12 March 2025

Trading conduct report 2-8 March

Market monitoring weekly report

Trading conduct report 2-8 March

1. Overview

1.1. Spot prices were lower than last week due to increased wind generation. However, prices were still mostly above $200/MWh due to hydro storage dropping to 65% nominally full, continued low inflows, the planned HVDC Pole 2 outage and forecasting inaccuracies.

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 2-8 March:

(a) The average spot price for the week was $269/MWh, a decrease of around $49/MWh compared to the previous week.

(b) 95% of prices fell between $0.09/MWh and $386/MWh.

2.3. Prices decreased this week due to wind being higher. However, prices still frequently spiked above $350/MWh due to:

(a) continued declining hydro storage

(b) continued low hydro inflows

(c) the planned HVDC Pole 2 outage

(d) large wind forecast inaccuracies

(e) demand forecast inaccuracies.

2.4. The highest price at Ōtāhuhu was $636/MWh at 3.30pm on Wednesday while the price at Benmore was $249/MWh. At this time, North Island residuals dropped 339MW lower than its lowest forecast. The North Island reserve prices also spiked to $181/MWh. This was due to a combination of wind being 166MW lower than forecasts two hours ahead of gate closure and 86MW lower than forecasts at gate closure. This wind over forecasting led to more hydro and thermal generation being used to cover the wind disparity in real time, reducing the availability of cheap reserve in the North Island, causing more expensive reserve to be dispatched.

2.5. The highest price of the week occurred at Kopu and was $662/MWh during the highest price at Ōtāhuhu. This was due to transmission losses making the price higher than at Ōtāhuhu.

2.6. Prices spiked to $384/MWh at Ōtāhuhu and $360/MWh at Benmore on Sunday at 6.30pm. Wind was 74MW lower than forecast at gate closure and demand was 77MW higher than forecast at this time.

2.7. Prices spiked above $350/MWh on Monday at 4.30pm and 5.30pm and this was also related to demand being higher than forecast.

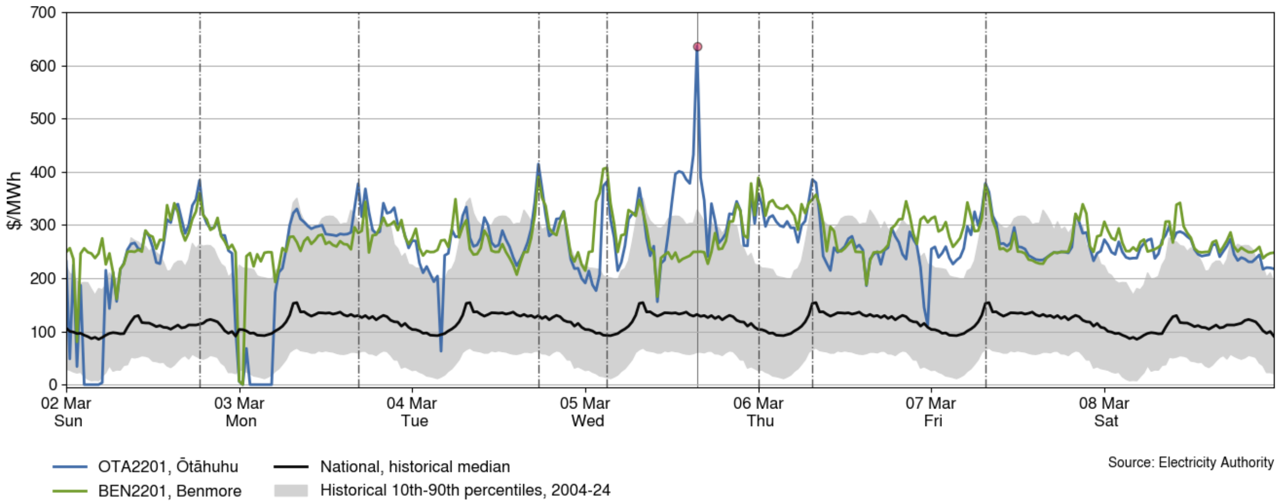
2.8. On Tuesday at 5.30pm, the prices spiked to $415/MWh at Ōtāhuhu and $390/MWh at Benmore. Wind was 192MW lower than forecast at gate closure and 118MW lower than forecast two hours ahead of gate closure. McKee also had to withdraw ~50MW of offered generation after gate closure due to a plant trip at the Mangahewa gas field.

2.9. On Wednesday at 3am, the price of Benmore spiked to $408/MWh while the price at Ōtāhuhu was $381/MWh. The increase in prices began at 2am during a South Island FIR spike to $138/MWh. Then 2.30-3am, wind was more than 200MW lower than forecast at gate closure and more than 125MW lower than forecast two hours ahead of gate closure. Southward HVDC transfer ramped down when wind was lower than forecast and more expensive hydro generation ramped up.

2.10. Wind or demand forecasting errors also contributed to price spikes on Thursday and Friday.

2.11. 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.

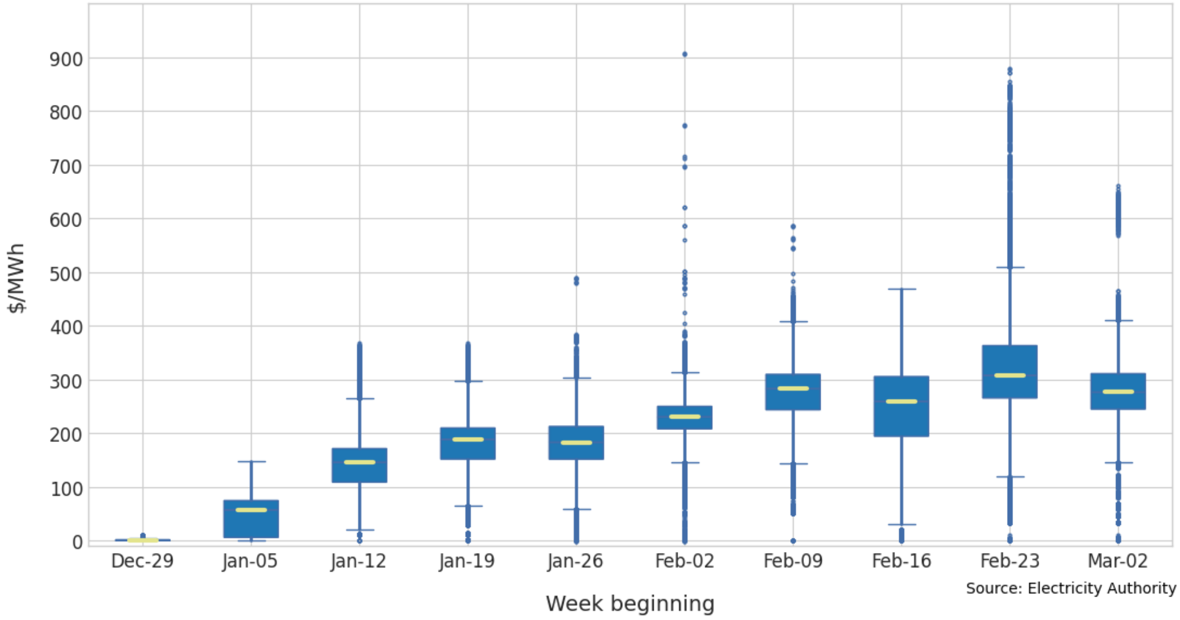
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 2-8 March



2.12. 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.

2.13. The distribution of spot prices this week was less volatile and skewed lower than last week. The median price was $276/MWh and most prices (middle 50%) fell between $245/MWh and $311/MWh.

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

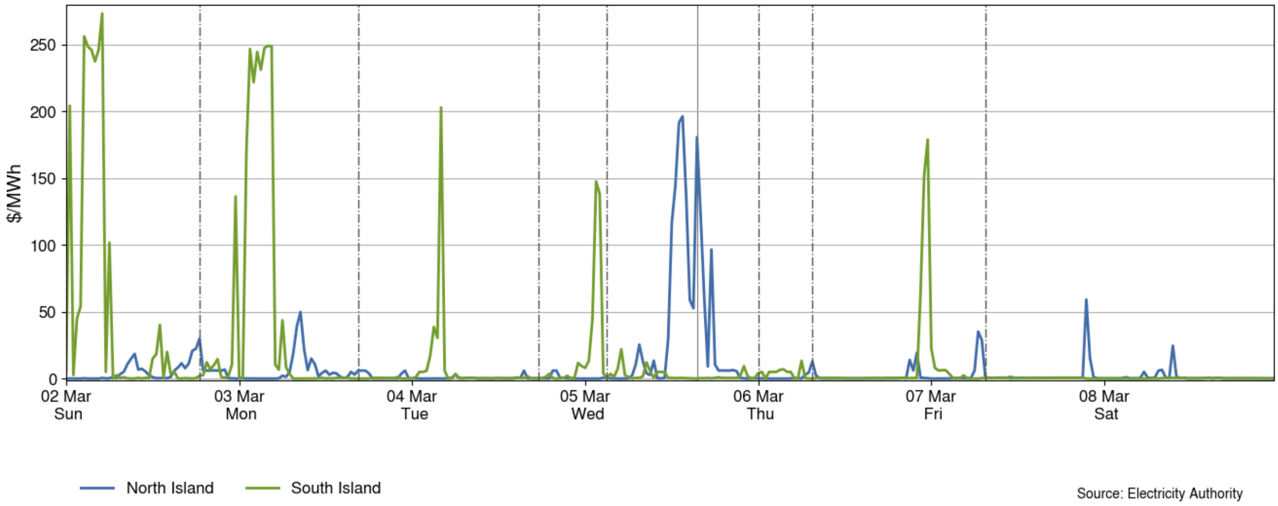


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh but spiked high in either island several times during the week. This was primarily due to the planned HVDC outage reducing reserve sharing between the islands.

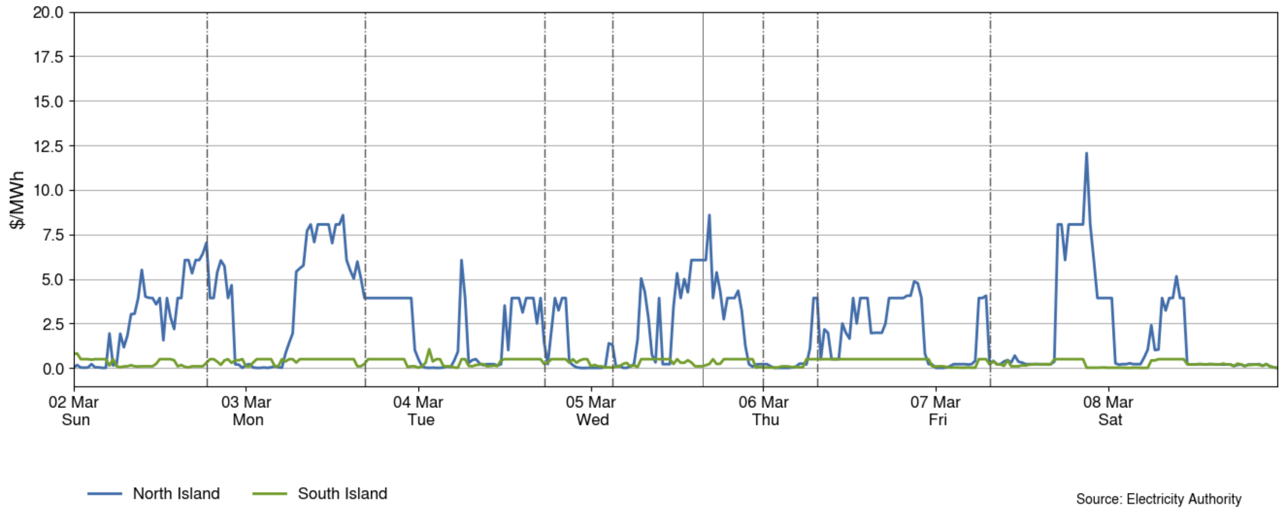
3.2. The highest FIR price was $273/MWh on Sunday at 5am in the South Island. The highest North Island FIR price was $196/MWh at 1.30pm on Wednesday.

Figure 3: Fast instantaneous reserve price by trading period and island, 2-8 March



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh and never got above $15/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 2-8 March



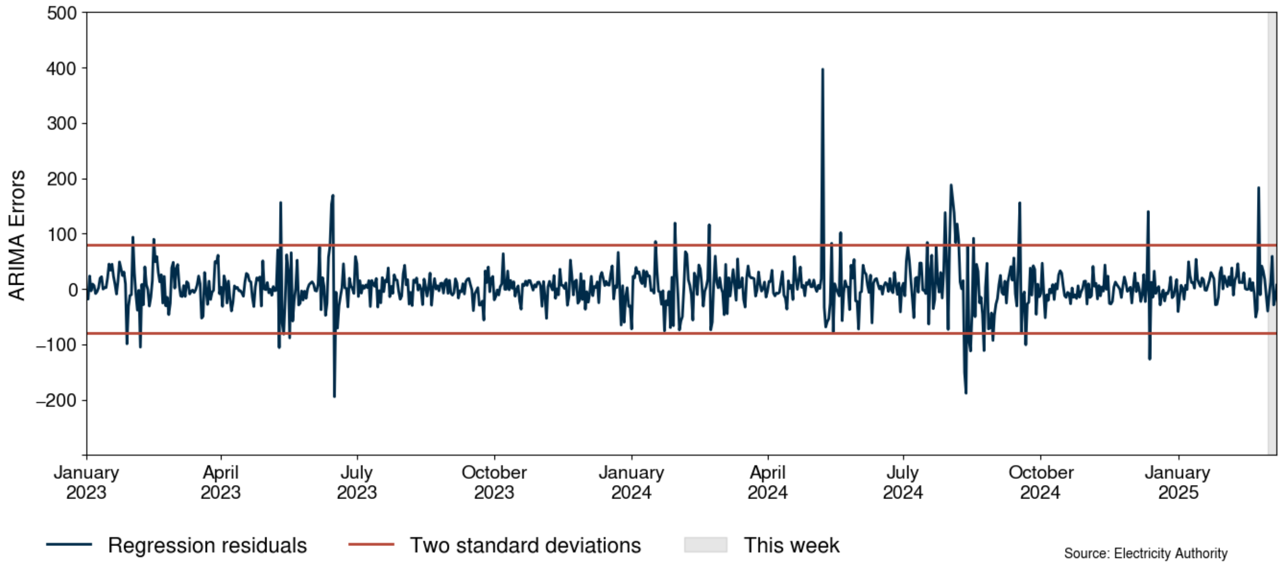
4. Regression residuals

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 the those predicted by the model.

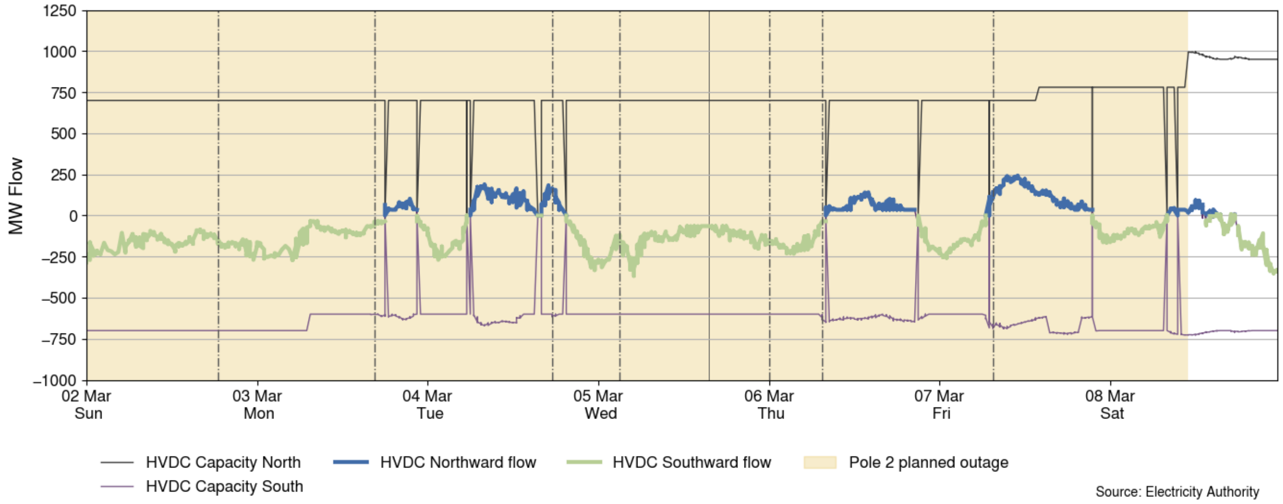
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 8 March 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 2-8 March. HVDC flows were lower this week due to the planned HVDC Pole 2 outage[1]. Most flows were southward.

Figure 6: HVDC flow and capacity, 2-8 March

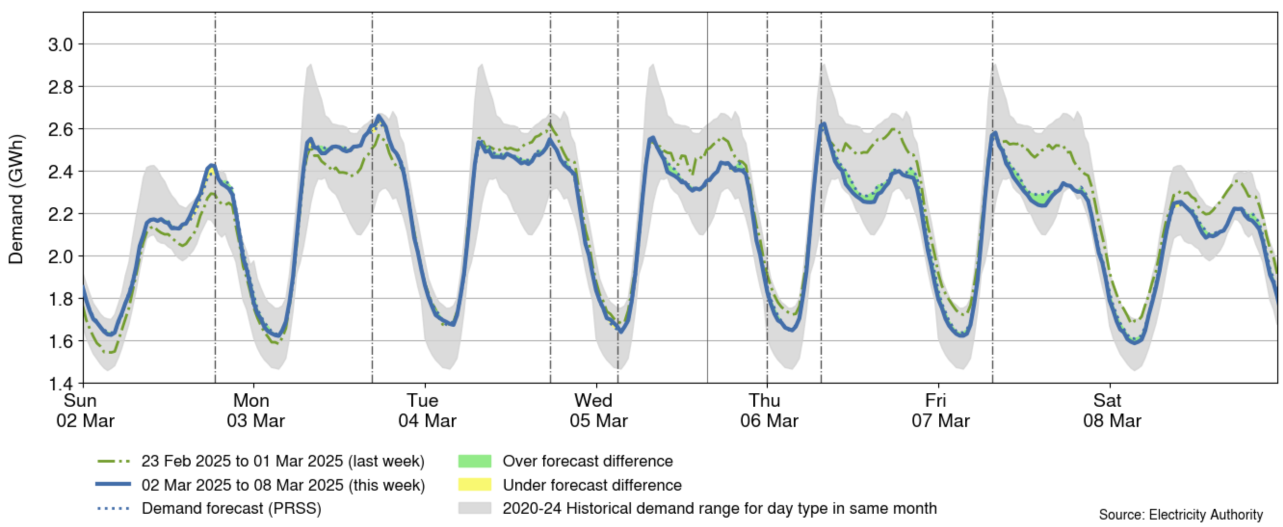


6. Demand

6.1. Figure 7 shows national demand between 2-8 March, compared to the historic range and the demand of the previous week. Demand was higher in the first part of this week when temperatures were above average, increasing cooling demand. Demand was lower from Tuesday.

6.2. This week, Tiwai started to ramp down its demand towards its 50MW agreed demand response due to commence 10 March.[2]

Figure 7: National demand, 2-8 March compared to the previous week



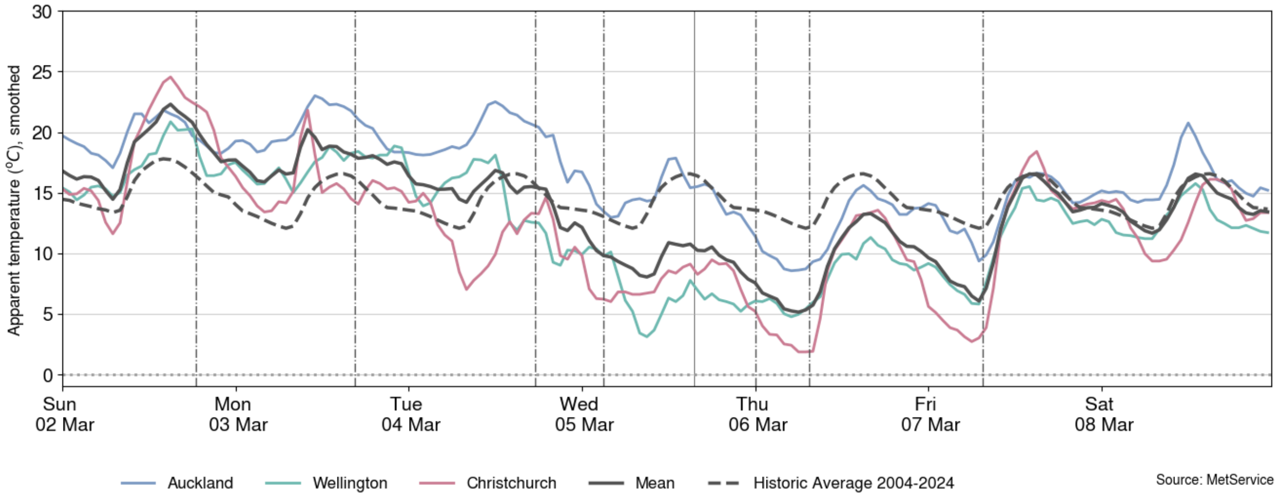
6.3. Figure 8 shows the hourly apparent temperature at main population centres from 2-8 March. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical

[1] Due to there only being one available pole at this time, capacity must drop to zero every time flows change direction.
[2] NZX, New Zealand's Exchange - Announcements, Meridian And Nzas Agree 50mw Reduction For Winter 2025

apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. Apparent temperatures ranged from 8°C to 23°C in Auckland, 3°C to 21°C in Wellington, and 1°C to 25°C in Christchurch. Apparent temperatures were above average Sunday to Monday and below average Wednesday to Thursday.

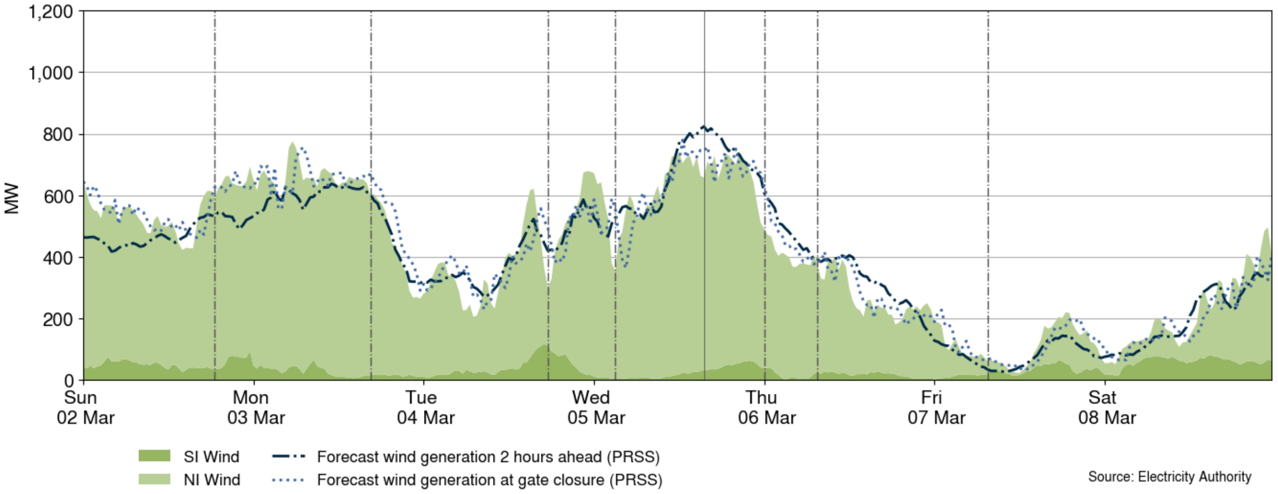
Figure 8: Temperatures across main centres, 2-8 March



7. Generation

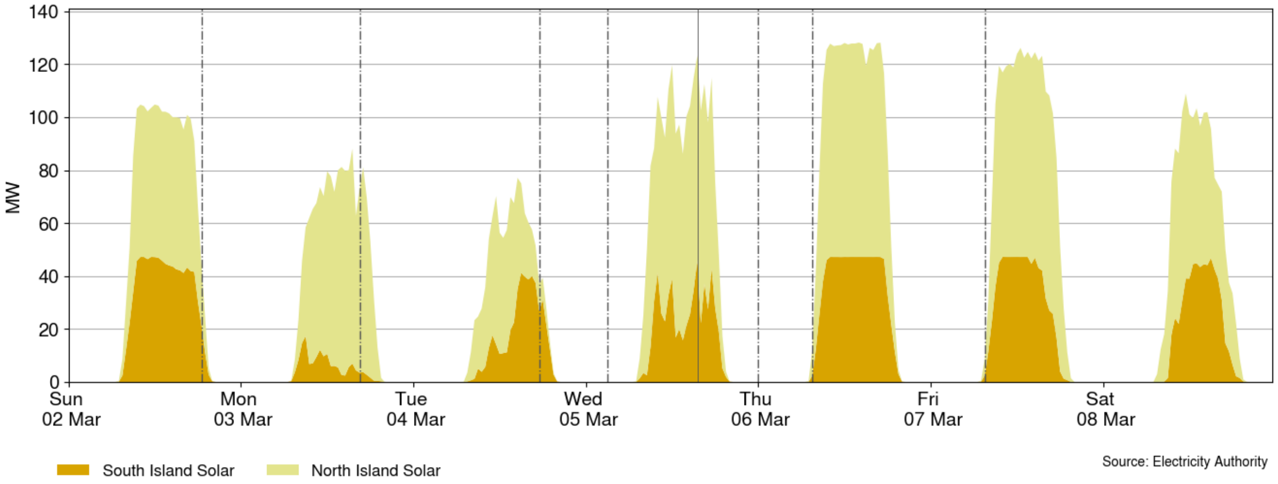
7.1. Figure 9 shows wind generation and forecast from 2-8 March. This week wind generation varied between 23MW and 775MW, with a weekly average of 403MW. The largest price spikes this week occurred during times when wind was overforecast. Wind generation was above 400MW for most of Sunday, Monday and Wednesday. Wind was very low on Friday.

Figure 9: Wind generation and forecast, 2-8 March



7.2. Figure 10 shows grid connected solar generation from 2-8 March. Solar generation reached above 120MW from Wednesday to Friday this week. Maximum solar generation was 128MW at 2pm on Thursday.

Figure 10: Grid connected solar generation, 2-8 March



7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[3]) 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 wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind 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.

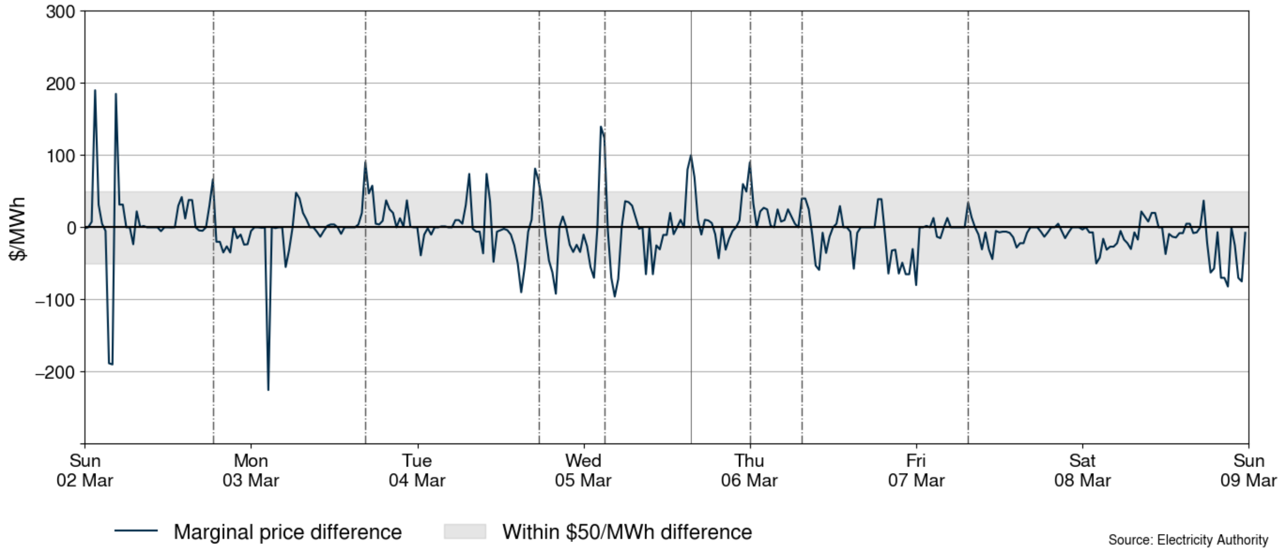
7.4. Most marginal price differences larger than plus or minus $50/MWh corresponded to wind or demand forecasting inaccuracies.

7.5. The largest positive difference was $190/MWh at 1.30am on Sunday. Wind was ~80MW lower than forecasts at gate closure at this time.

7.6. The largest negative difference was -$226/MWh at 2.30am on Monday. Wind was ~50MW higher than forecasts at gate closure at this time.

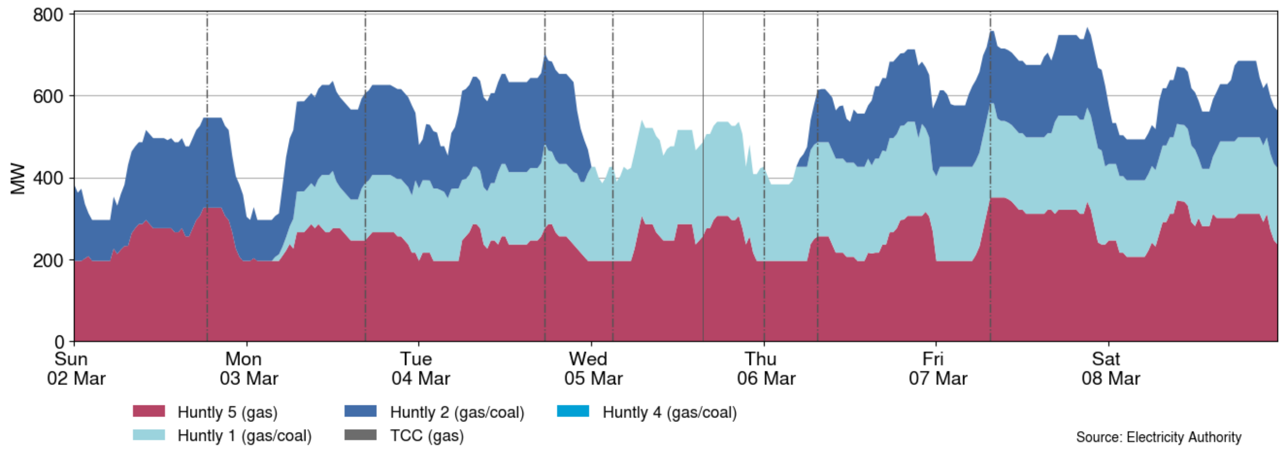
[3] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 2-8 March



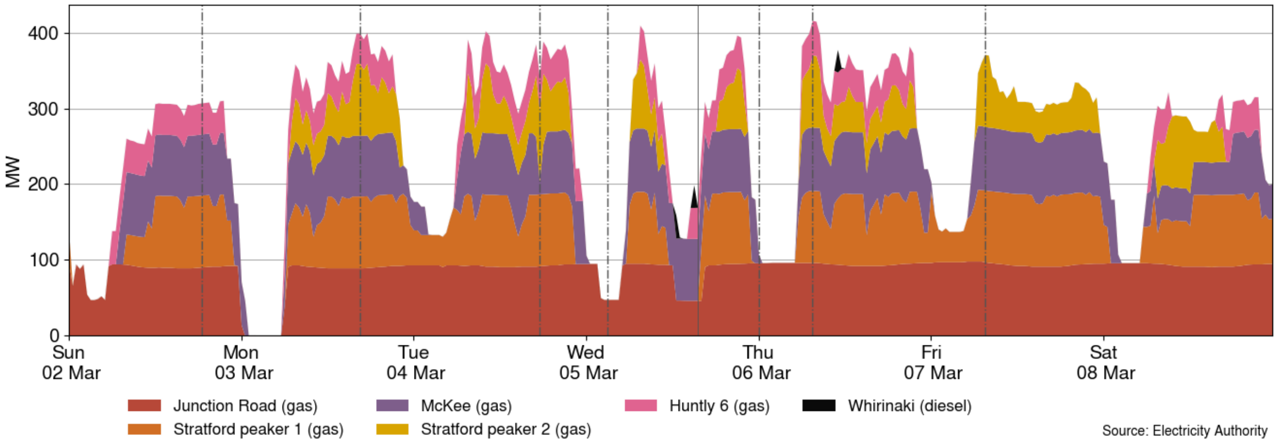
7.7. Figure 12 shows the generation of thermal baseload between 2-8 March. Huntly 5 generated baseload, Huntly 2 generated every day except Wednesday (when wind generation was highest) and Huntly 1 generated from Monday.

Figure 12: Thermal baseload generation, 2-8 March



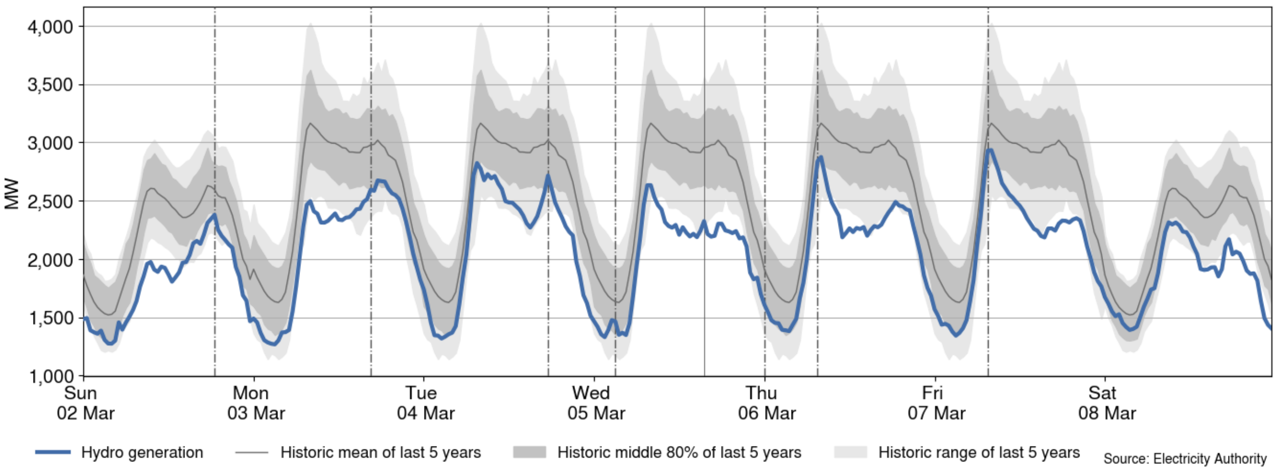
7.8. Figure 13 shows the generation of thermal peaker plants between 2-8 March. Junction Road, Stratford Peaker 1 and McKee generated every day. Stratford Peaker 2 and Huntly 6 generated most days. Whirinaki generated briefly on Wednesday and Thursday, likely to test these units after returning from outage.

Figure 13: Thermal peaker generation, 2-8 March



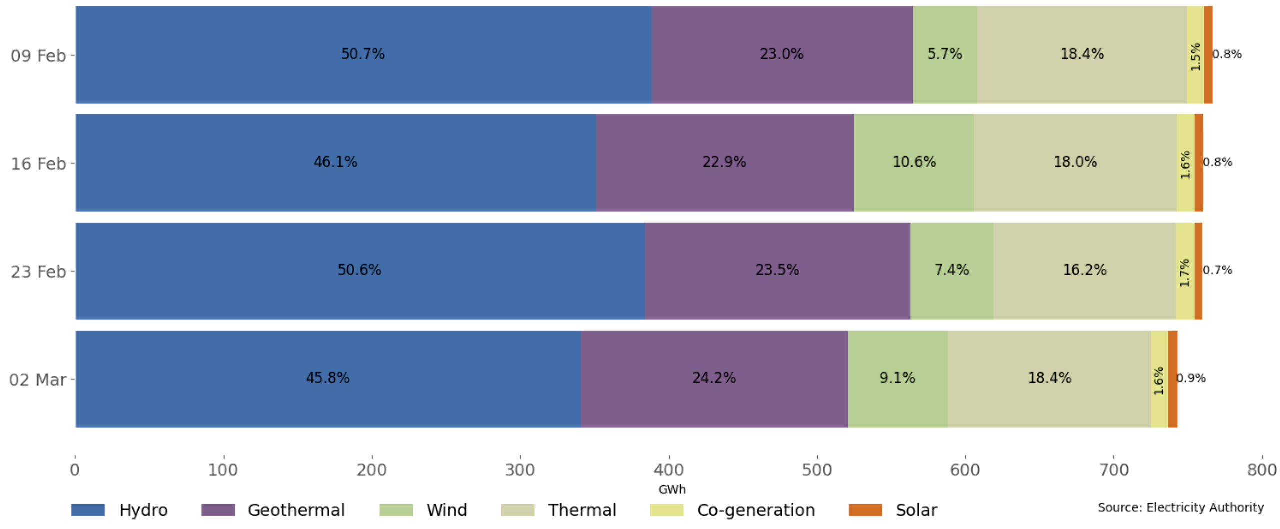
7.9. Figure 14 shows hydro generation between 2-8 March. Hydro generation was mostly below the historic 10th percentile due to low hydro storage. Hydro often increased above the 10th percentile during price spikes.

Figure 14: Hydro generation, 2-8 March



7.10. As a percentage of total generation, between 2-8 March, total weekly hydro generation was 45.8%, geothermal 24.2%, wind 9.1%, thermal 18.4%, co-generation 1.6%, and solar (grid connected) 0.9%, as shown in Figure 15. Hydro generation decreased significantly this week and thermal generation increased.

Figure 15: Total generation by type as a percentage each week, between 9 February and 8 March



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 2-8 March ranged between ~1,427MW and ~2,035MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC is on outage until 10 March (previously 21 March, although it does not typically generate at this time of year regardless).

(b) Huntly 4 is on outage until 20 March.

(c) Manapōuri unit 4 is on outage until 12 December.

(d) Manapōuri unit 5 is on outage until 21 March.

(e) Manapōuri unit 2 was on outage until 7-9 March.

(f) Manapōuri unit 6 was on outage until 6-7 March.

(g) Clyde unit 1 is on outage until 23 May.

(h) Clyde unit 2 was on outage 3 March.

Figure 16: Total MW loss from generation outages, 2-8 March

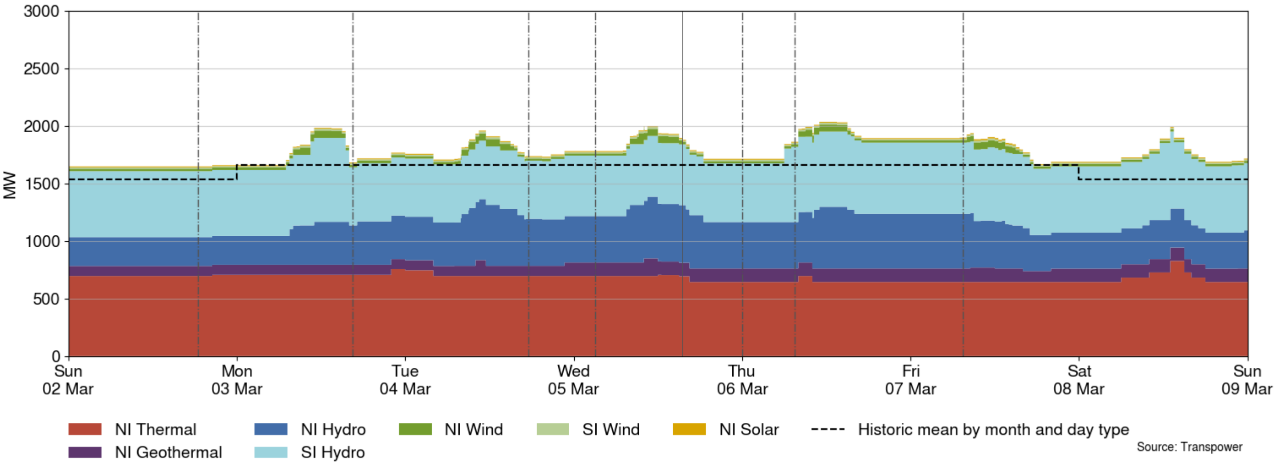
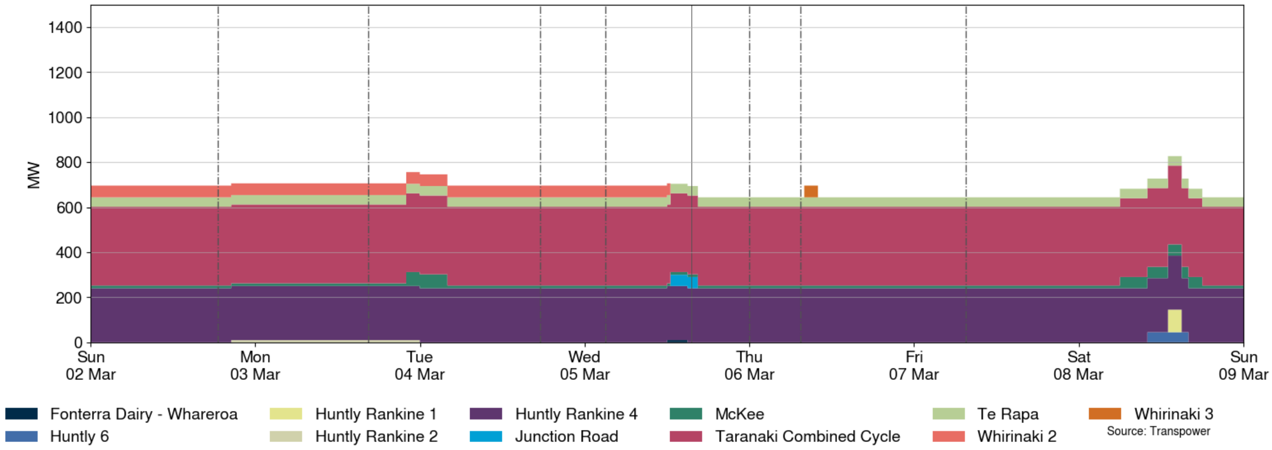


Figure 17: Total MW loss from thermal outages, 2-8 March

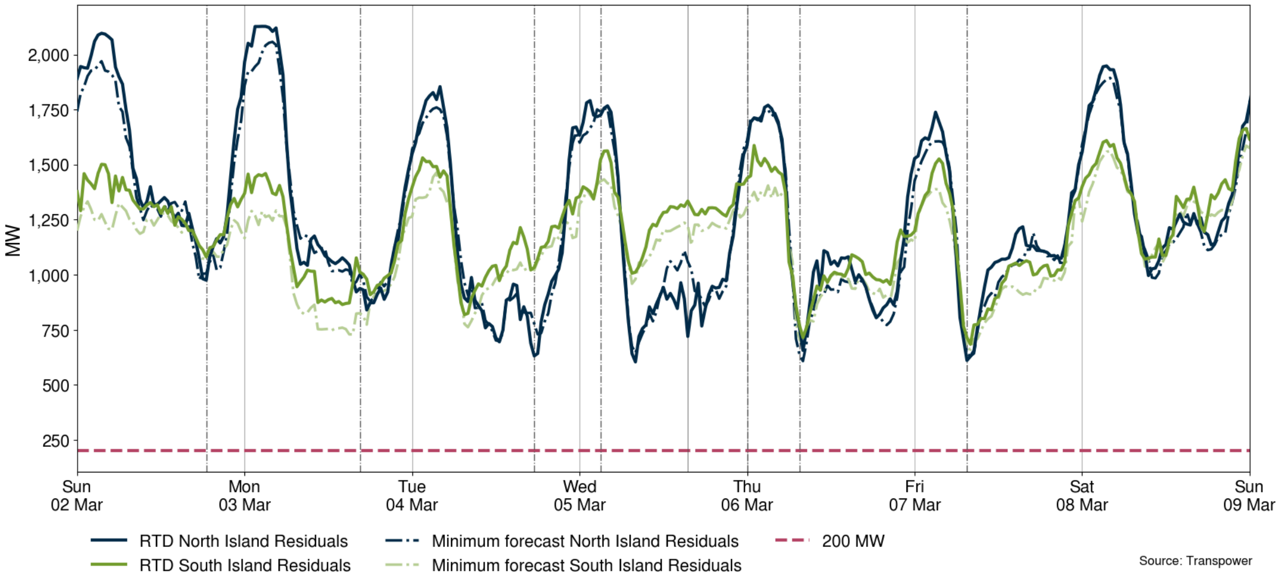


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 2-8 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 low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. North Island residuals reached a minimum of 604MW at 8am on Wednesday.

Figure 18: National generation balance residuals, 2-8 March



10. Storage/fuel supply

10.1. Figure 19 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. National controlled storage decreased to 65% nominally full and ~81% of the historical average for this time of the year.

10.3. Lake Pūkaki (65% full[4]) has decreased and is still below its historical 10th percentile.

10.4. Lake Takapō (69% full) has decreased to around its historic 10th percentile.

10.5. Lake Hawea (73% full) has decreased and is still between its historical mean and 10th percentile.

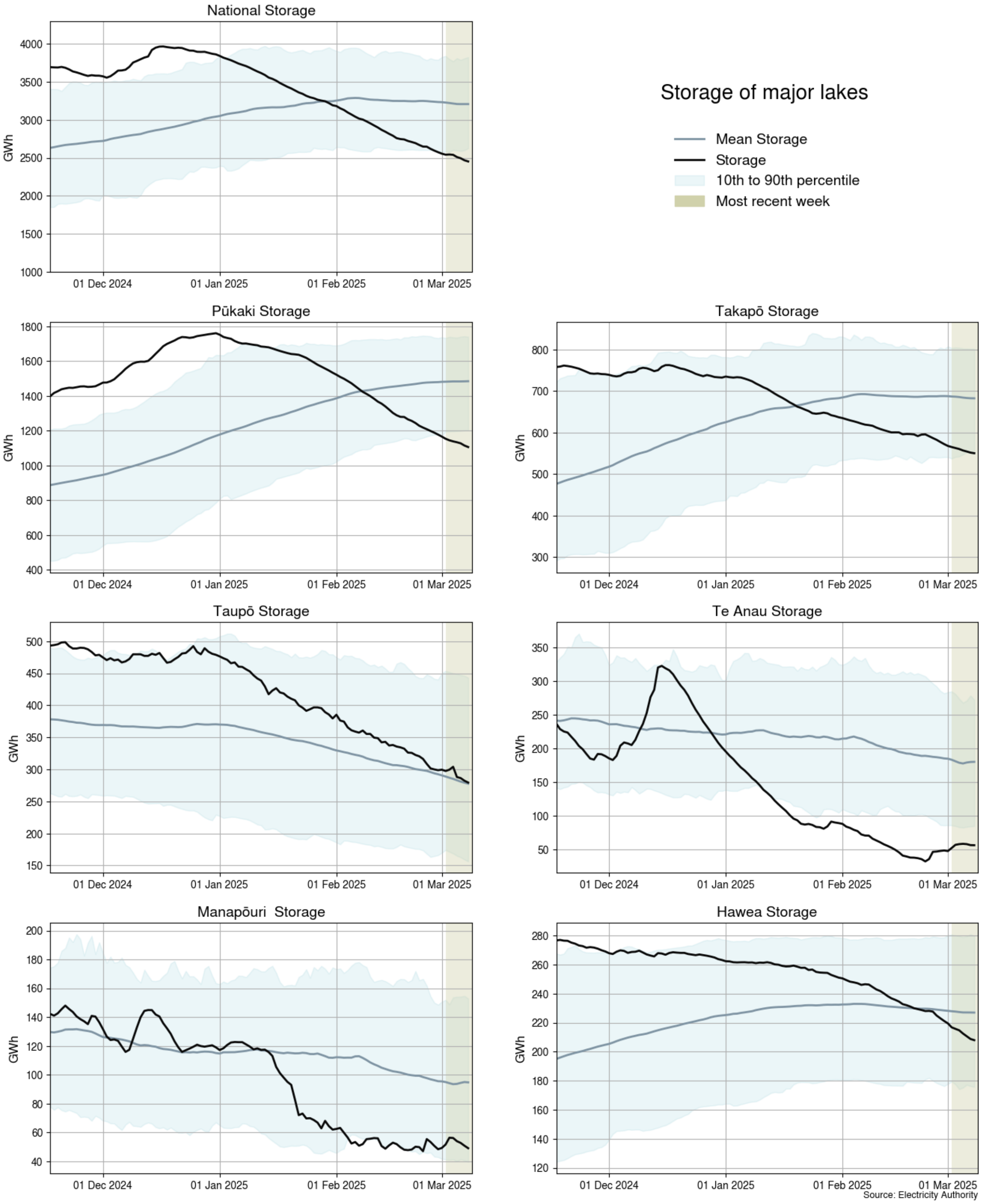
10.6. Lake Taupō (48% full) decreased and is still close to its historical mean.

10.7. Lake Te Anau has increased and is still below its historical 10th percentile.

10.8. Lake Manapōuri has fluctuated close to its historical 10th percentile.

[4] Percentage full values sourced from NZX Hydro.

Figure 19: 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 20 shows an estimate of thermal SRMCs as a monthly average up to 1 March. The SRMC for gas fuelled generation has increased compared to last month. The SRMC for coal and diesel fuelled generation remains similar.

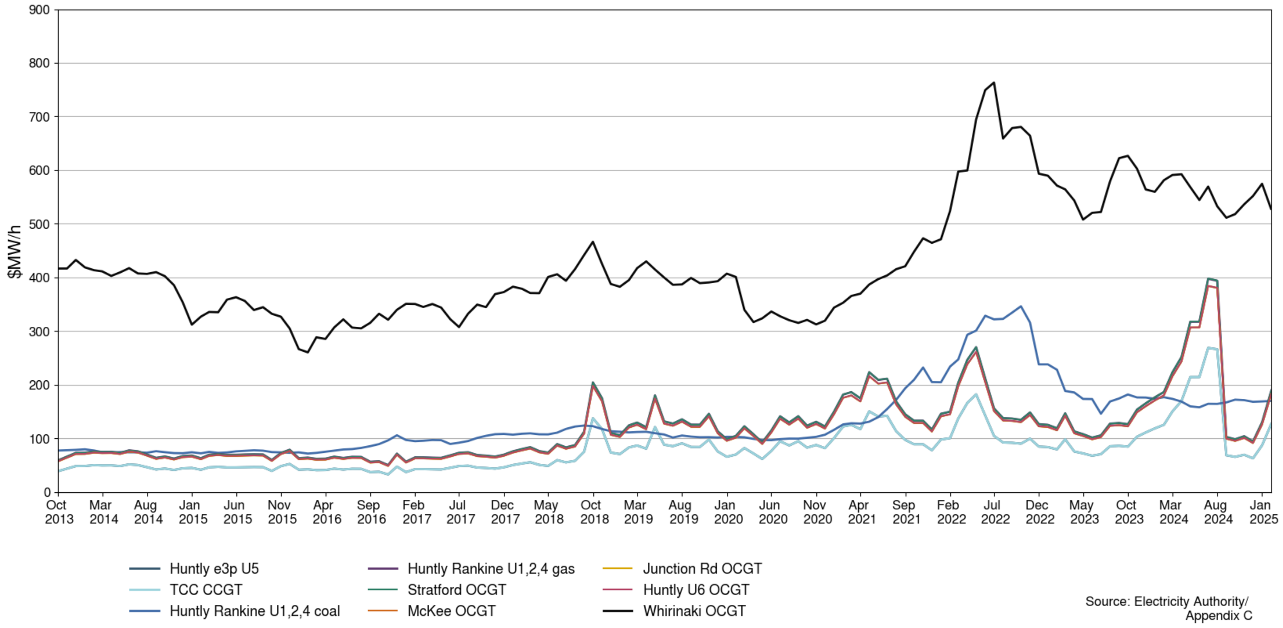
11.4. The latest SRMC of coal-fuelled Rankine generation is still ~$170/MWh, with the cost of running the Rankines on gas now more expensive at ~$224/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $150/MWh and $224/MWh.

11.6. The SRMC of Whirinaki is still ~$527/MWh.

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

Figure 20: Estimated monthly SRMC for thermal fuels

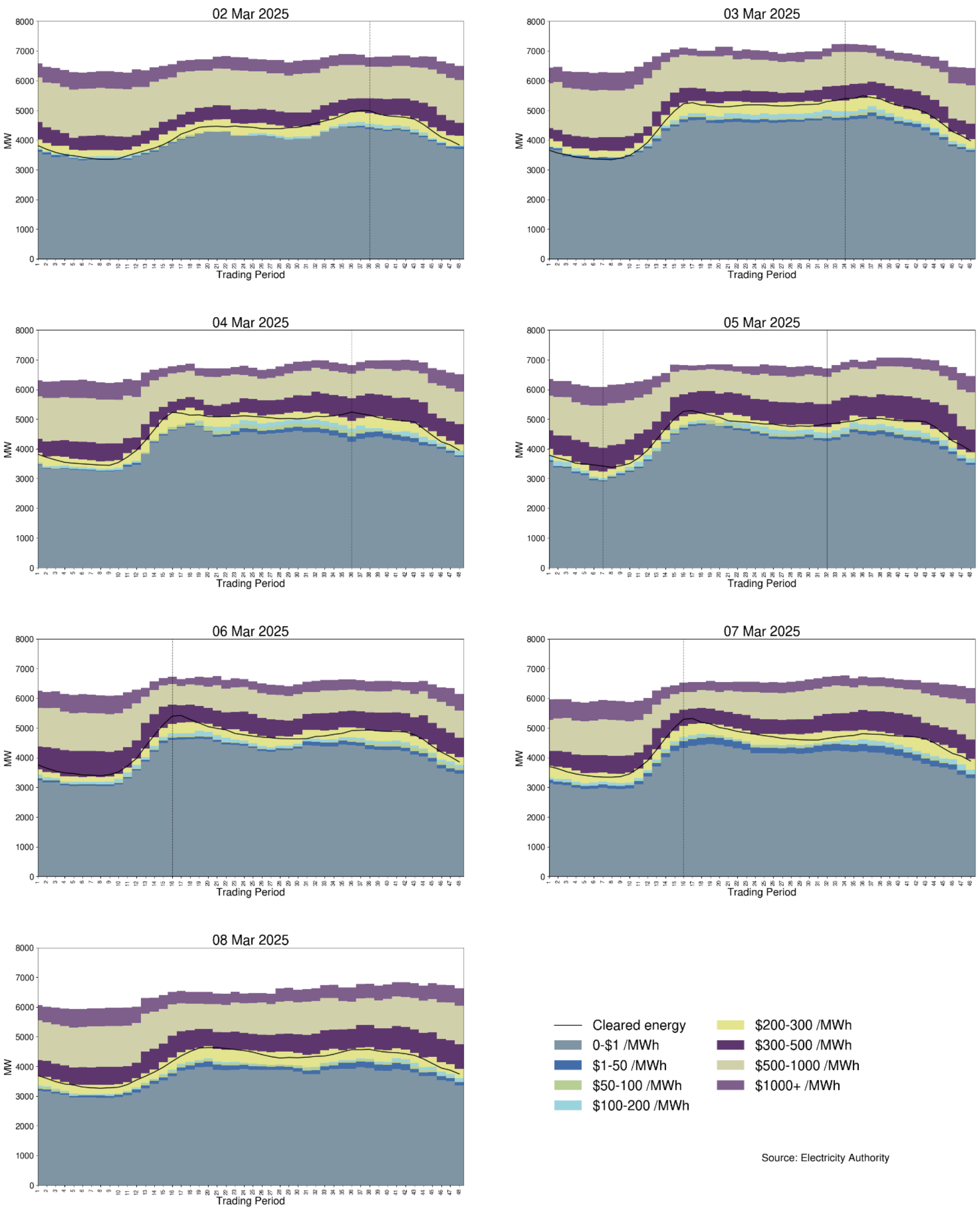


12. Offer behaviour

12.1. Figure 21 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 were clearing in the $200-300/MWh band this week.

Figure 21: Daily offer stacks

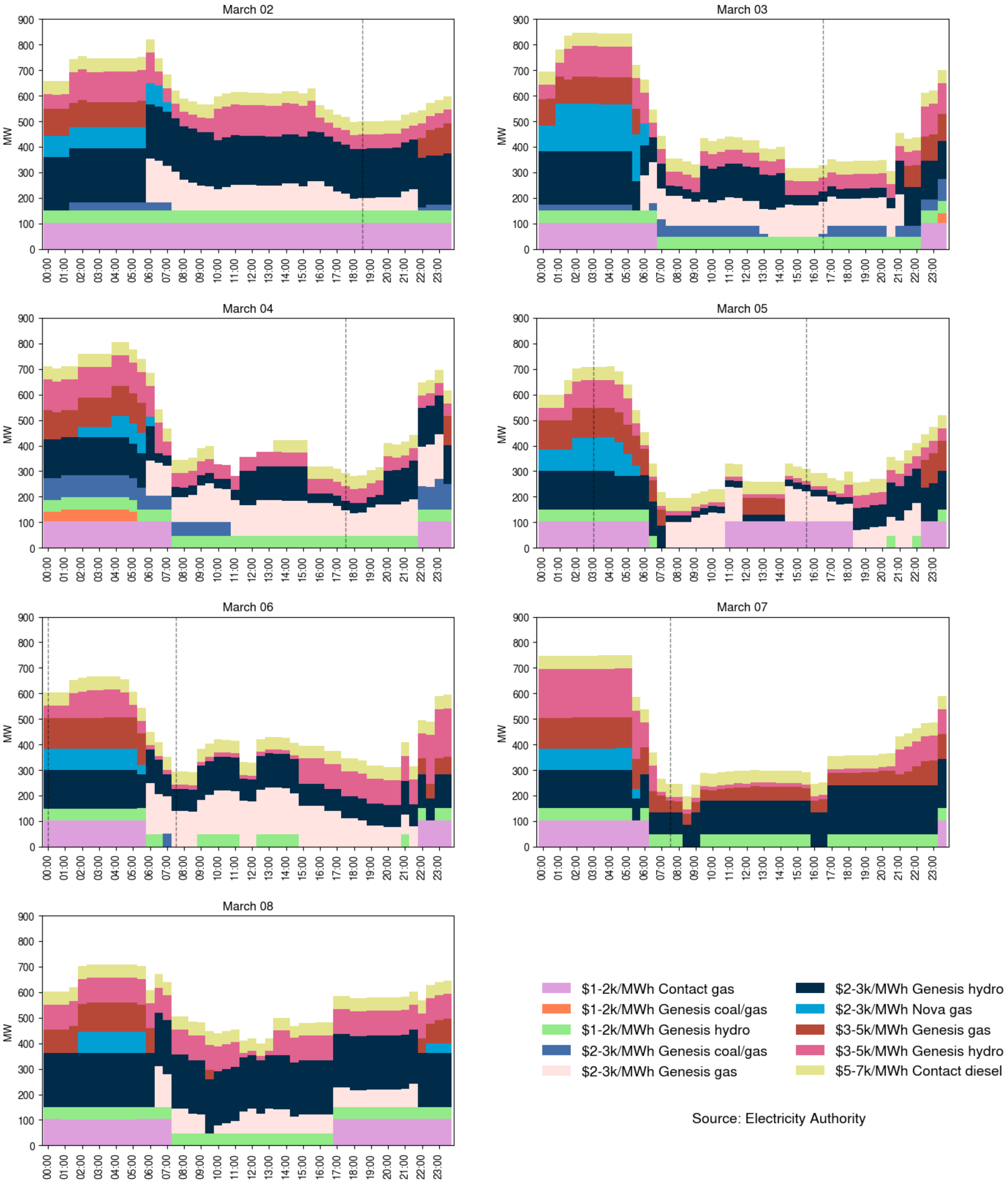


12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

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, wind 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 495MW per trading period was priced above $1,000/MWh this week, which is roughly 8.8% of the total energy available. This is ~0.6% more than last week. The monitoring team will be looking further into Stratford offers on 5 March.

Figure 22: 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. But the monitoring team will be doing further analysis on March 5 Stratford offers.

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
14/06/2023- 15/06/2023	15-17/ 15-19	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023- 30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
21/02/2025	16	Further analysis	Contact	Stratford	Thermal offer
23/02/2025- 1/03/2025	Several	Further analysis	Contact	Stratford	Stratford offers
5/03/2024	23-32	Further analysis	Contact	Stratford	Stratford offers