9 March 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 6 to 12 March

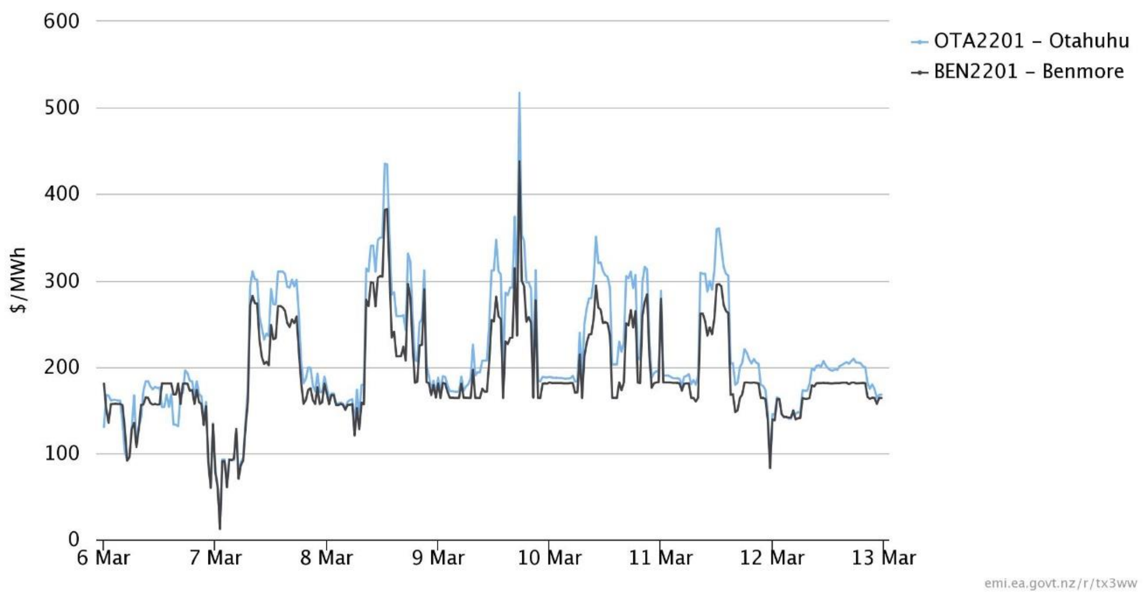
1.1. Prices this week appear consistent with supply and demand conditions. We have requested further regarding high priced offers of thermal peakers.

2. Prices

Energy prices

2.1. The average spot price this week was $200MWh[1], up 15% from last week. The highest price this week occurred at TP36 on 9 March reaching $517/MWh at Otahuhu.

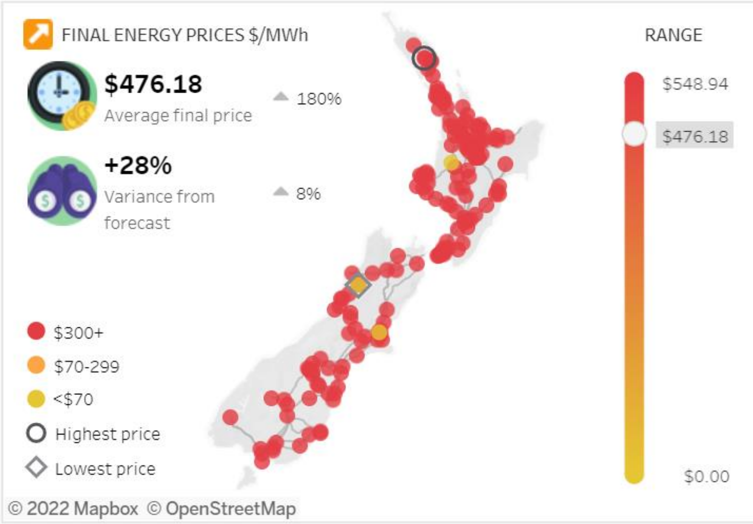
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.2. The simple average price for TP36 on 9 March was $476/MWh, with consistently high prices throughout New Zealand. As shown below, this price occurred when demand was high and wind generation low.

[1] The simple average of the final price across all nodes, as shown in the trading conduct summary dashboard

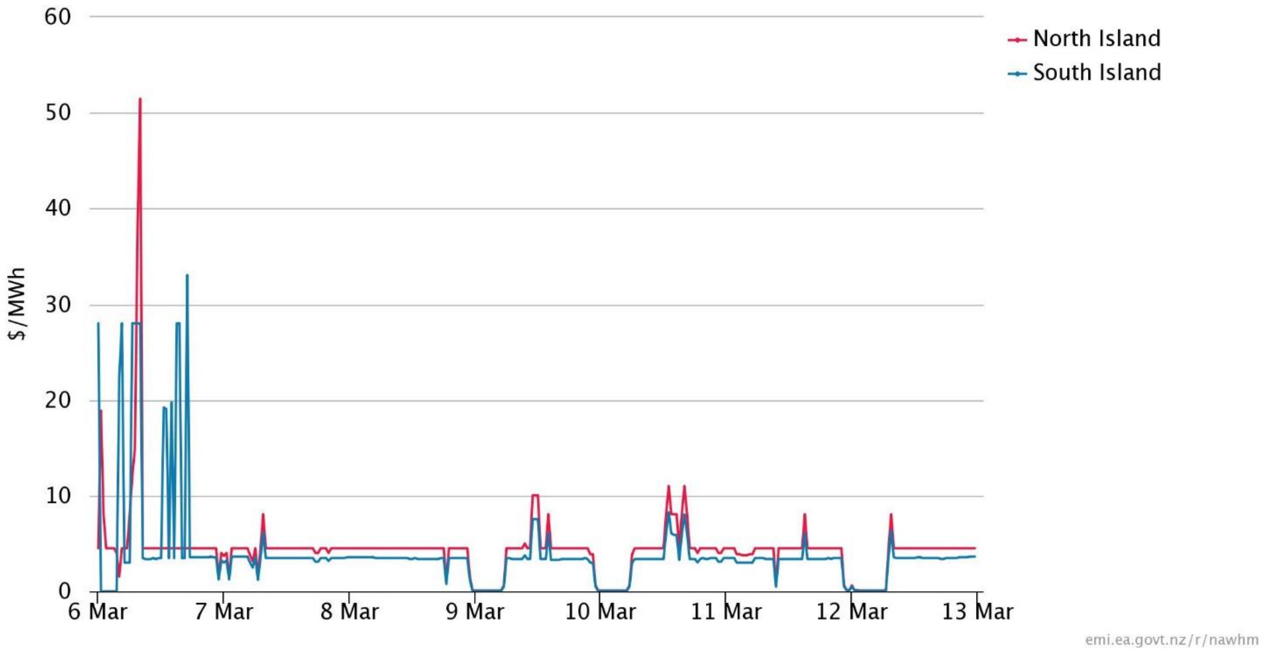
Figure 2: Nodal and average spot prices for TP36 on 9 March



Reserve Prices

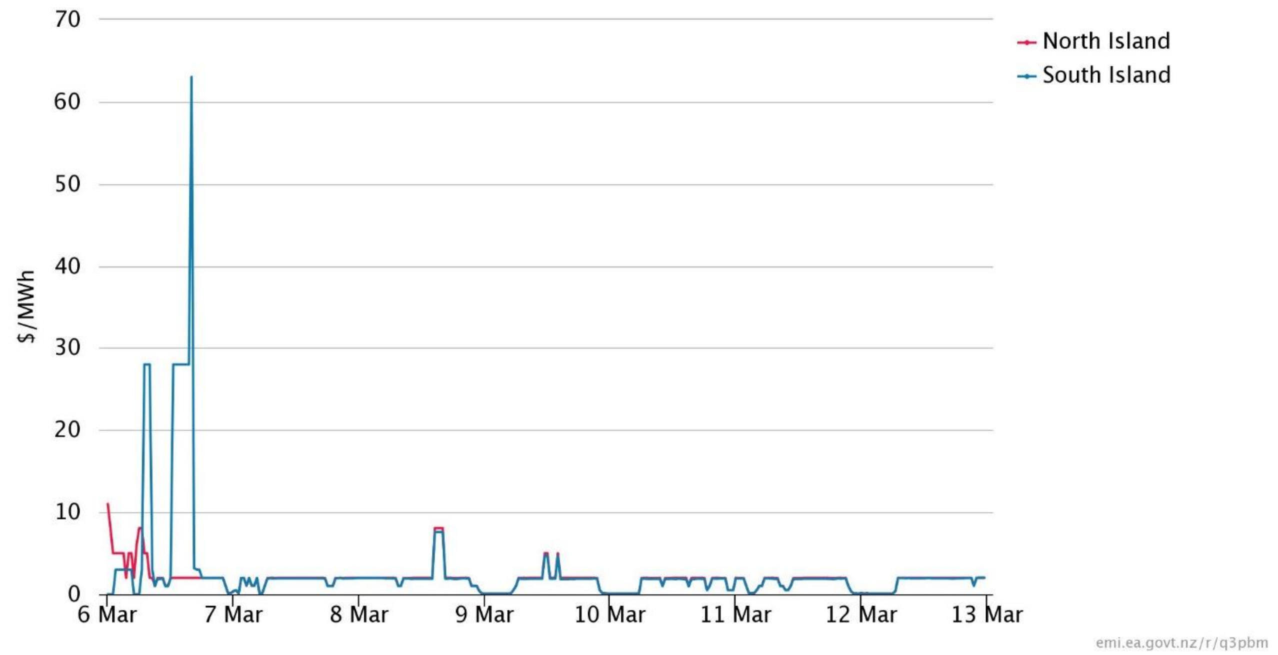
2.3. Fast instantaneous reserves (FIR) prices were usually below $10/MWh (see Figure 3). The exception is on 6 March during the HVDC outage when prices reached up to $52/MWh.

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were usually below $10/MWh (see Figure 4). The exception is on 6 March during the HVDC outage when prices reached up to $63/MWh.

Figure 4: SIR prices by trading period and Island

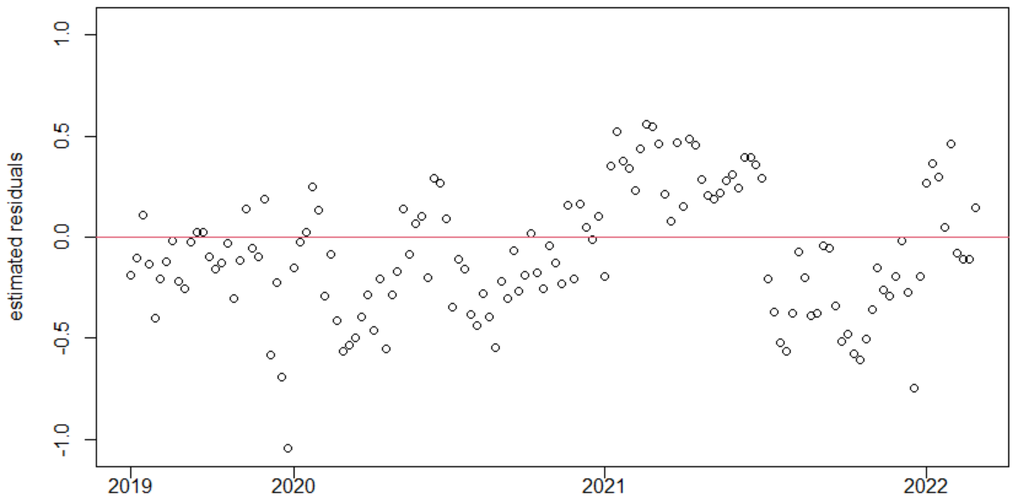


3. Residuals from regression models

3.1. The Authority's monitoring team has developed two regression models of the spot price. The residuals show how close the predicted prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in Appendix A.

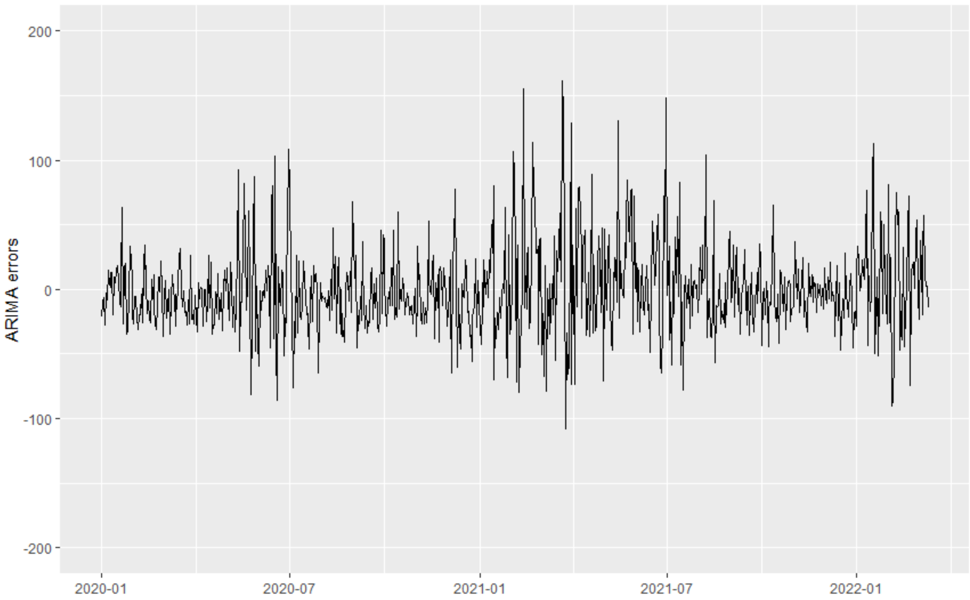
3.2. Figure 5 shows the residuals from the weekly model. During February the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 28 February 2022



3.3. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. The residuals for this week were within the normal range.

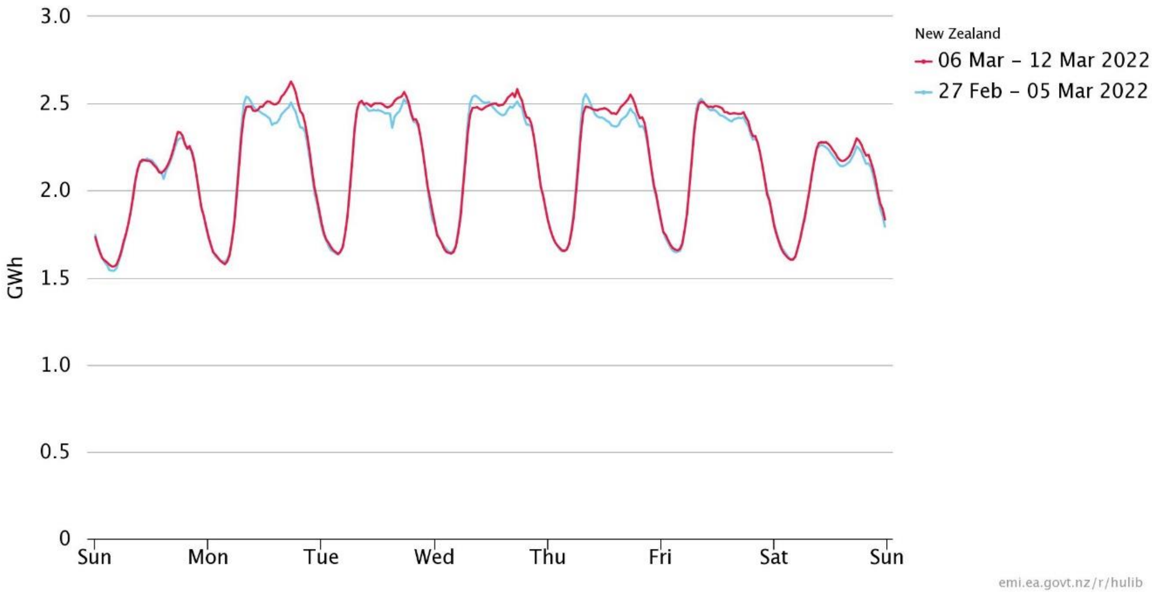
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 5 March 2022



4. Demand Conditions

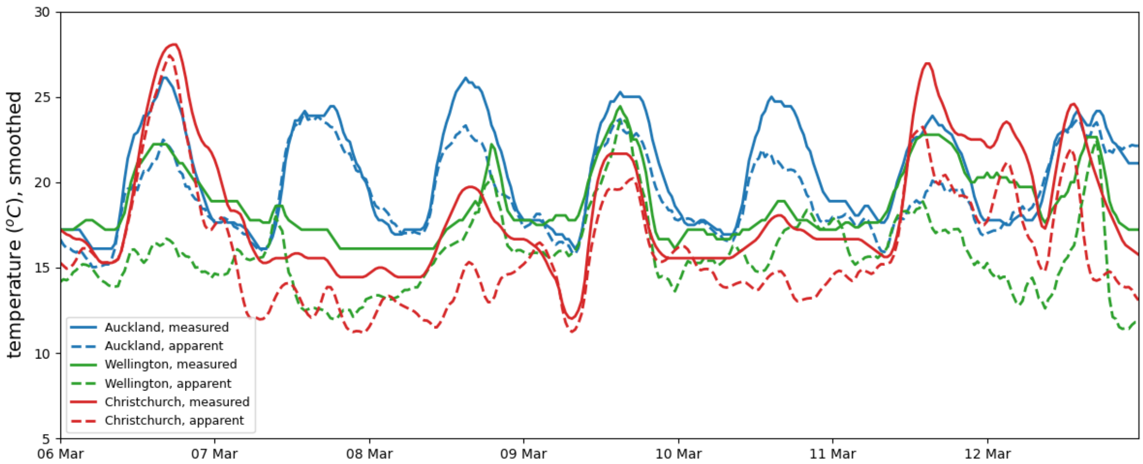
4.1. National demand was 1% higher than the previous week (see Figure 7). Demand was highest on the evening of 7 March when weather was cooler in Wellington and Christchurch (see Figure 8). On 9 March there was a drop in demand at TP35 followed by a sudden increase in TP36, when the highest price occurred. This appears to have been caused by demand at Tiwai dropping briefly in TP35 by 42MW, before returning to normal at TP36, coinciding with peak evening demand. The sudden increase in demand between these two trading periods likely contributed to the high price.

Figure 7: National demand by trading period compared to the previous week



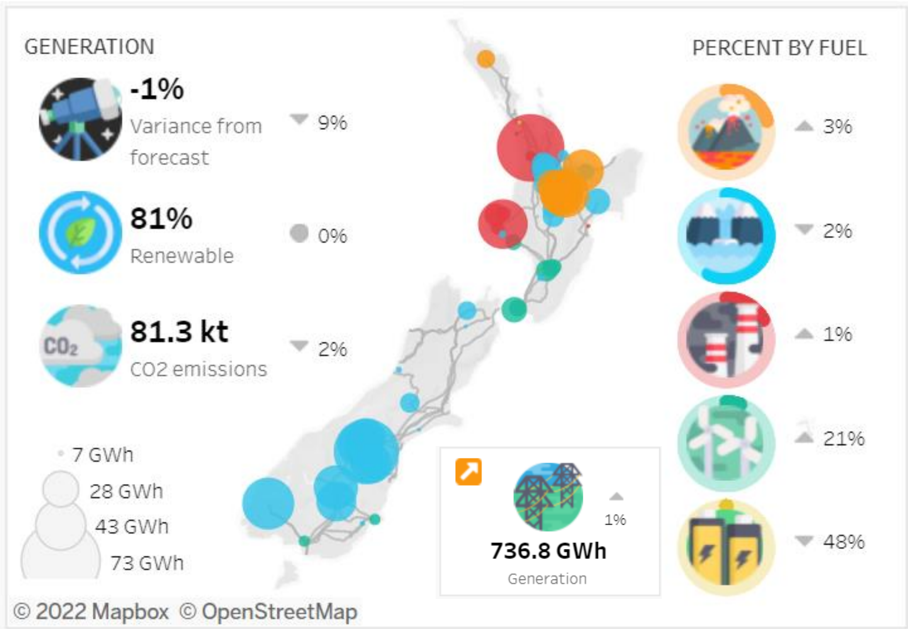
4.2. Figure 8 shows hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures have been variable in Christchurch and Wellington, with high temperatures on 6 and 11 March, and cooler temperatures on 7 and 10 March.

Figure 8: Hourly temperature data (actual and apparent) and humidity data at main population centres



5. Supply Conditions

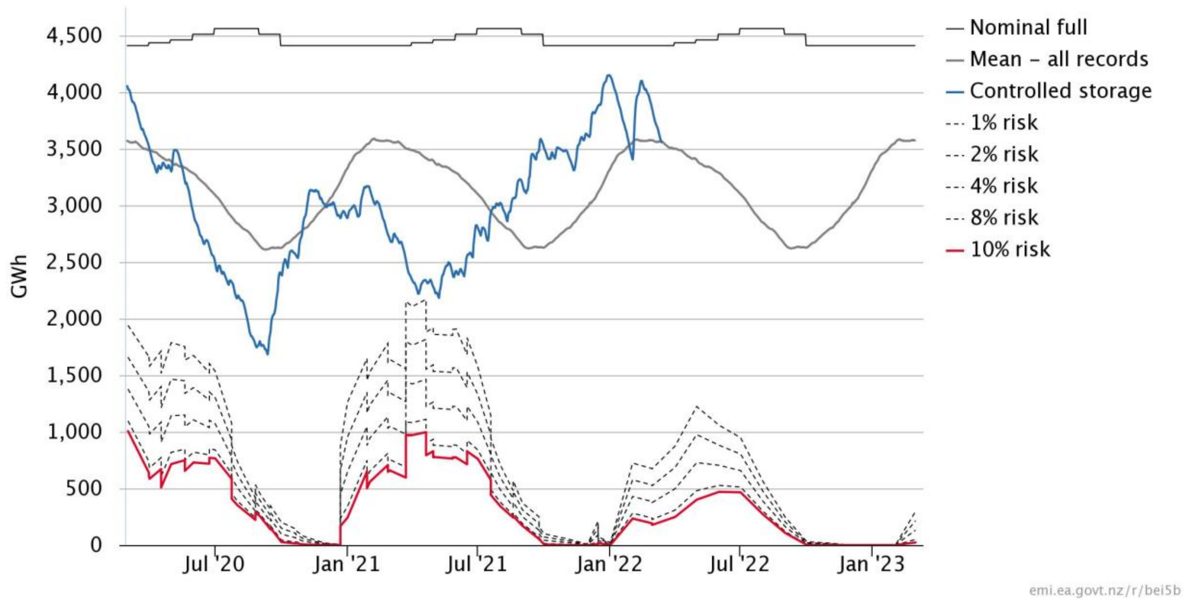
Figure 9: Generation in the last week compared to previous week



Hydro conditions

5.1. National hydro storage decreased by about 150GWh over the week, shown in Figure 10, to 74% of nominal full storage. Storage is close to the historical means for this time of year. Hydro generation contributed 57% of total generation this week, down 2% from last week. Drought conditions have caused low inflows for Clyde River and Lake Manapouri, which is currently around its low operating margins. This has curtailed generation in the lower South Island.

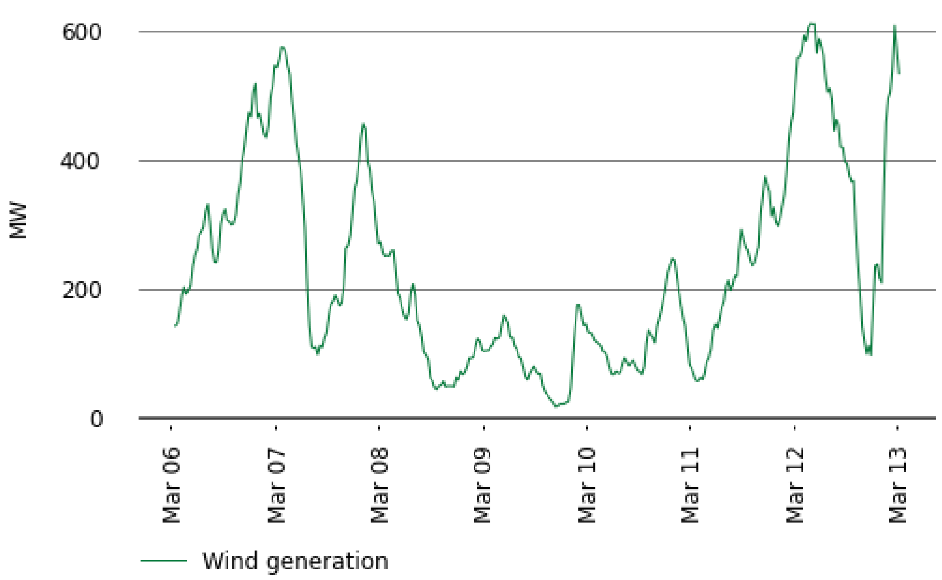
Figure 10: Electricity risk curves and hydro supply



Wind conditions

5.2. Total wind generation was 39GWh, up 21% from last week, and contributed about 5% of total generation. Wind generation was variable this week, with sharp increases and decreases in wind generation. This contributed to high prices as sharp drops in wind and low wind generation require more expensive generation to be dispatched.

Figure 11: Wind generation by trading period

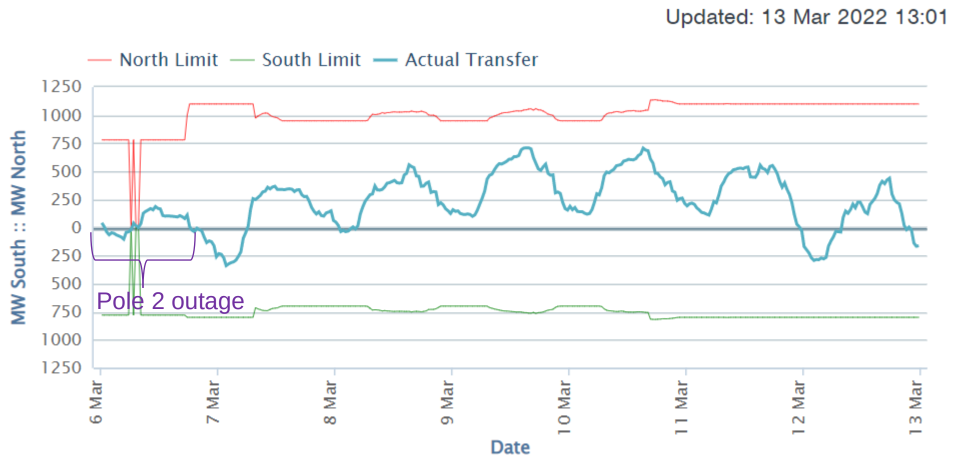


Significant outages

HVDC outage

5.3. There was a planned outage of the HVDC this weekend. Pole 2 was on outage from 5 March 5:30 to 6 March 17:30. As northward transfer was low, impact to the market was minimal. Figure 12 shows that the HVDC transfer each day, as well as the transfer limits and outages. When only one pole is in operation it has a minimum capacity required to operate so there were a few trading periods on 6 March when transfer capacity was 0MW as flows changed from Southward to Northward. This only had a small impact on energy prices but did cause higher reserve prices as this prevented reserve sharing.

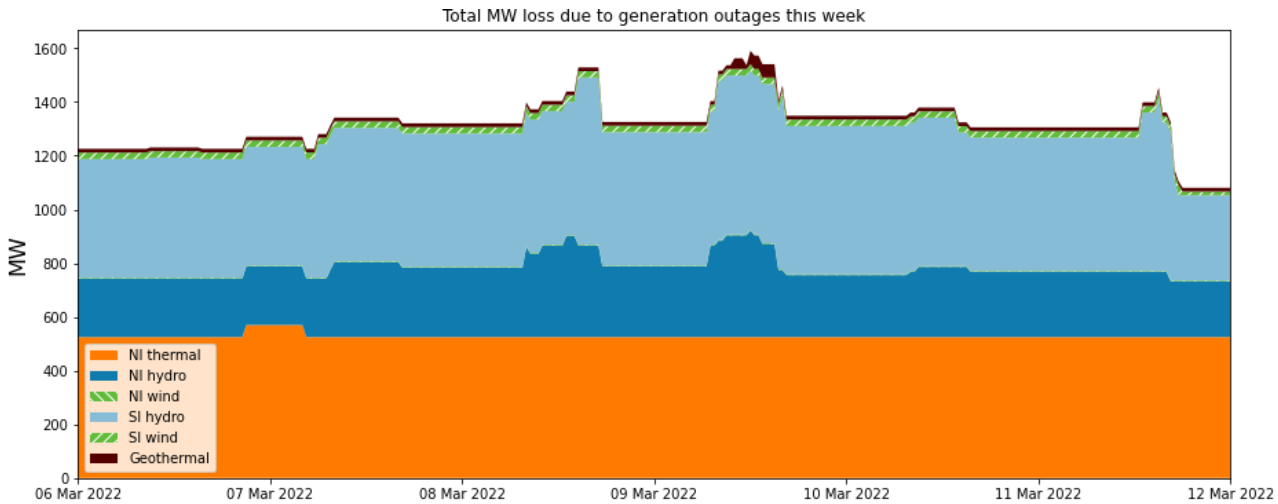
Figure 12: HVDC transfer, HVDC limits and HVDC outage



Generation outages

5.4. The amount of generation on outage started around 1200MW, with the highest amount of 1600MW occurring on 9 March, when there were several small outages. Most of these small outages ended prior to the evening peak. Outages at Manapouri and Ohau ended on 11 March, however generation may not increase at Manapouri significantly due to low lake levels.

Figure 13: Total MW loss due to generation outages



5.5. These are the more significant ongoing outages[2]:

(a) Clyde, 116MW (15 Feb 2021 – 1 July 2022)

(b) Berwick, 80MW (8 November 2021– 16 March 2022)

(c) Stratford peaker 1, 100MW, (31 October 2021 – 31 May 2022)

(d) Stratford peaker 2, 100MW (24 February – 1 September)

(e) Manapouri, 125MW (23 January – 25 March)

(f) Manapouri, 125MW (21 February – 11 March)

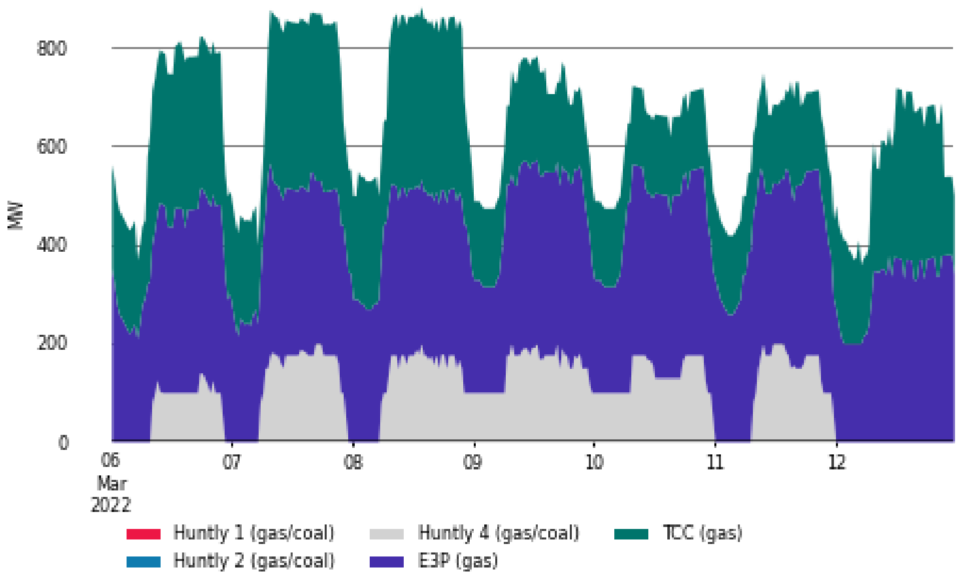
(g) Huntly, Rankine 2, 240MW (1 March – 18 March)

(h) McKee, 50MW, 15 February – 19 March

Thermal conditions

5.6. Overall, thermal generation contributed 17% of total generation this week, similar to last week. The E3P and TCC were both running continuously as baseload generation. Huntly 4 also ran for most of the week.

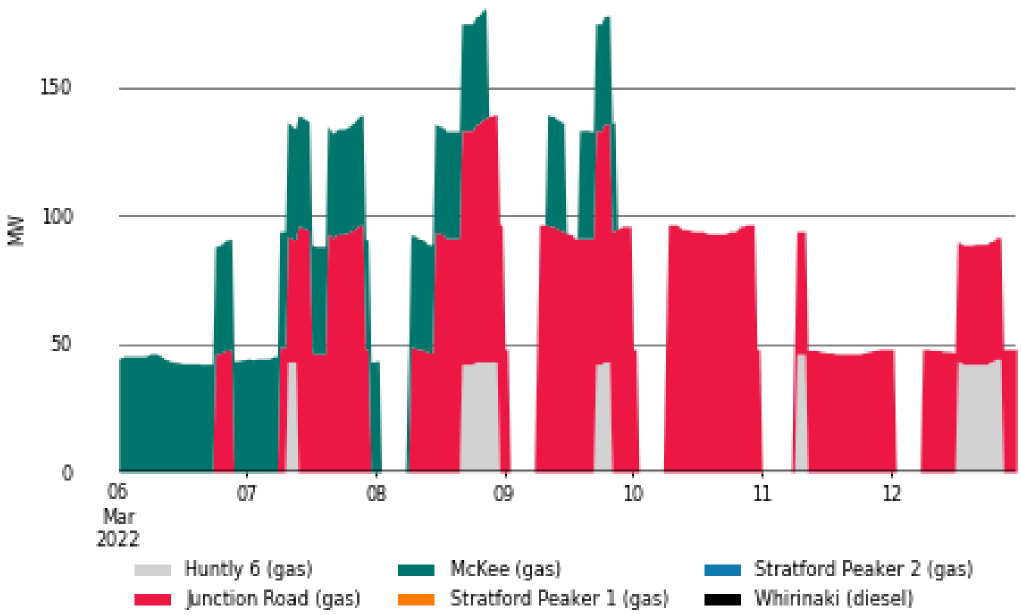
Figure 14: Generation from baseload thermal by trading period



[2] Detailed outage information is available from https://pocp.redspider.co.nz/

5.7. Junction Road was running as a peaker for most of the week, while McKee only ran during the first four days. Huntly 6 was also dispatched for short periods several times this week.

Figure 15: Generation from thermal peakers by trading period



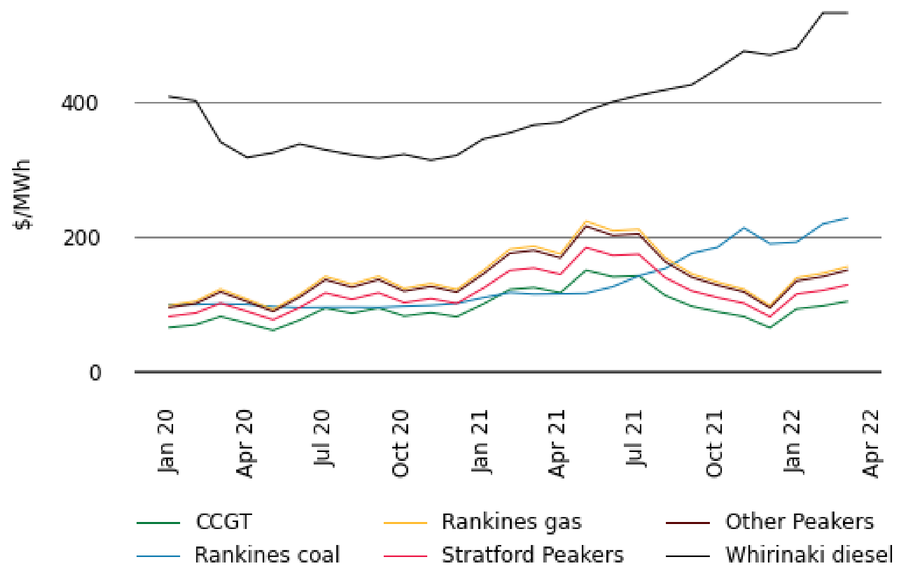
6. Price versus estimated costs

6.1. 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).

Thermal Fuels

6.2. The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices, and the average heat rates for each thermal unit. Figure 16 shows an estimate of thermal SRMCs as a monthly average. The thermal SRMC of gas increased in January and February, likely due to the increase in gas consumption. The SRMC of coal and diesel both increased due to global supply and demand conditions and remain high. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal. The carbon price has significantly increased in the last year, reaching a high of $85/tonne though has recently dropped to $72/tonne.

Figure 16: Estimated monthly SRMC for thermal fuels



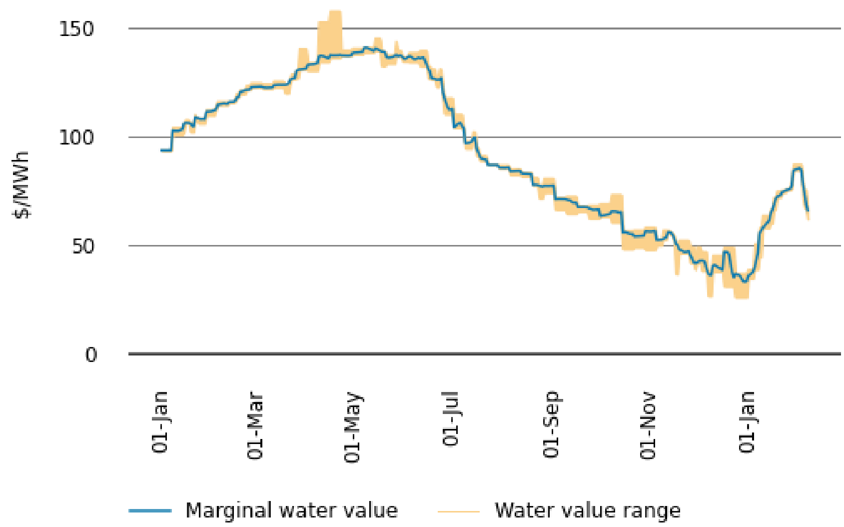
JADE Water values

6.3. The JADE[3] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 17 shows the national water values[4] to 20 February 2022 using values obtained from JADE. The outputs from JADE closest to actual storage levels are shown as the yellow water value range. These values are used to estimate marginal water value at the actual storage level, indicated by the blue line[5].

6.4. The marginal water value declined from June to December as hydro storage levels increased and gas costs decreased. In January, the water values increased as hydro storage decreased and gas costs increased. Between February 1 and 13 hydro storage increased which caused a steep decline in the water value, shown in figure 17. Since 20 February hydro storage has declined so the water value has likely increased

[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market. (More details in Appendix B)
[4] The national water values are estimated assuming all hydro storage reservoirs are equally full.
[5] See Appendix B, 3 for more details

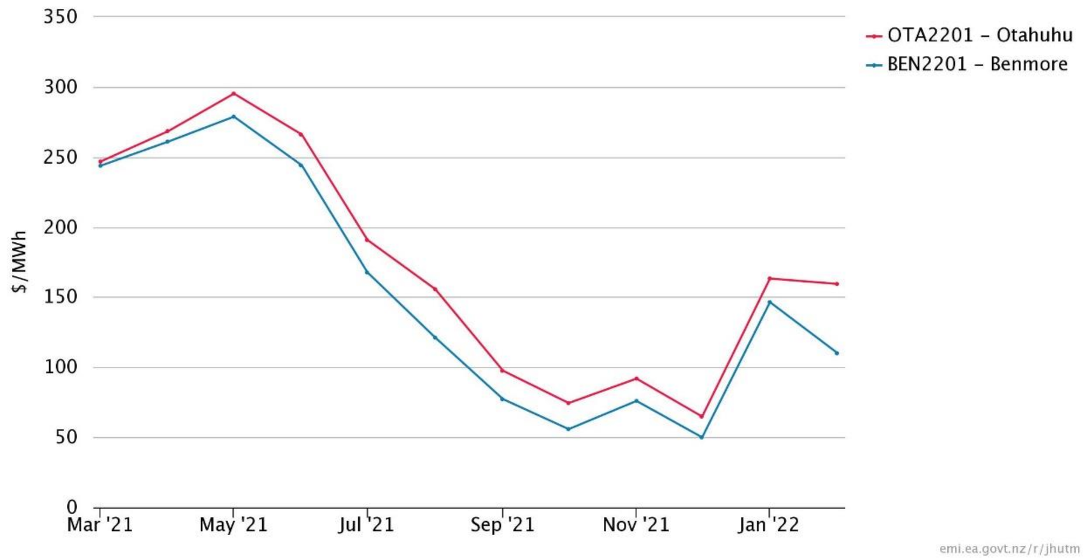
Figure 17: JADE water values for January 2021 to February 2022



Monthly prices

6.5. Figure 18 shows the average price each month at Otahuhu and Benmore for 2021. It shows that prices have declined since June, similar to the trend for gas costs and water values. The average price in January was higher as hydro storage declined, and thermal generation increased. In February the average price was lower, especially at Benmore, due to high inflows early in the month as well as the HVDC outage which caused low prices in the South Island, while North Island prices were closer to the price of thermal fuels.

Figure 18: Average monthly prices at Otahuhu and Benmore last 12 months



7. Offer Behaviour

Daily Offer Stacks

7.1. Figure 19 shows this week's daily offer stacks, adjusted to take into account wind generation, transmission constraints, reserves and frequency keeping.[6] The black line shows the cleared energy, indicating the range of the average final price. Note that the HVDC outage may result in the black line not indicating actual prices observed on 6 March.

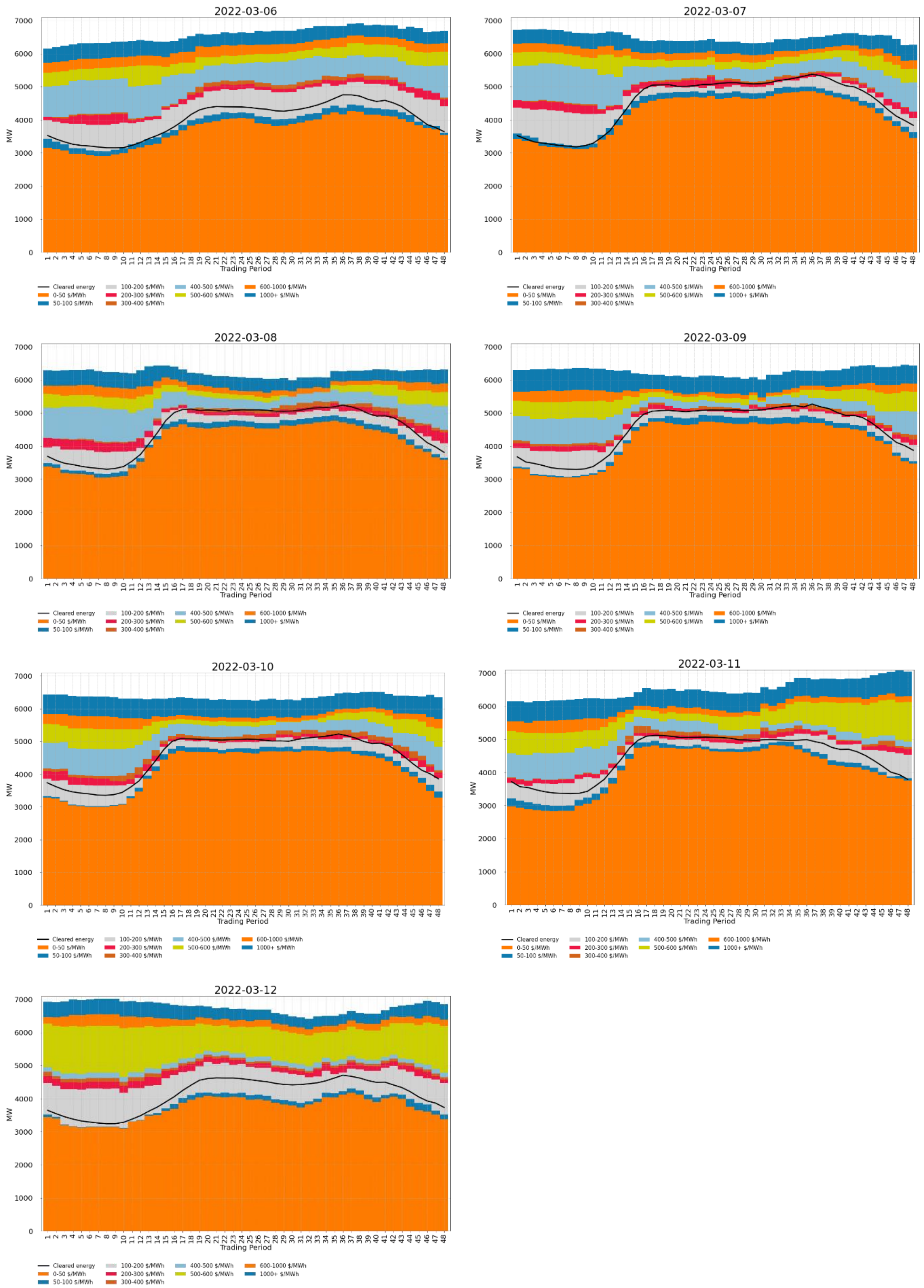
7.2. Both the per cent of offers over $350/MWh and the quantity weighted offer price increased this week, as hydro storage fell. This has resulted in less generation offered between $200 and $400/MWh and more offered between $400 and $600/MWh. This has resulted in higher prices when wind generation is low, or demand is higher than expected.

7.3. High wind generation caused noticeable higher generation offers later in day on 6 and 11 March compared to most other days with total generation offered low most of 9 March. Several generation outages also ended on 11 March, though the generation that returned outage at Manapouri has been offered at a high price due to low lake levels.

7.4. There has been an increase the high-priced offers for some thermal peakers. This may be due to the tight gas market and the start up of TCC, which is more efficient than gas peakers, but enquiries are ongoing to ensure offers reflect efficient market outcomes.

[6] The offer stacks show all offers bid into the market (where wind offers are truncated at their actual generation and excluding generation capacity cleared for reserves) in price bands and plots the cleared quantity against these.

Figure 19: Daily offer stack



Offers by trading period

7.5. The offer stacks of TP36 on 9 March are shown on Figure 20 and TP 35 on Figure 21 along with the generation weighted average price (GWAP) and cleared generation.

7.6. The offer curves of the two trading periods were similar and were both steep between $200 and $400/MWh, with a significant amount of generation offered between $500 and $600/MWh. There was about 100MW difference in cleared generation between the two trading periods, both because peak load occurred at TP36 as well as a drop in load from Tiwai in TP35. Actual load at TP35 was lower than forecasted while load at TP 36 was higher. As the offer stack was steep between these two different amounts of cleared generation that different in price was large.

Figure 20: Offer Stack for trading period 36 on 9 March

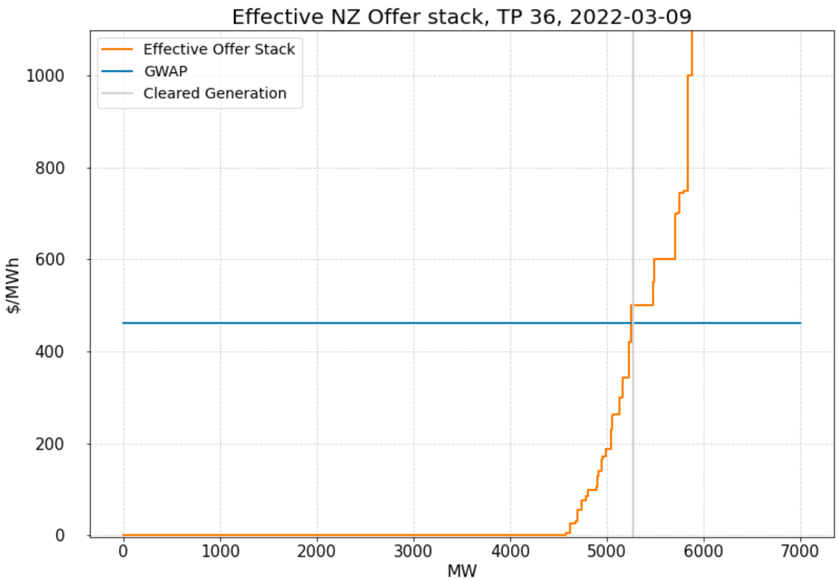
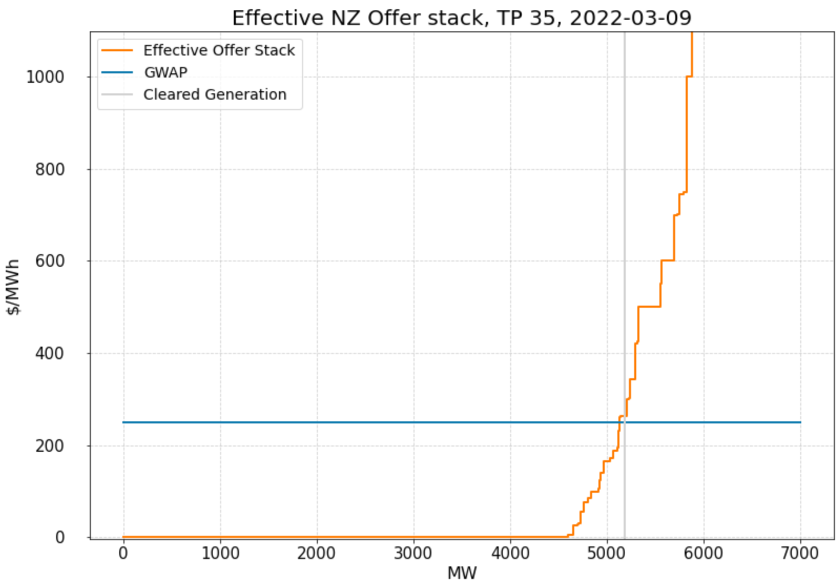


Figure 21: Offer Stack for trading period 36 on 9 March



8. Ongoing Work in Trading Conduct

8.1. The Authority has requested further information about recent high-priced offers of thermal peakers.

8.2. Further analysis of TP16 and 18 on 3 March has not found any breaches of trading conduct and found generation offers were consistent with the surrounding trading periods and pre-dispatch prices. High prices appear to have been driven by discrepancies between pre-dispatch forecasts and actual conditions.

8.3. After reviewing information received from Genesis regarding offers from Tekapo B while Lake Tekapo was spilling, this case has been passed to compliance to assess if the offers were compliant with trading conduct rules.

8.4. The Authority's compliance team has obtained information regarding withdrawn reserve offers and high energy prices. Further clarification and analysis is under way to consider compliance with the Code.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
10/03-13/03	All	Further analysis	Offer prices high for some thermal peakers, further information requested
03/03-05/03	4-10	Further analysis	Branch constraint, high prices in lower South Island
04/03	16, 18	Resolved	High prices and variance appear to be due to differences between pre-dispatch forecasts and actual conditions
25/02	23-27	Further analysis	Whirinaki dispatched while other thermal peakers had capacity – further information requested
19/02-24/02		Compliance enquiries in progress	High priced offers at Tekapo-passed to compliance
19/02-21/02	Several	Further Analysis	High South Island reserve prices
08/02-12/02	Several	Further Analysis	High inflows but continued high prices
30/06/21-20/08/21	Several	Compliance enquiries in progress	High energy prices in shoulder periods
30/06/21-21/08/21	Several	Compliance enquiries in progress	Withdrawn reserve offers

Appendix A Regression Analysis

1. The Authority's monitoring team has developed two regression price models. The purpose of these models is to understand the drivers of the wholesale spot price and if outcomes are indicative of effective competition.

Weekly Model

2. The weekly model is an updated version of the model published in https://www.ea.govt.nz/assets/dms-assets/27/27142Quarterly-Review-July-2020.pdf, Section 8, pg. 21-25

3. The regression equation is

$$\begin{aligned}\log(P_t - \theta_t) = \beta_0 &+ \beta_1(Storage_t - Seasonal.mean.storage_i)\\ &+ \beta_2(Demand_t - Ten.year.mean.demand_t) + \beta_3 Wind.generation_t\\ &+ \beta_4 \log(Gas.price_t) + \beta_5 Generation.HHI_t\\ &+ \beta_6 Ratio.of.adjusted.offer.to.generation_t + \beta_7 Dummy.gas.supply.risk_t\end{aligned}$$

where P_t is the PPI and trend adjusted weekly average spot prices; t =week 1,…,52 for each year; i = spring, summer, autumn, and winter

Daily Model

4. The daily model estimates the daily average spot price based on daily storage, demand, gas price, wind generation, the HHI for generation (as a measure of competition in generation), the ratio of offers to generation (a measure of excess capacity in the market), a dummy variable for the period since the 2018 unplanned Pohokura outage started, and the weekly carbon price (mapped to daily). The units for the raw data are as following: storage and demand are GWh, spot price is $/MWh, gas price is $/PJ, and wind generation is MW, carbon price is in New Zealand Units traded under NZ ETS, $/tonne.

5. We used the Augmented Dicky-Fuller (ADF) to test all variables to see if they are stationary. If not, we tested the first difference and then the second difference using the ADF test until the variable was stationary. The first difference of a time series is the series of changes from one period to the next. For example, if the storage is not stationary, we use $storage_t - storage_{t-1}$.

6. We fitted the data using a dynamic regression model with Autoregressive with five lags (AR(5)). Dynamic regression is a method to transform ARIMAX (Autoregressive Integrated Moving Average with covariates model) and make the coefficients of covariates interpretable.

7. Once we dropped the insignificant variables; the ratio of offers to generation, the dummy variable for 2018 and carbon price, we got the following model[7], where diff is the first difference:

$$y_t = \beta_0 - \beta_1\left(storage_t - 20.year.mean.storage_{dayofyear}\right) + \beta_2 diff(demand_t) - \beta_3\, wind.generation_t + \beta_4\, gas.price_t - \beta_5 diff(generation\ HHI_t) + \beta_6 dummy + \eta_t$$

$$\eta_t = \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t$$

8. ε_t, the residuals of ARMA errors (from AR(5)), should not significantly different from white noise. Ideally, we expect the ARIMA errors are purely random, and are not correlated with each other (show no systematic pattern). ARIMA errors equals y_t minus the estimate $\hat{y}$ with their five time lags.

[7] Updated, $diff(storage_t)$ has been replaced with $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$

Appendix B JADE water value model

1. JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[8] JADE is identical to DOASA in terms of model inputs and outputs but is written using the Julia modelling language JuMP.

2. DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[9] A version of DOASA has been used by EPOC for analysis of the New Zealand electricity market for many years, and SDDP is a well-known and widely accepted modelling tool for hydro-thermal optimisation in electricity systems. DOASA gives a consistent measure of the opportunity cost of water. The DOASA model seeks a policy of electricity generation that meets demand and minimises the expected fuel cost of thermal generation and value of lost load.

3. The JADE model outputs the marginal water value for a range of storage levels. The marginal water value, y, at the actual storage level, x, is estimated using the outputs closest to actual storage level (x_1, y_1) and (x_2, y_2) using the equation

$$y = y_1 + \left(\frac{x - x_1}{x_2 - x_1}\right)(y_2 - y_1)$$

4. The following are some of the limitations of the assumptions in the JADE model:
    a. Load is based on forecasts for future periods and recent periods where reconciled data was not yet available.
    b. Forecast plant and HVDC outages based on current POCP data
    c. The estimated thermal fuel costs used in JADE may not accurately represent what hydro generators face, in terms of thermal generator offers. Hydro generators must manage their storage levels within the context of volatile thermal fuel prices and availability, and the thermal fuel cost estimates may not perfectly represent these.
    d. Non-dispatchable plant, such as wind, is modelled as having constant power output instead of stochastic power output
    e. Some hydro station head ponds and major reservoirs are governed by complex resource consent rules. The model limits used in JADE are necessarily somewhat simplified and may not accurately reflect the actual flexibility of these limits.
    f. Inflow probability distributions are based on past inflow sequences.
    g. JADE does not directly model stagewise dependence (i.e., from week to week) of inflows, e.g., if it was wet last week, it's more likely to be wetter this week as well. However, JADE approximates this effect by an approach called Dependent Inflow Adjustment (DIA), which artificially increases the variance of historical inflows when generating the cutting planes.[9]

5. We use the average water value over all of New Zealand from JADE rather than the water values for individual reservoirs because the individual reservoir water values are very volatile. This is due to the following.
    a. JADE does a forward solve (linear programming), so as long as the objective values are the same, it is likely to use all water from one reservoir first until it hits some constraint, before moving to the next reservoir. This leads to the likely extreme

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[8] M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.
[9] Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

usage of small reservoirs (i.e., not using water proportional to total national storage by either holding back or letting it all go).

b. Therefore, small (constrained) reservoirs in JADE are expectedly more likely to hit maximum or minimum levels or constraints, and this will be reflected in the water values (high price if likely to hit minimum level and low price if likely to hit maximum level).

c. National water values are calculated based on absolute total national storage, not absolute individual reservoir storage, which tends to make the water values less volatile. That is, if we had two reservoirs with the same capacity and one had storage at 10 percent of capacity and the other at 90 percent, the national water value is based on total storage of 50 percent of total capacity