20 November 2023

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 12-18 November

1.1. This week spot prices were above historic average but generally below $200/MWh. There was a significant spike in prices during the Wednesday morning peak as a result of a drop in wind generation with wind forecasts out by more than 200MW. Generation outages remain above average for this time of year, with the early part of the week seeing over 3000MW of outages. Controlled hydro storage is currently around 67% nominally full.

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, we also single 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. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10th-90th percentiles adjusted for inflation. The figure also shows graphs of spot prices at Benmore and Ōtāhuhu individually, along with their historic national 10th-90th percentiles and historic median adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range[1] of historic prices, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 12-18 November:

(a) The average wholesale spot price across all nodes was $131/MWh.

(b) 95 percent of prices fell between $0.22/MWh and $195/MWh.

2.4. Overall, the majority of spot prices were below $200/MWh with the average weekly price increasing by $7/MWh compared to the previous week. Spot prices at both Benmore and Ōtāhuhu are still generally above the historic median values for this time of year.

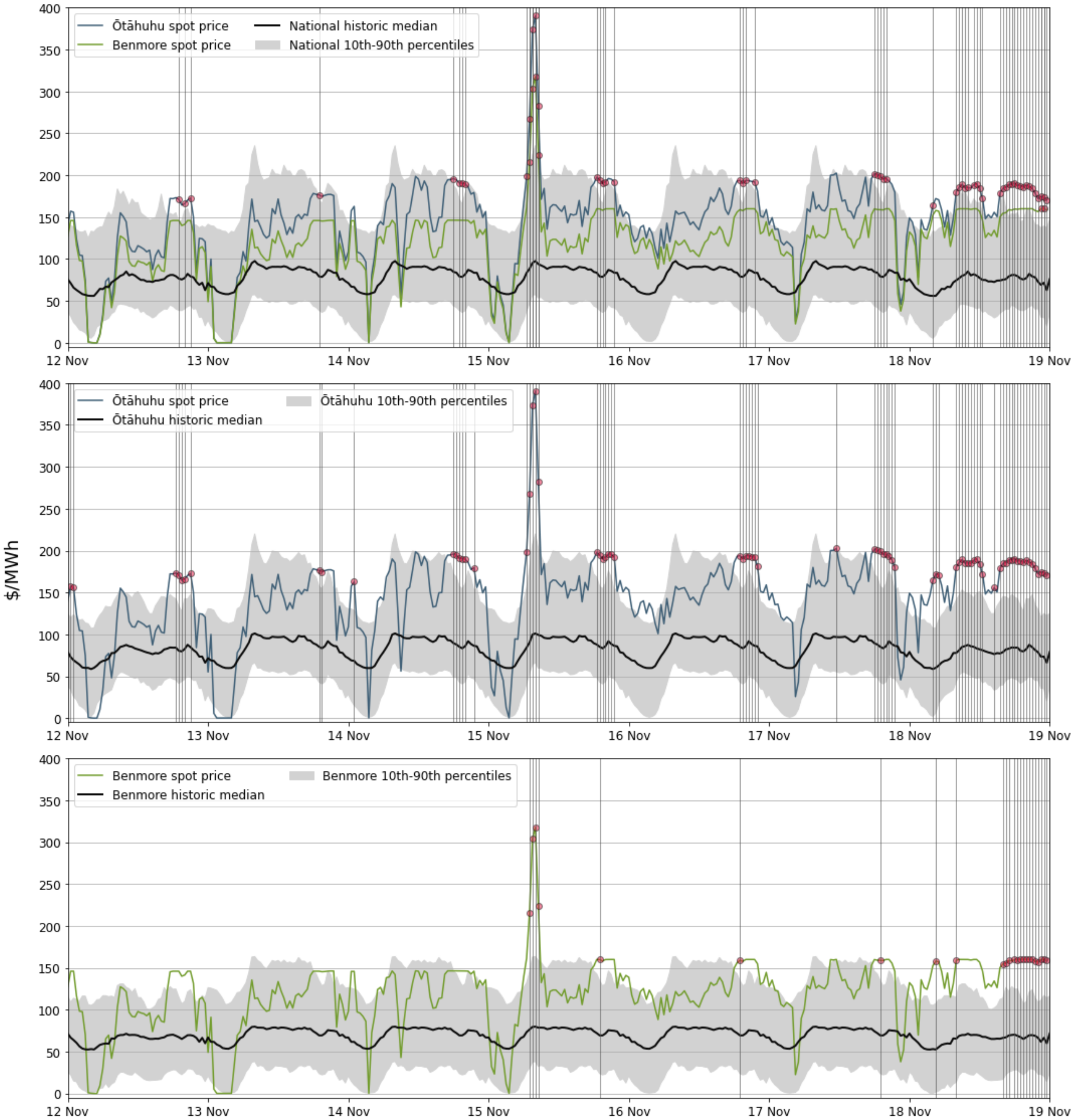
2.5. During the Wednesday morning peak from 7.00am to 8.30am prices at Ōtāhuhu and Benmore were above $200/MWh. The prices spiked over $300/MWh during the 7.30am and 8.00am trading periods where Ōtāhuhu prices were $374/MWh and $390/MWh, and Benmore prices were $304/MWh and $318/MWh. During the morning peak there was a large gap in actual and forecast wind with actual wind around 190-237MW less that than was forecast. This in turn saw higher priced hydro being dispatched to cover demand.

2.6. A number of prices during the weekday evening peak period were highlighted which was possibly due to lower than forecast wind and/or under forecast demand during these trading periods. At times the difference between wind forecast and actual wind was over 100MW. Also, on Saturday prices were flagged as being high although prices generally remained

[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day, and looking for prices that lie 1.5 times the interquartile range above the 75th percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

below $200/MWh. Really low wind conditions on Saturday as well as the evening wind forecasts being out by around 100-140MW would have contributed to these higher than average prices.

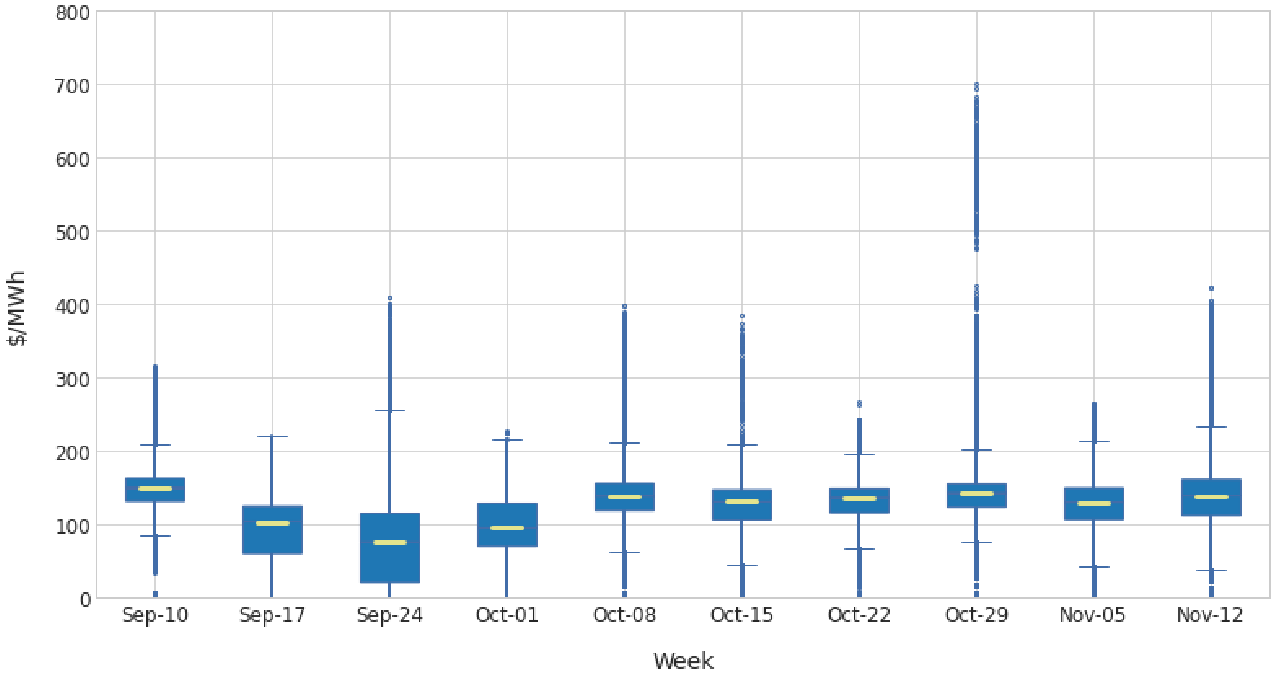
Figure 1: Wholesale spot prices between 12 November (Sunday) and 18 November (Saturday)



2.7. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The green line shows each week's median price, while the box part shows the lower and upper quartiles (where 50 percent of prices fell). The "whiskers" extend to points that lie within 1.5 times the inter-quartile range (IQR) of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

2.8. Most prices (middle 50%) fell between $111/MWh and $160/MWh, with the median price this week of ~$139/MWh. Compared to the previous week prices are sitting slightly higher with more outliers given the price spike on Wednesday morning.

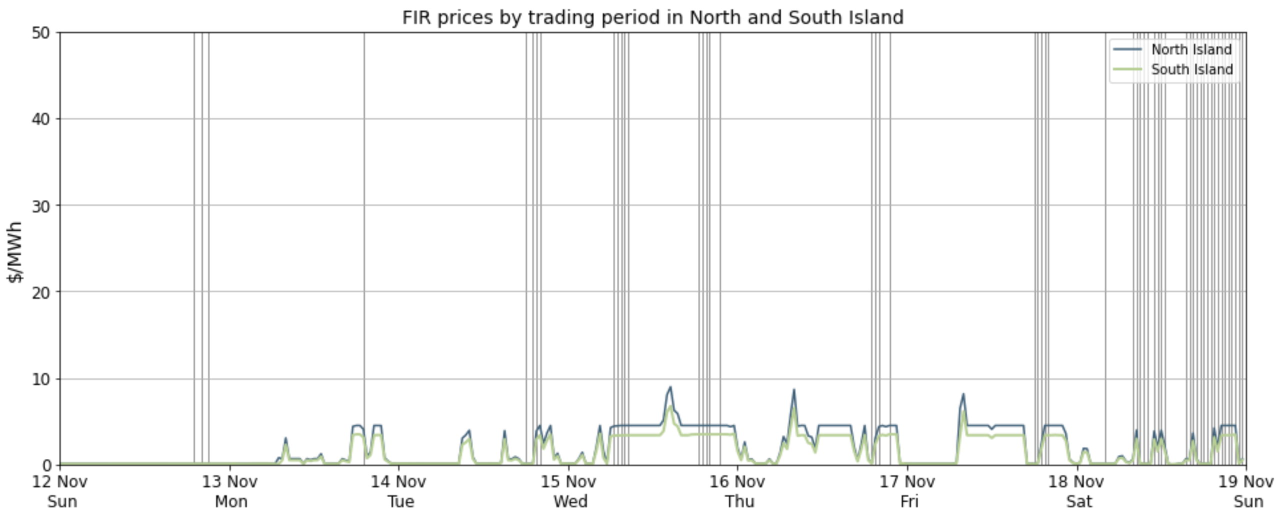
Figure 2: Boxplot showing the distribution of the spot prices this week and the previous nine weeks



3. Reserve prices

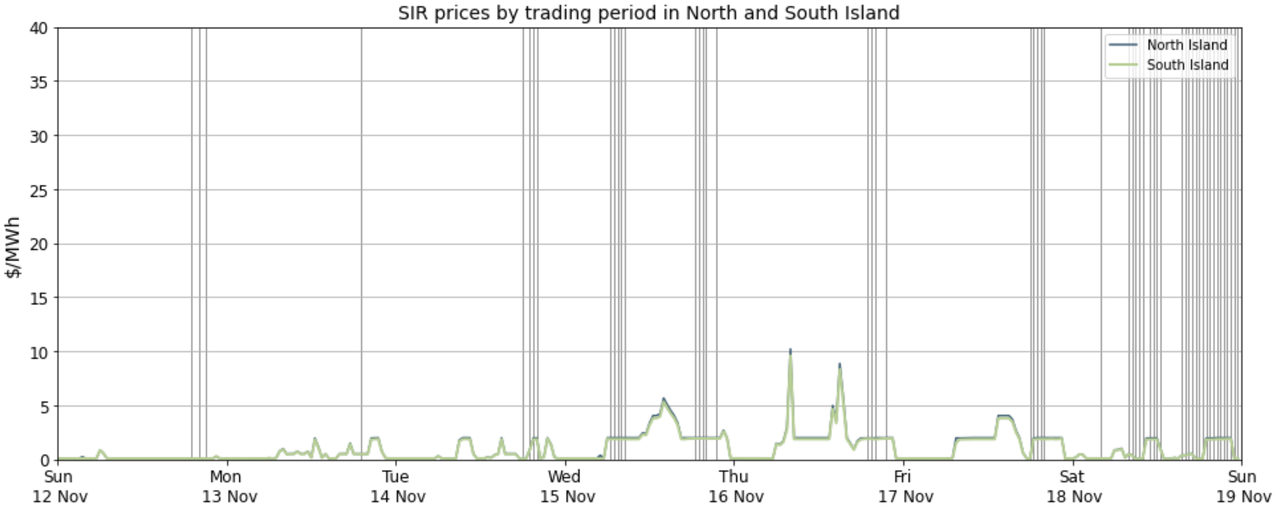
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were all under $10/MWh.

Figure 3: Fast Instantaneous Reserve (FIR) prices by trading period and island



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices mainly were under $5/MWh, with a few prices on Thursday close to $10/MWh.

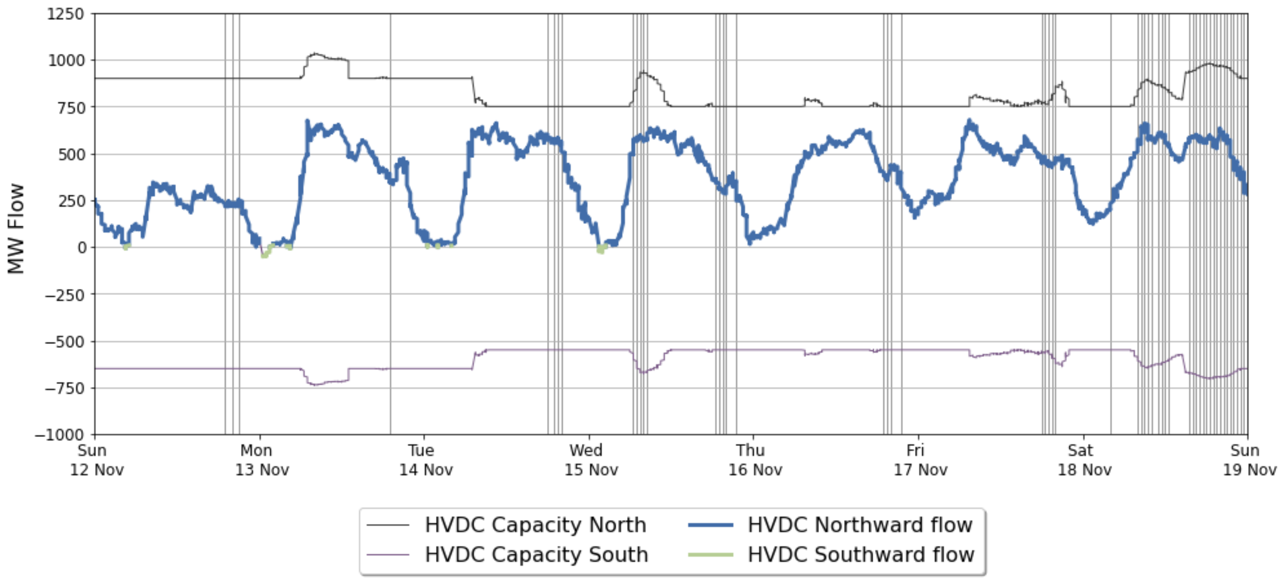
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 12-18 November. HVDC flows was mostly northwards this week. There was also reduced capacity northwards over most of the week due to transmission outages because of maintenance work.

Figure 5: HVDC flow and capacity



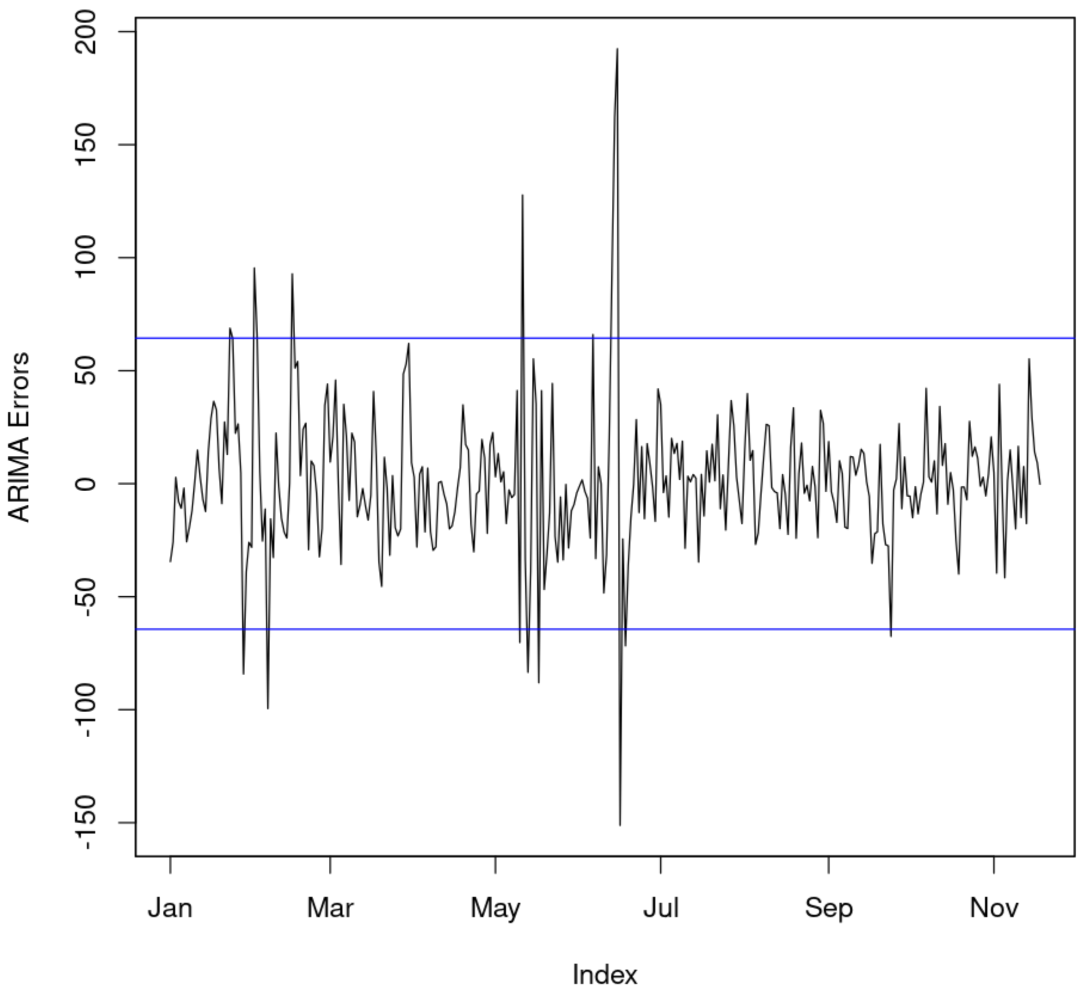
5. Regression residuals

5.1. The Authority's monitoring team uses a regression model to model spot price. The residuals show how close the predicted 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 on the trading conduct webpage.

5.2. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than 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 for in the regression analysis.

5.3. This week no residuals were above or below 2 standard deviations, indicating actual and modelled prices were similar.

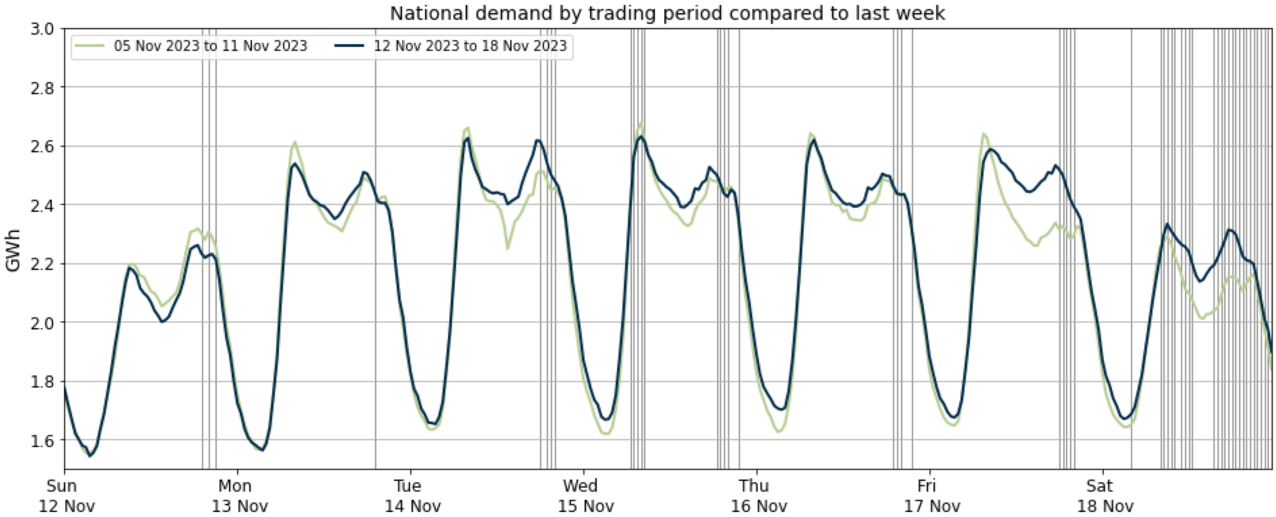
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 18 November 2023



6. Demand

6.1. Figure 7 shows national demand between 12-18 November, compared to the previous week. Overall, demand was higher than the previous week, particularly during the shoulder and evening peak periods on weekdays. Friday and Saturday saw the biggest difference compared the previous week, in line with a large drop in temperature over Friday evening and into Saturday.

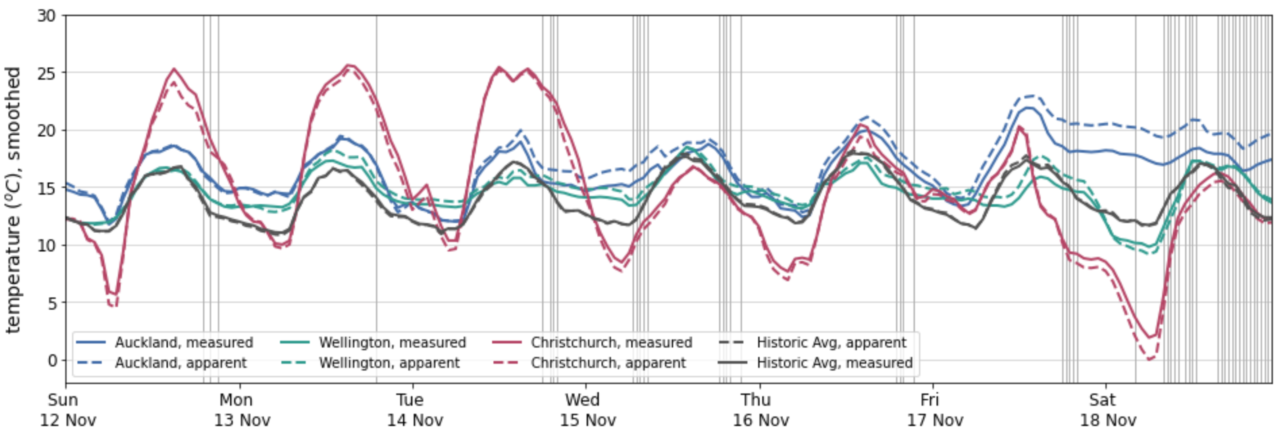
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 12-18 November. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Auckland temperatures continued to be on or above average this week. Wellington temperatures were mainly close to the historic average apart from a small dip close to 10℃ on Saturday. Christchurch temperatures fluctuated across the week with top temperatures reaching around 25℃ at the start of the week and Saturday morning seeing the coldest temperature of close to 0℃.

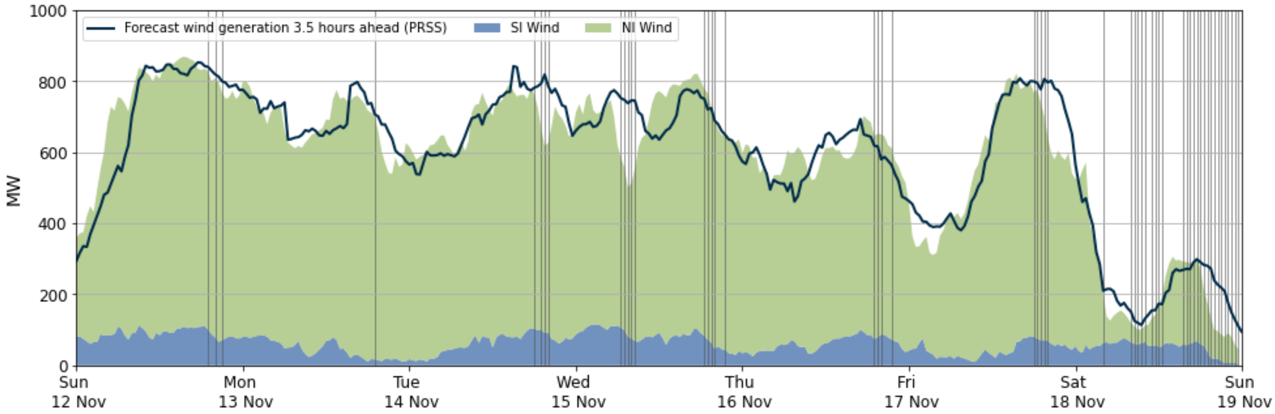
Figure 8: Temperatures across main centres



7. Generation

7.1. Figure 9 shows wind generation, from 12-18 November. Wind generation ranged between 44MW and 869MW across the week with wind consistently above 500MW for most of the early part of the week. High prices tended to occur when the forecast and actual wind generation deviated, especially on Wednesday morning.

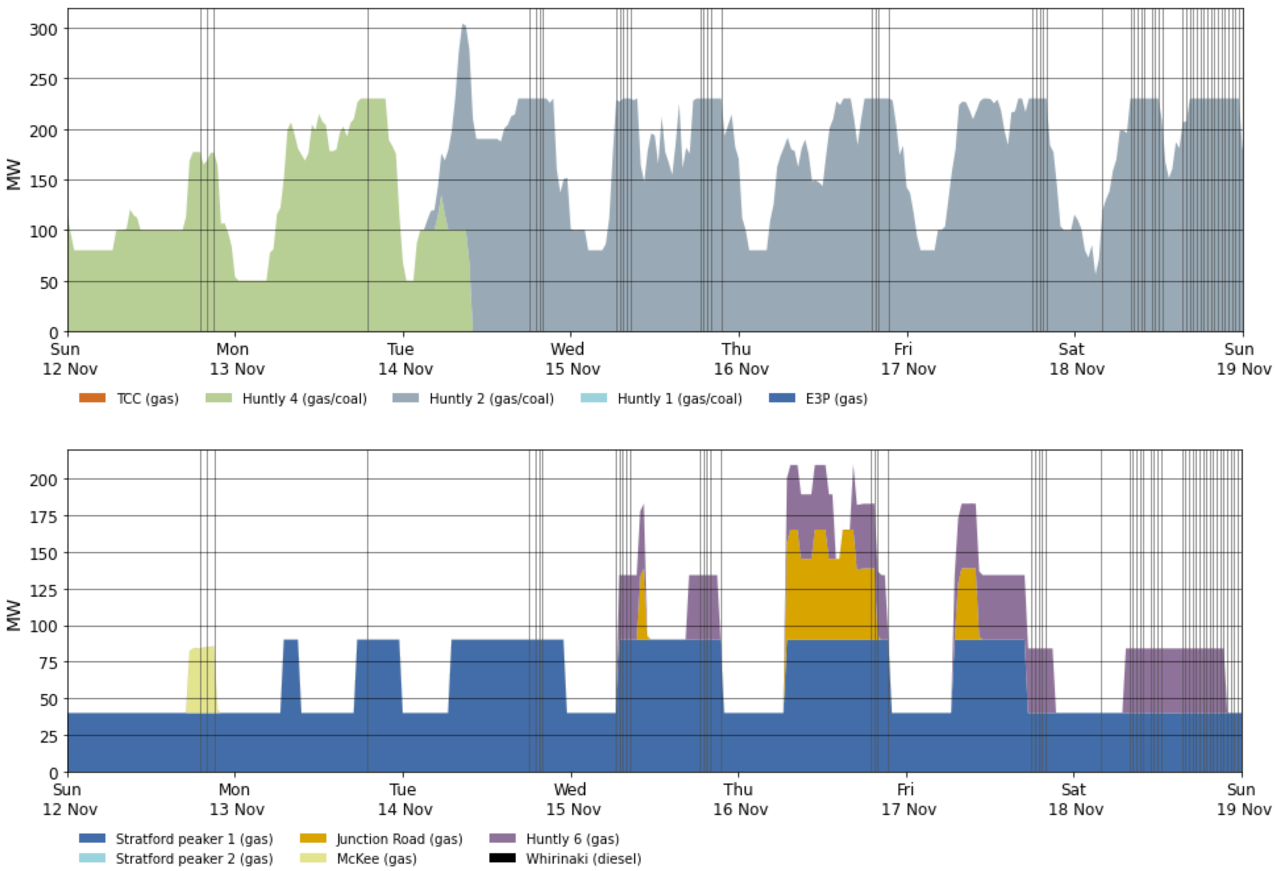
Figure 9: Wind generation and forecast between 12-18 November



7.2. Figure 10 shows the generation of thermal baseload and thermal peaker plants between 12-18 November. Huntly 4 ran as baseload at the start of the week with Huntly 2, returned from outage, running as baseload for the remainder of the week.

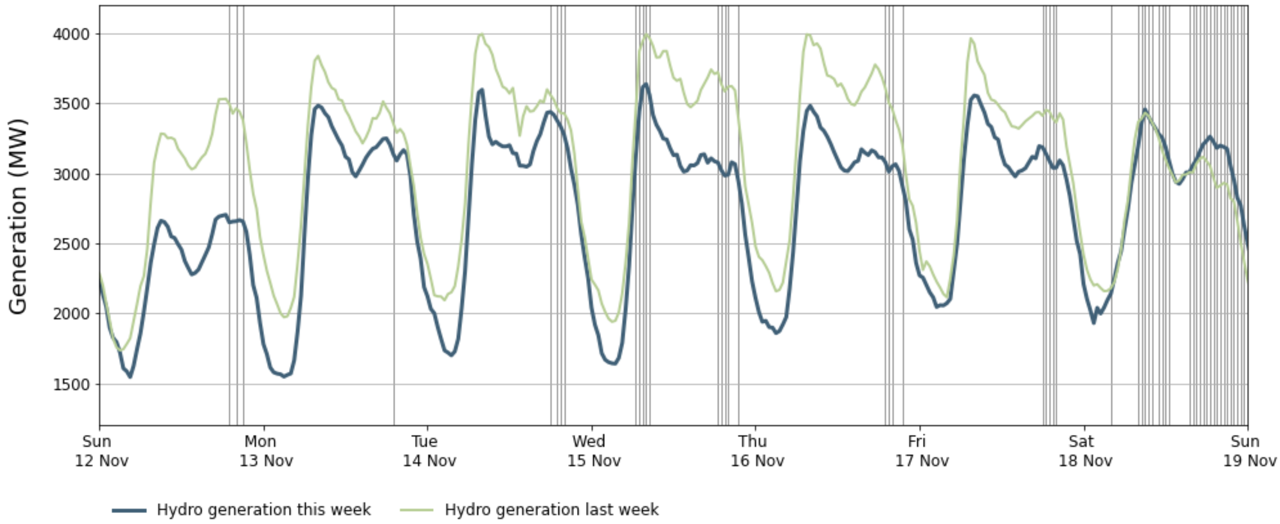
7.3. Stratford 1 ran continuously over the week, mainly at around 40MW and ramping up to around 90MW over the weekday peak and shoulder period. McKee only ran on Sunday evening with Huntly 6 and Junction Road generating from Wednesday to Saturday over peak and shoulder periods where needed.

Figure 10: Thermal generation between 12-18 November



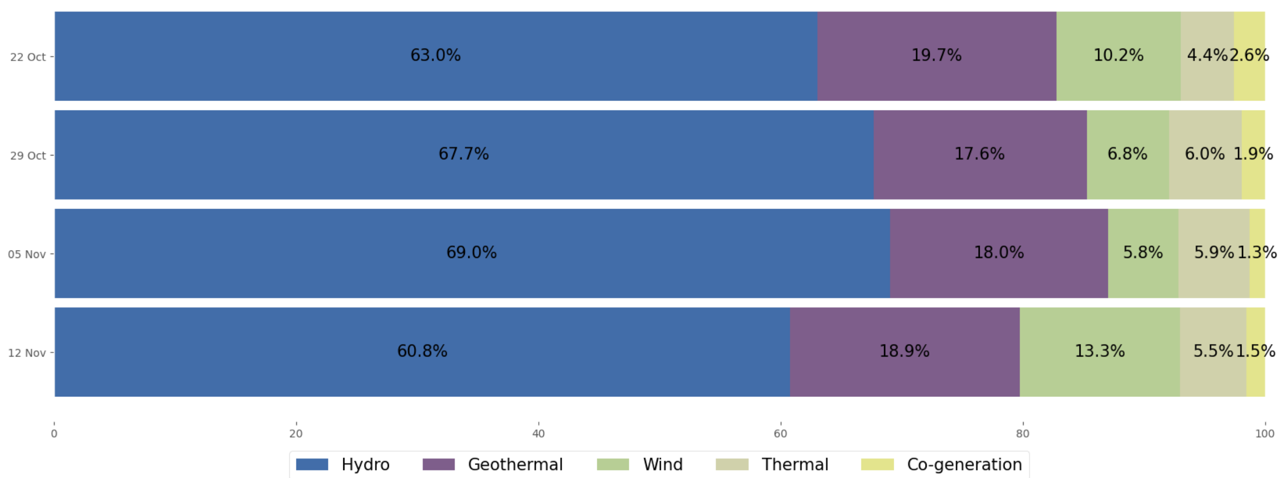
7.4. Figure 11 shows hydro generation between 12-18 November. Overall, there was less hydro generation this week compared to the previous week, in line with more wind generation across the week.

Figure 11: Hydro generation between 12-18 November



7.5. As a percentage of total generation, between 12-18 November, total weekly hydro generation was 60.8%, geothermal 18.9%, wind 13.3%, thermal 5.5%, and co-generation 1.5%. Higher wind generation across most of the week saw a reduction in hydro generation.

Figure 12: Total generation by type as a percentage each week between 22 October and 18 November



8. Outages

8.1. Figure 13 shows generation capacity on outage. Total capacity on outage between 12-18 November ranged between 1900MW and 3400MW. The high amount of generation on outage is due to a combination of outages due to equipment issues, such as Huntly 5, and regular maintenance outages, which are usually scheduled at this time of year when demand is lower.

8.2. Notable outages include:

(a) Huntly 5 on outage until 22 January 2024

(b) TCC is on outage until 22 December 2023

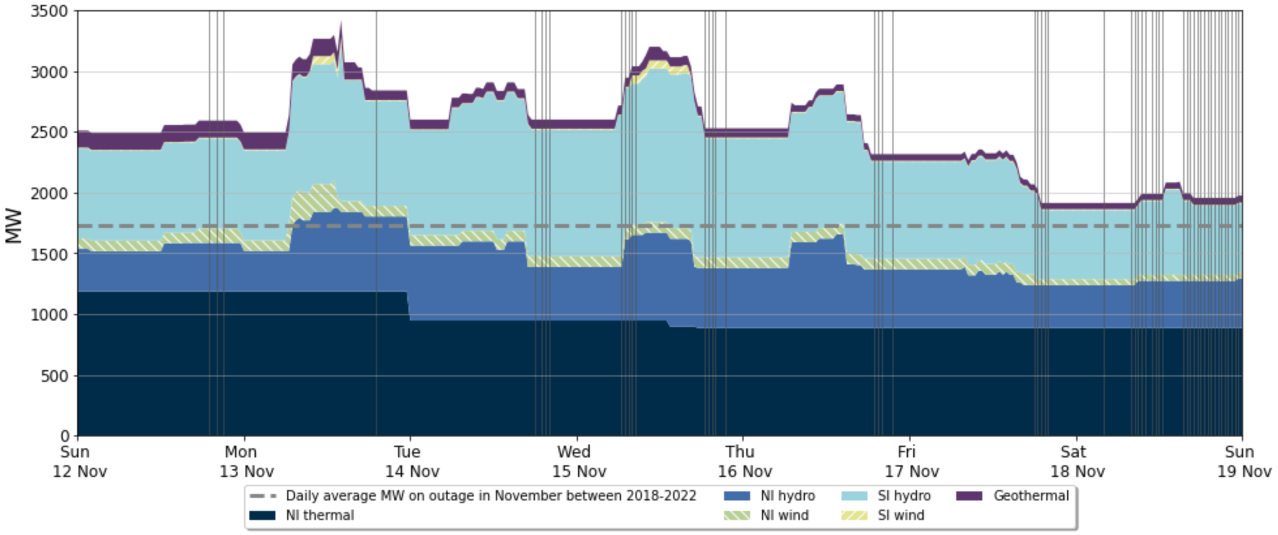
(c) Huntly 2 was on outage until 13 November

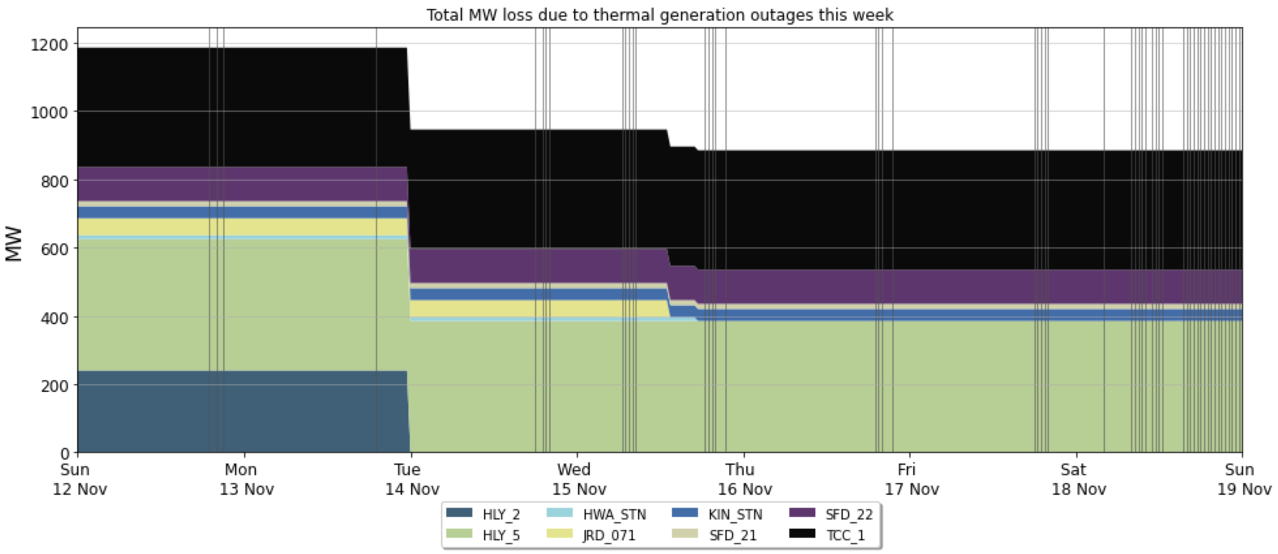
(d) Stratford 2 outage until 28 February 2025

(e) West Wind Station was on outage the morning of 13 November

(f) Various North and South Island hydro on outage

Figure 13: Total MW loss due to generation outages





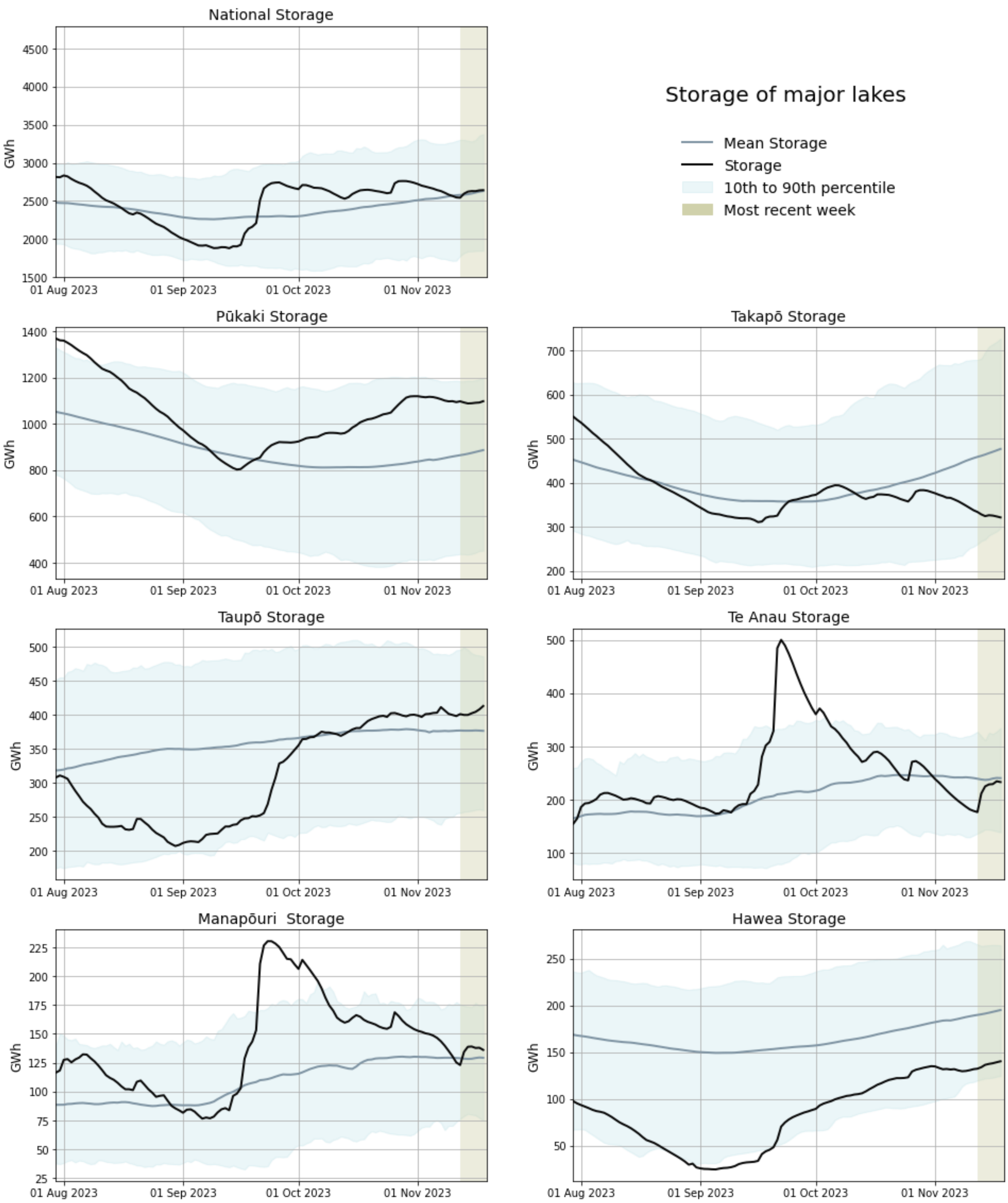
9. Storage/fuel supply

9.1. Figure 14 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.

9.2. National hydro storage increased in line with the historic mean and is still around 101% of the historic mean, with controlled storage as of 18 November at 66.9% nominally full.

9.3. Pūkaki storage remains high and close to its historic 90th percentile. Takapō storage has continued to decline this week and is approaching its 10th percentile region. Taupō storage has increased slightly and remains above its historic mean. Manapōuri and Te Anau had increases to storage levels. Manapōuri is sitting just above historic average, with Te Anau just below its historic mean storage levels. Hawea storage has been steady over the week but is still below its historic mean.

Figure 14: Hydro storage

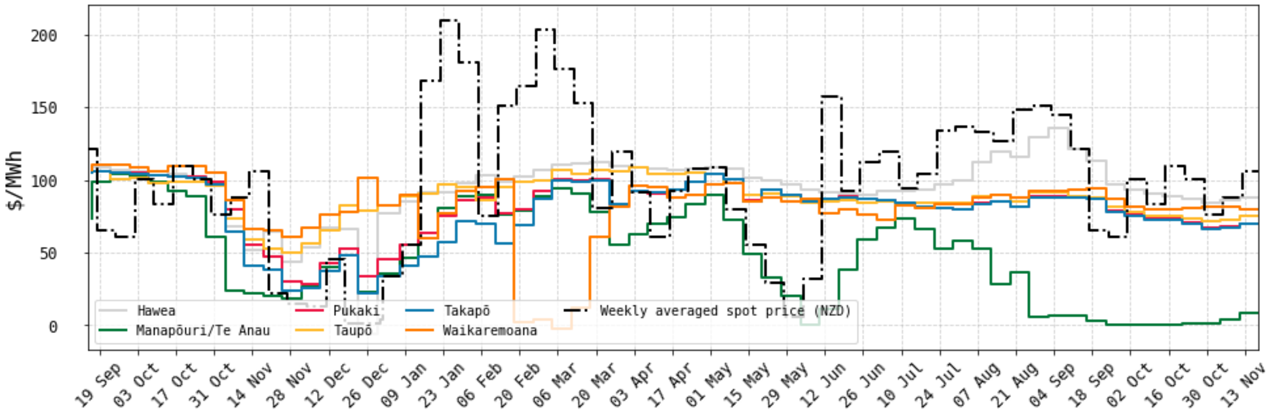


10. JADE water values

10.1. The JADE[2] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 15 shows the national water values between 15 September 2022 and 18 November 2023 obtained from JADE calculated as at the start of the week. These values are used to estimate the marginal water value at the actual storage level. More details on how water values are calculated can be found in Appendix B.

10.2. Manapōuri/Te Anau water values have increased by around $4/MWh. Most other water values increased by around $2/MWh.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 18 November 2023



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 16 shows an estimate of thermal SRMCs as a monthly average up to 1 November 2023. The SRMC of diesel plants has been increasing since May, and the SRMC of coal-fuelled and gas-fuelled plants has started to increase again. The recent increase in the SRMC of gas likely reflects increased production at Methanex, as well as gas production outages.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$161/MWh. This is now only slightly higher than the cost of running the Rankines on gas at $141/MWh, with Genesis continuing to run the Rankines on a combination of both fuels.

---

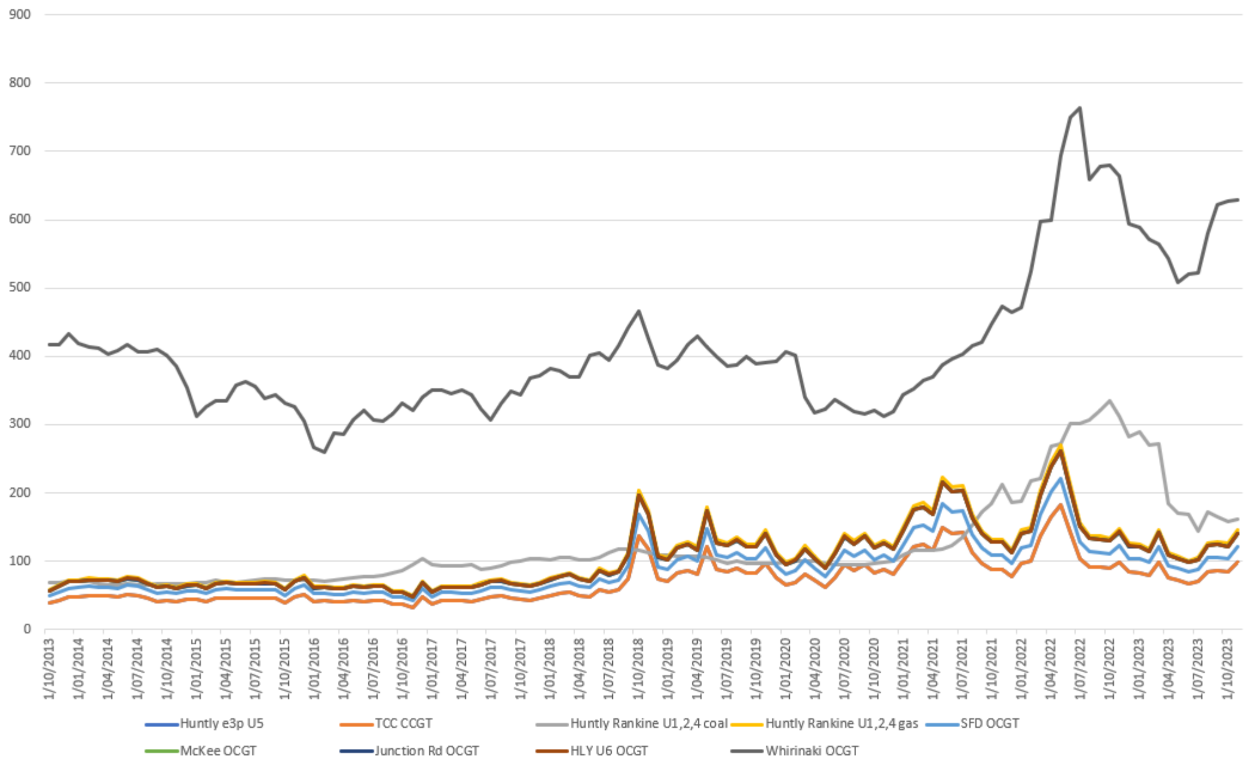
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

11.5. The SRMC of gas fuelled thermal plants is currently between $98/MWh and $141/MWh.

11.6. The SRMC of Whirinaki has increased to ~$629/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C on the trading conduct webpage. This appendix was recently updated to reflect the changes made to coal price indices by the Indonesian government. These changes have had the effect of decreasing the coal SRMC from April 2023.

Figure 16: Estimated monthly SRMC for thermal fuels



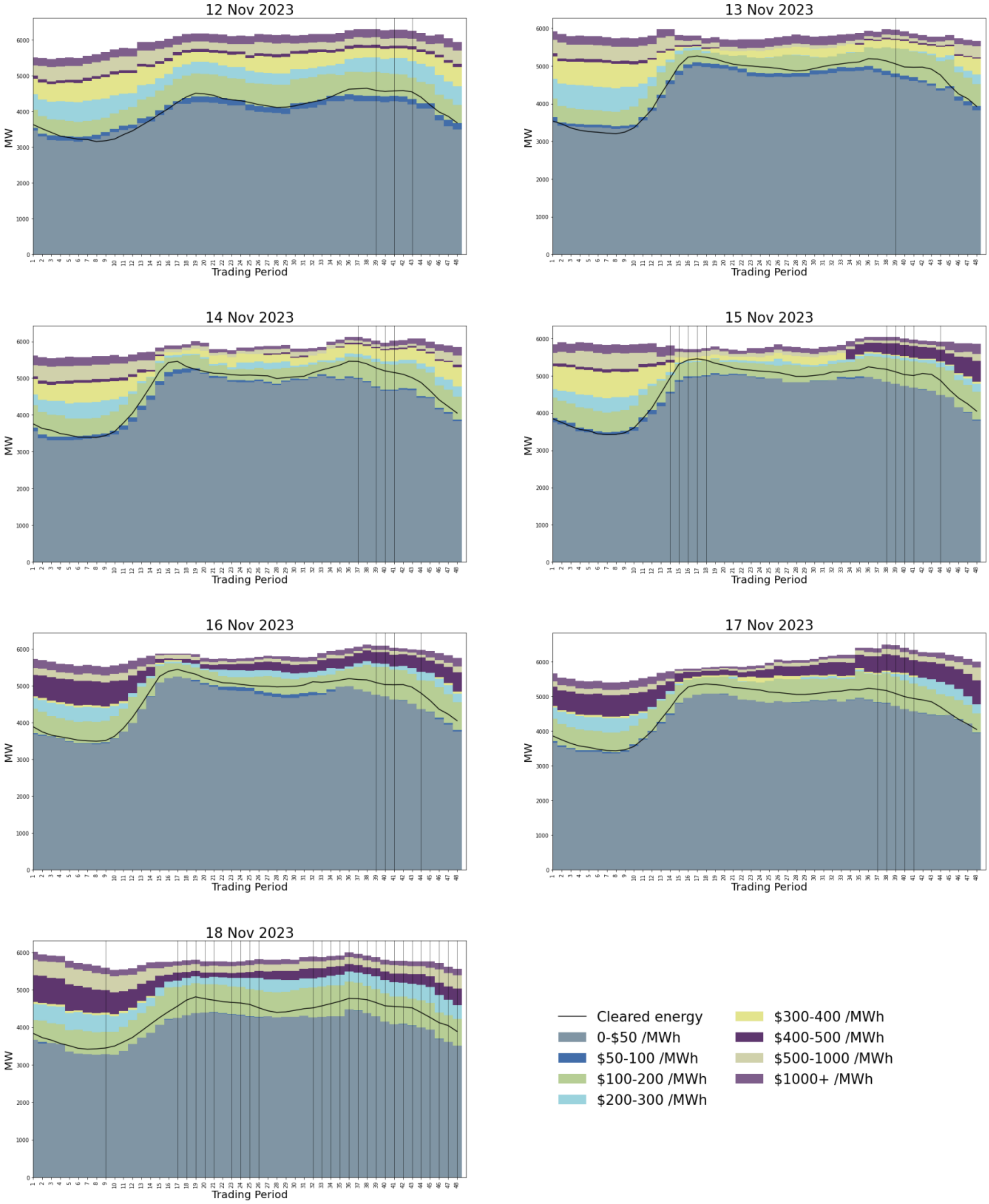
12. Offer behaviour

12.1. Figure 17 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 early part of the week saw some overnight prices clear in the $0-$50/MWh range. As with recent weeks, the majority of spot prices continue to clear in the $100-$200/MWh price band.

12.3. The high number of generation outages this week decreased the total amount of generation offered into the market, particularly between Monday morning and Friday afternoon. This meant that when demand was high, such as on Wednesday morning, there was less headroom in the stack. This, combined with wind generation below forecast, resulted in high prices on Wednesday morning.

Figure 17: Daily offer stacks



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	TP	Status	Participant	Location	Enquiry topic
07/10/2022	15-16	Further analysis	Genesis	Huntly 5	Prices change for final energy tranche.
14/06/2023	15-17	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers.
15/06/2023	15-19	Passed to Compliance	Genesis and Contact	Multiple	High energy prices associated with high energy offers.
22/09/2023-30/09/2023	Several	Further analysis	Contact	Multiple	High hydro offers.
11/10/2023	21	Further Analysis	Genesis	Tokaanu	High prices during off-peak time.