ELECTRICITY DISTRIBUTION SERVICES 2023 PRICING METHODOLOGY

From 1 April 2022

Pursuant to:

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

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. 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 sets out our Pricing Methodology to meet the requirements of the Information Disclosure Determination 2012 (ID)[1] and outlines Vector's approach to distribution pricing reform. It describes and explains the consumer groups, the price categories and components within each consumer group, how prices are set and 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] that sets out how we are evolving our prices to enable and deliver better outcomes for consumers. Please note that this document does not contain our Capital Contributions policy[4] which is also required by the ID.

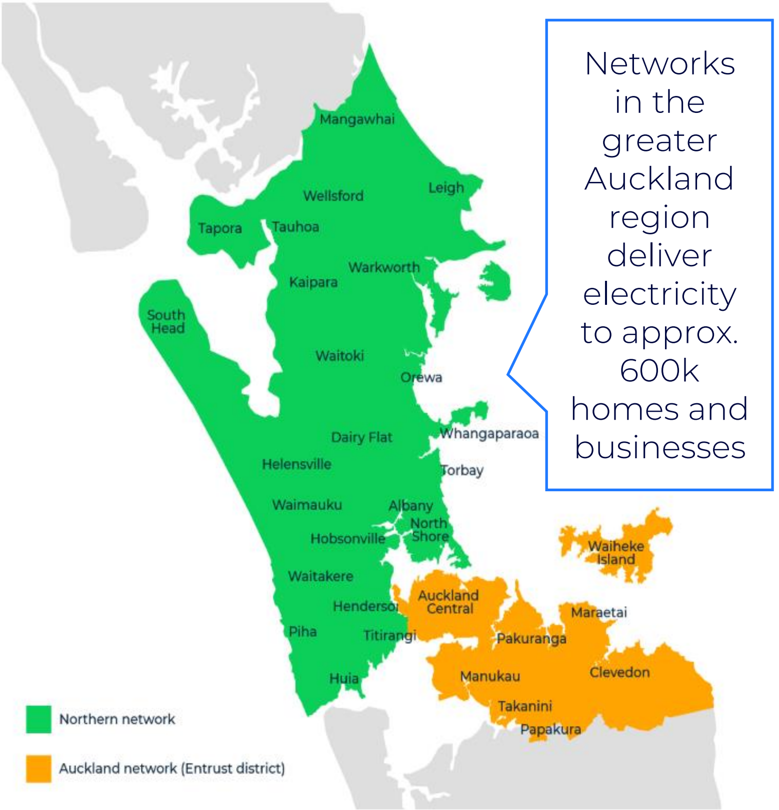
Prices are set to earn the level of revenue we are permitted to under the Default Price Path (DPP Determination)[5] , less any intentional under-pricing

When setting prices we take into account (amongst other things) - historical price structures, minimising rate shock to consumers, minimising recovery risk, pricing principles[6] and ensuring that prices to individual consumer groups reflect their allocation of costs

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 some less. We do though have discretion on the allocation approach applied providing it complies with pricing principles.

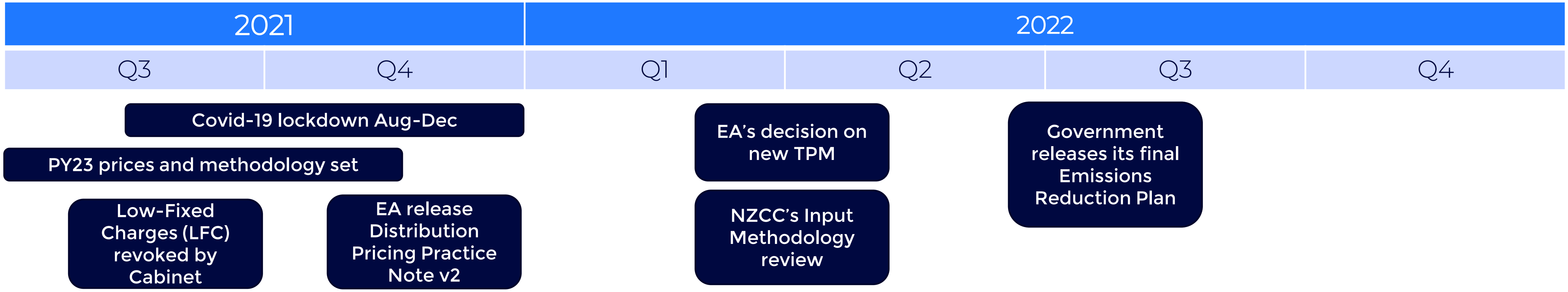
Figure 1: Our electricity distribution networks



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
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

PRICING CONTEXT

Figure 2: External events pricing timeline



- The future is unpredictable. Uncertainty around existing regulatory framework and new business models are evolving in response to new consumer demands, new technologies and decarbonisation. We have taken the strategic decision to embrace these changes rather than resist them. We see this new environment as an opportunity to revise our pricing in response to an evolving market, as shown in the pricing reform section (see pages 26-39).
- Distribution pricing is facing many drivers of change both from within the industry but also externally. Key is the decarbonisation of the sector in light of the government's net zero target by 2050. Electricity Distribution Businesses (EDBs) will be a critical enabler of the achievement of net zero. Vector is keeping a close eye on the government's final Emissions Reduction Plan and the implications for our business and our customers.
- In the regulatory space the Electricity Authority (EA) has been actively seeking views on the regulatory settings for distributors, Transpower's Transmission Pricing Methodology (TPM) and in December 2021 released a new version of its pricing Practice Note.
- Meanwhile the Commerce Commission has kicked off its review of the Input Methodologies this should ensure their framework is fit for purpose in light of the decarbonisation and digitalisation of NZ's energy networks.
- Lastly, Auckland faced its longest Covid-19 lockdown in the second half of 2021. Vector has been assessing the economic impact to our consumers as a consequence.

DERIVING OUR PRICES

GOVERNANCE, CONSULTATION & COMPLIANCE TIMEFRAME

Table 1: Timeframe for Vector's electricity price setting

Activity	Timeframe	Notes
Pricing innovation discussions	Late August 2021	Presentation and discussions with some retailers and electricity industry parties on potential pricing innovations
Board presentation	Late September 2021	Broad price change options discussed with Board
Draft prices agreed	Late October 2021	Quantity forecasts due October
Board information paper	Early November 2021	Detailed options presented to Board
Entrust consultation	Early to mid November 2021	Material to Entrust followed by presentation
Retailer consultation	Late November to early December 2021	Two week consultation period minimum, conducted meetings with eleven key retailers in the Auckland region
Auditor review	Early to mid December 2021	Findings prior to final price approval
Final price approval	Mid to late December 2021	Entrust and retailer feedback considered
Retailer and Entrust price notification	Late December 2021	Notified prior to summer holiday shutdown
Board approval	Late February 2022	Approval of the compliance statement and pricing methodology
Public disclosure	Early March 2022	20 working days prior to price change
Price changes	1 April 2022	Price change implemented

CONSUMER GROUPS

Consumer groups are determined on how certain groups of customers use the network and the nature of the network service they receive. These consumer groups 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, as outlined below:

- There is a 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.

We have added a new zone substation[7] commercial consumer group for consumers that are connecting directly to zone substations, to the existing five standard consumer groups, which are based on a measure of capacity connection and supply connection point type as shown in Table 2.

Table 2: Consumer groups

Consumer group and 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 or sub-transmission (11kV or higher) network
Zone substation	➢ Commercial	Large ≥ 69kVA	Directly from a Vector zone substation or 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 23, are included in a separate consumer group.

Consumer groups are mutually exclusive so a consumer can only be in one group.

The mass market consumer group is split into two subgroups: residential and general with a key difference between the subgroups being that the Low User Regulations[8] apply only to the residential subgroup.

The unmetered consumer group is also in the general subgroup.

The low voltage, transformer, high voltage and zone substation consumer groups are collectively referred to as commercial consumers.

[7] See page 21 for details on zone substation pricing
[8] The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low User Regulations)

PRICE CATEGORIES

Table 3 sets out the price categories[9] for consumers on our Auckland network (codes beginning with A) and our Northern network (beginning with W).

Table 3: Price categories

Consumer group and subgroup		Short description	Price category codes		Key eligibility criteria / purpose
			Auckland	Northern	
Mass market	Residential	Residential - time of use (TOU) - uncontrolled	ARHL ARHS	WRHL WRHS	Residential consumers without controllable load (hot water or smart vehicle charger) or a reticulated gas connection
Mass market	Residential	Residential - TOU - controlled	ARHLC ARHSC	WRHLC WRHSC	Residential consumers with controllable load or a reticulated gas connection
Mass market	Residential	Residential - exemption - uncontrolled	ARUL ARUS	WRUL WRUS	Residential consumers with a Vector provided exemption from TOU price categories, and without controllable load or a reticulated gas connection
Mass market	Residential	Residential - exemption - controlled	ARCL ARCS	WRCL WRCS	Residential consumers with a Vector provided exemption from TOU price categories, and with controllable load or a reticulated gas connection
Mass market	General	General - TOU	ABSH	WBSH	Non-residential < 69kVA consumers
Mass market	General	General - exemption	ABSN	WBSN	Non-residential < 69kVA consumers with a Vector provided exemption from TOU price categories
Unmetered	General	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
Low voltage (LV)		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
Transformer (TX)		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
High voltage (HV)		HV - non TOU	AHVN	WHVN	For smaller HV consumers (< 345kVA) who do not have TOU metering
Zone substation (ZS)		ZS - TOU	AZST	WZSH	Category for ZS consumers, requires TOU metering

[9] Price categories are the relevant price plan (or tariff) from the price schedule that define the line prices applicable to a particular ICP. An ICP is an installation control point being 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

PRICE COMPONENTS

We have a range of price components[10] that apply to different price categories depending on the characteristics of a particular category and the availability of metering data. Table 4 describes the various price components that we have. There are no changes from the previous year.

Table 4: 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
Fixed	Capacity	CAPY	$/kVA/day [11]	Daily price applied to the installed capacity (or nominated capacity for HV and ZS) of each consumer
Variable	Volume	AICO, 24UC, OFPK, PEAK	$/kWh [12]	Volume price, applies to all electricity distributed to each consumer. Controlled volume (AICO), uncontrolled volume (24UC), off peak volume (OFPK), or peak volume (PEAK) (0700 to 1100 and 1700 to 2100 weekdays including public holidays)
Variable	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
Variable	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
Variable	Power factor	PWRF	$/kVAr/day [13]	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[14] in any one half-hour period and the kWh demand recorded in the same period divided by three
Variable	Injection	INJT	$/kWh	Volume injection price applies to all electricity injected into the network by each consumer

Each price component is made up of three prices; distribution price, transmission price, and other-pass through price. These are used when setting the prices, with the transmission price set to recover the transmission costs, the other pass-through price set to recover the all pass-through costs, recoverable costs and regulatory adjustments excluding transmission costs, and the distribution price set to recover the remaining target revenue.

[10] Price components are the various prices that constitute the components of the total prices paid, or payable, by a consumer
[11] 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
[12] 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
[13] 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
[14] 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

MASS MARKET AND UNMETERED PRICE CATEGORIES

Like the previous year, for PY23 [15] our 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 peak time pricing during 7am-11am and 5pm-9pm weekdays and off-peak pricing during other times), and
- flat volumetric pricing - daily fixed price and any anytime volumetric price, available only as an exemption.

Our residential price categories include both controlled and uncontrolled price categories, with the controlled price categories designed to reward residential consumers for the benefit these households deliver to us in helping to reduce load during peak periods, via electrical hot water load control system, smart electric vehicle chargers or gas connections which can result in less electricity being used during peak periods.

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 consumers' volumes are determined by Vector based on load profiles and fitting input wattages.

Table 5 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 the same as the previous year, however the transmission and other pass-through prices for unmetered have moved to the fixed daily price component. The peak to off-peak differential for mass market TOU consumers is the transmission price.

Table 5: Price components applicable to mass market and unmetered price categories from 1 April 2022 [16]

Consumer group and subgroup		Price category description	Price category code		Daily		Volume				
							anytime		off-peak	peak	injection
			Auckland	Northern	-FIXD		-24UC	-AICO	-OFPK	-PEAK	-INJT
					$/day	$/day/fitting	$/kWh				
Mass market	Residential	TOU - uncontrolled	ARHL, ARHS	WRHL, WRHS	✓ D				✓ D P	✓ D T P	✓
Mass market	Residential	TOU - controlled	ARHLC, ARHSC	WRHLC, WRHSC	✓ D				✓ D P	✓ D T P	✓
Mass market	Residential	Exemption - uncontrolled	ARUL, ARUS	WRUL, WRUS	✓ D		✓ D T P				✓
Mass market	Residential	Exemption - controlled	ARCL, ARCS	WRCL, WRCS	✓ D			✓ D T P			✓
Mass market	General	TOU	ABSH	WBSH	✓ D				✓ D P	✓ D T P	✓
Mass market	General	Exemption	ABSN	WBSN	✓ D		✓ D				✓
Unmetered	General	Unmetered	ABSU	WBSU		✓ D T P	✓ D				✓

[15] Pricing year (PY) is the 12 month period from 1 April to 31 March each year. PY23 is 1 April 2022 to 31 March 2023

[16] D is distribution only price, D T P is distribution, transmission and other pass-through price, D P is distribution and other pass-through price (no transmission price)

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 .

TOU price categories (which are mandatory from 1 April 2022 for all new commercial consumers, and existing consumers with the metering capability) consist of a daily fixed (Northern network only), volume, capacity, demand, excess demand (for high voltage consumers) and power factor prices. Non-TOU price categories include daily fixed, volume, capacity and power factor prices (no demand prices).

We maintain a relativity in capacity and demand price levels between low voltage, transformer and high voltage price categories, with high voltage price levels 96% of transformer price levels which are, in turn, 96% of low voltage 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 shows the price components applicable to the price categories for the commercial consumer groups, there is no change from the previous year, however the other pass-through prices for have moved to the fixed capacity price component from the volume or demand price component.

Table 6: Price components applicable to commercial price categories [17]

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		✓ D P	✓ D	✓ D T		✓ D	✓
		WLVH	✓ D	✓ D P	✓ D	✓ D T		✓ D	✓
	Non TOU	ALVN, WLVN	✓ D	✓ D P	✓ D T			✓ D	✓
Transformer	TOU	ATXT		✓ D P	✓ D	✓ D T		✓ D	✓
		WTXH	✓ D	✓ D P	✓ D	✓ D T		✓ D	✓
	Non TOU	ATXN, WTXN	✓ D	✓ D P	✓ D T			✓ D	✓
High voltage	TOU	AHVT		✓ D P	✓ D	✓ D T	✓ D	✓ D	✓
		WHVH	✓ D	✓ D P	✓ D	✓ D T	✓ D	✓ D	✓
	Non TOU	AHVN, WHVN	✓ D	✓ D P	✓ D T			✓ D	✓
Zone substation	TOU	AHVT, WZSH		✓ D T P	✓ D	✓ D	✓ D	✓ D	✓

[17] D is distribution only price, D T P is distribution, transmission and other pass-through prices, D P is distribution and other pass-through prices(no transmission price), D T is distribution and transmission prices

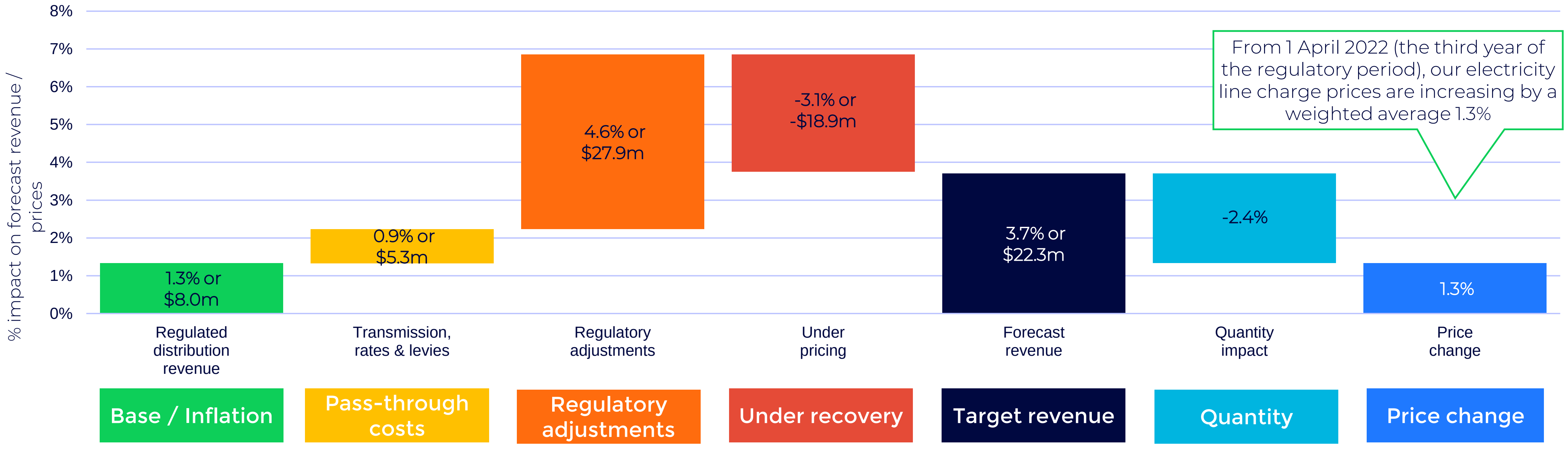
PY2023 PRICE SETTING

PRICE SETTING COMPLIANCE

Our prices are subject to the DPP Determination[18] which states that to be compliant with the price path, forecast revenue (target revenue) must not exceed forecast allowable revenue (revenue cap).

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[19] (including any adjustment to cap the forecast allowable revenue increase to ten percent as required by the DPP Determination).

Figure 3: Change in PY23 forecast revenue and contribution to price change[20]



[18] 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

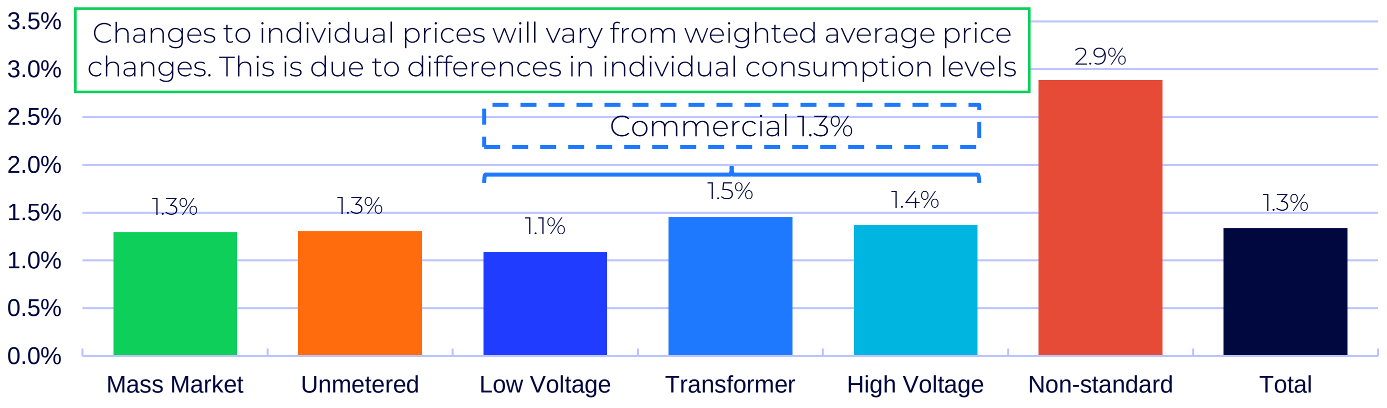
[19] Regulatory adjustments are intangible recoverable costs (not invoiced) such as incentives and wash-ups that impact the amount of line charge revenue that we are allowed to recover. These wash-ups include incremental rolling incentive scheme (IRIS), quality incentive adjustment, capex wash-up adjustment and wash-up account balance and have time value of money included. The amount includes a downwards adjustment to meet the revenue cap

[20] Measured as a change from PY22

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. Figure 4 shows how the weighted average price change is split across the existing consumer groups. Our electricity prices that apply from 1 April 2022, including the previous year's prices that were effective from 1 April 2021, are set out in Appendix 1.[21]

Figure 4: Weighted average price change by consumer group



- 1.3% average weighted price change, priced to be the same across mass market, unmetered and commercial
- Low voltage commercial consumers are lower than average to ensure they remain within their COSM allocation
- 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)

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 recently amended Low Fixed Charge (LFC) regulations.

For unmetered, the transmission and other pass-through prices are moved to the fixed daily price component, so these prices are least distortionary.

For commercial consumers, the price changes are impacted by the transitioning towards 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 transition towards alignment across the networks. The other pass-through prices are moved to the fixed capacity price components, so these prices are least distortionary.

We 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. In August and September 2021, Vector engaged with six retailers and other electricity industry participants on innovative pricing options as outlined in our May 2021 roadmap. Over November and December 2021, Vector conducted 11 retailer consultation meetings with no material issues raised with our proposed price changes.

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

PRICE STRUCTURE CHANGES

We have made three pricing structure changes applicable from 1 April 2022 as shown in Table 7 below.

Table 7: Price structure changes

• Controlled pricing for electric vehicle chargers
Vector has been advocating strongly in many forums for controllable electric vehicle chargers to become standard. As a first step down this path, we have expanded the eligibility criteria for the residential TOU controlled plans to include consumers with smart electric vehicle chargers with IP addresses that are capable of being connected to Vector's distributed energy resources management system (DERMS). Vector is developing the technical specifications and the parameters how the control would take place, and we will advise of those when they are complete. At any stage consumers could opt out and revert to the uncontrolled price plan if they chose. This addition of controllable electric vehicle chargers is about optionality and signalling for the future and we will continue to investigate further enhancements for our price categories.
• New zone substation consumer group
Vector has introduced a new TOU only commercial price plan, for consumers that have a connection directly to a Vector zone substation and/or have paid for their connection assets to Vector's high voltage network. The rationale for adding this consumer group is that provides a more accurate cost allocation by removing the high voltage lines and cables from their cost allocation which are downstream from their point of supply at the zone substation. Please see page 21 for how the prices are determined for the zone substation price categories.
• Mandatory commercial TOU price categories
We have made our commercial TOU price plans mandatory for all new commercial consumers, and for all existing commercial consumers with metering capable of recording half hourly data which contains at least two of the following channels; kWh, KVArh, kVAh. The move to mandatory commercial TOU pricing, follows mass market which was made mandatory from 1 April 2021. TOU pricing means that during peak times the line charges will be higher than during off-peak times, which better reflects the costs of electricity distribution and transmission as high electricity demand puts pressure on the electricity networks. TOU pricing offers residential, general and commercial consumers the ability to reduce their electricity bill by shifting some electricity use from peak to off-peak times. Commercial non-TOU plans will only be available for existing consumers that don't have the metering capability and the capacity of consumer's connection is less than or equal to 345 kVA. If the capacity is greater than 345 kVA and the consumer doesn't have the metering capability, then the consumer must either reduce their connection capacity to 345 kVA or lower; or install metering capable of recording half hourly data.

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 5.

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 PY23 is $625.3m ($603.0m for PY22).

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 6. These key components are categorised by cost driver i.e. either ‘asset’, ‘non-asset’, ‘transmission’ or ‘return’. These categorisations are summarised in Figure 7 and determine the way that the target revenue is allocated to consumer groups.

Figure 5: COSM structure

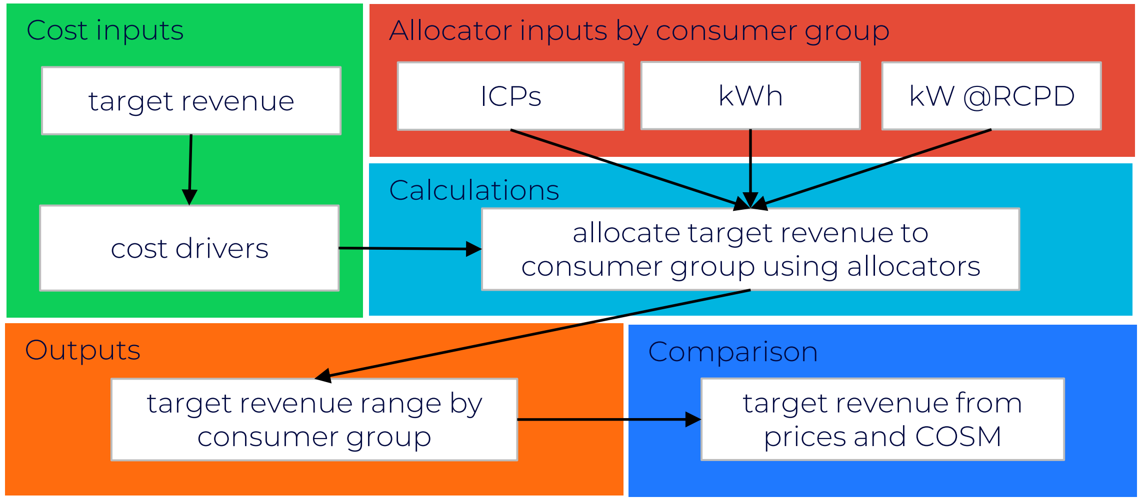


Figure 6: Target revenue by key components

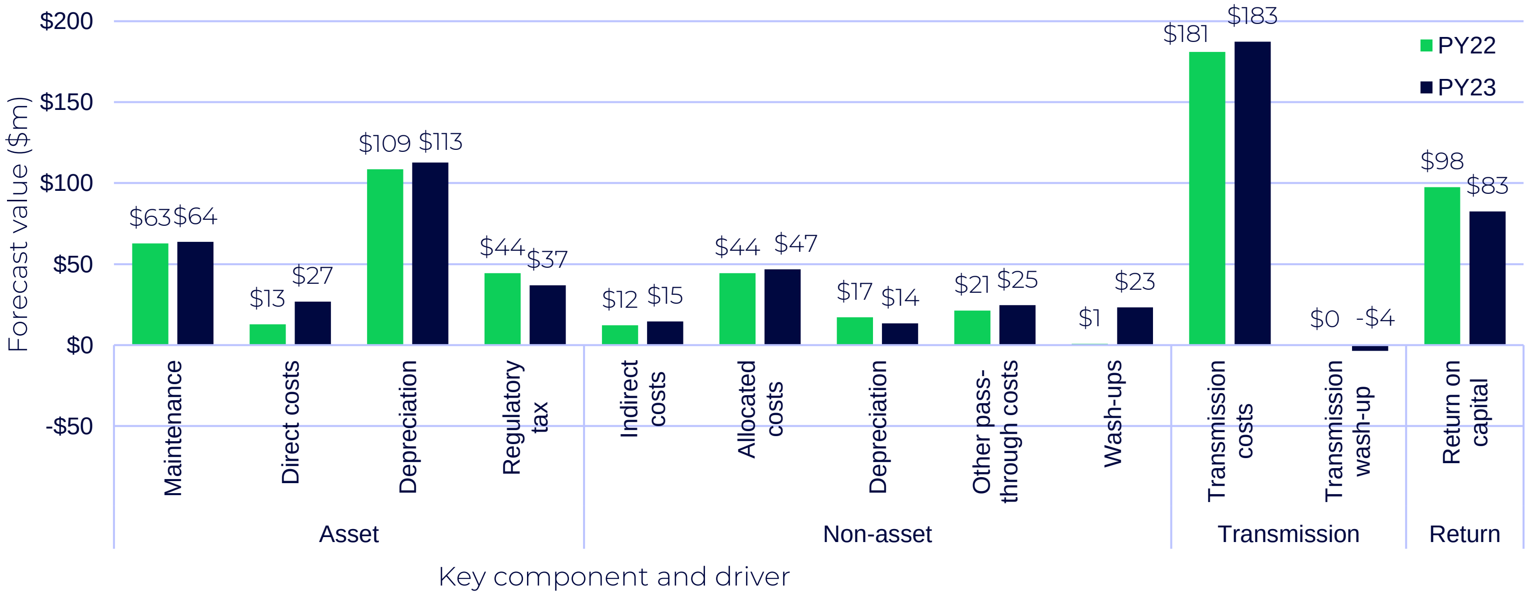
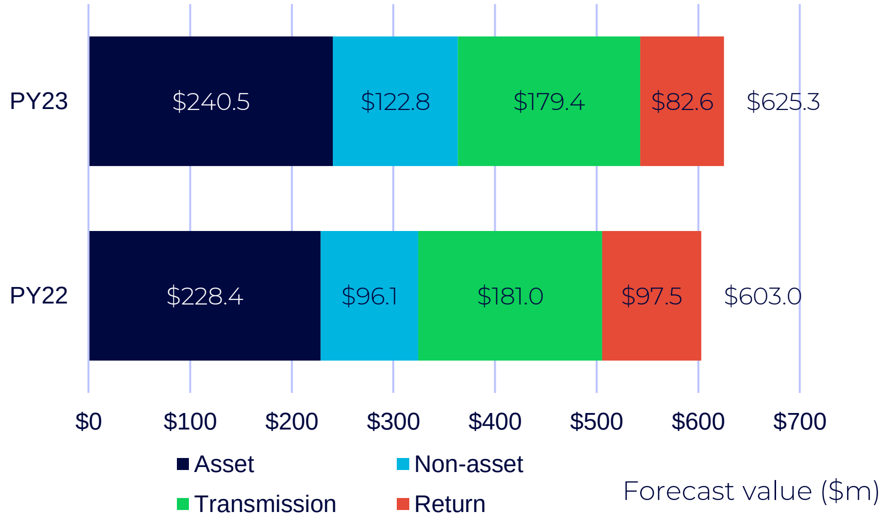


Figure 7: Target revenue by cost driver



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 three distinct categories as shown in Table 8.

We assume that costs associated with assets are incurred in proportion to the value of the assets. For example, as Category A assets make up 73% of the asset value of our Regulatory Asset Base (RAB)[22], we assume that 73% of maintenance costs will be associated with Category A assets.

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 consumers or groups of consumers 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 $629.3m to consumer groups using various cost drivers as summarised in Table 9.

Table 8: Asset categorisation

Asset category	Assets	Consumer groups	Asset value [23] (RAB)	
A	• Sub-transmission lines / cables • Zone-substations • HV lines / cables	All	$2,521m	73%
B	• Distribution substations that have no Vector-owned low voltage lines / cables leaving the substation	Transformer	$62m	2%
C	• Distribution substations that: o have Vector-owned low voltage lines leaving the substation, or o supply multiple end-consumers connected at low voltage • Low voltage assets	Low voltage, unmetered, mass market	$861m	25%

Table 9: Cost drivers used in the COSM

<table>
<tr><th rowspan="2">Consumer group</th><th colspan="3">Asset</th><th rowspan="2">Non-asset</th><th rowspan="2">Transmission</th><th rowspan="2">Return</th></tr>
<tr><th>A</th><th>B</th><th>C</th></tr>
<tr><td>Amount</td><td>$175.9m</td><td>$4.4m</td><td>$60.1m</td><td>$122.6m</td><td>$183.7m</td><td>$82.5m</td></tr>
<tr><td>Mass market</td><td rowspan="5">Contribution to RCPD</td><td rowspan="3">n/a</td><td rowspan="3">Contribution to RCPD or annual consumption</td><td rowspan="5">Number of consumers or annual consumption</td><td rowspan="5">Contribution to RCPD</td><td rowspan="5">Rate of return on assets</td></tr>
<tr><td>Unmetered</td></tr>
<tr><td>Low voltage</td></tr>
<tr><td>Transformer</td><td>Direct</td><td rowspan="2">n/a</td></tr>
<tr><td>High voltage</td><td>n/a</td></tr>
</table>

[22] Broadly the regulatory asset base represents the amount that we have invested in our regulated network, indexed by inflation and adjusted for depreciation

[23] The values are weighted averages of the last five years’ worth of data, with each year being weighted twice the previous year. Contribution to RCPD not obtained for previous two years as aggregated interval consumption data by consumer group was unable to be provided to Vector

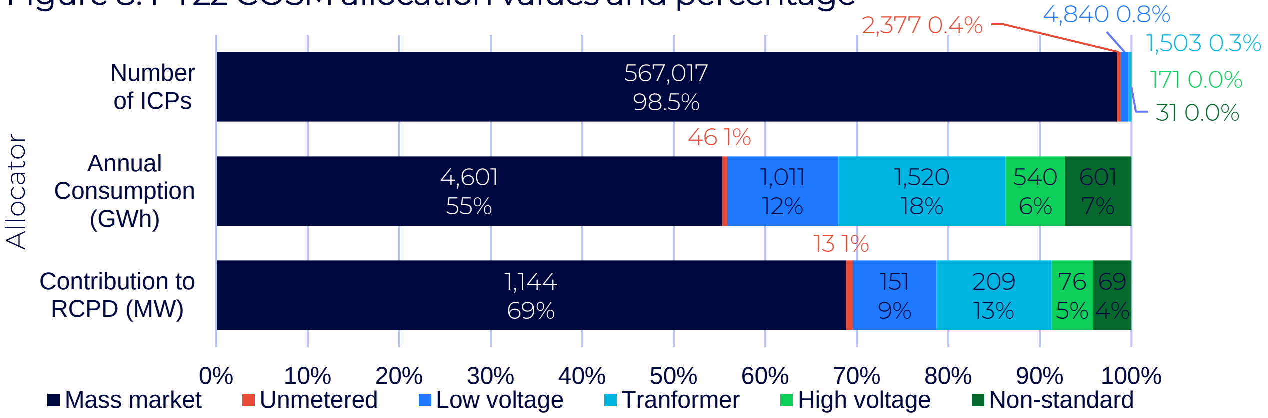
COST DRIVER ALLOCATION APPROACHES

We aim to allocate asset-related costs on the basis of a consumer group's usage of the assets during peak periods, as this usage drives the need for, and the size of, the assets.

- For Category A assets, an appropriate and readily available measure to allocate their costs, is consumer group's contribution to Transpower's Regional Coincident Peak Demand (RCPD)[24] periods.
- 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. We use both allocators to generate a band of cost allocation values as no one allocator is preferred to the other.

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 create a band of cost allocations using annual consumption and the number of consumers as the allocators.

Figure 8: PY22 COSM allocation values and percentage[25]



Costs categorised as 'transmission' are transmission charges from Transpower that we pass through to consumers. Transmission interconnection costs (which form the majority of transmission charges) are charged to us by Transpower on the basis of demand during RCPD periods. We mirror this approach by allocating transmission costs to each consumer group on the basis of that consumer group's demand during these RCPD periods.

'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 constant rate of return across the consumer groups' asset values.

[24] RCPD for a Transmission Region 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

[25] 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

TARGET REVENUE ALLOCATION & PRICE COMPARISON

The result of using the different allocators for category C 'asset costs' and 'non-asset costs' 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 PY23 prices by consumer group compared with the COSM allocations. The result is that PY23 prices produce forecasts that are in or near an acceptable range when compared to target revenue allocations.

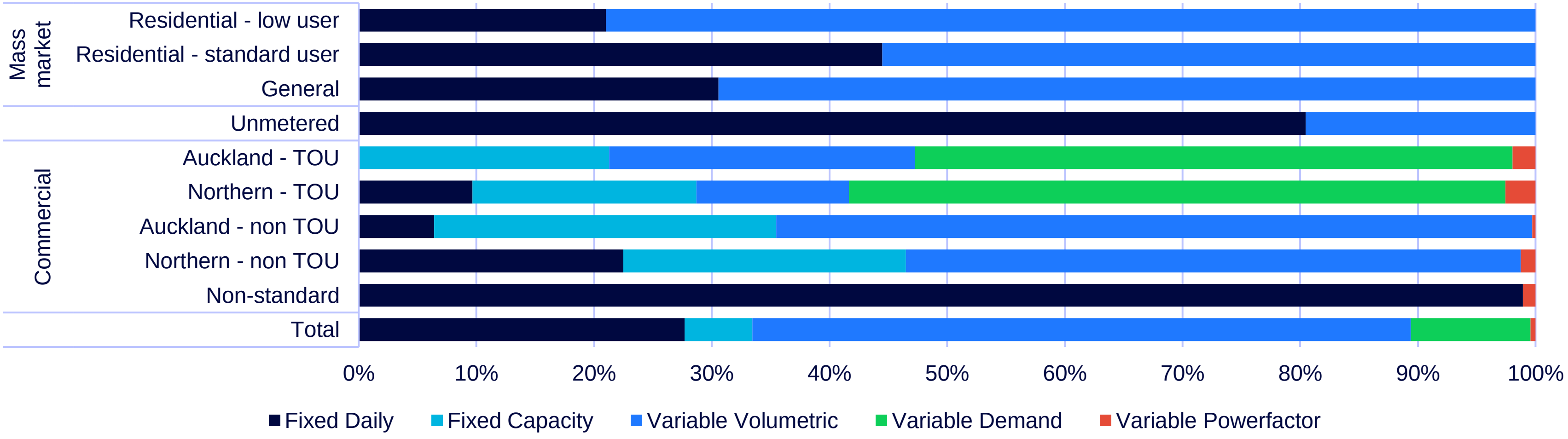
The pricing for non-standard consumers is calculated as per their contracts and is separate from the other consumer groups. The COSM is calibrated to produce the forecasted target revenue of $17.9m (2.9%) to be recovered from the 24 non-standard consumers (30 ICPs).

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: PY23 target revenue from prices compared with COSM allocations

Figure 10: Proportion of PY23 target revenue by price component and category



ZONE SUBSTATION CONSUMER GROUP

A new zone substation consumer group has been introduced, for consumers that have a connection directly to a Vector zone substation and/or have paid for their connection assets to Vector's high voltage network. The zone substation consumer group doesn't have any historic or forecast 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 RCPD and these are compared across the consumer groups. RCPD is how the majority of the costs are allocated to the consumer groups (above 75% for each of the commercial consumer groups) with the balance coming from ICP numbers and energy consumption (kWh). As a proxy for zone substation cost allocators, the allocators for the non-standard consumers were put into the new zone substation consumer group and the COSM was rerun. HV lines and cables from asset category A are not included for the zone substation cost allocation. This provided the relativity in cost per RCPD kW between the consumer groups as shown in Table 11 below. The cost per RCPD kVA for the zone substation consumer group is 79% of cost per RCPD kW for the high voltage consumer group.

Table 10: Cost relativities and consumption patterns

Commercial consumer group	Cost per RCPD kW %		% of commercial quantities		
	% of the above	% of low voltage	RCPD	Capacity	Demand
Low voltage		100%	35%	44%	26%
Transformer	85%	85%	48%	46%	55%
High voltage	91%	77%	18%	10%	19%
Zone substation	79%	61%			

There is a disconnect between how we price power (using kVA for capacity and demand prices) and how the cost is allocated (RCPD kW basis), as they have differing consumption patterns as shown in Table 10. The result is that the relative pricing levels for the existing commercial groups differ to the cost relativities. Assuming that potential zone substation consumers have similar consumption profiles to those on the current high voltage plans, it would allow the price level difference between high voltage and zone substation to match the cost level difference. Therefore a consumer with the average high voltage consumption profile should pay 21% less on zone substation prices compared to high voltage prices. This is the basis for determining the overall price levels required for the zone substation price categories.

The zone substation 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. The principles for determining the price levels for the zone substation price categories are as follows:

- No daily fixed charge, with a fixed charge only through a capacity price, like the existing Auckland network TOU commercial groups.
- Volumetric price to match the kWh allocation in the COSM for transformer, high voltage consumers.
- Capacity and demand to recover the % kW cost allocation and have aligned the capacity and demand prices for simplicity and understandability.
- Excess demand and power factor to be similar to the high voltage consumers, to provide similar price signals.
- Transmission and other pass-through prices are included in the fixed capacity price component to be least distorting, as it doesn't send a price signal for the consumer to change their consumption behaviour.

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. 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[26] 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 payments to any distributed generators. We make Avoided Cost of Transmission (ACOT) payments to distributed generators in accordance with our ACOT methodology. [27]

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 2022 for all distributed generators. As more distributed generation connects this may require more in-depth consideration and as a result pricing may change.

[26] Distributed generator is 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

[27] Further information on our policies for distributed generation can be found at https://www.vector.co.nz/personal/electricity/distributed-generation including ACOT at https://blob-static.vector.co.nz/blob/vector/media/vector/160120_v1-1_vector_dg_acot_policy.pdf

OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS

For PY23, 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

	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: 2.5 hours Rural: 4.5 hours	Urban: 4 Rural: 10	Approx. 600,000
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	6
	10 working days	As soon as practicable	3 hours	Not stated	7
	10 working days	Not stated	3 hours	Not stated	2
	10 working days	Not stated	Not stated	Not stated	2
	30 working days	As soon as practicable	As soon as practicable	Not stated	1
	4 working days	As soon as practicable	3 hours	Not stated	5
	7 working days	As soon as practicable	Priority	3 planned	2
	August each year	Not stated	1 hour	Not stated	1

PRICING REFORM

INTRODUCTION

In this section we will bring together the different elements that contribute to Vector's ongoing pricing reform program. From our corporate strategy to our customers, there are a number of attributes which ensure Vector is always at the forefront of ensuring distribution prices are fit for purpose in a decarbonising society.

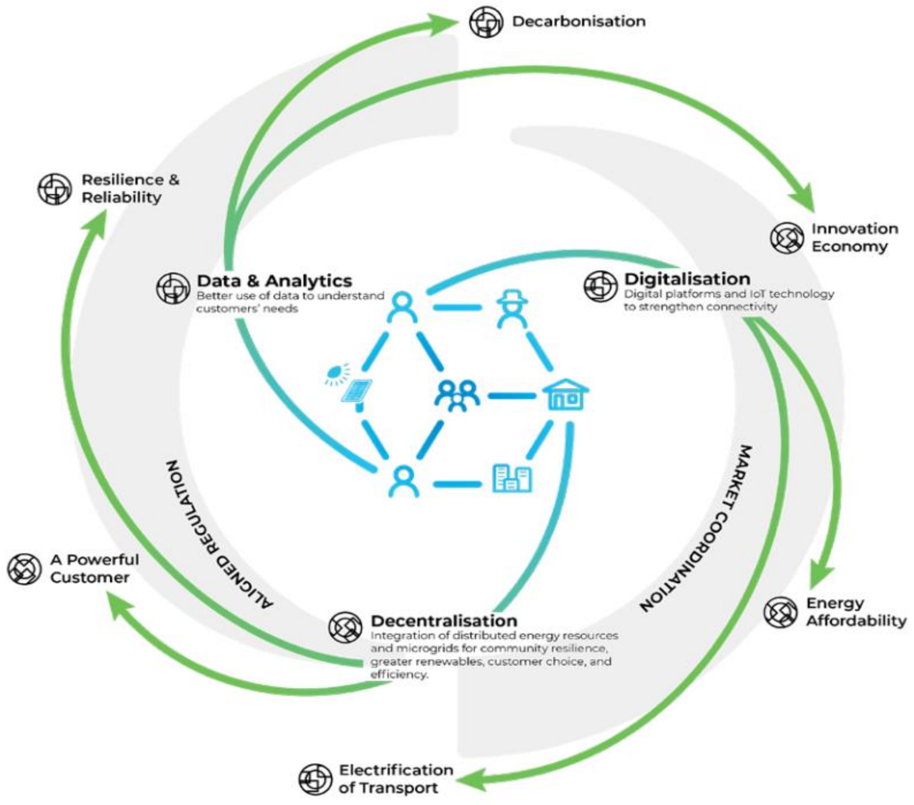
EMBEDDING SYMPHONY

Vector's Symphony Strategy is about creating a system for our customers that fits the future, delivering safe, cleaner, more reliable and affordable energy solutions that are developed with customers at the centre, and which helps us navigate future uncertainty.

Symphony is how we intend to transform the traditional poles and wires of the electricity networks serving the Auckland region into an intelligent energy system where customers have more choice and control.

Supporting Symphony:

- Traditional assets
- New technology
- Digital assets
- Delivering value from data analytics
- Capital contributions
- Line charge prices
- Customer integration/choice and experiences



CONSUMERS AT THE HEART OF OUR PRICING

Pricing is underpinned by consideration of:

- Customer effects & expectations
- Economic theory
- Practical implementation
- Regulatory & public perceptions
- Regulatory requirements
- Revenue risk implications
- Low Fixed Charge regulations
- Societal implications
- Decarbonisation
- Whole electricity system costs
- Historic trends and data analysis

Pricing structures need to satisfy customers needs:

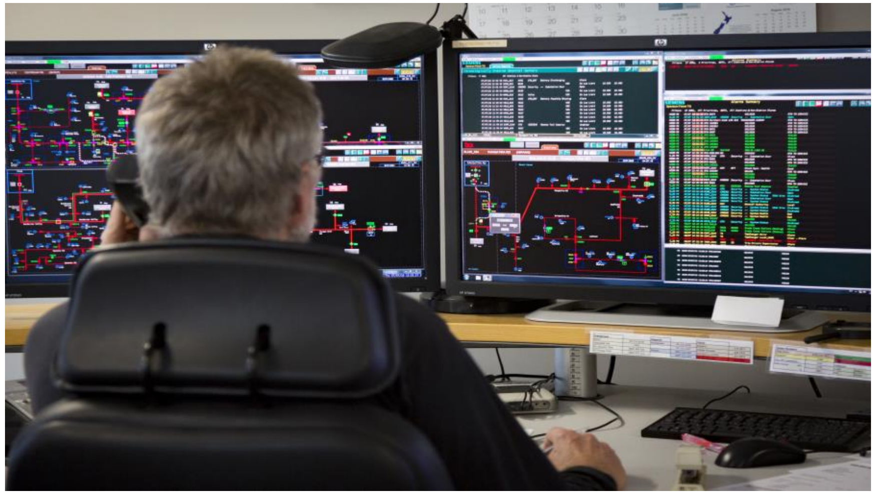
CONSUMER IMPACT

EVOLVING CUSTOMER NEEDS

Evolving customer needs and expectations, centred around the use of new technology and digitalisation, is resulting in massive shifts in service industries across the world. Energy is no different, and we need to be flexible to accommodate significant changes in behaviour at scale. As more adopt new technology to enhance and support their lives, they are becoming stakeholders and participants in the energy system. We are seeing this already with smart EV charging in domestic environments. This shift demands a flexibility and preparedness from Vector to enable a customer-centric electricity distribution system and the integration of new technology in line with technology availability, desired policy outcomes, and customers' expectations.

DATA-DRIVEN INSIGHTS

In addition to our relationships with our customers, and regular engagement, we use a data-driven approach to gather insights beyond what is available from other means. We have long recognised the need for a sophisticated understanding of the impact of our investment decisions on the diverse households and businesses that make up Auckland. To achieve this, we complement the knowledge we gain from the relationships we have with our customers with data and insights generated from analytics, regular structured engagements, daily feedback from customers, and often qualitative techniques. One of the more recent tools we have built to inform our network planning and ensure it will deliver the best outcomes for customers is our Granular Auckland Customer Model. The Granular Auckland Customer Model is built by including all customers connected to Auckland's electricity and gas networks. The importance of such robust analysis cannot be understated in the context of reliability of supply, multi-million-dollar investment decisions for critical electricity network infrastructure and the societal paradigm shift to decarbonisation.



ANALYSIS: COST ALLOCATION BY DEPRIVATION INDEX

As part of our 2021 Asset Management Plan, Vector produced some analysis on different customer demographics and neighbourhoods; with a particular focus on equity and understanding energy poverty and hardship. This is achieved through greater understanding of demographic energy use patterns. Understanding load profiles across a range of customer segmentation is important for the design of cost-reflective electricity tariffs which need to consider the impact on lower-income customers who spend a higher share of their income on electricity bills; this is something we continue to explore as we evolve our pricing.

More than two thirds of our customers would like to see information about the difference in the cost of electricity at peak time vs off-peak (Vector customer survey, Jan 2021)

PRICE SIGNALLING

Trade-offs between competing objectives:

- Service based/cost reflectivity – what is the customer purchasing, what drives Vector and customer investment?
- Simplicity/acceptability – could the customer understand the pricing, is it sufficiently predictable to be actionable?
- Bill impact – what are the customer-level drivers of their cost changes?

Successful pricing reform will not be just about economics. Careful consideration of the trade-off between the extent of cost-reflectivity and the practical understanding of the price signal is paramount. Consideration is also needed of bill impacts resulting from moving to new pricing. This transition needs to be careful managed especially in regard to vulnerable consumers. We welcome the section in the EA's 2nd Edition Practice Note which recognised this balance (see below).

With the introduction of Distributed Generation (DG) and increasing demand from e.g. electric heating and Electric Vehicles (EVs) and with the increasing capability of some resources to respond to time signals, time-of-use gains a higher importance than in the past. In such cases, a cost-reflective distribution tariff may require to be time-differentiated. While care should be given to the potentially conflicting time signals given by the time-of-use energy prices, (static) time-of-use tariffs, especially for larger consumers, can be a useful tool for reducing system peak-load, which is a main driver for network investments, thereby promoting network efficiency.

From the EA's Practice Note 2nd Edition:
Due to the differences between networks now, and the paths each will take in the years ahead as the country responds to the challenge of the low emissions future, as well as different evolutions of customer demands and consumption patterns, it is not possible to establish a single blueprint for efficient pricing for all networks.
In recognising that every network is different the Authority accepts that trade-offs will impact networks differently and be managed differently, in accordance with how each distributor plans its pricing reform.

Price vs Quality

Non-exempt Electricity Distribution Businesses (EDBs)[28] in New Zealand are regulated through price-quality paths meaning that while price is integral to the good performing electricity networks, the reliability and resilience of those networks is equally as important.

Investing efficiently

Investing in assets to meet demand peaks, which are underutilised during other times, could result in overbuilding of infrastructure and a significant cost associated with the electrification of the economy. To minimise this, we need to actively manage demand and unlock new value at the demand side of the electricity supply chain to minimise costs to consumers. For Vector, this includes data analytics, distributed energy solutions, and the digitalisation of the network. Through making these investments now, we believe we can better manage peak demand and avoid unnecessary investments in traditional pole and wire solutions which will burden future generations with long-term cost recoveries.

Whole Energy System Cost (WESC)

We encourage regulators to consider the WESC when assessing investments and designing regulation. The WESC was initially commissioned by the UK Department of Business, Energy and Industrial Strategy to capture the wider costs and benefits associated with different generation technologies. It was extended by the ReCosting Energy project to also assess demand-side technologies within this whole system framework.

Vector commissioned Frontier to apply this to the NZ energy market[28]. The WESC makes the true consumer value of digital and demand response technologies visible – revealing that the potential value of these technologies is accrued across multiple parts of the energy system. In our view the current market does not send signals which incentivise the most efficient investments for consumers as decisions and investments in our electricity system are assessed in strict market silos – i.e., by generators, the transmission network, distributors, and consumers separately. Decisions within these silos do not reflect the impact of investments on the whole electricity system.

[28] Non-exempt EDBs are subject to price-quality and information disclosure requirements – they are outlined here

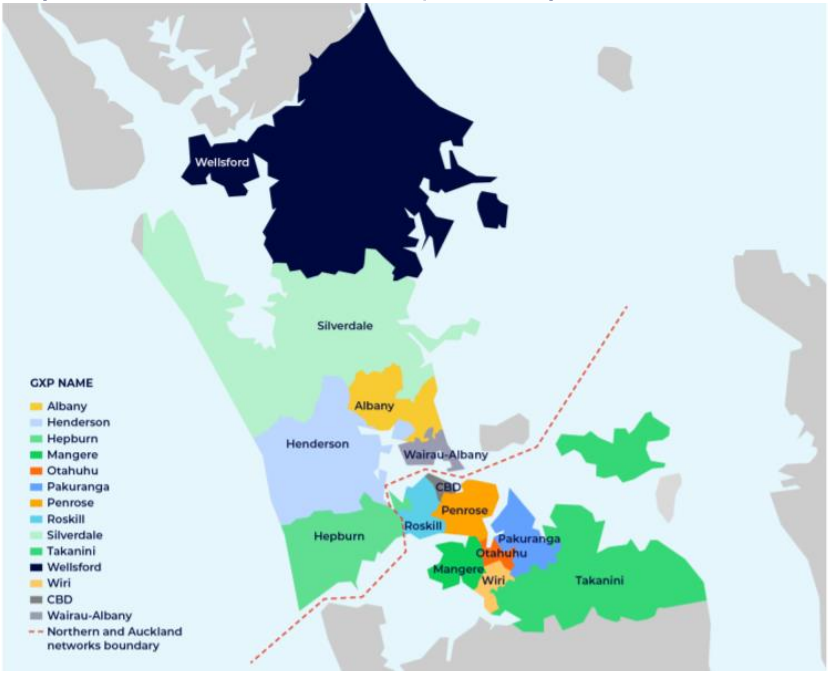
[29] https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/annex-3-whole-system-costs-in-nz.pdf

NETWORK CHARACTERISTICS

Our pricing reform program will consider (amongst others) the following key characteristics reported in our annual Asset Management Plan (AMP):

DER uptake
We are actively enabling the new energy future through our use of demand management and our DERMS (DER Management System) to control and manage DERs. The DERMS is an integrated platform that enables Vector Ltd to manage a large fleet of DERs as a single system. Demand management enables Vector Ltd to remotely control when specific loads are turned on to manage the demand on the network. Together, our demand management systems and DERMS enable reduction of peak demand that needs to be supplied through our network, therefore allowing us to defer investment, maintain reliability and minimise costs to our customers.

Figure 11: Vector's network planning areas



Zone Substations
There are 110 zone substations on our network which makes it challenging to price at that level of locational granularity

Regional variations
Explain how we assess the differences between our planning areas in the pricing models (and if we don't why we don't)

Utilisation
Our AMP disclosure reports demand at a transformer level within our 14 planning areas (see Figure 11 to the left). As much as we pay attention to keeping costs to a minimum and therefore impacting our prices at a macro level, the large number of transformers within our region makes it extremely complex to link our pricing at such a granular level. However we believe access to smart meter data will assist us in combining utilisation metrics directly into our pricing models

PRICING DEVELOPMENTS

vector electricity

Low Fixed Charges – Vector welcomes Cabinet's decision to revoke the LFCs at the end of 2022. The LFCs created challenges under the current regulatory framework in setting prices. Phasing them out will remove inefficiencies and inequities as the majority of distributors' costs are fixed and hence could be more efficiently recovered via some form of fixed charge.

Transmission Pricing Methodology – Vector has responded to the Transpower's TPM consultation and we await the final decision for implementation from April 2023. The proposed TPM reflects the Authority's 2020 TPM guidelines, which have significant flaws. We do not consider the proposed TPM is in the long-term benefit of consumers as it will result in a substantial wealth transfer from consumers to generators.

Controllable Tariff – Vector has expanded the eligibility criteria for the residential time of use controlled price categories to include consumers with smart electric vehicle chargers with IP addresses that are capable of being connected to Vector Ltd.'s distributed energy resources management system (DERMS).

EA guidance – Following the EA's workshop and consultation on Distribution pricing in the last quarter of 2021, they released their refreshed the Practice Note in December 2021 which was useful to ascertain not only the Authority's direction but also to understand the issues and opportunities that other EDBs are facing.

Innovative Pricing – please see our Pricing Roadmap for further details of the progress made on our innovative pricing program

Access to data - To assess the potential impacts of new line charge pricing models on consumers, it is essential that distributors have access to half-hourly consumer usage data at the ICP level. The current lack of access to this data is providing a barrier to the development and assessment of new pricing models. Please see the next slide for further details on data.

For further information on our future pricing developments, please see our electricity roadmap which is available at https://www.vector.co.nz/ personal/electricity/about-our-network/pricing under the heading "consumer-led pricing design". The roadmap is an evolving document and is updated periodically, but at least twice a year.

ACCESS TO DATA

Increasing visibility on the network provides the foundations for improved customer service

Table 13: List of enhanced network services enabled by access to data

Enhanced Network Services	Supporting Data
ICP mapping & connectivity	kWh, Voltage, Current, Power Factor, phase angle, total harmonic distortion (THD)
Demand Analysis and Forecasting	kWh, kVA
Transformer Voltage and Demand Profiling	kWh, Voltage, Current, Power Factor, phase angle, THD
Outage management	Last gasp / ping
Real-time Dynamic Voltage Management	kWh, Voltage, Reverse power, Power out, Power on
DER Identification	kWh, Reverse power
Public Safety	Impedance change (Voltage, Current)

Negotiations active with multiple metering equipment providers (MEPs) to access operational data but will take time: software and hardware updates for MEPs; data standards / delivery details; integrating and using data effectively

PRICING CHALLENGES

PASS-THROUGH

The impact of distribution pricing reform will be muted when distribution pricing signals are not passed through in some form in retail prices. There appears to be little return from developing more sophisticated price signals if these signals are lost or distorted when retailers re-bundle our prices. We suggest that the EA consider investigating this issue and ensure that retailers pass through efficiencies.

Ensuring price decreases from regulatory resets are passed through to consumers. This is important in: 1) ensuring energy affordability, 2) enabling consumers to make more informed decisions regarding DER investments, and 3) providing consumers greater control over their electricity expenditure that would instil confidence and promote their participation in energy markets.

OTHER SECTORS

At Vector we are keen to learn from other sectors and the difficulties they have overcome in order to learn and implement the right kinds of reform. In 2022 we will be taking a closer look at any lessons we can take away from the telecommunications industry in NZ.

We are also watching the impact of carbon pricing when it is introduced into the electricity sector. Although carbon pricing will affect generation costs primarily, the knock on effect on the end consumer will be interesting to observe as it could distort the price signals at a distribution level. While generation costs could increase and customer prices are impacted we could see users implementing energy efficiency measures in order to decrease usage and balance off the higher costs.

EV CHARGING TARIFF

Vector continues to explore different ways to price specifically for DERs including EVs. Before we implement these type of reforms we are looking to test and trial first. We are already learning from our very own Smart EV Charging Trial. See our Case Study on the next two slides

CASE STUDY: EV SMART CHARGING TRIAL

vector electricity

VEHICLE-TO-GRID TRIAL

EV NETWORK INTEGRATION GREEN PAPER

COMMERCIAL EV CHARGING GUIDE

VEHICLE-TO-HOME TRIAL *EECA LEVCF*

BATTERY INDUSTRY GROUP LAUNCHED

ELECTRIC BUS PARTNERSHIP WITH AT

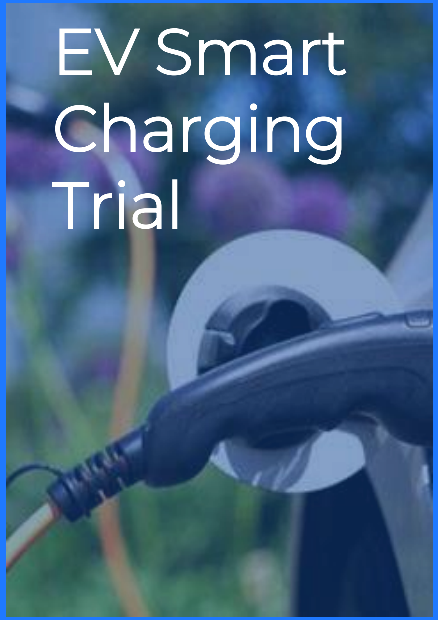
1st ELECTRIC BUS ON WAIHEKE

2016 | **2017** | **2018** | **Q1/2 2019** | **Q3/4 2019** | **Q1 2020** | **Q2 2020** | **Q3 2020** | **Q4 2020** | **Q1 2021** | **Q2 2021** | **Q3 2021** | **Q4 2021**

1,000 EVs in Auckland

5,000 EVs in Auckland

10,000 EVs in Auckland



Recruitment Begins in Auckland
~120 Residential EV Owners

Smart Charging Tests Begin in Auckland
Assess current behaviour and smart charging methods
Completed Q4 2021

Recruitment Begins in Waiheke
EECA LEVCF
~80 Res. EV Owners

Smart Charging Tests Begin in Waiheke
Assess current behaviour and smart charging methods
Disrupted by COVID-19

Summary of Activities:

- Recruit and install ~200 Residential 7kW smart, connected chargers
- Analyse smart meter and smart charger data to understand impact of unmanaged charging
- Develop and test multiple EV smart charging methods to integrate EV charging on network

Objectives:

- Share real-world EV charging data
- Understand customer satisfaction with network managed smart charging methods
- Demonstrate network integration of EV charging while maintaining customer satisfaction
- Inform EV Connection and Standards Guidelines

CASE STUDY: EV SMART CHARGING TRIAL

Our partnership with EVnex showed the value of remotely managed EV charging by a third party, with little direct consumer interaction or impact on experience. The key learnings are outlined below:

- Access to data on network conditions and locations of EV adoption will be valuable during early stages of the transition to transport electrification (sensitivity of ADMD[28])

- Customers were highly satisfied with all network managed EV charging options

- Smart charging effectively reduced demand during traditional network peak times

- The charging data collected is being used to explore other network impacts such as thermal and voltage impacts on LV networks from EV clustering and to update the assumptions used for our customer model.

[28] After Diversity Maximum Demand (ADMD) is used in the design of electricity distribution networks where demand is aggregated over a large number of customers. ADMD accounts for the coincident peak load a network is likely to experience over its lifetime and as such is an overestimation of typical demand

PRICING OVERSEAS – EUROPEAN UNION

- The European Union Agency for the Co-operation of Energy Regulators (ACER) each year publish a report on Distribution Tariff Methodologies in Europe[29]

- We were particularly interested in what the European Union (EU) member states have introduced for EV charging and time signalling

- As you can see from the summary to the right, pricing reform in the EU is limited with very few tariffs specifically for EV charging points. The limitation continues when we explore tariffs for both power-to-grid facilities and/or energy communities such as micro-grids where only Portugal has a specific tariff regime for self-consumption

- It is also interesting to note that the most common pricing tool for time signalling in the EU is the day/ night time differentiation with less than half using volume or capacity based tariffs

The distribution tariff treatment of EV recharging points

- Italy: operators of dedicated public points for electric vehicle recharging can opt for a special tariff structure, which is energy-based only

- Portugal: the distribution tariff is converted into an energy-only charge (EUR/kWh), the tariff applies to EV users through their electricity mobility supplier, and not to charging points operator

- Spain: there is a specific tariff (where the energy component has greater weight), which can be optionally chosen by the operator of the publicly accessible EV re-charging station

Time signals

Distribution tariffs for withdrawal in all Member States are subject to variation

- For all member states except Malta the main factors for variations is the voltage level
- 17 member states have integrated a time element in the tariff
- Only one member state has tariff variation by location
- The most commonly used time differentiation is a day/night differentiation
- In 9 member states, time differentiation is only energy-based
- In 8 member states time differentiation is both power and energy-based
- Dynamic tariffs are not implemented in any member state

[29] https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20D-Tariff%20Methodologies.pdf

PRICING OVERSEAS – CALIFORNIA, USA

Another jurisdiction we looked at was California, given its very advanced position with DER adoption. The Regulatory Assistance Project recently published a report[30] about TOU tariffs. They believe that getting TOU rate design right should be emphasized both in the short term — as an alternative to a large grid participation charge, (which is one of the tariff options in California structured as a monthly fee per kW of installed capacity) — and in the context of longer-term rate design reform. In short, ensuring that TOU rates for new DER customers have sufficiently low daytime prices is likely to be a more economically efficient way to reduce cost shifts.

> The goals of TOU rate design are much the same as all rate design, and indeed utility regulation generally. The desire of economic efficiency must be balanced with the need for customer understanding, costs must be allocated equitably across all customers, and overall revenue levels must provide the utility a reasonable opportunity for a fair rate of return. Compared to flat volumetric kWh rates, TOU rates are attempting to better correspond to predictable fluctuations in the marginal costs, both short- and long-run, of the electric system . Seasonal distinctions can also be important in a TOU rate structure, although such distinctions are possible in simpler rates.

[30] The Complex Landscape of Net Metering Reform in California: Ensuring A Smart TOU Rate Foundation - Regulatory Assistance Project (raponline.org)

APPENDICES

APPENDIX 1 - LINE CHARGE PRICES FROM 1 APRIL 2022

Table 14: Mass market and unmetered line charges prices
(previous price, if changing)

Consumer group and subgroup		Price category type	Price category description	Price category codes	Estimated number of consumers (PY23 avg.)	Total line charge prices – Daily $/day -FIXD	Total line charge prices – Daily $/day/fitting -FIXD	Total line charge prices – Volume – anytime $/kWh -24UC	Total line charge prices – Volume – anytime $/kWh -AICO	Total line charge prices – Volume – off-peak $/kWh -OFPK	Total line charge prices – Volume – peak $/kWh -PEAK	Total line charge prices – Volume – injection $/kWh -INJT	Transmission charge price* – Volume – anytime or peak $/kWh -24UC, -AICO or -PEAK
Mass market	Residential - low user	TOU	Uncontrolled	ARHL WRHL	32,952 22,203	0.30 *(0.15)*				0.0603 *(0.0658)*	0.1579* *(0.1647)**	-	0.0976 *(0.0992)*
Mass market	Residential - low user	TOU	Controlled	ARHLC WRHLC	160,868 104,858	0.30 *(0.15)*				0.0603 *(0.0658)*	0.1378* *(0.1446)*	-	0.0775 *(0.0791)*
Mass market	Residential - low user	Exemption	Uncontrolled	ARUL WRUL	914 616	0.30 *(0.15)*		0.0904* *(0.0963)**				-	0.0327 *(0.0349)*
Mass market	Residential - low user	Exemption	Controlled	ARCL WRCL	4,464 2,910	0.30 *(0.15)*			0.0842* *(0.0901)**			-	0.0265 *(0.0287)*
Mass market	Residential - standard	TOU	Uncontrolled	ARHS WRHS	19,623 18,655	1.12 *(1.09)*				0.0229 *(0.0230)*	0.1205* *(0.1219)**	-	0.0976 *(0.0992)*
Mass market	Residential - standard	TOU	Controlled	ARHSC WRHSC	92,029 70,089	1.12 *(1.09)*				0.0229 *(0.0230)*	0.1004* *(0.1018)**	-	0.0775 *(0.0791)*
Mass market	Residential - standard	Exemption	Uncontrolled	ARUS WRUS	545 518	1.12 *(1.09)*		0.0530* *(0.0535)**				-	0.0327 *(0.0349)*
Mass market	Residential - standard	Exemption	Controlled	ARCS WRCS	2,554 1,945	1.12 *(1.09)*			0.0468* *(0.0473)**			-	0.0265 *(0.0287)*
Mass market	General	TOU		ABSH WBSH	32,201 20,406	1.12 *(1.09)*				0.0229 *(0.0230)*	0.1205* *(0.1219)**	-	0.0976 *(0.0992)*
Mass market	General	Exemption		ABSN WBSN	5,155 3,267	1.12 *(1.09)*		0.0530* *(0.0535)**				-	0.0327 *(0.0349)*
Unmetered	General	Unmetered		ABSU WBSU	1,713 732		0.0813* *(0.08)*	0.0257 *(0.0257)**				-	0.0317 *(0.0196)*

* The transmission charge price is only included in this component of the line charge price

APPENDIX 1 - LINE CHARGE PRICES FROM 1 APRIL 2022

Table 15: Commercial TOU line charge prices
(previous price, if changing)

Consumer group	Price category type	Price category code	Estimated number of consumers (PY23 avg.)	Total line charge prices: Daily $/day -FIXD	Capacity $/kVA/day -CAPY	Volume anytime $/kWh -24UC	Demand $/kVA/day -DAMD	Excess demand $/kVA/day -DEXA	Power factor $/kVAr/day -PWRF	Volume injection $/kWh -INJT	Transmission charge price*: Capacity or Demand $/kVA/day -CAPY or -DAMD
Low voltage	TOU	ALVT	1,436		0.0469 *(0.0441)*	0.0123 *(0.0126)*	0.3123* *(0.3063)**		0.2917	-	0.1658 *(0.1828)*
		WLVH	263	11.15 *(11.37)*	0.0396 *(0.0356)*	0.0053 *(0.0054)*	0.2924* *(0.2759)**		0.2917	-	0.1658 *(0.1828)*
Transformer	TOU	ATXT	993		0.0450 *(0.0432)*	0.0123	0.2998* *(0.3001)**		0.2917	-	0.1658 *(0.1828)*
		WTXH	263	11.15	0.0380 *(0.0349)*	0.0053	0.2807* *(0.2704)**		0.2917	-	0.1658 *(0.1828)*
High voltage	TOU	AHVT	150		0.0432 *(0.0419)*	0.0123 *(0.0119)*	0.2878* *(0.2910)**	0.9504 *(0.9218)*	0.2917	-	0.1658 *(0.1828)*
		WHVH	26	11.15 *(10.82)*	0.0365 *(0.0339)*	0.0053 *(0.0051)*	0.2695* *(0.2623)**	0.8030 *(0.7458)*	0.2917	-	0.1658 *(0.1828)*
Zone substation	TOU	AZST	0		0.1228*	0.0058	0.1228	0.8000	0.2917	-	0.0829
		WZSH	0		0.1228*	0.0058	0.1228	0.8000	0.2917	-	0.0829

* The transmission charge price is only included in this component of the line charge price

APPENDIX 1 - LINE CHARGE PRICES FROM 1 APRIL 2022

Table 16: Commercial non-TOU line charge prices *(previous price, if changing)*

Consumer group	Price category type	Price category code	Estimated number of consumers (PY23 avg.)	Total line charge prices: Daily $/day -FIXD	Total line charge prices: Capacity $/kVA/day -CAPY	Total line charge prices: Volume anytime $/kWh -24UC	Total line charge prices: Power factor $/kVAr/day -PWRF	Total line charge prices: Volume injection $/kWh -INJT	Transmission charge price*: Volume anytime $/kWh -24UC
Low voltage	Non TOU	ALVN	2,428	1.83 *(1.87)*	0.0469 *(0.0441)*	0.0553* *(0.0568)**	0.2917	-	0.0164 *(0.0181)*
Low voltage	Non TOU	WLVN	959	5.92 *(6.04)*	0.0396 *(0.0356)*	0.0340* *(0.0351)**	0.2917	-	0.0164 *(0.0181)*
Transformer	Non TOU	ATXN	171	1.83	0.0450 *(0.0432)*	0.0553* *(0.0557)**	0.2917	-	0.0164 *(0.0181)*
Transformer	Non TOU	WTXN	140	5.92	0.0380 *(0.0349)*	0.0340* *(0.0344)**	0.2917	-	0.0164 *(0.0181)*
High voltage	Non TOU	AHVN	7	1.83 *(1.77)*	0.0432 *(0.0419)*	0.0553* *(0.0540)**	0.2917	-	0.0164 *(0.0181)*
High voltage	Non TOU	WHVN	0	5.92 *(5.74)*	0.0365 *(0.0339)*	0.0340* *(0.0334)**	0.2917	-	0.0164 *(0.0181)*

* The transmission charge price is only included in this component of the line charge price

APPENDIX 2 –TARGET REVENUE RECOVERY

Table 17: Proportion of mass market target revenue by price component

Consumer group and subgroup		Price category description	Code Auckland	Fixed Daily	Variable Volumetric	Code Northern	Fixed Daily	Variable Volumetric
Mass market	Residential - low user	TOU - uncontrolled	ARHL	0.58%	2.18%	WRHL	0.39%	1.66%
		TOU - controlled	ARHLC	2.82%	9.89%	WRHLC	1.84%	7.27%
		Exemption - uncontrolled	ARUL	0.02%	0.05%	WRUL	0.01%	0.05%
		Exemption - controlled	ARCL	0.08%	0.37%	WRCL	0.05%	0.22%
	Residential - standard user	TOU - uncontrolled	ARHS	1.28%	1.77%	WRHS	1.22%	1.71%
		TOU - controlled	ARHSC	6.02%	7.30%	WRHSC	4.58%	5.62%
		Exemption - uncontrolled	ARUS	0.04%	0.03%	WRUS	0.03%	0.03%
		Exemption - controlled	ARCS	0.17%	0.20%	WRCS	0.13%	0.14%
	General	TOU	ABSH	2.11%	4.95%	WBSH	1.33%	2.82%
		Exemption	ABSN	0.34%	0.82%	WBSN	0.21%	0.47%
Unmetered		Unmetered	ABSU	0.34%	0.08%	WBSU	0.22%	0.05%

Table 18: Proportion of commercial target revenue by price component

Consumer group	Short description	Category Auckland	Fixed Daily	Fixed Capacity	Variable Volumetric	Variable Demand	Variable Power factor	Category Northern	Fixed Daily	Fixed Capacity	Variable Volumetric	Variable Demand	Variable Power factor
Low voltage	TOU	ALVT	-	1.02%	1.02%	2.20%	0.13%	WLVH	0.17%	0.16%	0.11%	0.49%	0.03%
	Non TOU	ALVN	0.26%	1.14%	2.55%	-	0.01%	WLVN	0.33%	0.33%	0.69%	-	0.01%
Transformer	TOU	ATXT	-	1.85%	2.21%	4.28%	0.13%	WTXH	0.19%	0.49%	0.30%	1.33%	0.06%
	Non TOU	ATXN	0.02%	0.12%	0.24%	-	0.00%	WTXN	0.05%	0.08%	0.20%	-	0.01%
High voltage	TOU	AHVT	-	0.46%	0.84%	1.48%	0.05%	WHVH	0.02%	0.09%	0.10%	0.37%	0.01%
	Non TOU	AHVN	0.00%	0.00%	0.01%	-	0.00%	WHVN	-	-	-	-	-
Zone substation	TOU	AZST	-	-	-	-	-	WZSH	-	-	-	-	-

APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

The EA's Pricing Principles[31] (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 19: 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 both for individual consumers and for groups of consumers. The avoidable cost for an individual consumer is the cost of connecting that consumer to the network, and therefore excludes the cost of shared assets. The avoidable cost for a group of consumers is the cost of connecting that group of consumers 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 consumer. Our capital contributions policy ensures that individual consumers 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 consumers, it can be difficult to apply these on a consumer-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. 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 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.

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

APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

Principle (a): Economic costs of service provision (cont.)
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 consumers are structured in a very service reflective manner, utilising a variety of prices (daily, capacity, demand, volumetric, power factor) while our mass market prices are two part time of use, reflecting that peak usage is a general driver of investment over time. The mass market peak to off-peak differential is the transmission price whereas the transmission price for commercial consumers is through the demand charge. Including the transmission price in this way, closely reflects how the transmission costs are charged to us by Transpower on the basis of demand during RCPD periods. This approach will be reviewed once the EA's decision on the Transmission Pricing Methodology is finalised. We offer controlled load prices to residential end consumers in return for the ability to remotely manage their hot water cylinders and electric vehicles. This pricing approach signals the benefits to consumers of allowing us 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.

Self assessment score: 3.5 / 5	Further work required 1) once the TPM is finalised; 2) to review price signalling in relation to non-network alternatives (NWAs) (Vector currently has registrations of interest (ROIs) for NWAs out in Warkworth which we will learn from this year); 3) further exploration of the relationship between prices and service capacity

APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

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.

Self assessment score: 3 / 5	Further work required: supporting information for our assessment of price responsiveness of demand

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 transmission and 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.

Self assessment score: 4 / 5	Further work required: to review price signalling in relation to NWAs (Vector currently has ROIs for NWAs out in Warkworth which we will learn from this year)

APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

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 behaviour will result in significant changes to cost allocations between consumer groups. A simple pricing structure also makes it easier for consumers to understand and estimate their likely costs. We are particularly conscious of the effect of our pricing on consumers and seek to implement a pricing framework that provides appropriate incentives 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 will continue to undertake a range of trials so that we can 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 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 end consumers 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.

Self assessment score: 4 / 5	Further work required: 1) exploration of locational pricing and reasoning behind non-implementation at more granular level; 2) continue to engage and consult in order to evolve our pricing structures; 3) continue to link network characteristics and planning objectives with price setting

APPENDIX 4 – 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.

Director

Director

24 February 2022

Date