Electricity Report
7 – 13 June 2015

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 spot prices that occurred in each region during the week 7 to 13 June 2015. There were 11 occasions where the spot price exceeded the AER reporting threshold in South Australia. These are discussed later in this report. Of particular note, and material to the price volatility during this period, was the fire in the coal bunkers at Northern Power Station in South Australia that resulted in an extended outage for both units for a number of days.

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

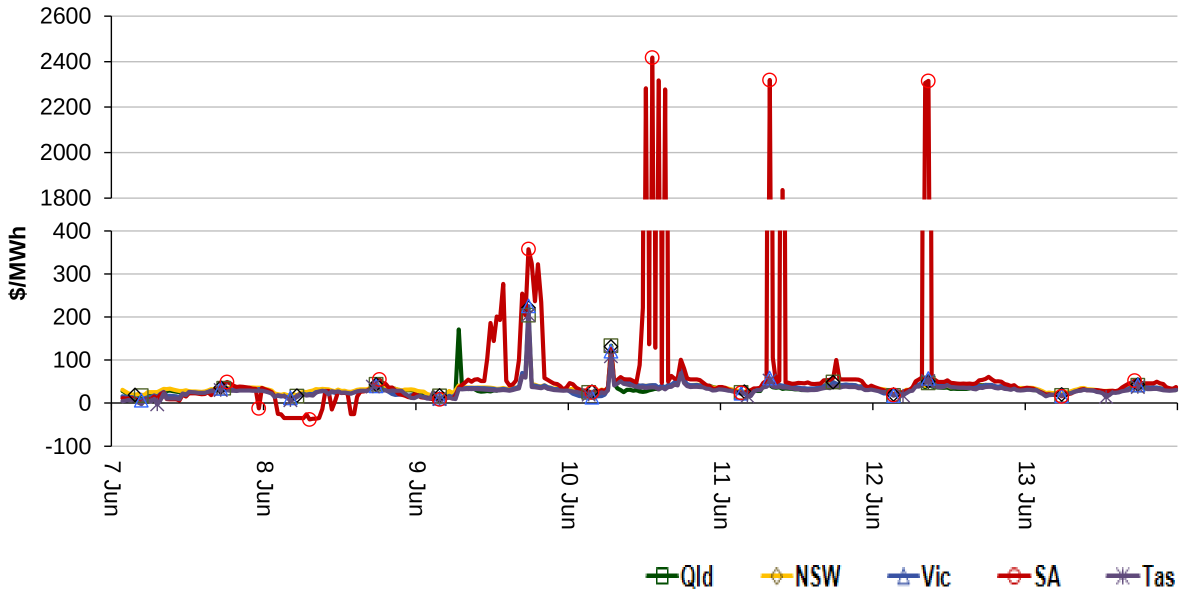


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

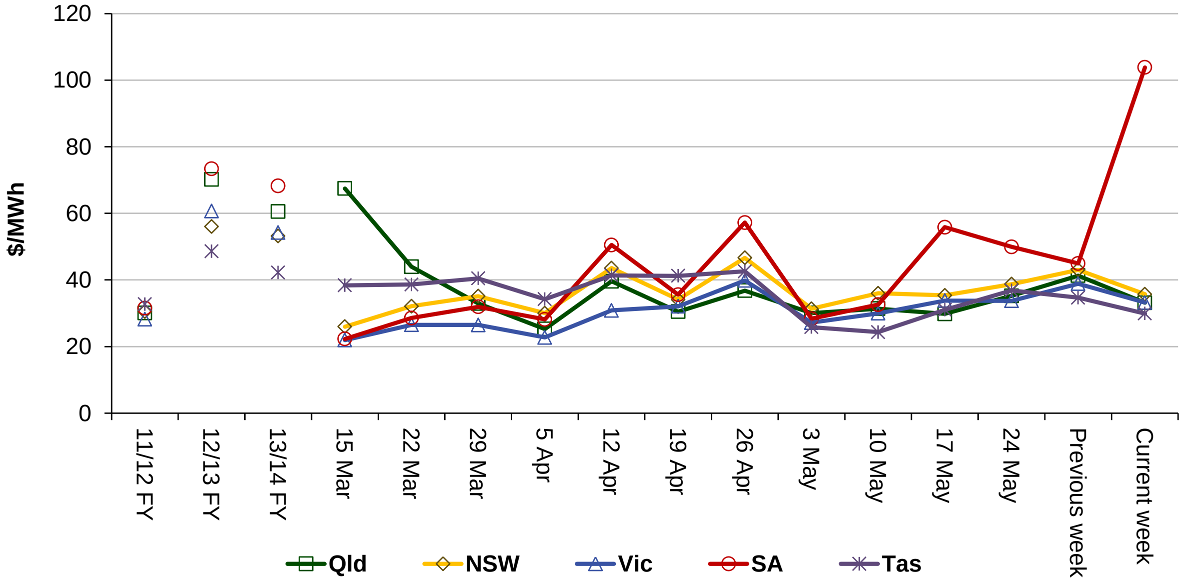


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	33	36	33	104	30
13-14 financial YTD	61	53	55	69	42
14-15 financial YTD	63	36	32	42	38

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 116 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	10	64	0	5
% of total below forecast	16	5	0	0

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

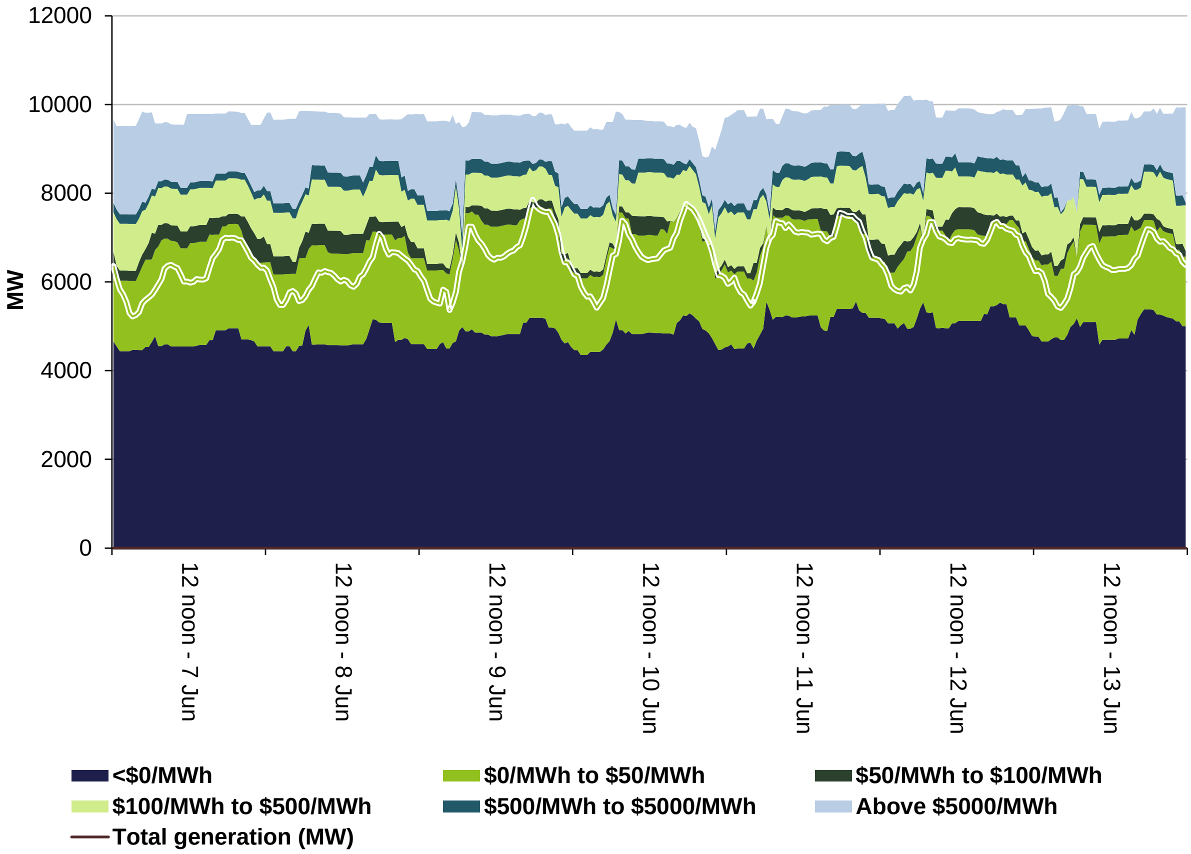


Figure 4: New South Wales generation and bidding patterns

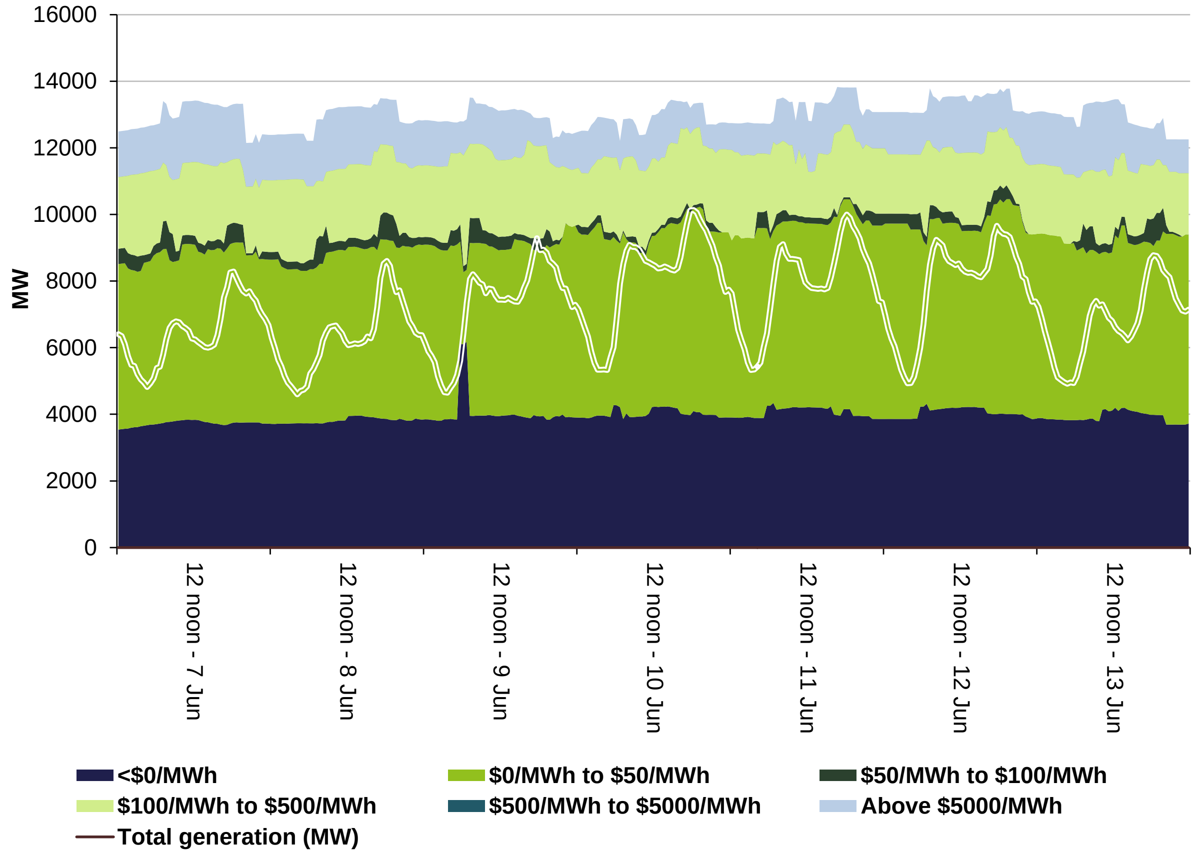


Figure 5: Victoria generation and bidding patterns

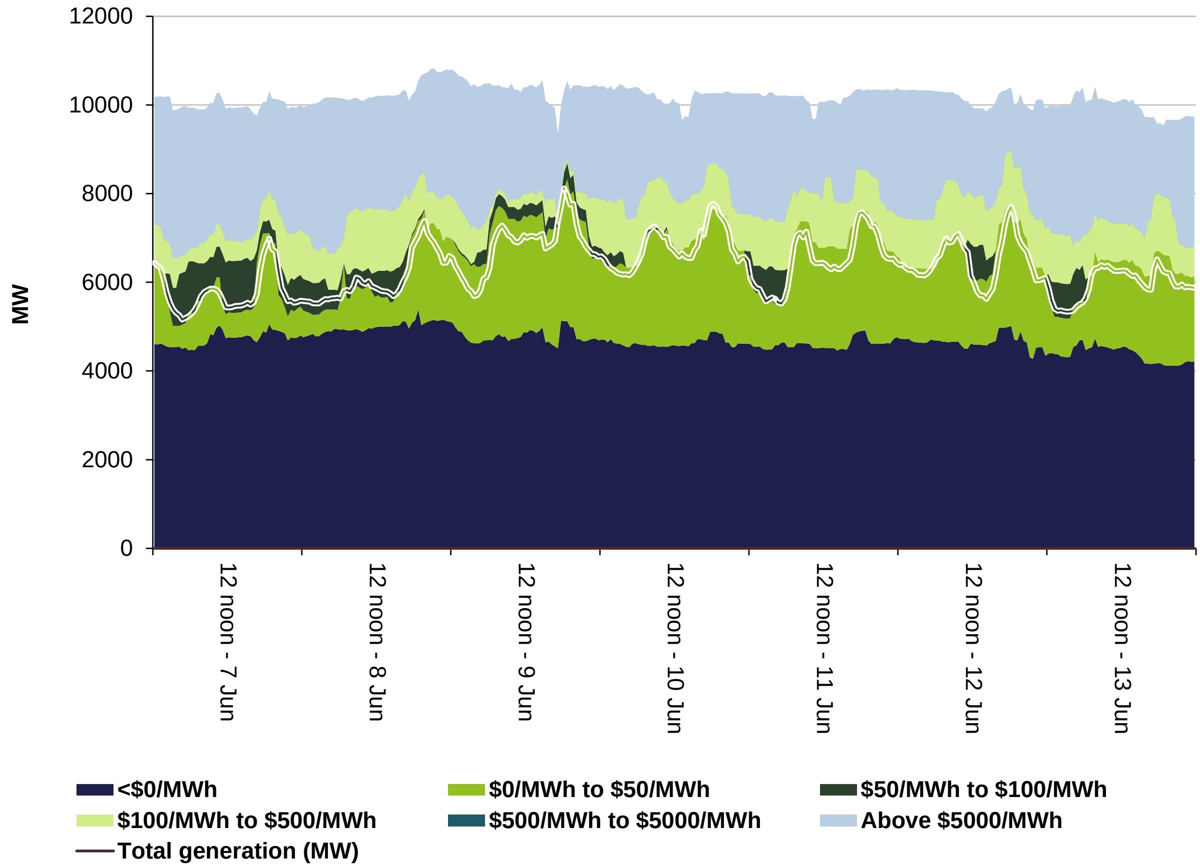
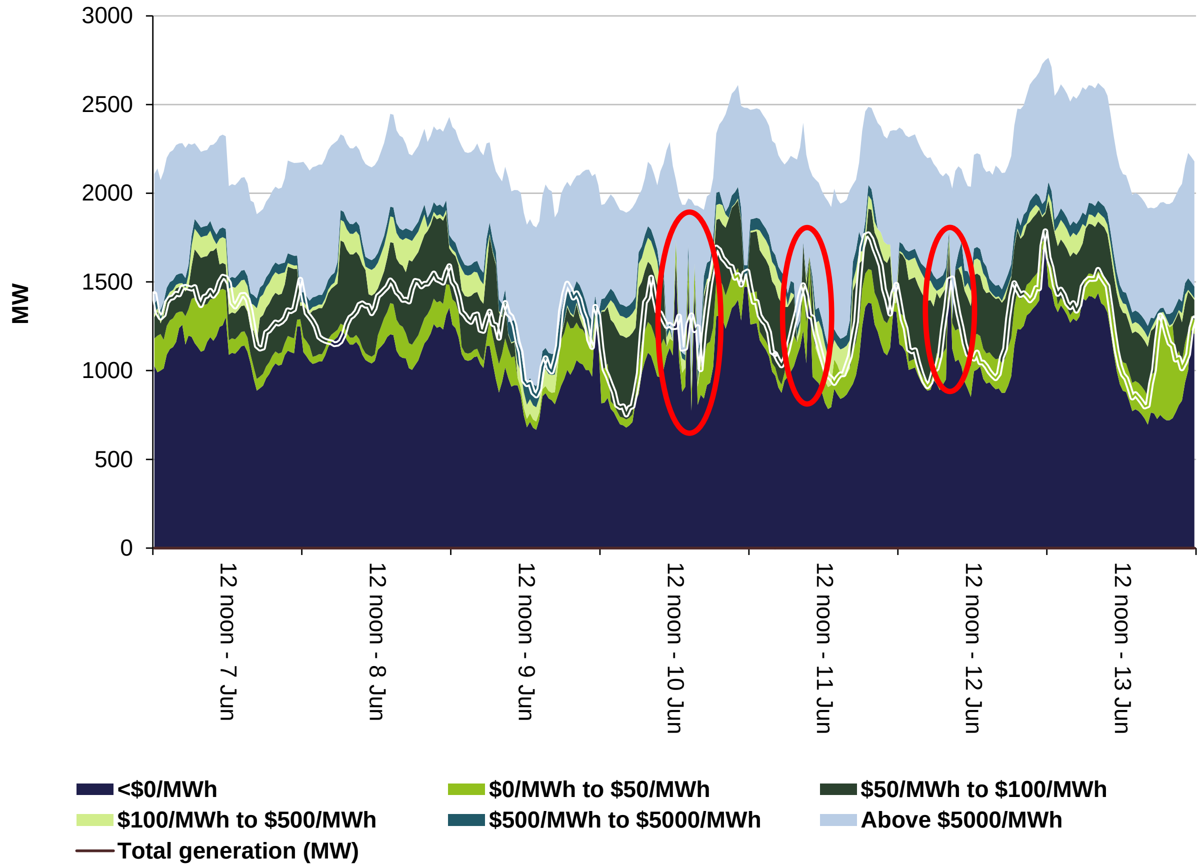
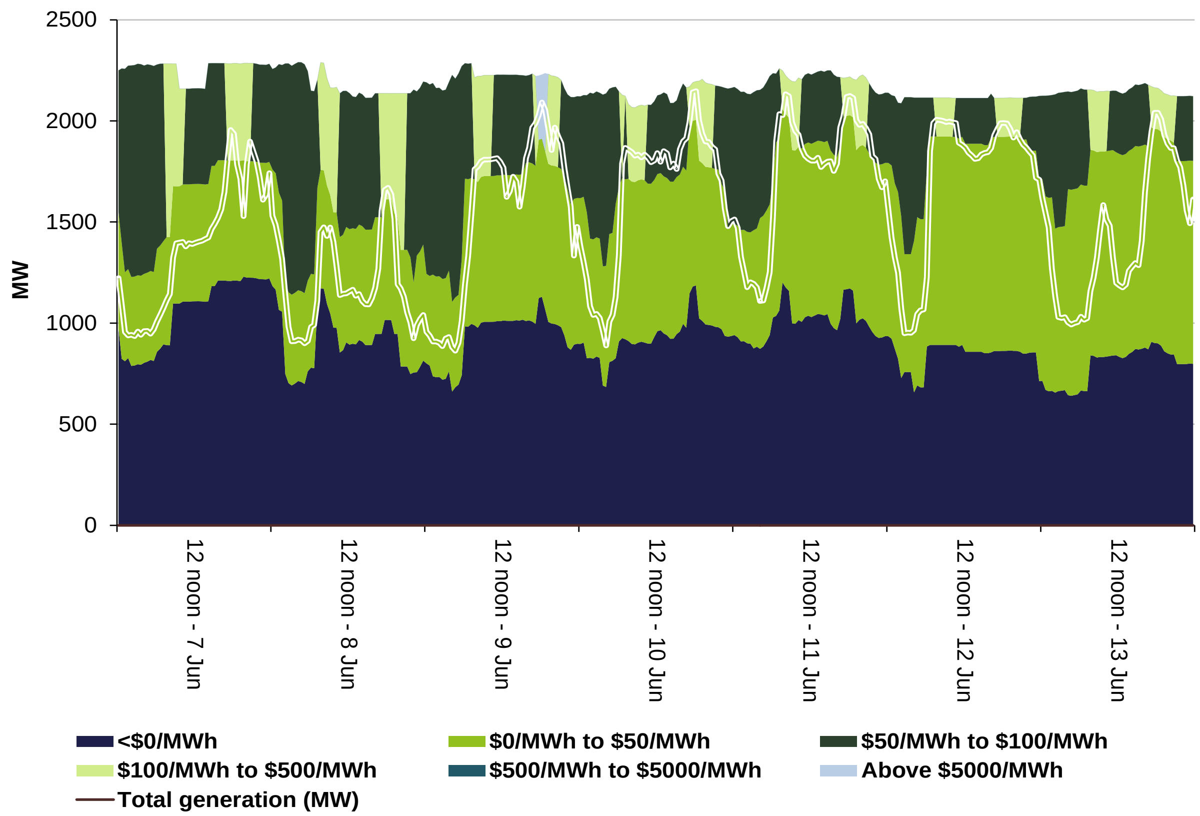


Figure 6: South Australia generation and bidding patterns



The red ellipses highlight rebidding from low prices to high prices by South Australian participants detailed in the "Detailed market analysis of significant price events".

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.

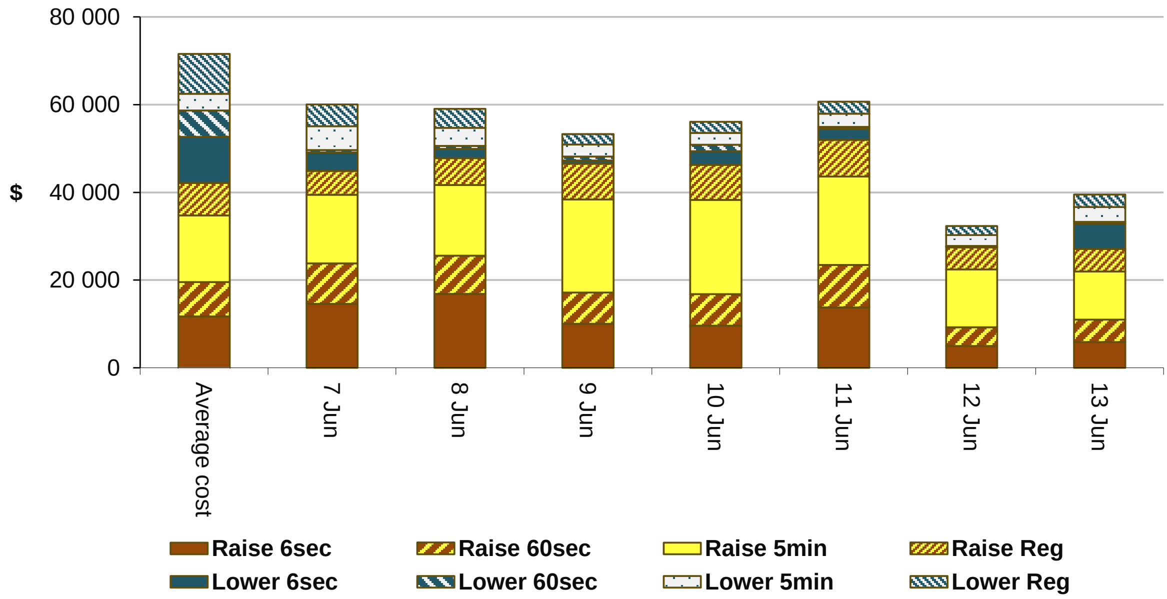
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $302 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $59 000 or 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 eleven occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $104/MWh and above $250/MWh.

Tuesday, 9 June

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
6 pm	357.60	57.01	65.09	1723	1776	1849	2017	2100	2156
6.30 pm	324.86	65.19	94.98	1822	1922	2009	2036	2106	2182
7.30 pm	322.64	55.09	94.98	1924	1916	2015	2038	2137	2173

Demand and available capacity was close to or lower than forecast four hours ahead.

Table 4: Rebids for the 6 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.29 pm		AGL	Torrens Island	200	<66	13 500	1601~A~050 Chg in AEMO PD~55 PD price increase SA $294 PE 16:30
5.16 pm	5.25 pm	Origin	Ladbroke, Quarantine	168	<96	13 500	1715A avoid uneconomic dispatch - avoid short run SL
5.35 pm	5.45 pm	AGL	Torrens Island	120	55	13 500	1731~A~050 chg in AEMO PD~55 PD price increase SA $205 18:00

At 5.25 pm, when the rebid at Ladbroke became effective, the dispatch price increased from $88/MWh to $351/MWh. The dispatch price fluctuated between $350/MWh and $590/MWh until 5.55 pm when the price fell to $146/MWh.

Table 5: Rebids for the 6.30 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.29 pm		AGL	Torrens Island	200	<66	13 500	1601~A~050 Chg in AEMO PD~55 PD price increase SA $294 PE 16:30
5.16 pm	5.25 pm	Origin	Ladbroke, Quarantine	168	<96	13 500	1715A avoid uneconomic dispatch - avoid short run SL
5.57 pm	6.05 pm	AGL	Torrens Island	80	55	13 500	1755~A~050 chg in AEMO PD~56 PD price increase SA 5MPD vs PD $57.99

Demand increased from 1767 MW at 6.10 pm to 1851 MW at 6.15 pm and the dispatch price increased from $56/MWh to $589/MWh. The dispatch price remained at $589/MWh until 6.30 pm went it fell to $66/MWh as a result of a small change in demand and a small increase in wind generation.

Table 6: Rebids for the 7.30 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.29 pm		AGL	Torrens Island	200	<66	13 500	1601~A~050 Chg in AEMO PD~55 PD price increase SA $294 PE 16:30
5.16 pm	5.25 pm	Origin	Ladbroke, Quarantine	168	<96	13 500	1715A avoid uneconomic dispatch - avoid short run SL
5.57 pm	6.05 pm	AGL	Torrens Island	60	55	13 500	1755~A~050 chg in AEMO PD~56 PD price increase SA 5MPD vs PD $57.99

Demand increased by 48 MW at 7 pm, this saw the dispatch price increase from $64/MWh to $589/MWh. The dispatch price remained at $589/MWh until 7.10 pm went it fell to $55/MWh as a result of a 103 MW reduction in demand largely due to non-scheduled generation increasing its output. At 7.15 pm the price increased to $589/MWh when demand increased by 77 MW, largely due to non-scheduled generation decreasing its output, and stayed there until 7.25 pm.

Wednesday, 10 June

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
12.30 pm	2282.42	350.99	350.99	1493	1468	1446	2075	2077	2039
1.30 pm	2417.48	350.99	350.99	1452	1459	1481	1953	2066	2023
2.30 pm	2316.88	59.98	64.96	1396	1530	1501	1928	2033	1997
3.30 pm	2277.98	54.40	59.77	1378	1538	1514	1930	2185	2102

Conditions at the time saw demand and available capacity close to or lower than forecast four hours ahead. A constraint was binding on Murraylink allowing no flows across it between 11.35 am and 2.35 pm, as forecast.

Table 8: Rebids for the 12.30 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.25 am		AGL	Torrens Island	170	<351	13 500	1000~A~050 chg in AEMO PD~55 PD intermittent + semischedule incr
11.34 am		AGL	Torrens Island	40	-1000	13 500	1130~A~040 CHG IN AEMO DISP~45 PRICE INCREASE VS PD SA $300.07 v
11.46 am		EA	Hallett	40	<590	13 482	11:46 A ADJ BANDS MAT CHG $SA @ 1150
11.53 am		GDF Suez	Mintaro	-84	<590	N/A	1153P unit trip on sync

The above rebidding left little capacity priced between $25/MWh and $12 000/MWh (which was either ramp rate limited, fully dispatched or off-line) meaning small changes in demand, rebids or interconnector flows could lead to large changes in price.

At 12.15 pm demand increased by 34 MW, a result of the reduction in output of non-scheduled generation. This saw the dispatch price increase to $13 482/MWh from $47/MWh at 12.10 pm. At 12.20 pm the dispatch price fell to previous levels when demand fell by 109 MW, largely due to on-scheduled generation increasing its output.

Table 9: Rebids for the 1.30 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
10.25 am		AGL	Torrens Island	170	<351	13 500	1000~A~050 chg in AEMO PD~55 PD intermittent + semischedule incr
11.34 am		AGL	Torrens Island	40	-1000	13 500	1130~A~040 CHG IN AEMO DISP~45 PRICE INCREASE VS PD SA $300.07 v
11.53 am		GDF Suez	Mintaro	-84	<590	N/A	1153P unit trip on sync
12.57 pm	1.05 pm	AGL	Torrens Island	50	-1000	13 500	1255~A~040 chg in AEMO disp~45 price increase vs pd sa $589.80 V
1.19 pm	1.30 pm	GDF Suez	Port Lincoln	-21	-1000	N/A	1319P unit failed to synchronise

The above rebidding left little capacity priced between $25/MWh and $13 000/MWh (which was either ramp rate limited, fully dispatched or off-line) meaning small changes in demand, rebids or interconnector flows could lead to large changes in price.

At 1.30 pm demand increased by 56 MW, this saw the dispatch price increase to $13 482/MWh from $292/MWh at 1.25 pm. At 1.35 pm the dispatch price fell to previous levels when demand fell by 120 MW, largely due to on-scheduled generation increasing its output.

Table 10: Rebids for the 2.30 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.53 am		GDF Suez	Mintaro	-84	<590	N/A	1153P unit trip on sync
1.18 pm		Origin	Ladbroke	41	-1000	13 500	1315A dec in SA dem 5MPD 1204 MW < 30MPD 1556 MW @ 1400 SL
1.40 pm		AGL	Bluff,Hallett ,Nth Brown Hill	236	<-89	13 500	1335~A~040 chg in aemo disp~44 price decrease VS PD SA $47.24 VS
1.52 pm		EA	Hallett	15	300	13 482	13:52 A adj bands $SA < 30PD fcst

The above rebidding left little capacity priced between $25/MWh and $13 000/MWh (which was either ramp rate limited, fully dispatched or off-line) meaning small changes in demand, rebids or interconnector flows could lead to large changes in price.

At 2.10 pm there was a small increase in demand and a reduction in wind generation which saw the dispatch price increase from $292/MWh at 2.05 pm to $13 482/MWh at 2.10 pm, set by Energy Australia's Hallett station. At 2.15 pm there was a 131 MW decrease in demand (largely due to the increased output of non-scheduled generation) and the dispatch price fell to $38/MWh.

Table 11: Rebids for the 3.30 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
11.53 am		GDF Suez	Mintaro	-84	<590	N/A	1153P unit trip on sync
1.18 pm		Origin	Ladbroke	41	-1000	13 500	1315A dec in SA dem 5MPD 1204 MW < 30MPD 1556 MW @ 1400 SL
2.54 pm	3.05 pm	EA	Hallett	30	300	13 482	14:53 A adj bands $SA < fcst hhe 1500

The above rebidding left little capacity priced between $25/MWh and $10 000/MWh (which was either fully dispatched or off-line) meaning small changes in demand, rebids or interconnector flows could lead to large changes in price.

At 3.10 pm there was a 62 MW increase in demand which saw the dispatch price increase from $62/MWh at 3.05 pm to $13 482/MWh at 3.10 pm, set by Energy Australia's Hallett station. At 3.15 pm there was a 162 MW decrease in demand (largely due to the increased output of non-scheduled generation) and around 550 MW of capacity was rebid from high to low prices and the dispatch price fell to $32/MWh.

Thursday, 11 June

Table 12: 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
8 am	2318.91	54.99	54.99	1755	1776	1830	2250	2256	2258
10 am	1834.76	54.99	54.99	1735	1769	1831	2141	2160	2134

Conditions at the time saw demand and available capacity close to that forecast.

Table 13: Rebids for the 8 am

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.28 am	7.35 am	Alinta	Northern	-120	-1000	N/A	0725~P~delayed rts~
7.32 am	7.40 am	AGL	Torrens Island	250	<55	13 500	0700~A~050 chg in AEMO PD~0800 intermittent + semischedule incre
7.47 am	7.55 am	AGL	Torrens Island	100	46	13 500	0745~A~040 chg in AEMO disp~40 demand decrease VS PD sa non-sch

At 7.55 am there was a 98 MW increase in demand (partly due to a decrease in non-scheduled generation) and AGL's rebid at Torrens Island became effective. This saw the dispatch increase from $74/MWh at 7.50 am to the price cap at 7.55 am. The dispatch price fell to previous levels at 8 am when there was a 62 MW decrease in demand (largely due to the increased output of non-scheduled generation).

Table 14: Rebids for the 10 am

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
9.13 am		Alinta	Northern	-130	-1000	N/A	0913~P~unit trip~~2HRS
9.42 am	9.50 am	AGL	Torrens Island	350	<55	>10 760	0930~A~050 chg in AEMO PD~10:00 55 PD avail gen decrease -169MW

At 9.50 am, when AGL's rebid at Torrens Island became effective, the dispatch price increased to $10 760/MWh (from $55/MWh at 9.45 am). The dispatch price fell to previous

levels at 9.55 am when there was a 179 MW decrease in demand (largely due to the reduced output of non-scheduled generation) and some rebidding of capacity from high to low prices.

Friday, 12 June

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
8.30 am	2306.02	54.99	54.99	1824	1851	1806	2108	2230	2244
9 am	2314.94	54.99	54.99	1828	1847	1804	2089	2207	2217

Demand was close to forecast and available capacity was around 120 MW lower than forecast four hours ahead.

Table 16: Rebids for the 8.30 am and 9 am

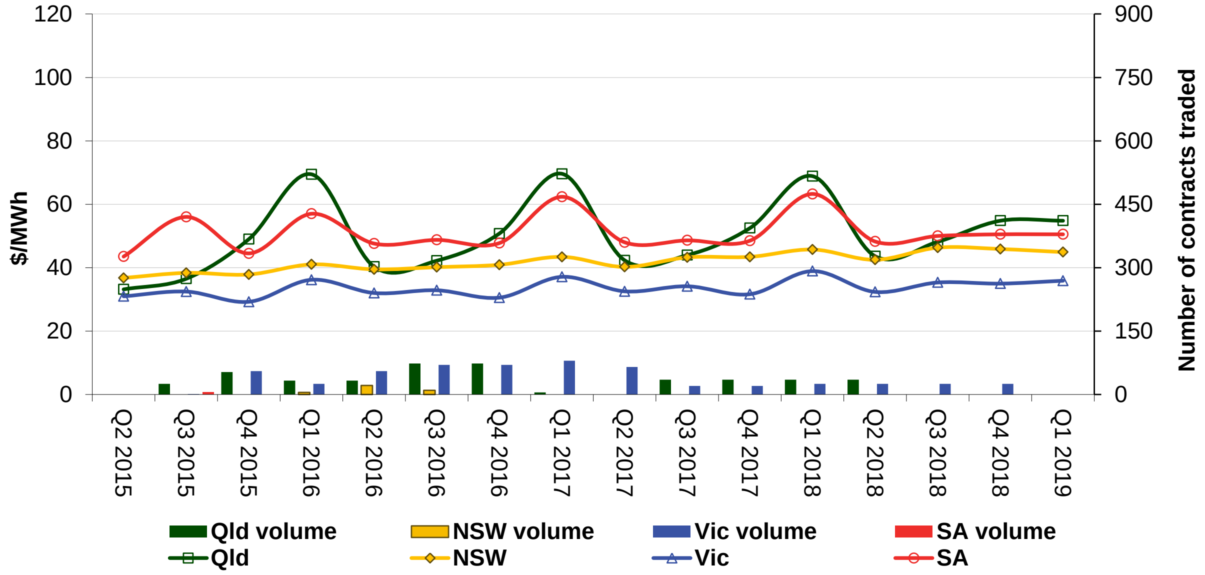
Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.03 am		Alinta	Northern	-160	<-1	N/A	0600~P~revised unit availability~
7.58 am	8.05 am	AGL	Torrens Island	350	<65	13 500	0730~A~050 chg in AEMO PD~56 price increase SA +77 0830 $142.89
8.36 am	8.45 am	Origin	Ladbroke	76	-1000	13 500	0835A dec in SA dem 5MPD 1855 MW < 30MPD 1924 MW @ 0835 SL

At 8.05 am, when AGL's rebid at Torrens Island became effective and Hallett was ramp rate limited, the dispatch increased to $13 500/MWh (from $65/MWh at 8 am). The dispatch price fell to previous levels at 8.10 am when there was a 90 MW decrease in demand (largely due to the reduced output of non-scheduled generation) and around 200 MW of capacity was rebid from high to low prices.

At 8.55 am demand increased by 134 MW (largely due to a decrease in non-scheduled generation) and the dispatch increased to $13 500/MWh (from $79/MWh at 8.50 am), set by Torrens Island and Ladbroke. The dispatch price fell to previous levels at 9 am when there was a 153 MW decrease in demand (largely due to the reduced output of non-scheduled generation) and around 120 MW of capacity was rebid from high to low prices.

Financial markets

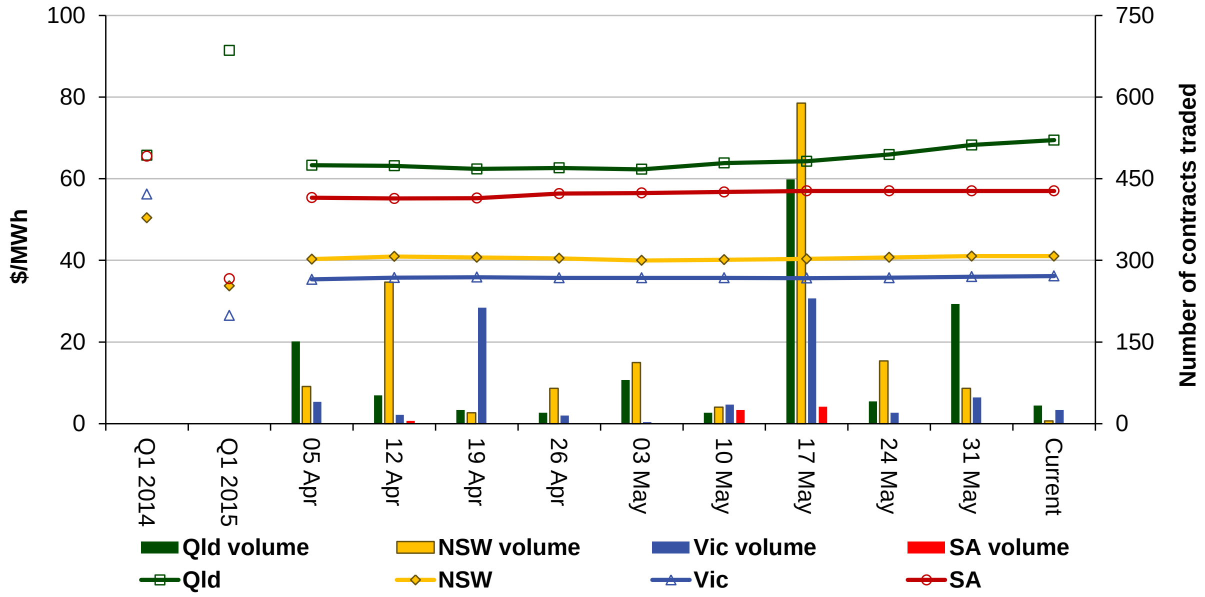
Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.



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)

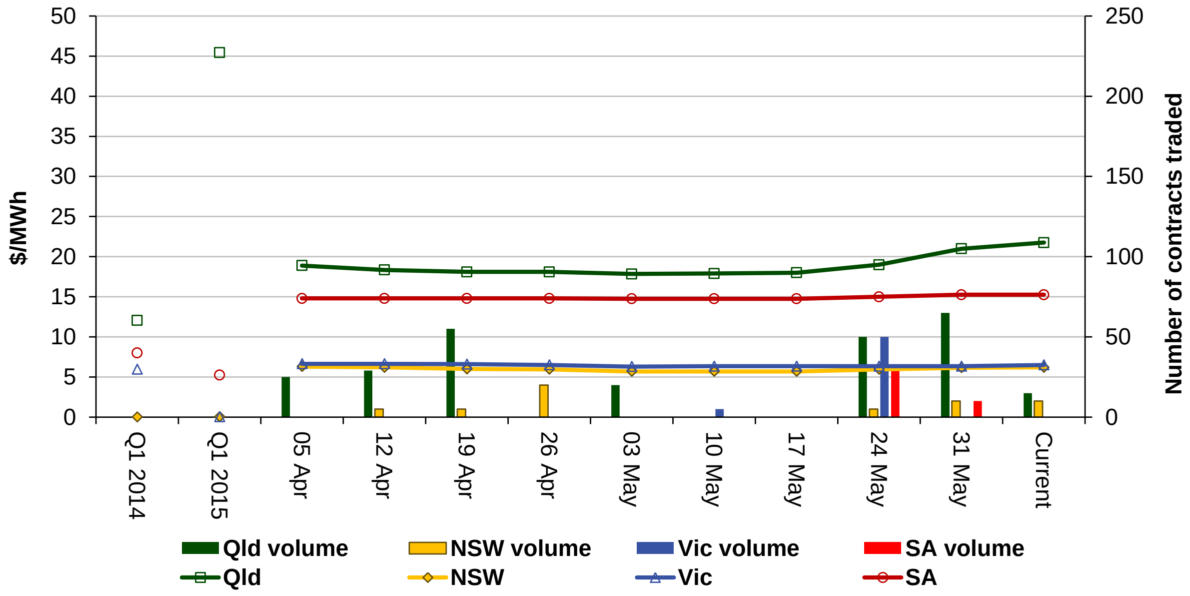


Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year.

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Performance of the Energy Sector](#) 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

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