7 April 2025

Trading conduct report 30 March-5 April 2025

Market monitoring weekly report

Trading conduct report 30 March-5 April 2025

1. Overview

1.1. Spot prices increased this week to an average of $365/MWh, mostly due to low wind generation, less thermal generation (due to an outage at Ahuroa and a Rankine outage until Wednesday) and more hydro generation than last week. National hydro storage saw a small increase due to inflows at the end of the week.

2. Spot prices

2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.

2.2. Between 30 March-5 April 2025:

(a) The average spot price for the week was $365/MWh, an increase of around $57/MWh compared to the previous week.

(b) 95% of prices fell between $217/MWh and $478/MWh.

(c) Spot prices were almost entirely above the historical 90th percentile, except for Sunday.

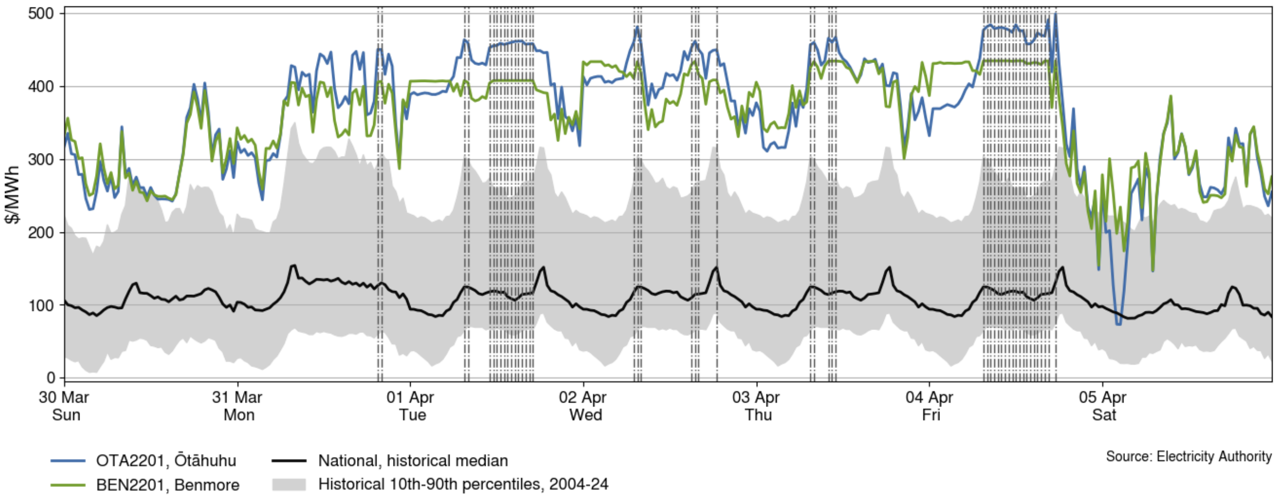
2.3. Weekday prices were often above $400/MWh at Ōtāhuhu due to low wind generation, less thermal generation than last week and more hydro generation, despite hydro storage continuing to decrease until inflows arrived on 3-4 April.

2.4. Spot prices were highest throughout Friday due to significant demand forecasting errors. The highest price at Ōtāhuhu was $499/MWh at 5.30pm on Friday when the evening demand peak was 173MW higher than forecast. The Benmore spot price at the same time was $435/MWh.

2.5. Following the highest price of the week, the Ōtahuhu spot price dropped to a minimum of $73/MWh at 2.00am on Saturday when wind generation was near its maximum for the week, demand was lower than at the same time on other days of the week and the amount of low price offers in the stack was slightly higher than previous days. The Benmore spot price at the same time was $198/MWh

2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices above $450/MWh are marked with black dashed lines.

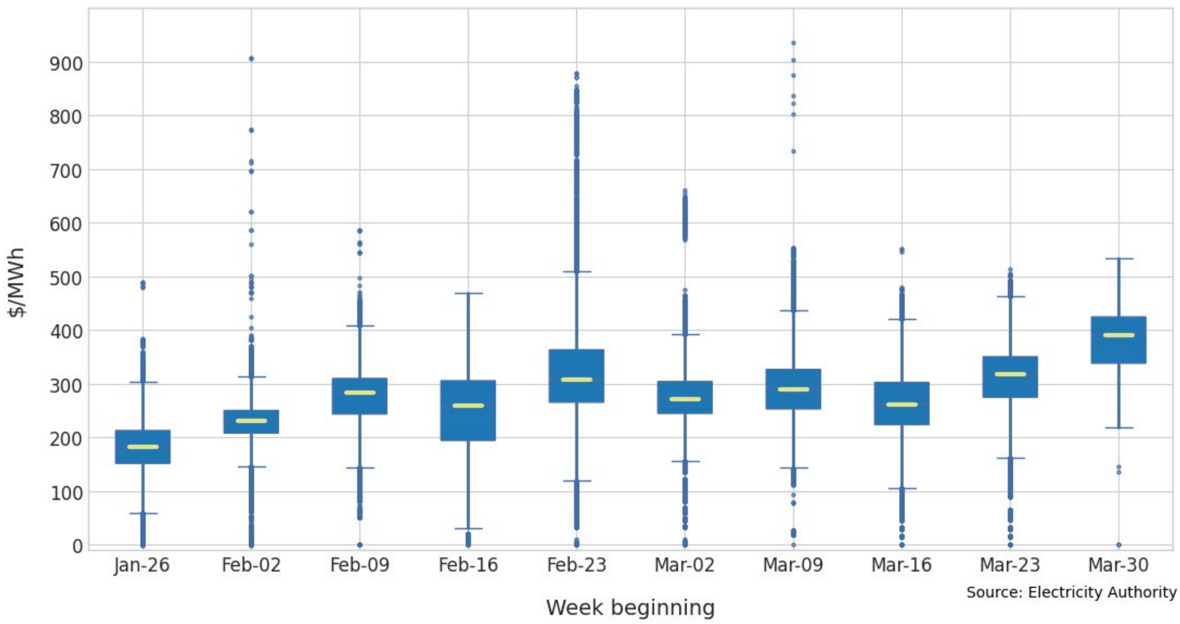
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 30 March-5 April 2025



2.7. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.8. The distribution of spot prices this week has shifted higher and has fewer very low prices. The median price was \$392/MWh and most prices (middle 50%) fell between \$338/MWh and \$425/MWh.

Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks

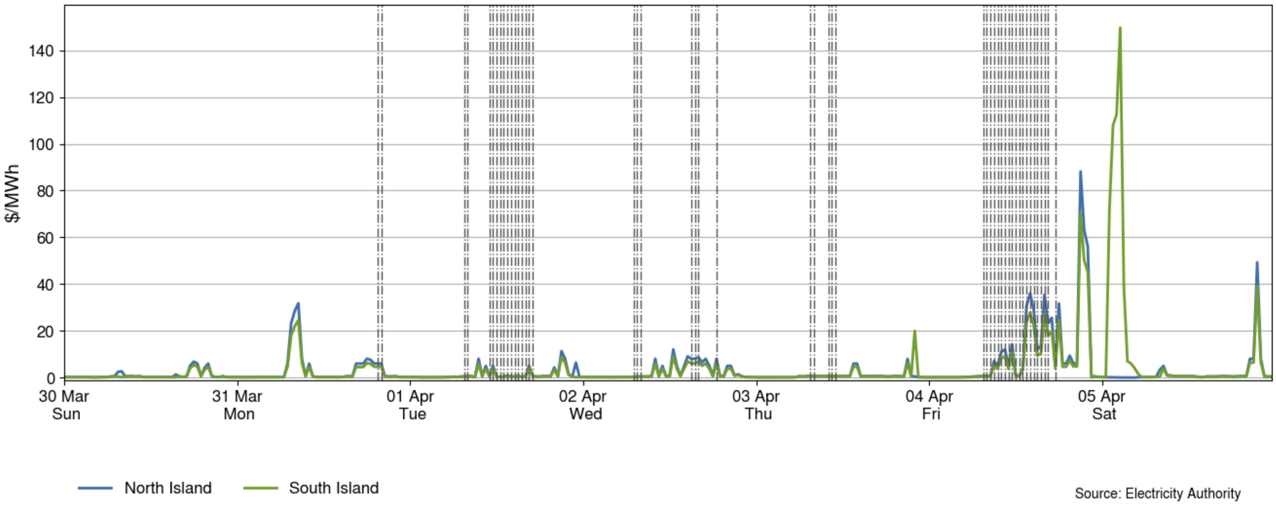


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices in the North Island and South Island increased to $88/MWh and $70/MWh respectively at 9.00pm on Friday due to a reduction in the amount of FIR offered.

3.2. The highest FIR price this week was $150/MWh in the South Island at 2.30am on Saturday when the HVDC was setting the South Island risk during southward HVDC flow. The FIR price in the North Island at the same time was $0/MWh.

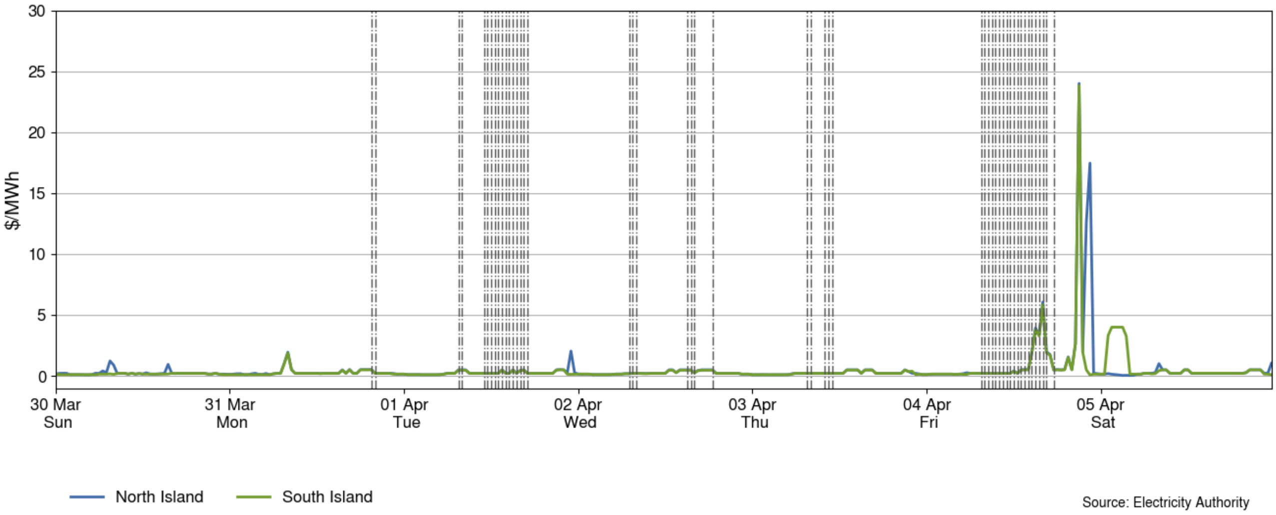
Figure 3: Fast instantaneous reserve price by trading period and island, 30 March-5 April 2025



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices in both islands spiked to $24/MWh at 9.00pm on Friday when total SIR offers reduced.

3.4. The North Island SIR price also spiked to $17/MWh at 10.30pm when the volume of North Island SIR cleared increased slightly. The South Island SIR price at the same time was $0.10/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 30 March-5 April 2025



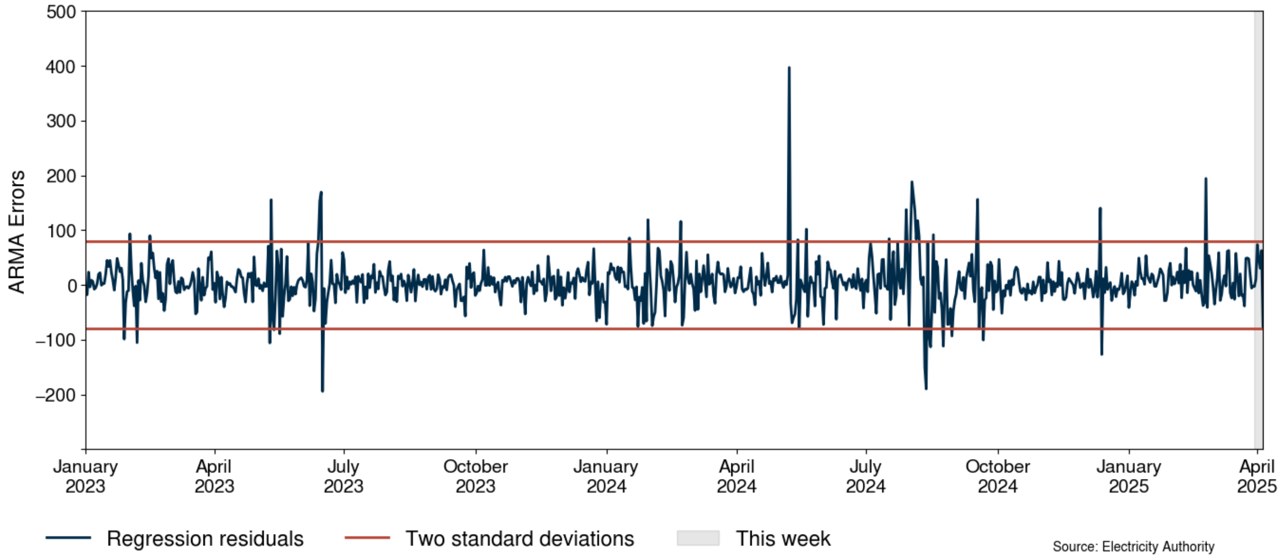
4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in Appendix A.

4.2. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the actual average daily price and vice versa. When residuals are small this indicates that average daily prices are likely largely aligned with market conditions. These small deviations reflect market variations that may not be controlled in the regression analysis.

4.3. This week, there were no residuals above or below two standard deviations, indicating that prices were similar to those predicted by the model.

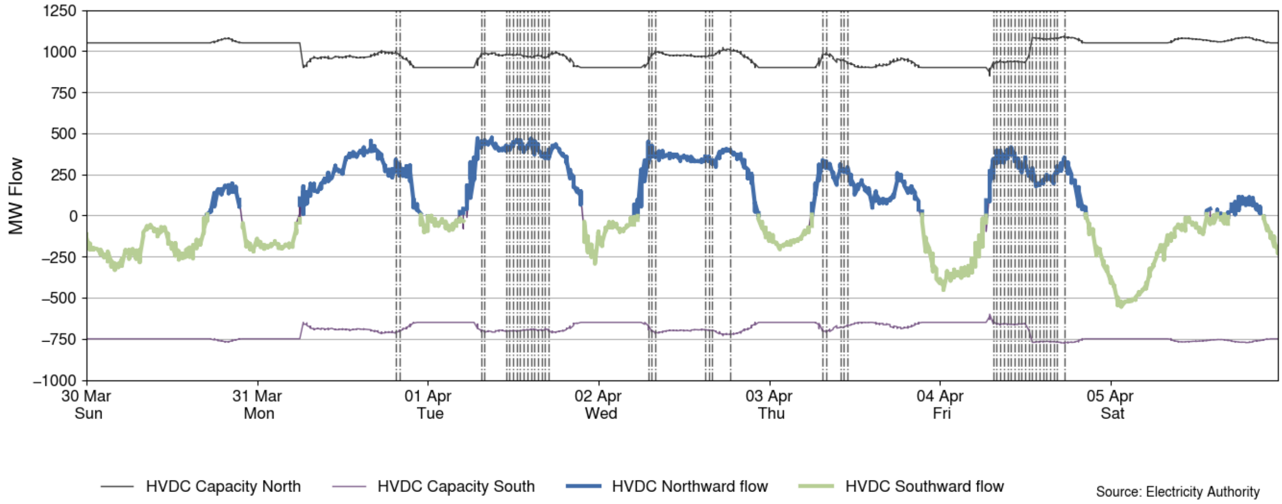
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 5 April 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 30 March-5 April 2025. HVDC flows were northward during the day and southward overnight for most of the week.

Figure 6: HVDC flow and capacity, 30 March-5 April 2025

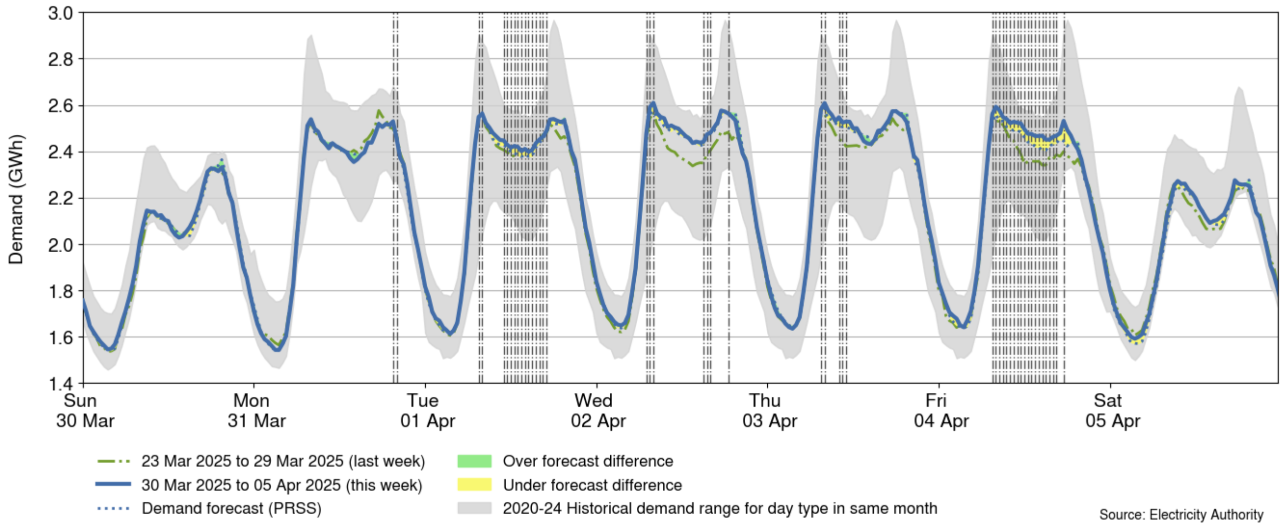


6. Demand

6.1. Figure 7 shows national demand between 30 March-5 April 2025, compared to the historic range and the demand of the previous week. Demand was higher than last week from Wednesday to Friday, otherwise demand was similar to last week. Total demand for the week was slightly higher than last week.

6.2. Demand on Friday was consistently higher than forecast, varying between 24-173MW higher than forecast between 4.00am-6.30pm. This was likely related to very high daytime temperatures.

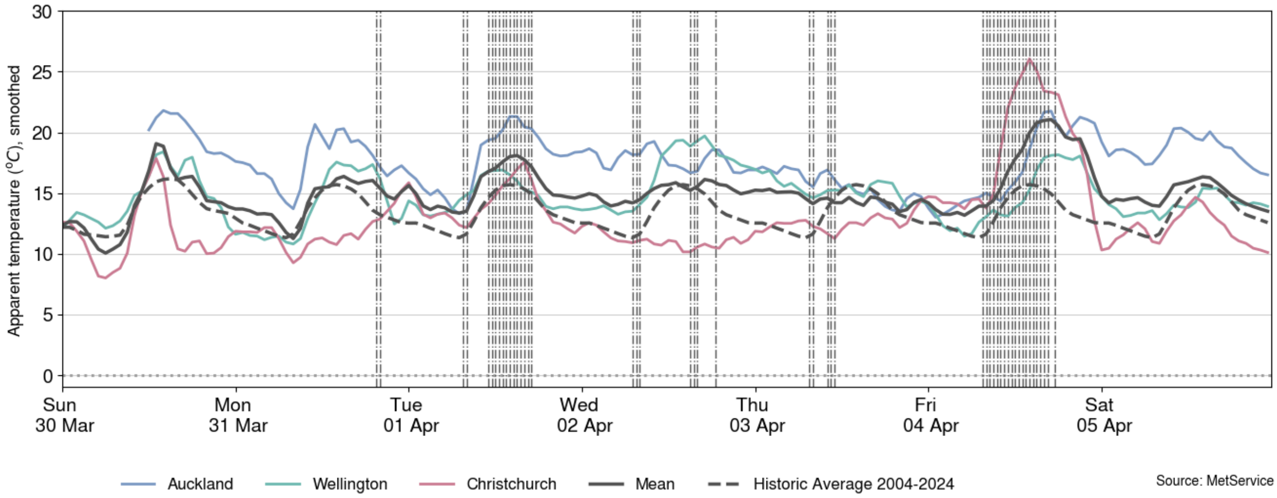
Figure 7: National demand, 30 March-5 April 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 30 March-5 April 2025. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. Apparent temperatures were mostly around average for this time of year (except for Friday) and ranged from 13°C to 22°C in Auckland, 11°C to 20°C in Wellington, and 8°C to 26°C in Christchurch.

Figure 8: Temperatures across main centres, 30 March-5 April 2025

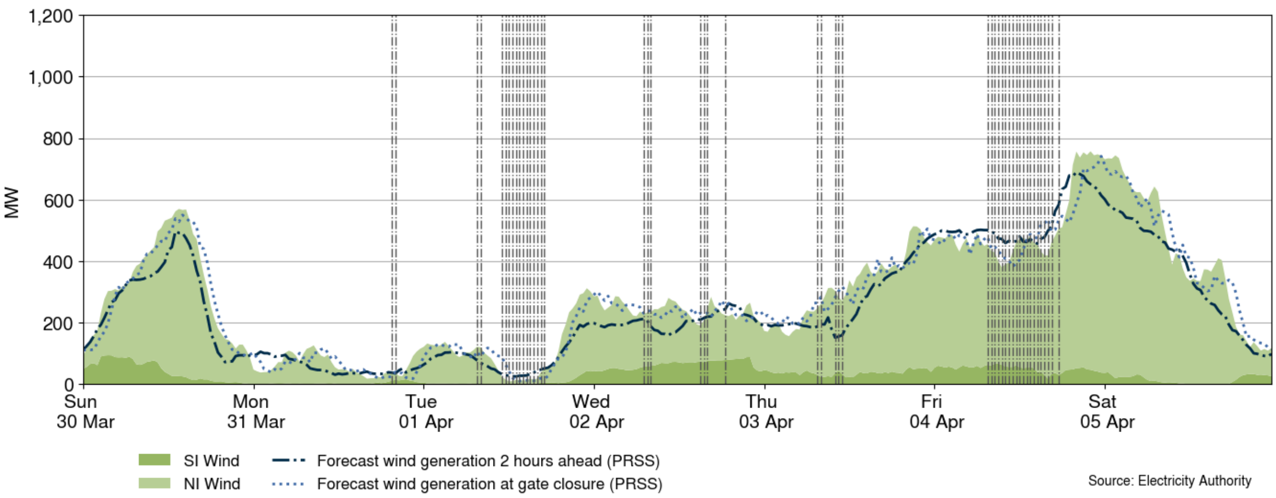


7. Generation

7.1. Figure 9 shows wind generation and forecast from 30 March-5 April 2025. Wind generation was low for most of the week, varying between 9MW and 757MW, with a weekly average of 283MW. A higher amount of wind farm outages this week also likely supressed wind generation.

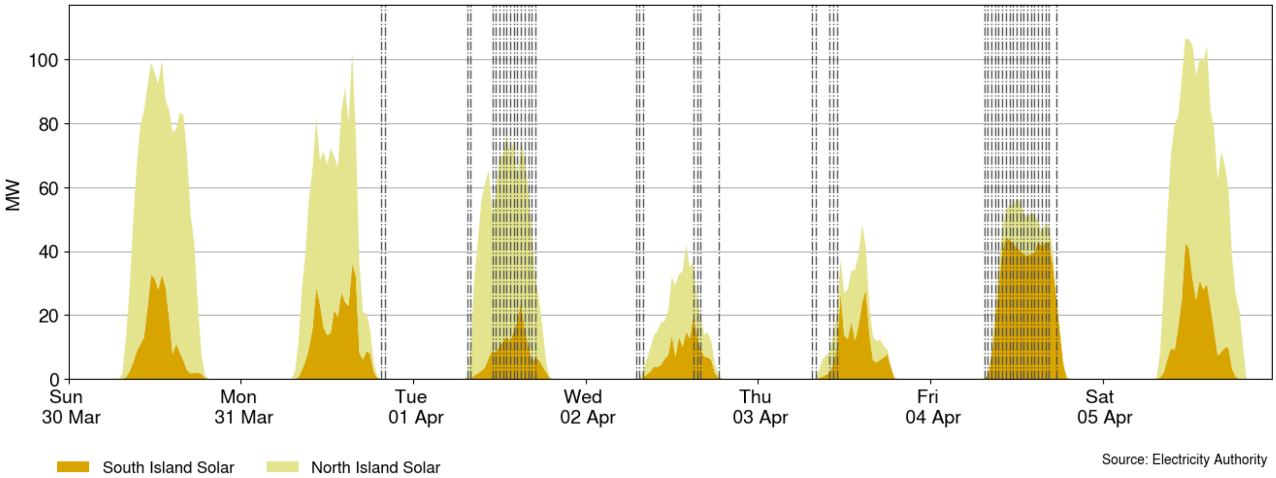
7.2. Wind was especially low on Tuesday afternoon. The greatest negative discrepancy with the gate closure forecast was 117MW at 4.00pm on Friday.

Figure 9: Wind generation and forecast, 30 March-5 April 2025



7.3. Figure 10 shows grid connected solar generation from 30 March-5 April 2025. Solar generation was low this week and only peaked above 100MW on Monday and Saturday.

Figure 10: Grid connected solar generation, 30 March-5 April 2025



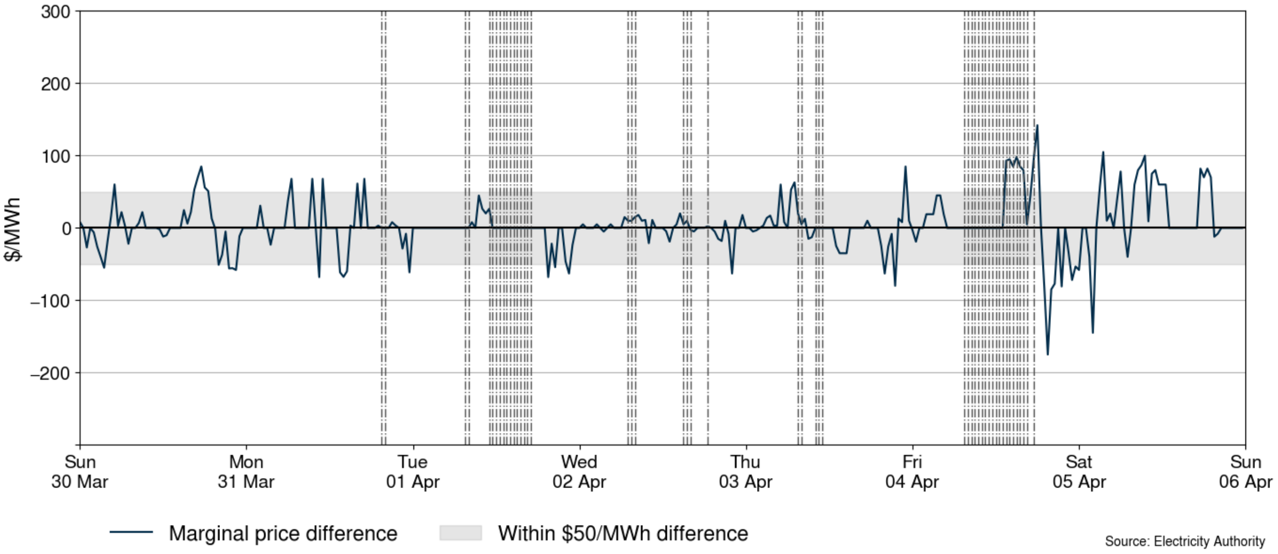
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.5. The largest positive marginal difference was $142/MWh at 6.00pm on Friday when wind generation was 37MW lower than forecast and demand was 139MW higher than forecast.

7.6. The largest negative marginal difference was $175/MWh at 7.30pm on Friday when wind generation was 161MW higher than forecast and demand was 66MW lower than forecast.

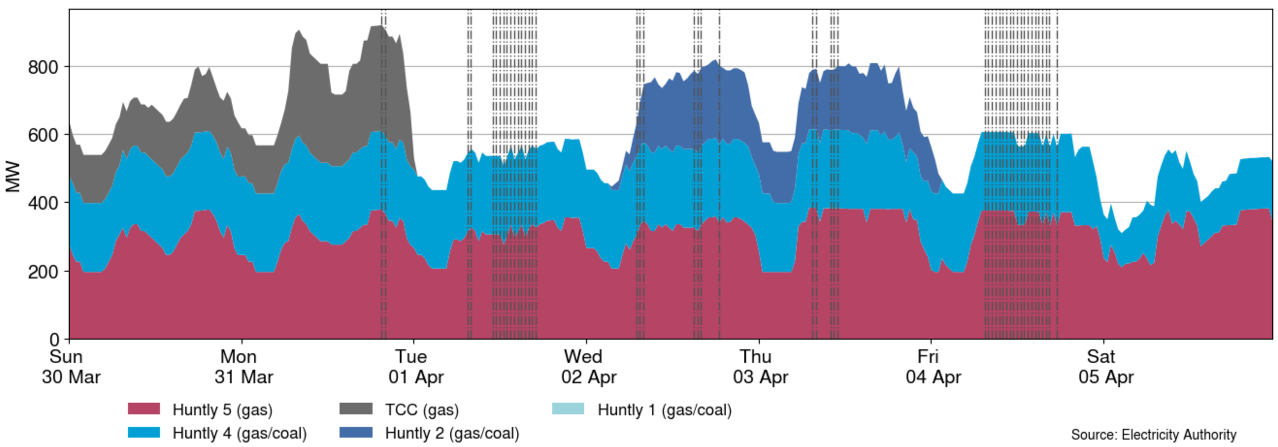
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 30 March-5 April 2025



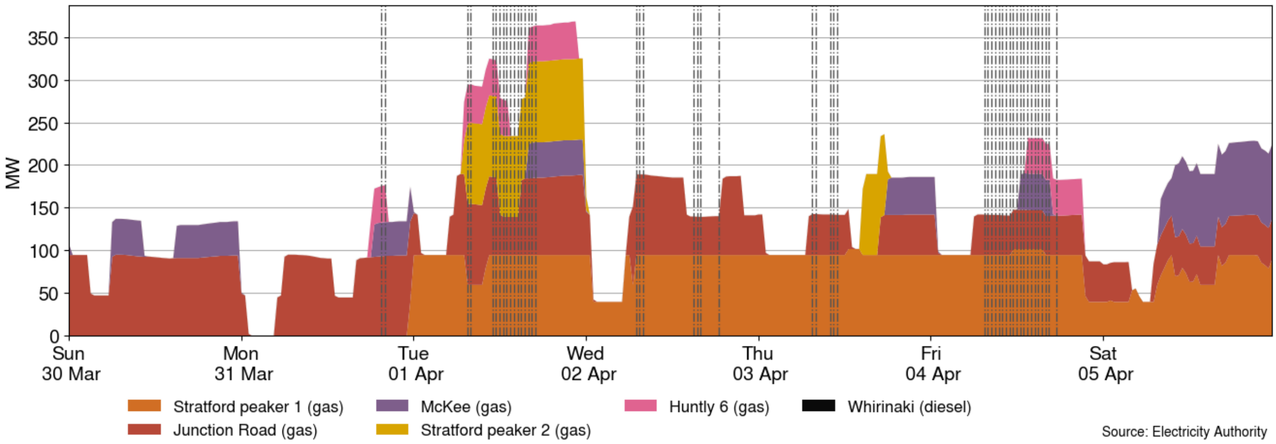
7.7. Figure 12 shows the generation of thermal baseload between 30 March-5 April 2025. Huntly 4 and 5 provided continuous baseload this week, with TCC generating through Sunday and Monday but was turned off, likely due to limited gas supply while Ahuora was on outage. Huntly 2 started generating on Wednesday, after returning from outage, but turned off again on Thursday evening. The monitoring team will enquire further with Genesis on why Rankine 2 offers were removed for Friday.

Figure 12: Thermal baseload generation, 30 March-5 April 2025



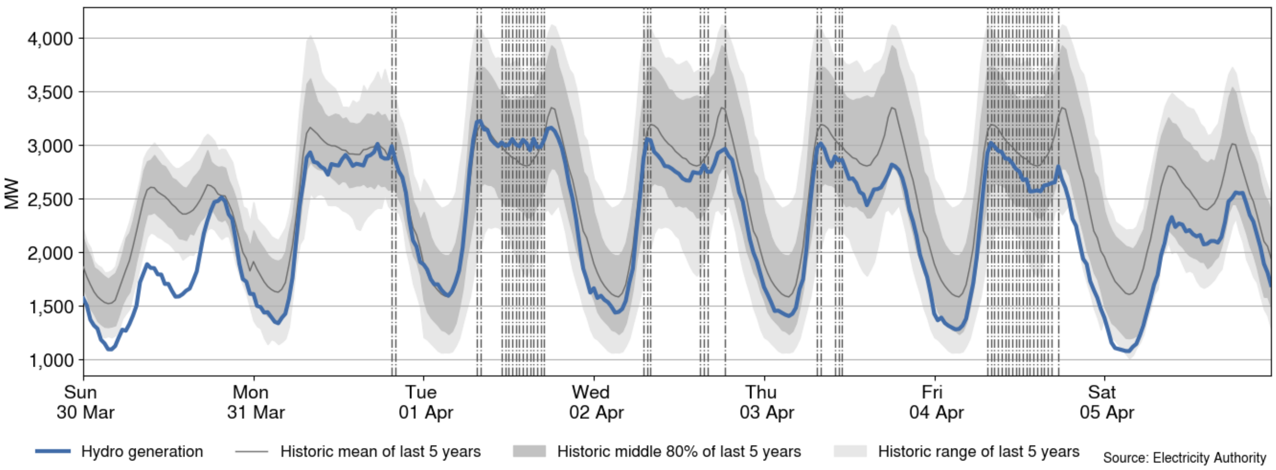
7.8. Figure 13 shows the generation of thermal peaker plants between 30 March-5 April 2025. Junction Road and Stratford 1 were the main peakers generating this week. McKee ran at least once each day except for Wednesday. Huntly 6 and Stratford 2 also generated at times during the week.

Figure 13: Thermal peaker generation, 30 March-5 April 2025



7.9. Figure 14 shows hydro generation between 30 March-5 April 2025. Hydro generation increased this week and was highest on Tuesday with generation around the historic mean of the last five years despite lower than average hydro storage for this time of year.

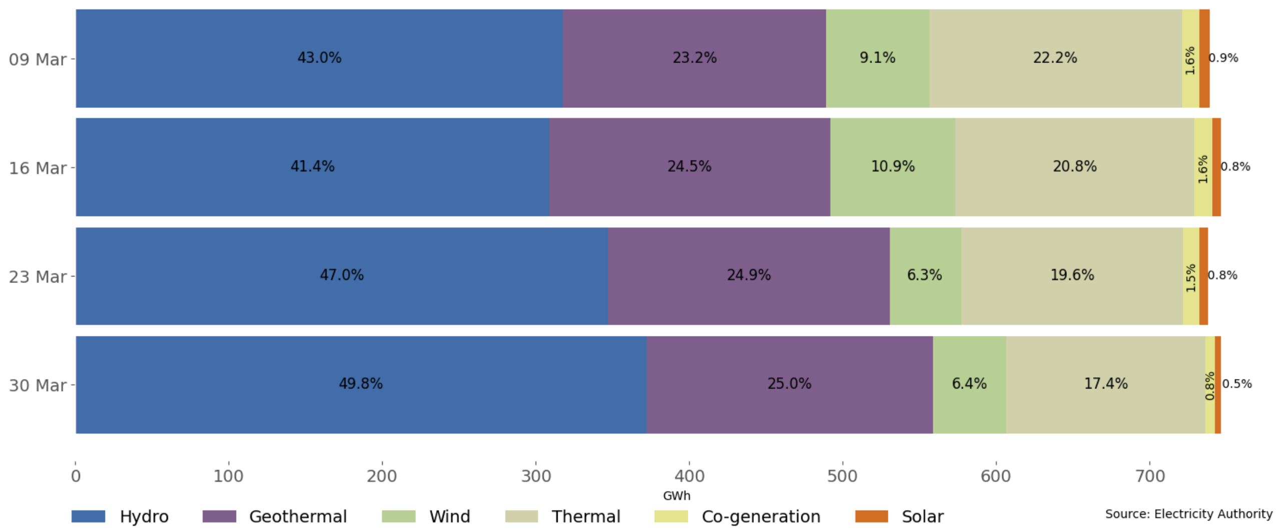
Figure 14: Hydro generation, 30 March-5 April 2025



7.10. As a percentage of total generation, between 30 March-5 April 2025, total weekly hydro generation was 49.8%, geothermal 25.0%, wind 6.4%, thermal 17.4%, co-generation 0.8%, and solar (grid connected) 0.5%, as shown in Figure 15.

7.11. Hydro generation increased and thermal generation decreased again in the last week, while wind generation remained low at just over 6% of the generation mix.

Figure 15: Total generation by type as a percentage each week, between 9 March-5 April 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 30 March-5 April 2025 ranged between ~1,350MW and ~2,410MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC was on outage from 1-4 April.

(b) Huntly 1 is on outage until 2 June.

(c) Huntly 2 returned from outage on 2 April.

(d) Turitea was on outage from 31 March-1 April.

(e) Tokaanu was on outage on 5 April.

(f) Manapōuri unit 2 is on outage until 17 April.

(g) Manapōuri unit 4 is on outage until 12 June 2026.

(h) Clyde unit 1 is on outage until 23 May.

(i) West Wind is on partial outage until 11 April.

Figure 16: Total MW loss from generation outages, 30 March-5 April 2025

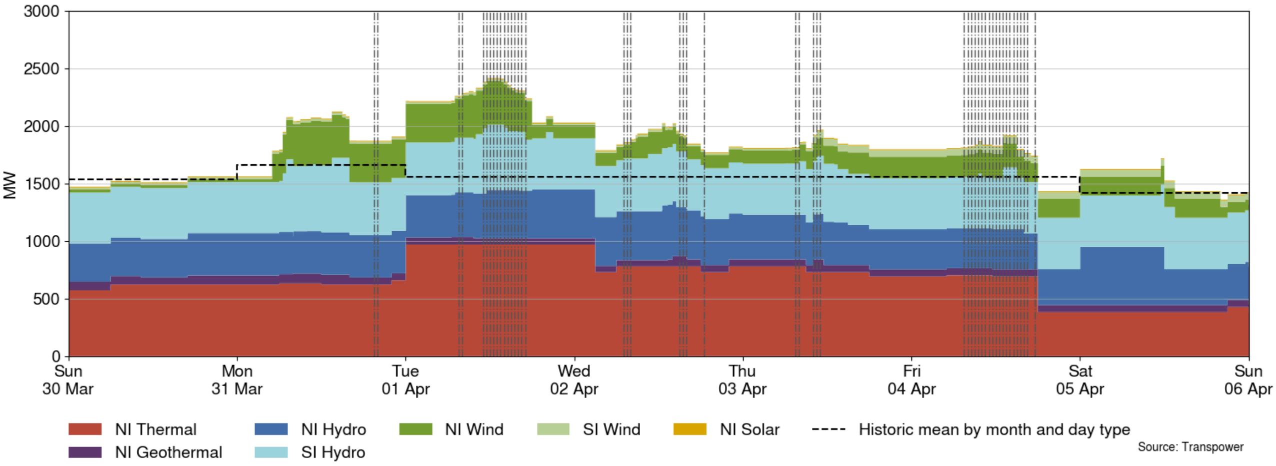
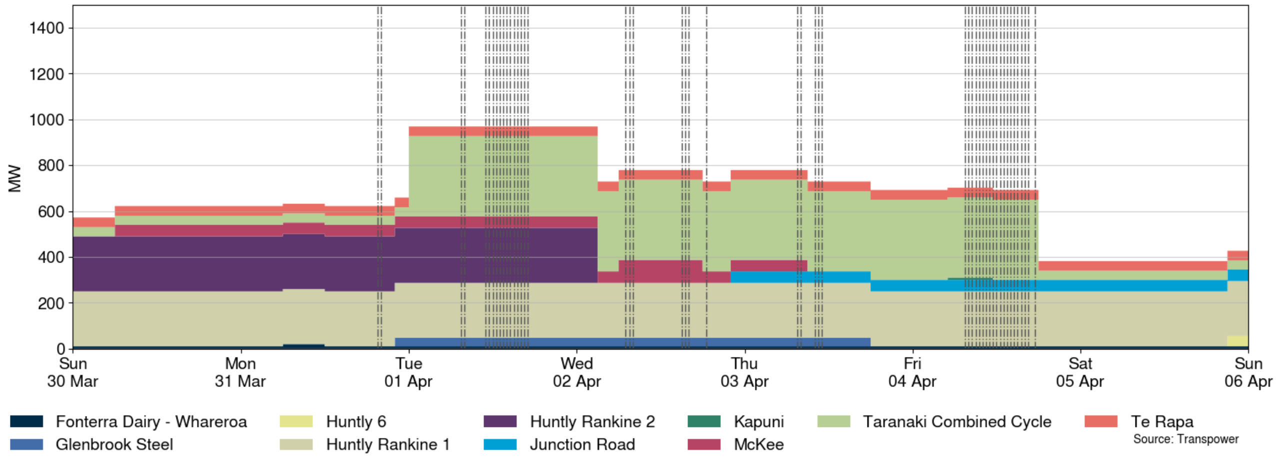


Figure 17: Total MW loss from thermal outages, 30 March-5 April 2025

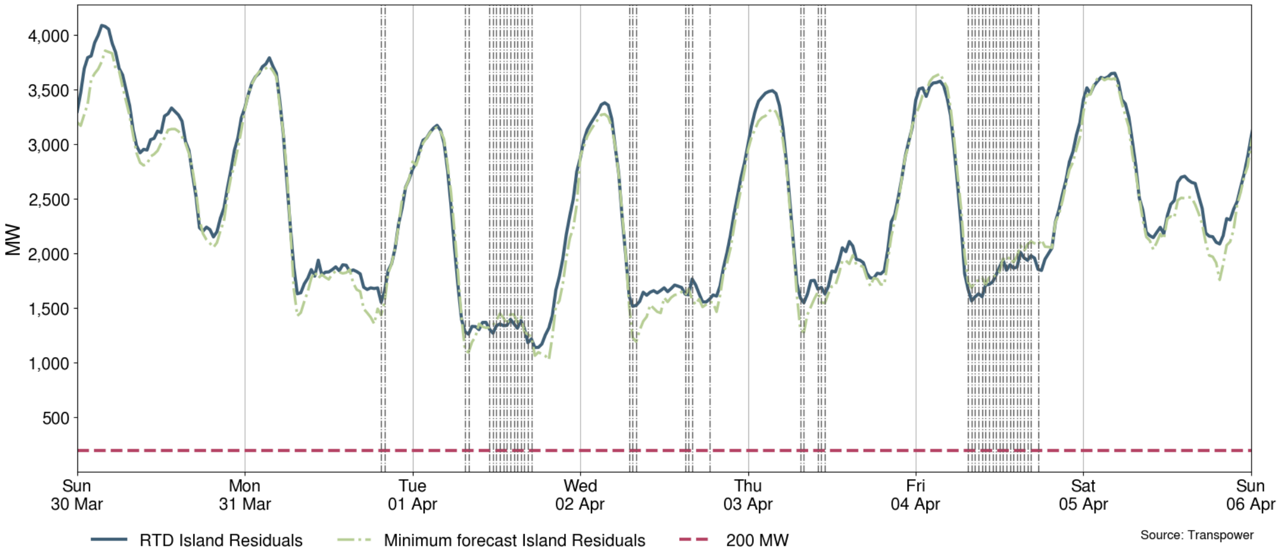


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 30 March-5 April 2025. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Residuals were healthy this week. The minimum North Island residual was 588MW at 5.30pm on Tuesday.

Figure 18: National generation balance residuals, 30 March-5 April 2025



10. Storage/fuel supply

10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

10.2. National controlled storage increased slightly this week. As of 5 April, national storage was ~61% nominally full and ~78% of the historical average for this time of the year.

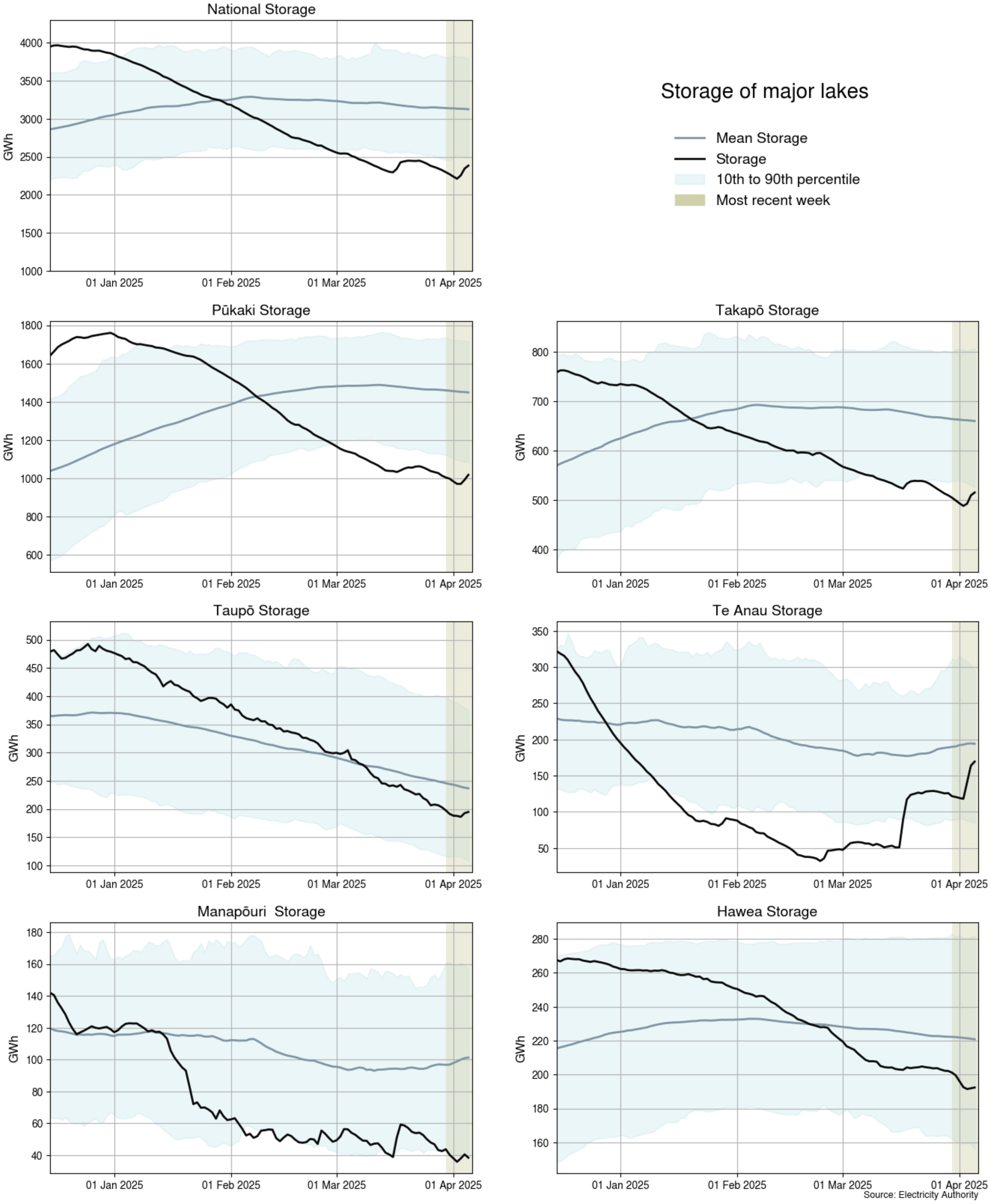
10.3. Storage at lakes Pūkaki (59% full)[2], Takapō (63% full) and Manapōuri remains at or below their respective historic 10th percentiles.

10.4. Storage at lake Te Anau increased this week and is between its historic mean and 10th percentile.

10.5. Storage at lakes Hawea (67% full) and Taupō (33% full) decreased in the last week and is between their respective historic means and 10th percentiles.

[2] Percentage full values sourced from NZX Hydro.

Figure 19: Hydro storage



11. Prices versus estimated costs

11.1. In a competitive market, prices should be close to (but not necessarily at) the short-run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).

11.2. The SRMC (excluding opportunity cost of storage) for thermal fuels is estimated using gas and coal prices, and the average heat rates for each thermal unit. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.

11.3. Figure 20 shows an estimate of thermal SRMCs as a monthly average up to 1 March. The SRMC for gas fuelled generation has increased compared to last month. The SRMC for coal and diesel fuelled generation remains similar.

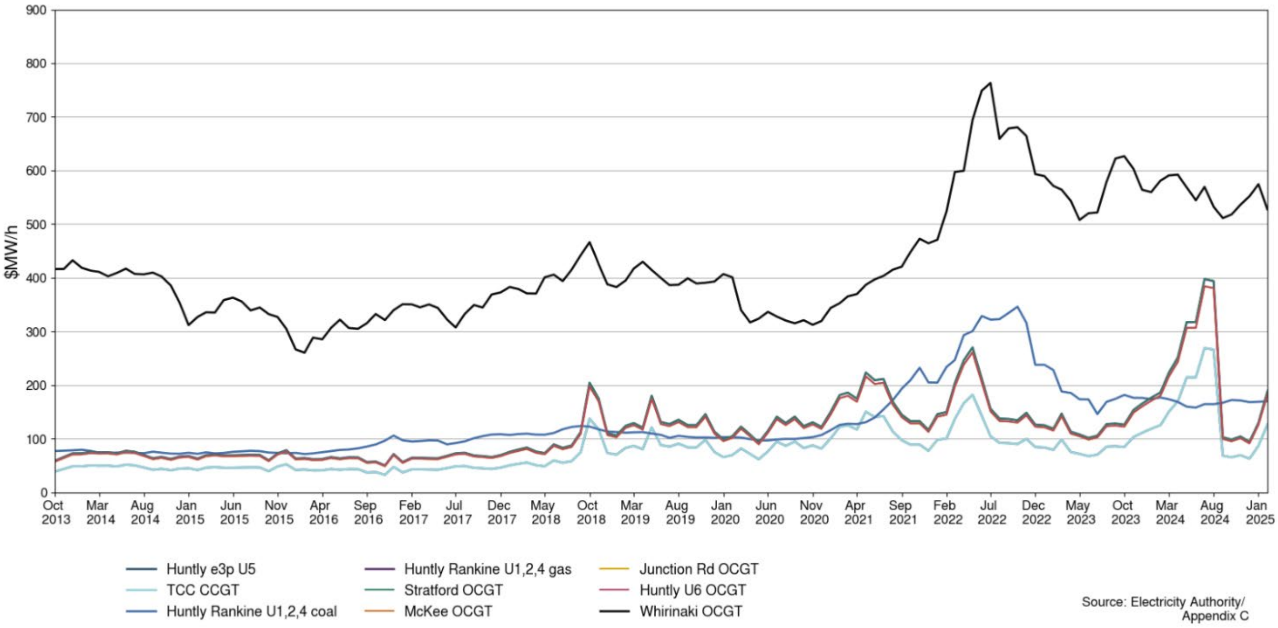
11.4. The latest SRMC of coal-fuelled Rankine generation is still ~$170/MWh, with the cost of running the Rankines on gas now more expensive at ~$224/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $150/MWh and $224/MWh.

11.6. The SRMC of Whirinaki is still ~$527/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

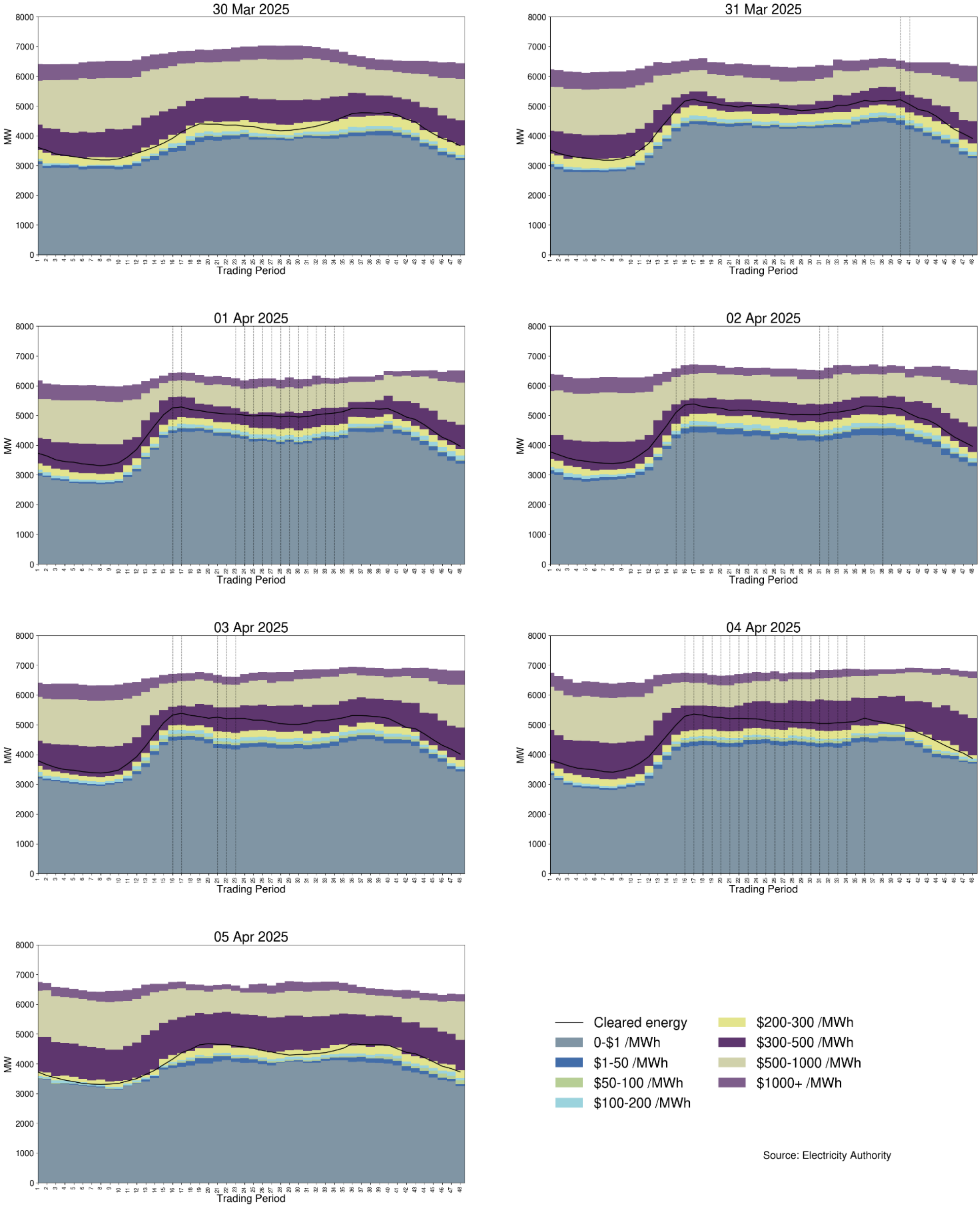
Figure 20: Estimated monthly SRMC for thermal fuels



12. Offer behaviour

12.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price. Most offers were clearing in the $300-500/MWh band and the marginal generation tended to be hydro due to the increased level of thermal outages.

Figure 21: Daily offer stacks



Source: Electricity Authority

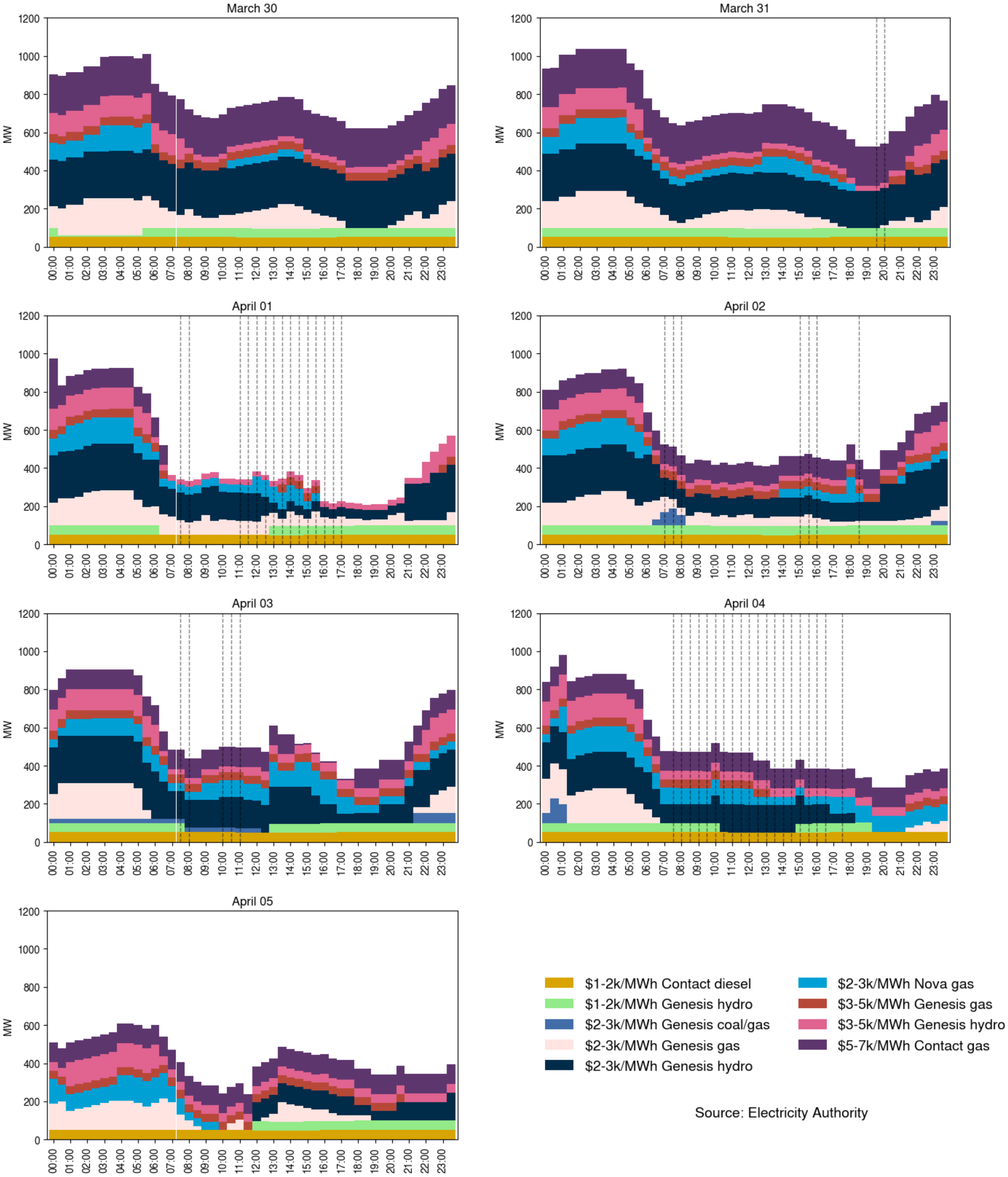
12.2. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

12.3. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren’t expecting to run. These high prices reflect increased operating costs of running for only a short time. So, if demand is unexpectedly high, wind generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.4. On average, 595MW per trading period was priced above $1,000/MWh this week, which is roughly 10% of the total energy available.

12.5. The volume of offers above $1000/MWh was highest on 30 and 31 March. The total amount of hydro offers above $1,000/MWh reduced this week due to increased inflows.

Figure 22: High priced offers

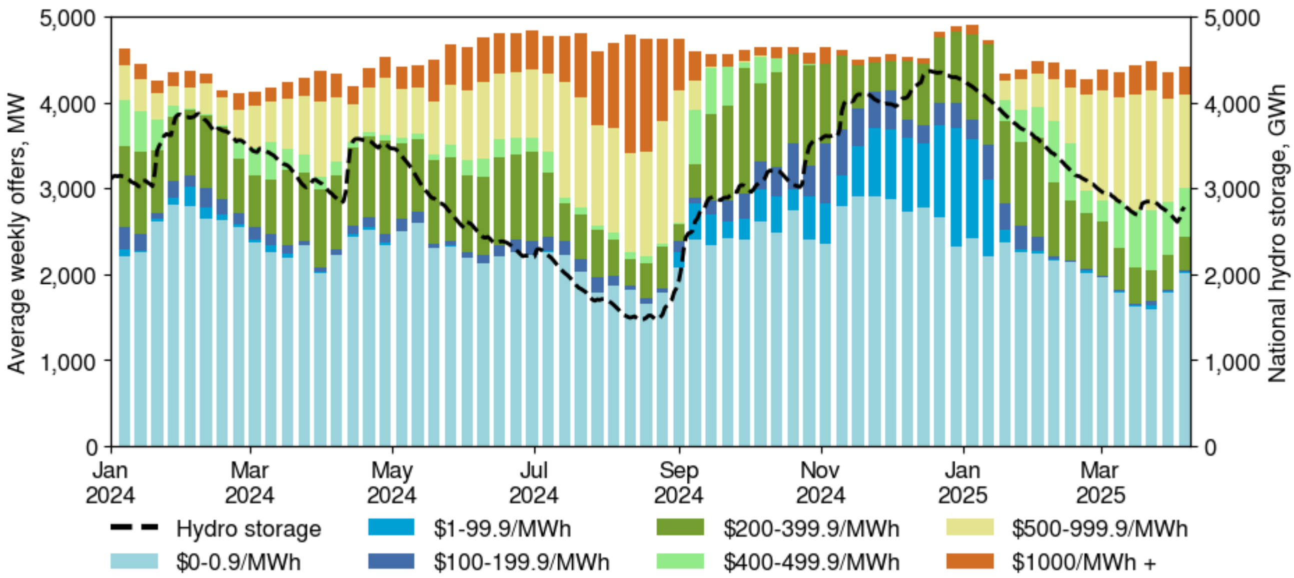


Source: Electricity Authority

12.6. Figure 23 shows average weekly hydro generation offers since the start of 2024, against national hydro storage. This illustrates periods of higher storage (e.g. November-December 2024) have higher proportions of low-priced offers to reflect the abundance of water for electricity generation. While periods of low storage (e.g. July-August 2024) have a larger volume of higher priced offers to reflect the scarcity of water and encourage more thermal generation to offset the risk of running out of water.

12.7. Hydro storage has decreased since the start of 2025 and the volume of low-priced hydro generation has reduced. The volume of low-priced offers is currently similar or slightly lower than in June 2024 when hydro storage first reached this level. This reflects that national hydro storage has reached this level earlier in the year, and caution heading into winter if low inflows are to continue. However, the volume of very high-priced hydro (above $1,000/MWh) is similar or less than June 2024.

Figure 23: Average weekly hydro generation offers, 2024-25



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
14/06/2023- 15/06/2023	15-17/ 15-19	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
18/03/2025	23-27	Further analysis	Genesis	Huntly	Unplanned outage
27/03/2025	20-28	Further analysis	Contact	Stratford peakers and TCC	Offers
4/04/2025	Several	Further analysis	Genesis	Huntly	Offers removed
2/04/2025-4/04/2025	Several	Further analysis	Genesis	Takapō and Tokaanu	Offers