HORIZON ENERGY DISTRIBUTION LIMITED

Pricing Methodology
For Line Charges introduced on 1 April 2012

15 March 2012

Electricity Information Disclosure Amendment Requirements Notice 2008

Disclosure of Pricing Methodology (Pursuant to Requirements 22 & 23 Part 4A of Commerce Act 1986)

Contents

1. Pricing Methodology

1.1. Background

Requirements 22 and 23 of the Electricity Information Disclosure Requirements 2004, (retained by the transition provisions in the Electricity Distribution (Information Disclosure) Requirements 2008 ("2008 IDR")) require the following information to be publicly disclosed annually:

- The methodology used to calculate the prices charged.
- The key components of revenue required to cover costs and profits including the cost of capital and transmission charges.
- The consumer groups used to calculate prices including:
  - The rationale for the consumer grouping;
  - How consumers are assigned to each consumer group; and
  - Relevant statistics for each consumer group.
- Method for allocating the revenue required to recover lines business costs from each consumer group and the rationale for the allocation method adopted.
- The method adopted for determining the proportion of fixed and variable charges and the rationale for the method adopted.

In addition, in February 2010 the Electricity Commission published its Distribution Pricing Principles and Information Disclosure Guidelines ("2010 IDG"). These contain a set of pricing principles and guidelines for information to be disclosed regarding the extent to which the pricing methodology adopted by an electricity distributor complies with those principles. The disclosure guidelines require the following disclosures (which are similar to, but not exactly the same as the 2008 IDR disclosure requirements):

- Prices are to be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked.
- The pricing methodology must demonstrate:
  - How the methodology links to the pricing principles and any non-compliance;
  - Rationale for consumer groupings and method for determining the allocation of consumers to consumer groups;
  - Quantification of key components of costs and revenues;
  - An explanation of the cost allocation methodology and the rationale for the allocation to each consumer group;
  - An explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design; and
  - Pricing arrangements 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.
- The pricing methodology should also:
  - Employ industry standard terminology, where possible; and
  - Where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and transition arrangements implemented to introduce the new methodology.

The methodology and information presented in this document complies with the 2008 IDR disclosure requirements as well as the new 2010 IDG.

1.2. Pricing Principles

The 2010 Electricity Commission's Distribution Pricing Principles are as follows:

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 stand alone costs) except where subsidies arise from compliance with legislation and/or other regulation;
   ii. Having regard, to the extent practicable, to the level of available service capacity; and
   iii. Signalling, to the extent practicable, the impact of additional usage on future investment costs.

b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.

c) Provided that prices satisfy (a) above, prices should be responsive to the requirement 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.

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.

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.

We have considered each of these principles in developing our line charges to apply from 1 April 2012. At the end of this document we include a summary demonstrating how each principle has been incorporated into our methodology.

1.3. Pricing Methodology

In developing our pricing methodology, and the associated line charge tariffs we undertake the following key steps:

- Determine the amount of revenue to be recovered via line charges for the pricing period, in this case 1 April 2012 – 31 March 2013;
- Consider how to group consumers into load groups for pricing purposes and determine the key attributes of each load group for the purpose of allocating the revenue requirement and calculating tariffs;
- Allocate the revenue requirement to load groups; and
- Determine the structure of tariffs to apply to each load group for the pricing period.

Our 2012/13 pricing methodology remains consistent with the 2011/12 pricing methodology and we set out our approach to each of these steps in the following sections of this report.

2. Revenue Requirement

2.1. External Limitations

Horizon Energy Distribution Limited ("Horizon Energy") must comply with the requirements of Part 4 of the Commerce Act 1986 ("the Act"). Subpart 6 provides for a Default Price-Quality Path ("DPP") to apply which includes limitations on the amount of revenue able to be recovered by Horizon Energy by way of line charges. Thus our total revenue requirement for the 12 month period commencing 1 April 2012 is determined on the basis of our best estimate of the allowable revenue consistent with Horizon Energy complying with the DPP.

Accordingly, our total revenue requirement is developed using a building block model of each component of cost consistent with providing electricity lines services, with an adjustment to those costs to ensure compliance with the DPP.

2.2. Revenue Building Blocks

Table 1 provides the pre-tax revenue building blocks for electricity lines services for the 12 month period commencing 1 April 2012.

Table 1: Revenue Building Blocks (Before Tax)

Cost Item	Total Network ($)
Connection Charges	1,989,114
Interconnection Charges	1,866,961
Notional Embedding	1,170,672
Avoided Transmission	3,503,638
Excess Interconnection	(219,632)
Electricity Authority Levies	80,203
Commerce Act Levies	32,226
Local Authority Rates	121,999
General Management, Administration and Overheads	3,488,831
System Management and Operations	1,920,889
Routine and Preventative Maintenance	1,012,720
Refurbishment and Renewal Maintenance	860,466
Fault and Emergency Maintenance	677,090
Depreciation on Network Assets	3,919,467
Depreciation on Non-Network Assets	532,518
Target Pre Tax Return on Assets	11,710,621
DPP Regulatory Constraint	(2,577,833)
Total Revenue Requirement	**30,089,951**

The revenue building blocks comprise transmission and avoided transmission charges forecast to be incurred by Horizon Energy during the period, to be passed onto consumers by way of line charges. These include Transpower's connection and interconnection charges. Interconnection charges reflect a rate per unit of coincident peak demand, determined using regional peaks. Connection charges are a fixed annual amount reflective of the connection assets Transpower has specifically built to connect Horizon Energy's network to the backbone of the national grid.

Loss rental rebates are excluded from the revenue requirement as these are passed directly to retailers and contracted customers, and thus do not impact on line charges.

Where a distributed generator provides local benefits by avoiding Transpower charges, Horizon Energy passes through this benefit to the distributed generator by way of an avoided transmission charge. This is recovered from consumers via the annual revenue requirement. The basis for determining the avoided transmission charge is Transpower's pricing methodology.

In addition, annual operating, maintenance and administration costs reflect the budgeted costs for providing lines services for the pricing period. These include other pass through costs permitted under the DPP such as local authority rates and industry levies.

The depreciation component of the revenue requirement reflects the annual charge associated with the consumption of the asset base (including system and non-system fixed assets) associated with the provision of electricity lines services. The depreciation charge is calculated from Horizon Energy's financial reporting asset values which have been established on a fair value basis in accordance with NZ IAS 16.

The return on asset component is derived from a target return on the asset base. This is derived using a pre-tax weighted average cost of capital of 10.2%.

The above revenue requirement is presented on a pre-tax basis.

2.3. Impact of DPP

The DPP for the pricing period commencing 1 April 2012 limits Horizon Energy's allowable revenues to $30.09M after adjusting for the difference between DPP allowed quantities and 2012/13 projected quantities. Accordingly the return on asset component of the revenue requirement is reduced by $2.58M as demonstrated in Table 1 above.

3. Load Groups

3.1. Disaggregation of Load Groups

The pricing methodology employed seeks to fairly allocate costs amongst various consumer groups (load groups). Load group disaggregation has been determined after consideration of the end use characteristics, location and capacity requirements of each connection. All connections are able to be classified by their service main fuse, selected from a range of national standard sizes.

Consumers are classified as domestic or non-domestic consumers. Non domestic consumers are further classified as general, network maximum demand, non-metered supplies or major consumers.

Domestic consumers are grouped together because they share similar network usage profiles. Typically, domestic load profiles indicate peak consumption from 7:30am - 9:30am and 5:30pm - 9:00pm. In addition it is necessary to distinguish between those domestic consumers which are subject to the low user fixed charge regulations and those which are not. As the low user fixed charge regulations only apply to primary residences, domestic consumers are allocated into one of the following load groups:

- Low user domestic (primary residence eligible for low fixed charges under the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004);
- Standard domestic (8,000 kWh annual consumption and above); and
- Non-standard domestic (low user domestic not eligible for the low user regulations, e.g. Holiday homes).

In contrast non-domestic consumers exhibit a wide range of load profiles due to the diverse nature of their commercial activities. Accordingly it is more appropriate to group these consumers together based on their assessed capacity requirements using their installed fuse rating or assessed installed transformer capacities. This approach reflects the fact that increased capacity requirements impose a greater demand on the value of assets required to supply these consumers.

Consumers are allocated into the general non domestic load groups as follows:

N1U or N1	1ø 60 Ampere only
N2U or N2R	3ø 60 Ampere (no 2ø availability)
N3U or N3R	3ø 100 Ampere (no 1ø or 2ø availability)
N4U or N4R	3ø 160 Ampere (no 1ø or 2ø availability)
N5U or N5R	3ø 160 Ampere (no 1ø or 2ø availability)

In addition, it is possible to separate out from general non-domestic consumers those which are non-standard, or which have certain limitations in terms of pricing. Accordingly, Horizon Energy also groups all non-domestic consumers which are unmetered (including street lighting and electric fence units) into an ‘other’ load group.

Non-domestic consumers with a connection of greater than 3 phase 100 Ampere are grouped as Network Maximum Demand (“NMD”) consumers (with the exception of those who may already be on capacity group 4 or 5 tariffs). This group is subject to demand metering in order to assess individual capacity requirements. This enables capacity based pricing for these larger non domestic consumers.

In addition major consumers with dedicated assets are treated individually and are hence removed from other non-domestic load groups.

The remainder of the document addresses the pricing methodology for those consumers on standard contract terms.

Thus the load groupings assumed for pricing purposes are as follows:

Table 2: Load Groups

Load Groups	
Domestic	
LUDU	Urban Low User Domestic
LUDR	Rural Low User Domestic
SDU	Urban Standard Domestic
SDR	Rural Standard Domestic
NSDU	Urban Non-standard Domestic
NSDR	Rural Non-standard Domestic
Capacity Groups	
N1U	Urban Capacity Group 1 (0-14 kVA)
N1R	Rural Capacity Group 1 (0-14 kVA)
N2U	Urban Capacity Group 2 (15-42 kVA)
N2R	Rural Capacity Group 2 (15-42 kVA)
N3U	Urban Capacity Group 3 (43-70 kVA)
N3R	Rural Capacity Group 3 (43-70 kVA)
N4U	Urban Capacity Group 4 (71-100 kVA)
N4R	Rural Capacity Group 4 (71-100 kVA)
N5U	Urban Capacity Group 5 (>100 kVA)
N5R	Rural Capacity Group 5 (>100 kVA)
Network Maximum Demand	
NMD	Network Maximum Demand
Specials	
UV	U/Veranda Lights
EF	Electric Fence
SL	Street Lights
PCM 24	PCM 24 Hour
PCMN	PCM Night Only

As illustrated above, further distinction is made between those domestic and capacity consumers located in urban and rural areas. For pricing purposes, Horizon Energy's distribution network has been segregated into urban and rural regions. The urban areas are the towns and built up areas of Kawerau, Edgecumbe, Whakatane and Opotiki. The rural area makes up the balance of the network. The boundaries determined previously have been retained to avoid unnecessary disruption to consumers and to minimise transaction costs.

The distinction between urban and rural network is used for those components of our pricing methodology, where the customer characteristics and network characteristics indicate that differential costs and therefore tariff levels are justified in order to reflect fair prices to all consumers.

3.2. Use of Load Groups Introduced in 2011

Horizon Energy continues to segregate the domestic load group into low user, standard and non-standard domestic load groups. This approach allows us to fully reflect the demands all domestic consumers make on the network and incorporated elements of cross subsidy between large/small and permanent/non-permanent domestic consumers. By segregating into the three domestic load groups we maintain a more economically robust basis for cost allocation and tariff design for all domestic consumers.

In addition, small general (N1) consumers have now been aligned to the non-standard domestic load groups to allow us to more appropriately reflect the cost of supply to these consumers.

3.3. Characteristics of Each Load Group

Table 3 below sets out the key characteristics of each load group, for the purpose of the pricing methodology.

Table 3: Statistics Relevant to Load Groups

Load Groups		Number of ICPs	Consumption (kWh)	AMD (kW)	Share of Total Assets (RC%)
Domestic					
LUD	Low User Domestic	13,288	65,110,922	16,347	21.6%
SD	Standard Domestic	5,342	53,624,257	13,463	17.8%
NSD	Non-standard Domestic	419	1,117,848	671	0.9%
Capacity Groups					
N1U	Urban Capacity Group 1 (0-14 kVA)	696	3,310,278	1,114	1.1%
N1R	Rural Capacity Group 1 (0-14 kVA)	1,113	3,505,581	1,780	3.3%
N2U	Urban Capacity Group 2 (15-42 kVA)	806	13,398,926	3,226	3.3%
N2R	Rural Capacity Group 2 (15-42 kVA)	1,903	24,905,158	7,611	14.2%
N3U	Urban Capacity Group 3 (43-70 kVA)	271	9,854,749	2,711	2.8%
N3R	Rural Capacity Group 3 (43-70 kVA)	294	12,807,309	2,942	5.5%
N4U	Urban Capacity Group 4 (71-100 kVA)	60	3,187,426	1,500	1.5%
N4R	Rural Capacity Group 4 (71-100 kVA)	42	2,495,650	1,055	5.5%
N5U	Urban Capacity Group 5 (>100 kVA)	32	2,420,050	960	1.0%
N5R	Rural Capacity Group 5 (>100 kVA)	27	1,624,306	810	1.5%
Network Maximum Demand					
NMD	Network Maximum Demand	155	44,982,840	12,404	11.6%
Specials					
UV	U/Veranda Lights	23	-	2	0.0%
EF	Electric Fence	19	-	2	0.0%
SL	Street Lights	22	2,228,388	550	1.5%
PCM 24	PCM 24 Hour	69	-	104	0.2%
PCMN	PCM Night Only	17	-	9	0.0%

4. Revenue Allocation to Load Groups

4.1. Cost of Supply Model

Horizon Energy has developed a Cost of Supply ("COS") model which separately allocates each component of the revenue requirement to load groups using a set of cost allocators. The COS model comprises the following key calculations:

- Identify the total revenue requirement to be recovered from line charges, by component (e.g. transmission charges, system management and operations costs, depreciation etc.) as outlined above;
- Allocate consumers into load groups consistent with the existing 2011 load group structure;
- Input identifying characteristics for each load group (e.g. number of ICPs, kWh, etc.);
- Allocate each component of the revenue requirement to the proposed load groups using cost of supply allocators (refer below) in order to determine the amount of revenue to be recovered from each load group;
- In addition derive a modified set of revenue allocations, assuming that the revenue to be recovered from each of the load groups is no more than +/- 10% of the revenue currently recovered from those consumers in order to generate a transitional revenue allocation scenario. This approach has been adopted to manage potential rate shock for individual consumers;
- Once the revenue requirement for each load group is determined, specify the proportion of fixed and variable, distribution and transmission tariffs in order to test alternative tariff options;
- Apply the tariff options derived for each load group, across the consumption bands evident in each load group to test the impact on high/average/low use consumers within each load group; and
- Refine the tariff options as required in order to meet regulatory requirements, manage price shock and implement pricing signals consistent with the pricing principles.

4.2. Allocation of Revenue to Load Groups

The revenue requirement is specified as a number of different cost categories as outlined above. The COS model incorporates sufficient flexibility to allocate each cost component to load groups using a range of different allocators. To some extent the range of allocators is limited by data availability and in some instances proxies have been developed for this purpose.

The relevant allocators which are currently available to Horizon Energy are:

- Installation Control Point ("ICP"count
- Load (kWh)
- Anytime Maximum Demand ("AMD")
- Replacement Cost of System Fixed Assets ($)
- Depreciated Replacement Cost of System Fixed Assets ($)

The 2012/13 revenue requirement is estimated to be $30.09M. We have allocated the components of the revenue requirement using the below cost allocators, the results of which are set out in Table 5

This allocator selection demonstrates the underlying drivers for electricity supply services being the provision and maintenance of adequate capacity. Thus we have selected allocators which best reflect the demand for capacity of each customer group. We have used these for those categories of cost within the overall revenue requirement which are directly related to the provision and maintenance of capacity. This also includes transmission charges, which reflect Transpower's requirement to provide adequate capacity (and maintain the availability of that capacity) for the national grid.

4.3. Information Used for Cost Allocators

The following information is used for the purpose of the cost allocation.

- ICPs – The number of ICPs within each load group are used to allocate components of the revenue requirement which are deemed to be shared equally across all ICPs commensurate with the demand each connected consumer places on those services provided to them;
- Load (kWh) – Annual consumption is also an allocator which may be used to share components of the revenue requirement between load groups, although under the current COS modelling assumptions, this is no longer used as all LRR revenues are now assumed to be passed on directly.
- Anytime Maximum Demand (kW) – Each load group is used to allocate transmission charges, consistent with Transpower's pricing methodology principles which effectively share the majority of the transmission charge via peak demand signals. This data is known for NMD and industrial consumers. It is estimated for the remaining load groups by using an assumed value for the average domestic consumer, and extrapolating the remaining load groups based on average load within each load group relative to the average domestic consumer.
- Asset related allocators ($) –The most recent financial reporting DRC valuation asset register is used for this purpose as this is the most recent asset register available with sufficient granularity and allocated into load groups as follows:

a) Asset Replacement Cost ("RC") and Depreciated Replacement Cost ("DRC") are allocated into the following network components:
   - Sub transmission;
   - Zone substations;
   - Distribution HV/LV; and
   - Street lighting assets.

b) Assets dedicated to the major industrial consumers are extracted from the above asset groups.

c) Street lighting assets are allocated directly to the street lighting load group.

d) In order to allocate the non-dedicated assets between rural and urban network segments it is assumed:
   - The sub transmission backbone including zone substation assets are shared equally across the entire network; and
   - Distribution assets located in the urban and rural areas are dedicated to those consumers located in urban and rural zones respectively. In order to achieve this all of the distribution assets are allocated into urban and rural zones by designating feeders as urban or rural. Locational identifiers from the fixed asset valuation are available for the purpose of ascribing all distribution assets to a feeder.

e) The sub transmission, zone substation, urban distribution and rural distribution assets are shared between urban and rural domestic, urban and rural capacity, NMD and special load groups on the basis of the anytime maximum demand of each load group.

f) Once the asset values are ascribed to each load group, the proportion of the total asset value assigned to each load group is used to apportion asset related components of the revenue requirement (e.g. Line maintenance, depreciation, and profit). RC is used for this purpose as it is independent of age.

Table 4: Summary of Cost Allocators Used for Revenue Requirements

Cost Item	Revenue Requirement ($)	Cost Allocator
Connection Charges	1,989,114	Anytime Maximum Demand
Interconnection Charges	1,866,961	Anytime Maximum Demand
Notional Embedding	1,170,672	Anytime Maximum Demand
Avoided Transmission	3,503,638	Anytime Maximum Demand
Excess Interconnection	(219,632)	Anytime Maximum Demand
Electricity Authority Levies	80,203	ICP Count
Commerce Act Levies	32,226	Asset Related Allocator
Local Authority Rates	121,999	Asset Related Allocator
General Management, Administration and Overheads	3,488,831	ICP Count
System Management and Operations	1,920,889	Asset Related Allocator
Routine and Preventative Maintenance	1,012,720	Asset Related Allocator
Refurbishment and Renewal Maintenance	860,466	Asset Related Allocator
Fault and Emergency Maintenance	677,090	Asset Related Allocator
Depreciation on Network Assets	3,919,467	Asset Related Allocator
Depreciation on Non-Network Assets	532,518	ICP Count
Target Pre Tax Return on Assets	11,710,621	Asset Related Allocator
DPP Regulatory Constraint	(2,577,833)	Asset Related Allocator
Total Revenue Requirement	**30,089,951**	

4.4. Revenue Requirement Allocation to Load Groups

Using the methodology and assumptions outlined above, the forecast revenue requirement for 2012/13 is allocated to load groups as follows (below). This reflects a transitional allocation method, which reflects movement towards more fully cost reflective allocations, but which limits movement between load groups to no more than +/-10% of revenue for the forthcoming year.

Table 5: Allocation of Revenue Requirement to Load Groups

Load Groups		Distribution Revenue ($)	Transmission Revenue ($)	Total Revenue ($)
Domestic				
LUD/SD	Low User and Standard Domestic	10,062,537	2,337,972	12,400,509
NSD	Non-standard Domestic	192,428	52,601	245,029
Capacity Groups				
N1	Capacity Group 1 (0-14 kVA)	1,103,552	228,620	1,332,172
N2	Capacity Group 2 (15-42 kVA)	3,378,060	849,927	4,227,986
N3	Capacity Group 3 (43-70 kVA)	1,463,237	443,376	1,906,614
N4	Capacity Group 4 (71-100 kVA)	352,507	179,926	532,433
N5	Capacity Group 5 (>100 kVA)	266,409	136,823	403,231
CC	Capacity Concession	(9,089)	-	(9,089)
Network Maximum Demand				
NMD	Network Maximum Demand	3,059,511	972,827	4,032,337
Specials				
UV	U/Veranda Lights	3,879	180	4,059
EF	Electric Fence	3,785	152	3,937
SL	Street Lights	214,222	43,137	257,359
PCM 24	PCM 24 Hour	34,339	8,122	42,461
PCMN	PCM Night Only	3,675	675	4,350

Table 6: Allocation of Revenue Requirement (Detailed) to Load Groups

Load Groups		Distribution Revenue ($)			Transmission Revenue ($)			
		Fixed	Variable	Total Distribution	Fixed	Variable	Total Transmission	Total Revenue ($)
Domestic								
LUD	Low User Domestic	-	5,915,643	5,915,643	727,435	555,769	1,283,204	7,198,847
SD	Standard Domestic	697,899	3,448,995	4,146,894	1,054,767	-	1,054,767	5,201,662
NSD	Non-standard Domestic	131,171	61,257	192,428	52,601	-	52,601	245,029
Capacity Groups								
N1	Capacity Group 1 (0-14 kVA)	570,683	532,869	1,103,552	228,620	-	228,620	1,332,172
N2	Capacity Group 2 (15-42 kVA)	1,052,667	2,325,392	3,378,060	849,927	-	849,927	4,227,986
N3	Capacity Group 3 (43-70 kVA)	128,608	1,334,630	1,463,237	443,376	-	443,376	1,906,614
N4	Capacity Group 4 (71-100 kVA)	6,425	346,082	352,507	179,926	-	179,926	532,433
N5	Capacity Group 5 (>100 kVA)	4,308	262,100	266,409	136,823	-	136,823	403,231
CC	Capacity Concession	(9,089)	-	(9,089)	-	-	-	(9,089)
Network Maximum Demand								
NMD	Network Maximum Demand	1,446,576	1,612,935	3,059,511	972,827	-	972,827	4,032,337
Specials								
UV	U/Veranda Lights	3,879	-	3,879	180	-	180	4,059
EF	Electric Fence	3,785	-	3,785	152	-	152	3,937
SL	Street Lights	214,222	-	214,222	43,137	-	43,137	257,359
PCM 24	PCM 24 Hour	34,339	-	34,339	8,122	-	8,122	42,461
PCMN	PCM Night Only	3,675	-	3,675	675	-	675	4,350

5. Tariff Structure

5.1. Key Considerations

As there are infinite combinations of tariffs possible, Horizon Energy has developed its tariff structure after consideration of the following factors:

- The extent to which Horizon Energy's underlying costs are fixed or variable;
- The manner in which transmission and avoided transmission charges are determined and the associated revenue risk that may arise in the manner in which these are passed on to consumers;
- The impact of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 and the requirement to maintain revenue equivalence at the 8000 kWh cross over between low user domestic and standard domestic tariffs;
- The manner in which costs can be shared between low, medium and high volume users within each load group;
- The existing tariff structures and the need to moderate step changes in any one pricing year;
- The signals that certain tariff structures send to consumers regarding incremental load, energy efficiency, demand management and capacity utilisation;
- Transaction simplicity/complexity and the availability of the information necessary to implement certain tariff options;
- The likelihood or otherwise of retailers repackaging tariffs and disrupting the intended pricing incentives;
- The likelihood of uneconomic bypass of the distribution system; and
- The service levels provided to different load groups.

5.2. Tariff Mix

The tariff approach adopted for 2012/13 is consistent with the existing approach in place for 2011/12.

As transmission charges are known with certainty at the time prices are set, Horizon Energy continues to remove revenue risk associated with the recovery of these external costs, and to pass these through to consumers as fully fixed charges (subject to low user regulatory constraints and transitional arrangements).

For distribution related costs, Horizon Energy continues to balance the trade-offs between revenue risk, energy efficiency, contributions to incremental capacity, intergroup cross subsidy (between low and high users within each load group) and tariff simplicity.

Horizon Energy's rationale is that all customers requesting and having a supply made available, must contribute to the required cost recovery through the fixed charge component regardless of energy consumption. This is seen as the fairest way to minimise cross subsidisation between customer groups. However having a variable element in the charge means customers can influence the final amount charged, which is consistent with our load management and energy efficiency objectives as well as assisting in meeting some of the economic pricing principles (refer section 6).

Accordingly, the distribution component of the revenue recovery for all load groups (with the exception of majors and NMD consumers) comprises:

- A unit charge (c/kWh) recovered on the basis of electricity consumption; and
- A fixed charge ($/day/ICP) recovered for every ICP within each load group on a consistent basis.

For NMD consumers, a more sophisticated tariff structure (consistent with the 2011/12 tariff structure) is provided which better reflects the diversity of consumers within this tariff group and the ability (given the additional information available about these consumers) to price on a capacity and demand basis, as follows:

- A unit charge (c/kWh) recovered on the basis of electricity consumption;
- A fixed charge ($/kVA/day) recovered for every unit of installed capacity for each consumer; and
- A fixed charge ($/kW) recovered for every unit of assessed peak demand for each consumer.

5.3. Transitional Assumptions

In order to manage the revenue impact of the fixed and variable revenue recoveries on low and high users within each load group, Horizon Energy has capped the amount of revenue to be recovered from each load group by way of fixed charges. These caps have been derived from historical ratios with a modest step up in the fixed proportion for the 2012/13 year for most load groups to reflect the policy of moving transmission charges to fully fixed from fully variable charges. The resulting revenue allocations are as follows.

Table 7: Percentage Revenue Allocation Across Load Groups

Load Groups		Fixed Revenue (%)	Variable Revenue (%)
Domestic			
LUDU	Urban Low User Domestic	10%	90%
LUDR	Rural Low User Domestic	10%	90%
SDU	Urban Standard Domestic	34%	66%
SDR	Rural Standard Domestic	34%	66%
NSDU	Urban Non-standard Domestic	75%	25%
NSDR	Rural Non-standard Domestic	75%	25%
Capacity Groups			
N1U	Urban Capacity Group 1 (0-14 kVA)	52%	48%
N1R	Rural Capacity Group 1 (0-14 kVA)	66%	34%
N2U	Urban Capacity Group 2 (15-42 kVA)	45%	55%
N2R	Rural Capacity Group 2 (15-42 kVA)	45%	55%
N3U	Urban Capacity Group 3 (43-70 kVA)	30%	70%
N3R	Rural Capacity Group 3 (43-70 kVA)	30%	70%
N4U	Urban Capacity Group 4 (71-100 kVA)	37%	63%
N4R	Rural Capacity Group 4 (71-100 kVA)	33%	67%
N5U	Urban Capacity Group 5 (>100 kVA)	34%	66%
N5R	Rural Capacity Group 5 (>100 kVA)	36%	64%
Network Maximum Demand			
NMD	Network Maximum Demand	60%	40%
Specials			
UV	U/Veranda Lights	100%	0%
EF	Electric Fence	100%	0%
SL	Street Lights	100%	0%
PCM 24	PCM 24 Hour	100%	0%
PCMN	PCM Night Only	100%	0%

5.4. Urban/Rural Differentiation

Special consideration has been given to the characteristics of connections located in urban and rural areas, and the different demands they make on the network. Connection density is a factor which influences differences in the costs of supply between urban and rural network locations. More investment is required in rural areas to provide the same connection capacity when compared to urban areas given the greater distances, on average between connections. However connections located in urban areas are generally larger on average due to the higher intensity of non-domestic connections.

In addition, network configuration and shorter response times generally result in higher service quality in urban areas when compared to rural areas. This offsets in part the investment imbalance.

For the purpose of the 2012/13 pricing methodology the following approach has been adopted in respect of urban/rural tariff differentials:

- Transmission charges are the same for urban and rural consumers within each load group reflecting the fact that the transmission service delivery occurs up to the Grid Exit Point (“GXP”) and thus is equivalent for all like customers irrespective of location on the distribution network;

- Distribution costs are allocated separately to urban and rural consumers for the domestic and general capacity load groups. No rural/urban allocation is undertaken for NMD or major consumers as the tariff methodologies applied to consumers within these groups are specific to the characteristics of each individual consumer;
- For domestic consumers, the urban and rural tariffs are equalised. This occurs because of the constraints of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 and the requirement to maintain revenue equivalence with the cross over to the standard domestic tariff at 8,000 kWh. Urban and rural tariff codes have been maintained and Horizon Energy plans to consider possible differentiation between rural and urban domestic tariffs in the future; and
- For general capacity consumers, urban and rural tariffs are implemented in order to recover the distribution component of the underlying costs for each network segment. The target revenue recovery is determined by the COS model (as outlined above) and the fixed and variable components of revenue are determined using the methodology outlined previously. This is the same underlying methodology as applied in previous years where urban/rural differentials have also been charged to general capacity consumers.

5.5. Future Consideration

Horizon Energy will continue to progress the movement of line charge towards fixed tariffs where there is an economic requirement to ensure capacity and quality of service within the network is maintained. As such Horizon Energy will be looking to increase the fixed portion of the load group tariffs in next year's pricing.

6. Distribution Pricing Principles

Horizon Energy's pricing methodology remains consistent with the Electricity Commission's Distribution Pricing Principles and Information Disclosure Guidelines 2010.

We have incorporated amendments following Concept Consulting Group Limited's report on the *Assessment of selected distributor's alignment against the Information Disclosure Guidelines, and their consideration of the Pricing Principles*. In addition we note the Electricity Authority consulted on the *Criteria for assessing alignment against the Information Disclosure Guidelines and Principle Principals* in September 2011, but have yet to release any determination on the final criteria.

The following section provides a brief summary of the extent to which each principle is reflected in this year's pricing methodology.

6.1. Economic Costs of Service Provision Principle

The revenue allocation approach adopted by Horizon Energy reflects an average approach to the allocation of the revenue requirement between consumer groups. By definition, for each consumer, this results in a revenue allocation which falls somewhere between stand alone cost and incremental cost on the basis that the cost allocators used are a reasonable representation of the underlying cost drivers of the business. Thus Horizon Energy's tariffs follow pricing principle (a)(i) and fall within a subsidy free range.

It is not possible to accurately estimate the stand alone costs for most consumers which are supplied a common service via a meshed and integrated network. However it is possible to conclude that stand alone costs would be higher than average costs for those consumers given the scale efficiencies in supplying them from an integrated network.

In addition, it is difficult to estimate the incremental cost of supplying each consumer each additional unit of capacity. However, it is reasonable to assume that the incremental cost of connecting each additional general consumer to the network is small. These conclusions along with the regulatory constraints of the weighted average price cap and the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 indicate that the pricing methodology adopted by Horizon Energy is consistent with the economic cost of service provision principle.

In addition, Horizon Energy's capacity banded load group structure is consistent with the pricing principle (a)(ii) having regard to the level of available service capacity, as prices increase across these bands as demand for capacity increases.

In terms of pricing principle (a)(iii) for signalling the impact of future usage on future investment costs, the most relevant price for this purpose is a demand charge, however this is only possible for consumers where demand information is available (such as the NMD load group). Weaker signals are provided for smaller load groups through the use of variable charges, as a reasonable proxy for demand, while having regard to transaction costs (refer below) and standard industry practice.

6.2. Efficiency and Demand Responsiveness Principles

This pricing principle (b) is similar to the Ramsey Pricing principle which suggests that natural monopolies which use marginal cost prices will under recover their total revenue requirement and accordingly such prices must be scaled up in some manner. Ramsey pricing suggests the scaling should take into account the price elasticity of each load group, and those with lower price elasticity's should bear a higher proportion of the scaling.

In practice this is a difficult principle to apply as price elasticity information is difficult to obtain and it is likely the price elasticity's will be different within each of Horizon Energy's load groups (for example different commercial users are likely to have very different price elasticity's depending on the importance of their electricity supply in meeting their business requirements). In addition, Horizon Energy's interposed arrangements with energy retailers limits the information available to us about the characteristics of our consumers.

However, by recovering a considerable portion of revenue by way of variable charges we indirectly reflect each consumer's willingness to pay. In addition, non-standard pricing with large consumers also directly reflects their willingness to pay for the services they receive.

6.3. Responsive to the Needs of Stakeholders Principle

Individual prices are determined for each of the major industrial consumers located on Horizon Energy's network. These reflect the specific assets associated with the supply of line function services to these customers, and the specific quality of service requirements of these customers. This is consistent with the economic value of the services to the customer and includes specific prices for service offerings which are 'non-standard'. By definition this approach follows the pricing principle (c)(i) in avoiding uneconomic bypass.

A similar approach is adopted for NMD customers, where the pricing methodology specifically recognises the installed capacity requirements of each individual NMD consumer and provides a combination of capacity and demand prices which reflect the capacity utilisation of each individual consumer. This combined with the variable consumption based tariff provides the appropriate mix of prices to ensure the demands of these consumers are adequately reflected in the prices they pay, enabling the stakeholders to make trade-offs for services following the pricing principle (c)(ii).

Prices charged to the remaining general domestic and non-domestic consumers are unable to be differentiated in the same way due to lack of information about each individual consumer and the uniform supply arrangements for these consumers which are connected to the main distribution network. This is consistent with the uniform quality of service provided to general consumers, with some differential reflected in the urban/rural regions of the network.

6.4. Encourage Investment in Transmission and Distribution Alternatives Principle

Horizon Energy has a number of significant embedded generators already connected to the network. These investors receive avoided transmission payments which are provided to them in a transparent nature consistent with Transpower's Transmission Pricing Methodology ("TPM"). Any new distributed generation is offered the same terms and conditions.

While encouraging of investment under the pricing principle (c)(iii), Horizon Energy's ability to pass onto other consumers the benefits of investment in distribution or transmission alternatives is currently limited by the metering capability provided to our customers.

6.5. Transparency, Promote Price Stability and Have Regard to the Impact on Stakeholders Principles

The tariff schedule sets out the prices to be charged in a transparent manner following pricing principle (d). There are no tariff structure changes introduced since the 2011/12 year.

Careful consideration was given to the changes introduced in 2011/12 and specific transitional arrangements remain in place to limit the impact of the 2011/12 changes in tariffs on individual consumers for the forthcoming year. These include limits on the amount of revenue recovery transferred between load groups for the year as well as limits on the step changes in the fixed and variable revenue recoveries within each load group in order to manage the impact on low and high users within each load group.

Horizon Energy plans to continue these transitional arrangements in future years until our revenue allocation objectives are fully met.

6.6. Give Regard to Transaction Costs and Economic Equivalence Across Retailers Principles

Following pricing principle (e), Horizon Energy's tariff structure is simple, limited to fixed daily and variable consumption tariffs for all but a small number of the largest consumers. The load grouping is consistent with industry standards, including domestic groups and capacity groupings for non-domestic consumers.

All posted tariffs apply to all customers within each relevant load group, for all retailers.

7. Glossary

AMD	Anytime Maximum Demand
COS	Cost of Supply
DPP	Default Price-Quality Path
DRC	Depreciated Replacement Cost
HV	High Voltage
ICP	Installation Control Point
kVA	Kilowatt Ampere
kW	Kilowatts
kWh	Kilowatt Hour
LRR	Loss Rental Rebates
LV	Low Voltage
NMD	Network Maximum Demand
NZ IAS	New Zealand Equivalent to International Accounting Standard
RC	Replacement Cost
TPM	Transmission Pricing Methodology