Electricity Pricing Methodology

1 April 2026 – 31 March 2027

Contents

1. Welcome

Kia ora koutou

Powerco is Aotearoa New Zealand's largest electricity distribution company by network length, supplying about one of every six residential customers in the country. We have the largest supply territory by area and the largest overall network length. Our networks stretch across the North Island from the Coromandel to the Wairarapa.

We are proud to provide an essential service to more than 363,000 homes and businesses, serving approximately one million customers. The electricity distribution assets we manage have long lives and are capital-intensive to create and maintain. We consider ourselves long-term asset stewards, providing effective and efficient asset planning and investment for current and future generations.

Since joining Powerco last year, I have been clear about a single, inescapable reality, the electrification of our economy will not simply fall into our laps. It requires a deliberate, nimble, and highly coordinated effort between the industry and our customers.

This document explains the mechanics of how we calculate our prices and, more importantly, how those prices support an affordable and secure transition to a low-emissions future.

We are navigating a perfect storm; household demand is flattening as cost-of-living pressures mount. Simultaneously, the removal of government incentives for EVs and industrial decarbonisation has slowed the pace of electrification.

This raises issues around intergenerational fairness and ensuring that the investments we make today to double our network capacity over the next 30 years do not place an unsustainable burden on households and businesses today. To achieve this, our 2026 methodology continues to prioritise efficient pricing signals that encourage energy use when the network has spare capacity, helping us keep the overall cost of the transition down.

We must decarbonise but not de-industrialise. For our large commercial and industrial partners, this methodology focuses on providing transparent, asset-based pricing that reflects your specific needs now and into the future.

Our objective is to be New Zealand's most customer-focused infrastructure operator. This methodology is a key part of that commitment ensuring our network remains a viable, resilient, and fair platform for all our communities as we walk, together, into the future.

Ngā mihi nui

Jason Franklin - Chief Executive Officer

2. How our pricing benefits you

Why it's important our prices reflect costs

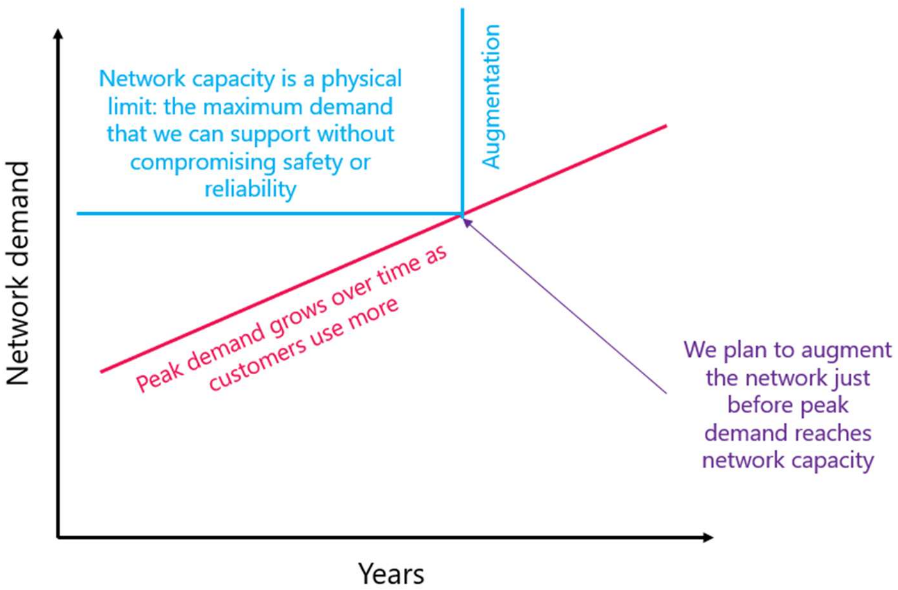
Many of the costs of operating an electricity network are fixed, we can't easily unbuild, re-use or move bits of it. This is why it's so important to see if we can delay making investments by using price signals and non-network solutions to keep network costs down.

Because we are a natural monopoly, the total amount of money we are allowed to charge for our services is capped by the Commerce Commission. They also check that our service meets or exceeds acceptable levels to make sure we spend enough on the network to maintain safe and reliable supply.

We recover a lot of our fixed costs through fixed charges – generally daily charges that vary with connection size, which recover all the costs of assets that are just used by that customer, and a proportion of the wider network costs that connect it to the national grid (which is owned and operated by Transpower).

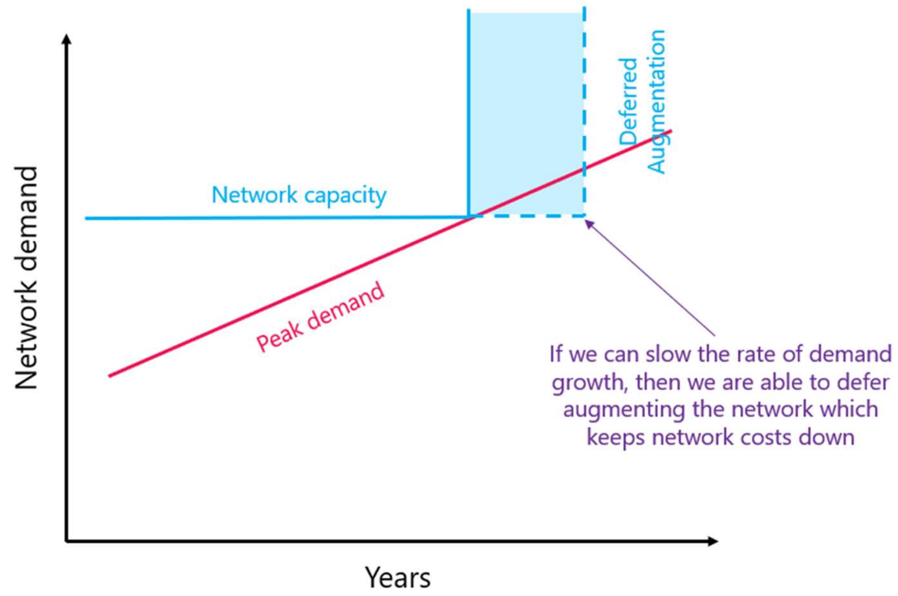
We have to ensure that our network can support maximum demand without compromising safety or the service that a customer receives. We plan to enhance the network before peak demand reaches network capacity which is illustrated in Figure 1 below.

Figure 1. Why we have to spend more on the network



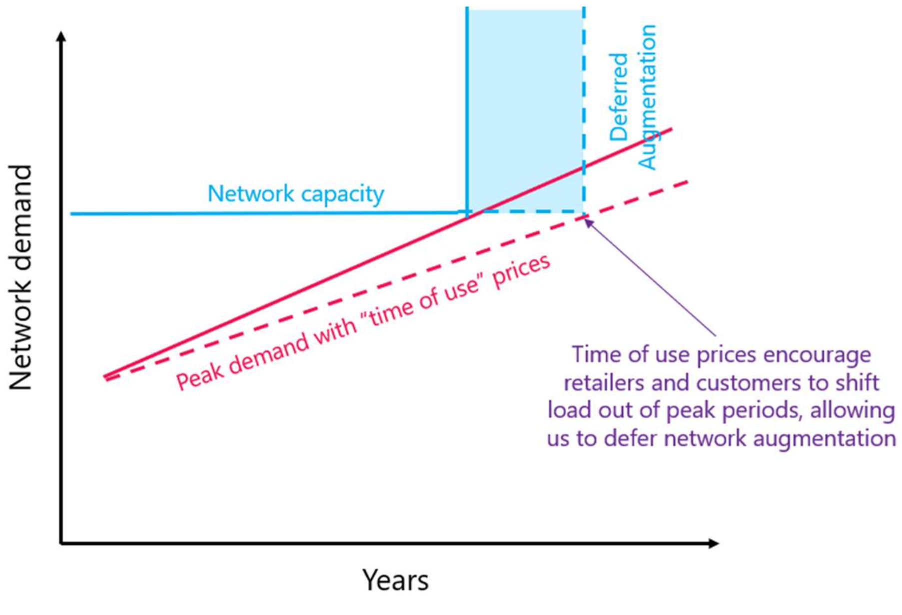
However, there are ways we can slow down the need to spend more on the network by either slowing down the demand by encouraging customers to use less at certain times (Figure 2) or by using a non-network solution to help add short term capacity to the network when the demand on the network is highest.

Figure 2. Slowing demand can defer network enhancement



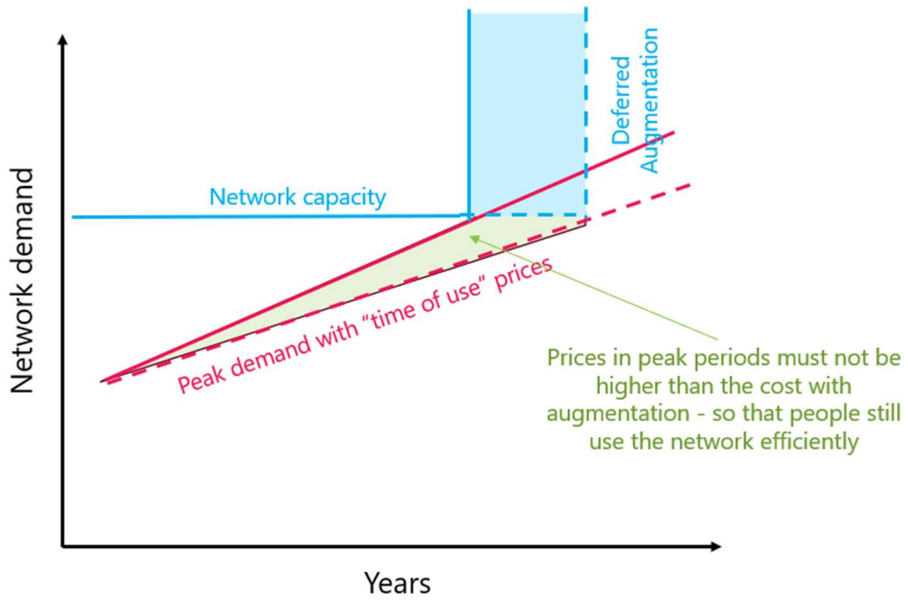
Where our asset management plan identifies that we'll need to expand the capacity of the network over the next 10 years, we signal a "peak" charge during the periods when our network is congested to signal how much one extra unit of electricity would cost if we had to upgrade the network to meet increases in load during these peaks (see Figure 3 below).

Figure 3. How using price signals can delay us spending money on the network



Economists call this the "long-run marginal cost" – it's a particularly important signal in a business like ours because while most of our costs are fixed in the short term, they're all variable in the long term but only when we make large and irreversible investments, so if customers are prepared to pay it then it's a sign that it would be efficient to upgrade the network.

Figure 4. Peak prices must encourage efficient use of the network



This "time-of-use pricing" describes how we charge different prices at different times of day (and in some cases on different days of the week and in different seasons) to make sure we only charge this "peak" rate during the periods when our network is most heavily used.

How and why we set our prices

Our Asset Management plan outlines how we will continue to meet the changing needs of our customers and communities over the next 10 years. It sets out how we intend to meet those needs as efficiently as possible, both by investing in new and replacement larger assets, increasing the capacity of existing resources and through non-network solutions where possible.

This section explains the detailed mechanics of how we set our prices, but our sequence is:

- Identify the time periods when the network demands are at peak
- Calculate peak prices from planned investment costs for each pricing region
- Recover the rest of our revenue through fixed and off-peak prices
- Where investment is close, we tender for network deferral options
- Identify the time periods when the network demands are at peak

In most areas the peak period is 7am-11am and 5pm-9pm on weekdays but we are introducing a new subregion with slightly different periods in the Northern Coromandel this year to reflect the fact that the network gets used heavily at the weekend there.

Calculate peak prices based on planned investment in each pricing region

We have to build our electricity network to handle the maximum loads (or generation export) that occur on them at any time but in many cases, those peaks only last for a few hours every year.

Traditionally we have had to increase this “hosting capacity” of the network to make sure we can meet new load and generation requirements, by building and replacing physical assets - wires, transformers, substations and the like.

To defer these investments, we use variable prices in peak periods to signal the cost of the local planned investment in each region.

Recover the rest of our revenue through fixed and off-peak prices

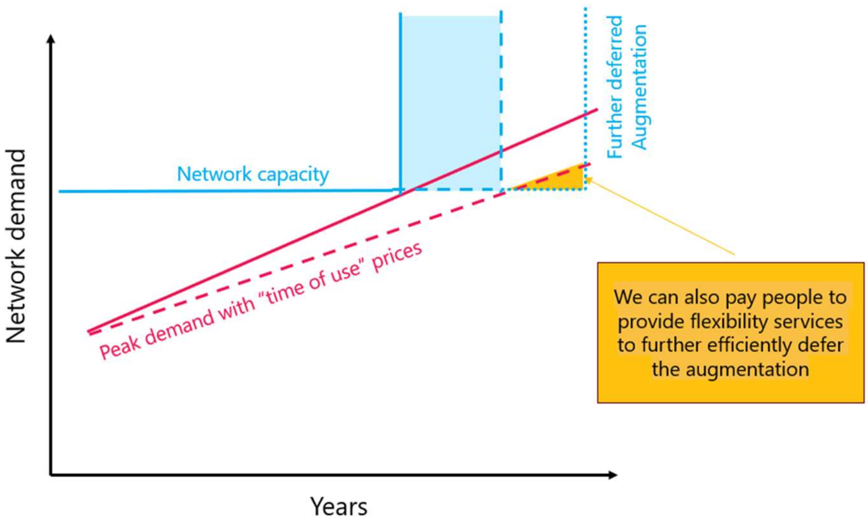
The amount of money we are allowed to charge by the regulator is capped so we forecast what we expect to recover through peak prices and recover the balance through fixed charges and low off-peak variable prices.

Because most of our costs are fixed, we use fixed prices to recover most of the balance.

Where investment is close, we tender for network deferral options

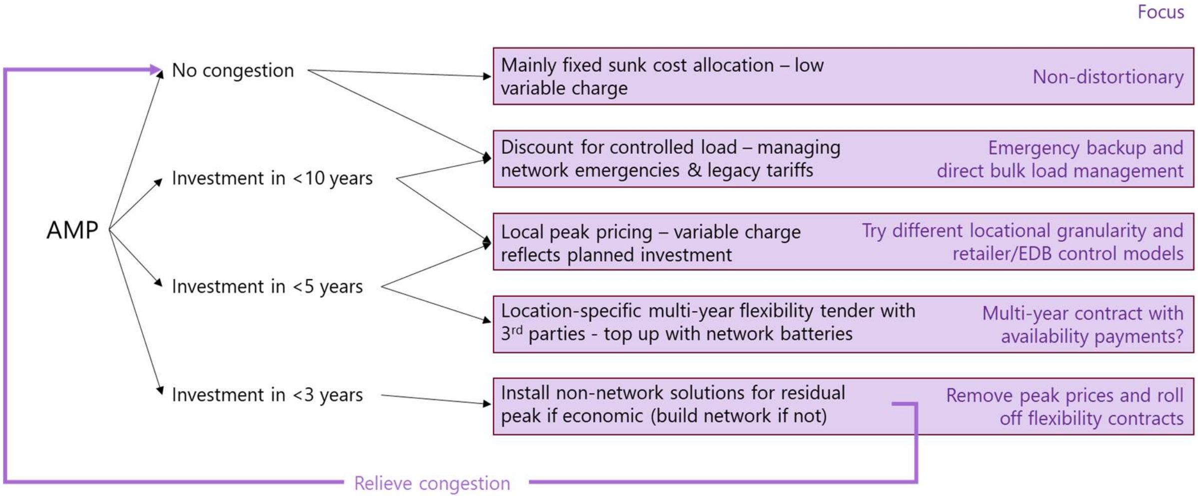
We can avoid or at least defer spending money on these physical capacity upgrades by reducing the size of the network peaks. This is achieved when our customers or their agents respond “flexibly” to peak prices by injecting electricity into the network (from a local generator or a battery) or reducing local demand in the part of the network which is congested (Figure 5).

Figure 5. How prices and flexibility can further defer network spend



The falling cost and improving capability of new technologies to control demand and store or generate electricity means that the opportunity for us to do this economically is improving all the time. Over the next decade we will refine and align the complementary initiatives to defer investment, each working over different time horizons, as shown in Figure 6 below:

Figure 6. Powerco investment framework



Over the next five years we will reach a steady state but in principle, our prices will roll through a sequence:

- Prices in areas of the network that are uncongested and where we aren't planning major investments for a decade will mainly be fixed – recovering the sunk costs of the network but not varying according to usage
- We'll offer slightly lower fixed prices to recover the costs of the network where we have the ability to control customers' loads (particularly their hot water cylinders) because we can directly shift their load to times of day when our network isn't congested
- We'll signal the cost of investments we're planning to accommodate growth with peak prices
- Once we get to within 5 years of any planned investment, we'll identify opportunities to go to market for "flexibility" solutions which can defer the growth in peak demand that's driving the investment and
- Once we start planning the project, we look for "non-network alternatives" to assess if they're cheaper and build them where possible and network assets where not.
- Once the project has been completed, there won't be any congestion, so we move to the start of the sequence, recovering costs through largely fixed prices.

How efficient pricing lowers costs

As Powerco is a wholesale business, for all but our largest customers we provide electricity distribution services to retailers who pay our bills. They may choose not to pass our charges on in exactly the form that we invoice them if they can find more effective ways to move demand out of peak periods.

At Powerco we encourage competition and we're proud to host around 30 retailers who compete on our networks and offer a range of products, prices and services for our customers to choose between.

We've seen retailers on our networks do all sorts of innovative things to respond to our prices, from creating imaginative new offers like an "hour of free power" to encouraging customers to use electricity in off-peak periods to sending instructions directly to the customer's EV (with their permission) telling it when to charge and when not to. In both cases the customer doesn't see our charges, and in the EV example they don't need to do anything - but they know they're paying a low price for their power.

Where retailers do pass our charges on directly with "time of use prices" that match our peak and off-peak periods, customers can minimise what they spend on electricity by trying to use electricity off-peak and avoiding the peak periods – say by running the dishwasher or charging the EV at night and even preheating rooms during the afternoon so the heat pump doesn't have to run as hard in the evening peak period.

Figure 7 below illustrates examples of how you can benefit from time of use pricing.

Figure 7: How customers benefit from time of use pricing[1]

Electric Vehicle driver

Professional who drives her electric vehicle during the day and plugs it in when she gets home.

Her retailer makes charging it as cheap as possible by controlling when the electric vehicle charges dynamically.

The retailer charges the car in the periods when wholesale electricity prices are lowest during Powerco's off-peak period but it's always fully charged when the customer wants to leave in the morning

Holiday home owner

Family stay in the holiday home during the summer holidays and for long weekends throughout the year.

In this region, Powerco's network is heavily used during these periods so network charges reflect that.

The family's electricity retailer charges a higher price during peak periods so the family saves money by running the washing machine and dryer at night

Busy family

Working parents with 3 kids don't have enough time to think about electricity but they pay lower electricity prices during the day and at night.

Their retailer controls their hot water cylinder so that it's only on off-peak when power's cheap but the water's always hot but they pay very little for it.

They've also put their washing machine on a timeswitch so that it runs at night

Single person living alone

Money's tight for this kuia. She pays a much lower price for electricity at night and in the middle of the day so she's careful not to use electricity outside these times where possible.

During winter she has the heating on during the day but turns it off at 5pm. By drawing the curtains the flat stays warm and comfortable until she goes to bed but without paying big power bills.

[1] Images generated using Microsoft Copilot

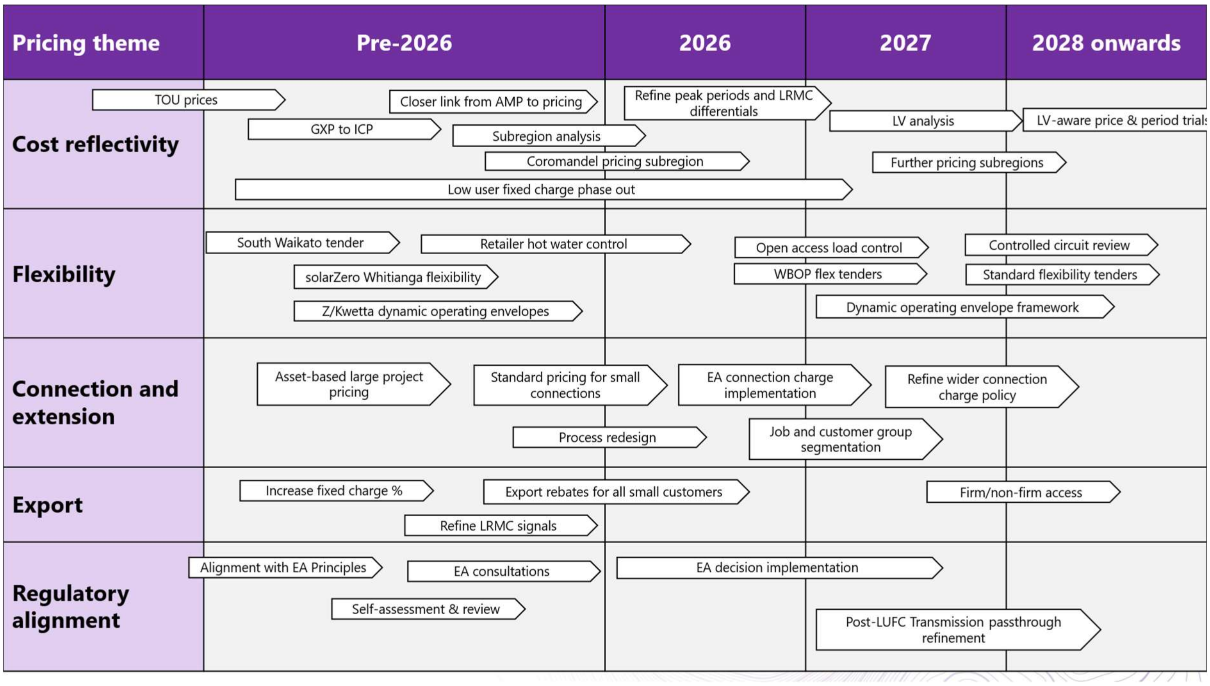
3. Improving Powerco's Prices to Benefit Our Customers

Our pricing improvement roadmap

Section 2 explains the benefits of cost reflective pricing in terms of deferring investment and creating options for lower supply costs.

This section explains the achievements that we have made on this journey so far, the changes we will be making this year and our future plans. The roadmap below (reproduced as a larger image in the appendices) summarises the key initiatives across the five pricing themes – aligning prices more closely with costs, exploiting flexibility as a complement to demand elasticity, developing efficient prices for those customers who generate electricity and want to export it into our network and how we are aligning with our regulators' reform initiatives.

Figure 8. FY27 Powerco pricing roadmap



Pricing reform achievements to date

At Powerco we have been using "time-of use pricing" since 2019. Every year we review our prices to make sure that they are as closely linked to our asset management plan as much as possible. We've done this in parallel with winding down the "low user fixed charge" rate we were previously required to offer. While well-intentioned, this charge distorts the cost of supplying customers, isn't in the long-term interests of small users and has made it very difficult to identify the difference that time of use pricing has this has made to when customers use our network. Once the low user charge is completely removed in 2027, we will be able to measure changes in network use with time of use price signals directly.

A major change we made in 2024 was to associate different prices with each individual connection on our network. In time this will allow us to trial more localised peak prices than we have been able to in the past.

"Flexibility" pilots at Powerco

Where the asset management plan identifies the need for a planned upgrade within 5 years, despite us signalling this with peak prices, there may be an opportunity to defer the project by paying third parties to inject electricity from a local generator or a battery or reduce demand in the affected area – using controllable load or injection in this way is called "flexibility". Over the years we have been experimenting with the use of flexibility:

- Our first step in this process was in 2018 when we called for expressions of interest in providing non-transmission network solutions as options for reinforcing electricity supply in the South Waikato. In this instance, the non-network alternatives were more expensive than the transmission solution.
- In 2021 we ran a tendering process for network support to the Coromandel Region. SolarZero was awarded a contract to provide 1MW of network support during peak consumption times. We paid them to keep their batteries fully charged when a local network peak was forecast and to export stored electricity into the network when the peak occurred.[2]
- In September 2023, we livened four controllable fast chargers for electric vehicles at Z's forecourt in Waiouru. These support the electricity network by intelligently responding (reducing load) to minimise impact during peak demand periods.
- In December 2023, Z Energy livened a 500kW flexible Kwetta EV fast charging array at Ngātea, on a part of our network which has voltage constraints during peak periods.
- Since February 2025 we have sought multiple expressions of interest from flex service providers to provide demand reduction services during peak electricity load times in the Mt Maunganui area.

These projects have informed our understanding of how we can use flexible connections to minimise the cost and maximise the speed of the transition as well as increasing our understanding about "dynamic operating envelopes" where we allow customers access to constrained parts of our network on terms which make the most of network capacity when it is available but don't adversely affect other network users when it's constrained.

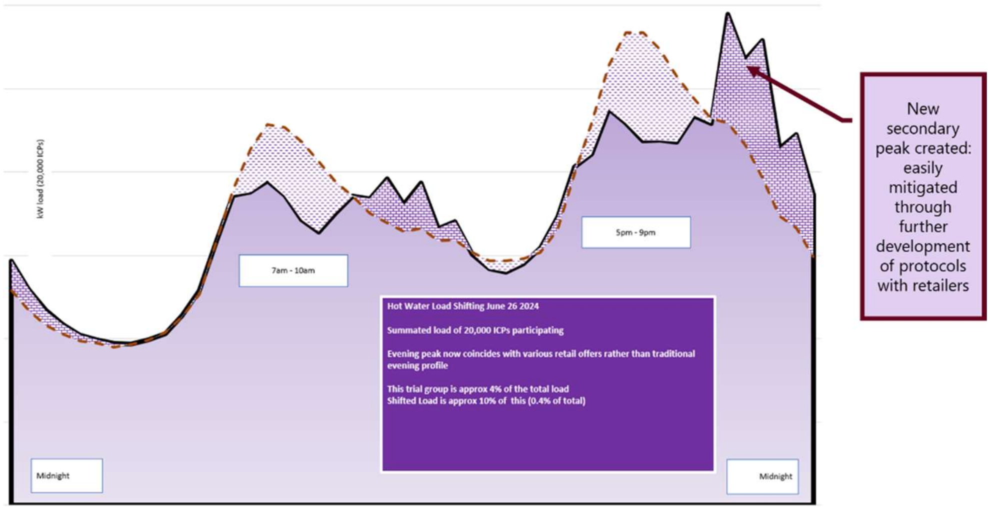
Retailer load control trials at Powerco

Like all electricity distribution businesses in New Zealand, Powerco offers "controlled" tariffs to customers whose hot water cylinders (and certain other loads) are attached to a dedicated circuit which they allow us to turn on and off (within limits to make sure we don't make their showers cold!).

This technology has been valuable as a way of reducing load during local and national system emergencies for decades. It is a broad-based solution – we send signals along our power lines to switch all the hot water cylinders the same part of the network on and off together.

[2] We have suspended the contract with SolarZero as a result of their liquidation: SolarZero enters liquidation | RNZ

During winter 2024, we ran a trial with several retailers to pilot this model. We retained the ability to override retailer instructions in the event of a local or national system emergency. It has been very popular with over 30,000 customers signed up in the first year. Our early experience is that retailers switching off individual hot water cylinders during the morning peak in the electricity spot market (dashed line in the graph below) has taken nearly 10% off the peak load that we would otherwise have experienced but without having to turn every single cylinder off.



Overtime, we expect to see an increasing proportion of load on our network controlled by retailers and other parties rather than us directly. A priority will be agreeing operating protocols for routine and emergency situations before we are able to look at the future of our pricing for and investment in control plant. There's more information in our 2025 Asset Management Plan Update.[3]

[3] https://www.powerco.co.nz/who-we-are/disclosures-and-submissions/electricity-disclosures

What's new in Powerco's 2027 pricing

Last year we implemented three important innovations:

- A new pricing subregion in the North Coromandel[4] where we experience very high network peaks during holiday periods. We are interested in working with retailers to understand how we can jointly use prices to minimise the cost of expanding the network by encouraging customers to shift load out of the peaks. We will continue with this differentiated pricing subregion this year, and

- Credits (negative variable charges) for customers who export power from generation or battery storage at their ICP at peak times to reflect benefit that local supply into the network in peak periods. This credit reflects the fact that injecting electricity has the same benefit as reducing demand. This is now explicitly required by the EA from 1 April 2026. Based on our experience with the export credit last year, we are increasing the credit amount this year.

We will continue to phase out the low-user fixed charge option, consistent with government policy to remove the tariff by 2027. This is the last year that a low fixed-charge option will be provided, with the daily charge on applicable categories increasing from 75 to 90c.

This year we will further refine our pricing to align with the Electricity Authority's guidelines[5] by

- introducing the provision for a capacity charge for small customers (up to 63 Amps single or 3-phase) as a form of cost-reflective fixed pricing where the local network is not congested and

- applying a consistent demand charge to all medium commercial (T/V28) customers to reflect the higher cost of supplying customers with peaky loads.

Next steps in improving our prices

Our priority over the next 5 years is to build on our experience with the North Coromandel pricing subregion and flexibility trials to introduce local pricing and flexibility initiatives to signal the cost of planned investments from the Asset Management Plan at an increasingly granular level.

In parallel we will work with retailers to review and adjust our pricing for controlled loads to contribute to these regional pricing and flexibility initiatives.

LV asset management

Powerco has detailed historic records of demand measured at our distribution transformers – at a street level rather than an individual customer's site. Retailers do measure customers' demand at an "Installation control point" or "ICP", but in the past we haven't had access to customer-level ICP data consistently across our networks. This means we have limited information about the actual loading and constraints of the "low voltage" ("LV") networks below the distribution transformers.

[4] ICPs attached to the Coromandel, Whitianga and Tairua Zone Substations.
[5] https://www.ea.govt.nz/documents/299/Distribution_pricing_practice_note.pdf

We acquired historic ICP-level demand data during 2024. We will be analysing this information in the coming years to understand the actual loadings and constraints on the LV networks that connect customers to our distribution transformers. Over the next 5 years we expect to use this information to develop "bottom-up" asset management plans for these parts of the network that are more granular than we can create with data from the distribution transformers.

In the same way that we are using the information in our current asset management plan to signal network constraints and planned investments at a pricing region and subregion level, we will explore how, in future, we can use pricing and flexibility tenders to defer and derisk planned investment on the LV network to minimise the cost of providing the network but make sure our customers don't face restrictions in using it.

4. How we actually calculate our prices

Network "prices" are a series of cost allocations. Because we are the only provider of an electricity network in our regions, the amount of money we are allowed to charge for our services is regulated by the Commerce Commission. Their job is to make sure what we charge for the regulated service is reasonable.

The Commission determines this by calculating a maximum revenue for us which is built up from "blocks" of efficient cost, including depreciation on the value of our assets, the cost of money invested in those assets, tax and operating costs.

The Electricity Authority also regulates how we turn this revenue into "prices" by dividing the revenue between groups of customers. This mimics what would happen in a competitive market. Our pricing methodology meets the Authority's Pricing Principles in 5 steps:

Calculating the revenue we are allowed to recover

1 April 2025 was the beginning of a new "default price quality path" under which the Commerce Commission sets our maximum distribution revenue. In the 2026/27 pricing year, this limit is $474 million.[6]

[6] *Electricity Distribution Services Default Price-Quality Path Determination 2025*, Commerce Commission. p. 45. This starting price is excluding wash-up amounts, pass-through and recoverable costs.

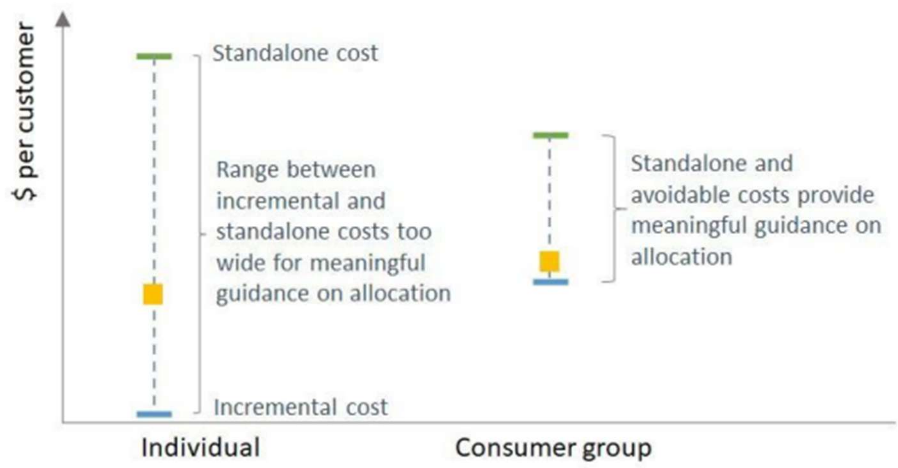
We calculate and publish the detailed calculation for this maximum allowable revenue amount in our *Annual Pricing Setting Compliance Statement*[7].

Grouping customers

In order to get the benefits of cost reflective pricing – deferring or avoiding planned investment by signalling it in peak periods – we need to be able to target price signals as precisely as possible to those customers whose changing electricity use is responsible for that investment need.

Even very broadly-based variable charges can be efficient, so long as they are between the cost of expanding the network and the cost building a standalone power supply to use instead of the network. Designing customer groups is important because if peak prices are set too broadly the cost of planned investments is averaged out so much that it doesn't create a strong enough signal even for the most price-sensitive customers to change their consumption behaviours. As illustrated by the Authority in their Pricing Practice Note[8]:

Figure 2: Comparison of subsidy test methods

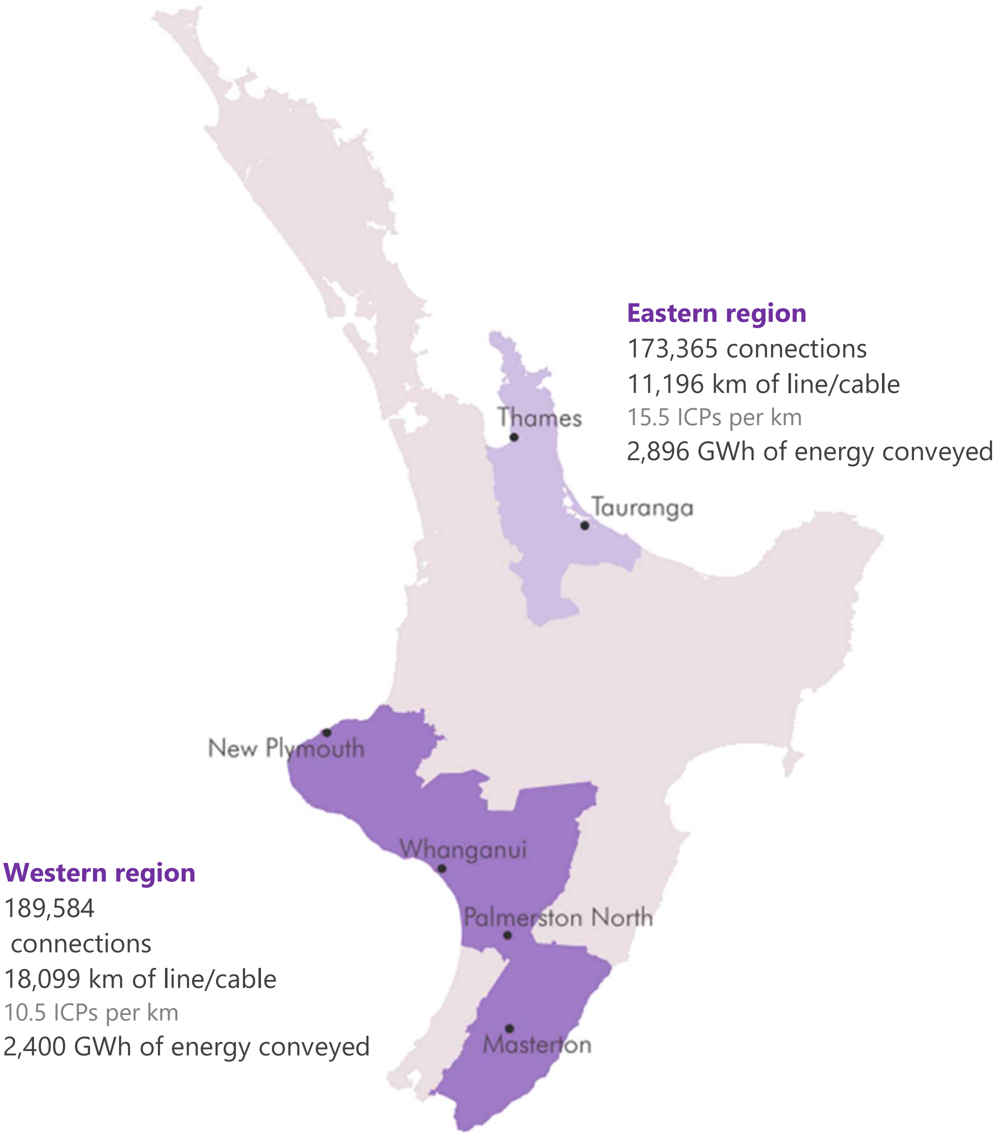


On the other hand, defining too many customer groups would also be inefficient because the "transaction costs" of managing the correspondingly large number of prices would be larger than the benefit of deferring planned investment by a few years.[9]

Because Powerco is one of the largest electricity distributors in New Zealand (we operate over 28,000 km of electricity distribution network across the North Island), we have four major pricing zones: two in the Eastern region covering Tauranga and Thames Valley and two in the Western region spanning Taranaki, Whanganui, Manawatu, and the Wairarapa. Within each region we separate predominantly urban zones from predominantly rural ones (see Figure 9):

[7] https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/disclosures/electricity-disclosures/4-default-price-quality-path/fy27/annual-price-setting-compliance-statement-1-april-2026---31-march-2027.pdf
[8] Electricity Authority, Distribution Pricing Practice Note: Second Edition v 2.2, October 2022 p.50
[9] Electricity Authority, Distribution Pricing Practice Note: Second Edition v 2.2, October 2022 p.50

Figure 9: Powerco's Eastern and Western network regions and key statistics[10]



Factors which influence our pricing approach and prices

There are three main factors which influence how we approach and calculate different prices:

- **Customer characteristics** including consumption patterns at different locations, uptake of solar panels, electric vehicles, or other technology
- **Network characteristics** including topography, growth, system reliability and security, customer density, network use, data availability
- **Regulatory requirements** imposed by legislation about the structure and level of prices

These are discussed further in the following.

[10] As at 31 March 2025.

Customer characteristics

Customer characteristics such as load profiles and connection type affect the cost of supplying the distribution service. Our pricing approach considers the following characteristics:

- **Load profiles**: Your electricity consumption can vary across the day and year for a range of reasons, e.g. weather or lifestyle. We allocate costs based on consumption profiles because it is the most important driver of fixed cost investment in network infrastructure.
- **Connection type / network use / capacity requirements**: A higher capacity connection typically requires more assets and therefore higher fixed costs. For example, a new dairy farm connection may need a specific asset which cannot be utilised by other customers. We allocate dedicated costs directly where possible.
- **Location**: Customers in the Eastern and Western regions are supplied using separate networks with their own cost characteristics. The charge we receive from Transpower at each point of connection to the national transmission grid ("Grid Exit Point") also varies.
- **Density**: The number of customers per kilometre varies across the network and impacts how we allocate costs. For example, the cost of supplying distribution services can be higher in lower density areas (typically rural areas) because the costs are shared across fewer customers.
- **Emerging customer preferences and technology choices**: Customer uptake of new technology such as solar panels and battery storage is changing the way energy markets operate. Distributors play a key role in facilitating these changes. We aim to keep our prices technology-neutral, with pricing related to impact on network costs rather than specific technology.

Network characteristics

Powerco operates over 29,000 km of electricity distribution network across the North Island of New Zealand. Our network is split into two regions, with the Eastern region covering Tauranga and Thames Valley and the Western region spanning across Taranaki, Whanganui, Manawatu, and the Wairarapa. These regions contain a range of urban and rural areas. Differences in the network requirements, population and load characteristics mean the cost of supply varies between and within our network regions.

Table 1: Network Characteristics as Described in our Asset Management Plan

Region	Pricing Zone	GXP(s)	Regional Description	Network Considerations
Eastern - Valley	VALLEY	Arapuni (ARI1101) Hinuera (HIN0331) Kinleith (KIN0331 & KIN0112) Kopu (KPU0661) Piako (PAO1101) Waihou (WHU0331) Waikino (WKO0331)	Valley includes a diverse range of terrain, from the rugged and steep forested coastal peninsula of Coromandel to the plains and rolling country of eastern and southern Waikato. Economic activity in these areas is dominated by tourism and farming respectively. From a planning perspective, this region presents significant challenges in terms of maintaining reliability on feeders supplying sparsely populated areas in what is often remote, difficult-to-access terrain. Investment priorities have focused on improving network security and resilience, and developing better remote control and monitoring facilities.	• Mostly favourable terrain for network construction and maintenance, with rather temperate weather. • Lower population density overall, when compared to the Tauranga region. • Coromandel (Kopu GXP) and Waikino are characterised by more rugged terrain with less adequate roads for heavy vehicles. • Seasonal fluctuations in population in the Coromandel cause holiday period peaks at certain zone substations. • The rest of the Valley's demands are more influenced by commercial and industrial sites and permanent residents. • Kinleith's demand is dominated by the pulp and paper plant located there, Powerco's largest industrial customer.
Eastern - Tauranga	TAURANGA	Tauranga (TGA0111 & TGA0331) Mt Maunganui (MTM0331) Te Matai (TMI0331) Kaitemako (KMO0331)	Tauranga is a rapidly developing coastal region, with horticultural industries, a port and a large regional centre at Tauranga. The principal investment activities in this zone have been associated with accommodating the rapid urban growth in Tauranga, maintaining safe and reliable supplies to the port, supplying new businesses, and supporting the horticultural industry.	• Steady population and demand growth in Tauranga and Mt Maunganui, which seems likely to continue. • Growth is expected in both the horticultural and residential sectors. • Exposure along the coast indicates future costs for the maintenance and replacement of deteriorating assets

Region	Pricing Zone	GXP(s)	Regional Description	Network Considerations
Western - Manawatu	A	Bunnythorpe (BPE0331) Linton (LTN0331)	Manawatu includes rural plains and high-country areas exposed to prevailing westerly winds. It is mainly agricultural in nature, but the large regional centre of Palmerston North has significant logistical industries, a university, and associated research facilities.	• The urban centre of Palmerston North is expected to have continued growth, while growth in the more rural Tararua area is expected to remain flat. • While windy weather is common, this is more of an issue in the more rugged and less accessible Tararua (Mangamaire GXP) area.
	B	Mangamaire (MGM0331)		
Western - Taranaki	A	Carrington (CST0331) Huirangi (HUI0331) Stratford (SFD0331)	Taranaki, which is situated on the west coast plains, is exposed to high winds and rain. The area, which includes the large regional centre of New Plymouth, has significant agricultural activity, oil and gas production, and some heavy industry.	• Chances of extreme weather and corrosion of assets from exposure along the coastline. • Population density varies considerably within the Taranaki region. • Growth in the region is heavily influenced by the agricultural, gas and oil industries.
	B	Hawera (HWA0331) Opunake (OPK0331)		
Western - Whanganui	A	Brunswick (BRK0331) Wanganui (WGN0331)	Whanganui includes the surrounding Rangitikei and is a rural area exposed to westerly sea winds on the coast and snowstorms in high country areas. It is predominantly agriculture-based with some industry.	• The rural areas of the Whanganui region are rugged and hilly. Flooding of the Whanganui River can occur. • Whanganui itself is experiencing growth which seems likely to continue. • The Ruapehu district is subject to extreme weather conditions and snowfall. Ohakune's population and demands are very seasonal, as a popular winter destination.
	B	Marton (MTN0331) Mataroa (MTR0331) Ohakune (OKN0111) Waverley (WVY0111)		
Western - Wairarapa	B	Greytown (GYT0331) Masterton (MST0331)	Wairarapa is more sheltered and is predominantly plains and hill country. It has a mixture of agricultural, horticultural and viticulture industries.	• Carterton and Greytown are growing and are expected to grow further. • Weather can be extreme in coastal areas and flooding can occur.

More detail of our investment plans and day-to-day asset management priorities across out network regions is in our Asset Management Plan, available at https://www.powerco.co.nz/who-we-are/disclosures-and-submissions/electricity-disclosures

Regulatory requirements

Our pricing approach is influenced by a range of regulatory requirements and expectations from Government, the Commerce Commission, and the Electricity Authority. The main obligations are:

- Setting prices to recover the allowable revenue the Commerce Commission approved for Powerco so we can invest in our network to improve reliability, resilience, and quality of supply. **Sections 5, 6 and 9** describe how we do this.
- Setting prices for distributed generation connected to and using our network according to Part 6 of the Electricity Industry Participation Code 2010, relating to the pricing of distributed generation. **Section 7**, and our Distributed Generation Policy, describe how we do this.
- Setting efficient and cost-reflective prices consistent with the Electricity Authority's Distribution Pricing Principles of August 2019[11]. **Section 11** describes how our pricing approach aligns with these.
- Providing information about our pricing approach, and price–setting for the year ahead in accordance with the Commerce Commission's Electricity Distribution Information Disclosure[12] requirements. **Section 12** describes how we meet these, along with information on our website at: https://www.powerco.co.nz/who-we-are/disclosures-and-submissions.
- We are required to offer household customers a low fixed charge tariff option (of 60 cents/day) by the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* (the "Low Fixed Charge Regulations"). The Low Fixed Charge Regulations prevent us from setting prices which fully reflect the cost of supply.

Other sources of Powerco pricing information

Other sources of pricing information are available on our website:

- Information for customers connecting distributed generation to our network about the connection process, connection charges and our approach to procuring distributed generation for network alternatives, is available in our Distributed Generation Policy here
- Information for commercial and industrial customers about new connections and upgrades is available here
- Technical information for retailers on our pricing is available in our Pricing Policy here
- Information for customers about our annual price and revenue changes is available in our Annual Price-Setting Compliance Statements here and our Reasons for Change factsheet here.

[11] The Electricity Authority Pricing Principles are available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper/

[12] The Commerce Commission Information Disclosure requirements are available at https://comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors

5. Customer groups for capacity and location

Prices are set for specific customer groups because it is not practical to set individual prices, except for large commercial and industrial customers. Connections are grouped across each network, based on location and connection size or capacity. These two criteria reflect the influence on costs of network and customer characteristics such as geography, rural/urban network density, mains size, protection rating and/or transformer capacity. The location and capacity criteria combine to determine the pricing category for a customer.

How capacity is factored into pricing

We split connections into five capacity groups in each region, with some additional sub-groups to cater for specific types, e.g. streetlights, which allows prices to reflect costs more closely for each customer group. We continue to assess the number of customer groups, and alignment across the regions, as network usage evolves.

The table below describes each group.

Customer capacity group
W01/W02, T01/T02 and V01/V02 – for **all unmetered connections** such as streetlights across the Powerco network The unmetered nature of the load and the associated dedicated equipment, require special consideration when allocating costs
W05/W06, T05S/T06S, V05S/V06S, and V05C/V06C – for **all residential customers and small commercial customers** with a fuse size of 3 Phase 63 Amps or less Any customers with a fuse size of up to 3 Phase 63 Amps are typically considered to be residential or small commercial customers and, as such, individually place minimal demands on our network and require minimal investment in on-site and upstream assets Providing specific eligibility criteria[13] are met, residential customers can choose between the low user price categories (W05/V05S/T05S) and the standard price categories (W06/V06S/T06S)
W22/T22/V22 – for **medium commercial customers** with a fuse size of greater than 3 Phase 63 Amps up to and including 3 Phase 250 Amps Any connections with these fuse sizes are typically commercial customers with higher average volumes than the W05/W06, T05S/T06S and V05S/V06S Price Categories. Therefore, this group places increased demands on different components of our network and requires larger investment in on-site and upstream assets
W29/T28/V28 – for **medium/large commercial customers** with an installed capacity of 200 – 299 kVA Any connections with this level of installed capacity are typically medium sized commercial customers with significantly higher average volumes than the T22/V22 Price Categories. Therefore, this group places increased demands on the upstream network assets and requires larger

[13] For details on the eligibility criteria for the low user (also known as low fixed charge) prices, please see the full Pricing Policy here.

Customer capacity group
investment in on-site and upstream assets ***W29 will initially include existing Commercial TOU Connections with installed capacity of 101 – 300 kVA until those outside the intended range are transitioned to W22 and W50*
W50/T50/V40 – for **large commercial customers** with an installed capacity of 300 – 1499 kVA. Any connections with this level of installed capacity are typically large commercial customers which require dedicated transformers and associated switch gear to meet their supply requirements
W60/T60/V60 – for **large commercial customers** with an installed capacity of 1,500 kVA and greater Any connections with this level of installed capacity are typically very large commercial/industrial customers who place increased demand on upstream network assets and require dedicated on-site transformers and dedicated feeders to meet their supply requirements Because connections in the V40, T50, W50, T60, V60 and W60 price categories typically require dedicated on-site and, in some cases, upstream assets, they are all individually priced based on their specific on-site and upstream assets and contribution to peak demands. While these customers are charged a constant daily price, it is reviewed each year based on the customer's previous year's peak demands (as detailed in Section 6) and any changes to the relevant assets in the current year. This ensures that their prices are regularly updated to reflect their individual contribution to network costs

The granularity of the groupings for each category reflects a trade-off between practicality, fairness, and cost-reflectiveness. We have made several incremental improvements over recent years to simplify our price structure, while maintaining or increasing fairness and limiting price impacts on customers.

Capacity criteria

Customers are grouped by the capacity of their connection to the network, being either their fused capacity when connected to a shared transformer, or the size of the transformer/s dedicated to them. Powerco's prices in the Eastern and Western regions are structured to reflect these different capacity bands.

Eastern

The Eastern customer groups have similar load characteristics, such as demand, fuse size and installed capacity, as well as those which use specific sets of assets.

Fuse size is used for most Eastern customer groups because, especially for residential and smaller commercial connections, their available capacity is limited by the size of the fuses at their installation, rather than the installed capacity of dedicated transformers. For this reason, connections typically have only one applicable price category. There are situations where customer preferences and metering can determine the price category, such as the low user (V05S/T05S) and T22 price categories.

Western

The four Western region customer groups have similar characteristics relating to their installed capacity and associated demand. They reflect the use by each customer group of components of the network, such as sub-transmission, high voltage (11kV), and low voltage (400V) assets, and the on-site assets at each connection such as transformers and associated switchgear.

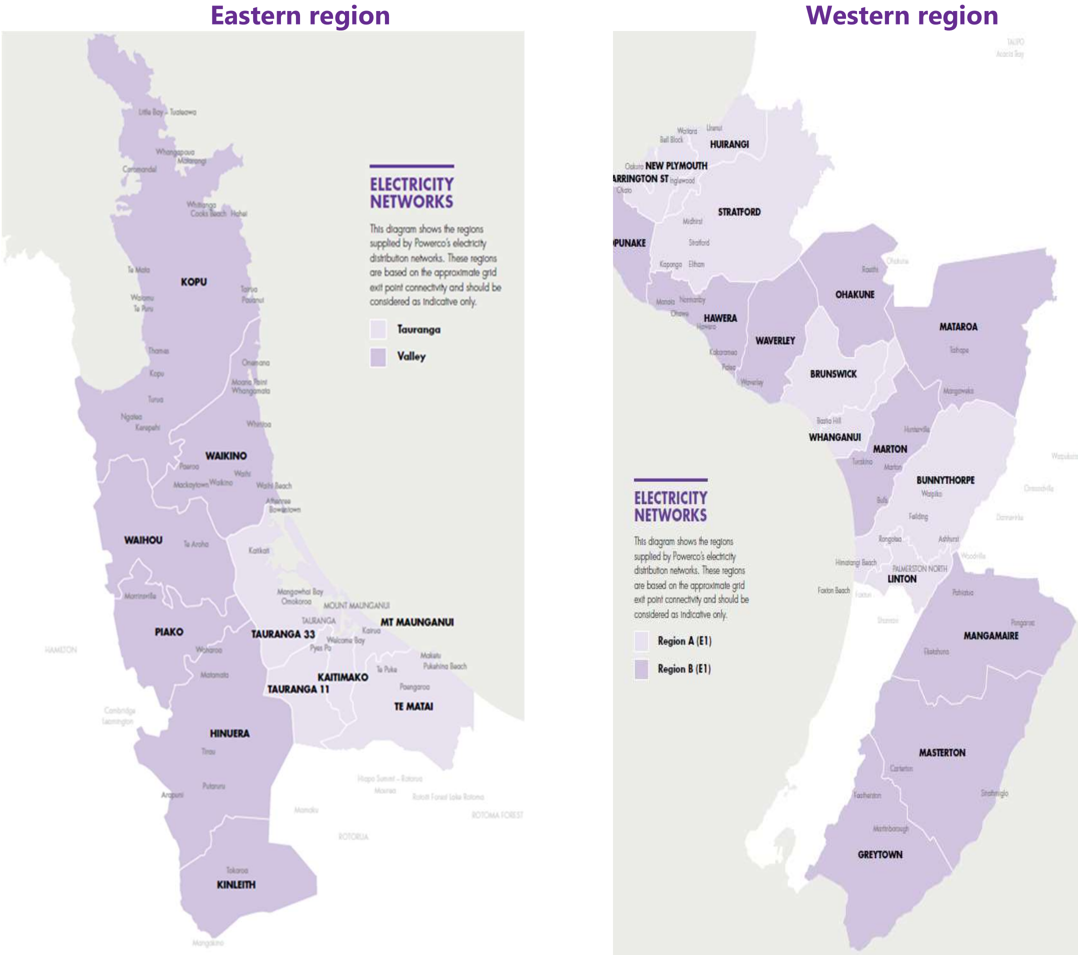
Most residential connections in the Western region make use of all the network assets but have limited on-site assets. Industrial connections (W50 price category) often have more on-site assets and make limited use of the low voltage (400V) network assets. The use of these customer groups means prices can better reflect the costs to supply these groups.

How location is factored into pricing

The location groupings reflect the underlying cost of supplying distribution services to customers in specific locations. The following figure shows the pricing zones for the Eastern and Western regions. Grouping customers by location assists in recognising the relative costs of supplying customers within specific areas and allows a fairer allocation of costs.

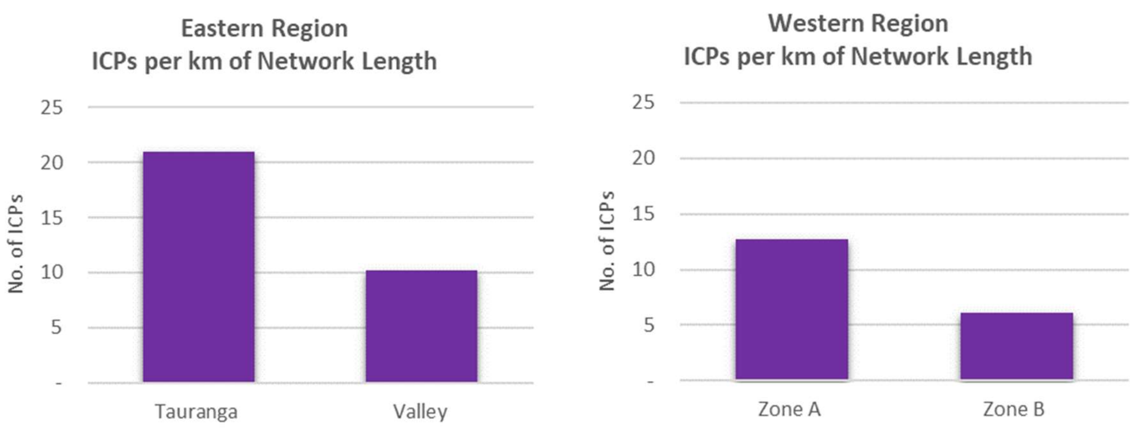
Figure 10: Eastern and Western region pricing zones

Eastern region **Western region**



The Eastern and Western regions are each split into two zones, reflecting customer density within each region (see below).

Figure 11: Average network density (Eastern and Western regions)



Eastern region

Customers are grouped based on connection to either the Tauranga or Thames Valley sub-regions. The Tauranga part of the network has a higher density than Thames Valley. Prices for residential customers on the Valley network are typically higher than in the Tauranga network because the lower network density and greater average system length means the costs of supply are allocated across fewer customers.

Western region

Customers are grouped by GXPs which have a similar network density:

- Zone A includes customers connected to GXPs supplying the high-density urban centres such as New Plymouth, Whanganui, and Palmerston North
- Zone B includes customers connected to GXPs supplying the remaining lower density areas

For residential and small commercial customers, prices for zone B are typically higher than zone A because the lower network density and greater average system length means the costs of supply are allocated across fewer customers.

Commercial and industrial customers are split between ten zones, with each zone representing a grouping of GXPs based on the structure of the network connecting them. For example, the GXPs of Huirangi, Carrington St and Stratford are grouped together into zone A, as they are interconnected at the 33kV and 11 kV level. The number of zones represents Powerco’s preference for greater transparency of costs within each price category, because changes to individual customer behaviour within these groups can affect the underlying cost structure.

6. Price categories for each customer group

Prices for customers are set three high-level ways:

- **Standard pricing** for residential and most commercial customers supplied according to the price categories in the standard price schedule
- **Non-standard, customer specific, asset-based pricing** for large connections (>299kVA), although also some smaller customers where asset-based pricing is appropriate
- **Non-standard, asset-based, building block pricing** for very large (typically >4MVA) connections, typically requiring a capacity upgrade or large new connection. These customers have a direct contractual relationship with Powerco for a defined term.

We also set prices for distributed generators, including payments to distributed generators providing network support services.

Standard pricing

We set standard prices each year using the process detailed in the following table.

Table 2: Standard pricing process

Activity	What's involved
Determine customer groups	• Assign customers (connections) to groups for allocating total costs. More detail on how we do this is in Section 5.
Calculate and allocate costs to customer groups	• Confirm the total forecast allowed revenue we can recover for the year. Forecast revenue is determined by the Commerce Commission to reflect efficient costs of supplying distribution services • Calculate expected costs for the year. The main component costs are operating costs (including administration costs), capital costs (including return on investment) and transmission costs • Allocate costs to each customer group to, as closely as possible, align benefit of access and use of the distribution service with the costs of supplying the distribution service • Determine price structures for each customer group based on the required price signals, relevant cost allocations, and complying with the relevant legal requirements More detail on how we do this is in Section 6.
Assess customer impacts of pricing variations	• Check the impact on customers of pricing variations, and adjust pricing as needed More detail on how we do this is in Section 10.

Non-standard pricing

Non-standard[14] pricing and individual account management is offered to industrial and large commercial customers to provide a tailored service. We offer this when the customer's needs are unique to their business need, e.g. timing and scale of investment. Our approach to non-standard pricing considers customers' individual capacity and demand to ensure, to the extent practicable, that the price is cost reflective.

We have two non-standard pricing approaches:

- Dedicated onsite assets, with demand-based allocation of *broader* upstream assets
  Price Categories: T50, V40, W50
- Dedicated onsite assets, with demand-based allocation of *specific* upstream assets
  Price Categories: T60, V60, W60

The number, size and pricing characteristics of non-standard customers are available in Appendix A. We disclose the number of new non-standard contracts each year on our website here.

Customer-specific asset-based pricing

Customer-specific asset-based pricing applies to large connections and others suitable for an asset-based price, including arrangements designed to mitigate the risk of uneconomic asset investment. Each price is set individually using this process which is detailed in Table 3 below.

Table 3: Asset-based pricing process

Activity	What's involved
Measurement and forecasts of customer demand and connections	A customer's demand, measured by historical AMD (Anytime Maximum Demand), PCD (Peak Coincident Demand) and ADL (Average Demand Level), is used to calculate asset-based prices
Calculate value of assets supplying the connection, including allocating value of shared assets	The assets used to supply the service are valued in association with RAB values to calculate the asset-based price. Assets are categorised as dedicated on-site assets or shared upstream assets. On-site assets are generally dedicated assets, and wholly allocated to the relevant customer. Upstream assets are allocated using the site's maximum demand and the demand of the section of the network (e.g. zone substation) that the relevant upstream assets are a part of.
Calculate return of and on capital, and depreciation	An annual rate of return is recovered on the asset valuations attributed to each connection – this is based on Powerco's prevailing weighted average

[14] A contract is considered non-standard if the price at which the electricity line services are to be provided is not determined solely by reference to a schedule of prescribed terms and conditions that is publicly disclosed

Activity	What's involved
	cost of capital (WACC). Depreciation is allocated based on the asset's calculated annual depreciation.
Allocate maintenance costs	Maintenance costs are allocated based on asset types and values where applicable, or to load groups based on the load group's RAB relative to the applicable GXP's total RAB. These costs are allocated against the assets used by each customer, using an appropriate rate.
Allocate indirect costs (fixed and variable).	Indirect costs are allocated to load groups based on total usage as a proportion of the applicable GXP's total usage. Indirect costs are all costs of Powerco's electricity business excluding transmission, asset-related costs, maintenance, interest, and tax. These costs are recovered via a fixed charge to each Consumer in the load group, and an allocation to each based on their PCD.
Allocate transmission costs	Transpower's Connection, Benefit-based, and Residual Charges are allocated to Powerco via various methods. We allocate and pass-through these charges to customers using mechanisms that reflect the TPM and the EA's Pricing Principles and TPM pass-through guidance. The Connection charge is based on the consumer's historical demand, as measured by AMD (load), being a proxy for the connection size. The Benefit-based and Residual charges are allocated based on historical usage, measured by ADL, which aligns with the Transmission Pricing Methodology's allocation method.

More information on criteria applying when a customer enters an asset-based load group is available in our Pricing Policy, available at: https://www.powerco.co.nz/who-we-are/disclosures-and-submissions/electricity-pricing

Customers on non-standard contracts

Non-standard contracted customers are generally significant commercial or industrial loads, and arrangements between the customer and Powerco may include provision for response to planned and unplanned interruptions, the management of load in the event of maximum demand levels being reached, or load managed in the event of abnormal network configurations. These arrangements have no direct effect on the determination of prices for these customers.

Pricing for distributed generation

We do not currently charge distributed generation for exporting electricity via our network on a volume basis, but since 1 April 2025 we have provided a rebate to residential customers for export during winter peak periods with a tariff of 5 cents a kWh. From 1 April 2026 this will update to 6 cents a kWh in our Western Region, and 7 cents a kWh in our Eastern Region. Customers will still need to pay fixed charges to recover the cost of the network that already exists, but the negative export tariff will reduce their overall bill. For more discussion on export credits refer to Section 3 above.

Prices for distributed generation are set in line with Part 6 of The Code, and our Distributed Generation Policy is available here.

Signalling the cost of relieving network congestion

Having determined how much of our regulated revenue is to be recovered from each customer group in each region, we then use the Asset Management Plan to identify all planned investment in that region, that is addressing growth in demand.

To signal to customers the long-term implications of their usage, our variable charges are set around the concept of long-run marginal costs (LRMC). There are various different ways of determining LRMC, and there are practical trade-offs to be made. Our approach uses the average incremental cost and, in our view, is the simplest most stable approach that is consistent with the Authority’s pricing principles.

For each region we then identify the periods in which demand peaks – when we need to signal the cost of new investment to test whether customers are willing to pay for it, which is what we have done in our Coromandel subregion pricing zone.

7. Our pricing structure and plans to evolve our pricing approach

Prices are set taking account of the customer, network, and regulatory characteristics relevant to each of our networks, and how that pricing can promote efficient network use. We recognise the importance of pricing to reflect evolving customer expectations, technology choices, and use of the network.

Network metrics and peak pricing approach

The following table highlights the diversity of the characteristics and costs within pricing zones, by displaying a range of metrics about the cost and use of the network for different locations. The metrics allow assessment of relativities across regions (i.e. there is no 'right' metric for a region).

- Direct OPEX. This is based on internal records of operational expenditure (e.g. vegetation management) matched to the GXP and applied across all connections
- RAB/km and RAB/ICP. This reflects the current value of network assets in the area to line length or ICP count. The metric combines asset age (older assets have lower value) as well as the network configuration required to meet customer needs.
- ICPs/km. This reflects network density (higher = more dense, lower = less dense)
- MWh/ICP. Reflects average annual consumption by small customers[15].

Although certain GXPs may have high-cost metrics in one category, they are often balanced by being lower in another category. This provides the ability to group them into appropriate pricing zones, based on their overall cost versus usage and density.

Table 4: Network metrics by GXP

Region	Pricing Zone	GXP(s)	Direct OPEX ($/ICP)	RAB/km	ICPs/km	RAB/ICP	Small Customer Consumption (MWh/ICP)
Valley	VALLEY	Arapuni (ARI1101)	$485	$61,397	3.1	$19,957	10.8
		Hinuera (HIN0331)	$334	$82,623	7.4	$11,212	10.3
		Kinleith (KIN0331 & KIN0112)	$349	$20,668	2.1	$9,928	9.2
		Kopu (KPU0661)	$90	$242,005	22.7	$10,645	6.3
		Piako (PAO1101)	$327	$148,147	11.5	$12,903	10.5

[15] Large customers are excluded here as they can distort the metric due to the scale of their consumption and because their pricing approach is able to be more closely targeted at their network use.

Region	Pricing Zone	GXP(s)	Direct OPEX ($/ICP)	RAB/km	ICPs/km	RAB/ICP	Small Customer Consumption (MWh/ICP)
		Waihou (WHU0331)	$369	$53,927	4.7	$11,381	12.0
		Waikino (WKO0331)	$138	$105,234	15.2	$6,910	6.2
Tauranga	TAURANGA	Tauranga (TGA0111 & TGA0331)	$78	$86,644	12.6	$6,895	7.9
		Mt Maunganui (MTM0331)	$143	$111,609	19.9	$5,616	7.4
		Te Matai (TMI0331)	$238	$175,933	15.5	$11,386	7.8
		Kaitemako (KMO0331)	$241	$1,379,879	234.2	$5,892	8.0
Manawatu	A	Bunnythorpe (BPE0331)	$116	$95,617	13.1	$7,298	9.2
		Linton (LTN0331)	$149	$111,484	18.5	$6,036	9.1
	B	Mangamaire (MGM0331)	$800	$72,536	4.2	$17,134	8.9
Taranaki	A	Carrington (CST0331)	$77	$168,304	23.8	$7,062	7.9
		Huirangi (HUI0331)	$217	$58,164	6.5	$8,886	9.0
		Stratford (SFD0331)	$265	$133,431	10.5	$12,718	11.1
	B	Hawera (HWA0331)	$240	$79,307	7.6	$10,501	9.8
		Opunake (OPK0331)	$726	$38,003	1.9	$19,598	13.4
Wanganui	A	Brunswick (BRK0331)	$61	$26,046	3.8	$6,918	7.5
		Wanganui (WGN0331)	$78	$208,023	25.4	$8,196	7.8
	B	Marton (MTN0331)	$122	$31,973	2.8	$11,411	8.9
		Mataroa (MTR0331)	$284	$3,818,090	229.8	$16,618	8.5
		Ohakune (OKN0111)	$637	$25,219	1.7	$14,709	7.9

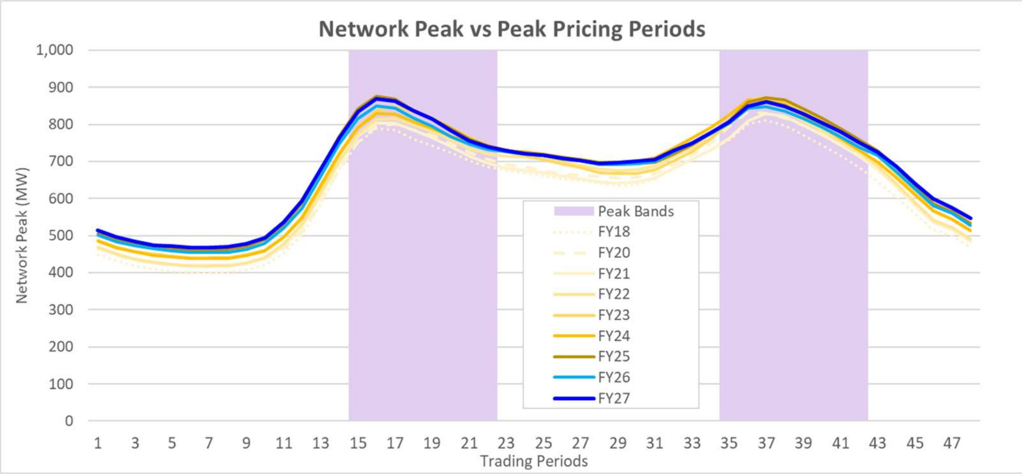
Region	Pricing Zone	GXP(s)	Direct OPEX ($/ICP)	RAB/km	ICPs/km	RAB/ICP	Small Customer Consumption (MWh/ICP)
		Waverley (WVY0111)	$572	$2,694	0.2	$14,087	11.9
Wairarapa	B	Greytown (GYT0331)	$394	$58,803	5.7	$10,308	10.1
		Masterton (MST0331)	$157	$191,664	23.0	$8,333	8.7

The table below summarises the usage characteristics, network characteristics, and resulting revenue allocation for each pricing zone. This demonstrates the alignment between allocated and forecast revenue at a regional level (rightmost two columns), and how various metrics align with that allocation, and with each other.

Table 5: Network summary

Pricing Zone	ICPs	MWh	Peak Coincident Demand	Coincident Maximum Demand	Regulatory Asset Base (RAB)	COSM Allocated Revenue	Forecast Recovered Revenue
Valley	22%	27%	24%	28%	26%	27%	23%
Tauranga	26%	25%	26%	25%	22%	22%	24%
Eastern	**48%**	**52%**	**50%**	**53%**	**48%**	**49%**	**47%**
A	36%	33%	35%	33%	31%	31%	34%
B	16%	15%	15%	14%	21%	20%	19%
Western	**52%**	**48%**	**50%**	**47%**	**52%**	**51%**	**53%**
Total	100%	100%	100%	100%	100%	100%	100%

Figure 12: Alignment of network demand to Peak/Off-Peak Periods



Note: The network demands relate to the observation window for the relevant financial year, e.g. FY27 peaks are observed between September 2024 to August 2025

Figure 13 shows the top 10 network peaks at each half-hourly trading period, overlaid with the time bands that represent Powerco's time-of-use peak pricing. It illustrates that:

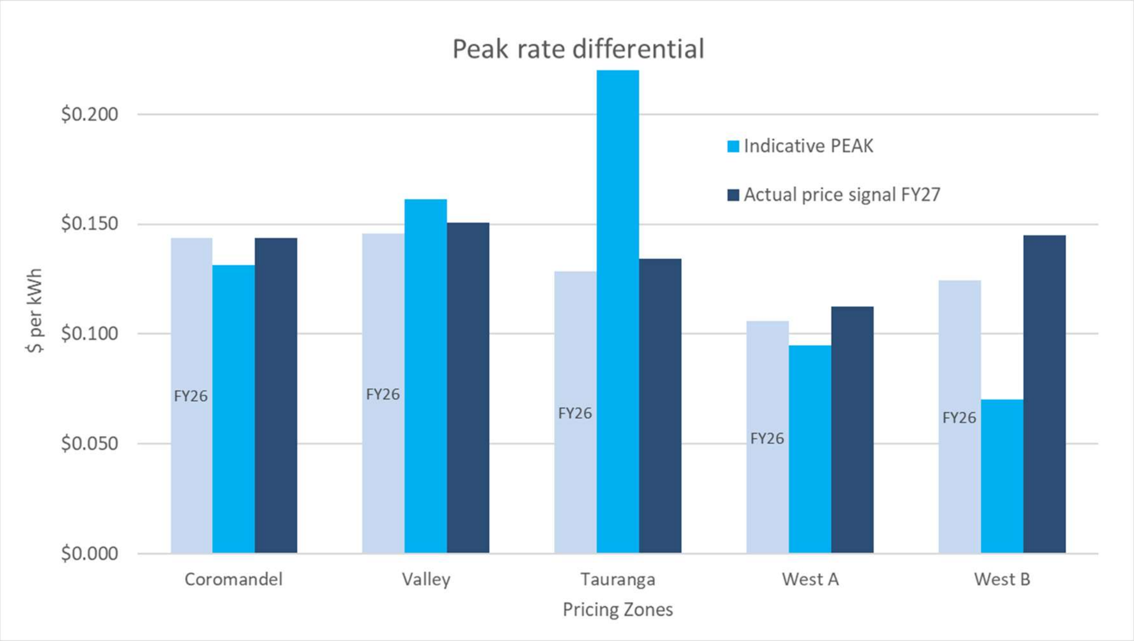
- The peak periods used for pricing align with the times that peak network demands occur
- The peak profile is relatively consistent between years, despite the economic and circumstantial (especially weather-based) factors that can affect any one year
- The peak/off-peak pricing approach, introduced in FY20, does not appear to have had a significant effect on usage patterns. This may reflect the distortions caused by the low-user fixed charge which we have been progressively reducing since 2021 and will be removed entirely in 2027. Other factors such as how much retailers respond to them and the degree and form to which they pass them through in retail bills, and relativities of electricity costs to other costs will affect this.

The merit of adjusting the time periods is always considered in the context of other factors, such as simplicity (for consumers to understand, and the industry to apply), suitability of the time bands at each network asset level, and consistency with an industry approach – if and when appropriate and efficient to do so. We consult with retailers regularly about possible changes to the structure of our prices, including whether, how, and when, to implement them.

Having demonstrated that the time-bands used for TOU pricing coincide with peak demands, we then look at the level of prices being signalled at peak periods. Figure 13, below, shows the prior year peak differentials, along with the differentials set for this year, being the combination of transmission and distribution prices. Adjacent to each 'actual' bar is an *indicative* level of the regions' distribution signal[16], based on future investment required.

[16] There are different ways this value can be assessed. The value shown reflects the annualised value of deferring growth projects by one year, translated into a price that applies at peak times.

Figure 13: Alignment of pricing signals and investment costs



While the indicative 'Winter' rate is significantly higher than the 'actual' in some cases, this is based on treating all non-Winter usage as off-peak, which is not how we have structured those differentials. We also believe there are several reasons to maintain a level of stability in the signals:

- It's unclear whether the observed demand (in)elasticity is due to lack of pass through by retailers, versus consumers choosing not to alter usage patterns
- The ongoing decarbonisation initiatives, including uptake of EVs, will result in these signals becoming more important over time, and influencing customer investment into technologies such as battery storage
- Excessive volatility in the signals is likely to adversely affect customer engagement, which can take years to build

Eastern Region – Tauranga and Thames Valley

For the Eastern region our prices are set and applied at a customer's metering point. The resulting line charge is passed to the retailer. This is referred to as an Installation Control Point (ICP) approach to set prices.

An overview of the current price structure and price components for each customer group is provided in the tables below. More detail on each customer group is provided in Section 9.

Residential and Small Commercial Price Structures (0 – 43kVA)

Prices for most residential and small commercial customers in the Eastern region have a fixed daily price plus several volume-based prices, which can vary depending on the type of meter and controlled load arrangement.

Table 6: Eastern region residential pricing structures

Customer group	Price categories	Fixed price	Variable price options: % of billed volume			
			non-TOU	Controlled	Peak	Off-Peak
		$/day	$/kWh	$/kWh	$/kWh	$/kWh
Residential and small commercial	T05S	✓	11.5%	21.0%	20.0%	47.5%
	T06S	✓	19.0%	14.5%	19.5%	47.0%
	V05S	✓	14.0%	19.0%	19.5%	47.5%
	V06S	✓	22.0%	8.5%	20.0%	49.5%
	V05C	✓	8.5%	15.0%	24.5%	52.0%
	V06C	✓	13.0%	8.5%	26.0%	52.5%

Fixed price and variable off-peak prices

The fixed price recovers a portion of Powerco's distribution costs, and excludes any transmission charges, while the variable off-peak prices include a small portion of transmission charges. The fixed price does not fully recover fixed distribution costs for T05S/V05S due to the restrictions of the Low Fixed Charge Regulations.

The variable TOU peak price

The variable TOU peak price recovers part of the distribution cost, and part of Transpower's benefit-based and residual charges. The difference between Peak and Off-peak prices reflects the desired distribution pricing signal amount, which is illustrated in Figure 13: Alignment of pricing signals and investment costs and discussed there.

Uncontrolled and Controlled prices

We offer a price differential between controlled and uncontrolled load, as we use load control to manage network security. This can also support efficient grid utilisation and reduce the need for network investment. Customers who accept controlled load benefit from lower distribution prices. The options differ based on type and duration of control: Controlled (17 hrs/day), Uncontrolled (24 hrs/day). We have aligned the Controlled and Off-Peak rates as of 1 April 2022, to reflect the benefit to Powerco of being able to shift load from critical peak periods for our network to maintain system security (whether it be for distribution or wider transmission purposes such as the tight national electricity supply conditions on May 10, 2024[17]). Refer to section 3 above, for how we have been trialling retailer control of hot water.

Commercial and Industrial Price Structures (43 – 1499 kVA)

Commercial and industrial pricing has components which adjust to reflect the connected capacity of each customer group. The fixed component is cost-reflective, as it's based on the level of demand that

[17] https://www.ea.govt.nz/documents/5155/Electricity_Authority_open_letter_to_industry_-_10_May_2024_event_concerns.pdf

customers place on different elements of our network such as sub-transmission, high voltage (11kV) and low voltage (400V).

Table 7: Eastern region commercial and industrial pricing structures

Customer group	Price categories	Fixed price	Variable charge: % of billed volume		
			non-TOU	Peak	Off-Peak
		$/day	$/kWh	$/kWh	$/kWh
Medium commercial	T22	✓	37.5%	18.5%	44.0%
	V22	✓	31.5%	19.5%	49.0%
Medium/large commercial	T28	✓	20.5%	22.5%	57.0%
	V28	✓	37.5%	17.5%	45.0%
Large commercial	V40 / T50	✓	✓*		

*V40 / T50 kWh charge is $0.00 /kWh

Medium commercial and industrial customers

Prices for medium commercial and industrial customers have a two-part structure comprising of a daily fixed price component and a consumption-based kWh variable price. The daily fixed price recovers fixed distribution costs. The variable capacity component recovers variable distribution and transmission costs. Customers whose plant creates inefficiencies on the local network (a “substandard power factor”) are charged for the reactive power that they consume.

Large commercial and industrial customers

Prices vary according to the location, connection capacity, and the peak demands of the individual connection. These custom prices support efficient capacity utilisation because they reflect the capacity used. If a customer’s capacity requirements change, they can request to upgrade or downgrade capacity. As with medium sized customers, customers with a substandard power factor are subject to a reactive power charge.

Western Region – Taranaki, Whanganui, Rangitikei, Manawatu, Tararua, and Wairarapa

Our Western prices are now set and applied at a customer’s metering point.[18] The resulting line charge is passed to the retailer. This is referred to as an Installation Control Point (ICP) approach to set prices.

Prices in the Western region are set for three customer groups:

- Residential and small commercial - capacity less than or equal to 43kVA

[18] Having completed the transition from GXP to ICP billing over the FY25 pricing year.

- Medium commercial - capacity between 44-299kVA
- Large commercial and industrial - capacity greater than or equal to 300kVA

An overview of the current price structure and price components for each customer group is provided in the tables below. More detail on each customer group is provided in Section 5.

Residential and Small Commercial Pricing Structures (≤43kVA)

The residential and small commercial group is priced using a two-part price structure comprising a fixed daily price and a variable time-of-use price with peak and off-peak components.

Table 8: Western region residential and small commercial pricing structures

Customer group	Price categories	Fixed price	Variable charge: % of billed volume			
			non-TOU	Controlled	Peak	Off-Peak
		$/day	$/kWh	$/kWh	$/kWh	$/kWh
Residential and small commercial	W05A	✓	13.5%	14.5%	21.0%	51.0%
	W06A	✓	23.5%	9.5%	19.5%	47.5%
	W05B	✓	20.5%	20.5%	38.5%	20.5%
	W06B	✓	27.0%	7.0%	18.5%	47.5%

Fixed price and variable off-peak prices

The fixed price recovers a portion of Powerco's distribution costs, and excludes any transmission charges, while the variable off-peak prices include a small portion of transmission charges. The fixed price does not fully recover fixed distribution costs due to the Low Fixed Charge Regulations, so the variable price is higher to compensate. The fixed daily charge for ICPs with Controlled load is lower.

Peak pricing

The variable TOU peak price recovers part of the distribution cost, and part of Transpower's benefit-based and residual charges. The difference between Peak and Off-peak prices reflects the desired distribution pricing signal amount.

Commercial and Industrial Price Structures

Commercial and industrial pricing has components which adjust to reflect the connected capacity of each customer group. The fixed component is cost-reflective, as it's based on the level of demand that customers place on different elements of our network such as sub-transmission, high voltage (11kV) and low voltage (400V).

Table 9: Western region commercial and industrial pricing structures

Customer group	Price categories	Fixed price	Variable charge: % of billed volume		
			non-TOU	Peak	Off-Peak
		$/day	$/kWh	$/kWh	$/kWh
Medium commercial	W22A	✓	37.0%	18.5%	44.5%
	W22B	✓	30.0%	19.5%	50.5%
Medium/large commercial	W29	✓	100%		
Large commercial	W50 / W60	✓	✓**		

*W22 is a newer Price Category, and submitted volumes are rapidly shifting to TOU
**W50 / W60 kWh charge is 0.00 $/kWh

Medium commercial and industrial customers

Prices for medium commercial and industrial customers have a structure comprising of a daily fixed price component, prices based on historical demand and a small consumption-based kWh variable price. Customers with a substandard power factor are subject to a reactive power charge.

Large commercial and industrial customers

Prices vary according to the location, connection capacity, and the peak demands of the individual connection. These custom prices support efficient capacity utilisation because they reflect the capacity used. Customers with a substandard power factor are subject to a reactive power charge.

Sharing value of deferral of investment

We see the potential for customers to help us defer network upgrades and improve quality of supply by providing network support services. This could be from demand response or distributed generation and could be directly (e.g. hot water load control) or indirectly (e.g. a third-party provider).

We share the value of deferring investment with customers providing network support services in several ways.

Load control

Our prices reflect the difference in long-term costs associated with investment in additional capacity in the distribution network.

- Residential customers (the W/T/V05S and W/T/V06S customer groups) offering control of their hot water, or similar load, receive discounts to the volume-based prices based on the availability and duration of load control
- The 'controlled' tariff rate has been set lower than the off-peak rate, in order to incentivise installation of controllable appliances, including from decarbonisation (consumers switching from gas to electric load), heat pumps, and home EV chargers

Configured well, load control systems are highly effective at reducing demands at peak times by deferring non-time-critical power usage. The benefits of load-control systems include more predictable peak demand magnitudes, fewer peaking generation plants and deferred transmission and distribution capacity augmentations. The benefits accrue across the entire electricity sector.

Demand-based allocation

Powerco's demand-based prices in the Western region are applicable to larger commercial and industrial customers. They are designed to reflect the relative costs of distribution and transmission for those customers groups and are further split by GXP groupings. This pricing method is an alternative to full asset-based pricing for each connection, while being more cost-reflective than using kWh-based prices.

Note: The demand is observed historically and applied as fixed charges in the following year.

Standalone power systems

We also support deferral and avoidance of investment through installation of standalone power systems where the efficient option is to provide an alternative energy supply rather than replacing network assets. In some cases, the cost of renewing these assets is greater than the present value of the line charges that would be recovered over the lives of the assets.

Evolving our pricing approach and prices

We are evolving our pricing approach and prices. You can find the detail on how we are doing this in our pricing roadmap.

Our pricing approach had incremental changes over the last few years to improve the alignment of cost with prices, and the predictability of line charges for retailers. This provided retailers and customers with a degree of certainty when making decisions about retail pricing, and investment in energy saving and off-peak devices.

However, changing customer preferences, technology, and retail markets are influencing how our network is used, so our pricing approach may need to evolve further too. We need to balance the need for our prices to reflect the costs of supplying each customer with other considerations, like being workable and predictable for retailers, and understandable for consumers. We also need to make sure our pricing complements changes to the external environment, such as the roll out of advanced metering infrastructure, the fall in cost of photovoltaic technology, and the way transmission prices are derived.

Transitioning to a single pricing structure

We completed a significant change in FY25 to replace the GXP approach to pricing in the Western region with an ICP methodology (as used in the Eastern region). ICP pricing more closely reflects retailer prices and consequently makes it possible to provide a greater number of targeted price signals to specific regions, customer groups, or individual customers to promote efficient use of the network.

It will require ongoing work with retailers to ensure a manageable transition between methodologies, including assessment of customer impacts.

Longer-term pricing direction

Powerco is subject to a regulated revenue allowance. A benefit of this approach is that it removes potential barriers to more cost-reflective pricing structures, such as by eliminating the risks involved with forecasting volumes. Powerco's roadmap reflects the removal of these barriers, including initiatives that will improve the alignment between costs and prices.

Issues we will continue to monitor over the next five years:

- Improving the alignment of fixed price components with fixed costs
- The impact of stronger peak demand pricing signals, both in terms of how narrowly peaks are targeted, and the actual pricing levels, on different types of customers' electricity usage
- The benefits and consequences of greater alignment of the pricing approaches used in the Eastern and Western regions
- The needs of customers when we are making price adjustments
- Customer preferences towards the way costs are allocated and reflected in prices
- Development and uptake of new technologies, such as PV and EVs, and the impacts these will have on our network
- Applying pricing signals meaningfully and only when required (i.e. using prices to signal to avoid congestion when there is a genuine cost to avoid)

Refer to Appendix B for our pricing roadmap.

8. Changes to our pricing in FY27

The Pricing Schedule for 2026-27 sets out the specific prices for customers connected to our networks. It is available on our website here. The prices reflect a total average increase in forecast revenue of 8.7% compared to last year.

The change in forecast revenue for the Eastern and Western regions is shown in the table below.

Table 10: Changes to Powerco's total forecast revenue

	Forecast Revenue (000)			
	FY26	FY27	$ Change	% Change
Eastern region	$282,385	307,004	24,619	8.7%
Western region	$296,275	321,846	25,571	8.6%
Total	**$578,660**	**$628,850**	**$50,190**	8.7%

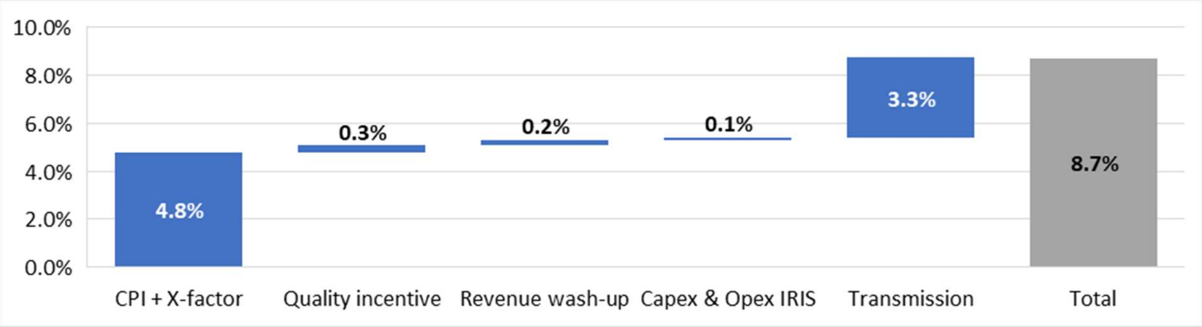
The primary reasons for changes to forecast revenue are described in the following table.

Table 11: Reasons for changes to forecast revenue FY27

Change	Description
Distribution revenue	Powerco's forecast net allowable revenue, which excludes pass-through and recoverable costs, and any wash-up draw down, has increased to $474m. This is due to allowed escalation of distribution revenue by Actual Inflation (CPI) and X-factor (a revenue smoothing mechanism)
Quality incentive adjustment	The quality incentive scheme allows Powerco additional revenue for performing better than the quality targets, and less revenue for performing below the quality targets. The overall quality incentive adjustment for FY27 is +$1.8m compared to +$0.1m in FY26
Revenue wash-up	An annual 'wash-up' of the difference between the revenue received and allowable revenue is calculated. The revenue wash-up drawdown amount for FY27 is +$19.3m compared to +$18.7m in FY26. This washup drawdown largely relates to the replacement of aged assets due to growth and reliability requirements and is effectively the accelerated depreciation on those assets. It is referred to 'loss on disposal' in regulatory accounting terms.
Capex and Opex IRIS	The IRIS mechanisms are designed to incentivise efficient capital and operating expenditure. The net adjustment to revenue is -$18.1m for FY27 compared to -$18.7m for FY26. This means Powerco's actual expenditure in preceding years was higher than our allowance, and we are returning a portion of that to customers through our total pass through and recoverable costs.
Change in transmission costs	Transpower's charges have increased for FY27, mostly due to an allowed increase in revenue allowance following Transpower's RCP4 reset. Powerco's FY27 transmission charges are $130.1m, up from $110.8m in FY26.

The figure below presents these components to illustrate the impacts for each change relative to the overall change in allowable revenue.

Figure 14: Percentage contribution to change in allowable revenue (FY27 vs FY26)



Prices have been adjusted, after consultation with retailers, to reflect this change. There have been some other changes to our pricing approach, as described and summarised below.

Table 12: Changes to pricing from 1 April 2026

Change	Description
Changes in fixed charges	The requirement to have an electricity low fixed-charge tariff option is being phased out by the Government over five years, starting from 1 April 2022. In line with this, the daily fixed charge for low user tariffs will rise from 75 cents per day to 90 cents per day from 1 April 2026, and FY27 will be the last year that a low fixed-charge option must be provided. This change is revenue neutral on an overall basis, although will mean the percentage price increase experienced by lower users will be higher than the average.
kVA capacity charge on smaller connections	We are introducing a capacity charge for residential and small commercial customers on the T06, V06, and W06 Price Categories. This is in addition to the daily fixed charge, although for FY27 the capacity charge rate will be set at zero. This change caters for the varying capacity sizes with these Price Categories, especially given increasing fixed charge recovery, and means costs can be recovered appropriately from those requiring larger connections. Adding a capacity metric also avoids adding Price Categories simply to add a different fixed charge and was signalled in last year's Pricing Methodology. The staged introduction allows time for: • Low Fixed Charge regulations to be removed; • Capacity values to be populated against each connection in Registry; and

	• Retailers to incorporate the change into systems and pricing plans where relevant.
Demand charge on medium commercial (200-299 kVA)	We are introducing a demand charge for Price Categories T28 & V28 (including T28N & V28N). The figure for each ICP will be calculated and set annually, based on the maximum demand within an observation period. This will further align pricing in our Eastern and Western Regions and reduce reliance on kWh prices, which are less relevant for connections of this size.
Allocation of non-network assets, and assets under construction	We have introduced allocations of non-network assets and assets under construction to connections of 1500 kVA and above. Historically the asset-based pricing for these only referenced the specific assets used to connect them and did not fully recognise the Regulatory Asset Base (RAB) required to provide the distribution network service. Powerco's total RAB is approximately $3 billion, with non-network assets making up approximately $130 million, and assets under construction (and related revaluations) making up approximately $550 million. While non-network assets are attributable to all connections on the network, 'assets under construction' includes assets not used for these customers (eg low voltage lines), therefore this balance is pro-rated before allocation.

9. Calculating and allocating costs across customer groups

For the FY27 pricing year, Powerco's total forecast revenue is $628.8m. We set prices to recover this amount by calculating and allocating costs across each customer group. The process involves:

- Calculating the total forecast revenue allowed by the Commerce Commission for the pricing year
- Identifying our major cost components, and whether the costs are fixed or avoidable
- Determining price signals required to reflect the expected costs of future investment
- Allocating costs to specific customer groups
- Checking alignment between cost types and price components

Prices are set to reflect major cost components

We use categories of operating and maintenance costs, depreciation, cost of capital, and recoverable costs including transmission and other pass-through costs such as local authority rates. The following table details the forecast costs for each of these categories for the FY27 pricing year.

Table 13: Expected costs of supplying distribution services in the FY27 pricing year

Cost type	Eastern region ($000)	Western region ($000)	Total ($000)
Operating and maintenance costs	$61,806	$67,672	$129,478
Depreciation	$59,953	$71,672	$131,625
Cost of capital	$113,994	$116,792	$230,786
Transmission costs[19]	$71,251	$65,710	$136,961
Forecast Revenue	**$307,004**	**$321,846**	**$628,850**[20]

More detail on each of these costs is provided below. Detailed information on Powerco's forecast and historical costs are available in Powerco's disclosures to the Commerce Commission. These disclosures include Powerco's Asset Management Plan, which contains forecasts of demand and costs for the next 10 years.[21]

Operating costs

Operating costs are the day-to-day costs of providing the distribution service, including:

- Network operation costs

[19] This includes other pass-through and recoverable costs (which comprise around 5%)
[20] This includes other regulated income
[21] Our disclosures, including Asset Management Plans, annual delivery report, and financial and technical disclosures are available here

- Network planning and asset management costs
- Network management and dispatch costs
- The cost of support services such as billing, record management, planning, contract administration, regulatory compliance, and resource costs
- Statutory charges and levies (excluding those that are pass through costs)

Depreciation

This component includes recovery of the depreciation on the network assets, which is part of our revenue allowance.

Cost of Capital

The cost of capital component includes recovery of the cost of debt and equity invested in Powerco, and the tax expense. Powerco requires large amounts of capital to maintain and develop network assets. Historical capital expenditure by type (e.g. system growth, replacement and renewal) is available on Powerco's website. Powerco's asset management plan provides a large amount of detail on the drivers of capital expenditure for the network.

Transmission costs

The transmission component includes all recoverable costs, such as Transpower's Connection, Benefit-based, Residual, and New Investment charges, as well as pass through costs such as council rates and statutory levies.

Transpower's charges are set according to the transmission pricing methodology determined by the Electricity Authority and 'passed through' to customers in our prices. More detailed information on the pass-through of transmission charges is in Table 16 (Appendix A).

Aligning costs and prices across Customer groups

Firstly, costs are allocated to customer groups and pricing zones. The allocation is a function of the load characteristics of the customer groups, network use, and cost of supply. When costs are directly attributable to a group or zone, they are allocated directly to them. When they aren't, we allocate more broadly. In summary:

- Operating costs: allocated to GXPs where attributable, spread broadly otherwise.
- Transmission costs: allocated to GXPs. Within each GXP, allocated based on demand.
- Cost of capital: allocated based on the value of assets in each network region

Pricing structures for each customer group are intended to marry the cost components with the attribute that drives it. Our intention is to recover fixed costs using fixed price components and avoidable costs using avoidable cost components. For example, we want the fixed daily price for residential customers to recover fixed costs. However, it is not practicable to do so yet for several reasons, such as the LFC regulations and data quality.

Eastern region

This approach also helps to ensure that customers have the right incentives to state their capacity requirements. Larger capacity price categories have the bulk of their line charges fixed, while lower capacity categories have a lower fixed component (as shown in the table below).

Table 14: Eastern region target revenue requirement split by fixed and variable price components for each customer group (FY27 pricing year)

Zone	Customer Group	Price Category	ICPs	Target Revenue Split			
				Fixed	Variable	Other[22]	Total
Tauranga	0-43kVA	Unmetered (T01/T02)	402	80.2%	19.8%	-	100%
		Low User (T05)	37,666	38.6%	61.4%	-	100%
		Standard (T06)	54,975	47.6%	52.4%	-	100%
	44-299kVA	Up to 3 Phase 250 Amps (T22)	837	49.3%	50.7%	-	100%
		200 - 299 kVA (T28)	156	48.5%	50.0%	1.5%	100%
	300 kVA + (incl. non-standard customers)	300 – 1,499 kVA (T50)	253				100%
		1,500 kVA + (T60)	43	97.9%	-	2.1%	100%
Valley	0-43kVA	Unmetered (V01/V02)	204	90.5%	9.5%	-	100%
		Low User (V05)	36,988	35.2%	64.8%	-	100%
		Standard (V06)	38,471	38.6%	61.4%	-	100%
	44-299kVA	Up to 3 Phase 250 Amps (V22)	616	37.1%	62.9%	-	100%
		200 – 299 kVA (V28)	59	47.3%	52.0%	0.7%	100%
	300 kVA + (incl. non-standard customers)	300 – 1,499 kVA (V40)	110	97.9%	-	2.1%	100%
		1,500 kVA + (V60)	35	99.1%	-	0.9%	100%

Powerco’s ability to align the price structure with costs is restricted by Low Fixed Charge Regulations which distort the balance between and levels of fixed and variable prices. Powerco determines the proportion of fixed and variable charges by reference to existing rates while recognising the largely fixed nature of the underlying costs. The regulations have a large influence on the level of the fixed and variable components for residential groups.

[22] Including reactive power charges (where applicable).

Western region

As for the Eastern region, distribution costs are largely fixed rather than related to the delivered energy volumes. Again, the Low Fixed Charge Regulations affect the balance between fixed and variable prices, although this is slowly abating through the LFC phase-out. Small customers were previously in one group due to GXP billing, but for FY27 will be split in a similar way to Eastern.

Customers in the W29 and W50 price categories are typically very large commercial or industrial businesses requiring dedicated on-site and upstream assets (such as dedicated feeders and transformers) to meet their supply requirements. The fixed price component of these price categories is typically higher than the other price categories to ensure that an appropriate return on investment is earned by Powerco.

Table 15: Western region target revenue requirement by fixed and variable price components for each customer group (FY27 pricing year)

Customer Group	Zone	Price Category	ICPs	Target Revenue Split			
				Fixed	Variable	Other[23]	Total
0-43 kVA	A	Unmetered (W01A/W02A)	529	8.6%	91.4%	-	100%
		Low User (W05A)	66,527	36.2%	63.8%	-	100%
		Standard (W06A)	58,625	31.5%	68.5%	-	100%
0-43 kVA	B	Unmetered (W01B/W02B)	360	11.9%	88.1%	-	100%
		Low User (W05B)	25,811	29.7%	70.3%	-	100%
		Standard (W06B)	30,102	29.0%	71.0%	-	100%
44-199 kVA	A	Up to 3 Phase 250 Amps (W22A)	177	37.0%	63.0%	-	100%
	B	Up to 3 Phase 250 Amps (W22B)	73	36.6%	63.4%	-	100%
200-299 kVA	A	200 – 299 kVA (W29)	301	50.3%	47.5%	2.2%	100%
300 kVA + (incl. non-standard customers)		300 – 1,499 kVA (W50)	277	98.2%	-	1.8%	100%
		1,500 kVA + (W60)	65	98.6%	-	1.4%	100%

[23] Including reactive power charges (where applicable).

10. Assessing customer impacts

We assess the impact on customers of each change to price structure and price level. We take account of:

- The scale of changes to line charges for customers or a customer group
- Whether the price structure is workable for retailers to adopt and apply
- The transaction costs associated with applying the price structure.

We assess the impact of price changes

The average line charge, including transmission, for residential customers is about 38%[24] of the total electricity bill. The demographic profile of our networks is diverse. We work hard to understand the impact of changes to our pricing on households, and to design our pricing to avoid large changes to line charges (or 'bill shocks').

A customer's line charges can vary for several reasons:

1. Changes to the Commerce Commission's Price-Quality path decision. For example, changes to the Weighted Average Cost of Capital that affects our allowable revenue. These changes are largely outside of our control.
2. Changes we make to our pricing methodology and revenue allocation between groups. These changes are largely within our control.
3. Changes in the way a customer is using the network – be that capacity, consumption, timing of demand

Identifying material price changes

We use a Cost of Supply Model (COSM) to evaluate how the pricing approach recovers different categories of cost from specific customer groups, and to identify potential customer impacts.

We assess price changes for residential and commercial/industrial customers differently. For residential customers we assess the price impact by examining the average change in price for all customers (to assess the average impact on customers). We engage with retailers about how any changes might impact on their customer bills. For commercial/industrial price categories, because there are a lot fewer customers, we can assess price impacts at a more granular level. If necessary, we implement changes in phases to mitigate the risk of price shocks.

As an example, for FY25 the GXP-ICP change in the Western Region introduced the W06 'standard user' Price Categories, alongside the LFC compliant Price Categories.

As the fixed charge differential between these two Categories is increased, it increases the price impact on low users. Combined with an overall increase in allowable revenue, and LFC phase-out, the

[24] Based on https://www.ea.govt.nz/your-power/bill/

effect on the average low user approached 20%. Due to this, we chose to limit the standard user fixed charge to 90c/day, compared to the low-user rate of 60c/day, to avoid amplifying the price shocks.

Checking price outcomes are subsidy-free

Finally, we check prices are within the subsidy-free zone. This involves checking that average prices for each customer group are between the estimated avoidable and stand- alone cost of supplying them.

Our prices reflect the economic costs of service provision, by allocating costs based on the shares of network benefit that consumers receive. Residential/small commercial connections make up 99% of all connections on our network. They use on average 8MWh per year for an average network cost of approximately $900 per year.

- Avoidable costs for an existing consumer are negligible (near zero) since almost all distribution costs relate to shared assets or services.
- Standalone costs on an ongoing basis, are calculated at between $5,000-$10,000 per year (including energy cost). We calculated the standalone costs based on the alternative supply of a residential consumer, using solar panels and batteries, or a generator with solar panels and batteries.

Price-quality path changes

We mitigate price impacts by calculating the customer impact before finalising our prices. If the COSM analysis is significantly different from the revenues recovered through existing prices, prices are adjusted to ensure a better alignment of revenues and costs. This means that changes to prices (up or down) are linked to the costs that drive them.

Customer engagement

We actively engage with our customers to understand what they value – we need our network to meet their needs, both now and in the future[25]. For example, our customer engagement has found that customers have an increasing willingness to take control of their energy options. This has influenced our strategy to invest in resources to study customer trends and emerging requirements, so we can prepare our network to accommodate them.

We use a variety of means to engage with our customers and capture their feedback about how we manage our network, including pricing. These include:

- Direct interaction with larger commercial and industrial customers
- Customer initiated engagement through promotion of customer facing communication channels
- Customer surveys
- Annual retailer consultations

[25] Our customer base includes retailers and their customers, directly contracted industrial businesses, local territorial authorities, and the NZTA.

- Stakeholder meetings and focus groups
- Website, digital services, and phone feedback
- Stands at agricultural field days, exhibitions, and trade shows where customers can provide face-to-face interaction

A key step in setting prices is a consultation process with retailers. We welcome their insights about customer preferences towards pricing.

Findings of our customer engagement surveys are reflected in our asset management planning process along with other key drivers such as safety and resilience.

We set workable prices for retailers to adopt and apply

Powerco consults with retailers and other customers several times throughout the year to discuss pricing issues (including potential improvements) and the impact of any pending review of our prices. A description of this process is available on request from Powerco. Powerco is aware of transaction costs and seeks to minimise them where feasible. Some examples of transaction costs that exist when Powerco transacts with key groups, and how we take these into account, are:

- **Retailers:** Transaction costs can occur when billing systems, the pricing strategy and/or risk management strategy are amended to accommodate large distribution price changes. Over twenty retailers operate on Powerco's network, and we have a detailed pricing consultation process, usually involving two rounds of consultation. There is a balance between rationalising price categories and options to minimise retailer transaction costs against more individualised pricing which some new retailers can accommodate easily with modern systems.

- **Customers:** Customers make medium to long-term investments based on electricity price structures. For example, a very low price for consumption may provide an incentive to invest in a storage heater. Powerco is aware that customers value pricing certainty and aims to minimise any large changes that impact these types of investment decisions. For residential customers we consider feedback from retailers (as they have responsibility for the ultimate price signal). We also collect information from commercial customers via direct engagement.

11. Alignment with Electricity Authority Pricing Principles & Focus Areas

The table below provides commentary about how our pricing approach aligns with the Electricity Authority's Pricing Principles, and the Electricity Authority's pricing focus areas.

Principle	Alignment demonstrated
A1 Prices are to signal the economic costs of service provision, including by being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs)	Forecast total revenue recovered from each customer or customer group falls between standalone and avoidable costs. This is discussed in Section 10. Sections 5, 6 and 9 describe how we set prices to reflect the cost of supply for each customer or customer group, and check cost allocations using our cost of supply model.
A2 Prices are to signal the economic costs of service provision, including by reflecting the impacts of network use on economic costs	We set prices to reflect the impacts of network use on economic costs, to the extent practicable. As described in Sections 2, 6 and 9, the prices for each customer group are designed to recover fixed costs and to signal avoidable costs, for each location. This is achieved by the components of the price structure for each customer group aligning to specific types of costs, to the extent practicable (e.g. the LFC Regulations require us to set prices which discourage consumption).

Principle	Alignment demonstrated
A3 Prices are to signal the economic costs of service provision, including by reflecting differences in network service provided to (or by) consumers	We set prices to reflect differences in the network service provided to, or by, customers. Section 7 describes how residential customers across both networks can choose controlled rate pricing which provides them a price discount in return for allowing us to reduce part of their consumption at pre-specified times. Our non-standard pricing for commercial and industrial customers allows those customers to obtain and pay for a distribution service which reflects their specific supply requirements. Section 10 describes how our customer engagement activities aid our understanding of customer preferences and informs our asset planning. We also use the insights from the Electricity Network Association’s customer engagement surveys and focus groups.
A4 Prices are to signal the economic costs of service provision, including by encouraging efficient network alternatives	We set prices to encourage efficient network alternatives. Section 7 describes how our pricing approach provides an incentive for commercial and industrial customers to manage the power factor and recover costs. The Powerco connection standard specifies that power factor correction is best applied at customers’ installations. Section 6 refers to our Distributed Generation Policy, which includes a mechanism for distributed generators to receive payments when they supply us a network support service. Additionally, our network management approach supports procurement of efficient network alternatives by tendering for solutions on a case-by-case basis. The benefits are reflected in lower costs of supply, and lower prices.

Principle	Alignment demonstrated
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.	We set prices to recover the cost of supplying distribution services, and to signal the opportunity for customers to avoid costs. As described in Sections 6, 7 and 9 the components of our prices are intended to recover the fixed costs and the avoidable costs associated with supplying specific customer groups, to the extent practicable. We are working to align the fixed and avoidable price components with the relevant costs.
C Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to reflect the economic value of services and enable price/quality trade-offs	We offer non-standard contracts and pricing to customers – primarily large commercial and industrial – to reflect their specific circumstances and cost of supplying distribution services, and to reduce the risk of inefficient demand curtailment, disconnection, or not connecting. Our approach is described in Section 6.
D Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	Our approach to pricing and setting prices is described in this Pricing Methodology document and is available to customers and interested people from our website and on request. We have previously used dedicated webpages for annual pricing changes, including survey options. We engage regularly with customers, retailers and other interested people on pricing, reliability and quality of supply and investment plans. Extensive information is available through our website, Asset Management Plan, and other publications. Our goal is to make good information available to people using our network (or wanting to in the future) for them to make the best possible decisions about energy-related investments and electricity use.

Focus areas from May 2024 *Open Letter to Distributors*

Focus area	Alignment demonstrated & comment
1. Allocate revenue transparently	Appendix A of this document includes detail of how we have allocated revenue transparently.
2. Assign all ICPs to time-varying distribution tariffs (limited exceptions only)	99.7% of ICPs are assigned to Price Categories that allow time-varying tariffs, and time sliced usage is expected from retailers where possible. In this document (e.g. Table 6) we have disclosed the billed proportions of supplied volume, which shows that non-TOU submission is now below 20%.
3. Set peak rates based on a measure of Long-Run Marginal Cost	The revenue recovery through the relevant peak differentials (being the peak price, minus the off-peak price) across our network reflect the long-run marginal cost of expected growth investments that are forecast in our AMP.
4. Reduce off-peak and controlled rates	Off-peak rates in have increased in FY26, given the converging pressures of a ~25% increase in allowable revenue, the ongoing LFC phase-out, and the potential distortionary impact of excessive fixed-charge increases prior to price structure change (such as fully embedding the GXP-ICP change, and capacity differentiation of smaller users). However, off-peak rates have been held as low as is practical, and in the case of the Eastern Region, are near to or below 5c/kWh. We believe this level provides minimal distortion, and is still reflective of the fact that certain costs are linked to usage We have continued to apply a lower rate for controlled usage, given the flexibility and efficiency that controllable load provides to the network.
5. Follow up on Asset Management Plan reporting on readiness for increased electrification	We responded to the EAs request for information on our initiatives to support electrification in 2024. Our FY2025 AMP update supports this vision for Aotearoa New Zealand by outlining the investment required in our electricity infrastructure needed to realise net-zero emissions targets by 2050.

12. How we meet the Commerce Commission Information Disclosure requirements

The table in this section provides references for how this pricing methodology complies with 2.4.1 to 2.4.5 of the Electricity IDD.

Information Disclosure Requirement	Compliance demonstrated
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;	Powerco's Electricity Pricing Methodology achieves this.
(2) Describes any changes in prices and target revenues;	See Section 8 and 9.
(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);	See Section 6.
(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.	See Section 10.
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.	No material changes to underlying methodology
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;	See Appendix A.
(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;	See Section 11.
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See Section 8.
(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;	See Section 9.

(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;	See Section 5.
(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;	See Section 8.
(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;	See Section 9, and Appendix A.
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	See Appendix A.
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;	Section 7 describes the pricing approach Powerco is adopting and changes and Appendix B.
(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;	See Section 6 and Appendix A.
(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—	See Section 6.

(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.	See Section 3 and 6.

13. Definitions

This pricing methodology uses industry standard terms where possible. A glossary of common terms is included for clarity. Additional information on definitions used in the document can be found in:

- Powerco's Electricity Pricing Schedule, Distributed Generation Policy and Asset Management Plan[26]; and
- The Commerce Commission's electricity default price-quality path notice and information disclosure requirements.[27]

Anytime Maximum Demand (AMD) means the highest kW peak occurring any time in the 12-month period from 1 September to 31 August, the result of which is applied in the subsequent Price Year commencing 1 April.

Average Demand Level (ADL) means the Consumer's average level of kW demand across the 12-month period from 1 September 2022 to 31 August 2023, the result of which is applied in the subsequent Price Year commencing 1 April 2024

Avoided Cost of Transmission (ACOT) is the amount equal to the actual reduction in the charges that are payable by Powerco to Transpower under the Grid Network Agreement. ACOT charges are a substitute for what otherwise could have been Transpower charges and are regulated by the Electricity Authority.

Coincident Maximum Demand (CMD) is the highest kW peak of each GXP, measured in accordance with the AMD method, but accounts for interconnection of certain GXPs.

Connection or **Point of Connection** means each point of connection at which a supply of electricity may flow between the Distribution Network and the Customer's installation, as defined by the Distributor.

Customer means a purchaser of electricity from the Retailer where the electricity is delivered via the Distribution Network.

COSM means Powerco's Cost of Supply Model.

Demand means the rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA).

Distributed Generation or **Embedded Generation** means electricity generation that is connected and distributed within the Network.

Distributed Generator or **Embedded Generator** means an electricity generation plant producing Embedded Generation

[26] Available at www.powerco.co.nz.
[27] Available at www.comcom.govt.nz.

Distribution Network or **Network** means:

Network region	Area	Transpower GXP	
Eastern	Valley (Thames Valley)	Arapuni Hinuera Kinleith Kopu	Piako Waihou Waikino
	Tauranga	Tauranga Mt Maunganui	Te Matai Kaitimako
Western	Wairarapa	Greytown Masterton	
	Manawatu	Bunnythorpe Linton	Mangamaire
	Taranaki	Carrington Huirangi Hawera	Opunake Stratford
	Whanganui	Brunswick Marton Mataroa	Ohakune Whanganui Waverley

Distributor means Powerco Limited, as the operator and owner of the Distribution Networks, and includes its subsidiaries, successors, and assignees.

Electricity Authority (EA) means the Electricity Authority which is an independent Crown entity responsible for regulating the New Zealand electricity market.

Grid Exit Point (GXP) means a point of connection between Transpower's transmission system and the Distributor's Network.

High-Voltage (HV) means voltage above 1,000 volts, generally 11,000 volts, for supply to Customers.

Installation Control Point (ICP) means a Point of Connection on the Distributor's Network, which the Distributor nominates as the point at which a Retailer is deemed to supply electricity to a Customer, and has the attributes set out in the Code.

kVA means kilovolt–ampere (amp).

kVAh means kilovolt ampere hour.

kVAr means kilovolt ampere reactive.

kW means kilowatt.

kWh means kilowatt hour.

Line Charges means the total charges levied by the Distributor on Customers for the use of the Distribution Network, as described in the Pricing Schedule. This is the combination of Powerco's prices with the relevant quantities.

Low Fixed Charge Regulations – Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. These are available here:
https://www.legislation.govt.nz/regulation/public/2004/0272/latest/DLM283614.html

Low Voltage (LV) means voltage of value up to 1,000 volts, generally 230 or 400 volts for supply to Customers.

MVA means Megavolt Ampere.

Network see **Distribution Network**.

Peak Coincident Demand (PCD) is the Consumer's average demand during the top 100 peak periods observed on Powerco's network. The peak periods are observed between
1 September 2022 and 31 August 2023 for the Price Year effective 1 April 2024. The PCD is used in calculating the Delivery Charges of a Consumer on Price Categories such as V40, T50, V60, T60 in the Eastern Region, and the W50 and W60 Price Categories in the Western Region.

Point of Connection means the point at which electricity may flow between the Network and the Customer's Installation and to which an Installation Control Point is allocated.

Powerco means Powerco Limited and any of its subsidiaries, successors, and assignees.

Power Factor is the ratio of active energy, measured in kilowatts (kW), to apparent energy, measured in kilovolt amperes (kVA). Reactive power, measured in kilovolt amperes reactive (kVAr), results from a non-parity power factor and may incur charges.

Price Category means the relevant price category selected by the Distributor from this Pricing Schedule to define the Line Charges applicable to an ICP.

Price Option means the price option within a **Price Category** where such a **Price Category** provides for **Retailer** choice amongst two or more options, subject to a particular configuration of metering and load control equipment.

Price Year means the 12-month period between 1 April and 31 March.

Recoverable Costs has the meaning specified in clause 3.1.3 of the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2012.

Region means the Eastern region or the Western region.

Registry means the Electricity Authority central Registry**.**

RAB means Powerco's Regulatory Asset Base - the value of assets used to provide the network service and publicly disclosed by Powerco under Information Disclosure requirements.

Retailer means the supplier of electricity to Customers with installations connected to the **Distribution Network**.

Temporary Accommodation means a non-primary place of residence in the context of the Electricity (Low-Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, such as holiday homes and other non-permanent places of residence that are predominantly not business premises.

Time of Use Meter (TOU) means metering that measures the electricity consumed for a particular period (usually half-hourly) and complies with Part 10 of the Code.

Appendix A: Allocation of costs across customer groups and price zones

This appendix summarises the approach and resulting allocations of costs to price zones and customer groups in each network region. The table below summarises our main cost components and the approach to allocating them.

Table 16: Cost allocations to customer groups

Cost component	Allocation approach
Operating costs	Allocated to the GXPs where the operating costs are incurred. Where we cannot attribute operating costs to a location, the costs are allocated to each network based on the assets, ICPs, and energy usage within the network. Common operating costs relating to the electricity business, e.g. administration costs, are allocated between regions and customer groups using each group's contribution to system demand, consumption and ICP numbers, depending on the type of expense. These costs are shared by all users, but the methodology recognises the contribution larger customers make to these costs.
Cost of capital and depreciation	Allocated to each relevant price region based on the RAB values and depreciation of the assets within those regions. The cost of capital and depreciation charges (on shared assets) are then allocated between customer groups, based on the aggregate of the maximum demands contributed by each group. *Other potential methods for allocation of these costs are considered, including capacity-based, coincident maximum demand, coincident 'top N' demand, anytime 'top N' demand, kWh usage, or various combinations of these measures, but each provides various drawbacks.* *For example, a capacity-based method would allocate more overall to residential customers, yet their demand diversification means the upstream capacity requirement is far less than the aggregated connected capacity.* *E.g. 40 residential customers might constitute 580kVA of fused capacity, yet can be supplied via a 200kVA transformer. The same size transformer might only supply 2 commercial customers, with combined capacity of 220kVA.*
Transmission costs	Transpower's Connection charge is directly attributed to GXPs. Allocation is based on customer demand, as measured by AMD (load). This provides a proxy for customers' size and ability to pay, while using a historical measure, across a 12-month period, aligning the stable nature of the cost with a charge that does not provide a strong price signal.

Cost component	Allocation approach
	Transpower's Benefit-based and Residual charges are allocated to Powerco based on historical usage. These costs are then allocated between customer groups in each location based on their portion of historical usage, as measured by ADL. The historical observation limits the avoidance of the charge, but recognises changing usage by customers over the medium term. The Authority describes these as "fixed-like" charges and recognises that *it may not be appropriate or possible for distributors to fully recover transmission charges via fixed lines charges because … LFC regulations cap the maximum fixed charge … charges may have an 'anchoring' effect …* (and) *distributors may limit year-to-year changes to manage bill impact* [28]. Our approach of re-bundling Transpower's historical maximum gross demand charges, which are rolled forward using lagged average total gross energy consumption, follows the Authority's guidance: • fixed charges within these constraints, • very low (1.6c/kWh) and uniform variable charges where unavoidable[29] • without introducing new distortionary incentives for customers to change behaviour inefficiently such as markedly different charges for different customer groups[30] While ADL currently uses a 12-month historical observation, this will evolve as the effects of the new TPM become apparent. Effects may include customer behaviours around avoiding charges, and the requirement for, and impact of, Benefit-based investments.

[28] *Transmission charge pass-through practice note*, Electricity Authority, October 2022. Clause 4.16
[29] *Transmission charge pass-through practice note*, Electricity Authority, October 2022. Clause 4.17
[30] *Open letter to distributors*, Electricity Authority, September 2022. Item 5

For the Eastern region, the table below sets out the allocations of costs to customer groups and zones, with the following table showing the resulting cost values.

Table 17: Cost allocations to Eastern region customer groups

Price Zone	Customer Group	Allocator For:		
		Operating Costs	Cost of Capital & Depreciation	Transmission Costs
Tauranga	0-43 kVA	37.3%	36.6%	23.0%
	44-299 kVA	4.2%	5.8%	3.4%
	300-1499 kVA	5.8%	4.9%	5.2%
	1500 kVA+	6.3%	3.8%	7.1%
Valley	0-43 kVA	29.6%	36.3%	28.7%
	44-299 kVA	3.7%	4.5%	3.9%
	300-1499 kVA	3.1%	2.6%	3.1%
	1500 kVA+	10.0%	5.5%	25.6%
Total		**100%**	**100%**	**100%**

Table 18: Cost components recovered from Eastern region customer groups

Price Zone	Customer Group	ICPs	Revenue required:			
			Operating Costs ($000)	Cost of Capital & Depreciation ($000)	Transmission Costs ($000)	Total ($000)
Tauranga	0-43 kVA	93,043	$23,068	$63,589	$16,392	**$103,049**
	44-299 kVA	992	$2,623	$10,057	$2,416	**$15,096**
	300-1499 kVA	253	$3,608	$8,536	$3,725	**$15,869**
	1500kVA+	43	$3,908	$6,555	$5,031	**$15,494**
Valley	0-43 kVA	75,663	$18,272	$63,146	$20,438	**$101,856**
	44-299 kVA	675	$2,281	$7,968	$2,745	**$12,994**
	300-1499 kVA	110	$1,855	$4,585	$2,176	**$8,616**
	1500 kVA+	35	$6,191	$9,511	$18,328	**$34,030**
Total		**170,814**	**$61,806**	**$173,947**	**$71,251**	**$307,004**

For the Western region the table below sets out the allocations of costs to customer groups and zones, with the following table showing the resulting cost values.

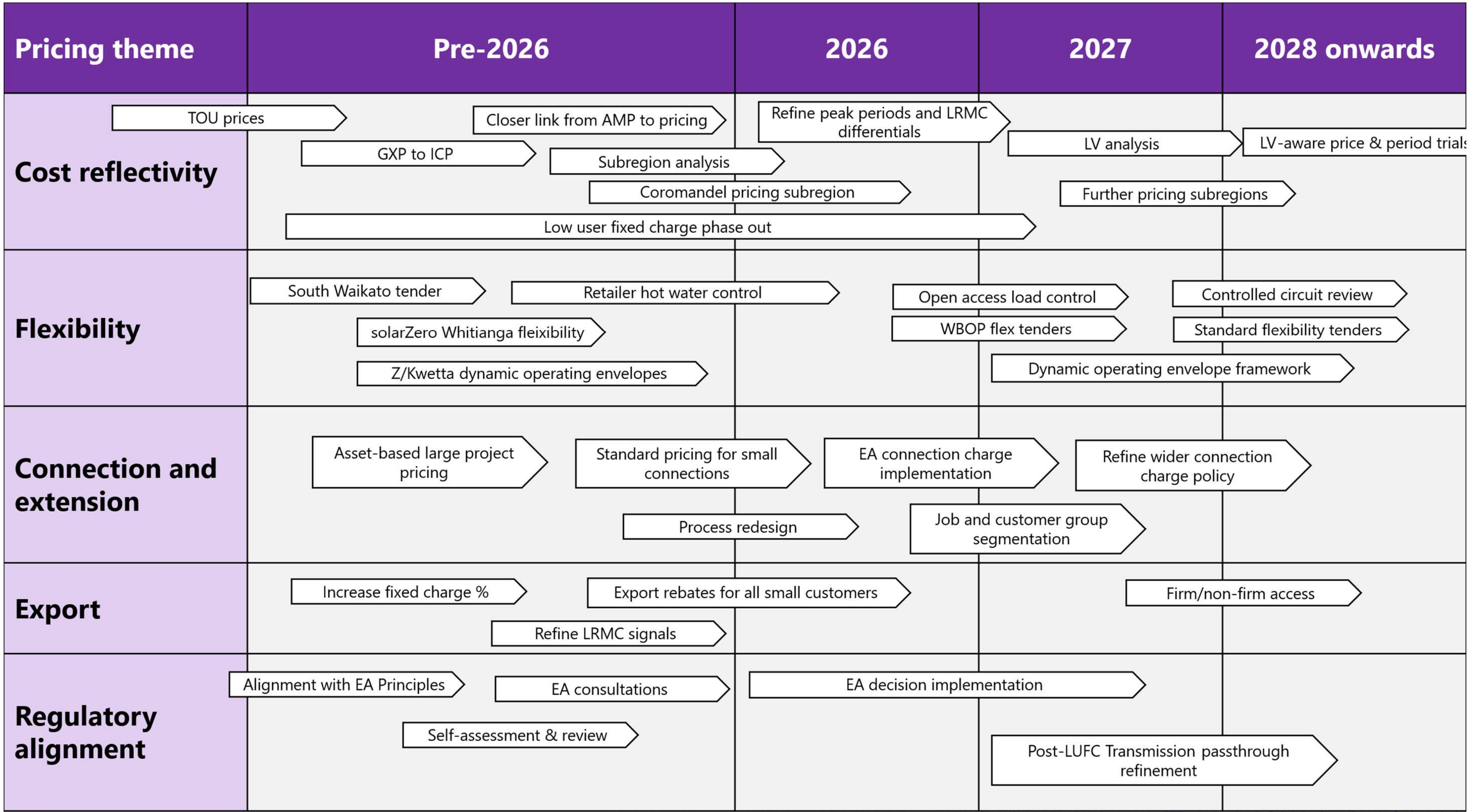
Table 19: Cost allocations to Western region customer groups

Customer Group	Price Zone	Allocator For:		
		Operating Costs	Cost of Capital & Depreciation	Transmission Costs
W01, W02, W05 & W06 (0-43 kVA)	A	46.5%	53.8%	44.1%
	B	34.5%	29.6%	24.6%
W22 & W29 (44-299 kVA)		4.1%	4.7%	4.6%
W50 (300-1,499 kVA)		7.8%	7.8%	11.5%
W60 (1,500 kVA+)		7.1%	4.1%	15.2%
Total		**100%**	**100%**	**100%**

Table 20: Total costs and components to be recovered from Western region customer groups

Customer Group	Price Zone	ICPs	Revenue required for:			
			Operating Costs ($000)	Cost of Capital & Depreciation ($000)	Transmission Costs ($000)	Total ($000)
W01, W02, W05 & W06 (0-43 kVA)	A	125,681	$31,471	$101,421	$28,971	**$161,863**
	B	56,273	$23,369	$55,848	$16,134	**$95,350**
W22 & W29 (44-299 kVA)		551	$2,741	$8,889	$3,037	**$14,667**
W50 (300-1,499 kVA)		277	$5,249	$14,712	$7,572	**$27,534**
W60 (1,500 kVA+)		65	$4,842	$7,594	$9,996	**$22,431**
Total		**182,847**	**$67,672**	**$188,464**	**$65,710**	**$321,846**

Appendix B: FY27 Powerco Pricing Roadmap



Appendix C: Directors' Certification

Director's Certificate for the
2027 Electricity Pricing Methodology
Certification of Year-beginning Disclosure

We, John Loughlin and Richard Van Breda,

being Directors of Powerco certify that, having made all reasonable enquiry, to the best of our knowledge:

(a) the following attached information of Powerco prepared for the purposes of clauses 2.4.1-2.4.5 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 a basis consistent with regulatory requirements or recognised industry standards.

Director

Director

19 March 2026

Date

19 March 2026

Date