Pricing strategy & roadmap

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Contents

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A copy of this Pricing Road Map and our Pricing Methodology can be downloaded from www.welectricity.co.nz/disclosures

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1 Introduction

Wellington Electricity Lines Limited's (**WELL**) is an Electricity Distribution Business (**EDB**) who is responsible for providing electricity distribution services in the Wellington region. We manage the poles, wires and equipment that provide electricity to approximately 400,000 customers in the Wellington, Porirua, Lower Hutt and Upper Hutt areas. We take electricity from Transpower's national grid, to residential homes, commercial and industrial businesses and Wellington's essential infrastructure assets like hospitals, water plants and air and sea ports.

We are investing around **$162m** in infrastructure on the Wellington network	We provide electricity to over **171,000** households and to **400,000** people in our community.	Our total network is around **6,700 km** in length with over **4,100 km** of it being underground cables.	We have around **4,000 substations** and **40,000 poles**.	There are about **5,000** electric vehicles connected to our network, **1,700** more than last year.

We recover the cost of owning and operating the network through a combination of tariffs and capital contributions for new connections. WELL is regulated by the Commerce Commission (**Commission**) and the Electricity Authority (**Authority**) and is required to publish how prices are calculated, what prices are for the upcoming pricing year and how much revenue it expects to collect from those prices. Our pricing disclosures can be found on our website at https://www.welectricity.co.nz/.

We also publish a Pricing Roadmap which summarises our plans for changes to prices and pricing structures, together with expected timeframes and progress updates. Our first Pricing Roadmap was published 2017 and we have been providing process updates in our Pricing Methodology pricing disclosure. We have completed the original actions and we provided a refreshed roadmap in 2021 that reflects advances in our thinking and changes in the industry. This 2022 updated provided a progress update and a summary of what we learnt implementing the 2021 Roadmap actions.

The updated Pricing Roadmap provides:

- A summary of network characteristics and capacity constraints on the Wellington network and their implications for our pricing strategy and price.
- A look at future energy use in Wellington and the impact on pricing. New Zealand's carbon neutral climate change targets in particular have important pricing implications.
- A Pricing Strategy that will ensure our future prices support us in delivering safe, reliable, cost effective and high quality electricity distribution services.
- An update on progress against the current roadmap.
- An overview of what we have learned over the last few years and the advances in our own thinking. This has led to new work programmes. One of those work programmes is an internal review of our own pricing structures and incorporating the Authorities new pricing setting methodology.
- A refreshed Pricing Roadmap which includes the new work programmes.

Last year we were considering whether to simplify our pricing disclosures by combining the Pricing Roadmap and the Pricing Methodology. We decided not to do this as it would add unnecessary complexity to the Pricing Methodology Director certification process. Keeping the Pricing Roadmap separate also allows us to provide regular updates throughout the year, outside of the ridged Pricing Methodology disclosure dates.

2 Network characteristics and implications for pricing

Network prices have two purposes - (1) to recover an Electricity Distribution Businesses' (**EDB's**) allowable revenue that it needs to build and operate the network, and (2) to signal the future cost of using the network. Signalling the future cost of using the network means prices that reflect the cost of building additional capacity to meet increases in future demand on the network. The higher cost reflects that to meet those peak periods of demand in the future, a larger, more expensive network will have to be built.

Reflecting the higher cost allows consumers to make informed choices about how they will use their money – they could pay the cost to building a larger network or avoid that cost by using energy during non-congested periods when the higher future costs are not applied. Accurately signalling the future cost of using the network will also let consumers make good investment decisions about purchasing appliances like solar and batteries or electric vehicles – customers can use prices to work out if the appliances could help save them money through energy savings or shifting more of their energy use to periods of the day when the cost of electricity is cheaper.

To set prices that reflect the future cost of using the network, a network operator must estimate what future demand will be. Specifically, to set tariffs that reflect the future cost of using the network, we need to know:

1. Where and when the network will exceed capacity;
2. What customer group is driving future energy use that is causing future capacity to be exceeded;
3. How much it will cost to build a larger network to meet the increase in future demand.

The electricity demand characteristics of a network will inform an EDBs pricing strategy and will guide the development of prices.

2.1 Future electricity use in Wellington

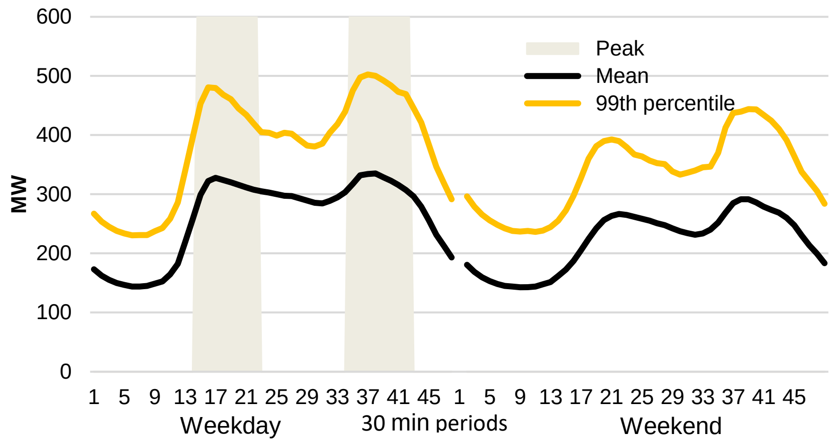
EDBs model future demand requirements as part of their Asset Management Plans (**AMP**). Our AMP can be found on our website at https://www.welectricity.co.nz/disclosures/asset-management-plan. Chapter 8 of our AMP forecasts future demand at each zone substation and models when that part of the network may run out of capacity. This model is used to plan how we will manage demand on that part of the network. WELL has a strategy of using load management tools (including peak demand period price signals and lower prices for consumers who provide us with hot water control) to delay having to invest in building a larger network for as long as possible. This helps us keep prices low. Where load management tools will no longer allow us to manage load within our security standards, we will increase the capacity of the network by building a larger network. This allows us to continue to provide a reliable electricity distribution services.

We will not repeat the demand forecasts provided in the AMP as we believe it is important to have a single, consistent view of future electricity demand. We do encourage readers to review chapter 8 of the AMP if they want to understand what is driving future investment on the Wellington network. This Pricing Roadmap provides a summary of future demand characteristics in the context of pricing. We have combined information from the AMP with customer consumption data from of our Time of Use (**ToU**) pricing study[1]..

2.1.1 General demand characteristics

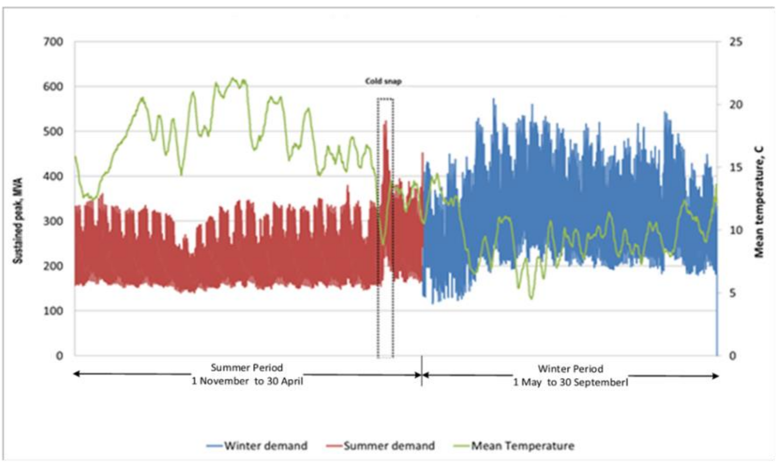
We have two predominant demand profiles on the Wellington network – parts of the network used primarily by residential consumers and parts used by commercial consumers. Residential consumers drive peak demand on the Wellington network, with the highest energy use being in the residential suburbs in the winter months when home heating is the highest. Figures 1 to 11 summarise the general demand characteristics on the Wellington network.

Figure 1 - Overall, Wellington is an evening peaking network



Energy use in Wellington is the highest during the morning as residential customer get ready for the day and in the evening when people are home and preparing dinner. The Wellington network has spare capacity during the day and at night.

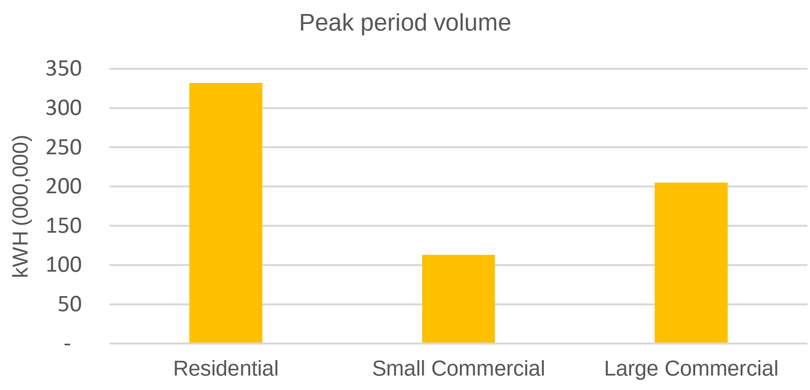
Figure 2 - Winters peaking network



There is a strong correlation between the demand profile and the ambient temperature. Energy use is higher in the winter (May to October) when consumers use more electricity to heat their homes.

[1] As part of our transition to ToU prices we implemented a detailed study customer consumption data. This analysis provided us with useful insights about how consumers use electricity.

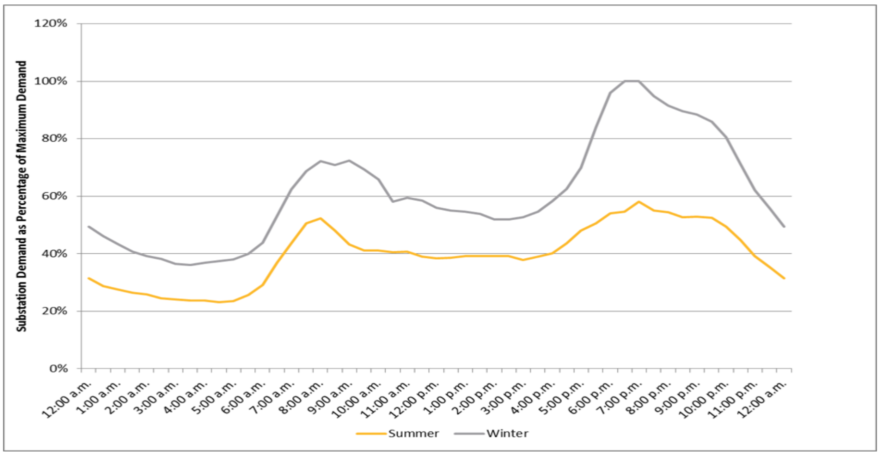
Figure 3 - Residential consumers drive peak demand on the network



The graph compares consumption during peak periods.

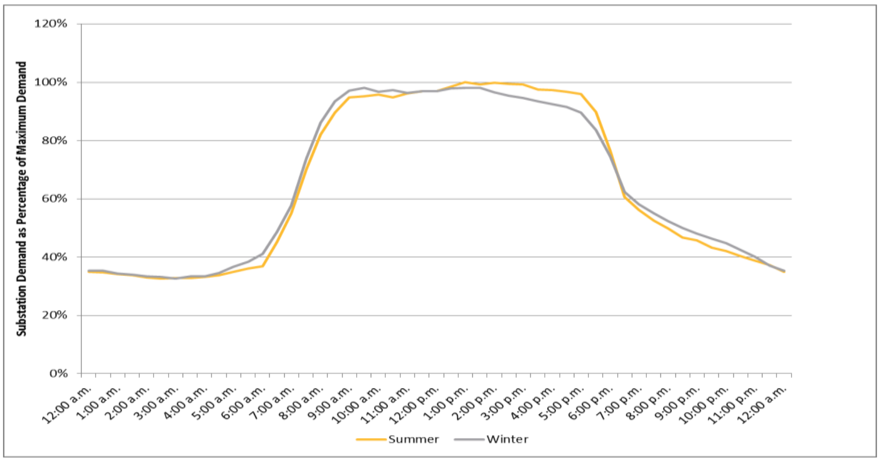
Residential consumers are the largest contributor to peak demand. Large commercial customers contribute significantly towards the morning network peak.

Figure 4 - Residential demand peaks during the week and in the evening



Residential consumer demand is the highest in the morning and evenings during the week. Demand still peaks in the morning and evenings on the weekend but not to the same extent.

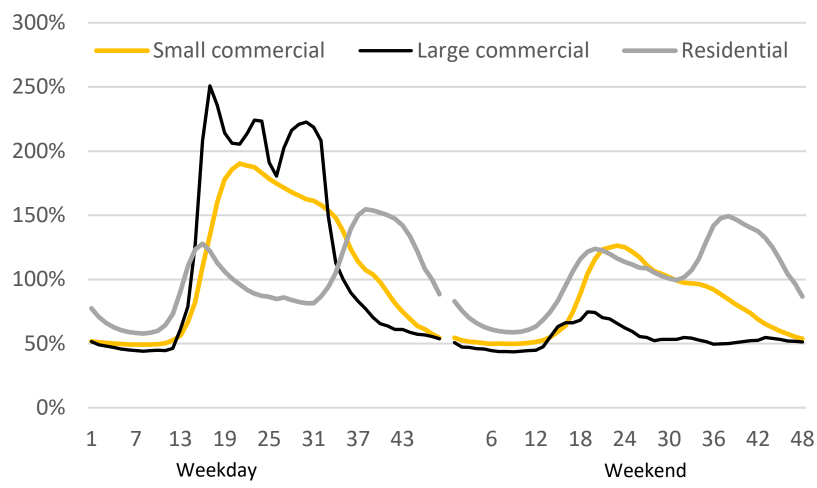
Figure 5 - Commercial demand peaks during working hours



The demand profile for commercial consumers peaks and then remains relatively flat through the day. There is also little difference in summer and winter demand.

Figure 6 - Commercial users have the highest enenery user per consumer

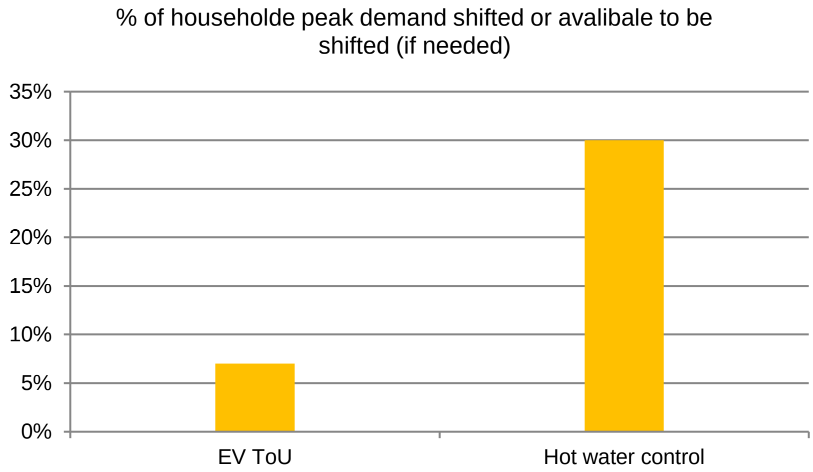
Demand per connection expressed as a proportion



of average demand shows commercial connections contribute towards the network's morning peak but not the evening peak. Commercial businesses demand is constant through the workday.

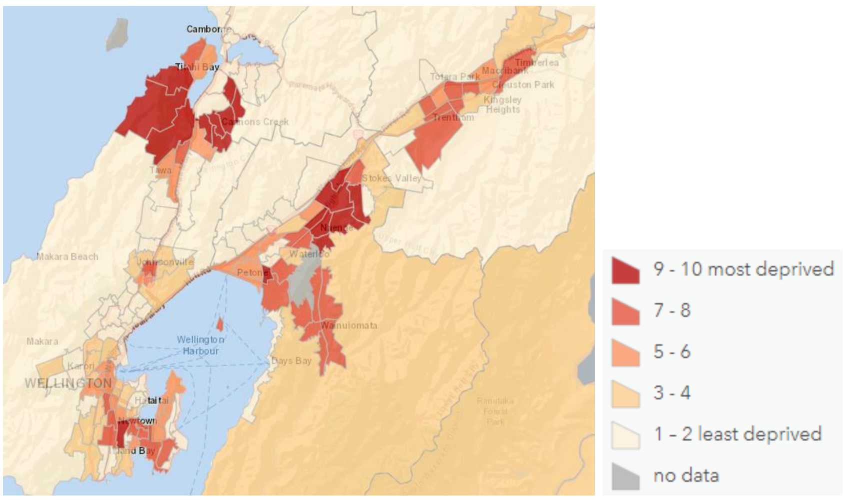
Residential consumers drive the networks evening peak.

Figure 7 - Directly managing demand is more effective than price signals alone



Our EV trial showed that education and price signals moved 7% of energy use away from peak demand. Hot water control provides the ability to move 30% of household away from peak demand. We only shift demand using hot water ripple relays if we need to.

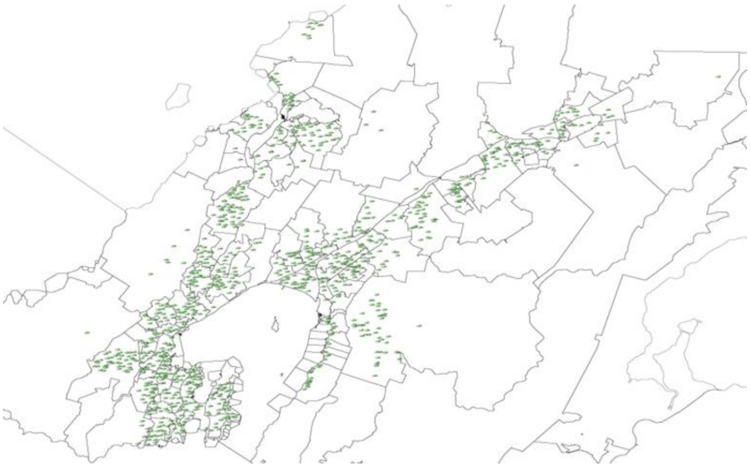
Figure 8 - Wide spread of household income levels[2]



Wellington has a wide spread of household income levels, including a large proportion who maybe experiencing energy poverty. We are cognisant of the impact that changing prices may have on this customer group.

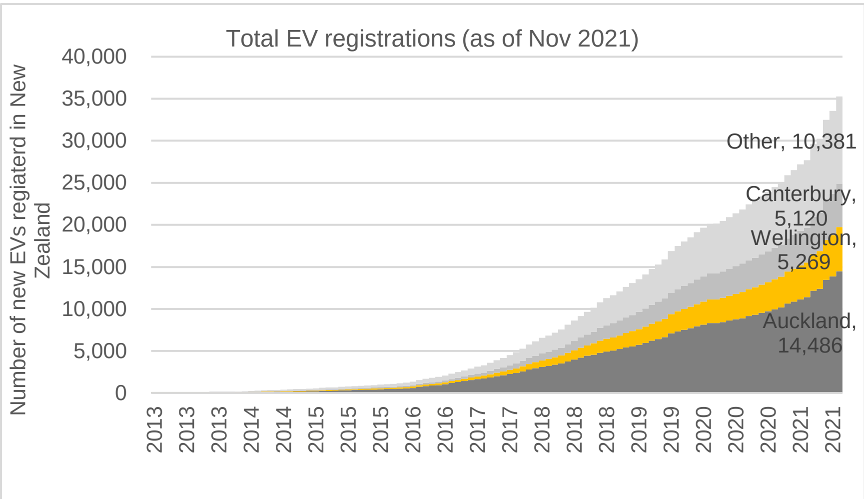
[2] From Environmental Health Intelligence New Zealand https://ehinz.ac.nz/indicators/population-vulnerability/socioeconomic-deprivation-profile/

Figure 9 - EV uptake is evenily spread across network



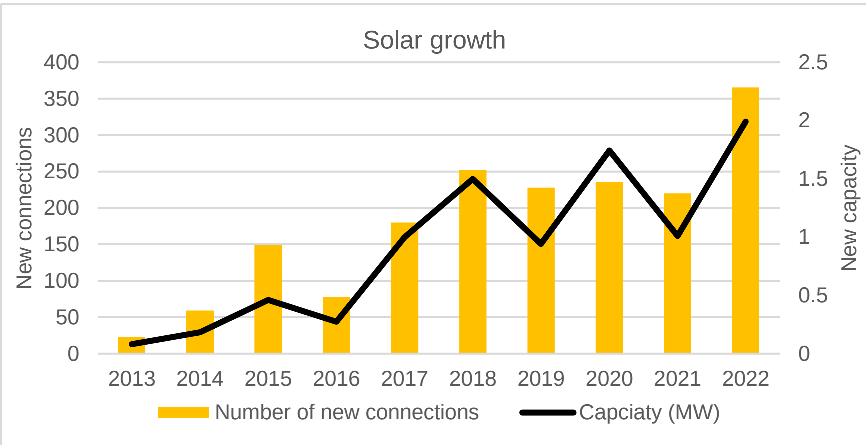
EV uptake is evenly spread across the network. As of 2021, New Zealand Transport Authority reported that there were approximately 5,000 EVs on the Wellington network. EDBs do not have visibility on the number or location of EVs being installed.

Figure 10 – rapid EV uptake



EV growth rates over the last year doubled. In November 2020 there were 3,400 EV's in Wellington. In November 2021 there were 5,300 EVs. EV growth over the last year has added a 0.5% increase in electricity consumption alone. The increase coincides with the Government's penalties for inefficient combustion vehicles and subsidies for EV's, that have been introduced as part of New Zealand's climate change programme.

Figure 11 - Low solar uptake

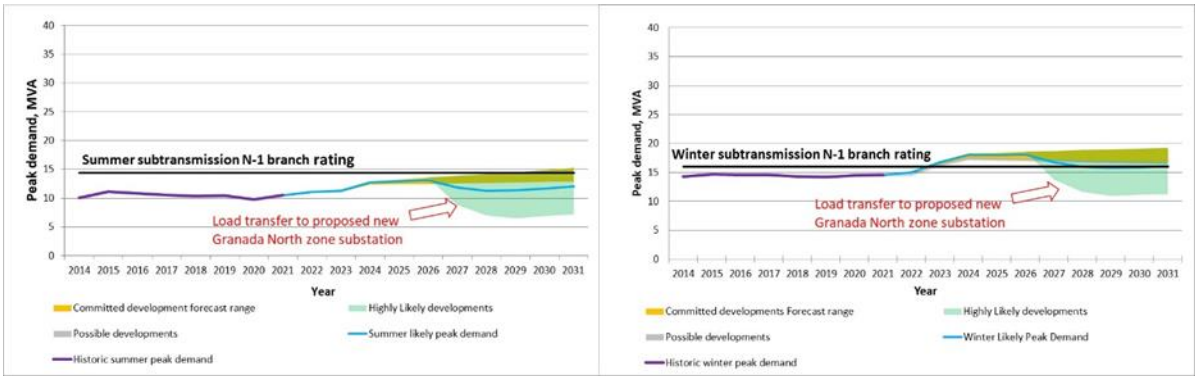


There is relatively low but growing solar uptake in Wellington. As of December 2021, Wellington has ~2,000 installations of solar with 8.7 MW capacity – 1.2% of customers. Nationally, 1.5% of customers have solar.

2.1.2 Location demand forecasts

Chapter 8 of the AMP provides volume forecast for each zone substation. The volume forecasts provide a demand forecast range and an estimation of when demand may exceed constraints. As described earlier, WELL has a strategy of using load management tools (including price signals) to delay having to invest in building a larger network for as long as possible. In many cases where demand exceeds capacity, we will use demand management tools (including pricing signals) to shift demand to other parts of the network or to shift load to less congested periods. This helps us maintain one of the lowest distribution prices in New Zealand while operating one of the most reliable networks. An example is the Tawa Street zone substation, which is illustrated in Figure11.

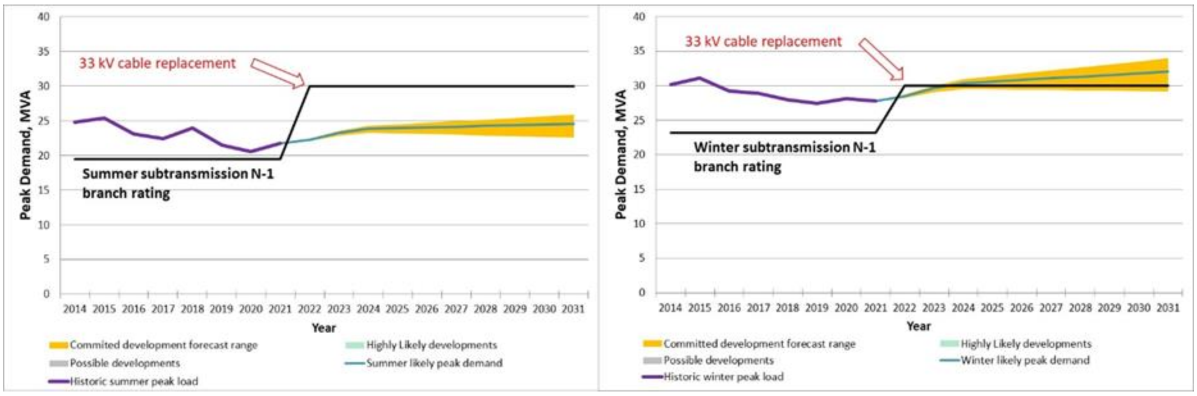
Figure 12 - Tawa street demand and capacity forecast



We expect that winter demand in Tawa may exceed N-1 capacity in 2023. We will use demand management tools to shift load away from the zone sub peak. In this example we plan to shift some load from Tawa to a proposed new zone substation at Grenada North and then manage supply security operationally by shifting load to adjacent zone substations. We will continue to monitor the winter load until we can no longer confidently provide a secure supply. We will then consider options to increase network capacity. As detailed in the AMP, we have nine zone substations where demand currently exceeds capacity, or where we expect that it soon will, and we will use load management tools (including price signals) to manage demand away from congested periods.

We also have some locations where we have decided that load management tools will not let us manage demand within the capacity constraints at some point in the future and that we need to increase network capacity. In these situations, we use price signals to delay when we will need to invest. While we may programme the investment to increase network capacity in the AMP, we continually assess network demand and will delay an investment if we can. Figure 13 from the AMP provides an example of this. Frederick Street is a commercial area that has a summer peak demand (due to office air conditioning). The demand forecast curve shows that demand has exceeded capacity in the summer for some time. We were able to delay investing in additional capacity by using demand management tools, including commercial prices with demand components that encourage reducing energy savings. We have now reached the point where energy use is expected to increase again and we can no longer hold off from investing.

Figure 13 – Fredrick Street demand and capacity forecast



We have nine zone substations where we have included an investment in the AMP to increase capacity and where we continue monitor demand and use demand management tools to delay when the investment is needed.

2.2 Impact of climate change initiatives

The Government has committed to reaching net zero carbon emissions by 2050. The Climate Change Commission has been tasked with developing and implementing a plan of how these targets will be achieved. The Climate Change Commission's '*2021 Draft Advice for Consultation'* (**Draft Advise**) proposed priority areas of action needed to meet the targets. New Zealand climate change programme was finalised in May 2022 with the release of the Emissions Reduction Plan (ERP). The actions included the electrification of light transport and the transition away from natural gas. This will increase electricity consumption and the amount of electricity distributed to consumers across New Zealand. As highlighted by the Climate Change Commission, the capacity and capability of electricity distribution businesses will be an important consideration. Like electricity generation and transmission, electricity distribution networks (and the supporting legislation, policy and regulation) will need to grow and develop to ensure that the increase in demand and reliance on electricity as a primary energy source can be met. This growth is in addition to the network growth forecast in our AMP.

Electricity is already an essential service, providing heating, cooling, cooking, appliance recharging, washing and other amenities needed to maintain healthy and happy lives. An important challenge will be meeting the climate change driven increase in demand while still maintaining a safe, secure and reliable supply for both existing and new services – this will mean developing extra capability and capacity as the climate change initiatives move from early adoption to being applied to all households and businesses.

2.2.1 New Zealand climate change programme and rapid network growth

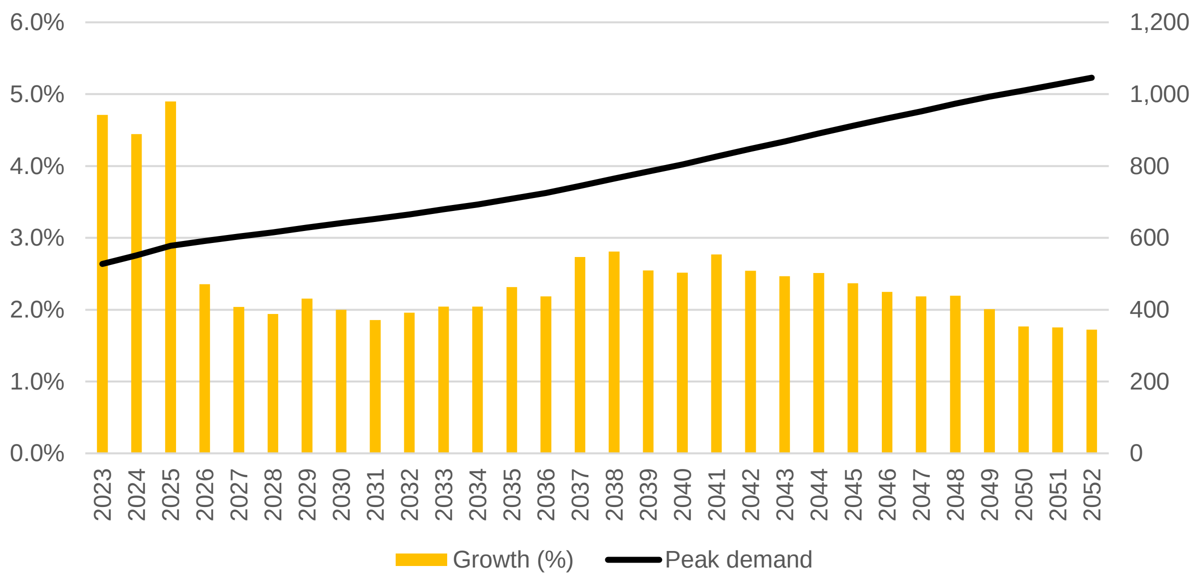
In 2021 we started development of a long term (30 year) network demand forecast model which models the impact of New Zealand emission reduction programme and population growth on the Wellington Network. Demand is forecast to increase by 108% over the next 30 years. Figure 14 summaries the main drivers and the current assumptions used, including those provided in the latest ERP. The assumptions assume a 24% demand offset (total % change in peak demand) from successfully using flexibility services to shift peak demand electricity use to off peak periods. Note, while the forecasts for EV and population driven peak demand growth can be made with a high level of confidence, the demand forecasts for gas and demand offset from flexibility services are less certain. The ERP includes the possibility of natural gas being replaced with a renewable gas source which would mean a lower demand forecast. The flexibility services forecast to offset some peak demand growth have yet to be developed to the scale needed. If these services are not developed to the extend expected, then demand may be higher than forecast.

Figure 14 - Growth assumptions and rates

Growth		Assumption	Peak demand MW 2050	Total change 2050 (%)	Annual change (%)
Current demand (2022)			504	n/a	n/a
Growth	Population growth	Population growth + housing shortage	154	31%	1.02%
	Transport electrification	Climate change programme	251	50%	1.66%
	Transition from gas	Climate change programme	260	52%	1.72%
New growth			665	n/a	n/a
Total new growth (2050) - uncontrolled			1168	132%	4.4%
Load control		Introduction of flexibility services	-123	-24%	-0.81%
Total new growth (2050) - controlled			1046	108%	3.59%

Figure 15 provides the demand forecast on the Wellington network. Peak demand increases from 504 MW (2022) to 1,046 MW (2052), a 108% increase. Growth is highest to begin with (between 4-5% p.a.) due to high probability, large electrification projects[3], before settling back to a long-term average growth of 2.5%.

Figure 15 – Peak demand growth and growth rate forecast



[3] This includes the electrification of public transport and the conversion of coal boilers to electricity.

2.2.2 We need to consider non-traditional solutions

Central to WELL's ability to deliver the climate change driven demand increase, is the ability to shift demand away from peak periods to better utilise the existing network. Distribution networks may not be able to meet the climate change driven demand increases by solely relying on traditional 'wire' solutions:

- **The size of the increase in demand:** An initial calculation of the change in electricity demand needed to meet New Zealand's emission reductions targets actions shows an 108% increase. This represents an unprecedented increase in demand outside of what the industry regulatory settings is currently structured to deliver. This is in addition to recent demand increases from new housing developments in response to the Wellington housing shortage.
- **Rapid uptake of electric vehicles:** The uptake of electric vehicles (EVs) is a cornerstone of the climate change actions to reduce carbon emissions. EV charging significantly increases household energy use and the governments promotion of EVs above fossil fuel driven transportation is likely to cause a rapid increase in electricity demand - an increase that may be difficult for traditional network reinforcement to keep pace with.
- **Time and resources needed to double the capacity of the network:** The significant increase in network investment will come at a time when other distribution networks, the transmission grid and other industries like transportation will also be replacing, developing and growing their infrastructure in response to the climate change targets. A finite pool of skilled resource in New Zealand (and potentially globally as other countries reduce carbon emissions) could make this level of growth unrealistic.

Shifting demand away from peak demand periods will allow WELL to reduce the amount of traditional network reinforcement needed, providing time for networks to build new capacity. WELL has a programme of develop flexibility services to:

- Keep consumer prices low.
- Provide time needed to build new capacity to deliver the residual electricity demand that cannot be shifted to less congested periods on the network.
- Allow t networks to continue to provide a reliable supply of electricity.

Flexibility services alone will not deliver the rapid increase in demand. The size of the increase (93% more demand) means that we will also have to build more capacity. Along with our long-term demand modelling, we have been building a detailed network model that we can use to model where and when our network assets will run out of capacity and will need upgrading. We expect to have developed the model to the point that we can incorporate the results into our AMP disclosures in 2023. This will also allow us to reflect any changes made the Climate Change Commissions final decarbonation programmes.

2.2.3 Confirming the value of controlling peak demand

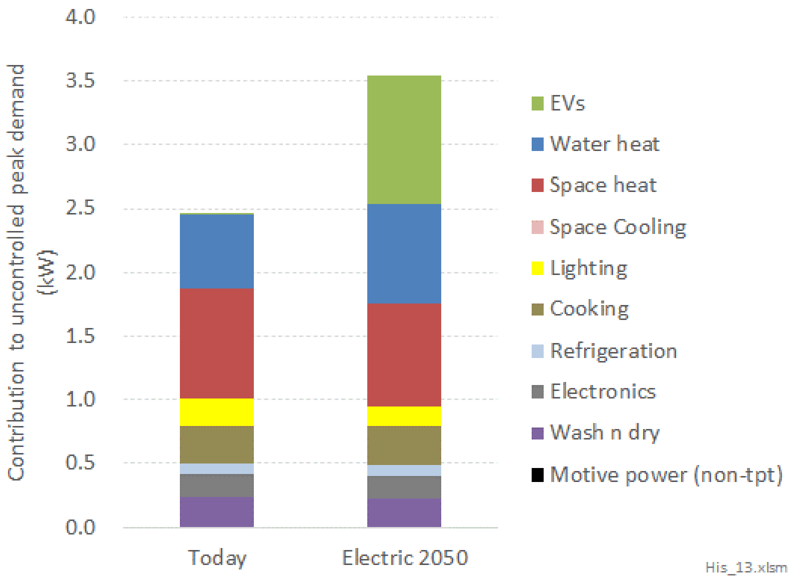
Utilising the spare network capacity during the day and at night appears to provide a viable way of meeting the climate change initiatives. Concept Consulting EV Study work programme supports this important assumption. While the findings are draft and are still being refined, they do support the strategy of using load control to meet the climate change targets.

The study analysed two points in time[4]:

- 'Today', being a breakdown of electricity consumption between end-uses as per EECA's Energy End-Use Database[5]
- 'Electric 2050', being the increase in average per household electricity consumption by 2050 assuming the degree of electrification proposed by the Climate Change Commission in its draft advice.

Figure 16 shows the estimated breakdown of average per household contribution to peak demand without any demand management – i.e., prior any appliance control or action by consumers to shift when they use an appliance. Prior to any demand management, the biggest driver of today's average uncontrolled household contribution to system peak is space heating, followed by water heating, then cooking, with other appliances driving the remaining 30% of peak demand. By 2050 they estimate that, if households have no incentive to manage when they charge their EVs, un-managed peak per household demand will increase by 45% - largely from EVs, with some increased contribution from water heating and small offsets from other uses. In total, EVs would represent 30% of un-managed peak per household demand.

Figure 16 - Breakdown of average per household contribution to peak demand prior to any appliance demand management



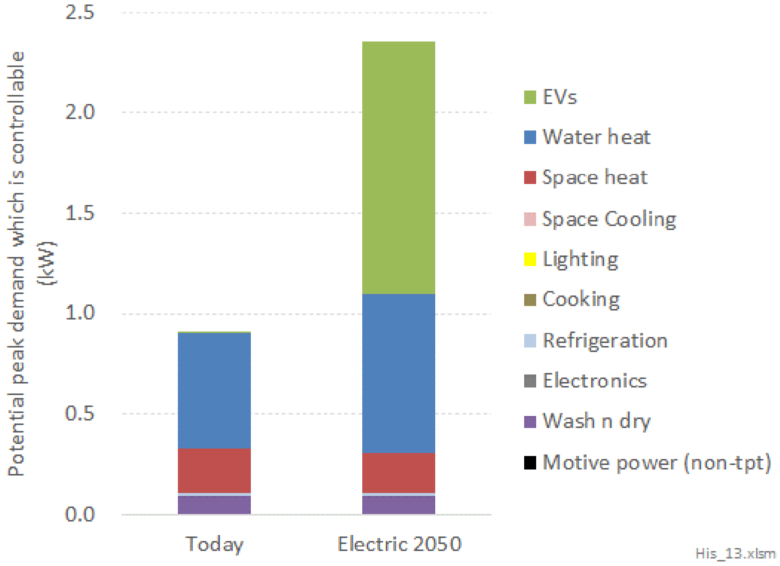
The study looked at what appliances have the most potential for demand management. Figure 17 shows an estimated breakdown of the potential for demand management[6]. The key takeaway is that EV charging and water heating have, by far, the most potential for load management.

[4] The key assumptions are natural gas and LPG space heaters all switch to heat pump electric, water heating all switches to electric, with 15% using heat pump cylinders (and the balance using resistive heating), household vehicles are all fully electric, and 20% of journeys shift to active or public transport, cooking is all switched to electric, and there are energy efficiency improvements across lighting (25%), space heating (15%), water heating (5%) and appliances (2.5%).

[5] https://tools.eeca.govt.nz/energy-end-use-database/

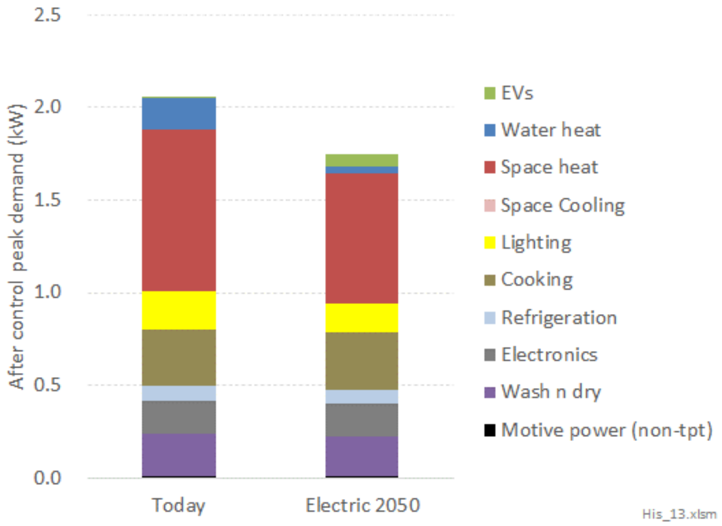
[6] The scope for easing capacity investment pressures depends on the size of the contribution to peak demand, and the extent to which the demand is time critical (1) some uses are inherently less time critical – for example, clothes and dishwashing are more delayable than lighting or cooking, and (2) other uses are non-time critical because the appliance has built-in storage that act as a buffer between supply and consumption.

Figure 17 - Breakdown of average household potential for appliance demand management during peak demand



The study combines demand growth and controllability to show a breakdown of peak demand with load management. Figure 18 shows that sustaining hot water control and adding EV management has the potential to eliminate capacity investment pressure from changes in average per household demand in the Electric 2050 scenario[7].

Figure 18 - Breakdown of average per household after-demand management contribution to peak demand



The study is also on a national basis. The Wellington network has the highest proportion of gas space heating in NZ and its urban environment is better suited to EVs than other networks. The potential for controlling peak demand is even higher in Wellington.

[7] Note, some efficient assumptions are also applied which means Figure 18 is not simply the addition of figure 16 and 17.

2.3 Conclusions

The key conclusions from the analysis of network characteristics are:

- Wellington is predominantly an urban network. Peak demand on the Wellington network is in the evening and in the winter. Residential consumers drive peak demand. The Wellington network has spare capacity in the day and at night.
- Where demand exceeds capacity, we will first use demand management tools (including pricing signals) to shift demand to other parts of the network or to shift load to less congested periods. Demand management tools provide important tools to allow us to delay investing in more capacity.
- In the future (assuming the current Climate Change work programmes will proceed) the accommodation of electric vehicles and transition from gas to electricity will be the largest drivers of peak demand in the future.
- While accommodating EVs will result in a large increase in demand, that energy demand is used for battery storage so is the easiest to move to less congested periods. EV technology enables owners to automatically charge during off peak periods and still have the charge needed to using the next day.
- The increase in energy demand from transitioning from residential consumers from gas to electricity is more difficult to move to off peak periods – gas for space heating and cooking will still be needed during peak demand periods. Some demand for hot water heating could be moved to off peak periods. Commercial gas displacement will require dedicated high voltage network investment to accommodate the scale of energy required.
- New capacity is needed to deliver the forecast 108% increase in demand. However, traditional wire solutions alone are unlikely to be able to meet this demand increase while maintaining affordable electricity prices. Flexibility services will help to provide distribution networks the time to build the additional capacity needed and will help keep prices affordable.
- To achieve this, WELL must develop and invest in flexibility services and demand management solutions. Prices must also be developed that signal (through cost reflective tariffs) the value shifting demand away from peak periods – this will be a focus of WELL future work programmes.
- New services that allow EDBs to directly manage demand appear to be more effective than a price signal alone.

3 Pricing strategy

We are planning to introduce prices to support new services that will offer consumers with smart devices (like smart electric vehicle chargers and household solar and battery equipment) the opportunity to participate in services that manage demand away from peak demand periods on the network. If we can shift peak demand away from busy periods on the network, we can delay building a larger network to meet the increase in electricity demand. Participating consumers will be rewarded with cheaper prices and we will be able to keep prices lower for everybody, than they would be if peak demand wasn't reduced.

The objective of WELL's pricing programme is to equitably collect the revenue that it needs to build and operate the network and to signal the future cost of using the network. Practically this means:

- Prices that will recover the cost to build and operate the network;
- Prices that encourage off peak use and discourage peak use;
- Prices that encourage consumers to allow WELL to directly manage demand on the network.

Signalling the cost of network congestion provides consumers with the opportunity to change their energy use behaviour and to reduce their electricity costs by moving their demand to lower congestion periods. This has the immediate benefit of less expensive lines charges (for those who move their energy consumption to off peak periods) and the long-term benefits of lower prices through avoiding or delaying network re-enforcement.

We want to move all consumers to cost-reflective pricing arrangements that better signal economic costs. The speed and shape of this transition is constrained by factors such as the need to limit price shock (especially for consumers who struggle with affordability), to comply with low-user low-fixed charge regulations, and the speed at which retailers can change their own processes and systems to include price signals.

Our pricing programme is informed by:

- The cost impact of re-enforcing the distribution network to meet growing demand during peak congestion periods. Signalling the cost of re-enforcing the network will let consumers choose to avoid network re-enforcement and have lower long-term prices, or to pay more to build a larger network that removes the anticipated restrictions on when energy can be used. The price signal therefore represents a clear price-quality trade-off for consumers;
- The risks (e.g. of congestion and cost of providing higher network capacity) and opportunities (e.g. to reduce network investment pressures) of new and maturing technologies – these increase the value of adopting prices that clearly signal congestion periods and costs of increasing network capacity, which encourages more efficient use of the network;
- The impact that prices changes will have on consumers, especially those in energy hardship. Practically this will likely mean a gradual transition to cost reflect prices over time.
- The Climate Change Commissions Draft Advice work programme;
- The Electricity Authority's revised pricing principles and supporting guidelines.

4 Completion of the original Pricing Roadmap

4.1 Progress update

In 2017 we published our first Pricing Roadmap which outlined how we are developing our prices. Progress against the roadmap is provided in Appendix A. Figure 19 provides a summary of the pricing programmes for each consumer group. The figure provides an assessment of the impact that each consumer group has on peak demand and the pricing programmes that WELL is implementing to reduce that demand. The roadmap initially focused on Electric Vehicle (EV) owners and residential consumers as the main potential contributors to peak demand and therefore the greatest driver for the need to re-enforce the network.

Figure 19 – Summary of progress on the Pricing Roadmap

Development Implementation

<table>
<tr><th rowspan="2">Consumer group</th><th rowspan="2">Impact on peak demand and future price increases</th><th colspan="6">Pricing programmes to signal peak demand</th></tr>
<tr><th>2019/20</th><th>2020/21</th><th>2021/22</th><th>2022/23</th><th>2023/24</th><th>2024/25</th></tr>
<tr><td rowspan="2">Residential consumers</td><td rowspan="2">High – main contributor to peak demand</td><td colspan="3" rowspan="2">Residential TOU</td><td colspan="3">Develop and transition to new pricing methodology</td></tr>
<tr><td colspan="3">Residential TOU</td></tr>
<tr><td rowspan="2">Flexibility services & DER</td><td rowspan="2">High – future contributor to peak demand</td><td colspan="3" rowspan="2">EV & Battery ToU tariffs</td><td colspan="3">Managed EV & battery charging tariff</td></tr>
<tr><td colspan="3">EV & Battery ToU tariffs</td></tr>
<tr><td>Small/medium commercial</td><td>Currently low – expected to increase to medium with DER aggregation</td><td colspan="3"></td><td colspan="3">Develop and transition to new pricing methodology</td></tr>
<tr><td>Large commercial</td><td>Low – cost reflective prices & contribution policy in place</td><td colspan="3"></td><td colspan="3">Develop and transition to new pricing methodology</td></tr>
</table>

In 2018, WELL completed the first phase of the Pricing Roadmap by trialling cost reflective electric vehicle (**EV**) prices and then introducing Time of Use (**ToU**) prices for EV and household battery system consumers. In 2019, WELL widened the eligibility for ToU prices to all residential consumers, offering it to retailers as an optional price category. From 1 April 2021, we then applied ToU to all residential consumers. Updates on specific aspects of the programme can be found at:

- **EV Trial**: Our EV trial helped us understand how consumers want to use their EV's. The EV trial results can be found at www.welectricity.co.nz/disclosures/pricing/evtrial/.
- **EV Connect**: We have been working with stakeholders to articulate the steps required to support EV adoption. An update on progress can be found at: https://www.welectricity.co.nz/about-us/major-projects/ev-connect/
- **ToU prices and how to benefit from them**: If people change when they use electricity, away from busy periods on the network, a larger network doesn't have to be built. Avoiding having to build a larger network means that prices can be kept low. Learn more about ToU prices at: https://www.welectricity.co.nz/disclosures/pricing/time-of-use-pricing/

4.2 EV Charging trial

In late 2017 WELL conducted a trial to better understand the home charging behaviours of EV owners and how they could potentially affect demand for electricity. The trial monitored the operation of 100 EVs and EV chargers and surveyed the vehicle owners about how they preferred to use their vehicles and their thoughts about potential EV services. The results of the trial have helped influence the design of our EV pricing and allowed us to gain an insight into customers' preferences for future EV charging services. A summary of the key findings is provided in Figure 20.

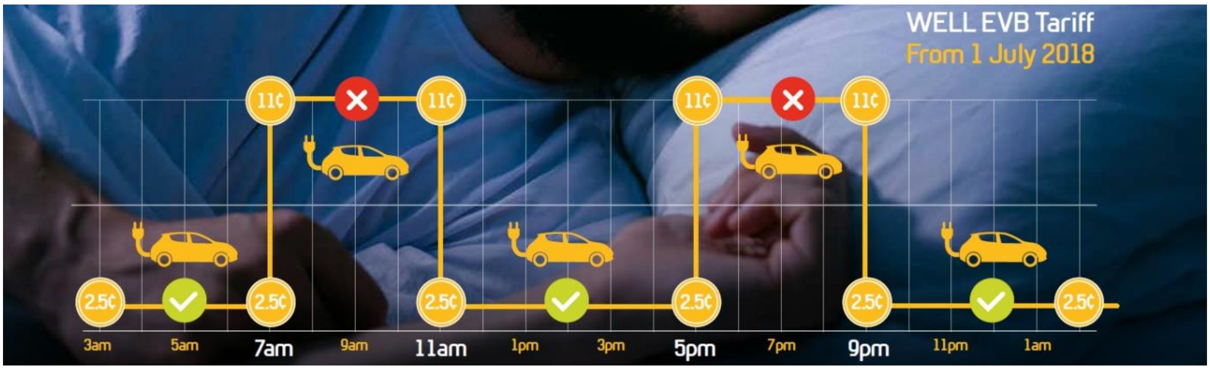
Figure 20 - Summary of the findings of the EV charging trial

Finding	Impact on pricing
EV charging will increase average residential demand by approximately 2,500kWh, equal to 1/4 - 1/3 of annual household electricity consumption.	The electrification of transportation will have a material impact on electricity use. A larger network will need to be built to meet this demand if the demand cannot be shifted to off-peak periods.
70% Drivers were comfortable with an EDB managing their EV charging.	Consumers are likely to be receptive to demand management services at the right price point.
80% of EV owners charge their vehicles after 9pm.	Charging during off-peak, night time periods appear to suit customer preferences – most consumers don't need to charge their vehicles during peak periods.
66% of EV owner's use a timer on their EV charges that lets them chooses when to charge.	Most vehicles have a timer that could be used to respond to ToU price signals. Newer EV's also have the equipment that would allow an EDB to manage when an EV charges.
EV's provide a 45% reduction in household energy costs.	Household costs should reduce with the transition to an EV. This should help to encourage a faster transition to EVs by bringing forward the point that it will be economic to change from the current petrol or diesel vehicle.

4.3 EV and Battery prices

Following the trial, WELL introduced new prices in July 2018 for households with EVs and batteries that reflected the benefits of charging their vehicles or batteries during less congested periods. For simplicity, the tariff applied to energy use for the entire household. Figure 21 - shows pictorially the higher prices for energy use during congested periods and the lower prices for less congested periods.

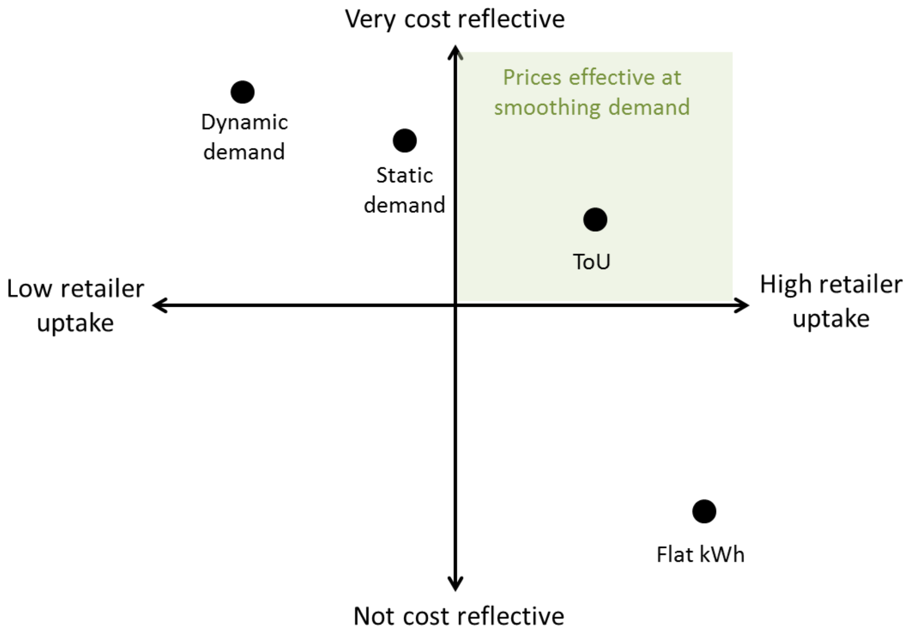
Figure 21 – WELLs 2018 EV and Battery prices



Initially we proposed to apply a peak demand price which we considered a more cost reflective pricing method than other pricing methodologies. However, following retailer feedback, we settled on ToU prices. Retailer billing systems were not able to provide the billing data needed to calculate demand prices. A critical lesson is that trade-offs will have to be made between how cost reflective prices are (how good prices are at signally congestion) and whether prices are understood and can be practically applied. While more complex pricing methods like demand based pricing provide good theoretical price signal of congestion, they are less likely to be passed through to consumers by retailers as they are difficult to implement and manage, and much harder for consumers to understand.

If prices are not passed through to consumers, they will be ineffective at achieving the purpose of efficient prices – to inform consumer's choices about when to use electricity. The graph below illustrates this trade-off. While ToU prices may not be the best at signalling congestion, retailers are more likely to pass prices onto consumers and therefore ToU is the most effective pricing method for encouraging consumers to use off-peak energy and smoothing congestion.

Figure 22 – trade-off between cost reflectivity and practical application



It is important to note that this assessment is for a point in time and that retailer billing systems will evolve, technology will assist consumers in choosing different pricing options and consumers will become more educated about their pricing choices. We do expect more cost reflective pricing options will become viable in the future.

4.4 ToU residential prices

For the reasons outlined in the previous section, we favour ToU pricing aligned with the emerging industry standard design for mass market consumers.

- WELL introduced optional residential ToU prices in 2020. Residential ToU prices were offered as a pricing option (rather than applying ToU to all residential consumers) following retailer feedback that more time was needed to develop and change internal processes and to consider how to practically apply the new prices. Approximately 12% or 18,000 residential consumers were voluntarily shifted to ToU prices.
- WELL applied ToU prices from 1 April 2021 to all residential consumers after consulting with retailers. Retailers provided constructive feedback which included learnings and suggestions from the application of ToU by other distribution networks in 2020.

4.4.1 Residential ToU Pricing Structure

Our residential ToU pricing structure reflects demand patterns *and* aligns with other network distribution ToU structures. Aligning pricing structures with other networks will help minimise implementation costs for retailers. Our ToU pricing structure is summarised in Figure 23.

Figure 23 – ToU price structure

Design parameter	**Industry standard?**	**Approach**	**Comment**
Hourly Pattern	Y	AM peak = 7 to 11 PM peak = 5 to 9 No shoulder	A shoulder period has not been included as consumers changing their 'discretionary' load are most likely to do this using timers on appliances (e.g. EV charging, or dishwashers) and are unlikely to discriminate between a peak and shoulder. In addition, a daytime shoulder will over-signal the value of midday solar production.
Weekly Pattern	Y	No peak periods on weekends	Low-cost weekend concept is relatively simple for consumers to understand and adjust to.
Seasonal Pattern	Y	Consistent signals year-round	Seasonal pattern adds complexity (for supply chain and consumers) and exacerbates winter energy hardship for vulnerable consumers facing budgeting challenges.

Figure 24 below illustrates the residential ToU pricing structure.

Figure 24 – Residential ToU pricing structure

Figure 25 illustrates the ToU structures that were being offered by different distribution networks in 2020. WELL's ToU structure aligned with the five other networks serving the majority of the New Zealand residential consumer market. It was also consistent with our existing EV and battery pricing structures and with the structure the Electricity Network Association are proposing to include in its 'pricing menu'[8].

Figure 25 – ToU structures aligned with WELL's residential ToU prices[9]

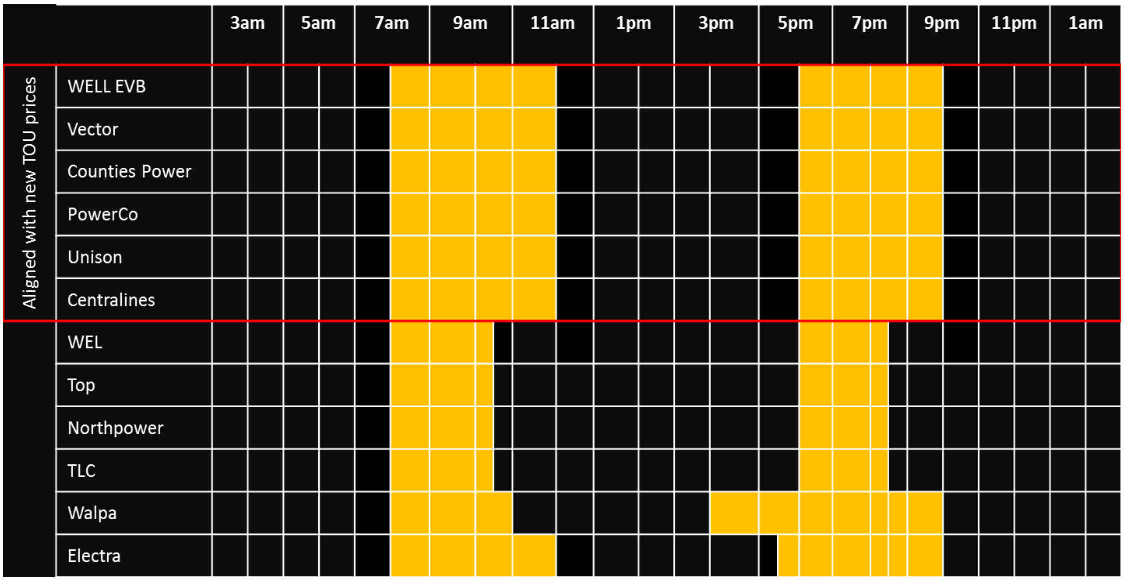
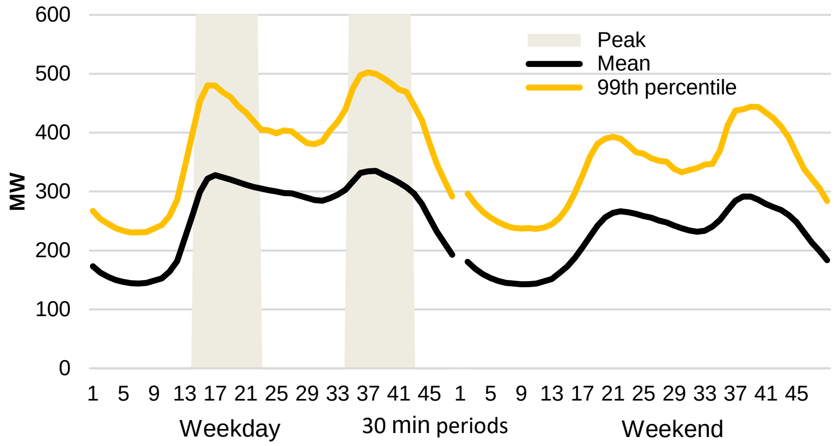


Figure 26 compares the standard time periods against demand patterns on our network. The residential ToU structure is a good match to the Wellington region's demand patterns.

[8] The pricing menu proposes a set of standard pricing structures designed to align distribution prices.

[9] The assessment against other network process was based on 1 April 2019 prices.

Figure 26 – Illustrating the peak pricing period's alignment with peak demand



ToU unit rates have been designed so that the pricing signals are consistent with WELL's existing prices and its unit rates for ripple control. A common fixed charge has been used for all residential consumers, with the exception of the low fixed charge restrictions which WELL will continue to apply in accordance with the applicable rules, noting that the current low fixed user restrictions are expected to change as a result of the Electricity Price Review recommendations.

ToU prices will not be applied to dedicated control prices as dedicated control prices are already low to reflect that this tariff provides WELL with the ability to move the supply of energy during peak demand periods.

4.4.2 Gradual uptake

The retailer consultation highlighted that not all retailers will be able to provide billing data in the 30 minute increments needed to calculate ToU data. The key reasons for Traders not being able to provide the half hour time sliced data needed to calculate ToU prices were (ranked from the largest to smallest in impact):

1. **Retailer billing systems and validation processes can't process half hour data needed for pricing:** Some Trader billing systems can't process all of the half hour data needed to calculate ToU prices. Other Traders' data validation processes have been designed for the market settlement process and not for distribution billing.

2. **Data agreements not in place with meter providers**: A Retailer will have a data agreement in place with meter providers for the provision of the half hour data. The agreement also ensures that the data is provided to the correct level of quality. Some Retailers are still negotiating terms and do not have data agreements in place. Feedback indicated that negotiations are difficult because Retailers have little influence over agreement terms. Terms include providing data that meets the required quality levels.

3. **Legacy meters or no communications**: Some ICPs do not have AMI meters that can provide half hour data needed to calculate ToU prices. Some meters are also not able to communicate the data.

4. **Incorrect registry flags:** The electricity registry comms flag can incorrectly show the meter is communicating when it is not. It takes up to 90 days to correct any errors. Feedback also suggested that there are weak incentives for meter providers to correct any errors so it could take longer than 90 days for corrections to be made.

5. **Intermittent communications or failed communications:** The communication status of a meter can change over time. If communications stop there will be a minimum of 90 days before the registry flag is adjusted and the ICP will be eligible for the 'opt out' price. Reasons for communications stopping include new buildings and physical obstructions, cell phone interference, reduced mesh density and meter box damage.

We have made a number of pricing structure changes to help manage the range of Trader specific issues and to encourage Retailers to correct any errors and to upgrade their own systems and processes so that ToU can be applied. Feedback indicates that about 40% of residential consumers (depending on how fast Traders can upgrade their billing systems) will not be able to apply ToU prices come 1 April 2021. Retailers are in the process of upgrading billing systems and continue to negotiate data agreements with Meter Providers. They have indicated that there are always likely to be legacy meters and meters with no communication, resulting in 10-15% of ICPs on our network where cost reflective prices can't be applied.

4.4.3 Customer impact of the annual price increase

WELL is cognisant of the potential impact ToU prices might have on those in energy hardship and the on-going economic impacts of Covid-19. As part of developing ToU prices, a sample data set representing over 10% of WELL's residential consumers was used to understand the customer impact of applying ToU prices. Household deprivation data was combined with the consumption data to analyse impacts on affordability.

WELL presented the customer impact and consulted with retailers, as the consumers representative, before any changes are made to price structures. The consultation documents include an estimate of the impact that any change will have on different customer groups, the benefits that the change will provide consumers and any potential downside. WELL used retailer feedback to refine the prices to help ensure any changes made benefit consumers overall and in the long term.

5 New work programmes

We have made good progress against the original Pricing Roadmap actions and we have advanced our own thinking on how to better manage electricity demand. The increases in demand that are likely to result from the climate change initiatives will make it even more important for networks to move energy use to less congested periods. The Authority have also refreshed their pricing methodology and the Electricity Pricing Review has recommended a number of changes that directly impact pricing. These changes have led to a number of new work programmes that include a pricing element.

5.1 Applying the cost reflective price setting methodology

The Pricing Roadmap has been updated to incorporate the Authority's new pricing methodology. The Electricity Authority provided updated Pricing Principles in 2019 and supported them with a Distribution Pricing Practice Note (2021) to help distributors interpret and apply the distribution pricing principles. The purpose of the new Pricing Principles is to provide prices that are more reflective of the underlying costs of providing distribution services.

Applying the principles requires a new approach to pricing, an approach which first sets a price signal which reflects the cost of using electricity during peak congestion periods, and then recovers any residual costs in a way that doesn't influence consumers energy use behaviours (i.e. the peak demand price signal already signals the future cost of using energy during peak demand periods and no further price signals are needed.

The remaining revenue should then be collected in a way that minimises any volatility from changes in consumer energy use habits, generally by using fixed charges). This differs from the past pricing approach which allocated costs to consumer groups using cost drivers, and then applied price signals that reflect the cost of using energy's during peak demand periods. Appendix 2 illustrates the new pricing approach – this diagram is sourced from the Electricity Authority's' Distribution Pricing Price Note 2021.

The new pricing approach is an important step in signalling the cost of using electricity during busy periods on the network. This will encourage consumers to shift discretionary energy use to less busy periods, and in some cases, helping us delay expensive network reinforcement.

5.1.1 Review of WELL's current price structures

In 2021 we reviewed our prices and developed a new pricing structure which aligns with the Electricity Authority cost reflective pricing methodology. The review first developed a new pricing structure from first principles (i.e. a pricing structured that had no regards to current prices). We then compared the structure to our current prices to understand the extend of the changes required and potential price shocks. The review highlighted key opportunities to improve our prices:

1. **Harmonise and calibrate peak signals** – peak signals are inconsistent across tariff components. Opportunity to improve consistency and refine analysis of appropriate signal strength.

2. **Enhance discount for controllability** – managed tariffs provide technology-specific discount for controllability (e.g. current hot water tariff via ripple control). Opportunity to broaden (incl. to EVs) and implement improved design. Internet-based signaling for new tech (e.g. EVs) offers greater ability to maximise load management value than current ripple control. Long-term, transitioning hot water control to new signalling platform would deliver benefits. Consider additional incentive mechanisms to address lack of awareness (and consequent reduced uptake) of controllability discounts.

3. **Rebalance fixed to variable ratios** – off peak variable rate is higher than underlying costs, discouraging low-cost off-peak consumption and frustrating efficient uptake of EVs. Opportunity to transition off-peak variable into fixed component to improve cost reflectivity (subject to LULFC transition path).

4. **Make cost allocation simpler and more robust** – allocation methods are complex and may not be the best methods for allocating residual costs in a least distortive way. Opportunity to simplify while also improving basis for allocating shared costs between consumer groups.

5. **Increase uptake** of cost reflective prices– opportunity to increase residential ToU uptake and review non-residential pricing.

5.1.2 Proposed future pricing structure

Our proposed future pricing structures includes changes to residential and non-residential prices.

General mass market tariffs: Our pricing proposes to use the long run marginal cost (LRMC) to set pricing signals for the mass market, rather than the more volatile short run costs. We believe that distribution pricing is best suited to signalling enduring (or slow-moving) network economic cost. We recognise that an 'accurate' estimate of network LRMC would vary by location and time – rising as load growth reduces capacity headroom before collapsing after each new capacity investment. However, due to general consumer inability to meaningfully respond to such granular and dynamic prices, distribution pricing is better suited to relatively stable, network-wide estimates of LRMC. To start with we are proposing to use a network level LRMC or possibly geographic pricing zones where the network has significant differences in the LRMC.

Flexibility services solving specific network issues: We will consider short run costs for flexibility services designed to solve specific short term network issues. These services are not designed to be enduring and will be targeted at flexibility providers who have the tools and expertise to respond to more complex price signals.

5.1.2.1 Proposed residential price structures

Figure 27 summarises the proposed structures for residential consumers. The structure assumes the removal of the current low fixed charge regulations which currently stop the implementation of cost reflective prices.

Our pricing proposes to use different price signals depending on the type of prices and behavioural changes being targeted.

Our proposed prices include a zero-rated off-peak price signals and rebalancing the variable/fixed price mix. Practically this means reducing the amount of revenue collected from off-peak periods and increasing the proportion of revenue collected from fixed prices. This provides several advantages:

- Reflects that there is excess capacity during off-peak periods and there are no peak period cost impacts.
- It clarifies the price signal to consumers. Currently, consumers must subtract the peak demand price signal away from the off-peak signal to reveal the true peak demand price signal. Rebalancing variable and fixed prices using the long run margin cost will also make the price signal more reflective of the cost of using energy during peak demand periods.
- It removes potential subsidisation distribution prices for solar users. Currently, solar users may be paying less because they are able to reduce their off-peak prices by offsetting their energy use using solar. This means they are avoiding paying for services they should be contributing towards – the network has capacity during the off-peak periods and there is no benefits of reducing demand at this time. Other customer prices then have to be raised to cover the revenue shortfall.

Early estimates of the LRMC show prices could collect 70% of the revenue from fixed prices and 30% from the peak price signal (the LRMC will be recalculated to confirm this). This translates to a peak demand price signal of around 9 cents a kWh. Currently our EVB tariff is around this at 11 cents kWh and our ToU is 5 cents a kWh.

Time-of-use (ToU) is the best-fit for now for smaller consumers; ToU is effective because it:

- is readily understood – it doesn't require consumers to understand a new usage statistic (e.g. peak demand) – and doesn't expose consumers to excessive volatility or risk
- can be implemented by most NZ retailers, helped along by its emerging prevalence amongst larger distributors
- sends an efficient signal and effective signal for the types of decisions small consumers make

Longer-term, successors to ToU may be appropriate, for example if:

- daily load profiles flatten enough that investment is driven by peak days rather than peak hours
- there are enough responsive demands (or injections) in a typical household to support more dynamic signalling
- retail (or aggregator) capability is no longer an impediment

However, more dynamic pricing (such as coincident peak demand) comes with significant implementation challenges and risk of repeated bill shocks.

We are proposing to compliment ToU prices with discounts for "appliances" that can be controlled to further manage network load. This is well established for hot water heating – a storage load that can be managed with minimal customer impact. Remote management allows staggered restoration to avoid risk of post-control peak. The same approach is attractive for electric vehicles (EV). Because it's a storage technology (using the EV battery), vehicle charging is a very 'shiftable' load, so with ToU alone there could be sizeable surge at onset of the off-peak period.

We propose offering a discounted charge for controlled load that is consistent with ToU design philosophy:

- A discount could be 100% if control fully effective at eliminating investment pressure
- scaled-down discount if the controlled load is not separately metered – i.e. 'inclusive' tariff
- Recover the cost of control systems from managed load parties using a fixed or annual charge

- Figure 27 - Future residential price structures

Component	Proposed Method	Reason selected
Peak demand charge	**Time of use for un-managed load, with limited opt-out.** - Weekday peak rate from 7am to 11am and 5pm to 9pm. Structure aligns with sector majority (aiding retail uptake) and network demand (aiding efficiency of price signal). - Zero-rated off peak (incl. weekends). Reflects excess capacity off peak (and no other cost impacts).	- Understood and can be implemented by retailers - Sets an efficient and effective signal for the types of decisions small consumers make (what appliance to buy, simple changes in routine – e.g. delaying running a dishwasher)
	Peak discount for manageable load - Discounted for metered controllable load. - Discounted for managed load - Discounted peak rate for "inclusive" controllable load. - Apply an additional fixed price increment to recover cost of control	- Discount appropriately rewards uptake. - Assumes flexibility service providers would be financially incentivising residential consumers, and not WELL directly
Residual cost allocation and recovery	**Energy-based cost allocation** - Allocate total costs between residential and business consumer groups using energy (GWh) or anytime peak demand as an allocator. - Cross-check against robust subsidy-free analysis. - Net off expected signalling revenue, then spread balance across ICPs to derive fixed charge per ICP.	- Least distortional impact on energy use behaviours - Simple and achieves EPR recommendation of reversing historic over-allocation to residential.

Component	Proposed Method	Reason selected
	Higher fixed rate • Fixed rate adjusted up to achieve full recovery of costs allocated to residential consumer group.	- Least distortional impact on energy use behaviours

5.1.2.2 Proposed non-residential price structures

The review of our commercial price structures also provides an opportunity to simplify the current structure which has a number of different price categories. **Error! Reference source not found.** 28 summaries our proposed non-residential price structures.

We are considering coincident peak demand (CPD) for large customers. CPD charges for usage during actual network peaks, rather than pre-defined peak periods. CPD typically:

- operates on lagged basis – e.g. usage measured over 12 months is used to set prices for future 12-month period
- is supported by notifications to make users aware when system demand is high and is likely to be a charging period (in ex post designs) or will be a charging period (in ex ante designs)
- can produce volatile outcomes that are difficult for consumers to predict (and slow to arrive)
- is better targeted than ToU in theory, but can produce excessive avoidance in practice

These characteristics mean CPD is only suited to larger, more sophisticated users (i.e. large energy-intensive businesses) who are able to manage their demand in a way that makes CPD effective in practice (and not just in theory). This type of pricing suits customers who can integrate load profiling into their operations.

We propose applying ToU to small and medium size customers because:

- is readily understood – it doesn't require consumers to understand a new usage statistic (e.g. peak demand) – and doesn't expose consumers to excessive volatility or risk
- can be implemented by most NZ retailers, helped along by its emerging prevalence amongst larger distributors
- sends an efficient signal and effective signal for the types of decisions small consumers make
- operates with existing commercial cycles (annual rate setting, monthly billing)

Figure 28 - Future non-residential price structures

Component	Proposed Method	Reason selected
Peak demand signal	**Small non-residential users (15kVA or less)** **Time of use** - Weekday peak rate from 7am to 11am and 5pm to 9pm. Structure aligns with sector majority (aiding retail uptake) and network demand (aiding efficiency of price signal). - Zero-rated off peak (incl. weekends). Reflects excess capacity off peak (and no other cost impacts).	- Understood and can be implemented by retailers - Sends an efficient and effective signal for the types of decisions small consumers make (what appliance to buy, simple changes in routine)

Component	Proposed Method	Reason selected
	- No distinction between those with dedicated transformers and those connected to low voltage network – no significant cost difference	
	Medium non-residential users (>15 to 300 kVA) **Time of use** - Peak and off-peak periods dependent on local demand profiles. - Zero-rated off peak - The majority of dedicated transformer connections are for connections greater than 300 kVA. Therefore, we are proposing no distinction between those with dedicated transformers and those connected to low voltage network for the medium price category.	- Understood and can be implemented by retailers - Sends an efficient and effective signal for the types of decisions small consumers make (what appliance to buy, simple changes in routine)
	Large non-residential users Current hypothesis is to apply coincident peak demand charge. - Separate prices for dedicated transformer and low voltage connections – as they have different long run marginal costs - Simplify the number of pricing components - Still considering the current power factor charge	- Largest users *may* be energy intensive (and sophisticated) enough to manage a coincident peak demand charge - Remove fixed daily charges and any time variable prices as they are no longer needed
Residual cost allocation and recovery	**Energy-based cost allocation** - Allocate total costs between residential and business consumer groups using energy (GWh) as allocator. - Cross-check against robust subsidy-free analysis. Apply fixed prices: - Small users – a fixed daily charge - Medium users - a fixed charge based on connected capacity - Large users - a fixed charge based on connected capacity	- Least distortional impact on energy use behaviours - A daily fixed fee for small users because there is not a range of different connections sizes - A fixed charge based on capacity for medium and large users will allow us to reduce the number of price categories and remove the current price steps between categories. - It also reflects that larger user should pay more because they are using a larger share of the network

The new price structures will continue to include direct agreements and individual tariffs for large connections with unique commercial or operating conditions. This will allow WELL:

- To offer services that reflect different price/quality trade-offs. This could include when a customer wants to connect to an area of the network that does not have the capacity to provide standard network security limits, within a time period that would not allow WELL to build more capacity.

- To allow customers to participate in providing flexibility services.

5.1.3 Impact of prices

Applying the proposed pricing structures will impact prices in multiple ways. Figure 29 summaries the key effects. We will be including a detailed analysis of the impact the changes will have on customer bills as part of our retailer's consultation. Feedback will be used to help us develop a transition plan.

Figure 29 – impact of applying the proposed pricing structures on customer bills

Change	Effect
Removal of low fixed charges	Increases fixed charge for low-users (and lowers variable charge). Will increase small users' bills and lower large users' bills. Average residential bill unchanged.
Only recover demand-driven costs via variable charges. Residual costs recovered via fixed charges	Will increase proportion of revenue from fixed charges. Increase small users' bills and lower large users' bills. Average bill within consumer group is unchanged
Only recover demand-driven costs through variable peak charges. Zero-variable-rate off-peak and managed load charges	Will increase bills for peakier consumers (those who use more energy during peak periods) and vice-versa for flatter consumers.
Revised cost allocation between consumer groups	Energy-based cost allocation will reduce residential consumer bills and increase non-residential (business) consumer bills.
Simplifying non-residential customer groups and making price consistent between customer groups	Little impact on the small and very large non-residual users. Could impact medium size businesses.

5.1.4 Proposed transition rules

It will take time to develop, implement and then transition to the new pricing setting methodology in a way that avoids large price changes for those consumers that will see price increases. We plan to consult on the new structures this year, including a set of transition rules that limit how much we can change prices to consumer groups. The transition rules are likely to be a percentage limit on any increase to the majority of consumers in a consumer group.

Each year we will then assess the impact of other price drivers (like changes to regulatory allowances and volume growth) and decide on the magnitude of that year's transition step to the new prices, based on what changes can be made while falling within the agreed rules.

5.1.5 Consultation on new pricing structures

This year we plan to consult with retailers and non-standard contract consumers about the changes needed to move to the new price setting methodology and the resulting pricing structures. We will also consult on the transition rules that will limit any price shocks to consumers – practically this means making the changes slowly over time.

In the consultation document we will provide:

1. The benefits of moving to the new structures
2. Proposed new structure and reasons for the selection
3. An estimation of any consumer impact
4. The transition rules
5. A forecast of a potential transition path. Note, the actual transition path will only be a forecast because the final path will be dependent on other pricing factors like forecast allowances and volume growth.

We hope to consult around June.

5.2 Services to manage congestion

A key component of our pricing strategy is to develop services that will assist us in managing congestion. WELL has trialled new technology that allows WELL to manage EV and battery charging during the peak demand periods. The new service will ensure EV owners vehicles are charged when they are needed and will provide WELL with the ability to manage EV charging within the networks capacity. WELL will offer the service for a lower price than standard distribution prices. This allows a real time ability to stabilise the LV network by having visibility of consumer charging behaviour and modulating the charge rate based on network capacity and supply quality at that point in time. WELL is trialling the DeX software that connects consumer devices, monitors network capacity and performance and manages the charging of EV's and batteries within the performance limits of the network.

5.3 Roadmap of changes needed to accommodate EVs on distribution networks

EV Connect is an industry wide work programme that focuses on how more energy can be delivered through the existing network. This is part of an Energy Efficiency & Conservation Authority (EECA) LEVCF project. The purpose of EV Connect is to support EV adoption while maintaining network security.

WELL has collaborated with its technology partner GreenSync to develop a roadmap of the industry changes needed to support the introduction of EVs and to offer managed EV charging flexibility services. Changes outlined in the EV Connect Roadmap include ensuring regulation and policy supports the action needed to connect EVs and that networks operators are appropriately funded. The Roadmap highlights the need for flexible regulation that allows stakeholders to test and develop new services without creating barriers that restrict or slow progress. While attention is specifically on EVs under this project, there are clear implications and relevance to wider categories of distributed energy resources (**DER**) like solar PV, batteries, hot water systems and other appliances. This was brought strongly to light through consultations with stakeholders who often noted that an initiative or approach that could apply to EVs or EV charging assets could also extend to or from arrangements for other types of DER.

The EV Connect Roadmap can be found on our website at: https://www.welectricity.co.nz/about-us/major-projects/ev-connect/. The website also includes the consultation documents, stakeholder feedback and workshop presentations that were used to construct the Roadmap.

Our pricing strategy includes the development of prices for managed EV charging and other flexibility services to support the services that the roadmap is developing.

5.4 Developing a long term investment plan

Managing demand to better utilise the existing network is expected to provide a large proportion of the additional demand needed to deliver the Governments emissions budgets. However, more capacity will need to be built in some areas where the increase in demand exceeds or is close to network capacity during non-congested periods. Our analysis of the cost impact of the Climate Change initiatives is very high level and does not have the detail needed to calculate future prices or price signals. WELL is developing a long term investment programme, beyond the 10 year regulatory planning period, that includes the climate change initiatives. From a pricing perspective, the long term investment plan will confirm the investment needed to deliver the Governments Climate Change Initiatives. This will inform the LRMC calculation and our price signals. We expect to be able to present the investment plan in the 2023 iteration of our asset management plan.

5.5 Incorporating pricing score card feedback

The Electricity Authority make an annual assessment about how cost reflective a distribution networks tariffs are. The Authority makes the assessment using a scorecard of different pricing attributes. Figure 30 summarises the 2021 assessment and the changes that have improved the score. We had the second highest scorecard score.

Figure 30 - Pricing scorecard assessment

Scorecard category	Score		Improvement made and work programmes updates
	2020	2021	
Description of network demand characteristics	2	5	A detailed description of the network capacity constraints and demand characteristics was provided in the updated roadmap. The description included the impact of the climate change actions on network demand.
Meets pricing principles	3	3	An updated pricing principles assessment has been included in this Pricing Methodology update.
Pricing strategy	2	4	Revised pricing strategy was included in the 2021 roadmap. The strategy focused on developing demand management tools in response to the expected increase in demand from the climate change actions.
Roadmap	2	5	Updated roadmap reflecting the Authorities new pricing methodology.
Peak pricing signal	2	3	Will be address in next review of Pricing Methodology – scorecard feedback was received after the last update.
Customer impact	2	3	Will be address in next review of Pricing Methodology – scorecard feedback was received after the last update.
Overall (average)	2.2	3.8	

The annual score card assessment includes specific feedback on how our pricing could be improved. Figure 31 summarisers the feedback and our response.

Figure 31: 2021 scorecard feedback and WELL's planned response

2021 Feedback	Response (Roadmap action)	Date to be implemented
Approach taken for residual revenue appears to rely on Ramseys pricing when there are other options available	Proposed new pricing structure includes fixed prices to recover residual revenue: • Fixed daily prices for residential and small non-0resdiential • Daily capacity charge for medium and large non-residential	• New structure developed 2021 ✓ • Consult with retailers 2022 • Implement 2023 onwards
Consider updating principles discussion by discussing departures from the principles (e.g., discuss any residual pricing inefficiencies?)	Pricing principles assessment expanded to include an assessment on the current structures and an assessment on the proposed future structure – highlighting the current departures from the principles	Added to the Pricing Methodology 2022 ✓
More explanation of the cost-reflectiveness of peak vs off-peak prices - greater insight into the calibration of variable price signals would enable more insight into the efficiency of pricing.	Proposed new pricing structure applies the EAs new pricing methodology which sets price signals first. The proposed new structured also: • Applies a high level LRMC to guide the upcoming retailer consultation and potential customer impact of changes • Scheduled a detailed LRMC calculation 2022	• Initial assessment to support retailer consultation 2021✓ • Detailed LRMC calculation 2022
Encourage WE to draw out the cost differentials in any change in pricing (i.e. geographic differences)	As part of this years LRMC calculation we will be considering geographic LRMC's	Detailed LRMC calculation 2022
Methodology could be improved with greater alignment with the new roadmap.	The Pricing Methodology has been updated to better align with the Roadmap.	Completed 2022 ✓
Consumer impacts identified/managed by analysis prior to introduction of new pricing. Discussion of consumer impact in methodology could be more explicit..	Our approach of calculating and consulting on (with retailers) potential customer impact of any price structure changes before they are applied, has been included in the Pricing Methodology.	Completed 2022 ✓

6 Refreshed Pricing Roadmap (excluding EV Connect Roadmap actions)

Regulatory year	2021/22	2022/23	2023/24	2024/25
Long term investment programme	✓ Calculate an initial view of the Climate Change investment requirements	• Refine long term investment programme with final climate change initiatives - inform LRMC • Review LRMC and adjust the pricing transition path if necessary		
Peak demand price signals	✓ Review ToU peak price signals for residential and calculate price signals for small commercial consumers ✓ Review pricing methods for large commercial consumers ✓ Review price signals for large commercial consumers	• Review LRMC for customer groups • Consider geographic pricing zones if different parts of the network have enduring significant differences in LRMC • Consult on new small commercial cost reflective prices • Consult on any changes to existing price structures		• Regular review price structures – confirm they are fit for purpose
Controllability discounts	✓ Select options for applying discounts/incentives for new controllable load - for both residential and commercial consumers ✓ Review price signals for hot water control, managed services ✓ Consistent with peak demand signals	• Align price signals with LRMC • Consult of new prices for managed services	• Add new prices as new managed services are developed as part of EV Connect	• Add new prices as new managed services are developed
Subsidy free residential	✓ Select pricing method to apply fixed prices ✓ Select allocation methods and consumer grouping approaches ✓ Calculate fixed prices ✓ Calculate total avoidable cost, and standalone network cost ✓ Tested to ensure total revenue from each customer group is with subsidy-free range	• Consult on any changes to existing price structures		• Regular review price structures – confirm they are fit for purpose
Transition	✓ Compare refreshed prices to current tariffs ✓ Understand price impact of each component of price structure change ✓ Develop a transition model that will manage price shocks ✓ Highlight other industry changes that that could accelerate or delay the transition – including the exit of LFC restrictions, price path updates and Transpower's new pricing	• Develop a transition path that will manage price shocks • Consult on transition rules	• Continuously refine the transition plan • Transition to new price structure	
Consumer education	✓ Educate customers on how to save money on distribution charges by managing usage and shifting load to off-peak periods (presented at home show, ToU and climate change videos)	• Continue to educate customers on how to save money on distribution charges by managing usage and shifting load to off-peak periods. • Promote new managed service with retailers and consumers	•	•
Transmission prices		• Develop prices to pass through Transpower prices • Consult on any changes to existing price structures	• Apply new prices	•
Exiting LFC	✓ Develop transition plan – ensure continued compliance with restrictions ✓ Start five-year transition	• Continue to apply transition plan		

7 Appendix 1: Progress against the current Pricing Roadmap

Initiate pricing reform (April 2017 – March 2018)		Develop detailed plans for pricing reform (April 2018 – March 2020)		Manage roll-out of future pricing (April 2020 – March 2025)	
Initiative	**Progress**	**Initiative**	**Progress**	**Initiative**	**Progress**
Identify overall objectives for pricing reform and update strategy and plan.	✓ Completed ✓ Updated for phase 2	Work with ENA and other distributors to ensure alignment of proposed price structures.	✓ Industry standard for residential consumers developed	Implement new price structures and prices (under revenue cap).	✓ Large commercial cost reflective already in place ✓ Residential ToU prices implemented ● Developing small commercial cost reflective (in progress) ● Developing managed EV and battery charging prices (in progress)
Determine preferred future price structures, e.g. ToU and/or demand and/or capacity.			✓ Residential ToU + DER management price ● Small commercial structures still to be developed and implemented	Transition consumers from old to new price structures.	✓ Transitioning all residential ToU in 2021
Consult with stakeholders on future pricing structures.	✓ Completed for EV trial	Further consult with stakeholders to explain preferred pricing structures and to educate them about upcoming pricing changes.	✓ Industry review panels ✓ Retailer residential ToU consultation complete	Further consult with stakeholders. Educate consumers on how to save money on distribution charges by managing usage and shifting load to off-peak periods.	✓ Energy Mate programme ✓ Educational webtools
High level scoping of metering, data and billing constraints/issues.	✓ Competed – industry review	Develop plan for remediation of metering / billing / data issues.	✓ Billing system tested for ToU rollout	Resolve implementation issues.	✓ ToU billing operational
Gather data for analytics.	✓ Completed for EV trial ✓ High level industry study ✓ Still to get for WELL network	Seek funding from Commerce Commission for required changes to billing systems. Work with 3rd parties (retailers, MSP) to resolve metering and data issues.	✓ Funding needs included in DPP capex ● Access to meter data now part of Code – consider most appropriate data source	Ongoing review of progress towards achieving pricing objectives.	✓ New Cost Reflective Pricing Methodology and pricing structures developed ● Consult with retailers on new structures and transition rules.
Introduce trial demand charge for residential EV consumers.	✓ Completed	Detailed modelling of new pricing structures and prices, including likely impacts on consumers. Consumer trials if required.	✓ High level industry analysis completed ✓ Consumer impacts of residential ToU analysed		
		Check of regulatory compliance	✓ New residential ToU prices comply with low fixed user restrictions		
		Separate pricing categories for EV residential consumers and update of demand charge from \$0.00/kW/month.	n/a Considering combining EV ToU with residential ToU ✓ Demand pricing replaced with ToU		
		Agree with EA/Retailers how retailers will pass through distribution price signals to end consumers.	✓ Consulted with retailers – majority suggested they would pass price signal through in some form.		

8 Appendix 2: New Pricing Methodology

From the Electricity Authority's Distribution-Pricing-Practice-Note-2021-2nd-edition, https://www.ea.govt.nz/assets/dms-assets/29/Distribution-Pricing-Practice-Note-2021-2nd-edition.pdf

Figure 1: Steps to setting efficient distribution pricing: 1) cost drivers and 2) any price signalling and 3) least distortionary residual allocation