Date: 17 July 2023

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

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1. Overview for week of 9 – 15 July 2023

1.1. This week, prices remained around the historical average, with low reserve prices. The northward flow of HVDC remained well below its maximum limit, with southward HVDC flows overnight. Hydro generation remained consistent compared to the previous week, as national hydro storage continued to decline. Thermal baseload was high this week with three Rankines and TCC generating. Thermal peakers ran frequently, especially at the beginning of the week to meet the high demand. From Wednesday onwards, wind generation was substantial. On Friday, demand was low due to the Matariki public holiday, and on Saturday, demand was also low compared to the previous week due to mild temperatures throughout the country.

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 at any node exceed their historical 90th percentiles. Prices above the historic 90th percentile are highlighted with a black line. Other notable prices, but which did not exceed the 90th percentile, are marked with black dashed lines.

2.2. Between 9 – 15 July:

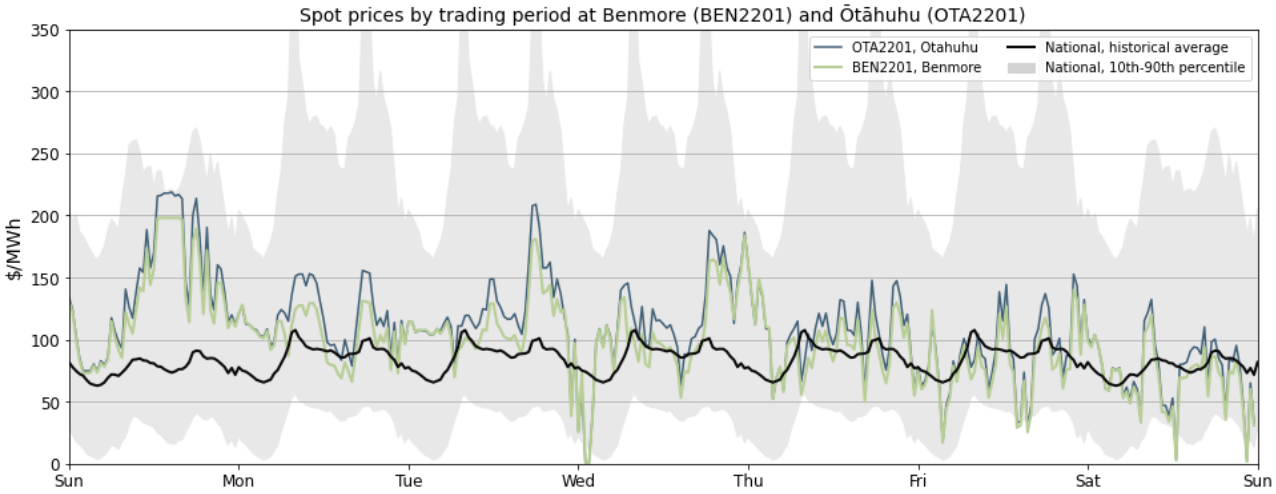
a) The average wholesale spot price across all nodes was $104/MWh.
b) 95 percent of prices fell between $31/MWh and $199/MWh.

2.3. Figure 1 shows spot prices at Benmore and Ōtāhuhu alongside their historic average and historic 10th - 90th percentiles adjusted for inflation.

2.4. Prices hovered again this week around the historic average and no prices were observed above the 90th percentile. Overall, most spot prices ranged between $100/MWh and $150/MWh. These average prices reflect the declining hydro storage levels and reduced inflows that have been observed over the past few weeks.

2.5. On Wednesday, there were instances of low prices, dropping below $1/MWh and falling below the historic 10th percentile. This occurred as wind generation experienced a sudden and significant increase, surpassing the initial forecast.

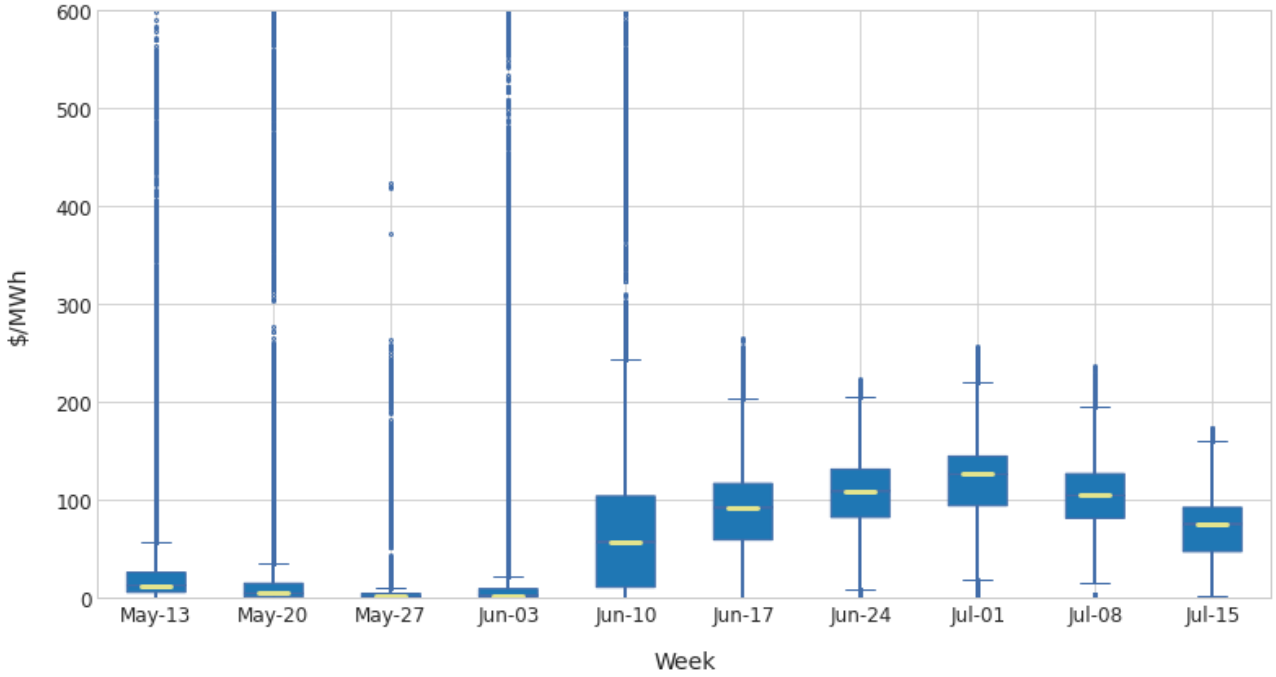
Figure 1: Wholesale Spot Prices between 9 July (Sunday) – 15 July (Saturday) 2023.



2.6. 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.

2.7. This week, the median and quartile prices were slightly lower compared to the previous week, bringing prices closer to the long-term average. Furthermore, there were no exceptionally high prices throughout the week.

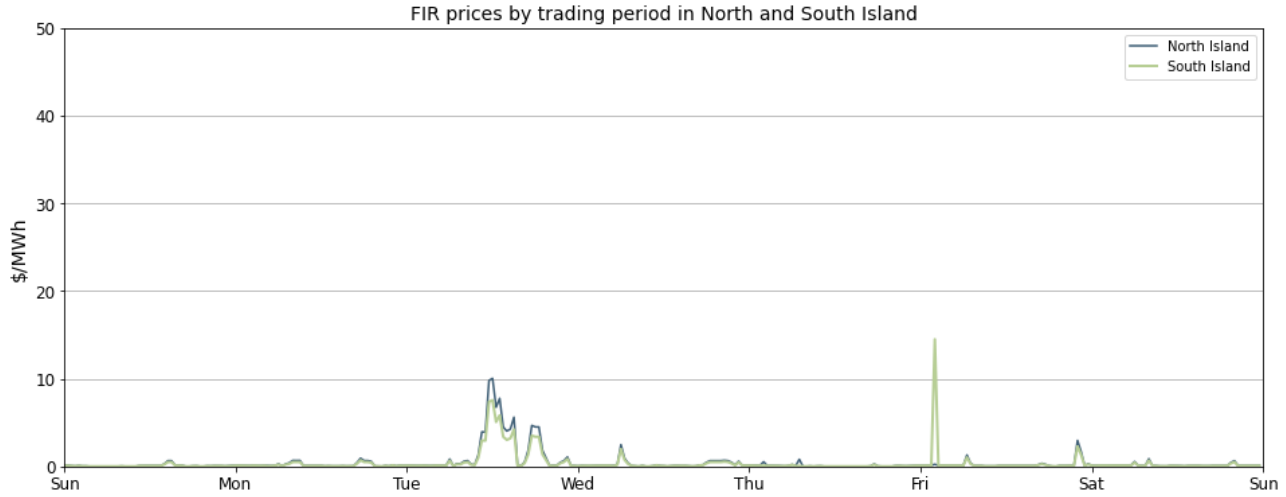
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks.



3. Reserve Prices

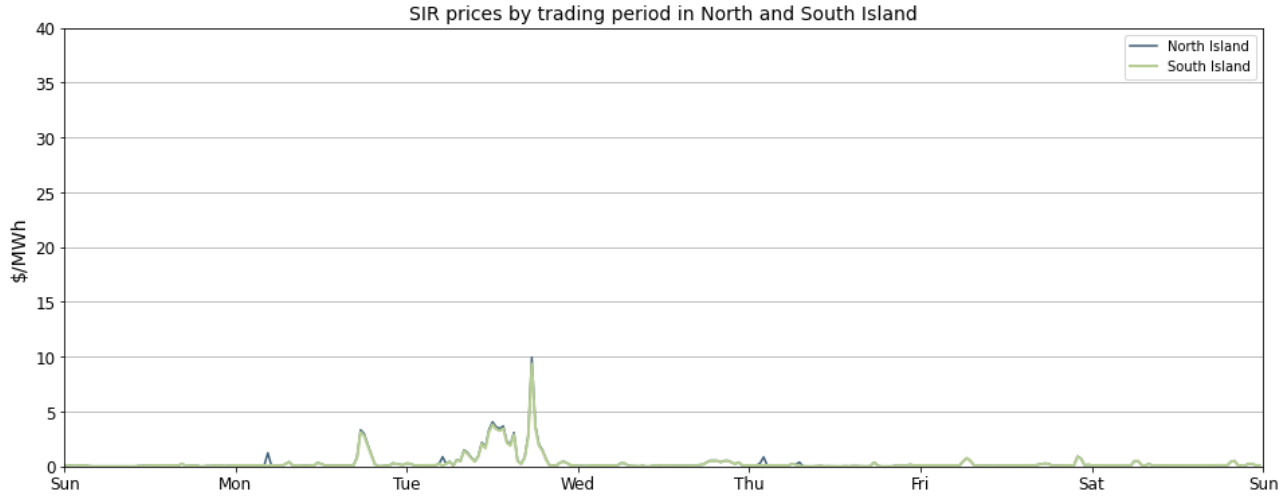
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week the FIR prices were below $10/MWh for both islands, except on Friday, 14 July at 2:00 am when the North Island price was $14.5/MWh, with the South Island price of $0.2/MWh. Last month E3P was risk setter, but as it is currently on outage the amount of reserve needed to cover the largest risk has been lower, which may have contributed to lower reserve prices.

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 were below $10/MWh this week, with no price spikes.

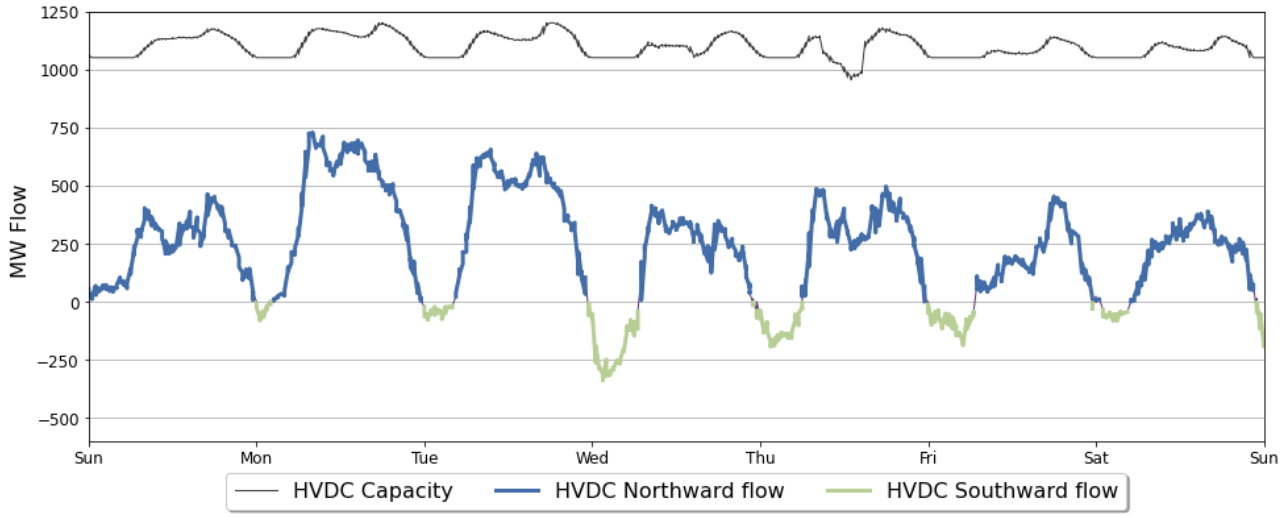
Figure 4: Sustained instantaneous reserve (SIR) prices by trading period and Island.



4. HVDC

4.1. Figure 5 shows HVDC flow between 9 – 15 July. HVDC flows were northward during the daytime and southward during the nighttime. The northward HVDC flow reached up to 750 MW during the daytime, while the southward flow during the nighttime remained below 350 MW. HVDC flow was well below the maximum limits.

Figure 5: HVDC northward flow and capacity.

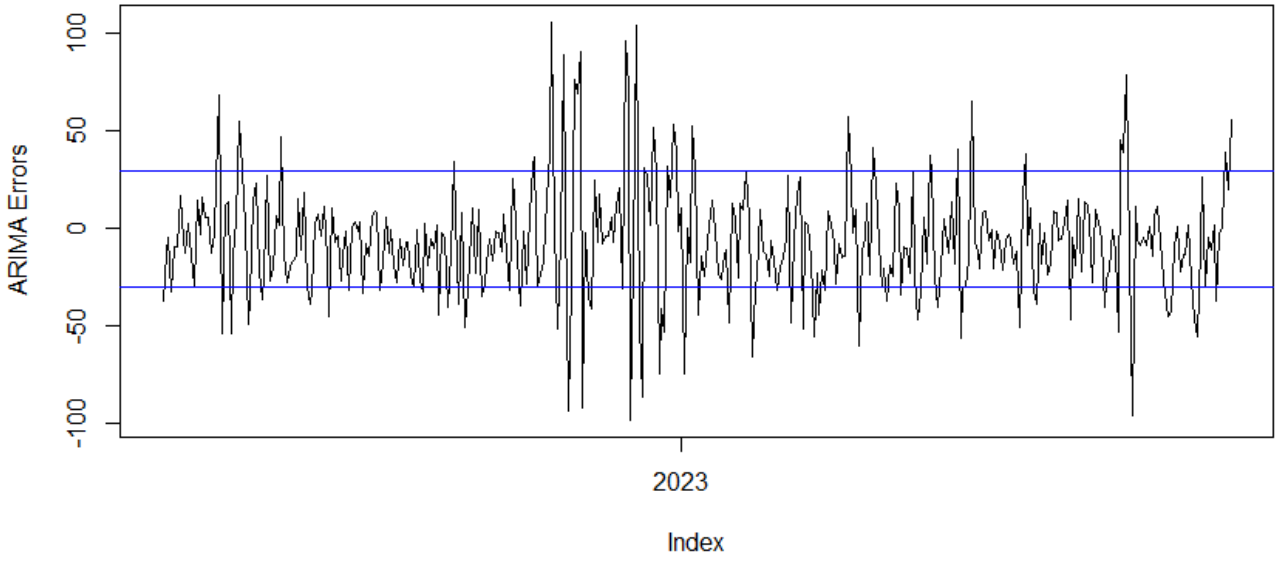


5. Regression Residuals

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. This week, there were some residuals that fell slightly above and below the one standard deviation. These residuals indicated that the modelled prices were occasionally lower or higher than the actual prices on certain days. While this may indicate that prices did not reflect underlying market conditions, on further analysis, it appears this is due to market variation which is not accounted for in the regression analysis.

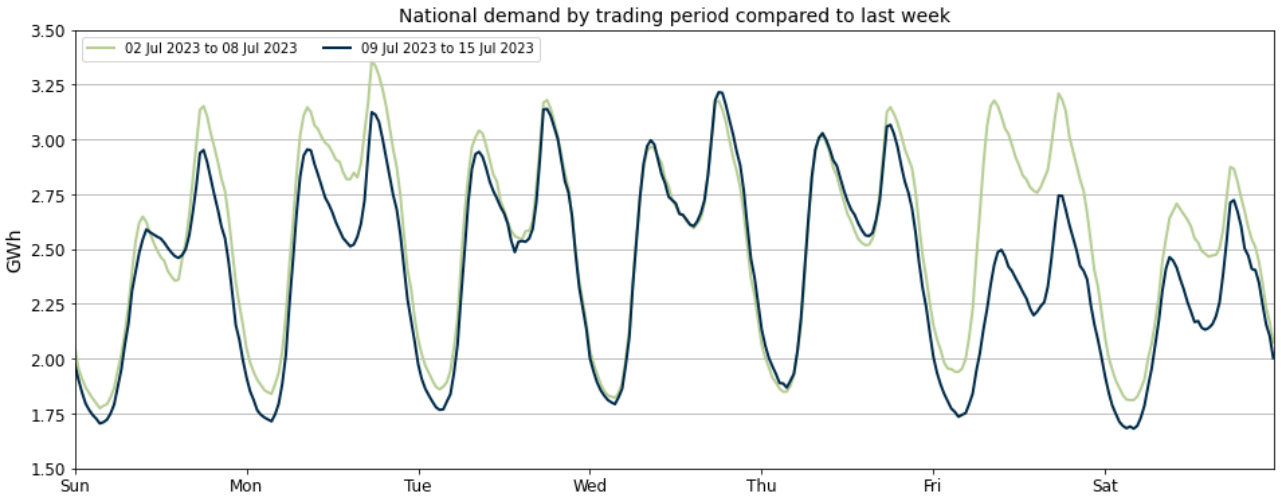
Figure 6: Residual plot of estimated daily average spot prices from 1 July 2022 – 15 July 2023. The blue lines show two standard deviations of the ARMA errors.



6. Demand

6.1. Figure 7 shows national grid demand between 9 – 15 July, compared to the previous week. Overall, demand was similar mid-week to the previous week. On Sunday and Monday, demand was lower in line with mild weather conditions nationwide. Friday saw a decrease in demand as a result of the Matariki public holiday. Additionally, on Saturday, demand declined due to the relatively mild temperatures experienced during that day.

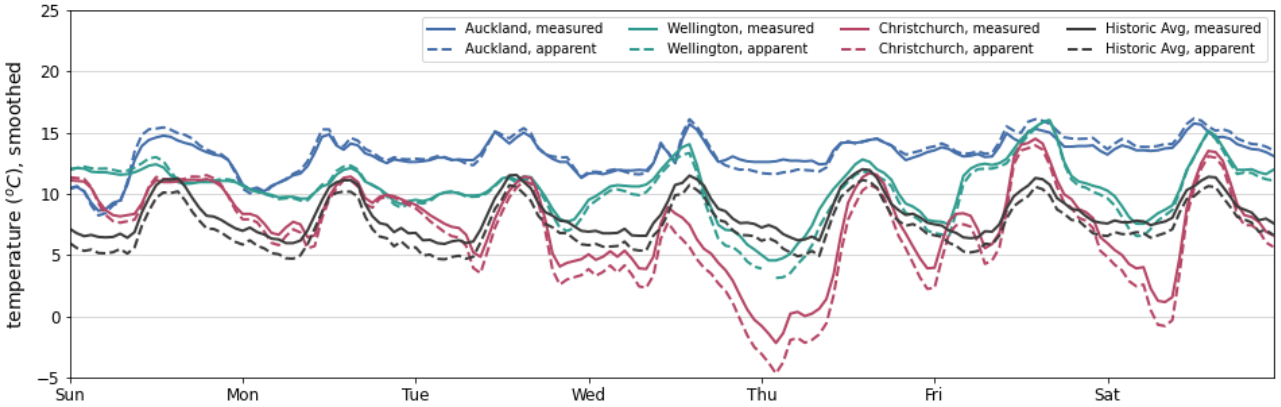
Figure 7: National demand by trading period compared to the previous week.



6.1. Figure 8 shows hourly temperatures at the three main population centres between 9 – 15 July. 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.

6.2. Temperatures in Auckland were mainly above average and mostly above 10 degrees. Wellington temperatures were around or above the historic average for most of the week with Thursday morning dropping around 5 degrees. Christchurch saw the most variation in temperatures where Thursday morning dipped below 0 degrees with apparent temperatures ranging from -5 degrees to 15 degrees.

Figure 8: Temperatures across main centres.



7. Outages

7.1. Figure 9 shows generation capacity on outage. Total capacity on outage between 9 – 15 July ranged between ~800 MW and 1250 MW.

7.2. Notable outages include:

(a) Huntly 5 is on outage from 30 June to midnight 31 July.

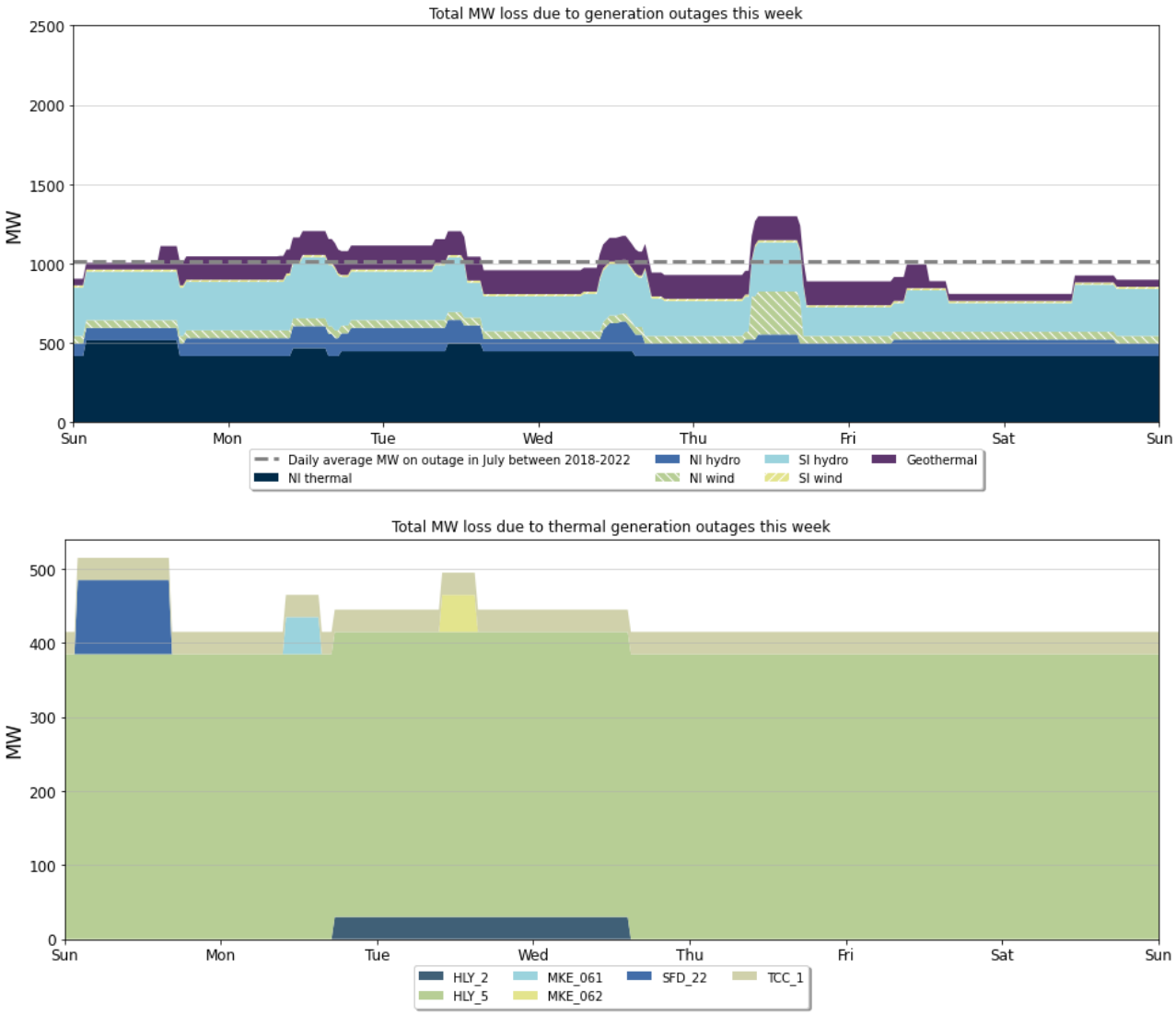
(b) Kawerau geothermal was on outage between 9-14 July.

(c) Various North and South Island hydro units remain on outage.

(d) Turitea wind farm was on short outage on 13 July.

(e) West Wind is partly on outage until 24 November.

Figure 9: Total MW loss due to generation outages.

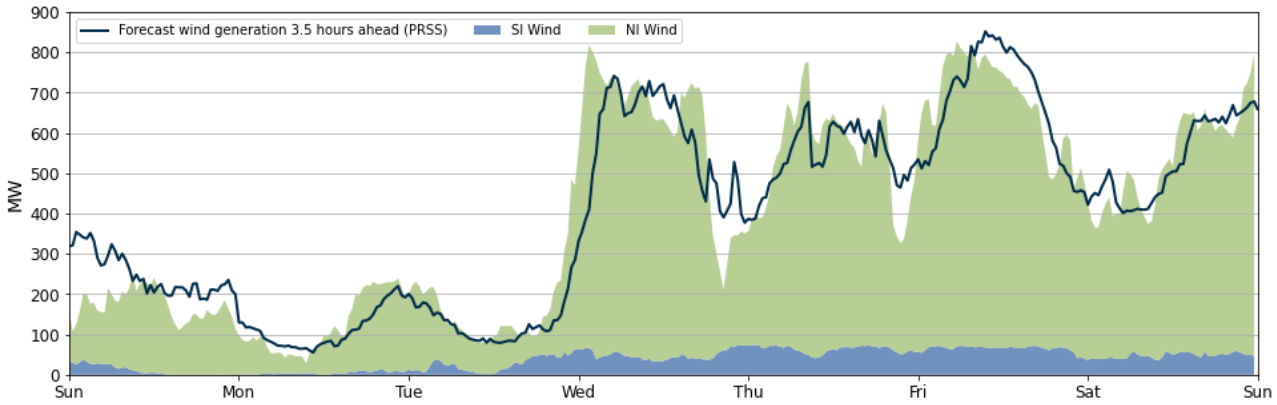


8. Generation

8.1. Figure 10 shows wind generation, from 9 – 15 July, ranged from 30 - 830 MW across the week, with Sunday having lower wind generation compared to what was initially forecasted. At the start of the week, wind generation remained below 200 MW. However, there was a steep increase in wind generation on Tuesday night, reaching a peak of 830 MW.

8.2. On Wednesday, wind generation hovered around 700 MW but dropped to 200 MW during the nighttime, falling below the predicted levels. By Friday morning, wind generation once again exceeded 800 MW, and for the majority of Saturday, it remained at approximately 650 MW.

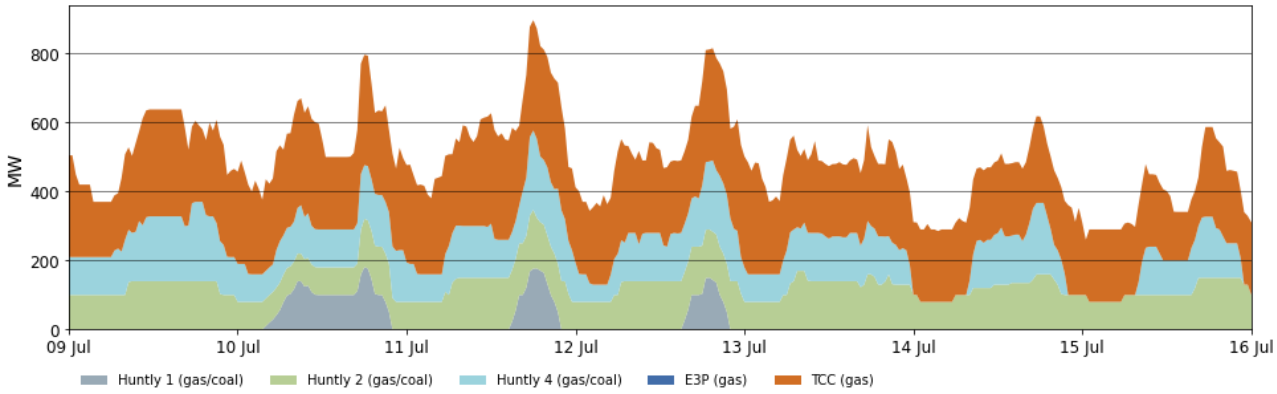
Figure 10: Wind Generation and forecast.

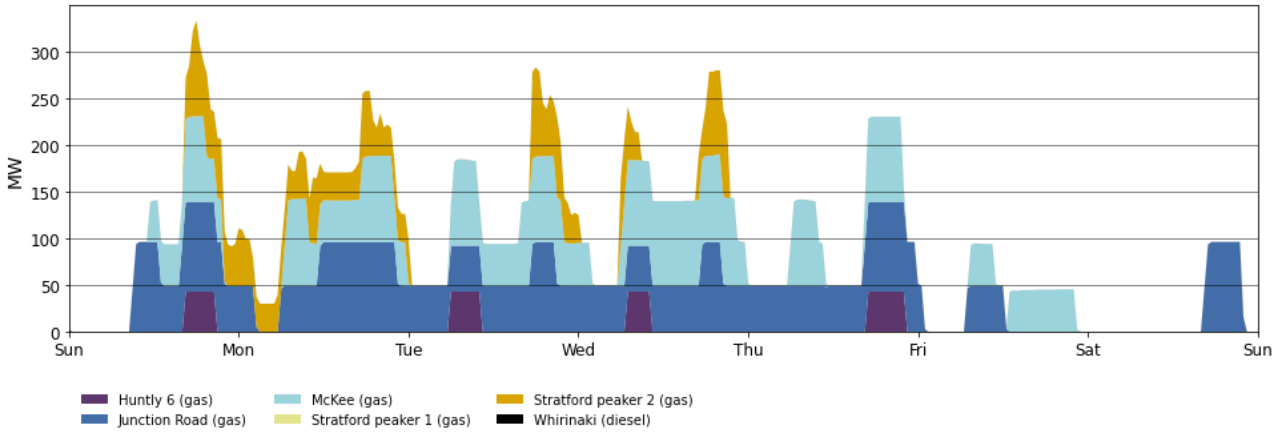


8.3. Figure 11 shows the generation of thermal baseload and thermal peaker plants between 9 – 15 July. Like the previous week, as E3P (Huntly 5) is on outage, Huntly was cycling the three Rankine units on and off to support baseload requirements. TCC and Huntly 2 ran continuously as baseload throughout the week. Huntly 4 ran as baseload from Sunday to Thursday, and on Friday and Saturday to support the load. Huntly 1 ran in support on Monday, and Tuesday and Wednesday during the evening peak.

8.4. Thermal peakers ran mostly at the beginning of the week when there was significantly higher demand and low wind generation. Stratford 2 ran during the Sunday evening peak till the Monday evening peak, and Tuesday evening and Wednesday morning and the evening peak period. Junction Road ran in some continuous blocks from Sunday afternoon to Monday morning and then again from Monday afternoon through Friday, also supported the baseload on Friday and Saturday. McKee has mainly covered the daily peaks, and also ran continuously on some days. Huntly 6 ran during the peak demand periods on Sunday, and from Tuesday to Thursday.

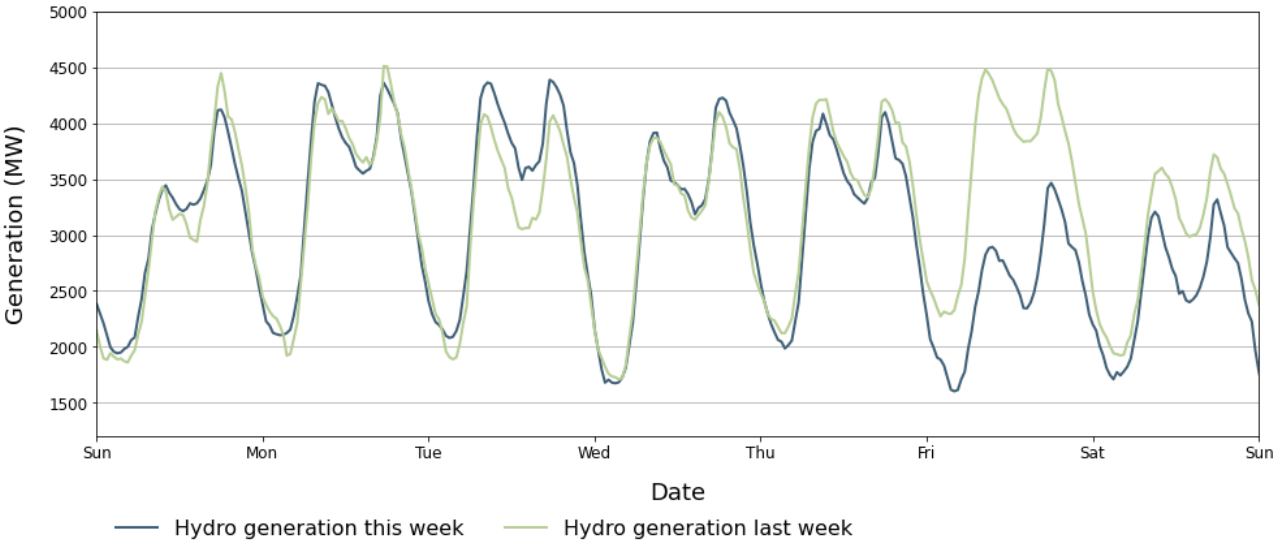
Figure 11: Thermal Generation.





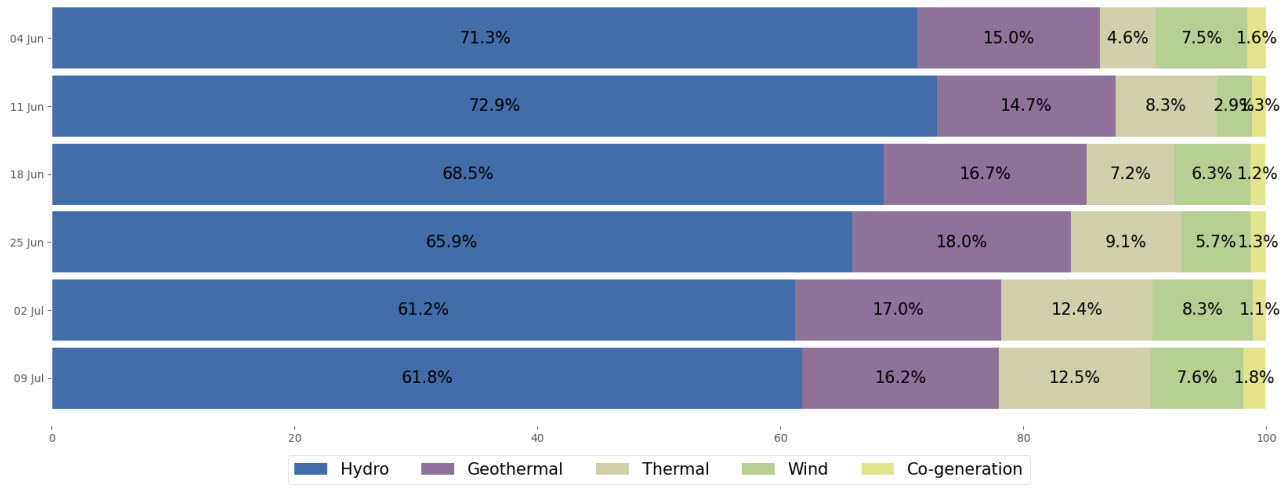
8.5. Figure 12 shows hydro generation between 9 – 15 July. For most of the week hydro generation was similar to previous week but higher on Tuesday due to low wind at the start of the day. However, hydro generation experienced a significant decrease between Friday and Saturday due to low demand and high wind generation.

Figure 12: Hydro generation between 9 – 15 July compared to the previous week.



8.6. As a percentage of total generation, between 9 – 15 July, total weekly hydro generation was 61.8 percent, geothermal 16.2 percent, thermal 12.5 percent, wind 7.6 percent, and co-generation 1.8 percent. Like last week, a notable increase in thermal generation compared to the previous few weeks can be attributed to relatively lower hydro generation.

Figure 13: Total generation as a percentage each week between 4 June and 15 July 2023.



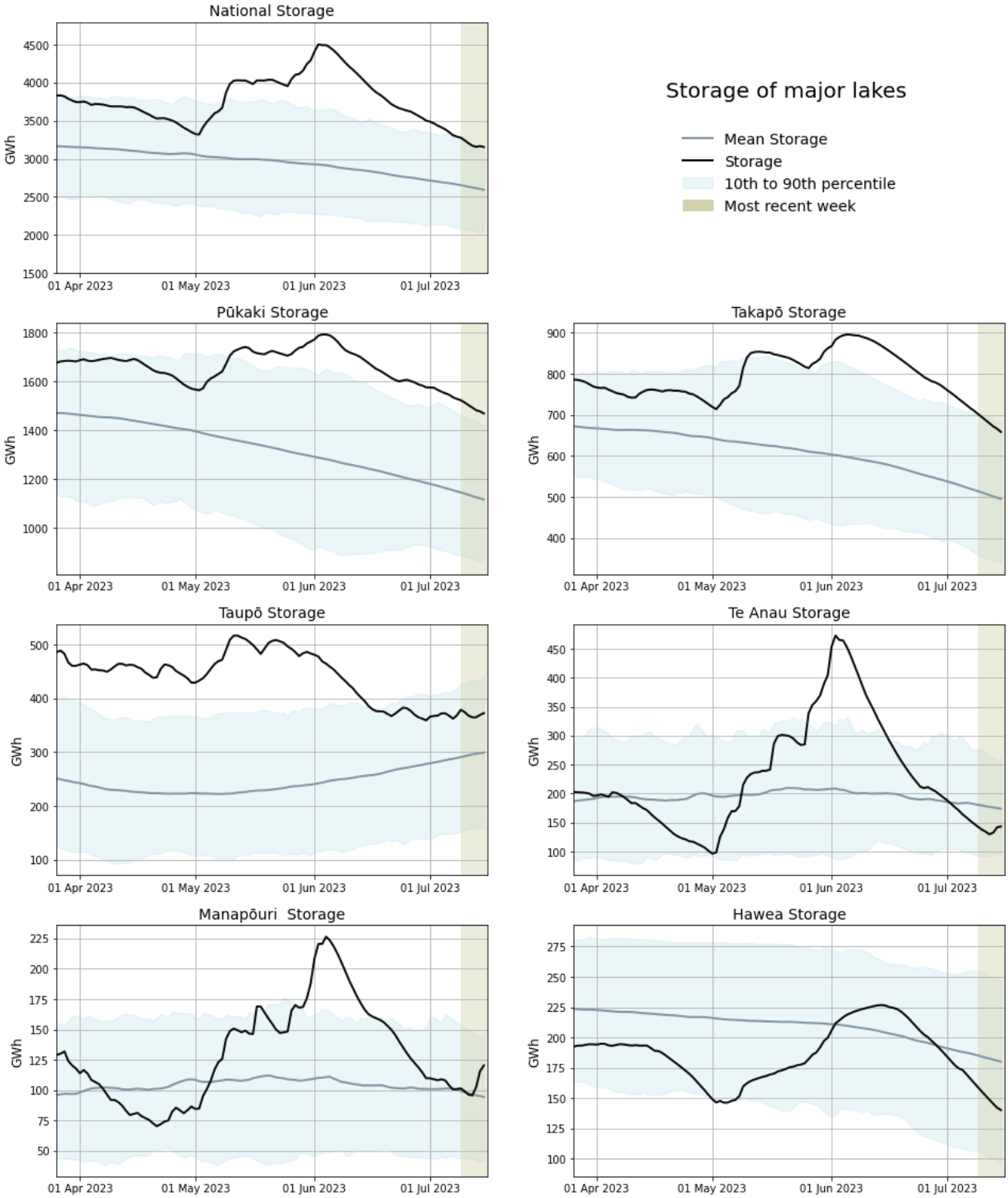
9. Storage/Fuel Supply

9.1. Figure 14 shows 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 levels have decreased this week to 77.2 percent of nominal full as of 15 July. However national controlled storage is still high at 118.3 percent of the historic mean for this time of year.

9.3. During this week, most lake levels experienced a decline. Lakes Pūkaki approaching its historic 90th percentile and Takapō dipping just under its historic 90th percentile. The significant increase in lake levels was observed at Manapōuri and is now above its historic mean. Te Anau decreased at the start of the week and then increased but still fell below its historical average. The storage level at Taupō is slightly below its historical 90th percentile. Hawea storage decreased and is currently below its historic mean for this time of year.

Figure 14: Hydro Storage.

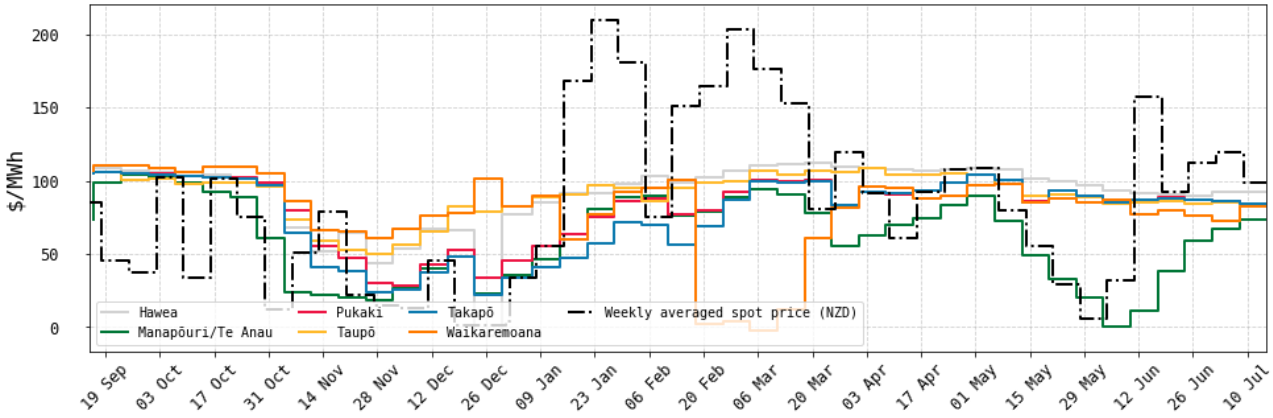


10. JADE Water Values

10.1. The JADE[1] 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 15 July 2023 using values obtained from JADE. 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. Recently the water values in most of the lakes remained relatively steady. Water values at Te Anau and Manapōuri have been increasing in recent weeks as storage decreased, with Te Anau below its historic average.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 15 July 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 July 2023. The SRMC of diesel plants has significantly decreased from March, and the SRMC of gas-fuelled and coal plants has also slightly decreased. A reduction in carbon prices has contributed to the decline in SRMCs.

11.4. In early July, Indonesian coal was at around ~$456/tonne (NZD) putting the latest SRMC of coal-fuelled Huntly generation at ~$247/MWh.

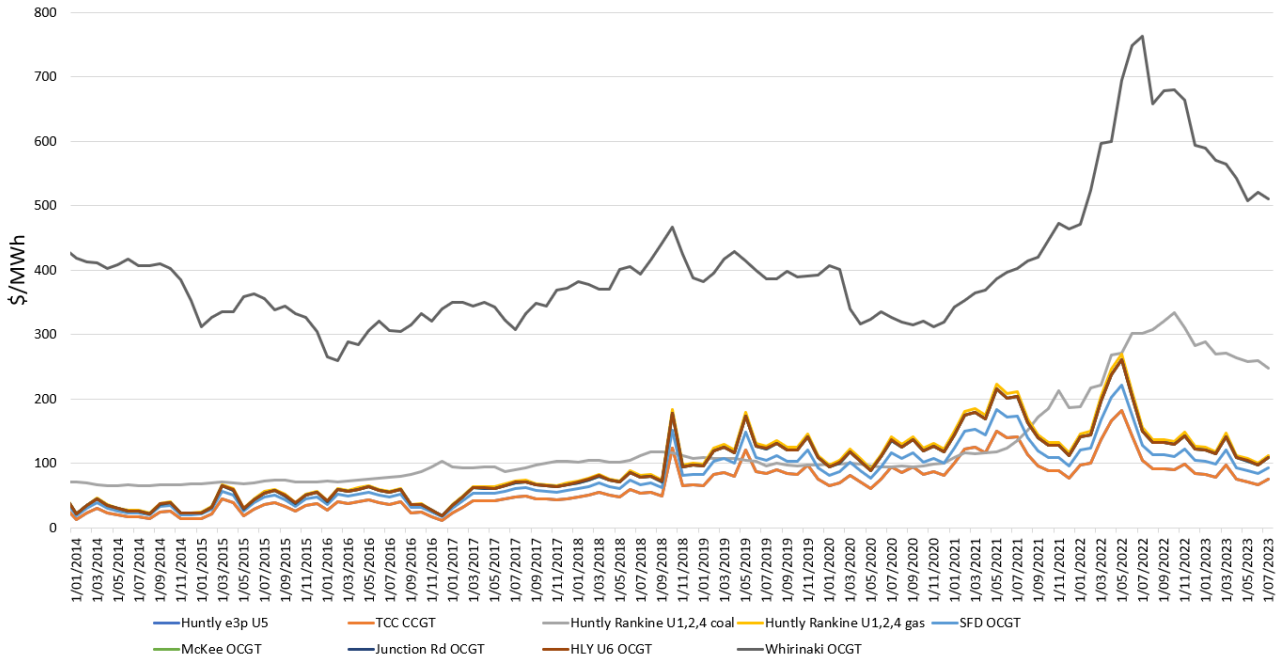
11.5. The SRMC of Whirinaki has decreased to ~$511/MWh.

11.6. The SRMC of gas fuelled thermal plants increased slightly and is between $75/MWh and $113/MWh, likely due to an increase in thermal generation.

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

[1] 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.

Figure 16: Estimated monthly SRMC for thermal fuels.



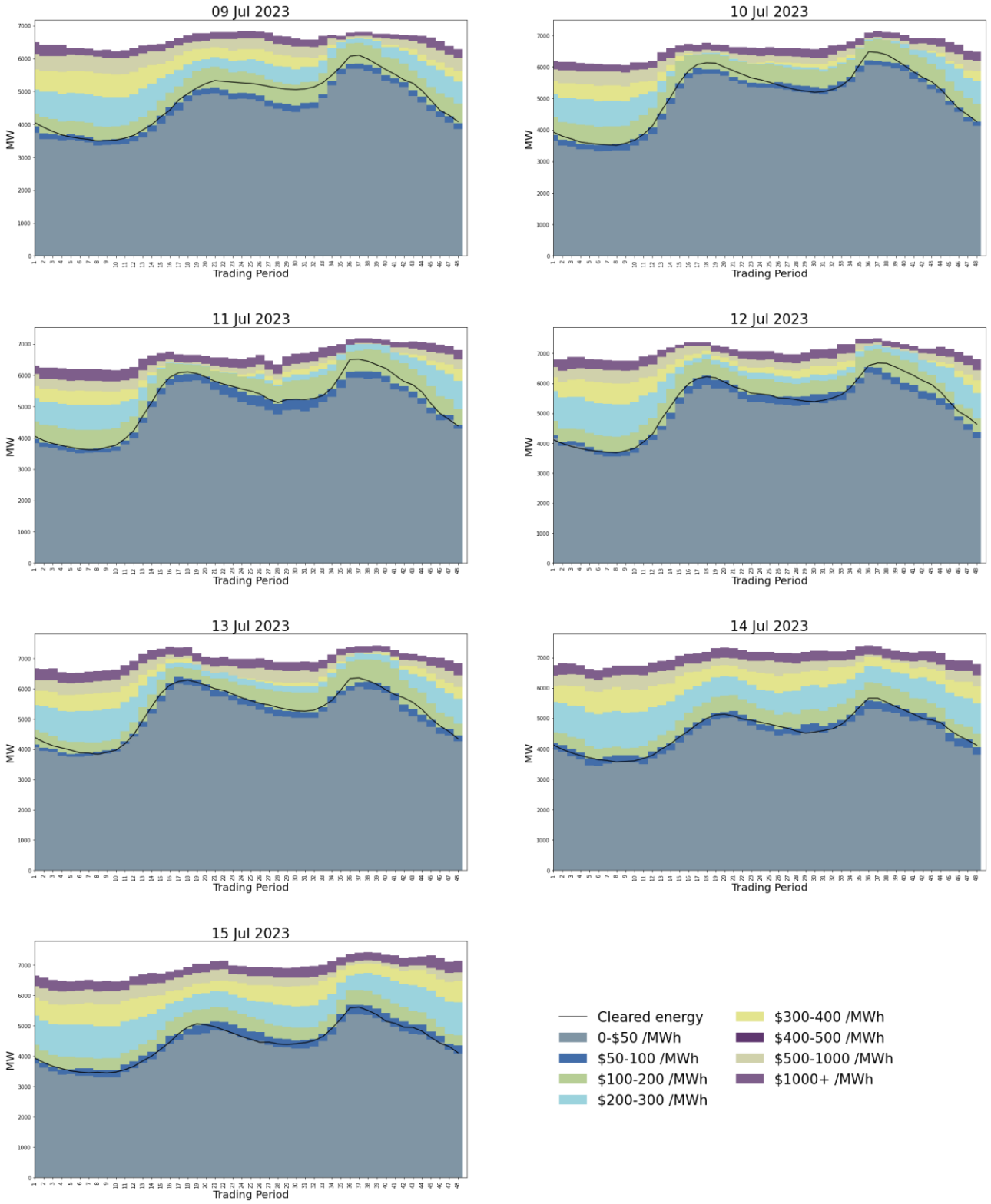
12. Offer Behaviour

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. Throughout the week, there was a higher volume of generation offered in the price range of $100-$200/MWh. The increase in generation at relatively higher price bands might be attributed to the decline in hydro storage, which was supplemented by thermal generation. On Sunday evening, in response to high demand, a significant quantity of generation was offered into the market within the $100-$200/MWh price range.

12.3. On Sunday, the majority of energy was cleared within the price range of $0 to $100/MWh. However, during the evening peak, some energy was also cleared in the $100 to $200/MWh band. Between Tuesday and Wednesday, there was an increase in the volume of generation cleared within the $50-$200/MWh range, primarily due to low wind generation. On Wednesday, the rise in wind generation resulted in more offers being cleared between $50-$100/MWh, with higher prices observed during the evening peak. On Friday and Saturday, because of lower demand, prices typically cleared within the range of $50-$100/MWh.

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.
15/1/2023 4/2/2023	Several	Further analysis	N.A.	Multiple	High energy prices associated with high hydro offers.
18/05/2023	Several	Further Analysis	Contact	Multiple	Market conditions which led to higher off-peak prices.
13/06/2023	14-16	Further Analysis	Genesis	Takapō	Offer changes.
14/06/2023	15-17	Further Analysis	Genesis	Multiple	High energy prices associated with high energy offers.
15/06/2023	15-19	Further Analysis	Genesis and Contact	Multiple	High energy prices associated with high energy offers.