ELECTRICITY DISTRIBUTION SERVICES 2024 PRICING METHODOLOGY

From 1 April 2023

Pursuant to: The Electricity Distribution Information Disclosure Determination 2012 (Consolidated 9 December 2021)

vector

Contents

INTRODUCTION & CONTEXT 3
INTRODUCTION 4
PRICING APPROACH CONTEXT 5
DERIVING OUR PRICES 6
CONSUMER GROUPS 7
PRICE CATEGORIES 8
MASS MARKET AND UNMETERED PRICE CATEGORIES 10
PY2024 PRICE SETTING 14
PRICE SETTING COMPLIANCE 15
PRICE STRUCTURE CHANGES 16
TRANSMISSION PASS-THROUGH PRICING 16
OTHER PRICE STRUCTURE CHANGES 19
PRICE CHANGES 21
CONSULTATION, GOVERNANCE, & COMPLIANCE TIMEFRAME 22
TARGET REVENUE AND ITS CATEGORISATION 23
COST DRIVERS 24
COST DRIVER ALLOCATION APPROACHES 25
DISTRIBUTION TARGET REVENUE ALLOCATION & PRICE COMPARISON 27
POLICIES & OBLIGATIONS 28
NON-STANDARD CONTRACTS & DISTRIBUTED GENERATION POLICIES 29
OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS 30
APPENDICES 31
APPENDIX 1 – GLOSSARY 32
APPENDIX 2 – LINE CHARGE PRICES FROM 1 APRIL 2023 34
APPENDIX 3 – TARGET REVENUE RECOVERY 39
APPENDIX 4 – CONSISTENCY WITH PRICING PRINCIPLES 41
APPENDIX 5 – DIRECTORS' CERTIFICATION 45

INTRODUCTION & CONTEXT

INTRODUCTION

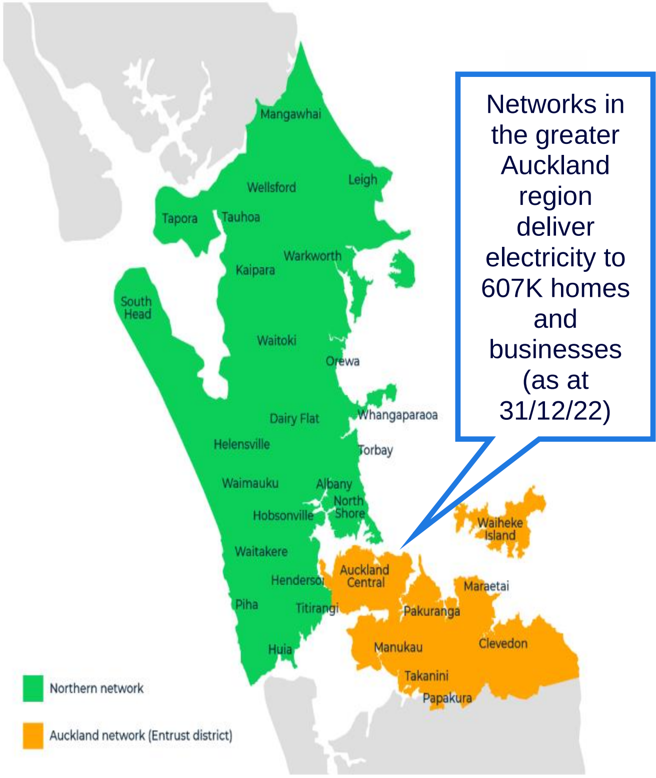
Vector Limited ("Vector", "our", "we", or "us") recovers the cost of owning and operating our electricity distribution networks (Network) through a combination of standard (published), non-standard prices for electricity distribution services, and capital contributions for new connections and upgrades.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

This document explains how our Pricing Methodology meets the requirements of the Information Disclosure Determination 2012 (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.

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 pricing guidance issued by the Electricity Authority. The roadmap is updated at least annually in April.

Figure 1: Our electricity distribution



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.

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[1] Electricity Distribution Information Disclosure Determination 2012 (consolidated December 2021), available at https://comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors/current-information-disclosure-requirements-for-electricity-distributors

[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 "customer-led pricing design"

[4] Available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/capital-contributions

Key Pricing Considerations:

Prices are set to earn the level of revenue we are permitted to under the Default Price Path (DPP Determination)[5], less any intentional under-pricing.

When setting prices, we take into account (amongst other things) - historical price structures, minimising rate shock, minimising recovery risk, pricing principles[6] 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.

Forecast revenue increases must not exceed 10% in any one year. Pricing under the allowed revenue is permitted and can be recovered in future periods (adjusted for time value).

Given network costs are largely fixed we typically apply any price increases to fixed components and price decreases to variable components. This means not all consumers will see the weighted average price change when prices change, some will see more and some less - this assumes that 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 this new environment as an opportunity to design and redesign our pricing in response to an evolving market. In the current year most of the structural price changes have been made in response to the new Transmission Pricing Methodology issued by Transpower which is effective 1 April 2023. We have also made some steps in designing prices to better reflect our changing market. More on our journey to evolve our prices can be found in our pricing roadmap[7].

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[5] Default Price-Quality Path Determination 2020 (consolidated May 2020) available https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-price-quality- paths/electricity-lines-default-price-quality-path/2020-2025-default-price-quality-path

[6] Available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper

[7] Available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing

DERIVING OUR PRICES

CONSUMER GROUPS

We determine consumer groups by how certain groups of customers use the network and the nature of the network service they receive. They are determined at a relatively high level, due to the physical nature of electricity distribution networks and the information that is available on consumer demand characteristics, detailed 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.

This year we have added a sub-transmission commercial consumer group[8]. 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	Tiny ≤ 1kVA	Low voltage network
Low voltage	Commercial	Large ≥ 69kVA	Low voltage network
Transformer	Commercial	Large ≥ 69kVA	Vector owned transformer(s) which supplies 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 29 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[9] 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.

[8] Details on sub-transmission pricing on page 17.
[9] 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) or DER
	Residential - TOU - controlled	ARHLC ARHSC	WRHLC WRHSC	Residential consumers with controllable hot water load (ripple or pilot wire)
	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 or a reticulated gas connection
	Residential – Anytime (exemption) – controlled	ARNLC ARNSC	WRNCL WRNSC	Residential consumers with a Vector provided exemption from TOU price categories, and with controllable load or a reticulated gas connection
	General – TOU	ABSH	WBSH	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
Low voltage (LV)	LV- TOU	ALVT	WLVH	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	WTXH	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	WHVH	Main category for HV consumers, requires TOU metering
Zone substation (ZS)	ZS – TOU	AZST	WZSH	Category for ZS consumers, requires TOU metering
Sub-transmission (ST)	ST – TOU	ASTT	WSTH	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. The only change from the previous year is that a peak volume price is now only applicable for the winter period (01 April to 30 September inclusive). The peak volume price in summer is now 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 is made up of two prices; distribution price and other-pass through price. These are used when setting the prices. With the other pass-through price set to recover all pass-through costs, recoverable costs and regulatory adjustments excluding transmission costs. With the distribution price set to recover the remaining target revenue. Different to last year, transmission costs have been removed from the price components as we have adopted a new GXP Pricing Methodology. (further explanation on page 16).

MASS MARKET AND UNMETERED PRICE CATEGORIES

Our PY24 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.

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.

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 price components for mass market and unmetered are unchanged however how the prices are determined has changed:

- The transmission component has been removed as we have adopted a new GXP Pricing Methodology (further explanation on page 16) to allocate and recover transmission costs which we consider is largely consistent with the EA’s pricing guidance.
- Residential standard and General TOU (marked with * below) have pass-through prices moved to the fixed daily price component from volume component to ensure share of revenue occurs at the fixed charge level.
- Mass market TOU consumers now have only one peak price in winter months to better focus the price signal to peak loads, as constraints are presently not a concern for most of our networks in summer months

Table 4: Price components applicable to mass market and unmetered price categories from 1 April 2023[10]

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	Time of use	Low user	ARHLC, ARHLD, ARHLU, WRHLC, WRHLD, WRHLU	✓ D		✓ D P	✓ D P	✓
			Standard user	ARHSC. ARHSD, ARHSU, WRHSC, WRHSD, WRHSU	✓ D P		✓ D	✓ D	✓
		Anytime (exemption)	Low user	ARNLC, ARNLU, WRNLC, WRNLU	✓ D	✓ D P			✓
			Standard user	ARNSC, ARNSU, WRNSC, WRNSU	✓ D P	✓ D			✓
	General	Time of use	General	ABSH, WBSH	✓ D P		✓ D	✓ D	✓
		Anytime (exemption)	General	ABSN, WBSN	✓ D P	✓ D			✓
Unmetered		Unmetered	Unmetered	ABSU, WBSU	✓ D P	✓ D			✓

[10] D is distribution only price, D P is distribution and other pass-through price. There is no longer a transmission price included in the price category prices.

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[11]

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	Time of use	ALVT, WLVH	✓ D	✓ D P	✓ D	✓ D		✓ D	✓
	Non TOU	ALVN, WLVN	✓ D	✓ D P	✓ D			✓ D	✓
Transformer	Time of use	ATXT, WTXH	✓ D	✓ D P	✓ D	✓ D		✓ D	✓
	Non TOU	ATXN, WTXN	✓ D	✓ D P	✓ D			✓ D	✓
High voltage	Time of use	AHVT, WHVH	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓
	Non TOU	AHVN, WHVN	✓ D	✓ D P	✓ D			✓ D	✓
Zone substation	Time if use	AZST, WZSH	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓
Sub-transmission	Time of use	ASTT, WSTH	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓

[11] D is distribution only price and D P is distribution and other pass-through prices. There is no longer a transmission price included in the price category prices.

Changes are:

- The transmission price component has been removed from the price categories as we have adopted a new GXP Pricing Methodology (further explanation on page 16) to recover transmission costs.
- Auckland network TOU price categories now include a fixed daily price, so now all commercial price categories have a fixed daily price.

We maintain a relativity in price levels between the commercial price categories, as shown in Table 6 below, with for example zone substation capacity and demand price levels are 90% of high voltage price levels which are, in turn, 96% of transformer price levels. This approach reflects the relative costs of serving these consumer groups. A transition towards an alignment of daily and volume (like there already is of power factor) is underway across Vector's networks.

Table 6: Commercial price relativities

Consumer group	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							
Transformer to low voltage	100%	96%	100%	96%		100%	100%
High voltage to transformer	100%	96%	100%	96%		100%	100%
Zone substation to high voltage	100%	90%	100%	90%	100%	100%	100%
Sub-transmission to zone substation	100%	80%	100%	80%	100%	100%	100%

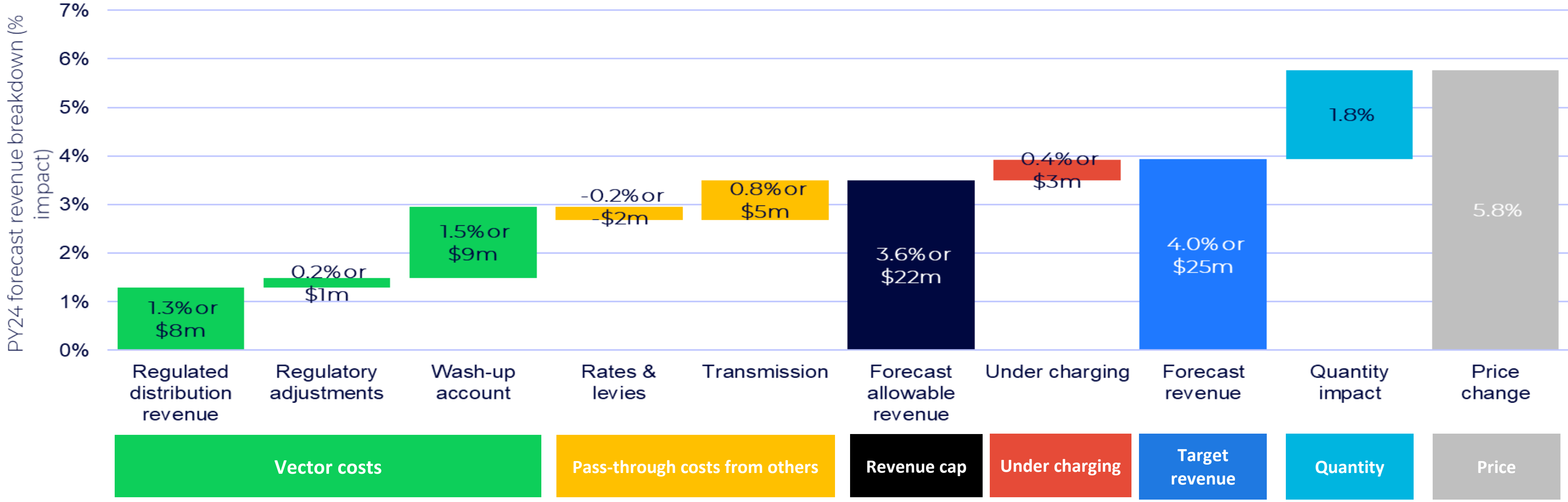
The zone substation and sub-transmission price categories are only TOU (no non-TOU option, as TOU price categories are mandatory for new commercial consumers) and priced the same across the Auckland and Northern networks. This is consistent with the transition towards aligning the other commercial consumer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

PY2024 PRICE SETTING

PRICE SETTING COMPLIANCE

Our prices are subject to the DPP Determination[12] which states that to be compliant with the price path, forecast revenue (target revenue) must not exceed forecast allowable revenue (revenue cap).

Figure 2: Change in PY24 forecast revenue and contribution to price change (measured from PY23)



Forecast allowable revenue equals the regulated distribution revenue (as set for every pricing year in the five-year regulatory period adjusted for inflation) plus forecast pass-through costs (e.g. transmission costs, council rates and statutory levies) plus regulatory adjustments (including any adjustment to cap the forecast allowable revenue increase to ten percent as required by the DPP Determination).

[12] Available at https://comcom.govt.nz/regulated-industries/electricity-lines/ electricity-lines-price-quality-paths/electricity-lines-default-price-quality-path/ 2020-2025-default-price- quality-path

PRICE STRUCTURE CHANGES

Transpower's new transmission pricing methodology (TPM)[13], our Symphony strategy, regulators and changing consumer preferences are driving a rethink of our price structures. In this pricing round our price structure changes are largely driven by the new TPM (effective 1 April 2023) which removes any peak signal in transmission prices. Many existing tariffs reflect the transmission peak price signal. Given the large impact of the TPM changes some existing prices will be in a transitional phase while change them to accommodate the new TPM.

TRANSMISSION PASS-THROUGH PRICING

Prior to 1 April 2023, distributors were allocated transmission charges largely based on their share of Regional Coincident Peak Demand. The peak signal has been removed under the new TPM. Regulations allow Vector to pass transmission costs through to consumers / retailers. The transmission charges to Vector are relatively stable, predictable and billed monthly at the GXP where the amount is 1/12th of a pre-set annual amount.

Vector’s previous transmission pass-through prices are not reflective of the new TPM as they were passed-though on variable peak volume or demand charges as a proxy for peak. Therefore, a change in our transmission pricing approach is necessary. In considering how we reflected the new TPM in our prices we considered alternative approaches. Key considerations in evaluating the alternatives were:

- Minimising risk of mismatching the revenue Vector receives from the transmission charge price relative to the transmission costs Vector incurs from Transpower;
- Compliance with EA’s voluntary distribution pricing principles and Distribution Pricing: Practice Note[14;]
- Potential to use the transmission charge price to send pricing signals that can result in reduced transmission costs in the long term thus benefitting consumers; and
- Potential to use the transmission charge price to strengthen distribution pricing signals that can result in reduced distribution costs in the long term thus benefitting consumers.

[13] More information about the new Transmission Pricing Methodology can be found on Transpower’s website
[14] More information about the Electricity Authority’s guidance on the treatment of transmission charges by distributors when setting line charges, focusing on the new TPM (Distribution Pricing Practice Note: Appendix C) can be found on the Electricity Authority’s website

The key considerations in respect of the new TPM as outlined in the EA's transmission charge pass-through guidance are:

- Transmission charges should not influence grid usage;
- The prospect of future charges should influence investment; and
- Locational variations in historical costs may influence investment.

These suggest, among other things, fixed charges where possible and mapping charges to pricing areas.

Four pricing options, status quo, fixed charges, ICP's maximum demand, GXP allocation pricing were evaluated against the key considerations mentioned above and on potential practical implementation issues, outlined in Table 7.

Table 7: Pricing options considered

Transmission pricing option	Description	Revenue risk	Pricing principles / guidance	Implementation
Status quo	Variable peak volume, and demand charges and anytime volume if no peak price	Present	Not consistent	No change
Transition to fixed charges	Fixed daily per ICP charge	Reduced	Consistent	Low user fixed charge regulations would require a phase in approach
Transition to maximum demand ICP charging	Based on ICP's anytime maximum demand	Partially reduced	Partially consistent	Only works for ICPs with smart meters, need a work around for others
Transition to a form of GXP allocation pricing	Bulk charge based on percentage share at each GXP	Removed	Consistent	Major change for retailers which could impact systems and processes

Given this assessment, a GXP allocation pricing approach was considered best placed to both minimise the revenue risk and be consistent with the pricing principles and guidance, therefore we transitioned to a GXP allocation approach which meant transmission cost recover pricing was not tied to individual ICPs. The transmission costs are determined at the GXP, load pattern at GXP relevant for allocation, there appeared to be no compelling reason why transmission cost recovery should be tied to ICPs especially when there is no mandatory requirement for retailers to pass on transmission cost recovery pricing to end users. Vector has considered and consulted a couple times over the last decade, on shifting the transmission pricing to GXP based pricing, but this was not progressed based on feedback around the uncertainty of the TPM. Now the new TPM is being implemented 1 April 2023 this uncertainty has been removed.

The transmission charge price has ceased to be a unit charge and an apportionment approach has been adopted. Vector has determined the transmission pass-through cost prices by dividing the total amount of 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 2022) based on the retailer ICP level submissions to Vector in the EIEP1 and EIEP3 format. The year to September 2022 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 2022 from EA registry-based data. The 31 December 2022 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 2022) for their ICPs as at 31 December 2022.
- Vector will look into the impacts of further quantity wash-ups for the year to September 2022 consumption data and ICP switching after 1 January 2023. If the impact of further washups or switching is material, we may reflect this in the transmission charges that apply from 1 April 2024.

Customer's annual transmission charges are calculated as follows:

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

Customers' GXP percentage shares are calculated as follows:

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

GXP's price for transmission is calculated as follows:

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

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

Transmission cost recovery is consistent with the EA's pricing guidance and aligns to how we are charged by Transpower under the new TPM. Another benefit of this pricing design is it allows a fixed monthly charge to retailers therefore providing certainty on transmission pass-through costs. The GXP transmission prices are in Appendix 2.

OTHER PRICE STRUCTURE CHANGES

We have made structure changes applicable from 1 April 2023 as shown in Table 8 below.

Table 8: Price structure changes

Changes	Rationale
Peak signal only in winter period (Apr-Sep) for residential and general time of use tariffs	Peak price signal only targeting actual peaks periods where network congestion may occur, winter peaking low voltage network. The time of use differential is based on an estimate of the long-run investment cost on an electricity network. Sapere[15], in a report commissioned by the EA, estimated the value of demand energy resources (DER) at $98 per kW per annum. The peak differential is calculated as: $$Peak\ differential = \frac{Value\ of\ demand\ management\ (per\ annum)}{Peak\ hours\ per\ year} = \frac{98}{1{,}048} = \$0.0935\ per\ kWh$$ $$Peak\ hours\ per\ year = Peak\ hours\ per\ peak\ day \times Peak\ days\ per\ year\ (8 \times 131 = 1{,}048\ hours)$$
Reduce price differential for residential ICPs between controlled hot water and uncontrolled, no differential for Northern	The benefit of hot water control is significantly reduced now the new TPM is in place. Ripple control no longer used to manage transmission peaks as no financial benefit to consumers under new TPM but still available as an option. No option for control with pilot wire. $$Control\ benefit\ (per\ day) = \frac{Value\ of\ demand\ management\ (per\ annum) \times minimum\ hot\ water\ load\ (kW) \times Option\ value\ \%}{Days\ per\ year} = \frac{98 \times 0.5 \times 15\%}{365} = \$0.02\ per\ day$$ This is the daily price difference between the Auckland residential standard user control and uncontrolled price categories. For residential low users, this is converted into an anytime volume or off-peak volume price by aligning the low and standard charges at 8,000kWh per annum.
Adjust the low residential user fixed daily line charge (from $0.30 to $0.45 per day)	To reflect the amended low user fixed charge regulations and to increase the proportion of revenue recovered through fixed charges
Remove dual energy residential ICPs from controlled tariffs	Price benefit is already through time of use price, with lower peak usage in winter period

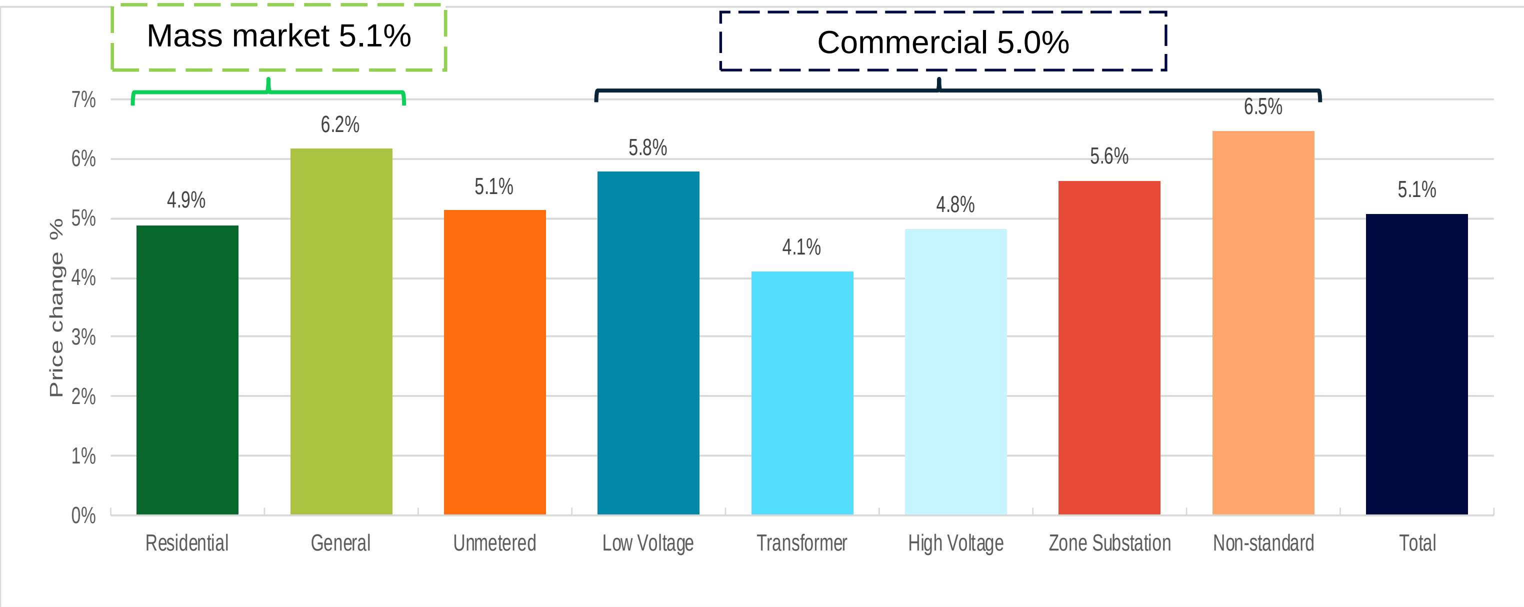
[15] Sapere's report is available here, https://www.ea.govt.nz/assets/dms-assets/28/Cost-benefit-analysis-of-distributed-energy-resources-in-New-Zealand-Sapere-Research-Group-final-13September.pdf_

New residential tariff for distributed energy resources (DER) ICPs	Incentivise ICPs for future load management, to be capable of connecting or responding to Vector's DERMS $$DER\ benefit\ (per\ day) = \frac{Value\ of\ demand\ management\ (per\ annum)\ \times minimum\ hot\ water\ load\ (kW)}{Days\ per\ year}$$ $$= \frac{98\ \times 0.5}{365} = \$0.13\ per\ day$$ This is the daily price difference between the residential standard user DER and uncontrolled price categories. For residential low users, this is converted into an anytime volume or off-peak volume price by aligning the low and standard charges at 8,000kWh per annum.
Un-align general (SME) to residential standard user	Improve cost recovery from SME but managing the bill impacts to an acceptable level. These were previously aligned to prevent arbitrage.
Continue to transition the alignment of commercial tariffs between the networks	Manage the bill impacts to acceptable level, which tend to be passed through by retailers for commercial ICPs.
Introduction of a new sub-transmission commercial consumer group	Vector has introduced a new TOU only commercial price plan, for consumers that have a connection directly to the Vector sub-transmission network and/or have paid for their connection assets to a Vector zone substation. The rationale for adding this consumer group is that it provides a more accurate cost allocation by removing the assets, which are downstream from their point of supply on the sub-transmission network, from their cost allocation.

PRICE CHANGES

We are conscious of the effect of price changes for consumers. Our starting point for calculating prices is the corresponding price from the previous year. Excluding transmission costs, (further explanation on page 16), Figure 3 shows how the weighted average price change is split across the consumer groups. Our electricity prices that apply from 1 April 2023, including the previous year's prices that were effective from 1 April 2022, are set out in Appendix 2.[16]

Figure 3: Weighted average price change by consumer group



5.1% average weighted price change (excluding transmission recovery costs) across mass market, unmetered and commercial.

For mass market consumers, the price increase is passed through fixed prices partially offset with decreases in volumetric prices. Vector has adjusted its prices to reflect the Low Fixed Charge (LFC) regulations. For standard residential ICPs and general ICPs, the other pass-through prices are moved to the fixed daily price components, so these prices are least distortionary.

For commercial consumers, the price changes are impacted by the transitioning towards price alignment between the Auckland and Northern networks, whose prices are different for legacy reasons. The daily and volume prices are aligned across the commercial groups (but still differ between the networks and price category type). Capacity and demand pricing is being transitioned towards alignment across the networks.

Non-standard consumers are priced as per their contracts and with forecast contract renewals having a higher price predominantly due to the higher inflation (which doesn't impact current standard prices).

[16] Our full price schedules are available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing`

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. Rather, we consulted with Entrust, whose beneficiaries are mass market consumers on the Auckland network, and retailers on behalf of consumers on the proposed price changes. We consult with retailers rather than end users as we generally bill our prices to retailers not end users. Retailers have discretion as to whether they pass our prices through to end users – some retailers do, some do not.

Table 9: Timeframe for Vector's electricity price setting

Activity	Timeframe	Notes
Pricing innovation discussion	August 2022	Internal discussions on potential pricing innovations
Board presentation	Late September 2022	Broad price change options discussed with Board
Draft prices agreed	Late October 2022	Quantity forecasts derived
Board information paper	Early November 2022	Detailed options presented to Board
Entrust consultation	Early to mid-November 2022	Material to Entrust followed by presentation
Retailer consultation	Mid-November to early December 2022	Three-week consultation period, conducted meetings with key retailers in the Auckland region.
Auditor review	December 2022 to Jan 23	Findings prior to final price approval
Final price approval	Mid to late December 2022	Entrust and retailer feedback considered. Individual responses provided to retailers on their feedback.
Retailer and Entrust price notification	Late December 2022 to January 2023	Provisional notification prior to Christmas, final notification mid/late January, before the 40 working days prior to price change requirement (as required under the Default Distributor Agreement)
Board approval	Late February 2023	Approval of the price setting compliance statement and pricing methodology
Public disclosure	Early March 2023	20 working days prior to price change
Price changes	1 April 2023	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 4.

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 PY24 is $649.8m ($625.3m for PY23).

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 in Figure 5.

Figure 4: COSM structure

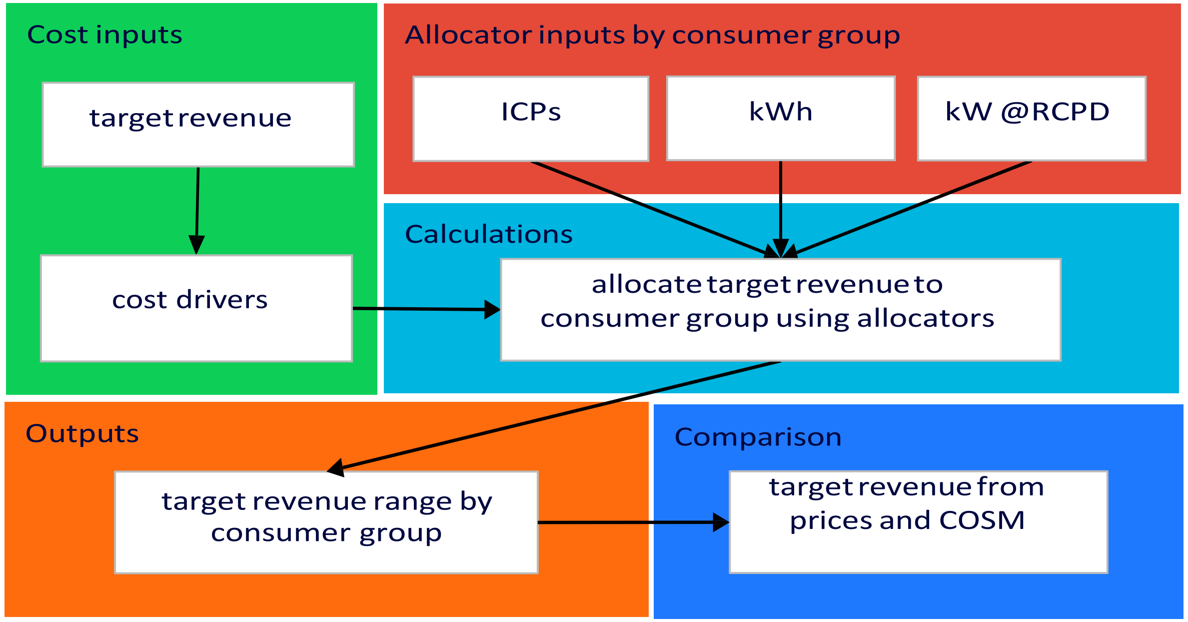
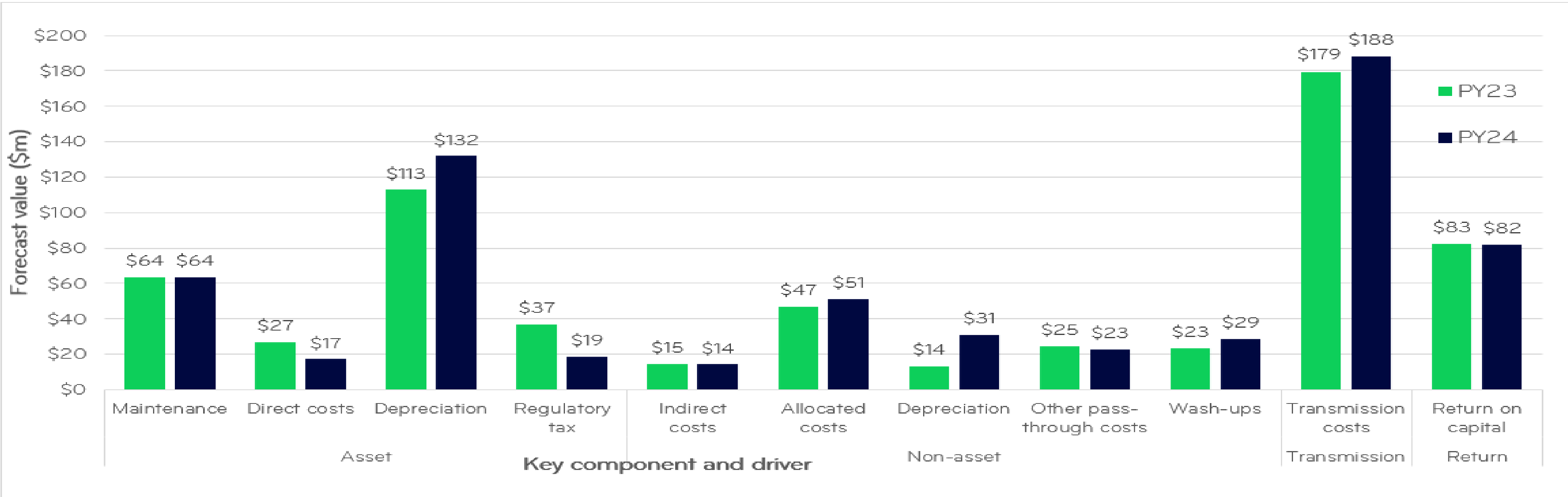


Figure 5: Target revenue by key components



COST DRIVERS

The key components are categorised by cost driver i.e. either 'asset', 'non-asset', 'transmission' or 'return'. These categorisations are summarised in Figure 6. and determine the way that the target revenue is allocated to consumer groups. 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 three distinct categories as shown in Table 10.

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 6: Target revenue by cost driver

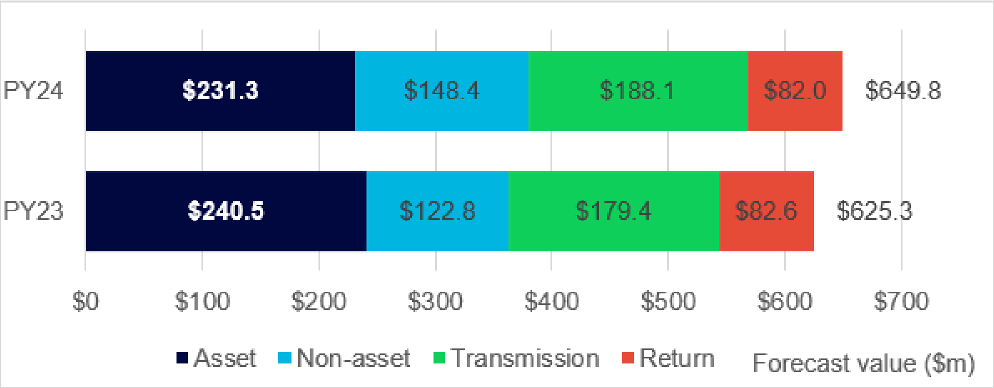


Table 10: Asset categorisation

Asset category	Assets	Consumer groups	Asset value [17] (RAB)	
A1	• Sub-transmission lines / cables	All	$608m	18%
A2	• Land and buildings • Zone-substations • Sub-transmission switch gear	All except sub-transmission	$612m	18%
A3	• HV lines / cables	All except sub-transmission and zone substation	$1,234m	36%
B	• Distribution transformers and substations that have no Vector-owned low voltage lines / cables leaving them	Transformer	$65m	2%
C	• Distribution 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	$889m	26%

[17] 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 $649.8m to consumer groups using various cost drivers as summarised in Table 11.

Table 11: 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>$41.3m</td><td>$41.5m</td><td>$83.8m</td><td>$4.4m</td><td>$60.4m</td><td>$148.3m</td><td>$188.1m</td><td>$82.0</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">RoR</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[18]) of the assets during peak periods, as this usage drives the need for, and the size of, the assets.

- For Asset Category A1, A2 and A3 assets, historically the consumer group’s contribution to Transpower’s Regional Coincident Peak Demand (RCPD)[19] periods, as a proxy for peak usage, was an appropriate and readily available measure to allocate their costs. The guidance from the Electricity Authority expects distributors to avoid, or transition away from, the recovery of fixed costs through time based use charges, such that a customer’s usage should have no or minimal impact on that customer’s own charge and total annual usage as a metric related to customer size is a less distortionary measure. As such, we are transitioning away from contribution to RCPD, by using from contribution to RCPD (kW) and annual consumption (kWh) to allocate A1, A2 and A3 asset related costs between consumer groups. This transitional approach mimics the approach for category C assets (see below) and minimises the bill impact variation between consumer groups given the current cost of living.

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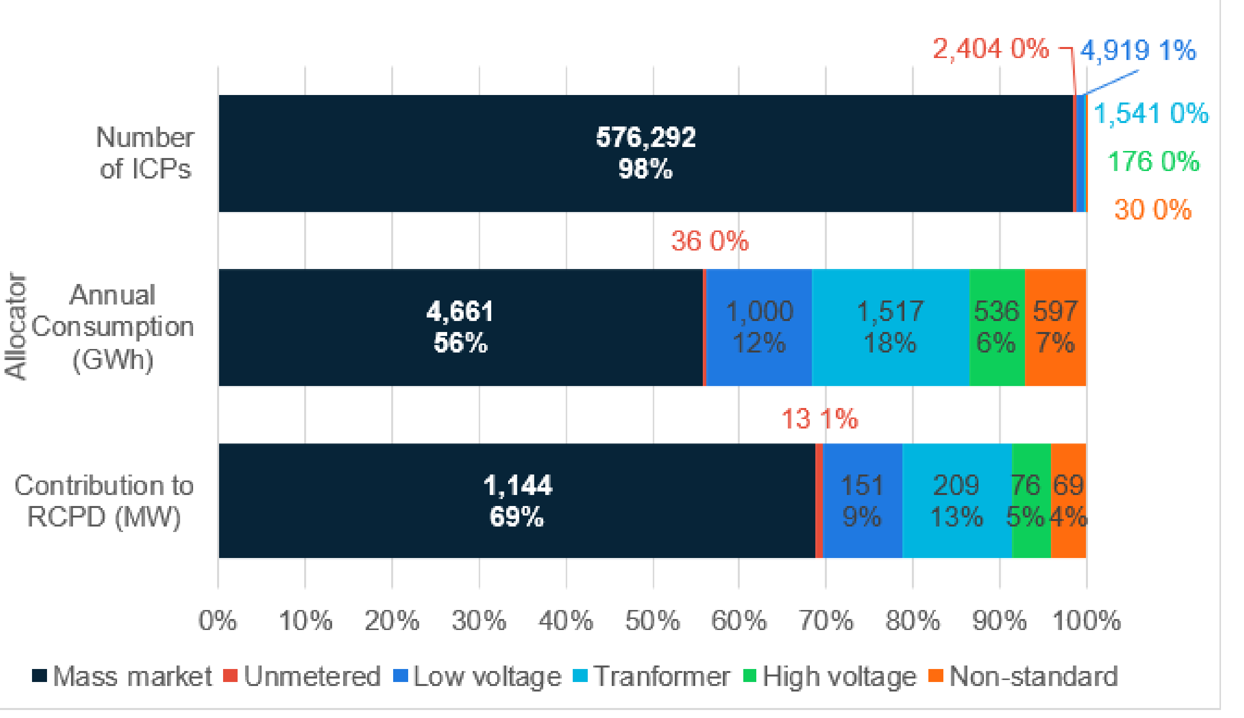
[18] Weighted average of last five year’s values from the billed quantities in Schedule 8 of our annual Electricity Information Disclosures (available at https://www.vector.co.nz/about- us/regulatory/ disclosures-electricity/financial-and-network-information), with each year being weighted twice the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

- For Category B assets, the costs do not require an allocation approach as they are used by one consumer group (transformer consumers).
- For Category C assets, that are assets located close to the end consumer, appropriate readily available allocators are contribution to RCPD and annual consumption.

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.

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 now excluded from the COSM as they are pass-through in bulk to the retailers/direct billed customers rather than being allocated to consumer groups. Please see page 16 for further details.

Figure 7: PY23 COSM allocation values and usage percentage



'Return' is the return on capital and is broadly generated through the usage of Vector's assets. A consumer groups' asset values are calculated in the same way as 'asset' related costs are. 'Return' is allocated using a calibrated constant rate of return across the consumer groups' asset values.

A new consumer group, sub-transmission, has been introduced for consumers that have a connection directly to a Vector sub-transmission and/or have paid for their connection assets to a Vector zone substation. The sub-transmission consumer group along with the zone substation group do not have any historic allocators to use to generate its target revenue allocation and prices, so the COSM couldn't be used in the same way as it was for the other consumer groups. Instead the COSM was used to obtain costs per kW and per kWh (how the asset costs are allocated in the COSM) and these are compared across the consumer groups. As a proxy for zone substation and sub-transmission cost allocators, the allocators for the non-standard consumers were put into the zone substation and sub-transmission consumer groups separately and the COSM was rerun. This provided an estimated relativity in cost per unit between the consumer groups. The asset cost allocation for the zone substation consumer group is 90% of high voltage consumer group and the cost for the zone substation consumer group is 80% of zone substation consumer group.

DISTRIBUTION TARGET REVENUE ALLOCATION & PRICE COMPARISON

The result of using the different allocators across the categories, creates a distribution and other pass-through 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 8 which shows target revenue calculated from PY24 prices by consumer group compared with the COSM allocations. The result is that PY24 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 $8.8m (1.4%) to be recovered from the 20 non-standard consumers (26 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 9. 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 8: PY24 distribution and other pass-through target revenue from prices compared with COSM allocations

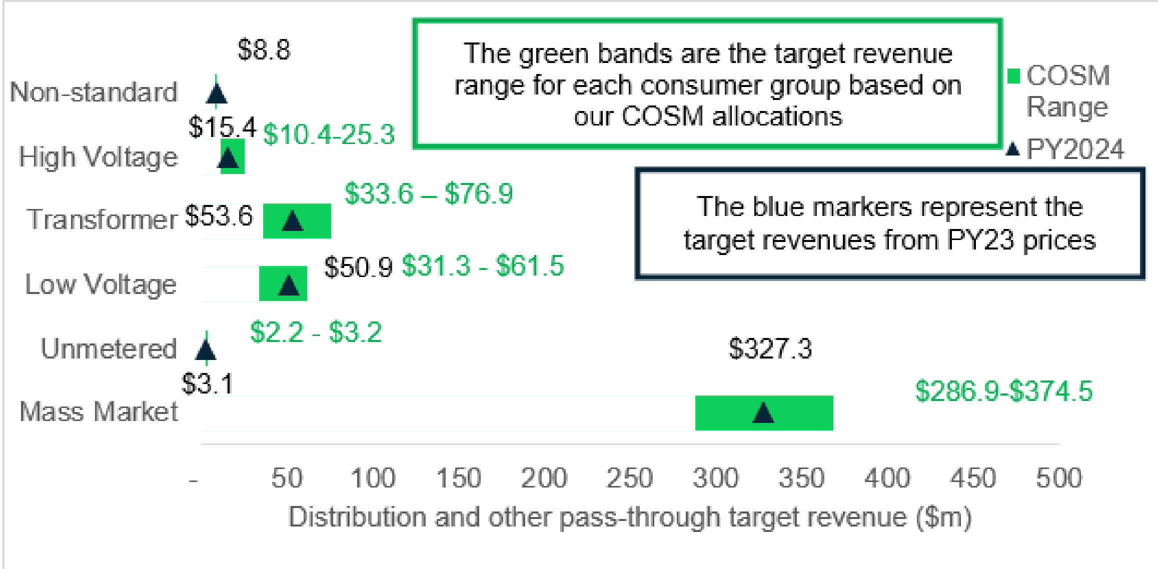
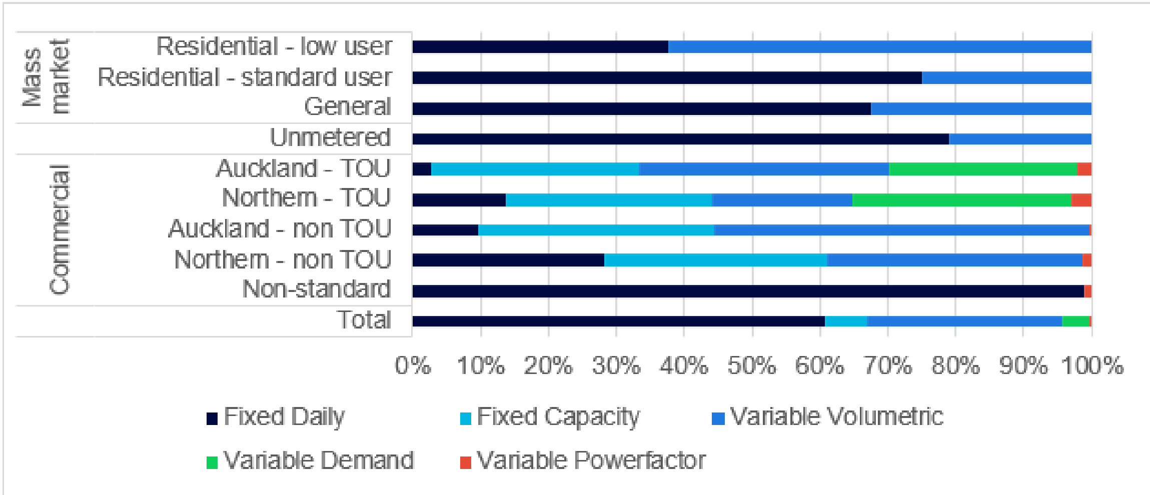


Figure 9: Proportion of PY24 target revenue by price component and category



POLICIES & OBLIGATIONS

NON-STANDARD CONTRACTS & DISTRIBUTED GENERATION POLICIES

Table 12: 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. 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 Cost of Service Model (COSM) used in assessing 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 energy into the network so this price continues to be $0.0000/kWh from 1 April 2023 for all distributed generators. As more distributed generation connects this may require more in-depth consideration and as a result pricing may change.

[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.

OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS

For PY24, 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 13. Our standard contract terms and non-contract terms are also compared.

Table 13: Summary of our obligations and responsibilities to consumers

	Planned interruption notice	Unplanned interruption notice	Fault restoration	No. of interruptions per annum	No. of consumers
Standard	4 days	As soon as practicable but no later than: - 20 mins during staffed control room hours, - 40 mins during on-call control room hours	CBD/Industrial: 2 hours	Urban: 4	Approx 607,000
			Urban: 2.5 hours		
			Rural: 4.5 hours	Rural: 10	
Non-standard	Same as standard consumers				1
	1 April each year, or 10 working days	As soon as practicable	2 hours	1 unplanned	1
	1 June each year	As soon as practicable	As soon as practicable	Not stated	2
	1 November each year	As soon as practicable	Priority	Not stated	5
	10 working days	As soon as practicable	3 hours	Not stated	5
	10 working days	Not stated	3 hours	Not stated	2
	10 working days	Not stated	Not stated	Not stated	4
	4 working days	As soon as practicable	3 hours	Not stated	4
	7 working days	As soon as practicable	Priority	3 planned	2

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
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
PY24	Pricing year (PY) is the 12-month period from 1 April to 31 March each year. PY24 is 1 April 2023 to 31 March 2024
RCPD for a Transmission Region	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

Regulatory Asset Base (RAB)	Broadly the regulatory asset base represents the amount that we have invested in our regulated network, indexed by inflation and adjusted for depreciation
Regulatory adjustments	Regulatory adjustments are intangible recoverable costs (not invoiced) such as incentives and wash-ups that impact the amount of line charge revenue that we are allowed to recover. These wash-ups include incremental rolling incentive scheme (IRIS), quality incentive adjustment, capex wash-up adjustment and wash-up account balance and have time value of money included. The amount includes any downwards adjustment required to meet the revenue cap

APPENDIX 2 - LINE CHARGE PRICES FROM 1 APRIL 2023

Distribution line charge prices for time of use residential and general ICPs from 1 April 2023 ***(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 2023)	Daily	Volume		
							off-peak	winter peak	injection
						$/day -FIXD	$/kWh -OFPK	$/kWh -PEAK	$/kWh -INJT
Mass Market	Residential - low user	Time of use	Controlled	ARHLC	99,129	0.45 *(0.30)*	0.0378 *(0.0603)*	0.1313 *(0.1378)*	0.0000
				WRHLC	61,720		0.0387 *(0.0603)*	0.1322 *(0.1378)*	
			DER	ARHLD	2,014	0.45 *(new)*	0.0328 *(new)*	0.1263 *(new)*	
				WRHLD	1,320				
			Uncontrolled	ARHLU	47,868	0.45 *(0.30)*	0.0387 *(0.0603)*	0.1322 *(0.1579)*	
				WRHLU	31,879				
	Residential - standard user	Time of use	Controlled	ARHSC	51,008	1.28 *(1.12)*	0.0000 *(0.0229)*	0.0935 *(0.1004)*	
				WRHSC	37,563	1.30 *(1.12)*			
			DER	ARHSD	1,157	1.17 *(new)*	0.0000 *(new)*	0.0935 *(new)*	
				WRHSD	928				
			Uncontrolled	ARHSU	22,214	1.30 *(1.12)*	0.0000 *(0.0229)*	0.0935 *(0.1205)*	
				WRHSU	19,669				
	General	Time of use	General	ABSH	11,465	1.52 *(1.12)*	0.0000 *(0.0229)*	0.0935 *(0.1205)*	
				WBSH	9,838				

Distribution line charge prices for non - time of use residential and general ICPs from 1 April 2023 *(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 2023	Daily		Volume		
								anytime		injection
						$/day -FIXD	$/day /fitting -FIXD	$/kWh -24UC	$/kWh -AICO	$/kWh -INJT
Mass market	Residential - low user	Anytime (exemption)	Controlled	ARNLC	40,692	0.45 *(0.30)*			0.0542 *(0.0842)*	0.0000
				WRNLC	30,086				0.0551 *(0.0842)*	
			Uncontrolled	ARNLU	11,706	0.45 *(0.30)*		0.0551 *(0.0904)*		
				WRNLU	7,000					
	Residential - standard user	Anytime (exemption)	Controlled	ARNSC	29,732	1.28 *(1.12)*			0.0164 *(0.0468)*	
				WRNSC	24,846	1.30 *(1.12)*				
			Uncontrolled	ARNSU	11,572	1.30 *(1.12)*		0.0164 *(0.0530)*		
				WRNSU	9,756					
	General	Anytime (exemption)	General	ABSN	26,423	1.52 *(1.12)*		0.0164 *(0.0530)*		
				WBSN	14,039					
Unmetered	General	Unmetered	Unmetered	ABSU	1,740		0.0550 *(0.0813)*	0.0226 *(0.0257)*		
				WBSU	745					

Distribution line charge prices for time of use commercial ICPs from 1 April 2023 *(previous price, if changing)*

Consumer group	Price category type	Price category codes	Estimated no. of ICPs (year avg. from 1 April 2023	Daily	Volume anytime	Capacity	Demand	Excess demand	Power factor	Volume injection
				$/day	$/kWh	$/kVA/day	$/kVA/day	$/kVA/day	$/kVAr/day	$/kWh
				-FIXD	-24UC	-CAPY	-DAMD	-DEXA	-PWRF	-INJT
Low voltage	Time of use	ALVT	1,417	2.10 *(new)*	0.0129 *(0.0123)*	0.0469	0.1364 *(0.3123)*		0.2917	0.0000
		WLVH	266	11.15	0.0059 *(0.0053)*	0.0436 *(0.0396)*	0.1249 *(0.2924)*			
Transformer	Time of use	ATXT	997	2.10 *(new)*	0.0129 *(0.0123)*	0.0450	0.1309 *(0.2998)*			
		WTXH	306	11.15	0.0059 *(0.0053)*	0.0419 *(0.0380)*	0.1199 *(0.2807)*			
High voltage	Time of use	AHVT	151	2.10 *(new)*	0.0129 *(0.0123)*	0.0432	0.1257 *(0.2878)*	0.8000 *(0.9504)*		
		WHVH	26	11.15	0.0059 *(0.0053)*	0.0402 *(0.0365)*	0.1151 *(0.2695)*	0.8000 *(0.8030)*		
Zone substation	Time of use	AZST	3	2.10 *(new)*	0.0059 *(0.0058)*	0.1050 *(0.1228)*	0.0261 *(0.1228)*	0.8000		
		WZSH	0							
Sub-transmission	Time of use	ASTT	0	2.10 *(new)*	0.0059 *(new)*	0.0840 *(new)*	0.0209 *(new)*	0.8000 *(new)*		
		WSTH	0							

Distribution line charge prices for non-time of use commercial ICPs from 1 April 2023 *(previous price, if changing)*

Consumer group	Price category type	Price category code	Estimated number of ICPs (year avg. from 1 April 2023)	Daily	Volume anytime	Capacity	Power factor	Volume injection
				$/day	$/kWh	$/kVA/day	$/kVAr/day	$/kWh
				-FIXD	-24UC	-CAPY	-PWRF	-INJT
Low voltage	Non-time of use	ALVN	2,450	2.10 *(1.83)*	0.0424 *(0.0553)*	0.0469	0.2917	0.0000
		WLVN	985	5.92	0.0202 *(0.0340)*	0.0436 *(0.0396)*		
Transformer	Non-time of use	ATXN	173	2.10 *(1.83)*	0.0424 *(0.0553)*	0.0450		
		WTXN	142	5.92	0.0202 *(0.0340)*	0.0419 *(0.0380)*		
High voltage	Non-time of use	AHVN	7	2.10 *(1.83)*	0.0424 *(0.0553)*	0.0432		
		WHVN	0	5.92	0.0202 *(0.0340)*	0.0402 *(0.0365)*		

Transmission line charges from 1 April 2023 *(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 2022 (MWh)	Implied volumetric rate $/kWh
ALB	Albany	Northern	19,923	16.6024	742,167	0.0268
HEN	Henderson	Northern	9,837	8.1971	490,818	0.0200
HEP	Hepburn Road	Auckland / Northern	13,501	11.2512	570,698	0.0237
HOB	Hobson St	Auckland	7,645	6.3706	269,984	0.0283
LFD	Lichfield	Northern	894	0.7453	67,297	0.0133
MNG	Mangere	Auckland	12,902	10.7517	637,647	0.0202
ROS	Mt Roskill	Auckland	14,610	12.1752	643,649	0.0227
OTA	Otahuhu	Auckland	6,279	5.2323	318,724	0.0197
PAK	Pakuranga	Auckland	13,862	11.5513	589,336	0.0235
PEN	Penrose	Auckland	45,646	38.0383	2,000,091	0.0228
SVL	Silverdale	Northern	9,465	7.8875	360,055	0.0263
TAK	Takanini	Auckland	10,603	8.8356	534,845	0.0198
WRD	Wairau Road	Northern	8,037	6.6977	500,119	0.0161
WEL	Wellsford	Northern	3,515	2.9292	157,306	0.0223
WIR	Wiri	Auckland	11,411	9.5088	463,111	0.0246
Total			188,129		8,345,847	

APPENDIX 3 – TARGET REVENUE RECOVERY

Table 14: 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	2.51%	4.11%	WRHLC	1.56%	2.71%
			DER	ARHLD	0.05%	0.08%	WRHLD	0.03%	0.05%
			Uncontrolled	ARHLU	1.21%	1.81%	WRHLU	0.81%	1.36%
		Anytime (exemption)	Controlled	ARNLC	1.03%	1.80%	WRNLC	0.76%	1.38%
			Uncontrolled	ARNLU	0.30%	0.36%	WRNLU	-	-
	Residential - standard	Time of use	Controlled	ARHSC	3.67%	1.36%	WRHSC	2.74%	1.00%
			DER	ARHSD	0.08%	0.03%	WRHSD	0.06%	0.02%
			Uncontrolled	ARHSU	1.62%	0.55%	WRHSU	1.44%	0.52%
		Anytime (exemption)	Controlled	ARNSC	2.14%	0.66%	WRNSC	1.81%	0.59%
			Uncontrolled	ARNSU	0.84%	0.15%	WRNSU	-	-
	General	Time of use	General	ABSH	0.98%	0.44%	WBSH	0.84%	0.34%
		Anytime (exemption)	General	ABSN	-	-	WBSN	1.20%	0.58%
Unmetered		Unmetered	Unmetered	ABSU	0.23%	0.06%	WBSU	0.15%	0.04%

Table 15: Proportion of commercial target revenue by price component

Consumer group	Short description	Category	Fixed	Variable				Category	Fixed	Variable			
		Auckland	**Daily**	**Capacity**	**Volume-tric**	**Demand**	**Power Factor**		**Daily**	**Capacity**	**Volumetric**	**Demand**	**Power Factor**
Low voltage	Time of use	ALVT	0.17%	1.02%	1.03%	0.88%	0.10%	WLVH	0.17%	0.18%	0.12%	0.19%	0.03%
	Non time of use	ALVN	0.29%	0.98%	1.60%	-	0.01%	WLVN	0.33%	0.36%	0.39%	-	0.01%
Transformer	Time of use	ATXT	0.12%	1.87%	2.25%	1.73%	0.10%	WTXH	0.19%	0.54%	0.34%	0.54%	0.05%
	Non time of use	ATXN	0.02%	0.10%	0.15%	-	-	WTXN	0.05%	0.08%	0.11%	-	0.01%
High voltage	Time of use	AHVT	0.02%	0.47%	0.85%	0.60%	0.04%	WHVH	0.02%	0.10%	0.11%	0.15%	0.01%
	Non time of use	AHVN	-	-	-	-	-	WHVN	-	-	-	-	-
Zone substation	Time of use	AZST	-	0.23%	0.13%	0.03%	-	WZSH	-	-	-	-	-
Sub-transmission	Time of use	ASTT	-	-	-	-	-	WSTH	-	-	-	-	-

APPENDIX 4 – CONSISTENCY WITH PRICING PRINCIPLES

The EA's Pricing Principles[21] (Pricing Principles) provide guidance to developing pricing methodologies for electricity distribution services. Table 16 demonstrates the extent to which the Pricing Methodology is consistent with the Pricing Principles.

Table 16 Pricing principles

Principle (a): Economic costs of service provision *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.*
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. 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

[21] Available at https://www.ea.govt.nz/operations/distribution/pricing/

consequence, some parts of the distribution system have spare capacity. In most cases, due to the availability of spare 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 page 16) 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.

We now offer a distributed energy resources tariffs to residential end consumers in return for the ability to remotely manage their load (e.g. hot water and electric vehicles 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 and therefore reduce the need for future investment costs.

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 to investment decisions. As we have limited information of demand responsiveness by consumer group, we allocate the shortfall across all consumer groups

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.

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.

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 ICPs. 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.

In recent years we have simplified a majority of our distribution price structure so that the transaction costs on retailers, end consumers, and ourselves are minimised. 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 i.e. we do not provide any discounts or special terms to end consumers who are supplied by a particular retailer. The non-differentiation of network prices is outlined in the agreements that we have with retailers operating on our network.

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. Our intent is to provide a clear pathway to the new energy future.

APPENDIX 5 – DIRECTORS' CERTIFICATION

Schedule 17: Certification for Pricing Methodology Disclosure

Clause 2.9.1

We, Jonathan Mason and Paula Rebstock, 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.

Jonathan P. Mason

Director

Dame Paula Rebstock

Director

20 February 2023

Date