18 November 2024

Trading conduct report 10-16 November 2024

Market monitoring weekly report

Trading conduct report 10-16 November 2024

1. Overview

1.1. Spot prices this week were very similar to last week, with the majority of prices between \$0.01-156/MWh. There was high northward HVDC transfer this week, and during days with low North Island wind, higher North Island reserve prices pushed up North Island prices, resulting in some price separation between the islands. Hydro storage continued to increase this week with national controlled storage at 134% of the historic mean as of 16 November.

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 10-16 November 2024:

(a) the average wholesale spot price across all nodes was \$42/MWh

(b) 95% of prices fell between \$0.01/MWh and \$156/MWh.

2.3. This week overnight prices remained low whilst during the day prices were more volatile and often close to the historic median or higher. Weekly average price decreased by around \$4/MWh compared to the previous week.

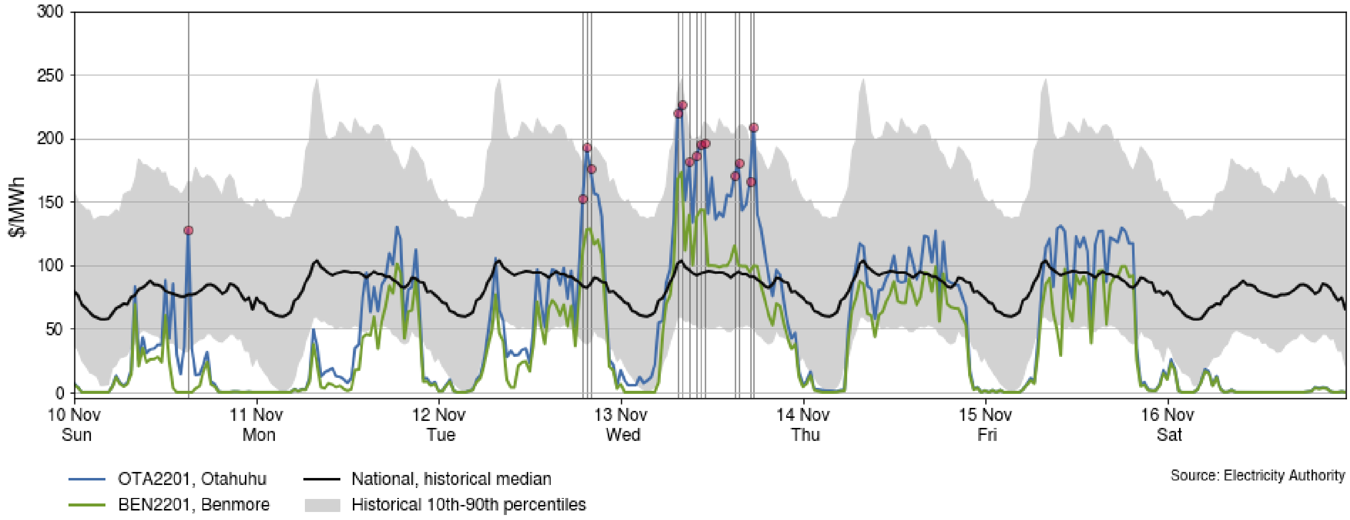
2.4. There was a small spike and separation in prices on Sunday afternoon at 1.00pm and then 3.00pm when the Ōtāhuhu price reached \$85/MWh and \$128/MWh, respectively. At the same time, the price at Benmore was \$3 and \$0.02/MWh, respectively. At the time there was high HVDC transfer, which was setting the North Island risk and low North Island wind, which increased the pressure on North Island hydro providers who can provide both energy and reserve.

2.5. Between 7.00-9.00pm on Tuesday evening prices were within \$108-\$193/MWh across both reference nodes with Ōtāhuhu prices ~\$30-65/MWh higher than Benmore over this period. Again, due to the high northward flow on the HVDC.

2.6. Between 7.00am and 7.00pm on Wednesday prices at Ōtāhuhu were between \$108-\$227/MWh. Benmore prices were mainly close to or above \$100/MWh at this same time with some periods of large price separation. The highest separation in prices was at 5.30pm where Ōtāhuhu prices were \$109/MWh higher than Benmore. Similarly to Sunday, there was high northward HVDC transfer occurring during times with low North Island wind generation. Without high thermal commitment, this puts pressure on North Island hydro providers to produce energy but also provide reserves, which increases to the price of both.

2.7. 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.

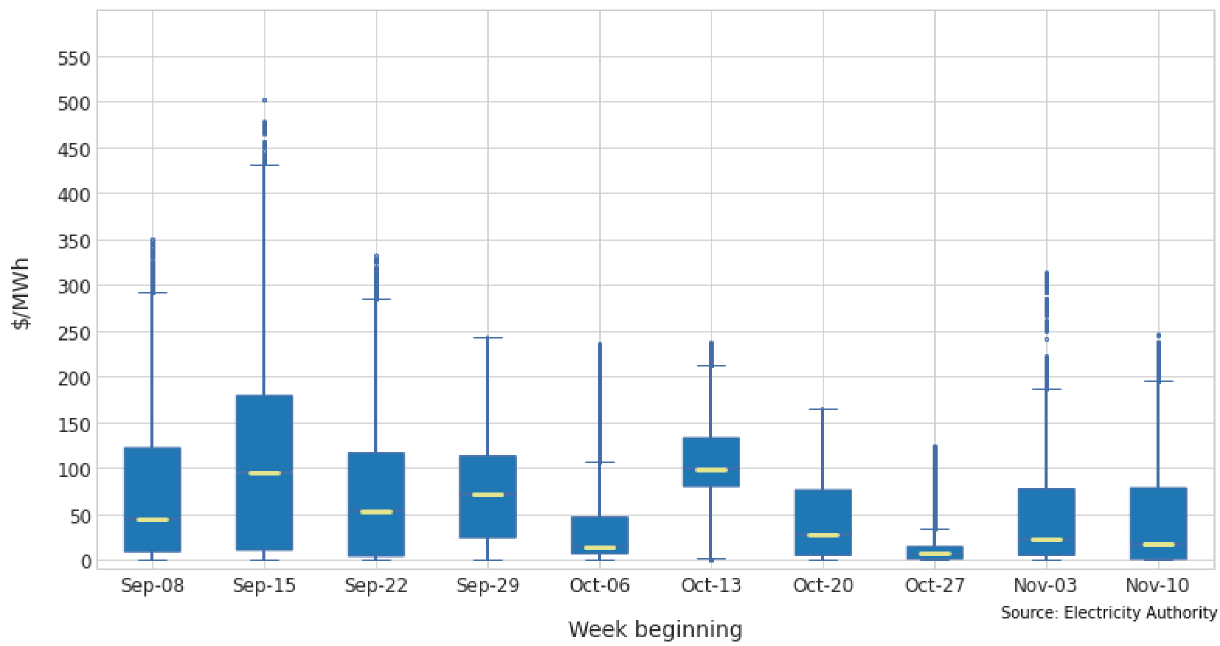
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 10-16 November 2024



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 prices was similar to the previous week. Most prices this week were within $1-$79/MWh and a median price of $17/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.

3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4.

3.3. South Island reserve prices this week were all near $0/MWh. In the North Island, on Sunday and Wednesday there were instances of higher FIR prices. These prices were occurring during times of high HVDC transfer and low North Island wind, which put price pressure on North Island hydro and thermal generators to provide sufficient North Island energy and reserves, which increased the price of both. There was also some separation in North Island SIR at this time although these prices remained below $10/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 10-16 November 2024

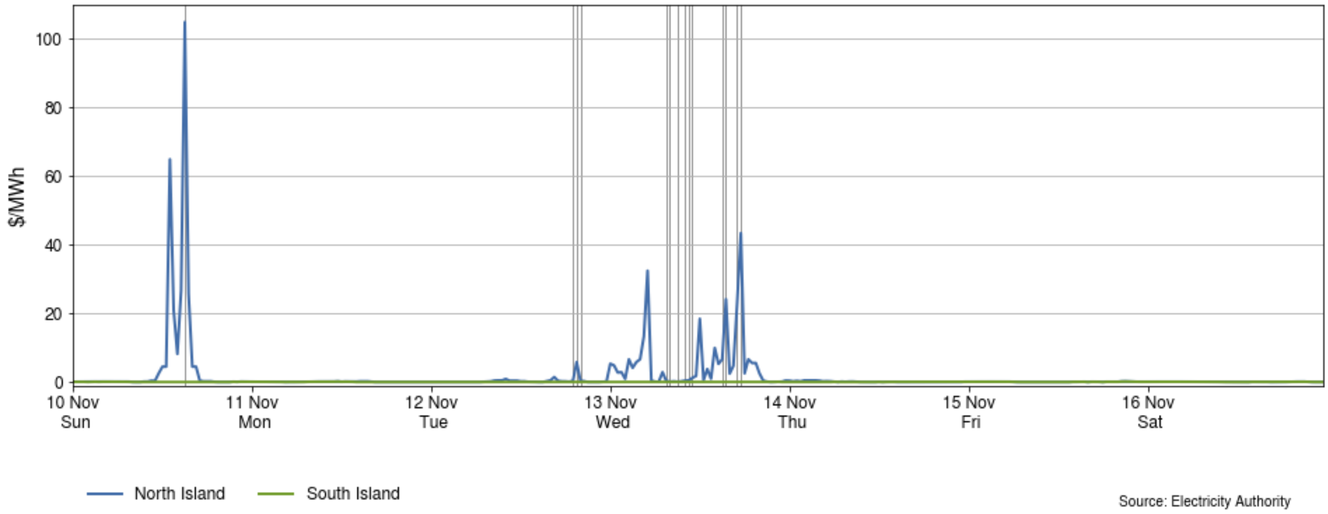
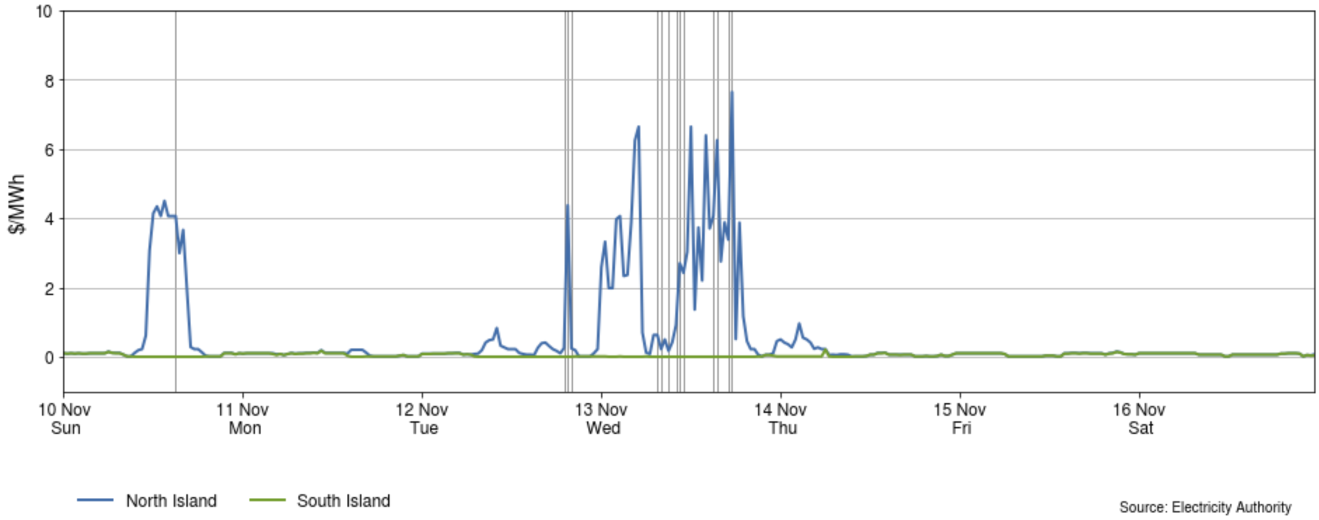


Figure 4: Sustained instantaneous reserve by trading period and island, 10-16 November 2024



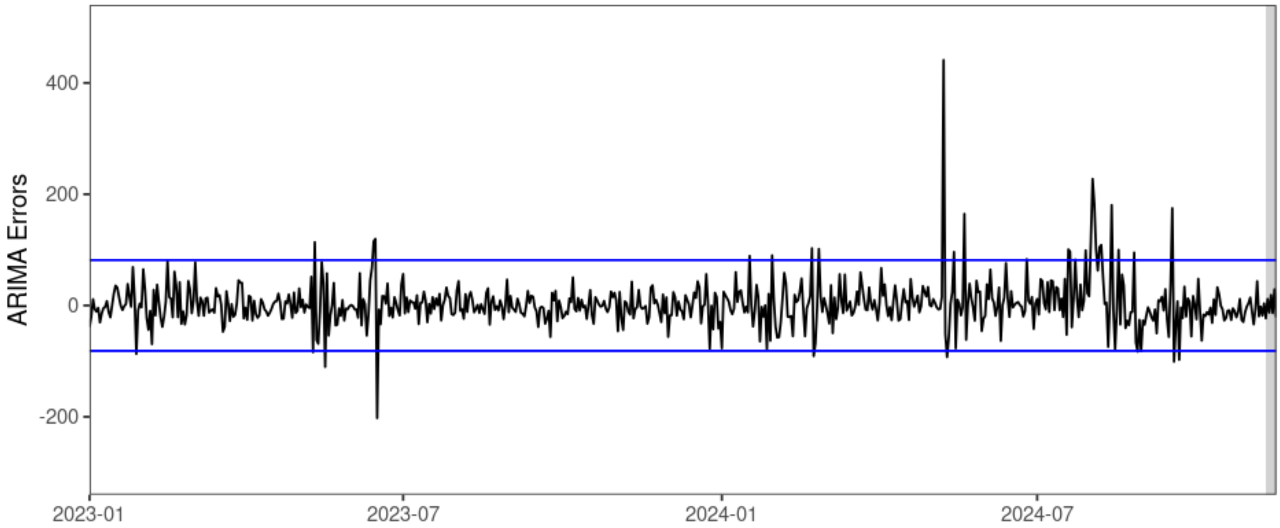
4. Regression residuals

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 residuals were small and within two standard deviations of the data indicating prices were close to what the model expected.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 16 November 2024

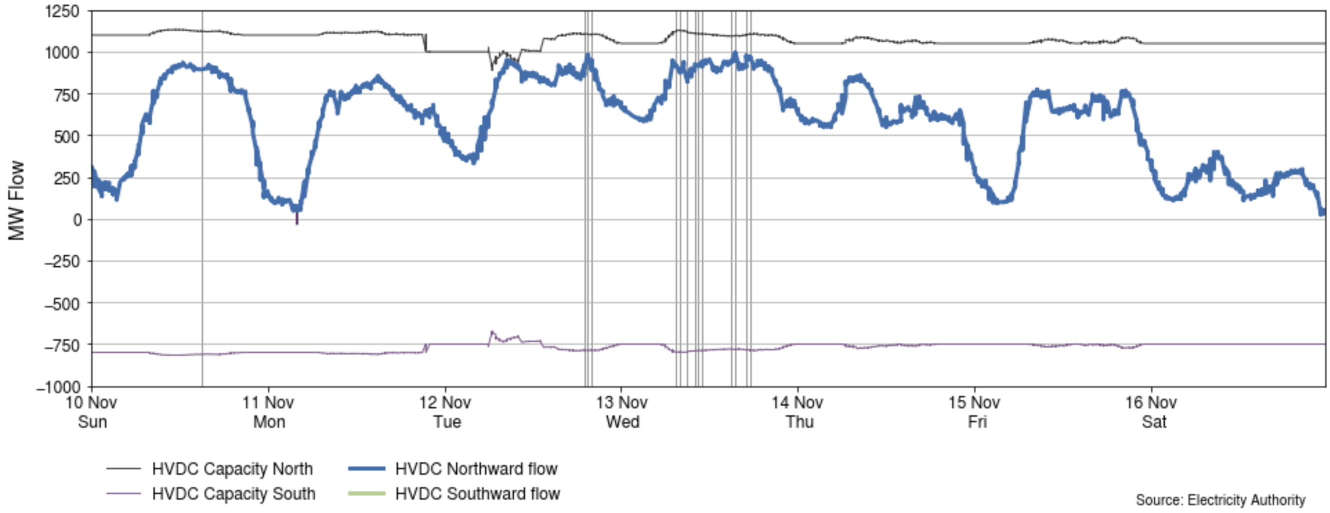


Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 10-16 November 2024. HVDC flows were northwards all week. Lower wind generation midweek saw northward flows close to capacity and was also where a number of the higher prices occurred this week.

Figure 6: HVDC flow and capacity, 10-16 November 2024



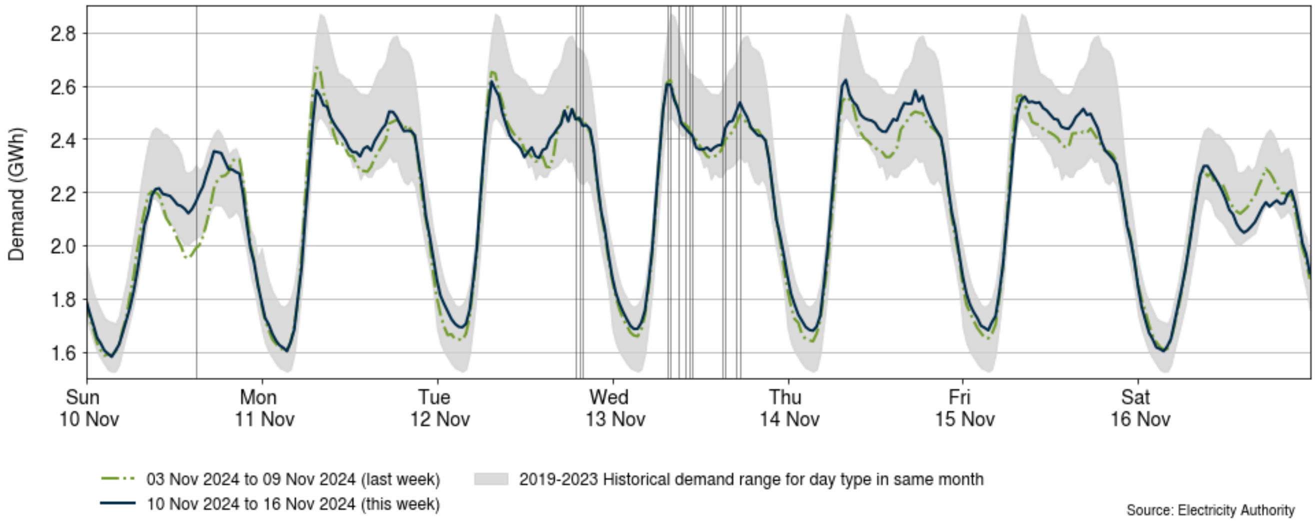
Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 10-16 November 2024, compared to the historic range and the demand of the previous week. Demand was similar to last week and within the historic range for this time of year.

6.2. Maximum demand for this week was 2.62GWh at 8.00am on Thursday.

Figure 7: National demand, 10-16 November 2024 compared to the previous week

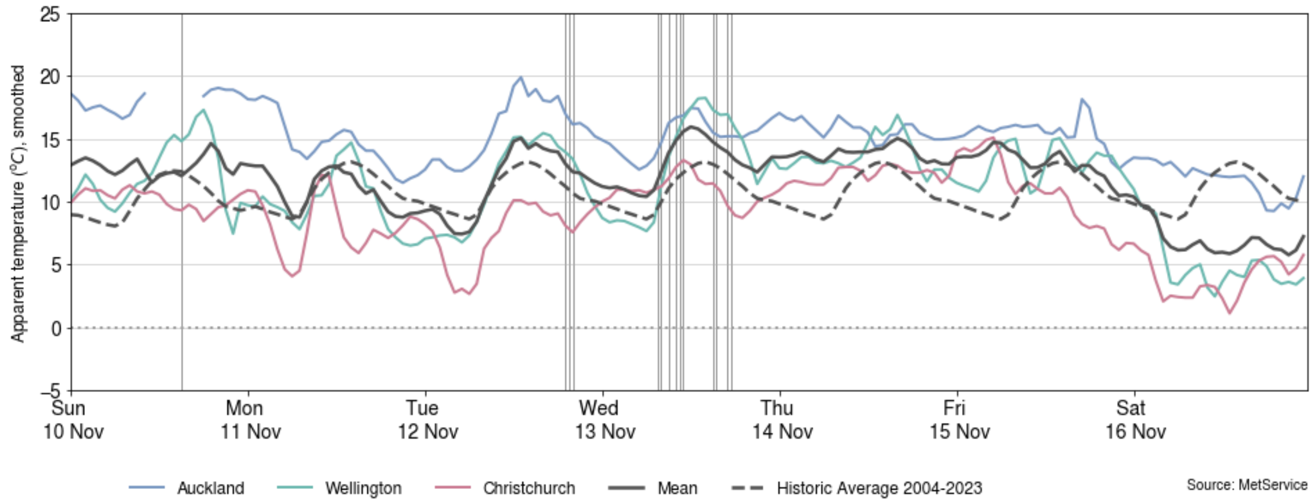


6.3. Apparent temperatures were near or slightly above the historic average this week, until Saturday when temperatures dropped. Apparent temperatures in Auckland ranged from 8.5°C to 21.6°C, Wellington ranged from 1.5°C to 18.4°C and Christchurch ranged from 0.8°C to 15.5°C.

6.4. Figure 8 shows the hourly apparent temperature at main population centres from 10-16 November 2024. 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. There is a small period of missing data for Auckland on Sunday.

6.5. Apparent temperatures were near or slightly above the historic average this week, until Saturday when temperatures dropped. Apparent temperatures in Auckland ranged from 8.5°C to 21.6°C, Wellington ranged from 1.5°C to 18.4°C and Christchurch ranged from 0.8°C to 15.5°C.

Figure 8: Temperatures across main centres, 10-16 November 2024



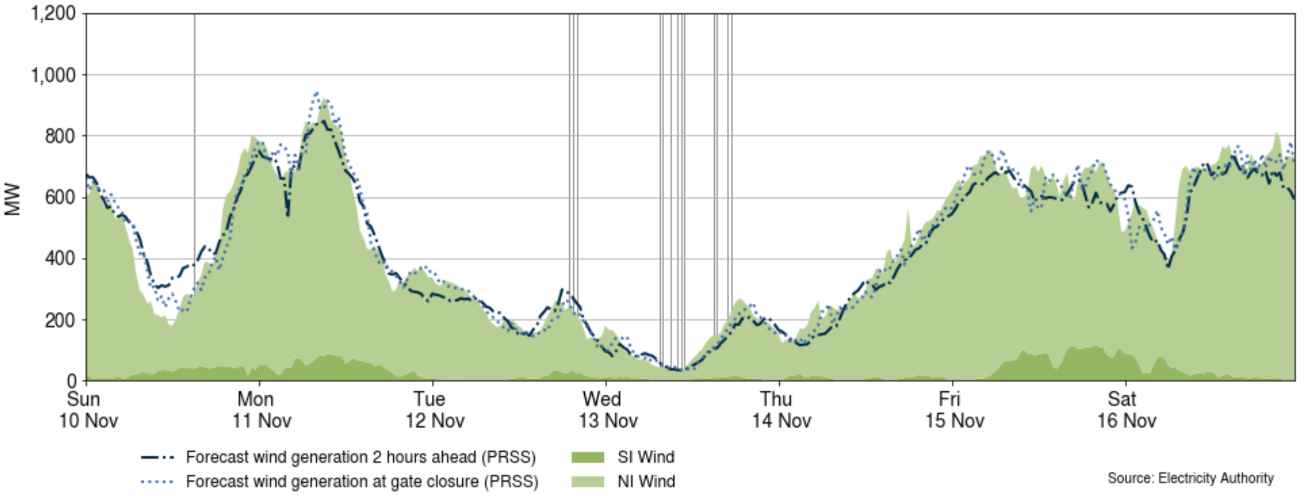
7. Generation

7.1. Figure 9 shows wind generation and forecast from 10-16 November 2024. This week wind generation varied between 34MW and 923MW, with a weekly average of 435MW. Wind generation was low on Sunday and from Tuesday until Thursday evening.

7.2. The biggest discrepancy between actual generation and the gate closure forecast was at 8.00am on Saturday when wind generation was ~200MW higher than forecast.

7.3. The largest discrepancy where wind generation was lower than forecast was at 2.00pm on Monday, when generation was ~140MW below the gate closure forecast.

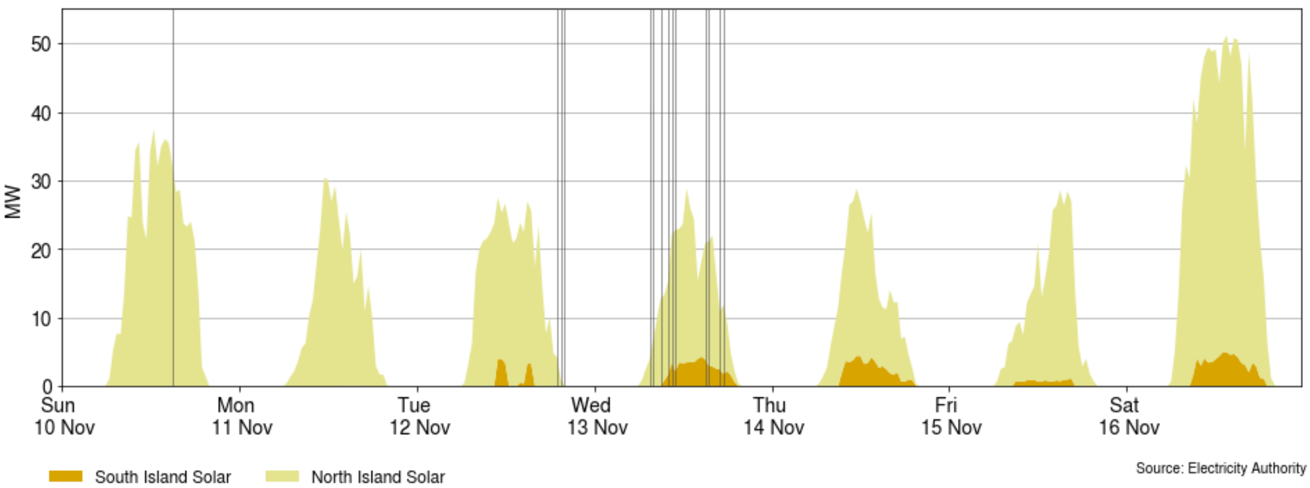
Figure 9: Wind generation and forecast, 10-16 November 2024



7.4. Lauriston solar farm (47MW) near Ashburton began commissioning this week and reached a maximum of 5MW on Saturday. Total solar generation peaked below 30MW every day this week except for Saturday and Sunday.

7.5. Figure 10 shows solar generation from 10-16 November 2024. Lauriston solar farm (47MW) near Ashburton began commissioning this week and reached a maximum of 5MW on Saturday. Total solar generation peaked below 30MW every day this week except for Saturday and Sunday.

Figure 10: Solar generation, 10-16 November 2024



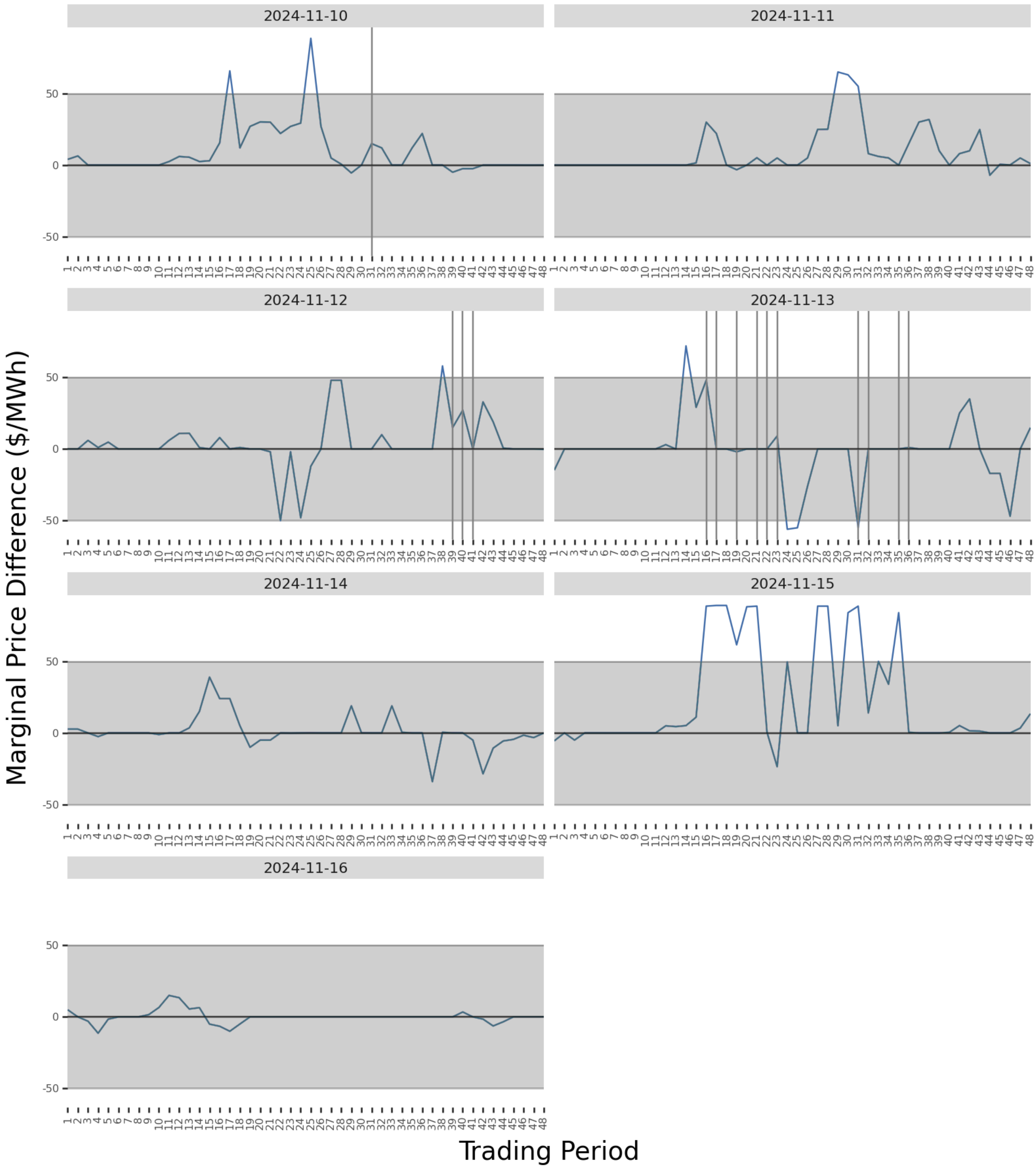
7.6. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-

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.

7.7. The majority of price differences this week were within ±$50/MWh. However, on Friday, 15 November, spot prices were consistently higher than the simulation. This was due to demand being consistently under forecast that day, with the demand at times being 150MW higher than forecast.

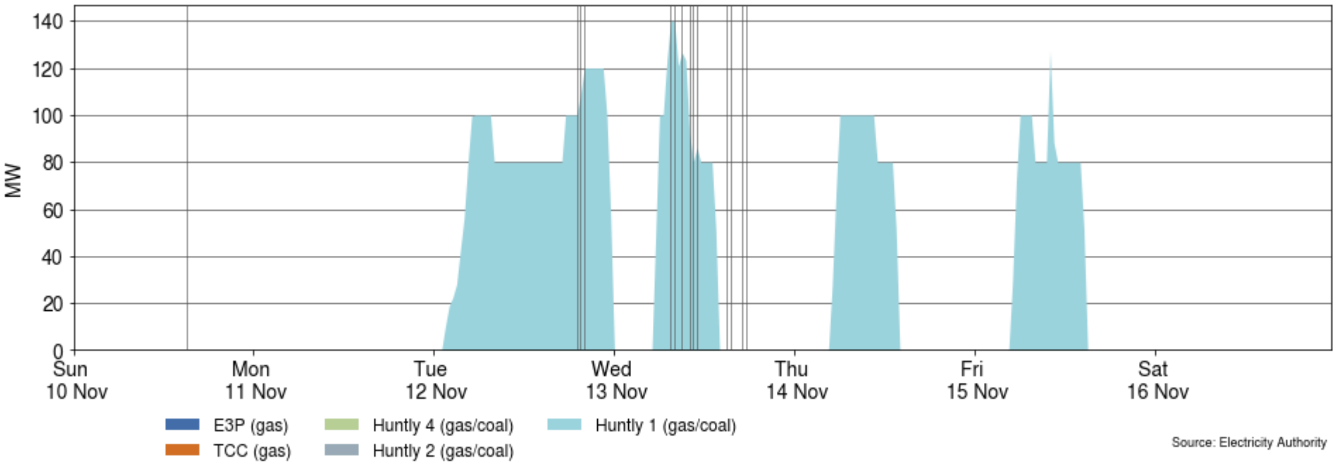
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 10-16 November 2024



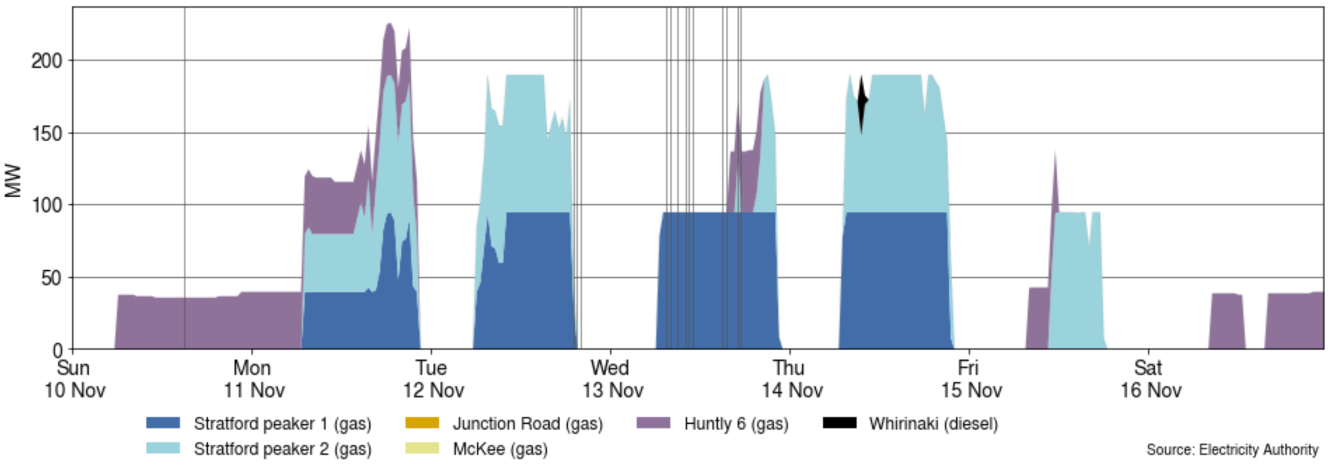
7.8. Figure 12 shows the generation of thermal baseload between 10-16 November 2024. Huntly 1 was the only slow start thermal unit to run this week and only ran during Tuesday to Friday.

Figure 12: Thermal baseload generation, 10-16 November 2024



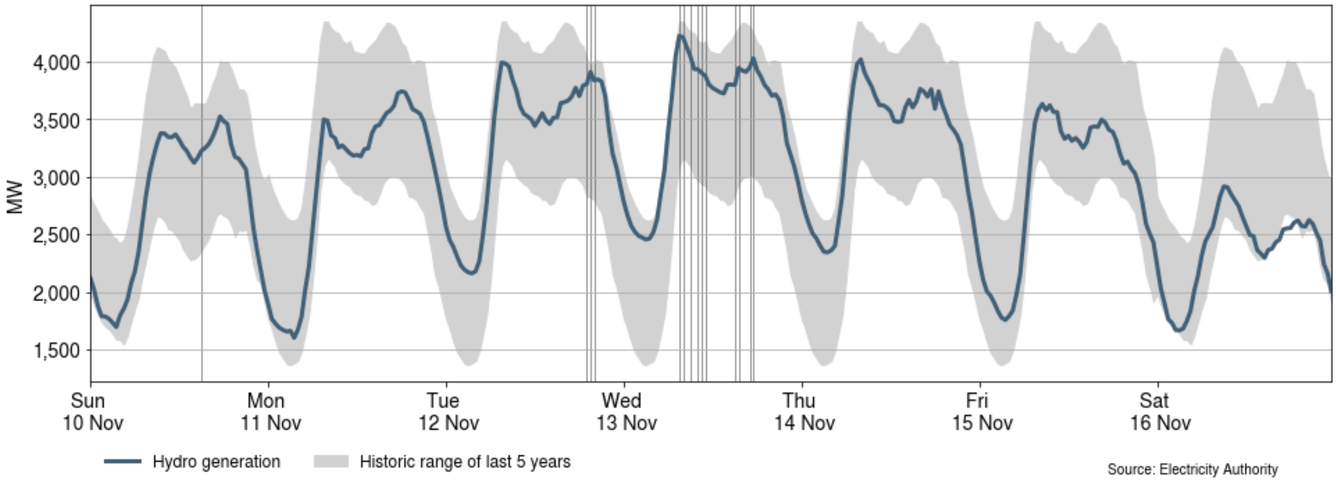
7.9. Figure 13 shows the generation of thermal peaker plants between 10-16 November 2024. Huntly 6 ran this week mainly on days when Huntly 1 was not running, generating continuously from Sunday morning through to late Monday. Both Stratford units were generating over daily peak and/or shoulder periods during the working week. Whirinaki also ran for a brief period on Friday morning, however, the unit was offered in at below $1/MWh.

Figure 13: Thermal peaker generation, 10-16 November 2024



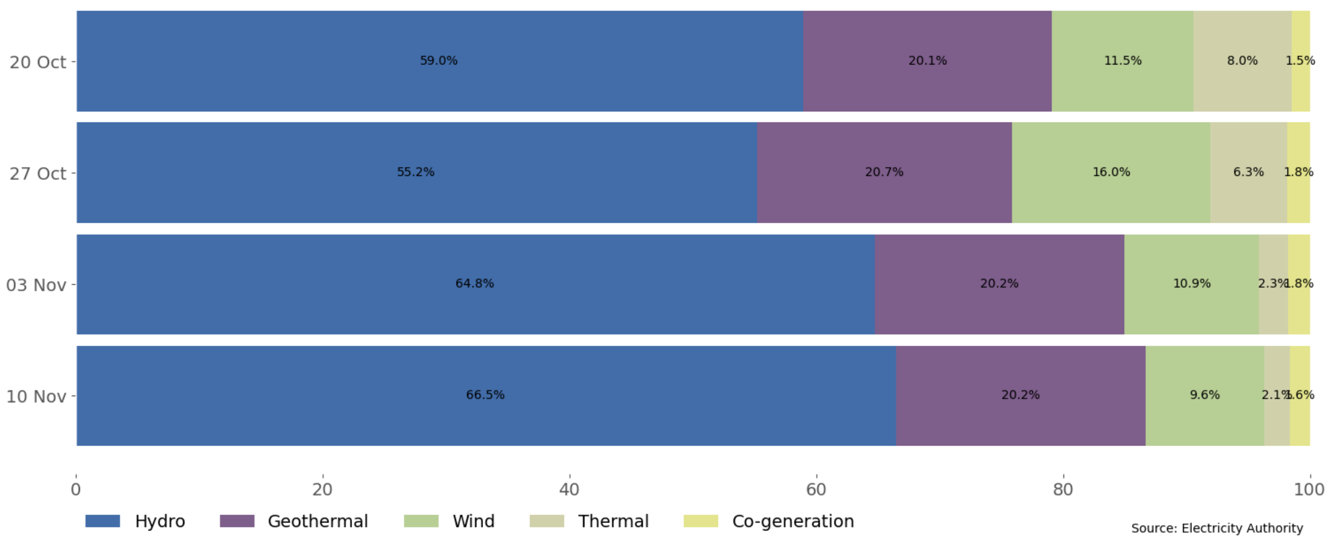
7.10. Figure 14 shows hydro generation between 10-16 November 2024. Hydro generation increased and was within the mid to higher range of the historic range of generation. This is due to a combination of higher available storage, lower thermal commitment, and some low wind generation midweek.

Figure 14: Hydro generation, 10-16 November 2024



7.11. As a percentage of total generation, between 10-16 November 2024, total weekly hydro generation was 66.5%, geothermal 20.2%, wind 9.6%, thermal 2.1%, and co-generation 1.6%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, 20 October to 16 November



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 10-16 November 2024 ranged between ~1550MW and ~2500MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 is on outage until 29 November

(b) Huntly 2 is on outage until 6 December

(c) Stratford 2 was on outage during 15 November and Stratford 1 is on outage until 1 December

(d) Tauhara geothermal unit was on outage until 16 November

(e) A number of large South Island hydro units were on outage across the week.

Figure 16: Total MW loss from generation outages, 10-16 November 2024

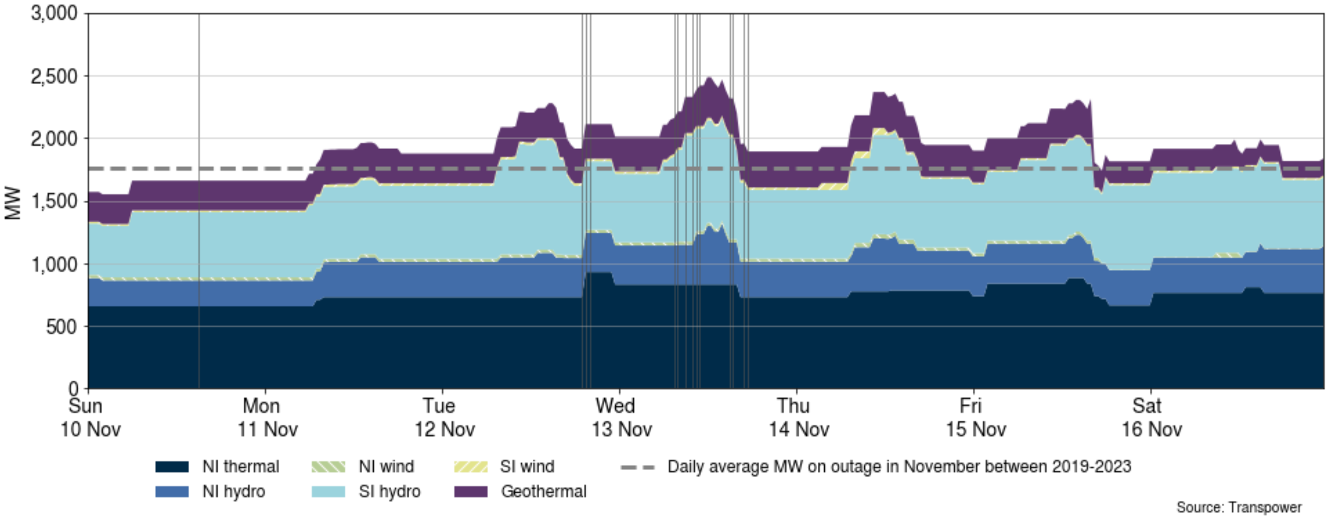
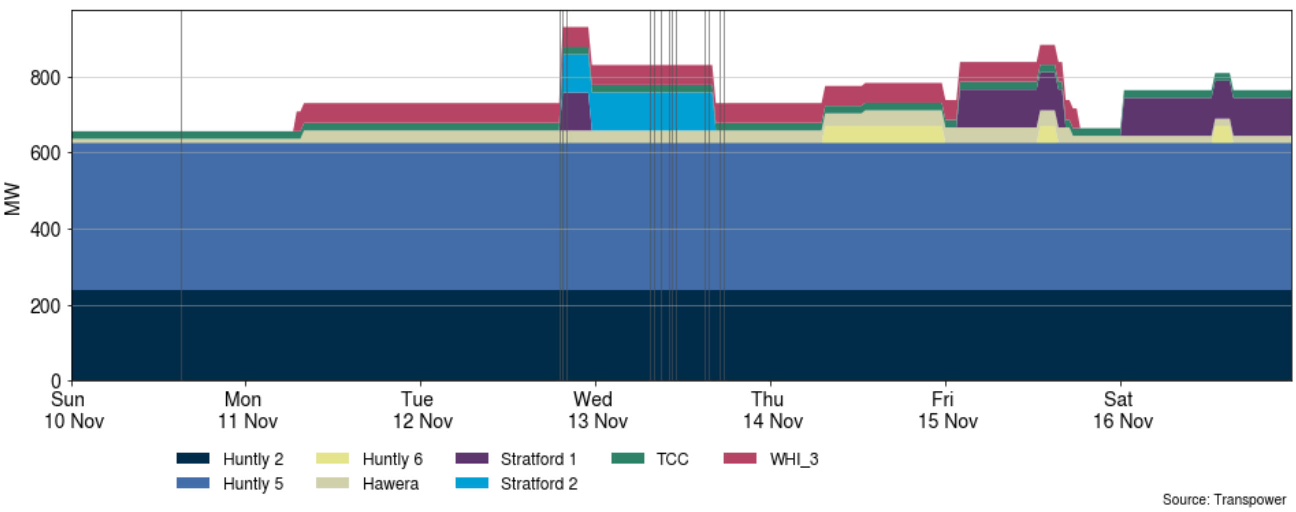


Figure 17: Total MW loss from thermal outages, 10-16 November 2024

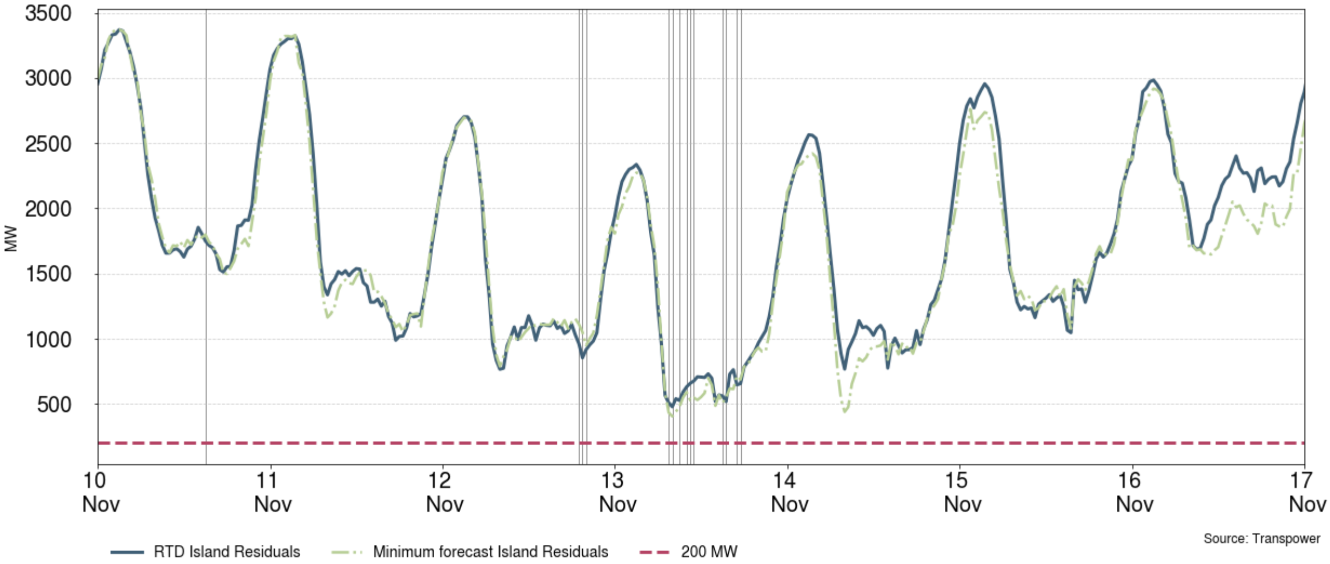


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 10-16 November 2024. 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 with the minimum residual being ~478MW on Wednesday at 8.00am.

Figure 18: National generation balance residuals, 10-16 November 2024



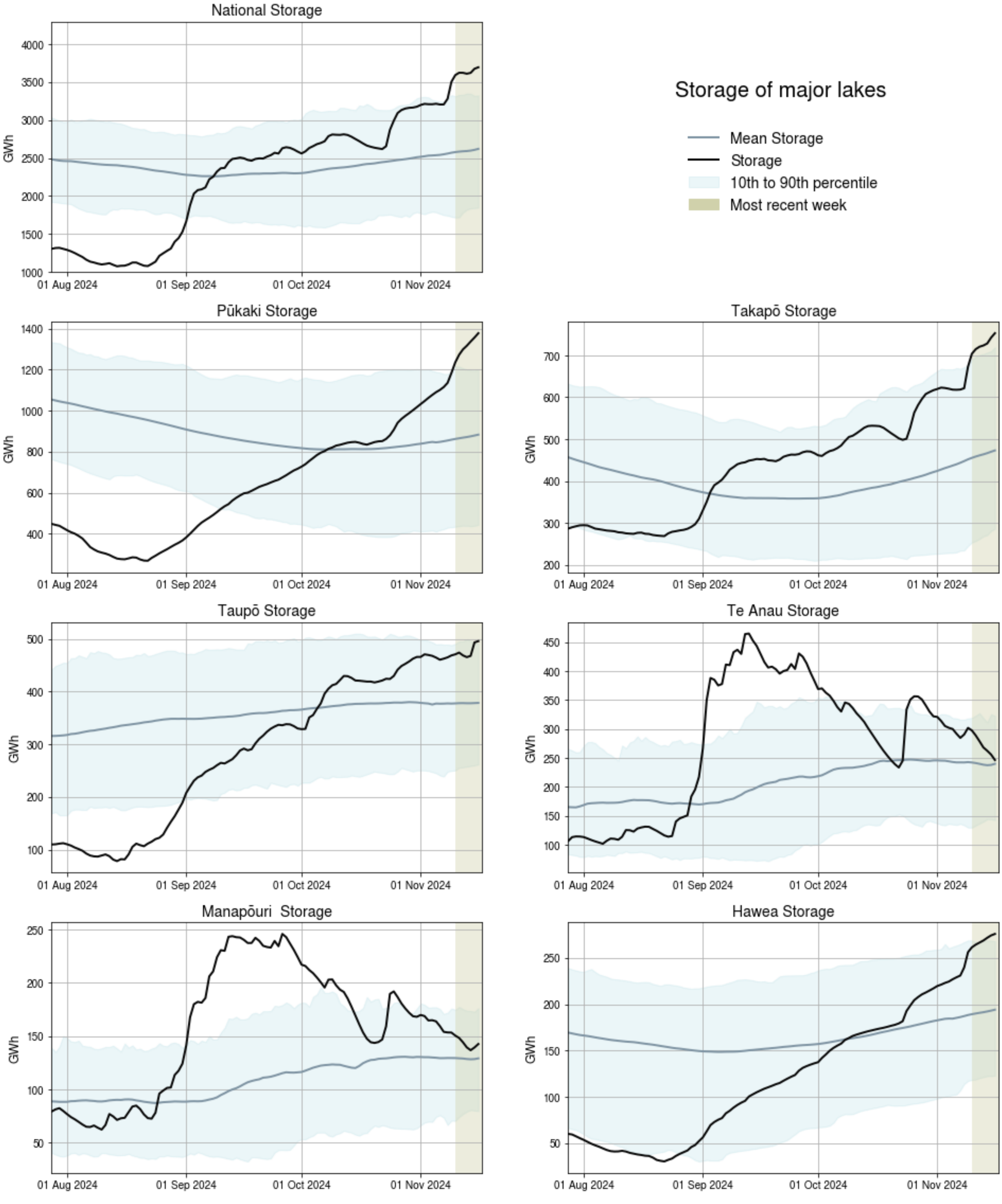
10. Storage/fuel supply

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 this week. As of 16 November, controlled storage was 88.3% nominally full and ~134% of the historical average for this time of the year.

10.3. Most lakes saw increases this week and are at or above their historic 90th percentile range, with Pūkaki seeing the steepest increase in storage across the week. Storage at Manapōuri and Te Anau decreased and is now just above their respective means.

Figure 19: Hydro storage



Source: Electricity Authority

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 November. The SRMC for gas is similar to the previous month with only a small increase. Coal and diesel SRMC have also increased since the previous month.

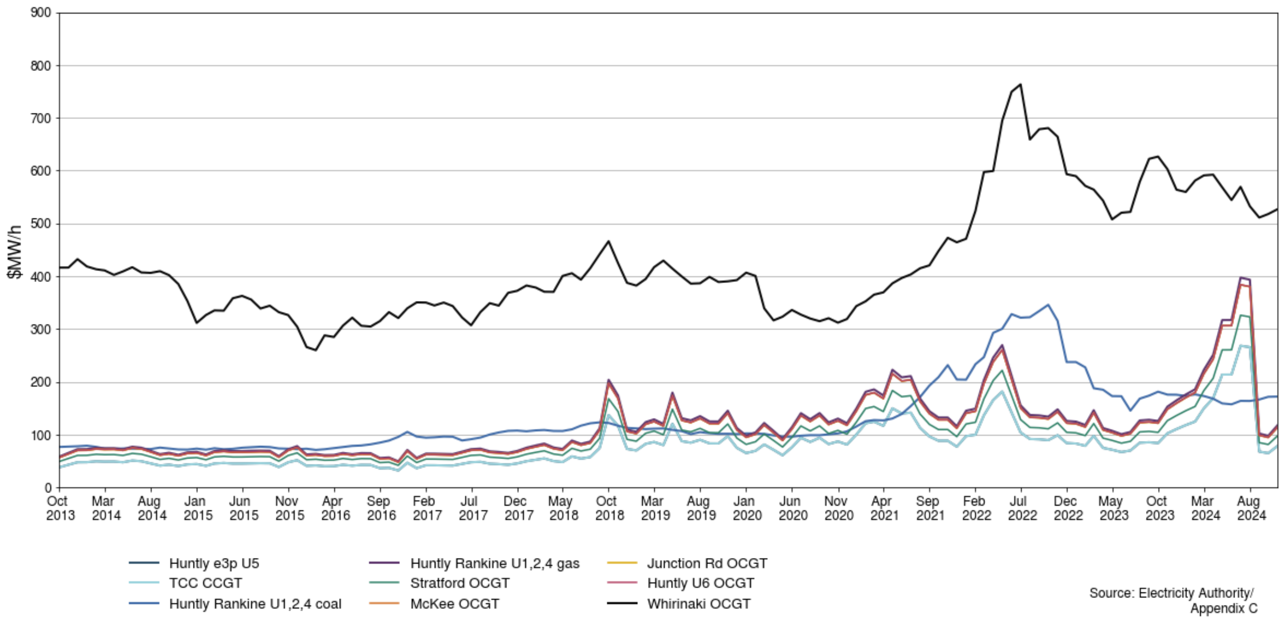
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$172/MWh with the cost of running the Rankines on gas remaining lower at ~$118/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $79/MWh and $118/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 20: Estimated monthly SRMC for thermal fuels



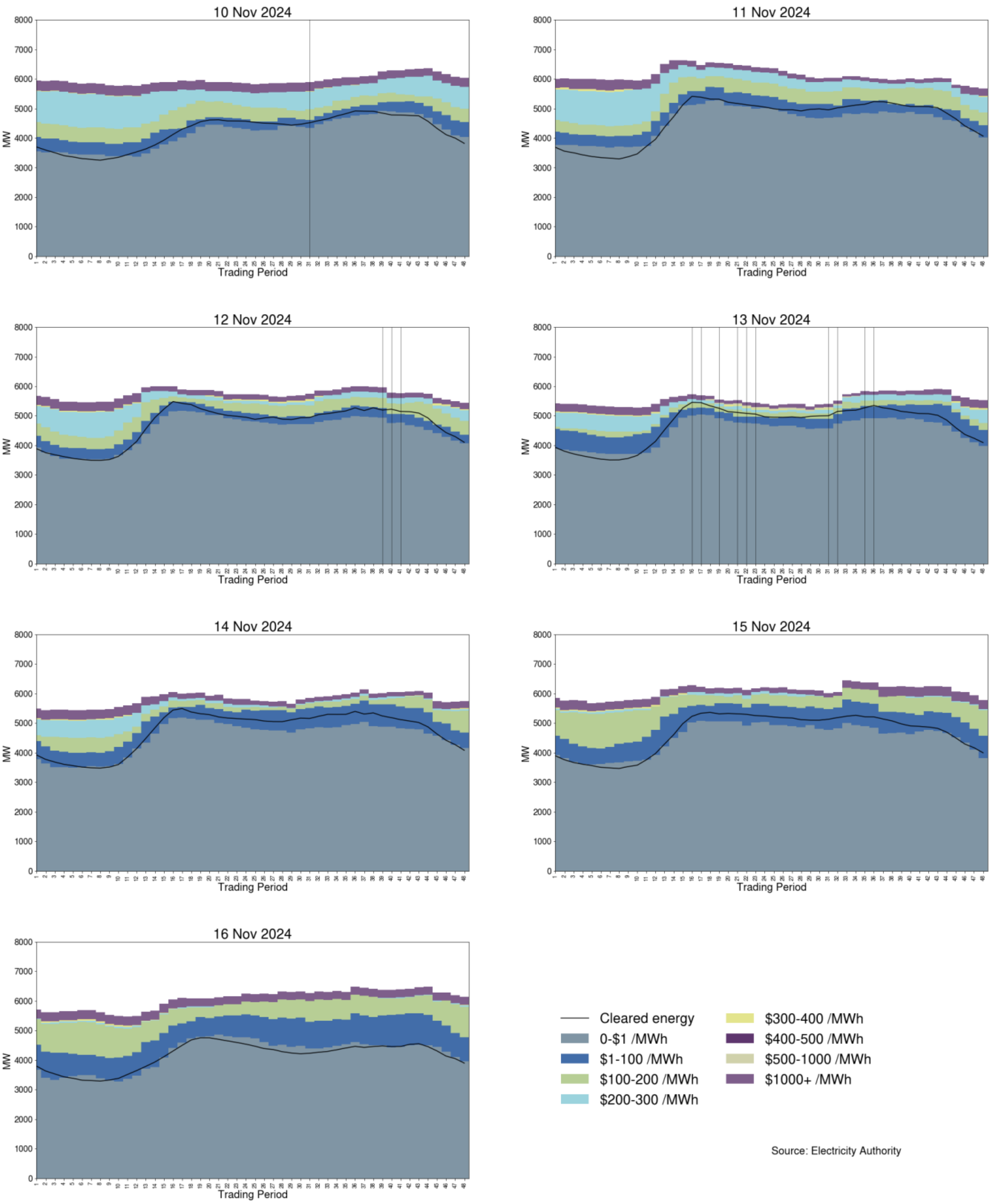
12. Offer behaviour

12.1. Offers mainly cleared in the $1-$100/MWh region this week. However, there were periods, mainly when demand was high and/or wind generation was low, where offers were clearing between $100-$200/MWh.

12.2. Figure 21 shows this week’s national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.3. Offers mainly cleared in the $1-$100/MWh region this week. However, there were periods, mainly when demand was high and/or wind generation was low, where offers were clearing between $100-$200/MWh.

Figure 21: Daily offer stacks



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	Passed to Compliance for advice	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance for advice	Contact	Multiple	High hydro offers
1/07/2024-23/08/2024	Several	These trading periods are now part of a s16 review	N/A	N/A	High energy prices
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers