EASTLAND
Infrastructure

PRICING METHODOLOGY DISCLOSURE

(On behalf of Eastland Network Limited)

Pursuant to:
Requirements 22 and 23 of the
Electricity Information Disclosure Requirements 2004

For Line Charges introduced on 1 April 2005

April 2005

CONTENTS

1.0 Introduction

This document describes Eastland Network Ltd's (ENL's) pricing methodology for the line charges in effect as at 1 April 2005.

This document has been prepared to comply with requirements 22 and 23 of the Electricity Information Disclosure Requirements 2004. The disclosure requirements require electricity line businesses to annually disclose:

- The methodology used to calculate the prices charged;
- The key components of the revenue required to cover costs and profits of the line business activities;
- The consumer groups used to calculate the prices charged, including:
    - The rationale for the consumer grouping;
    - The method of determining which group consumers are in;
    - For each consumer group, the statistics relating to that group.
- The method and rationale by which components of the revenue were allocated to consumer groups, and the numerical values of the different components;
- The method used to determine the proportion of charges which are fixed and the proportion which are variable, and the rationale for determining the proportions in this manner.

2.0 Pricing Principles

2.1 Regulation

Electricity lines companies are controlled by the requirements set out by the Commerce Commission in the Commerce Act (Electricity Distribution Thresholds) Notice 2004. This means that ENL is assessed annually against two thresholds:

i. a price path threshold, representing the expected annual change in lines business average prices (through applying a CPI-X formula); and
ii. a quality threshold, comprising a reliability criterion and a consumer communication criterion.

The price path threshold criteria limits ENL on the annual change in line charges by setting a threshold that can only change by a maximum of CPI-X[1] per annum. The X factor for ENL has been assigned at 2% for a period of 5 years.

For this reason, although pricing is designed to reflect the cost of supply, an adjustment to the final pricing must be made to ensure that ENL will comply with the regulations and not breach the price path threshold.

2.2 Revenue

Pricing should obtain sufficient revenue for ENL to meet the following requirements, while also ensuring that ENL does not breach the price path threshold.

- Meet its contractual obligations for connection to the Transpower Grid.
- Meet its contractual obligations for the delivery of energy over its network to the end-consumers.
- Comply with statutory requirements on public safety, environmental protection and quality of supply.
- Provide for new investment.
- Provide a commercially appropriate return on funds.

2.3 Efficiency

Pricing must be economically efficient in the investment signals it creates. This is achieved by matching the pricing structure to the cost structure as closely as practical.

2.4 Even-handedness

Pricing must be even-handed across different load groups. Specifically:

- The charges to various load groups using the network should vary according to their relative use of different assets.
- Where load groups have different service requirements, service at levels above the common denominator should be charged specifically to the load groups demanding higher levels of service.
- Average costing will be applied where there is common good usage of assets and services within a load group.
- Where new investment is required those users who obtain the benefit should be required to contribute towards the cost.

[1] Where, CPI is the change in the consumers price index. For more information refer to the New Zealand Gazette, Commerce Act (Electricity Distribution Thresholds) Notice 2004.

Pricing must also be even-handed in its treatment of different retailers and provide for equal access as a matter of statutory requirement.

2.5 Simplicity

Pricing must be kept as simple and as administratively efficient as practical. Specifically:

- Transmission charges should be separated from distribution charges.
- ENL should endeavour to ensure distribution costs are relatively stable over time.

2.6 Load Management

The pricing methodology should provide signals to encourage demand-side participation in load management.

3.0 Derivation of Revenue Requirement

The first step in developing pricing is to determine the cost structure and revenue requirement. Costs can then be allocated between different load groups.

The total revenue requirement is shown in Table 1.

Table 1 – Revenue Requirement

Component	**Revenue Requirement during 2005/06**
Cost of Capital	$7,205,947
Depreciation	$2,774,499
Maintenance	$1,930,710
Indirect Expenses	$3,791,196
Transpower Charges	$5,080,000
Avoided Transmission Charges	$2,410,000
TOTAL	**$23,192,352**

Note that Transpower Loss Rental Rebates are excluded from the revenue requirement as these are passed on transparently, and in full, via a separate rebate mechanism (separate to line charges), to ENL's customers and/or electricity retailers.

3.1 Distribution Revenue Requirement

The distribution revenue requirement is made up of the following components:

- Cost of Capital
- Depreciation
- Maintenance
- Indirect Expenses

A summary of the derivation of the key components is provided below.

3.1.1 Cost of Capital

Determination of Cost of Capital

Eastland Network Ltd has been undertaking, and is continuing to undertake, investment in its network to meet the following asset management objectives:

- Provide for growth
- Deliver appropriate service standards where network usage has changed.
- Age replacement of assets with appropriate modern solutions.

Capacity/security upgrades result in reconfiguration of network feeders and therefore changes the criteria used to allocated asset value, load and ICP's. It has therefore been necessary to assume a model of the network configuration in order to create some stability in pricing.

The asset values applied in this pricing methodology uses the 2004 ODV plus additions/removals to bring the value up to 31 March 2006.

Cost of Capital

Actual Cost of Capital on asset investment is targeted at the WACC figure of 7.5% averaged across the entire asset base. This figure determines the overall recovery required on total network assets, however different parts of network have had different effective rates applied via the application of multipliers to reflect the economic value differences. Multipliers are summarised below:

High Density Sub-Transmission (on ORC)	1.2
Medium Density Sub-Transmission (on ORC)	0.8
High Density Distribution (on ODRC)	1.2
Medium Density Distribution (on ODRC)	1.0
Low Density Distribution (on ODRC)	0.85

For sub-transmission assets, the Cost of Capital is based on replacement cost. This asset is critical to network operations, supporting large commercial loads. It is therefore maintained in an as new condition i.e. replacement on age failure is not an appropriate asset management strategy for this asset. This is the core of the companies' asset investment and the Cost of Capital reflects the fact that these assets are actually returning at higher rates. However they are constrained by the relative ease with which they can be by-passed and therefore the Cost of Capital is set below this trigger.

High Density network Cost of Capital is set at a figure greater than WACC to reflect higher levels of interconnection and under-grounding (service and amenity) where ODV Handbook Standard Values are inadequate i.e. ODV increase fails to capture actual expenditure. On a network where significant renewal work is a necessity getting an adequate investment signal is necessary to prevent the region being starved of vital infrastructure. Currently assets in Low Density areas deliver returns well below WACC. ODV Methodology undertakes economic valuation and optimisation on the basis of the maximum tariff being applied (i.e. the next most viable supply alternative). Eastland Network Ltd does not apply the maximum tariff to these areas and therefore under-recovers from Low Density assets. This is reflected in the above targeted returns and is in effect cross-subsidisation from high to low density connections.

The consequence of low returns in the Low Density network will be an incentive not to renew or reinvest until asset value depreciates and lower cost solutions can be agreed on with users.

The Cost of Capital requirement is allocated across load groups on the basis each group's asset value allocation.

3.1.2 Depreciation, Maintenance and Indirect Costs

The revenue requirement to cover the depreciation, maintenance and indirect costs is based on the budget for 2005/06.

3.2 Transmission Revenue Requirement

The transmission revenue requirement is made up of the following components:

- Transpower Charges
- Avoided Transmission Charges

Power supply on the East Coast is capacity constrained primarily by the Transpower owned transmission connection assets i.e. the spur assets dedicated to the regions use.

Traditional lines-type solutions to upgrading capacity and security standards do not represent the least cost solution. The cost of Transpower provided solutions have been determined via the New Investment Agreement Methodology Transpower applies to such upgrades.

Eastland Network Ltd has determined that better load management, optimising the configuration of its sub-transmission system and the introduction of distributed generation present a lower risk and more economic solution.

Consequently transmission recovery is intended to recognise the transmission benefit and avoidance of Transpower charges in order to fund these alternatives whether provided by ENL or another party.

3.2.1 Transpower Cost Recovery

Transpower charges are calculated per Transpower's methodology applying the following assumptions:

- Inflation is set at 0% as Transpower has announced its pricing movements for the coming year.
- Interconnection Rate at $55.81/kW as notified by Transpower.
- Gisborne GXP demand at 40,757kW (Net of D.G. and load control)
- The combined undiversified Wairoa and Tuai GXP demand at 9,071kW.

EVA Rebates

Transpower adjusts its asset valuation and return requirements from time to time. However, the contracted pricing position networks have with them tends to be locked into fixed terms. Consequently when downward value movements occur, Transpower over-recovers on its new revenue requirement.

Transpower has notified that they will be rebating an Economic Value Adjustment for the coming year and consequently the expected value of this rebate is netted off Eastland Network Ltd's transmission requirement. The rebate is asset based and therefore the allocation to each connection will be determined on the basis of asset usage i.e. as for the connection charge on the basis of the percentage of total kWh's metered at the GXP and reconciled to them for that month.

3.2.2 Avoided Transmission Costs

Based on the existing regulations set out in the Commerce Act (Electricity Distribution Thresholds) Notice 2004, a distribution company can pass through the costs of avoided transmission to its customers and/or electricity retailers via the line charges. ENL calculates the cost of avoided transmission based on the sum of following factors:

- Cost of Capital;
- Depreciation cost;
- Direct operating costs;
- Maintenance costs;
- Indirect costs.

4.0 Allocation of Revenue Requirement between Load Groups

4.1 Allocators

4.1.1 Feeder Classification

Each feeder has been given one of the following classifications on the basis of the load density characteristics it exhibits:

- High Density
- Medium Density
- Low Density
- Industrial

The actual feeder classification is summarised in Appendix 1, Table A.1.

The two load density indicators applied during assessment were ODV per connection and kWh per connection. Anomalies such as feeders providing interconnection capability that appear as a Low Density island surrounded by Medium Density classifications, were adjusted for smoother transition.

Industrial feeders are dedicated supplies.

The network has been segmented into these classifications to allow pricing to differentiate between connections with differing location and usage issues.

4.1.2 User Classification

Eastland Network Ltd has chosen to differentiate between Domestic and Non-Domestic consumers to reflect their different demands on reliability, security etc.

Industrial users with assessed demand greater than 300kVA and TOU metering attract TOU line charges. This group is a heavy user of the sub-transmission system but a relatively low user of the distribution network. It tends to drive the requirement for capacity and security upgrades.

4.1.3 Forecast ICP's by Load Group

ICP numbers as at mid 2005/06 have been forecast based on actuals as at 31 Dec 2005 for the seven load groups:

- Low Density Domestic
- Low Density Non-Domestic
- Medium Density Domestic
- Medium Density Non-Domestic
- High Density Domestic
- High Density Non-Domestic
- Industrial

The ratios derived from this allocation are used to apportion costs driven by "per connection" issues. The forecast ICP's by load group are summarised in Appendix 1, Table A.2.

4.1.4 Forecast Consumption by Load Group

Consumption has been similarly forecast for each load group. As the allocation is used to calculate ratios, forecast ICP consumption data has been applied. The forecast consumption by load group are summarised in Appendix 1, Table A.2.

4.2 Allocation of Revenue Requirement among Consumer Groups

Following the determination of the allocators, the Revenue Requirement, comprising of Distribution and Transmission Requirements, is allocated between Consumer Groups. A summary of the final allocation is shown Appendix 1 Table A.2 – Total Revenue Requirement by End-Consumer Group.

Generally, sub-transmission allocation has been based on usage, due to large users having higher load factors. Distribution allocation has generally been on the basis of connections in each load group. This reflects the fact that industrial users are low users of distribution asset and reflects connection density and rural network economic issues.

4.2.1 Allocation of Distribution Revenue Requirement

4.2.1.1 Allocation of Cost of Capital

The cost of capital associated with network assets has been allocated between sub-transmission and distribution as different methodologies are used for allocating these costs to the different load groups.

Sub-transmission Allocation

The cost of capital of sub-transmission assets has been allocated using feeder classification and kWh. The cost of capital of a sub-transmission asset is first distributed to a feeder level according to it's feeder classification and then to load group based on kWh.

This is in proportion to demand assuming the proposed network configuration as at 31 March 2006.

Zone substations are required to meet differing security standards depending on load size, user type and location. Assets required solely for enhanced security standards have been separated out.

Domestic levels of capacity requirement and low reliability/security demands don't necessitate the same levels of sub-transmission investment as non-domestic and industrial users.

Distribution Allocation
The cost of capital of distribution assets has been allocated using feeder classification and ICP volumes. The cost of capital is first distributed to a feeder level according to it's feeder classification and then the appropriate load group based on the level of ICPs in each load group.

This has been done on the basis of the proposed network configuration as at 31 March 2006.

4.2.1.2 Allocation of Depreciation
Depreciation is allocated on the basis of the asset value allocated to each load group.

Sub-transmission Allocation
Sub-transmission assets are depreciated over their full economic life i.e. they are treated as new assets. The sub-transmission depreciation revenue requirement has been allocated to each load group first by distributing asset value according to feeder classification and then by kWh associated with a load group on that feeder to determine the appropriate allocation.

Distribution Allocation
Distribution assets are depreciated over their remaining average economic life and therefore reflect the fact that a significant amount of low density assets are aging. The distribution asset depreciation requirement has been allocated to each load group by distributing asset value according to feeder classification and then by number of ICPs associated with a load group on that feeder to determine the appropriate allocation.

4.2.1.3 Allocation of Maintenance Costs
Maintenance costs are allocated in proportion to the asset value allocated to each load group.

Sub-transmission Allocation
The sub-transmission maintenance revenue requirement has been allocated to each load group first by distributing asset value according to feeder classification and then by kWh associated with a load group on that feeder to determine the appropriate allocation.

Distribution Allocation
The distribution maintenance requirement has been allocated to each load group by distributing asset value according to feeder classification and then by number of ICPs associated with a load group on that feeder to determine the appropriate allocation.

4.2.1.4 Allocation of Indirect Costs
This revenue covers costs that are not related solely to asset/network usage, however a large customer may require a higher level of management time than a smaller customer. Consequently indirect costs are applied based on 50% ICP allocation in each load group and 50% kWh allocation in each load group.

4.2.2 Allocation of Transmission Revenue Requirement

4.2.2.1 Allocation of Transpower Charges

Transmission costs have been allocated across load groups on the basis of the share of peak demand that that group represents with regard to the Transpower "12 peaks" Pricing Methodology. Costs are further allocated into density bands on the basis of the load group's consumption for Domestic and Non Domestic connections.

4.2.2.2 Allocation of Avoided Transmission Costs

The avoided transmission costs are allocated between load groups in proportion to the Transpower charges.

5.0 Pricing Structure

5.1 Pricing Strategy

Eastland Network uses ICP billing for charging end consumers. However ENL, and other lines companies, are restricted from charging individual customers their true cost of supply due to factors including:

- ENL's existing tariff structure has been functioning, in generally the same structure, for some time. If customers were allocated their true cost of supply, then an excessive level of rate shock would occur.
- Current Government regulation restricting the levels of differential pricing between domestic rural and urban customers and also restricting the level of domestic fixed tariff.

This prevents ENL and other New Zealand Lines Companies from making a true allocation of revenue requirements to each consumer and therefore determining tariffs through an allocation of costs methodology. This results in a considerable level of cross subsidisation between tariff groups.

Eastland Network has applied the pricing strategy, as discussed below, and not an cost allocation strategy. Therefore statistics such as ICPs per tariff group, kWh per tariff, installed capacity or other factors which may be considered for allocating the revenue requirement for each tariff are not required and as such are not included in this disclosure.

5.2 End-consumer grouping

The ENL pricing structure is based on the following end-consumer groupings:

PRICING CATEGORY DESCRIPTION	
Domestic - High Density Domestic - Medium Density Domestic - Low Density	
Non Domestic – High Density	Low Capacity (0 to 2.5kVA)* Small Single Phase (0 to 10kVA) Small Multi Phase (0 to 30kVA) Assessed Demand (31 to 100kVA) Assessed Demand (101 to 300kVA) Assessed Demand (301 to 500kVA) TOU Assessed Demand (501 to 1000kVA) TOU Assessed Demand (1001 to 4500kVA) TOU Assessed Demand (4501 to 6500kVA) TOU
Non Domestic - Medium	Low Capacity (0 to 2.5kVA)* Small Single Phase (0 to 10kVA) Small Multi Phase (0 to 30kVA) Assessed Demand (31 to 100kVA) Assessed Demand (101 to 300kVA) Assessed Demand (301 to 500kVA) TOU Assessed Demand (501 to 1000kVA) TOU Assessed Demand (1001 to 4500kVA) TOU Assessed Demand (4501 to 6500kVA) TOU

PRICING CATEGORY DESCRIPTION *Continued*	
Non Domestic - Low Density	Low Capacity (0 to 2.5kVA)*
	Small Single Phase (0 to 10kVA)
	Small Multi Phase (0 to 30kVA)
	Assessed Demand (31 to 100kVA)
	Assessed Demand (101 to 300kVA)
	Assessed Demand (301 to 500kVA) TOU
	Assessed Demand (501 to 1000kVA) TOU
	Assessed Demand (1001 to 4500kVA) TOU
	Assessed Demand (4501 to 6500kVA) TOU

TOU pricing category's are classified as "industrial" for the purpose of this pricing methodology.

End-consumers are assigned to a pricing category based on whether they are domestic or non-domestic, the feeder they are supplied from (which in turn allocates them to "high", "medium" or "low" density) and the connected capacity or assessed demand of the end-consumer. End-consumers must have a TOU meter fitted to attract a TOU charge, otherwise they will default to the assessed demand of 101 to 300kVA pricing category which attracts a standard variable charge.

5.3 Distribution Tariffs

ENL targets approximately 15% of its total distribution cost recovery requirement across all users as a fixed charge recovery.

Differentials between load groups are achieved by the fixed charges with respect to location/density issues and variable charges with respect to usage issues.

The regulated constraints on fixed charges for domestic consumers results in a cross-subsidy from High Density to Low Density consumers.

5.3.1 Variable Distribution Tariff

ENL has repackaged the "Time-of-Use" signals that apply to its cost structure into "non Time-of-Use" variable tariffs for controlled and uncontrolled options. Its pricing is therefore readily transparent to consumers at their connection level.

Analysis of the Gisborne GXP load profile is used to determine the signalling applied equally to all GXP's.

There is no differentiation for seasonal load and weekend variance. The profile peaks are domestic load driven. The industrial load group represents a relatively high portion of base consumption and has high load factor.

Being capacity constrained, there is a high level of peak signalling in variable tariff differentials to encourage retailers to market for connection of load that minimises consumption at peak times.

It is expected that load growth will therefore tend to flatten the load profile as consumers attempt to exploit the lower cost periods. Revenue growth will not be as high as load growth and therefore is not included in the revenue models assumptions.

5.3.1.1 Domestic Variable Tariffs

There is a 25% differential between the High Density Domestic Distribution variable tariff and the Low Density Domestic Distribution variable tariff. The differential between High Density and Medium Density connections is approximately 12%.

Consequently there is a significant level of cross-subsidy from high to low density areas i.e. Domestic tariffs have a high level of average costing.

The following approximate differentials have resulted between controlled and uncontrolled variable rates after summation of the distribution and transmission components.

Uncontrolled	1.00
Controlled	0.59
Night	0.17

The controlled night rate has the intention of encouraging the connection of larger more efficient higher storage capacity appliances.

Domestic load is considered to drive both the morning and evening daily peaks seen in ENL's system profile as they peak outside normal business hours. Differentials in tariffs are based on the following allocation of peak demand across the load groups as measured at the GXP.

	Peak
Domestic peak allocation	59%
Non Domestic peak allocation	18%
Industrial	23%

5.3.1.2 Non Domestic Variable Tariffs

Variable tariffs have been solved to deliver revenue targets after fixed charge recoveries have been accounted for. The process has been through a number of iterative cycles to smooth for the transition from "Non Time-of-Use" to "Time-of-Use" options. This results in various levels of cross-subsidisation within the Non-domestic/Industrial load group.

Because of the higher average consumption rates a large portion of revenue is being recovered via fixed charges. This allows lower variable rates and has reduced the sensitivity to volume change for Non Domestic consumers.

Load control differentials have resulted as follows:

	Controlled
Small singlephase	0.66
Small multiphase	0.65
Large 100 kVA	0.39
Large 300 kVA	0.38

5.3.1.3 Industrial Variable tariff

Connections are required to have a capacity requirement greater than or equal to 300kVA, and TOU metering to qualify for these charges.

These connections tend to have high load factors and have less opportunity to vary load during production hours.

They prefer a higher level of fixed charging and their TOU line charges allow more specific pricing to reflect the actual costs they create. Consequently peak signalling is reduced in their case to reflect the fact they don't create the peak. However, some peak signalling is preserved to encourage demand side management.

The contribution to cross-subsidy of domestic supply has been removed as an improved "User Pays" allocation of sub-transmission and distribution costs has been achieved.

5.3.2 Fixed Distribution Tariffs

These are based on capacity, phasing requirements and contribution to system load peak. The charges are averaged across all consumers classified into a load group.

Differentiation is relatively coarse but reflects the average marginal cost of the diversified demand a typical connection in each load group creates. They are however distorted by cross-subsidy and issues of compliance with Government Policy and regulations.

5.3.2.1 Domestic Fixed Charges

All domestic fixed charges have been set at 15c/day regardless of network location, connection size etc.

Fixed charges for domestic consumers are therefore totally average costed. All differentiation for these consumers is achieved via variable charges, providing an incentive for low consumption in low density areas of the network. Average costing results in the average consumer paying more than a "user pays" scenario as they carry the cross-subsidy burden.

All domestic consumers receive the benefit of the 15c/day Government Policy intended to reward low consumption behaviour. As this is the only domestic fixed charge and is not optional, compliance with the 8000kWh p.a. break-even requirement is automatic.

5.3.2.2 Non-Domestic Fixed Charges

Non domestic fixed charges are differentiated on the basis of assessed maximum demand and number of phases used. There is no differential representing network location in the fixed charge.

5.3.2.3 Industrial Fixed Charges

A higher component of fixed charge recovery has been targeted for these consumers as this is their preference. This reduces price sensitivity when volumes are large. Actual pricing position is more favourable when load factor is high and system peaks are avoided.

In terms of revenue recovery the industrial load group is averaged with all other Non Domestic consumers which results in a subsidy benefit to this group.

5.3.2.4 Definition of Domestic Supply

To qualify as a domestic connection in terms of ENL's pricing the following test will be applied:

- The connection must be the consumers primary and permanent place of residence.
- The consumer can only claim one connection whether on ENL's network or elsewhere as their primary place of residence.
- It is not permitted to avoid this single connection rule by listing another property under someone-elses name, trust, etc. where that party is sharing the residence on a primary and permanent basis.
- The connection is to be solely used as a residence and not as a business.

5.4 Transmission Tariffs

Transmission tariff components have been solved along similar methodology to distribution components.

5.4.1 New Investment

These charges are fixed and recovered for a finite term. Where upgrade is undertaken for a specific new load then these charges can be allocated to the retailer supplying that customer. Where upgrade is the result of base load growth and required for the common good, it is similar to the connection charge. There are no New Investment Agreements currently in place between ENL and Transpower.

5.4.2 Avoided Transmission

Where an investor provides assets as an alternative to Transpower providing transmission services, such as distributed generation, the benefit of avoided transmission charges will be passed through to the investor on a deprival basis with value calculated per Transpower's pricing methodology. The connection of generators to the ENL network, and the charge/rebates applicable are subject to ENL review on a case-by case basis.

Investment that increases capacity will be recognised via calculation of the Connection Charge, assuming Transpower upgrade. The benefit to consumers over the Transpower solution is that capacity can be delivered on a more capital-efficient incremental basis.

Investment that has the potential to reduce the "12 peak maximum demand", at a GXP will be recognised via pass-through of reductions in Transpower's Interconnection Charge.

The maximum potential for reduction in Transpower charges is dependent on operating assets in co-ordination with ENL's load management and any other party's capability. The level of risk and sharing of benefits between providers will be subject to contracted terms between parties.

Transmission charges are based on the assessed impact these alternative investments will have on the GXP load profiles both in terms of demand and kWh's.

It should be noted that the investor can equally be ENL, any retailer, any generator or independent party. However, the capacity requirement is capped at the ENL determined targets. Where there is a choice of alternative investments, preference will be given to the least cost solution to Eastland Network Ltd on offer at the time of commitment. As with Transpower New Investment Agreements, the commitment will be locked in for an agreed period and not subject to optimisation.

ENL carries the risk of managing transmission cost. This risk is recovered via transmission charges which include an avoided transmission component.

6.0 Losses

The allocation of losses is not a contracted Line Function Service and ENL does not charge specific recoveries for losses.

However in the absence of agreed individual estimated loss calculations the following defaults can be applied to reconcile the difference between ICP and GXP meter readings. These are applicable to all time periods, at all GXP's and network locations.

- 400V connected supplies 8.2%
- 11kV connected supplies 6.2%

7.0 Revenue Model

The pricing structure is applied to connection data to determine the revenue it creates from each load group.

Comparison of the revenues and costs associated with each load group can then be used to identify the cross-subsidies that exist between load groups and confirm compliance requirements are being met.

7.1 Calculated Revenue

The existing pricing structure under-recovers by approximately $0.7M. This is largely due to the regulations imposed under the Commerce Act (Electricity Distribution Thresholds) Notice 2004. Through these regulations ENL are controlled in the level of revenue received per annum. The allowable level of revenue is being achieved by ENL, however as costs continue to increase at a level approximately equal to inflation, and revenue cannot increase by the same amount, therefore ENL will not be recovering it's cost of capital.

7.1.2 Fixed/Variable Ratios

The Fixed Charges as a portion of total revenue for each load group are as follows:

- Low Density Domestic 7%
- Low Density Non-Domestic 24%
- Medium Density Domestic 8%
- Medium Density Non-Domestic 24%
- High Density Domestic 9%
- High Density Non-Domestic 18%
- Industrial 10%

The total fixed charge recovery is 13% of total distribution revenue.

Domestic connections have a fixed charge component of 10% or less.

ENL has a low level of fixed charge recovery, largely due to the sensitivity of the requirement to offer a Low Fixed Charge Option to a consumer base that has below average consumption characteristics.

Appendix 1 – Supporting Tables

Table A.1 - Feeder Classification

			Class
TEARAROA			
	0101	AWATERE	Low Density
	0102	HICKS BAY	Low Density
	0103	TE ARAROA	Low Density
RUATORIA			
	0201	RUATORIA FDR	Medium Density
	0204	MAKARIKA	Low Density
	0206	TIKI-TIKI	Low Density
TOKOMARU			
	0301	INLAND	Low Density
	0302	SEASIDE	Low Density
	0304	MATA RD	Low Density
TOLAGA			
	0401	TOKO-TIE	Low Density
	0402	TOWN	Medium Density
	0403	ROTOTAHI	Low Density
	0404	TAUWHAREPARE	Low Density
KAITI			
	0501	HERSCHELL	High Density
	0502	DALTON	Medium Density
	0503	TAMARAU	High Density
	0504	WAINUI	High Density
	0505	DE LATOUR	High Density
	0506	WHANGARA	High Density
PORT			
	1501	CHIPPER	Industrial
	1502	HARRIS ST	High Density
	1503	KAITI TIE	High Density
	1504	CARNARVON TIE	High Density
CARNARVON			
	0601	KAHUTIA	High Density
	0602	CITY	High Density
	0603	WATTIES	High Density
	0604	ANZAC ST	High Density
	0605	CHILDERS RD	High Density
	0606	AWAPUNI RD	High Density
	0607	GLADSTONE RD	High Density
	0608	PALMERSTON RD	High Density
	0609	ABERDEEN RD	High Density
MAKARAKA			
	0802	CAMPION	High Density
	0803	NELSON ROAD	High Density
	0804	HAISMAN ROAD	High Density
	0805	BUSHMERE ROAD	Medium Density
PARKINSON			
	0701	LYTTON RD	High Density
	0702	WILLOWS RD	Medium Density
	0703	ELGIN	High Density
	0704	CEDENCO A	Industrial
	0705	INNES ST	High Density
	0706	SOLANDER	High Density
	0707	JNL/CHARMERS RD	High Density
MATAWHERO			
	1403	Dunstan Rd Feeder	High Density
	1405	JNL-A Feeder	High Density
	1406	Bell Rd Feeder	Medium Density
JNL			Industrial
PATUTAHI (incl Pehiri, Ngatapa load)			
	0902	LAVENHAM RD	Low Density
	0903	WAIMATA	Medium Density
	0905	MURIWAI	Low Density
	0906	TE ARAI	Low Density
PUHA			
	1201	WHATATUTU	Low Density
	1202	KANAKANAIA	Low Density
	1203	TE KARAKA	Medium Density
	1204	MATAWAI	Low Density
KIWI (incl. Tuai load)			
	2001	WILSONS MILL	Medium Density
	2002	LAKE WAIKAREMOANA	Medium Density
	2003	RUAKITURI	Low Density
	3201	BRICKWORKS	Medium Density
	3202	AFFCO	Medium Density
	3203	NUHAKA	Low Density
	3204	BOROUGH ONE	High Density
	3205	BOROUGH TWO	High Density
TAHANUI			
	3501	MORERE FEEDER	Medium Density
BLACKS PAD			
	3301	MAHIA	Medium Density

Table A.2 – Total Revenue Requirement by End-Consumer Group

2005/06 Pricing Methodology									
	Allocator	Low Density		Medium Density		High Density		Industrial	Total
		Domestic	Non-Domestic	Domestic	Non-Domestic	Domestic	Non-Domestic		
Indirect Expenses	50%ICP, 50%kWh	$396,424	$266,620	$389,309	$186,686	$1,513,050	$510,783	$528,324	**$3,791,196**
Subtrans - Cost of Capital	feeder class and kWh	$434,055	$272,159	$315,076	$165,457	$657,424	$443,743	$682,490	**$2,970,403**
Subtrans - Depreciation	feeder class, ORC and kWh	$113,544	$71,194	$82,420	$43,282	$114,650	$77,385	$118,902	**$621,377**
Subtrans - Maintenance	feeder class, ORC and kWh	$86,003	$53,925	$62,428	$32,783	$86,840	$58,615	$90,061	**$470,655**
Distribution - Cost of Capital	feeder class and ICP	$809,174	$567,051	$594,188	$268,595	$1,706,656	$258,822	$31,058	**$4,235,544**
Distribution - Depreciation	feeder class, ODRC and ICP	$494,488	$346,526	$308,643	$139,518	$738,750	$112,035	$13,161	**$2,153,122**
Distribution - Maintenance	feeder class, ODRC and ICP	$335,318	$234,983	$209,294	$94,609	$500,954	$75,972	$8,925	**$1,460,055**
Transpower Charges	feeder class, kW and kWh	$352,369	$220,941	$318,244	$167,121	$1,854,912	$1,252,013	$914,400	**$5,080,000**
Avoided Transmission Charges	feeder class, kW and kWh	$167,167	$104,816	$150,978	$79,284	$879,988	$593,967	$433,800	**$2,410,000**
Total Revenue Requirement		**$3,188,540**	**$2,138,214**	**$2,430,581**	**$1,177,335**	**$8,053,224**	**$3,383,336**	**$2,821,122**	**$23,192,352**
kWh		22,946,260	14,387,656	22,157,656	11,635,748	81,345,197	54,905,724	79,461,535	**286,839,776**
ICP		3,215	2,253	3,190	1,442	12,812	1,943	42	**24,897**