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Electricity Distribution Business

Pricing Methodology

Effective 1 April 2016

1. GLOSSARY

Commerce Commission (Commission)	Responsible for the regulation of EDBs as provided for under Part 4 of the Commerce Act 1986
EDB	Electricity Distribution Business
Electricity Authority (EA)	Electricity Authority
Code	Electricity Industry Participation Code 2010
ICP	Installation Control Point: A point of connection on a local network which the distributor nominates as the point at which a retailer will be deemed to supply electricity to consumers
IDD	Electricity Distribution Information Disclosure Determination 2012, issued 1 October 2012 (Decision No. NZCC22)
kVA	Kilo Volt-Amp: Measure of apparent electrical power usage at a point in time
kW	Kilowatt: Measure of instantaneous real electrical power usage
kWh	Kilowatt hours: Measure of real electrical power usage per hour
Low fixed charge regulations	Electricity (Low Fixed Tariff Option for Domestic Consumers) Regulations 2004
Part 4	Part 4 of the Commerce Act 1986 governing the regulation of EDBs as administered by the Commerce Commission
Qualifying Customers	Redeemable Preference Shareholders in the MainPower Trust
Transpower	Owner and operator of the national transmission grid
WACC	Weighted Average Cost of Capital

2. INTRODUCTION

This pricing methodology describes the approach MainPower New Zealand Limited ("MainPower") has adopted to determine prices for consumers connected to its electricity distribution network, effective from 1 April 2016.

The purpose of this document is to provide customers and other interested stakeholders with relevant information on how prices have been set. This includes information on the price setting process and key inputs, assumptions, considerations, and decisions made in setting prices.

The remainder of this pricing methodology is structured as follows:

- Section 3 summarises our 2016 pricing approach
- Section 4 provides background information relevant to the development of prices. This includes a brief overview of our pricing objectives, regulatory obligations, recent consultations with customers, and our current pricing review and strategy.
- Section 5 sets out the methodology we have used to determine prices as at 1 April 2016, including the key considerations made in regards to determining target revenues, customer groups, pricing structures, and final charges.
- Appendix A details the extent to which our pricing methodology is consistent with the Electricity Authority's ("EA") electricity distribution pricing principles.
- Appendix B provides Directors Certification, as required by section 2.9.1 of the IDD.
- Appendix C maps compliance against the Electricity Distribution Information Disclosure Determination 2012 (NZCC 22) (IDD) disclosure requirements applicable to pricing methodologies.
- Appendix D provides detailed information on prices, customer statistics, and target revenues (by pricing region and price type).

3. PRICING SUMMARY

Our underlying pricing methodology is the same as that which applied from 1 April 2015. We have decided to hold prices constant in 2016/17.

The key steps we took to set prices are:

- the current pricing methodology was confirmed for this year against our pricing objectives and strategy, amongst other considerations
- the annual target revenue requirement to be recovered through prices in 2016/17 was determined as $58m
- pricing structures were confirmed. These include 2 pricing regions, 6 standard customer groups, and 1 non-standard connection
- target revenue was allocated to customer groups and prices consistent with the cost allocation approach applied in our 2015/16 pricing methodology.

This process is broadly illustrated in the figure below. Note that while prices have been held constant for the 2016/17 year, target revenue increased this year solely due to growth driving an increase in forecast billing quantities.

Figure 1: Allocation of target revenue to pricing regions and customer groups

<table>
<tr><th colspan="15">Target Revenue = $58m</th></tr>
<tr><th colspan="7">Mainpower Region $54.6m</th><th rowspan="2">Non-standard $1.4m</th><th colspan="7">Kaiapoi Region $2.4m</th></tr>
<tr><td>Residential</td><td>Non-residential</td><td>Large</td><td>Irrigation</td><td>Lighting</td><td>Council Pumping</td><td>Temporary SupplySupply</td><td>Residential</td><td>Non-residential</td><td>Large</td><td>Irrigation</td><td>Lighting</td><td>Council Pumping</td><td>Temporary supply</td></tr>
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4. BACKGROUND

About MainPower

MainPower provides distribution lines services to approximately 38,200 customers throughout the North Canterbury and Kaikoura regions. A number of rural towns, including Rangiora, Kaiapoi, Oxford and Kaikoura service these rural communities. Approximately 86% of our customer base is residential, with the majority of the remaining being small commercial, farming or irrigation customers. One large connection is offered non-standard pricing in recognition of its unique cost profile.

MainPower is one of a number of community-owned electricity distribution businesses ("EDBs") in New Zealand. Customers in the communities of North Canterbury and Kaikoura own MainPower through the MainPower Trust and elect its trustees. MainPower also serves customers in the old borough of Kaiapoi who are non-Qualifying Customers of the Company. Pricing regions are formed along the boundaries of these two areas.

Pricing and commercial objectives

The key commercial and pricing objectives that guide our pricing decisions are as follows:

- *Uniform variable pricing*: We have adopted a general objective of applying a uniform variable charge to all pricing options within a particular pricing region, irrespective of customer density, location, network configuration, or other load characteristics. There are a several exceptions to this general objective relating to pricing options that cater for specific usage and cost profiles. These exceptions are detailed below.
- *Rebates*: Revenues collected from customers that are considered surplus to our target revenue are returned to Redeemable Preference Shareholders (Qualifying Customers) of the MainPower Trust in the form of rebates. Rebates are credited to Qualifying Customers' accounts on a monthly basis. Rebate decisions do not form part of this disclosure. Qualifying Customers are advised in advance on an annual basis of the rebate levels that will apply for the coming year.
- *Uniform pricing across the MainPower and Kaiapoi pricing regions:* The total line service charge, net of Qualifying Customer rebates applicable to customers within these pricing regions, are charged on a uniform basis. Charges after the disbursement of rebates are generally the same for customers in both MainPower and Kaiapoi pricing regions.
- *Price certainty and stability:* Our pricing structure will provide a high level of certainty and understanding, while at the same time ensuring price stability.
- *Return on investment:* Where the return on investment for MainPower is less than our Weighted Average Cost of Capital (WACC), any upward movement in charges will be calculated on the basis that the increase is applied equally across all groupings.
- *Regulatory compliance*: We will comply with all applicable regulations relating to pricing and pricing methodologies. We will also consider other regulatory guidance (i.e. the pricing principles) in our pricing decisions. In circumstances where there is a conflict between this guidance and our pricing objectives, priority is given to the pricing objectives.

Customer expectations on price and quality

We regularly consult with our customers to gauge their general level of satisfaction with the distribution services we provide, as well as on price and quality expectations.

During recent years, we have engaged external research consultants to undertake a comprehensive customer survey in support of this. During 2015, 600 customers were surveyed. This included a representative sample of residential, commercial and large use customers.

The research showed that MainPower's overall customer service rating was maintained over the past year at just under 8 out of 10. The most important deliverable across all customers in 2015 was continuity – keeping the power on; most customers indicated that the quality of their power supply in 2015 had stayed the same over the past 12 months.

More than 8 out of every 10 respondents stated that any increase would be too much to pay for an improvement in the service provided by MainPower with residential customers less willing to pay any extra for a better service than commercial customers. In 2015 there was a noticeable, but still slight, increase in the percentage of customers willing to pay an extra $100/year for an improved service (the highest percentage in four years).

The survey results confirm a high level of satisfaction with respect to quality, reliability and price. We therefore conclude that no adjustments to the current balance of prices and quality are necessary.

Regulatory requirements applicable to pricing methodologies

MainPower's distribution business is subject to regulation under Part 4 of the Commerce Act 1986 ("Part 4"), as administered by the Commerce Commission ("Commission"). Our customer ownership means we are exempt from direct price control under Part 4. Customer ownership and oversight provides the necessary incentives to set prices consistent with the purpose of regulation under Part 4, in the long term interests of our customers. However, we remain subject to regulatory oversight in the form of information disclosures under the Electricity Distribution Information Disclosure Determination 2012 ("IDD"), including being required to publish annual pricing methodologies.

MainPower is also subject to industry regulations and pricing principles, as administered by the Electricity Authority ("EA"). In particular, the EA has developed a set of principles and information disclosure guidelines to assist EDBs. Under the IDD, EDBs must disclose the extent to which their pricing methodology is consistent with these pricing principles.

The key regulatory requirements directly applicable to this pricing methodology are:

- Section 2.4.1 – 2.4.5 of the IDD regarding the disclosure of pricing methodologies
- the EA's electricity distribution pricing principles and information disclosure guidelines
- the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the "Low Fixed Charge Regulations")
- Schedule 6.4 of Part 6 of the Code, which sets out pricing principles for distributed generation.

This pricing methodology has been developed consistent with these requirements. Appendix A discusses the extent to which our prices are consistent with the EA's pricing principles. Appendix B provides Directors' Certification against the IDD requirements. Appendix C provides a check-list which records where in this document we have demonstrated compliance against the applicable IDD regulations.

Pricing review and strategy

MainPower is progressing a comprehensive review of our pricing methodology. We plan to complete this review and start implementing more efficient pricing structures over the next 5 years, where required. This pricing strategy has not materially changed since our 2015 pricing methodology, subject to re-prioritisation of project work streams.

Several factors influenced our decision to undertake a review of our pricing:

- A shift in focus towards developing prices that better reflect our customers' needs
- the deployment of smart meters to the mass market and the potential pricing applications enabled by this technology
- evolving technological developments in consumer and energy-related products that change when and how our customers use the network (eg solar PV, batteries, electric vehicles, home automation)
- new regulations and regulatory guidance regarding economically efficient distribution pricing
- significant growth in irrigation connections and demand across the North Canterbury region
- the desire to review our long-serving pricing structures against our current commercial and pricing objectives, with consideration of recent innovations in pricing in the sector.

The primary objective of the review is to investigate alternative pricing structures and price setting approaches which address some or all of these issues. In particular, we are investigating options to align pricing more closely with:

- *Customer preferences:* pricing structures must reflect how and when customers use electricity and recognise the choices they have in relation to energy-related appliances and products.
- *Economic and regulatory principles and industry best practice.* Our aim is to structure prices to promote more efficient use of, and investment in, the network and energy-related products and appliances. This includes consideration of regulatory and industry guidance (for example: the Electricity Networks Association guidelines) on efficient pricing as well as innovative pricing approaches adopted across the sector.
- *Network cost drivers.* We have developed a cost of supply model which allocates our annual target revenue requirement to regions, customer load groups and prices based on appropriate cost-based allocators. This model will allow us to test different customer group scenarios, pricing options (e.g. for fixed and variable combinations, peak/off-peak pricing structures) and cost allocators. It will also analyse price shock, helping us to formulate a plan to transition any price changes over time.
- *Recent technology developments:* The deployment of smart meters across residential and small commercial connections means that, for the first time, we can measure use of electricity at a point in time, rather than just cumulative use. Using this new data, we are investigating time and/or demand based pricing structures for mass market customers which will signal the costs of providing distribution services more effectively. Time/demand based pricing will also provide us with the tools to accommodate evolving technologies, such as solar, batteries, electric vehicles, energy efficient appliances and home automation.

We have engaged PricewaterhouseCoopers (PwC) to assist with this review. They are providing advice on economic pricing frameworks, best practice distribution pricing approaches, and pricing regulation.

During 2016 we will begin a programme of public consultation to help us understand our customer's needs and expectations of our pricing and the services we provide. Feedback received under this consultation will be used to develop detailed pricing options and a strategy to implement any required changes.

We will consult with retailers and customers on preferred new pricing options prior to making any decisions on pricing. A new pricing methodology will be issued before prices take effect. Retailers will be notified of any price changes within 45 business days consistent with our conveyance only use of system agreement. Customers will be notified at least 20 business days prior to any changes taking effect.

Depending on the final outcomes of our review, we are planning to introduce new pricing structures progressively across customer groups to align with the deployment of smart meters and to effectively manage any transition to new pricing structures.

Some of the potential areas of change we are considering are highlighted in the figure below.

Figure 2: Potential changes to prices we considering and impact on customers

Potential area of change	**Considerations**	**Potential impact on customers**
Change in customer groups	We are reconsidering our current customer groups. We are investigating rationalisation of the current pricing groups and/or alignment of pricing structures to the Electricity Network Association's distribution pricing guidelines and that of our close peers. We are also investigating the merits of creating a distinct residential low fixed tariff option targeted at consumers using less than 8,000kWhs per annum. We would assign the remaining customers by load size.	Customers may be reallocated to new pricing options and may faces changes in their prices. Customers using less than 8,000 kWhs per annum will likely continue to receive the current 15 cents per day low fixed charge.
Aligning prices with network costs	We have developed a cost of supply model that allocates the components of target revenue to customer groups. The key output will be a set of implied cost allocations for each customer group and pricing option. This information will be used in making decisions on final prices.	Prices will be more reflective of the costs of providing distribution services to individual customer groups. Some customer groups may experience a change to their prices.
Introducing time or demand base charges	The main service a distributor provides is capacity in the network in order to meet peak demand. This is also a key driver of network costs. In recognition of this, we are investigating the merits of introducing a peak-time/demand charge which would align our pricing to the service we provide and our costs of providing that service. Smart meters are progressively being rolled out across the mass market which can facilitate this form of pricing. Furthermore, we are investigating applying demand charges to larger customers given that many have time of use meters.	Customers may be charged based on peak use characteristics, rather than or in addition to consumption.

5. PRICING METHODOLOGY

This section describes our methodology for setting prices effective from 1 April 2016. Given prices have not changed, this is the same approach as was applied in our 2015 pricing methodology. This section provides information on our approach to:

- calculating target revenue
- determining customer groups
- allocating costs to customer groups
- setting tariffs
- pricing non-standard customer services; and
- pricing distributed generation.

Target Revenue

We determine our target revenue requirement in order that revenue collected from prices will be sufficient to cover the operating and capital costs necessary to maintain capital and/or revenue reserves at a level considered appropriate by the Board.

Figure 3 sets out our target revenue requirement for the 2016/17 pricing, relative to the 2015/16 pricing year. While we have not changed prices this year, target revenue has increased to reflect forecast billing volume growth. This increase in revenue will recover our forecast costs, including our expected return on investment.

Figure 3: Components of Target Revenue

	2016/17 ($000)	2015/16 ($000)	Change (%)
Administration and Overheads	9,740	9,459	3.0%
Operations and Maintenance	5,783	4,604	25.6%
Transmission charges	14,343	13,733	4.4%
Depreciation	11,548	10,982	5.1%
Tax	6,254	5,124	22.0%
Return on investment	16,455	14,990	9.8%
Other Revenue	(5,698)	(6,744)	(15.5)%
Target Revenue Requirement from Prices	58,423	52,148	12.0%

Administration and Overheads include costs associated with managing the day to day business activities of our distribution business, such as management, accounting, finance and administration costs. This also includes local body rates and Electricity Act and Commerce Act levies. The increase in the administration and overheads costs for 2016/17 reflects MainPower's continued focus on health and safety; delivering a safe, secure and reliable electricity distribution network, implementing intelligent network technologies; and taking a leadership role in the community.

Operations and Maintenance captures costs associated with operating and maintaining the network, such as switching, planned and reactive maintenance and responding to faults.

Transmission costs are Transpower charges associated with:

- connection of MainPower's distribution network to the national grid (including interconnection, connection and new investment contract charges)
- the grid system operator function (a service which Transpower provides).

Depreciation represents the return of our original capital investment and is calculated based on the net book value of our distribution business.

Tax represents budgeted tax expenditure attributed to our distribution business.

In 2015/16, our return on investment is calculated as a WACC return on average net book value. We use a post tax WACC estimate of 6.17% for this calculation. This estimate is derived using the Capital Asset Pricing Model and is based on the following assumptions:

- a risk-free rate of 5.0% (as per PwC's Appreciating Value cost of capital report, June 2014)
- a debt premium of 1.50%
- an asset beta of 0.34 as the measure of non-diversifiable business risk based on the Commerce Commission's estimate
- a debt equity ratio of 40:60
- an investor tax rate of 28 per cent
- a post tax market risk premium of 7.5%.

We are holding our prices constant. The ROI for the 2016/17 disclosure year reflects the increase in billing volumes attributable to the growth that MainPower has experienced post earthquake which we estimate to be 7.6%.

We note that the post tax WACC estimate of 6.17% is less than the current cost of capital of 7.19% applied by the Commerce Commission to EDBs regulated under the Default Price-Quality Path.

Other revenue attributable to our distribution business is subtracted to determine the target revenue to recover from electricity distribution charges.

Customer groups

Our standard prices are structured across two pricing regions and six standard customer groups. We also have one non-standard customer which is discussed further below.

The two pricing regions were identified in order to provide for customers in and outside of the MainPower Trust boundaries:

- ***MainPower Region (MP):*** includes all customers connected to the distribution network that are not included in the Kaiapoi pricing region. These are Qualifying Customers consistent with the MainPower Trust boundary.

- ***Kaiapoi Region (KE):*** All customers connected to the electricity distribution network previously owned by Kaiapoi Electricity Limited, which was acquired by MainPower on 1 July 2004. These customers are non-Qualifying Customers but have a similar cost profile to customers in the MP region.

Within these pricing regions, we use six standard customer groups:

- ***Residential:*** A residential customer group has been adopted in order to show compliance with the low fixed charge regulations, which apply only to domestic customers.
- ***Non-residential and large users:*** Non-residential and large users are treated as a separate customer group in order to:
    - recognise the different connection load usage profiles of these customers (e.g. lower weighted average load factor), relative to residential customers
    - facilitate our approach to complying with the low fixed charge regulations (i.e. by separating residential and non-residential customers)
- ***Irrigation:*** This group was added in response to significant growth in irrigation in North Canterbury, mainly resulting from dairy conversions. It recognises the unique summer demand peaking load profile of these customers and incentivises efficient utilisation of available capacity in the network.
- ***Lighting:*** This group was established to recognise the distinct night-time only usage profile and dedicated assets attributable to lighting connections.
- ***Council Pumping:*** Council pumping is a separate customer group in the MP and KE pricing region that recognises their high peak load but less frequent use.
- ***Temporary supply:*** This customer group recognises the need for temporary supply connections (e.g. related to construction) as well as the additional costs associated with servicing this group.

Figure 4 summarises the prices offered for each pricing region and customer group.

Key statistics for each pricing region and price option are presented in Appendix D. This includes information on:

- price components, including fixed and variable prices, by distribution and transmission components
- target revenue and allocations of target revenue to pricing regions and prices
- pricing history
- ICPs, installed kVA, customer statistics, including delivered kWh consumption and chargeable peak demand.

Figure 4: MainPower Pricing Options

Pricing Option	Customer Group	Description and rationale
Residential All Inclusive Supply	**Residential**	A price option offered to residential customers that allows a portion of their load (i.e. hot water heating) to be interrupted for part of the day as required for network operations. This option is priced lower than the uncontrolled price to incentivise customers to offer controllable load. This lower price recognises the benefits to all customers relating to timely management of faults and in reducing peak demand related costs. This pricing option is offered as a low user and standard user option but both are priced the same to comply with the low fixed charge regulations.
Residential Uncontrolled Supply	**Residential**	A pricing option targeted to residential customers that do not offer controllable load (i.e. hot water heat). The pricing of this option recognises the additional network costs created by not being able to interrupt supply to manage faults and peak demand. This price is offered as a low user and standard user option but both are priced the same to show compliance with the low fixed charge regulations.
Residential Night Only	**Residential**	A special discounted pricing option which applies to consumption during the off-peak night period between 9.30pm to 7.30am. This incentivises customers to shift load to the off-peak night period, recognising the associated benefits in reducing peak demand. This is offered as a low user and standard user option.
Non-Residential General Supply and Large User Group	**Non-residential and Large Users**	This pricing option is offered to non-residential customers, typically being large users. A higher daily fixed charge is applied to take into account the lower weighted average load factor of these connections.
Irrigation	**Irrigation**	A pricing option targeted to irrigators in the MP and KE pricing regions. These customers are charged a fixed daily charge per kW of installed motor capacity connected. This recognises the relationship between network capacity costs and the relatively size of irrigation motors connected to the network.
Lighting	**Lighting**	Various pricing options applying to Street Lighting, Right of Way Lighting, and Under Veranda Lighting (all priced the same).
Council Pumping	**Council Pumping**	A price offered in the MP and KE pricing regions for connection of Council pumping facilities. Council pumping is priced based on the uniform pricing rule.
Temporary supply	**Temporary Supply**	A pricing option applying to temporary connections to the network. Priced higher than standard supply, this option recognises the additional costs in managing temporary connections. It also appropriately incentivises customers to shift to a standard pricing option as soon as is practical.

Allocation of Costs to Customer Groups

Given prices have been held constant, allocations of costs to prices were last made for the 2015/16 pricing year. The cost allocation method has not changed for the 2016/17 year.

The allocation of costs to customer and pricing groups recognise the predominant rural customer base as well as customers’ continued confirmation and support for our uniform charging regime.

Operating costs are, wherever possible, directly attributed to customer groups that solely create the need for these costs. Remaining shared operating costs are allocated to customer groups using allocation rules based on key drivers of cost, as follows:

Figure 5: Cost allocators

Cost Item	Allocation basis	Rationale
Administrative and Overhead costs	Consumption	An allocator based on connections or consumption is considered appropriate, given these costs are broadly shared by all users. We have used consumption to recognise that larger customers typically have a higher level of cost associated with them.
Operation and Maintenance costs	Net assets employed	While maintenance expenditure may arise for a variety of reasons (ie planned versus reactive maintenance), over time these costs are typically proportional to the value of assets installed. Aligning maintenance costs to net assets employed recognises this cost relationship.
Rates	Net assets employed	This recognises that rates are levied on the capital value of the network.
Levies	Consumption	This partly recognises the basis upon which these costs are charged to MainPower. For example, electricity levies are calculated based on MWhs and ICPs.
Capital Costs	Directly attributed to pricing regions using asset register records Allocated to pricing options by kWh consumption	Allocation basis seeks to represent relative utilisation of each network region.
Transmission charges	Directly attributed to pricing regions based on grid connections associated with each pricing region Allocated to pricing options by kWh consumption	Transpower charge on basis of grid connection. Consumption represents the relative utilisation of the transmission grid.

Price Setting

Prices are set to recover cost allocations to each customer group and pricing option using forecast volumes and current pricing structures. Appendix D sets out prices including the expected target revenue to be recovered from each price.

We have chosen to keep prices unchanged for the 2016/17 year. The price setting methodology and prices for the 2016/17 year are therefore the same as 2015/16 year.

MainPower has adopted the following uniform charges that apply to most customers in each pricing region:

- The 15 cent per day low fixed charge applies to all controlled residential customers irrespective of use. This approach complies with the low fixed charge regulations.
- Variable distribution and transmission line services are charged by way of a uniform consumption charge within each pricing region. KE variable charges are set to equal MP variable charges net of rebates. This structure is adopted to set a baseline price for the majority of customers. A number of exceptions to these general pricing rules are made to recognise specific cost attributes or customer profiles as well as to encourage specific usage behaviours:
- The Residential Night Only variable price is calculated for each pricing region at approximately 80% of the Residential All Inclusive Supply variable distribution price and approximately 10% of the Residential All Inclusive Supply transmission charge. These discounted prices are set to provide an incentive for customers to shift load to the off peak night period between 9.30pm to 7.30am, thereby reducing utilisation of available service capacity during the day.
- The total variable charge for the Residential Uncontrolled Supply - Low User Option is calculated at approximately 133% of the Residential Controlled Supply total variable charge. The Residential Uncontrolled Supply fixed distribution price has also been determined at 60 cents per day. These higher prices incentivise customers to shift to the Residential All Inclusive Supply pricing option and offer controllable load.
- The fixed distribution price for Non-Residential General Supply and Large User pricing options has been determined at 50 cents per day. This takes into account the higher costs associated with connection assets for these customers and the lower weighted average load factor of this customer group.
- Revenue collected from all customer groups by way of fixed distribution charges is limited to 10% of the total fixed and variable distribution revenue. Actual percentages will vary year on year and between customer groups as a result of changes in load factor and other load characteristics.
- The variable distribution price applicable to Temporary Supply customers is maintained at approximately the same rate as the Residential Uncontrolled Supply - Low User Option variable distribution price. A fixed price of $1.00 per day also applies. This structure recognises the additional costs we face in managing temporary supply connections and appropriately incentivises customers to shift to a standard pricing option.
- The fixed price applicable to Irrigation customers is 2 cents per day per kW of motor size connected (i.e. 50 cents per day for a motor size of 25 kilowatts) in recognition of capacity related costs.
- No fixed daily charge is applicable to Street Lighting, Right-of-Way Lighting or Under Veranda Lighting pricing options. Costs are recovered through a variable price.

- MainPower offers a discount to General customers using in excess of 500,000 kWhs per annum. The discount is calculated on a sliding scale, depending on consumption levels customers are offered a variable distribution price of between 7.165 cents per kWh and 1.646 cents per kWh applied on a straight line basis. A variable distribution price of 1.646 cents per kWh applies to all consumption over 1,000,000 kWhs.
- The variable distribution price applicable to General Supply customers within the KE pricing region, where consumption exceeds 500,000 kWhs, per annum is also discounted on a sliding scale basis. For consumption between 500,000 kWhs per annum and 1,000,000 kWhs a variable distribution price of between 3.810 cents per kWh to 1.564 cents per kWh is applied on a straight line basis. A variable distribution price of 1.564 cents per kWh applies for all consumption above 1,000,000 kWhs.

There has been an increase in costs to MainPower but we are able to absorb these through existing prices being applied to higher billing volume forecasts (thereby increasing target revenue).

Non-Standard Pricing

Only one non-standard customer is connected to our distribution network. The customer is situated close to a Transpower GXP and takes direct supply from the grid through MainPower's connection assets and equipment.

Prices are set for this customer to recover the actual costs we incur as follows:

- Transmission charges are passed on directly to the customer as billed by Transpower. This is possible as the customer is the only significant connection at the GXP it is connected to. Transmission charges account for 85% of lines charges, given the customer's limited usage of distribution assets.
- Distribution asset and equipment costs deployed at the connection (which have not already been recovered through capital contributions) are recovered fully through prices. This includes depreciation and a return on investment.
- Operations and maintenance costs incurred in relation to the connection are directly recovered each year in prices.
- Administration costs are recovered based on actual costs incurred.

Distribution costs are recouped through a fixed distribution charge. Transmission charges are recouped on the same basis that Transpower bills MainPower (although this is expressed on a cents per kWh basis in our pricing schedule).

Prices have been determined on this basis to discourage uneconomic bypass to the transmission grid. The fixed price seeks to minimise price volatility for both parties. Target revenues expected to be recovered from non-standard prices are detailed in Appendix D.

Our obligations and responsibilities in the event of an interruption to this customer are no different to that of other large standard customers connected to our network. The customer does have a higher level of circuit redundancy built into their connection that could result in quicker restoration times but the obligations and responsibilities to restore supply are no different. This level of redundancy is reflected in prices through the higher associated cost of the connection assets and equipment.

We will consider all requests for non-standard contracts on application based on the commercial merits of the proposal. Criteria by which we typically might decide to enter into a non-standard contract include:

- the customer is at risk of bypassing the network to an alternative network or energy source

- the customer has requested a non-standard connection or specialist equipment which cannot be accommodated into our standard pricing structures or capital contributions policy
- the customer requests non-standard pricing structures to mitigate risk which might otherwise impair their decision to connect to the network.

Distributed Generation Pricing

There are a limited number of small scale distributed generators connected to our network. These generation units are less than 10kW, generally under 2kW, and are typically associated with an existing ICP (i.e. photovoltaic solar panels supplementing distributed electricity supply). These connections rarely export electricity into the network.

We do not charge for small scale distributed generation connected to the network or make payments in regards to avoided costs. This decision reflects the following considerations:

- the low number of connections of this type
- the low cost to connect small scale distributed generation to the network
- the low volumes of electricity exported to the network from these connections
- the avoided costs (both in relation to transmission and distribution costs) which are associated with the reduced peak demand these generation units provide.

While we do not typically incur costs associated with the physical connection of small scale distributed generation, where we do, these costs will be met via contributions consistent with our capital contributions policy.

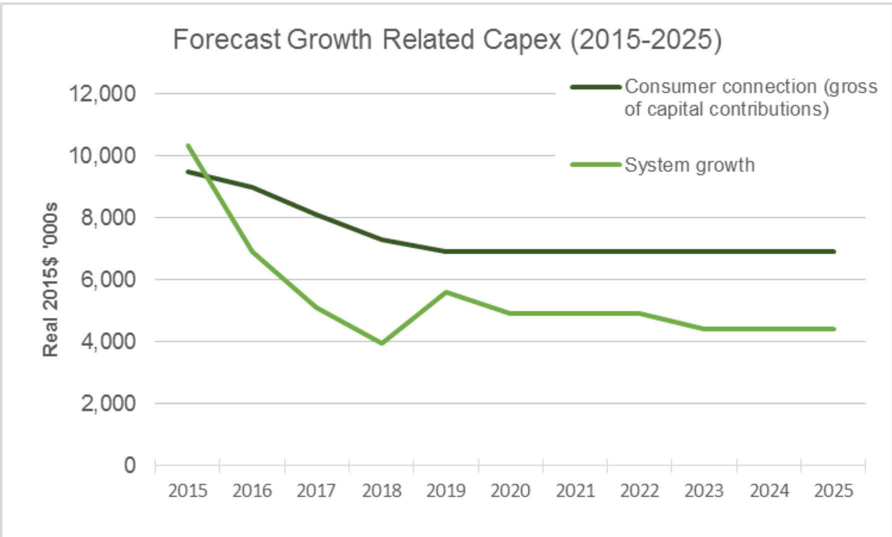
There are a small number of sites with larger scale distributed generation. Payments for avoided costs of transmission are made to one customer with large scale distributed generation under a commercial arrangement. We are developing a policy for pricing large scale distributed generation in the future.

APPENDIX A: ELECTRICITY AUTHORITY PRICING PRINCIPLES

This appendix describes the extent to which our pricing methodology is consistent with the EA's pricing principles, pursuant to section 2.4.3(2) of the IDD.

We have reviewed our pricing methodology against the pricing principles and are of the view that our pricing methodology is broadly consistent with the principles. We also signal how alignment with the principles may be refined and improved following our pricing review.

Pricing Principle	Extent of consistency
(a) Prices are to signal the economic costs of service provision, by:	
(i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;	The incremental costs of connecting an additional customer to the network include the costs of connection assets specific to the customer, incremental operating and maintenance costs, and upstream reinforcement costs required to accommodate the additional connection. MainPower's 'Network Extensions and Upgrades and Capital Contributions Policy' is the primary mechanism by which we ensure that prices recover incremental capital cost. We seek capital contributions for new connections and asset upgrades when the expected distribution revenue from a connection is less than the incremental capital costs (including a share of any upfront or future network augmentation costs). Distribution prices will therefore be in excess of incremental capital costs. The remaining incremental operational expenditure is recovered in distribution prices. Simple regression analysis shows us that over the last 10 years new connections have on average increased operating costs by $282 per annum (real $2015), across all connection sizes. This estimate is likely to overstate incremental costs as it includes non-consumer elated cost increases, such as recent regulatory and safety compliance costs. Our fixed charge will recover a proportion of these costs regardless of the level of consumption ($54.75 per annum in the case of controlled residential, and $182.50 per annum for non-residential). This will likely recover incremental costs for smaller connection sizes, which would usually contribute less towards operational costs. Revenue received from variable charges, which broadly increases proportional to the size of the connection and associated costs, will in most cases recover remaining incremental costs. For example, a customer on the Residential Controlled Supply price would only need to use 2,266kWh per annum to recoup the average incremental cost identified above. This also highlights that cross-subsidies may exist at very low levels of usage due to the application of the low fixed charge regulations. Prices are also likely to be less than stand alone cost. We understand stand alone cost to mean the cost to the customer of bypassing the network with alternative supply arrangements (e.g. connection to the grid through its own distribution assets, or alternative fuel or generation sources). For most mass market customers the costs of moving "off-grid" to a standalone energy solution (eg rooftop PV) is currently priced at a premium to distributed electricity supply. This is because the large economies of scale associated with network investments mean distribution networks currently remain competitive on price. Large customers are likely to be better placed to bypass the network at a lower overall stand alone cost. As an example, our largest connection is on a non-standard contract to discourage bypass of our network to the transmission grid. The non-standard arrangements ensure it is economic for this customer to remain connected to the network by pricing below the stand alone cost of connecting directly to the grid. We are looking to estimate stand-alone costs for different pricing regions and customer groups as part of our cost of supply modelling project. These will hopefully be provided in future pricing methodologies.
(ii) having regard, to the extent practicable, to the level of available service capacity; and	The primary service that distributors provide is access to network capacity. This pricing principle sets out that distributors should recognise this primary driver in setting prices and pricing structures.

	The 2010 – 2011 Canterbury earthquakes triggered a significant population shift north from the city of Christchurch to the surrounding areas of Rangiora and Kaiapoi. In 2015 alone, the number of connections on our network increased by just over 1% (2014 4.3%). In addition, irrigation demand is also rising as a result of numerous dairy farm conversions. This growth is putting pressure on available network capacity across our network. For instance, our peak load in 2015 was 109MW (2014:100MW). Signalling available service capacity in our prices is therefore important and a significant focus of our pricing review. We currently do not explicitly define customer groups by the level of available service capacity. However, the distinction made between low users, residential, non-residential, and large users does proxy different customer capacity profiles. Similarly, Residential Controlled and Night Special pricing options are designed to incentivise behaviours that reduce demand at the peak or during fault events. This reduces the pressure on available service capacity as well as defers investments in new capacity. The Irrigation price based on the installed kW capacity of irrigation motors and is designed to signal limited capacity in the high voltage distribution system. This price option, as well as capital contributions sought from irrigators, signals that upstream capacity is limited. One area being investigated as part of our pricing review that might improve alignment with this principle is the potential introduction of customer groups defined by load characteristics and time/demand based prices. As discussed above, we are investigating a small and large load group aligned to the typical load profiles of customers connected to our network. Peak-time/demand based charging structures could be used to signal the available service capacity on the network a different times of use.
(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs.	This principle asserts that behaviour which creates additional investment costs for distributors should be recognised in pricing, and that costs should accordingly be recouped from those customers that create them. The key drivers of future network investment costs relates to new connections and system capacity growth. Over the next 4 years capex is expected to remain high before reducing to more normal levels (see graph below). These investments stem mainly from growth in the residential population and use of irrigation.  We ensure we recoup incremental connection and upstream reinforcement costs through our capital contributions policy, as discussed above. The use of a consumption based variable charge is another pricing approach which recognises additional usage of capacity. While prices based on kWh consumption provide a crude proxy for capacity utilisation, they send a signal that additional usage of the network creates additional costs over time.

	As part of our review, we are considering the merits of peak-time/demand pricing, particularly for the large load group. This may align pricing more closely with this principle. Large customers typically have time of use meters making it practical to charge on peak usage. By contrast, it is impractical to price the mass market other than on consumption given the current fleet of non time-of-use meters. Mass market pricing more closely aligned with peak capacity usage is being investigated as an option as new smart meters are deployed on our network. The Residential Night Onlyprice provides incentives for customers who take up this option to shift their demand to the off-peak night period. The Residential Controlled price signal provides incentives to customers that offer up interruptible load which can be used to manage faults and reduce peak demand. In combination, these options appropriately signal the impact of additional usage on investment costs. As discussed above, the Irrigation price signals capacity constraints on the 11kV network attributable to this fast growing customer group by levying a higher fixed daily charge on relatively larger irrigation motors.
(b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to customers' demand responsiveness, to the extent practicable.	This principle sets out the economic principle of "Ramsey Pricing". This principle asserts it is economically efficient to charge more to those customers that have a higher willingness to pay and less to those with a lower willingness to pay. As a practical example, this principle suggests that a business that must operate or face significant shutdown costs would pay relatively more than a customer who is willing to have their supply interrupted. This is considered economically efficient as those customers that demand a service the most, pay the most. In competitive markets, customers that pay more will typically demand a higher level of service. In practice, it is difficult to apply willingness to pay considerations explicitly given the difficultly in measuring customer demand responsiveness. However, our recent customer surveys confirm that 8 out of 10 customers would not be willing to pay more for a higher quality of supply. 5% of the customers surveyed would be willing to pay $100 per year for higher quality of service. This suggests, in general, a low willingness to pay for higher value services for the majority of customers. We consider the willingness to pay principle can be practically applied by allowing customers to self-select into pricing options that balance their willingness to pay with the quality of supply they receive. For instance, the Residential Uncontrolled pricing option is higher recognising that customers who do not want their hot-water load interrupted are willing to pay more for that supply. Similarly, the Residential Night Onlyprice is targeted at customers who are willing to limit their demand at the peak in preference for a lower off peak charge. Our non-standard pricing also partially recognises willingness to pay considerations by customers that are readily able to bypass the network.
(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:	This suggests Principle (a) takes priority over these considerations.
(i) discourage uneconomic bypass;	This allows for a discount on price or other incentives being offered to customers at risk of bypassing our network. As discussed above, bypass options are likely to be more applicable to larger customers that have options over where they locate their business or which have access to alternative energy supply (e.g. gas, generation, the transmission grid). We have one customer that is directly supplied from Transpower's national grid, using MainPower's equipment. This customer could readily bypass the distribution network in favour of a direct connection to the grid. To recognise this risk, we have entered into a non-standard contract with this customer and prices are set with reference to the actual (or incremental cost) of offering these services. This discourages uneconomic bypass to the transmission grid.

(ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and	This principle allows for negotiation over price in recognition of different levels of service (e.g. redundancy) or non-standard arrangements (greater fixed charge component to reduce risk). As discussed above, MainPower has one non-standard contract and is willing to negotiate on price and quality outcomes and non-standard arrangements with other customers where necessary. In addition to incremental cost pricing, a flat fixed charge is applied which reduces price variability for this customer. Price and quality trade-offs are also sometimes addressed as part of our capital contributions policy. For instance, if a customer requires specialist equipment or connection redundancy then a contribution is typically sought from the customer to recover costs associated with this investment.
(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (eg distributed generation or demand response) and technology innovation.	This principle seeks to encourage the development of distributed generation, load control, and technological innovation. We do not levy annual charges on the connection of small scale distributed generation to the network. This provides appropriate incentives for customers to invest in distributed generation as they do not face any additional distribution costs beyond that related to their standard ICP connection. Furthermore, distributed generation will usually lower a customer's variable distribution charge resulting in lower annual charges. This further provides incentives to invest in this technology. Where there are upfront costs in relation to connecting distributed generation, which is unlikely, this will be dealt with as part of our capital contributions policy. Currently there are 2 customers with large scale distributed generation connected to our network (ie greater than 10kW), and we are considering our own distributed generation investments at Mt Cass. We will pay avoided transmission payments to one of these connections by commercial negotiation, but are seeking to develop a formal methodology for pricing large scale distributed generation in the future. Demand response measures are encouraged through the use of our Residential Controlled and Residential Night Only pricing options, which are priced attractively to incentivise customers to offer up interruptible load or reduce their demand at the day time peak, respectively.
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.	This principle requires distributors to consider the impact of pricing structure changes on customers (e.g. to be cognisant of price shock). MainPower's prices have not changed this year. As part of our current review of pricing, we are considering progressively transitioning customers to new pricing structures over time to avoid price shock. The principle also requires the development of prices to be transparent. We consider that the information provided in this pricing methodology provides appropriate explanations of how we have set prices and the rationale for doing so.
(e) Development of prices should have regard to the impact of transaction costs on retailers, customers and other stakeholders and should be economically equivalent across retailers.	This principle was added by the Electricity Authority out of concern that some distribution pricing structures were overly complex, creating transaction costs for retailers and customers. It also sought to minimise the potential for prices to be structured in a way which might favour certain retailers over others, the objective of this being to enhance retail competition on distribution networks. MainPower has a conveyance form of contractual relationship with our customers. We directly bill customers through our contractual arrangements with the retailer, but retailers are not charged directly. This reduces transaction costs for retailers as retailers do not need to rebundle distribution charges to align with their own pricing. Our current prices are not overly complex, align with industry standard pricing, and do not favour one retailer over another. We are also investigating further alignment to the ENA price standardisation guidelines as part of our review.

APPENDIX B: DIRECTORS CERTIFICATION

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURE

Pursuant to Clause 2.9.1 of section 2.9

We, WYNTON GILL COX and PETER ANTONY COX, being Directors of MainPower New Zealand Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of MainPower New Zealand Limited prepared for the purposes of clause 2.4.1 of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination; and

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.

....

Wynton Gill Cox
1 March 2016

....

Peter Antony Cox
1 March 2016

APPENDIX C: REGULATORY COMPLIANCE CHECKLIST

IDD Clause	Disclosure Requirement	Pricing Methodology Reference
2.4.1	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	This Pricing Methodology will be published on our website prior to 1 April 2016.
2.4.1(1)	Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	See below for document references to compliance against clause 2.4.3.
2.4.1(2)	Describes any changes in prices and target revenues;	Prices have not changed this year. There has been no change to the cost allocation method – this has been carried forward in current prices. Changes in target revenues are described in Section 5 under the heading 'Target Revenue' and in Figure 3. The component costs of target revenue have changed to reflect revised budgets. While prices have been held constant, target revenue has increased due to higher forecast billing quantities.
2.4.1(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 below for document references to compliance against clause 2.4.5.
2.4.1(4)	Explains whether, and if so how, the EDB has sought the views of customers, 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 customers, the reasons for not doing so must be disclosed.	The details of our previous consultation with customers on their price and quality expectations is discussed in section 4 under the heading 'Customer expectations on price and quality'.
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.	Not applicable. We have not changed our prices or pricing methodology. This document has been updated from our 2015 pricing methodology incorporating changes to reflect updates to target revenue, and other metrics etc.

2.4.3	Every disclosure under clause 2.4.1 above must-	
2.4.3(1)	Include sufficient information and commentary to enable interested persons to understand how prices were set for each customer group, including the assumptions and statistics used to determine prices for each customer group;	We consider this document provides information on how prices have been set. A glossary is provided in section 1 of terms commonly used in this document. Section 4 provides relevant context to our pricing decisions and signals potential outcomes of our current pricing review. Section 5 sets out the key inputs, assumptions, considerations and decisions made in respect of our pricing, consistent with the IDD disclosure requirements. Appendix A details the extent to which our pricing methodology is consistent with the EA's pricing principles. Appendix C summarises where in the document we have shown compliance with the pricing regulations. Appendix D details final prices, customer statistics and target revenue information.
2.4.3(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;	See Appendix A. We consider that our pricing is consistent with the pricing principles. We also discuss how potential changes to our pricing, signalled as part of our pricing review, may align more closely with these principles.
2.4.3(3)	State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See Section 5, Figure 3 and Appendix D. Figure 3 compares this year's target revenue to our previous year's target revenue by cost component. Appendix D details the breakdown of target revenue by price and cost component.
2.4.3(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;	See section 5 under the heading 'Target Revenue'. Figure 3 and Appendix D provides numerical values for each cost component.
2.4.3(5)	State the customer groups for whom prices have been set, and describe- a) the rationale for grouping customers in this way; b) the method and the criteria used by the EDB to allocate customers to each of the customer groups;	See Section 5 under the heading 'Customer Groups'.

2.4.3(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;	See Section 3. Prices have not changed in 2016/17.
2.4.3(7)	Where applicable, describe the method used by the EDB to allocate the target revenue among customer groups, including the numerical values of the target revenue allocated to each customer group, and the rationale for allocating it in this way;	See Section 5 under the heading 'Allocation of Costs to Customer Groups'. Costs are directly attributed to customer groups and prices where possible. Shared costs are allocated using appropriate cost allocators reflective of key network drivers. This approach has been carried forward from our 2015 pricing methodology. Appendix D provides the numerical values of target revenue allocated to each customer group.
2.4.3(8)	State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Appendix D details the proportion of target revenue to be collected from each customer group consistent with how prices are published in our pricing schedules.
2.4.4	Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	
2.4.4(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;	Our pricing strategy is discussed in section 4, under the heading 'Pricing Review and Pricing Strategy'. This strategy is subject to the outcomes of our review.
2.4.4(2)	Explain how and why prices for each customer group are expected to change as a result of the pricing strategy;	See Section 4, Figure 2 under the heading 'Pricing Review and Pricing Strategy'. We are unable to describe how prices will change as a result of applying our pricing strategy as the details of our pricing review have yet to be finalised. We plan to consult extensively with customers, retailers, and other affected parties to gain feedback on any proposed changes this year. As part of this, we will provide information on how different customer groups will be affected.

2.4.4(3)	If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	See Section 4, under the heading 'Pricing Review and Pricing Strategy'. This pricing strategy is largely unchanged from last year. However, our review is evolving as it progresses which means we have reprioritised project workstreams.
2.4.5	Every disclosure under clause 2.4.1 above must-	
2.4.5(1)(a) and (b)	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 customers subject to non-standard contracts; b) how the EDB determines whether to use a non-standard contract, including any criteria used; c) any specific criteria or methodology used for determining prices for customers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	See Section 5, under the heading 'Non-Standard Pricing'. We seek to recover actual costs incurred from our only non-standard customer, reflective of the incremental costs of the assets and costs to operate and maintain the connection. See Appendix A for a discussion of the extent to which our non-standard pricing aligns with the pricing principles. Prices are greater than incremental costs associated with the customer and are priced to discourage bypass to the transmission grid.
2.4.5(2)	Describe the EDB's obligations and responsibilities (if any) to customers subject to non-standard contracts in the event that the supply of electricity lines services to the customer 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 customers subject to non-standard contracts;	See Section 5, under the heading 'Non-Standard Pricing'. Our obligations and responsibilities in the event of an interruption to supply are no different to that of any other standard large user. However, our sole non-standard customer does have a higher level of circuit redundancy which might result in quicker restorations time. This is reflected in charges through the higher value of assets associated with these circuits.
2.4.5(3)	Describe the EDB's approach to developing prices for electricity distribution services provided to customers 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 5, under the heading 'Distributed Generation Pricing'. We do not currently charge for distributed generation connections. Physical connections costs are usually immaterial and are dealt with under our normal capital contributions policy. We make avoided transmission payments to 1 large distributed generation connection. For smaller connections, avoided costs are

		recognised in our decision not to charge distributed generators for conveyance of electricity.
2.9.1	Where an EDB is required to publicly disclose any information under clause 2.4.1, clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3), the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	See Appendix B for Directors Certification

APPENDIX D: PRICES, CUSTOMER STATISTICS AND TARGET REVENUE

MainPower New Zealand Limited

Appendix D

1 April 2016 Disclosure of Lines Services Pricing and Pricing Methodology as required under Part 4 of the Commerce Act 1986.
Line Service Charges and Revenue Exclude GST and Prompt Payment Discounts, Other Discounts and Customer Rebates

Customer Groupings and Categories	Line Services Charging Schedule at 1 April 2016												Pricing History at 31 March 2016			
	Distribution						Transmission			Total			Date Introduced		Previous Charge	
MainPower Region ICPs - MP Consumer Group	Fixed Charge			Variable Charge			Variable			Variable			Fixed	Variable	Fixed	Variable
Net Equity 2016-2017 $276,156,889	Code		cents/day	Code		c/kWh	Code		c/kWh	Code		c/kWh	Date	Date	cents/day	c/kWh
General Supply																
General Supply Fixed Charge - cents per Day																
Residential Controlled Supply	101	0	15.000	101	1	7.165	101	5	2.333	101	9	9.498	1-Sep-01	1-Apr-15	15.000	9.498
Residential Controlled Supply Low User Option	111	0	15.000	111	1	7.165	111	5	2.333	111	9	9.498	1-Oct-04	1-Apr-15	15.000	9.498
Residential Uncontrolled Supply	102	0	60.000	102	1	7.165	102	5	2.333	102	9	9.498	1-Sep-01	1-Apr-15	60.000	9.498
Residential Night Special Low User Option	113	0	0.000	113	1	7.165	113	5	2.333	113	9	9.498	1-Oct-04	1-Apr-15	0.000	9.498
Non Residential - General supply	121	0	50.000	121	1	7.165	121	5	2.333	121	9	9.498	1-Sep-01	1-Apr-15	50.000	9.498
Irrigation kW Connected Charge (47,500 kW)	124	0	2.000	124	1	7.165	124	5	2.333	124	9	9.498	1-Sep-01	1-Apr-15	2.000	9.498
Council Pumping	125	0	15.000	125	1	7.165	125	5	2.333	125	9	9.498	1-Sep-01	1-Apr-15	15.000	9.498
Street Lighting	126	0	0.000	126	1	7.165	126	5	2.333	126	9	9.498	1-Sep-01	1-Apr-15	0.000	9.498
Right of Way Lighting	127	0	0.000	127	1	7.165	127	5	2.333	127	9	9.498	1-Sep-01	1-Apr-15	0.000	9.498
Under Verandah Lighting	128	0	0.000	128	1	7.165	128	5	2.333	128	9	9.498	1-Sep-01	1-Apr-15	0.000	9.498
Large User Group	130	0	50.000	130	1	7.165	130	5	2.333	130	9	9.498	1-Sep-01	1-Apr-15	50.000	9.498
General Supply Variable Charge - cents per kWh																
Variable Charge - all Units						7.165			2.333			9.498	1-Sep-01	1-Apr-15	NA	9.498
Variable Charge - Volume Discount																
Total General Supply																
Other Supply Fixed and Variable Charge																
Residential Night Special	103	0	15.000	103	1	5.705	103	5	0.233	103	9	5.938	1-Oct-04	1-Apr-15	15.000	5.938
Residential Night Special - Low User Option	113	0	0.000	113	1	6.359	113	5	2.333	113	9	8.692	1-Sep-01	1-Apr-15	0.000	8.692
Residential Uncontrolled Supply Low User Option	112	0	15.000	112	1	9.549	112	5	2.333	112	9	11.882	1-Sep-01	1-Apr-15	15.000	11.882
Temporary Supply	122	0	100.000	122	1	9.404	122	5	2.333	122	9	11.737	1-Feb-10	1-Apr-15	100.000	11.737
Total MainPower Region Consumer Group																
MainPower ICPs - Direct Supply	Code		$/day	Code		c/kWh	Code		c/kWh	Code		c/kWh	Date	Date	cents/day	c/kWh
Net Equity 2016-2017 $2,000,000																
Total Direct Supply Consumer Group	140	0	60.625	140	1	0.000	140	5	2.013	140	9	2.013	1-Sep-01	1-Apr-14	60.625	2.013
Kaiapoi Region ICPs - KE Consumer Group																
Net Equity 2016-2017 $5,560,569	Code		cents/day	Code		c/kWh	Code		c/kWh	Code		c/kWh	Date	Date	cents/day	c/kWh
General Supply																
General Supply Fixed Charge - cents per Day																
Residential Controlled Supply	201	0	15.000	201	1	3.810	201	5	3.783	201	3	7.593	1-Nov-05	1-Apr-15	15.000	7.593
Residential Controlled Supply Low User Option	211	0	15.000	211	1	3.810	211	5	3.783	211	3	7.593	1-Nov-05	1-Apr-15	15.000	7.593
Residential Uncontrolled Supply	202	0	60.000	202	1	3.810	202	5	3.783	202	3	7.593	1-Nov-05	1-Apr-15	60.000	7.593
Residential Night Special Low User Option	213	0	0.000	213	1	3.810	213	5	3.783	213	3	7.593	1-Nov-05	1-Apr-15	0.000	7.593
Non Residential - General supply	221	0	50.000	221	1	3.810	221	5	3.783	221	3	7.593	1-Nov-05	1-Apr-15	50.000	7.593
Council Pumping	225	0	15.000	225	1	3.810	225	5	3.783	225	3	7.593	1-Nov-05	1-Apr-15	15.000	7.593
Street Lighting	226	0	0.000	226	1	3.810	226	5	3.783	226	3	7.593	1-Nov-05	1-Apr-15	0.000	7.593
Right of Way Lighting	227	0	0.000	227	1	3.810	227	5	3.783	227	3	7.593	1-Nov-05	1-Apr-15	0.000	7.593
Under Verandah Lighting	228	0	0.000	228	1	3.810	228	5	3.783	228	3	7.593	1-Nov-05	1-Apr-15	0.000	7.593
Large User Group	230	0	50.000	230	1	3.810	230	5	3.783	230	3	7.593	1-Nov-05	1-Apr-15	50.000	7.593
General Supply Variable Charge - cents per kWh																
Variable Charge - all Units						3.810			3.783			7.593	1-Nov-05	1-Apr-15		7.593
Variable Charge - Volume Discount																
Total General Supply																
Other Supply Fixed and Variable Charge																
Residential Night Special	203	0	15.000	203	1	3.655	203	5	0.378	203	3	4.033	1-Nov-05	1-Apr-15	15.000	4.033
Residential Night Special - Low User Option	213	0	0.000	213	1	3.004	213	5	3.783	213	3	6.787	1-Nov-05	1-Apr-15	0.000	6.787
Residential Uncontrolled Supply Low User Option	212	0	15.000	212	1	6.194	212	5	3.783	212	3	9.977	1-Nov-05	1-Apr-15	15.000	9.977
Temporary Supply	222	0	100.000	222	1	9.404	222	5	2.333	222	3	11.737	1-Feb-10	1-Apr-15	100.000	11.737
Total Kaiapoi Region Consumer Group																
	Code		cents/day	Code		c/kWh	Code		c/kWh	Code		c/kWh	Date	Date	cents/day	c/kWh
Net Equity 2016-2017 $283,717,458																
Total all Consumer Groups																

Customer Groupings and Categories	Customer Statistics 2016-2017				Revenue Requirement 2016-2017						Line Business Operating Costs (Targeted Revenue) 2016-2017						Return (Targeted)		Return (Maximum)	
	Customer	Installed	kWhs	Chargeable	Distribution		Trans	Total	Other	Total	Trans	Operational Expenditure				Total	Surplus	Return	Return	
MainPower Region ICPs - MP Consumer Group	Numbers	Capacity	Delivered	Demand	Fixed	Variable	Variable	Lines	Revenue*	Revenue	Costs	Admin & O/Hs	Ops & Mtce	Depreciation	Taxation*	Costs	After Tax	on Assets	at WACC	WACC
Net Equity 2016-2017 $276,156,889	Nos	kVA	kWhs	kWs	$	$	$	$	$	$	$	$	$	$	$	$	$	%	$	%
General Supply																				
General Supply Fixed Charge - cents per Day																				
Residential Controlled Supply	19,788				1,081,289	13,772,214	4,450,145	19,303,648												
Residential Controlled Supply Low User Option	7,322				406,336	3,245,568	1,050,146	4,702,050												
Residential Uncontrolled Supply	1,266				240,263	878,944	286,193	1,405,400												
Residential Night Special Low User Option	520				0			0												
Non Residential - General supply	5,098				958,099	8,418,747	2,643,623	12,020,469												
Irrigation kW Connected Charge (47,500 kW)	1,135				370,763	8,054,744	2,585,027	11,010,534												
Council Pumping	163				9,316	714,884	232,774	956,974												
Street Lighting	165				0	216,348	70,445	286,793												
Right of Way Lighting	0				0			0												
Under Verandah Lighting	0				0			0												
Large User Group	36				5,310	2,714,085	1,325,658	4,045,053												
General Supply Variable Charge - cents per kWh																				
Variable Charge - all Units			536,547,209					0												
Variable Charge - Volume Discount								0												
Total General Supply	**35,493**		**536,547,209**		**3,071,376**	**38,015,534**	**12,644,011**	**53,730,921**												
Other Supply Fixed and Variable Charge																				
Residential Night Special	1,857		3,689,444		91,873	210,483	8,596	310,952												
Residential Night Special - Low User Option	0		706,982		0	44,957	16,494	61,451												
Residential Uncontrolled Supply Low User Option	313		1,898,745		16,152	181,311	44,298	241,761												
Temporary Supply	343		728,015		131,978	68,463	16,984	217,425												
Total MainPower Region Consumer Group	**36,149**	**508.2**	**543,570,395**	**96,965**	**3,311,379**	**38,520,748**	**12,730,383**	**54,562,510**	**5,647,151**	**60,209,661**	**11,930,835**	**9,159,622**	**5,565,524**	**11,193,944**	**6,157,717**	**44,007,641**	**16,202,020**	**6.77**	**14,762,307**	**6.17**
					Other Revenue = Customer Capital Contributions $M4.590 Sundry $M1.057						* Includes both Actual and Notional Taxation							239,259,431		
MainPower ICPs - Direct Supply	Nos	kVA	kWhs	kWs	$	$	$	$	$	$	$	$	$	$	$	$	$	%	$	%
Net Equity 2016-2017 $2,000,000																				
Total Direct Supply Consumer Group	**1**	**6.5**	**68,184,800**	**10,558**	**221,280**	**0**	**1,218,490**	**1,439,770**	**0**	**1,439,770**	**1,218,490**	**45,000**	**51,060**	**93,572**	**8,716**	**1,416,837**	**22,933**	**1.15**	**123,400**	**6.17**
																		2,000,000		
Kaiapoi Region ICPs - KE Consumer Group																				
Net Equity 2016-2017 $5,560,569	Nos	kVA	kWhs	kWs	$	$	$	$	$	$	$	$	$	$	$	$	$	%	$	%
General Supply																				
General Supply Fixed Charge - cents per Day																				
Residential Controlled Supply	1,081				56,239	351,625	349,133	756,997												
Residential Controlled Supply Low User Option	615				32,240	126,360	125,464	284,064												
Residential Uncontrolled Supply	27				3,734	7,772	7,717	19,223												
Residential Night Special Low User Option	0				0			0												
Non Residential - General supply	210				38,344	290,441	288,383	617,168												
Council Pumping	17				877	36,367	36,110	73,354												
Street Lighting	31				0	13,962	13,863	27,825												
Right of Way Lighting	0				0			0												
Under Verandah Lighting	0				0			0												
Large User Group	6				1,096	244,011	368,945	614,052												
								0												
General Supply Variable Charge - cents per kWh								0												
Variable Charge - all Units			31,454,059					0												
Variable Charge - Volume Discount								0												
Total General Supply	**1,987**		**31,454,059**		**132,530**	**1,070,538**	**1,189,615**	**2,392,683**												
Other Supply Fixed and Variable Charge																				
Residential Night Special	129		190,915		6,680	6,978	722	14,380												
Residential Night Special - Low User Option	48		53,441		0	1,605	2,022	3,627												
Residential Uncontrolled Supply Low User Option	6		34,121		320	2,113	1,291	3,724												
Temporary Supply	16		12,269		5,298	1,154	286	6,738												
Total Kaiapoi Region Consumer Group	**2,057**	**20.3**	**31,744,805**	**7,077**	**144,828**	**1,082,388**	**1,193,936**	**2,421,152**	**51,203**	**2,472,355**	**1,193,935**	**534,927**	**166,289**	**260,156**	**87,312**	**2,242,619**	**229,736**	**4.13**	**343,087**	**6.17**
																		5,560,569		
	Nos	kVA	kWhs	kWs	$	$	$	$	$	$	$	$	$	$	$	$	$	%	$	%
Net Equity 2016-2017 $283,717,458																				
Total all Consumer Groups	**38,207**	**535**	**643,500,000**	**114,600**	**3,677,487**	**39,603,136**	**15,142,809**	**58,423,432**	**5,698,354**	**64,121,786**	**14,343,260**	**9,739,549**	**5,782,872**	**11,547,671**	**6,253,745**	**47,667,097**	**16,454,689**	**6.67**	**15,228,794**	**6.17**
																		246,820,000		