ELECTRICITY DISTRIBUTION SERVICES PRICING METHODOLOGY

From 1 April 2025

Pursuant to: The Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 (Consolidated 27 November 2024)

vector

Contents

INTRODUCTION & CONTEXT

INTRODUCTION

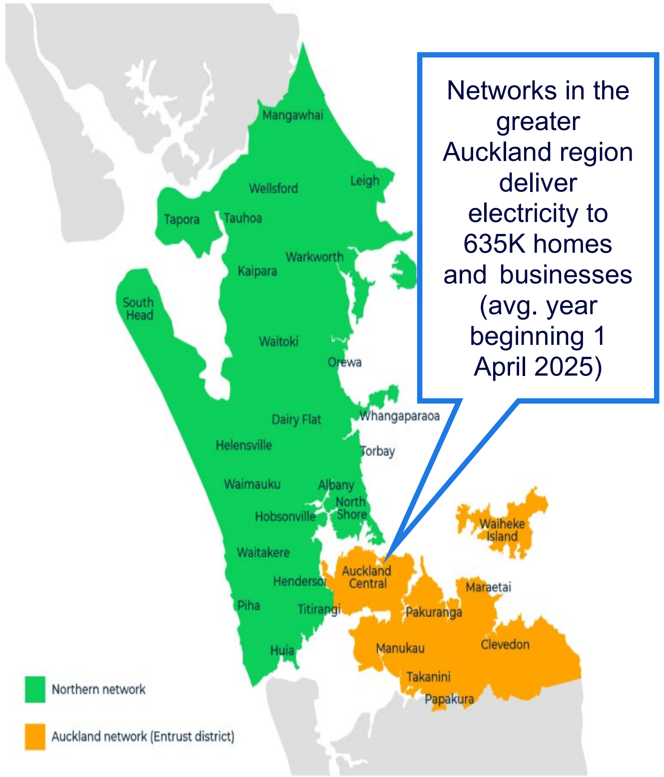
Vector Limited (“Vector”, “our”, “we”, or “us”) recovers the cost of owning and operating our electricity distribution networks (Network) through a combination of standard (published), non-standard prices for electricity distribution services, and capital contributions for new connections and upgrades. We are regulated by the Commerce Commission (Commission) and are required to publish our pricing methodology for electricity distribution services (Pricing Methodology).

In this document, we refer to consumers and customers however contractual requirements mean that our prices largely apply to ICPs, as we bill electricity retailers on an ICP basis. Electricity retailers have discretion as to whether they pass our charges onto end users though we encourage them to do so. Therefore, the consumer and customer impacts described in this document will only apply if our prices are passed through by the electricity retailers.

This document explains how our Pricing Methodology meets the requirements of the Information Disclosure (amendments related to IM review 2023) Amendment Determination 2024 (ID)[1]. It describes:

1. The consumer groups, the price categories and components within each consumer group;
2. Reasons for price changes;
3. How we comply with pricing principles;
4. How prices are set; and
5. The Cost of Service Model (COSM) allocation of target revenue to consumer groups.

Figure 1: Our electricity distribution



The ID requires price change commentary relating to a pricing strategy[2]. We do not currently have a pricing strategy as defined in the ID. We do however have a publicly available electricity pricing roadmap[3]. The roadmap sets out how we are evolving our prices to help deliver Vector’s Symphony Strategy and deliver better outcomes for consumers. As well, the roadmap explains how we are designing our prices in response to

1 Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 (consolidated 27 November 2024), available at https://comcom.govt.nz/__data/assets/pdf_file/0026/363365/Electricity-Distribution-Information-Disclosure-amendments-related-to-IM-Review-2023-Amendment-Determination-2024-red-lined-version-27-November-2024.pdf

2 A pricing strategy is a decision made by the Directors on the electricity distribution business’ plans or strategy to amend or develop prices in the future, and recorded in writing

3 Available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing under the heading “consumer-led pricing design”

pricing guidance issued by the Electricity Authority. The roadmap is updated at least annually in April.
As noted above capital contributions impact the way we set prices. This document does not contain our Capital Contributions policy[4] as it is disclosed in a separate document.

Key Pricing Considerations:

Prices are set to earn the level of revenue we are permitted to under the Default Price Path (DPP) set out in the DPP Determination[5]. The Commission determines that the allowable revenue an electricity distributor business (EDB) can earn over a five-year period from 2026 to 2030.

When setting prices, we take into account (amongst other things) - historical price structures, minimising rate shock, pricing principles[6] when appropriate, ensuring that prices to individual consumer groups reflect their allocation of costs, pricing guidance issued by the Electricity Authority and feedback from consultation processes with Entrust and retailers.

For the year commencing 1 April 2025 the Commission sets the forecast net allowable revenue a distributor can earn. On top of forecast net allowable revenue, the DPP allows prices to also change to reflect pass-through costs (e.g. Transpower transmission charges, council rates and statutory levies) and recoverable costs (e.g. IRIS, wash-up drawdown amount and quality incentive allowance).

Pricing under the forecast allowable revenue is permitted providing the undercharging is not below the undercharging limit set by the Commission. Any revenue foregone in the period due to pricing below the forecast allowable revenue and above the undercharging limit can be recovered in future periods. The undercharging recovered in future periods is adjusted for time value.

Not all consumers will see the weighted average price change when prices change, some will see more and some less depending on their consumption profile. Our calculation of the weighted average price change assumes our price changes are passed on by electricity retailers as we typically bill electricity retailers not end-use consumers.

PRICING APPROACH CONTEXT

The future is unpredictable. There is uncertainty around existing regulatory frameworks and new business models are ever evolving in response to new consumer demands, new technologies and decarbonisation. We have taken the strategic decision to embrace these changes. We see

4 Available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/capital-contributions
5 Default Price-Quality Path Determination 2025 available https://comcom.govt.nz/__data/assets/pdf_file/0027/363276/5BFINAL5D-Electricity-Distribution-Services-Default-Price-Quality-Path-Determination-2025-5B20245D-20-November-2024.pdf
6 Available at https://www.ea.govt.nz/industry/distribution/distribution-pricing/

this new environment as an opportunity to design and redesign our pricing in response to an evolving market. The regulatory framework plays a major part in our response this year. This year marks first year of the DPP4, the price change between the DPP cycles is more significant and is further explained in the section “Price Change”.

DERIVING OUR PRICES

CONSUMER GROUPS

We determine consumer groups based on how customers use the network and the nature of the network service they receive. Consumer groups are determined at a relatively high level, the main reasons for this are below:

- There is high degree of network meshing and interconnection of consumers;
- End consumers are not generally geographically segmented in their use of different network assets, for example, there are very few purely "industrial zones" or "residential zones"; and
- There is a mix of consumers, including a large number of consumers with relatively low individual consumption, and vice versa.

Our standard consumer groups are based on a measure of capacity connection and supply connection point type as shown in Table 1. Consumer groups are mutually exclusive so a consumer can only be in one group.

Table 1: Consumer groups

Consumer group	Subgroup	Capacity connection	Supply connection
Mass market	Residential & General	Small ≤ 69kVA	Low voltage network
Unmetered	General	Small ≤ 1kVA	Low voltage network
Low voltage	Commercial	Large ≥ 69kVA	Low voltage network
Transformer	Commercial	Large ≥ 69kVA	Vector owned transformer(s) which supplies the consumer's low voltage network
High voltage	Commercial	Large ≥ 69kVA	High voltage (11kV or higher) network
Zone substation	Commercial	Large ≥ 69kVA	Directly from a Vector zone substation
Sub-transmission	Commercial	Large ≥ 69kVA	Sub-transmission (11kV or higher) network
Non-standard		Various	Various

Consumers on non-standard contracts which have met certain eligibility criteria, as outlined on page 30 are included in a separate consumer group.

The mass market consumer group is split into two subgroups: residential and general with a key difference being that the Low User Regulations [7] apply only to the residential subgroup.

The unmetered consumer group is also in the general subgroup. The low voltage, transformer, high voltage, zone substation and sub-transmission consumer groups are collectively referred to as commercial.

[7] The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low User Regulations)

PRICE CATEGORIES

Table 2 sets out the price categories for consumers on our Auckland network (codes beginning with A) and our Northern network (beginning with W).

Table 2 Price categories

Consumer group	Short Description	Auckland	Northern	Key eligibility criteria /purpose
Mass Market	Residential - time of use (TOU) - uncontrolled	ARHLU ARHSU	WRHLU WRHSU	Residential consumers without controllable load, hot water (ripple or pilot wire)
	Residential - TOU - controlled	ARHLC ARHSC	WRHLC WRHSC	Residential consumers with controllable hot water load (ripple or pilot wire)
	Residential - TOU - Distributed energy resource (DER)	ARHLD ARHSD	WRHLD WRHSD	For customers with load that can be connected to or respond to our distributed energy resource management system
	Residential - Anytime (exemption) - uncontrolled	ARNLU ARNSU	WRNLU WRNSU	Residential consumers with a Vector provided exemption from TOU price categories, and without controllable load
	Residential - Anytime (exemption) - controlled	ARNLC ARNSC	WRNCL WRNSC	Residential consumers with a Vector provided exemption from TOU price categories, and with controllable load
	General – TOU	ABSH ABSHD	WBSH WBSHD	Non-residential < 69kVA consumers
	General – Anytime (exemption)	ABSN	WBSN	Non-residential < 69kVA consumers with a Vector provided exemption from TOU price categories
Unmetered	General – unmetered	ABSU	WBSU	Unmetered < 1kVA capacity connections, mostly street lighting

PRICE CATEGORIES (continued)

Table 2 Price categories

Consumer group	Short Description	Auckland	Northern	Key eligibility criteria /purpose
Low voltage (LV)	LV – TOU	ALVT ALVTS ALVTD	WLVH WLVHS WLVHD	Main category for LV consumers, requires TOU metering
	LV – non-TOU	ALVN	WLVN	For smaller LV consumers (< 345kVA) who do not have TOU metering
Transformer (TX)	TX – TOU	ATXT ATXTS ATXTD	WTXH WTXHS WTXHD	Main category for TX consumers, requires TOU metering
	TX – non-TOU	ATXN	WTXN	For smaller TX consumers (< 345kVA) who do not have TOU metering
High voltage (HV)	HV – TOU	AHVT AHVTS AHVTD	WHVH WHVHS WHVHD	Main category for HV consumers, requires TOU metering
	HV – non-TOU	AHVN	WHVN	For smaller HV consumers (< 345kVA) who do not have TOU metering
Zone substation (ZS)	ZS – TOU	AZST AZSTS AZSTD	WZSH WZSHS WZSHD	Category for ZS consumers, requires TOU metering
Sub-transmission (ST)	ST – TOU	ASTT ASTTS ASTTD	WSTH WSTHS WSTHD	Category for ST consumers, requires TOU metering

PRICE COMPONENTS

We have a range of price components that apply to different price categories depending on the characteristics of a particular category and the availability of metering data. Table 3 describes the various price components that we have. A peak volume price is applicable for the winter period (1 April to 30 September inclusive). The peak volume price in summer is the same as off peak volume price.

Table 3: Price components

Type	Component	Codes	Units	Description
Fixed	Daily	FIXD	$/day	Daily price applied to the number of days each consumer's point of connection (or fitting for unmetered connections) is energised
	Capacity	CAPY	$/kVA/day	Daily price applied to the installed capacity (or nominated capacity for HV, ZS and ST) of each ICP
Variable	Volume	AICO, 24UC, OFPK, PEAK	$/kWh	Volume price applies to all electricity distributed to each ICP. Controlled volume (AICO), uncontrolled volume (24UC), off peak volume (OFPK), peak volume (PEAK) (0700 to 1100 and 1700 to 2100 weekdays including public holidays). The winter period is for months April to September inclusive and, the summer period is for months October to March inclusive
	Demand	DAMD	$/kVA/day	Daily price applied to the average of the consumer's ten highest kVA demands between 8am and 8pm on weekdays each month
	Excess demand	DEXA	$/kVA/day	Daily price applied when the anytime maximum demand is greater than the nominated capacity and is applied to the difference between the anytime maximum kVA demand and the nominated capacity
	Power factor	PWRF	$/kVAr/day	Daily price determined each month where a consumer's power factor is less than 0.95 lagging. The kVAr amount is calculated as twice the largest difference between the recorded kVArh in any one half-hour period and the kWh demand recorded in the same period divided by three
	Injection	INJT	$/kWh	Volume injection price applies to all electricity injected into the network by each consumer

Each price component can be designed to recover distribution costs, pass-through and recoverable costs. Transmission costs are not part of the price components as we have adopted a GXP Pricing approach since 1 April 2023 with further explanation on on page 19.

MASS MARKET AND UNMETERED PRICE CATEGORIES

Our PY26 mass market price categories continue to be split into two pricing structures.

- two-part time of use - daily fixed price with different volumetric prices depending on the time period when the electricity is used (that has winter peak time pricing during 7am-11am and 5pm-9pm weekdays for months April to September inclusive and off-peak pricing during other times); and
- flat volumetric pricing - daily fixed price and any anytime volumetric price, which is only available as an exemption.

We apply peak and off-peak pricing to TOU metered ICPs unless an exemption is arranged with us. The peak price is only applicable in winter months to better focus the price signal to peak loads, as constraints are presently not a concern for most of the network in summer months.

Our residential price categories include controlled, uncontrolled and DER price categories. The controlled price categories are designed to provide a reward for the option of helping us to reduce load during winter peak periods. The DER price category is designed to provide the flexibility to manage load in the future such as electrical vehicles (EVs), batteries and smart appliances. These price categories help reduce usage during peak times therefore avoiding some capital investment. The DER price category is also made available for general TOU metered ICPs.

We have a two-part charge for unmetered price categories with fixed and volumetric prices. The fixed price is the number of days each point of connection of fitting is energised. Unmetered ICPs volumes are determined by Vector based on load profiles and fitting input wattages.

Table 4 shows the price components applicable to the price categories for the mass market and unmetered consumer groups.

- The pass-through costs recovery is only through the daily fixed charge. The transmission costs recovery is not included as we have adopted a GXP Pricing Methodology since 1 April 2023 to recover transmission costs.

Table 4: Price components applicable to mass market and unmetered price categories from 1 April 2025[8]

Consumer group and sub group		Price category type	Price category description	Price category codes	Daily	Volume anytime	Volume off-peak	Volume winter peak	Volume injection
					-FIXD	-24UC / -AICO	-OFPK	-PEAK	-INJT
					$/day or $/day/fitting	$/kWh			
Mass market	Residential	TOU	Low user	ARHLC, ARHLD, ARHLU, WRHLC, WRHLD, WRHLU	✓ D P		✓ D	✓ D	✓
			Standard user	ARHSC. ARHSD, ARHSU, WRHSC, WRHSD, WRHSU	✓ D P		✓ D	✓ D	✓
		Anytime (exemption)	Low user	ARNLC, ARNLU, WRNLC, WRNLU	✓ D P	✓ D			✓
			Standard user	ARNSC, ARNSU, WRNSC, WRNSU	✓ D P	✓ D			✓
	General	TOU	General	ABSH, ABSHD, WBSH, WBSHD	✓ D P		✓ D	✓ D	✓
		Anytime (exemption)	General	ABSN, WBSN	✓ D P	✓ D			✓
Unmetered		Unmetered	Unmetered	ABSU, WBSU	✓ D P	✓ D			✓

8 D is distribution cost recovery only and D P has both distribution and a pass-through cost recovery. There are no transmission cost recovery included in the price categories.

COMMERCIAL PRICE CATEGORIES

Our price structure for commercial price categories is largely historical. There were (and, to a lesser extent, still are) a variety of price categories with different combinations of price components and price levels, due largely to pricing differences that existed prior to both networks being owned by us.

All commercial price categories consist of daily fixed, anytime volume, capacity, power factor and injection prices. TOU price categories (which have been mandatory from 1 April 2022 for all new commercial consumers, and existing consumers with the metering capability) also have demand and excess demand (for high voltage and above consumers) prices.

Table 5 shows the price components applicable to the price categories for the commercial consumer groups.

Table 5: Price components applicable to commercial price categories[9]

Consumer group	Price category description	Price category codes	Daily	Capacity	Volume - anytime	Demand	Excess demand	Power factor	Volume - injection
			-FIXD	-CAPY	-24UC	-DAMD	-DEXA	-PWRF	-INJT
			$/day	$/kVA/day	$/kWh	$/kVA/day		$/kVAr /day	$/kWh
Low voltage	TOU	ALVT, WLVH ALVTS, WLVHS ALVTD, WLVHD	✓ D	✓ D P	✓ D	✓ D		✓ D	✓
	Non-TOU	ALVN, WLVN	✓ D	✓ D P	✓ D			✓ D	✓
Transformer	TOU	ATXT, WTXH ATXTS, WTXHS ATXTD, WTXHD	✓ D	✓ D P	✓ D	✓ D		✓ D	✓
	Non-TOU	ATXN, WTXN	✓ D	✓ D P	✓ D			✓ D	✓
High voltage	TOU	AHVT, WHVH	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓

9 D is distribution cost recovery and D P has both distribution and a pass-through cost recovery. There are no transmission prices included in the price categories.

Consumer group	Price category description	Price category codes	Daily	Capacity	Volume - anytime	Demand	Excess demand	Power factor	Volume - injection
			-FIXD	-CAPY	-24UC	-DAMD	-DEXA	-PWRF	-INJT
			$/day	$/kVA/day	$/kWh	$/kVA/day		$/kVAr /day	$/kWh
		AHVTS, WHVHS AHVTD, WHVHD							
	Non-TOU	AHVN, WHVN	✓ D	✓ D P	✓ D			✓ D	✓
Zone substation	TOU	AZST, WZSH AZSTS, WZSHS	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓
Sub-transmission	TOU	ASTT, WSTH ASTTS, WSTHS	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓

- The pass-through cost recovery is only as a capacity charge.
- The transmission cost recovery is not included as we have adopted a GXP Pricing Methodology since 1 April 2023 to recover transmission costs.

The zone substation and sub-transmission price categories are only TOU (no non-TOU option) and priced the same across the Auckland and Northern networks. This is consistent with the transition towards aligning the other commercial consumer groups' prices between the networks.

We maintain a relativity in the capacity price levels between the commercial price categories, as shown in Table 6 below, for example the high voltage capacity prices are 97% of transformer price levels which are, in turn, 93% of low voltage price levels. This approach approximates the different costs of serving these consumer groups according to where they connect to the network.

Table 6: Commercial capacity price relativities

Consumer group	Capacity ($/kVA/day)
Transformer to low voltage	93%
High voltage to transformer	97%
Zone substation to high voltage	90%
Sub-transmission to zone substation	80%

PY2026 PRICE SETTING

vector

PRICE CHANGES & PRICE SETTING COMPLIANCE

PRICE SETTING COMPLIANCE

Our prices comply with the price path set out in the DPP Determination[10]. To comply with the price path:

1. Our forecast revenue from prices must not exceed forecast allowable revenue (revenue cap).[11]
2. Revenue cap equals the regulated distribution revenue, regulatory adjustments, wash-up account, forecast pass-through (e.g. transmission costs, council rates and statutory levies).
3. Forecast revenue from prices equals prices times forecasted quantities, subtracting forecasted other regulated income (e.g. forecasted loss on disposal) and revenue from large connection contracts (where we have nil).
4. Target revenue[12] means prices times forecasted quantities without subtracting forecasted other regulated income and it is a term referred often in other sections (e.g. COSM allocation). This is different to DPP3 where target revenue and forecast revenue from prices are the same.
5. For further information how we comply with the price path, please refer our price setting compliance statement.

PRICE CHANGES

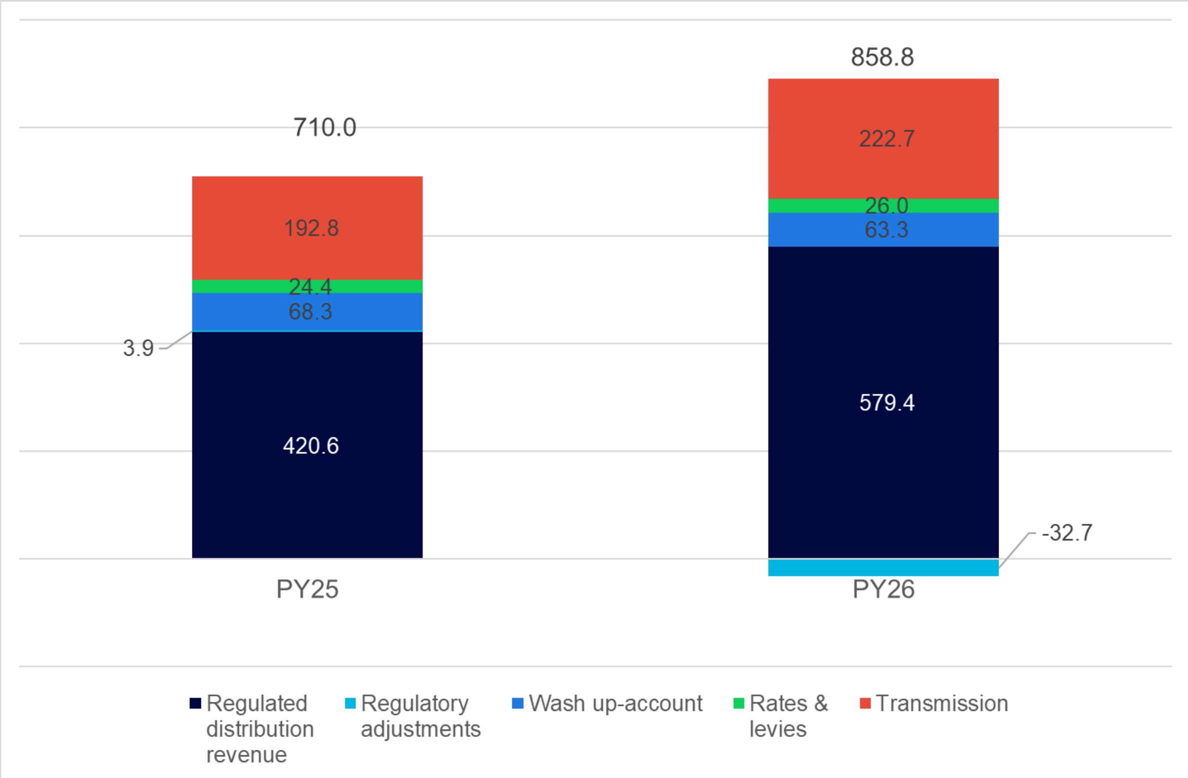
Prices are derived in reference to the revenue cap and forecasted quantities, explained above. Changes in the revenue cap and forecasted quantities will lead to price changes. The Commission sets our price path in a five-year cycle and 1 April 2025 marks the first year of DDP4. There is a significant change in the revenue cap between DPP3 and DPP4. This increase can be largely explained by the increase in interest rates between when DPP3 was set in 2019 and DPP4. Interest rates are key input for Commission to determine the revenue cap. To lessen the bill impacts between the DPPs, the Commission has limited the initial increase when setting the regulated distribution revenue for the first year, with a gradual increase throughout year 2 to year 5 of DPP4.

We are conscious of the effect of price changes for consumers. We therefore aligned the price increase (excluding transmission) to all consumer groups at the same weighted average rate to ensure price change to each group is as equal as possible. The increase in revenue cap from

[10] Available at https://comcom.govt.nz/regulated-industries/electricity-lines/projects/2025-reset-of-the-electricity-default-price-quality-path?target=documents&root=363275
[11] Available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/price-quality-path
[12] Target revenue means the revenue that the EDB expects to obtain from prices. This means our prices times forecasted quantities.

$710m to $859[13]m, together with the impact of change in forecasted quantities, has resulted in a PY26 weighted average price increase (excluding transmission) of 21% for mass market, unmetered and commercial groups. To quantify the change in the components of forecast allowable revenue (excluding transmission): regulated distribution revenue (+$159m), wash-up account and regulatory adjustments (-$32m), rates and levies (+$2m). Please refer to Figure 2

Figure 2 Forecast allowable revenue breakdown



Our transmission charges are bulk charged at GXP level to electricity retailers. This is a direct pass through of Transpower charges to Vector and the price change resulted is a direct reflection of how Transpower charges Vector (+$30m increase). Please refer to Transpower's explanation of their charges here.

Residential low user prices are required to comply the Low Fixed Charge (LFC) regulations. For residential low user consumers, Vector has increased the fixed price component from 60 cents to 75 cents to reflect the phase-out provisions in the LFC. LFC will be phased on 1 April 2027.

Non-standard consumers are priced as per their contracts which have largely fixed prices. The price change for non-standard contracts is usually inflation adjustments or calculated in accordance with terms in the contract.

Our electricity prices that apply from 1 April 2025, including the previous year's prices that were effective from 1 April 2024, are set out in Appendix 2.[14]

[13] $858.8m excludes the impact of forecasted gains and losses on disposed assets, which we are allowed to price in under DPP4 but we did not when determining the prices due to consideration of bill impacts.
[14] Our full price schedules are available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing

TRANSMISSION PASS-THROUGH PRICING

We moved to a GXP based transmission pricing approach[15] on 1 April 2023 in response to Transpower's new Transmission Pricing Methodology (TPM) that was effective on the same date. This approach determines the transmission pass-through cost prices by dividing the total amount of the Transpower monthly charges at each GXP for the upcoming pricing year by 100,000 to establish a price that would apply for each "1/1000th of a percentage share" of the charging unit. These prices are applied to each retailer or direct-bill end user's percentage share:

- Retailers and direct billed customers' GXP percentage shares are calculated using historic total energy usage (year to September 2024) based on the retailer ICP level submissions to Vector in the EIEP1 and EIEP3 format. The year to September 2024 was used so all months in the annual data include the three-month quantity wash-ups.
- ICPs are attributed to the retailer and GXP as at 31 December 2024 from EA registry-based data. The 31 December 2024 date was used so the ICP is attributed using the latest available information to minimise ICP switching impacts.
- Retailer and GXP volumes are the sum of the ICP volumes (year to September 2024) for their ICPs as at 31 December 2024.

Customer's annual transmission charges are calculated as follows:

$$\begin{aligned} &\mathit{Customer's\ annual\ transmission\ charges} \\ &\quad = \mathit{Customer's\ GXP\ percentage\ share} \times \mathit{GXP's\ price\ for\ transmission} \times 12 \times 100{,}000 \end{aligned}$$

Customers' GXP percentage shares are calculated as follows:

$$\mathit{Customers'GXP\ percentage\ share} = \frac{\mathit{Customers'energy\ usage}}{\mathit{GXP's\ total\ energy\ usage}}$$

GXP's price for transmission is calculated as follows:

$$\mathit{GXP's\ price\ for\ transmission} = \frac{(CC + BBC + RC + CRC + NIC)}{12 \times 100{,}000}$$

Where:

CC	is the total of connection charges for the relevant GXP
BBC	is the total of benefit-based charges for the relevant GXP
RC	is the residual charge for the relevant GXP
CRC	is the (allocated) cap recovery charge for the relevant GXP
NIC	is the total of new investment charges for the relevant GXP

We look to continuously evolve our pricing to meet changing consumer demands, regulatory requirements and feedback from the retailers and other stakeholders. Consistent with that continuous improvement, from 1 April 2025, we will introduce an annual wash-up mechanism into our transmission pricing that reflects the monthly ICP movements and volumes that occurred during the pricing year.

Annual transmission pass-through wash-up methodology (new)

[15] Please refer to the section of price structure changes in our 2024 pricing methodology for further explanation of these changes. Available at https://blob-static.vector.co.nz/blob/vector/media/vector-2023/electricity-pricing-methodology-2024.pdf

1. We will re-calculate the monthly amount by using actual volumes reported for each consumption month. The date of ICP attribution to retailers for wash-up calculations will be the final day of each consumption month. The wash-up calculations will be completed after we receive the month 3 wash-up files. For example, the April 25 wash-up calculation will be completed by Vector in August 2025.

2. We will compare the re-calculated monthly amount to the actual billed amount and the difference will be the wash-up amount. After the end of each full pricing year, we will issue a wash-up invoice or credit note for the accumulated 12 month wash-up amounts. This will occur by July following the end of the full pricing year.

Transpower adjustment events (new)

Under the clause 75 of schedule 12.4 of the Transmission pricing Methodology[16], Transpower can adjust relevant transmission charges from the date of an adjustment event. To mirror and recover Transpower's adjustment events, we included the forecasted adjustment event charges for the pricing year.

Our forecast is based on the best available information notified by Transpower at the time of pricing. We may adjust the transmission prices during the pricing year to reflect the adjustment events that are not included in the forecast amounts, providing any change meets the Commission's price path requirements and is permitted by Vector's default distribution agreement[17].

The GXP transmission prices are in Appendix 2.

[16] https://www.ea.govt.nz/documents/1812/New-TPM.pdf
[17] https://blob-static.vector.co.nz/blob/vector/media/vector-2024/vector-dda-v2-(website).pdf

PRICE STRUCTURE CHANGES

We have made the following price structure changes that will be applicable from 1 April 2025 as shown in Table 7 below.

Table 7: Price structure changes

Changes	Rationale	Effect/customer impact
Adjust the low residential user fixed daily line charge (from $0.60 to $0.75 per day)	To reflect the amended low user fixed charge regulations and to increase the proportion of revenue recovered through fixed charges.	Refer to page 17
Commercial DER categories are introduced for low voltage, transformer and high voltage ICPs	Approved ICPs can benefit by nominating a minimum guaranteed capacity and maximum site capacity that may be made available with integration to Vector's distributed energy resource management system (DERMS).	This will help reduce the approved low voltage, transformer and high voltage consumers' bills if passed on by the retailers.
Introduced an annual wash-up process for the transmission pass-through methodology	To better reflect retailer share of ICPs and volume at each GXP.	Refer to page 19

CONSULTATION, GOVERNANCE, & COMPLIANCE TIMEFRAME

Vector's price setting timeline, including governance, consultation, and notification, is outlined in the table below. Vector did not directly seek the views of consumers when setting prices or price structures as Vector largely bills retailers and not end users. Vector has no control on how or if its price changes are passed on to consumers. Rather, we consulted with Entrust, whose beneficiaries are mass market consumers on the Auckland network and retailers. Retailers have full discretion as to whether they pass our prices through to end users – some retailers do, some do not.

Table 8: Timeframe for Vector's electricity price setting

Activity	Date	Notes
Commission's draft decision on DPP4	May 2024	
Discussion and preparation	August 2024 to October 2024	Internal discussions on potential pricing innovations
Board presentation	Late October 2024	Price change discussed with Board
Draft prices determined for consultation	Late October 2024	Quantity forecasts derived
Commission's final decision on DPP4	Late November	
Entrust consultation	Early to mid-November 2024	Material provided to Entrust followed by presentation
Retailer consultation	Mid-November to early December 2024	Three-week consultation period, meetings with key retailers
Board presentation	Early December 2024	Price change impact discussed with Board
Auditor review	December 2024 to Jan 24	Findings prior to final price approval
Retailer consultation	Mid January 2025	One week targeted and supplementary consultation
Final price approval	Mid to late January 2025	Entrust and retailer feedback considered. Individual responses provided to retailers on their feedback.

Retailer and Entrust price notification	Late January 2025	Final notification for standard tariffs and price schedules
Non-standard prices and transmission charge notification	Late January 2025	Non-standard prices notified to consumers and transmission charges notified to retailers and direct billed consumers
Board approval of compliance and disclosure material	Late February 2025	Approval of the price setting compliance statement and pricing methodology for publication and provision to Commerce Commission
Public disclosure	Late February 2025	20 working days prior to price change
Price changes	1 April 2025	Price change implemented

TARGET REVENUE AND ITS CATEGORISATION

Our COSM is used to allocate target revenue to consumer groups using various cost drivers. The model structure is outlined in Figure 3.

Target revenue is the total revenue we expect to recover from our prices (complying with the regulated price path) and our forecasted quantities. The total target revenue for PY26 is $858.7m ($709.9m for PY25).

The total target revenue is broken down into the key components required to cover the costs and return on investment associated with the provision of electricity distribution services as shown below in Figure 5.

The key components are categorised by cost driver i.e. either 'asset', 'non-asset', 'transmission' or 'return'. These categorisations are summarised in Figure 4 and determine the way that the target revenue is allocated to consumer groups.

Figure 3: COSM structure

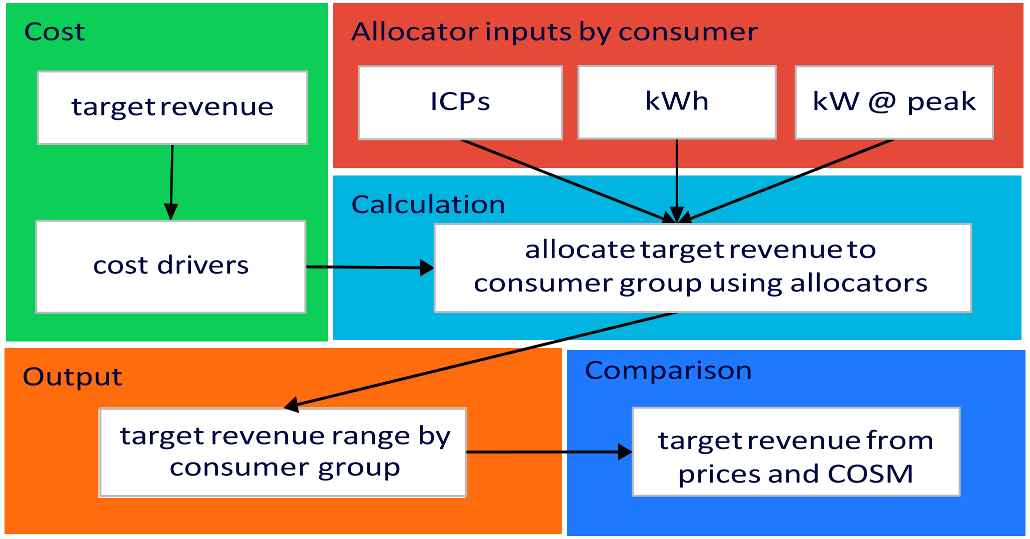


Figure 5: Target revenue by key components

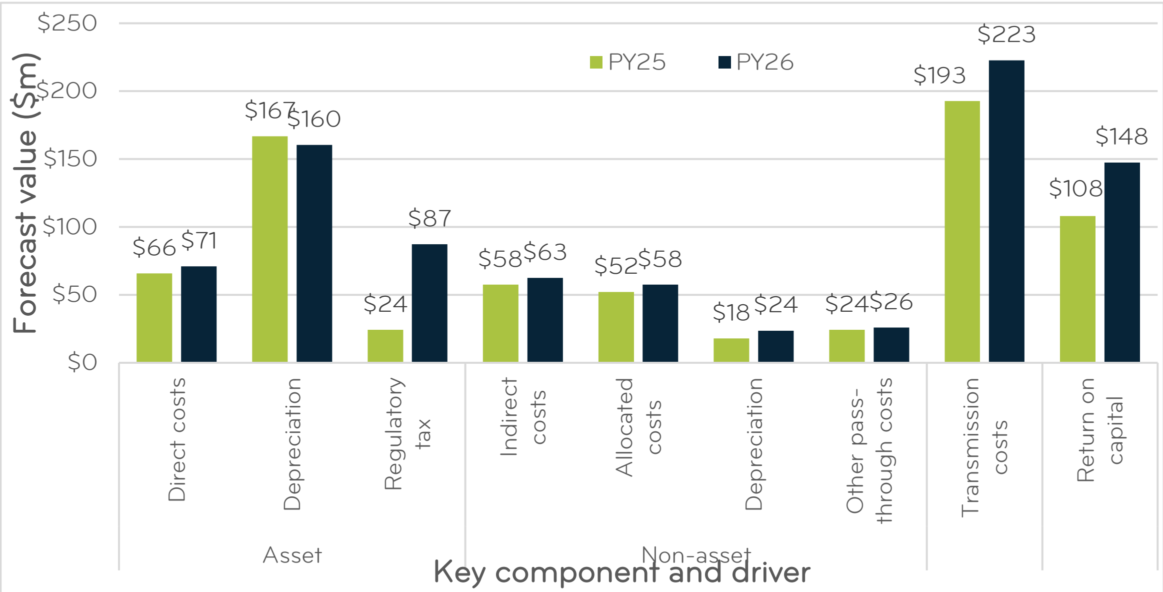
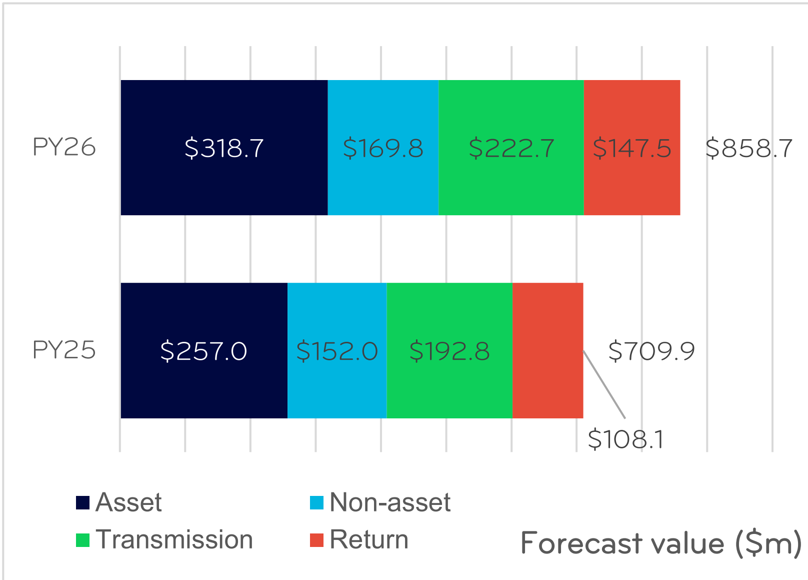


Figure 4: Target revenue by cost driver



COST DRIVERS

The key components categorised as 'asset costs' are those associated with expenditure and return on the electricity distribution network assets. We have grouped these network assets into five distinct categories as shown in Table 9 and Figure 7.

We assume that costs associated with assets are incurred in proportion to the value of the assets. For example, as Asset Category A3 assets make up 36% of the asset value in our Regulatory Asset Base (RAB), we assume that 36% of maintenance costs will be associated with Asset Category A3 assets.

Figure 7: Asset and customer location

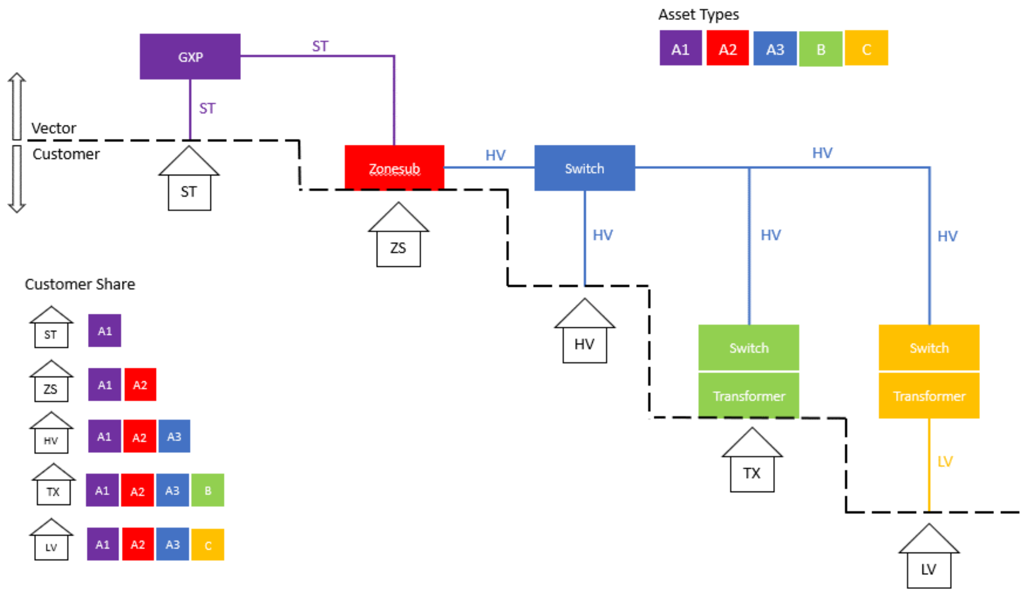


Table 9: Asset categorisation

Category	Assets	Consumer groups	Asset value [18] (RAB)	
A1	• Sub-transmission lines / cables	All	$646m	16%
A2	• Land and buildings • Zone-substations • Sub-transmission switch gear	All except ST	$736m	19%
A3	• HV lines / cables	All except ST and ZS	$1,435m	36%
B	• Distribution transformers and substations that have no Vector-owned low voltage lines / cables leaving them	Transformer	$75m	2%
C	• Distribution transformers and substations that: ○ have Vector-owned low voltage lines leaving the substation, or ○ supply multiple end-users connected at low voltage • Low voltage assets	Low voltage, unmetered, mass market	$983m	25%

[18] The values are weighted averages of the last five years' worth of data, with each year being weighted twice the previous year

COST DRIVER ALLOCATION APPROACHES

A key feature of an electricity distribution network is interconnected assets. Many consumers on the network share assets and it is difficult to identify precisely who benefits from which assets. While this means that the allocation of target revenue between consumer groups can be made in many ways, it also means that the cost of providing the network is shared widely and therefore the cost of network services is generally low for each consumer. The cost drivers of ‘asset’, ‘non-asset’, ‘transmission’ and ‘return’ are applied to the combined Northern and Auckland networks. Our COSM allocates the recovery of the $858.7m to consumer groups using the cost drivers as summarised in Table 10.

Table 10: Cost drivers used in COSM

<table>
<tr><th>Consumer group</th><th colspan="5">Asset</th><th>Non-asset</th><th>Transmission</th><th>Return</th></tr>
<tr><td></td><td>A1</td><td>A2</td><td>A3</td><td>B</td><td>C</td><td></td><td></td><td></td></tr>
<tr><td>Amount</td><td>$53.1m</td><td>$60.5m</td><td>$118.0m</td><td>$6.2m</td><td>$80.9m</td><td>$169.8m</td><td>$222.7m</td><td>$147.5m</td></tr>
<tr><td>Mass market</td><td rowspan="7">kW or kWh</td><td rowspan="6">kW or kWh</td><td rowspan="5">kW or kWh</td><td rowspan="3">n/a</td><td rowspan="3">kW or kWh</td><td rowspan="7">ICPs or kWh</td><td rowspan="7">n/a</td><td rowspan="7">Asset value</td></tr>
<tr><td>Unmetered</td></tr>
<tr><td>Low voltage</td></tr>
<tr><td>Transformer</td><td>Direct</td><td rowspan="4">n/a</td></tr>
<tr><td>High voltage</td><td rowspan="3">n/a</td></tr>
<tr><td>Zone substation</td><td rowspan="2">n/a</td></tr>
<tr><td>Sub-transmission</td><td>n/a</td></tr>
</table>

We aim to allocate asset-related costs on the basis of a consumer group’s usage (in percentage terms [19]) of the assets during peak periods, as this usage drives the need for, and the size of, the assets.

‘A1, A2, A3 and C asset related costs’ are allocated using a combination of contribution to peak usage (kW, network peak from 2021 onwards and Transpower’s Regional Coincident Peak Demand (RCPD) periods previously) and annual consumption. These cost allocators measure peak usage and the customer size.

‘B asset related costs’ do not require an allocation approach as they are used by one consumer group (transformer consumers).

‘Non-asset costs’ can be broadly summarised as overhead costs and pass-through costs (other than transmission costs). Costs categorised as ‘non-asset’ have no direct cost driver. We have chosen to use annual consumption and the number of consumers as the cost allocators.

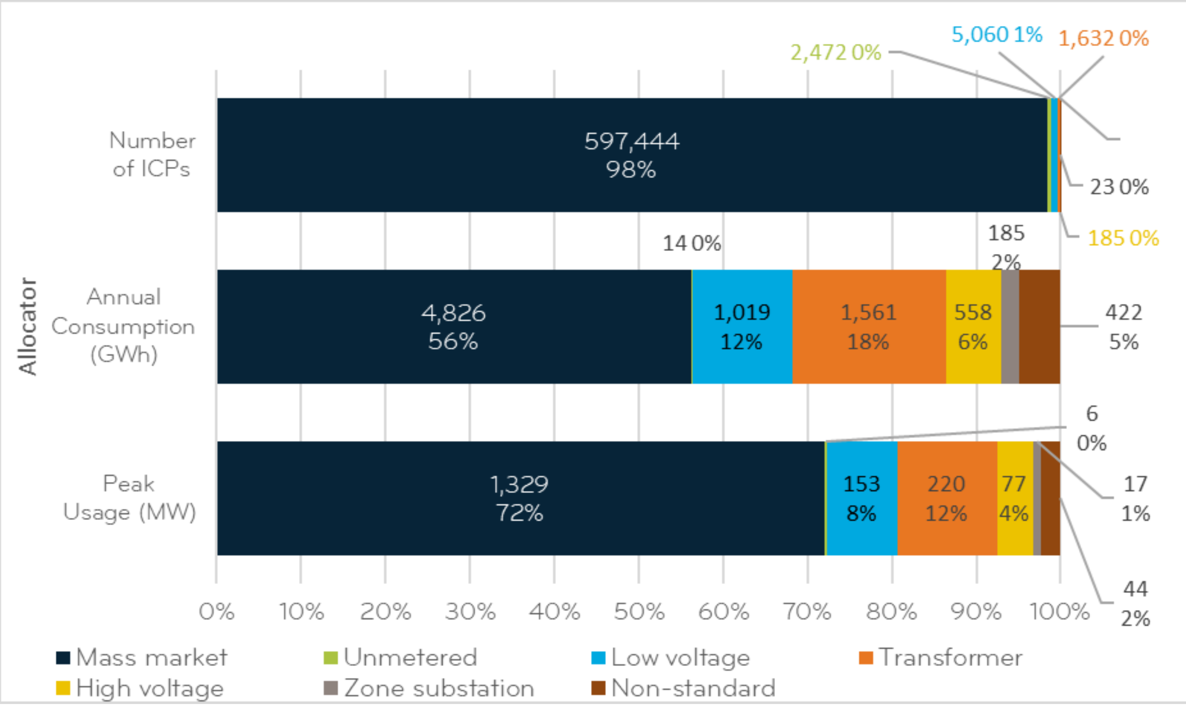
[19] Weighted average of last five year’s values from the billed quantities in Schedule 8 of our annual Electricity Information Disclosures (available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information), with each year being weighted twice the previous year

Costs categorised as ‘transmission’ are transmission charges from Transpower that we pass through to retailers. Transmission costs are part of Vector’s target revenue but are excluded from the COSM as they are pass-through in bulk to the retailers/direct billed customers rather than being allocated to consumer groups.

‘Return’ is the return on capital earned by Vector on its assets. A consumer groups’ asset values are calculated in the same way as ‘asset’ related costs are. ‘Return’ is apportioned across the consumer groups’ asset values.

The sub-transmission consumer group lacks historic allocators to determine its target revenue allocation and prices, so the COSM couldn’t be applied in the same manner as for other consumer groups. As a proxy for sub-transmission cost allocators, we estimated them based on the forecasted usage of sub-transmission consumer groups.

Figure 6 COSM allocation values and usage percentage



DISTRIBUTION TARGET REVENUE ALLOCATION & PRICE COMPARISON

The result of using the different allocators across the categories, creates a target revenue range by consumer group as the use of different allocators gives rise to different target revenue allocation results. The bands represent the lower and upper bounds of the different allocation approaches, as shown in Figure 9 which shows target revenue calculated from PY26 prices by consumer group compared with the COSM allocations. The result is that PY26 prices produce forecasts that are in or near an acceptable range when compared to target revenue allocations.

The pricing for non-standard consumers is calculated as per their contracts and is separate from the other consumer groups. The COSM is calibrated to produce the forecasted distribution target revenue of $6.8m (0.8%) to be recovered from the 15 non-standard consumers (21 ICPs).

Price setting is an iterative process, where the prices are only finalised once the price path compliance is managed, bill impacts are fair and tolerable, and prices deliver revenue from each consumer group consistent with their target revenue allocation.

The proportion of the aggregated price categories' target revenue is shown by price component in Figure 10. All price categories within the aggregation have similar proportioned price components. Please see Appendix 2 for the proportion of target revenue split by individual price category and price component.

Figure 9: PY26 distribution and other pass-through target revenue from prices compared with COSM allocations

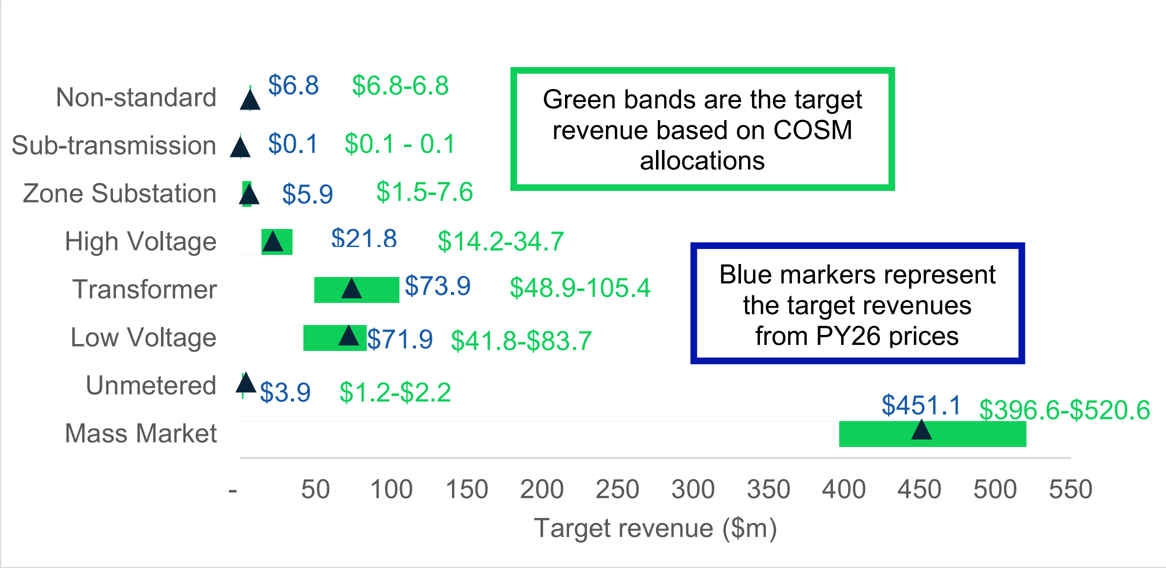
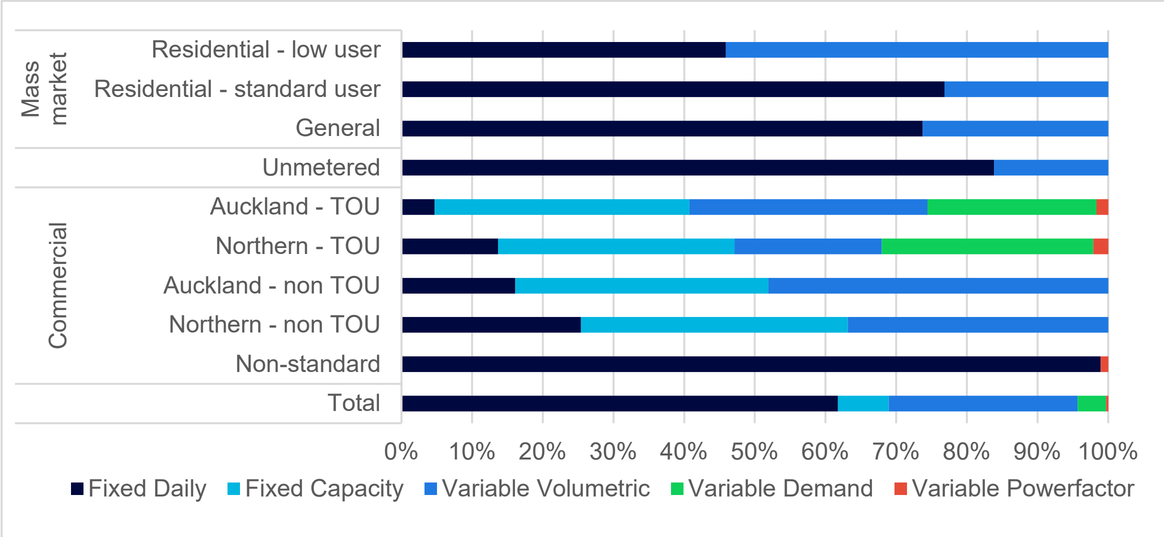


Figure 10: Proportion of PY26 target revenue by price component and category



POLICIES & OBLIGATIONS

NON-STANDARD CONTRACTS & DISTRIBUTED GENERATION POLICIES

Table 11: Criteria for non-standard contracts

Approach	Description
Criteria	For any new investments required by consumers, we apply our capital contributions policy. Our policy for determining capital contributions on our electricity distribution network is available at http://vector.co.nz/disclosures/electricity/capital-contributions. When a new investment is recovered through capital contributions, standard pricing applies unless otherwise agreed with Vector. Historical investments not recovered through capital contributions may be subject to non-standard contracts allowing for non-standard prices and tailored commercial arrangements to be applied to individual consumers.
Methodology	For determining prices for consumers subject to non-standard contracts, we use actual costs and/or allocated costs derived from an allocation model to determine prices. This allocation model is similar to the COSM used in determining standard pricing.

Approach to pricing distributed generation

Our policies and procedures for installation and connection of distributed generation are in accordance with the requirements of Part 6 (Connection of distributed generation) of the Electricity Industry Participation Code 2010 (the Code).

We charge each distributed generator prior to them connecting to the network based on the fees set out in Part 6 of the Code. We do not charge for connections smaller than 10 kW.

We do not make Avoided Cost of Distribution or Avoided Cost of Transmission (ACOT) payments to any distributed generators.[20]

To date given the small number of distributed generation consumers, we have not identified any short run incremental costs from the injection of

[20] Further information on our policies for distributed generation can be found at https://www.vector.co.nz/personal/electricity/distributed-generation. In previous years, Vector has made ACOT payments, but this has stopped from 1 April 2023 as per the EA's decision.

energy into the network, so this price continues to be $0.0000/kWh from 1 April 2025 for all distributed generators. As more distributed generation connects this may require more in-depth consideration and as a result pricing may change.

OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS

For PY26, our obligations and responsibilities to consumers in the event that the supply of electricity lines services to them is interrupted have no implications for determining prices. A summary of our obligations and responsibilities to consumers subject to non-standard contracts on our network (in the event that the supply of electricity lines services to the consumer is interrupted) is provided in Table 12. Our standard contract terms and non-contract terms are also compared.

Table 12: Summary of our obligations and responsibilities to consumers

<table>
<tr><th></th><th>Planned interruption notice</th><th>Unplanned interruption notice</th><th>Fault restoration</th><th>No. of interruptions per annum</th><th>No.of consumers</th></tr>
<tr><td rowspan="3">Standard</td><td rowspan="3">4 working days</td><td rowspan="3">Within 20 minutes to the retailer</td><td>CBD: 2 hours</td><td rowspan="2">CBD and Urban: 4</td><td rowspan="3">Approx 635,000</td></tr>
<tr><td>Urban: 2.5 hours</td></tr>
<tr><td>Rural: 4.5 hours</td><td>Rural: 10</td></tr>
<tr><td rowspan="9">Non-standard</td><td colspan="4">Same as standard consumers</td><td>1</td></tr>
<tr><td>1 April each year, or 10 working days</td><td>As soon as practicable</td><td>2 hours</td><td>1 unplanned</td><td>1</td></tr>
<tr><td>1 June each year</td><td>As soon as practicable</td><td>As soon as practicable</td><td>Not stated</td><td>2</td></tr>
<tr><td>1 November each year</td><td>As soon as practicable</td><td>Priority</td><td>Not stated</td><td>5</td></tr>
<tr><td>10 working days</td><td>As soon as practicable</td><td>3 hours</td><td>Not stated</td><td>4</td></tr>
<tr><td>10 working days</td><td>Not stated</td><td>3 hours</td><td>Not stated</td><td>2</td></tr>
<tr><td>10 working days</td><td>Not stated</td><td>Not stated</td><td>Not stated</td><td>1</td></tr>
<tr><td>4 working days</td><td>As soon as practicable</td><td>3 hours</td><td>Not stated</td><td>4</td></tr>
<tr><td>7 working days</td><td>As soon as practicable</td><td>Priority</td><td>3 planned</td><td>2</td></tr>
</table>

APPENDICES

APPENDIX 1 - GLOSSARY

Word	Definition
Distributed generator	A party with whom we have an agreement for the connection of plant or equipment to our electricity distribution network where the plant or equipment is capable of injecting electricity into our distribution network
EIEP1 & EIEP3	Under the Regulated electricity information exchange protocols (EIEP), EIEP1 provides detailed ICP billing and volume information and EIEP3 provides half hour metering information
Forecast allowable revenue	Refer to 3.1.1 (3) of the Electricity Distribution Services Input Methodologies (IM review 2023) Amendment Determination 2023[21] (Input Methodologies).
Forecast net allowable revenue	Refer to 3.1.1 (4) and (5) of the Input Methodologies.
Installation control point number (ICP)	An ICP is a physical point of connection on a local network which a distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer
kVA	kVA is kilovolt–ampere (amp), a measure of apparent power being the product of volts and amps. Used for the measurement of capacity and demand for pricing
kWh	kWh is kilowatt-hour, a unit of energy being the product of power in watts and time in hours. Used for the measurement of consumption for volumetric prices
kVAr	kVAr is kilovolt ampere reactive, is a unit used to measure reactive power in an AC electric power system. Used for the measurement of power factor in pricing
kVArh	kVArh is kilovolt ampere reactive hour, a unit of energy being the product of reactive power in kVAr and time in hours. Used for the measurement of power factor in pricing
Price categories	Price categories are the relevant price plan (or tariff) from the price schedule that define the line prices applicable to a particular ICP.
Price components	Price components are the various prices that constitute the components of the total prices paid, or payable, by a consumer
PY26	Pricing year (PY) is the 12-month period from 1 April to 31 March each year. PY26 is 1 April 2025 to 31 March 2026
Regional Coincident Peak Demand (RCPD)	RCPD is the sum of the offtake measured in kW (kilowatt, a measure of electrical power) in that Region during Regional Coincident Peak Demand Periods, as determined by Transpower each year. Where a Transmission Region is one of the four regional groups of connection locations (as defined in Transpower's Transmission Pricing Methodology), Upper North Island, Lower North Island, Upper South Island, and Lower South Island; and Regional Coincident Peak Demand Period means for the Upper North Island a half hour in which any of the 100 highest regional demands (measured in kW) occurs during 1 September to 30 August immediately prior to the start of the Pricing Year

[21] Available at https://comcom.govt.nz/__data/assets/pdf_file/0030/337683/Electricity-Distribution-Services-Input-Methodologies-IM-Review-2023-Amendment-Determination-2023.pdf

Regulatory Asset Base (RAB)	RAB broadly represents the amount we have invested in our regulated network, indexed by inflation and adjusted for depreciation
Regulatory adjustments	Regulatory adjustments include incremental rolling incentive scheme (IRIS) and quality incentive adjustment.

APPENDIX 2 - LINE CHARGE PRICES FROM 1 APRIL 2025

Distribution line charge prices for time of use residential and general ICPs from 1 April 2025 ***(previous price, if changing)***

Consumer groups and subgroups		Price category type	Price category description	Price category codes	Estimated no. of ICPs (year avg. from 1 April 2025)	Daily $/day -FIXD	Volume off-peak $/kWh -OFPK	Volume winter peak $/kWh -PEAK	injection $/kWh -INJT
Mass market	Residential -low user	Time of use	Controlled	ARHLC	138,810	0.7500 *(0.60)*	0.0444 *(0.0369)*	0.1575 *(0.1352)*	0.0000
				WRHLC	89,001		0.0454 *(0.0378)*	0.1585 *(0.1361)*	
			Approved DER	ARHLD	423		0.0381 *(0.0319)*	0.1512 *(0.1302)*	
				WRHLD	270				
			Uncontrolled	ARHLU	61,885		0.0454 *(0.0378)*	0.1585 *(0.1361)*	
				WRHLU	39,501				
	Residential -standard user	Time of use	Controlled	ARHSC	73,190	1.7253 *(1.41)*	0.0000	0.1131 *(0.0983)*	
				WRHSC	62,296	1.7453 *(1.43)*			
			Approved DER	ARHSD	240	1.5853 *(1.30)*			
				WRHSD	200				
			Uncontrolled	ARHSU	37,307	1.7453 *(1.43)*			
				WRHSU	31,055				
	General	Time of use	General	ABSH	30,217	2.1443 *(1.74)*			
				WBSH	19,601				
			Approved DER	ABSHD	-	1.9843		0.1131	
				WBSHD	-				

Distribution line charge prices for time of use commercial ICPs from 1 April 2025 ***(previous price, if changing)***

Consumer group	Price Category type	Price Category codes	Estimated no. of ICPs (year avg. from 1 April 2025)	Daily $/day -FIXD	Volume anytime $/kWh -24UC	Capacity $/kVA/day -CAPY	Demand $/kVA/day -DAMD	Excess demand $/kVA/day -DEXA	Power factor $/kVAr/day -PWRF	Volume injection $/kWh -INJT
Low voltage	Time of use	ALVT	1,596	4.76 *(3.93)*	0.0156 *(0.0129)*	0.0686 *(0.0568)*	0.1602 *(0.1321)*		0.3530 *(0.2917)*	0.0000
		WLVH	432	13.52 *(11.15)*	0.0089 *(0.0073)*				0.3530 *(0.2917)*	
	Time of use, approved solar	ALVTS	11	4.76 *(3.93)*	0.0156 *(0.0129)*				0.0000	
		WLVHS	8	13.52 *(11.15)*	0.0089 *(0.0073)*				0.0000	
	Time of use, approved DER	ALVTD	4	4.76	0.0156	0.0686	0.1602	0.0000	0.3530	
		WLVHD	1	13.52	0.0089	0.0686	0.1602	0.0000	0.3530	
Transformer	Time of use	ATXT	1,038	4.76 *(3.93)*	0.0156 *(0.0129)*	0.0639 *(0.0545)*	0.1602 *(0.1321)*		0.3530 *(0.2917)*	
		WTXH	417	13.52 *(11.15)*	0.0089 *(0.0073)*	0.0639 *(0.0545)*	0.1602 *(0.1321)*		0.3530 *(0.2917)*	
	Time of use, approved solar	ATXTS	10	4.76 *(3.93)*	0.0156 *(0.0129)*	0.0639 *(0.0545)*	0.1602 *(0.1321)*		0.0000	
		WTXHS	4	13.52 *(11.15)*	0.0089 *(0.0073)*	0.0639 *(0.0545)*	0.1602 *(0.1321)*		0.0000	
	Time of use, approved DER	ATXTD	4	4.76	0.0156	0.0639	0.1602	0.0000	0.3530	
		WTXHD	2	13.52	0.0089	0.0639	0.1602	0.0000	0.3530	

Distribution line charge prices for time of use commercial ICPs from 1 April 2025 *(previous price, if changing)* (con't)

Consumer group	Price Category description	Price Category code	Estimated no. of ICPs (year avg. from 1 April 2025)	Daily $/day -FIXD	Volume anytime $/kWh -24UC	Capacity $/kVA/day	Demand $/kVA/day -DAMD	Excess demand $/kVA/day -DEXA	Power factor $/kVAr/day -PWRF	Volume injection $/kWh -INJT
High voltage	Time of use	AHVT	153	4.76 *(3.93)*	0.0156 *(0.0129)*	0.0621 *(0.0523)*	0.1602 *(0.1321)*	0.8640 *(0.8000)*	0.3530 *(0.2917)*	0.0000
		WHVH	30	13.52 *(11.15)*	0.0089 *(0.0073)*	0.0621 *(0.0523)*	0.1602 *(0.1321)*	0.8640 *(0.8000)*	0.3530 *(0.2917)*	
	Time of use, approved solar	AHVTS	1	4.76 *(3.93)*	0.0156 *(0.0129)*	0.0621 *(0.0523)*	0.1602 *(0.1321)*	0.8640 *(0.8000)*	0.0000	
		WHVHS	-	13.52 *(11.15)*	0.0089 *(0.0073)*	0.0621 *(0.0523)*	0.1602 *(0.1321)*	0.8640 *(0.8000)*	0.0000	
	Time of use, approved DER	AHVTD	3	4.76	0.0156	0.0621	0.1602	0.0000	0.3530	
		WHVHD	2	13.52	0.0089	0.0621	0.1602	0.0000	0.3530	
Zone substation	Time of use	AZST, WZSH	8	4.76 *(3.93)*	0.0070 *(0.0059)*	0.1560 *(0.1279)*	0.0295 *(0.0243)*	0.8640 *(0.8000)*	0.3530 *(0.2917)*	
	Time of use, approved solar	AZSTS, WZSHS	-	4.76 *(3.93)*	0.0070 *(0.0059)*	0.1560 *(0.1279)*	0.0295 *(0.0243)*	0.8640 *(0.8000)*	0.0000	
Sub-transmission	Time of use	ASTT, WSTH	1	4.76 *(3.93)*	0.0070 *(0.0059)*	0.1240 *(0.1023)*	0.0295 *(0.0243)*	0.8640 *(0.8000)*	0.3530 *(0.2917)*	
	Time of use, approved solar	ASTTS, WSTHS	-	4.76 *(3.93)*	0.0070 *(0.0059)*	0.1240 *(0.1023)*	0.0295 *(0.0243)*	0.8640 *(0.8000)*	0.0000	

Distribution line charge prices for non - time of use residential and general ICPs from 1 April 2025 ***(previous price, if changing)***

Consumer groups and subgroups		Price category type	Price category description	Price category code(s)	Estimated no. of ICPs (year avg. from 1 April 2025)	Daily $/day -FIXD	$/day /fitting -FIXD	Volume anytime $/kWh -24UC or -AICO	injection $/kWh -INJT
Mass market	Residential – low user	Anytime (exemption)	Controlled	ARNLC	6,858	0.7500 *(0.60)*		0.0632 *(0.0531)*	0.0000
				WRNLC	4,251	0.7500 *(0.60)*		0.0642 *(0.0540)*	
			Uncontrolled	ARNLU, WRNLU	5,444	0.7500 *(0.60)*		0.0642 *(0.0540)*	
	Residential – standard user	Anytime (exemption)	Controlled	ARNSC	5,209	1.7253 *(1.41)*		0.0188 *(0.0162)*	
				WRNSC	3,656	1.7453 *(1.43)*		0.0188 *(0.0162)*	
			Uncontrolled	ARNSU, WRNSU	6,578	1.7453 *(1.43)*		0.0188 *(0.0162)*	
	General	Anytime (exemption)	General	ABSN, WBSN	9,606	2.1443 *(1.74)*		0.0188 *(0.0162)*	
Unmetered	General	Unmetered	Unmetered	ABSU, WBSU	2,504		0.0754 *(0.0617)*	0.0273 *(0.0237)*	

Distribution line charge prices for non-time of use commercial ICPs from 1 April 2025 *(previous price, if changing)*

Consumer group	Price category type	Price category code	Estimated no. of ICPs (year avg. from 1 April 2025)	Daily $/day -FIXD	Volume anytime $/kWh -24UC	Capacity $/kVA/day -CAPY	Power factor $/kVAr/day -PWRF	Volume injection $/kWh -INJT
Low voltage	Non-time of use	ALVN	2,353	4.76 *(3.93)*	0.0514 *(0.0424)*	0.0686 *(0.0568)*		0.0000
		WLVN	853	7.18 *(5.92)*	0.0303 *(0.0250)*	0.0686 *(0.0568)*		
Transformer	Non-time of use	ATXN	159	4.76 *(3.93)*	0.0514 *(0.0424)*	0.0639 *(0.0545)*		
		WTXN	82	7.18 *(5.92)*	0.0303 *(0.0250)*	0.0639 *(0.0545)*		
High voltage	Non-time of use	AHVN	6	4.76 *(3.93)*	0.0514 *(0.0424)*	0.0621 *(0.0523)*		
		WHVN	-	7.18 *(5.92)*	0.0303 *(0.0250)*	0.0621 *(0.0523)*		

GXP based line charges

Transmission line charges from 1 April 2025 *(previous price if changing)*

GXP	Connection location	Network	Vectors' annual transmission charges ($000)		$ per month for a 1/1000 of a percent share		Annual GXP volume ending Sep 2024 (MWh)		Implied volumetric rate $/kWh	
ALB	Albany	Northern	23,516	*(20,407)*	19.5965	*(17.0062)*	971,861	*(977,662)*	0.0242	*(0.0209)*
HEN	Henderson	Northern	11,982	*(10,069)*	9.9849	*(8.3912)*	548,587	*(530,467)*	0.0218	*(0.0190)*
HEP	Hepburn Road	Auckland / Northern	16,263	*(14,028)*	13.5523	*(11.6897)*	590,972	*(587,204)*	0.0275	*(0.0239)*
HOB	Hobson St	Auckland	10,118	*(8,227)*	8.4321	*(6.8558)*	268,628	*(289,212)*	0.0377	*(0.0284)*
LFD	Lichfield	Northern	1,136	*(981)*	0.9465	*(0.8179)*	65,157	*(75,544)*	0.0174	*(0.0130)*
MNG	Mangere	Auckland	15,526	*(13,373)*	12.9382	*(11.1439)*	653,947	*(668,120)*	0.0237	*(0.0200)*
ROS	Mt Roskill	Auckland	17,390	*(15,056)*	14.4917	*(12.5467)*	681,364	*(674,535)*	0.0255	*(0.0223)*
OTA	Otahuhu	Auckland	7,433	*(6,479)*	6.1944	*(5.3994)*	325,815	*(325,570)*	0.0228	*(0.0199)*
PAK	Pakuranga	Auckland	16,289	*(14,221)*	13.5745	*(11.8509)*	604,347	*(609,528)*	0.0270	*(0.0233)*
PEN	Penrose	Auckland	52,078	*(46,052)*	43.3979	*(38.3768)*	2,038,483	*(2,058,640)*	0.0255	*(0.0224)*
SVL	Silverdale	Northern	10,690	*(8,972)*	8.9081	*(7.4768)*	396,075	*(379,899)*	0.0270	*(0.0236)*
TAK	Takanini	Auckland	12,910	*(11,056)*	10.7585	*(9.2136)*	568,071	*(566,246)*	0.0227	*(0.0195)*
WRD	Wairau Road	Northern	9,729	*(8,235)*	8.1077	*(6.8627)*	314,322	*(318,881)*	0.0310	*(0.0258)*
WEL	Wellsford	Northern	4,302	*(3,688)*	3.5847	*(3.0732)*	172,045	*(167,239)*	0.0250	*(0.0221)*
WIR	Wiri	Auckland	13,772	*(11,908)*	11.4765	*(9.9230)*	468,847	*(459,955)*	0.0294	*(0.0259)*
Total			223,134	*(192,752)*			8,668,521	*(8,688,702)*		

The transmission charges are passed through in bulk to the retailers and direct billed ICPs as a fixed monthly amount based on their share of the historic GXP volumes (year to September 2024) in the table above. From 1 April 2025, we will also compare the historic volume share to the actual volume share (due to changes in ICPs and/or volumes through ICPs) and notify a final wash-up amount after the pricing year has finished.

Retailers determine how these transmission line charges are passed on to the consumer and retailers will be able to identify which GXP the consumer's ICP is connected to. Note that the use of volume to allocate transmission costs, leads to an implicit $ per historic kWh at each GXP.

APPENDIX 3 – TARGET REVENUE RECOVERY

Table 13: Proportion of mass market target revenue by price component

Consumer group	Customer type	Price Category type	Price Category description	Price Category Code	Fixed	Variable	Price Category Code	Fixed	Variable
				Auckland	**Daily**	**Volumetric**	**Northern**	**Daily**	**Volumetric**
Mass Market	Residential -low user	Time of use	Controlled	ARHLC	4.43%	5.35%	WRHLC	2.87%	3.44%
			DER	ARHLD	0.01%	0.01%	WRHLD	0.01%	0.01%
			Uncontrolled	ARHLU	1.97%	2.07%	WRHLU	1.26%	1.50%
		Anytime (exemption)	Controlled	ARNLC	0.22%	0.27%	WRNLC	0.14%	0.18%
			Uncontrolled	ARNLU	0.11%	0.11%	WRNLU	0.06%	0.07%
	Residential -standard	Time of use	Controlled	ARHSC	5.37%	1.79%	WRHSC	4.62%	1.38%
			DER	ARHSD	0.02%	0.01%	WRHSD	0.01%	-
			Uncontrolled	ARHSU	2.77%	0.81%	WRHSU	2.30%	0.64%
		Anytime (exemption)	Controlled	ARNSC	0.38%	0.10%	WRNSC	0.27%	0.08%
			Uncontrolled	ARNSU	0.29%	0.05%	WRNSU	0.19%	0.04%
	General	Time of use	General	ABSH	2.75%	1.01%	WBSH	1.79%	0.57%
			General	ABSHD	-	-	WBSHD	-	-
		Anytime (exemption)	General	ABSN	0.61%	0.25%	WBSN	0.27%	0.10%
Unmetered		Unmetered	Unmetered	ABSU	0.24%	0.05%	WBSU	0.15%	0.03%

Table 14: Proportion of commercial target revenue by price component

Consumer group	Short description	Category	Fixed		Variable			Category	Fixed		Variable		
		Auckland	**Daily**	**Capacity**	**Volumetric**	**Demand**	**Power Factor**	**Northern**	**Daily**	**Capacity**	**Volumetric**	**Demand**	**Power Factor**
Low voltage	Time of use	ALVT	0.32%	1.26%	1.02%	0.77%	0.08%	WLVH	0.25%	0.31%	0.17%	0.24%	0.03%
		ALVTS	-	0.01%	-	-	-	WLVHS	-	0.01%	-	-	-
		ALVTD	-	-	-	0.01%	-	WLVHD	-	-	-	-	-
	Non-time of use	ALVN	0.48%	1.03%	1.38%	-	-	WLVN	0.26%	0.37%	0.36%	-	-
Transformer	Time of use	ATXT	0.21%	2.09%	2.14%	1.53%	0.08%	WTXH	0.24%	0.78%	0.44%	0.60%	0.04%
		ATXTS	-	0.02%	0.01%	0.01%	-	WTXHS	-	0.01%	-	0.01%	-
		ATXTD	-	-	-	0.01%	-	WTXHD	-	-	-	-	-
	Non-time of use	ATXN	0.03%	0.10%	0.13%	-	-	WTXN	0.02%	0.05%	0.06%	-	-
High voltage	Time of use	AHVT	-	-	-	-	0.02%	WHVH	0.02%	0.13%	0.16%	0.20%	0.01%
		AHVTS	-	0.01%	-	-	-	WHVHS	-	-	-	-	-
		AHVTD	0.03%	0.52%	0.79%	0.55%	-	WHVHD	-	0.02%	-	0.07%	-
	Non-time of use	AHVN	-	-	-	-	-	WHVN	-	-	-	-	-
Zone substation	Time of use	AZST	-	0.47%	0.16%	0.04%	0.02%	WZSH	-	-	-	-	-
		AZSTS	-	-	-	-	-	WZSHS	-	-	-	-	-
Sub-transmission	Time of use	ASTT	-	-	-	-	-	WSTH	-	0.01%	-	-	-
		ASTTS	-	-	-	-	-	WSTHS	-	-	-	-	-

APPENDIX 4 – CONSISTENCY WITH PRICING PRINCIPLES

The EA's Pricing Principles[22] (Pricing Principles) provide guidance to developing pricing methodologies for electricity distribution services. Table 15 demonstrates the extent to which the Pricing Methodology is consistent with the Pricing Principles.

Table 15 Pricing principles

<u>Principle (a): Economic costs of service provision</u> *Prices are to signal the economic costs of service provision, including by:* *i. being subsidy free (equal to or greater than avoidable costs and less than or equal to standalone costs);* *ii. reflecting the impacts of network use on economic costs;* *iii. reflecting differences in network service provided to (or by) consumers; and,* *iv. encouraging efficient network alternatives.*
<u>Being subsidy free</u> The avoidable cost test can be applied for both individual ICPs and for groups of ICPs (consumer groups). The avoidable cost for an individual ICP is the cost of connecting that ICP to the network and therefore excludes the cost of shared assets. The avoidable cost for a group of ICPs is the cost of connecting that group of ICPs to the network, and includes the cost of assets shared by that group. Applying the avoidable cost test at a group level is more stringent because it includes shared costs for the group. Revenues for the group must be higher than just the sum of the avoidable cost for each individual ICP. Our capital contributions policy ensures that individual ICPs generally pay the costs of connecting to the network plus a contribution to the shared capital expenditure necessary for the long-term growth of the network. The standalone cost can be considered as the supply costs from lowest cost alternative energy source. While we monitor the cost of a range of alternative options for ICPs, it can be difficult to apply these on an ICP specific basis. In some instances, the economic value of the service, including where that is set by the cost of an alternative form of supply, may be notified to us by the consumer or their retailer. In these situations, this pricing principle is delivered through the operation of pricing principle (c), detailed below.

[22] Available at https://www.ea.govt.nz/industry/distribution/distribution-pricing/

Reflecting the impacts of network use on economic costs

The electricity distribution system consists of assets with significant capacity. When building the system, economies of scale exist such that the cost of installing an asset larger than that which is immediately required does not add significantly to the cost of network build. As a consequence, some parts of the distribution system have unused capacity. In most cases, due to the availability of unused capacity, the short run cost of the next unit of capacity is significantly less than the average cost.

Some areas of our network have high utilisation and the system requires expansion (for example, to connect a new user to the distribution system). We generally fund this expansion through capital contributions and/or non-standard prices which ensure recovery of the incremental capital investment. Our approach to recovering these costs is outlined in our electricity distribution capital contribution policy. These prices encourage efficient network alternatives to be investigated by the new user.

Our target revenue allocation, described in this document, illustrates how we utilise relevant cost drivers to reflect costs and usage of the network. We translate these into prices taking account of the materiality of the costs, our ability to estimate and signal the costs as well as the ability of participants to respond. We also consider important consumer aspects such as predictability, bill stability and equity.

Broadly we signal the economic cost of network use over different time periods using time of use prices and controlled load prices. Prices for commercial ICPs are structured in a very service reflective manner, utilising a variety of prices (daily, capacity, demand, volumetric, power factor). Our mass market prices are two part time of use, reflecting that peak usage is a general driver of investment over time. We have adopted a Grid Exit Point allocation method for recovering the transmission costs (as explained on 19) and charge this in bulk to retailers. This closely reflects the impacts of transmission costs of the network, charged to us by Transpower under the new TPM.

Reflecting differences in network service provided to (or by) consumers

Beyond our traditional core distribution services, we offer different network services with prices that reflect quality trade-offs and asset usage requirements. Our TOU pricing provides consumers options, if passed on by the retailers, on when they use the networks.

Encouraging efficient network alternatives

We offer a distributed energy resources tariffs to residential and commercial end users in return for the ability to remotely manage their load (e.g. hot water and electric vehicle charges). This pricing approach signals the benefits to consumers / retailers of allowing us or third parties to control some of their load and manage network congestion during peak periods through lower price options. These pricing options provide incentives to end consumers, (but only to the extent that retailers reflect those incentives to consumers) to shift demand away from peak periods, encouraging investments in non-traditional network alternatives, and therefore reduce the need for future investment costs in traditional network assets.

Not only do TOU prices provide incentives for demand management to shift load from peak to off-peak times, they also encourage efficient network alternatives such as distributed generation and battery storage usage at peak times.

Principle (b): Recovery of any shortfall

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

Pricing based on avoidable costs would almost certainly under-recover allowed revenues as the majority of our costs are fixed, so do not vary with the next unit of consumption. Our fixed costs are generally also sunk, so do not reduce if consumption reduces. Accordingly, the Pricing Methodology attempts to recover allowed target revenues in a manner that is as least distortionary as possible.

Principle (c): Responsive to requirements of consumers

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

i. reflect the economic value of services;

ii. enable price/quality trade-offs.

Reflect the economic value of services

We offer non-standard pricing in certain circumstances including where standard pricing would cause uneconomic bypass of the network.

Non-standard contractual arrangements are also able to address changes to the structure or level of prices (e.g. for atypical load patterns, or to address particular by-pass or fuel substitute situations), and differing service levels (e.g. a higher level of redundancy, or priority response if an outage occurs). The Pricing Methodology sets out how we take account of these issues when considering the design of a non-standard contract.

Where the connection of new load requires investment in the network (e.g. new subdivisions) then the cost of that investment is recovered via capital contributions and/or non-standard prices. Those prices provide the economic incentive for distribution alternatives to be investigated by the proponent of the development. For example, a new subdivision that adopts new technologies to reduce load will not require the same level of network investment.

Enable price/quality trade-offs

We offer price/quality trades-offs and price in the certainty of supply, demand and connection capacity. Through our controlled/DER/uncontrolled pricing, we reward consumers if passed on by the retailers, the benefit if they are willing to accept the potential interruption of hot water supply or management of smart load in the future. Through our TOU prices, we reward consumers, if passed on by the retailers, a benefit if they are willing to shift their usage pattern.

Principle (d): Pricing process

Development of prices should be transparent and have regards to transaction costs, consumer impacts, and uptake incentives.

We believe that a simple pricing structure enhances transparency. Costs are clearly identified and allocated to consumer groups on a simple and transparent basis.

A simple pricing structure reduces the likelihood that changes in consumer / retailer behaviour will result in significant changes to cost allocations between consumer groups. A simple pricing structure also makes it easier for consumers /retailers to understand and estimate their likely costs. We adhere to this while designing our price structures, however, please note that we bill our line charges to the electricity retailers and they bill the end consumers. They may or may not pass on our price structures.

We are particularly conscious of the effect of our pricing on consumers and seek to implement a pricing framework that provides appropriate incentives (if passed on by the electricity retailers) for consumers to continue to use our distribution services. Our decision to move and make mandatory mass market two-part time of use, followed extensive modelling of consumer effects for a range of potential pricing structures that considered the consumer impacts and incentives. We have consulted with stakeholders, including retailers and Entrust, and obtained consumer insights through application of detailed data analytics in the development of our prices and will continue to consult as appropriate going forward. The information we receive from stakeholders and customers helps us to understand consumer drivers and preferences. We have undertaken a range of trials and will continue to do so, in order to for us to anticipate and respond to consumer's requirements as technology and the move to net zero changes the future of energy. As previously mentioned, we update and publish our pricing roadmap on a regular basis.

We offer retailers and Entrust the opportunity to comment on our proposed price structures each year. This provides an opportunity for these stakeholders to identify any proposals that may increase transaction costs, and provides us the opportunity to address any concerns they may have. We also involve retailers when considering how our prices evolve and include them in any trials we undertake.

We offer the same network pricing to all ICPs irrespective of which retailer they use.

We expect to continue to evolve our pricing as consumer’s respond to the range of choices they have through technological innovation and increasing electrification, and regulatory reforms such as the Low User Regulations phase out.

APPENDIX 5 – COMPLIANCE REFERENCE

Table 16 Disclosure requirements from the ID determination

Determination clause	Requirement	Section of this document
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, 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, 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.	Price setting compliance Price changes Target revenue and its categorisation Transmission pass-through pricing Consultation, governance & compliance timeframe Non-standard contracts & distributed generation policies
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	(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.	Consumer groups Appendix 4 – consistency with pricing principles Target revenue and its categorisation Price setting compliance Price changes Distribution target revenue allocation & price comparison
2.4.4	Every disclosure under clause 2.4.1 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.	N/A
2.4.5	Every disclosure under clause 2.4.1 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;	Non-standard contracts & distributed generation policies Distribution target revenue allocation & price

	(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.	comparison
2.9.1	Where an EDB is required to publicly disclose any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	Appendix 6 – director's certification
Disclosure of prices **2.4.18**	Every EDB must at all times publicly disclose— (1) Each current price expressed in a manner that enables consumers to determine- (a) the consumer group or consumer groups applicable to them; (b) the total price for electricity lines services applicable to them; (c) the prices represented by each price component applicable to them; and (d) the amount of each current price that is attributable to transmission charges; (2) The number (or estimated number) of consumers which must pay each price; (3) The date at which each price was or will be first introduced; and (4) The price that was payable immediately before each current price (if any) expressed in the manner referred to in subclause (1).	Appendix 2 - line charge prices from 1 April 2025
2.4.19	Every EDB must, at least 20 working days before changing or withdrawing a price or introducing a new price that is payable by 5 or more consumers- (1) Publicly disclose- (a) the information specified in clause 2.4.18 in respect of that price; and (b) an explanation of the reasons for the new price or the changed or withdrawn price; (2) In addition, either-	

	(a) give written notice to each consumer by whom that price is, or in the case of a withdrawn price would have been, payable, including the information specified in clause 2.4.18 in respect of that price; or (b) notify consumers in the news section of either- (i) 2 separate editions of each newspaper; or (ii) news media accessible using the internet that is widely read by consumers connected to EDB's network; (c) notification under subclause (2)(b) must provide details of the price, including- (i) the changed price alongside the immediately preceding price applicable; and (ii) contact details where further details of the new or changed price can be found including the URL of the EDB's publicly accessible website.	
2.4.20	Every EDB must, in respect of- (1) All new prices payable; or (2) In the case of withdrawn prices, the prices which would have been payable; by 4 or fewer consumers, at least 20 working days before introducing a new price, give written notice to each consumer by whom that price is payable, the information specified in clause 2.4.18 in respect of that price.	

APPENDIX 6 – DIRECTORS' CERTIFICATION

Schedule 17: Certification for Pricing Methodology Disclosure

Clause 2.9.1

We, Doug McKay and Bruce Turner, being directors of Vector Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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

Director

Director

25 February 2025

Date