Eastland Network Limited

Pricing Methodology Disclosure

Pursuant to:

Requirements 2.4 of the Electricity Information Disclosure Determination 2012

For Line Charges introduced on 01 April 2014

March 2014

Contents

Introduction

This document sets out Eastland Network Limited's (ENL) pricing methodology for the line charges in effect as at 1 April 2014 and aims to provide an understanding of how ENL's prices are determined for consumers.

Each year ENL is required to publish a pricing methodology that complies with the Electricity Information Disclosure Determination 2012.

Prices are set to recover the economic costs of owning and operating the Electricity Distribution Network that conveys electricity throughout the Gisborne and Wairoa districts. The economic costs include the recovery of the costs of operation plus an appropriate return on investment (cost of capital). ENL also aims to develop economically efficient pricing to ensure that ENL is able to invest in its network over time at an appropriate level and also that consumers are able to consider the value they receive when considering alternatives.

Target Revenue

Target Revenue is calculated as all costs (including tax) plus a return on capital plus a return of capital (Depreciation). The table below shows the components of Target Revenue for ENL for the 2014/15 pricing year and the previous year for comparison.

Table 1

Target Revenue	**2014/15**	**2013/14**
Pass Through Costs[1]	365,419	365,314
Recoverable costs[2]	12,064,573	11,020,793
Total Recoverable & Pass-Through Costs	**12,429,992**	**11,386,107**
System Maintenance	3,330,348	3,079,752
Business Support	3,302,998	2,786,680
System Operations & Network Support	1,543,317	1,999,458
Total Operating Costs	**8,176,663**	**7,865,890**
Taxes	978,422	1,633,933
Depreciation	4,520,523	5,015,190
Return on Capital	8,218,567	6,701,541
Total Revenue Requirements	**34,324,168**	**32,602,661**

[1] Pass Through costs include EA fees, Council Rates, MBIE levies & EGCC levies

[2] Recoverable costs are the costs of Transmission ie Transpower and ACOT

Pass Through and Recoverable Costs

Pass through and recoverable costs are costs that are permitted by the Commerce Commission to be passed-through directly to consumers. Pass-through costs are costs that ENL has no ability to avoid and include costs such as Rates, Ministry of Business, Innovation and Employment Levies and the Electricity & Gas Complaints Commission Levies.

Transmission revenue requirement

Power supply on the East Coast is capacity constrained primarily by the Transpower owned connection assets i.e. the spur assets dedicated to the regions use. Traditional 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 that Transpower applies to such upgrades.

Eastland 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 Eastland or another party.

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

- Transpower Charges
- Avoided Transmission Charges
- Loss Rental Rebates.

Transpower

Transpower charges are comprised of two charges, connection charges and interconnection charges. Connection charges are a fixed annual amount and interconnection charges are a fixed rate per unit of regional co-incident peak demand.

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 transmission pricing methodology. The connection of generators to the Eastland network, and the charge/rebates applicable are subject to Eastland 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 basis. Investment that has the potential to reduce the regional co-incident peak demand at a GXP will be recognised via pass through of reductions in Transpower's interconnection charge. Avoided transmission charges are based on the assessed impact of these alternatives will have on GXP load profiles both in terms of demand and kWhs.

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

It should be noted that the investor can equally be Eastland, any retailer, any generator or independent party. However, the capacity requirement is capped at the Eastland determined targets. Where there is a choice of alternative investments, preference will be given to the least cost solution to Eastland 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.

Based on the regulations set out in the Electricity Distribution Services Default Price-Quality Path Determination 2012, a distribution company can recover the costs of avoided transmission to its consumers and/or electricity retailers via line charges. The avoided cost of interconnection charge is calculated as the reduction in ENL's RCPD due to the contribution from DG in reducing the RCPD.

The avoided cost of connection charge is the total amount of connection charges that have been

avoided due to the presence of Distributed Generation on ENL's network. Connection charges may be avoided
either by:

- Avoiding a new transmission connection asset; or
- Avoiding an existing transmission connection asset.

The amount of avoided connection charge is calculated based on the value of new transmission connection asset projects and/or existing transmission connection assets that have been avoided. The value of new transmission connection projects is converted to an avoided connection charge using Transpower's current pricing methodology for connection assets. The value of existing connection assets that are avoided is calculated based on the most recent connection charge (for the assets avoided) inflated to current costs.

Loss Rental Rebates

Transpower loss rental rebates are excluded from the revenue requirement as these rebates are passed on transparently via a separate rebate mechanism, to Eastland's consumers and/or electricity retailers. A $55,000 administration fee is charged in relation to the determination of pass through amount payable to each retailer.

Network operation and maintenance costs, indirect costs, pass through costs (non-transmission), network depreciation and taxation

The revenue requirement components including, network operation and maintenance, indirect, pass through (non transmission), network depreciation and taxation are based on budgeted costs for the 2013/14 period.

Return on investment

Return on investment revenue provides a return on investment to network owners and is determined as a product of asset value and the weighted average cost of capital. The target return on investment is determined using a weighted average cost of capital of 8.75%, however, the price path threshold creates a cap on this return and the actual return on investment may ultimately be less than this for the 2014 financial year.

Consumer Groups

Areas of the network that exhibit high consumer density have been identified in ENL geographic Information system (GIS) and the remainder of the network has been deemed low density. Separating the network and consumers into these categories allows Eastland to better examine the costs associated with supplying consumers in these two distinct areas and reflect the higher level of service offered to high density consumers. The high-low density segmentation exercise involved isolating areas of the network in ENL's GIS and extracting the corresponding network assets employed, ICP density and consumer usage data.

Consumers within each density classification are classed as either domestic or non-domestic consumers. Domestic consumers are grouped together because they share a similar network usage profile. Domestic consumer's peak usage occurs between the hours of 7:30am and 9:30am in the morning and 5:30pm and 9:00pm in the evening which corresponds with network peak demand. In contrast non-domestic consumers do not typically share a similar peak usage profile due to the diverse nature of their operations and as such are not able to be grouped in a similar manner. Eastland therefore groups non-domestic consumers based on their assessed capacity requirements using their installed fuse rating or transformer capacities where transformers are dedicated to supply of an individual consumer. This approach recognises that as consumer capacity requirement increase the value of assets employed to supply consumers' increases.

An installation only qualifies for domestic tariffs if it satisfies the following:

- It is the consumer's primary and permanent place of residence, i.e. excludes holiday homes, Shearers quarters, garages, pumps, trust owned properties etc.
- Only one installation control point (ICP) on a consumers account can be classed as domestic whether on Eastland Network Ltd or elsewhere.
- The installation is used as a residence and not for business purposes.
- Does not exceed the following current limits:

1 Phase	2 Phase	3 Phase
Up to 62 amps	Up 42 amps per phase	Up to 32 amps per phase

- All consumers wishing to change classification to the Domestic definition will be required to make a declaration, and supporting documentation such as appearing on the local electoral roll.

ENL also have a non-domestic Time of Use Tariff group. This tariff is available to non-domestic consumers who have a capacity requirement of greater than 201kVA. This tariff was introduced following consumer requests and will give consumers, who are still relatively low energy consumers by non-domestic levels, the ability to manage their loads more effectively and take advantage of a time of use tariff. The feedback from retailers during consultation was positive with regards to introducing a new TOU tariff.

Accordingly, Eastland employs the following consumer group classifications for both high and low density consumers:

Domestic	0 – 30kVA
Non-Domestic Low capacity	0-3kVA (Streetlighting)
Non-Domestic	0 – 30kVA
Non-Domestic	31 – 100kVA
Non-Domestic	101 – 300kVA
TOU	201 – 300kVA
TOU	301 – 500kVA
TOU	501 – 1000kVA
TOU	1001 – 4500kVA
TOU	4501 – 6500kVA
Generation	301 – 500kVA
Generation	501 – 1000kVA
Generation	1001 – 4500kVA
Generation	4501 – 6500kVA

Within the Domestic and Non-Domestic classifications, consumers are also offered reduced pricing for load control. Other non-generation consumers have reduced pricing available to encourage use off-peak.

(See Appendix 2 for further pricing details)

Cost Allocation

ENL has developed a cost of supply model to determine the revenue requirement by consumer group that would be necessary to meet an efficient cost allocation and reflects the actual cost of its services. This cost model has quantified a number of categories where costs are under or over recovered. However, as ENL is mindful of price shocks to consumers, the intention is to move prices towards those based on the revised cost allocation methodology over a period of 3-5 years. In doing so some load groups will face continual increases over this period while others will experience little or no change. It should be noted that future price movements may also be subject to changes in the regulations under which ENL operates.

Allocators

ENL's cost of supply model (COSM) contains the following input assumptions and statistics for the purpose of cost allocation. ENL used the following statistics to allocate costs to consumer groups.

Table 4: Allocator Statistics

Price Category	ICP's	KWhs	Installed kVA	AVG RCPD Contribution
PDH0030	13,630	83,472,038	58,727	67
PDL0030	6,019	39,688,118	43,466	13
PNH0003	129	371,282	203	0
PNH0030	1,637	23,455,144	15,728	22
PNH0100	266	21,161,543	15,059	10
PNH0300	61	10,768,912	14,425	7
PTH0300	5	1,176,130	386	4
PNH0500	16	7,684,883	6,265	9
PNH1000	21	26,401,118	16,553	20
PNH4500	1	6,885,416	1,500	29
PNH6500	1	22,731,420	1,000	150
PNL0003	108	250,419	127	0
PNL0030	3,325	18,080,676	29,823	17
PNL0100	80	4,248,057	4,992	5
PNL0300	11	1,737,389	2,745	1
PNL0500	3	1,593,948	1,100	15
PTL0300	1	179,360	250	1
PNL1000	1	749,583	500	0
PNL4500	1	12,590,639	1,000	121
PNL6500	0	0	0	0
PNG0500	0	0	0	0
PNG1000	6	117,130	0	0
PNG4500	1	0	1,000	0
PNG6500	1	0	1,000	0
	25,324	**283,343,205**	**215,849**	**492.35**

Allocation of Revenue Requirement

Following the determination of the allocators, the revenue requirement, comprised of distribution and transmission requirements, is allocated between consumer groups.

The total revenue requirement (as depicted in table 1) has been allocated to consumer groups using the allocation methodology set out in the paragraphs which follow. A summary of the final allocation is shown in Appendix 1.

ENL has recently changed its methodology from allocating costs on the basis of AMD to allocation on capacity installed. This is to reflect the view that there is virtually no growth in the ENL network and that ENL's costs are largely fixed and that distribution assets are built to meet the capacity requirements at a connection point. These assets are built to requirements irrespective of the actual volume of energy used.

ENL have allocated transmission costs to consumer groups using a close approximation to the methodology set out in Transpower's transmission pricing methodology. Interconnection charges are allocated to consumers based on their share of total co-incident peak demand on Eastland's network. Connection costs are allocated on the basis of capacity to reflect the assets owned and operated by Transpower are built for a particular capacity within the region.

Avoided transmission charges are allocated on the basis of RCPD as any reduction in coincidental peak also reduces the charges from Transpower.

Pass through costs are allocated on the basis of either capacity or ICP depending on whether the costs relate to assets built or overhead costs.

System Maintenance is allocated 80% based on capacity and 20% ICP. While these costs are largely driven by assets built, there is also some element of overhead which should be allocated on the basis of ICP.

Target return on investment and deprecation have been allocated to consumer groups based on capacity.

Cost Category	Allocator
Transmission costs – Variable component	RCPD
Transmission costs – Fixed Component	Capacity
Pass-through costs	Capacity or ICP
System Maintenance	Capacity 80%, ICP 20%
Business Support	ICP
Systems Operations & Network Support	Capacity or ICP
Taxes	ICP
Depreciation	Capacity
Return on Capital	Capacity

Price Structure

Eastland uses ICP billing for charging end consumers. However Eastland does not charge all consumers their true cost of supply due to a number of factors including:

- Low user regulations which restrict the level of domestic fixed charges;
- The complexity, and potential arbitrary results in determining individual costs of supply;
- The desire to make the tariff schedule administratively simple;
- The desire to manage rate shock;
- There must be a smooth price transition between non-domestic consumer groups;
- Recognition of high levels of reliability in high density areas
- Revenue constraints imposed by the Commerce Commission Default Price Path Determination 2012

The implication is that for some consumer groups the target return on investment component of the revenue requirement is not fully recovered.

For the 2014/15 year, ENL, in order to ensure that there is no breach of the Default Price Path as Determination 2012, will not increase any distribution portion of the 2014/15 prices. Total prices will increase however to recover transmission costs.

Domestic charges

The low user fixed charge regulations cap fixed charges to domestic consumers at 15 cents (excl GST) per day. ENL have set domestic fixed charges at 15 cents (excl GST) per day which is less than that determined by the COSM described earlier. As such the remainder of the fixed cost allocated to domestic consumers is recovered through variable charges.

All domestic consumers currently receive the benefit of the 15 cents per day government policy intended to reward low consumption behaviour. As this is the only domestic fixed charge and is not optional, compliance with the 8,000 kWh per annum break-even requirement is automatic.

Three variable rates are available to domestic consumers which reflect the metering options available on the Eastland network. These are uncontrolled, controlled and night rates and are priced at progressively lower rates to encourage consumption/the shift of consumption to periods outside of peak demand.

Electricity delivered to consumers via controlled metering allows Eastland to switch off load via ripple control to appliances connected to the controlled meter during periods of peak electricity demand. The price reduction is achieved through the reduction in peak period demand which drives transmission interconnection charges.

The Night Rate Tariff, which excludes street lighting, is a time controlled night rate which was introduced to encourage the connection of larger more efficient fixed wire storage capacity appliances such as night-store heaters. This tariff was applicable for those devices only and to the time period, half hour ending, 23:30 to 07:00. This tariff has seen negative growth in terms of connections and consumption due to the change in technologies and move away from the use of night store heaters. This tariff therefore, has been closed to all new connections since 2011 and no further connections are permitted to connect to it. Eventually, this tariff will be phased out entirely.

Transmission costs that have been allocated to domestic consumers are recovered predominantly through variable charges with a small portion recovered through fixed daily charges. Transmission charges have been structured in the same manner as distribution charges.

Non-domestic charges

In contrast to domestic charges there are no additional regulatory constraints that apply to the determination of non-domestic charges. It is however vital to set prices in such a manner that price stability and certainty is achieved. Non-domestic consumers have often made long term investment decisions based on cost inputs (including electricity) and this must be factored into price determination. Eastland are therefore limited in the rate shock that can be imposed on non-domestic consumers and as such are bound by legacy pricing in this regard. In order to move toward more cost reflective pricing a transition period as discussed in section 5.1 has been used. The cost of supply allocation previously examined has provided the direction in which non-domestic charges should move.

In addition, a smooth price transition between consumer groups as capacity requirements increase is required. This is to ensure that artificial incentives are not created for consumers to move from one capacity group to another to take advantage of lower prices available to consumer groups with different capacity requirements. This distorts a true cost of supply allocation but eliminates the price instability which flows from a cost of supply allocation where consumers move from one consumer group to another from year to year to exploit prices which relate to different capacity requirements.

Currently there is no location differential in the fixed charges to high and low density non-domestic consumers. However the cost allocation methodology used shows that the total value of assets used to supply low density consumers is significantly greater than that used to supply high density consumers. To reflect this finding an increase in the fixed charges to low density non-domestic consumers will be phased in over the transition period.

Variable charges to non-domestic consumers reflect the time of use pricing signals mentioned previously for domestic consumers. The process has been through a number of iterative cycles to smooth the transition from non time of use to time of use options.

Time of Use (TOU) tariff is also available to large consumers. To qualify for TOU charges consumers are required to have a capacity requirement greater than 201kVA and TOU metering. These connections tend to have high load factors and have less opportunity to vary load during production hours. As such TOU consumers prefer a higher level of fixed charging which consequently results in reduced peak demand signalling. This reduces the sensitivity of total charges to variation in consumption, which is predominantly outside of peak times, and reflects the decision to recover the majority of non-domestic costs through fixed charges. Some peak signalling is retained in the variable charges to encourage demand side management. It follows that, non-domestic consumer group variable prices decrease as the capacity of the consumer group increases.

Distributed generation

Distributed Generation pricing is determined in accordance with the Part 6 of the Electricity Industry Participation Code 2010

Distributed Generation capacity based connection tariffs are comprised of a Fixed Distribution charge only. A variable distribution component for energy flow from the generation installation through the distribution network is not charged. Similarly fixed and variable Transmission charges are not applied to Distributed Generation that do not export to the transmission grid. This pricing means that the Distributed Generator, (based on generation capacity) is charged only for the distribution assets employed to connect and distribute production.

In accordance with the regulations Eastland makes payments to distributed generators for Avoided Cost of Transmission. Annually these payments are based on the generators actual contribution to the reduction of transmission charges.

As set out in the Eastland Connection and Operation of Distributed Generation Policy Eastland will make payment to the Distributed Generator where they provide proven and long-term benefits to the distribution network, such as improvement of security of supply.

Payment for Reduction of Losses is not made, as the benefits are realized by the energy retailer and are passed on to end users. In addition, due to the varying load conditions typical in the distribution network, the assessment of the physical losses applicable to a single installation is typically complex, and as such Eastland does not financially recognize the reduction of losses.

Losses

The allocation of losses is not a contracted line function service and Eastland 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 GXPs and network locations.

Loss factors applicable to Eastland

- 400V connected supplies 1.0705
- 11kV connected supplies 1.0475

Uneconomic Bypass

Eastland do not consider there is any risk of uneconomic by pass.

Transmission assets

Eastland is currently engaged in a process to investigate the transfer of significant transmission assets from Transpower. Due to the early stage of the process pricing considerations regarding the potential transfer of any transmission assets has not been included in current pricing methodology.

Pricing Principles

Information Disclosures require ENL to demonstrate consistency with the pricing principles published by the Electricity Commission in March 2010 and adopted and amended by the Electricity Authority from time to time.

(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.

To determine whether or not prices are subsidy free requires ENL to determine what the standalone cost and incremental costs for each service and to determine if there is any cross-subsidisation. The stand-alone costs of a service or group of services "*is the cost of providing that service or group of services by themselves without any other service that is provided by the enterprise... the incremental cost of a service or groups of services is the additional cost of providing that service or group of services over and above the cost of providing all the remaining services*"[1]

Due to the number of price categories ENL has, ENL has grouped the domestic and non-domestic categories and repeated the exercise with a group of high density and a group of low density categories to check if cross-subsidies exist between the different types of consumers. The exercise provides evidence that ENL's prices are subsidy free in that the economic costs are greater than the incremental costs and less than standalone costs. While this work is somewhat rudimentary at this stage, it follows logically that no subsidies would exist as the incremental cost of consumers using one more unit of power or one additional consumer would be virtually nil. This is due to the high level of fixed cost infrastructure in place which is currently shared across a large number of existing consumers. In some isolated rural regions however, there would be areas where the incremental cost of becoming connected to the network would outweigh the cost of standalone systems such as solar PV and/or diesel generation. ENL intends to further develop it's COSM over the next 12 months to gain greater confidence in the outcomes and provide numerical support.

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

(iii) Signalling, to the extent practicable, the impact of additional usage on future investment costs.

ENL's tariff structure divides customers according to capacity thereby signalling the economic cost of service provision based on capacity.

ENL utilises a variable pricing structure to signal the impact of usage during peak times. This is particularly so with the Time of Use (TOU) and controlled load tariffs which allow the customer or the network to reduce load during peak periods.

The ENL network has experienced little or no growth for a number of years and this trend is expected to continue and there is also a possibility that volumes may decrease slightly. As a result the network has adequate capacity to meet current and future needs and major augmentation or capital investment is not required for the existing assets.

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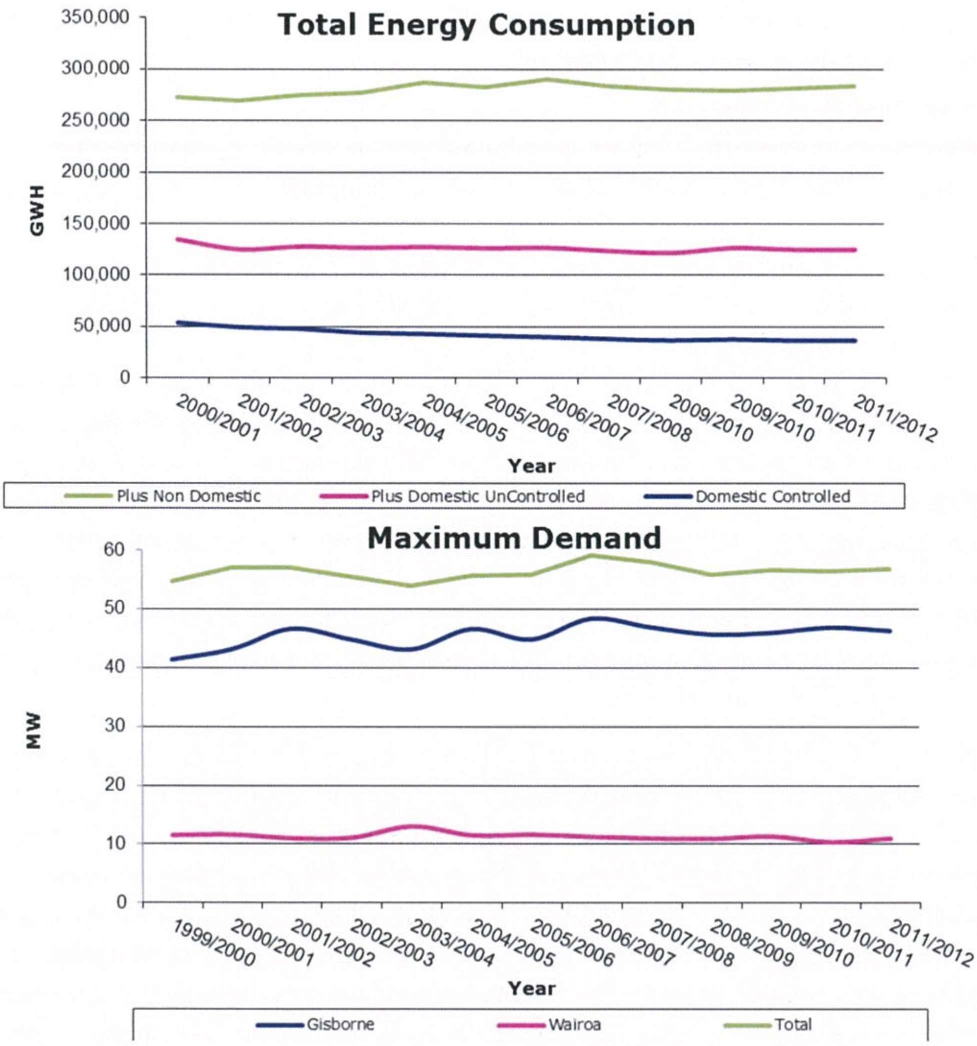
[1] Professor Gerald R Faulhaber, *Cross-subsidy analysis with more than two services, August 11,2002*

Table 4: ENL Energy Efficiency Measures *(Source: ENL 2013 Asset Management Plan)*

Measure	2011/12 Actual	2012/13 Forecast	2013/14	2014/15	2015/16	2016/17	2017/18	2018-2023
Load factor	61.4%	62%	62%	62%	62%	62%	62%	62%
Loss ratio	7.3%	7 %	7 %	7%	7 %	7 %	7 %	7 %
Capacity utilisation	23.1%	23%	23%	23%	23%	23%%	23%	23%

While ENL does encourage shifting of peak loads to off-peak through it's TOU pricing however, this signal can be somewhat diminished once re-packaged by the retailer. Night rates were once offered to consumers with night store heaters but with the change in trends and the move away from night-store heating appliances, there has been less and less requirement for this tariff over the years. As a result, it is no longer available for any new consumers.

Diagram 1: Energy Consumption and Demand *(Source: ENL 2013 Asset Management Plan)*



Capacity is showing some constraint in the Mahia region where loads during the peak holiday seasons of Easter and Christmas often exceeds the 1.5MVA transformer rating. This is relieved by operating one of the ENL diesel generators at Mahia beach. Loading in general at Mahia is increasing in conjunction with beach front sub-divisional activity and as more holiday homes become permanent residences. Pricing in Mahia however is not reflective of the constraint and need for new investment as pricing for this small region is not easily separable from general pricing. ENL however opted to charge a one-off capital contribution to Mahia property owners to enable the proposed investment in this area.

(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.

The structure of ENL pricing is to reward customers that have controllable load with lower prices. Further, industrial and commercial users have the option of selecting TOU pricing plans which encourage demand during non-peak periods. Where there is a shortfall in the recovery of costs from groups of consumers, this shortfall is currently being recovered through other groups of consumers including residential customers. A greater recovery of costs is collected from residential consumers as they are less price responsive but ENL is attempting to balance this back over the next 5 or more years.

(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;
ii. allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and
iii. where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation

Discouragement of uneconomic bypass via distribution line pricing is limited as Eastland see no real risk of bypass in this region. This is due to the fact that there is sufficient infrastructure and capacity on the Eastland network to cover current and future needs for the foreseeable future therefore no significant distribution investment is required. Where a new connection is isolated and some distance from existing distribution assets, there may be some bypass with the use of solar PV systems and or diesel gensets but there is likely to be a tradeoff with efficiency and/or reliability. ENL does provide some flexibility with regard to capital contributions for new connections to counter economic bypass at which point customers are able to make price quality trade-offs. For further information please refer to the ENL Capital Contributions Policy.

(D) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.

Development of prices is disclosed in this document which is publically available. Tariff categories have remained unchanged for a number of years with relatively small increases year on year. These prices are applicable to both the Wairoa and Gisborne networks and are the same across all retailers. This allows for simplicity across both regions and provides a level playing field for all retailers within the ENL region. ENL will continue to review the number of price categories it has and attempt to rationalize tariffs as it is able to. Eastland is very cognizant of the consumer base in the region and conscious of the impact any changes will have to this community.

Changes to Pricing Methodology

- ENL has changed its allocation methodology from Demand (AMD) to capacity installed. This is to reflect the view that there is virtually no growth in the ENL network, that ENL's costs are largely fixed and that distribution assets are built to meet the capacity requirements at a connection point. These assets are built to requirements irrespective of the actual volume of energy used.

- Asset Replacement cost is no longer used as an allocator to simplify calculations as ENL believes that capacity installed is a suitable proxy for asset value. Further there is always a need to adjust the asset values for age of asset which further adds to the complexity of calculations.
- ACOT costs have been moved from distribution to transmission to reflect its' true category. To avoid price shocks, these costs are not yet fully recovered through the transmission charges. ENL will continue to work towards full recovery of these costs over the next 5 years.
- Future prices are expected to increase as a result of the transfer of Transmission assets from Transpower in 2015/16 and for the 5 years following where the ACOT allowance is permitted to continue to be charged for that period. The value of this ACOT is expected to be approximately $3.5m per annum.

For the above changes there has been no impact on distribution prices for the 2014/15 year as ENL decided there would be no change in distribution prices for the 2014/15 year.

Glossary

AMP	Asset Management Plan
COSM	Cost of Supply Model
Domestic	Residential consumers
RCPD	Regional Coincident Peak Demand. Customer off-take at that connection location during a regional peak demand period
TOU	Time of Use

Appendix 1 – Consumer Group Cost Allocation

	Pass-through	Recoverable	System maintenance	Business Support	Systems Operations & Network Support	Tax	Depreciation	Return on Capital	TOTAL
PDH0030	136,965	2,114,499	1,005,644	1,777,755	717,583	526,611	1,229,926	2,236,075	**9,745,058**
PDL0030	78,707	937,865	620,442	785,055	351,391	232,551	910,312	1,654,999	**5,571,324**
PNH0003	929	8,107	5,399	16,825	6,096	4,984	4,243	7,714	**54,298**
PNH0030	25,466	644,477	226,632	213,513	103,257	63,247	329,388	598,846	**2,204,827**
PNH0100	17,134	415,002	177,303	34,694	41,387	10,277	315,373	573,367	**1,584,537**
PNH0300	15,333	352,594	163,219	7,956	31,085	2,357	302,100	549,235	**1,423,879**
PTH0300	429	74,259	7,550	652	981	193	8,087	14,703	**106,856**
PNH0500	6,601	263,013	75,909	2,087	13,038	618	131,211	238,549	**731,026**
PNH1000	17,323	618,247	196,400	2,739	33,508	811	346,677	630,278	**1,845,983**
PNH4500	1,565	526,676	40,307	130	2,996	39	31,414	57,113	**660,241**
PNH6500	1,045	2,625,174	135,742	130	2,012	39	20,943	38,076	**2,823,161**
PNL0003	733	7,642	4,131	14,086	5,020	4,173	2,656	4,829	**43,271**
PNL0030	49,520	786,327	413,973	433,678	205,552	128,465	624,580	1,135,522	**3,777,619**
PNL0100	5,635	163,239	59,821	10,434	13,360	3,091	104,558	190,092	**550,229**
PNL0300	2,914	65,533	30,967	1,435	5,888	425	57,480	104,501	**269,142**
PNL0500	1,160	274,973	24,285	391	2,298	116	23,037	41,883	**368,143**
PTL0300	265	25,187	3,741	130	536	39	5,236	9,519	**44,653**
PNL1000	525	8,108	5,435	130	1,028	39	10,471	19,038	**44,774**
PNL4500	1,045	2,121,223	111,617	130	2,012	39	20,943	38,076	**2,295,085**
PNL6500	-	-	-	-	-	-	-	-	**-**
PNG0500	-	-	-	-	-	-	-	-	**-**
PNG1000	33	-	138	783	265	232	-	-	**1,451**
PNG4500	1,045	16,215	10,847	130	2,012	39	20,943	38,076	**89,307**
PNG6500	1,045	16,215	10,847	130	2,012	39	20,943	38,076	**89,307**
	365,419	**12,064,573**	**3,330,348**	**3,302,998**	**1,543,317**	**978,422**	**4,520,523**	**8,218,567**	**34,324,168**

Appendix 2 - Consumer Group Statistics

Price Category		Consumer Group	Charge Type	ICPs	Units days/kWH	Prices Distribution	Transmission	Total	Forecast Revenue
Domestic									
PDH0030		Domestic	Fixed Daily Charge	13,580	365	0.1125	0.0375	**0.1500**	743,505
PDH0030		Domestic	Consumption Uncontrolled	-	59,039,209	0.1108	0.0400	**0.1508**	8,903,534
PDH0030		Domestic	Consumption Controlled	-	25,383,520	0.0576	0.0208	**0.0784**	1,988,985
PDH0030		Domestic	Consumption Night	-	32,532	0.0144	0.0052	**0.0196**	638
		TOTAL		**13,580**	**84,455,261**				11,636,661
PDL0030		Domestic	Fixed Daily Charge	5,969	365	0.1125	0.0375	**0.1500**	326,794
PDL0030			Consumption Uncontrolled	-	28,472,429	0.1291	0.0472	**0.1763**	5,019,772
PDL0030		Domestic	Consumption Controlled	-	10,597,685	0.0697	0.0255	**0.0952**	1,009,059
PDL0030		Domestic	Consumption Night	-	53,529	0.0168	0.0061	**0.0229**	1,228
		TOTAL		**5,969**	**39,123,642**				6,356,854
		Total Domestic		**19,549**	**123,578,903**				**17,993,515**

Price Category	Consumer Group	Charge Type	ICPs	Units days/kWH	Prices Distribution	Prices Transmission	Prices Total	Forecast Revenue
Non-Domestic - High Density								
PNH0003	Low Capacity (0 to 3kVA)	Fixed Daily Charge	129	365	0.2804	0.1115	**0.3919**	18,453
PNH0003	Low Capacity (0 to 3kVA)	Capacity Charge	-	-	-	-	-	
PNH0003	Low Capacity (0 to 3kVA)	Demand Charge	-	-	-	-	-	
PNH0003	Low Capacity (0 to 3kVA)	Consumption Uncontrolled	-	587,567	0.0899	0.0479	**0.1378**	80,967
PNH0003	Low Capacity (0 to 3kVA)	Consumption Controlled	-	-	0.0584	0.0311	**0.0895**	-
PNH0003	Low Capacity (0 to 3kVA)	Consumption Night	-	-	0.0112	0.0060	**0.0172**	-
	TOTAL		129	**587,567**				**99,419**
PNH0030	Demand (0 to 30kVA)	Fixed Daily Charge	1,672	365	1.5766	0.5774	**2.1540**	1,314,543
PNH0030	Demand (0 to 30kVA)	Capacity Charge	-	-	-	-	-	
PNH0030	Demand (0 to 30kVA)	Demand Charge	-	-	-	-	-	
PNH0030	Demand (0 to 30kVA)	Consumption Uncontrolled	-	21,486,517	0.0647	0.0344	**0.0991**	2,129,314
PNH0030	Demand (0 to 30kVA)	Consumption Controlled	-	907,710	0.0421	0.0224	**0.0645**	58,529
PNH0030	Demand (0 to 30kVA)	Consumption Night	-	9,607	0.0112	0.0060	**0.0172**	166
	TOTAL		**1,672**	**22,403,835**				**3,502,552**
PNH0100	Demand (31 to 100kVA)	Fixed Daily Charge	268	365	4.9067	1.9533	**6.8600**	671,042
PNH0100	Demand (31 to 100kVA)	Capacity Charge	-	-	-	-	-	
PNH0100	Demand (31 to 100kVA)	Demand Charge	-	-	-	-	-	
PNH0100	Demand (31 to 100kVA)	Consumption Uncontrolled	-	20,490,465	0.0441	0.0234	**0.0675**	1,383,636
PNH0100	Demand (31 to 100kVA)	Consumption Controlled	-	427,028	0.0286	0.0152	**0.0438**	18,700
PNH0100	Demand (31 to 100kVA)	Consumption Night	-	32,567	0.0112	0.0060	**0.0172**	561
	TOTAL		**268**	**20,950,060**				**2,073,940**
PNH0300	Demand (101 to 300kVA)	Fixed Daily Charge	59	365	9.2526	3.6833	**12.9359**	278,574
PNH0300	Demand (101 to 300kVA)	Capacity Charge	-	-	-	-	-	
PNH0300	Demand (101 to 300kVA)	Demand Charge	-	-	-	-	-	
PNH0300	Demand (101 to 300kVA)	Consumption Uncontrolled	-	13,157,012	0.0360	0.0191	**0.0551**	725,420
PNH0300	Demand (101 to 300kVA)	Consumption Controlled	-	17,144	0.0234	0.0124	**0.0358**	614
PNH0300	Demand (101 to 300kVA)	Consumption Night	-	-	0.0112	0.0060	**0.0172**	-
	TOTAL		**59**	**13,174,156**				**1,004,607**
PTH0300	TOU - Demand (201-300kVA)	Fixed Daily Charge	7	365	15.4210	6.1388	**21.5598**	55,085
PTH0300	TOU - Demand (201-300kVA)	Consumption Uncontrolled	-	-	-	-	-	
PTH0300	TOU - Demand (201-300kVA)	00-January-1900	-	-	-	-	-	
PTH0300	TOU - Demand (201-300kVA)	Consumption Evening Peak	-	165,416	0.0340	0.0170	**0.0510**	8,438
PTH0300	TOU - Demand (201-300kVA)	Consumption Morning Peak	-	199,967	0.0318	0.0159	**0.0477**	9,537
PTH0300	TOU - Demand (201-300kVA)	Consumption Off Peak	-	276,850	0.0250	0.0125	**0.0375**	10,388
PTH0300	TOU - Demand (201-300kVA)	Consumption Night	-	144,252	0.0112	0.0056	**0.0168**	2,424
	TOTAL		**7**	**786,485**				**85,873**
PNH0500	TOU - Demand (301-500kVA)	Fixed Daily Charge	16	365	17.3837	6.9201	**24.3038**	141,934
PNH0500	TOU - Demand (301-500kVA)	Capacity Charge	-	-	-	-	-	
PNH0500	TOU - Demand (301-500kVA)	Demand Charge	-	-	-	-	-	
PNH0500	TOU - Demand (301-500kVA)	Consumption Evening Peak	-	1,387,967	0.0340	0.0170	**0.0510**	70,850
PNH0500	TOU - Demand (301-500kVA)	Consumption Morning Peak	-	2,178,032	0.0318	0.0159	**0.0477**	103,963
PNH0500	TOU - Demand (301-500kVA)	Consumption Off Peak	-	2,820,236	0.0250	0.0125	**0.0375**	105,894
PNH0500	TOU - Demand (301-500kVA)	Consumption Night	-	2,068,039	0.0112	0.0056	**0.0168**	34,683
	TOTAL		**16**	**8,454,275**				**457,324**
PNH1000	TOU - Demand (501-1000kVA)	Fixed Daily Charge	21	365	26.9166	10.7150	**37.6316**	288,447
PNH1000	TOU - Demand (501-1000kVA)	Capacity Charge	-	-	-	-	-	
PNH1000	TOU - Demand (501-1000kVA)	Demand Charge	-	-	-	-	-	
PNH1000	TOU - Demand (501-1000kVA)	Consumption Evening Peak	-	4,071,941	0.0340	0.0170	**0.0510**	207,858
PNH1000	TOU - Demand (501-1000kVA)	Consumption Morning Peak	-	5,859,651	0.0318	0.0159	**0.0477**	279,477
PNH1000	TOU - Demand (501-1000kVA)	Consumption Off Peak	-	7,804,458	0.0250	0.0125	**0.0375**	292,638
PNH1000	TOU - Demand (501-1000kVA)	Consumption Night	-	6,701,313	0.0112	0.0056	**0.0168**	112,308
	TOTAL		**21**	**24,437,363**				**1,180,727**
PNH4500	TOU - Demand (1001-4500kVA)	Fixed Daily Charge	1	365	67.2916	26.7875	**94.0791**	34,339
PNH4500	TOU - Demand (1001-4500kVA)	Capacity Charge	-	-	-	-	-	
PNH4500	TOU - Demand (1001-4500kVA)	Demand Charge	-	-	-	-	-	
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Evening Peak	-	896,237	0.0340	0.0170	**0.0510**	45,747
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Morning Peak	-	1,119,332	0.0318	0.0159	**0.0477**	53,374
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Off Peak	-	1,609,543	0.0250	0.0125	**0.0375**	60,393
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Night	-	1,704,145	0.0112	0.0056	**0.0168**	28,570
	TOTAL		**1**	**5,329,256**				**222,424**
PNH6500	TOU - Demand (4501-6500kVA)	Fixed Daily Charge	1	365	102.4093	40.7674	**143.1767**	52,259
PNH6500	TOU - Demand (4501-6500kVA)	Capacity Charge	-	-	-	-	-	
PNH6500	TOU - Demand (4501-6500kVA)	Demand Charge	-	-	-	-	-	
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Evening Peak	-	3,785,807	0.0340	0.0170	**0.0510**	193,240
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Morning Peak	-	5,070,216	0.0318	0.0159	**0.0477**	241,768
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Off Peak	-	6,947,756	0.0250	0.0125	**0.0375**	260,475
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Night	-	7,218,037	0.0112	0.0056	**0.0168**	121,187
	Total		**1**	**23,021,817**				**868,929**
	Total High Density		2,174	119,144,814				9,495,795

Price Category	Consumer Group	Charge Type	ICPs	Units days/kWH	Prices Distribution	Transmission	Total	Forecast Revenue
Non-Domestic - Low Density								
PNL0003	Low Capacity (0 to 3kVA)	Fixed Daily Charge	108	365	0.2804	0.1115	**0.3919**	15,449
PNL0003	Low Capacity (0 to 3kVA)	Capacity Charge	-	-	-	-	**-**	
PNL0003	Low Capacity (0 to 3kVA)	Demand Charge	-	-	-	-	**-**	
PNL0003	Low Capacity (0 to 3kVA)	Consumption Uncontrolled	-	264,715	0.1039	0.0551	**0.1590**	42,088
PNL0003	Low Capacity (0 to 3kVA)	Consumption Controlled	-	-	0.0675	0.0358	**0.1033**	-
PNL0003	Low Capacity (0 to 3kVA)	Consumption Night	-	-	0.0130	0.0068	**0.0198**	-
	TOTAL							**57,537**
PNL0030	Demand (0 to 30kVA)	Fixed Daily Charge	3,375	365	1.5766	0.5774	**2.1540**	2,653,475
PNL0030	Demand (0 to 30kVA)	Capacity Charge	-	-	-	-	**-**	
PNL0030	Demand (0 to 30kVA)	Demand Charge	-	-	-	-	**-**	
PNL0030	Demand (0 to 30kVA)	Consumption Uncontrolled	-	15,937,409	0.0675	0.0358	**0.1033**	1,646,892
PNL0030	Demand (0 to 30kVA)	Consumption Controlled	-	1,243,728	0.0439	0.0233	**0.0672**	83,591
PNL0030	Demand (0 to 30kVA)	Consumption Night	-	104,567	0.0130	0.0068	**0.0198**	2,075
	TOTAL							**4,386,033**
PNL0100	Demand (31 to 100kVA)	Fixed Daily Charge	84	365	4.9067	1.9533	**6.8600**	210,327
PNL0100	Demand (31 to 100kVA)	Capacity Charge	-	-	-	-	**-**	
PNL0100	Demand (31 to 100kVA)	Demand Charge	-	-	-	-	**-**	
PNL0100	Demand (31 to 100kVA)	Consumption Uncontrolled	-	4,276,674	0.0514	0.0273	**0.0787**	336,368
PNL0100	Demand (31 to 100kVA)	Consumption Controlled	-	145,055	0.0334	0.0177	**0.0511**	7,419
PNL0100	Demand (31 to 100kVA)	Consumption Night	-	1,195	0.0130	0.0068	**0.0198**	24
	TOTAL							**554,137**
PNL0300	Demand (101 to 300kVA)	Fixed Daily Charge	11	365	9.2526	3.6833	**12.9359**	51,937
PNL0300	Demand (101 to 300kVA)	Capacity Charge	-	-	-	-	**-**	
PNL0300	Demand (101 to 300kVA)	Demand Charge	-	-	-	-	**-**	
PNL0300	Demand (101 to 300kVA)	Consumption Uncontrolled	-	1,208,921	0.0410	0.0218	**0.0628**	75,958
PNL0300	Demand (101 to 300kVA)	Consumption Controlled	-	1,037	0.0267	0.0141	**0.0408**	42
PNL0300	Demand (101 to 300kVA)	Consumption Night	-	-	0.0130	0.0068	**0.0198**	-
	TOTAL							**127,937**
PTL0300	TOU - Demand (201-300kVA)	Fixed Daily Charge	1	365	15.4210	6.1388	**21.5598**	7,869
PTL0300	TOU - Demand (201-300kVA)	Capacity Charge	-	-	-	-	**-**	
PTL0300	TOU - Demand (201-300kVA)	Demand Charge	-	-	-	-	**-**	
PTL0300	TOU - Demand (201-300kVA)	Consumption Evening Peak	-	430	0.0357	0.0177	**0.0534**	23
PTL0300	TOU - Demand (201-300kVA)	Consumption Morning Peak	-	14,284	0.0334	0.0166	**0.0500**	714
PTL0300	TOU - Demand (201-300kVA)	Consumption Off Peak	-	15,406	0.0262	0.0131	**0.0393**	605
PTL0300	TOU - Demand (201-300kVA)	Consumption Night	-	476	0.0118	0.0059	**0.0177**	8
	TOTAL							**9,220**
PNL0500	TOU - Demand (301-500kVA)	Fixed Daily Charge	3	365	17.3837	6.9201	**24.3038**	26,613
PNL0500	TOU - Demand (301-500kVA)	Capacity Charge	-	-	-	-	**-**	
PNL0500	TOU - Demand (301-500kVA)	Demand Charge	-	-	-	-	**-**	
PNL0500	TOU - Demand (301-500kVA)	Consumption Evening Peak	-	225,225	0.0357	0.0177	**0.0534**	12,036
PNL0500	TOU - Demand (301-500kVA)	Consumption Morning Peak	-	336,437	0.0334	0.0166	**0.0500**	16,828
PNL0500	TOU - Demand (301-500kVA)	Consumption Off Peak	-	445,919	0.0262	0.0131	**0.0393**	17,525
PNL0500	TOU - Demand (301-500kVA)	Consumption Night	-	335,937	0.0118	0.0059	**0.0177**	5,946
	TOTAL							**78,948**
PNL1000	TOU - Demand (501-1000kVA)	Fixed Daily Charge	1	365	26.9166	10.7150	**37.6316**	13,736
PNL1000	TOU - Demand (501-1000kVA)	Capacity Charge	-	-	-	-	**-**	
PNL1000	TOU - Demand (501-1000kVA)	Demand Charge	-	-	-	-	**-**	
PNL1000	TOU - Demand (501-1000kVA)	Consumption Evening Peak	-	118,032	0.0357	0.0177	**0.0534**	6,308
PNL1000	TOU - Demand (501-1000kVA)	Consumption Morning Peak	-	209,413	0.0334	0.0166	**0.0500**	10,468
PNL1000	TOU - Demand (501-1000kVA)	Consumption Off Peak	-	256,446	0.0262	0.0131	**0.0393**	10,080
PNL1000	TOU - Demand (501-1000kVA)	Consumption Night	-	145,349	0.0118	0.0059	**0.0177**	2,575
	TOTAL							**43,166**
PNL4500	TOU - Demand (1001-4500kVA)	Fixed Daily Charge	1	365	67.2916	26.7876	**94.0792**	34,339
PNL4500	TOU - Demand (1001-4500kVA)	Capacity Charge	-	-	-	-	**-**	
PNL4500	TOU - Demand (1001-4500kVA)	Demand Charge	-	-	-	-	**-**	
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Evening Peak	-	1,931,768	0.0357	0.0177	**0.0534**	103,232
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Morning Peak	-	2,983,779	0.0334	0.0166	**0.0500**	149,128
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Off Peak	-	3,801,083	0.0262	0.0131	**0.0393**	149,387
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Night	-	3,272,999	0.0118	0.0059	**0.0177**	58,037
	TOTAL							**494,123**
PNL6500	TOU - Demand (4501-6500kVA)	Fixed Daily Charge	-	365	102.4093	40.7674	**143.1767**	-
PNL6500	TOU - Demand (4501-6500kVA)	Capacity Charge	-	-	-	-	**-**	
PNL6500	TOU - Demand (4501-6500kVA)	Demand Charge	-	-	-	-	**-**	
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Evening Peak	-	-	0.0357	0.0177	**0.0534**	-
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Morning Peak	-	-	0.0334	0.0166	**0.0500**	-
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Off Peak	-	-	0.0262	0.0131	**0.0393**	-
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Night	-	-	0.0118	0.0059	**0.0177**	-
	TOTAL							**-**
	Total Low Density		**3,584**	**37,276,283**				**5,751,102**

Price Category		Consumer Group	Charge Type	ICPs	Units days/kWH	Prices Distribution	Transmission	Total	Forecast Revenue
		Generation							
PNG0500		Assessed Capacity (301 to 500kVA)		-	-	17.3837	-	**17.3837**	-
PNG1000		Assessed Capacity (501 to 1000kVA)		6	365	26.9166	-	**26.9166**	58,947
PNG4500		Assessed Capacity (1001 to 4500kVA)		1	365	67.2916	-	**67.2916**	24,561
PNG6500		Assessed Capacity (4501 to 6500kVA)		1	365	102.4093	-	**102.4093**	37,379
		Total Generation		**8**					**120,888**

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Pricing Methodology

Clause 2.9.1 of Section 2.9

We, Nelson Cull and John Rae, being directors of Eastland Network Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the following attached information of Eastland Network Limited prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information 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.

Dated this 19th day of March 2014.

Signature

Signature