Eastland Network Limited

Pricing Methodology Disclosure

Eastland Network

Pursuant to:

Requirements 2.4 of the Electricity Information Disclosure Determination 2012

For Line Charges introduced on 01 April 2015

March 2015

Contents

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

Directors Certificate

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 18th day of March 2015.

Signature

Signature

1. Introduction

This document sets out Eastland Network Limited's (ENL) pricing methodology for the line charges in effect as at 1 April 2015 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 Distribution 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.

Prices must also comply with the Electricity Distribution Services Default Price-Quality Path Determination 2015.

2. Target Revenue

Target Revenue is calculated as all costs (including tax) plus a return of capital (Depreciation) plus a return on capital. The table below shows the components of Target Revenue for ENL for the 2015/16 pricing year.

Table 1

Target Revenue	**2015/16**
Pass Through Costs[1]	378,936
Recoverable costs[2]	9,373,892
Total Recoverable & Pass-Through Costs	**9,752,828**
System Maintenance	5,829,873
Business Support	3,362,004
System Operations & Network Support	1,124,299
Total Operating Costs	**10,316,176**
Taxes	1,328,247
Depreciation	5,841,480
Return on Capital	8,586,517
Less Price-Path constraints	(2,591,298)
Total Revenue Requirements	**33,233,950**

[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

3. 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.

4. *Transmission Revenue Requirement*

Recoverable costs consist of charges payable to Transpower and Avoided Costs of Transmission as a result of distributed generation and as a result of the transfer of transmission assets to Eastland Network Limited.

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

Transpower

Transpower charges are comprised of two charges, connection charges and interconnection charges. Connection charges are a fixed annual amount based on the assets required to provide connection to the national grid. Interconnection charges are a fixed rate per unit of regional co-incident peak demand.

On 31 March 2015, Eastland Network Limited will acquire the majority of the local connection assets from Transpower. As a result the charges from Transpower for the assets transferred will no longer be included in recoverable transmission charges but will be included in Eastland Network's distribution charges from 1 April 2015 onwards.

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 a 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 that 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. Avoided charges payable to the generator are capped so that the generator earns no more than their weighted average cost of capital.

Avoided Transmission as a result of the transfer of connection assets from Transpower

On the 31 March 2015, Eastland Network Limited acquires the majority of the local connection assets from Transpower. As a result, Eastland Network will avoid $3.7m of connection charges from Transpower. However, for five years from 1 April 2015, Eastland Network Limited is able to continue to recover these avoided connection charges from customers through its line charges. These charges are reflected in the recoverable transmission charges component of prices and in part offset operational costs in relation to these assets not allowed for in the 2015-2020 pricing determination by the Commerce Commission.

The avoided costs are included in transmission charges for the 2015/16 year and will continue until the 2019/20 year. From 2020/21 they will no longer be included in transmission charges.

5. 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 regulatory costs for the 2015/16 period.

6. Return on Investment

Return on investment revenue provides a return on investment to network owners and is determined as the product of regulated asset value at the beginning of the financial year and the weighted average cost of capital (WACC). The target return on investment is that determined by the Commerce

Commission[1] as 7.19%, however, the price path threshold creates a cap on this return and the actual return on investment may vary from this. For the 2015/16 financial year, the target return on investment due to price-path constraints is expected to be 5.24%.

7. Pricing Methodology Changes

Under the Electricity Distribution Default Price Path 2015 which applies for the pricing year from 1 April 2015, it is necessary for ENL to separate prices into Pass-through, Transmission and Distribution components. As a result the methodology for allocating costs and calculating charges to these various categories has been reviewed and minor changes have been made to prices as outlined below.

8. Price Changes

For 2015/16 there has been a slight average reduction of 0.28% across all prices from the 2014/15 year. This is due to the reduction in Transmission recoverable costs (including Avoided Costs of Transmission payable for Distributed Generation and the acquisition of Transpower assets). However as the forecasting the Avoided costs of Transmission and other pass-through costs is imperfect and the setting of prices is completed well before more accurate information is available, ENL is projected to under-recover these costs by more than $500k in the 2015/16 year. This has had the effect of reducing Transmission prices by an average of 5% and corresponding revenue by $593k. It is expected that ENL will recover these pass-through and recoverable costs in future pricing years as permitted under the Electricity Distribution Default Price-Path Determination 2015.

Other changes to distribution prices.

There have been some minor changes to distribution pricing across various price categories due to the change in the way pass-through costs have been allocated under the new rules for price-path. The impact of these changes are detailed in Appendix 2.

Small changes have also been made to distribution prices in Time-of-Use (TOU) night rates which have been increased by up to 0.0017c per kWh to correct a historic anomaly detected in our prices that held night rates artificially low.

(see table in Appendix 2 for changes to individual tariffs)

9. 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

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[1] Cost of capital determination for electricity distribution businesses' default price-quality paths and Transpower's individual price-quality path [2014] NZCC 28

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 increases 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.
- 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.

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.

10. 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	13,588	84,541,142	58,727	904,245
PDL0030	5,632	38,642,909	43,466	81,727
PNH0003	137	603,338	203	35
PNH0030	1,788	22,384,106	15,728	40,343
PNH0100	268	20,929,405	15,059	2,671
PNH0300	63	13,361,819	14,425	423
PTH0300	8	1,027,136	386	12
PNH0500	14	8,346,704	6,265	148
PNH1000	20	24,518,473	16,553	442
PNH4500	1	5,999,297	1,500	29
PNH6500	1	23,064,046	1,000	150
PNL0003	117	272,193	127	35
PNL0030	3,719	17,568,261	29,823	59,017
PNL0100	88	4,391,739	4,992	393
PNL0300	15	1,256,367	2,745	15
PNL0500	3	1,342,662	1,100	44
PTL0300	1	41,191	250	1
PNL1000	1	764,130	500	7
PNL4500	1	12,445,083	1,000	121
PNL6500	0	0	0	0
PNG0500	0	0	0	0
PNG1000	6	0	0	0
PNG4500	1	0	1,000	0
PNG6500	1	0	1,000	0
	25,473	**281,500,000**	**215,849**	**1,089,859**

11. 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 allocates much of its asset based costs on the basis of capacity installed. This is to reflect the view that there is virtually no growth in the ENL network and that ENL's costs are driven by long lasting assets and therefore 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

12. 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.

Domestic charges

Since 2004 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 true domestic consumers currently receive the benefit of the 15 cents per day government policy intended to reward low consumption behaviour. ENL does not apply consumption, distance and/or service configuration exclusions to the application of this benefit.

There are variable rates on our pricing schedule for 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 realised 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.

13. Distribution Loss Factors

Line losses are determined as the metered energy (in kWh) measured by the metering equipment at each ICP multiplied by the appropriate loss factor. This calculates the equivalent energy at the GXP supplying that ICP for the purposes of the reconciliation agreement and the registry. The loss factor (appearing below) into which each ICP falls will be determined by the point within the distribution network voltage at which the metering for that ICP takes place, together with the particular circumstance of supply.

The allocation of losses is not a contracted line function service and Eastland does not charge specific recoveries for losses.

Loss factors applicable to ENL will change from 1 April 2015 as a result of the acquisition of Eastland transmission spur assets from Transpower. This is because the metering point for Transpower will change from three GXP's to one GXP. ENL will therefore pick up the losses that were previously factored in Transmission into its Distribution network.

The undermentioned Loss Factors are applicable to all time periods, at the GXP.

Loss factors applicable to Eastland

- 400V connected supplies (LV Low Voltage) 1.1051
- 11kV connected supplies (HV High Voltage) 1.0822

Loss adjustment factors are reviewed annually and may be amended by Eastland from time to time, to ensure that they reflect unaccounted for energy on the distribution network as accurately as possible.

14. Consumer Survey

Each year ENL commissions a survey seeking the views of consumers, including their expectation in terms of price and quality. At the time of writing, the 2015 survey process had commenced but was not yet completed. The key conclusions of the 2014 survey are

- All market segments continue to rank "keeping the lights on" and "getting the lights back on" as the 1st and 2nd most important aspect of electricity lines services.
- Eastland's performance in these 2 important aspects has declined since the September 2012 survey
- About 33% of Large Customers indicated a possible willingness to pay a bit more to have a bit more reliability
- About 25% (Gisborne) and 33% (Wairoa) of mass market customers indicated a willingness to pay a bit less to have a bit less reliability.
- Large Customers would prefer to share efficiency gains through increased reliability rather than lower prices, whilst mass market customers were evenly divided.
- Large Customers seem to be noticing flicker more often, with about 50% claiming it is a problem. This has worsened since September 2012.
- All 3 market segments indicated a willingness to allow non-critical heat pumps to be interrupted if it meant avoiding long-term price increases
- The majority of customers in all 3 segments believe that Eastland takes public safety seriously, however most customers across all market segments also indicated a very strong unwillingness to pay more for increased public safety

15. Uneconomic Bypass

Uneconomic bypass will occur where the charges from ENL are high enough to drive consumers to seek alternative options and the alternative option bears costs for the consumer but does not reduce costs of the same magnitude for the network. Uneconomic bypass will occur where the cost to the consumer of the alternative is lower than the price the network charges but higher than the incremental cost to the network of supplying the customer.

The incremental costs of supplying each new connection is very difficult to quantify but given that networks are built to have some spare capacity the cost would be minimal for each new connection added until such time as a step change in capacity is required. ENL's pricing reflects a smoothed approach to capacity increases as the Eastland Network area has had flat demand for many years with relatively few additional connections each year. Where capacity increases are required for specific customers, capital contributions are required to pay for the additional capacity to reflect the cost drivers at a specific point where there is minimal or no benefit to existing customers. If there are benefits for other customers, this is reflected in the amount contributed so that the costs are spread across the customers that benefit. However, those specific costs are not reflected in the ENL pricing schedule but are treated separately on a case by case basis.

Other risk of uneconomic bypass could come from large customers who could potentially connect directly into the Transmission network, however ENL views this risk to be highly unlikely as there are currently no consumers (existing or potential) of sufficient scale or close enough to Transmission lines to enable them to connect directly to Transpower's transmission lines and with the transfer of the Transpower assets to ENL this possibility is now even more remote.

16. 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*"[2]

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. In these instances, the customer is required to contribute towards the costs of connection to reduce or minimize the burden of these costs across the rest of the consumers.

(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.

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

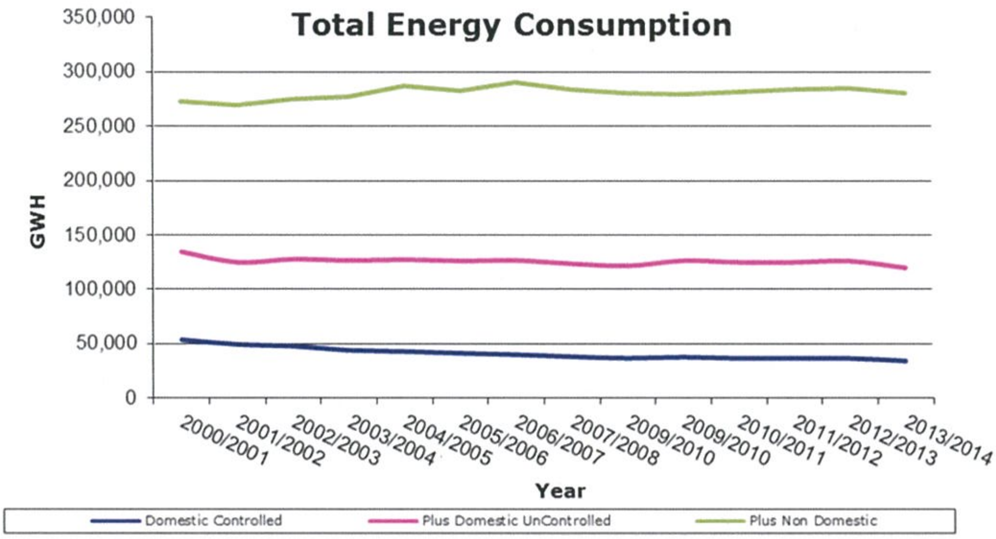
The ENL network has experienced little or no growth for a number of years and this trend is expected to continue and there is also a possibility that volumes may decrease slightly. As a result the network has adequate capacity to meet current and future needs and major augmentation or capital investment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

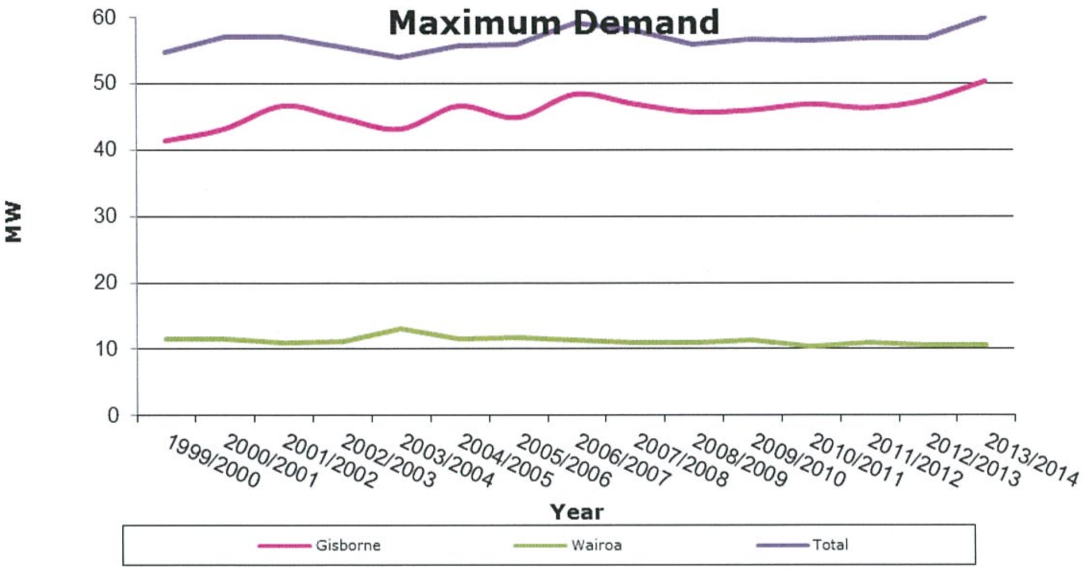
Table 4: ENL Energy Efficiency Measures *(Source: ENL 2015 Asset Management Plan)*

Measure	2013/14 Actual	2014/15 Forecast	2015/16	2016/17	2017/18	2018/19	2019/20	2020-2025
Load factor	57%	59%	59%	57%	55%	53%	53%	53%
Loss ratio	6.6%	7.0 %	9.5 %	9.5%	9.5%	9.5%	9.5%	9.5%
Capacity utilisation	24%	23%	24%	25%	26%	27%%	27%	28%

While ENL does encourage shifting of peak loads to off-peak through its TOU pricing, this signal can be somewhat diminished once re-packaged by the retailer.

Diagram 1: Energy Consumption and Demand *(Source: ENL 2015 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 on the website.

(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 publicly 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 rationalise 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.

Appendix 1 – Consumer Group Cost Allocation

	Pass-through	Recoverable	System maintenance	Business Support	Systems Operations & Network Support	Tax	Depreciation	Return on Capital	TOTAL
PDH0030	135,988	2,950,634	2,075,057	1,196,656	400,178	472,770	2,079,188	2,133,910	**11,444,380**
PDL0030	71,893	1,597,582	1,111,842	641,183	214,420	253,316	1,114,055	1,143,376	**6,147,666**
PNH0003	1,078	32,927	16,513	9,523	3,185	3,762	16,546	16,982	**100,516**
PNH0030	38,360	1,101,936	593,668	342,360	114,490	135,258	594,849	610,505	**3,531,425**
PNH0100	22,304	654,756	337,687	194,739	65,123	76,937	338,359	347,264	**2,037,168**
PNH0300	11,253	327,541	167,869	96,808	32,374	38,246	168,203	172,630	**1,014,925**
PTH0300	1,124	30,898	17,345	10,003	3,345	3,952	17,379	17,837	**101,882**
PNH0500	4,655	134,742	72,425	41,766	13,967	16,501	72,569	74,479	**431,104**
PNH1000	12,478	364,179	194,355	112,082	37,482	44,281	194,742	199,868	**1,159,467**
PNH4500	2,611	77,407	40,883	23,577	7,884	9,315	40,964	42,042	**244,683**
PNH6500	9,171	275,355	143,924	82,999	27,756	32,791	144,210	148,006	**864,210**
PNL0003	640	19,031	9,736	5,614	1,878	2,218	9,755	10,012	**58,884**
PNL0030	51,866	1,381,835	796,105	459,103	153,530	181,380	797,690	818,685	**4,640,194**
PNL0100	6,073	175,723	92,040	53,078	17,750	20,970	92,223	94,651	**552,508**
PNL0300	1,616	46,530	24,730	14,262	4,769	5,634	24,780	25,432	**147,753**
PNL0500	856	24,349	13,176	7,598	2,541	3,002	13,202	13,550	**78,274**
PTL0300	108	2,873	1,655	954	319	377	1,658	1,702	**9,647**
PNL1000	482	13,736	7,398	4,266	1,427	1,686	7,413	7,608	**44,016**
PNL4500	5,450	161,215	84,218	48,567	16,242	19,188	84,386	86,606	**505,872**
PNL6500	-	-	-	-	-	-	-	-	**-**
PNG0500	-	-	-	-	-	-	-	-	**-**
PNG1000	930	643	14,262	8,225	2,750	3,249	14,290	14,666	**59,015**
PNG4500	-	-	5,942	3,427	1,146	1,354	5,954	6,111	**23,934**
PNG6500	-	-	9,044	5,215	1,744	2,060	9,062	9,300	**36,425**
	378,936	**9,373,892**	**5,829,873**	**3,362,004**	**1,124,299**	**1,328,247**	**5,841,480**	**5,995,220**	**33,233,950**

Appendix 2 - Consumer Group Statistics

Price Category	Consumer Group	Charge Type	ICPs	Units	Current Year Prices			Forecast Revenue	Prior Year Prices			Change to prices			Reason for change
				days/kWH	Distribution	Transmission	Total		Distribution	Transmission	Total	Distribution	Transmission	Total	(Note number)
Domestic															
PDH0030	Domestic	Fixed Daily Charge	13,588	365	0.1125	0.0375	0.1500	743,943	0.1125	0.0375	0.1500	-	-	-	
PDH0030	Domestic	Consumption Uncontrolled	-	59,205,108	0.1110	0.0369	0.1479	8,756,435	0.1108	0.0400	0.1508	0.0002	(0.0031)	(0.0029)	a,b
PDH0030	Domestic	Consumption Controlled	-	25,304,676	0.0576	0.0192	0.0768	1,943,399	0.0576	0.0208	0.0784	-	(0.0016)	(0.0016)	a
PDH0030	Domestic	Consumption Night	-	31,359	0.0144	0.0048	0.0192	602	0.0144	0.0052	0.0196	-	(0.0004)	(0.0004)	a
	TOTAL		13,588	84,541,142				11,444,380							-
PDL0030	Domestic	Fixed Daily Charge	5,632	365	0.1125	0.0375	0.1500	308,352	0.1125	0.0375	0.1500	-	-	-	
PDL0030		Consumption Uncontrolled	-	28,181,996	0.1292	0.0435	0.1727	4,867,031	0.1291	0.0472	0.1763	0.0001	(0.0037)	(0.0036)	a,b
PDL0030	Domestic	Consumption Controlled	-	10,408,442	0.0698	0.0235	0.0933	971,108	0.0697	0.0255	0.0952	0.0001	(0.0020)	(0.0019)	a,b
PDL0030	Domestic	Consumption Night	-	52,472	0.0168	0.0056	0.0224	1,175	0.0168	0.0061	0.0229	-	(0.0005)	(0.0005)	a
	TOTAL		5,632	38,642,909				6,147,666							-
	Total Domestic		19,220	123,184,051				17,592,045							-
Non-Domestic - High Density															
PNH0003	Low Capacity (0 to 3kVA)	Fixed Daily Charge	137	365	0.2807	0.1115	0.3922	19,612	0.2804	0.1115	0.3919	0.0003	-	0.0003	a,b
PNH0003	Low Capacity (0 to 3kVA)	Capacity Charge	-	-	-	-	-		-	-	-	-	-	-	
PNH0003	Low Capacity (0 to 3kVA)	Demand Charge	-	-	-	-	-		-	-	-	-	-	-	
PNH0003	Low Capacity (0 to 3kVA)	Consumption Uncontrolled	-	603,264	0.0900	0.0441	0.1341	80,898	0.0899	0.0479	0.1378	0.0001	(0.0038)	(0.0037)	a,b
PNH0003	Low Capacity (0 to 3kVA)	Consumption Controlled	-	74	0.0584	0.0311	0.0895	7	0.0584	0.0311	0.0895	-	-	-	
PNH0003	Low Capacity (0 to 3kVA)	Consumption Night	-	-	0.0112	0.0060	0.0172	-	0.0112	0.0060	0.0172	-	-	-	
	TOTAL		137	603,338				100,516							-
PNH0030	Demand (0 to 30kVA)	Fixed Daily Charge	1,788	365	1.5784	0.5774	2.1558	1,406,918	1.5766	0.5774	2.1540	0.0018	-	0.0018	a,b
PNH0030	Demand (0 to 30kVA)	Capacity Charge	-	-	-	-	-								
PNH0030	Demand (0 to 30kVA)	Demand Charge	-	-	-	-	-								
PNH0030	Demand (0 to 30kVA)	Consumption Uncontrolled	-	21,420,291	0.0647	0.0317	0.0964	2,064,916	0.0647	0.0344	0.0991	-	(0.0027)	(0.0027)	a
PNH0030	Demand (0 to 30kVA)	Consumption Controlled	-	945,515	0.0421	0.0206	0.0627	59,284	0.0421	0.0224	0.0645	-	(0.0018)	(0.0018)	a
PNH0030	Demand (0 to 30kVA)	Consumption Night	-	18,301	0.0112	0.0056	0.0168	307	0.0112	0.0060	0.0172	-	(0.0004)	(0.0004)	a
	TOTAL		1,788	22,384,106				3,531,425							-
PNH0100	Demand (31 to 100kVA)	Fixed Daily Charge	268	365	4.9123	1.9533	6.8656	671,593	4.9067	1.9533	6.8600	0.0056	0.0000	0.0056	a,b
PNH0100	Demand (31 to 100kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNH0100	Demand (31 to 100kVA)	Demand Charge	-	-	-	-	-		-	-					
PNH0100	Demand (31 to 100kVA)	Consumption Uncontrolled	-	20,471,146	0.0442	0.0216	0.0658	1,347,001	0.0441	0.0234	0.0675	0.0001	(0.0018)	(0.0017)	a,b
PNH0100	Demand (31 to 100kVA)	Consumption Controlled	-	419,883	0.0287	0.0140	0.0427	17,929	0.0286	0.0152	0.0438	0.0001	(0.0012)	(0.0011)	a,b
PNH0100	Demand (31 to 100kVA)	Consumption Night	-	38,375	0.0112	0.0056	0.0168	645	0.0112	0.0060	0.0172	-	(0.0004)	(0.0004)	a,b
	TOTAL		268	20,929,405				2,037,168							-
PNH0300	Demand (101 to 300kVA)	Fixed Daily Charge	63	365	9.2632	3.6833	12.9465	297,705	9.2526	3.6833	12.9359	0.0106	0.0000	0.0106	b
PNH0300	Demand (101 to 300kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNH0300	Demand (101 to 300kVA)	Demand Charge	-	-	-	-	-		-	-					
PNH0300	Demand (101 to 300kVA)	Consumption Uncontrolled	-	13,345,440	0.0361	0.0176	0.0537	716,650	0.0360	0.0191	0.0551	0.0001	(0.0015)	(0.0014)	a,b
PNH0300	Demand (101 to 300kVA)	Consumption Controlled	-	16,379	0.0234	0.0114	0.0348	570	0.0234	0.0124	0.0358	-	(0.0010)	(0.0010)	a
PNH0300	Demand (101 to 300kVA)	Consumption Night	-	-	0.0112	0.0060	0.0172	-	0.0112	0.0060	0.0172	-	-	-	
	TOTAL		63	13,361,819				1,014,925							-

a = minor changes as a result of a slight change in how pass-through costs are allocated between distribution and transmission prices

b = Reduction in Transmission costs

c = Distribution Prices adjustment of TOU night rates

Price Category	Consumer Group	Charge Type	ICPs	Units	Prices			Forecast Revenue	Prior Year Prices			Change to prices			Reason for change
				days/kWH	Distribution	Transmission	Total		Distribution	Transmission	Total	Distribution	Transmission	Total	(Note number)
Non-Domestic - High Density															
PTH0300	TOU - Demand (201-300kVA)	Fixed Daily Charge	8	365	15.4387	6.1388	21.5775	63,006	15.4210	6.1388	21.5598	0.0177	0.0000	0.0177	b
PTH0300	TOU - Demand (201-300kVA)	Consumption Uncontrolled	-	-	-	-	-		-	-					
PTH0300	TOU - Demand (201-300kVA)	Consumption Controlled	-	-	-	-	-		-	-					
PTH0300	TOU - Demand (201-300kVA)	Consumption Evening Peak	-	197,830	0.0340	0.0157	0.0497	9,832	0.0340	0.0170	0.0510	-	(0.0013)	(0.0013)	a
PTH0300	TOU - Demand (201-300kVA)	Consumption Morning Peak	-	261,482	0.0318	0.0146	0.0464	12,133	0.0318	0.0159	0.0477	-	(0.0013)	(0.0013)	a
PTH0300	TOU - Demand (201-300kVA)	Consumption Off Peak	-	354,675	0.0251	0.0115	0.0366	12,981	0.0250	0.0125	0.0375	0.0001	(0.0010)	(0.0009)	a,b
PTH0300	TOU - Demand (201-300kVA)	Consumption Night	-	213,150	0.0128	0.0056	0.0184	3,930	0.0112	0.0056	0.0168	0.0016	0.0000	0.0017	a,b
	TOTAL		8	1,027,136				101,882							-
PNH0500	TOU - Demand (301-500kVA)	Fixed Daily Charge	14	365	17.4036	6.9201	24.3237	124,294	17.3837	6.9201	24.3038	0.0199	0.0000	0.0199	a,b
PNH0500	TOU - Demand (301-500kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNH0500	TOU - Demand (301-500kVA)	Demand Charge	-	-	-	-	-		-	-					
PNH0500	TOU - Demand (301-500kVA)	Consumption Evening Peak	-	1,340,183	0.0340	0.0157	0.0497	66,607	0.0340	0.0170	0.0510	0.0000	(0.0013)	(0.0013)	a
PNH0500	TOU - Demand (301-500kVA)	Consumption Morning Peak	-	2,156,162	0.0318	0.0146	0.0464	100,046	0.0318	0.0159	0.0477	-	(0.0013)	(0.0013)	b
PNH0500	TOU - Demand (301-500kVA)	Consumption Off Peak	-	2,793,251	0.0251	0.0115	0.0366	102,233	0.0250	0.0125	0.0375	0.0001	(0.0010)	(0.0009)	a,b
PNH0500	TOU - Demand (301-500kVA)	Consumption Night	-	2,057,108	0.0128	0.0056	0.0184	37,924	0.0112	0.0056	0.0167	0.0017	0.0000	0.0017	a,b
	TOTAL		14	8,346,704				431,104							-
PNH1000	TOU - Demand (501-1000kVA)	Fixed Daily Charge	20	365	26.9474	10.7150	37.6624	274,936	26.9166	10.7150	37.6316	0.0308	(0.0000)	0.0308	a,b
PNH1000	TOU - Demand (501-1000kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNH1000	TOU - Demand (501-1000kVA)	Demand Charge	-	-	-	-	-		-	-					
PNH1000	TOU - Demand (501-1000kVA)	Consumption Evening Peak	-	4,051,204	0.0340	0.0157	0.0497	201,345	0.0340	0.0170	0.0510	-	(0.0013)	(0.0013)	a
PNH1000	TOU - Demand (501-1000kVA)	Consumption Morning Peak	-	5,855,764	0.0318	0.0146	0.0464	271,707	0.0318	0.0159	0.0477	-	(0.0013)	(0.0013)	a
PNH1000	TOU - Demand (501-1000kVA)	Consumption Off Peak	-	7,866,751	0.0250	0.0115	0.0365	287,136	0.0250	0.0125	0.0375	0.0000	(0.0010)	(0.0010)	a,b
PNH1000	TOU - Demand (501-1000kVA)	Consumption Night	-	6,744,754	0.0128	0.0056	0.0184	124,343	0.0112	0.0056	0.0168	0.0016	0.0000	0.0017	a,c
	TOTAL		20	24,518,473				1,159,467							-
PNH4500	TOU - Demand (1001-4500kVA)	Fixed Daily Charge	1	365	67.3686	26.7875	94.1561	34,367	67.2916	26.7875	94.0791	0.0770	(0.0000)	0.0770	a,b
PNH4500	TOU - Demand (1001-4500kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNH4500	TOU - Demand (1001-4500kVA)	Demand Charge	-	-	-	-	-		-	-					
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Evening Peak	-	993,324	0.0340	0.0157	0.0497	49,368	0.0340	0.0170	0.0510	-	(0.0013)	(0.0013)	a
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Morning Peak	-	1,268,204	0.0318	0.0146	0.0464	58,845	0.0318	0.0159	0.0477	-	(0.0013)	(0.0013)	a
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Off Peak	-	1,827,486	0.0251	0.0115	0.0366	66,886	0.0250	0.0125	0.0375	0.0001	(0.0010)	(0.0009)	a,b
PNH4500	TOU - Demand (1001-4500kVA)	Consumption Night	-	1,910,283	0.0128	0.0056	0.0184	35,217	0.0112	0.0056	0.0168	0.0016	0.0000	0.0017	a,c
	TOTAL		1	5,999,297				244,683							-
PNH6500	TOU - Demand (4501-6500kVA)	Fixed Daily Charge	1	365	102.5265	40.7674	143.2939	52,302	102.4093	40.7674	143.1767	0.1172	0.0000	0.1172	a
PNH6500	TOU - Demand (4501-6500kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNH6500	TOU - Demand (4501-6500kVA)	Demand Charge	-	-	-	-	-		-	-					
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Evening Peak	-	3,765,548	0.0340	0.0157	0.0497	187,148	0.0340	0.0170	0.0510	-	(0.0013)	(0.0013)	b
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Morning Peak	-	5,085,541	0.0318	0.0146	0.0464	235,969	0.0318	0.0159	0.0477	-	(0.0013)	(0.0013)	b
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Off Peak	-	6,978,908	0.0251	0.0115	0.0366	255,428	0.0251	0.0125	0.0375	0.0000	(0.0010)	(0.0009)	a,b
PNH6500	TOU - Demand (4501-6500kVA)	Consumption Night	-	7,234,048	0.0128	0.0056	0.0184	133,363	0.0112	0.0056	0.0168	0.0016	0.0000	0.0016	a,c
	Total		1	23,064,046				864,210							-
	Total High Density		2,300	120,234,324				9,485,381							-

a = minor changes as a result of a slight change in how pass-through costs are allocated between distribution and transmission prices

b = Reduction in Transmission costs

c = Distribution Prices adjustment of TOU night rates

Price Category	Consumer Group	Charge Type	ICPs	Units	Prices			Forecast Revenue	Prior Year Prices			Change to prices			Reason for change
				days/kWH	Distribution	Transmission	Total	Forecast Revenue	Distribution	Transmission	Total	Distribution	Transmission	Total	(Note number)
Non-Domestic - Low Density															
PNL0003	Low Capacity (0 to 3kVA)	Fixed Daily Charge	117	365	0.2807	0.1115	**0.3922**	16,749	0.2804	0.1115	0.3919	0.0003	-	0.0003	a
PNL0003	Low Capacity (0 to 3kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNL0003	Low Capacity (0 to 3kVA)	Demand Charge	-	-	-	-	-		-	-					
PNL0003	Low Capacity (0 to 3kVA)	Consumption Uncontrolled	-	272,193	0.1040	0.0508	**0.1548**	42,135	0.1040	0.0551	0.1590	0.0000	(0.0043)	(0.0042)	a,b
PNL0003	Low Capacity (0 to 3kVA)	Consumption Controlled	-	-	0.0803	0.0358	**0.1161**	-	0.0675	0.0358	0.1033	0.0128	-	0.0128	a
PNL0003	Low Capacity (0 to 3kVA)	Consumption Night	-	-	0.0155	0.0068	**0.0223**	-	0.0130	0.0068	0.0198	0.0025	-	0.0025	a,c
	TOTAL							**58,884**							
PNL0030	Demand (0 to 30kVA)	Fixed Daily Charge	3,719	365	1.5784	0.5774	**2.1558**	2,926,358	1.5766	0.5774	2.1540	0.0018	(0.0000)	0.0018	a
PNL0030	Demand (0 to 30kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNL0030	Demand (0 to 30kVA)	Demand Charge	-	-	-	-	-		-	-					
PNL0030	Demand (0 to 30kVA)	Consumption Uncontrolled	-	16,163,244	0.0676	0.0330	**0.1006**	1,626,022	0.0676	0.0358	0.1034	0.0000	(0.0028)	(0.0028)	a,b
PNL0030	Demand (0 to 30kVA)	Consumption Controlled	-	1,313,785	0.0440	0.0215	**0.0655**	86,053	0.0440	0.0233	0.0673	0.0000	(0.0018)	(0.0018)	a,b
PNL0030	Demand (0 to 30kVA)	Consumption Night	-	91,232	0.0130	0.0063	**0.0193**	1,761	0.0130	0.0068	0.0198	-	(0.0005)	(0.0005)	b
	TOTAL							**4,640,194**							-
PNL0100	Demand (31 to 100kVA)	Fixed Daily Charge	88	365	4.9123	1.9533	**6.8656**	220,523	4.9067	1.9533	6.8600	0.0056	0.0000	0.0056	a
PNL0100	Demand (31 to 100kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNL0100	Demand (31 to 100kVA)	Demand Charge	-	-	-	-	-		-	-					
PNL0100	Demand (31 to 100kVA)	Consumption Uncontrolled	-	4,236,730	0.0515	0.0251	**0.0766**	324,534	0.0515	0.0273	0.0787	0.0000	(0.0022)	(0.0021)	a,b
PNL0100	Demand (31 to 100kVA)	Consumption Controlled	-	146,705	0.0334	0.0163	**0.0497**	7,291	0.0334	0.0177	0.0511	-	(0.0014)	(0.0014)	a,b
PNL0100	Demand (31 to 100kVA)	Consumption Night	-	8,304	0.0130	0.0063	**0.0193**	160	0.0130	0.0068	0.0198	-	(0.0005)	(0.0005)	b
	TOTAL							**552,508**							-
PNL0300	Demand (101 to 300kVA)	Fixed Daily Charge	15	365	9.2632	3.6833	**12.9465**	70,882	9.2526	3.6833	12.9359	0.0106	0.0000	0.0106	a,b
PNL0300	Demand (101 to 300kVA)	Capacity Charge	-	-	-	-	-		-	-					
PNL0300	Demand (101 to 300kVA)	Demand Charge	-	-	-	-	-		-	-					
PNL0300	Demand (101 to 300kVA)	Consumption Uncontrolled	-	1,255,501	0.0411	0.0201	**0.0612**	76,837	0.0411	0.0218	0.0629	0.0000	(0.0017)	(0.0017)	b
PNL0300	Demand (101 to 300kVA)	Consumption Controlled	-	867	0.0267	0.0130	**0.0397**	34	0.0267	0.0141	0.0408	0.0000	(0.0011)	(0.0011)	b
PNL0300	Demand (101 to 300kVA)	Consumption Night	-	-	0.0155	0.0068	**0.0223**	-	0.0130	0.0068	0.0198	0.0025	-	0.0025	b
	TOTAL							**147,753**							-

a = minor changes as a result of a slight change in how pass-through costs are allocated between distribution and transmission prices

b = Reduction in Transmission costs

c = Distribution Prices adjustment of TOU night rates

Price Category	Consumer Group	Charge Type	ICPs	Units days/kWH	Prices Distribution	Prices Transmission	Prices Total	Forecast Revenue	Prior Year Prices Distribution	Prior Year Prices Transmission	Prior Year Prices Total	Change to prices Distribution	Change to prices Transmission	Change to prices Total	Reason for change (Note number)
Non-Domestic - Low Density															
PTL0300	TOU - Demand (201-300kVA)	Fixed Daily Charge	1	365	15.4387	6.1388	**21.5775**	7,876	15.4210	6.1388	21.5598	0.0177	(0.0000)	0.0177	a
PTL0300	TOU - Demand (201-300kVA)	Capacity Charge	-	-	-	-	-		-	-					
PTL0300	TOU - Demand (201-300kVA)	Demand Charge	-	-	-	-	-		-	-					
PTL0300	TOU - Demand (201-300kVA)	Consumption Evening Peak	-	501	0.0358	0.0163	**0.0521**	26	0.0358	0.0177	0.0535	0.0000	(0.0014)	(0.0014)	a,b
PTL0300	TOU - Demand (201-300kVA)	Consumption Morning Peak	-	19,397	0.0334	0.0153	**0.0487**	945	0.0334	0.0166	0.0500	-	(0.0013)	(0.0013)	b
PTL0300	TOU - Demand (201-300kVA)	Consumption Off Peak	-	20,476	0.0262	0.0121	**0.0383**	784	0.0262	0.0131	0.0393	-	(0.0010)	(0.0010)	b
PTL0300	TOU - Demand (201-300kVA)	Consumption Night	-	817	0.0134	0.0059	**0.0193**	16	0.0118	0.0059	0.0177	0.0016	(0.0000)	0.0016	a,c
	TOTAL							**9,647**							-
PNL0500	TOU - Demand (301-500kVA)	Fixed Daily Charge	3	365	17.4036	6.9201	**24.3237**	26,634	17.3837	6.9201	24.3038	0.0199	0.0000	0.0199	a
PNL0500	TOU - Demand (301-500kVA)	Capacity Charge	-	-	-	-	-		-	-	-	-	-	-	
PNL0500	TOU - Demand (301-500kVA)	Demand Charge	-	-	-	-	-		-	-	-			-	
PNL0500	TOU - Demand (301-500kVA)	Consumption Evening Peak	-	223,555	0.0358	0.0163	**0.0521**	11,647	0.0358	0.0177	0.0535	0.0000	(0.0014)	(0.0014)	a,b
PNL0500	TOU - Demand (301-500kVA)	Consumption Morning Peak	-	334,288	0.0334	0.0153	**0.0487**	16,280	0.0334	0.0166	0.0500	-	(0.0013)	(0.0013)	b
PNL0500	TOU - Demand (301-500kVA)	Consumption Off Peak	-	450,207	0.0262	0.0121	**0.0383**	17,243	0.0262	0.0131	0.0393	-	(0.0010)	(0.0010)	b
PNL0500	TOU - Demand (301-500kVA)	Consumption Night	-	334,611	0.0134	0.0059	**0.0193**	6,470	0.0118	0.0059	0.0177	0.0017	(0.0000)	0.0016	a,c
	TOTAL							**78,274**							-
PNL1000	TOU - Demand (501-1000kVA)	Fixed Daily Charge	1	365	26.9474	10.7150	**37.6624**	13,747	26.9166	10.7150	37.6316	0.0308	(0.0000)	0.0308	a
PNL1000	TOU - Demand (501-1000kVA)	Capacity Charge	-	-	-	-	-		-	-	-	-	-	-	
PNL1000	TOU - Demand (501-1000kVA)	Demand Charge	-	-	-	-	-		-	-	-	-	-	-	
PNL1000	TOU - Demand (501-1000kVA)	Consumption Evening Peak	-	124,763	0.0358	0.0163	**0.0521**	6,500	0.0358	0.0177	0.0535	0.0000	(0.0014)	(0.0014)	b
PNL1000	TOU - Demand (501-1000kVA)	Consumption Morning Peak	-	215,081	0.0334	0.0153	**0.0487**	10,474	0.0334	0.0166	0.0500	-	(0.0013)	(0.0013)	b
PNL1000	TOU - Demand (501-1000kVA)	Consumption Off Peak	-	268,461	0.0262	0.0121	**0.0383**	10,282	0.0262	0.0131	0.0393	-	(0.0010)	(0.0010)	b
PNL1000	TOU - Demand (501-1000kVA)	Consumption Night	-	155,825	0.0134	0.0059	**0.0193**	3,013	0.0118	0.0059	0.0177	0.0016	(0.0000)	0.0016	a,c
	TOTAL							**44,016**							-
PNL4500	TOU - Demand (1001-4500kVA)	Fixed Daily Charge	1	365	67.3686	26.7876	**94.1562**	34,367	67.2916	26.7876	94.0792	0.0770	0.0000	0.0770	a
PNL4500	TOU - Demand (1001-4500kVA)	Capacity Charge	-	-	-	-	-		-	-	-	-	-	-	
PNL4500	TOU - Demand (1001-4500kVA)	Demand Charge	-	-	-	-	-		-	-	-	-	-	-	
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Evening Peak	-	1,969,889	0.0358	0.0163	**0.0521**	102,631	0.0358	0.0177	0.0535	0.0000	(0.0014)	(0.0014)	b
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Morning Peak	-	3,093,706	0.0334	0.0153	**0.0487**	150,664	0.0334	0.0166	0.0500	-	(0.0013)	(0.0013)	b
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Off Peak	-	3,980,340	0.0262	0.0121	**0.0383**	152,447	0.0262	0.0131	0.0393	-	(0.0010)	(0.0010)	b
PNL4500	TOU - Demand (1001-4500kVA)	Consumption Night	-	3,401,147	0.0134	0.0059	**0.0193**	65,763	0.0118	0.0059	0.0177	0.0016	(0.0000)	0.0016	a,c
	TOTAL							**505,872**							-
PNL6500	TOU - Demand (4501-6500kVA)	Fixed Daily Charge	-	365	102.5263	40.7674	**143.2937**	-	102.4093	40.7674	143.1767	0.1170	-	0.1170	a
PNL6500	TOU - Demand (4501-6500kVA)	Capacity Charge	-	-	-	-	-		-	-	-	-	-	-	
PNL6500	TOU - Demand (4501-6500kVA)	Demand Charge	-	-	-	-	-		-	-	-	-	-	-	
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Evening Peak	-	-	0.0358	0.0163	**0.0521**	-	0.0358	0.0177	0.0535	-	(0.0014)	(0.0014)	b
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Morning Peak	-	-	0.0334	0.0153	**0.0487**	-	0.0334	0.0166	0.0500	-	(0.0013)	(0.0013)	b
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Off Peak	-	-	0.0262	0.0121	**0.0383**	-	0.0262	0.0131	0.0393	-	(0.0010)	(0.0010)	b
PNL6500	TOU - Demand (4501-6500kVA)	Consumption Night	-	-	0.0134	0.0059	**0.0193**	-	0.0118	0.0059	0.0177	0.0016	(0.0000)	0.0016	a,c
	TOTAL							-							-
	Total Low Density		3,945	38,081,625				6,037,149							-
Price Category	**Consumer Group**	**Charge Type**	**ICPs**	**Units days/kWH**	**Prices Distribution**	**Prices Transmission**	**Prices Total**	**Forecast Revenue**	**Prior Year Prices Distribution**	**Prior Year Prices Transmission**	**Prior Year Prices Total**	**Change to prices Distribution**	**Change to prices Transmission**	**Change to prices Total**	
	Generation														
PNG0500	Assessed Capacity (301 to 500kVA)		-	-	16.9407	-	**16.9407**	-	17.3837	-	17.3837	(0.4430)	-	(0.4430)	a
PNG1000	Assessed Capacity (501 to 1000kVA)		6	365	26.9473	-	**26.9473**	59,015	26.9166	-	26.9166	0.0307	-	0.0307	a
PNG4500	Assessed Capacity (1001 to 4500kVA)		1	365	65.5769	-	**65.5769**	23,936	67.2916	-	67.2916	(1.7147)	-	(1.7147)	a
PNG6500	Assessed Capacity (4501 to 6500kVA)		1	365	99.7997	-	**99.7997**	36,427	102.4093	-	102.4093	(2.6096)	-	(2.6096)	a
	Total Generation		8					119,377							
			25,473	281,500,000				$ 33,233,952							

a = minor changes as a result of a slight change in how pass-through costs are allocated between distribution and transmission prices

b = Reduction in Transmission costs

c = Distribution Prices adjustment of TOU night rates