Electricity Report

15 to 21 December 2013

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 price outcomes, movements in the contract market, together with analysis of spot market activity and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep abreast of market conditions and identify compliance issues.

Weekly spotlight

Summary

The volume weighted average price in New South Wales and South Australia reached $102/MWh and $244/MWh, respectively this week as a result of a number of high spot prices in those regions on Thursday and Friday. There were fifteen spot prices above $1000/MWh with a maximum spot price of $10 627/MWh occurring in South Australia at 4pm on Thursday and $7696/MWh occurring in New South Wales at 1.30pm on Friday. In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue two separate reports into the circumstances that led to the spot price exceeding $5000/MWh on each of these days. There were also a number of high FCAS prices in Tasmania on Wednesday and Thursday, which are discussed further below.

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)

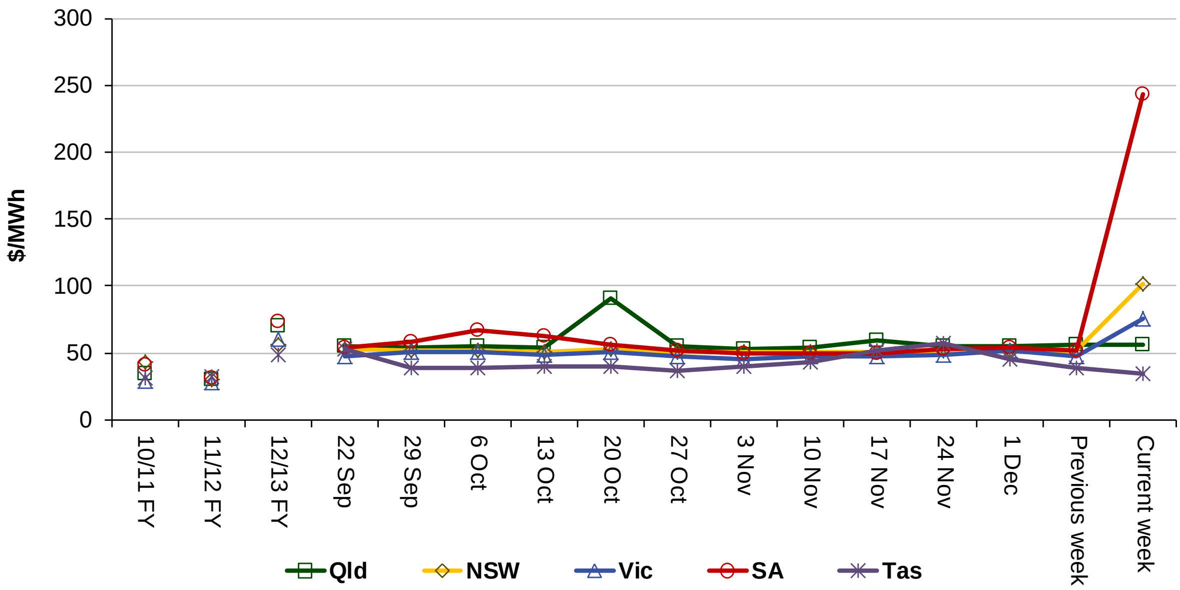


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	57	102	75	244	35
12-13 financial YTD	58	58	65	65	49
13-14 financial YTD	59	56	53	72	45

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 identify and review each occasion where 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 89 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average of 60 counts in 2012 and 78in 2011 . Reasons for the variations for this week are summarised in Table 2. 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	35	2	2
% of total below forecast	24	24	0	2

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

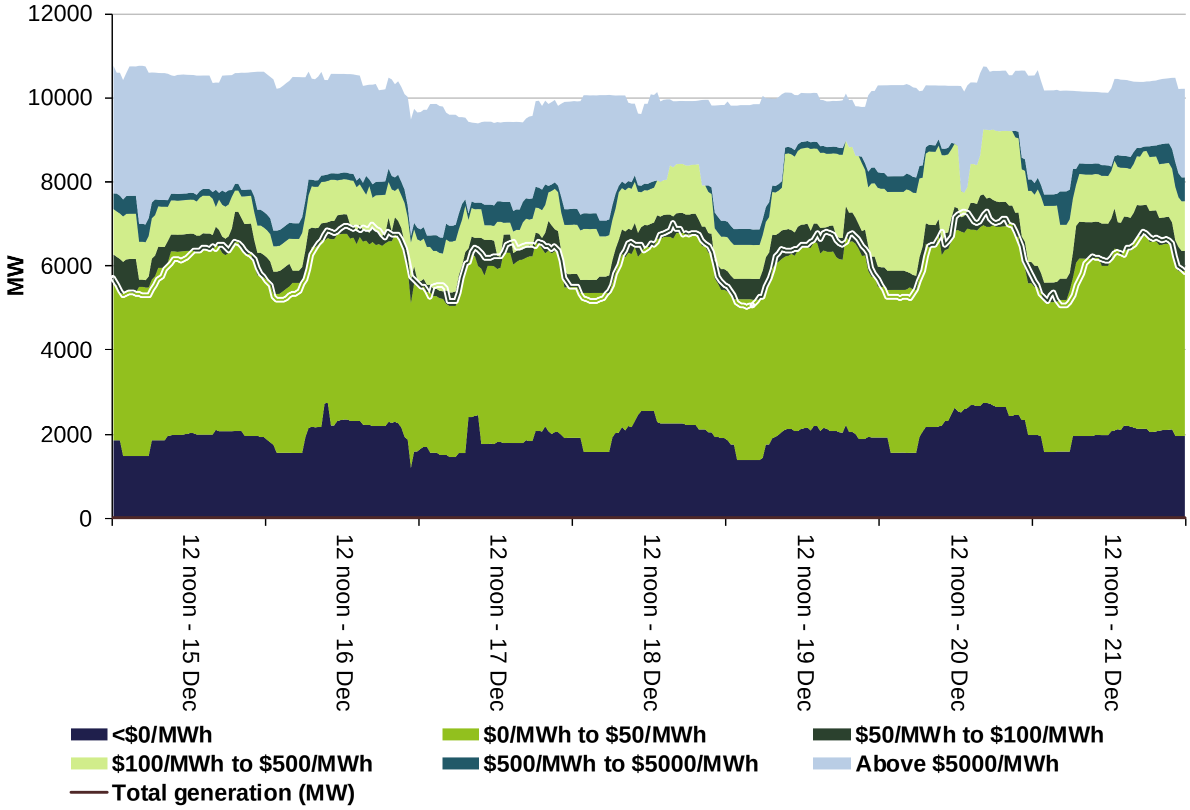


Figure 3: New South Wales generation and bidding patterns

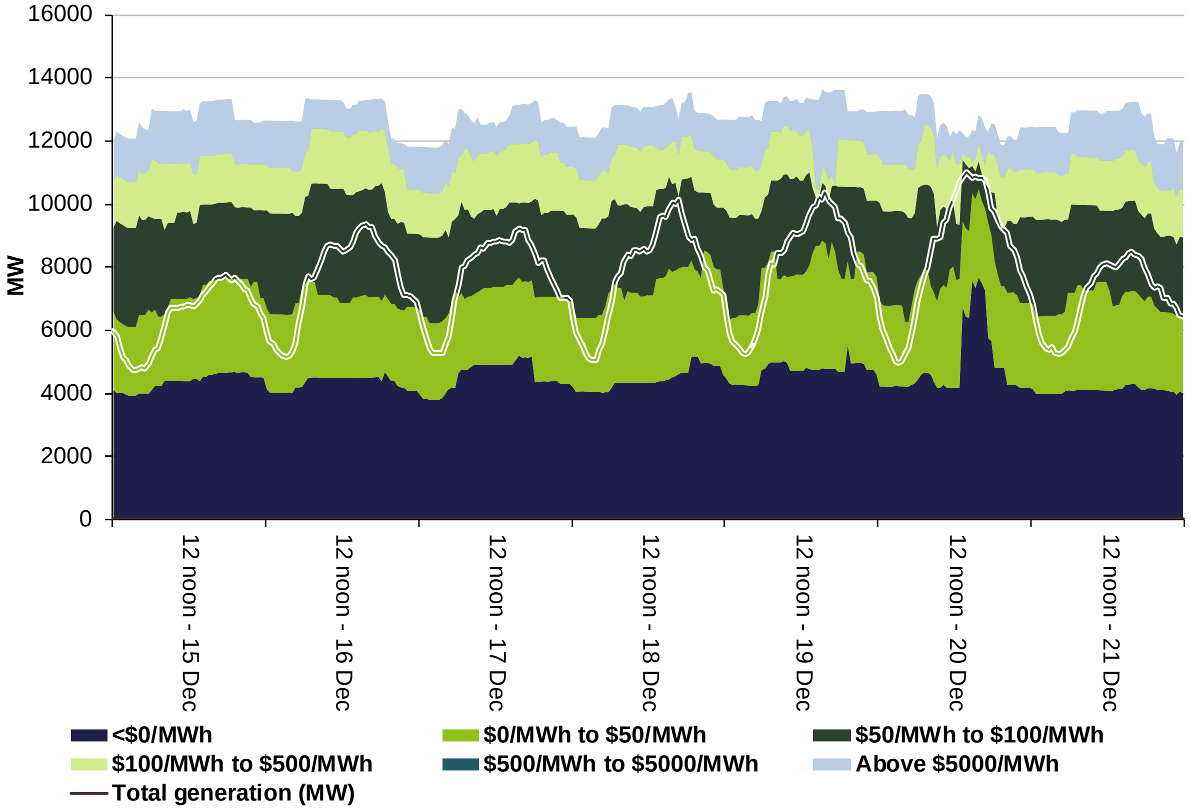


Figure 4: Victoria generation and bidding patterns

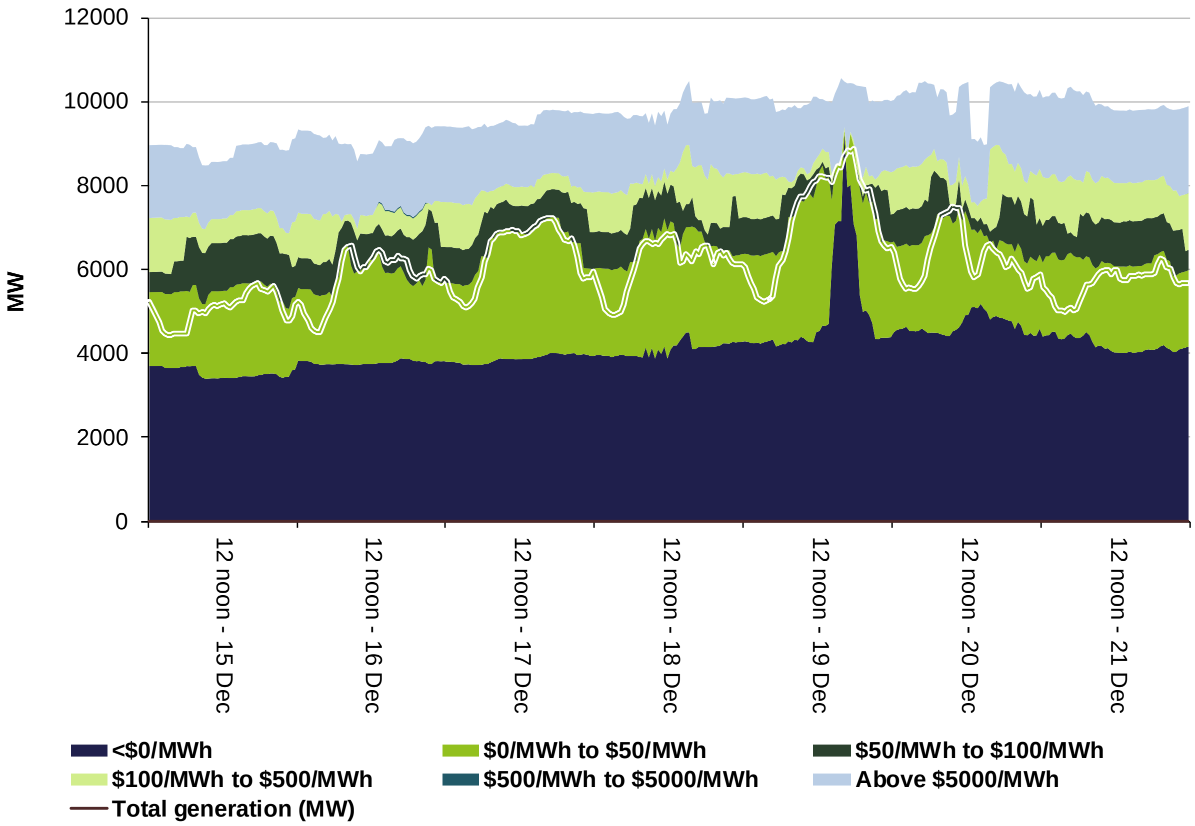


Figure 5: South Australia generation and bidding patterns

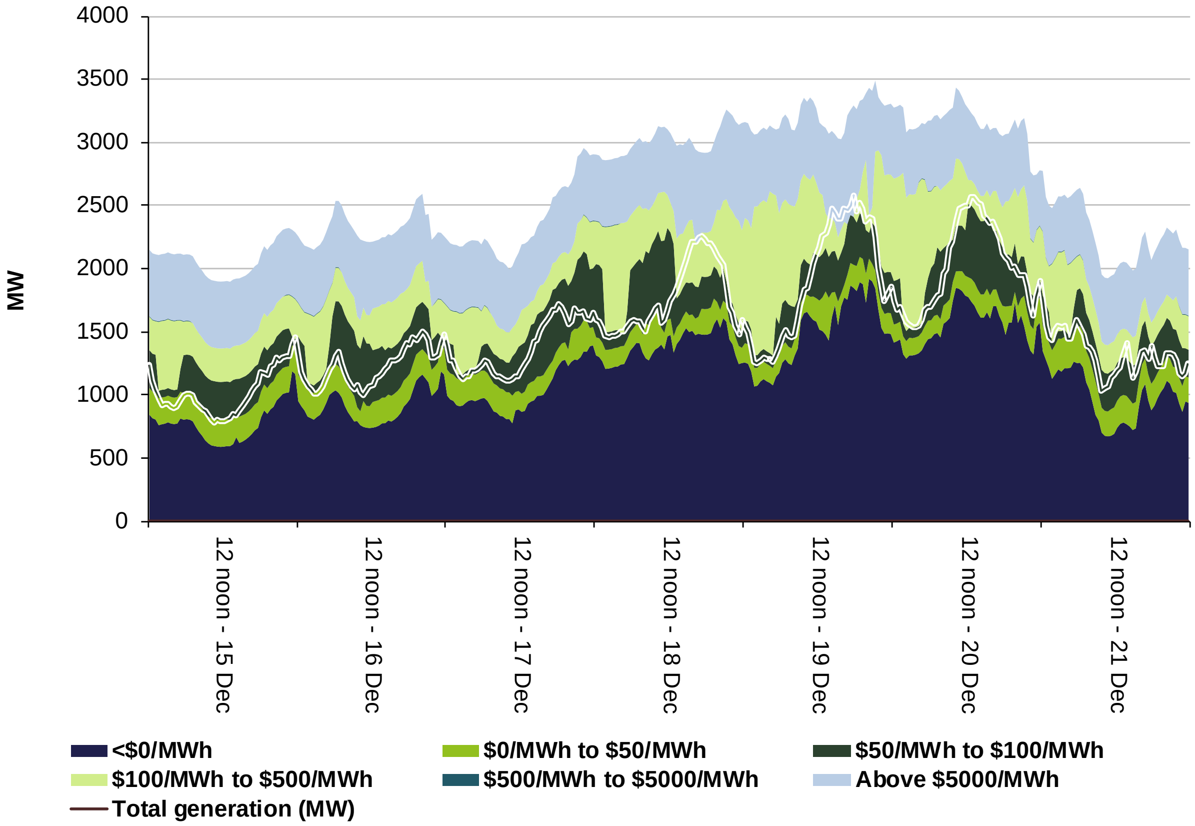
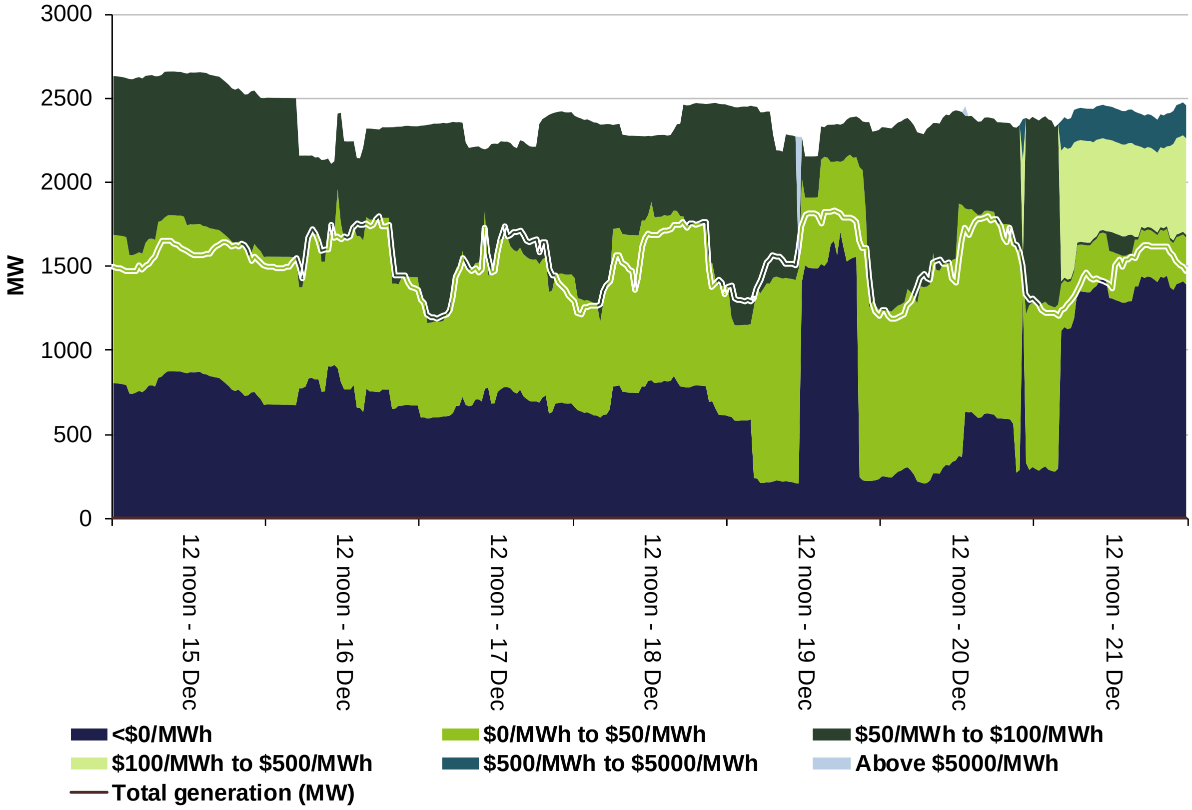


Figure 6: Tasmania generation and bidding patterns



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 $165 000 or less than 1 per cent of energy turnover on the mainland.

In Tasmania (where dedicated local services are required often) the total cost for the week was $718 000 or around 12 per cent of energy turnover in Tasmania. A majority of this cost ($663 475) occurred over a total of 8 dispatch intervals on Monday, Wednesday and Thursday.

On Monday 16 December at 6.49 pm, effective from 8.05 pm, Hydro Tasmania rebid all of its lower regulation service capacity from prices below $10/MW to $13 100/MW. The reason given was "1830A p30 Basslink flow different to forecast." At 8.40 pm the export limit across Basslink increased causing a 50 MW requirement for local lower regulation service in Tasmania. Given that all of this capacity was at the price cap, the price went to $13 100/MW. The cost of the service over that dispatch interval was $54 583. Effective from 8.45 pm the above rebid was reversed, resulting in lower prices.

On 18 December at around 4.40 pm the availability of Basslink was rebid from 594 MW to 571 MW. The reason given was "Scenario 1", which the AER understands means that Basslink was operating outside its technical envelope and flow needed to be reduced. This resulted in the target and the availability of Basslink aligning during the 5.05 pm, 5.10 pm and 5.15 pm dispatch intervals. With no headroom on Basslink to transfer lower regulation services, those services needed to be sourced locally resulting in an increase of 24 MW. These additional services were all priced at the price cap costing around $164 000. At 5.13 pm, effective from 5.20 pm, Hydro Tasmania rebid all available capacity for regulation services to below $10/MW resulting in the price returning to previous levels.

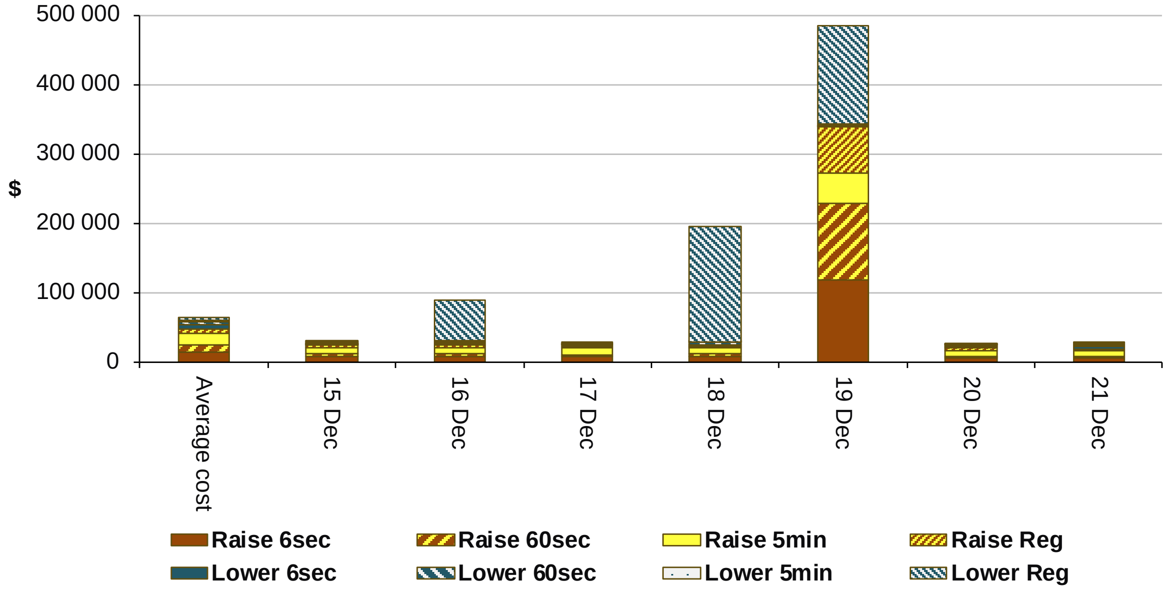
On Thursday 19 December, the flow across Basslink into Victoria was at its limit from around midday. Local lower regulation services were being dispatched to meet the requirement in Tasmania during this time. On six occasions (4 pm, 4.15 pm, 5.25 pm, 5.30 pm, 5.35 pm and 6.05 pm) the price for local lower regulation services spiked with prices ranging from $2467/MW to $13 100/MW. The high prices, generally related to the co-optimisation process of the service with energy and other frequency services (in Tasmania and on the mainland).

At 5.40 pm, the availability of Basslink was reduced from 594 MW to 571 MW for the following trading interval. The reason given was "Scenario 1". This resulted in the target and the maximum availability of Basslink aligning at 6.05 pm. As a result, the local lower regulation requirement increased by 24 MW and the price increased to $13 100/MW. Prices returned to lower levels from 6.15 pm. The total cost of this service was $133 424 during the 6.30pm trading interval.

The price of raise regulation service in Tasmania increased to $13 000/MW at around 8.50pm, with the resulting cost of $311 718. The increase related to issues with the Basslink frequency controller which occurred from around 8.25 pm. By 8.55 pm, the majority of raise regulation capacity was rebid to prices below $100/MW, while the remaining raise services was rebid to $2/MW or lower. The price for raise regulation in Tasmania returned to below $40/MW from 9 pm.

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 ten occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $102/MWh and above $250/MWh.

There were four occasions where the spot price in Victoria was greater than three times the Victoria weekly average price of $75/MWh and above $250/MWh, and one occasion where the spot price was below -$100/MWh.

There were ten occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $244/MWh and above $250/MWh.

New South Wales

Table 3: New South Wales, Friday 20 December 12.30 PM to 2.30 PM

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
12.30 PM	316.50	55.36	55.36	10 977	10 287	10 766	12 254	13 558	13 575
1.00 PM	337.83	55.36	55.66	11 139	10 448	10 923	12 269	13 327	13 574
1.30 PM	7696.44	57.94	55.36	11 296	10 835	11 018	12 255	13 153	13 645
2.00 PM	2457.95	62.10	55.66	11 501	10 968	11 115	12 240	12 372	13 641
2.30 PM	1270.83	62.89	56.75	11 635	11 019	11 173	12 333	12 658	13 932

In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh. The report will also include analysis of the spot prices outlined above.

Victoria

Table 4: Victoria, Thursday 19 December 4.00 PM to 6.00 PM

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
4.00 PM	789.86	280.75	52.91	9008	9063	8450	10 584	10 518	10 907
4.30 PM	1474.83	275.94	52.91	8978	9106	8504	10 490	10 527	10 690
5.30 PM	3667.01	50.29	61.83	8765	8894	8247	10 441	10 530	10 333
6.00 PM	467.74	50.29	61.6	8566	8651	8094	10 424	10 558	10 362

This was the first high demand day of the 2013/14 summer and demand was almost 700 MW higher than the previous which occurred on 2 December 2013.

Actual demand was relatively close to the four hours ahead forecast but was relatively consistently more than 550 MW above that forecast 12 hours ahead. Available capacity was up to 134 MW below forecast and up to 323 MW below that forecast twelve hours ahead.

At 1.52 pm, effective from 2.05 pm, GDF Suez rebid 150 MW of available capacity at Hazelwood power station from prices below $50/MWh to above $12 6000/MWh. The reason given was “1351A chg in fcast – dec vic dem 5M 8525MW<30MPD 8688MW”.

At 2.46 pm, effective from 2.55 pm, Ecogen Energy rebid 100 MW of available capacity at Newport power station from prices below $50/MWh to the price cap. The reason given was “14:45 A band adj for mat change in Vic price”.

At 3.08 pm, effective from 3.15 pm, EnergyAustralia rebid 156 MW of available capacity at Yallourn unit four from prices below $50/MWh to above $12 000/MWh. The reason given was “15:07 P band adj coal conservation SL”.

At 3.12 pm, effective from 3.20 pm, Ecogen Energy rebid 60 MW of available capacity at Jeeralang B power station from the price floor to close to the price cap. The reason given was “15:11 A band adj vic price below 30 fcast”. At 3.26 pm, effective from 3.35 pm, Ecogen Energy rebid 60 MW of available capacity at Newport power station from the price floor to the price cap. The reason given was “15:25 A band adj vic price below 30 pd”. Then at 3.52 pm, effective from 4 pm, Ecogen Energy rebid a further 87 MW of available capacity at Jeeralang B power station from the price floor to close to the price cap. The reason given was “15:51 A band adj vic price below 30 pd”.

The 5 minute demand increased by 76 MW from 3.55 pm to 4 pm. This along with the rebids above saw the 5 minute price increase from $70/MWh at 3.55 pm to $4516/MWh at 4 pm.

Over two rebids at 4.04 pm and 4.06 pm, effective from 4.15 pm, Snowy Hydro rebid 500 MW of available capacity at Tumut 3 in NSW from prices below $50/MWh to close to the price cap and increased the ramp down rate from 50 MW/min to 100 MW/min. The reason given for both rebids was "16:00 A VIC: act price $4,446.86 hgr thn 5mpd 16:00@15:51". These rebids resulted in Tumut 3 receiving a target at 4.15 pm of zero.

At 4.15 pm, as a result of the 500 MW reduction in output at Tumut 3 in NSW, a constraint managing voltage stability on the loss of a Dederang to Murray 330 kV line bound and reduced flows on the VIC-NSW interconnector into Victoria from 290 MW at 4.10 pm to 91 MW at 4.15 pm. With the interconnector constrained and a number of Victorian generators already at their maximum output, or trapped or stranded in FCAS, the Victorian price increased from $68/MWh at 4.10 pm to $8729/MWh at 4.15 pm. At 4.20 pm prices returned to previous level when a large volume of generation in Victoria was rebid to low prices.

At 5.25 pm, AEMO invoked a constraint from the constraint automation tool, to manage the potential overload of the Dederang to Shepparton 220 kV line for loss of Dederang to Glenrowan No.1 and No.3 220 kV lines. The constraint immediately bound and forced flows into New South Wales to increase from 287 MW at 5.20 pm to 610 MW at 5.25 pm. The 5 minute price increased from $51/MWh at 5.20 pm to $13 075/MWh at 5.25 pm and $8723/MWh at 5.30 pm.

There was no other significant rebidding.

Table 5: Victoria, Friday 20 December 1.30 PM

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
1.30 PM	-127.83	52.91	52.52	6694	7246	7110	9110	10 498	10 726

Conditions at the time saw demand 552 MW lower than forecast four hours ahead, with available capacity 1388 MW lower than forecast four hours ahead.

From 10.30 am, a system normal constraint, which manages flows on the Ballarat to Bendigo 220 kV line bound, forcing counter-price flows from New South Wales into Victoria. This constraint has Murray as the only generator on the left hand side of the constraint, making it and flows across the interconnector the only two variables that can be used to manage the flow.

From 12.40 pm, AEMO invoked negative settlement residue management constraints to manage counter-priced flows on the VIC-NSW interconnector. The constraints invoked bound or were violated up until 2.25 pm. During this period, around $2 million of negative settlement residues accrued. The total negative settlement residue accrued for the day was approximately $3million.

At 12.42 pm, effective from 12.50 pm, Snowy Hydro reduced the availability of Murray in Victoria from around 1350 MW to zero, all of which had been priced near the price cap. The reason given was "Murray constrained on at VoLL – price $1".

A combination of Murray being shut down and generators in New South Wales rebidding large amounts of capacity close to the price floor saw flows into Victoria increase from 423 MW at 1.25 pm to 1013 MW by 1.30 pm leading to generation in Victoria being reduced at its maximum ramp rate and resulting in the 1.30 pm 5 minute dispatch price in Victoria falling to -$969.9/MWh and $299/MWh in NSW.

More detailed analysis of the circumstances in New South Wales will be covered in the $5000 report.

There was no other significant rebidding.

South Australia

Table 6: South Australia, Wednesday 18 December 4.30 PM

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
4.30 PM	2390.35	199.99	200.24	2561	2404	2530	2956	3022	2878

Conditions at the time saw demand 157 MW higher than that forecast four hours ahead, while available capacity was close to forecast.

The temperature on 18 December exceeded 40 degrees in South Australia, having been in the high 30s on the preceding day, resulting in very high demand. At the time of high prices there was no generator capacity being offered at prices between $300/MWh and $10 500/MWh.

At 4.19 pm, effective for the 4.30 pm dispatch interval only, AGL rebid 120 MW of capacity at Torrens Island B from $200/MWh to the price cap. The reason given for the rebid was "16:15A chg in dispatch::increase vs 16:05 5pd $299 vs $199".

The 5 minute price increased from $243/MWh at 4.25 pm to $13 100/MWh at 4.30 pm with Torrens Island setting the price. At 4.35 pm prices returned to previous levels as AGL's rebid was no longer effective.

There was no other significant rebidding.

Table 7: South Australia, Thursday 19 December 2.30 PM to 6.00 PM

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
2.30 PM	2539.54	90.8	109.8	2542	2448	2555	3091	3050	3100
3.00 PM	2241.2	110.05	118.93	2580	2503	2573	3064	3029	3086
3.30 PM	4125.81	199.99	199.99	2610	2562	2601	3031	3087	3068
4.00 PM	10 627.00	299.81	199.99	2621	2614	2620	3026	3077	3054
4.30 PM	5639.52	299.81	199.99	2634	2712	2643	3079	3079	3059
5.00 PM	1868.2	199.99	199.99	2682	2734	2627	3212	3054	3042

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
5.30 PM	4427.2	299.81	199.99	2692	2765	2579	3257	3051	3057
6.00 PM	1928.8	199.99	197.32	2671	2721	2546	3219	3063	3064

In accordance with clause 3.13.7 of the Electricity Rules, the AER will issue a separate report into the circumstances that led to the spot price exceeding $5000/MWh. The report will also include the above spot prices in the analysis.

Table 8: South Australia, Thursday 19 December 8.30 PM

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
8.30 PM	2268.33	109.80	70.80	2559	2409	2171	3471	3114	3060

Conditions at the time saw demand 150 MW higher than forecast four hours ahead with available capacity 357 MW above forecast.

At the time of the high price there was no capacity offered at prices between $300/MWh and $10 000/MWh.

At 8.14 pm, effective from 8.25 pm, AGL Energy rebid 485MW of capacity at its Torrens Island power station from prices below $200/MWh to the price cap. The reason given was "19:31A chg in f/c::pd demand incr sa +139mw since 1731 [2030]".

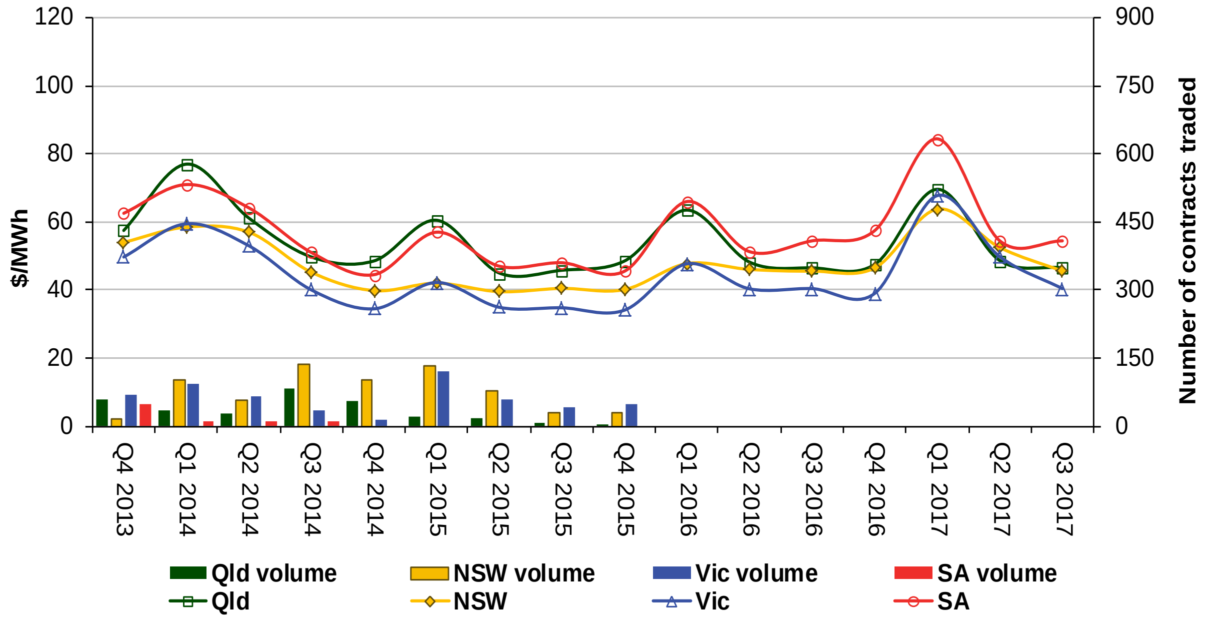
The 5 minute price increased from $110/MWh at 8.20 pm to $13 100/MWh at 8.25 pm with Torrens Island setting the price. At 8.30 pm the 5 minute dispatch price returned to previous levels when demand fell by 153 MW. This reduction in demand does not appear to have been as a result of the response of non-scheduled generation or a demand side reaction.

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.

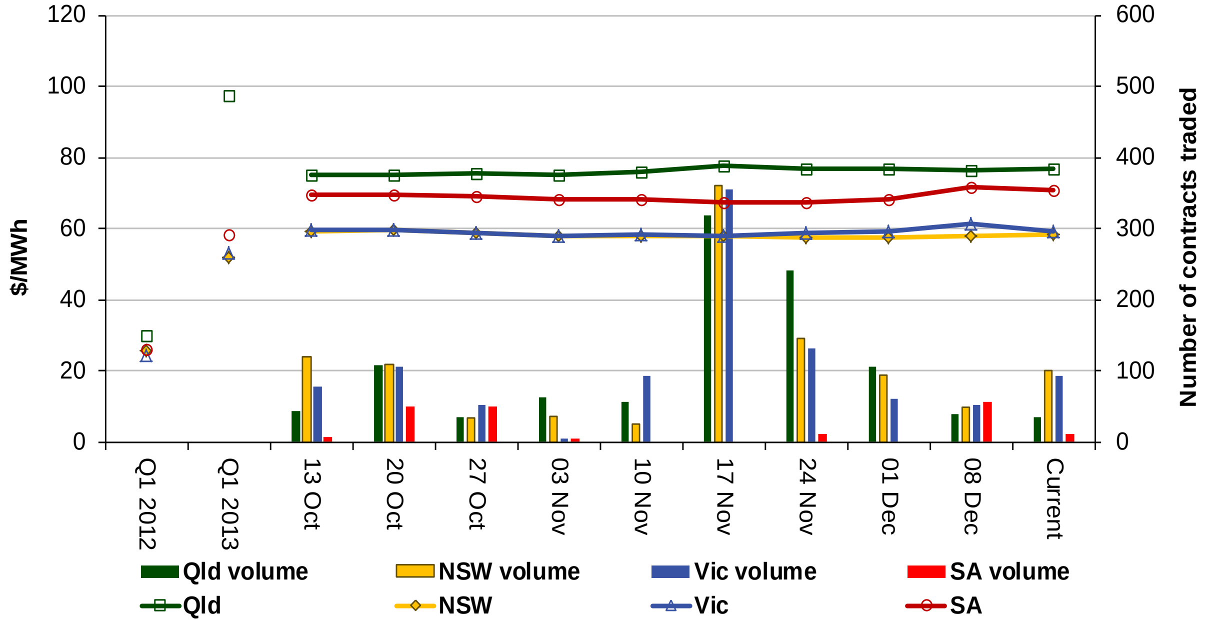
Figure 8: Quarterly base future prices Q4 2013 – Q3 2017



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)



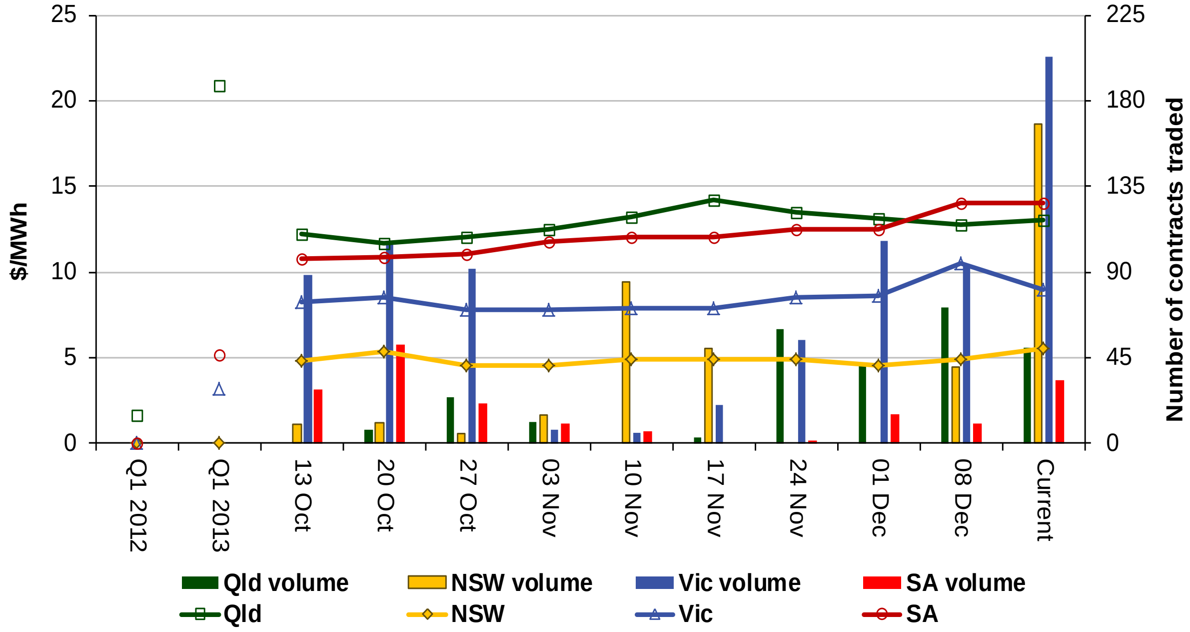
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: ASXEnergy.com.au

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

Australian Energy Regulator

February 2014