wellington electricity™

Notification of TPM price changes and consultation on future distribution price structures

November 2022

Contents

1 Purpose

The Electricity Authority (**the Authority**) is reforming prices for transmission and distribution services. The intent of the pricing reform is to provide prices that are more reflective of the underlying costs of providing lines services. Prices influence people's and businesses' use of electricity and the investments they, Electricity Distribution Businesses (**EDBs**), Transpower and others in the sector make. Cost reflective price signals support customers and the industry to make efficient infrastructure investments which will help reduce the size of any future price increases. Helping to ensure the industry is making efficient infrastructure investments will be especially important as New Zealand Emissions Reduction Programme (**ERP**) increases electricity demand and future investment requirements. The Authority have:

a. Applied a new Transmission Pricing Methodology (**TPM**) which is used to calculate the overall cost of transmission services that distribution networks pass through to retailers and direct customers. The TPM also provides how transmission costs should be passed through to customers.
b. Provided updated Pricing Principles and a new Pricing Methodology for distribution services.

The purpose of this document is to notify retailers and direct customers about changes to transmission prices and to consult on proposed changes to distribution prices. The approach of notifying new transmission prices (rather than consulting on any changes) reflects that the Authority and Transpower are responsible for consulting on the changes and setting transmission prices and that EDBs are expected to pass through prices and price signals.

This document has two parts:

Part 1: Notifies retailers and direct customers of the changes to transmission prices. Overall Transmission prices are forecast to decrease by 16.8%. Including distribution prices and other forecast cost increases, we expect lines changes to decrease by 7% (this will be confirmed in January next year).

However, the new TPM cost allocation methodology increases commercial transmission prices and decreases residential prices. While we have smoothed this transition, we still expect commercial prices for lines services (distribution and transmission services) to increase by 3% and residential prices will decrease by 11%.

Part 2: Consults with retailers and direct customers on future distribution price structures that reflect the Authorities new Pricing Methodology. We are not planning to start the transition to these price structures until 2024. The consultation includes:

a. Proposing a new distribution pricing structure that reflects the Authorities new pricing methodology and Pricing Principles and simplifies our pricing structures
b. Consulting on transition rules to guide how we move from existing price structures to the proposed future price structures.

Note, this document does not provide next year's final prices. Some of the inputs into next year's prices are not available yet and we will not be finalising prices until earlier in the new year. Retailers and direct customers will be notified of final prices by 31 January 2023, in line with our normal pricing disclosures.

We have included an estimate of the next years prices so that retailers and direct customers can see the impact of the new transmission charges in the context of next years expected overall prices. Practically this means providing early estimates of volume changes, transmission prices (finalised in December), council rates etc, that will be updated later in the year.

2 Part 1: Notification of TPM price changes

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:

- Electricity Industry Participation Code Amendment (Transmission Pricing Methodology) 2022, and
- Transmission Pricing Methodology 2022, Decision paper.

The change in approach has resulted in material price changes. The key changes being:

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

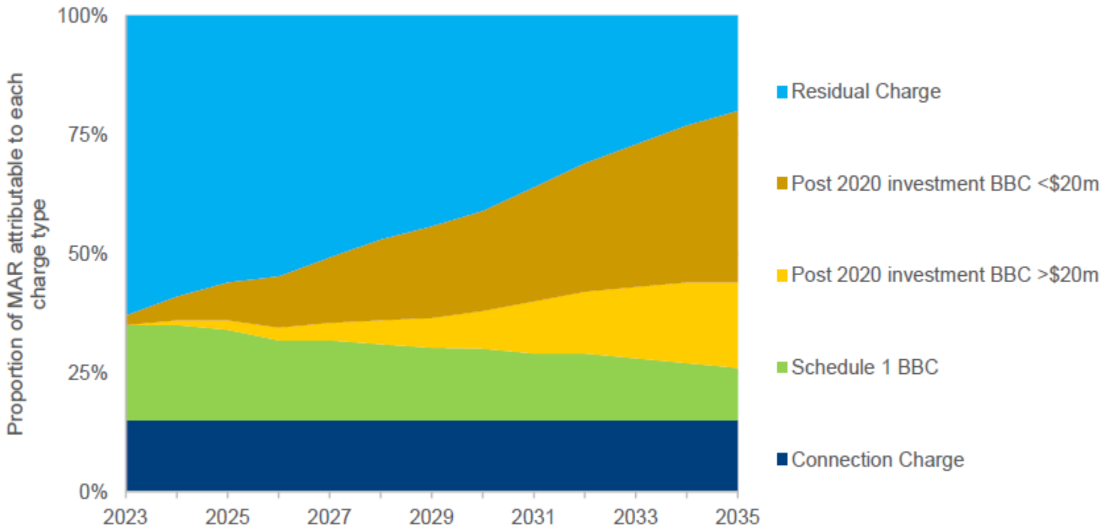
2.1 Future transmission costs

Future transmission charges will be made up of four components:

a. **Connection Charges:** Charges for connection assets – this has not changed from current prices.
b. **Benefit Based Charges:** Allocates costs of new and certain historical grid investments to customers in proportion to their benefit. Benefit-based charges (BBCs) recover capital and operating costs (including a share of overhead opex) attributable to a benefit-based investment.
c. **Residual Charges:** Residual charges recover Transpower's revenue not recovered through other transmission charges. Includes old investments and overheads not included in BBC.
d. **Provisions for adjusting transmission charges**: The TPM also allows for a number of other adjustments to Transmission charges, including:
   - Adjustments for substantial and sustained change in grid use
   - Reassigning costs if the forecast future loading is substantially less than the expected capacity of an investment
   - Prudent discount adjustments to ensure efficient investment decisions
   - Transitional cap to smooth aspects of the TPM transition

The residual charge includes the majority of historic grid investment, and the BBC provides for future investments (although the BBC also includes seven large investments made since 2018). This means that the proportion of overall transmission costs reflected in the BBC will increase over time and the proportion of residential costs will decline (as old assets are replaced). Figure 1 illustrates this transition.

Figure 1 – Transmission price components from 2023 to 2035



Source: Transpower TPM Reasons Paper Appendix B: indicative prices updated 15 September 2021

2.1.1 Removal of ACOT

Under the new TPM methodology, Avoided Cost of Transmission (ACOT) payments will no longer be required – the new methodology means there is no longer any transmission costs that can be avoided by generating on distribution networks. The Authority is considering whether to remove all provisions for ACOT payments from April 2023 (the Authority's preferred option) or to phase out ACOT payments over the next two pricing years. For the purposes of this notification, we have assumed that all payments will stop from April 2023. We will reflect the Authorities final decision in our final prices.

2.1.2 Transmission (including ACOT removal) costs for Wellington

Transpower provided a forecast (provided August 2022) of transmission costs that will apply from April 2023. Transpower will finalise the costs in December 2022. Figure 2 provides a forecast of each component of next year's transmission costs, the impact of the removal of ACOT and a comparison to current transmission costs.

Figure 2 – Forecast for next year's Transmission prices

Price component	Cost ($m p.a.)
Benefit based charge (BBC)	9.0
Residual (old investment + overhead)	30.5
Connection	8.2
Transitional cap	0.2
Total Transmission costs (applying April 2023)	47.9
Current Transmission costs (applying April 2022)	55.5
Difference	(7.6)
Less ACOT	(2.1)
Total Transmission costs less ACOT (applying from April 2023)	45.8
Difference	(9.7)
Difference (%)	(16.8%)

The current Transpower forecast indicates that Wellington's overall transmissions costs will reduce by $9.7m or 16.8% from April 2023. However, the Electricity Authority's TPM includes a cost allocation methodology change which will see some transmission costs increase and some decrease across the customer groups. We do expect that transmission prices will increase in the future, offsetting some of this decrease, as Transpower invests in the Central Park GXP. This investment is to strengthen the GXP to make it more resilient.

2.2 Passing through transmission costs

The Authority has provided guidance on the pass-through of transmission charges. The guidance aligns with the Authority's Distribution Pricing methodology, specifically:

1. transmission charges intended to send price signals that influence network use should be passed through as distribution charges that send the same price signal (and influence network use in the same way) as the transmission charge.

2. fixed transmission charges, which are not intended to influence customers' network use decisions, should be passed through as fixed (daily) distribution charges.

The Electricity Networks Association (ENA) has developed further principles to guide the practical application:

> **Principle 1**—distributors should not attempt a detailed replication of the allocation approach used in the TPM. Rather the allocation approach should be consistent with and have regard for the allocation approaches adopted by the TPM. In practice, this can be achieved by adopting the same underlying allocation drivers of demand (AMD[1]) and usage (kWh) share.

[1] Anytime maximum demand.

Principle 2—the pricing structures for the recovery of transmission costs should reflect the non-distortionary principle (prices should not influence the ongoing use of the grid) as outlined by the Authority in its Practice Note and implicit in the fixed charge adopted by the TPM.

Appendix A summaries how we have applied the guidelines and principles to allocate transmission costs to customer groups and tariff categories. The cost allocation reflects:

- The allocation drivers used to allocate costs to each customer group align with the TPM cost drivers – BBC and Residual costs are allocated by kWh and Connection costs are allocated by AMD which is approximated using connected capacity.
- Costs are allocated within the customer group using connected capacity:
    - Costs are allocated to residential and small commercial customers using a standard connected capacity size of 15kVA
    - Costs are allocated to medium commercial customers using a weighted average connected capacity
    - Costs are allocated to direct bill customers and large commercial customers using individual connected capacity.

Where we have a choice of cost driver, we have selected drivers where we have reliable access to supporting data needed to make the allocation calculation – i.e. we have kWh and connected capacity data for each ICP from which we can accurately calculate the cost drivers. We have also selected drivers that align with our current price structures, eliminating the need for retailers to make price structure changes to their billing systems and processes.

2.3 Customer impact

The change in approach has resulted in material price changes. The key changes being:

1. Changes in the overall costs assigned to each distribution network to pass through. As highlighted above, overall Transmission costs are forecasts to decreased by $9.7m or 16.8%.
2. Changes in the cost allocation methodology used to pass through costs to customers has changed how much revenue is recovered from residential and commercial customer groups.

2.3.1 Change in cost allocation methodology

The previous cost allocation approach used peak demand energy use to allocate Transmission costs. This resulted in a large proportion of the costs being recovered from residential customers who drive peak demand energy use on the Wellington network. The change of cost allocation methodology to energy used or anytime max demand means that more of the Transmission costs are now collected from commercial customers. A more detailed explanation of the how the change of cost allocation methodology has impacted Transmission tariffs, is provided in Appendix B.

Figure 3 illustrates the impact of changing the allocation methodology - specifically the change in the proportion of revenue allocated to each customer group. The change from allocating transmission costs using a peak demand driver, to energy consumed driver, has decreased the costs allocated to residential from 68% to 52% (differences being other customers) and increased the costs allocated to commercial customers from 28% to 46% (differences being other customers).

Figure 3 – illustrating the impact of the change in cost allocation methodology

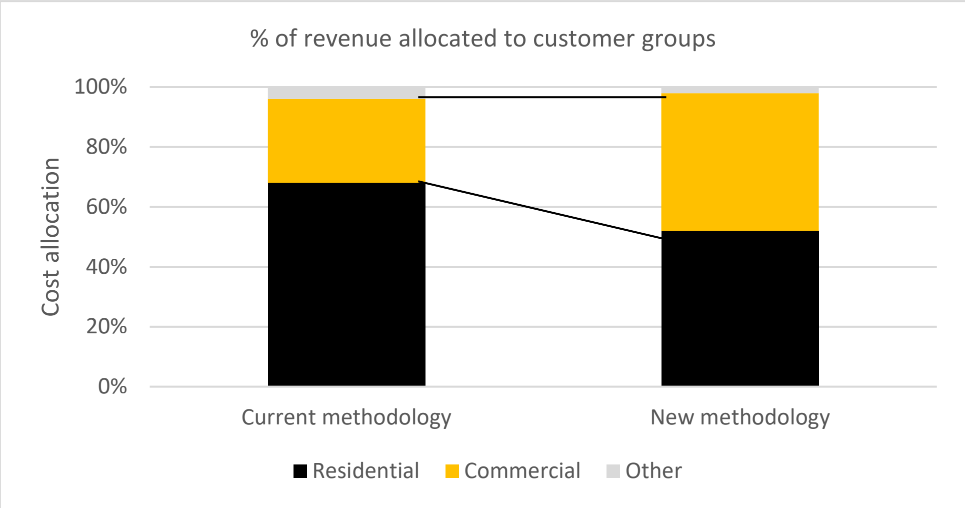


Figure 4 provides further details on the allocation of costs between customer groups.

The following narrative and analysis (figures 4 and 5) assume that overall transmission and distribution costs do not change so that the impact of the cost allocation changes can be isolated. The analysis uses 2022/23 transmission and distribution revenue.

Figure 4 – Impact of the new TPM cost allocation methodology on transmission costs

Customer group	Transmission prices		Diff $m	Diff %	% Collected from prices		Diff
	Old methodology $m	New methodology $m			Starting April 2022	Starting April 2023	
Residential	37.9	29.1	(8.8)	-23%	68%	52%	-16%
Commercial	15.7	25.6	9.8	62%	28%	46%	18%
Unmetered	1.3	0.4	(0.9)	-72%	2%	1%	-2%
Non-standard consumers	0.6	0.5	(0.1)	-16%	1%	1%	0%
Total	55.6	55.6	0	0%	100%	100%	0%

Figure 5 illustrates the impact of the change in methodology on total revenue (distribution and transmission). While the total dollar amount of transmission costs allocated to customer groups has not changed, the impact is diluted over a larger cost base within our lines charges. The change will be even further diluted when the other components of an electricity bill are added (i.e. Transmission makes up only 10% of a residential power bill).

Figure 5 – Impact of the new TPM cost allocation methodology on transmission with distribution costs included

Customer group	Transmission and distribution prices		Diff $m	Diff %	% Collected from prices		Diff
	Old methodology $m	New methodology $m			Starting April 2022	Starting April 2023	
Residential	105.5	97.2	(8.3)	-8%	67%	62%	-5%
Commercial	45.2	54.4	9.2	20%	29%	35%	6%
Unmetered	3.7	2.9	(0.9)	-23%	2%	2%	-1%
Non-standard consumers	2.0	2.0	(0.0)	-0%	1%	1%	0%
Total	156.4	156.4	0	0%	100%	100%	0%

The total amount of revenue recovered from residential customers has decreased from 67% to 62% (and the amount allocated to commercial customers has increased from 29% to 35%).

2.3.2 Overall price change – including other forecast changes

Adding in the expected reduction in transmission costs and forecast changes to distribution costs, provides an indication of the total change in next year's prices. Figure 6 provides a forecast of the expected changed in overall revenue. Note, this is a forecast only and is likely to change as cost inputs are finalised.

Figure 6 – Forecast change in overall revenue

Revenue components	Transmission & distribution revenue		Diff $m	Diff %
	Starting April 2022 $m	Starting April 2023 $m		
Distribution revenue[2]	98.8	97.6	(1.2)	-1.2%
Transmission revenue[3]	57.6	47.9	(9.7)	-16.8%
Total	156.4	145.5	(10.9)	-7.0%

Figure 7 provides a comparison of the revenue expected to be collected from each price category this year, and forecast revenue collected from each customer group next regulatory year. The comparison combines the change in overall revenue amounts and the TPM cost allocation changes.

Figure 7 – forecast revenue from prices for the year starting April 2023

Customer group	Revenue from prices		Diff ($)	Diff (%)
	Starting April 2022	Starting April 2023		
Residential	105.5	90.4	(15.1)	-14%
Commercial	45.2	50.6	5.4	12%
Unmetered	3.7	2.7	(1.1)	-29%
Non-standard consumers	2.0	1.9	(0.1)	-7%
Total	156.4	145.5	(10.9)	-7%

[2] Includes other pass through and recoverable costs and the washup account
[3] Includes Avoided cost of Transmission (ACOT) costs

The total amount of revenue allocated to residential customers has decreased 14% (and the amount collected from commercial customers has increased 12%).

2.3.3 Impact on commercial pricing categories

WELL has a number of different tariffs within its commercial price category. The different tariffs have been historically used to:

- Allow more cost reflective tariffs to be applied to large connections
- Allow different fixed daily tariffs to be applied different size connections

The new cost allocation methodology also changes how costs are allocated between tariff types within a cost category. As illustrated in Appendix 1, costs are allocated by connected capacity. A weighted average connected capacity has been used for small and medium commercial connections to convert the capacity charge into a fixed daily price, allowing us to maintain the existing price structure. We are proposing to simplify these categories in the future as we reform our distribution prices (as discussed in Part 2 of this document), but we will do this gradually overtime to reduce any price shocks.

Appling the new cost allocation methodology to the commercial tariffs shows significant price changes within the commercial tariffs are needed (illustrated in Figure 8). The differences reflect that WELL's individual commercial tariffs have evolved individually overtime, creating some inconsistencies. For this reason, WELL will adjust tariffs gradually over time to remove the pricing inconsistencies.

Figure 8 – Impact of applying the TPM cost allocation methodology to WELL's commercial tariffs

Commercial Categories	Total Revenue 2022 ($m p.a.)	Total Revenue 2023 with TPM ($m p.a.)	Difference ($m p.a.)	Difference (%)
GLV15	3.0	3.2	0.1	4.6%
GLV69	14.1	19.2	5.1	36.0%
GLV138	3.1	2.8	(0.3)	-9.9%
GLV300	3.0	3.3	0.3	10.4%
GLV1500	5.4	6.4	0.9	16.7%
GTX15	0.00	0.00	(0.0)	-15.3%
GTX69	0.03	0.03	0.0	32.2%
GTX138	0.1	0.1	(0.0)	-8.7%
GTX300	1.1	1.2	0.1	7.9%
GTX1500	10.3	9.9	(0.4)	-3.8%
GTX1501	4.9	4.5	(0.4)	-8.2%
Total	45.2	50.6	5.4	12.0%

2.3.4 Transition of prices

WELL will transition the revenue from prices between commercial and residential tariff categories gradually overtime. WELLs transition plan will limit any price increase to 10% maximum within a pricing category, this will mean a gradual shift between the residential and commercial categories as well as a gradually shift within the commercial tariffs. Figure 9 provides a comparison of the revenue expected to be collected from each price category this year, and forecast revenue collected from each customer group next regulatory year with our transition rules applied. The comparison combines the change in overall revenue amounts and the TPM cost allocation changes.

Figure 9 – Forecast revenue from prices for the year starting April 2023 with transition rules applied

Customer group	Revenue from prices		Diff ($)	Diff (%)
	Starting April 2022	Starting April 2023		
Residential	105.5	94.4	(11.1)	-11%
Commercial	45.2	46.6	1.4	3%
Unmetered	3.7	2.7	(1.1)	-29%
Non-standard consumers	2.0	1.9	(0.1)	-7%
Total	156.4	145.5	(10.9)	-7%

Figure 10 provides our projected transmission path – the transmission path makes gradual adjustments over a 10-year period to ensure price shocks are minimised. The transition path includes forecast changes to overall transmission and distribution revenue.

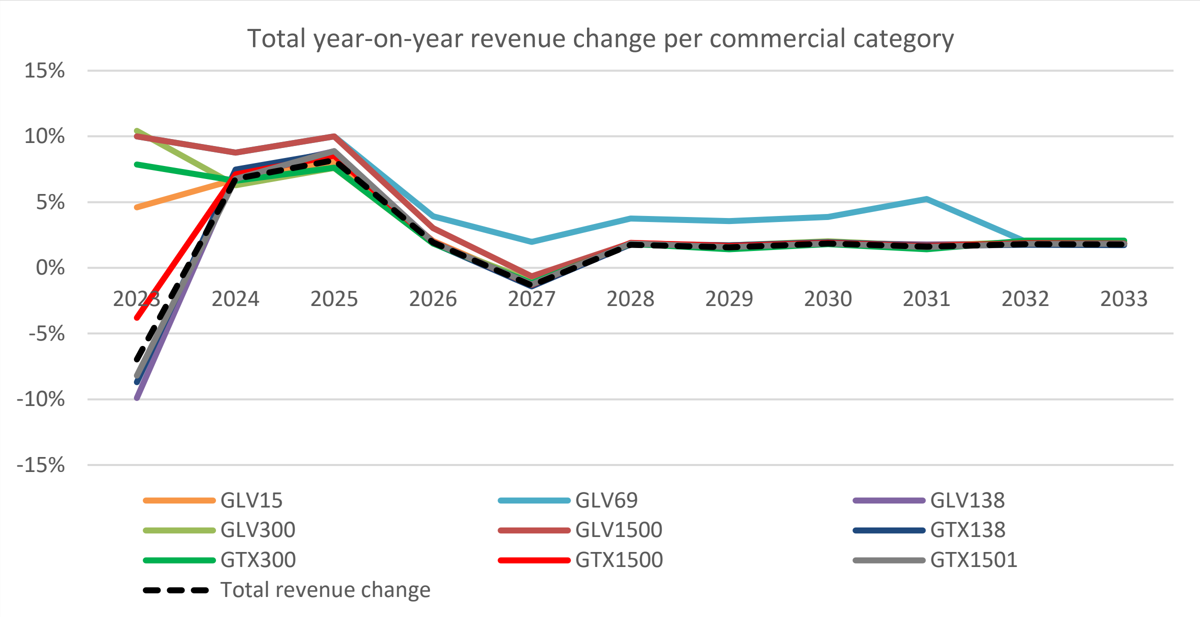
Figure 10 – Projected transition path for TPM changes including forecast total revenue changes

Categories	Starting revenue position 2022 ($m p.a.)	Transition of TPM price changes ($m p.a.)									Ending revenue position 2032 ($m p.a.)
		Year 1 2023	Year 2 2024	Year 3 2025	Year 4 2026	Year 5 2027	Year 6 2028	Year 7 2029	Year 8 2030	Year 9 2031	
Residential Total	**105.5**	**94.4**	**100.4**	**107.9**	**109.6**	**107.5**	**108.9**	**110.1**	**112.5**	**114.1**	**115.1**
Commercial Total	**45.2**	**46.6**	**50.3**	**54.8**	**56.3**	**56.2**	**57.8**	**59.1**	**61.0**	**62.6**	**64.4**
GLV15	3.0	3.2	3.4	3.7	3.7	3.7	3.8	3.8	3.9	4.0	4.1
GLV69	14.1	15.5	16.9	18.5	19.3	19.6	20.4	21.1	22.1	22.9	24.1
GLV138	3.1	2.8	3.0	3.3	3.4	3.3	3.4	3.4	3.5	3.6	3.6
GLV300	3.0	3.3	3.5	3.8	3.9	3.8	3.9	4.0	4.1	4.2	4.2
GLV1500	5.4	6.0	6.5	7.2	7.4	7.3	7.5	7.6	7.8	7.9	8.1
GTX15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GTX69	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GTX138	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
GTX300	1.1	1.2	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5
GTX1500	10.3	9.9	10.6	11.5	11.7	11.6	11.8	12.0	12.3	12.6	12.8
GTX1501	4.9	4.5	4.8	5.2	5.3	5.3	5.4	5.5	5.6	5.7	5.8

Figure 11 illustrates the commercial categories transition path graphically, showing each years expected price change. We have limited any annual adjustment for the TPM transition to 2% - noting the percentage limit relates to just the TPM adjustments and would be in addition to any increase or decrease in prices caused by other price changes (distribution and other pass-through and recoverable costs). Overall, we have ensured no price increase is greater than 10% each year for a particular customer category.

Reminder: the transition analysis is based on forecast future distribution and transition costs. Actual cost changes will differ. We will reapply the transition rules to actual cost changes.

Figure 11 – Transition path for each price category



2.4 Application

We will be applying these changes from 1 April 2023.

3 Part 2: Future distribution price consultation

Like most electricity distributors, we have been working on a pricing reform programme for our distribution services. Our pricing strategy and future pricing plans are provided in our Pricing Roadmap which we publish each year. The latest Roadmap, including a progress update, can be found on our website at:

As part of the Authority's pricing reforms, it has developed a new pricing methodology. Part 2 of this document consults on how we are applying the new pricing methodology to distribution pricing. The change in methodology would result in significant changes so we are also consulting on a transition approach to smooth any resulting price shocks.

3.1 How to make a submission

WELL welcomes feedback from stakeholders on the proposed new pricing structures and the transition approach to shifting to those structures. Stakeholders are invited to respond to the questions and/or to provide feedback on topics not covered by the questions.

Submissions can be provided to WE_CustomerService@welectricity.co.nz. Please include "Future distribution prices" in the subject line of the email.

The consultation process starts on 18 November 2022 with the distribution of this consultation document to all stakeholders. WELL will also be available during the consultation period to answer any questions. The consultation process will end at 5pm on 16 December 2022. WELL may not consider submissions received after this time and date.

While we will not be publishing stakeholder feedback, we will be summarising feedback on the key themes and will provide this feedback as part of our submission response.

3.1.1 Consultation timetable

The consultation timetable is provided in Figure 12 below.

Figure 12 – Consultation timetable

Consultation step	Consultation date
Consultation documents e-mailed to traders and consultation started	18 Nov 2022
Closing date for trader submissions	16 Dec 2022
WELL to circulate a summary of submission and our response to the feedback	Dec 2022/Jan 2023
Transpower provides their prices	Dec 2022
Calculate final prices	Dec 2022
Traders provided with final prices in EIEP 12 format	31 Jan 2023
Consumers notified of new prices	Late Feb 2023
New prices apply	1 Apr 2023

3.2 Background

The Electricity Authority provided updated Pricing Principles in 2019 and supported them with a Distribution Pricing Practice Note (2021) to help distributors interpret and apply the 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 pricing methodology, an approach which first sets a price signal which reflects the cost of using electricity during peak congestion periods, and then recovers any residual costs in a way that doesn't influence consumers energy use behaviours i.e. the peak demand price signal already signals the future cost of using energy during peak demand periods and no further price signals are needed. The remaining revenue should then be collected in a way that minimises any volatility from changes in consumer energy use habits, generally by using fixed charges. This differs from the past pricing approach which allocated costs to consumer groups using cost drivers, and then applied price signals that reflect the cost of using energy during peak demand periods. Appendix C illustrates the new pricing approach – this diagram is sourced from the Electricity Authority's' Distribution Pricing Price Note 2021.

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

3.3 Review of WELL's current price structures

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

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

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

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

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

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

3.4 Proposed future pricing structure

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

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

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

Question 1: Do you support the approach of using a network wide LRMC to provide an enduring price signal for mass market tariffs?

3.4.1.1 Proposed residential price structures

Our proposed structures assume the removal of the current low fixed charge regulations which currently stop the implementation of cost reflective prices.

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

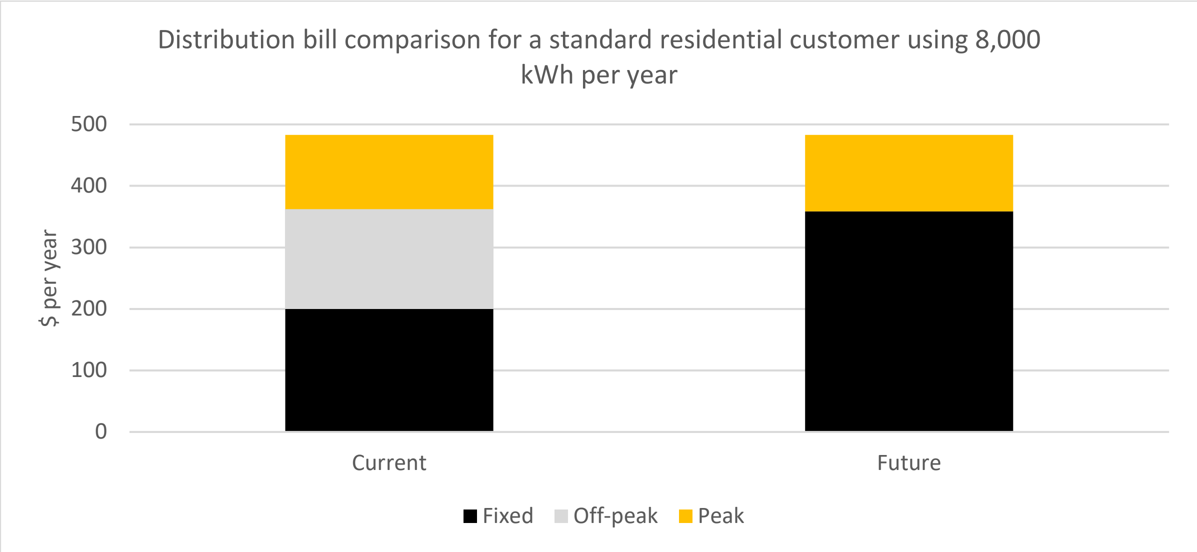
Our proposed prices include a zero-rated off-peak price signals and rebalancing the variable/fixed price mix. Practically this means reducing the amount of revenue collected from off-peak periods and increasing the proportion of revenue collected from fixed prices. This provides several advantages:

- Reflects that there is excess capacity during off-peak periods and there are no peak period cost impacts.
- It clarifies the price signal to consumers. Currently, consumers must subtract the peak demand price signal away from the off-peak signal to reveal the true peak demand price signal. Rebalancing variable and fixed prices using the long run margin cost will also make the price signal more reflective of the cost of using energy during peak demand periods.

- It removes potential subsidisation of distribution prices for non-solar users. Currently, solar users may be paying less because they are able to reduce their off-peak prices by offsetting their energy use using solar. This means they are avoiding paying for services they should be contributing towards – the network has capacity during the off-peak periods and there 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 in the day and then use the batteries to avoid higher peak prices.

Early estimates of the LRMC show prices could collect 70% of the revenue from fixed prices and 30% from the peak price signal. The LRMC will be recalculated to confirm this. This translates to a peak demand price signal of around 5 cents a kWh (just distribution prices). Currently our ToU tariff is around this at 5 cents a kWh[4]. Figure 13 compares the revenue collected from current and future prices, for a household consuming an average amount of electricity. The comparison assumes a future peak demand signal of 9 cents per kWh.

Figure 13 – Comparison of current and future residential pricing structures



The transition to the future price structures will remove the off-peak prices and increase the fixed daily price. 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.

Question 2: Do you support only using a peak period price and a fixed price (i.e. price signals that only signal peak demand)?

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

- is readily understood – it doesn't require consumers to understand a new usage statistic (e.g. peak demand) – and doesn't expose consumers to excessive volatility or risk

[4] Our EVB prices have a higher 8 cents a kWh. We will consider simplifying the pricing structure by removing EVB prices once we are ready to offer the new managed EV and battery changing service.

- can be implemented by most NZ retailers, helped along by its emerging prevalence amongst larger distributors
- sends an efficient signal and effective signal for the types of decisions small consumers make

Question 3: Do you support continuing to use ToU prices, instead of other pricing methods that may be more cost reflective but more complex to apply?

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

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

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

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

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

- A discount could be 100% if control 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

Question 4: Do you support applying different strength price signals depending on a connections ability to be controlled?

Figure 14 summarises the proposed structures for residential consumers. The figure also provides the reasons the price component was selected.

Figure 14 – Future residential price structures

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

Question 5: Do you support using energy used to allocate revenue between residential and commercial customers? If not, what other method do you think is more appropriate?

Question 6: Do you have any other comments relating to the proposed residential price structures?

3.4.1.2 Proposed non-residential price structures

The review of our commercial price structures also provides an opportunity to simplify the current structure which has a number of different price categories. Figure 15 summaries our proposed non-residential price structures.

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

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

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

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

Question 7: Do you support using coincident peak demand for large customers? If not, what alternative method do you think would be more appropriate?

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

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

Question 8: Do you support using ToU for small and medium customers? If not, what alternative method do you think would be more appropriate?

Figure 15 – Future non-residential price structures

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

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

Question 9: Do you support using a fixed charge based on connected capacity to apply residual costs?

Question 10: Do you have any other comments relating to the proposed commercial price structures?

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

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

3.5 Consumer impact

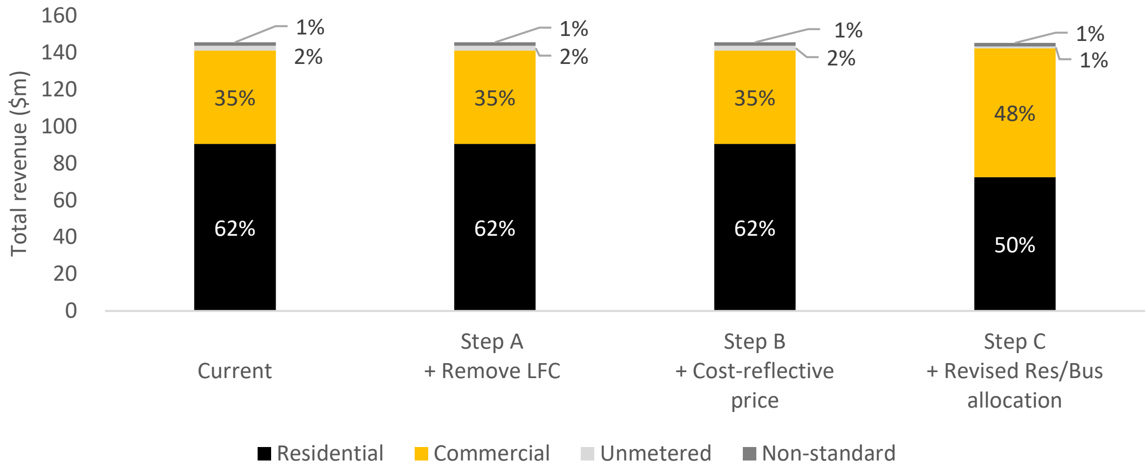
The new price structures will impact prices in multiple ways. Figures 16 summaries the key effects.

Figure 16 – 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 proportion of revenue from fixed charges. Increase small users' bills and lower large users' bills. Average bill within consumer group is unchanged
Only recover demand-driven costs through variable peak charges. Provide zero variable rate off-peak and managed load charges	Will increase bills for peakier consumers (those who use more energy during peak periods) and vice-versa for flatter consumers.
Revised cost allocation between consumer groups	Energy-based cost allocation will reduce residential consumer bills and increase non-residential (commercial) consumer bills.
Simplifying non-residential customer groups and making price consistent between customer groups	Little impact on the small and very large non-residual users. Could impact medium size businesses.

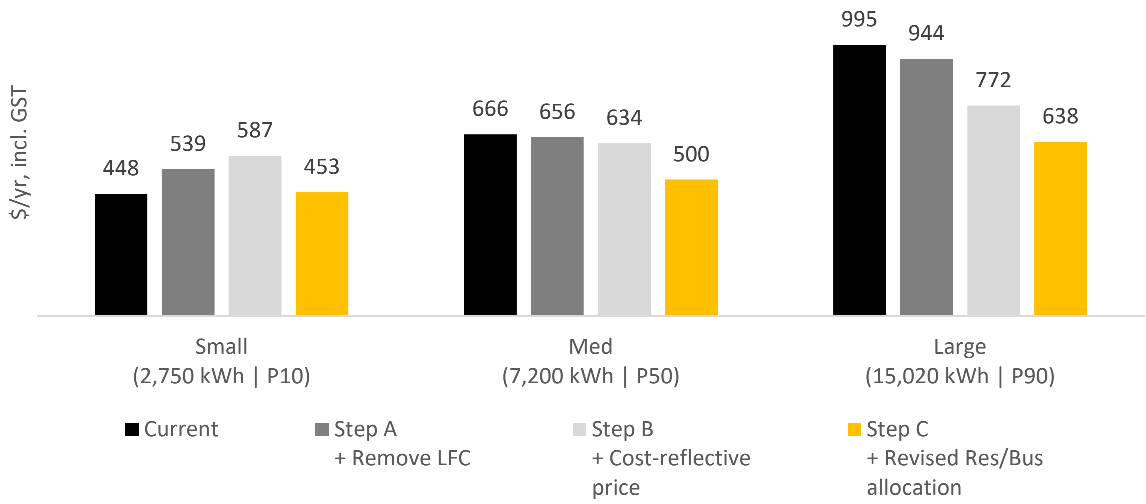
Figure 17 shows the projected impact of the implementation of the new price structures between the residential and commercial price categories. Step A – removal of the low fixed charge and Step B – introducing cost-reflective prices would see no change in the proportion of revenue collected between residential and commercial tariffs. Step C – revising the residential and business allocation would result in revenue collected from residential customers decreasing from 62% to 50% and revenue collected from commercial customers increasing from 35% to 47%. This reflects the change from a peak demand cost driver which allocates more cost to residential customers, to an energy use driver which allocates more costs to commercial customers. To minimise any price shocks to consumers, WELL will implement the transition over a number of years and will limit the size of any changes (see section 3.6).

Figure 17 – Residential and commercial impact on total revenue collection based on pricing structure changes



Each price structure change impacts small, medium, and large residential consumers differently. Figure 18 shows that Step A – removal of the low fixed charge, sees an increase in small consumers bills, a largely unchanged bill for medium users and a decrease in the bills of large users. WELL will continue to remove the LFC restrictions in line with the industries four-year exit pathway. Step B – introducing cost-reflective prices would see the same trend in bills as that of the LFC transition. Step C – revising the residential and business allocation would result in a reduction in all residential users bills as more revenue is collected from commercial customers.

Figure 18 – Price structure changes on residential consumers



Appendix D provides the impact on the key small of medium commercial tariffs.

The impact on the larger commercial tariffs (GLV1500, GTX 1500 and GTX 1501) will depend on the final peak demand pricing method selected. We will consult again at a later date about different pricing options.

Step A (removal of the LFC restrictions) will have no impact on commercial price categories and has not been shown for commercial customers. The transition impact of Step B (cost-reflective pricing) will result in similar transition impacts as that of the residential category, an increase in smaller commercial users' tariffs and a decrease in large users' tariffs. Step C (Revised Res/Bus allocation) will see an overall shift to revenue collected from commercial users. This change will result in the larger commercial tariffs seeing a greater increase in their total bill.

3.6 Transition

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. We propose:

- 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 structurers. 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 gradually shift within the commercial tariffs. Practically the transition rules will mean the transition will be over a number of years. The transition of transmission prices, exit of low fixed user restrictions, higher inflation or higher than expected changes to the regulatory price path, could all extent the transition period.

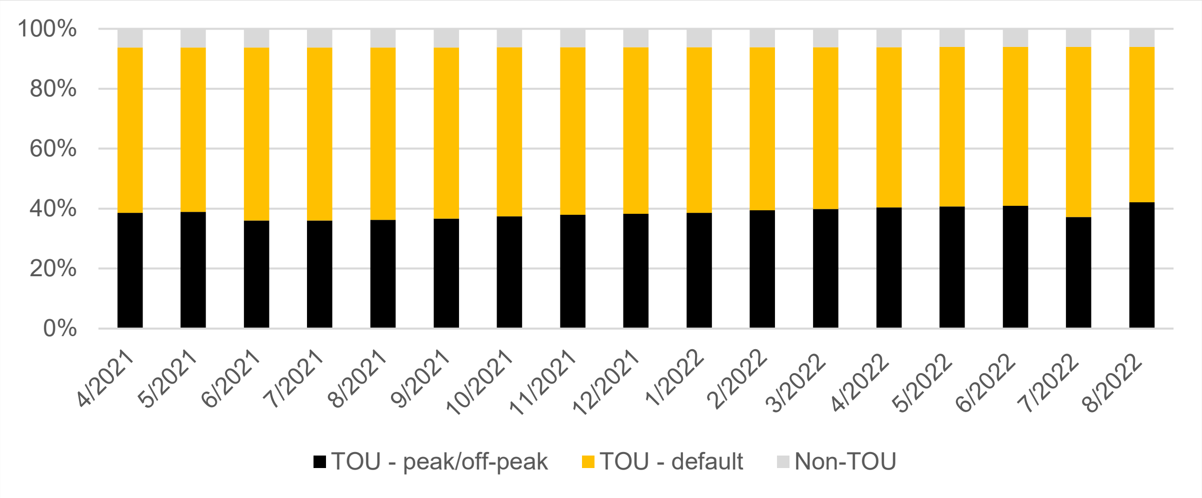
Question 11: Do you support the transition rules? If not, what do you think would be a more appropriate solution?

3.7 Application of ToU

Last year we applied Time of Use (**ToU**) prices to all residential consumers which have a communicating smart meter. Our consultation with retailers before the new prices were applied showed that some retailer billing processes, and/or billing systems, could not provide the peak and off-peak data needed to apply ToU prices. To provide those retailers more time to update their system, we included an anytime variable and an all-inclusive price option within the ToU codes with the expectation that retailers could submit data to these codes until they were ready to provide data in the peak and off-peak format.

Figure 19 shows that approximability 40% of consumers are currently being billed using peak and off-peak prices. About 55% of consumers have communicating smart meters but aren't submitting data in the peak/off-peak format.

Figure 19 – ToU uptake



Question 12: Are you submitting peak and off-peak residential consumption data? If not, for what reason can you not participate in ToU prices? And when do you think you will be able to participate in ToU prices?

4 Next steps and closing

Thank you for taking the time to read this consultation document. Please don't hesitate to ask any questions you might have by email to WE_CustomerService@welectricity.co.nz. Please include "Future pricing consultation" in the subject line of the email.

We look forward to answering any questions and receiving your submissions.

Appendix A: Pass through methodology

Transmission cost	Cost driver - price categories	Price category	Cost driver - within price categories	Customer group	Tariff
Residual	kWh	Residential	Fixed capacity (15 kVA)	Residential	Fixed daily
		Commercial	Fixed capacity (15 kVA) avg. connected capacity Individual connected capacity	Small (15kVA and under) Medium (4 x categories from 15kVA to 1500kVA - GLV & 3 x categories from 15kVA to 300kVA - GTX) Large (2 x categories from +300 kVA - GTX)	Fixed daily Fixed daily or capacity charge Capacity charge
		Non-metered	Fixed capacity Fixed capacity	Non-street lighting streetlighting	Fixed daily Fixed daily
		Direct	Individual connected capacity	Direct bill	Capacity charge
Benefit based	kWh	Residential	Fixed capacity (15 kVA)	Residential	Fixed daily
		Commercial	Fixed capacity (15 kVA) avg. connected capacity Individual connected capacity	Small (15kVA and under) Medium (4 x categories from 15kVA to 1500kVA - GLV & 3 x categories from 15kVA to 300kVA - GTX) Large (2 x categories from +300 kVA - GTX)	Fixed daily Fixed daily or capacity charge Capacity charge
		Non-metered	Fixed capacity Fixed capacity	Non-street lighting streetlighting	Fixed daily Fixed daily
		Direct	Individual connected capacity	Direct bill	Capacity charge
Connection	Connected capacity	Residential	Fixed capacity (15 kVA)	Residential	Fixed daily
		Commercial	Fixed capacity (15 kVA) avg. connected capacity Individual connected capacity	Small (15kVA and under) Medium (4 x categories from 15kVA to 1500kVA - GLV & 3 x categories from 15kVA to 300kVA - GTX) Large (2 x categories from +300 kVA - GTX)	Fixed daily Fixed daily or capacity charge Capacity charge
		Non-metered	Fixed capacity Fixed capacity	Non-street lighting streetlighting	Fixed daily Fixed daily
		Direct	Individual connected capacity	Direct bill	Capacity charge

5 Appendix B: Impact of changing the cost allocation driver

The change in the methodology that the TPM uses to allocate revenue has increased the proportion of Transmission costs allocated to commercial customers. This Appendix explains the impact of the change in methodology using an illustrative load curve representing demand on the Wellington network. Figure 20 illustrates the Wellington networks average demand profile. Demand on the Wellington network is highest in the morning and evening.

Figure 20 – An illustrative demand profile on the Wellington network

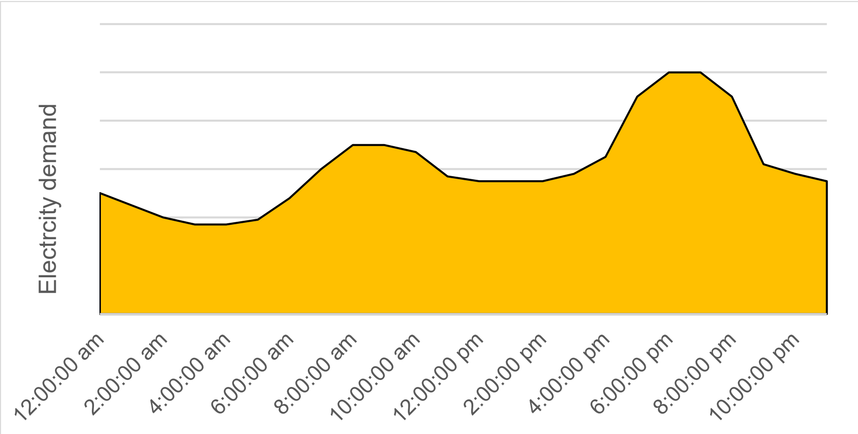
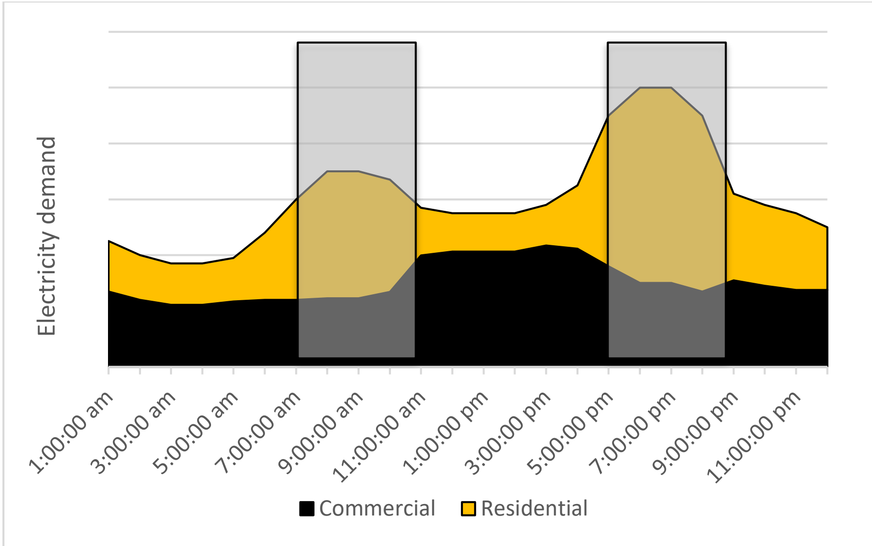


Figure 21 shows the proportion of electricity consumed by the Commercial and Residential customer groups (for illustrative purposes, other minor customers groups have been excluded).

The shaded grey areas are peak demand periods on the network. The Wellington networks peak demand period is between 5pm and 9pm in the evening when residential consumers get home from work and cook dinner and heat their homes. Residential customers consume more peak demand energy (about 70%) than commercial customers (about 30%). Commercial businesses tend to have slowed their energy use by this time. The current pricing methodology which uses peak demand energy use therefore allocates a greater proportion of Transmission costs to residential customers.

Figure 21 – energy demand by customer groups

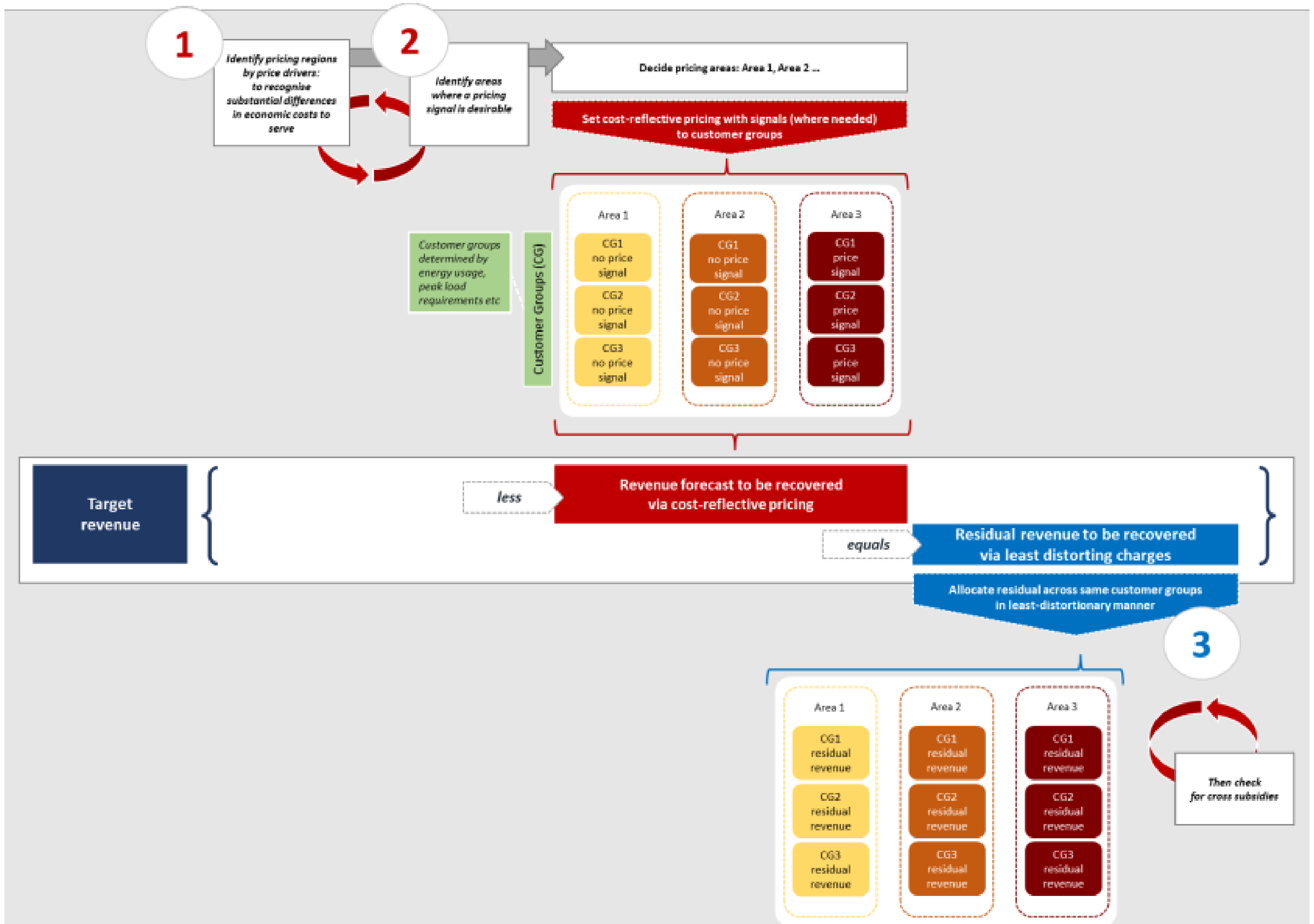


The black shaded are shows total commercial energy use and the yellow shaded area shows total residential energy use. Residential and commercial customers consume about the same proportion of total energy on the Wellington network. While commercial connections consumer more per connection than residential consumers there are fewer connection (30k compared to 140k residential connections) – overall the greater number of lower energy consuming residential connections use about the same overall amount of electricity as commercial consumers. Using total electricity use as a cost driver means Transmission costs are allocated in similar proportions between residential and commercial customers. Changing the TPM cost driver to total electricity consumed therefore increases the proportion of Transmission costs allocated to commercial customers.

6 Appendix C: New Distribution Pricing Methodology

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

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



7 Appendix D: Price structure changes on commercial consumers

The transition impact of Step B (cost-reflective pricing) will result in similar transition impacts as that of the residential category, an increase in smaller commercial users' tariffs and a decrease in large users' tariffs. Step C (Revised Res/Bus allocation) will see an overall shift to revenue collected from commercial users. This change will result in the larger commercial tariffs seeing a greater increase in their total bill.