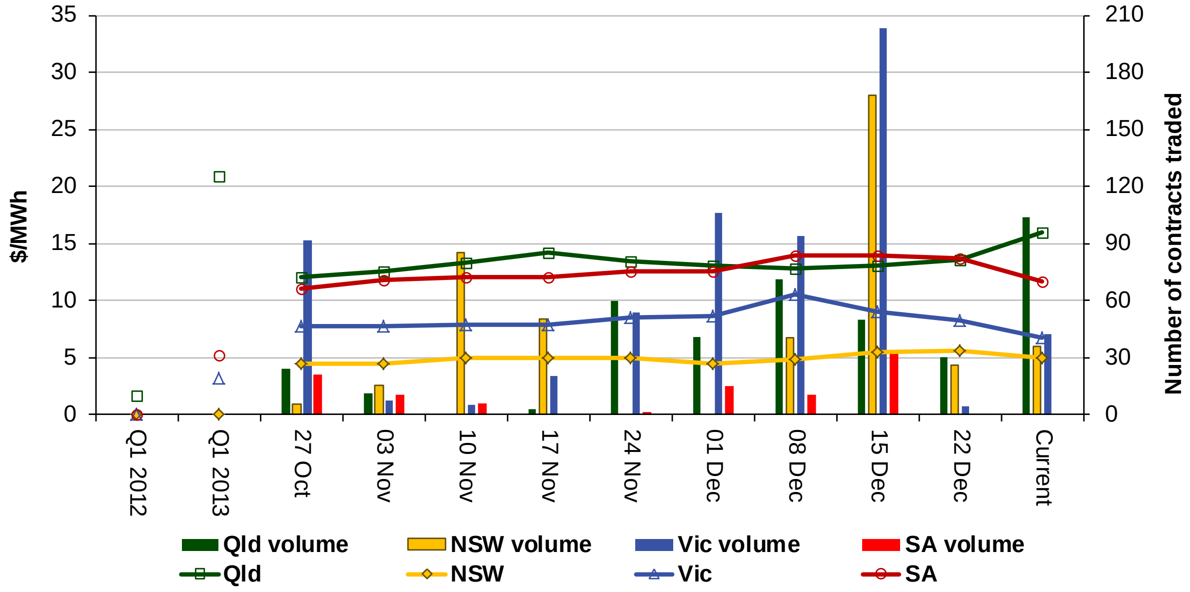
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Industry statistics 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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