12 May 2025

Trading conduct report 4-10 May 2025

Market monitoring weekly report

Trading conduct report 4-10 May 2025

1. Overview

1.1. The average spot price decreased by $45/MWh this week to $300/MWh. National hydro storage has increased to ~66% nominally full and ~87% of the historical average for this time of year.

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 4-10 May:

(a) The average spot price for the week was $300/MWh, a decrease of around $45/MWh compared to the previous week.

(b) 95% of prices fell between $112/MWh and $437/MWh.

2.3. Prices have decreased this week, which is likely due to increased hydro inflows. However, prices are still mostly above $250/MWh as hydro storage remains low and thermal generation is high.

2.4. The highest price at Ōtāhuhu was $445/MWh at 7.30am on Monday. This was during the highest demand for the week. At this time demand was 196MW higher than forecast and wind generation was only 50MW.

2.5. Demand was also higher than forecast on Tuesday morning. Prices at Ōtāhuhu spiked to $421/MWh at 7.30am while demand was 83MW higher than forecast.

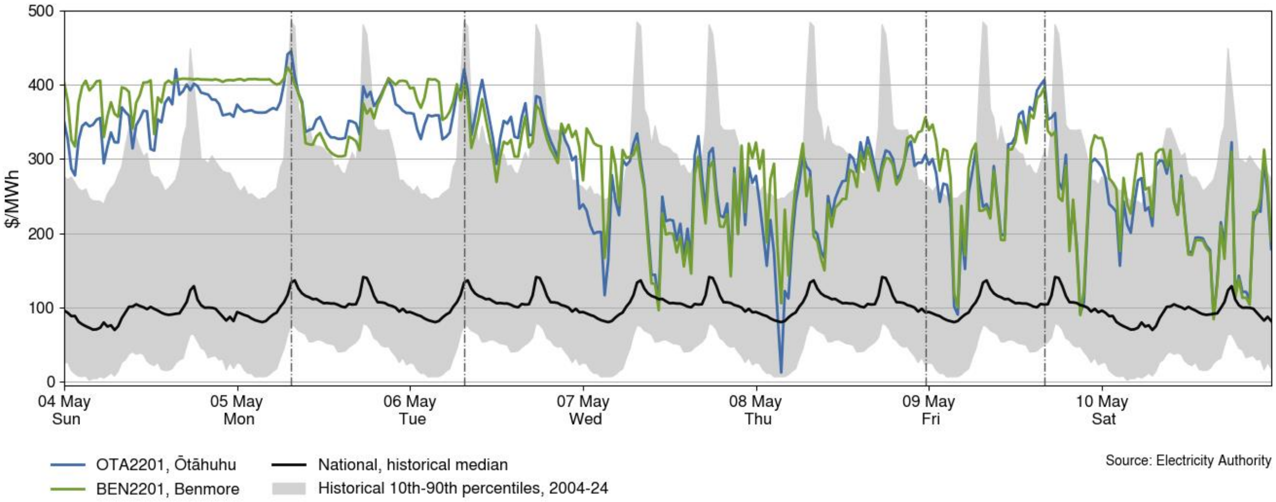
2.6. At 11.30pm on Thursday, the price at Benmore reached $356/MWh while the price at Ōtāhuhu was $306/MWh.

2.7. Prices also reached above $400/MWh at Ōtāhuhu on Friday. At 4.00pm, the price at Ōtāhuhu spiked to $406/MWh. Demand was 100MW higher than forecast and wind was 145MW lower than forecast at gate closure, causing a collective forecast error of 245MW at this time.

2.8. The highest price of the week at any node occurred on Wednesday at 7.30am when the price at Fernhill (Hawke's Bay) was $10,425/MWh. At this time the price at Tuai was $4,999/MWh. These very high prices were likely due to a combination of planned line outages increasing demand at Fernhill and line constraints restricting generation into the Hawke's Bay region. The monitoring team is looking further into this price.

2.9. 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 are marked with black dashed lines.

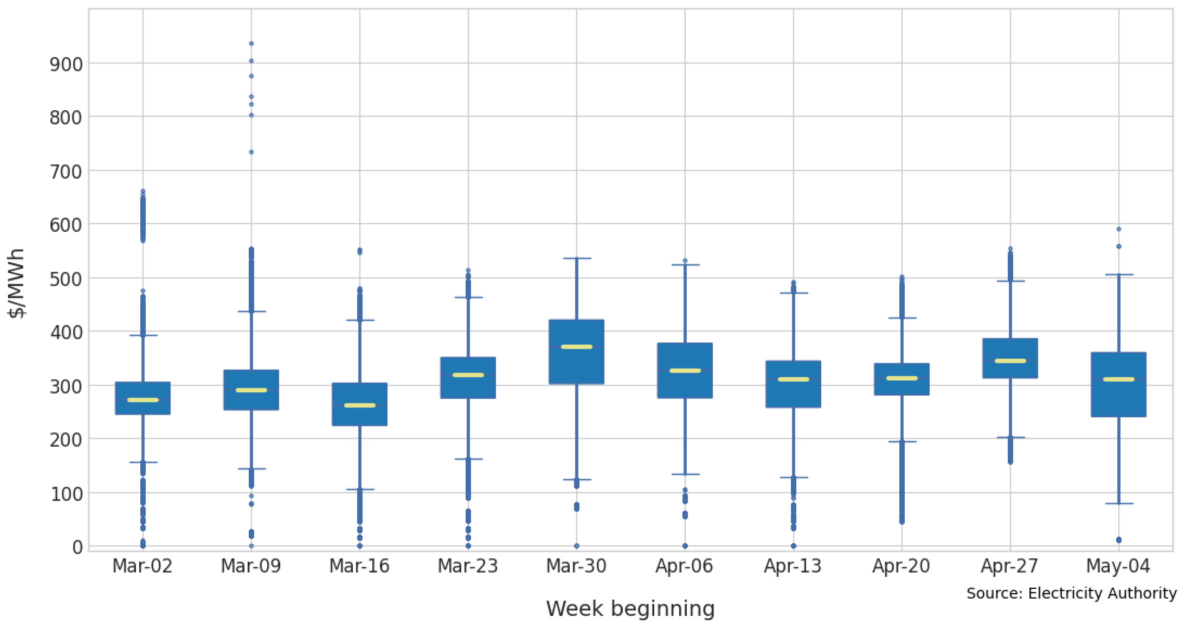
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 4-10 May



2.10. 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.

2.11. The distribution of spot prices this week was skewed lower compared to last week but more volatile. The median price was $311/MWh and most prices (middle 50%) fell between $241/MWh and $359/MWh.

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

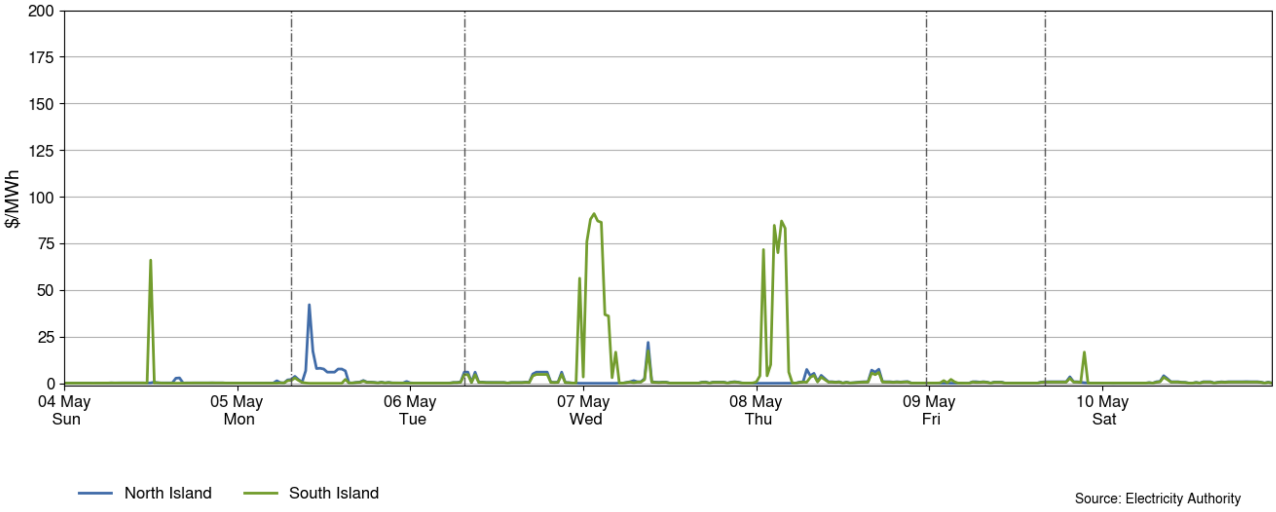


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh but spiked above $30/MWh in the North or South Islands several times.

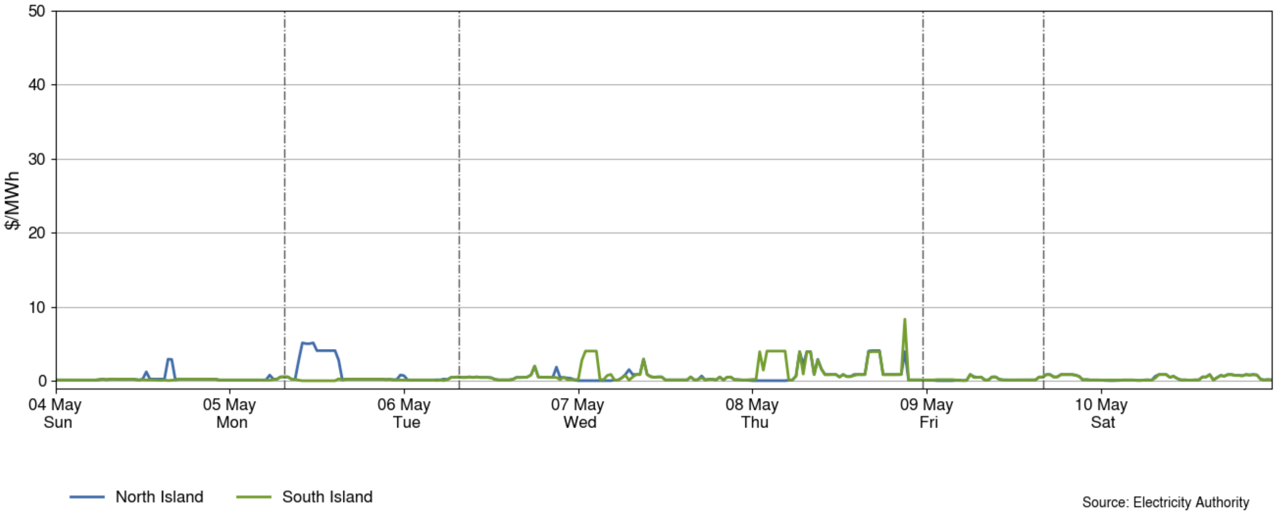
3.2. All these higher FIR prices were likely due to the increased FIR required to cover the risk set by the HVDC flowing south. On Sunday, an HVDC outage likely contributed to the spike.

Figure 3: Fast instantaneous reserve price by trading period and island, 4-10 May



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh and did not reach above $10/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 4-10 May



4. Regression residuals

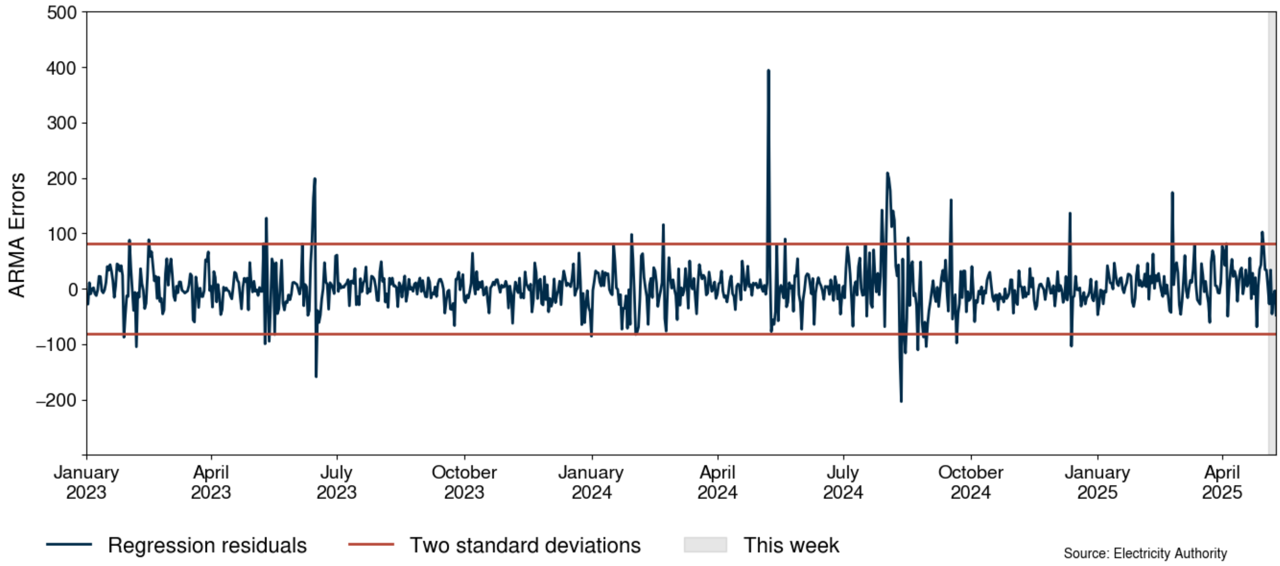
4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and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

4.4. Last week, an error in the modelling led to an incorrect figure. On Wednesday 30 April, residuals were above 2 standard deviations. This was likely due to Meridian pricing up their hydro offers from that day and large demand under forecasting.

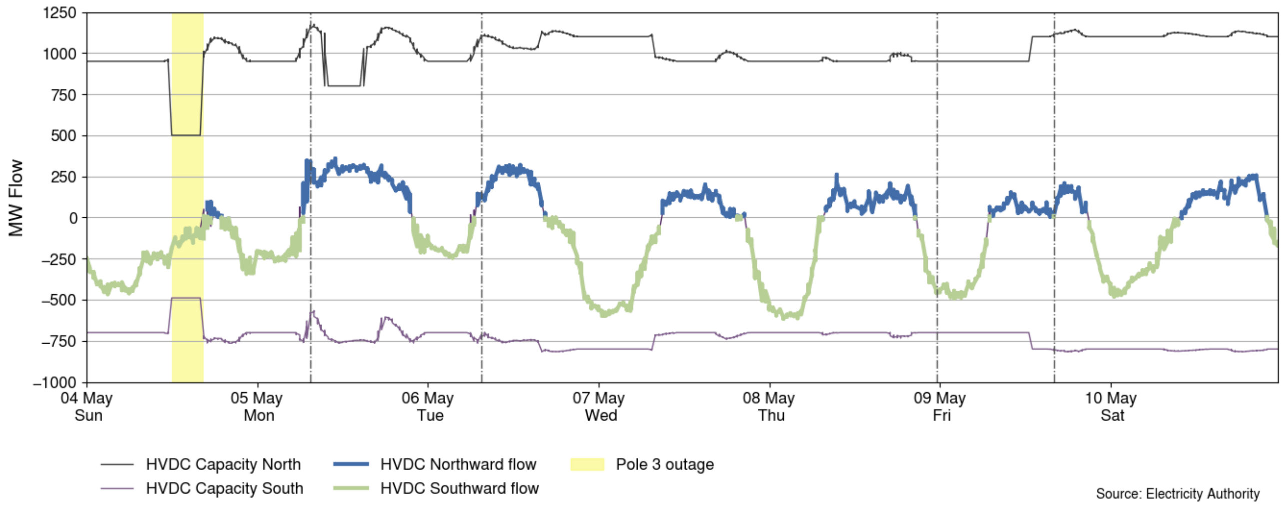
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 10 May 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 4-10 May. HVDC flows were mostly northward during the day and southward at night. Pole 3 was on outage from 12.00pm to 4.30pm on Sunday. Northward transfer was highest on Monday when wind was very low.

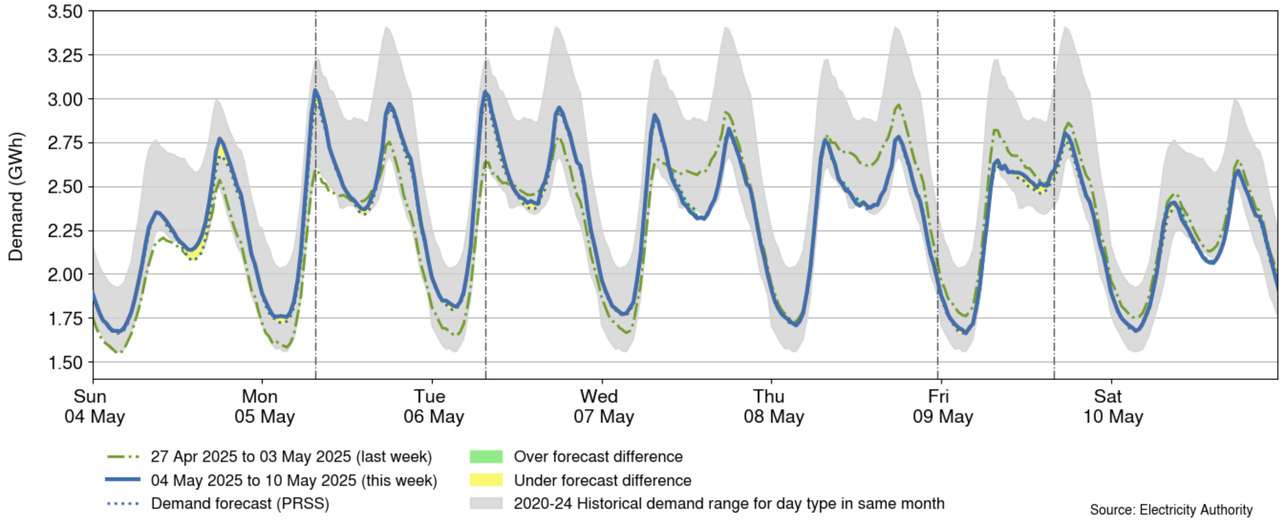
Figure 6: HVDC flow and capacity, 4-10 May



6. Demand

6.1. Figure 7 shows national demand between 4-10 May, compared to the historic range and the demand of the previous week. At the start of the week demand was higher than the previous week but lower towards the end of the week. Maximum demand, 3.05GWh, occurred at 7.30am on Monday during the highest price at Ōtāhuhu.

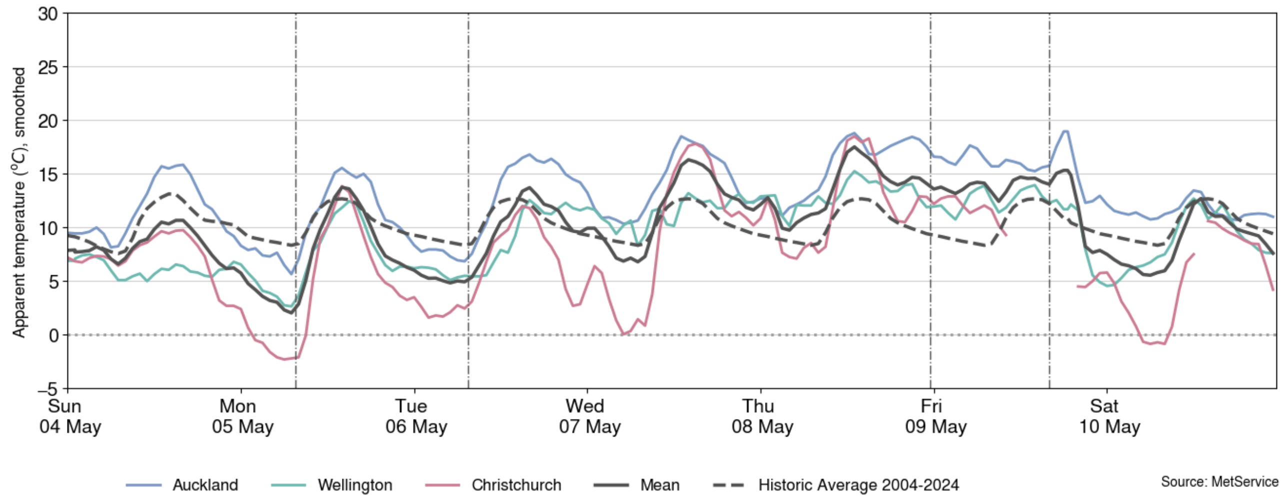
Figure 7: National demand, 4-10 May compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 4-10 May. 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.

6.3. Apparent temperatures were mostly below average at the start of the week and mostly above average towards the end of the week. They ranged from 6°C to 19°C in Auckland, 2°C to 16°C in Wellington, and -2°C to 20°C in Christchurch. There is missing temperature data for Christchurch on Friday and Saturday.

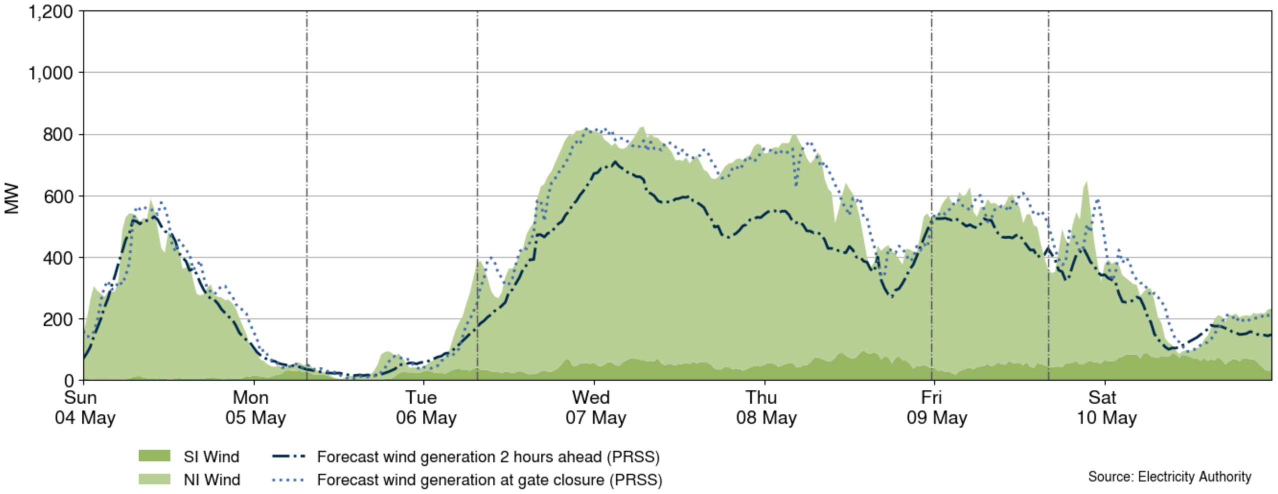
Figure 8: Temperatures across main centres, 4-10 May



7. Generation

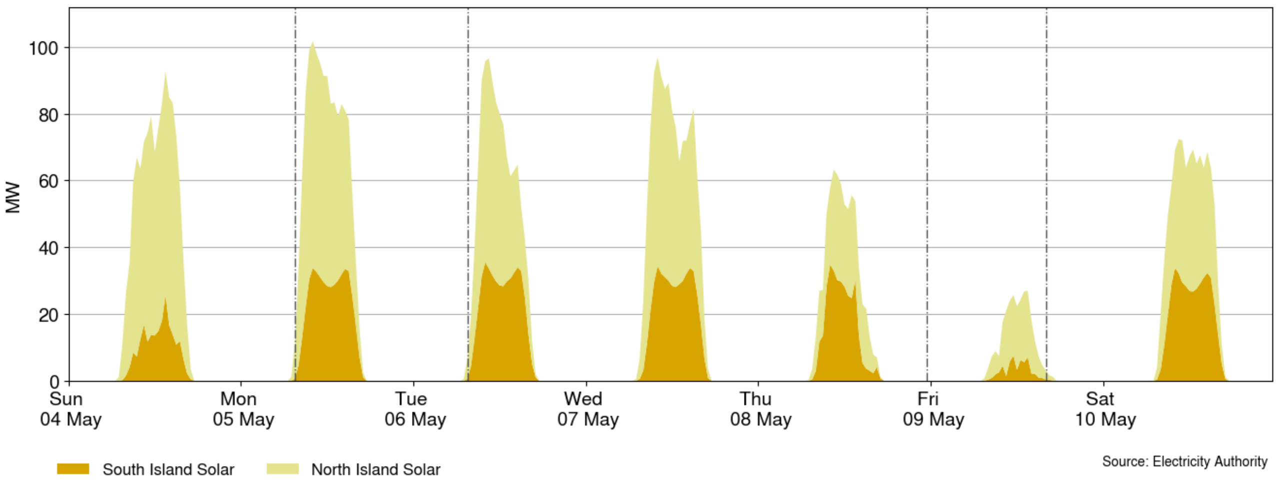
7.1. Figure 9 shows wind generation and forecast from 4-10 May. This week wind generation varied between 4MW and 823MW, with a weekly average of 412MW. Wind generation was very low on Monday but was mostly above 600MW on Wednesday and Thursday. Wind was highly underforecast in the 2-hour ahead window on Tuesday and Wednesday.

Figure 9: Wind generation and forecast, 4-10 May



7.2. Figure 10 shows grid connected solar generation from 4-10 May. Solar generation was mostly above 60MW this week but very low on Friday.

Figure 10: Grid connected solar generation, 4-10 May



7.3. 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.

---

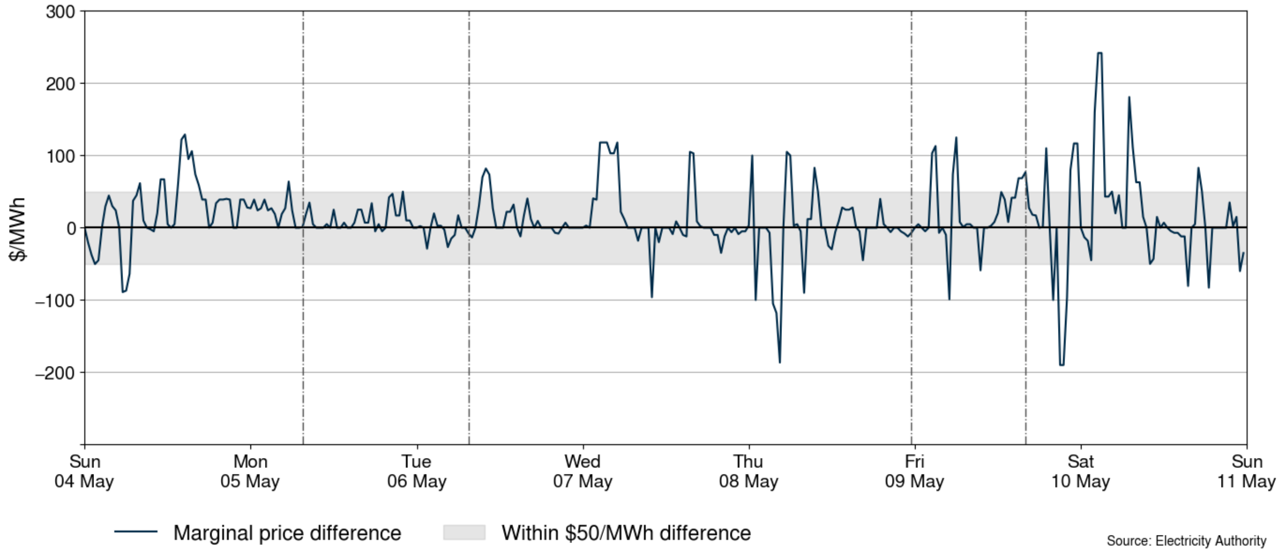
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

7.4. Marginal price differences were often outside the ±$50/MWh band this week due to frequent demand and wind forecasting inaccuracies.

7.5. The largest positive marginal price difference was +$242/MWh at 2.30am on Saturday. Demand was 27MW higher than forecast and wind was 41MW lower than forecast at gate closure, creating a collective 68MW difference.

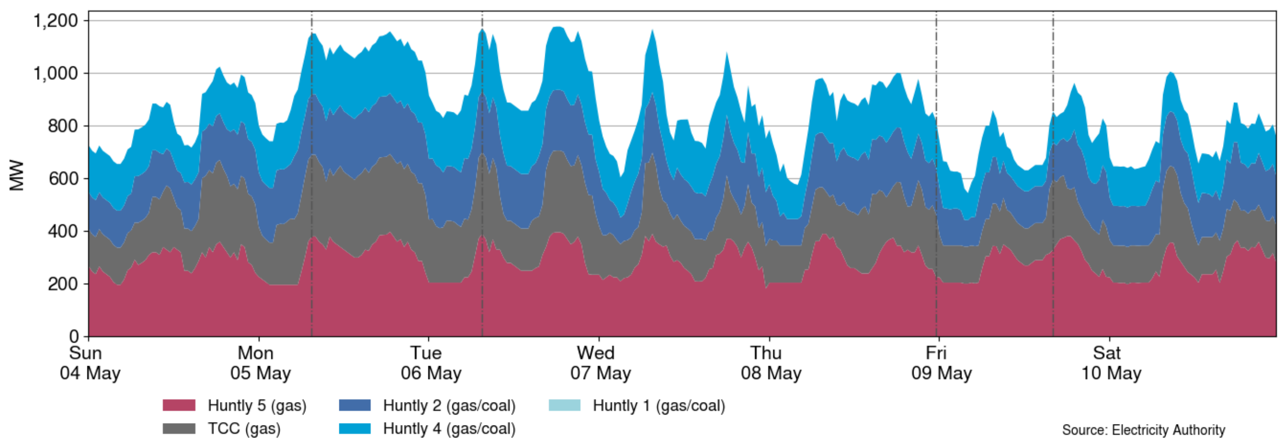
7.6. The largest negative marginal price difference was -$190/MWh at 9.00pm on Friday. Wind was 194MW higher than forecast at gate closure during this trading period.

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, 4-10 May



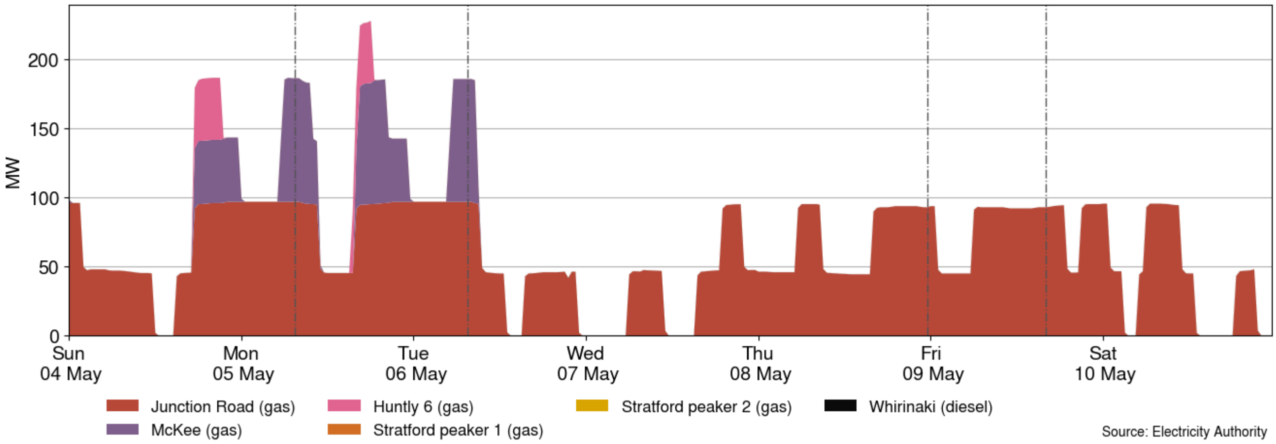
7.7. Figure 12 shows the generation of thermal baseload between 4-10 May. Huntly 5, TCC, Huntly 2 and Huntly 4 generated baseload this week.

Figure 12: Thermal baseload generation, 4-10 May



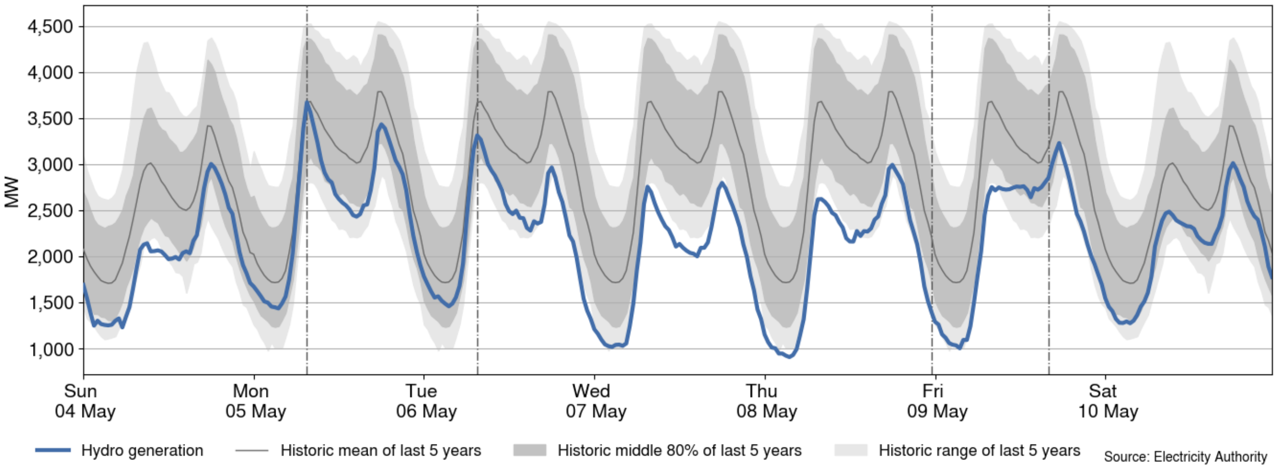
7.8. Figure 13 shows the generation of thermal peaker plants between 4-10 May. Junction Road generated every day this week. McKee and Huntly 6 generated on Monday and Tuesday when demand was higher and wind was lower.

Figure 13: Thermal peaker generation, 4-10 May



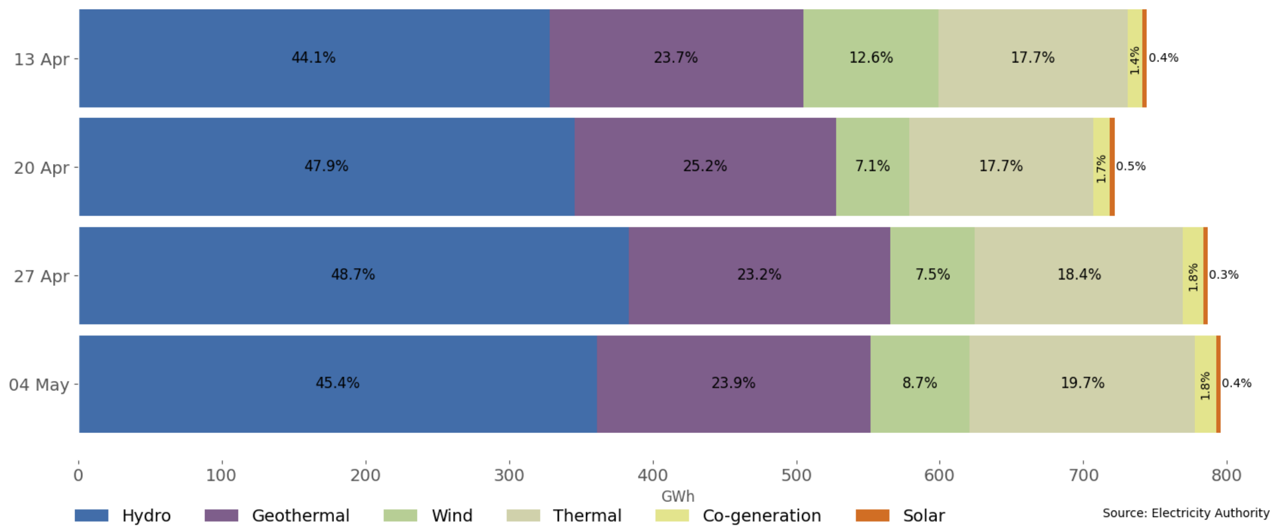
7.9. Figure 14 shows hydro generation between 4-10 May. Hydro generation was mostly below the historic 10th percentile this week, but higher on Monday and Tuesday when demand was higher and wind was lower.

Figure 14: Hydro generation, 4-10 May



7.10. As a percentage of total generation, between 4-10 May, total weekly hydro generation was 45.4%, geothermal 23.9%, wind 8.7%, thermal 19.7%, co-generation 1.8%, and solar (grid connected) 0.4%, as shown in Figure 15. This week, hydro generation decreased while wind and thermal generation increased.

Figure 15: Total generation by type as a percentage each week, between 13 April and 10 May 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 4-10 May ranged between ~1,042MW and ~1,905MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

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

(c) Manapōuri units 1, 2 and 0 were on outage 7, 8 and 10 May, respectively. The unit 2 outage was unplanned.

(d) Rangipō went on a short notice outage 9-10 May.

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

(f) Clyde units 2 and 4 were on outage 10 May. Unit 4 was also on outage 9 May.

(g) Stratford peaker 1 is on outage until 30 June.

Figure 16: Total MW loss from generation outages, 4-10 May

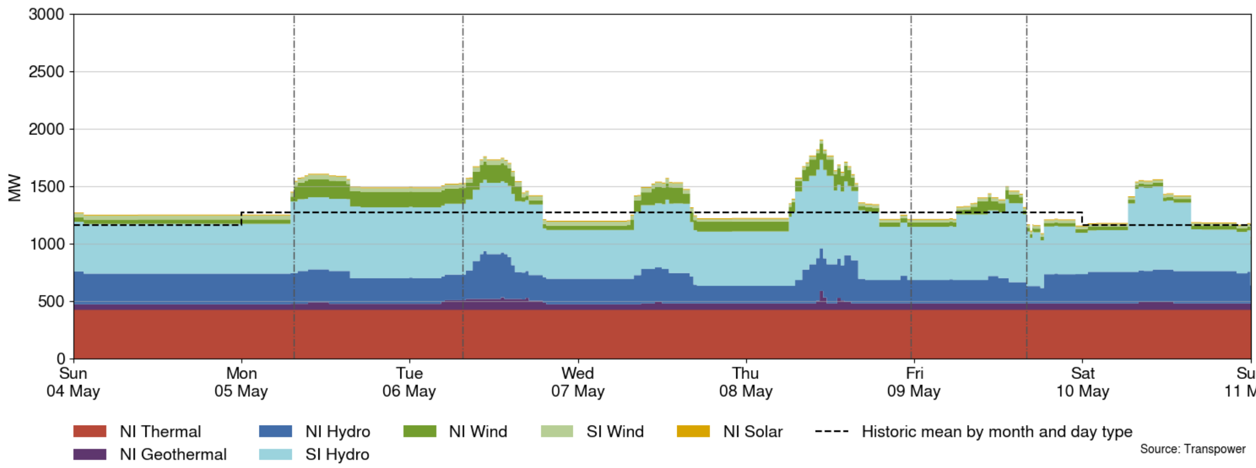
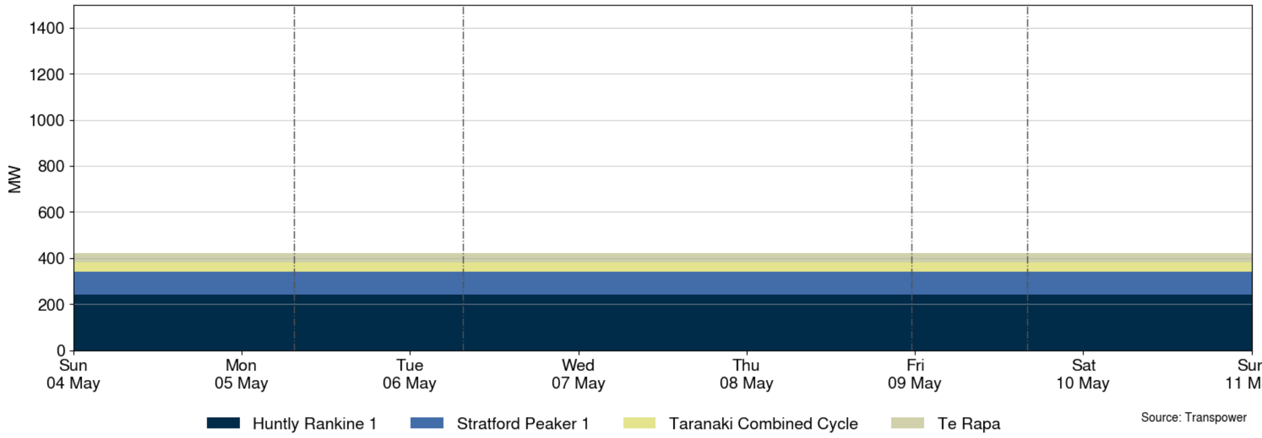


Figure 17: Total MW loss from thermal outages, 4-10 May

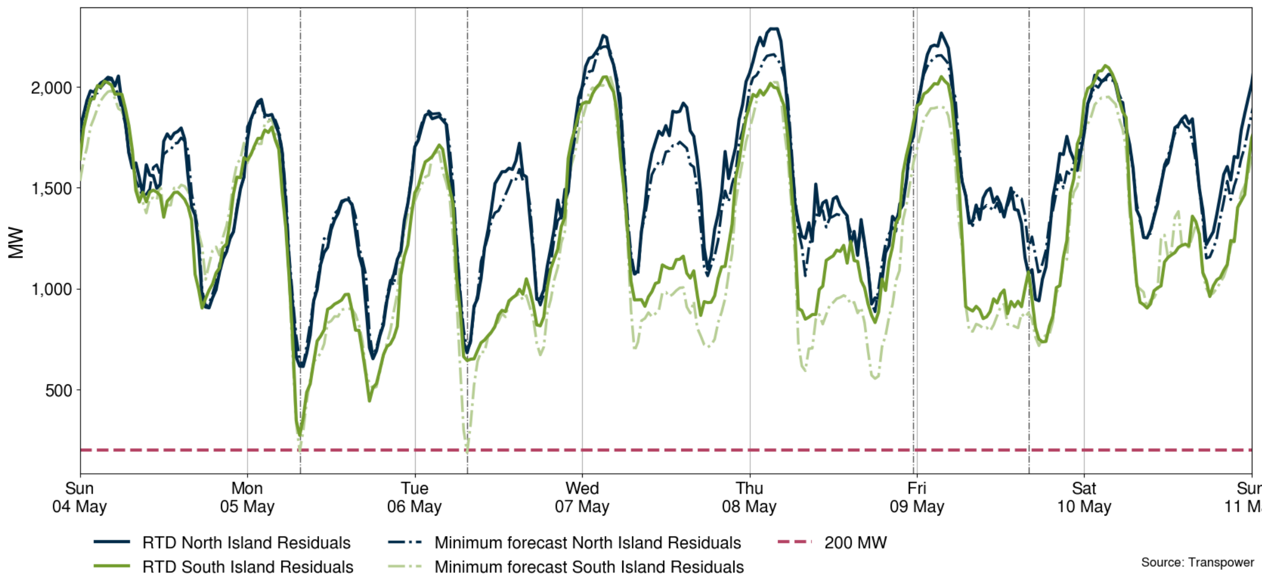


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 4-10 May. 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. Dashed lines represents the forecast residuals and the solid lines represents the real-time dispatch (RTD) residuals.

9.2. South Island residuals were consistently below North Island residuals this week, reaching as low as 274MW at 7.30am on Monday. South Island residuals were forecast to drop to 189MW at 7.30am on Tuesday, but this did not occur in RTD.

Figure 18: National generation balance residuals, 4-10 May



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 hydro storage increased sharply this week to 66% nominally full and ~87% of the historical average for this time of the year.

10.3. Storage at lakes Pūkaki (65% full)[2] and Takapō (57% full) remained around their historical 10th percentiles.

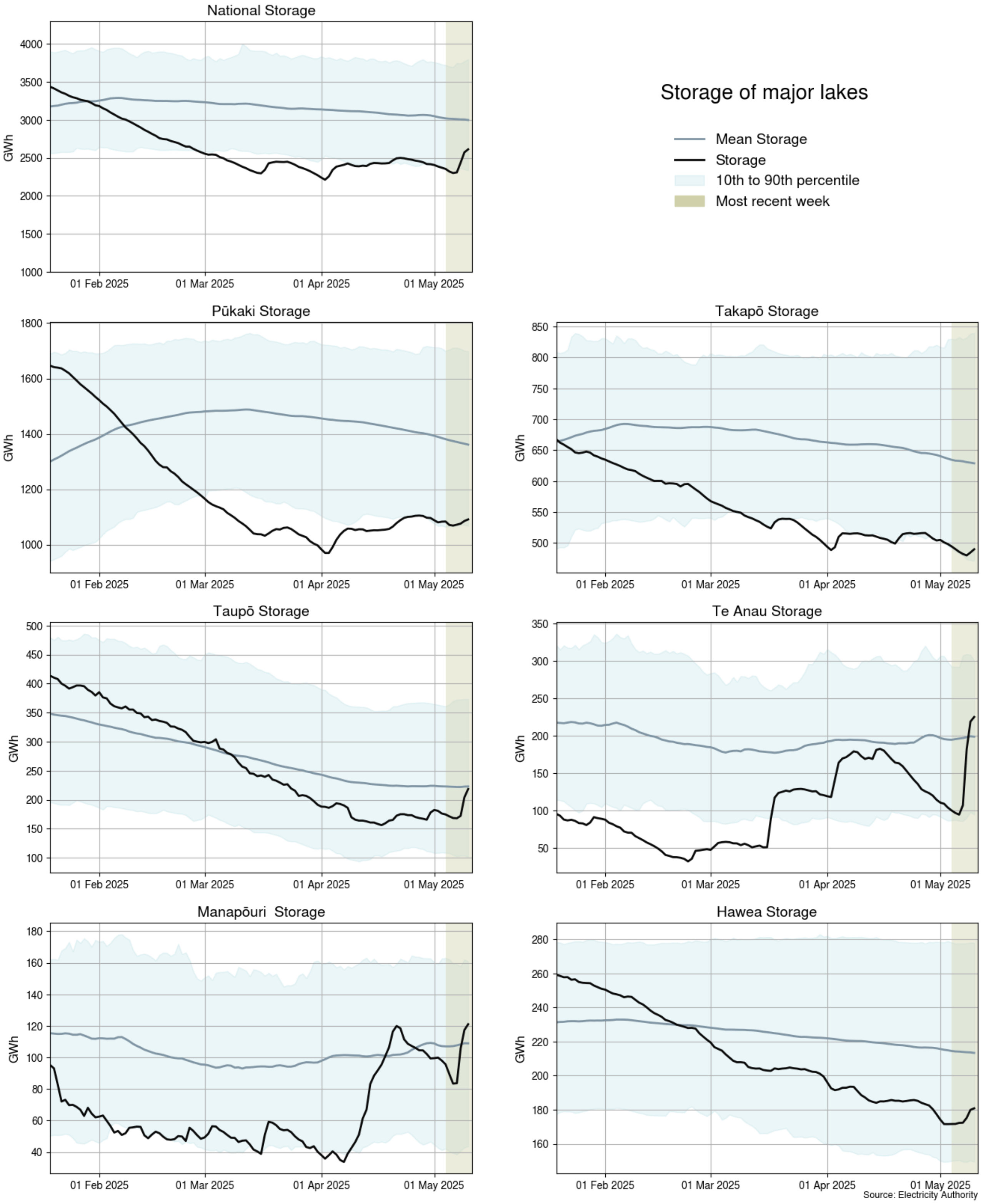
10.4. Lakes Te Anau and Manapōuri increased to above their historic means.

10.5. Storage at Lake Taupō (39% full) increased to around its historic mean.

10.6. Lake Hawea (64% full) increased to between its historical 10th percentile and mean.

[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 May 2025. The SRMCs for gas powered generation have increased slightly while coal and diesel fuelled generation decreased. As was the case last month, it is likely cheaper to run the Rankines on coal.

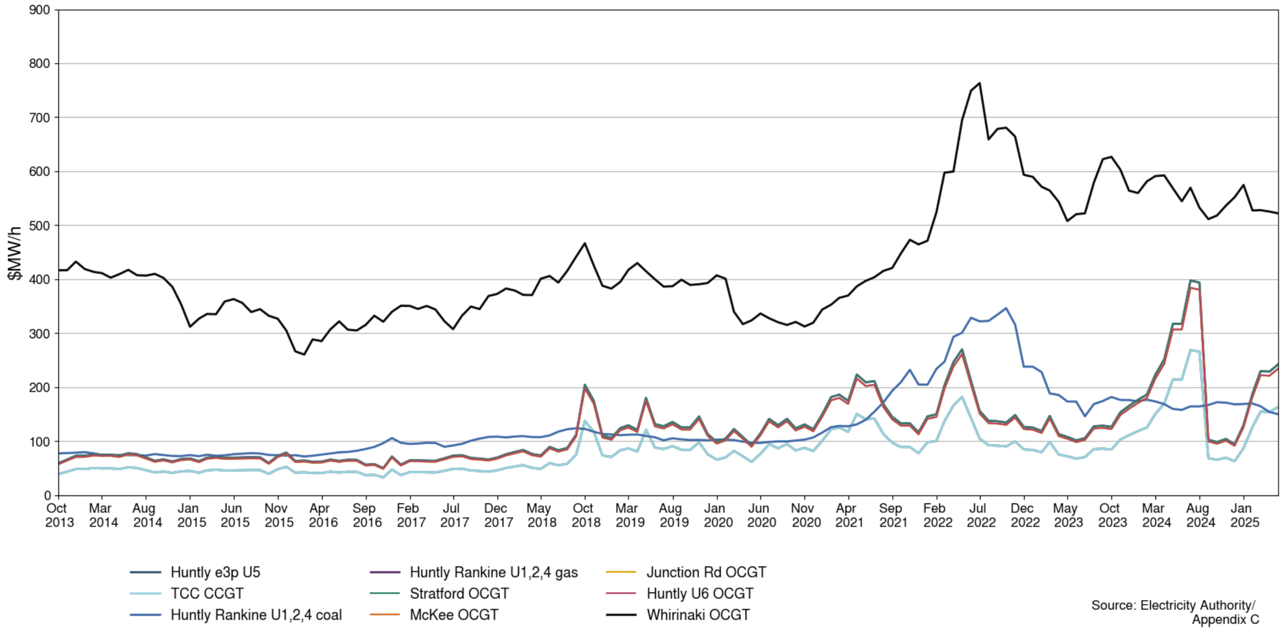
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$242/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $163/MWh and $242/MWh.

11.6. The SRMC of Whirinaki is ~$522/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

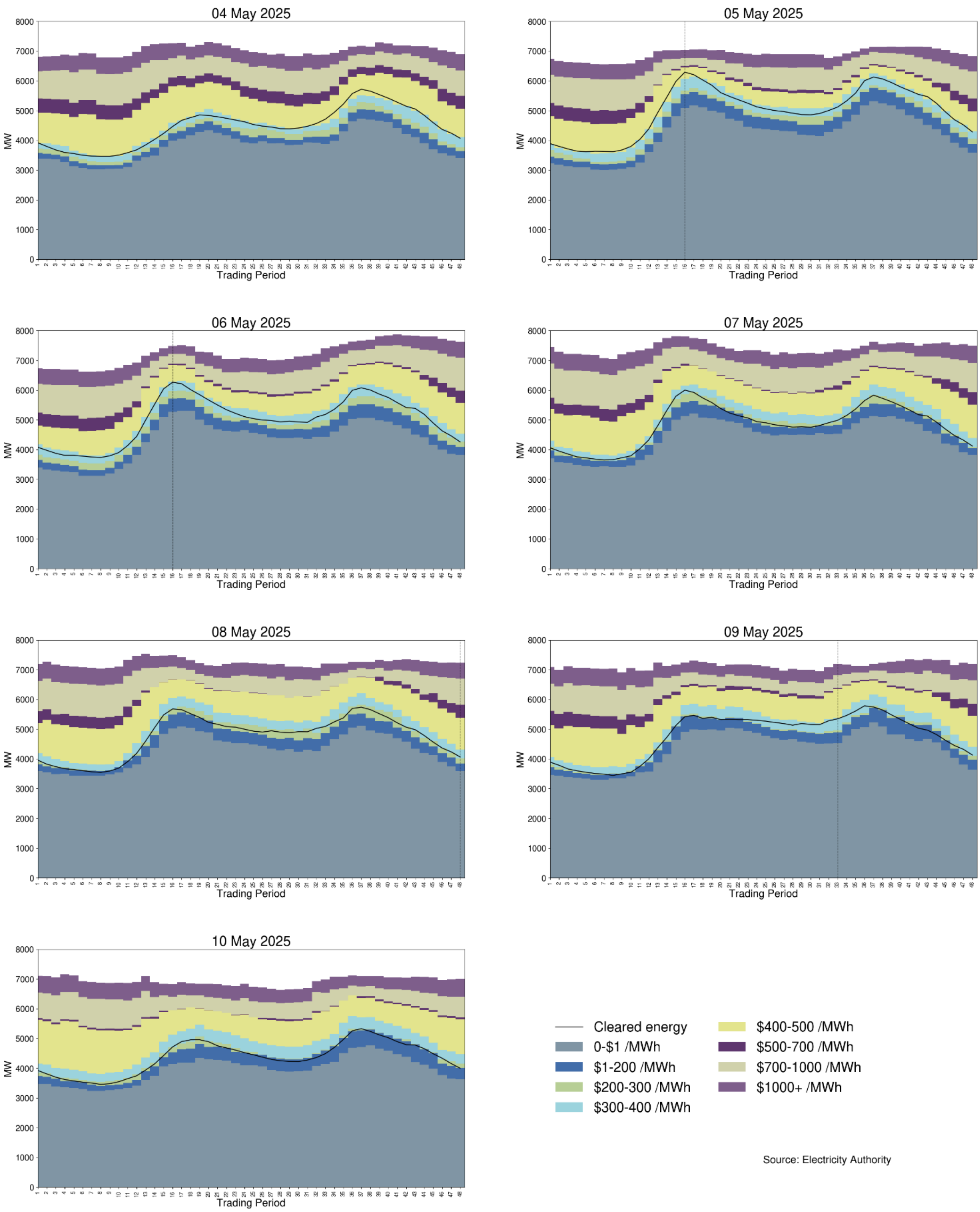


12. Offer behaviour

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.

12.2. Offers were generally clearing in the $200-$500/MWh region this week.

Figure 21: Daily offer stacks



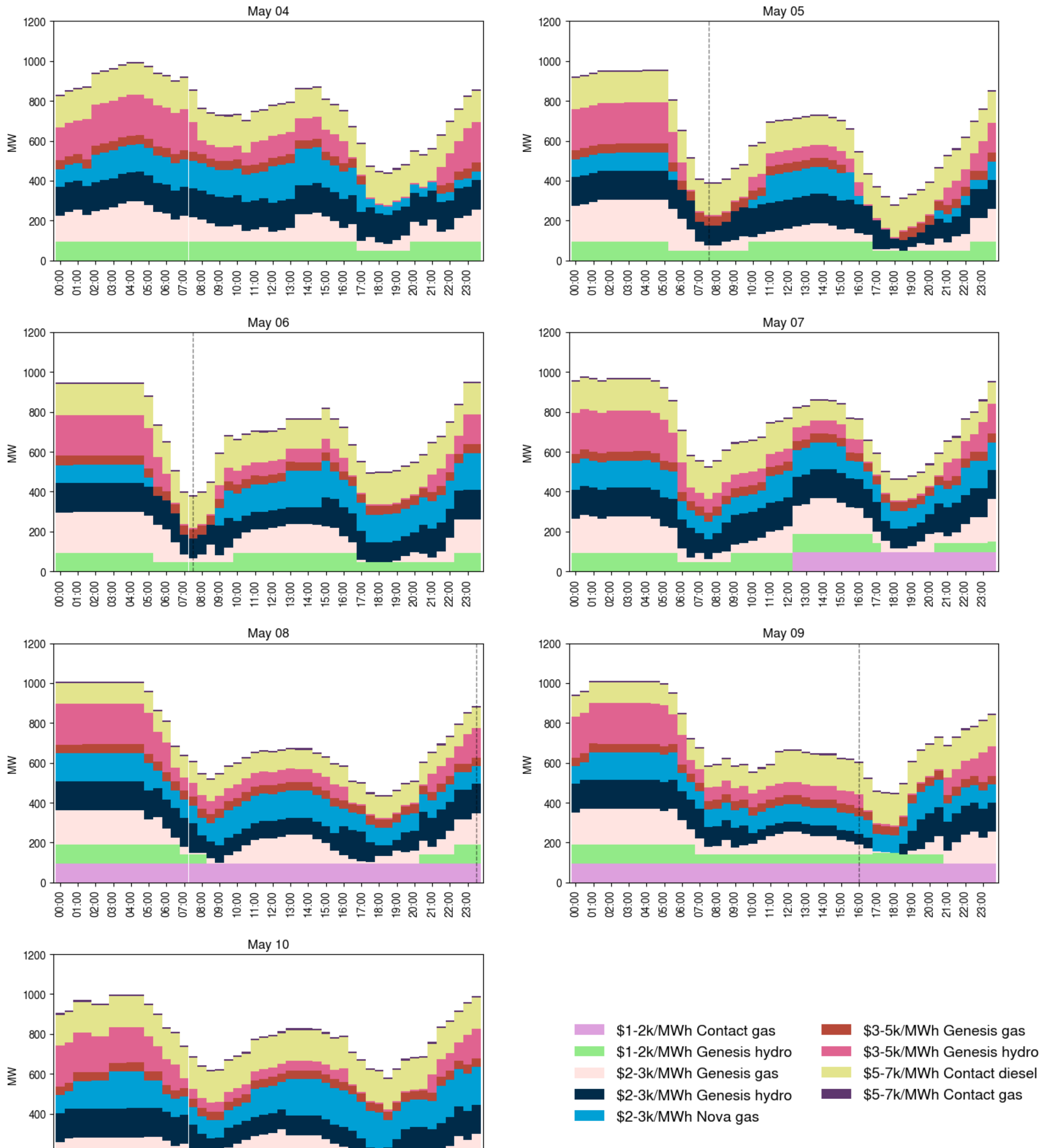
12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.4. 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.

12.5. On average 735MW per trading period was priced above $1,000/MWh this week, which is roughly 11.9% of the total energy available. This is 1.4% higher than the previous week.

12.6. Contact priced a portion of Stratford Peaker generation higher from Wednesday this week.

Figure 22: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions, however, the monitoring team will be looking further into the high prices in Hawkes Bay.

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
1/03/2025-26/04/2025	Several	Further analysis	Genesis	Takapō	Hydro offer pricing
27/04/2025-3/05/2025	Several	Further analysis	Nova	McKee	Offer pricing
7/05/2025-8/05/2025	Several	Further analysis	N/A	Fernhill	Wholesale price