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Market performance Quarterly review

April – June 2024

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1. Purpose

1.1. This document is a review of the performance of New Zealand's energy market from 1 April to 30 June 2024.

1.2. The Government Policy Statement sets out expectations for the electricity industry. Section 29 states that effective competition is essential for our electricity system to deliver reliable electricity at the lowest price to consumers. The Electricity Authority Te Mana Hiko (Authority) quarterly market review retroactively considers the market over the last quarter. It seeks to assess whether spot prices were reflective of the underlying supply and demand conditions the sector faced. It also analyses changes in the retail and forward market. Visibility of the previous market conditions, and of our market monitoring, gives the sector higher confidence that prices are being set in a competitive market.

2. Highlights

2.1. National demand was higher this quarter than the 2019-23 historic average, especially in May, when May average temperatures were the coldest New Zealand has seen in 15 years.

2.2. Two customer advice notices (CAN) were issued by Transpower for low residual supply on 8 and 10 May, with the 10 May CAN upgraded to a warning notice. This 8-10 May period saw the highest spot prices of the quarter, with several prices over $500/MWh and the highest price of $4,650/MWh.

2.3. Thermal generation this quarter increased by 59% compared to the same quarter last year to 1,791GWh, mostly due to decreasing hydro storage.

2.4. The new Tauhara geothermal unit started running continuously at around 155MW in late May, leading to increased geothermal generation in the weeks it ran.

2.5. National controlled hydro storage increased in April due to a major rainfall event, then declined over the rest of the quarter. Storage at the end of the quarter was 2,182GWh or ~48% nominally full.

2.6. The mean daily volume-weighted average price (VWAP) for gas in Q2 2024 was ~$26/GJ. This is an increase of ~$9/GJ on the previous quarter and ~$17/GJ on Q2 2023.

2.7. Meridian Energy, Mercury Energy and Pulse Energy Alliance lost the largest number of electricity connections (ICPs) this quarter. Contact Energy, Flick Electric and 2degrees gained the largest number of electricity connections this quarter.

2.8. Retail electricity prices increased at above the rate of inflation (ie, in real terms). In nominal terms (ie, not adjusted for inflation), prices have increased by ~$136 per year for the average household.

2.9. Forward prices increased for all contracts this quarter. Near term futures likely saw increases because of declining hydro storage, while long term futures increases are likely reflecting gas supply concerns.

2.10. The price of New Zealand carbon units (NZUs) decreased over the quarter from $64 per unit to $51 per unit.

3. Electricity demand

Demand across the quarter

3.1. Figure 1 shows the total daily electricity demand in 2024 and the 2019-23 historic average demand between April and June.

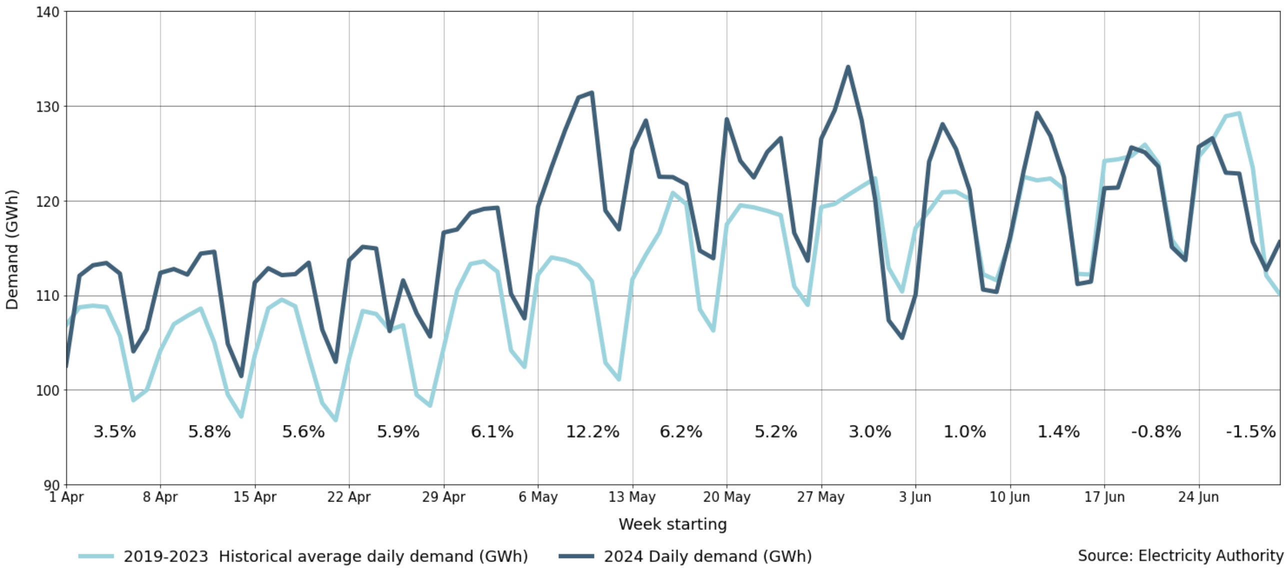
3.2. National weekly demand increased by between 1.0% and 12.2% compared to the historic average for most of the quarter. Demand increase was likely driven by unseasonably cold temperatures (May 2024 was the coldest New Zealand has seen in 15 years[1]).

3.3. The last two weeks of June saw decreases of 0.8% and 1.5% compared to the historical average, likely because June temperatures were slightly above average.[2]

3.4. Two customer advice notices[3,4] (CAN) were issued by Transpower for low residual supply[5] on 8 May and 10 May. These corresponded with unseasonably low temperatures and high demand during the week starting 6 May when demand was 12.2% up on the historical average. The 10 May CAN was upgraded to a Warning Notice (WRN), however, an industry wide response averted any supply shortfalls.

3.5. Several grid emergency notices[6] (GEN) warnings were also issued on 11 and 12 May related to extreme solar activity which resulted in 8 South Island lines being removed from service for 11-12 May.

Figure 1: New Zealand daily demand compared to historical average, April to June 2024



3.6. Figure 2 displays New Zealand demand and Figure 3 displays national apparent temperatures during the week when the two CAN notices were issued for the mornings of 8 and 10 May. All main centres experienced temperatures below the historical national average and Christchurch dipped below -5°C on the morning of Friday 10 May. These unseasonably cold temperatures saw peak demand rise to near or above the historical maximum demand for May 2019-23.

1 NIWA Climate Summary for May 2024
2 NIWA Climate Summary for June 2024
3 CAN Low Residual Situation 5371178083
4 CAN Low Residual Situation 5373464415.
5 These are issued when national residual generation is less than 200MW in the forward schedules.
6 GEN G5 Extreme Geomagnetic Induced Current event South 5380954216

Figure 2: New Zealand demand compared to the historical range, 6 May to 12 June 2024

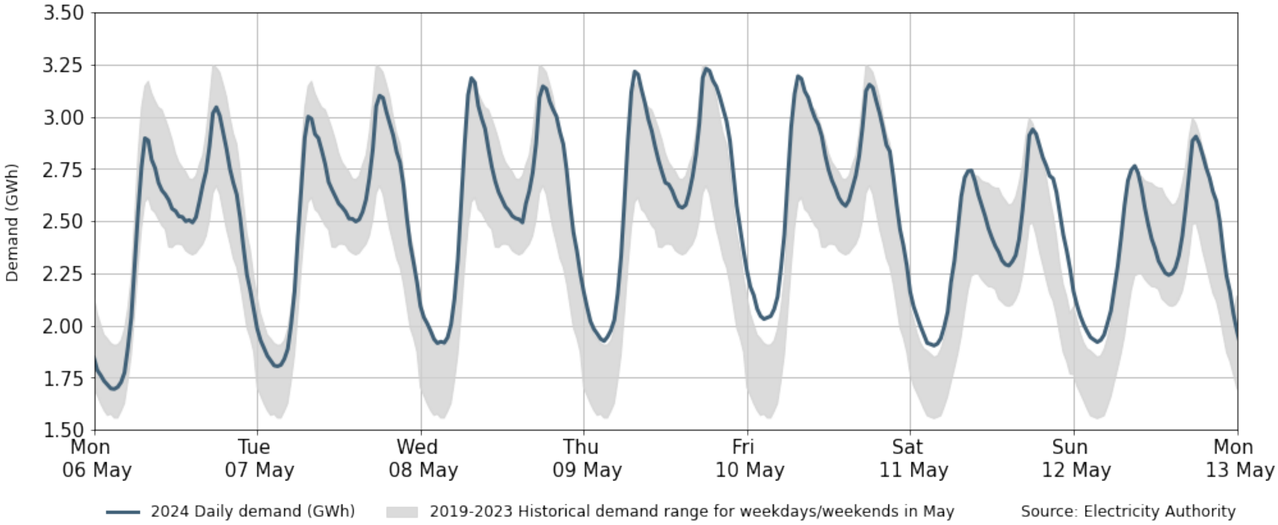
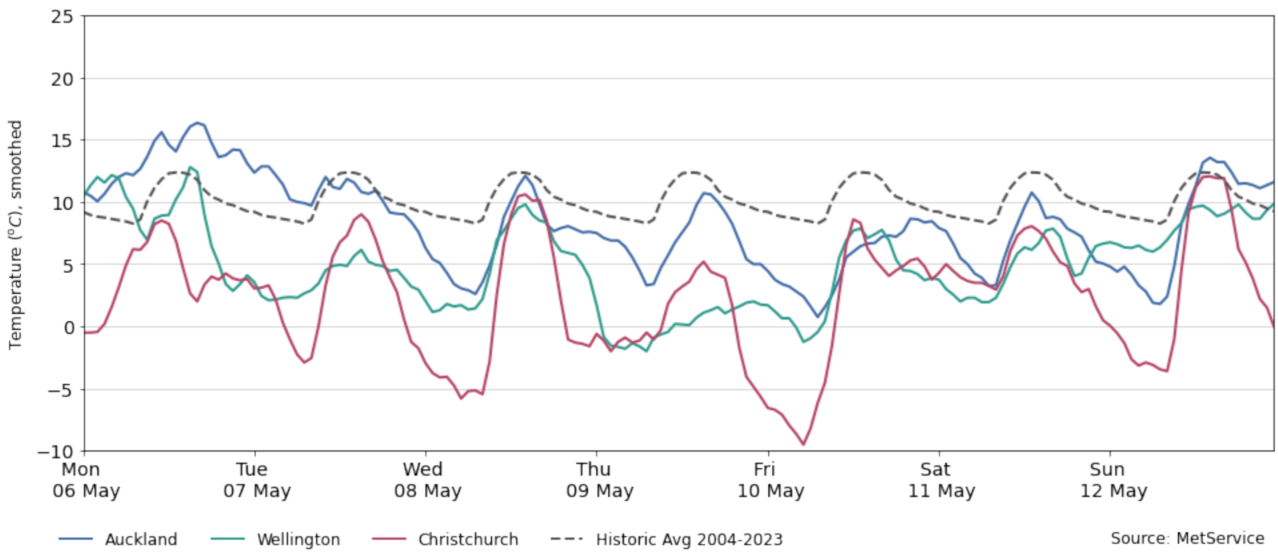


Figure 3: Apparent temperatures across main centres, 6 May to 12 June 2024



4. Wholesale electricity price and consumption

4.1. Figure 4 shows the half hourly and daily national wholesale electricity spot prices between April and June 2024. The historic daily average between 2018-23 adjusted for inflation is also displayed. Figure 5 shows the weekly spot price distributions between April and June 2024.

4.2. The middle 50% prices in Q2 2024 were between \$232/MWh and \$280/MWh. The average wholesale spot price for Q2 2024 was \$261/MWh, which is significantly higher compared to the averages of Q1 2024 (\$188/MWh) and Q2 2023 (\$79/MWh).

4.3. Prices saw a decrease in the middle of April when hydro storage increased. There were several high prices over \$500/MWh in May. This included the maximum for the quarter of \$4,650/MWh on the morning of Wednesday 8 May. These high May prices related to the increased demand peaks (as discussed in Section 3), low wind generation, wind forecasting inaccuracies, and unusually low hydro storage. Prices were fairly stable in June.

4.4. Average weekly prices were relatively consistent this quarter, excluding the slight price dip in April.

Figure 4: Half hourly, daily and daily historic average wholesale electricity prices, April to June 2024

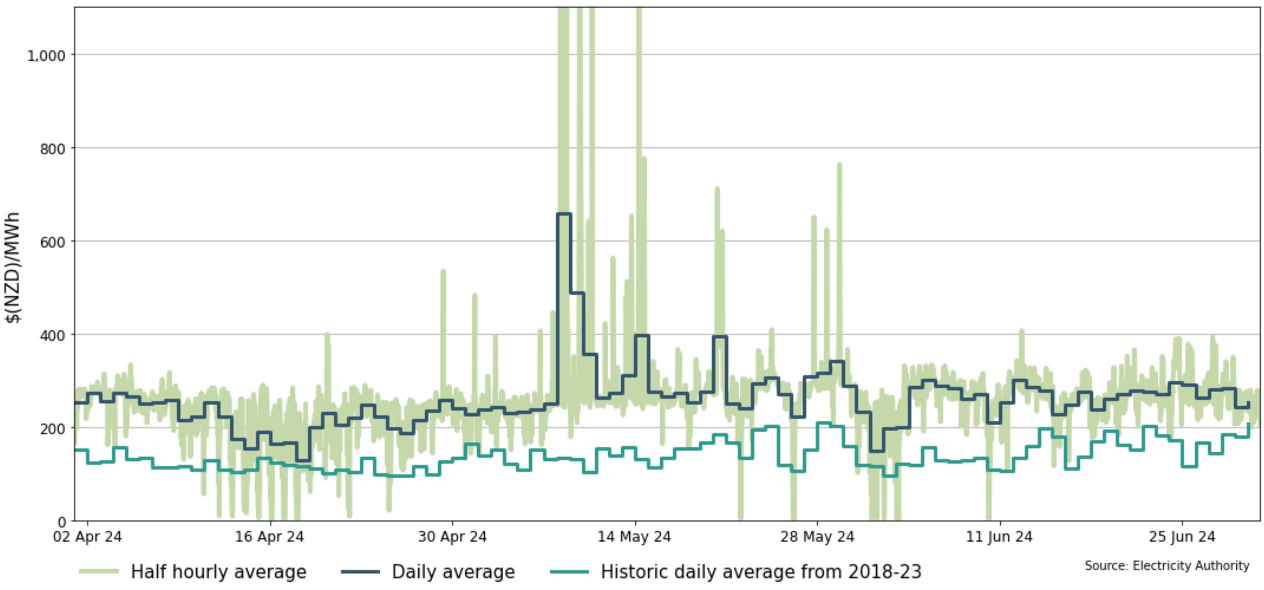
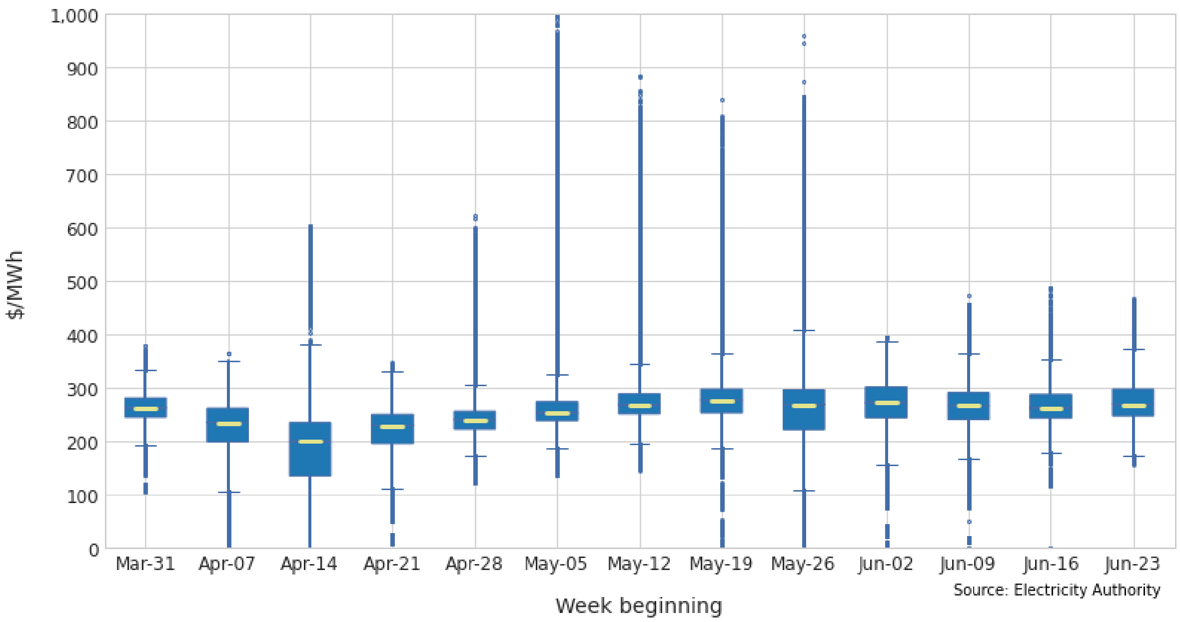


Figure 5: Box plot distributions of weekly spot prices between, April to June 2024



Generation composition influence on price

4.5. 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. The source of electricity generation plays a role in price, as different sources have different prices and generation characteristics.

4.6. 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 so they can affect prices for weeks or months.

4.7. Figure 6 shows the daily total wind generation and the daily average national spot prices between April and June. 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.

4.8. While the increased wind generation did cause some decreases in wholesale electricity prices in Q2 2024 (Figure 6).

4.9. Table 1 shows the correlations between wind and price. The correlations are negative as generally when wind is higher, spot prices are lower. The higher the correlations, the greater the impact wind generation had on price. In 2024, the inverse relationship was not as strong as in previous quarters. Due to low hydro storage, wind generation has often been displacing the more expensive hydro generation in this quarter. This is different to previous quarters where cheap wind generation was displacing thermal generation. This led to prices remaining high despite days of high wind generation in May and June. For example, in late May and early June, high levels of wind generation only pushed the daily average price down to $131/MWh.

Figure 6: Daily wind generation and average wholesale price, April to June 2024

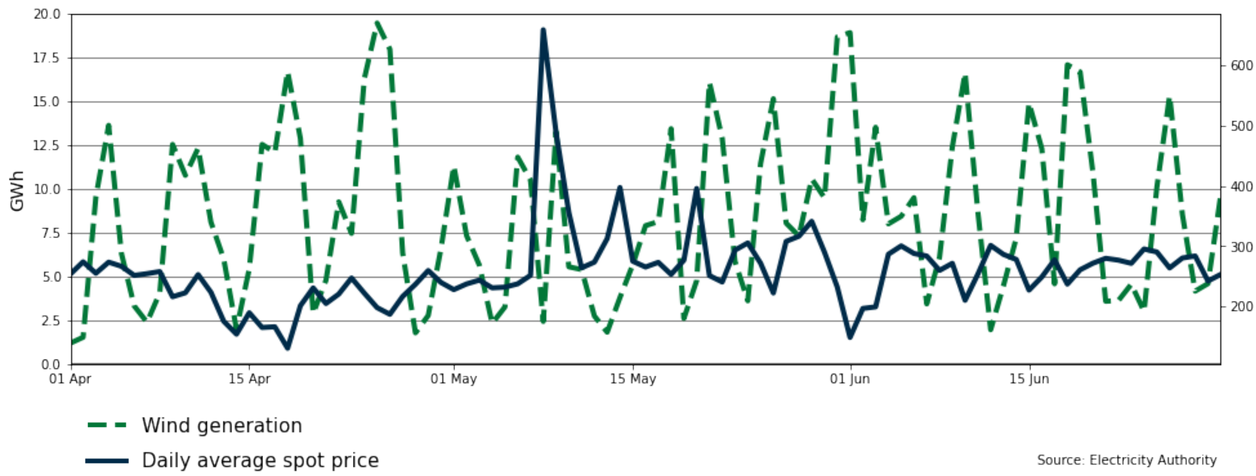
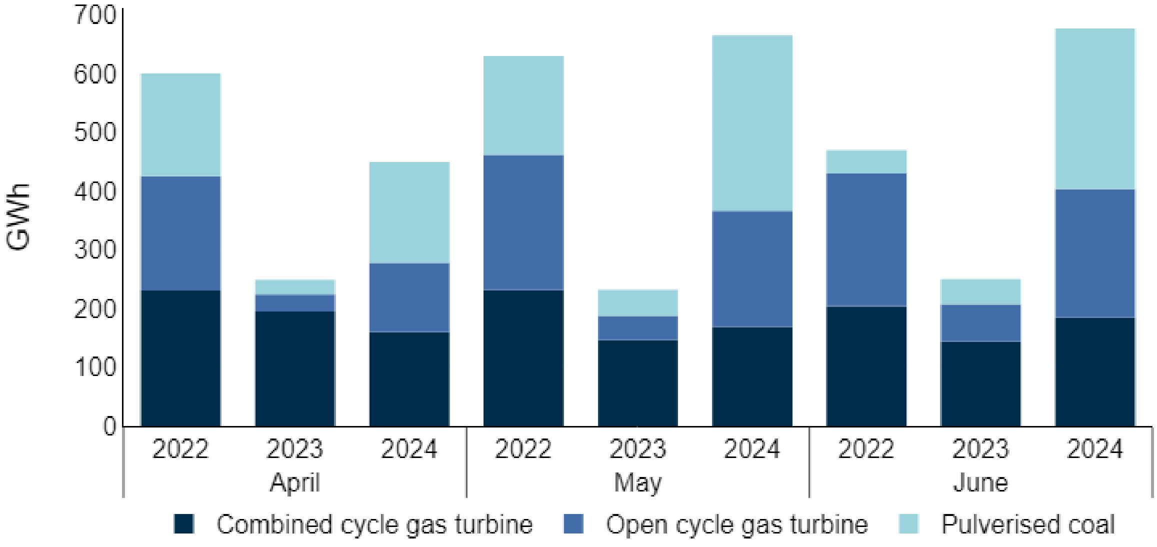


Table 1: Correlation of wind generation and average wholesale price, Q2 2024 and previous four quarters

Quarter	Correlation of wind generation and price
Q2 2024	-0.32
Q1 2024	-0.44
Q4 2023	-0.42
Q3 2023	-0.45
Q2 2023	-0.39

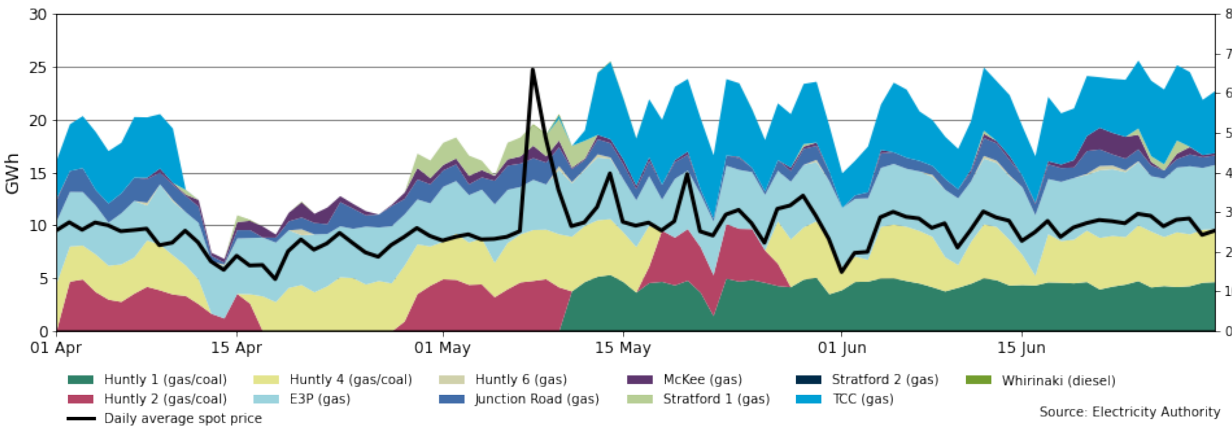
4.10. Figure 7 shows the total thermal generation by type and month in Q2 for the past three years. Overall, there was a 59% increase in thermal generation this quarter (1,791GWh) compared to Q2 2023 (730GWh). This was largely due to the substantially decreased hydro storage this quarter.

Figure 7: Monthly total thermal generation, Q2 2022-24



4.11. Figure 8 shows the daily total thermal generation and daily average spot price between April to June 2024. Thermal generation decreased in mid to late April because TCC turned off during the increase in hydro storage and was on outage in early May. E3P ran consistently throughout the quarter, likely due to the decreased hydro. Stratford 1 came on in early May, likely due increased demand, which also increased the daily average spot price. Huntly 1 came back on 11 May, after being on outage since 3 February.

Figure 8: Daily total thermal generation and average wholesale price, April to June 2024

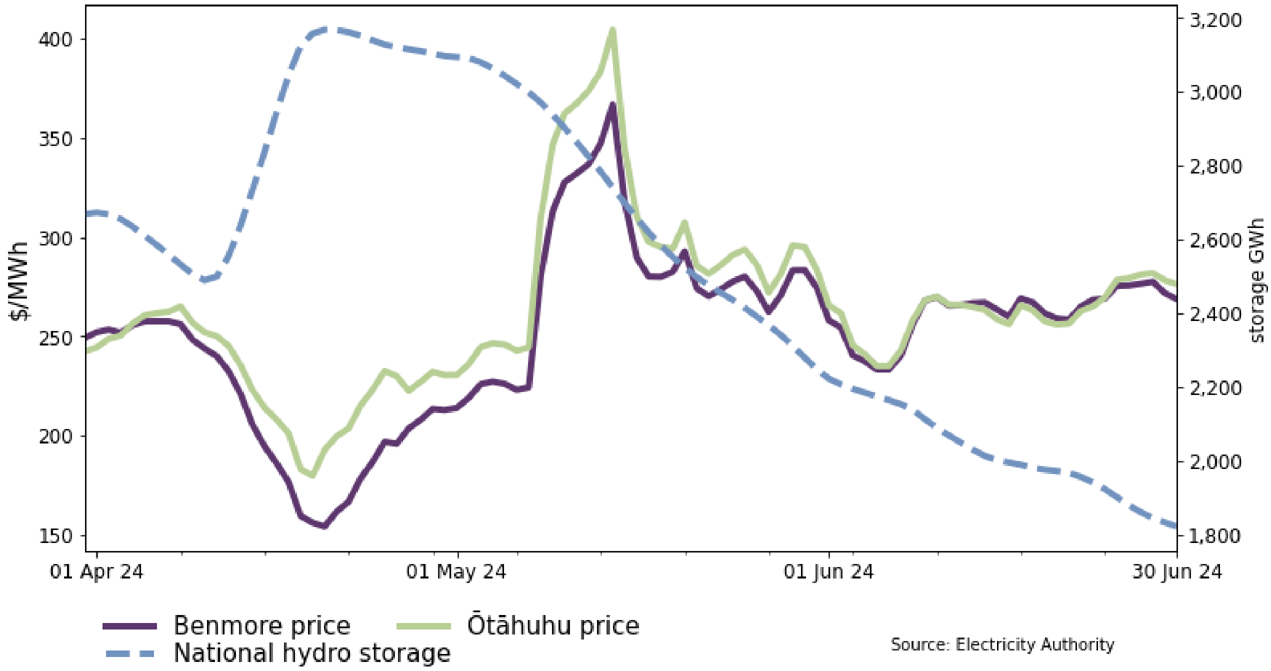


4.12. Figure 9 shows the rolling seven-day average wholesale prices at Benmore and Ōtāhuhu and the daily national hydro storage.

4.13. 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.

4.14. Figure 9 shows that hydro storage levels increased briefly in April, before falling during the rest of Q2 2024. The increase in April drove wholesale prices down, but prices increased substantially as hydro storage decreased in May. Prices remained high in June as hydro storage continued to fall.

Figure 9: Rolling seven-day average of wholesale price versus hydro storage, April to June 2024



Generation by fuel type

4.15. Figure 10 shows the weekly breakdown of electricity generation by fuel type.

4.16. Hydro generation was highest the week of 14 April, making up 59.4% of the weekly generation, when hydro storage was also high. Hydro continued to contribute more than 55% of the weekly generation until the week of 12 May when storage began to decrease.

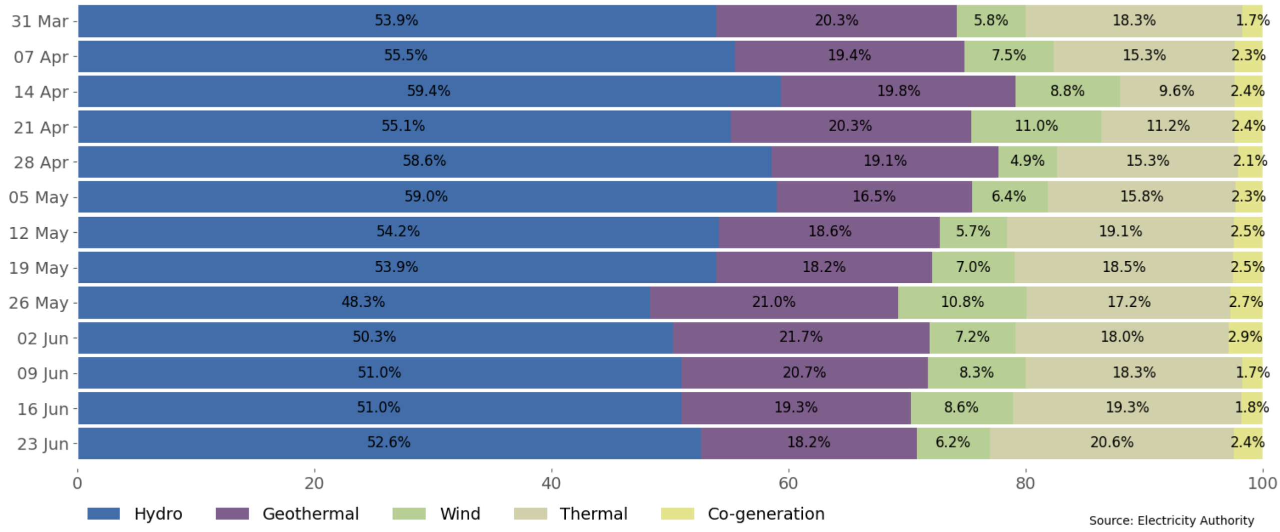
4.17. Average wind generation this quarter was 7.5%, a decrease from the previous quarter (9.3% in Q1 2024) but an increase compared to the same quarter last year (4.9% in Q2 2023).

4.18. The average thermal supply this quarter was 16.7%. This is a substantial increase from both last quarter (12.2% in Q1 2024) and the same quarter last year (6.5% in Q2 2023).

4.19. The inverse relationship between renewable and thermal generation can be seen in Figure 10. The weekly share of thermal generation was lowest when wind and hydro generation were high. When wind or hydro generation is low, thermal generation generally increases to compensate. Thermal generation was typically high this quarter, even during periods of high wind, as hydro storage was low enough that wind generation was compensating for decreased hydro generation.

4.20. The new Tauhara geothermal unit started running continuously at around 155MW in late May, leading to increased geothermal generation. Geothermal was decreased in the last week of June when Tauhara was on outage.

Figure 10: Weekly generation share by fuel type, April to June 2024



5. Water storage levels

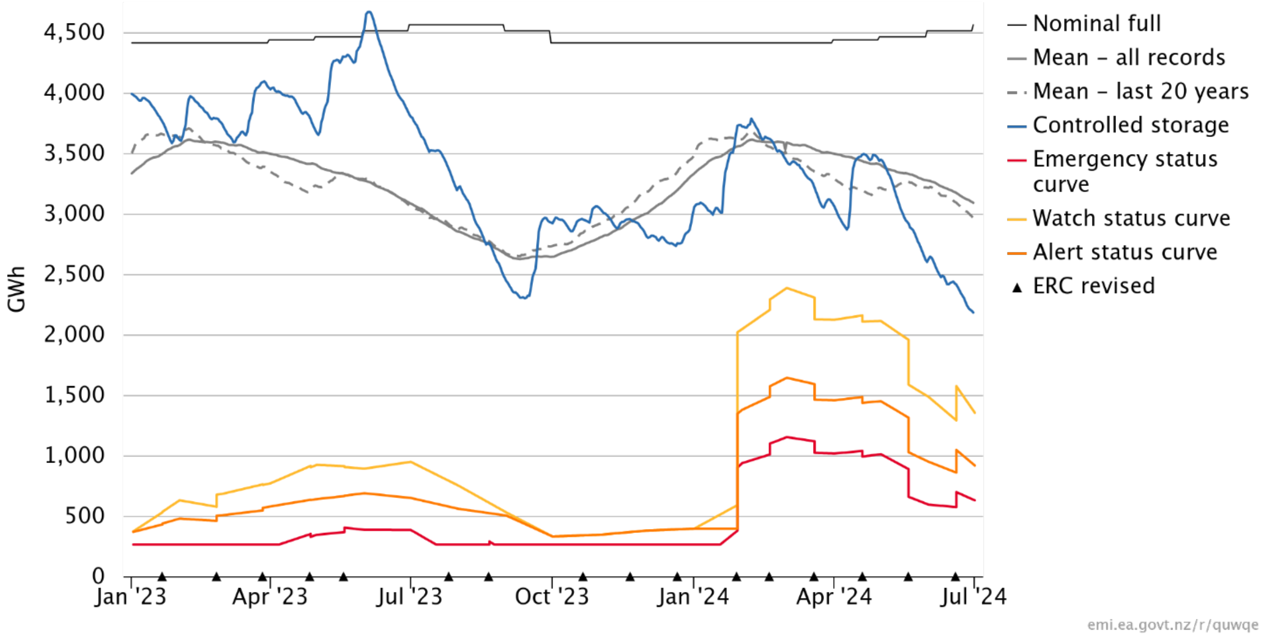
National hydro storage levels

5.1. Figure 11 shows the national hydro storage levels from January 2023 to June 2024.

5.2. At the beginning of Q2 2024, national storage was 3,056GWh. Hydro storage declined over the quarter with only one significant rainfall event in April which saw storage peak at 3,494GWh on 20 April. Storage at the end of Q2 2024 was 2,182GWh which is 1,640GWh lower than storage at the end of Q2 2023.

5.3. Electricity risk curves reduced over the quarter. This reduction mostly occurred in May because of a reduction in modelled gas usage by the petrochemical industry, making more gas available for electricity generation.[7]

Figure 11: National hydro storage levels, January 2023 to June 2024



[7] ERC Update Log - May 2024 including Reduced Gas Availability

Lake storage levels

5.4. Figure 12 shows individual lake levels in Q2 2024 and the difference location can have on hydro inflows.

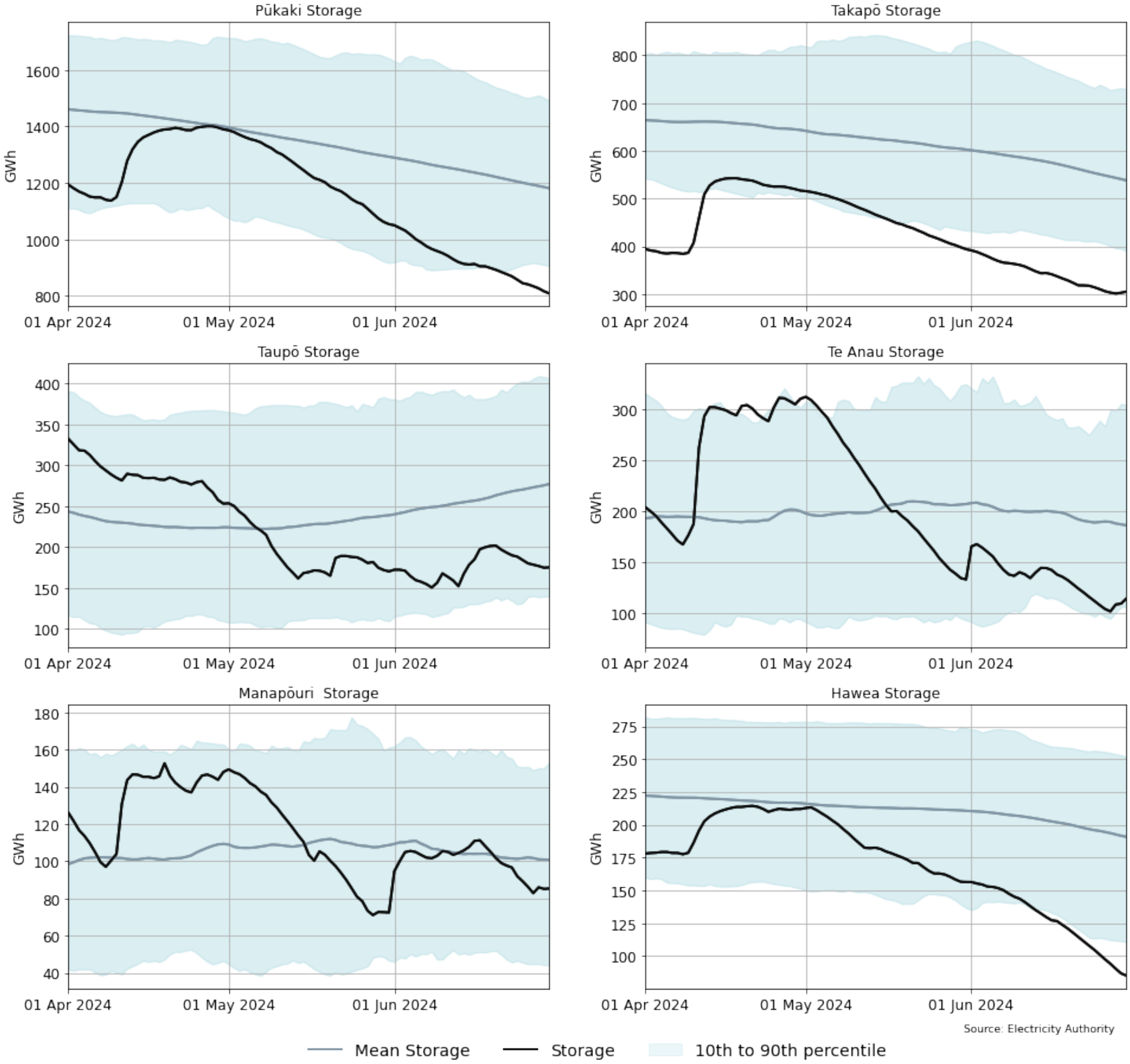
5.5. Pūkaki and Hawea storage rose to near their mean storage after the April rainfall event and reduced to below their 10th percentile by the end of the quarter.

5.6. Takapō storage rose to just above its 10th percentile after the April rainfall event and dropped below its 10th percentile from the middle of the quarter.

5.7. Taupō storage declined over the quarter despite a small top up in the middle of June but was still above its 10th percentile at the end of the quarter. Taupō did not see an increase in storage in April because of its North Island location.

5.8. Te Anau and Manapōuri storage increased well above their mean levels after the April rainfall event and got small top ups at the end of May. Te Anau storage peaked above its 90th percentile for a brief time before dropping to its 10th percentile by the end of the quarter.

Figure 12: Lake storage levels for April to June 2024 versus historical average and 10th and 90th percentiles



6. Wholesale gas prices, production and consumption

Gas prices

6.1. Figure 13 shows the daily volume-weighted average gas price and New Zealand carbon unit price for April to June 2024.

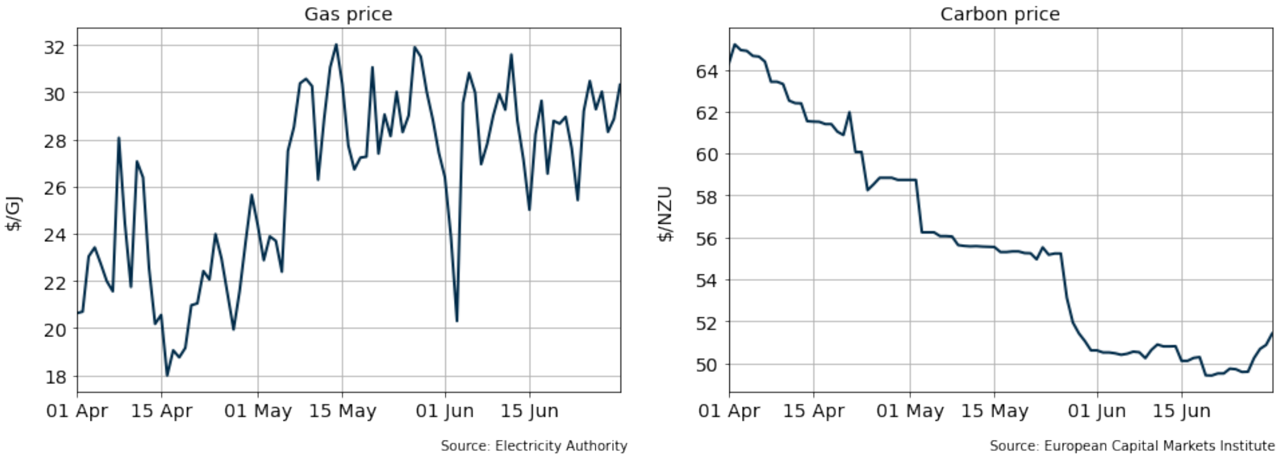
6.2. The average daily volume-weighted average price (VWAP) for gas in Q2 2024 was \$26.24/GJ. This is an increase of around \$9.20/GJ on the previous quarter and \$17.36/GJ on Q2 2023.

6.3. Gas prices increased from \$20/GJ in late April to \$32/GJ on 14 May. This coincides with the cold snap and the return of TCC from outage on 12 May.

6.4. Ahuroa gas storage facility withdrawals (~1,750TJ) totalled more than gas injections (~1,120TJ) for Q2 2024.[8]

6.5. The carbon price reduced from April to June 2024. This suggests the increase in gas spot price reflects the decreasing gas supply rather than an increase in the carbon price.

Figure 13: Daily volume-weighted average price for gas and NZ carbon unit price, April to June 2024



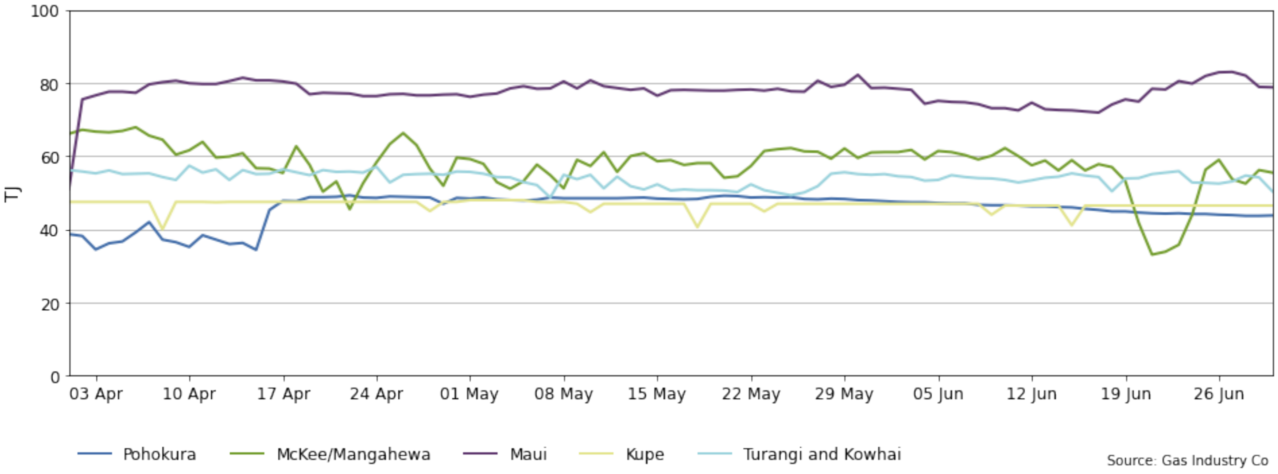
Gas production

6.6. Figure 14 shows daily gas production at major fields between April to June 2024.

6.7. Total gas production was steady for most of the quarter between 275-295TJ/day. Production was below 275TJ/day at the start of the quarter because of the planned Maui outage on 1 April and between 15-24 June because of decreased McKee/Mangahewa production.

[8] https://www.gasindustry.co.nz/data/gas-storage/

Figure 14: New Zealand gas production, April to June 2024 from gas production and consumption



Gas consumption

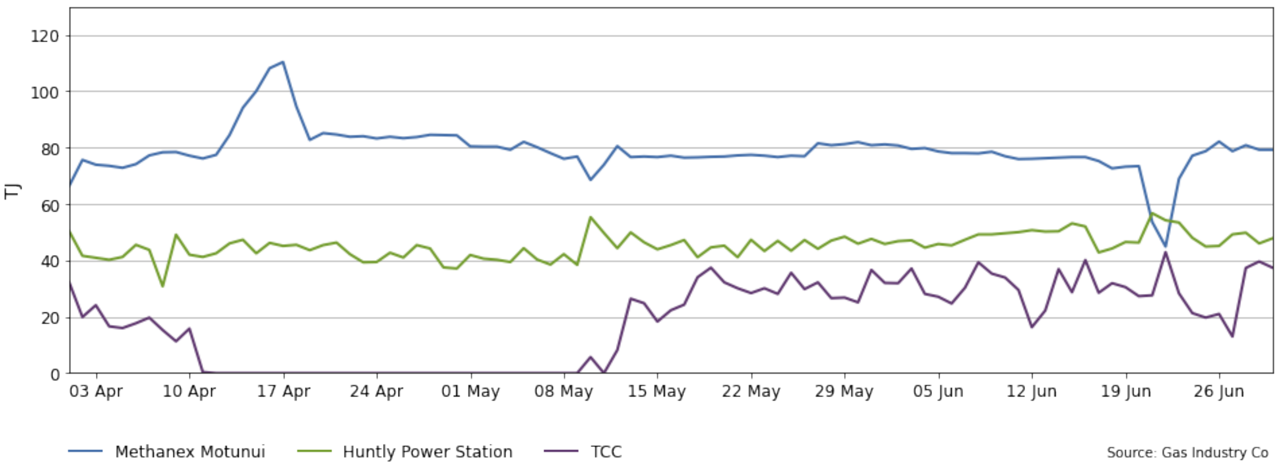
6.8. Figure 15 shows the daily gas consumption by major users between April to June 2024.

6.9. Gas consumption in Q2 2024 was steady, with the exceptions of Methanex Motonui consumption peaking briefly in the middle of April (when TCC turned off) and dropping briefly in the middle of June. TCC did not consume any gas from 12 April to 9 May because of its outage between 3-12 May and also likely due to the increased hydro storage and dispatch reducing the need for thermal generation.

6.10. Gas consumption has significantly reduced compared to Q2 2023. This reduction is mostly related to Methanex Motonui operating only one production train instead of two as in Q2 2023.

6.11. The Methanex dip in consumption at the end of June aligned with the dip in production from McKee/Mangahewa.

Figure 15: New Zealand gas consumption, April to June 2024

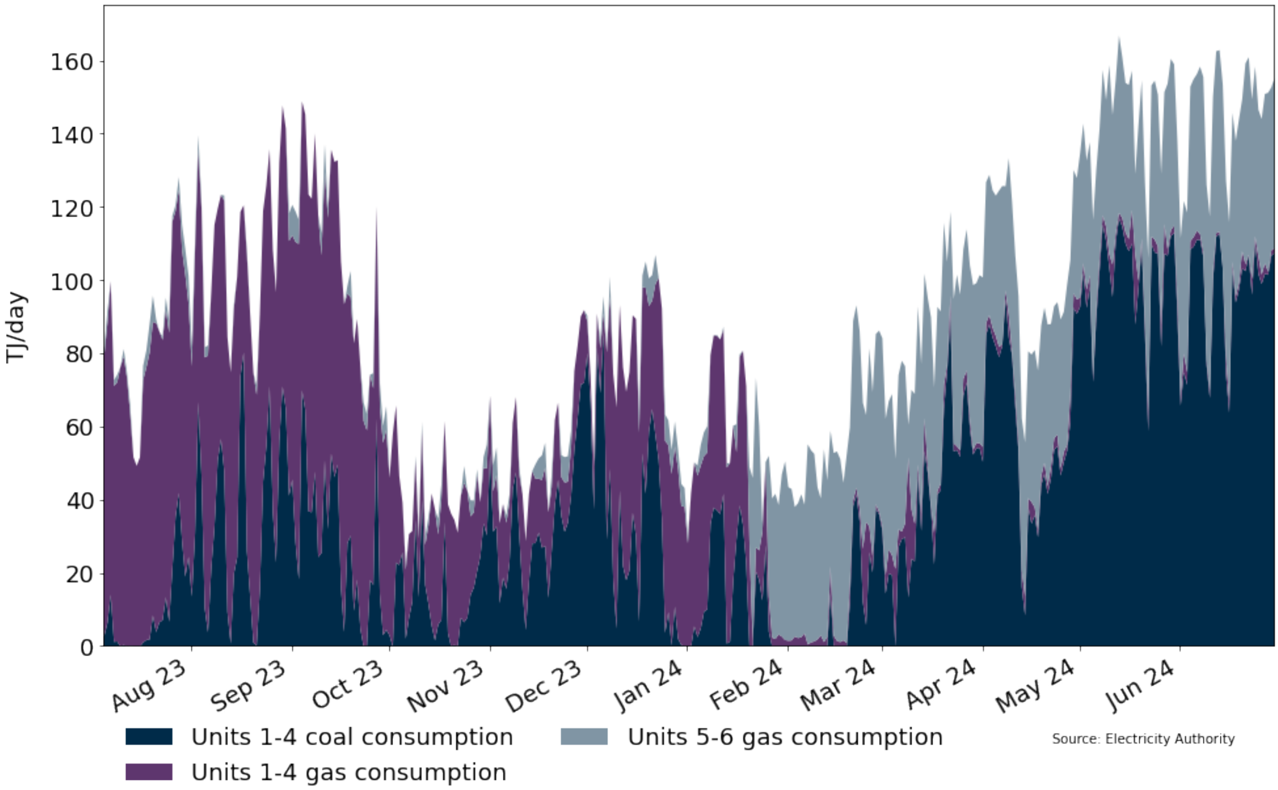


6.12. Figure 16 shows the estimated daily total energy consumption across all Huntly units between August 2023 to June 2024.

6.13. Huntly fuel consumption increased compared to the previous quarter. Consumption dropped in mid-April due to the increase in hydro storage but increased for the rest of the quarter as storage declined again.

6.14. Rankine units ran almost exclusively on coal in Q2 2024, likely because the short run marginal cost of coal was lower than gas.

Figure 16: Estimated Huntly fuel consumption, July 2023 to June 2024



7. Retail electricity

Retailer switching

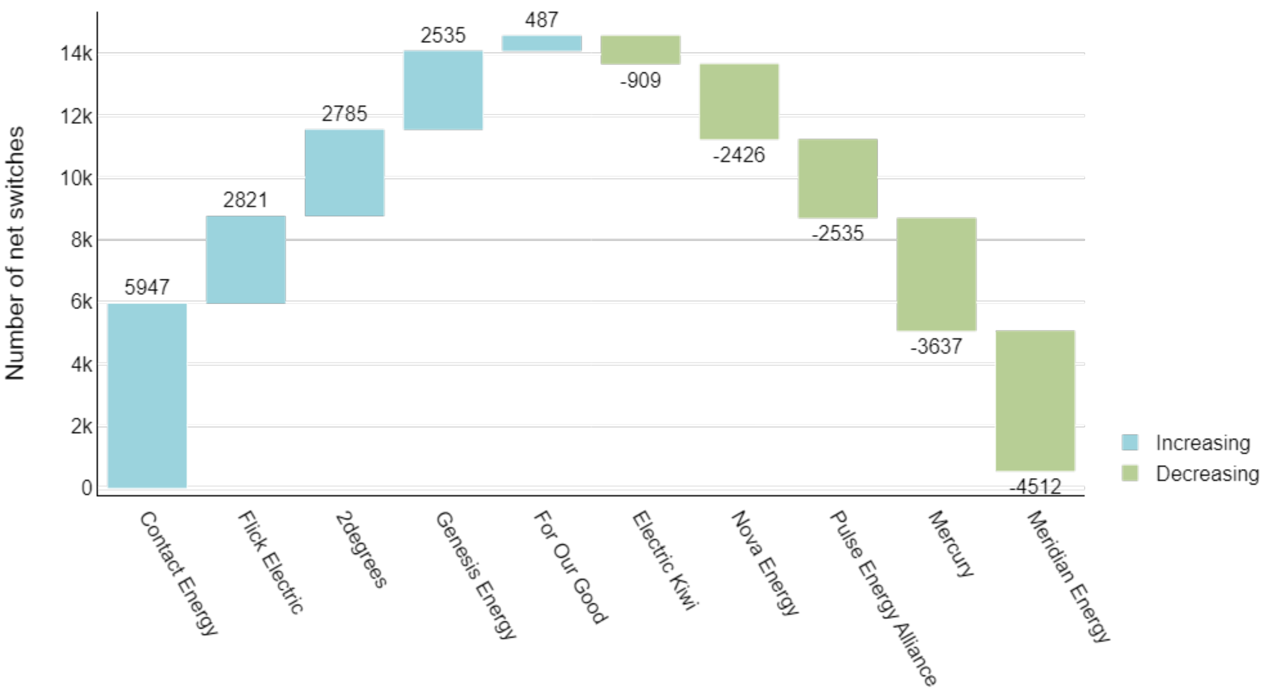
7.1. Figure 17 shows the top 5 retailers who gained and the bottom 5 retailers who lost the most electricity connections (ICPs) between April and June 2024.

7.2. Contact Energy experienced the greatest net gain in ICPs by a significant margin at 5,947. Flick Electric continued to gain market share for the fifth quarter in a row, with a net gain of 2,821 ICPs this quarter.

7.3. Meridian Energy experienced the greatest net loss in ICPs, losing 4,512 over the quarter.

7.4. 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 again decreased from the last quarter, at 3,637 ICP losses compared to 4,385 in Q1 2024.

Figure 17: Top 5 increases and bottom 5 decreases in ICP net switching by retailer, April to June 2024

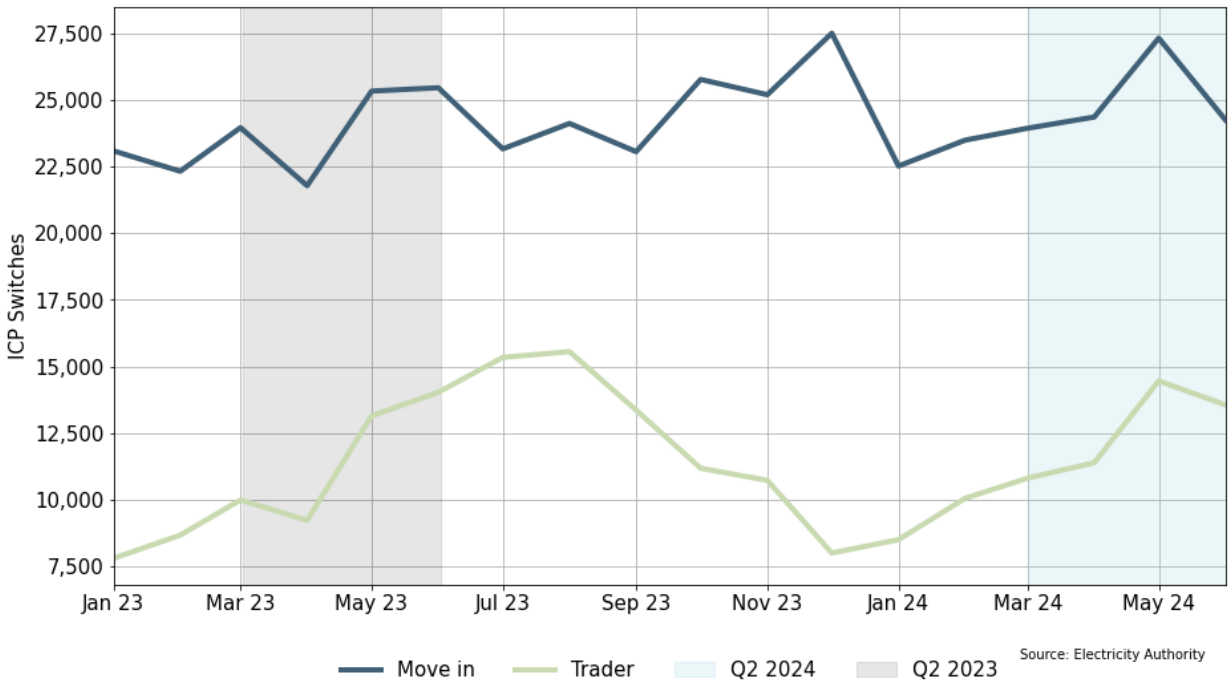


7.5. Figure 18 shows the number of ICPs that have changed electricity suppliers between 1 January 2023 and 30 June 2024 categorised by type 'move in' and 'trader'. Move in[9] switches are switches where the customer does not have an electricity provider contract with a trader. In contrast, trader switches are switches where the customer does have an existing contract with a trader, and the customer obtains a new contract with a different trader.

7.6. In Q2 2024, move in and trader switching rates both increased during April and May, then decreased during June. This is different from Q2 2023, where both switching rates decreased in April then increased in May and June.

[9] At an ICP.

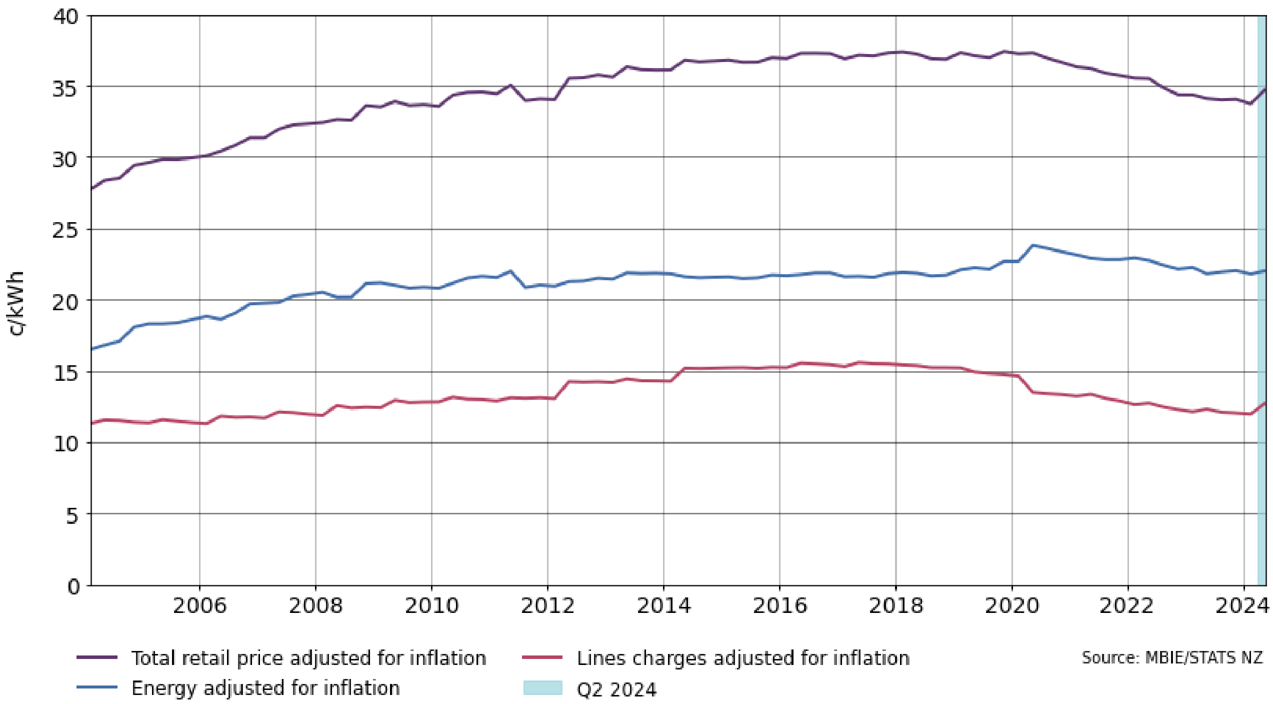
Figure 18: Breakdown of monthly ICP switching by type, January 2023 to June 2024



Retail prices

7.7. Figure 19 shows the domestic electricity price by component (QSDEP) adjusted for inflation from 2004-24. Based on the trends in Figure 19, energy retail prices tracked above the rate of inflation. Changes in price were driven by the increase in line charges this quarter. Adjusting for inflation, electricity costs remain below their 2020 peak.

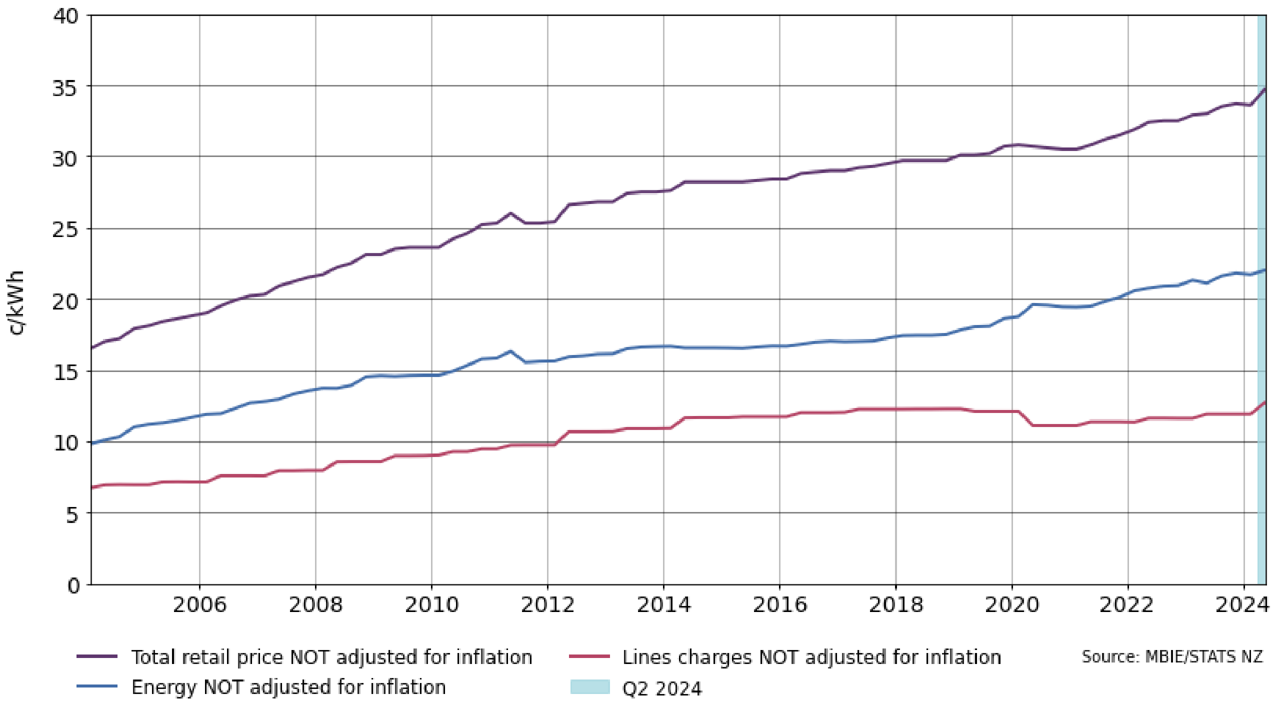
Figure 19: Domestic electricity prices by component adjusted for inflation (base 2024 Q2 CPI)



7.8. Figure 20 shows the domestic electricity prices by component without adjusting for inflation. In the last 12 months, nominal values have risen by 5.2%. For a typical household using

8,000kWh annually, this equates to an extra $136 per year on their electricity bill compared to one year ago.

Figure 20: Domestic electricity prices by component without inflation adjustment



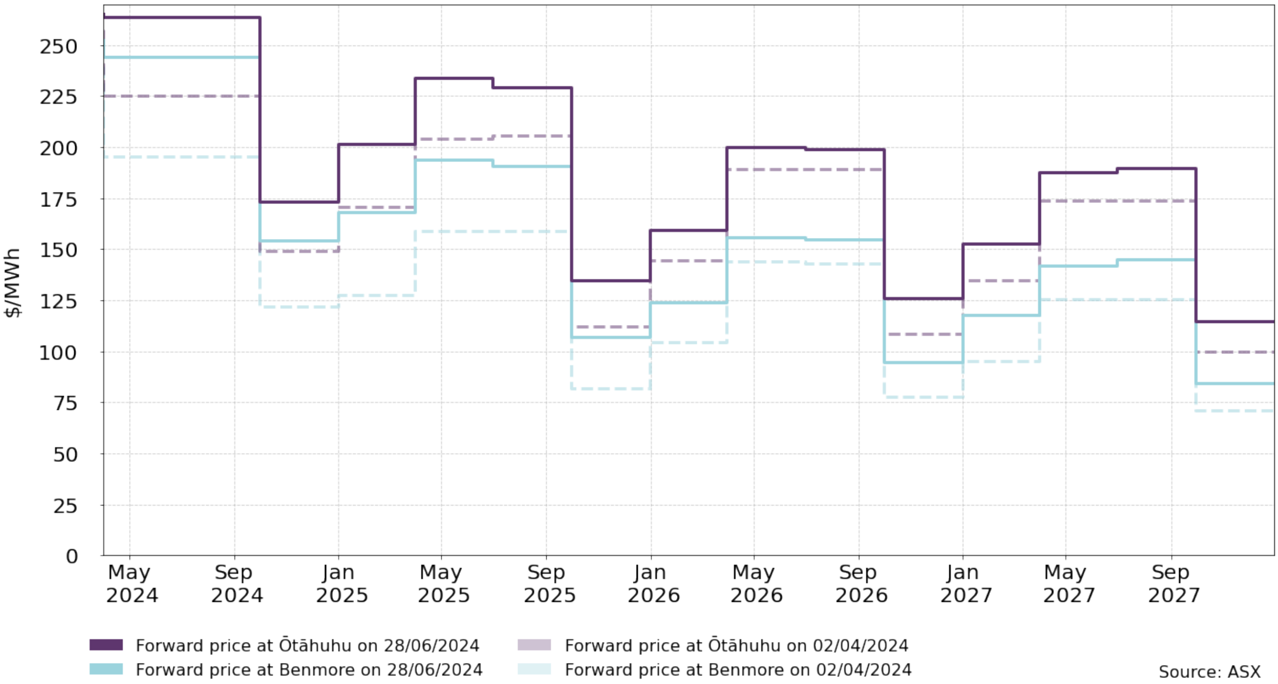
8. Forward market and carbon pricing

Forward pricing

8.1. Figure 21 shows the quarterly forward prices up to 2027, with the first snapshot (dashed lines) at the beginning of April 2024 and second snapshot at the end of June 2024 (solid lines).

8.2. In Q2 2024, forward prices increased for all contracts. Near term futures increased the most, likely because of declining hydro storage. Long term futures price increases are likely reflecting concerns around sustained low gas production and increased reliance on coal for security of supply.

Figure 21: ASX forward prices for the start and finish of Q2 2024



Carbon pricing

8.3. Figure 22 shows the New Zealand carbon unit price between September 2022 to June 2024 as recorded by the European Capital Markets Institute.

8.4. At the beginning of the quarter, the carbon price was $64 per unit. The carbon price decreased over the quarter to a minimum of $49 per unit before rising to $51 per unit at the end of the quarter.

8.5. At auction on 20 March 2024, 11.2 million NZUs were available[10] and 2.97 million NZUs were sold at a clearing price of $64/NZU. At auction on 19 June 2024, 11.8 million NZUs were available.[11] This auction received no bids and all units from this auction have been rolled over to the 4 September 2024 auction.

Figure 22: New Zealand Units price, September 2022 to June 2024

[10] NZX Managed Auction Service
[11] NZX Managed Auction Service

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 2024 to 30 June 2024, ie, two quarters of data. The Authority includes six-monthly updates of these indicators in every second quarterly review.

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 2024 to 30 June 2024:

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

(b) The frequency of low prices occurring during off-peak times remains similar to levels seen in 2023-24 and offer prices have reflected underlying conditions, consistent with competition

(c) The lower share of very low prices reflected the declining hydro storage seen over this period, and the increased reliance on thermal generation.

(d) Thermal offers are reflective of changing market conditions. Thermal operators have been constrained in their outputs due to a declining coal stockpile and reduced gas production.

(e) All schemes had a significant proportion of offers above the estimated water values, however, this may reflect the under-valuation of water in the JADE modelling, the Authority will be investigating this further.

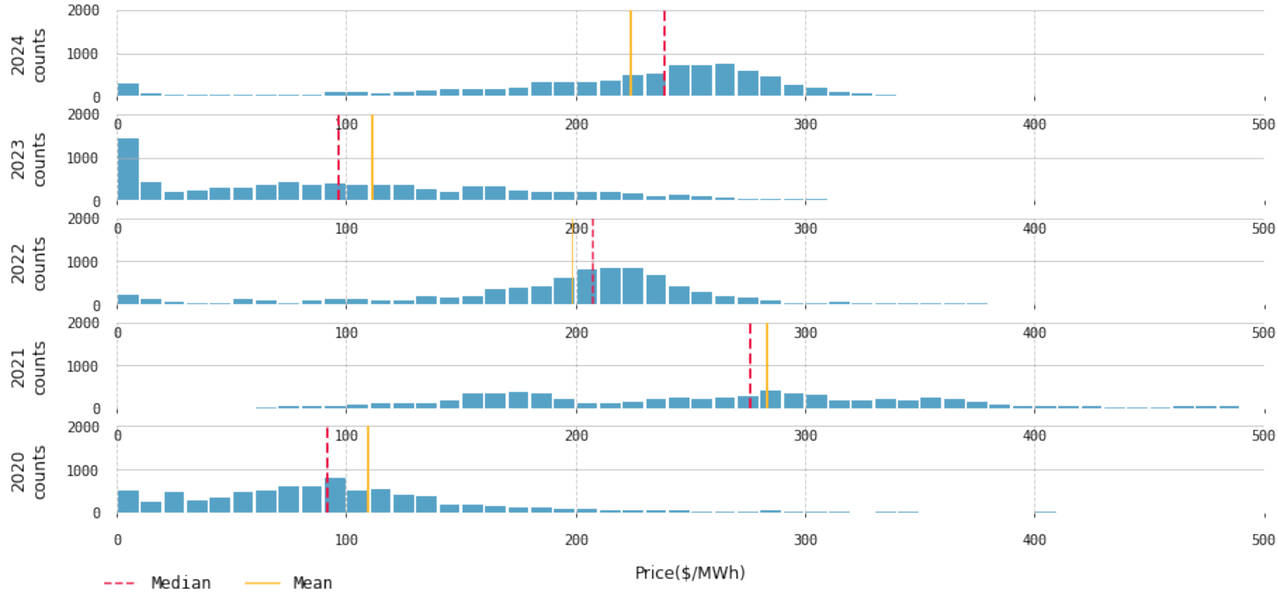
Very low prices

9.5. 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.

9.6. Figure 23 and Table 2 give insight into the distribution of prices in the first half of 2024.

9.7. In the first half of 2024, declining hydro storage over the 6-month period saw average wholesale prices increase. Hence, only 3.3% of all trading periods during these six months had prices below $10/MWh. This compares with 16.7% for the same period the year before. There is, however, quite a long tail of lower prices over the period, despite declining hydro storage. Figure 24 highlights spot prices below $10/MWh between January-June 2024, these prices mostly occurred during times of increasing hydro storage.

Figure 23: Histogram of price counts for the first six months of each year



9.8. Additionally, of the very low prices in the first half of 2024, close to one quarter of them occurred in daytime off-peak times. This is an increase since 2021, when the new trading conduct provisions were implemented.

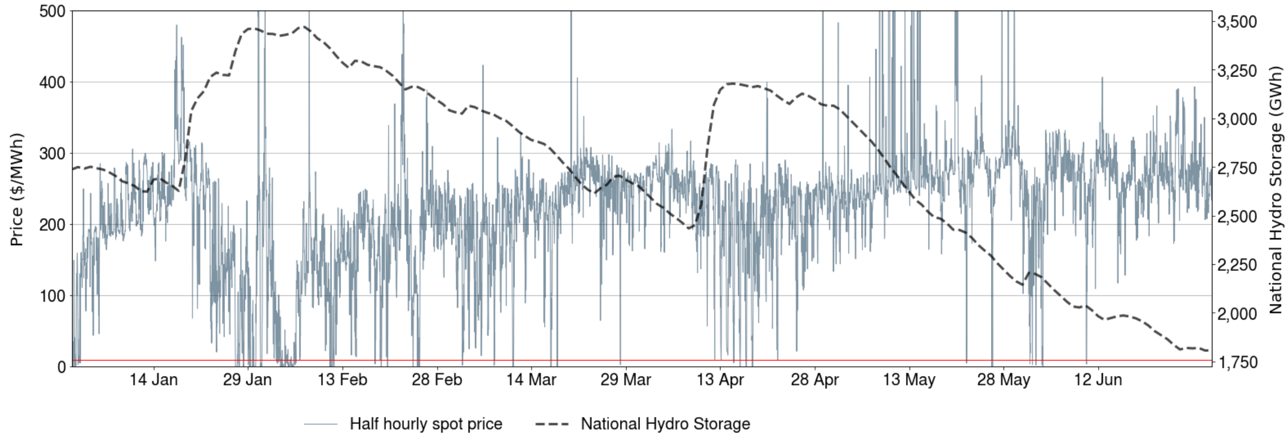
9.9. The median 'very low' price in 2024 was lower when compared to 2023, being $0.50/MWh compared to $2.08/MWh in 2023. However, this value was from a much smaller number of intervals where prices were below $10/MWh – 292 as compared to 1,466 in 2023.

9.10. The smaller share of very low-price intervals (3.3% were below $10/MWh in 2024, compared to 16.9% in 2023) represents the difference in hydrology between the years, with hydro storage largely declining over the first half of 2024, compared to 2022 and 2023 when storage was largely increasing.

Table 2: 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)
2024	25.7%	$0.50/MWh
2023	29.3%	$2.08/MWh
2022	24.0%	$0.02/MWh
2015 - 2021	9.2%	$1.95/MWh

Figure 24: Half hourly spot prices and national hydro storage between January-June 2024, the red line indicates $10/MWh



9.11. When looking at the distribution of prices across the first half of the year for the last five years, Figure 25 shows that the number of intervals above $200/MWh was similar this year to the distribution seen in 2021 - which was another year where hydro storage decreased over the first six months of the year. There were, however, a higher number of trading periods with low prices in 2024 compared to 2021. Conversely, the amount of trading periods where prices were below $10, $20 or $30/MWh have decreased when compared to 2023, which reflects the difference in hydrological conditions between the years.

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

	2024	2023	2022	2021	2020
equal or greater than $1001/MWh	14	24	2	1	1
from $201/MWh to $1000/MWh	6006	1273	4985	5957	949
from $101/MWh to $200/MWh	1899	2920	2702	2430	2810
from $91/MWh to $100/MWh	108	399	127	56	806
from $81/MWh to $90/MWh	63	370	92	67	609
from $71/MWh to $80/MWh	53	421	41	69	629
from $61/MWh to $70/MWh	41	370	102	39	520
from $51/MWh to $60/MWh	36	302	135	18	489
from $41/MWh to $50/MWh	48	300	30	11	346
from $31/MWh to $40/MWh	45	232	26	11	292
from $21/MWh to $30/MWh	54	219	85	15	498
from $11/MWh to $20/MWh	79	430	138	4	272
equal or less than $10/MWh	292	1430	225	12	517

Counts: 1000, 2000, 3000, 4000, 5000, 6000

Price separation

9.12. 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.

9.13. The mean ratio of the Haywards to Benmore price continues to be higher since the introduction of the trading conduct rule compared to previous years. However, the mean this year is lower than that seen in 2023 – as periods of high inflows during 2022-23 led to greater instances of very low South Island prices – with the HVDC binding and creating price separation. The median price separation in 2024 was higher than that seen in 2022-23, as prices between the nodes were often separated by roughly $37. This separation reflects that nodal prices are consistent with nodal costs, and typically North Island prices are higher than South Island prices due to increased costs associated with transmission of South Island power Northward. These nodal price differences allow investors to see opportunities associated with different connection points, both in terms of electricity generation and consumption.

9.14. However, the mean ratio of the Benmore to Manapōuri price is low again this year. This is probably because, despite hydro storage being higher at the Manapōuri and Te Anau Lake levels, the loss of two generating units meant that the generation from Manapōuri was curtailed, and the Southland region would have been importing energy from higher up the country to meet demand.

9.15. The median price separation between Haywards to Benmore is a lot lower than the mean price separation in 2024 again, which results from a few periods of extreme price differences, where the price was 1 or 2 cents at Benmore. Because this analysis 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 2024 compared to the mean is consistent with the very low prices discussed in the previous section which skew the distribution[12]. Hence, both the mean and median price separation are investigated as this gives a fuller picture of what is happening.

Table 3: Price separation

	Ratio of Haywards to Benmore price		Ratio of Benmore to Manapōuri price	
Year	**Mean**	**Median**	**Mean**	**Median**
2024	34.52	1.37	1.03	1.025
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

[12] 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.

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

9.16. For the summer and early autumn season the El Niño Southern Oscillation (ENSO) was in its El Niño phase. This phase typically brings more rainfall to the major southern catchments. However, this summer was characterised as a ‘dry’ El Niño year, where rainfall was mostly below average for the summer and autumn period. This was also compounded by a spring/summer season in 2023 which saw below mean storage by the end of the year, which meant all lakes, bar Taupō, began the year below 100% of their mean storage.

9.17. All hydro locations except Manapōuri/Te Anau had declining storage for most of the first half of 2024. Most catchments only saw two significant inflow events, one in late January and another in mid-April.

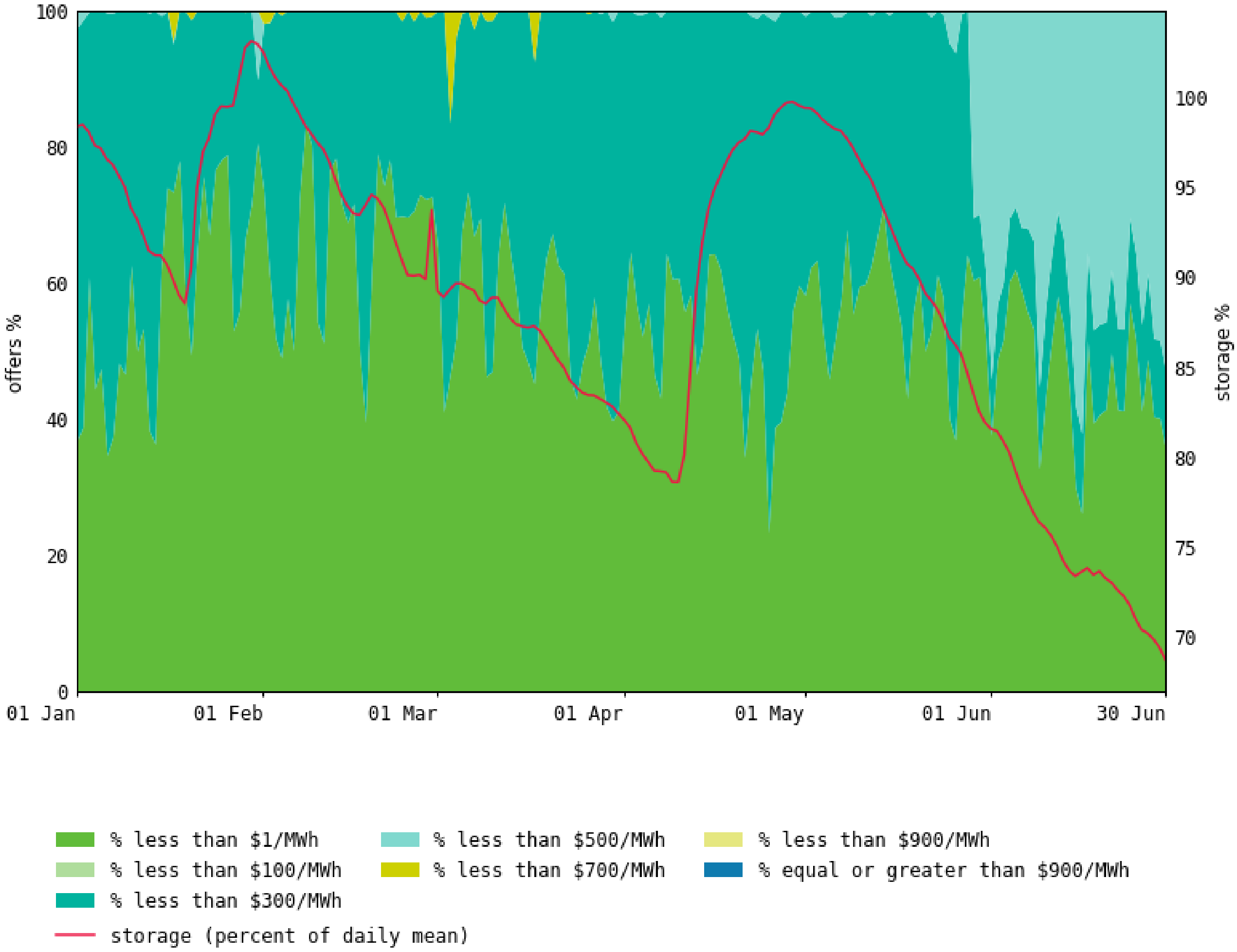
9.18. The adjusted offers[13] from the Waitaki scheme and storage (as a percentage of daily mean) at Pūkaki is shown in Figure 26.

9.19. Meridian increased the amount of offers priced below $1/MWh in late January as storage in the Waitaki increased, however, storage only reached roughly 100% of mean. While the majority of offers in this scheme remained below $300/MWh as storage declined over February and March, the quantity of offers priced below $1/MWh similarly decreased. In mid-April storage increased again, however, offers did not change dramatically as storage only increased from roughly 80% of mean to 100% of mean.

9.20. The proportion of low-priced offers dipped on 25 April which was the ANZAC day public holiday. When Pūkaki storage dipped to roughly 80% of mean again in late May, Meridian priced up their upper tranches from $100-$300/MWh to be between $300-500/MWh.

[13] Adjusted offers are those adjusted to account for cleared reserve

Figure 26: Adjusted offers vs available storage for Meridian Waitaki for January to June 2024

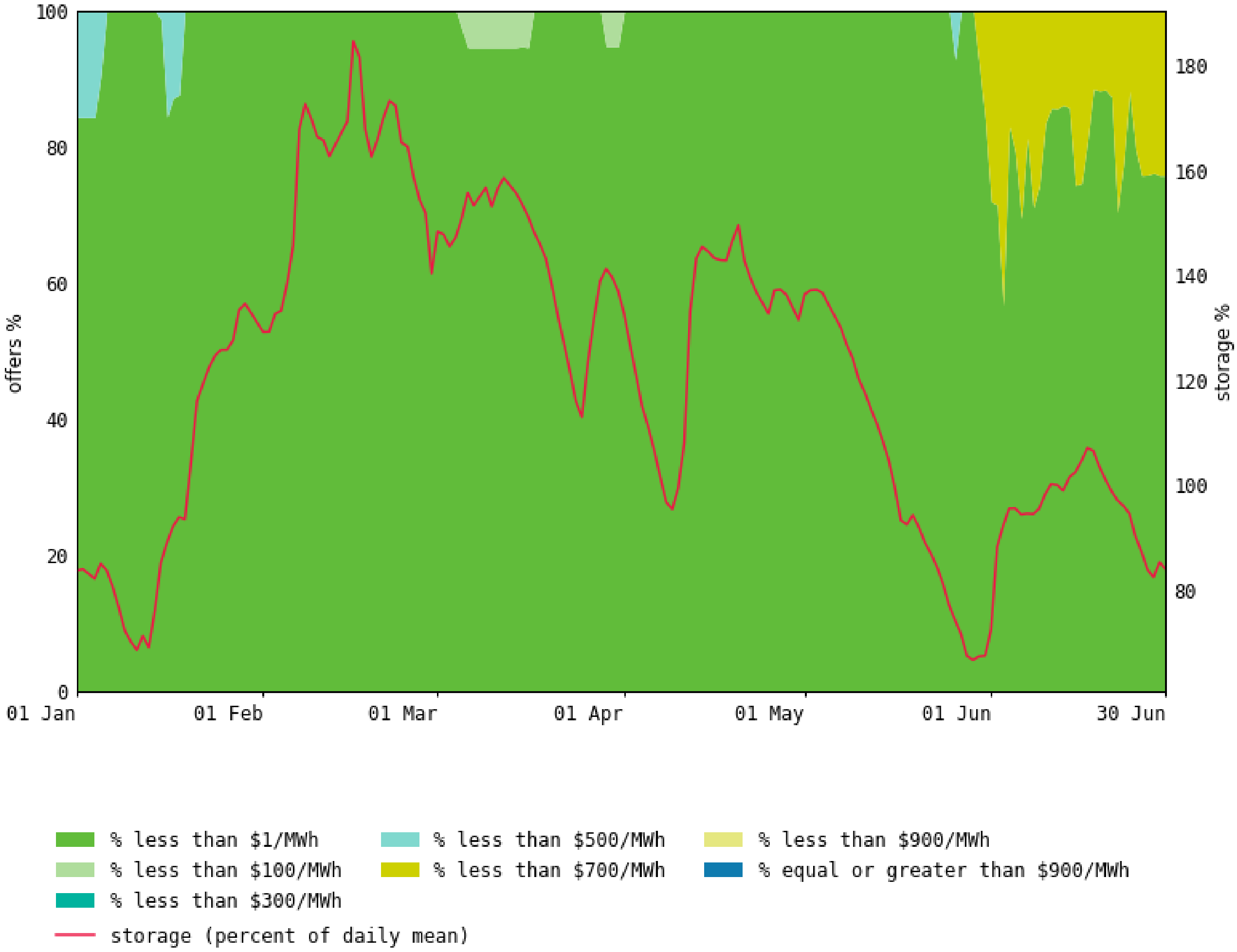


9.21. The adjusted offers from the Manapōuri scheme and storage (as a percentage of daily mean) at lakes Manapōuri and Te Anau is shown in Figure 27.

9.22. Allowable storage in the Manapōuri reservoir is not deep and fluctuates quickly in comparison to other locations. As a result, Meridian Manapōuri offers followed their storage levels closely. Lake Manapōuri spent much of this period above its mean storage level and offers were nearly all priced below $1/MWh to reflect this. Only once storage reached below 100% of the daily mean in late May did some offers increase to be priced between $500-700/MWh to discourage dispatch and maintain lake levels.

9.23. Due to two generation units of Manapōuri being on outage, the Manapōuri lake spilled at times where inflows exceeded maximum possible outflow, this occurred mostly in April.

Figure 27: Offers vs available storage for Meridian Manapōuri for January to June 2024



9.24. The adjusted offers from the Waikato scheme and storage (as a percentage of daily mean) at lake Taupō is shown in Figure 28.

9.25. 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 5. An example is the dip in low priced offers in early April during the Easter period.

9.26. However, there is some correlation with storage levels, as in late January after moderate inflows, the share of weekday offers below $100/MWh increases from around 50% to around 80% of offers until conditions eased.

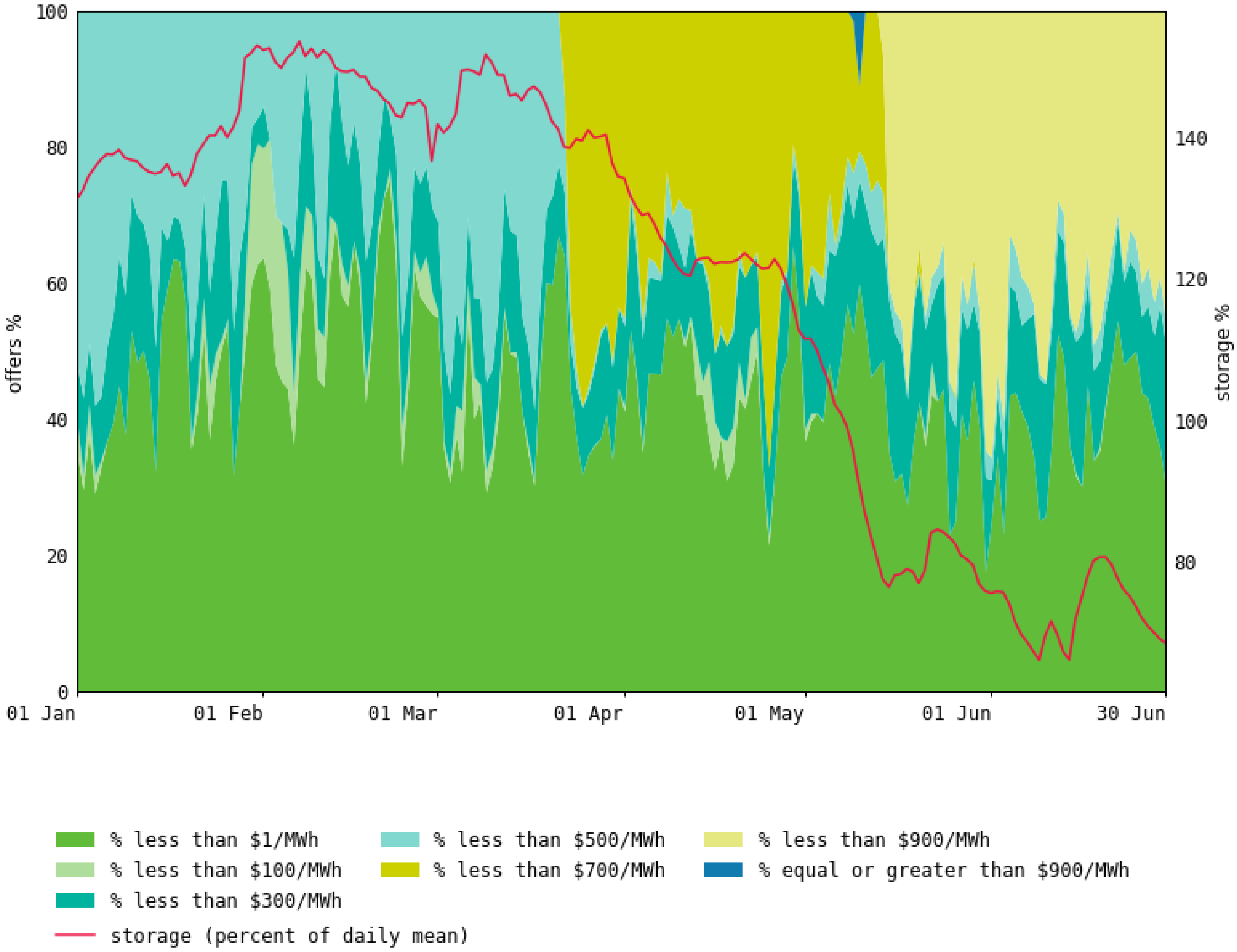
9.27. Mercury's offers priced below $1/MWh dipped in weeks with high wind generation, as Mercury balance their low-priced generation between their wind and hydro stations. This occurred notably in mid-March.

9.28. Overall, the proportion of offers priced below $300/MWh slowly decreased as storage at Taupō decreased. In late March, the high-priced offers increased from being between $300-500/MWh to $500-$700/MWh. This occurred as wholesale prices were increasing as the Southern lakes began drawing down, and Mercury subsequently priced up their offers to maintain their storage levels heading into winter. This occurred again in mid-May after short period with a large drawdown, where the proportion of high-priced offers increased to be priced between $700-900/MWh.

9.29. After a very significant decline over early May around 10% of offers were priced above $900/MWh to reflect the stored waters increased value. As the storage decline plateaued over June, the proportion of offers priced under $900/MWh increased.

9.30. 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 higher percentage of offers below $1/MWh. On average 60% of offers were priced below $1/MWh during peak times compared to an average of 40% during off-peak.

Figure 28: Adjusted offers vs storage for Mercury Waikato for January to June 2024

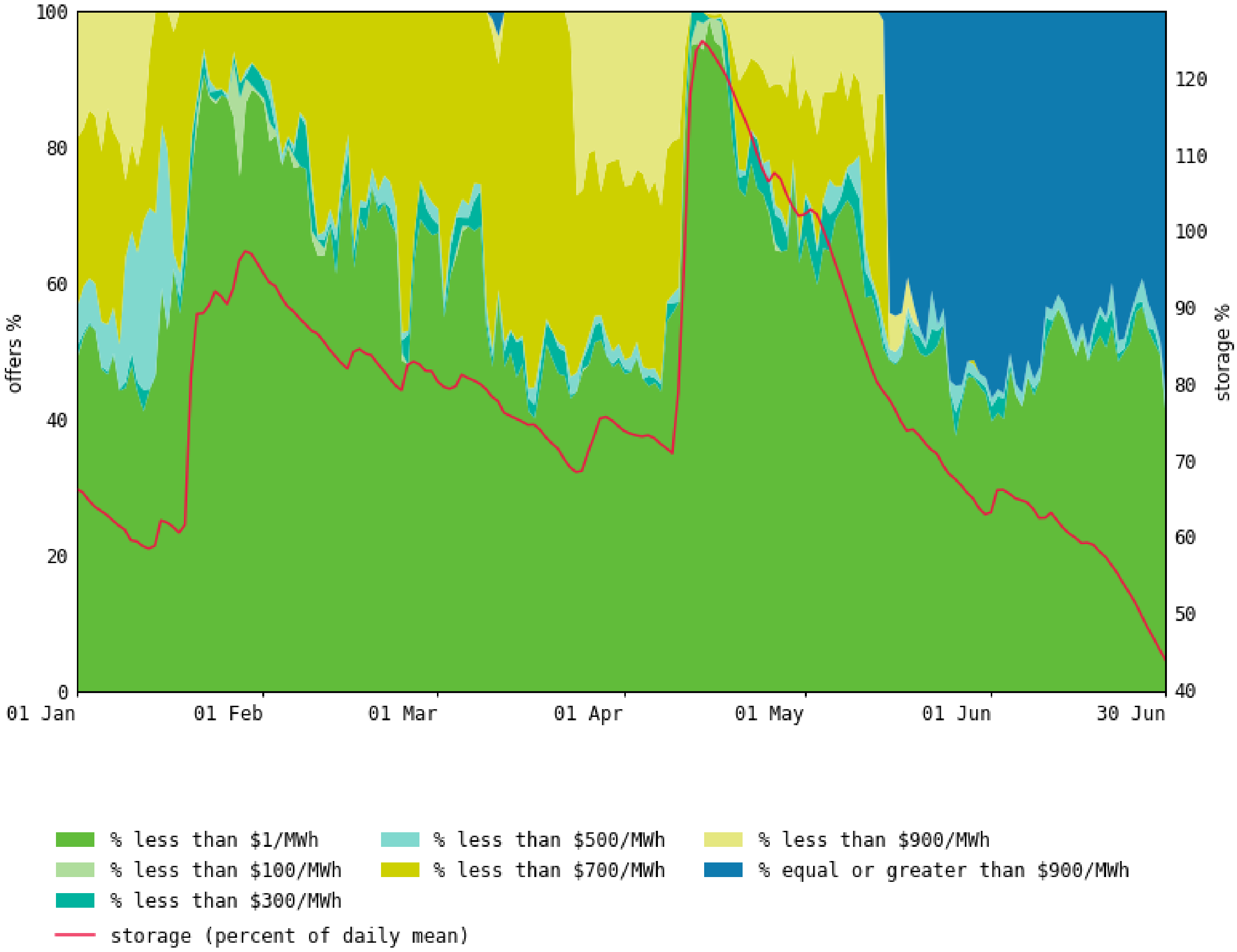


9.31. The adjusted offers from the Clutha scheme and storage (as a percentage of daily mean) at lake Hawea is shown in Figure 29

9.32. The Contact Clutha scheme also does not have much storage and runs mostly as a run of river scheme. However, during the first half of 2024, its offers are closely aligned with storage levels rather than week-to-week demand, as the scheme relied more on water from Hawea.

9.33. The quantity of low-priced offers increased after the January and April inflow events. As storage decreased in May, roughly 50% of Clyde offers were priced above $900/MWh to reflect the increasingly value of the remaining Hawea storage as during winter the Southern lakes typically see their lowest quantity of inflows as precipitation falls as snow.

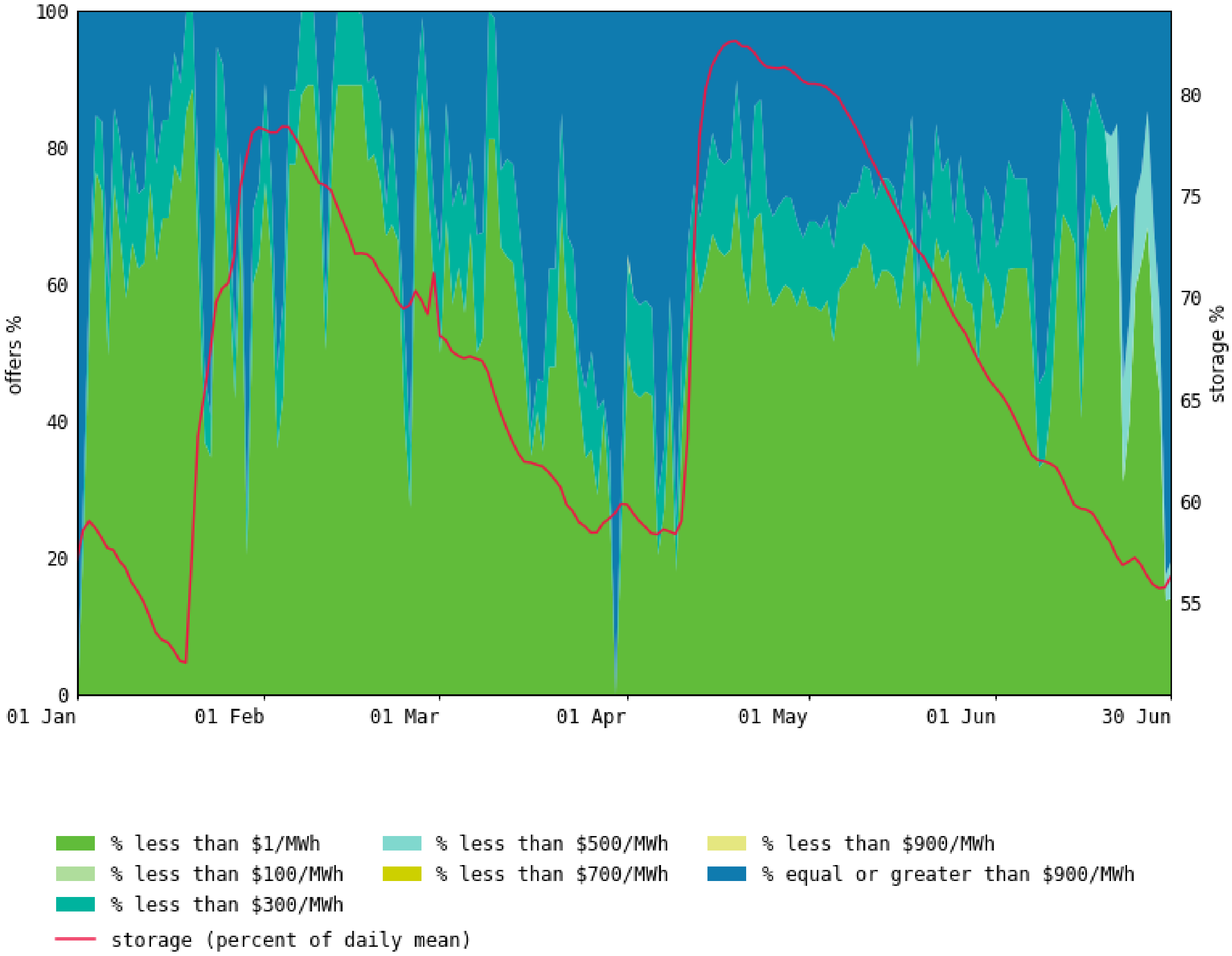
Figure 29: Adjusted offers vs storage for Contact Clutha for January to June 2024



9.34. The adjusted offers from the Takapō scheme and storage (as a percentage of daily mean) at lake Takapō are shown in Figure 30.

9.35. Genesis' offering at Takapō followed storage more closely this year, with the majority of offers at less than $1/MWh, which would have represented the energy they needed to cover their contracts. However, the remaining water was priced high as storage at Takapō remained below mean for the entirety of the first half of 2024.

Figure 30: Adjusted offers vs storage for Genesis Takapō for January to June 2024



9.36. Table 4 to Table 8 cover the dates when the reservoir storage was above its long-term average. Takapō spent all of January to June 2024 below this threshold (as visible in Figure 6), but most other major storage locations, aside from Manapōuri and Taupō, had limited periods of high[14] 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.

9.37. Prices above $300/MWh when storage was high increased for the Waikato and stayed about the same for the Waitaki when compared to last year, noting that these two schemes only spent a small percentage of time above 100% of mean in 2024. This increase for the Waikato reflects Mercury needing to price their water higher in 2024 to prevent a steep drawdown as the southern lakes spent much of this half of the year in decline.

9.38. Similarly, the percentage of offers above final prices increased for the Waikato and Waikati schemes this year, as both Mercury and Meridian were able to conserve more water by having more wind generation (both had increases to their wind portfolios this year). The Clutha scheme, however, saw a decrease in the offers above final prices.

9.39. For Stratford, the increase in the percentage of offers above thermal SRMC likely reflects the downgrade of gas storage available to Contact at its Ahuroa storage facility and the

[14] 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).

reduction in gas production, which has seen daily gas supply unable to meet demand. It is likely that Contact have been unable to secure enough gas each day to run TCC at full capacity, so the additional capacity has been priced high to reflect the additional costs Contact would bear if TCC were running closer to its maximum output.

9.40. For Mercury and Meridian, the quantity of offers priced above their water values likely reflects an under-valuation of hydro costing in the JADE model. The monitoring team is looking further into how to update this model to more accurately reflect the risk parameters associated with running out of water.

9.41. We have not found any instances in our weekly monitoring of behaviour that is inconsistent with competition over this period, and offers are largely correlated with storage and water values as we would expect under competitive outcomes (see next section).

9.42. Stratford and Huntly largely decreased 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 is likely due to the increased thermal commitment required in 2024 to supply electricity while hydro storage was decreasing. These reductions reflect the increased efficiency these units gain when running for long periods of time. However, these figures remain high when compared to 2022, and reflect the large increase in gas prices experienced by the sector over the past few years.

Table 4: percentage of offers over $300/MWh, January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2024	36%	2%	NA	19%	64%	24%
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 5: Percent of offers above final price, January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2024	43%	37%	NA	21%	69%	27%
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 6: percentage of offers above the average forward price January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2024	32%	21%	NA	15%	44%	20%
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 7: percentage of offers above thermal SRMCs January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2024	42%	37%	NA	19%	69%	24%
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 8: Percentage of offers above water values January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2024	48%	37%	NA	22%
2023	32%	17%	8%	17%

Relationship of storage and offers to cost

9.43. Table 9 to Table 11 show the relationships between the average water values for each associated reservoir and hydro storage and offers, for when hydro storage was high. Figure 31 shows the relationship between these water values and offers.

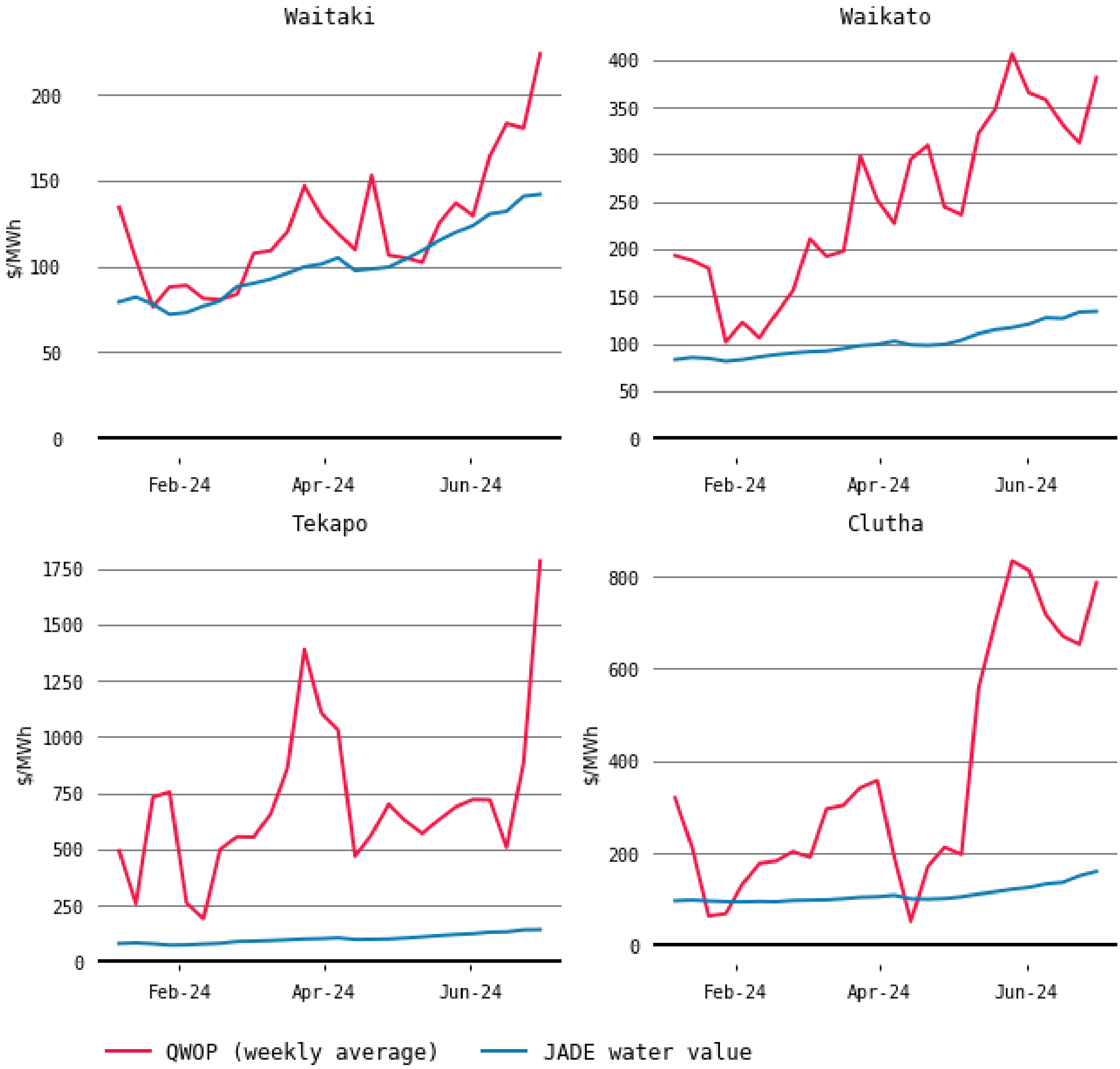
9.44. For January to June this year, all schemes had a JADE water value which was negatively correlated with storage (as shown in Table 8), meaning that water values increased as storage decreased, which is consistent with competition.

9.45. Figure 31 shows an increase in quantity weighted offer prices between January and June, which as shown above was correlated with storage declines in these schemes. However, while the JADE water value also increased, for all schemes bar the Waitaki, the quantity-weighted-average-price (QWOP) was much higher than the marginal water values in each scheme (as discussed above).

9.46. It is not unexpected for generators to price water high when storage is low/declining, and many lakes were below average heading into 2024. High demand throughout later summer and autumn also led to high drawdown of the lakes.

9.47. Through our trading conduct monitoring we queried generators about their high hydro offers and found many were pricing their water to reflect the risk of it running out or breaching their consenting agreements. We found generators typically priced up when storage dramatically decreased due to increased dispatch, as was seen in May when demand was unusually high. There may also have been a decreased confidence overall heading into winter 2024 with regards to back up supply from coal and gas, which was also likely impacting water values. These edge cases aren't captured well by the JADE model and the Authority will be enquiring on how to include additional parameters.

Figure 31: Quantity weighted offer prices for January - June 2024



9.48. All schemes had 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.

9.49. All schemes also had a positive correlation of water values with the percent of offers above $300/MWh, and with QWOP, meaning that as water values increased the proportion of offers above $300/MWh, and the QWOP increased, as expected under competitive outcomes.

9.50. The overall picture presented by the indicators suggests a continuation of the trading conduct provisions having a positive impact on generator behaviour.

Table 9: Correlations of water values with hydro storage - January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2024	-0.87	-0.72	-0.59	-0.29
2023	0.49	-0.32	0.17	-0.41

Table 10: Correlation of water values with percentage of offers above $300/MWh - January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2024	0.52	0.57	0.44	0.50
2023	0.13	-0.18	-0.30	-0.04

Table 11: Correlation of water values with QWOP - January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2024	0.86	0.70	0.79	0.41
2023	0.28	0.05	0.15	0.05