

# ELECTRICITY DISTRIBUTION SERVICES 2021 PRICING METHODOLOGY

From 1 April 2020

Pursuant to:

The Electricity Distribution Information Disclosure  
Determination 2012 (Consolidated April 2018)

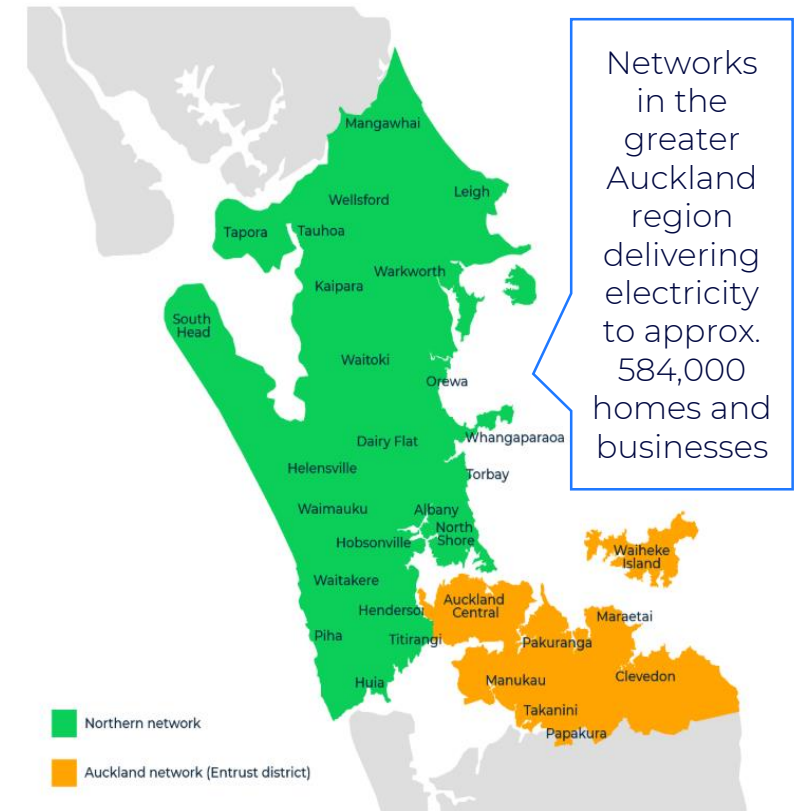


# EXECUTIVE SUMMARY

Vector (“our”, “we”, or “us”) recovers the cost of owning and operating our electricity distribution networks (Network) through a combination of standard (published) and non-standard prices for electricity distribution 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 distribution services (Pricing Methodology).

This document sets out our Pricing Methodology to meet the requirements of the Information Disclosure Determination 2012 (ID)<sup>1</sup>. It 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 the pricing strategy<sup>2</sup>, but we do not currently have a pricing strategy as defined in the ID. We do however have a publicly available electricity pricing road map<sup>3</sup> that sets out how we are evolving on prices to enable and deliver better outcomes for consumers.

**Figure 1: Our electricity distribution networks**




 PY21 prices<sup>4</sup> are derived from PY20 prices & change in net allowable revenue & change in pass-through and recoverable costs & pass-through balance allowance<sup>5</sup> & change in quantities

 When setting prices, historical price structures, minimising rate shock to consumers and minimising recovery risk are taken into account

 Given network costs are largely fixed we typically apply any price increases to fixed components and price decreases to variable components

 The prices determined are checked to ensure they will not earn revenue “out of step” with target revenue for each consumer group

 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

<sup>1</sup> Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018), available at <https://comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors/current-information-disclosure-requirements-for-electricity-distributors>

<sup>2</sup> 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

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

<sup>4</sup> Pricing year (PY) is the 12 month period from 1 April to 31 March each year. PY21 is 1 April 2020 to 31 March 2021

<sup>5</sup> The pass-through balance allowance is an estimated wash-up of the under or over-recovery from PY20 of pass-through and recoverable costs. It is estimated as PY21 prices were set before the end of PY20

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# 1 – CONSUMER GROUPS

Consumer groups are determined on how they 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 maintained the same five standard consumer groups as in the previous year, based on a measure of capacity connection and supply connection point type as shown in Table 1.

**Table 1: Consumer groups**

Consumer group and subgroup		Capacity connection	Supply connection
Mass market	<ul style="list-style-type: none"> <li>➤ Residential</li> <li>➤ General</li> </ul>	Small $\leq$ 69kVA	Low voltage network
Unmetered	<ul style="list-style-type: none"> <li>➤ General</li> </ul>	Tiny $\leq$ 1kVA	Low voltage network
Low voltage	<ul style="list-style-type: none"> <li>➤ Commercial</li> </ul>	Large $\geq$ 69kVA	Low voltage network
Transformer	<ul style="list-style-type: none"> <li>➤ Commercial</li> </ul>	Large $\geq$ 69kVA	Vector owned transformer(s) which supplies consumer's Low Voltage network
High voltage	<ul style="list-style-type: none"> <li>➤ Commercial</li> </ul>	Large $\geq$ 69kVA	High voltage or sub-transmission (6.6kV or higher) network
Non-standard		Various	Various

Consumers on non-standard contracts which have met certain eligibility criteria, as outlined on page 11, 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<sup>6</sup> apply only to the residential subgroup.

The unmetered consumer group is also in the general subgroup.

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

<sup>6</sup> The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low User 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 – PRICE CATEGORIES

Table 2 sets out the price categories<sup>7</sup> for consumers on our Auckland network (codes beginning with A) and our Northern network (beginning with W).

Table 2: Price categories from 1 April 2020

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
		Residential - TOU - controlled	ARHLC ARHSC	WRHLC WRHSC	Residential consumers with controllable load or reticulated gas connections
		Residential - exemption - uncontrolled	ARUL ARUS	WRUL WRUS	Residential consumers with a Vector provided exemption from TOU price categories, and without controllable load or reticulated gas connections
		Residential - exemption - controlled	ARCL ARCS	WRCL WRCS	Residential consumers with a Vector provided exemption from TOU price categories, and with controllable load or reticulated gas connections
	General	General - TOU	ABSH	WBSH	Non-residential < 69kVA consumers
		General - exemption	ABSN	WBSN	Non-residential < 69kVA consumers with a Vector provided exemption from TOU price categories
Unmetered	General - unmetered	ABSU	WBSU	Unmetered < 1kVA capacity connections, mostly street lighting	
Low voltage (LV)	LV- TOU	ALVT	WLVH	Main category for LV consumers, requires TOU metering	
	LV- non TOU	ALVN	WLVN	For smaller LV consumers (< 345kVA) who may not have TOU metering	
Transformer (TX)	TX - TOU	ATXT	WTXH	Main category for TX consumers, requires TOU metering	
	TX - non TOU	ATXN	WTXN	For smaller TX consumers (< 345kVA) who may not have TOU metering	
High voltage (HV)	HV - TOU	AHVT	WHVH	Main category for HV consumers, requires TOU metering	
	HV - non TOU	AHVN	WHVN	For smaller HV consumers (< 345kVA) who may not have TOU metering	

<sup>7</sup> 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

### 3 – PRICE COMPONENTS

We have a range of price components<sup>8</sup> that apply to different price categories depending on the characteristics of a particular category and the availability of metering data. Table 3 describes the various price components that we have. There are no changes from the previous year.

Table 3: Price components

Type	Component	Codes	Units	Description
Fixed	Daily	FIXD	\$/day	Daily price applied to the number of days each consumer's point of connection (or fitting for unmetered connections) is energised
	Capacity	CAPY	\$/kVA/day <sup>9</sup>	Daily price applied to the installed capacity (or nominated capacity for AHVT and WHVH) of each consumer
Variable	Volume	AICO, 24UC, OFPK, PEAK	\$/kWh <sup>10</sup>	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)
	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 <sup>11</sup>	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 <sup>12</sup> 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

<sup>8</sup> Price components are the various prices that constitute the components of the total prices paid, or payable, by a consumer

<sup>9</sup> 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

<sup>10</sup> 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

<sup>11</sup> 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

<sup>12</sup> 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

## 4 – PRICING DEVELOPMENTS



The future is unpredictable. New business models are evolving in response to new consumer 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.

Our consumer insights show that some consumers are interested in adopting new technology to manage their usage and save money while others prefer simplicity and convenience. Ultimately, we seek 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 *consumer-led* review of pricing. This included consultations with consumers, retailers, industry experts and obtaining consumers insights through application of detailed data analytics.

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 carefully managed especially in regard to vulnerable consumers.

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. 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. The Low User Regulations have introduced inefficiencies and inequities as the majority of distributors' costs are fixed and hence could be more efficiently recovered via some form of fixed charge.

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 will be updated periodically, but at least twice a year.

# 5 - MASS MARKET PRICING REFORM



We have undertaken a thorough review of our mass market price structures with the intention of increasing the economic price signals; the primary distribution investment driver is peak demand or capacity. Our commercial plans (low voltage, transformer and high voltage) already include demand and capacity prices so no change to their pricing structure was considered at this point in time.

There are trade-offs between competing goals when considering pricing structures such as service base/cost reflectivity, simplicity/acceptability and bill impact. These are underpinned by regulatory requirements, including the Low User Fixed Charge Regulations and Electricity Authority's Pricing Principles, economic theory, practical implementation aspects, regulatory and public perceptions, consumer effects and expectations and revenue risk implications.

Five pricing structures were considered for our mass market price categories for PY21: existing pricing, two-part TOU, dynamic volumetric, demand based and fixed. These pricing structures were assessed against the objectives and upon balancing a range of trade-offs, TOU is the best overall candidate for a standard price structure for now. TOU offers consumers the ability to reduce their electricity bill by shifting some electricity use from peak to off-peak times as well as encouraging take-up of new technology.

Mass market TOU plans were in place prior to 1 April 2020, but from 1 April 2020 we have made them mandatory, with only exemptions available for retailers and consumer meters that are currently incapable of reconciling on these plans. There are now two time of use options, the existing TOU which is now an 'uncontrolled' plan and a new 'controlled' plan. The previous 'gas' plans have been merged with the 'controlled' plans, which had the same prices, as shown in the mapping table for mass market consumers.

<sup>13</sup> For ICPs currently on residential half hourly price categories, they would migrate to the uncontrolled price categories unless they meet one of the following criteria, then they would migrate to controlled price categories:

- Consumer has an electrical hot water cylinder connected to our load control system; or
- Consumer has an active connection to our gas distribution network.

Table 4: Price category mapping for mass market consumers

Consumer group	Prior to 1 April 2020		From 1 April 2020 TOU		From 1 April 2020 exemption				
	Price category description and code(s)								
Mass market	Residential - low user	Uncontrolled	ARUL, WRUL	➔	Uncontrolled	ARHL, WRHL	↔	Uncontrolled	ARUL, WRUL
		Half hourly <sup>13</sup>	ARHL, WRHL	➔					
		Controlled	ARCL, WRCL	➔	Controlled	ARHLC, WRHLC	↔	Controlled	ARCL, WRCL
		Gas	ARGL, WRGL	➔					
	Residential - standard	Uncontrolled	ARUS, WRUS	➔	Uncontrolled	ARHS, WRHS	↔	Uncontrolled	ARUS, WRUS
		Half hourly <sup>13</sup>	ARHS, WRHS	➔					
		Controlled	ARCS, WRCS	➔	Controlled	ARHSC, WRHSC	↔	Controlled	ARCS, WRCS
		Gas	ARGS, WRGS	➔					
	General	Half hourly	ABSH, WBSH	➔					
		General	ABSN, WBSN	➔	General	ABSH, WBSH	↔	General	ABSN, WBSN



## 6 – HOW MASS MARKET AND UNMETERED PRICES ARE DERIVED



From 1 April 2020, our mass market price categories are 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 to TOU of consumption information.

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 or gas connections which typically use less electricity during peak periods.

Our residential prices are subject to the Low User Regulations, and we comply with these regulations by offering low user price categories for residential consumers at their primary place of residence 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.

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 us 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.

Table 5: Price components applicable to mass market and unmetered price categories from 1 April 2020

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

## 7 – HOW COMMERCIAL PRICES ARE DERIVED

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 which have not been fully aligned yet due to the resulting bill shock.

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. Except for 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.

Table 6 shows the price components applicable to the price categories for the commercial consumer groups, there is no change from the previous year.

Table 6: Price components applicable to commercial price categories

Consumer group	Price category description	Price category codes	Daily	Volume - anytime	Capacity	Demand	Excess demand	Power factor	Volume - injection
			-FIXD	-24UC	-CAPY	-DAMD	-DEXA	-PWRF	-INJT
			\$/day	\$/kWh	\$/kVA/day			\$/kVAr/day	\$/kWh
Low voltage	TOU	ALVT		✓	✓	✓		✓	✓
		WLVH	✓	✓	✓	✓	✓	✓	
	Non TOU	ALVN, WLVN	✓	✓	✓		✓	✓	
Transformer	TOU	ATXT		✓	✓	✓		✓	✓
		WTXH	✓	✓	✓	✓	✓	✓	
	Non TOU	ATXN, WTXN	✓	✓	✓		✓	✓	
High voltage	TOU	AHVT		✓	✓	✓	✓	✓	✓
		WHVH	✓	✓	✓	✓	✓	✓	
	Non TOU	AHVN, WHVN	✓	✓	✓		✓	✓	

# 8 – NON-STANDARD CONTRACTS & DISTRIBUTED GENERATION POLICIES



Table 7: Criteria for non-standard contracts

Approach	Description
Criteria	<p>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 <a href="http://vector.co.nz/disclosures/electricity/capital-contributions">http://vector.co.nz/disclosures/electricity/capital-contributions</a>. When a new investment is recovered through capital contributions, standard pricing applies.</p> <p>Historical investments required by consumers and 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.</p>
Methodology	<p>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.</p>

## 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<sup>14</sup> 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.<sup>15</sup>

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.

To date given the small number of distributed generation consumers, 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 2020 for all distributed generators. As more distributed generation connects this may require more in-depth consideration and as a result pricing may change.

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>.

<sup>14</sup> 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

<sup>15</sup> kW is kilowatt, a measure of electrical power. Also used for the measurement of demand during peak periods for the allocation of transmission charges from Transpower

## 9 – OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS

For PY21, 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 8. Our standard contract terms and non-contract terms are also compared.

Table 8: Summary of our obligations and responsibilities to consumers

	Planned interruption notice	Unplanned interruption notice	Fault restoration	No. of interruptions per annum	No. of consumers
Standard	4 days	As soon as practicable but no later than: - 20 mins during staffed control room hours, - 40 mins during on-call control room hours	CBD/Industrial: 2 hours	Urban: 4	Approx. 584,000
			Urban: 2.5 hours		
			Rural: 4.5 hours	Rural: 10	
Non-standard	Same as standard consumers				1
	1 April each year, or 10 working days	As soon as practicable	2 hours	1 unplanned	1
	1 June each year	As soon as practicable	As soon as practicable	Not stated	2
	1 November each year	As soon as practicable	Priority	Not stated	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	2

# 10 – PRICE SETTING

Our prices are subject to the Electricity Distribution Services Default Price-Quality Path Determination 2020 (DPP)<sup>16</sup> which states that our Forecast Revenue from Prices (FRFP) must not exceed Forecast Allowable Revenue (FAR).

FAR equals the Forecast Net Allowable Revenue (FNAR) plus Forecast Pass-through and Recoverable Costs (FPRC) (e.g. transmission costs, council rates and statutory levies) plus Opening Wash-up Account Balance (OWAB, any under/over recovery from the previous periods during the current regulatory period) plus Pass-Through Balance Allowance (PTBA, any under/over recovery from the previous regulatory period). The DPP sets our Forecast Net Allowable Revenue (FNAR) that can be earned from prices for every pricing year in the five year DPP regulatory period.

 PY21 prices are derived from PY20 prices & Δ net allowable revenue & Δ pass-through and recoverable costs & pass-through balance allowance & Δ quantities

From 1 April 2020 (the first year of the regulatory period), our electricity line charge prices are decreasing by a weighted average 9.5% with a breakdown shown in Figure 3. This decrease is primarily due to:

- lower net allowable revenue from the DPP;
- a reduction in forecast transmission charges; and
- forecast pass-through balance from PY20 carried forward

<sup>16</sup> 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>

Figure 2: PY21 Forecast revenue from prices vs Forecast allowable revenue

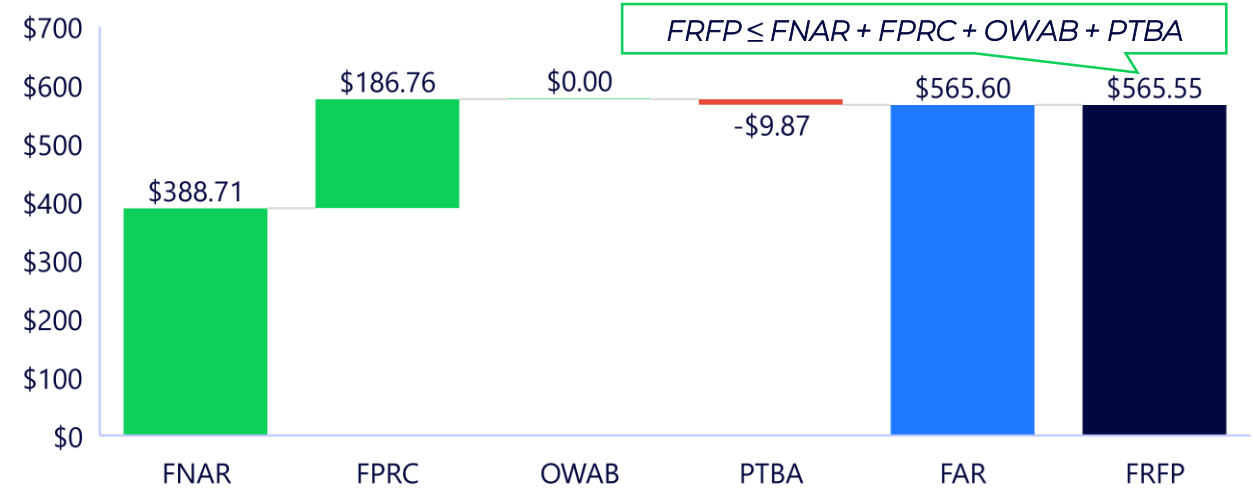
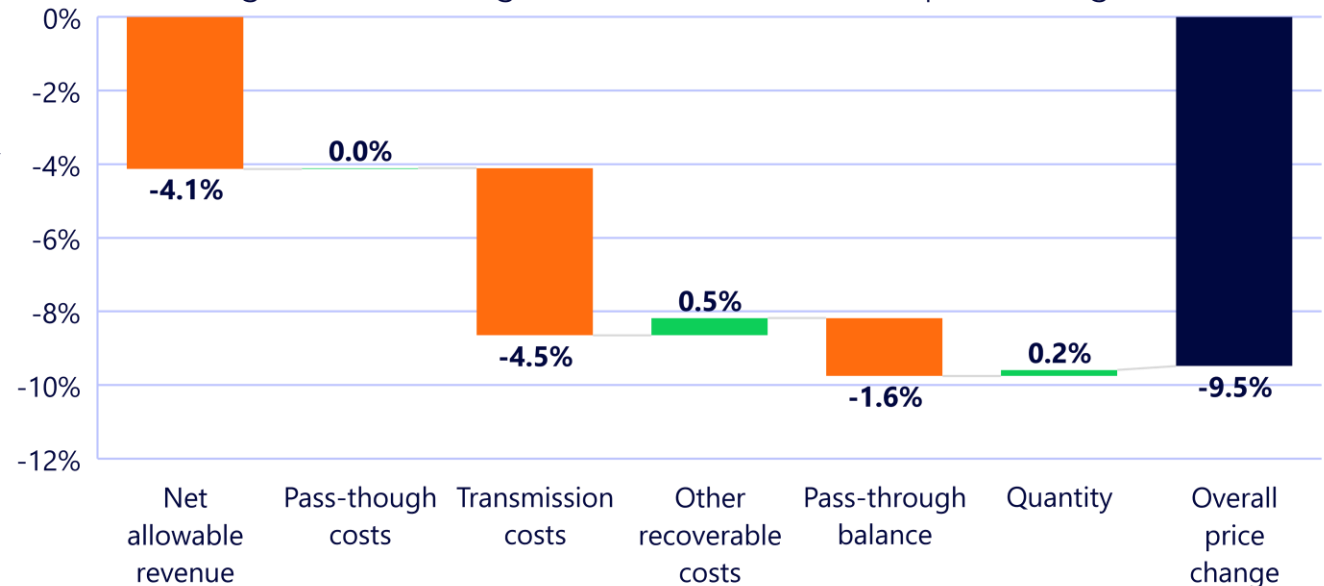


Figure 3: Percentage contribution to the PY21 price change



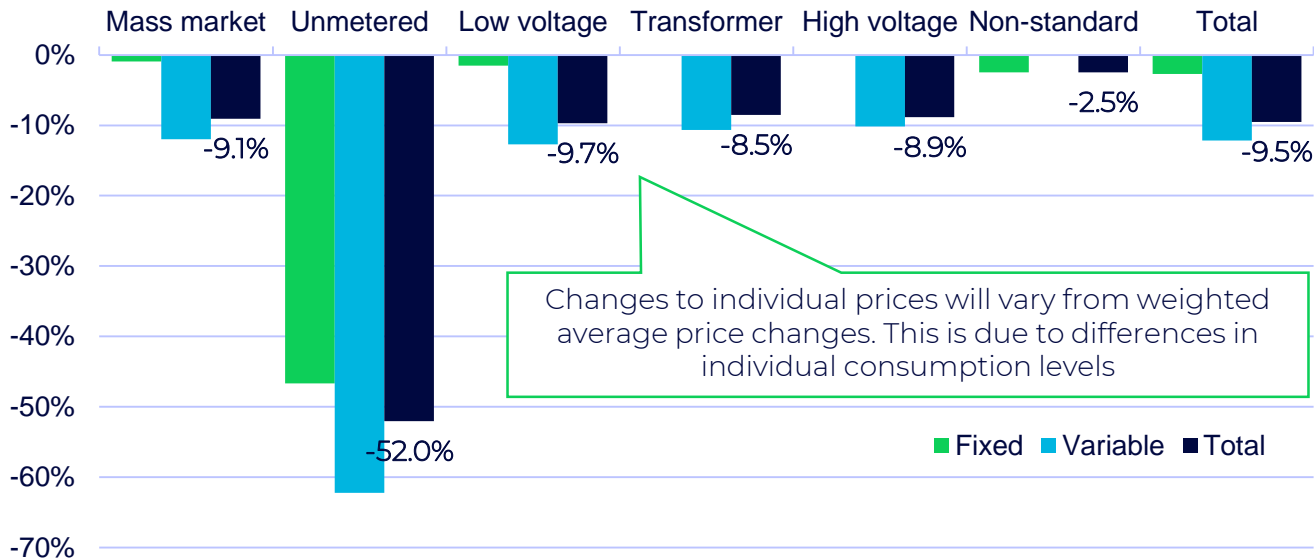
# 11 – PRICE CHANGES

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 decrease of 9.5% is split across the consumer groups and price component type. Our electricity prices that apply from 1 April 2020, including the previous year's prices that were effective from 1 April 2019, are set out in Appendix 1.<sup>17</sup>



*When setting prices, historical price structures, minimising rate shock to consumers, and minimising recovery risk are taken into account*

Figure 4: Weighted average price change by consumer group



*Given network costs are largely fixed we typically apply any price increases to fixed components and price decreases to variable components*

For mass market consumers, this is achieved by keeping fixed daily prices unchanged and reducing the variable volumetric prices.<sup>18</sup>

For unmetered consumers, both the fixed daily and variable volumetric prices were significantly reduced, but volumetric prices to a greater extent to increase the fixed proportional share.

For commercial consumers, this is achieved by predominantly keeping fixed daily and capacity prices unchanged (there are some low voltage daily price reductions to obtain price level relativity). Different levels of reductions across the variable volumetric and demand prices to allow for similar overall price changes between the TOU and non TOU commercial price categories. Power factor remains unchanged, consistent with previous years' approaches.

The decision to primarily decrease the variable prices reflects the fact that the majority of our costs are fixed and sunk, so implicitly increasing the fixed portion of revenues aligns the recovery of revenues with the way costs are incurred.

We did not directly seek the views of consumers when setting prices. Rather, we consulted with Entrust, which represents mass market consumers on the Auckland network, and retailers on behalf of consumers on the proposed price changes. We have considered and largely accommodated their views in our final prices.

<sup>17</sup> Our full price schedules are available at <https://www.vector.co.nz/personal/electricity/about-our-network/pricing> and <https://www.vector.co.nz/business/electricity/about-our-network/pricing>

<sup>18</sup> There is a slight reduction in the mass market weighted average fixed price due to an assumed shift from standard to low user price categories, this reduces the weighted average price but there are no changes to the actual fixed prices

# 12 - 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 PY21 is \$565m (\$624m for PY20).

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 ‘profit’. These categorisations determine the way that the target revenue is allocated to consumer groups.

Figure 5: COSM structure

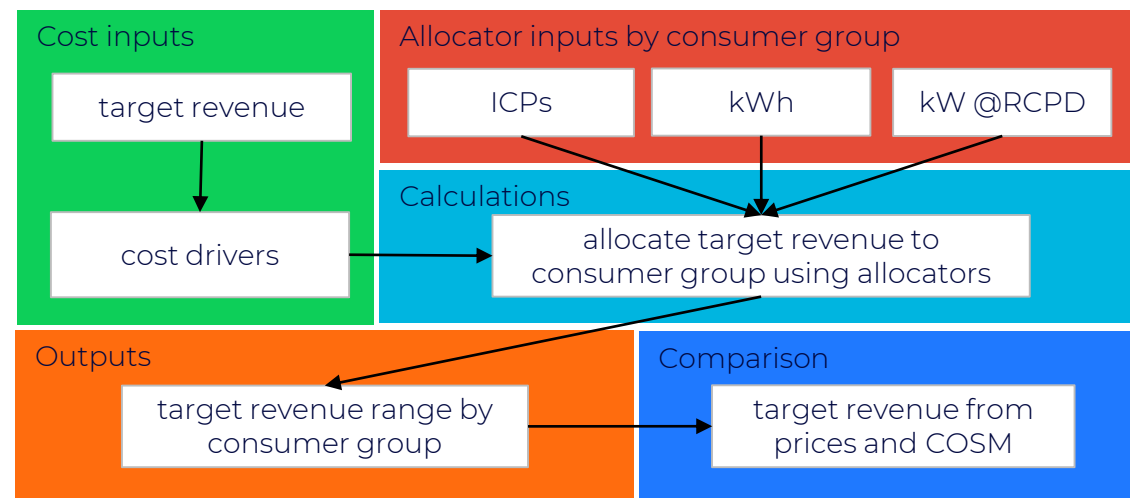
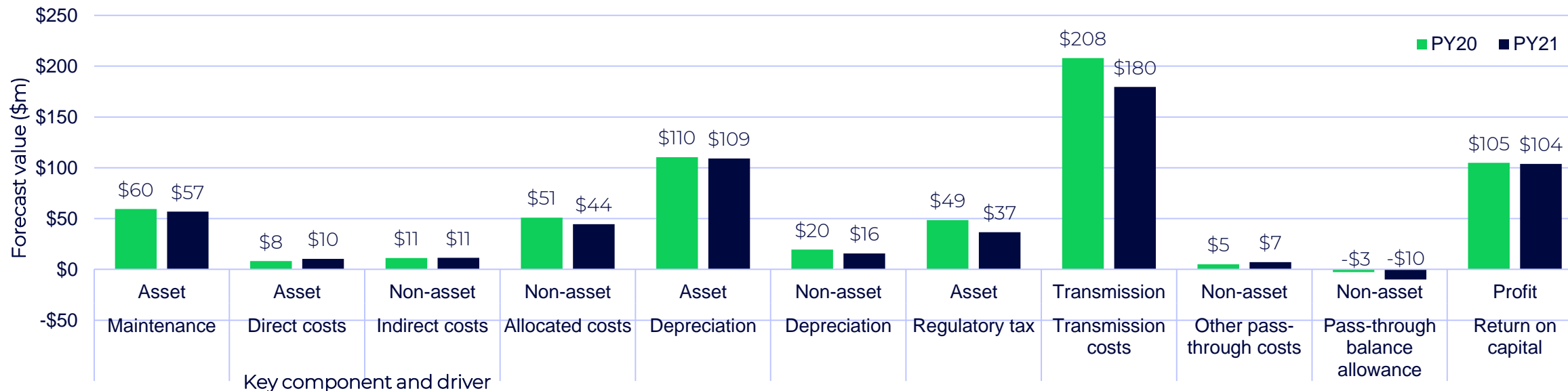


Figure 6: Target revenue by key components



# 13 – COST DRIVERS



As indicated in Figure 6 on the previous page, the key components of target revenue are categorised by cost driver, which are summarised in Figure 7.

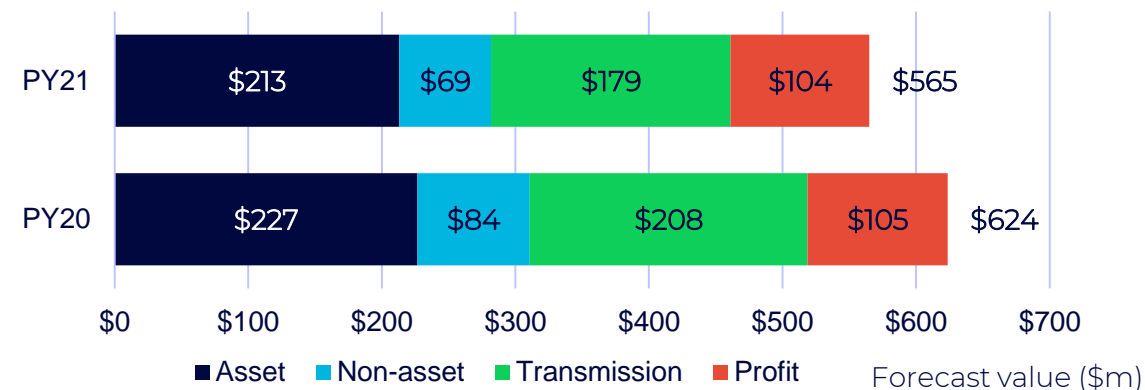
The key components categorised as ‘asset costs’ are those associated with expenditure and return on the electricity distribution network assets. We have grouped these network assets into three distinct categories as shown in Table 9.

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 71% of the asset value of our Regulatory Asset Base (RAB)<sup>19</sup>, we assume that 71% of maintenance costs will be associated with Category A assets.

Table 9: Asset categorisation

Asset category	Assets	Consumer groups	Asset value <sup>20</sup> (RAB)	
A	<ul style="list-style-type: none"> <li>Sub-transmission lines / cables</li> <li>Zone-substations</li> <li>HV lines / cables</li> </ul>	All	\$2,075m	71%
B	<ul style="list-style-type: none"> <li>Distribution substations that have no Vector-owned low voltage lines / cables leaving the substation</li> </ul>	Transformer	\$58m	2%
C	<ul style="list-style-type: none"> <li>Distribution substations that:                             <ul style="list-style-type: none"> <li>have Vector-owned low voltage lines leaving the substation, or</li> <li>supply multiple end-consumers connected at low voltage</li> </ul> </li> <li>Low voltage assets</li> </ul>	Low voltage, unmetered, mass market	\$797m	27%

Figure 7: Target revenue by cost driver



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.

<sup>19</sup> The regulatory asset base represents the amount that we have invested in our regulated network, indexed to inflation and adjusted for depreciation

<sup>20</sup> The values are weighted averages of the last five years' worth of data, with each year being weighted twice the previous year



# 14 – COST DRIVER ALLOCATION APPROACHES



The cost drivers of ‘Asset’, ‘Non-Asset’, ‘Transmission’ and ‘Profit’ are applied to the combined Northern and Auckland networks. Our COSM allocates the recovery of the \$565m to consumer groups using various cost drivers as summarised in Table 10. 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.

Table 10: Cost drivers used in the COSM

Consumer group	Asset			Non-asset	Transmission	Profit
	A	B	C			
Amount	\$151m	\$4m	\$58m	\$69m	\$179m	\$104m
Mass market	Contribution to RCPD	n/a	Contribution to RCPD or annual consumption	Number of consumers or annual consumption	Contribution to RCPD	Rate of return on assets
Unmetered						
Low voltage						
Transformer		Direct	n/a			
High voltage		n/a				

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)<sup>22</sup> 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 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.

<sup>21</sup> Grid exit point (GXP) is a point of connection between Transpower’s transmission system and the distributor’s network

<sup>22</sup> RCPD for a Transmission Region is 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

# 15 – TARGET REVENUE ALLOCATION



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.

‘Profit’ 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, as outlined in the previous page. ‘Profit’ is allocated using a constant rate of return across the consumer groups’ asset values.

Table 11: Value of allocators<sup>23</sup> and target revenue allocation range

Consumer group	No. of consumers		Annual consumption		Contribution to RCPD		Target revenue (\$m)		
	Unit	ICPs	GWh		MW		Lower	Upper	
Mass market		550,502	98.5%	4,576	54%	1,143	69%	387.8	421.3
Unmetered		2,322	0.4%	53	1%	13	1%	4.2	4.5
Low voltage		4,646	0.8%	1,030	12%	151	9%	47.1	61.3
Transformer		1,463	0.3%	1,563	19%	209	13%	55.3	69.4
High voltage		165	0.0%	578	7%	75	5%	18.3	23.4
Non-standard		31	0.0%	638	8%	70	4%	18.9	18.9
Total		559,129		8,438		1,661			

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 two right hand columns of Table 11.

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 \$18.9m (3.3%) to be recovered from the 31 non-standard consumers.

<sup>23</sup> 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

# 16 – PRICE COMPARISON

Figure 8 shows target revenue calculated from PY21 prices by consumer group compared with the COSM allocation. The result is that PY21 prices produce forecast revenues that are in an acceptable range when compared to target revenue allocations.



*The prices determined are checked to ensure they will not earn revenue “out of step” with target revenue for each consumer group*

The proportion of the aggregated price categories’ target revenue is shown by price component in Table 12. 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.



*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*

Figure 8: PY21 target revenue from prices compared with COSM allocations

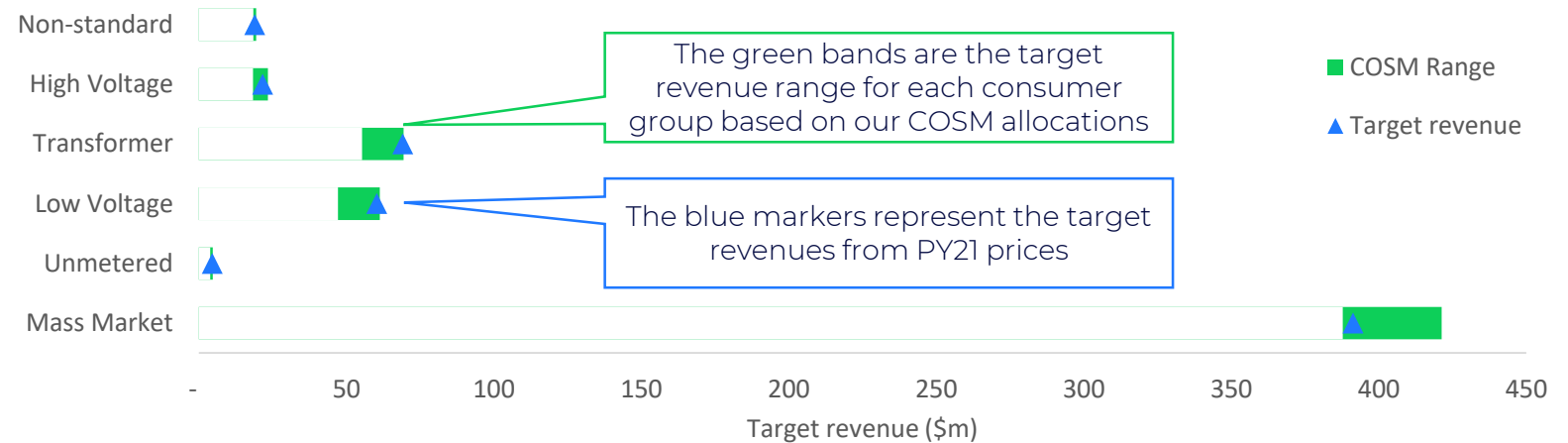


Table 12: Value of allocators and target revenue allocation range

Consumer group	Description	Fixed prices		Variable prices		
		Daily	Capacity	Volume	Demand <sup>24</sup>	Power factor
Mass Market	Residential - low user	12%	-	88%	-	-
	Residential - standard user	45%	-	55%	-	-
	General	28%	-	72%	-	-
Unmetered	Unmetered	73%	-	27%	-	-
Low Voltage, Transformer & High Voltage	Auckland - TOU	-	19%	27%	51%	3%
	Northern - TOU	9%	17%	14%	57%	3%
	Auckland - non TOU	7%	26%	66%	-	1%
	Northern - non TOU	22%	20%	56%	-	2%

<sup>24</sup> Includes demand and excess demand price components

# APPENDIX 1 - LINE CHARGE PRICES FROM 1 APRIL 2020



Table 9: 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 (PY21 avg.)	Total line charge prices							Transmission charge price*
					Daily		Volume					Volume
					anytime	off-peak	peak	injection	anytime or peak			
					\$/day	\$/day/fitting	\$/kWh	\$/kWh	\$/kWh	\$/kWh	\$/kWh	\$/kWh
-FIXD	-FIXD	-24UC	-AICO	-OFPK	-PEAK	-INJT	-24UC, -AICO or -PEAK					
Mass market	Residential - low user	TOU	Uncontrolled	ARHL WRHL	25,623 13,849	0.15		0.0621 (0.0644)	0.1542* (0.1551)*	-	0.0921 (0.0877)	
			Controlled	ARHLC WRHLC	127,913 82,839	0.15 (new)		0.0621 (new)	0.1354* (new)	-	0.0733 (new)	
		Exemption	Uncontrolled	ARUL WRUL	5,980 3,111	0.15	0.0925* (0.1000)*			-	0.0369 (0.0344)	
			Controlled	ARCL WRCL	32,931 21,465	0.15		0.0863* (0.0928)*		-	0.0307 (0.0274)	
	Residential - standard	TOU	Uncontrolled	ARHS WRHS	13,407 13,270	1.01		0.0229 (0.0252)	0.1150* (0.1159)*	-	0.0921 (0.0877)	
			Controlled	ARHSC WRHSC	76,205 60,411	1.01 (new)		0.0229 (new)	0.0962* (new)	-	0.0733 (new)	
		Exemption	Uncontrolled	ARUS WRUS	3,176 3,108	1.01	0.0533* (0.0608)*			-	0.0369 (0.0344)	
			Controlled	ARCS WRCS	18,099 14,348	1.01		0.0471* (0.0536)*		-	0.0307 (0.0274)	
	General	TOU	ABSH WBSH	29,354 17,941	1.01		0.0229 (0.0252)	0.1150* (0.1159)*	-	0.0921 (0.0877)		
		Exemption	ABSN WBSN	7,264 4,441	1.01	0.0533* (0.0608)*			-	0.0369 (0.0344)		
	Unmetered	Unmetered	ABSU WBSU	1,746 629		0.08 (0.15)	0.0257* (0.0680)*		-	0.0260 (0.0344)		

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

# APPENDIX 1 - LINE CHARGE PRICES FROM 1 APRIL 2020



Table 10: Commercial line charge prices  
(previous price, if changing)

Consumer group	Price category description	Price category code	Estimated number of consumers (PY21 avg.)	Total line charge prices							Transmission charge price*	
				Daily	Capacity	Volume anytime	Demand	Excess demand	Power factor	Volume injection	Volume anytime or Demand	
				\$/day -FIXD	\$/kVA/day -CAPY	\$/kWh -24UC	\$/kVA/day -DAMD	\$/kVA/day -DEXA	\$/kVAr/day -PWRF	\$/kWh -INJT	\$/kWh or \$/kVA/day -24UC or -DAMD	
Low voltage	Non TOU	ALVN	2,232	1.78 (1.79)	0.0421	0.0541* (0.0632)*				0.2917	-	0.0187 (0.0212)
		WLVN	901	5.74 (6.26)	0.0339	0.0335* (0.0430)*				0.2917	-	0.0187 (0.0212)
	TOU	ALVT	1,479		0.0421	0.0120 (0.0139)	0.2917* (0.3205)*			0.2917	-	0.1900 (0.2208)
		WLVH	260	10.82 (11.79)	0.0339	0.0050 (0.0059)	0.2628* (0.2908)*			0.2917	-	0.1900 (0.2208)
Transformer	Non TOU	ATXN	165	1.74	0.0412	0.0530* (0.0619)*				0.2917	-	0.0187 (0.0212)
		WTXN	132	5.63	0.0332	0.0328* (0.0383)*				0.2917	-	0.0187 (0.0212)
	TOU	ATXT	937		0.0412	0.0117 (0.0137)	0.2858* (0.3132)*			0.2917	-	0.1900 (0.2208)
		WTXH	288	10.61	0.0332	0.0049 (0.0058)	0.2575* (0.2842)*			0.2917	-	0.1900 (0.2208)
High voltage	Non TOU	AHVN	8	1.68	0.0399	0.0514* (0.0599)*				0.2917	-	0.0187 (0.0212)
		WHVN	0	5.46	0.0322	0.0318* (0.0371)*				0.2917	-	0.0187 (0.0212)
	TOU	AHVT	143		0.0399	0.0113 (0.0132)	0.2772* (0.3024)*	0.8778		0.2917	-	0.1900 (0.2208)
		WHVH	24	10.30	0.0322	0.0048 (0.0056)	0.2498* (0.2745)*	0.7084		0.2917	-	0.1900 (0.2208)

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

# APPENDIX 2 – TARGET REVENUE RECOVERY



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

Consumer group and subgroup	Price category description	Code	Fixed	Variable	Code	Fixed	Variable	
		Auckland	Daily	Volumetric	Northern	Daily	Volumetric	
Mass market	Residential - low user	TOU - uncontrolled	ARHL	0.25%	1.92%	WRHL	0.13%	1.11%
		TOU - controlled	ARHLC	1.24%	8.97%	WRHLC	0.80%	6.20%
		Exemption - uncontrolled	ARUL	0.06%	0.36%	WRUL	0.03%	0.23%
		Exemption - controlled	ARCL	0.32%	2.50%	WRCL	0.21%	1.60%
	Residential - standard user	TOU - uncontrolled	ARHS	0.87%	1.19%	WRHS	0.87%	1.21%
		TOU - controlled	ARHSC	4.97%	6.01%	WRHSC	3.94%	4.88%
		Exemption - uncontrolled	ARUS	0.21%	0.21%	WRUS	0.20%	0.21%
		Exemption - controlled	ARCS	1.18%	1.41%	WRCS	0.94%	1.07%
	General	TOU	ABSH	1.91%	5.17%	WBSH	1.17%	2.81%
		Exemption	ABSN	0.47%	1.35%	WBSN	0.29%	0.73%
	Unmetered	Unmetered	ABSU	0.36%	0.13%	WBSU	0.22%	0.09%

Table 14: Proportion of commercial target revenue by price component

Consumer group	Short description	Category	Fixed		Variable			Category	Fixed		Variable		
		Auckland	Daily	Capacity	Volumetric	Demand	Power factor	Northern	Daily	Capacity	Volumetric	Demand	Power factor
Low voltage	TOU	ALVT	-	1.02%	1.19%	2.44%	0.21%	WLVH	0.18%	0.14%	0.12%	0.48%	0.03%
	Non TOU	ALVN	0.26%	0.90%	2.29%	-	0.02%	WLVN	0.33%	0.29%	0.75%	-	0.02%
Transformer	TOU	ATXT	-	1.76%	2.41%	4.60%	0.22%	WTXH	0.20%	0.47%	0.33%	1.45%	0.08%
	Non TOU	ATXN	0.02%	0.10%	0.21%	-	0.00%	WTXN	0.05%	0.07%	0.23%	-	0.01%
High voltage	TOU	AHVT	-	0.43%	0.92%	1.70%	0.07%	WHVH	0.02%	0.09%	0.12%	0.45%	0.01%
	Non TOU	AHVN	0.00%	0.00%	0.01%	-	0.00%	WHVN	-	-	-	-	-

# APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

The Electricity Authority's Pricing Principles<sup>25</sup> (Pricing Principles) and Distribution Pricing Practice Note<sup>26</sup> (Practice Note) 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 and Practice Note.

Table 15: 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. Our capital contributions policy ensures that individual consumers generally pay the costs of connecting to the network.

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.

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.

<sup>25</sup> Available at <https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper/>

<sup>26</sup> Available at <https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/distribution-pricing-practice-note-and-scorecards/>

## 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.

Figure 9 shows our forecast capital expenditure excluding capital contributions to meet future demand from our 2019 Asset Management Plan<sup>27</sup>. 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 all connections.

Our target revenue allocation illustrates how we utilise relevant cost drivers. 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.

We signal the level of available capacity and future investment costs 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. We offer controlled load prices to residential end consumers in return for the ability to remotely manage their 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. These pricing options provide incentives to end consumers to shift demand away from peak periods and therefore reduce the need for future investment costs.

Figure 9: Forecast capital expenditure to meet future demand



<sup>27</sup> Available at <https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/asset-management-plan>



## 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.

### 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 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/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 adapts new technologies to reduce load will not require the same level of network investment.

## 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 mass market and general to 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 this Pricing Methodology and we continue to consult as appropriate when applying it and future methodologies. The information we receive helps us to understand consumer drivers and preferences. We continue to undertake a range of trials so that we can anticipate and respond to consumer's requirements as technology 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 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.

# APPENDIX 4 – DIRECTORS’ CERTIFICATION

## Schedule 17: Certification for Pricing Methodology Disclosure

Clause 2.9.1

We, Jonathan Mason and

Alison Parterson, being directors of Vector Limited  
certify that, having made all reasonable enquiry, to the best of our knowledge:

- a) The following attached information of Vector Limited prepared for the purposes of clauses 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
- b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Jonathan P. Mason  
Director

Alison Parterson  
Director

24/02/20.  
Date