Date: 7 August 2023

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

TRADING CONDUCT REPORT

1. Overview for week of 30 July – 5 August 2023

1.1. During this week, prices were mostly just above the historic average and below $200/MWh. There were some price spikes during peak periods in the latter half of the week when demand was high due to cold temperatures across the country and when wind generation was low. Thermal baseload generation was high during this cold snap with all three Rankines running as well as TCC. One of the highest price spikes occurred on Wednesday evening with the highest demand recorded this winter. Demand on Wednesday evening was over 200MW higher than forecast and came close to the record from 9 August 2021. It should be noted that there were no apparent issues with generation capacity to meet these demand requirements. The percentage of generation from hydro was similar to the previous week with hydro storage continuing to decrease and currently at 111 percent of the historic mean.

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.

2.2. Between 30 July – 5 August:

a) The average wholesale spot price across all nodes was $136.79/MWh.
b) The middle 50 percent of prices fell between $105.96/MWh and $154.39/MWh.

2.3. Overall, the majority of spot prices were below $200/MWh and hovering just above the historic average for this time of year. The vertical black lines highlight the price spikes above the 90th percentile, while the red dashed lines on the graph show the three highest demand peaks that occurred which are in the system operator's top ten trading period demand peaks.

2.4. There were a few price spikes during evening and morning peaks in the second half of the week due to high demand. The first price spikes were on Wednesday evening at 5.30pm and then 6.00pm, where prices at Ōtāhuhu reached around $861/MWh and $663/MWh, respectively. The prices at Benmore at these times were $669/MWh and $512/MWh. These spikes occurred due to high demand as temperatures fell across the country and a fall in wind generation. Demand was over 200MW higher than forecast which caused tight supply and saw Whirinaki constrained on.

2.5. The next price spike occurred on Thursday at 7.30am. The price at Ōtāhuhu was $446/MWh and the price at Benmore was $334/MWh. During this trading period temperatures across the country were below the historic average, baseload thermal generation was high with all three Rankines running as well as TCC, hydro generation was ramped up and wind generation was around 300MW. Whirinaki was also constrained on during this period. Prices remained above $240/MWh for the next trading period but did not breach the historic 90th percentile.

2.6. The Friday morning peak saw prices spike at the 7.30am and 8.00am trading periods. At 7.30am the price at Ōtāhuhu was around $662/MWh and the price at Benmore was $509/MWh. At 8.00am the prices were $558/MWh and $435/MWh respectively at Ōtāhuhu and Benmore. Demand was high at over 3.25GWh due the temperatures dropping to single digits across the whole country. Wind generation was low and so this demand was met with high thermal generation and increased hydro generation.

Figure 1:Wholesale Spot Prices between 30 July (Sunday) – 5 August (Saturday) 2023

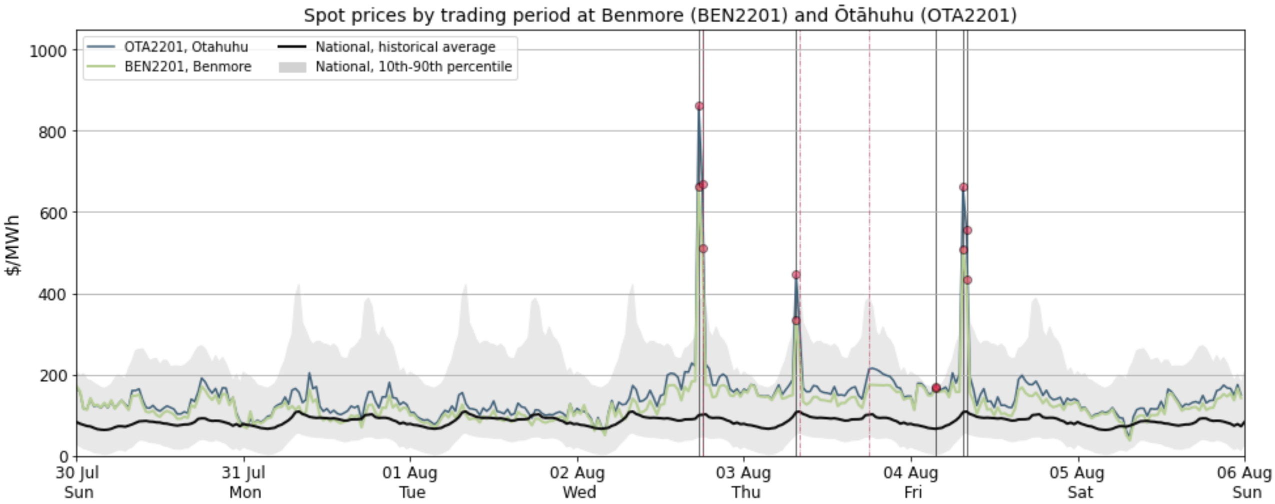
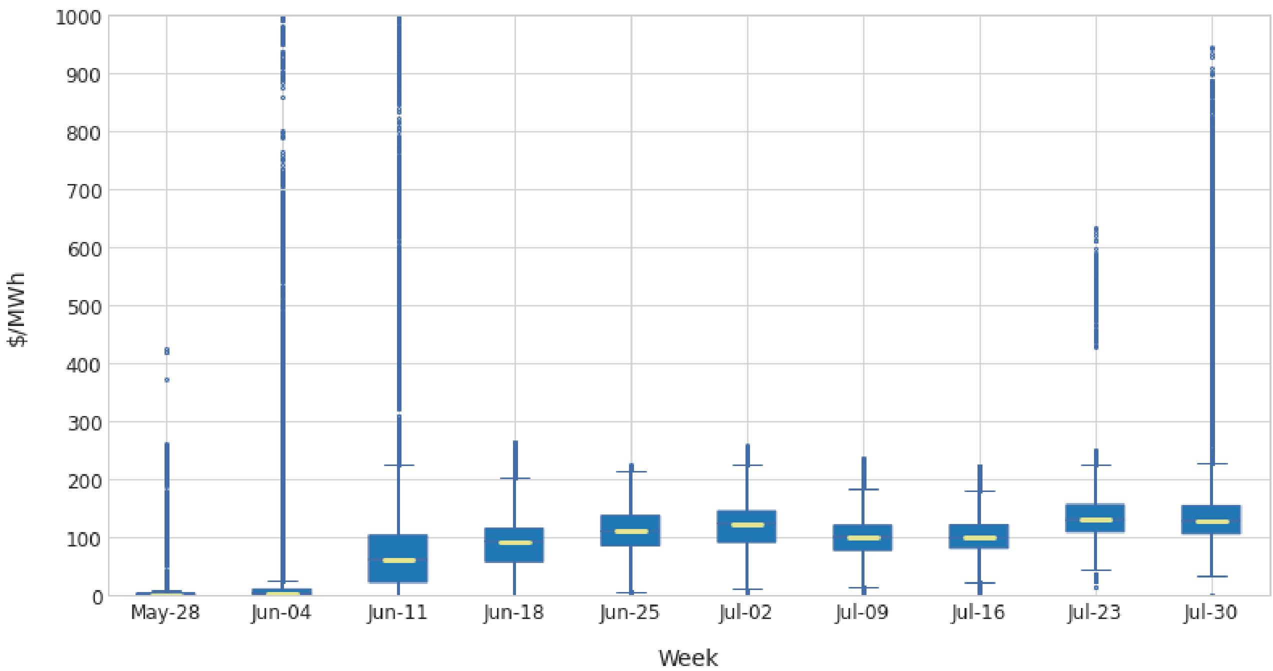


Figure 2:Wholesale Spot Prices between 23 July (Sunday) – 29 July (Saturday) 2023

2.7. Figure 3 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. During this week, the median and quartiles were similar to the previous week with the middle 50 percent of prices in the range of $106/MWh to $154/MWh. There were a number of outliers given the small IQR distribution due to the price spikes that occurred; some 5-minute prices reaching over 900/MWh.

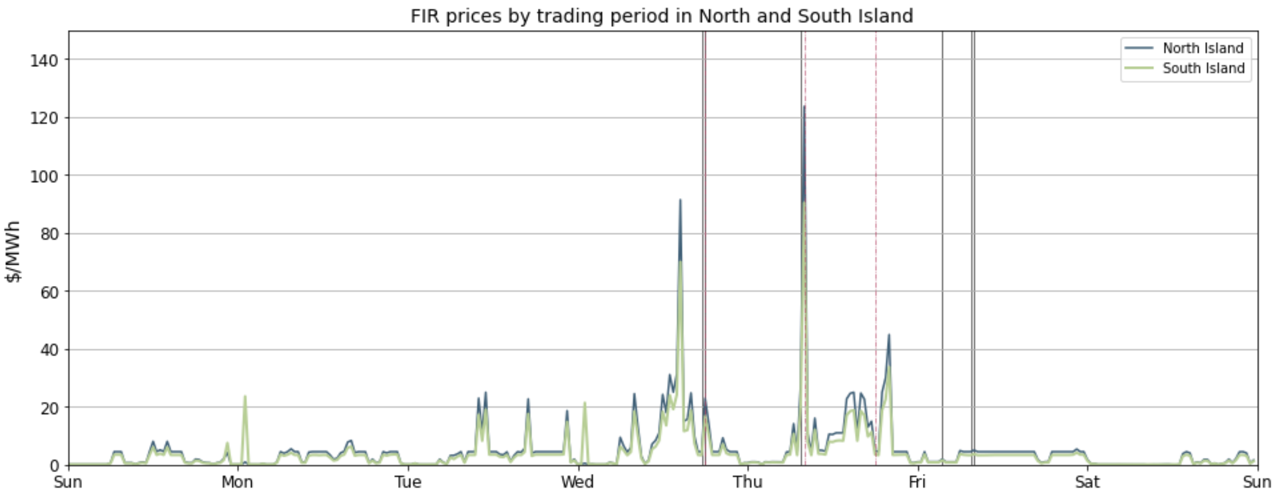
Figure 3: Boxplots showing the distribution of spot prices this week and the previous nine weeks.



3. Reserve Prices

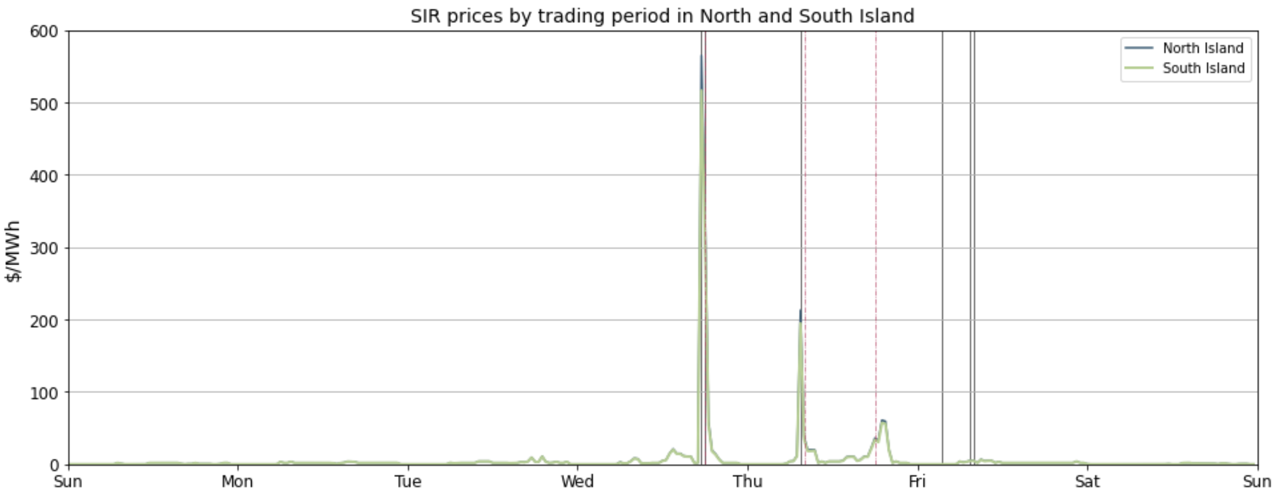
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 4. This week the FIR prices were mostly below $20/MWh for both islands, although there were a few spikes. The highest FIR spike was at 8.00am on Thursday 3 August in line with the high peak demand and when northward HVDC flow was over 750 MW. The North Island price reached $124/MWh and the South Island price was $90/MWh, reflecting the tight supply of capacity.

Figure 4: Fast instantaneous reserve (FIR) prices by trading period and Island.



3.2. SIR prices for the North and South Islands are shown in Figure 5. SIR prices were mostly below $10/MWh this week. There were spikes in line with the high demand peaks on Wednesday evening and Thursday morning. The highest SIR price was on Wednesday 2 August at 5.30pm in line with the high spot price during this trading period. The North Island SIR price reached $565/MWh and the South Island SIR price reached $516/MWh, reflecting the tight supply of capacity.

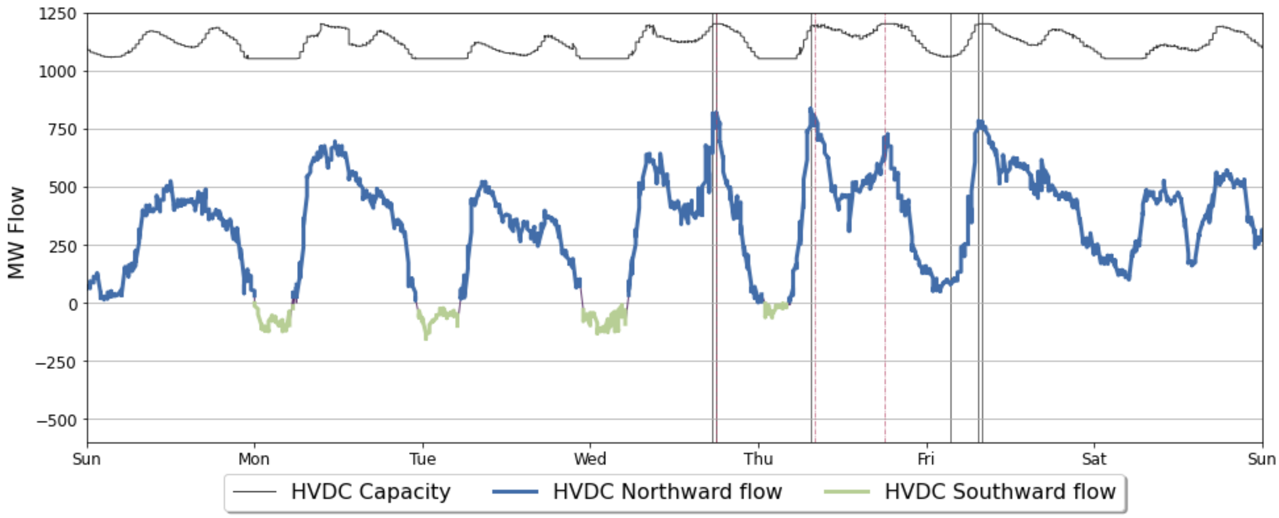
Figure 5: Sustained instantaneous reserve (SIR) prices by trading period and Island.



4. HVDC

4.1. Figure 6 shows HVDC flow between 30 July – 5 August. The first half of the week, the HVDC was mainly northward with the usual overnight flow south. Over Friday to Sunday the flow was all northwards coinciding with a drop off in wind generation and increase in demand due the colder temperatures. The HVDC ramped up during the high peak demand periods in the latter part of the week with northward transfer above 750MW but still well below the capacity limits. Southward overnight flow at the start of the week was lower than 150 MW.

Figure 6: HVDC northward flow and capacity.



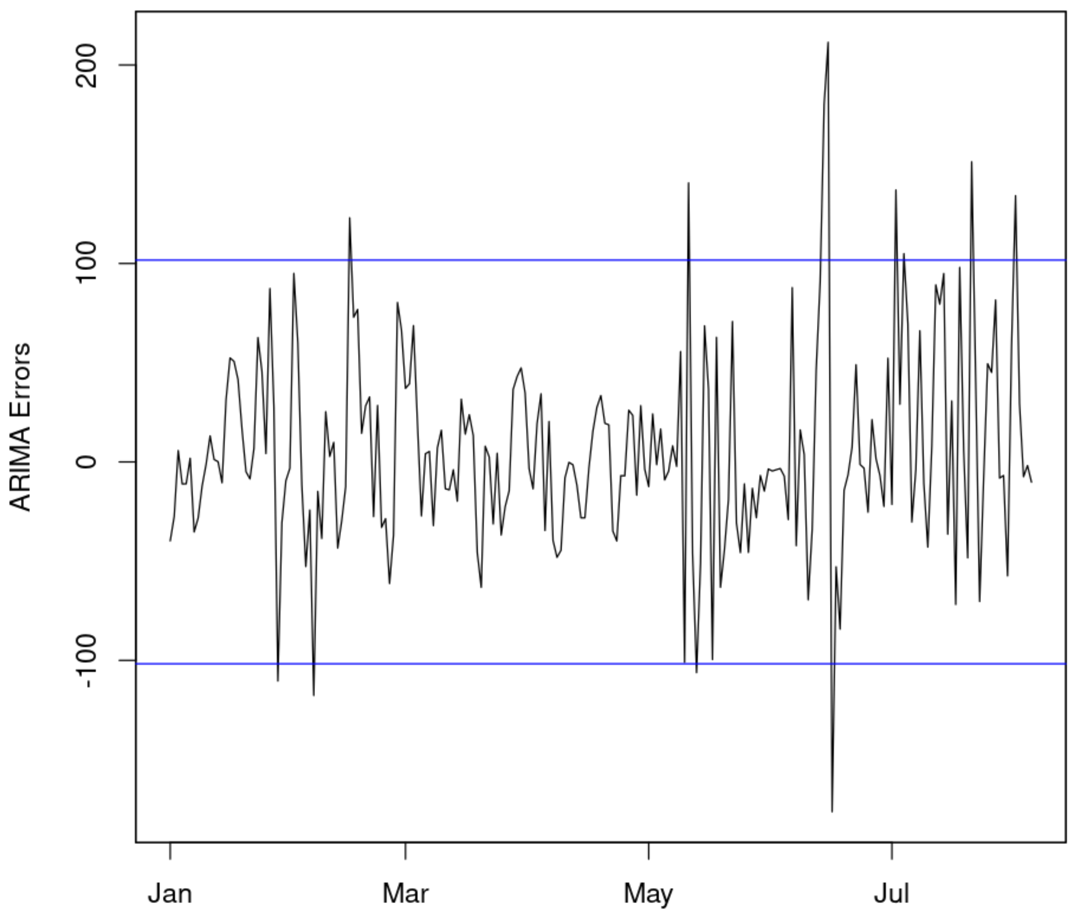
5. Regression Residuals

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 7 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.

5.3. This week, residuals were above two standard deviations on Tuesday. The residual on Tuesday indicates prices were higher than modelled. Wind generation was higher on Tuesday compared to Monday, while demand was lower, conditions which the model expects to dampen prices. However, the price remained close to the long-term average. Further analysis of market conditions indicate prices on these days were close to current fuel costs for hydro and thermal generation, and therefore were consistent with current market conditions.

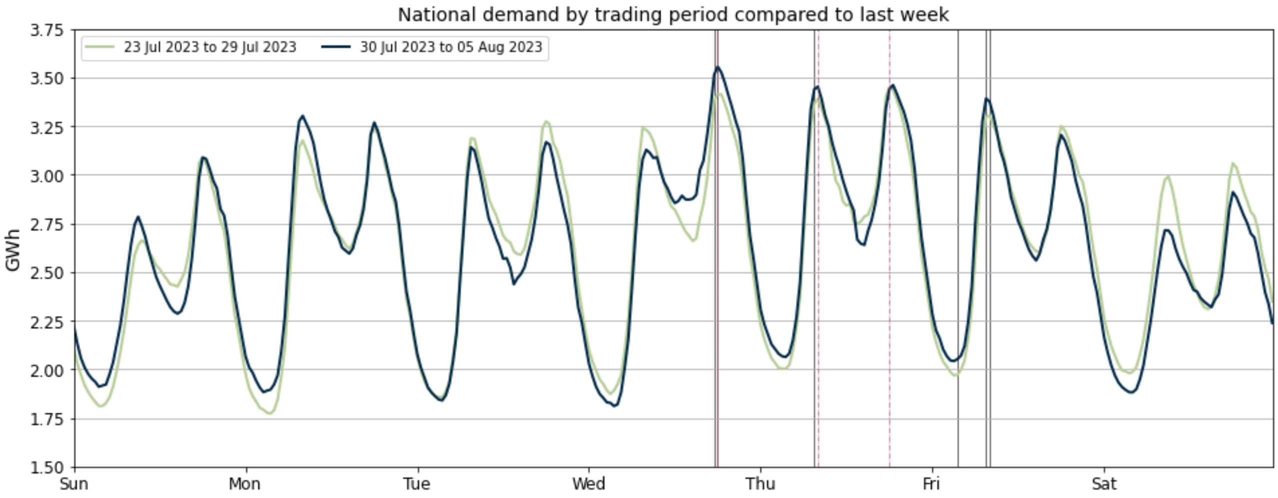
Figure 7: Residual plot of estimated daily average spot prices from 1 July 2023 – 05 August 2023. The blue lines show two standard deviations of the ARMA errors.



6. Demand

6.1. Figure 8 shows national grid demand between 30 July – 5 August, compared to the previous week. Overall, most days had a similar pattern in demand to the previous week. However, there were a few morning peak periods that were slightly higher than the previous week. Also, Wednesday evening peak demand was significantly higher than the previous week, with demand above 3.5GWh, close to the record demand seen on 9 August 2021. Peak demand was under forecast by over 200MW on 2 August, which likely contributed to high prices. Average national demand at 8.00am and 6.00pm on 3 August also made it into the system operator's top ten highest recorded demand peaks.

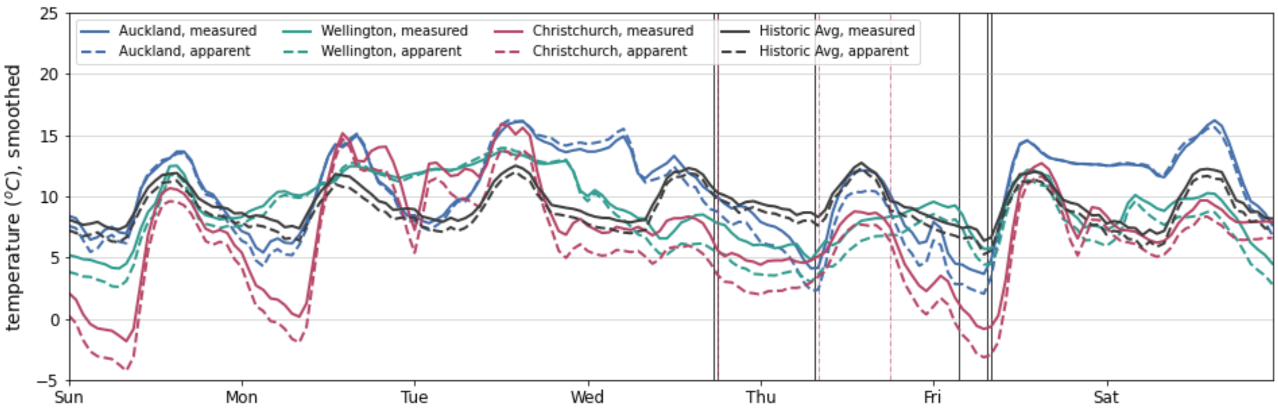
Figure 8: National demand by trading period compared to the previous week.



6.2. Figure 9 shows hourly temperatures at the three main population centres between 30 July – 5 August. 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. Temperatures were close to or above the historic average in most regions at the start of the week. On Wednesday temperatures fell, with apparent temperatures reaching below 5 degrees in Wellington and Christchurch. From Thursday to Friday morning temperatures in Auckland, Wellington and Christchurch were all in the single digits, with Christchurch's apparent temperature falling to -4 degrees. Temperatures rose on Friday afternoon to above historic averages for all centres, ending the cold spell.

Figure 9: Temperatures across main centres.



7. Outages

7.1. Figure 10 shows generation capacity on outage. Total capacity on outage between 30 July – 5 August ranged between ~750MW and ~1300MW.

7.2. Notable outages include:

(a) Huntly 5 extended outage to 20 May 2024.

(b) Huntly 2 was on outage from 28 July to 1 August.

(c) TCC had a short partial outage on 5 August (130MW loss/200MW remaining).

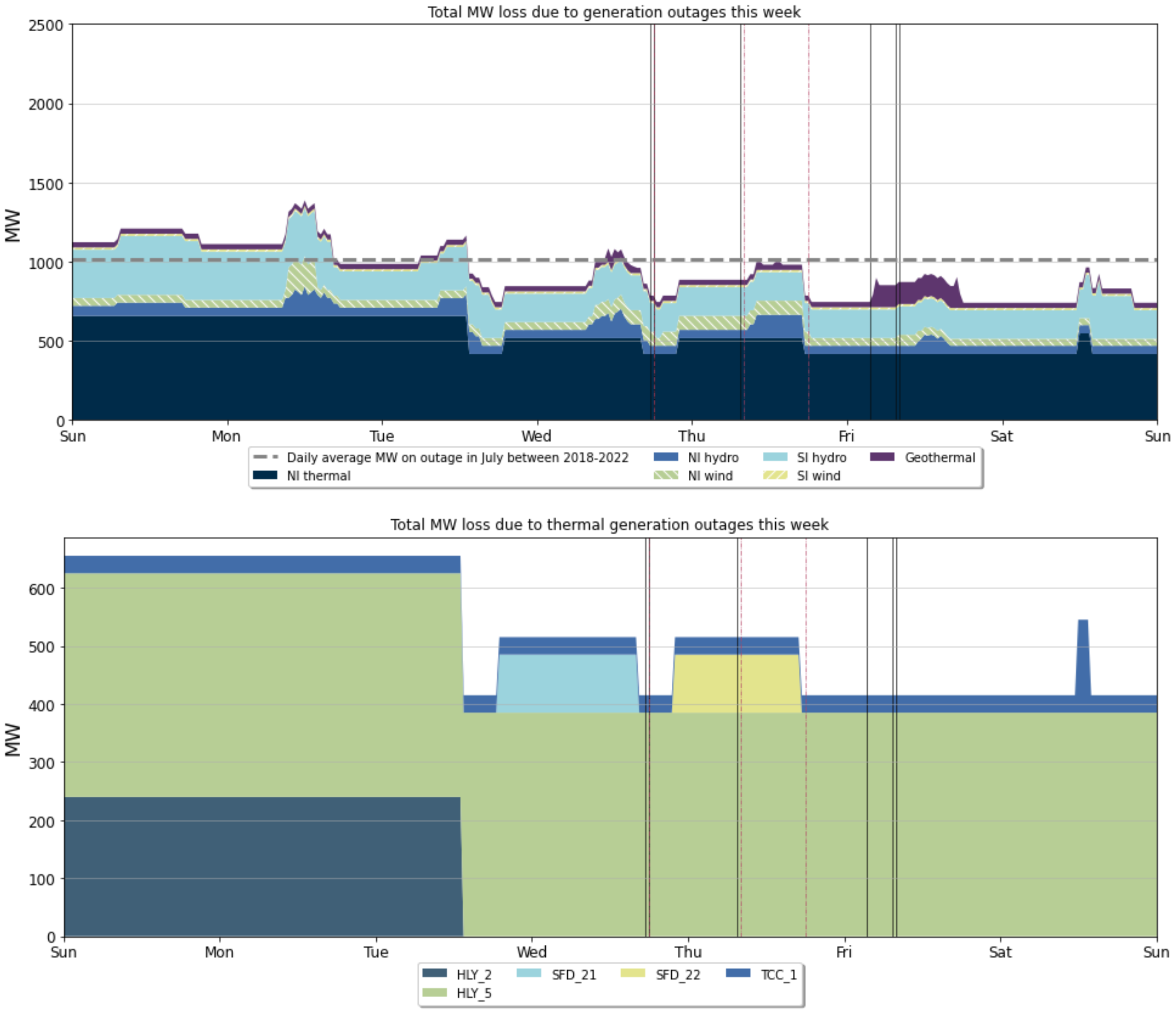
(d) Stratford 1 was on outage 1 - 2 August and Stratford 2 was on outage 2 - 3 August.

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

(f) West Wind Station was on outage 31July, with a partial outage of 44MW still in place until 24 November.

(g) Kawerau geothermal unit was on outage 4 August.

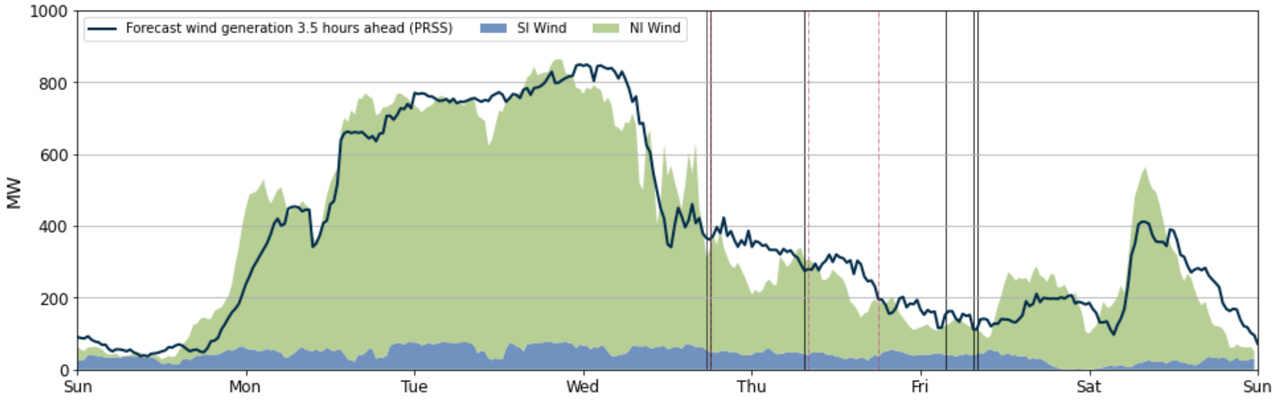
Figure 10: Total MW loss due to generation outages.



8. Generation

8.1. Figure 11 shows wind generation, from 30 July – 5 August, ranged from ~29 MW to 864 MW. From Monday to Wednesday mid-afternoon wind generation was mainly above 500 MW before dropping off on Wednesday evening. The wind generation remained below 300 MW for most of Thursday and Friday. The price spikes coincided with the periods of low wind generation.

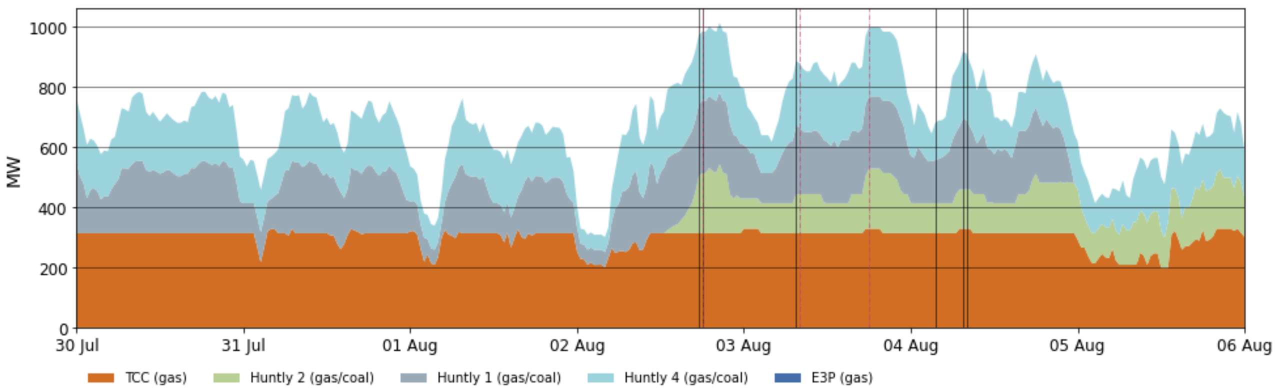
Figure 11: Wind Generation and forecast.

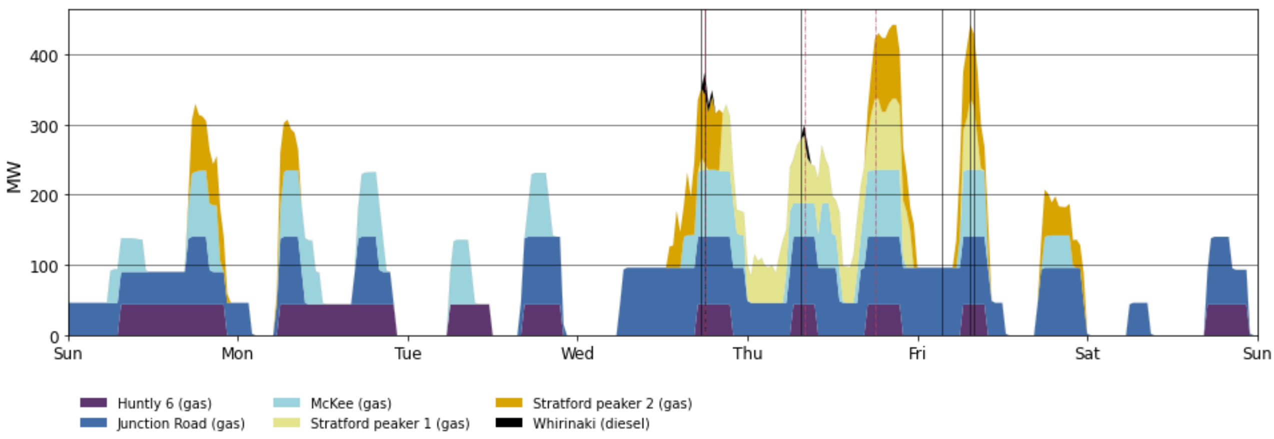


8.2. Figure 12 shows the generation of thermal baseload and thermal peaker plants between 30 July – 5 August. TCC ran all week as baseload with at least two Rankine units supporting. Huntly 4 ran all week with Huntly 1 running Sunday to Friday. After returning from outage Huntly 2 ran from Wednesday afternoon through to Saturday. As a result, three Rankines were running from Wednesday to Friday when wind generation decreased, and temperatures dropped.

8.3. All peakers ran during this week with Whirinaki constrained on during the Wednesday evening and Thursday morning high peak demand times. Junction Road ran every day during the peaks as well as running continuously from Wednesday to Friday. All peakers except Whirinaki ran on Thursday evening and Friday morning whilst wind generation was low to cover the demand.

Figure 12: Thermal Generation.

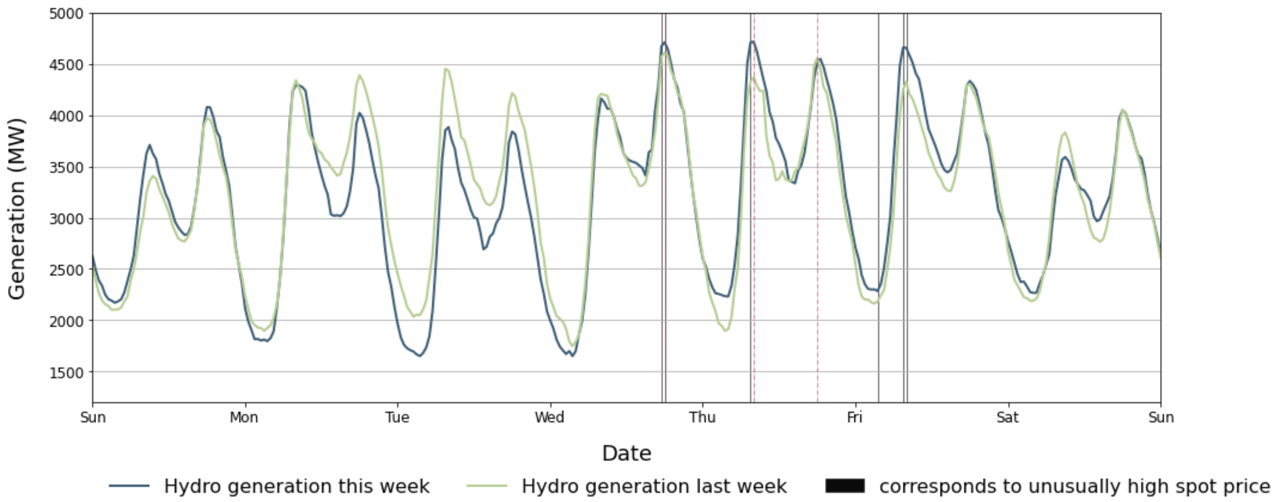




8.4.

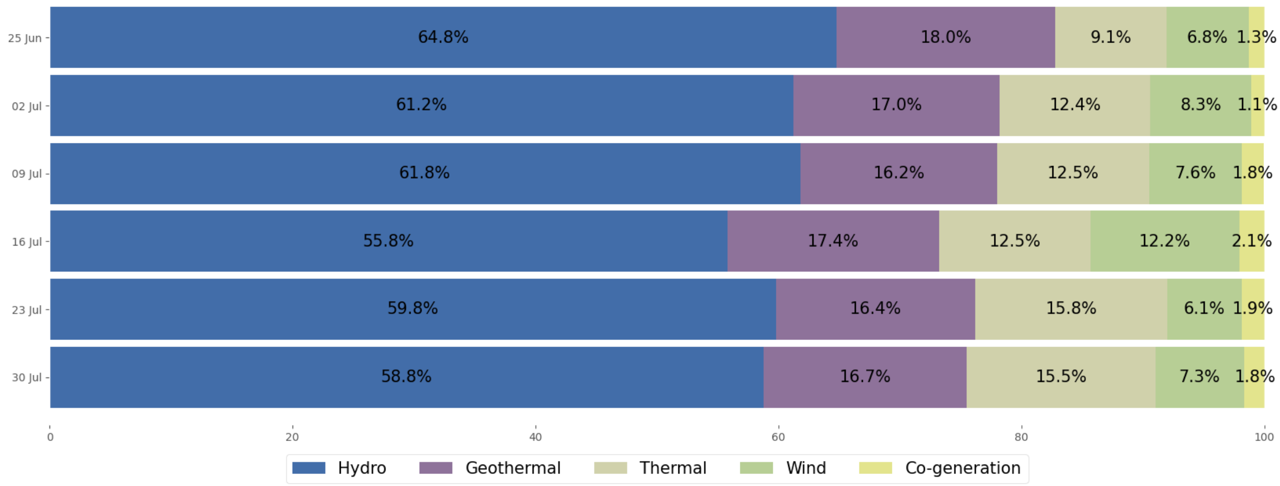
8.5. Figure 13 shows hydro generation between 30 July – 5 August. Overall, hydro generation was slightly lower than the previous week. High wind generation and milder temperatures on Tuesday saw a drop in hydro generation compared to the previous Tuesday. However, during the high demand periods over Wednesday to Friday hydro generation ramped up, with Thursday and Friday morning seeing much higher hydro generation than the previous week.

Figure 13: Hydro generation between 23 – 29 July compared to the previous week.



8.6. As a percentage of total generation, between 30 July – 5 August, total weekly hydro generation was 58.8 percent, geothermal 16.7 percent, thermal 15.5 percent, wind 7.3 percent, and co-generation 1.8 percent. There was a similar proportion of hydro and thermal generation this week covering the high demand periods, with only a small increase to wind generation.

Figure 14: Total generation as a percentage each week between 18 June and 29 July 2023.



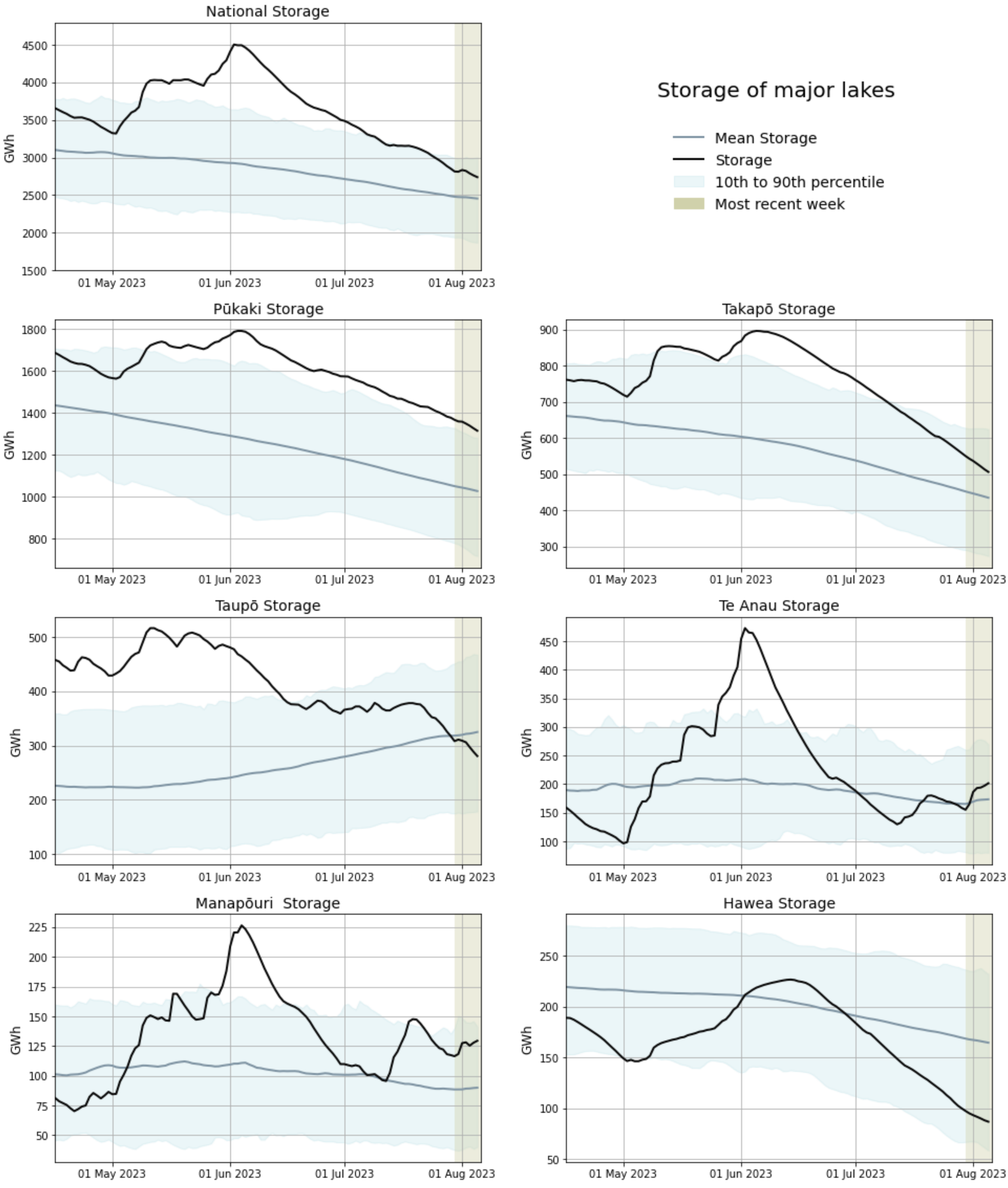
9. Storage/Fuel Supply

9.1. Figure 15 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 continued to decrease with controlled storage at 68.9 percent nominally full as of 5 August and 111 percent of historic mean.

9.3. During this week, the storage levels in most lakes decreased. Pūkaki is steadily declining and remains just above its historic 90th percentile. Takapō is declining more steeply and is beginning to approach its historic mean. Taupō storage has taken a sharp drop over the last week and is now below its historic mean at under 300GWh. Te Anau and Manapōuri have increased slightly over the last week, with Manapōuri still close to its historic 90th percentile and Te Anau now back above its historic mean. Hawea storage is steadily decreasing but is above its historic 10th percentile.

Figure 15: Hydro Storage.

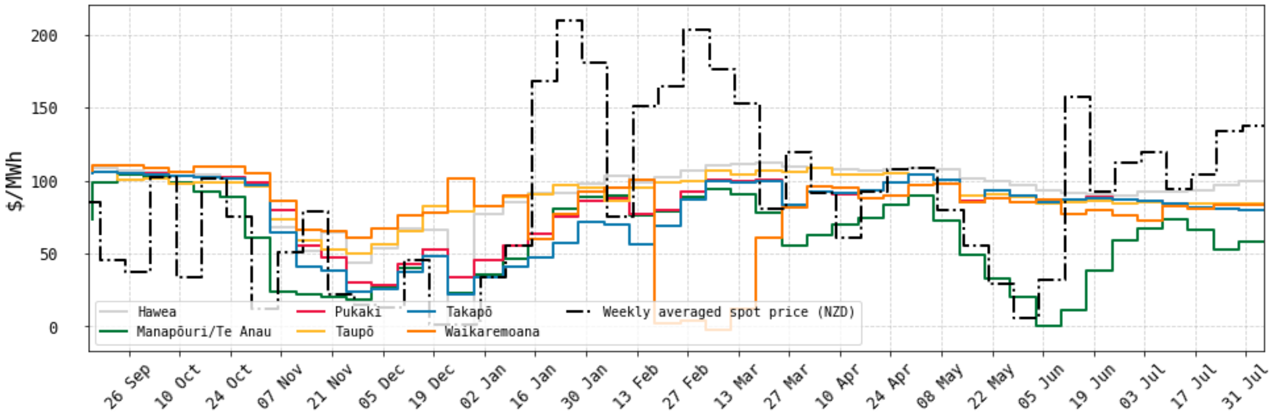


10. JADE Water Values

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 16 shows the national water values between 15 September 2022 and 5 August 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. Recently the water values in most of the lakes remained relatively steady, except for Hawea and Manapōuri/ Te Anau. This is due to storage remaining sufficiently high to last until the end of winter. Water values at Hawea, Te Anau and Manapōuri are more volatile due to limited storage capacity, with water values increasing after storage fell in the preceding week.

Figure 16: JADE water values across various reservoirs between 15 September 2022 and 5 August 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 17 shows an estimate of thermal SRMCs as a monthly average up to 1 August 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 ~$315/tonne (NZD) putting the latest SRMC of coal-fuelled Huntly generation at ~$270/MWh.

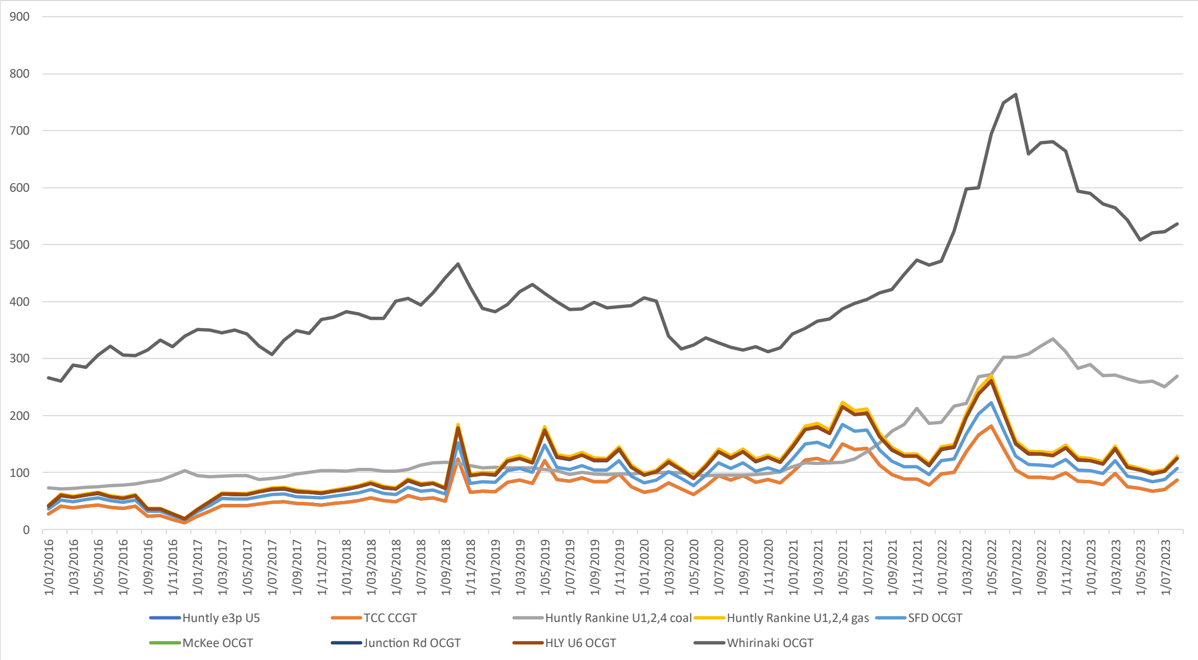
11.5. The SRMC of Whirinaki has decreased to ~$536/MWh.

11.6. The SRMC of gas fuelled thermal plants increased again and is currently between $86/MWh and $129/MWh, likely due to increased demand for gas.

[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.

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

Figure 17: Estimated monthly SRMC for thermal fuels.



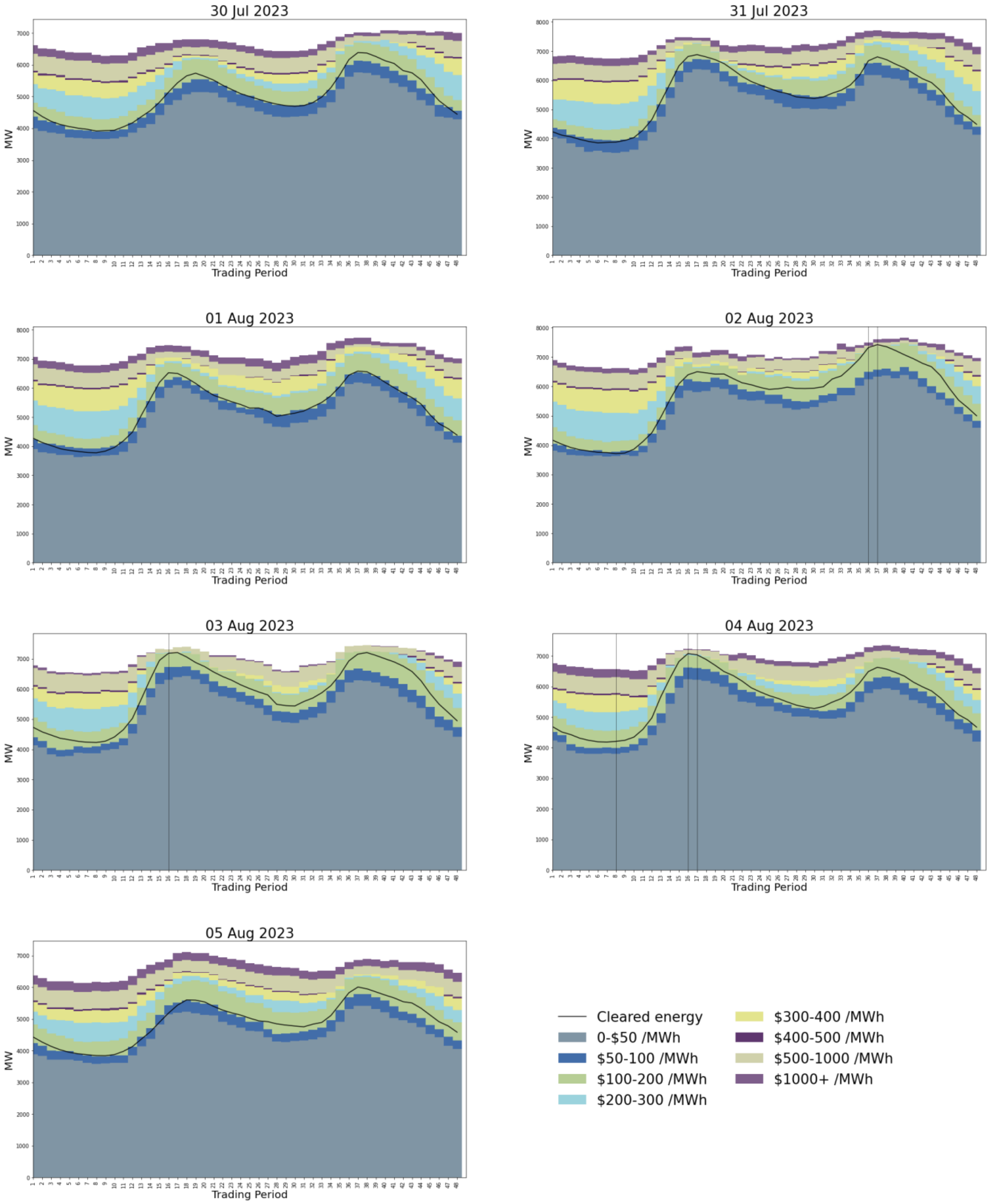
12. Offer Behaviour

12.1. Figure 18 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 there was an increase in generation offered between $100-$200/MWh, especially in the second half of the week. This increase in offers at this price reflected increased demand, with prices usually clearing in this price range.

12.3. During peak trading periods there was very little generation priced between $200/MWh and $500/MWh, this was likely as most generation was running, and the remaining generation capacity were units with high start up costs that did not expect to be dispatched. As a result, when demand was under forecast by over 200MW on 2 August it resulted in large price spikes. By contrast demand was still high in the evening on 3 August, but as it was more accurately forecast prices remained around $200/MWh.

Figure 18: 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.