ELECTRICITY PRICING METHODOLOGY

1 APRIL 2021 – 31 MARCH 2022

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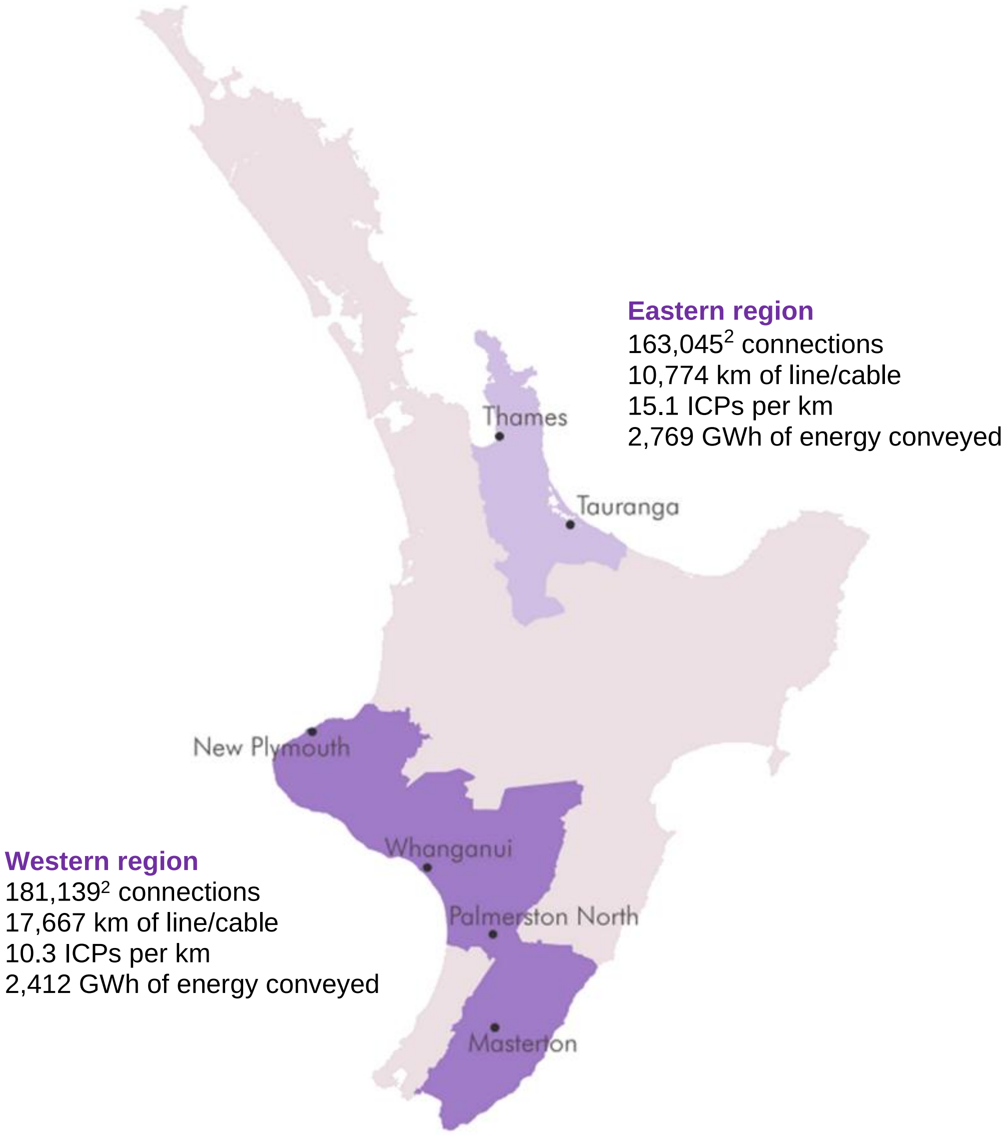
1. ABOUT POWERCO

Powerco’s electricity network supplies electricity to about 340,000 customer connections across two regions of the North Island. In terms of both supply area and network length, our network is the largest of any single distributor in New Zealand. The two network regions are referred to as Eastern (Valley and Tauranga) and Western (Taranaki, Whanganui, Manawatu and Wairarapa). Both regions contain a mix of urban and rural areas.

Figure 1: Powerco's Eastern and Western network regions and key statistics[1]



[1] As at 31 March 2020.

[2] Number of connections differs from ICP counts, because inactive ICPs are included.

2. HELPING YOU UNDERSTAND HOW WE SET ELECTRICITY PRICES

The purpose of this document is to help you understand how Powerco sets prices for its electricity distribution services. It demonstrates to customers and interested people how our electricity pricing methodology (our approach) recovers the costs of supplying distribution services in an efficient and fair way.

- Section 2 (this section) describes the role of distribution pricing and the main factors we consider when developing prices
- Section 3: our current pricing approach and plans to evolve it
- Section 4: changes to our pricing approach and prices in 2021-22
- Section 5: how standard and non-standard prices are set
- Section 6: the customer groups we use
- Section 7: how we calculate and allocate costs across customer groups
- Section 8: how we assess the customer impact of price changes
- Section 9: how the pricing approach and prices align with the Electricity Authority pricing principles
- Section 10: compliance obligations

WE SET PRICES TO RECOVER COSTS AND HELP CUSTOMERS MAKE DECISIONS ABOUT USING OUR NETWORK

We set prices to recover the cost of supplying electricity distribution services to each customer or group of customers connected to our network. For many customers, our prices are part of several components of a retail bill. Retailers package our prices in different ways, which can impact on the degree you can 'see' our prices.

The distribution services we supply are:

- Access to the network, so customers can take electricity to power their homes and businesses, or inject electricity they generate
- New connections or reduced/expanded capacity. New customers wanting access or the ability to take or inject more/less electricity than they currently do.

The Commerce Commission regulates and sets the revenue (which sets the 'cost') we can recover through our prices in each year. These regulations also require us to include other costs in our prices, such as transmission prices and regulatory levies.

Our approach to setting prices can inform customer decisions about connecting to, and using, our network by signalling the cost of supply. These costs are affected by a range of factors influencing the network infrastructure required to supply the distribution service. We want our prices to reflect these costs so we can plan and operate our network assets efficiently, reliably, and safely.

We review our pricing approach annually (at a minimum) so prices give customers the best possible information about the costs of supplying them. This is increasingly important as customers and their agents use our network in new ways by adopting technology and services like solar panels, electric vehicles, electric heating and cooling, and energy management systems.

FACTORS WHICH INFLUENCE OUR PRICING APPROACH AND PRICES

The factors which influence our pricing approach and pricing can be grouped into three areas:

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

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, eg 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 connection may need a dedicated transformer which cannot be utilised by other customers.
- **Location**: Customers in the Eastern and Western regions are supplied using separate networks with their own cost characteristics. Another key factor is the relevant Grid Exit Point connecting our network to the national transmission grid, because this impacts the Transpower's charges which we reflect in our prices.
- **Density**: Customer density[3] varies across the network and impacts on cost allocation. 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 offerings such as solar panels and battery storage are changing in the way energy markets operate. Distributors play a key role in facilitating these changes. We try to keep our prices technology-neutral, so the pricing is aligned with the impact on network costs.

[3] A measure of customer density is the number of customers per km of network length.

Network characteristics

Powerco operates over 28,000 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, 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.

Our regions have been experiencing sustained population and economic growth in recent years and, as a result, we have experienced strong demand growth across parts of our networks. Areas of growth include:

- Bay of Plenty – population growth and horticulture processing volumes
- Taranaki – population growth and dairy intensification
- Other regions – population growth and changing land-use patterns

Because of this we are investing in our network to support residential and industrial growth while addressing security and reliability needs. 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/Publications/Disclosures/Electricity/.

Regulatory requirements

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

- Setting prices over 2019-2023 to recover the allowable revenue the Commerce Commission approved for Powerco so we can invest in our network to improve reliability and quality of supply. **Sections 5-7** 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 5**, 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[4]. **Section 9** describes how our pricing approach aligns with these.

- Disclosing information about our pricing approach, and price–setting for the year ahead by the Commerce Commission's Electricity Distribution Information Disclosure[5] and CPP requirements. **Section 10** describes how we meet these, along with information on our website at: http://www.powerco.co.nz/publications/disclosures/.

[4] 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/

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

- We are required to offer household customers a low fixed charge tariff option (of 15 cents/day) by the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the low fixed charge regulations). The Electricity Authority monitors and enforces the regulations. The Low Fixed Charge Regulations prevent us from setting prices which reflect the cost of supply.

OTHER SOURCES OF 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 in our Capital Contributions Policy here
- Technical information for retailers on our pricing is available in our Pricing Policy here
- Information for customers about how our annual price and revenue changes due to our Customised Price Path is available in our Annual Price-Setting Compliance Statements here
- Information about pricing changes from 1 April 2021 is available in our Reasons for Change factsheet here

3. CURRENT PRICING APPROACH AND PLANS TO EVOLVE OUR PRICING

Prices are set taking account of the network, customer and regulatory characteristics relevant to each of our networks. As such, we recognise the importance of pricing to reflect evolving customer expectations, technology choices, and use of the network.

PRICING IN THE EASTERN REGION – TAURANGA AND THAMES VALLEY

For the Eastern region our prices are set and measured 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 6.

Residential and Small Commercial Price Structures (0 – 41kVA)

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 you have.

Table 1: Eastern region residential pricing structures

Customer group	Meter type	Price categories	Fixed price	Variable price options					
				Uncontrolled	Controlled	Night	All inclusive	Peak	Off-Peak
				24UC	CTRL	NITE	AICO	PEAK/ PKIN	OFPK/ OPIN
			$/day	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Residential and small commercial	Non-TOU	V05S/T05S	✓	✓	✓	✓	✓		
		V06S/T06S	✓	✓	✓	✓	✓		
	TOU	V05S/T05S	✓		✓	✓		✓	✓
		V06S/T06S	✓		✓	✓		✓	✓

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.

Uncontrolled, Controlled, and Night-rate prices

We offer a price differential between controlled and uncontrolled load. 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), and Night Only (23:00 – 07:00). The NITE tariff is also a form of controlled load and is a separately metered supply to permanently wired appliances. No uncontrolled appliances are connected to the NITE supply meter.

The variable TOU peak price

The variable TOU peak price recovers part of the distribution cost and most of the recoverable costs such as Transpower's connection, interconnection and new investment charges as well as council rates and statutory levies. The difference between Peak and Off-peak prices largely reflects transmission interconnection charges, which are based on demand at peak times.

Commercial and Industrial Price Structures (42 – 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 customers place on different elements of our network such as sub-transmission, high voltage (11kV) and low voltage (400V).

Table 2: Eastern region commercial and industrial pricing structures

Customer group	Meter type	Price categories	Fixed price			Power Factor	Variable charge		
				DIST	TRAN	PFC	24UC	CTRL	TOU
			$/day	$/kW	$/kW	$/kVAr/mth	$/kWh	$/kWh	$/kWh
Medium commercial	Non-TOU	T22 / V22	✓				✓	✓	
		T28N / V28N	✓				✓	✓	
	TOU	T28 / V28	✓			✓	✓	✓	
Large commercial	TOU	V40 / T50		✓	✓	✓			

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 with a substandard power factor are subject to a power factor price.

Large commercial and industrial customers

Prices vary according to the location, kW 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. Customers with a substandard power factor are subject to a power factor price.

PRICING IN THE WESTERN REGION – TARANAKI, WANGANUI, RANGITIKEI, MANAWATU, TARARUA, AND WAIRARAPA

For customers on the Western region, the network service is priced at the point electricity enters the distribution network from the national grid rather than at the customer's connection to the distribution network. Retailers decide how to on-charge their share of the cost of the distribution service to their customers. This is known as a Grid Exit Point (GXP) approach to pricing.

Like the Eastern region, pricing in the Western region is influenced by local network and customer characteristics. The network has significant variations in network density reflecting the relative number of customers to the length of wires. This network density has an impact on the cost of supply, which we reflect using two different (density) zones. Within these zones, customers are grouped according to capacity Prices in the Western region are set for three customer groups:

- Residential and small commercial - capacity less than or equal to 100kVA
- Medium commercial - capacity between 101-300kVA
- Large commercial and industrial - capacity greater than 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 6.

Residential and Small Commercial Pricing Structures (≤100kVA)

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 3: Western region residential and small commercial pricing structures

Customer group	Meter type	Price categories	Fixed price	Variable price options		
				Peak	Off-Peak	
			FDC	ERP	ERD	ERN
			$/day	$/kWh	$/kWh	$/kWh
Uncontrolled	TOU Non-TOU	E1UCA/E1UCB	✓	✓	✓	✓
Controlled	TOU Non-TOU	E1CA/E1CB		✓	✓	✓

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.

Peak pricing

The peak price is set to recover part of the distribution cost and most of the recoverable costs such as Transpower’s connection, interconnection and new investment charges as well as council rates and statutory levies. The difference between peak and off-peak prices largely reflects Transpower’s interconnection charges, which are based on demand at peak times.

Commercial and Industrial Price Structures (>100kVA)

Commercial and industrial connections (E100 and E300) are priced using a fixed component (monthly fixed price for E100 and monthly fixed capacity price for E300), and prices based on historical demands. Connections with substandard power factor are also subject to monthly power factor charge. The E100 and E300 pricing structure is presented in the following table.

Table 4: Western region commercial and industrial pricing structures

Customer group	Meter type	Price category	Fixed price	Fixed price	Demand price		
			$/ICP/day	$/kVA/day	DIST $/kW/day	TRAN $/kW/day	PFC $/kVAr
Medium commercial	TOU	E100	✓		✓	✓	✓
Large commercial	TOU	E300		✓	✓	✓	✓

The fixed component recovers fixed distribution costs, and the demand-based components recover the variable distribution costs and all transmission costs. For connections with a substandard power factor there is also a power factor charge, which is based on the previous month’s recording.

Price levels vary according to location and size of the connection. More detail on the pricing approach is provided in Section 6.

EVOLVING OUR PRICING AND PRICES

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

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 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. 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.

As a first step, we plan to replace the GXP approach to pricing in the Western region with an ICP methodology (as used in the Eastern region) in the coming years. 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. The transition involves significant system changes and requires access to consumption data so we can set prices accurately. It will require us to 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 and includes initiatives that will improve the alignment between costs and prices.

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

- Improving the alignment of fixed price components with fixed costs.
- The impact a stronger peak demand pricing signal would have 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.

4. CHANGES TO OUR PRICING APPROACH AND PRICES IN 2021-22

The Pricing Schedule for 2021-22 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 2.0%[6] compared to last year.

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

Table 5: Changes to Powerco's total forecast revenue

	Forecast Revenue ($000):			
	2020/21	**2021/22**	**$ Change**	**% Change**
Eastern region	174,510	177,058	2,548	1.5%
Western region	177,079	181,705	4,626	2.6%
Total	**351,589**	**358,763**	**7,174**	**2.0%**

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

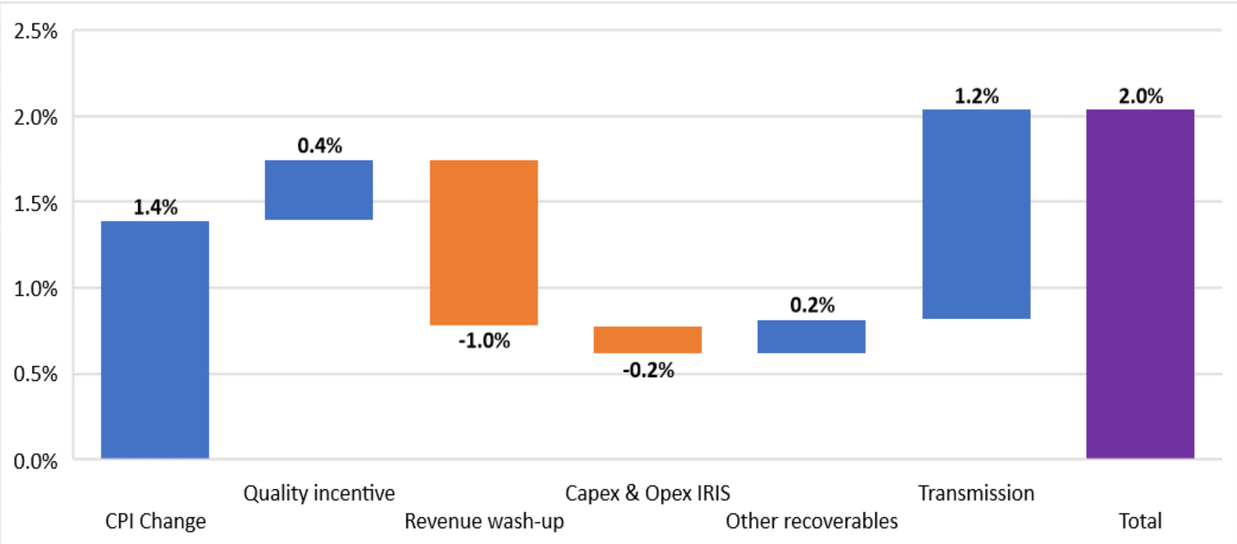
[6] This reflects the change from the forecast for FY21 to the forecast for FY22. It may differ from figures published elsewhere, which compare the forecast for FY22 against the most recent estimate for FY21.

Table 6: Reasons for changes to forecast revenue

Change	Description
CPI change	Powerco's forecast net allowable revenue, which excludes pass-through costs and recoverable costs and any wash-up draw down, is adjusted annually for the forecast change in Consumer Price Index (CPI). This forecast change of 2.03% has increased forecast revenue by $4.9m.
Quality incentive adjustment	The quality incentive scheme allows Powerco to earn additional revenue for performing better than the quality targets, and to receive less revenue for performing below the quality targets. The overall quality incentive adjustment for FY22 is +$0.5m, compared to -$0.8m in FY21. The average duration of unplanned outages was 181 minutes per customer – 15 minutes above the target – incurring a negative revenue adjustment of $1.1m. The average frequency of unplanned outages was significantly better than target, providing a positive revenue adjustment of $1.6m.
Revenue wash-up	Powerco calculates an annual 'wash-up' of the difference between the revenue received and allowable revenue. The revenue wash-up amount decreased from +$8.3m in FY21 to +$4.8m in FY22.
Capex and Opex IRIS	The IRIS mechanisms are designed to incentivise efficient capital and operating expenditure. The net adjustment to revenue is -$1.6m for FY22, compared to -$1.0m in FY21. This means Powerco's actual expenditure in preceding years was less than our allowance, and we are sharing a portion of those efficiency gains with our customers by reducing our total pass through and recoverable costs.
Change in transmission costs	Transmission costs, including Transpower's charges and ACOT payments, are recoverable costs that are reflected directly in revenue. These increased from $100.1m in FY21 to $104.4m in FY22. Chargeable RCPDs, including the demands offset by ACOT generators, increased from 793MW in FY21 to 828MW in FY22.

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

Figure 2: Percentage contribution to change in allowable revenue (FY21-FY22)



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 7: Changes to pricing from 1 April 2021

Change	Description
Change in variable charge elements	Powerco has adjusted prices to reflect the revenue allowance this year. Within these changes there have been specific adjustments to certain tariffs, including: • The night rate will increase, aligning it closer to the off-peak rate, reflecting that night usage is purely in off-peak hours. • The all-inclusive rate will increase relative to our uncontrolled rate, to further our aims of aligning the two rates. • The TOU all-inclusive rates will increase relative to the TOU uncontrolled rates, for the same alignment purposes as above. • The uncontrolled rate will increase relative to TOU prices, with the intention of aligning them over time.
E100 & E300 minimum AMD reduced	The minimum chargeable Anytime Maximum Demand (AMD) for E100 and E300 Price Categories will be reduced to 30kW and 100kW respectively (from 100kW and 300kW respectively). This will allow our prices to be more cost reflective as charges will reflect actual shares of distribution costs.
T41 price category closed and migrated	T41 Price Category will be closed and the ICPs migrated to the T28 Price Category, which covers an identical connection capacity range.

5. HOW PRICES ARE SET FOR EACH CUSTOMER GROUP

Prices for customers in both the Eastern and Western regions 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 (>1500kVA Western region and >299kVA Eastern region), although also some smaller customers where asset-based pricing is appropriate
- **Non-standard asset-based building block pricing** for very large (>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.

When setting prices, we consider the opportunities to share the value of deferring planned network investment. One way we do this is through a discount for controlled load.

STANDARD PRICING

We set standard prices using the process detailed in Table 8.

Table 8: 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 6.
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 (including ACOT) • 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 relevant cost allocations, and complying with the relevant legal requirements More detail on how we do this is in Section 7
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 8.

NON-STANDARD PRICING

Non-standard[7] 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, eg 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:

- Eastern region: Asset-based building block pricing (the T50/60 and V40/60 price categories).
- Western region: Customer-specific asset-based pricing (the SPECIAL price category)

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 in both the Eastern and Western regions and others that opt for an asset-based price. Asset-based pricing may also apply to generation connections and special arrangements designed to mitigate the risk of uneconomic asset bypass. Each price is set individually using this process.

[7] A contract is considered non-standard if: (a) 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; and (b) fewer than five people have such contracts with Powerco.

Table 9: Asset-based pricing process

Activity	What's involved
Measurement and forecasts of customer demand and connections	A customer's demand, measured by AMD (anytime maximum demand) or OPD (on peak demand) 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 to calculate the asset-based price. We use ORC or ODRC methods depending on the customer load group. For price categories T50 and V40 the ODRC methodology is used while for price categories T60, V60 and SPECIAL, the ORC methodology is used. ORC (Optimised Replacement Cost) is an estimate of the current cost of replacing the asset with one that can provide the required service in the most efficient way and ORDC (Optimised Depreciated Replacement Cost) is an estimate of the ORC value, less an allowance for depreciation that reflects the age of the asset. Assets are categorised as dedicated on-site assets or shared upstream assets.
Calculate return of and on capital	An annual rate of return is recovered on the asset valuations attributed to each customer – this is based on Powerco's prevailing weighted average cost of capital (WACC). • a 45-year annuity factor is used to obtain a return of and on the capital invested for assets valued using ORC • a WACC-based rate of return is used for those assets valued using ODRC to calculate the return on capital invested. A straight-line depreciation charge is used to obtain a return of capital.
Allocate maintenance costs	Maintenance costs are allocated to the relevant load groups based on the load group's ODV relative to the applicable GXP's total ODV[8]. These costs are allocated among the customers within the load group based on each customer's AMD as a proportion of the aggregate AMD of the load group.
Allocate indirect costs (fixed and variable).	Indirect costs are allocated to load groups based on its total ODV as a proportion of the applicable GXP's total ODV. Indirect costs are all costs of Powerco's electricity business excluding transmission, asset-related costs, maintenance, interest, and tax.
Allocate transmission costs	Transpower's connection charge allocation is based on the customer's demand measured by AMD. Where a customer is both an offtake customer and an injection customer at a connection location, connection charges for that location are calculated separately for that customer as an offtake customer and an injection customer. • Interconnection charges are allocated based on the customer's OPD multiplied by Transpower's interconnection rate. • ACOT charges from distributed generators are also allocated to customers on the same basis as connection and interconnection charges.

[8] Optimised Deprival Value (ODV) means the value attributed by applying the ODV methodology published by the Commerce Commission in 2010.

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/publications/pricing-schedules/.

Asset-based building block method (BBM)

The asset-based building block method is to set prices for very large (>4MVA) customers in both regions. These customers have a direct contractual relationship with Powerco for a defined term, typically for:

- a step change upgrade is needed but the increase in the customer's demand may not be as significant; or
- a new customer connection is required that involves significant investment.

BBM asset-based pricing comprises the following input components:

- return on capital investment, plus accounting depreciation in period or year;
- sub-transmission cost allocation of direct and indirect costs for sub-transmission asset utilisation in period or year;
- operating and maintenance costs;
- tax adjustment; and
- recovery of pass-through costs and recoverable costs (eg transmission charges and regulator levies).

CUSTOMERS ON NON-STANDARD CONTRACTS

Non-standard contracted customers are generally significant commercial or industrial loads, and thus arrangements between the parties include provision for response to planned and unplanned interruptions. For example, customers are given direct contact with Powerco's Network Operations Centre which enables them to liaise directly should a network event occur and help co-ordinate restoration. Some non-standard agreements include operational protocols detailing 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

Prices for distributed generation, and payments from Powerco to distributed generators for avoided cost of transmission (ACOT) and network support services are set according to the Distributed Generation Policy, available here. Powerco does not currently have any electricity distribution services which receive prices from distributed generation.

We pay ACOT and charge each distributed generator prior to connection to the network based on the conditions and fees set out in Part 6 of the Code. We do not charge distributed generation for exporting electricity via our network.

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 (eg hot water load control) or indirectly (eg a third-party provider).

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

Load control

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

- Residential customers in the Western region (the E1 customer group) offering control of their hot water have the daily fixed price discounted by 15 cents/day to 0 cents/day.
- Residential customers in the Eastern region (the T/V05S and T/V06S customer groups) offering control of their hot water receive discounts to the volume-based prices based on the availability and duration of load control.
- NITE price option is also a form of controlled load and is a separately metered supply to permanently wired appliances. No uncontrolled appliances are connected to NITE supply meter. The Load Control Equipment when in operation must result in the reduction to zero of all controllable loads and all load connected to the NITE supply meter.

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 price

Powerco's demand 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 reflective than using kWh-based prices.

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.

6. HOW WE GROUP CUSTOMERS

Prices are set for specific customer groups because it is not practicable to set individual prices, except for large commercial and industrial customers. Consequently, a key step of the pricing approach is grouping connections across each network. We group connections based on location and connection size or capacity. These 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.

We use six groups of connections for the Eastern region and three groups for the Western region. The table below describes each group.

Table 10: Customer groups used for the Eastern and Western regions

<table>
<tr><th>Eastern region</th><th>Western region</th></tr>
<tr><td>T01/T02 and V01/V02 – for all unmetered connections such as streetlights in the Valley and Tauranga regions

The unmetered nature of the load and the associated dedicated equipment, require special consideration when allocating costs</td><td rowspan="2">E1 – All residential and most commercial customers including unmetered connections

All connections with a connected capacity of less than 100 kVA which represents all residential and most commercial customers.

The E1 price category has been limited to less than 100 kVA to provide a relatively simple price structure for most customers while excluding all connections which require dedicated on-site and/or upstream assets</td></tr>
<tr><td>T05S/T06S and V05S/V06S – for all residential customers and small commercial customers with a fuse size of 3 Phase 60 Amps or less

Any customers with a fuse size of up to 3 Phase 60 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[9] are met, residential customers can choose between the low user price categories (V05S/T05S) and the standard price categories (V06S/T06S)</td></tr>
<tr><td>T22/V22 – for medium commercial customers with a fuse size of greater than 3 Phase 60 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 T05S/T06S and V05S/V06S price categories. Therefore, this group places increased demands on different components of our network and requires a slightly larger investment in on-site and upstream assets</td><td>E100 – Includes all connections with an installed capacity of greater than 100 kVA up to 300 kVA.

These equate to medium-large commercial customers. This price category has been defined because connections with this level of capacity place different levels of demand on different components of our network assets such as sub-transmission, high voltage (11kV) and low voltage (400V) assets and typically require dedicated on-site assets such as transformers and associated switchgear.</td></tr>
</table>

[9] For details on the eligibility criteria for the low user (also known as low fixed charge) prices please see the full pricing policy here.

<table>
<tr><th>Eastern region</th><th>Western region</th></tr>
<tr><td>T28/V28 – for medium 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 a slightly larger investment in on-site and upstream assets.</td><td></td></tr>
<tr><td>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</td><td rowspan="2">E300 & SPECIAL – Includes all connections with an installed capacity of greater than 300 kVA, including non-standard connections and connections with individually assessed pricing.

Connections with a connected capacity of greater than 300 kVA are large commercial / industrial customers.

This price category has been defined because connections with this level of capacity place different levels of demand on different components of our network assets such as sub-transmission, high voltage (11kV) and low voltage (400V) assets and typically require a higher level of dedicated on-site and up-stream assets (such as transformers, switchgear and feeders) than the E100 price category.</td></tr>
<tr><td>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 which 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, T60 and V60 price categories typically require dedicated on-site and 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 10). This ensures that their prices are regularly updated to reflect their individual contribution to network costs</td></tr>
</table>

Customers are assigned to a group based on the location of the GXP that is associated with their connection and based on installed capacity of their connection. More detail on the location and capacity criteria is provided below.

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 limiting price impacts on customers.

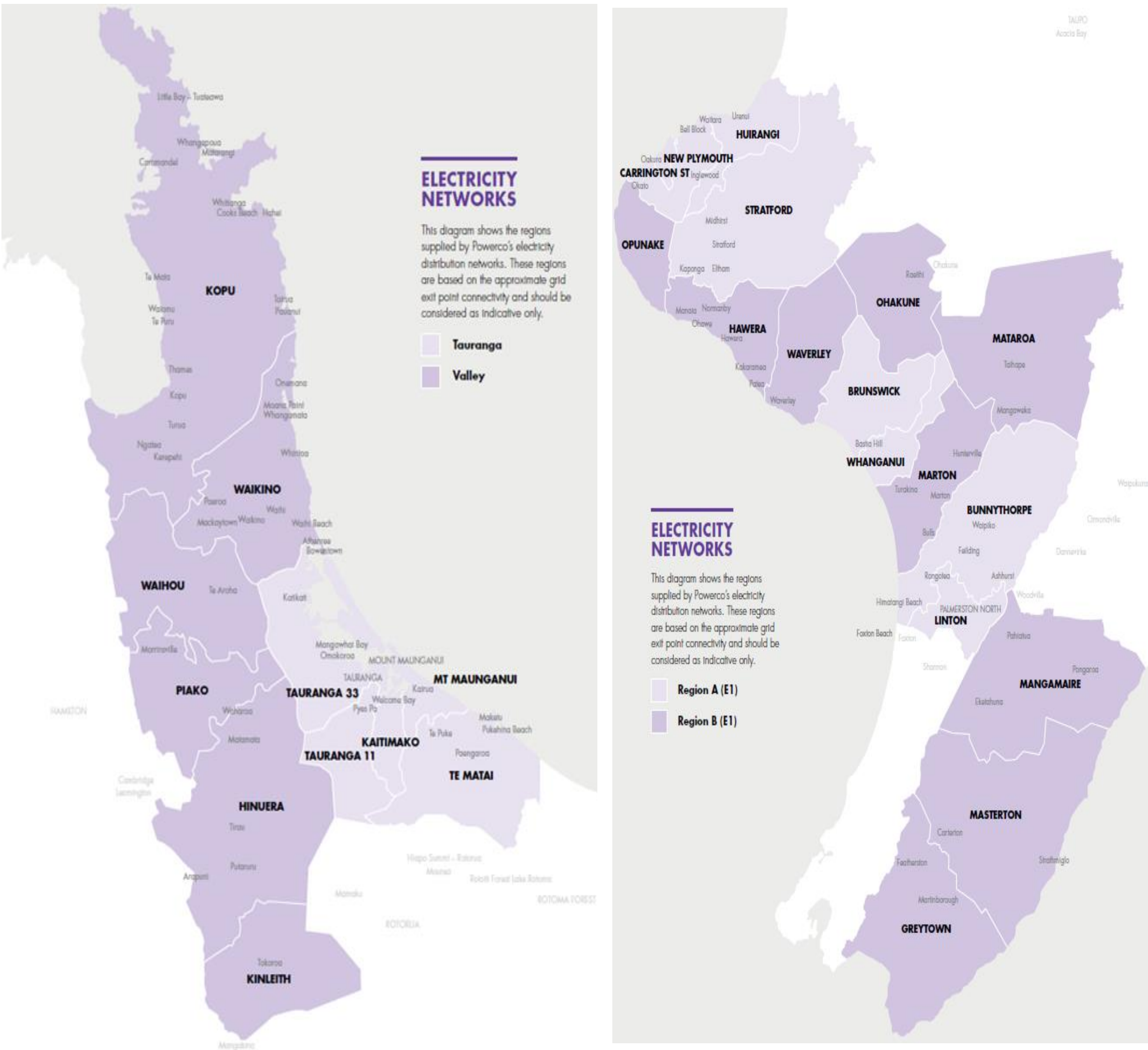
We use different Eastern and Western customer groups for historical reasons. The difference is due to more capacity bands for customers on the Eastern region, which allows prices to reflect costs more closely for each customer group. We will reassess the number of customer groups in the Western region as part of the transition to ICP pricing.

How location is factored into pricing

The location criteria 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.

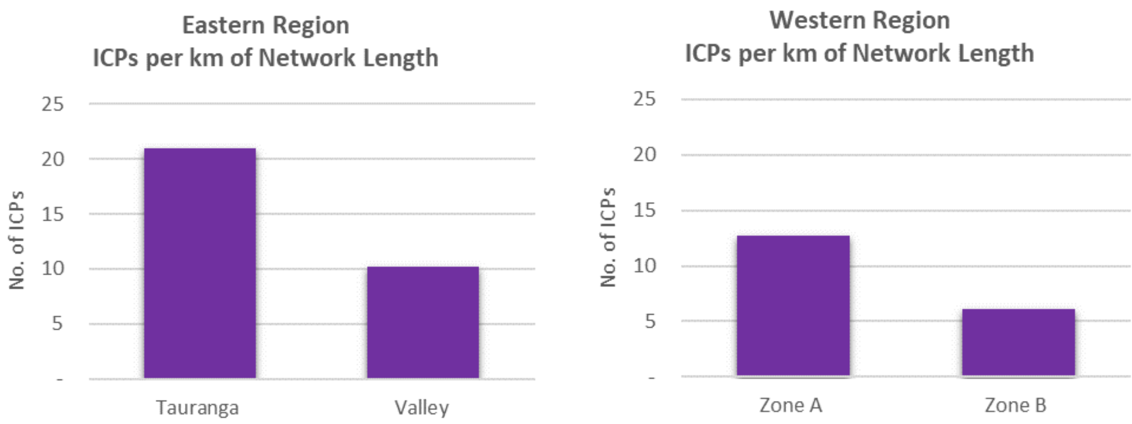
Figure 3: Eastern and Western region pricing zones

Eastern region | **Western region**



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

Figure 4: 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 of New Plymouth, Whanganui, and Palmerston North.
- Zone B includes customers connected to GXPs supplying the remaining low density and typically rural 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 not grouped into zones A and B. Instead, there are ten GXP zones with each zone representing a grouping of GXPs based on geographical proximity and the structure of the network connecting them. For example, the GXPs of Huirangi, Carrington St and Stratford are grouped together into zone A (as seen in the figure above). The number of zones represents Powerco's preference for greater transparency of costs within this price category because changes to individual customer behaviour within these groups can have on the underlying cost structure.

Capacity criteria

Capacity criteria are used to group customers by capacity of their connection or the local network (eg local transformer). Capacity is used to allocate costs because it is a significant influence on network cost. Powerco's prices in the Eastern and Western regions are structured to reflect different capacity bands.

Eastern

The six 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 some Eastern groups because 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 three 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 (E1) connections in the Western region make use of all the network assets but have limited on-site assets. Industrial connections (E300 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 reflect costs across these groups.

7. CALCULATING AND ALLOCATING COSTS ACROSS CUSTOMER GROUPS

For the 2021/22 pricing year, Powerco's total forecast revenue is $358.8m. We set prices to recover this amount by calculating and allocating costs across each customer group. The process involves:

- Confirming 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
- 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 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 2021/22 pricing year.

Table 11: Expected costs of supplying distribution services in the 2021/22 pricing year

Cost	Eastern region ($000)	Western region ($000)	Total ($000)
Operating and maintenance costs	$46,944	$51,351	**$98,295**
Depreciation	$31,750	$38,602	**$70,352**
Cost of capital	$41,415	$42,042	**$83,457**
Transmission costs[10]	$56,949	$49,710	**$106,659**
Forecast Revenue	**$177,058**	**$181,705**	**$358,763**

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.[11]

Operating costs

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

- Network operation costs

[10] This includes other pass-through and recoverable costs (which comprise around 2%)
[11] Our disclosures, including Asset Management Plans 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 (eg 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 recovery of all recoverable costs such as Transpower's connection, interconnection, and new investment charges as well as council rates and statutory levies, and any avoided cost of transmission (ACOT) payments made by Powerco to distributed generators.

Transpower's charges are set according to the transmission pricing methodology determined by the Electricity Authority and 'passed through' to customers in our prices. Detailed information on the transmission charges is available on the Transpower website.

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

Powerco's price structure in the Eastern region has been designed so that customers with higher connected capacity have a higher fixed component than those with lower connected capacity. This benefits both Powerco and customers by making line charges more predictable and more closely related to the actual cost of supply.

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).

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.

Table 12: Eastern region target revenue requirement split by fixed and variable price components for each customer group (2021/22 pricing year)

Zone	Customer Group	Price Category	ICPs	Target Revenue Split			
				Fixed	Variable[12]	Demand	Total
Tauranga	0-41kVA	Unmetered (T01/T02)	285	77.8%	22.2%	-	100%
		Low Usage (T05)	32,733	10.5%	89.5%	-	100%
		Standard (T06)	55,970	37.0%	63.0%	-	100%
	42-299kVA	3 Phase 60 – 3 Phase 250 Amps (T22)	649	37.5%	62.5%	-	100%
		200 - 299 kVA (T28)	143	52.3%	45.0%	2.7%	100%
	300 kVA + (incl. non-standard customers)	300 – 1,499 kVA (T50)	220	97.2%	-	2.8%	100%
		1,500 kVA + (T60)	33	97.3%	-	2.7%	100%
Valley	0-41kVA	Unmetered (V01/V02)	205	94.6%	5.4%	-	100%
		Low Usage (V05)	37,014	10.6%	89.4%	-	100%
		Standard (V06)	35,595	28.5%	71.5%	-	100%
	42-299kVA	3 Phase 60 – 3 Phase 250 Amps (V22)	535	32.3%	67.7%	-	100%
		200 – 299 kVA (V28)	46	43.8%	55.4%	0.8%	100%
	300 kVA + (incl. non-standard customers)	300 – 1,499 kVA (V40)	88	96.5%	-	3.5%	100%
		1,500 kVA + (V60)	25	98.5%	-	1.5%	100%

[12] Including power factor prices (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 and are exacerbated when applied to GXP pricing. As a result, charges for residential and small commercial customers (E1 in the below table) are mostly variable, despite most network costs being fixed.

Customers in the E100 and E300 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 13: Western region target revenue requirement by fixed and variable price components for each customer group (2021/22 pricing year)

Customer Group	Price Zone	ICPs	Target Revenue Split			
			Fixed	Variable	Demand[13]	Total
E1 – up to 100 kVA	A	122,129	4.1%	95.9%	-	100%
	B	54,347	3.0%	97.0%	-	100%
E100 (101 – 300 kVA)	A	59	15.1%	-	84.9%	100%
	B	10	9.5%	-	90.5%	100%
	C	2	26.8%	-	73.2%	100%
	D	1	10.0%	-	90.0%	100%
	E	19	13.6%	-	86.4%	100%
	F	6	11.4%	-	88.6%	100%
	G	4	6.5%	-	93.5%	100%
	H	28	9.6%	-	90.4%	100%
	I	96	14.8%	-	85.2%	100%
	J	2	10.8%	-	89.2%	100%
E300 (301 kVA+)	A	79	29.2%	-	70.8%	100%
	B	6	20.7%	-	79.3%	100%
	C	1	10.0%	-	90.0%	100%
	D	2	21.9%	-	78.1%	100%
	E	31	28.7%	-	71.3%	100%
	F	9	26.6%	-	73.4%	100%
	G	2	15.6%	-	84.4%	100%
	H	22	18.9%	-	81.1%	100%
	I	82	25.3%	-	74.7%	100%
	J	1	52.9%	-	47.1%	100%
Non-Standard		34	98.4%	-	1.6%	100%

[13] Including power factor prices (where applicable).

8. 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% 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, or other ways.

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 significantly less 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.

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 approximately 8MWh per year for a network cost of approximately $800 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 $6,000-$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[14]. 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
- 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.

[14] Our customer base includes 23 retailers, 13 directly contracted industrial businesses, 19 local territorial authorities and the NZTA.

Findings of our customer engagement surveys are reflected in our asset management planning process along with other key drivers such as safety and resilience. Details of our approach and findings of the 2019 consultation programme are published in our most recent Electricity Asset Management Plan (2019).

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.

9. ALIGNMENT WITH ELECTRICITY AUTHORITY PRICING PRINCIPLES

The table below provides commentary about how our pricing approach aligns with the Electricity Authority's Pricing Principles (available here).

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 8. Sections 5-7 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, 5 and 7, 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 (eg the LFC Regulations require us to set prices which discourage consumption).
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 5 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 8 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.

PRINCIPLE	ALIGNMENT DEMONSTRATED
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 3 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 5 refers to our Distributed Generation Policy 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.
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 3, 5 and 7, 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 5.
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. For example, the "More for less" webpage was used for the FY21 pricing changes, and included a survey option. 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.

10. HOW WE MEET THE COMMERCE COMMISSION INFORMATION DISCLOSURE REQUIREMENTS

The table in this section provides commentary about 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 4.
(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 5.
(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 8.

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

2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	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 9.
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See Section 4.
(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 7.
(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 6.
(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 4.

Information Disclosure Requirement	**Compliance demonstrated**
(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 7, 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 3 describes the pricing approach Powerco is adopting.
(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 5 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— (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;	See Section 5.
(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 5.

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[15]; and
- The Commerce Commission's electricity default price-quality path notice and information disclosure requirements.[16]

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.

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

Coincident Maximum Demand (CMD) see "On Peak Demand".

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.

Customised Price Path Determination or **CPP Determination** means the Powerco Limited Electricity Distribution Customised Price-Quality Path Determination 2018[17]. This sets out the price path and quality standards the Powerco must comply with over the period 1/4/2018 to 31/3/2023.

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.

[15] Available at www.powerco.co.nz.
[16] Available at www.comcom.govt.nz.
[17] The CPP is described in more detail on the Commerce Commission's website, http://www.comcom.govt.nz/regulated-industries/electricity/cpp/cpp-proposals-and-decisions/powercocpp/

Distribution Network or **Network** means:

Network region	Area	Transpower GXP
Eastern	Valley (Thames Valley)	Kinleith Kopu Hinuera 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: http://www.legislation.govt.nz/regulation/public/2004/0272/latest/096be8ed8163f72d.pdf

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**.

Optimised Replacement Cost (ORC) is an estimate of the current cost of replacing the asset with one that can provide the required service in the most efficient way. Under this approach, asset values are adjusted if assets exhibit excess capacity, are over-engineered, are poorly designed (compared with modern technology) or are poorly located.

Optimised Depreciated Replacement Cost (ODRC) is an estimate of the ORC value, less an allowance for depreciation that reflects the age of the asset.

On Peak Demand (OPD) is the average of Customer's demand during the 100 regional peak periods as notified by Transpower. The 100 regional peak periods will be between 1 September 2019 and 31 August 2020 for the Price Year effective 1 April 2021. The OPD is used in calculating the Line Charges of a Customer on an asset-based load group, such as the V40, T50, V60, and T60 load groups.

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.

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.

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

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 14: Cost allocations to customer groups

Cost component	Allocation approach
Operating costs	Allocated directly to the GXP 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, eg 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 network based on the RAB values and depreciation of the assets within each network. The cost of capital and depreciation charges are allocated between customer groups, based on the aggregate of the maximum demands contributed by each group.
Transmission costs	Directly attributed to GXPs. Transmission costs are allocated between customer groups in each location using a weighted average of the regional coincident maximum demand (based on the 100 regional coincident peak demands) attributable to each load group and the number of ICPs within each load group. This is because Transpower's interconnection charges, which represent the major part of Powerco's transmission costs, are directly related to these regional coincident peak demands.

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 15: Cost allocations to Eastern region customer groups

Price Zone	Customer Group	Allocator For:		
		Operating Costs	Cost of Capital & Depreciation	Transmission Costs
Tauranga	0-41kVA	37.4%	38.6%	33.6%
	42-299kVA	6.5%	6.1%	3.2%
	300kVA+	4.2%	5.5%	5.9%
	Non-Standard	3.3%	3.7%	6.9%
Valley	0-41kVA	36.3%	34.0%	29.2%
	42-299kVA	4.3%	4.4%	3.1%
	300kVA+	1.6%	2.4%	2.3%
	Non-Standard	6.5%	5.2%	15.8%
Total		**100%**	**100%**	**100%**

Table 16: 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	0-41kVA	88,987	$17,559	$28,266	$19,112	$64,937
	42-299kVA	792	$3,064	$4,462	$1,819	$9,345
	300kVA+	220	$1,957	$4,031	$3,381	$9,369
	Non-Standard	33	$1,526	$2,733	$3,928	$8,187
Valley	0-41kVA	72,813	$17,023	$24,866	$16,640	$58,529
	42-299kVA	581	$1,998	$3,218	$1,767	$6,983
	300kVA+	88	$753	$1,770	$1,303	$3,826
	Non-Standard	25	$3,064	$3,819	$8,999	$15,882
Total		**163,540**	**$46,944**	**$73,165**	**$56,949**	**$177,058**

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 17: Cost allocations to Western region customer groups

Customer Group	Price Zone	Allocator For:		
		Operating Costs	Cost of Capital & Depreciation	Transmission Costs
E1 – up to 100 kVA	A	52.5%	50.7%	51.3%
	B	30.6%	33.1%	23.2%
E100 (101 – 300 kVA)	A	0.7%	0.8%	0.8%
	B	0.3%	0.2%	0.2%
	C	0.0%	0.0%	0.0%
	D	0.0%	0.0%	0.0%
	E	0.3%	0.3%	0.3%
	F	0.1%	0.1%	0.1%
	G	0.1%	0.1%	0.1%
	H	0.6%	0.6%	0.5%
	I	1.3%	1.3%	1.4%
	J	0.0%	0.0%	0.0%
E300 (301 kVA+)	A	2.5%	2.1%	3.3%
	B	0.3%	0.3%	0.5%
	C	0.2%	0.2%	0.2%
	D	0.2%	0.2%	0.2%
	E	1.2%	1.2%	1.9%
	F	0.4%	0.4%	0.3%
	G	0.2%	0.2%	0.3%
	H	1.0%	1.0%	1.2%
	I	4.5%	2.8%	4.3%
	J	0.0%	0.0%	0.0%
Non-Standard		3.0%	4.3%	10.0%
Total		**100%**	**100%**	**100%**

Table 18: 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)
E1 – up to 100 kVA	A	122,129	$26,940	$40,923	$25,511	$93,374
	B	54,347	$15,699	$26,729	$11,531	$53,959
E100 (101 – 300 kVA)	A	59	$371	$658	$410	$1,439
	B	10	$131	$172	$81	$384
	C	2	$9	$14	$4	$27
	D	1	$13	$20	$4	$37
	E	19	$143	$224	$140	$507
	F	6	$57	$89	$45	$191
	G	4	$66	$104	$53	$223
	H	28	$310	$487	$261	$1,058
	I	96	$651	$1,023	$676	$2,350
	J	2	$20	$32	$15	$67
E300 (301 kVA+)	A	79	$1,281	$1,685	$1,628	$4,594
	B	6	$164	$259	$232	$655
	C	1	$91	$143	$107	$341
	D	2	$96	$151	$90	$337
	E	31	$630	$990	$932	$2,552
	F	9	$189	$297	$160	$646
	G	2	$106	$166	$165	$437
	H	22	$496	$779	$583	$1,858
	I	82	$2,334	$2,226	$2,115	$6,675
	J	1	$12	$20	$6	$38
Non-Standard		34	$1,542	$3,453	$4,961	$9,956
Total		**176,974**	**$51,351**	**$80,644**	**$49,710**	**$181,705**

DIRECTOR CERTIFICATION

DIRECTORS' CERTIFICATE CONFIRMING REGULATORY COMPLIANCE OF THE POWERCO ELECTRICITY PRICING METHODOLOGY 2021

Certification for Year-beginning Disclosure

We, JOHN LOUGHLIN and PAUL CALLOW, being directors of Powerco Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Powerco Limited prepared for the purposes of clause 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.

Signed:

Director JOHN LOUGHLIN

Date: 26/03/21

Director PAUL CALLOW

Date: 26/03/21