ELECTRICITY PRICING METHODOLOGY

2019

EFFECTIVE 1 APRIL 2019

DISCLOSED IN ACCORDANCE WITH SECTION 2.4.1 OF THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012

CONTENTS

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[1]; and
- The Commerce Commission's electricity default price-quality path notice and information disclosure requirements.[2]

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.

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 Consumer's installation, as defined by the Distributor.

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

Customer means a direct Customer or a Retailer (where the Retailer is the Customer).

Customised Price Path Determination or **CPP Determination** means the Powerco Limited Electricity Distribution Customised Price-Quality Path Determination 2018.[3] 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.

Distribution Network or **Network** means:

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[1] Available at www.powerco.co.nz.
[2] Available at www.comcom.govt.nz.
[3] 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/

<table>
<tr><th>POWERCO REGION</th><th>DISTRIBUTION NETWORK</th><th>CONNECTED TO TRANSPOWER GXPS</th></tr>
<tr><td rowspan="2">EASTERN</td><td>VALLEY
(Thames Valley)</td><td>Kinleith
Kopu
Hinuera
Piako
Waihou
Waikino</td></tr>
<tr><td>TAURANGA</td><td>Tauranga
Mt Maunganui
Te Matai
Kaitimako</td></tr>
<tr><td rowspan="4">WESTERN</td><td>WAIRARAPA</td><td>Greytown
Masterton</td></tr>
<tr><td>MANAWATU</td><td>Bunnythorpe
Linton
Mangamaire</td></tr>
<tr><td>TARANAKI</td><td>Carrington
Huirangi
Hawera
New Plymouth
Opunake
Stratford</td></tr>
<tr><td>WANGANUI</td><td>Brunswick
Marton
Mataroa
Ohakune
Wanganui
Waverley</td></tr>
</table>

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 Consumers.

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 Consumer, 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 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 Consumers.

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 Consumer's demand during the 100 regional peak periods as notified by Transpower. The 100 regional peak periods will be between 1 September 2017 and 31 August 2018 for the Price Year effective 1 April 2019. The OPD is used in calculating the Line Charges of a Consumer 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 Consumer'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 a particular ICP.

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 as the case may be.

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

RAB means Powerco's Regulatory Asset Base.

Retailer means the supplier of electricity to Consumers 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.

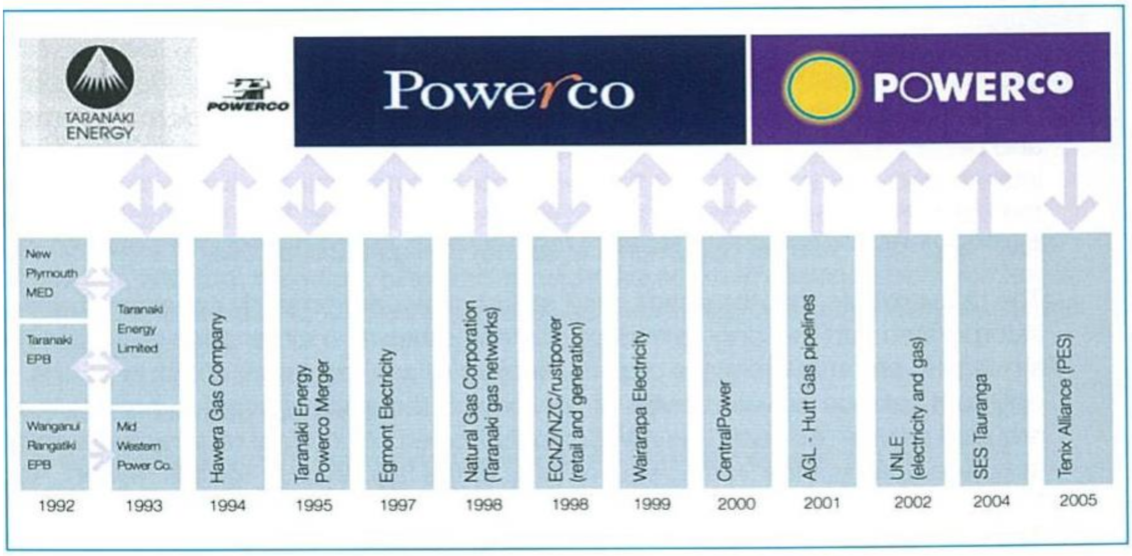
Price Option means the price option within a **Price Category** where such a **Price Category** provides for **Retailer** choice amongst two or more options, subject to a particular configuration of metering and load control equipment.

1. INTRODUCTION

Powerco is a utility network ownership and management business. It is New Zealand's largest provincial distributor of electricity and gas, with around 446,000 consumers connected to its networks. Powerco's electricity networks are located in Tauranga, Thames Valley, Coromandel Peninsula, Eastern and Southern Waikato, Taranaki, Whanganui, Rangitikei, Manawatu and Wairarapa. Our gas pipeline networks are in Hutt Valley, Porirua, Wellington, Horowhenua, Manawatu, Taranaki and Hawke's Bay.

From the mid-1990s until the early 2000s, Powerco grew significantly through mergers and acquisitions (see Figure 1). Funds managed by QIC Limited have a 58% stake in Powerco, with the remaining 42% holding owned by AMP Capital Limited.

Figure 1: History of Powerco mergers and acquisitions



2. COMPLIANCE REQUIREMENTS FOR THIS PRICING METHODOLOGY

This document contains information that must be disclosed in accordance with clauses 2.4.1 to 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012. This disclosure also requires we demonstrate the consistency between our pricing methodology and the Electricity Authority's pricing principles[4]. Any areas of inconsistency need to be explained[5]. We believe this pricing methodology is consistent with the Authority's pricing principles.

Other requirements that affect distribution pricing are contained in the CPP Determination and the Low Fixed Charge Regulations. Compliance with these requirements is published separately on our website (eg the CPP price-setting statement) or communicated directly with the Electricity Authority (Low Fixed Charge Regulations).

Detailed below are:

- the Information Disclosure requirements;

[4] As specified in *Distribution Pricing Principles and Information Disclosure Guidelines*, originally published by the Electricity Commission in March 2010.
[5] Clause 2.4.3(1) of the Electricity Distribution Information Disclosure Determination 2012 refers.

- the Electricity Authority's pricing principles;
- the pricing implications of the CPP Determination;
- the pricing implications of the Low Fixed Charge Regulations.

ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012 – CLAUSES 2.4.1 TO 2.4.5

The Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 came into force on 1 October 2012. Clauses 2.4.1 to 2.4.5 of the Determination state:

Disclosure of pricing methodologies

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

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

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

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

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

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

2.4.3 Every disclosure under clause 2.4.1 above must—

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

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

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

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

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

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

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

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

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

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

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

(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;

(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;

(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.

2.4.5 Every disclosure under clause 2.4.1 above must–

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

(a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;

(b) how the EDB determines whether to use a non-standard contract, including any criteria used;

(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;

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

(a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts;

(b) any implications of this approach for determining prices for consumers subject to non-standard contracts;

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

(a) prices; and

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

ELECTRICITY AUTHORITY'S DISTRIBUTION PRICING PRINCIPLES

Clause 2.4.3(2) from information disclosure requirements refers to "pricing principles". These are maintained by the Electricity Authority[6] and repeated in the table below. This pricing methodology includes material to demonstrate the extent to which our pricing methodology is consistent with these principles.

Distribution Pricing Principles		
(a)	Prices are to signal the economic costs of service provision, by:	
	(i)	being subsidy free (equal to or greater than incremental costs, and less than or equal to stand alone costs), except where subsidies arise from compliance with legislation and/or other regulation;
	(ii)	having regard, to the extent practicable, to the level of available service capacity; and
	(iii)	signalling, to the extent practicable, the impact of additional usage on future investment costs.
(b)	Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.	
(c)	Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:	
	(i)	discourage uneconomic bypass;
	(ii)	allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and
	(iii)	where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.
(d)	Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.	
(e)	Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.	

[6] https://www.ea.govt.nz/operations/distribution/pricing/

CUSTOMISED PRICE-QUALITY PATH DETERMINATION – IMPLICATIONS FOR PRICING

In November 2017, the Commerce Commission published its CPP Draft Determination for the 5-year period 1/4/2018-31/3/2023[7]. The changes to Powerco's electricity prices that take effect from 1 April 2019 reflect the Commission's determination. The CPP Determination includes requirements on Powerco to disclose information about how it has carried out its price–setting for the year ahead. This disclosure is available on our website http://www.powerco.co.nz/publications/disclosures/ and is consistent with the pricing methodology.

LOWER FIXED CHARGE TARIFF REGULATIONS – IMPLICATIONS FOR PRICING

The Low Fixed Charge Regulations require that a "low user" option must made available for every residential standard price option that is available where:

- the fixed price component is no more than 15 cents per day and
- the total charges per year for the average residential consumer are the same or no more than those incurred under the standard option.

Consequently, changes to the annual charges for an average[8] residential consumer, must be equal or lower for "low fixed charge" options when compared to the equivalent standard option.

[7] The draft determination was used for price setting in 2018 because the final determination was not available at the time of price setting. We have published the Commerce Commission's approval of this on our website as part of compliance with the CPP Determination. This can be found here: http://www.powerco.co.nz/publications/disclosures/electricity/

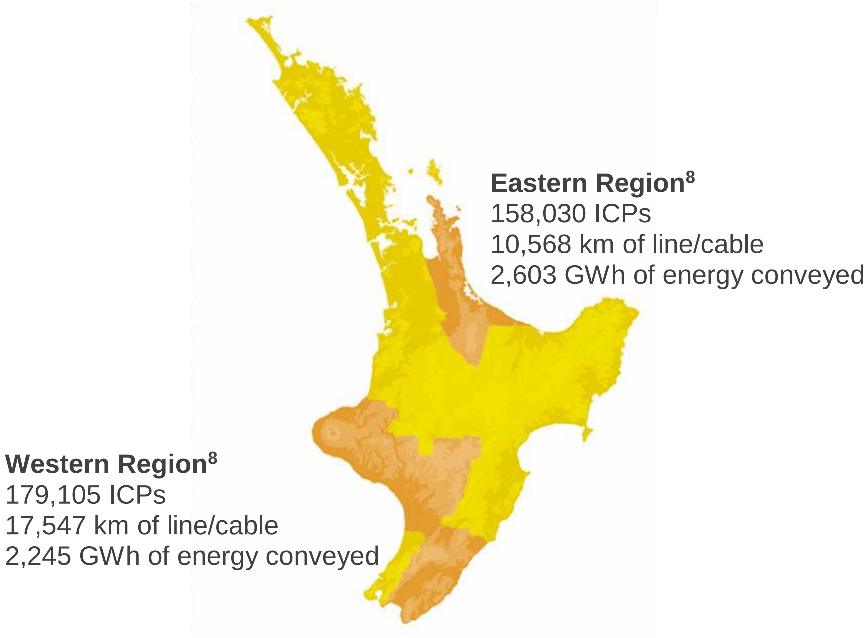
[8] Average consumer is defined as an 8,000 kWh per annum consumer in accordance with the Low Fixed Charge Regulations.

3. OVERVIEW OF OUR PRICING METHODOLOGY AND FUTURE PLANS

Two different pricing methodologies continue to be used across Powerco's network. The Western Region (as highlighted in Figure 2 below) uses a Grid Exit Point (GXP) methodology which can be considered a wholesale delivery model and the Eastern Region uses an Installation Control Point (ICP) methodology which is a retail delivery model. Both methodologies are checked against a cost of supply model developed by Powerco to ensure that prices recover the costs of service provision.

These two methods have several differences, but the principal difference is the way that quantities are measured and used to determine prices.

Figure 2: Map of Powerco's Eastern and Western Regions



EASTERN REGION – OVERVIEW OF THE METHODOLOGY

An Installation Control Point (ICP) methodology is used for the Eastern Region. This is a retail delivery methodology where the network service is priced a consumer's metering point and, as such, Powerco relies on retailers to provide complete and accurate data in order to derive billable quantities.

Powerco has two separate price schedules in the Eastern Region. These reflect the different network density between them. They are:

- Thames Valley (or Valley, which includes the Coromandel) and
- Tauranga.

Each of these price schedules consists of around six different price categories reflecting customer fuse sizes:

[9] Figures from Powerco's Electricity Information Disclosure 2018.

Tauranga	Valley	Description
T01/T02	V01/V02	Unmetered connections
T05/T06	V05/V06	All consumers with a fuse size less than 60 Amps (3 phase). This covers residential and small commercial customers.
T05S/T06S	V05S/V06S	All consumers with a fuse size less than 60 Amps (3 phase) on a TOU price. This covers residential and small commercial customers.
T22	V24	Commercial customers with a fuse size between 60-250 Amps (3 phase)
T24/T41	V28	Commercial customers with an installed capacity of 200– 299 kVA
T43/T50	V40	Commercial customers with an installed capacity of 300–1499 kVA
T60	V60	Commercial customers with an installed capacity over 1,500 kVA

These price categories are defined around consumer groups with similar load characteristics, such as installation type (such as Unmetered, Non-Half Hour (NHH), and Half Hour (HH)), fuse size and installed capacity of the consumer's installation. Fuse size is used for some price categories because their available capacity is limited by the size of the fuses at their installation rather than the installed capacity of dedicated transformers.

The granularity of the groupings for each price 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 consumers. Powerco will continue to consult with retailers and consumers to ensure our price structures reflect an appropriate balance of these factors.

This ICP based methodology is more consistent with retail pricing. As a result, retailers can provide a greater number of targeted price signals to specific groups or segments of consumers to reflect the costs of their network use.

WESTERN REGION – OVERVIEW OF THE METHODOLOGY

A GXP methodology applies in the Western Region covering Taranaki, Wanganui, Rangitikei, Manawatu, Tararua and Wairarapa. The GXP methodology is a wholesale delivery model where quantities are derived using reconciled GXP volumes which are then allocated to retailers based on their relevant shares.

Powerco uses three price categories in the Western region:

E1	All residential consumers and most commercial customers
E100	Commercial customers with installed capacity from 100 kVA to 300 kVA
E300	Commercial customers with installed capacity greater than 300 kVA. Powerco also has a non-standard SPECIAL price category which is a subset of the E300 price category and is reserved for individual prices charged to major customers (discussed in section 10).

These price categories reflect the different levels of demand that each consumer group places on components of the network, such as sub-transmission, high voltage (11kV), and low voltage (400V) assets, and the on-site assets at each connection. For example, most residential (E1) connections make use of all the network assets, but have limited on-site assets. An industrial connection in the E300 price category has many more on-site assets, but makes limited use of the low voltage (400V) network assets. The use of these consumer groups makes it possible for prices to reflect costs across these groups.

Each price category in the Western Region is further differentiated by pricing zones which reflect groupings of GXPs with similar characteristics such as network density and geographical location. High density networks typically have lower costs per customer than low density networks.

Volumes and demand data for industrial consumers, normally 11kV network users, are calculated from half hour metering data adjusted for losses. The remaining volume and demand inputs is derived from the reconciliation process and retailer ICP counts accessed from the industry registry.

PRICING REFORM – OUR ROADMAP

Over recent years, the structure and level of distribution pricing has received attention from regulators, retailers, and other stakeholders. In the past, our prices for residential and small commercial customers had a time-of-use (TOU) component of their total distribution charge. A day/night structure applied, where prices were lower overnight than in the day. This year we have modified this structure as described later in this methodology.

More broadly, Powerco's approach to pricing reform involves two core activities

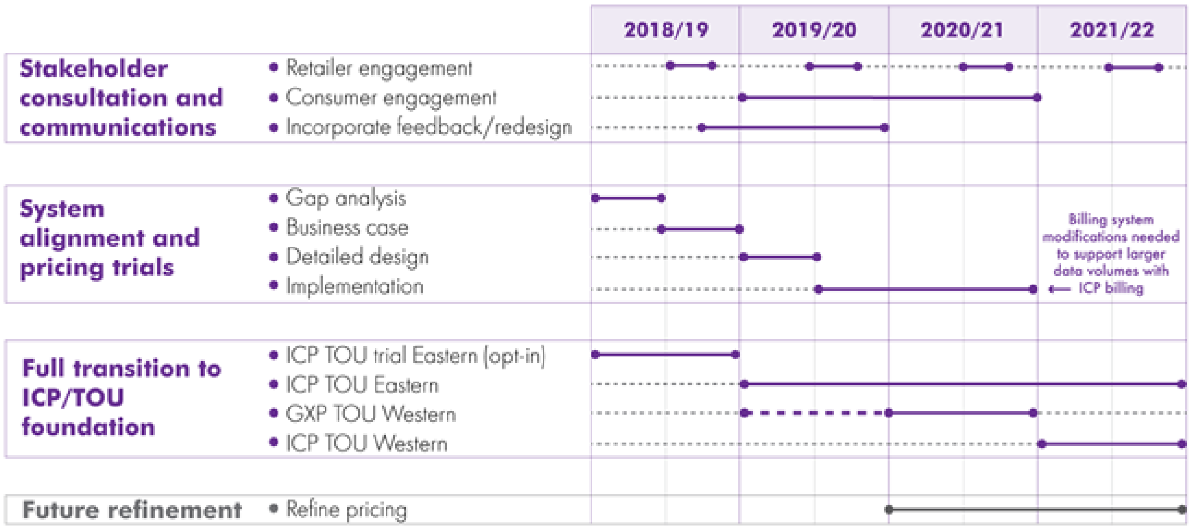
- transitioning the Western Region to ICP-based pricing
- introducing differential time-of-use charging across our network to better reflect the costs of network use during the daily peak consumption periods.

From 1 April 2018 Powerco has operated under a under a revenue cap. One of the reasons the Commerce Commission chose this approach is that it removes potential barriers for EDBs to move to more efficient pricing structures. Powerco's roadmap reflects the removal of these barriers and includes initiatives that will improve the alignment between costs and benefits.

The introduction of these changes is contingent on having appropriate infrastructure to capture, process, and invoice these new charges. It is also contingent a penetration of smart meters exceeding 70% and retailers being able to implement the charges.

Our 2018 pricing methodology included a roadmap that outlined the activities and indicative timings we plan to carry out to improve the cost-reflectivity of our pricing. Figure 3 is an update to that roadmap. We are planning to introduce differential time-of-use charging across our entire network in 2021. This is contingent on several factors, including systems upgrades approved in the CPP Determination that affect other parts of Powerco.

Figure 3: Powerco's pricing reform roadmap (2019 update)



4. CHANGES TO THE METHODOLOGY AND PRICING SCHEDULE

The final prices contained in the Pricing Schedule[10] for 2019/20 reflect an average annual increase in estimated charges, in nominal terms, of 0.6%. Relative to 2018, this change reflects:

- A 2.2% increase in our allowed revenue from $278.9m to $284.9m, reflecting the CPP Determination
- A 3.0% reduction in total pass through charges from $121.1m to $117.5m, reflecting changes to transmission charges and other recoverable costs.

Table 1 provides details of changes to pricing introduced from 1 April 2019

Table 1: Summary of price rationalisation, adjustments and pricing schedule updates for the 2019 price year

Specific Variation	Description
TOU Pricing	Powerco trialled TOU pricing for mass market consumers in the Eastern Region in 2017. This applied to consumers on the T05/T06 and V05/V06 price categories with advanced metering. From 1 April 2019 this is being applied to all customers with advanced metering, in both the Eastern and Western Regions. We consulted with retailers regarding this change, and they can apply for a temporary exemption to TOU pricing if they are unable to supply TOU information. Due to these exemptions, and limited advanced metering availability, the TOU charge will apply for approximately 40% of customers.
Western Region demand charge	From 1 April 2019 the peak demand charge ($/kW/month) has been replaced with a cents/kWh price for mass market consumers. This is in line with moving all mass market consumers to TOU pricing. The cents/kWh charge has been set to reflect the same effective cost as the discontinued demand charge.
Increase of Power factor charge for E100/E300 price categories.	From 1 April 2017 Powerco introduced a new power factor charge, for the 457 customers on the E100 & E300 price categories in the Western region. From 1 April 2019, this charge will increase from $3kVAr/month to $7/kVAr/month. Retailer feedback strongly supported a gradual introduction of the power factor charge to enable customers to gain an understanding of their particular power factor issues. This approach will also allow customers to have sufficient time to correct any issues before the charge becomes material over the coming years.
Price re-balancing for the V28 price category.	From 1 April 2019, Powerco has further reduced the fixed charges for 42 customers on the V28 price categories. The fixed charge will drop from $36.61 to $34.11/day, with an appropriate uplift in the associated variable charges to partially mitigate the decrease in fixed charge revenue. Powerco will continue to reduce the fixed charge for this consumer group in future years until it is aligned to the equivalent charges in the Tauranga region.

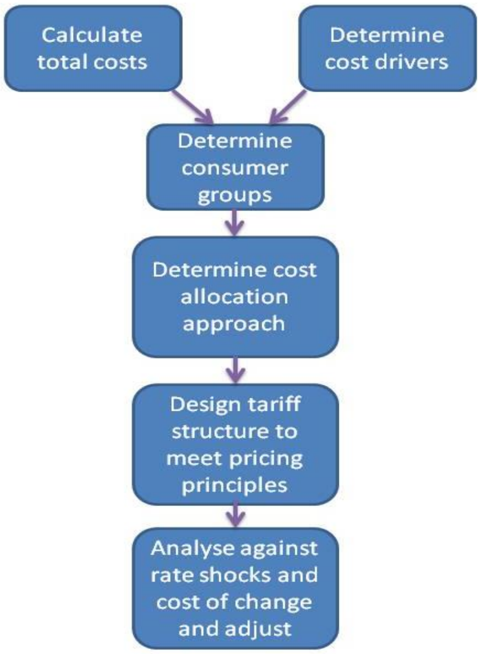
All the changes outlined in Table 1 were discussed in detail with retailers during two rounds of consultation before being implemented. In all cases we have chosen the relevant course of action in collaboration with retailers. When we confirmed our approach during our draft pricing notification no feedback was received, suggesting that our approach was inappropriate and therefore no alternative approaches were considered.

[10] For further details on our prices and how we apply our charges please see the full pricing policy at: http://www.powerco.co.nz/Publications/Pricing-Schedules/Electricity/

5. SUMMARY OF PRICING PROCESS

The pricing process is summarised in Figure 4.

Figure 4: Overview of the pricing process



A description of the pricing process is:

- calculate total costs for the relevant period; these include transmission costs (including ACOT), capital costs, operating costs, maintenance costs and administration costs;
- determine the key drivers of network expenditure;
- determine suitable groupings of connections across each network based on similarities of network and consumer characteristics such as geography, rural/urban connection density, mains size, protection rating and/or transformer capacity;
- determine the allocation of costs (such as operating costs, transmission costs and cost of capital) across each network and price category;
- calculate prices based on the relevant cost allocations, ensuring compliance with the relevant legal requirements;
- assess the pricing structure to take account of the effect of price shocks and adjust as needed.

6. QUANTIFICATION OF KEY COMPONENTS OF COSTS AND REVENUES

The key components of network costs and revenue for Powerco's Eastern and Western Regions are summarised below. Network assets, customer density and system length largely drive these costs. Consequently, these costs are largely fixed and independent of the volume of electricity consumed across our network.

OPERATING COSTS

These are costs associated with the provision of electricity distribution services, including:

- statutory charges and levies (excluding those that are pass through costs);
- network planning and asset management costs;
- network management and dispatch costs;
- network operation costs;
- the cost of support services such as billing, record management, planning, contract administration, regulatory compliance and resource costs;
- depreciation on electricity lines business assets; and
- tax.

Detailed information on Powerco's historical costs is disclosed each year in Powerco's annual information disclosure to the Commerce Commission. This information is publicly disclosed on Powerco's website, including by cost category.

Powerco's Asset Management Plan contains forecasts of capital and operating expenditure over a 10 year period which helps to form a view of future costs. This information is also publicly disclosed on Powerco's website.

Powerco's operating costs relating to the electricity business are allocated directly to each relevant region. Where this is not possible, the allocation between regions is based on the assets, ICPs, and energy usage within each region.

Powerco's indirect operating costs relating to the electricity business are allocated between regions and customer groups using a weighted average of each group's contribution to system demand and ICP numbers. These costs are shared equally by all users, but the weighting recognises the contributions larger consumers make to these costs.

TRANSMISSION COSTS

These are the costs charged to Powerco by Transpower for transmission services. It includes Transpower's interconnection, connection and new investment charges and any avoided cost of transmission (ACOT) payments made by Powerco.

Transmission costs are allocated between customer groups 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.

COST OF CAPITAL

This is the cost of capital (both debt and equity) invested in Powerco. Powerco requires large amounts of capital to maintain and develop network assets to meet increased demand, satisfy quality standards and legal compliance requirements, and achieve performance targets for safety and reliability. Historical capital expenditure by drivers (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.[11]

Capital costs are allocated between regions based on the RAB value of assets.

SUMMARY OF KEY COMPONENTS OF FORECAST REVENUE

Powerco is subject to a revenue cap over the CPP period. The CPP Determination describes how Powerco should calculate the revenue we can recover in a pricing year - our maximum allowable revenue. This includes rules around how various costs we pass-through are treated, for example transmission costs. For the 2020 pricing year, Powerco's maximum allowable revenue is $402,403,000 and this applies to the entire network. When setting prices we aim for a slightly lower revenue number, because we cannot exceed this maximum allowance. For the 2020 pricing year, this amounts to $402,290,000 and we term this our "forecast revenue".

Table 2 outlines how we have allocated our forecast revenue to the Eastern and Western regions.

Table 2: Key components of Powerco's forecast revenue for the 2020 pricing year

Key Component	Eastern Region ($000)	Western Region ($000)	Total Network ($000)
Operating and maintenance costs	$81,261	$86,672	$167,933
Transmission costs[12]	$62,966	$54,551	$117,517
Cost of Capital	$53,067	$63,773	$116,840
Forecast Revenue	**$197,294**	**$204,996**	**$402,290**

[11] Section 26 of Powerco's 2017 Asset Management Plan, available at www.powerco.co.nz.
[12] Transmission costs include Transpower's charges, avoided costs of transmission (ACOT), and other pass-through and recoverable costs.

7. THE ROLE OF THE COST OF SUPPLY MODEL IN SETTING PRICES

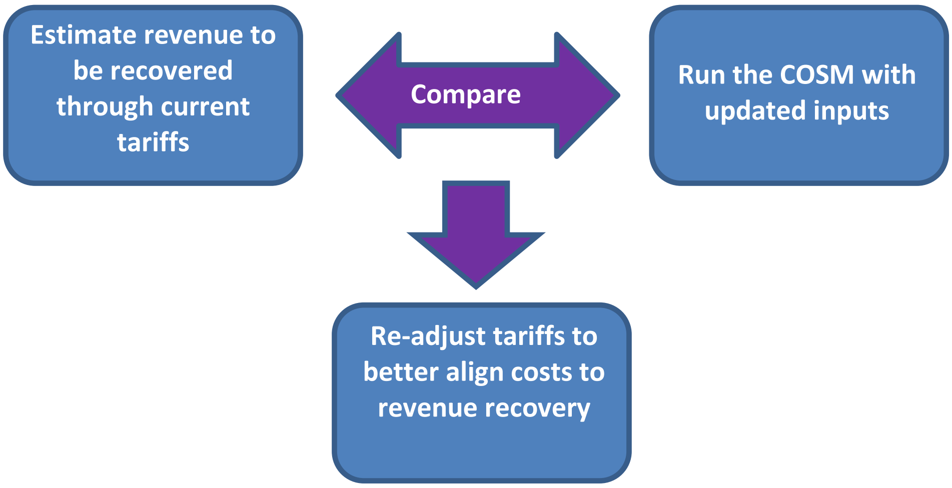
Powerco uses a cost of supply model (COSM) to allocate three broad categories of cost: transmission costs, operating and maintenance costs, and capital costs. The role of the COSM is not to set prices, but rather to evaluate how current price structures recover different categories of cost. This process of verifying prices through the COSM is used for both the Eastern and Western regions. If the results of the COSM are significantly different from the revenues recovered through existing prices, prices are adjusted to ensure a better alignment of revenues and costs.

Powerco's cost allocation can be summarized in three steps.

- Prices used in the previous pricing year are adjusted to reflect changes to the forecast revenue requirement.
- COSM is run using recent financial data and inputs.
- Costs and revenues are compared. If changes are required, prices are readjusted by applying discretion while aiming to maintain price stability and minimise price shocks to the extent practicable.

Figure 5 below illustrates this process.

Figure 5: Cost allocation process and the COSM's role



The COSM uses a number of key inputs and cost drivers to determine the appropriate allocation of costs between the relevant consumer groups. The key allocators contained within this model are:

- Number of connected ICPs;
- Energy usage (kWh);
- Maximum energy demands (AMD & CMD/OPD);
- Regulated Asset Base value and depreciation

The COSM aggregates costs at a GXP level, and then allocates these across customer pricing categories. At a high level there are three types of customers, being residential, commercial, and commercial/industrial. The Western Region's three main pricing categories align closely to these groups, while the Eastern Region's pricing categories are more granular, and in some instances crossover the three customer types.

The three broad groups used in each region are presented in the Table 3 below. Although some minor differences between the two regions exist, the three groups used in each region are essentially the same.

Table 3: Consumer groups used by the COSM

Groups	Eastern Region	Western Region
Residential	**Mass Market.** Includes unmetered, residential and small commercial consumer groups	**E1.** All residential and most commercial consumers including unmetered connections
Commercial	**Commercial.** Capacity greater than 69 kVA but less than 299 kVA	**E100.** Includes all connections with an installed capacity of greater than 100 kVA up to 300 kVA
Larger customers	**Larger customers.** Capacity greater than or equal to 300 kVA (this includes individually priced consumers in the V40, T50, V60 and T60 groups)	**E300.** Includes all connections with an installed capacity of greater than 300 kVA, including non-standard connections

Where possible, the costs of operating Powerco's electricity business are allocated directly to each GXP, which implicitly ties these to each region. Where direct allocation is not possible, each region is allocated costs based on ICP numbers, energy usage, and RAB value.

Transmission costs are allocated directly to each region, because the costs are directly attributed to specific GXPs. Capital costs are allocated to regions based on the RAB value of the assets within each region.

Powerco's operating costs, transmission costs and capital costs are then subsequently split between price categories based on ICP numbers, energy usage, and maximum demands.

The resulting cost allocations by region and consumer groups are then compared to the historical revenue for each consumer group to identify any potential material variances. If the results of the COSM are significantly different to the existing revenues recovered through existing prices, then prices are adjusted appropriately to achieve a better alignment of revenues and costs.

8. CUSTOMER-SPECIFIC PRICING

ASSET-BASED PRICING

This pricing method applies to large Powerco consumers 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 asset bypass.

The methodology for setting line charges under asset-based pricing has the following components:

- measurement and forecasts of consumer demand and connections;
- asset valuation and allocation;
- return of and on capital;
- allocation of maintenance costs; and
- allocation of indirect costs (fixed and variable).

Asset-based charges to consumers are allocated on the basis of a full price year and apply for the full price year. Charges are based on customers' level of demand, measured by AMD (anytime maximum demand) or OPD (on peak demand).

The asset-related element of the charge requires the assets used to supply the service to be valued, using either the ORC or ODRC methods. Whether the ORC or ODRC methodology is adopted depends on the consumer load group. For load groups T50 and V40 the ODRC methodology is used. For load groups T60 and V60 the ORC methodology is used.

Asset-based pricing requires assets to be categorised as on-site assets or upstream assets:

(a) on-site assets are dedicated assets behind the point of connection and normally include transformers and switch gear. These assets are allocated fully to the consumer that uses them;

(b) upstream assets are the meshed assets of the network. These assets are shared between a number of consumers and can generally be categorised as feeder assets, substation assets, sub-transmission assets and grid exit point (GXP) assets. These assets are allocated across the consumers they serve.

Powerco's charges are calculated to enable it to obtain a return on the capital it has invested. An annual rate of return is recovered on the asset valuations attributed to each consumer – this is based on Powerco's prevailing weighted average cost of capital (WACC). For those assets valued using ORC, Powerco uses a 45 year annuity factor to obtain a return of and on the capital it has invested (as measured by ORC). For those assets valued using ODRC, Powerco applies the WACC-based rate of return to the ODRC values to obtain a return on its capital invested. A straight-line depreciation charge is used to obtain a return of its capital.

Maintenance costs are allocated to the relevant load groups (T50 and V40) based on the load group's RAB relative to the applicable GXP's total RAB. These costs are allocated among the consumers within the load group based on each consumer's AMD as a proportion of the aggregate AMD of the load group.

Indirect costs are all costs of Powerco's electricity business excluding transmission, asset-related costs, maintenance, interest and tax. Indirect costs are allocated to the load group based on the load group's total RAB as a proportion of the applicable GXP's total RAB.

Powerco's transmission costs are based on Transpower's charges, which it determines using its transmission pricing methodology (TPM), which is set out in Schedule 12.4 of the Electricity Industry Participation Code 2010. The TPM is used to recover the full economic costs of Transpower's services. Transpower charges Powerco at each GXP using the TPM.

The TPM includes connection and interconnection charges. Powerco allocates these charges in the following manner:

- **Connection charges**: Powerco allocates Transpower's connection charges on the basis of the consumer's demand measured by AMD. Where a consumer is both an offtake consumer and an injection consumer at a connection location, connection charges for that location are calculated separately for that consumer as an offtake consumer and an injection consumer. Powerco also allocates charges from embedded generators to its consumers. This charge includes a connection charge and an ACOT charge. These charges are allocated by Powerco to its consumers on the same basis that Powerco uses to allocate Transpower's connection and interconnection charges.
- **Interconnection charges**: Powerco allocates Transpower's interconnection charges to its customers based on the consumer's OPD multiplied by Transpower's interconnection rate.

When a Powerco consumer enters an asset-based load group the following policies apply:

- Powerco will estimate the OPD and AMD for the new or upgraded site. This estimate will be based on an assessment of the plant and machinery located on the site, demand from similar sites across the industry and any estimates of demand provided by the consumer.
- The estimated demand will apply for the current price year (i.e. the period between the later of 1 April or the connection date for the upgraded assets and 31 March of the subsequent year).
- The estimated demand will assume full demand from the time of the installation of the asset (rather than ramping up over a period of time), unless otherwise agreed between Powerco and the consumer, or their representative, at the time of Powerco's approval of the request for site connection or alteration.
- The estimated demand will continue to apply in the subsequent year if the upgraded site has not been connected and operational for the full duration of the applicable measurement period, unless otherwise agreed between Powerco and the consumer or their representative, at the time Powerco approves the request for site connection or alteration.
- New prices will be effective from network livening (i.e. "ready" status).

The following Powerco policies apply when a site exits an asset-based load group or revision to charges is requested:

- If a consumer intends exiting a site, and the retailer is notified of this intention, the retailer must notify Powerco as soon as practical so that final charges can be determined and levied in the forthcoming billing run.
- Powerco, at its discretion, may allow a consumer to exit the load group when the site downgrades its installed capacity. Alternatively, Powerco may require the site to continue to the end of the price year in the current load group at the current peaks, for instance if an upgrade to the site has only recently occurred.

- Powerco may leave the consumer in the same load group and down-grade peak estimates in instances where there is no removal of on-site assets but there will be a reduction in loading on the network.
- Where there is a bona fide change in consumer at particular premises (i.e. a new entity), the retailer may apply for, and Powerco will, at its discretion, undertake a review of the asset-based charges once during the price year to reflect the change arising from an alteration in AMD and the expected change in OPD.

ASSET-BASED BUILDING BLOCK METHOD (BBM)

This pricing methodology applies to very large (>4MVA) customers in both regions. These customers have a direct contractual relationship with Powerco for a defined term. BBM asset-based pricing applies primarily to customers where:

- a step change development is needed but the increase in the customer's demand may not be as significant; and/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 (e.g. transmission charges and regulator levies).

9. HOW CAPITAL CONTRIBUTIONS ARE TREATED

Powerco's electricity network is constantly growing as new homes and businesses connect to its network, and existing consumers require new assets as their electricity demand increases. To be fair to our current electricity consumers, who are not increasing their load, we sometimes require a contribution to the capital cost of investments.

When an application is received to connect to Powerco's network, or install additional capacity, Powerco's Customer Works team will determine the level of customer contribution required (if any) based on:

- the degree to which the incremental revenue received from the new customer or the additional assets installed to upgrade service to an existing customer will enable Powerco to receive a return on the investment, considering:
  - the marginal increase in operating and maintenance costs;
  - the marginal increase in overhead costs; and
  - the marginal increase in transmission costs (applicable to the electricity network only);
- the value of any deferral of renewal expenditure that results from the early replacement of existing assets due to customer-initiated work;
- the application of an avoidable cost allocation methodology to identify and allocate incremental costs.

Any capital contributions received do not form part of Powerco's regulated asset base and no return on the value of these contributions is recovered by Powerco's charges.

Further information on capital contributions is available from Powerco's capital contribution guide: http://www.powerco.co.nz/media/1862/20130222-elec-capital-contributions-policy-20171102-v4.pdf

10. EASTERN REGION PRICING METHODOLOGY

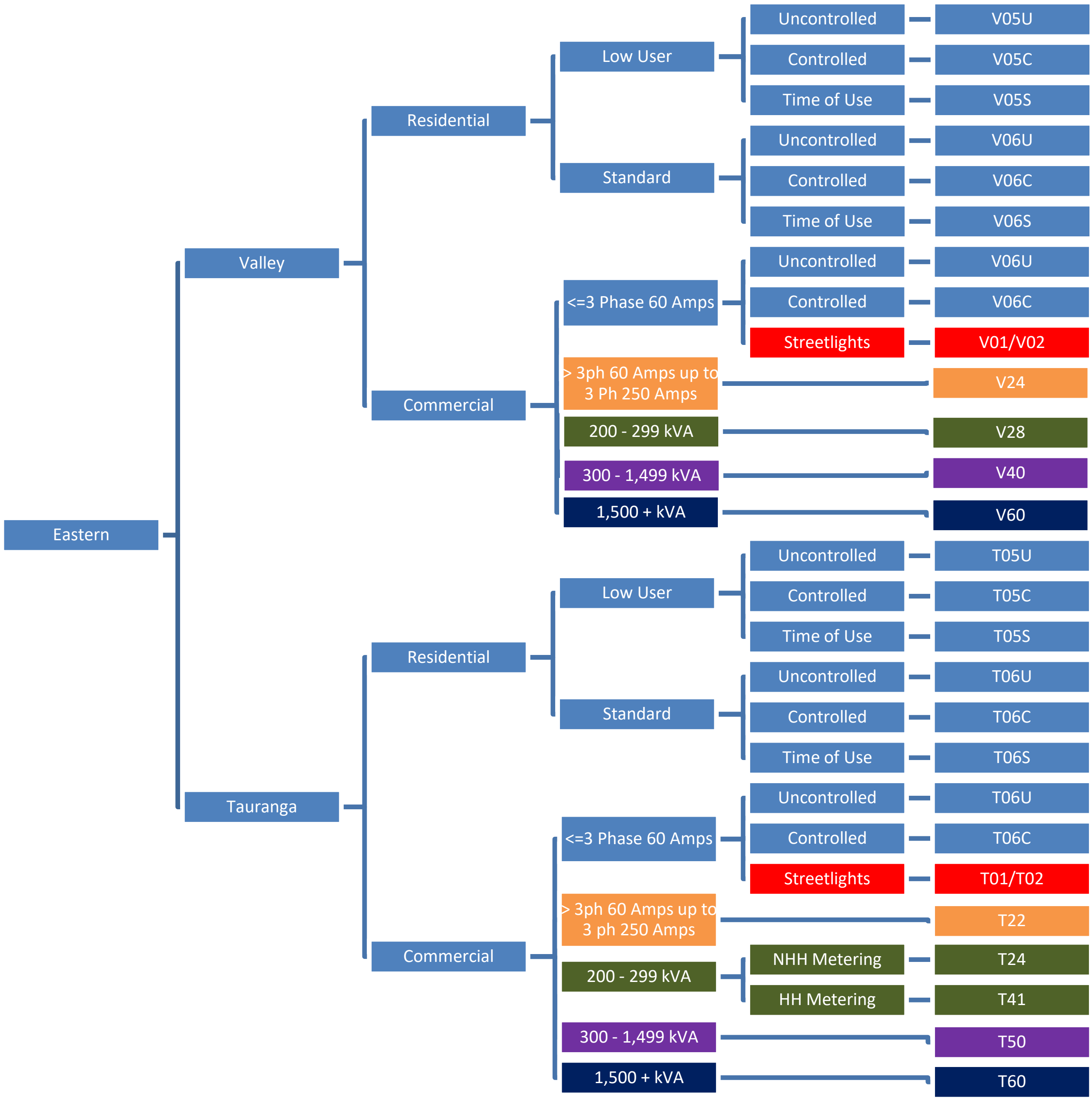
CONSUMER GROUPS

Powerco uses six consumer groups in the Eastern Region for pricing purposes:

- Group 1: T01/T02 and V01/V02 − for all unmetered connections such as streetlights in the Valley and Tauranga regions;
- Group 2: T05/T06 and V05/V06 − for all residential consumers and small commercial consumers with a fuse size of 3 Phase 60 Amps or less;
- Group 3: T22/V24 − for commercial customers with a fuse size of greater than 3 Phase 60 Amps up to and including 3 Phase 250 Amps;
- Group 4: T24/T41/V28 − for commercial customers with an installed capacity of 200 – 299 kVA;
- Group 5: T50/V40 − for commercial customers with an installed capacity of 300 – 1499 kVA; and
- Group 6: T60/V60 − for commercial customers with an installed capacity of 1,500 kVA and greater.

  Groups 5 and Group 6 equate to the Western region's E300 consumer group.

Figure 6: Overview of the Eastern Region price category allocation process



	Residential / small commercial		Unmetered load
	Greater than 3 Ph 60 amps up to 3 Ph 250 amps		200 - 299 kVA
	300 - 1,499 kVA		1,500 kVA and above

Figure 6 above shows how separate price categories are defined in the Eastern Region that group consumers with 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 categories, rather than simply kVA, as in the Western Region, 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, but there are situations where consumer preferences and metering can determine the price category (such as the low user (V05/T05) and the T24/T41 price categories).

Eastern Region consumers are also allocated to either the Valley or Tauranga distribution networks, based on the location of the GXP that is associated with the consumer's ICP (as shown in Figure 7). Once allocated, the price categories are published for each ICP on the Electricity Registry[13] to enable retailers and other parties to determine the distribution charges that apply to that ICP.

Figure 7: Map of Eastern Electricity Network

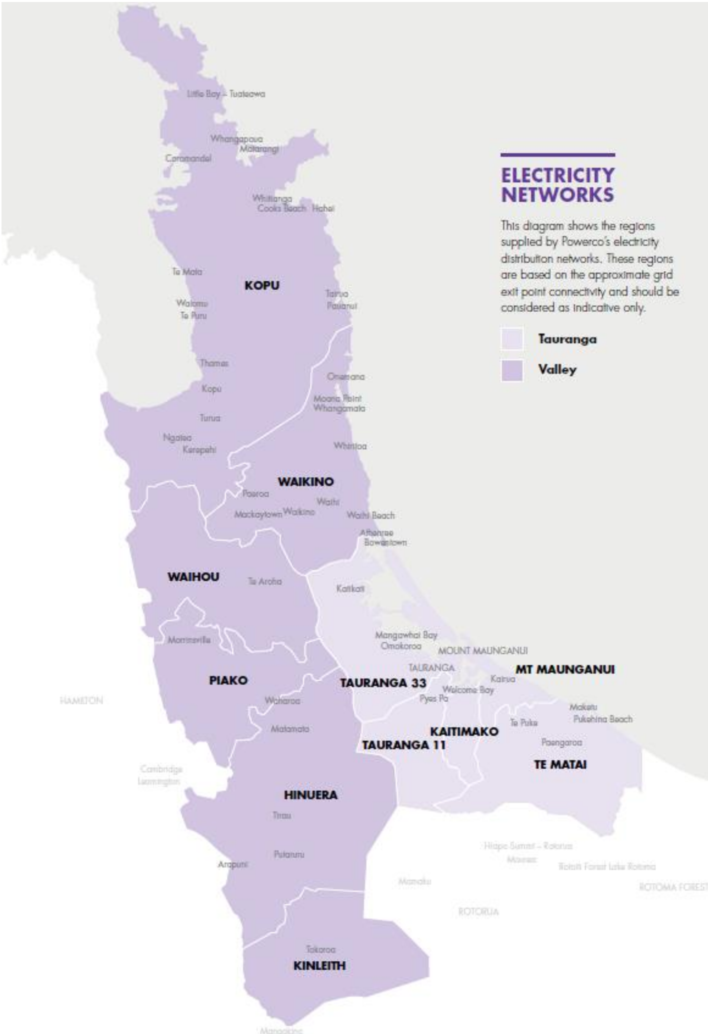


Table 4 describes the statistical characteristics of each consumer group and demonstrates that average volume and average anytime maximum and on peak demands are quite different for each group. Information about anytime maximum demand and on peak demand is currently only available for connections that have half hour meters. Consequently, assumptions must be made to estimate the load profiles of the remaining consumer connections. Where appropriate, this is done by using the average demand/kWh for all connections in each consumer group. For the residential and small commercial consumer groups, this is calculated by subtraction. As smart meters become more widely used and data made available, additional peak demand information will become available for mass market customers.

[13] https://www.electricityregistry.co.nz

Table 4: Statistics for Eastern Region consumer groups used in the pricing methodology

Region	Consumer Group	ICPs	Volume (MWh)	Anytime Maximum Demand (kW)	On Peak Demand (kW)
Tauranga	Unmetered (incl. streetlights)	243	9,216		
	Residential & Small Commercial	82,923	638,579		
	3 Phase 100 Amps up to and including 3 Phase 250 Amps	547	59,537	27,370	6,956
	200 - 299 kVA	142	33,939	13,312	4,512
	300 - 1,499 kVA	203	193,866	55,165	25,132
	1,500 kVA +	31	165,753	44,950	23,632
	Total	**84,089**	**1,100,889**	**140,797**	**60,232**
Valley	Unmetered (incl. streetlights)	188	4,644		
	Residential & Small Commercial	70,440	568,682		
	3 Phase 100 Amps up to and including 3 Phase 250 Amps	461	63,941	21,235	7,973
	200 - 299 kVA	37	10,647	3,314	1,384
	300 - 1,499 kVA	79	59,683	19,305	7,198
	1,500 kVA +	29	637,378	145,279	74,336
	Total	**71,234**	**1,344,975**	**189,133**	**90,891**

Note: Demand figures for any non-half hourly connections in these consumer groups have been estimated using the average demand/kWh for all connections in that particular consumer group.

The T01/T02 and V01/V02 price categories (coloured red in figure 5) are for unmetered streetlights which, due to the unmetered nature of the load and the associated dedicated equipment, require special consideration when determining our revenue requirement.

The T05/T06, V05/V06, and T05S/T06S price categories (coloured light blue in figure 5) are for all residential consumers and small commercial consumers with a fuse size of 3 Phase 60 amps or less. Any consumers with a fuse size of up to 3 Phase 60 Amps are typically considered to be residential or small commercial consumers and, as such, individually place minimal demands on our network and require minimal investment in on-site and upstream assets. Providing specific eligibility criteria[14] are met, residential consumers can choose

[14] For details on the eligibility criteria for the low user (also known as low fixed charge) prices please see the full pricing policy at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

between the low user price categories (V05/T05) and the standard price categories (V06/T06).

The T22/V24 price categories (coloured light brown in figure 5) are for connections with a fuse size of greater than 3 Phase 60 amps up to 250 amps. Any connections with these fuse sizes are typically commercial consumers with higher average volumes than the T05/T06 and V05/V06 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.

The T24/T41/V28 price categories (coloured green in figure 5) are for connections with an installed capacity of greater than 200 kVA up to 299 kVA. Any connections with this level of installed capacity are typically medium sized commercial consumers with significantly higher average volumes than the T22/V24 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. The T41 price category is available only for connections in this consumer group with half hourly (HH) metering.

The T50/V40 price categories (coloured purple in figure 5) are for connections with an installed capacity of greater than 300 kVA up to 1,499 kVA. Any connections with this level of installed capacity are typically large commercial consumers which require dedicated transformers and associated switch gear to meet their supply requirements.

The T60/V60 price categories (coloured dark blue in figure 5) are for connections with an installed capacity of greater than 1,500 kVA. Any connections with this level of installed capacity are typically very large commercial/industrial consumers 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 consumers are charged a constant daily price, it is reviewed each year based on the consumer’s previous year’s peak demands (as detailed in Section 10). This ensures that their charges are regularly updated to reflect their individual contribution to network costs.

The ICP pricing methodology more closely reflects retailer prices and consequently makes it possible to provide a greater number of targeted price signals to specific groups or individual consumer market segments to encourage efficient use of the network.

Powerco’s charges are structured so that the fixed revenue component increases as the connected capacity of each price category increases. This is to help ensure that our overall charges reflect the level of demand that consumers place on different components of our network such as sub-transmission, high voltage (11kV) and low voltage (400V).

COST ALLOCATION METHODOLOGY

Powerco uses our cost-of-supply model (COSM) to confirm that the allocation of costs that results from current prices broadly aligns with the costs incurred by Powerco. Where significant differences exist, then prices are adjusted.

Tables 5 and 6 provide a summary of the statistics and the allocation factors used in the COSM to allocate costs between regions and price categories for the Eastern Region.

Table 5: Summary of the statistics used to allocate the costs of Powerco's lines business activities by key revenue components to each consumer group for the 2020 price year

EASTERN REGION						
Distribution network	Consumer Group	Allocator for:				
		ICPs	RCPDs (kW)	LV Asset Value ($000)	HV Asset Value ($000)	Total Asset Value ($000)
Tauranga	Mass market (Including Unmetered ICPs)	83,166	54,587	85,223	221,393	**306,616**
	69 – 299 kVA	689	5,309		21,676	**21,676**
	300 kVA + (including non-standard consumers)	234	16,674		71,983	**71,983**
Valley	Mass market (including unmetered ICPs)	70,628	44,148	97,529	228,055	**325,584**
	69 – 299 kVA	498	3,449		16,117	**16,117**
	300 kVA + (including non-standard consumers)	108	26,956		95,625	**95,625**
Total		**155,323**	**151,123**	**182,752**	**654,849**	**837,601**

Table 6: Summary of the factors used to allocate the costs of Powerco's lines business activities by key revenue components to each consumer group for the 2020 price year

EASTERN REGION				
Distribution network	**Consumer Group**	**Allocator for:**		
		Operating Costs	**Transmission Costs**	**Cost of Capital**
Tauranga	Mass market (Including Unmetered ICPs)	35%	30%	37%
	69 – 299 kVA	3%	4%	2%
	300 kVA + (including non-standard consumers)	8%	14%	8%
Valley	Mass market (including unmetered ICPs)	41%	28%	39%
	69 – 299 kVA	2%	4%	2%
	300 kVA + (including non-standard consumers)	11%	20%	12%
		100%	**100%**	**100%**

QUANTIFICATION OF KEY COMPONENTS OF COSTS AND REVENUES

The key components of costs and revenues are described in Section 8. The breakdown of these costs into consumer groups is provided in Table 7.

Table 7: Powerco's allocated revenue requirement for the 2019 price year by consumer group

EASTERN REGION						
Distribution network	**Consumer Group**	**ICPs**	**Revenue required for:**			
			Operating Costs $(000s)	**Transmission $(000s)**	**Cost of Capital $(000s)**	**Total $(000s)**
Tauranga	Mass market (incl. Unmetered ICPs)	83,166	28,204	19,033	19,381	**66,618**
	69 – 299 kVA	689	2,162	2,351	1,321	**5,834**
	300 kVA +	233	6,833	8,998	4,347	**20,178**
	Non-standard	1	65	122	39	**226**
Valley	Mass market (incl. unmetered ICPs)	70,628	32,948	17,430	20,788	**71,167**

EASTERN REGION						
Distribution network	Consumer Group	ICPs	Revenue required for:			
			Operating Costs $(000s)	Transmission $(000s)	Cost of Capital $(000s)	Total $(000s)
	69 – 299 kVA	498	1,778	2,216	1,037	**5,031**
	300 kVA +	101	6,074	4,199	4,032	**14,305**
	Non-Standard	7	3,196	8,617	2,122	**13,935**
Total		**155,323**	**81,261**	**62,966**	**53,067**	**197,294**

FIXED AND VARIABLE CHARGES

In Powerco's Eastern region consumers are typically charged a two-part price which consists of a variable (cents/kWh) price and a fixed price ($/day). For the V40, T50, V60, and T60 price categories, charges consist primarily of a fixed price component.

Consumers in the V40, T50, V60, and T60 price categories are typically very large commercial/industrial consumers which require dedicated on-site and upstream assets (such as dedicated feeders and transformers) to meet their supply requirements. Therefore, their charges are determined on an individual basis and are fixed to ensure that an appropriate level of return on investment is made by Powerco.

From an economic point of view, a two-part price should ideally be structured such that all marginal costs are charged based on a variable basis and all other costs on a fixed basis (so as not to distort behaviour). However, marginal costs are typically small (zero if spare capacity exists) which would result in most charges being fixed.

However, an economically pure single fixed charge would not provide consumers with any incentive to manage their consumption and therefore would likely result in substantial growth which would put increased pressure on our network and increase the need for future capital expenditure. A high fixed charge may also act as a significant deterrent to existing and potential customers.

Powerco wishes both to promote the economically efficient use of our network and encourage organic growth. Therefore our prices are designed to allow end-consumers the opportunity to modify their behaviour to enable the efficient use of network assets. The roll out of advanced metering infrastructure should allow us, in future, to send a more efficient price signal based on peak period time of use, rather than solely volume as at present.

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

This approach also helps to ensure that no perverse incentives exist for customers to under or over state their capacity requirements in order to alter their allocated load group. The larger capacity price categories have the bulk of the charges fixed, while lower capacity connections have the fixed component set at around 25% of their total line charge (as shown in Table 8).

However, Powerco's ability to amend the existing fixed and variable price structure is somewhat restricted by the limitations imposed on residential fixed charges by the Low Fixed Charge Regulations and Powerco's preference to avoid price shocks to consumers. Consequently, Powerco determines the proportion of fixed and variable prices 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 8: Powerco's target revenue requirement split by fixed and variable price components to each consumer group for the 2020 price year

<table>
<tr><th></th><th colspan="4">EASTERN REGION</th></tr>
<tr><th rowspan="2">Distribution network</th><th rowspan="2">Consumer Group</th><th rowspan="2">Price Category</th><th colspan="2">Revenue split</th></tr>
<tr><th>Fixed</th><th>Variable[15]</th></tr>
<tr><td rowspan="8">Tauranga</td><td rowspan="3">Mass market (Including Unmetered ICPs)</td><td>Unmetered (T01/T02)</td><td>75.8%</td><td>24.2%</td></tr>
<tr><td>Low Usage (T05)</td><td>9.9%</td><td>90.1%</td></tr>
<tr><td>Standard (T06)</td><td>32.7%</td><td>67.3%</td></tr>
<tr><td rowspan="3">69 – 299 kVA</td><td>3 Phase 60 – 3 Phase 250 Amps (T22)</td><td>34.8%</td><td>65.2%</td></tr>
<tr><td>200 – 299 kVA (T24)</td><td>58.5%</td><td>41.5%</td></tr>
<tr><td>200 – 299 kVA (T41)</td><td>37.3%</td><td>62.7%</td></tr>
<tr><td rowspan="2">300 kVA + (incl. non-standard consumers)</td><td>300 – 1,499 kVA (T50)</td><td>97.2%</td><td>2.8%</td></tr>
<tr><td>1,500 kVA + (T60)</td><td>97.6%</td><td>2.4%</td></tr>
<tr><td rowspan="7">Valley</td><td rowspan="3">Mass market (including unmetered ICPs)</td><td>Unmetered (V01/V02)</td><td>90.3%</td><td>9.7%</td></tr>
<tr><td>Low Usage (V05)</td><td>9.9%</td><td>90.1%</td></tr>
<tr><td>Standard (V06)</td><td>24.2%</td><td>75.8%</td></tr>
<tr><td rowspan="2">69 – 299 kVA</td><td>3 Phase 60 – 3 Phase 250 Amps (V24)</td><td>28.6%</td><td>71.4%</td></tr>
<tr><td>200 – 299 kVA (V28)</td><td>43.0%</td><td>57.0%</td></tr>
<tr><td rowspan="2">300 kVA + (incl. non-standard consumers)</td><td>300 – 1,499 kVA (V40)</td><td>96.7%</td><td>3.3%</td></tr>
<tr><td>1,500 kVA + (V60)</td><td>98.5%</td><td>1.5%</td></tr>
</table>

[15] Including power factor charges (where applicable).

TREATMENT OF TRANSPOWER'S RENTAL REBATES

Transpower's rental rebates associated with operation of its HVAC network are excluded from the bundled prices and are passed through to retailers directly. Further information about this process can be found in Powerco's electricity pricing schedule (which is available at: http://www.powerco.co.nz/Publications-and-Disclosures/Pricing-Schedules/Electricity).

SHARING VALUE OF DEFERRAL OF INVESTMENT

Powerco recognises that the ability to control and shift load during peak times via load signalling equipment has the potential to defer investment.

Because of this potential to defer investment Powerco continues to offer a number of price options such as AICO and CTRL in the Valley and Tauranga distribution networks that provide discounts to consumers based on the availability and degree of load control at the consumer's ICP.

Powerco also provides several discounted "NITE" price options within these networks which are designed to incentivise consumers to shift load from peak to off-peak periods in order to flatten peaks and consequently reduce the need for new investment. A detailed description of these prices and associated eligibility criteria is available on Powerco's website[16].

Powerco continues to encourage embedded and distributed generation by providing payments to generators equivalent to Powerco's avoided costs of transmission (subject to Powerco's Distributed Generation (DG) Policy).

[16] For further details on our prices and how we apply them please see the full pricing policy at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

11. WESTERN REGION PRICING METHODOLOGY

OERVIEW OF APPROACH TO GROUPING CONSUMERS FOR PRICING

RATIONALE FOR CONSUMER GROUPS

Powerco uses three consumer groups for cost allocation and pricing purposes in the Western Region. The three groups are:

- E1, which applies to all connections with a connected capacity of less than 100 kVA connections (which includes unmetered connections);
- E100, which applies to all connections with a connected capacity of between 100 and 300 kVA;
- E300, which applies to all connections with a connected capacity of greater than 300kVA (which includes connections with individually assessed pricing).

These price categories are based around groups of consumers with similar characteristics relating to their installed capacity and associated demand as these groups place different demands on different components of our network such as sub-transmission, high voltage (11kV) and low voltage (400V) network assets as well as onsite assets such as transformers and associated switchgear. Annex A provides information on the characteristics of the network and consumers in the Western Region.

The characteristics of each consumer group are provided in Table 10. Ideally, Powerco would have more information on anytime maximum demand and on peak demand but currently this information is only readily available for connections with half hourly metering. Where this information is not available assumptions have been made about the load profiles of the relevant consumers as is the case for the E1 price category where the demands are determined by subtraction.

The E1 price category is for all connections with a connected capacity of less than 100 kVA which represents all residential and the majority of commercial consumers. The E1 price category has been limited to less than 100 kVA to provide a relatively simple price structure for the vast majority of consumers while excluding all connections which require dedicated on-site and/or upstream assets.

The E100 price category is for all connections with a connected capacity of between 100 and 300 kVA, which equates to medium-large commercial consumers. 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.

The E300 price category is for all connections with a connected capacity of greater than 300 kVA which equates to large commercial / industrial consumers. 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.

The specification of separate price categories for the E100 and E300 groups makes the underlying costs of supplying these consumers more transparent.

In addition to these price categories Powerco also has non-standard charges which apply in cases where our standard charges are not appropriate. These consumers are placed on the SPECIAL price category. This is typically only for connections with capacity greater than 1,500 kVA where there is significant network investment required for the connection and/or unique commercial arrangements that require special consideration. This is discussed in further detail in Section 15.

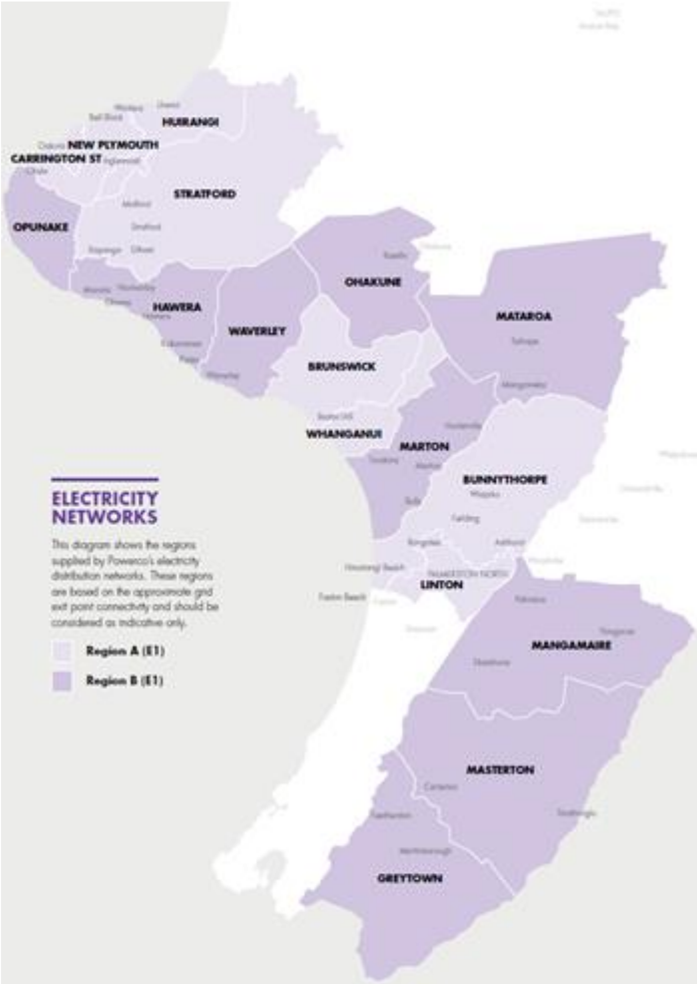
RATIONALE FOR PRICING ZONES

Within each price category the individual charges are classified by a pricing zone which is a grouping of GXPs with similar characteristics such as rural/urban connection density and geographical location.

Pricing zones allow our price structure to have the ability to reflect the difference in the costs of supplying consumers within specific regions across the Western network. This allows us the ability to reflect a fairer allocation of the operating costs, transmission charges and capital costs within each geographical location rather than across the entire network.

The E1 price category is split into two zones with Zone A being for all consumers supplied in the high density urban centres of New Plymouth, Whanganui and Palmerston North and Zone B for all consumers supplied in the remaining low density and typically rural areas (as shown in Figure 8). These two zones have been defined to be based on the similar underlying cost structures across the GXPs within each zone while keeping the price structure relatively simple for consumers and retailers.

Figure 8: Map of Western Electricity Network



The E100 and E300 price categories are split into ten zones with each zone representing a grouping of GXPs based on geographical proximity. For example, in diagram 4 the GXPs of Huirangi, Carrington St, New Plymouth, and Stratford are grouped together into zone A. The number of zones represents Powerco's preference for greater transparency of costs within this price category due to the impact that changes to individual consumer behaviour within these groups can have on the underlying cost structure.

The consumer groups and price zones used allow the specific underlying costs of supplying each consumer group and price zone to be more accurately reflected in our charges. these groupings represent a trade-off between the simplicity required to reduce processing costs and the level of complexity required to allocate costs while providing efficiency-promoting price signals to the relevant network users. Powerco regularly consults with customers to ensure that an appropriate balance is reached.

ALLOCATING CONSUMERS TO GROUPS AND ZONES

Consumers are allocated to a region and pricing zone based on the GXP that is associated with their connection (as shown in Figure 7).

Consumers are then allocated to a price category based on the installed capacity at their connection.

Once allocated, price categories are published for every connection on the Electricity Registry[17] to enable retailers and other parties to determine the distribution charges that apply for that connection.

Table 9: Statistics for Western Region Consumer Groups used in the Pricing Methodology

Consumer Group	ICPs	Volume (MWh)	Anytime Maximum Demand (kW)	On Peak Demand (kW)
E1: Less than 100kVA connections	171,070	1,577,161		
E100: 100 to 300kVA connections	218	109,241	199,419	13,135
E300: Greater than 300kVA connections (including non-standard consumers)	271	733,926	182,317	82,385
Total	**171,559**	**2,420,328**	**381,736**	**95,520**

COST ALLOCATION METHODOLOGY AND RATIONALE FOR ALLOCATION TO EACH CONSUMER GROUP

In the Western Region, Powerco uses a GXP-based pricing methodology. Prices from the previous pricing year are adjusted to reflect changes in the overall revenue requirement. The revenue stream of the updated prices is then compared to the results of the COSM. If changes in prices are required as a result of the comparison, adjustments are done while having regard to price stability.

For the E1 price category, prices for zone B are typically higher than zone A due to the lower connection density and greater average system length for the GXPs in zone B compared to zone A. This is reflected in the COSM outputs, which show that it is more costly (on average) to supply ICPs in zone B. Similarly, the charges set for the price zones for the E100 and E300 groups broadly reflect the costs of supplying customers in these groups serviced from these GXPs, as shown by the COSM outputs.

Tables 10 and 11 provide a summary of the statistics and allocation factors used in the cost of supply model to allocated costs between regions and price categories for the Eastern Region.

[17] https://www.electricityregistry.co.nz

Table 10: Summary of the statistics used to allocate the costs of in relation to Powerco's lines business activities by key revenue components to each consumer group for the 2019 price year

WESTERN REGION						
Consumer Group	Price Zone	ICPs	RCPDs (kW)	LV Asset Value ($000)	HV Asset Value ($000)	Total Asset Value ($000)
E1 – less than 100 kVA	A	118,474	50,845	141,999	257,461	399,461
	B	52,596	21,655	64,128	218,732	282,859
E100 (100 – 300 kVA)	A	53	758		4,626	4,626
	B	9	138		890	890
	C	0	0		0	0
	D	1	4		57	57
	E	19	312		1,334	1,334
	F	5	98		804	804
	G	4	71		1,404	1,404
	H	29	454		3,613	3,613
	I	96	1,448		6,550	6,550
	J	2	25		449	449
E300 (300 kVA+ incl. non-standard consumers)	A	85	6,140		34,333	34,333
	B	11	1,606		10,395	10,395
	C	2	264		3,168	3,168
	D	3	230		3,720	3,720
	E	34	2,298		9,564	9,564
	F	11	696		5,693	5,693
	G	3	222		4,418	4,418
	H	28	1,787		12,903	12,903
	I	90	6,100		27,268	27,268
	J	4	371		6,626	6,626
Total		**171,559**	**95,520**	**206,127**	**614,008**	**820,135**

Table 11: Summary of the factors used to allocate the costs of in relation to Powerco's lines business activities by key revenue components to each consumer group for the 2019 price year

WESTERN REGION				
Consumer Group	Price Zone	Allocator for:		
		Operating Costs	Transmission Costs	Cost of Capital
E1 – less than 100 kVA	A	50.5%	50.5%	48.7%
	B	31.2%	20.9%	34.5%
E100 (100 – 300 kVA)	A	0.8%	0.9%	0.6%
	B	0.1%	0.2%	0.1%
	C	0.0%	0.0%	0.0%
	D	0.0%	0.0%	0.0%
	E	0.2%	0.3%	0.2%
	F	0.1%	0.1%	0.1%
	G	0.1%	0.1%	0.2%
	H	0.5%	0.6%	0.4%
	I	1.0%	1.3%	0.8%
	J	0.0%	0.0%	0.1%
E300 (300 kVA+ Including non-standard consumers)	A	4.6%	6.4%	4.2%
	B	1.2%	1.7%	1.3%
	C	0.3%	0.8%	0.4%
	D	0.4%	0.8%	0.5%
	E	1.4%	2.9%	1.2%
	F	0.6%	1.1%	0.7%
	G	0.5%	0.8%	0.5%
	H	2.0%	2.5%	1.6%
	I	3.8%	6.5%	3.3%
	J	0.7%	1.3%	0.8%

QUANTIFICATION OF KEY COMPONENTS OF COSTS AND REVENUES

The key components of costs and revenues are described in Section 8. The breakdown of these costs into consumer groups is provided in Table 12.

Table 12: Powerco's allocated revenue requirement for the 2019 price year by consumer group

WESTERN REGION						
Consumer Group	Price Zone	ICPs	Revenue required for:			
			Operating Costs $(000s)	Transmission Costs $(000s)	Cost of Capital $(000s)	Total $(000s)
E1 – less than 100 kVA	A	118,474	43,787	27,555	31,062	102,404
	B	52,596	27,041	11,396	21,995	60,432
E100 (100 – 300 kVA)	A	53	712	488	360	1,559
	B	9	81	103	69	253
	C	0	0	0	0	0
	D	1	5	5	4	14
	E	19	201	153	104	458
	F	5	76	48	63	186
	G	4	128	47	109	284
	H	29	451	303	281	1,035
	I	96	838	729	509	2,076
	J	2	40	17	35	92
E300 (300 kVA+)	A	83	3,841	2,293	2,322	8,456
	B	9	750	264	808	1,822
	C	2	268	121	246	636
	D	2	337	159	289	786
	E	33	1,084	973	744	2,801
	F	11	535	207	443	1,184
	G	2	402	159	344	905
	H	23	1,626	678	1,003	3,308
	I	88	3,076	2,414	2,120	7,610
	J	4	593	17	515	1,125
Non-standard		14	800	348	348	348
Total		**171,559**	**86,672**	**54,551**	**63,773**	**204,996**

FIXED AND VARIABLE CHARGES

Similar to the Eastern Region, distribution costs tend to be fixed in nature rather than related to the delivered energy volumes. The assets employed are expensive and the cost of the assets is not directly related to the usage of the asset, i.e. the cost is the same regardless of whether or not the assets are being used by an end-consumer at any particular time.

Powerco wants to promote efficient use of the network and therefore Powerco's charges, to the extent practicable, are designed to allow end-consumers the opportunity to modify their behaviour in order to use the network efficiently.

In Powerco's Western region consumers are typically charged a price which consists of a variable price (cents/kWh) and/or a demand price ($/kVA or $/kW) and a fixed price (either $/day or $/kVA per day).

From an economic point of view, these prices should ideally be structured such that all marginal costs are charged on a variable basis and all other costs on a fixed basis (so as not to distort behaviour). As marginal costs are typically small (zero if spare capacity exists) this would result in the majority of charges being fixed.

However, a fixed charge would not reflect the impact of additional usage on future investment costs (i.e. the long run marginal cost) and hence would not provide consumers with the right incentives to control consumption during peak demand periods.

In the E1 price category Powerco has three types of charges which apply to all consumers in this price category. A variable volume charge (c/kwh) with different rates for consumption during the Day and Night periods, a variable demand charge for the single anytime maximum demand for the month ($/kW) and a fixed charge ($/day).

The E100 and E300 price categories typically have three charges - a distribution demand charge ($/kW/day) based on the customers anytime maximum demand (AMD), a transmission demand charge ($/kW/day) based on peak demand (OPD) over the prior year, and a fixed charge (either $/day for the E100 group or $/kVA based on installed capacity per day).

The demand charges across all three price categories were initially set to reflect the costs that Powerco incurs as a result of consumers using its network during peak times. The variable and fixed charges are set at a level sufficient to recover the balance of revenue across the price categories.

Consumers in the E100 and E300 price categories are typically very large commercial/industrial consumers which require dedicated on-site and upstream assets (such as dedicated feeders and transformers) to meet their supply requirements. Therefore, the fixed charge 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.

Powerco's ability to amend the existing fixed and variable price structure is somewhat restricted by the limitations imposed on residential fixed charges by the Low Fixed Charge Regulations and Powerco's preference to avoid price shocks to end-consumers. Consequently, 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 13: Powerco's target revenue requirement split by fixed and variable charge components for each consumer group for the 2020 price year

WESTERN REGION					
Consumer Group	Price Zone	ICPs	Target Revenue Split		
			Fixed	Demand[18]	Variable
E1 – less than 100 kVA	A	118,474	3.2%	0.0%	96.8%
	B	52,596	2.4%	0.0%	97.6%
E100 (100 – 300 kVA)	A	53	11.2%	88.8%	0.0%
	B	9	6.9%	93.1%	0.0%
	C	0			
	D	1	7.6%	92.4%	0.0%
	E	19	11.1%	88.9%	0.0%
	F	5	8.6%	91.4%	0.0%
	G	4	5.7%	94.3%	0.0%
	H	29	7.4%	92.6%	0.0%
	I	96	11.5%	88.5%	0.0%
	J	2	8.8%	91.2%	0.0%
E300 (300 kVA+)	A	83	25.2%	74.8%	0.0%
	B	9	20.1%	79.9%	0.0%
	C	2	8.6%	91.4%	0.0%
	D	2	13.8%	86.2%	0.0%
	E	33	25.9%	74.1%	0.0%
	F	11	29.2%	70.8%	0.0%
	G	2	14.5%	85.5%	0.0%
	H	23	15.4%	84.6%	0.0%
	I	88	22.7%	77.3%	0.0%
	J	4	27.4%	72.6%	0.0%
Non-standard		14	99.0%	1.0%	0.0%
Total		**171,559**			

TREATMENT OF TRANSPOWER RENTAL REBATES

Transpower's rental rebates associated with operation of its HVAC network are excluded from the bundled prices and are passed through to retailers directly. Further information about this process can be found in Powerco's electricity pricing schedule (which is available at: http://www.powerco.co.nz/Publications-and-Disclosures/Pricing-Schedules/Electricity/).

SHARING VALUE OF DEFERRAL OF INVESTMENT

Powerco recognises that the ability to control and shift load during peak times via load signalling equipment has the potential to defer investment.

Because of the benefits relating to the potential to defer investment Powerco continues to offer a discount to the daily fixed price for consumers with controllable load in the E1

[18] Including power factor charges (where applicable).

consumer group of 15 cents per day (compared to the maximum low volume price of 15 cents per day for consumers without controllable load).

Powerco's volume-based prices to the mass market group (E1) in the Western region are also structured to encourage consumers to shift load to off-peak periods by offering a significant discount of 7.3-7.8 cents/kWh for consumption during the off-peak night period (11pm – 7am). A detailed description of the Western Region price structures and associated eligibility criteria is available on Powerco's website[19].

Powerco also continues to encourage embedded and distributed generation by providing payments to generators equivalent to Powerco's avoided costs of transmission (subject to Powerco's Distributed Generation (DG) Policy).

[19] For further details on our prices and how we apply our charges please see the full pricing policy at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

12. SUMMARY OF PROJECTED REVENUE ACROSS REGIONS AND PRICE GROUPS

The tables below summarise the projected revenue from Powerco prices and forecast quantities for the Eastern and Western regions for each consumer group and provide a comparison with the previous year.

Table 14: Changes to Powerco's forecast revenue – Eastern Region

EASTERN REGION				
Distribution network	Price Group	Forecasted Revenue ($'000s)		
		2018/19	2019/20	Change
Tauranga	Mass market (Including Unmetered ICPs)	70,971	70,279	-692
	69 – 299 kVA	9,154	10,621	1,467
	300 kVA + (including individually price consumers)	17,700	20,286	2,586
	Sub-total - Tauranga	**97,825**	**101,186**	**3,361**
Valley	Mass market (including unmetered ICPs)	66,280	65,689	-591
	69 – 299 kVA	6,823	8,044	1,221
	300 kVA + (including individually priced consumers)	21,291	22,375	1,084
	Sub-total - Valley	**94,394**	**96,108**	**1,714**
Total		**192,219**	**197,294**	**5,075**

Table 15: Changes to Powerco's forecast revenue – Western Region

WESTERN REGION			
Consumer Group	Forecast Revenue ($'000s):		
	2018/19	2019/20	Change
E1 – less than 100 kVA	166,108	162,524	-3,584
E100 (100 – 300 kVA)	7,412	7,508	96
E300 (300 kVA+)	33,189	34,964	1,775
Total	**206,709**	**204,996**	**-1,713**

Table 16: Changes to Powerco's total forecast revenue

	Forecast Revenue ($'000s):		
	2018/19	2019/20	Change
Eastern region	192,219	197,294	5,075 (+2.6%)
Western Region	206,709	204,996	-1,713 (-0.8%)
Total	398,928	**402,290**	**3,362 (+0.8%)**

The changes in forecast revenue from 2018/19 to 2019/20 year are due to:

- changes to the underlying revenue allowances resulting from the application of the CPP Determination (set by the Commerce Commission);
- pass through of changes in transmission charges and other pass through costs such as council rates and Electricity Authority and Commerce Commission levies;
- adjustments to Powerco's forecasts of chargeable quantities to reflect historical regional trends, including the number of ICPs and associated volume and demand growth;
- re-balancing of our prices across regions and consumer groups to ensure that our charges better align with our underlying costs. This helps to ensure that all consumers across our various regions and consumer groups pay a fair and equitable amount which reflects their utilisation of our network and the costs associated with their supply;
- adjustments to individual asset based pricing to reflect revised demands and asset allocations for customers that are in the 300 kVA consumer groups.

The average 0.8% revenue change does not reflect the change to an individual consumer's distribution charges (which Powerco passes to the consumer's retailer). Although 2019 forecast revenue is greater than 2018 forecast revenue, there are more customers using the network (more connections and more volume) for this forecast revenue to be allocated.

13. OUR APPROACH TO SETTING PRICES FOR NON-STANDARD CONTRACTS

NON-STANDARD CONTRACTS

The number, size and pricing characteristics of non-standard customers on Powerco's network are described in tables 7 and 12 and Section 10.

Powerco's practice is to offer non-standard pricing and individual account management to industrial and large commercial customers to address the risk of uneconomic bypass and to enable arrangements that are tailored to customers' needs. Customers must first discuss the prospect of bypass directly with their individual account managers before non-standard pricing for this reason will be considered. Powerco's approach to non-standard pricing includes taking into account customers' individual capacity and demand to ensure, to the extent practicable, that the price is cost reflective.

Through these processes, Powerco discourages uneconomic bypass of its network and promotes direct negotiation to tailor its services to the specific needs of the business. For example, a number of years ago Powerco determined that a large industrial consumer group in the Wairarapa region presented a potential bypass threat due to its size and location. Powerco subsequently reached agreed commercial terms with this consumer group to mitigate the risk of uneconomic bypass. This approach is consistent with the Electricity Authority's pricing principle (c)(i). It states that prices should be responsive to the requirements and circumstances of stakeholders in order to discourage uneconomic bypass.

Further details on non-standard pricing is available on Powerco's website at:
http://www.powerco.co.nz/Publications/Disclosures/Electricity/

POWERCO'S OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS SUBJECT TO NON-STANDARD CONTRACTS IN THE EVENT THAT THE SUPPLY OF ELECTRICITY LINES SERVICES IS INTERRUPTED

Non-standard contracted consumers are generally significant commercial or industrial loads, and thus arrangements between the parties include provision for response to planned and unplanned interruptions. For example, such 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 management in the event of abnormal network configurations.

These arrangements have no direct effect on the determination of prices for these consumers.

POWERCO'S APPROACH TO DEVELOPING PRICES FOR ELECTRICITY DISTRIBUTION SERVICES PROVIDED TO CONSUMERS THAT OWN DISTRIBUTED GENERATION

Powerco currently does not impose any standard ongoing charges in relation to distributed generation, but we do apply connection charges for the connection of distributed generation. These charges are negotiated directly with the customer and are consistent with the pricing principles in Schedule 6.4 to Part 6 of the Electricity Industry Participation Code 2010.

The connection charges are based on the incremental costs of providing connection services to the distributed generation, assuming recovery of the reasonable costs incurred by Powerco to connect the generator and to comply with Powerco's connection and operation standards. The incremental cost is net of the transmission and distribution costs that an efficient service provider would be able to avoid as a result of the connection of the distributed generation.

Powerco's prices include a pass-through cost which reflects the "avoided cost of transmission" (ACOT). Payments to distributed generators are summarised in Table 17 below. Prices for the year assume 12 monthly payments. These reflect the Electricity Authority's assessment of distributed generation eligible for ACOT payments[20], as well as our distributed generation policy. This policy is available at: www.powerco.co.nz/Get-Connected/Distributed-Generation/ and includes a description of how ACOT is calculated.

Table 17: Value of forecasted ACOT payments for 2019 price year by generator

Generator	GXP	RCPD (kW)	ACOT ($/year)
Generator 1	Bunnythorpe	4,998	$546,672.49
Generator 2	Carrington	0	0
Generator 3	Greytown	1,535	$167,904.86
Generator 4	Hawera	0	0
Generator 5	Huirangi	0	0
Generator 6	Huirangi	0	0
Generator 7	Linton	5,585	$610,920.11
Generator 8	Linton	9	$1,032.55
Generator 9	Masterton	308	$33,680.29
Generator 10	Ohakune	253	$27,635.95
Generator 11	Opunake	0	0
Generator 12	Stratford	0	0
Generator 13	Stratford	0	0
Generator 14	Stratford	0	0
Generator 15	Tauranga	37,581	$4,110,568.22
Generator 16	Waikino	127	$13,851.88
Annual total		**50,396**	**$5,512,266.35**

[20] The Authority's project is here https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/acot-code-change-implementation/, and the decision about 'Lower North Island' distributed generation is the one relevant to customers connected to Powerco's network.

14. DEMONSTRATING CONSISTENCY WITH THE ELECTRICITY AUTHORITY'S PRICING PRINCIPLES

This section demonstrates how Powerco's pricing methodology demonstrates the consistency of our pricing methodology with the Electricity Authority's pricing principles.

The pricing principles are based on sound economic theory, but it can be difficult to demonstrate compliance using quantitative information. Powerco considers that it is currently compliant with the pricing principles. However, we will continue to gather and analyse more information on consumers' behaviour and assess that information against the principles.

Particular matters we will continue to investigate and monitor over the medium-term are:

- the impact a stronger peak demand pricing signal would have on different types of consumers' electricity usage;
- the benefits and consequences of greater alignment of the pricing approaches used in the Eastern and Western regions; and
- the willingness of consumers to accept price adjustments.

a) i) Prices are to signal the economic costs of service provision, by being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation.

INCREMENTAL COST

The term 'incremental cost' (IC) is defined as the cost of the next additional unit of production and "long run incremental cost" (LRIC) is defined as the cost of providing an additional unit, including the capital cost of increasing the capacity of the network. The LRIC may be the present value of the cost of a future addition to the network.

Incremental costs are difficult to evaluate in a meaningful way for electricity distribution businesses (EDBs). Much of the time the IC is zero, meaning that the next unit of electricity can be distributed to a customer within the existing capacity of the network system. Once in a while the IC will be a very large number, meaning that the next unit of electricity would require additional installed capacity to be distributed.

In addition, the "unit" being supplied could be an extra unit of capacity to an existing customer, or providing a connection for a new customer. To calculate IC, Powerco has analysed the forecasted level of growth on the network over the next ten years against the forecasted customer connection and system growth capex. This results in a proxy for incremental cost of 0.98 c/kWh.

Powerco is required by legislation to supply some consumers at prices which may be below the marginal cost of connection. This is mainly in remote locations which have few customers and where electricity supply was originally supported by public subsidisation. 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. The Electricity Industry Act 2010 now allows EDBs to provide alternative energy supply, rather than continuance of supply via line services. Powerco is actively identifying these customers and has installed several standalone power systems. With consumer consent, we will seek to install additional standalone systems where this is appropriate.

STANDALONE COST

Cross subsidisation exists when customers pay more for a service than the costs another firm would incur if it served those customers on a stand-alone basis. Standalone cost (SAC) is also a difficult figure to calculate for each load group on Powerco's network.

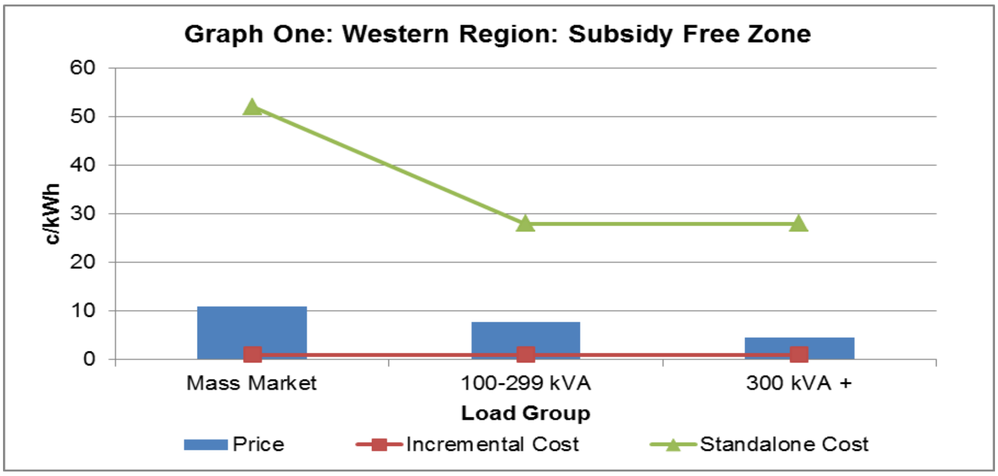
Powerco has attempted to calculate the SAC for each price group by considering the costs of alternative power supply. A 2009 Ministry for Innovation, Business and Employment report[21] provided c/kWh estimates for stand-alone photo-voltaic power systems for different levels of capacity. We have used the estimated costs of solar in 2020 for the Auckland region (Table 8.1 of the report) as estimates of stand-alone costs across the network. These are:

- $0.52/kWh for mass-market prices (based on the '<2kW' group in the 2009 report)
- $0.28 /kWh for our 100 kVA -199 kVA & 300 kVA + customers (based on the '>100 kW' group in the report)

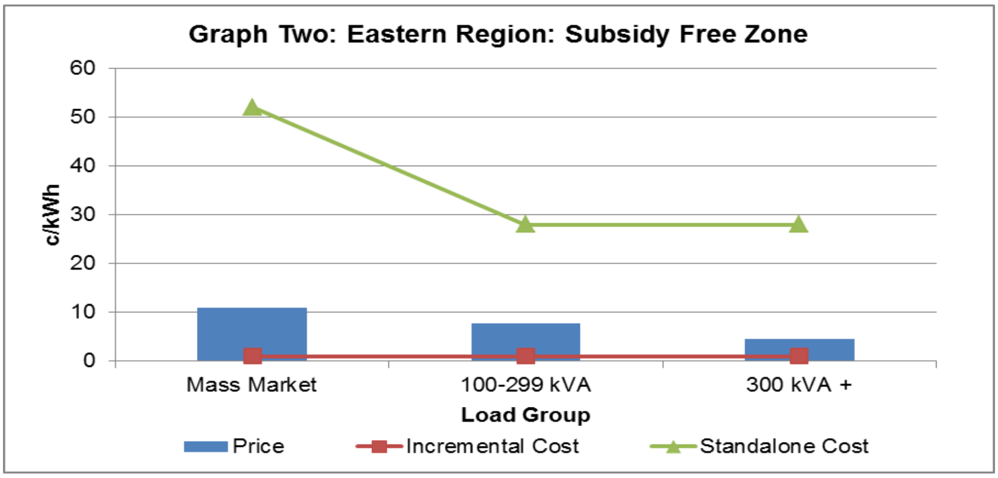
SUBSIDY FREE ZONE

Graphs One and Two in Figure 9 below indicate that Powerco's pricing is within the subsidy-free zone for each of Powerco's price group.

Figure 9: Illustration of how Powerco's prices fall within the subsidy-free zone



[21] See http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/technical-papers/solar-photovoltaic-energy/



A large number of assumptions have been made when determining the IC and SAC estimates, and, as only part of Powerco's pricing is by volume, the graphs should be considered illustrative only. We also recognise that the simplified approach does not recognise locational factors (other than between the Eastern and Western regions). For example, the averaging could mask the difference between rural and urban consumers and obscure the few specific customers that are supplied at below marginal cost.

However, Powerco's use of a cost of supply model provides additional reassurance that prices are in the subsidy free zone by allocating actual costs of supply to individual price categories. By regularly reviewing the costs of supply and revenue by price category Powerco ensures that our charges fall within the subsidy free zone.

a) ii) Prices are to signal the economic costs of service provision, by having regard, to the extent practicable, to the level of available service capacity.

a) iii) Prices are to signal the economic costs of service provision, by signalling, to the extent practicable, the impact of additional usage on future investment costs.

These two principles require that prices should look to the future and be based on long run marginal costs. In essence, prices should be low where future investment is low (and spare capacity exists) and high where capacity is constrained and investment is needed.

The most significant cost driver that influences the need to invest to develop the network is the combined peak demand of all consumers in an area. Powerco designs and constructs its network to meet this peak load.

Powerco's prices in the Eastern and Western regions are structured to reflect different capacity bands, which allow us to differentiate our charges based on the provision of different levels of end-use capacity to our consumers.

Our prices across both regions also provide differentials between peak and off-peak consumption in order to reflect the difference in long term costs associated with investment in additional network capacity.

Powerco's demand charge in the Western region for both mass market and larger commercial/industrial customers is designed to signal the cost of new investment by ensuring that consumers that contribute towards the peak demand on our network are charged accordingly.

In addition, Powerco offers discounted charges for customers who opt for load control prices. 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.

Transmission costs are a function of transmission capacity and signal the economic costs of service provision on the Transpower network. These costs represent around 25% of distribution prices, so also work to ensure distribution prices meet this principle.

b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.

Given the nature of distribution networks, prices based on efficient incremental costs are likely to under-recover allowed revenues. However, setting prices based on a precise definition of price responsiveness, or price elasticity of demand, is difficult for electricity distribution for a number of reasons. First, there is limited information on the actual price elasticity of demand for electricity in New Zealand. Second, retailers re-bundle distribution prices into a final retail price for their consumers. In many cases, the structure of distributors' prices (i.e. the extent to which prices are charged on a daily or per unit of energy basis) is changed by retailers. It is therefore very difficult to discern customers' responsiveness to changes in distribution prices alone.

The Commerce Commission, in its work on the pricing methodologies of regulated suppliers, has acknowledged the difficulty of this issue. It has stated that it would judge this principle by checking to see if certain rules have been followed. For example, where one group of consumers is less price-responsive than another group of consumers of the same service, then, all else being equal, one would expect the prices of the less price-responsive consumers to be higher.

Graphs one and two in Figure 8 show that, as consumers' capacity increases, the unit cost expressed as a c/kWh charge reduces. Larger consumers tend to exhibit a higher price elasticity of demand, because they are typically better able to modify their usage patterns to consume during low cost periods or switch to alternative energy sources (e.g. gas) if the cost of electricity rises. As larger consumers also face, on average, lower prices per unit, this is consistent with the Commerce Commission's expectation.[22]

[22] Research on how elasticity of electricity consumers based on size is very limited. However, in Powerco's experience large electricity consumers demonstrate a stronger interest in price signals to shift load. See Powerco's Consumer Report 2009-2011 for a summary of the feedback from consumers.

c) i) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to discourage uneconomic bypass.

The main risk of bypass of the distribution network is large consumers opting to connect directly to the Transpower's network or install generation. Powerco's practice is to offer non-standard pricing and individual account management to industrial and large commercial customers to address the risk of uneconomic bypass and to enable arrangements that are tailored to customers' needs. This approach takes in to account customers' individual capacity and demand to ensure that the price is cost reflective, 9to the extent practicable).

When Powerco becomes aware of the potential for bypass it is through these processes that we discourage uneconomic bypass. We promote direct negotiation to tailor our services to the specific needs of the business. For example, several years ago Powerco determined that a large industrial consumer group in the Wairarapa region presented a potential by-pass threat due to its size and location. Powerco subsequently agreed commercial terms with this consumer group to mitigate the risk of uneconomic by-pass. Further details on non-standard pricing is available on Powerco's website at:
http://www.powerco.co.nz/Publications/Disclosures/Electricity/

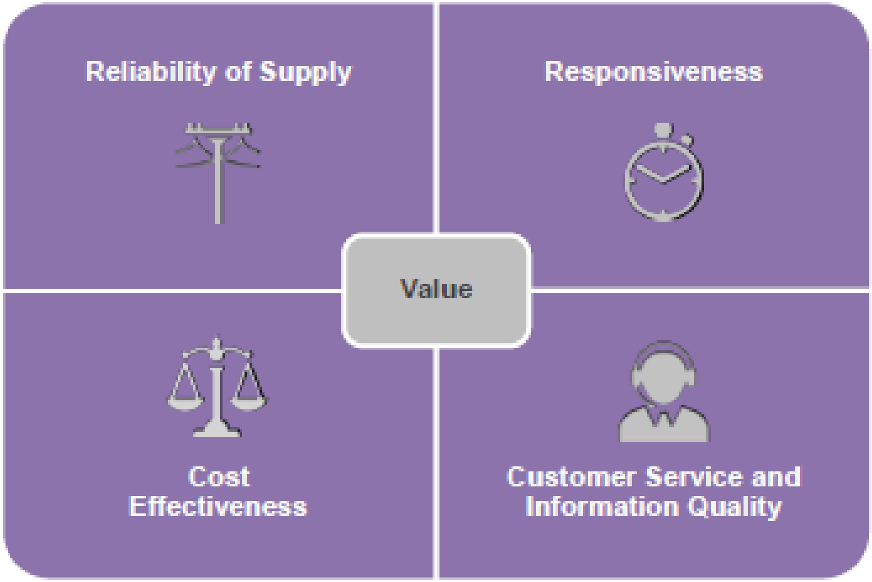
c) ii) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services.

Mass market customers are generally not able to choose the quality of service they receive. For example, Powerco cannot offer one person a higher quality and higher price than their neighbour. Powerco has an established and extensive annual consultation programme to help it understand the general preferences and expectations of consumers.

The findings of our consumer engagement 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 2017 consultation programme are published in our most recent Electricity Asset Management Plan (2017). This is available on Powerco's website.

The scale and range of consultation we complete provides us with appropriate insight into the areas of our service that our customers value. Feedback from our customers typically falls into four key service dimensions, as set out in Figure 10.

Figure 10: The four service dimensions most valued by our customers



Powerco submitted a Customised Price-quality Path (CPP) application to the Commerce Commission in June 2017. A CPP application is required to meet a set of mandatory customer consultation requirements as specified by the CPP Input Methodologies. Powerco's application built on our existing customer consultation programme and concluded in early 2017 with customer engagement on our initial CPP proposal.

The CPP customer engagement was focused on ensuring our plan was aligned to our customers' expectations and needs in regards to price and quality of service. A targeted approach of engagement for our industrial and commercial customers was adopted. To engage mass-market customer a range of material and channels was used to create awareness and allow feedback to be provided. Figure 11 provides an overview of how we reached mass-market customers.

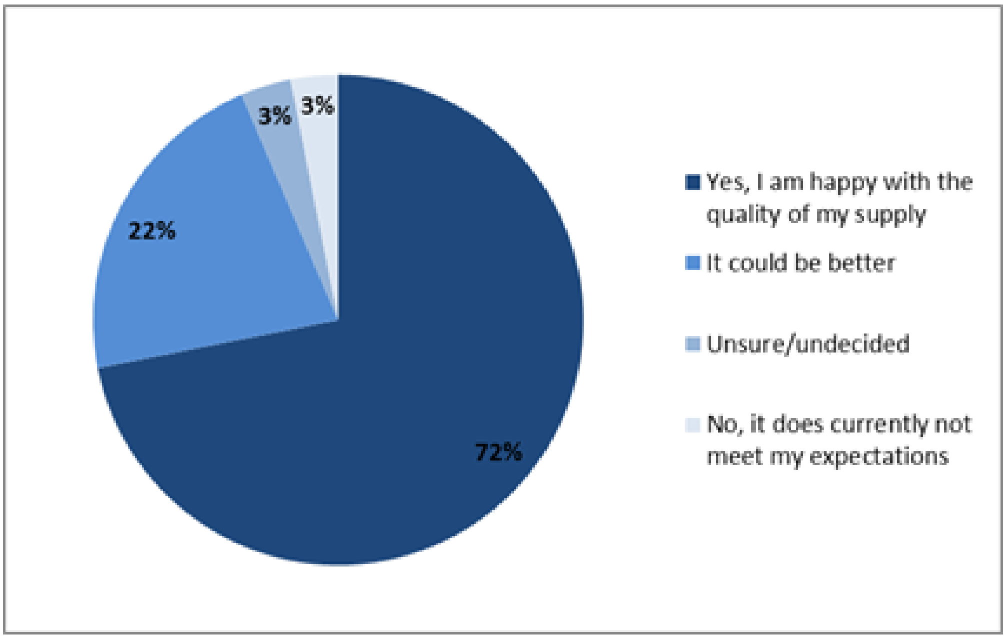
Figure 11: How we reached our mass- market customers

The full conclusions of our CPP customer engagement, and how it influenced our CPP proposal, can be found in the Powerco Customised Price-quality Path Proposal available on the Commerce Commission website.

In regard to pricing, the key findings were that our customers were price conscious and affordability is a concern for them. However, customers value long-term planning, good asset management and expect current level of service to be maintained. Our final CPP proposal considered this feedback and the investment plan balances the expenditure need to maintain current service levels and customers desire to avoid significant price increases.

In addition to our CPP related consultation Powerco continued to engage directly with customers through in-person surveys. Feedback from these interactions in 2018 concluded that Powerco's networks provide an appropriate level of quality. For example, in the last 12 months Powerco surveyed 2374 customers on its networks. Only 3.21% said the current quality of their electricity supply did not meet their expectations. The results are shown in Figure 12 below.

Figure 12: Responses to Powerco's customer satisfaction survey



Powerco's stakeholders and how their interests are identified are described below.

STAKEHOLDER	MAIN INTEREST	HOW STAKEHOLDERS' INTERESTS ARE IDENTIFIED
Electricity consumers	• Service quality and reliability • Price • Safety • Information • Environmental	• Consultation and retailer feedback • Dedicated client managers for large consumers • Appropriate price paths and quality standards • Incident reports, complaints and complements • Measurement and benchmarking of Powerco performance
Retailers	• Efficient business-to-business processes • Service to final consumers • Price	• Dedicated relationship client managers • Contracting agreements • Direct engagement

STAKEHOLDER	MAIN INTEREST	HOW STAKEHOLDERS' INTERESTS ARE IDENTIFIED
Embedded Generators	• Technical performance and rules • Reliability • Connection agreement	• Direct engagement and negotiation • Contractual connection agreements
Transpower (as grid and system operator)	• Technical performance and rules compliance • GXP loading and planning	• Direct engagement • Administration of Electricity Governance Rules
Commerce Commission	• Pricing levels • Quality standards • Effective governance	• Meetings with Commissioners and staff • Quality responses to consultation papers, decision papers and regulatory determinations
Electricity Authority	• Market operation • Access • Pricing methodology	• Reporting • Meetings with Board members and staff
State bodies and regulators	• Safety via the Ministry of Business, Innovation and Employment • Environmental performance via the Ministry for the Environment	• Published acts, rules and determinations • Formal reporting • On-going consultation
Powerco's shareholders	• Efficient and effective business management and planning • Financial performance • Governance • Risk management	• Corporate governance and arrangements • Formal reporting • KPIs
Employees and Contractors	• Safe, productive working environment • Training and development • Continuous improvement, adoption of new technology and practices	• Regular dialogue, internal communications and employee surveys • Contractor negotiations and dialogue • Unions and employee arrangements
Public, iwi, landowners	• Public safety • Land access and respect for traditional lands • Environmental	• Consultation and feedback • Access and easement negotiations and agreements • Acts, regulation and other requirements

For non-standard customers, Powerco is able to offer a service more tailored to their requirements. Powerco continues to consult with these customers through one-to-one liaison with key account managers, consistent with the Parsons Brinckerhoff Associates best practice recommendations.[23] This works well as large customers are usually familiar with the issues involved in price/quality trade-offs and strong relationships provide a firm foundation for discussing all aspects of quality and price.

The number, size and pricing characteristics of non-standard customers on Powerco's network are described in tables 7 and 8 and Section 15.

c) iii) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to, where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation

Powerco's Asset Management Plan reviews distribution alternatives and technological innovation. Powerco's pricing methodology aims to complement this approach. Below are some examples of how this works:

- Demand-side management is encouraged through demand-based network charges in some cases.
- Load control is used to reduce demand peaks. This has been proposed to modify the timing of irrigation pump use in areas where voltage complaints have arisen.
- Power factor correction is best applied at customers' installations and this is set out in Powerco's connection standard. In some cases it is applied to the distribution network, particularly in the Valley area, with shunt capacitors (generally 750 kVA banks) used at key locations on distribution feeders. Powerco's pricing provides an incentive to manage the power factor and recover costs.
- Load transfer through the distribution network is considered prior to any substation capacity upgrade, and the effectiveness of price signals to manage demand.
- Solar-powered installations have been supplied in place of network extensions for some remote small loads, such as electric fence units.
- Micro-grids and remote-area power systems are being implemented in some remote rural areas. Changes in the Electricity Industry Act 2010 allow Powerco to work with consumers to install alternative energy supply. An example of this is Powerco's **BASE**POWER product which provides a continuous and reliable supply of electricity, similar or better than grid supply. **BASE**POWER is a modular system with a generator, energy storage and innovative energy management system combined with renewable supplies from PV solar panels, micro hydro and, potentially, wind turbines.[24] This also provides Powerco with information about changes to standalone costs.

[23] Parsons Brinckerhoff (April 2005) Report to the Commerce Commission: *Electricity Distribution Business Asset Management Plans and Consumer Engagement: Best Practice Recommendations*, section 6.4.2.2, p.56.
[24] More information on adoption rates and pricing is available from Powerco on request.

d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.

TRANSPARENCY

Powerco's prices for 2019/20 are available to customers through a range of media channels and locations:

- two advertisements each year in the Wairarapa Times Age, Manawatu Standard, Wanganui Chronicle, Taranaki Daily News, Bay of Plenty Times and Waikato Times;
- pricing schedules are sent to all customers with whom Powerco has a use of system agreement;
- Powerco's website; and
- available to view on request or at our offices by appointment.

This pricing methodology is also published on Powerco's website.

PRICE STABILITY, CERTAINTY AND IMPACT ON CUSTOMERS

The impact on customers of changes to the established allocation methodology is a central consideration in the pricing process. This is the reason that Powerco has moved away from the pricing it inherited from UNL very cautiously.

Powerco's pricing methodology has not changed materially over the last ten years. In particular, the level of differential between peak and off-peak charges has not changed materially, which provides retailers and consumers with a degree of certainty when making decisions about investment in energy saving and off-peak devices.

Powerco is, however, continually looking to improve its pricing methodology to ensure that the balance between price categories, fixed and variable charges and the peak and off-peak differentials are appropriate. Our pricing methodology must also complement technological developments, such as the roll out of advanced metering infrastructure, the fall in cost of photovoltaic technology and the uptake of plug-in electric vehicles.

Powerco consults with retailers and other customers a number of times throughout the year to discuss our pricing methodology (including potential improvements) and the impact of any pending review of our prices. A description of this process is available on request from Powerco.

For non-standard customers, Powerco continues to consult with customers through one-to-one liaison with key account managers which provides a channel for discussions around all aspects of quality and price.

e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.

Powerco is very 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. Twenty retailers operate on Powerco's network (both east and west) and we have a detailed consultation process, generally with three rounds of consultation on prices with retailers. The pricing methodology has not changed materially from last year but we will continue to rationalise our price categories and price options to ensure that retailers' transactions costs are minimised.

Consumers: Consumers make medium to long term investments based on electricity price structures. For example, a very low price for consumption at may provide an incentive to invest in a storage heater. Powerco is aware that consumers value pricing certainty and aims to minimise any large changes that impact these types of investment decisions. We mainly collect feedback from retailers (as they have responsibility for the ultimate price signal), but also collect information from consumer consultation.

Powerco also takes the impact on the following stakeholders into account when setting prices. An overview of our relationship with these stakeholders is described in section 2.4 of Powerco's Asset Management Plan.

- Transpower;
- Commerce Commission;
- Ministry of Business, Innovation and Employment;
- Electricity Authority;
- Electricity and Gas Complaints Commission.

ECONOMIC EQUIVALENCE ACROSS RETAILERS

Powerco's pricing methodology is applied consistently to all retailers. All retailers in the same region face the same price options, applicable charges and/or calculation methodology. Therefore we consider our prices to be economically equivalent across retailers.

Powerco's annual consultation process with retailers also allows them to raise any concerns over pricing at an early stage of the pricing process.

15. SUMMARY OF COMPLIANCE WITH CLAUSES 2.4.1 TO 2.4.5 OF THE ELECTRICITY INFORMATION DISCLOSURE DETERMINATION 2012

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;	Table 14 and Table 15 for changes to the target (or forecast) revenues and Section 12 for a description of the changes. Changes to the pricing methodology that underpins those prices are described in 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);	Described in Section 13
(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 14(c)(ii)
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.	Powerco's public advertisements reflect changes to the pricing methodology and prices.
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;	Powerco's Electricity Pricing Methodology achieves this.
(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 14

Information Disclosure Requirement	Compliance demonstrated
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See Table 2.
(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 Table 2, Table 7 and Table 12.
(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 the discussion on consumer groups in Section 10 (Eastern) and Section 11 (Western).
(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;	Section 4 details the updates that have been made to our pricing schedule.
(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 sections 10 (Eastern) and 11 (Western).
(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 Table 8 and Table 13
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 approach to pricing reform that Powerco is adopting. This involves transitioning the Western Region to ICP-based pricing and introducing differential time-of-use charging to better reflect the cost of network use.
(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 13, Table 7, and Table 12.

Information Disclosure Requirement	Compliance demonstrated
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;	See the discussion on non-standard contract criteria in Section 13
(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;	See the discussion on non-standard contract criteria in Section 13
(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 the discussion on non-standard contract pricing in Section 13
(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 the discussion on DG pricing in Section 13

ATTACHMENT 2

DIRECTORS' CERTIFICATE CONFIRMING REGULATORY COMPLIANCE OF THE POWERCO ELECTRICITY PRICING METHODOLOGY 2019

Certification for Year-beginning Disclosure

We, John Loughlin Director 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 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

Date: 14/3/19

Director

Date: 14/3/19