Electricity Distribution Business Pricing Methodology for Prices Effective 1 April 2014

28 March 2014

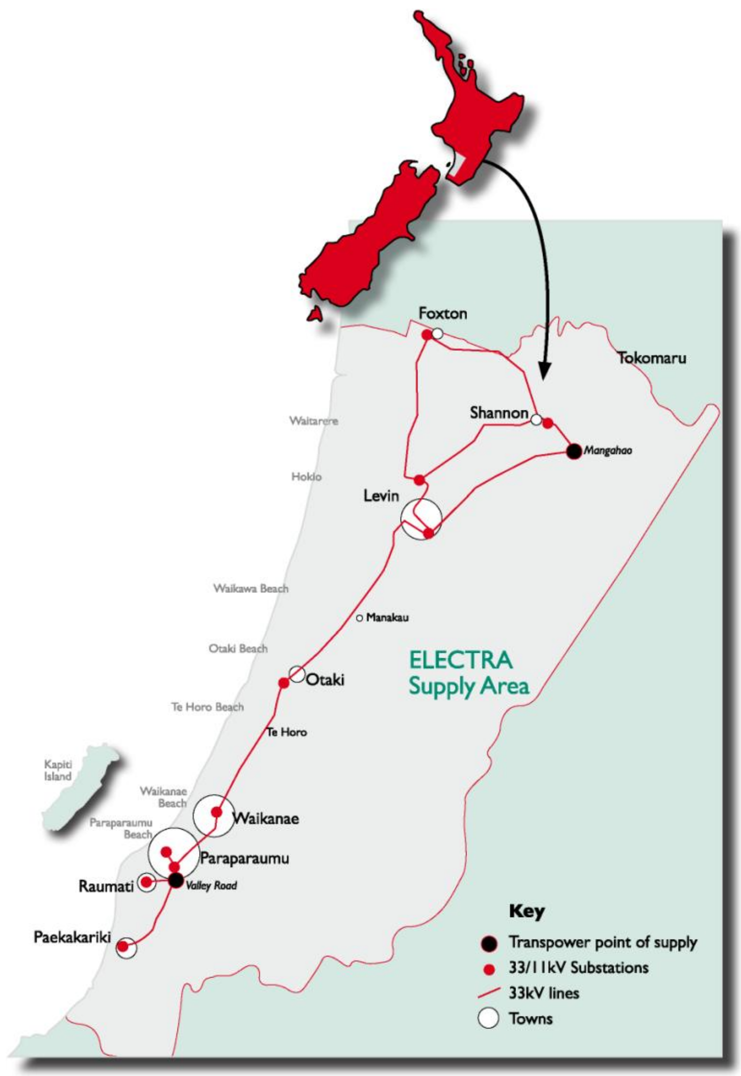
Table of Contents

1. Introduction

The purpose of this document is to describe Electra Limited's ('Electra') methodology for setting electricity distribution prices that will apply to consumers from 1 April 2014.

Electra owns and operates the electricity distribution network in the Kapiti and Horowhenua regions. This is a geographic area of around 1700 square kilometres where the network is concentrated mainly along the coast to supply a number of towns from Paekakariki to Foxton. Paraparaumu and Levin are the largest of these towns.

The towns in Kapiti have their origins as seaside resorts, and more recently as fast growing dormitory areas where a good proportion of residents travel to Wellington for work. The Horowhenua includes a number of seaside villages with holiday homes, but also includes a more developed commercial sector centred on Levin.



Electra receives electricity supply from Transpower's national transmission grid at two locations situated at either end of its network; at Valley Road in Paraparaumu and at Managahao. Electricity is then distributed to 42,651 consumers across 2,256kms of electrical circuit.

Electra is owned by the Electra Trust, which appoints Directors and holds all the shares on behalf of all those consumers connected to the network. Consumer trust ownership means that all surpluses not required for the operations and development of the core business are returned to consumers via sales discounts on their electricity accounts.

Electra's network is a 'natural monopoly', in that it is considered more economically efficient for one network to supply all consumers, due to the significant economies of scale. However, this means Electra is not directly exposed to competitive forces that drive markets to deliver improved efficiency and services. While legislators would typically seek to regulate such businesses to ensure price and quality outcomes consistent with competitive markets, consumer trust 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. In 2008, this was formally recognised when Electra was exempted from the 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 regulatory control, Electra is subject to regulatory oversight in the form of information disclosure. 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 its Electricity Authority's distribution pricing principles (see section 11).

2. Overview of approach to setting prices in 2014/15

Electra resets it prices at 1 April each year for the forthcoming pricing year. The key steps Electra takes each year to set prices can be summarised as follows:

- Existing pricing structures and levels are reviewed against our pricing objectives and strategy
- The annual target revenue requirement to be recovered from prices is determined for the pricing year based on internal budget forecasts;
- Tariffs are set to recover this target revenue requirement with consideration of:
    - our pricing objectives and strategy
    - cost drivers and cost of supply model outputs
    - consumer groups and tariff structures
    - forecast connections and consumption data
- The pricing methodology is updated to ensure that the approach to determining tariffs is transparently disclosed, consistent with the applicable regulatory requirements.

Key components of our approach are set out in more detail in the following sections of this methodology statement.

3. Electra's pricing objectives

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

- **Consideration and compliance with regulatory requirements relating to pricing, including**:
    - the low fixed charge regulations
    - Section 2.4 of the Information Disclosure Determination;
    - the EA's distribution pricing principles and information disclosure guidelines;
    - Part 6 of the Electricity Industry Participation Code on pricing distributed generation.
- ***Transparency and simplicity for consumers and retailers:*** It is important that consumers understand how prices are set and the impact of our prices 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 in retail prices.
- ***Fairness between all consumers and retailers:*** As a consumer owned business, fairness in pricing is particularly important. One tangible example of this is that, in the main, we do not differentiate between consumers based on whether they are domestic or commercial, rural or urban, but rather on usage of the network and the extent to which consumers create or benefit from costs.
- ***Encouragement for consumers to shift load away from peak periods and to use assets efficiently:*** Electra must 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 also recognise the importance of the efficient use of energy use behaviours consistent with reducing peak demand. Pricing is one tool that can be used to incentivise such outcomes.
- ***Cost recovery:*** This objective recognises that prices must recover our costs in order for Electra to remain commercially sustainable. This includes a commercially acceptable rate of return for our shareholders (commensurate with our consumer trust ownership) and to finance debt.

4. Recent changes to our pricing methodology

Figure 1 summarises the key changes we have made to our pricing methodology over the past two years.

Figure 1: Recent changes to the pricing methodology

Prices valid from:	**Summary of key changes**	**Impact on consumers**
1 April 2014	Prices reset to recover 2014/15 target revenue requirement.	Aggregate prices increased to reflect a 5.9% increase in Electra's costs.
	Peak time prices increased relative to off-peak prices to incentivise more efficient use of network capacity.	Day time and peak rates under the Night/Day, Triple Saver, and Standard Industrial tariff options increased. Off-peak and night charges unchanged.
	The content and structure of the methodology statement updated in response to feedback from EA.	The pricing methodology provides greater understanding of how we set our prices, consistent with the EA's expectations.
1 April 2013	Introduction of the Standard Industrial tariff option.	Large commercial consumers eligible to take up this option benefit from a mix of higher fixed charges and lower variable charges compared to the Triple Saver tariff.
	Prices reset to recover the 2013/14 target revenue requirement.	Prices increased to reflect a 3.11% increase in Electra's costs, resulting mainly from increases in Transpower charges.
	The content and structure of the methodology statement updated to ensure consistency with new information disclosure requirements.	The pricing methodology aligns with the Commerce Commission's disclosure requirements.

In 2013 Electra completed a detailed review of the effectiveness of its 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 was split from the current Triple Saver tariff option. This was 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 option but with a higher fixed charge component, off-set by reduced variable charges. This better recognises fixed costs incurred in providing services to this consumer group.
    - the Triple Saver tariff is to be eventually repositioned as a mass market TOU tariff option, which could in the future potentially complement any deployment of smart metering technology on the network.
    - peak time charges should increased to further incentivise efficient use of the network.

As a result, the Standard Industrial tariff was introduced on 1 April 2013 and peak time prices have progressively been raised. Further analysis is planned before on repositioning the Triple Saver tariff option as a mass market tariff.

Aside from these changes our tariff structures remain largely unchanged. Accordingly, our primary focus is on updating annual prices to recover the 2014/15 target revenue requirement.

5. Target revenue requirement

We determine our annual target revenue requirement from internal budgets. Our estimate of target revenue for the 2014/15 period is set out in Figure 2, alongside the 2013/14 target revenue requirement which is provided for comparison purposes. This shows that the 5.9% increase in target revenue is made up almost equally from increases in transmission costs ($1.06M) and distribution related costs ($1.05M). We discuss each component briefly below.

Figure 2: 2014/15 Annual Target Revenue Requirement (Year Ending 31 March)

	2014/15	2013/14	Change (%)
Transmission Charges (including ACOT)	$10.25M	$9.19M	11.5%
Direct Costs: Operational & Maintenance	$6.53M	$6.48M	0.8%
Indirect Costs: Administration / Overheads	$3.20M	$2.96M	8.1%
Depreciation	$7.57M	$7.49M	1.1%
Return on Investment (before tax)	$10.00M	$9.32M	7.3%
	$37.55M	$35.44M	5.9%

Transmission Charges

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

- *Interconnection Charges:* calculated based on Electra's relative to 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 from which Electra receives supply from the grid;
- *New Investment Agreement Charges:* in relation to new connection assets; and
- *Avoided Cost of Transmission (ACOT):* The Mangahao Grid Exit Point (GXP) is shared with the Mangahao hydro scheme. Electra is responsible for paying all connection charges associated with the Mangahao GXP but our consumers share in

the avoided Transpower interconnection charges that result from the generator reducing peak grid demand at this GXP. This arrangement 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.

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, overheads and regulatory costs:

- *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.
- *Regulatory Costs:* These costs relate to regulatory compliance and industry levies.

Capital charges

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

6. Cost drivers

We have considered the relevant drivers of costs that we are seeking to recover, in order to inform our decisions on consumer groups, tariff structures, and the level of charges. This section sets out the key cost drivers relevant to price setting. To provide context, we begin by providing an overview of the characteristics of Electra's network.

Network characteristics

Electra receives supply from the national grid from two Transpower GXPs. Transpower does not permit continuous connection between these GXPs, but load is transferred between north and south to meet operational requirements. Electra's northern area (Horowhenua) takes 33kV supply at the Mangahao GXP. The southern area (Kapiti) takes 33kV supply at the Paraparaumu GXP.

The network currently faces constraints at the two GXPs, which are both approaching maximum capacity. The Paraparaumu GXP is currently being upgraded to increase its existing capacity as part of the Transmission Gully highway project. This upgrade is expected to be cost neutral to Electra over the life of the asset. Mangahao GXP is expected to increase in capacity as part of Transpower's lifecycle replacement programme (scheduled for 2017/18). Any additional Transpower charges, as well as any 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 in Paraparaumu, Raumati, Waikanae, Levin and Otaki (see map in page 3). This feeder network supplies the 11kV distribution network that extends radially with extensive meshing in urban areas. 11kV supply is stepped down to the 400V network, which supplies all but a handful of consumers who take supply at 11kV.

The utilisation of the network is heavily weighted towards small mass market consumers (i.e. domestic and small commercial users represent approximately 98% of connections and over 80% of maximum demand). This is evidenced by the fact that Electra continues to have the lowest average use per consumer of all New Zealand electricity distribution businesses. It is partly for this reason that Electra's tariff structure is strongly focussed on the needs of the mass market.

Key cost drivers

The target revenue requirement, presented in Figure 2 above, highlights the costs associated with supplying electricity distribution services. 91% of this revenue requirement is associated with directly investing in, maintaining and operating the network, as well as receiving supply from Transpower. The remaining 9% 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.

Electra considers that the key network cost drivers in this respect are:

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

The table below highlights key statistics relevant to these cost drivers.

Figure 3: Key network statistics

Consumer numbers	42,651
Total circuit length (km)	2,256
Customer density (ICPs/km)	18.9
Zone substation installed firm capacity (MVA)	189
Maximum demand (MW)	93
Utilisation of installed firm capacity (%)	57.7
Energy conveyed (GWh)	409
Energy density (kWh/ICP)	9,592

Source: 2013 Information Disclosures

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.

Circuit length

The distance between the demand base and the GXP influences the length of lines and cables required to deliver electricity to consumers. Consumers who are further from the main supply areas create relatively higher costs for Electra.

In practice, extensive meshing of the distribution network in urban centres makes it difficult to distinguish line length for a particular consumer or group of consumers, as it is difficult to track the flow of electricity. The key distinguishing distance factor is therefore the relative length of the sub-transmission and distribution feeder network required to supply different load centres.

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 does not reflect the regional benefits that accrue to both urban and rural consumers from services provided to each other, and is 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 consumer group or tariff structure design.

Consumer connections

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

Consumer specific asset usage

Network costs that directly relate to one consumer or group of consumers should be identified and recovered from those parties where practical. This aligns recoupment of costs with the causer and 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.

We considered as part of our 2013 pricing review whether consumer specific asset usage could be better reflected in our pricing methodology. In particular, distinctions based on network regions, use of the high voltage network only, and use of dedicated equipment (i.e. transformers) were considered. We concluded that there is very little variation in asset utilisation across consumers (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 at the time of connection as part of our contributions policy, rather than through pricing. Similarly, while Electra operates two distinct networks, both the north and south networks comprise compact geographical areas with similar network and consumers characteristics. We have therefore concluded that there is very little benefit in recognising dedicated asset usage in pricing, apart from for street-lighting and community lighting.

Summary of key cost drivers applicable to pricing

The key cost drivers recognised in our pricing methodology are:

- Usage of network capacity;
- New or upgraded connections; and
- Usage of dedicated street light or community lighting assets.

7. Consumer groupings

This section sets out the basis for the consumer groupings we have adopted in our 2014/15 pricing methodology. We confirmed our consumer groupings our 2013 pricing review by considering our pricing objectives, the cost drivers identified above, and the EA pricing principles.

As discussed above, small mass market consumers comprise the vast majority of the connections on our network and account for much of the peak demand. These consumers have a range of end-use types, although they can be defined as mainly residential and small business consumers. Connections are low voltage, typically 60 Amp single phase or 20 Amp three phase, and use non-time of use meters. This limits our ability to charge based on demand profiles. Despite this, our analysis suggests these consumers have a typical residential demand profile which peaks in the morning and early evenings.

We also have several hundred larger consumers. These consumers are typically commercial, have TOU metering, and have annual consumption between 40,000kWh to 3MWh. They have a range of 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.

Noting this distinction, we have adopted a “small” mass-market group and a “large” consumer group. Large consumers are defined as users with TOU meters using more than 40,000kWh per annum.

We considered further disaggregation of these consumer groups but decided against this primarily for simplicity reasons, 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 low fixed charge regulations (LFC). Currently, we charge the legislated 15 cent per day low fixed charge to all consumers in the small load group.

We note there currently exists an overlap in one tariff category, between the small and large consumer groups. The Triple Saver tariff, open to TOU consumers using more than

25,000kWh per annum, currently has consumers that are in the small consumer group (less than 40,000 kWh) and others in the large consumer group. This means there currently exists a medium consumer group that uses more than 25,000kWh and uses TOU meters.

Looking forward, we anticipate that the existing Triple Saver tariff will become a mass market TOU tariff for consumers with smart meters (see p29) and therefore fall into the small consumer group. Until such time, we have adopted a medium consumer group which comprises those consumers on the current Triple Saver tariff.

As identified above, we have also identified street lighting and community lighting as a separate consumer group. This is because they utilise dedicated assets (i.e. streetlight circuits) and have defined demand usage profiles (i.e. at night).

In summary, we have adopted four consumer groups for our 2014/15 pricing:

- Small
- Medium
- Large
- Street lighting.

8. Tariff options

This section sets out the 2014/15 tariff options. Figure 4 provides a brief description of each of the tariff options, the estimated number of consumers, expected use, forecast revenue recovered, and average price from each:

Figure 4: Tariff options offered by Electra

Tariff Group	Description	Consumer group	2014/15 Users (est.)	2014/15 kWhs (est.)	2014/15 Revenue (forecast)	Average Price (forecast) c/kWh	2014/15 Revenue (forecast) $/ICP
Anytime/ Paygo	A standard price for using electricity at any time of the day. Can be used in conjunction with other TOU tariff options. PayGo is the alternative tariff label for Anytime consumers that are on pay as you go retail tariffs.	Small	13,836	72,777,000	$9,256,436	12.72	$669.01
Anytime/ Managed Saver	A price which consumers may choose for hot water heating (and for other uses) on the basis that they accept interruptible supply in return for a lower price. Electra is able to switch off the load for up to 4 hours each day.	Small	24,092	Anytime 127,025,000 Managed Saver 54,959,000	$18,245,152	10.03	$757.31
Combined	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	23,376,000	$2,347,320	10.04	$702.37

Tariff Group	Description	Consumer group	2014/15 Users (est.)	2014/15 kWhs (est.)	2014/15 Revenue (forecast)	Average Price (forecast) c/kWh	2014/15 Revenue (forecast) $/ICP
Night/Day	For continuous electricity supply at two time of use prices: • a lower off-peak rate set for the 10 hours between 9pm and 7am; and • a higher peak-rate during the day.	Small	1,602	Night: 4,643,000 Day: 7,705,000	$1,099,892	8.91	$686.57
Super Thrifty	A night rate between 11pm and 7am 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.	Small	651	1,703,000	$16,349		
Thrifty	As for Super Thrifty with the addition of an afternoon heating boost.	Small	2,003	4,085,000	$46,978		
Triple Saver	A three rate (peak, off-peak and night) TOU option for medium to large commercial consumers with the ability to either move load or otherwise take advantage of price signals. As from 1 April 2011, Electra limited the triple saver option to those consumers with annual consumption in excess of 25,000kWh for new connections. Existing consumers who have elected this tariff can continue to use it.	Medium	448	40,506,000	$2,446,244	6.04	$5460.37

Tariff Group	Description	Consumer group	2014/15 Users (est.)	2014/15 kWhs (est.)	2014/15 Revenue (forecast)	Average Price (forecast) c/kWh	2014/15 Revenue (forecast) $/ICP
Standard Industrial	A new three rate (peak, off-peak and night) TOU option differentiated from Triple Saver by higher fixed and lower variable charge components. It is targeted at larger commercial consumers and still rewards the ability to either move load away from peak, or otherwise take advantage of price signals. This tariff is available from 1 April 2013. As it will advantage larger electricity users it is expected that many will migrate from Triple Saver to take advantage of the benefits that it offers.	Large	223	68,663,000	$3,812,222	5.55	$17,095.07
Street Lighting	For connection and management of street lights.	Lighting	-	3,168,000	$291,700	9.20	
Community Lighting	For connection and management of community lighting (e.g. sports fields, shop verandas)	Lighting	-	486,000	$51,090	10.51	
Total			**43,167**	**409,093,000**	**$37,555,056**	**9.18**	**$862.37**

All tariff groups are charged a variable tariff levied on kWh consumption 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 have been developed to incorporate signals to 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 the known GXP capacity constraints.

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

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 cost-driver, a consumption charge is preferred:

- due to the lack of ubiquitous half-hourly TOU metering across the small consumer group;
- to align with existing retail pricing structures, which are predominantly based on volumetric charges; and
- to align with the low fixed charge regulations, which essentially require distributors to offer a fixed and volumetric tariff option in order to show compliance.

Despite this, many of our tariff options are designed to incentivise off-peak usage by setting higher variable prices at peak periods and lower prices during the shoulders and off peak periods. We believe this provides a reasonable proxy for a maximum demand charge by aligning higher prices to periods of network constraints (see figure 6).

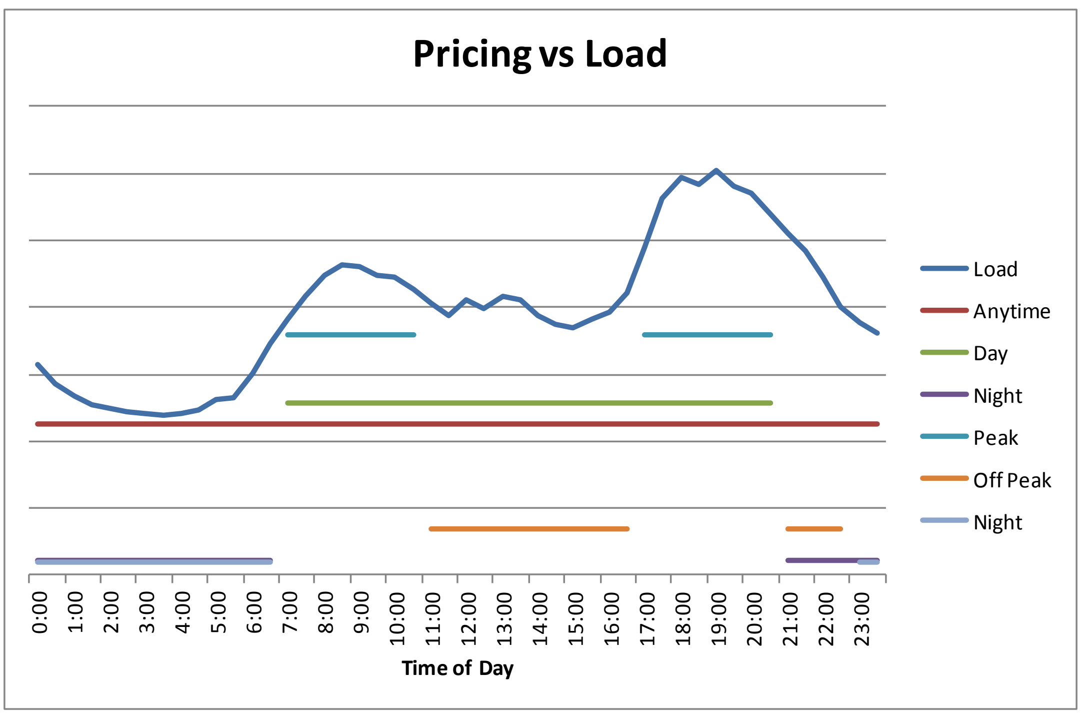
Figure 5 sets out the various TOU tariff options and TOU periods.

Figure 5:*TOU tariff options*

TOU Tariff Group	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	• Off-peak rate from 2100-0700 • Peak 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 6 provides an example of Electra's typical peak-demand-day profile and associated pricing periods.

Figure 6: *Typical TOU periods relative to typical peak-demand-day profile (illustrative)*



Controlled load tariff options are also offered, such as the Managed Saver or Combined tariff. These permit Electra to disconnect load for up to four hours a day, typically either during times of network congestion or in order to facilitate timely restoration of network faults.

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

All other consumers are charged based on the Anytime tariff (often in combination with controlled load tariff options). Anytime consumers account for 33% of ICPs and over 50% of consumption. They are charged the highest average variable tariff to recognise their ability to use network capacity at any time without constraint.

Fixed charge

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

- investments in existing network capacity, which is a fixed cost;
- ‘per connection’ cost drivers;
- our need for revenue stability; and
- a fixed charge is required to comply with low fixed charge regulations.

Given the majority of our consumers are domestic consumers covered by the low fixed charge regulations, we opted to apply the 15 cent per day low fixed charge to all small and medium consumer groups.

A separate fixed daily charge was applied to the Standard Industrial tariff upon its introduction. A fixed daily charge of 80 cents per day is now applied to this group. This charge seeks to better align fixed charges for large consumers with the fixed costs attributable to these consumers.

Transmission charges

Electra on-charges Transpower’s charges to electricity retailers on a cost-recovery basis plus a small administration charge. Fixed and variable transmission tariffs are set to recover transmission costs using forecasts of consumption and connections. This calculation accommodates different variable (kWh) 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 us.

A 10 cent per day and 20 cent per day transmission charge is applied in the Low Fixed Charge and Standard Industrial charge, respectively.

Power factor charge

We reserve the option to apply an additional charge in the situation 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 that the consumer needs to improve its power factor with the ultimate goal of avoiding unnecessary network reinforcement.

Distributed Generation

Electra has less than 40 distributed generation sites connected to its network (0.1% of connections). All but two of these are small sites (less than 5kW) supplying at 400V. We use standard charging for the import meters and do not charge for distributing any energy exported.

We currently do not make direct payments to distributed generation in relation to ACOT. Avoided costs are recognised in our decision not to charge these generators for injection into the network. We believe this approach is consistent with the requirements of schedule 6.4 of Part 6 of the Electricity Industry Participation Code, which requires distributors to price distributed generation at no more than incremental cost, taking into account any avoided costs.

As discussed above, 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.

Non-Standard pricing

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

9. 2014 Prices

Figure 7 sets out our 2014 prices and the proportion of the target revenue requirement expected from each tariff category in the 2014/15 pricing year. It compares these to 2013 prices. The proportion of the target revenue requirement sought from each tariff has not materially changed from that recovered in 2013/14.

Figure 7: 2014 Combined Unit Prices (excluding GST)

Tariff option	units	Time period	From 1 April 2014 (c/unit)	% 2014/15 revenue (Forecast)	1 April 2013 to 31 March 2014 (c/unit)	% 2013/14 revenue (Actual)	2014/15 price increase
Anytime/Paygo	**kWh**		11.88	62.6%	11.18	62.4%	+6.26%
Managed Saver	**kWh**		3.42	5.0%	3.42	5.3%	NC
Combined	**kWh**		9.28	5.7%	8.66	5.7%	+7.16
Night/Day	**kWh**	**Night**	1.11	0.1%	1.11	0.2%	NC
	kWh	**Day**	12.51	2.5%	11.72	2.5%	+6.74%
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**		9.21	0.8%	8.52	0.8%	+8.10%
Community Lighting	**kWh**		10.58	0.1%	9.85	0.2%	+7.41%
Triple Saver - LFC[1]	**kWh**	**Night**	0.96	0.3%	0.96	0.3%	NC
	kWh	**Off Peak**	2.37	1.0%	2.37	1.0%	NC
	kWh	**Peak**	13.52	5.1%	11.98	4.8%	+12.85%
Standard Industrial[1]	**kWh**	**Night**	0.91	0.4%	0.91	0.5%	NC
	kWh	**Off Peak**	2.29	1.5%	2.29	1.7%	NC
	kWh	**Peak**	11.4	8.0%	10.79	7.7%	+5.65%
Supply charge	**ICP**		0.150	6.1%	0.15	6.5%	NC
Supply charge (SI)	**ICP**		0.80	0.5%	0.70	0.5%	+14.29%

Note:

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

2 – prices effective 1 April to 31 March in year beginning 2014

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

The key decisions made in determining 2014/15 tariffs are summarised below:

- Maintain existing pricing structures, consistent with outcome of 2013 pricing review;
- Maintain the 15 cent fixed daily charge for all small and medium consumer groups to comply with the low fixed charge regulations;
- Increase the fixed daily distribution charge for Standard Industrial tariff to 50 cents per day and reduce the variable charge in order to better reflect fixed costs associated with this consumer group and to incentivise further uptake of this tariff option;
- Incentivise more efficient use of network capacity during periods of network congestion by:
  - increasing peak and day tariffs on the Triple Saver, Standard Industrial and Day/Night tariffs;
  - maintaining off-peak and night tariffs on the Triple Saver, Standard Industrial and Day/Night tariffs; and
  - maintaining Thrifty and Super Thrifty tariffs.
- Encourage consumers to offer more controllable load by maintaining Managed Saver tariffs relative to Anytime tariff;
- Increase Anytime, peak, day, street lighting and community lighting variable tariffs to recover the remaining distribution and transmission target revenue requirement not already recovered through fixed charges based on consumption forecasts; and
- Test the resulting tariff revenues for each consumer group against cost of supply model outputs.

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 appropriate cost allocators derived from network cost drivers. The outputs of this model helped inform our pricing decisions, including our decisions on consumer groups and tariff setting. However, the model is not applied explicitly to set tariffs. Rather it was used to:

- test whether prices are consistent with implied cost allocations of costs to consumer groups and tariffs;
- test whether there is a definable cost difference between small and large consumer groups; and
- test alternative approaches to setting fixed and variable charges, which may better encourage efficient usage during peak periods.

This year we have updated the model to determine whether the expected revenue to be recovered from each consumer groups in 2014/15 aligns with allocations of target revenue requirement to those groups.

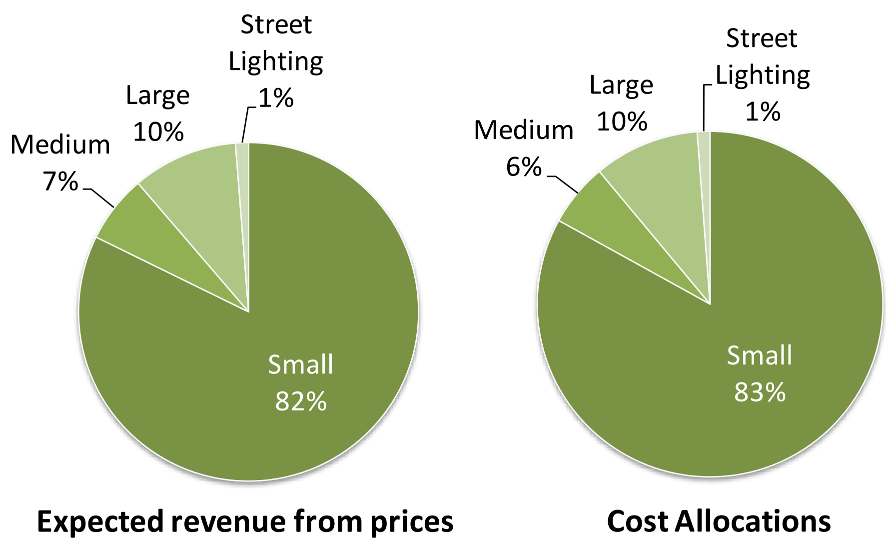
The model allocates the various cost components of the target revenue requirement using cost allocators that are consistent with the cost drivers identified above:

Figure 8: 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 RAB 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 connections assets are determined by relative number of connections.
Transmission Costs	Coincident maximum demand	Recognises that Transpower charges are based on providing a level of 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 reflects that larger consumers create relatively higher costs per connection.

Figure 9 compares the proportion of revenue expected to be recovered from each consumer group from 2014 prices relative to implied cost allocations. Prices for the small consumer group could increase slightly to recover the full costs associated with this group, whereas Triple Saver prices (i.e. medium consumer group) could reduce slightly. However, these refinements are relatively insignificant and we are satisfied that prices broadly align with costs. In drawing this conclusion, we note that cost of supply model outputs will vary year on year in response to changes in inputs and that explicitly aligning prices to the model can create price volatility.

Figure 9: Preliminary cost allocations versus revenues



Price increases for average consumers

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

Figure 10: Impact on average consumer

Tariff category	**Average Annual consumption (kWh)**	**2014/15 annual lines charges**	**2013/14 annual lines charges**	**Change**	**Change**
Anytime only/Paygo	5,260	$669.01	$631.74	+$37.27	+5.90%
Anytime/Managed Saver	7,553	$757.31	$722.83	+$34.60	+4.77%
Triple Saver	60,000	$3641.43	$3,312.79	+$328.64	+9.92%
Standard Industrial	300,000	$16,659.10	$15,915.55	+$743.55	+4.67%
Street Lighting (70W fitting) and Community Lighting	356	$32.81	$31.10	+$1.71	+5.5%

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.

10. Pricing strategy

Since completing our 2013 review, our pricing strategy for the next five years will:

- Monitor and encourage uptake of the Standard Industrial tariff option and refine pricing in response to consumer feedback and usage behaviours;
- Apply any price increases required to meet annual target revenue requirement mainly to peak tariffs. This will increase the differential between peak and non-peak tariffs to signal the benefits of reductions in consumption during peak periods to help avoid further expenditure on network reinforcement.;
- Monitor deployment of mass-market smart meters on the network and investigate, where necessary, potential TOU tariff options that can make use of this technology.
- Our first move in this area is to reposition the Triple Saver tariff to a mass market tariff giving consumers more choice. In order to maintain relativity with other mass market options Triple Saver price will need to increase commencing in the 2014/15 pricing year. To avoid price shocks the price for the Peak component of Triple Saver will need to increase by around 15% per annum for the next two years while the Off Peak and Night components remain unchanged. Existing Triple Saver consumers will be encouraged to move either to the Standard Industrial tariff if they are large enough or to another mass market tariff if it is of benefit.
- Monitor the consistency of prices against cost of supply model outputs (as discussed above).

11. Consistency with the Electricity Authority's pricing principles

This section describes the extent to which our pricing methodology is consistent with the EA'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, operations and maintenance costs.

As already discussed, we ensure prices are greater than incremental capital costs outside of distribution prices, as part of its network extensions policy[1]. Under this policy, consumers pay for their connection assets, including additional 11kV and 400V power lines/cables and transformers required to meet required electrical load and quality of supply standards. Where these assets are vested with Electra, then we will pay for ongoing maintenance and operations of the assets. We will also give a refund to consumers where the required asset upgrade is excessive for the particular connection. Accordingly, distribution prices will typically always be in addition to incremental asset costs.

Other incremental costs (e.g. operations 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

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

consistent with implied cost allocations based on appropriate cost drivers. 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 $186 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). At this low level of consumption prices are unlikely to fall below incremental cost. It also highlights that the application of the 15 cent per day low fixed charge at very low levels of consumption is likely to create cross-subsidisation. The option of a higher fixed charge for the new Standard Industrial tariff will go some way to resolve this issue for larger users.

Stand alone cost

We interpret 'stand alone cost' to mean the cost to provide similar distribution services to one sub-group of consumers, as if the other groups did not exist. 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. This is partly because our consumers are free to choose which tariff group they belong to and are generally uniformly spread across our meshed network.

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 due to extensive geographical spread of consumer types across our network. While the engineered capacity of each stand alone network could be optimised in recognition of the smaller consumer sub-group, we would not expect this to offset any 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 likely to fall below stand alone costs. Prices are likely to fall below stand alone costs 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).

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 may be subsidising rural consumers due to relatively higher connection density, we do not consider disaggregating rural and urban tariffs is beneficial for the following reasons:

- Rural circuits, poles, and equipment are also used by urban consumers as electricity may flow through sub-transmission and distribution circuits in rural area to urban centres.
- Electra does not differentiate service quality by location. Network reliability standards are instead based on the aggregated load for all consumers supplied by the relevant section of the network. Fault response times are based on the fact that all connections are within 30 minutes drive of a depot and are therefore standard for all.
- Our network area is relatively compact so rural areas are close to urban areas. This is evidenced by the fact that none of our circuits are in 'remote' areas (as defined under information disclosure requirements), suggesting any cross subsidy is likely to be low.
- The government has recognised this potential for rural/urban cross-subsidisation and signalled in the Electricity Industry Act 2010 that regulation may 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 differentiate consumer groups by utilisation of service capacity into small, medium and large consumer groups. Street lighting is also a separate consumer group in recognition of the specific demand profile of this group.

Furthermore, by offering differential prices for peak/off-peak/night loads, we reward consumers (through lower prices) based on their ability to limit consumption during times of network congestion. Similarly, our controlled tariff option rewards consumers that offer up interruptible load.

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

We consider that current variable pricing structures appropriately signal the impact of each extra unit on future investment costs, particularly when combined with time of use and controlled load pricing options. 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 usage away from peak periods.

Higher peak time variable charges coupled with low charges during off-peak and shoulder periods (under the Day/Night, Triple Saver, Standard Industrial tariffs, Thrifty and Super Thrifty tariff options) sends a clear signal to consumers of the long-term benefits of moving consumption away from peak periods. 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 been increasing peak charges, relative to off-peak, in order to increase the incentive on consumers 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 permits pricing based on a consumers' willingness to pay. All consumers on our network are offered exactly the same tariff options and consumers themselves select their pricing plan. We consider the provision of a range of tariff choices aligns with practices in competitive markets and is perhaps 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.

(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. Our calculations indicate that a constant load greater than 5MW closer than 2km to a GXP would be required to make bypassing Electra’s network cheaper than the cost of the most appropriate tariff. 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.

While we do not have a formal approach to discourage bypass of our network, 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 for services. In reality, the nature of our consumer base does not require non-standard terms.

Requests for price/quality tradeoffs (e.g. the provision of dedicated equipment) are typically dealt with under our network extensions policy (as summarised above). This policy gives consumers the discretion to select the assets they that meet their quality requirements with incremental asset and construction costs met by the person requiring the work to be done. We then 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 have provided 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.

Distributed generation is not charged for distribution services (only for import meters). This encourages connection of distributed generation, consistent with Part 6 of the Electricity Industry Participation Code, and recognises the local benefits arising from the connection of such generation in terms of reducing peak load.

The GXP sharing arrangements with Mangahao hydro scheme, which is notionally embedded in our network, incentivises investment in this plant as a transmission alternative. In return, consumers share in avoided transmission cost savings arising from this local generation. This contractual arrangement is an example of a transmission alternative that acts to lower 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 to make the development of prices more transparent.

We have included in Section 10 of this document the potential impacts on consumers of implementing our future pricing strategy. In introducing the new Standard Industrial tariff we have enabled consumers to self-select this tariff, but are working with Retailers to encourage uptake where it is in the consumer's best interest. It is more appropriate for larger consumers currently using the Triple Saver option.

Steadily increasing the price for Triple Saver avoids price shock issues that would result when Triple Saver is made available unconditionally. The adjustment will enable all consumers who manage their load during peak periods to reduce their overall costs by taking advantage of unused capacity outside those times. Consumers can then adopt the option which best suits their circumstances.

The nature of Electra's ownership ensures that the concerns of consumers (who are our owners) are taken into account when considering price changes. In addition to this, we undertake regular market research with residential and commercial consumers in relation to a variety of issues, including charging, reliability and service. The last survey was carried out in December 2013. In addition to this, the Electra Trust provides feedback from time to time on behalf of the consumers that it represents, including on prices.

The new Standard Industrial tariff was not directly discussed with consumers, but feedback from a number of the larger businesses was used to inform the overall review process.

Retailers were advised about the Standard Industrial tariff in November 2012 and asked how we might work together to advise all their current Triple Saver customers who would benefit by transferring to the new “Standard Industrial” price option after 1 April 2013. As noted, this process is ongoing.

(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. As already discussed, we have shown a bias toward tariff simplicity in defining consumer groups and tariff structures. This reduces transaction costs for retailers relative to more complex tariff structures.

All retailers operating on Electra’s network pay the same prices, related to either the options their particular customers choose. All consumers are able to remain on their current tariff option or choose another more suited to their needs.

12. Glossary

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

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.
Pricing Year:	The year starting 1 April and ending on 31 March.
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 Pricing Effective 1 April 2014

Electra

Electricity Network Charges Kapiti Coast and Horowhenua: Effective 1 April 2014

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 2014 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
37,163	A	**Anytime**		All	8.82	9.02	2.36	2.86	11.18	11.88
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	6.72	6.93	1.94	2.35	8.66	9.28
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	9.32	9.61	2.40	2.90	11.72	12.51
592	TS	**Triple Saver**	Night	2300-0700	0.75	0.75	0.21	0.21	0.96	0.96
	TS		Peak	0700-1100	9.58	10.62	2.40	2.90	11.98	13.52
				1700-2100	9.58	10.62	2.40	2.90	11.98	13.52
	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
506	A	**PayGo**		All	8.82	9.02	2.36	2.86	11.18	11.88
	All PayGo sites incur a standard Supply Charge F									
	U	Street Lighting		Timetable	6.15	6.34	2.37	2.87	8.52	9.21
	U	**Community Lighting**		Timetable	7.48	7.71	2.37	2.87	9.85	10.58
152	SI	**Standard Industrial**	Night	2300-0700	0.70	0.70	0.21	0.21	0.91	0.91
	SI		Peak	0700-1100	8.39	8.50	2.40	2.90	10.79	11.40
				1700-2100	8.39	8.50	2.40	2.90	10.79	11.40
	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	**50.00**	**60.00**	**20.00**	**20.00**	**70.00**	**80.00**

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.

Triple Saver Option

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

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 2015. 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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Electra

CERTIFICATION FOR YEAR-BEGINNING DISCLOSURE – PRICING METHODOLOGY

We, Patricia Frances McKelvey and Ian Andrew Wilson, 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

Patricia Frances McKelvey – Director **Date** 28/3/14

Ian Andrew Wilson - Director **Date** 28/3/14