

Market Performance Quarterly Review Q1 2020

Information paper

12 April 2020



Contents

1	Purpose of the report	3
2	Highlights over the last quarter	3
3	Demand	4
4	Retail market	4
5	Wholesale market	7
	Spot market commentary	7
	Generation	8
	Future generation in New Zealand	9
6	Forward Markets	9
7	Ancillary services	11
8	Special topic 1: HVDC and Pohokura outages	11
9	Special Topic 2: Impact of the Lockdown	15

Figures

Figure 1: 2020/19 Monthly demand compared to average	4
Figure 2: Number of ICPs by small retailer	5
Figure 3: Number of switches and % saves	6
Figure 4: Domestic Electricity Prices by component (QSDEP)	6
Figure 5: Average spot price and South Island storage	7
Figure 6: Net pivotal monitoring	8
Figure 7: Generation by fuel source 2015-2019	9
Figure 8: ASX Forward prices at Otahuhu and Benmore	10
Figure 9: Monthly trading volumes for ASX baseload contracts	10
Figure 10: Monthly ancillary services costs	11
Figure 11: HVDC transfer October 2019 - March 2020	12
Figure 12: Benmore and Otahuhu prices during HVDC outage	13
Figure 13: Lake Taupo's levels 2019/2020	13
Figure 14: Slow-starting Thermal, January to March 2020.	14
Figure 15: Thermal peakers, January-March 2020	14
Figure 16: NZ Total demand before and after lockdown	15
Figure 17: NZ Average 5-minute change in demand before and after lockdown	16
Figure 18: Daily load at Pauatahanui node	16
Figure 19: Demand from the largest industrial power users 2020	17

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 (Authority).

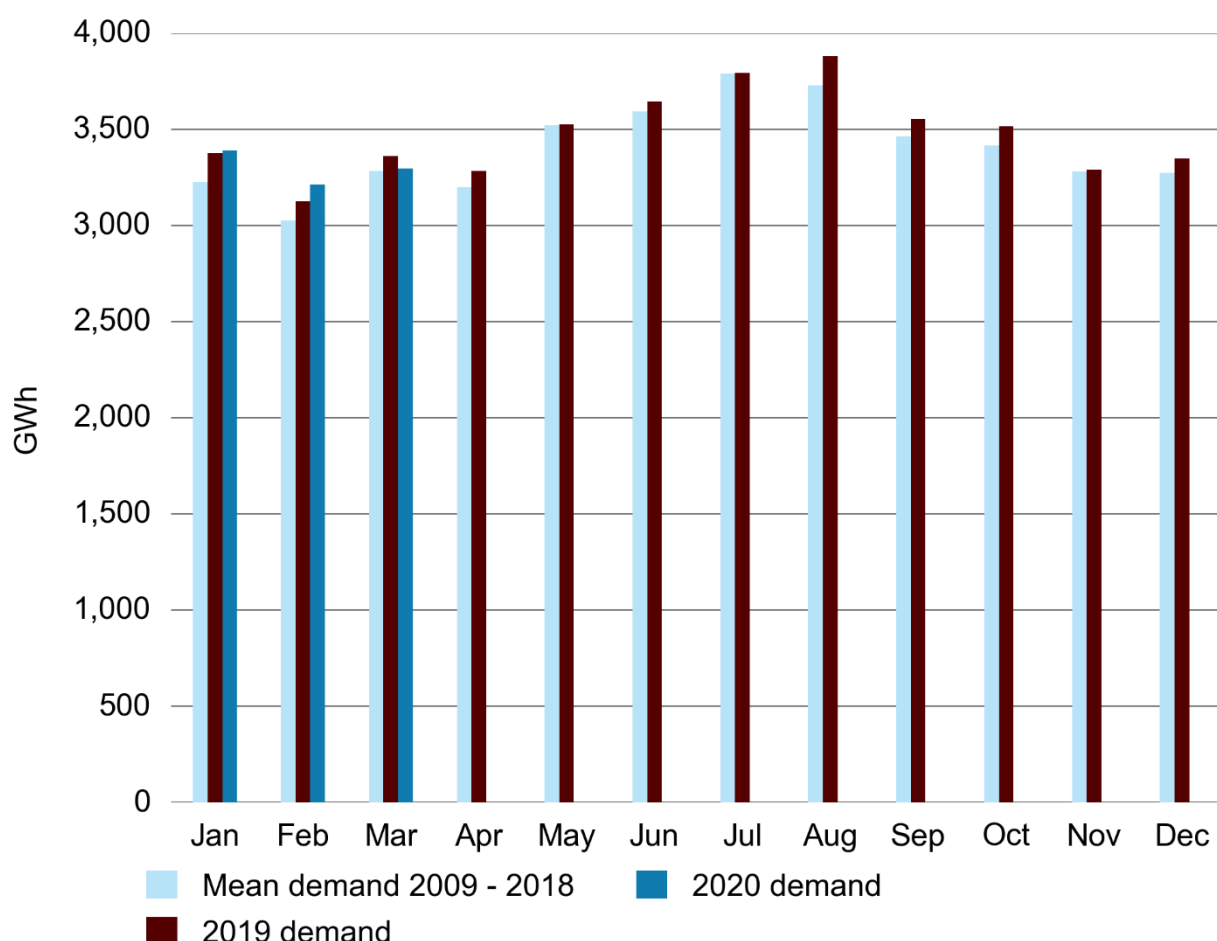
2 Highlights over the last quarter

- 2.1 **Demand was trending up.** Prior to the lockdown demand was higher than average this last year, with almost all the months in 2019 and 2020 being higher than the average over the last 10 years. The additional potline at Tiwai contributed to the increase in consumption.
- 2.2 **Recent lockdown has reduced demand.** Many large industrial power users and non-essential commercial users have either reduced their demand or shut down completely — including the additional potline at Tiwai. The increase in residential demand from people staying at home was small in comparison, leading to a drop in overall demand.
- 2.3 **HVDC and Pohokura outages caused price separation.** The main impact of the HVDC outage was higher prices in the North Island and higher thermal generation. Otherwise the outages were successfully finished without disruptions.
- 2.4 **Hydro storage is at mean levels for this time of year.** There were high inflows in the South Island from heavy rain this summer. High use and low inflows since then have seen levels drop to about the mean level for this time of year.
- 2.5 **Forward prices have dropped.** Forward prices predict a decrease in prices both this year and in the longer term.

3 Demand

- 3.1 Reconciled demand (including Tiwai) was higher than average (since 2009) in all months in 2019 and for the first two months of 2020. Note that 2020 was a leap year, so February had one extra day.

Figure 1: 2020/19 Monthly demand compared to average



Source: Electricity Authority

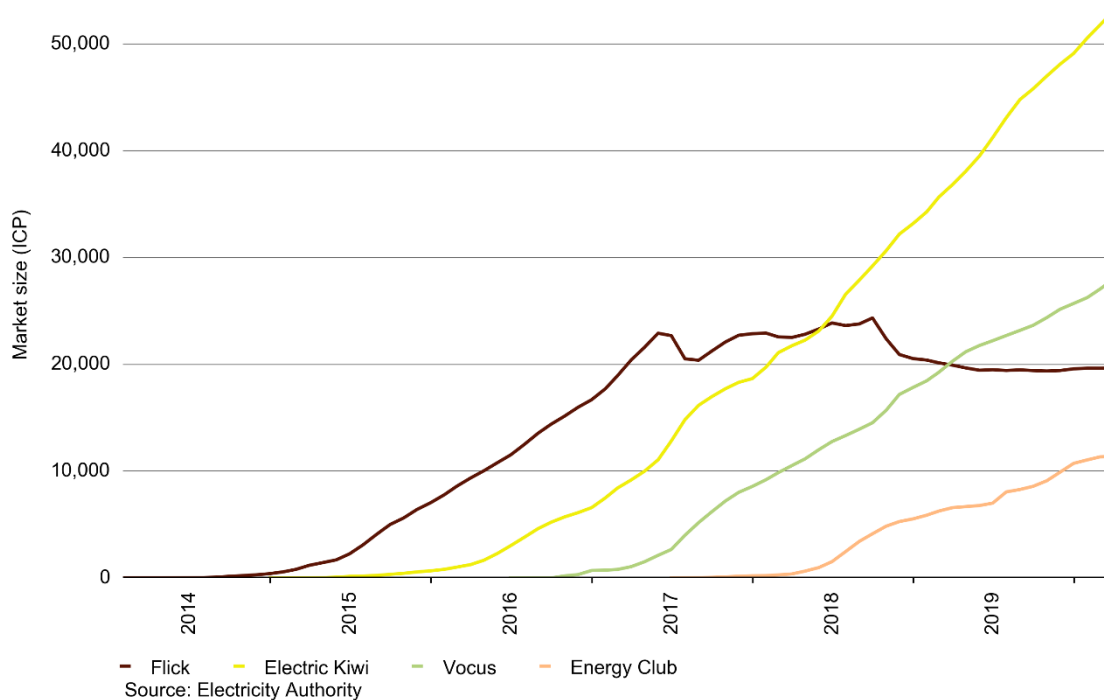
- 3.2 Some of the increase in demand may have been due to dry weather increasing irrigation load, especially in the North Island this summer. Tiwai aluminium smelter also contributed to the increase, when it started a fourth potline in September 2018, increasing demand by 50 MW.
- 3.3 Demand dropped in the last week of March due to the impact of the lockdown to prevent the spread of COVID-19. See Section 9 on page 15 for more details. It is unclear at this point what the long term impact of COVID-19 will be on demand. The fourth potline at Tiwai was shut down on 2 April 2020.

4 Retail market

- 4.1 In the last quarter four of the large five retailers lost ICPs, with only Meridian growing by 5,078 ICPs. This was mostly through its brand Powershop which gained 4,187 ICPs. Genesis had the largest loss at 4,024 ICPs, Mercury lost 3,653 ICPs and Contact lost 2,361 ICPs. Altogether these five retailers have 73.4% of the market

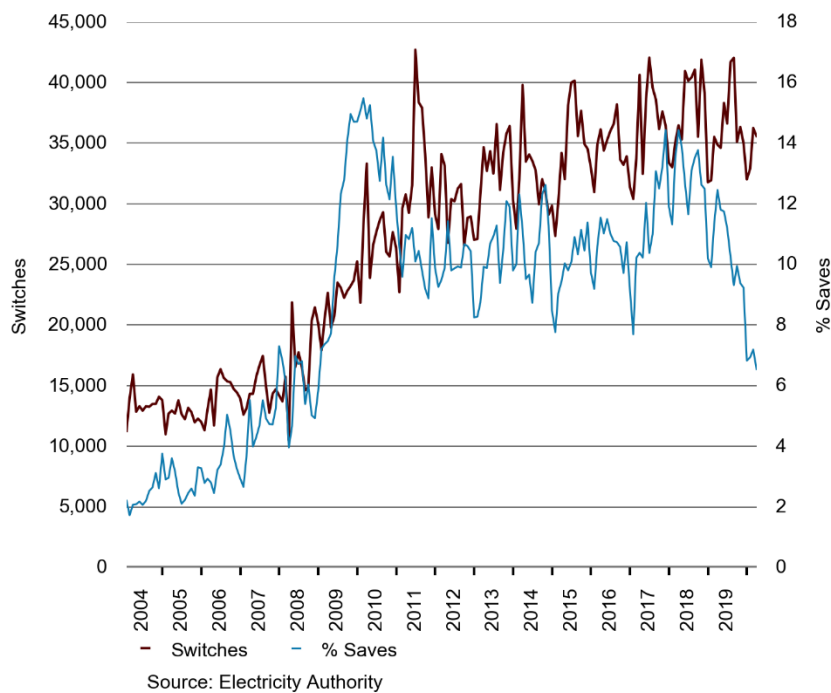
- 4.2 Figure 2 shows the growth of four retailers that started since 2014, and currently have between 10,000 and 55,000 ICPs (0.5%-2.5% of market share). Flick Electric, the largest retailer offering spot market prices, grew between 2014 and 2018, peaking at 25,000 ICPs. ICP numbers dropped after periods of high prices in 2017 and late 2018. Flick's ICPs remained flat in 2019 and currently sit at 20,235 ICPs. Electric Kiwi offers an off-peak "Hour of Power" and is now the largest retailer that started since 2014, serving 52,501 ICPs. Vocus bundles electricity with broadband services and has 30,486 ICPs. Energy Club charges on a weekly basis and has 11,487 ICPs.

Figure 2: Number of ICPs by small retailer



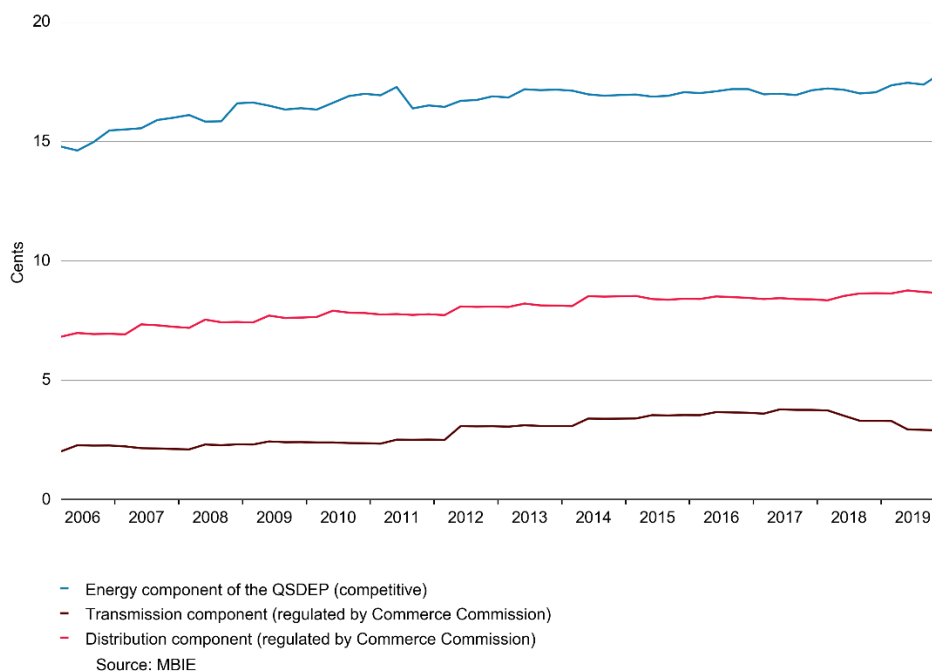
- 4.3 Figure 3 shows that monthly switching has followed a seasonal pattern the last three years, peaking at over 40,000 switches in the winter months and then reducing to around 32,000 in the summer months.
- 4.4 "% Saves" refers to the percent of switches that ended up remaining with their original retailer, usually as a result of a "win-back", where the losing retailer contacts a switching customer to offer them a better deal to stay. In 2017 and 2018 saves were about 10-14% of switches. However, in 2019 this dropped to 10% and then 8%. Win-backs were under scrutiny during 2019, including by the electricity price review (EPR). This resulted in a ban of win-backs in February 2020. It is possible some retailers cut back on win-back activity early in anticipation of the change.

Figure 3: Number of switches and % saves



4.5 Figure 4 compares changes in the components that make up MBIE's QSDEP- an indicator of residential retail prices, adjusted for inflation. The chart shows how the energy component of the QSDEP in real terms levelled off from May 2011. However, in 2019 the energy component has increased. This is consistent with the increase in the average spot price. In contrast, the transmission component decreased in 2018 and 2019 after several years of increase.

Figure 4: Domestic Electricity Prices by component (QSDEP)

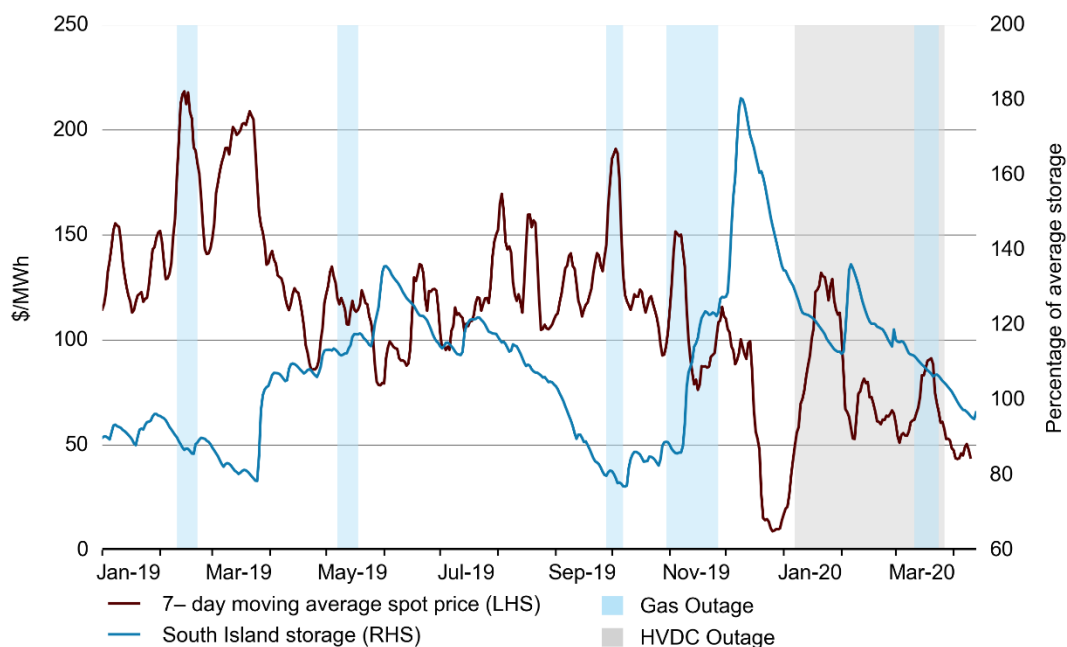


5 Wholesale market

Spot market commentary

- 5.1 The spot market has been heavily influenced by hydro storage and thermal fuel supply. Prices were relatively high in February, March and September 2019. When South Island storage began recovering from April 2019 and then again in October 2019 the spot price decreased in response.
- 5.2 Prices were very low over the Christmas/New Year break, when demand is at the lowest. The HVDC outage and Pohokura outage likely increased the spot price in the beginning of 2020, with price separation between North and South Island (see Section 7 on page 11 for more information on the Outage). The end of March saw demand drop as a result of the COVID-19 lockdown (see Section 9 on page 15), resulting in lower prices.

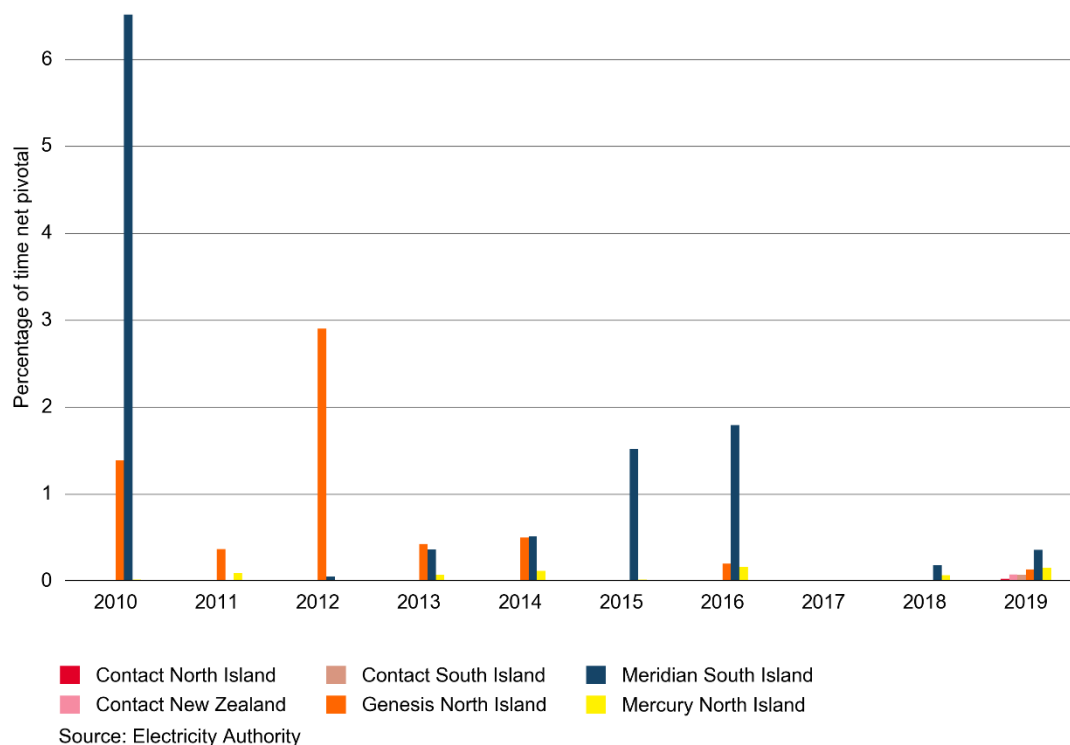
Figure 5: Average spot price and South Island storage



Sources: Electricity Authority and NZX Hydro

- 5.3 Being net pivotal means that an electricity generator could offer its generation into the spot market at a very high price and still be dispatched at a profit, given its position in the retail, forward, and Financial Transmission Rights (FTR) markets. This is at one end of a spectrum of strategies that generators could use to increase profits. What distinguishes net pivotal generators is that there is no counter strategy available to other generators that could limit high prices. Therefore, this measure is aimed at identifying extreme situations, where the pivotal generator could take unilateral action to increase the price and the upside of this action was uncapped. During most trading periods, while generators can change their offers, spot market prices are constrained by actual and potential competitive responses by other generators, or by portfolio positions that make increasing prices unprofitable.

Figure 6: Net pivotal monitoring

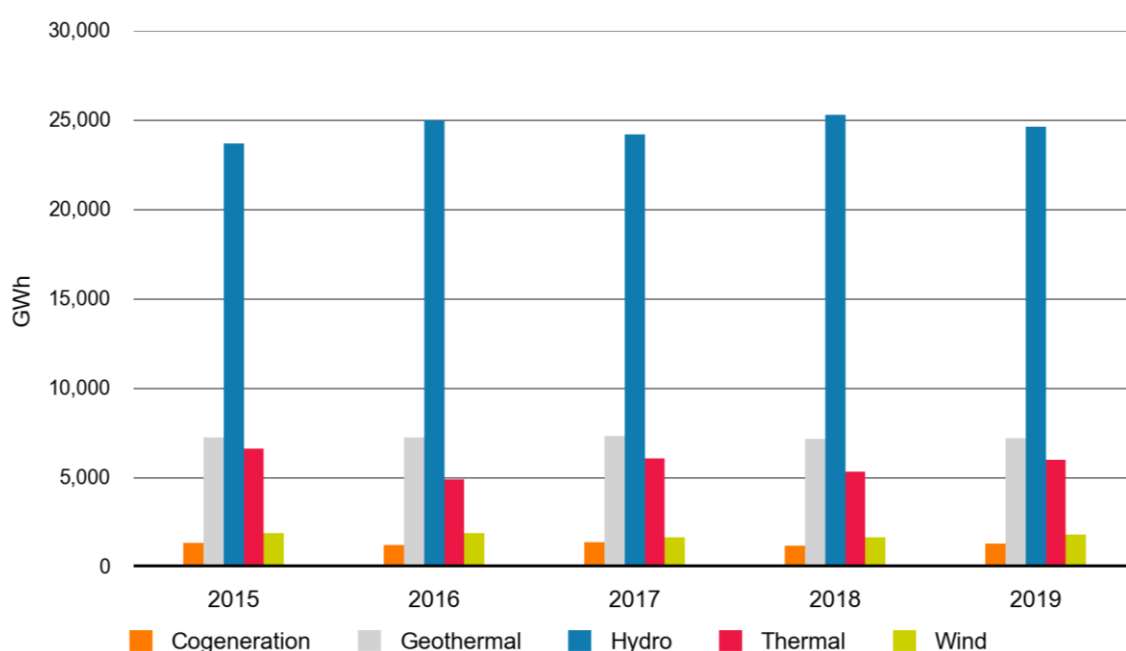


- 5.4 Figure 6 shows the results from net pivotal monitoring over the last 10 years. It measures the percentage of trading periods where each generator is net pivotal, either across one island or nationally. In the last few years, no one generator was net pivotal for more than 1% of trading periods. Meridian Energy is the generator who is most frequently net pivotal, due to their concentration of generation in the South Island. In 2019, Contact, Genesis and Mercury also had a small number of trading periods in which they were net pivotal.

Generation

- 5.5 Figure 7 shows generation by fuel source. 2019 fuels sources were similar to the previous four years. Hydro fuel, which is the main fuel source, was lower than 2016 and 2018, but still higher than 2015 and 2017. Thermal was higher in the years that hydro was lower, and vice versa.
- 5.6 Wind was about 10% higher in 2019 compared to 2017 and 2018 and is likely to continue getting higher as there are several new wind farms currently under construction.

Figure 7: Generation by fuel source 2015-2019



Source: Electricity Authority

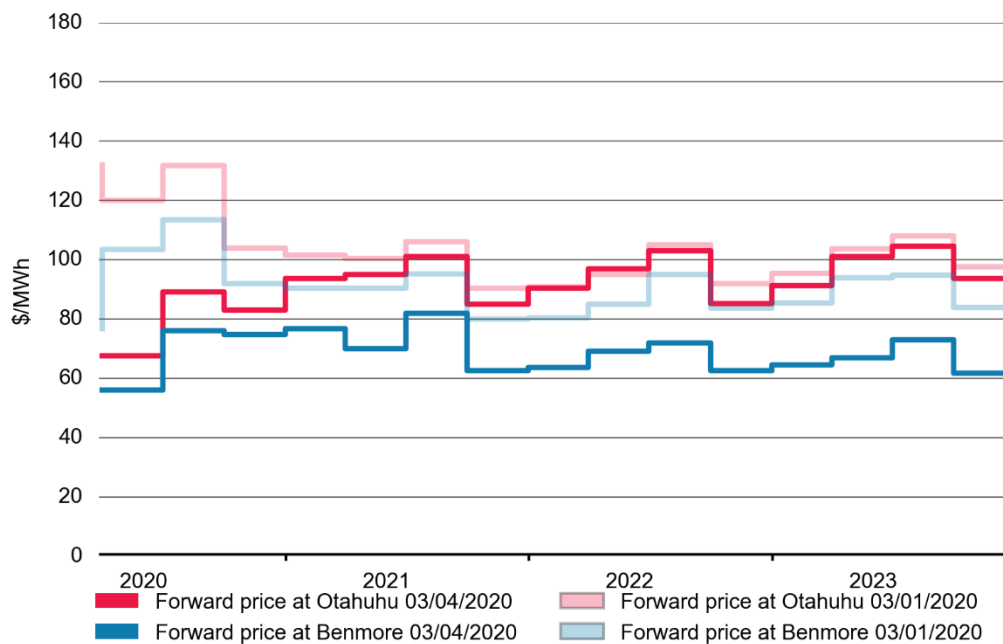
Future generation in New Zealand

- 5.7 Most of the future generation planned in New Zealand is from renewable sources, mostly from wind. The new thermal generation planned are peaker plants including Nova's 100 MW thermal plant at Junction road in Taranaki, which completed commissioning on 17 March 2020.
- 5.8 Generators which are under construction or seeking consent, include:
- Construction of Tilt Renewable's 133 MW Waipipi wind farm (formerly known as Waverly) in Taranaki is expected to finish in March 2021.
 - Mercury's 222 MW Turitea wind farm in Manawatu which is on course to start generating next summer.
 - Contact's drilling campaign at the Tauhara steam field near Taupo to support a final investment decision on new generation at the site.
 - Meridian seeking potential contractors for the civil works at its consented 270 MW wind farm northwest of Napier.
 - Mainpower's 90 MW Mt Cass wind farm.
 - Todd's pipeline includes plans for a 360 MW gas-fired peaker in the Waikato.
 - Genesis is in discussions about a 300MW solar farm in the North Waikato.

6 Forward Markets

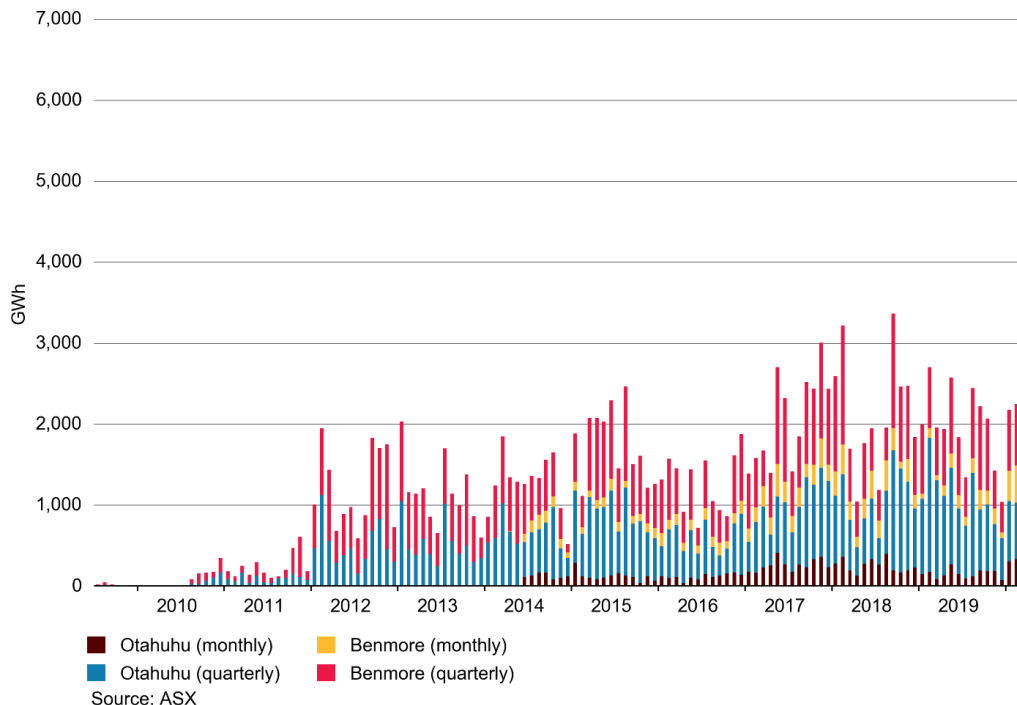
- 6.1 Figure 8 shows forward price at Otahuhu (North Island) and Benmore (South Island) from early January and early April. Forward prices for the next two quarters have dropped significantly, likely a response to the COVID-19 situation, including the current lockdown. It is likely that the successful return of the Pohokura pipeline and a fall in gas prices also contributed, easing uncertainty about gas supply in the near future.

Figure 8: ASX Forward prices at Otahuhu and Benmore



- 6.2 Forward prices for the next few years out have also dropped, especially for Benmore. This is likely in anticipation of the longer-term economic impacts from COVID-19. The drop-in prices at Benmore may be due to speculation that Tiwai will close its operations.

Figure 9: Monthly trading volumes for ASX baseload contracts



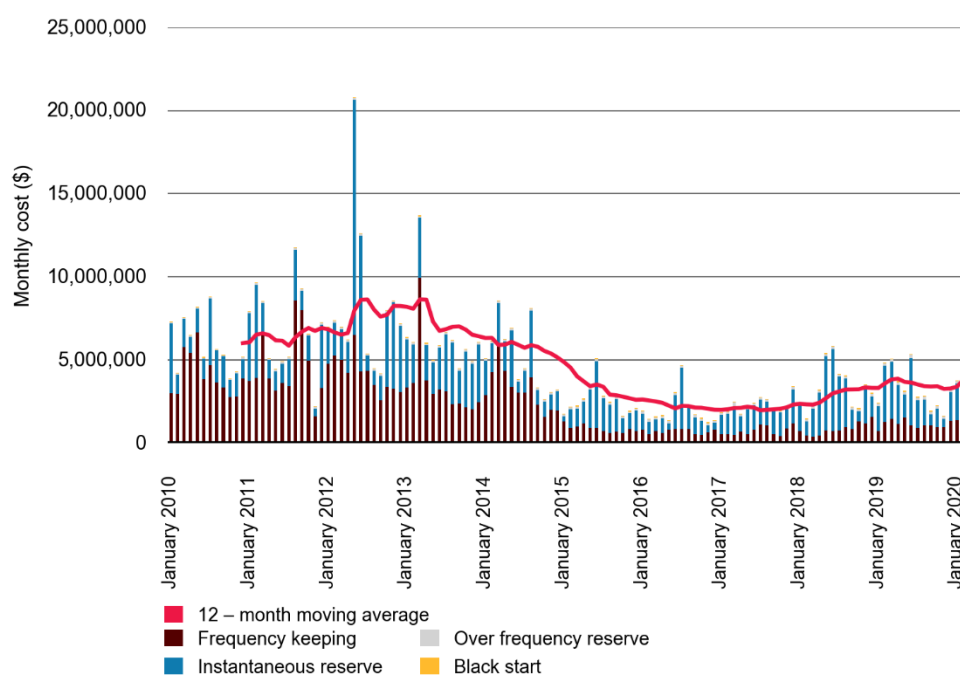
- 6.3 Figure 9 shows the volume of trades in the future market. In March there was a higher than normal level of quarterly trades. New market making arrangements may have had an impact, though it is unclear why that would have increased activity in March specifically, as current arrangements were in place during February. Increased trade

activity may also have been due to participants taking advantage of low forward prices or changing their respective positions in response to the COVID-19 situation and the lockdown which followed.

7 Ancillary services

- 7.1 Figure 10 shows ancillary services costs since the beginning of 2010. The moving average shows how costs have been falling since early 2013, mostly driven by decreases in frequency keeping costs. High energy prices since the end of 2018 have likely contributed to the slight rise in ancillary service costs over the last 18 months.
- 7.2 Instantaneous reserve costs were high in February as a result of the HVDC outage. This meant that there was less capacity for reserve sharing between the islands, so the North Island needed to dispatch more reserves to cover generation. North Island reserves, especially from thermal generation is usually more expensive.

Figure 10: Monthly ancillary services costs

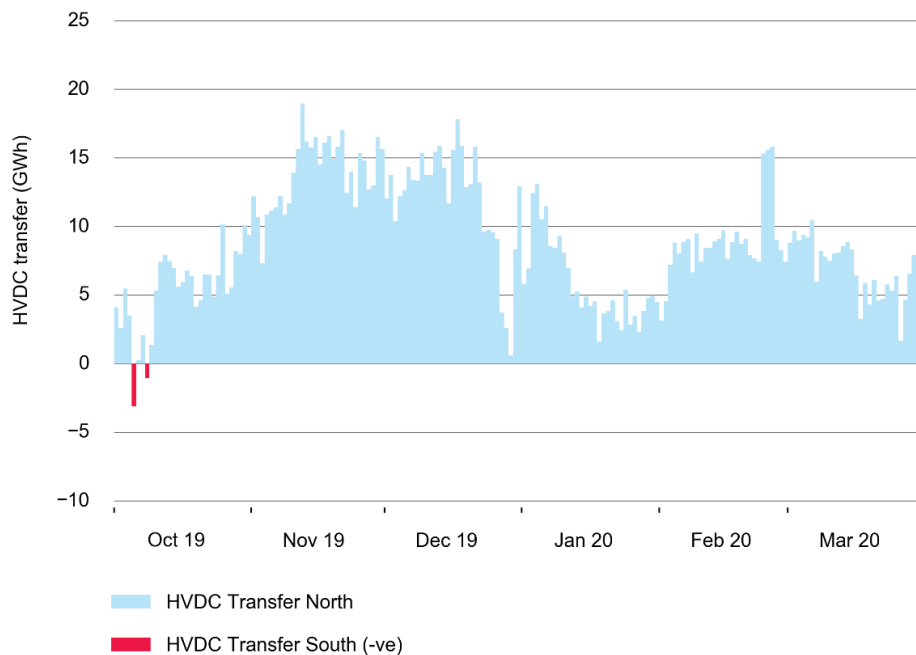


8 Special topic 1: HVDC and Pohokura outages

- 8.1 Transpower does an annual maintenance outage of the HVDC each summer. This summer they scheduled a major outage which started on 7 January and was scheduled to finish on 9 April. Transpower finished the HVDC outage early at 2pm on the 29 March. Transpower announced in a CAN notice (27 March) that this was due to good weather and the COVID-19 alert level moving to level 4 (lockdown, essential work only).
- 8.2 For the majority of the outage only one pole (monopole) was on outage, allowing limited transfer between the two islands. The full bi-pole outages, during which no transfer between the islands could take place, were scheduled and took place during weekends, when demand is lowest.
- 8.3 Pohokura Production Station was on a full outage from 11 March to 24 March. The onshore outage finished on 24 March and Pohokura Production Station was back to full onshore gas production rates on 25 March. A proactive inspection and maintenance

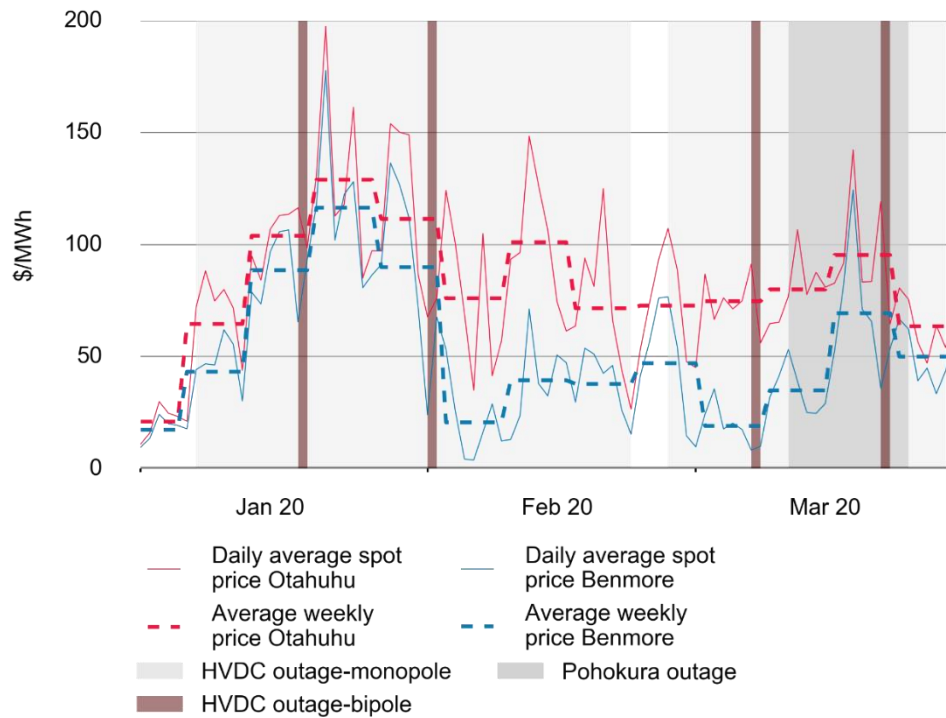
work on the Pohokura undersea pipeline also started on the 11 March and finished 6 April.

Figure 11: HVDC transfer October 2019 - March 2020



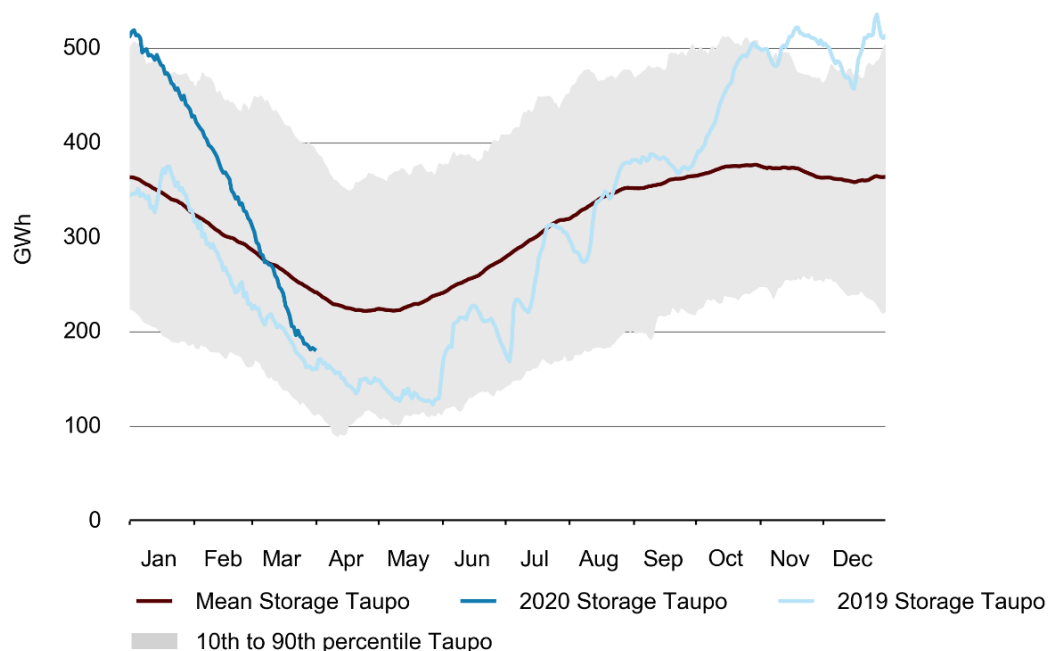
- 8.4 Figure 11 shows the HVDC transfers over the last six months. In November and December HVDC transfer was around 15 GWh per day. Once the outage started transfer stayed below 10 GWh per day. HVDC transfer was below 5 GWh most days between Saturday 18 January and 1 February when transfer limits were only 406 MW.
- 8.5 Pole 2 testing ended early on 24 February and HVDC transfer jumped up to 15 GWh per day until the pole 3 outage starts on the 27 February. This shows how the outage was constraining transfer over the HVDC.
- 8.6 Figure 12 shows the average prices at Otahuhu (North Island) and Benmore (South Island). There was price separation between the two, with the daily average price at Otahuhu up to \$88/MWh higher than at Benmore. This price separation is encouraging in the sense that it suggests South Island hydro generators are not using offers to manage the HVDC constraint.

Figure 12: Benmore and Otahuhu prices during HVDC outage



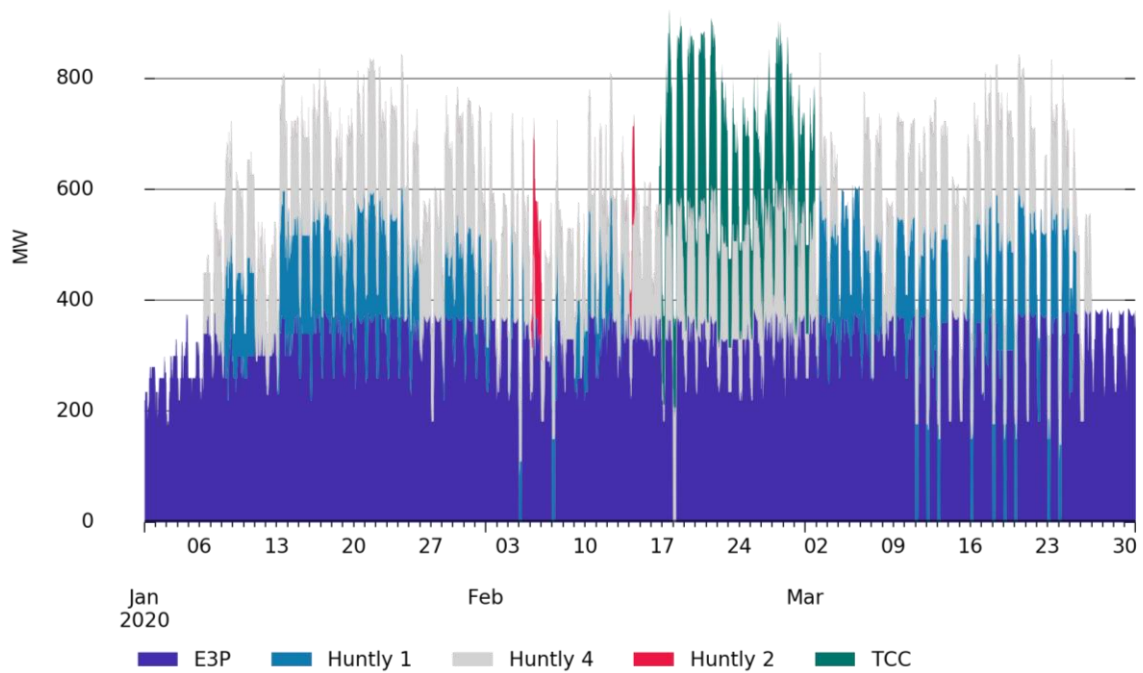
8.7 The outages have increased reliance on North Island hydro generation to supply North Island load. Figure 13 shows how Lake Taupo's water levels declined steadily during the HVDC outage. While lake levels started above the 90th percentile, they are now below average and almost as low as in 2019, which was also a dry year.

Figure 13: Lake Taupo's levels 2019/2020



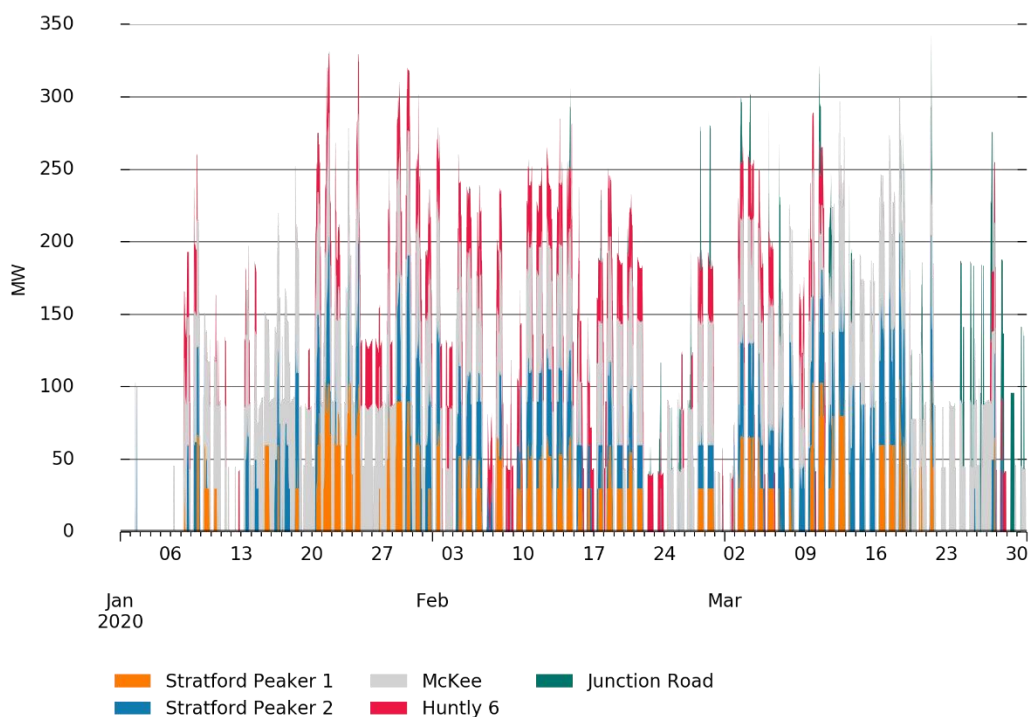
8.8 Figure 14 shows generation from slow starting thermal. Both just before and after the HVDC outage started only E3P was dispatched. The outage increased demand for North Island thermal, and so Huntly 1 and Huntly 4 were running for much of the outage. TCC ran between the 17 March and 2 February, during which time Huntly 1 did not run. During the full Pohokura outage E3P ran less frequently.

Figure 14: Slow-starting Thermal, January to March 2020.



- 8.9 Thermal peakers were running during the HVDC outage. Whirinaki was the only peaker that did not run at all during the outage. Huntly 6 did not run during the Pohokura outage, so peak demand was met by the Stratford peakers, McKee and occasionally Junction Road.

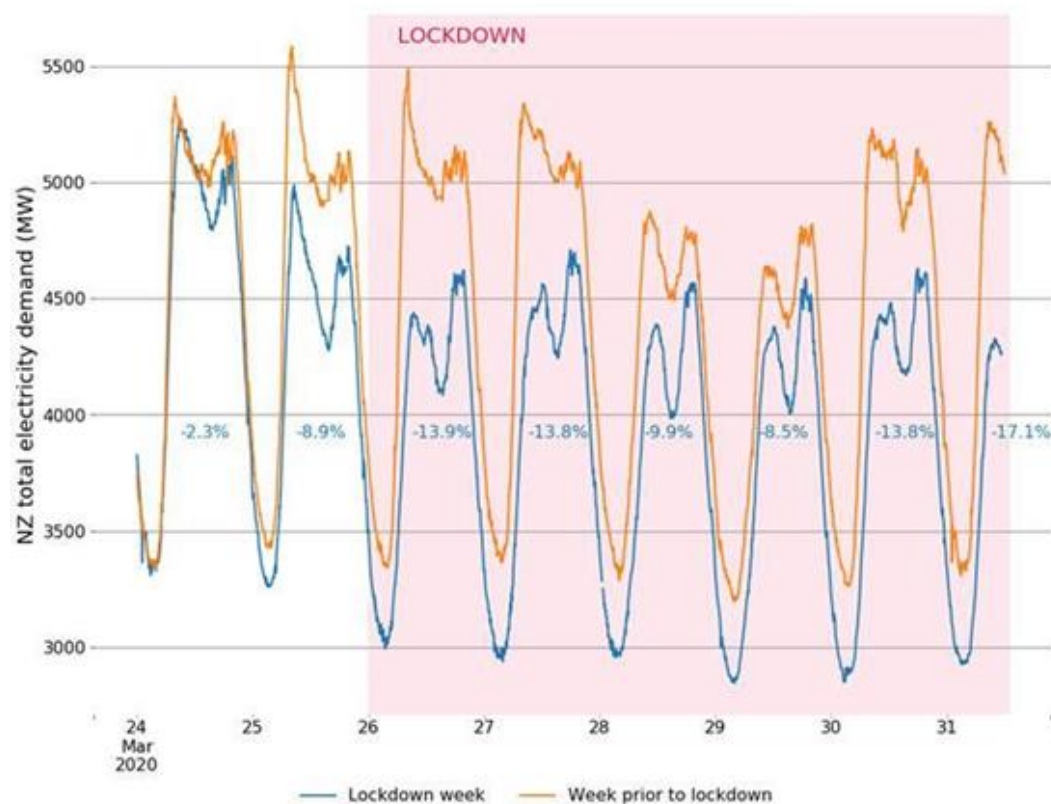
Figure 15: Thermal peakers, January-March 2020



9 Special Topic 2: Impact of the Lockdown

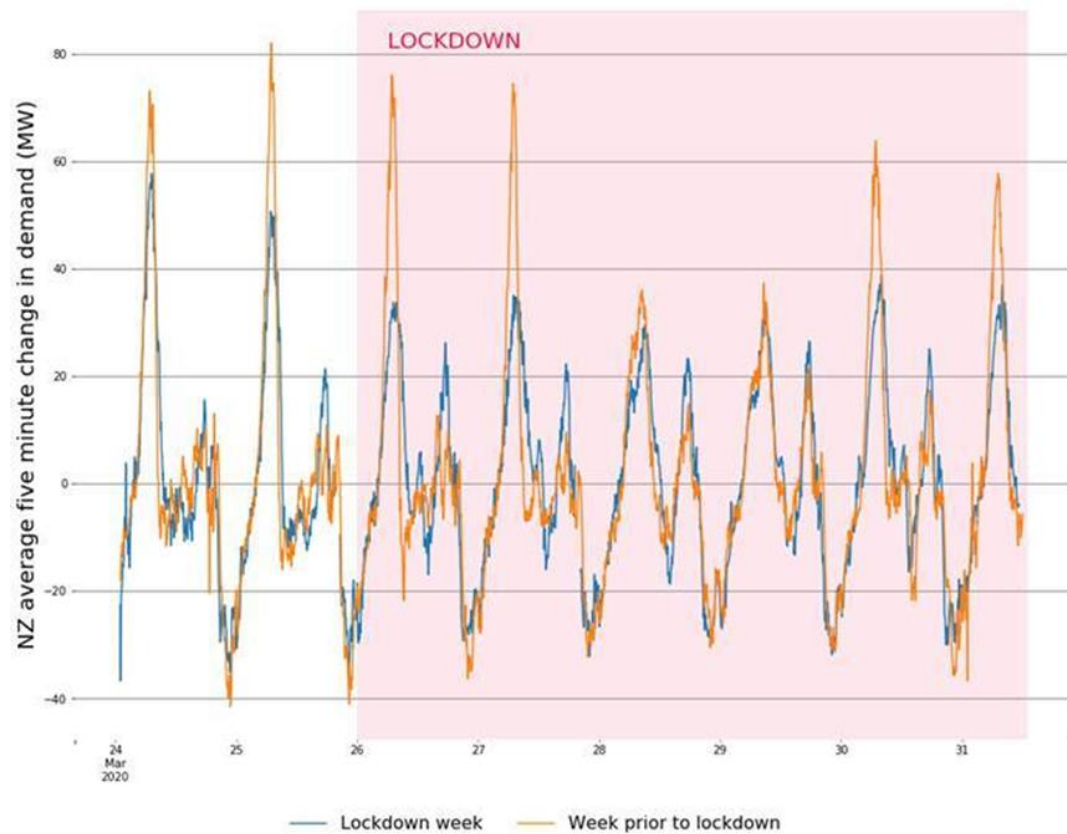
- 9.1 Due to COVID-19, the government implemented a lockdown which started on the 26 March 2020 and is currently scheduled to last for four weeks. New Zealanders not working in essential services must stay at home and stop physical interactions with others outside their own household. All non-essential businesses were required to close (Tiwai was granted an exemption due to time and staffing required to shut down and start-up operations).
- 9.2 Figure 16 shows that overall demand has dropped. During the first week of lockdown, demand on weekdays was around 13.8% lower than the previous week, Saturday was 10% lower and Sunday 8.5% lower. The daily pattern of demand has also changed, from a morning peak around 8am to an evening peak. This is due to people changing their habits as they stay at home and cook at home in the evenings.

Figure 16: NZ Total demand before and after lockdown



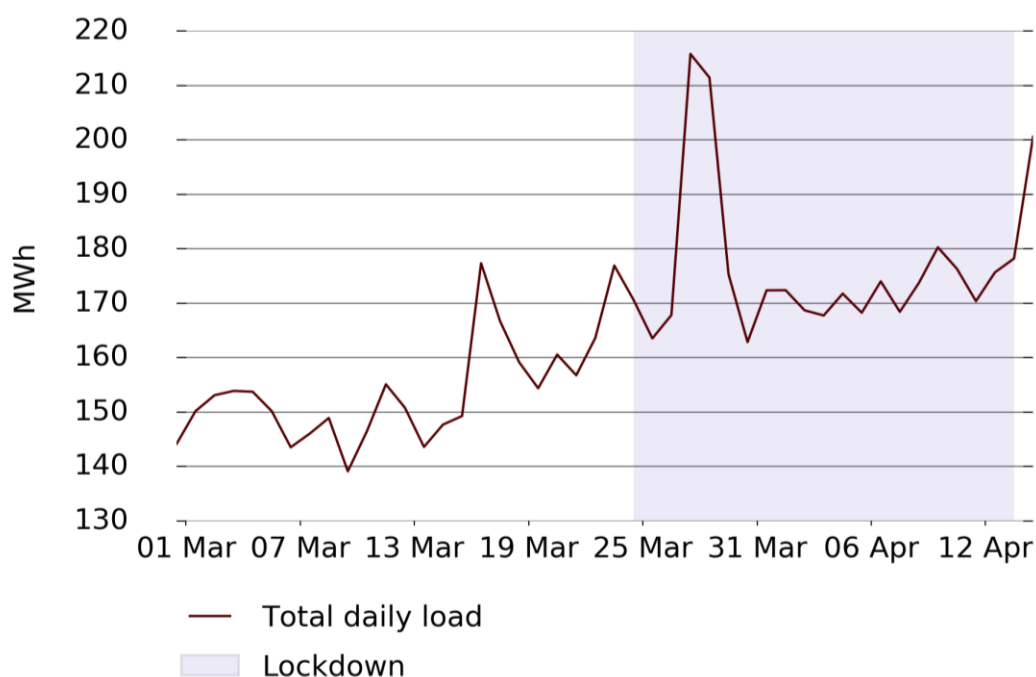
- 9.3 Figure 17 shows the average 5-minute change in demand. This shows how quickly demand changes, which is important for dispatching generation and security of supply. Prior to the lockdown the 5-minute change would peak at 80 MW in the morning. Since the lockdown the 5-minute change peaks later in the morning and is less than 40 MW. The evening change peak is slightly higher than before the lockdown, but still below 40 MW. This should increase system security as the sudden shifts in demand are smaller.
- 9.4 Transpower has been using a Sunday forecast for the lockdown period. So far this has seemed like a good strategy with demand similar to a Sunday, but with morning demand increasing earlier. Transpower states that it will monitor and adjust the forecast as actual load and trends become known over the lockdown.

Figure 17: NZ Average 5-minute change in demand before and after lockdown



9.5 Figure 18 shows daily load at the Pauatahanui node. This node was chosen as demand from this node is primarily residential. The first half of March daily demand was around 150 MWh a day. In the second half of March residential demand increased as people started staying at home, to around 175 MWh per day. Demand increased more on the 28 and 29 March, during a spell of cold weather.

Figure 18: Daily load at Pauatahanui node



9.6 Many of New Zealand's large industrial power users have closed or reduced their production to essential production only. Figure 19 shows drop in energy use by industrial users in the days following the lockdown announcement. Information from these large consumers to Transpower has given an indication of a drop in demand of 236 MW (Transpower, 2020). Tiwai Point Aluminium Smelter do not have to close their operations, but they have shutdown potline 4 to ensure they have staff cover for the rest of their production. This reduced industrial demand by a further 50 MW.

Figure 19: Demand from the largest industrial power users 2020

