

Market Performance Quarterly Review

October-December 2020
Information paper

2 February 2021



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1 Purpose of the report

- 1.1 This document covers a broad range of topics in the electricity market. It is published quarterly to provide visibility of the regular monitoring undertaken by the Electricity Authority.
- 1.2 This quarter's review includes a general overview of the quarter (October to December) and the year 2020.

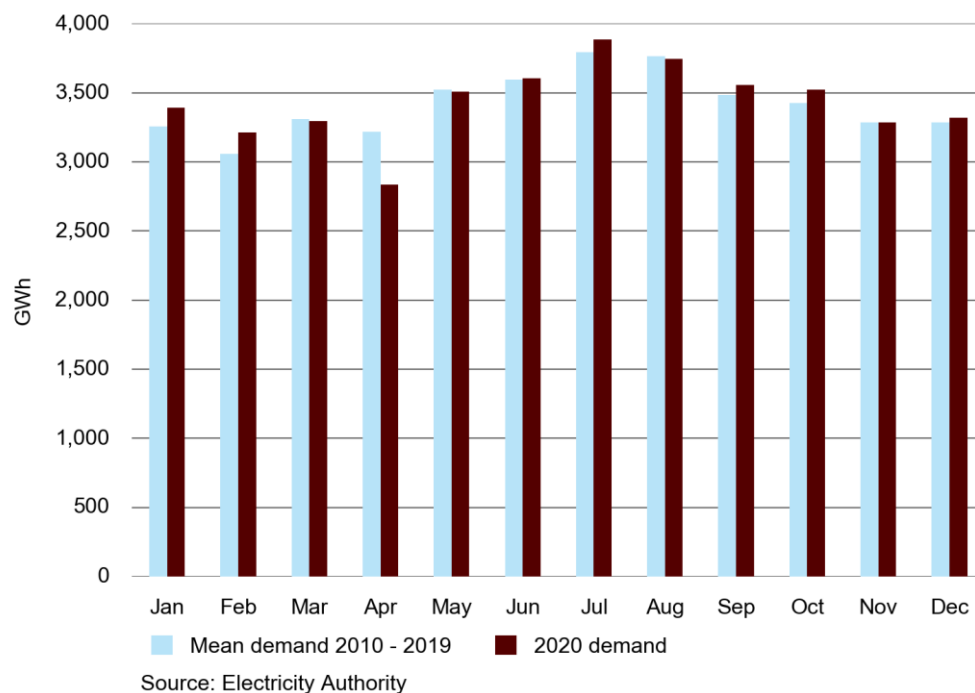
2 Highlights

- 2.1 Demand was higher than average most months in 2020 especially in October when irrigation demand was high.
- 2.2 Medium sized retailers continued to grow, especially Electric Kiwi who gained 22,000 ICPs during 2020. Move-in switches reached an all time high in December 2020.
- 2.3 Declining gas production at Pohokura saw an increase in renewable generation in the last quarter. Prices dropped over spring due to high inflows but then increased as La Niña weather conditions caused dry weather patterns.
- 2.4 Forward prices were volatile in 2020 due to the announcements regarding the Tiwai aluminium smelter's potential closure in 2021. Forward prices for 2021 also increased in the last quarter due to reduced gas production at Pohokura and continued very dry conditions.

3 Demand

- 3.1 Total reconciled demand was 41.2 TWh in 2020 down from 41.7 TWh in 2019. The fall in demand was mostly due to the large reduction in both industrial and commercial demand during Covid19 alert level 4 in March and April. The Tiwai aluminium smelter was given one of the few exemptions from this shutdown, but it did shutdown potline 4 in early April, reducing Tiwai's demand by 50MW. This potline has not restarted.
- 3.2 Figure 1 shows monthly reconciled demand (including Tiwai) for 2020 compared to the average (since 2010). Demand was lower than average from March to May and for August, all periods when the Covid19 alert level was at 4 or 3 (in Auckland only for August). Otherwise, demand was higher suggesting the possibility of underlying demand growth.

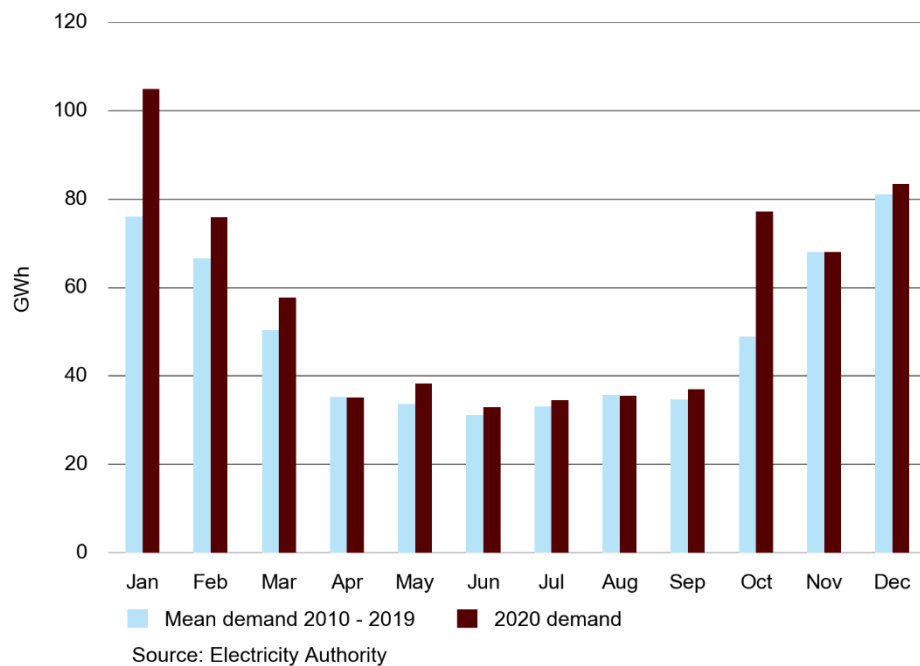
Figure 1: Monthly reconciled demand in 2020 compared to 2010-2019



- 3.3 Demand was more than 2.5% higher than average in January, February, and October. During these months there was higher demand from irrigation load due below average rainfall, especially in the Canterbury region¹. Irrigation load's demand profile is the reverse of the national average with higher demand in summer and lower in winter. This is shown by Figure 2 using Ashburton as a proxy for Canterbury's irrigation demand. Ashburton's demand was 38% higher in January and 58% higher in October due to dry conditions which increased demand for irrigation.

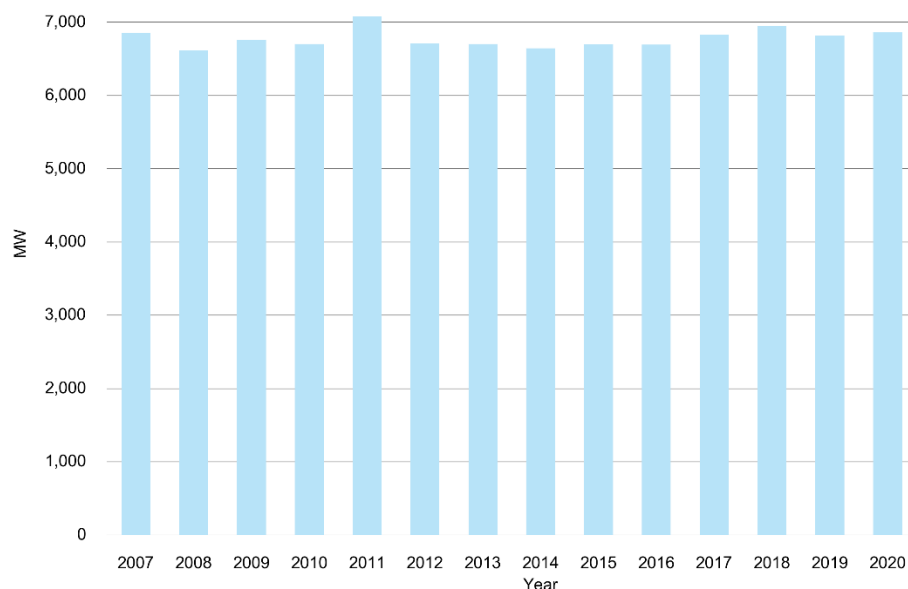
¹ NIWA Monthly climate summary, [January](#), [February](#) and [October](#) 2020, <https://niwa.co.nz/climate/monthly>

Figure 2: Ashburton's monthly reconciled demand in 2020 compared to 2010-2019



- 3.4 Peak demand in 2020 was 6,860 MW, higher than the peak in 2019 but lower than 2018 or the peak in 2011 of 7,080 MW. The peak period for 2020 occurred between 6:30pm and 7pm on 8 July. On this day there were severe gales in the north of the country and a cold southerly in the south.

Figure 3: Peak generation (MW) of each year 2007-2020



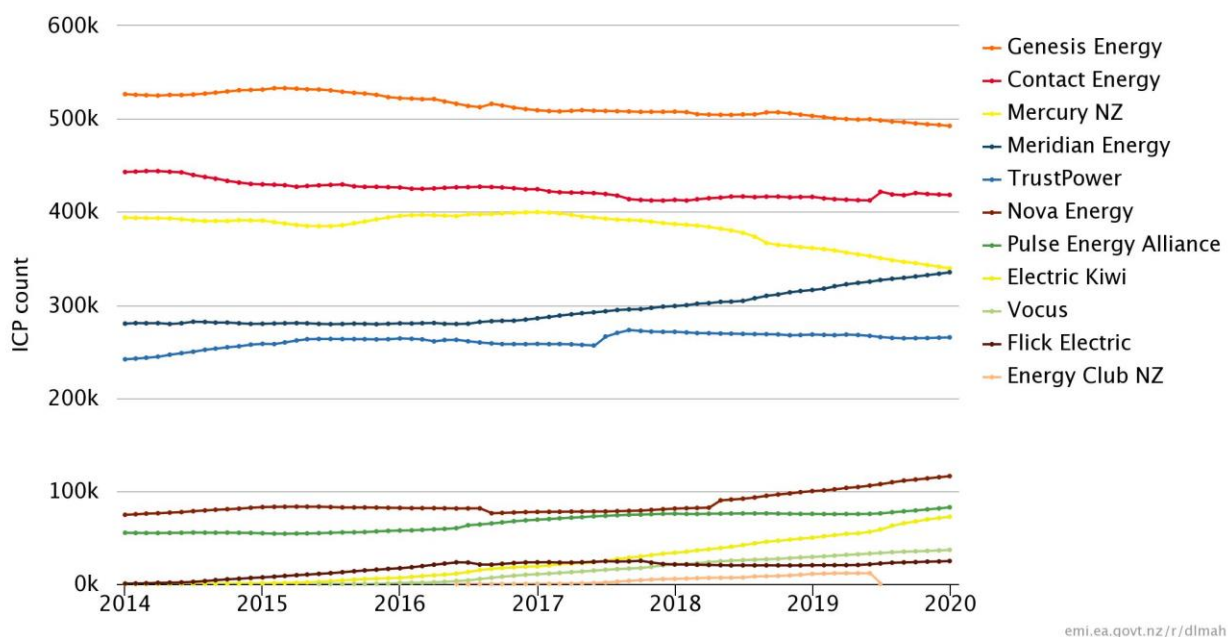
- 3.5 Despite the pandemic reducing 2020's total demand, there are early indications that demand is starting to grow. The Climate Change Commission has also called for accelerated electrification of transport and process heat which would increase future demand. Conversely, some large industrial consumers are under review and could reduce their demand, such as Marsden Point refinery, and the Tiwai aluminium smelter may close after 2024 which would reduce demand by 570 MW (5 TWh per year), which is 12% of current demand.

- 3.6 The ongoing impact of climate change will also impact future demand for electricity. Average temperatures are expected to keep increasing, which would reduce heating demand in winter but increase cooling and irrigation demand in summer. Extreme weather events, such as the storm in August 2011, can also increase peak winter demand, even if total winter demand decreases.

4 Retail

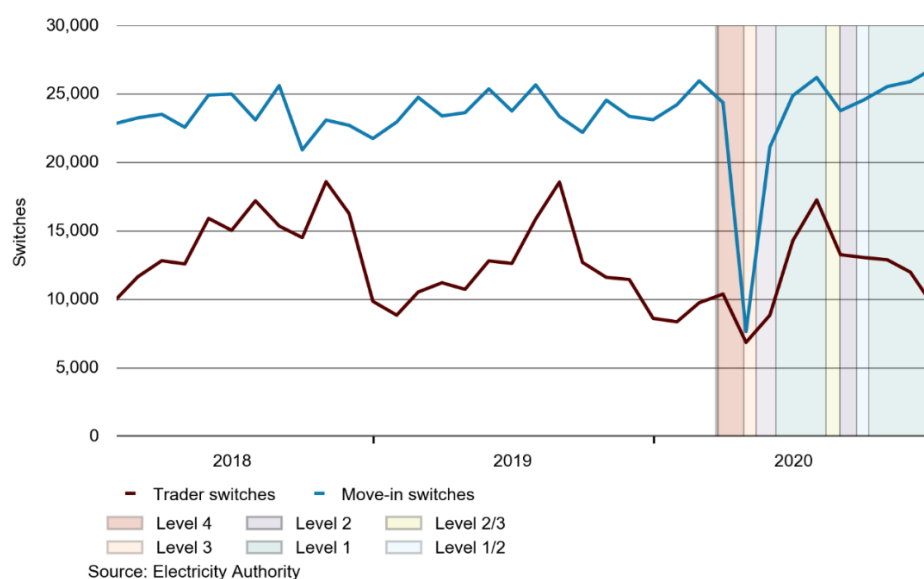
- 4.1 The retail market is currently made up of five large retailers and over thirty small to medium sized retailers. Figure 4 shows the number of ICPs by retailers with over 10,000 ICPs. Despite losing 10,000 ICPs during 2020 Genesis remains the biggest retailer. Mercury lost almost 22,000 ICPs and Trustpower lost 3,000 ICPs. Meridian grew by 19,000 ICPs ending with 335,000 ICPs. Three-quarters of its growth was from its Powershop brand, which now has just under 100,000 ICPs.
- 4.2 Contact lost ICPs most months of 2020. However, in June it acquired 11,000 ICPs from Energy Club NZ. Overall, it gained 2,000 ICPs during 2020 ending the year with 418,000 ICPs.
- 4.3 Medium sized retailers all grew in 2020. Nova Energy grew by 16,000 ICPs and Pulse Energy by 7,000 ICPs. Electric Kiwi had the highest growth, gaining 22,000 ICPs. Flick Electric had more modest growth, gaining 4,500 ICPs.

Figure 4: Number of ICPs by retailer (with at least 10k ICPs during 2020) 2015-2020



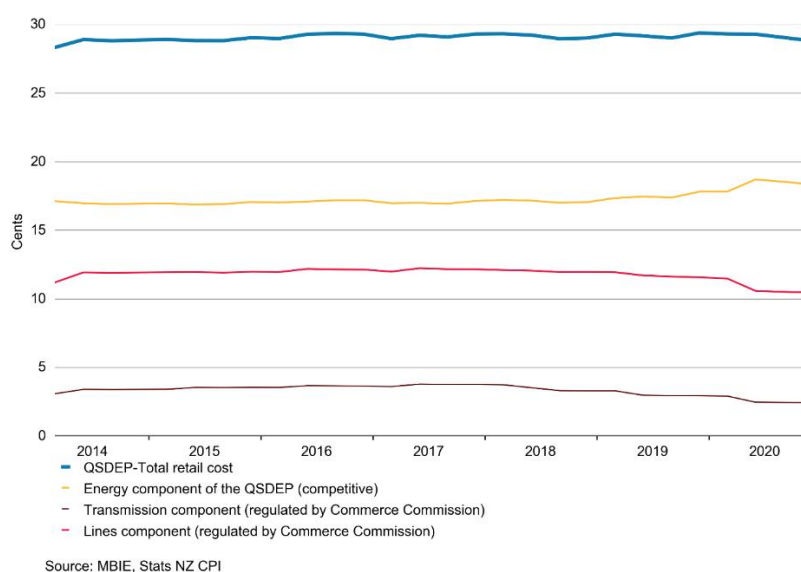
The total number of switches this last quarter was down by 5,000 switches on the previous quarter due to a decline in trader switches over summer, following yearly trends. However, move in switches increased to a record high of 27,000 switches in the month of December. Switching behaviour this year has been impacted by the alert levels for Covid19,

with record low switching in April, as well as a decline in August. **Figure 5: Move-in and trader switches 2018-2020 with Covid-19 alert levels**



- 4.4 The Quarterly Survey of Domestic Electricity Prices (QSDEP) indicator is an average price series based on publicly advertised tariffs in the retail market. The series estimates costs based on an average household consumption of 8,000 kWh per year to calculate a per energy unit charge. It does not capture actual costs to households, which may vary based on type of tariff and total electricity use.
- 4.5 Figure 6 shows the QSDEP adjusted for inflation between 2014 and 2020. It shows that between 2015 and 2018 retail costs, including for each component, were stable and in line with inflation. Since 2018 there has been an increase in the energy component of the cost of electricity, reflecting ongoing gas scarcity since the 2018 Pohokura outage. This has been partially offset by a decrease in transmission and distribution costs, with a drop in the cost of these two components from 1 April 2020 when the new price-quality paths set by the Commerce Commission came into effect.

Figure 6: Real QSDEP by component, 2014-2020

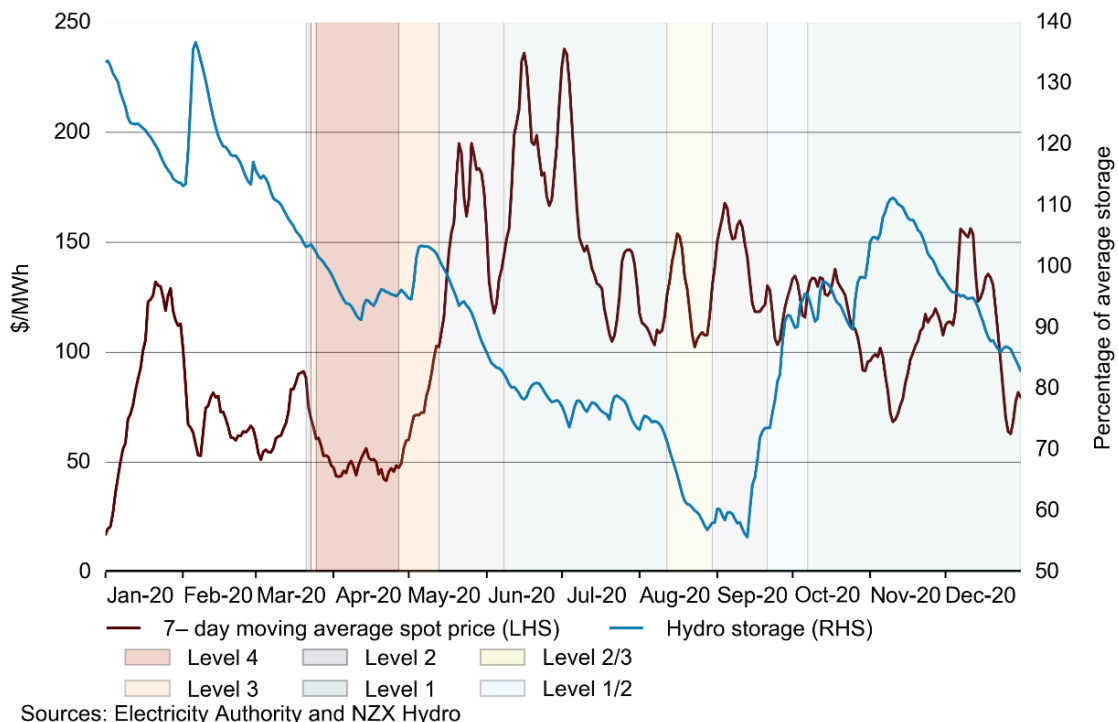


5 Wholesale

Spot Market Commentary

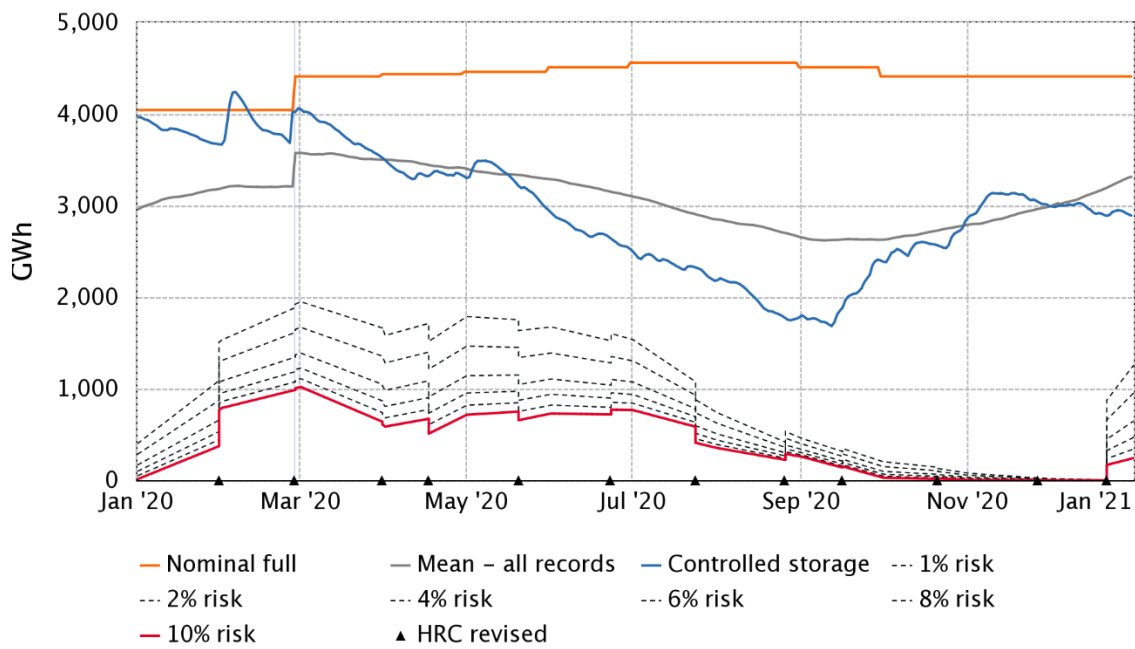
- 5.1 The market in the fourth quarter was characterized by fluctuating hydro storage levels and spot prices alongside a declining gas supply. Throughout the quarter low North Island inflows and decreasing gas supply caused hydro generation to replace a shortfall in thermal generation, hindering the growth of hydro storage levels. The year ended with below average lake levels and gas availability increasing the chances of high spot prices occurring when trying to meet demand in 2021.

Figure 7: Average Spot Price and Hydro Storage



- 5.2 Over 2020 hydro storage decreased from January to mid-September due to below average inflows and higher than average demand once the country came out of lockdown. Storage levels rose in September once snow melt and rain in spring increased inflows. Below average rainfall across much of the North Island from October to December left hydro storage below historical average levels at the end of the quarter. Wholesale spot prices followed the expected inverse relationship with hydro storage, declining in early November when storage was at its peak for the quarter and peaking in early December after storage started decreasing halfway through the quarter.
- 5.3 Despite falling hydro storage levels in late December spot prices fell with decreased holiday demand. Prices in the wholesale spot market remained within the range of \$70-\$155/MWh. As seen in Figure 7 hydro storage was approximately 80% of average historical storage levels at the end of the year 2020.

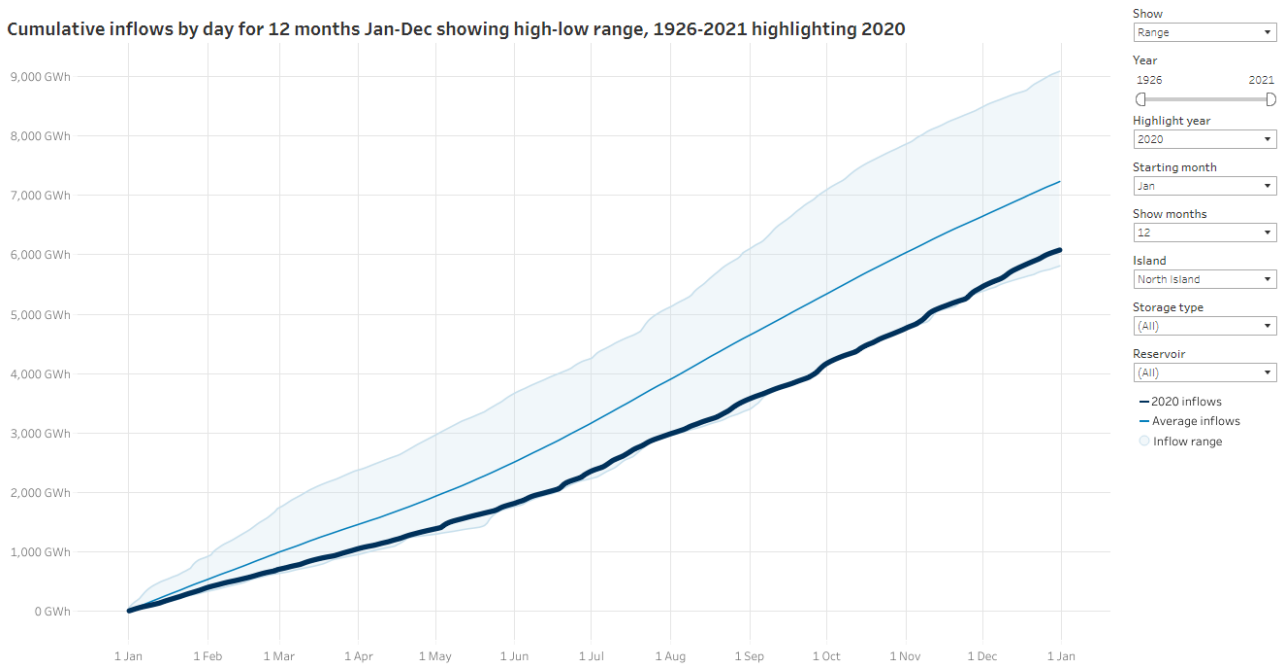
Figure 8: Total Controlled Storage v Historical Risk Curves



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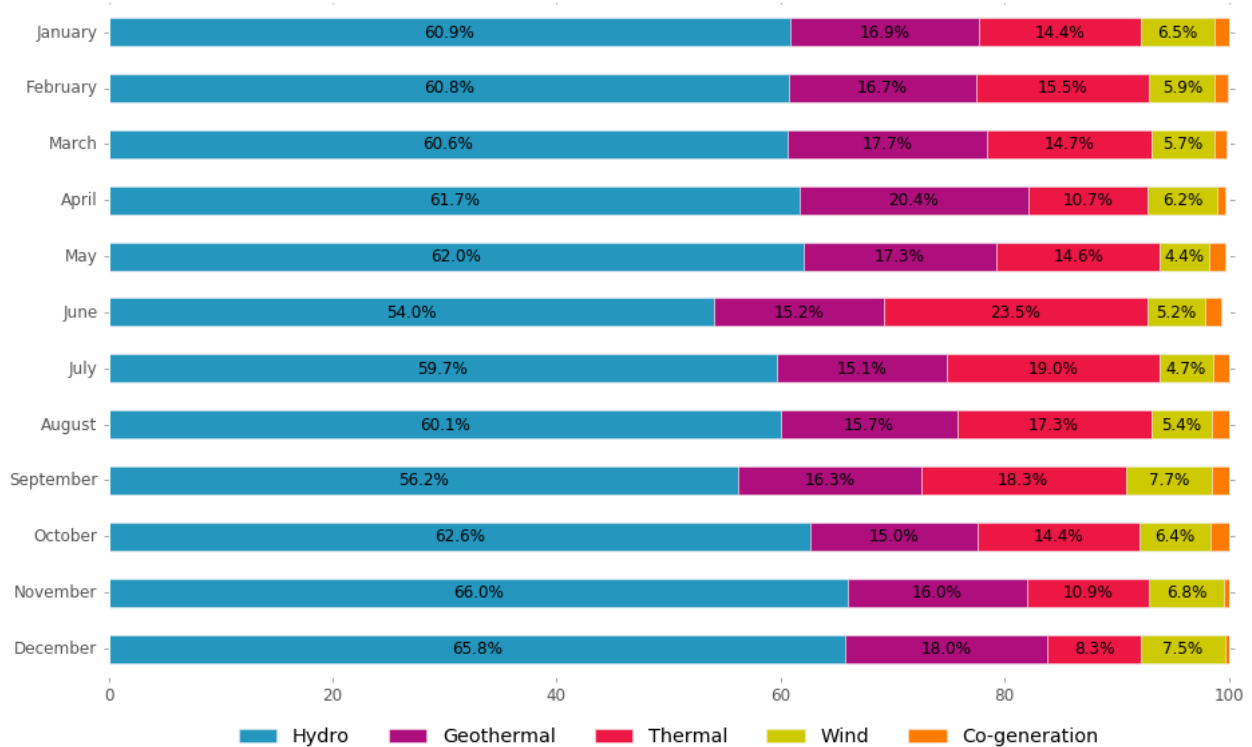
Figure 9: North Island Cumulative Inflows

Cumulative inflows by day for 12 months Jan-Dec showing high-low range, 1926-2021 highlighting 2020



5.4 Figure 9 shows the total cumulative North Island inflows for 2020 against the range of cumulative inflows for the North Island since 1926. Inflows for 2020 were the 9th lowest on record – as a result there was very little southward flow across the HVDC link for October and November. Southward flow increased in December as lake levels in the South Island began to decline, with Lake Pukaki falling below historical average levels.

Figure 10: Generation by Fuel Type



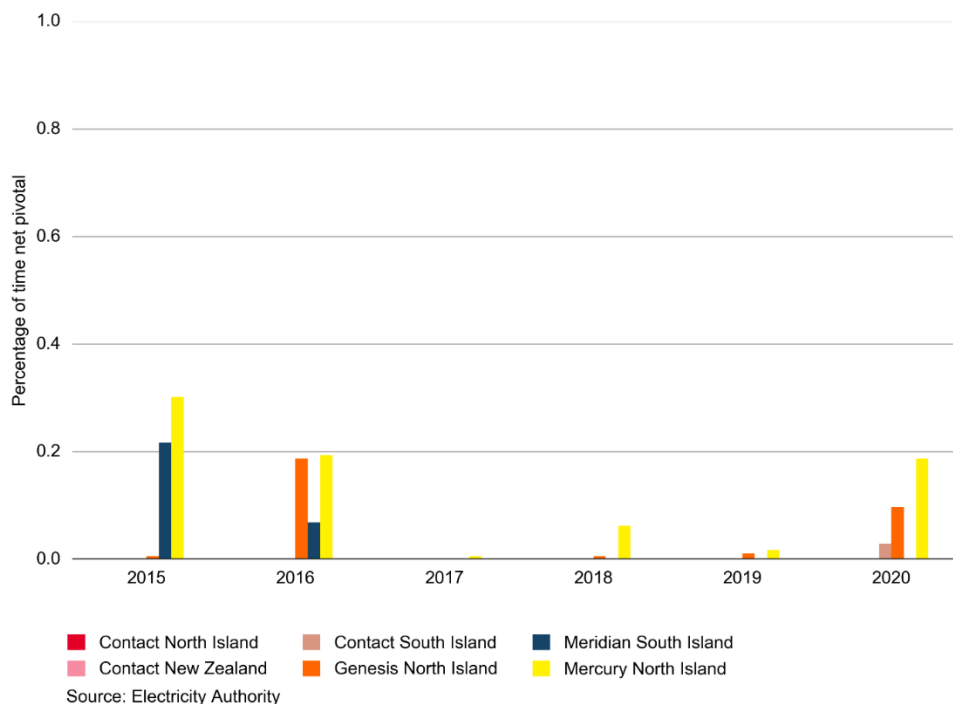
- 5.5 Figure 10 shows fuel type as a percentage of total generation for each month in 2020. Hydro averaged 65% of total generation for the quarter followed by geothermal (16%), thermal (11%), wind (7%) and small amounts of co-generation.
- 5.6 The reduction in demand over summer as well as the decreasing supply of gas caused thermal generation to shrink over the quarter, reducing to 8.3% in December from 14.4% in October. As a percentage hydro generation was higher in each month of the quarter than every other month in the year reducing hydro storage accumulation. Higher than average wind generation only partially offset decreasing hydro storage leading to prices spiking in early December.
- 5.7 The uptake of distributed generation, predominantly solar, continues to rise slowly, increasing from 1.41% to 1.46% of all ICPs over the last quarter. On 31 Dec 2020 distributed generation had a total capacity of 1623 MW at 32,196 ICPs.

Figure 11: Daily Gas Production and Consumption



- 5.8 Firstgas upgraded its Ahuroa gas storage facility in early October, enabling daily gas injection and gas extraction rates to increase to 65 TJ per day. As with earlier parts of the year, however, outages continued to disrupt the gas supply chain, Kupe being out for almost two weeks in early December with production lowered by more than 45 TJ/day. Pohokura, New Zealand's largest gas field, continued to have problems with its offshore wells despite intervention. As seen in the top half of Figure 11, which shows daily gas production by major fields, Pohokura production reduced from 164 TJ/day to 133 TJ/day during the last quarter of 2020. While the rate of decline has slowed post-intervention it has not lifted leading to a tight gas market going into 2021. With the expectations of further gas reductions, coal imports have increased, with all three Rankine units available to run in 2021.

Figure 12: Percent of time when generators were net pivotal

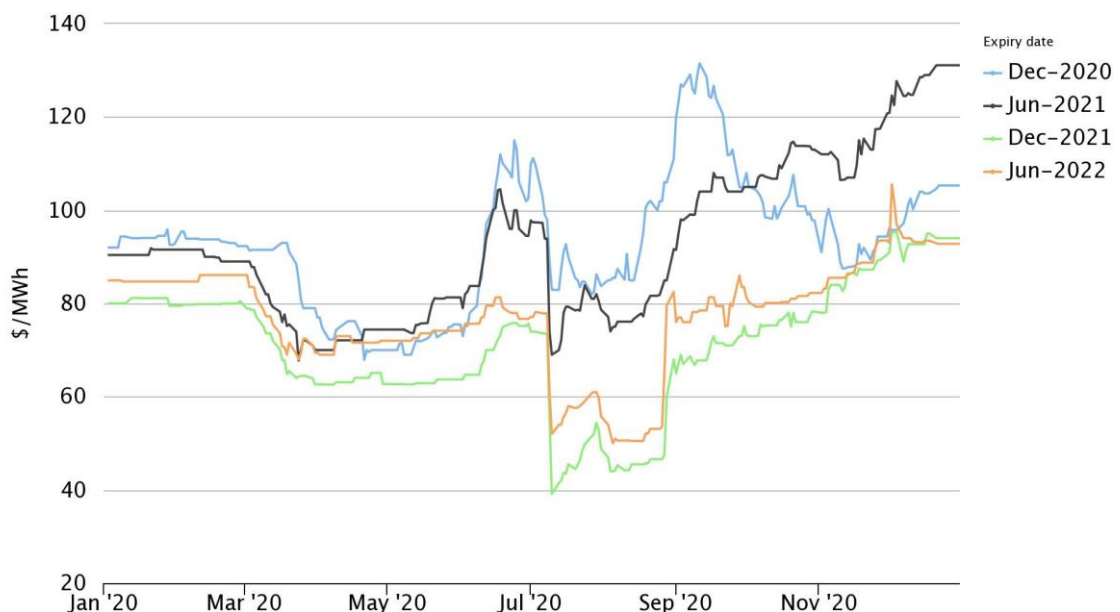


- 5.9 An electricity generator is net pivotal when it could offer its generation at a very high price and still be dispatched at a profit, given its position in the retail, forward and FTR markets. In this situation, other generators have no counter strategy available which would limit high prices, giving rise to an exceptional situation where the pivotal generator could take unilateral action to increase the price as high as they wanted to increase their profits. However, in most trading periods spot market prices are constrained by actual and potential competitive responses by other generators or by portfolio positions that would make increasing prices unprofitable.
- 5.10 Figure 12 shows the percent of time that each generator was identified as being net pivotal across a large part of the grid, either at an island level or nationally. In 2020 all generators were net pivotal for less than 0.2% of the time. Mercury was net pivotal in the North Island the most, with most periods occurring during the 'shoulder' seasons before and after winter when storage in Lake Taupo was low and less thermal generation was available. Most of the times when Genesis was net pivotal occurred in July when thermal generation was necessary to meet winter peak demand.

6 Forward market

- 6.1 Quarterly forward prices were volatile during 2020, as shown in Figure 13 and Figure 14. Prices initially dropped in March in response to the pandemic, its global impact on fuel prices and its predicted impact on the local economy. Prices increased in June, as both government support and the drop in alert level saw the economy bounce back. The shorter term prices particularly increased as hydro levels dropped below the mean.
- 6.2 Meridian's announcement on 9 July regarding Rio Tinto's intention to close on 31 August 2021 had an immediate impact on futures prices at Benmore with prices dropping by at least \$20/MWh for 2021 and beyond. The price changes at Otahuhu were not as dramatic, due to insufficient transmission to export all the excess supply Northwards. Announcements by the government in September indicating it was in negotiations with Tiwai reversed the drop in prices seen in July.
- 6.3 In the last quarter forward prices have been influenced by inflows, particularly for December 2020 and June 2021. Forward prices for June 2021 particularly increased due to the arrival of La Niña weather patterns which were predicted to cause low inflows during the first half of 2021.

Figure 13: Quarterly forward prices (December and June) at Benmore by trading date in 2020



emi.ea.govt.nz/r/omoyf

Figure 14: Quarterly forward prices (December and June) at Otahuhu by trading date in 2020



emi.ea.govt.nz/r/ws5fb

- 6.4 Figure 15 and Figure 16 show the long run trends in hedge contracts by showing the price of quarterly contracts one, two or three years ahead, at Benmore and Otahuhu. Prices at least one year ahead are not influenced by current hydrology and but do factor in other changes in demand and supply, such as new generation. Prior to 2018, prices were stable with a mean around \$70/MWh and followed a seasonal pattern.
- 6.5 There was a clear break in this pattern in late 2018, when there was a large gas outage at Pohokura. Since then prices at both nodes have been volatile. These outages highlighted the gas supply risk, which has continued to emerge with the downwards trend at Pohokura this year. Speculation on Tiwai's exit also added to the volatility, especially at Benmore. Although Tiwai's situation was resolved in January 2021, low inflows and the continued fall in Pohokura's output has meant that forward markets continue to be volatile.

Figure 15: Forward prices at Benmore for one, two and three years in the future.

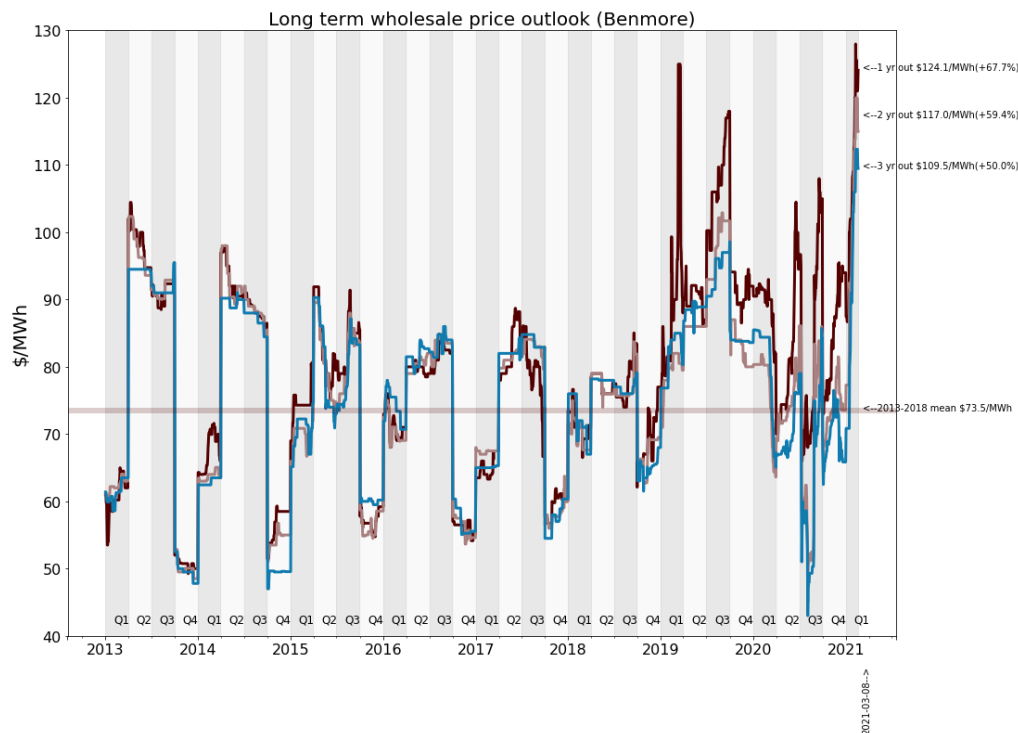
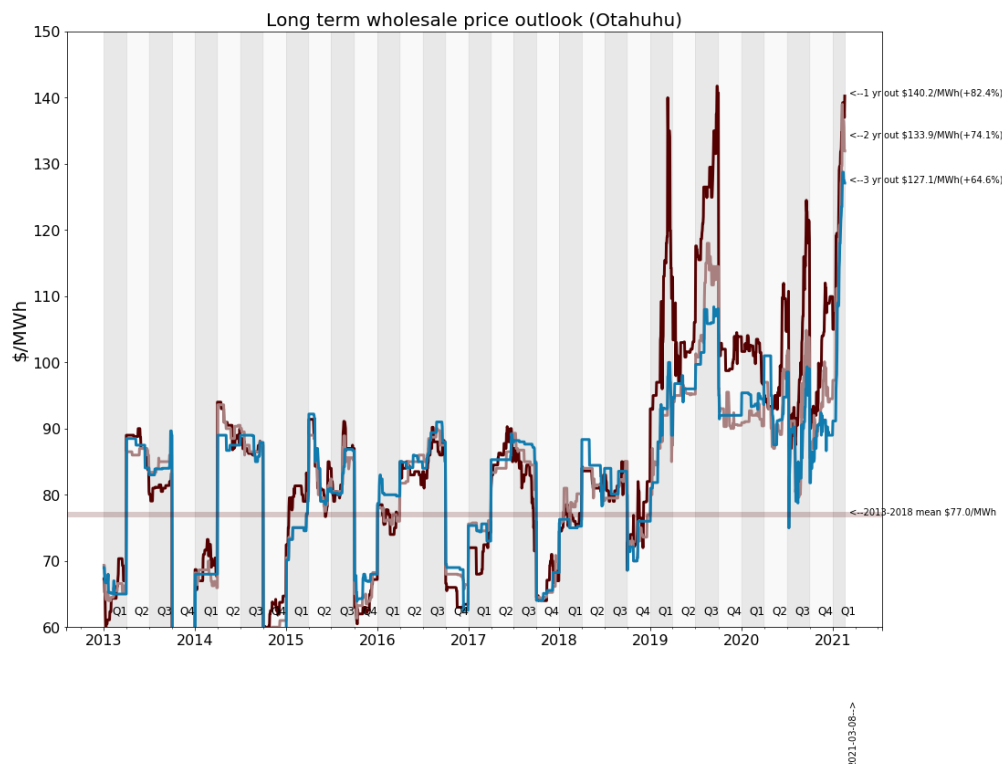
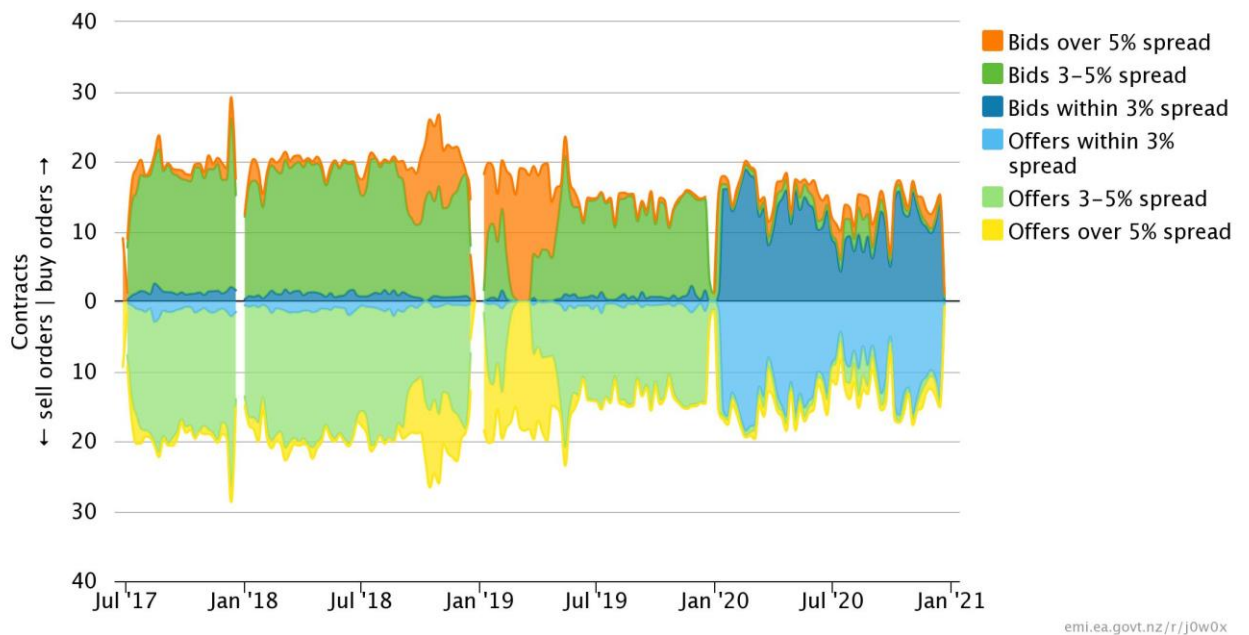


Figure 16: Forward prices at Otahuhu for one, two and three years in the future.



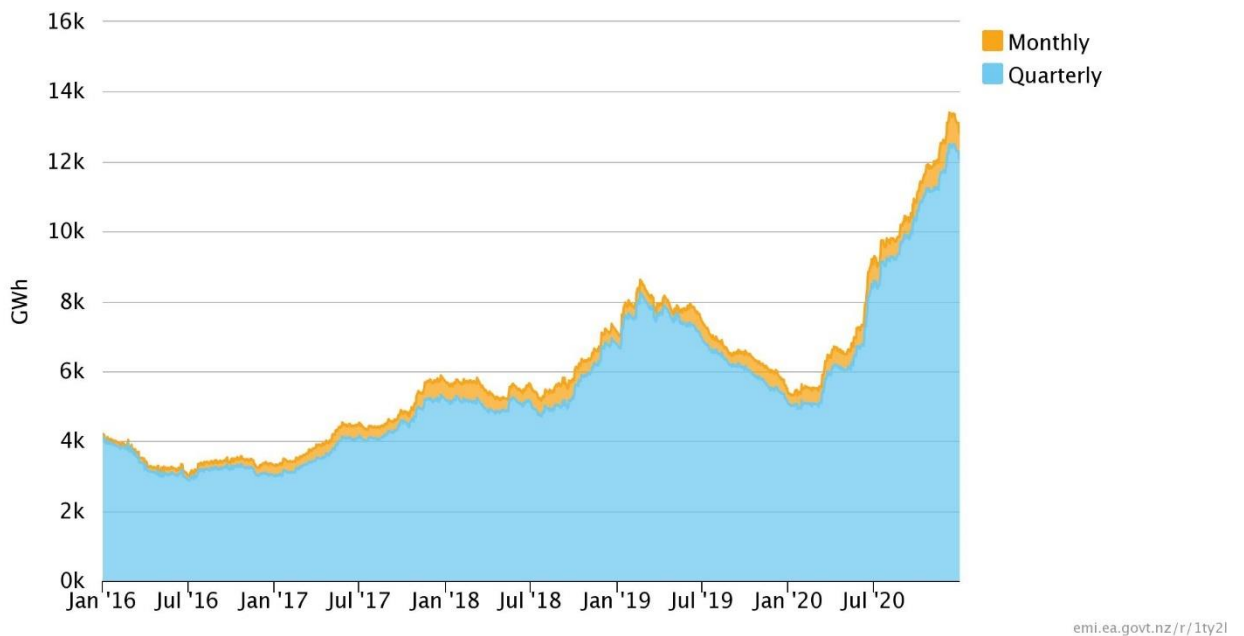
6.6 An amendment to market making arrangements was introduced in January 2020. These changes required the four largest generators to provide a minimum number of buy and sell quotes during the majority of NZEF market-making periods, with a bid-ask spread no greater than 3%. Figure 17 shows the bid-ask spreads for all contracts—the changes resulted in spreads falling from being predominantly between 3 and 5% to within 3%.

Figure 17: Bid and offer spreads for all contracts 2017-2021



6.7 Figure 18 shows the amount of unmatched open interest in the futures market. It shows that open interest has doubled during 2020 after the market making changes were introduced.

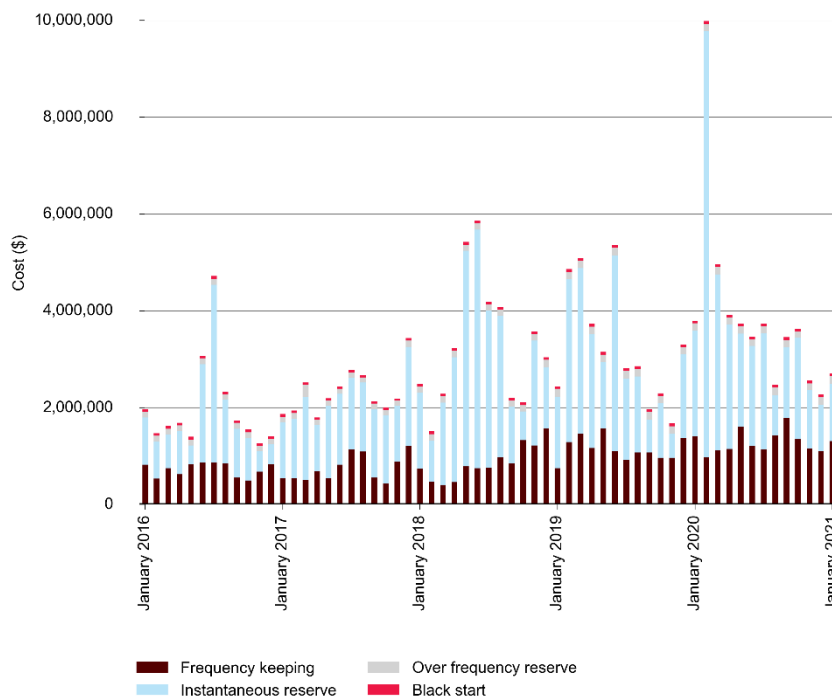
Figure 18: Unmatched open interest (UOI) of baseload exchange traded futures



7 Reliability

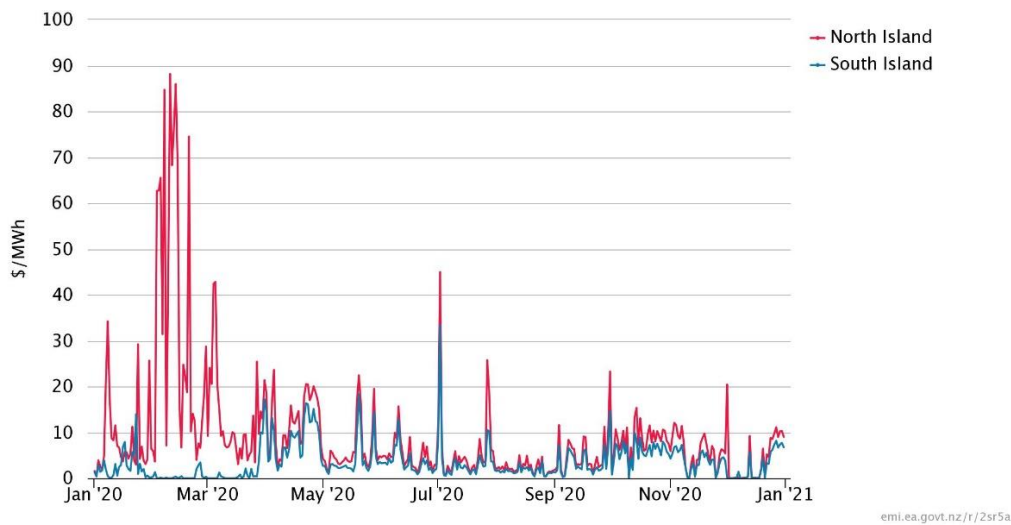
- 7.1 Four main ancillary services maintain the reliability of the network. The total costs of these are shown on Figure 19. Frequency keeping is done by one or more generators able to vary their generation to maintain frequency within the acceptable band. This is needed to match load with generation between dispatches. The cost of frequency keeping dropped in 2015 when the system operator began using Frequency Keeping Control (FKC) which reduced the amount of frequency keeping services required. There was a small increase in frequency keeping costs during 2018 but it still remains below \$2 million per month.

Figure 19: Monthly ancillary service costs



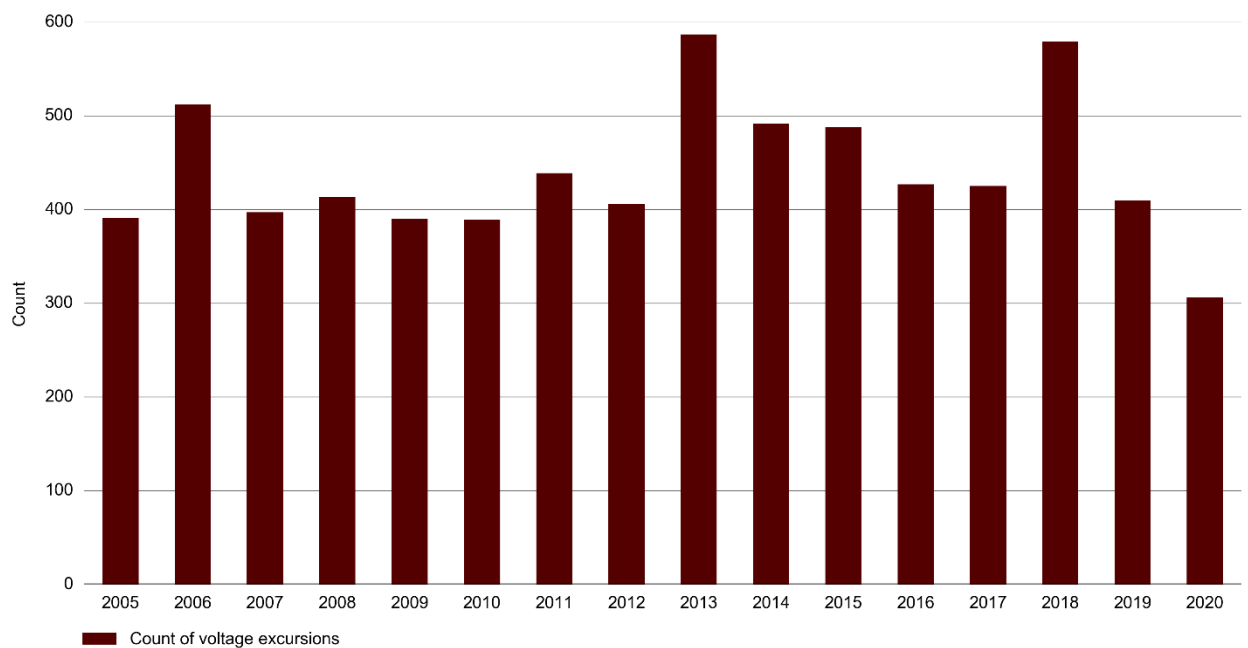
- 7.2 In the event of the sudden loss of generation or transmission assets the system needs instantaneous reserves which respond quickly to prevent cascade failure. Instantaneous reserves (IR) can be provided by both generators and large industrial users who are willing to have load interrupted. The price of reserve is co-optimised with energy as available generation can either be used for energy or reserve but not both at the same time. While Figure 19 shows the total cost, Figure 20 shows the unit price for fast instantaneous reserves (FIR).
- 7.3 The cost of IR is usually low (below \$5/MWh), increasing when supply is tight and energy prices are high. The cost of IR was particularly high between February and April 2020. This was mostly due to the HVDC outage in February and March which limited sharing of both energy and reserves between the islands. As supply was more abundant in the South Island at this time, there was an increase in North Island prices of FIR up to \$90/MWh. The HVDC outage ended on 28 March, shortly after alert level 4 started. This also impacted reserve costs as there was a reduction in interruptible load as the industrial users closed non-essential production, with prices in both islands between \$5 and \$20/MWh.

Figure 20: Price of FIR in the North and South Island 2020



- 7.4 Transpower monitors both voltage and frequency of the grid and sends excursion notices when voltage or frequency measures fall outside of stated limits. Figure 21 and Figure 22 show an estimate of the number of times excursions occurred based on the number of excursion notices issued each year. Tracking excursion notices can help indicate the state of transmission and generation and inform if more in-depth investigation is needed.
- 7.5 Voltage excursions are usually around 400 per year, with some high years reaching up to 600. In 2020 just over 300 excursion notices were issued. The drop is partly due to fewer notices issued during April when the country was at alert level 4. During this period several industrial users who are direct connects were turned off, so there was less equipment connected to the grid which could cause voltage excursions.

Figure 21: Annual number of voltage excursions (estimated)



- 7.6 Frequency excursions happen much less frequently than voltage excursions. Since the system operator introduced Frequency Keeping Control (FKC) the number of excursions has dropped to less than 30 excursions per year.

Figure 22: Annual number of frequency excursions (estimated)

