8 December 2025

Trading conduct report
30 November-6 December 2025

Market monitoring weekly report

Trading conduct report 30 November-6 December 2025

1. Overview

1.1. This week the average spot price decreased by $40/MWh to $7/MWh. The proportion of geothermal and wind generation rose this week, while the proportion of hydro generation fell below 70%. HVDC flows were mostly northward throughout the week. National hydro storage stayed steady at 102% nominally full and 146% of the historical average. However, this includes storage at Manapōuri, Te Anau, Takapō and Pūkaki which is expected to spill.

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 November-6 December:

(a) The average spot price for the week was $7/MWh, a decrease of around $40/MWh compared to the previous week.

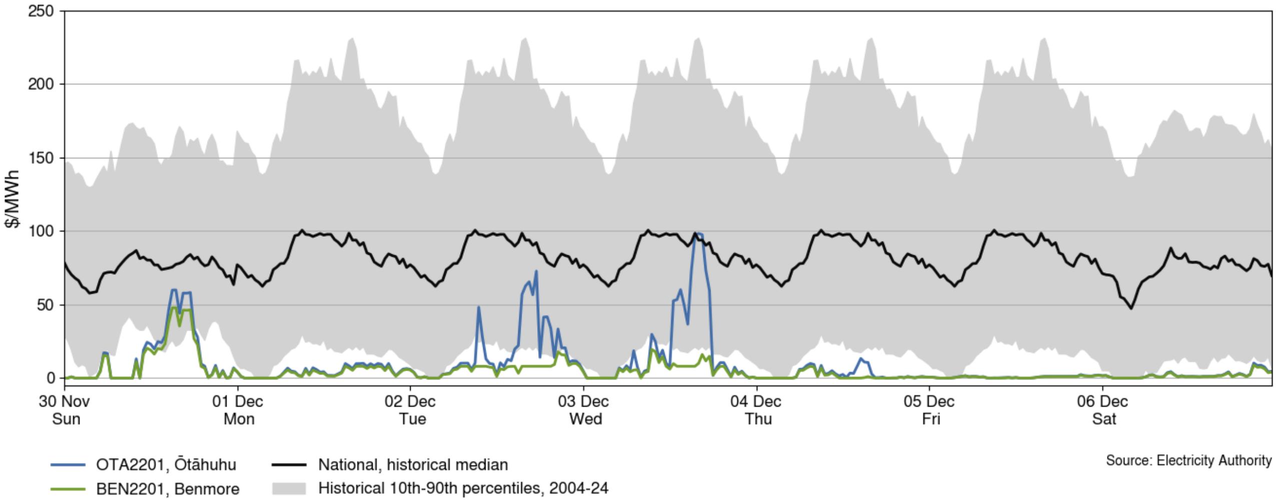
(b) 95% of prices fell between $0.01/MWh and $53/MWh.

2.3. This week, prices remained mostly below $50/MWh at Ōtāhuhu and below $25/MWh at Benmore. Prices were higher on Sunday when demand was higher than forecast, while prices were very low on Friday and Saturday. Some price separation was observed on Tuesday and Wednesday during periods of high northward HVDC flow, at times approaching $90/MWh in the North Island.

2.4. The highest price of the week at Ōtāhuhu occurred on Wednesday at 4.00pm, reaching $98/MWh. Demand was 106MW higher than forecast at this time and the HVDC was near its northward capacity.

2.5. 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.

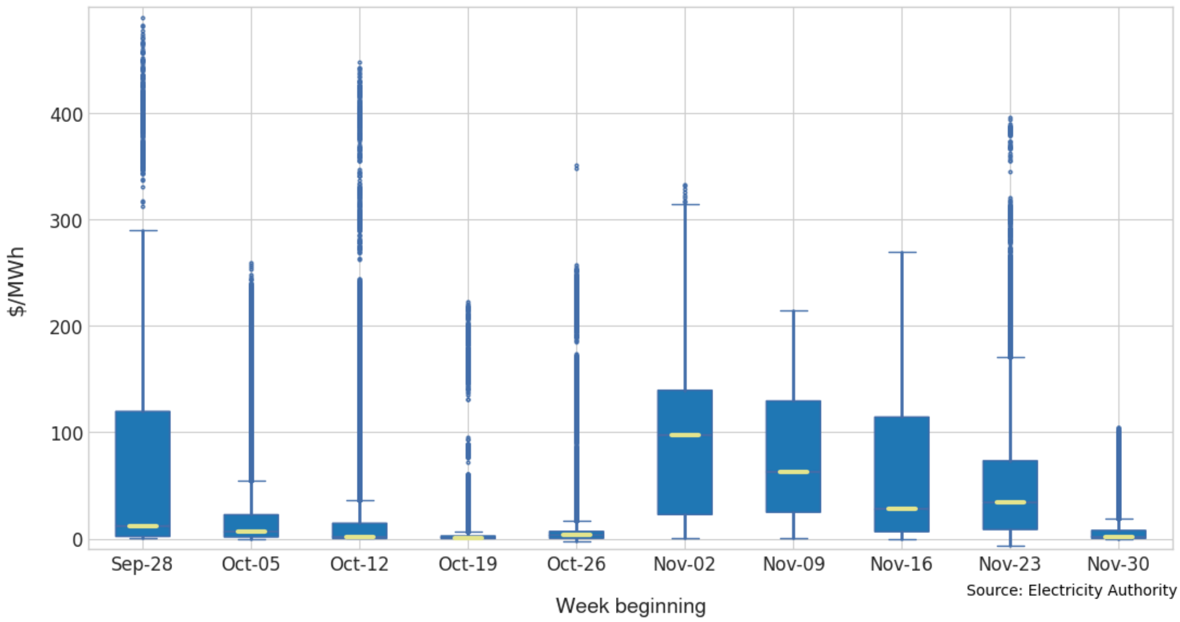
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 30 November-6 December



2.6. 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.

2.7. The distribution of spot prices this week was skewed lower and was less volatile compared to last week. The median price was $2/MWh and most prices (middle 50%) fell between $0.20/MWh and $8/MWh.

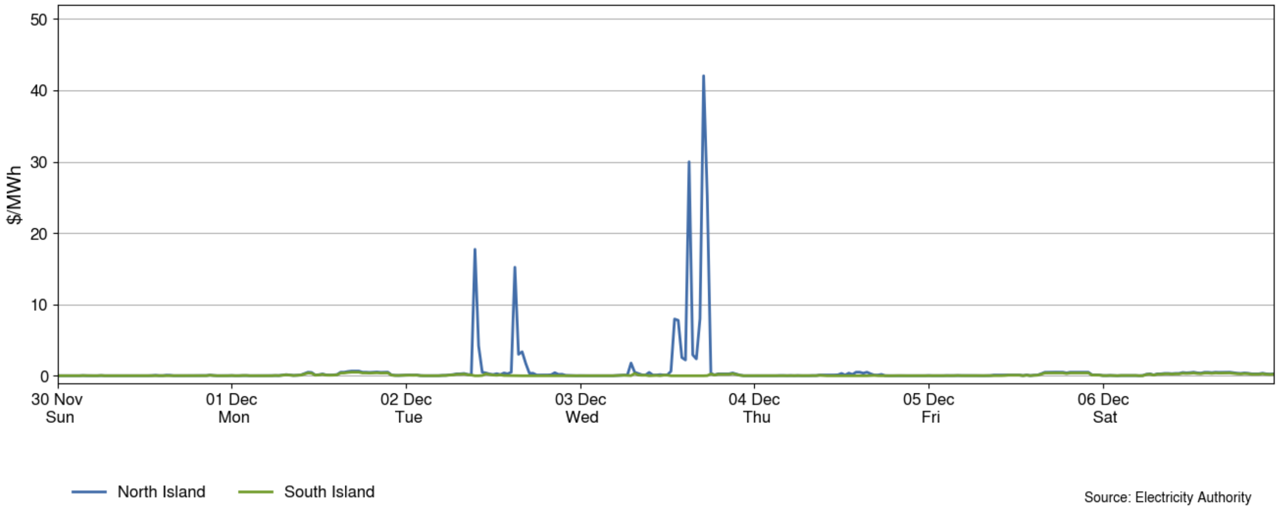
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

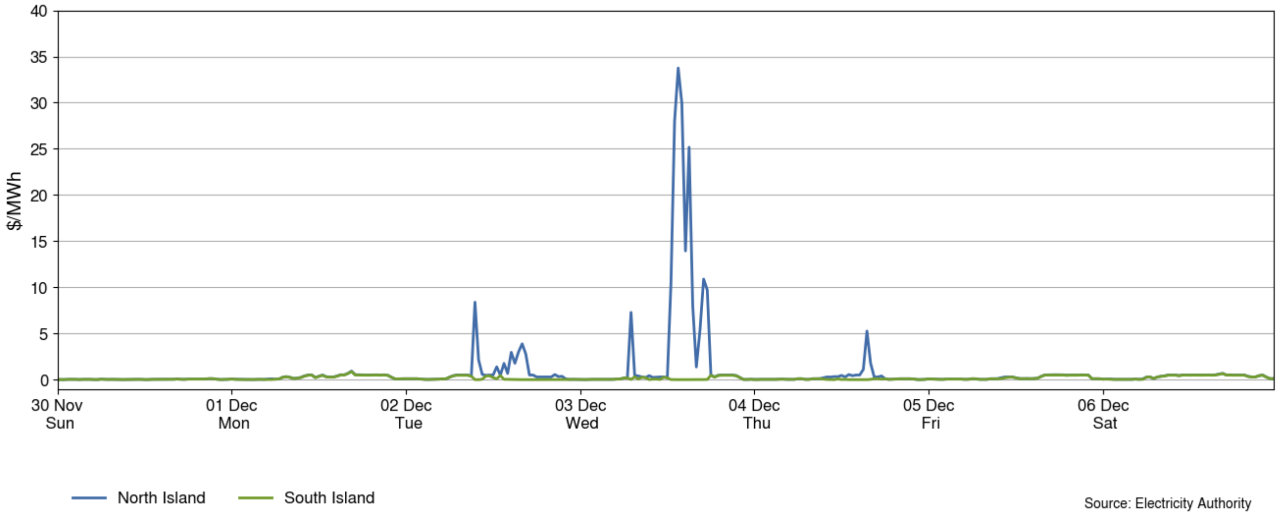
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $20/MWh, except for three price spikes on Wednesday at 3.00pm, 5.00pm and 5.30pm in the North Island. At 3.00pm and 5.00pm, a group of Manawatū wind farms were setting the North Island risk. At 5.30pm, the HVDC was setting the North Island risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 30 November-6 December



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $20/MWh, except for four North Island price spikes on Wednesday at 1.00pm, 1.30pm, 2.00pm, and 3.00pm. From 1.00pm-2.00pm, the HVDC was setting the North Island risk, while the group of Manawatū wind farms were the risk setters at 3.00pm.

Figure 4: Sustained instantaneous reserve by trading period and island, 30 November-6 December



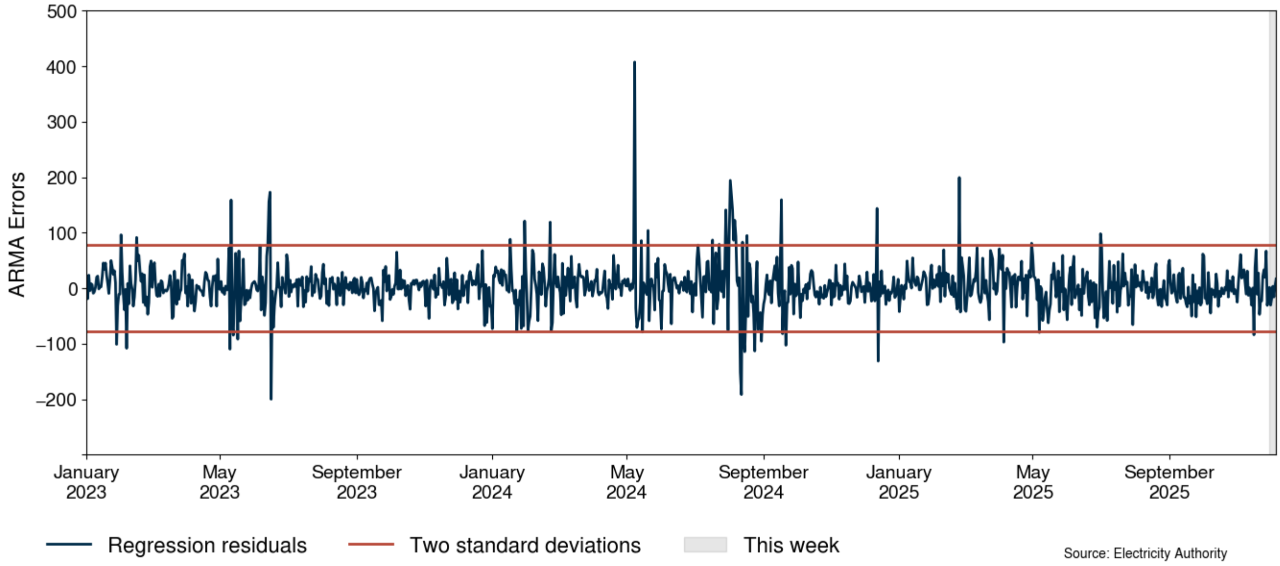
4. Regression residuals

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 - 6 December 2025

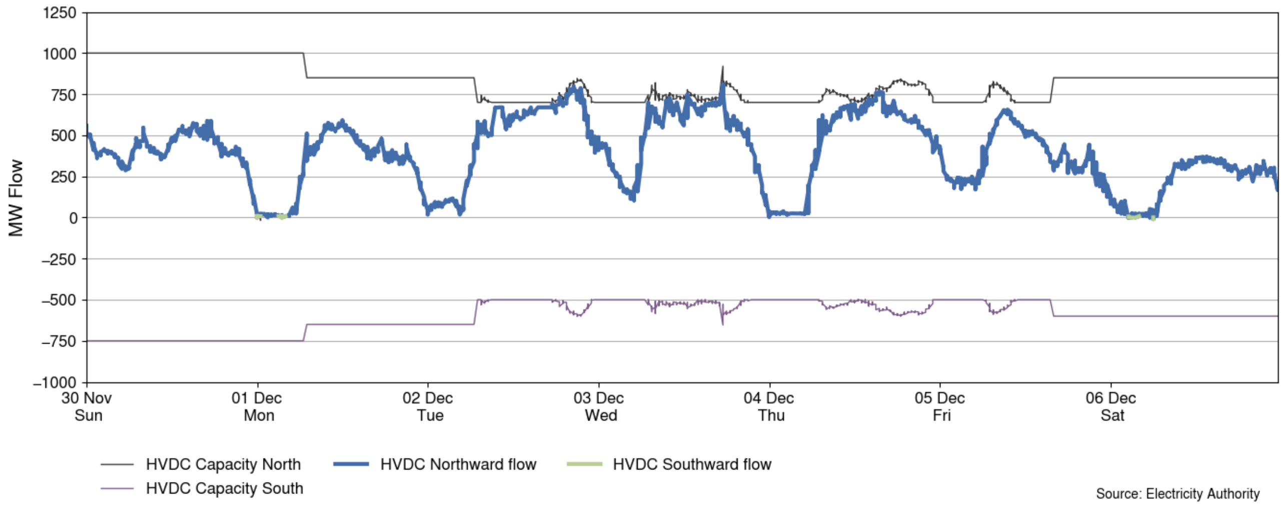


5. HVDC

5.1. Figure 6 shows the HVDC flow between 30 November-6 December. HVDC flows were mostly northward this week, due to high hydro generation in the South Island.

5.2. The highest northward flow occurred at 5.30pm on Wednesday with a flow of around 920MW. HVDC northward flows were close to their capacity limits at times between Tuesday and Thursday.

Figure 6: HVDC flow and capacity, 30 November-6 December

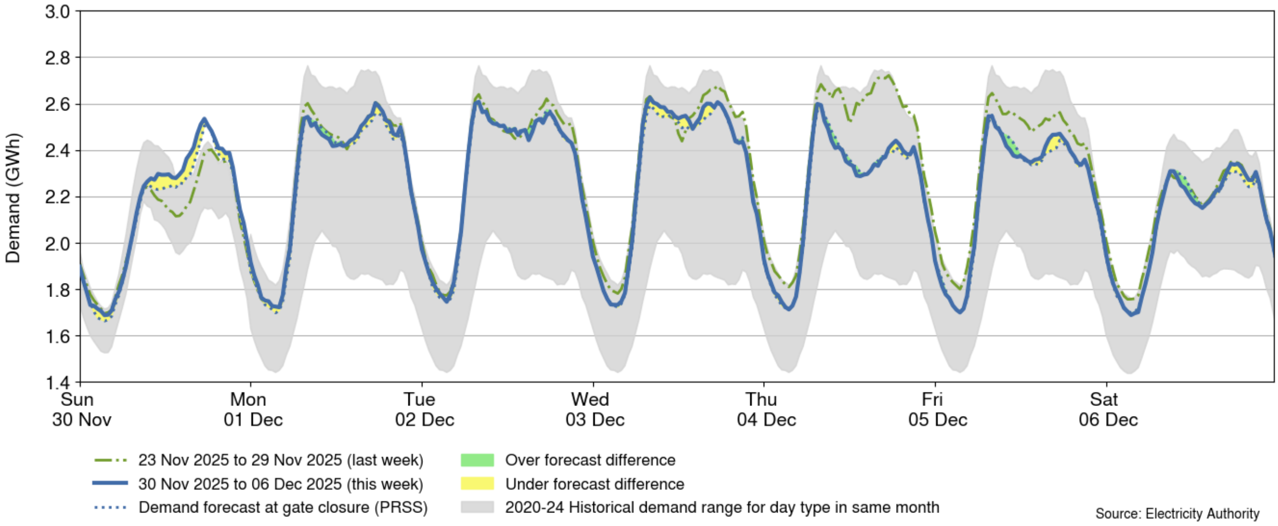


6. Demand

6.1. Figure 7 shows national demand between 30 November-6 December, compared to the historic range and the demand of the previous week.

6.2. On Sunday, demand was higher than forecast throughout the day, likely due to warm temperatures. On Thursday and Friday, demand was lower than the previous week. The highest demand of the week was around 2.63GWh at 8.00am on Wednesday.

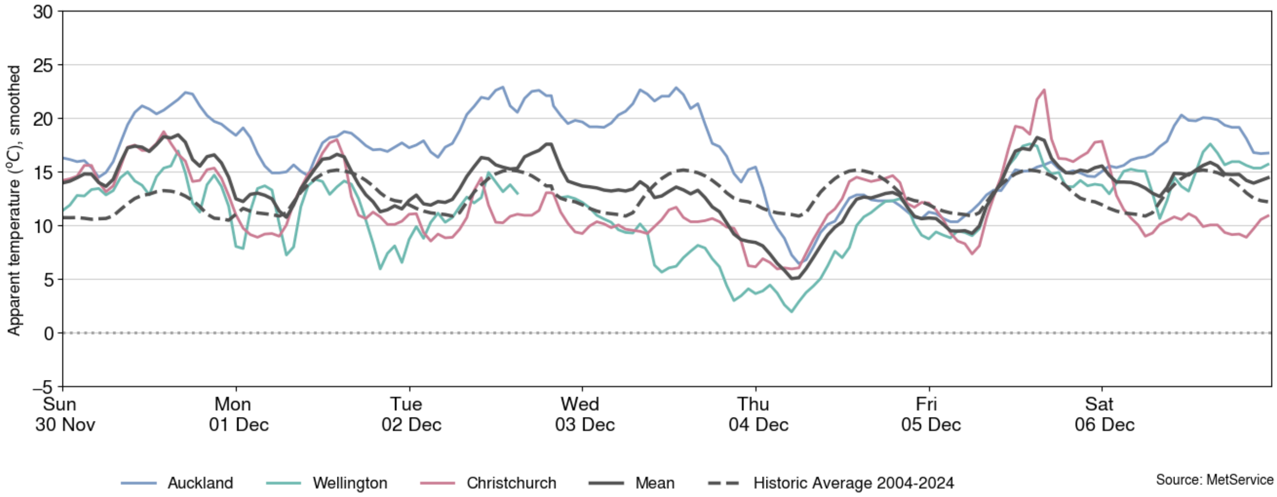
Figure 7: National demand, 30 November-6 December compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 30 November-6 December. 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 ranged from 6°C to 24°C in Auckland, 2°C to 18°C in Wellington, and 5°C to 25°C in Christchurch. Note that temperature data is missing for Wellington between 3.00pm and 8.00pm on 2 December.

Figure 8: Temperatures across main centres, 30 November-6 December

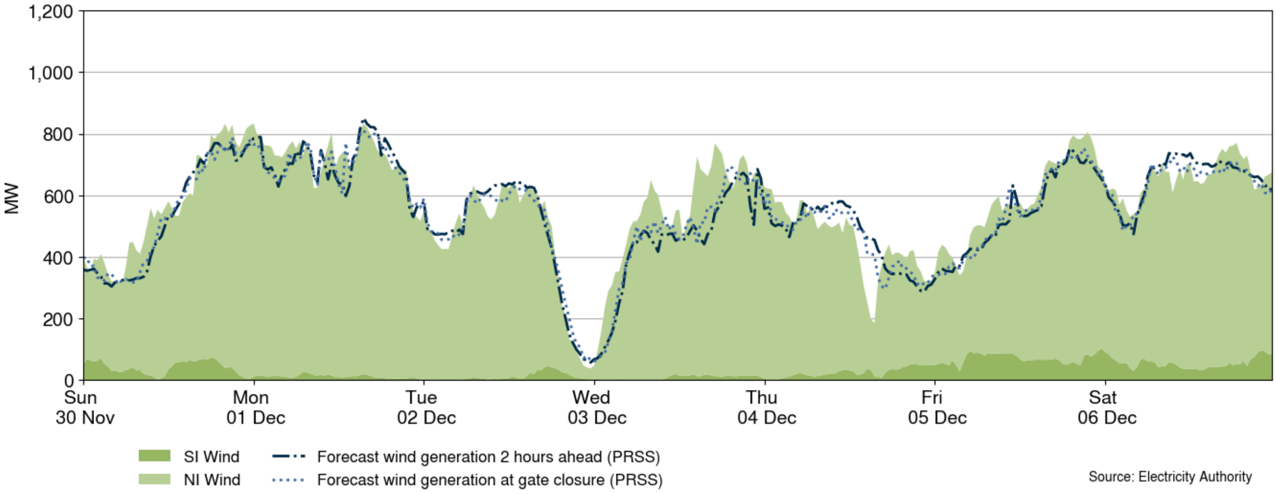


7. Generation

7.1. Figure 9 shows wind generation and forecasts from 30 November-6 December. This week wind generation varied between 38MW and 833MW, with a weekly average of 571MW.

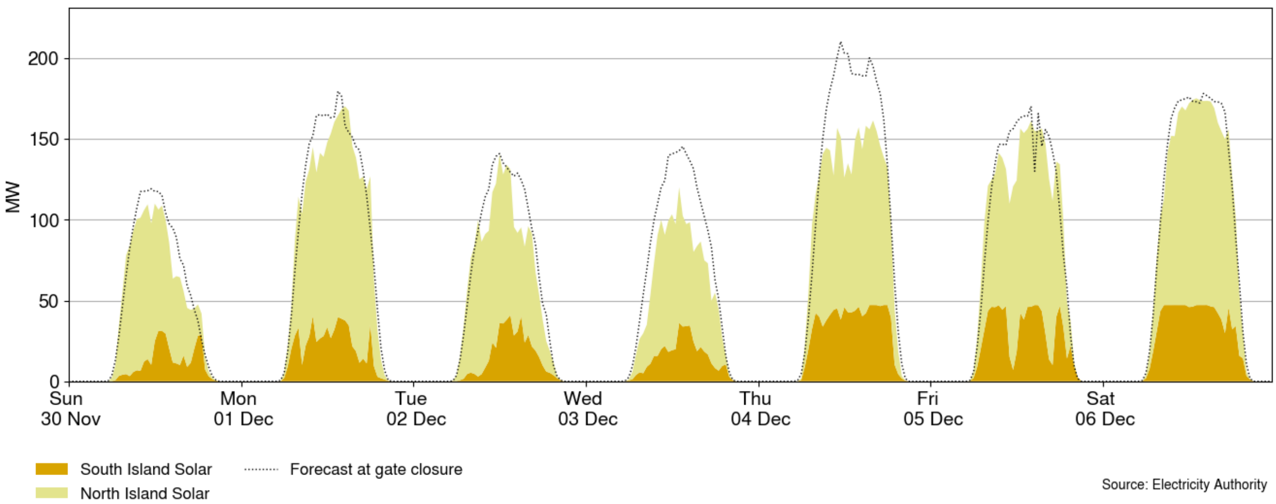
Wind generation increased above 700MW on Sunday, remaining relatively high through the week aside from drops on Tuesday and Thursday.

Figure 9: Wind generation and forecast, 30 November-6 December



7.2. Figure 10 shows grid connected solar generation from 30 November-6 December. Solar generation reached above 100MW every day, peaking on Sunday at 1.00pm at around 175MW. On Thursday there were large forecasting errors at Twin Rivers Solar Farm. The monitoring team is looking further into these errors.

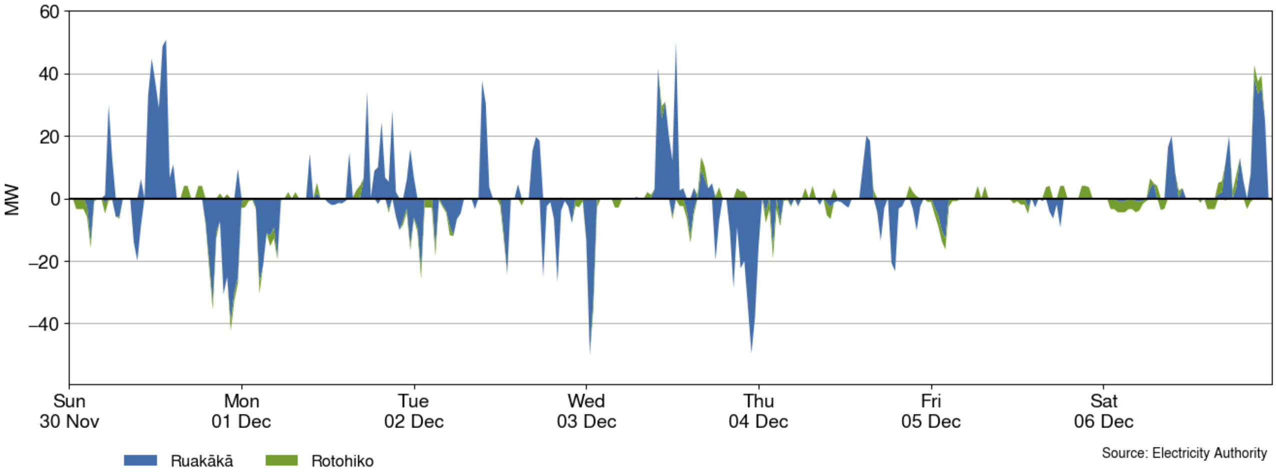
Figure 10: Grid connected solar generation, 30 November-6 December



7.3. Figure 11 shows when the grid scale batteries at Rotohiko (35MW/35MWh) and Ruakākā (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.4. This week, the batteries charged mostly during times of low overnight prices. When prices were high during the daytime, such as on Sunday, the batteries were mostly discharging. But when prices were low during the day, like on Friday-Saturday, the batteries discharged less.

Figure 11: Grid scale battery charge and discharge, 30 November-6 December



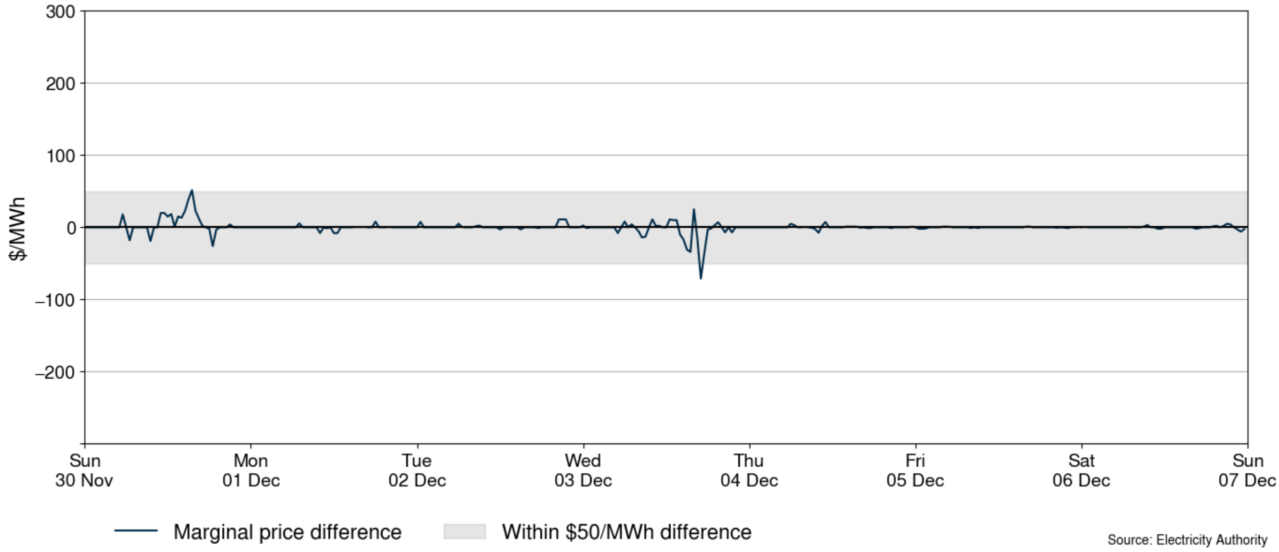
7.5. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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.

7.6. One trading period this week had a positive marginal price difference above $50/MWh. A difference of $52/MWh occurred on Sunday at 3.30pm when demand was 178MW higher than forecast and wind was 50MW lower than forecast.

7.7. The largest negative difference of just over $50/MWh occurred on Wednesday at 2:30pm. During this time wind generation was 282MW higher than forecast.

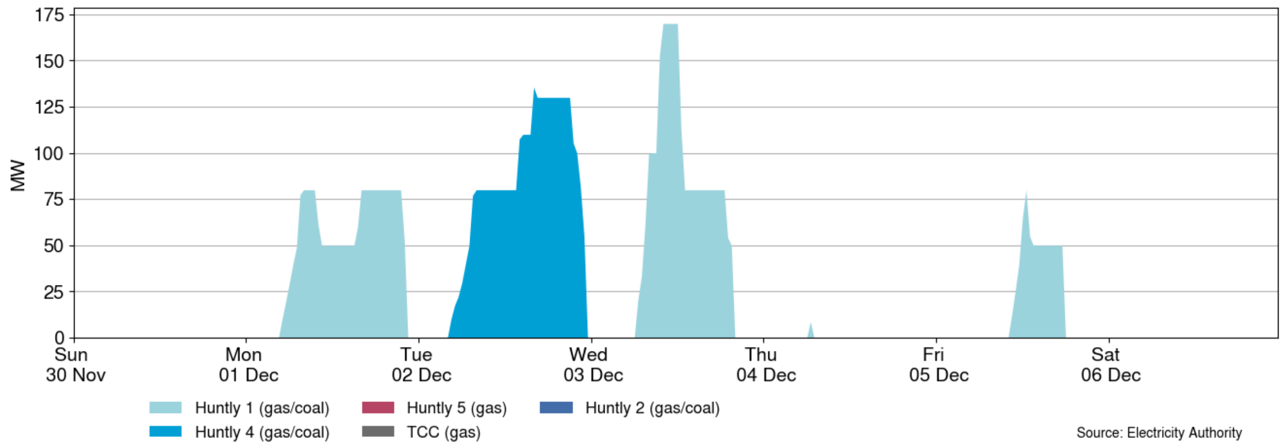
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 30 November-6 December



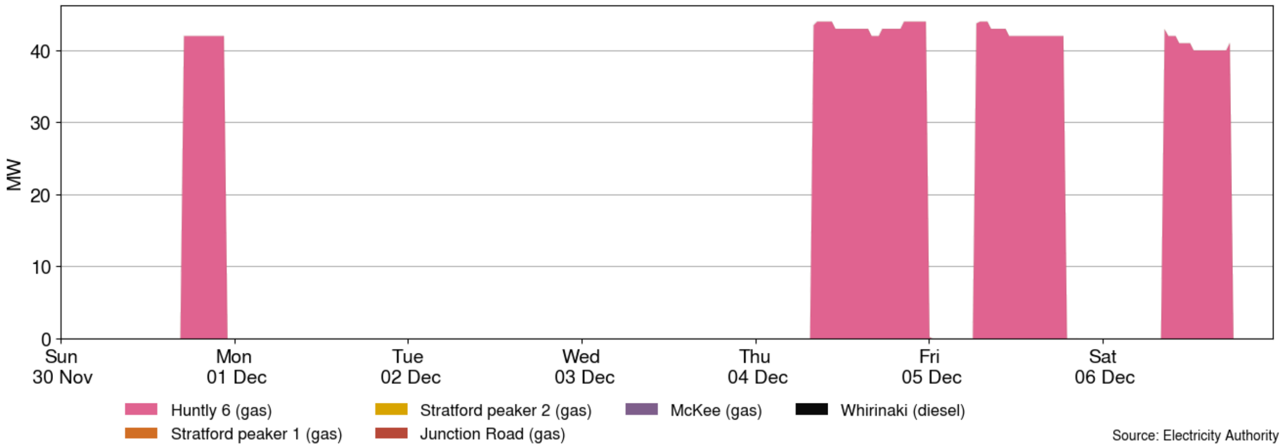
7.8. Figure 13 shows the generation of thermal baseload between 30 November-6 December. Huntly 1 ran on Monday and Wednesday, before tripping off at 6.41am on Thursday. Huntly 4 ran on Tuesday. Huntly 1 then came back online and ran on Friday.

Figure 13: Thermal baseload generation, 30 November-6 December



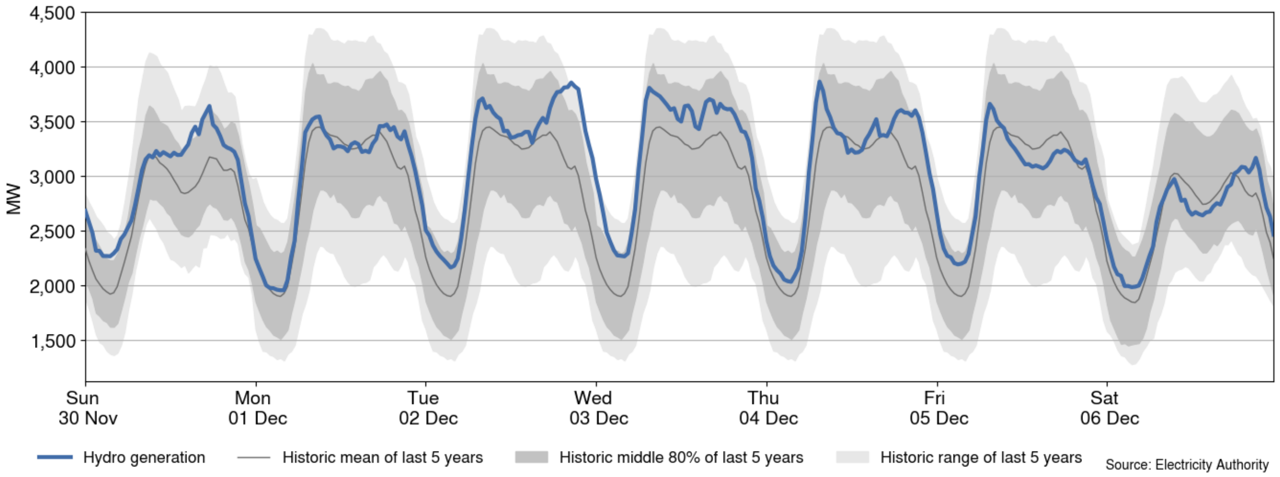
7.9. Figure 14 shows the generation of thermal peaker plants between 30 November-6 December. Huntly 6 ran on Sunday and on Thursday after the Huntly 1 trip. Huntly 6 also ran on Friday and Saturday.

Figure 14: Thermal peaker generation, 30 November-6 December



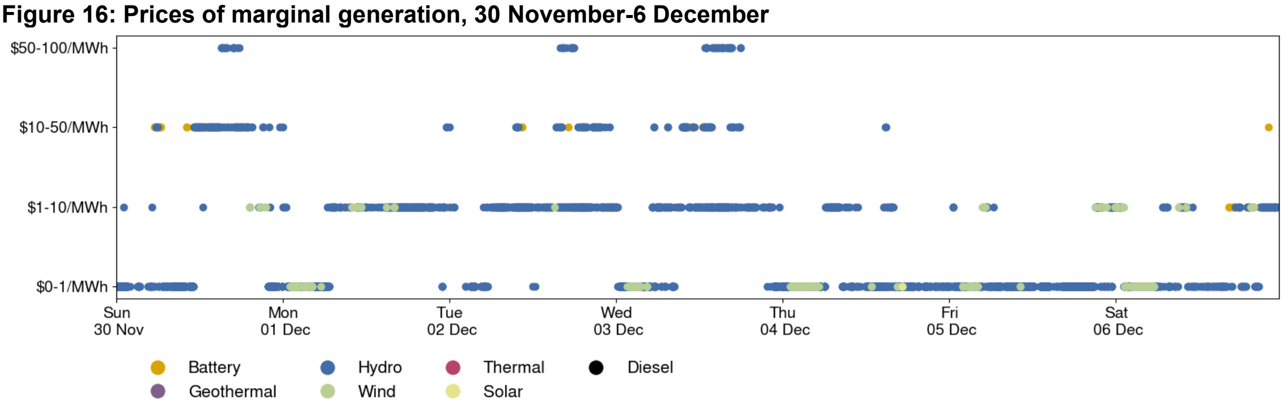
7.10. Figure 15 shows hydro generation between 30 November-6 December. Hydro generation remained mostly within the middle 80% of historic generation. Hydro generation was high on Tuesday evening, likely due to falling wind during the evening peak.

Figure 15: Hydro generation, 30 November-6 December



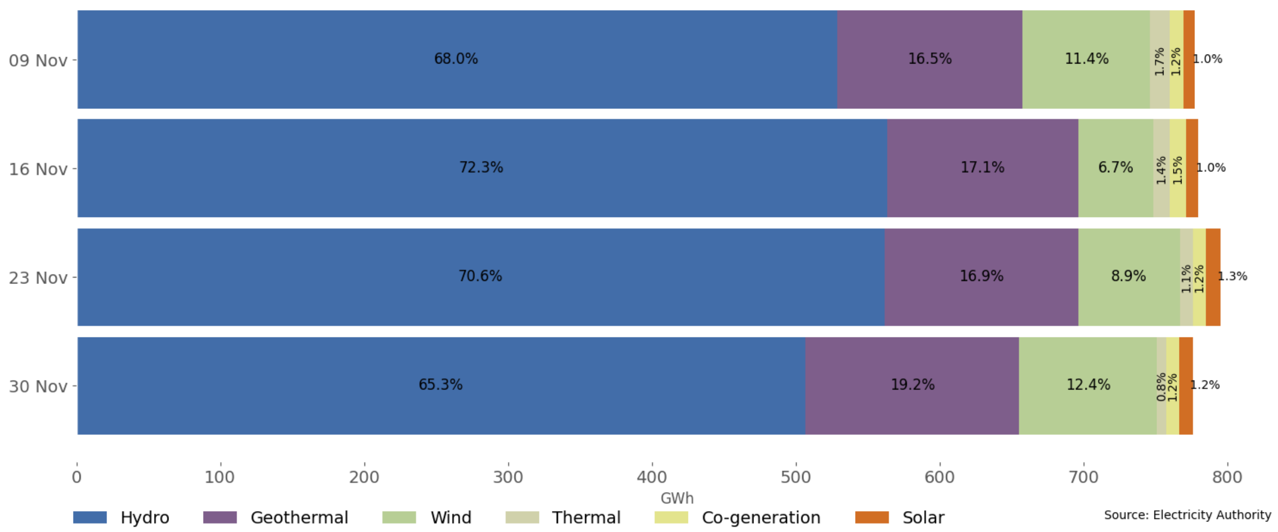
7.11. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period. The highest prices this week were caused by Mercury and Genesis hydro generation on Sunday, Tuesday, and Wednesday. The most common technology setting prices this week was hydro generation. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 30 November-6 December



7.12. As a percentage of total generation, between 30 November-6 December, total weekly hydro generation was 65.3%, geothermal 19.2%, wind 12.4%, thermal 0.8%, co-generation 1.2%, and solar (grid connected) 1.2%, as shown in Figure 17. The increase in geothermal resulted from some geothermal plants returning from outage.

Figure 17: Total generation by type as a percentage each week, between 9 November 2025 and 6 December 2025



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 30 November-6 December ranged between ~2,024MW and ~3,077MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 30 November-6 December

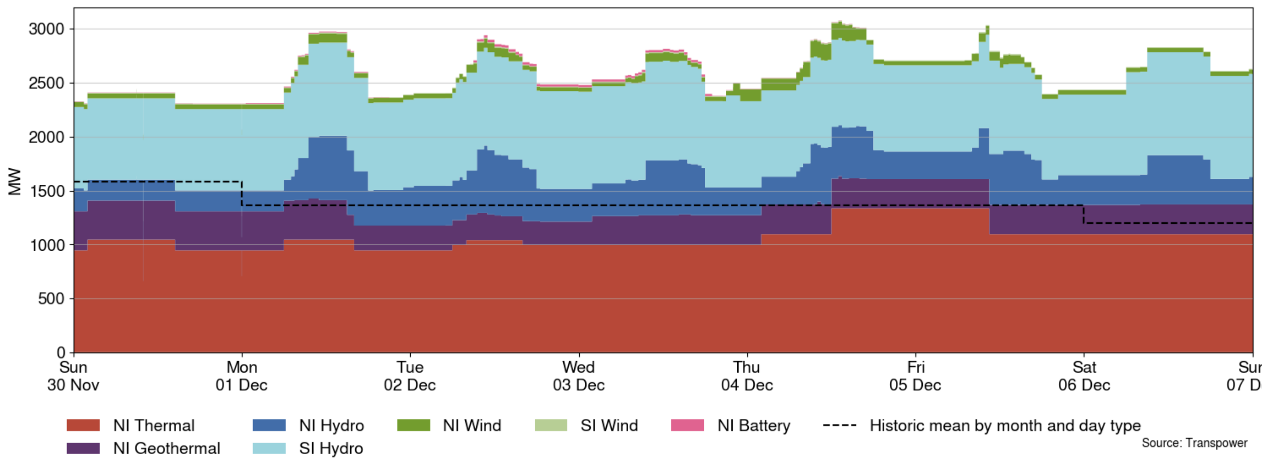
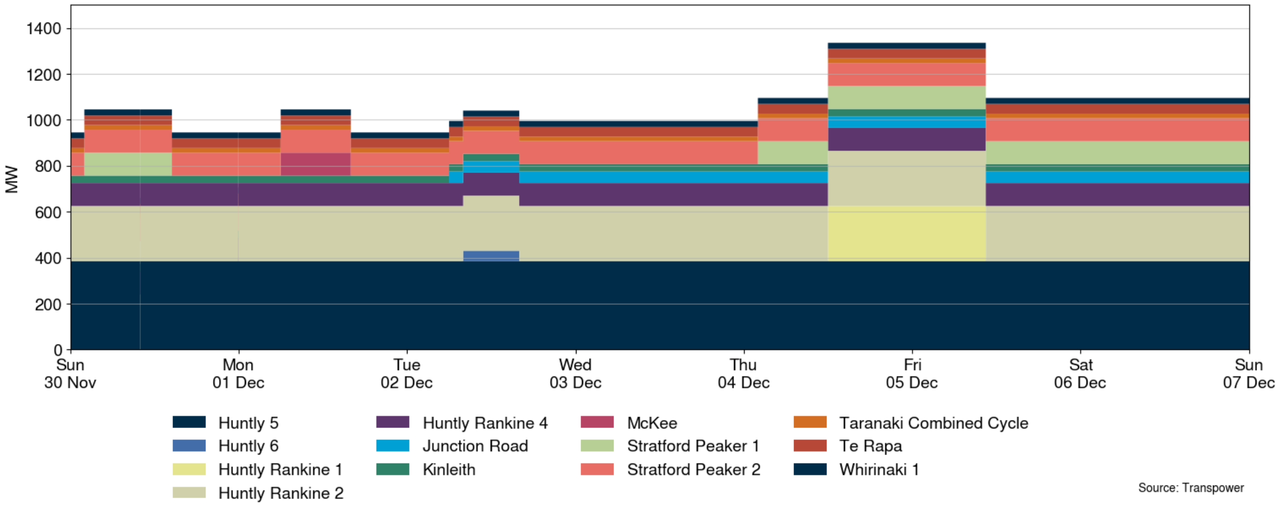


Figure 19: Total MW loss from thermal outages, 30 November-6 December



8.2. Notable outages include:

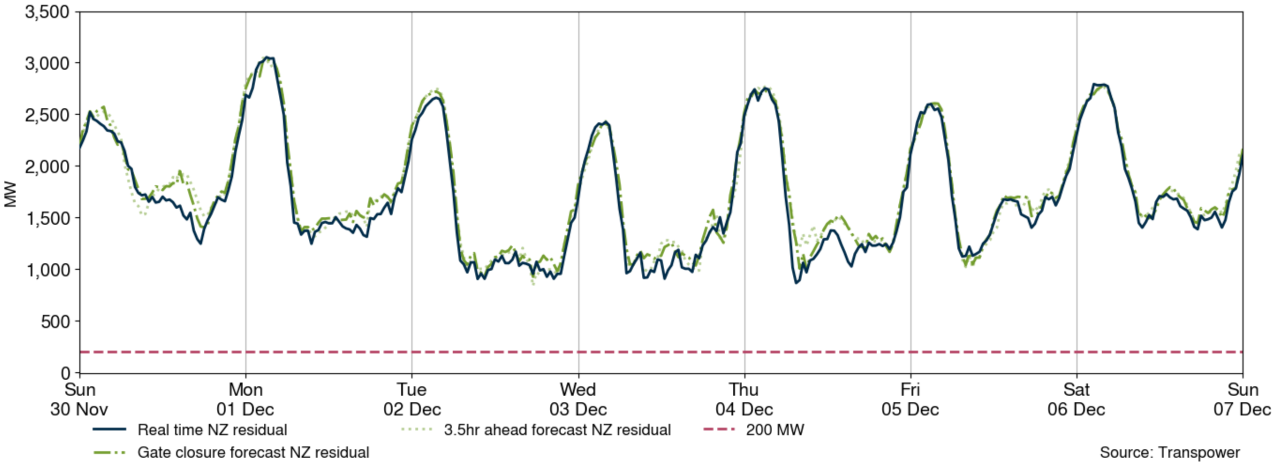
Plant	Partial or Full	End Date
Nga Awa Purua	Full	1 December 2025
Ruakākā battery	Partial	4 December 2025
Stratford Peaker 2	Full	8 December 2025
Huntly 4	Partial	9 December 2025
Benmore unit 3	Full	12 December 2025
Stratford Peaker 1	Full	14 December 2025
Huntly 5	Full	21 December 2025
Tauhara geothermal	Full	22 December 2025
Ōhau C	Partial	16 January 2026
Ōhau A	Partial	18 February 2026
Roxburgh unit 5	Full	25 February 2026
Rangipo unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026
Manapōuri unit 4	Full	12 June 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 30 November-6 December. 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. Overall, residuals were healthy this week. The lowest national residual was 867MW on Thursday at 7.30am.

Figure 20: National generation balance residuals, 30 November-6 December



10. Storage/fuel supply

10.1. Figure 21 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. As of 6 December, national controlled storage stayed steady at 102% nominally full and ~146% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (102% full[2]) and Lake Takapō (104% full) are above their respective 90th percentile. Both lakes have exceeded their storage capacities and are spilling.

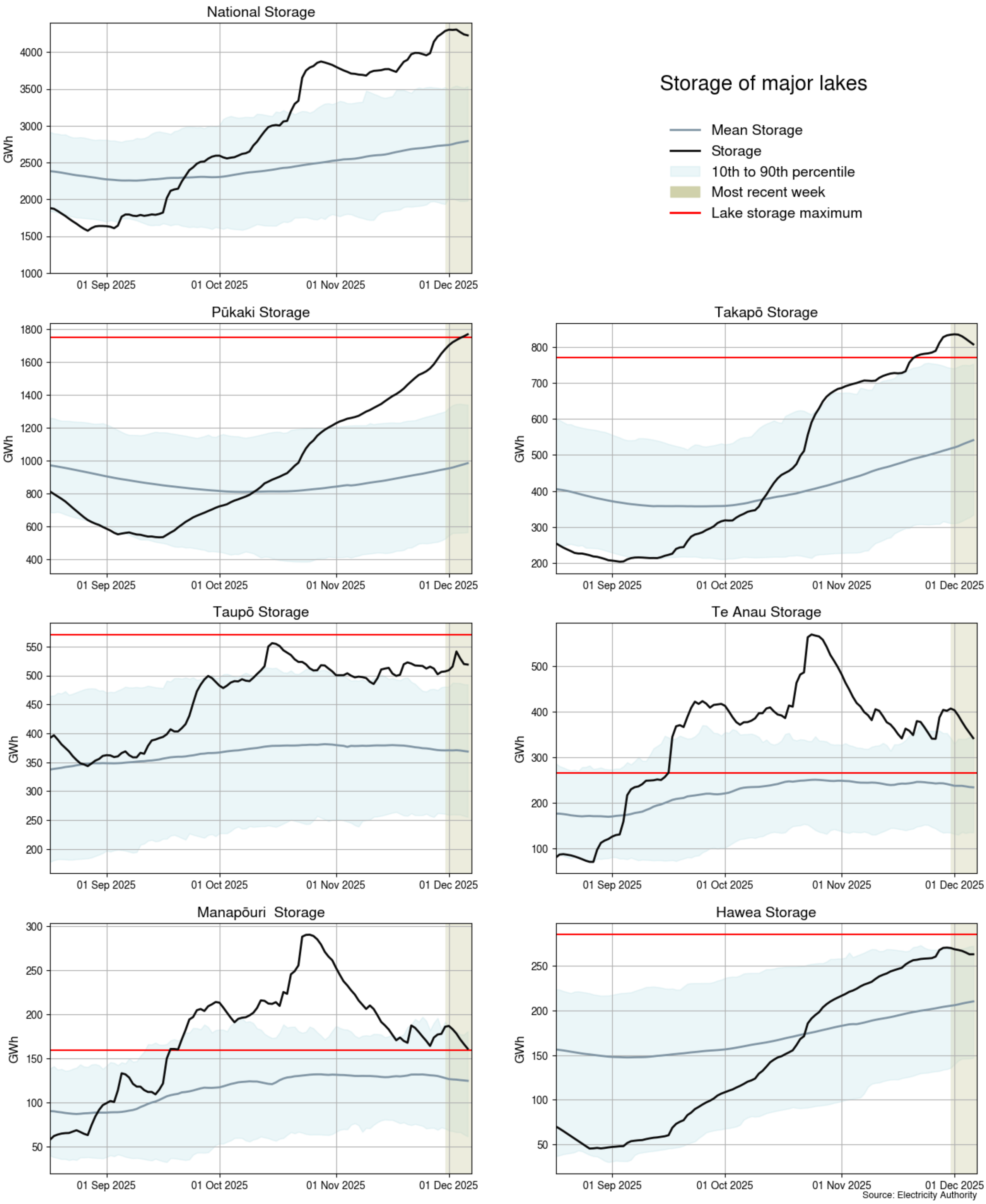
10.4. Storage at Lake Te Anau (139% full) is close to its historic 90th percentile, while Lake Manapōuri (108% full) is below its historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (91% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (93% full) is just below its historic 90th percentile.

[2] Percentage full values sourced from NZX Hydro.

Figure 21: 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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 December 2025. The SRMCs for all thermal fuel types have decreased.

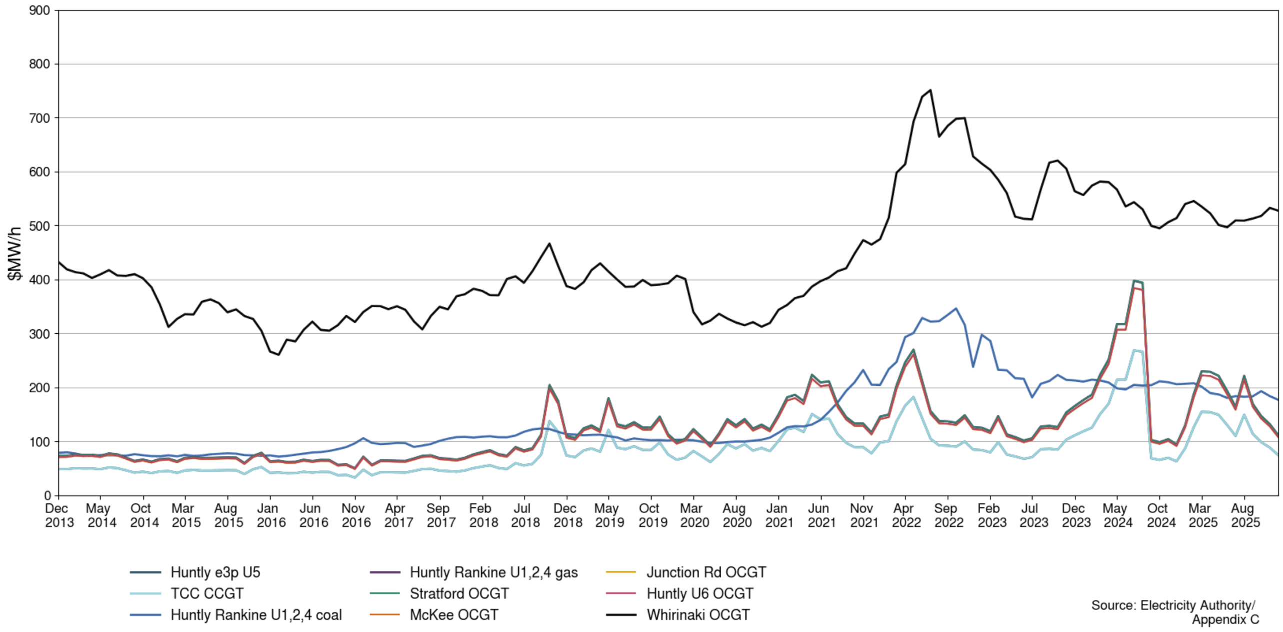
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$177/MWh. The cost of running the Rankines on gas is ~$111/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $74/MWh and $111/MWh.

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

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

Figure 22: Estimated monthly SRMC for thermal fuels

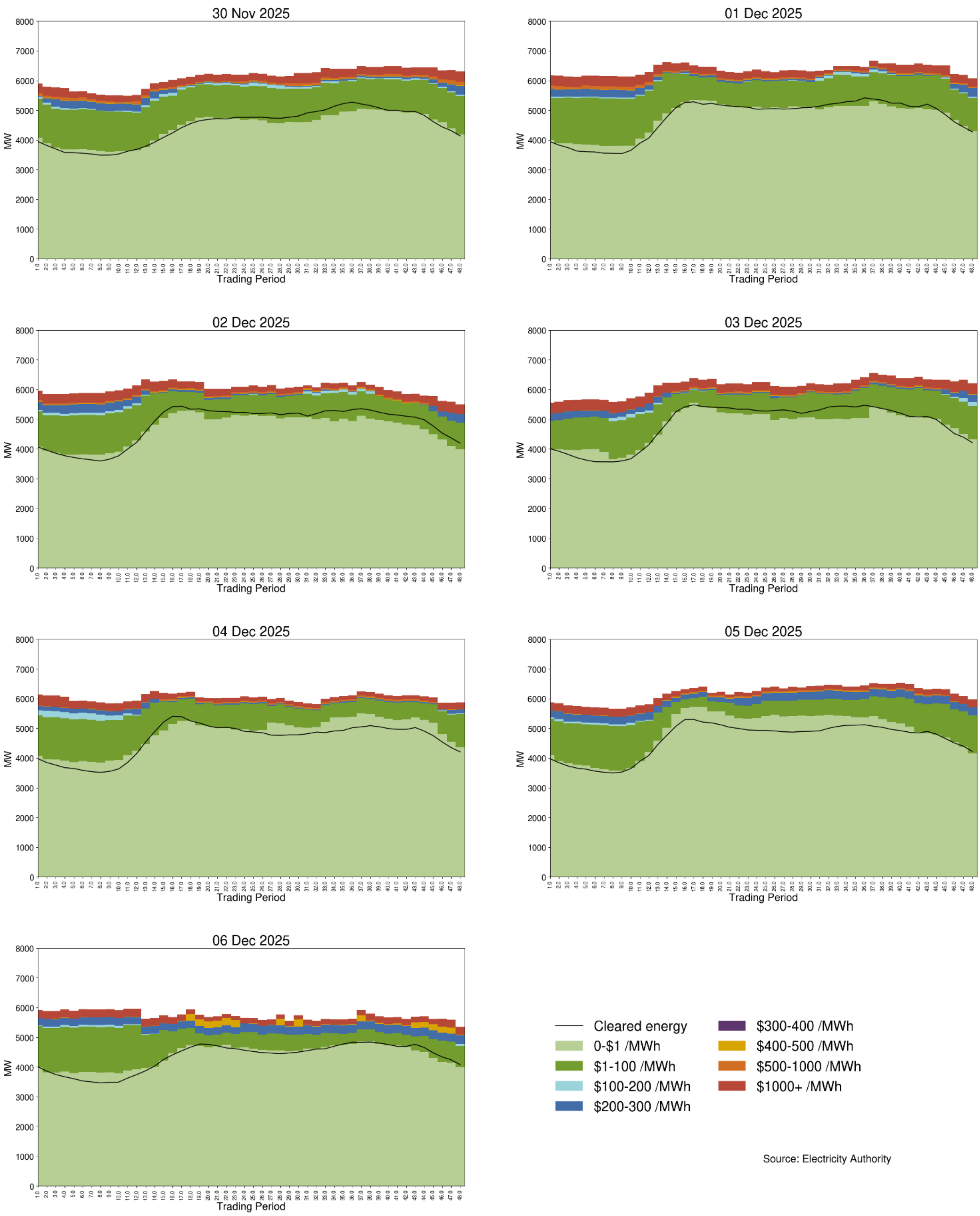


12. Offer behaviour

12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. This week, all offers cleared below $100/MWh. On Thursday evening and Friday, lower demand meant energy cleared in the lower band between $0-1/MWh.

Figure 23: Daily offer stacks



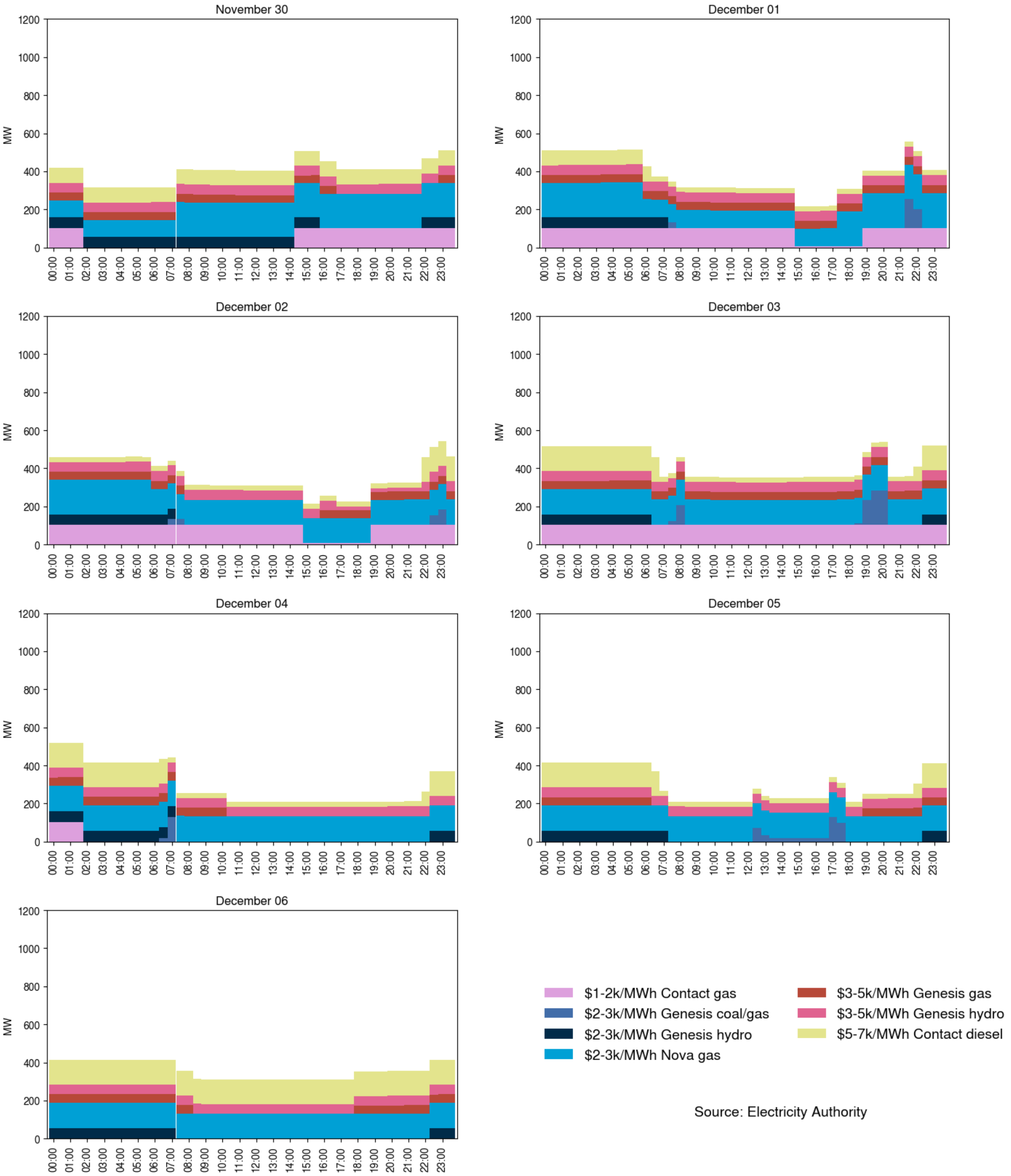
Source: Electricity Authority

12.3. Figure 24 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 361MW per trading period was priced above $1,000/MWh this week, which is roughly 7% of the total energy available.

Figure 24: 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.

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
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers
21/10/2025-1/11/2025	Several	Further analysis	Contact	Clyde	Offers
5/11/2025	23-24	Further analysis	Contact	Stratford	Offers
18/11/2025	Several	Further analysis	Contact	Clutha Scheme	Offers
24/11/2025-27/11/2025	Several	Further analysis	Genesis	Tekapo	Offers
27/11/2025	27	Further analysis	Contact	Roxburgh	Offers
27/11/2025-3/12/2025	Several	Further analysis	Meridian	Waitaki chain	Offers
4/12/2025	Several	Further analysis	Rānui Generation	Twin Rivers solar farm	Solar forecast