1 December 2025

Trading conduct report 23-29 November 2025

Market monitoring weekly report

Trading conduct report 23-29 November 2025

1. Overview

1.1. This week the average spot price decreased by $11/MWh to $47/MWh. The proportion of hydro generation fell this week but remained over 70%, while geothermal generation remains lower due to plant outages. HVDC flows were entirely northward throughout the week. National hydro storage increased to 102% nominally full and 147% of the historical average. However, this includes storage at Manapōuri, Te Anau and Takapō, 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 23-29 November:

(a) The average spot price for the week was $47/MWh, a decrease of around $11/MWh compared to the previous week.

(b) 95% of prices fell between $0.30/MWh and $152/MWh.

2.3. This week prices remained mostly below $200/MWh at Ōtāhuhu and $150/MWh at Benmore. Prices were particularly low on Saturday and Sunday, driven by low demand alongside high hydro generation on Sunday and high wind generation on Saturday. Prices on Friday were also lower due to higher wind generation.

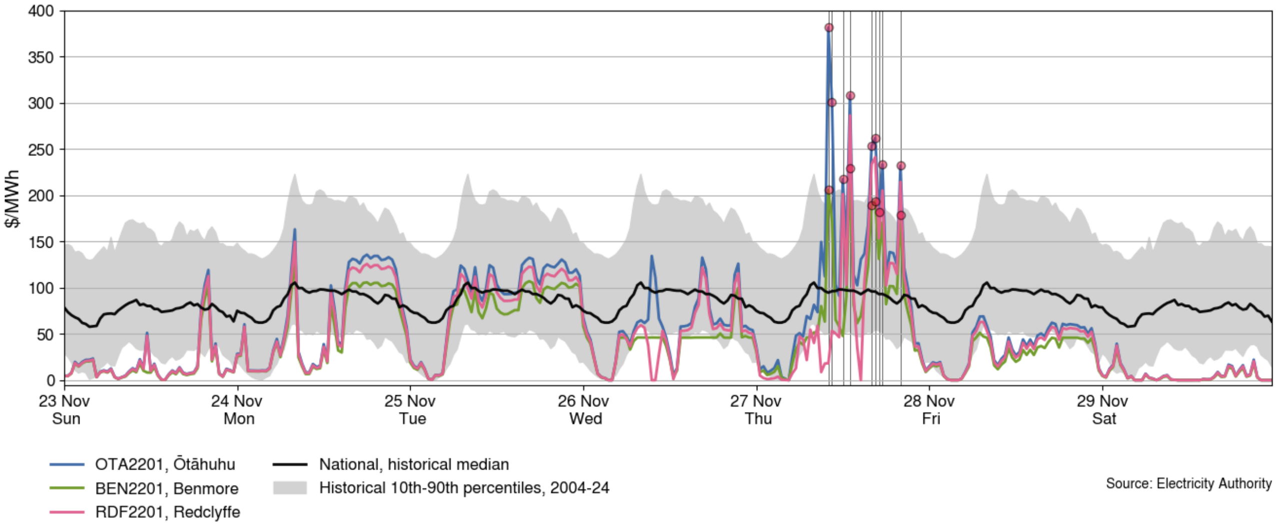
2.4. Some price spikes occurred on Thursday, mostly due to wind and/or demand forecast errors. Prices ranged between $218/MWh-$381/MWh at Ōtāhuhu, and between $131/MWh-$229/MWh at Benmore during this period.

2.5. The highest price of the week at Ōtāhuhu occurred on Thursday at 10.00am, reaching $381/MWh. The Benmore spot price was $206/MWh at this time. Demand was 106MW higher than forecast, while wind was 28MW lower than forecast at this time. The highest Benmore spot price this week was $229/MWh at 1.00pm on Thursday.

2.6. Redclyffe and nearby nodes observed low prices and price separation on Wednesday and Thursday due to constraints on Wairakei ring generation. During these days, prices fell at times to $0.01/MWh. Negative prices also occurred on Thursday at several nodes in the area due to these constraints.

2.7. Figure 1 shows the wholesale spot prices at Benmore, Ōtāhuhu and Redclyffe 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.

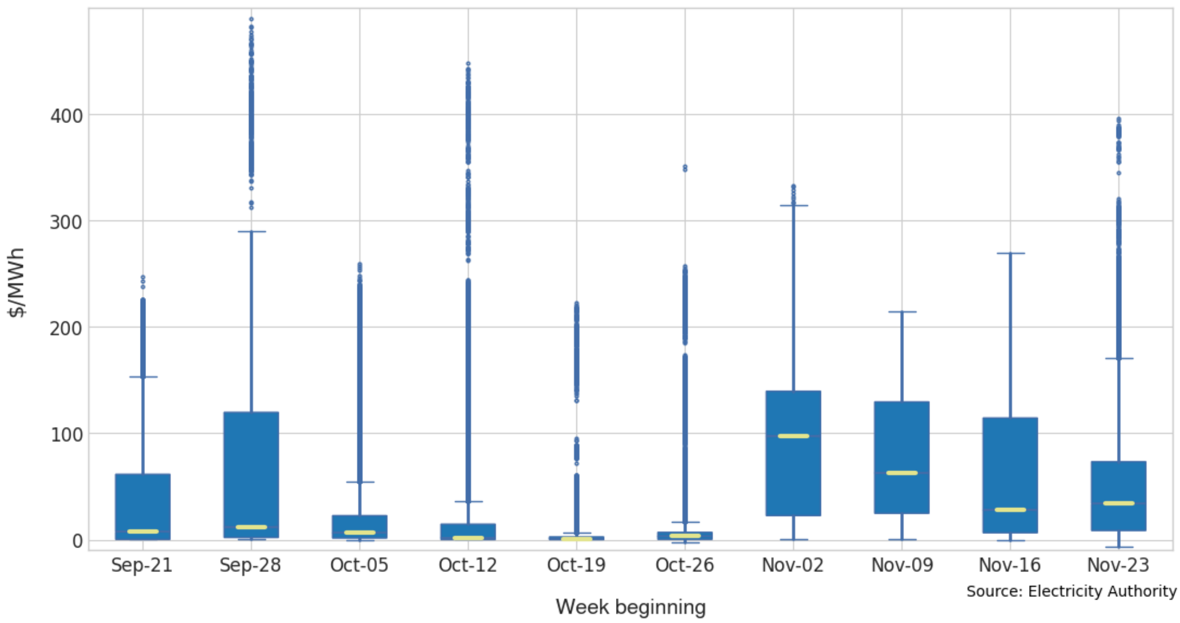
Figure 1: Wholesale spot prices at Benmore, Ōtāhuhu and Redclyffe, 23-29 November



2.8. 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.

2.9. The distribution of spot prices this week was narrower than last week, although there were several high-priced outliers. The median price was $34/MWh and most prices (middle 50%) fell between $9/MWh and $73/MWh.

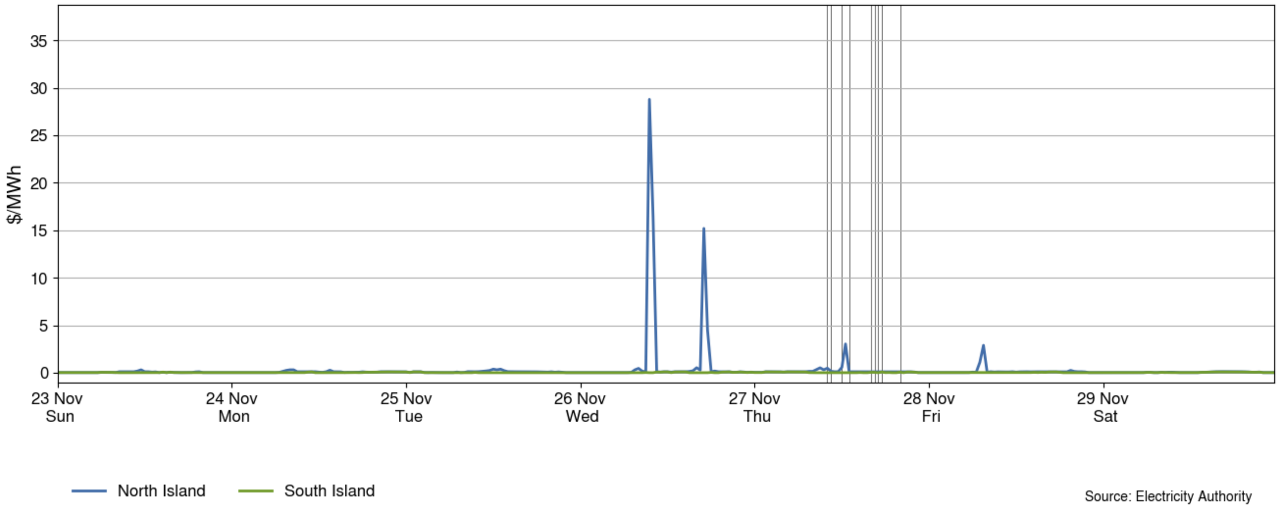
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



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 $5/MWh, except for three price spikes on Wednesday at 9.30am, 10.00am, and 5.00pm in the North Island. At the time of the two morning price spikes, the HVDC was setting the North Island risk. Ruakākā was not offering FIR reserve at these times and the Northpower battery was also not offering FIR reserve during the morning spikes.

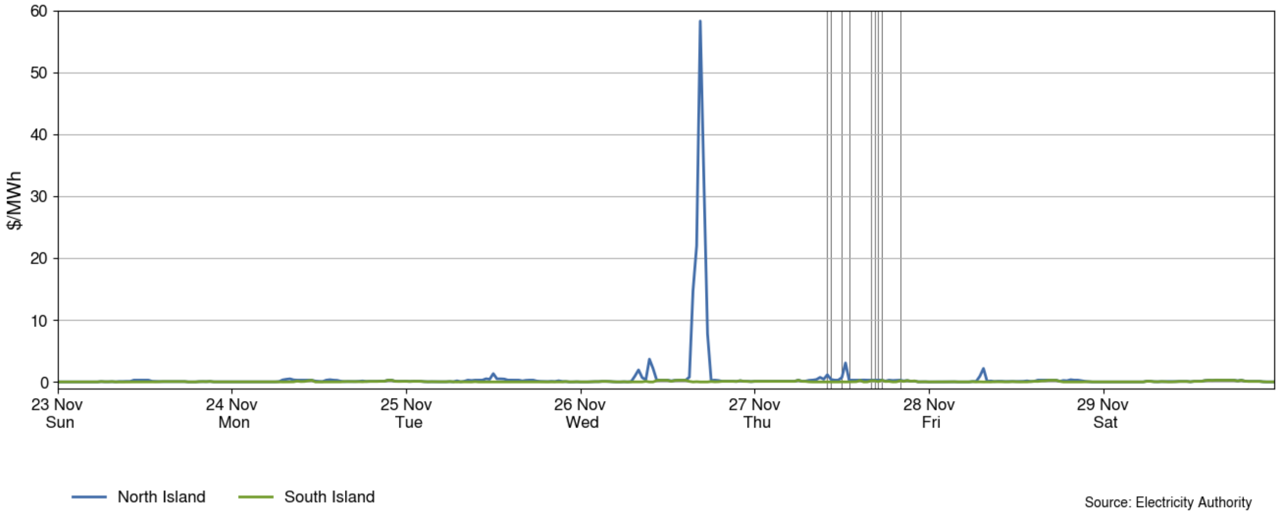
Figure 3: Fast instantaneous reserve price by trading period and island, 23-29 November



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh, except for three North Island price spikes on Wednesday between 4.00pm and 5.00pm. During this time, the Ruakākā battery was not offering SIR reserve, likely contributing to higher SIR prices.

3.3. The times when batteries don't offer reserve is due likely to insufficient charge.

Figure 4: Sustained instantaneous reserve by trading period and island, 23-29 November



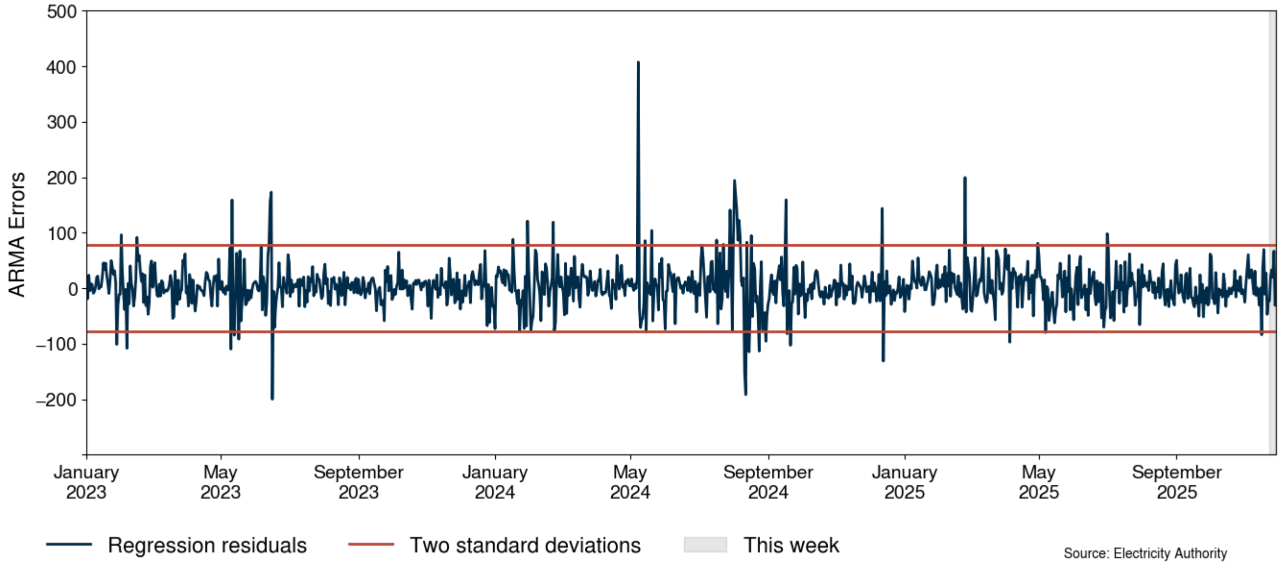
4. Regression residuals

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 - 29 November 2025

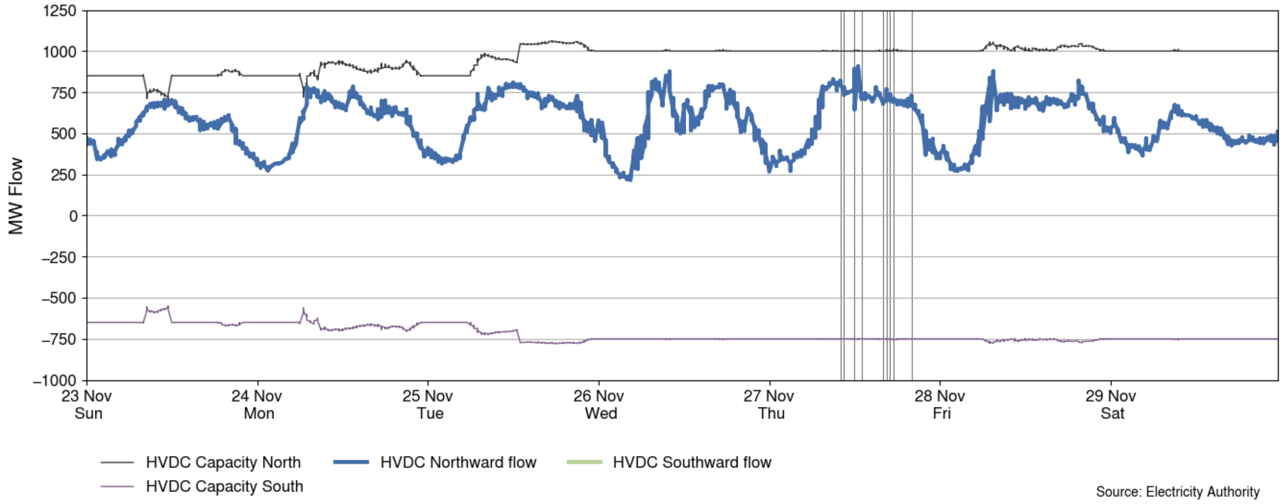


5. HVDC

5.1. Figure 6 shows the HVDC flow between 23-29 November. HVDC flows were entirely northward this week due to high hydro generation in the South Island.

5.2. The highest northward flow occurred at 12.30pm on Thursday with a flow of around 1006MW. HVDC northward flows were close to their capacity limits at times on Sunday and Monday.

Figure 6: HVDC flow and capacity, 23-29 November



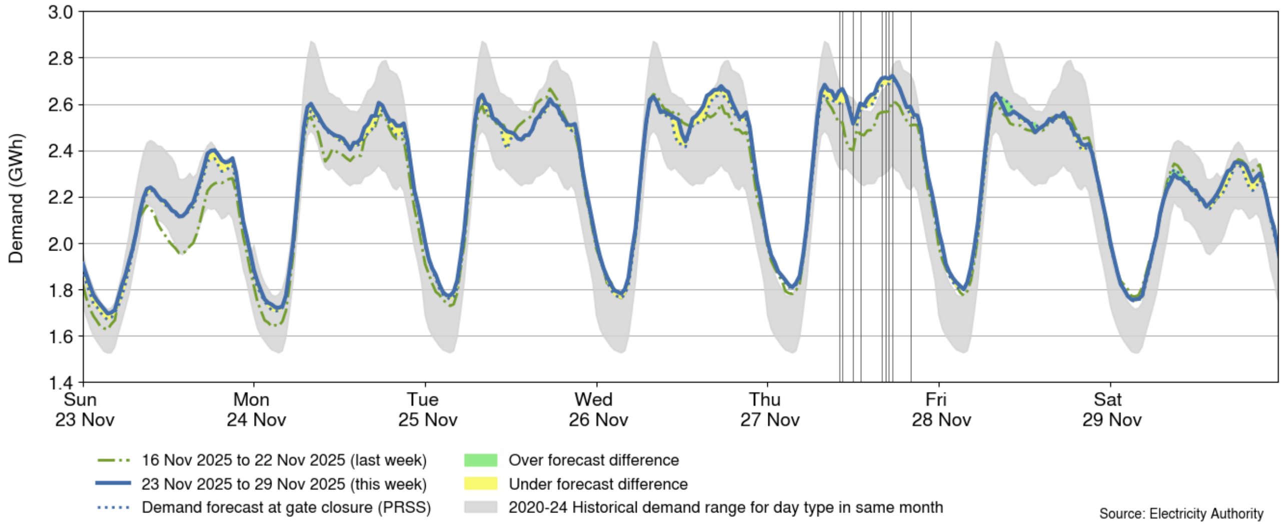
6. Demand

6.1. Figure 7 shows national demand between 23-29 November, compared to the historic range and the demand of the previous week.

6.2. On Sunday, demand was higher than last week and was higher than forecast in the evening.

6.3. On Thursday, during the high price spikes, demand was higher than the previous week, at times higher than the historic demand range, and was underforecast. The highest demand of the week was around 2.72GWh at 5.30pm on Thursday.

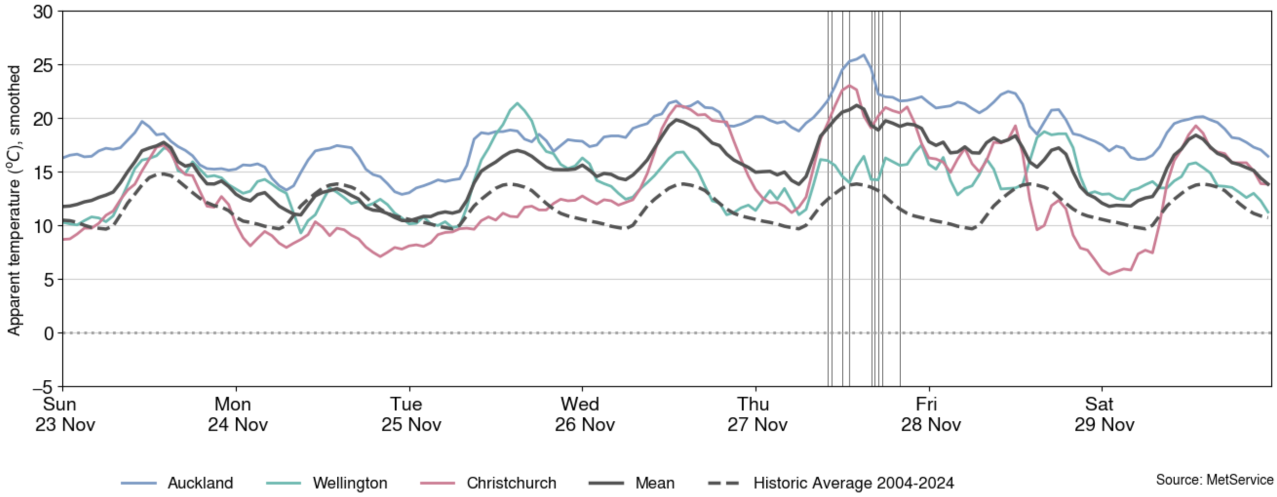
Figure 7: National demand, 23-29 November compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 23-29 November. 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.

6.5. Apparent temperatures ranged from 13°C to 26°C in Auckland, 9°C to 22°C in Wellington, and 5°C to 23°C in Christchurch. High temperatures on Thursday may have contributed to higher afternoon demand.

Figure 8: Temperatures across main centres, 23-29 November

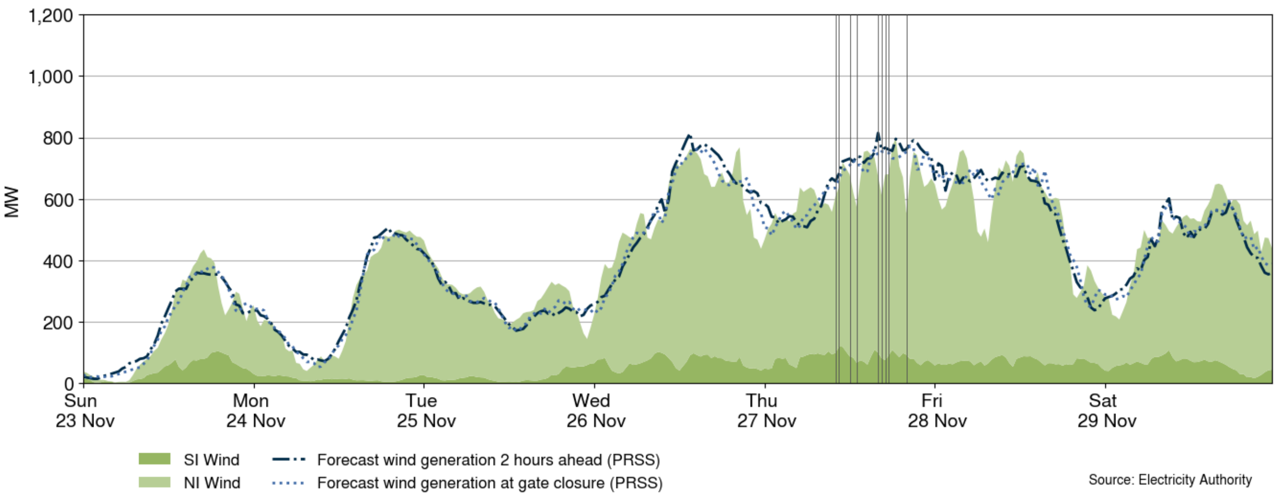


7. Generation

7.1. Figure 9 shows wind generation and forecast from 23-29 November. This week wind generation varied between 3MW and 799MW, with a weekly average of 422MW.

7.2. Wind generation was low at the beginning of the week, remaining below 600MW between Sunday and Tuesday. From Wednesday, wind generation increased, before it declined slightly on Saturday. The wind forecasting errors on Thursday were an amalgamation of errors across multiple wind farms. These errors ranged between 140-200MW, and occurred during times of high demand.

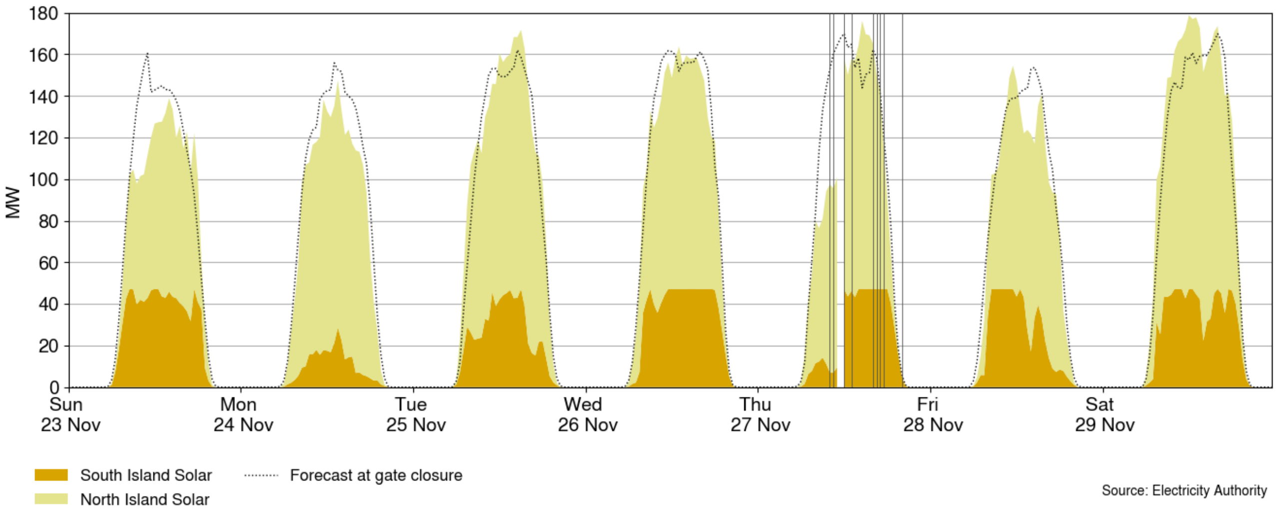
Figure 9: Wind generation and forecast, 23-29 November



7.3. Figure 10 shows grid connected solar generation from 23-29 November. Solar generation reached above 120MW daily, peaking on Saturday at 12.00pm at around 179MW.

7.4. Solar data is missing for trading period 24 on Thursday.

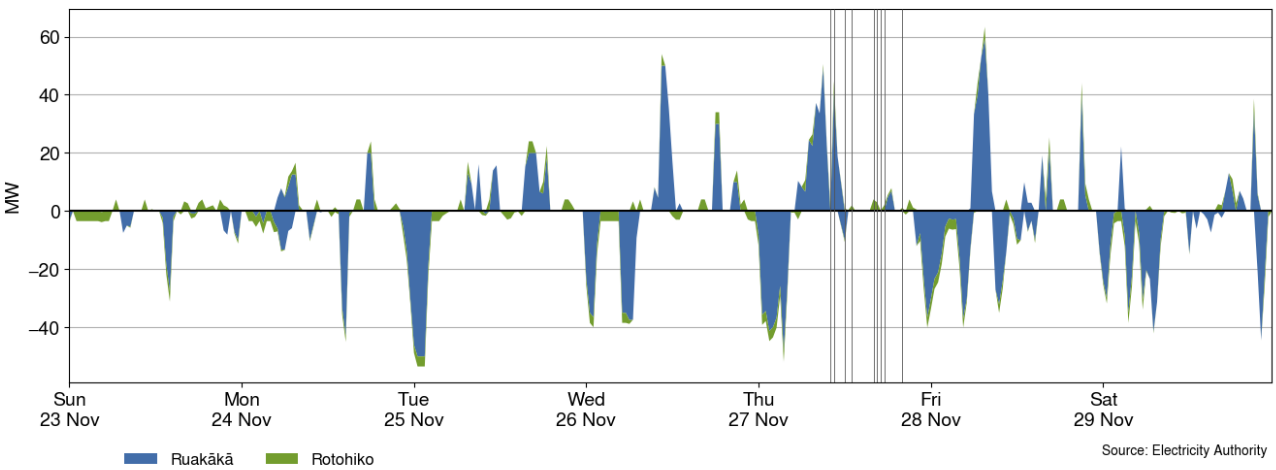
Figure 10: Grid connected solar generation, 23-29 November



7.5. Figure 11 shows when the grid scale batteries 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.

7.6. When prices were low, such as Saturday and Sunday, or overnight, the batteries were mostly charging. During the week, the batteries were discharging during the day when prices were higher. Ruakākā was not offering during some of the high prices on Thursday likely due to insufficient charge.

Figure 11: Grid scale battery charge and discharge, 23-29 November



7.7. 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

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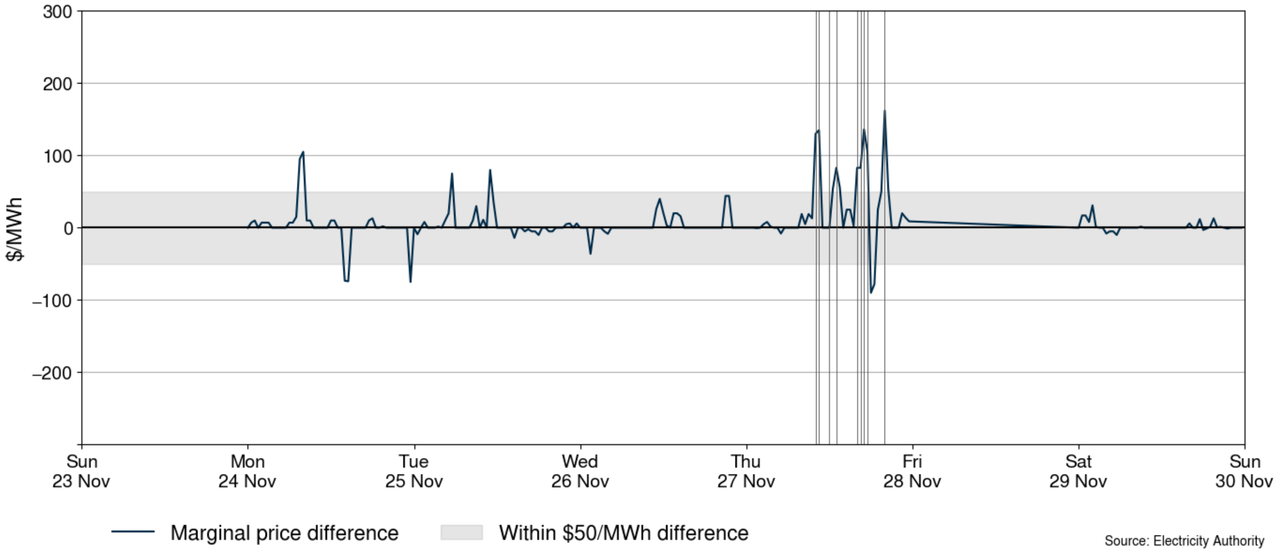
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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.

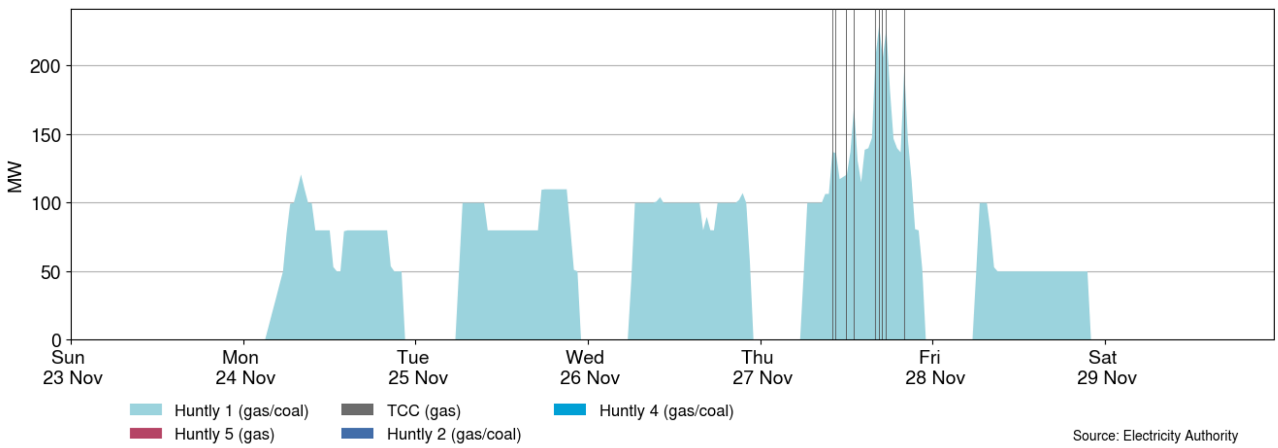
7.8. A few trading periods this week had positive marginal price differences above $50/MWh, which were driven by wind and demand forecasting errors. The largest positive price difference of $162/MWh occurred at 8.00pm on Thursday evening during a price spike, when demand was 71MW higher than forecast and wind 200MW lower than forecast.

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, 23-29 November



7.9. Figure 13 shows the generation of thermal baseload between 23-29 November. Huntly 1 ran every day from Monday to Friday. Huntly generation ramped up on Thursday when wind generation was underforecast. There was no thermal generation overnight during the week.

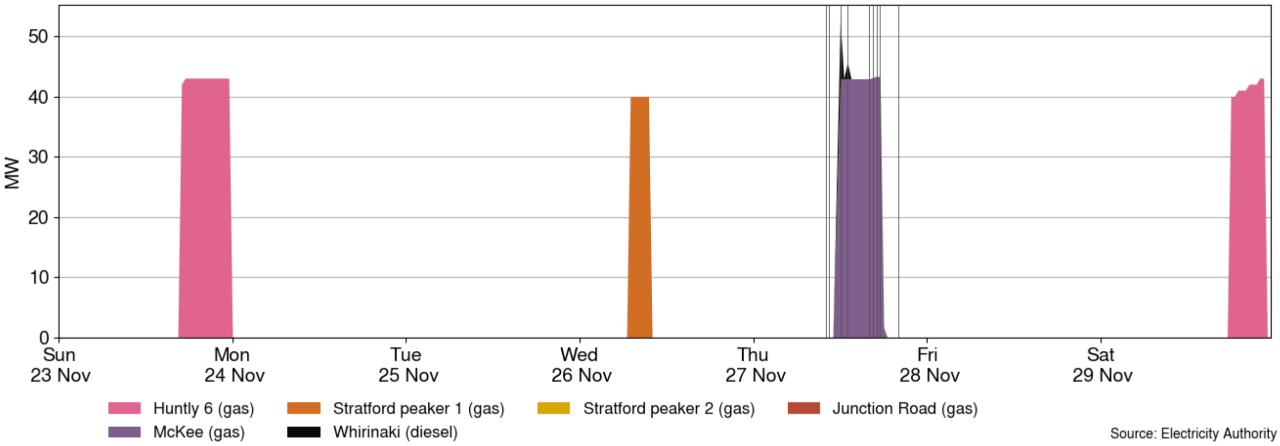
Figure 13: Thermal baseload generation, 23-29 November



7.10. Figure 14 shows the generation of thermal peaker plants between 23-29 November. Huntly 6 ran on Sunday and Saturday. Stratford Peaker 1 ran on Wednesday.

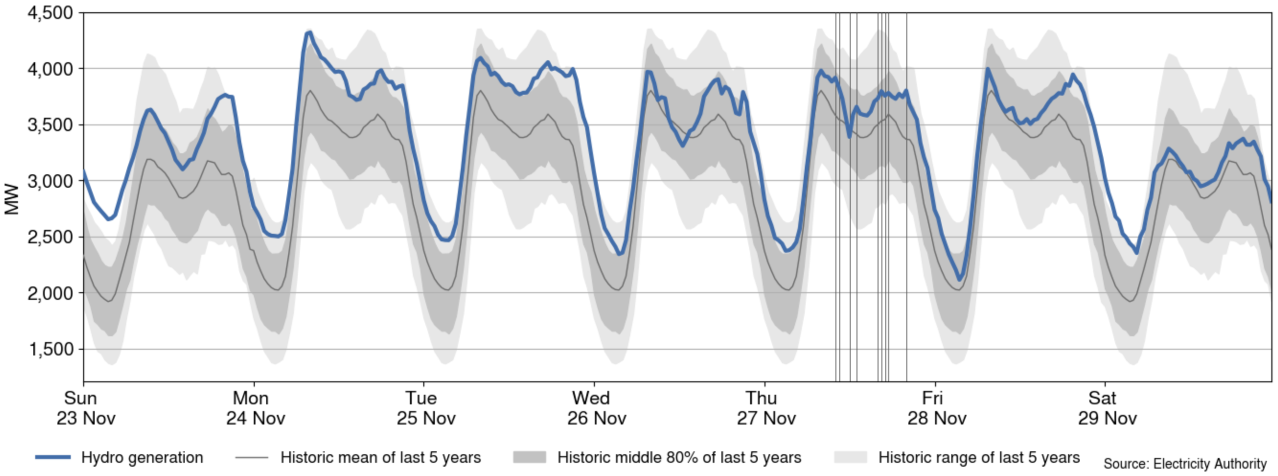
7.11. McKee ran on Thursday, with Whirinaki also being dispatched on Thursday during some of the price spikes.

Figure 14: Thermal peaker generation, 23-29 November



7.12. Figure 15 shows hydro generation between 23-29 November. Overall, hydro generation was high throughout the week. The highest hydro generation was on Monday during the morning peak.

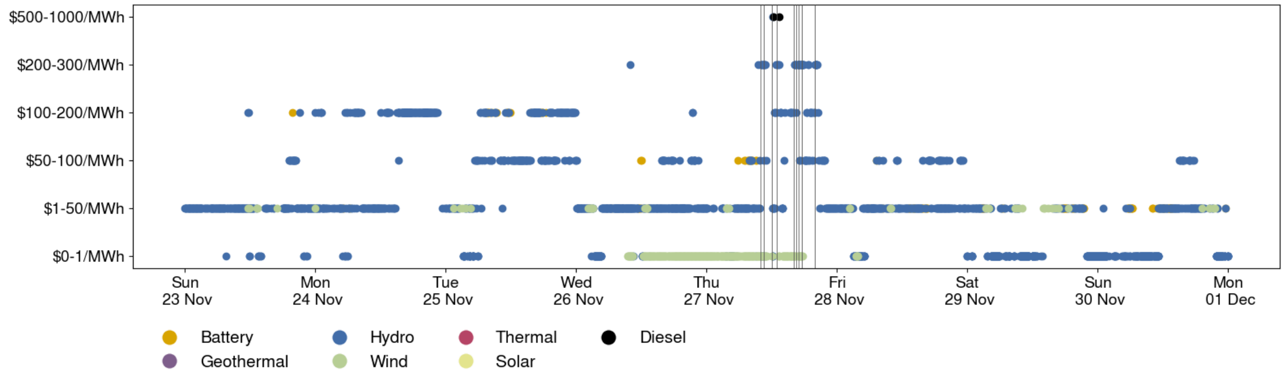
Figure 15: Hydro generation, 23-29 November



7.13.

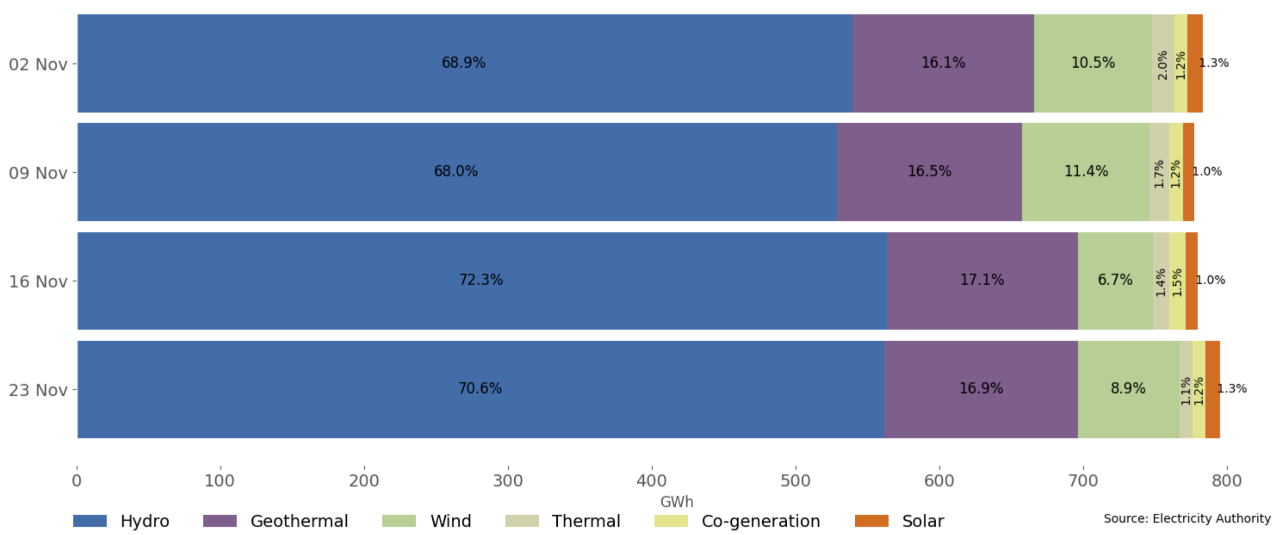
7.14. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple plants marginal for each 5-minute period. The highest prices this week were caused by Whirinaki generation on Thursday morning. Most marginal prices were between $1-50/MWh. The most common technology setting prices this week was hydro generation. On Wednesday-Thursday during the Wairakei ring constraints, Harapaki wind farm was marginal in the Hawkes Bay.

Figure 16: Prices of marginal generation, 23-29 November



7.15. As a percentage of total generation, between 23-29 November, total weekly hydro generation was 70.6%, geothermal 16.9%, wind 8.9%, thermal 1.1%, co-generation 1.2%, and solar (grid connected) 1.3%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 2 and 29 November



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 23-29 November ranged between ~1,661MW and ~2,925MW, which is above average for this time of year. Figure 19 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 is on extended outage until 21 December 2025.

(b) Huntly 2 is on outage until 30 November 2025.

(c) Tauhara geothermal is on outage until 22 December 2025.

(d) Nga Awa Purua geothermal is on outage until 1 December 2025.

(e) Stratford Peaker 2 is on outage until 8 December 2025.

(f) Huntly 4 was on partial outage until 2 December 2025.

(g) Ruakākā battery was on partial outage until 26 November 2025.

(h) Benmore unit 3 is on outage until 12 December 2025.

8.3. Some outages finishing in 2026 include:

(a) Ōhau A is on partial outage until 4 February 2026.

(b) Ōhau C is on partial outage until 16 January 2026.

(c) Roxburgh unit 5 is on outage until 25 February 2026.

(d) Rangipo unit 6 is on outage until 29 March 2026.

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

Figure 18: Total MW loss from generation outages, 23-29 November

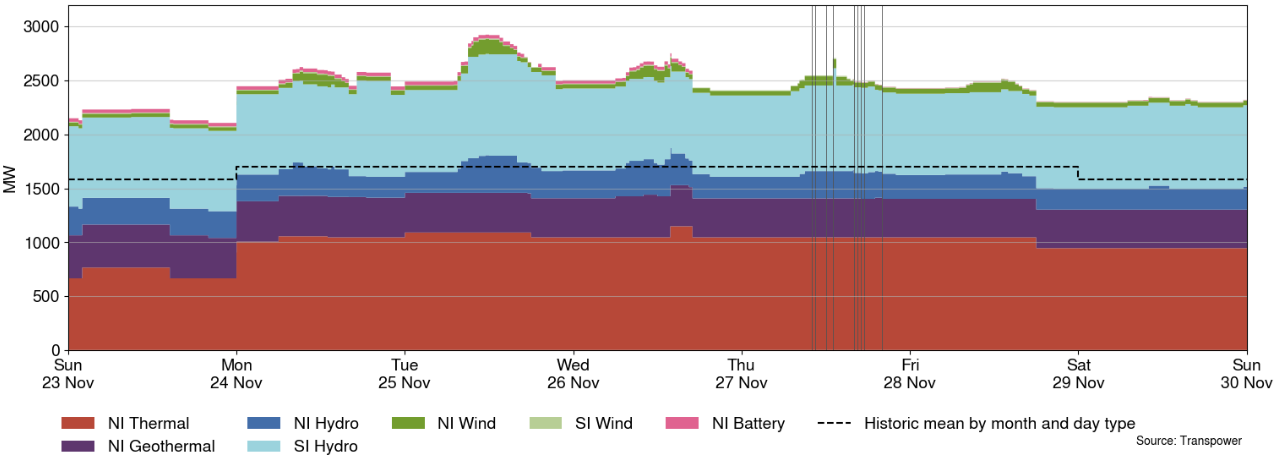
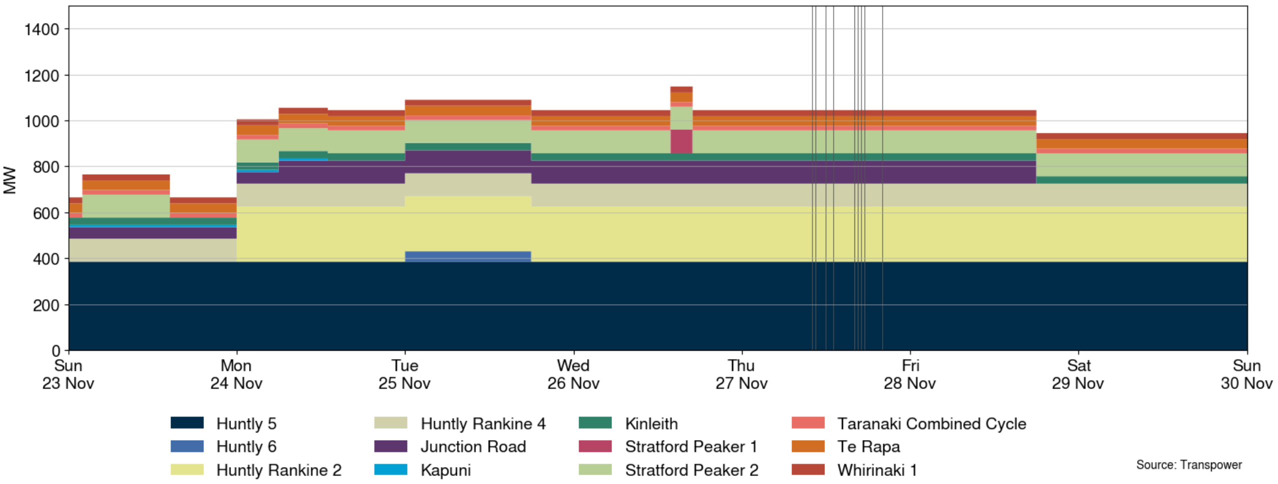


Figure 19: Total MW loss from thermal outages, 23-29 November

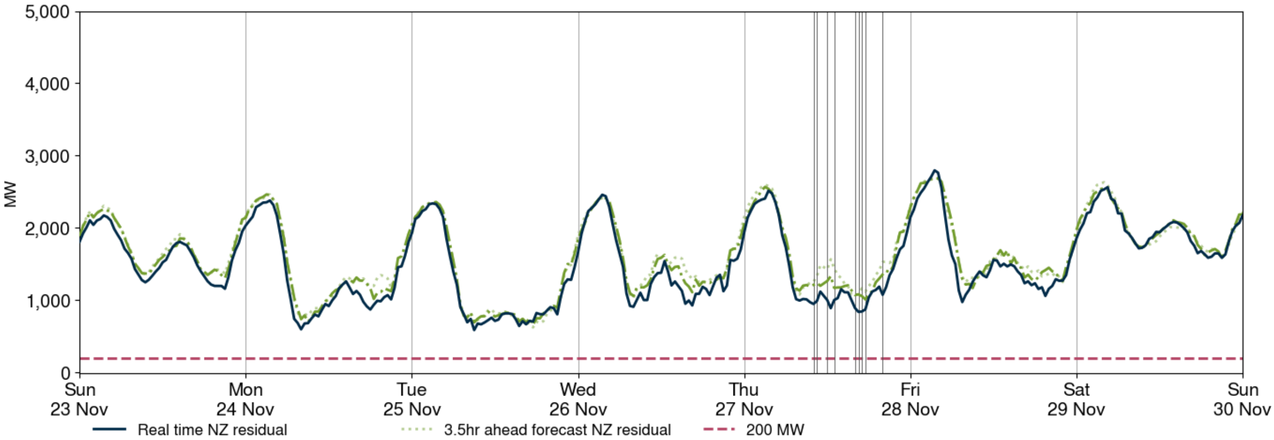


9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 23-29 November. 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 588MW on Tuesday at 9.00am.

Figure 20: National generation balance residuals, 23-29 November



Source: Transpower

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 30 November 2025, national controlled hydro storage increased to 102% of nominal full and ~161% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (96% full[2]) and Lake Takapō (108% full) are above their respective 90th percentile. Lake Takapō has exceeded its storage capacity and is spilling.

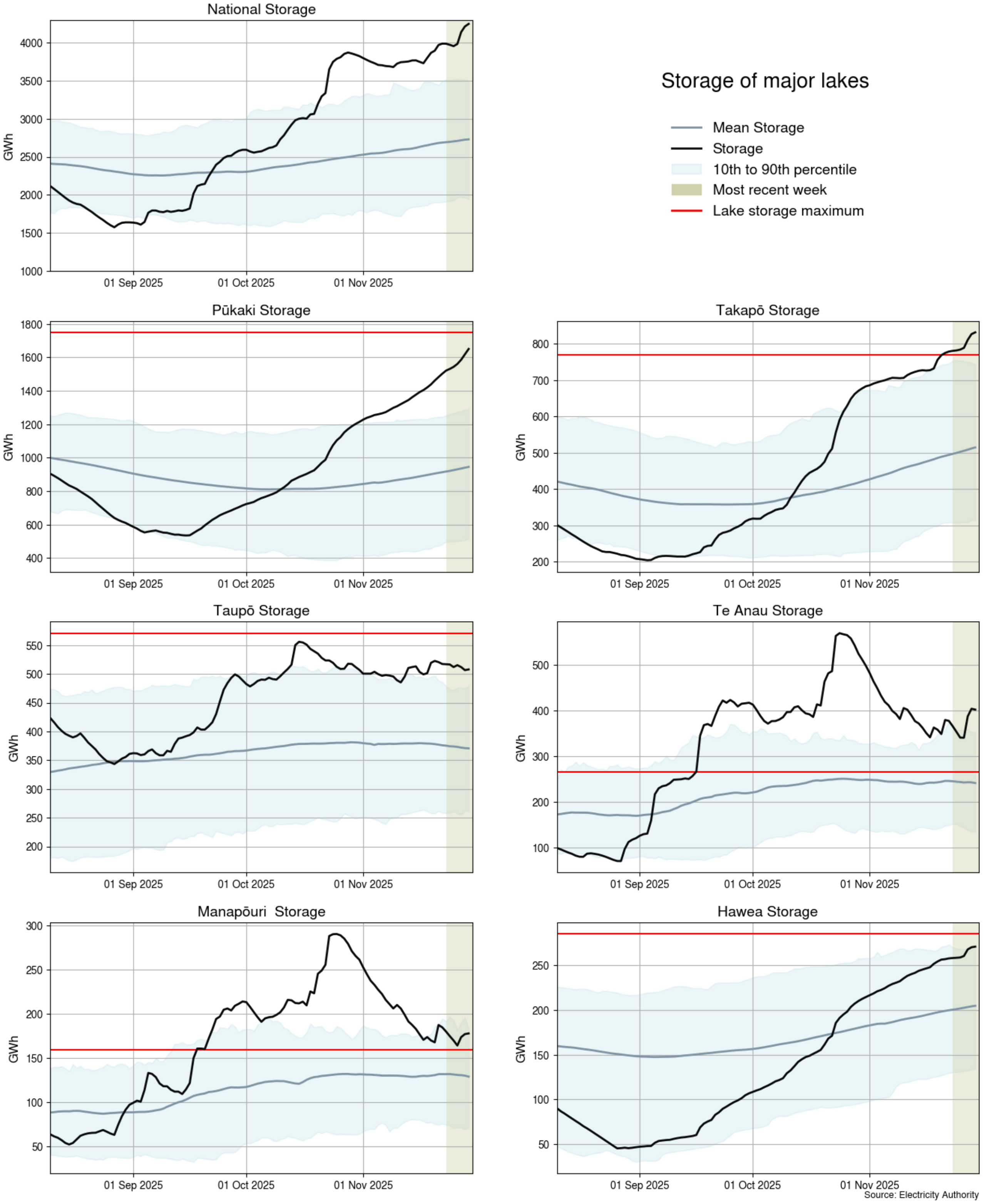
10.4. Storage at Lake Te Anau (153% full) is above its historic 90th percentile, while Lake Manapōuri (118% full) is just below its historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (89% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (95% full) is close to 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 November 2025. The SRMCs for gas-powered and coal-powered generation decreased, while the SRMC for diesel-fuelled generation increased.

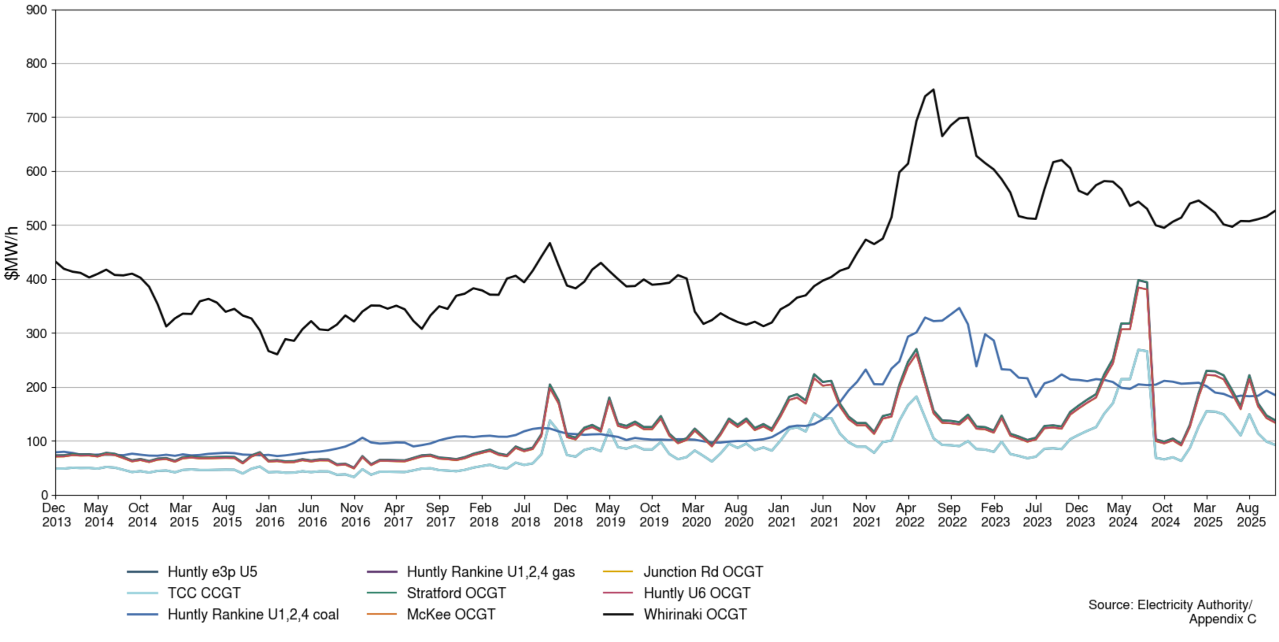
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$184/MWh. The cost of running the Rankines on gas is ~$138/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $92/MWh and $138/MWh.

11.6. The SRMC of Whirinaki is ~$526/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



Source: Electricity Authority/ Appendix C

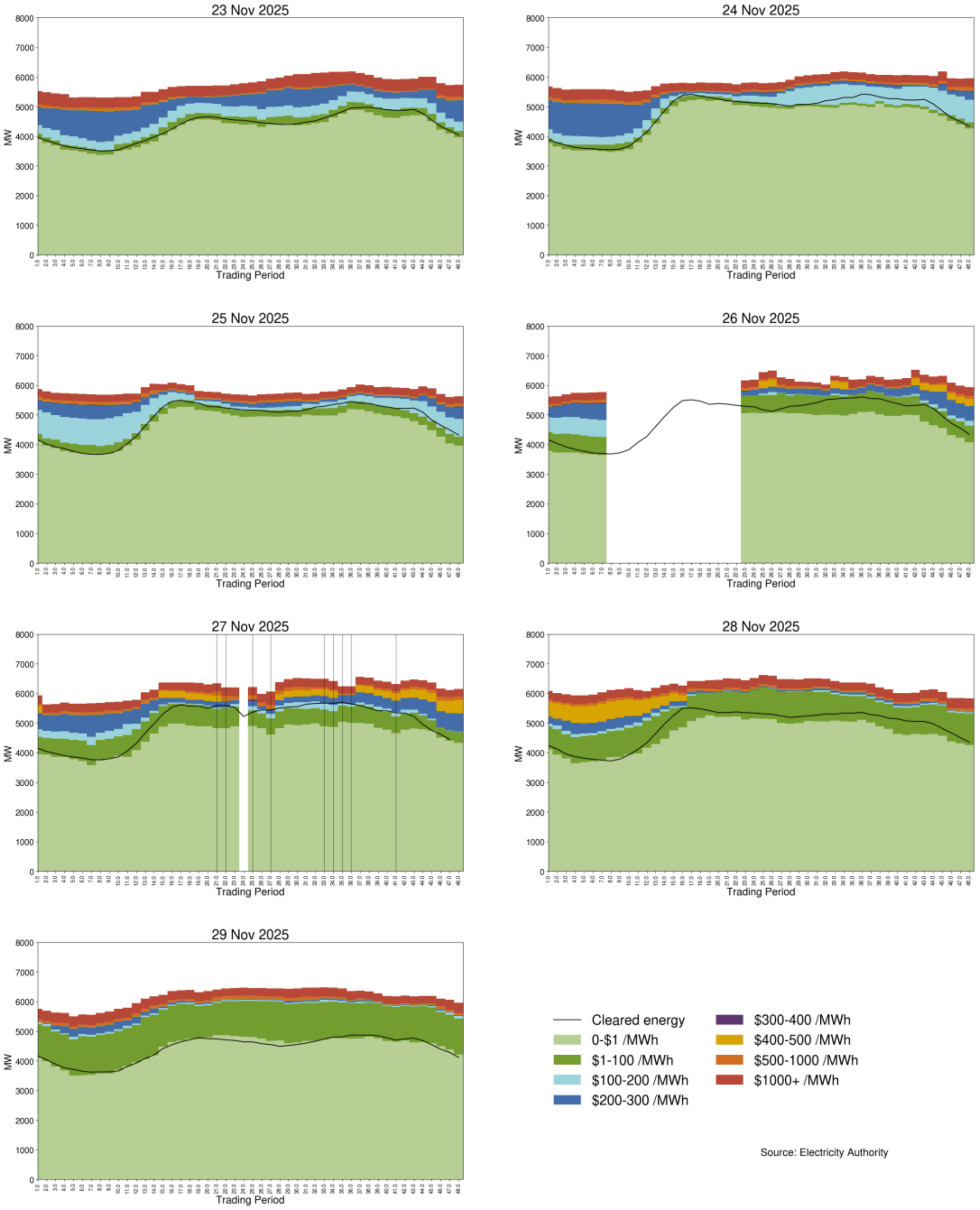
12. Offer behaviour

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, most offers cleared below $100/MWh on Sunday, Friday and Saturday, and within the $0/MWh-$200/MWh range on the remaining days. On Thursday, wind and demand forecast errors pushed some offered energy into the next band of $200–$300/MWh.

12.3. Real time data is missing for trading periods 8-22 on 26 November and trading period 24 on 27 November.

Figure 23: Daily offer stacks



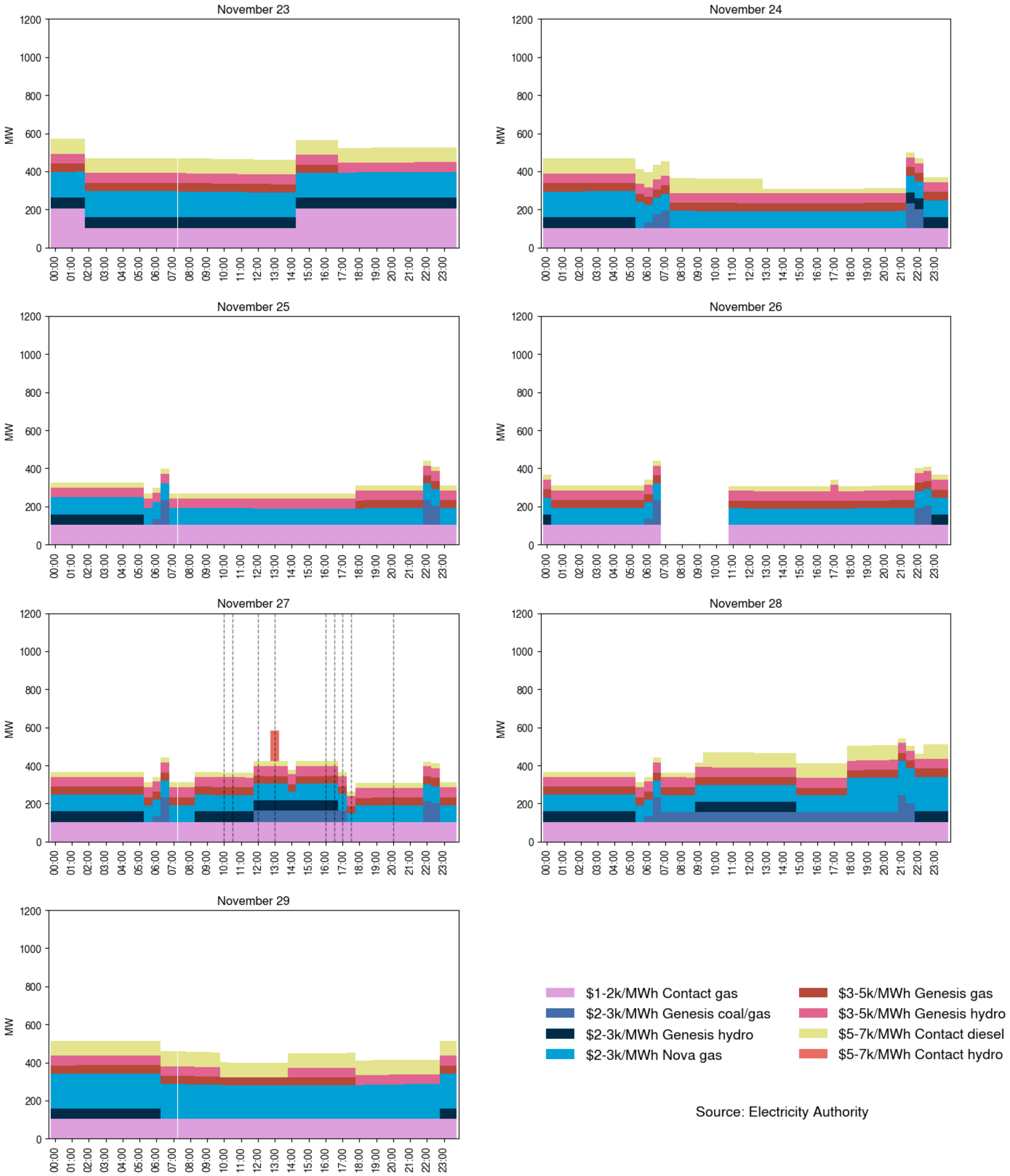
12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.5. 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.

12.6. On average 395MW per trading period was priced above $1,000/MWh this week, which is roughly 8% of the total energy available. Offers data is missing for 7am-11am on 26 November.

12.7. High hydro offers from Contact on 27 November are being further analysed by the monitoring team.

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. The monitoring team is looking further into Waikato and Roxburgh offers this week.

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
19/11/2025	21-30	Further analysis	Meridian	Ruakākā	Offers
18/11/2025	Several	Further analysis	Contact	Clutha Scheme	Offers
24/11/2025	Several	Further analysis	Mercury	Waikato chain	Offers
27/11/2025	27	Further analysis	Contact	Roxburgh	Offers