Market Performance Quarterly Review

April - June 2023

Contents

Figures

1. Purpose

1.1. This document covers a broad range of topics in the electricity market. It is published quarterly to provide visibility of the regular monitoring undertaken by the Electricity Authority (Authority).

2. Highlights

2.1. April of Q2 2023 was relatively mild with no major events occurring. In early May and early June, cold snaps created very high demand events, leading to seven Customer Advice Notices (CANs) being issued for low residual situations.

2.2. In May in particular these low residual situations resulted in very high price spikes. However, the average wholesale price for the quarter was around $79/MWh, less than half of the price for the same period last year.

2.3. The Turitea wind farm was commissioned in Q2 2023 – the largest wind farm in New Zealand at a total capacity of 222MW.

2.4. Hydro storage for the start of June 2023 was the highest on record since May 2009, leading to many lakes spilling at this time.

2.5. The combination of additional wind generation and very high hydro meant much less thermal generation for this quarter compared to last year.

2.6. The annual consumer satisfaction report was released in Q2 2023, with similar levels of customer satisfaction to the previous year. These similar levels of consumer satisfaction were reflected in similar levels of switching.

2.7. Gas production finished the quarter down compared the start of the quarter, partially due to lower demand from gas generation. Gas generation was down compared to last year due to mild conditions and low wholesale prices. Te Rapa co-generation plant was ramped down and closed, consistent with advice from Contact Energy.

2.8. The failure of the second New Zealand Unit (NZU) auction caused NZU prices to drop rapidly in the quarter. Changes to the NZU price settings shortly after the end of the quarter have reversed most of this drop and prices appear to be stabilising.

3. Electricity Demand

3.1. Figure 1 shows the increase in total demand across Q2 2023 as the country moved into the cooler months. While there were a couple of weeks well above average demand, this was balanced out by milder temperatures for most of the quarter. The net outcome was that total monthly demand was almost exactly the same as last year, varying by only 4-10GWh per month.

3.2. A mild start to Autumn meant weekly demand in the first half of Q2 2023 was close to or below the average of the last 5 years. Temperatures dropped towards the end of May, but an extended cold snap combined with low wind in the first two weeks of June resulted in demand up to 4% higher than the long-term average. Sharp cold snaps contributed to 3 low residual situations in early May and 4 low residual situations in June, all of which received CAN notifications.

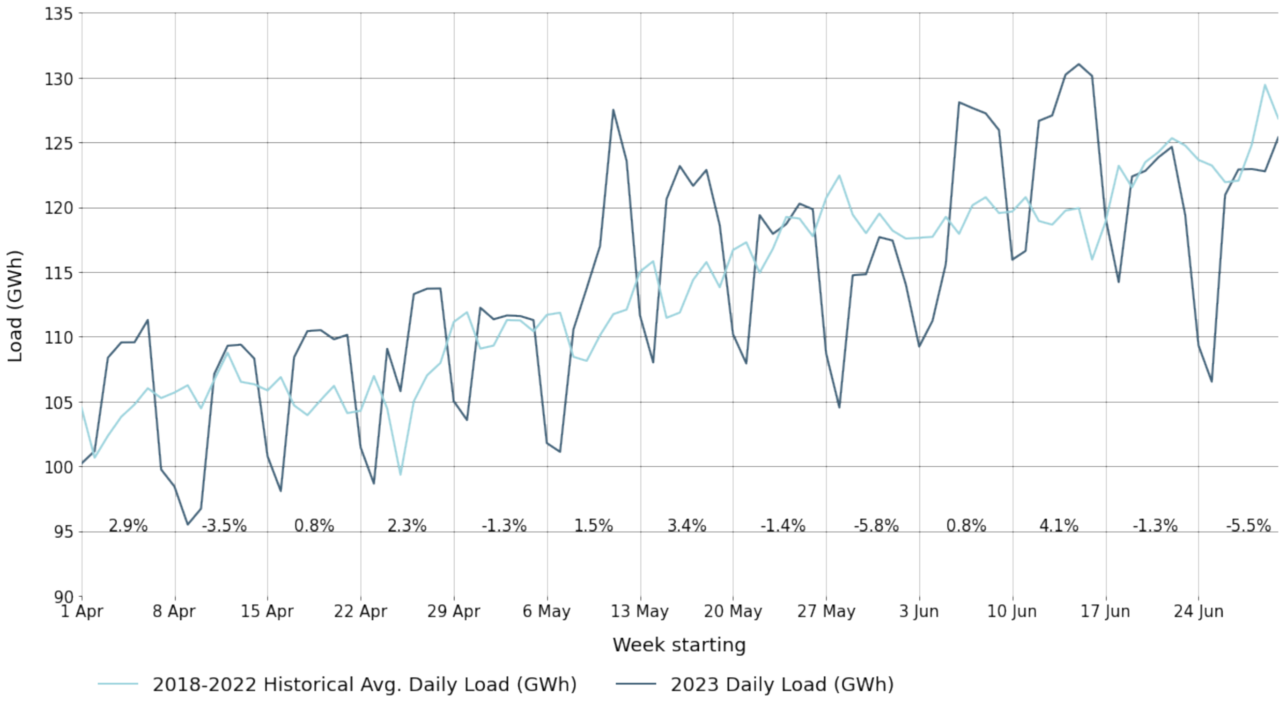

Figure 1: New Zealand daily load compared to historical average for April to June

3.3. Figures 2 – 4 explore some of the seven-day intervals in Q2 2023 where there was noteworthy demand or when a CAN was issued.

3.4. There was an extended drop in temperatures across both islands on Thursday 11th and Friday 12th of May. This contributed to a lift in demand and the issuing of a CAN notice for a low residual situation. Cold temperatures and elevated demand continued into the following week as shown in Figure 2, with an additional low residual CAN issued for Tuesday 16th of May.

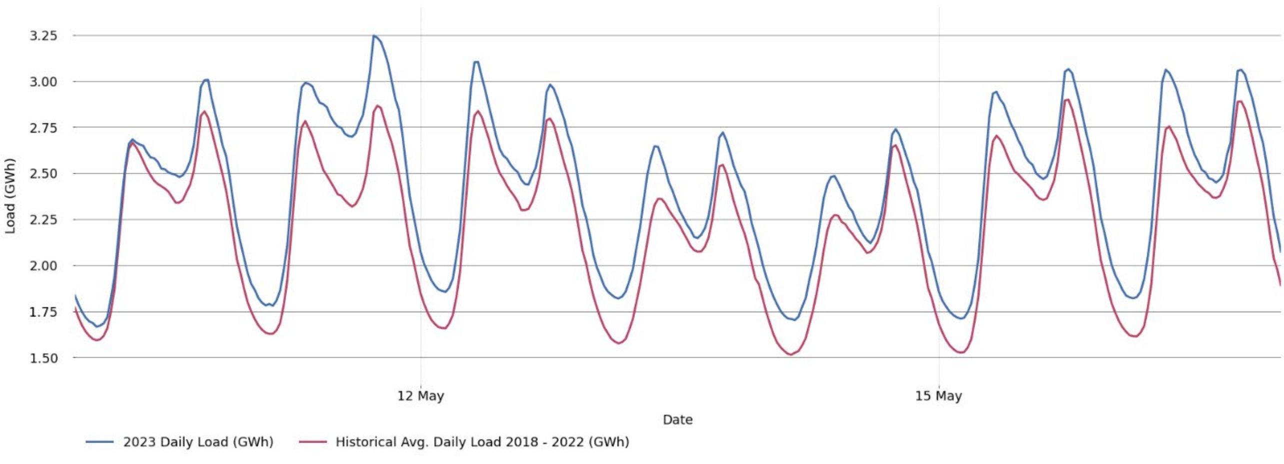

Figure 2: Half hourly load for 10th – 16th May 2023 vs historical demand

3.5. Maximum demand for Q2 2023 was reached on the evening of June 6th, when demand reached approximately 3.35GWh (6.7GW) – shown in Figure 3. This demand coincided with cold temperatures, but also very strong winds, which helped to avoid a low residual situation at this time of maximum demand.

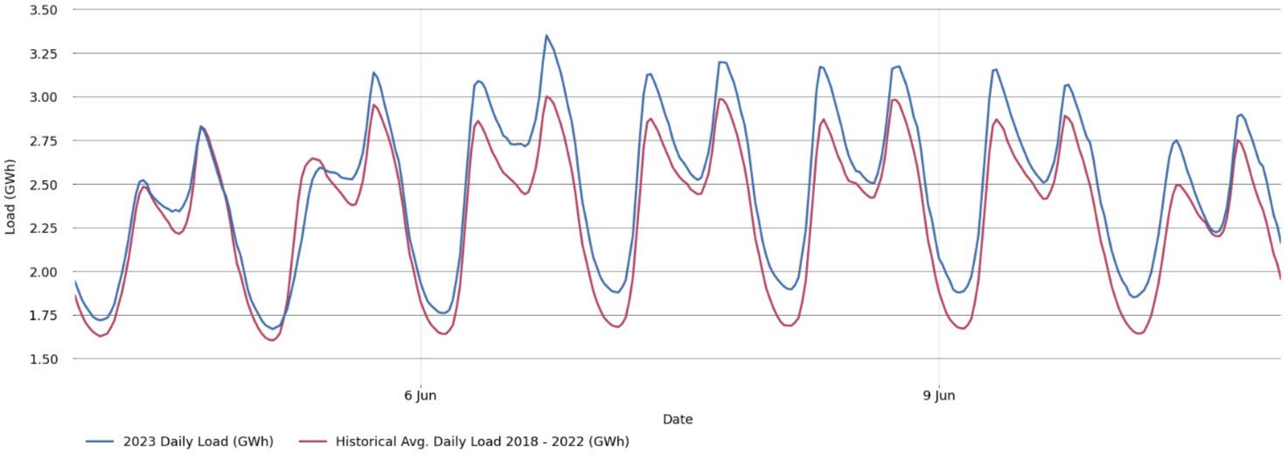

Figure 3: Half hourly load for 4th - 10th June 2023 vs historical demand

3.6. Figure 4 shows how demand was significantly higher than the long-term average for the whole working week in the week of 11th to 17th June. As a result, there were 4 low residual situations – the evening of the 12th, the morning and evening of the 14th and the evening of the 15th of June. Cold weather lifted demand, but very low wind generation contributed to the CAN low residual situations.

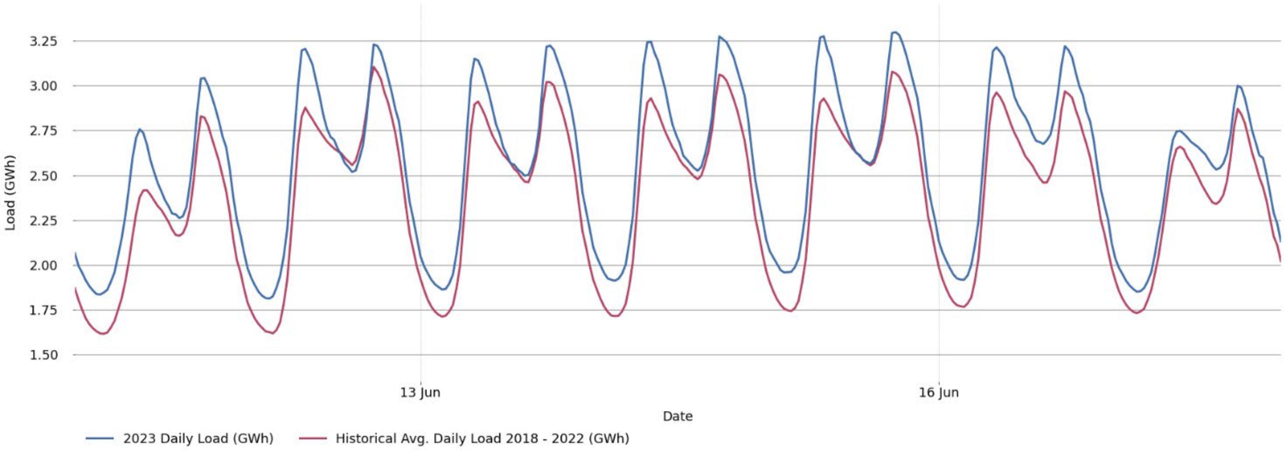

Figure 4: Half hourly load for 11th – 17th June 2023 vs historical demand

4. Wholesale electricity price and composition

4.1. Q2 2023 saw a broad range of wholesale prices, with higher volatility than normal for this quarter. Figure 5 shows that a range of individual half-hour spikes took place at times of high demand such as those discussed in the previous section. The highest price reached was $4029/MWh on 15th June. However, the overall average wholesale price for Q2 2023 was around $79/MWh, less than half of the average for the same time last year of $192/MWh.

4.2. Figure 6 is a view of wholesale prices below $350/MWh and it makes it clear most intervals of the quarter were below $250/MWh. Further to this, record levels of hydro storage contributed to an extended period between mid-May and mid-June where most half hours traded below $50/MWh, which helped drive down the overall average for the quarter.

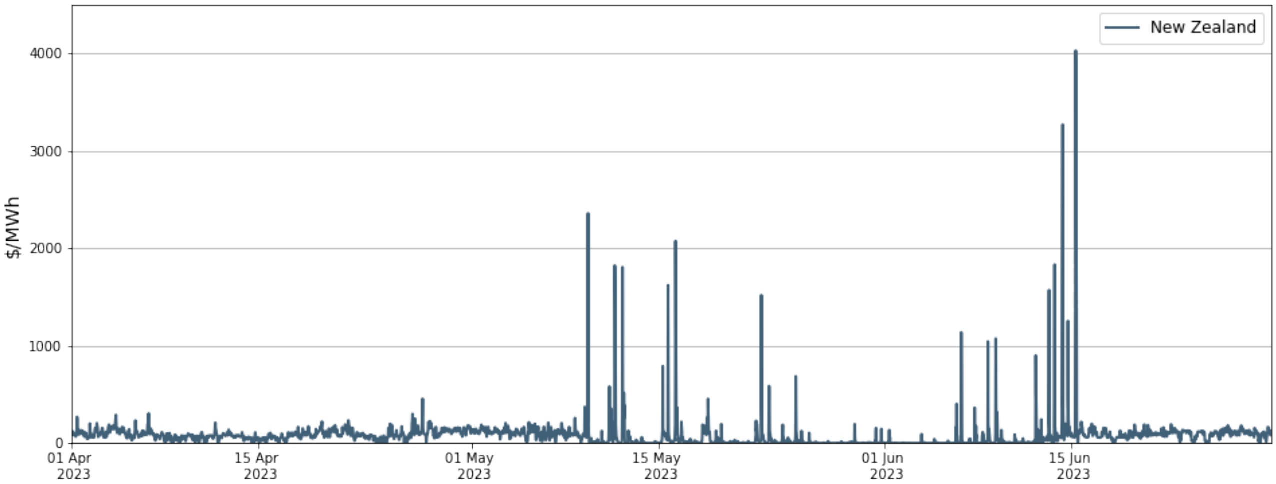

Figure 5: Average New Zealand wholesale price per half hour for April - June 2023

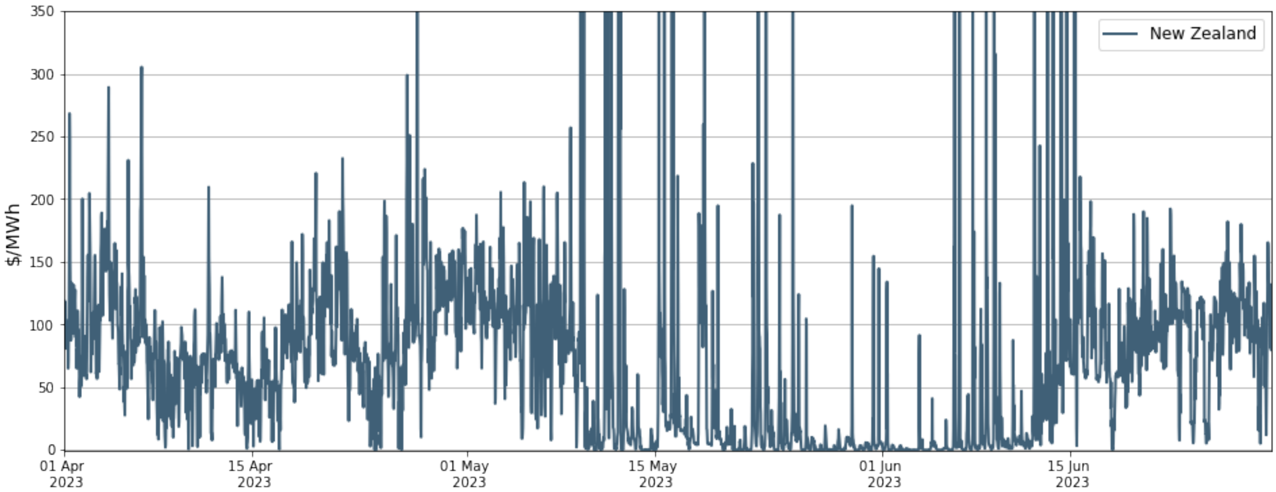

Figure 6: Average New Zealand wholesale price per half hour for April - June 2023 - detail

4.3. In the generation mix, the availability of wind generation had a notable impact on the daily average wholesale price. The effect of combined high hydro and large amounts of wind in late May and early June is evident in the low wholesale prices. Conversely, around 14th of June, there was combined high demand and low wind, resulting in a large spike in wholesale prices, as seen in Figure 7.

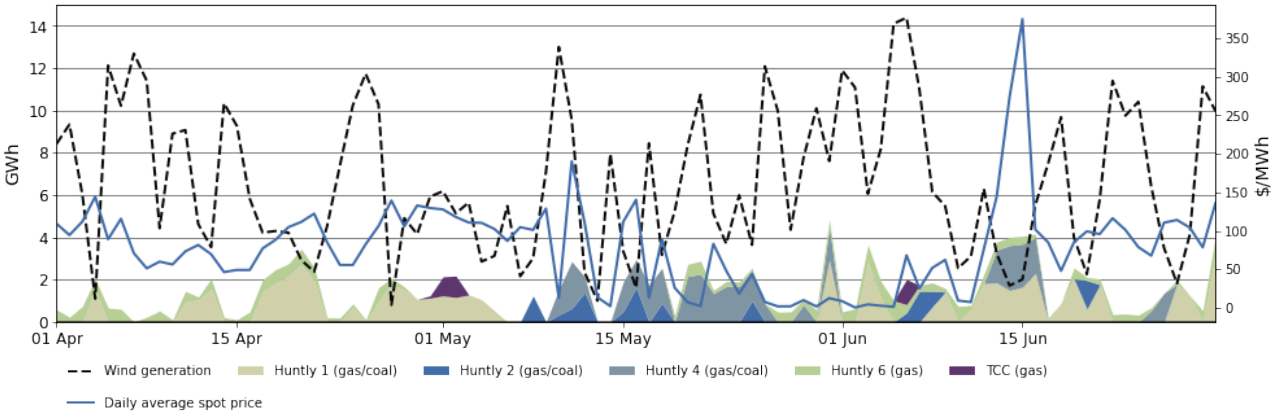

Figure 7: Daily wind and peaking generation and average wholesale price for April to June 2023

4.4. The effects of increasing levels of hydro supply across Q2 2023 are visible in Figure 8 as the daily average MW provided by hydro generation continued to increase. Hydro generation peaked in early to mid-June when a prolonged high-pressure system suppressed wind generation and kept temperatures low, resulting in high demand.

4.5. Geothermal output was reduced for most of Q2 2023 due to a long outage at Kawerau. Their return to service in mid-June is visible in Figure 8. Thermal generation was suppressed towards the end of May due to abundant hydro and wind generation but increased in June as winter weather caused demand to increase.

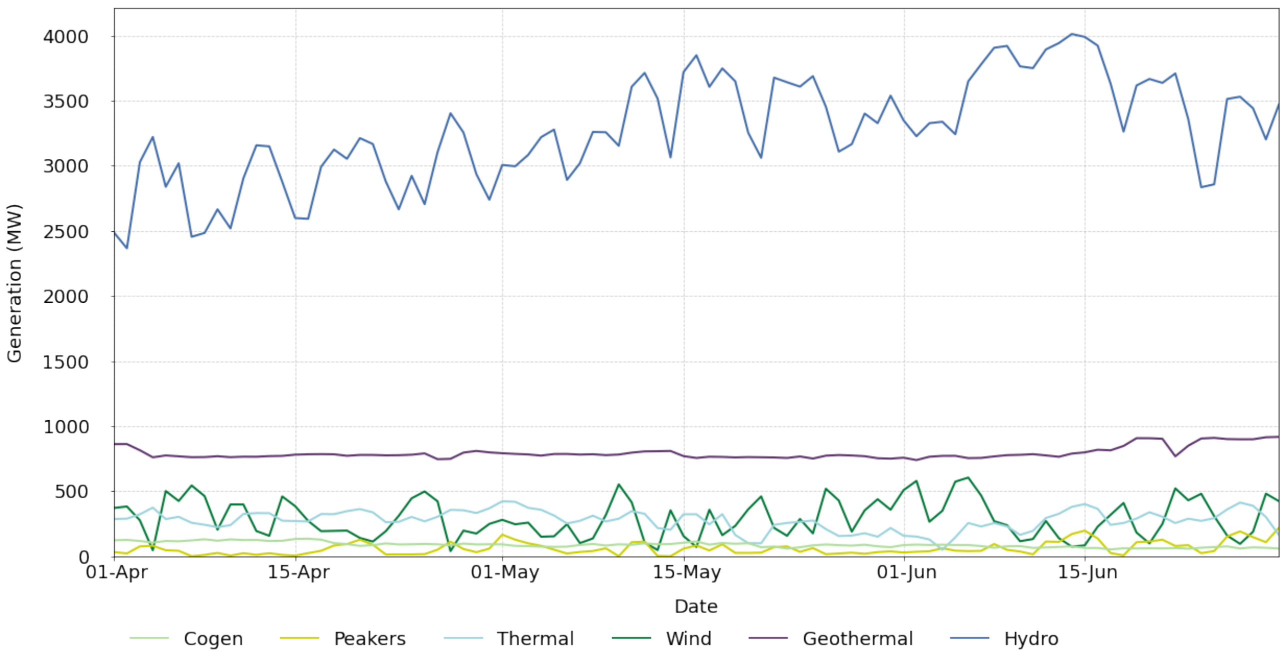

Figure 8: Average daily generation by fuel type for April - June 2023

4.6. Figure 9 shows the weekly breakdown of electricity generation by fuel type. The record levels of hydro supply in May are evident in the above average hydro generation from early May to mid-June – averaging 72% of total generation for this period, and 70% for the quarter. For comparison, in Q1 2023, hydro made up an average of 63% of supply.

4.7. The high levels of hydro generation displaced generation from other fuel types even as demand increased due to cooler weather. Across the remainder of the quarter, the largest fluctuations in generation fuel type came from wind and thermal generation, ranging from 3-7% and 7-9% respectively[1]. Geothermal generation had a reduced share of supply due to an outage for most of the quarter, which reduced its share to around 14-15% most weeks.

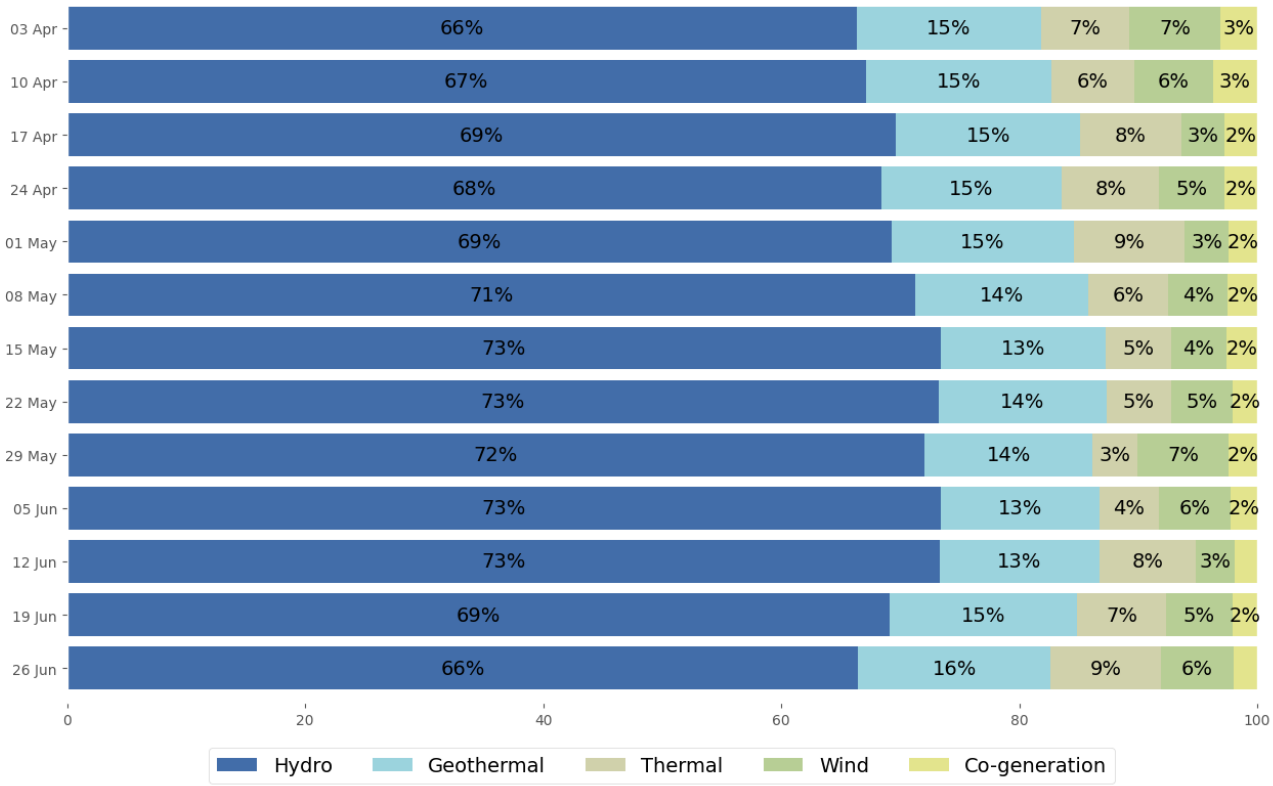

Figure 9 Weekly generation share by fuel type for April - June 2023

5. Water storage levels

5.1. Q2 2023 finished with most hydro dams at or above average levels. During May, total hydro storage levels were the highest on record since May 2009, resulting in lakes spilling. In the South Island in Q2 2023, very high inflows made up for the below average flows of Q1 2023. South Island lakes were filled to well above average levels in late May and early June, apart from Hawea, which came off a very low base.

[1] Labels on Figure 9 may not add up to 100% due to rounding.

5.2. The North Island continued to receive above normal rainfall in both April and May, boosting levels in Lake Taupō well above typical levels until mid-June. While rainfall on the North Island eased in June, Figure 10 shows Taupō remained above average at the end of the quarter, even with more generation than average dispatched by Mercury.

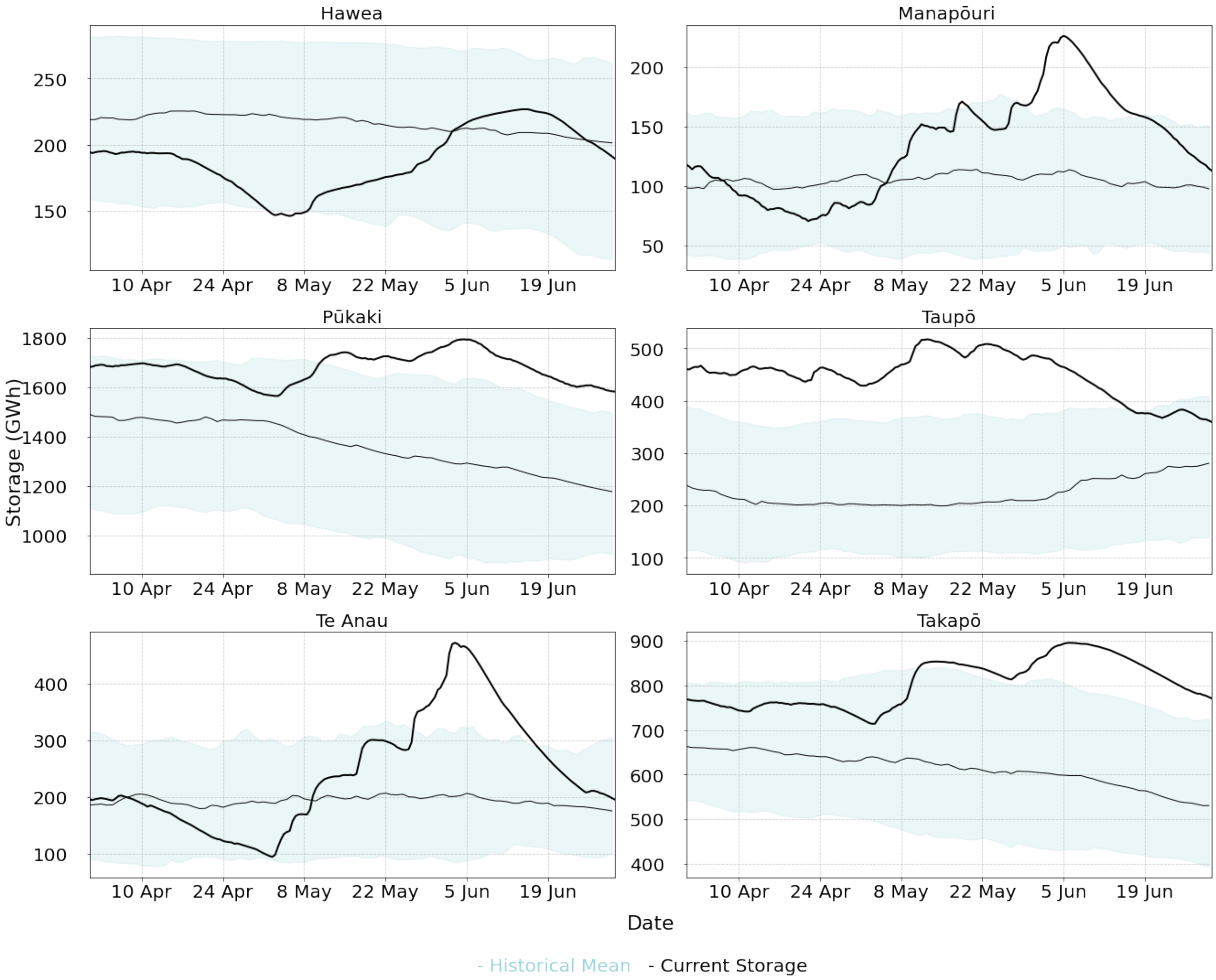

Figure 10: Lake storage levels for April – June 2023 vs typical historical storage levels

5.3. Figure 11 shows the 7-day rolling average of both hydro storage and North and South Island wholesale prices. The inverse relationship between storage and price is visible, particularly in late May and early June as South Island storage reached its highest levels of the quarter, and at the end of June as levels began to drop and prices began to rise. The exception to this pattern is the middle of June, when there were several CANs issued due to a tight supply/demand balance, which pushed up prices for that week.

5.4. There is noticeable price separation between the North and South Islands visible in Figure 11 – prices are higher in the North Island. This is because most hydro supply in New Zealand is in the South Island and this pushes prices down in the South Island before pushing prices down in the wider system.

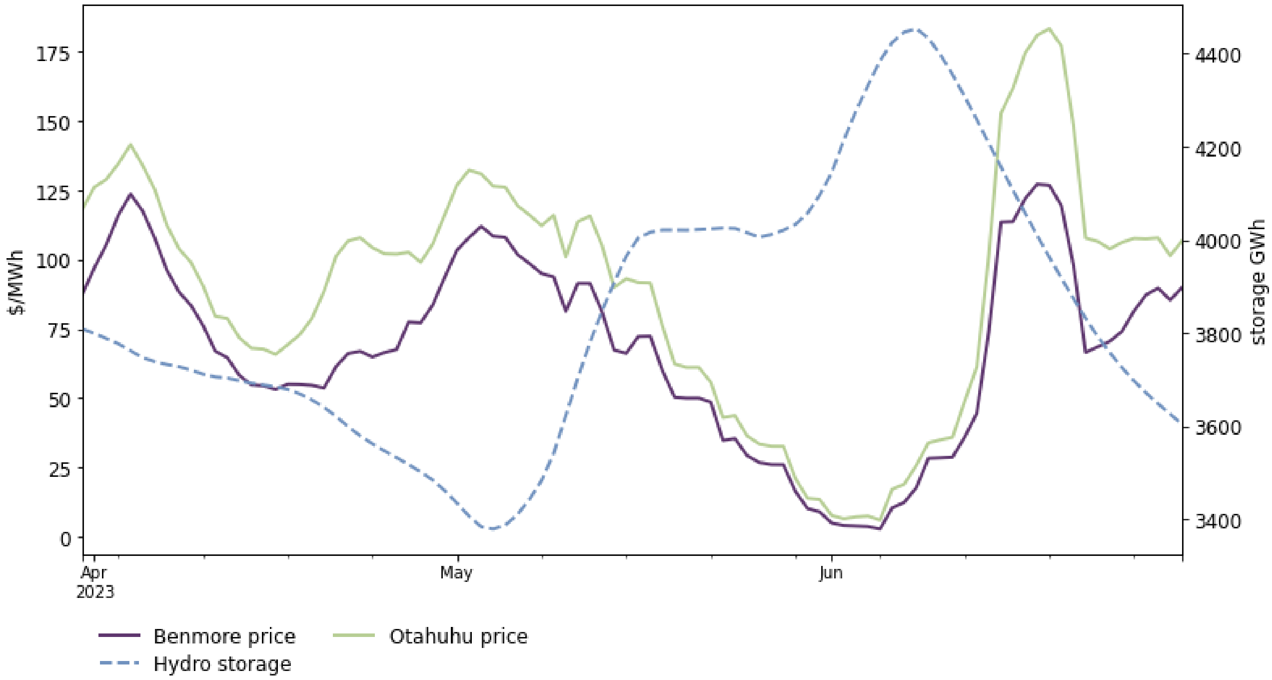

Figure 11: Rolling 7-day average wholesale price vs national hydro storage for April - June 2023

5.5. As Figure 12 shows, the quarter finished with over 3.5TWh of hydro storage, an increase of around 1TWh on the previous year. Consistent with last quarter, this remains the highest level of hydro storage for this time of year in more than 5 years and should minimise the need for higher priced coal and gas generation through winter. While short term high demand can be occasionally challenging to meet[2], this high hydro storage ensures bulk supply remains firm for the winter months.

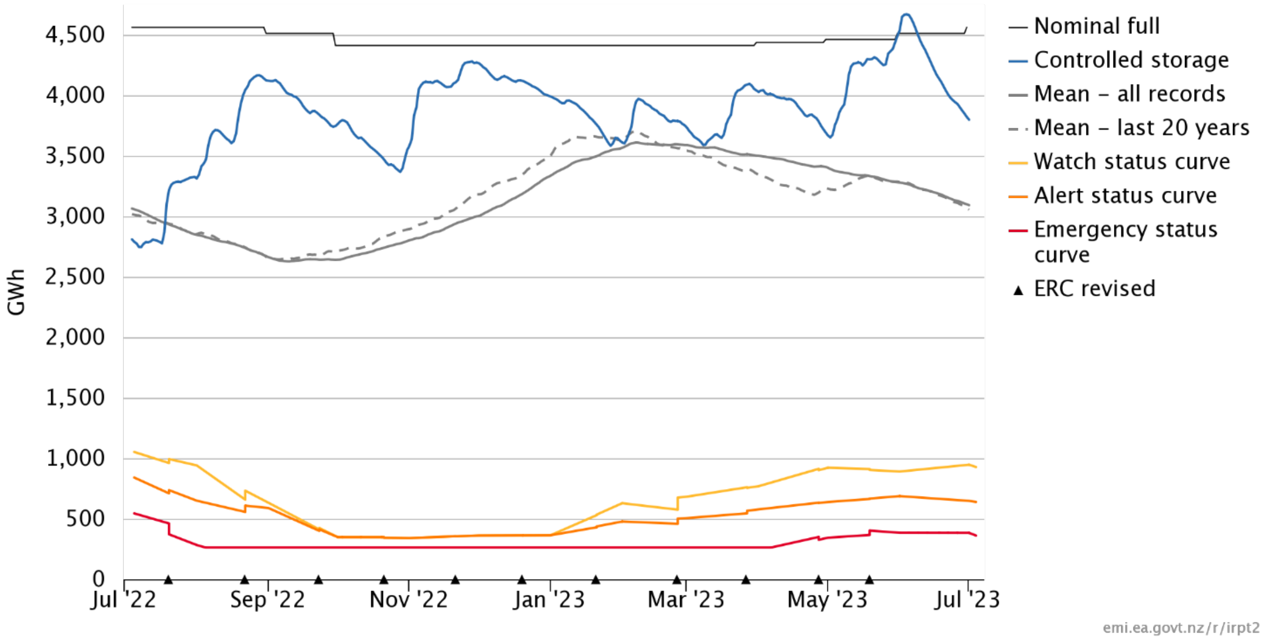

Figure 12: National storage levels for July 2022 to July 2023

[2] https://www.ea.govt.nz/news/eye-on-electricity/high-hydro-levels-and-wholesale-prices/

6. Wholesale gas prices, production, and consumption

6.1. The volume weighted average price for Q2 2023 was $8.88/GJ, more than $2/GJ lower than the previous quarter and less than half the average price in Q2 2022. Price volatility has also continued to decline when compared with the previous quarter and year, reducing price shocks. As previously noted, in this quarter there was an abundance of hydro supply, and this suppressed demand for gas generation. This reduction in gas demand contributed to lower gas spot prices.

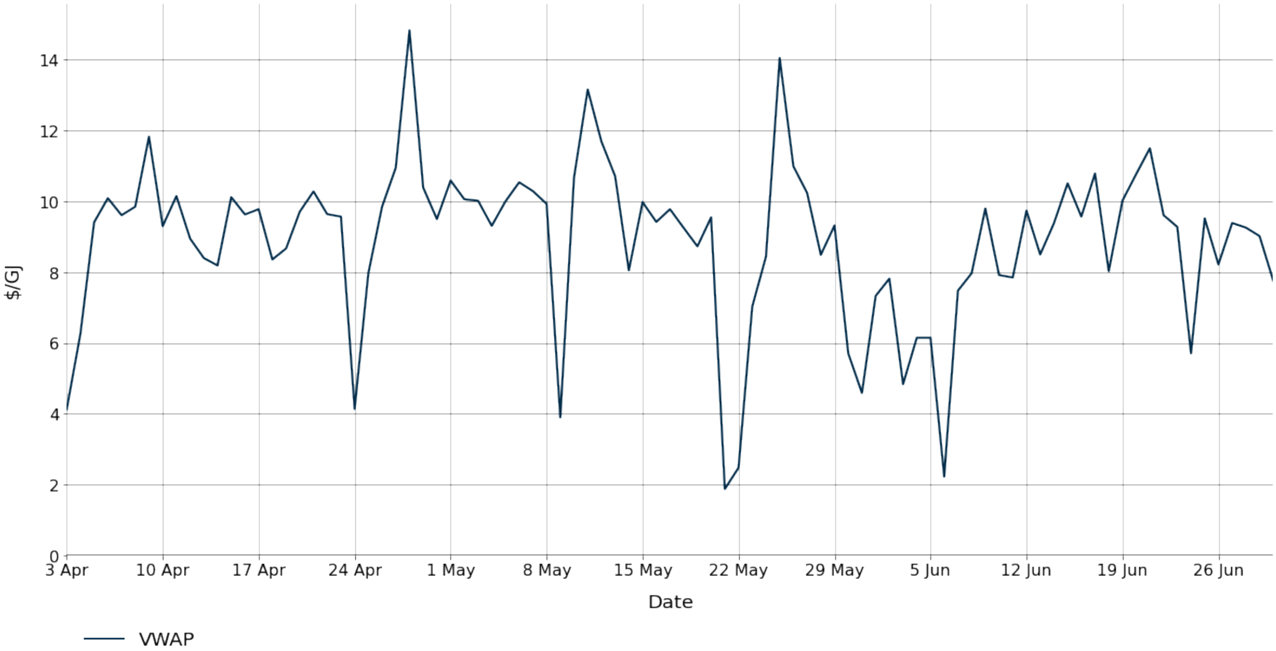

Figure 13: Daily volume-weighted average price for gas for April to June 2023

6.2. With gas storage notionally near-full in Q2 2023, gas production was more directly influenced by gas demand than normal. Reduced demand for marginal gas generation depressed overall gas demand and prices. Gas production started the quarter at 411TJ/day and finished the quarter at 327TJ/day. Production in all fields declined in this quarter, with the largest decline coming from McKee/Mangahewa, shown in Figure 14.

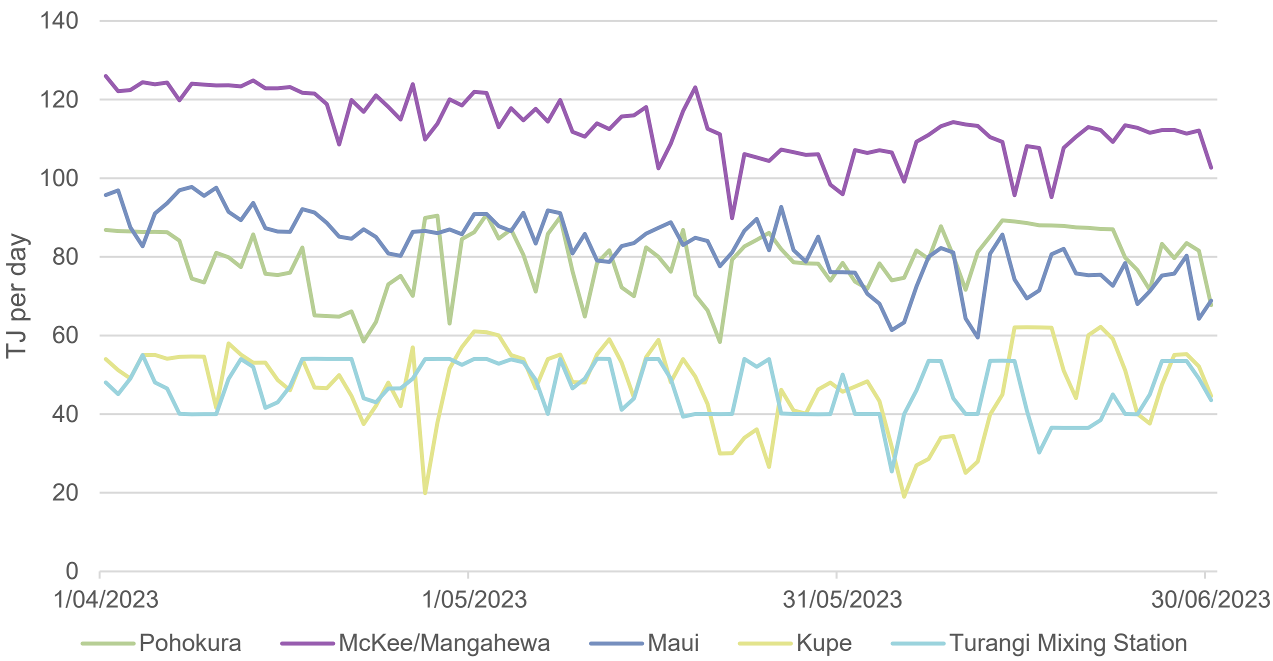

Figure 14: New Zealand gas production for April to June 2023

6.3. Gas consumption by Huntly power station dropped slightly in late May and early June, consistent with exceptional hydro levels, as visible in Figure 15. Stratford power station (Taranaki Combined Cycle - TCC) did start twice in Q2 2023 but did not remain online for an extended period during the quarter. TCC is expected to run for an extended period during Q3 2023.

6.4. Methanex continued to operate at normal levels for most of the quarter but did begin to ramp down operation in late June in preparation for a scheduled turnaround, which will run for about half of Q3 2023. The Waitara Valley plant occasionally provided support to Motunui, running at about 6-7TJ/day when in operation.

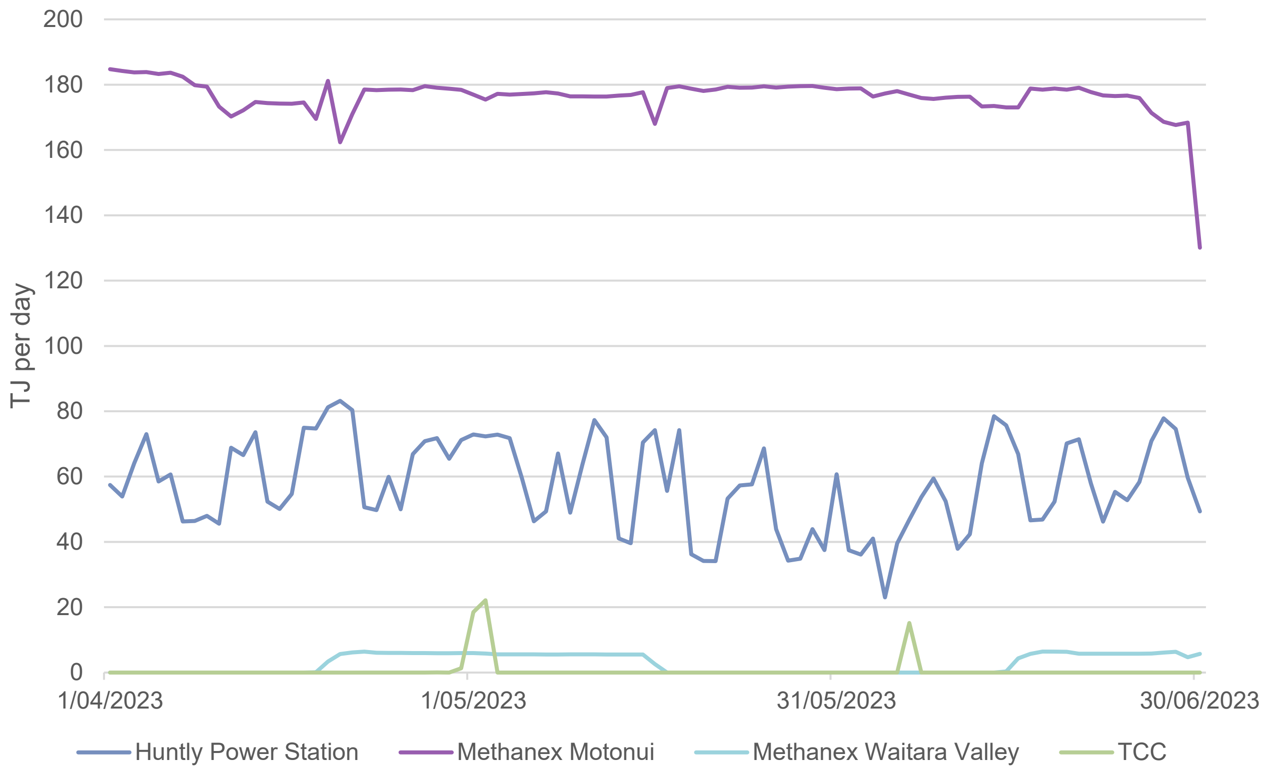

Figure 15: New Zealand gas consumption by major consumers April to June 2023

6.5. Figure 16 shows the fuel consumption of the largest thermal generator in New Zealand, Huntly. A mild autumn and high hydro levels reduced the need for gas generation below typical levels for this season. As temperatures and hydro levels both began to drop in June, generation from Huntly has begun to increase.

6.6. Coal consumption at Huntly remained below typical levels for this time of year – the high cost of coal generation and the abundance of alternatives meant coal generation was rarely needed.

6.7. Huntly 5 suffered a major outage on 30 June and was expected to be offline for multiple months due to a technical fault at the time of writing. This will limit the amount of gas generation able to be supplied by Huntly in Q3 2023.

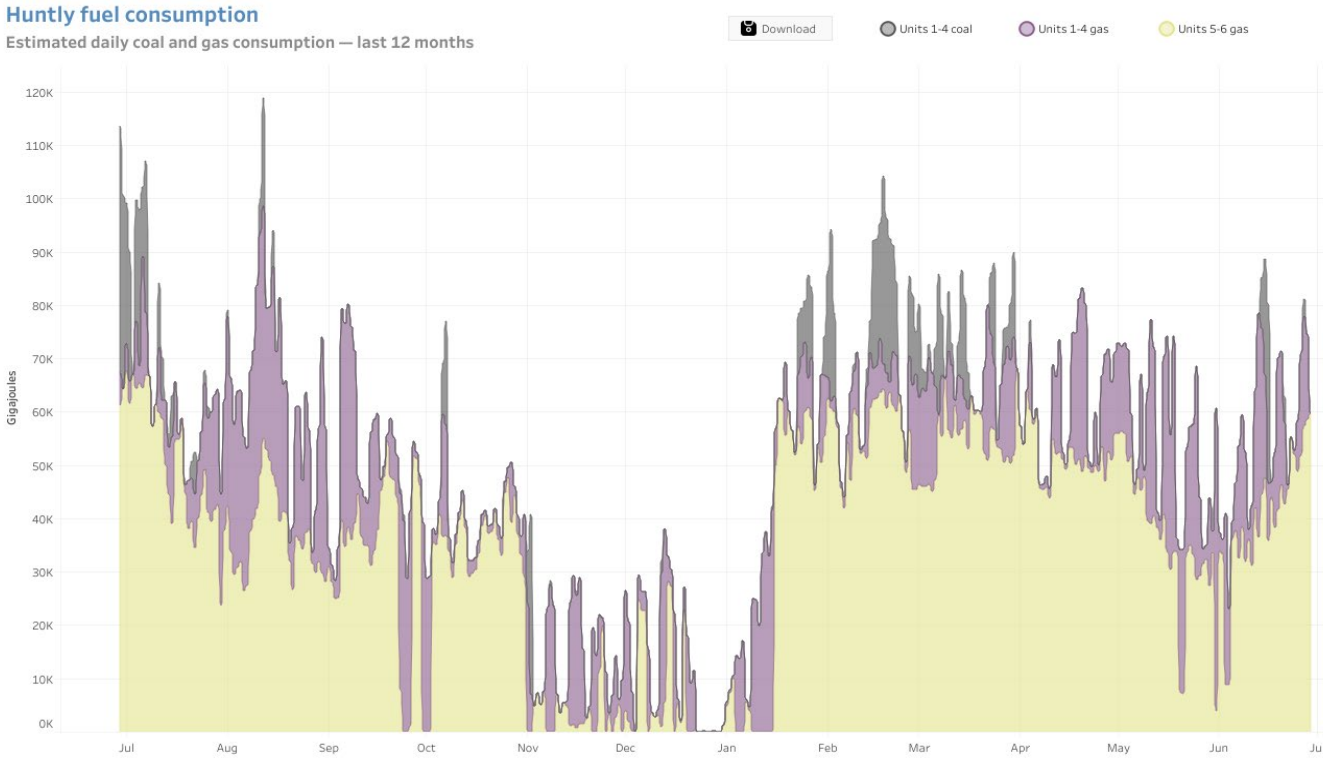

Figure 16: Huntly fuel consumption for the last 12 months to June 2023

7. Retail electricity

7.1. In Q2 2023, total ICPs increased by around 7600. Of the major retailers, Meridian and Genesis Energy failed to achieved a net gain of ICPs across the quarter. The other major retailers gained ICPs as shown in Figure 17. While the major retailers still retain over 84% of market share, this is gradually declining as smaller retailers continue to pick up more ICPs. Major movements in ICPs were dominated by Ourpower and Trustpower retail customers being transferred to Frank Energy and Mercury Energy respectively.

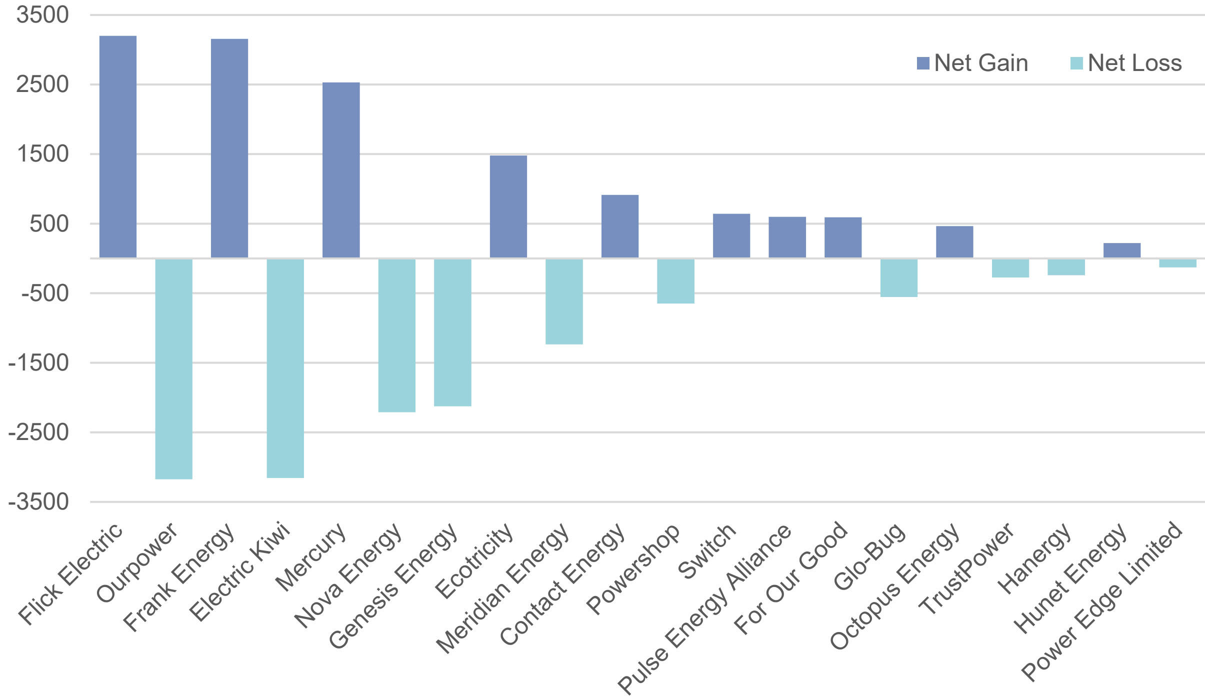

Figure 17: Top 20 movements in ICP net switching by electricity retailer for April to June 2023

7.2. The release of the Consumer NZ customer satisfaction survey[3] indicated customer satisfaction with electricity retailers has not changed much in the last 12 months. This is reflected in Figure 18 where trader switching remains consistent with annual trends, with lifts in switching in Q2 2023. Move-in switching, where new metering connections are added, rather than transferring from another retailer, remains below the peak in July 2022 and the broader trend appears to be easing when compared to recent years.

[3] https://www.consumer.org.nz/articles/best-and-worst-power-companies-in-2023

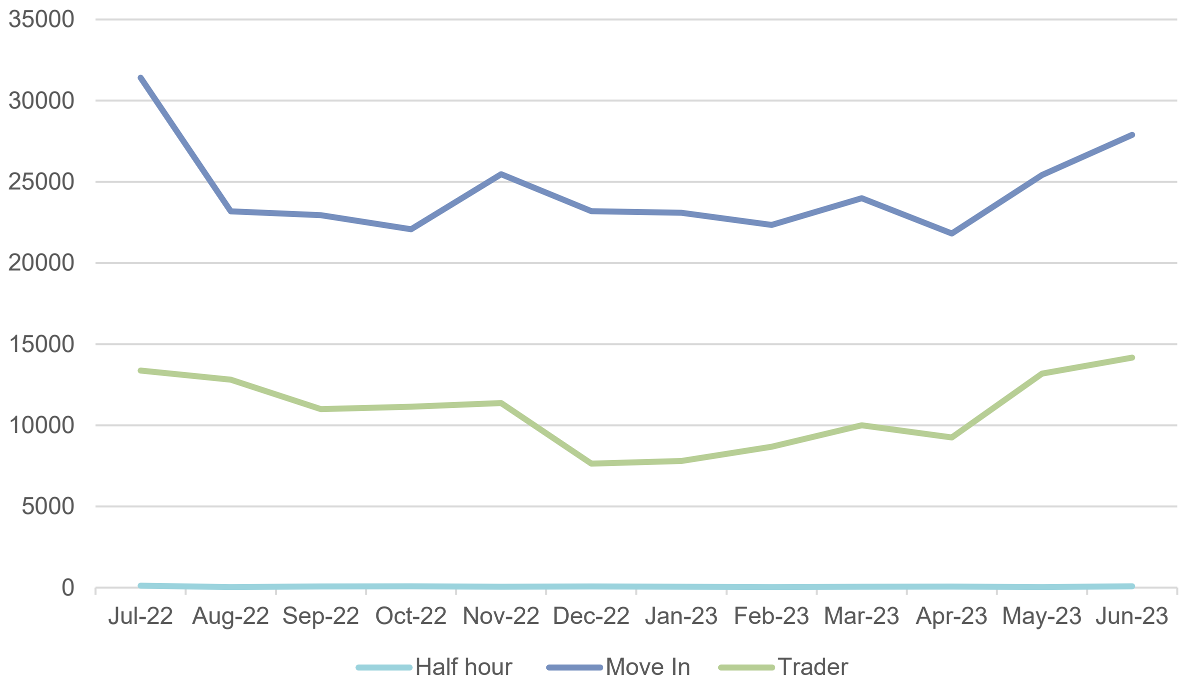

Figure 18: Breakdown of monthly ICP switching by type from emi.ea.govt.nz/r/14qr

7.3. The Retailer Financial Stress (RFS) notice data request code amendment implemented in August 2022 allows the Authority to monitor financial stress faced by consumers. This replaces the data request implemented in response to Covid-19 and requires a different set of retailers selected under a new criterion to answer slightly different questions. The new data starts from October 2022 and is not directly comparable to previous data.

7.4. In the last 6 months, there has been a gradual uplift in the number of customers requesting payment flexibility or payment deferral, as indicated in Figure 19. It is not yet certain if this is a trend to be addressed or a short-term increase which will ease.

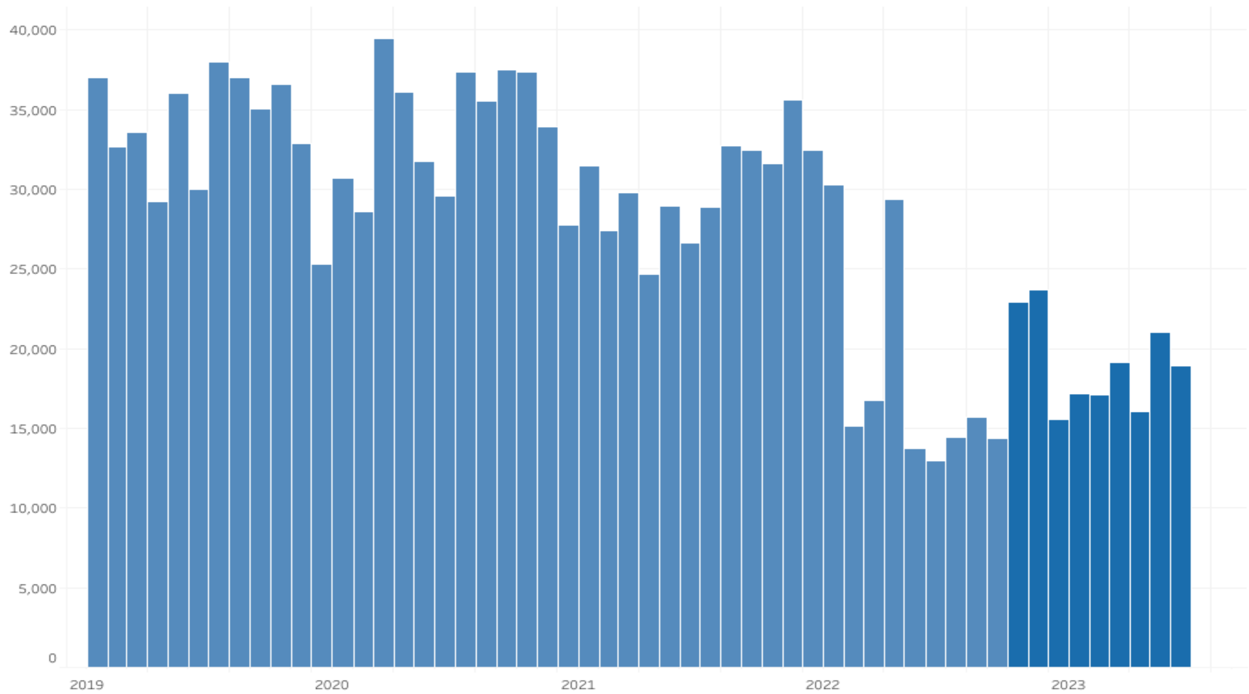

Figure 19: Customer enquiries for payment flexibility up to June 2023

7.5. Debt more than 30 days in arrears is an early indicator of both customer and retailer stress. Figure 20 indicates the total debt in this category was increasing up to April 2023 where it reached around $38.4 million but has eased in the last two months to around $28.7 million.

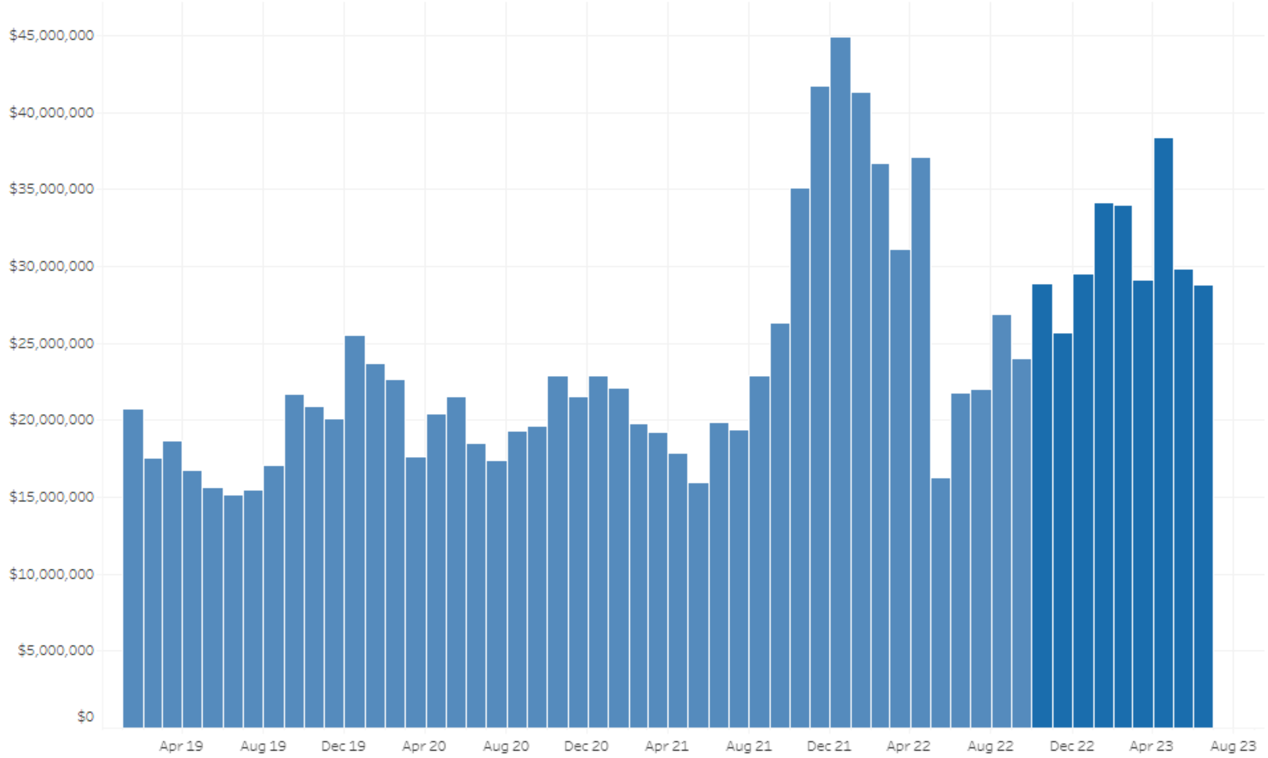

Figure 20: Total debt from customers 30+ days overdue and not yet scheduled for disconnection

7.6. Figure 21 shows the ICPs where participants have been disconnected for more than 24 hours as a result of non-payment. These ICPs either haven't paid their invoices or been able reach an agreement through the credit management process. This is connected to long term debt where the next step is typically disconnection, as the debt is regarded as being harder to recover. Over the last 6 months, this has averaged around 950 ICPs, or about 0.05% of all ICPs and this is a slight increase on previous months.

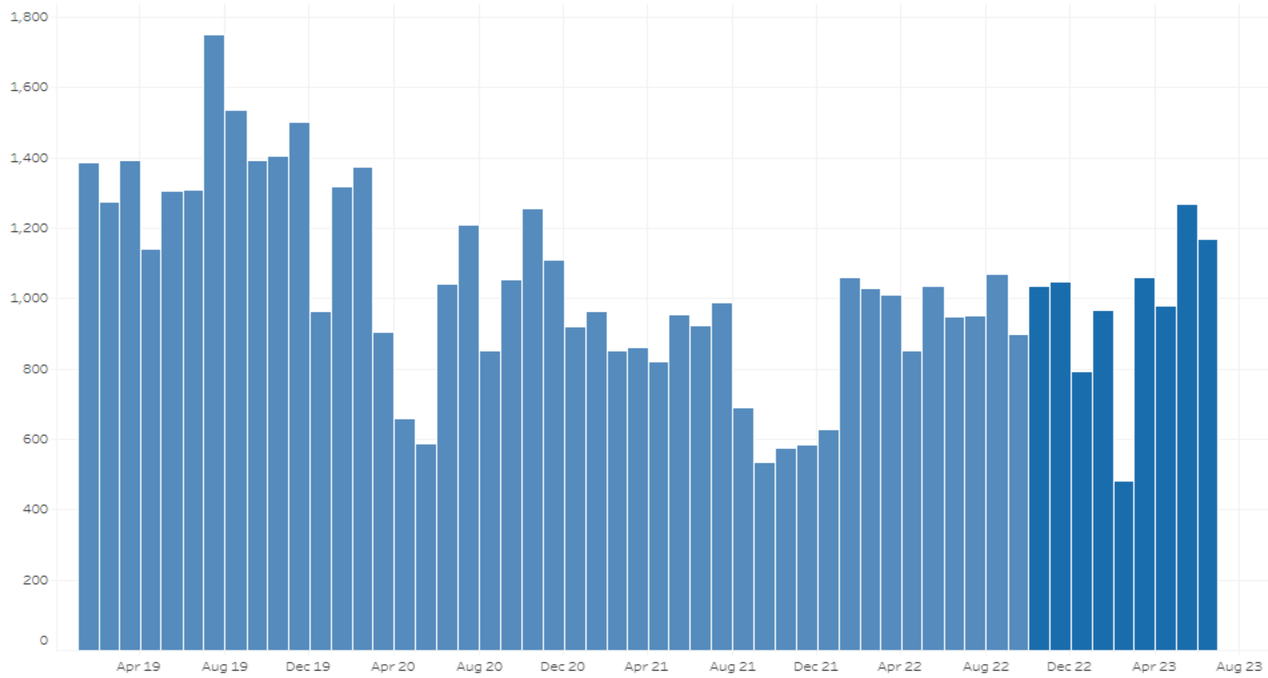

Figure 21: Total ICPs disconnected for non-payment for more than 24 hours

8. Forward market and carbon pricing

8.1. In Q2 2023, forward prices for the remainder of 2023 continued to ease as hydro storage levels remained high. In addition to this, global fuel prices for gas and coal have continued to ease across the quarter, reducing the operational costs for thermal generation and hence forward prices. Prices for later years have eased slightly, but forward prices for the cooler months in future years, particularly in the North Island, remained high.

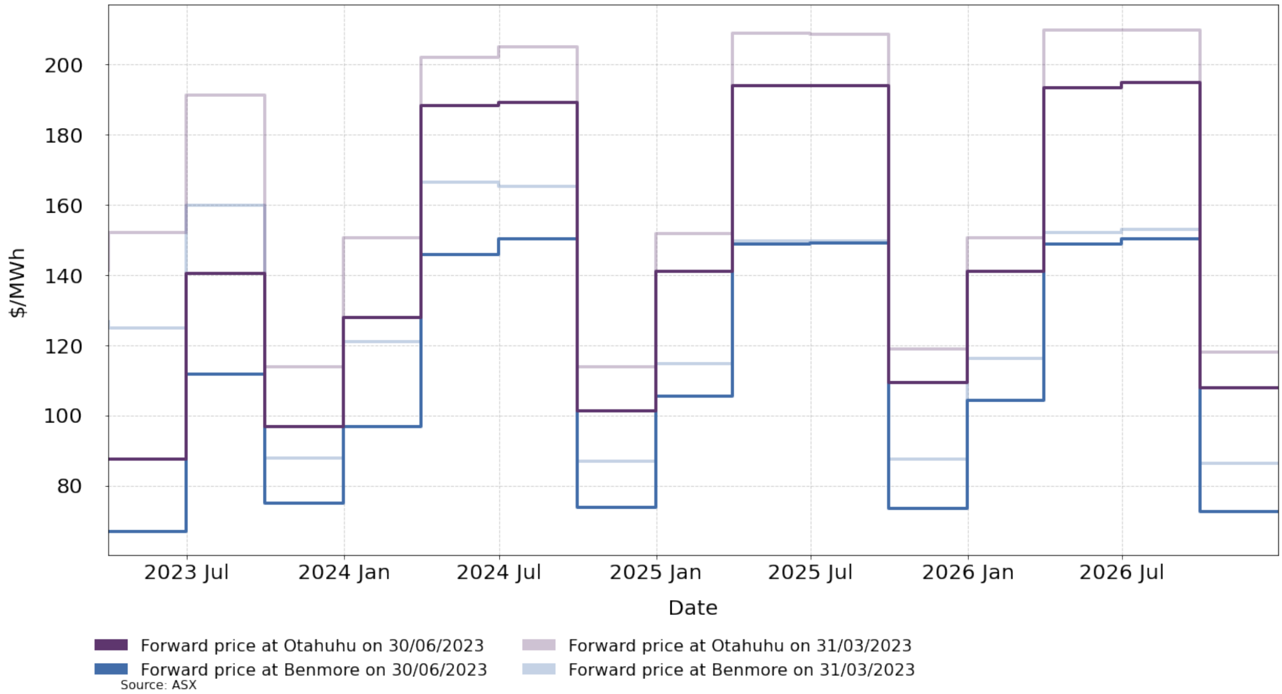

Figure 22: ASX forward prices for the start and finish of Q2 2023

8.2. There was a rapid decline in the New Zealand unit (NZU) prices over Q2 2023 which eased potential costs for thermal generation in the short term. NZU prices peaked in December 2022 above $88. As visible in Figure 23, at the end of the quarter, NZU prices had dropped to $41 per unit. The failure of the second 2023 NZU auction contributed to prices sliding further in Q2 2023 – prices dropped to less than half of the peak reached in late 2022.

8.3. After the end of Q2 2023, the government agreed to realign the NZU pricing in line with the Climate Change Commission's advice, which is expected to reverse the trend of declining prices somewhat in future quarters.

Figure 23: NZU price from April 2022 to June 2023

9. Structure Conduct Performance analysis

9.1. 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 (SCP) 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.

9.2. The period considered is 1 January 2023 to 30 June 2023, ie, two quarters of data. The Authority will continue to include 6-monthly updates of these indicators in every second quarterly review going forward.

9.3. 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.

9.4. For the period 1 January 2023 to 30 June 2023:

(a) Price separation has reflected underlying conditions, consistent with competition

(b) The frequency of low prices has increased and offer prices have reflected underlying conditions, consistent with competition

(c) This may be partially influenced by the very high levels of hydro storage, particularly in May and June, as well as the new provisions

(d) Thermal offers are reflective of changing market conditions, where additional starts increase operating costs above SRMC

(e) Water values appear disconnected from offers; it is possible the unusual North Island inflows this year and exceptional national hydro levels in May and June distorted outcomes. In a competitive market, one would expect a positive relationship between offers and cost, as generators should increase their offer prices if their costs increase.

10. Very low prices

10.1. If prices are being determined in a competitive environment, one 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.

10.2. Figure 24 and Table 1 give an insight into the large share of very low prices in the first half of 2023. In the first half of 2023, very high hydro levels contributed to an extended period of very low prices. Close to 17% of all intervals for these six months were prices below $10/MWh as a result. This compares with 2.5% for the same period the year before.

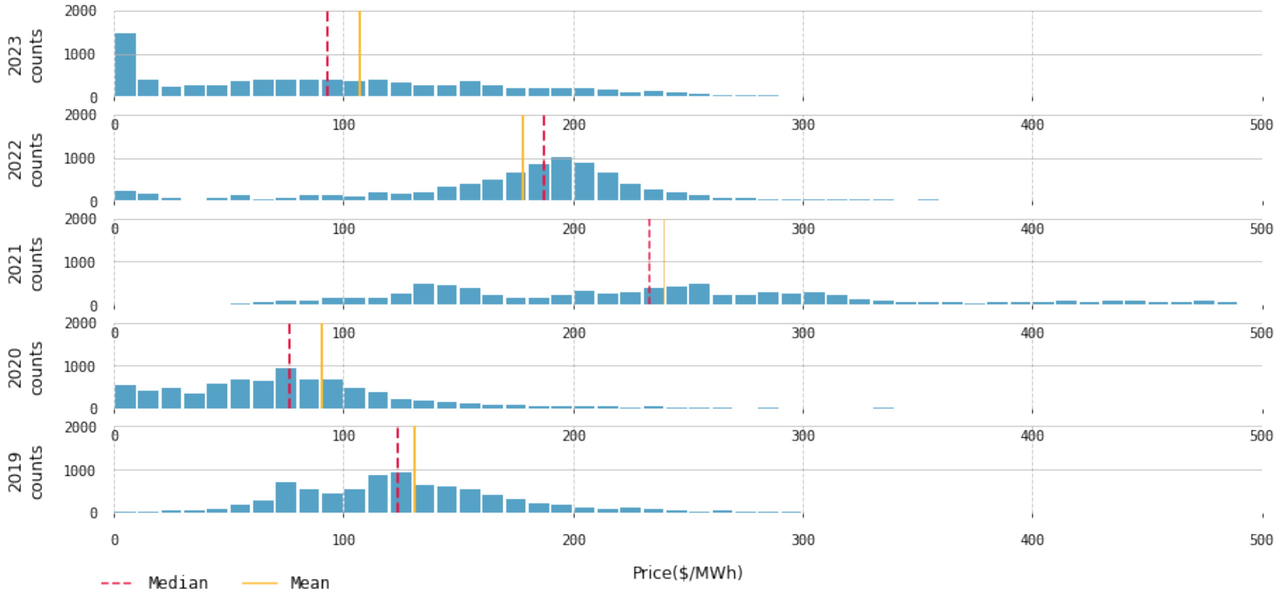

Figure 24: Histogram of price counts for the first six months of each year

10.3. Of the very low prices in the first half of 2023, close to one third of them occurred in off-peak times. This is an increase since 2021, when the new trading conduct provisions were implemented.

10.4. The median 'very low' price in 2022 was lower, but this value was from a much smaller number of intervals where prices were below $10/MWh – 229 as compared to 1466 in 2023. The small share of very low price intervals (2.6%) in 2022 did not have the same distribution of prices between $0.01/MWh and $10/MWh, and was dominated by prices below $1/MWh. The higher share of very low price intervals in other years allowed for a wider distribution of sub $10/MWh prices.

Table 1: Very low prices January 1 to July 31

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	29.3%	$2.08/MWh
2022	24.0%	$0.02/MWh
2015 - 2021	9.2%	$1.95/MWh

10.5. When looking at the distribution of prices across the first half of the year for the last 5 years, Figure 25 shows that the number of intervals above $200/MWh has declined from the peak in 2021. Conversely, the amount of trading periods where prices were below $10, $20 or $30/MWh have all increased in the last 2 years, following the introduction of the trading conduct provisions. The number of trading periods with prices below $10/MWh was higher in 2023 than in any of the past four years. While there were an unusual number of prices above $1001/MWh in 2023, this correlates to times when CAN notices were issued due to low residuals.

	2023	2022	2021	2020	2019
equal or greater than $1001/MWh	24	2	0	0	0
from $201/MWh to $1000/MWh	1084	3111	5374	649	828
from $101/MWh to $200/MWh	2957	4427	2757	1984	5354
from $91/MWh to $100/MWh	404	143	169	673	448
from $81/MWh to $90/MWh	398	144	101	697	539
from $71/MWh to $80/MWh	412	89	93	962	719
from $61/MWh to $70/MWh	392	55	71	652	309
from $51/MWh to $60/MWh	375	155	55	683	212
from $41/MWh to $50/MWh	263	83	17	598	92
from $31/MWh to $40/MWh	278	16	17	353	65
from $21/MWh to $30/MWh	227	76	16	502	54
from $11/MWh to $20/MWh	410	160	8	435	23
equal or less than $10/MWh	1466	229	12	550	47

Counts: 0, 1000, 2000, 3000, 4000, 5000

Figure 25: Heat map of price distribution for the first six months of each year

11. Price separation

11.1. An indication of economic withholding (consistent with the exercise of significant market power) would be subdued price separation, although 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.

11.2. The mean ratio of Haywards to Benmore price continues to be higher since the introduction of the trading conduct rule compared to previous years. However, the mean of the ratio of the Benmore to Manapouri price is low this year. This is probably because – despite national storage levels being above mean – Manapōuri and Te Anau lake levels were mainly below mean until mid-May this year.[4] This meant offer prices were higher at Manapōuri during this time, lowering dispatch from Manapōuri and therefore decreasing price separation between Manapōuri and Benmore.

11.3. The median price separation is a lot lower than the mean price separation in both 2022 and 2023, which results from a few periods of extreme price differences, where the price was 1 or 2 cents at Benmore. Because this work uses a ratio, these extremely low prices can result in a very large ratio. For example, one dollar at Haywards and 1 cent at Benmore would yield a ratio of 100. The much lower median in 2023 and 2022 compared to the mean is consistent with the very low prices discussed in the previous section which skew the distribution[5]. Both mean and median are investigated as this gives a fuller picture of what is happening.

Table 2: Price separation

	Ratio of Haywards to Benmore price		**Ratio of Benmore to Manapouri price**	
Year	**Mean**	**Median**	**Mean**	**Median**
2023	190.84	1.05	1.087	1.06
2022	352.84	1.03	116.8	1.01
2015-2021	24.48	1.06	54.85	1.09

[4] Note: this only includes trading periods when hydro storage is high (ie., where total New Zealand storage is greater than or equal to 100 percent of mean). Periods for the Haywards/ Benmore ratio where one or more of the HVDC poles has been on outage have been excluded, as have periods for the Benmore/Manapōuri ratio where there was an outage for the CUWLP (ie, the Naseby to Livingston line or the Naseby to Roxburgh line was on outage). It also excludes 9 August 2021 when demand was cut.

[5] The median can be defined as the number that is found in the middle of the set of data, so is not affected as much as the mean is by some very large values in the data.

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

12.1. All hydro locations except Manapōuri/Te Anau had high levels for most of the first half of 2023, peaking at record totals for New Zealand storage in early June. In late May and early June, most hydro locations were needing to generate or spill, due to the very high levels of supply. In some cases, this may have muted price sensitivity to changes in demand.

12.2. In the first quarter of 2023, South Island inflows were below the long-term average, which saw storage decrease from around 140% of average at the beginning of January to below mean by early March. Correspondingly, Meridian lifted the majority of its highest offer prices to a higher bracket as storage decreased. As storage rebounded from mid-March, Meridian increased its lower-priced offers. By May, it had near 100 percent of offers priced below $50/MWh as storage reached 130% of mean. In June it had 100 percent of offers less than $1/MWh for a few weeks as storage reached 140% of mean. Since June storage decreased slightly with forecasts of El Nino weather patterns in Spring/Summer this year. Meridian increased its offer prices correspondingly.

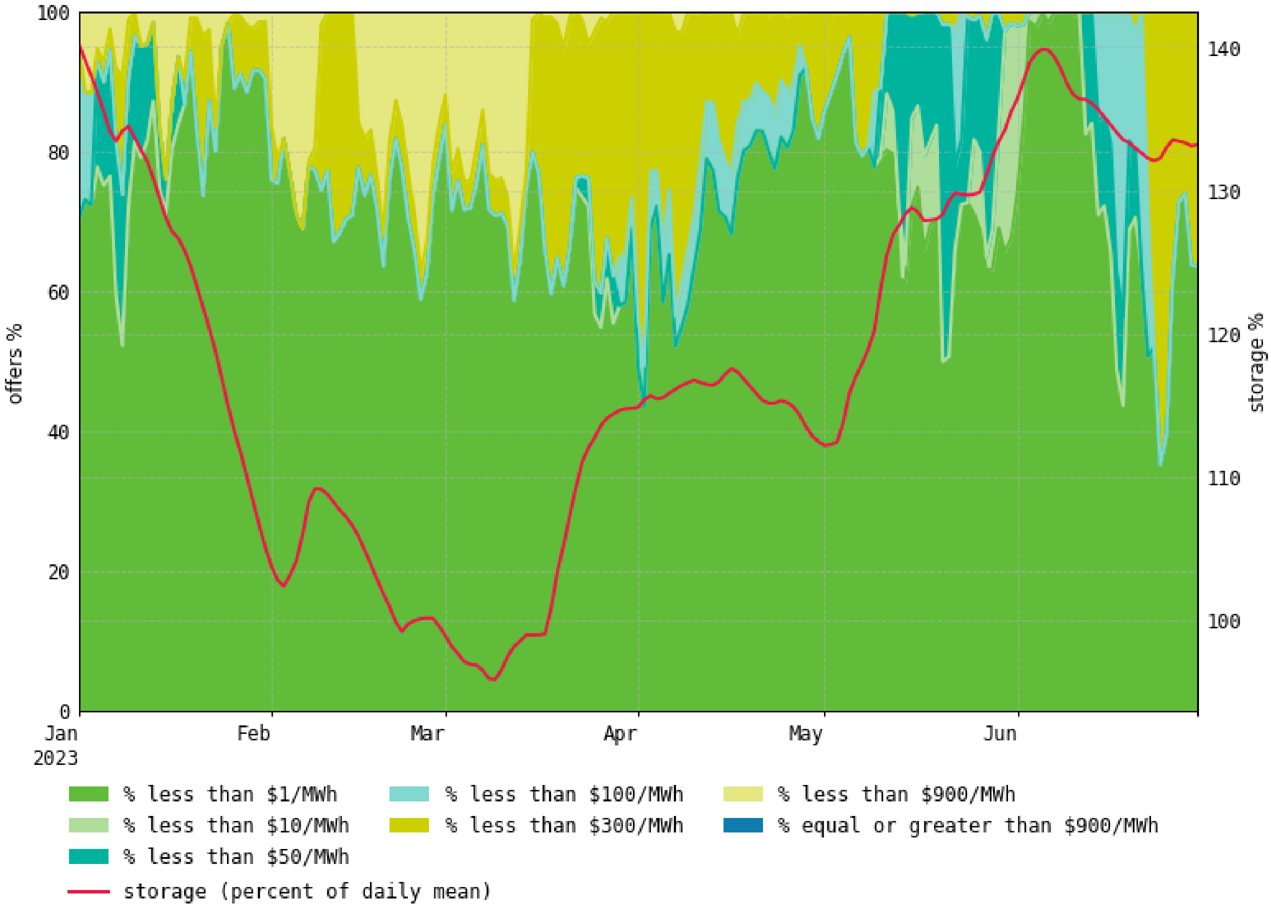

Figure 26: Offers vs available storage for Meridian Waitaki for January to June 2023

12.3. Manapōuri reservoir is not deep and fluctuates quickly in comparison to other locations. As a result, Meridian Manapōuri offers followed their storage levels closely. In late January through to March, when storage was approaching 50% of average, less than half of all offers were below $50/MWh and the remainder were between $300-$900/MWh. As levels went above the long-term average the share of low-price offers increased; up to 100% of offers when Manapōuri was spilling in May and June.

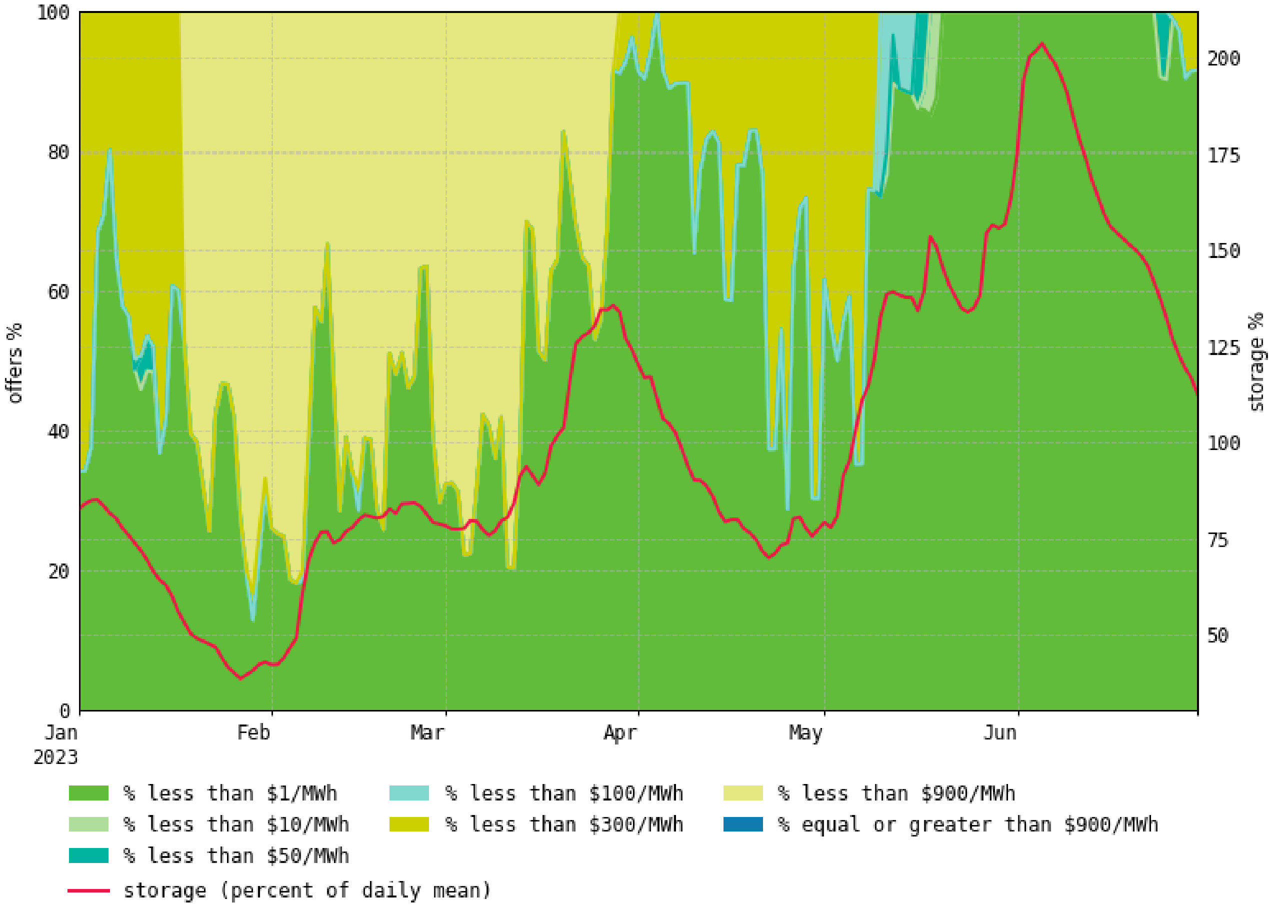

Figure 27: Offers vs available storage for Meridian Manapōuri for January to June 2023

12.4. The Mercury Waikato scheme is the largest hydro scheme on the North Island but does not have the depth of some of the southern hydro schemes. As such, its offers are more directly correlated with weekly demand patterns than overall storage levels – as visible in Figure 28. An example is the dip in low priced offers in early April during the Easter period.

12.5. However, there is some correlation with storage levels – in both February and May after large inflows, the share of offers below $10/MWh increases from around 70% to around 90% of offers until conditions eased. Mercury's offer prices also increased from mid-June as storage decreased and El Nino forecast conditions for Spring/Summer became more likely. At all times, around 20% of offers are above $300/MWh. As with last time, Mercury's offer prices for peak and off-peak trading periods were examined separately. For peak trading periods it had a lower percentage of offers above $300/MWh. From mid-May to mid-June it often had 100% of offers priced below $10/MWh for peak trading periods.

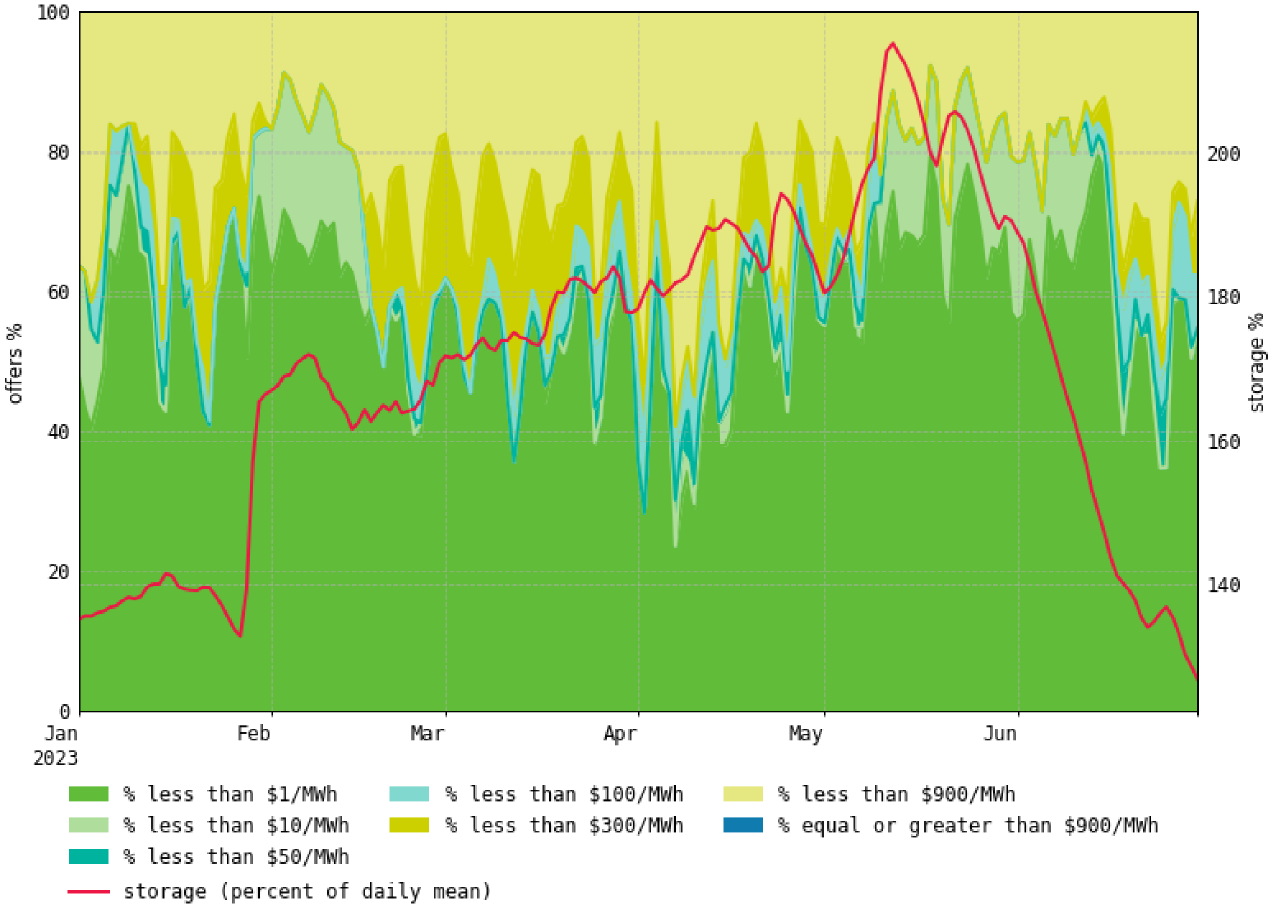

Figure 28: Offers vs storage for Mercury Waikato for January to June 2023

12.6. The Contact Clutha scheme also does not have much storage and similarly to the Waikato scheme, its offers are more closely aligned with week-to-week demand traces rather than its storage levels in the first half of 2023. The share of very low-priced offers increased as overall demand increased in the colder months and it is only as storage levels exceeded 120% of the long-term average that the higher priced offers began to drop.

12.7. The brief period where storage is high and offer prices are also high is explained by outages from 7-10 June 2023.

12.8. As with Mercury, Contact also had a higher percentage of lower priced offers for peak trading periods.

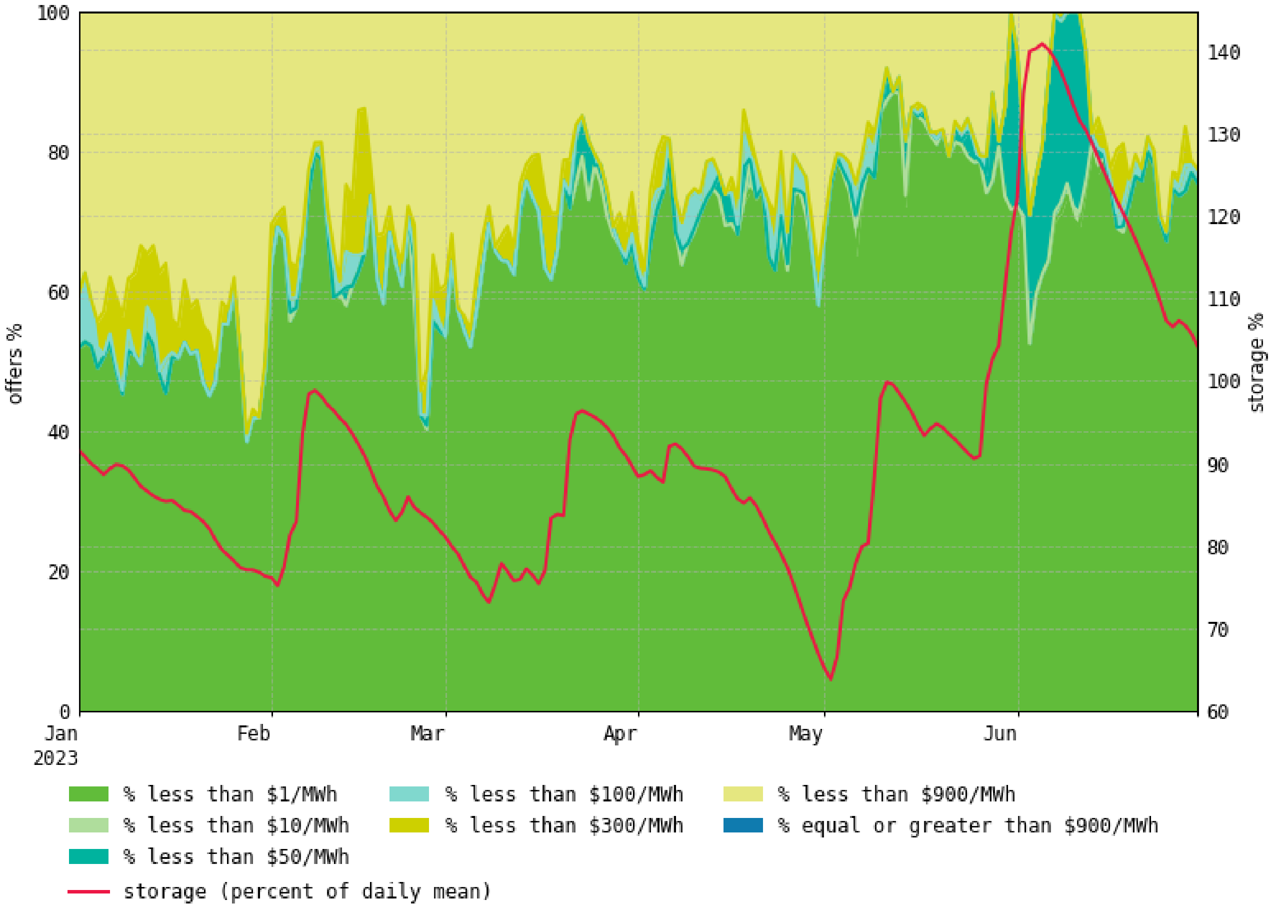

Figure 29: Offers vs storage for Contact Clutha for January to June 2023

12.9. Genesis Takapō offered in a similar pattern to the previous year, with the majority of offers at less than $1/MWh. In the middle of May, there were a series of CAN notices for low residual situations, which correspond with most of the higher priced offers at Takapō. These periods are explored in more detail in the weekly trading conduct reports.

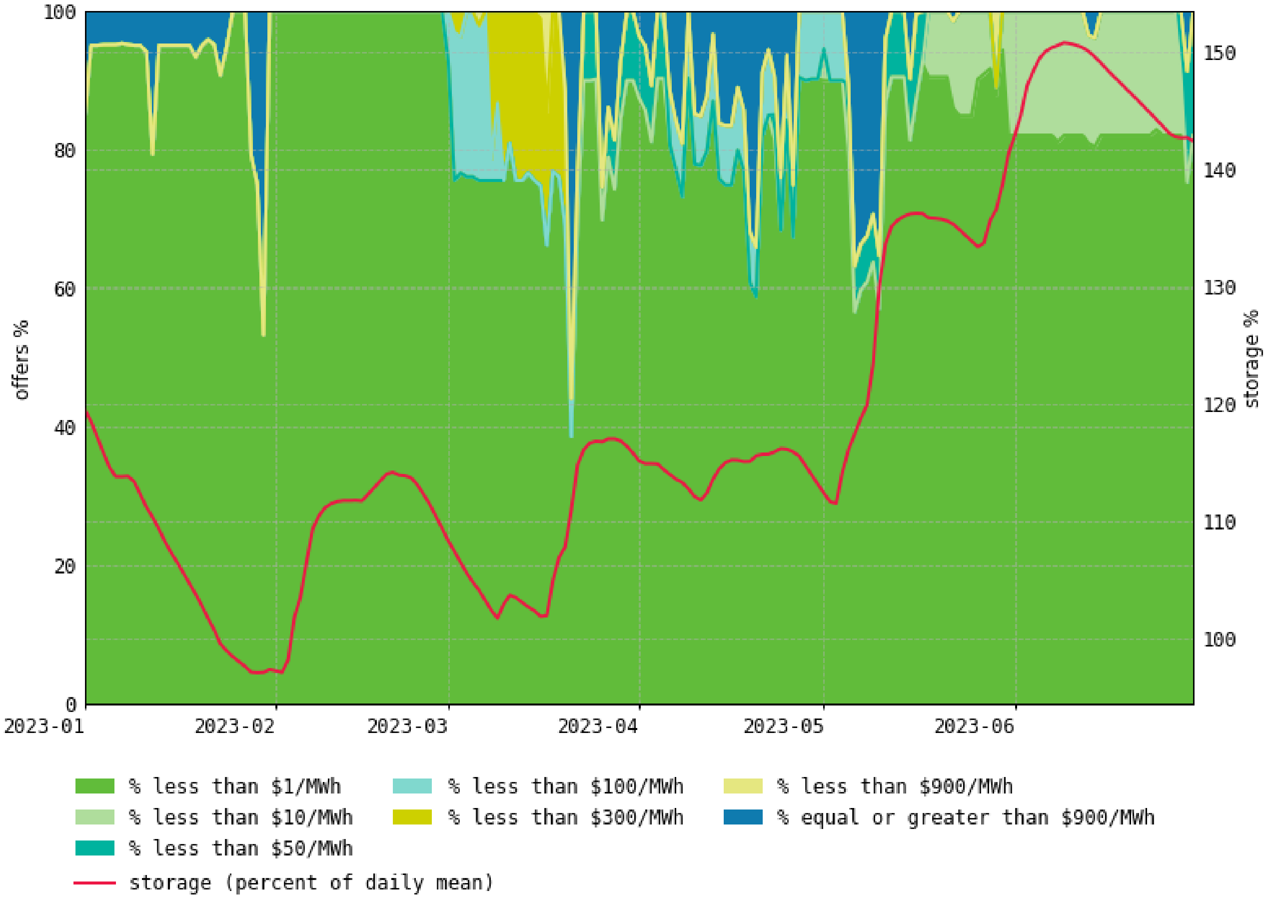

Figure 30: Offers vs storage for Genesis Takapō for January to June 2023

12.10. Tables 3 to 6 cover the dates when the reservoir storage was above the long-term average storage. Clutha (Hawea) spent much of January to June 2023 below this threshold (as visible in Figure 29), but most other major storage locations had high storage[6] in the first half of the year. These tables consider the percentage of offers above $300/MWh, and above the final price or above various measures of cost.

12.11. Prices above $300/MWh when storage was high decreased for the Waikato and stayed about the same for all other hydro participants when compared to last year. Similarly, the percentage of offers above final prices was similar compared to last year for the Waitaki, Clutha and Takapō, and decreased for Waikato.

12.12. Stratford and Huntly increased on all metrics when compared to last year – percentage of offers above $300/MWh, above final price, above the forward price and above short run marginal cost (SRMC). This was determined to be the result of several underlying factors and most likely not the exercise of market power. Increasing hydro storage throughout the first half of the year exerted downward pressure on forward prices. This also meant a greater proportion of hydro generation was dispatched and hence final prices were lower –

[6] Only trading periods when hydro storage was high are included for each table – 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. Only periods of high hydro storage are included because there were few trading periods where total New Zealand storage, Pukaki, Takapō or Taupo storage were low (ie, less than 80 percent of mean) in these months in 2023. Note this means only about one month of data is included in the tables for Contact (Clutha).

Section 4 and 5 of the main report outline how hydro displaced a large share of thermal generation in Q2 2023.

12.13. The higher dispatch of hydro generation has also meant a change in operating conditions for thermal generators, which are reflected in higher offer prices. For both Stratford and Huntly the amount of operating hours has declined and the amount of restarts per unit has increased. Given each restart carries additional cost, short term operating costs and hence offer prices would increase all else being equal.

Table 3: percentage of offers over $300/MWh, January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2023	25%	4%	5%	16%	74%	23%
2022	44%	0%	7%	15%	42%	13%
2019-2021	44%	25%	2%	12%	34%	10%
2014-2018	7%	23%	2%	0%	0%	5%

Table 4: Percent of offers above final price, January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2023	34%	22%	8%	27%	83%	35%
2022	55%	16%	7%	31%	56%	23%
2019-2021	54%	32%	2%	30%	61%	19%
2014-2018	42%	38%	8%	13%	62%	20%

Table 5: percentage of offers above the average forward price January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2023	19%	9%	4%	12%	56%	23%
2022	38%	10%	6%	8%	42%	15%
2019-2021	35%	20%	1%	16%	42%	13%
2014-2018	25%	20%	5%	3%	37%	11%

Table 6: percentage of offers above thermal SRMCs January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2023	25%	10%	5%	17%	76%	26%
2022	32%	7%	7%	16%	19%	16%
2019-2021	32%	28%	2%	21%	33%	14%
2014-2018	24%	31%	7%	3%	27%	13%

Table 7: Percentage of offers above water values January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)

2023	32%	17%	8%	17%

13. Relationship of storage and offers to cost

13.1. For January to June this year, only the Waitaki and Clutha JADE water values were negatively correlated with storage (as shown in Table 8). For the Waikato, this may be due to storage this year following a much different pattern to normal (historical) storage trajectories. It may also be because Taupō storage followed a different trajectory this year to South Island storage.

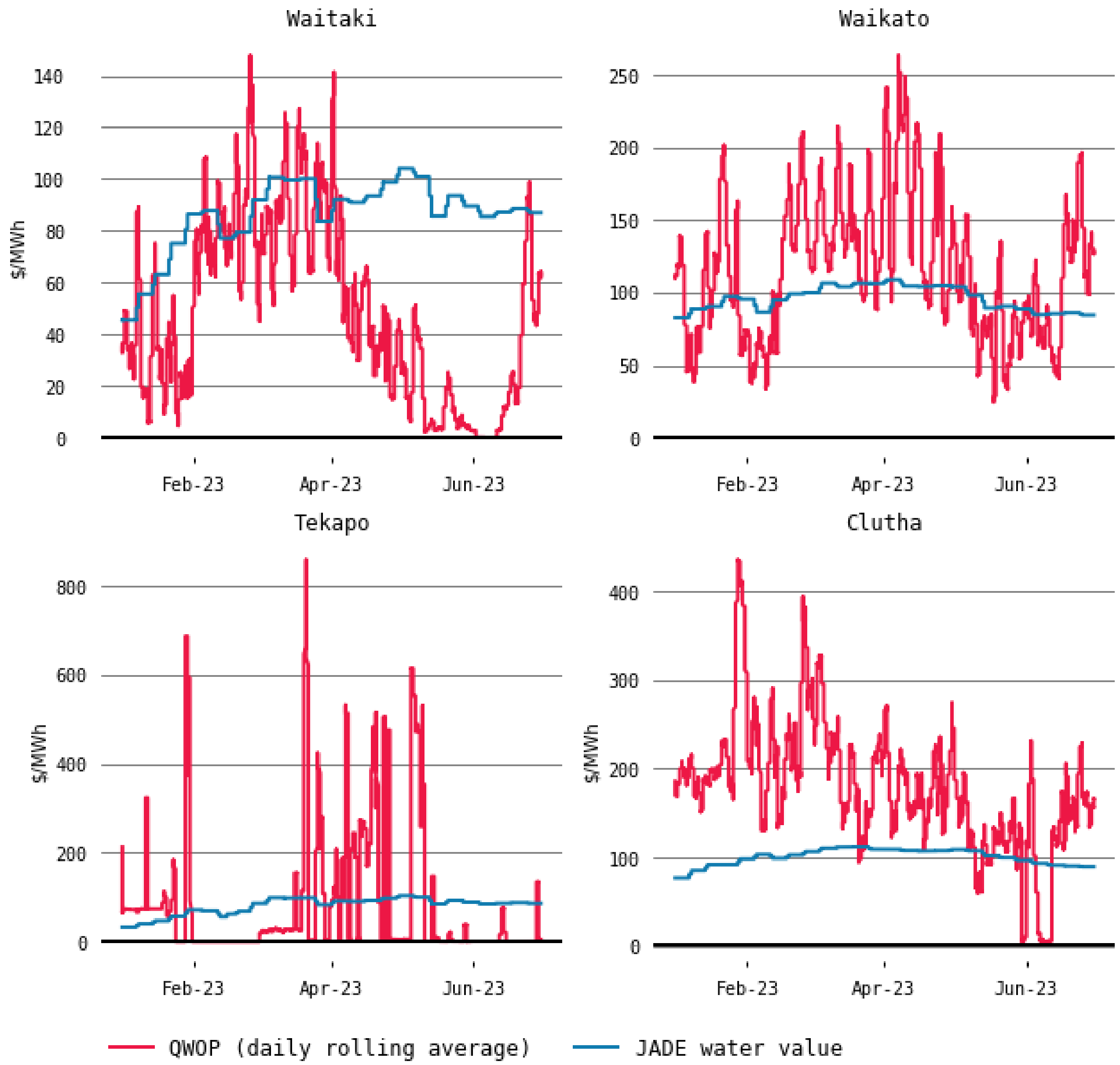

Figure 31: Quantity weighted offer prices for January - June 2023

13.2. When water values are calculated, the storage available in other reservoirs also needs to be accounted for. This was tested by examining the correlation of national storage with Taupō water values. This correlation was -0.41, confirming the theory. However, this was not the case for Takapō (the correlation of national storage with Takapō water values was 0.11). This may be due to the increase in storage over May and June when historically storage usually decreases at this time of year. While storage increased, water values remained high.

13.3. Similar to the findings last time, none of the schemes had strong positive correlations between offers and the JADE water values (both for the daily percentage of offers greater than $300/MWh and for QWOP – although Mercury had a higher correlation with QWOP). However, we may not expect this relationship to be strong when the water values are not highly correlated with storage. The overall picture presented by the indicators suggests a continuation of the trading conduct provisions having a positive impact on generator behaviour.

Table 8: Correlations of water values with hydro storage - January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2023	0.49	-0.32	0.17	-0.41

Table 9: Correlation of water values with percentage of offers above $300/MWh - January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2023	0.13	-0.18	-0.30	-0.04

Table 10: Correlation of water values with QWOP - January to June 2023

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2023	0.28	0.05	0.15	0.05