Market performance quarterly review

October - December 2023

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1. Purpose

This document is a review of the performance of New Zealand's energy market from 1 October to 31 December 2023. It aims to provide visibility of the monitoring of the market undertaken by the Electricity Authority Te Mana Hiko (Authority) during this period.

2. Highlights

National electricity demand was similar to the 2018-22 historic average over October and November, however, demand increased compared to the historic average in December.

There were three customer advice notices issued for low residual situations on 10 October, 2 and 3 November 2023. This is an increase from the previous quarter and was related to lower thermal commitment and plant outages.

Huntly 5 remained on outage this quarter, with Huntly 1 and 4 running as baseload. TCC turned off early in the quarter but came back online in December.

Increased installed wind capacity saw several wind generation records this quarter. There were serval days with average daily wind generation over 500MW.

National hydro storage mostly fell throughout this quarter, with several lakes receiving some inflows in late December.

Daily volume weighted average gas prices were mostly between $8-$15/TJ this quarter, with prices rising in December when more thermal generation turned on.

Mercury, Contact Energy and Manawa Energy lost the largest number of electricity connections (ICPs) this quarter, with the largest gainers being Genesis Energy, Meridian Energy and Flick Electric.

While electricity prices increased at below inflation (ie, in real terms), in nominal terms prices have increased since last year – bills are approximately $96 per year higher for an average household.

The price of New Zealand Units (NZUs) rose over the quarter and reached a maximum of $72.

3. Electricity demand

Demand across the quarter

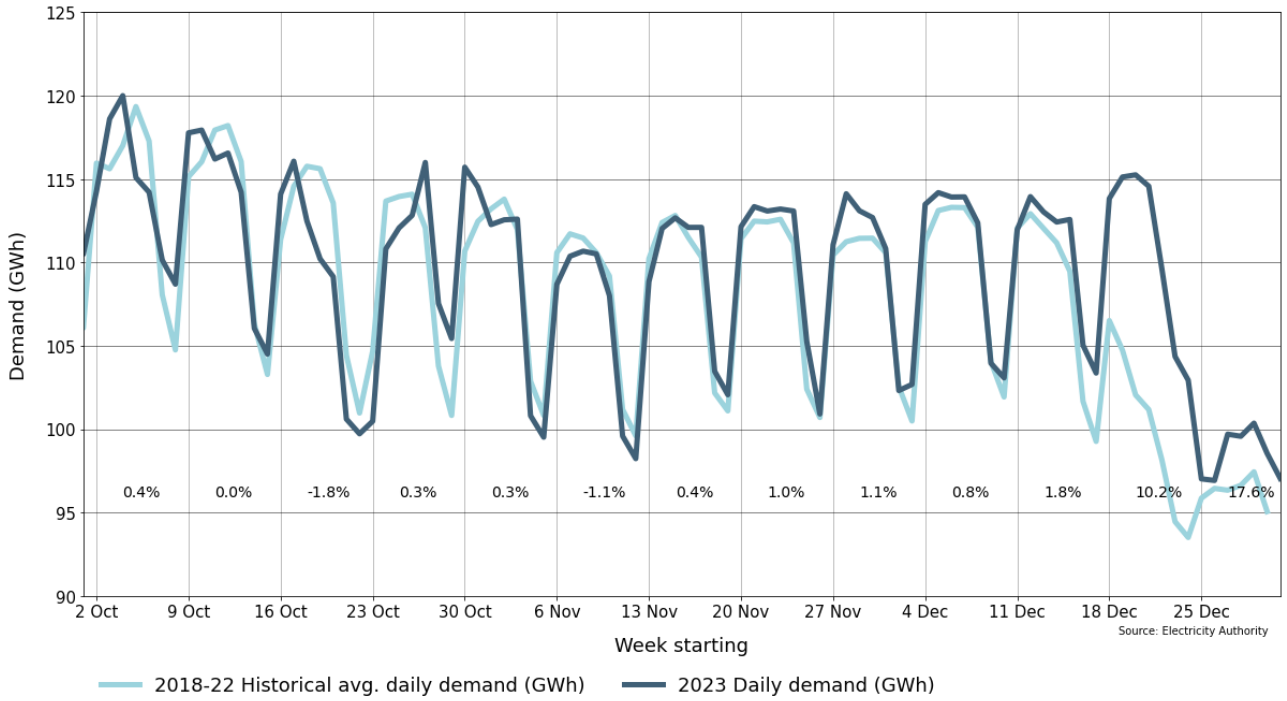
Total daily electricity demand in 2023 and the 2018-22 historic average electricity demand between October and December is shown in Figure 1.

National demand was close to the historic average between October and November and demand also began to fall as temperatures increased. However, demand was significantly higher than usual in December, possibly due to high temperatures, which increased cooling load. This is evident in **Error! Reference source not found.**, where demand is consistently above the long-term average for the month. Demand then rapidly fell off during the Christmas holiday period. But, compared to the historic average, holiday demand was significantly higher in 2023. With demand between 25-31 December being 17.5% higher than the historic average between 2018-22. Note however that this comparison matches week and weekday, so comparisons during the holiday period include years where major holidays fell both during weekdays and weekends.

Across Q4 2023, there were three customer advice notices (CANs) for low residual supply, issued on 10 October, 2 November and 3 November 2023. However, only one CAN for low residual supply was issued in Q3 2023. The increase in CANs this quarter was likely due to decreased thermal commitment and an increased number of planned outages occurring in the warmer months while demand is comparatively low.

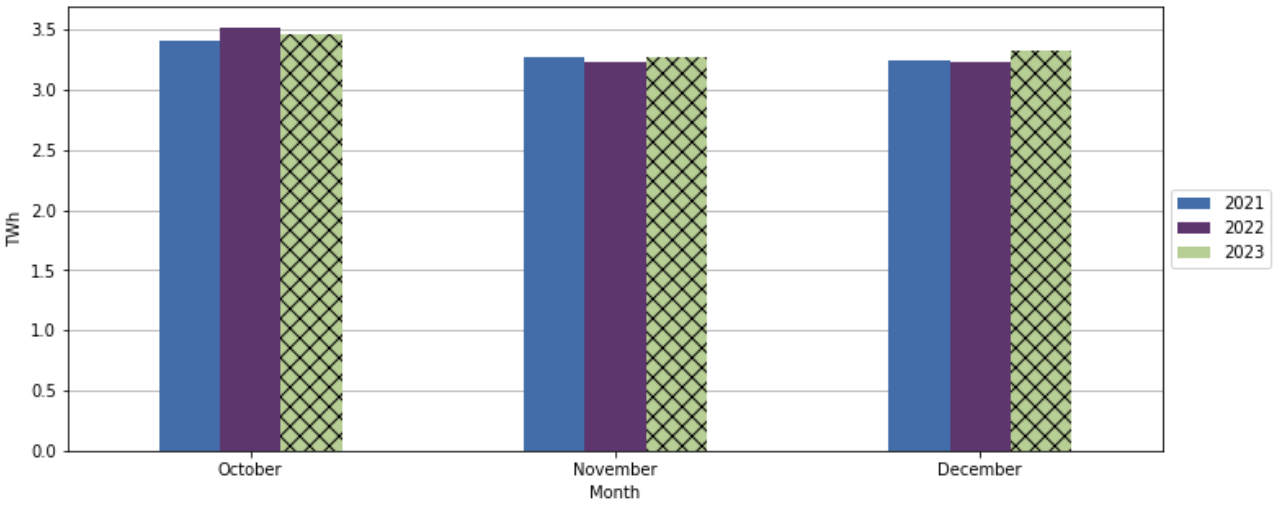
Monthly total demand for October to December is shown in Figure 2. Total demand in October 2023 was lower when compared to 2022. While November 2023 demand was similar to 2021. December 2023 demand was higher than both 2021 and 2022. It was also higher than demand in November 2023.

Figure 1: New Zealand daily demand compared to historical average, October to December 2023[1]



[1] Historic demand is compared to current demand by week and weekday.

Figure 2: Monthly total demand, October to December 2021-23



4. Wholesale electricity price and composition

Figure 3 shows the half hourly and daily national wholesale electricity spot prices between October and December 2023. Also shown are the historic daily average prices adjusted for inflation (1997-2022).

The half hourly Q4 2023 spot prices continued to be volatile, as seen in Q3 2023. The majority of prices this quarter were between $100/MWh and $200/MWh, with prices increasing in mid-December as hydro storage dropped and output from thermal generation increased.

This quarter saw fewer prices over $500/MWh compared to the last quarter, and more instances of near zero spot prices. Prices generally spiked over $300/MWh when wind generation was low, or was below forecast, and during peak demand periods. Near zero prices typically occurred when demand was low and wind generation was high.

The maximum half-hourly average price for the quarter was $601/MWh on the morning of Wednesday 1 November. Low wind generation saw two Rankine units required, in addition to multiple peaking units, including Whirinaki.

Figure 4 shows the weekly price distributions between October and December 2023.The average wholesale spot price for Q4 2023 was $145/MWh, which is higher than the average Q3 2023 price ($124/MWh) and the Q4 2022 price ($43/MWh).

Higher than average demand in mid-December 2023, coupled with continued declining hydro storage and increased thermal generation contributed to the higher prices shown in Figure 4. Prices eased at the end of the quarter as demand decreased during the Christmas holiday period and hydro storage increased due to some heavy rainfall.

Figure 3: Half hourly, daily and daily historic average wholesale electricity prices, October to December 2023

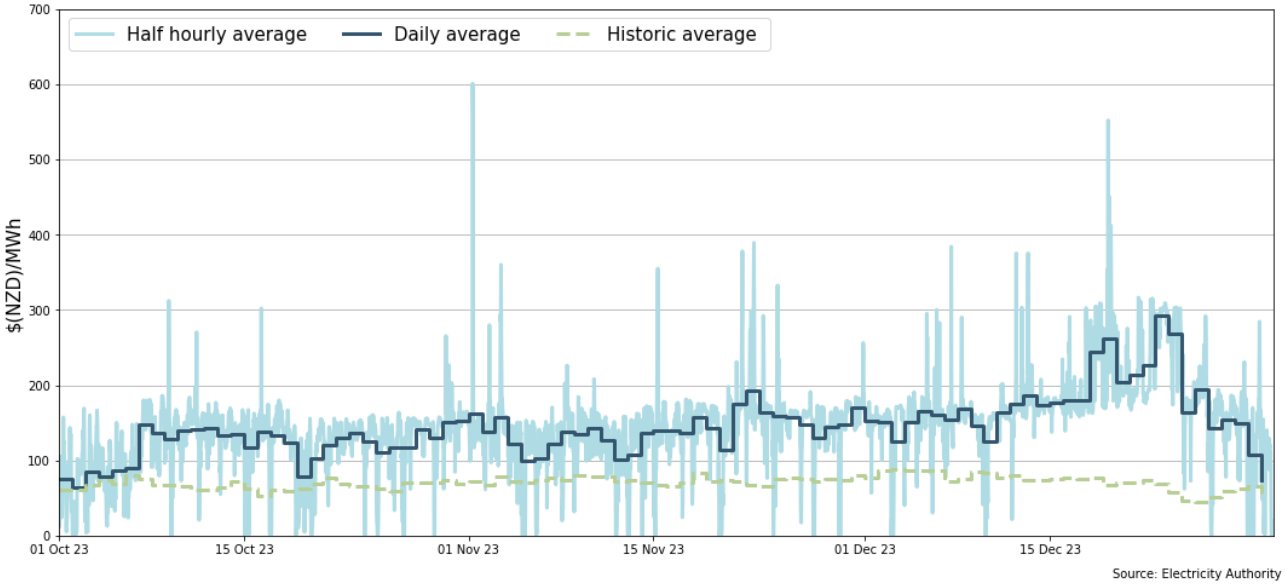
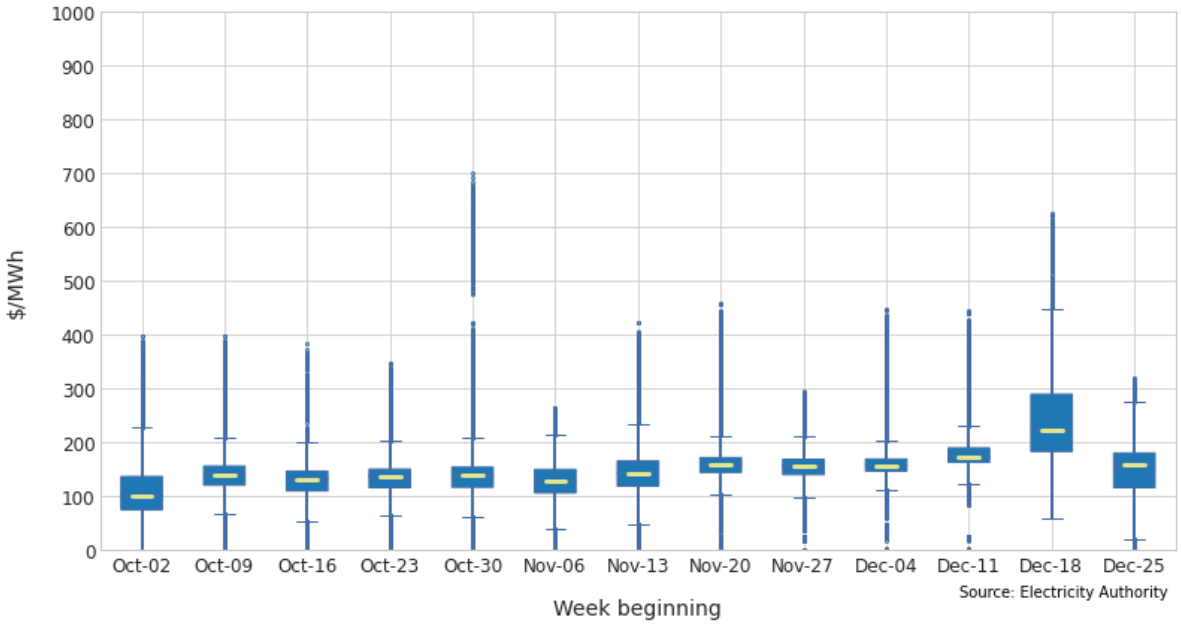


Figure 4: Box plot distributions of weekly spot prices between, October to December 2023



Generation composition influence on price

While instantaneous demand is one of the key drivers of wholesale prices, the average wholesale market price is affected by a broad range of factors. These include the source of the electricity generation, as different sources have different prices and generation characteristics.

The effects of the factors are visible at different time scales. Wind and demand have the most impact on half-hourly prices as these elements change the most quickly. Thermal generation is typically on for hours or days at a time and affects daily average prices. Hydro storage levels take days or weeks to change significantly and so affects longer-term average prices.

Figure 5 shows the daily total wind generation and the daily average national spot prices between October to November 2023. Wind generation typically has an inverse relationship with average wholesale price. Since wind generation has no fuel costs, when the wind is blowing it has no reason not to offer all its generation into the market. With these low operating costs, it can offer a lot of generation at low prices, which displaces more expensive generation.

The relationship between high wind and low wholesale electricity prices in Q4 2023 can be seen in Figure 5. For example, in mid-November 2023, an extended period of high wind kept prices below the quarterly average for most of a week. Similarly, in early October, high levels of wind generation and high hydro storage helped push the daily average price down to $64/MWh.

Figure 5: Daily wind generation and average wholesale price, October to December 2023

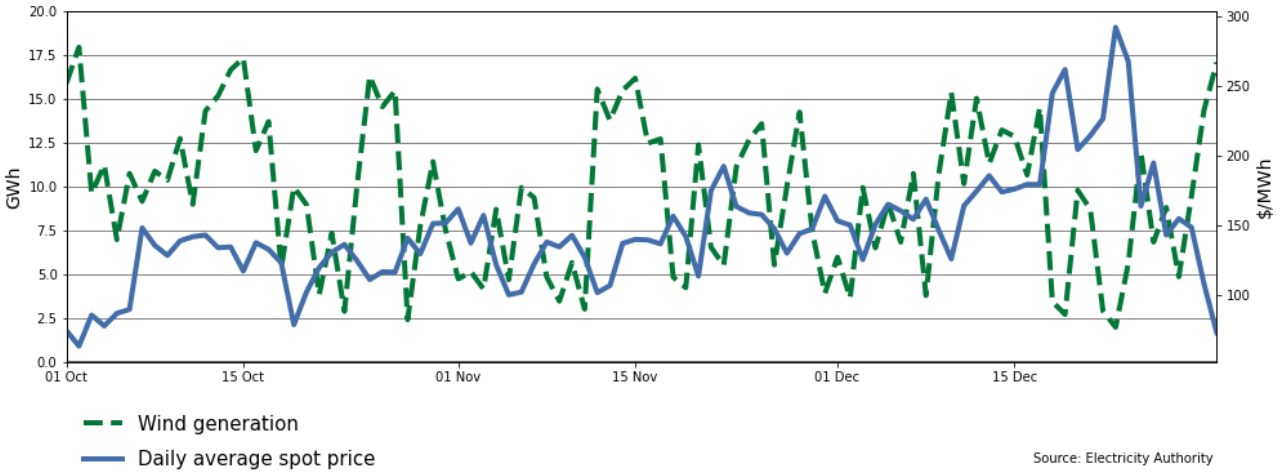


Figure 6 shows the total wind generation by month in Q4 for the past three years. Wind generation capacity has increased by 400MW in 2023, and wind generation has risen with it. Total wind generation in Q4 2021 was 723GWh; in Q4 2023 it was 967GWh.

Figure 6: Monthly wind generation in Q4, 2021-23

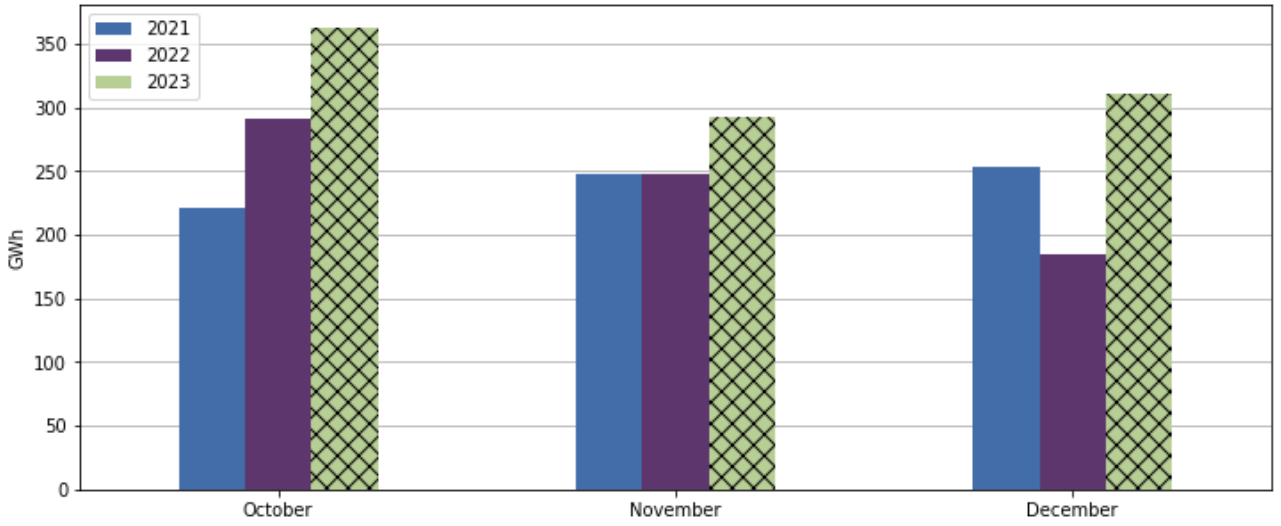


Figure 7: Top 10 largest daily average wind generation, 2021-23

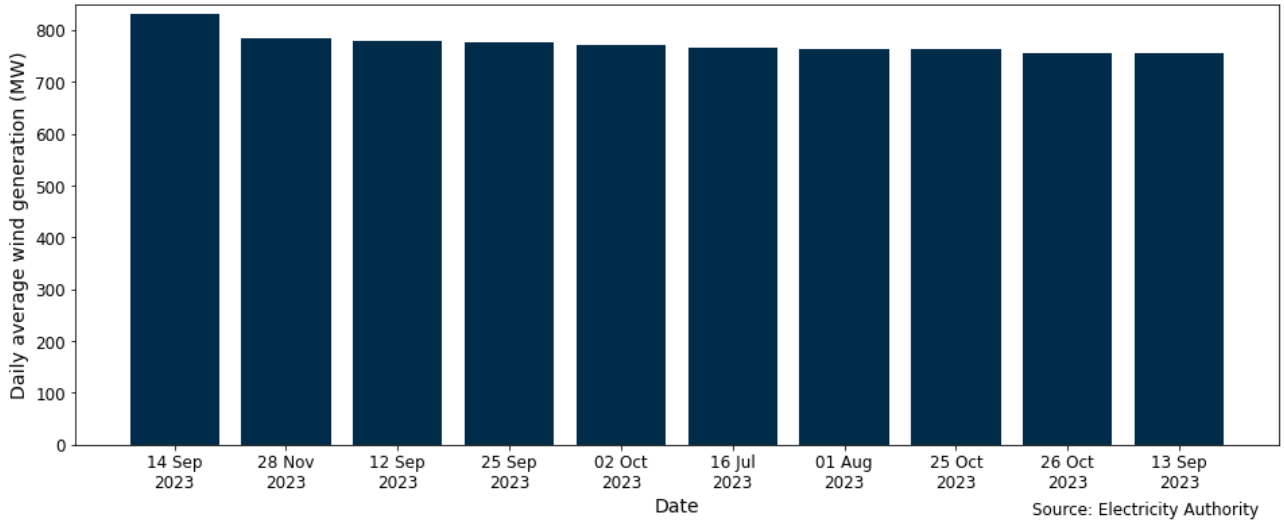


Figure 7 shows the top 10 largest daily average wind generation days between 2021 and 2023. All the days shown in Figure 7 are from 2023, with the highest daily average wind generation occurring on 14 September 2023. These occurrences in 2023 reflect the increased installed wind capacity, with 221MW added at Turitea and 43MW added at Kaiwera Downs. Sections of the 176MW Harapaki wind farm also came online in late 2023.

The amount of thermal generation required also affects wholesale prices. Thermal generation includes fuel costs and carbon prices, so it is more expensive. At times of higher demand, a thermal generator is often the marginal generator. As a result, it often sets or influences the wholesale prices.

Figure 8 shows the daily total thermal generation and daily average spot price between October to December 2023. Daily average spot prices increased in early October as TCC was turned off. Throughout October to mid-December a mix of Huntly 1, Huntly 4 and Huntly 6 ran to cover baseload, and daily average prices stayed mostly between $100-$200/MWh. Prices then increased again in mid-December as TCC was turned on again to compensate for declining hydro storage.

Figure 8: Daily total thermal generation and average wholesale price, October to December 2023

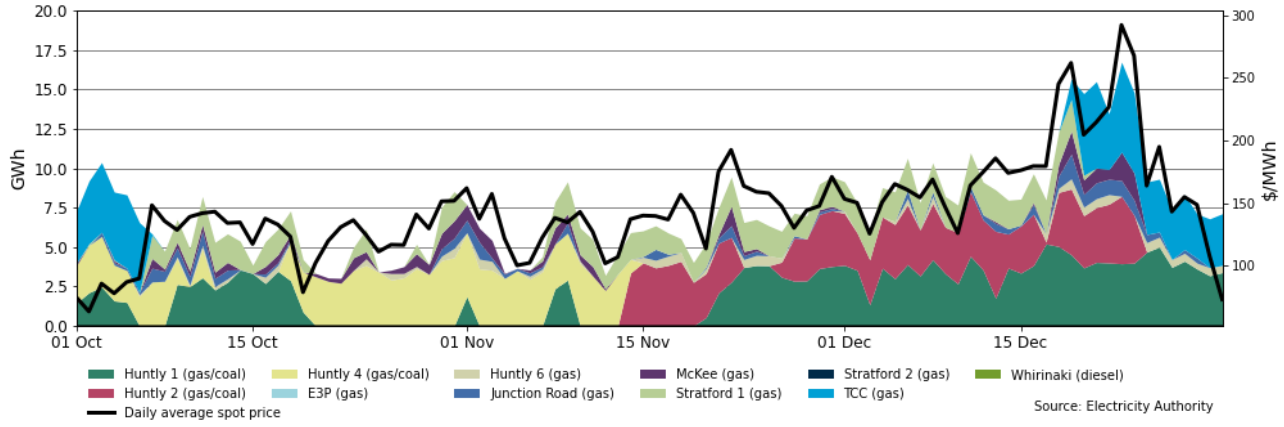
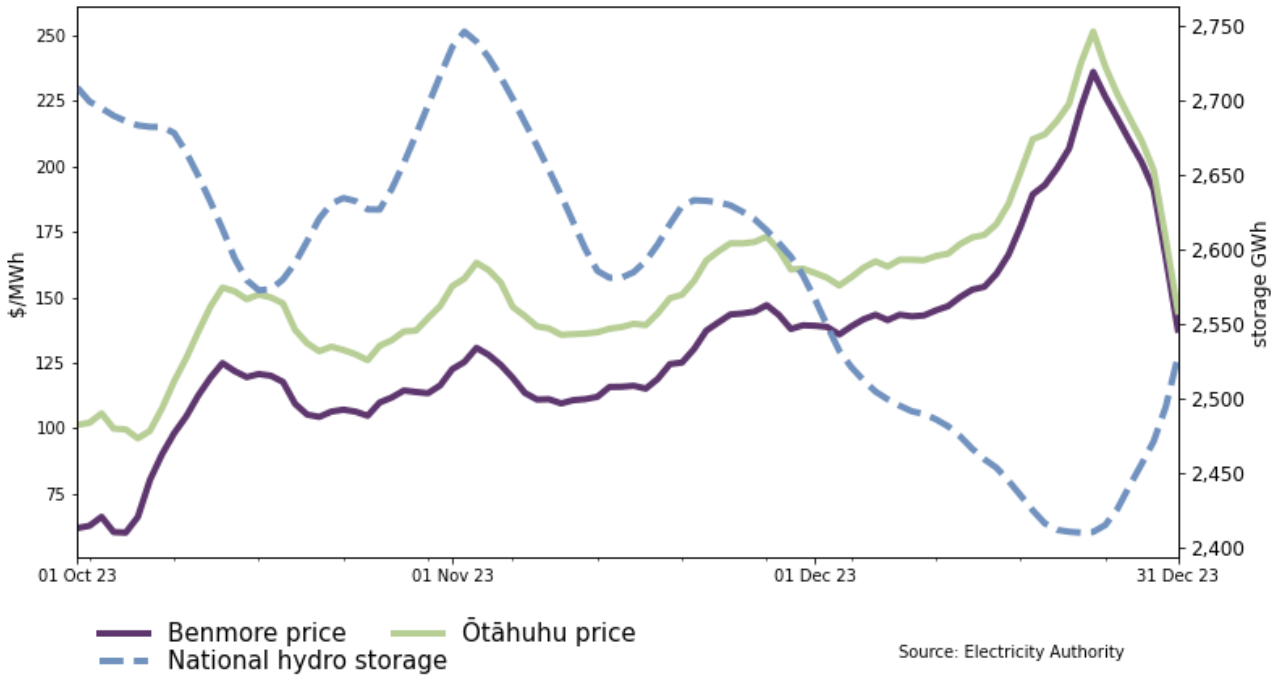


Figure 9 shows the rolling seven-day average wholesale prices at Benmore and Ōtāhuhu and the daily national hydro storage.

The amount of hydro energy in storage is the final element that affects wholesale electricity prices. High amounts of hydro storage keep prices lower, while low storage levels typically correlate with higher prices. This is not always clear on a day-to-day basis, but is easier to see over a rolling average, as in Figure 9.

Figure 9 shows that hydro storage levels decreased overall in Q4 2023, but began to increase in late December, bringing average wholesale prices back down. Prices increased in early November despite hydro storage increasing significantly at the same time, due to low wind requiring the use of multiple thermal units.

Figure 9: Rolling seven-day average of wholesale price versus hydro storage, October to December 2023



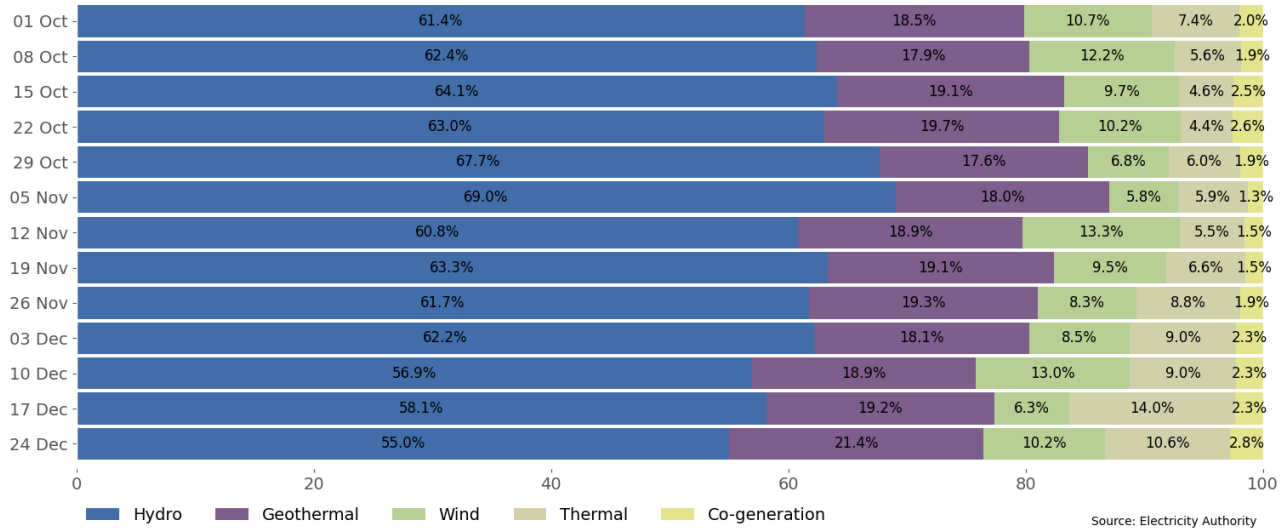
Generation by fuel type

Overall share of thermal supply decreased compared to the previous quarter, dropping from an average of 14.4% in Q3 2023 to 7.5% in Q4 2023. This was still significantly higher than thermal share in Q4 2022, which averaged just 2.5%. Thermal generation peaked for the quarter in mid-December.

The declining levels of hydro supply are evident in the shrinking share of hydro generation shown in Figure 10, dropping from 69% to 55% over the last half of the quarter. Overall, the average share of hydro generation was 62%, up from 58% in Q3.

Average wind generation this quarter was 9.6%, an increase from both the previous quarter and the same quarter last year. Wind generation made up 7.2% of total generation in Q4 2022 and 8.2% in Q3 2023.

Figure 10: Weekly generation share by fuel type, October to December 2023



5. Water storage levels

National hydro storage levels

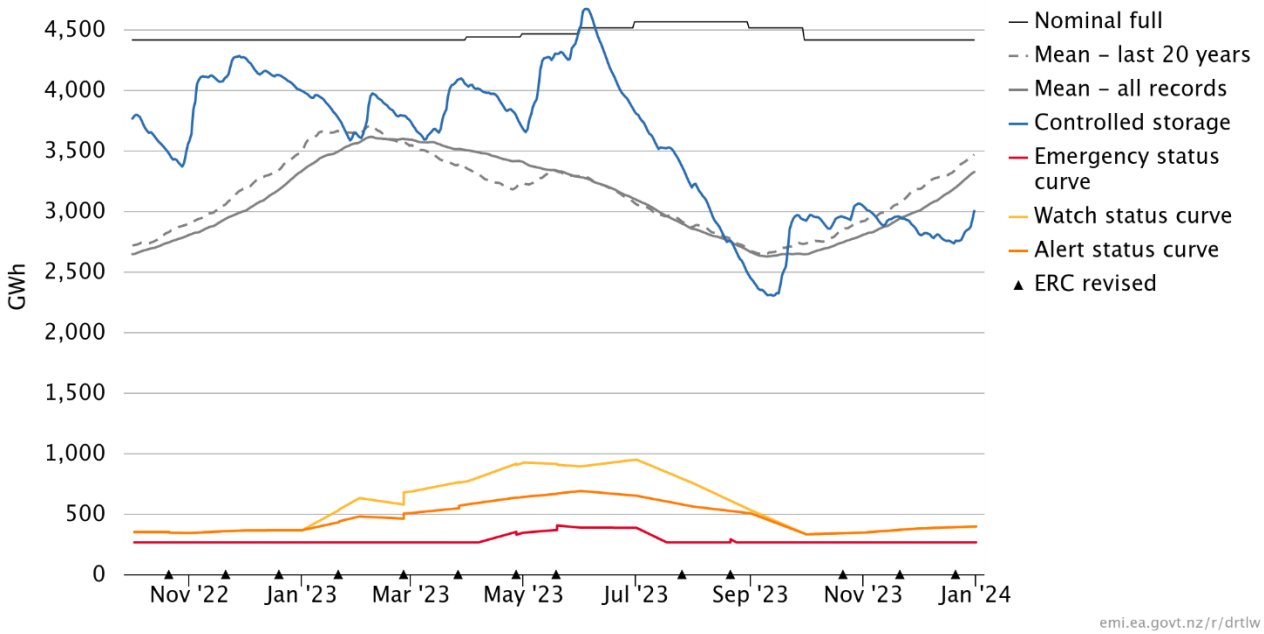
Figure 11 shows the national hydro storage levels from October 2022 to December 2023.

Hydro storage declined across most of Q4 2023 due to below average inflows. Inflows increased in late October and again in late December 2023.

Quarter 4 2023 started with hydro storage at 2,700GWh and dropped to a minimum of 2,400GWh on 23 December, before lifting to 2,500GWh by the end of the quarter. This was 1,133GWh lower than Q4 last year.

El Niño conditions were confirmed for New Zealand during the quarter. El Niño usually results in high hydro inflows, but can sometimes cause dry summers with below average inflows, as seen this quarter.

Figure 11: National hydro storage levels, October 2022 to December 2023



Lake storage levels

Error! Reference source not found. shows individual lake levels in Q4 2023 and the difference location can have on hydro inflows. Inflows to the southernmost lakes began to decline in November, resulting in below historic average storage levels for most of the quarter.

Levels at Taupō were close to the historic average for most of the quarter, before rapidly rising in late December.

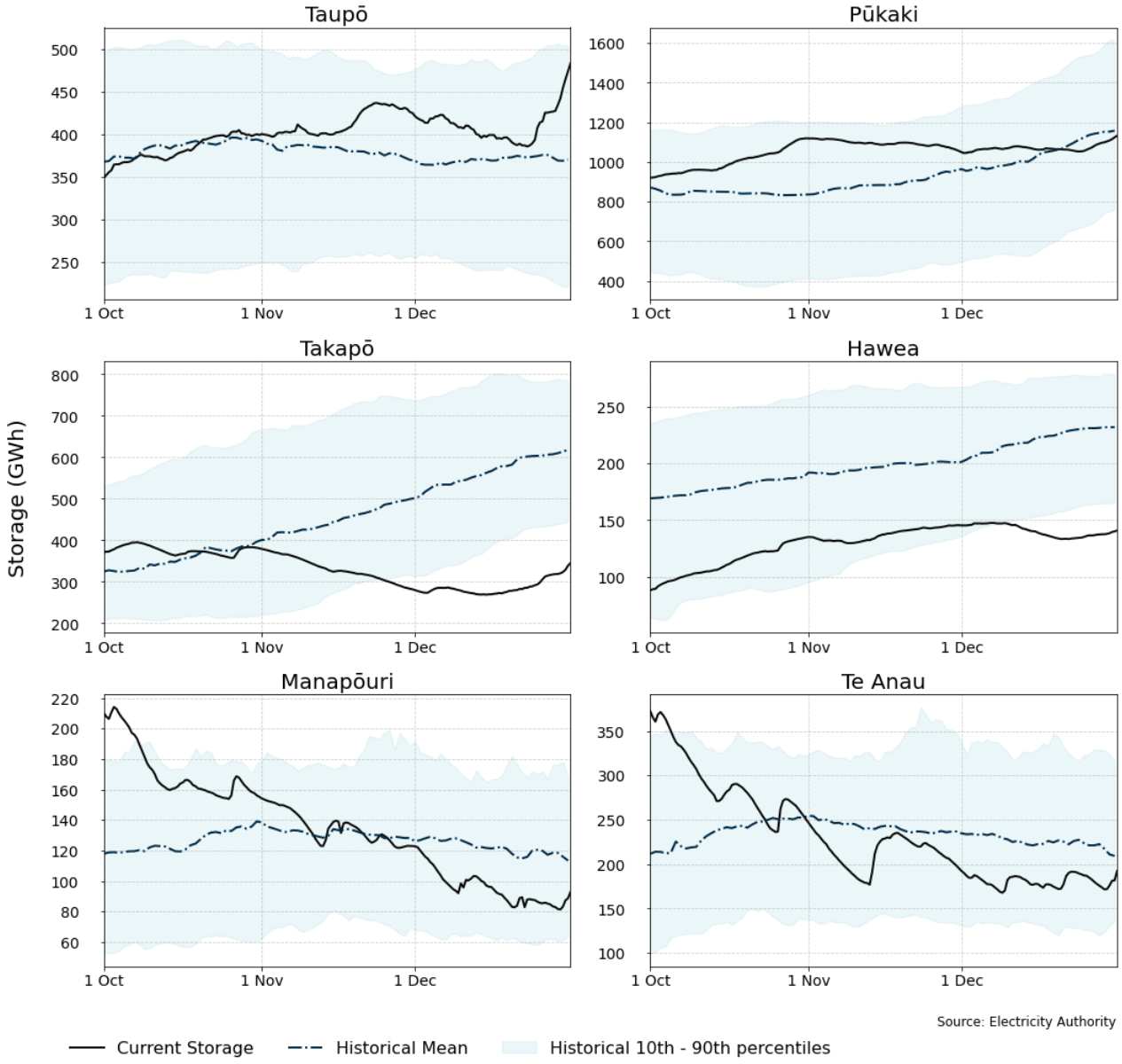
The storage level at Pūkaki was above average but below the 90th percentile until mid-December, from which point it remained close to the historic mean.

By mid-December, levels at Takapō had declined from slightly above average to below the 10th percentile. Storage then began to increase but remained below the 10th percentile.

For the southernmost lakes, Manapōuri and Te Anau, storage levels declined from above the 90th percentile to below mean by mid-November. Both lakes continued to decline in December, with a small uptick in late December.

Storage levels at Hawea increased throughout the quarter, in line with historical trends, but were below average and dropped below the 10th percentile in late December.

Figure 12: Lake storage levels for October to December 2023 vs historical average and 10th and 90th percentiles



6. Wholesale gas prices, production and consumption

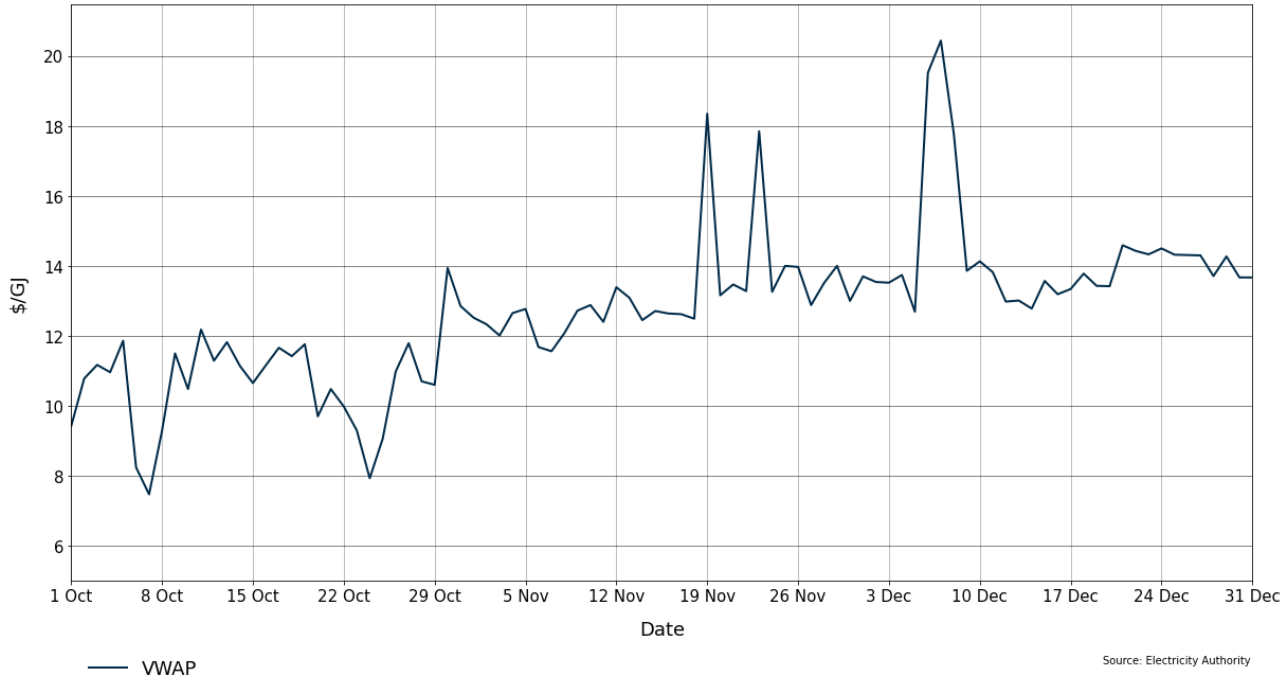
Gas prices

Figure 13 shows the daily volume-weighted average gas price for October to December 2023.

The volume-weighted average price (VWAP) for gas in Q4 2023 was $12.71/GJ. This is an increase of around $2.55/GJ on the previous quarter and similar to prices in Q4 2022. VWAP prices peaked on 7 December 2023, as the Kupe field outage ended and gas consumption by the Huntly powerplant increased.

Across the quarter, global gas prices eased downwards. New Zealand gas isn't traded in a global market and prices followed the opposite trajectory due to increased demand, especially by electricity producers later on in the quarter.

Figure 13: Daily volume-weighted average price for gas, October to December 2023



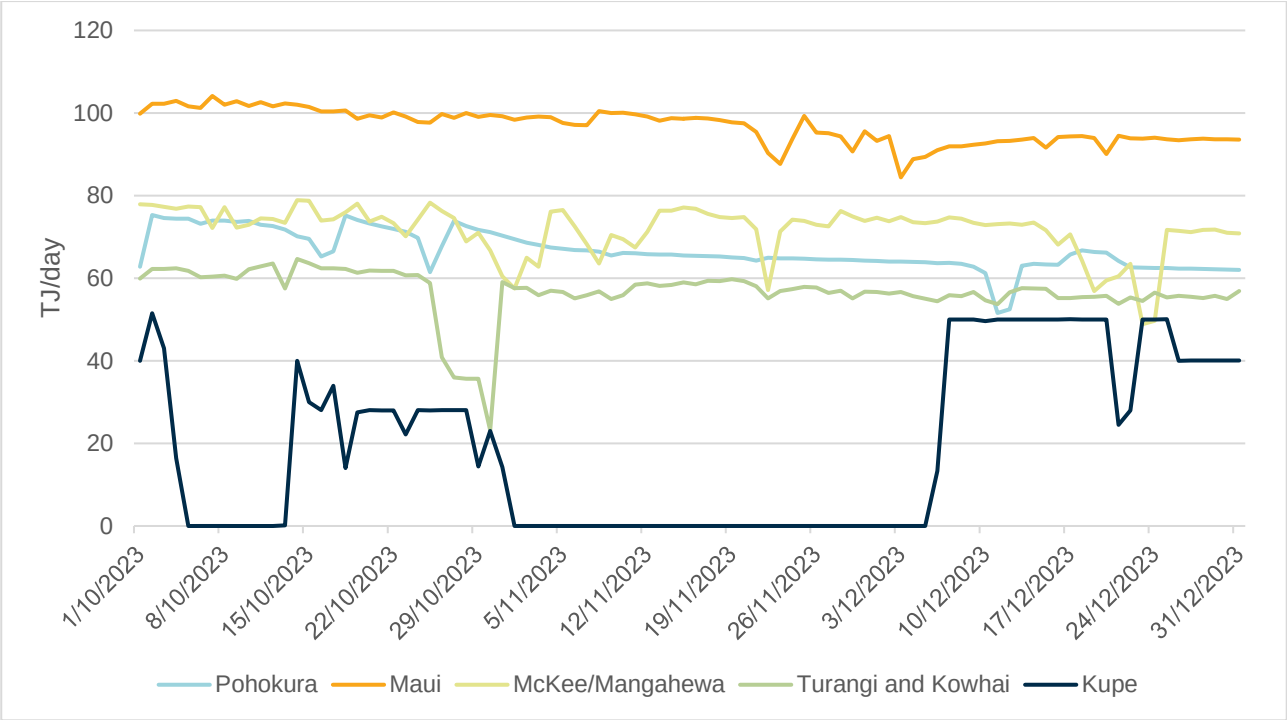
Gas production

Figure 14 shows daily gas production at major fields between October to December 2023.

In Quarter 4 2023, total gas production decreased gradually, starting the quarter at 334TJ/day (based on typical output in the first week of October) and finishing at 323TJ/day. Production at Māui, McKee/Mangahewa and Turangi, Pohokura and Kōwhai all decreased over the quarter.

Planned outages occurred at Kupe from 1 November to 5 December and Turangi and Kōwhai from 25 to 31 October. These outages further reduced the total gas production output during the quarter.

Figure 14: New Zealand gas production, October to November 2023 from gas production and consumption – Gas Industry



Gas consumption

Figure 15 shows the daily gas consumption by major users between October to December 2023. Gas generation in Q4 2023 decreased compared to the previous quarter, as electricity demand was lower. Methanex Motunui was responsible for most of quarter's consumption, with other consumption by other major consumers generally remaining below 60TJ/day.

Gas generation at Huntly increased from early December, correlating with the Kupe field returning from outage, and subsequent increasing wholesale gas and electricity spot prices. In mid-December TCC gas consumption returned while Stratford peaker consumption stopped.

Figure 16 shows the estimated daily total energy consumption across all Huntly units between January and December 2023. There was a decrease in Huntly fuel consumption compared to the previous quarter, with decreasing load as winter ended reducing the Rankine running from three to two. Consumption for the quarter remained low until December, when declining hydro storage led to increased thermal generation. The increased generation in December was initially fuelled mostly by coal, before a rapid shift to the use of gas. This change in fuel usage coincided with the end of the planned outage at Kupe, so the initial dependence on coal was likely due to limited availability of gas.

Figure 15: New Zealand gas consumption by major consumers, October to December 2023 from Gas production and consumption – Gas Industry

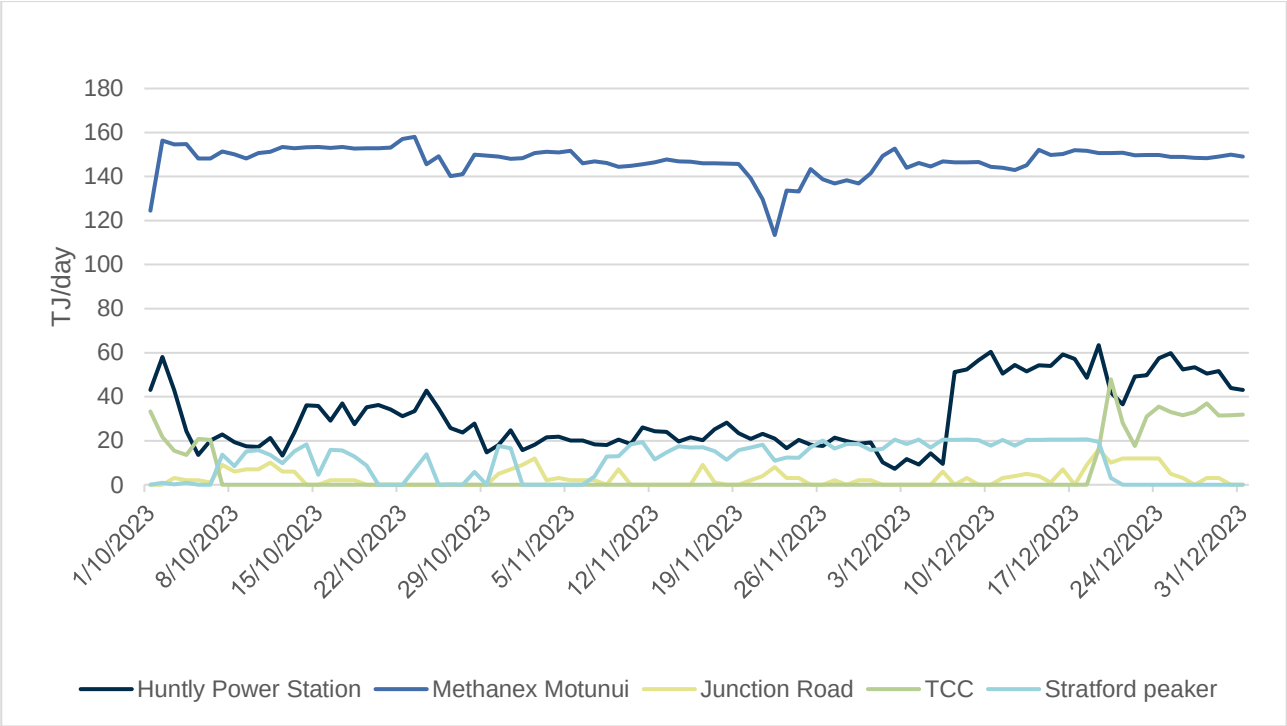
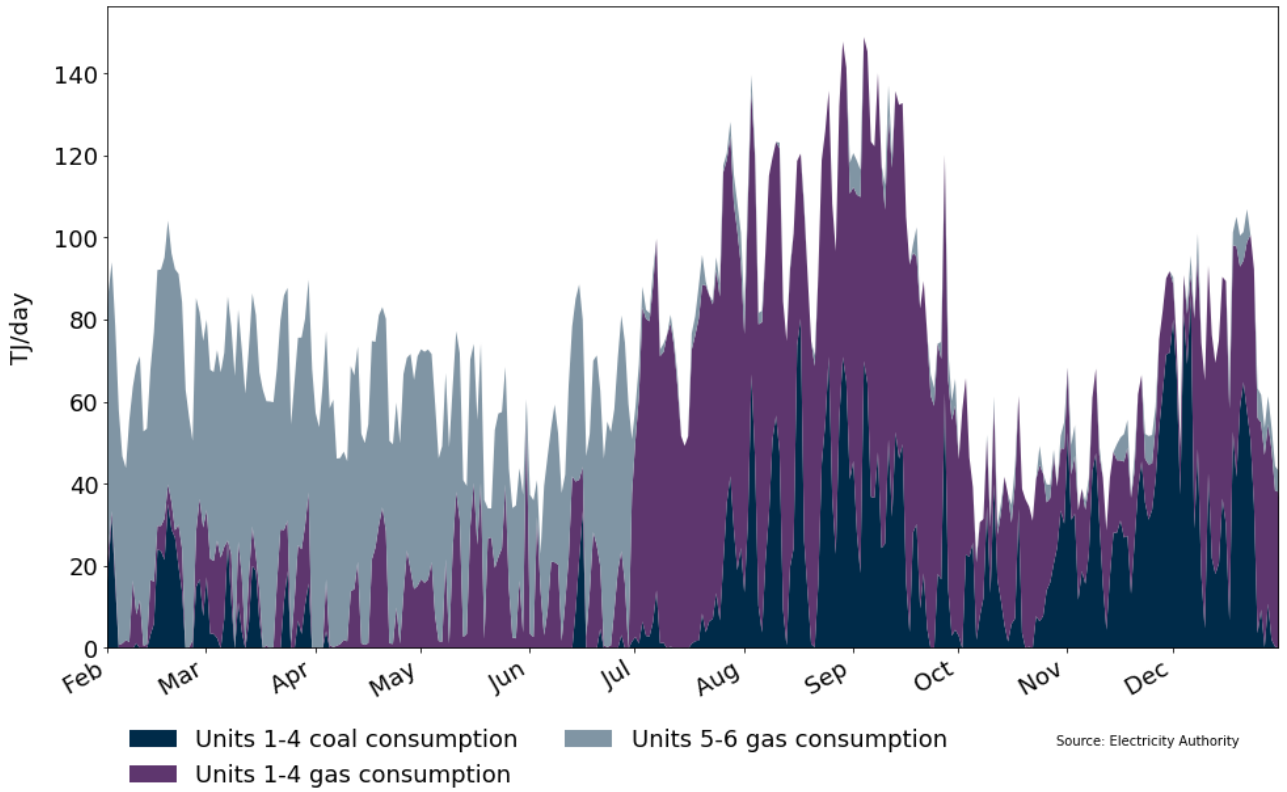


Figure 16: Estimated Huntly fuel consumption, 28 January to 31 December 2023



7. Retail electricity

Retailer switching

Figure 17 shows the 20 retailers who either gained or lost the most electricity connections (ICPs) between October and December 2023.

Genesis Energy and Meridian Energy experienced the greatest net gain in ICPs, at 6,956 and 5,571 respectively. Flick Electric continued to gain market share for the third quarter in a row, with a net gain of 1,474 IPCs this quarter.

After purchasing Trustpower in May 2023, Mercury Energy transitioned all Trustpower customers to Mercury by the end of Q2 2023. Mercury have experienced net ICP losses since this switch, which is likely due to former Trustpower customers seeking a new retailer. However, Mercury's net losses have decreased from the last quarter, at 6,869 ICP losses compared to 7,450 in Q3 2023.

Manawa Energy, which only provides energy to commercial customers, also lost ICPs this quarter.

Figure 17: Top 20 movements in ICP net switching by retailer, October to November 2023

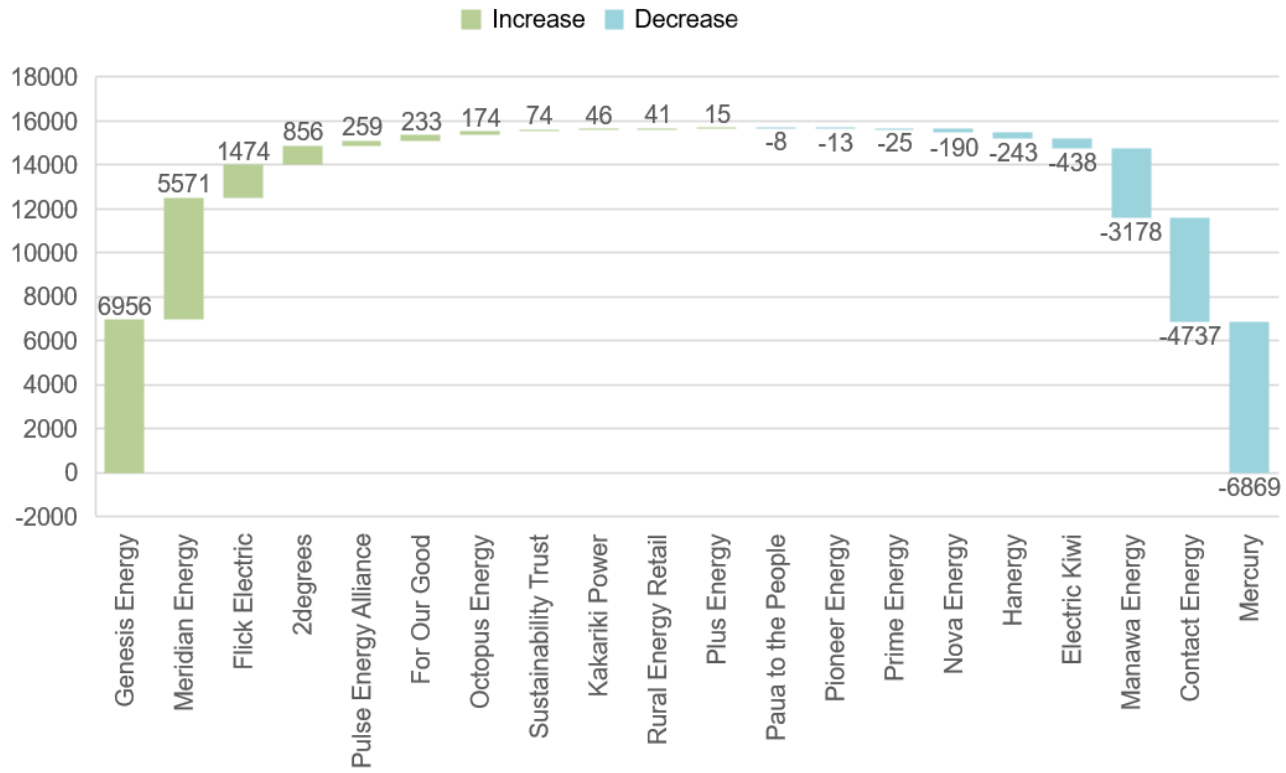
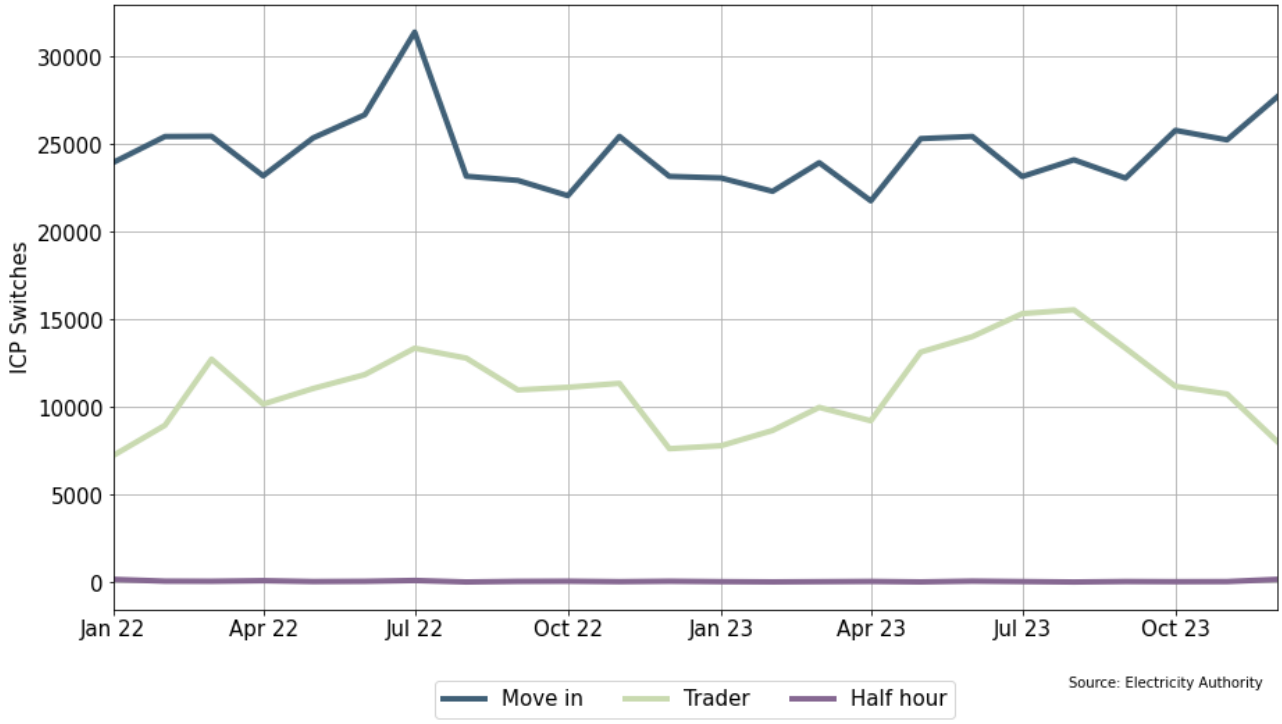


Figure 18 shows the number of ICPs that have changed electricity suppliers from 1 January 2022 and 31 December 2023 categorised by type 'move in', 'trader' or 'half hour'. Move in switches are switches where the customer does not have an electricity provider contract with a trader. In contrast, trader switches are switches where the customer does have an existing contract with a trader, and the customer obtains a new contract with a different trader.

Move-in consumer switching rates increased over Q4 2023, while trader switching rates decreased. Trader switches were roughly the same as Q4 in 2022, with switches decreasing each month between October and December. Move-in switches, however, increased over the quarter, unlike Q4 2022, with the highest annual level of move-in switches occurring in December 2023. This may be due to the increase in housing sales after the 2023 election.

Figure 18: Breakdown of monthly ICP switching by type, January 2022 to December 2023



Retail prices

Figure 19 shows the domestic electricity price by component (QSDEP) adjusted for inflation from 2004-23. Based on the trends in Figure 19, energy retail prices tracked below the rate of inflation. Changes in prices were driven by the line charges as adjusted for inflation, which continued to decline. After adjusting for inflation, costs for electricity declined marginally from the 2020 peak.

Figure 19: Domestic electricity prices by component adjusted for inflation (base 2023 Q4 CPI)

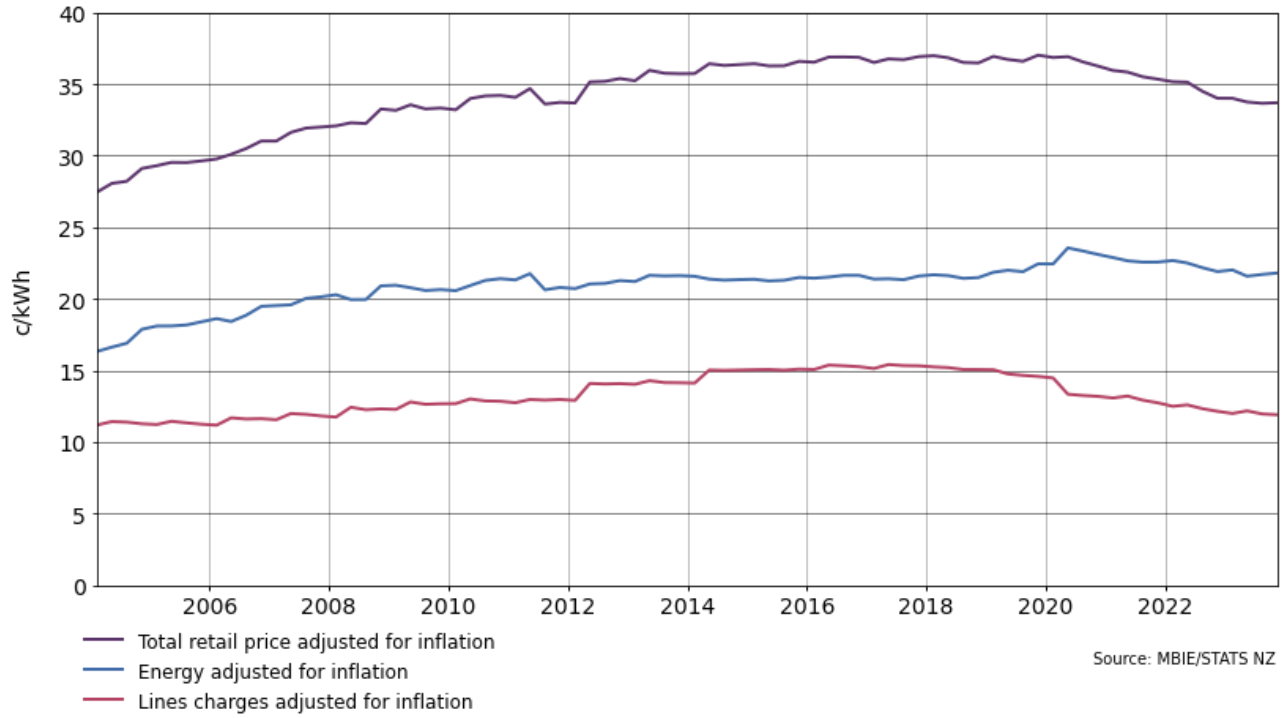
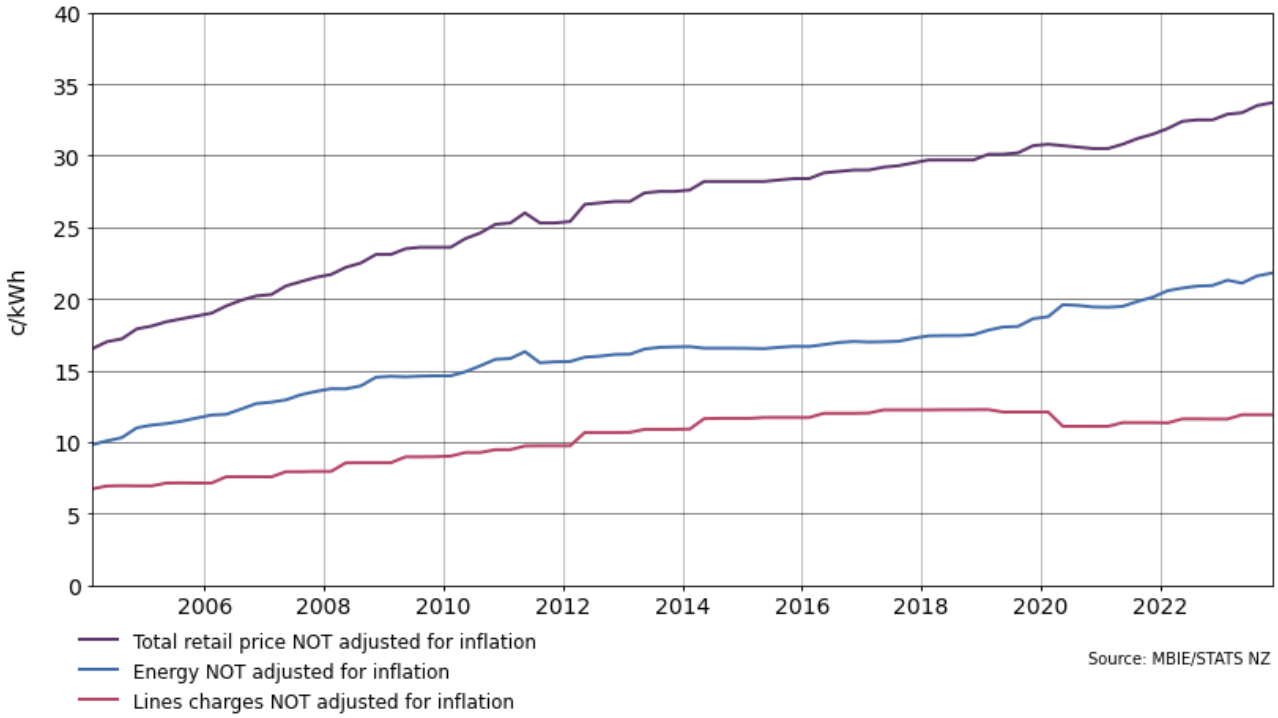


Figure 20 shows the domestic electricity prices by component without adjusting for inflation. While electricity prices are increasing at a rate below inflation (as per Figure 19), Figure 20 this makes it clear that in nominal terms, electricity prices have increased with energy costs being one of the main factors. In the last 12 months, nominal values have risen by 3.7%. For a typical household using 8,000kWh annually, this equates to an extra $96 per year on their electricity bill compared to one year ago.

Figure 20: Domestic electricity prices by component without inflation adjustment



8. Forward market and carbon pricing

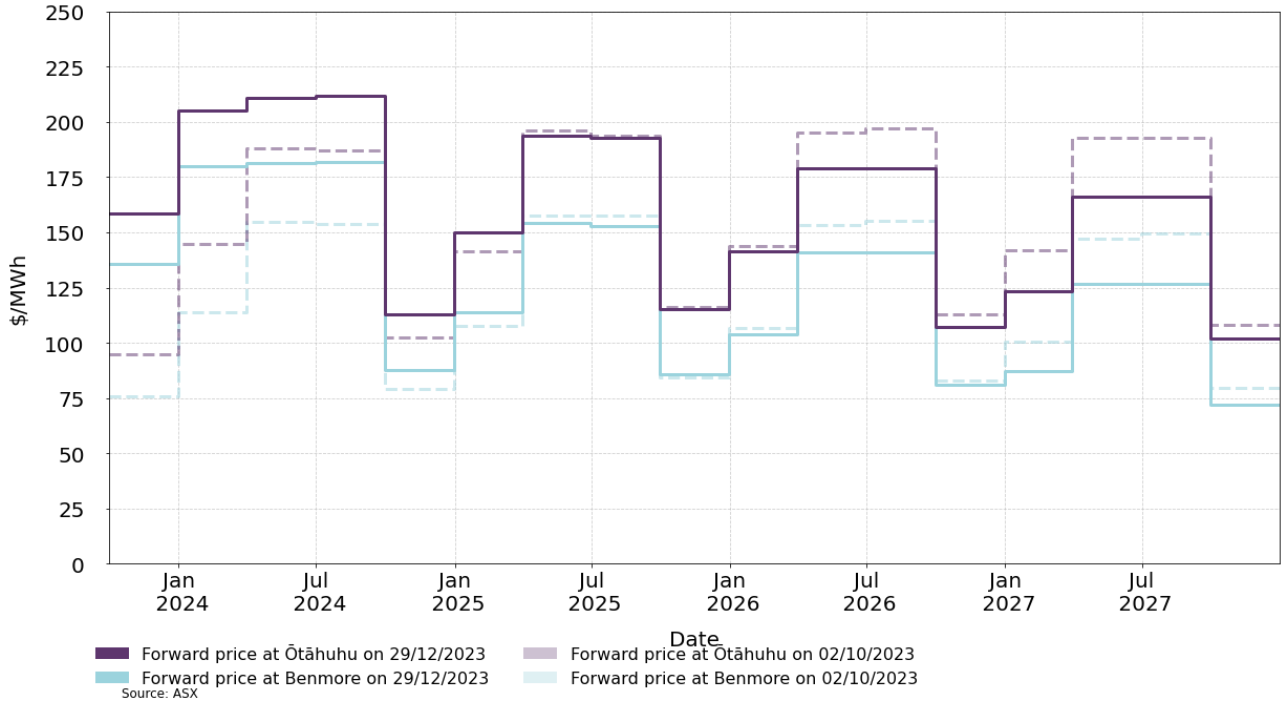
Forward pricing

Figure 21 shows the quarterly forward prices up to 2027 at the beginning of October 2023 and end of December 2023.

In Quarter 4 2023, quarterly forward prices for contracts up to April 2025 increased, and prices for all longer-term contracts decreased, as per Figure 21. Prices for the next 12 months are high, but gradually decrease over later years. This is likely to reflect the increased planned generation build now that Lake Onslow is not going ahead.

Near-term contract prices likely increased due to the declining hydro storage experienced across Q4 2023, along with uncertainty around generation availability for winter 2024. The decrease in longer term contract prices likely reflects higher proportions of renewable generation being online and thermal retirements.

Figure 21: ASX forward prices for the start and finish of Q4 2023



Carbon pricing

Figure 22: New Zealand Units price, July 2022 to December 2023

Figure 22 shows the New Zealand carbon unit price between July 2022 to December 2023 as recorded by the European Capital Markets Institute.

To try to minimise the impacts on the cost of living, the Government did not adopt the New Zealand Unit (NZU) floor prices recommended by the Climate Change Commission in 2022. Following this action, NZU prices dropped in 2023. The sharpest drops coincided with the scheduled NZU auctions, which failed to clear. Prices reached a low of $35 per unit in early July 2023.

In mid-July 2023, the High Court issued a judgment saying the Government's December 2022 action was ultra vires[2] . The Government then made changes in line with the pricing recommended by the Climate Change Commission and NZU prices began to return to previous levels. At the close of Q3 2023, prices were $66 per unit, down slightly from $73 per unit in early September (see Figure 22). The Climate Change Commission recommended prices step up gradually in coming years.

In early September 2023, the third NZU auction took place and failed to reach minimum levels. This was expected and did not cause the same sharp drop of NZU prices seen at the March and June auctions[3]. All unsold NZUs were rolled into the final auction in December 2023, which had 15 million NZUs available[4].

NZU prices increased slightly towards the December auction, but no NZUs were sold. No 2023 NZUs will roll over to 2024, and the market will reset in 2024.

[2] https://www.capitalletter.co.nz/news/climate-change-response-act-2002/142596/climate-change-lawyers-climate-action-v-minister
[3] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/090623-new-zealands-carbon-auction-fails-on-lower-bids-lifts-spot-price-slightly
[4] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/090623-new-zealands-carbon-auction-fails-on-lower-bids-lifts-spot-price-slightly

9. Structure, conduct and performance indicator analysis

This section assesses whether observed outcomes in the market are consistent with competitive outcomes. The approach used is the same as the approach used in the post implementation review of the trading conduct provisions (the post-implementation review), using the Structure-Conduct-Performance framework. The simple premise of the framework is that the structure of the market determines the conduct of its participants. The more competitive the structure, the more competitive the conduct of participants and the more efficient their performance.

The period considered is 1 July 2023 to 31 December 2023 ie, two quarters of data. The Authority will continue to include six-monthly updates of these indicators in every second quarterly review going forward.

Six key indicators are used to assess the competitive outcomes:

- The first two of these are the frequency of both very low prices and price separation, which should reflect underlying market conditions.
- Offers are also tested against supply and demand conditions; prices above $300/MWh or final price may indicate economic withholding if they cannot be related to underlying conditions.
- Finally, investigating offers in relation to known costs, including opportunity costs: the percentage of offers above cost and the relationship of storage and offers to cost.

In summary, for the period 1 July 2023 to 31 December 2023:

a) Price separation continued to reflect underlying conditions since the introduction of the trading conduct rule compared to previous years.

b) There were fewer periods of very low prices in 2023 due to underlying conditions, however the median ‘low’ price was still below $1/MWh.

c) Thermal offers were reflective of changing market conditions, where additional starts increased operating costs above short-run marginal costs. In 2023 additional less efficient Huntly Rankine units ran as baseload to cover the unplanned outage of Huntly 5.

d) While some hydro generators had a higher percentage of offers above various measures of cost, overall their offers were consistent with storage trends. We are still undertaking further analysis of one instance of higher-priced offers at Clyde and will continue to monitor all generator offers.

e) Water values were correlated with storage and hydro generator offers, as expected under competition.

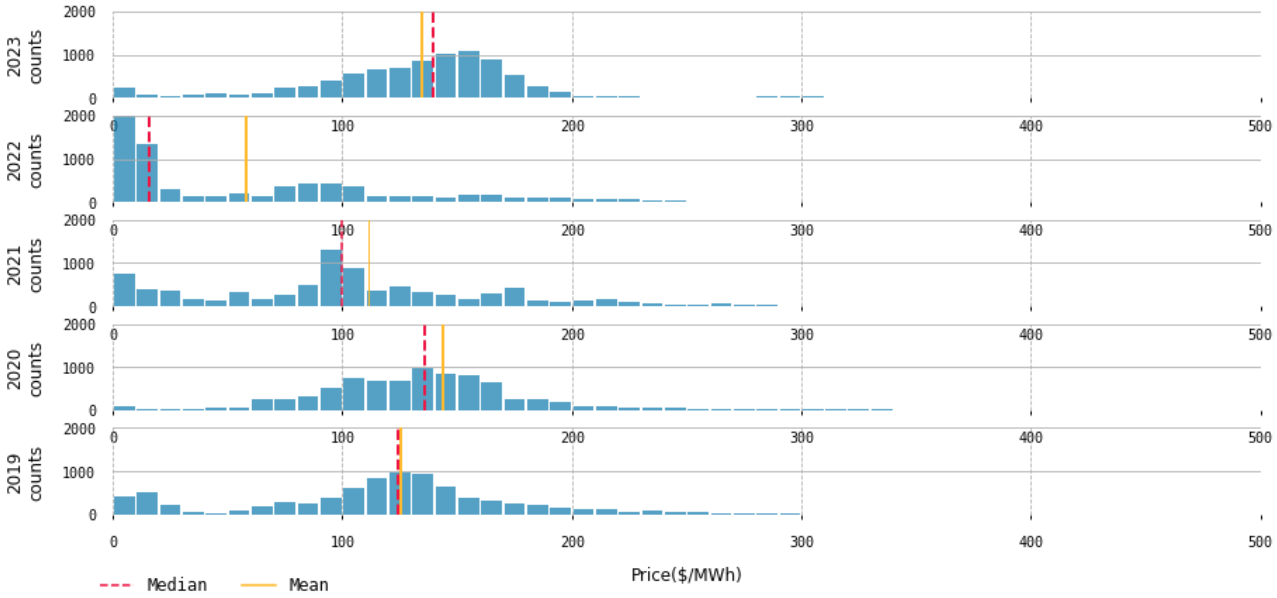
10. Very low prices

If prices are being determined in a competitive environment, we would expect very low prices in off-peak trading periods to occur more frequently than in a market where participants are exercising market power. If participants are economically withholding generation (in a manner consistent with the exercise of significant market power), very low prices would be less likely to occur. It is important to note this is an indicator only, as fewer low prices could also arise from prudent hydro storage management.

Figure 23 and Table 1 give insights into the share of very low prices in the second half of 2023. Consistently declining hydro storage between July and September, and lower than average inflows during November and December in the South Island, contributed to fewer periods of very low prices from July to December 2023. The mean and median spot price between July to December 2023 was higher when compared with the same periods from 2019-2022 (with most of these years having higher storage compared to 2023). However, there was still a large tail of prices below the

median. This meant the mean was lower than the median this year. That is, despite underlying conditions leading to higher average prices, there were still periods of low prices at times.

Figure 23: Histogram of price counts (adjusted for inflation) for the second six months of 2019-23



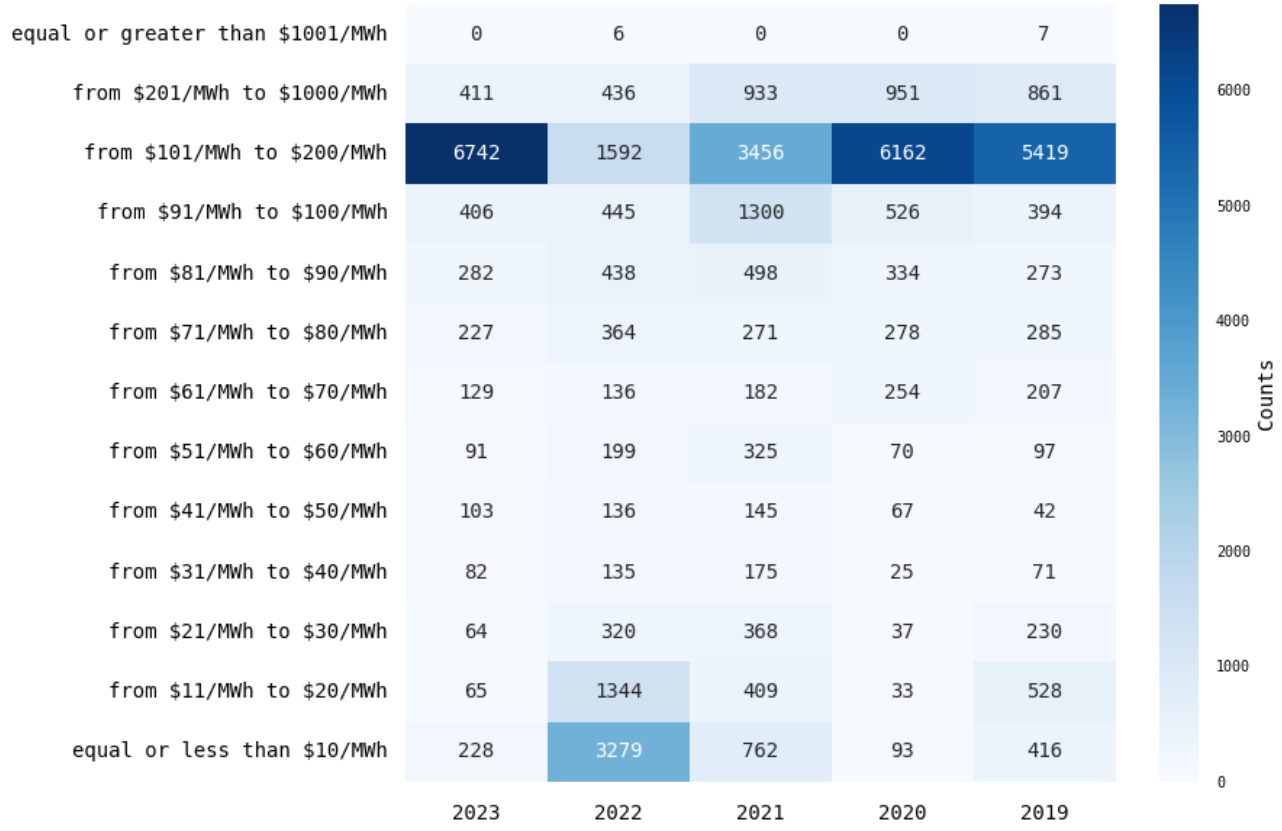
Of the very low prices in the second half of 2023, only 12% of them occurred in daytime off-peak times. This is a decrease from the same period in 2019, 2021, and 2022, but higher than in 2020. This is consistent with hydro storage levels – hydro storage was quite high in 2021 and 2022, but lower in 2023 from July to December. 2020 had even lower storage than 2023 but a lower percentage of low prices during daytime off-peak times. The median of 'very low' prices in 2023 increased from the same period in 2022 and 2021 (again consistent with differing hydro storage levels) but remains below $1/MWh and below the median from 2019.

Table 1: Very low prices, 1 July to 31 December 2023

Year	Share of very low prices occurring during daytime off-peak times (9am – 4:30pm)	Median price of all very low prices (all trading periods)
2023	12.3%	$0.84/MWh
2022	28.3%	$0.41/MWh
2021	19.8%	$0.22/MWh
2020	2.2%	$0.04/MWh
2019	21.9%	$5.80/MWh

When looking at the distribution of prices across the first half of the year for the last 5 years, **Error! Reference source not found.** shows that the July to December 2023 period was dominated by prices between $101-$200/MWh. This period in 2023 saw far fewer prices below $10/MWh than the same period in 2022, 2021 and 2019. As discussed above, this reflects the differing hydro storage levels in each year, with storage quite high in this period in 2022 and 2021 but lower in 2023. 2020 had even lower storage over these months (below mean until late October), reflected by an even lower number of trading periods with prices below $10/MWh compared to 2023. 2019 had storage levels of around mean until November and December when there was a large rainfall event with spilling in the South Island. Prices were adjusted (downwards) in this period after an Undesirable Trading Situation was found.

Figure 24: Heat map of price distribution (adjusted for inflation), July to December 2019-23



11. Price separation

If prices are being determined in a competitive environment, we would expect price separation to occur more frequently. In the past, price separation has been avoided by generators by reducing the volume of low priced generation—economic withholding. This type of offering would not be consistent with the new provisions.

An indication of economic withholding (consistent with the exercise of significant market power) would be subdued price separation. Subdued price separation can also result from hydro generators trying to conserve water in periods of low hydro storage or for other reasons. Large price differences, or price separation, indicate where transmission is constrained. These prices are important investment signals. When large amounts of South Island generation are exported north, transmission could become constrained. This should lead to lower prices in the South Island than in the North Island.

The mean ratio of Haywards to Benmore price, shown in Table 2, continues to be higher since the introduction of the trading conduct rule compared to previous years, with the ratio increasing from 12.2 in 2022 to 31.3 in 2023. However, the mean ratio of Benmore to Manapōuri is close to 1. This meant that prices tended to be similar between these nodes. This was mainly due to Meridian Energy having at least one Manapōuri unit and Contact Energy having at least one Roxburgh unit on outage over the entire six months. This means there was a lower transfer of electricity northwards, which in turn means transmission constraints were less likely to bind and prices to separate.

Between Haywards and Benmore, the median price separation was a lot lower than the mean price separation. This is because prices often separated by roughly ~$10-30/MWh for a few trading periods per day, often around peak times. This is consistent with storage trajectories over this time being similar in the South and North Islands. The median and mean were similar for the ratio between Benmore and Manapōuri, indicating that prices were largely very similar. Both the mean and median price differences are investigated as this gives a fuller picture of what is happening.

Table 2: Price separation

Year	Ratio of Haywards to Benmore price		Ratio of Benmore to Manapōuri price	
	Mean	Median	Mean	Median
2023	31.3	1.04	1.05	1.06
2022	12.2	1.04	9.80	1.05
2021	68.7	1.06	26.91	1.08
2015-20	1.34	1.04	8.40	1.08

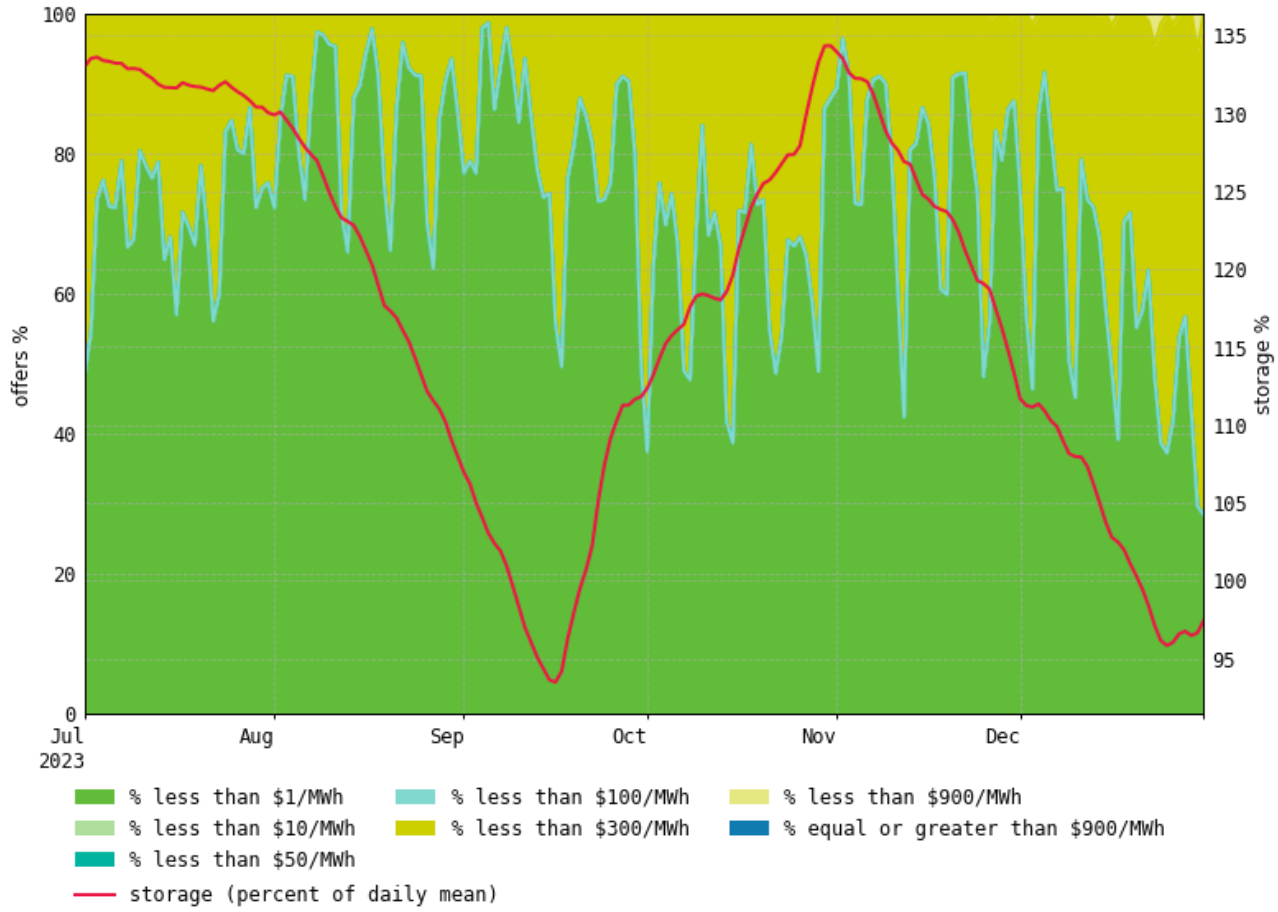
12. Percentage of offers above $300/MWh, final price and various estimates of cost

While national hydro storage overall mostly decreased between July to December 2023, the individual hydro storage lakes all had somewhat different storage patterns. However, all lakes declined between July and September. In September a large rainfall event saw storage in all catchments increase, with all lakes at some point reaching over 100% of their daily historic means. Some lakes needed to spill to manage their inflows.

Storage at lake Pūkaki decreased during the third quarter of 2023, with storage reaching a low in mid-September. Strong inflows from both rain and melting snow saw storage increase until late October, after which it steadily decreased again.

Meridian Energy kept most of its offers for its Waikati chain priced either between $0-1/MWh (green) or between $100-300/MWh (yellow), with a small amount priced between $50-$100/MWh (blue). Meridian retained a large proportion of low-priced offers as storage started declining over August, probably due to Manapōuri outages and the expectation of higher inflows during spring, but reduced these lower-priced offers in October. This coincided with increasing storage at Pūkaki but also after a large increase in storage at Manapōuri, which resulted in spilling. Meridian may therefore have been prioritising generation from Manapōuri (with 100% of offers at that time below $1/MWh at Manapōuri) and therefore slightly reducing generation from their Waitaki chain. Meridian increased the proportion of low-priced offers on the Waitaki at the end of November. As storage declined from early November the proportion of low-priced offers also declined. Expectations of El Niño conditions became stronger over this time but uncertainty remained about what inflows might eventuate under El Niño with higher sea temperatures.

Figure 25: Offers vs available storage for Meridian Waitaki, July to December 2023



Storage at Manapōuri increased sharply twice in the period between July to December 2023, once in July and then again in September. Otherwise, storage mostly decreased. However, storage remained over 80% of the daily historic mean as unit outages reduced the draw down rates of the lake, except for in late December. Offers at Manapōuri remained mostly below $1/MWh for most of the period, with only some offers between $100-$300/MWh which occurred when Manapōuri storage reached its lowest points of the period in July, September and December 2023.

Figure 26: Offers vs available storage for Meridian Manapōuri, July to December 2023

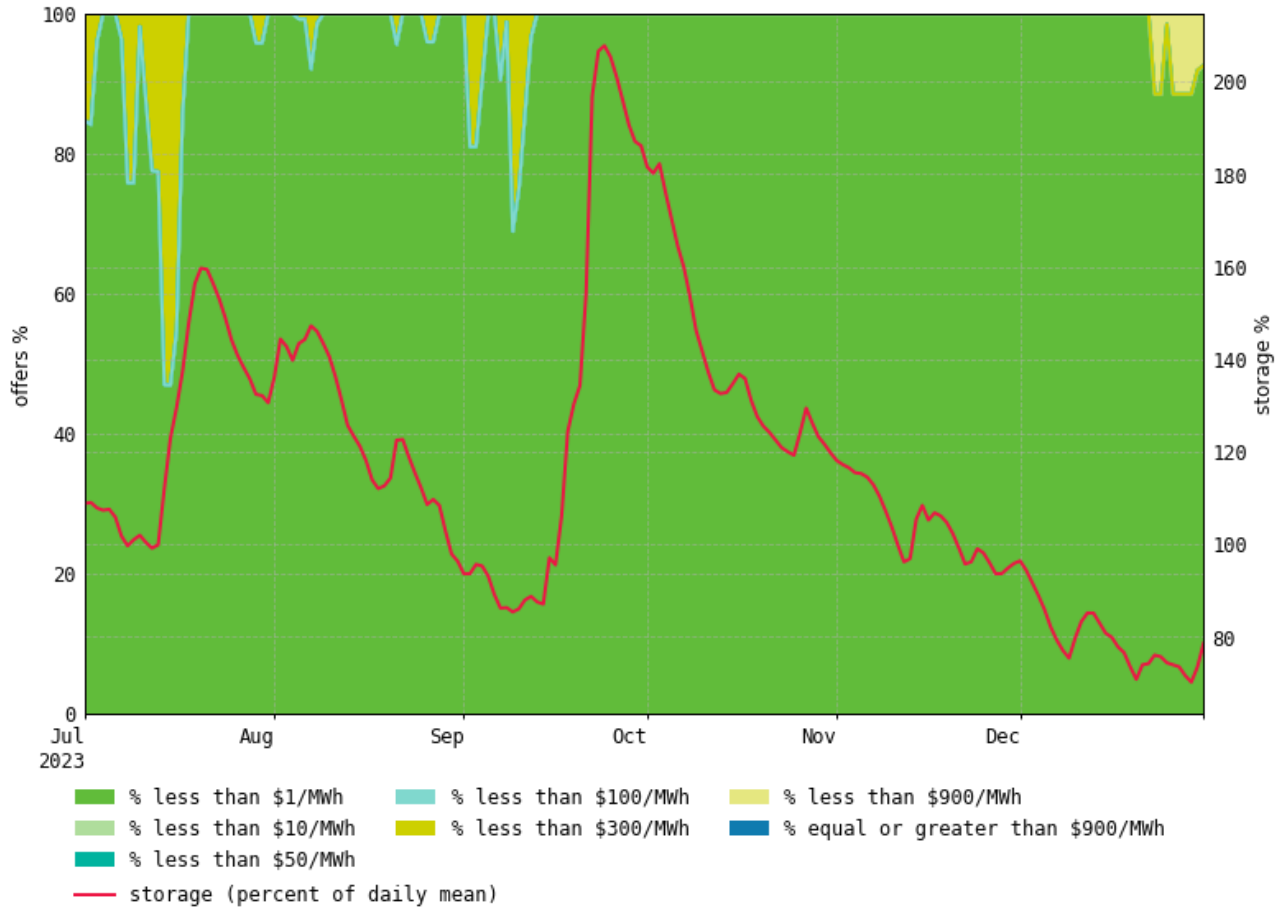
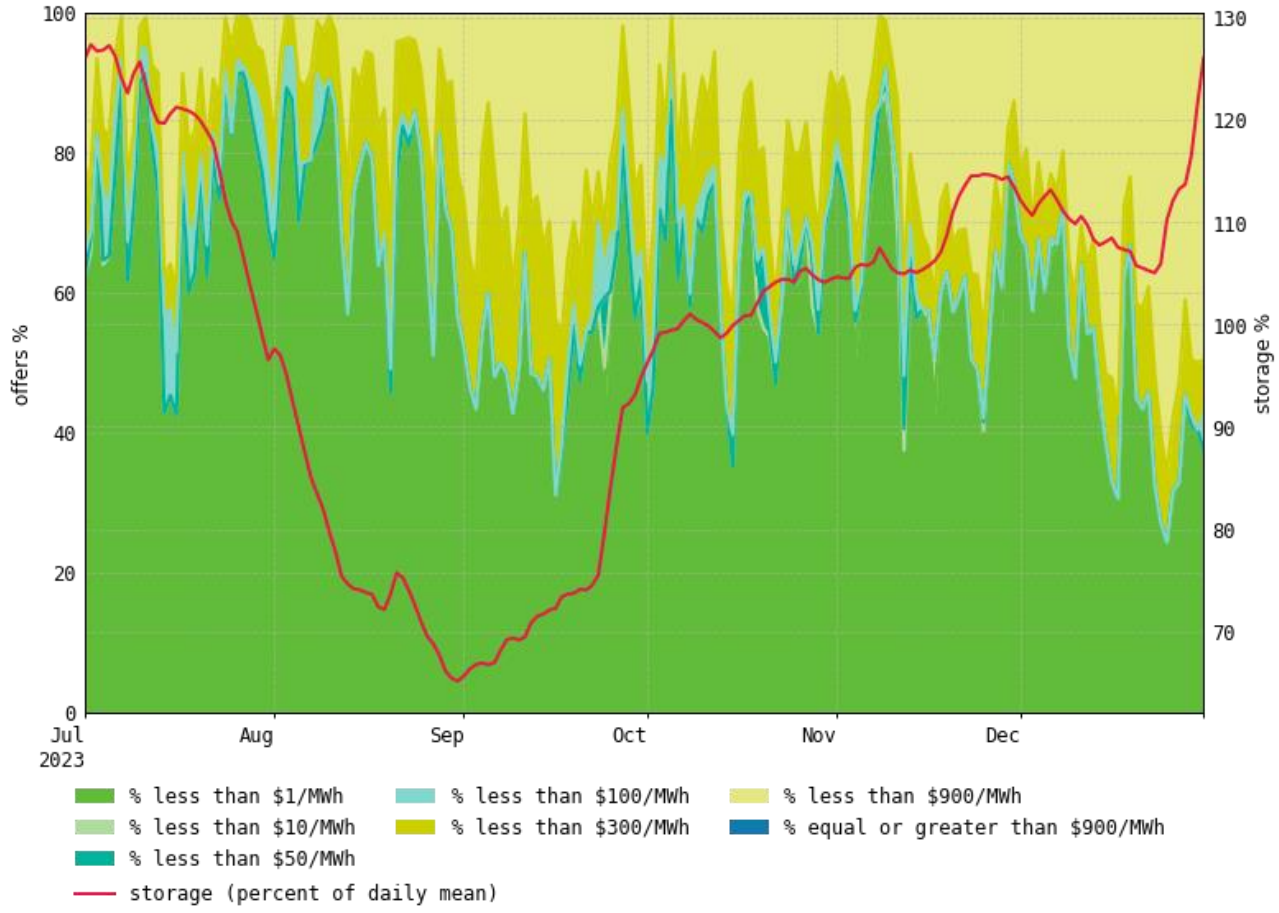


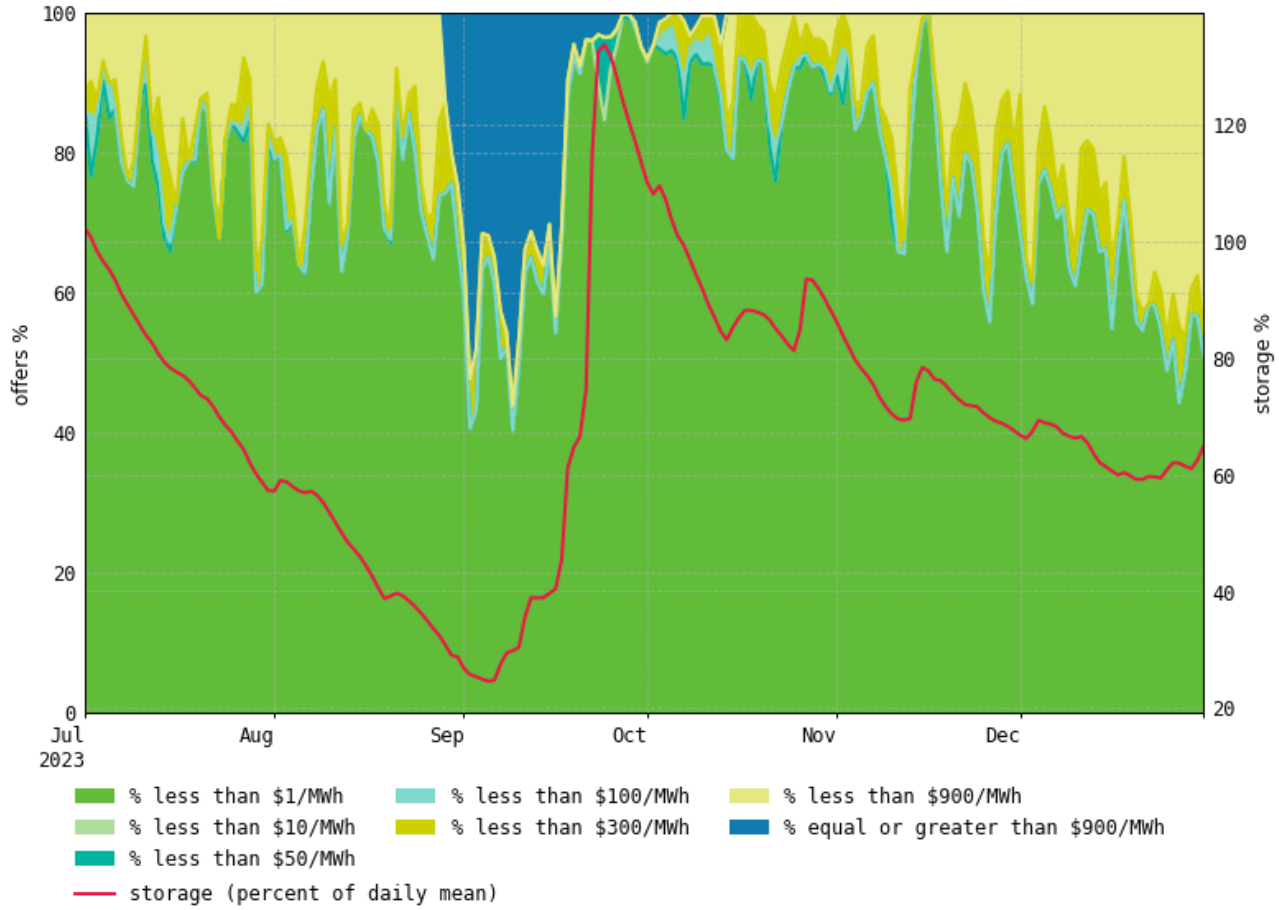
Figure 27: Offers vs storage for Mercury Waikato for July to December 2023



The Waikato has less ability to store water than the Takapō and Waitaki scheme, because it is essentially a run-of-river scheme. This means Mercury Energy needs to manage flows through their system so that the water is in head ponds when it is needed. This gives them less flexibility to change offers with changing Taupō storage levels. However, from July to December 2023 the general trend in offer prices appears to follow storage trends.

Storage at Taupō decreased sharply between late July and late August, reducing from ~135% of average to ~65%. Offer prices increased during this period in line with this decreasing storage. Storage then increased sharply in late September, with a corresponding increase in low-priced offers. Storage then generally decreased until late December with offer prices generally increasing over this time.

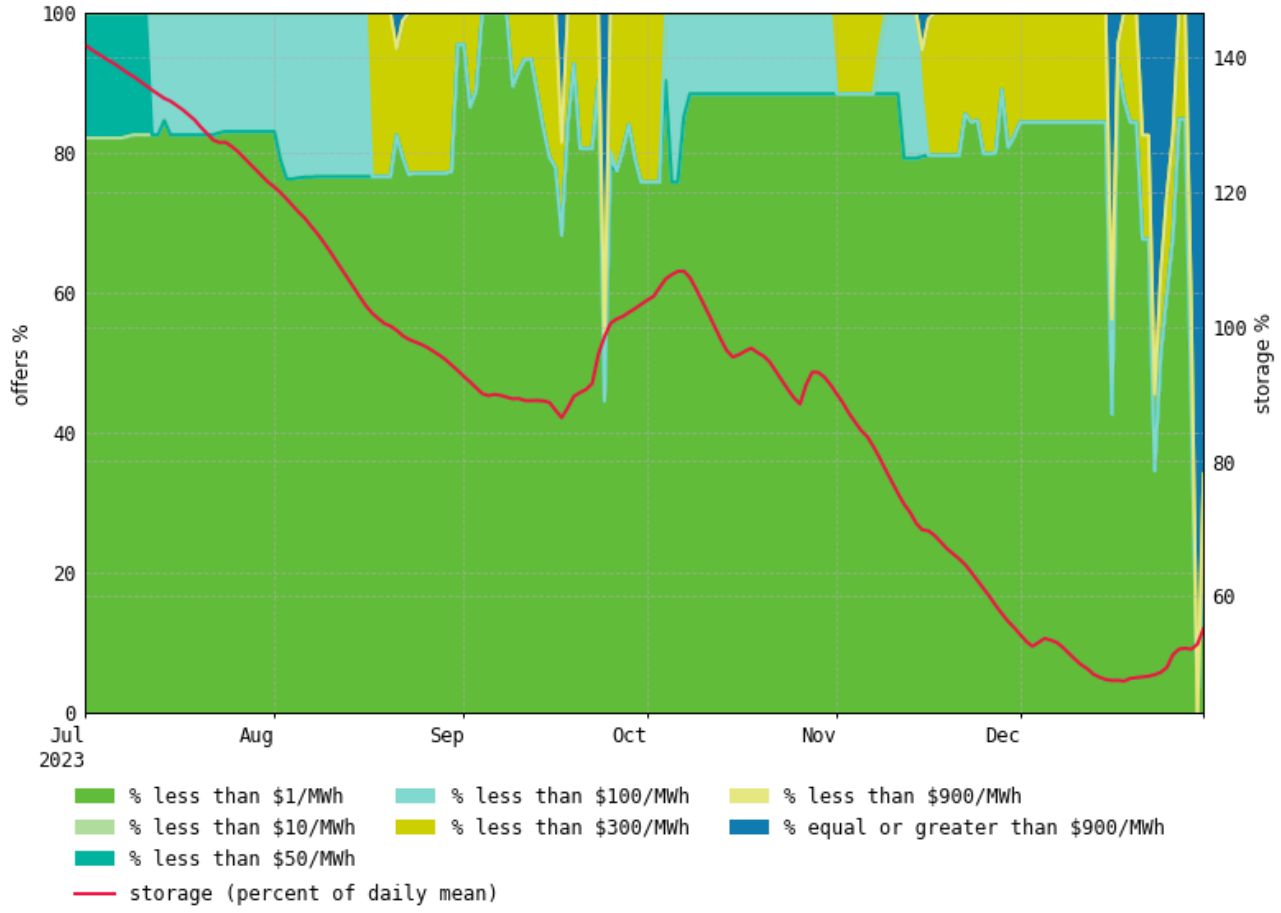
Figure 28: Offers vs storage for Contact Clutha, July to December 2023



Contact Energy's Clutha scheme has little control storage and can be considered a run-o- river scheme. However, despite having less flexibility, Contact Energy's Clutha offers were adjusted, as storage at Hawea fluctuated.

Storage at Hawea decreased drastically between July and early September, with storage dropping from ~100% of average to ~25%. The proportion of high-priced offers slowly increased over this period, before increasing rapidly after Hawea's storage reached its minimum in early September. Contact continued to have offers over $900/MWh at Clyde during September until storage began climbing above ~60% of mean. A small proportion of Contact's offers remained above $900/MWh during times of spill at Clyde in late September and continued into October once storage at Hawea had peaked. We indicated in our weekly trading conduct reports that further analysis was needed into these higher priced offers by Contact. This further analysis is ongoing. In mid-October, offers over $900/MWh were replaced with offers between $300-900/MWh, and the proportion of these offers increased over time as storage at Hawea fell once again.

Figure 29: Offers vs storage for Genesis Takapō, July to December 2023



Storage at Takapō largely decreased between July and December, with a small rise in late September. Genesis kept the proportion of low-priced offers mostly between 75-90% of total offers for most of this period. This changed in December, once storage decreased below 60% of the average, with several periods where there was a high proportion of offers above $900/MWh. Genesis seems to have priced their final 10-25% of offers at their Takapō plants in accordance with their storage ie, between $10-100/MWh when storage was at or above 100% of average (July, early August and October), and between $100-300/MWh when storage was below 100% of average (late August, September and November).

Table 3 to Table 7 show the percent of offers above $300/MWh, final price, and various measures of cost, for 1 July to 31 December 2023 compared to previous years, when hydro storage was high (for the Waitaki, Takapō, and Waikato), or low (for the Clutha).[5]

These tables show that the amount of high-priced offers along the Takapō decreased compared to previous years, while the percentages for the Waitaki and Waikato compared to previous years were consistent with storage trends.

Since storage at Hawea was only above mean for 9% of the time during July to December 2023, we ran these figures for when hydro storage was low (less than 80% of mean) for Clutha. Hawea storage was less than 80% of mean about 70% of the time over this period. While there were no

[5] Only trading periods when hydro storage was high are included for each table for the Waitaki, Takapō, and Waikato ie, where total New Zealand storage or storage for the relevant catchment is greater than or equal to 100 percent of mean. This is to control for storage. Note that Takapō storage was only above 100% of mean around 33% of the time over these months in 2023. For the Clutha, we have only included trading periods when hydro storage was low (less than 80% of mean) since hydro storage in these catchments was lower than 80% of mean for 70% of the time over July to December 2023. We also checked the results for Takapō for these low storage trading periods and got similar conclusions as when using the high hydro storage trading periods.

periods of storage below 80% of mean in 2022 or 2021, when compared to 2019-20 and 2014-18, the percentage of high-priced Clutha offers during times when storage was low was similar to in 2019-20, which was before the introduction of the new trading conduct rules, and higher than in 2014-18. However, over all trading periods, Contact's percentage of high-priced offers was still lower than some of the percentages for Mercury (Waikato) during periods of high hydro storage (figures are in brackets in the tables). Additionally, Contact's offers are correlated with storage and water values as we would expect under competitive outcomes (see next section). As mentioned above, there is one period where Contact had high priced offers that we are still analysing.

The proportion of high priced offers increased for the Waikato scheme in 2023 compared to 2022, and were similar to 2019-2021. This is consistent with storage trajectories – in 2022 Taupō storage was higher than mean for the whole six months and had an increasing trend, consistent with the lower percentages in that year. Taupō storage in 2021 started lower than at the same time in 2023 but was generally increasing and reached a higher level by the end of the year compared to in 2023. The high percentages in 2023 of offers above thermal SRMCs and water values for the Waikato is somewhat concerning. However, we have not found any instances in our weekly monitoring of behaviour that is inconsistent with competition over this period, and their offers are correlated with storage and water values as we would expect under competitive outcomes (see next section).

The proportion of high-priced offers also increased for the Waitaki scheme for most indicators compared to 2022, and were similar to 2019-21. However, hydro inflows over these months in 2023 were around mean. In 2022, 2021 and 2019 inflows were all above mean. Meridian may also have been cognisant of maintaining storage at Pukaki considering outages at Manapōuri.

The percentages of higher priced offers at the thermal plants Stratford and Huntly both decreased when compared to previous years. During this time Huntly 5 was not running due to a mechanical fault. So when the Rankines and TCC were running, they were often covering baseload, and had fewer higher priced energy tranches.

Table 3: percentage of offers over $300/MWh, July to December,

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2023	38	0	3	41 [34]	66	16
2022	10	0	13	N/A	89	26
2021	35	4	9	N/A	67	19
2019-20	40	25	6	45	36	17
2014-18	6	24	6	15	2	4

Table 4: Percent of offers above final price, July to December

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2023	45	34	7	44 [37]	73	26
2022	26	24	15	N/A	98	40
2021	53	33	11	N/A	82	30
2019-20	49	34	8	42	59	25
2014-18	37	39	22	37	64	20

Table 5: percentage of offers above the average forward price July to December

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	McKee	Huntly OCGT	Stratford peakers	Rankines (coal)	E3P	TCC
2023	30	23	3	29 [24]	48	55	54	16	N/A	5
2022	12	5	12	N/A	90	84	97	32	20	42
2021	30	11	7	N/A	60	55	62	24	14	21
2019-20	31	22	5	30	35	61	62	27	9	11
2014-18	21	22	13	23	60	63	45	16	4	9

Table 6: percentage of offers above thermal SRMCs July to December

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	McKee	Huntly OCGT	Stratford peakers	Rankines (coal)	E3P	TCC
2023	43	26	4	43 [36]	70	79	81	22	N/A	22
2022	7	1	13	N/A	92	81	98	11	24	48
2021	24	8	10	N/A	87	52	42	23	20	15
2019-20	30	27	6	40	56	28	64	19	13	9
2014-18	20	31	18	31	87	22	49	21	14	19

Table 7: Percentage of offers above water values July to December

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2023	50	36	12	45 [38]
2022[6]	15	15	11	N/A

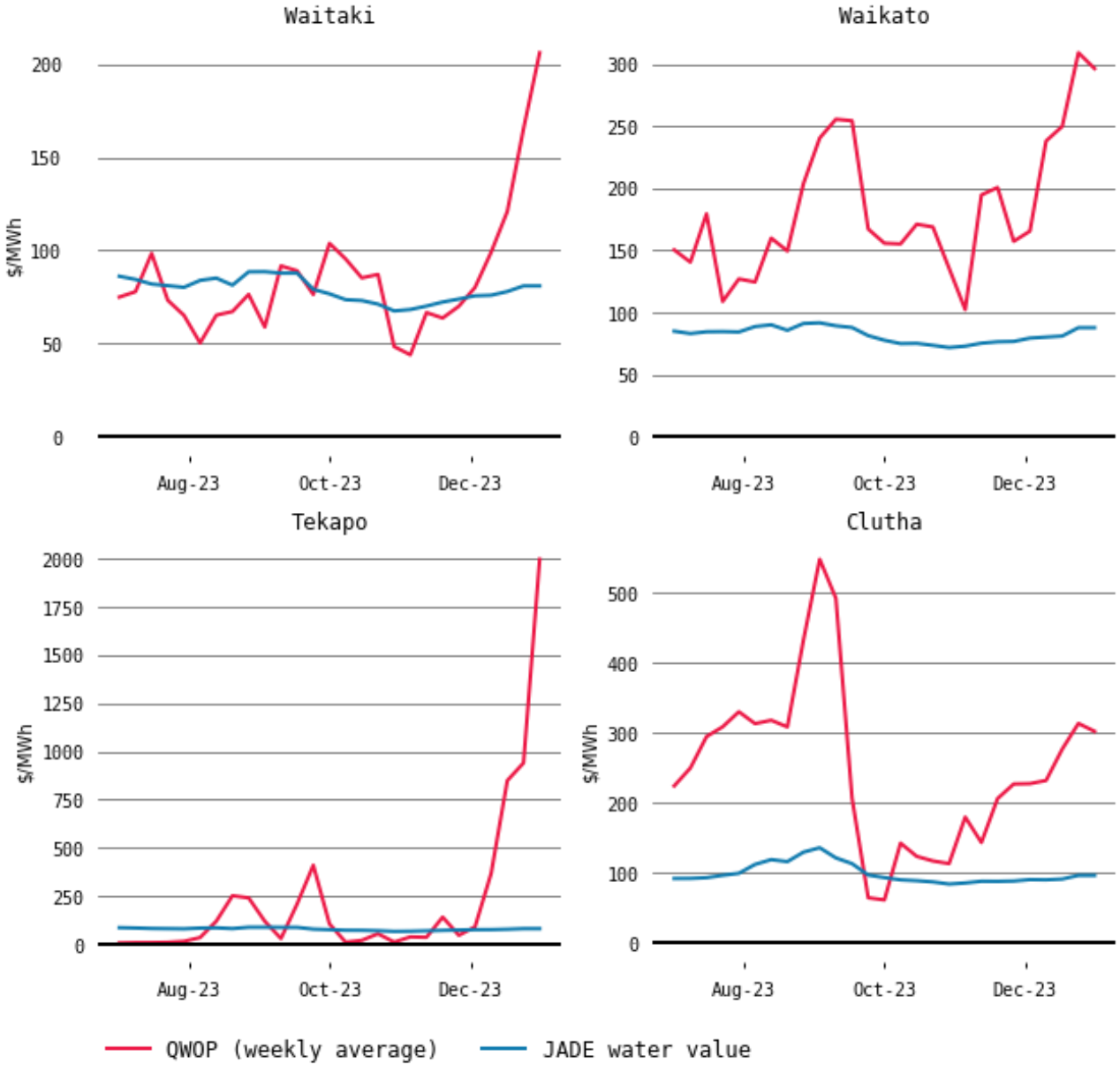
[6] 16 September to 31 December 2023

14. Relationship of storage and offers to cost

Tables 8 to 10 show the relationships between the average water values for each associated reservoir and hydro storage and offers, for when hydro storage was high. Figure 30 shows the relationship between these water values and offers. Note that the 2022 values used shows these relationships between these water values and offers for 16 September to 31 December 2022 only.

Figure 30 shows a large increase in quantity weighted offer prices at the end of December for the Waitaki and Takapō. This coincides with low inflows and storage at this time for Hawea, Pukaki, Takapō, and Taupō (with Taupō storage increasing from mid-December). Average spot prices increased between early and mid-December, however with the onset of the Christmas period, these higher offer prices for a higher proportion of generation did not affect prices as demand decreased. Storage usually increases for the South Island lakes at this time of the year which is perhaps why the water values did not increase by much. Storage at Manapōuri was also below mean and decreasing, and below mean at Hawea, at this time.

Figure 30: Quantity weighted offer prices, July to December 2023



The Waikato, Waikati and Clutha schemes continue to have negative correlations between hydro storage and water values ie, water values decreased when storage increased and vice versa,

which is what we would expect under competitive outcomes. However, Takapō had a positive correlation, meaning water values decreased as storage decreased. We believe this is because inflows were around mean levels over this time, so storage was decreasing more due to higher generation than due to low inflows.

Meridian had a negative correlation of water values with the percentage of offers above $300/MWh. This is because they did not have any offers above $300/MWh when hydro storage was above mean (which was most of the period). Genesis also had very few times with offers above $300/MWh for Takapō, and usually a high proportion of low-priced offers. Its quantity weighted offer prices (QWOP) increased at the time it had outages (ie, operation of the remaining units perhaps became more complex requiring higher priced offers) and at the end of the period which would have affected its correlation of water values with its QWOP (see discussion above about the increase in QWOP at the end of December). Both Mercury and Contact had a positive correlation of water values with the percent of offers above $300/MWh, and with QWOP, as expected under competitive outcomes.

Table 8: Correlations of water values with hydro storage, July to December 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2023	-0.35	-0.27	0.35	-0.66
2022[7]	-0.48	-0.76	-0.56	-0.61

Table 9: Correlation of water values with percentage of offers above $300/MWh, July to December 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2023	0.32	-0.23	0.00	0.63
2022[8]	-0.46	0.19	0.13	0.69

Table 10: Correlation of water values with quantity weighted offer prices, July to December 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2023	0.33	0.14	-0.02	0.73
2022[9]	0.18	0.38	-0.12	0.01

[7] 16 September to 31 December 2023
[8] 16 September to 31 December 2023
[9] 16 September to 31 December 2023