Review of price separation and instances of high spot and reserve market prices in November 2022

Background

In November 2022, heavy rainfall and high hydro storage reduced average spot prices compared to previous months. There were, however, still some high wholesale energy and reserve prices. These high prices often occurred for brief periods and in the North Island[1]. While spot prices were below $38/MWh for 75% of November, there were still prices as high as $562/MWh.

This document outlines our understanding of the underlying conditions in November which contributed to the high energy and reserve prices and the price separation. There is also detail on specific high prices.

Analysis

During the Electricity Authority's weekly monitoring of trading conduct, 12 trading periods during November were highlighted for further analysis. *Figure 1* shows spot prices at Benmore and Ōtāhuhu between 6-27 November 2022, alongside the historic median spot price and the historic 10th- 90th percentiles, adjusted for inflation. Solid lines highlight spot prices which exceeded the 90th historic percentile. While dotted lines show prices which did not exceed the 90th percentile but underwent further analysis. These 12 trading periods are summarised in *Table 1*.

Table 1: Summary of trading periods highlighted for further analysis in November 2022

Date	time	Trading period	Price at Benmore or Otahuhu breached 90th percentile	Otahuhu price($/MWh)	Benmore price($/MWh)
07-11-2022	8:00 am	17	N	168	23
08-11-2022	12:30 pm	26	N	218	3
09-11-2022	8:00 am	17	N	383	89
15-11-2022	8:00 am	17	Y	371	349
16-11-2022	6:00 pm	37	N	258	286
17-11-2022	7:00 am	15	N	334	251
17-11-2022	3:00 pm	31	Y	345	129
21-11-2022	8:00 am	17	Y	530	62
21-11-2022	12:30 pm	26	N	273	62
22-11-2022	5:30 pm	36	N	347	62
22-11-2022	9:00 pm	43	Y	368	228
24-11-2022	7:30 am	16	N	291	24

[1] The phenomenon of high prices in one island and low prices in the other is called price separation.

Figures 2 and *3* show that the North and South Island sustained instantaneous reserve (SIR) and fast instantaneous reserve (FIR) prices between 6-27 November 2022, respectively. As with spot prices, the FIR and SIR prices were often separated between the North and South Islands, with high prices in the North. Many of the North Island SIR and FIR spikes coincided with high spot prices in the North Island.

Figure 1: Half-hourly wholesale spot prices at Benmore and Ōtāhuhu between 6- 27 November 2022

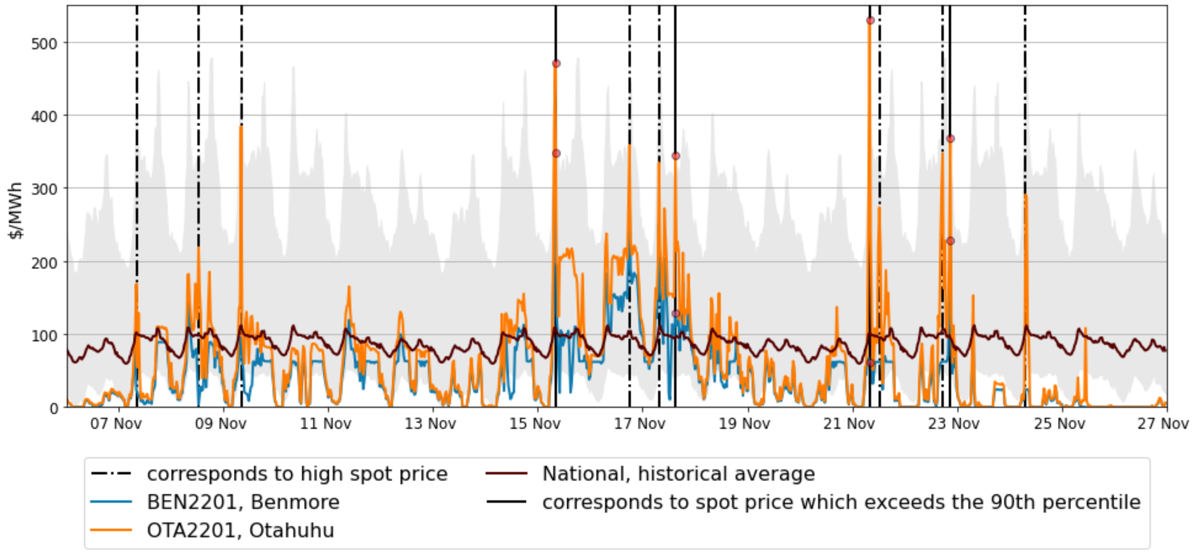


Figure 2: Fast instantaneous reserve prices (FIR) by trading period in the North and South Islands between 6-27 November 2022

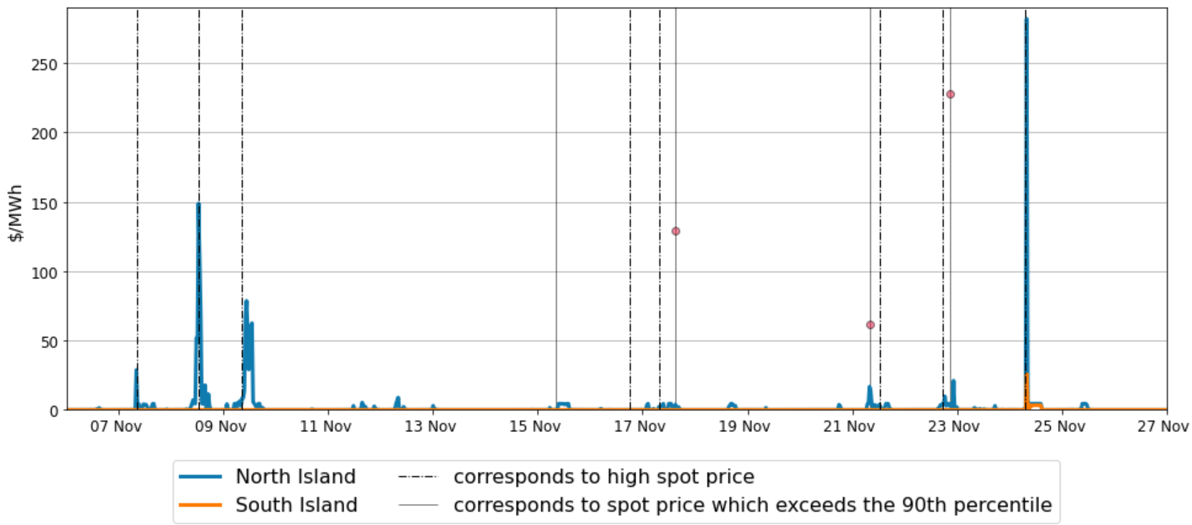
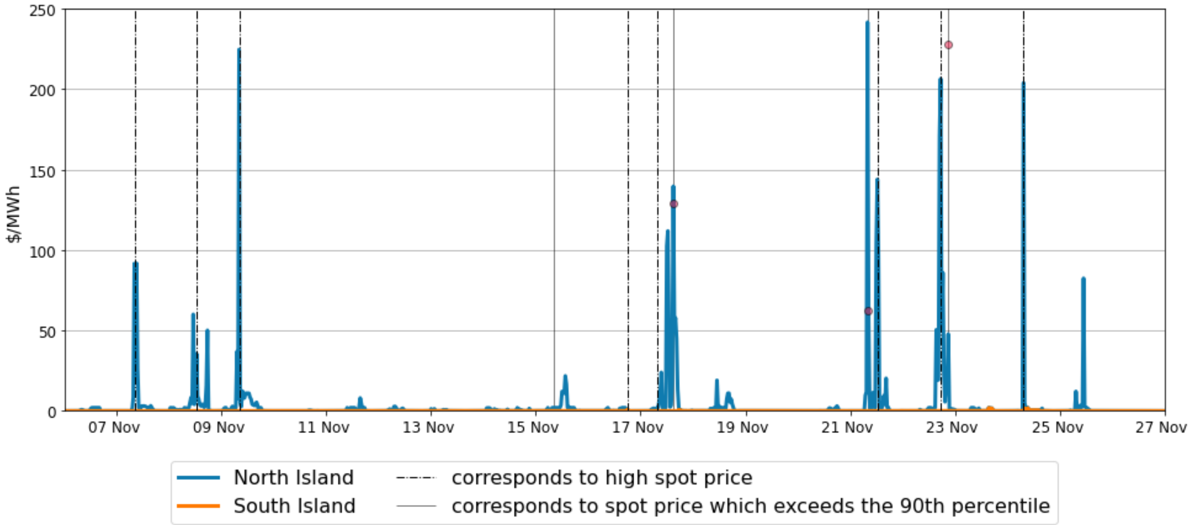


Figure 3: Sustained instantaneous reserve prices (SIR) by trading period in the North and South Islands between 6-27 November 2022

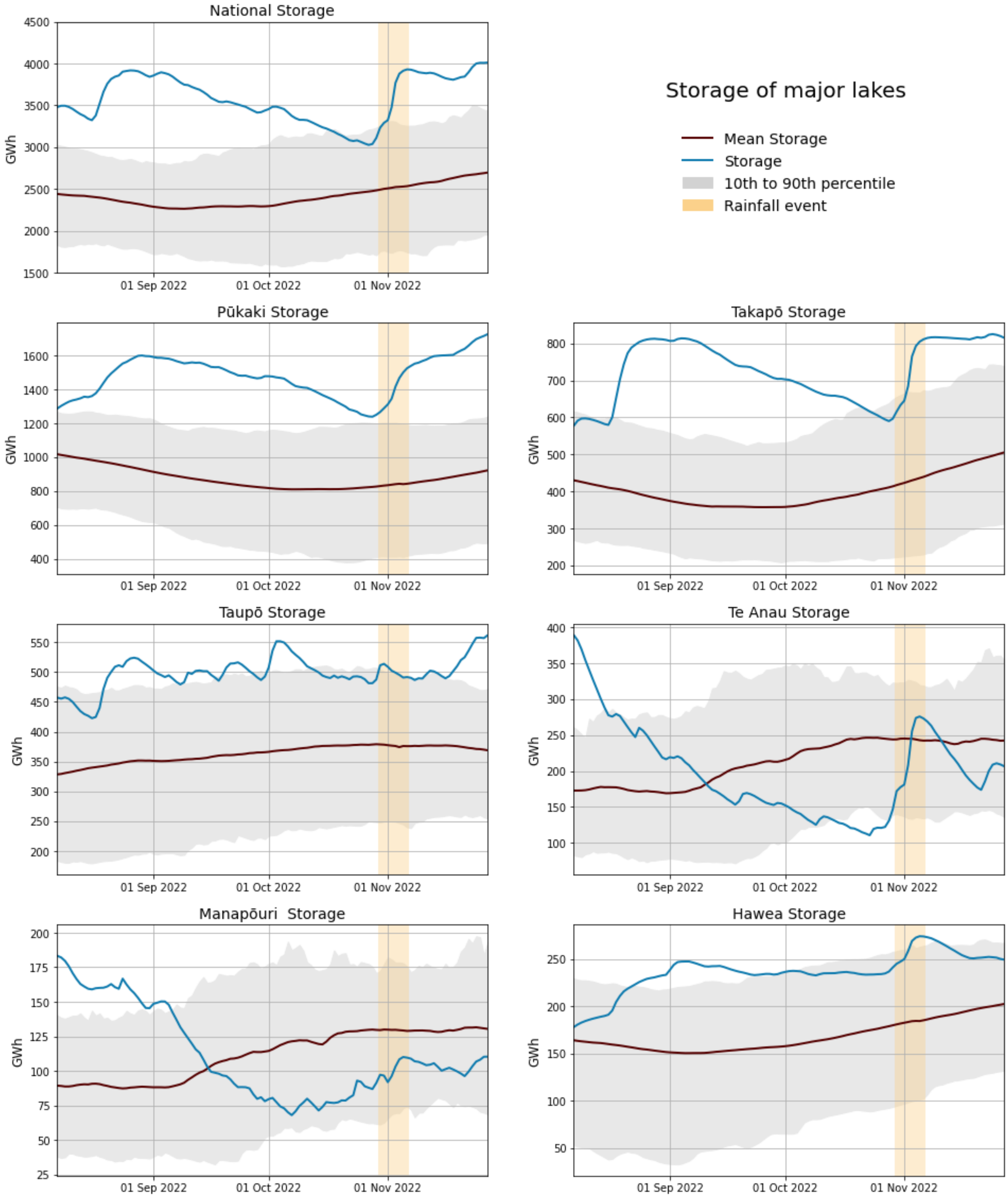


Market conditions in November

Heavy rain in early November refilled many South Island hydro lakes. As a result, southern hydro generators operated with high outputs and low offer prices. *Figure 4* shows national hydro storage, and storage at individual lakes between 7 August and 27 November 2022, alongside each respective historic mean and 10th and 90th percentiles. The yellow highlight in each sub figure highlights the rainfall event which caused national hydro storage to increase by 1,686 MW in early November. These figures show how the Southern hydro lakes, particularly Pūkaki and Takapō had large increases in storage, whilst Lake Taupō had only a small increase followed by a decrease.

As the rain mainly filled the southern hydro lakes, generation in the South Island increased, and more electricity was exported north. This meant the HVDC inter-island cable was often running close to its transfer limit, especially when the wind was low in the North Island.

Figure 4: National hydro storage and storage at individual lakes, between 7 August and 27 November 2022, alongside each respective historic mean and 10th and 90th percentiles of historic storage levels



Given the high volumes the HVDC was transferring, it was often a risk setter on the system - which was covered by the North Island[2] instantaneous reserves[3]. This increased the required amount of North Island reserves and sometimes caused high North Island FIR and SIR prices. This also

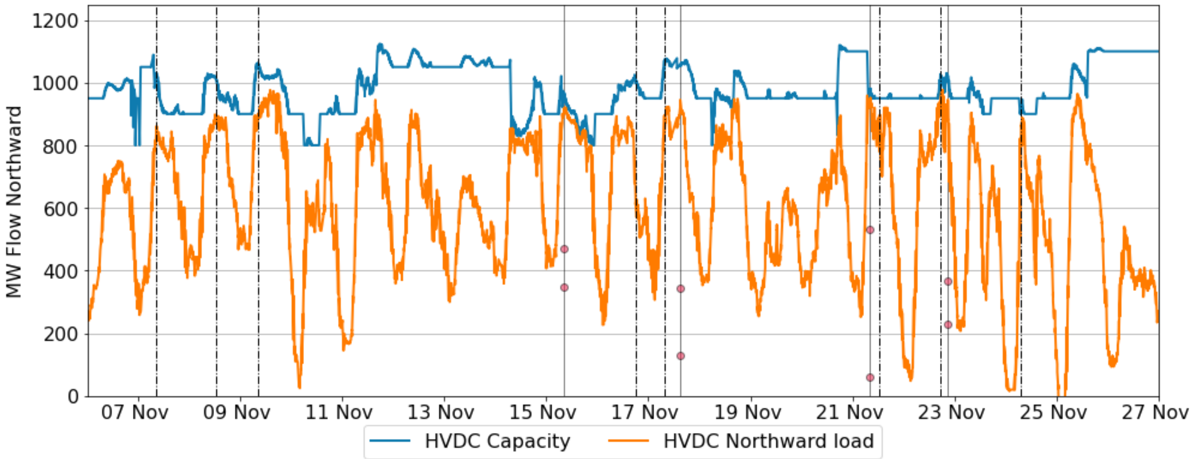
---

[2] It is possible that HVDC and a North Island generator are both binding - in which case the rest of the reserve to cover the generator risk can be on either island.
[3] Read our explainer: [Keeping the lights on with reserves]

contributed to price separation between the islands, as the effective cost of using cheap South Island electricity to meet North Island demand increased by the cost of North Island reserve.

Figure 5 shows the HVDC load and capacity between 6-27 November 2022, with the solid lines indicating times when the wholesale spot prices exceeded the 90th percentile of historic prices. The dotted lines are high prices, which did not exceed the 90th percentile. Note how frequently high prices correlated with high HVDC load, which was often close to capacity.

Figure 5: Northward HVDC load and capacity between 6-27 November 2022



Outages of North Island thermal and geothermal power stations were also contributing factors to price separation and high prices in November. Geothermal power stations run cheaply and continuously, so when they are on outage, thermal or hydro power stations must run in their place - sometimes at a higher cost. Also, the largest and most efficient Huntly thermal unit, Huntly 5, was on outage. Note, the normal daily megawatt quantity of outages for November is around 1,500 MW, as outages are often scheduled when demand is low[4]. Hence, the magnitude of the outages in November 2022 isn't uncommon, however, the loss of generation that runs nearly continuously impacts the market more than generation which would only occasionally run.

Figure 6 shows the total MW loss due to outages between 6-27 November 2022, split by generation type. From 12 November onwards, more than 150 MW of geothermal generation went on outage, with this stepping up to 250 MW on 20 November 2022.

Figure 7 shows the total MW loss due to thermal outages between 6-27 November 2022. Huntly 5 was on outage between 1 and 20 November. This was aligned with the Kupe gas field outage, which decreased total daily gas field output by roughly 60 TJ/day. Both Stratford gas peakers also had outages in November.

[4] Read our explainer: [Keeping the lights on with reserves]()

Figure 6: Total MW loss due to outages between 6-27 November 2022

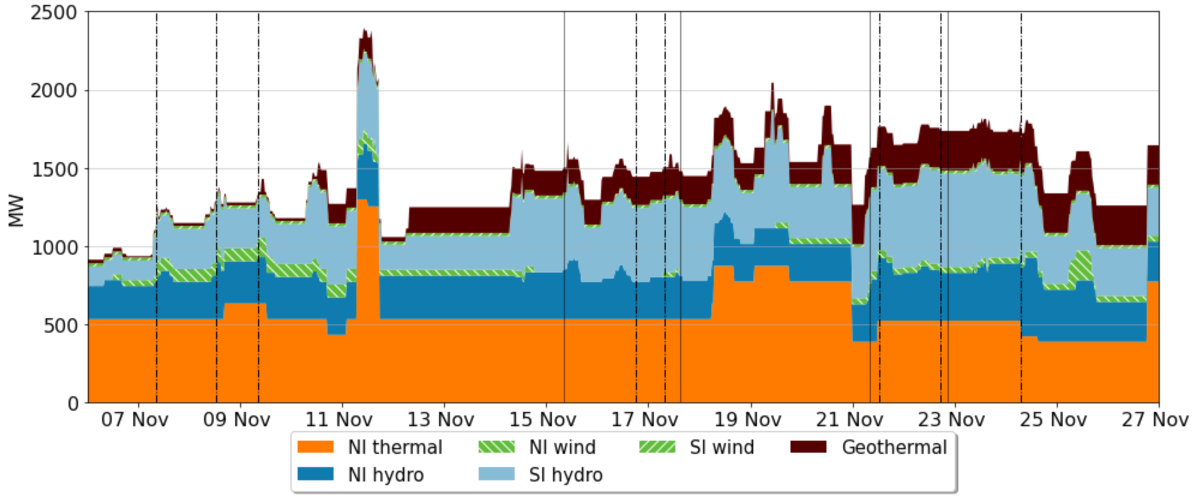
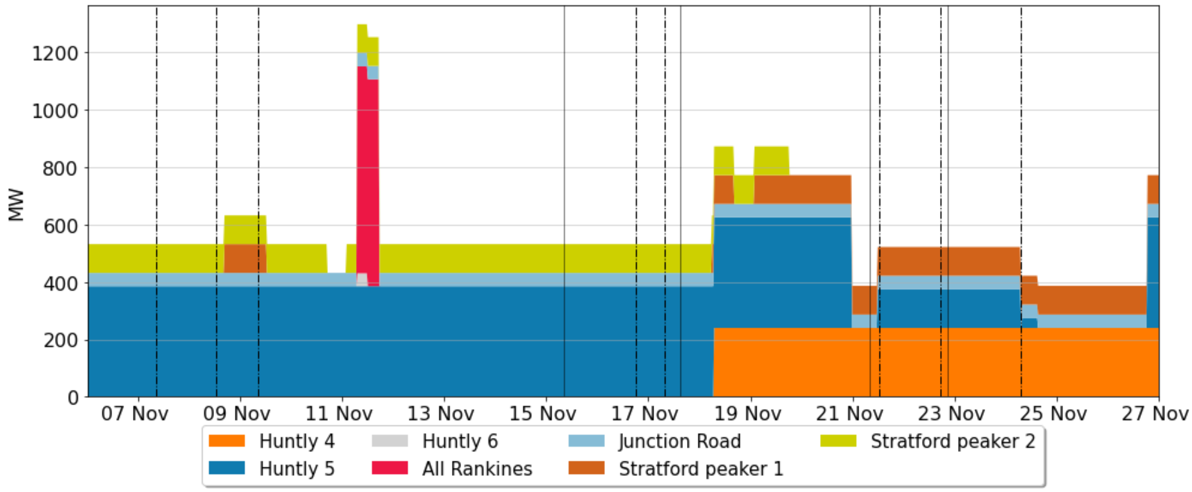


Figure 7: Total MW loss due to thermal outages between 6-27 November 2022



Furthermore, both low North Island wind generation and deviations between actual and forecast wind generation were other factors influencing spot prices in November 2022. Generally, when wind generation was forecast to be high, forecast prices (as published on WITS) were often low.

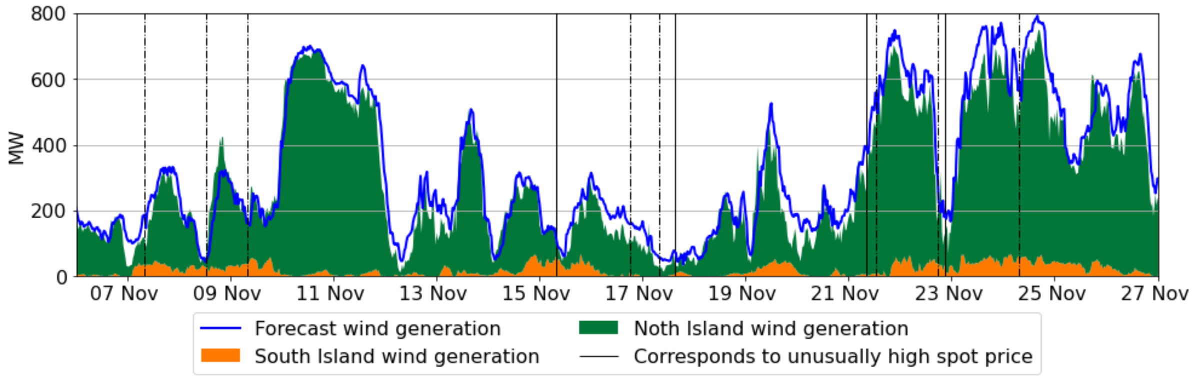
As a result, thermal generators often expected average prices to be lower than the short run marginal cost (SRMC) of running their thermal units, including start-up costs. Many thermal operators submitted high priced offers to reduce the likelihood of dispatch – given the low forecast price, and to ensure their start-up costs were covered if they were dispatched for a single trading period.

Often almost all hydro was clearing - with higher amounts needed to cover baseload due to the geothermal outages – so thermal generation was sometimes the only option available to cover shortfalls in wind generation. This sometimes meant that high thermal tranches were cleared, with the pre-dispatch price and real time price then differing substantially.

If forecast wind generation and forecast prices more accurately reflected the actual wind generation totals, then some thermal generators may have decreased their offer prices. If the pre-dispatch price was then above a unit's SRMC, insuring both fuel and start-up costs would be covered, if they ran for several trading periods.

Figure 8 shows the North and South Island wind generation in megawatts and the total forecast wind generation, between 6-27 November 2022. During this period, high spot prices often occurred when wind generation in the North Island was low or when total wind generation was less than forecast.

Figure 8: North and South Island wind generation in MW and the total forecast wind generation, between 6-27 November 2022



Specific high prices and their resolutions

The following trading periods were highlighted for further analysis during the weekly monitoring of trading conduct. On request, generators provided additional information to the Authority regarding offers during some of these trading periods.

Trading period 17 (8:00 am) on 15 November. High spot prices occurred in both Islands. Further analysis found both the McKee and Junction Road thermal units, operated by Nova Energy, were both priced above $1,000/MWh. This lack of lower cost peakers meant that Stratford 1 and all South Island hydro generation was dispatched.

Nova Energy offers tend to be based on whether pre-dispatch prices meet each unit's SRMC, if so, they would reduce their offers, ensuring the units would run, if not, offers remain high. Note, however, sometimes other factors are involved. The Authority also made inquiries with Genesis regarding units at Huntly. Genesis, however, opted not to have this information publicly disclosed.

Trading period 37 (6:00pm) on 16 November. There were high energy prices in both islands. Again, many thermal peakers had been priced high, as the pre-dispatch price did not cover the plant's SRMC. This led to all South Island hydro being dispatched, alongside a higher tranche of Huntly 1.

Trading period 16 (7:30am) on 17 November. Spot prices were high in both islands. Further analysis found that the maximum amount of generation from Rangipo dam had decreased. Also, offer tranches at Patea dam were high when compared to the same trading period in previous days. Rangipo dam experienced a high inflow event on November 17, which reduced the maximum generation capacity – to ensure plant safety. High prices at Patea reflected the recent drawdown of the lake, with the lake containing only 2 GWh, so offers were priced high to reduce the likelihood of dispatch and conserve water.

Trading period 31 (3:00pm) on 17 November. Further analysis of the high North Island spot price found that McKee and Junction Road thermal units were all priced above $1,000/MWh. Wind generation in the North Island was low and the HVDC was transferring high loads northwards, setting the risk, and requiring a high amount of reserve. Both McKee and Junction Road had been running throughout the day but were priced high during this trading period. Again, Nova Energy had high priced offers at the time, as pre-dispatch prices weren't above the unit's SRMC. The lack of lower priced thermal offers led to higher priced tranches of hydro being dispatched.

The 21 and 22 November. There were high North Island energy and SIR prices during several trading periods. This resulted from higher priced offers clearing as the North Island energy market was rather tight, as a high quantity of reserves were needed to cover the risk posed by the HVDC. This was exacerbated by periods of low wind and several partial outages of Mercury hydro generation stations.

Trading period 43 (9:00pm) on 22 November. There were high energy and reserve prices in both islands. Further analysis found that North Island wind generation was low, and nearly all hydro in the South Island was dispatched. Huntly 6 and Huntly 1 ran during the peak that evening but reduced their generation in line with gas availability.

Trading period 16 (7:30 am) on 24 November. There was a high energy and SIR price in the North Island. The North Island was experiencing the tight reserve and energy conditions explained above. However, further analysis found that this was likely compounded by the maximum output from the Rangipo dam decreasing by 60 MW. According to Genesis, as the dam was returning to service after a weather event, one of the generators suffered a technical fault which temporarily reduced its maximum output.