26 February 2025

Trading conduct report 16-22 February

Market monitoring weekly report

Trading conduct report 16-22 February

1. Overview

1.1. Spot prices decreased slightly this week compared to last, as average wind generation was higher and demand was slightly lower. However, prices were still mostly above $200/MWh due to continued dry forecasts and hydro storage dropping to 70% nominally full and high thermal generation. The annual planned HVDC outages also began this week, which limited transfer of energy and reserve between the islands.

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 16-22 February:

(a) The average spot price for the week was $239/MWh, a decrease of around $38/MWh compared to the previous week.

(b) 95% of prices fell between $0.38/MWh and $364/MWh.

2.3. Prices were lower this week compared to last week due to higher wind generation and persistent demand over forecasting. However, prices continue to be above $200/MWh this week due to:

(a) low hydro storage

(b) low hydro inflows

(c) dry forecasts

(d) unexpected Huntly outages

(e) the planned HVDC outage

2.4. The highest price at Ōtāhuhu was $413/MWh at 10am on Saturday. This was during the planned HVDC bi-pole outage that commenced at 5am on Saturday, leading to higher North Island prices the entire day[1]. At the time of the highest price, wind generation forecasts at gate closure were 187MW over forecast.

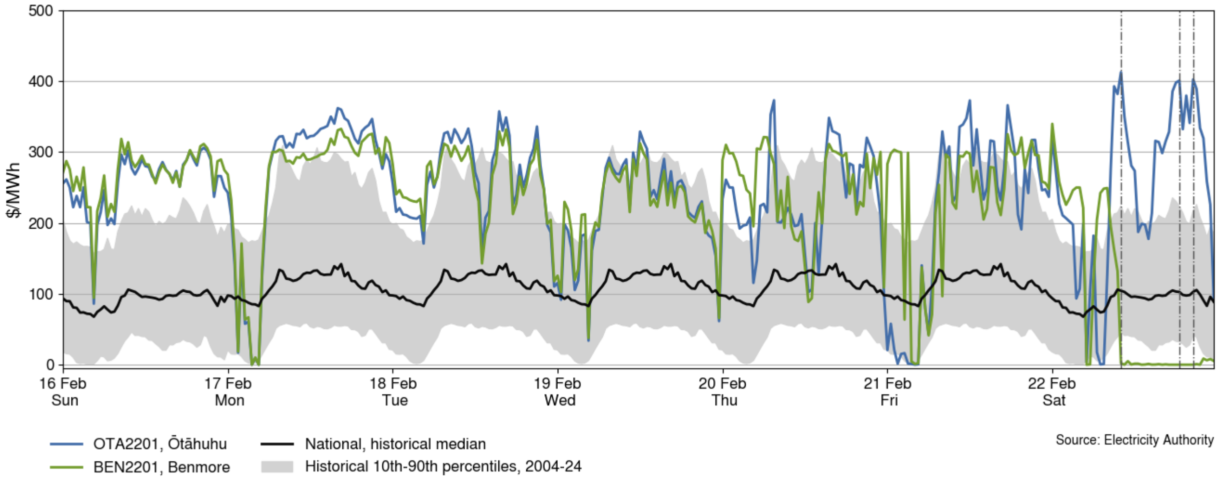
2.5. There were also times when South Island prices were higher than those in the North Islands. This occurred early on Thursday, Friday and Saturday mornings. These prices were elevated due to the cost of South Island reserve during the HVDC pole 3 outage.

2.6. The highest price of the week occurred at Wellsford and was $427/MWh at 10am on Saturday. This was during the highest price at Ōtāhuhu and was due to transmission losses making the price slightly higher than at Ōtāhuhu.

[1] A bi-pole HVDC outage means that no energy or reserve can be shared between islands. This often leads to spikes in reserve prices, an increase in North Island thermal generation increasing North Island spot prices, and a decrease in South Island hydro with very low South Island spot prices.

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. Prices above $400/MWh are marked with black dashed lines.

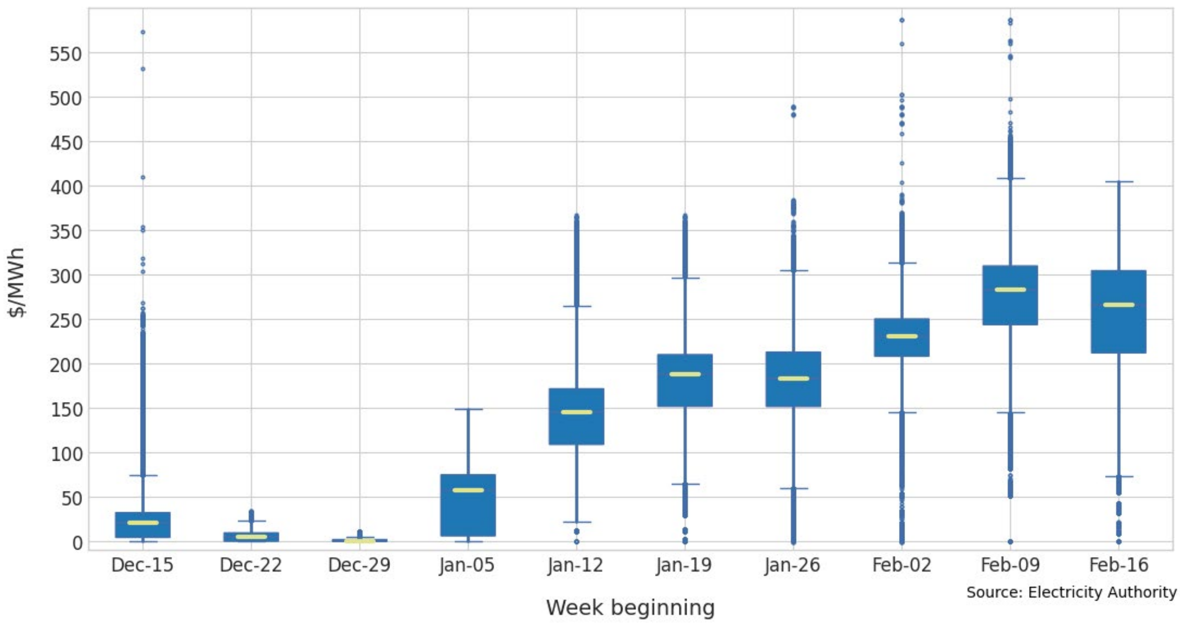
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 16-22 February



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 was skewed slightly lower than last week. The median price was $266/MWh and most prices (middle 50%) fell between $212/MWh and $304/MWh.

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



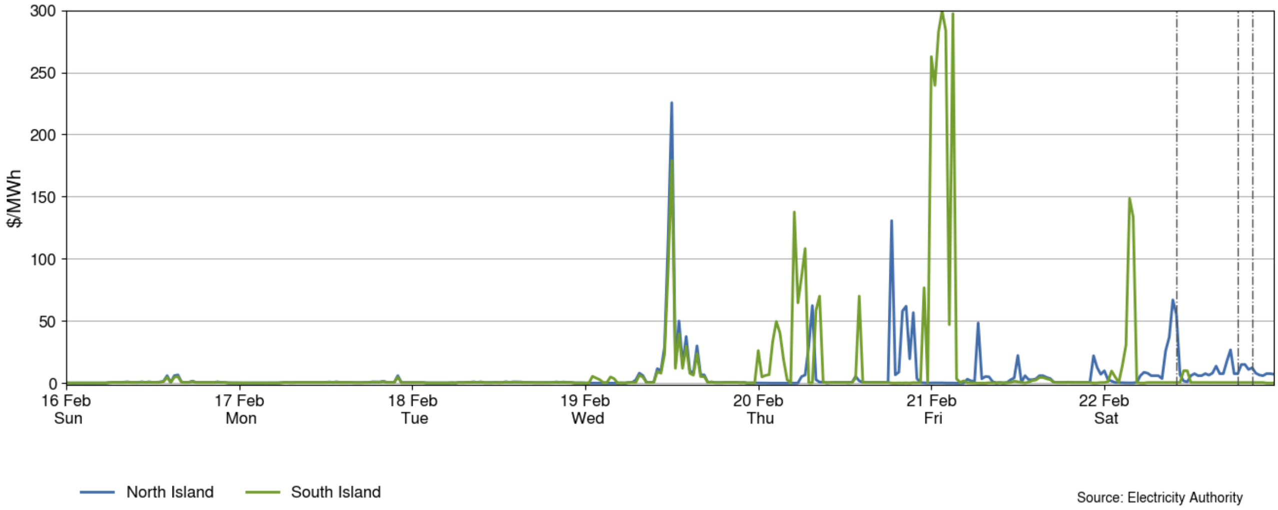
3. Reserve prices

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 several times during the week.

3.2. FIR spiked to $226/MWh in the North Island and $179/MWh in the South Island at 12pm on Wednesday. This was during a time period when HVDC transfer was between 25-40MW, preventing reserve from being shared between the islands.[2] Wind was over 100MW lower than forecasts two hours ahead of gate closure and at gate closure at this time. Hydro reserve offers were also lower surrounding this period when compared to the rest of the day.

3.3. FIR price separation between the islands and spikes in the North and South Island from Thursday were related to the scheduled HVDC pole outages.

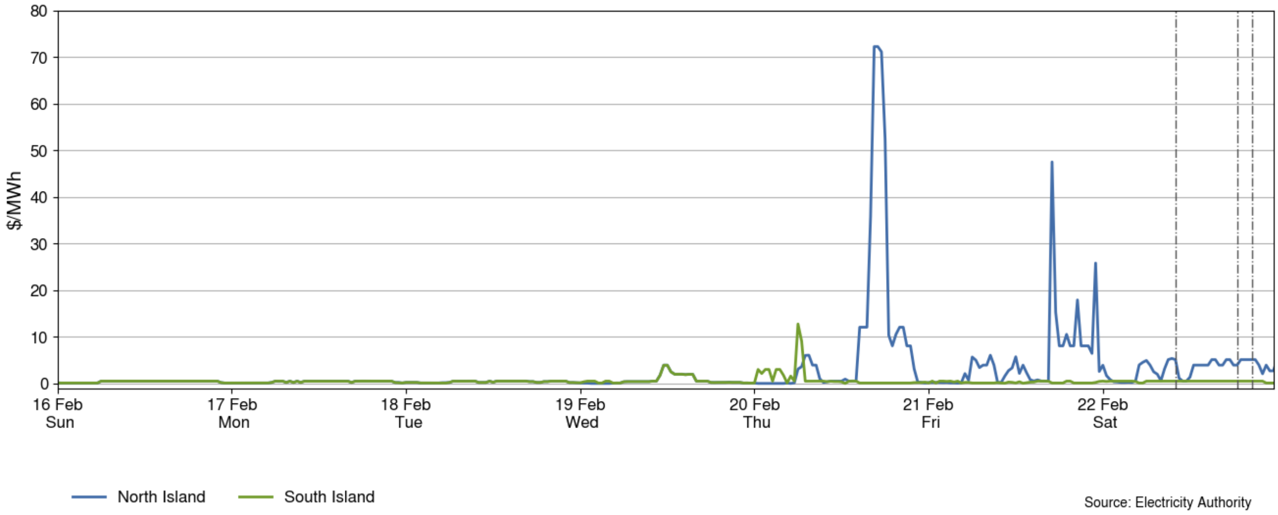
Figure 3: Fast instantaneous reserve price by trading period and island, 16-22 February



3.4. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh but got higher in the North Island from Thursday during the HVDC pole outages. The maximum North Island SIR price occurred at 4.30pm on Thursday, during which time North Island residuals were relatively low at 345MW.

[2] If the HVDC energy transfer is between 22.5MW and 65MW, this is the 'no reserve zone' and no FIR can be shared. This leads to lower energy costs but higher reserve costs.

Figure 4: Sustained instantaneous reserve by trading period and island, 16-22 February



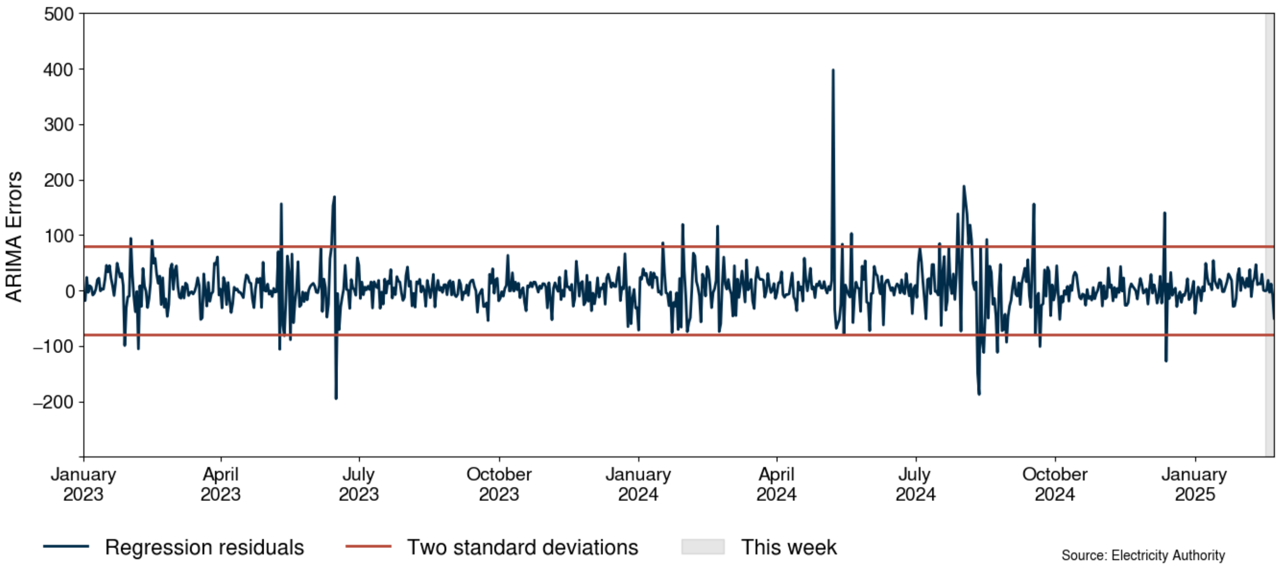
4. Regression residuals

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.

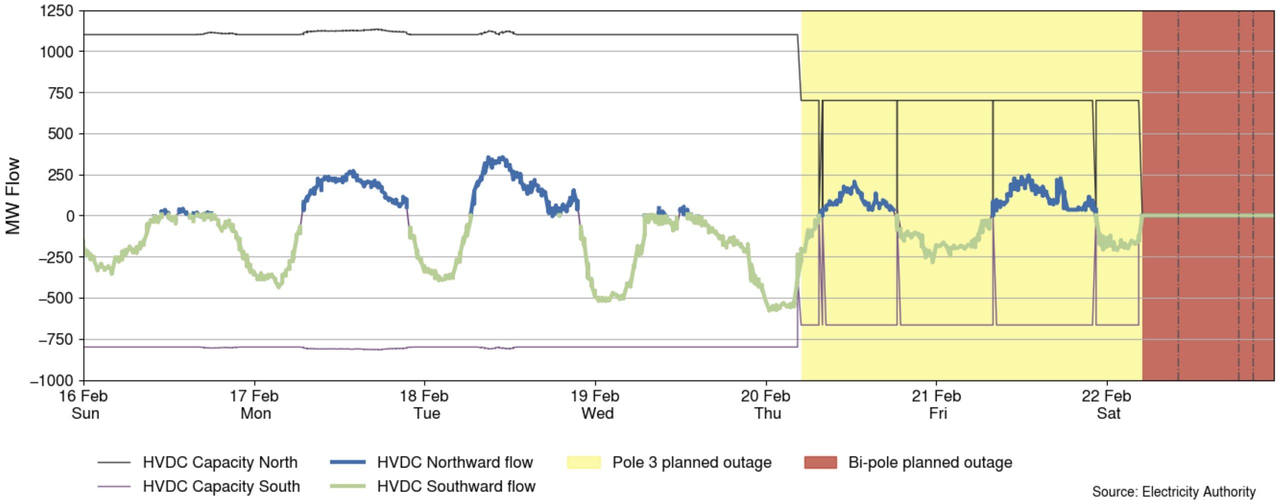
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 22 February 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 16-22 February. HVDC flows were close to zero for much of Sunday and Wednesday due to low hydro generation. All flows were lower during the Pole 3 outage, as expected.[3] Flow was zero during the bi-pole outage on Saturday, which is also as expected.

Figure 6: HVDC flow and capacity, 16-22 February

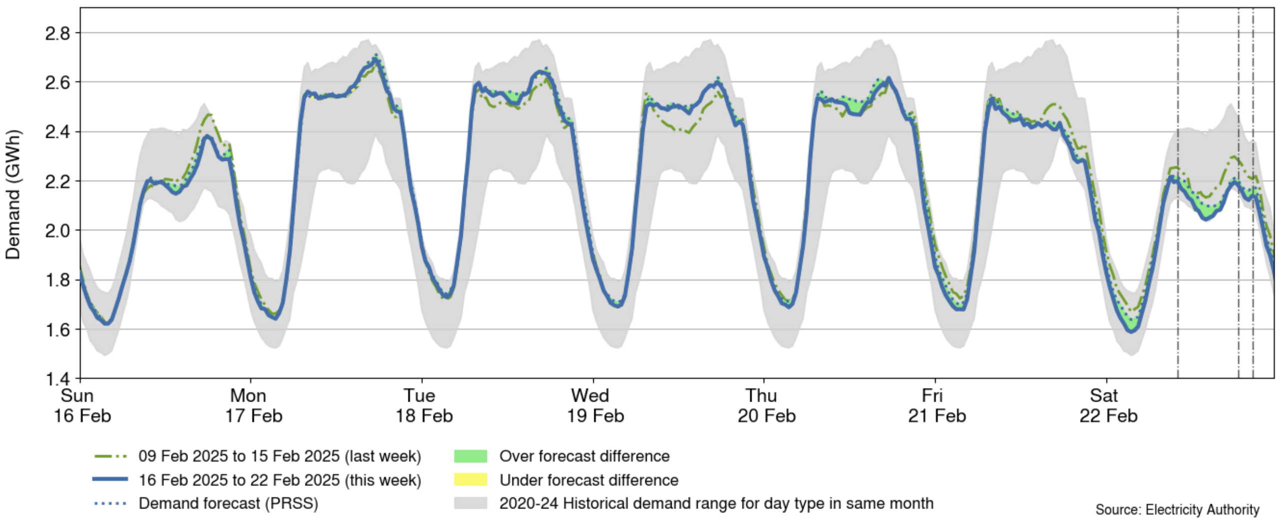


6. Demand

6.1. Figure 7 shows national demand between 16-22 February, compared to the historic range and the demand of the previous week. Demand was mostly on the higher end of the historic range. There was very little under forecasting, however demand was sometimes over forecast, which may have led to prices being lower than expected at times.

6.2. Demand was highest on Monday afternoon, reaching a maximum of 2.69GWh at 5.30pm.

Figure 7: National demand, 16-22 February compared to the previous week



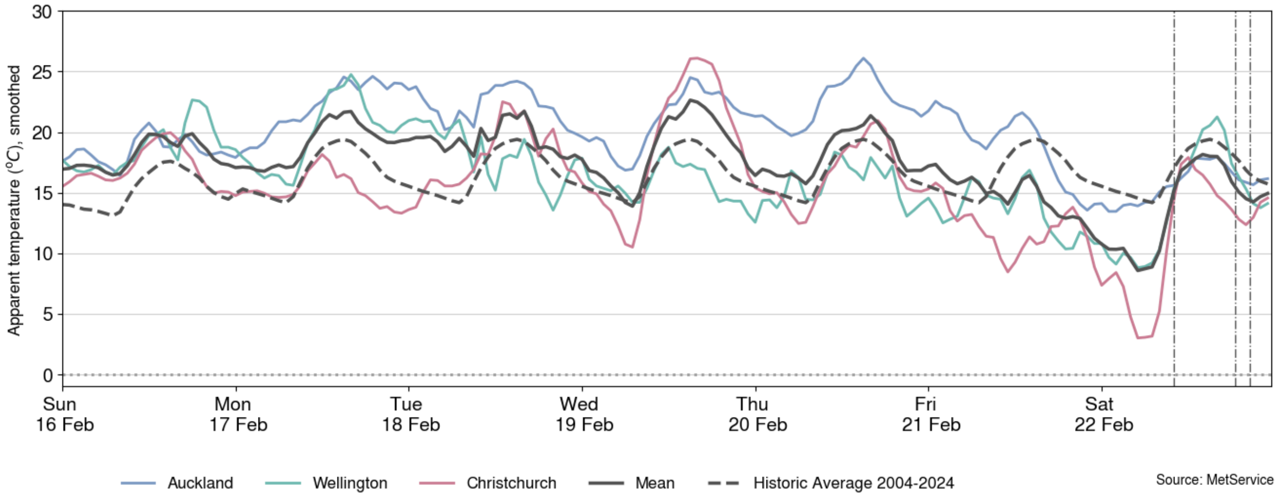
6.3. Figure 8 shows the hourly apparent temperature at main population centres from 16-22 February. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also

[3] Due to there only being one available pole at this time, capacity must drop to zero every time flows change direction.

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 13°C to 26°C in Auckland, 9°C to 25°C in Wellington, and 3°C to 26°C in Christchurch. Apparent temperatures were mostly above average up to Thursday, which may have led to higher cooling demand earlier in the week.

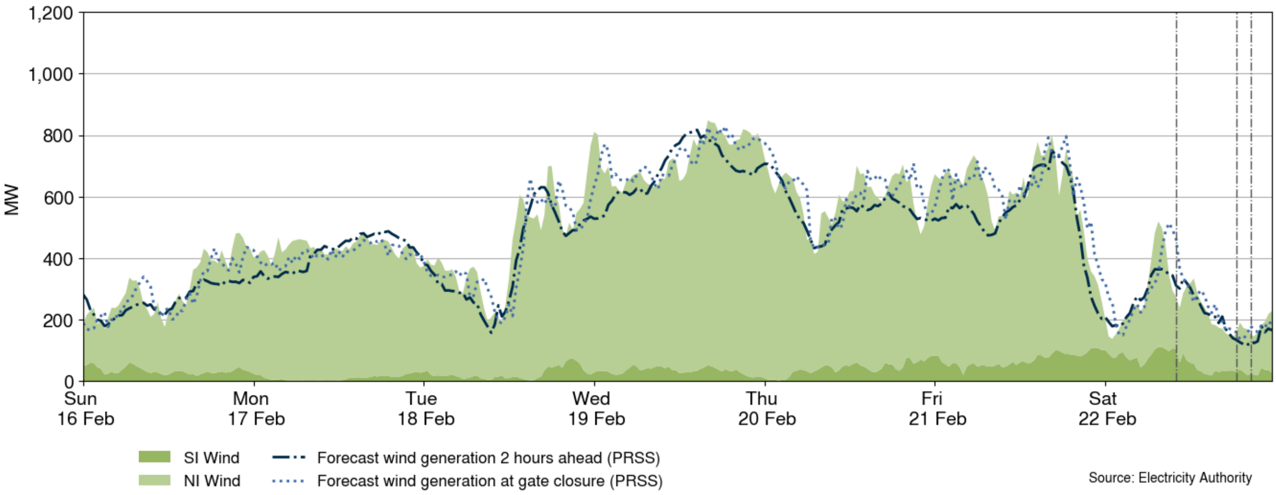
Figure 8: Temperatures across main centres, 16-22 February



7. Generation

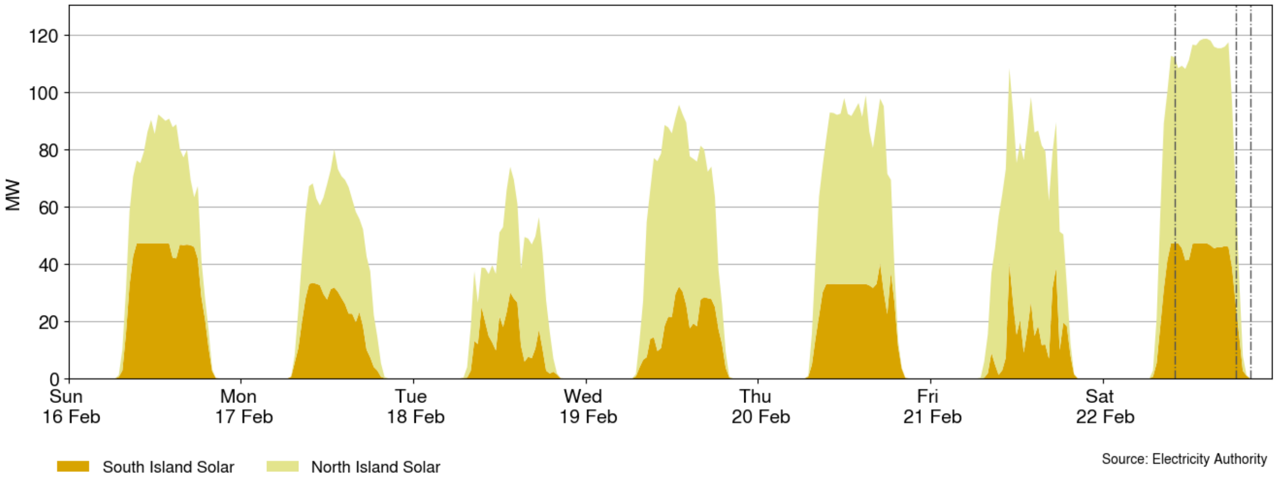
7.1. Figure 9 shows wind generation and forecast from 16-22 February. This week wind generation varied between 137MW and 848MW, with a weekly average of 480MW. This week's average is the highest average wind generation of the year so far. However, wind still only reached above 600MW from Tuesday to Friday. Wind was lower on Sunday and Saturday.

Figure 9: Wind generation and forecast, 16-22 February



7.2. Figure 10 shows grid connected solar generation from 16-22 February. Solar generation reached above 80MW every day except Monday and Tuesday. Generation was consistently above 110MW on Saturday, reaching a maximum of 119MW at 2.30pm.

Figure 10: Grid connected solar generation, 16-22 February



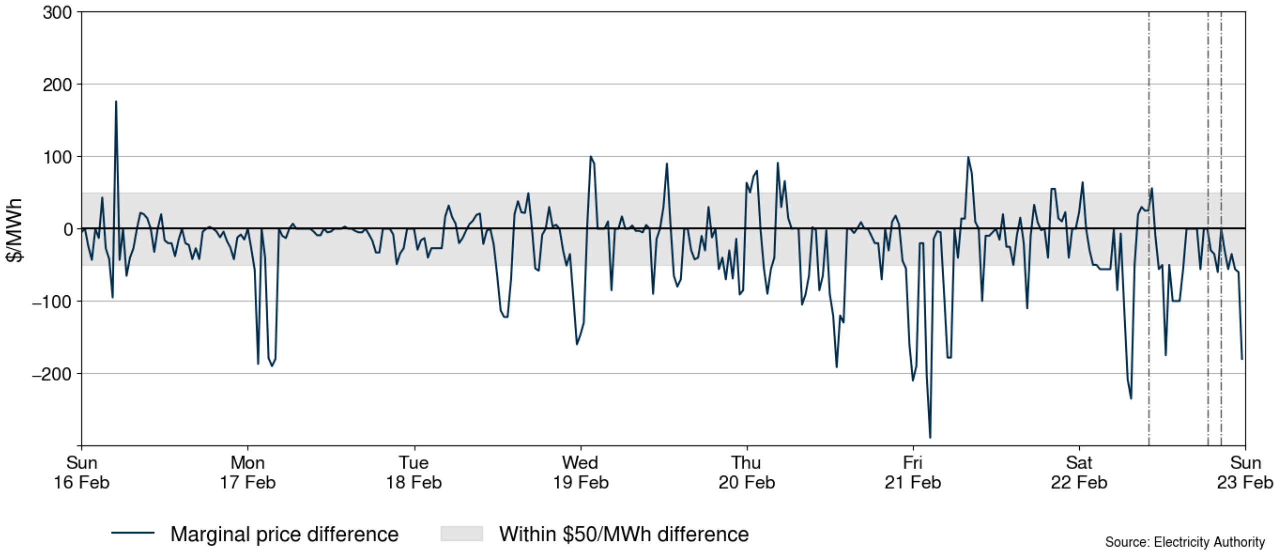
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[4]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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. There were many marginal price differences this week that were above +$50/MWh or below -$50/MWh. The large negative marginal price differences corresponded to demand being lower than forecast or wind being higher than forecast, leading prices to be lower than if the actual forecast demand has occurred.

7.5. Most large positive differences corresponded to wind being lower than forecast.

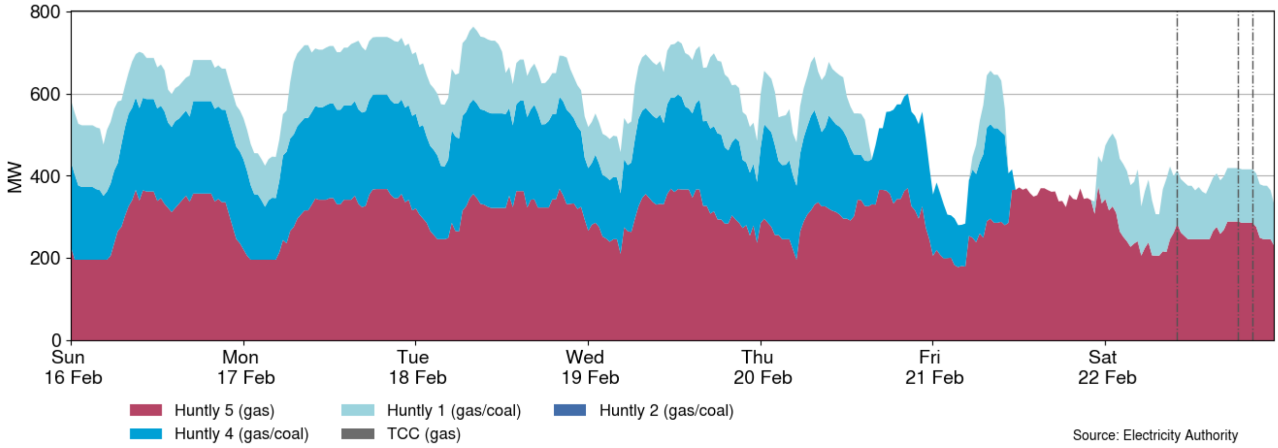
[4] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 16-22 February



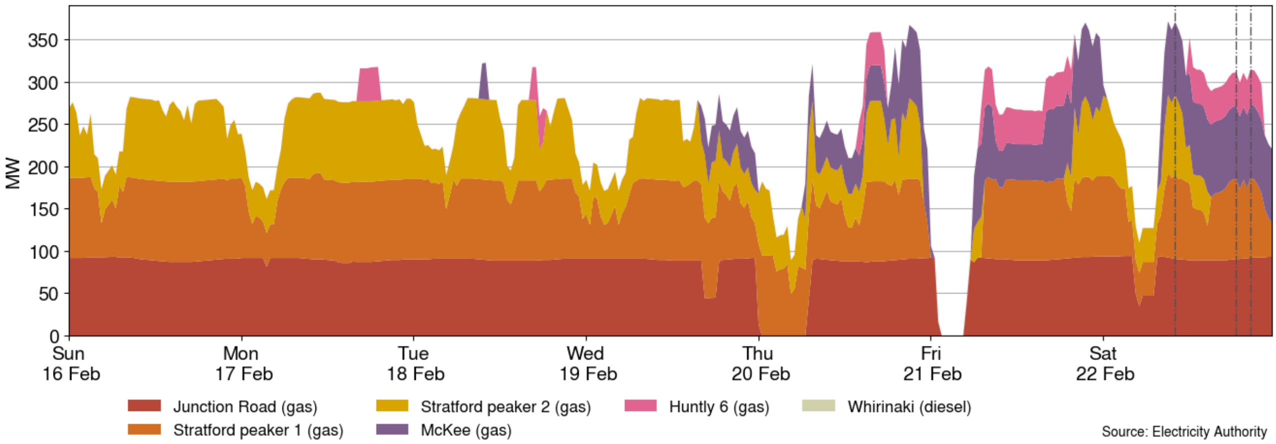
7.6. Figure 12 shows the generation of thermal baseload between 16-22 February. Huntly 5 generated baseload again this week. Huntly 4 did the same until Friday. Huntly 1 generated every day. Several unplanned or short notice partial outages decreased Huntly generation from Thursday.

Figure 12: Thermal baseload generation, 16-22 February



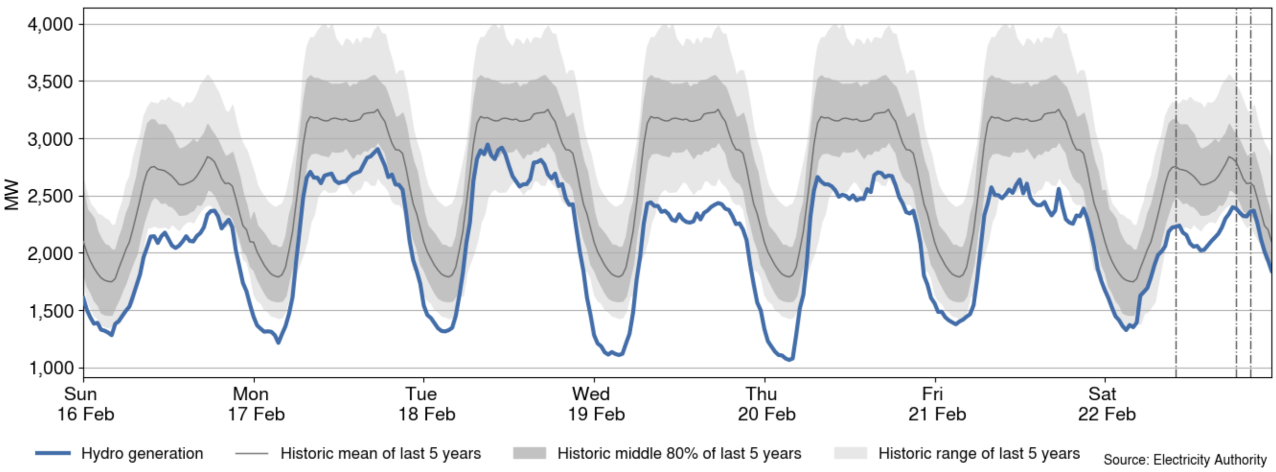
7.7. Figure 13 shows the generation of thermal peaker plants between 16-22 February. Junction Road and both Stratford Peakers generated every day. Huntly 6 and McKee generated for short times at the beginning of the week and ramped up during the HVDC pole outages on Friday and Saturday when Huntly 4 may have been off due to an unplanned Huntly station outage.

Figure 13: Thermal peaker generation, 16-22 February



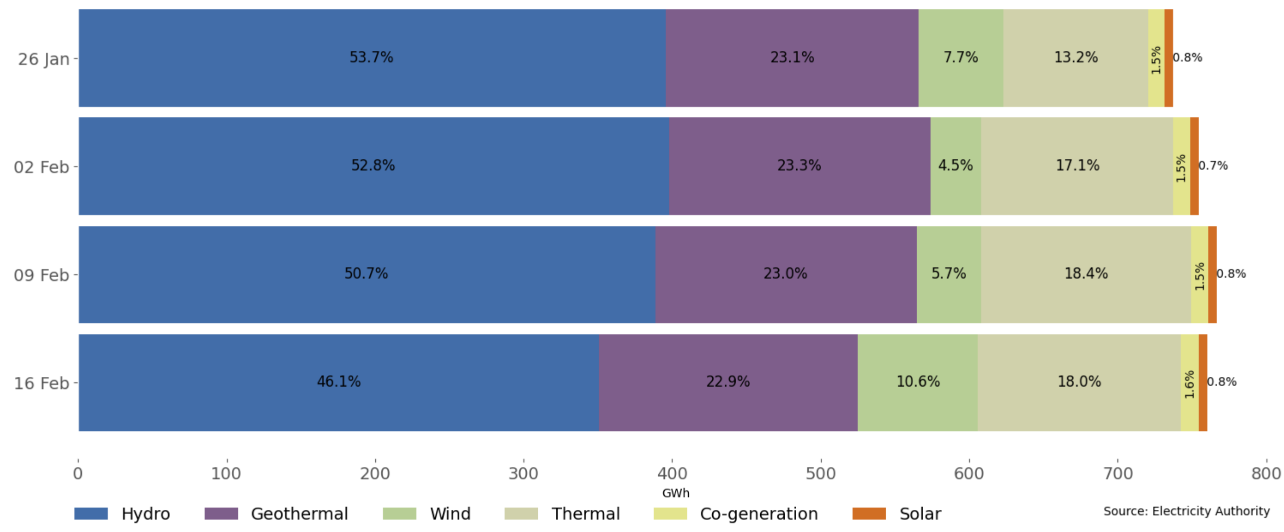
7.8. Figure 14 shows hydro generation between 16-22 February. Hydro generation was mostly below the historic 10th percentile this week, getting especially low on Monday, Wednesday and Saturday.

Figure 14: Hydro generation, 16-22 February



7.9. As a percentage of total generation, between 16-22 February, total weekly hydro generation was 46.1%, geothermal 22.9%, wind 10.6%, thermal 18%, co-generation 1.6%, and solar (grid connected) 0.8%, as shown in Figure 15. Hydro generation substantially decreased this week but an increase in wind generation kept the total renewable generation roughly the same.

Figure 15: Total generation by type as a percentage each week, between 26 January and 22 February



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 16-22 February ranged between ~1,856MW and ~2,678MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC is on outage until 21 March (although it does not typically generate in summer regardless).

(b) Huntly station was on unplanned partial outage 21 February and 22 February.

(c) Huntly 2 is on outage until 28 February.

(d) Ōhau A was on outage 22 February.

(e) Huntly 1 was on an unplanned partial outage 18 February and a short notice partial outage 20 February.

(f) Manapōuri unit 4 is on outage until 18 September.

(g) Manapōuri unit 3 was on outage 18-20 February.

(h) Manapōuri unit 5 is on outage until 14 March.

(i) Clyde unit 1 is on outage until 25 June.

(j) Clyde unit 4 was on outage 18-19 February.

(k) Stratford Peaker 2 was on unplanned outage 21 February.

(l) Huntly 4 was on unplanned outage on 20 February.

Figure 16: Total MW loss from generation outages, 16-22 February

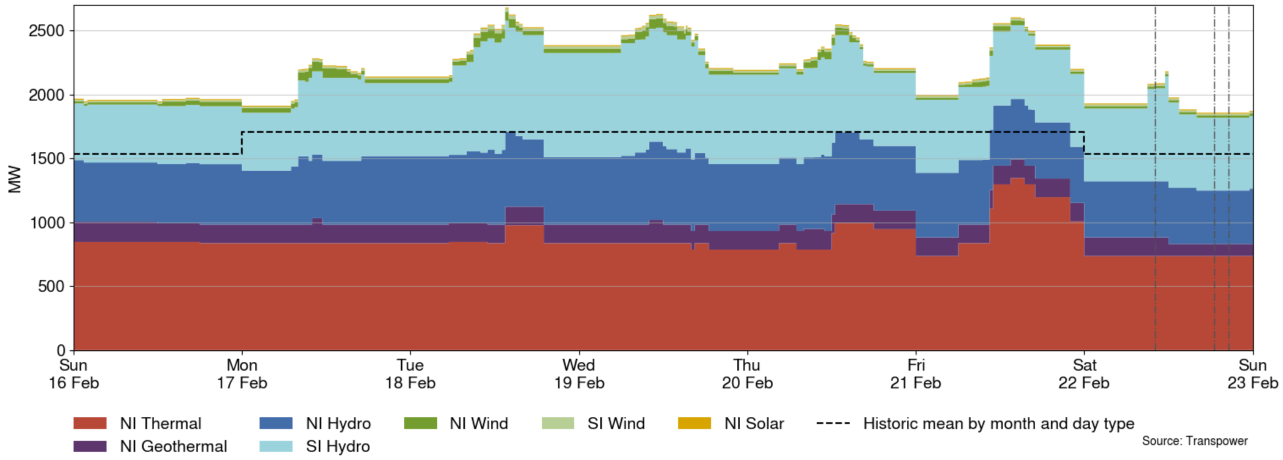
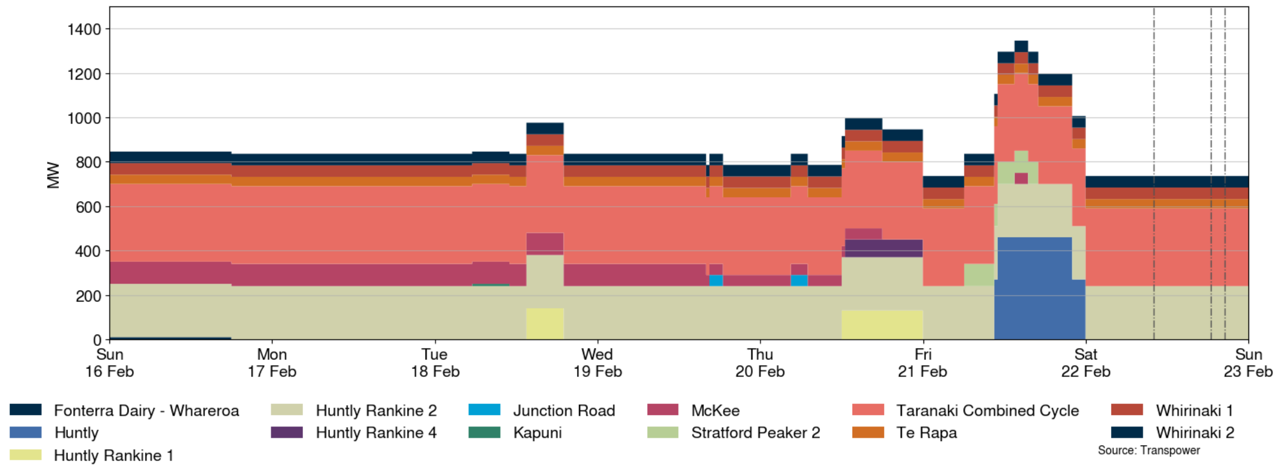


Figure 17: Total MW loss from thermal outages, 16-22 February

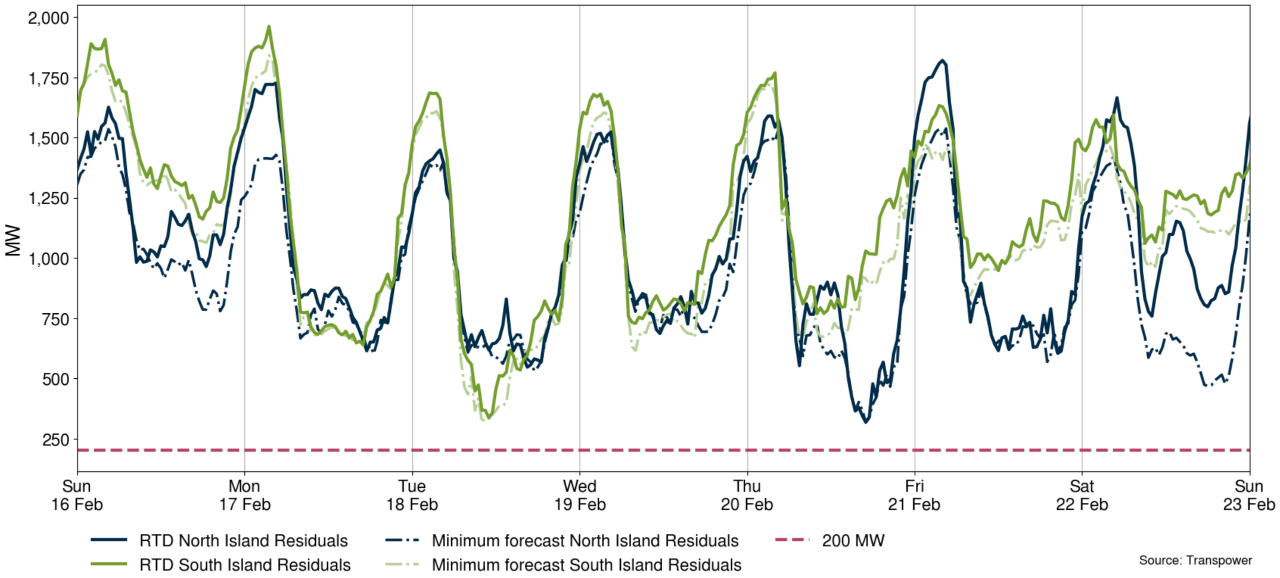


9. Generation balance residuals

9.1. Figure 18 shows the North Island and South Island generation balance residuals between 16-22 February. 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. The minimum North Island residual this week was ~317MW at 5pm on Thursday. This was during the Pole 3 outage.

Figure 18: North Island and South Island generation balance residuals, 16-22 February



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 continued to decrease and ended the week 70% nominally full and ~86% of the historical average for this time of the year.

10.3. Lake Pūkaki has decreased and is between its historical mean and 10th percentile.

10.4. Lake Takapō has remained roughly the same and is between its historical mean and 10th percentile.

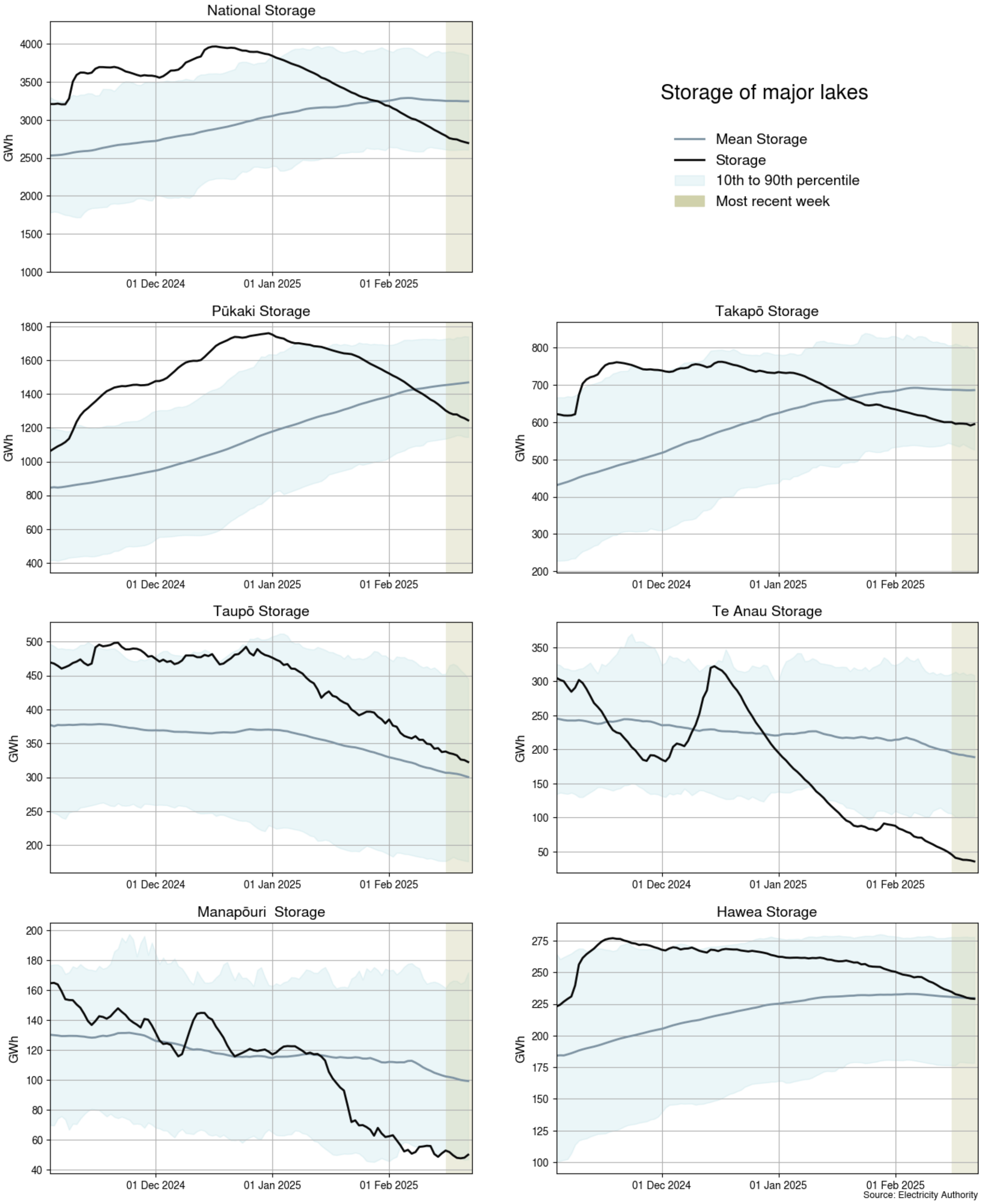
10.5. Lake Taupō decreased and is still between its historical mean and 90th percentile.

10.6. Lake Te Anau has decreased and is still below its historical 10th percentile.

10.7. Lake Manapōuri has fluctuated around its historic 10th percentile.

10.8. Lakes Hawea decreased to below its historical mean.

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 February. The SRMC for gas fuelled generation has increased compared to last month, the SRMC for coal remains similar and the SRMC for diesel fuelled generation has decreased.

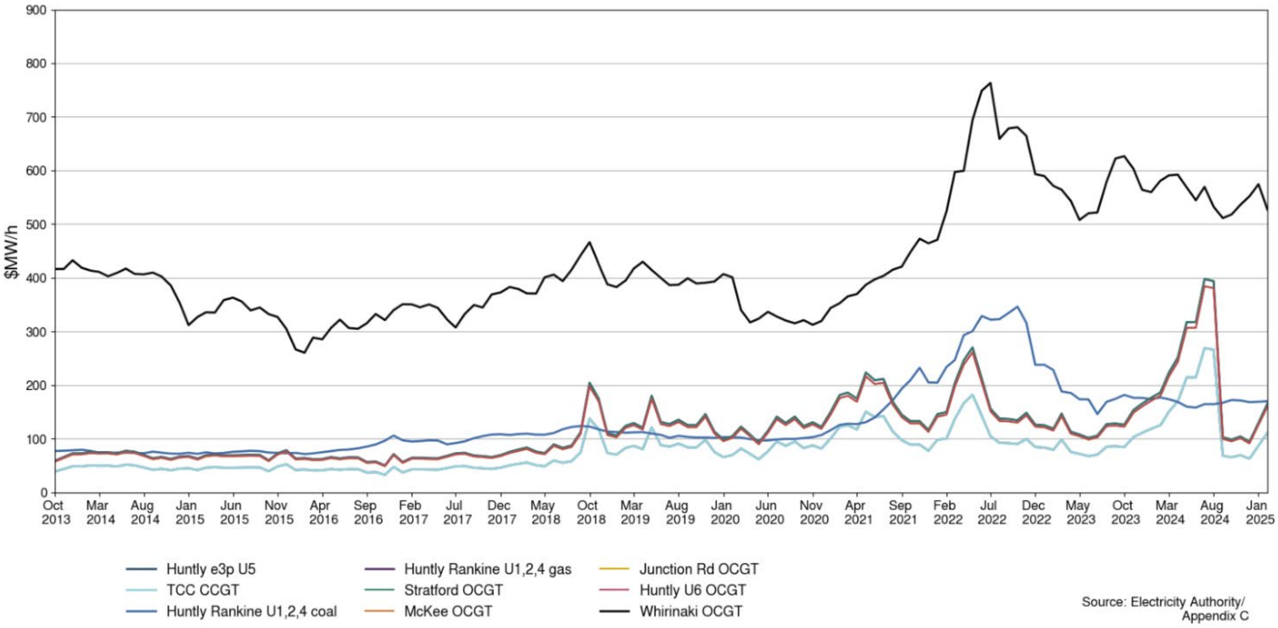
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$170/MWh, with the cost of running the Rankines on gas slightly lower at ~$165/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $111/MWh and $165/MWh.

11.6. The SRMC of Whirinaki is ~$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.

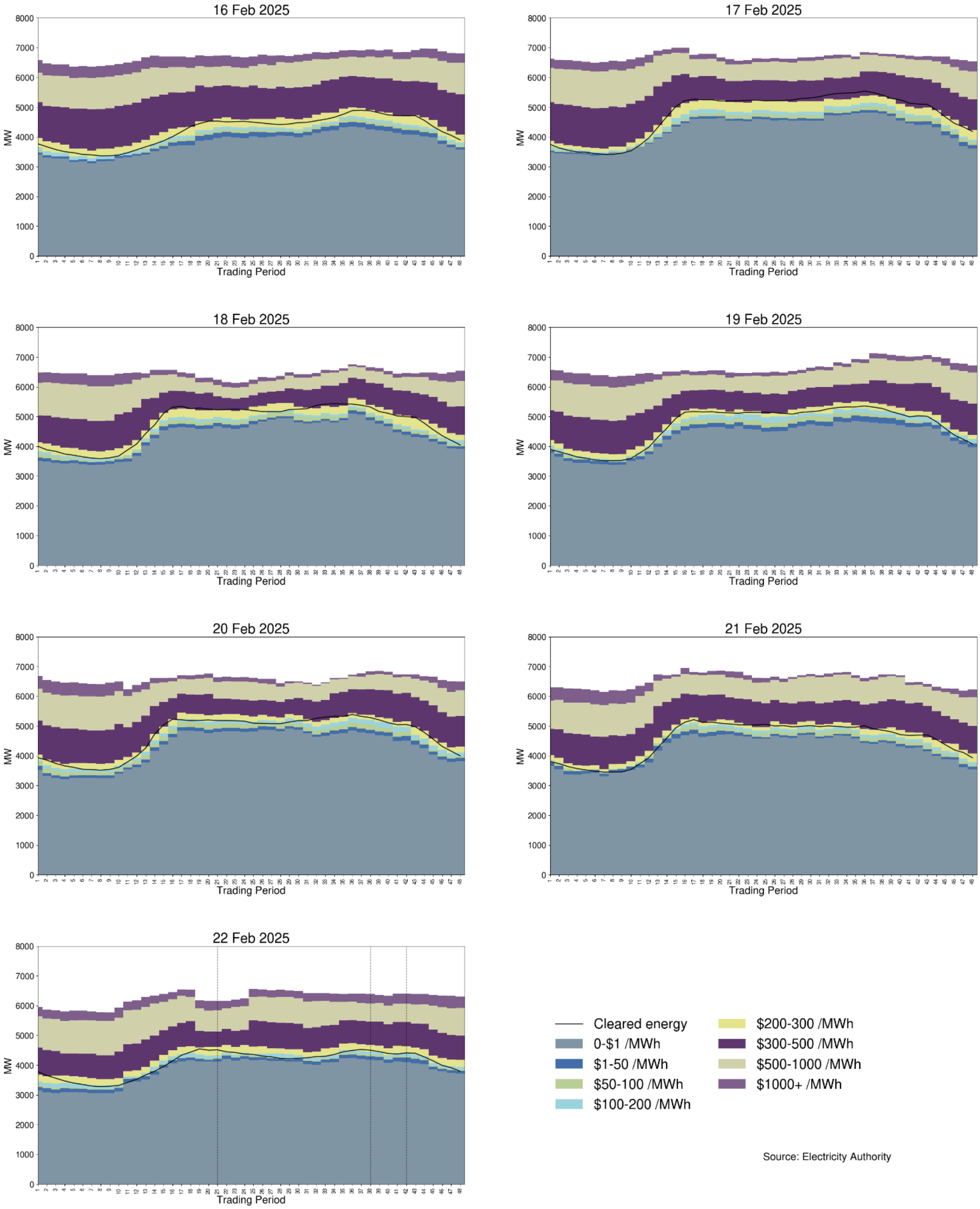
12.2. Most offers were clearing in the $200-300/MWh band this week.

12.3. On Saturday there was a reduction in offers due to:

(a) Ōhau A outage 9am to 12pm.

(b) There appears to be some capacity unoffered at Takapō – the monitoring team will be contacting Genesis regarding this.

Figure 21: Daily offer stacks



Source: Electricity Authority

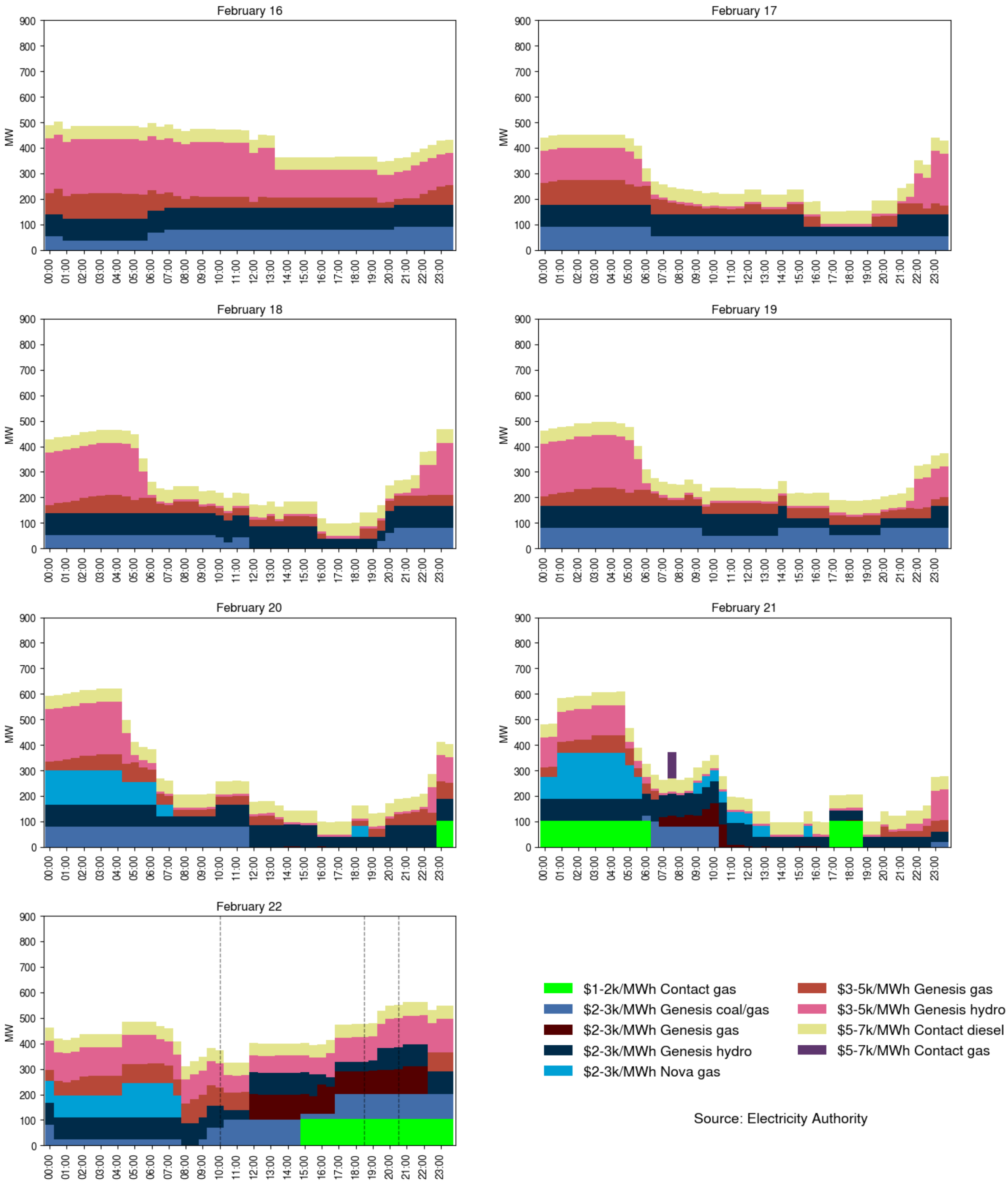
12.4. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

12.5. 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, wind 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 331MW per trading period was priced above $1,000/MWh this week, which is roughly 6.14% of the total energy available. This is a ~0.8% increase from last week.

12.7. Contact Energy has priced some of its Stratford Peaker gas generation very high from Thursday. We will be analyzing this offer further.

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. Some offers at Takapō and the Stratford peakers will be analyzed further.

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
26/01/2025- 1/02/2025	Several	Further analysis	Genesis	Takapō	Hydro offers
21/02/2025	16	Further analysis	Contact	Stratford	Thermal offer
22/02/2025	18-40	Further analysis	Genesis	Takapō	Hydro offers