ELECTRICITY AUTHORITY
TE MANA HIKO

Market performance Quarterly review

October – December 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 October to 31 December 2024. 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 Q4 2024. It also analyses changes in the retail and forward market. This review also includes our six-monthly Structure, Conduct, Performance (SCP) review which 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.

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. National demand was below average in October and the start of November due to above average temperatures, lower industrial demand and due to the Tiwai Point aluminium smelter demand still increasing following its winter demand response. Demand then increased above average at the end of November and start of December before dropping back below average in the last week of December.

2.2. Spot electricity prices were almost entirely below the historical average this quarter due to high hydro inflows.

2.3. Thermal generation was very low from the start of November, providing less than 1% of the total generation mix in three weeks this quarter, and dropping to 0.5% of the total generation mix in the last week of December.

2.4. National hydro storage increased significantly this quarter from 65% nominally full on 1 October to 95% nominally full on 31 December. This is a significant improvement on hydro storage compared to one year ago at the end of Q4 2023 when hydro storage was only 68% nominally full.

2.5. Spot gas prices averaged $8/GJ this quarter after dropping from their peak of more than $50/GJ last quarter following the Methanex gas deal with Contact and Genesis.

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

2.7. Retail electricity prices increased at slightly above the rate of inflation this quarter (ie, in real terms). In nominal terms (ie, not adjusted for inflation), prices have increased by ~$133/MWh per year for the average household.

2.8. Futures prices for 2025 all decreased over the quarter by $30-70/MWh, likely due to the high hydro inflows during the quarter which improved the hydro storage outlook for 2025. All other futures prices from 2026 onwards increased over the quarter.

2.9. The price of New Zealand carbon units (NZUs) decreased slightly over the quarter from $65/NZU to $63/NZU.

3. Electricity demand

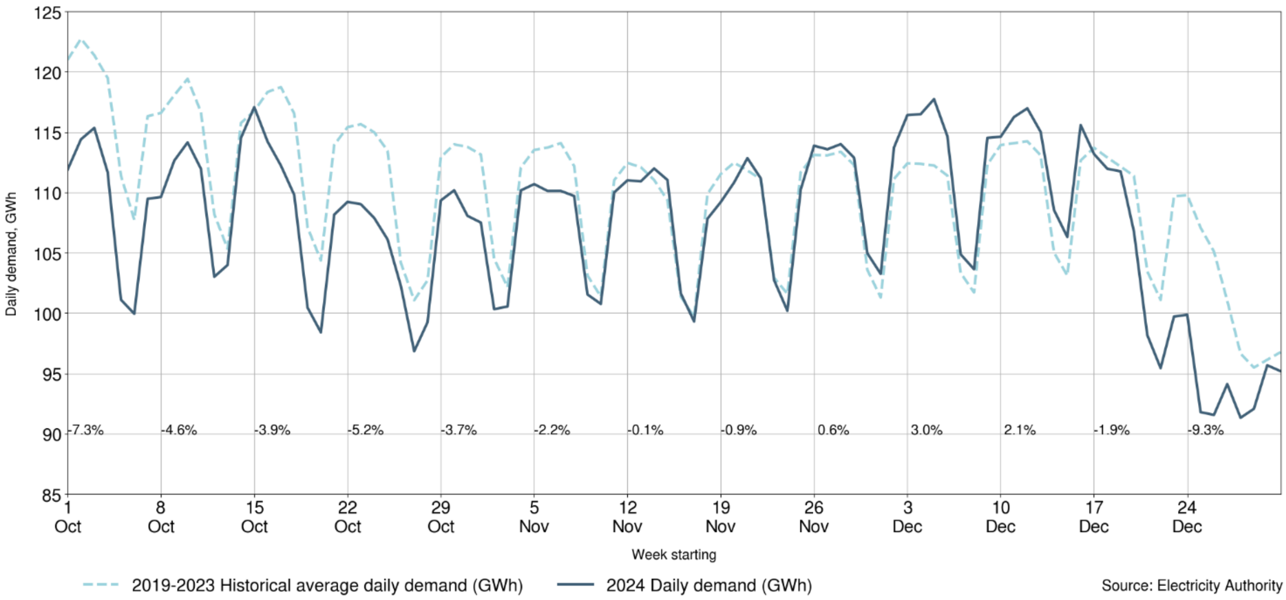
3.1. Figure 1 shows the total daily electricity demand in 2024 and the 2019-23 historic average demand between October and December.

3.2. National demand in October was 4-7% lower than the historic average due to above average temperatures[1] requiring less heating, lower industrial demand following some plant turn downs and shutdowns, and demand at Tiwai Point aluminium smelter still ramping back up following its demand response during winter.

3.3. November and December temperatures were also above average[2,3] and national demand increased through November and into the start of December from near the historical average to 3% above the historical average. Increasing demand from the end of October is partially due to the increasing demand at Tiwai Point aluminium smelter.

3.4. Demand usually drops at the end of December during the Christmas holiday period. This year, demand dropped more than usual to 9% below the historical average which is a combination of reduced industrial load, cooler weather reducing air conditioning load and reduced irrigation load from South Island rainfall.

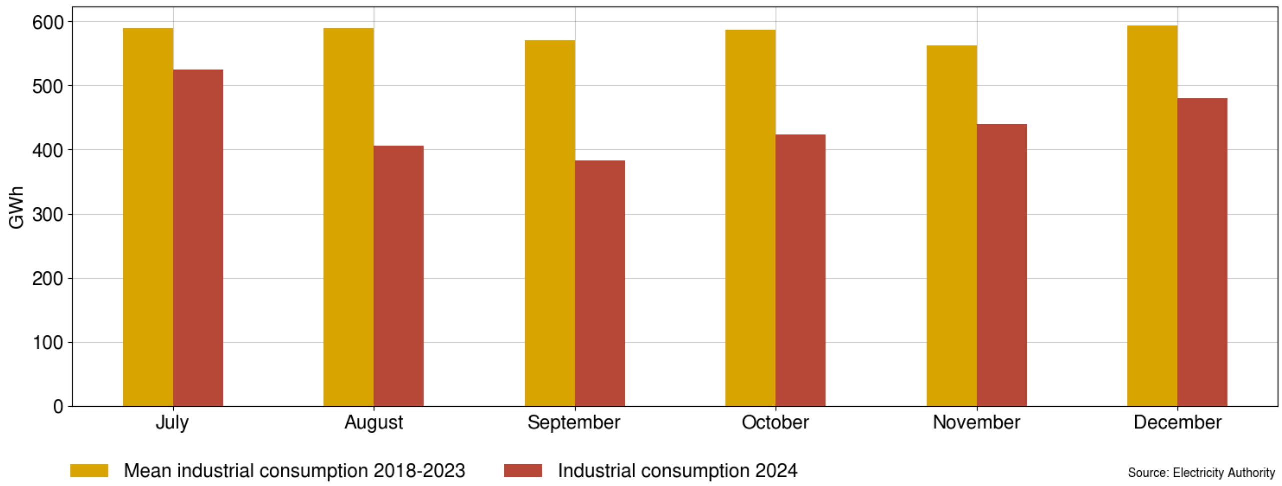
Figure 1: New Zealand daily demand compared to historical average, October–December 2024



3.5. Figure 2 shows the daily electricity demand from major industrial users since July 2024. Industrial users included are the Tiwai aluminium smelter, Glenbrook steel mill, Kinleith paper mills, Winstone pulp and Panpac. In August, demand from industrial users dropped below the historical average. Demand from industrial users increased over Q4 2024 but remained below average, with the Tiwai Point aluminium smelter expected to increase back to usual demand in April 2025.

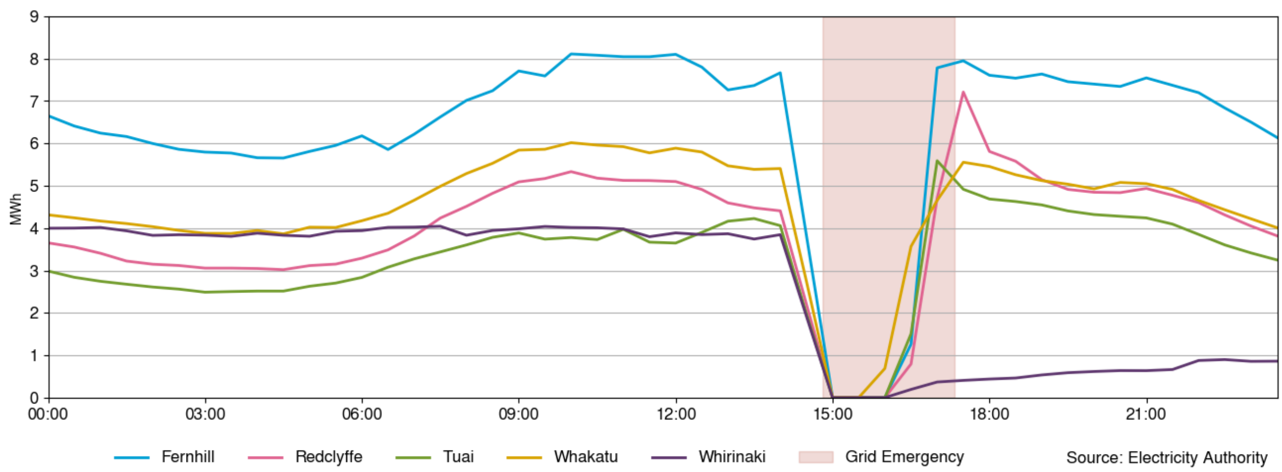
[1] Climate Summary for October 2024 | NIWA
[2] Climate Summary for November 2024 | NIWA
[3] Climate Summary for December 2024 | NIWA

Figure 2: Monthly demand from major industrial users, July–December 2024



3.6. A Grid Emergency Notice (GEN) was issued on 21 December after a lightning strike caused an unplanned outage to the Hawkes Bay area.[4] Figure 3 shows the demand across five Hawkes Bay sites on 21 December, with the GEN period highlighted in red. Electricity supply was lost at 2.49pm and restored by 5.20pm.

Figure 3: Hawkes Bay demand by site, 21 December 2024.



4. Wholesale electricity price and consumption

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

4.2. The middle 50% of prices in Q4 2024 were between $4/MWh and $61/MWh. The average wholesale spot price for Q4 2024 was $38/MWh. This is $263/MWh lower than Q3 2024 ($301/MWh) and $107/MWh lower than Q4 2023 ($145/MWh).

4.3. Prices this quarter were almost entirely below the historic daily average and lower than the same quarter last year. These low prices were primarily driven by high hydro inflows and

[4] GEN RPT for Unplanned outage Hawkes Bay 5854778628.pdf | Transpower

generation. Periods where the daily average price increased to near the historical average typically occurred during days of low wind generation.

4.4. The highest price this quarter was $3,073/MWh at 8.30am on 12 December when an unplanned outage of HVDC pole 2 occurred.[5] At the time, wind generation was low, demand was at its peak for the week and all available thermal peaker generation turned on to meet North Island demand. Reserve scarcity pricing was also triggered during three 5-minute trading periods.

Figure 4: Half hourly, daily and daily historic average wholesale electricity prices, October–December 2024

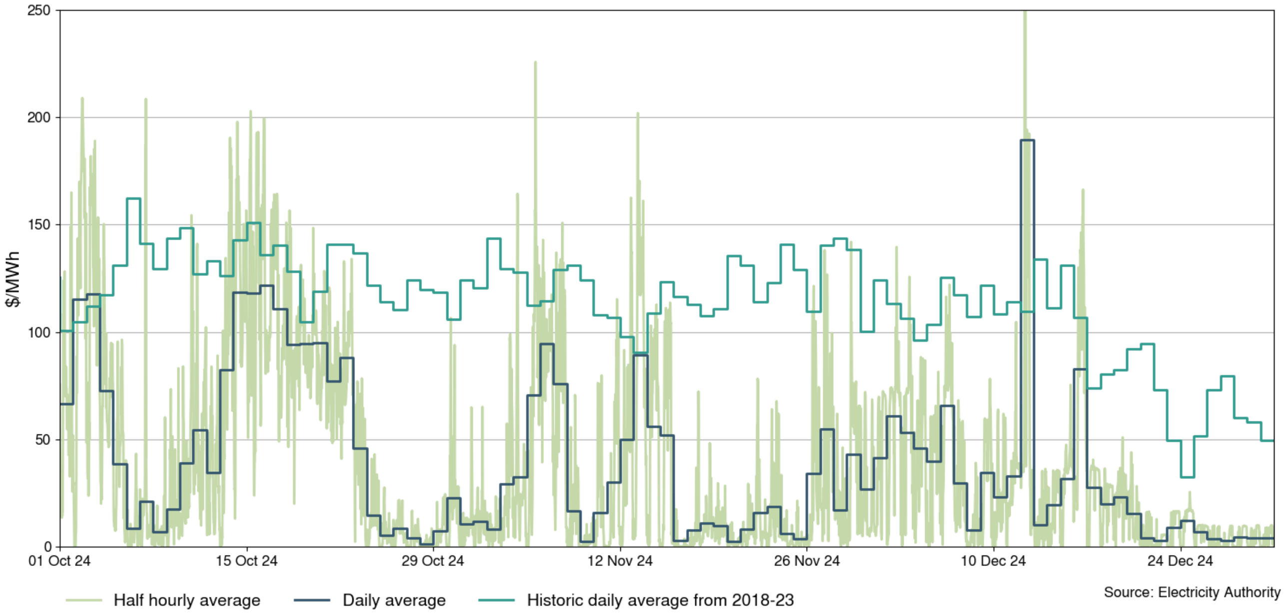
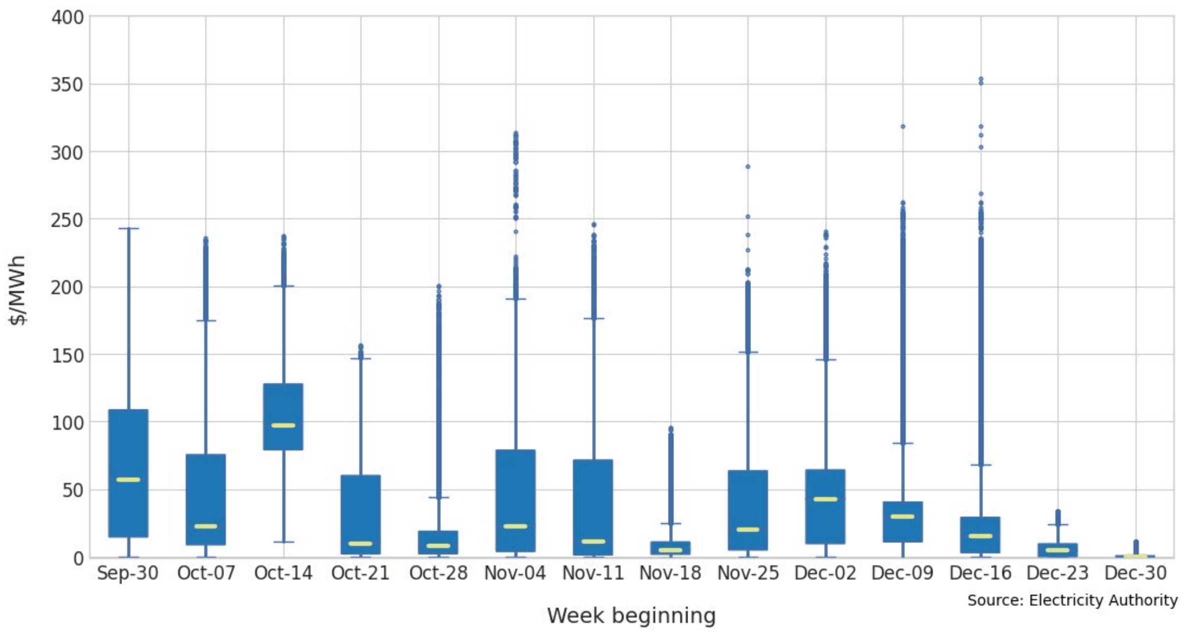


Figure 5: Box plot distributions of weekly spot prices, October–December 2024



[5] CAN Unplanned Outage HVDC Pole 2 5826773743.pdf | Transpower

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.

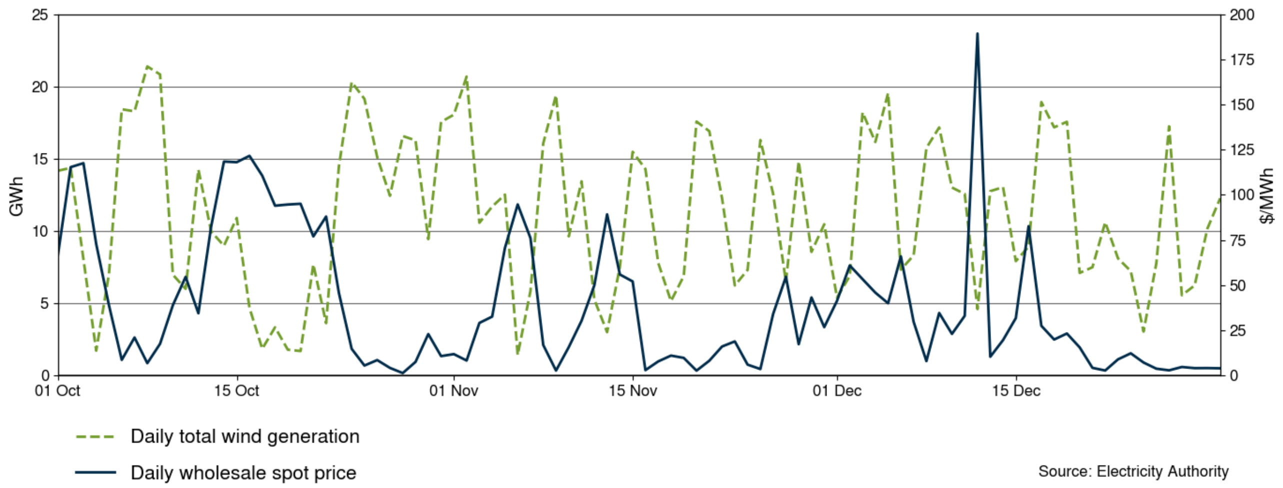
4.6. The effects of these factors are visible at different time scales:

- 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. 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. Figure 6 shows this inverse relationship between daily total wind generation and the daily average national spot prices between October and December 2024. Periods of low wind generation in mid-October, early November and mid-December also corresponded to higher spot prices.

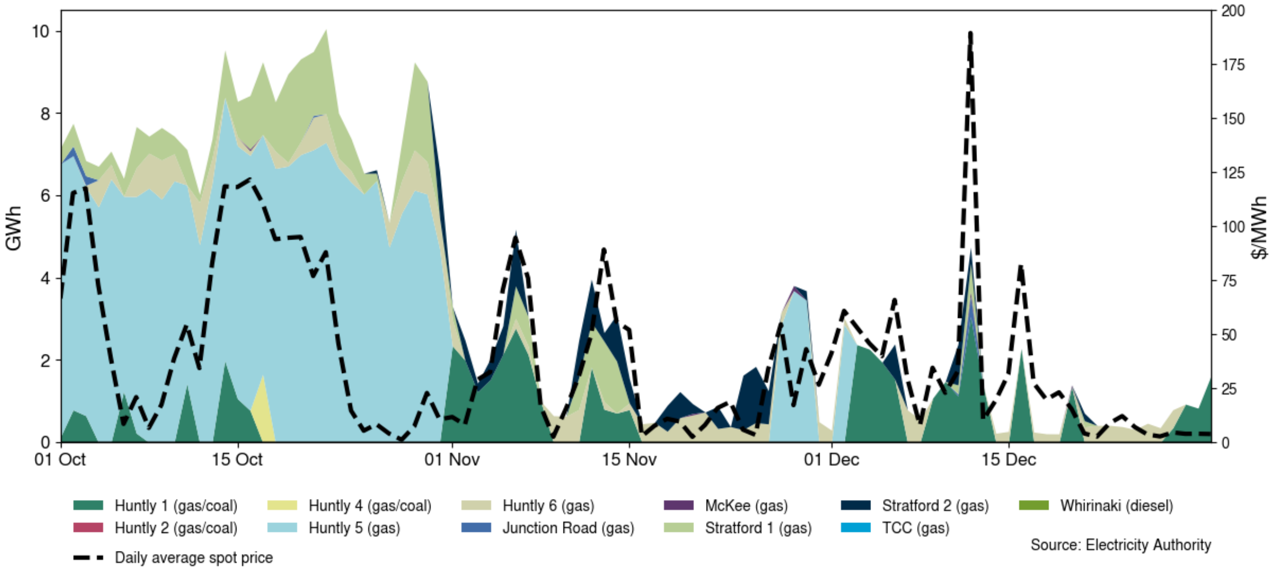
Figure 6: Daily wind generation and average wholesale price, October–December 2024



4.9. Figure 7 shows the daily total thermal generation and daily average spot price between October and December 2024. Thermal generation was highest in October and primarily provided by Huntly 5.

4.10. Thermal generation reduced from the end of October when Huntly 5 went on outage. Spikes in thermal generation throughout November and December correspond to days of lower wind generation and higher spot prices, including on 12 December during the unplanned HVDC pole 2 outage.

Figure 7: Daily total thermal generation and average wholesale price, October–December 2024

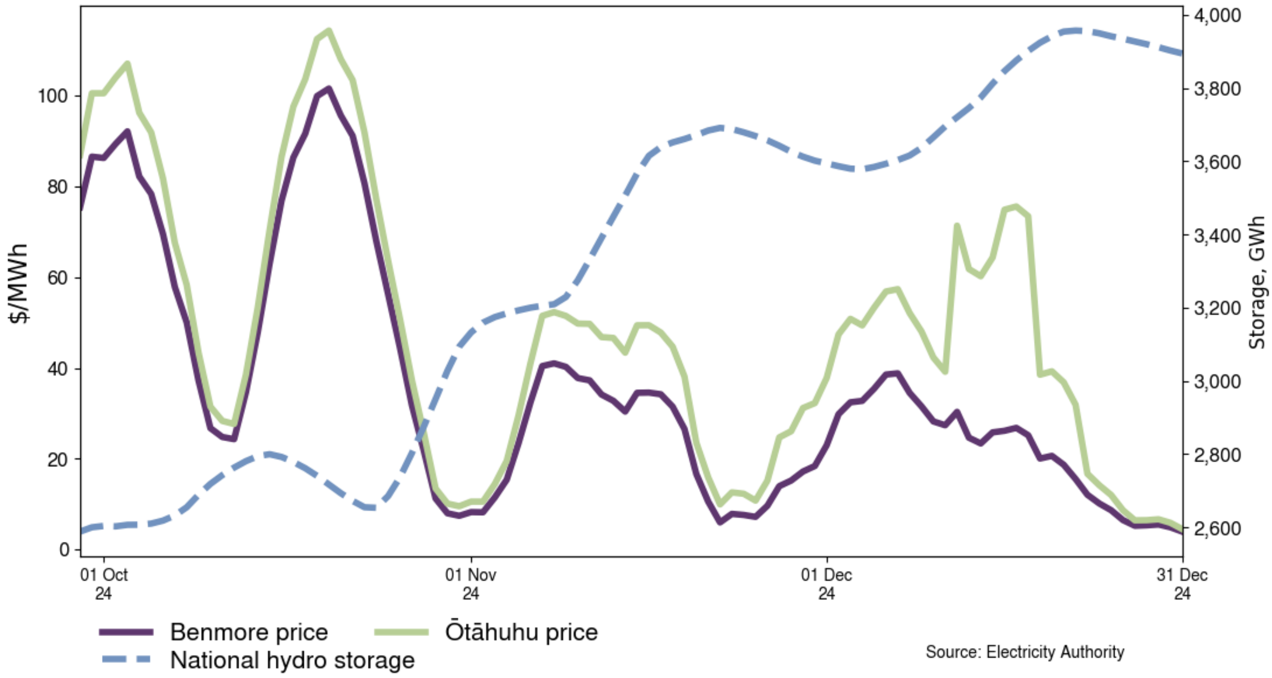


4.11. Figure 8 shows the rolling seven-day average wholesale prices at Benmore (representing the South Island) and Ōtāhuhu (representing the North Island) and the daily national hydro storage.

4.12. 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.

4.13. Wholesale electricity prices trended downwards as hydro storage increased throughout October and November. However, in December, the Ōtahuhu spot price began to increase while the Benmore price continued to decrease. This occurred because most hydro generation is based in the South Island, so during times of very high hydro storage and generation, large amounts of electricity is transferred to the North Island across the HVDC link. There is a limit to the amount of electricity that can be transferred using the HVDC, and once that limit is reached, more expensive energy and reserves in the receiving island must be dispatched to meet demand – leading to price separation between the South Island and North Island.

Figure 8: Rolling seven-day average of wholesale price versus hydro storage October–December 2024



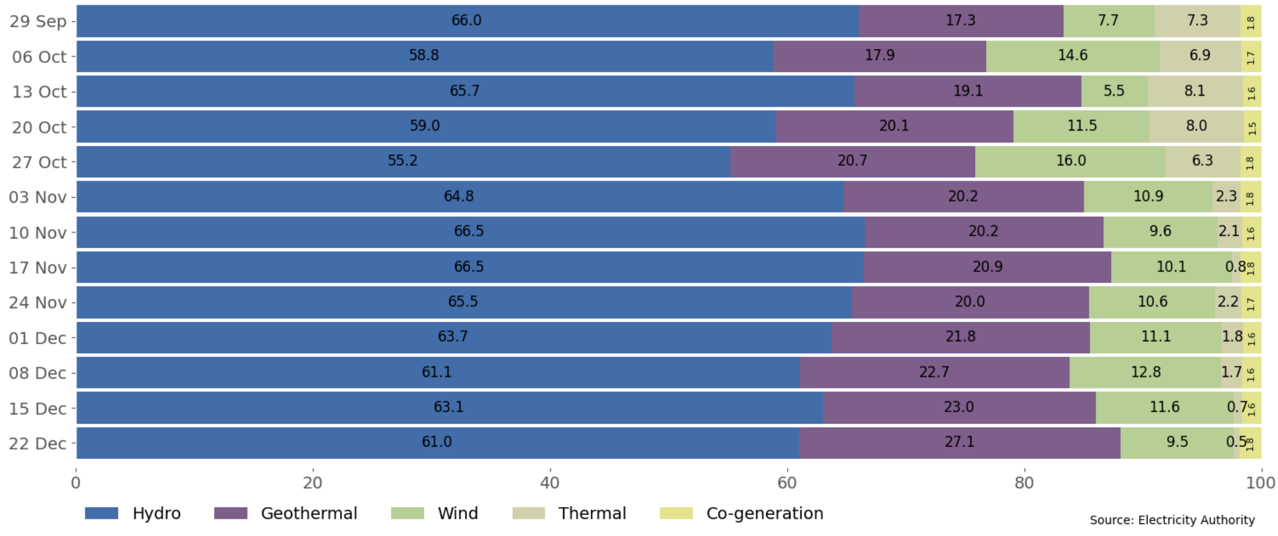
Generation by fuel type

4.14. Figure 9 shows the weekly breakdown of electricity generation by fuel type and illustrates how thermal generation tends to be highest in weeks of low wind or hydro generation. October saw thermal generation providing 6-8% of the total generation mix when hydro generation was increasing and Genesis had access to gas from Methanex.

4.15. Thermal generation reduced from the start of November when Huntly 5 went on outage and when hydro generation was consistently providing more than 60% of the total generation mix.

4.16. Reduced demand over the holiday period in the last week of December saw thermal generation contribute only 0.5% of the total generation, while geothermal increased to 27%, because its generation output is relatively stable and does not ramp up or down with demand.

Figure 9: Weekly generation share by fuel type, October to December 2024

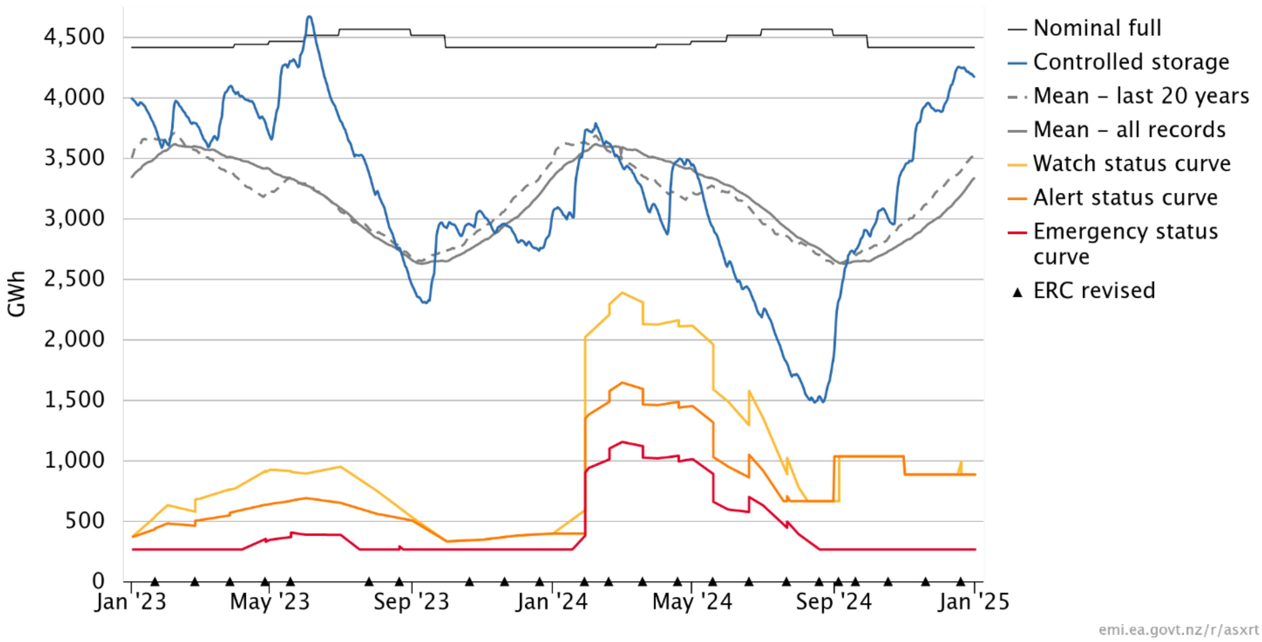


5. Water storage levels

National hydro storage levels

5.1. Figure 10 shows the national hydro storage levels from January 2023 to December 2024. National hydro storage increased rapidly from 65% nominally full at the start of October to 95% nominally full at the end of December. This is a significant improvement on hydro storage compared to a year ago at the end of Q4 2023 when hydro storage was only 68% full.

Figure 10: National hydro storage levels, January 2023 – December 2024



Lake storage levels

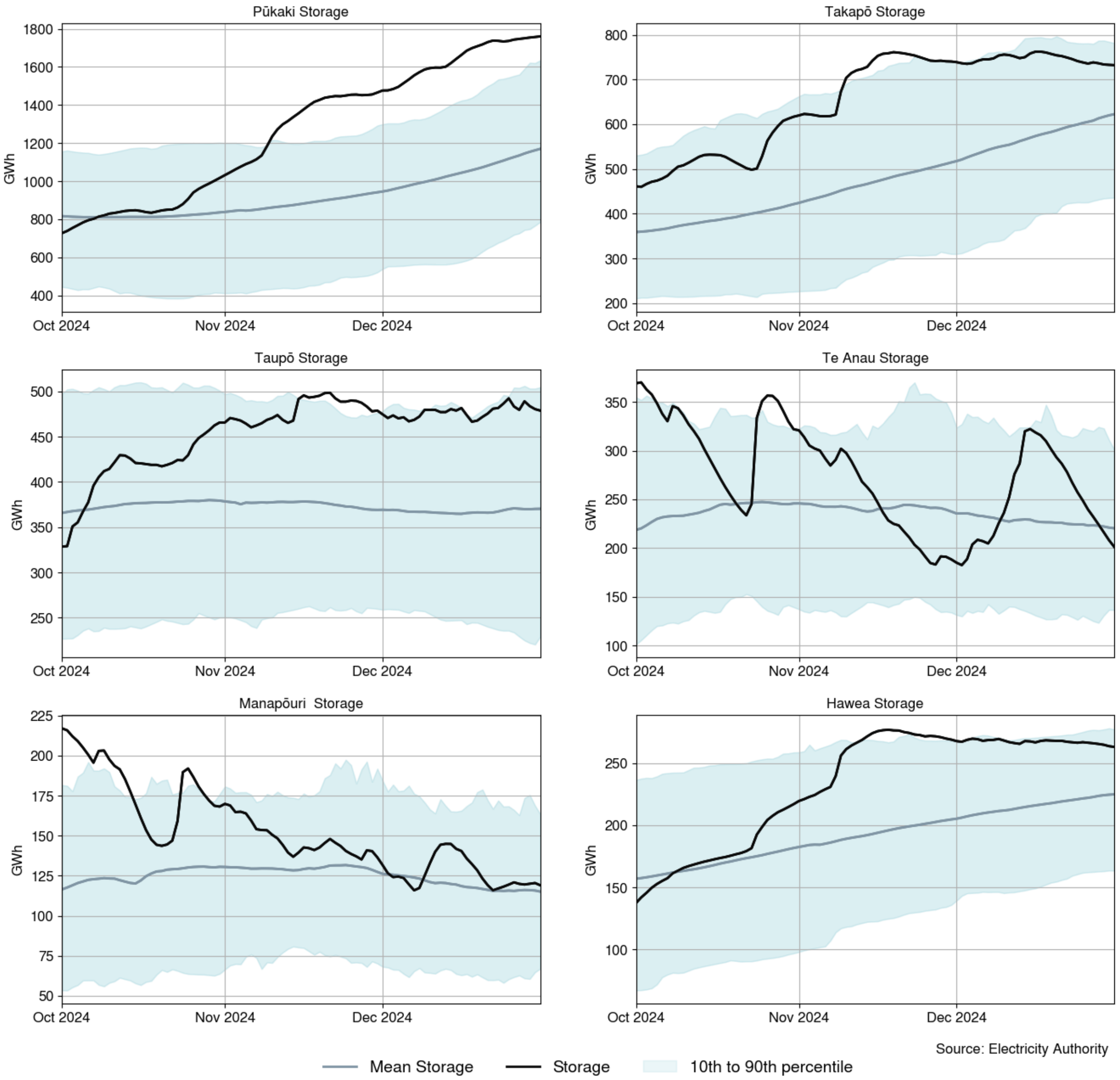
5.2. Figure 11 shows individual lake levels for October to December 2024 and the difference location can have on hydro inflows.

5.3. Lake Pūkaki is the largest hydro storage lake in New Zealand. Its stored water increased consistently over the quarter from just below the historical mean to above the historical 90th percentile.

5.4. Storage at Lakes Takapō, Hawea and Taupō steadily increased in October and November and remained near their respective historical 90th percentiles from the end of November to December.

5.5. Despite large inflows in October, lakes Te Anau and Manapōuri decreased from above their respective 90th percentiles at the start of the quarter to near their historical means by the end of the quarter.

Figure 11: Lake storage levels for October–December 2024 versus historical average and 10th and 90th percentiles



Source: Electricity Authority

6. Wholesale gas prices, production and consumption

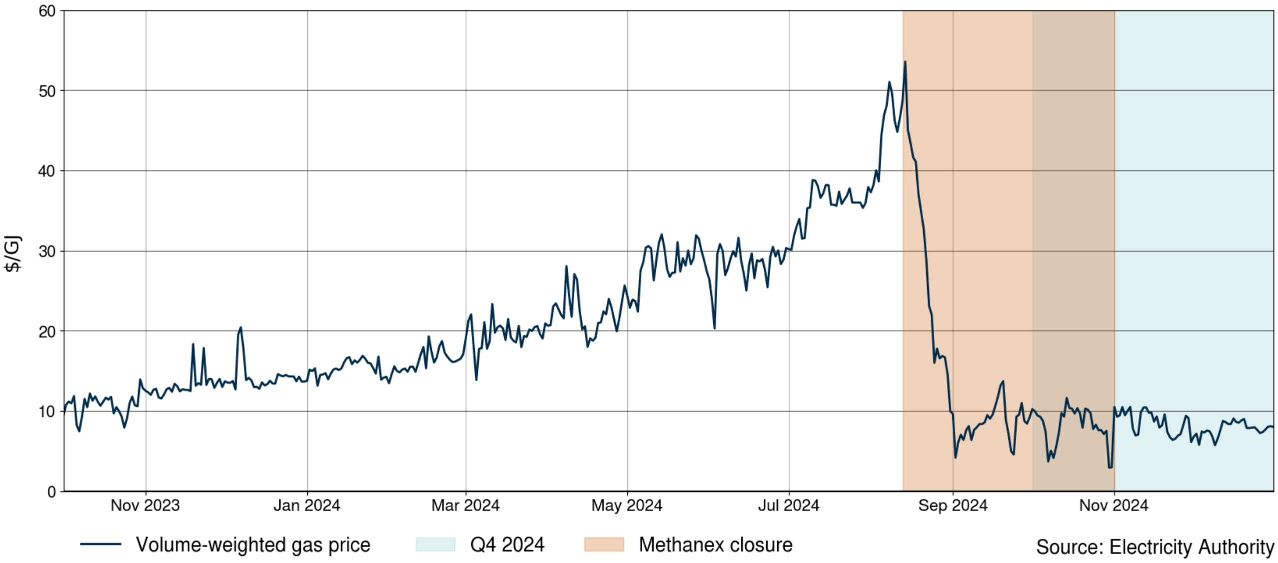
Gas prices

6.1. Figure 12 shows the daily volume-weighted average gas price for October to December 2024.

6.2. The average daily volume-weighted average price (VWAP) for gas in Q4 2024 was $8/GJ which is a decrease compared to both Q3 2024 ($27/GJ) and Q4 2023 ($13/GJ).

6.3. Gas spot prices dropped to below $10/GJ last quarter after Methanex production was stopped to provide additional gas supply for electricity generation. Gas spot prices remained mostly below $10/GJ this quarter even after Methanex production restarted in November, partially because of lower demand from thermal generation.

Figure 12: Daily volume-weighted average price for gas and NZ carbon unit price, October–December 2024



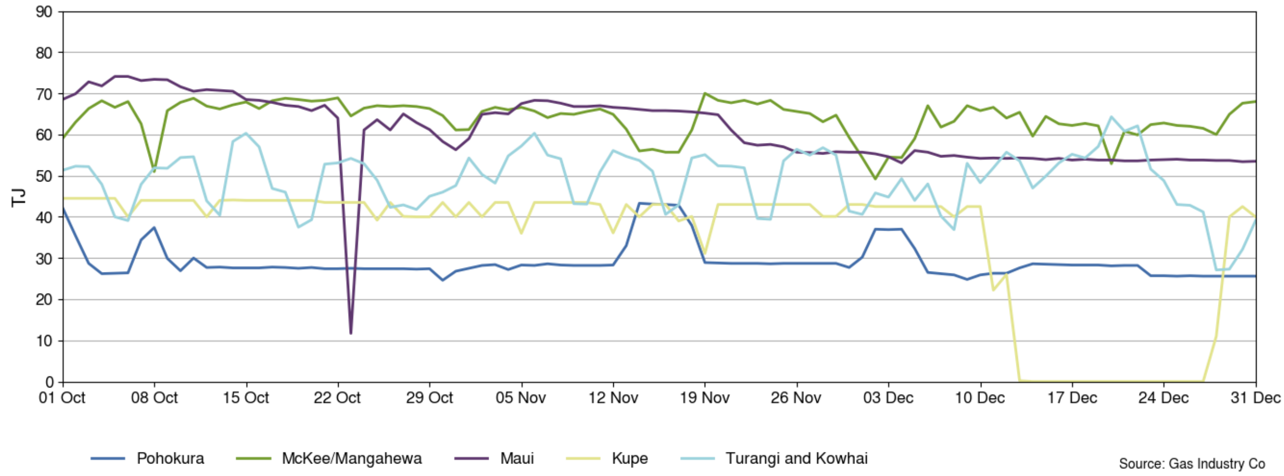
Gas production

6.4. Figure 13 shows daily gas production at major fields for October to December 2024.

6.5. Total gas production at major fields varied from 177 to 268TJ/day this quarter. Production at Pohukura was 25-43TJ/day, production and McKee/Mangahewa was 49-70TJ/day and production at Turangi and Kowhai was 27-64TJ/day.

6.6. Production at Maui was 53-74TJ/day this quarter, except for 23 October when it was offline for a planned outage. Production at Kupe was 31-45TJ/day, except for 13-28 December when it was offline for an unplanned outage.

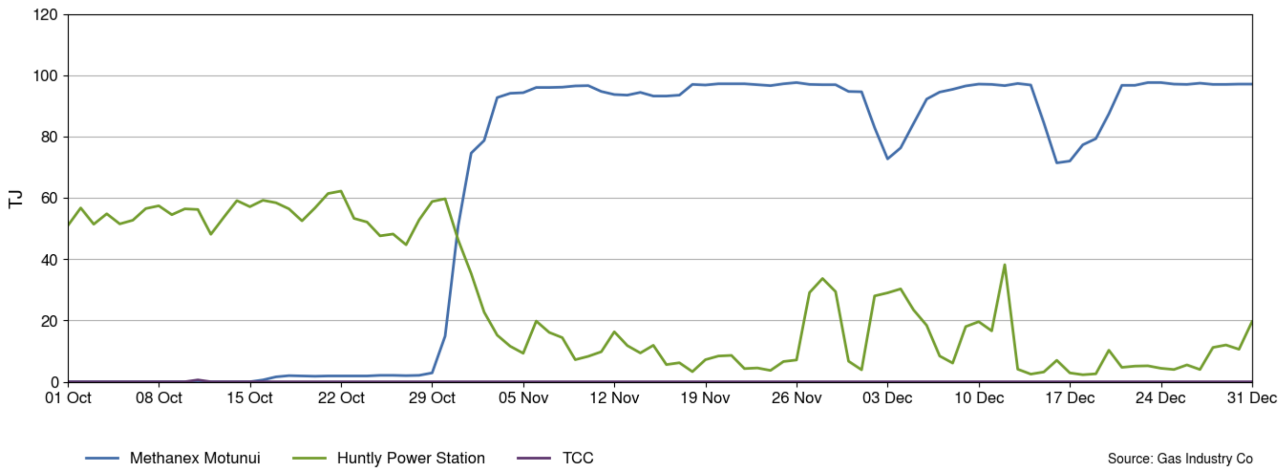
Figure 13: New Zealand gas production, October to December 2024



shutdown over winter to provide extra gas for electricity generation.

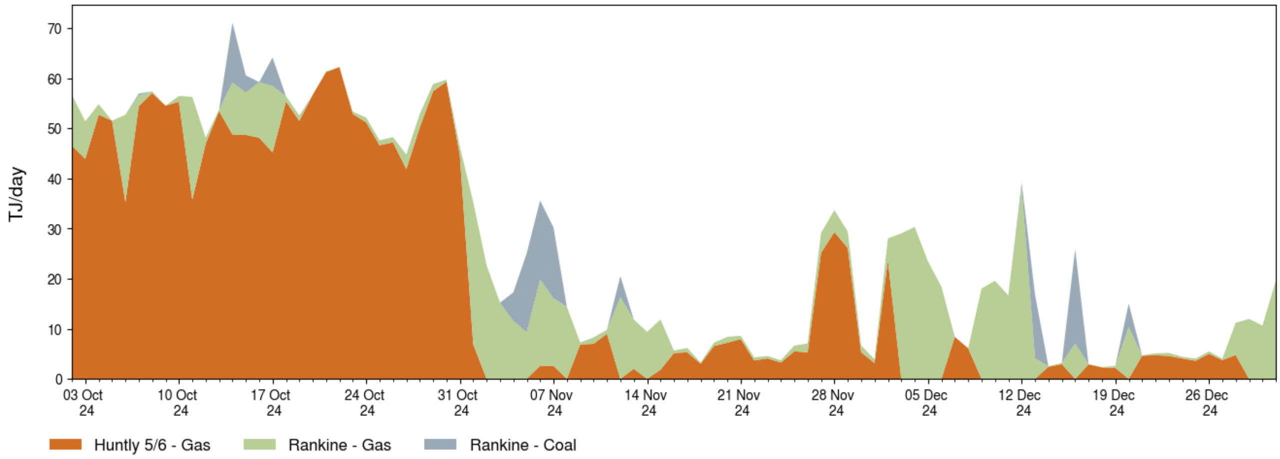
6.9. Gas consumption at Huntly reduced from ~50-60TJ/day at the start of November to 2-40TJ/day from the rest of the quarter after Methanex restarted and thermal generation reduced.

Figure 14: New Zealand gas consumption, October–December 2024



6.10. Figure 15 shows the estimated daily total energy consumption across all Huntly units for October to December 2024. Gas usage in Huntly 5 was highest in October and reduced from the start of November when Methanex restarted. The Rankine units were primarily fuelled by gas this quarter, with short periods of coal consumption.

Figure 15: Estimated Huntly fuel consumption, October–December 2024



7. Retail electricity

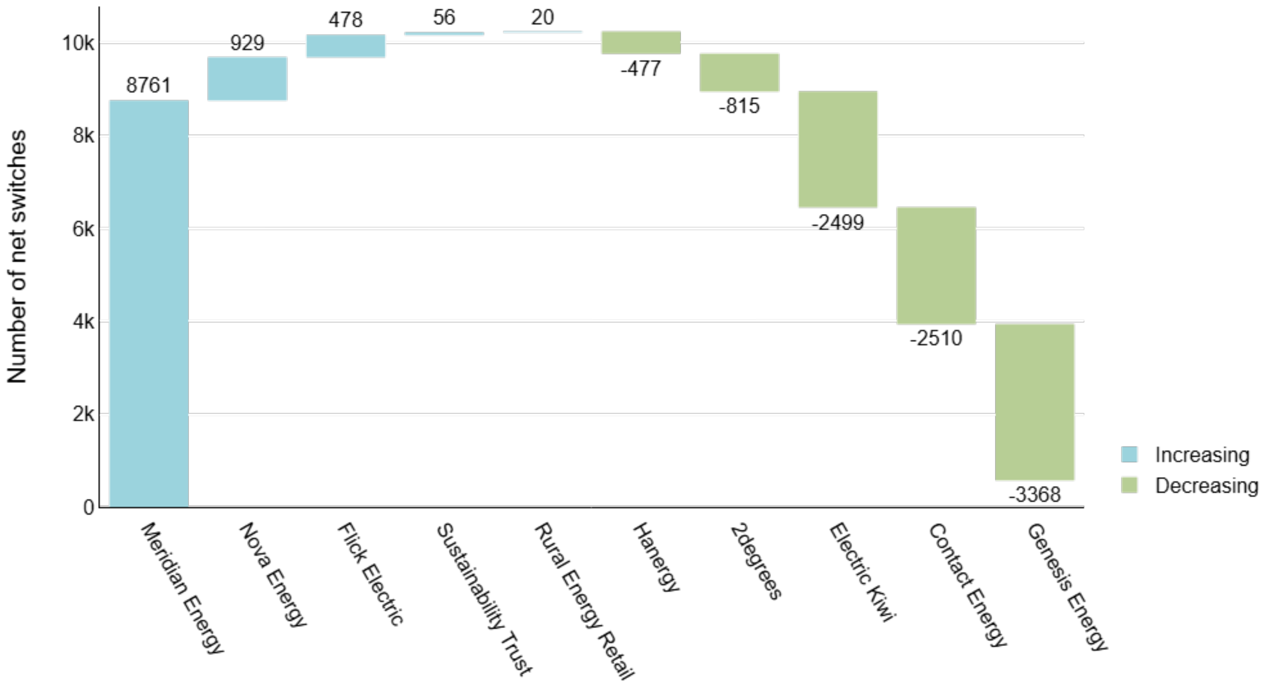
Retailer switching

7.1. Figure 16 shows the top 5 retailers who gained and the bottom 5 retailers who lost the most electricity connections (ICPs) for October to December 2024.

7.2. Meridian had the greatest net gain in ICPs at 8,761 net switches. Nova and Flick were second and third with 929 and 478 net switches respectively.

7.3. Genesis and Contact had the greatest net loss in ICPs and 3,368 and 2,510 net switches respectively.

Figure 16: Top 5 increases and bottom 5 decreases in ICP net switching by retailer, October–December 2024



7.4. Figure 17 shows the number of ICPs that have changed electricity suppliers between January 2023 and December 2024 categorised by type 'move in' and 'trader'. Move in[6] 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.

7.5. In Q4 2024, the number of move in switches remained steady and similar to Q4 2023. The number of trader switches reduced during Q4 2024 and has dropped below the number of trader switches in Q4 2023.

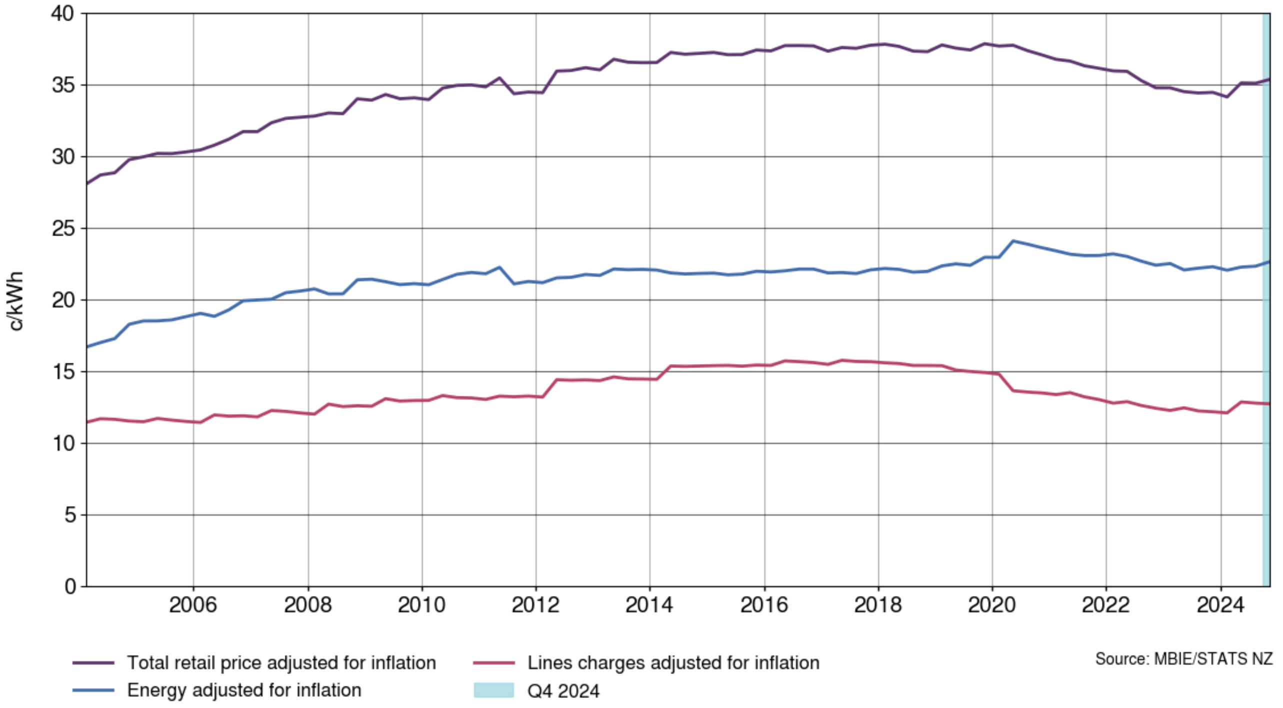
[6] At an ICP.

Figure 17: Breakdown of monthly ICP switching by type, January 2023 – December 2024

Retail prices

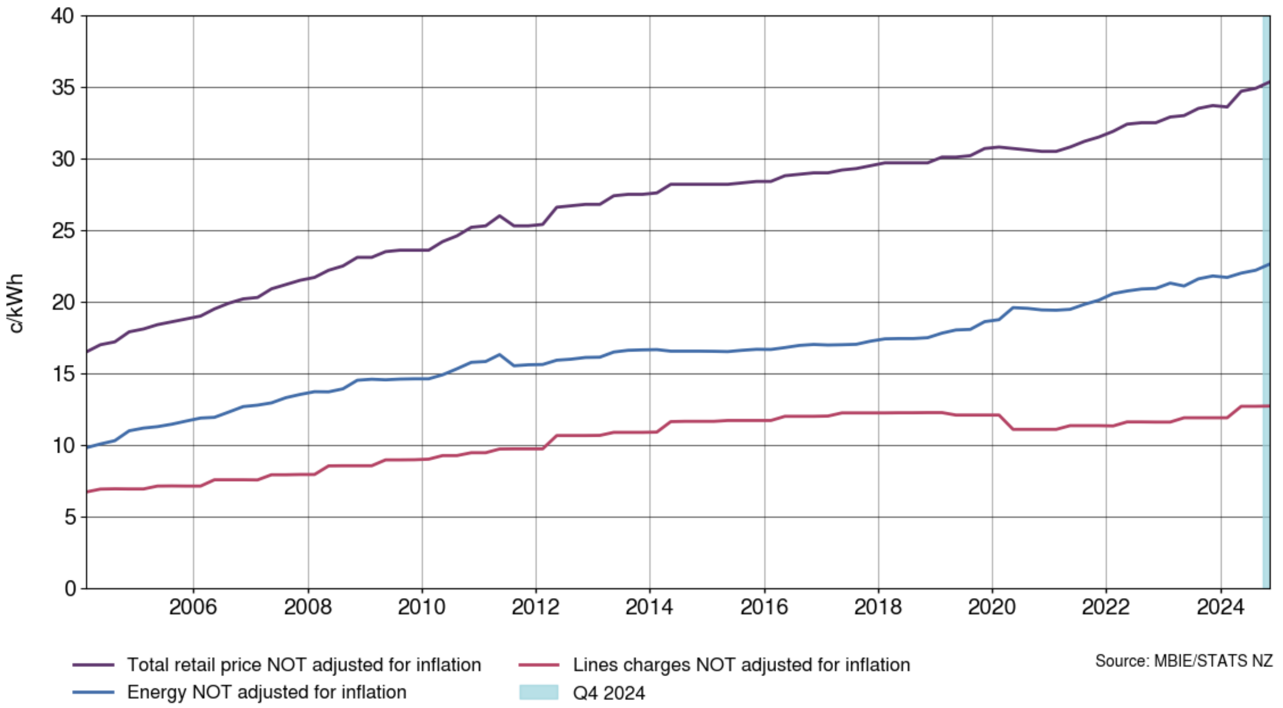
7.6. Figure 18 shows the domestic electricity price by component (QSDEP) adjusted for inflation from 2004–24. Energy retail prices increased slightly more than the rate of inflation this quarter.

Figure 18: Domestic electricity prices by component adjusted for inflation (base Q4 2024 CPI), 2004–24



7.7. Figure 19 shows the domestic electricity prices by component without adjusting for inflation. In the last 12 months, nominal values rose by 4.9%. For a typical household using 8,000kWh annually, this equates to an extra $133 per year on their electricity bill compared to one year ago.

Figure 19: Domestic electricity prices by component without inflation adjustment, 2004–24



8. Forward market and carbon pricing

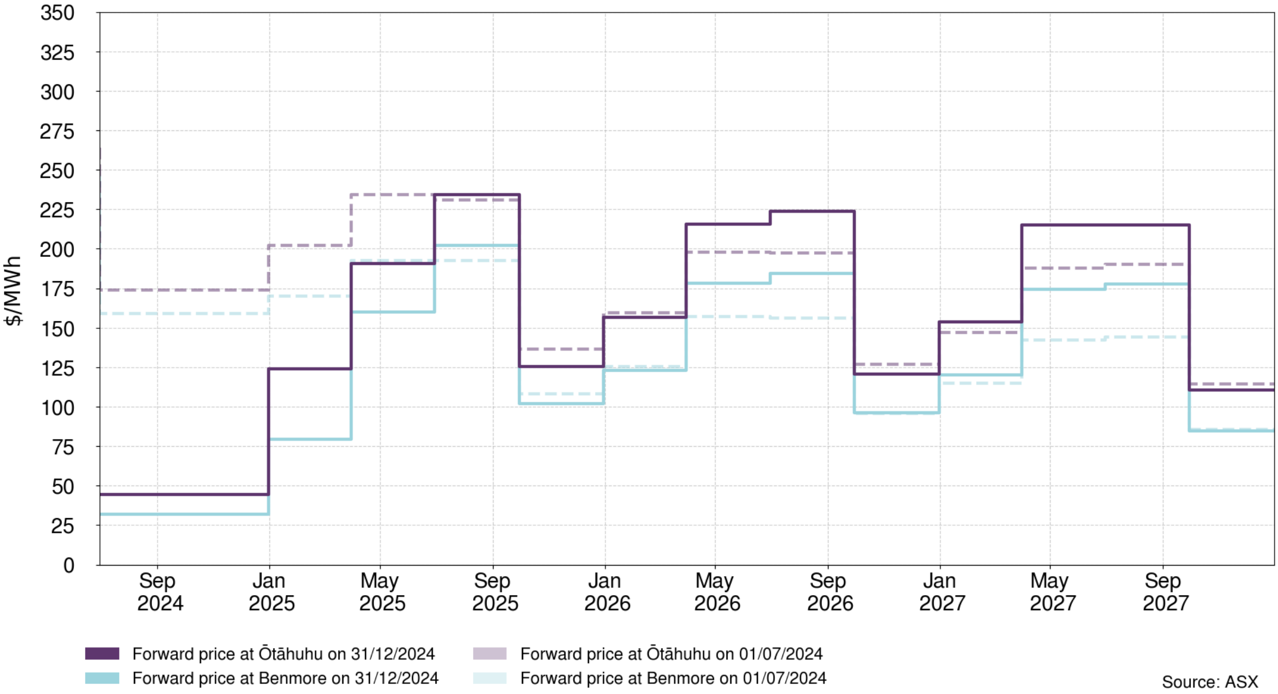
Forward pricing

8.1. Figure 20 shows the quarterly forward prices up to 2028, with the first snapshot (dashed lines) at the beginning of October 2024 and second snapshot at the end of December 2024 (solid lines).

8.2. 2025 futures prices all decreased over the quarter by $30-70/MWh, likely because of high hydro inflows during the quarter which improved the hydro storage outlook for 2025.

8.3. All other futures prices from 2026 onwards increased over the quarter, with the largest increases for the winter futures prices. Long term futures price increases are likely reflecting concerns around sustained low gas production and increased reliance on coal for security of supply.

Figure 20: ASX forward prices for the start and finish of Q4 2024



Carbon pricing

8.4. Figure 21 shows the New Zealand carbon unit price between October 2023 and December 2024 as recorded by the European Capital Markets Institute.

8.5. The carbon price dropped from ~$65/NZU at the start of the quarter to ~$63/NZU at the end of the quarter.

8.6. After the June and September carbon auctions did not receive any bids, the December carbon auction cleared 4.033M units at the floor price of $64/NZU.

Figure 21: New Zealand Units price, October 2023 – December 2024

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 July 2024 to 31 December 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:

(a) The first two of these are the frequency of both very low prices and price separation, which should reflect underlying market conditions.

(b) 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.

(c) 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 July 2024 to 31 December 2024:

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

(b) The frequency of low prices occurring during off peak increased when compared to 2023, and was similar to 2022. The median low price increased, however, this reflected the underlying conditions over this period.

(c) The high share of prices under $10/MWh and the high share of prices between $300-400/MWh reflected the shift from the system's reliance on thermal generation, during the time of low hydro inflows, to one with an abundance of hydro generation.

(d) Thermal offers were reflective of changing market conditions. Thermal operators were constrained in their output due to a declining coal stockpile and reduced gas production. Thermal offers using on-sold Methanex changed in mid-August to reflect the increase in supply.

(e) All schemes had a proportion of offers above the estimated water values. However, this may reflect the under-valuation of water during times of heightened risk in the JADE modelling. The Authority is continuing to investigate 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 during times of declining hydro storage.

9.6. Figure 22 and Table 1 give insight into the distribution of prices in the second half of 2024.

9.7. The price distribution for the last six months of 2024 was similarly shaped to 2022 (Figure 22). However, elevated spot prices in July and August 2024 when hydro storage was very low meant the number of prices above $300/MWh was higher in the last six months of 2024. The frequency of very low prices increased from the end of August as hydro storage began to increase.

9.8. The share of low prices during daytime off-peak periods in the last six months of 2024 increased compared to the last six months of 2023, although the median price of all very low prices increased (Table 1). In 2023, due to the lower hydro lakes, fewer low prices occurred during off-peak periods: only 12.3%. In 2022, there were prices very close to $0/MWh due to the high hydro inflows, with more frequent hydro spill. In 2024, the only lake with spill was Manapōuri, and the prices under $10/MWh were more varied. However, if we consider the mean low price in these years, they are more similar: $3.3/MWh (2024), $2.3/MWh (2023) and $2.3/MWh (2022). All these are lower than the mean from 2015-2020 which is $4.5/MWh.

Figure 22: Histogram of price counts for the last six months of each year

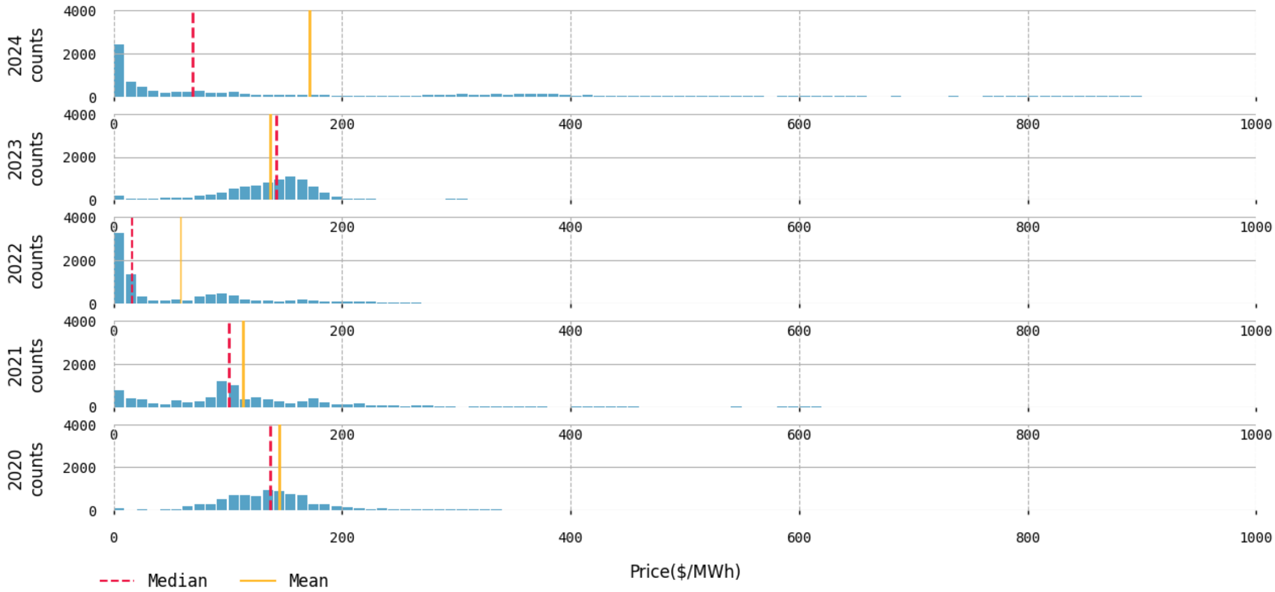
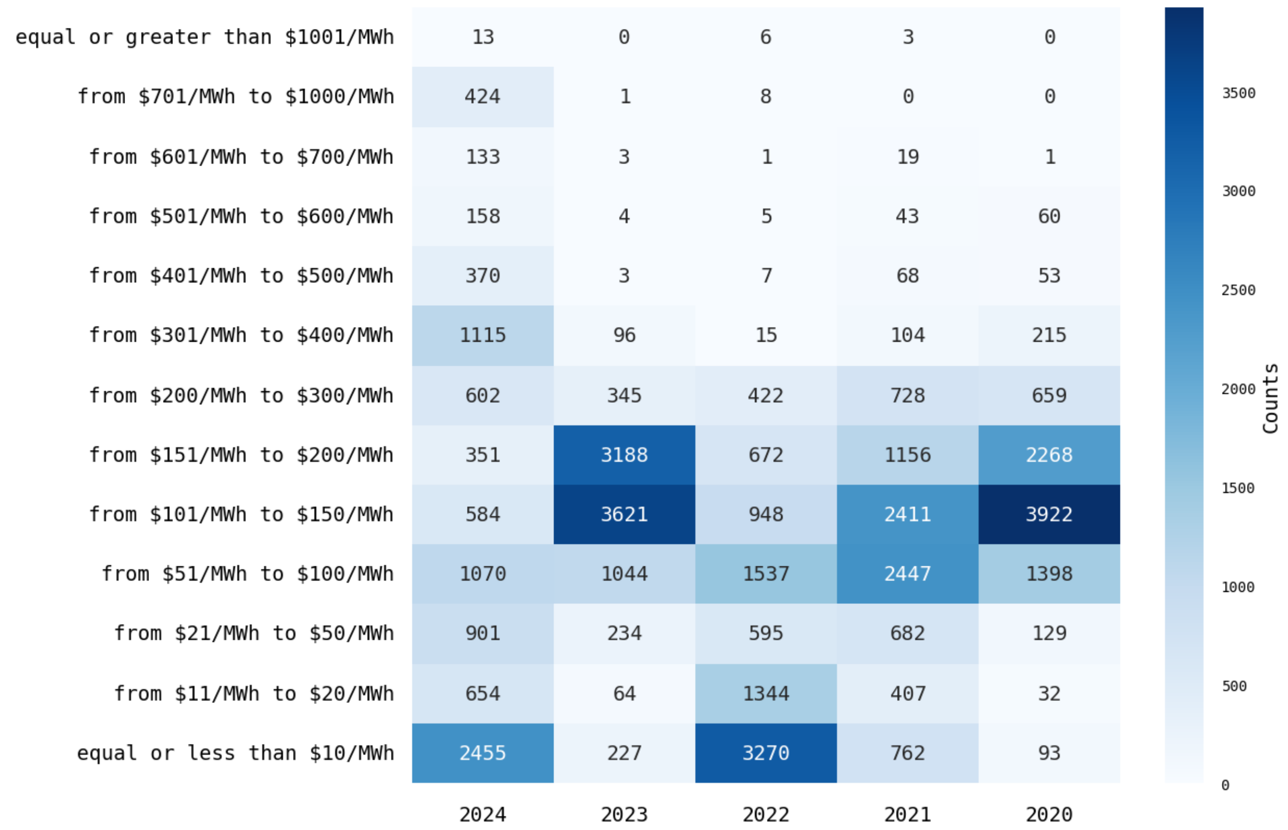


Table 1: Very low prices from 1 July – 31 December 2024

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	27.2%	$2.30/MWh
2023	12.3%	$0.80/MWh
2022	28.2%	$0.40/MWh
2021	19.8%	$0.20/MWh
2015 - 2020	13.4%	$5.84/MWh

9.9. Figure 23 show the heatmap of price distribution for the last six months of each of the last five years. The July-December 2024 period was dominated by prices less than $10/MWh, between $51-100/MWh and between $301-400/MWh. These three buckets of prices reflect the underlying conditions in the market over this time. Between July and August, prices were consistently above $300/MWh. After hydro generation increased prices were often below $100/MWh. Then once hydro lakes were above mean, and especially due to the lower demand and during periods of high wind generation, prices were often below $10/MWh.

Figure 23: Heat map of price distribution for the last six months of each year



Price separation

9.10. 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 is exported north, transmission could become constrained. This should lead to lower prices in the South Island than in the North Island.

9.11. The mean ratio of Haywards to Benmore price separation continues to be higher since the introduction of the reading conduct rule when compared to previous years. This mean is similar to 2023. In both years periods of high inflows during led to greater instances of very low South Island prices – with the HVDC binding and creating price separation. However, the median price separation remains close to 1. This occurred as between June-August prices between the islands were roughly similar as the HVDC was often exporting South due to the low southern lake levels. However from mid August onwards, hydro storage across all major lakes rapidly increased, with several instances were the HVDC export northward was binding and North Island prices included the higher reserve cost associated with the HVDC risk. The median price separation in 2024 was roughly similar to the level seen in previous years.

9.12. Between Benmore and Manapōuri the mean price separation increased above the mean seen in 2023. This is due to the lake levels at Manapōuri quickly filling during the early spring rain and then, both due to high rainfall and two units being on outage, the scheme continuously spilling between September and November 2024. While the lake is spilling all generation is priced at near zero. However, lake levels at Pukaki did not reach spill levels until very late December (however, generation at Benmore was typically priced low to reflect the increased storage) and hence generation at Benmore was priced slightly higher than that at Manapōuri. The median separation remains similar to previous years.

Table 2: Price separation

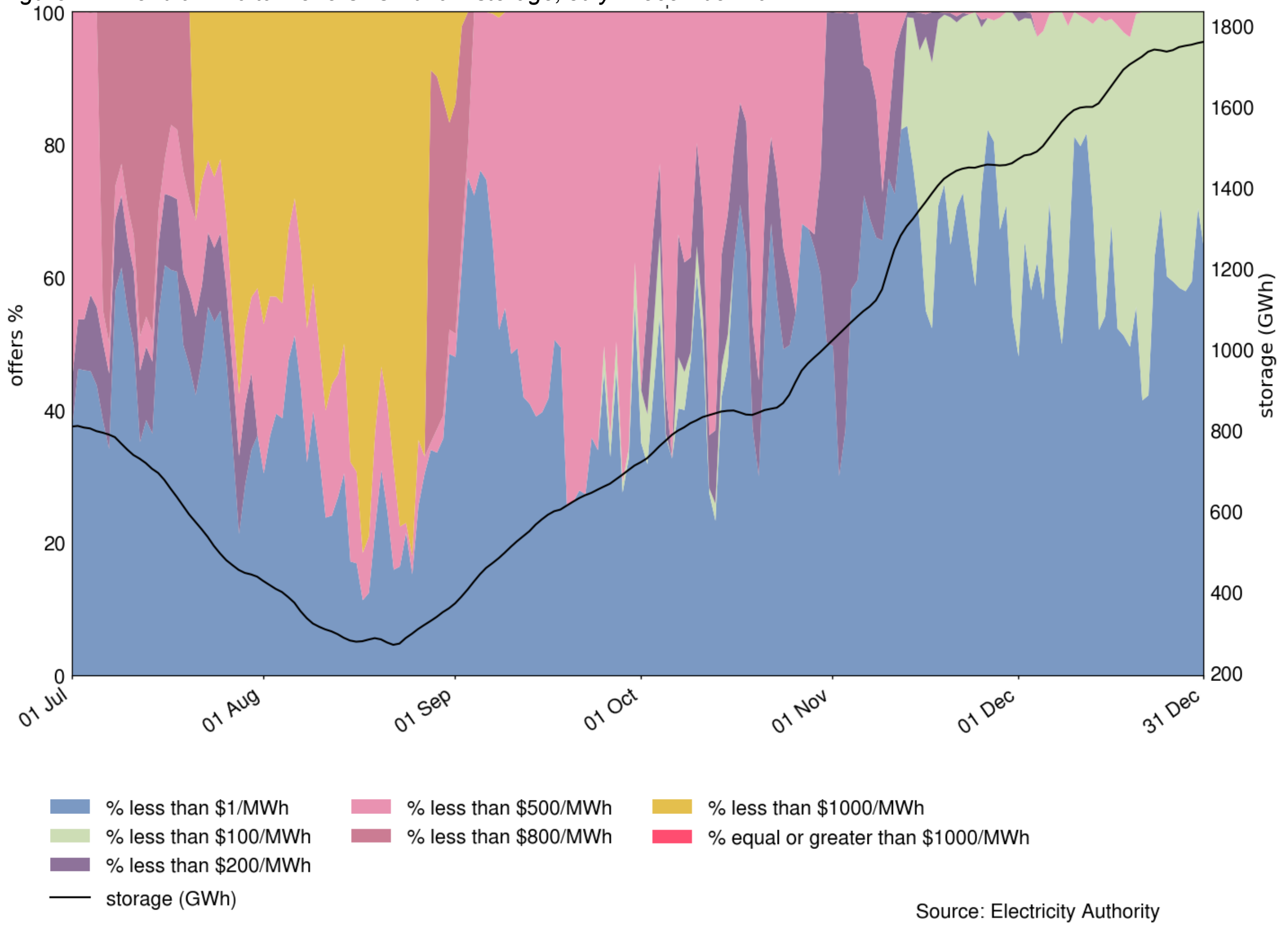
	Ratio of Haywards to Benmore price		Ratio of Benmore to Manapōuri price	
Year	**Mean**	**Median**	**Mean**	**Median**
2024	29.6	1.04	1.47	1.08
2023	31.3	1.04	1.05	1.05
2022	12.2	1.04	9.80	1.06
2021	68.6	1.06	26.9	1.09
2015-2020	1.35	1.04	8.40	1.09

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

9.13. Throughout the first half of 2024 and into August, hydro storage across all major catchments was declining. This decline arose from the combination of high electricity demand associated with cool dry weather and low hydro inflows. The inflow pattern changed drastically however, in mid-August, with all schemes rapidly increasing in storage.

9.14. Figure 24 shows how Meridian's Waitaki scheme offers changed over July-December as Pukaki storage fluctuated.

Figure 24: Meridian Waitaki offers vs Pūkaki storage, July–December 2024



Source: Electricity Authority

9.15. In early July, the amount of low-priced Waitaki generation increased. However, the top tranche of generation was priced up to between $500-$800/MWh, which is near the thermal generation short run marginal costs (SRMC). As storage at Pūkaki continued to decrease over July this was later priced up to $800-$1,000/MWh, and the proportion of generation priced below $1/MWh fell from 40-60% in early July to less than 20% in mid-August.

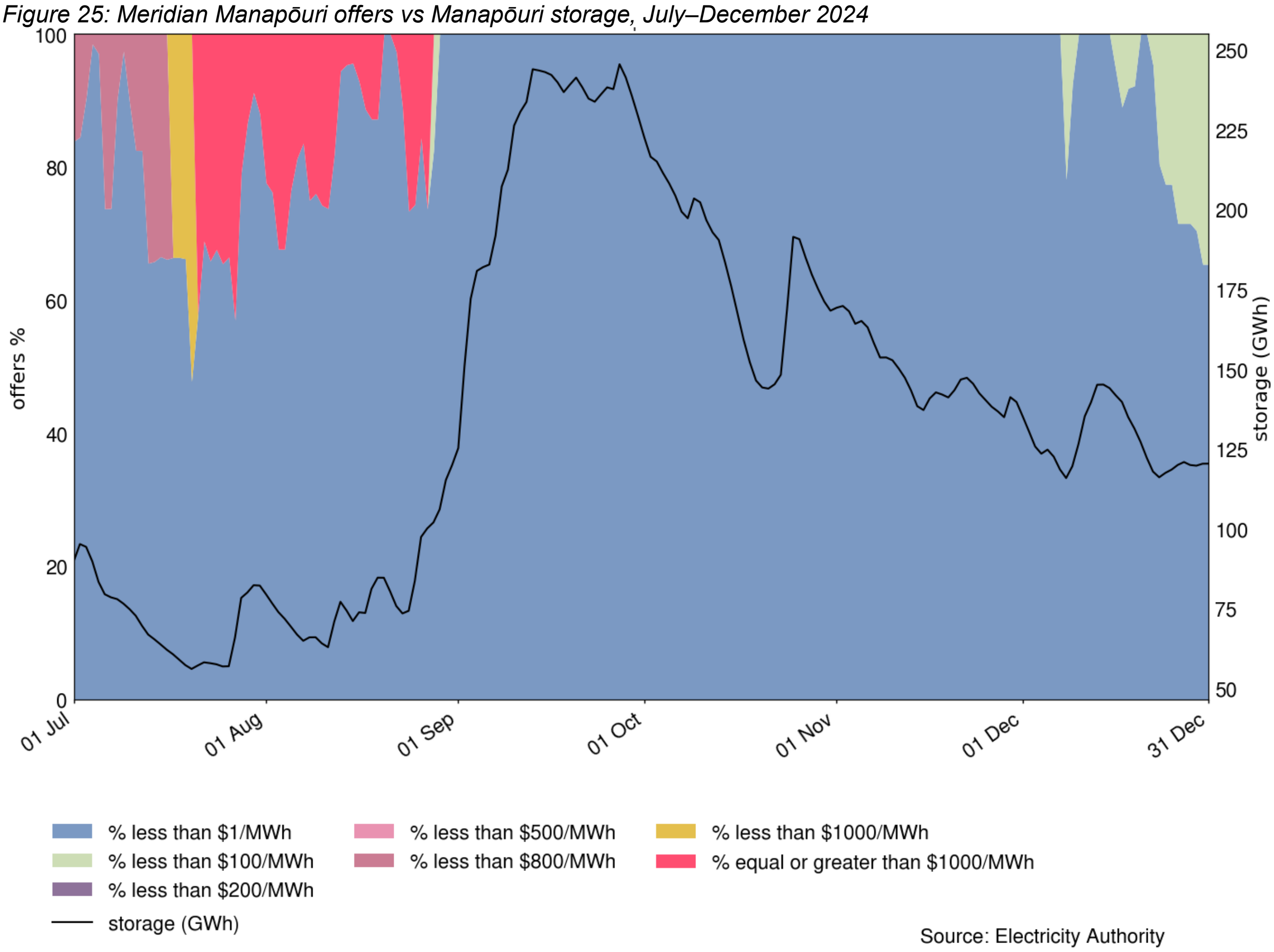
9.16. This dramatic decline in low priced offers followed Pūkaki's decline from 807GWh on 1 July to 436GWh by 31 July, a 370GWh drop which is 13% of its total storage. Meridian was pricing the majority of Pūkaki's water to be near the generation of last resort, keeping it available in the market for security of supply, but signalling that thermal generation should be dispatched, including the diesel-fuelled Whirinaki, before large amounts of water in Pūkaki were used for generation. At this time, snow storage in the Waitaki catchment was also well below mean for 2024, which indicated that Pūkaki refill for 2025 could be below average, which further increased the value of the water in Pūkaki in July 2024.

9.17. Storage in Pūkaki reached a minimum of 268GWh on 22 August, at which point inflows increased to exceed outflows and storage increased. Following heavy rainfall in early September, Meridian offered over 70% of available capacity on the Waitaki scheme. At this time the Waitaki scheme was primarily running on inflows from tributaries, and outflows from Pūkaki were low, allowing storage to increase significantly. However, as rainfall eased throughout September, a higher proportion of Waitaki's flow was originating from Pūkaki, and hydro offers changed to reflect this. From November onwards nearly all hydro generation was priced below $100/MWh which reflected the abundance of water and the upcoming snow melt.

9.18. It is important to note that Meridian balances its low-priced generation across both hydro schemes and wind farms. Hence, on days in September when there was high generation from wind, Meridian decreased its amount of low-priced generation along the Waitaki.

9.19. Figure 25 shows how Meridian's Manapōuri scheme offers over July-December as Manapōuri storage changed.

Figure 25: Meridian Manapōuri offers vs Manapōuri storage, July–December 2024



Source: Electricity Authority

9.20. The Manapōuri reservoir has a narrow operating range and can fluctuate between its maximum and minimum range quickly in comparison to other locations. As a result, Meridian's Manapōuri offers follow its storage levels closely, with most of the generation offered below $1/MWh when lake levels are high.

9.21. Two generation units (128MW each) at Manapōuri were on outage, one returned in [December 2024](), and the other will in [September 2025](). These outages likely limited flexibility at Manapōuri over winter 2024.

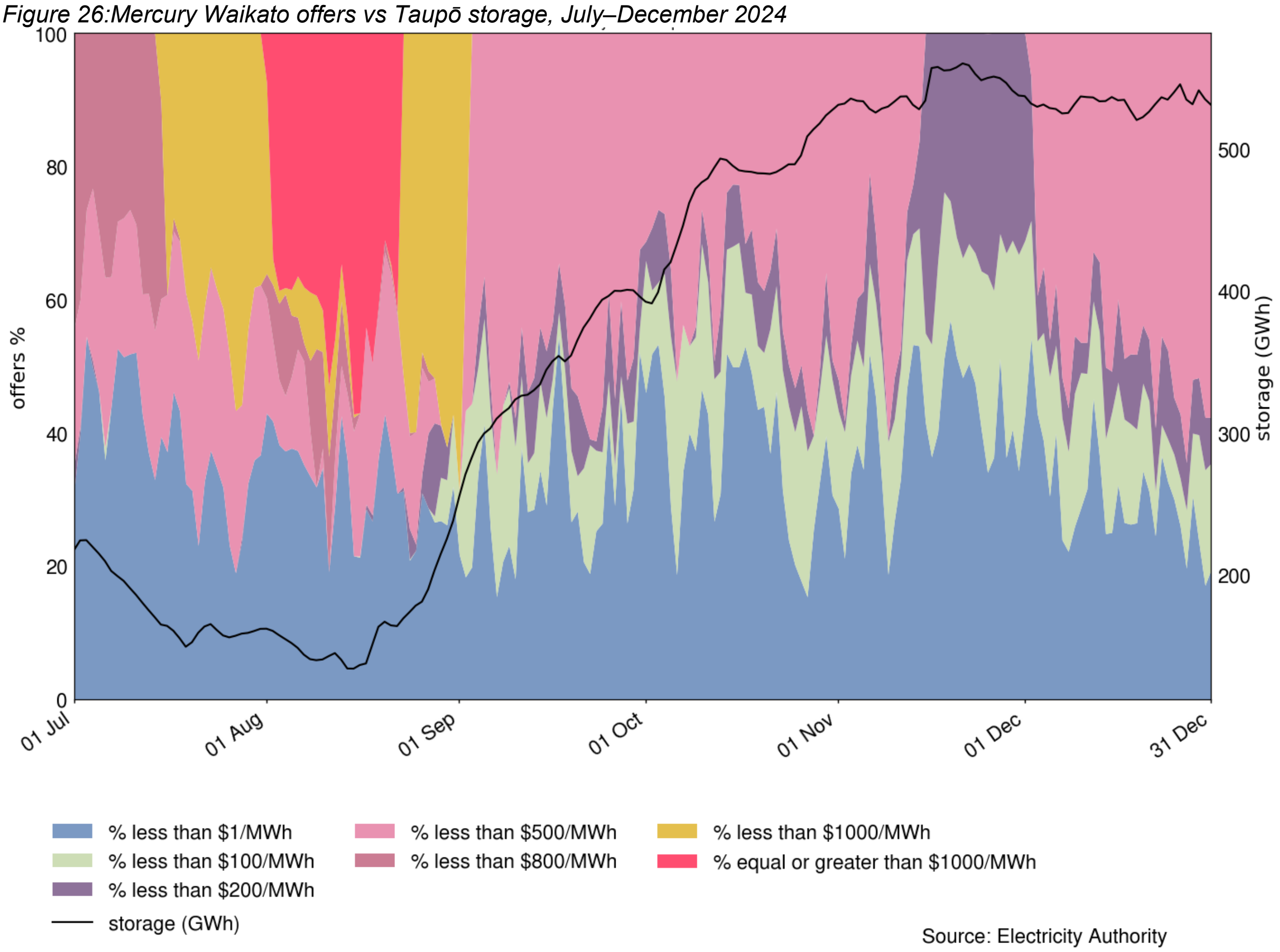
9.22. In mid-July this high-priced tranche was briefly between $800-$1,000/MWh before quickly being priced up to greater than $1,000/MWh. Storage in Manapōuri reached a low of 53GWh on 26 July.

9.23. In mid-August, Meridian priced most of the energy at Manapōuri below $1/MWh, this was when Tiwai demand response was ramping towards 185MW, which allowed Meridian greater flexibility across their portfolio. In late December as inflows began to slow, some generation was priced between $1-100/MWh.

9.24. Due to record inflows in the Waiau catchment, significant spill occurred down the Waiau river beginning in early September.

9.25. Figure 26 shows Mercury's changes to Waikato scheme offers as Taupō storage changed between July-December 2024. Mercury's Waikato scheme is the largest hydro scheme in the North Island but with smaller capacity than some of the southern hydro schemes. As such, its offers are more directly correlated with weekly demand patterns than overall storage levels. Mercury's offers priced below $1/MWh dipped in weeks with high wind generation, as Mercury balances its low-priced generation between its wind and hydro stations.

Figure 26:Mercury Waikato offers vs Taupō storage, July–December 2024



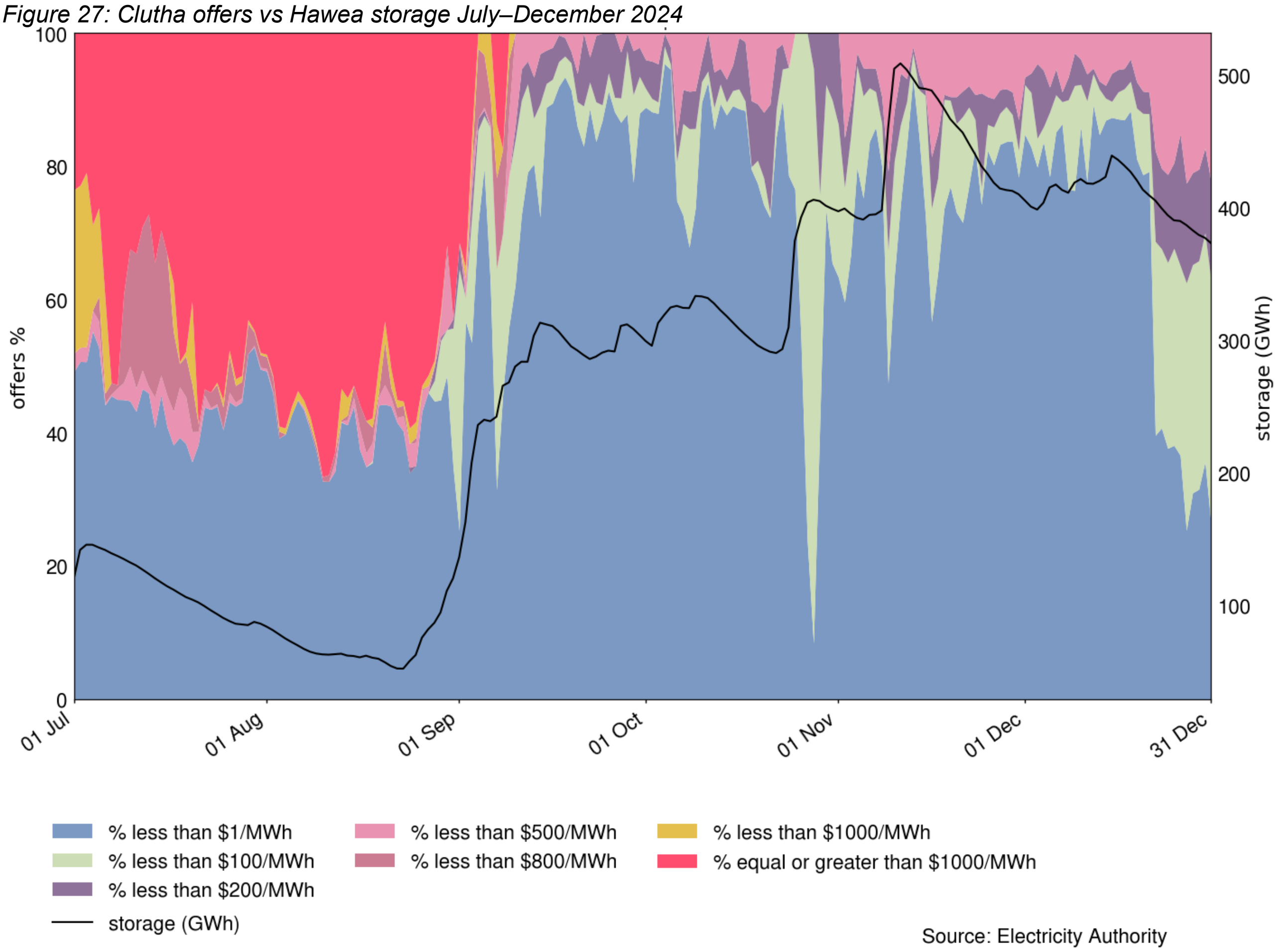
Source: Electricity Authority

9.26. Storage at Taupō was below average heading into winter 2024. In mid-July, the upper tranches of generation were priced between $800-$1,000/GWh, which was after losing 52GWh over two weeks.

9.27. In late July around 40% of offers were priced above $1,000/GWh as storage in Taupō reached 161GWh on 1 August. Once storage began increasing in mid-August, Mercury priced down their higher tranches of energy. While the energy priced below $1/MWh stayed relatively constant, the next lowest tranche then priced between $1-$100/GWh, where previously it had been mostly priced between $300-$500/GWh. As storage peaked in late November, all generation was priced below $200/MWh.

9.28. The Contact Clutha scheme also does not have much storage and runs mostly as a run of river scheme. However, its offers have closely aligned with storage levels at Hawea, as shown in Figure 27.

Figure 27: Clutha offers vs Hawea storage July–December 2024



Source: Electricity Authority

9.29. After a small Hawea storage increase in mid-July, there were some offers priced between $300-$500/MWh. These offer prices reflected the schemes reliance on outflows from Hawea, as run of river flows from Wakatipu and Wanaka were lower due to low rainfall. However, as storage continued to decrease, there were essentially only two tranches of energy by early August, roughly 45% of energy was priced below $1/MWh, while the rest was priced above $1,000/GWh.

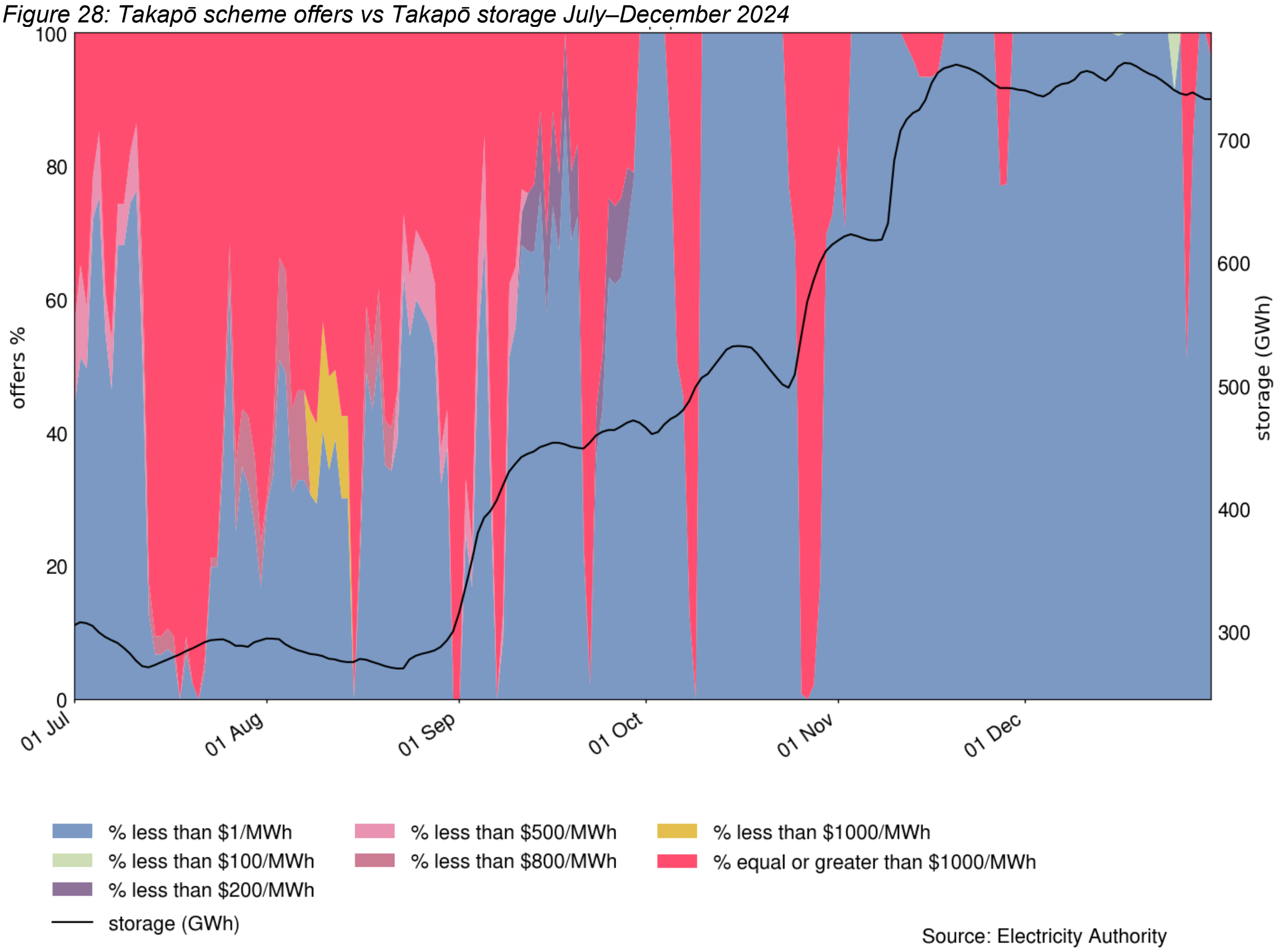
9.30. Storage reached a low of 51GWh on 23 August, which is 12% of full. As storage at Hawea rapidly increased, Contact was able to run the Clutha scheme while using minimum Hawea storage, as the run of river flows from tributaries were sufficient.

9.31. Throughout September roughly 80-90% of offers were priced below $1/GWh, with some remaining energy priced high. These offers are being analysed further in the trading conduct monitoring. There was a period of two days in late November where the proportion of offers under $1/MWh dropped. This was due to Contact offering the scheme in a way to avoid marginal running and dispatch in the rough running ranges at Clyde during periods with low pricing. During Monday the 28th of October, Contact offered low-priced energy from a Stratford peaker.

9.32. As storage began to fall in late December, the proportion of low-priced generation also fell. However, spot prices over this time were often below $10/MWh.

9.33. Takapō (Figure 28) is New Zealand's second largest hydro lake. Water from Takapō flows through the Takapō hydro plants and into Pūkaki, where the water is later used to feed Meridian's Waitaki scheme.

Figure 28: Takapō scheme offers vs Takapō storage July–December 2024



Source: Electricity Authority

9.34. Takapō reached a minimum of 272GWh on 14 July, which is 25% of full, during this time Genesis priced most water in Takapō above $1,000/MWh, and Genesis turned on its third

Rankine. Low priced offers returned around a week later as storage stabilised. Once storage began increasing in late August, close to 60% of weekday offers were priced below $1/MWh

9.35. Genesis priced the majority of Takapō generation above $1,000/MWh, over a period where storage slightly increased. Genesis continued to highly price weekend generation at Takapō, even after Takapō storage had increased. However, this was due to Genesis needing to preserve water due to resource consent conditions. Takapō's minimum lake level increases from 701.8 meters above sea level (masl) to 704.1 masl on 1 October. This impacted offer behaviour in August and September (particularly given the low inflows between May and August), as Genesis needed to ensure lake levels were high enough to not risk breaching conditions when the step change occurred on 1 October. The majority of generation was priced below $1/MWh over November and December as lake levels approached 100% full.

9.36. TablesTable 3 - Table 7 cover dates when reservoir storage (for individual lakes and nationally (when considering thermal operator)) was above its long-term average.

9.37. The hydro lakes were above mean during the following times:

(a) Pukaki from 9 October

(b) Taupo from 7 October

(c) Hawea from 4 September

(d) Takapō from 4 September

(e) Manapōuri from 26 August

9.38. These tables consider the percentage of offers above $300/MWh, and above the final price or above various measures of cost.

9.39. The percentage of offers above $300/MWh when storage was high decreased for the Waikato and Clutha compared to 2023 consistent with the higher inflows experienced in 2924. Offers above $300/MWh during times of high storage remained low at the Waitaki which has been a consistent and notable change since the trading conduct rules came into force in 2021. Offers above $300/MWh were higher this year at Takapō, which was largely due to Genesis managing low lake levels with without breaching their resource consents.

9.40. Since hydro generation dominated generation when storage was high, thermal units weren't often running and were only offering into the market to ensure security of supply. Hence these offers are higher than they were in 2023 as they reflect the start-up costs associated with running for short periods of time. However, in 2023, hydro generation was generating less energy due to lower lake levels and more thermal generation was online to over baseload.

Table 3: percentage of offers over $300/MWh[7], July–December 2014-24

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	Stratford [offers over $200/MWh]	Huntly
2024	20	0	17	1	70[70]	29
2023	38	0	3	9	34[34]	16
2022	19	1	12	19	84[88]	40
2021	37	4	9	5	72[74]	19
2019-2020	41	25	6	9	45[52]	18
2014-2018	9	24	17	0	2[3]	12

9.41. In 2024, when storage was high, there was across all major hydro and thermal generators more generation priced above the final price. This is because prices were often very low during times when hydro generation was high: prices were often below $60/MWh. Part of this was also due to periods of high wind generation, and increases in geothermal baseload, displacing hydro and thermal generation.

Table 4: Percent of offers above final price, July–December 2014-24

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	Stratford	Huntly
2024	56	38	18	25	76	36
2023	45	34	7	13	73	26
2022	26	24	15	28	98	40
2021	53	33	11	17	82	30
2019-2020	49	34	8	31	59	25
2014-2018	37	39	22	7	64	20

[7] Offers in previous years have been adjusted for inflation

Table 5: percentage of offers above the average forward price July–December 2014-24

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	McKee	Huntly OCGT	Stratford peakers	Rankines (coal)	E3P	TCC
2024	29	11	11	7	69	44	45	21	6	nan
2023	30	23	3	5	48	55	54	16	N/A	5
2022	12	5	12	15	90	84	97	32	20	42
2021	30	11	7	8	60	55	62	24	14	21
2019-2020	31	22	5	12	35	61	62	27	9	11
2014-2018	21	22	13	2	60	63	45	16	4	9

9.42. All hydro schemes except Takapō (which had some high offers due to consenting requirements) had no offers above thermal SRMCs when hydro storage was high in 2024. This reflects the system's changing priority to store thermal fuels rather than water as hydro storage increased in 2024.

9.43. Nova's offering strategy for McKee and Junction Road is to offer the full capacity of a unit at below $1/MWh during periods when it wants the unit to run, which usually correspond to periods the prices are expected to be higher than the SRMC, and to offer remaining capacity above $2,000/MWh, so it is not dispatched unless needed for security reasons. As Mckee was seldom needed once hydro generation increased, the majority of its offers were above $2,000/MWh.

9.44. The other thermal operators have a similar proportion of offers above thermal SRMCs as 2023, which reflect the similar high gas prices the sector faced to 2023, and the somewhat flat coal price.

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

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	McKee	Huntly OCGT	Stratford peakers	Rankines (coal)	E3P	TCC
2024	0	0	17	0	99	64	70	29	7	N/A
2023	43	26	4	10	70	79	81	22	N/A	22
2022	7	1	13	11	92	81	98	11	24	48
2021	24	8	10	6	87	52	42	23	20	15
2019-2020	30	27	6	14	56	28	64	19	13	9
2014-2018	20	31	18	3	87	22	49	21	14	19

9.45. In our the previous SCP analysis we noted that sometimes the JADE model under-valued hydro costing. This is also evident when risk was very high in July-August. These edge cases aren't captured well by the JADE model and the Authority is processing work on how to update JADE to more accurately reflect the risk parameters associated with running out of water. We have, however, included the analysis based on the current water values, as we mainly analyse correlations (which do not depend so much on values but rather movements). We also include the percentage of offers above water values for completeness but note that this indicator will be affected more by the issues identified with the modelling.

9.46. An additional review of winter 2024 has also been conducted and found that thermal and hydro offers were consistent with the market conditions at the time. Our review will be published on our website.

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

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)
2024	28	46	14	19
2023	50	36	12	9
2022[8]	15	15	11	25

Relationship of storage and offers to cost

9.47. Table 8 to Table 10 show the relationships between the average water values for each associated reservoir and hydro storage and offers, for when hydro storage was high. Figure 29 shows the relationship between these water values and offers.

9.48. For July to December 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.

9.49. Figure 29 shows that quantity weighted offer prices peaked for all schemes, except Tekapo, in early August when hydro storage was at its lowest nationally. At this time several of these schemes were approaching their minimum lake levels, after which they could only generate if they had access to their contingent storage (Pukaki, Hawea, Takapō). However, once storage began rapidly increasing, the QWOP decreased across all schemes. The QWOP at Takapō peaked in early October which was due to an effort to keep the scheme within its consenting boundary (as discussed above).

9.50. 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. These edge cases aren't captured well by the JADE model and the Authority will be enquiring on how to include additional parameters.

9.51. 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.

9.52. 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.

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

[8] (16 September[8] to 31 December)

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

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2024	-0.92	-0.98	-0.75	-0.69
2023	-0.35	-0.27	0.35	-0.66
2022[9]	-0.48	-0.76	-0.56	-0.61

Table 9: Correlation of water values with percentage of offers above $300/MWh - July–December

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2024	0.75	0.92	0.83	0.93
2023	0.32	-0.23	0.0019	0.63
2022	-0.46	0.19	0.13	0.69

Table 10: Correlation of water values with QWOP, July–December

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2024	0.8	0.97	0.79	0.67
2023	0.33	0.14	-0.023	0.73
2022	0.18	0.38	-0.12	0.005

[9] (16 September to 31 December)

Figure 29: Quantity weighted offer prices for July–December 2024