Electricity Distribution Business Pricing Methodology for Prices Effective 1 April 2015

27 March 2015

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2 Introduction

The purpose of this document is to describe Electra Limited's ('Electra') approach to setting electricity distribution prices from 1 April 2015.

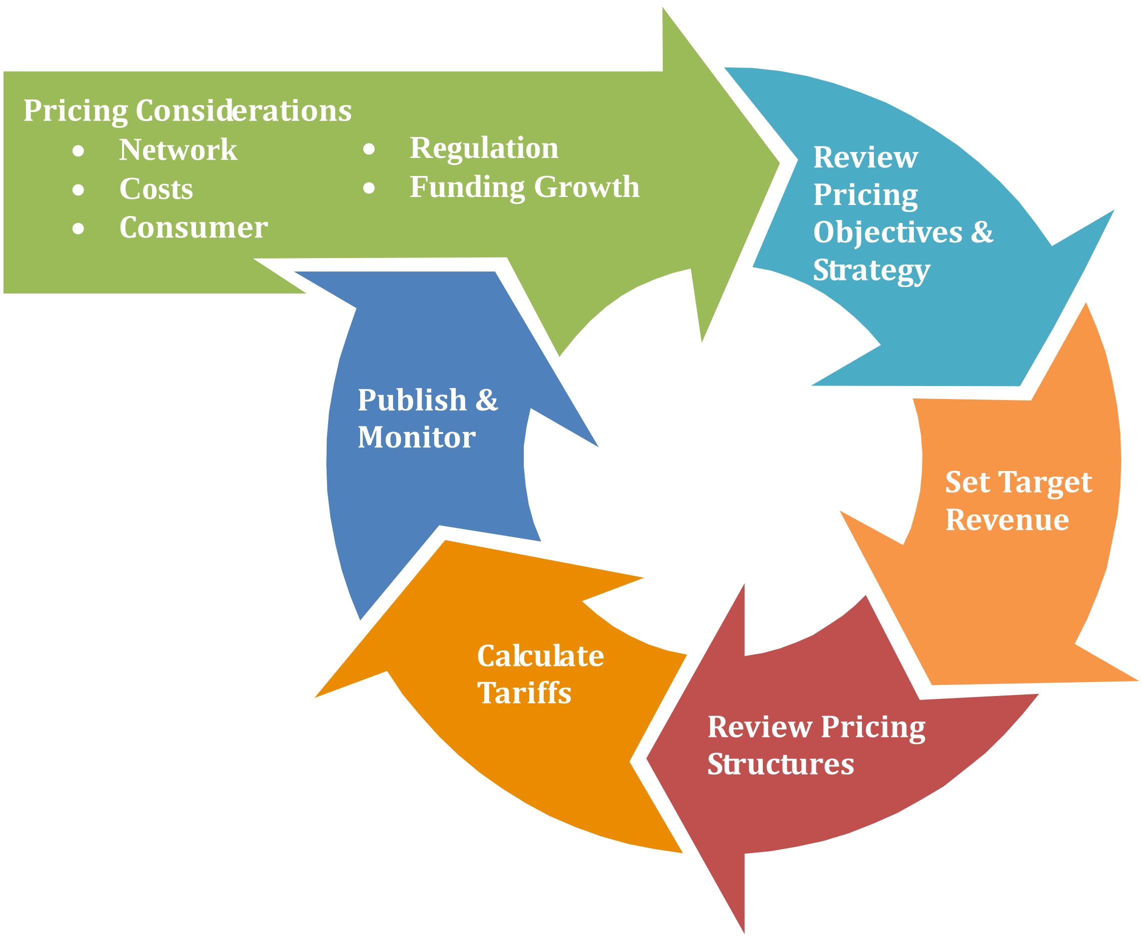
Electra owns and operates the local electricity distribution network in the Kapiti and Horowhenua regions. The network distributes some 402 Gigawatt hours (GWh) of electricity each year from the national grid to approximately 42,900 consumers. Load on the network is mainly comprised of domestic and small commercial connections, concentrated in the main towns along the coast, with larger commercial loads centred on Paraparaumu and Levin.

Electra is owned by its consumers through the Electra Trust, which appoints Directors and holds all of the shares on behalf of the consumers connected to the network.

3 Summary of 2015 pricing methodology

3.1 Approach to setting prices

Electra resets it prices at 1 April each year for the forthcoming pricing year. Our annual pricing review cycle is illustrated as follows:



- **Review pricing considerations:** We have reviewed the key pricing considerations influencing our pricing decisions (See Section 4)
- **Review pricing objectives and strategy:** We have reviewed our pricing objectives and strategy (See Section 5)
- **Set target revenue:** We have calculated our target revenue to be recovered through prices (See Section 6)
- **Review pricing structures:** We have reviewed and confirmed our four consumer groups and various tariff options (see Section 7-8)

- **Calculate tariffs:** We have calculated tariffs (see section 9) which will recover our target revenue. In this respect we have considered:
    - pricing structures
    - the cost of supplying different consumer groups
    - expected connections and consumption over the pricing period.
- **Publish and monitor:** Our pricing methodology is updated and published on our website. This ensures that our approach to determining tariffs is transparently disclosed, consistent with regulatory requirements (see section 10).

3.2 Changes to pricing in 2015

The new prices that apply from 1 April 2015 are set out in the appendix with 2014 prices provided for comparison purposes. Additional detail is provided in section 9. Figure 1 summarises the key changes to be introduced from 1 April 2015.

Figure 1: Changes to the pricing methodology in 2015

Change	Impact on consumers
Prices reset to recover 2015/16 target revenue	Aggregate prices increased to reflect a 2% increase in Electra's costs
Standard Industrial daily fixed charge increased	Daily fixed charge increased from 80c/day to 90 c/day per ICP.
Anytime and peak time prices increased relative to off-peak and controlled prices, to incentivise more efficient use of network capacity	• Anytime, Day and Peak use kWh rates increased under the Anytime, Night/Day, Triple Saver, and Standard Industrial tariff options. • Managed, Off-peak, Night, Super Thrifty and Thrifty charges unchanged.
New distributed generation (DG) export tariff introduced for those exporting electricity on to network.	Tariff set at zero at this time, hence no impact on consumers. Purpose is to monitor uptake of DG.
The content and structure of the methodology statement updated to improve readability.	To provide greater understanding of how we set our prices.

4 Pricing considerations

4.1 Network characteristics

The network supplies a relatively compact geographic area of around 1700 square kilometres, with connections concentrated along the coast, in order to supply a number of towns from Paekakariki to Foxton. Paraparaumu and Levin are the largest of these towns.

Electra receives supply from the national grid from two Transpower Grid Exit Points (GXPs). Electra's northern area (Horowhenua) takes 33kV supply at the Mangahao GXP. The southern area (Kapiti) takes 33kV supply at the Paraparaumu GXP. While Transpower does not permit continuous connection between these GXPs, load is transferred between north and south to meet operational requirements. The two regions are therefore treated as one network for pricing purposes.

The network faces capacity constraints at these two GXPs, which are being addressed by the following upgrades:

- The Paraparaumu GXP feed has been upgraded to a 220kV supply and capacity increased from 60MVA to 120MVA as part of Transpower's project to accommodate the new Transmission Gully highway.
- The capacity of the Mangahao GXP will be upgraded as part of Transpower's lifecycle replacement programme (scheduled for 2017/18).

The upgrade to the Paraparaumu GXP is expected to be cost neutral to Electra over the life of the asset, as part of an arrangement between Electra and Transpower. However, any additional Transpower charges associated with Mangahao, as well as costs associated with our own corresponding network investments, will need to be recovered from consumers unless utilisation of existing capacity on the network can be reduced.

A meshed 33kV sub-transmission network extends from the two GXPs to the main population centres (see map in page 3). This feeder network supplies 11kV distribution circuits that extend radially, with extensive meshing in urban areas. This is stepped down to the 400V low voltage network, which supplies all but a handful of consumers who take supply at 11kV.

4.2 Cost drivers

We have considered the relevant drivers of costs that we are seeking to recover, in order to inform our decisions on consumer groupings, tariff structures, and the level of charges.

90% of our costs are associated with directly investing in, maintaining and operating the network, as well as receiving supply from Transpower's network (see breakdown of target revenue in Section 6.1). The remaining 10% is associated with general management and administration. The key cost drivers relevant to setting prices are therefore weighted heavily towards investment in, and operation of, the network.

Key cost drivers associated with investing in and operating the network include:

- the engineered capacity of the network (measured in kVA);
- the length of circuit required to supply consumers (measured in kms);
- the number of consumer connections (measured in ICPs); and
- consumer specific asset use.

Figure 2: Key network statistics

Consumer numbers	42,908
Total circuit length (km)	2,263
Consumer density (ICPs/km)	18.6
Zone substation installed firm capacity (MVA)	189
Maximum demand (MW)	93
Utilisation of installed firm capacity (%)	59
Energy conveyed (GWh)	402
Energy density (kWh/ICP)	9,572

Source: 2014 Information Disclosures

4.2.1 *Network capacity*

The network is designed and operated to meet forecast electricity demand up to an engineered peak and at a level of service consistent with consumers' expectations. As demand reaches system limits, Electra must consider further investments in network capacity to meet demand. Consumer usage of the available network capacity is therefore a key driver of existing and future network costs.

4.2.2 *Circuit length*

The length of circuit required to transmit electricity from the GXP supply point to the demand base is a key driver of network investment costs. Consumers who are further from the main supply areas create relatively higher costs for Electra.

In practice, the network is relatively compact and extensive meshing of the distribution network in urban centres makes it difficult to distinguish line length for a particular consumer or group of consumers (i.e. due to the difficulty in tracking electrical flows).

It is potentially more practical to measure the relative length of the sub-transmission and distribution feeder network required to supply different demand regions. While a demarcation could conceivably be made between rural and urban consumers on this basis, such a pricing approach is inconsistent with our strong community focus and consumer ownership. It is also potentially at odds with government policy intentions with regards to electricity pricing in rural areas. Therefore, while circuit length is a relevant cost driver we have not factored this into our pricing design.

4.2.3 *Consumer connections*

New connections, and upgrades to connections, drive asset-related and ongoing operations and maintenance costs. Electra's network extension policy requires consumers to pay for connection related asset costs upfront. Each new connection also creates operating and maintenance costs, including network operations and planning, fault restoration, maintenance and general administration costs. New connections therefore increase operating costs over time, which must be reflected in prices.

4.2.4 *Asset usage*

Network costs that directly relate to one consumer or group of consumers are identified and recovered from those parties where practical. This aligns recoupment of costs with the beneficiary of those assets. The provision of street-lighting and community lighting is a service category that has specific assets identifiable to a dedicated group of consumers.

In 2013 we considered whether consumer specific asset use could be better reflected in our pricing methodology. In particular, use of high and low voltage assets and dedicated equipment (i.e. transformers) were considered. We concluded that there is very little variation in asset utilisation within our consumer base (e.g. less than 0.1% of consumers directly connect to 11kV feeders). For those consumers that require dedicated equipment this is generally dealt with as part of our network extension policy, rather than through pricing. We therefore consider that there is little benefit in dedicated asset pricing, with the exception of street-lighting and community lighting.

4.2.5 Summary of key cost drivers applicable to pricing

The key cost drivers recognised in our pricing methodology are:

- Network capacity
- New or upgraded connections
- Dedicated street light or community lighting asset use.

4.3 Consumer considerations

4.3.1 Consumer ownership

Electra is owned by its consumers through the Electra Trust. Consumer trust ownership means that surpluses not required for the operation and development of the business are returned to consumers via electricity sales discounts on their electricity accounts.

4.3.2 Consumer profiles

Electra's pricing structures are focussed towards the mass market because the consumer base is dominated by small loads. Domestic and small commercial users represent approximately 98% of connections and over 80% of maximum demand. As a result, Electra has the lowest average use per connection of all New Zealand electricity distribution businesses (ie 9,572kWhs per connection versus the industry average of 15,967kWh).

Mass market connections are low voltage, typically 60 Amp single phase or 40 Amp three phase. Our analysis suggests these consumers have a typical residential demand profile which peaks in the morning and early evenings.

Our pricing must also cater for several hundred large commercial loads. In contrast to the mass market, most large commercial loads have TOU metering, and much higher levels of annual consumption (ranging from 40,000kWh to more than 3GWh). They also have distinct demand behaviours: many have flat demand across the standard working day, whereas others vary by time of day and season. From a cost driver perspective, large consumers have higher capacity connections and utilise a greater proportion of the installed network capacity relative to the average mass market connection.

4.3.3 Consumer feedback

In December 2014, we undertook a survey of our consumers in order to better understand their views on prices, quality of supply, and consumption patterns. We surveyed 300 consumers (both residential and commercial). Feedback received included:

- 98% of respondents believed that Electra provides a reliable service (up from 72% in 2012), with 78% believing that faults were fixed quickly.
- 44% believed that charges were reasonable.

While the improvement in reliability is pleasing, Electra is working hard to keep prices affordable, with this year's price increase matching cost inflation expectations.

The survey also highlighted increasing use of energy efficient products, which is expected to continue to exert downward pressure on consumption. In the short-term, falling consumption means variable prices per kWh will increase in order to recover our annual target revenue.

The survey also highlighted reasonable interest from consumers in alternative forms of energy supply, with 2% of respondents indicating they had installed solar photovoltaic (PV) supply and 18% suggesting they were considering it. The installation of PV creates both commercial and operational challenges and opportunities for the network, which we need to better understand. Accordingly, we intend to more proactively monitor uptake of small scale DG (including PV) and analyse the potential network impacts.

Figure 3: Consumer survey results

% of respondents that		2012	2013	2014
Use energy efficient light bulbs	Domestic	78%	84%	89%
	Commercial	54%	61%	72%
Use a heat pump	Domestic	27%	32%	35%
	Commercial	30%	30%	33%

4.4 Regulatory considerations

Electra's network is a 'natural monopoly': That is, it is considered more economically efficient for one network to supply all consumers, due to economies of scale. Accordingly, Electra is not directly exposed to competitive forces that drive markets to deliver improved efficiency and services. Legislators typically regulate such businesses to ensure price and quality outcomes consistent with competitive markets. However, consumer ownership provides the necessary incentives to ensure Electra delivers an efficient and reliable service to its consumers (who are also its owners) at fair prices. This was formally recognised in 2008 when Electra was exempted from price and quality regulations applying to electricity distribution networks under Part 4 of the Commerce Act 1986, as administered by the Commerce Commission.

While exempt from direct price and quality control, Electra is subject to regulatory oversight in the form of information disclosure regulation. This pricing methodology is required to be disclosed under the Commerce Commission's Information Disclosure Determination. As part of these requirements we must describe the extent to which our pricing methodology is consistent with the Electricity Authority's distribution pricing principles (see Section 10). These principles provide guidance on economic concepts and market considerations which are applicable for setting efficient network prices.

Electra must also comply with the following regulations that affect pricing:

- **The Electricity (Low Fixed Charges Tariff Options for Domestic Consumers) Regulations 2004 (LFC Regulations):** These require Electra to offer a tariff option to domestic consumers (using less than 8,000kWh per annum) that has a fixed daily tariff not exceeding 15 cents.

- **The Electricity Industry Participation Code, Part 6 - pricing of distributed generation (Part 6):** Any charges applying to distributed generation (DG) connections must not exceed the incremental costs of connecting this DG to the network, including any avoided costs.
- **The Electricity Industry Participation Code, Part 12A:** Electra must consult with retailers on any changes to pricing structures.

4.5 Network extensions policy

In addition to distribution prices, consumers are required to fully fund the cost of their own connection assets, at the time of connection. Connection assets include additional 11kV and 400V power lines and cables and transformers required to provide the electrical load and quality of supply sought by consumers. Where these assets are vested with Electra, then we will pay for ongoing maintenance and operations of the assets. We may also provide a refund to consumers where the required asset upgrade exceeds the consumer's requirements.

For the avoidance of doubt, distribution prices do not seek to recover connection costs paid for by consumers under our network extension policy. Further information on our network extension policy can be found on our website at:

http://www.electra.co.nz/docs/disclosures/network_extensions__upgrade_policy_disclosure.pdf

5 Pricing decisions

This section sets out our key pricing decisions, including our pricing objectives and strategy.

5.1 Pricing objectives

Electra's pricing objectives, which guide our pricing decisions, include:

- ***Consideration and compliance with all regulatory requirements relating to pricing:*** as discussed 4.4
- ***Transparency and simplicity for consumers and retailers:*** It is important that consumers understand how prices are set and how changes to prices impact on their electricity costs. Gaining 'buy-in' from retailers is also crucial given consumers deal primarily with their retailer, and to ensure that price signals are appropriately passed on to consumers via retail prices.
- ***Fairness between consumers and retailers:*** As a consumer owned business, fairness in pricing is particularly important. One tangible example of this is that we do not explicitly seek to differentiate between consumers based on whether they are domestic or commercial, rural or urban, but rather we focus on use of the network and the extent to which consumers' create costs for the network.
- ***Encouragement for consumers to shift load away from peak periods and to use assets efficiently:*** Electra's primary obligation is to build and maintain its network to meet the peak demands of its consumers. Any deferral of investment in network capacity is beneficial to all consumers if it can be managed without compromising service delivery. Over the longer term, we recognise the importance of the efficient use of energy and encourage behaviours that reduce peak demand. Pricing is one tool that can be used to incentivise such outcomes.
- ***Cost recovery:*** Prices must recover our costs in order for Electra to remain commercially sustainable.

5.2 2013 Pricing review

In 2013 Electra completed a detailed review of the effectiveness of our current pricing structures. As part of this review we assessed the consistency of our prices with the EA's pricing principles. We also built a cost of supply model to:

- Understand the alignment between prices and implied cost allocations; and
- Test new tariff options and structures.

The key conclusions of this review were:

- Existing prices broadly align with implied cost allocations to consumer groups.
- Existing consumer groups and tariff structures are effective in meeting Electra's pricing objectives, subject to the following refinements:
    - a new standard industrial tariff option should be split out from the current Triple Saver tariff option. This would be targeted at larger time of use (TOU) consumers using more than 40,000kWh per annum. This tariff is similar in structure to the Triple Saver tariff but with a higher fixed charge component, off-set by reduced variable charges. This better reflects the higher proportion of fixed costs incurred in providing services to this group.
    - the Triple Saver tariff should be repositioned as a mass market TOU tariff option, which will complement the eventual deployment of smart metering technology on the network.
    - peak time charges should be increased to further incentivise efficient use of existing network capacity.

The standard industrial tariff was introduced on 1 April 2013 and peak time prices have progressively been raised on 1 April 2014 and 1 April 2015.

5.3 Pricing strategy

Our pricing strategy for the next five years is to:

- Monitor and encourage uptake of the standard industrial tariff option;
- Refine pricing in response to consumer feedback and use;

- Any price increases required to meet annual target revenue requirements will be applied to peak time or anytime tariffs. This will increase the differential between peak and non-peak tariffs, in order to better signal the benefits of reducing consumption during peak periods. This helps to avoid further expenditure on network reinforcement;
- Monitor the deployment of mass-market smart meters on the network and investigate, where necessary, potential TOU tariff options that can make use of this technology. We plan to reposition the Triple Saver tariff to a mass market tariff which gives consumers more choice. As part of this we plan to:
    - Progressively increase the Triple Saver price (this commenced in the 2013/14 pricing year) to maintain relativity with other mass market options. To avoid price shocks, the Peak component of Triple Saver will need to increase by around 15% per annum (3-5% of the final retail bill) for the next two years while the Off Peak and Night components remain unchanged.
    - Encourage the larger Triple Saver consumers to move to the Standard Industrial tariff given the pricing advantages available to this group on consumers.
- Monitor the consistency of prices against cost of supply model outputs.

This strategy, largely based on our 2013 pricing review, applies at the time of publication of this methodology. However, we note that in 2015 we plan to undertake a further comprehensive review of Electra's pricing strategy to determine whether there are further refinements to our strategy that can be made. Any changes will be communicated in our next pricing methodology.

6 Target revenue

6.1 2015/16 target revenue

We determine our annual target revenue requirement from internal budgets. Our estimate of target revenue for the 2015/16 period is set out in Figure 4 alongside the 2014/15 target revenue, which is provided for comparison purposes.

Total target revenue has increased by 2%, which largely reflects increases in distribution related costs. We discuss each component briefly below.

Figure 4: Annual Target Revenue Requirement (Year Ending 31 March)

	2015/16	2014/15	Change (%)
Transmission Charges	$9.50M	$10.25M	(6.0)%
Direct Costs: Operations & Maintenance	$7.53M	$6.53M	3.4%
Indirect Costs: Administration & Overheads	$4.29M	$3.20M	14.4%
Depreciation	$8.73M	$7.57M	15.3%
Return on Investment (before tax)	$8.24M	$10.00M	(4.8%)
	$38.29M	$37.55M	2.0%

6.2 Transmission charges

The transmission component of target revenue includes the following Transpower related charges, which Electra is obliged to pay:

- *Interconnection Charges:* based on Electra's relative contribution to Regional Coincident Peak Demand (RCPD) in the Lower North Island (LNI) region of the grid;
- *Connection Charges:* for the provision of connection assets at the two GXPs from which Electra receives supply from the grid;
- *New Investment Agreement Charges:* in relation to new connection assets; and

- *Notional Avoided Cost of Transmission (ACOT):* The Mangahao Grid Exit Point (GXP) is shared with the Mangahao hydro scheme. Electra is responsible for paying all Transpower connection charges associated with the Mangahao GXP but our consumers share any avoided Transpower interconnection charges that result from the generator reducing Regional Coincident Peak Demand at this GXP. This arrangement is not a specific cost but is implicitly recognised in the connection and interconnection charges.

Transpower also calculates rental rebates and returns these to distributors over the pricing year. As these are not known at the time of setting prices, Electra estimates the rebates on an annual basis and includes this credit in the transmission revenue requirement. Any additional rental rebates received above this estimate are returned to consumers through sales discounts, whereas Electra carries the risk of any deficit.

6.3 Operating costs

Operating costs associated with providing electricity distribution services can be classified as 'direct costs', associated with maintenance and operation of the network, and 'indirect costs', associated with administration and overheads:

- *Maintenance & Operating Costs:* Forecast maintenance and operating costs are sourced from Electra's ten year Asset Management Plan (AMP) forecasts. The target revenue requirement for the forthcoming pricing year reflects the first year of this forecast.
- *Administration & Overheads:* These are costs incurred in running the distribution business activities of Electra. They comprise general management, finance, office services and other administrative costs and are sourced from budgets. They also include regulatory compliance costs and industry levies.

6.4 Capital charges

Capital charges reflect a return of the capital investment Electra has made in the network (i.e. annual depreciation) and a target return on that investment (gross of tax). These charges are derived from the total value of the distribution business assets, depreciation rates and target rates of return.

7 Consumer groups

The basis for the consumer groupings we have adopted in our 2015 pricing methodology is unchanged from last year. Our four consumer groups are:

- Small
- Medium
- Large
- Lighting.

We established these consumer groupings in our 2013 pricing review after testing our key pricing considerations, objectives and strategy (see Section 5). Consistent with the distinction identified between mass market and large commercial consumer loads (as discussed in Section 4.3.2), we have adopted a “small” group and a “large” group. Large consumers are defined as users with TOU meters using more than 40,000kWh per annum.

We considered further disaggregation of the small and large consumer groups but decided against this primarily for simplicity, because:

- The small number of large consumers, coupled with the diversity of demand and end user types within this group did not justify further disaggregation.
- Breaking up the small consumer group would have created further complexity in complying with the LFC regulations. Currently, we charge the legislated 15 cents per day fixed charge to all consumers in the small consumer group.

However, a medium consumer group is temporarily being recognised as we transition large Triple Saver consumers to the standard industrial tariff (a large consumer group). This group currently includes both small (25,000-40,000kWh per annum) and large consumers (>40,000kWh per annum). The Triple Saver tariff will move to the small consumer group when large consumers have transitioned across.

As described in Section 4.2.4, we have also identified street lighting and community lighting as a separate consumer group. This recognises that these connections use dedicated assets (i.e. streetlight circuits) and have unique demand profiles (i.e. at night).

There are no non-standard consumer groups (i.e. defined as applying to less than 4 connections) connected to the network.

8 Tariff structure

8.1 Tariff options

This section sets out the 2015 tariff options. Figure 5 provides a brief description of each of the tariff options, the estimated number of consumers to which each tariff is expected to apply, expected use, forecast revenue recovered, and average price:

Figure 5: Electra's tariff options

Tariff Group	Description	Consumer group	2015/16 Users (est.)	2015/16 kWhs (est.)	2015/16 Revenue (forecast) $000	Average Price (forecast) c/kWh	2015/16 Revenue (forecast) $/ICP
Anytime/ Paygo	A standard price for using electricity at any time of the day. Can be used in conjunction with TOU tariff options. PayGo is the alternative tariff label for Anytime consumers that are on 'pay as you go' retail tariffs.	Small	13,836	70,973,345	9,453	13.32	$685
Anytime/ Managed Saver	A price which consumers may choose for hot water heating (and for other uses) on the basis that supply is able to be interrupted in return for a lower price. Electra is able to switch off load for up to 4 hours each day under this tariff.	Small	24,092	Anytime 123,582,671 Managed Saver 52,129,954	18,242	10.38	$757
Combined (Closed)	A combination of Anytime and Managed Saver prices on a weighted average (60:40) basis. This was implemented to assist consumers who wanted to use either Thrifty or Super Thrifty tariffs, while retaining Anytime and Managed Saver options, but did not have room on their switchboard for a third meter. This option is now closed to new consumers.	Small	3,342	21,988,880	2,320	10.55	$694

Tariff Group	Description	Consumer group	2015/16 Users (est.)	2015/16 kWhs (est.)	2015/16 Revenue (forecast) $000	Average Price (forecast) c/kWh	2015/16 Revenue (forecast) $/ICP
Night/Day	For continuous electricity supply at two time of use prices: • an night time rate set for the 10 hours between 21:00 and 7:00; and • a peak-rate during the day.	Small	1,602	Night: 4,612,392 Day: 7,502,128	1,124	9.28	$701
Super Thrifty	A night rate between 23:00 and 7:00 reflecting the large amount of available capacity on the network at this time. Designed for hot water, storage heating or under floor heating loads. Anytime rates apply outside these times. This does not function as a standalone option and must be used in conjunction with another price option.	Small	651	1,007,214	9.7	NA	NA
Thrifty	As for Super Thrifty with the addition of an afternoon heating boost.	Small	2,003	3,971,210	46	NA	NA
Triple Saver	A three rate (peak, off-peak and night) TOU option currently targeted towards medium-sized commercial consumers with the ability to move load or otherwise take advantage of price signals. From 1 April 2011, Electra limited the triple saver option to new connections with annual consumption in excess of 25,000kWh. Existing consumers who have elected this tariff can continue to use it.	Medium	448	32,456,768	2,343	7.22	$5,230

Tariff Group	Description	Consumer group	2015/16 Users (est.)	2015/16 kWhs (est.)	2015/16 Revenue (forecast) $000	Average Price (forecast) c/kWh	2015/16 Revenue (forecast) $/ICP
Standard Industrial	A three rate (peak, off-peak and night) TOU option which differs from the Triple Saver tariff by higher fixed and lower variable charges. It is targeted at larger commercial consumers by rewarding those able to move load away from peak, or otherwise take advantage of price signals.	Large	223	79,981,287	4,393	5.49	$19,700
Export	For those that are generating electricity and exporting some or all of this. For monitoring purposes only.	For monitoring only	151	unknown	$0	0	0
Street Lighting	For connection and management of street lights.	Lighting	NA	3,181,130	306	9.21	NA
Community Lighting	For connection and management of community lighting (e.g. sports fields, shop verandas).	Lighting	NA	478,999	53	10.58	NA
Total			**43,154**	**401,865,978**	**38,290**	**9.53**	**$879**

All tariff groups are charged a variable tariff and a fixed daily charge. Fixed and variable tariffs are separated between distribution and transmission components, which seek to recover distribution and transmission costs, respectively.

Specific tariffs in both the small, medium and large consumer groups incorporate signals which incentivise consumers to move their consumption off-peak and to offer up interruptible load. This aligns our pricing incentives to the key capacity utilisation cost driver and our GXP capacity constraints.

Each tariff option has been specified to achieve certain objectives. However, we are reliant on electricity retailers to fairly reflect our prices in their retail tariffs.

8.1.1 Variable charges

A variable tariff based on kWh consumption is applied to all tariff groups. While a charge based on each consumer's relative share of coincident maximum demand would align more closely with the utilisation of network capacity, a consumption charge is preferred because:

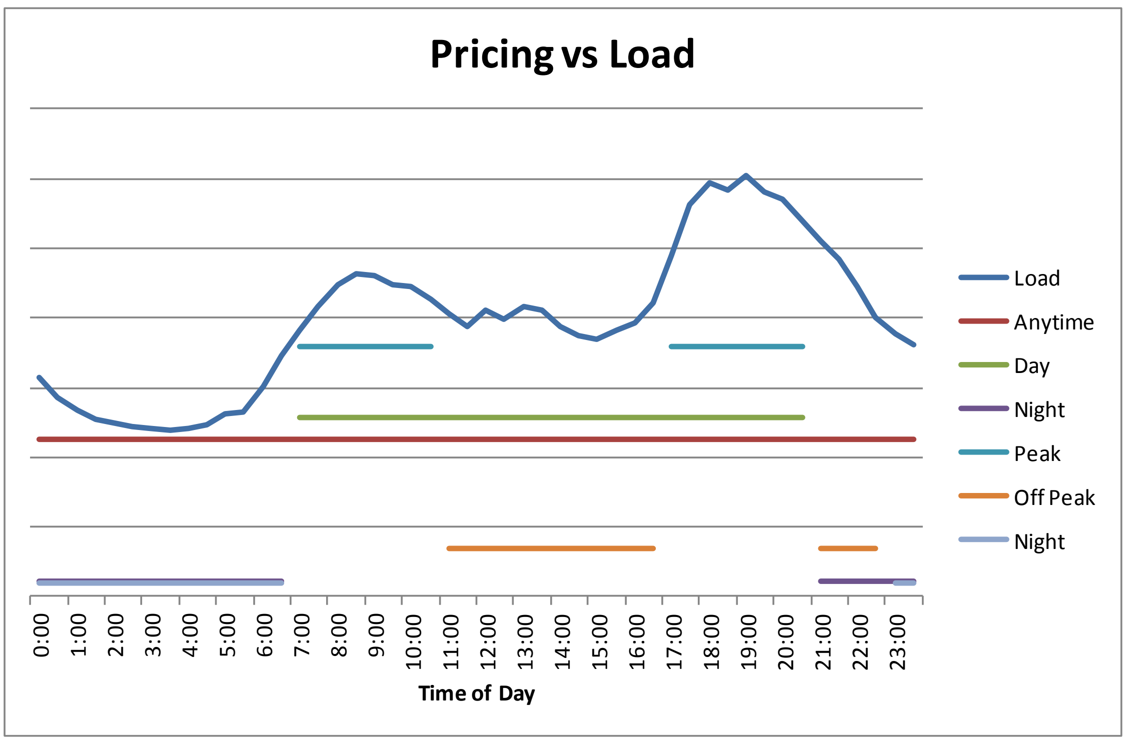
- there is a lack of ubiquitous half-hourly TOU metering across the small consumer group;
- it aligns with existing retail pricing structures, which are predominantly based on volumetric charges; and
- it aligns with the LFC regulations.

Despite this, several of our tariff options are designed to incentivise efficient use of our existing network capacity by setting higher variable prices at peak periods and lower prices during the shoulders and off peak periods. Moreover our Triple Saver TOU tariff will be available within the next two years to be utilised by retailers for any small consumer with a smart meter. Figure 6 illustrates our TOU tariff options and TOU periods. Figure 7 illustrates how these pricing periods align to our typical daily load profile.

Figure 6:*TOU tariff options*

TOU Tariff	TOU Periods
Super Thrifty	• Off-peak rate from 2300-0700 • Other times charged at the Managed Saver or Combined rates
Thrifty	• Off-peak rate from 2300-0700 • Boost from 1300-1600 • Other times charged at the Managed Saver or Combined rates
Night/Day	• Night rate from 2100-0700 • Day rate from 0700-2100
Triple Saver and Standard Industrial	• Night rate from 2300-0700 • Peak rate from 0700-1100 & 1700-2100 • Off-peak rates from 1100-1700 and 2100-2300

Figure 7: ***TOU periods and typical daily load profile (illustrative)***



Controlled load tariffs are also offered, such as the Managed Saver or Combined tariffs. These allow us to disconnect load for up to four hours a day, typically during times of network congestion or in order to allow us to restore network faults.

A variable charge is levied on street lighting and community lighting consumers. This recognises network capacity use as well as the use of dedicated assets such as street lighting circuits and poles.

Other consumers are charged the Anytime tariff (often in combination with controlled load tariff options). Anytime consumers account for 86% of connections and almost 50% of consumption. The Anytime tariff is the highest variable tariff which recognises that these consumers are able to use the network at any time without constraint.

8.1.2 Fixed charges

A fixed daily charge is applied to all consumers. We consider that a fixed charge appropriately recognises:

- investments in existing network capacity;
- ‘per connection’ cost drivers;
- our need for revenue stability; and
- the LFC regulations.

Given the majority of our consumers are domestic consumers which are eligible for the low fixed charge option, we opted to apply the 15 cent per day fixed charge to all small and medium consumers.

A fixed daily charge of 90 cents is included in the Standard Industrial tariff. This charge better reflects the fixed costs attributable to these consumers.

8.1.3 Transmission charges

Electra on-charges Transpower’s charges on a cost-recovery basis. Fixed and variable transmission tariffs are set to recover transmission costs using forecasts of consumption and connections. This accommodates the different charges relating to off peak and peak pricing.

Any over-recovery of transmission charges is returned to consumers through the sales discount. Any under-recovery is borne by Electra.

A 10 cent supply charge for transmission services is applied to all consumers, except Standard Industrial who are charged 20 cents per day.

8.1.4 Power factor charges

We reserve the option to apply an additional charge where a commercial consumer has a power factor materially below 0.95 lagging. The charge will be based on a multiplier of 2% of the monthly total network charges for every 0.01 power factor below 0.95 lagging. This charge allows us to signal the need for improvements in power factors with the ultimate goal of avoiding unnecessary network reinforcement.

8.2 Non-standard pricing

We currently do not have any non-standard pricing arrangements. We will assess any requests for non-standard pricing as required.

8.3 Distributed generation (DG)

Electra has 151 DG sites connected to its network (0.004% of connections). All but two of these are small sites (less than 5kW) supplying at 400V. We use standard charging for import meters and do not charge for distributing exported energy. We have introduced an export tariff which would potentially enable us to do this. Currently, it is set at zero cents per kWh. This has been introduced to help us monitor uptake of DG on the network.

We currently do not make direct payments to DG for ACOT. Avoided costs are recognised by not charging generators for injection into the network. We believe this approach is consistent with the incremental cost pricing principle under Part 6 of the Electricity Industry Participation Code.

The Mangahao power station near Shannon is notionally embedded for transmission purposes, but is not connected to our network and does not use distribution services. We are responsible for paying all connection charges associated with the Mangahao GXP but our consumers share in the avoided Transpower charges that result from the generator reducing peak grid demand at this GXP. ACOT is therefore implicitly recognised in this arrangement.

8.4 Discount

Electra has previously credited consumers with a discount each year on a discretionary basis. In 2015/16 we have posted this discount in our pricing schedule so that consumers have greater transparency and certainty over their total net electricity costs.

The sales discount will be credited to the consumer connected to each metered supply point (ICP) on 31 January 2016. The value of the discount will be $50.00 plus 11.5% of each connection's total fixed and variable line and transmission charges for the previous twelve months.

9 2015 prices

9.1 Changes to pricing

Figure 8 sets out our prices and the proportion of the target revenue expected to be recovered from each tariff in the 2015/16 pricing year. It compares these to 2014 prices. The share of target revenue sought from each tariff is not materially different to that recovered in 2014/15

Figure 8: 2015 Total Line Charges (excluding GST)

Tariff option	units	Time period	From 1 April 2015 (c/unit)	% 2015/16 revenue (Forecast)	1 April 2014 to 31 March 2015 (c/unit)	% 2014/15 revenue (Actual)	2015 price change
Anytime/Paygo	**kWh**		12.29	62.4%	11.88	62.6%	+3.45%
Managed Saver	**kWh**		3.42	4.7%	3.42	5.0%	NC
Combined	**kWh**		9.75	5.6%	9.28	5.7%	+5.06%
Night/Day	**kWh**	**Night**	1.11	0.1%	1.11	0.1%	NC
	kWh	**Day**	13.17	2.6%	12.51	2.5%	+5.28%
Super Thrifty	**kWh**		0.96	0.0%	0.96	0.0%	NC
Thrifty	**kWh**		1.15	0.1%	1.15	0.1%	NC
Street lighting	**kWh**		9.62	0.8%	9.21	0.8%	+4.45%
Community Lighting	**kWh**		11.10	0.1%	10.58	0.1%	+4.91%
Triple Saver - LFC[1]	**kWh**	**Night**	0.96	0.2%	0.96	0.3%	NC
	kWh	**Off Peak**	2.37	0.7%	2.37	1.0%	NC
	kWh	**Peak**	15.01	5.2%	13.52	5.1%	+11.02%
Standard Industrial[1]	**kWh**	**Night**	0.91	0.5%	0.91	0.4%	NC
	kWh	**Off Peak**	2.29	1.8%	2.29	1.5%	NC
	kWh	**Peak**	11.51	9.0%	11.4	8.0%	+0.96%
Supply charge	**ICP**		0.150	6.0%	0.150	6.1%	NC
Supply charge (SI)	**ICP**		0.90	0.2%	0.80	0.5%	+12.50%

Note:

1 – revenue based on estimated uptake of the new Standard Industrial tariff option.

2 – prices effective 1 April 2015

3 – please refer to Appendix on page 39 for full pricing schedule

The key decisions underlying our 2015 prices are:

- Maintain existing pricing structures, with the exception of a new zero charged export price;
- Maintain the 15 cent fixed daily charge for all small and medium consumer groups, compliant with the LFC regulations;
- Increase Standard Industrial fixed daily charge by 10 cents per day to better incentivise uptake of this tariff option;
- Increase Anytime, peak, day, street lighting and community lighting variable tariffs to recover the distribution and transmission target revenue not expected to be recovered through fixed charges;
- Incentivise more efficient use of network capacity during periods of network congestion by:
    - increasing Peak and Day use tariffs on the Combined Triple Saver, Standard Industrial and Day/Night tariff options;
    - maintaining off-peak and night use tariffs on the Triple Saver, Standard Industrial and Day/Night tariff options; and
    - maintaining the Thrifty and Super Thrifty tariffs.
- Encourage consumers to offer more controllable load by maintaining Managed Saver while increasing the Anytime tariff; and
- Test the resulting expected tariff revenues for each consumer group against cost of supply model outputs.

9.2 Price increases for average consumers

The table below shows how the average consumer in each consumer group is affected by our 2015 price changes.

Figure 9: Impact on average consumer (total line charges)

Tariff Category	Average Annual consumption (kWh)	2015/16 annual lines charges	2014/15 annual lines charges	$ Annual Change	% Annual Change
Anytime only/Paygo	5,130	$685	$664	+$21.03	+3.2%
Anytime/Managed Saver	7,293	$757	$737	+$20.20	+2.7%
Triple Saver	72,448	$4,894	$4,495	+$399.41	+8.9%
Standard Industrial	358,660	$19,490	$19,308	+$182.47	+0.9%
Street Lighting (70W fitting) and Community Lighting	356	$34	$33	+$1.40	+4.3%

Notes:

1. The Anytime/Managed Saver combination is based on the Electricity Authority standard comparison for those consumers with electric water heating. Approximately 55% of Electra's consumers use this option.
2. Average annual consumption figures based on Electra analysis
3. Annual consumption is split between peak, off-peak, and night for the Standard Industrial and Triple Saver tariffs in line with the average across these consumers.

9.3 Testing of prices against cost allocations

In 2012 we developed a cost of supply model which allocates target revenue to consumer groups and tariffs, based on cost allocators which reflect network cost drivers. The outputs of this model inform our pricing decisions, however the model does not explicitly set tariffs. Rather the model:

- tests whether prices are consistent with implied cost allocations to consumer groups and tariffs;

- tests whether there are cost differences between small and large consumer groups; and
- tests alternative approaches to setting fixed and variable charges.

This year we have compared the model outputs against expected revenue to be recovered from each consumer group to determine to what extent prices align with implied allocations of target revenue.

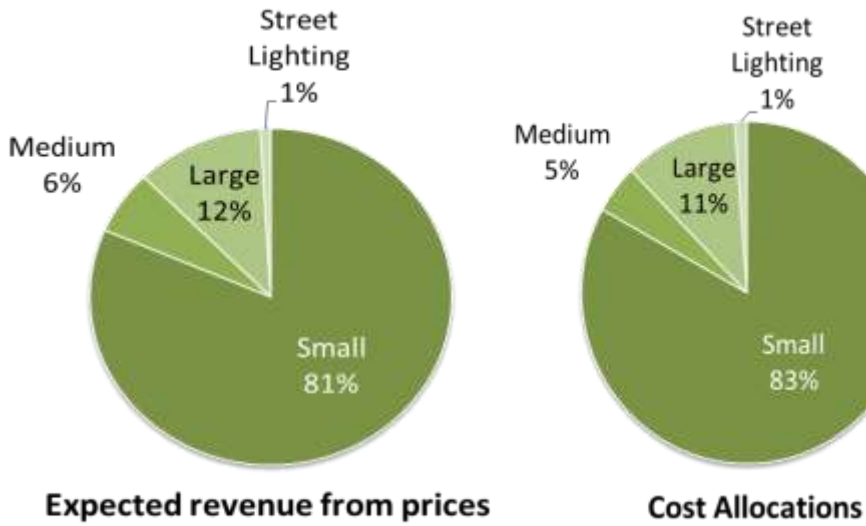
The model allocates the various components of target revenue using cost allocators that are consistent with our cost drivers, as follows:

Figure 10: Allocators applied in cost allocation model

Cost category	Cost allocator	Rationale
Return on investment, network depreciation, direct costs, rates	A composite allocator is created by allocating regulatory asset base values to consumer groups as follows: • Connection assets: ICPs • Streetlight assets: directly attributed to streetlight lighting • All other assets: Coincident maximum demand	The main cost driver for core network assets is utilisation of installed capacity weighted by the value of that capacity. Streetlight assets are directly attributable to the lighting consumer group, whereas connection assets are associated with number of connections.
Transmission costs	Coincident maximum demand	This recognises that Transpower charges are based on providing supply capacity, determined by the capacity of the GXP and core grid assets.
Indirect costs, depreciation on non-system fixed assets	A 50:50 weighting of ICPs and kWhs	This weighting recognises that larger consumers create relatively higher costs per connection.

Figure 11 compares the proportion of revenue expected to be recovered from each consumer group relative to implied cost allocations.

Figure 11: Cost allocations and revenues



Prices for the small consumer group could increase slightly to recover costs allocated to this group, whereas the medium and large consumer groups could reduce slightly. These refinements are relatively insignificant and we are satisfied that prices broadly align with costs. In reaching this conclusion, we note that cost of supply model outputs will vary year on year in response to changes in inputs. Explicitly aligning prices to the cost of supply model therefore can result in price volatility.

10 Consistency with the Electricity Authority's pricing principles

This section describes the extent to which our pricing methodology is consistent with the Electricity Authority's pricing principles.

(a) Prices are to signal the economic costs of service provision by:

(i) being subsidy free, that is, equal to or greater than the incremental costs and being less or equal to standalone costs, except where subsidies arise from compliance with legislation and/or other regulation

This principle sets out that prices are subsidy free where they fall within the range of incremental cost and stand alone cost, as illustrated by the following equation.

Incremental Cost ≤ Prices ≤ Stand Alone Cost

Incremental Cost

We interpret 'incremental cost' to mean the additional cost incurred in connecting one more consumer to the network. This is likely to comprise connection costs, any costs associated with reinforcing the network in relation to that connection, as well as additional administration, operating and maintenance costs.

As already discussed, we ensure prices are greater than incremental capital costs through our network extensions policy. Accordingly, distribution prices will exceed incremental asset costs.

Other incremental costs (e.g. operating and maintenance) resulting from a new connection are recovered through distribution prices. As highlighted in the previous section, our cost of supply modelling reveals that costs are being apportioned broadly consistent with implied cost allocations based on the cost drivers we have identified. As such, we would not expect prices to exceed incremental operating costs.

However, our analysis suggests that on average over the last ten years a new connection contributed to a $193 per annum real increase in operating expenditure. We note a new Anytime consumer would need to consume only 1,100kWh in a year for prices to fall below incremental cost (i.e. based on the 15 cent per day fixed charge and existing Anytime prices). Such low levels of consumption are unusual, suggesting prices are unlikely to fall below incremental cost. This also highlights that the 15 cent per day fixed charge at very low levels of consumption is likely to create cross-subsidisation. The option of a higher fixed charge for the Standard Industrial tariff goes some way to resolve this issue for larger connections.

Stand alone cost

We interpret 'stand alone cost' to mean the cost to provide similar distribution services to a consumer (or group of consumers) on a stand-alone basis, either from a stand alone network or alternative energy supply.

In practice, it is difficult to estimate the costs associated with a hypothetical stand alone network that would be required to service one consumer group. However, at a conceptual level, we would expect to apply the same network configuration in order to supply each sub-group of consumers on a stand-alone basis. This is because our consumers are generally uniformly spread across our relatively compact and meshed network. While the engineered capacities of standalone networks could be optimised for smaller consumer groups, we would not expect this to offset the loss of scale efficiencies that result.

The fact that expected revenue recovered from consumer groups aligns to implied cost allocations provides further evidence that prices are unlikely to exceed stand alone costs. This is an expected outcome where cost allocators are linked to key cost driver relationships (i.e. utilisation of demand and new connections) and where dedicated assets are assigned directly to consumer groups that use those assets (i.e. street light circuits and connections).

Improvements in PV and battery storage mean it is also now possible for small consumers to disconnect from the network (albeit with a lower security of supply). However, such solutions do not appear to be economic when compared to distribution based supply. A relatively small 8kWh/day stand alone system can cost in excess of $50,000 to install, excluding maintenance and regular battery replacement costs. Larger systems cost much more. Our analysis suggests that the stand alone cost of off-grid solar solutions, in ideal circumstances, is in excess of 80c - 1.60c/kWh[1]. This

[1] Assumes replacement of batteries every 10 years; 50%-100% usage of the 8kWh capacity each day over a 25 year period, and funding based on a mortgage rate of 6%.

significantly exceeds the average 7-13c/kWh charge Electra's consumers pay (see figure 5), as well as the average final delivered price residential consumers pay on Electra's network of 26.3c/kWh[2]. Despite this, we are monitoring uptake of solar closely, given the rapidly falling technology costs and consumer interest expressed in consumer surveys.

Rural/urban cross-subsidy

A cross subsidy could potentially arise from not explicitly recognising circuit length as a cost driver in prices. As discussed earlier, the only discernable cross-subsidy that is likely to arise in relation to circuit length is between rural and urban consumers. While consumers in urban areas could be subsidising rural consumers due to relatively higher connection density, we do not consider disaggregating rural and urban consumers for pricing purposes is beneficial for the following reasons:

- Rural circuits, poles, and equipment are used by urban consumers as electricity may flow through sub-transmission and distribution circuits to urban centres.
- Our network area is relatively compact so rural areas are close to urban areas.
- Electra does not differentiate service quality by location. Network reliability standards are based on the aggregated load for all consumers supplied by the relevant section of the network. Fault response times are similar for rural and urban connections because all connections are located within 30 minutes drive of a depot.
- The Electricity Industry Act 2010 includes provisions for regulations to be applied to distributors that would limit price increases in rural areas.

(ii) having regard, to the extent practicable, to the level of available service capacity

We group consumers into small, medium and large consumer groups because they use service capacity differently. Lighting is also a separate consumer group in recognition of the specific demand profile of this group.

By offering differential prices for peak/off-peak and day/night loads, we reward consumers (through lower prices) that limit consumption during times of network

[2] Ministry of Business Innovation and Employment, Quarterly Survey of Domestic Electricity Prices, 15 Nov 2014

congestion. Similarly, our controlled tariff option rewards consumers that offer up interruptible load. We have recently focused on increasing the peak/day price signal to encourage consumers to move consumption to off-peak periods.

(iii) and having regard to the extent practicable, the impact of additional usage on future investment costs

It has always been our objective to use prices to signal the costs of meeting peak demand and to encourage consumers to consider the benefits of moving demand away from peak periods.

We recognise that consumption based charges provide a limited price signal regarding the impact of additional usage on future investment costs. However, higher peak time variable charges coupled with low charges during off-peak and shoulder periods (for example, under the Day/Night, Triple Saver, Standard Industrial tariffs, Thrifty and Super Thrifty tariff options) provide strong pricing signals to consumers of the long-term benefits of moving consumption away from peak periods. Furthermore, Anytime charges are relatively high recognising that those consumers are unconstrained in their use of network capacity. The controlled rate for hot water heating (under the Managed and Controlled tariff options) also rewards consumers that offer up interruptible load.

In recent years, we have increased peak charges, relative to off-peak charges, and controlled charges in order to increase the incentives to reduce peak-time demand.

(b) *Where prices based on "efficient" incremental costs would under recover allowed revenues, the shortfall is made up by prices being set in a manner that has regard to consumers' demand responsiveness, to the extent practicable.*

This principle promotes pricing based on a consumers' willingness to pay. All mass market consumers on our network are offered exactly the same tariff options and consumers select their pricing plan. We consider that the provision of a range of tariff choices aligns with competitive markets and is one of the best ways of aligning prices to consumer willingness to pay. For example, selection of time of use or controlled and uncontrolled tariffs reveals a consumer's willingness to pay relative to the quality of supply that they are willing to accept.

TOU based charges also reveal willingness to pay. For instance peak time prices incentivise consumers with a low willingness to pay to shift demand off peak.

(c) *Provided prices satisfy (a) (i), prices are responsive to the requirements and circumstances of consumers in order to* –

(i) discourage uneconomic bypass

Our current pricing methodology combined with the nature of our consumer base has not resulted in any uneconomic bypass of the network. We estimate that a constant load greater than 5MW and closer than 2km to a GXP would be required to make bypass cheaper than our existing prices. We do not have any connections which meet these criteria. At that level of load, system bypass would not only be economic but probably appropriate for the customer.

We remain open to discussing alternative pricing arrangements with large consumers that are presented with bypass opportunities.

(ii) allow negotiation to better reflect the economic value of services and enable consumers to make price/quality trade-offs or non standard arrangements for services

We have no non-standard pricing arrangements. In reality, the nature of our consumer base does not justify non-standard terms.

Requests for specific levels of service (e.g. the provision of dedicated equipment) are typically dealt with under our network extensions policy. This policy gives consumers the discretion to select the assets and hence quality of supply that meet their requirements, with incremental asset costs met by the beneficiary. We recover the cost of maintaining the asset through our normal revenue stream.

(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.

Our Managed, Thrifty, and Super Thrifty tariff options provide incentives to consumers to invest in night store equipment and controllable hot water cylinders. This effectively provides for a consumer demand response that reduces usage during times of network congestion.

DG is not charged for distribution services. This encourages connection of DG, consistent with Part 6 of the Electricity Industry Participation Code. However, we will continue to review the impact of DG uptake on the network through the Export tariff.

The GXP sharing arrangement with Mangahao hydro scheme, which is notionally embedded in our network, acknowledges this plant as a transmission alternative. In return, our consumers share in transmission cost savings arising from local generation. This contractual arrangement is an example of a transmission alternative that lowers prices to consumers.

(d) *Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the impact on stakeholders*

We have considered feedback on our 2013/14 pricing methodology as part of the Electricity Authority's review and have revised this document in order to improve the transparency of our pricing method. We also regularly review the structure of this document to improve it.

We have transitioned price increases over multiple years to avoid price shock. For example, increasing the content of Triple Saver over a number of years.

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

Our relatively simple pricing structure ensures low transaction costs for all. We have a bias toward tariff simplicity which minimises transaction costs for retailers.

All retailers operating on Electra's network pay the same prices. All consumers are able to remain on their current tariff option or choose another more suited to their needs.

11 Glossary

We have sought to present our pricing methodology using standard industry terminology and to include sufficient information to enable pricing decisions to be readily understood by consumers. This glossary is provided for the convenience of the reader.

2015/16	The year starting 1 April and ending on 31 March.
ACOT	Avoided Cost of Transmission: The difference between actual transmission costs and theoretical transmission costs if certain mitigation (e.g. Distributed Generation) is not present.
AMP	Asset Management Plan: A record of the company's plans to manage the network to provide a specified level of service.
Coincident Maximum Demand (CMD):	Relative demand (typically expressed in kWs or kVA) of a particular consumer or consumer group at the GXP system peak (i.e. as measured by system maximum demand).
Commerce Commission	Responsible for the economic regulation of electricity distribution businesses as provided for under Part 4 of the Commerce Act 1986.
Electricity Authority (EA)	Responsible for regulation of the electricity market as provided for under the Electricity Industry Act 2010.
GXP	Grid Exit Point: The point at which Electra's network is deemed to connect to Transpower's transmission network.
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 (i.e. a consumer connection point).
Information Disclosure Determination	As set out in the Commerce Commission's 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.

kWh	Kilowatt hours: Measure of real electrical power usage per hour.
Low fixed charge regulations	As set out in the Electricity (Low Fixed Tariff Option for Domestic Consumers) Regulations 2004. These require Electra to make a tariff option available for domestic consumers who have annual usage less than 8,000kWhs. Prices must be set such that the fixed daily charge does not exceed 15 cents (excl GST) and consumers should be no worse off under this tariff option at 8,000kWhs relative to other tariffs.
Power Factor	The ratio of real power (e.g. kWs) to apparent power (e.g. kVA). 0.98 is considered normal on our network.
RCPD	Regional Coincident Peak Demand: Transpower calculates its interconnection charge for each GXP by its relative share of RCPD.
Sub-transmission	A power line that transports or delivers electricity at 33kV on Electra's network.
System Maximum Demand	Aggregate peak demand for the network, being the coincident maximum sum of GXP demand and embedded generation output.
Target revenue requirement	The revenue that we estimate needs to be recovered through prices over the pricing year in order to recover Electra's costs of investing in and operating the network.
TOU	Time of Use: Refers to tariff options that rely on meters that measure consumption by time of use.
Transpower	Transpower New Zealand Limited: The owner and operator of the national electricity transmission network. Transpower delivers electricity from generators to distribution networks and large direct connect consumers around the country.

Appendix: Electra’s prices effective 1 April 2015

Electra

Electricity Network Charges Kapiti Coast and Horowhenua: Effective 1 April 2015

Electra owns and operates the electricity lines and distribution assets in the Kapiti-Horowhenua region.
Electra invoices these charges to Electricity Retailers, who then include these in your regular electricity bill.

Electra Electricity Network Charges from 1 April 2015 compared to existing prices (excluding GST)

Users (Est)	Price Code	Price Option	Price Option Component	Time Zone On	Line Function cents / unit		Transmission cents / unit		Total cents / unit	
					Existing	New	Existing	New	Existing	New
37,669	A	**Anytime / PayGo**		All	9.02	9.49	2.86	2.80	11.88	12.29
23,997	M	**Managed Saver**		As required	2.32	2.32	1.10	1.10	3.42	3.42
3,295	C	**Combined (closed)**		As required	6.93	7.47	2.35	2.28	9.28	9.75
657	N	**Super Thrifty**		2300-0700	0.75	0.75	0.21	0.21	0.96	0.96
2,123	B	**Thrifty**		2300-0700	0.94	0.94	0.21	0.21	1.15	1.15
				1300-1600	0.94	0.94	0.21	0.21	1.15	1.15
1582	DN	**Night / Day**	Night	2100-0700	0.90	0.90	0.21	0.21	1.11	1.11
	DN		Day	0700-2100	9.61	10.36	2.90	2.81	12.51	13.17
592	TS	**Triple Saver**	Night	2300-0700	0.75	0.75	0.21	0.21	0.96	0.96
	TS		Peak	0700-1100	10.62	12.28	2.90	2.73	13.52	15.01
				1700-2100	10.62	12.28	2.90	2.73	13.52	15.01
	TS		Off peak	1100-1700	1.27	1.27	1.10	1.10	2.37	2.37
				2100-2300	1.27	1.27	1.10	1.10	2.37	2.37
112	EX	**Export**		All	0.00	0.00	0.00	0.00	0.00	0.00
	U	Street Lighting		Timetable	6.34	6.83	2.87	2.79	9.21	9.62
	U	**Community Lighting**		Timetable	7.71	8.31	2.87	2.79	10.58	11.10
152	SI	**Standard Industrial**	Night	2300-0700	0.70	0.70	0.21	0.21	0.91	0.91
	SI		Peak	0700-1100	8.50	8.63	2.90	2.88	11.40	11.51
				1700-2100	8.50	8.63	2.90	2.88	11.40	11.51
	SI		Off peak	1100-1700	1.19	1.19	1.10	1.10	2.29	2.29
				2100-2300	1.19	1.19	1.10	1.10	2.29	2.29
43,391	F	**Supply Charge**		cents/day	**5.00**	**5.00**	**10.00**	**10.00**	**15.00**	**15.00**
152	S	**Supply Charge - Standard Industrial**		cents/day	**60.00**	**70.00**	**20.00**	**20.00**	**80.00**	**90.00**

Power Factor Charge
This applies to commercial consumers. Where the power factor is less than 0.95 Electra reserves the right to impose a power factor charge.
The charge will be based on a multiplier of 2% of the monthly total Network charges for every 0.01 power factor below 0.95 lagging.

Combined Option
The Combined option is no longer available except to existing users. Existing users must have electric hot water which, if required, is able to be controlled by Electra, plus either a Thrifty or Super Thrifty meter.

Triple Saver Option
The Triple saver option is only available to consumers using more than 25,000kWh per year.

Export
For those who are be generating electricity on their premises and exporting some or all of this into Electra's distribution network.

Sales Discount
A Sales Discount will be credited to the current consumer at each metered supply point (ICP) at the discount date of 31 January 2016.
The discount will be $50.00 plus 11.5% of the ICP's total fixed and variable Line and Transmission charges for the previous twelve months

	Network Losses	Loss Factor Code	Loss Factor
Network Losses	6.6%	1	1.071

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CERTIFICATION FOR YEAR-BEGINNING DISCLOSURE – PRICING METHODOLOGY

We, Ian Andrew Wilson and Neil Francis Mackay, directors of Electra Limited certify that, having made all reasonable enquiries, to the best of our knowledge that:

a) The following attached information of Electra prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respect 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

IAWilson

Ian Andrew Wilson – Director

27/3/15

Date

Neil Francis Mackay - Director

27/3/15

Date