

AURORA ENERGY LTD

Use-of-System Pricing Methodology

Methodology Applicable from 1 April 2009

Prices Applicable from 1 April 2009

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1 INTRODUCTION

This document outlines the methodology by which use-of-system charges (line charges) are determined. It has been developed following consultation with various interested parties and comments and suggestions for improvement are welcome at any time. Included is all the information required by Section 14(4) of the Electricity Distribution (Information Disclosure) Requirements 2008 (being Section 22 and 23 of the Electricity Information Disclosure Requirements 2004) as published by the Commerce Commission.

2 PRICING OBJECTIVES

2.1 Revenue

Aurora Energy Ltd (Aurora) must obtain sufficient revenue to:

- (a) meet its contractual obligations for connection to the Transpower grid;
- (b) meet its contractual obligations for delivery of energy over the distribution network;
- (c) comply with statutory requirements on public safety, environmental protection and quality of supply;
- (d) provide a commercially appropriate return on funds.

2.2 Efficiency

Improvements in the efficiency of electricity delivery will be achieved by promoting efficient investment in and operation of the network, by clearly signalling the fixed and variable costs of delivery.

2.3 Fairness

As a supplier of an essential service, Aurora intends to set fair and reasonable prices. Delivery charges as a whole are cost-based and the recovery of those costs will be spread fairly over users of the network. The application of fairness to delivery pricing is one of the most difficult objectives to achieve, because users have varying views on what is fair - based to a large extent on how the pricing methodology impacts on their individual line charges.

The pricing methodology follows closely the recommendations of the Ministry of Commerce document "Electricity Disclosure Guidelines". These guidelines recognise amongst other aspects that:

- (a) individual delivery charges should reflect the costs of supplying each connection point - the level of charges should take into account the power to be delivered, the number and type of circuits and the condition and age of the assets;
- (b) where individual delivery charges do not apply, consumers are placed in load capacity groups; each group's charges will vary according to their respective use of different types of assets;
- (c) where new investment is required, those users who obtain the benefit should be required to contribute towards the cost.

The above guidelines have been modified in order to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, which requires domestic consumers using up to 9,000 kWh per annum, to have as an option, the fixed portion of their line charges limited to 15 cents per day. This has been applied to the recovery mechanism used for costs in load groups L1 and L1A only.

3 COST STRUCTURE

The pricing methodology is based on cost recovery. Consequently, the price structure closely relates to the corresponding cost structure. The following cost categories are involved:

3.1 Distribution Costs

Distribution costs derive from two cost drivers.

Asset Costs: (94% of total distribution costs)

- (a) provision of assets - the cost of funding including return to shareholder;
- (b) maintaining the assets to safety, legal, consumer and economic requirements;

System Operation Costs: (3% of total distribution costs)

- (a) provision of fault response services;
- (b) provision of congestion signalling facilities to minimise investment in the transmission and distribution networks, and to provide energy retailers and their customers with a load switching services which may not relate to network investment.

Overhead Costs: (3% of total distribution costs)

- (a) provision of support services related to the above items.

The variation of these costs per \$ of capacity provided for consumer use is significant between GXP's (a 3.1 range from 72% to 224%), as follows:

Variation of \$ORC* asset per MW

	ORC	MW peak	ORC/MW	
Clyde	\$ 57,605,174	16.1	\$3,584,417	224%
Cromwell	\$ 90,688,934	27.7	\$3,269,601	205%
Frankton	\$ 79,410,261	47.9	\$1,658,077	104%
South Dunedin	\$ 80,280,270	67.5	\$1,189,058	74%
Halfway Bush	\$141,672,371	122.7	\$1,155,001	72%
Weighted Average	\$450,329,757	281.9	\$1,579,039	100%

* Optimised Replacement Cost (ORC) is a standardised measure of the "used and useful" distribution assets.

Optimised Depreciated Replacement Cost of assets has not been used in the above illustration because ORC is less susceptible to significant variation when large zone substation and transmission assets are replaced or upgraded. Older assets also generally require more maintenance and a ratio using ODRC does not appropriately reflect these higher maintenance costs.

3.2 Transmission Costs

Transmission costs are determined by the Electricity Commission approved transmission pricing methodology for Transpower NZ Ltd using the following price components:

Interconnection Charge: (77% of transmission costs)

This charge is based on the average of the 100 demands at each GXP at the dates and times of the highest 100 peak half hour demands for the Lower South Island region in the 12 months to 31 August prior to the pricing year beginning 1 April.

Connection Charge: (23% of total transmission costs)

This charge represents the fixed connection costs associated with the dedicated assets at each grid exit point.

The variation of these costs per MW of capacity provided for consumer use is significant between GXP (a 1.42 range from 85% to 121%), as follows:

Variation in \$ of transmission cost per MW

GXP	\$/MW	% of average
Clyde	\$69,050	96%
Cromwell	\$60,953	85%
Frankton	\$87,368	121%
Halfway Bush	\$66,375	92%
South Dunedin	\$76,996	107%
Weighted Average	\$72,105	100%

3.3 Combined Transmission and Distribution Costs

When the cost driver ratios are combined the following composite ratios result.

GXP Area	Transmission Costs	Distribution Costs	Composite Costs	70%-Target Pricing	Price Zone
Weighting	29%	71%	100%	100%	
Clyde	96%	224%	187%	161%	CML & CYD
Cromwell	85%	205%	169%	148%	
Frankton	121%	104%	109%	107%	FKN
Halfway Bush	92%	72%	78%	85%	SDN & HWB
South Dunedin	107%	74%	84%	89%	
Average	100%	100%	100%	100%	

Due to the significant differences in the cost driver ratios, separate pricing areas are used. However, to reduce pricing complexity, where area costs are within 10% of each other, then a common average pricing structure is applied. This is a reasonable compromise between appropriately signalling the very different investment costs in each location, while keeping complexity to a minimum.

Distribution costs are thus predominantly related to asset value, with the result that a strict application of cost-recovery would mean that each consumer paid charges related to the assets they use.

At the January 2008 Directors meeting, it was decided that pricing should move from recovering a minimum of 50% of the full delivery costs in each of the pricing areas to full recovery with transition over a number of years. The present recovery of 70% is shown in the table above and it is expected that the recovery will move to at least 80% from 1 April 2010.

While the ratio of 70%-target prices between the Clyde and Cromwell GXP areas has moved outside the 10% range for common pricing since last year, some aspects of transmission pricing are expected to be of a short term nature and Cromwell pricing is expected to move within 10% of Clyde in the near future.

3.4 Overall Revenue Requirements for Year Ended 31 March 2010¹

Target weighted average cost of capital		\$28.412 million
Expenses		
Network depreciation	\$10.957 million	
Other	\$17.698 million	
		\$28.655 million
Tax expense		\$12.177 million
Target distribution revenue		\$69.244 million
Transmission services		\$20.341 million
Target delivery revenue		\$89.585 million
Less regulatory discount		\$17.744 million
Total delivery revenue budgeted for 2008/09		\$71.841 million

This revenue requirement is derived from the four pricing areas as follows:

	Distribution \$ million	Transmission \$ million	Total \$ million
Dunedin HWB & SDN area	27.091	13.340	40.431
Central CML & CYD area	15.696	2.800	18.496
Central FKN area	8.699	4.185	12.884
Heritage Estate area	0.014	0.016	0.030
Total	51.500	20.341	71.841
Weighting	71%	29%	100%

The allocation of these area requirements is shown in section 3.5, where they are allocated to the load groups detailed in section 4.3, except for Heritage Estate, where the connection numbers are so small that the breakdown by load group is less meaningful.

¹ As Aurora has a 30 June balance date, budgets are not available for the June 2010 year and distribution costs have been taken from the reforecast for the 2008/09 year adjusted for the expected revenues. Transmission costs reflect the expected transmission expenses for the year ending March 2010.

3.5 Load Group Characteristics and Area Cost Allocations

The statistical parameters used for the allocation of area costs to load groups are as follows:

Statistics for the Dunedin Area GXP's of Halfway Bush and South Dunedin

Group	kVA Range	Number of Connections to the Network	Energy Delivered Per Annum GWh	Group Anytime Demand MW	Sum of Installed Capacity MVA	Group Congestion Period Demand MW
St L	0	2	7.1	1.6	6.6	1.07
L1	0 - 15	49,872	415.0	139.5	739.7	101.73
L2	16 - 149	2,850	149.0	32.4	145.5	25.43
L3	150 - 499	181	93.0	20.9	45.9	15.43
L4	500 - 2499	66	91.0	21.3	47.6	14.15
L5	2500+	10	99.0	20.3	41.6	15.39
Total		52,981	854.1	236.0	1026.9	173.21

Dunedin Area Distribution Costs by Asset \$000

Total Asset Costs by Asset Class	Total \$
33kV Lines	2,160
Zone Substations	6,304
HV Lines	6,777
Distribution Substations	5,838
LV Lines	6,012
Total	27,091

Dunedin Area Distribution Costs Allocated to Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	W33	Total
33kV lines	13	1,208	291	182	176	179	111	2,160
Zone substations	41	3,716	895	559	543	550	-	6,304
HV lines	48	4,294	1,039	649	638	109	-	6,777
Distribution substations	72	3,690	1,003	624	303	146	-	5,838
LV lines	53	4,751	1,145	63	-	-	-	6,012
Total	227	17,659	4,373	2,077	1,660	984	111	27,091

Transmission Costs Allocated to Dunedin Area Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	W33	Total
Transmission	84	7,736	1,979	1,208	1,125	1,209	-	13,340

Statistics for the Central Area GXP's of Cromwell and Clyde

Group	kVA Range	Number of Connections to the Network	Energy Delivered Per Annum GWh	Group Anytime Demand MW	Sum of Installed Capacity MVA	Group Congestion Period Demand MW
St L	0	5	1.7	0.4	1.5	0.25
L1	0 - 15	14,906	108.4	39.0	217.8	32.08
L2	16 - 149	1,351	61.0	13.9	70.2	8.49
L3	150 - 499	77	14.5	8.3	17.4	3.22
L4	500 - 2499	12	12.8	5.6	8.6	2.39
L5	2500+	0	0.0	0.0	0.0	0.00
Total		16,351	198.4	67.2	315.5	46.43

Distribution Costs for Clyde and Cromwell by Asset \$000

Total Asset Costs by Asset Class	Total \$
66kV & 33kV Lines	1,191
Zone Substations	1,663
HV Lines	7,789
Distribution Substations	2,863
LV Lines	2,190
Total	15,696

Distribution Costs for Clyde and Cromwell Area Allocated to Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
66kV & 33kV lines	5	544	167	83	58	-	334	1,191
Zone substations	9	1,057	324	161	112	-	-	1,663
HV lines	43	4,951	1,517	753	525	-	-	7,789
Distribution substations	17	1,937	598	292	20	-	-	2,863
LV lines	14	1,613	497	66	-	-	-	2,190
Total	88	10,102	3,103	1,355	715	-	334	15,696

Transmission Costs for Clyde and Cromwell Area Allocated to Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
Transmission	16	1,854	553	215	162	-	-	2,800

Statistics for the Frankton Area GXP

Group	kVA Range	Number of Connections to the Network	Energy Delivered Per Annum GWh	Group Anytime Demand MW	Sum of Installed Capacity MVA	Group Congestion Period Demand MW
St L	0	3	1.0	0.2	1.0	0.16
L1	0 - 15	9,841	90.4	30.9	144.1	28.02
L2	16 - 149	1,144	55.0	13.4	55.8	9.70
L3	150 - 499	64	27.0	8.1	16.2	4.83
L4	500 - 2499	21	28.2	9.4	14.9	5.96
L5	2500+	1	3.5	3.4	4.5	1.12
Total		11,074	205.1	65.3	236.5	49.79

Distribution Costs for Frankton area by Asset \$000

Total Asset Costs by Asset Class	Total \$
33kV Lines	451
Zone Substations	1,397
HV Lines	3,505
Distribution Substations	1,660
LV Lines	1,686
Total	8,699

Distribution Costs for Frankton Area Allocated to Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
33kV lines	2	233	90	50	59	17	-	451
Zone substations	5	723	279	154	184	52	-	1,397
HV lines	12	1,851	724	401	477	40	-	3,505
Distribution substations	7	942	400	221	90	-	-	1,660
LV lines	8	1,171	456	51	-	-	-	1,686
Total	34	4,920	1,949	877	810	109	-	8,699

Transmission Costs for Frankton Area Allocated to Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
Transmission	15	2,122	876	480	568	124	-	4,185

4 REVENUE STRUCTURE

Use-of-system charges closely follow the methodology recommended by the Ministry of Commerce document "Electricity Disclosure Guidelines 1994" and modified as discussed in section 2.3 to meet the Government's regulatory requirement for Standard Domestic consumers. The methodology is also consistent with the Model Approaches to Distribution Pricing formulated by an industry group in 2004. These guidelines recommend revenue allocations by load groups according to their general usage of asset classes.

4.1 Variations from Ministry of Commerce Guide

Where options or variations to the Ministry of Commerce Guide have been adopted, then these are outlined below:

- (a) Costs are allocated to each load group on the basis of asset use and in the ratio of 50% group Anytime Demand and 50% group Congestion Period Demand, instead of the 100% group Anytime Demand method in the Guide. This improves the signalling of investment costs to users who cause the investment.
- (b) Charges apply per Installation Control Point (ICP).
- (c) Rural or remote rural loads are so few in number in comparison with those supplied by the meshed network that they have been included in the meshed network.
- (d) Charges for load group 4 (500 to 2499 kVA) and load group 5 (2500+ kVA) have been calculated on the basis that they are all HV metered installations; an additional charge will apply where Aurora owns the associated transformer and switchgear.
- (e) Charges do not include energy losses on the distribution network. Energy retailers must purchase their share of system losses using the loss factors as published on Aurora's website www.electricity.co.nz.
- (f) Charges exclude metering services involved with the provision of meters or meter reading. These services are provided by others.

4.2 Asset Valuation

Book values of the assets are allocated pro rata across asset groups based upon the ODV value.

4.3 Maintenance of Existing Assets

The maintenance programme is determined by; safety requirements, reliability objectives, and repairs to equipment following faults. The safety and reliability requirements set the planned programme for maintenance and are detailed in the Asset Management Plan.

The amounts budgeted for maintenance are detailed in the Asset Management Plan under the following categories:

- system control
- subtransmission lines and cables (66kV & 33 kV)
- zone substations (33 kV to 11 kV and 6.6 kV transformation)
- HV lines and cables (11 kV and 6.6 kV)
- distribution substations (11/6.6 kV to 400 V transformation)
- LV lines and cables (400 V).

Use of the above assets by each load group determines the total cost to be recovered from each load group.

4.4 Load Groups

The rationale for each load group is as follows:

- Load Group 0 - Unmetered connections less than 1 kVA with defined load pattern (subset of load group L1).
- Load Group 1 - Single phase 60 amp capacity connections or less that share LV asset costs.
- Load Group 2 - All remaining connections that share LV asset costs.
- Load Group 3 - Three phase connections that may share some LV asset costs.
- Load Group 3A - Three phase connections generally supplied direct from distribution transformer (subset of load group 3)
- Load Group 4 - Three phase connections supplied direct from distribution transformer - transformer may be owned by consumer and connections share general HV asset costs
- Load Group 5 - Three phase connections - generally HV consumers and have dedicated HV lines / cables to supply the connection

5 PRICING COMPONENTS

5.1 Distribution Cost-Recovery Components

5.1.1 Standard Domestic Connections

A "Standard Domestic" connection is one where the connection capacity is either 15 kVA (single phase 60 amps) or 8 kVA (single phase 32 amps) and the electricity retailer advises Aurora that the electricity use is for domestic purposes. If there is a likelihood of injection of energy from the connection, then two-way import / export metering must be installed to remain on the Standard Domestic variable tariff.

Two components of line charges are used and the pricing details are outlined in Schedules 1 to 4 (A1, B1, C1, D1). The components are as follows:

5.1.1.1 Fixed Component

The fixed component has been set at 15 cents/day which is the maximum fixed line charge permitted under the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

5.1.1.2 Variable Components

The variable components are defined by the existing metering arrangements for each network area.

In the Dunedin area, most domestic connections have a single meter, which records general purpose and controlled water heating (16 hours service) consumption.

In the Central and Te Anau areas, most domestic connections have two meters – one to record general purpose consumption and one to record controlled water heating (16 hours service) consumption.

In both areas, the charges for controlled loads are discounted to reflect the lower contribution to peak loads by these loads.

5.1.2 Other Connections (Non-Domestic Connections and Non-Standard Domestic Connections including street lighting)

Five components of line charges are used and the pricing details are outlined in Schedules 1 to 3 (A2, A3, B2, B3, C2, C3, D2, D3). The components are as follows:

5.1.2.1 Fixed Charge

This charge recovers costs that are incurred on a connection basis.

5.1.2.2 Assessed Capacity Charge

LV Metered Connections

This charge recovers costs associated with the distribution system local to each connection point, ie LV lines and cables, distribution substations, and HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity is the minimum fuse size, mains size or standard distribution transformer size required to supply the maximum anytime power demand. Normally this will be the minimum fuse size for capacity up to 276 kVA and installed distribution capacity for capacity greater than or equal to 300 kVA.

HV Metered Connections

This charge recovers costs associated with the distribution system local to each connection point, ie HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity is the lesser of the installed distribution transformer capacity (kVA) and minimum standard transformer capacity greater than 1.18 times the maximum anytime power demand (kVA). The factor of 1.18 is used so that the average ratio of maximum anytime power demand (kVA) to Assessed Capacity (kVA) for HV metered connections is the same as for LV metered connections in Load Groups 4 and 5. See also 4.1(d).

5.1.2.3 *kVA-km Charge*

For the L3, L3A, L4 and L5 load groups (assessed capacity 150 kVA or greater) the costs associated with HV lines and cables and subtransmission lines and cables are recovered by a kVA-km charge. The total kVA-km for each connection is the product of the connection capacity in kVA and the circuit distance from the distribution substation supplying the connection to the Aurora zone substation and then to the nearest Transpower supply point.

This charge recognises that additional investment in lines and cables is required to supply network connections that are a long way from Transpower supply points compared to those that are close to a Transpower supply point. At more remote locations, alternatives to electricity may be more appropriate and this component signals this fact.

5.1.2.4 *Congestion Period Demand Charge*

This charge recovers costs associated with zone substations and subtransmission lines and cables, which are sized for system peak loads.

The basis for the Congestion Period Demand (CPD kW) is the energy used at the installation when Aurora is managing demand. This energy usage will accumulate and at the end of the Congestion Period the accumulated energy is divided by the duration of the Congestion Period to obtain average power demand. If a consumer commences during the year a negotiated Congestion Period Demand will apply until a full winter is completed. The Congestion Period Demand for each installation is set at 1 October to the average of CPD kW (Previous Winter) and CPD kW (at 1 October previous year).

The Congestion Period is likely to occur on cold winter days, anytime between 7.30 am and 10.00 pm, and to last typically for two to three hours (but could last for up to ten hours on occasions) and is most likely to occur on approximately 20 to 50 days during the May to September period with most activity during June, July and August. The congestion will be signalled via ripple control whenever the Congestion Period applies. Consumers may use this to operate a warning device to directly control deferrable load or to start up a standby generator, whichever is the most convenient.

Where it is not presently economic to install Congestion Period Demand metering for connections such as Load Group 1 and 2, then any charges that would normally be recovered via a Congestion Period Demand charge will be recovered via an Effective Congestion Period Demand charge based upon kWh consumption at the installation during Winter days (0700 hours - 2300 hours). This will be based upon the four months consumption reported by electricity retailers for the period May to August. Energy consumed by defined night loads are discounted 100% and energy used by controlled loads are discounted 50% for their daytime energy. The list of discount rates for kWh usage on each controlled rate register is set out in Schedule 6. The effective Congestion Period Demand for each installation is set at 1 October to the average of CPD kW (Previous Winter) and CPD kW (at 1 October previous year). Thus a strong economic signal exists for consumers to accept controlled loads.

By signalling network congestion in this way, Aurora is able to defer the need for investment in more capacity, which is a very expensive alternative. Load is controlled only when the network loading is approaching the network's capacity. Consumers do not have to respond every time the signal is sent. Many will respond only when it suits, however the rewards for responding are substantial.

5.1.2.5 *Equipment Charge*

This charge recovers costs associated with distribution substations for the load groups 500 to 2499 kVA and 2500+ kVA where the consumer has opted not to own their own transformers or switchgear.

5.2 **Transmission Cost-Recovery Components**

The following methodology is used as the basis for recovery of transmission charges. It best signals the transmission cost drivers that Transpower has reflected through its pricing structure. The same methodology is used to recover avoided Transpower Interconnection charges paid to TrustPower Ltd, Ravensdown Ltd and Pioneer Generation Ltd for the use of embedded generation at peak load times. Each component of transmission costs is allocated as follows:

5.2.1 Connection Charges

These charges have been allocated to load groups on the basis of 50% by each load group's share of anytime demand and 50% by each load group's share of winter day kWh. This improves the signalling of investment costs to those users who cause them.

5.2.2 Interconnection Charges

These charges have been allocated to each load group on the basis of the congestion period demand of each load group. The congestion period demand is the average demand of each load group whilst the load control service is being applied at the time of system load peaks. This is expected to apply for approximately 150 to 200 hours per year and mainly during the winter months of June, July and August.

5.2.3 Standard Domestic Supply

For Standard Domestic connections in load groups L1A (8 kVA) and L1 (15 kVA) the charges are recovered by a variable cents/kWh charge.

For other L1A (8 kVA) and other L1 (15 kVA) connections and the L2 (16-149 kVA) load group the connection charges are recovered by way of a charge per installed kVA capacity and the interconnection charge by way of a \$/kW using the previous year's winter day average demand.

For the L3 (150-249 kVA), L3A (250-499 kVA), L4 (500-2499 kVA) and L5 (2500+ kVA) load groups, the connection charges are recovered by way of a charge per installed kVA capacity and the interconnection charge by way of a charge per congestion period demand kW.

5.2.4 Loss and Constraint Rental Rebates

Loss and Constraint Rental Rebates are credits rebated by Transpower as a result of money received from the Clearing Manager for the Wholesale Electricity Market and are excluded from transmission charges. The rebates are allocated each month to Retailers on the basis of each retailers total transmission charges for the month in which the rebate applied. This credit is currently available in say mid-June for the month of April.

6 SEASONAL LOADS

6.1 Background

Aurora has a large number of seasonal loads connected to its network such as irrigation pumps, general pumps and fruit packing houses. Some connections, such as irrigation pumps, have been disconnected to avoid line charges over the winter period.

6.2 Line Pricing Recovery

Aurora's use-of-system charges are based on recovery by equal monthly instalments of an annual charge, which is adjusted after each network congestion period to reflect prior-winter peak period usage. Deliberate disconnection for part of a year to avoid part year charges is unacceptable.

6.3 Policy

For seasonal loads with capacity greater than 15kVA and advised to retailers, the following applies from 1 July 2006:

- 6.3.1 Any advice of a reconnection of a seasonal load that was disconnected within the previous 12 months will result in a Reconnection Charge equal to the monthly line charges not paid during the disconnected period, unless a written explanation satisfactory to Aurora is received.
- 6.3.2 Where disconnections occur for more than 12 months then Aurora reserves the right to remove assets dedicated to supply the de-energised ICPs and decommission the connection. Any request for subsequent reinstatement will be treated as if an application for a new connection was being made.
- 6.3.3 The Reconnection Charge will be invoiced to the retailer who requests the re-energisation and it is possible that the retailer will be back billed for up to 12 months of line charges. It is essential that new retailers accepting switches check whether the ICP has been de-energised on the Registry and if it is a seasonal load.

SCHEDULE 1**AURORA CHARGES FROM 1 APRIL 2009*****SOUTH DUNEDIN AND HALFWAY BUSH GRID EXIT POINTS***

A.1 - STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Transmission
Fixed Annual Charge (15 kVA)		SHSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		SHSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢/kWh)	
General Purpose	All day Summer	010S	4.92	1.10
General Purpose	All day Winter	010W	5.40	3.62
Controlled Variable Charges			(¢/kWh)	
General Purpose + 16 hour water heat	All day Summer	017S	2.69	1.33
General Purpose + 16 hour water heat	All day Winter	017W	3.96	2.07
Night + 3 hours	11 hour service	024	1.46	0.50
Night rate		028	0.56	0.00
Gen Purpose + 16 hour w/h - D/N	Summer Day	011S	4.72	1.33
Gen Purpose + 16 hour w/h - D/N	Winter Day	011W	5.01	4.08
Gen Purpose + 16 hour w/h - D/N	Summer Night	012S	0.56	0.00
Gen Purpose + 16 hour w/h - D/N	Winter Night	012W	0.56	0.00

A.2 - STREET LIGHTING		Registry Code	Per Annum	
			Distribution	Transmission
Fixed Annual Charge	0000201300DE692	SDNSTL	\$77,701	\$28,821
Fixed Annual Charge	0000203111DE930	HWBSTL	\$148,869	\$55,219

A.3 - OTHER CONNECTIONS				Per Annum			
	Registry Code	Load Group	Capacity kVA	Fixed \$	Capacity \$/kVA	kVA-km \$/kVA-km	Congestion Period \$/kW
Distribution	SH0	L0	0 - 1	\$102.51			
	SH0A	L0A (note 5)	0 - 2	\$212.82			
	SH1A	L1A (note 6)	0 - 8	\$9.89	\$12.98		\$81.97
	SH1	L1	0 - 15	\$9.89	\$11.53		\$81.97
	SH2	L2 (note 8)	16 - 149	\$19.40	\$16.69		\$73.14
	SH3	L3	150 - 249	\$388.00	\$23.84	\$0.27	\$57.01
	SH3A	L3A	250 - 499	\$388.00	\$22.02	\$0.27	\$57.01
	SH4	L4 (note 9)	500 - 2499	\$970.00	\$12.48	\$0.27	\$44.80
	SH5	L5 (note 9)	2500+	\$970.00	\$7.10	\$0.27	\$28.61
Transmission	SH0	L0	0 - 1	\$53.65			
	SH0A	L0A (note 5)	0 - 2	\$116.05			
	SH1A	L1A (note 6)	0 - 8		\$3.02		\$68.20
	SH1	L1	0 - 15		\$2.18		\$68.20
	SH2	L2	16 - 149		\$1.68		\$68.20
	SH3	L3	150 - 249		\$3.82		\$66.93
	SH3A	L3A	250 - 499		\$3.82		\$66.93
	SH4	L4	500 - 2499		\$3.73		\$66.93
	SH5	L5	2500+		\$4.31		\$66.93

Notes - Refer to Schedule 5

SCHEDULE 2**AURORA CHARGES FROM 1 APRIL 2009*****CLYDE AND CROMWELL GRID EXIT POINTS***

B.1 - STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Transmission
Fixed Annual Charge (15 kVA)		CCSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		CCSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢/kWh)	
General Purpose	All day Summer	101S	8.62	1.09
General Purpose	All day Winter	101W	11.73	2.79
Controlled Variable Charges			(¢/kWh)	
Peak Water Heating	20 hour service	109	6.50	1.49
Standard Water Heating	16 hour service	106	4.70	0.89
Night + 5 Hours	13 hour service	103	5.30	1.28
Night + 3 Hours	11 hour service	104	4.33	0.68
Night		108	3.50	0.00

B.2 STREET LIGHTING			(¢/kWh)	
Fixed Annual Charge per lamp		CCSTL	\$12.00	
Variable Charge		110	3.44	1.23

B.3 - OTHER CONNECTIONS				Per Annum			
	Registry Code	Load Group	Capacity kVA	Fixed \$	Capacity \$/kVA	kVA-km \$/kVA-km	Congestion Period \$/kW
Distribution	CC0	L0	0 - 1	\$171.30			
	CC0A	L0A (note 5)	0 - 2	\$326.60			
	CC1A	L1A (note 6)	0 - 8	\$12.00	\$24.09		\$155.26
	CC1	L1	0 - 15	\$12.00	\$22.02		\$155.26
	CC2	L2 (note 8)	16 - 149	\$24.00	\$27.40		\$144.00
	CC3	L3	150 - 249	\$480.00	\$41.58	\$0.33	\$145.00
	CC3A	L3A	250 - 499	\$480.00	\$38.70	\$0.33	\$145.00
	CC4	L4 (note 9)	500 - 2499	\$1260.00	\$31.10	\$0.33	\$123.80
	CC5	L5 (note 9)	2500+	\$1260.00	\$20.78	\$0.33	\$104.24
Transmission	CC0	L0	0 - 1	\$42.20			
	CC0A	L0A (note 5)	0 - 2	\$106.23			
	CC1A	L1A (note 6)	0 - 8		\$1.00		\$68.20
	CC1	L1	0 - 15		\$0.18		\$68.20
	CC2	L2	16 - 149		\$0.10		\$65.00
	CC3	L3	150 - 249		\$0.14		\$66.93
	CC3A	L3A	250 - 499		\$0.14		\$66.93
	CC4	L4	500 - 2499		\$0.75		\$66.93
	CC5	L5	2500+		\$0.75		\$66.93

Notes - Refer to Schedule 5

SCHEDULE 3**AURORA CHARGES FROM 1 APRIL 2009*****FRANKTON GRID EXIT POINT- (excluding Frankton sub area)***

C.1 - STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Transmission
Fixed Annual Charge (15 kVA)		FRSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		FRSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢/kWh)	
General Purpose	All day Summer	201S	5.87	1.44
	All day Winter	201W	7.23	3.72
Controlled Variable Charges			(¢/kWh)	
Peak Water Heating	20 hour service	209	3.46	1.69
Standard Water Heating	16 hour service	206	1.44	1.23
Night + 5 Hours	13 hour service	203	2.20	1.48
Night + 3 Hours	11 hour service	204	1.36	1.01
Night		208	1.20	0.00

C.2 STREET LIGHTING			(¢/kWh)	
Fixed Annual Charge per lamp		FRSTL	\$12.00	
Variable		210	2.12	1.93

C.3 - OTHER CONNECTIONS				Per Annum			
	Registry Code	Load Group	Capacity kVA	Fixed \$	Capacity \$/kVA	kVA-km \$/kVA-km	Congestion Period \$/kW
Distribution	FR0	L0	0 - 1	\$115.57			
	FR0A	L0A (note 5)	0 - 2	\$209.40			
	FR1A	L1A (note 6)	0 - 8	\$10.30	\$17.14		\$81.23
	FR1	L1	0 - 15	\$10.30	\$15.66		\$81.23
	FR2	L2 (note 8)	16 - 149	\$16.75	\$18.10		\$97.02
	FR3	L3	150 - 249	\$380.00	\$35.43	\$0.30	\$59.65
	FR3A	L3A	250 - 499	\$380.00	\$33.37	\$0.30	\$59.65
	FR4	L4 (note 9)	500 - 2499	\$1,000.00	\$21.24	\$0.30	\$61.71
	FR5	L5 (note 9)	2500+	\$1,000.00	\$8.36	\$0.30	\$47.92
Transmission	FR0	L0	0 - 1	\$53.79			
	FR0A	L0A (note 5)	0 - 2	\$121.80			
	FR1A	L1A (note 6)	0 - 8		\$5.79		\$68.20
	FR1	L1	0 - 15		\$5.40		\$68.20
	FR2	L2	16 - 149		\$4.04		\$68.20
	FR3	L3	150 - 249		\$9.69		\$66.93
	FR3A	L3A	250 - 499		\$9.69		\$66.93
	FR4	L4	500 - 2499		\$11.41		\$66.93
	FR5	L5	2500+		\$11.27		\$66.93

Notes - Refer to Schedule 5

SCHEDULE 3A**AURORA CHARGES FROM 1 APRIL 2009*****FRANKTON GRID EXIT POINT - (Frankton sub area)***

A prudent discount policy applies in the Frankton sub area.

Pricing in the sub area is less than or equal to the standard Frankton GXP pricing. Lower distribution line charges within the sub area reflect lower costs to reticulate an area close to the Frankton GXP.

Frankton sub area is a defined area close to the FKN GXP. Affected ICPs are defined on the Registry by a pricing code of "FK" instead of the standard code of "FR".

SCHEDULE 4**AURORA CHARGES FROM 1 JUNE 2008*****HERITAGE ESTATE - TE ANAU AREA - NORTH MAKAREWA GRID EXIT POINT***

(Note 12)

E.1 - STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Transmission
Fixed Annual Charge (15 kVA)		HESD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		HESD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢/kWh)	
General Purpose	All day Summer	401S	6.57	1.38
General Purpose	All day Winter	401W	8.30	3.63
Controlled Variable Charges			(¢/kWh)	
Standard Water Heating	16 hour service	406	2.81	1.10
Night + 3 Hours	11 hour service	404	2.51	0.91
Night		408	2.40	0.00

E.2 STREET LIGHTING			(¢/kWh)	
Fixed Annual Charge per lamp		HESTL	\$12.00	
Variable		410	2.83	1.25

E.3 - OTHER CONNECTIONS				Per Annum			
	Registry Code	Load Group	Capacity kVA	Fixed \$	Capacity \$/kVA	kVA-km \$/kVA-km	Congestion Period \$/kW
Distribution	HE0	L0	0 - 1	\$125.17			
	HE0A	L0A (note 5)	0 - 2	\$235.03			
	HE1A	L1A (note 6)	0 - 8	\$10.60	\$19.01		\$110.97
	HE1	L1	0 - 15	\$10.60	\$17.54		\$110.97
	HE2	L2 (note 8)	16 - 149	\$21.12	\$21.19		\$99.42
Transmission	HE0	L0	0 - 1	\$49.30			
	HE0A	L0A (note 5)	0 - 2	\$124.10			
	HE1A	L1A (note 6)	0 - 8		\$2.22		\$68.20
	HE1	L1	0 - 15		\$1.26		\$68.20
	HE2	L2	16 - 149		\$1.33		\$68.20

Notes - Refer to Schedule 5

SCHEDULE 5

AURORA CHARGES FROM 1 APRIL 2009

NOTES

- (1) All charges are exclusive of GST.
- (2) Variable charges apply to kWh as metered at each ICP. The hours of service for water heating loads are target minimum levels of service. In unusual network circumstances it may be necessary for the target level to be less.
- (3) Capacity provided is on the basis of the smaller of mains size, LV fuses or transformer capacity.
- (4) Load group L0 is for approved unmetered supplies only.
- (5) Load group L0A is for approved unmetered builders temporary supply with maximum capacity of 15 kVA and subject to special conditions.
- (6) 8 kVA connections require a sealed 32 Amp MCB installed on the meter board.
- (7) The Summer period is 1 October to 30 April and Winter is 1 May to 30 September.
- (8) For connections in LG2 and above that satisfy the criteria for domestic as defined in the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, then Standard Domestic pricing is available as an option.
- (9) For L4 and L5 load groups an additional \$7.20 per kVA of capacity applies if Aurora owns the distribution transformer.
- (10) An additional \$85.20 per kVAr per annum of equivalent corrective capacitance applies if the installation power factor is required to be improved to 0.95.
- (11) Loss Rental Rebates are excluded from transmission charges and are credited separately.
- (12) Heritage Estate is a small 180 lot subdivision in the Te Anau area constructed in 2005.

SCHEDULE 6

REGISTER DISCOUNT RATES FOR ASSESSED CPD kW CALCULATION

The table below lists the discount rate to be applied to the winter kWh for each register prior to the calculation of the assessed CPD kW for each ICP.

Register Contents	Pricing Code Dunedin		Pricing Code Clyde/Cromwell		Pricing Code Frankton		Pricing Code Frankton sub area		Pricing Code Heritage Estate		CPD kW Discount
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	
IN19	017S	017W	-	-	-	-	-	-	-	-	42%
UN24	010S	010W	101S	101W	201S	201W	301S	301W	401S	401W	Nil
CN11	024	024	104	104	204	204	304	304	404	404	75%
CN8	028	028	108	108	208	208	308	308	408	408	100%
IN16	011S	011W	-	-	-	-	-	-	-	-	20%
IN8	012S	012W	-	-	-	-	-	-	-	-	100%
CN20	-	-	109	109	209	209	309	309	-	-	25%
CN16	006	006	106	106	206	206	306	306	-	-	50%
CN13	-	-	103	103	203	203	303	303	-	-	60%
CN10	-	-	145	145	245	245	345	345	-	-	100%
DC16	013	013	-	-	-	-	-	-	-	-	50%
NC8	014	014	-	-	-	-	-	-	-	-	100%
D16	015	015	115	115	215	215	315	315	415	415	Nil
N8	016	016	116	116	216	216	316	316	416	416	100%
GENPV	090	090	190	190	290	290	390	390	490	490	Nil

For a description of register contents refer to the Standard Domestic pricing schedules for each area. The following codes apply to non Standard Domestic pricing. CN10 - Irrigation 10 hour service June, July, August, DC16/NC8 – Controlled 16 hour service metered Day / Night, IN16/IN8 - Same as IN19 but metered Day / Night. GENPV is for energy injected into the network at ICPs with distributed generation.