Electricity Report

AUSTRALIAN ENERGY REGULATOR

15 – 21 August 2021

Weekly Summary

Weekly volume weighted average (VWA) prices ranged from $21/MWh in Tasmania to $62/MWh in New South Wales. Weekly VWA prices across the NEM have been below $65/MWh in August. Despite this, higher prices in July have led to quarter to date prices at least $20/MWh higher across the mainland compared to the same time last year.

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 15 to 21 August 2021.

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

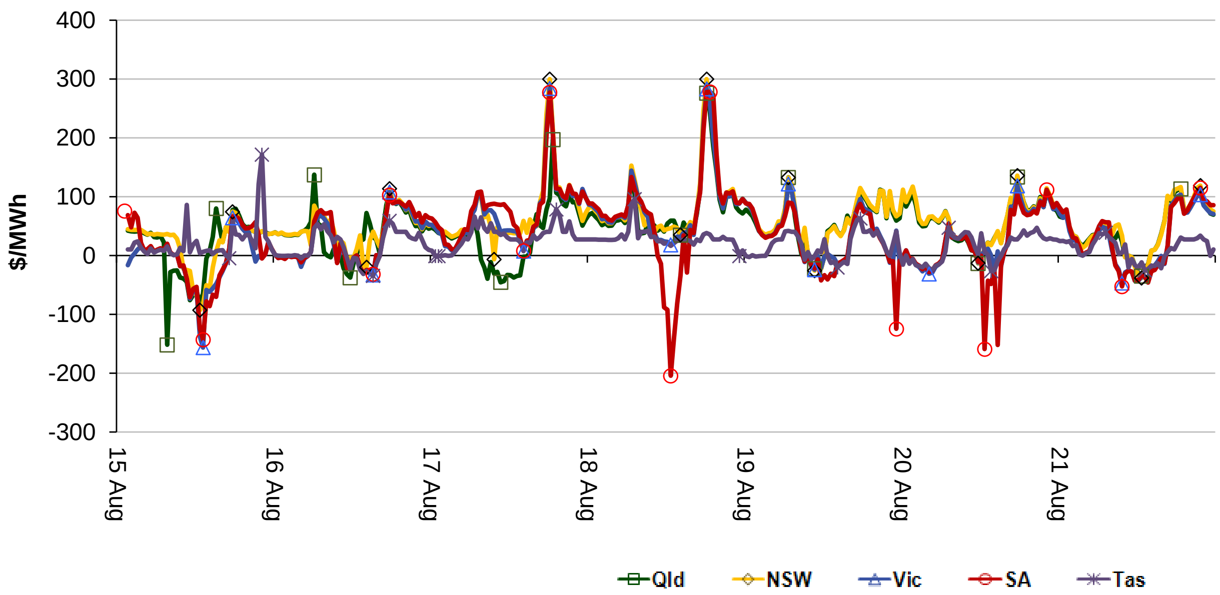


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

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

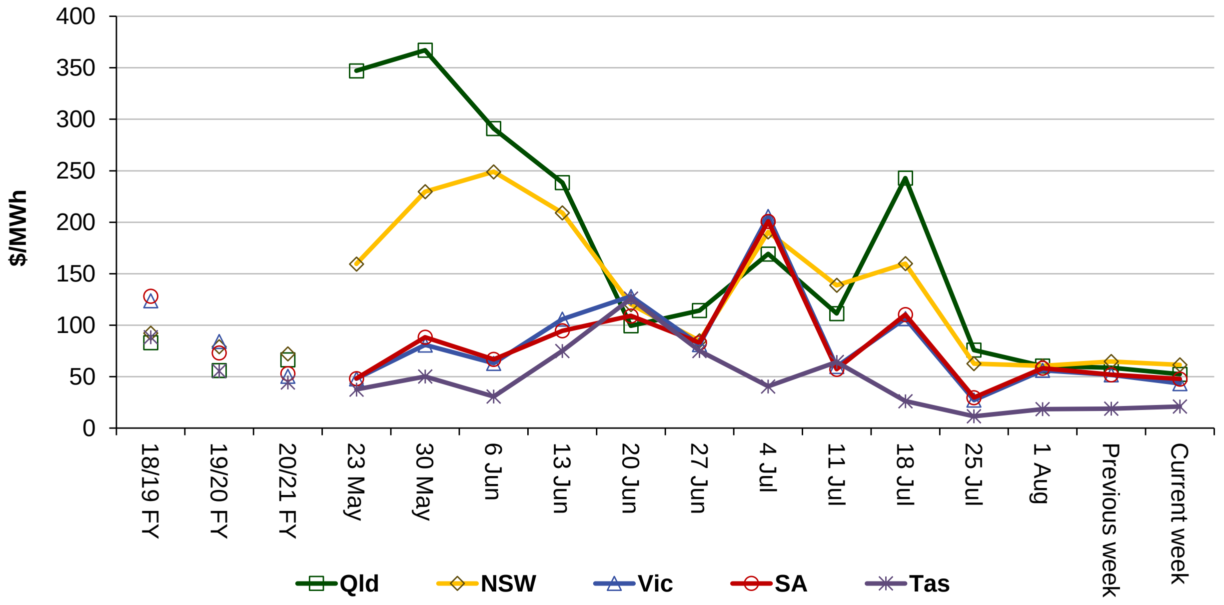


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	52	62	43	48	21
Q3 2020 QTD	37	49	61	56	57
Q3 2021 QTD	114	108	81	81	31
20-21 financial YTD	37	49	61	56	57
21-22 financial YTD	114	108	81	81	31

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 298 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	10	20	0	1
% of total below forecast	10	53	0	7

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

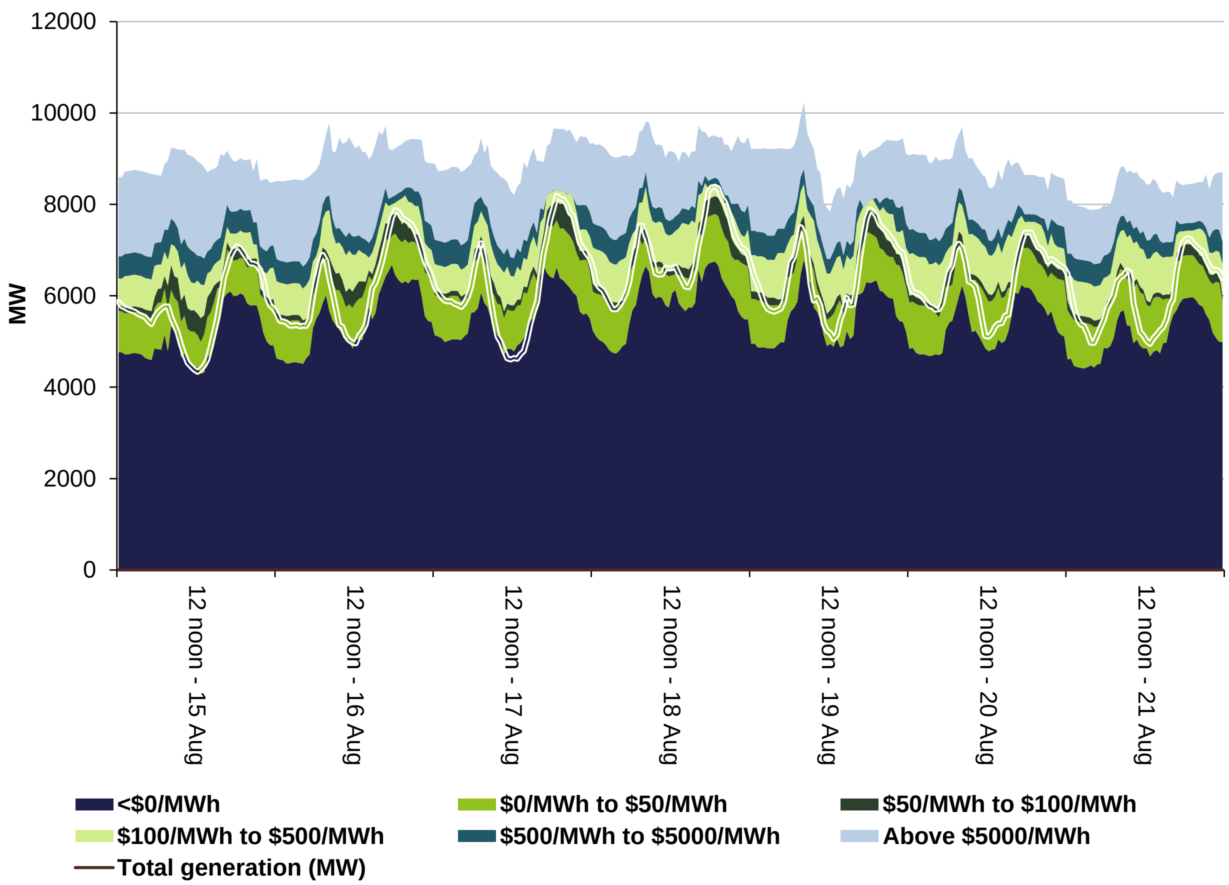


Figure 4: New South Wales generation and bidding patterns

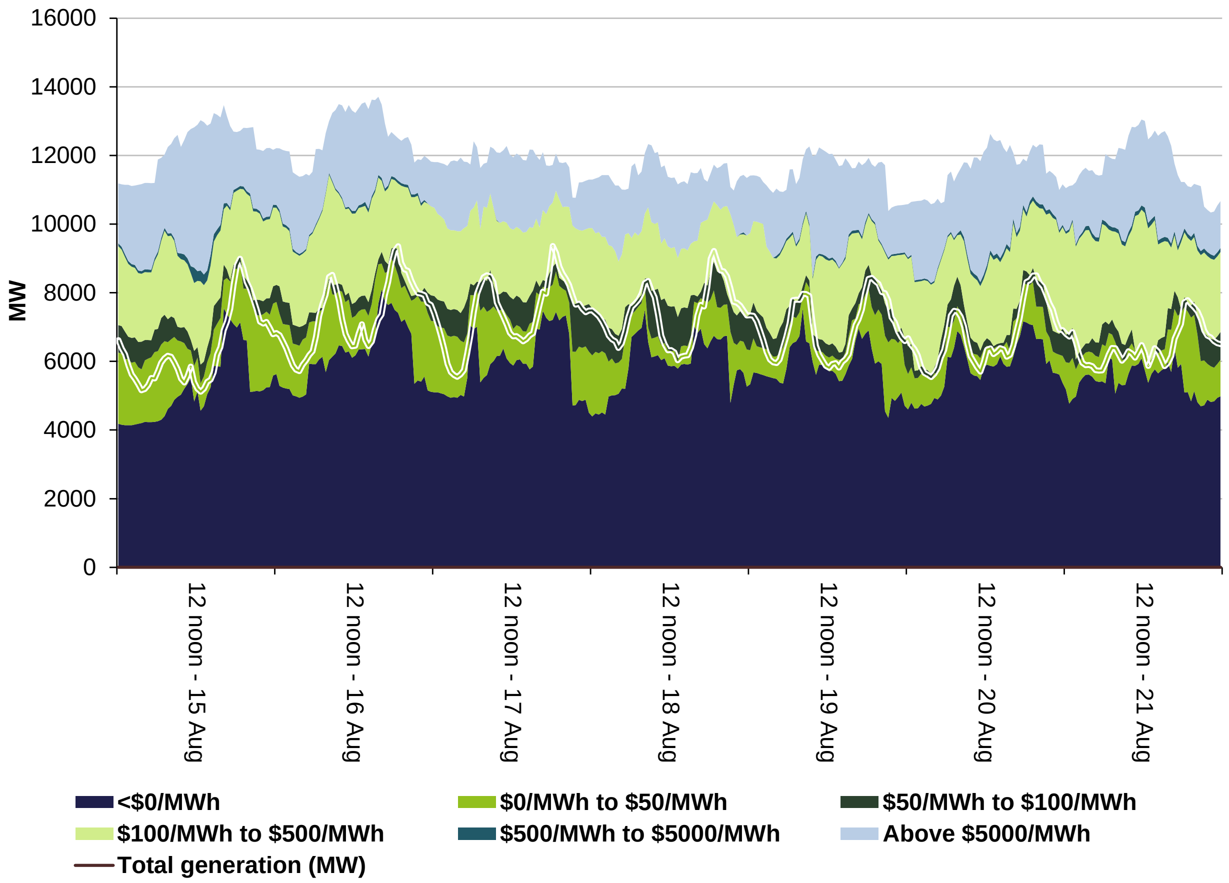


Figure 5: Victoria generation and bidding patterns

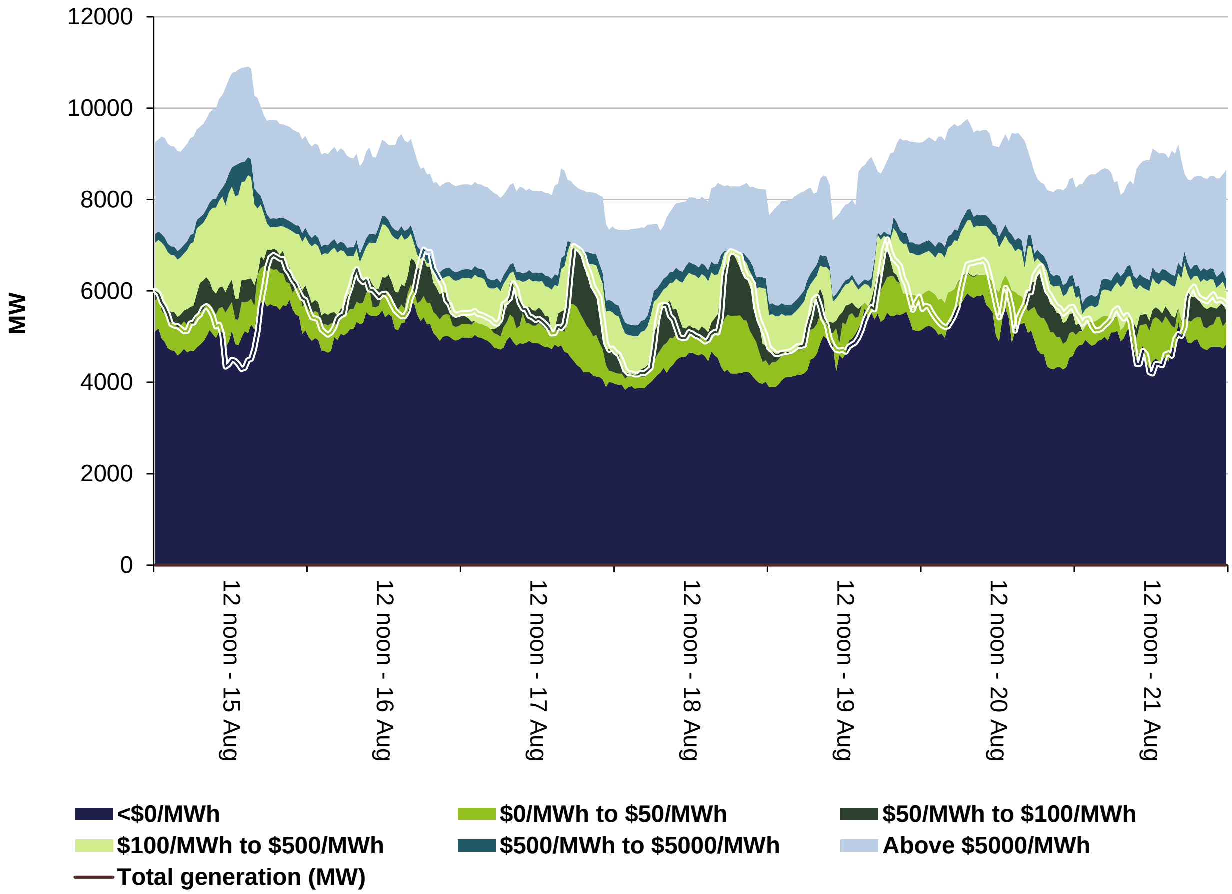


Figure 6: South Australia generation and bidding patterns

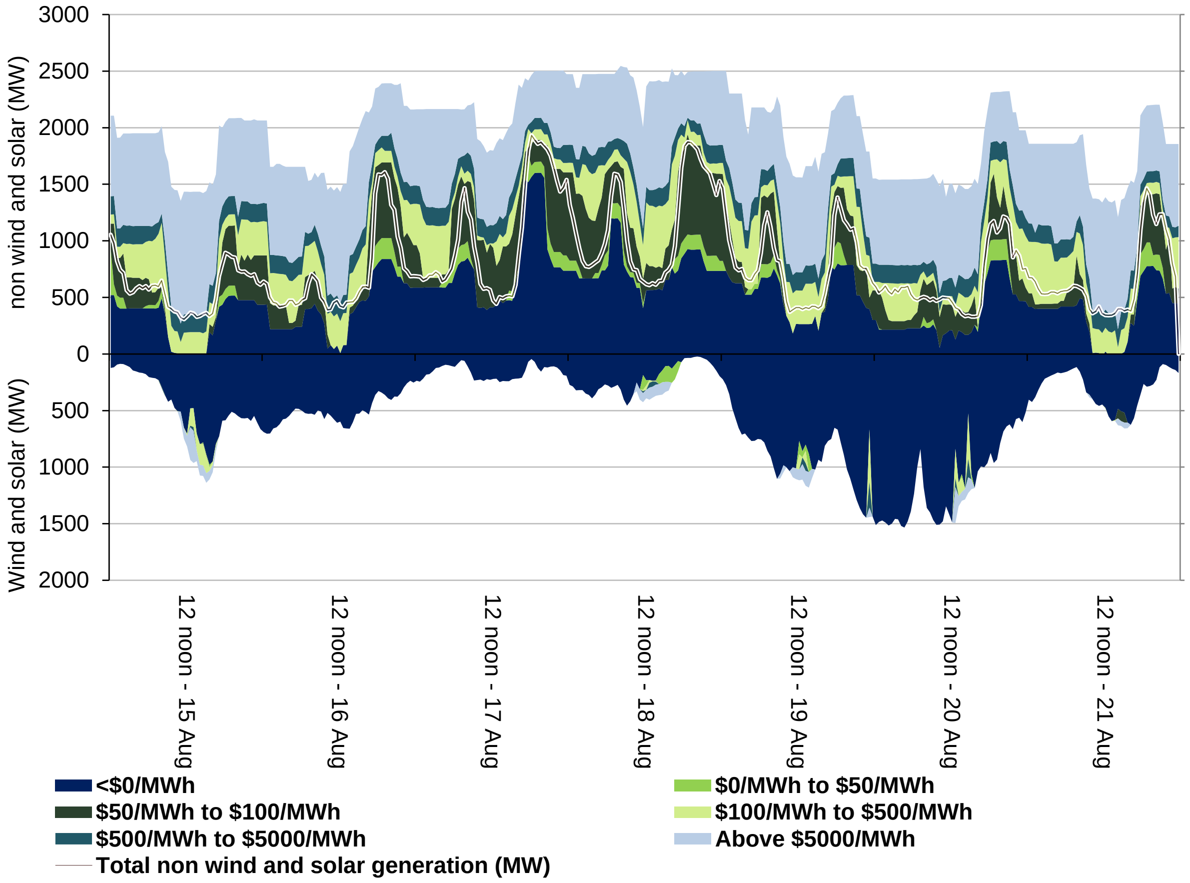
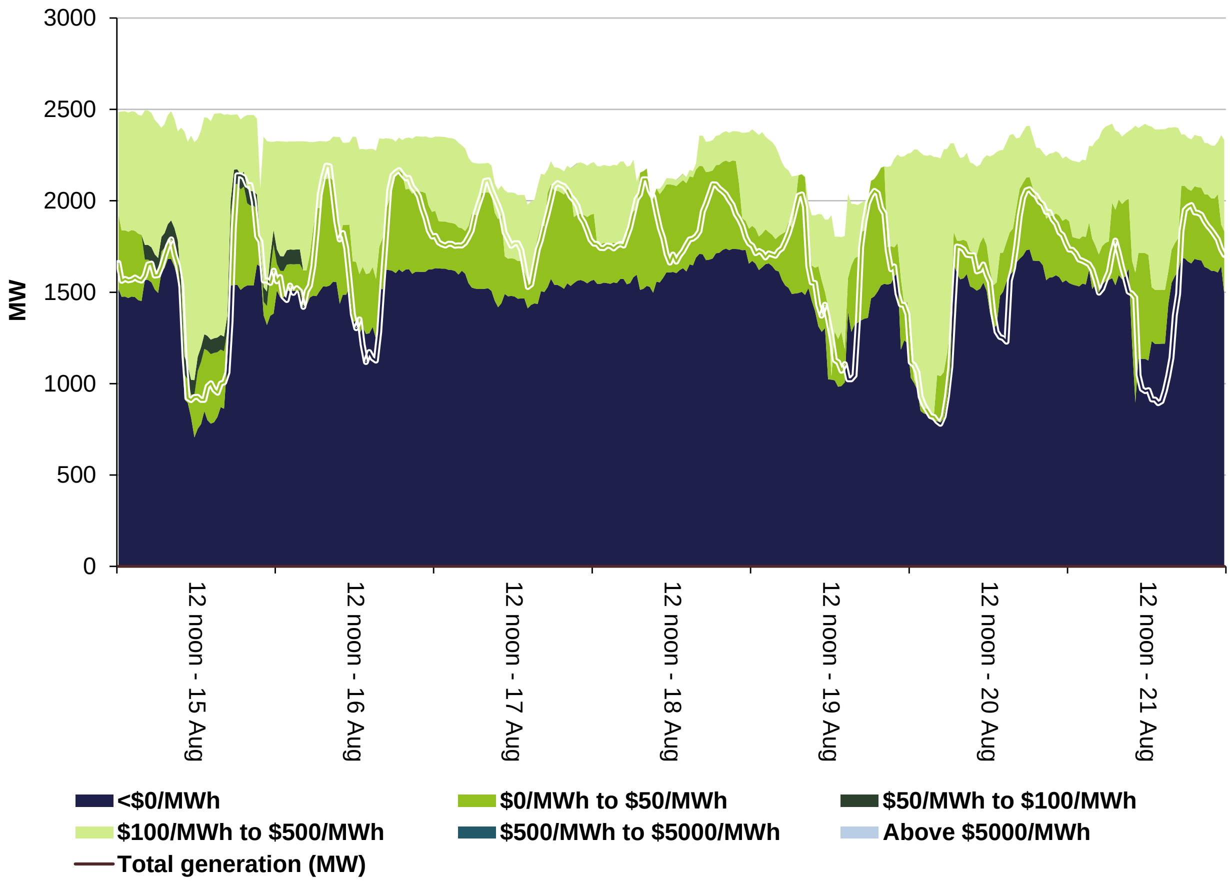


Figure 7: Tasmania generation and bidding patterns



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.

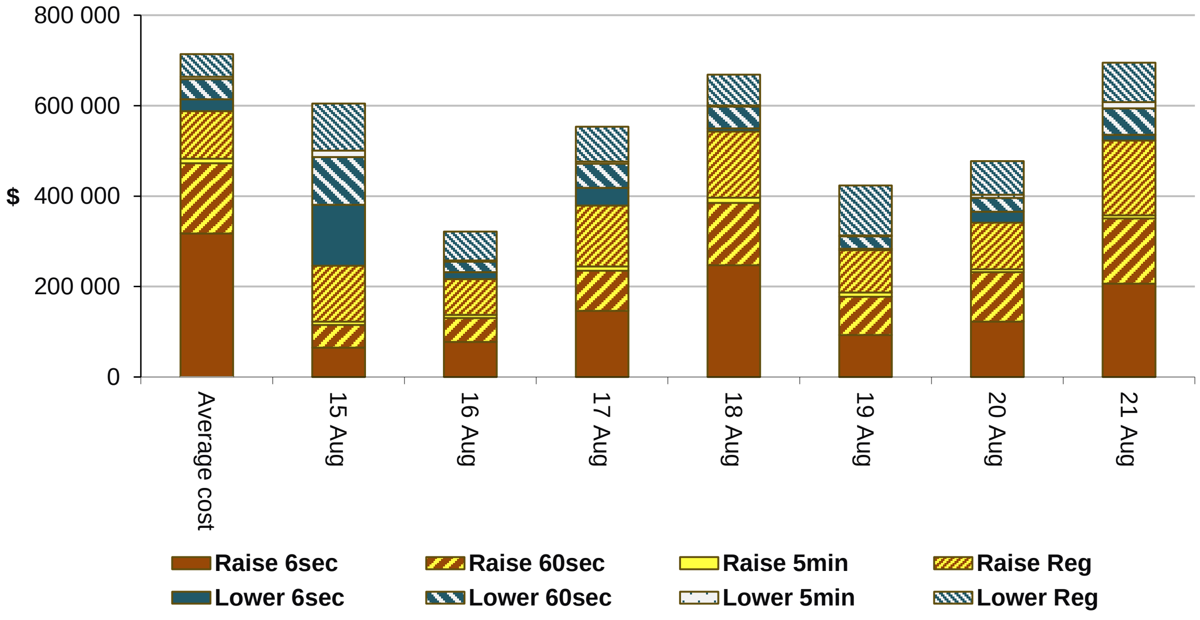
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3,287,000 or less than 2% of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $456,500 or around 10% 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 1 occasion where the spot price in Queensland was greater than 3 times the Queensland weekly average price of $52/MWh and above $250/MWh and there was 1 occasion where the spot price was below -$100/MWh.

Sunday, 15 August

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	-151.59	24.20	24.15	5,179	5,338	5,368	8,953	8,779	8,768

Demand was 159 MW lower than forecast and availability was 174 MW higher than forecast, 4 hours prior. Availability was higher than forecast due to higher than forecast renewable generation which offers mostly below $0/MWh.

At 7.55 am Wivenhoe's Pump 2 tripped and stopped consuming 240 MW, requiring less generation to be dispatched in Queensland. With a number of generators ramp-down constrained, price dropped to the floor for 5 minutes. In response to the low price, participants rebid over 970 MW of capacity from prices at or close to the floor to prices above $237/MWh.

Wednesday, 18 August

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
6.30 pm	276.01	293.39	290.68	7,522	7,489	7,487	9,500	9,354	9,503

Prices were aligned across the mainland and will be treated as 1 region. Price was close to forecast.

New South Wales

There were 3 occasions where the spot price in New South Wales was greater than 3 times the New South Wales weekly average price of $62/MWh and above $250/MWh.

Tuesday, 17 August

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
6.30 pm	299.98	299.99	299.99	10,345	10,533	10,518	11,816	12,078	11,964

Prices were aligned across New South Wales, Victoria and South Australia and will be treated as 1 region. Prices were as forecast.

Wednesday, 18 August

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
6.30 pm	299.98	299.99	301.10	10,268	10,372	10,445	11,466	11,639	11,779
7 pm	265.16	299.99	299.99	10,242	10,403	10,483	11,732	11,895	12,152

Prices were aligned across the mainland and will be treated as 1 region. Price was close to forecast.

Victoria

There were 3 occasions where the spot price in Victoria was greater than 3 times the Victoria weekly average price of $43/MWh and above $250/MWh and there were 2 occasions where the spot price was below -$100/MWh.

Sunday, 15 August

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	-137.93	-1,000	-1,000	2,946	3,109	3,049	10,798	10,470	10,044
1.30 pm	-156.35	-1,000	-1,000	2,921	3,139	3,079	10,838	10,496	10,056

Prices were aligned between Victoria and South Australia and will be treated as 1 region. Collectively, demand was close to forecast while availability was between 513 MW and 573 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast renewable generation which mostly offers below $0/MWh.

From 8.30 am, participants rebid at least 1,200 MW from the floor to higher prices in response to the forecast price. Price was between $-713/MWh and $-31/MWh throughout both trading intervals.

Tuesday, 17 August

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
6.30 pm	284.07	301.41	318.00	6,849	6,865	6,947	8,262	8,350	8,366

Prices were aligned across New South Wales, Victoria and South Australia and will be treated as 1 region. Prices were close to forecast.

Wednesday, 18 August

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
6.30 pm	283.43	288.75	308.02	6,789	6,820	6,813	8,284	8,169	8,187
7 pm	258.79	298.20	311.51	6,788	6,815	6,830	8,288	8,189	8,182

Prices were aligned across the mainland and will be treated as 1 region. Price was close to forecast.

South Australia

There were 4 occasions where the spot price in South Australia was greater than 3 times the South Australia weekly average price of $48/MWh and above $250/MWh and there were 7 occasions where the spot price was below -$100/MWh.

Sunday, 15 August

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
1 pm	-124.57	-1,000	-889.28	509	349	366	2,369	2,184	2,245
1.30 pm	-142.69	-1,000	-879.66	491	306	326	2,396	2,165	2,231

Prices were aligned across Victoria and South Australia and will be treated as 1 region. See Victoria section for analysis.

Tuesday, 17 August

Table 11: 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
6.30 pm	277.31	301.77	333.79	1,939	1,988	2,030	2,546	2,758	2,625

Prices were aligned across New South Wales, Victoria and South Australia and will be treated as 1 region. Prices were close to forecast.

Wednesday, 18 August

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
1 pm	-204.27	8.45	38.05	804	922	947	2,789	2,858	2,839
1.30 pm	-142.54	24.30	38.15	795	884	917	2,797	2,834	2,814
6.30 pm	277.85	278.76	305.40	1,848	1,799	1,833	2,533	2,548	2,517
7 pm	278.21	300.24	311.91	2,008	1,940	1,968	2,530	2,538	2,515
7.30 pm	273.35	299.79	310.46	2,053	1,988	2,015	2,530	2,545	2,530

For the 1 pm and 1.30 pm trading intervals, demand was between 89 MW to 118 MW lower than forecast and availability was between 37 MW to 69 MW lower than forecast, 4 hours prior. Lower than forecast availability was due to removal of up to 35 MW of capacity priced at the cap by AGL at Barkers Inlet for maintenance, and lower than forecast solar generation which usually offers below $0/MWh.

Imports over the Murraylink interconnector were higher than forecast, 4 hours prior, which decreased the amount of generation required to meet demand in South Australia. The lower than forecast demand and higher imports over Murraylink resulted in prices below forecast during both trading intervals.

For the 6.30 pm to 7.30 pm trading intervals, prices were aligned across the mainland and will be treated as 1 region. Price was close to forecast.

Thursday, 19 August

Table 13: 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
11.30 pm	-124.49	35.45	8.95	1,317	1,275	1,265	3,230	2,886	2,534

Demand was 42 MW higher than forecast and availability was 344 MW higher than forecast, 4 hours prior. Higher than forecast availability was due to higher than forecast wind generation which usually offers below $0/MWh.

There was no capacity offered between the floor and $70/MWh, so small changes in demand or availability caused large fluctuations in price. At 11.10 pm, demand dropped by 19 MW and resulted in price dropping to the floor. In response to the low price, participants rebid at least 740 MW from the floor to prices above $138/MWh. Prices were above $57/MWh for the remainder of the trading interval.

Friday, 20 August

Table 14: 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	-158.97	-116.04	-24.50	877	819	1,058	2,972	2,620	2,614
3 pm	-152.07	2.51	0.32	846	892	1,052	2,706	2,521	2,366

For the 1 pm trading interval, prices were close to forecast.

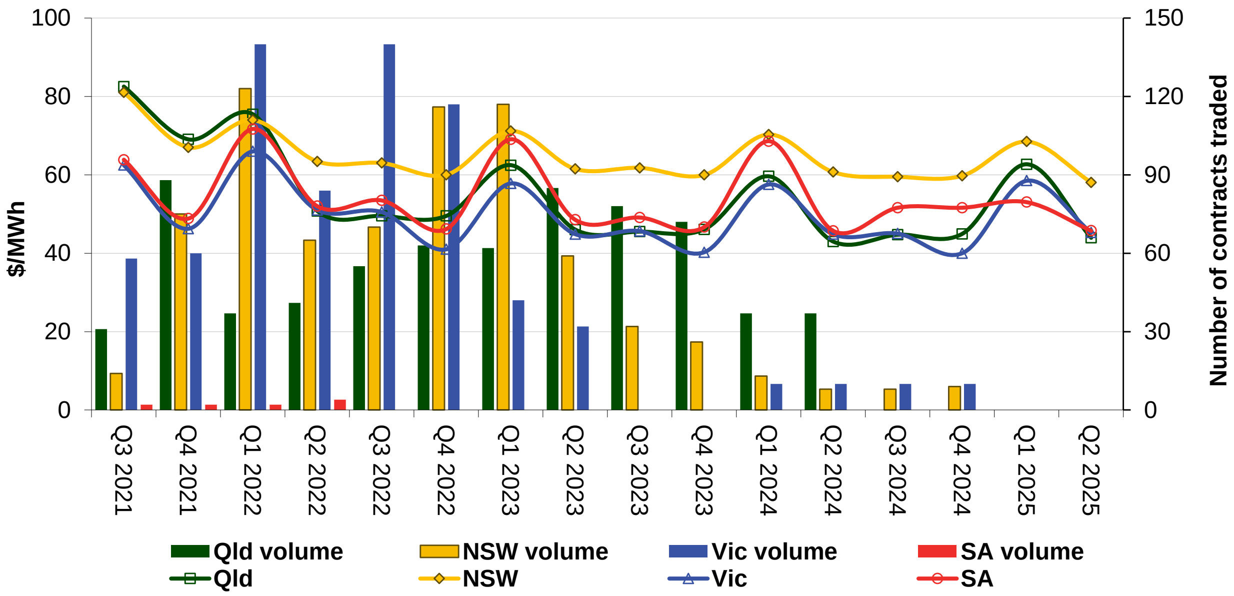
For the 3 pm trading interval, demand was 46 MW lower than forecast and 185 MW higher than forecast, 4 hours prior. Higher than forecast demand was due to higher than forecast wind generation which usually offers below $0/MWh.

Effective 2.40 pm, rebids by participants shifted around 320 MW of capacity from prices above $123/MWh to the floor. This resulted in price dropping to the floor for 5 minutes. In response to the low price, participant rebid over 1,000 MW from the floor to higher 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.

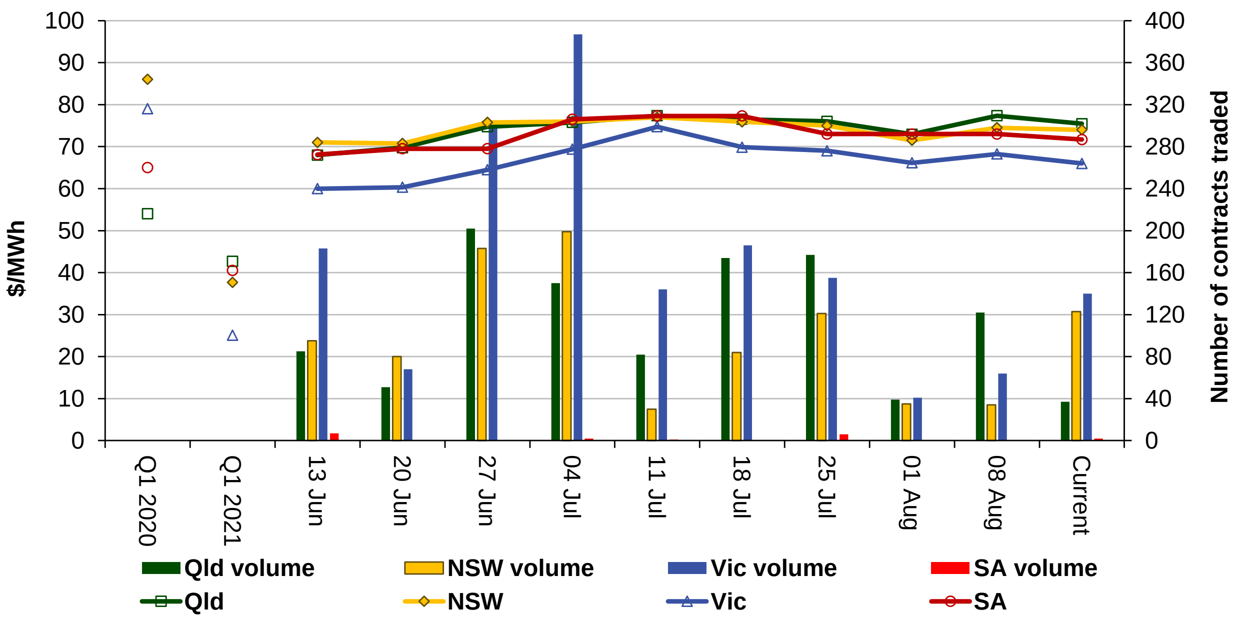
Figure 9: Quarterly base future prices Q3 2021 – Q2 2025



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2022 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 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 2022 base contracts over the past 10 weeks (and the past 2 years)

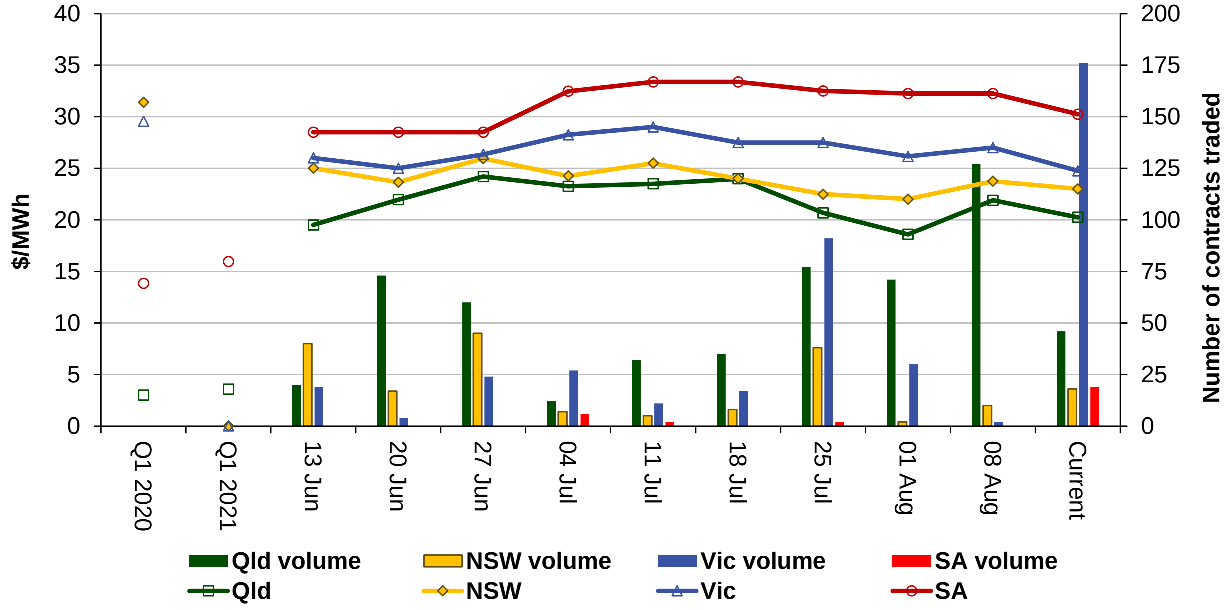


Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Figure 11 shows how the price for each regional Q1 2022 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing Q1 2021 and Q1 2020 prices are also shown.

Figure 11: Price of Q1 2022 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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