23 March 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 15-21 March 2026

Market monitoring weekly report

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1. Overview

1.1. This week the average spot price increased by $62/MWh to $188/MWh. Higher demand, lower wind generation due to wind farm outages, higher thermal generation, and decreasing hydro storage have all contributed to higher prices this week. National hydro storage decreased this week to 82% nominally full and ~103% of the historical average for this time of 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 15-21 March:

(a) The average spot price for the week was $188/MWh, an increase of around $62/MWh compared to the previous week.

(b) 95% of prices fell between $165/MWh and $208/MWh.

2.3. Prices are higher this week due to higher demand, lower wind generation related to wind farm outages, higher thermal generation and declining hydro storage.

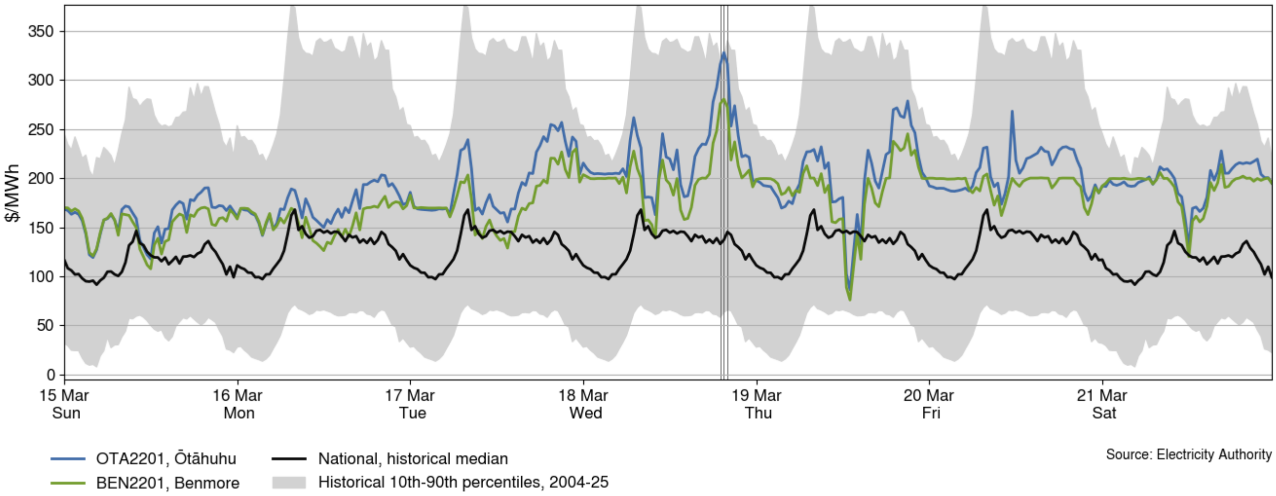
2.4. Prices spiked above $300/MWh on Wednesday between 7.00pm and 8.00pm, with the maximum Ōtāhuhu price this week of $328/MWh occurring at 7.30pm. During this time, wind generation declined, demand was between 114MW-145MW higher than forecast and intermittent generation was between 33MW-103MW lower than forecast.

2.5. Other prices over $250/MWh occurred mostly during morning or evening peaks.

2.6. Benmore prices were higher than prices at Ōtāhuhu during periods of southward HVDC flow overnight between Thursday and Saturday.

2.7. 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.

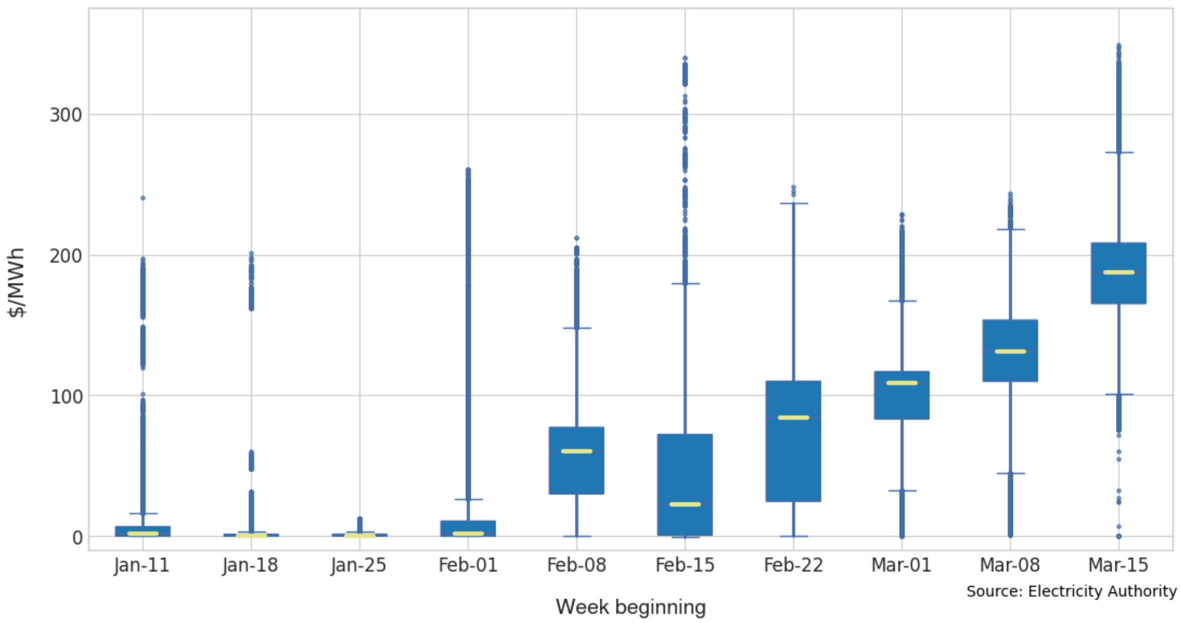
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 15-21 March



2.8. 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.

2.9. The distribution of spot prices this week has shifted higher compared to last week. The median price was $187/MWh and most prices (middle 50%) fell between $165/MWh and $208/MWh.

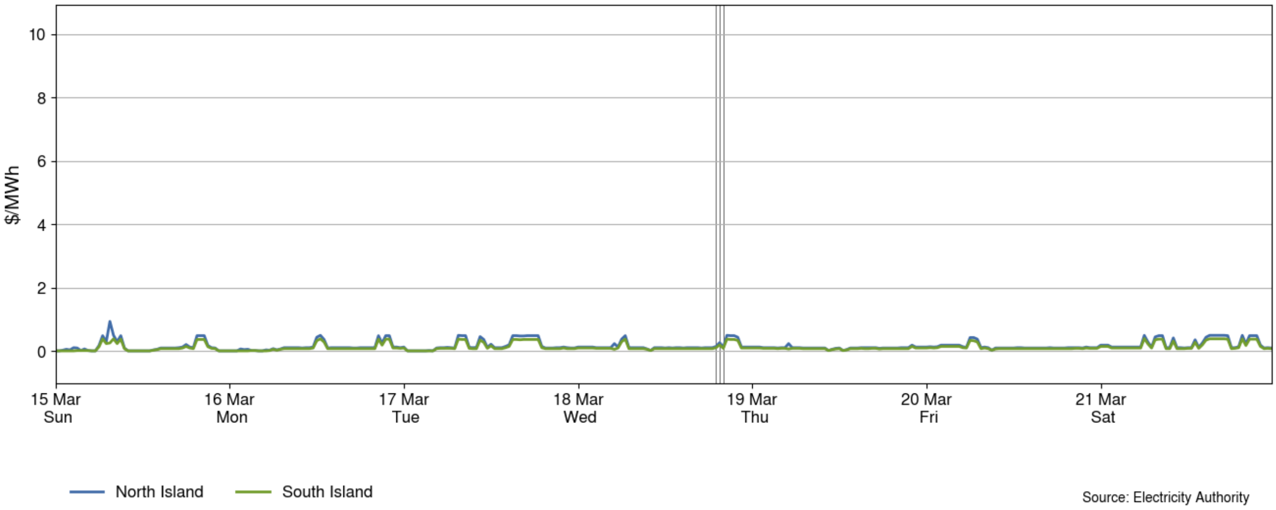
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

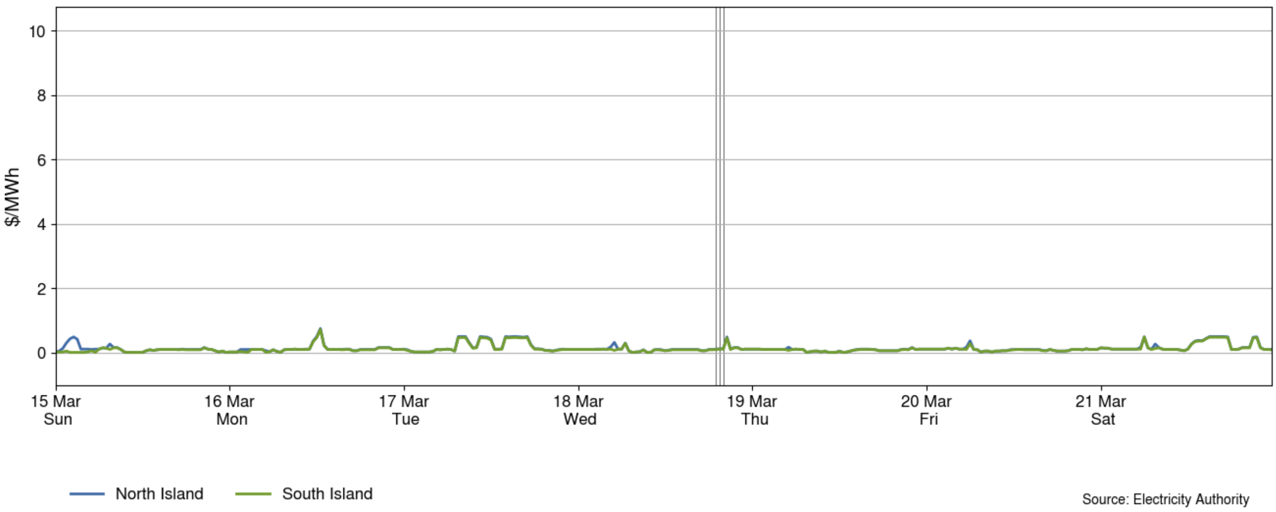
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices across both the North and South Islands remained below $1/MWh this week.

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



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices across both the North and South Islands remained below $1/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 15-21 March



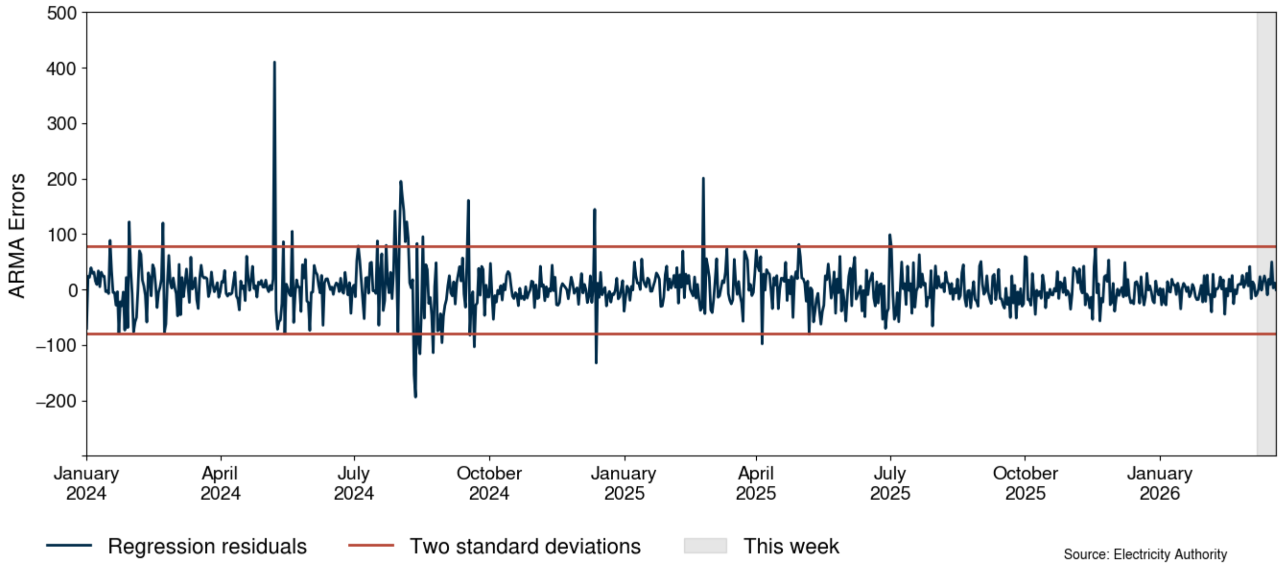
4. Regression residuals

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 - 21 March 2026

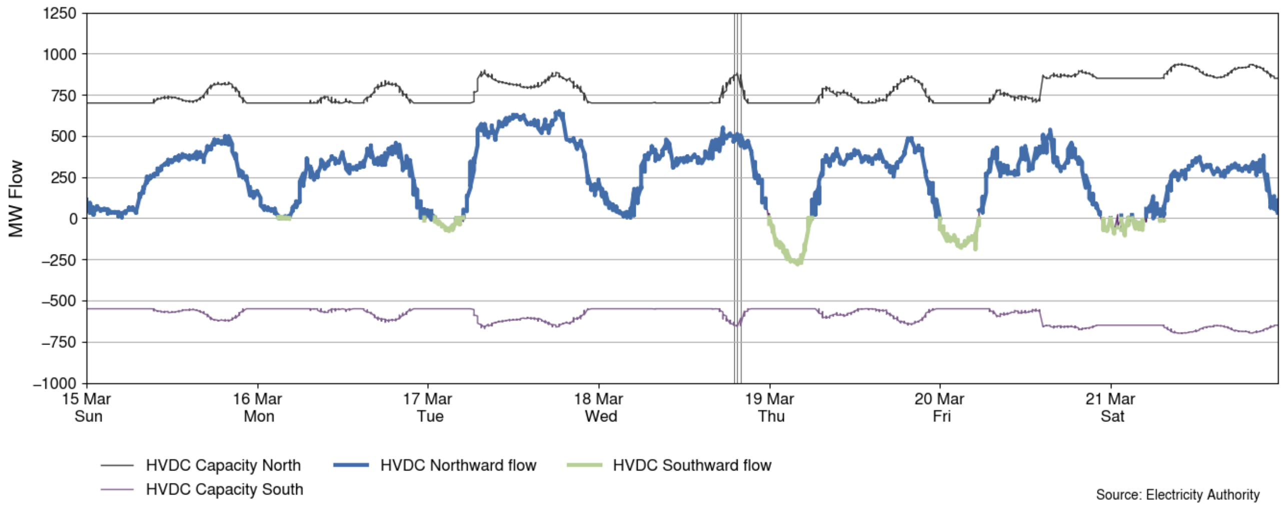


5. HVDC

5.1. Figure 6 shows the HVDC flow between 15-21 March. HVDC flows were mostly northward this week, with periods of southward flow overnight most days. Higher wind generation on Thursday saw increased levels of southward flow overnight.

5.2. The highest northward flow occurred at 6.30pm on Tuesday with a flow of 650MW.

Figure 6: HVDC flow and capacity, 15-21 March



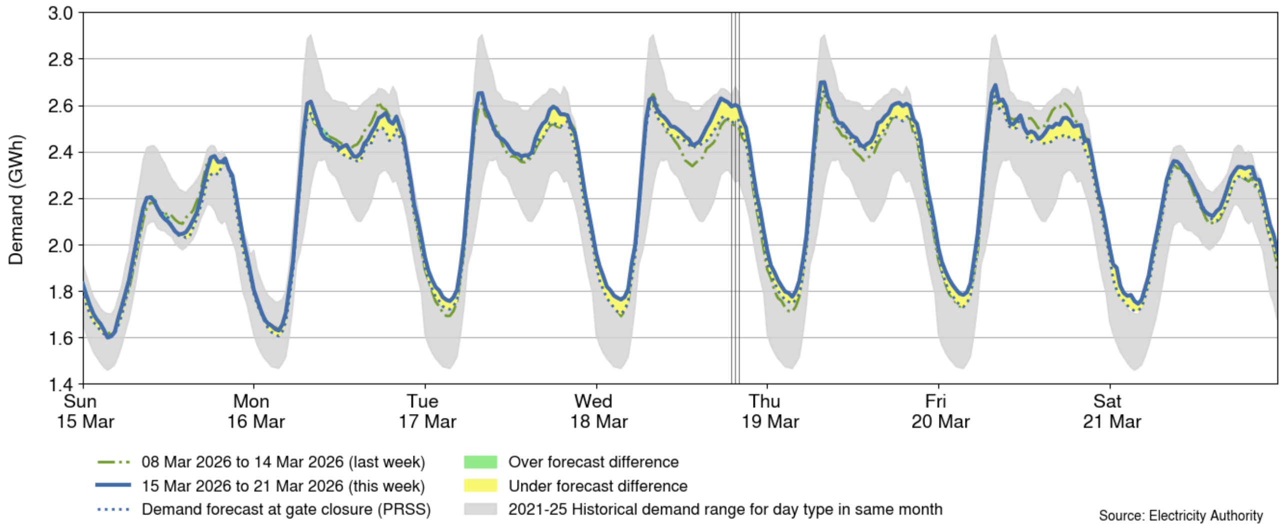
6. Demand

6.1. Figure 7 shows national demand between 15-21 March, compared to the historic range and the demand of the previous week.

6.2. Demand was mostly similar to the previous week, aside from on Wednesday where demand was higher during the evening peak. Persistent demand under forecasting this week was the result of an amalgamation of errors across different nodes.

6.3. The highest demand of the week was around 2.7GWh at 8.00am on Thursday.

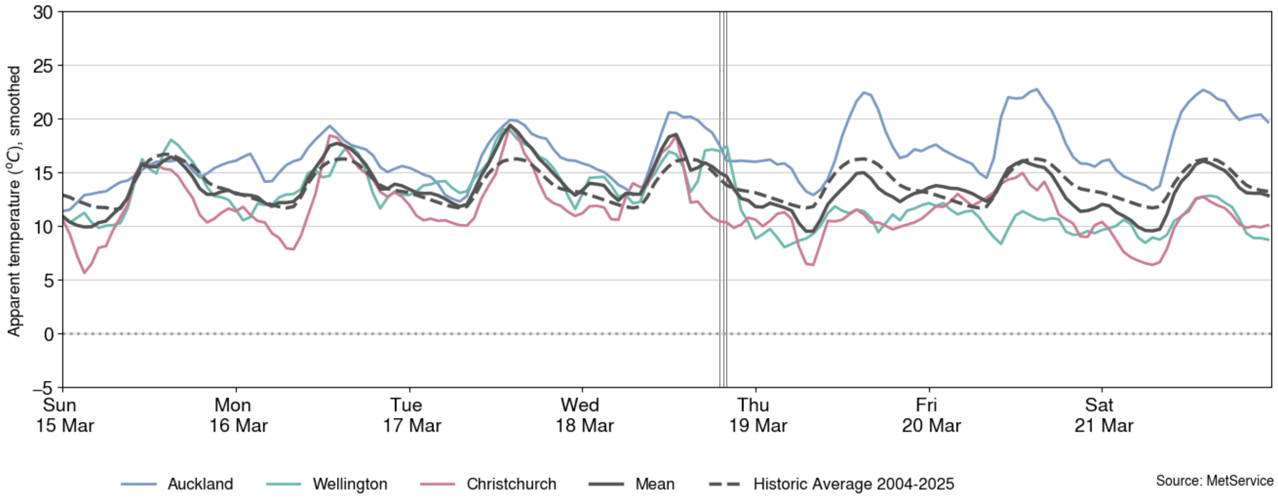
Figure 7: National demand, 15-21 March compared to the previous week



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

6.5. Apparent temperatures ranged from 11°C to 23°C in Auckland, 8°C to 19°C in Wellington, and 5°C to 20°C in Christchurch.

Figure 8: Temperatures across main centres, 15-21 March



7. Generation

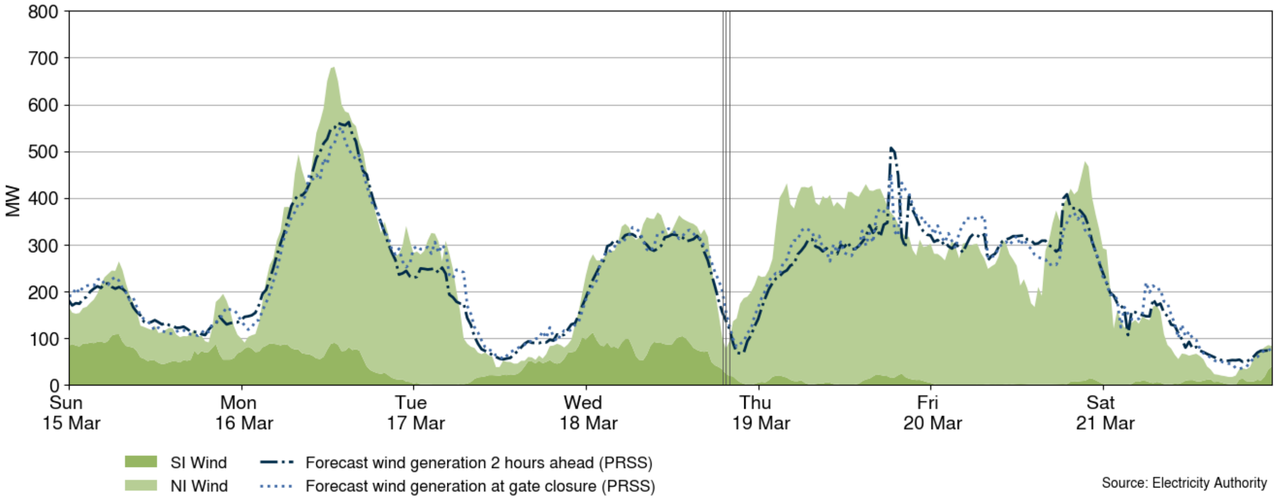
7.1. Figure 9 shows wind generation and forecast from 15-21 March. This week wind generation varied between 17MW and 680MW, with a weekly average of 246MW.

7.2. Wind generation remained close to or below 400MW for much of the week, aside from on Monday and briefly on Friday.

7.3. The Turitea wind farm was on outage between Tuesday and Thursday with the Waipipi wind farm on outage on Friday, contributing to lower wind generation this week.

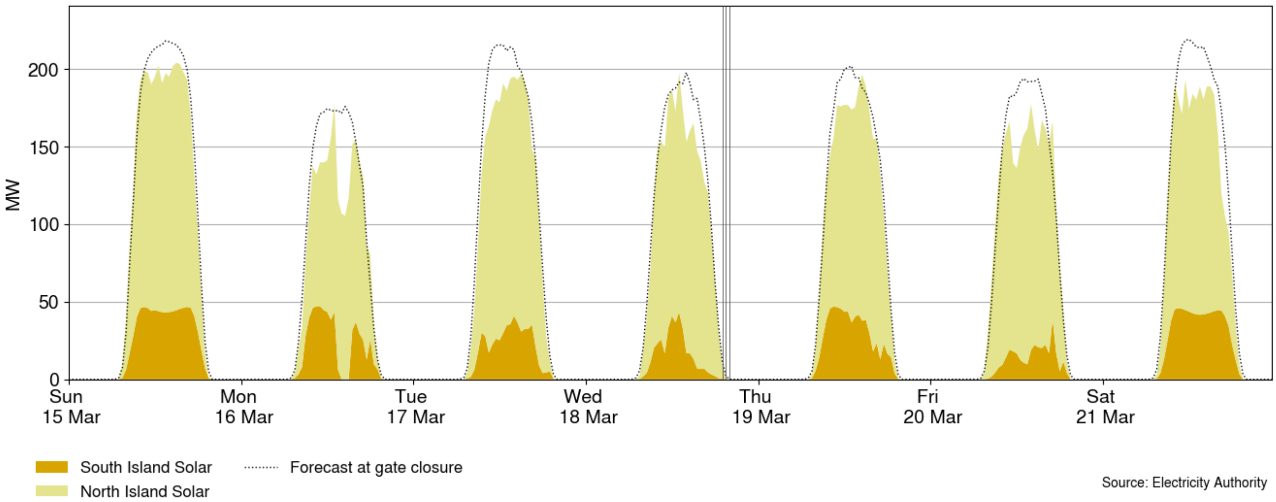
7.4. On Thursday, large forecasting errors occurred as the Turitea outage came to an end. Wind forecasting errors on Friday were the result of an amalgamation of errors across multiple windfarms.

Figure 9: Wind generation and forecast, 15-21 March



7.5. Figure 10 shows grid connected solar generation from 15-21 March. Solar generation reached above 175MW each day this week, peaking on Sunday at 3.00pm at 204MW.

Figure 10: Grid connected solar generation, 15-21 March

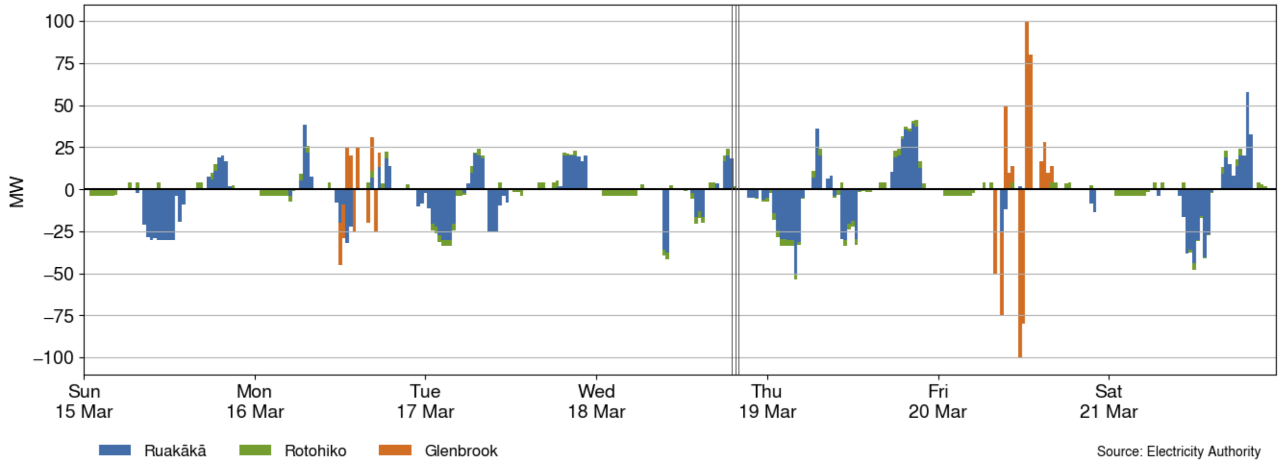


7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are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

7.7. This week the batteries mostly charged during relatively lower prices during the day or overnight. The batteries mostly discharged during the day when prices were higher. Glenbrook charge and discharge continues to vary as it commissions.

7.8. The Ruakākā battery did not discharge during the highest prices on Wednesday evening, likely due to lack of charge.

Figure 11: Grid scale battery charge and discharge, 15-21 March



7.9. 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.

7.10. Several trading periods this week had marginal price differences greater than $50/MWh.

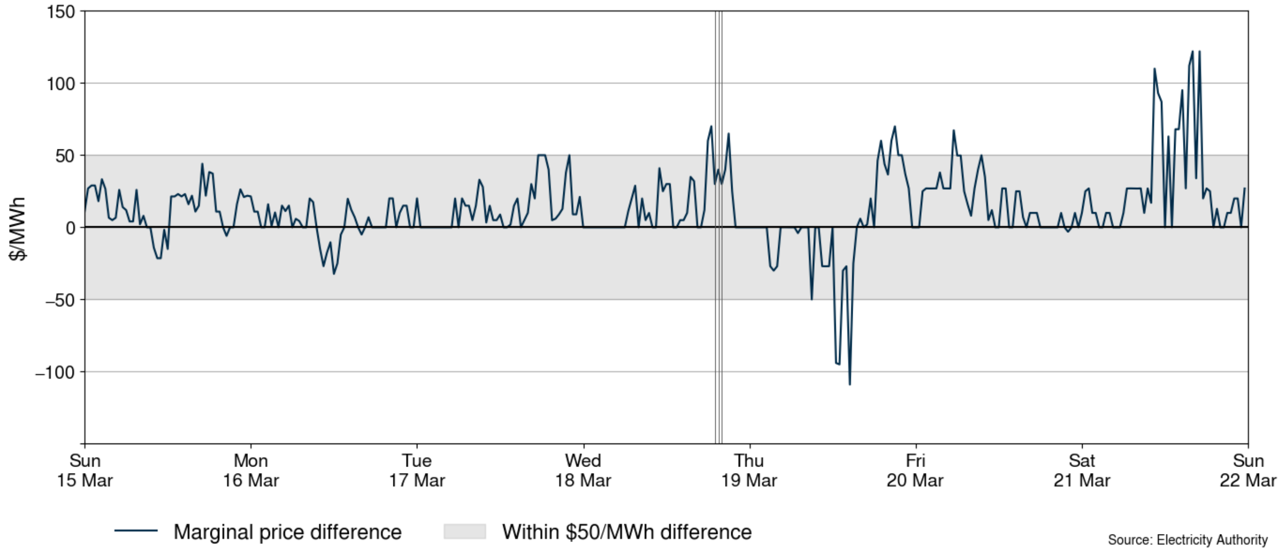
7.11. Several positive differences occurred on Saturday between 10.30am and 5.00pm, with intermittent generation consistently lower than forecast and demand often higher than forecast during this time.

7.12. The largest positive differences of $122/MWh occurred during this time at 4.00pm and 5.00pm. Demand was 93MW and 107MW higher than forecast, and intermittent generation 58MW and 46MW lower than forecast, respectively.

7.13. The largest negative difference of $109/MWh occurred on Thursday at 2.30pm. While demand was 59MW higher than forecast, which would typically cause higher prices than expected, intermittent generation was 96MW higher than forecast at this time.

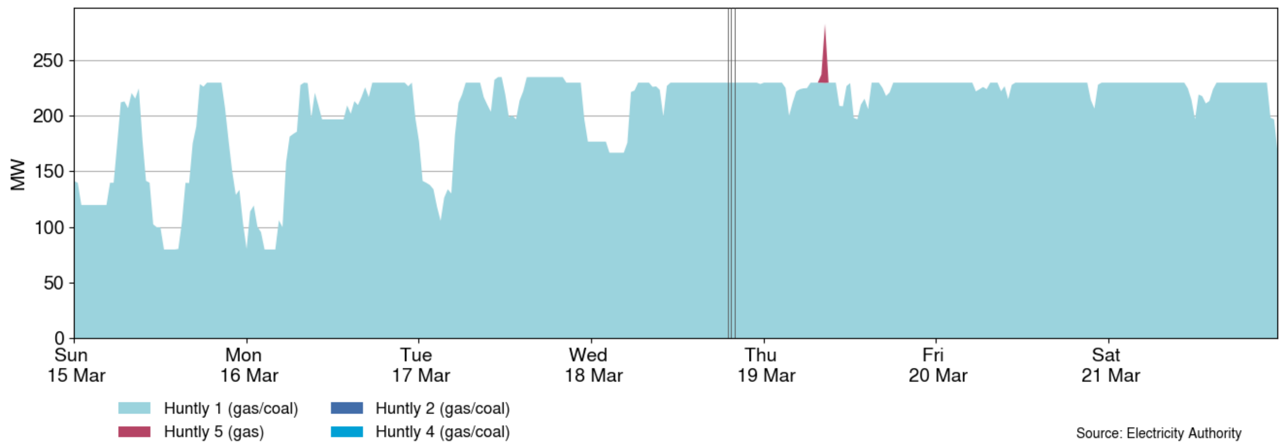
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 15-21 March



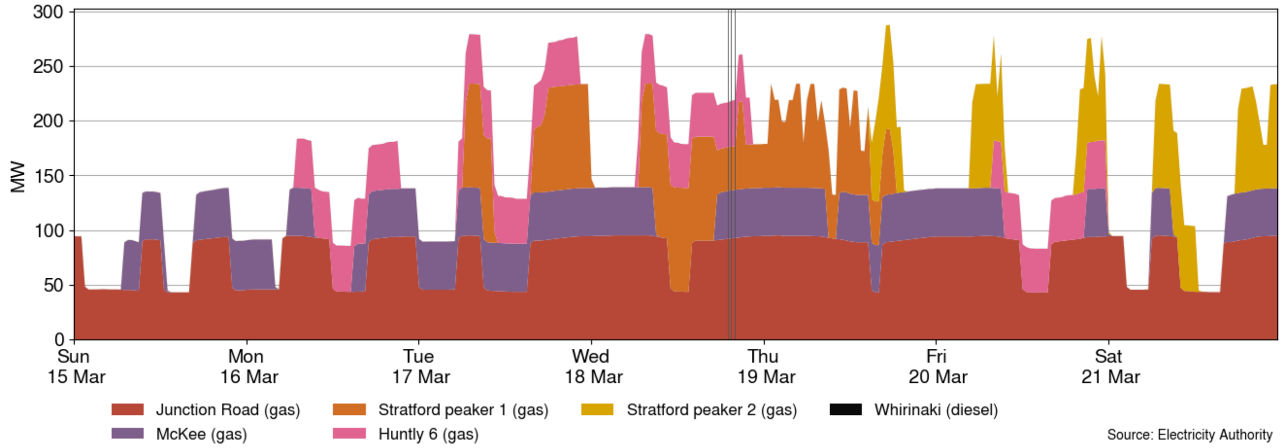
7.14. Figure 13 shows the generation of thermal baseload between 15-21 March. Huntly 1 ran continuously throughout this week with Huntly 5 tripping on startup on Thursday at 8.57am.

Figure 13: Thermal baseload generation, 15-21 March



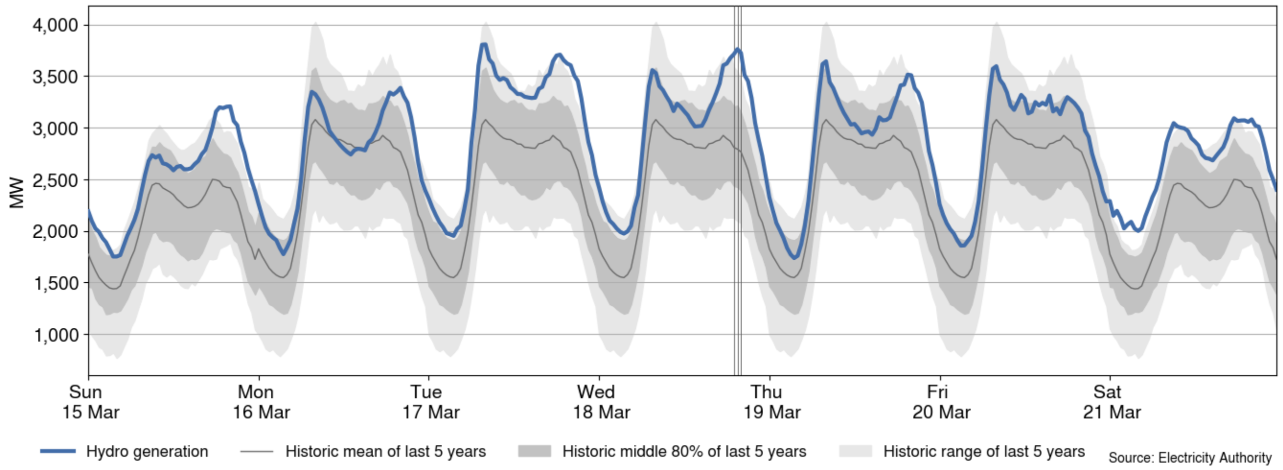
7.15. Figure 14 shows the generation of thermal peaker plants between 15-21 March. Junction Road ran continuously though the week, with McKee running at times every day. Stratford peaker 1 ran between Tuesday and Thursday and Stratford peaker 2 running between Thursday and Saturday. Huntly 6 ran between Monday and Wednesday and on Friday.

Figure 14: Thermal peaker generation, 15-21 March



7.16. Figure 15 shows hydro generation between 15-21 March. Hydro generation was above the historic mean for almost the entire week, reaching above the historic range during evening peak demand on Sunday, Tuesday, Wednesday and Saturday.

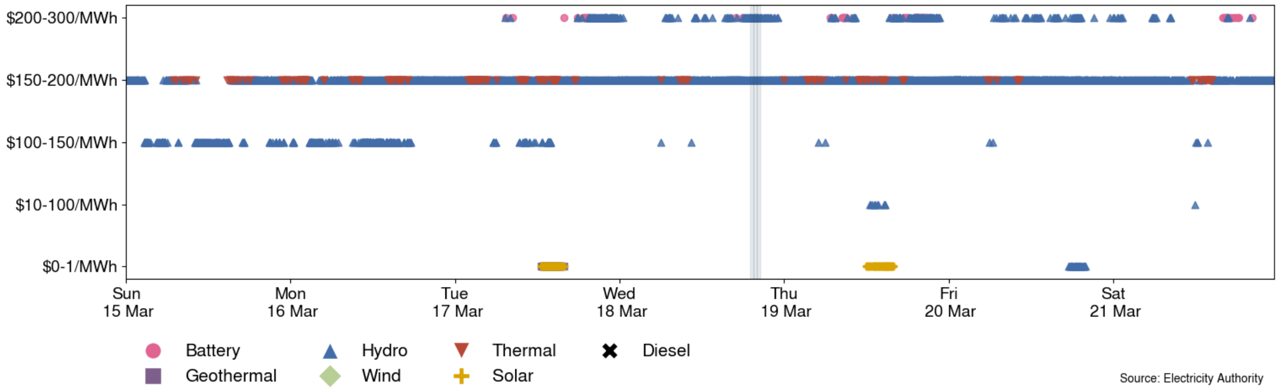
Figure 15: Hydro generation, 15-21 March



7.17. 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.

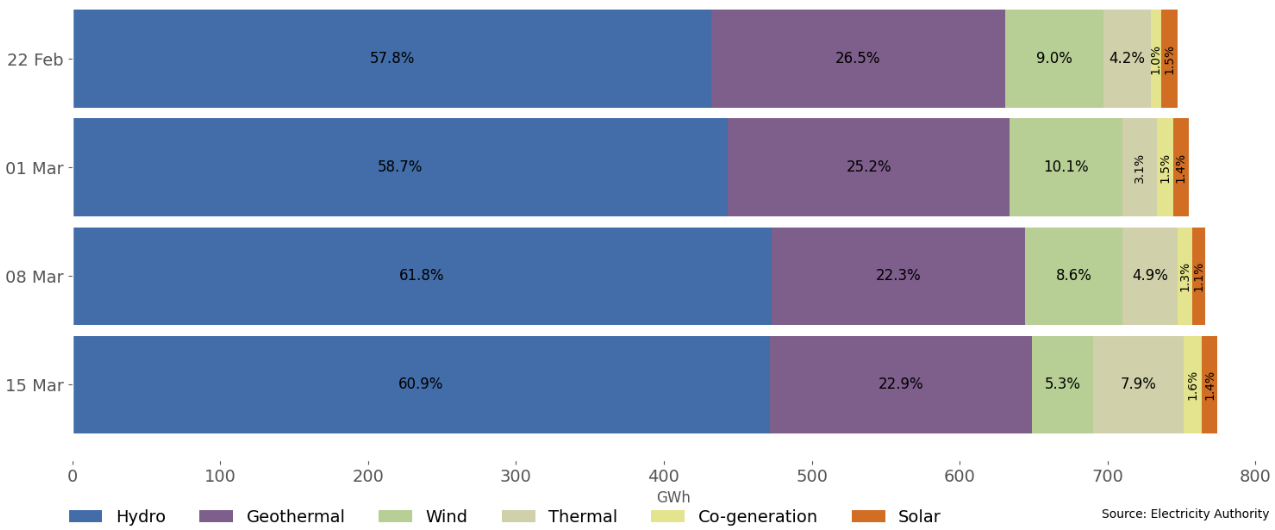
7.18. The highest prices this week were set by Meridian hydro on Wednesday. The most common technology setting prices this week was hydro generation, with thermal generation the second most common. Most marginal prices were between $150-200/MWh.

Figure 16: Prices of marginal generation, 15-21 March



7.19. As a percentage of total generation, between 15-21 March, total weekly hydro generation was 60.9%, geothermal 22.9%, wind 5.3%, thermal 7.9%, co-generation 1.6%, and solar (grid connected) 1.4%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 22 February and 21 March



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 15-21 March ranged between ~1,591MW and ~2,870MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 15-21 March

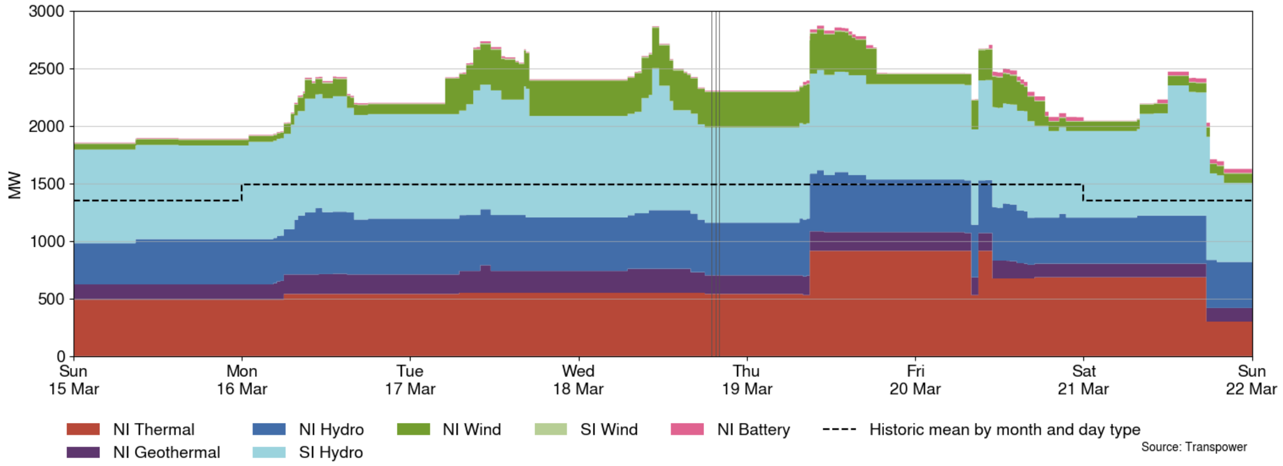
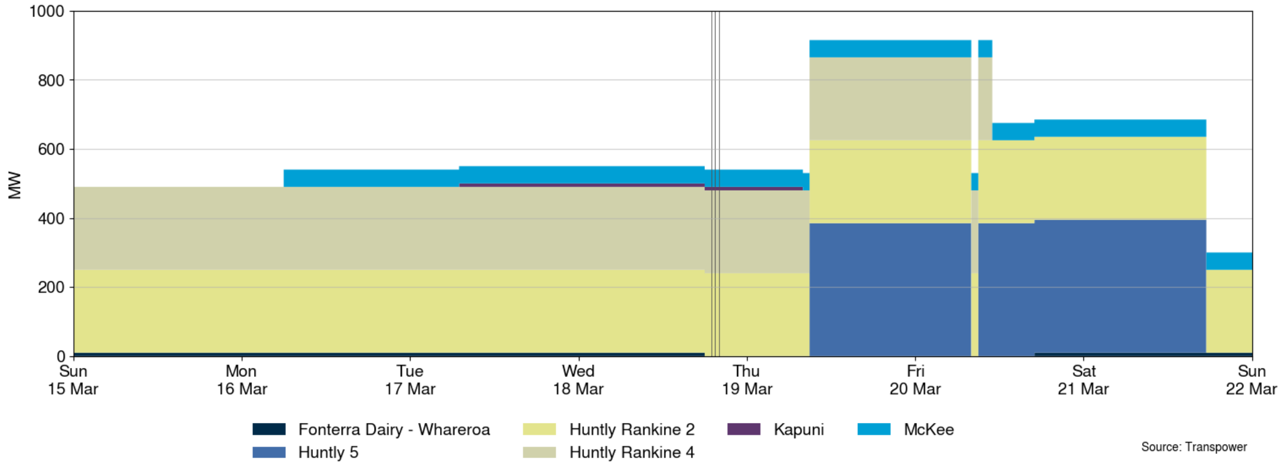


Figure 19: Total MW loss from thermal outages, 15-21 March



8.2. Notable outages include:

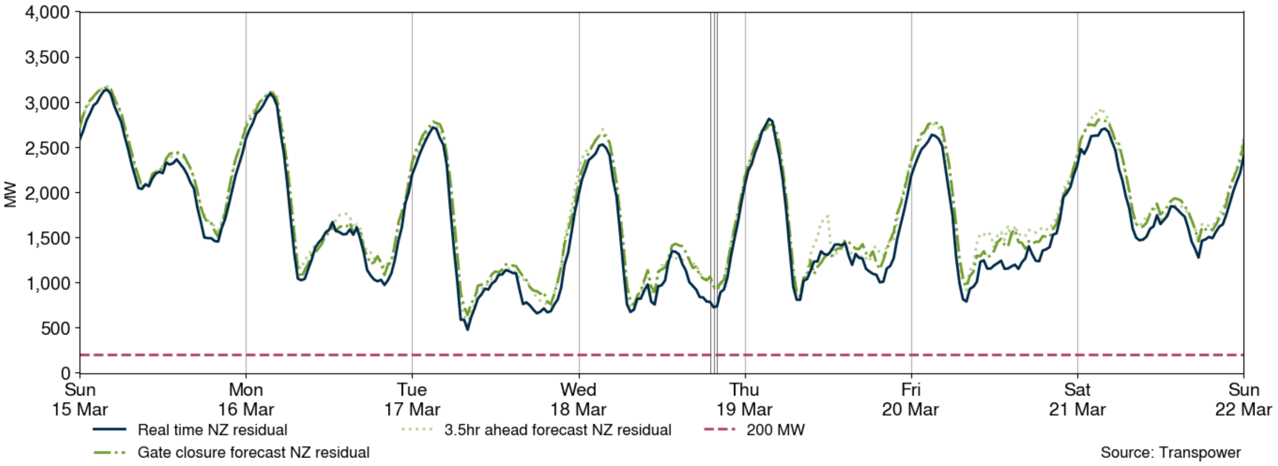
Plant	Partial or Full	End Date
Turitea wind farm	Full	19 March 2026
Waipipi wind farm	Full	20 March 2026
Huntly 4	Full	20 March 2026
Huntly 5	Full	21 March 2026
Rangipō unit 6	Full	29 March 2026
Benmore unit 5	Full	2 April 2026
Huntly 2	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	12 June 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 15-21 March. 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. Overall, national residuals were healthy this week. The lowest national residual was 475MW on Tuesday at 8.00am.

Figure 20: National generation balance residuals, 15-21 March



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 21 March, national controlled storage has decreased to 82% nominally full and ~103% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (84% full[2]) is now close to its historic mean, while Lake Takapō (75% full) is below its historic mean.

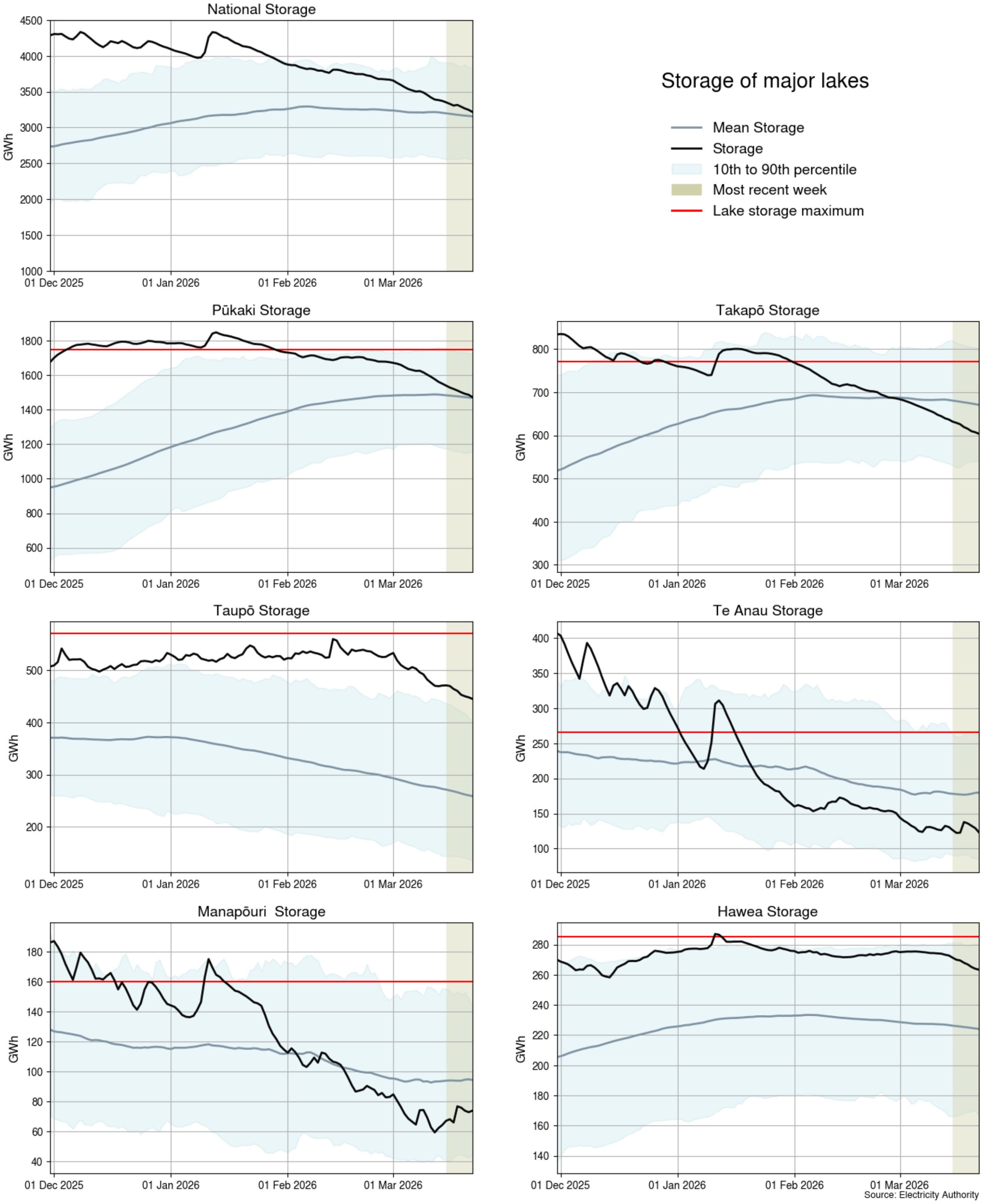
10.4. Storage at Lake Te Anau (46% full) is below its historic mean, with Lake Manapōuri (47% full) also below its historic mean.

10.5. Storage at Lake Taupō (78% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (92% 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 March 2026. Coal prices were last updated on 1 February so previous prices have been carried forward. The SRMCs for all thermal-fuelled generation have increased.

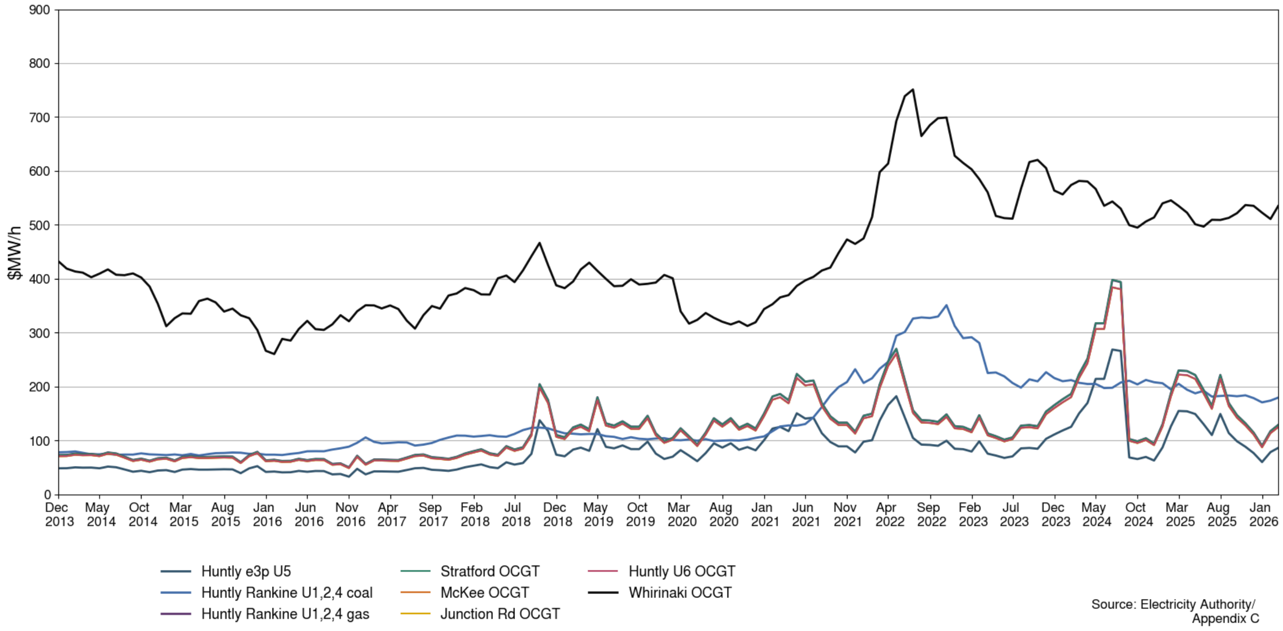
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$179/MWh. The cost of running the Rankines on gas is ~$128/MWh.

11.5. The SRMC of gas-fuelled thermal plants is currently between $86/MWh and $129/MWh.

11.6. The SRMC of Whirinaki is ~$535/MWh.

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



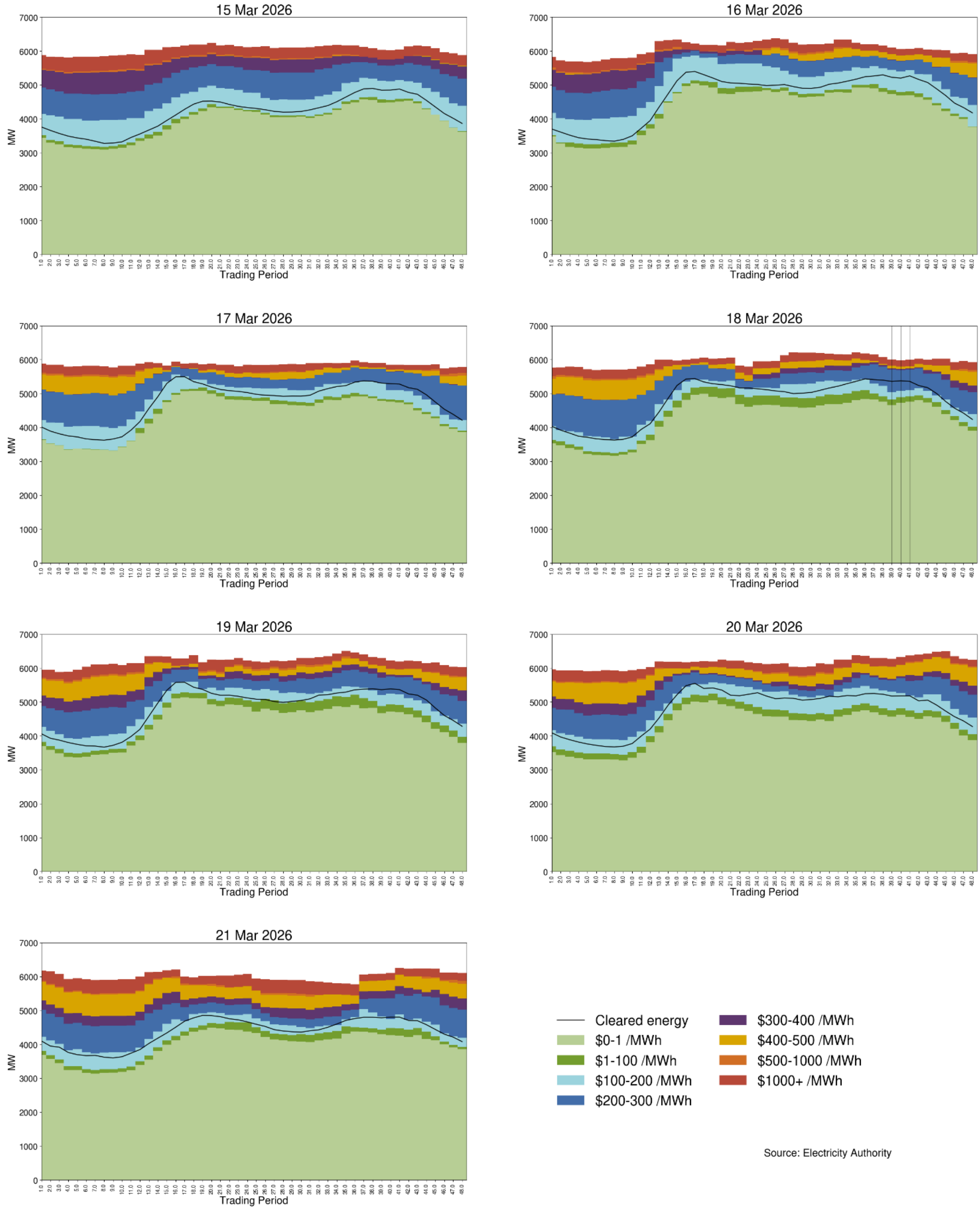
12. Offer behaviour

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 this week cleared below $200/MWh, although offers did clear above $200/MWh at times between Tuesday and Saturday.

12.3. Higher priced Mercury hydro offers were priced up from the $300-400/MWh range into the $400-500/MWh range on Monday. On Wednesday, higher priced Contact and Manawa hydro offers were priced up into the $300-400/MWh range.

Figure 23: Daily offer stacks



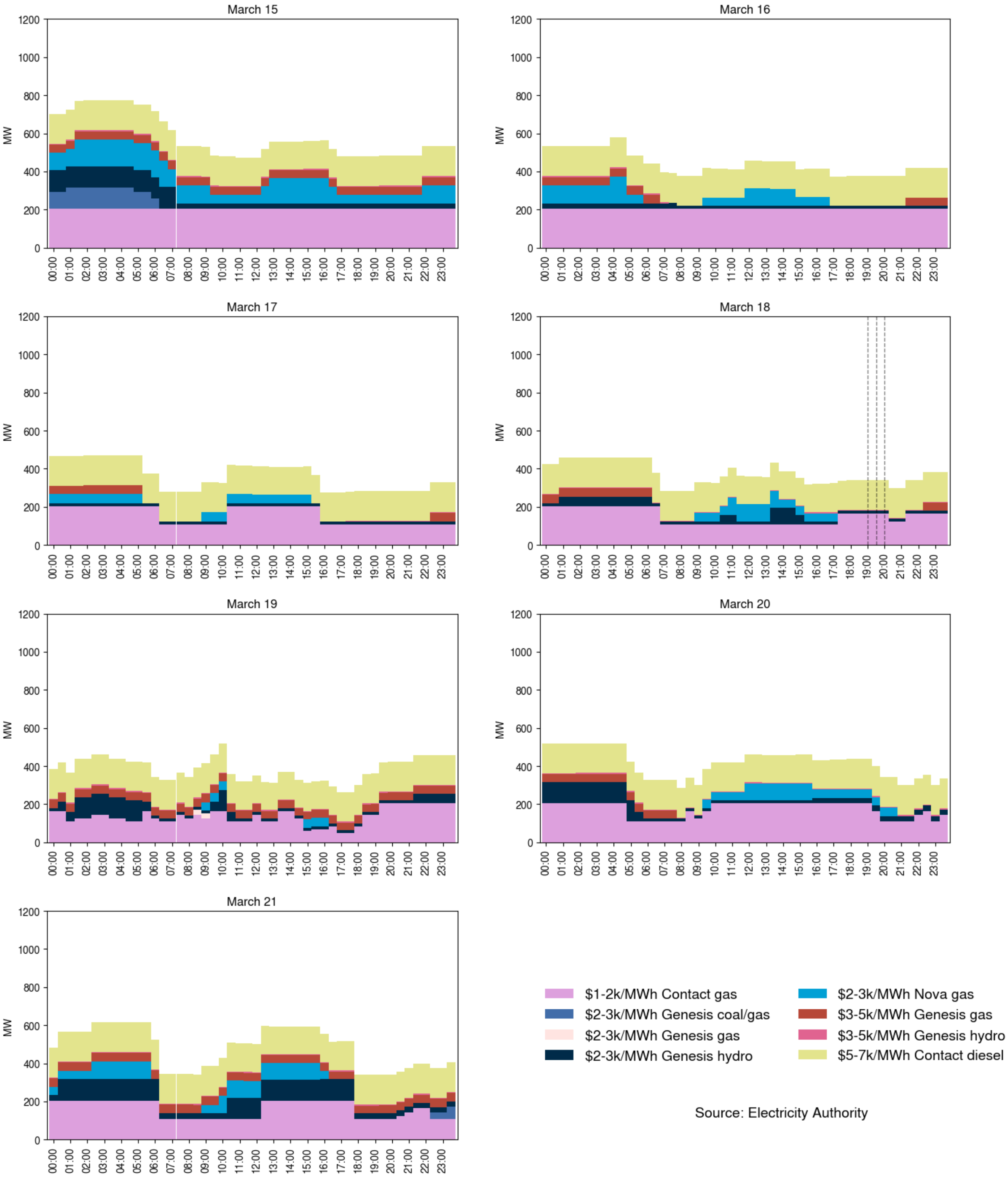
Source: Electricity Authority

12.4. 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.

12.5. 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.

12.6. On average 446MW per trading period was priced above $1,000/MWh this week, which is roughly 9% of the total energy available.

Figure 24: 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
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
13/03/2026	27-30	Further analysis	Contact	Clyde	Offers