
# Pricing strategy & roadmap

Prepared April 2023

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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 seaports.

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|---|---|---|---|---|
| We are investing around **$162m** in infrastructure on the Wellington network | We provide electricity to over **173,000** households and **400,000** people in our community. | Our total network is around **6,700 km** in length with over **4,200 km** of it being underground cables. | We have around **4,000 substations** and **40,000 poles**. | There are about **7,800** electric vehicles connected to our network, **3,400** 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 (**Roadmap**) which summarises our plans for changes to prices and pricing structures, together with expected timeframes and progress updates. Our first Roadmap was published in 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 the Authority's 2019 Distribution Pricing Principles. This 2023 update provides a progress update, including proposed new tariff structures.

This 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 Emissions Reduction Plan **(ERP)** in particular has 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.
- Proposed new pricing structures which reflect the Authority's 2019 Distribution Pricing Principles and Pricing Methodology. We consulted with retailers on the new pricing structures in 2022 and we will be finalising the structures this year and will start the transition to the new prices in April 2024.
- Adjustments to the Roadmap to reflect 2022 changes to the Authority's pricing scorecard.
- A refreshed Roadmap which includes the development and transition to the new distribution price structures and the other pricing changes including the exit of Low Fixed User restrictions and new Transmission Pricing Methodology.

# 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 of building a larger network or avoid that cost by using energy during non-congested periods. 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

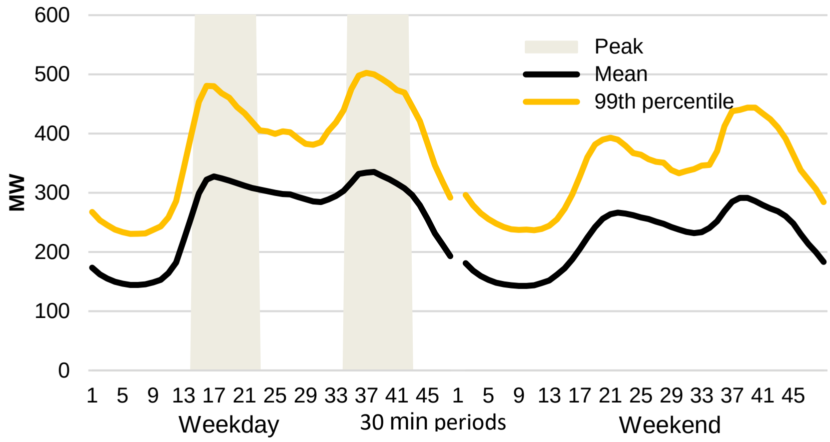
EDBs model future demand requirements as part of their Asset Management Plans (**AMP**). Our AMP can be found on our website at https://www.welectricity.co.nz/disclosures/asset-management-plan. Chapter 4 provides a long-term view of network demand, including the impact of New Zealand's decarbonisation plans on the Wellington network. Chapter 9 forecasts the medium-term 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. We have 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.

We will not repeat the demand forecasts provided in the AMP as we believe having a single, consistent view of future electricity demand is important. We do encourage readers to review chapters 4 and 9 of the AMP if they want to understand what is driving future investment on the Wellington network. This 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 our Time of Use (**ToU**) pricing study[1].

### 2.1.1 General demand characteristics

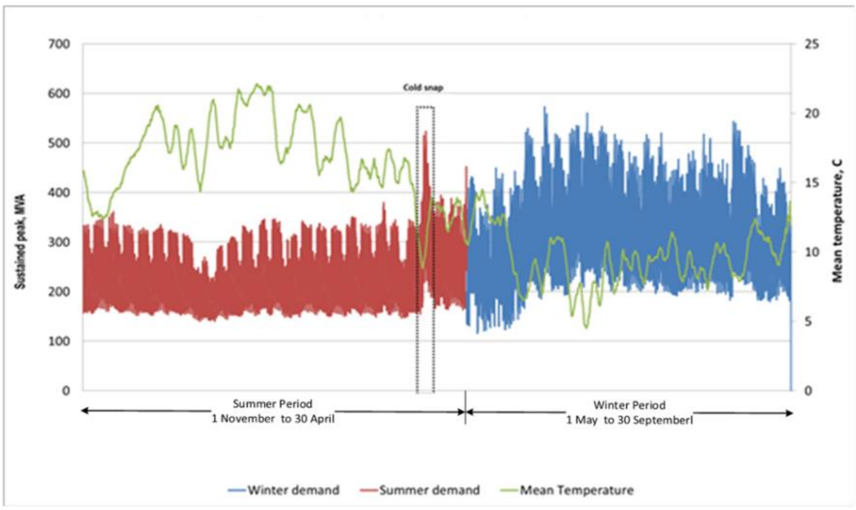
We have two predominant demand profiles on the Wellington network – parts of the network used primarily by residential consumers and parts used by commercial consumers. Residential consumers drive peak demand on the Wellington network, with the highest energy use being in the residential suburbs in the winter months when home heating is the highest. Figures 1 to 12 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 customers 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.

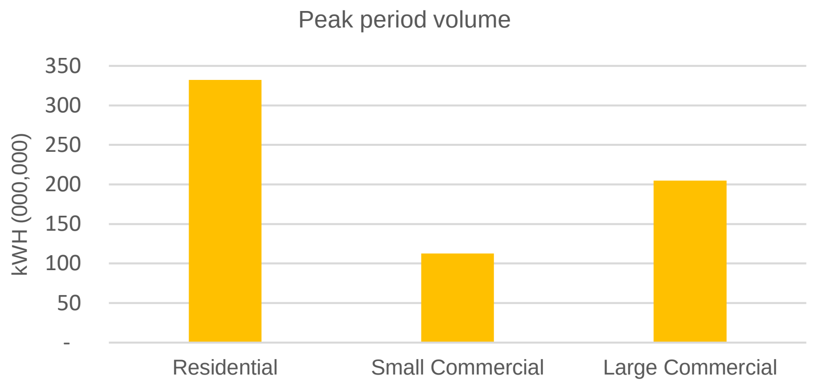
Figure 2 - Winters peaking network




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.

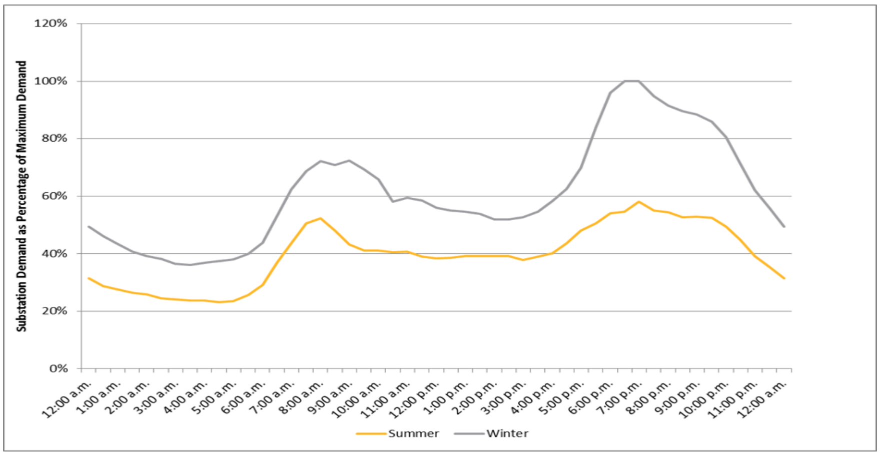
Figure 3 - Residential consumers drive peak demand on the network




The graph compares consumption during peak periods.

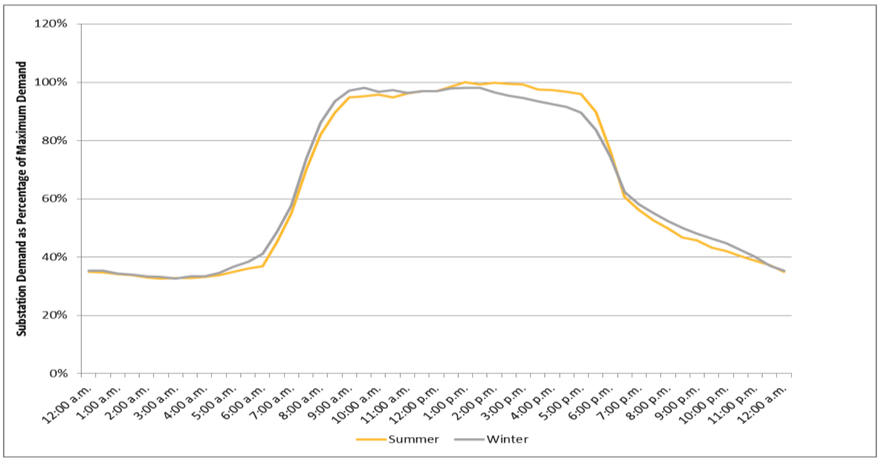
Residential consumers are the largest contributor to peak demand. Large commercial customers contribute significantly towards the morning network peak.

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



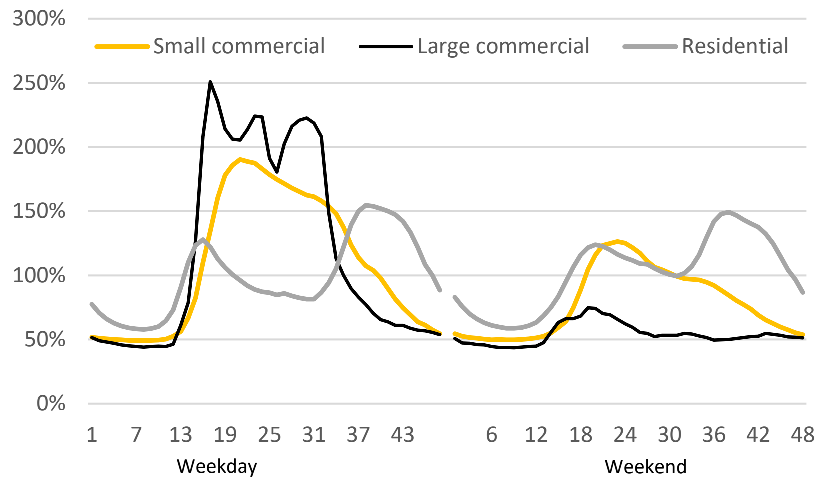

Residential consumer demand is the highest in the morning and evenings during the week. Demand still peaks in the morning and evenings on the weekend but not to the same extent.

Figure 5 - Commercial demand peaks during working hours




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

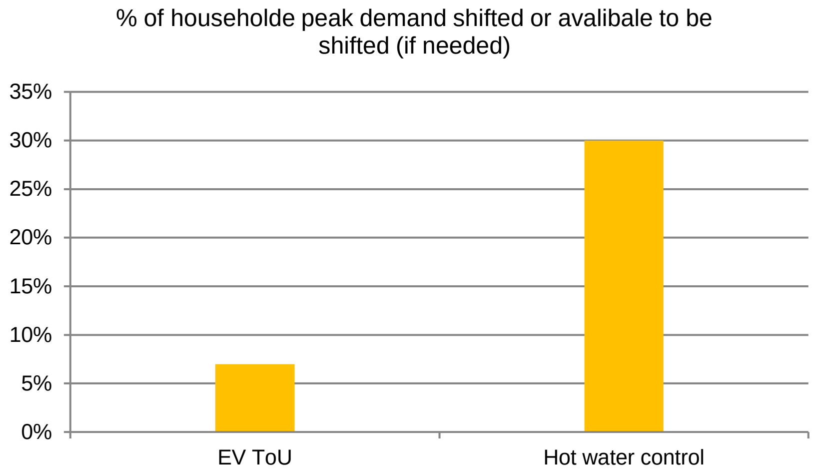
## Figure 6 - Commercial users have the highest energy user per consumer




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 business demand is constant throughout the workday.

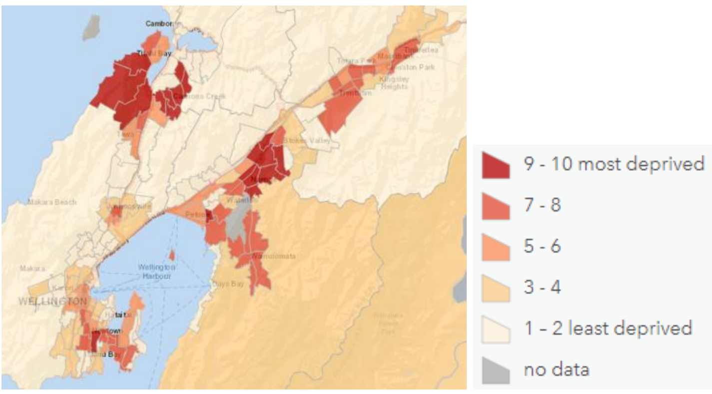
Residential consumers drive the network's evening peak.

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




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

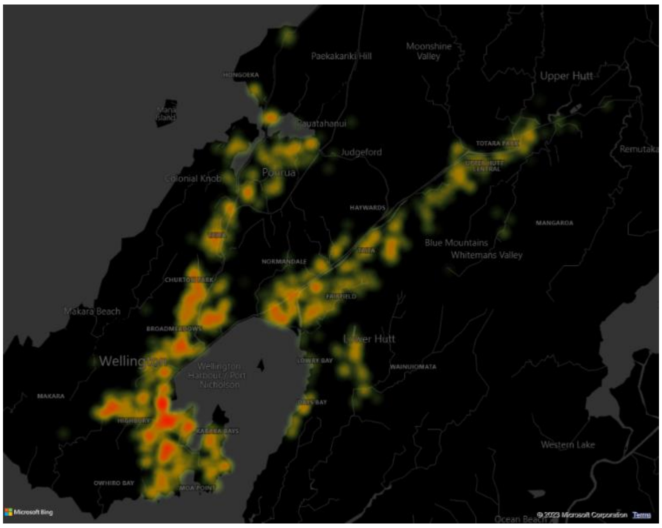
## Figure 8 - Widespread household income levels[2]




Wellington has a wide spread of household income levels, including a large proportion who may be 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/

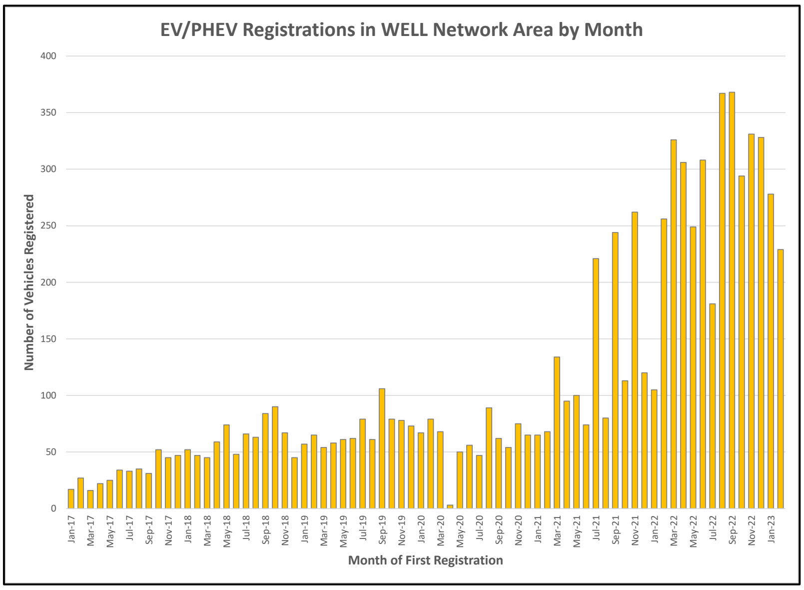
## Figure 9 - EV uptake is evenly spread across the network




Wellington's dense urban networks with short travel distances is well suited to EVs.

EV uptake is evenly spread across the network. As of 2022, New Zealand Transport Authority reported that there were approximately 7,800 EVs on the Wellington network. EDBs do not have visibility on the number or location of EVs being installed.

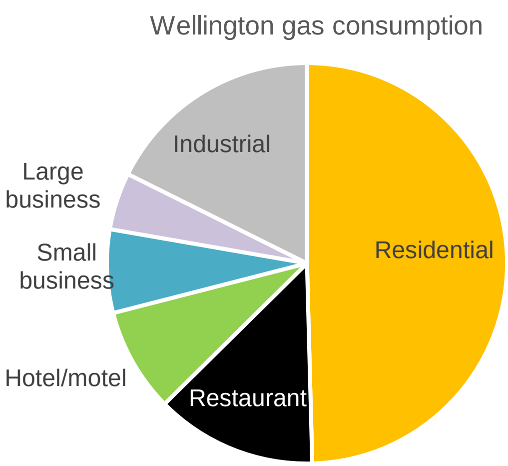
## Figure 10 – Rapid EV uptake




EV growth numbers have nearly doubled to 7,800 over the last 12 months. Over half of all new destratifications are now hybrid or all-electric vehicles.

Growth rates could have been more rapid. EV registrations are currently being limited by the manufacturer's ability to supply new vehicles, with waiting lists for new EVs of up to 12 months being reported in the media.

## Figure 11 – High gas use

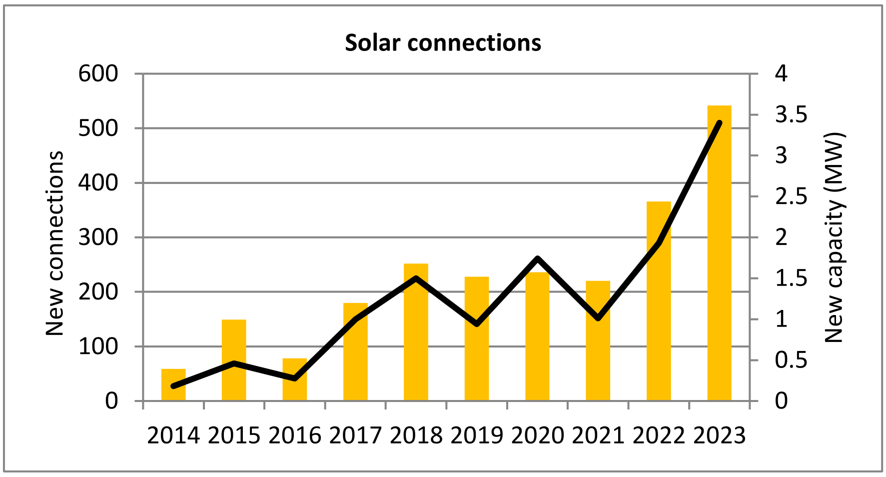



Wellington has New Zealand's highest residential gas use. One-third of 55,000 households have gas connections.

There is also high commercial gas use, the equivalent of 60-100 MW of electricity use.

In total, there is the equivalent of 250 MW of gas use in Wellington – decarbonisation means some or all of this load could be electrified.

Figure 12 – Low but increasing solar uptake

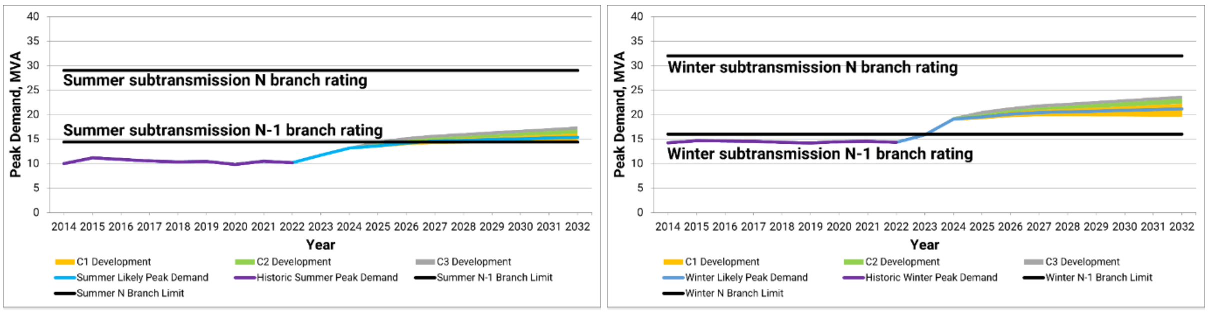



There is relatively low but growing solar uptake in Wellington. As of March 2023, Wellington has ~2,300 installations of solar with 12.4 MW capacity – ~1.3% of customers. Nationally, ~2% of customers have solar.

### 2.1.2 Location demand forecasts

Chapter 9 of the AMP provides volume forecasts 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 times of the day. 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 Figure 13.

Figure 13 - 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 the load away from the zone-sub during peak demand periods. 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.

## 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 for 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's 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.

### 2.2.1 New Zealand climate change programme and rapid network growth

In 2021 we started the development of a long-term (30-year) network demand forecast model which models the impact of New Zealand's emission reduction programme and population growth on the Wellington Network. Peak demand is forecast to increase by 108% over the next 30 years. Figure 14 summarises the peak demand forecast and the key drivers of that demand.

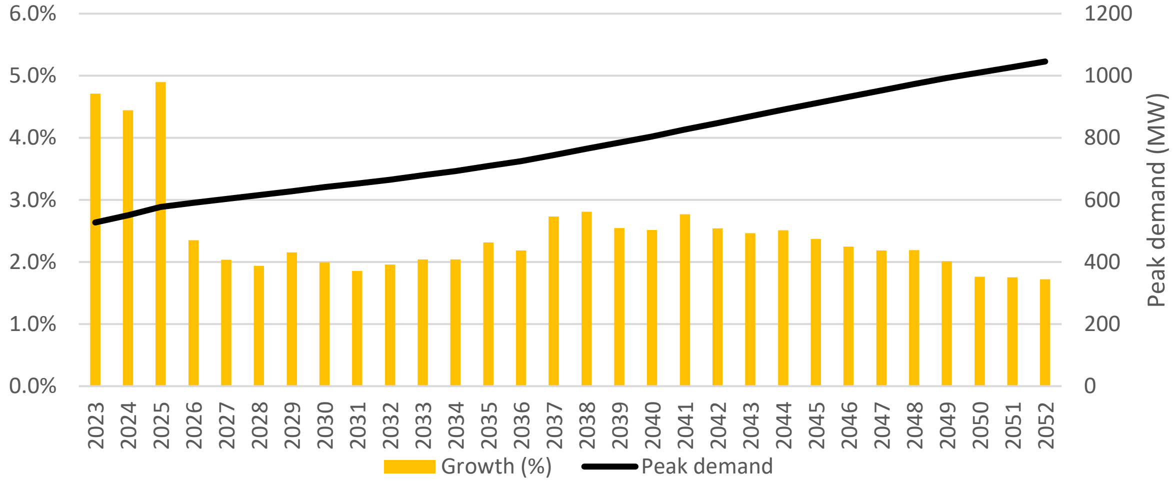
Figure 14 - Growth assumptions and rates

| 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 management | | Introduction of flexibility services | -123 | -24% | -0.81% |
| Total new growth (2050) - controlled | | | 1046 | 108% | 3.59% |

Figure 15 provides forecast peak demand growth on the Wellington network. Peak demand is forecast to increase 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 the long-term average growth of 2.5%.

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

Figure 15 – Peak demand growth and growth rate forecast

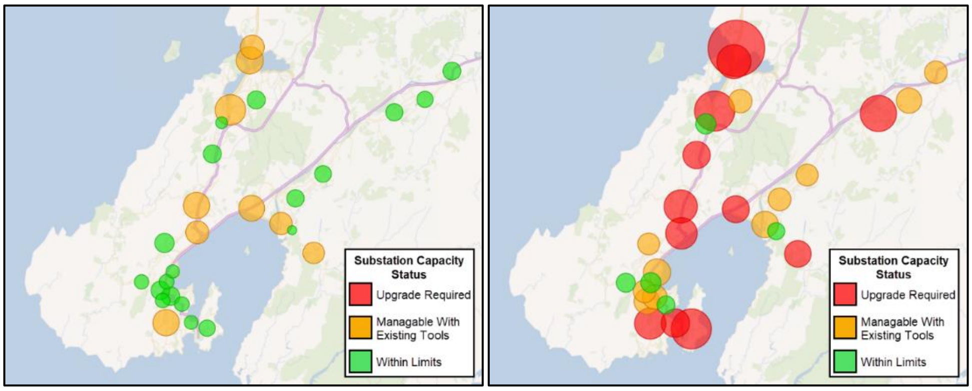



### 2.2.2 Limited capacity headroom

For the last decade, the Wellington distribution network has operated under a 'business as usual' operating environment with modest new connections growth and a steady asset replacement programme. The past business and regulatory focus on closely matching demand and capacity and keeping prices low by not building new capacity before it is needed. The focus on efficiency has meant customers on the Wellington network have benefited from low prices and good quality of supply. However, it now means that the Wellington network does not have the capacity available to meet the ERP-related demand increases. The capacity that is available through load management and the limited network headroom, is quickly being used up by the rapid uptake of EVs and the electrification of public transport.

Figure 16 shows the forecast increase in maximum demand at each zone substation relative to their rated capacity from 2022 to 2032. Loading beyond these capacity limits can either be managed using existing tools (for example temporary load transfers or flexibility services) or require an asset upgrade where these tools are insufficient. This illustrates the extent to which decarbonisation will drive the need to reinforce the network.

Figure 16 - Change in Zone Substation Demand vs Capacity from 2022 (Left) to 2032 (Right)



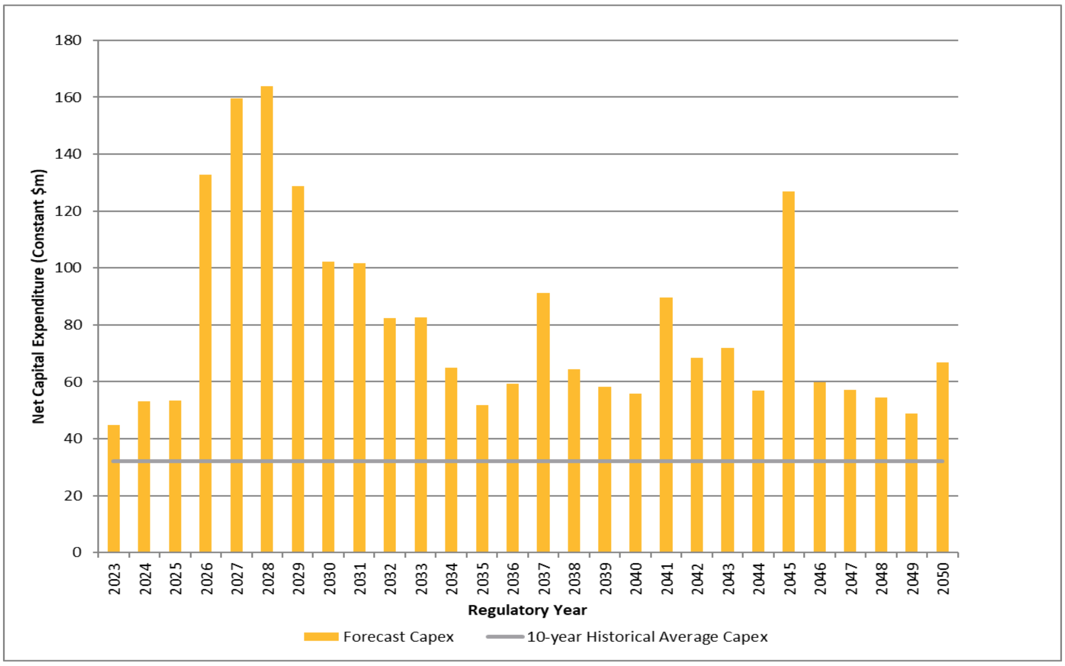

### 2.2.3 Step change in investment in new capacity

The forecast 108% increase in peak demand and limited existing spare capacity, requires an investment in new capacity. This will require an investment in both traditional new capacity – larger equipment – and new demand management capability (flexibility services) that allows more electricity to be delivered using the existing network. We are also about to start replacing two of our largest asset fleets. The zone substation power transformer fleet and the underground cable fleets are coming to the end of their useful lives. Many of the assets due to be replaced are the same assets that require capacity upgrades.

This year's Asset Management Plan provides a 30-year combined capital expenditure programme which rationalises the investment programme so that new assets have both the capacity needed to meet future growth expectations and are replaced before they adversely impact quality.

We are forecasting a $2.0 billion capital investment programme over the next 30 years. Under the past business-as-usual operating environment, which has been focused on providing a steady and reliable supply of electricity, our capital expenditure has averaged $32m per year for the last ten years. This is expected to increase to an average of $72m per year for the next 30 years. The capital expenditure forecast for 30 years is shown in Figure 17.

Figure 17 - WELL's 30-year Capital Expenditure Forecast




### 2.2.4 We need to consider non-traditional solutions

Central to our ability to deliver the climate change-driven demand increase, is the ability to shift demand away from peak periods using flexibility services, to better utilise the existing network. Much of the ERP-related demand growth will be related to Distributed Energy Resources (DER) - customer-owned smart devices that can be used to generate, store, or manage electricity. These devices are connected to homes and businesses and form part of the local distribution network. An example of DER is smart, web-enabled EV batteries and chargers. The battery charging can be remotely managed, delaying the charging until the electricity network is not congested and electricity prices are lower. Flexibility services aggregate the management of consumer DER to help balance demand and supply in the electricity network and support its efficient use. Using flexibility services to deliver more electricity using the existing network is reflected in the growth forecast

(Figure 14) by the 24% demand offset provided by load management.

The Electricity Sector has identified the development of flexibility services as being a key to enabling the delivery of New Zealand's Emissions reduction targets. The Ministry for the Environment's '*Emission Reduction Plan',* the Authority's '*Updating the Regulatory Settings for Distribution Networks'* consultation, Transpower's '*Whakamana i Te Mauri Hiko',* and Boston Consulting Group's '*Future is Electric'* all highlight the central roles flexibility services will have in spreading out the investment in new capacity, managing demand and supply uncertainty, and helping to manage the size of customer bill increases.

Flexibility services for new smart DER are in their infancy and still need to be developed into an industry-wide solution that will provide the scale needed to manage peak demand electricity use needed to release the full value stack of benefits. We have a range of programmes focused on the development of flexibility services. Our EV Connect programme established the steps and actions needed for the industry to develop flexibility services and tested the technology needed to manage those services. We are also working with Orion to develop and trial residential flexibility services. The trials will start this year.

Our pricing structures will need to include price signals for flexibility services while also being flexible enough to allow services to be trailed, tested and refined. The development of price structures that can also provide price signals for flexibility services is an important addition to this year's Roadmap.

#### 2.2.4.1 Finding the Best Way to Shift Demand

Communicating smart EV chargers provide the greatest opportunity for shifting demand using flexibility services on the Wellington network, as the chargers could be actively managed so that vehicles are only charged during off-peak periods. Further benefits could be realised by using the EV battery to supply the household during peak demand periods, reducing network congestion even further.

We have been part of Concept Consulting EV study work programme. A key deliverable of the programme was to establish what load can be shifted to a less congested period. This would allow EDBs to focus on the development of flexibility services for customer DER that can be practically moved.

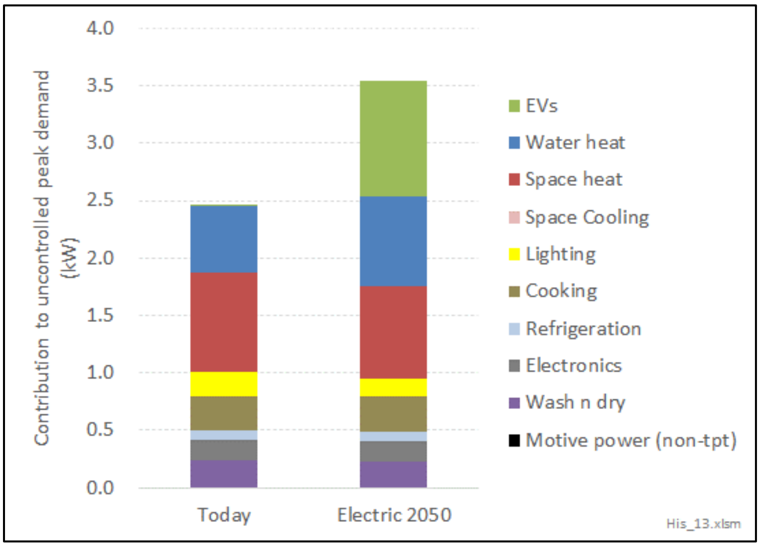
The study found that the management of EV chargers and hot water provides the best opportunity for shifting peak residential demand. Of new demand, the management of EV chargers has the largest influence on peak demand, which is why WELL's work programme to date has focused on EV chargers. WELL's future work programmes will consider hot water and how the current hot water control capability can be maintained and expanded, particularly as gas hot water heating systems are electrified.

The Concept Consulting EV study analysed two points in time:

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

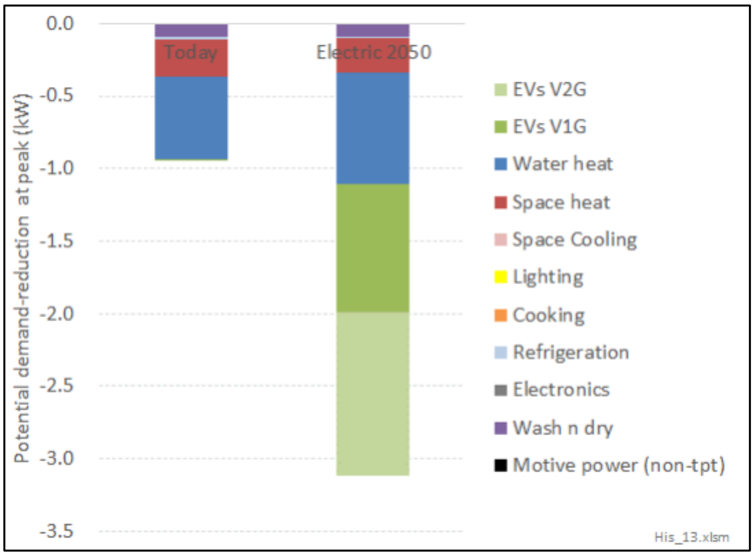
Prior to any demand management, the biggest driver of today's average uncontrolled household contribution to the system peak is space heating, followed by water heating, then cooking, with other appliances driving the remaining 30% of peak demand. By 2050, if households have no incentives to manage when they charge their EVs, unmanaged peak per household demand will increase by 45% - largely from EVs, with some increased contribution from water heating (due to gas being removed) and small offsets from other uses. In total, EVs would represent 30% of unmanaged peak demand per household, as shown in Figure 17.

Figure 17 - Average Contribution to Peak Demand Prior to Demand Management




The study looked at what appliances have the most potential for demand management. Figure 18 shows an estimated breakdown of the potential for appliance demand management. The key takeaway is that EV charging and water heating have the most potential for load management. This reflects that EV and hot water heating can be managed away from peak demand periods with little impact on a customer's quality of life. Other uses like cooking and heating have less potential because customers cannot sensibly defer those activities until off-peak periods.

Figure 18 - Breakdown of average household potential for appliance demand management during peak demand



While the study is based on national data, WELL's network has the highest proportion of residential gas heating in New Zealand, and its urban environment is better suited to EVs than other network areas. Therefore, the potential for controlling peak demand through the use of flexibility services is even higher in Wellington.

## 2.3 Conclusions (in relation to pricing)

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 during 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, the accommodation of electric vehicles and the transition from gas to electricity will be the largest drivers of peak demand.
- 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 use the vehicle 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.
- Stable and low historic growth has meant we have been able to match capacity and demand while avoiding expensive network reinforcement. However, this means we do not have spare capacity to meet the emission reduction-related demand increase. The whole network is constrained.
- 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

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 their appliances to be directly managed.

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 when the network is not congested. This has the immediate benefit of less expensive line 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 pricing regulations, and the speed at which retailers can change their 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 price 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 Government's Emissions Reduction Plan, specifically the programme to electrify activities and services that are currently provided by using fossil fuels. This includes the electrification of transportation and the potential transition from using gas in homes and businesses to using electricity.
- The Authority's revised pricing principles and supporting guidelines.

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.

# 4 Completion of the original Roadmap

In 2017 we published our first Roadmap which outlined how we are developing our prices. We have now completed the original Roadmap and have moved to a new Roadmap that includes the Authority's updated Pricing Principles (provided in 2019) and new Pricing Methodology (provided in 2021).

Two un-completed actions from the original Roadmap have been incorporated into the updated roadmap:

| Outstanding action | Why it wasn't complete | Where this is now addressed |
|---|---|---|
| Developing small commercial cost-reflective prices. | Hadn't reached the due date and development is in progress. | Included in the new roadmap – consulted with retailers on the new structure in 2022. Will implement in April 2024. |
| Developing managed EV and battery charging prices. | Hadn't reached the due date and development is in progress. | Included in the new roadmap – consulted with retailers the on new structure in 2022. Price signal methodology developed in 2022 and will be applied to updated investment profiles in 2023 (which will capture ERP related investment). Will implement in April 2024. |

## 4.1 Complete roadmap and pricing programmes

Progress against the original Roadmap is provided in Appendix A.

The initial Roadmap focused on residential consumers and Electric Vehicle (EV) owners as the main contributors to current and future peak demand and therefore the largest driver for the need to reinforce the network.

In 2018, WELL completed the first phase of the 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 EVs. 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/

An updated Roadmap has now been developed that reflects the Authority's updated 2019 Distribution Pricing Principles and the New Pricing Methodology. The new Roadmap is presented in Chapter 5.

## 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 electricity demand. 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 insight into customers' preferences for future EV charging services. A summary of the key findings is provided in Figure 19.

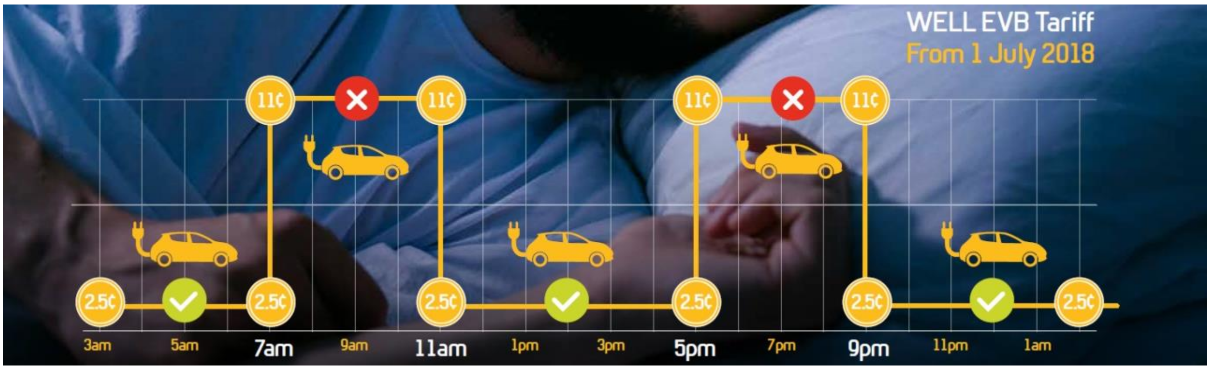
Figure 19 - Summary of the findings of the EV charging trial

| 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% of 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, nighttime periods appear to suit customer preferences – most consumers don't need to charge their vehicles during peak periods. |
| 66% of EV owners use a timer on their EV charges that lets them choose when to charge. | Most vehicles have a timer that could be used to respond to ToU price signals. Newer EVs also have the equipment that would allow an EDB to manage when an EV charges. |
| EVs 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 is applied to energy use for the entire household. Figure 20 shows pictorially the higher prices for energy use during congested periods and the lower prices for less congested periods.

Figure 20 – WELL's 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.

## 4.4 Mandatory ToU 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 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 21.

Figure 21 – ToU price structure

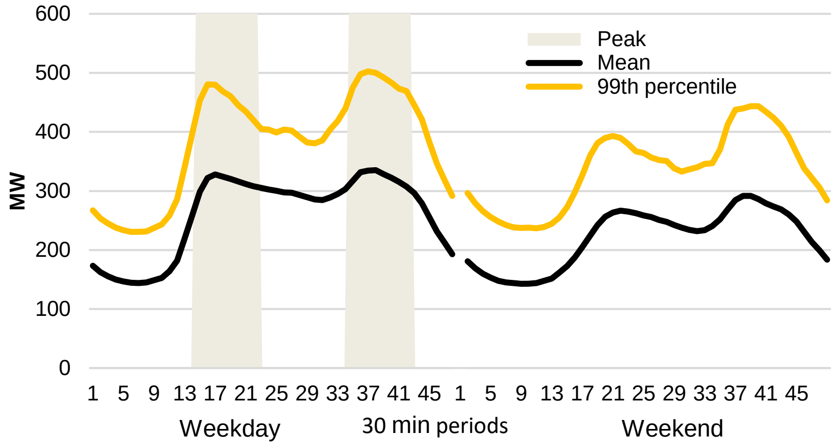
| Design parameter | Industry-standard | Approach | Comment |
|---|---|---|---|
| Hourly Pattern | Y | AM peak = 7 to 11<br>PM peak = 5 to 9<br>No shoulder | A shoulder period has not been included as consumers changing their 'discretionary' load are most likely to do this using timers on appliances (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 | The low-cost weekend concept is relatively simple for consumers to understand and adjust to. |

| Design parameter | Industry-standard | Approach | Comment |
|---|---|---|---|
| Seasonal Pattern | Y | Consistent signals year-round | Seasonal pattern adds complexity (for the supply chain and consumers) and exacerbates winter energy hardship for vulnerable consumers facing budgeting challenges. |

WELL's ToU structure aligned with the ToU structures of the other five 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'[4].

Figure 22 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.

Figure 22 – 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. 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

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

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 several pricing structure changes to help manage the range of Retailer specific issues and to encourage Retailers to upgrade their systems and processes so that ToU can be applied. 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

We are cognisant of the potential impact ToU prices might have on those in energy hardship. As part of developing ToU prices, a sample data set representing over 10% of our residential consumers was used to understand the customer impact of applying ToU prices. Household deprivation data was combined with consumption data to analyse impacts on affordability.

We presented the customer impact and consulted with retailers, as the consumer's 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. We used retailer feedback to refine prices to help ensure any changes made benefit customers overall and in the long term.

# 5 Updated Roadmap and pricing work programmes

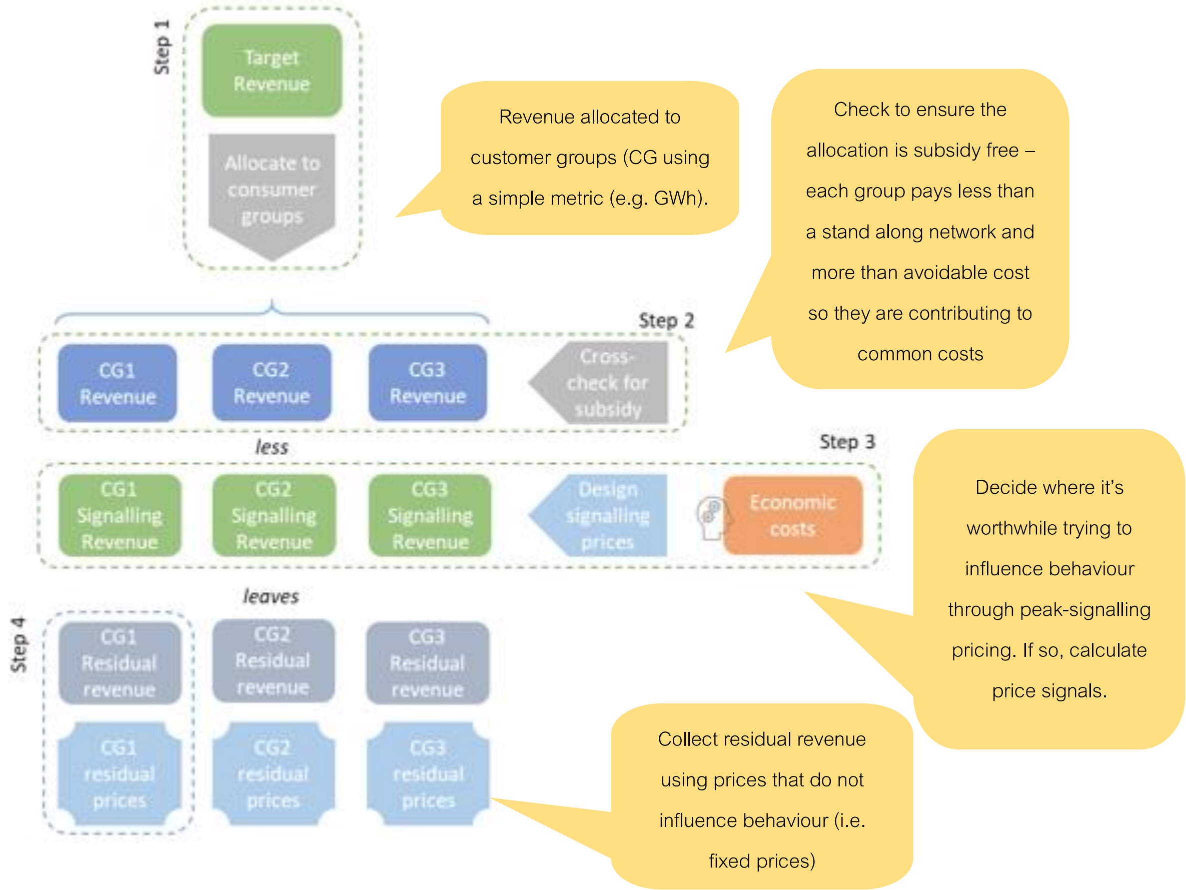
We have made good progress against the original Roadmap actions, and we have advanced our thinking on how to better manage electricity demand. The expected increases in demand from New Zealand Emissions Reduction Plan will make it even more important for networks to move energy use to less congested periods on the network. The Authority has also refreshed its Pricing Methodology and the Electricity Pricing Review has recommended changes that directly impact pricing. These changes have led to new pricing work programmes and an updated Roadmap.

## 5.1 Applying the cost reflective price setting methodology

The Roadmap has been updated to incorporate the Authority's new pricing methodology. The 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.

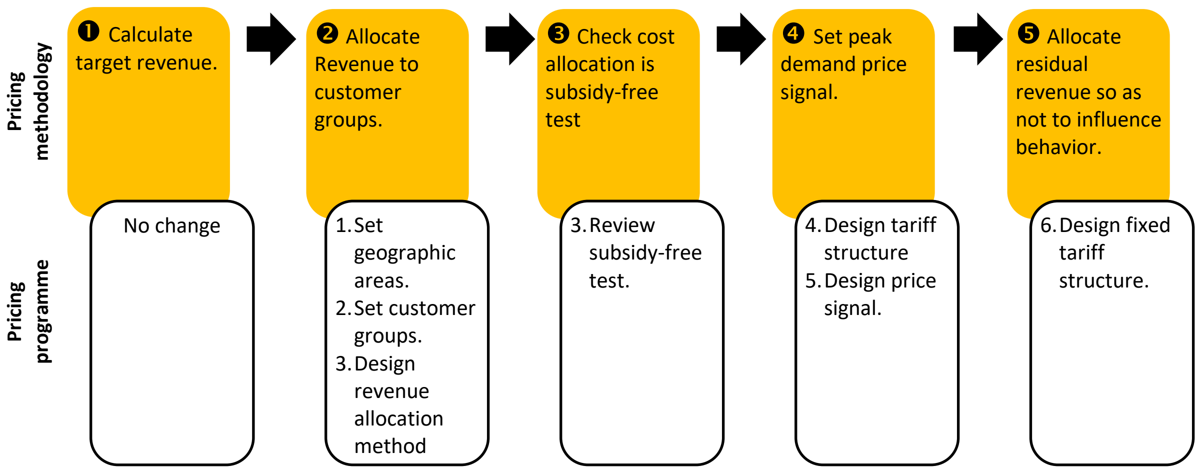
Applying the principles requires a new approach to pricing, an approach which first sets a price signal which reflects the cost of using electricity during peak congestion periods, and then recovers any residual costs in a way that doesn't influence consumers' energy use behaviours (i.e. the peak demand 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 electricity during peak demand periods. Figure 23 summarises and describes the steps in the new pricing methodology.

Figure 23 – Cost reflective pricing methodology



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. Figure 24 summarises the pricing methodology steps and the pricing work programmes that we are applying to implement each step.

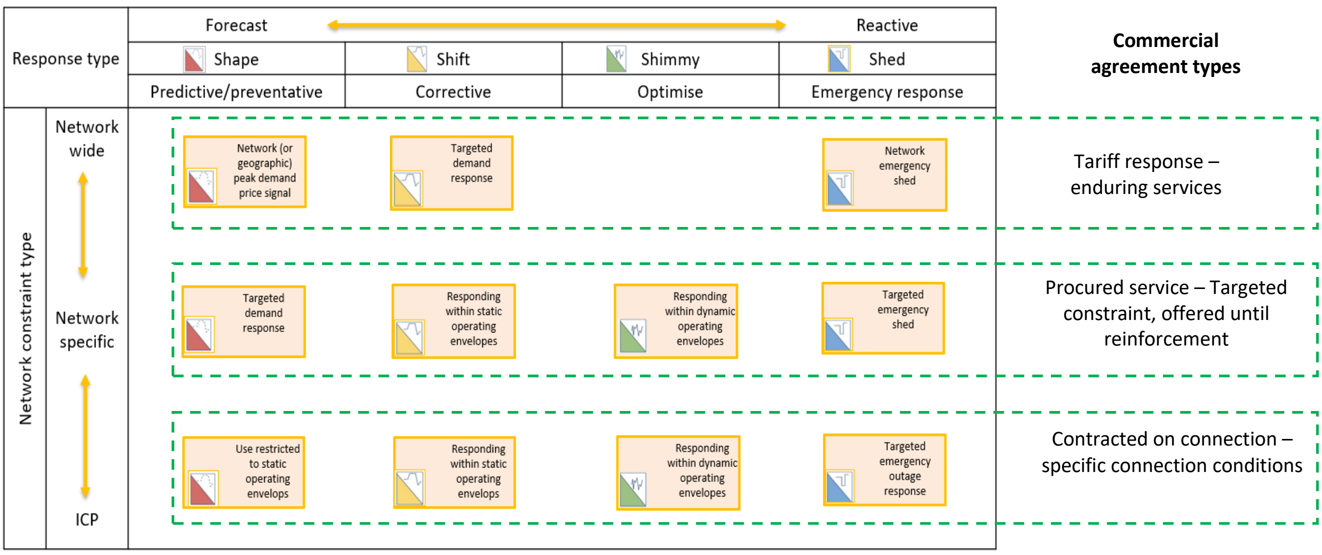
Figure 23 – New Pricing Methodology and implementation programme




## 5.2 Commercial framework for flexibility services

Flexibility services can be provided in exchange for a lower tariff (as is currently provided for hot water ripple control), by purchasing a flexibility service to respond to a specific network constraint, or by a lower cost to connect to the network for a new connection that can avoid building new capacity by managing when the new connection uses electricity. The primary value reflected in all of these prices is the benefit of deferring network reinforcement. Figure 24 illustrates the different types of flexibility services we are considering and trailing (see our Asset Management Plan) and the different commercial models that we will need.

Figure 24 - Flexibility service use cases and commercial frameworks



We are developing a framework of how flexibility services can be valued and priced. The framework will influence how we design our tariff structures and price signals – tariffs for flexibility services must maintain their consistency with procured flexibility services and other tariff price signals.

## 5.3 Other regulatory changes impacting prices

The Roadmap has also been updated to reflect other regulatory changes.

### 5.3.1 Transmission Pricing Methodology (TPM)

In April 2022, the Authority released its new TPM which will be applied from April 2023. The final TPM decision and its inclusion in the Electricity Code is provided in the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology) 2022, and Transmission Pricing Methodology 2022, Decision paper. These can be found on the Authority's and Transpower's websites respectively. The change in approach has resulted in material changes to EDB tariffs. The key changes are:

a. Changes in the overall costs assigned to each distribution network to pass through.

b. Change in the cost allocation methodology used to pass through costs to customers.

We have separated Transmission pricing from our previous cost allocation methodology and have implemented a new allocation methodology in line with the TPM. We communicated the new transmission pricing methodology to retailers in 2022 and started the transition to the new prices on April 2023.

### 5.3.2 Exit low-fixed users

Low Fixed User Regulations require EDBs to offer specific pricing plans to residential consumers who use less than 8,000 kWh per annum (called low users). The legislation applying the fixed price restrictions is being phased out over five years. EDBs can increase their fixed price for low-energy users by 15 cents, each year for the next five years. Prices this year included the second fixed price adjustment. The fixed daily change for residential low users has been increased from 30 cents per day to 45 cents per day.

## 5.4 Transition to the new tariffs

To minimise any price shocks, we propose applying transition rules which limit the size of any price changes. The transition rules will allow us to adjust the speed and size of the transition to other price changes. Transmission rules are needed for both the transmission to new distribution tariff structures, but also for transmission prices.

## 5.5 Updated Roadmap

A new Roadmap has been developed that includes the implementation of the new pricing methodology, the development of a commercial framework for flexibility services, the application of the new Transmission pricing Methodology, the exit of the low fixed user restrictions and the development of transition rules to minimise customer price shocks. Figure 25 provides the updated Roadmap.

We have already made good progress on the Roadmap. In 2021 we developed new pricing structures that reflect the Authority's new pricing methodology and we consulted with retailers on those structures in 2022. In 2021 we made ToU prices mandatory to all residential consumers and in 2022 we designed new prices that reflect the TPM and started the transition to those prices in 2023. In 2022 we started the exit of low fixed user restrictions in line with the five-year exit path set by the Ministry of Business, Innovation and Employment.

Figure 25 – Updated Roadmap

| Pricing programme | | 2021/22 | 2022/23 | 23/24 | 24/25 | 2025+ |
|---|---|---|---|---|---|---|
| | Set geographic areas, customer groups and design revenue allocation method | Define geographic areas, customer groups and design revenue allocation methodology ✓ | • Customer impact analysis ✓<br>• Consult with retailers ✓ | Refine and finalise | Apply from 1 April | Apply transition rules and regular reviews |
| | Review subsidy-free test | Continue to apply high-level subsidy-free test | Develop a more accurate test | Consult with retailers | Apply from 1 April | |
| | Design tariff structure, including fixed tariff structure | • Mandatory residential ToU ✓<br>• Design tariff structures ✓<br>• Design fixed tariff structure ✓ | • Customer impact analysis ✓<br>• Consult with retailers ✓ | Refine and finalise | Apply from 1 April | |
| | Design price signal | • Draft ERP ✓<br>• Draft long-term investment programme ✓ | • Final ERP ✓<br>• Finalise long-term investment programme ✓ | • Revised LRMC methodology ✓<br>• Calculate price signals to include ERP investment | Apply from 1 April | |
| | Commercial framework for flexibility services | • Continue to apply EVB ToU prices ✓ | | • Design commercial framework<br>• Flexibility trial | Continue to include in flexibility trials | |
| | Apply TPM | Authority develop new TPM ✓ | • Apply TPM to tariffs ✓<br>• Customer impact analysis ✓<br>• Communicate changes ✓ | • Update & include in Pricing Methodology<br>• Start transition to new tariffs | Second year of transition. | |
| | Exit low-fixed users | Customer impact analysis ✓ | First year of transition – fixed prices move from 15c to 30c ✓ | Second year of transition – fixed prices move from 30c to 45c ✓ | Third year of transition – fixed prices move from 45c to 60c | |
| | Develop transition rules | Develop transition rules to avoid price shock ✓ | Consult with retailers ✓ | Apply from 1 April (TPM changes and LFU exit) ✓ | Apply from 1 April (distribution price structures) | |

# 6 Pricing work programme progress update

This chapter provides a progress update for each of the Roadmap workstreams.

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 structure that had no regard to current prices). We then compared the structure to our current prices to understand the extent 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 the analysis of appropriate signal strength.

2. **Enhance discount for controllability** – managed tariffs provide technology-specific discounts for controllability (e.g. current hot water tariff via ripple control). Opportunity to broaden (incl. to EVs) and implement the improved design. Internet-based signalling for new tech (e.g. EVs) offers a greater ability to maximise load management value than current ripple control. Long-term, transitioning hot water control to a new signalling platform would deliver benefits. Consider additional incentive mechanisms to address the lack of awareness (and consequently 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 method for allocating residual costs in the least distortive way. Opportunity to simplify while also improving the basis for allocating shared costs between consumer groups.

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

In November 2022 we consulted with retailers on the new pricing structures and the potential impact the changes will have on customers. We also proposed transition rules which would limit the size of any price change to avoid customer price shocks. Retailers were supportive of the new structure and the transmission rules. We are now considering the feedback and we will respond to retailers shortly.

We have more thinking to do on prices for large commercial customers. We expect to consult again on more detailed large commercial structures in 2023. We plan to start the transition to the new structures on 1 April 2024.

## 6.1 Set geographic areas, customer groups and revenue allocation method

We propose to continue to use a single pricing area, simplify the commercial customer groups and use historic energy used (GWH) as the revenue cost allocator.

#### 6.1.1 Selecting geographic pricing areas

We will continue to use a single geographic pricing area for distribution tariffs and will procure flexibility services to solve specific network constraints. The combination of tariffs and procedure services will allow us to offer:

- An enduring tariff price signal that customers are more likely to respond to and retailers and more likely to be able to reflect in their prices.
- Short-term, high-value prices for specific constraints to flexibility providers who can respond to more complex price signals on a customer's behalf. These prices would be offered by a procurement process, rather than by a mass market tariff.

Most customers have low engagement in electricity pricing overall, as shown by low retailer switching rates (approximately 2% of customers in the last 12 months). Customers are unlikely to respond to complex distribution prices which only make up a minor proportion of an electricity bill. Customers use price signals to make occasional decisions (like appliance purchases or changing their general routines and habits) rather than to support daily consumption decisions. The exception is large commercial customers who will be better placed to respond to more complex price signals.

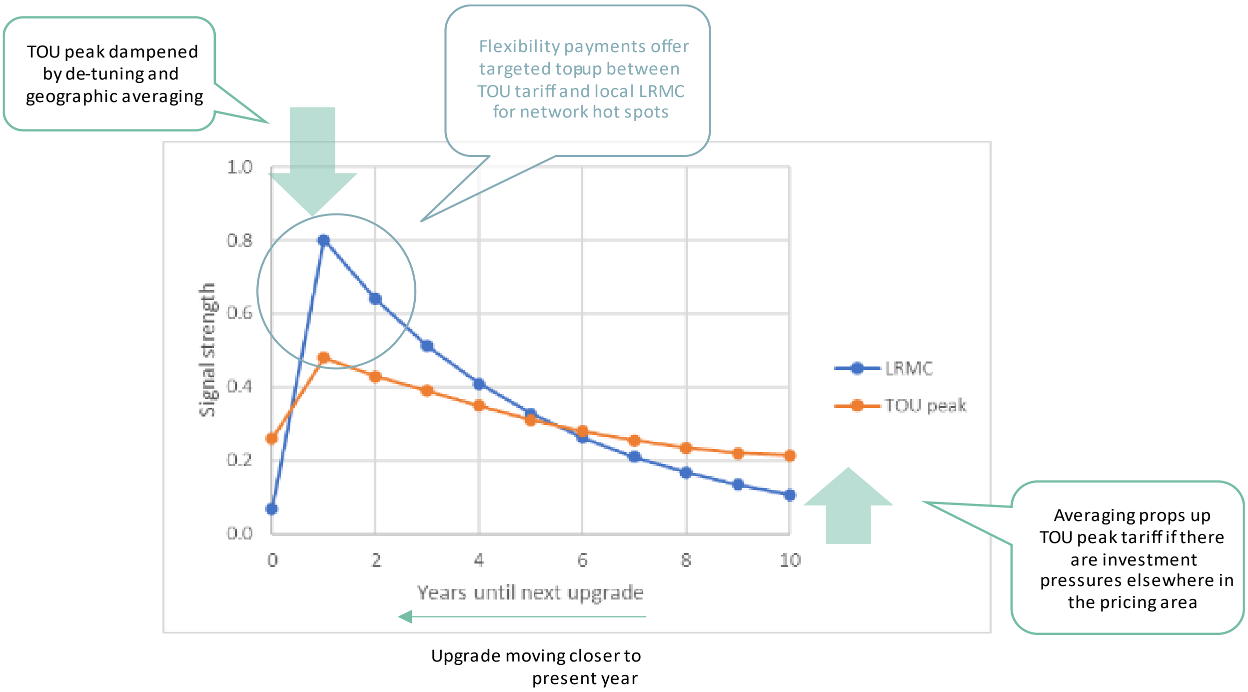
Retailers are also limited in their ability to pass through complex and disaggregated price signals. As shown by our application of ToU prices, if prices are too complex, they will get bundled back up into a general price and price signal.

For the reasons above, we have selected a single geographic area. The Wellington network suits a single geographic area because it is relatively homogeneous in its design, electricity use and congestion (as shown in the network characterises section). Most importantly, we expect network constraints across the whole network due to the large emissions reduction-related demand increase. Our AMP provides a detailed view of the network constraints.

However, we recognise that tariff price signals alone are unlikely to provide the demand response we need to manage the rapid uptake of DER and increase in demand. We are complementing network-wide tariff price signals with constraint-specific procured flexibility services. Prices for procured flexibility services reflect the higher value, but short-term nature of these services. Flexibility providers specialise in responding to specific constraints on behalf of customers and can respond to granular and dynamic price signals where mass market retailers may not be able to.

Figure 26 shows the relationship between a tariff service (shown as the ToU price curve) and a procured flexibility service (shown as the long-run marginal cost price curve). Both curves reflect the value of deferring the need to build new capacity in constrained parts of the network. The price curves include a time value of money adjustment which is why services are worth more now than later.

Figure 26 - Differences in Valuing Tariff and Flexibility Responses




The ToU or tariff price curve is lower because the price signal is network wide and includes parts of the network where there is no congestion. A network or geographic price curve that reflects an average of all constraints will be enduring over time, providing a stable price signal to flexibility providers.

The procured cost curve is sharper and has a higher value, reflecting the response is to a specific constraint and does not have non-constrained elements diluting the price signal. These higher value price curves will be for a short period of time until the constraint is resolved by investing in more capacity.

Both curves fall to zero in the very short term, reflecting that there is not enough time for prices to defer an investment – networks will have to build traditional capacity and have probably already started that process so that they can maintain network security.

### 6.1.2 Selecting customer groups

Currently, we have a large number of customer groups – we have 6 residential, 12 commercial and 2 non-metered price categories. We plan to apply a fixed charge based on the size of a customer connection which will allow us to reduce the number of commercial customer groups[5]. The removal of low fixed user restrictions will also allow us to reduce the number of residential pricing groups. We plan to reduce the number of customer groups to four.

Figure 27 provides the customer groups and notes the transition path to combine the existing price categories. The customer groups reflect customers with:

[5] The alternative to a capacity charge is a fixed daily charge. However, a fixed daily charge requires multiple price categories to allow a n application of a daily rate which matches the size of a connection.

- Similar consumption patterns and connection requirements. This includes similar peak demand periods (see network characteristics).
- Similar standalone and avoidable costs. This includes separating large commercial customers that do not use the low-voltage network.
- Similar connection capacity and service level.

Figure 27 – customer groups

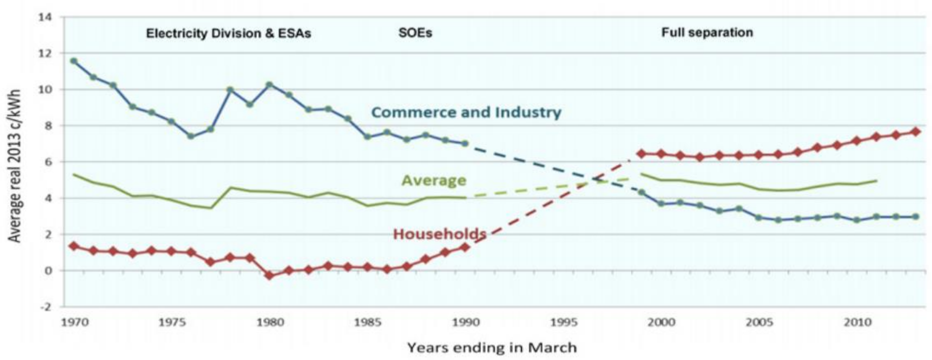
| Customer groups | Allocator | Current price categories | Transition |
|---|---|---|---|
| Residential | All residential connections | All existing residential price groups | Combine low-user and standard-user customer groups once the low-fixed user transition is complete.<br>Combine EVB and ToU price categories once the new price signal is calculated. |
| Small non-residential | 15 KVA and less | GLV15 and GTX15 | Combine price categories from 1 April 2024. Very few customers on GTX15 so the price categories can be combined immediately. |
| Medium non-residential | (>15 to 300kVA) | GLV69, GTX69, GLV138, GTX138, GLV300 and GTX300 | There are large differences between the existing price categories. Combining the price categories will take time – the rate of transition will depend on the application of the transition rules. |
| Large non-residential | | GLV1500, GTX1500 and GTX 1501 | |

### 6.1.3 Allocating revenue to customer groups

We propose allocating total costs between residential and business consumer groups using historic energy used (GWh) as allocator. Moving to simple GWh-based network cost allocation (guided by stand-alone and avoidable cost considerations) will make prices fairer and deliver improved social and economic outcomes.

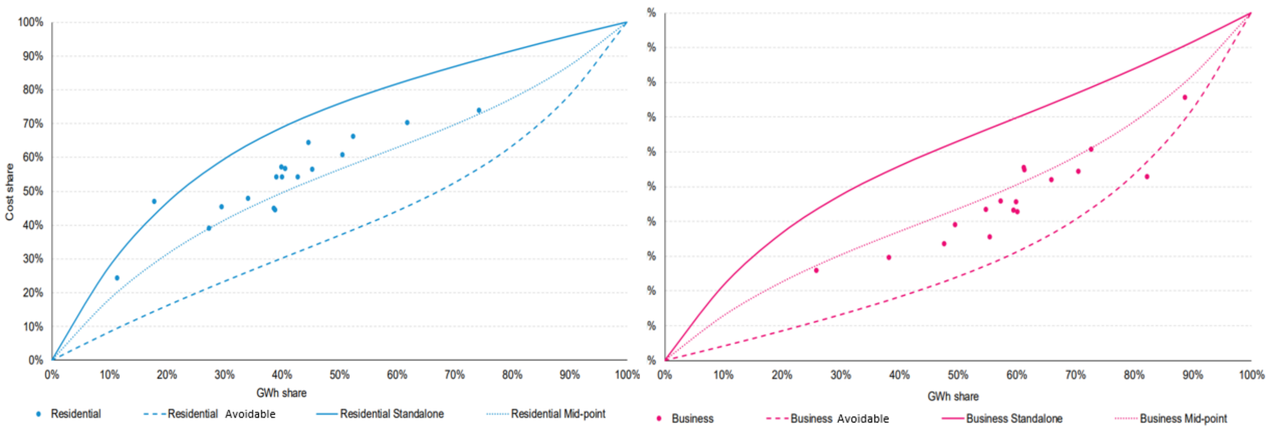
This approach also aligns with the Electricity Pricing Review recommendations which highlighted networks were over allocating costs to residential customers. Figure 28 from the Electricity Pricing Review, 2018 first report, shows that before 1997, commercial customers were paying more than average and after 1997 residential customers were paying more.

Figure 28 - Household and commercial distribution charges




EDB Cost-of-supply models are currently over-allocating costs to residential customers because they are using peak energy use metrics to allocate non-peak demand driver costs - residential customers are paying for peak-demand energy use in both their peak demand prices and in their fixed daily charges. Figure 29 shows that households are currently paying more per kWh than commercial customers using current tariffs.

Figure 29 – Comparing share of costs and energy used by residential and commercial customers




The change from using the cost-of-supply model which uses peak demand cost drivers, to the simplified GWH cost driver creates a significant shift of revenue allocated between residential and commercial customer groups. Figure 30 shows that the new cost allocation methodology using the GWH allocator, allocated approximability 50% of the residential costs to both residential and commercial customers. The current Cost of Supply model, which uses a peak demand allocator, allocates approximately 70% of costs to residential customers and 30% to commercial customers.

Figure 30 – Comparison of GWH allocation methodology and current Cost-of-supply model

| **Consumer group** | Allocating costs using the current Cost of Supply model | Allocating costs using energy used (GWH) | Difference |
|---|---|---|---|
| Residential | 68% | 49% | 19% |
| Commercial | 29% | 50% | -21% |
| Non-metered | 0.2% | 0.1% | 0.1% |

| Consumer group | Allocating costs using the current Cost of Supply model | Allocating costs using energy used (GWH) | Difference |
|---|---|---|---|
| Streetlights | 3% | 1% | 2% |
| **Total** | **100%** | **100%** | **0%** |

The customer impact of this change will be even larger for commercial customers as the change will be applied across a lower number of connections (there are 30k commercial connections compared to 140k residential connections).

## 6.2 Review subsidy-free test

The subsidy-free test is used to cross-check the allocation of costs to consumer pricing groups. This ensures that prices will recover at least the avoidable cost of providing services to a customer group (so that other groups aren't funding their services and they are contributing to shared costs) and so that customers aren't paying more than what it would cost to provide standalone services (i.e. customers are better off disconnecting from the electricity network).

The subsidy-free is also an important adjustment to ensure that the customer groups are recovering their significant costs to supply. This includes ensuring customer groups aren't paying for assets that they don't use. For example, ensuring the large commercial customer groups aren't funding the low voltage network which they do not use as they have a dedicated transformer asset connecting them directly to the high voltage network. Under the previous Cost-Of-Supply model, this is done via the cost allocation drivers. Now that costs are allocated using the simple GWH cost driver, the subsidy-free test must now do this.

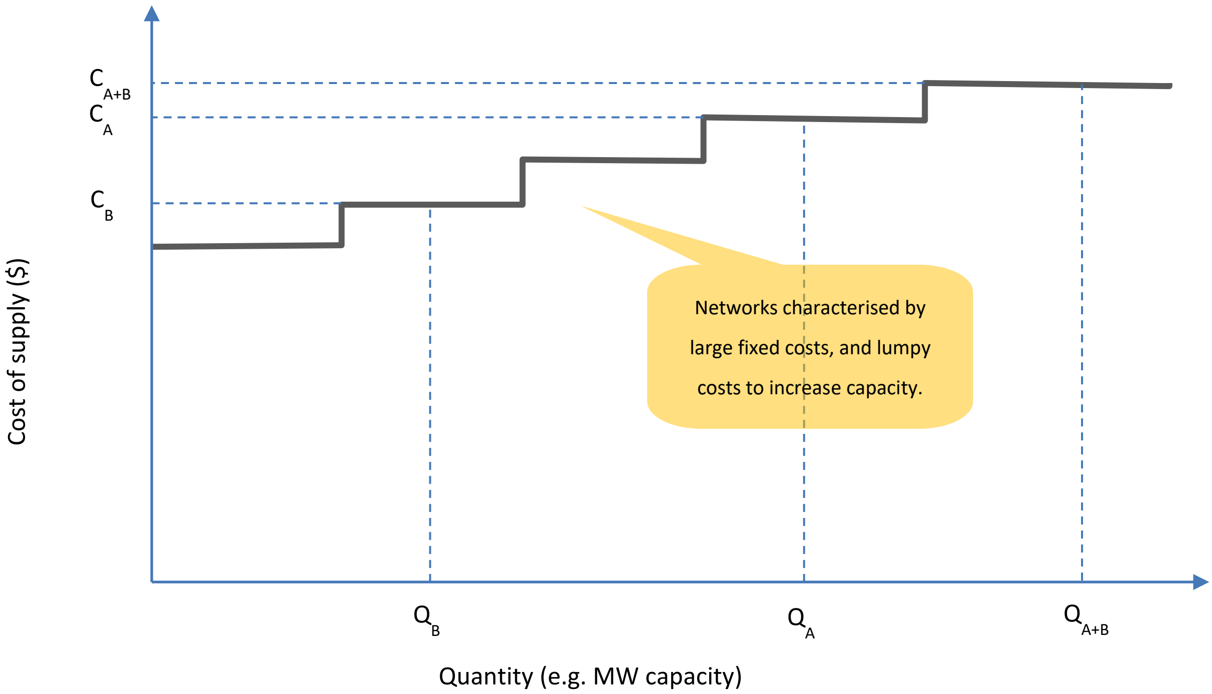
While the allocation of costs of supplying a service to each customer group doesn't have to be exact, the subsidy-free test does have to be accurate enough to capture the material costs. Our current subsidy-free tests use an off-grid standalone cost and an avoidable operating cost methodology to calculate the avoidable cost. This results in a wide subsidy-free range. This range has increased further with the removal of transmission costs from the test (The new TPM now sets transmission prices independently of distribution prices).

In 2022, we commissioned the development of a refined subsidy-free test based on consumer group-level analysis. The calculation is more complex and requires engineering knowledge and detailed cost information to calculate the cost of hypothetical standalone and avoidable networks. The refined calculation will result in a narrower subsidy-free range.

The new methodology first calculates the standalone cost to provide individual networks for each customer group. The avoidable cost is then calculated as the difference between the combined cost of the standalone networks, less the standalone costs of the other networks (i.e. the incremental cost to provide services for a customer group). Figure 31 illustrates the revised methodology.

Figure 31 – refined subsidy-free methodology

| Consumer Group | Avoidable cost | Standalone cost |
|---|---|---|
| A | $C_{A+B} - C_B$ | $C_A$ |
| B | $C_{A+B} - C_A$ | $C_B$ |




We will be applying the new methodology this year (2023) at the same time as we will be implementing the revised LRMC calculation.

## 6.3 Design tariff structure

In November 2023 we consulted with retailers on the new pricing structures and the potential impact the changes will have on customers. This included a new general tariff structure for all customers. The structure has two components:

1. A peak demand price signal that reflects the network-wide LRMC (the cost of using electricity during peak demand periods). The strength of the price signal will vary depending on how effective the price is at shifting peak demand electricity use. There will be no off-peak signal once the Low Fixed User restrictions have been removed.

2. A fixed capacity charge to recover residual costs.

Practically this means reducing the amount of revenue collected from off-peak periods and increasing the proportion of revenue collected from fixed prices. This will shift pricing incentives from encouraging customers to reduce overall energy use (promoted by the off-peak price signal) to reducing energy use during busy periods on the network when the network has limited capacity. The new structure provides several advantages:

- Reflects that there is excess capacity during off-peak periods and does not penalise customers for using electricity when there is capacity.

- It clarifies the price signal to consumers. Currently, some 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 marginal cost will also make the price signal more reflective of the cost of using energy during peak demand periods.

- It removes potential subsidisation of distribution prices for solar users. Currently, solar users may be paying less because they can 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 are no benefits of reducing demand at this time. Other customer prices then have to be raised to cover the revenue shortfall. Customers with solar ***and*** a battery will be able to use solar to charge their batteries during the day and then use the batteries to avoid higher peak prices.

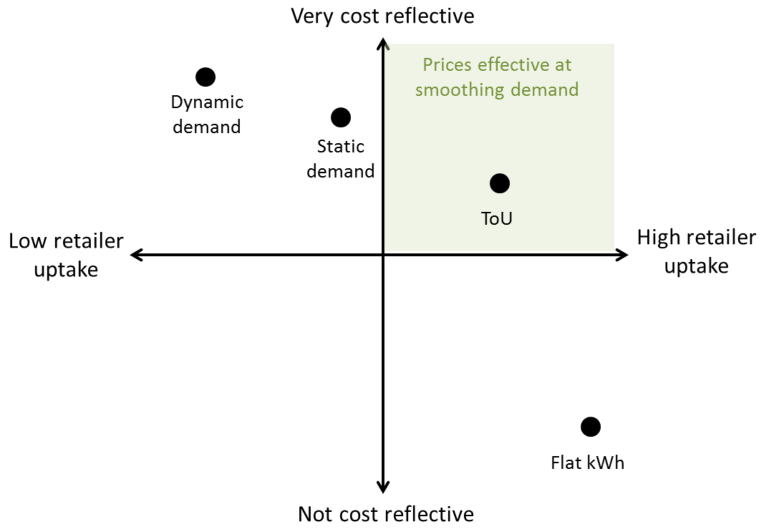
### 6.3.1 Selecting a method for signalling peak demand

ToU is currently the best fit for smaller consumers. ToU is effective 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 New Zealand 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.

This view was supported by our learnings from the EVB charging trial. A critical lesson is that trade-offs will have to be made between how cost-reflective prices are (how good prices are at signalling congestion) and whether prices are understood and can be practically applied. While more complex pricing methods like demand-based pricing provide a 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 consumers' 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 32 – the 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. 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.

#### 6.3.1.1 Complementing ToU with prices for managed services

We are proposing to complement 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.

We propose offering a discounted charge for controlled load. The discount will be consistent with the ToU price signal:

- A discount could be 100% of the peak demand price signal if control is 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

#### 6.3.1.2 Price signals for large users

Large electricity users may be better equipped to respond to more complex price signals. We are considering coincident peak demand (**CPD**) for large customers. CPD charges for usage during actual network peaks, rather than pre-defined peak periods. We consulted on using CPD last year and will refine our thinking this year.

### 6.3.2 Selecting a fixed price design

As per the Pricing Methodology provided in Chapter 5.1, any residual revenue not collected by the peak demand price signal will be recovered in a way that does not influence customers' network use decisions. Practically this means collecting the revenue using a fixed daily distribution charge. The residual revenue that will be collected by the fixed daily charge is calculated for each customer group as *revenue allocated to customer groups (using GWH) – revenue collected by peak demand price signal = revenue to be collected by fixed daily charge*.

We propose calculating the fixed daily charge using connected capacity like we currently do for our GTX1500 and GTX1501 tariffs. A capacity charge allocates the total revenue to be recovered by the fixed charge across customers in a customer group, by their share of total connected capacity within the group. We have selected this method because it avoids jumps in fixed price payments between price categories like we currently have using a fixed daily charge. This also helps us reduce the number of commercial price categories – we currently have multiple commercial price categories to allow us to apply a fixed daily charge which is reflective of the size of the customer connections in a price group. The capacity charge scales to the size of the connects and avoids the need for multiple categories.

We have applied a standard 15 kWA connection for all residential and small customers.

### 6.3.3 Residential price structures

Figure 33 summarises the residential price structures proposed to retailers in 2022.

Figure 33 – Residential pricing structure

| Component | Proposed method | Reason selected |
|---|---|---|
| Peak demand charge | **Time of use for unmanaged load, with limited opt-out (ToU currently in place, but with wide opt-out options).**<br>- Weekday peak rate from 7am to 11am and 5pm to 9pm. The structure aligns with the sector majority (aiding retail uptake) and network demand (aiding the efficiency of price signal).<br>- Zero-rated off-peak (incl. weekends). Reflects excess capacity off-peak (and no other cost impacts). | - Understood and can be implemented by retailers<br>- 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**<br>- Discounted for metered controllable load.<br>- Discounted for managed load.<br>- Discounted peak rate for "inclusive" controllable load.<br>- Apply an additional fixed price increment to recover the cost of control. | - Discount appropriately rewards uptake.<br>- Assumes flexibility service providers would be financially incentivising residential consumers, and not WELL directly |
| Residual cost | **Energy-based cost allocation** | - Least distortionary impact on energy |

| Component | Proposed method | Reason selected |
|---|---|---|
| allocation and recovery | - Cross-check against robust subsidy-free analysis.<br>- Net off expected signalling revenue, then spread balance across ICPs to derive fixed charge per ICP. | use behaviours<br>- Simple and achieves Electricity Price Review (**EPR**) recommendation of reversing historic over-allocation to residential. |
| | **Higher fixed rate**<br>- Fixed rate adjusted up to achieve full recovery of costs allocated to the residential consumer group. | - Least distortionary impact on energy use behaviours |

### 6.3.4 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 a lagged basis – e.g. usage measured over 12 months is used to set prices for the 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 can manage their demand in a way that makes CPD effective in practice. This type of pricing suits customers who can integrate load profiling into their operations.

We are early in our thinking about price structures for larger commercial customers. We will be consulting again in 2023 as we refine our thinking.

Figure 34 summarises the non-residential price structures proposed to retailers in 2022.

Figure 34 – Non- residential pricing structures

| Component | Proposed method | Reason selected |
|---|---|---|
| Peak demand signal | **Small non-residential users (15kVA or less)**<br><br>**Time of use**<br>- Weekday peak rate from 7am to 11am and 5pm to 9pm. Structure aligns with sector majority (aiding retail uptake) and network demand (aiding the efficiency of price signal).<br>- Zero-rated off-peak (incl. weekends). Reflects excess capacity off-peak (and no other cost impacts).<br>- No distinction between those with dedicated transformers and those connected to low voltage network – no significant cost difference | - Understood and can be implemented by retailers<br>- Sends an efficient and effective signal for the types of decisions smaller consumers make (what appliance to buy, simple changes in routine)<br>- Remove fixed daily charges |

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

## 6.4 Design price signal

The peak demand price signal reflects the cost of using electricity when the network is congested. It signals the cost of building new capacity and the value that can be avoided if energy use is shifted to off-peak periods.

### 6.4.1 LRMC

As highlighted in section 6.1, customers do not respond to granular and dynamic price signals. Prices should reflect the enduring (or slow-moving) network economic cost rather than transient operational network costs. For this reason, we have chosen to use the long-run marginal cost (LRMC) to signal the cost of using electricity during peak demand periods. While short-run costs may provide a more accurate and dynamic measure of congestion, customers are unlikely to respond, and retailers are unlikely to be able to pass them through.

### 6.4.2 Calculating the price signal

Our current price signals are based on the past low growth assumptions – the 5c per kWh price signal reflects that while there is congestion, the cost to build new capacity was low. The price signals were therefore relatively weak. Previous price signals were calculated using a simple average incremental cost methodology. The application of the price signals between tariff types hasn't been consistently applied and there are different signal strengths between different tariffs.

The step change in emissions reduction-related demand growth has now been incorporated into our asset management planning processes (the 2023 AMP is the first AMP to include the step change). The network is forecast to be more constrained, reflecting there is limited spare capacity to meet the demand increase and that new capacity will need to be developed. The LRMC now needs to be re-calculated. It is expected that the resulting price signal will be much stronger.

In 2022 we implemented a review of our LRMC methodology which we use to set the strength of our price signals. The purpose of the review was to ensure the LRMC calculation was fit for purpose, given the high value of being able to shift demand away from when the network is congested. The review considered two methods:

1. Average incremental cost which divides the present value of forecast growth capex (annualised) by the present value of forecast demand growth

2. The perturbation approach which divides the present value of the change in capex that would be needed to deliver a step change in demand.

Figure 35 provides our assessment of the two methodologies. We prefer the perturbation method as it provides a more accurate price signal.

Figure 35– selection of a LRMC methodology

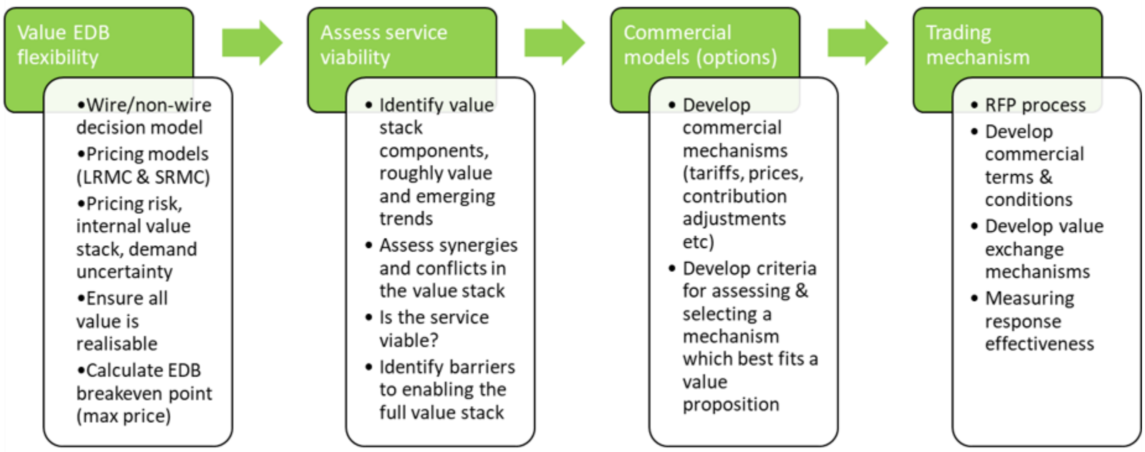
| Method | Pros | Cons |
|---|---|---|
| Average incremental cost (AIC) | • simple to apply using inputs from an AMP<br>• commonly used by Australian distributors<br>• if using the counterfactual approach, can address the interaction between growth and other drivers | • not very robust<br>• assumes a continuous (non-discrete) relationship between growth and investment<br>• more robust variants (counterfactual, segmentation) reduce simplicity |
| Perturbation | • flexible and intuitive<br>• outputs provide useful insight (investment pressure heatmap)<br>• robust | • more work than (simple version of) AIC<br>• project-based approach less holistic than AIC with counterfactual |

We have developed a calculation methodology which uses our asset management planning outputs to calculate the long-run marginal cost. We are incorporating the new methodology into the next asset management plan process. We will start making any changes to the strength of our peak demand price signals from April 2024.

## 6.5 Commercial framework for flexibility services

As part of the joint Resi-Flex project with Orion, we are developing a commercial framework for flexibility services. This includes a framework for deciding when flexibility services will provide a viable alternative to traditional services and how much an EDB can pay for purchasing flexibility services. The framework will provide the price for procuring non-wire solutions for specific network constraints. Figure 36 summarises the components of the commercial framework being developed.

Figure 36 – Components of the commercial framework for flexibility services




## 6.6 Apply TPM

We applied our new TPM pricing structures from 1 April 2023. The key changes were:

1. Changes in the overall costs assigned to each distribution network to pass through. Overall Transmission costs decreased by $5.6m or 10%.

2. Changes in the cost allocation methodology used to pass through costs to customers have changed how much revenue is recovered from residential and commercial customer groups.

3. Removal of all ACOT payments.

Our Pricing Methodology provides the new cost allocation methodology. The new TPM Pricing Methodology creates a large shift between commercial and residential prices, with commercial transmission prices overall increasing by approximability 18%. The size of specific increases varies between commercial price categories.

To avoid price shocks, we are transitioning to the new commercial and residential prices gradually over time. We are limiting any price increase to a maximum of 10% p.a. for any commercial price category. Figure 37 is from this year's Pricing Methodology and compares the proportion of costs allocated to each customer group before the transition rules are applied, to this year's allocation of costs after the first transition year. The gap will close over time as prices are gradually transitioned.

The speed of the transition will depend on other influences on prices and what headroom is available each year to make the transition (i.e. if other drivers are increasing commercial prices then there will be less headroom available within the 10% limit and the transition will be slower). Our current view, taking into account other regulatory drivers like high inflation, decarbonisation spend, and the likely WACC increase, is that most commercial price categories will take four years to transition. However, one price category could take up to eight years.

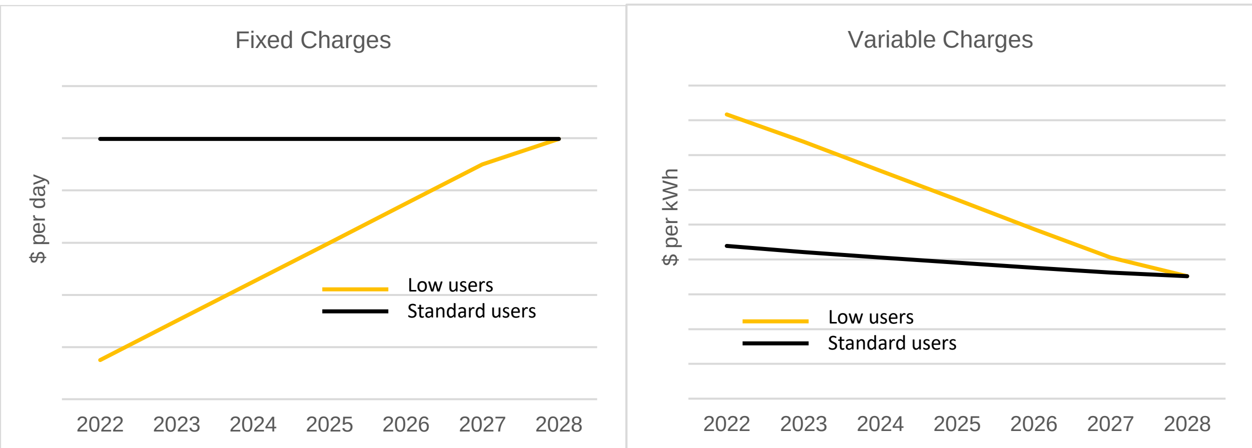
Figure 37 – Impact of the transition rules on this year's prices

| | **% of target revenue (1 April 2023 to 31 March 2024)** | | |
|---|---|---|---|
| **Consumer group** | **Cost allocations once the TPM transmission is complete** | **Cost allocations after the first transition year (2023/24 prices)** | **Difference** |
| Residential | 52% | 62% | -10% |
| General Low Voltage | 36% | 26% | 10% |
| General Transformer | 12% | 11% | 0% |
| Non-metered | 0.1% | 0% | 0% |
| Streetlights | 0.6% | 1% | 0% |
| **Total** | 100% | 0% | 100% |

## 6.7 Exit low-fixed users

We are exiting the low fixed user pricing restrictions in line with the legislative five-year exit. We applied the second 15c fixed price increment from 1 April 2023 (low user fixed prices increased from 30 cents to 45 cents). The transition aligns low user prices with standard user prices. Figure 38 illustrates the transition – low-user fixed prices are increasing to align with standard-user fixed prices, and low-user variable prices are decreasing to align with standard-user variable prices. Note, standard user variable prices also decrease reflecting the removal of the cross-subsidisation (current price restrictions mean that standard users subside low user prices).

Figure 38 – exit from low fixed user restrictions



## 6.8 Develop transition rules

The new price structures will impact prices in multiple ways. Figure 39 summarises the key effects.

Figure 39 – Impact of applying the proposed pricing structures on customer bills

| Change | Effect |
|---|---|
| Only recover demand-driven costs via variable charges (i.e. set the price signal first). Residual costs recovered via fixed charges | Will increase the proportion of revenue from fixed charges. Increase small users' bills and lower large users' bills. The average bill within the consumer group is unchanged |
| Only recover demand-driven costs through variable peak charges. Provide zero variable rate off-peak and managed load charges | This 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 (commercial) consumer bills. |
| Simplifying non-residential customer groups and making prices consistent between customer groups | Little impact on the small and very large non-residual users. Could impact medium size businesses. |

To minimise any price shocks, we proposed applying transition rules which limit the size of any price changes. The transition rules will allow us to adjust the speed and size of the transition to other price changes. Retailers were generally supportive of the approach of smoothing price shocks and the rules. The transition rules for distribution prices are:

- Only applying a distribution price structure transition adjustment, if the overall price change for a price category is less than 5%
- Limiting any price increase within a pricing category to a maximum of 5%.

Note, these proposed transition rules will only apply to the transition of prices to the proposed new distribution price structures. The overall change in distribution allowance and distribution revenue set by the Commerce Commission, maybe higher than 5% - changes that are outside of our ability to limit the price increase to 5%.

The transition rules will mean a gradual shift between the residential and commercial categories as well as a gradual shift within the commercial tariffs. Practically the transition rules will mean the transition will be over several years. The transition to transmission prices, exit of the low-fixed user restrictions, higher inflation or higher-than-expected changes to the regulatory price path, could all extend the transition period.

Note, the transition rules for applying the new TPM are different. We have applied a higher 10% threshold to those changes.

# 7 Pricing scorecard

The Authority makes an annual assessment of how cost-reflective distribution network tariffs are. The Authority makes the assessment using a scorecard of different pricing attributes. Figure 40 summarises the 2021 assessment and the changes that have improved the score. We had the second-highest scorecard score in 2021. An assessment wasn't made by the Authority in 2022.

Figure 40 - Pricing scorecard assessment

| Scorecard category | Score | | Improvements made and work programme 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 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 | A 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 climate change actions. |
| Roadmap | 2 | 5 | Updated Roadmap reflecting the Authority's new pricing methodology. |
| Peak pricing signal | 2 | 3 | Will be addressed in the next review of Pricing Methodology – scorecard feedback was received after the last update. |
| Customer impact | 2 | 3 | Will be addressed in the next review of Pricing Methodology – scorecard feedback was received after the last update. |
| Overall (average) | 2.2 | 3.8 | |

## 7.1 Incorporating pricing score card feedback

This Roadmap also provides a self-assessment against the revised scorecard categories and weighting that were released by the Authority last year[6]. The Roadmap has been updated to include the new focus areas the Authority have included in the revised assessment.

To help inform our pricing programme, we have made a scorecard self-assessment, including the new pricing focus areas. The self-assessment includes our response to the last scorecard assessment and suggestions on how to improve the Authority's assessment.

[6] Open letter to distributors - Distribution Pricing Reform September 2022

Figure 41– Scorecard self-assessment and response to feedback

| Assessment | 2021 score | 2023 Self-assessment | Response (Roadmap action) | Progress |
|---|---|---|---|---|
| Circumstances | 5 | 5 | Circumstances updated for finalised Emissions Reduction Plan. This includes a new section on the emissions-reduction related step change in investment (increasing from \$0.5b to \$1b across the next 10 years).<br><br>This will impact the LRMC and the strength of the peak demand price signal. | Circumstances updated✓ |
| Principles | 3 | 4 | 1. Following scorecard feedback, the pricing principles assessment is expanded to include an assessment of the current structures and an assessment of the proposed future structure – highlighting the current departures from the principles.<br>2. Clarification that the planned allocation of residual revenue uses fixed prices to recover residual revenue (not Ramseys pricing). | • Assessment added to the Pricing Methodology 2022✓<br>• New structure developed, including new fixed prices 2021 ✓<br>• Consult with retailers 2022✓<br>• Implement 2024 onwards |
| Strategy | 4 | 4 | Continued focus on developing managed services to provide some of the capacity needed to deliver the step change in emission-reduction related investment. Pricing methodology expanding to include pricing for procured flexibility services. | Roadmap updated✓ |
| Roadmap | 5 | 5 | Initial Roadmap complete and revised Roadmap provided. The revised Roadmap includes new pricing principles a and new pricing methodology. | Roadmap updated✓ |
| Efficiency | 3 | 4 | 1. Narrative expanded to provide WELL's approach of having only one pricing region and using procured flexibility services to solve specific network constraints.<br>2. Narrative provided to explain current peak demand price signal calculation (based on past, pre-emissions reduction investment capex)<br>3. New LRMC calculation being introduced to | • Pricing Methodology updated in 2023✓<br>• New LRMC methodology developed✓<br>• LRMC methodology |

| Assessment | 2021 score | 2023 Self-assessment | Response (Roadmap action) | Progress |
|---|---|---|---|---|
| | | | support WELL's step change in emissions-reduction related growth investment. The methodology was developed in 2022, retailers will be consulted in 2023 and price signals adjusted in April 2024. | applied to step change in emissions reductions investment 2023 |
| Consumer impact | 3 | 4 | Narrative in Pricing Methodology expanded to describe the approach WELL takes for identifying and managing customer impact:<br>• An analysis is made before the change and used as part of the retailer consultation before any changes are made.<br>• Prices are transitioned gradually to avoid price shocks and to allow customers to adjust their budgets and behaviours.<br>Customer analysis and supporting retailer consultations completed since the last scorecard assessment include the TPM changes and new distribution tariff structures. | • Pricing Methodology updated in 2023✓ |
| Progress against roadmaps | New for 2023 | 4 | Initial Roadmap complete. Good progress on the new Roadmap – consulted on new structures with retailers last year. New structures will be applied from April 2024. | Roadmap updated✓ |
| Progress against focus areas | New for 2023 | 4 | The specific assessment is provided in section 7.2.1. | • Pricing Methodology narrative updated to include focus areas 2023✓ |
| **Weighted total[7]** | **3.8** | **4.2** | | |

[7] 'Efficiency' and 'progress' against focus areas' have double weightings.

### 7.1.1 Progress against focus areas

Figure 42 – Progress against the scorecard focus areas

| Focus areas | Approach and progress |
|---|---|
| Distributors' Roadmaps responding to future network congestion | 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-related network demand and the development of flexibility services to mitigate some of the peak demand increase.<br>The Roadmap also provides an overview of the commercial framework we are developing to price flexibility services. |
| Distributors' response to any significant first-mover disadvantage issues facing customers seeking to connect to their networks (new and expanded connections) | WELL's Customer Contribution Policy and its supporting internal implementation guidelines have removed significant first-mover disadvantage. Thee Pricing Methodology provides a summary of how we ensure those who benefit from connecting assets, fund a corresponding share of the asset cost. |
| The extent to which distributors are following the Authority's guidance on the pass-through of new transmission charges | WELL is applying the Authority's guidance on passing-through transmission charges. Our application methodology is provided in the Pricing Methodology. Note, the changes have resulted in large price increases for some commercial customers. We have chosen to smooth the changes over time.<br>The changes have resulted in all transmission costs being passed through as a fixed charge (except residential prices which still have low fixed user restrictions applied). |
| Whether distributors are increasing their use of fixed charges to match the phase-out path of the low fixed charge tariff regulations | WELL is increasing its fixed charges in line with the low fixed users transition path. Fixed prices for low fixed users increase from 30c to 45c per day from 1 April 2023. |
| Distributors avoiding, or transitioning away from, recovery of costs that are fixed in nature through use-based charges, such as charges based on a customer's Anytime Maximum Demand (AMD) | In 2022 WELL consulted with retailers about a new price structure of a peak demand price signal (based on the cost of congestion) and a fixed charge based on energy used and connected capacity. WELL is currently considering retailer feedback and will release its final price structures shortly.<br>WELL will be consulting again this year, focusing on price structures for large commercial businesses. Our early thinking is to use a peak demand price signal.<br>We will start to transition to the new price structures from 1 April 2024, after we have completed the retailer consultation. |

# 8 Appendix 1: Progress against the previous 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<br>✓ 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<br>✓ Residential ToU prices implemented<br>● Developing small commercial cost-reflective prices (in progress)<br>● 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<br>● 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 EV trial | Further consultation with stakeholders to explain preferred pricing structures and to educate them about upcoming pricing changes. | ✓ Industry review panels<br>✓ Retailer residential ToU consultation complete | Further consultation 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<br>✓ Educational web tools |
| High-level scoping of metering, data and billing constraints/issues. | ✓ Competed – industry review | Develop a 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 EV trial<br>✓ High-level industry study<br>✓ 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<br>✓ Access to meter data is now part of the Code – consider the most appropriate data source | Ongoing review of progress towards achieving pricing objectives. | ✓ New Cost Reflective Pricing Methodology and pricing structures developed<br>✓ 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<br>✓ Consumer impacts of residential ToU analysed | | |
| | | Check 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<br>✓ Demand pricing replaced with ToU | | |
| | | Agree with EA/Retailers on 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. | | |