Pricing Methodology
Electricity Distribution Network

Pursuant to the Electricity Distribution Information Disclosure Determination 2012.

Effective from 1st April 2022

Contents

Definitions and common acronyms

Assets	The hardware, equipment or plant that is part of our electricity distribution network.
Controlled Energy	Electricity supply for which we temporarily cease supply when required, typically during periods of high load. It is most commonly water heating load.
Customer	An end user who is connected to the electricity distribution network.
Customer Load Groups	The customer segments that have similar electricity requirements and that share similar pricing methodologies.
GXP	Grid exit Point. This is the point where EA Networks' electricity distribution network connects to Transpower's transmission network.
ICP	Installation Control Point. This is the isolation point where a customer connects to the distribution network and where the retailers metering is located.
kW	Kilowatt. The measure of electrical capacity.
kWh	Kilowatt-hour. The measure of electricity consumption by which retail electricity consumption is measured.
kVA	Kilovolt Ampere. A unit of measure for how much power is being provided through a business or home's electrical circuits or technology.
Retailer	The entity that charges customers for their electricity usage.
RCPD	Regional Coincident Peak Demand. This affects the way that Transpower allocates interconnection cost.
Target Revenue	The forecasted annual revenue we expect to earn as determined under the Default Price Path rules and guidelines.
Transmission costs	Transmission costs are comprised of charges directly from Transpower, Avoidable Cost of Transmission paid to Generators (now ceased), and recoverable costs including regulatory levies and local authority rates.
WACC	Weighted Average Cost of Capital. This is the measure of the return an Electricity Distribution company may achieve under the Default Price Path regulations set by the Commerce Commission.

1. Introduction

1.1. Purpose

The purpose of this document is to detail how EA Networks develops the prices it charges for connection to, and use of, the network.

1.2. About EA Networks

EA Networks is the trading name of Electricity Ashburton Limited. We own and operate the electricity distribution network located in Mid Canterbury. We are a consumer owned cooperative with every connected customer entitled to own shares in the company.

Our network delivers electricity to households and businesses across an area of about 3,500km^2, between the Rangitata River in the south, the Rakaia River in the north and the foothills of the Southern Alps in the west. Three distribution lines run into up-river gorges through the foothills.

From a network engineering perspective there are two general network designs; rural and urban.

The rural distribution network configuration is predominantly long radial overhead feeders with some interconnection to adjacent feeders and substations.

The urban 11kV distribution network is based upon a similar principle to the rural arrangement, except the network is largely underground cable, the interconnections are more frequent, and the overall feeder lengths are significantly shorter.

There are four hydro generating stations embedded in the network. Lavington is 0.5MW, Cleardale is 1MW station, Montalto is 1.6MW station and Highbank is 28MW station.

2. Summary of current revenue and pricing

We have reviewed our pricing against the Commerce Commission's (Commission) Default Price Path (DPP) requirements. The pricing approach is in-line with previous years with the main exception being changes to our 'General' load group brought about by changes to low fixed charge regulations.

Gross prices will reduce on average for 2022-23 compared to 2021-22 because forecast chargeable quantities provide an uplift in revenue. When balanced against our regulated allowable revenue, average overall prices reduce.

2.1. Target revenue for 2022-23

Target revenue for 2022-23 is $41.7 million, representing a $0.6 million, or 1.4% increase from $41.2 million in 2021-22. The target revenue for 2022-23 is set to recover:

- $33.6 million for delivering Distribution services, representing a $0.5 million or 1.5% increase from 2021-22.
- $8.2 million for pass-through and Transmission costs, representing a $0.07 million or 0.8% increase from 2021-22.

2.2. Key change to prices this year

During 2021 the Government announced changes to the low fixed charge regulation[1] (LFC). We have implemented changes to our equivalent LFC load group (General Supply 20 – GS20) and intend to mirror the glide path to phase out LFC prices set by the regulations.

Introducing the revised fixed price of $0.30 per day for 2022/23 (increasing from $0.15 per day) has required changes to all other tariffs within the General supply category to maintain the same revenue requirement from each. We have also reduced the variable rate to ensure that, in aggregate, the changes are revenue neutral for all categories.

We expect to continue to align GS20 with the glide path set by the revised regulations, increasing the fixed price to match those detailed in the regulations (i.e., increasing the fixed rate by 15 cents each year through to 1st April 2026 (from 1st April 2027 the regulation will be removed).

This is discussed further in Section 6.2 General Customer Load Group information and Section 7.1 Low fixed charge regulation.

There have been no other significant changes to our prices or our Pricing Methodology.

[1] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

More detail on the change to target revenue for 2022-23 compared to 2021-22 is shown here:

Target revenue, $000	2022-23	2021-22	$ change	% change
Distribution services	$33,560	$33,052	$508	1.5%
Pass-through and transmission costs	$8,179	8,114	$65	0.8%
Target Revenue	**$41,739**	**$41,166**	**$573**	**1.4%**

2.3. Average change in prices for 2022-23

Prices for each Customer Load Group, in aggregate, will on average reduce for 2022-23 by 0.1% (compared to 2021-22) largely due to an increase in forecast chargeable energy quantities that will help recover revenue. The average aggregate change for each Customer Load Group is shown here:

Customer Load Group	Average change %
General	0.1%
Irrigation	-0.3%
Industrial	0.5%
Large Users	0.0%
Generation	-0.1%
Average change – all groups	**-0.1%**

Note: For this Table the Large User Customer Load Group includes Streetlighting.

2.4. Summary of revenue and cost

The following tables provide an overview of our revenue recovery by customer type, as well as a breakdown of major cost types and more detail on recoverable pass-through costs.

Target Revenues by Customer Load Group

This table shows how total Target Revenue for 2022/23 is recovered by Customer Load Group.

Customer Load Group	Connections	Target revenue ($000)
General	18,814	$19,841
Irrigation	1,615	$18,382
Industrial	42	$1,754
Large Users	12	$1,355
Generation	4	$407
Total	**20,487**	**$41,739**

Target Revenues by Cost Category

This table shows the main costs comprising the Target revenue for 2022-23.

Cost category	Target revenue ($000)
Distribution services	
Operations & maintenance	$13,058
Administration	$5,574
Depreciation	$10,882
Cost of capital	$4,046
Subtotal	**$33,560**
Pass-through costs	
Rates & levies	$294
Transmission	
Transmission – connection	$2,004
Transmission – interconnection	$5,881
Transmission – subtotal	**$7,885**
Subtotal	**$8,179**
Target revenue	**$41,739**

Pass-through costs are actual costs. No cost of capital or margin is recovered from these costs.

For 2022-23, the *Transmission – interconnection cost* includes a $1.0 million early repayment of a Transpower New Investment Contract. The early repayments are designed to reduce material year-to-year volatility in transmission – interconnection costs caused by the current transmission pricing methodology (TPM). The year-to-year volatility was adversely affecting customers, particularly in the Irrigation Customer Load Group. The volatility in transmission costs is expected to cease with introduction of the proposed new TPM.

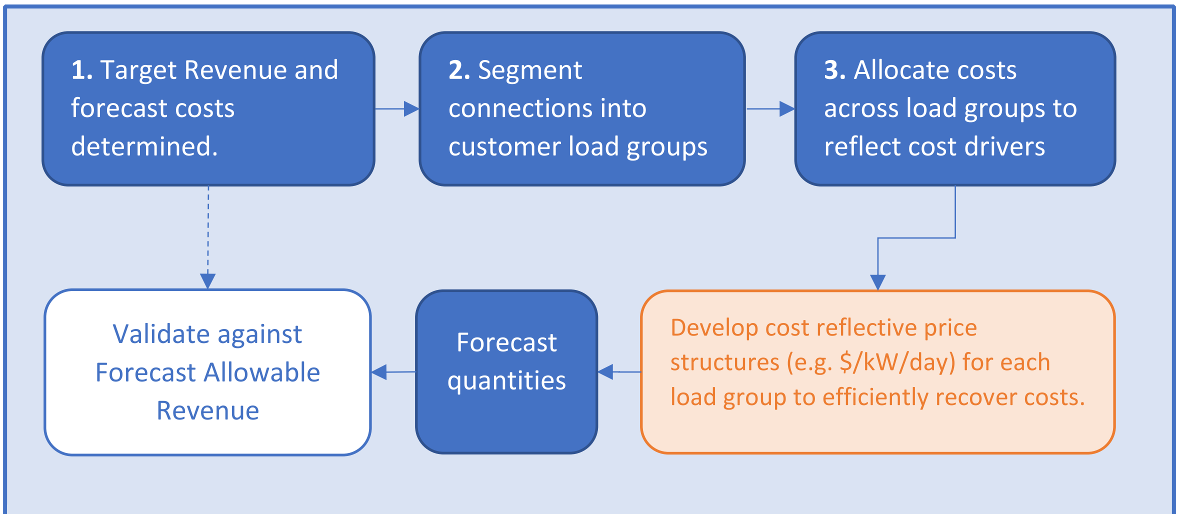
3. Overview of pricing methodology

EA Networks is an electricity distribution business (EDB). Our costs are largely fixed as we build and maintain long-life network assets. These assets are designed to enable the delivery of electricity to connected customers (current and future) in the Mid Canterbury region. We are a non-exempt EDB meaning we are regulated in terms of prices and quality of supply.

We recover our regulated revenue through prices charged (via electricity retailers) to customers that are connected to the electricity network. Where possible, we aim to provide a fixed price signal reflecting the cost to deliver capacity to customers, albeit that a proportion of our revenue is recovered from variable price structures, largely due to current regulations.

The prima facie strategy to develop prices is to reflect and recover as accurately as feasible the cost of providing network services to connected customers. In general terms, the greater the capacity (the level of demand) required by a customer, the greater the cost to provide network service to the customer. This is because the fixed cost of infrastructure required to meet greater demands at a connection is higher. Put another way, our costs are driven by peak demands (how fast energy is being used) rather than volume (how much energy is used).

The development of our methodology and the prices that result is based on economic pricing principles given practical, physical, regulatory and commercial constraints. An overview of the price development process and pricing methodology is provided here:



Overview of Pricing Methodology

Costs are allocated based on segmentation of connected users. The purpose of these segmented types is to group individual customers into load groups that share similar electricity demand profiles, capacity requirements and cost drivers – this enables the allocation of network assets by group to reflect utilisation by that group.

There are five broad connection types (some have sub-categories to further delineate capacity requirements and better reflect cost to serve, such as the General group):

1. General – households, commercial businesses connected to the low voltage network, including single and 3-phase supply.
2. Irrigation – connections with irrigation pumps (>20kW).
3. Industrial – industrial/commercial connections.
4. Large Users – connections with dedicated assets and specific connection requirements[2].
5. Generation – distributed generators (>10kW).

We allocate our costs across these Customer Load Groups based on the assets required to meet their level of demand needs.

Price components

Prices are applied across a combination of fixed, capacity, and variable price components, depending on the Customer Load Group. The proportion of total revenue recovered, in aggregate, from each customer group using fixed, capacity and variable price components is shown here:

	Customer Load Groups					
	General	**Irrigation**	**Industrial**	**Large Users**	**Generation**	**Total**
Fixed	8%	0%	0%	2%	1%	11%
Capacity	0%	44%	4%	2%	0%	39%
Variable	39%	0%	0%	0%	0%	50%
Total	48%	44%	4%	3%	1%	100%
The price components used for pricing for each Customer Load Group are shown here:						
Fixed	$/con/day			$/day	$/day	
Capacity		$/kW/day	$/kVA/day	$/fixture/day		
Variable	$/kWh			$/kVA/day		

Where possible, we recover costs through fixed charges or capacity charges. However, we must comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 ('Low Fixed Charge Regulations'). This regulation requires a low 'fixed charge' component to the pricing design (for 2022/23 this price is $0.30 per day for networks) and therefore the balance of the revenue requirement must be met through a high variable component for these customers. This fixed charge, totalling just under $110 per annum for the average residential customer, in no way reflects or recovers the fixed costs that are associated with delivering electricity network services to customers who are eligible for this price category. Instead, the regulations drive us to recover, or try to recover, the true cost to serve these customers via variable energy demand and associated prices.

However, the government recently updated the legislation, establishing a 5-year period before it will be repealed. During this period a new maximum fixed rate has been defined, allowing EDBs to charge a higher fixed rate, increasing incrementally over the 5-year period. EA Networks plans to

[2] Streetlighting costs are allocated to a Streetlighting Customer Load Group. This load group is included in the Large User Customer Load Group.

mirror the prices defined in the legislation. For simplicity we allow all General (GS20) customers access to the Low Fixed Charge product type and have used it to shape the overall design of the wider ‘General’ product group.

3.1. Managing consumer impacts of pricing changes

We assess the impact on consumers of each change to price structure and price level. We take account of the potential that the price change will result in bill shock for a Customer Load Group, or consumers within a Customer Load Group.

We believe that price stability is important and critical to the efficient running of the local economy, and our customer research confirms this. Our pricing is designed to minimise volatility between years across the Customer Load Groups. This is to mitigate bill shock and assist them with efficient budgeting and planning of electricity expenses.

Price stability is maintained through consistency and our approach to price development. Only when critical to customers’ needs, regulatory change or for the financial stability of the business, will we make wholesale changes to our Pricing Methodology. Our upcoming pricing reform work may lead to changes to the structure of our prices and allocation of our costs to load groups/customer segments.

Our Customer Load Groups have also been developed to promote price stability and specifically mitigate price volatility.

> *For example: our Irrigation Price is a fixed daily charge based on connected kilowatts (kW) (capacity size). This charge is incurred irrespective of usage. We price in this way to ensure consistency each year in the price charged to irrigators and to signal to them the fixed costs incurred in building the network to meet their demand. If a variable charge was applied, it would be challenging to forecast demand and establish appropriate pricing to accurately recover our fixed costs. Variable charging would, for this load group, result in volatile prices between years.*

In addition to load group and price design, our board of directors approve any changes made to prices and this Pricing Methodology. Prior to any approval, a review is undertaken to firstly ensure compliance with the Default Price Path (DPP) determination. The board then take a holistic approach to determining the final changes (if any) to be made. Factors such as the fairness of a change as it affects our different Customer Load Groups, the ultimate impact on these groups and the financial position of the company are, amongst other factors, considered. Only when the board of directors is satisfied that all stakeholders have been considered and fairly treated will a change be approved.

Practically, this means discretion will be applied to a material increase in the level of any price component of the price structure for any Customer Load Group. Options we have to manage price shocks include averaging the associated costs across other Customer Load Groups or foregoing a portion of the Forecast Allowable Revenue.

As with prior years, EA Networks has worked to mitigate price shocks expected from significant increases in forecast transmission costs (under a proposed new TPM). We have done this by early repayment of Transpower New Investment Contracts. Early repayment mitigates price volatility by smoothing total revenue across financial years and reducing potential volatility. At the time of writing there was no confirmed date for implementation of the proposed new TPM. All repayments have been based on EA Networks’ best estimate of this.

4. Pricing considerations and objectives

4.1. Regulatory context

Our pricing is regulated by the Commerce Commission ('Commission') under Part 4 of the Commerce Act and the Electricity Authority under the Electricity Industry Act 2010 and Electricity Industry Participation Code 2010. These regulations ensure that distribution services are delivered at prices that are fair and reasonable and at an acceptable quality.

EA Networks' Pricing Methodology and prices are guided by and comply with regulations and guidelines governing the electricity industry, including:

- Distribution Pricing Principles published by the Electricity Authority (EA).
    - We are expected to set efficient prices consistent with the Authority Pricing Principles published in June 2019. APPENDIX A – Alignment with Electricity Authority Pricing Principles describes how we do this.
    - The EA also released a pricing practice note in 2021.
- Electricity Distribution Information Disclosure Determination 2012 (IDD).
    - We are required to disclose information about our pricing approach and prices. APPENDIX B – Alignment with Commerce Commission Information Disclosure describes how we do this.
- Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
    - We are required to offer a low fixed charge price option (of not more than 30 cents/day) for a consumer's primary residence.
- Electricity Distribution Services Default Price-Quality Path Determination 2020.
    - We are required to set prices to recover no more than the Forecast Allowable Revenue under the DPP determination.
- Electricity Industry Participation Code 2010, Part 6 (Connection of Distributed Generation).
    - Sets out requirements for setting prices for distributed generators connecting to and using our network.

4.2. Network context

We have one supply point from the transmission grid. A 33kV and 66kV sub-transmission network supplies 24 zone substations varying in size from 5 MVA to 40 MVA. The distribution network is a mixture of 22kV, 11kV and low voltage (LV) with both overhead and underground variants of each. Overall, the distribution system is about 24% underground cable by circuit length.

The main urban area in the district is Ashburton township, with about 20,000 residents. Smaller towns of Methven (1,900 people) and Rakaia (1,600 people) are also significant in terms of residential electricity consumer count. The district has a total population of about 35,000 people.

The area we serve is largely rural land used for cropping and dairy farming and has a high level of irrigation. Other significant loads are vegetable and meat processing facilities, and a ski-field.

Dramatic load growth has occurred in the Mid-Canterbury region. The summer maximum demand has more than trebled since 1996 and more than doubled since 2003. The network has peaked at 181 MW twice in the past five years. Irrigation load has doubled since 2005 and now is approaching an installed capacity of 147 MW. This growth has in-turn driven significant capital development on

EA Networks' network. However, irrigation load growth has now slowed and we do not expect to see any further growth.

We anticipate uptake of large scale distributed generation and electrification of industrial processes (heat) and transport to impact our network, though the timing of this remains uncertain.

There is already a large amount of distributed generation on our network, with an installed capacity of approximately 33 MW, though most capacity is associated with four distributed generators. The largest Distributed Generation (DG) connection is Highbank, a hydro generator owned by Trustpower, with 29 MW capacity.

4.3. Overview of Network Assets & Network Characteristics

EA Networks 2021-2031 Asset Management Plan (AMP) comprehensively describes the network assets and network characteristics. The following overview is from that AMP[3]:

Network Inputs and Outputs:

Maximum Load Demand	181	MW (Dec 2020)
Maximum Delivered Energy	607	GWh (2019-20)
Annual Load Factor	42	% (2019-20)
Subtransmission Lines	422	km
MV Distribution Lines	2,204	km
LV Distribution Lines	473	km
Distribution Substations	6,581	km
* Data as at January 2021		

Substations	Peak Load	Load characteristics
Ashburton	19 MW	Supplies 60% of urban Ashburton and some outlying areas. The load has a winter peak consisting almost entirely of residential dwellings.
Carew	16 MW	Mostly summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Load exceeds firm capacity.
Coldstream	16 MW	Load exceeds firm capacity. The high general demand is a consequence of the large number and size of dairy sheds. The dominant load is irrigation pumps which are summer peaking.
Dorie	11 MW	Summer peaks with irrigation load. The high general demand is a consequence of the large number and size of dairy sheds.
Eiffelton	9 MW	Mostly irrigation.
Fairton	8 MW	Supplies rural residential, industrial, and irrigation load. The ex-Silver Fern Farm meat-works are now owned by a vegetable processing company, and indications have been given that the site

3 The latest Asset Management Plan (2022-2032) was an update only and did not refresh these values.

Substations	Peak Load	Load characteristics
		will be developed for vegetable processing. Previously, the industrial load was non-seasonal, but total load peaked in summer with irrigation load. Another vegetable processing plant forms the base load.
Hackthorne	15 MW	The load is summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Maximum load currently exceeds firm capacity.
Lagmhor	11 MW	Mainly irrigation. Firm capacity exceeds maximum load.
Lauriston	15 MW	Summer peaking due to irrigation demand. The high general demand is a consequence of the large number and size of dairy sheds.
Methven 66/11 & 66/33	5 MW + 5 MW	Summer peaking due to irrigation demand. The high general demand is a consequence of the large number and size of dairy sheds and related irrigation.
Mt Hutt	2 MW	Peaks in winter associated with ski-field activities. Maximum load exceeds firm capacity. Zero irrigation. Cleardale hydro generation is connected at 11kV. Switched firm capacity is sufficient for essential services of the major consumer.
Montalto	2.5 MW	A temporary substation located near the Montalto hydro power station.
Mt Somers	3 MW	Maximum load matches firm capacity. The load is balanced between extensive rural farms, Mt Somers township, and a couple of lime quarries. The load is slightly summer peaking due to the irrigation but remains close to the summer peak during winter due to the residential demand.
Northtown	17 MW	Provides additional capacity and security to Ashburton township and immediate surrounds. Load is winter peaking in line with residential demand
Overdale	14 MW	The load is summer peaking and irrigation based, although Rakaia township with its residential/commercial demand causes higher base loads than some other irrigation-serving substations.
Pendarves	16 MW	Irrigation load causes this site to summer peak at 10 times its winter peak. Firm capacity is available to all load.
Seafield	8 MW	Dedicated to ANZCO's meat-works. Non-seasonal peak load
Wakanui	13 MW	A summer peak load; mostly irrigation.

Source: EA Networks Asset Management Plan 2021-31, pp208-209

Additional information is available in our published Asset Management Plan, available at: https://www.eanetworks.co.nz/disclosures/

4.4. Customer context

The network has been designed to service customers (both load and generation) with their energy distribution needs. There are five main categories of customer (load groups):

1. General
2. Irrigation
3. Industrial
4. Large Users
5. Generation

The General and Irrigation Customer Load Groups provide 92% of total revenue, with the General group providing 48% of total revenue and the Irrigation group providing 44% of total revenue. There are 18,814 low voltage residential and small business connections in the General group, and 1,615 connections in the Irrigation group.

Irrigation load can be high. While most distribution networks in New Zealand experience peak loads during winter, EA Networks' maximum network demand occurs during the irrigation season (typically September to April), and can be three times higher (on average) than base load during winter. This is almost entirely driven by farmers' response to prevailing weather conditions and thus difficult to forecast. Irrigation demand during the season has a significant bearing on Transpower's interconnection cost that is charged to EA Networks and passed-on to our connected customers.

4.5. Consumer consultation

During October-November 2021, EA Networks undertook consumer consultation. This was based on a random selection of end user customers conducted by an independent survey firm.

EA Networks uses the results of consumer consultation in developing pricing approaches and this pricing methodology. In summary, the results indicated that customers continue to be supportive of the current level of prices, with a majority of those surveyed not willing to pay higher prices to reduce potential for outages, or to reduce time without power. No detailed questions were asked about the structure of our prices.

How we obtain customer insights to help shape prices

We take a proactive approach in gathering the views of consumers using the electricity distribution network. Every 24 months an independent survey is carried out to address pricing and consumer expectations regarding outages and quality of supply (and how these relate to price). The survey samples residential (urban and rural) and small business customers. The output of any survey or relevant public information is used when determining prices and other business matters such as capital investment. Our next broad customer survey is planned to be completed in the final quarter of 2023.

In addition to our biennial survey that directly targets consumers, the company structure lends itself to direct feedback from customers. EA Networks is a co-operative company, our end user customers are also (generally) our shareholders. A Shareholders' Committee has been established and has operated since the co-operative was set-up. This committee represents all consumer shareholders and is focussed on ensuring that consumer views are prioritised. The committee takes an active role in providing feedback to our board and management regarding customer expectations on price changes and related matters.

Our single largest shareholder is the local District Council. This entity is also one of our largest connected customers and is represented on the Shareholders Committee. We seek and receive regular direct feedback in relation to pricing from the District Council.

EA Networks also ensures that there is a local focus to the make-up of our Board of Directors. This ensures that local views are always considered when making business decisions, including pricing.

From these combined sources we are comfortable that we are considering the views of both individual customers and the wider market from a macro perspective, especially where that relates to pricing.

4.6. Feedback

We welcome feedback on our Pricing Methodology and any questions that customers may have regarding this or their specific circumstances. Any enquiries should be addressed to;

General Manager Customer & Commercial

Phone (03) 307 9800, or email; enquiries@eanetworks.co.nz

5. Pricing methodology

5.1. Background

The purpose of this section is to outline in detail our methodology for setting prices and to disclose the current pricing derived from that methodology.

5.2. What our pricing covers

Electricity industry market segments. Our prices include costs relating to Transmission and Distribution only. Together these costs are referred to as delivery costs.

There are four key market segments to the electricity industry; generation, transmission, distribution and retail. EA Networks is responsible for *Distribution* within the Mid-Canterbury region.

It is Transpower's role to deliver electricity up and down the length of New Zealand (*Transmission),* taking energy supply from the *Generation* companies. Transpower hand-over within each region to the relevant distribution company via a number of grid exit points (GXPs).

End user customers have their electricity relationship with Retailers. It is generally the retail sector that charge end user customers for the total cost of electricity supply and usage. This charge includes all costs from the different market segments. As such, despite end users receiving only one electricity invoice each month, the four participants' costs and margins are included in that charge. We invoice retailers that have customers connected to our distribution network.

Our pricing (that is charged to Electricity Retailers) covers both *Transmission* and *Distribution* costs – together called *delivery costs*. *Transmission* charges are a direct pass-through of those charges levied on us by Transpower (the national grid operator). *Distribution* charges reflect the costs associated with maintaining and operating our local electricity distribution network. We disclose each separately in the Pricing Schedule.

This document details the methodology we use to derive pricing for *Distribution* and how we allocate *Transmission* costs that are ultimately included in our final delivery prices invoiced to retailers each month.

Equitable treatment of retailers

Our charges are applied to retailers that use our network to provide electricity to end users. Retailers that wish to sell electricity to customers within our network area must sign a Default Distributor Agreement (DDA). The DDA forms the commercial terms and understanding between the Retailer and ourselves and covers a myriad of operational and performance objectives and responsibilities. It also details how we charge and how we will invoice retailers.

Our DDA is based on the principle of providing equitable treatment of retailers.. That is, each retailer is treated equally regardless of size or any other differentiating factor. We do not have differential prices, service targets or operational procedures for each individual retailer. Whilst this maintains simplicity in how we deal with retailers, it also ensures a level playing field and should enable greater competition within the retail sector.

5.3. Future pricing approach

The purpose of this section is to provide customers and interested parties with an indication of the direction that EA Networks sees pricing (in terms of methodology and pricing approach) heading.

Our prices are determined by taking account of the network, consumer and regulatory characteristics relevant to our network. As such, we recognise the importance of evolving pricing as circumstances and characteristics change.

We have a pricing development workplan that sets out a roadmap for evolving our pricing approach and structures that reflect the underlying cost to supply the distribution service desired by our customers.

The near-term focus of the workplan is to identify the activities we will undertake to develop a pricing structure which, to the extent practicable, has fixed and variable price components that align to the fixed and variable costs of supply for each customer (load) group.

High level implication of future pricing approach

We believe it is important to provide an early signal of any changes to our methodology, given the long-term nature of our investments and those of our customers that may be affected by electricity network pricing approaches.

The impacts of the future pricing approach will differ for each Customer Load Group and each customer. Identifying customer impacts of pricing changes is an action included in the pricing development workplan.

Broadly, the likely impact of transitioning to a pricing structure which has fixed and variable price components which align to the fixed and variable costs of supply for each customer group will be to increase the proportion of revenue recovered through fixed and fixed-like charges, and reduce the proportion of revenue recovered through variable charges.

More than two decades of significant network investment mean the network has significant capacity, with only isolated areas of network congestion which might result in marginal (avoidable) costs which would be reflected in variable or congestion based charges. As such, we expect most costs recovered through prices will be fixed or capacity based. This is the approach for the large user, industrial and irrigation customer groups.

However, the General customer group can expect a gradual rebalancing of the levels of the variable charge and fixed charge, with the level of the variable charge falling and the level of the fixed charge increasing. This commenced this year as we align to changes in low fixed charge regulation.

An implication for these customers is an overall decline in the individual benefit of reducing or avoiding consumption by investing solar panels and batteries. There may continue to be localised benefits from reducing or avoiding consumption depending on the specific network conditions. We began the transition this year with changes to our General load group portfolio.

5.4. Pricing philosophy

Our philosophy to pricing is based on two views; the internal (business) view focusses on what we must do and what we require financially to operate our business sustainably over the long term. The second view is external and that of customers and how we price in the most accurate (cost reflective) and equitable way that we can. The external view considers the wider market including the regulatory framework that we work within and must comply with.

Internal perspective

We are a commercial organisation and therefore accurate pricing is fundamental to the financial sustainability of our business. Prices applied to use the services that we provide must recover our costs of doing business as well as ensure that we can maintain the assets required to deliver our services. Inherently our pricing is based on forecast quantity information and therefore it is important that we have the most accurate information and assumptions to ensure that our prices result in actual revenue that in-turn recovers our cost of doing business.

We must ensure the company generates an adequate return to ensure that we can continue as a viable business (going concern). This requires revenue but also a strong focus on costs and management of our investment in network assets. Our investments are typically long term and therefore planning is very important so that we ensure decisions made today will not burden the company in the future.

Accuracy and *Sustainability* are therefore two over-arching principles that we focus on from an internal pricing methodology perspective.

External perspective

As well as considering internal requirements, we pay particular attention to external factors when considering our pricing methodology. There are four principles that underpin our approach to developing products and prices; *Simplicity, Stability, Equity* and *Transparency.*

By focussing on *simplicity,* we aim to have a pricing methodology that is easy to understand and follow whilst being cost reflective. It is critical to us that end user customers can understand the prices that they are charged in relation to the nature of their supply, and further, to appreciate why we charge for our services the way we do. This allows customers to make informed decisions about their supply to ensure it is sized appropriately.

We believe that price *stability* is important and critical to the efficient running of the local economy. Businesses and residents need confidence in the prices they pay for core services such as electricity. Our pricing is designed to minimise volatility across the Customer Load Groups. This is to mitigate bill shock and assist them with efficient budgeting and planning of electricity expenses. We cannot always control this given the quantum of some input costs, notably transmission costs. However, to the extent possible we aim to develop prices that are stable year-on-year.

Equity is the fairness of our pricing, both between customer types as well as inter-generational customer groups. Whilst inherently difficult to apply charges that exactly correlate to the costs of supplying an individual customer, we endeavour to allocate the cost of running the business and the distribution network in such a way that those who use more, or drive more of the cost, in-turn pay for that (beneficiary pays). This is the purpose of establishing Customer Load Groups and identifying the assets and costs associated with running our network and allocating those accurately and fairly to each group of users.

We are entirely open and *transparent* with our methodology for pricing. We make this information publicly available and explain it in detail. Further, we engage with the community to share this information and seek feedback by way of customer surveys and regular interaction and communication with electricity users.

Through application of these four over-arching principles we aim to create a pricing methodology that serves the needs of our business whilst meeting customer expectation.

5.5. Pricing development activities

The pricing development workplan sets out near and longer-term activities.

The workplan reflects the uncertainty about what may come, identifying near-term activities focused on preparing for pricing changes once more is known about the nature and timing of regulatory changes. There are material regulatory changes on the horizon, particularly regarding the adoption of a new Transmission Pricing Methodology (TPM). However, the nature and timing of that change is not currently known.

Near term pricing development activities are:

- overarching pricing development activities relating to obtaining information and capability required to identify pricing structures which meet the pricing objective and philosophy
- low fixed charge-related activities relating to responding to the allowable price changes embedded within the low fixed charge regulations
- Transmission Pricing Methodology (TPM) activities relating to responding to prospective changes to the TPM

More detail is available in the Pricing Development Workplan on our website.

5.6. Our approach to developing prices

The development of our methodology and the prices that result is based on economic pricing principles given practical, physical, regulatory and commercial constraints.

In general, shared assets and shared costs are allocated proportionally across Customer Load Groups using network capacity (kVA) associated to that load group. Specific assets and specific costs that can be attributed to a load group are allocated to that group only.

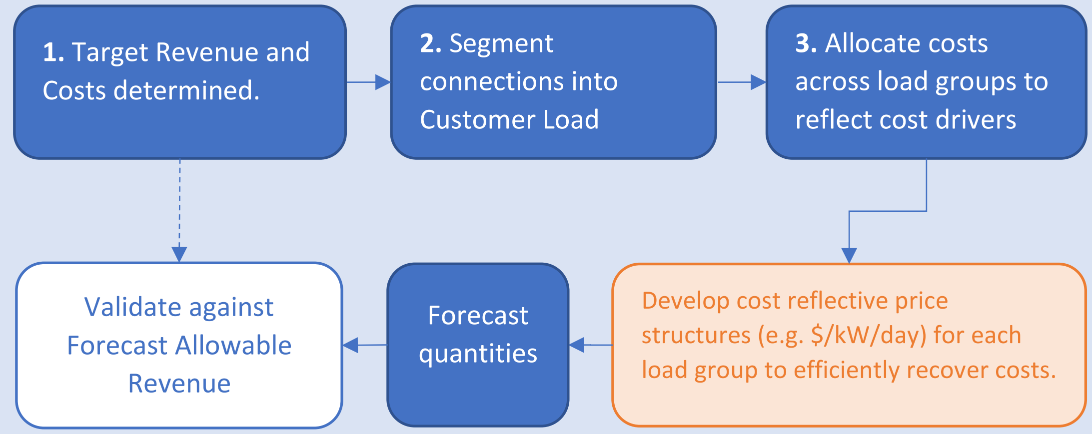
> *For example: if we build a new feeder (electricity line) that only allows irrigation connections to connect to the network, the costs associated with that line will be allocated only to the Irrigation load group. Other load groups pricing will be unaffected by this capital development.*
>
> *If on the other hand, we invest in equipment that improves the general quality of electricity supply (i.e. it benefits all connected users) then the costs associated with that will be shared amongst all load groups proportionally.*

There are practical limits to the information available to allocate assets and costs. Electricity networks generally have significant legacy assets upon which modern upgrades have been applied. In addition, technology improvements can and will be incorporated where appropriate, but these can take many years to have an effect across the aggregate network.

Consequently, when allocating assets and developing prices a degree of averaging is inevitable. Despite this, and by applying the four principles of our approach to pricing, we aim to establish prices that do reflect the costs associated with supplying electricity to different end users (Customer Load Groups).

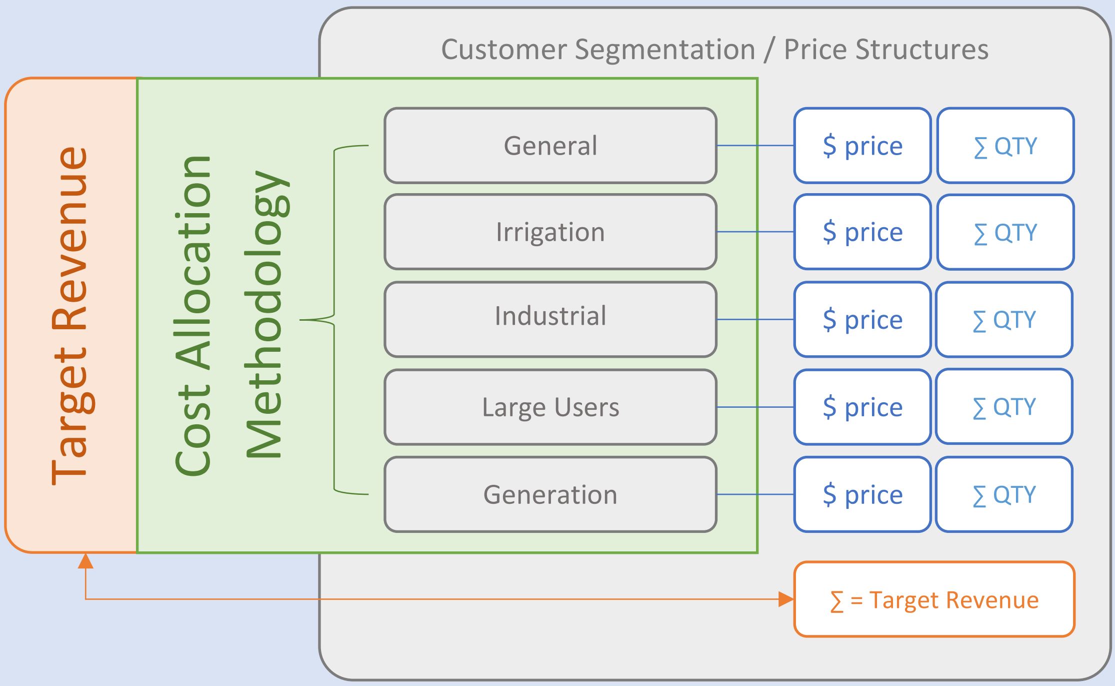
5.7. Price development process

The price development process is outlined in the following diagram.



Overview of Pricing Methodology

The following diagram illustrates how the process links together to form our pricing methodology and pricing.



Where QTY (quantity) may be volume, capacity, demand, number or any combination. See Pricing details for specific information.

Overview of Cost Allocation Methodology

5.8. Target Revenue and costs determined

Each year we review the costs associated with operating the electricity distribution network for the financial year (from 1st April to 31st March). These costs are separated into five key areas.

- Distribution services costs:
    - Operations and maintenance
    - Administration
    - Depreciation
    - Cost of capital (return on investment)
- Pass-through and Transmission costs:
    - Rates & levies
    - Transmission.

The sum of these five costs is our ***Target Revenue***.

This table shows the main costs making up the Target revenue for 2022-23.

Cost category	Target revenue ($000)
Distribution services	
Operations & maintenance	$13,058
Administration	$5,574
Depreciation	$10,882
Cost of capital	$4,046
Subtotal	**$33,560**
Pass-through costs	
Rates & levies	$294
Transmission	
Transmission – connection	$2,004
Transmission – interconnection	$5,881
Transmission – subtotal	**$7,885**
Subtotal	**$8,179**
Target revenue	**$41,739**

We use historic financial information and known changes (e.g. staff numbers changing affecting salaries and wages) to derive operations and maintenance, administration and depreciation cost trends to forecast these costs for the next financial year.

Cost of capital is unique in that it is not separately identifiable (additional steps are required to determine the value of cost of capital). To calculate Cost of Capital; first, we determine our *Forecast Allowable Revenue* as calculated under the Default Price Path regulatory regime (or lower target as specified by our Board). This is effectively the total return on assets we are allowed to earn as defined by the Commerce Commission (the Regulator). Secondly, we subtract the costs already identified (operations and maintenance, administration depreciation, and Transmission) with the difference being our Cost of Capital.

Forecast Revenue from Prices (FRAP, derived by multiplying our prices by forecast quantities) is compared with Forecast Allowable Revenue (FAR) to ensure that we set prices (and therefore derive revenue) that is consistent with the Default Price Path Determination. FRAP must not exceed FAR. Additional information can be found in the Price Setting Compliance Statement[4].

For the financial year ending 31st March 2023 our Target Revenue is **$41.739 million**.

5.9. Segment connections into Customer Load Groups

Segmenting connections into Customer Load Groups allows us to establish prices that better reflect the nature of assets and costs incurred in delivering electricity to specific groups of customers.

For example: the assets and costs associated with delivering low voltage connections to the average family home are significantly different to those required to deliver electricity to an industrial manufacturing business. Segmentation is essential so that one group is not subsidising another group or being disproportionately charged for infrastructure that they are not benefitting from.

The criteria for segmenting connections is to group connections that share similar electricity usage patterns (load profiles), have similar demand requirements (e.g. criticality of supply and diversity needs) and that drive similar incremental cost to our business. This this enables the allocation of network assets by group to reflect utilisation by that group.

Once connections are segmented logically, *Customer Load Groups* are created. We aim to have as few groups as possible as we believe that this simplifies the pricing methodology and the derivation of prices. It also improves segmentation accuracy by reducing the potential for a customer to be consistent with more than one group.

From this segmentation process we have created five Customer Load Groups;

- General (low volt)
- Industrial (medium volt)
- Irrigation (medium volt)
- Large Users
- Generation

Where the segments are broad we have established sub-groups within each (where appropriate) that allows better granularity when it comes to allocating prices to end users. However, the pricing methodology applied to these sub-groups is identical within the broader group, except that different fixed daily prices apply based on connected capacity (kVA).

For example: within General (low volt) we have five sub-groups that differ based on size of connected load – GS05 (up to 7kVA), GS20 (up to 29kVA), GS50 (up to 45kVA), G100 (up to 111kVA) and G150 (above 111kVA).

[4] A copy is available at https://www.eanetworks.co.nz/disclosures/

The methodology for allocating costs and determining prices is identical for the five sub-groups, except that a higher fixed daily price applies for larger connections.

In essence – a customer who has higher network needs, uses more of the available network capacity and/or requires more network assets to deliver their energy requirements will pay more through our network prices. Put another way, a customer can reduce their network prices by reducing the capacity or amount of demand they place on the electricity network.

Each Customer Load Group is described in more detail later.

5.10. Allocate costs across Customer Load Groups

The *Cost Allocation Methodology* simply refers to the way that we allocate our Target Revenue (by category) across the Customer Load Groups. The intention of the methodology is to establish a relationship between the Customer Load Groups and the costs associated with supplying electricity to them – in other words, how to recover Target Revenue in the most cost reflective way that we can. From this we can derive pricing by load group.

For example: we may construct a sub-station to supply a single Major User. The costs associated with this are allocated to that user and their pricing reflects recovery of those costs. Other Customer Load Group pricing is unaffected by those costs.

However, if a sub-station services all Customer Load Groups, the costs associated with it a shared proportionally by all groups.

Summary of allocation method

Cost	Allocation method
Pass-through and Transmission	Anytime maximum demand of Customer Load Group
Distribution services costs:	
Operations and maintenance	Anytime maximum demand of Customer Load Group
Administration	Number of connections (ICPs)
Depreciation	Anytime maximum demand of Customer Load Group
Cost of capital (return on investment)	Anytime maximum demand of Customer Load Group

5.11. Pass-through and Transmission costs

Transmission costs are passed on to us by Transpower. There are two costs incurred; ‘Connection’ and ‘Interconnection’ costs.

Connection costs recover the costs associated with Transpower’s local grid exit point (GXP).

As interconnection assets are also used to supply other lines companies, interconnection costs are shared based on the demand measured for each distribution network during the 100 half-hour peak demand periods on the Upper South Island region (known as the Regional Coincident Peak Demand – RCPD). These peaks are recorded each year by Transpower. We allocate these costs to each customer group based on that group’s contribution to total network capacity used.

We allocate transmission costs by applying the proportional contribution to total sub-transmission Network Capacity (kVA) less any non-contributing capacity.

Transpower notify us each year, in advance of setting our prices, what their charge will be for the coming year. We apply no margin to the transmission charge. It is a direct pass-through of Transpower's notified charges to us.

Transmission costs include pass-through costs, specifically, local authority rates and regulatory levies. These are forecast to be 1% of total revenue for 2022-23.

5.12. Administration costs

We allocate Administration Costs based on the number of Installation Control Points (ICPs). This is an equal allocation but one that sees accurate sharing of this general cost on a per connection basis. We hold the view that Administration Costs increase or decrease in line with the volume of connections more than any other metric.

5.13. Operations and Maintenance, Depreciation and Return on Investment costs

We allocate the costs of Operations and Maintenance, Depreciation and Return on Investment based on the share of the replacement cost of assets. We allocate the replacement asset value across Customer Load Groups using two methods.

The primary allocator of costs is the replacement cost of Dedicated Assets used. Where possible we allocate the specific assets used by each Customer Load Group to that group. As such we take our Total Asset Pool and allocate Dedicated Assets to the appropriate Customer Load Group. A summary of the result of this allocation can be seen in Appendix D.

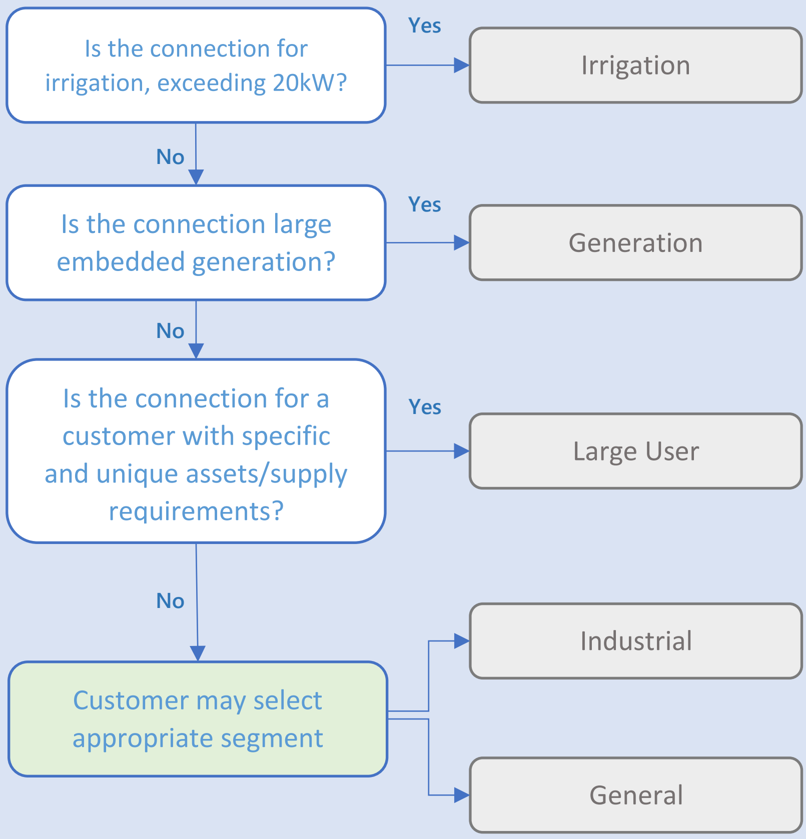
The secondary allocator for the residual Total Asset pool is network capacity (kVA), i.e. a proportional allocation across all load groups based on network capacity used. We believe that this is the best proxy for allocating shared assets fairly to each Customer Load Group. Network capacity is before diversity demand at the medium voltage bus based on Anytime Maximum Demand.

6. Detail on connection segmentation approach

The following section provides detail of our Pricing Methodology at the customer segment level. It expands on the earlier section to provide readers with increased granularity on specific parts of the methodology and approach that we use relating to each Customer Load Group. Customers have some optionality regarding their segmentation in most circumstances unless the cost drivers relating to their connection type are quite specific (e.g. irrigation exceeding 20kW installed capacity).

6.1. Your Customer Load Group selection

The following approach is used to determine which Customer Load Group you are in;



Customer segmentation decision tree

The approach is flexible as it allows most customers to choose which customer segment they belong to and within each segment there are additional choice provided by way of connection sizing (fuse size), uncontrolled energy supply and controlled energy supply. Each incentivises a customer to make appropriate choices to get the most benefit.

> *For example: a customer in the General load group can reduce their variable line charges by selecting Controlled Energy supply. They can further reduce their line charges by making decisions about their connection fuse sizing – by reducing their load requirements they can reduce their line charges.*

6.2. General

Number of customers	18,814
Load group target revenue	$19.84 million (48% of total)

The General Customer Load Group is for any connection made to our low voltage (400 volt) network including single and three phase supplies except for irrigation connections that exceed 20kW.

End users within this load group are charged a two-part price, with a fixed component and a variable component. The variable component can have several sub-components depending on the end-user's preferences, and metering configuration.

The fixed component is based on the maximum capacity of each supply (based on fuse size) charged in $/day.

The variable components are based on the quantity of electricity consumed (kWh) charged in $/kWh. The volume charge is further separated between Controlled and Uncontrolled supply. There are multiple meter options available to provide customer choice with regard to their Controlled, Uncontrolled and Night-time usage.

It is irrelevant to us whether the connection supplies a business or residential user – this is because our cost drivers are not dependent on that distinction, but rather the assets employed to supply electricity to the connection and our ability to control load (supply).

> *For example: it can often be challenging and subjective to differentiate a business connection from a residential connection. As our costs are not affected by this differentiation it is meaningless to attempt to segment based on that differentiation. Rather, it is more accurate to use actual data that is linked to our cost drivers – size of connection is known by the type of fusing and can be easily determined as can the average cost. In addition, actual usage can be measured using electricity consumption meters and whether the site is controlled or uncontrolled.*

Regulatory change

During 2021 the Government announced changes to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. We have implemented changes to our equivalent LFC load group (General Supply 20 – GS20) and will mirror the glide path for maximum fixed prices set by the amendment to this regulation.

Introducing the revised fixed rate of $0.30 per day (increasing from $0.15 per day) has required changes to all other categories within the General load group to maintain the same revenue requirement from each. We have also reduced the variable rate to ensure that, despite the changes, in aggregate the changes are revenue neutral for all categories.

Price calculation

The General segment has various sub-groups to provide flexibility and choice to the customer. Complying with low fixed charge regulations, we offer a standard price of $0.30 fixed rate per day (GS20). Most of the low voltage customers are on this price that relates to up to 29kVA supply (single phase with 80 amp fusing, 2 phase 63 amp fusing or 3 phase 30 amp fusing).

We determine the total recovery of Target Revenue for the General segment from fixed charges, and the balance of Target Revenue is recovered from the variable usage charge.

To provide further flexibility to customers and to also incentivise different energy consumption profiles, we offer two variable use prices: Controlled and Uncontrolled.

Controlled Energy allows us to shed load (temporarily cease supply) when required during peaks on our network or the wider Upper South Island region. This could be during times when energy consumption across our network needs to be reduced (typically when we are nearing our maximum capacity). The ability to control load is very important to network operation as it allows us to invest more efficiently to deliver electricity to a customer. Since we can control this load, we incentivise use of this price by offering it at a lower variable rate compared to Uncontrolled.

Uncontrolled Energy is constant supply, 24 hours per day. We have no operational ability to cease supply to these connections. For this reason, we charge more for this type of supply than we do for Controlled supply.

The Controlled Energy price is a legacy price that was established at a significant discount to the Uncontrolled Energy Price. To continue with stable pricing, we have not altered this differential and any adjustments to prices are reflected equally between the two prices. However, we anticipate this will be reviewed as we undertake pricing reform (refer to our workplan for more information).

Based on load profiling, we calculate the usage of each ICP within the General segment from the previous year’s statistical result plus forecasted changes. We then multiply this by the Controlled Energy rate, obtaining a total revenue estimate for that price.

To determine the Uncontrolled Energy rate, we take total Target Revenue for this segment, deduct revenue from the fixed charge and the variable Controlled Energy charge to obtain a shortfall. This shortfall represents the Target Revenue required for our Uncontrolled Energy price. Again, by applying load profiles for each ICP we determine a rate for this price.

Target revenue is achieved by summing the revenue for each component: fixed rate, variable Controlled Energy, and variable Uncontrolled Energy.

Prices available

Price Code	*Description*	*Units*
GS05	General Supply – less than 5kVA	$/day
GS20	General Supply – 20kVA	$/day
GS50	General Supply – 50kVA	$/day
G100	General Supply – 100kVA	$/day
G150	General Supply – 150kVA	$/day
GUEN	Anytime Supply	$/kWh
GCOP	Controlled 16h Supply	$/kWh
G10N	Night Boost Supply	$/kWh
GNEN	Night only Supply	$/kWh
GEDG	Anytime injection	$/kWh
MCSL	Unmetered street lighting	$/fixture/day
MCRF	Unmetered Floodlight – Closed	$/fixture/day
MCRU	Unmetered Under Veranda - Closed	$/fixture/day

6.3. Irrigation

Number of customers	1,615
Segment target revenue	$18.38 million (44% of total)

The Irrigation Customer Load Group is unique in that these connections are for a specific purpose, irrigation, or more specifically, electric pumps on a single connection (water/effluent pumps including centre pivot motors for example).

We have a specific price for irrigation connections because they typically create a seasonal load with very little diversity between connections. This differs from most other users that have a load profile spanning the calendar year and with significant diversity between the timing of usage and peak usage. The resulting specific load profiles influence costs, particularly relating to costs of meeting peak demand requirements.

Irrigation is seasonal and weather dependent. Irrigation typically starts during September/October and ends around March. It occurs when water is required on crops and pasture. If it has been particularly wet, then irrigation usage reduces. Conversely, during dry periods irrigation can be at full capacity and for many days or weeks throughout the season. Then, during drought conditions, irrigation load tends to reduce as users face water restrictions.

We are also aware that a few irrigation connections are maintained as a backup for other water supplies. We must maintain and reserve the capacity in our network for these irrigation pumps even though they are infrequently used.

These specific characteristics have implications for network costs. We have designed our network to meet maximum demand in any area. We do not control irrigation connections and therefore we price for the maximum demand that is made available. We have had feedback directly from irrigators that a controlled load would be unacceptable to their operation hence our network design is based on maximum demand availability.

End-users in the irrigation load group are charged a one-part price, with a single $/kW/day fixed component. We price irrigation based on maximum capacity of the connection, since usage is irrelevant to our cost drivers.

Some end-users may also face price components relating to their impact on quality of supply from harmonic distortion.

Relating this to our pricing principles, this approach ensures stability by allowing irrigators to fix their prices for our services. It also maintains simplicity, by having a straight-forward method for calculating the cost of the service. Transparency, through open and honest communication of how we derive this price and why we price the way we do, and finally equity; we are charging irrigators for the cost of their capacity and assets required to deliver a maximum demand service to them. In addition to this last point, urban and other non-irrigation customers are not subsidising assets required for the irrigation load.

A price for energy consumed exists (IUEN) however this is zero-rated based on our preference for fixed/capacity based charges for this supply type.

Price calculation

To ensure that we manage our risk, we apply only a fixed rate charge to the irrigation price. There is no variable component in our charges due to the inherent difficulty forecasting usage profiles for irrigation connections. This means that whether a connection is being used or not, the customer will incur the fixed daily charge.

We calculate the value of assets required to service irrigation customer based on Network Capacity (after accounting for Dedicated Assets). This allows us to determine the appropriate share of Target Revenue for the Irrigation Price.

Based on our record of irrigation connections, and our related records of connection size, we divide the Target Revenue by the installed capacity and further divide this by 365 to establish a daily rate per connected kilowatts (kW).

Only irrigation connections exceeding 20kW capacity are required to be on the Irrigation Price.

Harmonics mitigation incentive and Differential Price

During January 2014, we changed our connection standard with respect to Variable Speed Drives (VSD) on irrigation price connections. From that date, all irrigation connections with a VSD and *cumulative* load exceeding 20kW are required to have a harmonic filter installed or make other adjustments to their connection to mitigate the adverse effects of harmonic distortion (e.g. removing VSDs and using soft-starters instead).

To assist customers affected by this change we established a one-off discount paid once a customer became compliant with our revised standard. This programme is now completed and the discount is no longer available.

Those customers that did not make their sites compliant with our connection standard had their ICP placed on the Irrigation without harmonic mitigation price (ISCF). Connections on this price can only revert to the standard irrigation price (ISCH) after becoming compliant. The differential price adds $0.10 per kW per day over and above the prevailing Irrigation price rate (ISCH).

More information regarding this standard can be found at:

www.eanetworks.co.nz/power/network-harmonics

Prices available

Price Code	***Description***	***Units***
ISCH	Capacity charge	$/kW/day
ISCF	Capacity charge without harmonic mitigation	$/kW/day
IUEN	Anytime supply	$/kWh

6.4. Industrial

Number of customers	42
Segment target revenue	$1.75 million (4% of total)

The Industrial Customer Load Group is for connections wanting the ability to manage their distribution costs by managing their energy use (under a specific maximum demand).

End-users have the choice to switch between General and Industrial (subject to capacity requirements).

End-users in this group are charged a single price based on their daily peak demand, measured in kVA.

All Industrial connections must have a Time of Use Meter installed to record Maximum Demand. This price group is not available to any seasonal supply customers such as irrigation.

Price calculation

All revenue derived from the Industrial group is recovered based on maximum demand (both network and transmission recovery) measured in $/kVA/day. This provides an incentive to customers to manage their peak demand, which in-turn can reduce our requirement to invest in upstream assets. End-users can have different prices based on their metering configuration and whether we can control load at that location.

The Industrial Supply kVA Anytime Demand price is based on demand that is measured on peak half-hourly demand over the billing period (one month).

Industrial Supply kVA – Day Demand has peak demand measurement limited to the hours of 8am to midnight.

Industrial Peak Demand – the Peak Demand component relates to transmission which is measured between 4:30pm and 9:00pm weekdays excluding public holidays. The Anytime component is based on the peak half-hourly demand over the billing month.

Prices available

Price Code	Description	Units
ICMD	Industrial Supply - Anytime Demand charge	$/kVA/day
IEMD	Industrial Supply – Anytime Supply	$/kWh
ICDYMD	Industrial Day Demand - Day Demand charge	$/kVA/day
ICDYAD	Industrial Day Demand - Anytime Demand charge	$/kVA/day
IEDS	Industrial Day Demand - Anytime Supply	$/kWh
ICDPD	Industrial Peak Demand – Peak Demand charge	$/kVA/day
ICDAM	Industrial Peak Demand - Anytime Demand charge	$/kVA/day
ICEN	Industrial Peak Demand - Anytime Supply	$/kWh

6.5. Large User

Number of customers	12
Segment target revenue	$1.36 million (3% of total)

The Large user Customer Load Group is for connections supplied through separately identifiable assets and/or connection requirements. Each Large User has its own Price Code since the pricing to them is unique due to the dedicated assets usually employed to supply them. Despite being coded individually the users remain connected to an electricity retailer and therefore are covered by our standard DDA.

Price calculation

Our pricing to Large Users is fully explained through direct contact with each user when they connect to our network. The approach and methodology is identical to all other segments. We believe that direct negotiation allows the specific requirements of the customer to be met. They are generally atypical users that have bespoke supply requirements and it is important that we meet their requirements wherever possible.

We charge a fixed monthly rate based on connected capacity (measured in kVA but charged $/day, fixed). This allows for the recovery of both dedicated and shared assets. This approach provides certainty over their electricity supply costs and enables choices to be made regarding capacity – there is a direct correlation between the size of the installation and the cost of supply. We value dedicated assets the same way as shared assets by using replacement cost.

Large users can also choose a $/kWh or $/kVA/day price component. This provides a mechanism for demand response and relates to Transpower transmission interconnection costs.

> *For example: we charge Mt Hutt a variable transmission cost $/kVA/day for energy consumption during peak periods. This incentivises Mt Hutt to utilise electricity for snow making during network off-peak periods (i.e. weekends between 11pm and 7am).*

Generally, we charge a variable transmission rate where they contribute to peak usage (that incurs interconnection costs). Where they elect not to use electricity during peak periods there is no variable transmission charge levied.

Prices available

Price Code	*Description*	*Units*
LUCM	ANZCO Seafield Plant fixed charge	$/day
LECM	ANZCO Anytime supply	$/kWh
LMCM	ANZCO Anytime demand charge	$/kVA/day
LUPP	Talley's Fairfield Plant fixed charge	$/day
LEPP	Talley's Anytime supply	$/kWh
LMPP	Talley's Anytime demand charge	$/kVA/day
LUMH	Mt Hutt Ski Area fixed charge	$/day
LEMH	Mt Hutt Ski Area Anytime supply	$/kWh
LMMH	Mt Hutt Ski Area Peak demand charge	$/kVA/day
LUHP	Highbank Pumps Capacity charge	$/day
LEHP	Highbank Pumps Anytime supply	$/kWh
LMHP	Highbank Pumps Anytime demand charge	$/kVA/day
MCSL	Street Lighting Unmetered street lighting	$/fitting/day

6.6. Large Generation

Number of customers	4
Segment target revenue	$0.41 million (1% of total)

The Large Generation Customer Load Group is for specific generators.

Presently we have four large distributed generators operating on our network; Highbank, Montalto, Cleardale and Lavington. As with Large Users, we explain electricity supply charges directly with these customers when required due to the bespoke nature of their requirements.

We act in accordance with the requirements of Part 6 (Connection of Distributed Generation) of the Electricity Participation Code 2010 when dealing with generation customers.

Allowance is made for variable cost pass-through, but these prices are presently set to zero.

Price calculation

When pricing for large distributed generators we have regard to;

- The value of dedicated assets (transformers, switch and fusing equipment) required for the customer connection to the distribution network, and;
- The value of network assets (shared between all load groups) that must be upgraded (upstream assets).
- Individual requirements of the Large Distributed Generator.

This detail ensures that the pricing charged to these customers is reflective of the costs incurred to enable grid connection. Each Large Distributed Generator has half hourly metering installed. The half hourly metering allows us to determine the distributed generators contribution to Transpower's:

- HVDC costs (100% pass-through to the distributed generator)

As per the Electricity Authority decision of 5th February 2019, distributed generation on our Network is not eligible to qualify to receive avoided cost of transmission payments from 1st October 2019.

Prices available

Price Code	*Description*	*Units*
LHUB	Highbank Fixed charge	$/day
LEHB	Highbank Anytime supply	$/kWh
LMHB	Highbank Anytime demand	$/kVA/day
LUMO	Montalto Fixed charge	$/day
LEMO	Montalto Anytime supply	$/kWh
LMMO	Montalto Anytime demand	$/kVA/day
LUCD	Cleardale Fixed charge	$/day
LECD	Cleardale Anytime supply	$/kWh
LMCD	Cleardale Anytime demand	$/kVA/day
LULN	Lavington Fixed charge	$/day
LELN	Lavington Anytime supply	$/kWh
LMLN	Lavington Anytime demand	$/kVA/day

7. Other information

7.1. Low fixed charge regulation

We are required to comply with the low fixed charge regulation[5] that require both Distributors and Retailers alike to offer low fixed charge prices. Specifically, we are required to offer a fixed line charge price not exceeding $0.30 per day (excluding GST) for the financial year 2022/23 to residential home users that have usage at or below 9,000 kWh per annum. We provide this price within our General customer segment, refer to price code GS20 (General).

In September 2021 the Government agreed to phase-out the regulations. Phasing-out the regulations will see the maximum low fixed charge increase gradually over 5 years until it is about the same as the standard fixed charge. Each year, the maximum low fixed charge will increase by 30 cents (note this is at the retail level, only half of this relates to network companies). The gradual increase will help minimise the impact of higher power bills on households paying the discounted low fixed charge. While the regulations set the maximum amount, power companies may choose to set lower prices for their low fixed charges.

7.2. Non-standard contracts

EA Networks does not have any customer or group of customers on non-standard contracts. All end users are contracted (ultimately) to the network via our standard DDA that we have with each Retailer operating on our network.

7.3. Capital contributions

We have separate capital contributions within our New Connections and Extensions Policy, this is available on our website.

We receive capital contributions for upgrades and network extensions.

For Rural & Rural Residential Connections greater than 300 kVA each capital contribution is bespoke and priced based on time and materials required to complete the specified work. However, it is based only on the incremental cost to connect the customer – that is the cost of the network assets that are incremental to any standard connection. This includes any upstream assets that must be upgraded to enable the connection to be made.

> *For example: if a new customer connection required 100 metres of additional overhead line to reach the connection point (ICP), the customer would pay for the cost of this new line, related poles and other identifiable costs. They would not typically be charged for a transformer as this cost is captured within the standard connection fee (which would also be charged). In addition, if we had to upgrade the entire line from single-phase to three-phase, the customer would be charged the cost of performing this upgrade.*

There is a high level of transparency of pricing made available to affected customers in a consistent manner to our general pricing methodology.

[5] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

For Rural & Rural Residential Connections less than and equal to 300 kVA standard capital rates apply. The standard capital contribution rates are listed in Schedule A of New Connections and Extensions Policy.

7.4. Discretionary discounts and dividends

Discounts, when determined, are paid to all connected consumers. The Consumer Discount Methodology[6] defines how discounts are allocated to consumers. At the beginning of every year Directors determine the value of the discount pool.

EA Networks has a binding ruling with the Inland Revenue Department (IRD) that requires the following principles to be considered when determining the quantum of the discount pool (if any):

- Current and ongoing capital investment requirements.
- Operational requirements.
- Borrowing/debt repayments, taking into account intergenerational fairness.

For 2022/23 the discount pool is $3.0 million + GST. This will be paid to consumers via their electricity retailer in March 2023.

EA Networks may, in its sole discretion, elect to pay a dividend to shareholders.

[6] A copy of the Consumer Discount Methodology is available at https://www.eanetworks.co.nz/disclosures/

APPENDIX A – Alignment with Electricity Authority Pricing Principles

This appendix (and Appendix B that follows) outlines and comments on aspects of this methodology that relate to the regulatory requirements of the Electricity Authority's pricing principles and the Commerce Commission's information disclosure requirements.

The information disclosure requirements require us to prepare and disclose a statement of the level of alignment with the Authority's pricing principles. We set this out below.

Alignment with Electricity Authority pricing principles

The Electricity Authority published Pricing Principles[7] that provide an approach for developing and assessing pricing methodologies for electricity distribution companies. After publishing the Pricing Principles, the Authority published a 'Practice Note' to help distributors interpret and apply the Pricing Principles. The Authority has also introduced a scorecard to evaluate distributors pricing plans against the principles.

The Authority published a refreshed Practice Note[8] in December 2021 with an emphasis on expected timeframes for distribution pricing reform and what 'good looks like'.

The purpose of this section of our Pricing Methodology is to demonstrate how EA Networks' pricing approach is consistent – in our view and to the extent practicable – with the principles established by the Electricity Authority.

(a) 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);

Forecast revenue and prices for each Customer Load Group (in aggregate) are greater than attributable avoidable costs and less than attributable standalone costs, except for the General customer group. We look forward to implementing changes made to the Low Fixed Charge regulations at a national level to enable greater flexibility in pricing to signal the economic costs of service provision. Until the complete removal of that regulation, EA Networks remains constrained in its ability to provide more cost-reflective product design across the entire product portfolio.

The workplan includes activities to confirm the allocation of costs of supply to each Customer Load Group and the extent of alignment between price levels and price components. These activities will confirm relationship between prices and avoidable and standalone costs.

Where expansion is required, we generally fund this by way of capital contribution from the party driving that expansion.

For example, if we are required to extend our existing overhead power network to connect to a new dairy farm installation (say 700 metres for the single connection), the farmer will be charged the full incremental cost of extending the network to connect the property.

[7] Distribution Pricing Principles, published by the Electricity Authority, June 2019.
[8] https://www.ea.govt.nz/assets/dms-assets/29/Distribution-Pricing-Practice-Note-2021-2nd-edition.pdf

By charging customers directly for the incremental works we ensure that there are no subsidies within the pricing (where incremental costs can be directly attributed).

(ii) *REFLECTING THE IMPACTS OF NETWORK USE ON ECONOMIC COSTS;*

Prices for each Customer Load Group broadly signal the impacts of network use on economic costs, except for the General Customer Load Group (due to the approach take to comply with the low fixed charge regulations).

The pricing workplan includes activities to confirm the pricing structures align with the overarching pricing approach and to ensure price component of the structure for each Customer Load Group signals – to the extent practicable – the impact of network use on economic costs. Changes to the TPM are expected to result in current pricing more closely aligning with economic costs (when a new TPM becomes effective).

Price structures for irrigation, large users and generation use fixed and capacity charges to signal the impact of network use on economic costs. For 2022-23, 100% of costs allocated to these groups are recovered using fixed and capacity charges. Controlled load pricing and capacity charges are currently used to signal opportunities for load management – i.e. to signal that increasing capacity increases our cost to serve.

Fixed charges are set using connection capacity, with the daily fixed price rising in-line with the increased size of the connection. Connection size is a reasonable proxy for a consumer's responsiveness to the fixed charge level. That is, customers that require a larger connection to ultimately consume more electricity are likely to expect to pay a higher amount for that connection. As larger connections drive greater cost onto our business this has the added benefit of recovering those costs more accurately.

In addition, we provide prices structured to suit those users that have maximum demand needs (irrigation) by offering a fixed daily capacity charge with no variable component. This removes price volatility that could result due to the unpredictability of load and usage which would result from volume-based charge.

(iii) *REFLECTING DIFFERENCES IN NETWORK SERVICE PROVIDED TO (OR BY) CONSUMERS; AND*

We signal the level of available capacity, and differences in services, through pricing to reflect the needs of each Customer Load Group. Some customers require uncontrolled capacity regardless of time of day (e.g. irrigation). The price for irrigation is therefore based on the cost of creating this capacity (maximum demand) and is a fixed daily charge. For others that have less critical demand where we can control load, associated prices are created that signal this fact.

We do provide for non-standard agreements and negotiate directly with large users for their electricity distribution needs. This allows bespoke pricing to be established that meets the unique circumstances of the customer (e.g. for atypical load patterns, higher levels of redundancy or to address particular by-pass or alternate energy substitution situations).

(iv) ENCOURAGING EFFICIENT NETWORK ALTERNATIVES.

We set our prices to encourage efficient network alternatives. Customers in the General Customer Load Group are encouraged to opt for demand response supply through our controlled load prices. These prices provide a significantly reduced rate compared to the uncontrolled variable rate.

We consider the increasing availability of solar DG, batteries and energy management capability provides opportunities for us to work with end-users to optimise network use (particularly peak demand) and network capacity required (timing of network upgrades).

A specific opportunity to refine prices to encourage efficient network alternatives, and manage peak demand impacts, exists with our pricing approach for the Irrigation load group. Doing so could also assist with managing the (current) volatility in transmission costs.

(b) WHERE PRICES THAT SIGNAL ECONOMIC COSTS WOULD UNDER-RECOVER TARGET REVENUES, THE SHORTFALL SHOULD BE MADE UP BY PRICES THAT LEAST DISTORT NETWORK USE.

Our differentiated Customer Load Groups and related prices are designed provide a range of prices that better reflect usage profiles at a more granular level, varying the level of fixed versus variable charging.

Generally, a price that has a higher level of fixed charging will have reduced variable charging. This is critical in the price structure to ensure that costs are fairly recovered whilst also providing appropriate pricing signals.

We look forward to implementing the changes made to the Low Fixed Charge regulations to enable greater flexibility in pricing to signal the economic costs of service provision. Until then, EA Networks is constrained in its ability to provide more cost-reflective product design across the entire product portfolio.

(c) PRICES SHOULD BE RESPONSIVE TO THE REQUIREMENTS AND CIRCUMSTANCES OF END USERS BY ALLOWING NEGOTIATION TO:

(i) REFLECT THE ECONOMIC VALUE OF SERVICES; AND

(ii) ENABLE PRICE/QUALITY TRADE-OFFS.

We offer non-standard contracts to consumers who have non-standard network connection and operation requirements to appropriately reflect the economic value to them of the network service. For standard consumers, we set prices to be less than the standalone cost of supply.

We regularly engage with consumers to test price/quality preferences via surveys and direct interaction. We also enable consumers to make price/quality trade-offs by offering controlled and uncontrolled prices in addition to incentives to change capacity (if possible).

Connections in the General Customer Load Group are encouraged to opt for demand response supply through our controlled load prices. These options provide a reduced price compared to the uncontrolled variable price and aim to reflect the value of load management.

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

We work to make sure our prices are developed in a transparent way. We publish this Pricing Methodology and provide information on our website on the Customer Load Groups, prices, pricing and related statistical information.

When we change prices, we do so with due regard given to the impact on stakeholders of any changes in prices and/or transaction costs. Consumers have a reasonable expectation that our prices will be stable and will not shift significantly over time. Changes to our prices have been, and will continue to be, consistent with the limits placed on us under the DPP Determination by the Commerce Commission.

We manage the transaction costs on retailers by discussing pricing with other EBD’s to help with standardisation of pricing, thereby reducing transaction costs for retailers and consumers.

We have endeavoured to minimise transactions costs as well as processing costs incurred by retailers by maintaining a simple and concise price portfolio. Whilst balancing the needs of end user customers and their specific pricing requirements, our portfolio of prices extends to only six Customer Load Groups and less than sixty specific prices. Changes to this are limited and only made when necessary for new customers or for changes to the business.

Our Default Distributor Agreement is open access and all retailers share the same terms and conditions. Specifically, all retailers have access to the same prices and no retailer incurs differential pricing or service levels of any kind.

APPENDIX B – Alignment with Commerce Commission Information Disclosure

The following excerpt is from the Electricity Distribution Information Disclosure Determination 2012 (consolidated December 2021) (IDD) that relates to disclosure of pricing methodologies. We have included this for ease of reference. The numbering relates the original IDD document.

Information Disclosure Requirement	Reference in this document
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	Process obligation – disclose (publish) before 1st April each year This Pricing Methodology is publicly disclosed before the end of March each year for prices that apply from 1st April the same year
(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	See Information Disclosure 2.4.3 below
(2) Describes any changes in prices and target revenues;	See Section 2, page 6, Summary of current revenue and pricing and APPENDIX C – Pricing Schedule 2022-23
(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	See Section 7.3, page 36, Non-standard contracts EA Networks does not pay export credits to distributed generation customers. See APPENDIX C – Pricing Schedule 2022-23 for applicable prices
(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	See Section 4.5, page 15, Consumer consultation

Information Disclosure Requirement	Reference in this document
2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	EA Networks has not changed its pricing methodology. This pricing methodology is publicly disclosed before the end of March each year for prices that apply from 1st April the same year consistent with the requirement in Information Disclosure 2.4.1 above.
2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Section 3, page 9, Overview of pricing methodology for overview of pricing development process See Section 5.6, page 20, Our approach to developing prices - this gives detail on each process step, including assumptions and criteria used, e.g: ○ Page 21, price development process ○ Page 23-24, how connections are assigned to Customer Load Groups – criteria are load profile, peak demand, capacity requirements ○ Page 26 graphic showing key criteria for assigning connections to Customer Load Groups ○ Page 24, measures for allocating costs across Customer Load Groups (see table)
(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	APPENDIX A – Alignment with Electricity Authority Pricing Principles
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Section 2.1 Target revenue for 2022-23
(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Section 2.4, page 8, Summary of revenue and cost / Target Revenues by Cost Category Section 5.8, page 22, Target Revenue and costs determined

Information Disclosure Requirement	Reference in this document
(5) State the consumer groups for whom prices have been set, and describe– (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Section 5.9, page 23, Segment connections into Customer Load Groups Section 6.1**,** page 26, Your Customer Load Group
(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Section 2.3, page 7, Average change in prices for 2022-23
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	Section 5.10, page 24, Allocate costs across Customer Load Groups, describes the allocation method for each cost category: ○ Page 24, table, Summary of allocation method ○ Page 24, We allocate transmission costs by applying the proportional contribution to total sub-transmission Network Capacity (kVA) less any non-contributing capacity. ○ Page 25, Administration costs allocated based on number of ICPs (in each Customer Load Group) ○ Page 25, We allocate the costs of Operations and Maintenance, Depreciation and Return on Investment based on the share of the replacement cost of assets Section 2.4, page 7, Summary of revenue and cost. Table – quantifies target revenue by Customer Load Group
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Section 3, page 10, Overview of pricing methodology. Table shows aggregate average revenue recovered from all Customer Load Groups through fixed, capacity, and variable price components

Information Disclosure Requirement	Reference in this document
2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	EA Networks does not produce a 'Pricing Strategy'. However, we note: See Section 5.3, page 18, Future pricing approach where we say - "We have a pricing development workplan which sets out a roadmap for evolving our pricing approach and pricing to offer pricing structures which reflect the underlying cost to supply the distribution service desired by our customers." AND "The near-term focus of the workplan is to identify the activities we will undertake to develop a pricing structure which – to the extent practicable – has fixed and variable price components which align to the fixed and variable costs of supply for each customer (load) group."
(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	
2.4.5 Every disclosure under clause 2.4.1 above must–	
(1) Describe the approach to setting prices for non-standard contracts, including– (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;	See Section 7.2, page 36, Non-standard contracts - "EA Networks does not have any customer or group of customers on non-standard contracts."
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;	NA
(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which	NA

Information Disclosure Requirement	Reference in this document
these criteria or that methodology are consistent with the pricing principles;	
(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain— (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts; (b) any implications of this approach for determining prices for consumers subject to non-standard contracts;	NA
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the— (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	See Section 6.2, page 29, General - Table of prices available for General Customer Load Group includes the GEDG (Export kWh) price code, currently with a $0 price, i.e., no payments/charges See Section 6.6, page 35, Large Generation - describes charges/payments to our four large DG customers. "We act in accordance with the requirements of Part 6…". Within our regulated pricing, no "avoided cost of transmission" payments are made to any DG customers following publishing of the Electricity Authority's qualifying list in February 2019.
2.4.6 Every EDB must at all times publicly disclose a description of its current policy or methodology for determining capital contributions, including-	See Section 7.3, page 36, Capital contributions - "We have separate capital contributions within our New Connections and Extensions Policy, this is available on our website or from our offices". Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
1(a) the circumstances (or how to determine the circumstances) under which the EDB may require a	New Connections and Extensions Policy document, (Capital Contribution Policy document), sections 4.2 – 4.7 describes circumstances under which a capital contribution is required (for different types of new

Information Disclosure Requirement	Reference in this document
capital contribution;	connection). Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
1(b) how the amount payable of any capital contribution is determined. Disclosure must include a description of how the costs of any assets (if applicable), including any shared assets and any sole use assets that are included in the amount of the capital contribution, are calculated;	New Connections and Extensions Policy document, (Capital Contribution Policy document), sections 4.2 – 4.7 describes how the amount payable is determined, see Schedule A of that document for current rates. Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
1(c) the extent to which any policy or methodology applied is consistent with the relevant pricing principles;	See Section 7.3, page 36, Capital contributions that notes "There is a high level of transparency of pricing made available to affected customers in a consistent manner to our general pricing methodology. Our Capital Contribution Policy document, page 3, notes "Our economic aim is to apply efficient pricing policies which reflect the economic costs of providing our delivery service." Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
2) A statement of whether a person can use an independent contractor to undertake some or all of the work covered by the capital contribution sought by the EDB	Our Capital Contribution Policy document, page 8, notes "Customers are required to make a larger contribution but are also able to minimise their total outlay by selecting the most competitive approved contractor to carry out the extension work." Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
3) If the EDB has a standard schedule of capital contribution charges, the current version of that	See New Connections and Extensions Policy document, Schedule A.

Information Disclosure Requirement	Reference in this document
standard schedule	Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
2.4.7 When a consumer or other person from whom the EDB seeks a capital contribution, queries the capital contribution charge, (and when the charge is not covered in the standard schedule of capital contribution charges, or no such schedule exists) the EDB must, within 10 working days of receiving the request, provide reasonable explanation to any reasonable query from that consumer or other person of the components of that charge and how these were determined	Our process is to respond within the defined time for any query of such charges.

APPENDIX C – Pricing Schedule 2022-23

Electricity delivery price schedule for EA Networks

(applicable from 1 April 2022)

This schedule lists the prices that EA Networks uses to charge electricity retailers for the electricity delivery service in its Ashburton based network area. The delivery service includes the transmission and distribution of electricity to homes and businesses, but does not include the cost of the electricity itself.

Connection category	Price category code	Price category	Number of connections	Description	Delivery Prices (excl GST) 1 April 2021 to 31 March 2022	From 1 April 2022	Unit of measure	Transmission Proportion
General supply	*Fixed charges*							
	GS05	General Supply - less than 5 kVA	53	Capacity charge	0.5183	**0.5320**	$/con/day	0.0%
	GS20	General Supply - 20 kVA	15,998	Capacity charge	0.1500	**0.3000**	$/con/day	0.0%
	GS50	General Supply - 50 kVA	1,730	Capacity charge	0.3000	**0.7500**	$/con/day	0.0%
	G100	General Supply - 100 kVA	728	Capacity charge	0.6000	**2.5800**	$/con/day	0.0%
	G150	General Supply - 150 kVA	306	Capacity charge	0.9000	**4.6000**	$/con/day	0.0%
	Volume charges			Anytime supply	0.0776	**0.0689**	$/kWh	15.7%
				Controlled 16h supply	0.0160	**0.0140**	$/kWh	0.0%
				Night boost supply	0.0160	**0.0140**	$/kWh	0.0%
				Night only supply	0.0000	**0.0000**	$/kWh	
				Anytime injection	0.0000	**0.0000**	$/kWh	
	Other charges			Unmetered street lighting	0.1907	**0.1901**	$/fixture/day	1.6%
				Unmetered floodlighting	0.2819	**0.2876**	$/fixture/day	0.0%
				Unmetered verandah lighting	0.2482	**0.2532**	$/fixture/day	0.0%
Irrigation	ISCH	Irrigation	1,606	Capacity charge	0.3560	**0.3550**	$/kW/day	25.9%
				Anytime supply	0.0000	**0.0000**	$/kWh	
	ISCF	Irrigation without harmonic mitigation	9	Capacity charge	0.4560	**0.4550**	$/kW/day	20.2%
				Anytime supply	0.0000	**0.0000**	$/kWh	
	ISCM	Irrigation Managed Trial (ending 31 March 2022)	0	Capacity charge	0.3560	**NA**	$/kW/day	
				Irrigation managed rebate	(0.1000)	**NA**	$/kW/day	
				Anytime supply	0.0000	**NA**	$/kWh	
Industrial	ICMD	Industrial Supply	34	Anytime demand charge	0.3297	**0.3313**	$/kVA/day	22.6%
				Anytime supply	0.0000	**0.0000**	$/kWh	
	ICDYMD	Industrial Day Demand	2	Day demand charge	0.3297	**0.3313**	$/kVA/day	22.6%
				Anytime demand charge	0.0000	**0.0000**	$/kVA/day	
				Anytime supply	0.0000		$/kWh	
	ICDPD	Industrial Peak Demand	6	Peak demand charge	0.0700	**0.0748**	$/kVA/day	100.0%
				Anytime demand charge	0.2597	**0.2565**	$/kVA/day	0.0%
				Anytime supply	0.0000		$/kWh	
Large Users	LUCM	ANZCO Seafield Plant	1	Fixed charge	694.2752	**693.9621**	$/day	0.0%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Anytime demand charge	0.0759	**0.0754**	$/kVA/day	100.0%
	LUPP	Talley's Fairfield Plant	1	Fixed charge	97.3677	**97.3238**	$/day	0.0%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Anytime demand charge	0.0768	**0.0764**	$/kVA/day	100.0%
	LUMH	Mt Hutt Ski Area	1	Fixed charge	334.2198	**334.0691**	$/day	0.0%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Peak demand charge	0.0601	**0.0576**	$/kVA/day	100.0%
	LUHP	Highbank Pumps	1	Capacity charge	0.1375	**0.1385**	$/kW/day	66.9%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Anytime demand charge	0.0000	**0.0000**	$/kVA/day	
Generation	LUHB	Highbank	1	Fixed charge	933.2564	**932.8355**	$/day	0.0%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Anytime demand charge	0.0000	**0.0000**	$/kVA/day	
	LUMO	Montalto	1	Fixed charge	95.6663	**95.6232**	$/day	0.0%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Anytime demand charge	0.0000	**0.0000**	$/kVA/day	
	LUCD	Cleardale	1	Fixed charge	69.5061	**68.5883**	$/day	0.0%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Anytime demand charge	0.0000	**0.0000**	$/kVA/day	
	LULN	Lavington	1	Fixed charge	19.2526	**19.2439**	$/day	0.0%
				Anytime supply	0.0000	**0.0000**	$/kWh	
				Anytime demand charge	0.0000	**0.0000**	$/kVA/day	
Street lighting	MCSL	Street Lighting	8	Unmetered street lighting	0.1907	**0.1901**	$/fixture/day	1.6%

[9] A copy of this Pricing Schedule is available for download from https://www.eanetworks.co.nz/disclosures/

APPENDIX D – Directors’ certification

Directors’ certification of Pricing Methodology

In accordance with clause 2.9.1 of section 2.9 of the Commerce Commission’s Information Disclosure Determination for electricity distribution businesses the certification of Electricity Ashburton Limited’s Pricing Methodology document is included below.

We, Philip John McKendry, and Paul Jason Munro, being directors of Electricity Ashburton Limited (EA Networks), certify that having made all reasonable enquiry and to the best of our knowledge:

a) The attached information of EA Networks, 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.

Paul Jason Munro **Philip John McKendry**

30 March 2022