Pricing Methodology: 1 April 2015

Executive Summary

The Lines Company Limited (TLC) is in the business of supplying its connected customers with reliable capacity. Capacity is a term used to describe the customer requirements or the ability of the network to supply energy at a moment in time. Reliability is a term used to describe the length of time and frequency that the network is unavailable to supply customers with electricity. It is the capacity requirements of its connected customers, rather than the amount of energy conveyed which determines the investment the company has to make in its network. The prices charged reflect the investment the company has made, and intends to make in order to provide a reliable supply capacity to its connected customers.

For the period 1 April 2015 to 31 March 2016, TLC's estimated target revenue is $39.6 million. This figure represents the recovery of the cost of supplying capacity to approximately 24,000 customers and provides for a regulated return on investment to shareholders. The total cost recovered from customers includes $7.1 million recovered on behalf of Transpower and generators operating within the network. At 31 March 2015, the estimated investment in the network is $176 million.

The move to charging for capacity and demand/load was in response to the network constraints presented by an aged network with low demand and connection density, combined with a high proportion of customers with low annual consumption. On evaluation, this meant that a volumetric charging methodology was unsuitable to deliver a sustainable network. The aim of TLC is to build and maintain a network which is "right-sized" for the customer requirements and economically sound for both customers and shareholders.

To ensure the efficient use of network assets in a manner that provides service quality benefits to the customer at an affordable price and a regulated return to the shareholder, TLC charges customers for their capacity and demand requirements as opposed to their energy consumption.

By developing and maintaining a direct contractual relationship with its customers TLC is able to apply a demand based pricing methodology more effectively than through the traditional retailer channel. Direct to customer billing services and customer engagement provide customers with the opportunity to get guidance on how to better manage kW load requirements and offers a better forum to communicate price/quality trade off requirements.

The pricing methodology used to set individual prices will determine how accurately charges paid by each customer recover the cost of supplying capacity to their installation. The current pricing methodology of demand charging means that prices should recover at least the marginal cost of supplying capacity to an individual and no more than the standalone cost of supply.

The process followed when setting prices is to initially determine the revenue requirement deemed sufficient to operate a sustainable network for the following year. Next, customers on the network are grouped by similarities at point of connection, demand density and capacity requirements. These three factors influence the cost of supply to the customer. The variation in costs attributed to each consumer group drives the allocation of revenue recovery. Finally, a tariff model is developed that serves not only to recover revenue but to communicate to the customer the cost of service and signal where individual customer behaviour can influence those costs.

Figure 1: Sequential diagram of TLC's Pricing Methodology

By aligning the cost of supply to charges recovered from the customer, TLC is able to make efficient and economically sound investment decisions to the benefit of both customer and shareholder.

The integration of asset management planning with the pricing methodology is a critical process in TLC's business model. Revenue constraints combined with an aged network meant that TLC shareholders had to choose between network development and asset renewal. The development of a pricing methodology based on capacity and demand requirements, and the communication of this methodology to customers was part of a strategy to slow demand growth and channel available resources to asset renewal. A focus on asset renewals has contributed to an improvement in quality of service levels.

Since the introduction of demand charging in 2007, metering technology has improved substantially. This has allowed TLC to be progressive in its rollout of advanced meters and look toward replacing assessed capacity and demand charges with measured quantities. Currently 72% of customers have both fixed capacity (Network Charge) and variable demand (kW load) assessed through the use of a statistical process which produces a demand profile. The wide scale advanced meter installation project commenced in September 2013. Full installation will enable a closer alignment between asset management strategy and pricing methodology.

TLC's asset management strategy is focussed on providing just in time assets that will be utilised, provide service and earn revenue. The long term aim of our pricing methodology is to signal the lifecycle costs of the assets that are necessary to provide the capacity and quality service requirements of the consumer.

One of our primary objectives is to facilitate the lowest possible cost of lines and energy prices to our customers in what is by national standards a difficult set of challenges when operating an aged rural network.

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Abbreviations

TLC	The Lines Company
EDB	Electricity Distribution Business
EA	Electricity Authority
ComCom	Commerce Commission
AMP	Asset Management Plan
ICP	Installation Connection Point
kW	Kilowatt
kWh	Kilowatt-hour
kVA	Kilovolt-ampere
ACOT	Avoided Cost of Transmission
LNI	Lower North Island Transpower transmission region
RCPD	Regional Coincident Peak Demand
DPP	Default Price Quality Path
ID2012	Information Disclosure Determination 2012
IM2012	Input Methodologies Determination 2012
TOU	Time of Use
POS	Point of supply

Pricing Abbreviations

kW Load	Based on the average of the six highest peaks at a connection during periods of load control.
Network Charge	Chargeable capacity.

Consumer Group Terminology

HT	Hangatiki	**WK**	Whakamaru	**OK**	Ohakune
ON	Ongarue	**NP**	National Park	**TK**	Tokaanu
LV	Low Voltage Supply (400V)			**HV**	High Voltage Supply (11kV/33kV)
HI	High Density (demand density ≥ 50kVA/km)				
LO	Low Density (demand density < 50kVA/km)				

Pricing Plans

LFCP	Regulated Distribution Tariff (Low Fixed Charge)
SUP	Standard User: Capacity normally < 100kVA
MUP	Major User: Capacity normally ≥ 100kVA

1. Pricing Methodology Overview

In order to accurately reflect the cost of supplying capacity, TLC line charges are payable by connected customers, according to the capacity each consumer requires and the assets used to provide that capacity. The methodology used to set prices is based on assessed or measurable quantities of power rather than energy usage. Demand Charging and Dedicated Asset Charges enable TLC to set prices that signal to the consumer the relative costs of safe, reliable supply to their installation. Sequentially, there are four stages employed in setting prices:

1. Determine target revenue within regulated levels;
2. Identification of consumer groups;
3. Allocation of target revenue between these groups;
4. Development of pricing plans to recover target revenue and send pricing signals aligned to consumer behaviour.

Crucial to this process is alignment to the regulatory models developed by the Commerce Commission and Electricity Authority. These models ensure that revenue and prices reflect the cost of operating an efficient distribution network.

1.1. Customer Consultation

Customer engagement is an essential process in the development of a quality product or service. Consumers connected to TLC's network have a direct contractual relationship with TLC for the supply of capacity at a known price and level of quality. This relationship provides a level of transparency in pricing not common across the industry where lines charges are bundled with retail energy prices.

Supporting this direct customer relationship is a dedicated customer service team, including a fault and outage response team. Amongst other things, in conjunction with network engineers, TLC employees are available to provide energy and demand management advice. Six times a year, customers receive a customer newsletter outlining company news and network issues.

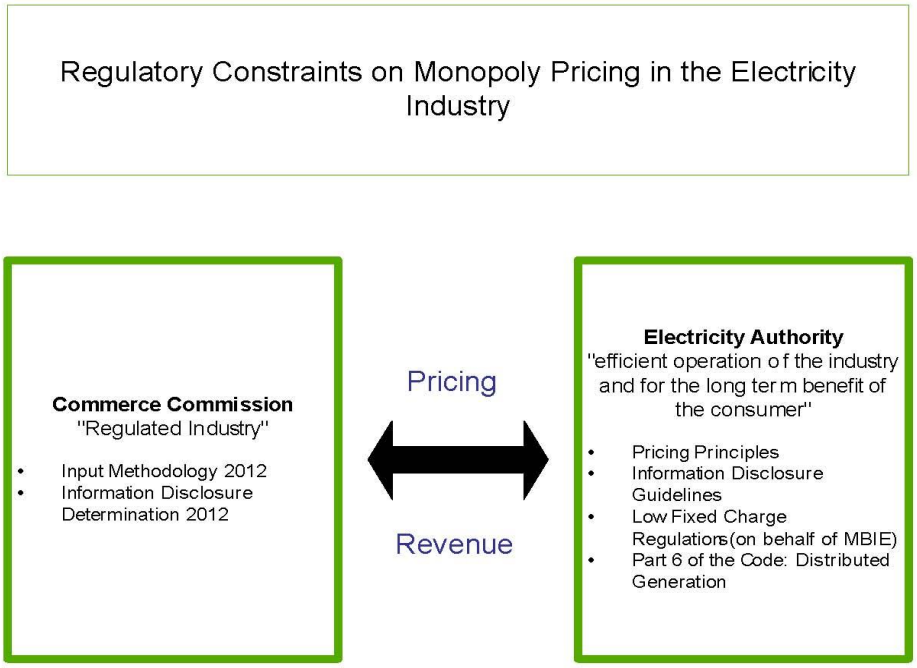
Newsletters, website updates and regulatory disclosures are effective at communicating matters of a routine nature. Regular community clinics are also run and these provide consumers with the opportunity to discuss with TLC representatives their opinions and expectations regarding price and the level of service. Customer viewpoints are considered during the development of investment decisions in all aspects of TLC's product delivery.

In 2014 public meetings were held in all the main town centers. Feedback from these meetings, and other channels is regularly reviewed. This assists the company to establish what issues customers wish to change or discuss. As a result of this analysis, changes to the vacant property relief policy are planned for 2015/2016. Performance targets and current indicators of service expectations are presented in the Asset Management Plan[1] and Annual Report[2].

[1] 2014 TLC Asset Management Plan and 2015 TLC Asset Management Plan Update
[2] 2014 TLC Annual Report

1.2. Regulatory Considerations

The EDB model is not subject to competitive market forces. As a natural monopoly the model is subject to both quality of service and price regulation. The following diagram looks only at the pricing constraints that TLC is subject to under current regulations.



1.2.1. Commerce Commission

TLC is one of 29 companies operating in New Zealand that provide electricity lines services. Sixteen of these companies, including TLC, are obliged to set target revenue and service levels according to Input Methodology requirements determined by the Commerce Commission (ComCom). TLC is subject to the "Default Price/Quality Path" (DPP) requirements and compliance is tested annually on revenues charged and network reliability performance against regulatory set targets. The Input Methodology is used to establish the capital requirements of an efficient distribution business and the service level appropriate. Public disclosure of the Pricing Methodology is one means of assessing compliance with the DPP. This document and other regulatory disclosures to ComCom can be viewed and downloaded from TLC's website. The scope and framework of this Pricing Methodology is prescribed by Section 2.4: Information Disclosure Determination 2012 (ID2012). *Refer to Appendix 3: Information Disclosure Determination 2012 Alignment Table.*

1.2.2. Electricity Authority

The statutory objective set for the Electricity Authority (EA) by the Electricity Industry Act 2010 is:

To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The primary tools used by EA to assist in the delivery of this objective are:

1.2.2.1. Pricing Principles

EA have elected to use a principles based model rather than a prescriptive one-size fits all.
Refer to: Appendix 1: Pricing Principles Alignment Table.

1.2.2.2. Information Disclosure Guidelines

These guidelines have been developed to aid distributors in the disclosure of their pricing methodologies and to specifically show alignment with the pricing principles model. *Refer to: Appendix 2: Information Disclosure Guidelines Alignment Table.*

1.2.2.3. Low Fixed Charge Regulations

The Low Fixed Charge Regulations 2004 (LFC) are monitored by the Ministry of Innovation and Employment (MBIE). The EA is charged with administering compliance. Under the LFC, TLC is obliged to offer a regulated tariff to its domestic customers. This tariff must:

- Have a fixed charge of not more than 15 cents per day (excl. GST and net of prompt payment discount);
- The average domestic customer should pay no more in total per year on the regulated tariff than on any alternative plan.

The structure of the lower user tariff results in a significant portion of domestic customers paying less than the incremental cost of supply to their installations. As total revenue is constrained by regulation, it is implicit that lost revenue is sought elsewhere, effectively creating a level of cross subsidy. This position is recognised in Section (a) (i) of the Pricing Principles, "…except where subsidies arise from compliance with legislation and/or other regulation."

Since 2005 TLC has held an exemption from full compliance with the Low Fixed Charge Regulations. This exemption expires on 31 March 2015.

1.2.2.4. Distributed Generation

Regulation on the structure and value of both payments to generators and prices charged is contained within Part 6: Connection of Distributed Generation of the Electricity Industry Participation Code 2010.

The presence of generators on the TLC distribution network presents a set of technical connection issues. These issues range from safety considerations to system interference with neighbouring connections. Most large distributed generators have dedicated assets and associated charges plus load and associated charges when generation is not occurring or injection is at a level lower than the load required.

Payments made to generators connected to the TLC network are referred to as "Avoided Cost of Transmission" (ACOT) payments, as these costs would otherwise be payable to the national grid operator, Transpower. Where the generator is injecting into a Transpower POS at times when ACOT

charges apply, then ACOT is not paid for any such injection. Generator output data signals also have to be supplied to the TLC SCADA system for ACOT payments to be made. Administration and engineering SCADA costs attributable to the generators are also allocated.

1.3. Changes to Pricing Methodology

There are no major changes in the 2015 pricing methodology from previous years.

1.4. Pricing Strategy

TLC is committed to a programme of network renewal and development which provides customers with an acceptable price/quality trade-off and also is economically right sized to ensure the network is not over capitalised and shareholder value not compromised. An adequate revenue stream is required to build and maintain the network in accordance with the set strategy and prices must be periodically adjusted to earn the required revenues. Over the past 4 years, the Company has elected to price at below sustainable regulatory levels in response to the difficult economic times faced by both individual customers and communities. From 1 April 2015, TLC believes it must increase its prices to begin the path of revenue recovery to sustainable levels. This higher price path will likely result in price increases to customers at rates higher than inflation over the next four years culminating with revenues being aligned to regulatory targets by 2018. Price increases in the range of 3% - 5% (including recoverable transmission costs) are currently being forecast but remain dependent on inflation staying at currently low levels and inflation only adjusted increases in transmission charges. The additional revenue will be used to secure network renewals, address ever changing hazard management requirements and deliver improved returns to our community trust shareholder.

The advanced meter rollout project and how customers respond to demand side management opportunities, is expected to have an impact on the forward price path. Consistent with TLC's pricing methodology, long term pricing benefits to the customer are clearly available if load is shifted.

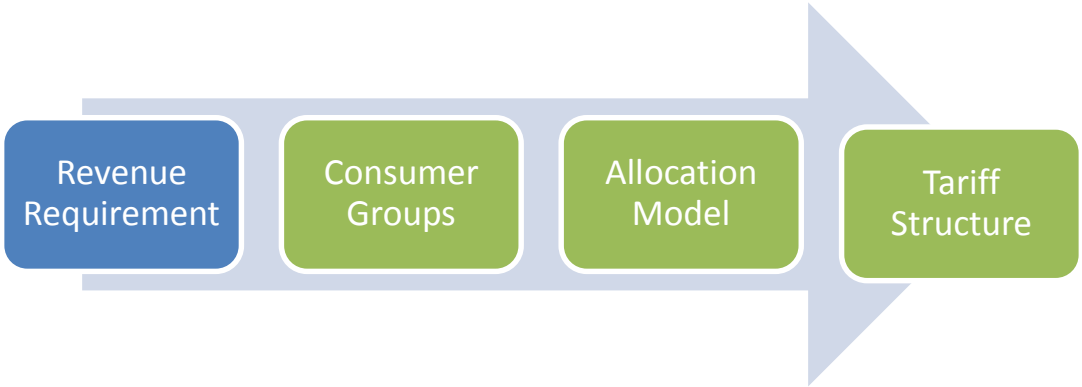
The company has a proven track record in finding innovative solutions to network renewal and hazard management. These innovations are driven by our need to hold down costs, but maintain or improve service quality standards. The company has been recognised in the past and will continue to strive to lead by example.

A work project is considering the feasibility of recognising similarities between customers based on service quality targets. This innovative approach aligns with the price/quality trade off with which the ComCom develops price pathways for non–exempt EDBs. Currently, TLC's Terms and Conditions and Asset Management Plan consider the provision of levels of service quality. The challenge for the company is to develop a pricing methodology that supports this approach at a consumer group level.

New approaches are being investigated and it is hoped that these will allow a greater integration of asset management, cost recovery and customer service. Furthermore, it is hoped these innovative systems will enable a level of transparency so that customers can better see the price quality trade off they are being offered. And in turn, make informed decisions as to their acceptance of the trade off in conjunction with the level of general service they require.

2. Standard Contract Pricing Methodology

2.1. Revenue Requirement



Sequential diagram of TLC's Pricing Methodology

Target revenue is based on the aggregate of the following costs:

- Return on capital invested;
- Return of capital invested (depreciation);
- Recovery of direct operating costs (e.g. maintenance, etc.);
- Recovery of customer and administration costs (e.g. billing, etc.);
- Recovery of Pass-through costs (e.g. industry rates and levies);
- Recoverable costs (e.g. Transpower and ACOT).

The Input Methodologies 2012 (IM2012) developed by ComCom provides the methods and processes necessary to establish revenue targets. Price setting is the mechanism by which the network investment and related costs to operate a network are recovered. The investment in the network by TLC includes assets such as poles, wires, transformers, switchgear and substations. Valuation of the asset investment for price setting purposes is estimated at $176 million. The value of the assets owned by an EDB is commonly referred to as the Regulated Asset Base (RAB).

IM2012 identifies distribution, customer and administration costs that are either allowable, as in the asset renewal programmes necessary to maintain a quality provision of supply, able to be passed on, as in industry levies and rates, or recoverable.

Recoverable costs include transmission costs payable to Transpower for connection assets and interconnection demand charges, plus avoided cost of transmission payments (ACOT) made to generators feeding directly into TLC distribution network.

Aggregation of these costs provides an indicative Target Revenue for the pricing period starting 1 April 2015. These costs are quantified in the following table (Table 1).

Target Revenue: 1 April 2015 - 31 March 2016 Projected Distribution, Pass-through and Recoverable Costs			
Cost	Description	$m	%
Distribution	Capital related	$ 24.3	58%
	Maintenance	$ 5.4	13%
	Customer and administration	$ 5.0	12%
Pass-through	Rates and levies	$ 0.3	1%
Recoverable	Transmission	$ 7.1	17%
Total to Recover		$ 42.1	100%
Total Target Revenue		$ 39.6	94%

Table 1: 2015 Target revenue

The total Target Revenue of $39.6m is the combined revenue from both standard contracts ($34.1m) and non standard contracts ($5.6m).

2.1.1. Distribution Costs

Distribution costs account for an estimated 84% of total costs.

ComCom regulates electricity distribution monopolies using a price/quality trade-off. Provision of reliable supply, measured in terms of outage duration and frequency, is balanced against the asset investment to deliver customer capacity requirements. Higher capital costs suggest higher revenue which suggests higher prices. Implicit is the assumption that asset investment should result in increased standards of reliability. Customer consultation is very important and these consultations should provide customers with the opportunity to influence the investment decisions being made on their behalf.

Underlying these costs are requirements around safety and quality. For example, TLC must keep the voltage plus other more technical quantities such as harmonics levels within certain limits. Safety is legislated under two pieces of legislation, one focuses on worker and the other on public safety.

The cost lines in Table 1 detail:

1. A return on capital invested, combined with a return of capital invested, at the Commerce Commission regulated rate, accounts for 58% of total costs recovered through revenues. Comparatively[3], TLC capital expenditure by connection point is at the median range. These costs include:
    a. Depreciation of assets at regulated rates;
    b. Return on investment at a regulated rate.

    The current target revenue provides a return less than that regulated by the Commerce Commission.

2. Operating expenditure is 25% of total costs and include:
    a. Network Maintenance – vegetation management, lines and pole maintenance fall within this cost line;

[3] 2014 Price Waterhouse Cooper Information Disclosure Compendium

b. Customer and Administration – all other costs required to support and run an EDB including network management, business support systems and customer engagement.

3. Pass-through Costs are specifically allowed by IM2012 and are made up of industry levies and attributable local government rates.

2.1.2. Recoverable Costs

Transmission and ACOT charges represent 17% of total costs. Table 2 provides a breakdown of these costs by Point of Supply (POS).

Recoverable Costs - Transmission and ACOT	
Point of Supply	2015 $m
Hangatiki	$ 3.7
Whakamaru	$ 0.2
Ohakune	$ 0.6
Ongarue	$ 1.3
National Park	$ 0.6
Tokaanu	$ 0.8
Total	$ 7.1

Table 2: 2015 Recoverable Costs

ComCom allows EDBs to recover from customers the costs paid for transmission and ACOT. These recoverable costs include charges from Transpower and distributed generators based on the capacity requirements measured in the preceding 12 months to the year ended 31 August 2014.

Transpower charges are a combination of connection and interconnection charges. The interconnection charge is a variable charge and the quantity (kW) is the average of the loads at that POS co-incidental with the top 100 half hour peaks experienced on the Lower North Island transmission grid (LNI) over the 12 months ended 31 August.

The Whakamaru supply point is unique and transmission charges are replaced by a different mechanism. Recoverable costs for the Whakamaru supply point are based on economic transmission costs avoided.

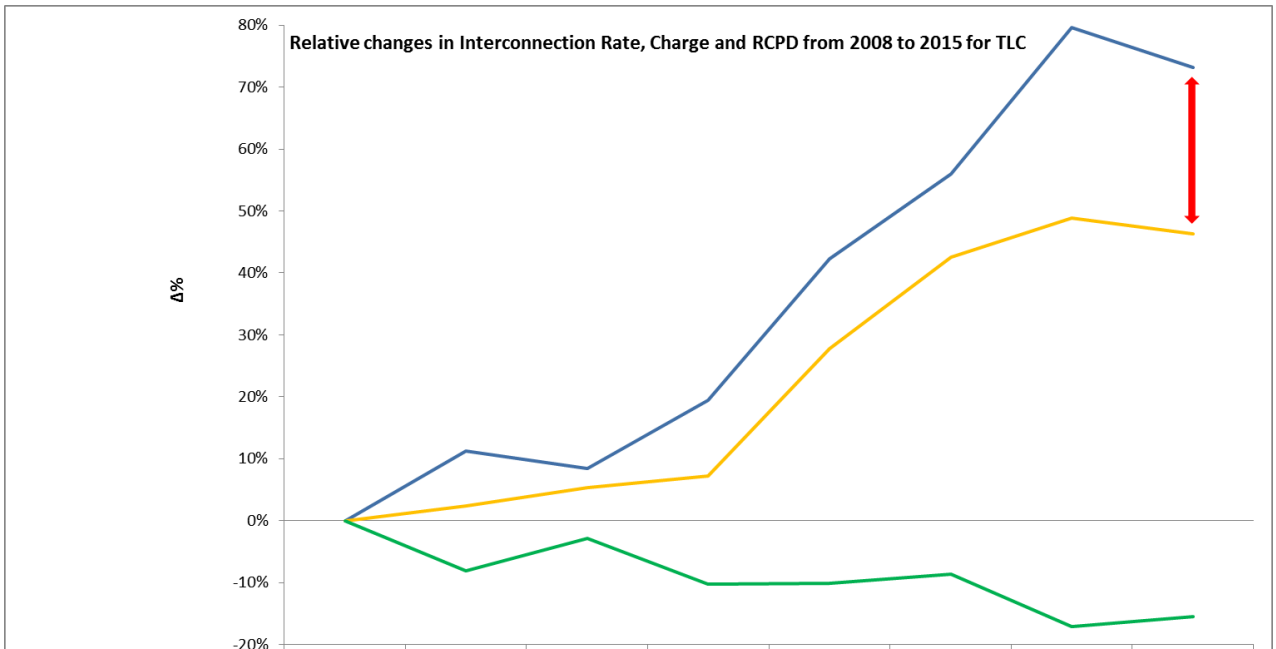
ACOT payments to embedded generators on the network are legislated at the same rate as the interconnection charge from Transpower.

During the 12 months ended 31 August 2014, TLC controlled load in order to minimise the co-incidental peaks, minimise transmission charges, hence minimise the costs recovered from customers.

2.1.2.1. Interconnection Rates

Since 2008, the interconnection rate has increased from $63.74 per kW to $110.35, approximately 73%. During this same period, Transpower's interconnection charge to TLC has increased from $2.55m to $3.73m or 46%. The difference in increases between the rate and the charge is due to the reduction in TLC's Regional Coincident Peak Demand (RCPD). TLC's load controlling policy and practices have contributed to the reduction in RCPD and interconnection charges that TLC recover from our customers.

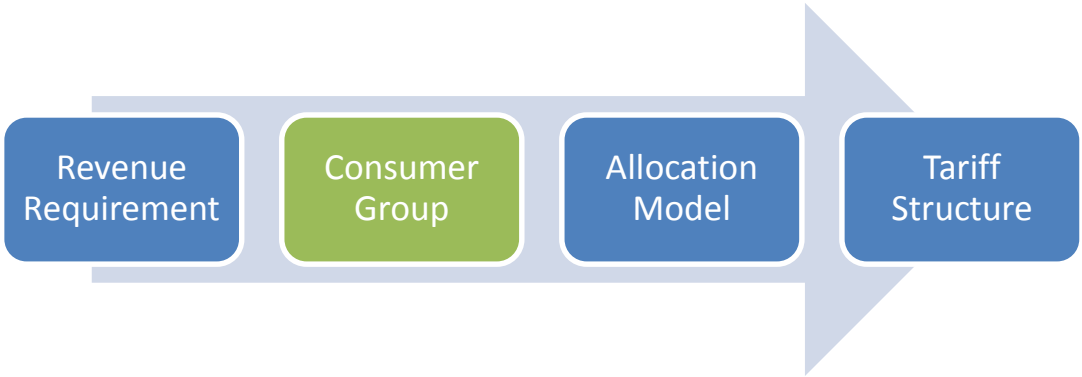
Figure 2, below, shows the trend of an increasing interconnection rate (blue), an increasing interconnection charge (yellow), but decreasing RCPD (green). The red arrow shows a diverging ratio between the interconnection rate and the interconnection charge meaning that TLC's RCPD has decreased over time.



	2008	2009	2010	2011	2012	2013	2014	2015
Interconnection Rate Δ%	0%	11%	8%	19%	42%	56%	80%	73%
Interconnection Charge Δ%	0%	2%	5%	7%	28%	43%	49%	46%
RCPD Δ%	0%	-8%	-3%	-10%	-10%	-9%	-17%	-15%
Interconnection Rate ($/kW)	63.74	70.94	69.12	76.14	90.66	99.44	114.47	110.35
Interconnection Charge ($m)	2.55	2.61	2.69	2.73	3.26	3.63	3.80	3.73
RCPD (kW)	39,999	36,772	38,854	35,915	35,939	36,549	33,153	33,805

Figure 2: Interconnection rate, charge and RCPD changes

2.2. Consumer Group



Sequential diagram of TLC's Pricing Methodology

In order to recover Target Revenue, TLC must identify the customers from whom this revenue will be procured. Cost drivers are identified and customers are grouped according to their exposure to these drivers and individual influence on these drivers.

The nature of a distribution network means that there is a high level of fixed cost to be shared. Where possible, customers who benefit from the dedicated use of distribution assets are charged accordingly. Where dedicated use has been identified and recovered through a dedicated asset charge, the point of connection is redefined and the customer shares only the common cost of a high voltage distribution network. This is lower than the shared cost of a low voltage distribution network.

Defining a Consumer Group and the key features considered is discussed below.

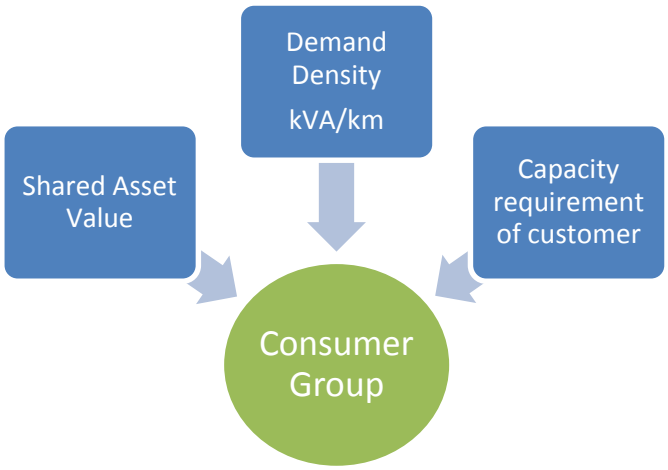


Figure 3: Consumer Group Definers

Shared Asset Value

Distribution assets are aggregated at a regional level, aligned to transmission POS and include the length of line, transformers, poles and other distribution related assets. By grouping customers based on POS, TLC is able to best match invested infrastructure costs to those who benefit. An exception is when the capacity requirements of a customer are sufficiently large to require investment in additional dedicated network infrastructure. Individual customer contracts are negotiated with these customers. There are six different pricing regions: Hangatiki, Whakamaru, Ohakune, Ongarue, National Park and Tokaanu. Where an area could be supplied from more than one POS, the customers in that area are grouped with those with whom they share the most in common.

Five of these regions correspond to POS on the national grid. These five POS are where the distribution network, as owned and maintained by TLC, intersects with the national transmission network (National Grid) operated by Transpower. The sixth POS is Whakamaru where TLC minimises transmission costs by contracting directly with a generator.

Demand Density

Demand density at ICP is an important cost driver. Demand density is a ratio of demand (capacity as measured at the distribution transformer) to line length from feeder.When compared with high demand density, low demand density, generally illustrated in remote areas with low population count, requires an increased level of investment per connection. Customers are grouped according to demand density at point of connection.

Capacity Requirement

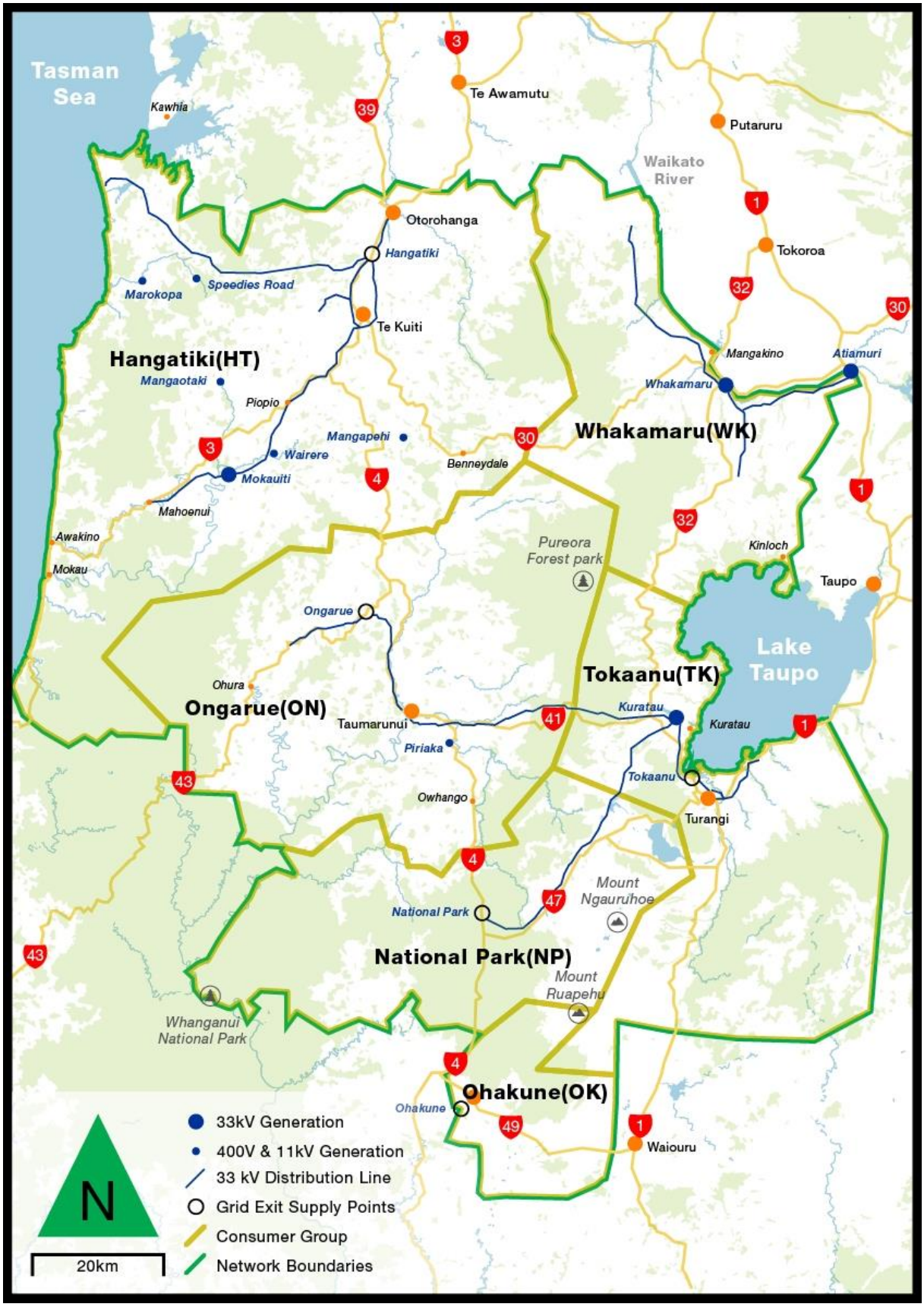
The capacity requirement of individual customers is also considered. If sufficiently large, the capacity requirement of an individual customer can affect the reliability and supply of capacity to other customers on the local network.

The following table provides illustration of the Standard Contract Consumer Group matrix and a count of customers within each defined group.

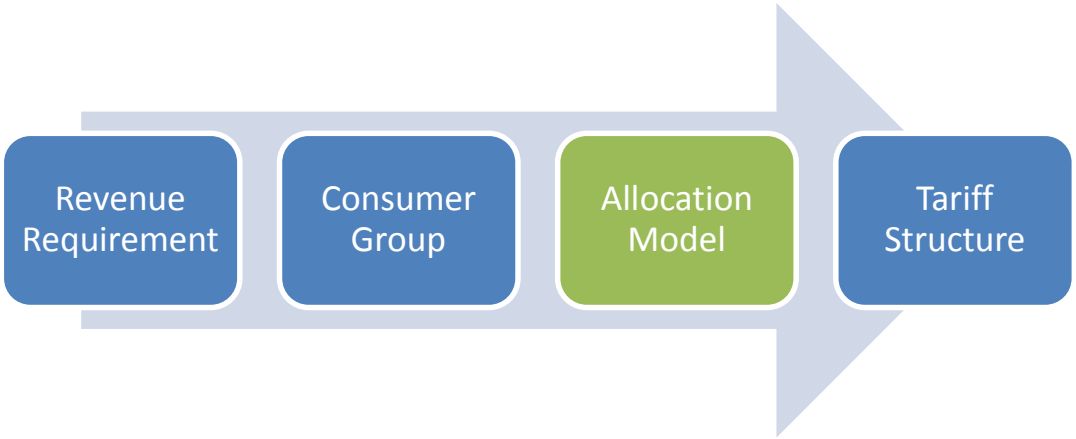
Consumer Groups (Excluding Non Standard Contracts) 2015 Total Customer Number - 23,716								
	Hangatiki				Whakamaru			
	HIHV	LOHV	HILV	LOLV	HIHV	LOHV	HILV	LOLV
Capacity <100kVA	1,405	1,691	4,788	1,083	82	1,176	732	492
Capacity ≥100kVA*	17				1			
	Ohakune				Ongarue			
	HIHV	LOHV	HILV	LOLV	HIHV	LOHV	HILV	LOLV
Capacity <100kVA	218	0	1,734	0	480	780	2,841	605
Capacity ≥100kVA*	0				2			
	National Park				Tokaanu			
	HIHV	LOHV	HILV	LOLV	HIHV	LOHV	HILV	LOLV
Capacity <100kVA	70	153	390	205	128	101	4,484	49
Capacity ≥100kVA*	3				6			
HI=High Density; LO=Low Density; HV=High Voltage; LV=Low Voltage *As Priced on MUP								

Table 3: Standard Contract Customer Groups and 2015 ICP count

TLC Network and Regional Consumer Groups



2.3. Allocation Model



Sequential diagram of TLC's Pricing Methodology

Having quantified Target Revenue and defined Consumer Groups, allocation of costs between Consumer Groups and/or individual customers is required.

The measurements and statistics relevant to the allocation of costs incurred are provided in the following table. Cost information is in reference to total network costs as provided in Table 1 and thus includes costs for all customers, not just Standard Contract customers.

2015 Allocation Assumptions and Costs					
Supply Point	Demand Density	No. of connections	Line Length	Network	kW Load
		ICP	km	kVA 000's	kW/kVA 000's
Hangatiki	High	6,216	770	58.3	45.3
	Low	2,774	924	16.1	7.2
Whakamaru	High	816	140	6.8	2.8
	Low	1,668	545	18.2	8.5
Ohakune	High	1,954	99	13.3	9.9
	Low	0	105	0.0	0.0
Ongarue	High	3,325	429	21.7	10.1
	Low	1,385	636	7.6	3.0
National Park	High	464	148	5.0	5.7
	Low	358	155	5.7	1.8
Tokaanu	High	4,619	203	29.8	12.3
	Low	150	180	0.9	0.3
Network		23,729	4,334	183.3	106.9

Table 4: 2015 Allocation Model Assumptions and Costs. Part 1

2015 Allocation Assumptions Costs				
	RAB	Capital related Costs	Maintenance Costs	Customer & Admin Costs
Supply Point	$m	$m	$m	$m
Hangatiki	$ 70.7	$ 9.7	$ 2.1	$ 2.1
Whakamaru	$ 26.9	$ 3.5	$ 0.7	$ 0.4
Ohakune	$ 16.1	$ 2.1	$ 0.2	$ 0.4
Ongarue	$ 28.1	$ 4.2	$ 1.4	$ 0.9
National Park	$ 12.8	$ 1.7	$ 0.3	$ 0.2
Tokaanu	$ 21.5	$ 3.2	$ 0.6	$ 0.9
Network	$ 176.0	$ 24.3	$ 5.4	$ 5.0

Table 5: 2015 Allocation Model Assumptions and Costs. Part 2

Regulatory Asset Base (RAB)

- This provides the base for allocation of capital related costs

Capital related costs

- These costs are based on the estimated value of the network assets as retrieved from asset management systems. The costs include an allowance for both a return *on* capital and a return *of* capital at the regulated rate of return. If dedicated network asset use can be identified, the cost will be allocated to those customers receiving the benefit.

Operational costs

Maintenance Costs

- Asset management systems are used to identify costs by consumer group, where available. Supply voltage, demand density and network age impact total maintenance costs.
- Maintenance costs include both direct and indirect costs (being principally network support costs) and are allocated between high and low voltage supply. Historical averages are used to give a cost per km of line. These costs are allocated to Consumer Groups based on line length statistics. If there are negotiated contracts in place, a cost is deducted from the consumer group allocation.

Customer and Administration

- Administration costs include the provision of shared services including corporate governance, finance, human resources, pricing and regulatory management and information technology. Unless clearly attributable to an individual these costs are allocated across the consumer groups with reference to capital costs. If clearly

attributable, the cost will be passed on as a service fee or as part of a negotiated contract.

- Customer costs include billing services, demand side management services and customer support services. The costs are allocated to consumer groups on proportional basis (ICP count) or as part of a negotiated contract.

Pass-through costs

- These are allocated in the same manner as outlined for Administration costs.

Recoverable costs

- Recoverable transmission costs are allocated on the basis of variable kW load at point of connection.

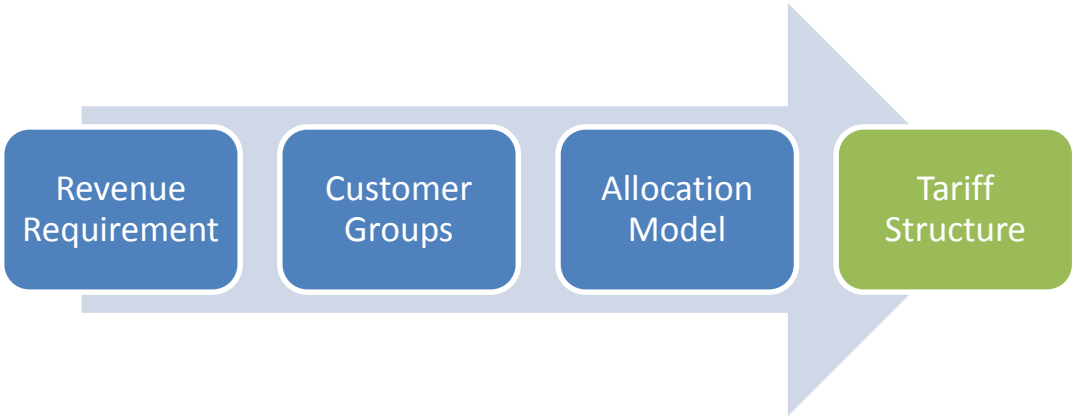
Target Revenue by Consumer Group

The following table shows target revenue allocation by Standard Contract consumer groups. This allocation has been made in line with the methodology and assumptions as outlined above, but excludes revenue earned from Non Standard Contract and Distributed Generator customers.

Consumer Groups (Excluding Non Standard Contacts) 2015 Total Target Revenue - $34.1m								
	Hangatiki				Whakamaru			
	HIHV	LOHV	HILV	LOLV	HIHV	LOHV	HILV	LOLV
Capacity <100kVA	$ 2.97	$ 2.59	$ 5.50	$ 1.10	$ 0.24	$ 3.30	$ 0.57	$ 0.60
Capacity ≥100kVA*	$ 1.79				$ 0.22			
	Ohakune				Ongarue			
	HIHV	LOHV	HILV	LOLV	HIHV	LOHV	HILV	LOLV
Capacity <100kVA	$ 0.32	$ -	$ 2.05	$ -	$ 0.74	$ 1.10	$ 3.50	$ 0.59
Capacity ≥100kVA*	$ -				$ 0.14			
	National Park				Tokaanu			
	HIHV	LOHV	HILV	LOLV	HIHV	LOHV	HILV	LOLV
Capacity <100kVA	$ 0.15	$ 0.29	$ 0.59	$ 0.76	$ 0.45	$ 0.13	$ 3.74	$ 0.04
Capacity ≥100kVA*	$ 0.32				$ 0.26			
HI=High Density; LO=Low Density; HV=High Voltage; LV=Low Voltage *As Priced on MUP								

Table 6: 2015 Target Revenue Allocations by Consumer Group

2.4. Tariff Structure



Sequential diagram of TLC's Pricing Methodology

The recovery of Target Revenue requires the development of a methodology to set prices . Currently, the majority of EDBs use a methodology that combines volumetric (energy consumption), demand charging for their larger capacity customers and daily fixed charges. Prior to 2007, TLC used a similar mixed charging methodology. In 2007, TLC moved to a charging methodology aligned to economic costs of service provision.

Meters capable of recording energy use over pre-set time periods are referred to as Time-of Use (TOU) meters. The limited number of Time-of-Use (TOU) meters at customer installations in 2007 was an issue for consideration by TLC when moving to demand charging. However, the network constraints presented by an aged network with low demand and connection density, combined with a high proportion of customers with low annual consumption, and alternatives such as solar reducing in price meant that a volumetric charging methodology was unsustainable. In 2007, TLC adopted demand charging for all of its customers.

In addition to the fixed and variable demand charges, TLC has dedicated asset charges. Dedicated asset charges apply when there is clear and identifiable benefit provided to customers.

The three main pricing components used to recover distribution related target revenue at TLC are:

- Fixed charge (Network Charge);
- Variable charge (kW Load Charge);
- Dedicated asset recovery (Transformer and other dedicated assets including relay fees).

Complementing these pricing components are:

- Low Fixed Charge: this charge forms part of the regulated distributor tariff option, as required, for eligible customers. The charge must be no greater than 15 cents per day, and when combined with a variable charge, must be such that the average consumer will pay no more than on any alternative tariff. For eligible consumers, this charge replaces the network charge;

- Service fees: these fees recover costs incurred in the provision of dedicated services such as de-energisation and re-energisation requests;

- Transmission charges: these charges pass on recoverable transmission and ACOT costs from Transpower and Generators.

- Relief Policies and rebates: These offer relief at times when change to individual circumstance mean that current charging is inappropriate. The financial impact of these policies has a small overall impact on total revenue recovery.
  The policies can be found on the company website:
  www.thelinescompany.co.nz/customers/customer-relief-policies.

2.4.1. Demand Charging

A demand charging methodology concentrates on the peak demand at an installation as the capacity requirement is the main driver of network maintenance, growth and development. In addition, consideration can be given to the co-incidental peak demand, the peak demand at an installation, at a specific time. TLC demand charging methodology uses a fixed charge to represent the capacity requirement of the installation and a variable charge to provide consumers a signal of their specific load patterns.

The allocation of revenue between these two pricing components is decided with reference to the short and long term strategic goals of the business. Pricing differentials can influence customer behaviour and elicit a demand side response (DSM). Currently, TLC derives close to 50% of Target Revenue from variable charges. From a consumer viewpoint, if the largest part of their monthly bill is a charge that they can reduce by load management, then the consumer is in a position to make a cost/benefit decision.

The emphasis by TLC on shifting load is eliciting a short term demand response by consumers with TOU meters. The benefit to both consumers and TLC has been outlined. In the long term, with the full rollout of TOU meters, TLC hopes to influence power factor efficiencies at the point of connection and have available information of the harmonic contributions of installations. The combination of capacity charges and demand charges will be used to drive this response.

The way capacity and demand charges are determined is influenced by the type of meter at the installation. The majority of meters currently on TLC's network are only capable of providing volumetric data (energy throughput – kWh).Therefore, both fixed and variable charges for these meters are assessed. This assessment is made using energy consumption data provided by energy retailers. Consumers who have TOU meters at their installation are able to effect load management without the need to focus on energy consumption as is required by customers with volumetric meters.

To learn more about the processes and rules used to calculate billable quantities to consumers for both Network Charge and kW Load, plus the transitional options used to ensure pricing equity between consumers with different meter types, please follow the links provided on the customer section of the website www.thelinescompany.co.nz/customers/pricing-and-billing or request a hard copy.

Fixed charge

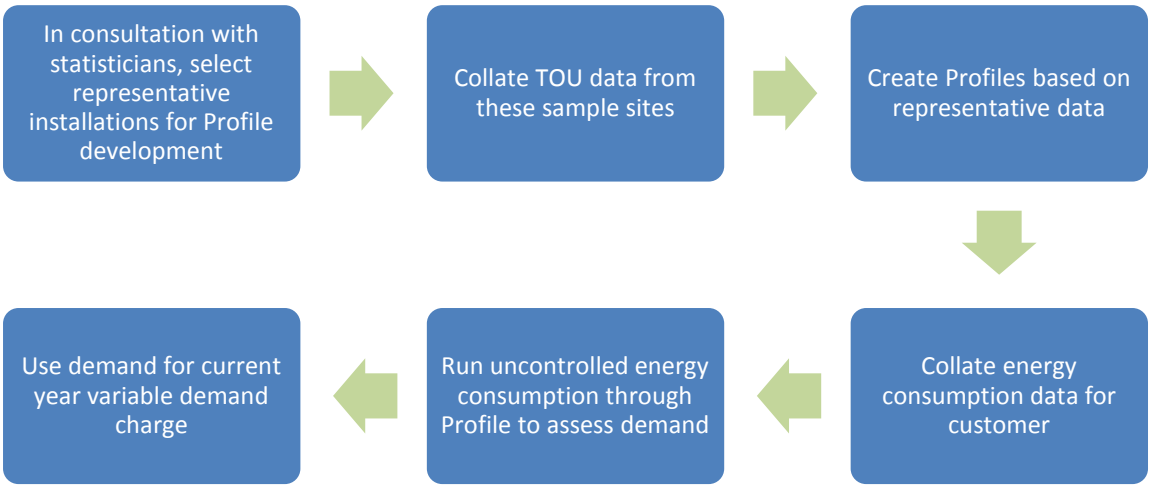
The quantity used in the fixed charge is a reflection of the capacity requirement of the connection. This capacity requirement is established as part of the connection agreement at the time of connection and unless there is a significant change to the structure or use of the connection, it is expected that the capacity requirement will remain constant from year to year. This charge is referred to as the **Network Charge** and most consumers connected to the network incur this charge.

Variable charge

To determine the uncontrolled load at an ICP with a TOU meter, TLC uses the average of the qualifying top six, two hours of uncontrolled load during periods of load control. This charge is referred to as **"kW Load"**, and is usually reset on an annual basis. This charge applies to customers on the Standard User plan and Low Fixed Charge plan.

TOU meters are able to record consumption data in time intervals. This data can be downloaded and analysed to produce a load usage pattern for that consumer. In 2007, TLC used a representative selection of TOU meter data to mathematically produce an equation to predict that a certain level of energy consumption has a point of equivalence with demand ("profile"). Statisticians are used by TLC in the development of the profile equations. Using profiles, TLC was able to introduce variable demand charging even though the vast majority of its customers still had energy consumption only meters.

The following diagram shows the essential steps in this process. The process level decision and rules are provided on both the company website[4] and in hard copy on request.



As at 1 April 2015 28% of consumers benefit from the installation of TOU meters. TLC has acted to ensure charging equity between customers by offering an opt back to the consumer's relevant profile.

The availability of the opt back is a transitional measure. TLC is currently installing advanced TOU meters at all connections on the network. This project is prioritised and it is expected that within 3 years all connections will have TOU meters. TLC will also offer access to other tools such as in-home displays to assist consumers in managing load.

At 1 April 2015, approximately 32% of consumers with TOU meters will opt back to the relevant profile. The objective of the opt back option is to ensure fairness to consumers as they learn, understand and transition to TOU measured demand – including how to 'beat their bills'.

[4] www.thelinescompany.co.nz/customers/pricing-and-billing

Consumers on the Major Users Plan (MUP) do not have a kW load charge. The singular impact of these consumers on local network infrastructure and demand peaks means the capital investment incurred is irrespective of time of use, and recovery of this cost is through the use of dedicated asset and/or network charges.

2.4.2. Dedicated Asset Recovery

Where identifiable, consumers are charged for the use of assets and associated investment as dedicated to their individual supply. The pricing components included are:

- Dedicated transformer charge;
- Dedicated lines charge;
- Control relay charge;
- Pole mounting charge for streetlights.

Standard use consumers, who pay for the use of a dedicated transformer, are charged a lower network charge. The high voltage network charge recovers less of the shared cost of supply. The transformer to which they are connected is dedicated to their use and their connection is to the high voltage distribution network. This price differential is shown on the tariff schedule as high and low voltage.

2.4.3. Low Fixed Charge

All EDB's have an obligation to provide a Regulated Distributor tariff option to consumers in their principal place of residence. This tariff (Low Fixed Charge Plan) must have a fixed charge of no more than 15 cents per day and the sum of fixed and variable charges must be such that, for the average consumer, this tariff is not more than any alternative tariff offered. The requirement to offer such a tariff option, and the resulting subsidy, is acknowledged in section (a) (i) of the Pricing Principles.

Eligibility for this Tariff is based on the definition of an "average consumer". The regulations define an average consumer as a customer in their primary place of residence with annual consumption below 8,000 kWh (9,000 kWh for applicable South Island regions). As the regulations don't define an average customer with regards to load, TLC has determined an average consumer for application of this Pricing Methodology. Explanation and supporting data for this has been provided to the EA under disclosure requirements in the regulations. (Reg. 23(d)). For the period 1 April 2015 to 1 April 2016, the average consumer has a kW load of 2.4 kW.

2.4.4. Service fees

Other pricing components used to recover target revenue are:

- Account fees;
- De-energisation and re-energisation charges.

These charges recover the dedicated provision of the respective service. Similar to the dedicated asset charges, when dedicated provision of service is identified, it is recovered and shared costs reduced.

2.4.5. Transmission charges

The transmission charge recovers the connection and interconnection charges payable to Transpower plus any other recoverable costs payable to Distributed Generators on TLC network.

Customers with capacity requirements less than 100 kVA (SUP) contribute to the recovery of these costs through a single variable transmission charge based on the same quantity as the kW load charge.

Large capacity customers on the MUP have two transmission charges:

- Connection Charge – recovers a portion of the connection charge from Transpower;
- Individual Peak Demand/Demand coincidental with 100 highest Transpower peaks – based on either, the average of the highest six, two hour peaks recorded at the installation over the previous year; or the load co-incidental with Transpower's top 100 LNI peaks where an installation may make a significant impact on LNI RCPD. The decision to recover transmission from MUP using anytime peaks is that the load patterns of these consumers has a greater singular impact on network constraints.

2.4.6. Price Changes

Target Revenue has increased by 2% from the preceding year. The following table shows the Target Revenue allocated by Pricing Component. The price component allocation is made in line with current methodology, and excludes revenue earned from Non Standard Contracts and Distributed Generator customers.

Standard Contracts - Target Revenue and Price Components				
		2014	2015	2015
Cost	Key Price Component	$m	$m	% of Total
Distribution	Fixed Capacity Charges	$ 8.0	$ 7.9	23%
	Variable Demand Charges	$ 15.6	$ 16.2	48%
	Dedicated Asset Charges	$ 3.1	$ 3.3	10%
	Low Fixed Charges	$ 0.3	$ 0.3	1%
	Service Fees	$ 0.3	$ 0.2	1%
Recoverable	Transmission Charges	$ 6.2	$ 6.1	18%
Total		$ 33.6	$ 34.0	100%

Table 7: 2015 Price Changes

3. Non-Standard Contract Pricing Methodology

3.1. Non-Standard Contracts

TLC currently has 13 consumers connected to its network on Non-Standard Contracts. The rationale for using a non-standard contract is based on the cost of the assets dedicated (substantially dedicated) to the provision of the connection and the service levels required to maintain supply at the connection.

Non-Standard Contracts - Target Revenue and Price Components						
Non-Standard Contracts	No. of Customers	Revenue 2014	Revenue 2015	2015 - % of Target Revenue earned from Key Pricing Components		
		$m	$m	Assets	Network	Transmission
Total	13	$ 5.0	$ 5.6	66%	11%	23%

Table 8: Non-Standard Contract Statistics

Shared network and transmission costs are recovered as per standard contracts. Typically a non-standard contract consumer will require a capacity over 100 kVA.

The price charged for the dedicated assets will be driven by:

- An asset maintenance cost based on the costs to maintain the dedicated assets. It includes a charge based on the line length of the dedicated asset multiplied by the relevant rate per km;
- A value related cost to earn a rate of return on the Regulatory Asset Value of the dedicated assets during the regulatory return period;
- A recovery of capital cost to reflect depreciation of the asset during the contract term. The estimated value of the assets at the end of the current contract period is influenced significantly by the likelihood of the operation continuing beyond the contact period, or the assets being of value on contract expiry.
- Customer related costs, depending upon the time commitment and frequency of interaction, required to maintain the contractual relationship.

3.1.1. Pricing Principles alignment

The non-standard contract methodology aligns with the Pricing Principles in that:

- It prices on the basis of being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs);
- It has regard to the level of available service capacity;
- Prices are set with regard to consumers' demand responsiveness.

Prices are responsive to the requirements and circumstances of stakeholders in order to discourage uneconomic bypass.

3.2. Supply obligation

There is no specific obligation that would increase the supply obligation in a non-standard contract. However, an increased level of service is implicit when dedicated assets are installed as part of the infrastructure requirements.

4. Distributed Generation Pricing Methodology

Prices charged and payments made to Generators on TLC's network are in accordance to the intent of Part 6: Connection of Distributed Generation of the Electricity Industry Participation Code 2010 and the pricing principles outlined in that document. The code has different regulations for injection, less than and greater than 10 kW.

4.1. Distributed Generation Charges

Distributed Generators, at point of connection, may be charged a:

- Network Charge based on capacity requirements;
- Dedicated Asset charge based on recovery of investment and related costs;
- An administration charge to cover costs associated with calculation of ACOT payments, general account maintenance, and engineering and other technical costs that relate to distributed generation generally and for specific installations.

4.2. Distributed Generation Payments

Generators may receive payment for the benefit they provide in avoiding transmission charges from Transpower. These ACOT payments are recovered from the interconnection portion of transmission charges made to all customers on TLC's network. Where possible the calculation of this benefit is dependent upon the current methodology used by Transpower to allocate their interconnection charges. Currently, the benefit is calculated as follows:

- The average injection by the generator at the time of each of the top 100 LNI peaks in the preceding year ending 31 August. Where negotiated, ACOT will be paid only if the generator supplies metering data to TLC in a format that can be constantly fed into TLC's network operating system;
- Adjusted by losses between the point of injection into the network and the Transpower POS;
- Multiplied by the charge, per kW, as charged by Transpower.

Appendix 1: Pricing Principles Alignment Table

Pricing Principles		Pricing Methodology Reference
(a) Prices are to signal the economic costs of service provision by:		
	(i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation	Section 1
	(ii) having regard, to the extent practicable, to the level of available service capacity	Section 1.4
	(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs	
(b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable		Section 2.4.1
(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:		
	(i) discourage uneconomic bypass	Section 3
	(ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price / quality trade-offs or non-standard arrangements for services	Section 1.1 , Section 2.2 , Section 3
	(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives and technology innovation	Section 4
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact to stakeholders		Section 1.4
(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		n/a

Appendix 2: Information Disclosure Guidelines Alignment Table

Information Disclosure Guidelines		Pricing Methodology Reference
(a) Prices should be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked		
(b) The pricing methodology disclosed should demonstrate:		
	(i) How the methodology links to the pricing principles and any non-compliance	refer; Alignment table
	(ii) The rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings	Section 2.2
	(iii)Quantification of key components of costs and revenues	Section 2
	(iv) An explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping	Section 2.3
	(v) An explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design	Section 2.4
	(vi) Pricing arrangements that will be used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management, where alternatives are practicable and where network economics warrant.	Section 2.4 , Section 4
(c) The pricing methodology should:		
	(i) Employ industry standard terminology, where possible	Abbreviations
	(ii) Where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition to introduce the new methodology	Section 1.3

Appendix 3: Information Disclosure Determination 2012 Alignment Table

Information Disclosure Determination 2012 requirements	Price Methodology Reference
Section 2.4.1 Every EDB must publically disclose, before the start of each pricing year, a pricing methodology which- (4) Explains whether, and if so how, the EDB has sought the **views of consumers**, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Section 1.1
Section 2.4.3 Every disclosure under clause 2.4.1 above must- **(1)** Include sufficient information and commentary to enable interested persons to understand how **prices** were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group	Section 2.3
(2) Demonstrate the extent to which the pricing methodology is consistent with the **pricing principles** and explain the reasons for any inconsistency between the pricing methodology and the pricing principles	refer Alignment table
(3) State the **target revenue** expected to be collected for the disclosure year to which the pricing methodology applies	Section 2.4, Section 3
(4) Where applicable, identify the **key components of target revenue** required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components	Section 2.1
(5) State the **consumer groups** for whom the prices have been set, and describe - **(a)** the rationale for grouping consumers in this way **(b)** the method and the criteria used by the EDB to allocate consumers to each of the consumer groups	Section 2.2
(6) If **prices have changed** from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons	Section 2.4.6
(7) Where applicable, describe the method used by the EDB to **allocate the target revenue** among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way	Section 2.3
(8) State the **proportion of target revenue** (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18	Section 2.4, Section 3

Appendix 3: Information Disclosure Determination 2012 Alignment Table (continued)

Information Disclosure Determination 2012 requirements	Price Methodology Reference
Section 2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a **pricing strategy** - **(1)** Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set	Section 1.4
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy	
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes	
Section 2.4.5 Every disclosure under clause 2.4.1 above must- **(1)** Describe the approach to setting prices for **non-standard contracts**, including- **(a)** the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts	Section 3
(b) how the EDB determines whether to use a non-standard contract, including any criteria used	
(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles.	
(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the **supply of electricity lines services to the consumer is interrupted**. This description must explain- **(a)** the extent of the differences in the relevant terms between standard contracts and non- standard contracts	Section 3.3
(b) any implications of this approach for determining prices subject to non-standard contracts	
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own **distributed generation,** including any payments made by the EDB to the owner of any distributed generation, and including the- **(a)** prices; and **(b)** value, structure and rationale for any payments to the owner of the distributed generation.	Section 4

Appendix 4: Director's Certification - Schedule 17

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1 of section 2.9

We, Angus Malcolm DON and John McFadyen RAE, being directors of The Lines Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the following attached information of The Lines Company Limited prepared for the purposes of clause 2.4.1, clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

26 MARCH 2015	26 MARCH 2015
Date	Date
Angus Malcolm DON	**John McFadyen RAE**
Chairman	Director

Appendix 5: Schedule of Rates 2015

The Lines Company Limited
Schedule of Rates
1 April 2015

The Lines Company Limited Lines Charges

Effective 1 April 2015 (excl. GST)

Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012. Commencement date: 1 April 2015.

Consumer Group	Forecast number of ICPs as at 1 April 2015	Lines Charges																				
		Distribution Charges									Transmission Charges											
		Fixed Charge						Variable Charge			Variable Charge											
		Network			Low Fixed Charge			kW Load			kW Load			Connection			Individual Peak demand			Co-incidental demand		
Hangatiki		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	1,780				5.07	5.07	4.56	23.97	25.01	22.51	7.37	7.42	6.68									
Low Density/Low Voltage	243				5.07	5.07	4.56	31.68	33.03	29.73	7.37	7.42	6.68									
High Density/High Voltage	249				5.07	5.07	4.56	19.53	20.39	18.35	7.37	7.42	6.68									
Low Density/High Voltage	285				5.07	5.07	4.56	23.26	24.28	21.85	7.37	7.42	6.68									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	3,008	4.00	4.16	3.74				17.75	18.46	16.61	7.37	7.42	6.68									
Low Density/Low Voltage	840	7.70	8.01	7.21				17.75	18.46	16.61	7.37	7.42	6.68									
High Density/High Voltage	1,156	1.87	1.94	1.75				17.75	18.46	16.61	7.37	7.42	6.68									
Low Density/High Voltage	1,406	3.66	3.81	3.43				17.75	18.46	16.61	7.37	7.42	6.68									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	1	115.24	119.85	107.87										18.73	18.89	17.00	73.35	70.10	63.09			
11 kV	19	109.20	113.57	102.21										18.73	18.89	17.00	73.35	70.10	63.09			
33 kV	1	66.26	68.91	62.02										18.73	18.89	17.00	73.35	70.10	63.09			
Stepped	1	81.91	85.19	76.67										18.73	18.89	17.00	73.35	70.10	63.09			
Co-incidental demand																				130.45	125.75	113.18
Whakamaru		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	248				5.07	5.07	4.56	29.96	31.24	28.12	1.68	1.57	1.41									
Low Density/Low Voltage	80				5.07	5.07	4.56	36.44	37.97	34.17	1.68	1.57	1.41									
High Density/High Voltage	17				5.07	5.07	4.56	25.52	26.62	23.96	1.68	1.57	1.41									
Low Density/High Voltage	189				5.07	5.07	4.56	28.67	29.91	26.92	1.68	1.57	1.41									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	484	4.00	4.16	3.74				23.74	24.69	22.22	1.68	1.57	1.41									
Low Density/Low Voltage	412	7.11	7.39	6.65				23.74	24.69	22.22	1.68	1.57	1.41									
High Density/High Voltage	65	1.87	1.94	1.75				23.74	24.69	22.22	1.68	1.57	1.41									
Low Density/High Voltage	987	3.38	3.52	3.17				23.74	24.69	22.22	1.68	1.57	1.41									
Major User Plan		$/kVA/annum															$/kVA/annum			$/kVA/annum		
400 V	1	115.24	119.85	107.87													20.80	18.88	16.99			
11 kV	1	206.71	214.98	193.48													20.80	18.88	16.99			
33 kV	1	66.26	68.91	62.02													20.80	18.88	16.99			
Stepped	1	81.91	85.19	76.67													20.80	18.88	16.99			
Co-incidental demand																				130.45	125.75	113.18

The Lines Company Limited Lines Charges																						
Effective 1 April 2015 (excl. GST)																						
Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012. Commencement date: 1 April 2015.																						
Consumer Group	Forecast number of ICPs as at 1 April 2015	Lines Charges																				
		Distribution Charges									Transmission Charges											
		Fixed Charge						Variable Charge			Variable Charge											
		Network			Low Fixed Charge			kW Load			kW Load			Connection			Individual Peak demand			Co-incidental demand		
Ohakune		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	302				5.07	5.07	4.56	20.80	21.70	19.53	6.54	6.51	5.86									
Low Density/Low Voltage	0				5.07	5.07	4.56	24.84	25.89	23.30	6.54	6.51	5.86									
High Density/High Voltage	43				5.07	5.07	4.56	16.34	17.06	15.35	6.54	6.51	5.86									
Low Density/High Voltage	0				5.07	5.07	4.56	18.32	19.12	17.21	6.54	6.51	5.86									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	1,432	4.02	4.18	3.76				14.54	15.11	13.60	6.54	6.51	5.86									
Low Density/Low Voltage	0	5.96	6.19	5.57				14.54	15.11	13.60	6.54	6.51	5.86									
High Density/High Voltage	175	1.88	1.95	1.76				14.54	15.11	13.60	6.54	6.51	5.86									
Low Density/High Voltage	0	2.83	2.94	2.65				14.54	15.11	13.60	6.54	6.51	5.86									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	1	115.24	119.85	107.87										15.00	15.81	14.23	61.43	62.31	56.08			
11 kV	1	119.61	124.27	111.84										15.00	15.81	14.23	61.43	62.31	56.08			
33 kV	1	66.26	68.91	62.02										15.00	15.81	14.23	61.43	62.31	56.08			
Stepped	1	81.91	85.19	76.67										15.00	15.81	14.23	61.43	62.31	56.08			
Co-incidental demand																				130.45	125.75	113.18
Ongarue		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	993				5.07	5.07	4.56	24.87	25.94	23.35	8.46	8.57	7.71									
Low Density/Low Voltage	208				5.07	5.07	4.56	32.62	34.01	30.61	8.46	8.57	7.71									
High Density/High Voltage	118				5.07	5.07	4.56	20.41	21.32	19.19	8.46	8.57	7.71									
Low Density/High Voltage	168				5.07	5.07	4.56	24.16	25.21	22.69	8.46	8.57	7.71									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	1,848	4.02	4.18	3.76				18.61	19.35	17.42	8.46	8.57	7.71									
Low Density/Low Voltage	397	7.74	8.05	7.25				18.61	19.35	17.42	8.46	8.57	7.71									
High Density/High Voltage	362	1.88	1.96	1.76				18.61	19.35	17.42	8.46	8.57	7.71									
Low Density/High Voltage	612	3.68	3.83	3.45				18.61	19.35	17.42	8.46	8.57	7.71									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	1	115.24	119.85	107.87										25.91	26.20	23.58	84.28	76.59	68.93			
11 kV	2	123.82	128.77	115.89										25.91	26.20	23.58	84.28	76.59	68.93			
33 kV	1	66.26	68.91	62.02										25.91	26.20	23.58	84.28	76.59	68.93			
Stepped	1	81.91	85.19	76.67										25.91	26.20	23.58	84.28	76.59	68.93			
Co-incidental demand																				130.45	125.75	113.18

The Lines Company Limited Lines Charges																						
Effective 1 April 2015 (excl. GST)																						
Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012. Commencement date: 1 April 2015.																						
Consumer Group	Forecast number of ICPs as at 1 April 2015	Lines Charges																				
		Distribution Charges									Transmission Charges											
		Fixed Charge						Variable Charge			Variable Charge											
		Network			Low Fixed Charge			kW Load			kW Load			Connection			Individual Peak demand			Co-incidental demand		
National Park		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	97				5.07	5.07	4.56	26.37	27.44	24.70	9.86	10.65	9.59									
Low Density/Low Voltage	37				5.07	5.07	4.56	31.20	32.46	29.21	9.86	10.65	9.59									
High Density/High Voltage	18				5.07	5.07	4.56	21.03	21.92	19.73	9.86	10.65	9.59									
Low Density/High Voltage	34				5.07	5.07	4.56	23.39	24.36	21.92	9.86	10.65	9.59									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	293	4.82	5.00	4.50				18.44	19.14	17.23	9.86	10.65	9.59									
Low Density/Low Voltage	168	7.14	7.41	6.67				18.44	19.14	17.23	9.86	10.65	9.59									
High Density/High Voltage	52	2.26	2.35	2.12				18.44	19.14	17.23	9.86	10.65	9.59									
Low Density/High Voltage	119	3.39	3.52	3.17				18.44	19.14	17.23	9.86	10.65	9.59									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	1	115.24	119.85	107.87										47.35	55.66	50.09	68.18	72.13	64.92			
11 kV	2	159.20	165.25	148.73										47.35	55.66	50.09	68.18	72.13	64.92			
33 kV	1	66.26	68.91	62.02										47.35	55.66	50.09	68.18	72.13	64.92			
Stepped	1	81.91	85.19	76.67										47.35	55.66	50.09	68.18	72.13	64.92			
Co-incidental demand	1																			130.45	125.75	113.18
Tokaanu		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	1,106				5.07	5.07	4.56	23.18	24.19	21.77	5.75	5.58	5.02									
Low Density/Low Voltage	12				5.07	5.07	4.56	30.93	32.26	29.03	5.75	5.58	5.02									
High Density/High Voltage	34				5.07	5.07	4.56	18.72	19.57	17.61	5.75	5.58	5.02									
Low Density/High Voltage	16				5.07	5.07	4.56	22.47	23.46	21.11	5.75	5.58	5.02									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	3,378	4.02	4.18	3.76				16.92	17.60	15.84	5.75	5.58	5.02									
Low Density/Low Voltage	37	7.74	8.05	7.25				16.92	17.60	15.84	5.75	5.58	5.02									
High Density/High Voltage	94	1.88	1.96	1.76				16.92	17.60	15.84	5.75	5.58	5.02									
Low Density/High Voltage	85	3.68	3.83	3.45				16.92	17.60	15.84	5.75	5.58	5.02									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	1	115.24	119.85	107.87										8.69	10.03	9.03	58.45	56.96	51.26			
11 kV	6	119.61	124.39	111.95										8.69	10.03	9.03	58.45	56.96	51.26			
33 kV	1	66.26	68.91	62.02										8.69	10.03	9.03	58.45	56.96	51.26			
Stepped	1	81.91	85.19	76.67										8.69	10.03	9.03	58.45	56.96	51.26			
Co-incidental demand																				130.45	125.75	113.18

The Lines Company Limited Common Fees and Charges
Effective 1 April 2015 (excl. GST)

Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012

Charge Type	Commencement Date	Forecast number of ICPs as at 1 April 2015			
Dedicated Transformer Charge			Previous	Current	After PPD
Billing Code			$/month		
T5	1 April 2015	3,143	24.85	25.84	23.26
T10		886	41.24	42.89	38.60
T15		1,688	56.49	58.75	52.88
T30		196	74.82	77.81	70.03
T50		186	82.91	86.23	77.61
T75		101	101.15	105.20	94.68
T100		45	113.06	117.58	105.82
T200		20	194.85	202.64	182.38
T300		5	235.16	244.57	220.11
T500		2	275.34	286.35	257.72
T750		2	330.52	343.74	309.37
T1000		1	372.64	387.55	348.80
T1250		1	393.70	409.45	368.51
T1500		3	443.23	460.96	414.86

Charge Type	Commencement Date	Forecast number of ICPs as at 1 April 2015			
Dedicated Lines Charges			Previous	Current	After PPD
Line Type			$/month		
11kV 3 phase o/head (>50mm<150mm)	1 April 2015	2	0.60	0.62	0.56
11kV 3 phase o/head (<50mm)			0.51	0.53	0.48
11kV single phase			0.43	0.45	0.41
11kV single phase SWER			0.38	0.40	0.36
400V 4 wire system			0.70	0.73	0.66
400V 2&3 wire system			0.57	0.59	0.53
400V underbuilt 4 wire			0.37	0.38	0.34
400V underbuilt 2&3 wire			0.33	0.34	0.31
11kV cables (>50mm<240mm)			1.58	1.64	1.48
11kV cables (<50mm)			1.30	1.34	1.22
400V 3&4 wire heavy (>240mm)			1.21	1.26	1.13
400V 3&4 wire medium (<240mm)			1.01	1.05	0.95
400V 2&3 wire light			0.60	0.62	0.56

The Lines Company Limited Common Fees and Charges
Effective 1 April 2015 (excl. GST)

Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012

Charge Type	Commencement Date	Forecast number of ICPs as at 1 April 2015	Previous	Current	After PPD
Relay Fees			$/Unit/month		
	1 April 2015	17,108	1.62	1.67	1.50
Streetlight Charges			$/pole/month		
For streetlights mounted on poles belonging to The Lines Company		6	4.50	4.68	4.21

The Charges for Streetlights comprise:

1/ For those on a dedicated streetlight circuit;

a. An asset charge based on the value of the streetlight circuit as per the dedicated line charge, plus

b. the charges applicable to half-hour customers.

2/ For other lights, the charges applicable to non half-hour customers.

3/ For streetlights mounted on power poles forming part of The Lines Company network, an additional charge per month per pole

4/ The standard load shifting and control charges where those services are supplied.

Billing Charge		33	$/month		
			141.32	146.97	132.27

applicable to customers on the Major User Plan

Load Shifting Charge		10	$/plant operation		
			2.50	2.58	2.32

De-Energisation and Re-Energisation Schedule
Travel and cost incurred
Prompt Payment Discount not applicable

	The Lines Company has depots at the following towns; Te Kuiti, Taumarunui, Turangi & Ohakune. The following measurements are from these depots. Otorohanga is included in Urban A.	Urban A	Rural B	Remote C	Special D
		Inside 50 km/h zone.	Up to 25 kms from depot.	Over 25 kms from depot.	Door Knock Request
		$	$	$	$/request
1	**EARLY - NEXT DAY:** Job request by 2:00 pm and executed next working day by 4:30 pm.	46.58	58.22	174.66	60.00**
	Previous Charges	46.58	58.22	174.66	60.00
2	**LATE - NEXT DAY**: Job request after 2:00 pm executed next working day by 4:30 pm.	52.40	64.05	203.77	** Additional charge if no contact is made by customer prior to 2 working days before De-energisation. Further charges of $15 per 10 minute blocks apply if staff member is onsite and required to wait whilst customer contacts The Lines Company or Energy Retailer for extension of payment.
	Previous Charges	52.40	64.05	203.77	
3	**SAME DAY:** Job request for same working day before 3:00 pm and executed that day.	69.86	81.51	261.99	
	Previous Charges	69.86	81.51	261.99	
4	**AFTER HOURS:** Re-energisation request only. From 3:00 pm onwards on any given weekday, weekend or public holiday before 10:00 pm.	116.44	174.66	349.31	
	Previous Charges	116.44	174.66	349.31	
5	**AFTER HOURS:** Re-energisation request only. After 10:00 pm on any given day including public holidays.	232.88	291.09	523.97	
	Previous Charges	232.88	291.09	523.97	
7	**CANCELLATION FEE:** Applies if request 1(a,b,c) is cancelled between 2:00-4:00pm on day prior to scheduled action. If cancellation after 4:00 pm then full charge applies.	36.23	47.87	164.31	
	Previous Charges	36.23	47.87	164.31	

- The disclosure of this document is in accordance with Section 2.4.1 of the Information Disclosure Determination 2012.

- The development of this methodology is in alignment with the Pricing Principles developed by the Electricity Authority, in accordance with statutory objectives defined in the Electricity Industries Act 2010.

- The Pricing Methodology employed by The Lines Company Limited recovers regulated income under the Default Price Quality Path as prescribed by Commerce Commission Input Methodology Determination 2012.

- The disclosure year is 1 April 2015 to 31 March 2016.