8/05/2025

Market performance Quarterly review

January – March 2025

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1. Purpose

1.1. This document is a review of the performance of New Zealand's energy market from 1 January to 31 March 2025. It aims to provide visibility of the monitoring of the market undertaken by the Electricity Authority Te Mana Hiko (Authority) during this period.

1.2. This review seeks to assess whether spot electricity prices were reflective of the underlying energy supply and demand conditions faced by the sector for Q1 2025. It also analyses changes in the retail and forward market.

1.3. We want to provide visibility of previous market conditions, and of the Authority's market monitoring, to give the energy sector higher confidence that prices are being set in a competitive market. This reflects the expectations set out in paragraph 29 of the Government Policy Statement to the Electricity Authority (October 2024) that 'effective competition is essential for our electricity system to deliver reliable electricity at lowest possible cost to consumers'.

2. Highlights

2.1. This quarter had the lowest hydro inflows for January to March on record[1]. These low inflows resulted in hydro storage falling sharply from above the historic 90th percentile to below the historic 10th percentile.

2.2. Prices this quarter steadily increased to around $300/MWh in tandem with decreasing hydro storage.

2.3. In Q1 2025, the correlation between wind generation and spot price was the lowest it's been in recent years. This is because wholesale prices this quarter were influenced by declining hydro storage and the resulting increased thermal generation.

2.4. National electricity demand was lower than average this quarter due to lower industrial consumption (partially due to Tiwai demand response having been implemented) and lower irrigation load.

2.5. Spot gas prices increased from $8/GJ to $26/GJ this quarter as more thermal generation came on. Meanwhile gas production continued to decline.

2.6. Meridian gained the largest number of electricity connections (ICPs) this quarter and Genesis and Electric Kiwi lost the largest number of ICPs.

2.7. Retail electricity prices increased at approximately the rate of inflation this quarter (ie, in real terms). In nominal terms (ie, not adjusted for inflation), prices have increased by ~$166 per year for the average household.

2.8. All winter future prices increased over the quarter. Winter 2025 futures increased the most by $72-127/MWh. This is likely due to the possibility of changing weather patterns effecting hydro storage, declining gas production and the possible retirement of TCC.

2.9. The price of New Zealand carbon units (NZUs) decreased slightly over the quarter from $63/NZU to $60/NZU.

3. Electricity demand

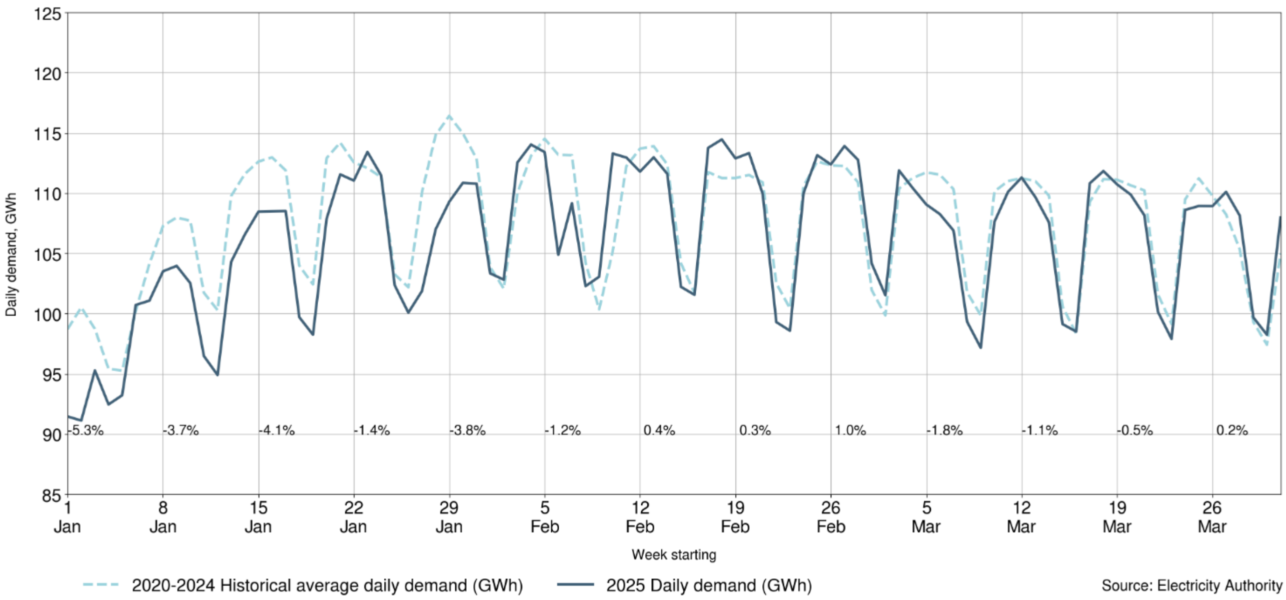
Demand across the quarter

3.1. Figure 1 shows the total daily electricity demand in 2025 and the 2020-24 historic average demand between January and March.

[1] Since 1926.

3.2. Demand was consistently lower that the historic average for most of the quarter, especially in January. For certain weeks, especially in February, consumption was above average. The low demand on 6 February was due to the Waitangi Day public holiday.

Figure 1: New Zealand daily demand compared to historical average, January to March 2025



3.3. Figure 2 shows the total monthly consumption and factors that may have affected the monthly consumption. Total consumption was lower than average in January and slightly lower than average in February and March.

(a) Industrial consumption was consistently lower than average this quarter largely due to the demand response agreement with Tiwai aluminium smelter restricting Tiwai consumption.

(i) Demand at Tiwai had been gradually ramping up since 12 September 2024 when the maximum level of demand response ended last year. This demand response was due to end entirely on 12 April 2025.

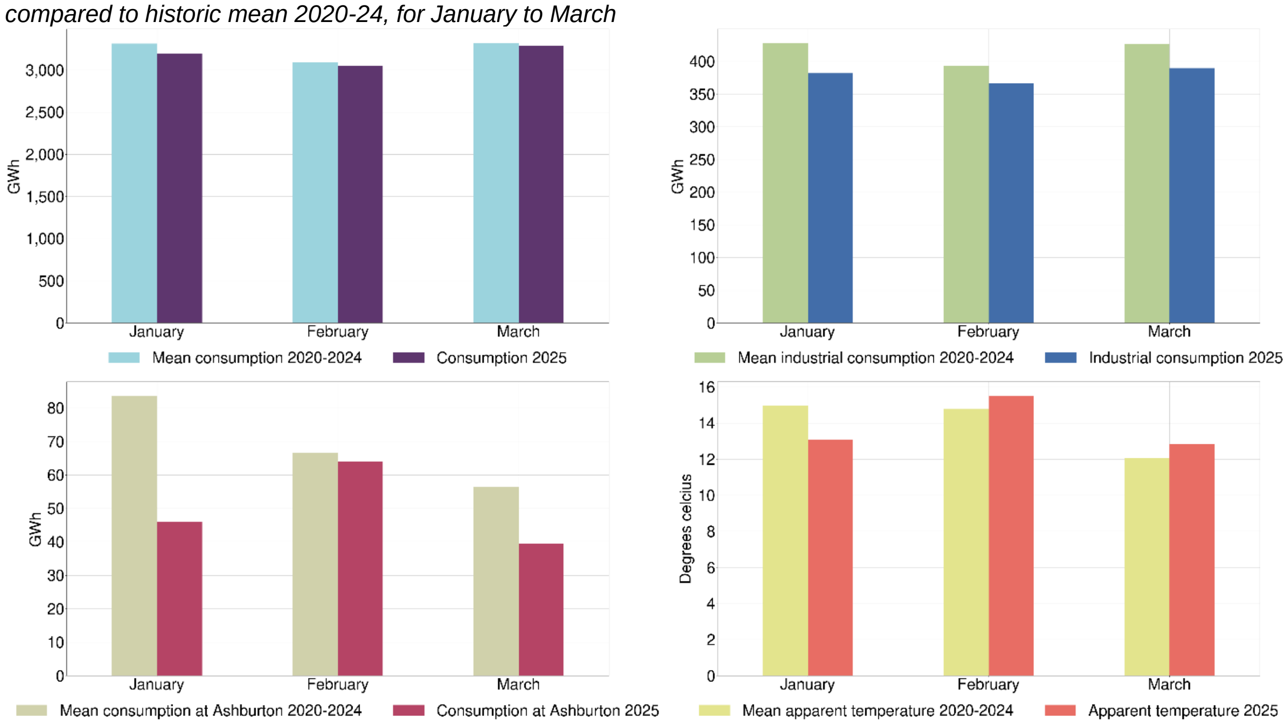
(ii) However, on 25 February it was announced that 50MW of demand response would be active 10 March to 31 August 2025.

(b) Consumption at the Ashburton node is a good indicator of irrigation load in the Canterbury region. This quarter, consumption at Ashburton was below average, especially in January. This means that irrigation load was likely below average as well.

(c) Apparent temperatures were lower than the historic average in January, but higher in February and March, likely increasing cooling demand in the second part of the quarter compared to historic cooling demand for those months.

(d) Thus, total consumption was likely lower than average this quarter due to lower industrial consumption and lower irrigation load. This was exaggerated in January, likely due to significantly lower irrigation load and lower than average apparent temperatures leading to less cooling demand.

Figure 2: Total consumption, industrial consumption, Ashburton consumption and apparent temperature in 2025, compared to historic mean 2020-24, for January to March



Sources: Electricity Authority, MetService

3.4. On 24 February 2025, a CAN (customer advice notice) was issued to warn of possible low residual supply between 1.30pm-5.30pm[2]. This followed residuals being below 200MW from 11.30am-1.00pm after two units unexpectedly stopped generating[3] during the scheduled HVDC Pole 2 outage[4].

4. Wholesale electricity price and consumption

4.1. Figure 3 shows the half hourly and daily national wholesale electricity spot prices between January and March 2025. The historic daily average between 2018-24 adjusted for inflation is also displayed. Figure 4 shows the weekly spot price distributions between January and March 2025.

4.2. The middle 50% prices in Q1 2025 were between $160/MWh and $301/MWh. The average wholesale spot price for Q1 2025 was $223/MWh. This is $185/MWh higher than Q4 2024 ($38/MWh) and $35/MWh higher than Q1 2024 ($188/MWh).

4.3. Prices this quarter steadily increased in tandem with decreasing hydro storage. Prices were mostly around or below the historic average in January, but mostly above the historic average in February and March.

4.4. The highest half hourly average price of the quarter was $1,611/MWh at 12.30pm on 24 February. This was during the period of low residual supply described in paragraph 3.4, which led to high reserve prices. These high reserve prices increased the spot price.

[2] CAN Low Residual Situation 6033202536.pdf
[3] Trading conduct report 23 February-1 March
[4] CAN Planned Outage HVDC Pole 2, HVDC Pole 3 5985536633.pdf

Figure 3: Half hourly, daily and daily historic average wholesale electricity prices, January to March 2025

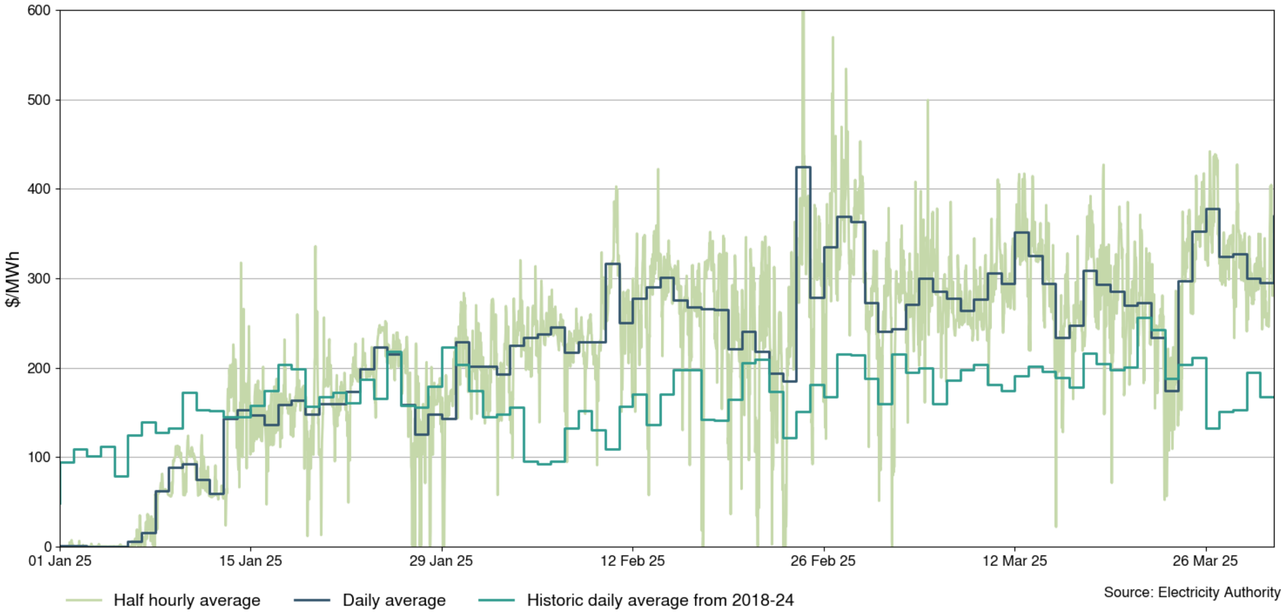
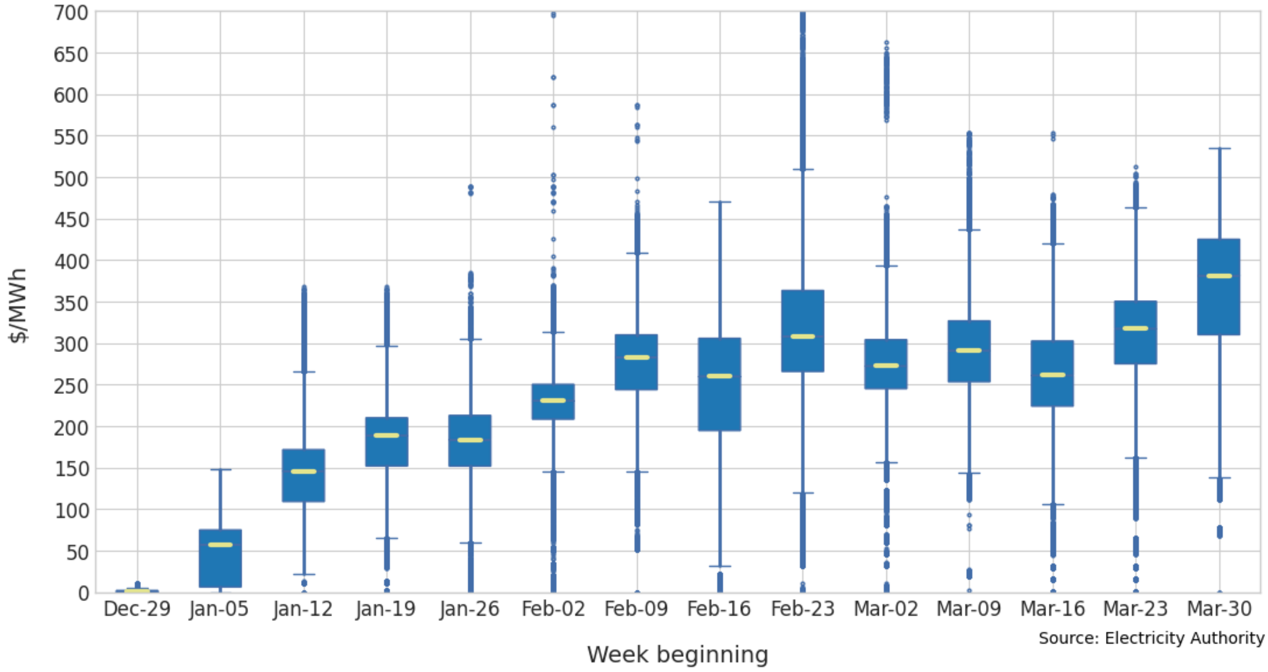


Figure 4: Box plot distributions of weekly spot prices between, January to March 2025



4.5. Measures relating to wholesale spot market competition can also be found on the Electricity Authority's Competition Dashboard.

Generation composition influence on price

4.6. 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.

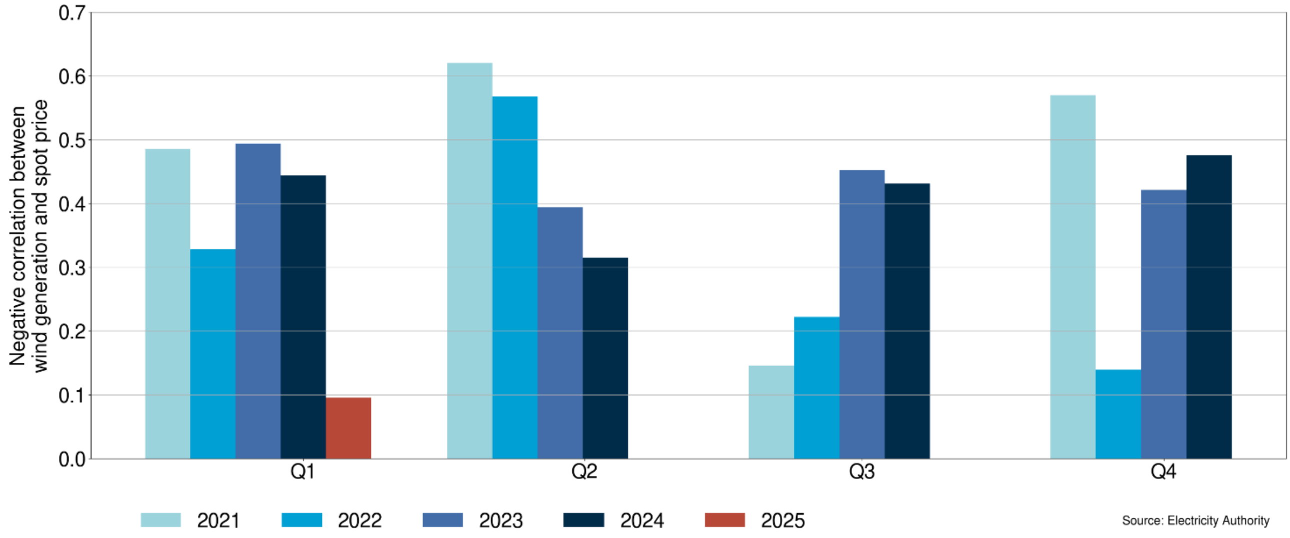
4.7. The effects of the factors are visible at different time scales. Wind and demand have the most impact on half-hourly prices as these elements change the most quickly. Thermal generation is typically on for hours or days at a time and affects daily average prices. Hydro storage levels take days or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

4.8. Figure 5 shows the quarterly correlation between daily total wind generation and the daily average national spot prices. Wind generation typically has an inverse relationship with average wholesale price (ie, a negative correlation). Since wind generation has no fuel costs, when the wind is blowing generators have no reason not to offer all their wind generation into the market. With these low operating costs, wind generators can offer a lot of generation at low prices, which displaces more expensive generation.

4.9. In Q1 2025, the correlation between wind generation and spot price was the lowest it's been in recent years. This is because the prices this quarter were heavily driven by declining hydro storage and increased thermal generation.

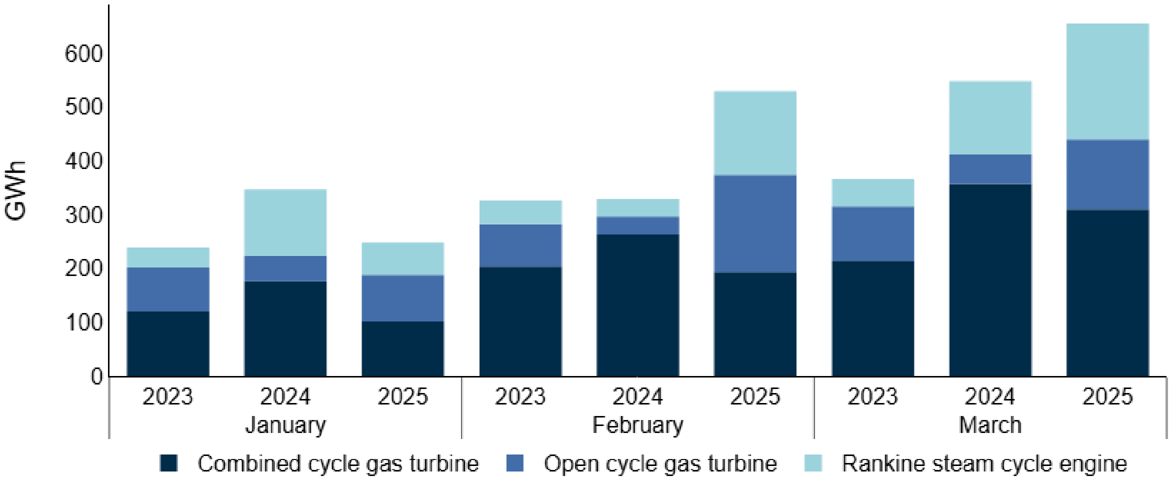
4.10. Wind was also lower in Q1 2025, with average generation at 27% of capacity, compared to 32% in Q1 2024 and 29% in Q1 2023. This is even more significant when considering the extra ~220MW of wind capacity added after Q1 2023. This lower wind generation contributed to the weaker correlation.

Figure 5: Strength of the relationship between daily wind generation and average wholesale price, 2021-25



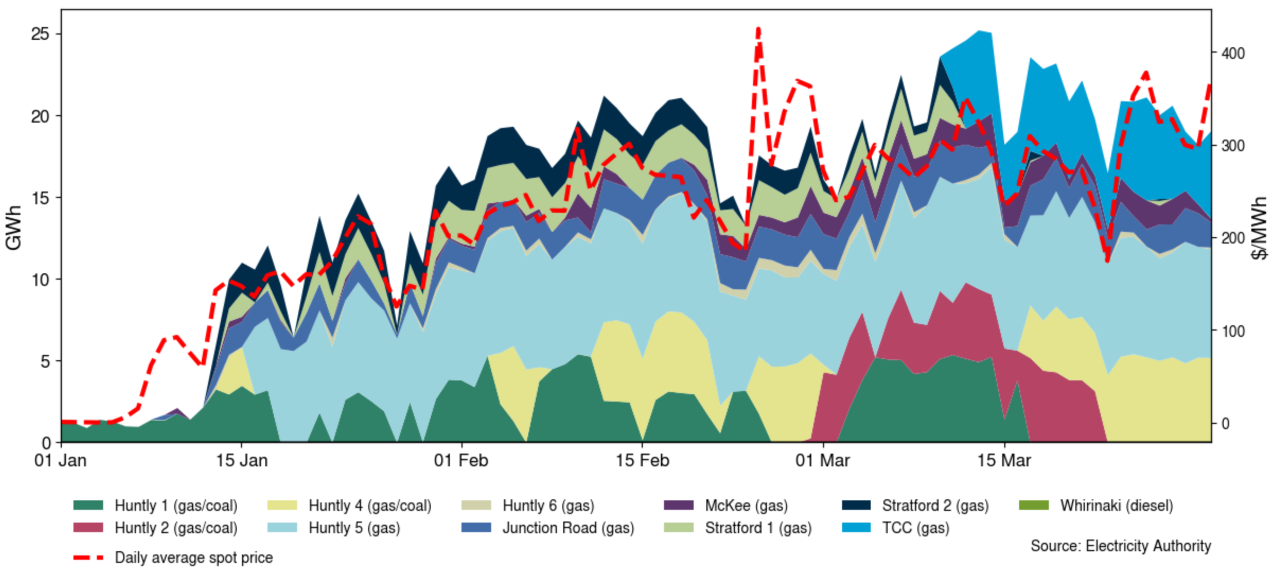
4.11. Figure 6 shows the total thermal generation by type and month in Q1 for the past three years. Total thermal generation was lower in January 2025 when hydro storage was high, and much higher in February and March as hydro storage was rapidly declining. Due to especially low hydro inflows in Q1 2025, and lower levels of wind generation, thermal generation in February and March 2025 was significantly higher than in 2023 and 2024. This year a higher coal stockpile is being maintained to run the Rankine units and more coal powered generation is being used.

Figure 6: Monthly total thermal generation, Q1 2023-25



4.12. Figure 7 shows the daily total thermal generation and daily average spot price between January and March 2025. There was a strong relationship between spot price and thermal generation in Q1 2025. As hydro storage declined, hydro generators increased their offer prices and thermal generation came online to converse more hydro storage.

Figure 7: Daily total thermal generation and average wholesale price, January to March 2025

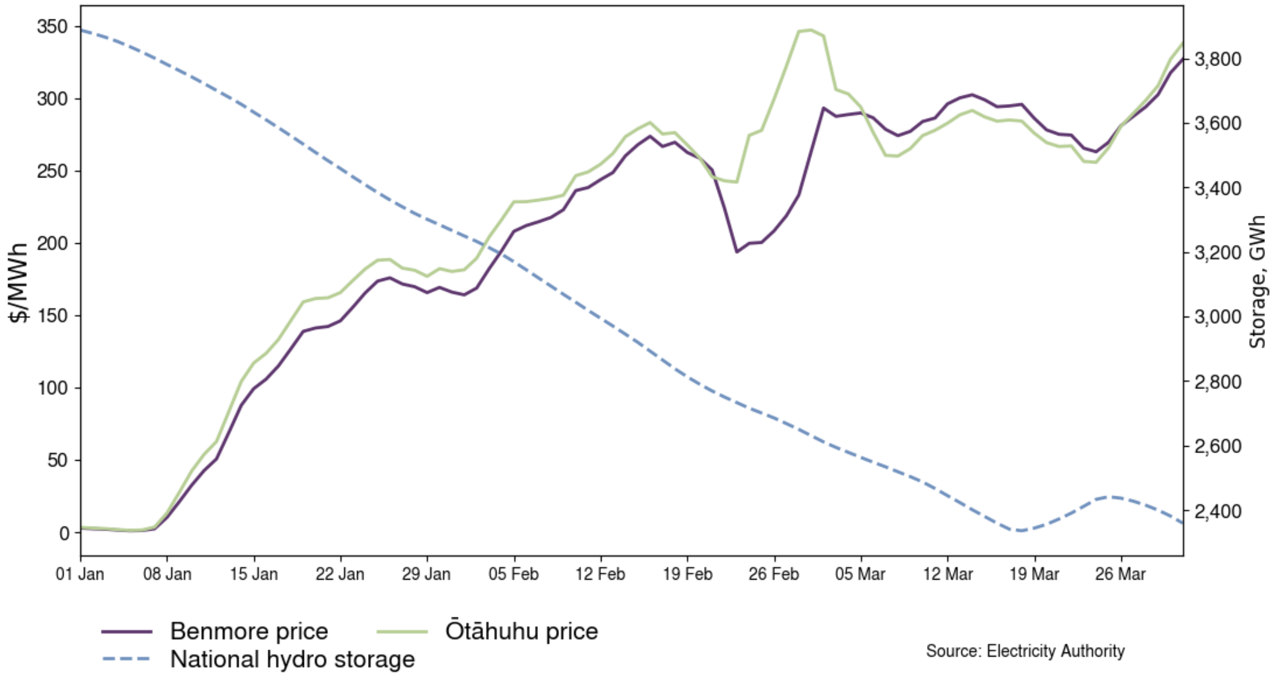


4.13. Figure 8 shows the rolling seven-day average wholesale prices at Benmore and Ōtāhuhu and the daily national hydro storage.

4.14. 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 8.

4.15. This quarter the relationship between hydro storage and price was very pronounced. As hydro storage decreased throughout the quarter, prices increased. The visible period of price separation was due to planned HVDC outages. For more on why hydro storage has such a significant effect on prices, especially before winter, you can read this Eye on Electricity article.

Figure 8: Rolling seven-day average of wholesale price versus hydro storage January to March 2025



Generation by fuel type

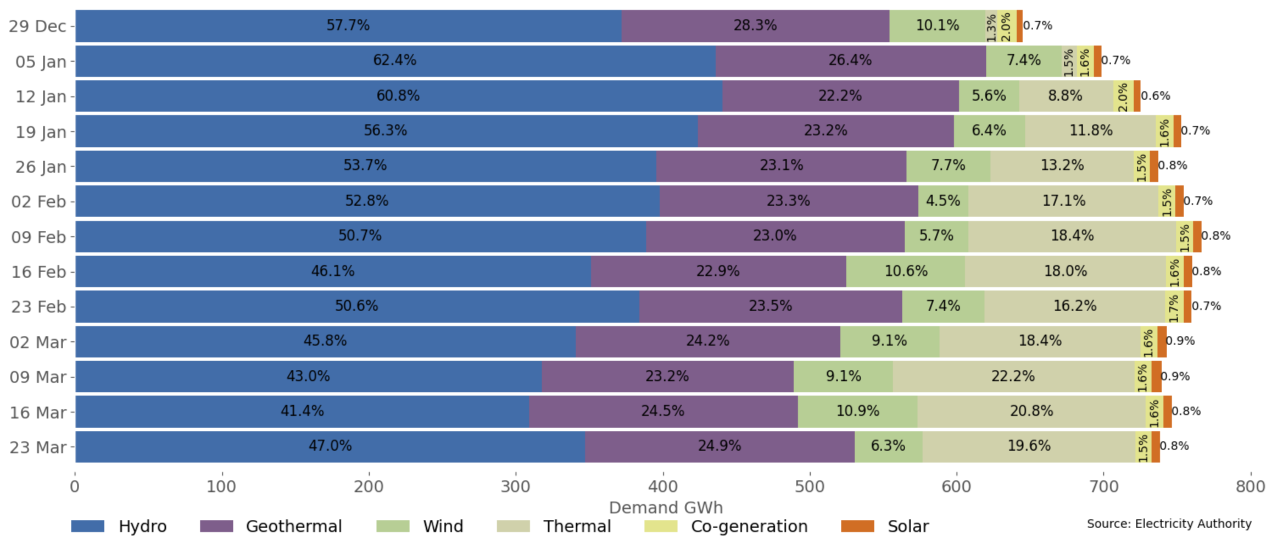
4.16. Figure 9 shows the weekly breakdown of electricity generation by fuel type relative to demand.

4.17. Geothermal generation is generally consistent and offers cheap baseload. Some weeks geothermal generation is less because of geothermal outages. Wind generation is the most volatile and often changes a lot week to week due to short term weather patterns. Hydro generation is high when hydro storage is abundant, and lower when hydro storage is low.

4.18. 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.

4.19. Due to low hydro storage in February and March, thermal was already generating more than is typical for summer months. Since cheaper thermal generation was already generating, more expensive hydro storage had to be dispatched when wind generation was low, causing higher prices.

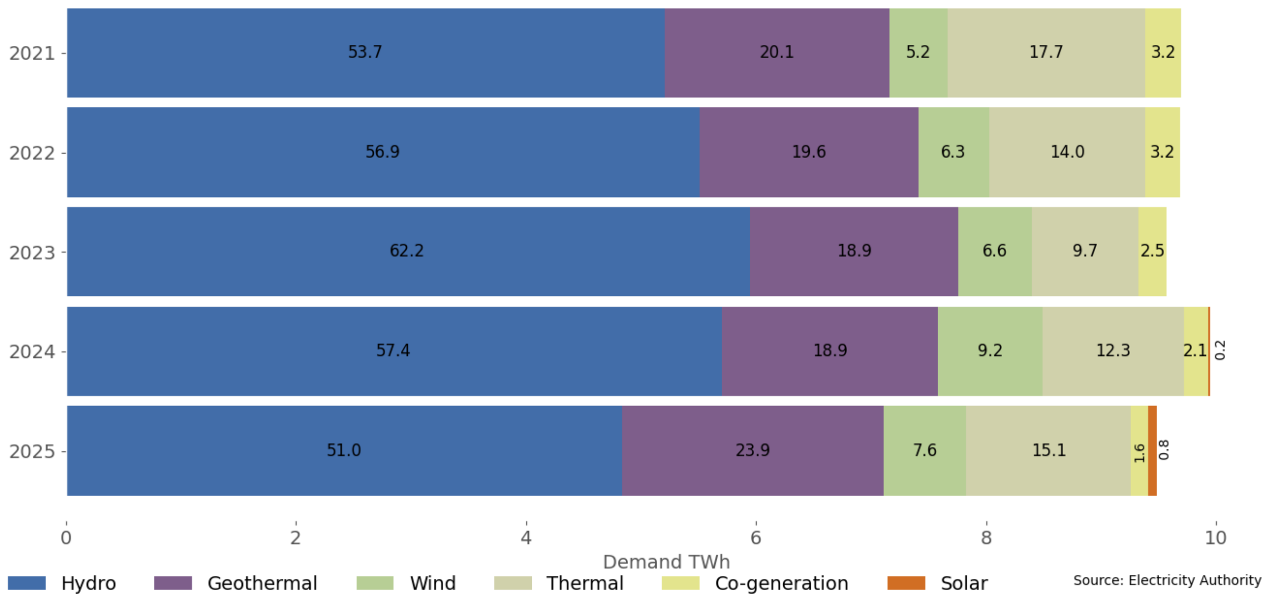
Figure 9: Weekly generation share by fuel type, January to March 2025



4.20. Figure 10 shows the quarterly breakdown of electricity generation by fuel type relative to demand for Q1 2021-25. Due to low hydro storage for much of this quarter, hydro generation was lower than is typical for Q1. Geothermal generation was higher in Q1 2025 than in previous years due to there being new geothermal units completed since Q1 2024. More thermal generation was dispatched in Q1 2025 than in Q1 2022-24 to allow less hydro generation. Several grid connected solar farms also began generating last year, which can be seen in the share of solar generation increasing.

4.21. Q1 2024 had higher demand than Q1 in other years. Global energy demand has been accelerating in recent years due to increased electrification, climate change and our growing need for computational power.[5] In New Zealand, Q1 2024 also had below average temperatures leading to greater heating demand and above average irrigation demand.[6] As discussed in section 3, demand for Q1 2025 has been lower due to the Tiwai demand response agreement and higher autumn temperatures.

Figure 10: Generation share by fuel type for Q1, 2021-25



Relevant Outages

4.22. Figure 11 shows how much generation was on outage in Q1 2025 compared to the historic average. This quarter, generation on outage was close to average in January and most of March, but above average in February.

4.23. Figure 12 shows which thermal units were on outage and shows that the above average MW loss in the middle of the quarter was primarily due to TCC being on outage. This TCC outage came at a time when TCC would not ordinarily have been generating.

4.24. The Huntly Rankines experienced several unplanned and short notice outages this quarter due to high temperatures and cooling issues[7]. Generators also had long planned outages for each unit this year for routine maintenance.

[5] Global Energy Review 2025 – Analysis - IEA
[6] Was electricity demand higher in 2024? | Electricity Authority
[7] Cooling tower issue causes unplanned outage | Genesis NZ

Figure 11: Total MW loss from generation outages, Q1 2025

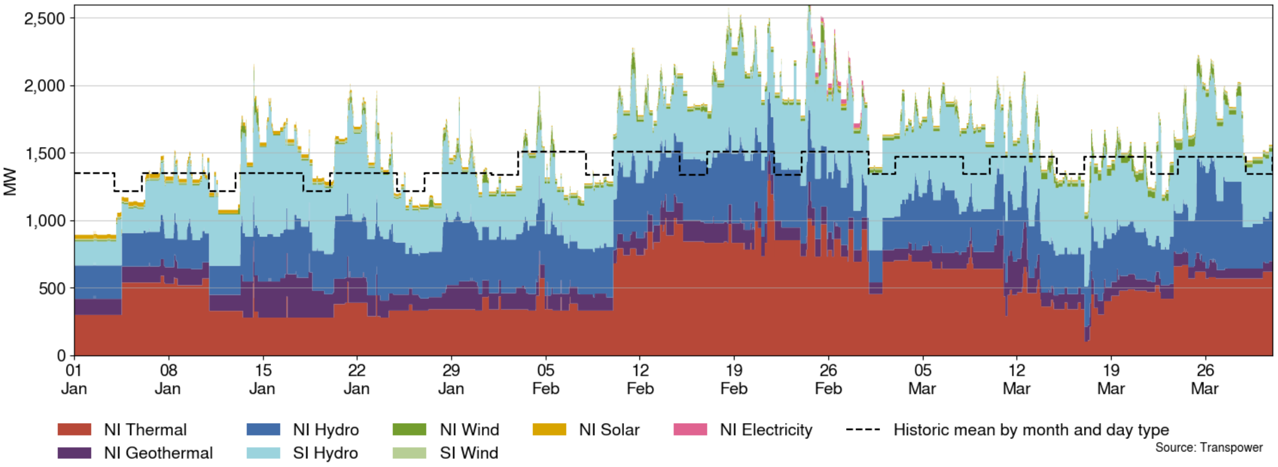
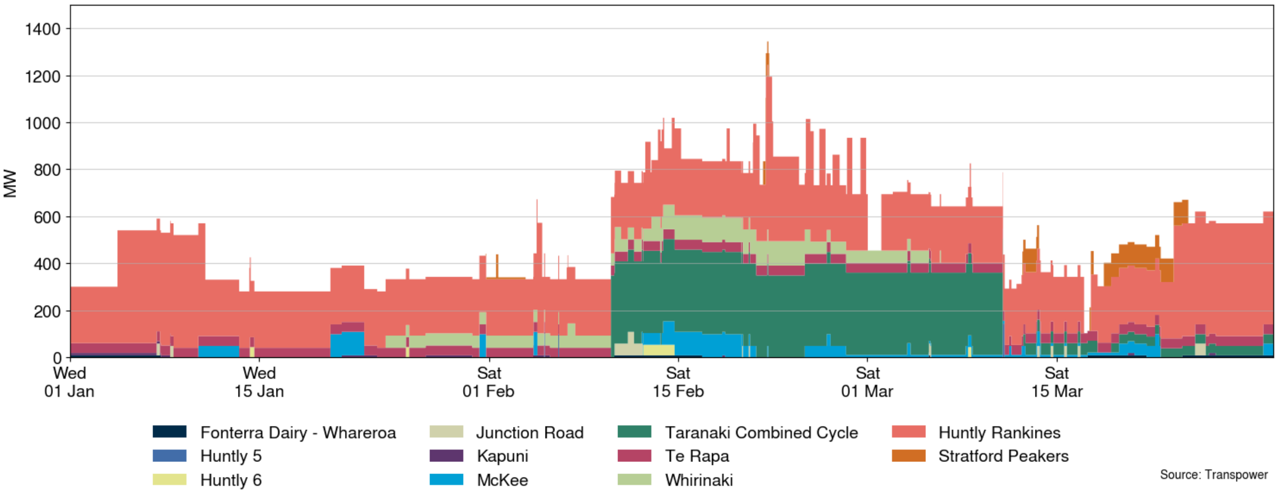


Figure 12: Total MW loss from thermal generation outages, Q1 2025



4.25. The HVDC cable also had its annual planned outages[8] this quarter. HVDC outages limit energy or reserve that can be shared between islands. This usually causes spikes in reserve prices, an increase in North Island thermal generation and a decrease in South Island hydro. Prices during this time tend to be higher in the North Island and very low in the South.

4.26. When hydro storage is low, however, reduced energy sharing between islands can lead to higher South Island reserve and spot prices instead.

[8] CAN Planned Outage HVDC Pole 2, HVDC Pole 3 5985536633.pdf, CAN Planned Outage HVDC Pole 2, HVDC Pole 3 5998297595.pdf

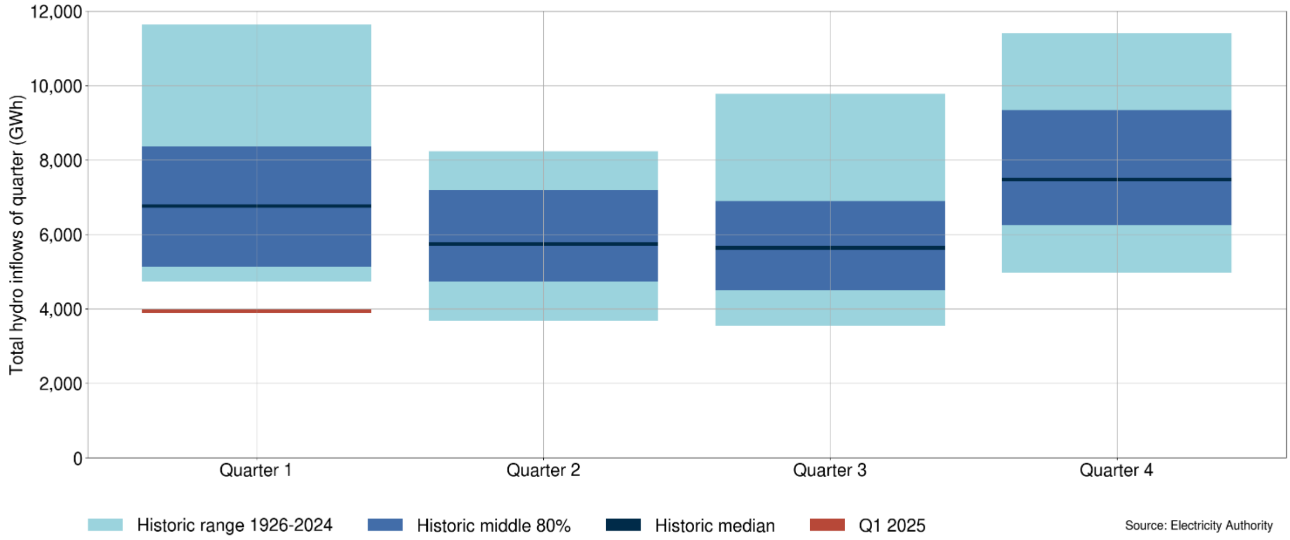
5. Water storage levels

National hydro storage levels

5.1. Figure 14 shows the national hydro storage levels from June 2024 to December 2025, and how the electricity risk curves have changed throughout Q1 2025

5.2. The hydro storage inflows in Q1 2025 were the lowest on record for January to March by ~850GWh, with records going back to 1926 (Figure 13). That is equivalent to enough generation to power the entirety of New Zealand for approximately a week.

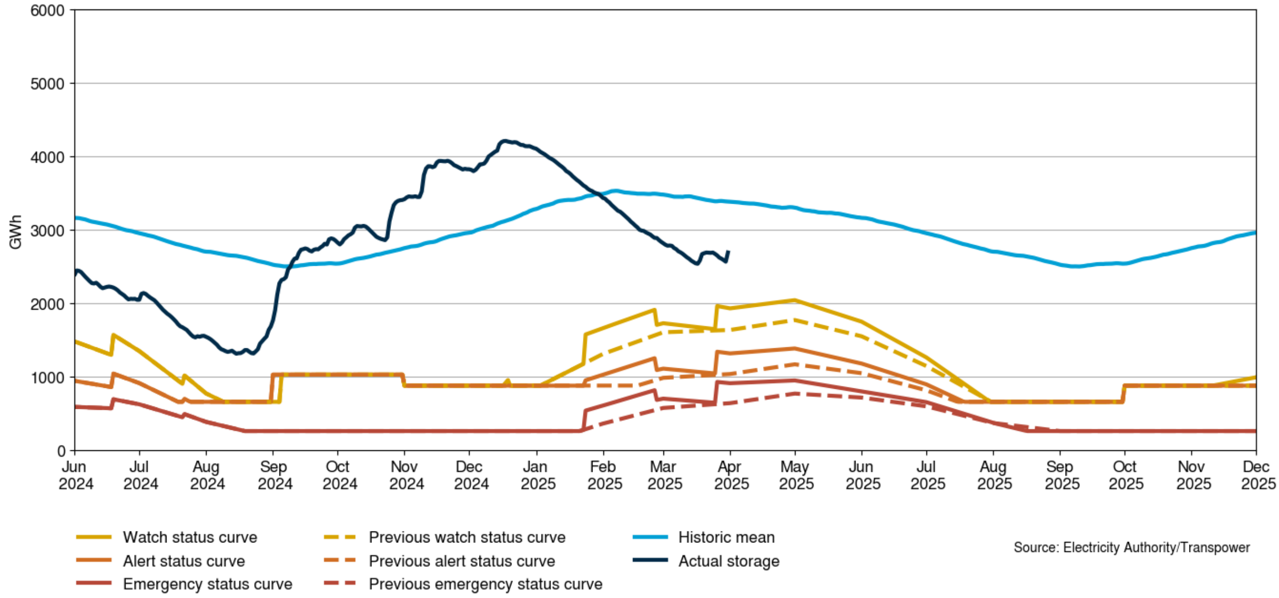
Figure 13: Total national hydro inflows for Q1 2025 compared to historic quarters, 1926-2024



5.3. As a result of these low inflows, hydro storage dropped sharply this quarter, but a small amount of rain kept it steady towards the end of March. By the end of March, hydro storage was 60% nominally full and ~77% of the historic mean.

5.4. The electricity risk curves, which indicate the different levels of electricity risk associated with lower hydro storage, increased throughout the quarter. This increase has been primarily due to uncertainty surrounding thermal fuel supply. In particular, gas production has been down.

Figure 14: National hydro storage levels, June 2024 to December 2025



Lake storage levels

5.5. Figure 15 shows individual lake levels for January to March 2025 and the difference location can have on hydro inflows.

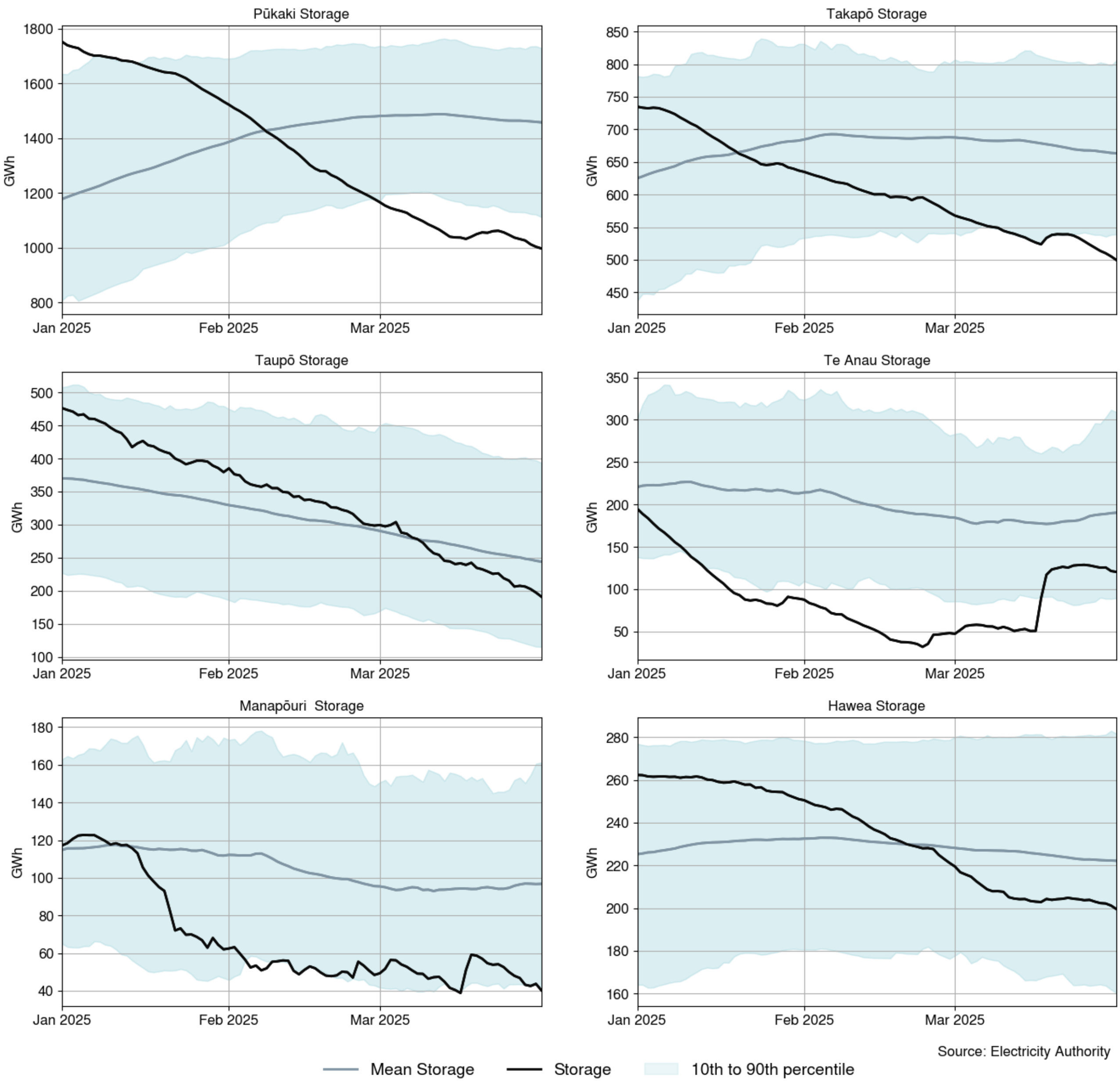
5.6. Lake Pūkaki is the largest hydro storage lake in New Zealand. Its stored water decreased consistently over the quarter from above the historical 90th percentile to below the historic 10th percentile.

5.7. Lake Takapō decreased from above its historic mean to below its historic 10th percentile.

5.8. Lakes Hawea and Taupō decreased from above their historic means to below them.

5.9. Lakes Te Anau and Manapōuri are smaller storage lakes that tend to fluctuate. They both stayed mostly below their historic means, with Lake Te Anau dropping below its historic 10th percentile for most of the quarter.

Figure 15: Lake storage levels for January to March 2025 versus historical average and 10th and 90th percentiles



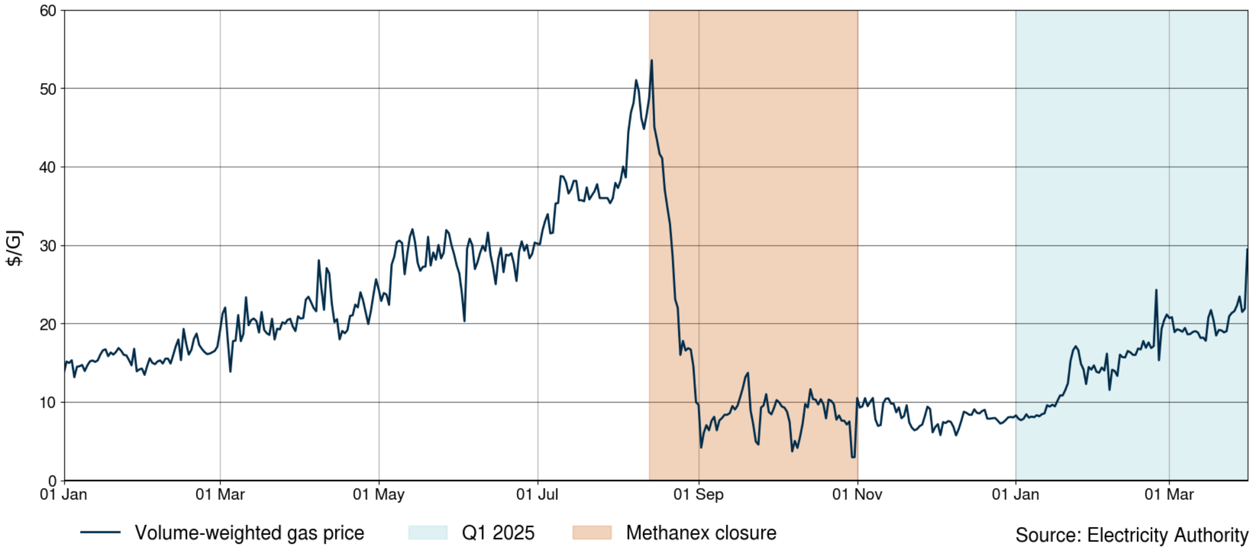
6. Wholesale gas prices, production and consumption

Gas prices

6.1. Figure 16 shows the daily volume-weighted average gas price and New Zealand carbon unit price for January 2024 to March 2025.

6.2. The average daily volume-weighted average price (VWAP) for gas in Q1 2025 was $16/GJ. This is $8/GJ more than Q4 2024 and $1/GJ less than Q1 2024. Gas price started low in Q1 2025 at $8/GJ. This was after the Methanex deal increased gas availability and high hydro inflows lowered gas usage last quarter. However, as gas demand rose with decreasing hydro storage, and more gas storage got used up, gas prices also rose. At the end of the quarter, gas prices were $29/GJ.

Figure 16: Daily volume-weighted average price for gas and NZ carbon unit price, January 2024 to March 2025



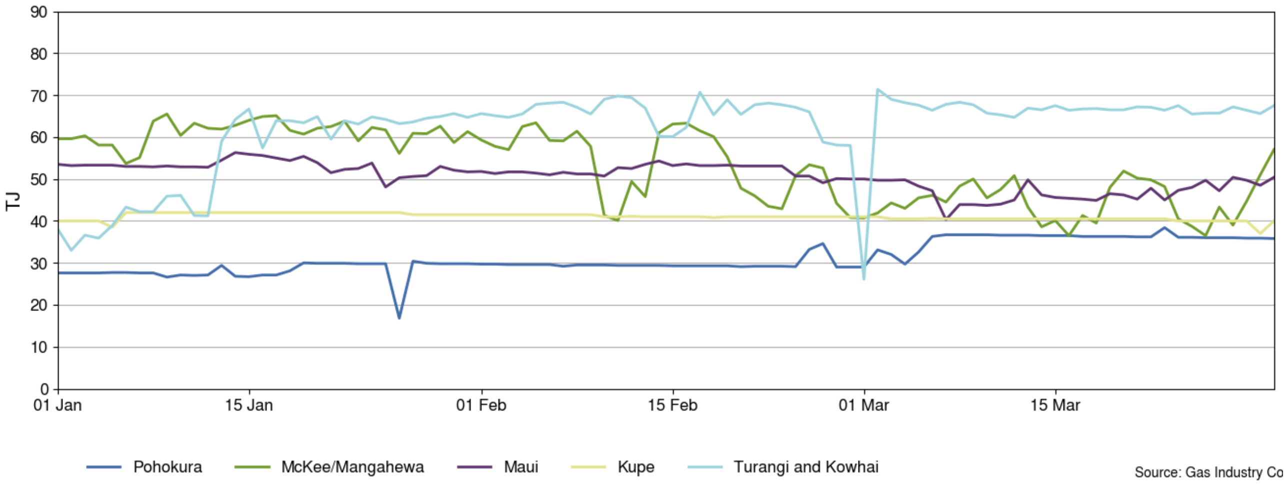
Gas production

6.3. Figure 17 shows daily gas production at major fields between January to March 2025.

6.4. Total gas production at major fields varied from 187TJ/day to 256TJ/day in Q1 2025. This quarter's maximum is 12/TJ/day lower than last quarter's.

6.5. Production at Pohokura was 17-38TJ/day, production at McKee/Mangahewa was 37-66TJ/day, production at Turangi and Kowhai was 26-71TJ/day, production at Maui was 40-56TJ/day this quarter and production at Kupe was 37-42TJ/day.

Figure 17: New Zealand gas production, January to March 2025



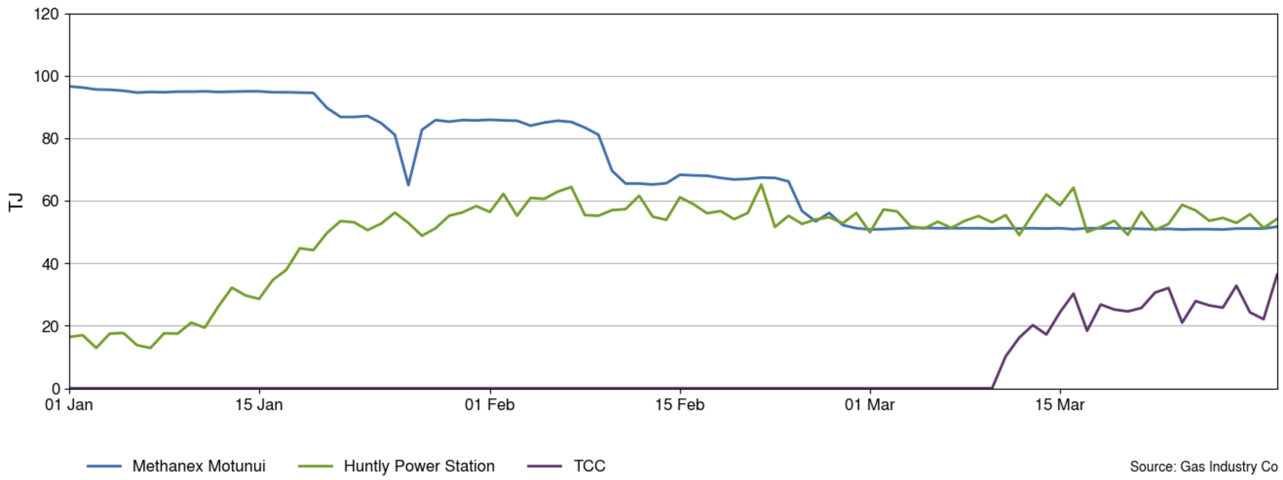
Gas consumption

6.6. Figure 18 shows the daily gas consumption by major users between January to March 2025.

6.7. Gas consumption at TCC remained at zero until it started generating on 11 March. When generating, its consumption reached up to 26TJ/day.

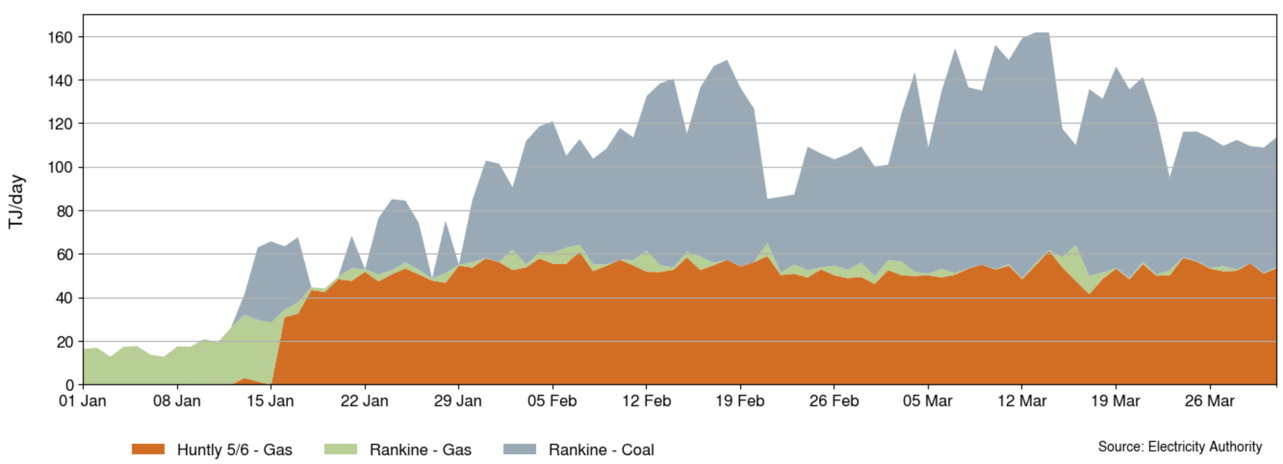
6.8. Gas consumption at Methanex reduced from 97TJ/day to 51TJ/day. Gas consumption at Huntly increased from ~13TJ/day to ~65TJ/day.

Figure 18: New Zealand gas consumption, January to March 2025



6.9. Figure 19 shows the estimated daily total fuel consumption across all Huntly units between January and March 2025. At the start of the quarter, the Rankine units were generating with gas. However, in mid-January the Rankines switched to using mostly coal as Huntly 5 began generating. Genesis has announced that they intend to maintain a coal stockpile of 500kt between March and August 2025[9].

Figure 19: Estimated Huntly fuel consumption, January to March 2025



[9] Genesis increases coal stockpile for winter amid gas shortage | Genesis NZ

7. Retail electricity

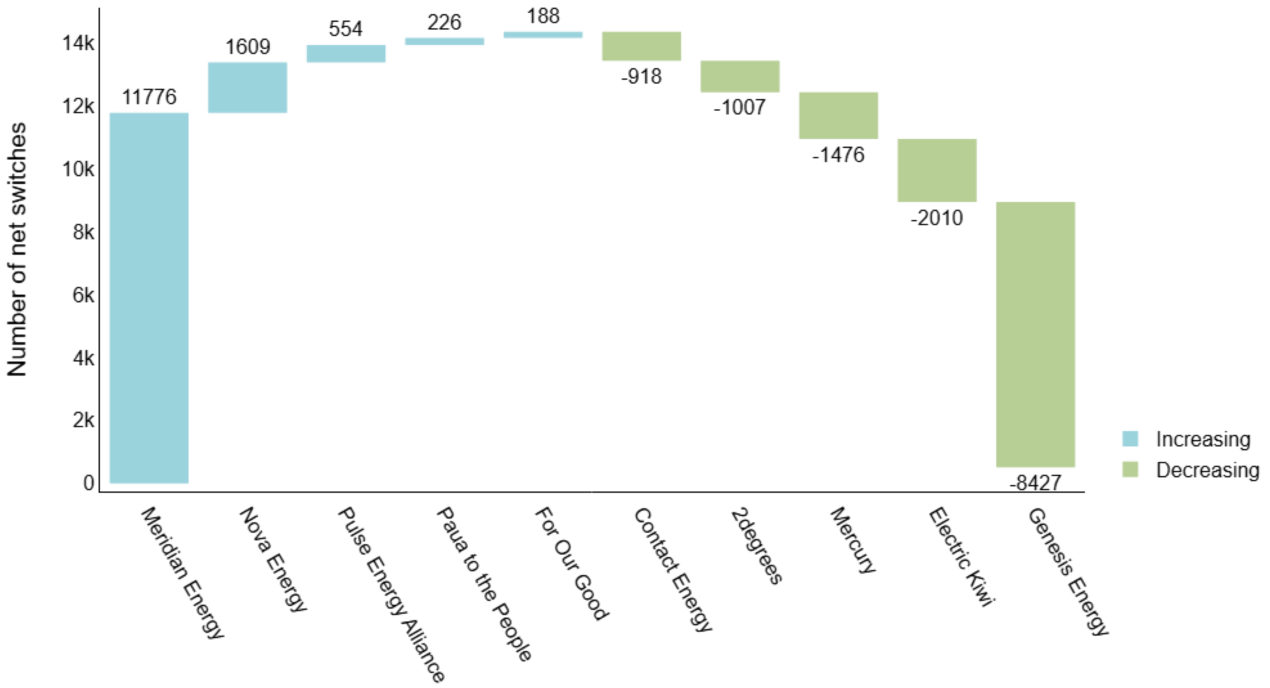
Retailer switching

7.1. Figure 20 shows the top 5 retailers who gained and the bottom 5 retailers who lost the most electricity connections (ICPs) between January and March 2025.

7.2. Meridian had the greatest net gain in ICPs at 11,776 net switches. Meridian also had the greatest net gain last quarter. Nova and Pulse were second and third with 1,609 and 554 net switches respectively.

7.3. Genesis and Electric Kiwi had the greatest net loss in ICPs and 8,427and 2,010 net switches respectively.

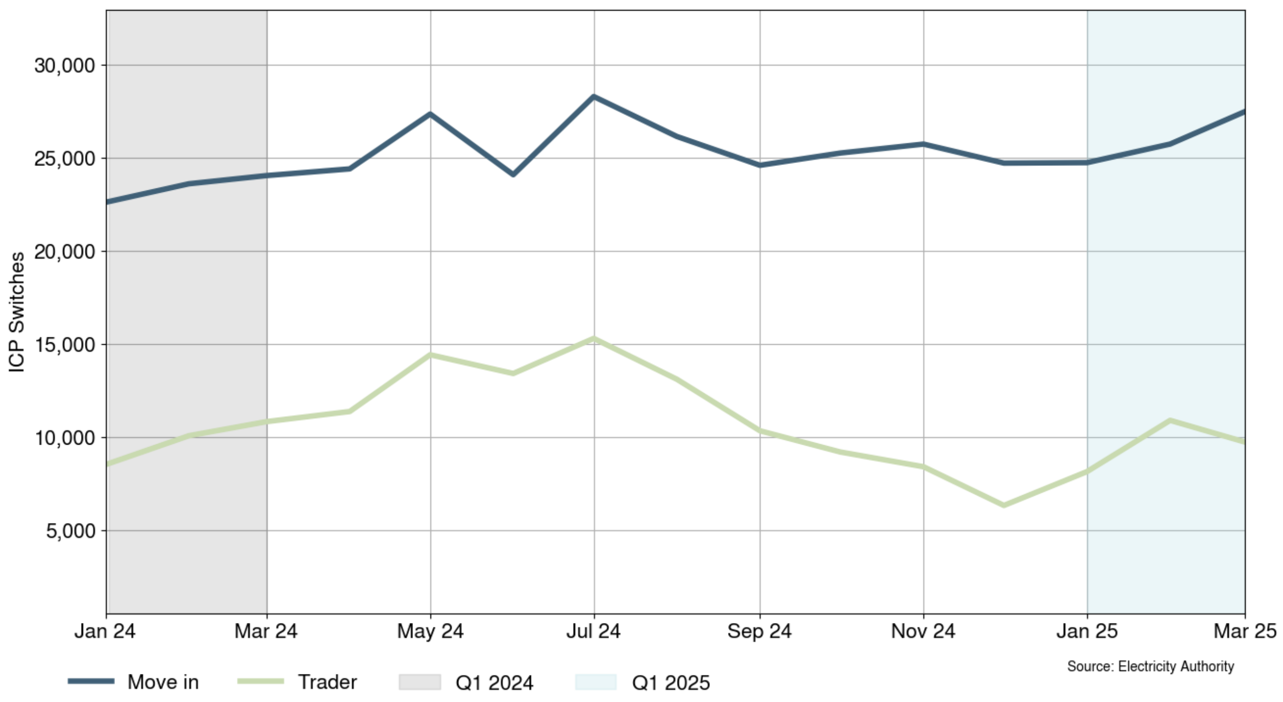
Figure 20: Top 5 increases and bottom 5 decreases in ICP net switching by retailer, January to March 2025



7.4. Figure 21 shows the number of ICPs that have changed electricity suppliers between January 2024 and March 2025 categorised by type ‘move in’ and ‘trader’. Move in switches at an ICP 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.

7.5. In Q1 2025, the number of move in switches increased, which is similar to the same quarter last year. The number of trader switches fluctuated in Q1 2025, increasing in the first months of the quarter but decreasing in March.

Figure 21: Breakdown of monthly ICP switching by type, January 2024 and March 2025

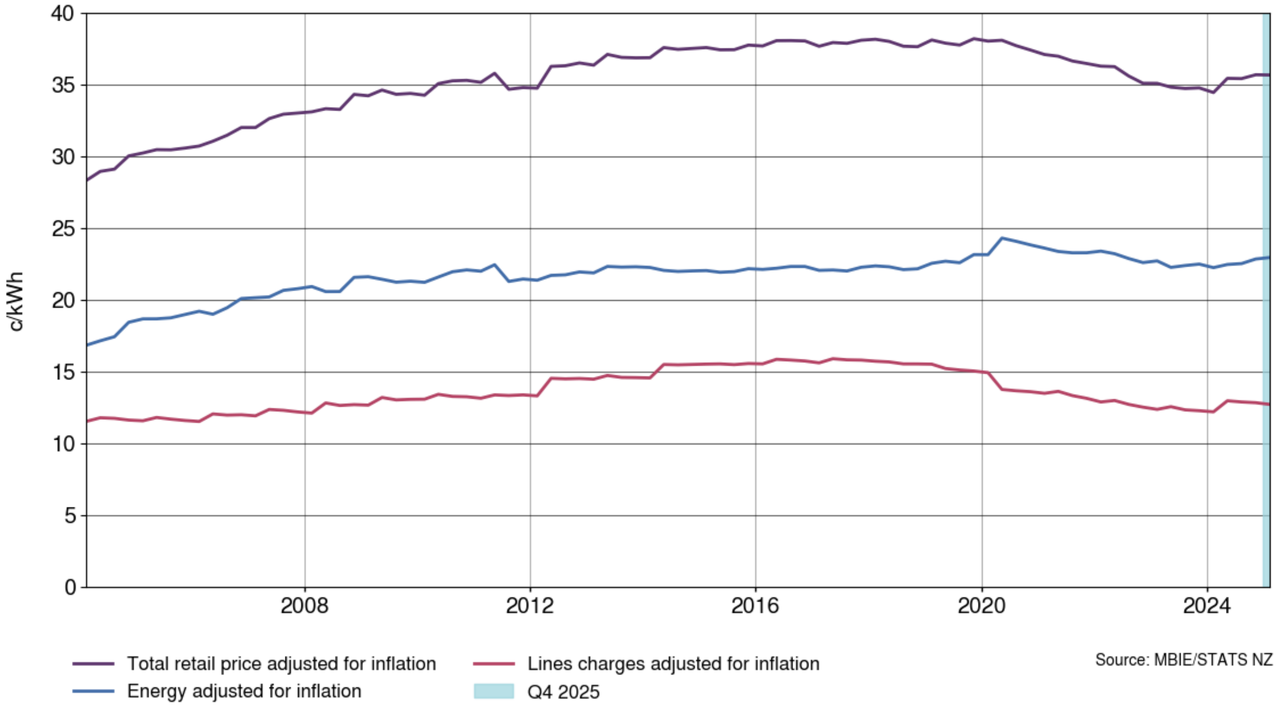


7.6. Measures relating to retail market competition can also be found on the Electricity Authority's Competition Dashboard.

Retail prices

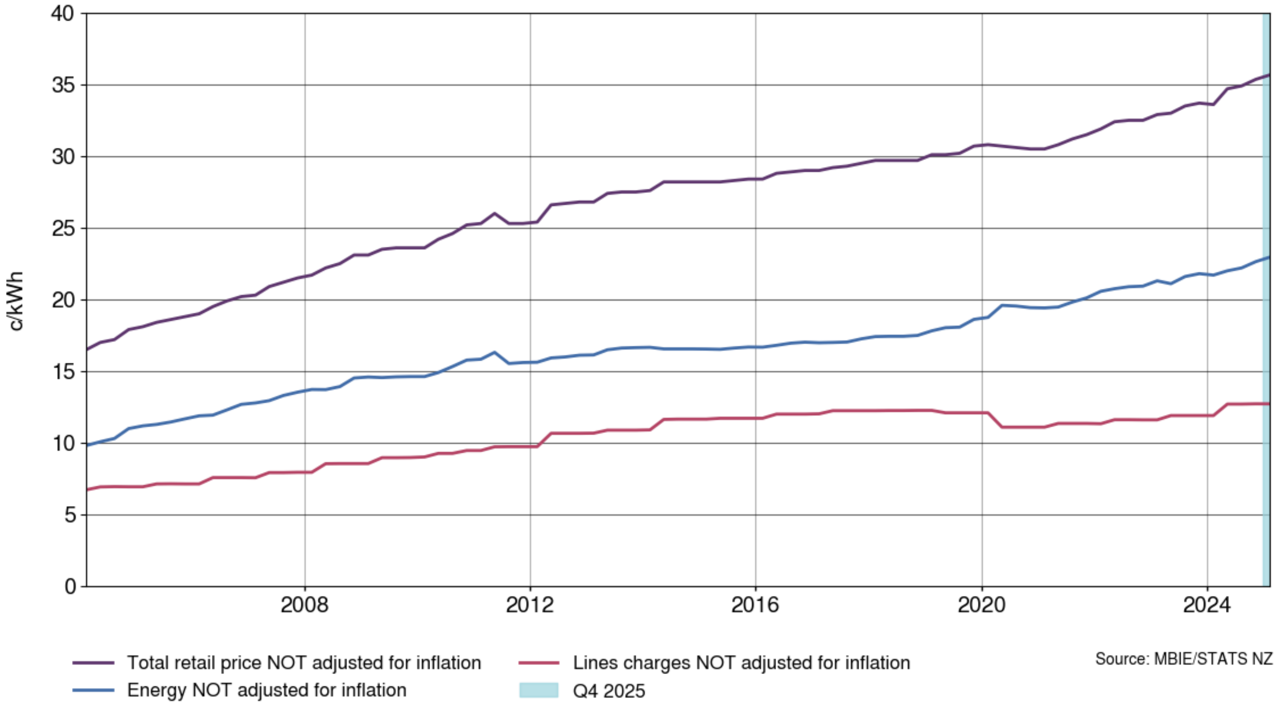
7.7. Figure 22 shows the domestic electricity price by component (QSDEP) adjusted for inflation from 2004 to March 2025. When adjusted for inflation, prices appear relatively steady this quarter.

Figure 22: Domestic electricity prices by component adjusted for inflation (base Q1 2025 CPI), January 2004 to March 2025



7.8. Figure 23 shows the domestic electricity prices by component without adjusting for inflation from 2004 to March 2025. In the last 12 months, nominal values rose by 6.2%. For a typical household using 8,000kWh annually, this equates to an extra $166 per year on their electricity bill compared to one year ago.

Figure 23: Domestic electricity prices by component without inflation adjustment, January 2004 to March 2025



8. Forward market and carbon pricing

Forward pricing

8.1. Figure 24 shows the quarterly forward prices up to 2028, with the first snapshot (dashed lines) at the beginning of January 2025 and second snapshot at the end of March 2025 (solid lines).

8.2. Front end future prices increased sharply as hydro storage dropped. June 2025 futures increased the most over the quarter by $121/MWh at Ōtāhuhu and $127/MWh at Benmore. September 2025 futures also increased significantly. Other 2025 futures and longer term winter futures also increased to a lesser extent.

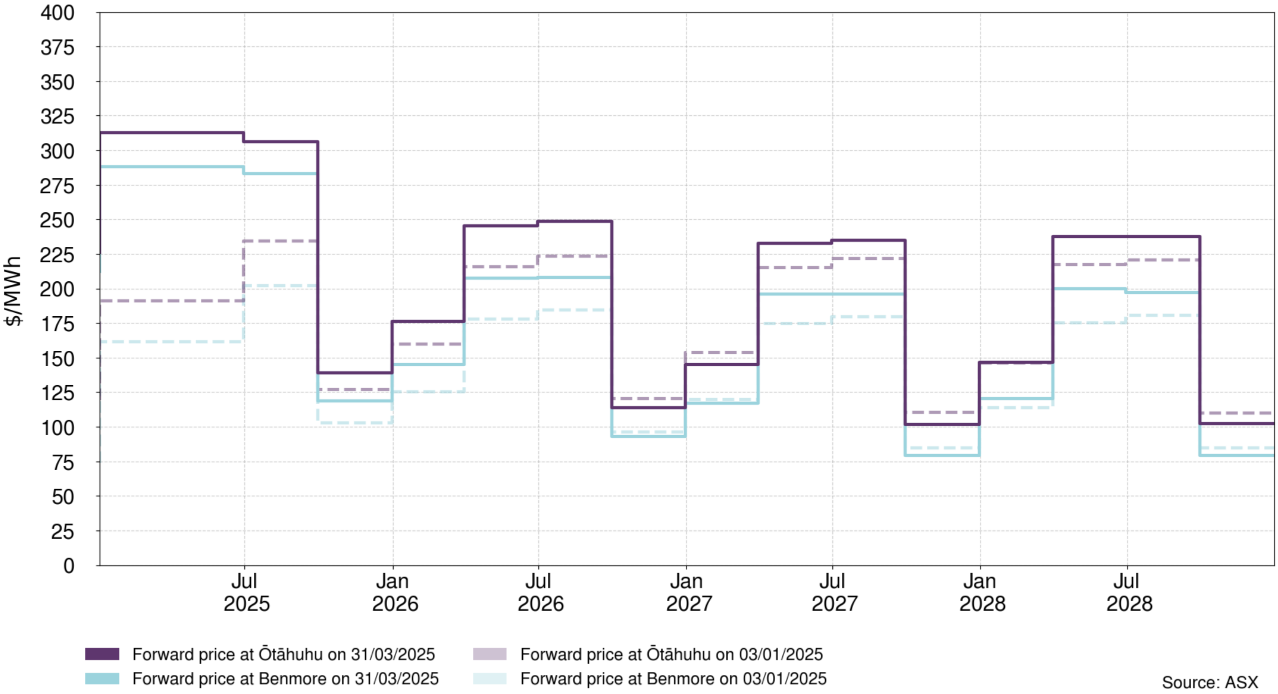
8.3. These higher long term winter futures likely relate to concerns surrounding:

(a) Changing weather patterns affecting hydro inflows

(b) Declining gas production

(c) The possible retirement of TCC

Figure 24: ASX forward prices for the start and finish of Q1 2025



8.4. Measures relating to the futures market can also be found on the Electricity Authority's Competition Dashboard.

Carbon pricing

8.5. Figure 25 shows the New Zealand carbon unit price between January 2024 and March 2025 as recorded by the European Capital Markets Institute.

8.6. Carbon unit prices stayed relatively steady over Q1 2025 until prices started dropping slightly in March. The mean carbon price in Q1 2025 was $63/NZU. The carbon price was $63/NZU at the start of January but dropped to $60/NZU by the end of March.

Figure 25: New Zealand Units price, January 2024 to March 2025