23 December 2024

# Trading conduct report 15-21 December 2024

Market monitoring weekly report

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## 1. Overview

1.1. Spot prices decreased compared to last week to an average of $29/MWh and were mostly below the historical median. National hydro storage remained stable at ~96% full and hydro generation remained high, resulting in almost entirely northward HVDC transfer this week. Thermal generation remains low at less than 1% of the generation mix.

1.2. This will be the final trading conduct report published in 2024. We will return in January with a report covering 22 December – 4 January.

## 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 15-21 December 2024:

(a) the average wholesale spot price across all nodes was $29/MWh.

(b) 95% of prices fell between $0.03/MWh and $172/MWh.

2.3. Overall, the majority of spot prices were within $7-$33/MWh and the weekly average price decreased by around $16/MWh compared to the previous week.

2.4. Prices were mostly below the historical median this week and dropped below the historic 10th percentile at the end of the week.

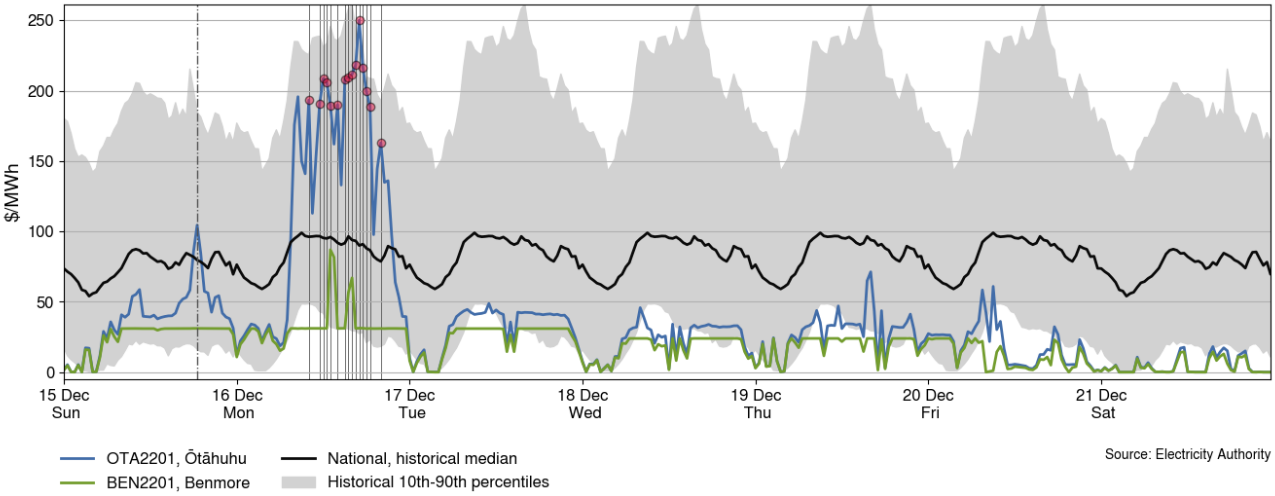
2.5. The Ōtāhuhu spot price increased above the historical median to $106/MWh on Sunday at 6.30pm while the Benmore price remained low at $31/MWh. At this time, national demand was ~100MW higher than forecast and above the historical range for this time of year and wind generation was ~50MW lower than forecast.

2.6. Monday saw volatile Ōtāhuhu spot prices that separated from Benmore for most of the day due to low wind generation and the HVDC running near its northward limit. The highest Ōtāhuhu spot price for the week was $250/MWh at 5.00pm on Monday, when the Benmore spot price was $31/MWh, and wind generation was ~170MW lower than forecast.

2.7. The Ōtāhuhu spot price also spiked at 12.00pm on Monday at $209/MWh when the Benmore spot price was $31/MWh. At the time, wind generation was ~130MW lower than forecast and national demand was ~110MW higher than forecast.

2.8. 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.

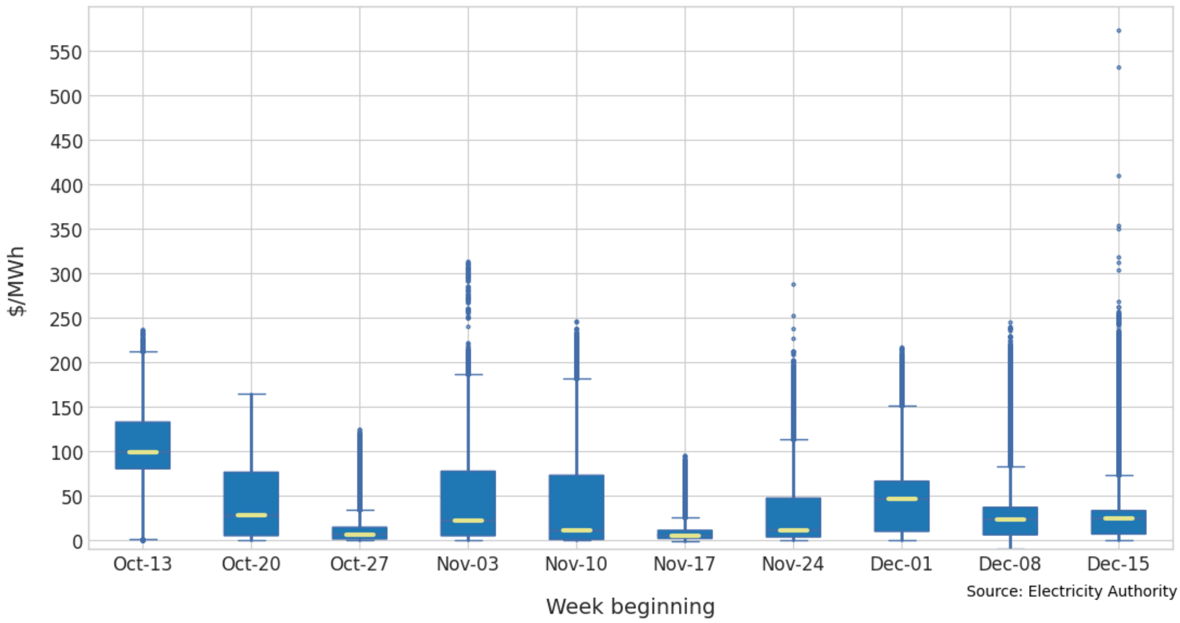
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 15-21 December 2024**




2.9. 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.

2.10. The price distribution this week was similar to last week's with a median spot price of $24/MWh. There were some North Island nodes this week that had prices exceeding $300/MWh due to line constraints. These nodes include MTR0331 (Mataroa), MST0331 (Masterton), GYT0331 (Greytown), OKN0111 (Ohakune), MGM0331 (Mangamaire) and NPK0331 (National Park).

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

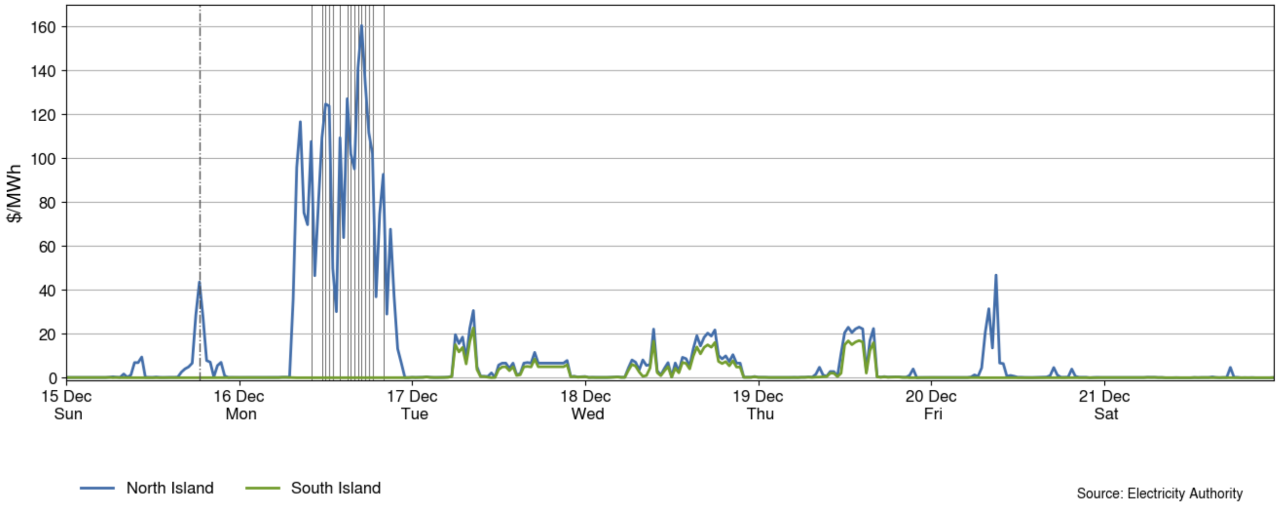


# 3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3.

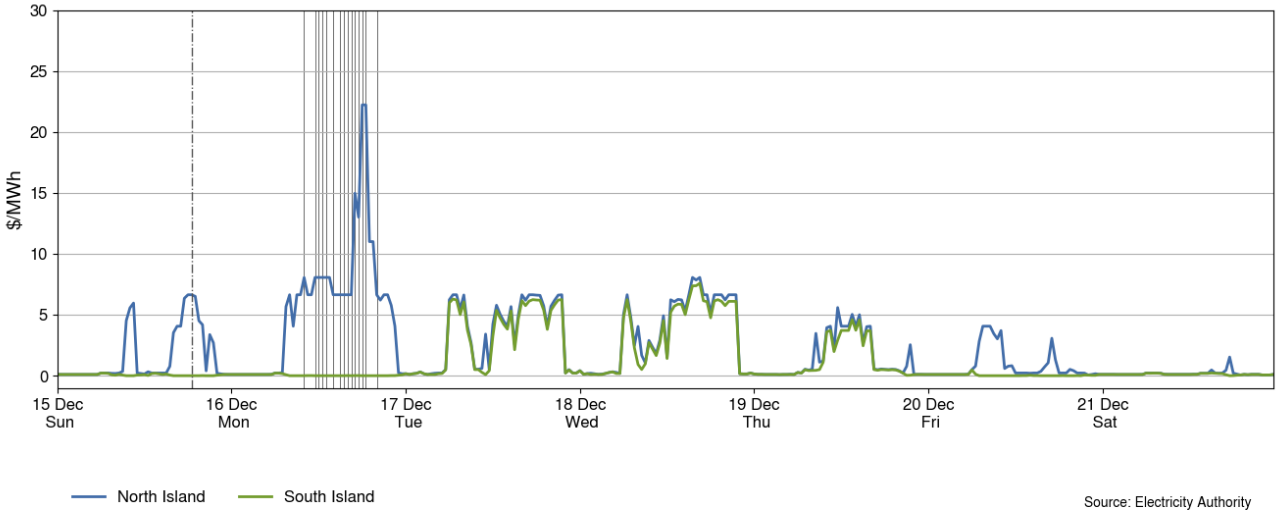
3.2. Separation between North and South Island FIR prices occurred on Sunday evening, during the day on Monday and on Friday morning because of high northward HVDC flow and the HVDC setting the risk in the North Island. North Island FIR prices peaked at $160/MWh on Monday at 5.00pm, at the same time, the South Island FIR price was $0/MWh.

**Figure 3: Fast instantaneous reserve price by trading period and island, 15-21 December 2024**




3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. North Island SIR prices also separated on Sunday, Monday and Friday when the HVDC was setting the risk. North Island SIR reached a maximum of $22/MWh on Monday between 6.00pm and 6.30pm, when the South Island SIR price was $0/MWh.

**Figure 4: Sustained instantaneous reserve by trading period and island, 15-21 December 2024**



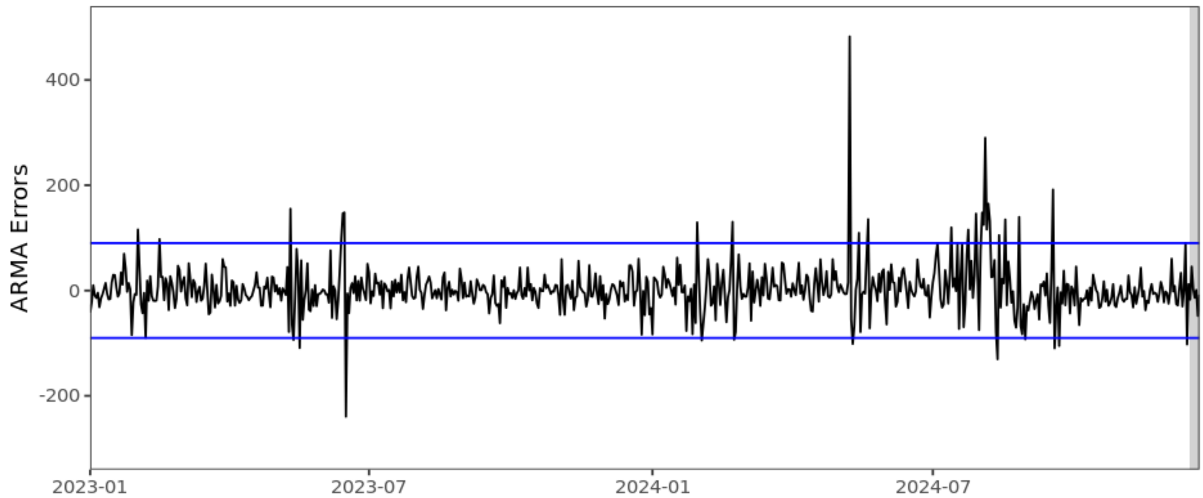

# 4. Regression residuals

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, 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 – 21 December 2024**

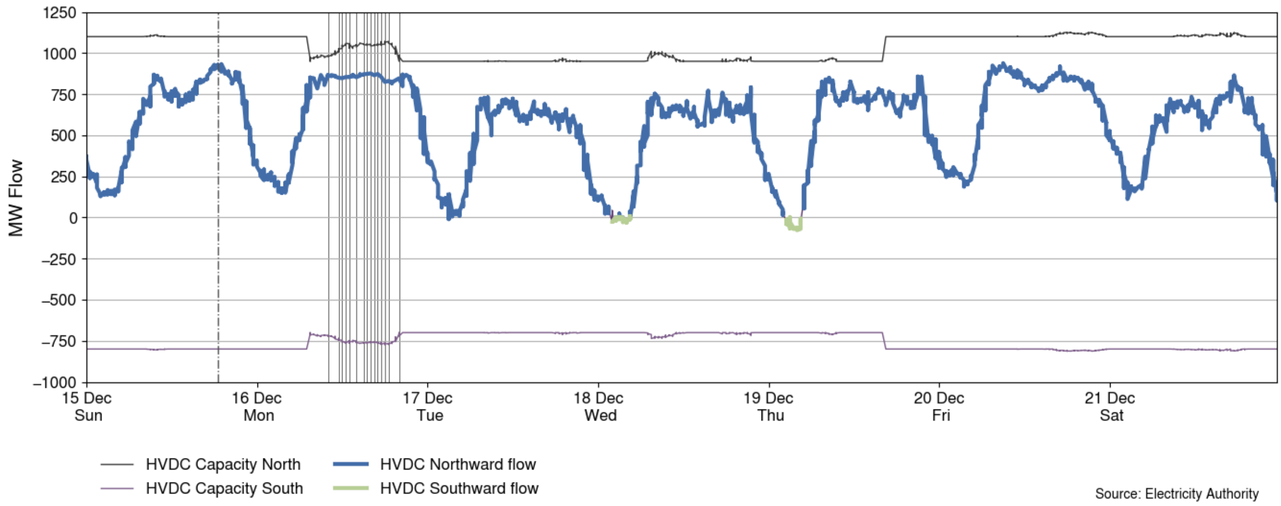



Source: Electricity Authority/Appendix A

# 5. HVDC

5.1. Figure 6 shows the HVDC flow between 15-21 December 2024. HVDC flows were almost entirely northward this week, with a small amount of southward flow overnight on Wednesday and Thursday.

**Figure 6: HVDC flow and capacity, 15-21 December 2024**

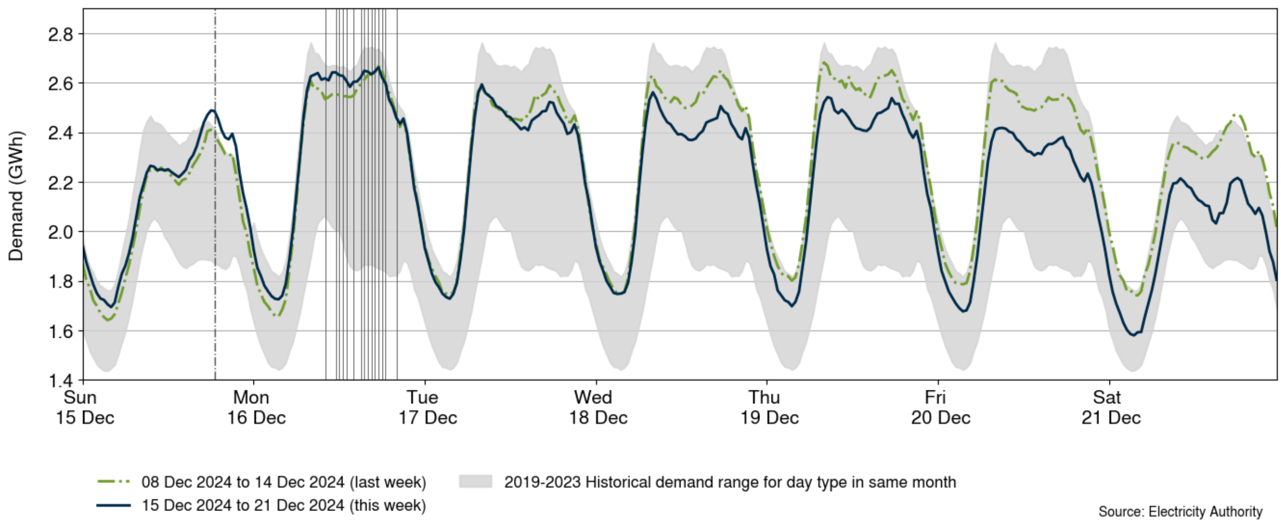



# 6. Demand

6.1. Figure 7 shows national demand between 15-21 December 2024, compared to the historic range and the demand of the previous week. The maximum demand this week was around 2.66GWh (5.33GW) at 5.30pm on Monday.

6.2. Demand followed a similar pattern to national average temperatures this week. Demand was higher on Sunday and Monday when national temperatures were higher and more cooling was likely running, and there was lower demand through the middle of the week when cooling demand was likely lower.

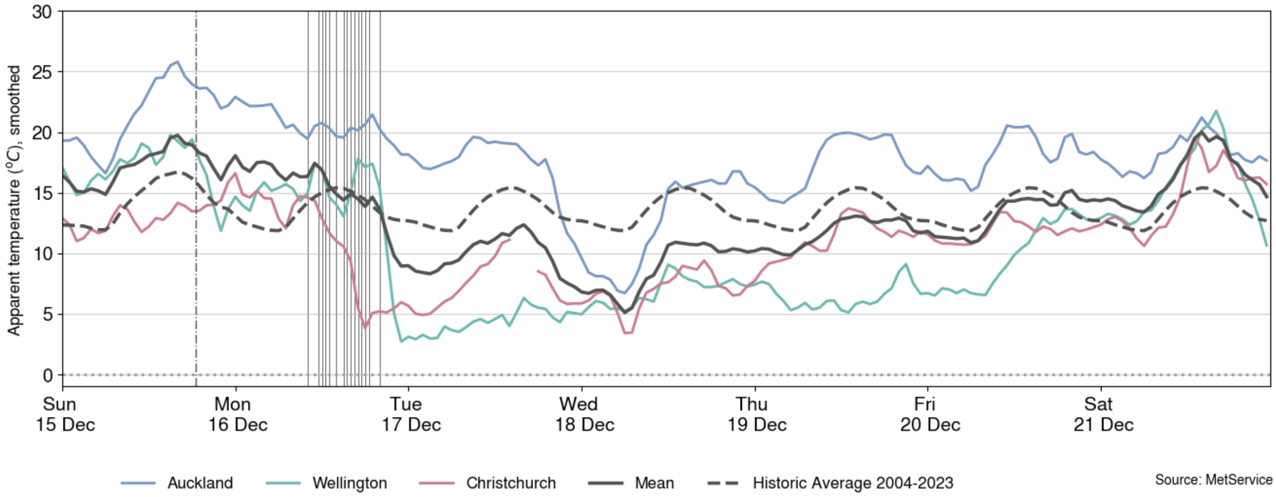
**Figure 7: National demand, 15-21 December 2024 compared to the previous week**




6.3. Figure 8 shows the hourly apparent temperature at main population centres from 15-21 December 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.

6.4. Apparent temperatures ranged from 6°C to 27°C in Auckland, 2°C to 23°C in Wellington, and 3°C to 20°C in Christchurch. Apparent temperatures were lowest during the middle of the week and dropped well below average on Wednesday morning.

**Figure 8: Temperatures across main centres, 15-21 December 2024**

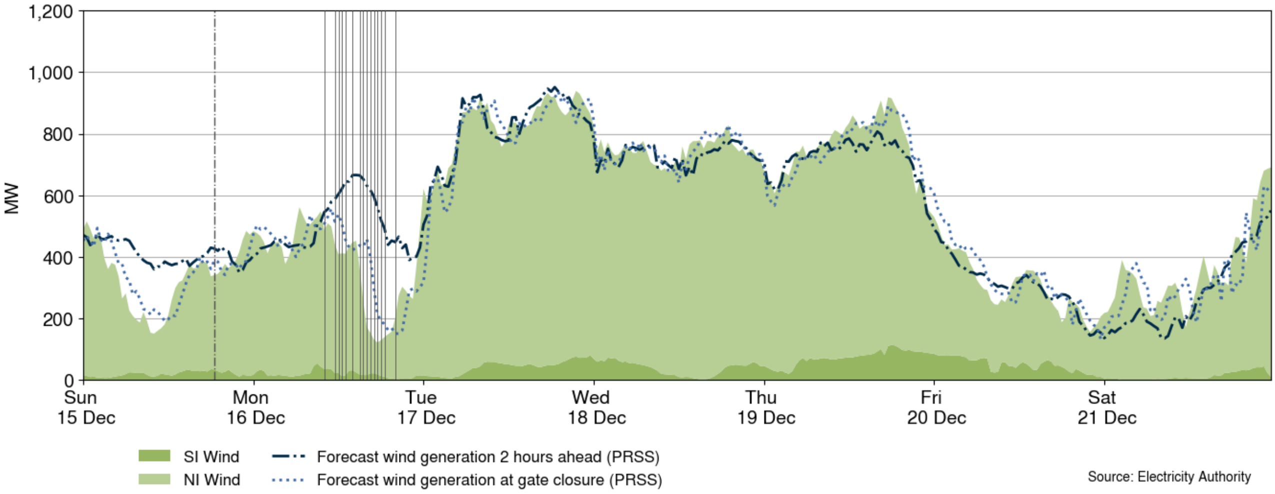



## 7. Generation

7.1. Figure 9 shows wind generation and forecast from 15-21 December 2024. Wind generation this week varied between 122MW and 939MW, with a weekly average of 529MW. Wind generation was strong through the middle of the week before reducing on Friday.

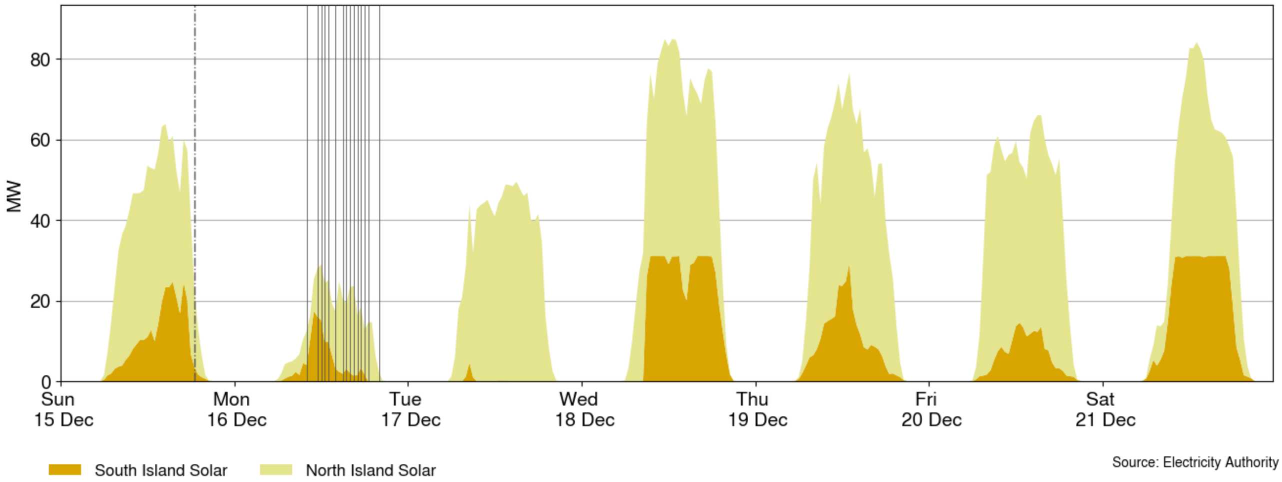
7.2. Monday saw some large discrepancies between generation and both the 2 hours ahead and gate closure forecasts. The largest discrepancy between generation and the gate closure forecast was ~290MW at 4.00pm on Monday when wind generation was reducing quickly.

**Figure 9: Wind generation and forecast, 15-21 December 2024**




7.3. Figure 10 shows solar generation from 15-21 December 2024. Solar generation reached a peak of at least 60MW every day this week except for Monday and Tuesday.

**Figure 10: Solar generation, 15-21 December 2024**



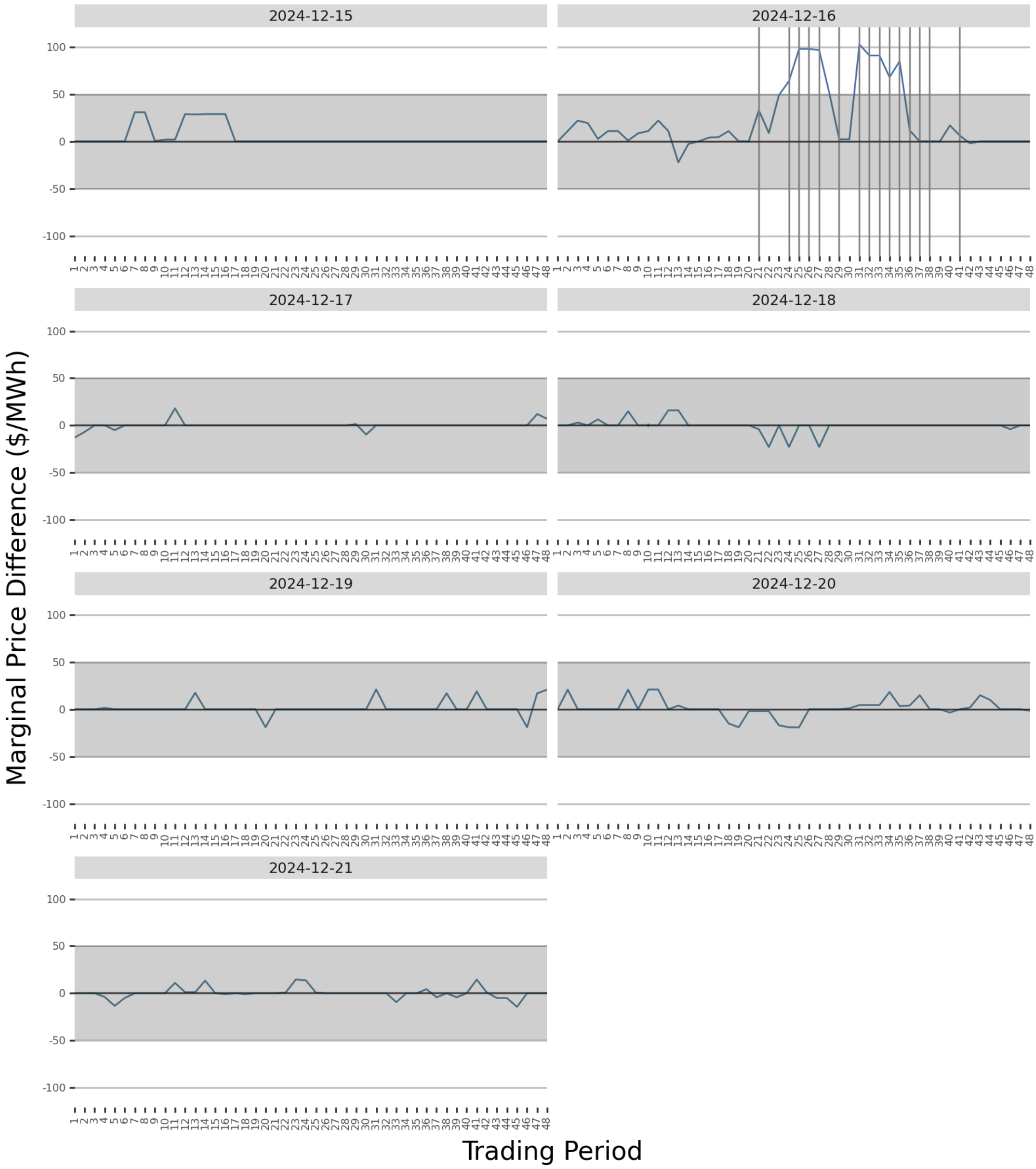

7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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. Several positive marginal price differences this week occurred on Monday. The largest difference was +$103/MWh at 3pm when national demand was ~66MW higher than forecast and wind generation was ~75MW lower than forecast.

7.6. Marginal price differences were less than $50/MWh every other day this week.

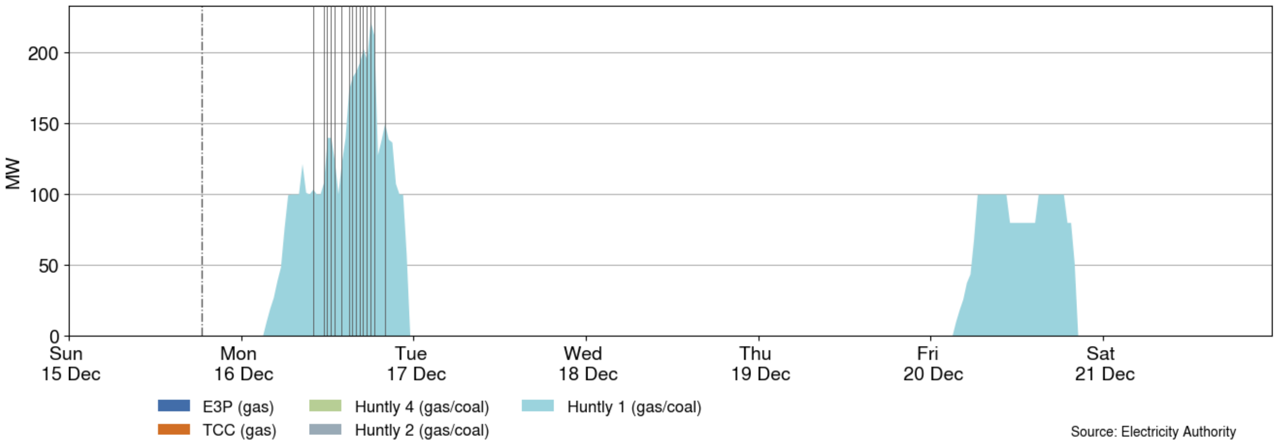
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

**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, 15-21 December 2024**



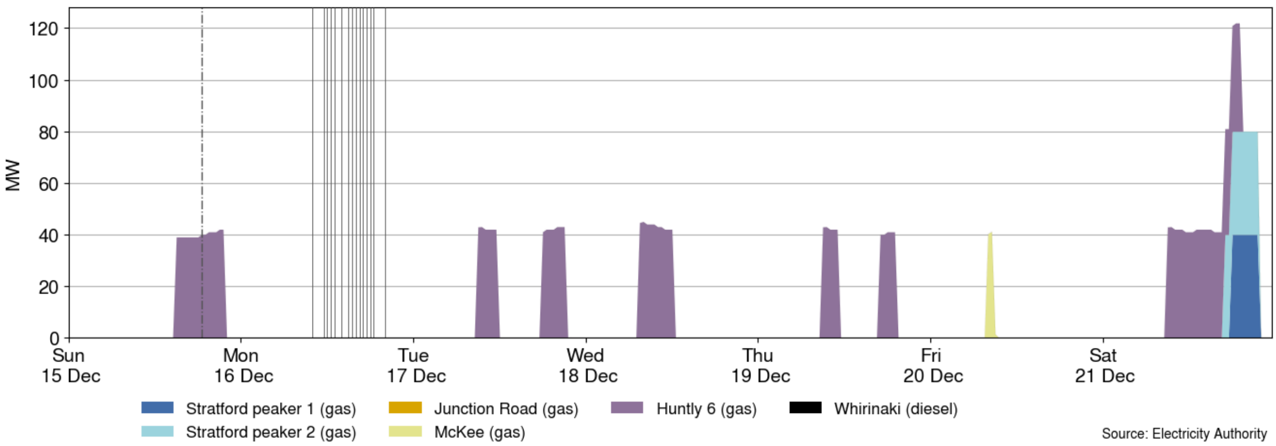

7.7. Figure 12 shows the generation of thermal baseload between 15-21 December 2024. Huntly 1 ran as baseload this week on Monday and Friday when wind generation was lower.

**Figure 12: Thermal baseload generation, 15-21 December 2024**



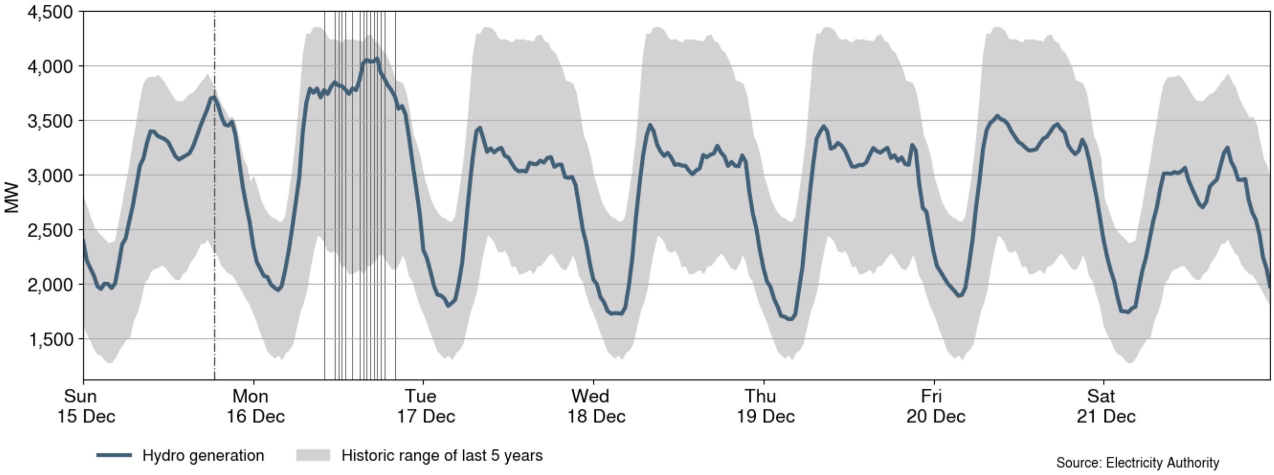

7.8. Figure 13 shows the generation of thermal peaker plants between 15-21 December 2024. Huntly 6 ran every day this week except for Monday and Friday. McKee ran briefly on Friday morning and both Stratford peakers ran on Saturday evening.

**Figure 13: Thermal peaker generation, 15-21 December 2024**



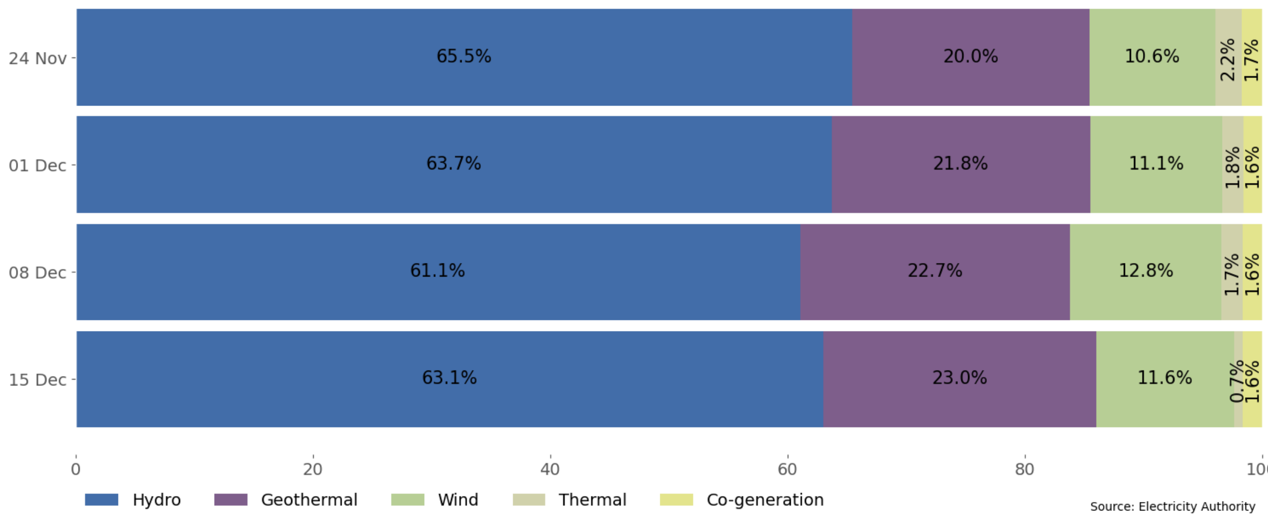

7.9. Figure 14 shows hydro generation between 15-21 December 2024. Hydro generation was highest on Monday and was lower from Tuesday onwards because of reduced demand when national temperatures dropped.

**Figure 14: Hydro generation, 15-21 December 2024**



7.10. As a percentage of total generation, between 15-21 December 2024, total weekly hydro generation was 63.1%, geothermal 23%, wind 11.6%, thermal 0.7%, and co-generation 1.6%, as shown in Figure 15. Hydro generation increased this week and thermal generation reduced to less than 1% of the total generation mix.

**Figure 15: Total generation by type as a percentage each week, 24 November – 21 December 2024**




# 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 15-21 December 2024 ranged between ~850MW and ~1,901MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage until 14 March 2025.

(b) Huntly 5 returned from outage on 17 December.

(c) Manapōuri unit 6 returned from long-term outage on 16 December.

(d) Several large hydro units are on outage.

**Figure 16: Total MW loss from generation outages, 15-21 December 2024**

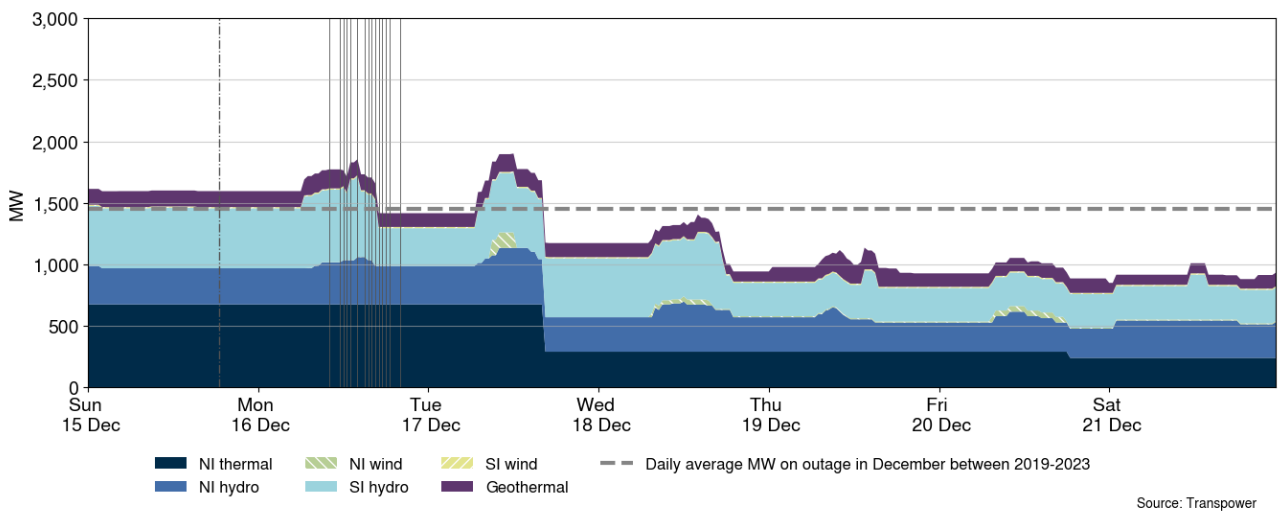
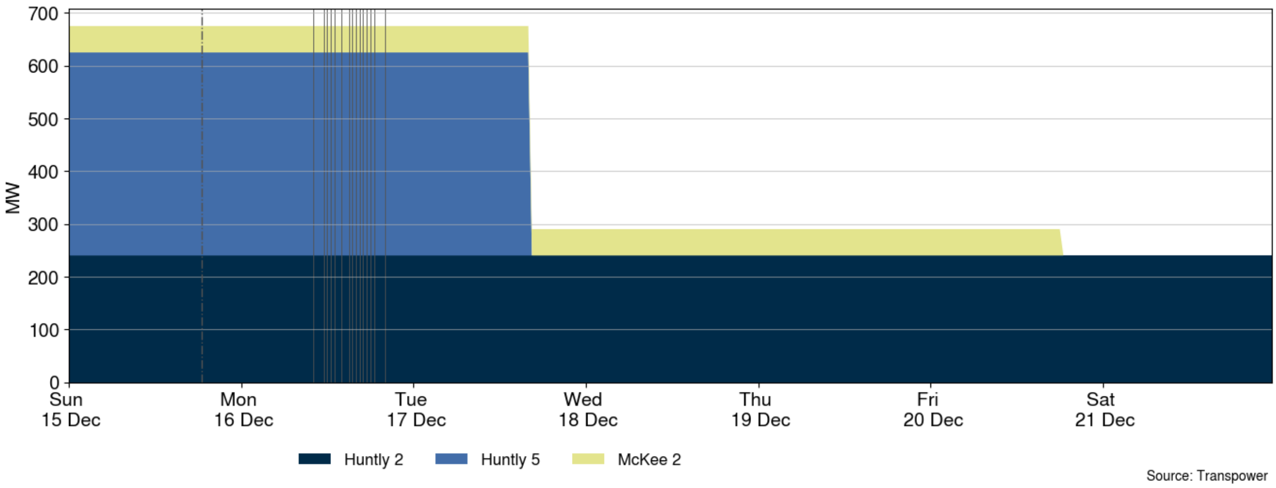


**Figure 17: Total MW loss from thermal outages, 15-21 December 2024**

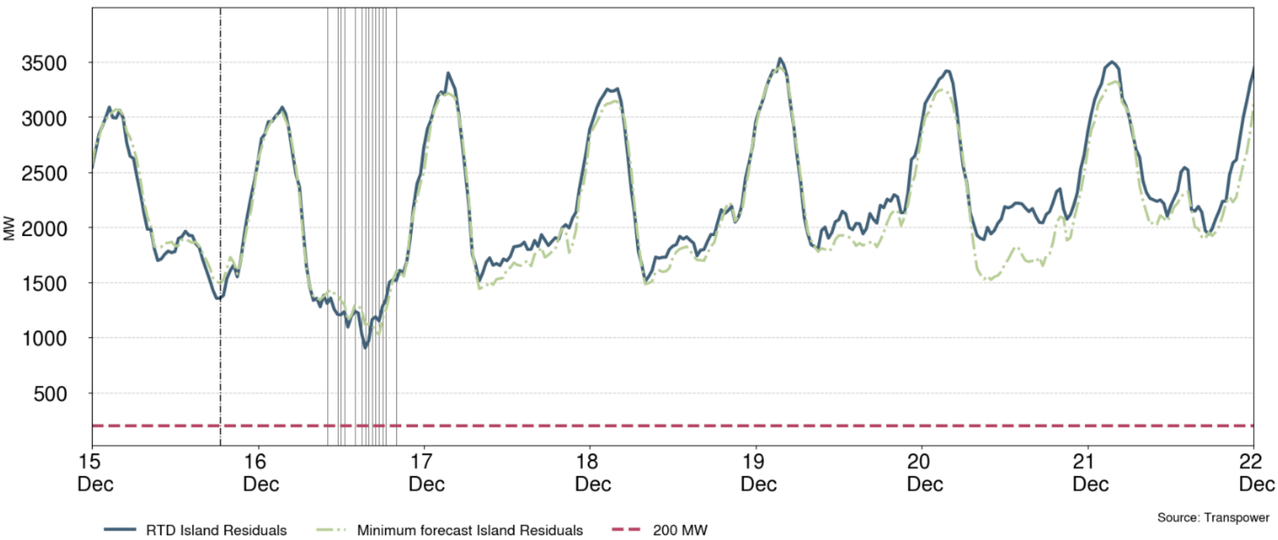



# 9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 15-21 December 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. The minimum North Island residual this week was ~720MW at 3.30pm on Monday.

**Figure 18: National generation balance residuals, 15-21 December 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 remained steady this week at ~96% nominally full and ~132% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki continues to increase above its 90th percentile and is now ~100% full and spilling. Storage at Lakes Takapō (97% full), Taupō (84% full) and Hawea (94% full) held steady this week around their 90th percentiles.[2]

10.4. Lake Manapōuri reduced this week to its historical mean and Lake Te Anau reduced to slightly below its historic 90th percentile.

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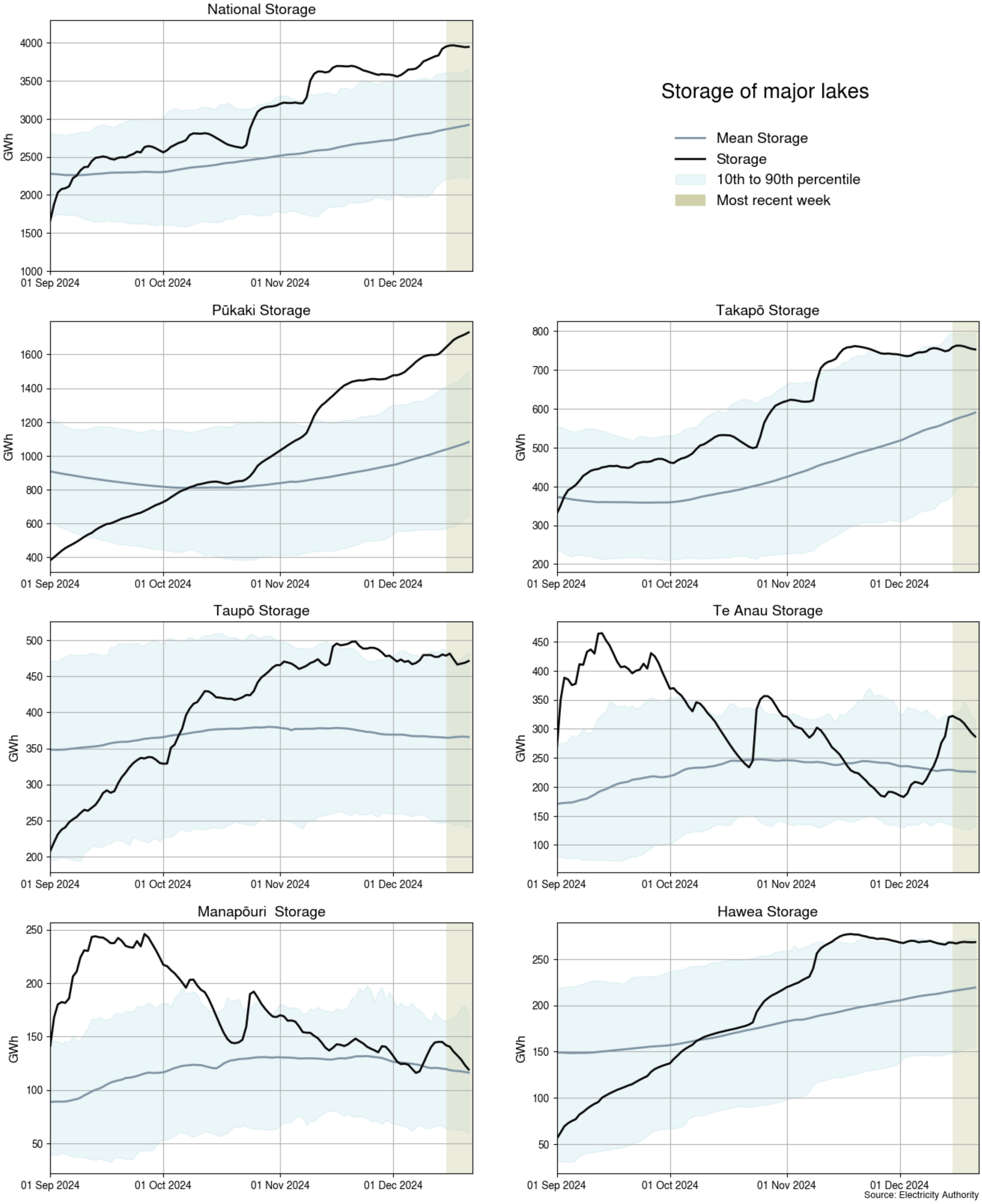
[2] Percentage full values sourced from NZX Hydro.

**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 December 2024. The SRMC for gas fuelled generation has decreased compared to last month and the SRMC for coal and diesel fuelled generation remains similar to last month.

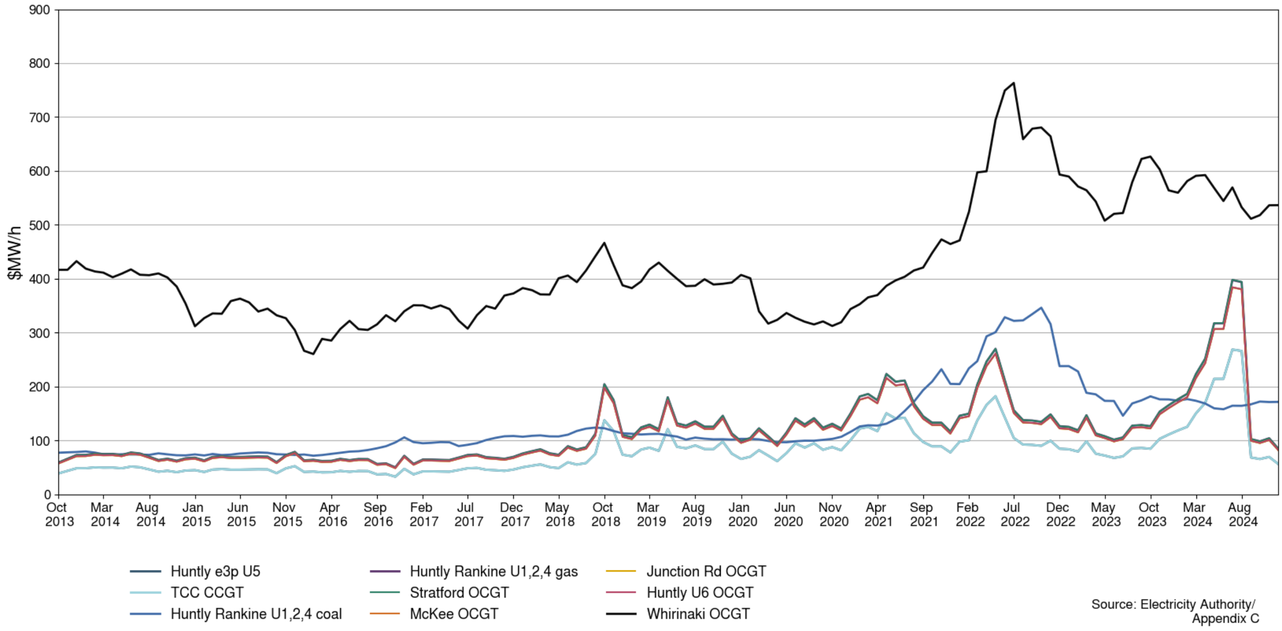
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$171/MWh, with the cost of running the Rankines on gas remaining lower at ~$85/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $56/MWh and $85/MWh.

11.6. The SRMC of Whirinaki is ~$536/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**



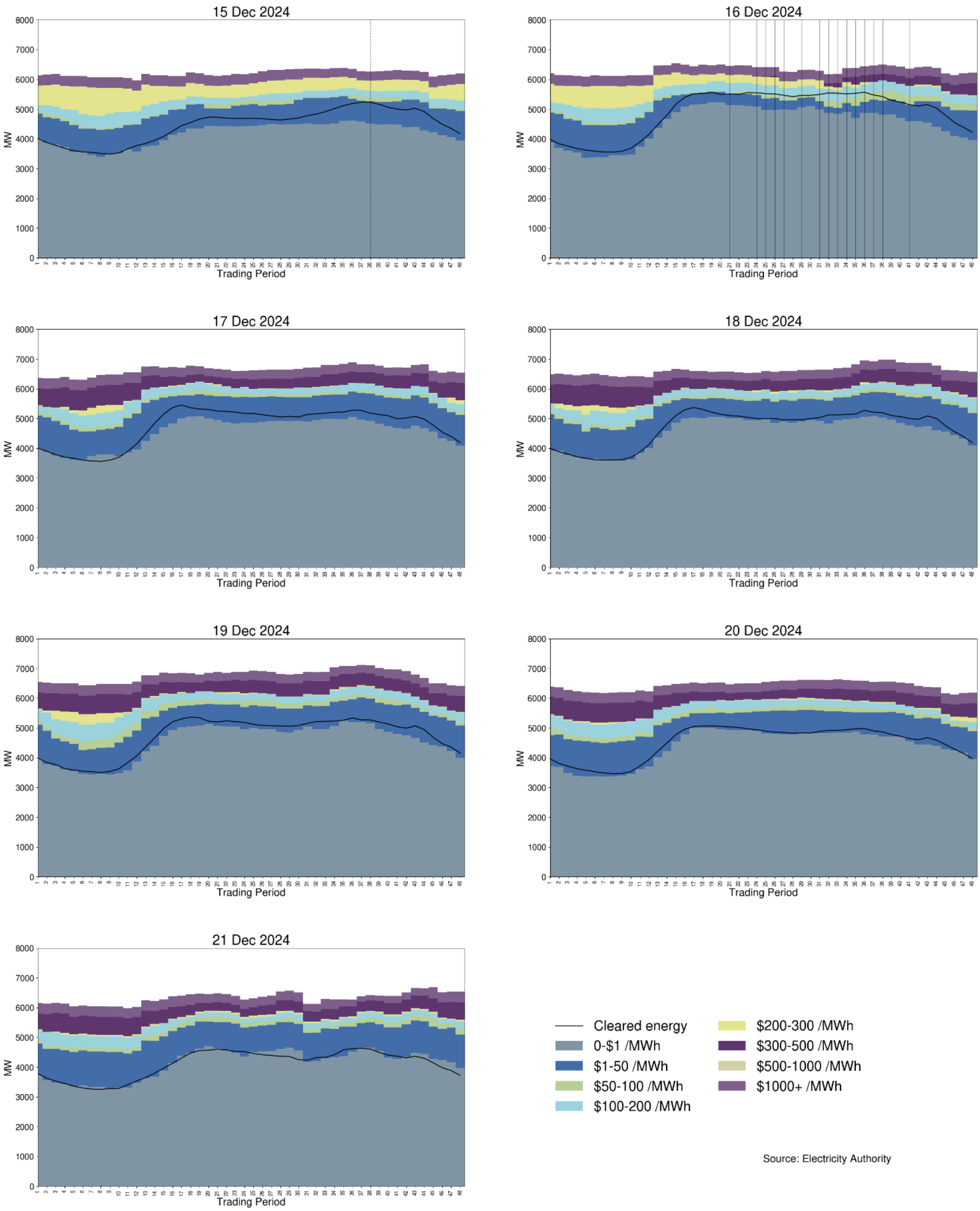

## 12. Offer behaviour

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. The offer stack dropped on Saturday 21st December in the afternoon when a lightning strike resulted in multiple trippings and loss of supply to the Hawkes Bay area.[3] The $300-500/MWh band increased from Monday afternoon, the monitoring team will be further analysing these offer changes.

[3] GEN RPT for Unplanned outage Hawkes Bay 5854778628.pdf

**Figure 21: Daily offer stacks**




Source: Electricity Authority

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

12.4. 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, 460MW per trading period was above $1,000/MWh this week, which is roughly 7% of the total energy available. The high priced Stratford offers reduced on Saturday when they were generating.

**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.

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 |
| **3-4/09/2024 and 13-18/09/2024** | Several | Further analysis | Contact Energy | Clutha scheme | Hydro offers |
| **8-14/12/2024** | Several | Further analysis | Genesis | Waikaremoana | Hydro offers |