28 April 2026

Trading conduct report 19-25 April 2026

Market monitoring weekly report

Trading conduct report 19-25 April 2026

1. Overview

1.1. This week the average spot price increased by $29/MWh to $98/MWh. Higher prices this week are related to higher demand, lower wind generation and reserve price spikes. National controlled storage has decreased to 86% nominally full and ~112% of the historical average for this time of the year.

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 19-25 April:

(a) The average spot price for the week was $98/MWh, an increase of around $29/MWh compared to the previous week.

(b) 95% of prices fell between $0.27/MWh and $249/MWh.

2.3. Prices are higher this week compared to last week, due to higher demand and lower wind generation.

2.4. On Wednesday, prices spiked between $350-429/MWh from 5.30pm to 6.30pm at Ōtāhuhu. During this time, evening demand was high and wind was up to 100MW lower than forecast.

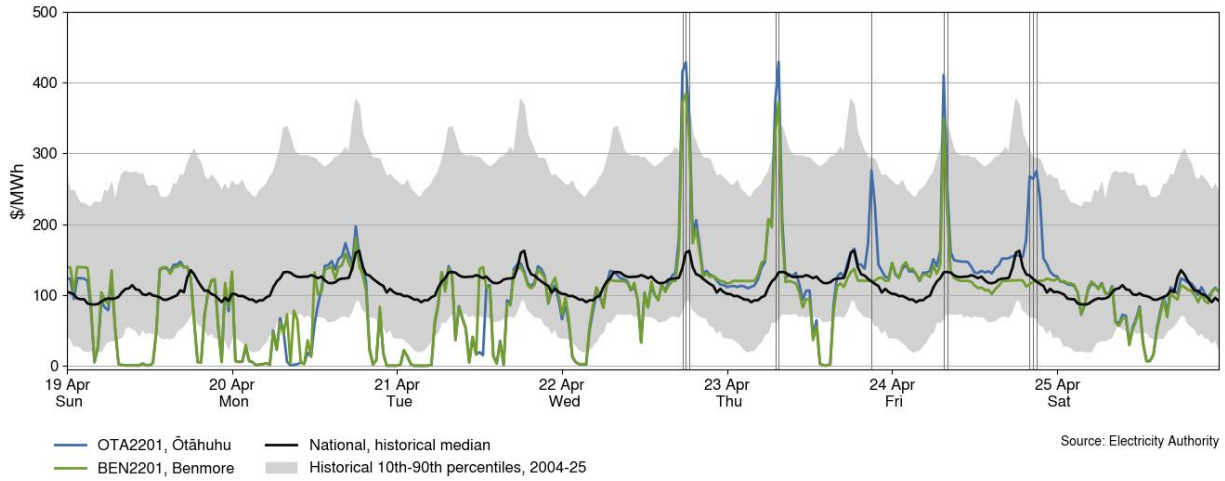
2.5. Ōtāhuhu prices spiked up to $429/MWh between 7.00am to 7.30am on Thursday as well, during high morning demand and low wind generation, with wind also up to 61MW lower than forecast and demand up to 141MW higher than forecast.

2.6. On Friday, North and South Island reserve price spikes contributed to price spikes up to $411/MWh at 7.30am.

2.7. There were two occurrences of noticeable price separation between Ōtāhuhu and Benmore during the week. These occurred during North Island reserve price spikes, on Thursday at 9.00pm and on Friday from 8.00pm to 9.00pm, where Ōtāhuhu was priced roughly $150/MWh more than Benmore.

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.

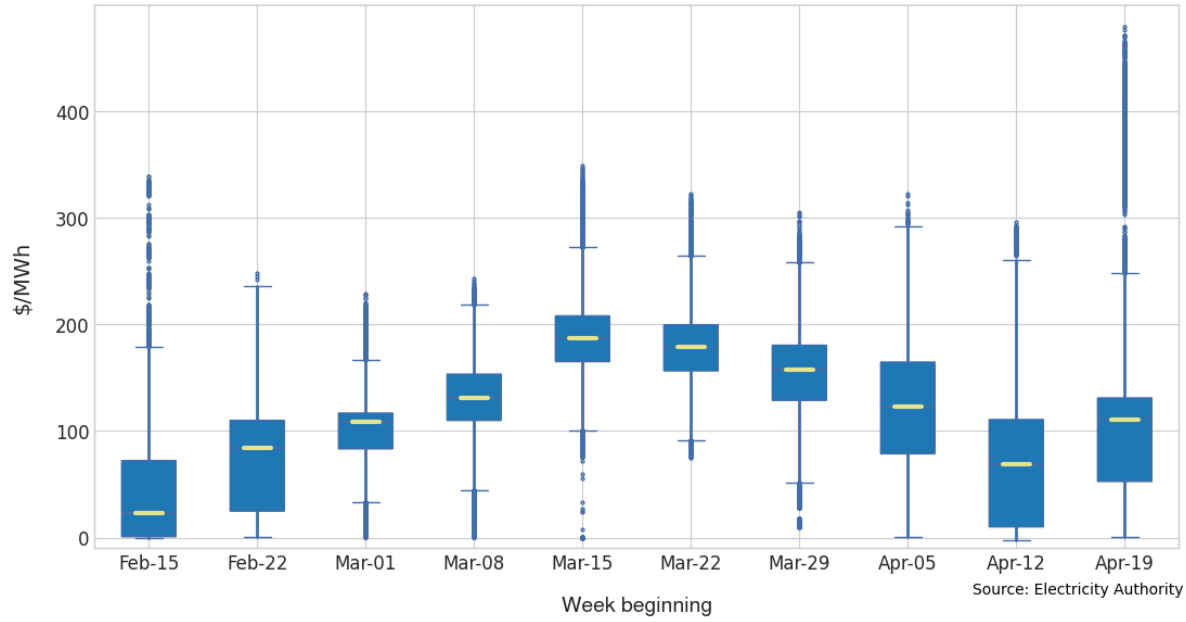
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 19-25 April



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 distribution of spot prices this week was higher than the previous week. The median price was $111/MWh and most prices (middle 50%) fell between $52/MWh and $131/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. FIR prices remained mostly below $1/MWh, aside from several spikes across the week.

3.2. On Tuesday from 12.00pm to 12.30pm, South Island FIR prices reached $67/MWh and $70/MWh while North Island FIR prices remained below $1/MWh. During these times, Ohau

A was the primary risk setter and the amount of reserve needed to cover this risk increased during the unplanned HVDC outage due to a lack of reserve sharing.

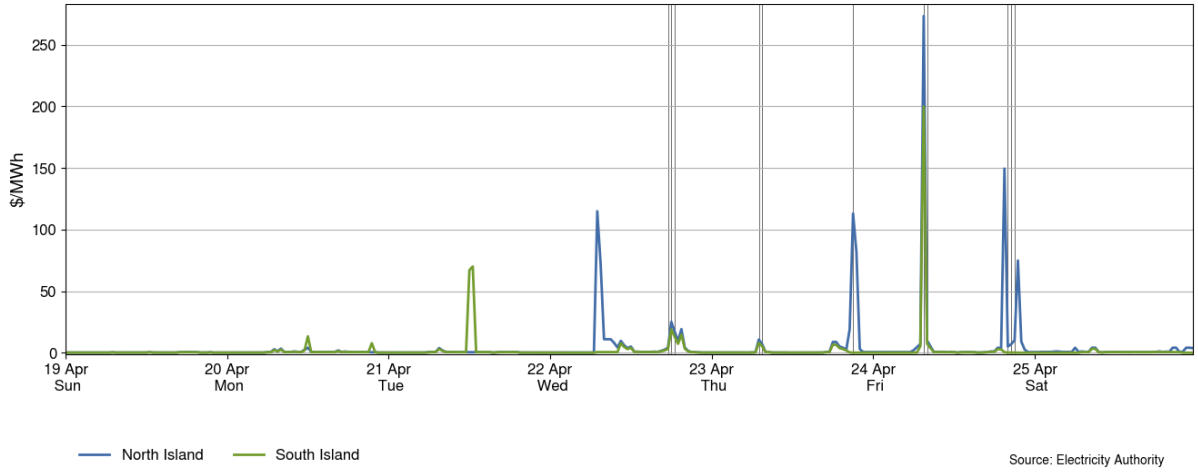
3.3. On Wednesday from 7.00am to 7.30am, North Island FIR prices reached $115/MWh and $72/MWh, while South Island FIR prices remained below $1/MWh. During this time, Harapaki wind farm was the risk setter. The amount of reserve needed to cover this risk increased as the output from the wind farm increased.

3.4. On Thursday from 9.00 pm to 9.30pm, North Island FIR prices reached $113/MWh and $82, while South Island prices remained below $1/MWh. At 9.00pm, the risk setter was Huntly 5 and the HVDC. At 9.30pm, the HVDC was the risk setter, with the amount of reserve needed to cover the risk during these two trading periods increasing.

3.5. On Friday at 7.30am, North Island FIR prices reached $273/MWh and South Island FIR prices reached $200/MWh. At this time, Huntly 5 was the risk setter and the national generation balance residuals were low (Section 9.2).

3.6. On Friday at 7.30 pm and 9.30 pm, North Island FIR prices reached $150/MWh and $75/MWh while South Island FIR prices remained below $1/MWh. During these times, the HVDC becomes a risk setter where Huntly 5 was previously. The amount of reserve needed to cover the HVDC increased as the risk off-set provided by the secondary HVDC pole reduced while it ran in reduced voltage.

Figure 3: Fast instantaneous reserve price by trading period and island, 19-25 April



3.7. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices mostly remained below $1/MWh, aside from multiple high price spikes across the week.

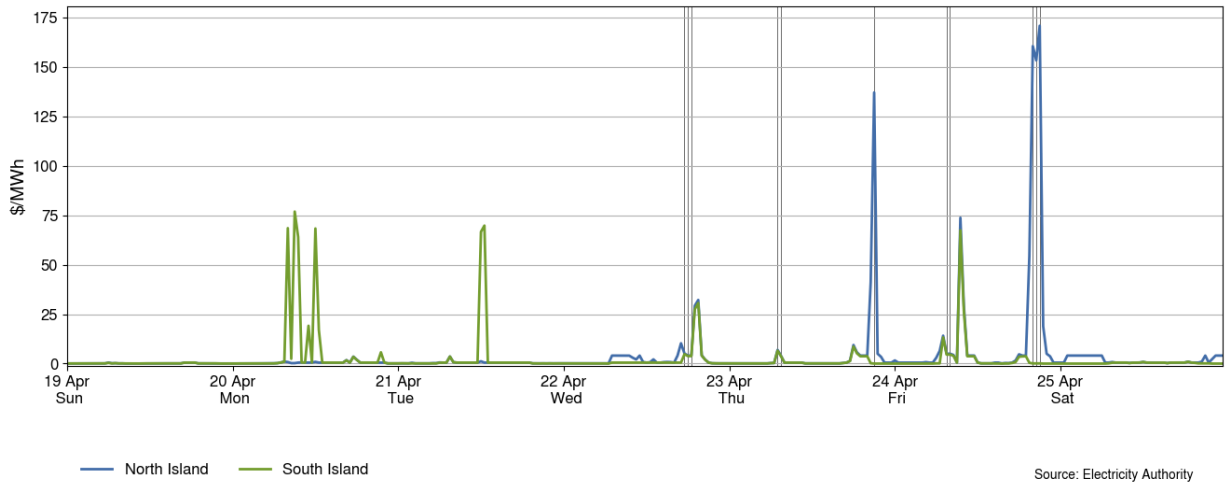
3.8. On Monday from 8.00am to 12.30pm, the South Island SIR prices spiked up to between $64/MWh to $76/MWh on six occasions. At these times, North Island SIR prices remained below $2/MWh.

3.9. On Thursday from 8.30pm to 9.00pm, North Island SIR prices reached $41/MWh and $137/MWh while South Island SIR prices remained below $1/MW/h. During these times Huntly 5 and the HVDC were the risk setters.

3.10. On Friday, North Island SIR prices reached $73/MWh at 9.30am while South Island SIR prices reached $67/MWh. During this time, Huntly 5 was the risk setter.

3.11. On Friday from 7.30pm to 9.00pm, North Island SIR prices reached $55/MWh, $161/MWh, $153/MWh and $171/MWh, while South Island SIR prices remained below $1/MWh. At these times, Huntly 5 and the HVDC were the risk setters.

Figure 4: Sustained instantaneous reserve by trading period and island, 19-25 April



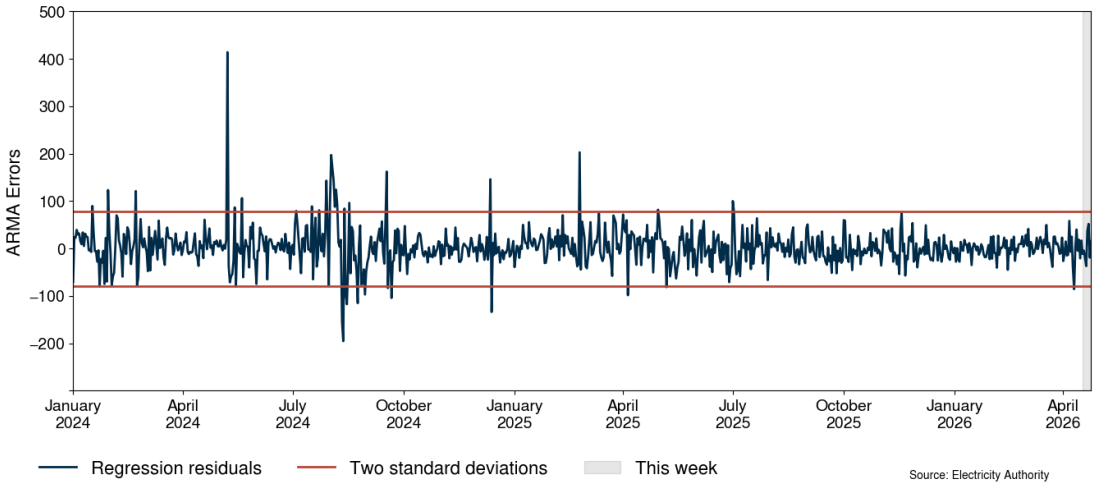
4. Regression residuals

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 2024 - 25 April 2026



5. HVDC

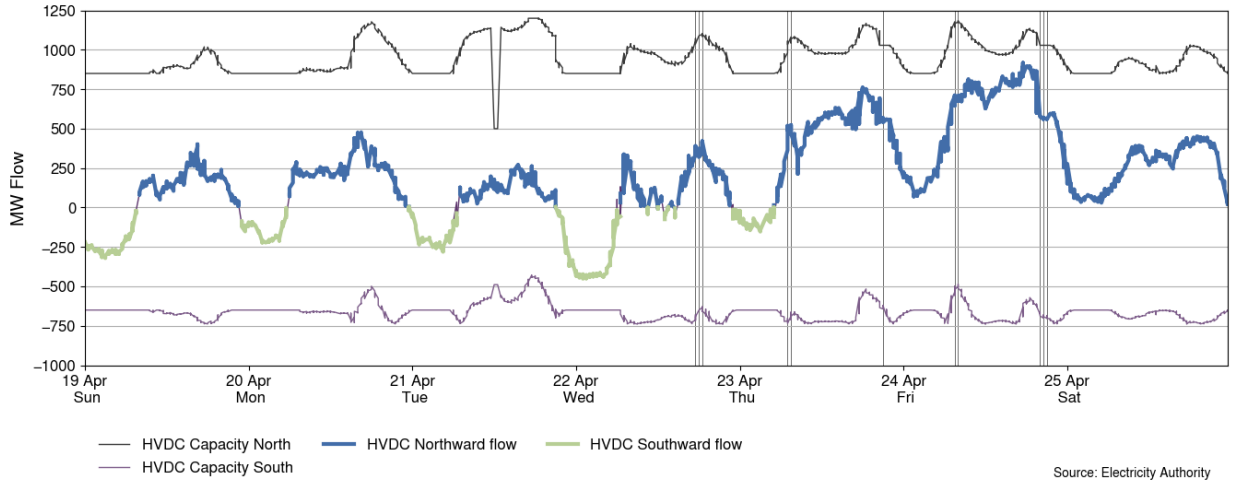
5.1. Figure 6 shows the HVDC flow between 19-25 April. HVDC flows were mostly northward this week, with only northward flow since Thursday morning.

5.2. The highest northward flow occurred on Friday at 5.30pm, with a flow of around 917MW.

5.3. The highest southward flow occurred on Wednesday, with a flow of around 541MW.

5.4. No southward flow occurred onward from the morning of Thursday, due to low wind generation.

Figure 6: HVDC flow and capacity, 19-25 April

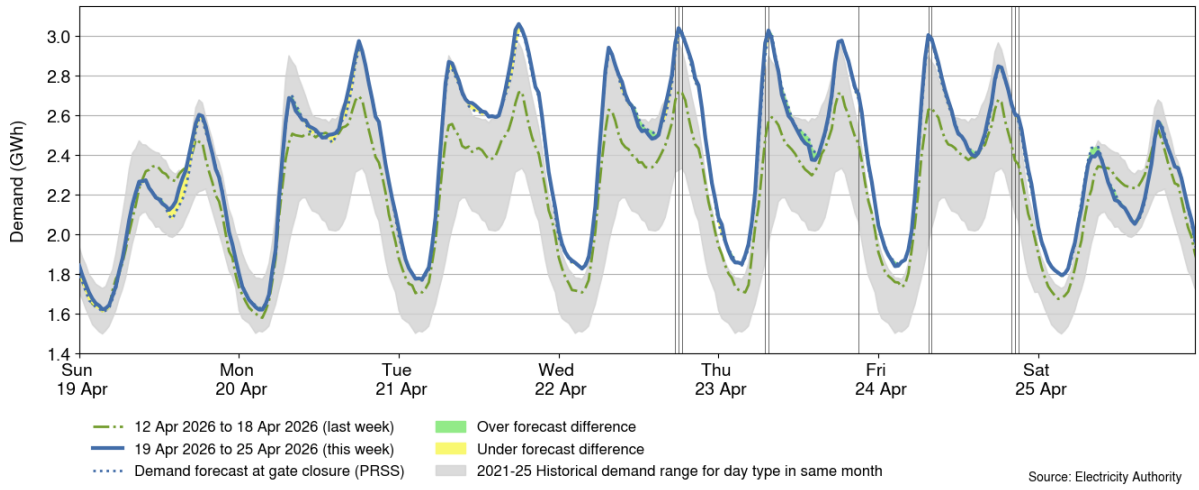


6. Demand

6.1. Figure 7 shows national demand between 19-25 April, compared to the historic range and the demand of the previous week.

6.2. Demand was higher than the previous week due to colder temperatures across the country and the end of the school holidays and university break.

Figure 7: National demand, 19-25 April compared to the previous week



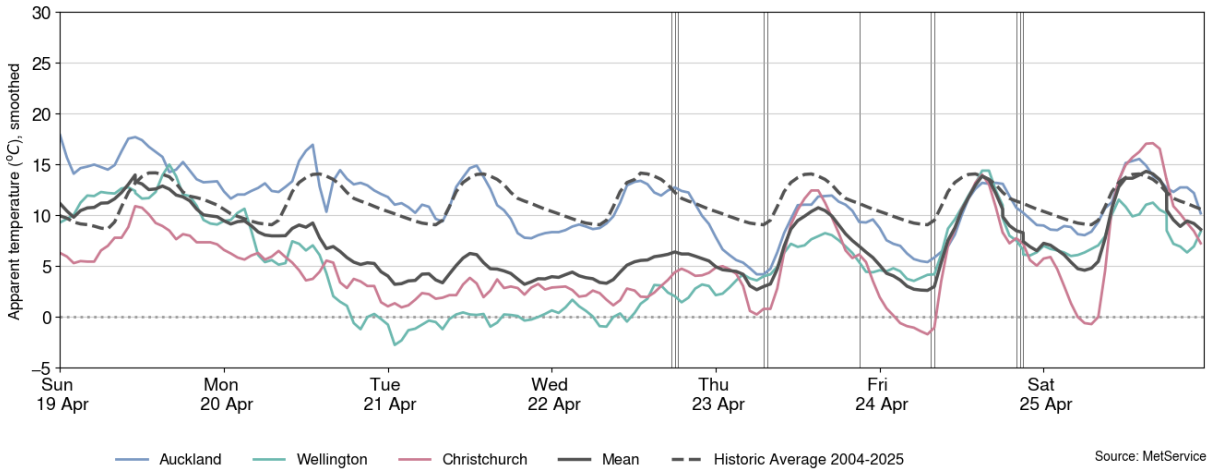
6.3. Figure 8 shows the hourly apparent temperature at main population centres from 19-25 April. The apparent temperature is an adjustment of the recorded temperature that accounts

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 4°C to 18°C in Auckland, -4°C to 15°C in Wellington, and -2°C to 17°C in Christchurch.

6.5. The Wellington, Christchurch and Auckland apparent temperatures are all mostly lower than the previous week. The week's average apparent temperature is mostly below the historic average apparent temperature.

Figure 8: Temperatures across main centres, 19-25 April

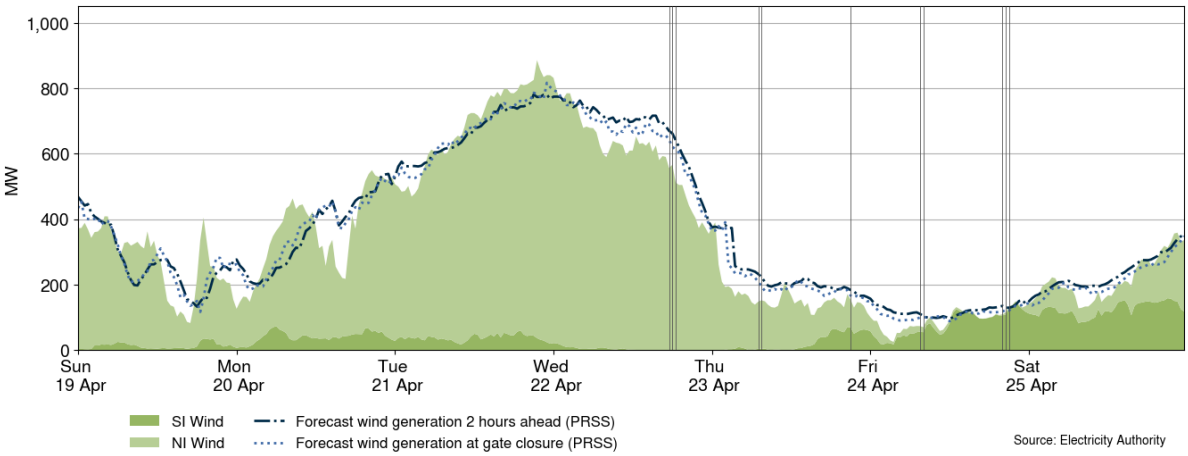


7. Generation

7.1. Figure 9 shows wind generation and forecast from 19-25 April. This week wind generation varied between 25MW and 885MW, with a weekly average of 343MW. Wind generation was low on Sunday and Monday, before increasing on Tuesday and Wednesday, and was then low for the rest of the week.

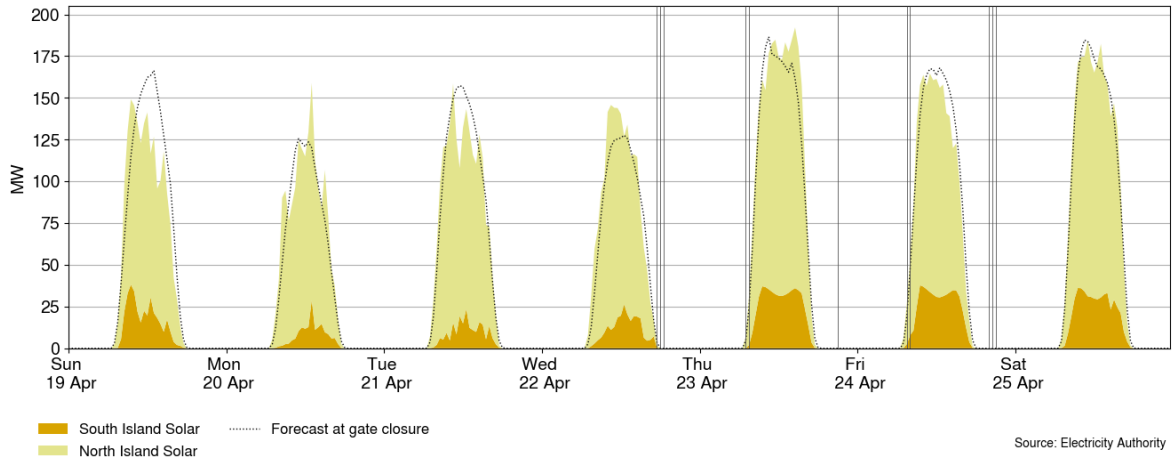
7.2. Wind was consistently below forecast from Wednesday morning to Thursday evening, with Turitea contributing to many of these errors.

Figure 9: Wind generation and forecast, 19-25 April



7.3. Figure 10 shows grid connected solar generation from 19-25 April. Solar generation was high this week, reaching above 125MW every day, and peaked at 192MW at 2.30pm on Thursday.

Figure 10: Grid connected solar generation, 19-25 April

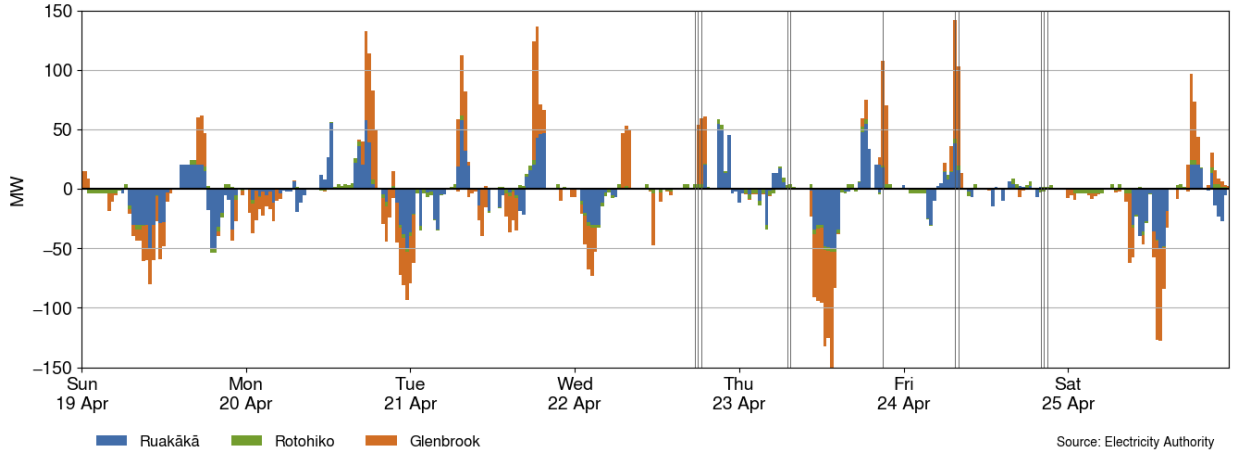


7.4. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.5. This week, the batteries mostly charged during times of relatively lower prices overnight or during the day. The batteries mostly discharged during higher prices during the day. From Wednesday night onwards the batteries did not charge much overnight, as the price generally remained above $100/MWh. The batteries charged during the day on Thursday and Saturday, when prices were generally lower than the adjacent nights.

7.6. Ruakākā and Glenbrook discharged during the high-priced period on Friday morning. Glenbrook discharged during the high-priced period on Wednesday evening, with Ruakākā mostly missing out due to being on outage.

Figure 11: Grid scale battery charge and discharge, 19-25 April



7.7. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and

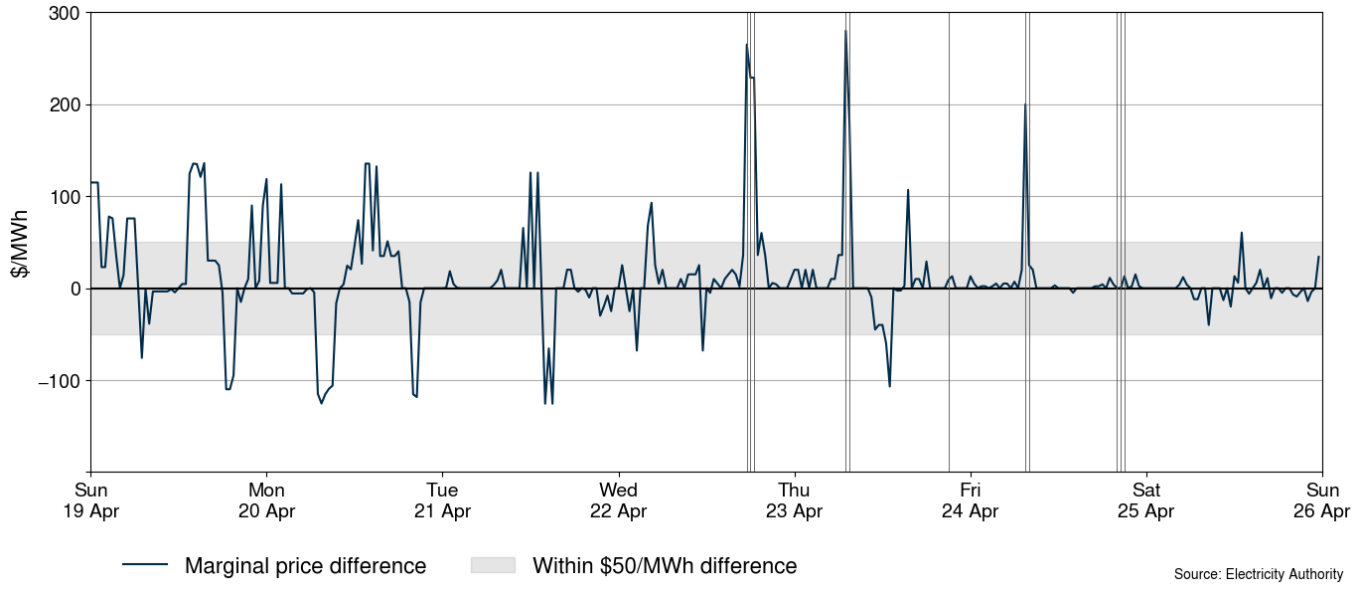
demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or intermittent generation is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and intermittent generation forecasting, the 1-hour ahead and the RTD intermittent generation 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.

7.8. A number of trading periods this week had marginal price differences greater than $50/MWh.

7.9. Marginal price differences of over $150/MWh occurred on Wednesday from 5.30pm to 6.30pm, on Thursday at 7.00am and 7.30am, and on Friday at 7.30am. During these times, wind generation was lower than forecast and demand slightly higher than forecast.

7.10. The maximum positive difference of $280/MWh occurred on Thursday at 7.00am. At this time, demand was 141MW higher than forecast, and wind generation was 61MW lower than forecast.

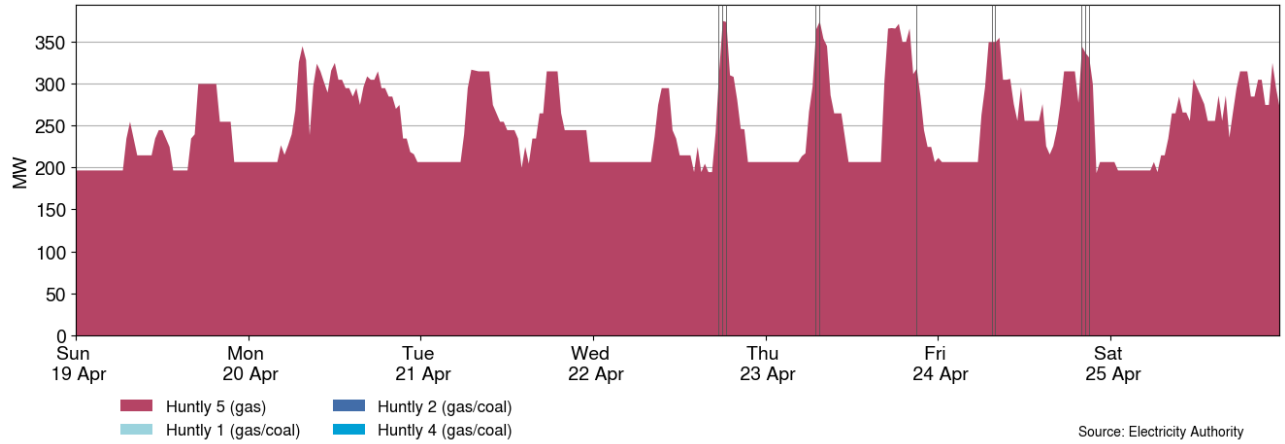
Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 19-25 April



7.11. Figure 13 shows the generation of thermal baseload between 19-25 April. Just Huntly 5 ran continuously throughout the week.

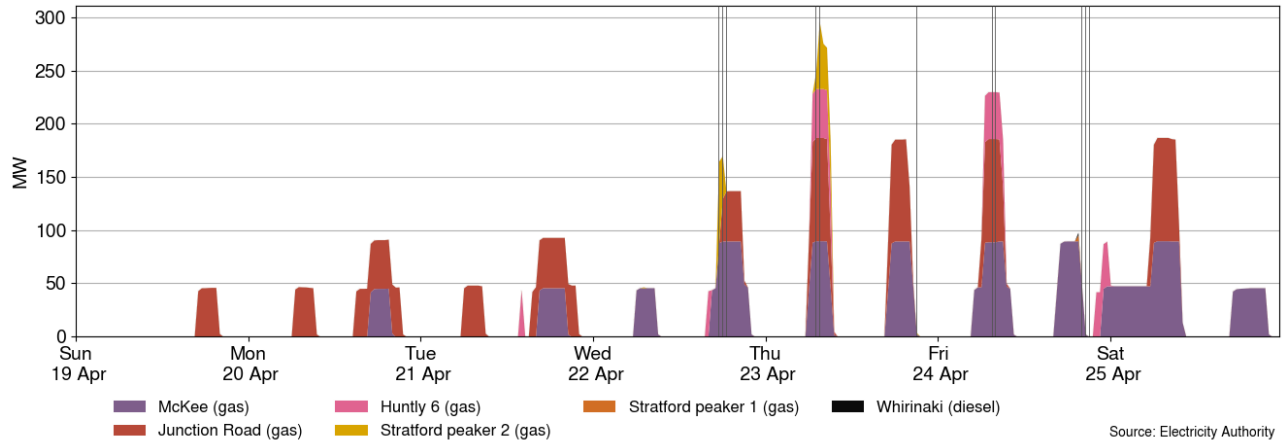
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 13: Thermal baseload generation, 19-25 April



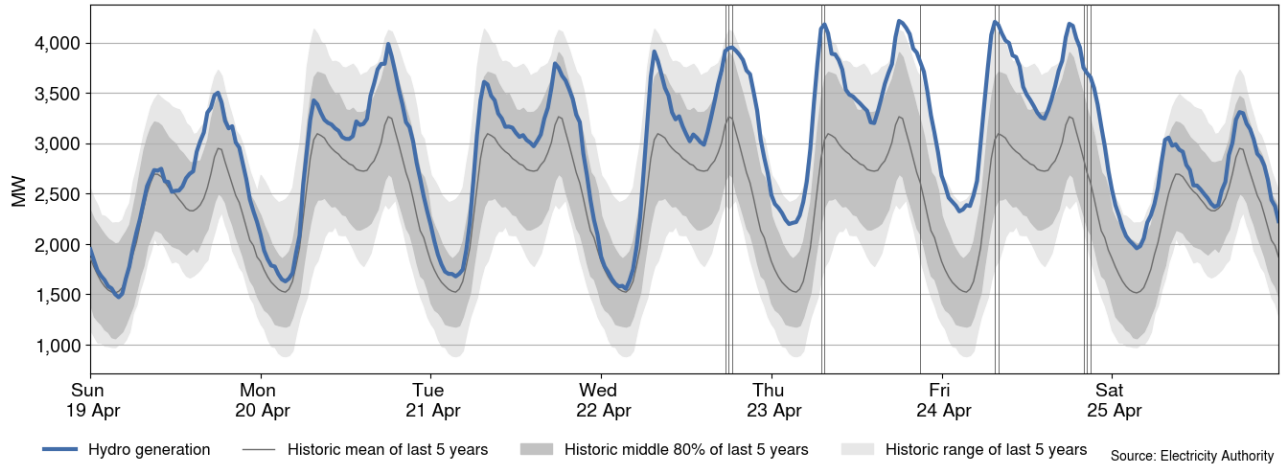
7.12. Figure 14 shows the generation of thermal peaker plants between 19-25 April. Junction Road ran at times each day, McKee ran at times from Monday to Saturday, Huntly 6 ran at times from Tuesday to Saturday, and Stratford 2 ran at times on Wednesday and Thursday. The peakers were not running during the periods of price separation on Thursday evening and Friday evening.

Figure 14: Thermal peaker generation, 19-25 April



7.13. Figure 15 shows hydro generation between 19-25 April. Hydro generation has been much higher than last week due to higher levels of demand. Hydro generation exceeded the historic range at times on Thursday and Friday and exceeded the middle 80% at times throughout the week.

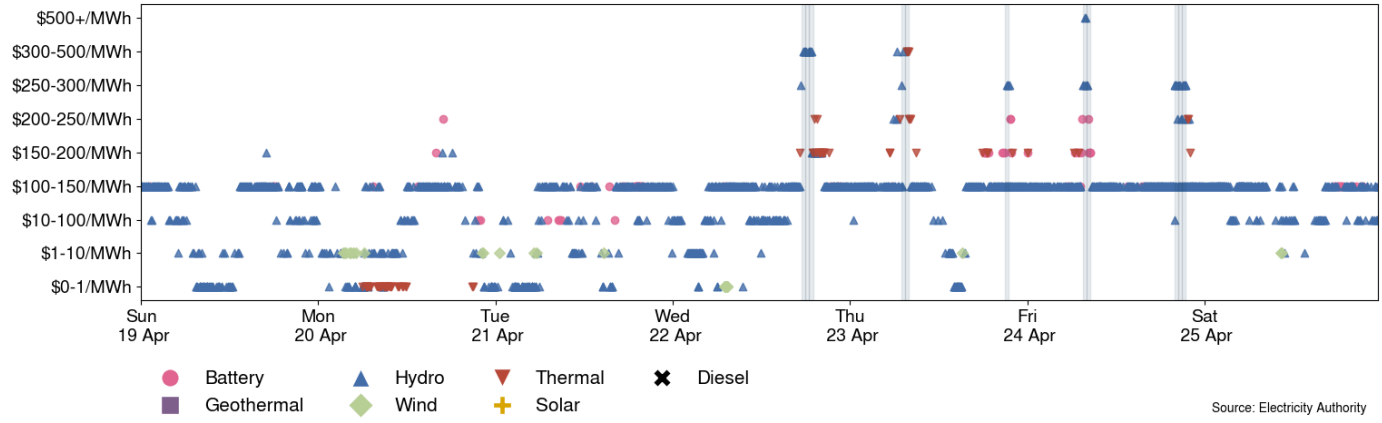
Figure 15: Hydro generation, 19-25 April



7.14. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period.

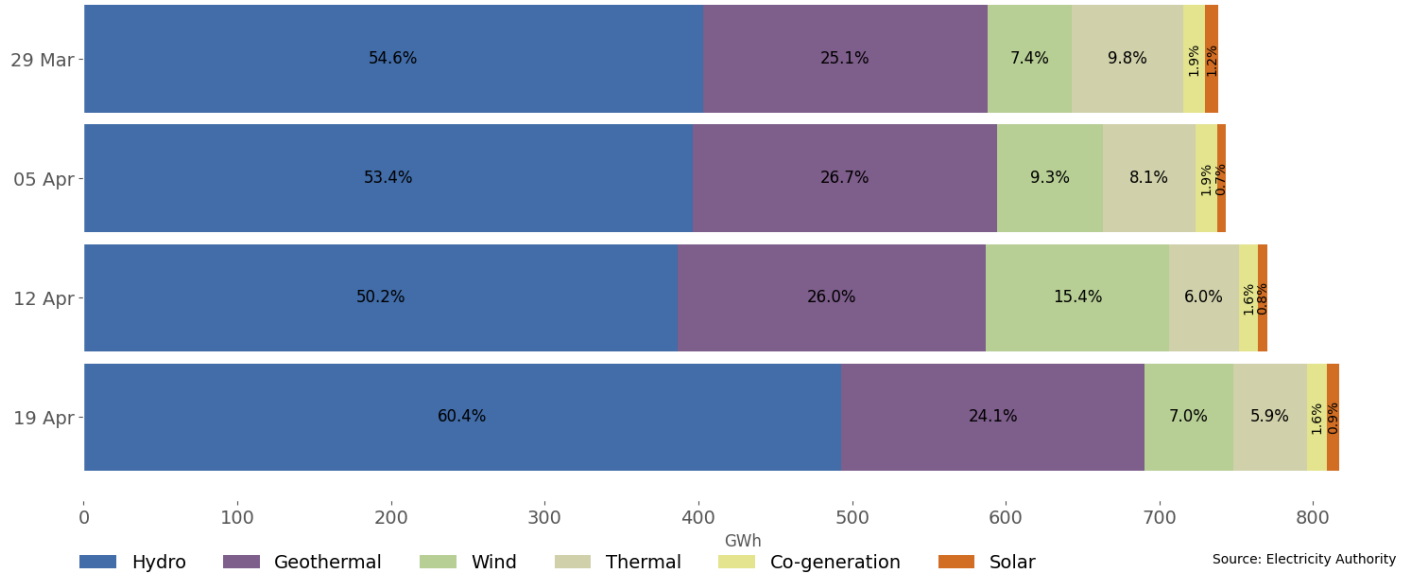
7.15. The highest prices were set by Genesis hydro on Friday. The most common technology setting prices was hydro generation, with wind the second most common. Most marginal prices were between $100-150/MWh.

Figure 16: Prices of marginal generation, 19-25 April



7.16. As a percentage of total generation, between 19-25 April, total weekly hydro generation was 60.4%, geothermal 24.1%, wind 7.0%, thermal 5.9%, co-generation 1.6%, and solar (grid connected) 0.9%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 29 March and 25 April



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 19-25 April ranged between ~1,012MW and ~2,034MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 19-25 April

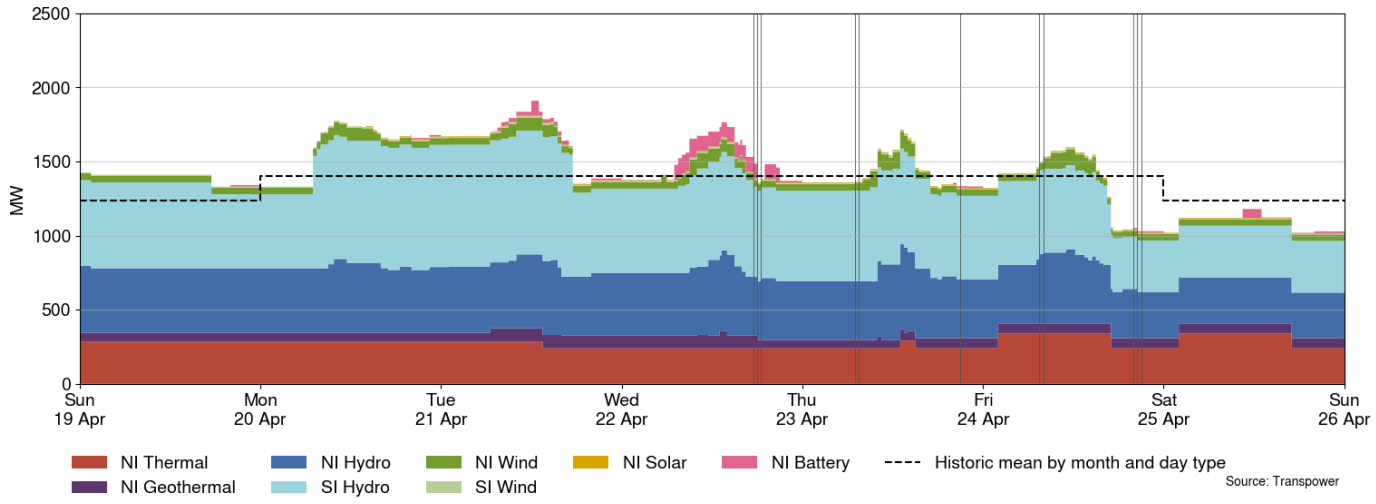
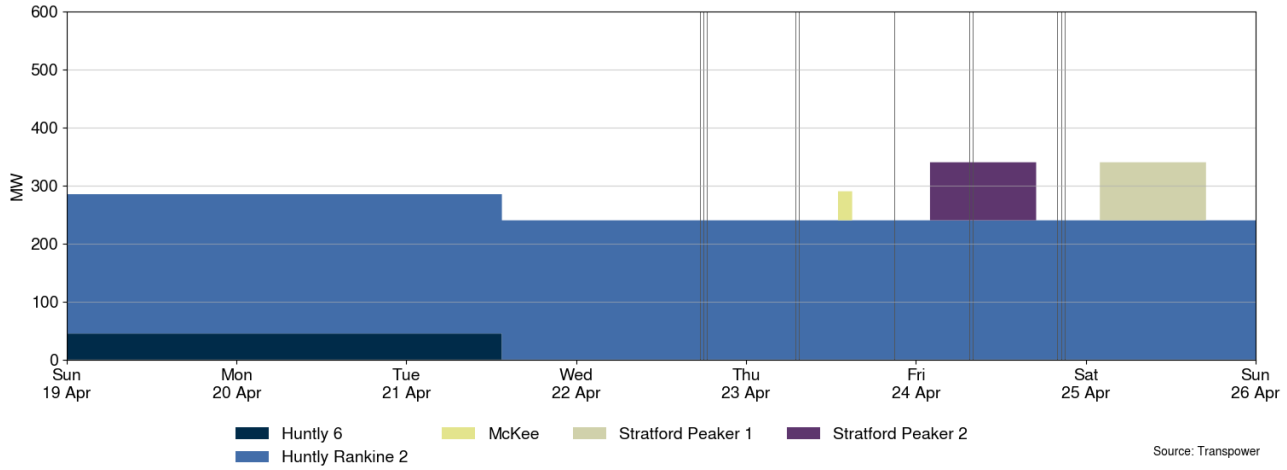


Figure 19: Total MW loss from thermal outages, 19-25 April



8.2. Notable outages include:

Plant	Partial or Full	End Date
Huntly 6	Full	21 April 2026
Manapōuri unit 1	Full	21 April 2026
Manapōuri unit 2	Full	21 April 2026
Ruakākā	Full	22 April 2026
Manapōuri unit 3	Full	24 April 2026
Huntly 2	Full	20 May 2026
Rangipō unit 6	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	30 June 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

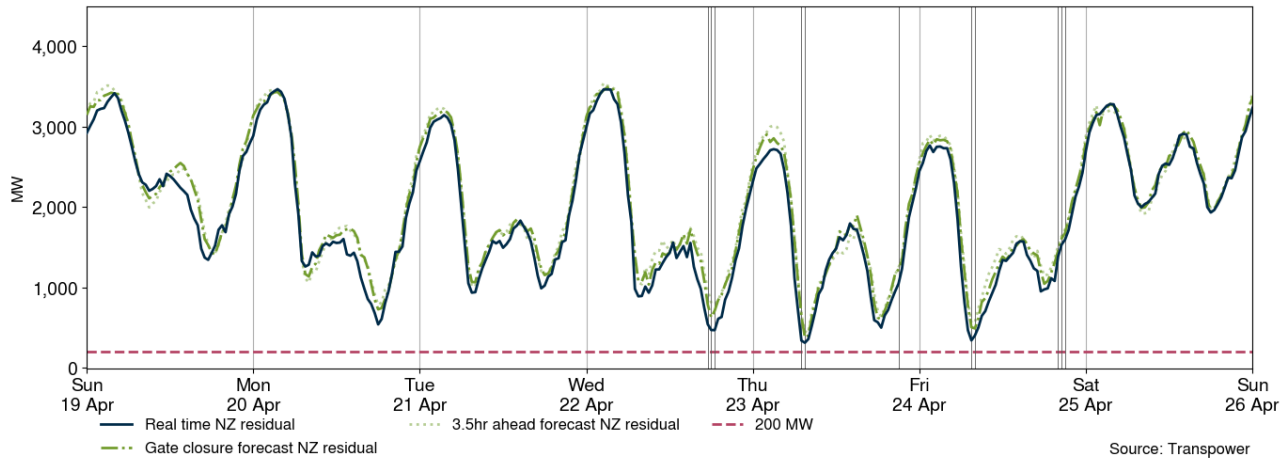
9.1. Figure 20 shows the national generation balance residuals between 19-25 April. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a forecast low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. National residuals neared 200MW at times this week. The lowest national residual was 313MW at 7.30am on Thursday.

9.3. The national residual dropped below 500MW during the afternoon peak on Wednesday, and the morning peaks on Thursday and Friday.

9.4. The South Island residual dropped below 200MW during the morning peaks on Wednesday, Thursday, and Friday, and during the afternoon peaks on Monday, Wednesday and Thursday.

Figure 20: National generation balance residuals, 19-25 April



10. Storage/fuel supply

10.1. Figure 21 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. As of 25 April, national controlled storage was 86% nominally full and ~112% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (86% full[2]) is above its historic mean, while Lake Tekapō (78% full) is below its historic mean.

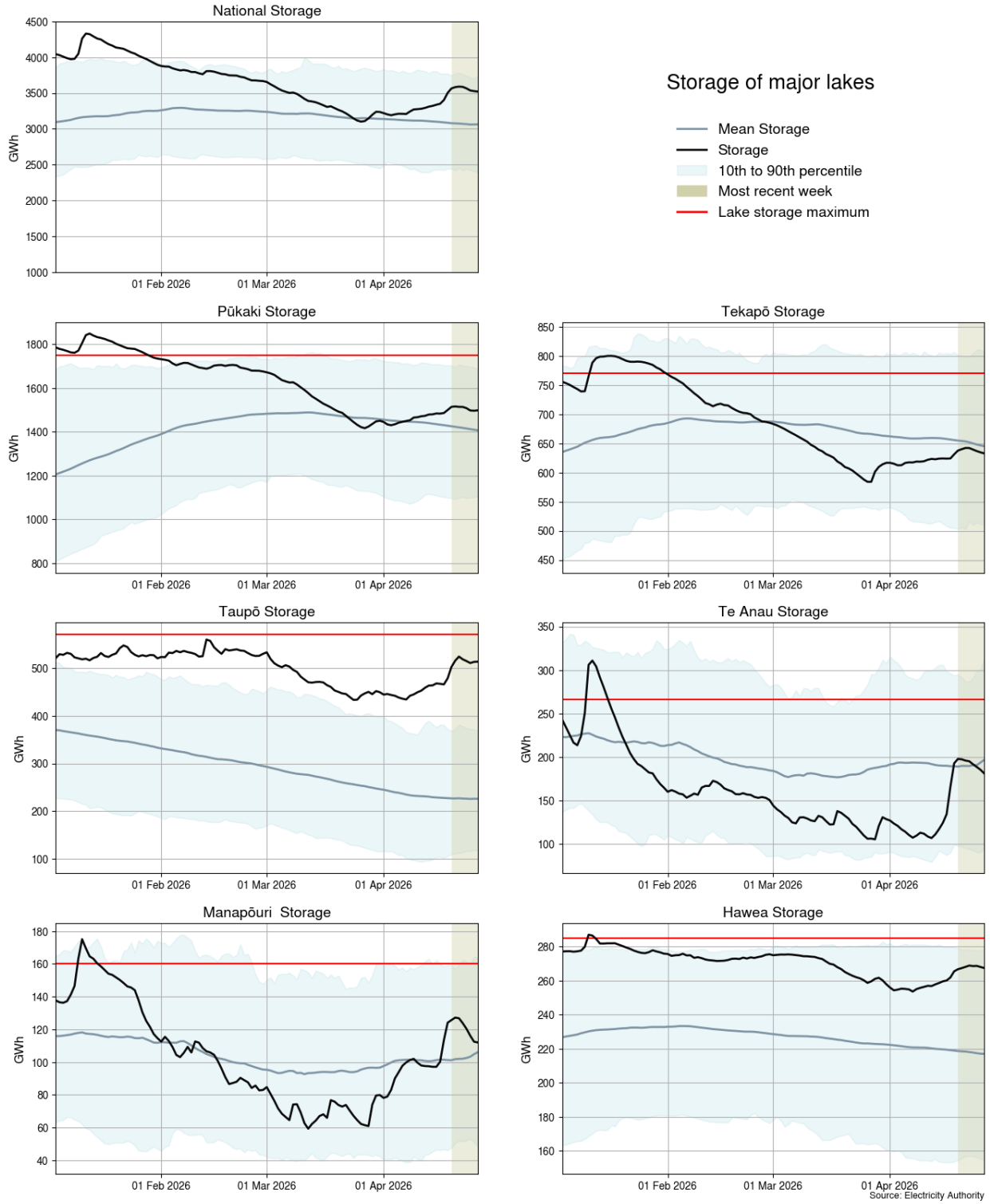
10.4. Storage at Lake Te Anau (67% full) is below its historic mean, with Lake Manapōuri (70% full) above its historic mean.

10.5. Storage at Lake Taupō (90% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (94% full) is below its historic 90th percentile but remains above its historic mean.

[2] Percentage full values sourced from NZX Hydro.

Figure 21: 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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 April 2026. The SRMCs for all thermal-fuelled generation have increased, with the SRMC for diesel-fuelled generation increasing the most.

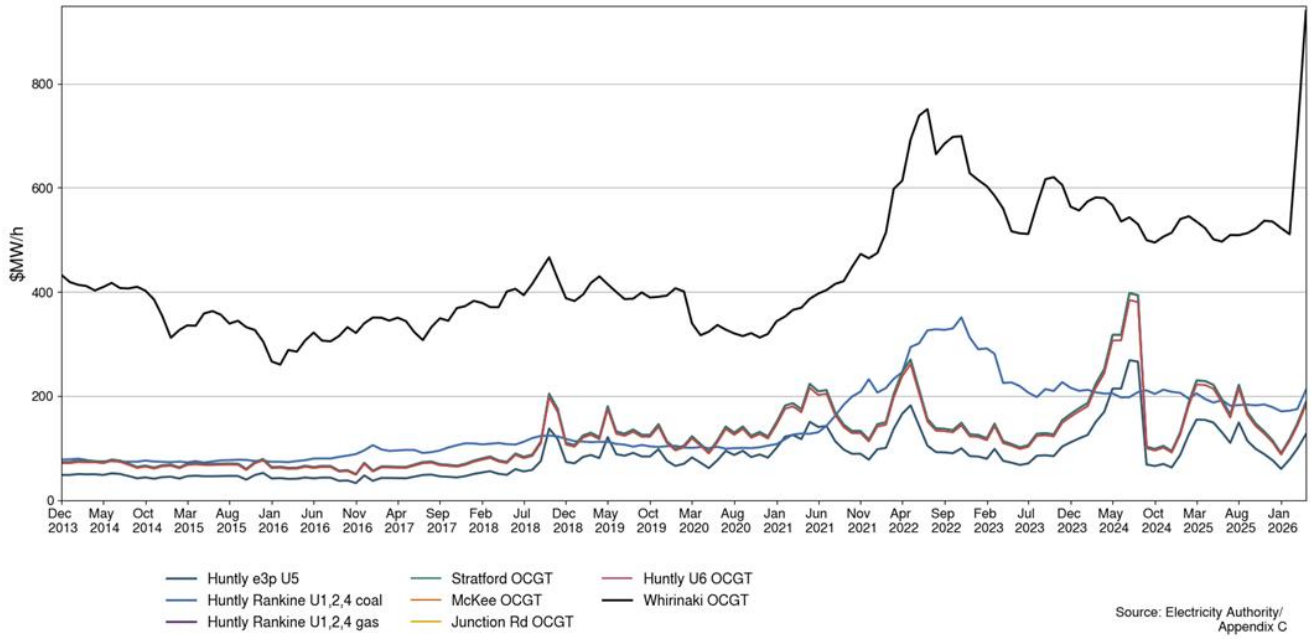
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$212/MWh. The cost of running the Rankines on gas at ~$188/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $126/MWh and $189/MWh.

11.6. The SRMC of Whirinaki, using diesel, has increased by ~$236/MWh to ~$940/MWh following ongoing international supply issues.

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

Figure 22: Estimated monthly SRMC for thermal fuels

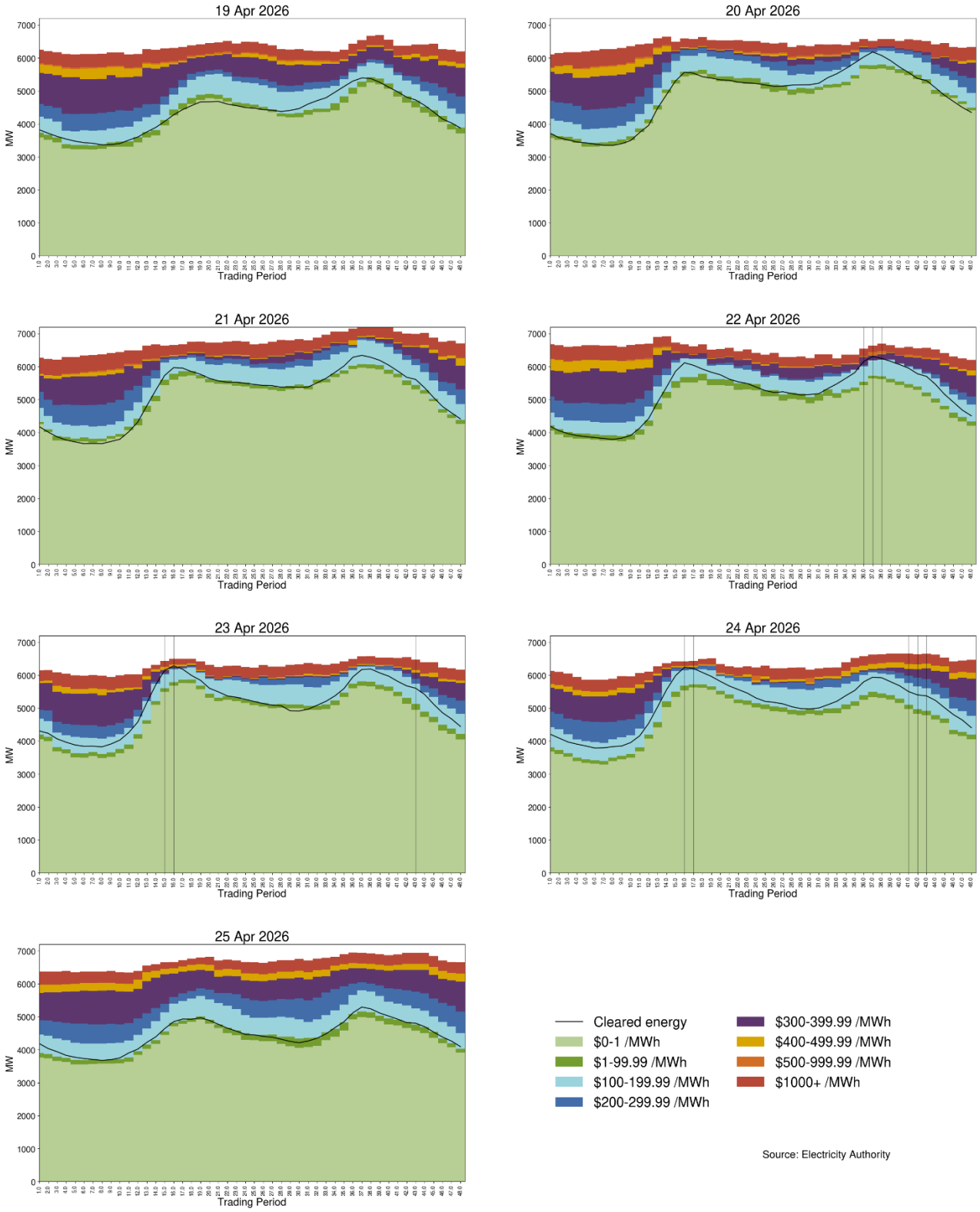


12. Offer behaviour

12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Most offers cleared below $200/MWh this week, although energy did clear above $300/MWh at times of high demand on Wednesday, Thursday and Friday.

Figure 23: Daily offer stacks



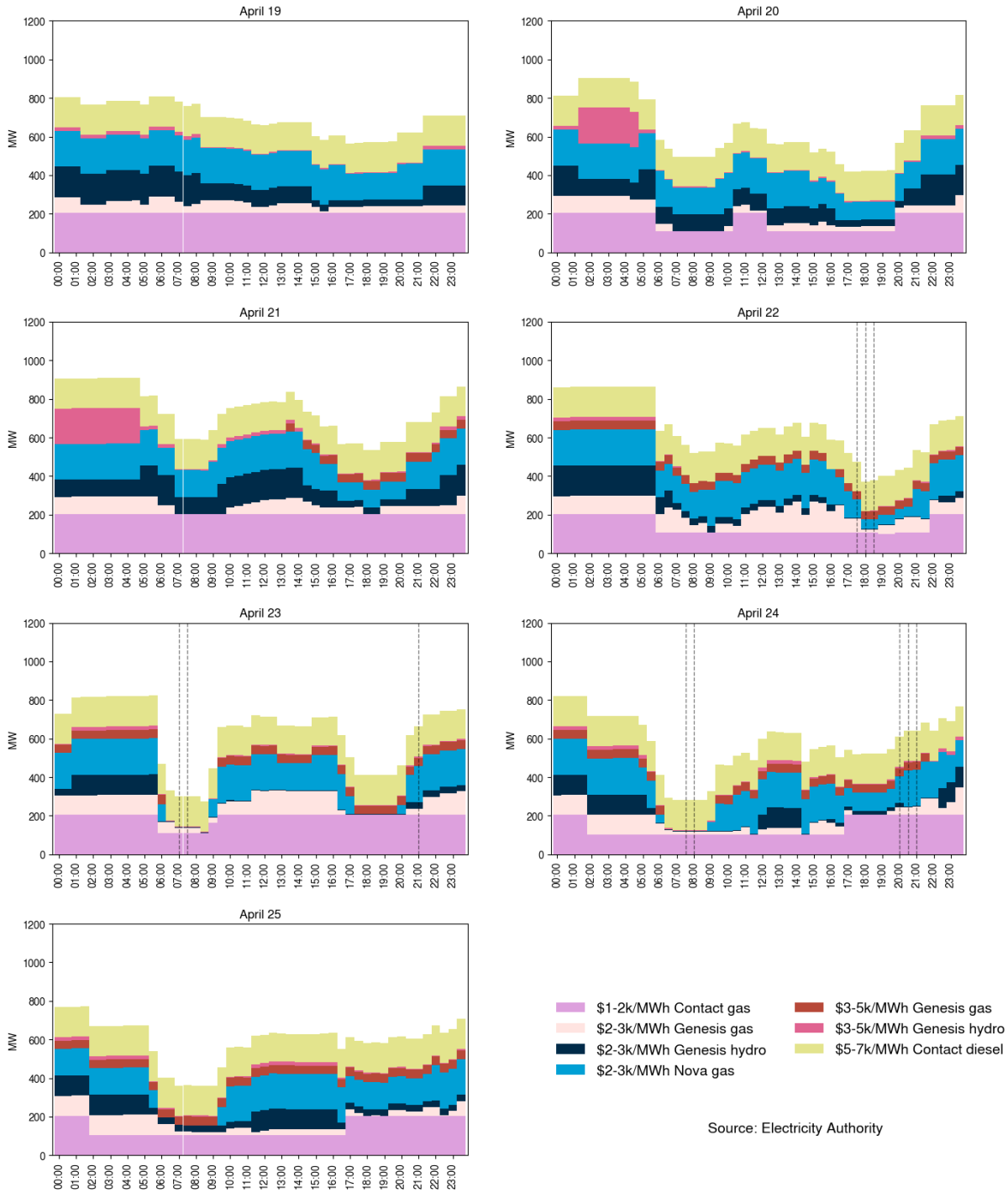
12.3. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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, intermittent 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 647MW per trading period was priced above $1,000/MWh this week, which is roughly 12% of the total energy available.

Figure 24: High priced offers



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. The monitoring team is looking into Genesis hydro offers further this week.

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
04/02/2026-05/02/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers
03/03/2026-04/03/2026	Several	Further analysis	Genesis	Waikaremoana	Offers
13/03/2026	27-31	Further analysis	Genesis	Huntly 1 and 4	Offers
22/04/2026-24/04/2026	Several	Further analysis	Genesis	Tokaanu	Offers