Electricity Report

AUSTRALIAN ENERGY REGULATOR

10 – 16 January 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $27/MWh in Victoria to $50/MWh in New South Wales. Quarter to date VWA prices are between $15/MWh and $36/MWh lower in all regions except New South Wales. New South Wales quarter to date VWA prices are down by $128/MWh, driven by a number of high priced events during Q1 2020.

Variations in forecast demand, generator rebidding and limits on interconnector flows throughout the week saw our weekly price thresholds breached on 23 occasions.

Purpose

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 10 to 16 January 2021.

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

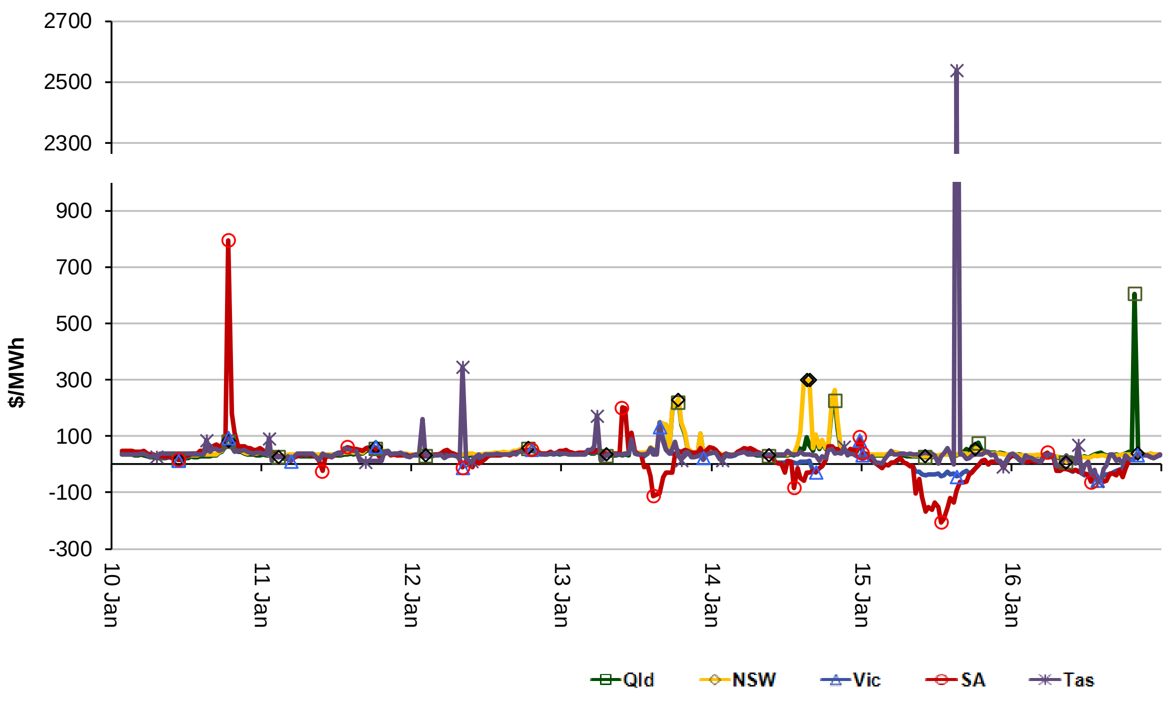


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

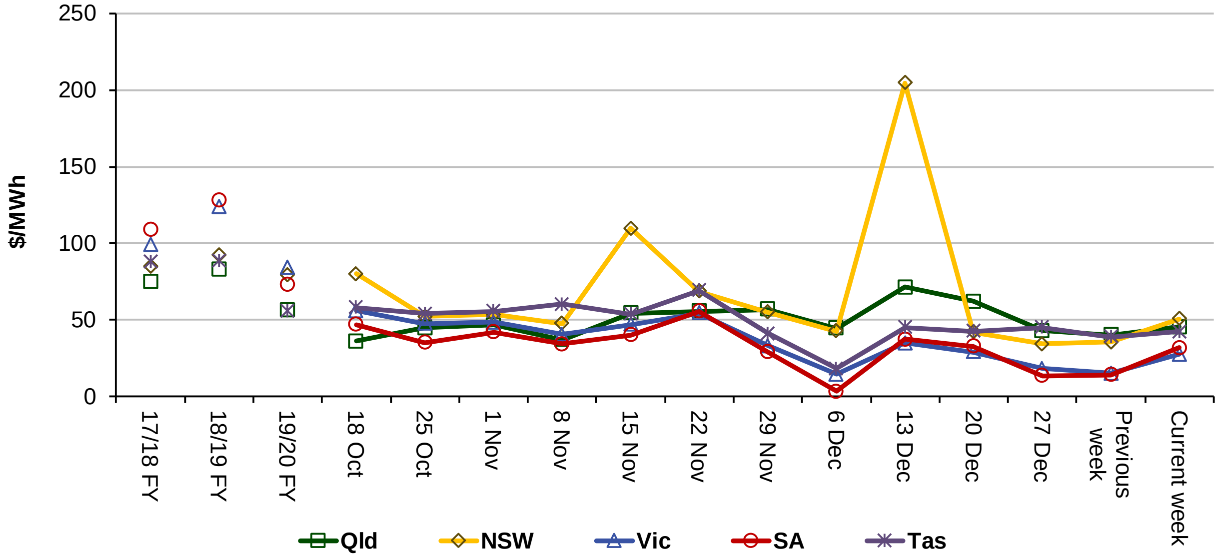


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	45	50	27	32	42
Q1 2020 (QTD)	56	170	57	57	72
Q1 2021 (QTD)	41	42	21	23	40
19-20 financial YTD	64	88	90	82	73
20-21 financial YTD	41	58	46	40	48

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 221 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2020 of 233 counts and the average in 2019 of 204. 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	40	1	1
% of total below forecast	11	30	0	10

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

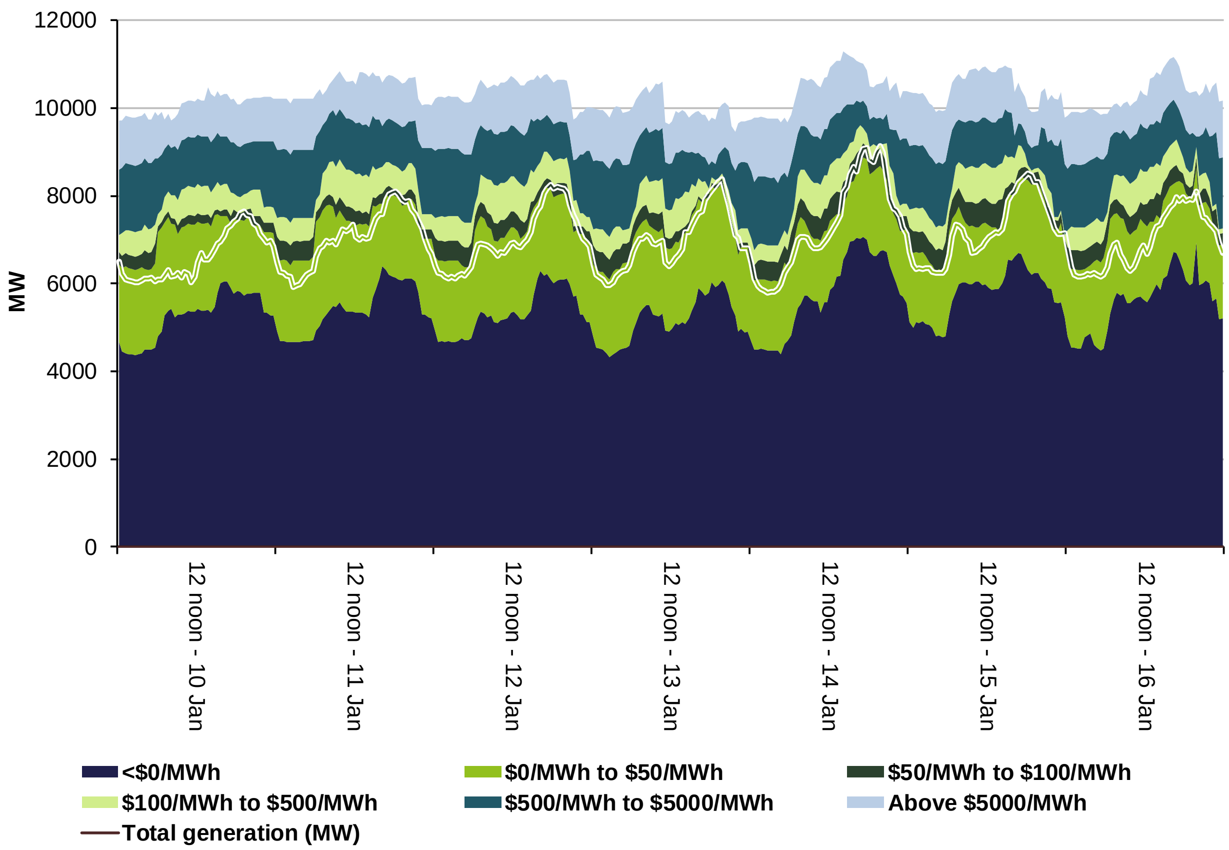


Figure 4: New South Wales generation and bidding patterns

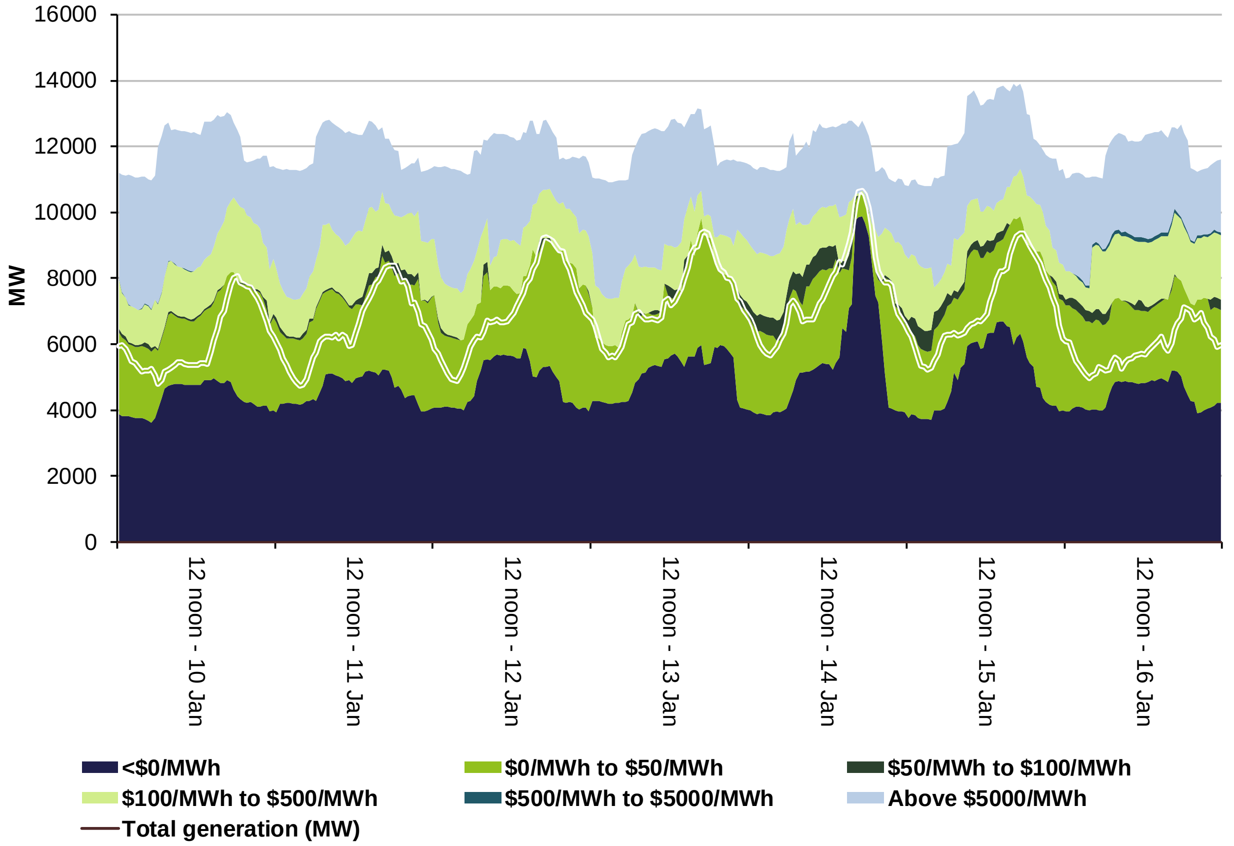


Figure 5: Victoria generation and bidding patterns

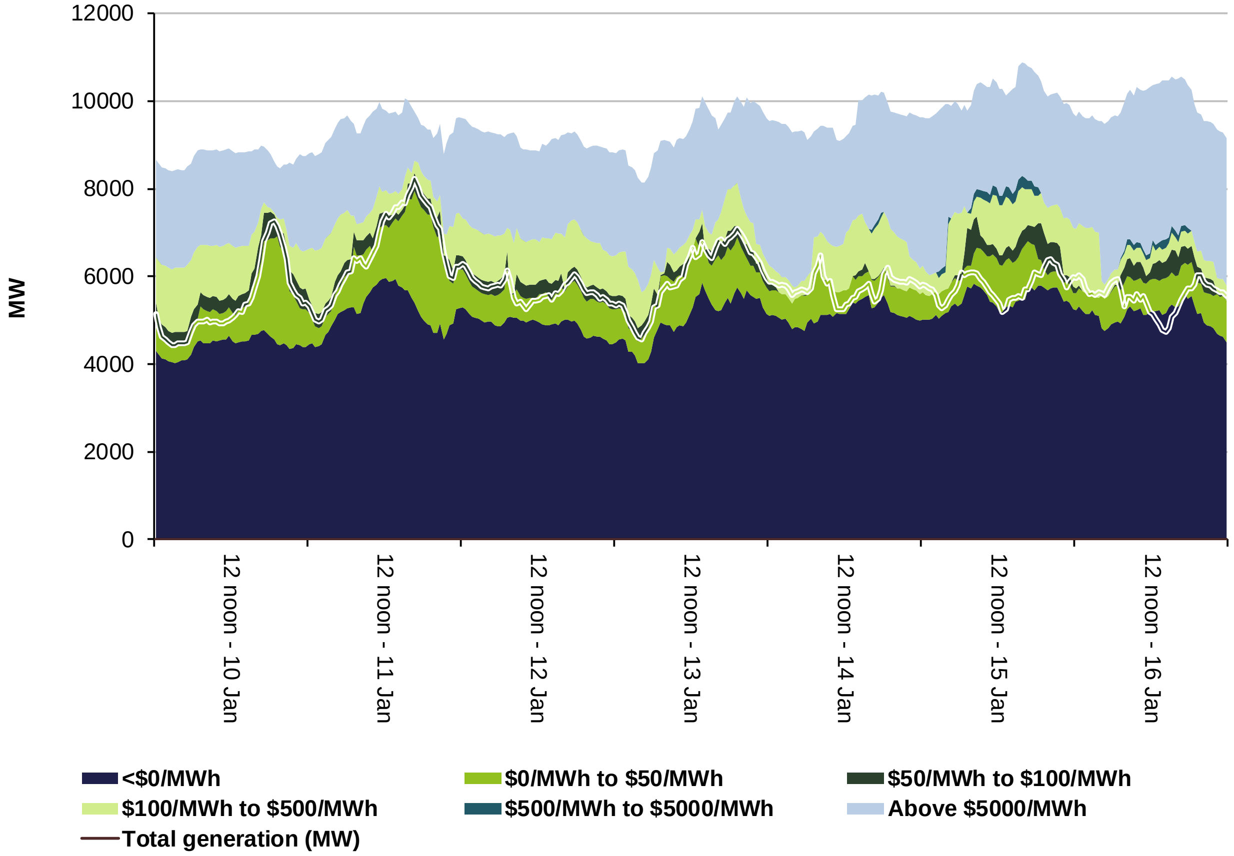


Figure 6: South Australia generation and bidding patterns

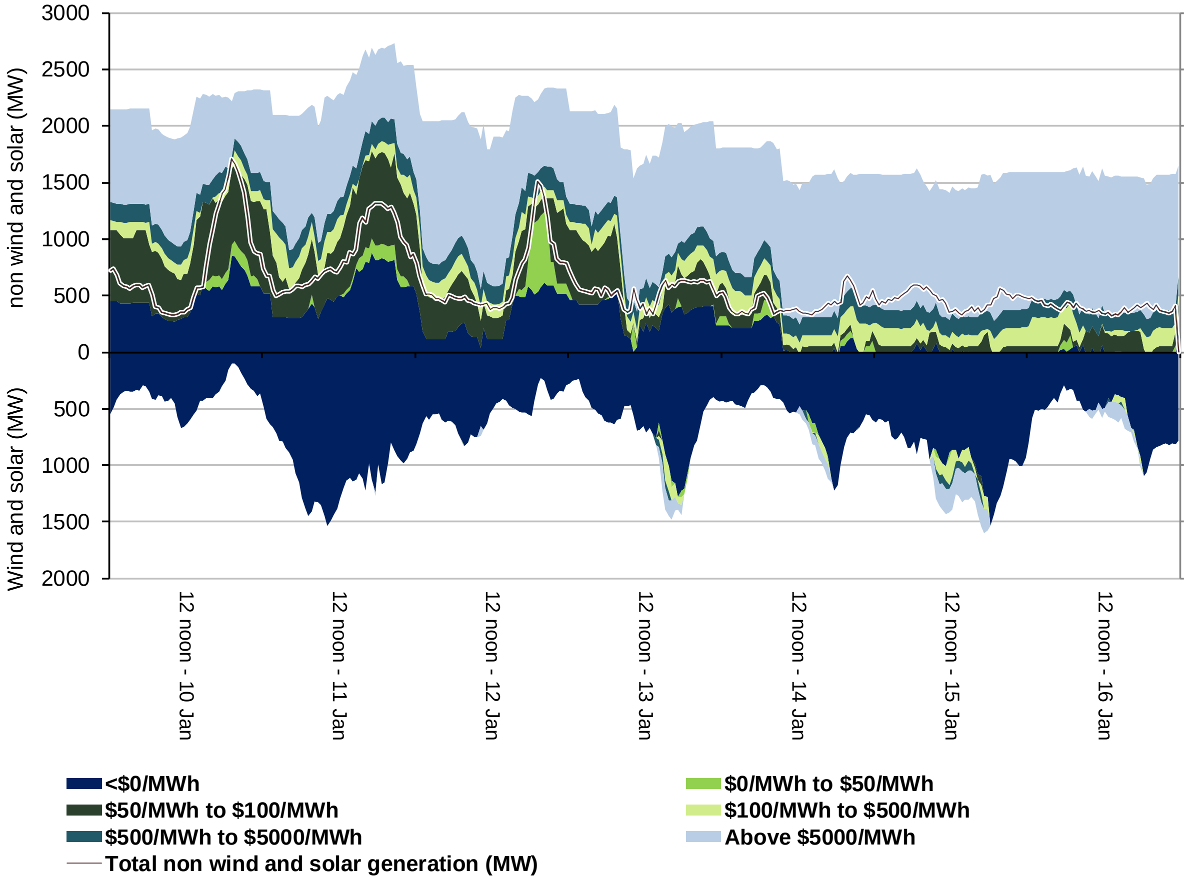
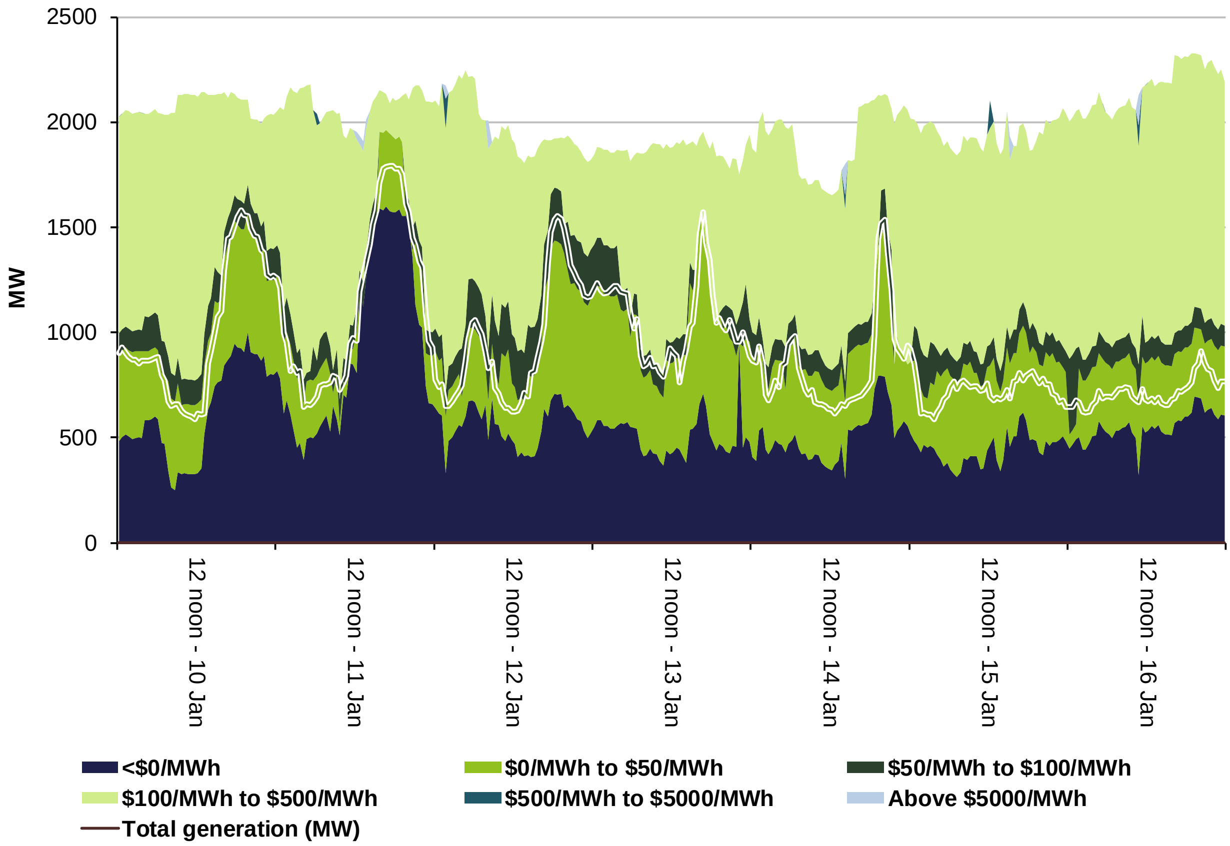


Figure 7: Tasmania generation and bidding patterns



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.

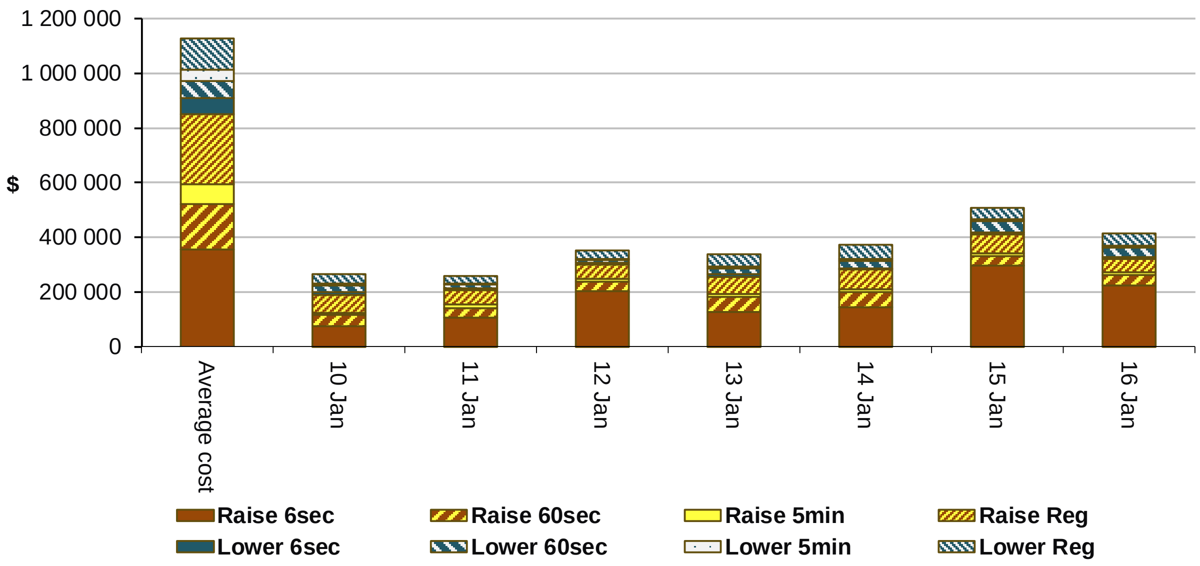
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1,573,000 or around 1% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $936,000 or less than 13% 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

Queensland

There was one occasion where the spot price in Queensland was greater than three times the Queensland weekly average price of $45/MWh and above $250/MWh.

Saturday, 16 January

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 pm	605.30	60.54	47.73	7,739	7,811	7,792	10,391	10,220	10,544

Demand was 72 MW less than forecast, while availability was 171 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, all of which was priced below -$900/MWh, and a rebid at 5.16 pm by Origin Energy at Darling Downs Power Station which added over 20 MW of capacity at $0/MWh due to plant reasons.

At 7.35 pm, demand increased by over 200 MW. With several generators unable to come on in 5 minutes, the dispatch price was set at $3,500/MWh. In response, participants rebid just over 1,000 MW of capacity from prices above $349/MWh to below $0/MWh. Prices remained below $31/MWh for the rest of the trading interval.

New South Wales

There were four occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $50/MWh and above $250/MWh.

Thursday, 14 January

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
3 pm	299.93	61.01	299.99	10,648	10,054	10,267	12,703	12,784	12,807
3.30 pm	299.99	65.00	299.99	10,981	10,351	10,631	12,921	12,966	13,193
4 pm	299.99	61.01	299.99	11,235	10,638	10,951	12,770	12,979	13,160
8 pm	263.97	85.74	300	9887	10,158	9,955	11,259	11,191	11,437

For the 3 pm to 4 pm trading intervals, demand was between 594 MW and 630 MW higher than forecast, while availability was between 45 MW and 209 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to rebids by participants which removed capacity from various prices due to plant reasons and forecast prices.

For the 3 pm trading interval, a rebid at 1.35 pm by Snowy Hydro at Tumut shifted 205 MW from $61/MWh to $300/MWh due to changes in forecast prices. The combination of higher than forecast demand and Snowy Hydro's rebid saw prices set higher than forecast throughout the trading interval.

For the 3.30 pm and 4 pm, higher than forecast demand saw prices set above forecast throughout each trading interval.

For the 8 pm trading interval, demand was 271 MW lower than forecast and availability was close to forecast, four hours prior. Between 6.45 pm and 7.23 pm, Snowy Hydro at Tumut rebid nearly 1100 MW of capacity from the price floor to $300/MWh due to forecast prices. The combination of higher than forecast demand and participant rebids shifting and removing capacity meant prices were set above forecast throughout the trading interval.

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 $32/MWh and above $250/MWh and there were fifteen occasions where the spot price was below -$100/MWh.

Sunday, 10 January

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
7 pm	795.21	279.53	278.01	2,417	2,424	2,390	2,475	2,612	2,588

Demand was close to forecast while availability was 137 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to lower than forecast wind generation, all of which was priced below $0/MWh.

Throughout the trading interval, constraints limited imports into South Australia from Victoria over the Murraylink and Heywood interconnectors for system security reasons. At 7 pm, constraints related to system security limited generation from several semi-scheduled generators, resulting in the dispatch price increasing to $3,426/MWh.

Wednesday, 13 January

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
3 pm	-112.37	31.30	31.34	764	823	836	3,096	2,440	2,596
3.30 pm	-105.07	51.73	33.64	808	933	834	3,369	2,504	2,528
4 pm	-104.48	118	43.67	896	937	855	3,422	2,667	2,477

Demand was between 41 MW and 125 MW lower than forecast while availability was between 656 MW and 865 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation, most of which was priced below $0/MWh, and rebids by Engie at Pelican Point adding 185 MW of capacity at the floor due to 'revised tolling nominations'.

The combination of lower than forecast demand and higher than forecast availability resulted in prices below forecast.

Friday, 15 January

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
9 am	-102.08	-38.27	-200	948	826	805	2,397	2,424	2,608
10 am	-114.75	-190.00	-895.85	905	647	641	2,737	2,602	2,725
10.30 am	-167.54	-511.12	-1000	873	560	549	2,805	2,600	2,727
11 am	-153.00	-649.33	-1000	779	477	454	2,830	2,625	2,737
11.30 am	-161.33	-837.17	-1000	739	407	389	2,874	2,643	2,737
Midday	-134.47	-885.09	-1000	720	359	339	2,851	2,630	2,731
12.30 pm	-150.84	-649.33	-1000	636	326	287	2,831	2,614	2,737
1 pm	-205.73	-801.08	-1000	579	295	261	2,692	2,613	2,736
1.30 pm	-195.05	-775.68	-1000	565	278	248	2,706	2,648	2,754
2 pm	-154.00	-1000	-1000	577	252	241	2,761	2,676	2,765
2.30 pm	-120.19	-1000	-1000	577	244	239	2,736	2,713	2,780
3 pm	-134.67	-649.33	-1000	605	280	266	2,746	2,755	2,800

For the 9 am trading interval, demand was 122 MW higher than forecast while availability was close to forecast, 4 hours prior. Effective from 8.55 am, rebids by Lincoln Gap Wind Farm and Trustpower at Snowtown Wind Farm shifted over 310 MW from -$40/MWh to the price floor due to forecast prices. At 9 am, demand fell by 33 MW while wind generation increased by almost 40 MW. As a result, the 9 am dispatch price fell to -$512/MWh leading to the lower than forecast price.

For the 10 am to 3 pm trading intervals, demand was between 258 MW and 361 MW higher than forecast, while availability was close to or up to 231 MW higher than forecast, 4 hours prior. Higher than forecast availability was mainly due to higher than forecast renewable generation, most of which was priced below $0/MWh. Higher than forecast demand and rebids by participants shifting at least 380 MW of capacity to higher prices throughout each trading interval due to forecast prices resulted in higher than forecast prices.

Tasmania

There were two occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $42/MWh and above $250/MWh.

Tuesday, 12 January

Table 8: 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	344.20	32.05	33.64	896	1,035	1,068	2,009	1,981	1,904

Demand was 139 MW lower than forecast, while availability was close to forecast, 4 hours prior. At 8.25 am there was an unplanned outage of the Basslink interconnector, meaning cheap generation from Victoria was unable to be sourced. Effective from 8.25 am, rebids by Wild Cattle Hill at Cattle Hill Wind Farm and Hydro Tasmania at Musselroe Wind Farm shifted over 310 MW from below -$277/MWh to above $2000/MWh due to FCAS prices. With other generators trapped/stranded or ramp constrained and unable to set price, the 8.25 am dispatch price reached $2000/MWh.

Friday, 15 January

Table 9: 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
3.30 pm	2,537.34	35.36	35.36	1,102	1,050	1,085	2,000	1,956	1,950

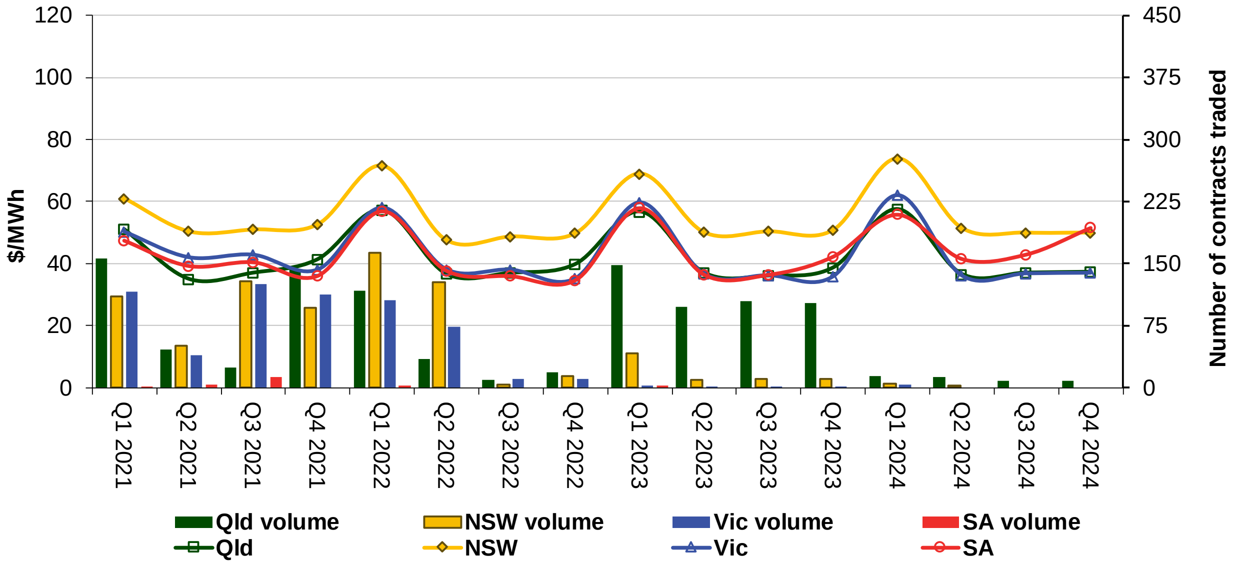
Demand and availability were close to forecast 4 hours prior.

From 2.10 pm, AEMO reclassified the Farrell to Sheffield lines from non-credible to credible contingencies for potential loss due to lightning. Effective from 3.10 pm, rebids by Wild Cattle Hill at Cattle Hill Wind Farm and Hydro Tasmania at Musselroe Wind Farm shifted over 310 MW from below -$277/MWh to $15,000/MWh due to forecast energy prices and to avoid high FCAS costs. With several generators ramp constrained, and no capacity offered between $400/MWh and $15,000/MWh, the 3.10 pm dispatch price reached $15,000/MWh.

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 Q1 2021 – Q4 2024

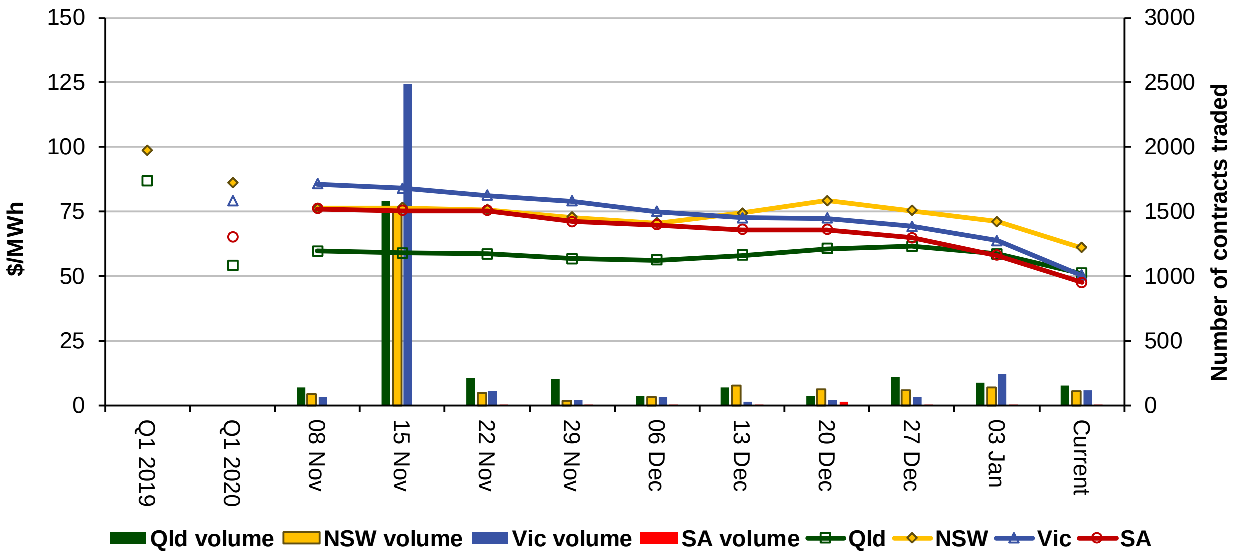


Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2021 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2020 and Q1 2019 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

The high volume of trades in Figure 10 is a result of the conversion of base load options to base future contracts on 19 November 2020.

Figure 10: Price of Q1 2021 base contracts over the past 10 weeks (and the past 2 years)

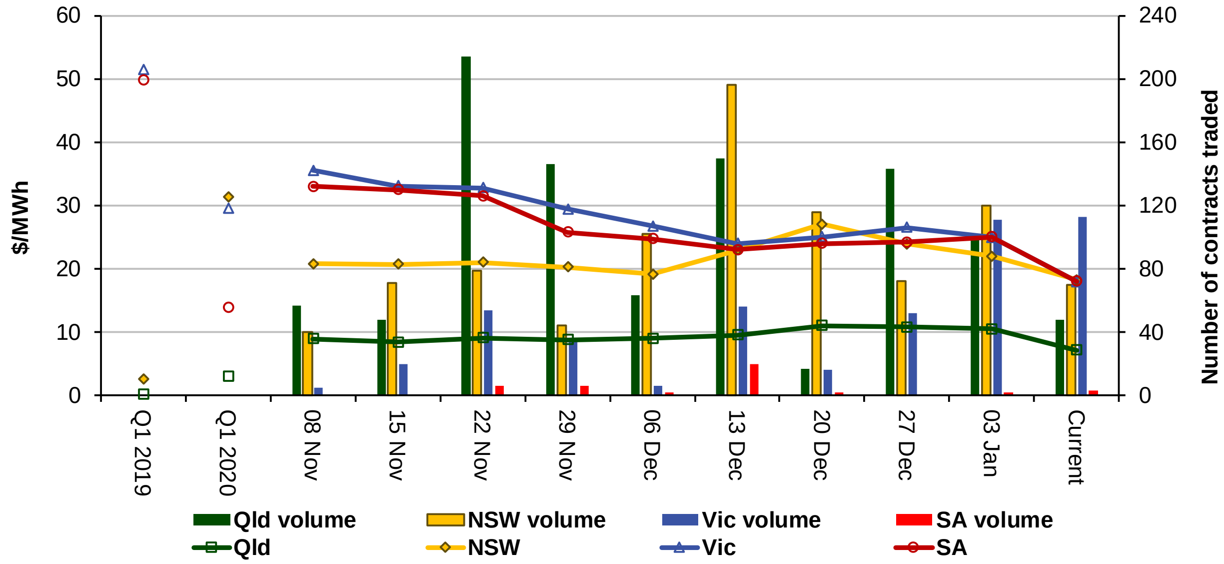


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2021 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2020 and Q1 2019 prices are also shown.

Figure 11: Price of Q1 2021 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics](#) section of our website.

Australian Energy Regulator
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