Electricity Report

1 – 7 May 2016

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 1 to 7 May 2016.

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

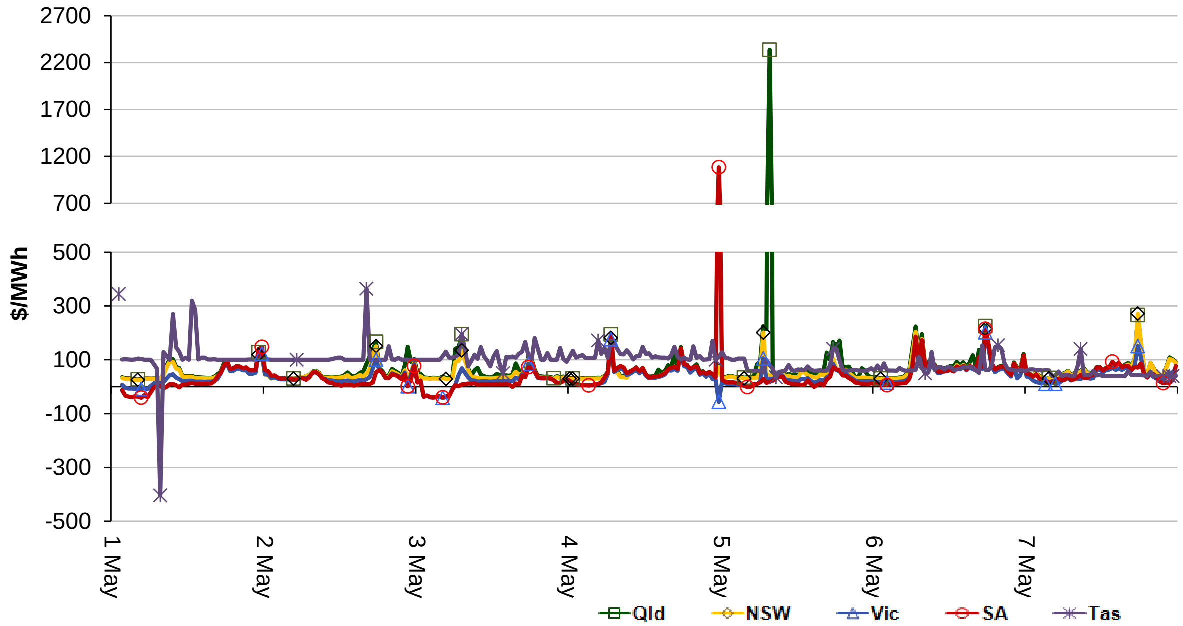


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

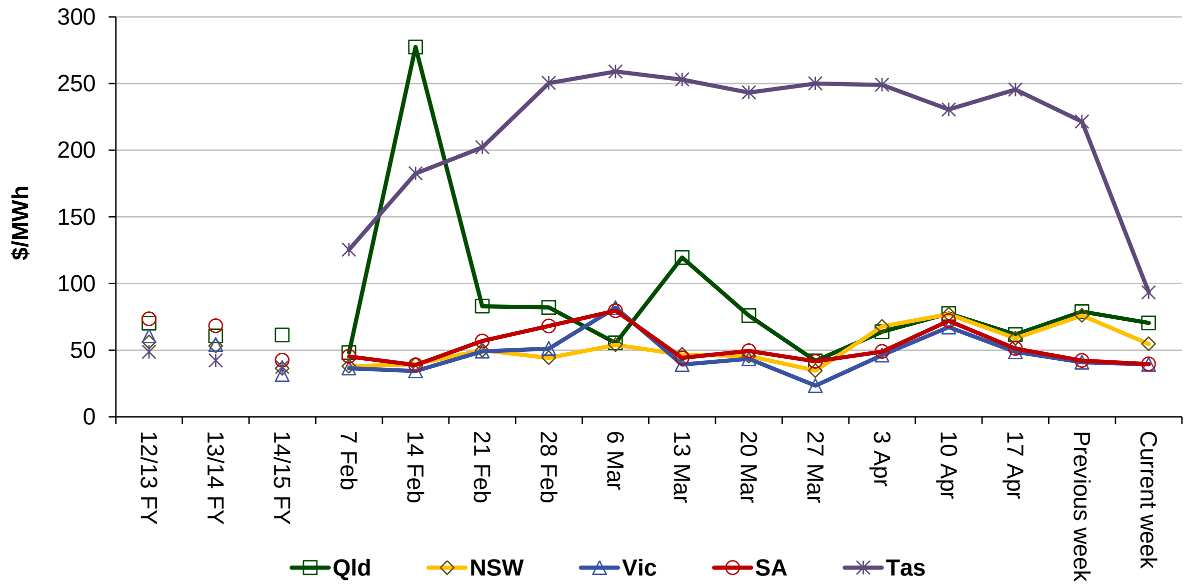


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	70	55	39	40	93
14-15 financial YTD	66	36	31	40	38
15-16 financial YTD	61	48	44	60	104

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 331 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2015 of 133 counts and the average in 2014 of 71. 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	7	17	0	6
% of total below forecast	39	21	0	11

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

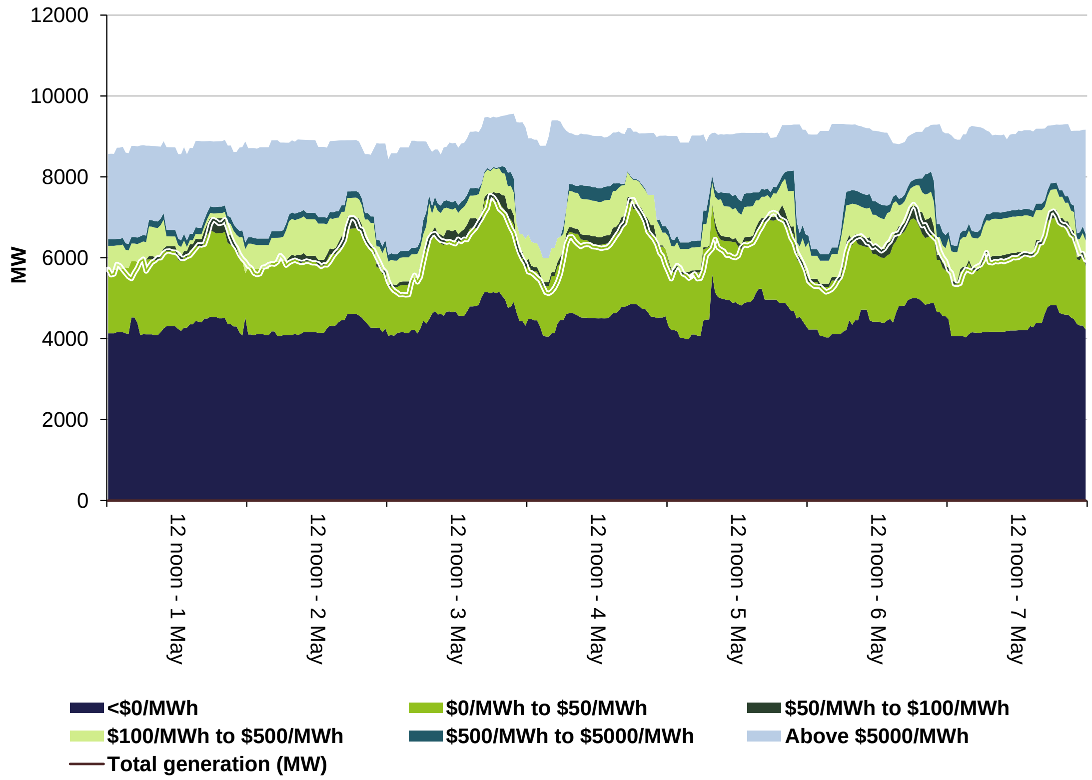


Figure 4: New South Wales generation and bidding patterns

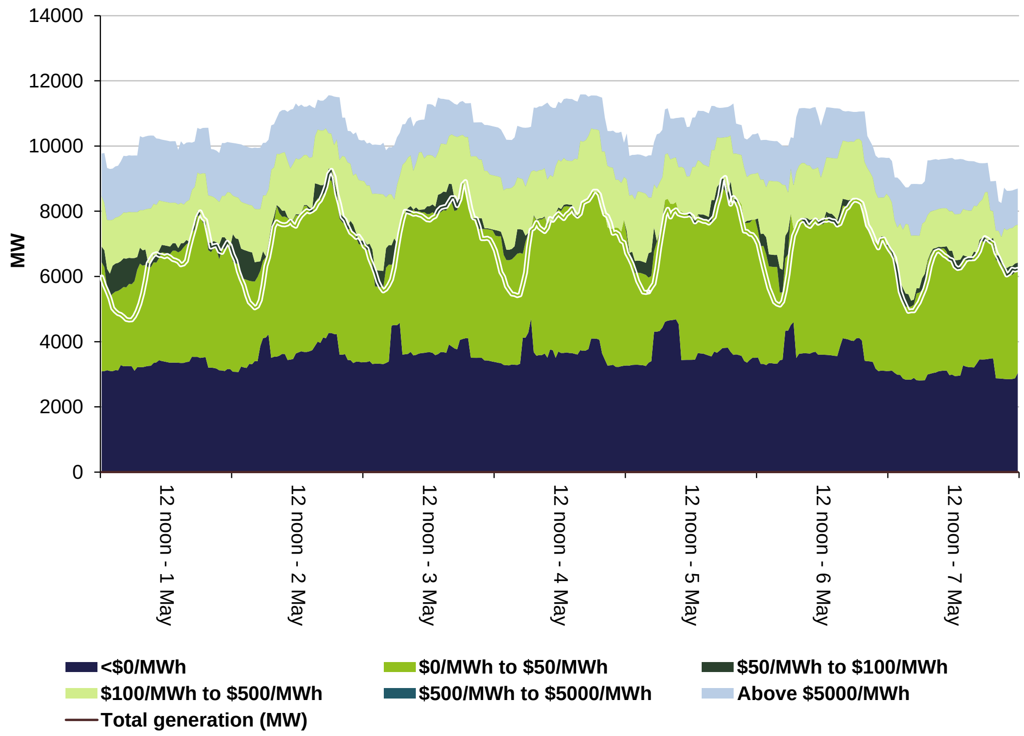


Figure 5: Victoria generation and bidding patterns

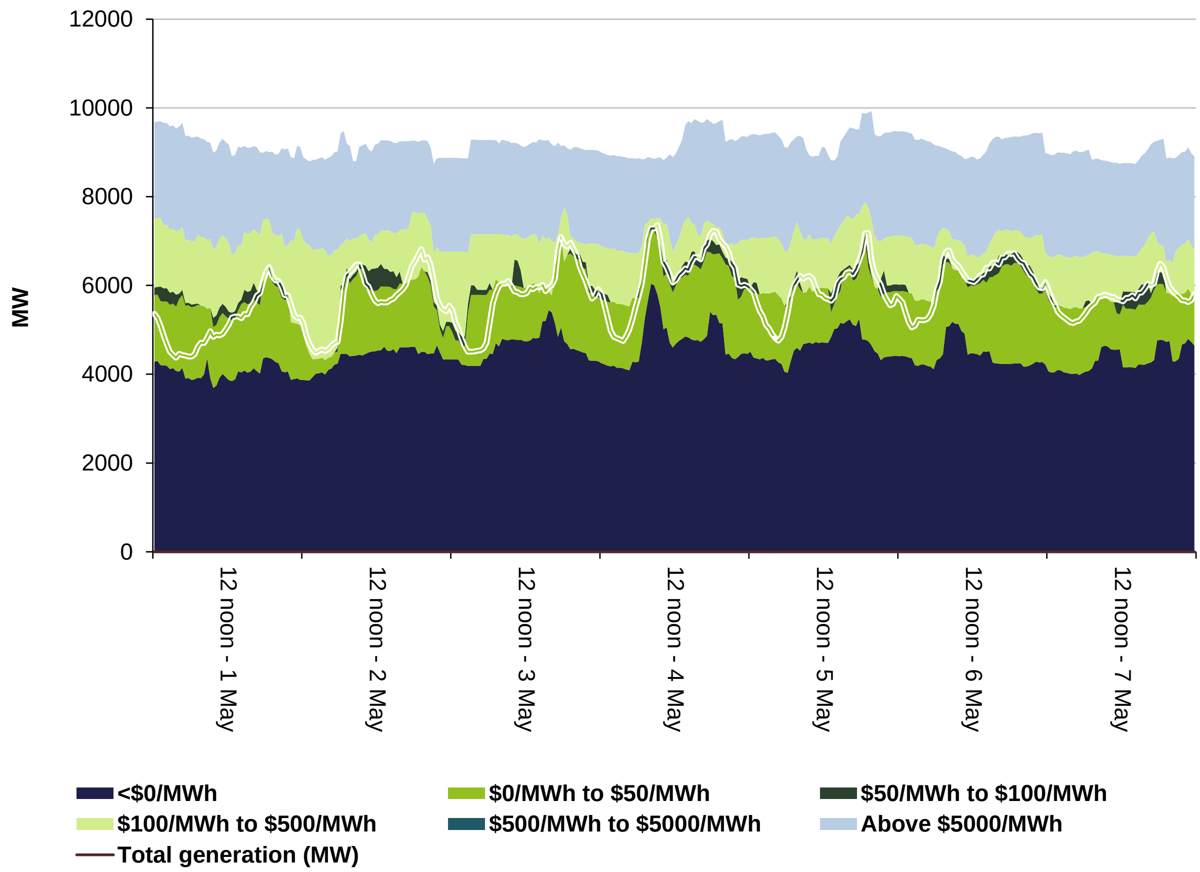


Figure 6: South Australia generation and bidding patterns

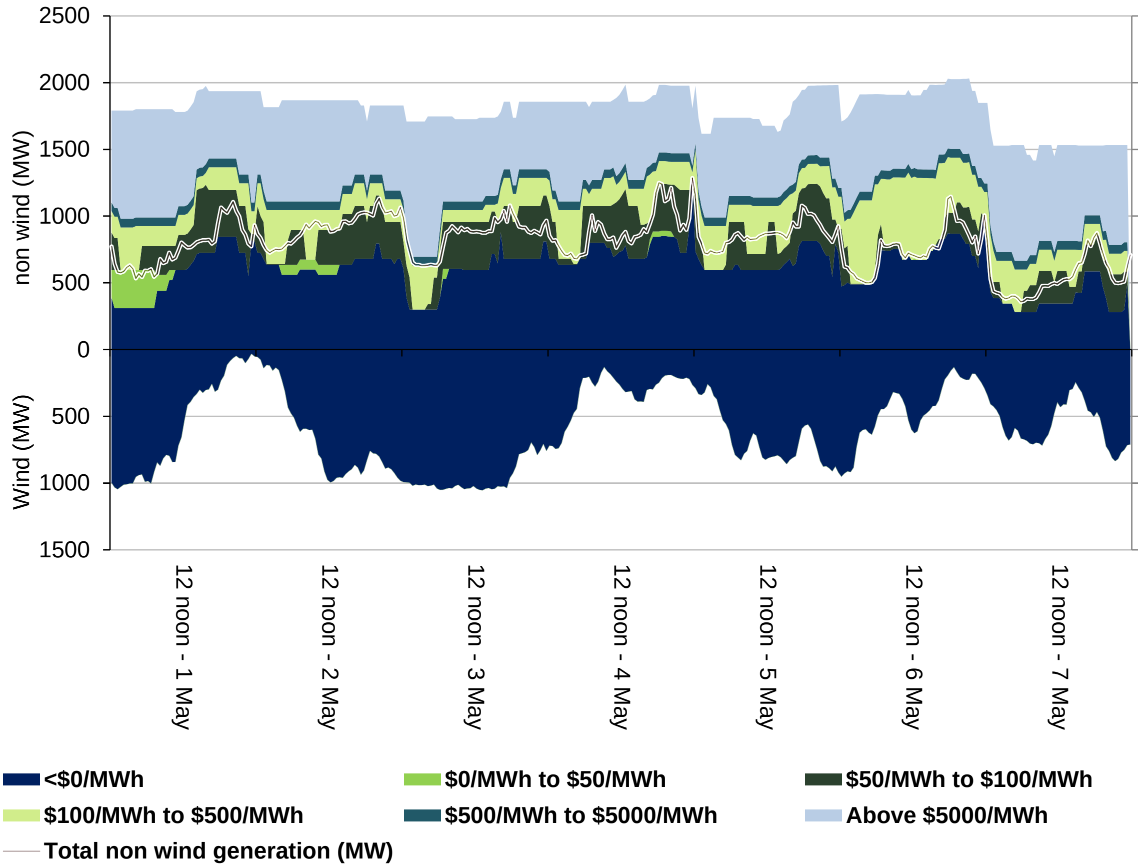
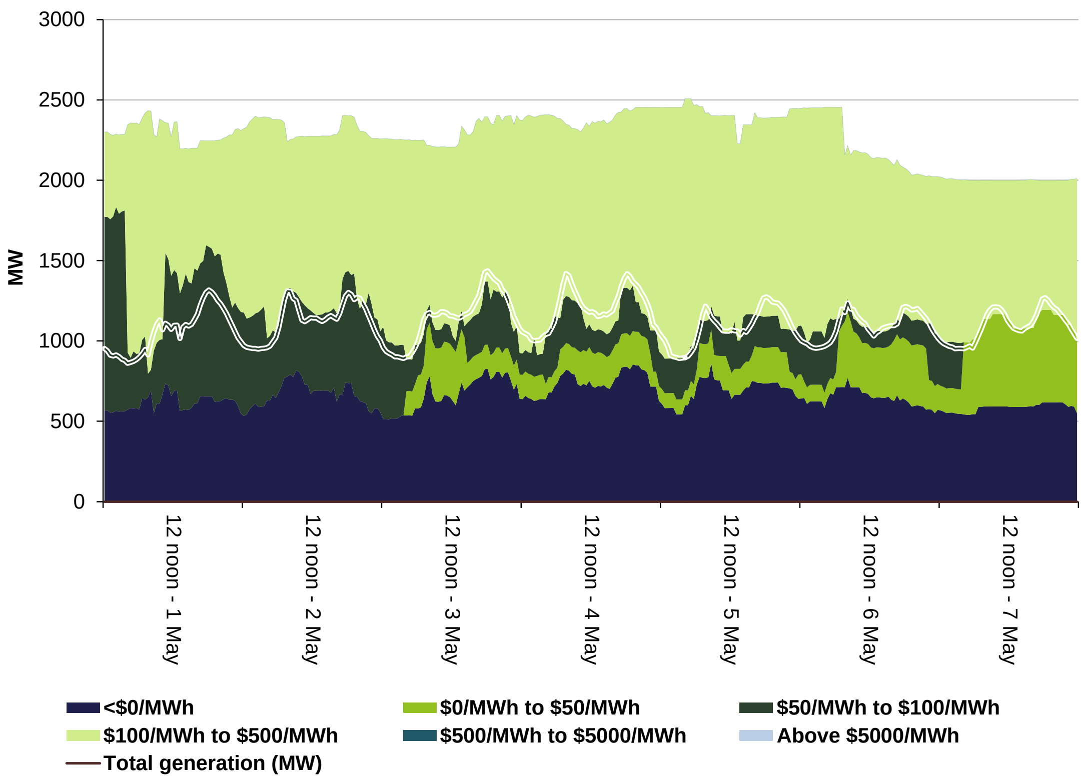


Figure 7: Tasmania generation and bidding patterns



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.

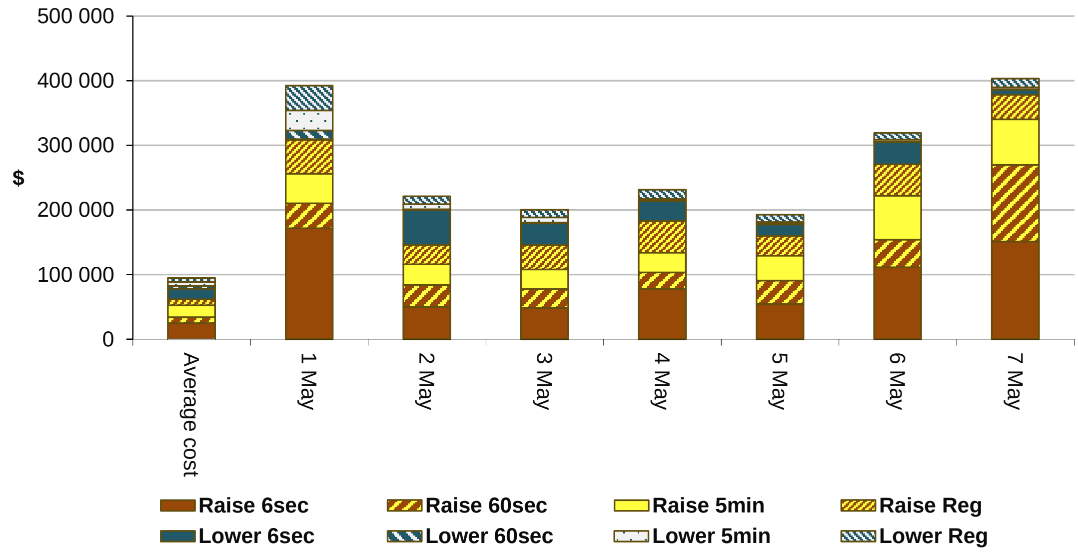
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $147 000 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $496 000 or around 3 per cent of energy turnover in Tasmania. The high FCAS cost in Tasmania is largely attributed to the high raise 6 second requirements on 1 May 2016.

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.

Queensland

There were two occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $70/MWh and above $250/MWh.

Thursday, 5 May

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
8 am	2336.52	296.94	200.15	6398	6522	6573	9081	9015	9350

Conditions at the time saw demand around 100 MW below forecast and availability close to forecast four hours ahead.

During the 8 am trading interval, a network constraint limiting flows across the Calliope River and Boyne island 132 kV line was either binding or violating. As a result of the constraint binding during the 7.50 am dispatch interval, the low-priced Gladstone units were constrained down by approximately 100 MW.

With a 108 MW increase in demand and lower priced capacity either ramp rate limited or fully dispatched, the price increased from $46/MWh at 7.45 am to $13 795/MWh at 7.50 am. The dispatch price then reduced to $27/MWh at 7.55 am when around 500 MW of capacity was rebid from high to low prices by ERM, Arrow Energy and Stanwell.

Saturday, 7 May

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 pm	266.23	297.55	308.99	6698	6666	6592	9269	9189	9191

Price demand and availability were close to forecast.

New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $55/MWh and above $250/MWh.

Saturday, 7 May

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
8 am	271.18	299.60	299.80	8416	8446	8334	9476	9718	9779

Conditions at the time saw price and demand close to forecast four hours ahead, while availability was more than 200 MW below forecast.

South Australia

There was one occasion where the spot price in South Australia was greater than three times the South Australia weekly average price of $40/MWh and above $250/MWh.

Wednesday, 4 May

Table 6: 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	1083.81	28.96	12.21	1514	1529	1541	2154	2317	2509

Conditions at the time saw demand close to forecast four hours ahead and availability more than 150 MW above forecast four hours ahead.

At 11.35 pm, demand increased from 1349 MW to 1525 MW (176 MW increase), due to hot water load. With limited imports, a sudden increase in demand and a number of generators either ramp rate limited or stranded in FCAS, the dispatch price increased from $32/MWh at 11.30 pm to $6426/MWh at 11.35 pm. The price then reduced to $26/MWh in the following dispatch interval when there was an increase in local low-priced generation.

Tasmania

There were four occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $93/MWh and above $250/MWh and there was one occasion where the spot price was below -$100/MWh.

Sunday, 1 May

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
1.30 am	344.42	102.32	103.08	727	830	865	2286	2287	2335

Conditions at the time saw demand 100 MW below forecast four hours ahead and availability close to forecast four hours ahead. The spot price increased from $100/MWh at 1.20 am to $1560/MWh at 1.25 am due to the co-optimisation of the energy and FCAS markets.

Table 6: 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	-404.13	145.26	145.28	744	956	1035	2433	2391	-404.13

Conditions at the time saw demand around 200 MW below forecast and availability close to forecast four hours ahead.

As a result of lightning, a constraint used to prevent the overload of the Palmerston to Waddamana 110 kV line for the loss of the Liapootah to Waddamana to Palmerston No.1 and No.2 220 kV lines was binding. This constraint saw to up to 212 MW of hydro generation being constrained on in Southern Tasmania and generation in Northern Tasmania ramped down. This resulted in dispatch prices at or near the price floor at 7.35 am, 7.45 am and 7.50 am.

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
1 pm	319.72	140.08	140.06	960	864	909	2364	2431	2431
1.30 pm	285.18	140.06	104.06	883	904	898	2196	2398	2430

For the 1 pm trading interval demand was approximately 100 MW above forecast four hours ahead and availability was less than 100 MW below forecast four hours ahead. For the 1.30 pm trading interval demand was close to forecast four hours ahead and availability was 200 MW below forecast four hours ahead.

The spot price increased from $100/MWh at 12.55 pm to $1414/MWh at 1 pm and then back to $1207/MWh at 1.05 pm. These high spot prices were due to the co-optimisation of the energy and FCAS markets.

Monday, 2 May

Table 10: 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
4.30 pm	363.61	106.23	100.43	969	1036	1041	2284	2262	2252

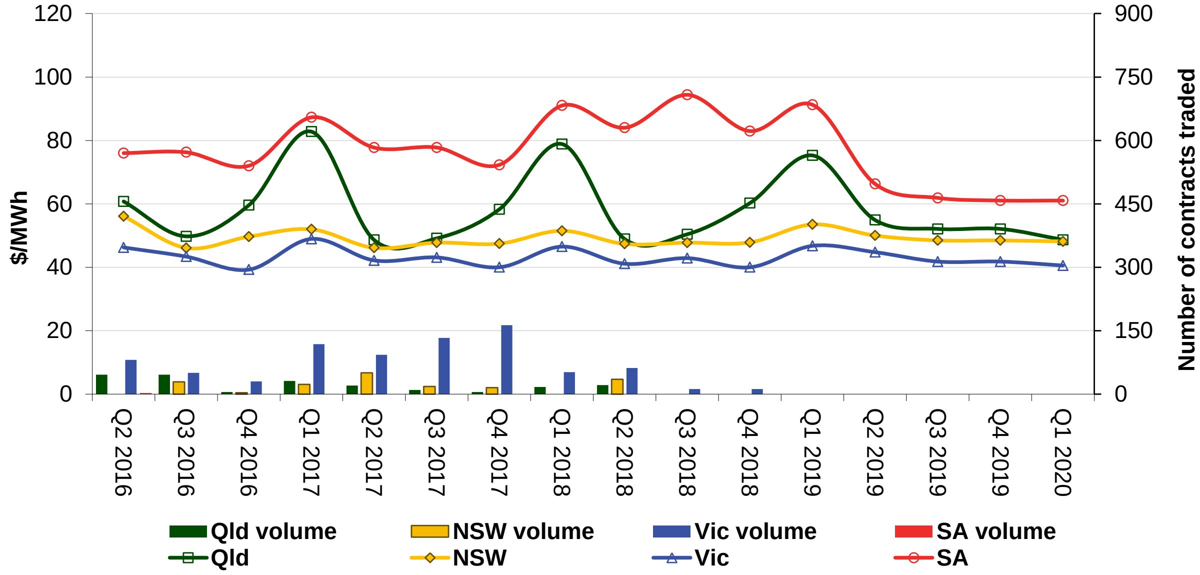
Conditions at the time saw demand and availability close to forecast four hours ahead.

The spot price increased from $100/MWh at 4.10 pm to $1063/MWh at 4.15 pm and then back to $672/MWh at 4.20 pm. These high prices were due to the co-optimisation of the energy and FCAS markets.

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.

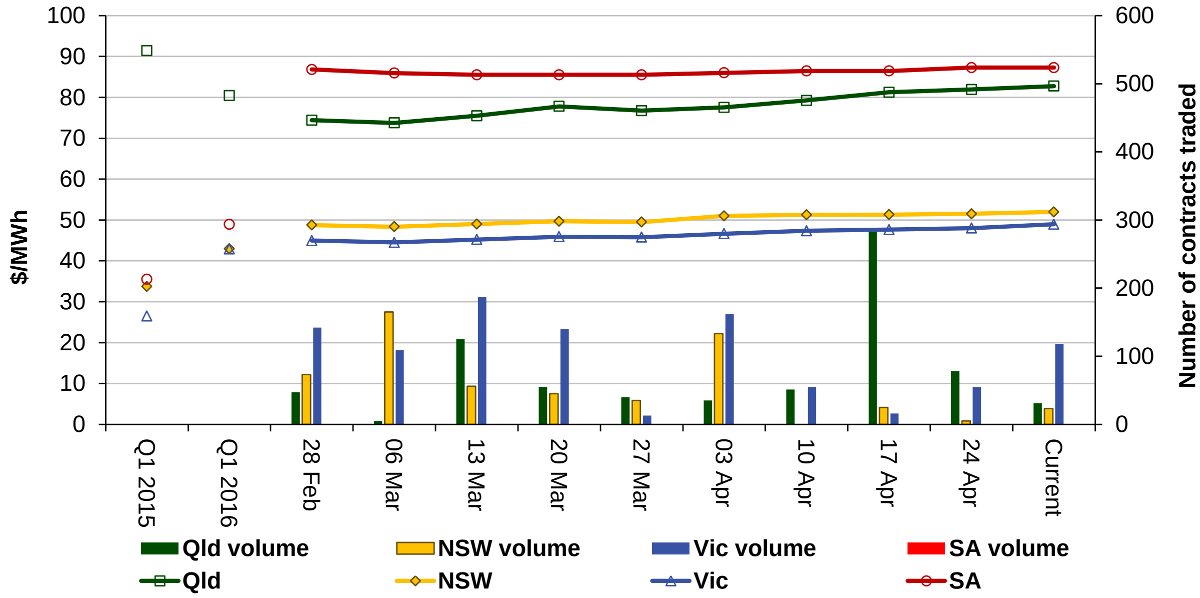
Figure 9: Quarterly base future prices Q2 2016 – Q1 2020



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 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 2017 base contracts over the past 10 weeks (and the past 2 years)



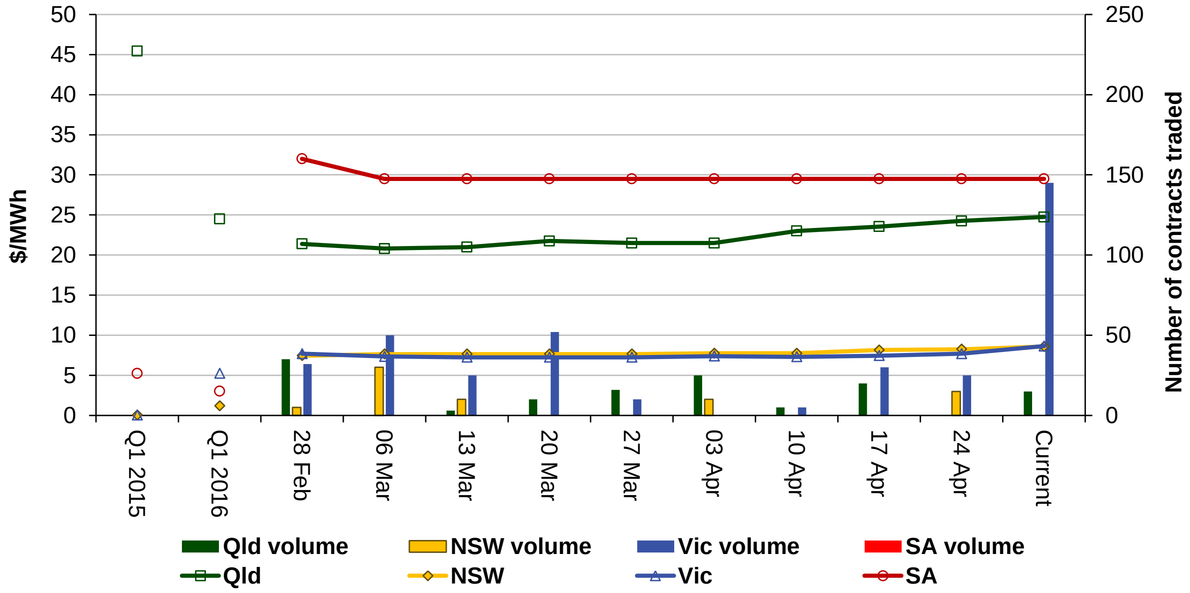
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

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 11 shows how the price for each regional Quarter 1 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
May 2016