Pricing methodology -
Electricity distribution network

From 1 April 2017

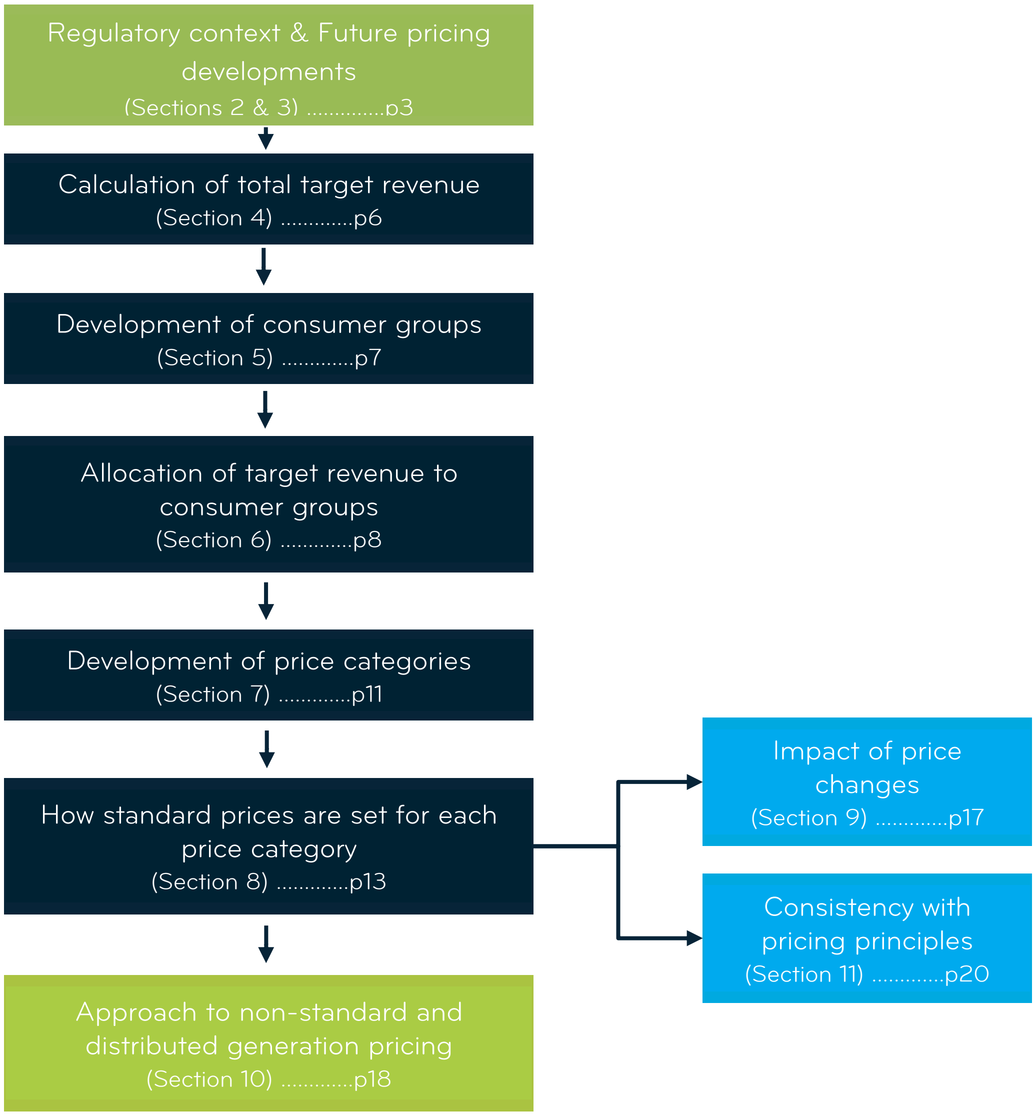
Pursuant to:
The Electricity Distribution
Information Disclosure Determination 2012 (consolidated in 2015)

1 INTRODUCTION

Vector owns and operates the electricity distribution network in the greater Auckland region and delivers electricity to more than 550,000 homes and businesses. We recover the cost of owning and operating the network through a combination of standard (published) and non-standard prices for electricity lines services, and capital contributions for new connections.

We are regulated by the Commerce Commission (Commission) and are required to publish our pricing methodology for electricity lines services (Pricing Methodology). This document describes our methodology and meets the requirements of the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) (Disclosure Determination). It provides information to assist interested parties in understanding how our electricity lines prices are set.

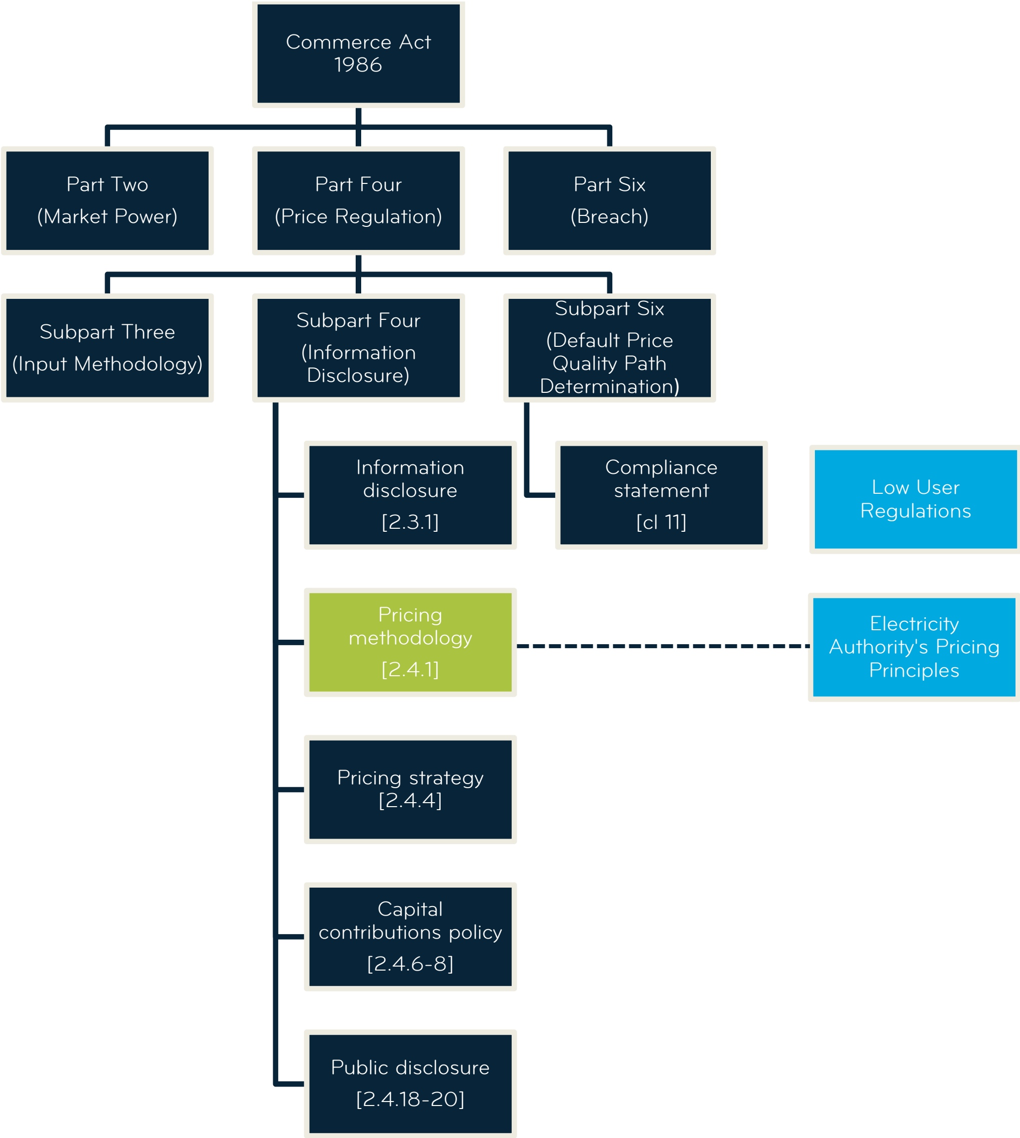
Figure 1. Process used to allocate costs and set prices



2 REGULATORY CONTEXT

This sections sets out the regulatory context within which we provide electricity lines services. It provides an overview of three main areas:

- Commerce Act regulation
- Low User regulation
- Electricity Authority Pricing Principles



2.1 Commerce Act regulation

Under the Commerce Act 1986 (the Act) the Commission regulates markets where competition is limited, including electricity distribution services. Under the Act, the Commission makes two determinations directly relevant to our annual electricity price-setting process:

- Price-Quality Path Determination
- Disclosure Determination

Price-Quality Path Determination
Our electricity network prices are subject to the Electricity Distribution Services Default Price-Quality Path Determination 2015 (Price-Quality Path Determination). The Price-Quality Path Determination sets our Maximum Allowable Revenue from distribution prices for the year beginning 1 April 2015 and allows distribution prices to increase by the Consumer Price Index (CPI) in the following four years of the regulatory period. The Price-Quality Path Determination also allows for the recovery of costs that are largely outside of our control, known as pass through and recoverable costs. These include transmission charges, council rates and levies.

Disclosure Determination
Under Part 4 of the Act, businesses supplying distribution services are also subject to information disclosure regulation which requires information about their performance to be published. The purpose of this regulation is to ensure that sufficient information is readily available to interested persons to assess whether the purpose of Part 4 of the Act is being met. As a result, we must make disclosures under the Disclosure Determination. This document contains the information that must be disclosed in accordance with clauses 2.4.1 to 2.4.5 of the Disclosure Determination.

Clause 2.4.4 of the Disclosure Determination requires the disclosure of a documented and Board-approved pricing strategy. We do not have a pricing strategy as defined in the Disclosure Determination.

2.2 Low User Regulations
Our residential prices are also subject to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low User Regulations). These regulations require distributors to offer residential consumers a price option at their primary place of residence with a fixed price of no more than $0.15 per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option is no greater than any other residential price option for consumers using up to 8,000 kWh per annum.

2.3 Pricing Principles
We have developed our prices with reference to the Electricity Authority's Pricing Principles (Pricing Principles). The purpose of the Pricing Principles is to ensure prices are based on a well-defined, clearly explained and economically rational methodology. While the Pricing Principles are voluntary, the Disclosure Determination requires each electricity distribution business to either demonstrate consistency with the Pricing Principles or explain the reasons for any inconsistencies.

Section 11 of this document sets out the Pricing Principles and comments on the extent to which our Pricing Methodology is consistent with them.

3 FUTURE PRICING DEVELOPMENTS

The future is unpredictable. New business models are evolving in response to new customer demands and new technologies. 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. We do not believe economically-principled, efficient pricing should be an end goal in and of itself. Preliminary research suggests that some consumers are interested in adopting new technology to manage their usage and save money while others prefer simplicity and convenience. Ultimately we are seeking to implement pricing structures that meet consumer preferences, send the right signals and are well understood by consumers. Therefore we have decided to undertake a review of pricing through an engagement programme that is *consumer-led*.

We have formalised our Customer Pricing Engagement Programme to include the following:

- Identify key pricing objectives
- Develop preliminary pricing concepts
- Consult with internal stakeholders
- Consult with our Customer Advisory Board
- Conduct Online survey of residential customers
- Conduct new pricing trials
- Conduct focus group assessment
- Conduct pricing analysis

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. Retailers need to ensure that our pricing is passed through to our consumers. Re-packaging our tariffs risks obscuring the price signal and in turn preventing consumers from the potential benefits our pricing may afford.

It is worth highlighting that any substantial change to pricing structures creates challenges under the current regulatory framework in forecasting and allocating volumes for the purpose of weighting and setting prices.

4 CALCULATION OF TOTAL TARGET REVENUE

This section sets out the amount of revenue that we are expected to recover through prices (total target revenue) and breaks this down by key cost components.

4.1 Total target revenue

Total target revenue for 2017/18 is $627m. This compares with total target revenue for 2016/17 of $618m.

Table 1. Target revenue 2017/18 and 2016/17

Cost category	Component	Cost category	Target revenue ($m)	
			2017/18	2016/17
Distribution	Maintenance	Asset	51	49
	Direct costs	Asset	12	12
	Indirect costs	Non-Asset	9	16
	Allocated costs	Non-Asset	45	36
	Depreciation - system assets	Asset	94	92
	Depreciation - non-system assets	Non-Asset	13	13
	Regulatory tax adjustment	Asset	7	18
	Regulatory tax allowance	Asset	47	44
	Return on capital	Asset	120	115
Pass-through and recoverable	Pass-through balance[1]	Non-Asset	(5)	-
	Rates	Non-Asset	9	9
	Levies	Non-Asset	3	3
	CAPEX wash-up	Non-Asset	(2)	(2)
	Transmission costs	Transmission	224	213
Total target revenue			627	618

The third column of Table 1 categorises cost components as either ‘Asset’, ‘Non-Asset’ or ‘Transmission’. These categorisations determine the way that the costs are allocated to consumer groups, and are discussed in Section 6.

[1] Most recently available pass-through balance at the time of setting prices.

5 DEVELOPMENT OF CONSUMER GROUPS

The following section explains how we have developed distinct groups of consumers in order to allocate the components of total target revenue to these groups as part of the price setting process.

We have developed consumer groups based on their utilisation of the network and the nature of the network service they receive. Due to the physical nature of distribution networks and the information that is available on consumer demand characteristics, these consumer groups are defined at a relatively high level. Examples of the network characteristics include:

There is a high degree of network meshing and interconnection of consumers	This means that multiple end consumers utilise many of the same assets. A large industrial consumer consuming large volumes of electricity per year is likely to be using some of the same network assets as a residential end consumer consuming only small amounts.
End consumers are not generally geographically segmented in their use of different network assets	For example, there are in general very few purely “industrial zones” or “residential zones”. A residential consumer is likely, in part at least, to use the same assets as an industrial consumer. A map of the location of different types of consumers across a portion of the network is included as Appendix 2 and illustrates this point.
There is a mix of consumers, including a large number of consumers with relatively low individual consumption, and vice versa	For example, end consumers with a capacity less than 69kVA represent 99% of all connections but they only use 54% of the energy transported over the distribution network.

Table 2 shows the consumer groups we use and the relationship between the consumer group and capacity. We also allocate consumers to consumer groups based on their point of connection to the network, metering type and end usage. Consumer groups are therefore generally mutually exclusive, i.e. an end consumer can logically only fit within one group.

Table 2. Relationship between connection capacity and consumer groups

Capacity	Consumer group	Consumer group description
Small ≤ 69kVA	Mass market	Supplied from our low voltage network with a connection capacity less than 69 kVA.
	Unmetered	Supplied from our low voltage network and have capacity less than 1 kVA
Large > 69kVA	Low voltage	Supplied from our low voltage (400V three phase or 230V single and two phase) network with a connection capacity of greater than 69 kVA;
	Transformer	Supplied from a transformer(s) owned by Vector and which supplies the consumer’s low voltage (400V three phase or 230V single and two phase) network;
	High voltage	Supplied directly from our high voltage or sub-transmission (6.6kV or higher) network

6 ALLOCATION OF TARGET REVENUE TO CONSUMER GROUPS

The following section explains how we use our Cost of Service Model (COSM) to allocate the costs of owning and operating the distribution network to the consumer groups described in the previous section to determine how much total target revenue we intend to recover from each consumer group.

6.1 Features of electricity distribution system assets

A key feature of an electricity distribution system is that it is a network of 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 costs between consumers or groups of consumers can be made in many different 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.

6.2 Cost types

Table 1 in Section 4 lists the components of total target revenue and categorises these components as either ‘Asset’, ‘Non-Asset’ or ‘Transmission’, summarised in Table 3.

Table 3. Total target revenue by cost allocation category

Revenue type	Category	Value ($m)
Distribution	Asset	331
	Non-asset	67
Pass-through	Transmission	224
	Non-asset	5
Total		627

6.3 Apportioning ‘Asset’ costs by asset types

Costs categorised as ‘Asset’ are costs associated with expenditure on electricity distribution network assets. We have grouped these network assets into three distinct categories as shown in Table 4.

Table 4. Asset categorisation

Asset category	Assets	Consumer groups
A	• Sub-transmission lines / cables • Zone-substations • HV lines / cables	All
B	• Distribution substations that have no Vector-owned low voltage lines / cables leaving the substation	Transformer
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

We assume that costs associated with assets are incurred in proportion to the value of the assets. In this way each ‘asset’ cost listed in Table 1 is split amongst the three asset categories. For example, as Category A assets make up 69% of the value of our Regulatory Asset Base, we assume that 69% of maintenance costs will be associated with Category A assets.

6.4 Summary of allocation approaches

The allocators for ‘Asset’, ‘Non-Asset’ and ‘Transmission’ costs are applied to the combined Northern and Auckland networks. The allocators used to allocate costs to consumer groups are summarised below:

Table 5. Allocators used in the COSM model

<table>
<tr><th rowspan="2">Consumer group</th><th colspan="3">Asset costs</th><th rowspan="2">Non-asset costs</th><th rowspan="2">Transmission costs</th></tr>
<tr><th>A</th><th>B</th><th>C</th></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></tr>
<tr><td>Unmetered</td></tr>
<tr><td>Low voltage</td></tr>
<tr><td>Transformer</td><td>Directly attributed</td><td rowspan="2">n/a</td></tr>
<tr><td>High voltage</td><td>n/a</td></tr>
</table>

6.5 Allocation of ‘Asset’ related costs to consumer groups

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, the most appropriate peak periods to use are GXP peaks and zone substation peaks. We have found that a consumer group’s contribution to GXP peaks is very similar to that group’s contribution to Transpower’s Regional Coincident Peak Demand (RCPD) periods. Given the ready availability of RCPD data, and the less reliable nature of zone substation peak data, we use contribution to RCPD peak to allocate Category A asset costs. We allocate Category A asset costs in proportion to a consumer group’s demand during RCPD periods.

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

Category C assets are low voltage assets located close to the end consumer. The most appropriate allocator for Category C asset costs might therefore be a consumer group’s Anytime Maximum Demand, or demand coincident with a distribution substation peak. However data for these measures are not readily available for mass market consumers, so proxy allocators are used instead. The readily-available proxies are demand at RCPD periods and annual consumption. We use both allocators to generate a band of cost allocation values as no one allocator is preferred to the other.

6.6 Allocation of ‘Non-asset’ costs to consumer groups

‘Non-asset’ costs can be broadly summarised as overhead costs and pass-through and recoverable 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.

6.7 Allocation of 'Transmission' costs to consumer groups

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.

6.8 Values for allocators

Table 6 summarises the value of each of the allocators used in the COSM. The values are weighted averages of up to five years' worth of data, with more recent years weighted more heavily.

Table 6. Value of Allocators

Allocator	Number of consumers	Annual consumption	Contribution to RCPD
Units	ICPs	MWh	MW
Source	Schedule 8 of the Information Disclosures	Schedule 8 of the Information Disclosures	Metering data
Mass market	534,421	4,507	1,134
Unmetered	2,260	56	14
Low voltage	4,490	1,028	154
Transformer	1,386	1,494	215
High voltage	147	538	73
Non-standard	42	759	85
Total	542,746	8,382	1,676

6.9 Total target revenue allocated to each consumer group

The result of using the different allocators outlined in Table 5 creates a band by consumer group as shown in Table 7.

Table 7. Total target revenue allocation bands by consumer group

Consumer group		HV	TX	LV	Unmetered	Mass market	Non-standard
Total target revenue ($m)	Lower	20	65	53	5	428	18
	Upper	25	80	69	5	465	18

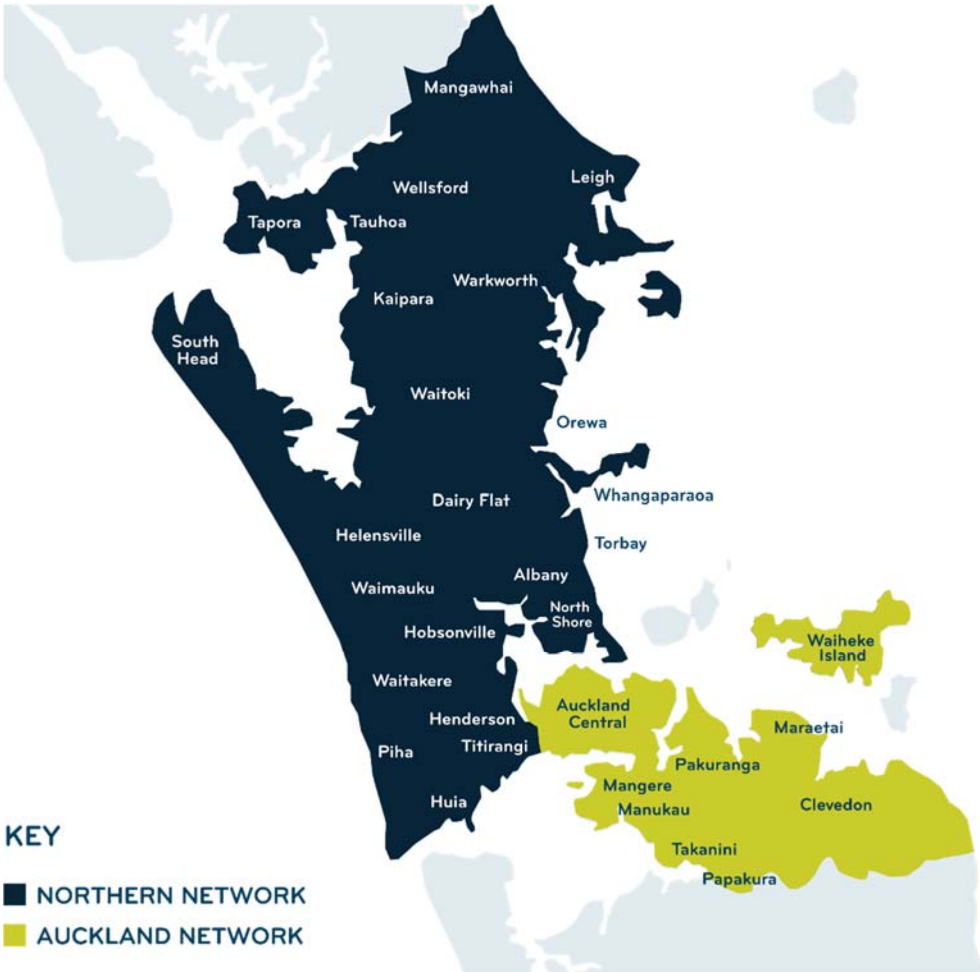
7 DEVELOPMENT OF PRICE CATEGORIES

The following section provides an overview of the various price categories that we offer within each consumer group (as described in Section 5). The key pricing differences between these categories and the reasons for these are described in Section 8.

7.1 Auckland and Northern networks

We have different price categories for consumers on our Auckland network (codes beginning with A) and our Northern network (beginning with W). Price levels are the same on the two networks for mass market consumers but differ for other consumers.

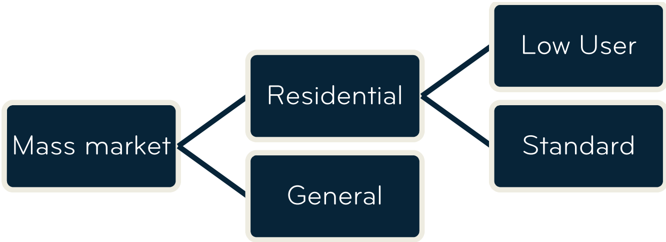
Figure 2. Auckland and Northern electricity distribution networks



7.2 Mass market consumer group

The mass market consumer group is split into two subgroups, residential and general (see Figure 3) with the key difference between the subgroups being that the Low User Regulations apply only to the residential subgroup.

Figure 3. Mass market price categories



The subgroups are further split into price categories as set out in Table 8. Residential price categories ending in 'L' are the price categories that comply with the Low User Regulations. Prices for 'general' consumers are the same as standard residential consumers.

Table 8. Mass market price categories

Price category code(s)		Short description	Key eligibility criteria / purpose
Auckland	Northern		
ARCL ARCS	WRCL WRCS	Residential controlled	Residential consumers with controllable load
ARUL ARUS	WRUL WRUS	Residential uncontrolled	Residential consumers without controllable load
ARGL ARGS	WRGL WRGS	Residential gas	Residential consumers who also have reticulated gas connections
ARHL ARHS	WRHL WRHS	Residential half hourly	Residential half hourly pricing option
ABSN	WBSN	General	Non-residential < 69 kVA consumers
ABSH	WBSH	General half hourly	Non-residential < 69 kVA half hourly pricing option

7.3 Other consumer groups

The remaining consumer groups are split into price categories as set out in Table 9. The key differences between price categories relate to metering requirements and connection capacities.

Table 9. Other price categories

Price category code		Short description	Key eligibility criteria / purpose
Auckland	Northern		
ABSU	WBSU	General unmetered	Unmetered < 1 kVA capacity connections, mostly street lighting
ALVT	WLVH	Low voltage time of use	Main category for low voltage consumers, requires time of use metering
ALVN	WLVN	Low voltage non time of use	Alternative category available to smaller low voltage consumers (< 345 kVA) who may not have time of use metering
ATXT	WTXH	Transformer time of use	Main category for transformer consumers, requires time of use metering
ATXN	WTXN	Transformer non time of use	Alternative category available to smaller transformer consumers (< 345 kVA) who may not have time of use metering
AHVT	WHVH	High voltage time of use	Main category for high voltage consumers, requires time of use metering
AHVN	WHVN	High voltage non time of use	Alternative category available to smaller high voltage consumers (< 345 kVA) who may not have time of use metering

8 HOW STANDARD PRICES ARE SET FOR EACH PRICE CATEGORY

The following section explains how we set our prices to recover the total target revenue allocated to consumer groups. It explains what types of prices are used and how the levels of prices are determined.

We generally endeavour to recover the components of total target revenue in line with how those costs are incurred, while having regard to (among other things) historical price structures, minimising rate shock to consumers, and minimising recovery risk.

8.1 Overview of 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. In some cases the price components for each category are historical and were inherited by us.

Table 10. Description of price components

Price type	Price component	Code(s)	Units	Description
Fixed	Daily	FIXD	$/day	Daily price applied to the number of days each consumer's point of connection is energised.
	Capacity	CAPY	$/kVA/day	Daily price applied to the installed capacity (or nominated capacity for AHVT and WHVH) of each consumer.
Variable	Volume	AICO 24UC OFPK PEAK	$/kWh	Volume price, applies to all electricity distributed to each consumer. Rate may vary depending on price category, e.g. controlled volume (AICO), uncontrolled volume (24UC), off peak volume (OFPK), or peak volume (PEAK).
	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.

8.2 How prices are derived

Table 11. Proportion of target revenue by price component for the mass market consumer group

Description	Price categories	Fixed prices Daily	Variable prices Volume
Residential, low user	ARCL, ARUL, ARGL, ARHL, WRCL, WRUL, WRGL, WRHL	10%	90%
Residential, standard	ARCS, ARUS, ARGS, ARHS, WRCS, WRUS, WRGS, WRHS	42%	58%
General[2]	ABSN, ABSH, WBSN, WBSH	21%	79%

Our mass market price categories predominantly have a two part charge comprising of a daily fixed price and a volume consumption price. This is largely a result of the historic availability of consumption information. As smart meters have become common, a half hourly price category has been introduced with prices that differentiate between peak and off-peak consumption in an attempt to reflect the costs to us of consumers' consumption during those time periods.

The majority of our costs are fixed and sunk, so we have been seeking to increase the fixed portion of revenues to align the recovery of revenues with the manner in which costs are incurred. Fixed prices in the standard mass market price categories have increased from $0.99 per day to $1.01 per day.

Our residential prices are subject to the Low User Regulations, as discussed in section 2.2. We comply with these regulations by offering low user price categories with a fixed price of $0.15 per day and volume prices that ensure that consumers who use 8,000 kWh per year or less are better off on the low fixed price categories.

Volume prices are then set to recover the remainder of the revenue allocated to the mass market consumer group, while minimising rate shock to consumers. For non-half hourly price categories, volume prices for low user price categories have increased by $0.0019/kWh and for standard price categories have increased by $0.0010/kWh. For half hourly price categories, volume prices for low user price categories have increased by $0.0006/kWh and for standard price categories have decreased by $0.0003/kWh.

General prices are aligned with residential standard price categories as these consumers have similar characteristics to residential consumers on standard price categories.

[2] Prices are aligned between standard residential categories and general categories, however as average volume consumption for general consumers is higher than for residential consumers, volume makes up a larger portion of revenue in the general price categories.

Table 12. Proportion of target revenue by price component for the unmetered consumer group

Description	Price categories	Fixed prices	Variable prices
		Daily	Volume
Unmetered	ABSU, WBSU	57%	43%

We have a two part charge for unmetered price categories. The daily fixed price has remained at its 2016/17 level of $0.15/day and the volume price has increased by $0.0013/kWh.

Table 13. Proportion of target revenue by price component for LV, TX and HV consumer groups

Description	Price categories	Fixed prices		Variable prices		
		Daily	Capacity	Volume	Demand	Power factor
Auckland TOU	ALVT, ATXT, AHVT	-	15%	27%	54%	4%
Northern TOU	WLVH, WTXH, WHVH	8%	14%	14%	61%	3%
Auckland non-TOU	ALVN, ATXN, AHVN	6%	23%	70%	-	1%
Northern non-TOU	WLVN, WTXN, WHVN	17%	15%	66%	-	2%

Our price structure for low voltage, transformer and high voltage 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.

Current TOU price categories on the Auckland network consist of volume, capacity, demand, power factor, and (in the case of AHVT) excess demand prices. On the Northern network TOU plans also include a daily fixed price. Non-TOU plans on both networks include daily fixed, volume, capacity and power factor prices.

We maintain a relativity in price levels between low voltage, transformer and high voltage price categories. With the exception of power factor prices, high voltage price levels are 97% of transformer price levels which are, in turn, 98% of low voltage price levels. This approach reflects the relative costs of serving these consumer groups.

We continue to align the prices for low voltage, transformer and high voltage consumer groups between the Auckland and Northern networks. In addition, we continue to increase the fixed-like portion of revenues to align the recovery of revenues with the manner in which costs are incurred. For these reasons we have increased the demand and capacity price components on both the Auckland and Northern network, while decreasing the volume price component on the Auckland network.

We include a power factor price to incentivise low voltage, transformer and high voltage consumers to maintain a power factor of 0.95 or higher in accordance with our distribution code[3]. We have reviewed consumer responses to the current level of power factor prices and are satisfied the existing prices are sufficient to incentivise consumers to correct poor power factor (if any). Accordingly, we have left the power factor price unchanged from 1 April 2017.

[3] https://vectorwebstoreprd.blob.core.windows.net/blob/vector/media/vector/090227-distribution-code-update-feb-09.pdf

8.3 Consultation prior to setting prices

We did not directly seek the views of consumers when setting prices. Rather, we consulted with Entrust, which represents consumers in the Auckland network. We also consulted with retailers on a range of pricing initiatives. We have considered and largely accommodated these views in our final prices.

In the future, we will look to incorporate the views of consumers when developing any new pricing constructs as part of our Pricing Engagement Programme. We have already commenced the Programme with a customer survey, eliciting customers' level of energy engagement, personal preferences in electricity plan design, and specific feedback on three possible new price structures. We look forward to continuing the Programme of engagement and using the learnings and outcomes of the Programme to inform our future pricing design.

9 IMPACT OF PRICE CHANGES

From 1 April 2017, we are increasing prices by a weighted average of 1.3%. The contributors to this increase are: CPI (0.2 percentage points), changes to pass-through and recoverable costs, including pass-through balance (0.8 percentage points), and volume changes (0.3 percentage points). Individual prices may change by more or less than the overall weighted average price change.

9.1 Impact of prices changes on consumer groups

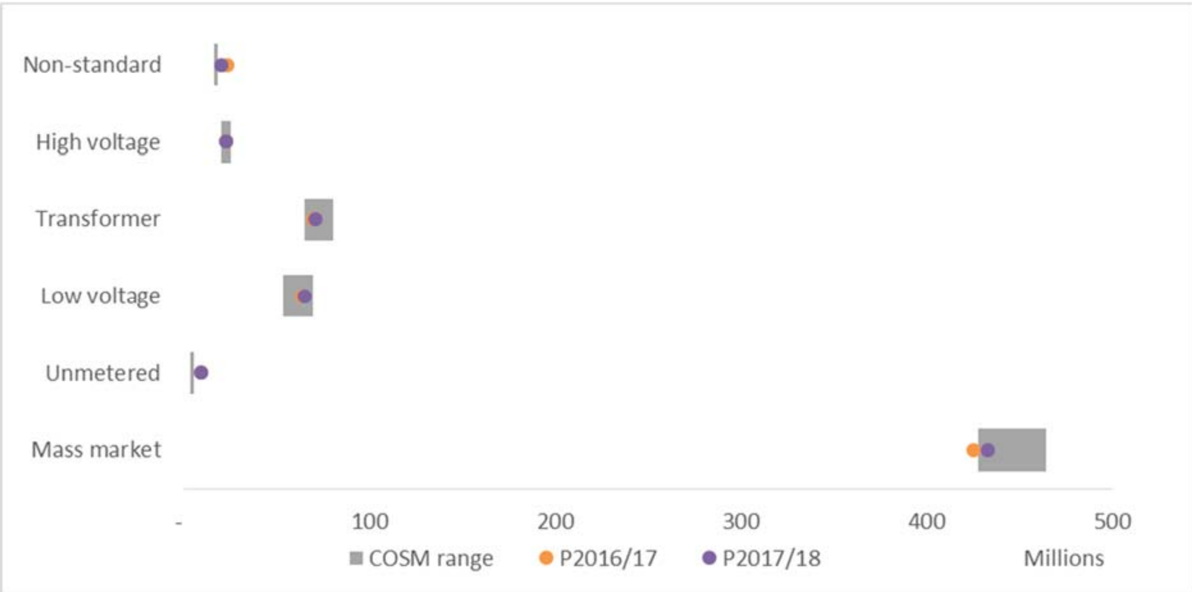
Table 14 shows the weighted average change to prices by consumer group. As these are weighted average price changes, some consumers will see a greater or lesser impact, depending on their consumption profile.

Table 14. Impact of weighted average price changes on consumer groups

Size	Consumer group	Price change
Small (≤69kVA)	Mass market	1.8%
	Unmetered	0.8%
Large (>69kVA)	Low voltage	2.2%
	Transformer	1.7%
	High voltage	0.6%
	Non-standard[4]	-11%

Figure 4 shows revenue forecast to be recovered from 2016/17 and 2017/18 prices compared with the desired COSM outcomes. The desired COSM outcomes are a range of acceptable cost allocations and are presented as a grey band while the revenues from 2016/17 and 2017/18 prices are presented as orange and purple dots respectively[5].

Figure 4. Revenue recovered compared with COSM outcomes



[4] Non-standard revenue has decreased primarily due to non-standard consumers moving to standard price categories.

[5] Not all orange dots may be visible due to the small magnitude of some price changes.

10 APPROACH TO NON-STANDARD AND DISTRIBUTED GENERATION PRICING

In certain circumstances our published standard prices may not adequately reflect the actual costs of supplying a consumer, reflect the economic value of the service to the consumer or address the commercial risks associated with supplying that consumer. Non-standard contracts allow tailored prices and commercial arrangements to be applied to individual consumers.

10.1 Non-standard target revenue

Of the target revenue for 2017/18 of $627m, $18.2m (2.9%) is forecast to be recovered from 33 non-standard consumers.

10.2 Criteria for non-standard contracts

Consumers may be assessed for non-standard terms or pricing if they meet one of the following criteria:

a) The capacity of the consumer's point of connection is greater than or equal to 1.5 MVA; or
b) The consumer's (forecast) maximum demand (twice the maximum kVAh half hourly reading) is greater than or equal to 1.5 MVA; or
c) The ratio of the consumer's (forecast) maximum demand over their (forecast) average demand in any year is greater than four; or
d) We incur capital expenditure greater than $250k augmenting the electricity distribution network in order to provide electricity lines services to the consumer.

We assess whether to apply non-standard pricing and the corresponding contractual arrangements to new consumers on a case-by-case basis. Generally, if a consumer does not meet at least one of the assessment criteria, they will be subject to published standard distribution prices. Meeting one or more of the assessment criteria does not mean that a non-standard arrangement will apply, merely that the consumer may be reviewed to determine whether standard pricing and standard contractual terms are suitable, given the consumer's individual circumstances. At the conclusion of a non-standard pricing agreement, the consumer will be required to negotiate in good faith at our request before seeking to access standard prices.

For new investments that qualify for non-standard pricing, we use actual costs and / or allocated costs derived from an allocation model to determine prices. This allocation model is consistent with the COSM used in determining standard pricing. The description provided under Section 11 to show consistency with the Pricing Principles therefore applies to the allocation model used for non-standard pricing.

For new non-standard investments, we apply a 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.

10.3 Our obligations and responsibilities

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 15.

Our standard contracts terms and non-standard contract terms are compared in Table 15:

Table 15. Summary of our obligations and responsibilities to Non-standard consumers

	Planned interruption notice	Unplanned interruption notice	Fault restoration	Number of interruptions per annum	Number of consumers
Standard	4 days	15 mins	CBD/Industrial: 2 hours Urban: 2.5 hours Rural: 4.5 hours	Urban: 4 Rural: 10	Approx. 550,000
Non-standard	Same as standard	Same as standard	Same as standard	Same as standard	8
	1 April each year, or 10 working days	As soon as practicable	2 hours	1 unplanned	1
	1 April each year, or 10 working days	As soon as practicable	As soon as practicable	Not stated	0
	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	3
	10 working days	As soon as practicable	3 hours	Not stated	11
	10 working days	Not stated	Not stated	Not stated	1
	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	3
	7 working days	As soon as practicable	Priority	3 planned	1
	August each year	Not stated	1 hour	Not stated	2

For the current pricing year 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.

10.4 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 payments to any distributed generators. We make Avoided Cost of Transmission (ACOT) payments to three distributed generators.

We have not identified any short run incremental costs from injection of energy into the network so this price continues to be $0.0000/kWh from 1 April 2017 for all distributed generators.

Further information on our policies for distributed generation can be found at https://www.vector.co.nz/personal/solar/connecting-your-generation-to-our-network

11 CONSISTENCY WITH PRICING PRINCIPLES

The Electricity Authority's Pricing Principles provide an approach to developing pricing methodologies for electricity distribution services. This section demonstrates the extent to which the Pricing Methodology is consistent with the Pricing Principles.

11.1 Pricing Principle (a)

Pricing Principle (a) states that:

a) *Prices are to signal the economic costs of service provision, by:*
   i. *being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;*
   ii. *having regard, to the extent practicable, to the level of available service capacity;*
   iii. *and signalling, to the extent practicable, the impact of additional usage on future investment costs.*

Incremental Costs

The incremental cost test can be applied both for individual consumers and for groups of consumers. The incremental cost for an individual consumer is the cost of connecting that consumer to the network, and therefore excludes the cost of shared assets. The incremental 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.

Our capital contributions policy ensures that individual consumers generally pay the costs of connecting them to the network.

Applying the incremental 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 incremental cost for each individual consumer.

The allocation of all Category B asset costs directly to the transformer consumer group and Category C asset costs directly to the low voltage, unmetered and mass market consumer groups ensures that these consumer groups pay at least the incremental cost of connecting them to the network.

Standalone costs

While we monitor the cost 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.

Available Service Capacity

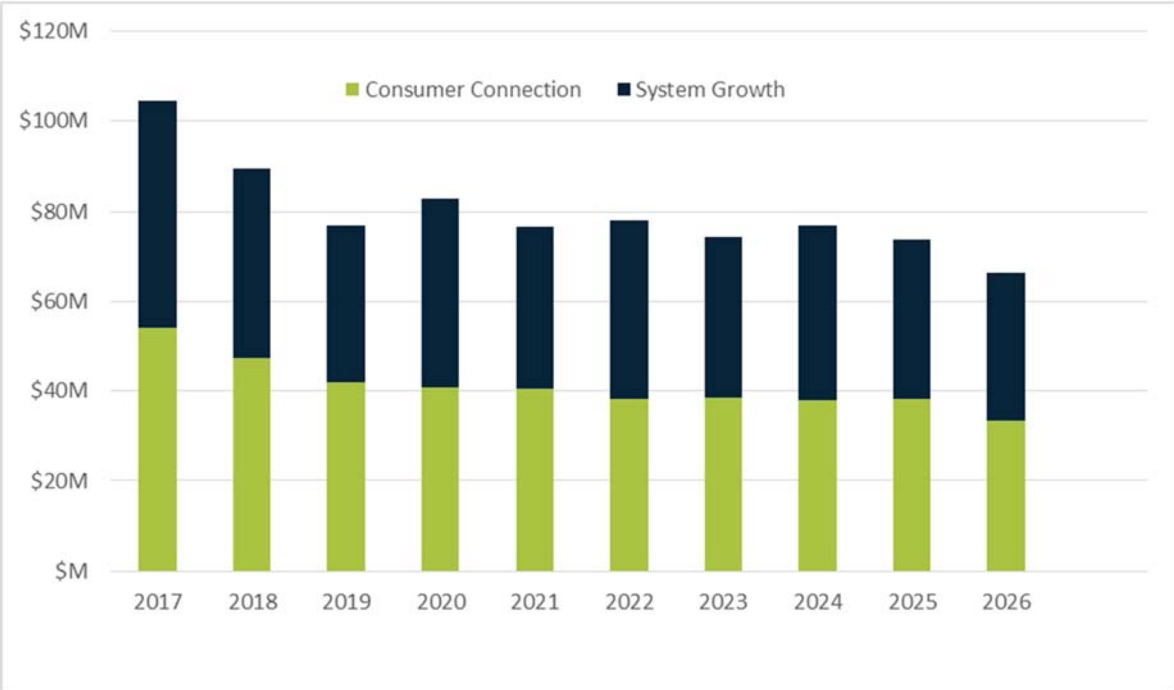
The electricity distribution system consists of assets with significant capacity. When building the system, economies of scale exist such that the cost of installing an asset larger than that which is immediately required does not add significantly to the cost of network build. As a consequence many 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 nil.

In a few cases, however, areas of our network have high utilisation. Where the system requires expansion (for example in order to connect a new user to the distribution system) then 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.

Future Investment Costs

Figure 5 shows our forecast capital expenditure to meet future demand from our 2016 Asset Management Plan[6]. Consumer connections allow for the costs of connecting new consumers and reticulating new subdivisions, while system growth relates to expansion of the network to provide the capacity to meet the electricity needs of these new connections.

Figure 5. Forecast Capital Expenditure to Meet Future Demand



We signal the level of available capacity and future investment costs over different time periods through the use of TOU prices and controlled load prices. This provides incentives to end consumers to shift demand away from peak periods and therefore reduce the need for future investment costs.

We offer controlled load prices to residential end consumers in return for the ability to remotely manage the electricity supply of end consumers' hot water cylinders. This pricing approach signals the benefits to consumers of allowing us to control their hot water load and manage network congestion during peak periods through lower price options.

11.2 Pricing Principles (b) and (c)

Pricing Principles (b) and (c) state that:

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[6] Available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/asset-management-plan

b) *Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.*
c) *Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:*
    i. *discourage uneconomic bypass;*
    ii. *allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and*
    iii. *where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.*

Demand responsiveness
Pricing based on incremental 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 using the COSM, as described in section 6.

Stakeholder circumstances
As described in section 10, 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 obliges us to take account of the issues described above when considering the design of a non-standard contract.

The Pricing Methodology does not provide specific incentives for investment in transmission and distribution alternatives. 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 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 utilises energy efficient buildings and solar heating or solar PV will not require the same level of network investment. Additional price signals beyond the requirements for capital contributions are not warranted by the economics of our distribution network.

11.3 Pricing principle (d)
Pricing principle (d) states that:

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

The existing Pricing Methodology for the electricity distribution system is transparent in that it is documented and is available to consumers and other stakeholders from our website and is provided to them on request.

We have promoted price stability and have had regard to the impact on stakeholders by ensuring that, where practicable, changes to prices have been limited for all consumption patterns to be no more than 10% each year. Where possible we have signalled expected future increases in prices ahead of time so that consumers are able to factor such increases into their budgets. We have consulted with stakeholders, including retailers and Entrust, in the development of this Pricing Methodology and we continue to consult as appropriate when applying it and future methodologies.

11.4 Pricing principle (e)

Pricing principle (e) of the Principles states that:

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

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 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.

APPENDIX 1. GLOSSARY

Connection or **Point of Connection:** each point of connection at which a supply of electricity may flow between the Distribution Network and the Consumer's installation.

Demand: the rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA).

Distributed Generator (DG): a party with whom Vector has an agreement for the connection of plant or equipment to Vector's electricity Distribution Network where the plant or equipment is capable of injecting electricity into Vector's distribution network.

Distribution Network or **Network:** the electricity distribution network in each area that Vector supplies distribution services, as defined by the following table:

Network	GXP	
Auckland	Hepburn Hobson Street Mangere Otahuhu Pakuranga	Penrose Roskill Takanini Wiri
Lichfield	Lichfield	
Northern	Albany Henderson Hepburn	Silverdale Wairau Road Wellsford

Distributor: the operator and owner of a Distribution Network.

Grid Exit Point (GXP): a point of connection between Transpower's transmission system and the Distributor's Network.

High-Voltage (HV): voltage above 1,000 volts, generally 11,000 volts, for supply to Consumers.

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.

kVA: kilovolt–ampere (amp), a measure of apparent power being the product of volts and amps. Used for the measurement of capacity and demand for capacity and demand prices.

kVAh: kilovolt ampere hour, a unit of energy being the product of apparent power in kVA and time in hours. Used for the measurement of power factor for power factor prices.

kVAr: kilovolt ampere reactive, is a unit used to measure reactive power in an AC electric power system. Used for the measurement of power factor for power factor prices.

kW: kilowatt, a measure of electrical power. Used for the measurement of demand during peak periods for the allocation of transmission charges.

kWh: kilowatt-hour, a unit of energy being the product of power in watts and time in hours. Used for the measurement of consumption for volume prices.

Low voltage (LV): voltage of value up to 1,000 volts, generally 230 or 400 volts for supply to Consumers.

Maximum Allowable Revenue (MAR): Starting price specified in Schedule 1 of the Price-Quality Path Determination that applies to the regulatory period 1 April 2015 to 31 March 2020.

Network: see Distribution Network.

Price Category: the relevant price category selected by the Distributor from the Price Schedule to define the Line Prices applicable to a particular ICP.

Price Component: the various prices that constitute the components of the total prices paid, or payable, by a consumer.

Pricing Engagement Programme: A Vector-specific programme of initiatives designed to elicit customer preferences in order to inform the design of electricity pricing plans. Initiatives may include online surveys, focus groups, social media interaction, and so forth.

Pricing Year: the 12 month period from 1 April to 31 March each year.

Regional Coincident Peak Demand (RCPD): for a Transmission Region, the sum of the offtake measured in kW 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: represents the amount that Vector has invested in its regulated network, indexed to inflation and adjusted for depreciation.

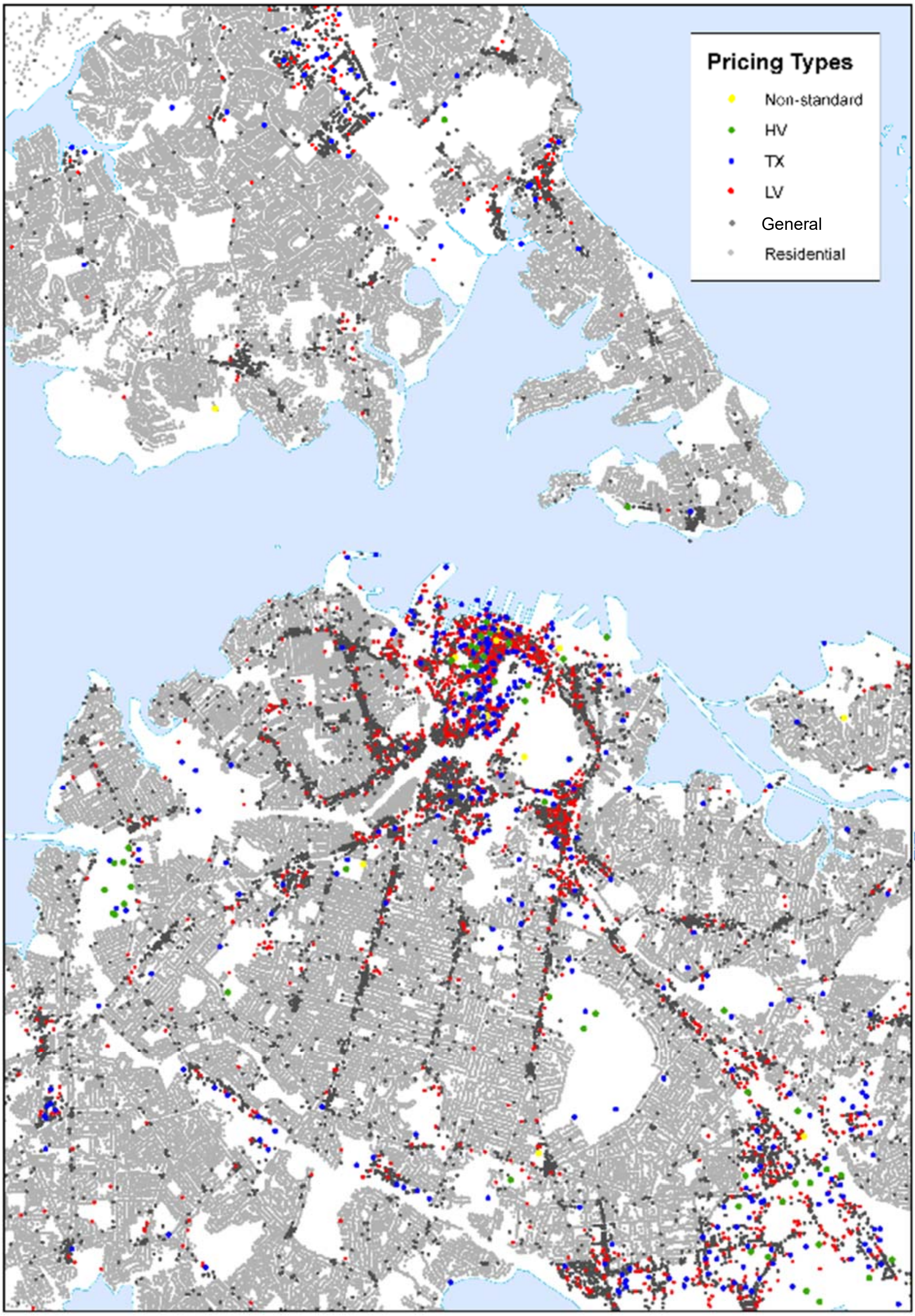
Retailer: the supplier of electricity to Consumers with installations connected to the Distribution Network.

Target revenue: the revenue Vector expects to receive from prices during the pricing year.

Time of Use Meter (TOU): metering that measures the electricity consumed for a particular period (usually half-hourly).

Transmission Costs: the transmission charges that Vector incurs from Transpower.

APPENDIX 2.   SPATIAL ILLUSTRATION OF PRICING TYPES



APPENDIX 3. PROPORTION OF TARGET REVENUE BY PRICE COMPONENT

	Fixed		Variable		
	Daily	Capacity	Volumetric	Demand*	Powerfactor
WRCL	0.76%	-	7.07%	-	-
WRUL	0.07%	-	0.66%	-	-
WRGL	0.07%	-	0.66%	-	-
WRCS	4.47%	-	6.66%	-	-
WRUS	0.47%	-	0.70%	-	-
WRGS	0.47%	-	0.70%	-	-
WRHL	0.00%	-	0.00%	-	-
WRHS	0.00%	-	0.00%	-	-
WBSU	0.30%	-	0.21%	-	-
WBSN	1.28%	-	4.02%	-	-
WBSH	0.00%	-	0.01%	-	-
WLVN	0.28%	0.22%	0.91%	-	0.02%
WLVH	0.13%	0.09%	0.10%	0.42%	0.03%
WTXN	0.04%	0.06%	0.26%	-	0.01%
WTXH	0.15%	0.36%	0.32%	1.41%	0.07%
WHVN	0.00%	0.00%	0.00%	-	0.00%
WHVH	0.01%	0.06%	0.09%	0.35%	0.01%
ARCL	1.08%	-	9.84%	-	-
ARUL	0.17%	-	1.38%	-	-
ARGL	0.17%	-	1.38%	-	-
ARCS	5.72%	-	8.29%	-	-
ARUS	0.70%	-	1.04%	-	-
ARGS	0.70%	-	1.04%	-	-
ARHL	0.00%	-	0.00%	-	-
ARHS	0.00%	-	0.00%	-	-
ABSU	0.58%	-	0.44%	-	-
ABSN	2.12%	-	7.87%	-	-
ABSH	0.00%	-	0.04%	-	-
ALVN	0.21%	0.71%	2.22%	-	0.02%
ALVT	-	0.86%	1.23%	2.74%	0.28%
ATXN	0.01%	0.08%	0.19%	-	0.00%
ATXT	-	1.37%	2.33%	4.74%	0.28%
AHVN	0.00%	0.00%	0.01%	-	0.00%
AHVT	-	0.33%	0.88%	1.76%	0.08%
NS	3.13%	-	-	-	-

* Includes Excess demand

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Alison Paterson and

Hugh Fletcher, 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 clause 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.

A Paterson

Director

HMFletcher

Director

23 February 2017

Date