23 March 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 13 to 19 March

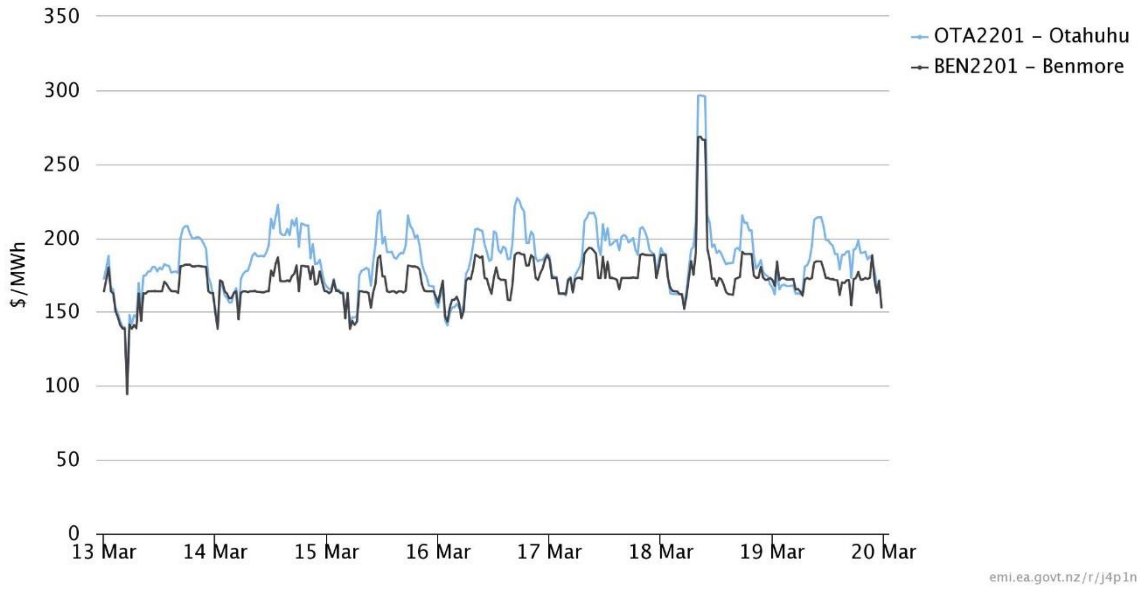
1.1. Prices this week appear consistent with supply and demand conditions.

2. Prices

Energy prices

2.1. The average spot price this week was $179MWh[1], down 11% from last week. This week prices were usually between $140/MWh and $225/MWh at Benmore and Otahuhu. The highest price this week occurred at TP18 on 18 March reaching $296/MWh at Otahuhu.

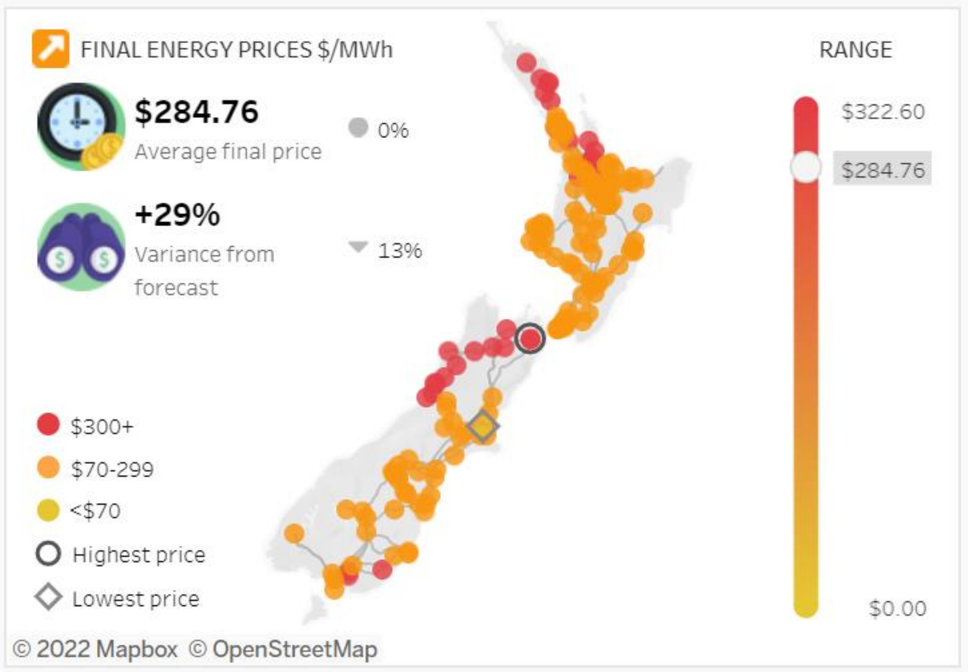
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.2. The simple average price for TP18 on 18 March was $285/MWh. Prices reached over $300/MWh in some parts of the country between TP17 and TP20, coinciding with the morning peak.

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

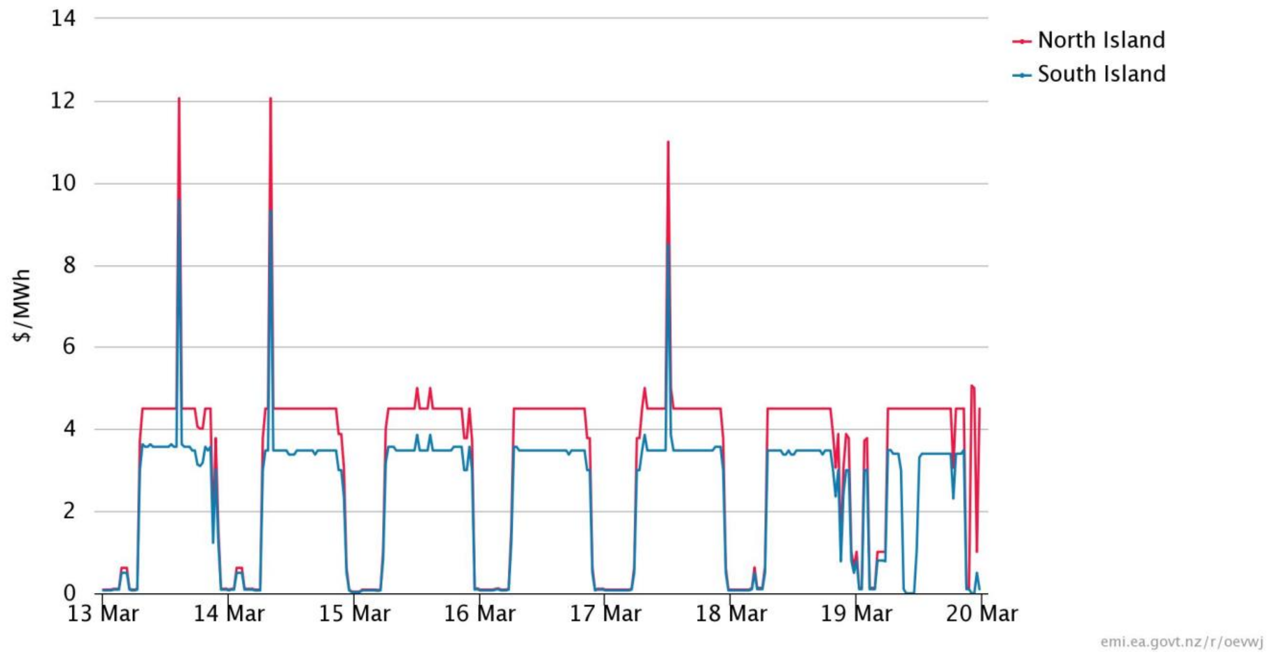
Figure 2: Nodal and average spot prices for TP18 on 18 March



Reserve Prices

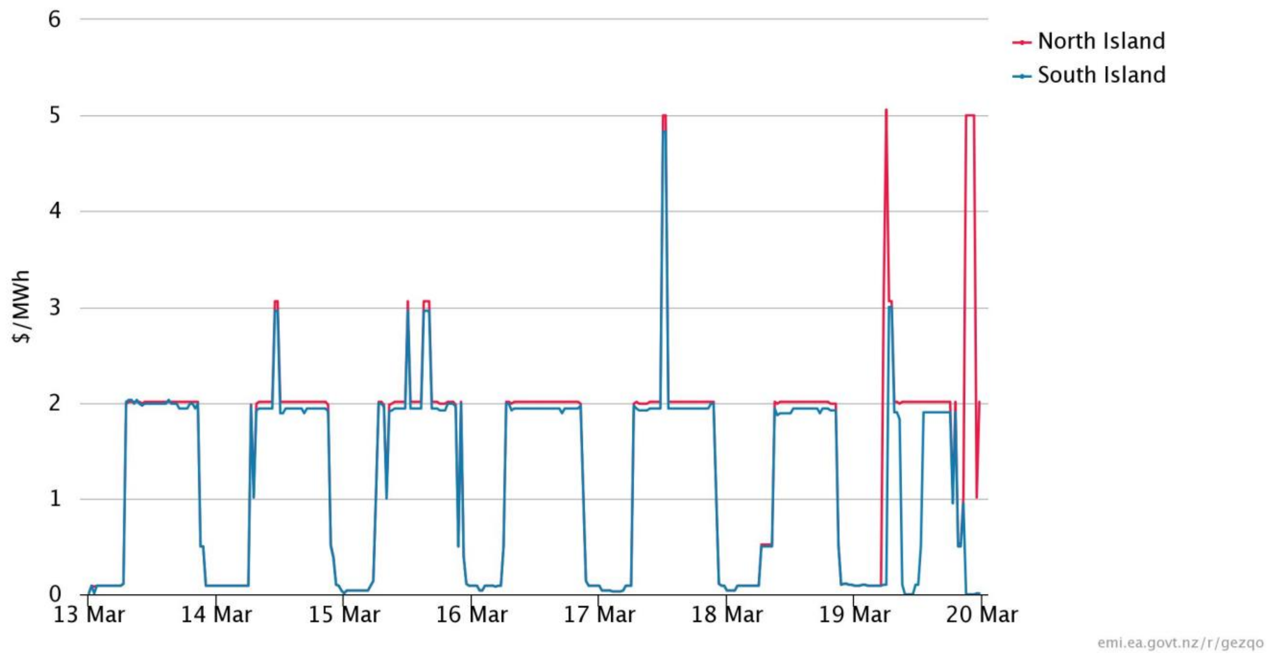
2.3. Fast instantaneous reserves (FIR) prices this week were usually below $5/MWh, occasionally reaching $12/MWh (see Figure 3).

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were below $5/MWh this week (see Figure 4).

Figure 4: SIR prices by trading period and Island

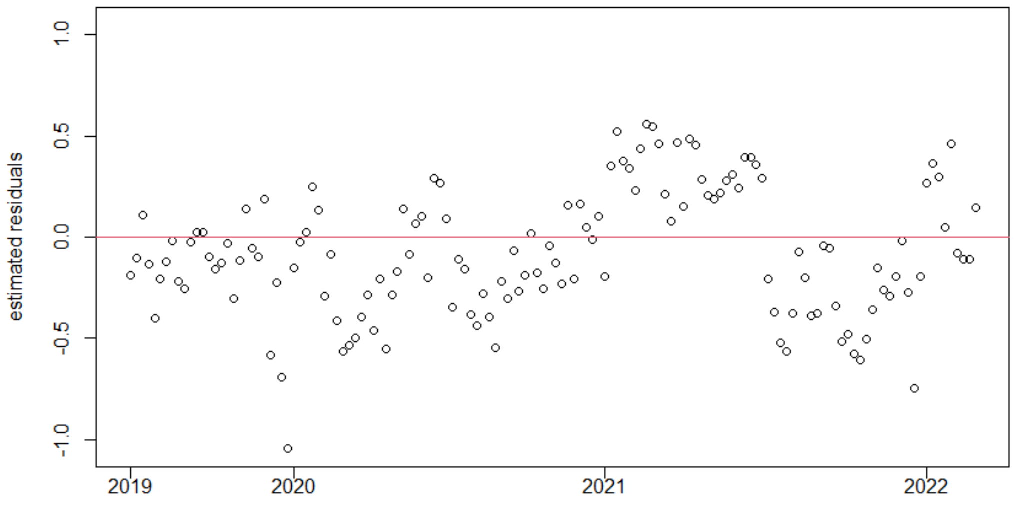


3. Residuals from regression models

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.

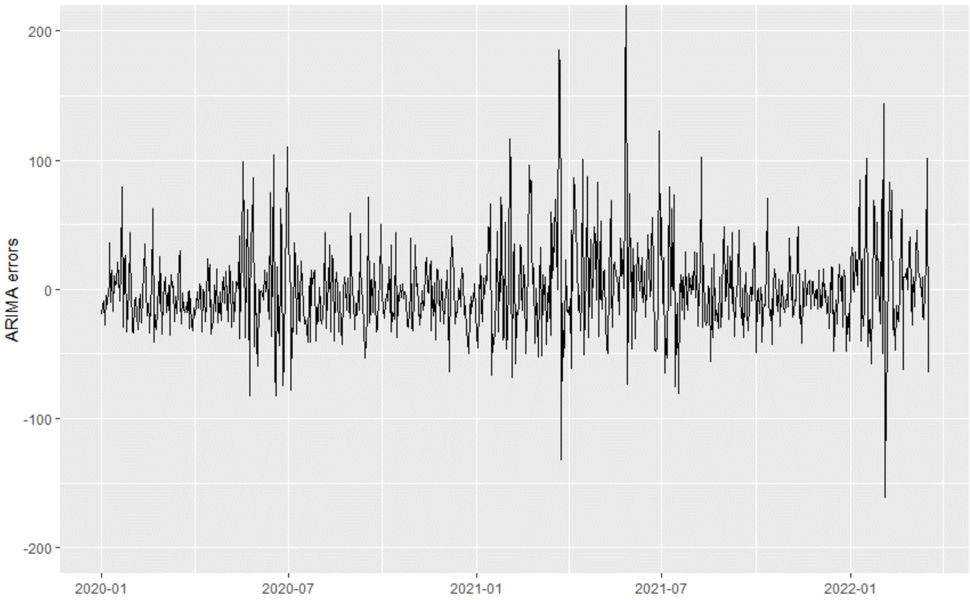
3.2. Figure 5 shows the residuals from the weekly model. During February the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

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. There was a high residual on 18 March, while the residuals for earlier in the week were within the normal range. The high residual on 18 March may be due to the high price after a sequence of stable prices, which caused the autoregressive model to start predicting stable prices would continue. As the demand and supply conditions discussed below explain why prices were higher on 18 March than the previous days, this day has not been flagged for further analysis.

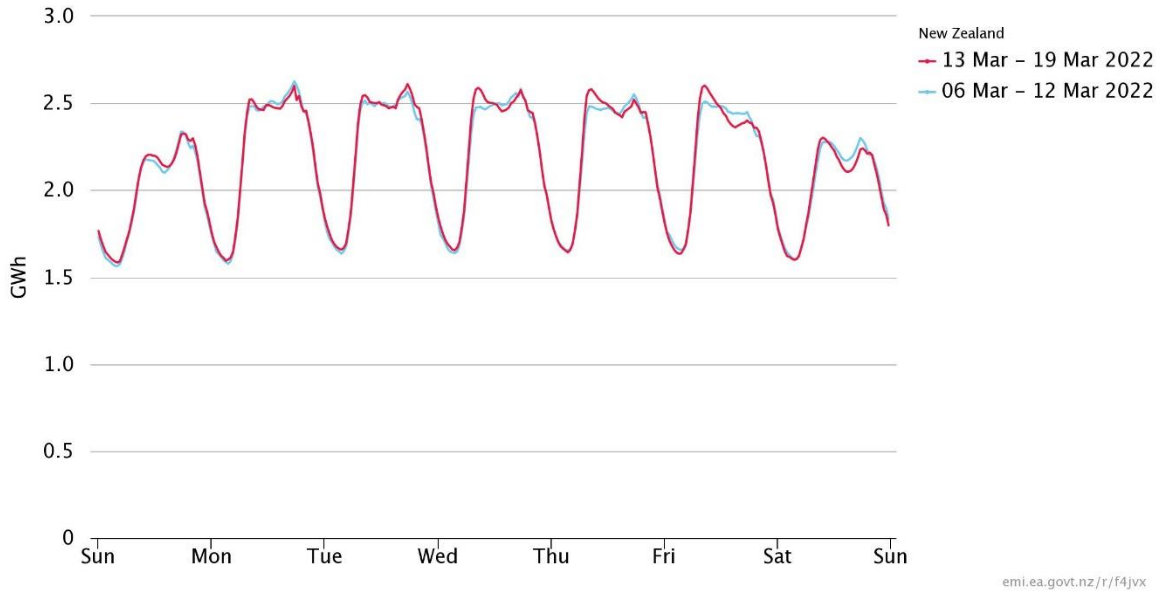
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 19 March 2022



4. Demand Conditions

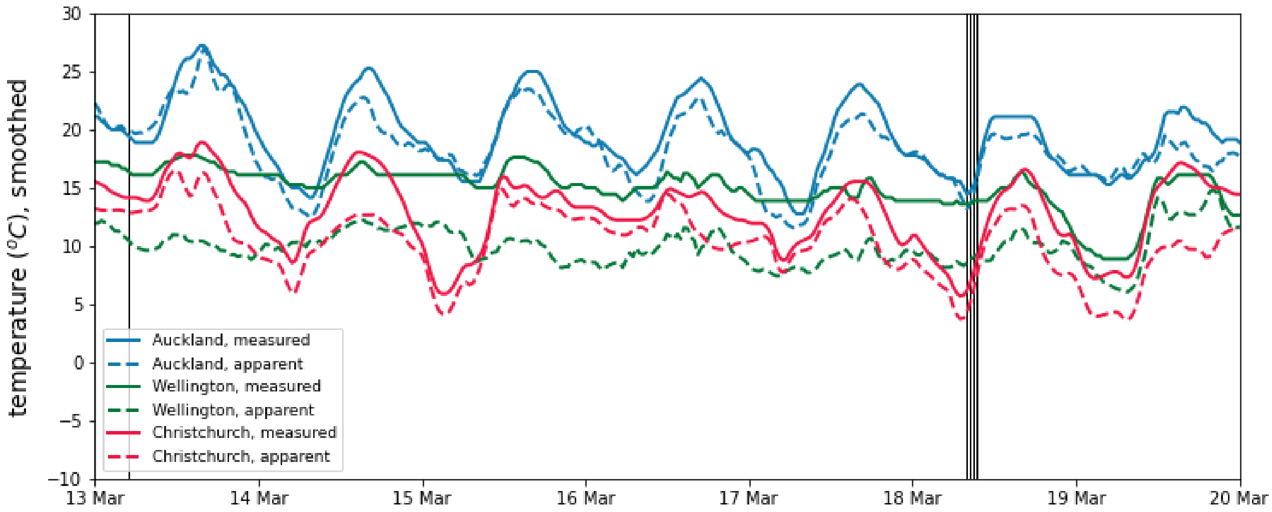
4.1. National demand was similar to the previous week, though morning demand was higher, especially on 18 March (see Figure 7). This was likely due to colder temperatures, shown in Figure 8. The high prices on 18 March coincided with high demand. Morning and evening peaks are likely to become more pronounced as temperatures continue to cool.

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



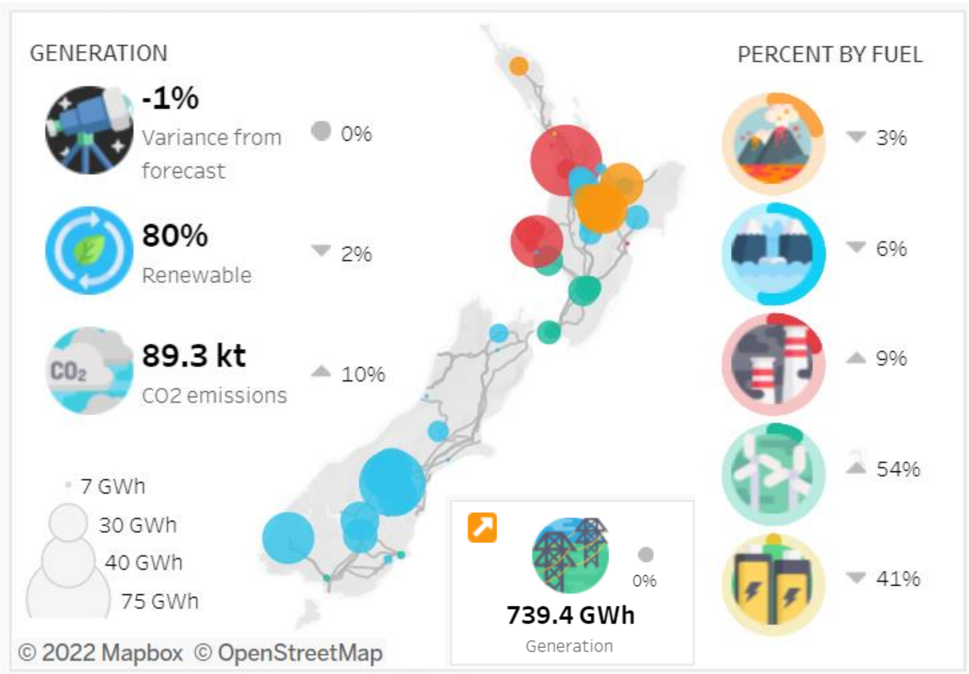
4.2. Figure 8 shows hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. The vertical black lines also indicate when the lowest (13 March) and highest (18 March) prices occurred. While temperatures remain warm in Auckland, temperatures were quite mild in Wellington the whole week, with apparent temperatures around 10 degrees. Temperatures in Christchurch were also frequently cold overnight, particularly on 18 March which coincided with high morning demand and high prices.

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



5. Supply Conditions

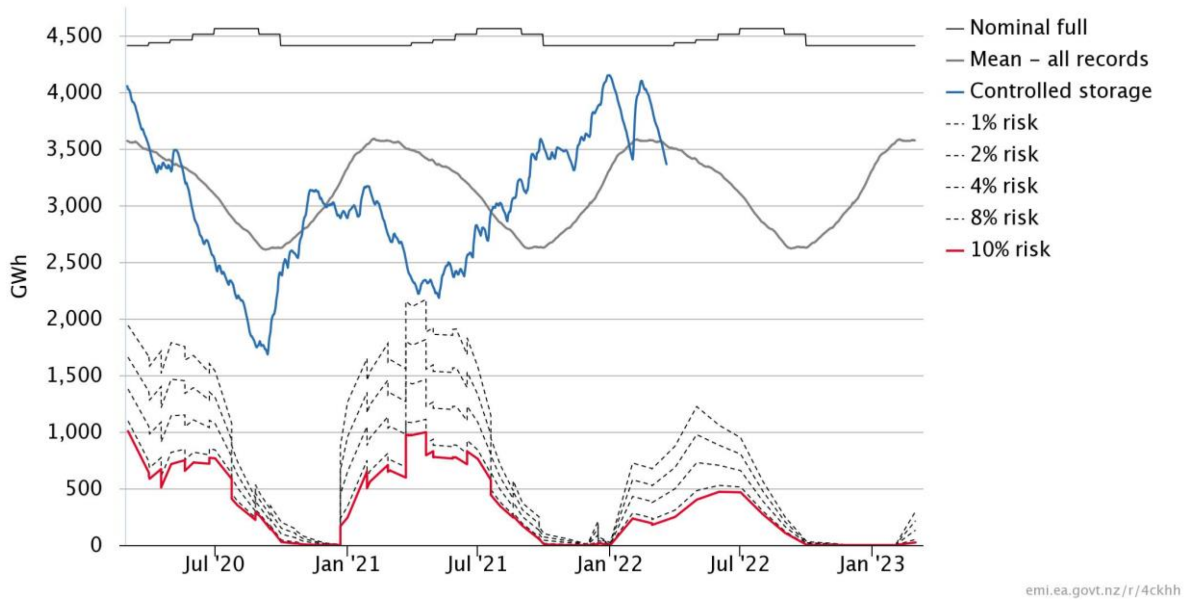
Figure 9: Generation in the last week compared to previous week



Hydro conditions

5.1. National hydro storage decreased by about 150GWh over the week, shown in Figure 10, to 70% of nominal full storage. Storage is now below the historical means for this time of year. Hydro generation contributed 53% of total generation this week, down 6% from last week. Drought conditions in Fiordland have caused low inflows into several reservoirs including Lake Manapouri, which is currently in its low operating margins. This has curtailed generation in the lower South Island.

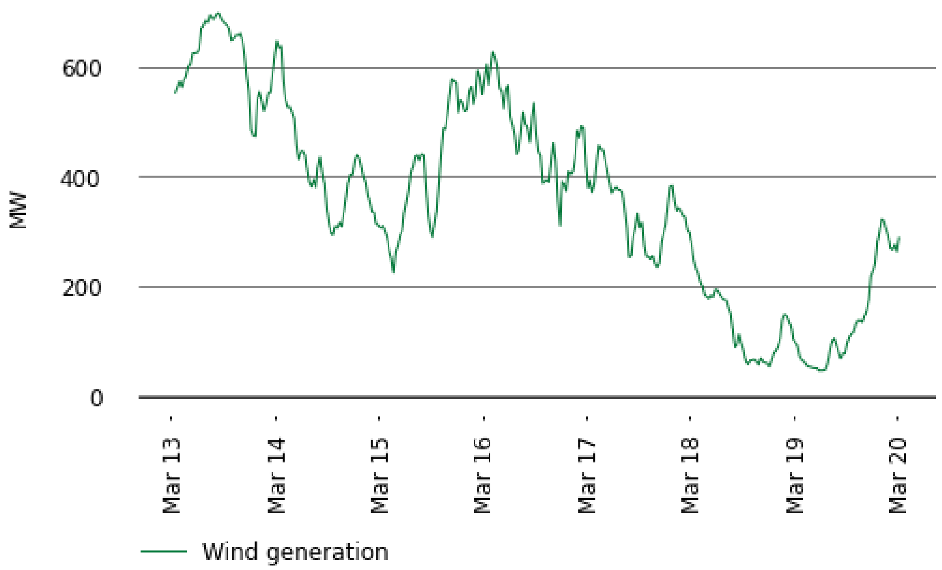
Figure 10: Electricity risk curves and hydro supply



Wind conditions

5.2. Total wind generation was 60GWh, up 54% from last week, and contributed about 8% of total generation. Wind generation was high in the first half of the week, especially on the 13 March when it reached 700MW. Wind generation fell significantly on 17 and 18 March to below 100MW. The highest prices on 18 March coincided with a steep drop from 200 to 100MW.

Figure 11: Wind generation by trading period

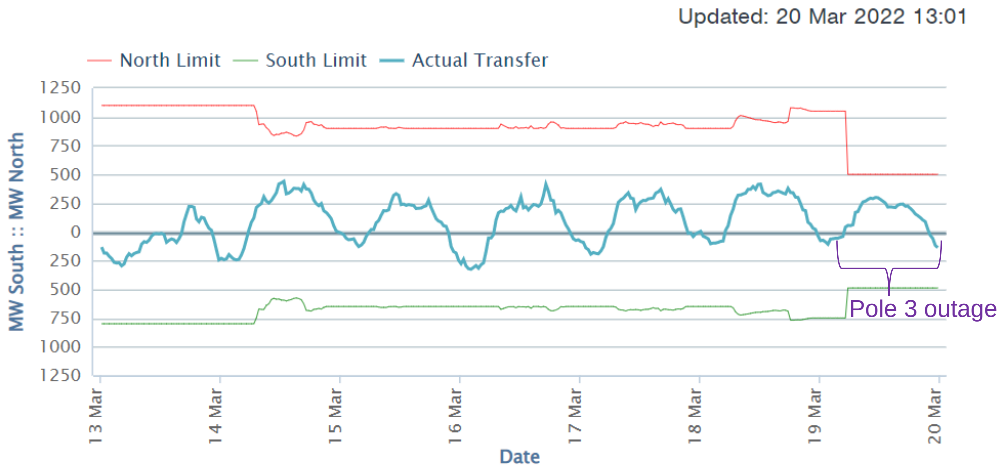


Significant outages

HVDC outage

5.3. Figure 12 shows that the HVDC transfer each day, as well as the transfer limits and outages. This shows that northward transfer has been below 500MW every day this week and there has been southward transfer at night of up to 325MW. There was a planned outage of. Pole 3 from 19 March 05:30 to 20 March 16:00, which reduced transfer limits to 500MW. As transfers were low already, the impact to the market was minimal.

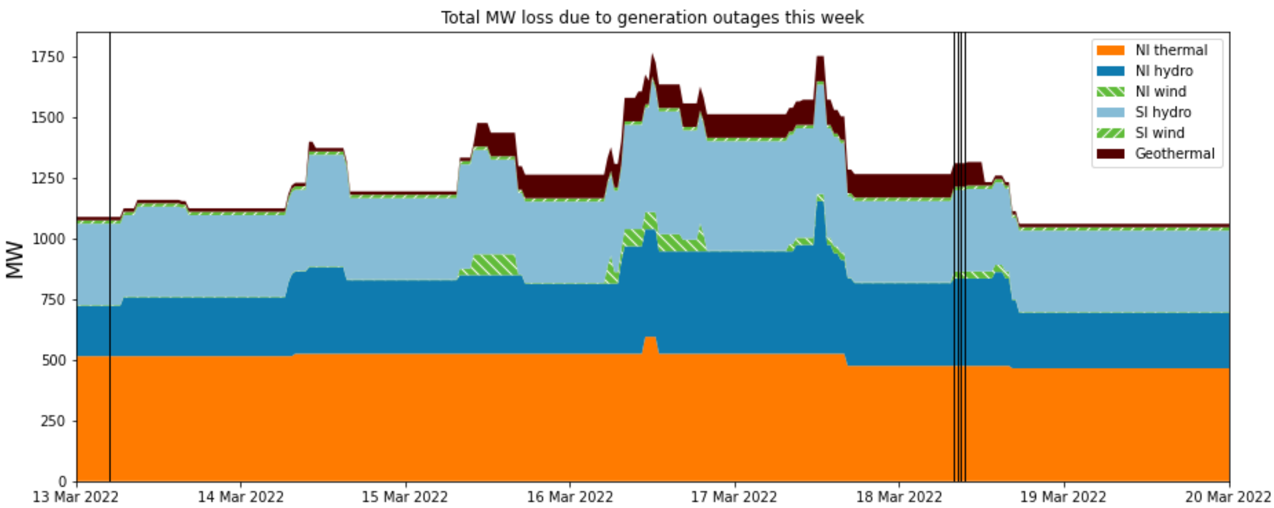
Figure 12: HVDC transfer, HVDC limits and HVDC outage



Generation outages

5.4. Figure 13 shows the impact generations has on generation capacity, with vertical lines indicating when the lowest (13 March) and highest (18 March) prices occurred. The amount of generation on outage started around 1100MW, with the highest amount on outage occurring on 16 and 17 of March with up to 1700MW of capacity on outage. There was an 83MW geothermal outage at Te Mihi from 15 to 18 March. As well as the geothermal outage, there were a couple of small outages that started at 8am on 18 March that could have contributed to the higher prices.

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 2022)

(e) Manapouri, 125MW (23 January – 25 March 2022)

(f) Huntly, Rankine 2, 240MW (1 March – 18 March 2022)

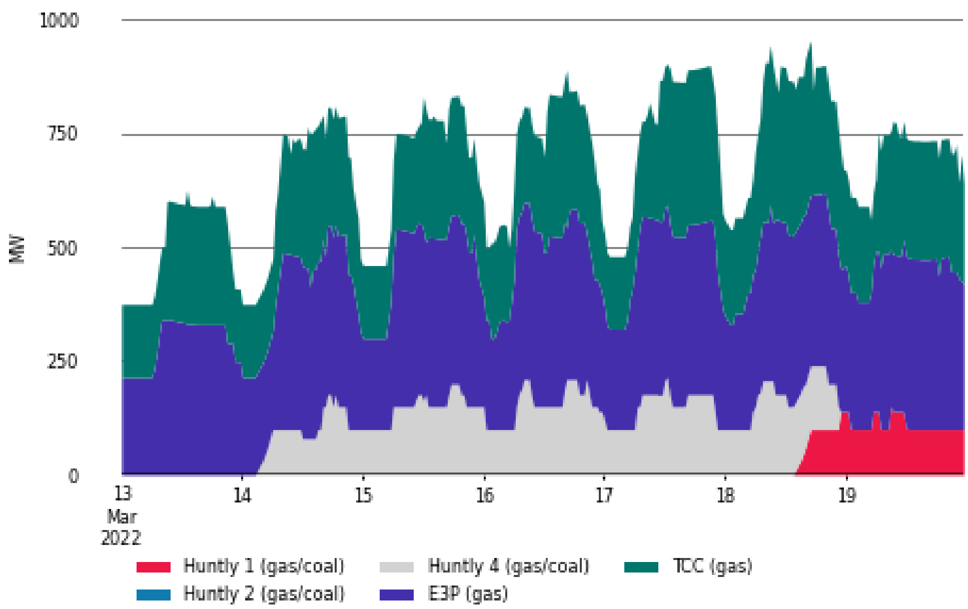
(g) McKee, 50MW, (13 February – 17 March 2022)

Thermal conditions

5.6. Overall, thermal generation contributed 19% of total generation this week, up 9% from last week. This increase was likely due to higher levels of generation from TCC and thermal peakers after last week's gas outage at Ahuroa ended.

5.7. Both TCC and E3P continued to run this week as baseload. Huntly 4 also ran for most of the week until 18 March when Huntly 1 started and Huntly 4 ramped down.

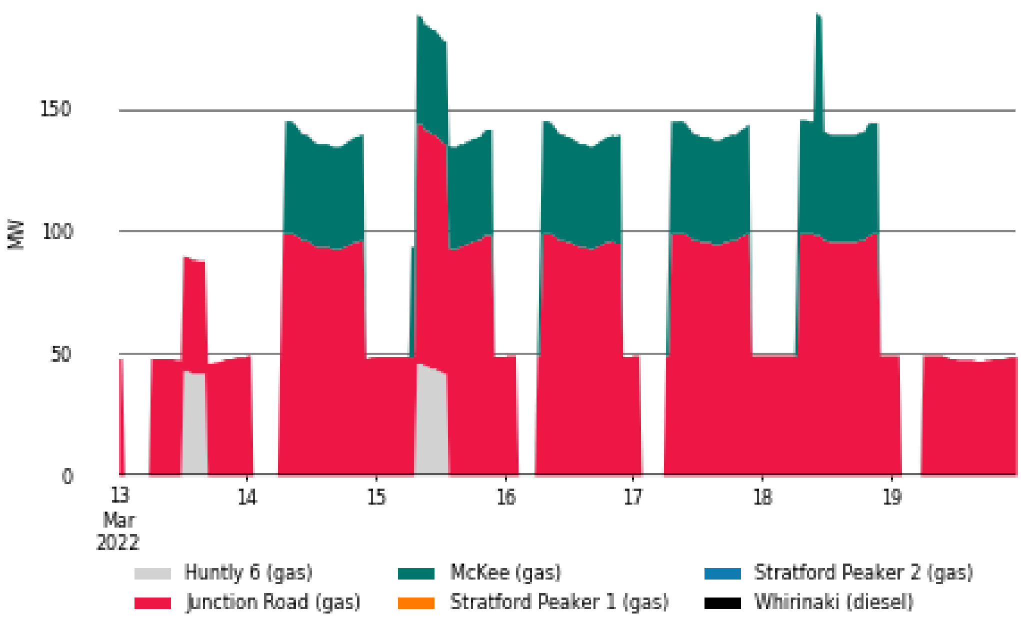
Figure 14: Generation from baseload thermal by trading period



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

5.8. Todd's dispatch of thermal peakers was curtailed up to 13 March due to the tight gas market after the unplanned outage at Ahuroa last week. However, all units not on outage were running from 14 March. An outage of one unit at McKee finished on 17 March and it ran on 18 March in response to the high prices. Huntly 6 also ran on 13 and 15 March. The two Stratford Peakers are both on outage.

Figure 15: Generation from thermal peakers by trading period



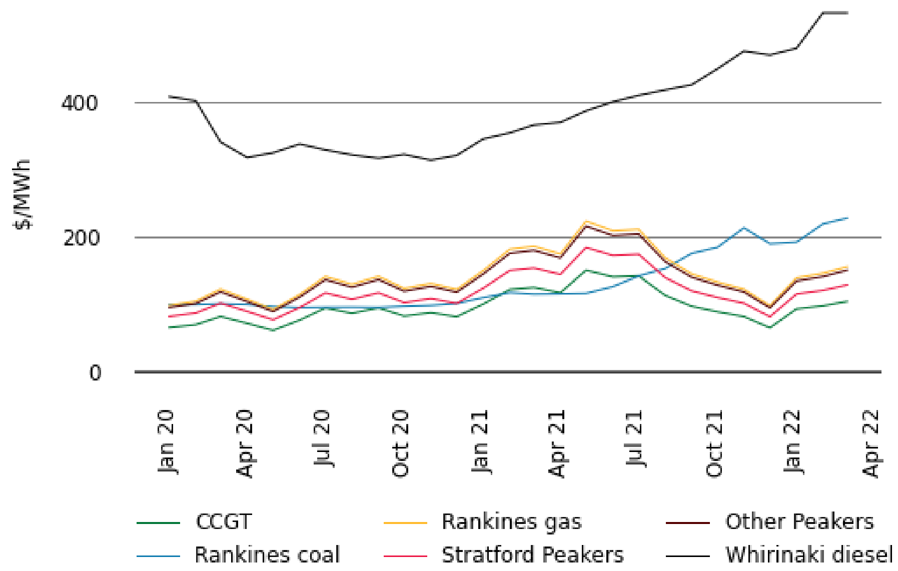
6. Price versus estimated costs

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 $73/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].

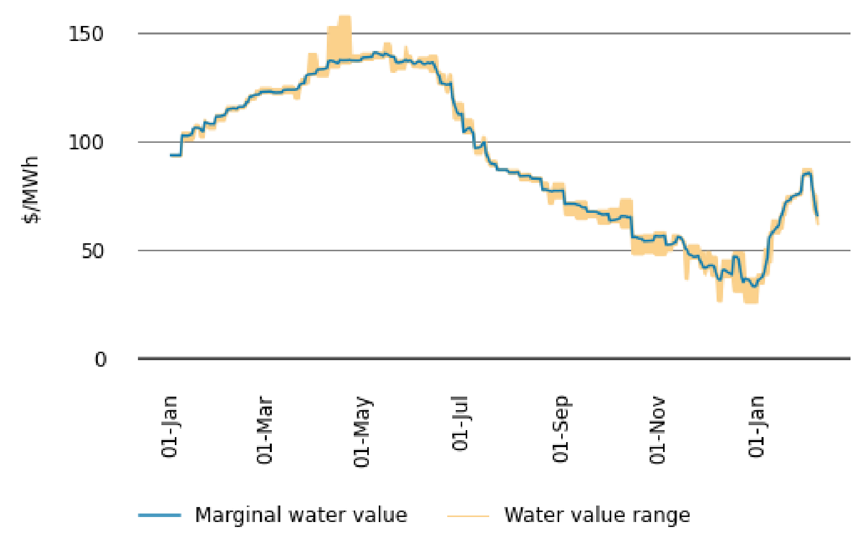
6.4. The marginal water value declined from June to December as hydro storage levels increased and gas costs decreased. In January, the water values increased as hydro storage decreased and gas costs increased. Between February 1 and 13 hydro storage increased which caused a steep decline in the water 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 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 19 March.

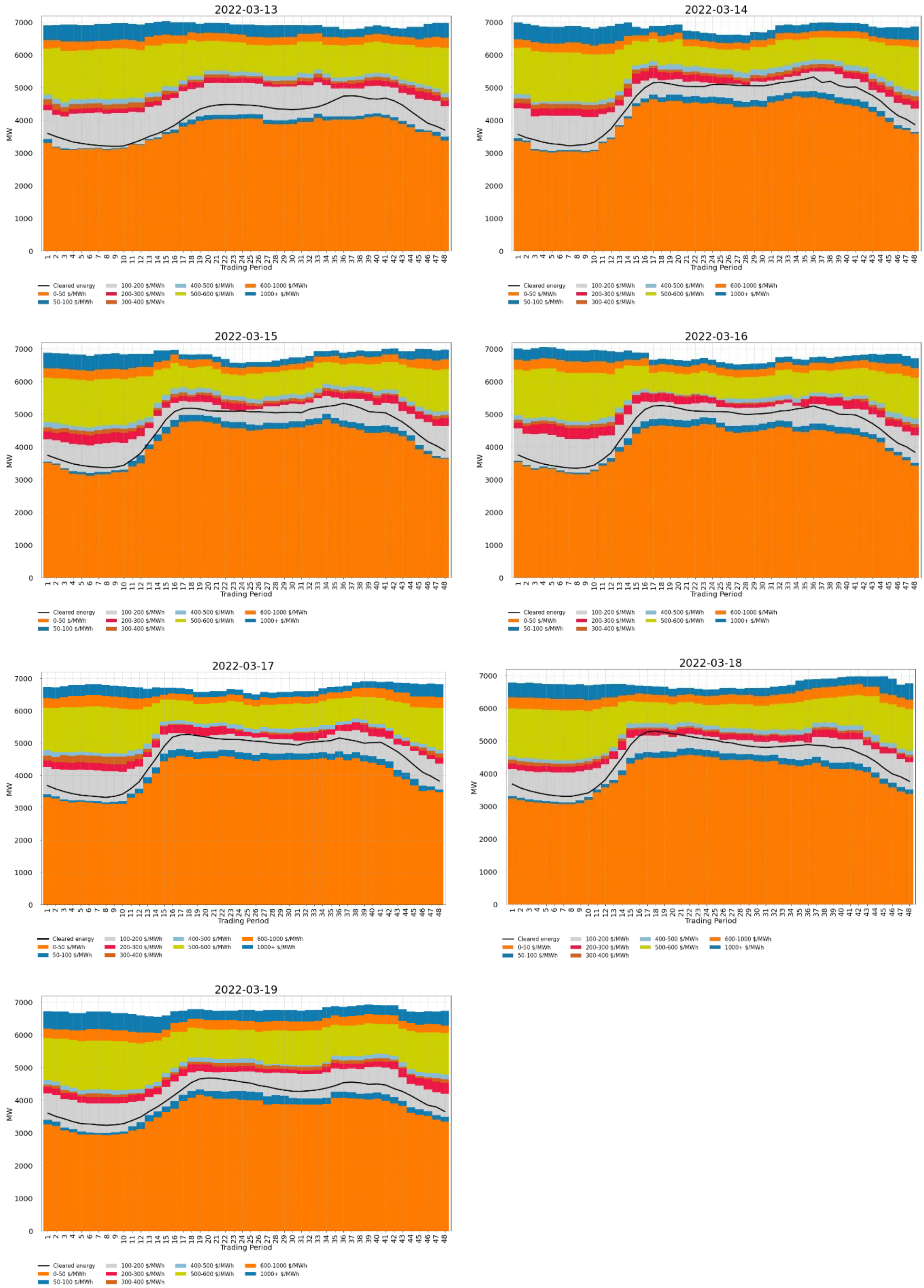
7.2. Both the per cent of offers over $350/MWh and the quantity weighted offer price decreased this week compared to last week. This was likely due to the unplanned Ahuroa outage last week as well as increased wind generation. There was a noticeable increase in generation offered between $100-$200/MWh, which resulted in less price fluctuations.

7.3. However, there continues to be a high amount of generation offered between $500-$600/MWh. Manapouri is currently offering at least 400MW at $600/MWh due to being in its low operating margins which restrict daily drawdown. Clyde and Roxburgh, whose inflows are also impacted by the drought, as well as some generation capacity from North Island hydro and thermal generation is also being offered in this price range, likely to conserve fuel for winter.

7.4. Generation outages caused a noticeable decrease in total generation offered from 16 to 18 March. In particular, the geothermal generation outages would have reduced generation offered at very low prices from 16 to 18 March.

[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 TP18 on 18 March are shown on Figure 20 and TP 18 on 11 March on Figure 21 along with the generation weighted average price (GWAP) and cleared generation.

7.6. The GWAP of both TP18 on 11 and 18 March were close. There were some similarities between these two dates, for example, they were both Fridays and wind generation was low. However, the offer curve was steeper on 11 March, likely due to the unplanned outage of Ahuroa which caused a tight gas market. Likewise, cleared generation was higher this week than the same time last week. If cleared generation on 18 March had been the same as on 11 March, the GWAP would have been lower.

Figure 20: Offer Stack for trading period 18 on 18 March

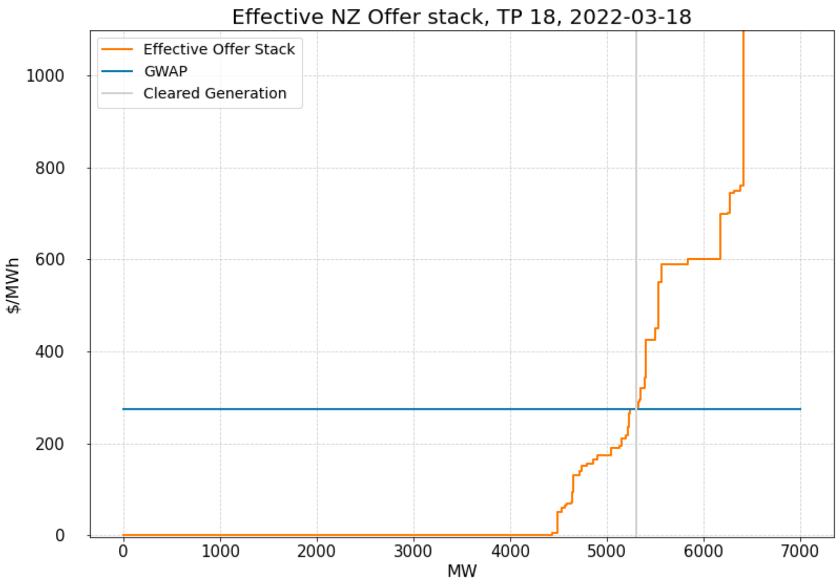
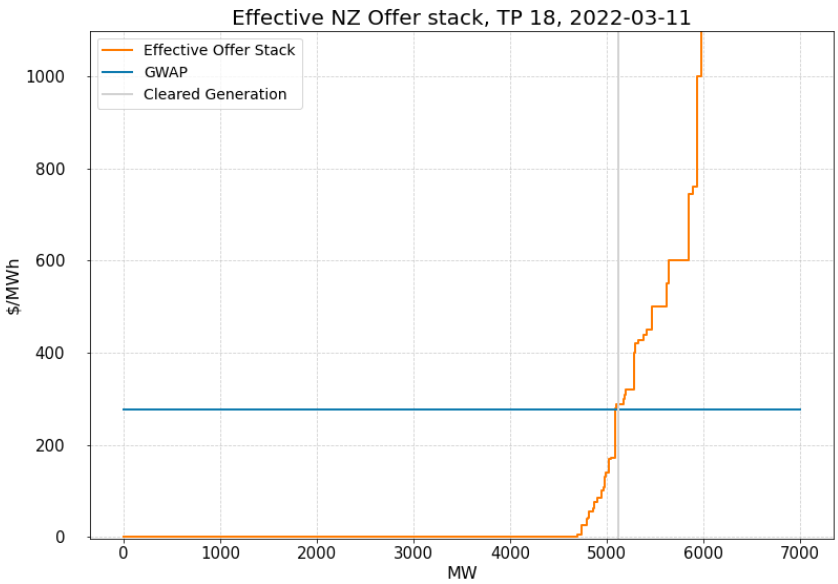


Figure 21: Offer Stack for trading period 18 on 18 March



8. Ongoing Work in Trading Conduct

8.1. No trading periods have been identified for further analysis this week. Prices were higher on the morning of 18 March compared to the rest of the week, as flagged by the daily regression model, but this appears to be due to high demand and low wind generation.

8.2. The Authority requested further information from Contact and Todd regarding recent high-priced offers of thermal peakers between 10 and 13 March. Between the 8 and 10 March there was an unplanned outage at Ahuroa which reduced the supply of gas to TCC. As a result, Contact sourced gas from the market which reduced the available gas for thermal peakers. This was economically efficient as the TCC is more efficient than thermal peakers. This was also reflected in gas spot prices which were 130% higher on 11 March than one week earlier. The high priced offers of the thermal peakers therefore reflected the temporary scarcity of gas in the market.

8.3. Further information was also received regarding high priced offers of thermal peakers on 25 February, which resulted in the brief dispatch of Whirinaki. Todd has indicated that the expected priced between TP23 and 27 was below their short run marginal cost, and as they did not want to run a unit at Junction Road either at a loss or inefficiently, they chose to offer that capacity at a high price. Pre-dispatch prices did indicate that prices would be lower than final prices were for these trading periods.

8.4. 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.

8.5. 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	Resolved	High offer prices of thermal peakers reflected temporary scarcity of gas during the Ahuroa outage
03/03-05/03	4-10	Further analysis	Branch constraint, high prices in lower South Island
25/02	23-27	Resolved	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

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

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