Pricing Methodology

Prepared 03 March 2023

For the assessment period ending 31 March 2024

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1 Glossary

Abbreviation/Term	Definition or description
2023/24 Disclosure of Prices	Wellington Electricity Lines Limited's Disclosure of Prices
Annual Pricing Setting Compliance Statement	Discloses how much revenue a network can collect and demonstrates that forecast prices are set at a level to collect that revenue.
ACOT	Avoided cost of transmission – an amount payable to large, distributed generators within Wellington Electricity's network in recognition that these generators may cause WELL to avoid Transpower charges. ACOT payments are not included in the new TPM and will not be paid from 1 April 2024.
Capacity	The maximum amount of energy that a part of the network is able to carry at any point in time
Commerce Commission	New Zealand Commerce Commission (NZCC)
Consumer	A person, residential or business, that uses electricity or acquires electricity lines services
Consumer group	The category of consumer used by the Electricity Distribution Business (EDB) for the purpose of setting prices
Controlled load	An amount of electrical load which a consumer makes available to the distributor's load control system to turn off during periods of network congestion or to assist in restoring supply
CPI	Consumer Price Index inflation
CPP	The Commerce Commission sets a price-quality path for each regulated lines company - a price path is the maximum total revenue a lines company can recover from its consumers and the quality path is the minimum level of quality of service that it must provide. A customised price path (CPP) is a unique price-quality path used to deliver a specific programme of work
Delivery price	The total delivery price for both distribution and transmission services (also known as lines charges)
Demand	Electricity use at a point in time
Distributed generator	Any person who owns or operates equipment that is connected to Wellington Electricity Lines Limited's distribution network, including through a consumer installation, which is capable of injecting electricity into the network

Distribution Network	A distribution network is the network of equipment that carries electricity from the high voltage transmission grid to industrial, commercial and domestic users
Distribution pricing practice note	The 2021 distribution pricing practice note 2nd edition 2021 provides guidelines to help distributors interpret and apply the distribution pricing principles. This can be found on the Electricity Authority's website.
DPP	The Commerce Commission sets a price-quality path for each regulated lines company - a price path is the maximum total revenue a lines company can recover from its consumers and the quality path is the minimum level of quality of service that it must provide. A default price path (DPP) is a low cost, standard method of calculating the price-quality path for lines company's not on a CPP
DPP Determination 2020	WELL's current price-quality path, Decision No [2020] NZCC 25, Electricity Distribution Services Default Price-Quality Path (Wellington Electricity transition) Amendments Determination 2020
EDB	An Electricity Distribution Business is an entity that owns and operates an electricity distribution network to provide electricity distribution services
Electricity Authority	The Electricity Authority. The Electricity Authority is an independent Crown entity responsible for the efficient operation of the New Zealand electricity market. It is the electricity market regulator
Electricity distribution services	Electricity distribution services are the conveyance of electricity on lines from the transmission GXP to consumers ICPs
EV	Electric Vehicle
Flexibility Services	Services which use consumer smart devises to move electricity demand away from congested periods on the network.
GXP	A point of supply to Wellington Electricity Lines Limited's distribution network from Transpower's national transmission grid
HV	High Voltage – equipment or supplies at voltages of 11kV, 22kV or 33kV
ICP	An Installation Control Point (ICP) is a physical point of connection on a local network or an embedded network that the distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer
ID Determination 2012	Electricity Distribution Information Disclosure Determination 2012 – consolidated version – 9 December 2021

IM Determination 2012	Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) – 20 May 2020
LFC Regulations	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulation 2004
Lines charges	Refer to Delivery price
LRMC	Long Run Marginal Costs
LV	Low Voltage – equipment or supply at a voltage of 220V single phase or 415V three phase
Network	The electricity distribution network owned by Wellington Electricity Lines Limited for the conveyance of electricity. Network assets include substations, lines, poles, transformers, circuit breakers, switchgear, cabling etc.
Point of connection	A point at which a consumer's fittings interconnect with the Network as described by diagrams as used from time to time by Wellington Electricity Lines Limited
Power factor (PF)	A measure of the ratio of real power to total power of a load. The relationship between real, reactive and total power is as follows: PF = Real Power (kW) / Total Power (kVA) Total Power (kVA = $(kW^2 + kVAr^2)^{0.5}$
Pricing Methodology	Wellington Electricity Lines Limited's Pricing Methodology Disclosure Document
Pricing Principles	The Electricity Authority's updated Distribution Pricing Principles have been provided in "Distribution Pricing: Practice Note", August 2019. This can be found on the Electricity Authority's website.
RAB	Regulated Asset Base – is the regulated value of the distribution assets that Wellington Electricity uses to provide line function services
Regulatory Period	A regulatory period is the period of time that a price-quality path Determination applies to. The Regulatory Period for a DDP is usually five years
Regulatory Year	A regulatory year is the period from 1 April to 31 March
TPM	Transmission Pricing Methodology is the methodology and approach, set by the Electricity Authority and implemented by Transpower, to allocate transmission costs to the user of grid services, including EDBs.
WELL	Wellington Electricity Lines Limited

2 Introduction

Wellington Electricity Lines Limited (**WELL**) owns and operates the electricity distribution network in the Wellington region. We manage the poles, wires and equipment that provide electricity to approximately 400,000 consumers in the Wellington, Porirua, Lower Hutt and Upper Hutt areas. We will be investing $162m between April 2021 to March 2025 (the current regulatory period) on the network to maintain a modern network and to build new capacity to meet Wellingtons growing electricity use.

We are investing around **$162m** in infrastructure on the Wellington network	We provide electricity to over **173,000** households & premises and to over **400,000** people	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.

WELL recovers the cost of owning and operating the network through a combination of standard (published) and non-standard prices for electricity lines services, and capital contributions for new connections. WELL is regulated by the Commerce Commission (**Commission**) and is required to publish its Pricing Methodology used to calculate prices for its electricity lines services. WELL is also regulated by the Electricity Authority (**Authority**), who provides guidance on how network tariffs are derived. This document describes WELL's price setting methodology and outlines how costs are allocated to and recovered from the consumer groups who receive electricity distribution services from the Wellington distribution network for the pricing year commencing 1 April 2023.

3 Regulatory background

WELL is a supplier of electricity distribution lines services and is regulated by:

- The Commission under Part 4 of the Commerce Act 1986 (Part 4); and
- The Authority under the Electricity Industry Act 2010.

3.1 Commerce Act 1986

Under Part 4 of the Commerce Act 1986, the Commission regulates markets where competition is limited, including electricity distribution services. The Commission regulates electricity distribution services in two ways:

1. By ensuring Electricity Distributors Businesses (**EDB**) operating and business performance is transparent. This allows the Commission, stakeholders and the public to judge whether a business is performing. The Commission sets an Information Disclosure Determination which provides the information that EDBs must disclose publicly. This Pricing Methodology is part of that determination.
2. By regulating the price (how much a customer pays for the service) and quality (the level of quality it must provide) to ensure EDB's face incentives and pressures that are similar to those in a workably competitive market. The Commission sets a price-quality path determination which provides how much revenue an EDB can collect (price) and the service quality it must provide.

3.2 Price-quality path determination

WELL is currently on the *Electricity Distribution Services Default Price-Quality Path (Wellington Electricity transition) Amendments Determination 2020* (**DPP Determination 2020**) price-quality path. This price path is for the regulatory period between April 2021 and March 2025. The DPP Determination 2020 regulates two components of WELL's prices: the distribution price component and the pass-through and recoverable price component. The distribution price component recovers the cost of operating the electricity distribution network and providing electricity distribution services. The pass-through and recoverable price component recovers costs that are largely outside WELL's control. These include council rates, levies, transmission costs and other recoverable costs.

At the commencement of each regulatory period, the Commission determines quantum total amount of allowable revenue for WELL to ensure that the business recovers what the Commission determines as a sufficient return on an efficient level of forecast operating and capital expenditure. This is achieved by the computation of "building blocks", whereby the Commission determines the revenue to recover operating expenditure, depreciation and an "industry benchmarked" rate of return on capital employed. Once allowable revenue is determined for each year of the regulatory period, the present value of the revenue is calculated; this present value is then "smoothed" over the regulatory period as forecast net allowable revenue.

The DPP Determination 2020 sets WELL's forecast net allowable revenue from distribution prices for each year of the current regulatory period. A mechanism at the end of each pricing year allows for any differences between allowable revenue and actual revenue to be washed up in subsequent years with a time value of money adjustment.

Pass-through price components recover the actual pass-through and recoverable costs that WELL incurs. A mechanism at the end of each pricing year allows for any differences between pass-through and recoverable costs and pass-through price revenues to be washed up in subsequent years with a time value of money adjustment.

The prices provided in this Pricing Methodology are compliant with WELL's regulatory DPP Determination 2020 for the 2023 Assessment Period, i.e. the year commencing 1 April 2023.

3.3 ID Determination 2012

WELL is also subject to information disclosure regulation under Part 4[1]of the Commerce Act 1986. The purpose of this regulation is to ensure that sufficient information is readily available to interested persons to assess whether the purpose of Part 4 of the Act is being met. As a result, WELL must make disclosures under the ID Determination 2012, including publicly disclosing its Pricing Methodology before the start of each disclosure year commencing 1 April. The requirements of the ID Determination 2012 relating to pricing methodologies are set out in Appendix A.

3.4 Authority's price reform

The Authority is reforming prices for transmission and distribution services. Note, the price reform is for methods used to calculate the unit tariffs which pass costs on to customers – not the total amount of revenue that is allowed to be collected (which is provided by the Commerce Act 1986 and is the responsibility of the Commission).

[1] Section 54F of the *Commerce Act 1986*

The intent of the 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, 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 increases electricity demand and future investment requirements. The Authority have:

- 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.

- Provided updated Pricing Principles and a new Pricing Methodology for distribution services.

3.4.1 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 of the Authority's and Transpower's websites respectively. The change in approach has resulted in material changes to EDB tariffs. 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

These changes will apply from 1 April 2023. This Pricing Methodology provides the new Transmission cost allocation methodology.

3.4.2 Distribution Pricing Principles 2019

The Authority's Distribution Pricing Principles 2019 provides voluntary pricing principles for EDBs to use when developing their tariff structures. The Authority have also provided the Distribution Pricing Practice Note to help distributors interpret and apply the distribution pricing principles. In accordance with the ID Determination 2012, we demonstrate WELL's pricing methods are consistent with the Pricing Principles in Appendix B.

The Authority also provide an annual scorecard assessment of how well an EDBs prices reflect the pricing principles and are reflective of the underlying costs of providing distribution services.

3.5 Other regulatory requirements

Other regulatory requirements directly applicable to this pricing methodology are:

- The LFC Regulations - these require EDBs to offer a pricing plan to residential consumers who use less than 8,000kWh per annum (called low users). The pricing plan has a fixed daily price. Other variable charges must be set so that residential low users are no worse off than residential standard users when consumption is at 8,000kWh per annum. 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.
- Schedule 6.4 of Part 6 of the Electricity Code sets out pricing principles for distributed generation.

3.6 Related pricing documents

In addition to this Pricing Methodology disclosure document, the following documents support WELL's prices and price setting process - they can all be found on WELL's website:[2]

Document	Purpose
Annual Compliance Statement	Confirms that WELL has met its revenue and quality expectations set out by the price-quality path.
Annual Price Setting Compliance Statement	Confirms that WELL's forecast prices have been set at a level to collect the allowances determined by the price–quality path set by the Commission.
Customer Contributions Policy[3]	WELL collects revenue from its (1) on-going tariffs or from (2) customer contributions toward new connections. The Customer Contribution Policy is a regulatory disclosure which sets out how WELL calculates a customer's contribution towards a new connection.
Network Pricing Schedule	The Network Pricing Schedule provides Retailers with WELL's network lines charges and the terms and conditions of their application. Specifically, the Network Pricing Schedule provides: (a) Pricing structure; (b) Pricing categories, and the eligibility criteria for each price category; (c) Price options (if any); and (d) Unit prices.
Disclosure of Prices	The Disclosure of Prices provides stakeholders (consumers, retailers and regulators) with prices and any price changes for the upcoming regulatory year. The Disclosure of Prices is a regulatory Information Disclosure requirement.
Line Charge Notice	The Line Charge Notice provides WELL's tariffs for the upcoming regulatory year. WELL publishes the Line Charge Notice in the Dominion Post newspaper, on news website Stuff and on WELLs own website.
Pricing Roadmap	The Pricing Roadmap updates stakeholders about WELL's plans for future changes to pricing structures and/or prices, together with expected timeframes and progress updates.

4 Pricing Roadmap and future pricing

Our Pricing Roadmap provides a close look at our future pricing plans, including our transition to prices which are more cost reflective. 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 climate change related electricity demand (from the electrification of transportation and gas appliances). Participating consumers will be rewarded with cheaper prices and will help keep prices lower for everybody in the long term (lower than they would be if peak demand wasn't reduced, and we had to build more capacity). These new prices will complement our Time of Use (ToU) prices we introduced in 2020.

[2] Available at: www.welectricity.co.nz/disclosures/pricing
[3] Available at: www.welectricity.co.nz/disclosures/customer-contributions/

4.1 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 lines charges (for those who move their energy consumption to off peak periods) and the long-term benefits of lower prices through avoiding or delaying network re-enforcement.

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

Our pricing programme is informed by:

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

4.2 Updated pricing approach

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

Applying the principles requires a new approach to pricing, an approach which first sets a price signal which reflects the cost of using electricity during peak congestion periods, and then recovers any residual costs in a way that doesn't influence consumers energy use behaviours (i.e. the peak demand price signal already signals the future cost of using energy during peak demand periods and no further price signals are needed. The remaining revenue should then be collected in a way that minimises any volatility from changes in consumer energy use habits, generally by using fixed charges). This differs from the past pricing approach which allocated costs to consumer groups using cost drivers, and then applied price signals that reflect the cost of using energy's during peak demand periods. Appendix C illustrates the new pricing approach – this diagram is sourced from the 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.

4.3 Review of pricing structure

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.

4.3.1 Retailer consultation

In November 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 so as to avoid customer price shock. 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 from 1 April 2024.

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4.4 Proposed future price 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.

4.4.1 Residential price structures

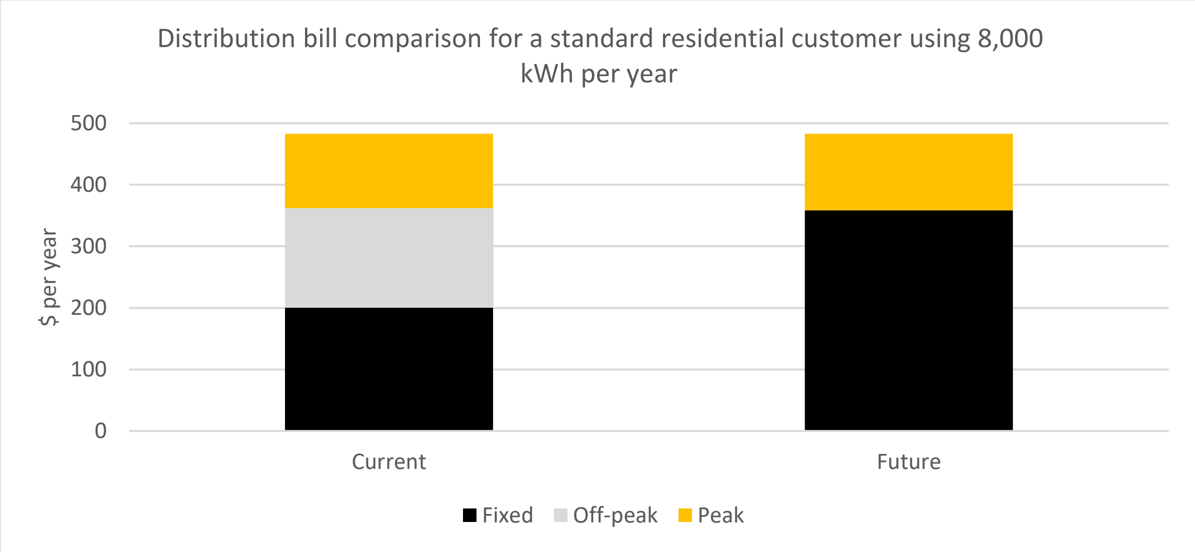
Our residential price structures assume the removal of the current low fixed charge regulations which currently stop the implementation of cost reflective prices.

Our prices will use different price signals depending on the type of prices and behavioural changes being targeted. This includes 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 1 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 1 – 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.

ToU is the best-fit for now for smaller consumers; ToU is effective because it:

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

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

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

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

We are proposing to compliment ToU prices with discounts for "appliances" that can be controlled to further manage network load. This is well established for hot water heating – a storage load that can be managed with minimal customer impact. Remote management allows staggered restoration to avoid risk of post-control peak. The same approach is attractive for electric vehicles (**EV**). Because it's a storage technology (using the EV

[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.

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

Figure 2 summarises the proposed structures for residential consumers. The figure also provides the reasons the price component was selected.

Figure 2 – 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

4.4.2 Proposed non-residential price structures

The review of our commercial price structures also provides an opportunity to simplify the current structure which has many different price categories.

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)

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

Figure 3 summaries our proposed non-residential price structures.

Figure 3 – 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). - 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 - 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
	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 <u>connections</u> greater than 300 kVA. Therefore, we are	- 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
	proposing no distinction between those with dedicated transformers and those connected to low voltage network for the medium price category.	
	Large non-residential users Current hypothesis is to apply coincident peak demand charge. - Separate prices for dedicated transformer and low voltage connections – as they have different long run marginal costs - Simplify the number of pricing components - Still considering the current power factor charge	- Largest users *may* be energy intensive (and sophisticated) enough to manage a coincident peak demand charge - Remove fixed daily charges and any time variable prices as they are no longer needed
Residual cost allocation and recovery	**Energy-based cost allocation** - Allocate total costs between residential and business consumer groups using energy (GWh) as allocator. - Cross-check against robust subsidy-free analysis. Apply fixed prices: - Small users – a fixed daily charge - Medium users - a fixed charge based on connected capacity - Large users - a fixed charge based on connected capacity	- Least distortional impact on energy use behaviours - A daily fixed fee for small users because there is not a range of different connections sizes - A fixed charge based on capacity for medium and large users will allow us to reduce the number of price categories and remove the current price steps between categories. - It also reflects that larger user should pay more because they are using a larger share of the network

The new price structures will continue to include direct agreements and individual tariffs for 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.

4.4.3 Consumer impact

The new price structures will impact prices in multiple ways. Figure 4 summaries the key effects.

Figure 4 – 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

Change	Effect
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.

The retailer consultation provided a more detailed analysis of the customer impact of the changes.

4.4.4 Proposed transition rules

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.

4.4.5 Next steps

We consulted with retailers in November 2022 on the overall price structures. We will be considering feedback and responding to retailers with changes to the proposed structures shortly. We also have some more thinking to do on the structures for large commercial customers. The next steps are:

1. Respond to retailer consultation feedback (from November consultation) and provide any refinements to the price structures (Q1 2023)
2. Consult on a refined structure for large commercial customers (Q2 2023)
3. Strat the transition to the new pricing structures (1 April 2024)

4.5 Progress against roadmap

In 2017 WELL published a Pricing Roadmap which outlined how we are developing our prices. We refresh the roadmap as our pricing strategy develops and as we learn from the implementation of the Roadmap workstreams. Progress against the roadmap is provided in Appendix D.

Figure 5**Error! Reference source not found.** provides a summary of the pricing programmes for each consumer group. The figure provides an assessment of the impact that each consumer group has on peak demand and the pricing programmes that WELL is implementing to reduce that demand. The roadmap initially focused on Electric Vehicle (EV) owners and residential consumers as the main potential contributors to peak demand and therefore the greatest driver for the need to re-enforce the network.

Figure 5 – Summary of progress on the Pricing Roadmap

Development | Implementation

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

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

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

network means that prices can be kept low. Learn more about ToU prices at: https://www.welectricity.co.nz/disclosures/pricing/time-of-use-pricing/

4.6 This year's pricing programme

The focus of this year's programme is to finalise our new pricing structures. We will consult for the second time with retailers, focusing on prices for large commercial customers. To support the new price structure and to support the development of flexibility services, we are also implementing a new LRMC calculation methodology that was developed in 2022 and we are developing a commercial framework for residential flexibility services. We will also be encouraging retailers to continue to develop their billing processes and practices so that more consumers are billed using TOU prices.

4.6.1 Consultation on new pricing structures

This year we will finalise our future pricing structures. In November we consulted with retailers on our new price structures and we are currently considering feedback. We will be responding to retailers in Q1 this year, highlighting any changes we have made to our proposed pricing structures. We will also be consulting again with retailers, focusing on price structures for large commercial customers. We plan to consult Q2 2023.

4.6.2 Long run marginal cost calculation methodology

In 2022 we implemented a review of our LRMC methodology which we use to set the strength of our price signals. We 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 6 provides our assessment of the two methodologies. We prefer the perturbation method as it provides a more accurate price signal.

Figure 6 – selection of a LRMC methodology

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

4.6.2.1 Commercial framework for residential flexibility services

We are partnering with Orion to develop and trial flexibility services for residential customers – services that use customer smart devises (like EV chargers) to shift electricity use away from busy periods on the network. We will be working with flexibility providers to trail managed services in 2023. We will also consider new tariffs to support these services. The most likely focus of the trials will be managing how electric vehicles charge and how we can avoid charging during peak demand periods on the network.

As part of the work program to develop and trial residential flexibility services with Orion, we will also be developing a commercial framework for those services. We are getting expert advice on developing an overarching framework and different pricing options.

Prices for flexibility services will work closely with our distribution service tariffs. Flexibility services that are procured to solve a specific network issue (like a capacity constraint on a section of the low voltage network) will be based on avoided cost related to that specific network issue (short run marginal costs). Network tariffs based on an enduring, networkwide price signal, encouraging all network users to avoid using electricity during the networks peak demand periods. The network tariffs price signal is based on the long run marginal cost for the whole network.

4.6.2.2 Combining EVB and residential ToU prices

WELL will consider simplifying the pricing structure by removing EVB prices once we are ready to offer the new managed EV and battery changing service. WELL expects that the new service will provide a comparable replacement to the current EVB prices.

4.6.2.3 Continue to transition from low fixed charge restrictions

The government made legislative changes in 2021 to remove the low fixed charge regulations. The transition is over five years to reduce any price shocks to consumers. We made the second step in the transition this year, increasing the daily fixed charge of residential low users from 30 cents to 45 cents. A corresponding decrease in the variable price component was also made.

4.6.2.4 Encourage retailers to support ToU prices

We have offered retailers exemptions from applying ToU if their billing systems and processes cannot provided the consumption data needed to apply peak and off-peak prices. Only 40% of consumers are being charged peak and off-peak process. This year we will encourage retailers to continue to develop their processes so that ToU tariff can be applied as intended. We will consider applying higher prices to those who continue to apply the alternative anytime variable and all inclusive prices from 1 April 2024.

4.7 Electricity Authority's pricing scorecard

The Electricity Authority make an annual assessment about how cost reflective a distribution networks tariffs are. The Authority makes the assessment using a scorecard of different pricing attributes.

Figure 7**Error! Reference source not found.** summarises the 2021 assessment (the last assessment before the Authority delayed scorecard assessments for a year) and the changes that have resulted in the improved score. We had the second highest scorecard score in the last assessment.

Figure 7 - Pricing scorecard assessment

Scorecard category	Score		Improvement made and work programmes updates
	2020	2021	
Description of network demand characteristics	2	5	A detailed description of the network capacity constraints and demand characteristics was provided in the updated roadmap. The description included the impact of the climate change actions on network demand.
Meets pricing principles	3	3	An updated pricing principles assessment has been included in this Pricing Methodology update.
Pricing strategy	2	4	Revised pricing strategy was included in the 2021 roadmap. The strategy focused on developing demand management tools in response to the expected increase in demand from the climate change actions.
Roadmap	2	5	Updated roadmap reflecting the Authorities new pricing methodology.
Peak pricing signal	2	3	A new commercial framework for calculating price signals – includes a more accurate LRMC calculation for network wide tariffs and a short run marginal cost of procuring flexibility services in response to specific network constraints. The framework will be applied from 1 April 2024. The low fixed user restrictions will mean we will have to transition to the new price signals.
Customer impact	2	3	WELL consults with retailers about all price structure changes. The consultations include a customer impact analysis. See section 7.6.1 for retailer consultation and customer impact analysis for recent price structure changes. WELL has also adopted an approach of transitioning changes that create price shocks. While this delays the implementation of some changes, it limits the impact of changes to customers. We also consider the impact to those in energy poverty. WELL consulted with retailers on whether to transition prices and they agreed it was sensible.
Overall (average)	2.2	3.8	

The 2021 scorecard assessment also provided feedback on areas of improvement. Our Pricing Roadmap provides a summary of how our pricing work programme is addressing the feedback.

The Pricing Roadmap also provides a self-assessment against the revised scorecard categories and weighting that were released by the Authority last year[5]. The Roadmap has been updated to include the new focus areas the Authority have included in the revised assessment. Figure 8 provides a summary of the Authorities new areas of focus and WELL's current approach to those subjects.

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

Figure 8 – WELL's approach and progress on the new 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. The Roadmap also provides an overview of the flexibility trials we will be implement this year and 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. Section 6.2.2.1 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 pass-through of new transmission charges	WELL is applying the Authority's guidance on passing-through transmission charges. Our application methodology is provided in section 6.3.2 of this Pricing Methodology. Note, the changes have resulted in large price increases for some commercial customers. We have chosen to smooth the changes over time. 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. 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. We will start to transition to the new price structures from 1 April 2024, after we have completed retailer consultation.

5 This year's pricing structure changes

The key change to price structure this regulatory year is the application of the Authority's new TPM. We have also retained the 2021 ToU pricing structure changes in this disclosure to assist consumers still transiting to using ToU prices. This reflects there are still 55% of residential customers with communicating smart meters who are not using the peak and off peak ToU pricing.

The proposed new pricing structure for distribution services that we are currently refining with stakeholder feedback, will result in new price structures (a simplified peak and fixed pricing comments) a different cost of supply model (allocating costs by energy used rather than using a selection of different cost drivers) and refined price signals (set using a more accurate LRMC methodology). We will update this Pricing Methodology with the new framework once we start the transition 1 April 2024.

5.1 Applying the TPM changes

In November 2022 we notified retailers of the change in methodology used to allocate transmission costs and the impact that the changes would have on customers. We also provided transition rules we are applying which smooths the transition over time and limits the size of price shocks. The Pricing Notice included a customer impact analysis and our response to questions.

The key changes include:

- A change in how Transpower classifies its costs and allocates them to grid customers. This has resulted in a reduction in the total transmission cost allocated to the Wellington network.
- A change in how costs are allocated to customers. We have used guidance from the Authority to develop a transmission cost allocation methodology
- The removal of ACOT payments

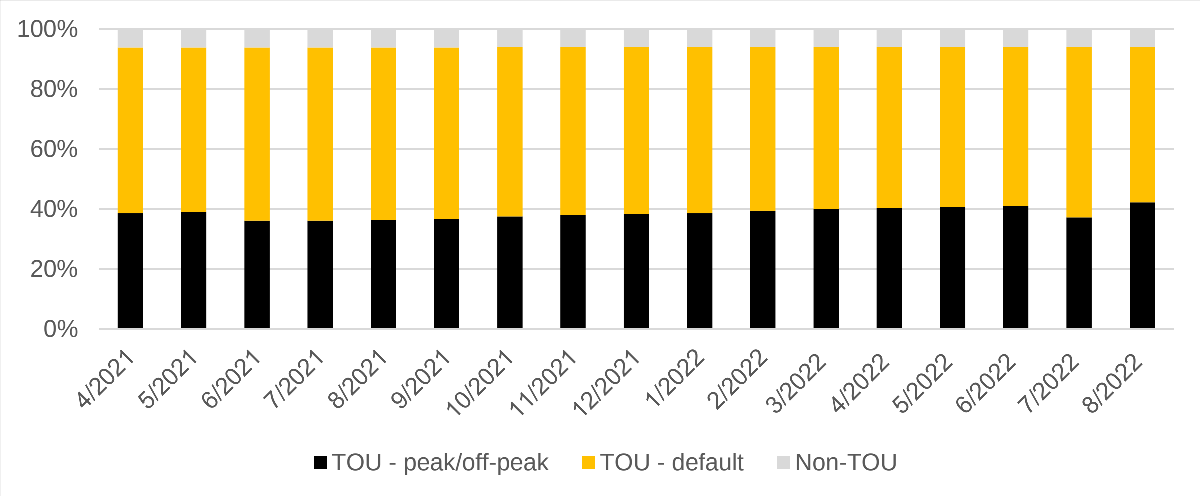
This Pricing Methodology has been updated to include the change in the classification of transmission cost, the removal of ACOT payments and the change in cost allocation methodology.

5.2 Transition to residential ToU prices

In 2021 WELL 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 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 9 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. This year we will be encouraging retailers to update their systems and processes to apply ToU prices as intended. We are considering whether to apply higher prices to those who don't next year.

Figure 9 - ToU uptake



We have retained last year's ToU pricing structure changes in this disclosure of to assist consumers still transiting to using ToU prices. Our website provides useful tools and guidance on how to benefits from the new prices: https://www.welectricity.co.nz/disclosures/pricing/time-of-use-pricing/.

5.2.1 Residential ToU prices

ToU prices were applied to all residential consumers from 1 April 2021.

5.2.2 Eligibility criteria

Alternative prices are available for meters that cannot provide the half hour data needed to calculate ToU prices. The alternative prices reflect previous current anytime variable and all inclusive price structure. The eligibility for the 'alternative pricing', are:

- Consumers who do not have communicating smart meters that record consumption data in 30 minute time periods needed to calculate ToU prices.
- ICPs with intermittent or stopped communications,
- Retailers who do not have smart meter agreements with meter providers,
- Retailers who need validation process and billing system upgrades to process half hour consumption data needed to calculate ToU prices.

Details of the eligibility criteria are provided in the Network Pricing Schedule which can be found on WELL's website. WELL does expect that retailers will correct issues which prevent data being provided in half hour increments. In time, only those ICPs who do not have communicating smart meters will be exempt from ToU prices.

5.2.2.1 Pricing categories

The final price categories are provided Network Pricing Schedule which can be found on WELL's website.

5.2.2.2 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 10.

Figure 10 - ToU price structure

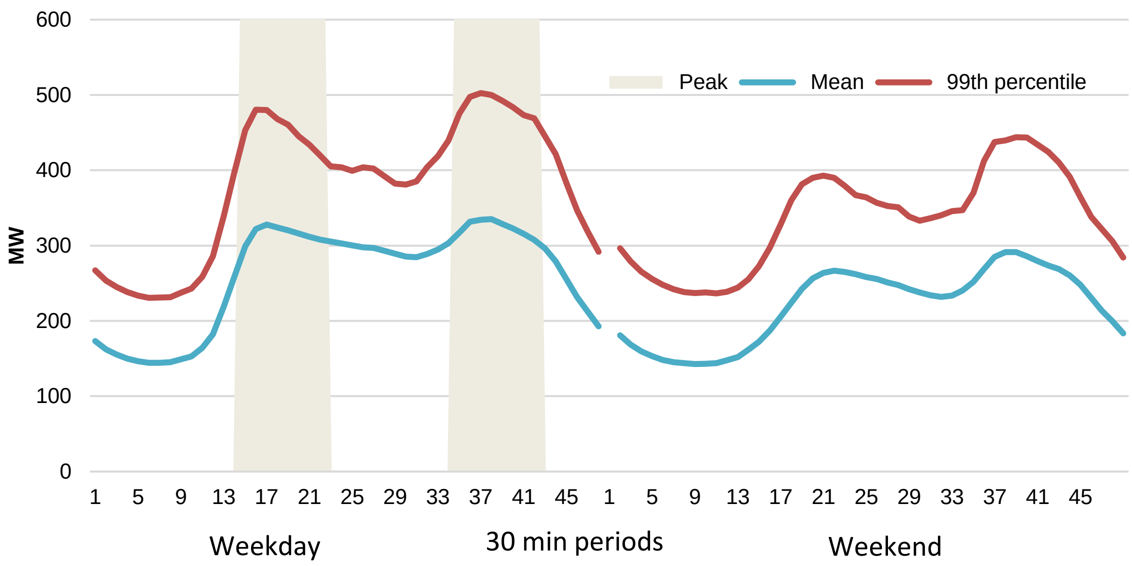
Design parameter	Industry standard?	Approach	Comment
Hourly Pattern	Y	AM peak = 7 to 11 PM peak = 5 to 9 No shoulder	A shoulder period has not been included as consumers changing their 'discretionary' load are most likely to do this using timers on appliances (e.g. EV charging, or dishwashers) and are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

Figure 11 below illustrates the residential ToU pricing structure.

Figure 11 – Residential ToU pricing structure

Figure 12 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 12 - Illustrating the peak pricing period's alignment with peak demand



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

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

Residential ToU prices and their eligibility criteria are provided in the Network Pricing Schedule along with all of WELL's prices. The Network Pricing Schedule can be found on WELL's website www.welectricity.co.nz/disclosures/pricing/.

6 Setting prices for the 2023/24 regulatory year

The objective of WELL's pricing methodology is to develop electricity distribution prices that:

- Are cost reflective – better signalling to consumers the impact of their usage on future expenditure;
- Are consumer and retailer centric, such that prices:
    - Are logical and simple to understand;
    - Allow consumers to manage their usage and bills;

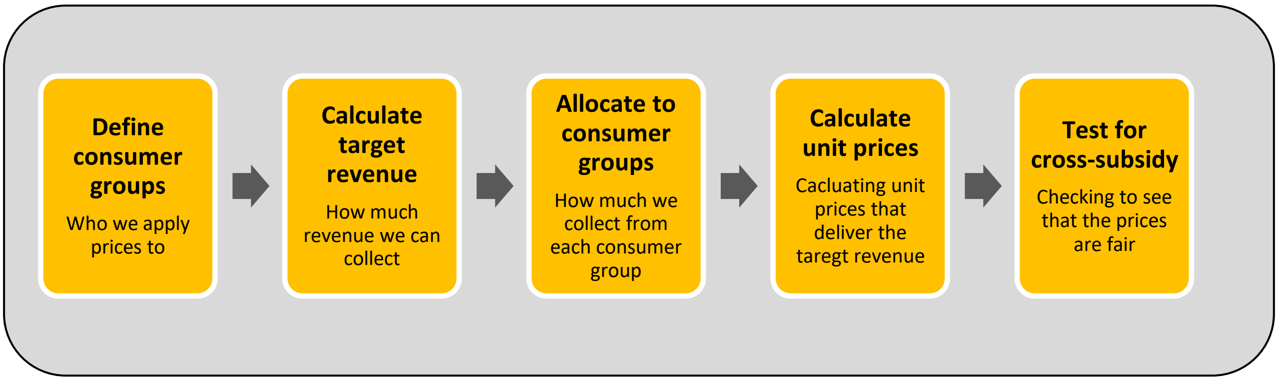
  - Can be passed on transparently by retailers
- Minimise revenue volatility and under-recovery;
- Seek to reduce price shock to consumers;
- Are forward looking, being robust to changes in technology and regulation;
- Are practical and achievable to implement within the next 1-5 years; and
- Are not inconsistent with pricing structures used by other EDBs.

WELL's price setting process is described in Figure 13. Each step is described in detail in the following section of this chapter. The Pricing Methodology starts with defining the consumer groups that WELL will apply different prices to. WELL then calculates how much overall revenue it will collect from prices. The revenue calculation is determined by the Commission and provided in the 2020 DPP Determination.

WELL uses a cost of supply model to allocate revenue to each consumer group based on how much it costs to provide distribution services to each consumer group. In parallel, unit prices (tariffs) are calculated to deliver the target revenue. The calculation includes the impact of any forecast volume changes. The revenue from the cost of supply model is then compared to revenue from prices to check that they are approximability the same. If they are not, unit prices are adjusted. This ensures unit prices are reflective of the costs to provide services.

Lastly, WELL checks that there is no cross-subsidisation between customer groups – that costs are allocated equitably between groups. This is done by testing whether revenue from prices for each consumer group falls within the subsidy free range – that revenue from prices is less than the stand-alone cost (it's not better for consumers to receive services from another source) and greater than the avoidable cost (another consumer group isn't subsidising the direct costs of providing the service).

Figure 13 - The Price setting process



6.1 Define consumer groups

This section sets out the rationale and criteria for our consumer groups.

6.1.1 Defining consumer groups

WELL has adopted the following consumer groups for pricing purposes:

- Standard contracts:
  - Residential Low User Time of Use (RLUTOU);
  - Residential Standard User Time of Use (RSUTOU);
  - Residential Low User (RLU);
  - Residential Standard User (RSU);
  - Residential Low User EV and Battery Storage (RLUEVB);

- Residential Standard User EV and Battery Storage (RSUEVB);
- General Low Voltage Connection (GLV);
- General Transformer Connection (GTX); and
- Unmetered (G).

- Non-standard contracts.

Consumers are grouped by voltage level connection, end use, and their utilisation of electricity assets. As an example, the General Transformer Connection group does not make use of the low voltage (LV) reticulation network, as it connects directly to the high voltage network via a dedicated transformer.

Our Price Schedule (called Wellington Electricity Lines Charges Notice from 1 April 2023) sets out prices for the 2023/24 year for the standard contract consumer groups. Non-standard contract consumer groups are notified directly of their pricing.

The criteria used by WELL to allocate consumers to consumer groups is as follows:

6.1.1.1 Residential (including EVB and Time of Use)

The Residential consumer groups are consistent with the definition of "Domestic consumer" in the Low Fixed Charge Regulations, where the primary use of the point of connection is a home not normally used for any business activity. Consumers in these groups almost exclusively are connected to the LV Network, place similar capacity demands on the network, and can use night boost[6] and controlled[7] tariffs, provided they have the required metering, dedicated interruptible load and meet other eligibility criteria.

WELL has three types of residential prices – (1) ToU prices that signal peak congestion periods, (2) an alternative price for residential consumers who do not have meters that can provide the data to calculate ToU prices and (3) ToU prices for EV and battery consumers. Each of the three types of prices has a low user and standard user variant, resulting in six residential price categories in total. Figure 14 provides the residential price categories.

Figure 14 - The residential price categories

Price category	**Price category code**	**Purpose**
Residential Low User Time of Use	RLUTOU	ToU prices signal peak and off peak periods of network demand. These are our standard residential consumer prices that most residential consumers will be on. Lower off peak prices encourage consumers to use energy away from the more expensive peak periods. Consumers who move their energy use away from peak periods will benefit from lower prices.
Residential Standard User Time of Use	RSUTOU	
Residential Low User	RLU	Alternative prices for consumers that do not have meters that can provide the half hour data needed to calculate ToU prices. We estimate that about 10% of consumers will need these price categories.
Residential Standard User	RSU	

[6] Night boost is a separately metered supply to permanently wired appliances, such as night store heaters, which are switched on and off at specific times. Night boost supply will be switched on during the night period (11pm to 7am) and for a minimum two hour boost period during the day (generally between 1pm to 3pm). Customers on EVB plans are not eligible for night boost pricing.

[7] A controlled supply is a supply that allows WELL to control energy supply to permanently wired appliances, such as hot water cylinders. The load control associated with a controlled supply is not operated based on specific daily times.

Price category	Price category code	Purpose
Residential Low User Electric Vehicle & Battery Storage	RLUEVB	These price categories are legacy ToU prices for Electric Vehicle and Battery consumers. These prices operate in the same way as the ToU prices but have different price levels. In the future we expect to combine these prices with residential ToU prices and offer an alternative manage charging price for EV and Battery consumers at a similar price level as the current EV and Battery ToU prices.
Residential Standard User Electric Vehicle & Battery Storage	RSUEVB	

A low user (Residential Low User, Residential Low User Electric Vehicle and Battery and Residential Low User Time of Use) is a residential consumer who consumes less than 8,000 kWh per year and who is on a low fixed charge retail pricing plan. The Low Fixed Charge Regulations require electricity distribution businesses (EDB's) to offer a pricing plan to domestic low users with a fixed price of no more than 45 cents per day. The low fixed user restrictions are being removed over a five-year period. Prices will increase from 30c to 45c per day from 1 April 2023. Low fixed prices will increase by 15 cents per day each year until 1 April 2027, when Low Fixed Charge Regulations are removed. An accompanying decrease in variable prices is also applied to each increase in fixed prices.

A standard user (Residential Standard User, Residential Standard User Electric Vehicle and Battery and Residential Standard User Time of Use) is a residential consumer who consumes more than 8,000 kWh per year.

Time of Use prices (Residential Low User Time of Use and Residential Standard User Time of Use) apply to all residential consumers – these are our primary residential price category's. Time of Use prices provide consumers with the opportunity to save money by changing when they use energy to less congested period of the day. To be eligible for Time of Use, a consumer must be a residential consumer as defined in WELL's Network Pricing Schedule. A consumer must also have an advanced meter with reliable communication (AMI meters that provide usage in half hour increments). This is required to allow different prices to be applied to different times of the day.

Consumers who do not have an advanced meter with reliable communication are eligible for the alternative Residential Low User and Residential Standard default price categories. These alternative prices do not need data in half hour increments. See the Network Pricing Schedule for details around eligibility for the different residential prices.

The Time of Use category will enable a wider range of consumers to save money if they move their energy use to off peak periods of the day[8]. Managing congestion on the Wellington network supports the electrification of New Zealand's vehicle fleet and industrial processes – essential steps to achieving New Zealand's zero carbon targets.

WELL will continue to offer EVB pricing to EV and Battery consumers. When EV prices were introduced in 2016, the unit rates were set lower than would normally be available to consumers with Uncontrolled or All-inclusive metering configurations. The lower rate was intended to help support the introduction of what was at the time was a relatively new technology by partially offsetting the high purchase price of EVs.

Only private owners of Electric Vehicles (EV) with a battery capacity of 12kWh and above and/or household battery systems of 4kWh capacity and above, who also have a smart meter, are eligible for the EV and battery price plans RLUEVB and RSUEVB. For electric vehicle eligibility, only private PHEV and private registered EVs

[8] This assumes that a consumer uses a retailer that offers Time of Use prices.

qualify for this plan. Scooters or bikes do not qualify. RLUEVB and RSUEVB are optional plans and consumers can choose the Residential ToU price categories.

WELL is trialling new technology to allow the charging of EV's to be managed when the network is congested and will consider new prices for this service in the future for consumers with EV's.

6.1.1.2 General Low Voltage Connection

The General Low Voltage Connection group is connected to the LV network with a connection capacity of up to 1500kVA, where the premises are a non-residential site used for business activity (e.g. a shop or a farm).

6.1.1.3 General Transformer Connection

The General Transformer Connection group includes consumers who receive supply from a transformer, owned by WELL and dedicated to supplying a single consumer, where the premises is a non-residential site used for business activity.

6.1.1.4 Voltage and asset distinctions

Figure 15 depicts the relationship between consumer groups, load and asset utilisation characteristics.

Figure 15 – Consumer group and load characteristics

Connection asset characteristics	**Unmetered**	**Residential**	**General Low Voltage**	**General Transformer**	**Non-Standard**
<1kVA	✓				
<=15kVA		✓	✓	✓	
>15kVA & <=69kVA			✓	✓	
>69kVA & <=138kVA			✓	✓	
>138kVA & <=300kVA			✓	✓	
>300kVA & <=1500kVA			✓	✓	
>1500kVA				✓	✓
Low voltage	✓	✓	✓	✓	
Transformer	✓	✓	✓	✓	✓
High voltage				✓	✓
Dedicated assets	✓[9]			✓[10]	✓[11]

[9] Streetlight circuits
[10] Transformers
[11] Dedicated network assets

6.1.1.5 Non-standard contracts

The non-standard contracts group is made up of consumers who have atypical connection characteristics. For non-standard consumers, a confidential agreement exists between WELL and the individual consumer which sets out the terms and conditions for the supply of the electricity lines services including the price.

In accordance with its Customer Contributions Policy[12], WELL uses the following criteria to determine if a non-standard contract is appropriate:

- The consumer represents an unusual credit risk; or
- The consumer wants to reserve future network capacity; or
- There are unusual asset ownership or demarcation issues; or
- The consumer and/or WELL wishes to contract for additional services not covered in standard contracts; or
- The site to be connected has unusual locational or security issues; or
- Any other unusual circumstances that WELL, at its discretion, considers warranting the use of a non-standard rather than standard contract.

6.1.1.6 Unmetered

The Unmetered consumer group includes consumers who do not have any metering because the cost of metering is prohibitive relative to their consumption. This includes streetlights, bus shelters, traffic lights etc.

6.2 Calculate target revenue

The target revenue for the 2023/24 pricing year is $146.6 million, reflecting the revenue WELL expects to earn from the provision of electricity lines services, based on prices that will apply for the period. Target revenue is determined by the DPP Determination 2020 and is disclosed before each regulatory year starts in a networks Annual Pricing Setting Compliance Statement. The Annual Pricing Setting Compliance Statement outline the amount which WELL can collect through prices to cover costs and to provide the allowable return on investment. Figure 16 summarises the components of WELL's target revenue. The Annual Pricing Setting Compliance Statement can be found on our website at https://www.welectricity.co.nz/disclosures/pricing/

Figure 16 – Key cost components to fund the provision of electricity line services[13]

[12] Available at: www.welectricity.co.nz/disclosures/customer-contributions/

[13] Sourced from WELL's forecasts and notifications

Components	2023/24 ($m)
Operating expenditure	38.0
Depreciation[14]	34.3
Return on capital[15]	22.5
Transpower charges	50.0
Other recoverable costs	(2.6)
Pass-through costs	4.4
Target revenue	146.6

6.2.1 Cost components

WELL uses the Input Methodologies[16] to determine total the target revenue in each disclosure year. The following figure describes the cost components of target revenue.

Figure 17 – Key cost components to cover provision of electricity line services

Cost component	Description
Operating expenditure	Operating expenditure includes forecast costs associated with operating and maintaining the network and managing day to day business activities. Operating expenditure is provided by the DPP determination.
Depreciation	Reduction in the value of WELL's asset base over time, due in particular to wear and tear. Depreciation is provided by the DPP determination.
Return on capital	A pre-tax return on WELL's regulatory asset base. Return on capital is provided by the DPP determination.
Transpower charges	Charges payable to the national electricity grid operator, Transpower, to transport energy from generators to WELL's network. This includes connection charges, benefit based chargers, residual charges and other transmission provisions. WELL passes these charges onto its consumers at cost.
Other recoverable costs	Other recoverable costs include the recovery of capex wash up adjustments, incentives and pass-through balances, as allowed under the DPP.

14 Regulatory depreciation
15 Including tax, revaluations and inflation smoothing
16 IM Determination 2012

Cost component	Description
Pass-through costs	This includes local council rates, Commerce Commission levies, Electricity Authority levies and Utilities Disputes Limited levies. WELL passes on these charges to consumers at cost.

6.2.2 Relationship with the Customer Capital Contribution policy

WELL's standard and non-standard tariffs recover the cost of operating the existing distribution network. The costs to operate the distribution network include on-going maintenance costs, the cost to replace aging assets, electricity power restoration, business and network support costs and vegetation management. Tariffs also fund building new network capacity to support new connections and increasing customer demand. These costs are for assets and services that many customers benefit from and therefore are shared across customers.

The cost of a new customer connecting to the network or customers altering their existing services, are funded by either (or a combination of) tariff and upfront customer capital contribution. These costs are for assets that only the connecting customer, or the customer altering their existing connection benefit from. The cost of connecting to the network or altering existing services is the capital cost of designing and installing the new connection assets or any new assets needed to adjust a customer's existing services. Figure 18 summarises how distribution service costs are recovered.

Figure 18 – how distribution service costs are recovered

Distribution service costs	Costs are recovered by:
Costs to operate the existing network, including maintenance, vegetation management, asset replacement, service interruptions and emergency responses, system interruptions, network and business support.	Tariffs
The costs of building new capacity to allow future customers to connect and to deliver increasing electricity demand	Tariffs
Capital costs to connect to the network and costs to relocate network assets at a customer's request	Customer capital contribution and/or tariffs

A customer capital contribution payment is a one-off payment made at the start of a project and is used to directly fund capital works. The rules (the Input Methodologies), used to calculate the on-going allowances a network has to fund the operation of a network, require that the customer capital contributions are excluded from the allowance calculation. This reflects the customer rather than WELL has funded some or all of the capital costs of connecting. This also means that the customer capital contribution is excluded from tariffs, ensuring the assets are not paid for twice.

Practically, customer capital contributions are excluded from allowances by subtracting the contributions from the value of the assets added to the Regulatory Asset Based (RAB). The RAB records the value of the assets that WELL has invested in and is used to calculate the allowances that a distribution network operator is provided to recover the cost of purchasing the assets and the return for making that investment. Excluding customer capital contributions from the RAB ensures a customer's investment is not included in the revenue used to set tariffs. i.e. ensuring the costs of the assets funded directly by customers are not included in the overall target revenue provided in this section and those costs are excluded from tariffs.

EDB's are required to disclose its methodologies for calculating customer capital contributions. WELL's Customer Contribution Policy can be found at https://www.welectricity.co.nz/disclosures/customer-contributions/

6.2.2.1 Avoiding first mover disadvantages when connecting to the network

An area of pricing focus for the Authority and part of the revised scorecard assessment is for EDB's to response to any significant first mover disadvantage issues facing customers seeking to connect to their networks (new and expanded connections). A first mover disadvantage might occur if a new connection requires wider network reinforcement that provides additional capacity or security benefits to other customers who do not contribute towards funding the asset.

WELL customer contribution methodology means significant first mover disadvantages are avoided. WELL has a process to allocate the cost of reinforcement required for a connecting asset to those who benefit from using those assets. We do this by including a share (based on the benefits available) of the reinforcement assets on the RAB and is therefore included in network tariffs funded by other customers who may benefit[17]. If the customers who benefit from the wider reinforcement associated with a new connection aren't known, the customer contribution policy allows connection costs to be reimbursed from future customers who may benefit. The process of allocating costs to those who benefits (wider network reinforcements costs in particular) is

[17] Tariffs include

provided in internal guidelines that outline how WELL practically delivers the Customer Contribution Policy. The process of allocating costs to those who benefit is summarised in Appendix E.

6.3 Cost allocation

WELL has a Cost of Supply Model (COSM), which is used to allocate costs between different consumer groups. Previously, WELL used a single cost allocation methodology for Distribution and Pass-through and Recoverable (which includes Transmission costs) costs. The new TPM methodology provides a specific cost allocation methodology for the allocation of Transmission costs. WELL notified retailers of the new Transmission cost allocation methodology in November 2022. Two COSM models are now used:

1. COSM for Distribution, Pass-through and Recoverable costs (excluding Transmission costs)
2. COSM for Transmission costs

6.3.1 COSM for Distribution, Pass-through and Recoverable costs (excl Transmission costs)

WELL notes that the Electricity Authority have recommended a new approach towards allocating costs in its “Distribution Pricing: Practice Note”, August 2019. WELL consulted with retailers on a new cost allocation methodology last year. The proposed methodology allocates costs to customer groups using an energy use (GWH) cost driver. We will be using retailer feedback to finalise the cost allocation model and will start the transition 1 April 2024. WELL will continue to use its current COSM approach until then. We will update the next version of the Pricing Methodology to reflect the new cost allocation methodology.

6.3.1.1 How the COSM is used

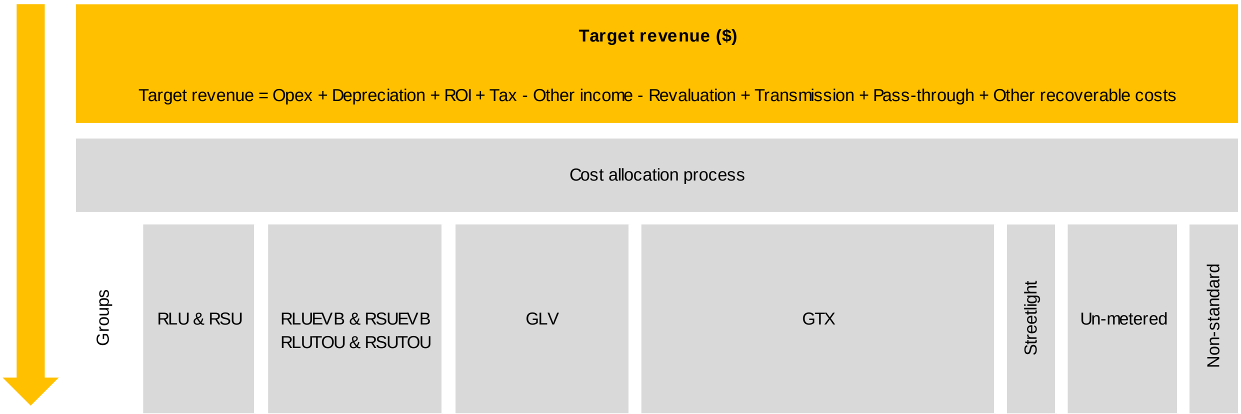
The COSM model was used to calculate unit prices in 2016 when it was first implemented. Rather than use the COSM model to re-calculate unit prices each pricing year, it is used to test whether unit prices are collecting the approximately correct levels of revenue. If there is a significant difference, prices are progressively adjusted to align to the cost of supply over time to mitigate the risk of price shocks occurring.

The focus of our COSM analysis for the majority of consumer groups is on the proportion of target revenue to recover from each consumer group, rather than the dollar amount to recover. Applying the COSM at the price level adds significant complexity and increases unnecessary volatility due to the inherent volatility in some allocator metrics (e.g. demand) and costs (e.g. maintenance).

6.3.1.2 COSM summary

The COSM allocates the various expenditure components of WELL’s target revenue to consumer groups. Figure 19 summaries the allocation methodology.

Figure 19 – COSM model



Revenue from non-standard consumers is initially removed from target revenue, as these consumers are typically priced based on recovery of actual costs. Allocators and other inputs are also adjusted to remove non-standard consumers. The remaining cost components of target revenue are allocated to consumer groups as follows:

- Costs are directly attributed to consumer groups where known (e.g. streetlight maintenance).
- Shared costs are allocated using cost drivers. The cost drivers used are provided in Figure 20.

Figure 20 – Key cost components to cover provision of electricity line services

Consumer group cost allocator		Cost components	Rationale
RAB	A composite RAB allocator is created by allocating regulatory asset base values to consumer groups as follows: • Connection assets: by ICPs • Streetlight assets: directly attributed to streetlights • LV network assets are allocated to non-metered, residential, LV and streetlights by proportion of their demand • All other assets: demand This seeks to directly attribute asset costs to consumers where possible	• ROI • Network depreciation • Revaluations • Tax • Opex (routine and asset renewal)	RAB costs are allocated to consumer groups based on that consumer group's utilisation (share of demand) of the network assets.
ICPs	Consumer connections	• Opex (service interruptions, emergencies, vegetation management)	A general allocator that recognises that all consumers benefit from expenditure to prevent and respond to interruptions to supply.
kWh	kWh consumption	• Other income • Opex (system operations and network support) • Non-network depreciation	A general allocator to recognise that consumers benefit from operation of the network in proportion to their use of the network.
ICPs & kWh	A 50:50 weighting of ICPs and kWhs	• Opex (business support) • Pass-through costs • Wash-ups and incentives	This weighting recognises that larger consumers create relatively higher costs per connection, and that levies are incurred in proportion to ICPs and kWhs.

Figure 21 provides the cost allocations for each of the cost drivers provides in Figure 20.

Figure 21 – COSM allocators by consumer group (excl. non-standard)

Consumer group	Demand	RAB	ICPs	kWh	Weighted ICPs & kWh
Residential	68.2%	69.3%	84.5%	49.1%	66.8%
General Low Voltage	18.9%	18.6%	8.8%	26.0%	17.4%
General Transformer	12.0%	9.8%	0.3%	24.1%	12.2%
Non-metered	0.1%	0.1%	0.6%	0.1%	0.4%
Streetlights	0.8%	2.2%	5.8%	0.7%	3.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

The proportion of the total costs allocated to each customer group is provided in Figure 22. The COSM outputs have been calculated by applying the cost driver allocations provided in Figure 21 to the cost groups summarised in Figure 20.

Figure 22 – COSM allocations of costs to consumer groups (excl. non-standard)

Consumer group	% of revenue allocated
Residential	67.5%
General Low Voltage	18.3%
General Transformer	10.8%
Non-metered	0.2%
Streetlights	3.2%
Total	**100.0%**

6.3.1.3 Application to prices

Figure 23 compares revenue collected from prices and revenue allocated using the COSM for the regulatory year 1 April 2023 to 31 March 2024. The difference represents the under/(over) recovery of costs. The figure shows the difference is not significant and there is no need to adjust prices. If there was a significant difference, WELL would progressively adjust prices over time to mitigate the risk of price shocks.

Figure 23 – Revenue from prices relative to cost of supply (excl. non-standard)

	Proportion of target revenue (1 April 2023 to 31 March 2024)		
Consumer group	**Implied COSM allocation**	**2023/24 pricing (applied)**	**Difference**
Residential	67.5%	66.7%	0.8%
General Low Voltage	18.3%	18.8%	-0.5%
General Transformer	10.8%	11.2%	-0.4%
Non-metered	0.2%	0.2%	0.0%
Streetlights	3.2%	3.1%	0.1%
Total	100.0	100.0%	0.0%

6.3.2 COSM for transmission costs

The TPM classifies transmission costs into 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 TPM allocates these cost pools to each grid customers, including WELL. WELL then passes these costs through to its own customers. The allocation methodology was developed for Transmission costs using the guidelines provided by the Electricity Network Association (**ENA**). The ENA's guidelines were informed using the EA's Distribution Pricing Practice Note[18], which provides specific guidance on how to apply the TPM to Distribution Prices. The EA's expectations are:

[18] https://www.ea.govt.nz/assets/dms-assets/30/Distribution-Pricing-Practice-Note-v-2.2-October-2022.pdf

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

The Transmission costs allocated to Wellington Electricity are all fixed so the cost allocation methodology focuses on prices that will not influence a customer's energy behaviours i.e. distribution prices relating to Transmission costs will also be fixed (noting that low fixed user restrictions means we are having to transition these changes).

The Distribution Pricing Practice Note also provided practical guidance about the application methodology. The ENA's guidelines summarise this guidance in two principles:

- 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) or usage (kWh) share.

- 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) implicit in the fixed charge adopted by Transpower.

We used these two principles to select the cost drivers used to allocated Transmission costs to each customer group. Appendix F 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 – Benefit Based Costs 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.

We did have a choice of using energy used or anytime maximum demand for allocating Residual costs as the TPM used both cost drivers to allocate Residual costs. We selected energy used (GWH) to allocated Residual costs because:

- **It is consistent with the TPM allocation approach (principle 1)**: Consistent with the guidance provided by the EA and the ENA, we have used an allocation approach that has regard to the TPM, rather than replicating it. We have used a simple single cost allocator and a one year's historic data set to simplify the allocation calculation. The TPM uses both AMD (for the initial cost allocation) and GWH (to annually update the cost allocation). As provided by the ENA pricing guidelines, it is therefore appropriate that distributors use either approach when allocating Residual charges to pricing groups.

- **It meets the non-distortionary principle (principle 2):** Costs are allocated to the customer groups using historic energy used. A single customer cannot materially impact the proportion of total Transmission cost allocated to a customer group by charging how they consume electricity. The EA's Distribution Pricing Practice Note provides that GWH is the best cost driver for ensuring customers cannot influence the ongoing use of the grid (paragraph 4.40).
- **The GWH cost driver is transparent, readily available and is an accurate data source:** Historical electricity use is disclosed publicly as part of our Annual Compliance Statement Disclosures. The electricity used data is externally audited and certified by our directors before it is disclosed on our website and provided to the Commerce Commission.

6.3.2.1 Revenue allocation

Figure 24 provides the energy used and connected capacity cost drivers used to allocated revenue to each customer group.

Figure 24 – Cost driver allocators by consumer group

Consumer group	Connected capacity (%)	GWH (%)
Residential	62%	49%
General Low Voltage	28%	38%
General Transformer	9%	12%
Non-metered	0.0%	0.1%
Streetlights	0.1%	0.8%
Total	100%	100%

The proportion of the total costs allocated to each customer group is provided below. The COSM outputs have been calculated by applying the cost driver allocations provided in Figure 25 to the TPM cost categories.

Figure 25 – COSM allocations of costs to consumer groups (excl. non-standard)

Consumer group	% of revenue allocated
Residential	52%
General Low Voltage	36%
General Transformer	12%
Non-metered	0.1%
Streetlights	0.6%
Total	100%

6.3.2.2 Application to prices and transition

WELL is transitioning the revenue from prices between commercial and residential tariff categories gradually overtime. WELL's transition plan limits any price increase to 10% maximum within a pricing category, resulting in a gradual shift between the residential and commercial categories as well as a gradually shift within the commercial tariffs. Figure 26 compares the proportion of revenue allocated using the cost drivers and the actual proportion of revenue allocated to each customer group by prices. The gap will close over time as WELL transitions prices within the transition rules.

Figure 26 – comparison between COSM revenue allocated and revenue allocated by prices.

	% of target revenue (1 April 2023 to 31 March 2024)		
Consumer group	**Implied COSM allocation**	**2023/24 pricing (applied)**	**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%

6.4 Calculating tariffs

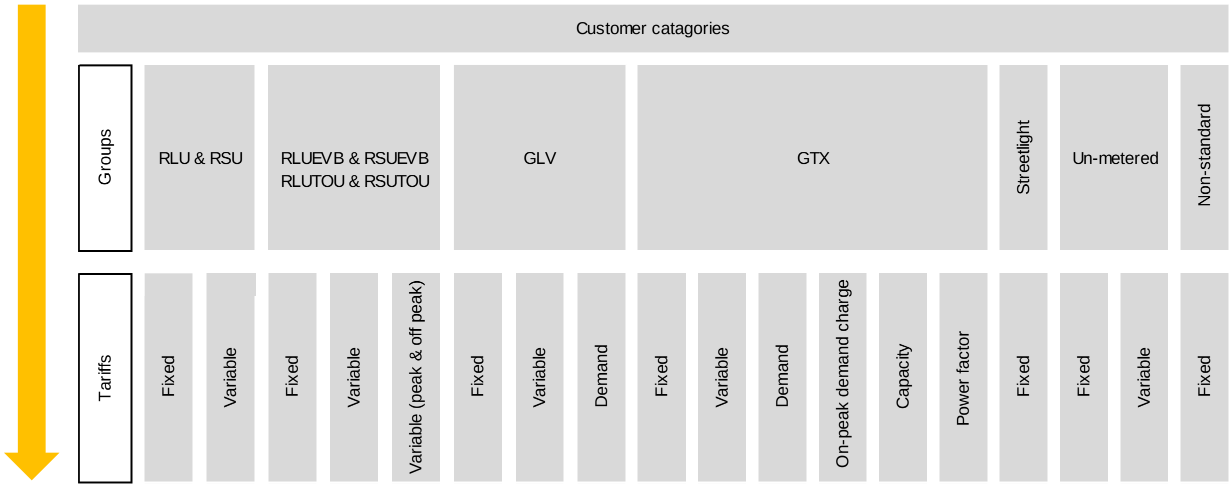
WELL's tariffs are a function of how much revenue it needs to collect and volumes. The tariff setting process is disclosed each year in its Price Setting Compliance Statement which can be found at: https://www.welectricity.co.nz/disclosures/price-quality-path-annual-compliance-statements/. The statement includes the target revenue calculation and any volume changes. It also includes final tariffs, quantities and the resulting revenue.

6.4.1 Tariff components

Each customer category has a number of different pricing components. Customer prices have a fixed and variable component. The fixed component doesn't change with energy use and is either a daily fixed charge or a capacity charge. The variable component varies with energy used (kWh), any time peak demand (kW), peak demand (kW) or energy used during peak and off-peak time periods (kWh).

Figure 27 provides a summary of the different tariff components. Note, there are also other tariff types which provide discounts for devises that can be remotely managed so that their use doesn't fall during busy networks periods. WELL's Network Pricing Schedule provides the full detail about all of the tariff types and components. This can be found at https://www.welectricity.co.nz/disclosures/pricing/

Figure 27 – tariffs for each customer category



6.4.2 Setting price signals – discounts for off peak electricity use

WELL offers tariff discounts for using electricity away from congested periods on the network. This reflects that WELL will have to build new capacity in the future to meet increasing demand for electricity (See the Pricing Roadmaps for an overview of network congestion). Figure 28 summarises the off-peak discount if provides for its residential prices, and the discounted price for allowing WELL to directly manage hot water and night store heating.

Figure 28 – current off peak price signals

Tariff type	Per kWh off peak discount (difference to peak demand price)
ToU off peak discount	5 cents
Controlled discount (discount for participating in managed hot water heating)	5 cents
Night boost (Discount for participating in managed night store heating)	6 cents
EV and battery ToU prices	9 cents

The discount reflects a historic LRMC and was verified when we introduced residential ToU prices in 2020 by calculating the cost for residential customers to provide an alternative to using peak demand (using battery storage). Note, this LRMC was calculated before the Governments Emissions Reduction Plan was released. The electrification of many activities currently provided by fossil fuels will significantly increase peak demand and capacity constraints. We are currently recalculating the LRMC to reflect the Emission Reduction Plan related electricity use. We expect that the LRMC and peak demand price signals will increase.

6.4.3 Changes between tariff types

The application of the TPM to an EDB's share of Transmission costs, and the transition away from the Low Fixed User restrictions, means there is a shift from variable tariffs to fixed tariffs. This means the overall amount of revenue collected from fixed prices will increase and the amount from variable prices will decrease. Section 7.1.6 demonstrates the change in revenue collected from fixed and variable prices.

6.5 Test for cross-subsidisation

To help ensure the consumer groups are free from cross subsidisation, we test whether revenue collected from prices is less than the stand alone cost and greater than the avoidable cost (the cross subsidy free range), for each consumer group. The customer groups tested are residential and small, medium and larger non-residential customers. Note, this test has been adjusted to exclude Transmission costs as these are now set and passed through using the TPM cost allocation methodology.

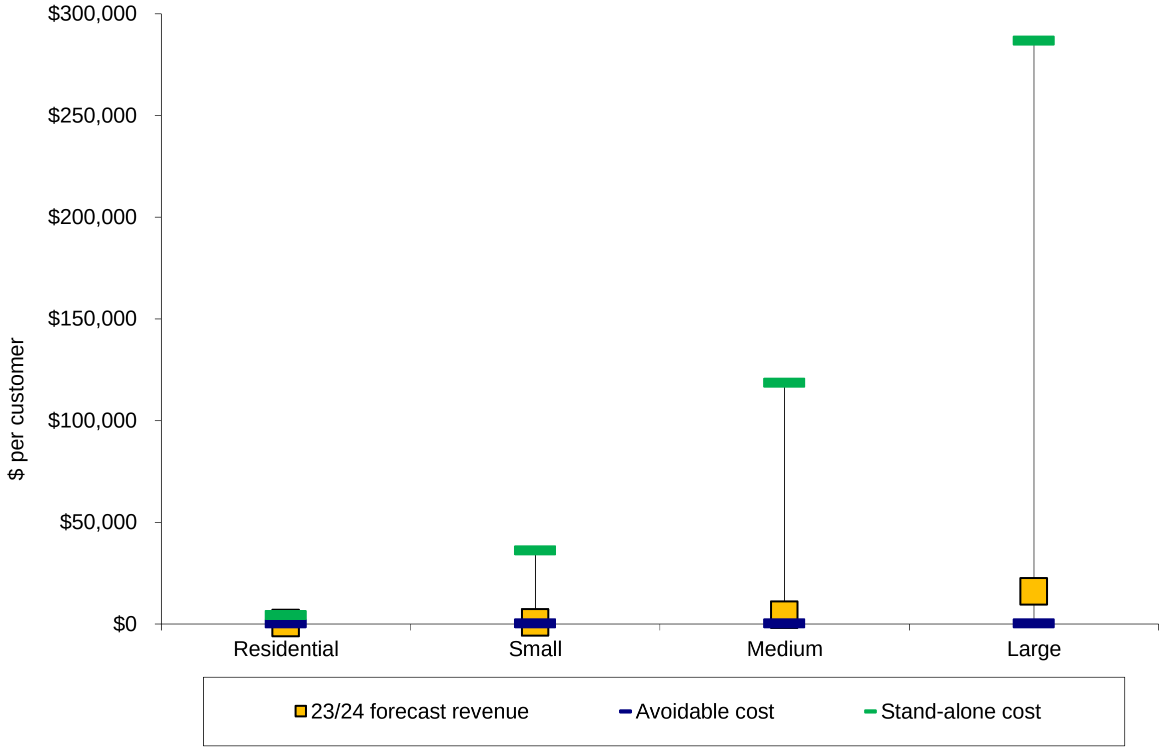
Stand-alone cost (SAC): considers the costs that a consumer would face to supply their energy needs from alternative energy sources. This represents the cost of going 'off-grid' or bypassing the network. The Electricity Authority's pricing principles practice note (the Guidance) suggests that SAC should be estimated with reference to micro grid schemes under which a group of consumers share energy resources.

Prices above stand-alone cost could not be sustained due to threat of competing energy sources and may create the possibility of inefficient bypass of the network. That is, consumers would be better off disconnecting from the electricity network and taking up the alternative energy solution where total electricity charges exceed SAC. This is inefficient as WELL's average unit cost to operate the network will increase for the remaining consumers, which may potentially further distort network usage. It is therefore better to discount prices below SAC in order to retain those consumers that are at risk of bypass.

Avoidable costs: the avoidable cost for a consumer group is the cost that can be avoided, should the distribution business no longer serve that consumer group (whilst still supplying all other remaining groups). If a consumer group were to be charged below its avoidable cost, it would be economically beneficial for the business to stop supplying that consumer group as revenue obtained from the consumer would not cover these costs. Further, where avoidable costs are higher than revenue recovered, the associated price levels may also result in inefficient levels of consumption.

As demonstrated in Figure 29, the revenue for each consumer group is within the subsidy free range established by stand-alone (SAC) and avoidable costs (AC). Revenue from the residential customer groups falls on the avoidable cost limit but is within the margin of error for the test. There is no requirement to adjust prices. There is no requirement to adjust prices.

Figure 29 – Comparison of avoided costs, stand-alone costs, and revenue from prices[19]



[19] Includes distribution, pass- through and recoverable costs.

7 Impact of 2023/24 price changes

Prices for all consumers are set in accordance with the IM Determination 2012 and DPP Determination 2020 which are defined by the Commerce Commission. The DPP Determination 2020 allows WELL to recover a net allowable revenue for the 1 April 2023 to 31 March 2024 assessment period of $94.8m. The IM Determination 2012 defines how pass-through and recoverable costs are treated.

In 2023/24, WELL will be in its third year of the regulatory period determined by the DPP Determination 2020. Prices include:

- Regulatory allowances provided by the DPP3 Determination[20]
- Transpower transmission costs;
- Pass-through costs;
- Other recoverable costs; and
- Cost of supply allocations.

Prices for residential consumers are also adjusted to comply with the LFC Regulations.

7.1 Changes to standard prices

The following adjustments have been made to prices.

7.1.1 Regulatory allowances provided by the DPP3 Determination

The Commission calculated a regulatory allowance (as provided in the DPP Determination 2020) for WELL's four-year regulatory period. Allowances for Distribution Services have increased by 2.0% from last year's allowance. The increase reflects an inflationary allowance increase as determined by the regulatory model.

7.1.2 Transpower transmission charges

Transpower Electricity Lines Service charges have decreased by $5.6m or 10%. This reflect the new TPM allocating less transmission costs to Wellington users.

7.1.3 ACOT

Previously WELL paid Avoided Cost of Transmission (ACOT) charges to large distributed generators within WELL's network in recognition that these generators may cause WELL to avoid Transpower charges. The new TPM has removed ACOT payments, reducing prices.

[20] As defined in Electricity Distribution Services Default Price-Quality Path Determination 2020

7.1.4 Pass-through costs

Pass-through costs have increased from last year by 4.2%. Pass-through costs comprise of council rates and industry levies. Pass-through costs are charged on to consumers at cost. The increase is largely due to above inflation increases in council rates and Commerce Commission levies due to the Commissions increased work program.

7.1.5 Other recoverable costs

Other recoverable costs include cost savings incentives, quality incentives and the wash-up account balance. The wash-up account balance is the difference between actual revenue collected and the revenue that WELL is allowed to collect. This ensures that WELL does not earn more revenue than it is allowed. These adjustments are made in line with the IM Determination and the DPP Determination 2020. Other recoverable costs have decreased by $4.2m due to mainly to an increase in the washup account reflecting that WELL is reimbursing an over recovery of revenue in the regulatory year starting 1 April 2021.

7.1.6 Balance between fixed and variable prices for users

The application of the Transmission Pricing Methodology to an EDB's share of Transmission costs, and the transition away from the Low Fixed User restrictions, means there is a shift from variable tariffs to fixed tariffs. This means the overall amount of revenue collected from fixed prices will increase and the amount from variable prices will decrease. Specifically:

- The second year of the transition to remove the fixed daily restrictions for low users has increased low user fixed daily charges from 30c to 45c. There is also an offsetting reduction in the variable charge.
- The application of the TPM means Transmission costs are now collected by fixed prices. All variable tariffs have been removed for commercial transmission charges. Some variable charges still exist for residual transmission tariffs due to the low fixed user restrictions.

This year's tariff changes include large offsetting changes between these two tariff types. The overall price change a customer will see, will depend on the offsetting amount between the tariff types. For example, Residential Standard User Uncontrolled daily tariff has increased from 99c to $1.2 (a 24% increase) and the Standard User Uncontrolled variable tariff has decreased by 44%. The overall impact is a 13% decrease. A comparison of tariffs is provided on our webpage that provides retailers with a summary of the key changes to 2023/24 prices (https://www.welectricity.co.nz/disclosures/pricing/2023-pricing-retailer-guidance). Figure 30 illustrates the shift of revenue collected between fixed and variable tariffs for each customer group. 52% of revenue collected is now fixed, reflecting that most Transmission revenue is collected from fixed tariffs and an increase in the low users daily rate.

Figure 30 - proportion of revenue collected from fixed and variable tariffs

Pricing year	2022/23		2023/24		Difference	
Fixed /variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	31%	69%	47%	53%	-16%	16%
General Low Voltage	37%	63%	63%	37%	-26%	26%
General Transformer	27%	73%	52%	48%	-25%	25%
Non-memtered	7%	93%	24%	76%	-18%	18%
Streetlights	100%	0%	100%	0%	0%	0%

Pricing year	2022/23		2023/24		Difference	
Total	33%	67%	52%	48%	-19%	19%

7.1.7 Volume changes

WELL also forecasts unit volumes that the prices are applied to – the unit volumes that unit prices are applied to, to calculate a consumer's bill. An increase in volumes means that there are more consumers and higher volumes of electricity use that WELL's can spread its costs over. This means that lower prices are needed to recover those costs. Prices have fixed and variable volume components, each requiring separate quantity forecasts – the fixed component requiring a forecast for the number of new connections and the variable component requiring a forecast of electricity used (kWh). This year's volume forecasts are summarised below.

Figure 31: Volume forecasts

Standard consumer groups (excl. unmetered)	Forecast connections		Forecast volume (kWh)	
	Annual % change from 2021/22 base year	Forecast base	Annual % change from 2021/22 base year	Forecast base
Residential (includes low user, standard user and EV)	0.8%	5-year historic average	0.7%	Maintain current post covid volumes plus 0.7% EV related increase
General Low Voltage	0.3%	5-year historic average	0.0%	Maintain current post covid volumes (after 6 years of declining volumes)
General Transformer	1.6%	5-year historic average	0.0%	Maintain current post covid volumes (after 6 years of declining volumes)

We are forecasting an increase in volumes overall which contributions towards the overall price reduction.

7.1.8 Summary of adjustments

The figure below summarises the change in lines charges for the 1 April 2023 to 31 March 2024 regulatory year compared to the previous year. The percentage change is calculated as a weighted average of all prices.

Figure 32 - Change in overall price

Price change element	Contribution to total average change in delivery charges
Change in allowances	1.2%
Transpower transmission charges	-3.6%
ACOT removal	-1.3%
Pass-through costs (rates, levies etc)	0.1%
Other recoverable costs (incl. wash-ups, incentives and pass-through balance movement)	-2.7%
Total change in costs	-6.3%
Volume changes	-1.0%
Total weighted average price change	-7.3%

Our delivery charges represent around 30-40% of the total electricity bill paid by consumers. However, consumers should be aware that energy retailers will package up our prices into their own retail offerings and the actual impact on consumer electricity bills will vary according to price plans, consumption and the extent to which energy retailers pass through WELL's network prices. Consumers should check with their energy retailer if they wish to further understand the actual impact on their total electricity bill.

7.2 Non-standard contracts

For consumers on non-standard contracts WELL changed the distribution and transmission price component from 1 April 2023 in accordance with the conditions of the non-standard contracts. Total delivery charges are the sum of the distribution and transmission prices.

For non-standard contracts established prior to the transfer of ownership of the network in 2009, WELL continued previously agreed connection policies and prices (reviewed annually). For non-standard contracts established under WELL's ownership, WELL has applied the methodology in accordance with WELL's Customer Contributions Policy.[21]

The following figure shows the number of contracts and connections covered under non-standard agreements.

Figure 33 – Non-standard contract statistics[22]

Non-standard contract statistics	Total
Number of non-standard contracts	11
Number of ICPs	19
Target revenue	**$1.88m**

[21] Available at: www.welectricity.co.nz/disclosures/customer-contributions/

[22] Target Revenue includes transmission and pass-through cost recovery

7.3 Obligations and responsibilities to consumers on non-standard contracts

All of WELL's non-standard contracts contain the same commitments to supply security and restoration priority as WELL's standard Use of Network Agreements and Default Distribution Agreements with retailers. WELL's non-standard agreements have some special conditions:

- One non-standard contract commits WELL to contract specific communications protocols in the event of supply disruption;
- None of WELL's non-standard pricing is affected by supply disruptions; and
- WELL has one non-standard contract where certain types of supply disruptions impose financial obligations on WELL.

As noted above, where WELL's non-standard contracts were established prior to 2009, WELL will honour the previously agreed connection policy and price.

7.4 Distributed generation

Distributed generators may be on either standard or non-standard contracts depending on the circumstances.

A $0.00/kWh-injection price applies for standard DG connections. This is done so that billing information can be recorded for these connections for monitoring purposes.

For further information on connection of distributed generation refer to our website: www.welectricity.co.nz/getting-connected/generating-your-own-electricity/

In-line with the Authority's new TPM, WELL will no longer provide ACOT payments from 1 April 2023.

7.5 Service charges

A service charge relates to work performed for a consumer by WELL's approved contractors. These charges are set to recover incremental costs and include external contractor rates and an administration fee to recover WELL's processing costs (e.g. updating network records and registry information etc.). The figure below sets out the charges applicable for the 2023/24 year. Prices have been calculated by applying 2% inflation uplift to last year's prices.

Figure 34 – Service charges

Description	Unit	Charge Effective 1 April 2022	Charge Effective 1 April 2023
New connection fee – single phase connection	per connection	$176	$180
New connection fee – two or three phase connection	per connection	$442	$451
Site visit fee	per site visit	$176	$180
Permanent disconnection fee	per disconnection	$330	$337

Description	Unit	Charge Effective 1 April 2022	Charge Effective 1 April 2023
General administration fee - to cover costs such as late, incorrect or incomplete consumption data, administering Embedded Networks, etc	per hour	$136	$139

WELL's Network Pricing Schedule[23] provides further descriptions of these charges.

7.6 Consumer views on pricing

WELL seeks consumer views of changes to price structures before a change is made, by consulting retailers as the consumer advocate. We also regularly check with consumers that we continue to provide services at a level of quality that they are willing to pay for.

7.6.1 Consulting before price structure changes

WELL consults with retailers, as the consumers representative, before any changes are made to price structures, The consultation documents include an estimate of the impact that any change will have on different customer groups, the benefits that the change will provide consumers and any potential downside. WELL then uses retailer feedback to refine the prices to help ensure any changes made benefit consumers overall and in the long term. We will usually consider transitioning changes over time to avoid price shocks.

Consultations and pricing notifications (including customer impact analysis) to date include:

- 2020 – applying optional ToU prices
- 2021 - Applying ToU prices to all residential customers
- 2022 – new pricing structures to align with the Authority's new pricing methodology
- 2022 – Notification on the application of the TPM cost allocation methodology to Transmission costs

7.6.2 Understanding expectations of price and quality

Since November 2017, WELL has surveys consumers who have been impacted by outages to better understand consumers' expectations of price and As at December 2023, 6,893 have responded to the questions asking about outages experienced and the price of services.

Figure 35 summarises the responses.

WELL also conducted a similar survey of randomly selected consumers in 2018, to act as a control group and to determine whether frequency of outage experience had any impact on the survey results. The results of that survey have been added to responses from a survey published on the Wellington Electricity website to form a control group, shown in

23 Available at: www.welectricity.co.nz/disclosures/pricing

Figure 35.

Figure 35 – Monthly cost/quality trade-off survey questions

		Yes		No		Maybe	
No.	**Question**	**Post outage survey**	**Control Group**	**Post outage survey**	**Control Group**	**Post outage survey**	**Control Group**
1	Would you be prepared to pay a bit more for your power if it meant fewer power cuts?	8%	14%	53%	16%	39%	70%
2	Would you be prepared to have slightly more power cuts if it meant prices were a bit cheaper?	4%	9%	76%	68%	20%	23%
3	Would you be prepared to pay $2 on top of your monthly electricity bill if it meant that the Wellington region was better prepared for a major natural disaster?	48%	10%	17%	10%	35%	80%

The results for question 1 show that the majority of consumers surveyed after an outage were comfortable with the current price/quality balance – that they are not willing to pay more for fewer outages. There is some inconsistency with the control group who were unsure whether they would pay more for fewer outages.

The results for question 2 are more consistent between those surveyed after an outage and the control group. The results suggest that consumers are broadly satisfied with their current level of reliability and the price of delivering that service.

The results for question 3 differ significantly between the two sample groups with consumers willing to pay more to be better prepared for a natural disaster or were unsure.

We do not believe that the survey results provide any compelling reasons to adjust our approach to calculating base prices from prior years.

7.7 Proportion of target revenue by price component

Clause 2.4.3(8) of the ID Determination 2012 requires that the proportion of target revenue collected through each price component is noted. This is shown for the regulatory year 1 April 2023 to 31 March 2024 below.

Figure 36 – Proportion of target revenue by price component

Consumer group	Consumer plan code	Fixed (FIXD) connection/ day $	Uncontrolled (24UC) kWh $	All inclusive (AICO) kWh $	Controlled (CTRL) kWh $	Night (NITE) kWh $	Peak uncontrolled (P-UC) kWh $	Off-peak uncontrolled (OP-UC) kWh $	Peak all inclusive (P-AI) kWh $	Off-peak all inclusive (OP-AI) kWh $
Residential low user time of use	RLUTOU	14,456,713	11,247,677	6,130,051	748,853	37,493	4,147,920	3,471,254	2,299,260	2,421,970
Residential standard user time of use	RSUTOU	26,535,470	5,894,686	3,776,523	235,037	36,292	3,076,638	1,209,410	1,762,080	549,487
Residential low user	RLU	865,990	1,080,577	626,255	33,974	2,840	0	0	0	0
Residential standard user	RSU	2,005,453	871,214	331,817	15,215	3,349	0	0	0	0
Residential low user EV and battery storage	RLUEVB	30,125	0	0	515	0	0	0	0	0
Residential standard user EV and battery storage	RSUEVB	66,938	0	0	297	0	0	0	0	0
General low voltage	GLV15	1,996,364	1,242,222	0	0	0	0	0	0	0
General low voltage	GLV69	9,672,056	5,811,444	0	0	0	0	0	0	0
General low voltage	GLV138	1,620,539	1,189,253	0	0	0	0	0	0	0
General low voltage	GLV300	2,301,287	1,011,015	0	0	0	0	0	0	0
General low voltage	GLV1500	3,864,839	584,135	0	0	0	0	0	0	0
General transformer	GTX15	745	1,448	0	0	0	0	0	0	0
General transformer	GTX69	17,938	10,556	0	0	0	0	0	0	0
General transformer	GTX138	65,539	50,794	0	0	0	0	0	0	0
General transformer	GTX300	770,046	470,130	0	0	0	0	0	0	0
General transformer	GTX1500	1,348,226	1,256,426	0	0	0	0	0	0	0
General transformer	GTX1501	419	135,388	0	0	0	0	0	0	0
Unmetered - non-street lighting	G001	49,796	154,823	0	0	0	0	0	0	0
Unmetered - street lighting	G002	3,235,611	0	0	0	0	0	0	0	0
Non-standard Contracts	IC	0	0	0	0	0	0	0	0	0
Total network revenue		**68,904,092**	**31,011,787**	**10,864,647**	**1,033,890**	**79,974**	**7,224,558**	**4,680,664**	**4,061,341**	**2,971,457**

safer together

Consumer group	Consumer plan code	Peak (PEAK) kWh $	Off-peak (OFFPEAK) kWh $	Demand (DAMD) kVA/month $	Capacity (CAPY) kVA/day $	On-peak demand charge (DOPC) kW/month $	Power factor (PWRF) kVAr/month $	Non-standard contracts (IC) $	Total revenue regulatory year $
Residential low user time of use	RLUTOU	0	0	0	0	0	0	0	**44,961,190**
Residential standard user time of use	RSUTOU	0	0	0	0	0	0	0	**43,075,623**
Residential low user	RLU	0	0	0	0	0	0	0	**2,609,636**
Residential standard user	RSU	0	0	0	0	0	0	0	**3,227,049**
Residential low user EV and battery storage	RLUEVB	44,059	38,896	0	0	0	0	0	**113,595**
Residential standard user EV and battery storage	RSUEVB	46,101	6,133	0	0	0	0	0	**119,468**
General low voltage	GLV15	0	0	0	0	0	0	0	**3,238,586**
General low voltage	GLV69	0	0	0	0	0	0	0	**15,483,500**
General low voltage	GLV138	0	0	0	0	0	0	0	**2,809,792**
General low voltage	GLV300	0	0	0	0	0	0	0	**3,312,301**
General low voltage	GLV1500	0	0	1,531,638	0	0	0	0	**5,980,612**
General transformer	GTX15	0	0	0	0	0	0	0	**2,193**
General transformer	GTX69	0	0	0	0	0	0	0	**28,494**
General transformer	GTX138	0	0	0	0	0	0	0	**116,333**
General transformer	GTX300	0	0	0	0	0	0	0	**1,240,176**
General transformer	GTX1500	0	0	3,186,168	4,216,704	0	0	0	**10,007,523**
General transformer	GTX1501	0	0	0	2,101,711	2,577,576	120,481	0	**4,935,575**
Unmetered - non-street lighting	G001	0	0	0	0	0	0	0	**204,619**
Unmetered - street lighting	G002	0	0	0	0	0	0	0	**3,235,611**
Non-standard Contracts	IC	0	0	0	0	0	0	1,881,993	**1,881,993**
Total network revenue		**90,160**	**45,029**	**4,717,807**	**6,318,415**	**2,577,576**	**120,481**	**1,881,993**	**146,583,871**

8 Appendix A – Pricing Methodology - Information Disclosure Requirements

2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-

(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;

(2) Describes any changes in prices and target revenues;

(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);

(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.

2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.

2.4.3 Every disclosure under clause 2.4.1 above must-

(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;

(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;

(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;

(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;

(5) State the consumer groups for whom prices have been set, and describe-

(a) the rationale for grouping consumers in this way;

(b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;

(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;

(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;

(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.

2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-

(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.

2.4.5 Every disclosure under clause 2.4.1 above must-

(1) Describe the approach to setting prices for non-standard contracts, including-

(a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;
(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;

(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain-

(a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts;
(b) any implications of this approach for determining prices for consumers subject to non-standard contracts;

(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the-

(a) prices; and
(b) value, structure and rationale for any payments to the owner of the distributed generation.

9 Appendix B – Consistency with Pricing Principles

The Electricity Authority's Pricing Principles have been updated and provided in "Distribution Pricing: Practice Note" August 2019. We have assessed how well our current Pricing Methodology meets the principles.

We have developed a revised Pricing Methodology that reflects the Electricity Authority's updated Pricing Principles and Cost Reflective Pricing Methodology. Last year we consulted with Retailers on the new structures, and we are currently refining the methodology using their feedback. Our proposed Pricing Methodology is provided in our Pricing Roadmap and is summaries in this Pricing Methodology disclosure. We will be refining our thinking this year by consulting again with retailers, focusing on prices for large commercial businesses.

For each of the Pricing Principles we have assessed alignment with our current methodology and against our future Pricing Methodology.

Pricing Principle (a) (i)

(a) Prices are to signal the economic costs of service provision, including by:

(i) i. being subsidy free (equal to or greater than avoidable costs, and less than or equal to stand-alone costs);

Subsidy free means that consumers in consumer groups are no worse off by being part of the whole network – that they are not better off with another service, or they are not paying for the incremental costs of another consumer group. WELL calculates the stand alone and avoidable cost for each major consumer group – residential, non-residential consumers connected to the low voltage network and non-residential consumers with dedicated transformers.

Stand-alone cost calculation: considers the costs that a consumer would face to supply their energy needs from alternative energy sources. This represents the cost of going 'off-grid' or bypassing the network. The Electricity Authority's pricing principles practice note (the Guidance) suggests that SAC should be estimated with reference to micro grid schemes under which a group of consumers share energy resources.

To estimate SAC we have investigated micro-grid schemes under which consumers generate and store their own electricity and use LPG substitutes to create a hypothetical standalone network. We note that there are few real world off-grid micro-grid schemes in New Zealand. However, using publicly available information we were able to design and cost a hypothetical micro-grid that might be capable of supplying a subdivision or business park grouping of consumers. Our research suggests that the most common and economic off-grid solution would use a combination of solar PV, batteries, backup diesel generation, and LPG.

Avoidable costs: The avoidable costs associated with each of the consumer groups were derived by estimating how short-term costs reduce if a specific consumer group is no longer supplied. Consistent with the guidance, avoidable costs include short-term variable cash costs, such as repairs and maintenance, billing and customer service costs, and transmission charges. Network asset costs are excluded as they are fixed in nature and are not avoided if a consumer group disconnected from the network.

Principle	Current Methodology	Future Methodology
Being subsidy free	Estimated short run avoidable cost and the cost of a standalone alternative in line with the Authority's Distribution Pricing Practice Note 2021.	The stand-alone cost will also be updated as alternatives to distribution services are developed.

(ii) reflecting the impacts of network use on economic costs, and

Pricing structures are economically efficient where they assist to efficiently signal the economic costs of servicing different network usage profiles. WELL's prices are initially based on building block allowable revenues under Part 4 regulation, reflecting key network investment and operating costs. WELL then considers the drivers of consumer usage to develop prices for each consumer group. WELL's pricing has regard to the economic cost of using existing network capacity and to the cost of future capacity, as follows:

Time of use (ToU) charges: From 1 April 2021, Wellington Electricity will implement mandatory ToU pricing for Residential consumers. These pricing structures incentivise efficient use of peak network capacity and signal the cost of investing in new capacity by charging a higher price during periods when the network is typically congested and a lower price during off-peak periods.

Demand (kW): The demand charge applied to GTX1501 pricing plans provides a price signal by incentivising larger consumers to reduce their demand at high network congestion periods.

Night boost: The night boost pricing option ('NITE') applies to separately metered and permanently wired appliances, such as night store heaters, which are switched on and off at specific times. This controlled option will be switched on during the off-peak night period (11pm to 7am) and for a minimum "boost period" during the day of two hours generally between 1pm and 3pm. This incentivises consumers who have invested in these heating options to use these loads during off-peak periods.

Load management: Wellington Electricity provides lower prices to consumers that offer up dedicated controllable loads (e.g. electric hot-water cylinders). This lower price signals to consumers the cost savings associated with shifting consumption away from network peaks or other congestion periods (e.g. during outages).

Use of LV and HV assets: All pricing categories disaggregate consumers by their use of LV and HV assets. Our cost of supply model also only allocates LV costs to consumer groups that use these assets aligning use of these assets to network pricing.

WELL does not specifically factor circuit length into prices. The relatively compact and interconnected nature of our network makes this difficult to apply in practice.

Dedicated equipment: The GTX pricing group distinguishes the distinct costs associated with providing dedicated transformers, as well as recognises that these consumers do not typically use LV circuit assets. This is also reflected in our cost of supply model which allocates a higher proportion of transformer costs direct to the GTX group.

Connection capacity: kVA bands are applied across our general pricing groups to reflect differences in installed connection capacity. This typically reflects differences in the usage of different sizes of transformers and circuit voltage capacity.

Power factor charge: To encourage power factor management, a power factor charge is applied to General Transformer Connections greater than 1500 kVA (GTX1501) who fail to correct inductive loads. This signals to the consumer the need to manage power factor to optimise network capacity and quality of supply.

Streetlights: Separate streetlight charges seek to directly recover the cost of streetlight assets and maintenance.

Connection costs: Differences in connection costs are recognised through fixed daily charges, capacity bandings, and capital contributions for new connections.

Transmission cost pass-through: Transmission costs are passed-through to consumers using methodologies which are in line with the TPM. Specifically, WELL passes through costs as a fixed charge reflecting that TPM prices are not signalling grid congestion.

Looking forward: WELL's Future Pricing Roadmap summarises the changes WELL expects to make to its pricing in the future. WELL implemented ToU pricing initially for EVB consumers from 1 July 2018 and expanded it to include all residential consumers in 2020. WELL continues to investigate efficient pricing options and is considering efficient prices for small commercial consumers and prices for managing EV charging. This year, WELL will be finalising its new price structures that reflect the Electricity Authority's new Cost Reflective Pricing Methodology. We will start to transition to the new structures from 1 April 2024.

Principle	Current Methodology	Future Methodology
Signal economic cost	We signal the economic cost of using the network by: • Tariffs that reflect the cost of using electricity during peak demand periods • A Customer Contribution policy that ensures connecting consumers fund the incremental cost of connecting	Continue to refine its price signals for using energy during peak demand periods. Key programmes include: 1. Refine the LRMC calculation and reflect the cost of using electricity during peak periods in the allocation of variable and fixed prices. 2. Consideration will be given to geographic price signals – prices that reflect significantly different LRMC for specific parts of the network. 3. Develop cost reflective prices for small and medium size non-residential consumers,

Principle	Current Methodology	Future Methodology
	Recent improvements include the application of mandatory ToU pricing for all residential consumers.	replacing any-time variable price components. 4. Consider capacity based fixed prices for medium and large non-residential consumers 5. Transition away from low fixed charges to standard pricing

(iii) reflecting differences in network service provided to (or by) consumers;

Networks in New Zealand generally do not offer different levels of service for its core distribution services. The regulatory framework is based on providing set levels of quality for all consumers within a service area. Regulatory penalties and incentives are applied to quality targets based on those service levels.

However, we note the Distribution Pricing Practice note broadens the definition of this principle to encompass any differences in the network service provided by or to a distributor.

WELL's pricing reflects different network service offerings that account for price and quality trade-offs, asset usage requirements, and consumption preferences. Specific examples of consumer service preferences that are catered for in our pricing are also discussed above and include:

- **Time of use and night boost prices**: Time reflective cost reflective prices reflect consumer preferences over when they use the network.
- **Interruptible supply**: Consumers can offer up interruptible hot water load in exchange for a discount on prices. Specific reliability requirement can also be negotiated as part of our network connections policy.
- **Connection capacity**: The different pricing categories reflect a range of connection sizes reflecting different consumer requirements.
- **Dedicated equipment:** WELL pricing and connections policy provides consumers with the option of being provided with dedicated equipment. Dedicated transformers are provided under GTX pricing. WELL also provides a range of dedicated equipment using direct agreements with consumers.
- **Non-standard terms:** Large industrial connections with atypical seasonal or daily load profiles are also offered non-standard terms to better meet their preferences for fixed of variable pricing or asset charges. Non-standard terms could also reflect different levels of security and operating restrictions for a specific consumer.

This year we will be trailing residential flexibility services that manage electricity use away from peak demand periods on the network. Prices for these services will reflect the value of avoiding network upgrades.

Principle	Current Methodology	Future Methodology
Prices that reflect the service being provided	Different service levels are reflected by: • Pricing differentials reflecting different levels of distribution services provided. • Non-standard contractual terms, prices and consumer contributions reflecting different service levels.	We will continue to develop new services and prices to reflect changing consumer demand. We are currently developing: • Managed EV charging services that will allow demand to be managed during peak demand periods. Consumer will receive lower prices in return. • Continue to offer large consumers non-standard terms that reflect their specific operational needed and budgets.

(iv) encouraging efficient network alternatives;

Network pricing should encourage efficient investments in alternatives to traditional transmission or distribution network supply (including demand response). Network alternatives include distributed generation (e.g. Solar PV, wind, hydro), storage, interruptible demand, and flexibility services. Our pricing structures (e.g. ToU, NITE, Controlled, and demand pricing) encourage investments in non-traditional network alternatives where they are more efficient:

- As discussed in Principle (a) (i) above, our prices are less than stand-alone cost for all consumer groups so are therefore likely to discourage inefficient investment in off-grid alternative energy solutions. This reflects that most residential solar solutions only provide 25% of a household's energy needs. The network is still needed to provide the remaining 75%. Conversely, if an individual or consumer group can find a more cost-effective alternative than the prices signal, they would be better to use that service.

- Our prices signal the cost of future network reinforcement if consumers use electricity during peak demand periods (i.e. price signals are set using the LRMC). This allows consumers to choose to use electricity during peak demand period and pay more, or avoid using electricity during busy periods and avoid the investment cost.

- Our peak period prices encourage alternative network solutions where they are more efficient than using traditional solutions to solve capacity or security constraints. Examples are lower prices for hot water control and peak ToU tariffs that signal when it is efficient to purchase distributed energy resources like household batteries to shift load to off peak periods.

Principle	Current Methodology	Future Methodology
encouraging efficient network alternatives	Our current prices signal when it would be efficient to use network alternates.	Refine and improve the price signals, including: • Refine the stand alone and avoidable cost calculation] • Refine peak demand periods to reflect any changes in peak periods due to changes in energy use behaviours. • Refine the LRMC calculation, including considering geographic price signals • Develop and offer flexibility services as an alternative to traditional solutions to capacity and security constraints.

b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

Prices are first set to signal future economic costs. Where these prices result in a short-fall of revenue, this short fall should be recovered by a pricing mechanism that least distorts network usage. Because this residual amount has no need to send a price signal (because all the price signalling work is done in the first step) this residual recovery process should be done in a way that means a consumer has no reason to change their electricity consumption use or pattern.

In practice, non-distortionary charges are likely to target consumers that demand a service the most or which are less likely to change their usage behaviour due to a price change. A challenge with this approach is it can be difficult to identify consumers based on willingness to pay due to lack of information on price elasticities (i.e. a measure of willingness to pay) specific to different consumer groups in the New Zealand electricity sector.

WELL's recovery of the residual revenue is in line with the Distribution Pricing Practice Note 2021 and applies a fixed daily charge per ICP. WELL has different non-residential pricing categories that reflect different size connections. Fixed prices are larger for larger sized connections reflecting that those connections are using a larger proportion of the network.

Principle	Current Methodology	Future Methodology
least distorting recovery of residual revenue	Fixed charges are applied by ICP. The size of the charge reflects the size of the connection and reflects how much of the network's capacity is	Refine and improve the fixed charges used to recover residual revenue:

Principle	Current Methodology	Future Methodology
	being used (or is available to the consumer). Currently, WELL collects 52% of its revenue from fixed charges which does not align with the LRMC. The overall residual amount could be refined.	• Refine the LRMC calculation and the residual amount to be collected from fixed prices. • Retain the least distorting fixed daily prices for residential and small non-residential connections where the connections sizes are similar. • Apply least distorting fixed charge based on connected capacity for medium to large non-residential connections that reflect the portions of the network that a connection uses.

c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

i. reflect the economic value of services; and

Prices above stand-alone cost could not be sustained in a competitive market and may result in inefficient bypass of the existing infrastructure. As Wellington Electricity's prices are below the stand-alone costs, bypassing the network is discouraged suggesting that the prices reflect the economic value of services.

However, we are open to considering non-standard arrangements for large connections that may be prone to bypass to the gas or electricity transmission network. Note, EDBs cannot offer different quality levels to the mass market i.e. the mass market use shared assets that provide a single level of quality.

Principle	Current Methodology	Future Methodology
reflect the economic value of services	Prices are set below the standalone cost and reflect the economic value of services. We offer individual prices and terms for large customers with unique requirements.	We will continue to offer individual prices and terms for large customers with unique requirements.

i. enable price/quality trade-offs

Price/quality trade-offs are reflected through different service and asset level offerings affecting firmness of supply, reliability and connection capacity:

- Uncontrolled pricing plans have higher prices recognising the higher willingness to pay for consumers that do not want their hot-water load interrupted.
- ToU and NITE prices are targeted to consumers that are willing to shift their demand to the off-peak.
- Demand pricing and kVA bands allow consumers to self-select the capacity service they require, consistent with their willingness to pay.
- WELL's connections policy enables non-standard connection or assets to be recovered through capital contributions. For example, higher security of supply through multiple levels of redundancy can be recovered through these contributions at the time of connection.
- Large general connections can choose between sharing a distribution transformer on the GLV group or, having their own dedicated transformer on the GTX pricing group. This reflects consumer preferences over security of supply.

WELL has committed to standard pricing categories for most consumers. However, non-standard pricing structures can be agreed by negotiation for large industrial connections. This policy seeks to balance the need for non-standard pricing arrangements with the need to reduce transaction costs for retailers and consumers.

Principle	Current Methodology	Future Methodology
enable price/quality trade-offs	Standard prices reflect different service offering. We offer individual prices and terms for large customers with unique requirements.	We will continue to offer new prices for new services offering different service levels. In the future this will include flexibility services. We will also continue to offer individual prices and terms for large customers with unique requirements.

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

Our pricing methodology and annual price changes are transparently published on our website. These disclosures are designed to provide all the relevant information that consumers and retailers need in order to understand how prices are set. The level of aggregate prices has been set within the constraints of the DPP Determination 2020 which is set and overseen by the Commission.

We also seek to signal changes in prices in our pricing strategy. We have sought to reduce retailer transaction costs by developing pricing to reflect standard consumer profiles and connection characteristics, where possible. New ToU pricing, in particular, has been developed to try to align to ToU structures that other EDBs are adopting, thereby reducing transaction costs for retailers. Before we make any price structure changes, we consult with retailers as the consumers representative. The consultation document includes the potential impact on customer electricity bills and options to transition or smooth changes if there is a risk of price shocks.

WELL seeks to limit transaction costs arising from its network charges, by limiting the complexity of charges and structures and the number of charging parameters within each charge. However, economic efficiency criteria are weighted more highly.

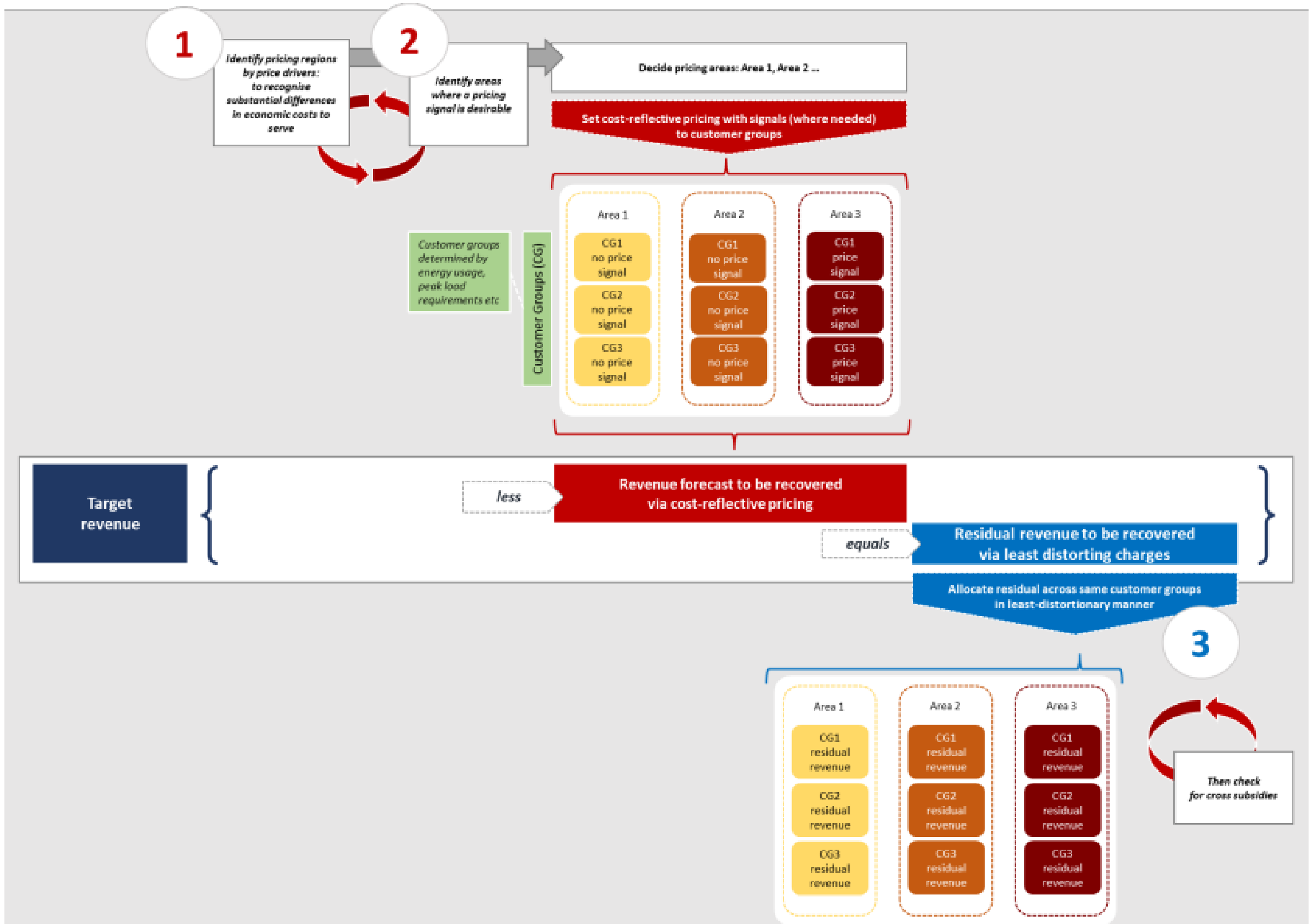
WELL applies the same charging structure to all retailers, excluding any non-standard contracts. A separate contractual agreement is negotiated with non-standard consumers as they have unusual connection characteristics making the tariff structure to all retailers inappropriate.

Principle	Current Methodology	Future Methodology
Transparent	We provide out Pricing Methodology to explain how prices are derived and the Pricing Roadmap outlining how we are refining our Pricing Methodology going forward.	Continue to publicly disclosure our pricing methodology and future pricing plans.
Transaction costs	• We have developed our ToU pricing structures to align with other networks. • Limiting the complexity of charges and structures and the number of charging parameters within each charge	• We are planning to simplify our pricing structures. We consulted on the new structures with retails last year and will apply them from 1 April 2024. This includes reducing the number of price categories and pricing components. • We will align new price structures with other networks where it is sensible. • The exit of the low fixed user tariffs will clarify residual pricing.
Customer impacts	We consult with retailers as the consumers representative before changes are made. The consultation document includes the potential impact on customer electricity bills and options to transition or smooth changes if there is a risk of price shocks.	We will continue to consult with retailers on any price structure changes.
Uptake incentives	We ensure that price signals for our different price options are consistent in the value they reflect – that consumers aren't incentivised to select a pricing options over another which has a better economic benefits.	• Refine the price signals for our prices, aligning them with the LRMC. • Correct the relativity of the ToU and EVB ToU price signals.

10 Appendix C – New Pricing Methodology

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

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



11 Appendix D – Progress against current Pricing Roadmap[24]

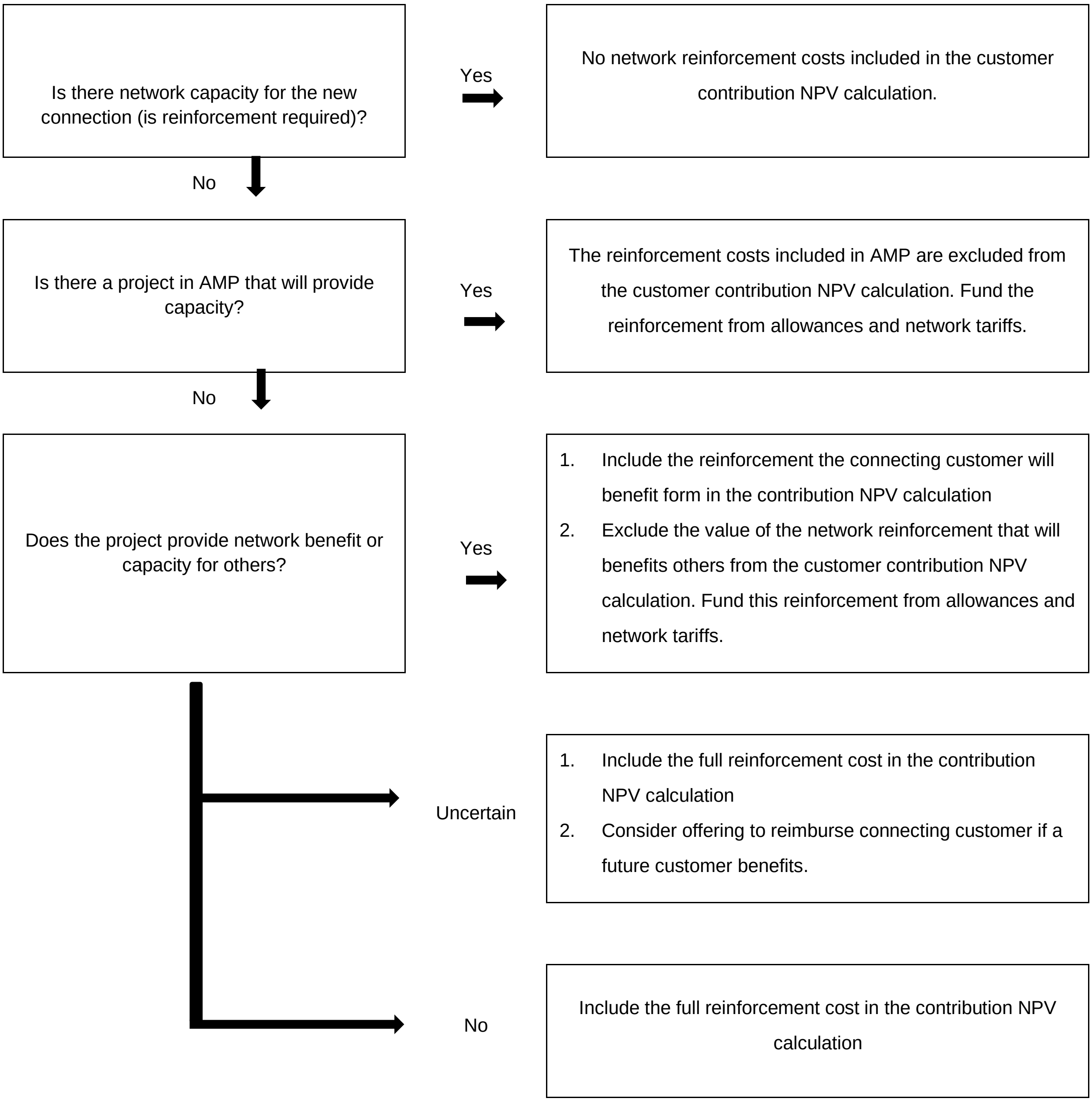
Initiate pricing reform (April 2017 – March 2018)		Develop detailed plans for pricing reform (April 2018 – March 2020)		Manage roll-out of future pricing (April 2020 – March 2025)	
Initiative	**Progress**	**Initiative**	**Progress**	**Initiative**	**Progress**
Identify overall objectives for pricing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

[24] Note, the roadmap in Appendix 1 is focused on residential prices as the main driver of peak demand. Prices for Commercial consumers will be addressed in the later stages of the roadmap.

Appendix E – allocating connection costs (including any required network reinforcement)

WELL allocates network reinforcement related with a new connection to those who benefit. Generally, we include the proportion of network cost that benefits other customers on the RAB and in wider network tariffs. If there is uncertainty about whether other customer may benefit (e.g. we are unsure whether there will be new growth to use spare capacity) we can reimburse the connecting customer. While the Contribution Policy provides the option to reimburse reinforcement costs, it is rarely used because most spare capacity is expected to be used by climate change related demand increases. Figure 37summarises the process of assessing how network reinforcement relating to a new connection is allocated to each customer.

Figure 37 – allocation of network reinforcement relating to a new connection



12 Appendix F – Transmission 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)	Small (15kVA and under)	Fixed daily
			avg. connected capacity	Medium (4 x categories from 15kVA to 1500kVA - GLV & 3 x categories from 15kVA to 300kVA - GTX)	Fixed daily or capacity charge
			Individual connected capacity	Large (2 x categories from +300 kVA - GTX)	Capacity charge
		Non-metered	Fixed capacity	Non-street lighting	Fixed daily
			Fixed capacity	streetlighting	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)	Small (15kVA and under)	Fixed daily
			avg. connected capacity	Medium (4 x categories from 15kVA to 1500kVA - GLV & 3 x categories from 15kVA to 300kVA - GTX)	Fixed daily or capacity charge
			Individual connected capacity	Large (2 x categories from +300 kVA - GTX)	Capacity charge
		Non-metered	Fixed capacity	Non-street lighting	Fixed daily
			Fixed capacity	streetlighting	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)	Small (15kVA and under)	Fixed daily
			avg. connected capacity	Medium (4 x categories from 15kVA to 1500kVA - GLV & 3 x categories from 15kVA to 300kVA - GTX)	Fixed daily or capacity charge
			Individual connected capacity	Large (2 x categories from +300 kVA - GTX)	Capacity charge
		Non-metered	Fixed capacity	Non-street lighting	Fixed daily
			Fixed capacity	streetlighting	Fixed daily
		Direct	Individual connected capacity	Direct bill	Capacity charge

13 Appendix G – Directors' Certification

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Richard Pearson and Charles Tsai, being directors of Wellington Electricity Lines Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of Wellington Electricity Lines Limited prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on the basis consistent with regulatory requirements or recognised industry standards.

Richard Pearson Director	Charles Tsai Director
3 March 2023	3 March 2023