NETWORK TASMAN LIMITED

PRICING METHODOLOGY DISCLOSURE

For Year Commencing 1 April 2011

Pursuant to

Electricity Information Disclosure Requirements

Issued 31 March 2004

(Consolidating all amendments to 31 October 2008)

For compliance with :

Requirement 22: Disclosure of Pricing Methodology

Requirement 23: Contents of Pricing Methodology Disclosures

Network Tasman Limited
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1.0 REGULATORY REQUIREMENT

1.1 The Information Disclosure Requirements 2004 (Sections 22 & 23) gazetted by the NZ Commerce Commission require electricity line businesses to annually disclose:

- The pricing methodology used to calculate line prices
- key components of revenue required to cover the costs and profits, (including cost of capital and transmission), of the line owners business activities
- consumer groups and consumer statistics used in the calculation of line prices and charges
- the method of allocating costs and revenues amongst consumer groups
- the method by which the line owner determines the proportion of fixed and variable charges.

1.2 The Electricity Authority has also promulgated Distribution Pricing Principles and Information Disclosure Guidelines (February 2010) in which it promotes a principles based approach to on line pricing and specific information disclosures concerning EDB pricing. The Authority and its predecessor have developed these guidelines to be consistent with the Information Disclosure Requirements 2004.

2.0 FINANCIAL INFORMATION

2.1 This pricing disclosure relies on financial information drawn from NTL's line business budget and financial forecasts for the year ending 31 March 2012. Line business costs have been separated from NTL's other non line business activities in a manner consistent with the Electricity Information Disclosure Handbook 2004 (as amended to 31 October 2008).

2.2 The forecast financial information provides the transmission, operating, maintenance, depreciation and overhead cost data used in determining NTL's line business annual revenue requirement.

2.3 Network capital costs are calculated using NTL's estimate of WACC and the Regulatory Asset Base (RAB) derived for Information Disclosures at 31 March 2011. The RAB is based on the 2004 ODV of systems fixed assets and this is rolled forward to 31 March 2011 using the methodology inherent in the Information Disclosure Regulations. The roll forward accounts for actual capital expenditure and depreciation for the intervening period to 31 March 2011.

3.0 NETWORK TASMAN PRICING PRINCIPLES

3.1 NTL's pricing methodology reflects, to the extent possible:

- The pricing principles stated in NTL's Statement of Corporate Intent and agreed between NTL and its shareholder; Network Tasman Trust.
- The Distribution Pricing Principles and Information Disclosure Guidelines (February 2010) produced by the NZ Electricity Commission and now administered by the NZ Electricity Authority.

3.2 The following pricing principles are embodied within NTL's SCI and are included in Use of Systems Agreements with retailers:

- A fair and reasonable rate of return to shareholders (cost of capital measured on a pre-tax, pre discount basis) will be recovered
- This cost of capital will be reasonably allocated to, and recovered from, each consumer group

- Direct and indirect distribution costs and depreciation will be reasonably allocated to, and recovered from, each consumer group
- Transmission costs will be allocated and recovered in a manner that reasonably reflects how these costs are incurred by each consumer group
- Appropriate economic signals will be given to consumers relating to their use of the distribution and transmission systems
- Regulatory and public policy requirements imposed by Government, the Commerce Commission and the Electricity Authority will be accommodated within network pricing as required
- Pricing will retain a reasonable level of uniformity amongst like consumers and across NTL's regional areas.
- Pricing will be simple to understand, implement and administer
- Pricing will provide certainty and medium term stability for consumers and retailers. The distribution component of pricing will be changed, at most, once in any 12 month period while the transmission component may change whenever Transpower alters its transmission charges.

3.3 The specific pricing principles promulgated in the Electricity Authority Guidelines are stated in Section 18 and are also viewable at:

http://www.ea.govt.nz/our-work/programmes/transmission-work/principles-or-model-approaches-to-distribution-pricing/

3.4 Where pricing objectives or principles are in conflict, Network Tasman Directors exercise their discretion and judgement to achieve an acceptable trade off between conflicting items.

4.0 LINE CHARGE DERIVATION

4.1 Line charges are the sum of distribution charges and transmission charges. Each component has different underlying cost drivers and so distribution and transmission pricing components are derived separately.

5.0 DISTRIBUTION SERVICES

5.1 The derivation of distribution pricing links costs to prices by allocating costs to load groups and then calculating tariffs for those load groups. The stages involve:

- Determination of NTL's Overall Distribution Revenue Requirement
- Identification of Load Groups
- Allocation of Distribution Revenue Requirement to Load Groups
- Derivation of Distribution Prices for Load Groups

6.0 NTL DISTRIBUTION REVENUE REQUIREMENT

6.1 The revenue requirement for a the distribution network is the sum of:

- operating & maintenance costs
- overhead costs
- return *of* capital employed (depreciation)
- return *on* capital employed (WACC)

6.2 Network Tasman Ltd's distribution costs are accumulated into the following classifications:

- Direct Network Costs which include operations and maintenance costs and direct overheads

- Indirect Network Costs which include indirect overheads and administration costs
- Depreciation (return of capital) which is based on ODV rates for systems assets and financial reporting rates for non systems assets
- Capital Costs (return on capital/assets employed) which is calculated by applying WACC to NTL's RAB

6.3 The sum of the costs above equates to the line business's total distribution revenue requirement. Information on NTL's 2011-12 distribution revenue requirement by cost classification and load group is provided in Appendix A.

6.4 The allowable return on capital is represented by the weighted average cost of capital (WACC) for the distribution business and covers the cost of debt (interest costs) and the cost of equity finance. The cost of capital is obtained by multiplying the pre-tax WACC by the RAB and non-system asset values allocated to each load group. The non system asset values are based on their financial reporting book values.

6.5 The cost of capital (WACC) is derived using the Capital Asset Pricing Model. For the financial year commencing 1 April 2011 NTL used the following inputs:

- 5 year government stock rate to estimate the risk free rate at 5.10%
- Target capital structure of 40% debt to total assets
- Cost of debt 7.3%
- Asset beta of 0.40 as the measure of the line business systematic risk
- post tax market risk premium for equity of 7.5%
- corporate tax rate of 28.0%

Based on these inputs NTL has calculated a pre tax cost of capital of 10.0% or a post tax WACC of 7.2% for the assets of NTL's line business

7.0 LOAD GROUPS

7.1 NTL's distribution revenue requirement is allocated to consumer load groups and distribution charges are derived for ICP's (Installation Control Points) within consumer load groups.

7.2 The allocation of ICP's to load groups is determined according to the service levels required by customers at their specific ICP's, namely by the :

- maximum capacity/demand an ICP can place on the network
- use/reliance an ICP places on particular segments of the network
- type of metering installed at an ICP

Consumer ICP's are classified to load groups as follows:

Consumer Group	**Network Segment Used**	**Maximum capacity requirement**
Group 1	General 400V / 11 /33kV	Fused <= 15 kVA
Group 2	General 400V / 11 /33kV	Fused > 15 & < 150 kVA
Group 3	Limited 400V and 11 / 33kV	AMD>150kVA+ hhr metering
Group 6	Dedicated & Semi dedicated network, 33 kV and limited 11kV	>= 2000 kVA + 11kV hhr metering

Explanation:

- 400V/11/33kV indicates the voltage level at which the consumers in this Group take supply and the components of the network they use.
- The kVA indicates the consumer's potential anytime maximum demand (AMD) as measured by the size of the ICP fuse installed or the AMD obtained from half hourly (hhr) data available from consumer TOU meters.
- Dedicated consumers are those utilising dedicated or semi dedicated feeders, substations and network assets at voltages of at least 11kV and usually 33kV and have 11kV metering.

7.3 Government policy and SCI requirements encourage Network Tasman to treat loads on rural spurs lines largely the same as those on the urban meshed parts of the network. Consequently load groups, and therefore distribution charges, are not differentiated across the various geographical areas serviced by the network.

7.4 Load group statistics used to allocate costs and calculate prices are provided in Appendix A.

8.0 ALLOCATION OF NETWORK COSTS TO LOAD GROUPS

8.1 Direct Network Costs, Systems Depreciation and Capital Costs

Direct network costs, systems depreciation and capital costs can be directly assigned against network asset categories as shown in Figure 3.1 below. These network costs are then accumulated into those associated with the upper & lower segments of the network as shown in Figure 3.2.

8.2 Using the Figure 3.3 formulae, the network costs accumulated to the upper network segments are apportioned to each load group on the basis of coincident maximum demand (CMD), calculated on a 3 year rolling average basis at each GXP.

8.3 A key difference between the treatment of the upper and lower network cost components is that

- no lower network costs are allocated to load Group 6, as this group relies solely on upper network assets for its supply.
- allocations for the 400V cost components are modified to reflect Group 3’s minimal reliance on these assets.

FIGURE 3.1 ALLOCATION OF DIRECT COSTS TO COMPONENTS OF THE NETWORK

NETWORK COMPONENT	DIRECT NETWORK COSTS	DEPRECIATION	RETURN ON ASSETS	TOTAL DIRECT COST (TDC)
General 400V lines	a1	b1	r1	c1
Distribution transformers	a2	b2	r2	c2
General 11 kV lines	a3	b3	r3	c3
Dedicated 11 kV lines	a4	b4	r4	c4
Sub transmission. lines and zone subs.	a5	b5	r5	c5
Dedicated networks	a6	b6	r6	c6
TOTALS	**a**	**b**	**r**	**c**

FIGURE 3.2 NETWORK UPPER AND LOWER NETWORKS

NETWORK COMPONENT	TDC BY COMPONENT	UPPER NETWORK ALLOCATION	LOWER NETWORK ALLOCATION
General 400V lines	c1	d1	e1
Distribution transformers	c2	d2	e2
General 11 kV lines	c3	d3	e3
Dedicated 11 kV lines	c4	d4	e4
Sub transmission. lines and zone subs	c5	d5	e5
Dedicated networks	c6	d6	e6
TOTALS	**c**	**d**	**e**

Note : d1& d2 =0 and e5,& e6 =0

FIGURE 3.3 ALLOCATION OF DIRECT NETWORK COSTS TO LOAD GROUPS

Load Group	**Supply Voltage V**	**Coincident Demand MVA**	**Accumulated Formula MVA**	**Cost Allocation Formula**	**Total Direct Cost Allocation By Group**
(1) 400V Gen < = 15 kVA	230/400	M1	A1	(M1/A6*d)+(M1'/A3*e)	TDC 1
(2) 400V Gen > 15&<150kVA	400	M2	A2	(M2/A6*d)+(M2'/A3*e)	TDC 2
(3) 400V & 11kV > 150 kVA	400/11,00O	M3	A3	(M3/A6*d)+(M3'/A3*e)	TDC 3
(6) Ded. Network	Over 11000	M6	A6	(M6/A6*d)	TDC 6

Note: A1 = M1,A2 = M1+M2,A3=M1+M2+M3 etc.

M1', M2', M3' are CMD's adjusted to reflect G3 minimal use of the 400V lower network assets

8.4 Allocation of Indirect Network Costs

- Indirect network costs include general administration and overhead costs and depreciation on non systems fixed assets
- Management estimates are used to allocate indirect network costs to Group 6 & bulk supply consumers.
- The remaining indirect network costs are allocated to load Groups 1,2 & 3 in proportion to their relative shares of installed capacity (measured by fuse size or dedicated transformer capacity).

FIGURE 3.4 LOAD GROUP REVENUE REQUIREMENT

Load Group	**Supply Voltage**	**Total Direct Cost Allocation**	**Total General Overhead Allocation**	**Total Distribution Revenue Requirement**
(1) 400V Gen < = 15 kVA	230/400	TDC 1	OH1	TR1 = TDC 1+OH1
(2) 400V Gen > 15 & < 150 kVA	400	TDC 2	OH2	TR2 = TDC 2+OH2
(3) 400V &11kV > 150 kVA	400/11000	TDC 3	OH3	TR3 = TDC 3+OH3
(6) Ded. Network	11000 and over	TDC 6	OH6	TR6 = TDC 6+OH6

9.0 DERIVATION OF DISTRIBUTION TARIFFS.

9.1 General

The TRi totals from figure 3.4 identify the distribution revenue requirement for each load group recoverable through distribution tariffs. Revenue is recovered using "fixed" and "variable" tariff components.

Fixed tariffs are either daily charges (expressed as cents/day) or capacity/demand based tariffs (expressed as cents/kVA/day).

Variable tariffs are based on consumption or usage (expressed as cents/kWh).

9.2 Determining the proportion of fixed and variable tariffs

(a) NTL must strike a balance between the conflicting demands of:
- economic rationale
- government policy and regulatory requirements
- electricity retailers desire for simplicity, predictability and minimisation of transaction costs
- the expectations of different electricity consumers

(b) Economic theory encourages the application of cost reflective pricing. Regionally differentiated pricing with a strong peak demand emphasis would be the logical result. This supports economic efficiency by reflecting
- the sunk nature of networks asset based costs
- the fixed nature of line business cost structures
- the new investment demands caused by loads at peak times.

The government owned grid operator Transpower operates a pricing methodology along these lines.

(c) Government policy and regulations however compel distributors to provide low fixed charge tariffs to lower use domestic consumers and to ensure rural and urban pricing structures remain closely aligned.

(d) NTL also acknowledges many consumers and environmental groups oppose high fixed charge structures and expect a significant element of their charges to vary with consumption so a greater level of influence can be exerted over their electricity bills. These views conflict with the preferences of higher use business consumers who consider capacity based charges properly and fairly reflect costs of supply and reward high load factor consumers for efficient use of network assets.

(e) To achieve a compromise between these conflicting demands NTL’s distribution pricing is structured such that:
- Group 1 fixed charges are set at 15 cents per day (for both small business and residential consumers) to meet government regulatory requirements and to minimise NTL’s & retailers’ transactions costs. As a consequence Group 1 pricing no longer reasonably reflects the fixed costs of supply to poor load factor or remotely located consumers in this group.
- Groups 2 & 3 contain mostly larger, higher load factor business consumers so greater reliance is placed on fixed capacity based pricing that is applied to either installed fused sizes or AMD’s obtained from TOU metering.
- Group 6 consumers have fully fixed charges reflecting the high levels of assets dedicated for their supply; they essentially pay an annual fixed rental for the dedicated assets used in their supply irrespective of their load profiles.

- There is no tariff differentiation between regional areas and consequently the revenue recovered in rural areas does not always fully reflect the cost of supply to those areas.
- There is no differentiation of tariffs (fixed or variable) based on consumers end use of electricity (i.e. between business or domestic).

9.3 **Fixed and Capacity based Tariffs**

(a) Load Group 1 ICP’s have a single fixed charge expressed as a "cents per day" charge because all ICP’s in this Group have the same 15 kVA fuse capacity limiting maximum demands on the network.

(b) Group 2 fixed charge is expressed as "dollars per kVA of anytime maximum demand" which is applied to the installed fuse capacities (between 20 and 150 kVA) limiting the maximum demands each consumer within in this group can place on the network.

(c) For load Group 3 fixed charges are expressed as:

(i) "dollars per AMD" (AMD=anytime maximum demand) and

(ii) "dollars per Winter RCPD demand" The winter demand is the customers average demand measured coincident against the top 12 regional coincident peak demands (RCPD) on Transpower’s transmission system in the Upper South Island.

9.4 **Variable/Consumption based Tariffs**

(a) Variable line tariffs are expressed as "cents per kWh" and apply to all customer groups except Group 6.

(b) The cents per unit charges vary across differing tariffs, depending on the time of use profile or the level and type of load intruptability the consumer commits to in advance.

9.5 **Revenue Adequacy**

(a) The distribution revenue requirement for each group, (TR1 to TR6 in Figure 3.4) may exceed what that group is currently paying. For some groups full recovery is unobtainable if rate shock is to be avoided or if NTL wants to avoid breaching either Government policy constraints or the Commerce Commission’s regulatory default price pathway. This is particularly notable for network segments and customer groups where connection density is low and where load factor is poor.

(b) Consequently Network Tasman must choose between deliberately breaching the regulatory price pathway or accepting a shortfall of actual distribution revenue over the total revenue requirement. To date NTL has accepted the latter.

(c) Under recovery of distribution revenue from a particular customer group is not made good by over recovery from any of the other groups.

10.0 DERIVATION OF DISTRIBUTION PRICES

Load Group 1.

10.1 Total Group 1 distribution revenue requirement "TR1" is split between that part to be recovered by a fixed charge (FC1), and that part to be recovered by a variable charge (VC1).

10.2 The total annual fixed charge for Group 1 ICP's is set at $55pa. or 15 cents/day. The distribution component of this fixed charge, FC1, is $43.25 and is recovered from all consumers (ICPs) with no account being taken of geographical area or whether they are business or residential consumers. This approach was adopted to:

- meet Government low user regulatory requirements
- avoid unwarranted discrimination between small business and small residential consumers
- minimise the additional transaction and administration costs NTL and electricity retailers face in delivering the lower user tariff requirement.
- minimise the level of irrecoverable revenue leakage at risk under regulatory price path formulas as a consequence of delivering the low user pricing requirements part way through a control period.

10.3 The total variable charge VC1 recovers the residual revenue from TR1 and is combined with VC2 for Group 2 and variable tariffs are then set for both load groups at common levels. This promotes simplicity and lowers both NTL's and retailers' transaction costs.

10.4 The tariff rates are determined by dividing the number of units consumed by Group 1 and 2, after establishing a set of relative weightings between the tariff types on offer.

10.5 The relative weights are in part driven by legacy issues and in part reflect the relative costs of providing network services at "peak" versus "off peak" times. The weighting provides a signal for consumers to shift consumption "off peak" and to permit components of their supply to be interrupted by NTL load control devices. The weights are allocated by management using among other factors the historic relative differences between unit charges. To provide a material difference between variable tariff rates, controlled and off peak rates are set to be less than half the standard anytime rate.

Load Group 1 : 2011-12 Budget Data :

TR1 budgeted 2011-12		$13,140,000
Number of G1 ICPs (forecast)		33,781
Total to be recoverable by fixed charges		
Fixed charge per annum	=	$43.25 pa or 11.85 cents /day
	=	33,781*$43.25
FC1 =	$1,461,000	
Total Variable Charge VC1	=	$13,140,000 - 1,461,000
	=	$11,679,000 & accumulated with Group 2 VC2 for recovery

Load Group 2

10.6 The Group 2 distribution revenue requirement TR2 is split between that to be recovered by a fixed capacity charge (FC2), and that to be recovered by a variable charge (VC2).

10.7 Each ICP in Group 2 has an Anytime Maximum Demand (AMD between 20 and 150 kVA) based on installed supply fuse sizes and expressed in kVA.

10.8 Group 2 Fixed charge revenue is set at 20% of TR2 or at approximately twice the level for Group 1. This ensures the resulting capacity charges step up materially for consumers wishing to either move between Group 1 and Group 2 or to upgrade their installed fuse size within the kVA bands available in Group 2. Consumers are provided with a clear signal to minimise their peak capacity demands and to use scare network capacity efficiently.

10.9 The total fixed charge revenue (FC2) is divided by the sum of all AMDs in the group to give a tariff expressed in dollars per kVA per annum. This rate is the same for all consumers within the group with no account being taken of geographical area.

10.10 The dollar per kVA tariff is multiplied by the individual ICP's AMD (derived from installed fuse size), to give a "demand charge" per year. This is divided by 365 and is billed on a daily basis.

10.11 The total variable charge (VC2) recovers the residual revenue of TR2 and is combined with VC1 to be recovered using common tariff rates as described above in 10.3-10.5.

Load Group 2 profile from 2011-12 budget data:

Consumer	AMD (kVA)
x	40
y	70
z	110
....	....
Total Group 2	115,000 kVA

Group 2 TR2 Budget 2011-12	$6,696,000
Total Fixed Charge FC2 = 20%	$1,343,000
Total Variable Charge VC2=80%	$5,353,000 accumulated with VC1 from Group 1 for recovery

Capacity Tariff = $1,343,000 / 115,000
= $11.68 per kVA pa.

Consumer "x" AMD Charge per day = (11.68 * 40) / 365
= $1.28 per day

Group 1 & 2 Variable Tariffs

Total $ to be recovered from variable charges for Group1
VC1 = $13,140,000 – $1,461,000
= $11,679,000

Total $ to be recovered from variable charges from Group 2
VC2 = $6,696,000 - $1,343,00
= $5,353,000

Combined Group1&2 amount to be recovered from variable tariffs
VC1+VC2 = $11,679,000+$5,353,000
= $17,031,000

Tariff s Common to G1& G2	Allocated Weightings	G1+G2 Budgeted Units
A - Anytime	100%	236 GWh
B - Day	110%	21 GWh
C - Controlled Water	46%	68 GWh
D - Night	33%	14 GWh

Line Charge Tariff A = $17,031,000 / (236*1.0 +21* 1.10+68 * 0.46+14*0.33)
= 5.76 cents per kWh of A metered consumption

Line Charge Tariff B = $0.0576 * 1.10
= 6.33 cents per kWh of B metered consumption

Line Charge Tariff C = $0.0576 * 0.46
= 2.67 cents per kWh of C metered consumption

Line Charge Tariff D = $0.0576 * 0.33
= 1.91 cents per kWh of D metered consumption

11.0 DERIVATION OF DISTRIBUTION PRICES - Load Group 3.

11.1 The total Group 3 distribution revenue requirement TR3 is split between that part recoverable by a capacity charges (FC3) and that recoverable by a variable charge (VC3). Group 3 customers are primarily larger, high load factor business consumers and so the fixed or capacity based charges for this group are set to recover approximately 50% of TR3. This provides strong signals to minimise anytime and winter peak demand levels and rewards good load factor much more than is the case in Groups 1&2 .

11.2 At the beginning of the billing year the consumer's AMD and Winter RCPD are measured directly from TOU data supplied by retailers:

- A G3 customers Winter RCPD quantity is the average of that consumers kW load coincident with Transpower's 12 peak loads on USI grid for the year ending 31st August in the previous year.
- A G3 customer's AMD is that consumers highest half hourly kVA at any time, in any month, during the year.

11.3 The total fixed charge revenue FC3 is divided by the sum of the AMDs and the Winter RCPDs after establishing the relative weighting between the anytime and winter demand charges. The weighting is heavily biased towards the AMD charge because the RCPD is primarily used as a mechanism for passing through Transpower Interconnection charges. This gives a dollar per AMD kVA and a dollar per Winter RCPD kW as distribution tariffs .

11.4 The dollar per AMD (Winter RCPD) tariff is multiplied by the ICP's AMD (Winter RCPD), to give the ICP's anytime (winter) demand charge per year. This is then divided by 365 and billed on a daily basis.

11.5 The total variable charge (VC3) recovers the residual revenue from TR3 not met by capacity charges and tariff rates are determined by dividing by the number of units consumed by load Group 3, and a relative weighting is established between the tariffs for summer day, summer night, winter day and winter night. This weighting process uses a similar rationale outlined for Group 1.

Load Group 3: Category 3.4 2011-12 Budget Data :

Consumer	AMD	Winter RCPD
x	225	200
y	194	120
Group Total	36,037	15,036

Total Group 3 Dist Revenue - TR3		$3,507,547
Fixed Charge recovery %		49%
Total Fixed Charge Revenue - FC3		$1,722,333
Total Variable Charge Revenue-VC3		$1,785,214
Ratio Anytime to Winter Approx		90:10
AMD Tariff	=	($1,722,333 * 0.903)/36037
	=	$43.18 per kVA
WMD Tariff	=	($1,722,333 *0.097)/15036
	=	$11.06 per kW pa.

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<u>Consumer Capacity Charges</u>

Consumer "x" Winter RCPD	=	200 * 11.06 / 12
	=	$184 per month
Consumer "x" AMD Charge	=	225 * 43.00 / 12
	=	$809 per month

(The Variable charge per tariff is calculated in the same manner as Example 1)

12.0 DERIVATION OF DISTRIBUTION PRICES - Load Group 6.

12.1 These consumers are large enough, and few enough, to warrant individual calculation of line charges based on the ODRC values and direct costs associated with the dedicated or semi-dedicated assets used in their supply. General overheads are allocated using management estimates.

12.2 Distribution charges are calculated as an annual fixed amount, and are billed monthly.

13.0 TRANSMISSION SERVICES

13.1 The grid owner Transpower charges NTL for use of the transmission grid. NTL recovers transmission costs by allocating them to consumer groups and recovering them through the transmission component within overall line charges.

14.0 ALLOCATION OF TRANSMISSION COSTS.

14.1 Transpower's transmission charges levied on NTL are relatively fixed and unavoidable. Transmission charges are billed by GXP and include the following components:

- Connection charges (net of EVA adjustments if any)
- Interconnection charges
- New investment charges
- Loss and constraint rental rebate credits

14.2 Connection costs and new investment charges are levied at each Transpower grid exit point (GXP) supplying NTL's network. These are allocated to load groups on the basis of each group's (CMD) demand contribution coincident with the AMD of that GXP. Forecast loss rental rebates are allocated to customer Groups 1,2&3 on the basis of forecast consumption levels and are netted off total transmission costs to be recovered from each group.

14.3 Interconnection charges are allocated between load groups on the basis of each group's demand level measured coincident with Transpower's Upper South Island RCPD 12 peak chargeable half hours recorded over the winter of the previous year.

14.4 The connection, new investment and interconnection costs allocated to each group at each GXP are summed to obtain the gross transmission costs to be recovered from that group.

14.5 NTL recovers transmission costs from load Groups via a separate transmission pricing schedule within overall line charges as follows:

(a) Consumers are classified into the same load groups in the same way used for distribution pricing (see Section 7.0)

(b) Transmission costs for Group 6 and Bulk Supply customers are recovered on a direct pass through basis (see Section 18.0).

(c) The remaining transmission costs, after Group 6 pass through, are recovered from Group's 1-3 via NTL's standard transmission pricing schedule.

(d) For Groups 1-3 transmission charges are recovered on a “fixed” and “variable” basis using similar rationale to that used in distribution pricing.

(e) To the extent possible within regulatory pricing constraints, NTL attempts to recover Transpowers connection and new investment costs allocated to Groups 1 & 2 via fixed or capacity charges and the interconnection cost allocated through variable charges.

(f) For load Group 1 the fixed charge is expressed as a "cents per day" charge.

(g) For load Group 2 the fixed charge is expressed as “dollars per anytime maximum capacity” (AMD) measured in kVA and based on customer fuse size.

(h) For load Group 3 the fixed capacity charge is expressed as "dollars per kW of Winter RCPD” and “dollars per kVA” of AMD, and is based on data from TOU meters. The Winter RCPD component directly passes through Transpower’s interconnection charges attributable to Group 3 consumers while the AMD component recovers connection costs attributable to this group. No variable (kWh) transmission tariffs are used to recover the transmission costs attributable to Group 3 consumers.

(i) The variable Transpower charge is expressed as "cents per unit (kWh)" for Groups 1&2 and varies across tariffs, depending on the historical usage profile and load control availability.

15.0 FIXED TRANSMISSION CHARGES FOR GROUPS 1 - 3

15.1 Group 1

The total transmission cost allocated to Group 1 (TT1) is split between that part to be recovered by a fixed charge (TFC1) and that part to be recovered by a variable charge (TVC1).

The total fixed charge (TFC1) is divided by the number of ICPs in Group 1 to give the annual Group 1 charge per ICP.

The annual fixed charge is billed on a daily basis (annual charge per ICP / 365).

15.2 Group 2

The total transmission cost allocated to Group 2 (TT2) is split between that part to be recovered by a fixed charge (TFC2), and that part to be recovered by a variable charge (TVC2).

Each ICP within Group 2 has an Anytime Maximum Demand (AMD) as described in the Group 2 fixed distribution charge calculation in section 10.9 above.

The total fixed charge (TFC2) is divided by the sum of all individual AMDs within Group 2. This gives a dollar tariff per kVA of AMD per annum.

The dollar per kVA tariff is multiplied by the ICP's AMD, to give a "demand charge" per year. This is divided by 365 and billed on a daily basis.

15.3 **Group 3**

The total transmission cost allocated to Group 3 (TT3) is recovered by fixed charges (TFC3a and TFC3b).

The connection and new investment component (TFC3a) is divided by Group 3's total AMD to yield a $/kVA rate. This rate is then applied to each individual consumers' AMD to determine their annual charge which is divided by 12 and billed monthly.

The interconnection portion (TFC3b) is recovered based on individual customers demands measured coincident with the USI RCPD demand measured over the previous year (Winter RCPD). The total amount recoverable by the Winter RCPD charge (TFC3b), is divided by the total Winter RCPD kWs for the group. This gives a dollar tariff per kW of Winter RCPD. The dollar per Winter RCPD tariff is then multiplied by each ICP's Winter RCPD to give the ICP's annual charge and is divided by 12 and billed monthly.

16.0 VARIABLE TRANSMISSION CHARGES GROUPS 1-3

16.1 Group 1&2 variable charge amounts are combine (TVC1+TVC2) and recovered using common variable tariff rates in a similar manner to G1&2 distribution charges.

16.2 Each variable distribution tariff option for Groups 1&2 is classified as either a "peak" or an "off peak" tariff. Off peak time is for night only consumption (occurring between 2300 and 0700), ripple controlled consumption or summer only consumption. Those in the peak time classification, are, by default, the remainder of the tariffs (Anytime or Day tariffs) and where consumption is not interruptible by NTL load control equipment.

16.3 A relative weighting is applied to differentiate peak and non peak tariffs for each group.

16.4 The total amount to recover by this variable charge (TVC1+TVC2) is then divided by total kWh consumption Groups 1&2, having established the weighting between the various peak and off peak tariffs described in (16.2) above.

16.5 No variable tariffs are used in Group 3 pricing to recover transmission costs.

Transmission Cost Recovery: Budget 2011-12 data

		Total
Group 1 RCPD		45,713 kW
Group 2 RCPD		18,819 kW
Group 3 RCPD		18,594 kW
Group 6 RCPD		22,109 kW
RCPD at GXPs		105,235 kW
TFC1	=	$388,400
TFC2	=	$356,750
TVC1+TVC2	=	$6,316,900
TT(1+2)	=	$7,062,050
TT3	=	$1,658,800
Group 1 ICPs		33,781
Group 2 AMD		115,000 kVA
Group 3 AMD		43,741 kVA
Group 3 Winter RCPD		18,594 kW
Group 6 CMD		22,109 kVA

G1 Fixed Charge	=	$388,400 / (33,781) / 365 * 100
	=	3.15 cents per day
G2 Fixed Charge	=	$356,750 /115,000
	=	$3.10 per kVA pa.

Group 1&2 Variable Transmission Tariffs

Tariff s Common to G1& G2	Allocated Weightings	G1+G2 Budgeted Units
A - Anytime	100%	236 GWh
B - Day	110%	21 GWh
C - Controlled Water	45%	68 GWh
D - Night	34%	14 GWh

Variable Tariff A	=	$6,316,900 / (236*1.0 +21* 1.10+68 * 0.45+14*0.34)
	=	2.14 cents per kWh of A metered consumption
Variable Tariff B	=	$0.0214 * 1.10
	=	2.36 cents per kWh of B metered consumption
Variable Tariff C	=	$0.0214 * 0.45
	=	0.73 cents per kWh of C metered consumption
Variable Tariff D	=	$0.0214 * 0.34
	=	0.97 cents per kWh of D metered consumption

Group 3

TFC3a Connection	=	$ 322,500
TFC3b Interconnection	=	$1,336,300
TT3 Total	=	$1,658,800

G3 Fixed Charges

TFC3a Connection	=	$322,500 / 43,741
	=	$7.37 per kVA of AMD
TFC3b Interconnection	=	$1,336,300 /18,594
	=	$71.87 per kW of Winter RCPD/ pa.

17.0 TRANS POWER CHARGES - GROUP 6 & BULK SUPPLY .

17.1 These consumers are large enough and few enough to have their Transpower charges individually calculated. The charges are determined on a cost reflective or "look through" basis from the underlying Transpower charging methodology

17.2 Connection and new investment charges are allocated to each Group 6 customer in proportion to their demands co-incident with the relevant GXP's chargeable demands and are billed as a monthly fixed amount.

Group 6 Budget Data 2011-12
Connection & NIA Charge Allocation -
For Stoke GXP :

Trans Power Connection & NIA Charges Stoke GXP	=	$1,106,620
Chargeable AMD for Stoke GXP	=	120.148 MVA
Group 6 Consumers CMD	=	22.109 MVA
G6 Consumers Transmission Connection Charge	=	22.109/120.148 * $1,106,620
	=	$203,634 pa. or $16,970 / month

17.3 Interconnection charges are passed through directly at the Transpower charge rate and are levied on the consumers demand (grossed up for distribution network losses between the customer TOU meter and the GXP TOU meter) coincident with the Upper South Island RCPD chargeable demands.

17.4 Any Common Quality Service Charges or Loss Rental Rebates are passed directly through to Group 6 consumers each month on the same basis as they are credited or charged to NTL by Transpower.

18.0 DISTRIBUTION PRICING PRINCIPLES & INFORMATION DISCLOSURE GUIDELINES

18.1 The Electricity Authority has prepared a set of Guidelines for Distribution Pricing Principles and Information Disclosure dated February 2010. This section evaluates NTL's general compliance with these Guidelines.

18.2 Pricing Principles from the Guidelines and NTL's general compliance with them is discussed below :

Pricing Principles *(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;
The subsidy free test is a relatively academic notion. In theory it requires a separate test for each of NTL's 36,500 consumers. To accurately estimate both incremental costs and stand alone costs for particular customers or groups of customers is extremely difficult and resource intensive and so the issue is addressed in general terms below. Allocation of consumers and then costs to load groups and the development of prices for those load groups necessarily requires averaging and employment of a number of assumptions. The resulting pricing is at best reasonably cost reflective for broad groups of consumers. However the subsidy free range for line services for mass market consumers is also likely to be quite broad because the incremental costs for the additional consumer/kVA/kWh are low while their standalone costs of supply are high. This broad range means the cost reflect pricing methodology described in this document should generally lead to pricing within the subsidy free range. <u>Standalone Test</u> Distribution networks are natural monopolies and by definition deliver significant and long term economies of scale to an extent that tests for standalone costs of alternative lines supply (over build) against existing cost reflective prices for small and medium sized consumers are largely redundant. NTL line pricing for Group 1 & 2 consumers is materially lower than the standalone economic costs associated with alternative lines supply. This contention is well supported by the fact that: • NTL pricing methodology is cost reflective by Load Group • NTL earns less than the regulators WACC on the ODV of its systems fixed assets • the real costs of overbuild would be well in excess of the regulators Replacement Cost of NTL's network (regulatory RC's are understated) and NTL's systems RC is assessed to be over twice the ODV. • Hence new overbuild costs combined with NTL's line business economies of scale means any replication of NTL distribution assets would be uneconomic when assessed against NTL' current mass market line charges built off ODV based costs, either for individual consumers or for larger groups of consumers.

An alternative stand alone test for small and medium sized consumers is to compare the cost of line supply against the costs of alternative standalone energy supply using on site micro generation plant. At present time micro generation costs remain materially higher than industry supply costs although this test is more about cost of delivered energy than a disaggregated test focused just on the transport component of electricity costs. With consumers primarily interested only in the overall delivered cost of energy, the standalone subsidy free test for line charges is problematic given the need to split line and energy costs.

Standalone cost tests have more relevance for the small number of larger consumers at specific locations on NTL's network. NTL's pricing methodology for Group 3& 6 consumers is cost reflective and uses ODV based economic costs attributable to these customers. Additionally these consumers share in the economies of scale arising from sharing grid exit point costs, shared upper network distribution assets, and from sharing indirect distribution costs. Alternative supply via overbuild to these consumers would require economic costs to reflect full asset replacement costs plus the loss of key scale economies. These standalone costs are therefore likely to be well in excess of NTL's current line charges which is unsupportive to an overbuild business case. In the past NTL has also commissioned bypass castings for major customer sites to identify standalone costs and to assess the reasonableness of existing line charge levels.

<u>Incremental Costs</u>
Incremental cost is the additional cost associated with supplying an additional unit of service.

For distribution businesses the additional unit of service could be the connection of an additional consumer, the supply of an additional kVA of capacity or the transportation of an additional unit (kWh) of electricity.

Generally incremental costs for extra kVA, kWh or connections are very low where the network has available capacity but at some point step changes in costs occur. It is difficult to assign or attribute the step changes in core network costs to specific additional units of service unless the additional load (service) is large relative to the network segment supporting it.

NTL's new connection policy requires developers and consumers to fund any network extension necessary to support a new connection and NTL is primarily left with funding new transformer capacity and any augmentation of upper network capacity. Annual line charges are normally sufficient to service NTL's incremental costs for new connections plus provide a contribution to service & reinforce the core network.
Similarly the incremental costs of additional capacity or kWh are generally low and incremental revenues from variable and capacity charges are normally sufficient to service those incremental costs.

NTL policy also seeks connection contributions based on distance and kVA for new loads in less economic areas of the network. This helps shore up incremental revenue where incremental costs tend to be highest. Additionally NTL policy reserves the right to seek capacity contributions from any new load that takes up a significant portion of existing available line capacity at a particular site. This ensures that NTL has the ability to assess the incremental cost of the new load against its likely future revenue stream to ensure the site will be properly support incremental cost from future line charge revenues.

Regulatory requirements to offer a low user tariff to all domestic consumers and to maintain urban and rural line tariffs at similar levels tend to compromise incremental cost recovery and create subsidisation of some loads. Network costs for domestic electricity users do not vary materially with consumption (kWh) levels but the low fixed charge tariff requirements comprises revenue earning ability from low users relative to their incremental costs of supply. Similarly incremental costs in rural segments of the network tend to be higher than more dense urban areas but restrictions on the level differentiation between rural and urban tariffs leads to under recovery of incremental costs in these higher cost geographical segments.

Regulatory requirements tend to restrict line revenue available from one subgroup of consumers down to or below their incremental costs of supply while at the same time raising the revenue from another subgroup of consumers up towards their stand alone costs of supply; consequently economic efficiency is compromised.

(ii) having regard, to the extent practicable, to the level of available service capacity; and

NTL Group 2&3 pricing features kW and kVA pricing related to the capacity demands consumers in these groups make on the distribution network and the transmission grid. The service level (kVA) signals are moderate for Group 2 consumers but are strong for Group 3 consumers. Group 6 pricing reflects service levels demanded via charges based on the level of dedicated and semi dedicated distribution assets NTL commits to the supply of these consumers. Similarly within both Groups 3 & 6, Transpower's Interconnection Charges (a grid service capacity charge) are reflected directly through to each consumer on the basis of their demands coincident with the grid's USI regional peak demand.

Where consumers use available network and grid capacity inefficiently NTL reserves the right to apply a kVA based power factor charge on sites where poor power factor has been recorded.

As already stated, NTL also employs a kVA per kilometre contribution regime for new loads locating on high cost segments of the network. This contribution recognises service levels by way of both distance and capacity.

In Group1 capacity/service level signals are weak to non existent. This is primarily due to the regulatory low user tariff requirements restricting fixed/capacity pricing to a maximum of 15 cents per day. NTL applies this rate across Group 1 to avoid ongoing transaction costs and to mitigate the irrecoverable revenue leakage inherent in the regulatory price pathway had NTL had offered both an optional low user tariff and a cost reflective fixed/capacity charge. Consequently NTL Group 1 pricing is primarily kWh based and therefore poorly reflects the available service levels to these consumers. Low use/low load factor consumers under pay for their available service capacity while high use/high load factor consumers over pay for the same capacity. This inefficiency is an inevitable consequence of the low user tariff regulations

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

The term "additional usage" is undefined but presumably relates to additional connections, additional kVA demands or additional kWh consumption across the network. Given a network's primary function is to deliver capacity (kVA) across distance between points of injection and load, additional kVA is probably the most meaningful measure of additional usage for an electrical network.

Future investment tends to be driven by the timing and location of peak loads on the network. Hence to develop pricing components that reflect potential future investment costs with any precision requires kVA based charges that have locational and timing components associated with them. Alternative tightly time bound differentiated kWh based tariffs could also provide useful signalling.

Within an ICP based pricing regime, the ability to providing signals relating to the impact additional usage has on future investment is problematic. Firstly very few mass market consumers have time of use metering, or as yet in this region, smart metering. Consequently it is not possible to create peak time kVA based charges or kWh based charges that have a useful time component embedded within them. Secondly low user regulations prevent useful kVA signals being delivered to domestic consumers. Thirdly, there is a general desire by consumers, regulators, retailers and most distributors to avoid differentiated pricing between time zones and also across geographical segments of the distribution network for mass market consumers with traditional interval metering. The alternative for mass market consumers is a set of relatively blunt pricing instruments focused on maximum demand measured by installed fuse sizes and peak time kWh tariffs. NTL uses both these measures but they are very blunt in terms of signalling the impact of usage on future new investment.

For Group 3 & 6 all consumers have TOU metering installed. These consumers face winter demand charges that directly reflect their contribution to the peak demand levels on the Upper South Island grid and on the distribution network. To the extent that the Interconnection Charge is reflective of Transpower's future grid upgrade costs, it is a reasonably clear signal. These consumers also face an anytime demand charge which in part reflects the current and future cost of delivering capacity on the distribution network. However while it signals consumers to minimise demands in general it does not specify any critical network times or locations.

New loads wishing to connect to the distribution network may be required to make cost contributions to upper network assets where capacity is scarce. Demands under NTL's contribution policy directly reflect any potential shortfall between expected new revenues and the incremental investment caused by the new load.

As is noted below most consumers tend to see and react to delivered electricity pricing signals rather than the individual line and energy components. NTL's line charges now account for between only 30-35% of delivered charges for most mass market consumers. From 1 April 2011 NTL's mass market (Group1&2) variable line tariffs are about 34% -35% of the retailers delivered tariff for "peak" rates and 18%-20% for "off peak" rates. Consequently NTL has a very muted impact on delivered prices; its pricing is relatively invisible to the consumer. Additionally retailers rebundle and alter the price relativities between peak and off peak rates. Thus network signally of extra usage does not necessarily get through to consumers so far as kWh charges (which account for the bulk of mass market line revenue) are concerned.

(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.

This test of efficient pricing focuses on Ramsey concepts of loading any revenue shortfalls over incremental cost onto consumers, products and services where the demand elasticities are the lowest.

Most consumers respond to the full delivered cost of electricity rather then just the lines

	component of the charges. As stated, NTL's line charges typically make up 30 -35% of most consumers power bills while the generation and retail component makes up the remaining 65-70%. Line pricing signals therefore tend to get heavily buried within retail prices and are subject to rebundling so they provide only weak and relatively ineffective consumption signals. There influence on electricity demand elasticities is relatively muted for mass market consumers. Therefore the means used to spread and collect the under recovered revenue is not particularly important as it will cause minimal distortion at the mass market level. Demand elasticity is largely a function of the availability of substitutes. In terms of electricity delivered through traditional centralised generation plant, power grids and distribution networks the alternatives that drive demand elasticity are primarily gas, coal, wood, distributed generation, solar water heating and energy efficiency substitutes. For virtually all NTL consumers coal and gas are not particularly viable substitutes in this region and commodity pricing and ETS charges are likely to make them less so in the future. Incremental use of wood is increasingly being marginalised as a heat source by clean air regulations in NTL's major urban areas. Small scale distributed generation is not fully viable although a number of consumers choose to adopt these micro technologies out of interest and a desire for independence and "greenness" rather than as a primary reaction to electricity prices. Energy efficiency tends to present one off opportunities for consumers to lower consumption at discrete points of time while solar water heating is now a reasonably viable option vis electrically heated water. Thus other than for water heating most electrical consumption is relatively inelastic and so revenue recovery over and above efficient incremental costs can be spread across most tariff classes without causing consumption distortions. However in applying this logic, NTL remains mindful of the need to retain off peak, controlled, night and summer kWh tariff rates at substantial discounts to peak and uncontrolled rates. The "peak" tariff rates tend to show the least elasticity and encouraging use of "off peak" and "controlled" rates is beneficial for network efficiency.
(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;
	Bypass may occur through alternative network assets (i.e. by overbuild of existing network) or by customers adopting alterative energy sources. Network pricing can help address the overbuild bypass incentives by ensuring network charges remain below the standalone economic costs for alternative lines supply for particular customers or groups of customers. This matter is addressed in (a)(1) above and NTL considers its network pricing and polices discourage inefficient bypass. NTL is unaware of any consumers exercising overbuild bypass choices solely in response to line charge levels. Bypass achieved through consumers adopting alternative energy sources is more problematic. This type of bypass is incentivised by the delivered cost of energy rather than just the lines cost. NTL has little control over the delivered cost of electricity and as noted above NTL's line charges typically make up only 30-35% of energy bills for most mass market consumers. Given this fact NTL is very limited in what it can do to discourage inefficient uptake of alternative energy sources as a means of bypassing the electricity system.
	(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
NTL is mindful that for mass market consumers the electrical network is a "general commons" and the notion of offering price quality/trade offs for specific customers is flawed. Generally other than offering a choice of differing capacity levels to mass market consumers NTL is generally unable to offer other differentiated lines services to one consumer without offering it to all other adjacent consumers sharing the same network whether they want the service or not. However larger customers are more able to contract for different levels of service where they have high levels of asset dedication. NTL's Group 6 consumers have specific and dedicated network requirements and these requirements are reflected in their commercial relationships and pricing with NTL. NTL has surveyed and consulted with Group 3&6 and larger Group 2 consumers concerning price quality/trade offs as part of the thresholds price control regime operated by the Commerce Commission. The these consultations showed that these consumers held primary concerns over changes of price rather than changes to service quality. Quality was of second order interest and concern. NTL found it difficult to isolate consumers views down to those just centred on lines performance rather than those centred on the performance of the whole delivered energy package.
(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.
NTL line pricing indirectly encourages consideration of distribution and transmission alternatives and innovation in the following ways: • NTL charges embedded generator only for their incremental costs of connecting to the network and passes through, in full, any demonstrable saving in transmission interconnection charges that embedded generators achieve provided they have TOU metering installed. • NTL pricing passes through Transpower interconnection charges directly to Group 3 & 6 consumers based on TOU data. They can thereby gain full value from any means they may have of reducing or avoiding demand coincident with USI peak grid loads. • NTL Group 3 pricing has a substantive capacity based AMD charge which incentivises consumers to minimise their peak loads on the distribution network. Demand reduction such as on site power factor correction or any other means is rewarded by way of materially lower (circa $50/kVA) annual network charges. • NTL Group 3 pricing includes a power factor charge applicable at consumer sites where power factor is worse than 0.95. This combined with AMD and RCPD capacity charges strongly incentivises consumers to install technology that enables scarce grid and distribution capacity to be used efficiently. • NTL Group 2 pricing includes capacity charges based on installed fused sizes. This incentivises consumers to minimise their ICP fusing requirements and to find ways of avoiding increasing peak loads on the network. It acts as a disincentive for consumers to move up from Group 1 to Group 2. • NTL pricing has, for all consumers, higher kWh rates on tariffs chargeable on "peak" consumption whereas consumption known to be "off peak" or is "controlled" is subject to substantially lower tariff rates. The "on peak" tariff rates are, in general, more than double the "off peak" and "controlled" rates so in theory consumers are incentivised to move consumption away from peak. However given NTL's distribution tariffs are mostly no more than 35% of the delivered power bill, these signals are substantially muted by energy retailers who tend to offer no or minimal "off peak" incentives in the energy portion (the other 66%) of consumers power costs.

- NTL requires an upfront contribution, reflecting both kVA and distance, for new loads seeking capacity in remote areas. The contribution signal is stronger the larger the load and the further it is away from an NTL GXP or zone substation. This progressively encourages all remote new loads to minimise their new capacity demands on the distribution network and to explore alternative ways of supplying their new capacity demands.
- New connections/loads on NTL's distribution network are required to fund any new line assets (excluding transformers) necessary to establish their new connection to the existing distribution network. This policy helps NTL avoid funding uneconomic network extensions and incentivises new connections to consider the most economic means of providing power to their particular sites.

(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.

Pricing transparency, stability and certainty is supported by NTL in the following ways:

- NTL makes commitments to stability and certainty in its SCI with NT Trust
- NTL makes commitments to stability and certainty in its UOSA with retailers and in pricing consultations with retailers.
- NTL may only change its distribution pricing once in any 12 month period however NTL reserves the right to alter transmission pricing whenever Transpower changes its charges to NTL.
- NTL undertook a major simplification of its line pricing in 2004 and has rolled forward this pricing in accord with its pricing methodology and pricing commitments since that date.
- The requirement to comply with the low user regulations and the pass through of changes to Transpower's pricing regime are the primary causes for rate shock for some consumers since 2004. The low user regulations were detrimental to high load factor consumers while changes to Transpower's charging methodology adversely impacted on all consumers; especially those in Group 3.
- NTL has operated at or below its regulatory price path threshold since its introduction in 2003 and this has promoted rate stability and certainty for retailers, consumers and stakeholders. Consequently the distribution component of NTL's line charges have been falling or stable in real terms for at least 10 years.
- NTL pricing avoids cross subsidisation between consumer load groups and consequently the company accepts under recovery of allowable revenue in groups where there are higher numbers of uneconomic consumers.
- NTL annually publishes its SCI, Annual Financial Statements, detailed pricing methodology, line prices, AMP, threshold compliance statements and Regulatory Information Disclosures on its website and makes them publicly available.

(e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.

The structure of NTL's current line pricing was developed in consultation with retailers, it is simple to understand and minimises transaction costs for retailers, consumers and NTL. The Use of Systems pricing described below is standard and applies equally to all retailers:

- There is a single standard fixed daily charge for all Group 1 consumers (covers 33,781 out of NTL's 36,472 ICPs). This single fixed daily charge fully meets the low user tariff regulations so complexity is avoided and transaction costs are minimised.

- There is one standard kVA capacity charge rate applicable for all Group 2 consumers (covers all but 23 of the 2571 Group 2 ICP's) and the chargeable capacity quantities for each Group 2 ICP are directly available to all electricity retailers from the Registry
- There are just 5 core variable (kWh) tariff rates applied to all but 23 of the Group 1 &2 consumers (i.e. the 5 core tariffs are on offer to 36,329 out of NTL's 36,472 ICP's)
- The regulatory requirement to make available a low user charge for all domestic consumers more than doubles the number of prices in the Group 2 tariff schedule despite only 23 domestic customers in this group taking up the option. The regulations increase complexity and transaction costs for NTL & retailers.
- There is no tariff variation by regional/geographical area or by consumer type /use (i.e. by business, domestic, irrigation etc) for the 36,352 mass market consumers
- NTL's Group3 line charges are relatively straight forward but rely heavily on TOU data. The 117 Group 3 TOU consumers are split in categories by size with 110 of the consumers being in the most numerous category. Each group 3 consumer faces a winter and an anytime peak capacity charge with NTL supplying the relevant annual chargeable demand quantities directly to retailers. Consumption charges are TOU based and are split between day and night on a summer winter basis.

18.3 The Information Disclosure Guidelines and NTL's general compliance with them is discussed below :

Information Disclosure Guidelines
(a) *Prices should be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked.*
NTL's pricing methodology is extensively explained above, is published annually and is made available on the company's website. The underlying pricing methodology has not been subject to revision for the 2011-12 year.
(b) The pricing methodology disclosed should demonstrate:
(i) how the methodology links to the pricing principles and any non-compliance;
The link between the pricing methodology and the Electricity Authority pricing principles has been explained in Section 18.
(ii) the rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings;
See Sections 7.0 - 7.4 for NTL's approach to allocating consumers to load groups and note this is applicable to both distribution and transmission pricing components
(iii) quantification of key components of costs and revenues;
See Section 6.0- 6.6 for description of distribution costs and revenue components. See Section 14.0-14.5 for description of transmission costs and revenue components See Appendix A for NTL data on cost and revenue components
(iv) an explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping;
See Section 8.0 – 8.4 for description of rationale for allocation of distribution costs to consumer Load Groups See Section 14.1 – 14.5 for description of rationale for the allocation of transmission costs to consumer Load Groups See Appendix A for NTL's data showing the allocation of costs to Load Groups
(v) an explanation of the derivation of the tariffs to be charged to each consumer group

and the rationale for the tariff design; and
See Sections 9.0-12.0 for description of distribution tariff components & derivation See Sections 15.0-17.0 for description of transmission tariff components & derivation See Appendix A for NTL tariff data for 2011-12
(vi) pricing arrangements that will be used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management, where alternatives are practicable and where network economics warrant.
NTL's network is not currently subject to load constraints so at this juncture it is not warranted to have specific incentives schemes to curtail load. NTL does not offer any specific direct incentives to share the value of any deferral of investment in distribution or transmission assets. There are however a number useful indirect incentives within NTL's line pricing and contractual agreements that rewards any customer behavior that limits peak demands or lowers NTL costs. • Distributed generators are directly reward via pass through of the full value of any savings they cause with respect to NTL's Interconnection Charges. Any potential for deferral of distribution investment will be site and plant specific and so must be dealt with on a case by case basis. • Group 6 consumers obtain full benefit from any reduction in RCPD coincident demands with respect to Interconnection Charges directly passed through by NTL. • Group 3 AMD and RCPD demand charges automatically reward effective load management and other alternatives for reducing load at critical times • Group 2 capacity charges provide moderate rewards for management of consumer's peak loads. Lower investment in LV equipment such as transformers and fuses should result • Off peak & controlled kWh charges incentivise and reward consumers for shifting load or enabling their load to be interrupted. NTL's peak network and grid loads are about 10% lower than they would have otherwise been as a consequence of substantial consumer uptake of controlled tariff options.
(c) The pricing methodology should:
(i) employ industry standard terminology, where possible; and
NTL employs standard industry terminology throughout its pricing methodology.
(ii) where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition arrangements implemented to introduce the new methodology
No material change has been made to NTL's pricing methodology in the year commencing 1 April 2011

Appendix A

NETWORK TASMAN LIMITED

THE ELECTRICITY DISCLOSURE REQUIREMENTS 2004

REQUIREMENTS 22 & 23

- Requirement 22 Disclosure of Pricing Methodologies
- Requirement 23 Contents of Pricing Methodologies

LOAD GROUP STATISTICS USED IN PRICING METHODOLOGY

Forecast for year commencing 1 April 2011

Customer Group	Number of ICP's	Coincident Maximum Demand	Anytime Maximum Capacity	Winter Maximum RCPD	Consumption Peak	Consumption Off Peak	Total Consumption
	#	kW	kVA	kW	kWh	kWh	kWh
Group 1	33,781	52,517	506,715	45,713	168,209,709	66,435,424	234,645,133
Group 2	2,571	23,863	114,988	18,819	88,474,800	12,576,337	101,051,137
Group 3	117	20,020	41,669	18,594	89,967,675	33,286,152	123,253,827
Group 6	2	21,690	26,307	20,318	N/A	N/A	120,309,161
Bulk supply	1	N/A	34,232	28,262	N/A	N/A	152,276,311
Total	**36,472**	**118,089**	**723,911**	**131,706**			**731,535,569**

N/A Not used in pricing methodology
(1) Based on 3 year rolling average
(2) Based on Time of Use metering data
(3) Based on customer installed fuse capacity

SEPARATION OF ESTIMATED REVENUE AND COSTS COMPONENTS TO LOAD GROUPS
For the year commencing 1 April 2011.

Customer Group	Transmission Costs	Direct NW Costs	Indirect NW Costs	Depreciation	Allowable PreTax Return on ODV of Assets	Total Revenue Requirement
	$	**$**	**$**	**$**	**$**	**$**
Group 1	$ 4,545,630	$ 3,579,456	$ 1,961,220	$ 2,983,349	$ 7,439,230	**$ 20,508,885**
Group 2	$ 1,915,175	$ 1,680,764	$ 445,056	$ 1,400,857	$ 4,730,259	**$ 10,172,111**
Group 3	$ 1,822,768	$ 902,204	$ 254,289	$ 751,955	$ 2,400,903	**$ 6,132,120**
Group 6	$ 1,633,082	$ 59,414	$ 50,000	$ 80,371	$ 282,657	**$ 2,105,524**
Bulk supply	$ 2,307,608	$ -	$ 35,000	$ -	$ -	**$ 2,342,608**
Total	**$ 12,224,263**	**$ 6,221,837**	**$ 2,745,565**	**$ 5,216,531**	**$ 14,853,050**	**$ 41,261,247**

5 April 2011

Director - Networks Branch
Commerce Commission
PO Box 2351
The Terrace
Wellington

Dear Sir

Disclosure of Pricing Methodology 2011-12

Pursuant to the Electricity Information Disclosure Requirements issued 31 March 2004 (Consolidating all amendments to 31 October 2008), Part 5 Clause 22 & 23, please find attached a copy of Network Tasman Limited's line pricing, line pricing methodology and information concerning line business costs to be recovered by line charges for the 2011-12 financial year. Also attached is a copy NTL's Asset Management Plan for 2011-12.

This information has been publicly disclosed on the company's web site and directors' statutory declarations are also attached.

Should you have any queries concerning this information please do not hesitate to contact me on DDI (03) 989 3615.

Yours sincerely
NETWORK TASMAN LIMITED

S W Mackey
Chief Executive Officer

Enclosures

IN ACCORDANCE WITH THE COMMERCE ACT
(ELECTRICITY INFORMATION DISCLOSURE REQUIREMENTS 2004).

Requirement 36(l)

STATUTORY DECLARATION IN RESPECT OF STATEMENTS AND INFORMATION SUPPLIED TO THE COMMERCE COMMISSION

I, Christopher IM Turner, of Hill Street, Richmond, being a director of Network Tasman Limited, solemnly and sincerely declare that having made all reasonable enquiry, to the best of my knowledge, the information attached to this declaration is a true copy of the information made available to the public by Network Tasman Limited under the Commerce Commission's Electricity Information Disclosure Requirements 2004.

And I make this solemn declaration conscientiously believing the same to be true and by virtue of the Oaths and Declarations Act 1957.

Declared at this 5th day of April 2011

____
CIM Turner

____
Signature

Justice of the Peace (*or* Solicitor *or* other person authorised to take a statutory declaration)