23 March 2022

Trading Conduct Report

Market Monitoring Weekly Report

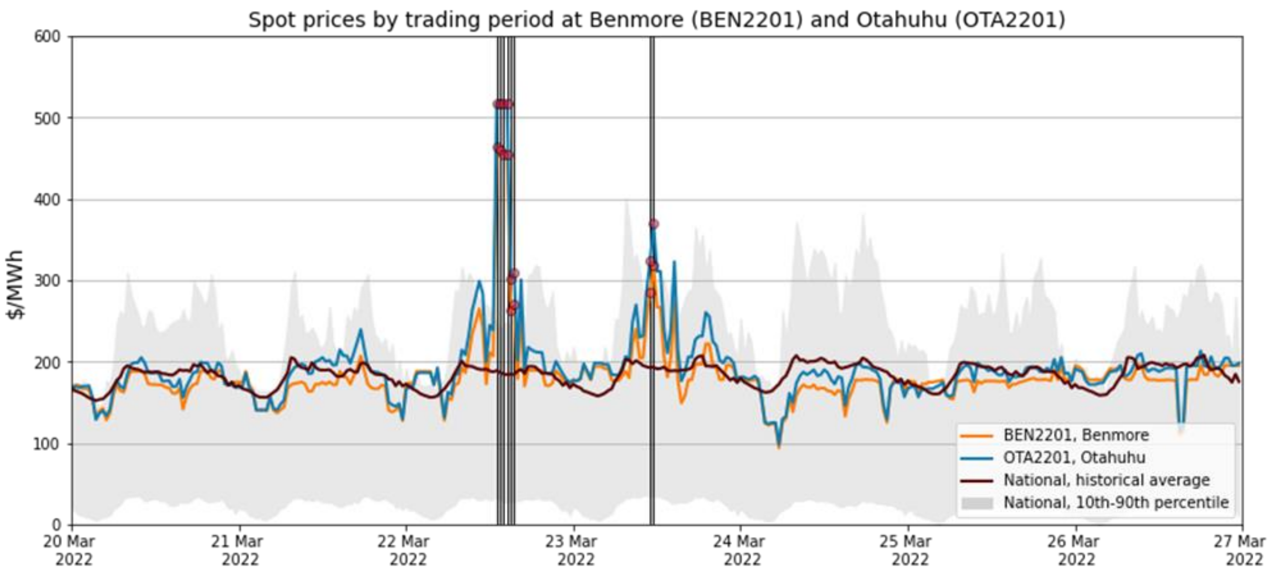
1. Overview for the week of 20 to 26 March

1.1. Wholesale spot prices this week appear to be consistent with supply and demand conditions.

2. Spot Prices

2.1. Figure 1 shows prices from the past week at Benmore and Otahuhu, historic average prices and historic 10th-90th price percentiles along with the trading periods with the highest prices for the week marked out by vertical lines. Electricity wholesale spot price between 20 and 26 March averaged $189.09/MWh, compared to an average of $155.67/MWh for the same period from the previous five years. 95 per cent of prices in the past week fell between $127.78/MWh and $298.24/MWh.

Figure 1: Wholesale Spot Prices



2.2. The highest prices for this week which exceeded the historical 90th percentile occurred on 22 and 23 March as detailed below in Table 1.

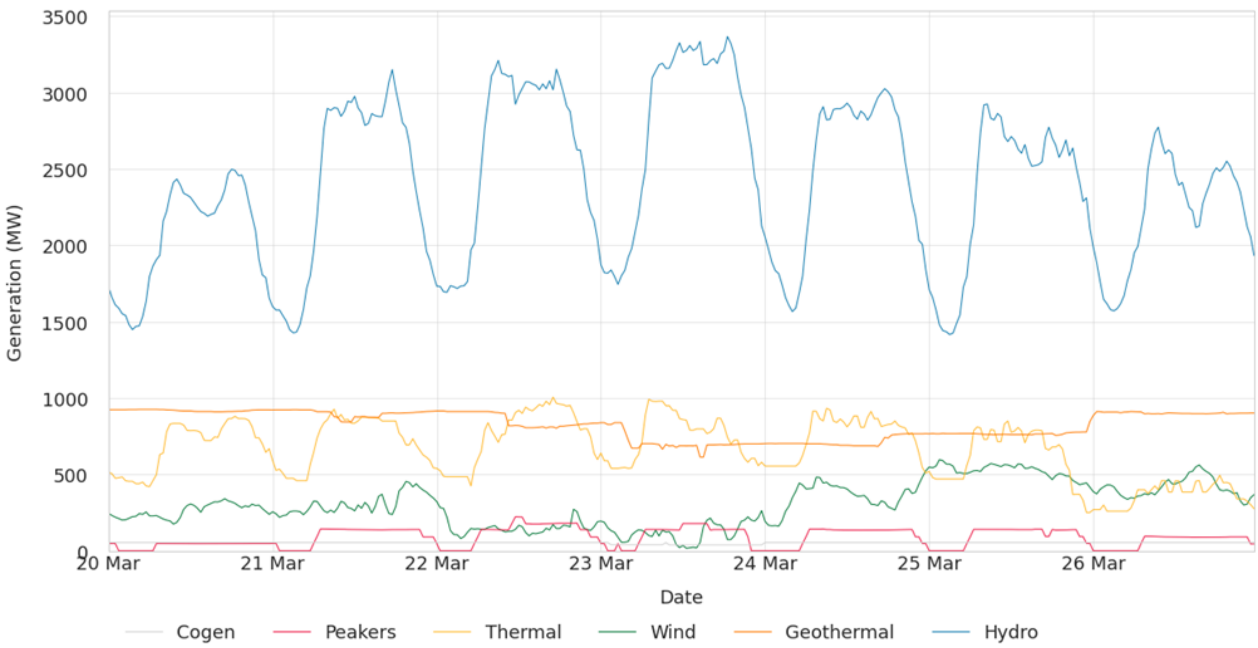
Table 1: High Priced Periods

Date	Trading Period	Historic mean	10th percentile	90th percentile	BEN2201	OTA2201

22/03/2022	27	$189.36	$33.42	$252.49	$463.25	$517.49
22/03/2022	27	$187.01	$31.36	$233.96	$461.18	$517.49
22/03/2022	29	$185.04	$27.89	$248.54	$454.81	$516.67
22/03/2022	29	$184.45	$28.45	$247.71	$454.98	$516.67
22/03/2022	31	$185.05	$28.83	$246.92	$262.84	$301.69
22/03/2022	31	$184.69	$28.67	$254.57	$270.09	$310.00
23/03/2022	23	$192.93	$35.17	$269.59	$284.85	$323.62
23/03/2022	23	$193.60	$35.96	$304.88	$318.74	$369.24

2.3. High prices on 22 March were due to a reduction in geothermal generation which unfortunately coincided with a planned outage at McKee//Mangahewa gas field, an unplanned outage at Maui gas field and low wind generation causing highly priced thermal and hydro generation to be dispatched, pushing spot prices up. The changes in generation fuel mix are illustrated in *Figure 2*.

Figure 2: Generation by Fuel Type



2.4. Geothermal capacity was reduced by around ~250 MW between 23 to 25 March. Te Mihi capacity reduced by 83 MW between 10:30 22 March and 17:00 24 March. Nga Awa Purua (Rotokawa II) capacity reduced by 136 MW between 4:00 23 March and 17:30 25 March as well as 56 MW between 3:30 23 March and 04:00 23 March. Tuaropaki capacity was also reduced by 31 MW between 10:00 8 March and 25 March.

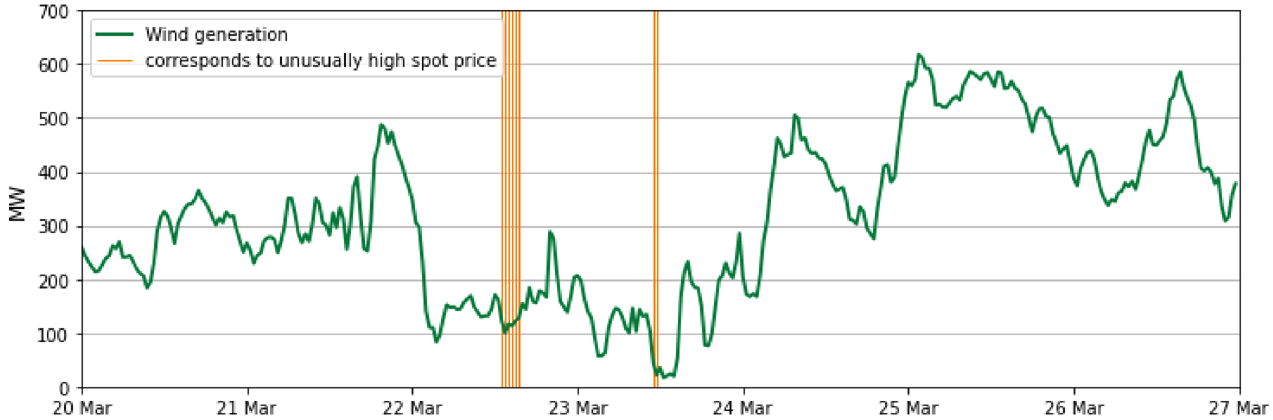
2.5. McKee/Mangahewa gas field underwent a planned production outage from 21 March 2022 to 26 March 2022 reducing production by 23/TJ day.

2.6. An unplanned power failure causing plant shutdown at Maui gas field caused production to drop by around ~65 TJ/day on 23 March.

2.7. Wind generation as seen in Figure 3 dropped to some of its lowest points of the week during the highest priced periods (indicated by vertical lines), at around ~120 MW on 22 March and around ~25 MW on 23 March. Total wind generation averaged around ~317

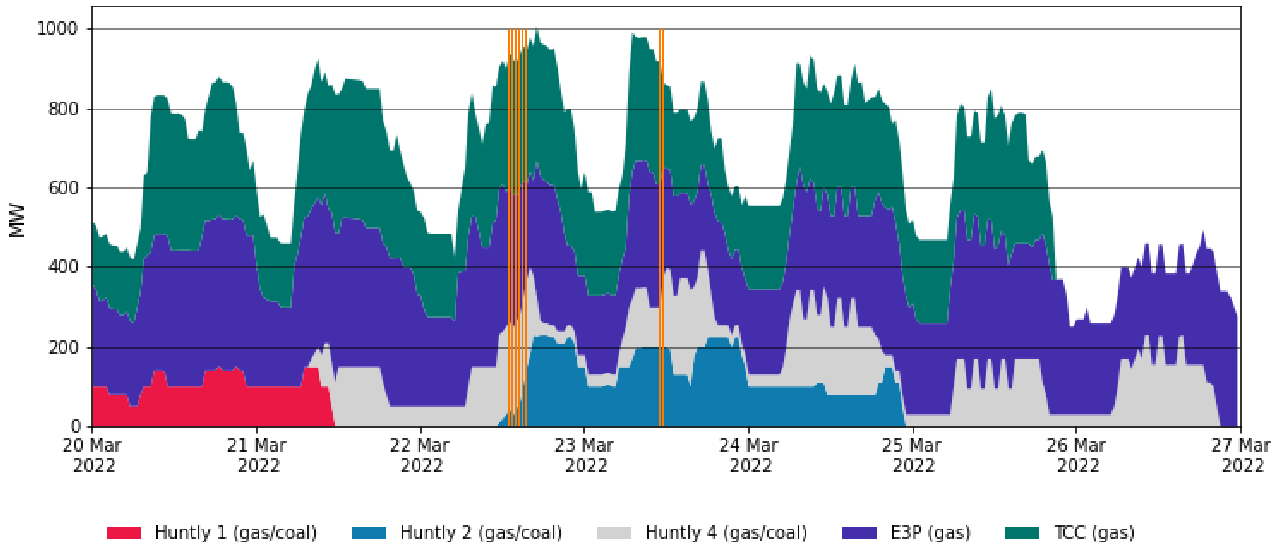
GWh for the week, around ~7.6 per cent of total generation. Wind generation was relatively high at the beginning and end of the week, reaching over 600 MW on 25 March. The drop in wind generation in the middle of the week is what contributed to high prices.

Figure 3: Wind Generation



2.8. To make up for the shortfall in generation caused by geothermal outages and low wind thermal generation rose, some of the changes in thermal generation can be seen in Figure 4, with Huntly 2 run between 22 March and 24 March. The increase was relatively limited however with Stratford peakers also on outage at the time. The remaining shortfall was made up by hydro generation, some of which was priced highly to conserve water in the face of falling hydro storage, pushing up marginal prices as a result.

Figure 4: Thermal Generation

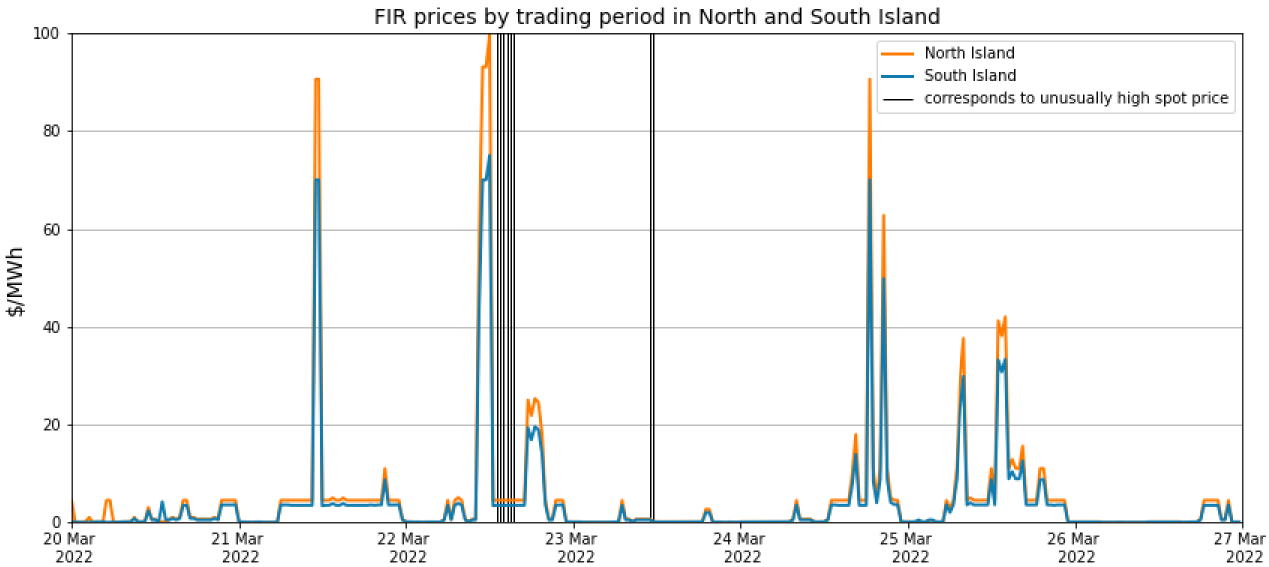


2.9. Outside of the high price periods identified, spot prices appeared to follow typical patterns seen in previous weeks, remaining within historical bounds..

3. Reserve Prices

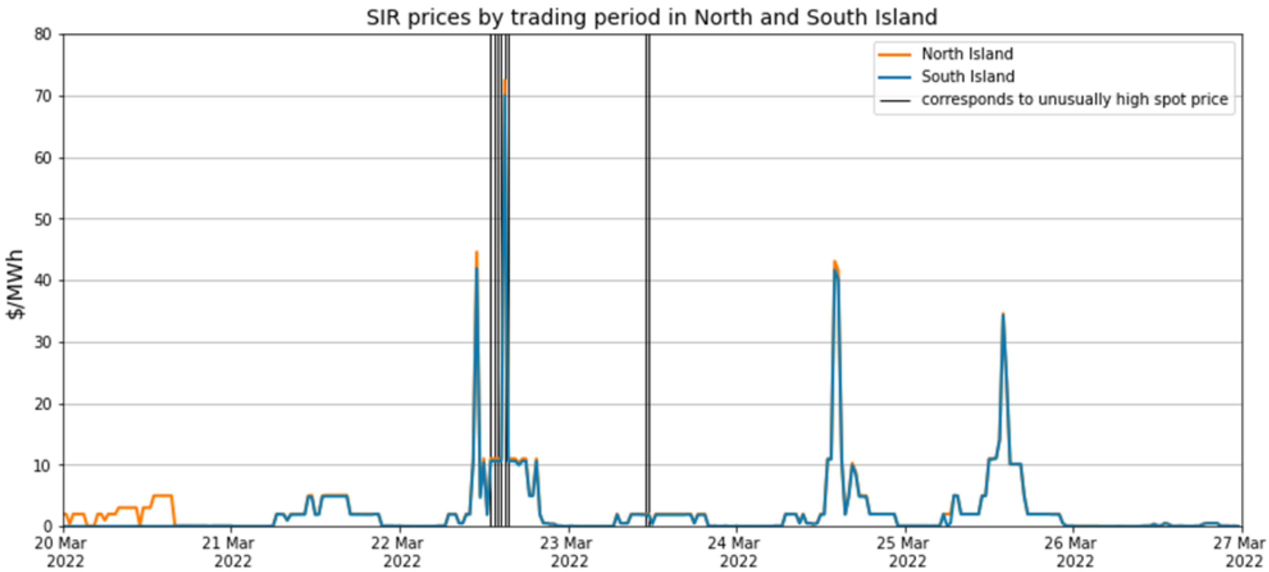
3.1. Fast instantaneous reserves (FIR) prices this week as seen in Figure 5 tended to remain below $20/MWh with occasional price spikes to around ~$100/MWh, some of which correlated to the high priced periods discussed earlier (indicated by vertical lines).

Figure 5: FIR prices by trading period and Island



3.2. Sustained instantaneous reserves (SIR) prices this week as seen in Figure 6 tended to remain below $10/MWh with occasional price spikes to almost ~$75/MWh, most of which again correlated to the high priced periods discussed earlier (indicated by vertical lines).

Figure 6: SIR prices by trading period and Island

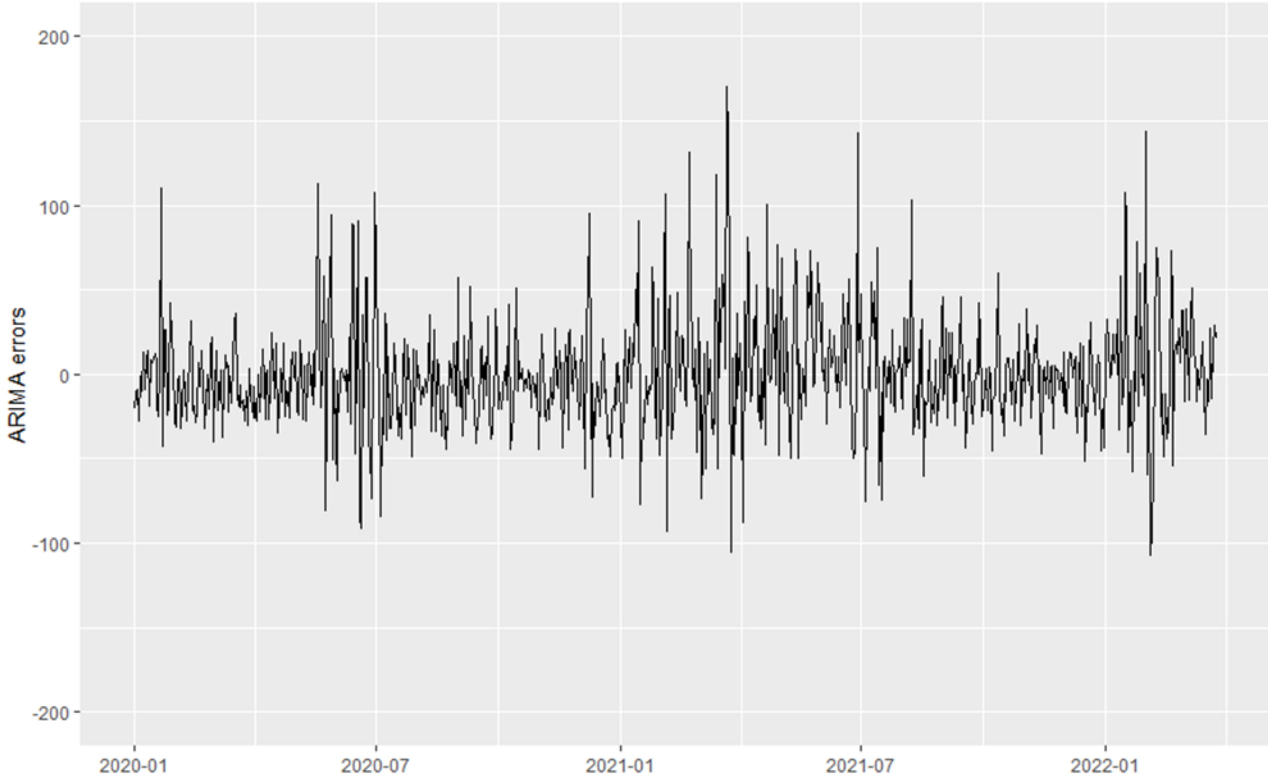


4. Regression Residuals

4.1. 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.

4.2. Figure 7 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. There was little difference between residuals this week and the week before. Residuals for this week were within the normal range and, with the factors contributing to high prices this week understood, no days this week have been flagged for further analysis as a result of inspecting the residuals.

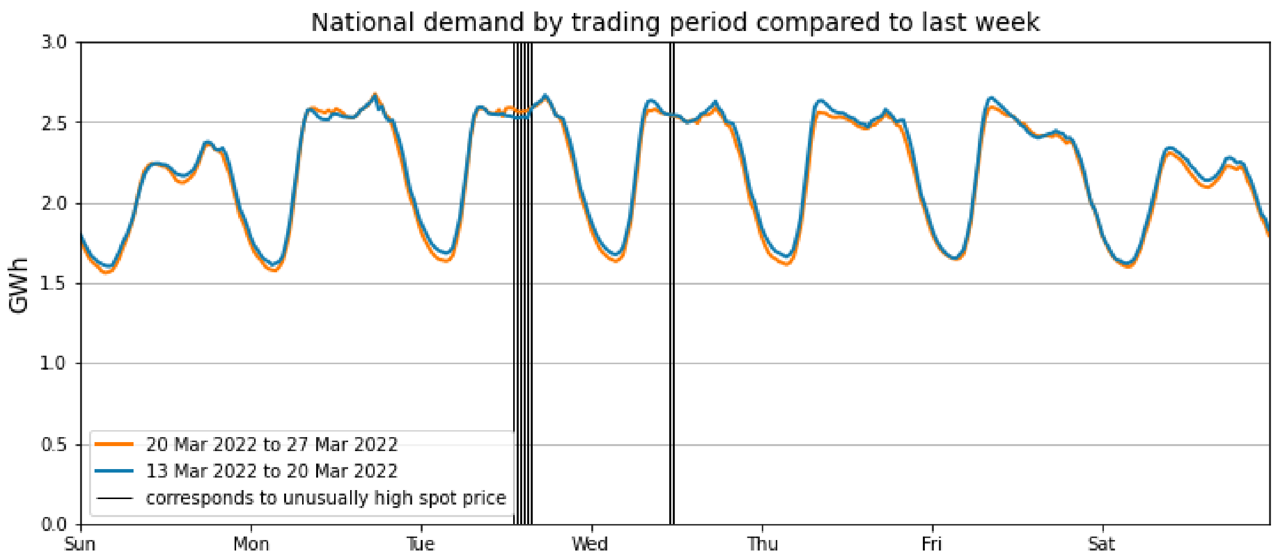
Figure 7: Residual plot of estimated daily average spot price from 1 January 2020 to 26 March 2022



5. Demand

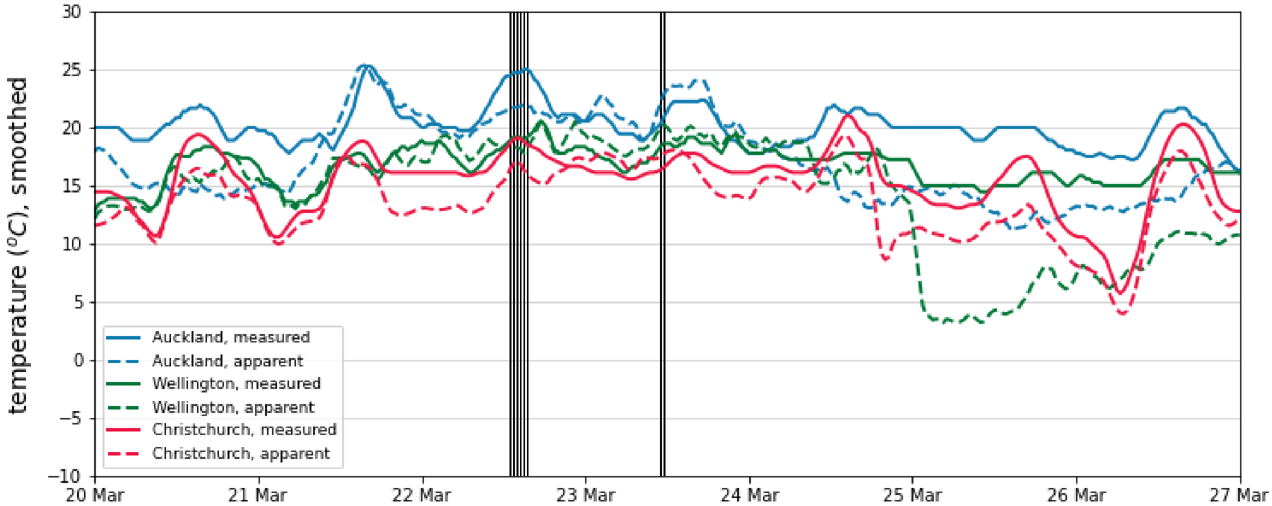
5.1. Figure 8 shows national grid demand against national demand from the previous week. Demand this week was very similar to the past week. Daily load profiles remained consistent across the week with demand only dropping over the weekend (Friday afternoon inclusive) despite cooling temperatures. Demand for the week peaked at 5,224 MW on 5:30pm 21 March 2022.

Figure 8: National demand by trading period compared to the previous week



5.2. Figure 9 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 were fairly constant over the week only dropping in the weekend which may have caused weekend demand to be higher than it would have been otherwise. Morning and evening peak demand is likely to become more pronounced as temperatures continue to cool going into winter.

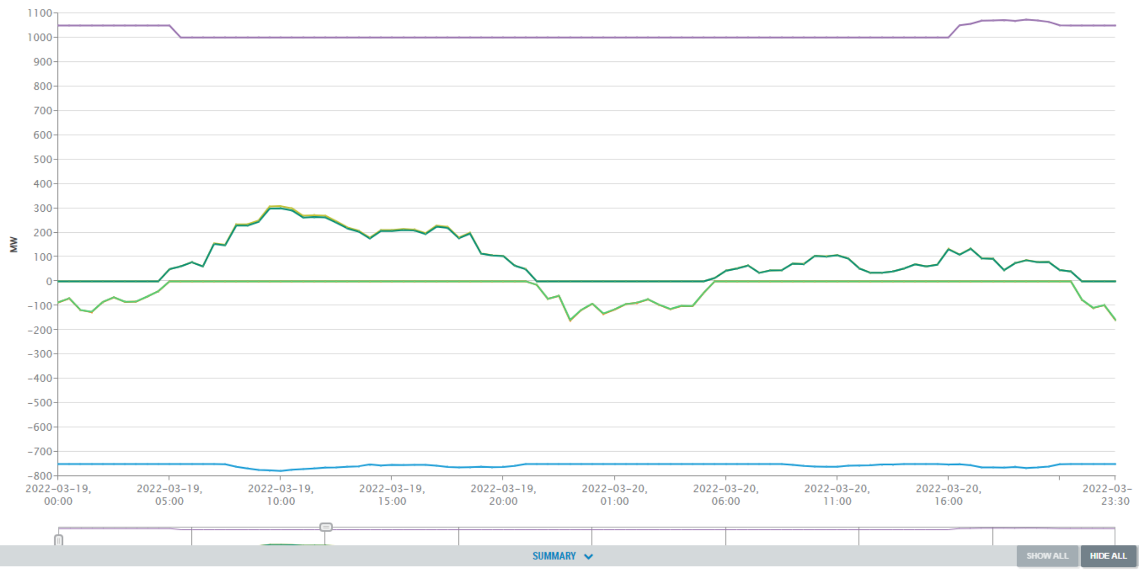
Figure 9: Hourly temperature data (actual and apparent) and humidity data at main population centres



6. Outages

6.1. There was a planned outage of Pole 3 from 05:30 19 March to 16:00 20 March which reduced transfer limits to 500 MW at the HVDC. Figure 10 shows HVDC transfer for the weekend of 19 and 20 March. Flows were within 300 MW over the weekend, well below the transfer limit. This means prices were not impacted, avoiding the price separation between Islands sometimes caused by HVDC outages.

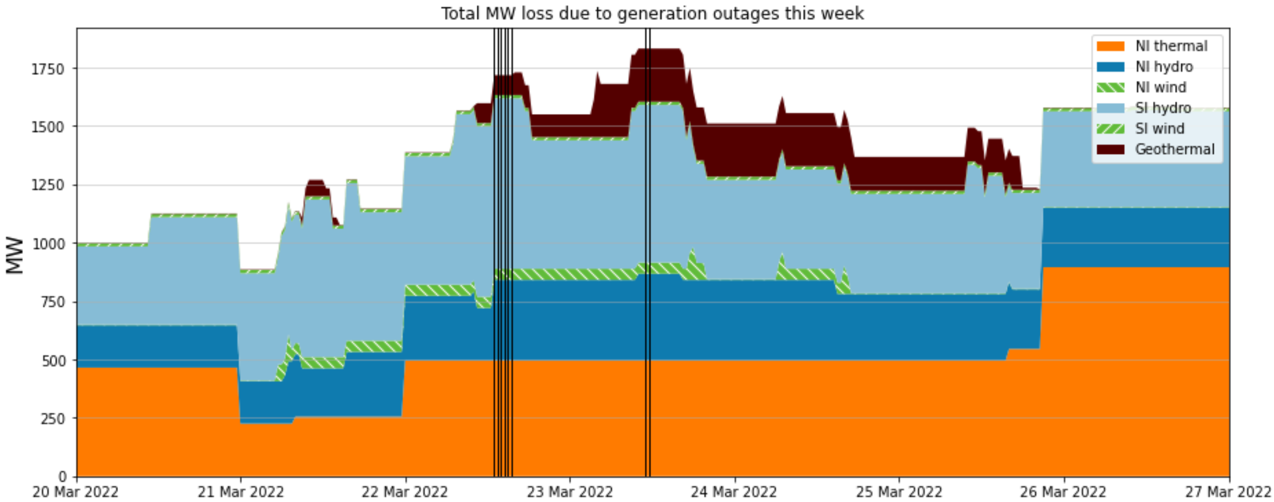
Figure 10: HVDC flow



NORTH	TIME	MW	SOUTH	TIME	MW
PRS Total Bipole Capacity North	2022-03-20 23:30:00 (TP 48)	1,050.000	PRS Total Bipole Capacity South	2022-03-20 23:30:00 (TP 48)	-750.000
PRS Total Sent North	2022-03-20 23:30:00 (TP 48)	0.000	PRS Total Sent South	2022-03-20 23:30:00 (TP 48)	-158.446
PRS Total Received North	2022-03-20 23:30:00 (TP 48)	0.000	PRS Total Received South	2022-03-20 23:30:00 (TP 48)	-157.250

6.2. Figure 11 shows generation capacity lost due to outages between 20 March and 26 March by fuel type. As mentioned previously geothermal generation outages were higher than usual. Total capacity on outage exceeded 1,750 MW on 22 and 23 March, the days that held the highest priced periods for the week. Significant outages this week include outages at Huntly 1 (240 MW), Huntly 4 (240 MW), Manapōuri (125 MW), Stratford (100 MW) and TCC (350 MW).

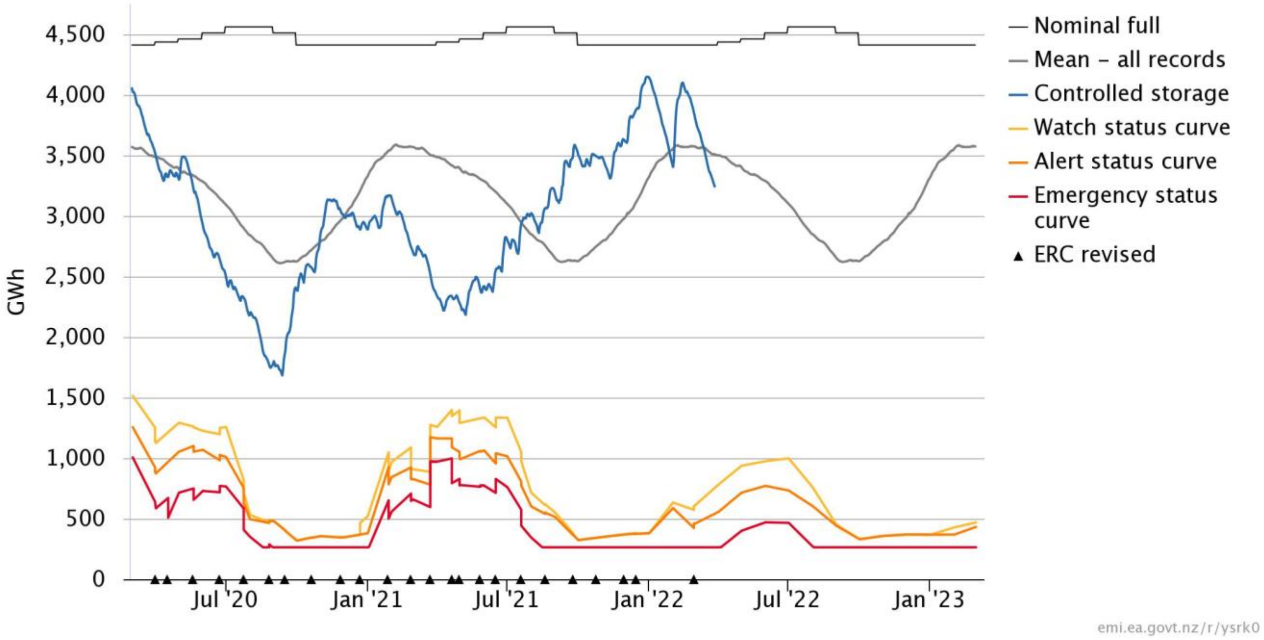
Figure 11: Total MW loss due to generation outages



7. Hydro

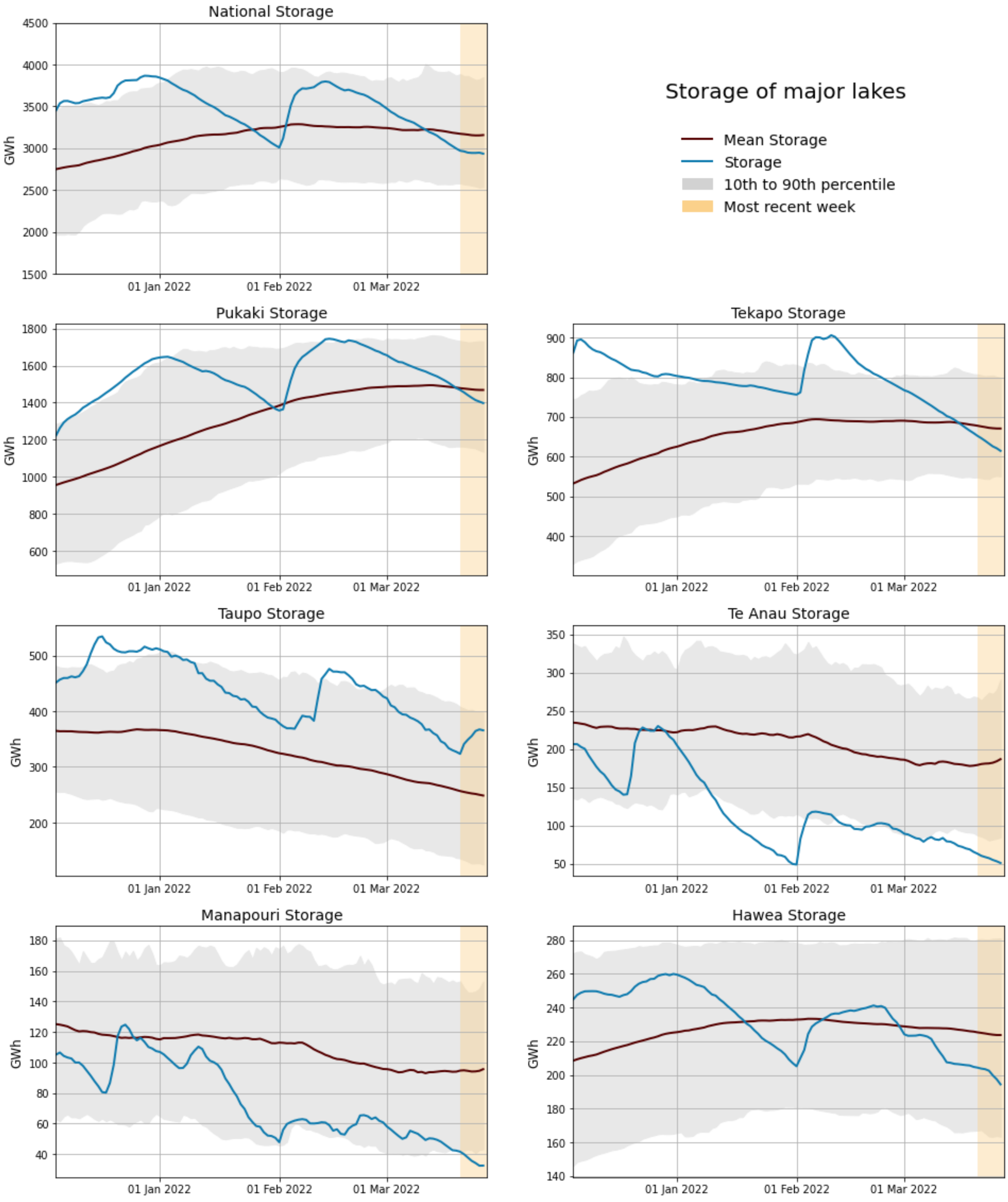
7.1. Figure 12 shows total controlled national hydro storage which totalled 3,244 GWh on 27 March, 266 GWh below the historic mean, 3,510 GWh, for the same day. National hydro storage decreased by 121 GWh over the week. The reason for decreasing storage is due to historically low hydro inflows. Historically, hydro inflows from 1 March to 27 March averaged 1,839 GWh. For the same period this year hydro inflows have totalled 1,051 GWh. Almost a ~50 per cent difference. Drought conditions in Fiordland have caused low inflows into several reservoirs including Lake Manapōuri and curtailed generation in the lower South Island.

Figure 12: Hydro Storage



7.2. Figure 13 shows the storage of major lakes over the last four months. While Lakes Pukaki, Tekapo and Taupo are still close to their historic means, Lake Manapōuri and Te Anau levels continue to remain below their low operating range, restricting generation from Manapōuri.

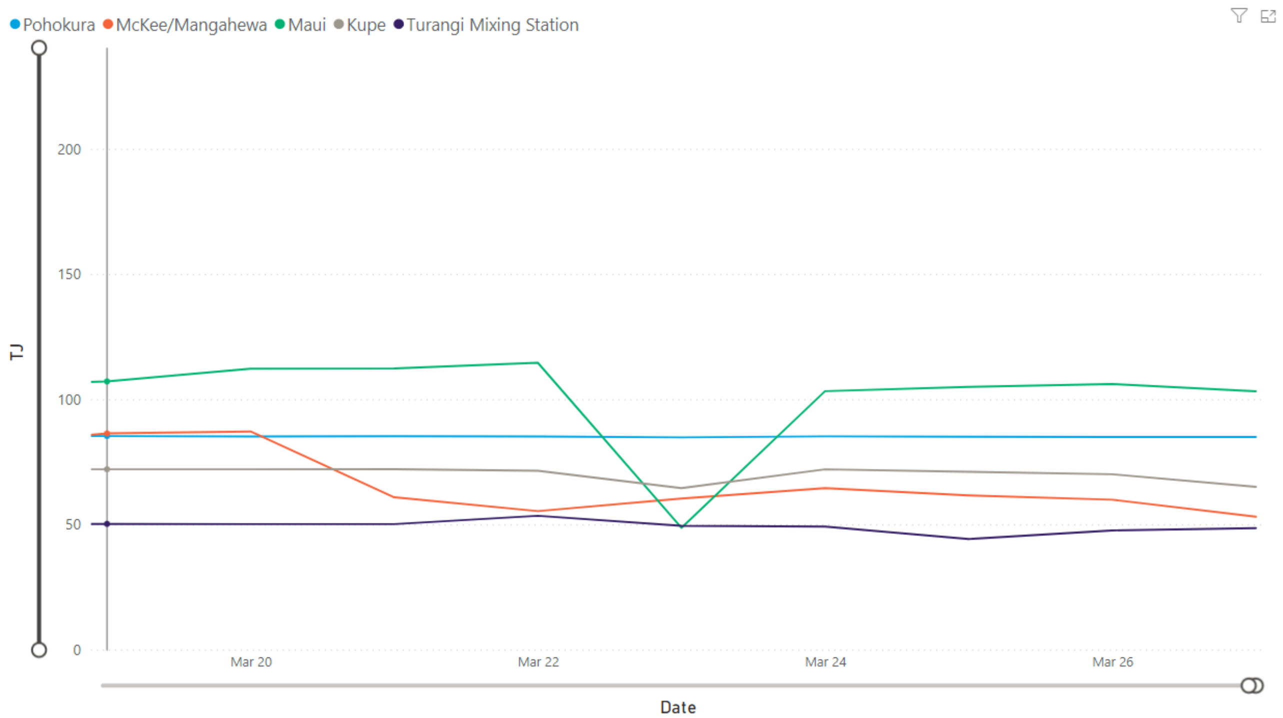
Figure 13: Major Lake Storage



8. Thermal

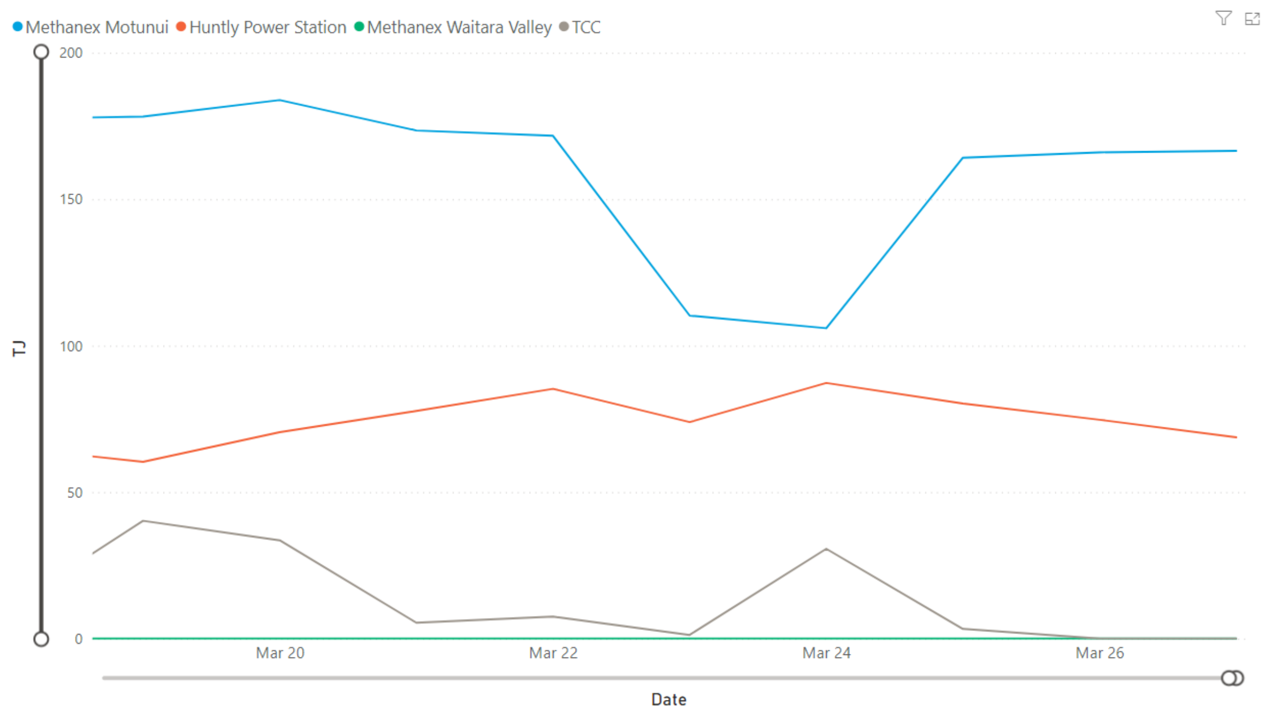
8.1. Total gas production from major gas fields totalled 354.8 TJ/day on 27 March. Gas outages at McKee and Maui mentioned earlier can be seen below in Figure 14 which shows the production of major gas fields.

Figure 14: Major Gas Production



8.2. Due to the outages consumption at the largest consumer, Methanex, dropped significantly. Consumption at Huntly also dropped, though to a lesser extent. Despite the decline thermal generation rose by 13 per cent compared to the previous week. At the same time gas prices rose to between $33/GJ and $47/GJ which pushed up the opportunity cost of thermal generation and increased marginal prices during periods when thermal generation increased.

Figure 15: Major Gas Consumption



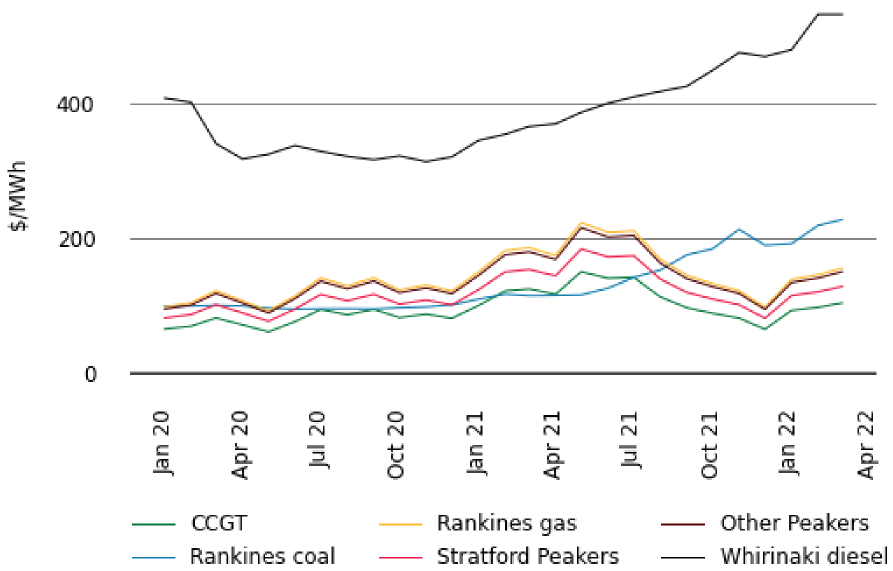
9. Price versus estimated costs

9.1. 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).

9.2. 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.

9.3. 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. Following the March ETS auction spot carbon units have been trading at between $70-75/tonne on the secondary market. Carbon unit prices on the secondary market closed at $76/tonne on 28 March 2022.

Figure 16: Estimated monthly SRMC for thermal fuels



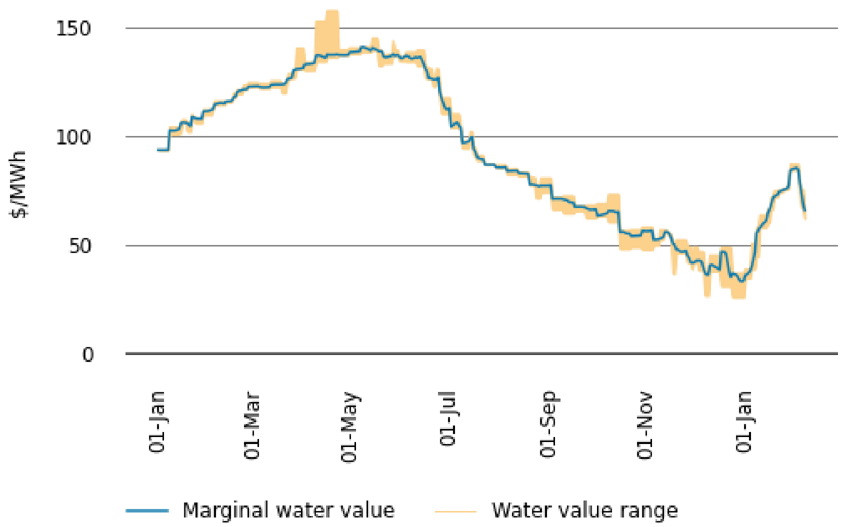
10. JADE Water values

10.1. The JADE[1] 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[2] 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[3].

[1] 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)
[2] The national water values are estimated assuming all hydro storage reservoirs are equally full.
[3] See Appendix B, 3 for more details

10.2. 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

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



11. Offer Behaviour

11.1. Figure 18 shows this week's daily offer stacks, adjusted to take into account wind generation, transmission constraints, reserves and frequency keeping.[4] The black line shows cleared energy, indicating the range of the average final price.

11.2. A steep offer curve this week meant drops in low priced offers caused by low wind resulted in significant increases in marginal prices.

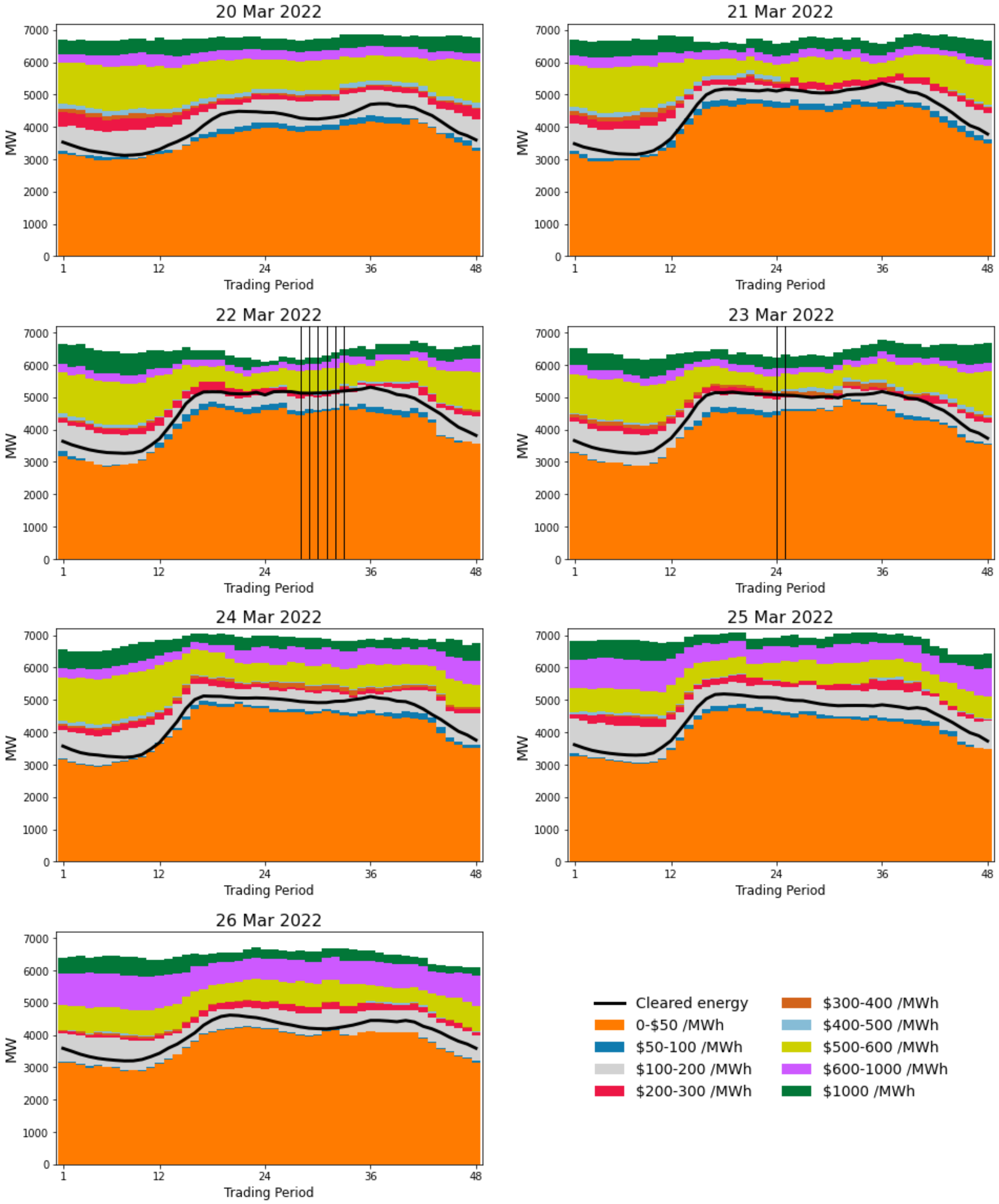
11.3. There was less generation offered in low price tranches in the middle of the day, which contributed to higher prices on 22 March, but these offers were changed well in advance of the trading period and pre-dispatch prices did not indicate prices would be high, suggesting the changes were made by generators wanting to conserve their resources when they expected demand to be low and not to take advantage of market conditions.

11.4. The percentage of $600-$1000/MWh offers noticeably increased from 24 March while the percentage of lower priced tranches decreased. The loss of inexpensive geothermal generation would have added to the reduction in lower priced tranches.

11.5. Manapōuri continues to offer in at least 400MW at $600/MWh due to its restricted 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.

[4] 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 18: Daily offer stack



12. Ongoing Work in Trading Conduct

12.1. High prices on 22 and 23 March appear to be driven by low wind and outages. No trading periods have been identified for further analysis this week.

12.2. Further analysis is being done on the trading periods in Table 2 as indicated.

12.3. Further information has been requested regarding reserve offers in the South Island during the full bipole outage from 19 to 21 February. 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 2: Trading periods identified for further analysis

Date	TP	Status	Notes
03/03-05/03	4-10	Further analysis	Branch constraint, high prices in lower South Island
19/02-24/02		Compliance enquiries in progress	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.
19/02-21/02	Several	Further Information Requested	High South Island reserve prices
08/02-12/02	Several	Further Analysis	High inflows but continued high prices
08/02, 10/02	16-17, 19	Resolved	Further analysis of high FIR prices identified in previous reports found that they were due to SPD co-optimisation of the energy and reserve markets. In these cases, the energy market cleared at a point on the offer curve where the next highest offer price was substantially higher than the marginal offer price. Clearing higher priced reserves prevented higher energy prices and resulted in overall lower costs to the market. Also, on 8 February reserve requirements increased and interruptible load decreased. This created a tighter FIR market, increasing the chance of higher priced FIR. Evidence does not suggest that reserve offers were changed to increase either reserve or energy prices.
30/06/21-20/08/21	Several	Compliance enquiries in progress	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.
30/06/21-21/08/21	Several	Compliance enquiries in progress	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.

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[5], 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.

[5] 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.[6] 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.[7] 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.[7]

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

[6] M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.

[7] 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