

# *Information Disclosure by Aurora Energy Ltd* for the year ended 31 March 2011

Pursuant to the  
*ELECTRICITY DISTRIBUTION (INFORMATION DISCLOSURE) REQUIREMENTS 2008*

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### **Information Disclosure Disclaimer**

*Information disclosed in this document has been prepared solely for the purposes of the Electricity Information Disclosure Requirements 2008.*

*The Requirements require the information to be disclosed in the manner it is presented.*

*The information should not be used for any other purpose than that intended under the Requirements.*

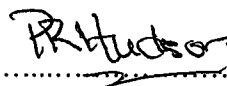
*The information disclosed is for the lines business as described in the Requirements. There are other activities of the Company that are not required to be reported under the Requirements.*

### **A STATUTORY DECLARATION FOR PUBLICLY DISCLOSED INFORMATION (REQUIREMENT 13(1))**

I, Raymond Stuart Polson of 80 Browns Road, St Albans, Christchurch, being a director of Aurora Energy Ltd, 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 information made available to the public by Aurora Energy Ltd under the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008.

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 Dunedin this 27<sup>th</sup> day of July 2011

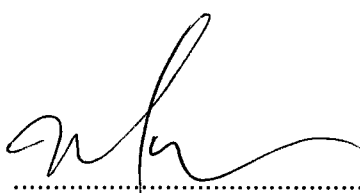


Justice of the Peace (or Solicitor or other person authorised to take a statutory declaration)

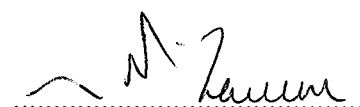
**B CERTIFICATE FOR DISCLOSED INFORMATION (REQUIREMENT 11(1))**

We, Raymond Stuart Polson and Stuart James McLauchlan, directors of Aurora Energy Ltd, certify that, having made all reasonable enquiry, to the best of our knowledge, the following attached audited information of Aurora Energy Ltd prepared for the purposes of requirement 3, 4, 6 and 7(5) of the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008 complies with those Requirements -

- (i) Report FS1: Regulatory Profit Statement;
- (ii) Report FS2: Regulatory Asset and Financing Report;
- (iii) Report FS3: Regulatory Tax Allowance Report;
- (iv) Report AV1: Annual Regulatory Valuation Roll-Forward Report
- (v) Report AV2: Valuation Disclosure by Asset Class (for System Fixed Assets);
- (vi) Report AV3: System Fixed Assets Replacement Cost Roll-Forward Report;
- (vii) Report AV4: Merger or Acquisition Regulatory Asset Base Disclosure;
- (viii) Report MP1: Network Information Report;
- (ix) Report MP2: Performance Measures Report;
- (x) Report MP3: Price and Quality Report;
- (xi) Report AM1: Expenditure Forecasts and Reconciliation.



Raymond Stuart Polson



Stuart James McLauchlan

27 July 2011

# C DISCLOSURE OF INFORMATION REQUIRED IN FINANCIAL STATEMENTS (REQUIREMENT 3(1))

## REPORT FS1: REGULATORY PROFIT STATEMENT

ref		Electricity Distribution Business: <b>Aurora Energy Limited</b>	For Year Ended <b>2011</b>	
5				
6	<b>Income</b>			
7				
8				
9	Net Line Charge Revenue Received	72,117		
10	plus Discretionary Discounts and Customer Rebates	-		FS1a
11	<b>Gross Line Charge Income</b>		72,117	
12				
13	Capital Contributions	4,620		
14	plus Net Value of Vested Assets	-		
15	<b>Total Capital Contributions and Vested Assets</b>		4,620	
16				
17	AC Loss Rental Rebates Received	1,486		
18	less AC Loss Rental Rebates Passed On	1,486		
19	<b>Net AC loss rental income (deficit)</b>		-	
20				
21				
22	<b>Other Income</b>	698		
23			698	
24				
25	<b>Total regulatory income</b>		77,435	
26				
27				
28	<b>Expenses</b>			
29				
30	Transmission Charges - Payments to Transpower	18,297		
31	plus Avoided Transmission Charges - payments to parties other than Transpower	1,250		
32	<b>Total Transmission Costs</b>		19,547	
33				
34	<b>Operational Expenditure:</b>			
35	General Management, Administration and Overheads	4,453		
36	System Management and Operations	4,907		
37	Routine and Preventative Maintenance	3,194		to AM1
38	Refurbishment and Renewal Maintenance	1,103		to AM1
39	Fault and Emergency Maintenance	4,155		to AM1
40	Pass-through Costs	862		
41	Other	331		
42	<b>Total Operational Expenditure</b>		19,005	to MP2
43				
44				
45	<b>Operational earnings</b>		38,883	
46				
47				
48	Regulatory Depreciation of System Fixed Assets (incl. value of assets decommissioned)	8,545		from AV1
49	plus Depreciation of Non-System Fixed Assets (incl. value of assets decommissioned)	-		from AV1
50	<b>Total Regulatory Depreciation</b>		8,545	to FS3
51				
52				
53	<b>Earnings before interest and tax (EBIT)</b>		30,338	to FS3
54				
55	less Regulatory Tax Allowance		3,626	from FS3
56				
57	plus Indexed Revaluation (of System Fixed Assets)		13,233	from AV1
58	plus Revaluations of Non-System Fixed Assets		-	from AV1
59				
60	<b>Regulatory profit / loss (pre-financing and distributions)</b>		39,945	to MP2

## REPORT FS1: REGULATORY PROFIT STATEMENT (cont)

### Notes to Regulatory Profit Statement

69	<b>FS1a: Discretionary Discounts: Customer Rebates and other line charge adjustments</b>		<b>(\$000)</b>
70	Customer Rebates		
71	Line Charge Holidays and other Discretionary Discounts		
72	<b>Total Discretionary Discounts and Customer Rebates</b>		<b>-</b>

75	<b>FS1b: Related party expenditure - summary</b>		<b>(\$000)</b>
76	Avoided Transmission Charges		
77	Operational Expenditure	15,967	
78	Subvention Payment	331	
79	Other related party expenditure		
80	<b>Total Related Party Expenditure</b>		<b>16,298</b>
81	<i>N.B.: The additional Related Party information that is required to be disclosed in accordance with</i>		
82	<i>Section 3 of the Information Disclosure Handbook is to be disclosed by way of a separate note to this</i>		
83	<i>Schedule and forms part of this Schedule.</i>		
84			

87	<b>FS1c: Operational Expenditure notes</b>		<b>(\$000)</b>
88			
89	<b>Merger and Acquisition Expenses</b>		
90	Merger and Acquisition Expenses (not to be included in Operational Expenditure)	-	
91			
92	<b>Material items (if greater than 10% of the Operational Expenditure line item)</b>		
93	Material item amount 1		<i>Notes to be provided separately</i>
94	within expenditure category:	Select one	
95			
96	Material item amount 2		<i>Notes to be provided separately</i>
97	within expenditure category:	Select one	
98			
99	Material item amount 3		<i>Notes to be provided separately</i>
100	within expenditure category:	Select one	
101			
102	<i>(further disclosures to be provided on separate page if required)</i>		
103			

106	<b>FS1d: Vested Assets</b>		<b>(\$000)</b>
107	Consideration Paid for Vested Assets		-

110	<b>FS1e: Reclassified items in Operational Expenditure</b>		<b>(\$000)</b>
111	Value of items which have been reclassified since previous disclosure (if greater than 10% of any affected line item)		
112	Previous classification:	Select one	
113	New classification:	Select one	
114			
115			<b>(\$000)</b>
116	Value of items which have been reclassified since previous disclosure (if greater than 10% of any affected line item)		
117	Previous classification:	Select one	
118	New classification:	Select one	
119			
120			<b>(\$000)</b>
121	Value of items which have been reclassified since previous disclosure (if greater than 10% of any affected line item)		
122	Previous classification:	Select one	
123	New classification:	Select one	
124			
	<i>to be repeated as required for multiple reclassifications</i>		

## REPORT FS2: REGULATORY ASSET AND FINANCING STATEMENT

ref	Electricity Distribution Business:	Aurora Energy Limited	
5		For Year Ended	2011
6			
7	<b>Capital Expenditure on System Fixed Assets (by primary purpose)</b>	<b>(\$000)</b>	
8	Customer Connection	5,776	to AM1
9	System Growth	5,996	to AM1
10	Reliability, Safety and Environment	2,041	to AM1
11	Asset Replacement and Renewal	7,055	to AM1
12	Asset Relocations	1,426	to AM1
13	<b>Total Capital Expenditure on System Fixed Assets</b>	<b>22,294</b>	to AM1
14			
15			
16	<b>Capital Expenditure on Non-System Fixed Assets</b>	<b>-</b>	from AV1
17			
18			
19	<b>Capital works roll-forward (for System Fixed Assets)</b>		
20	Works Under Construction at Beginning of Year	8,369	
21	plus Total Capital Expenditure on System Fixed Assets	22,294	
22	less Assets Commissioned in Year	21,234	from AV1
23	<b>Works under construction at year end</b>	<b>9,429</b>	
24			
25			
26	<b>Regulatory Investment Value calculation</b>		
27	System Fixed Assets: regulatory value at end of Previous Year	296,258	from AV1
28	Non-System Fixed Assets: regulatory value at end of Previous Year	-	from AV1
29	Finance During Construction Allowance (on System Fixed assets)	7,258	2.45%
30	<b>Total Regulatory Asset Base value at beginning of Current Financial Year</b>	<b>303,517</b>	
31			
32	plus System Fixed Assets Commissioned in Year	21,234	from AV1
33	System Fixed Assets Acquired From (Sold to) a Non-EDB in Year	-	from AV1
34	Non-System Fixed Assets: Asset Additions	-	from AV1
35	Regulatory Asset Base investment in Current Financial Year - total	21,234	
36	<b>Regulatory Asset Base investment in Current Financial Year - average</b>	<b>10,617</b>	
37			
38	plus (minus) where a merger or acquisition has taken place within the year		
39	<b>Adjustment for merger, acquisition or sale to another EDB</b>	<b>-</b>	from AV4
40			
41	<b>Regulatory Investment Value</b>	<b>314,134</b>	to MP2

## REPORT FS3: REGULATORY TAX ALLOWANCE CALCULATION

ref		Electricity Distribution Business:	Aurora Energy
5		For Year Ended	2011
6			
7			(\$000)
8			30,338 from FS1
9			
10	add	Total Regulatory Depreciation	8,545 from FS1
11		Other Permanent Differences - not deductible	
12		Other Temporary Adjustments - Current Period	418
13			8,963
15	less	Non Taxable Capital Contributions and Vested Assets	4,620
16		Tax Depreciation	14,314
17		Deductible Discretionary Discounts and Customer Rebates	
18		Deductible Interest	8,281 from row 53
19		Other Permanent Differences - Non Taxable	
20		Other Temporary Adjustments - Prior Period	
21			27,215
22			
23		Regulatory taxable income for Year	12,086
24			
25	less	Tax Losses Available at Start of Year	
26		Net taxable income	12,086
27			
28		Statutory Tax Rate	30%
29		Regulatory Tax Allowance	3,626 to FS1

## Notes to Regulatory Tax Allowance Calculation

36	<b>FS3a: Description of adjustments classified as "other"</b>
37	
38	The Electricity Distribution Business is to provide descriptions of items recorded in the four "other" categories above (explanatory
39	notes can be provided in a separate note if necessary).
40	
41	
42	
43	
44	
45	

48	FS3b: Financing assumptions (for Deductible Interest and Interest Tax Shield calculation)				
49					
50	Standard Debt Leverage Assumption (debt/total assets)	40%	%		
51					
52	Standard Cost of Debt Assumption	6.59%	%		
53					
54	Deductible Interest	8,281	\$000	to row 18	
55					
56	Interest Tax Shield Adjustment	2,484	\$000	to MP2	

## **STATEMENT OF ACCOUNTING POLICIES**

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### **Special Purpose Financial Statements**

These financial statements have been prepared in accordance with the requirements of the Electricity Distribution (Information Disclosure) Requirements 2008 and relates to the Line Business of Aurora Energy Limited which includes the conveyance of electricity, ownership of works for conveyance of electricity and provision of line function services.

### **Specific Accounting Policies**

The methodology adopted to allocate costs, revenues, assets and liabilities to the Lines Businesses is in accordance with the Requirements and/or the Electricity Information Disclosure Handbook.

The particular accounting policies adopted in the preparation of these financial statements are:

(a) **Revenue**

Revenue shown in the Regulatory Profit Statement (report FS1) relates to the Line Business.

(b) **Expenditure**

Expenditure shown in the Regulatory Profit Statement is derived as follows:

- Transmission charges, employee remuneration, administration and operating expenses are directly attributable to the Line Business.
- Maintenance and operation is provided in accordance with a 10 year Asset Management Services Contract with *DELTA* Utility Services Ltd.
- Other costs are allocated in accordance with the avoidable cost allocation methodology.

(c) **Distinction Between Capital and Revenue Expenditure**

Capital expenditure is defined as all expenditure on the creation of a new asset, and any expenditure which results in a significant improvement to the original function of an existing asset. Revenue expenditure is defined as expenditure which maintains an asset in working condition and expenditure incurred operating the Company.

(d) **Changes in Accounting Policies**

There have been no changes in accounting policies. All policies have been applied on bases consistent with those used in previous years.



**Note 1 : Disclosure of Information Relating to Transactions Between Persons in a Prescribed Business Relationship and Related Parties**

	2011 \$000	2010 \$000
<b>During the Year the Line Business:</b>		
<b>Purchased the following services from DELTA Utility Services Ltd:</b>		
Asset maintenance	8,452	9,091
Network management, operation and other	7,515	7,315
Consumer reconnections and disconnections	-	-
	<hr/>	<hr/>
Total	15,967	16,406
 Network capital work and development		
distribution substations	888	793
low voltage reticulation	2,209	2,049
distribution lines and cables	2,694	3,457
distribution transformers	1,322	1,781
zone substations	3,485	2,402
other plant and equipment	4	6
sub-transmission reticulation	2,971	1,406
	<hr/>	<hr/>
Total	13,573	11,894

Network operation and maintenance is charged in accordance with a Fixed Term Contract which was renewed for a 10 year period on 1 July 2007. Capital work is subject to open tender, established market rates, or competitive pricing.

At balance date, \$4,652,219 was owed to DELTA Utility Services Ltd (2010: \$3,681,128). Of this, \$3,309,976 was due and payable in April, while \$1,342,243 relating to capital work-in-progress was payable at a later date.

**Other Line Business Related Parties:**

The Lines Business has a borrowing facility with Dunedin City Treasury Ltd. During the year it paid \$8.049 million interest (2010: \$7.625 million) and as at 31 March 2011, \$119.80 million of loan monies were outstanding (2010: \$106.630 million).

During the year, the Lines Business also undertook the following transactions with Dunedin City Holdings Ltd:

Purchase of subvention expense	\$ 0.331 million (2010: \$1.58 million)
Dividends paid	\$13.985 million (2010: \$10.40 million)

As at 31 March 2011, no subvention monies were outstanding (2010: \$1.181 million).

No related party transactions took place at a nominal or nil value. No related party debts have been written-off or forgiven during the period.

During the year, the Lines Business also undertook the following transactions with Dunedin City Council:

Rates paid	\$ 0.403 million (2010: \$0.338 million)
Undergrounding of street lights	\$ nil (2010: \$0.119 million)

## D DISCLOSURE RELATING TO ASSET VALUATIONS (REQUIREMENT 4(1))

### REPORT AV1: ANNUAL REGULATORY VALUATION ROLL-FORWARD REPORT

ref	Electricity Distribution Business:						Aurora Energy Limited	
5	For Year Ended:						2011	
6	Year of most recent ODV						2004	
7								
8								
9								(\$000)
10		ODV Year	ODV Year	ODV Year	ODV Year	ODV Year	ODV Year	
11		+ 1	+ 2	+ 3	+ 4	+ 5	+ 6	+ 7
12	For Year Ending:	2005	2006	2007	2008	2009	2010	2011
13	<b>System Fixed Assets</b>							
14	Regulatory Value at End of Previous Year*	193,833	210,575	221,825	238,932	259,761	277,953	296,258
15	plus							
16	Assets Commissioned	12,560	13,720	17,945	16,683	18,139	20,804	21,234
17	Gross Value of Vested Assets							
18	Assets Acquired from (Sold to) a Non-EDB							
19	Asset Additions	12,560	13,720	17,945	16,683	18,139	20,804	21,234
20	plus							
21	Indexed Revaluation	5,222	7,071	5,630	8,043	7,713	5,688	13,233
22	less							
23	Depreciation of System Fixed Assets	5,915	6,241	6,444	6,819	7,295	7,735	8,106
24	Regulatory Value of Assets Decommissioned		141	24	419	365	452	439
25	Regulatory Depreciation (incl. value of assets decommissioned)	5,915	6,382	6,468	7,238	7,660	8,187	8,545
26	plus (minus)							
27	Acquisition of System Fixed Assets from another EDB	-	-	-	-	-	-	-
28	less Sale of System Fixed Assets to another EDB	-	-	-	-	-	-	-
29	Net Acquisitions (Sales) of System Fixed Assets from (to) an EDB	-	-	-	-	-	-	-
30	plus (minus)							
31	Net Increase (Decrease) Due to Changes in Asset Register Information	4,875	(3,159)		3,341			
32								
33	Regulatory Value of System Fixed Assets at Year End	210,575	221,825	238,932	259,761	277,953	296,258	322,180
34								
35	<b>Non-System Fixed Assets</b>							
36	Regulatory value at end of previous year	3	3	2	2	1	1	-
37	plus							
38	Asset Additions							
39	Revaluations							
40	less Depreciation (incl. value of assets decommissioned)	1	1	1	1	1	1	
41	plus Net Acquisitions (Sales) of Non-System Fixed Assets from (to) an EDB	-	-	-	-	-	-	-
42	Regulatory Value of Non-System Fixed Assets at Year end	3	2	2	1	1	-	-
43								
44								
45	Total Regulatory Asset Base Value (excluding FDC)	210,577	221,827	238,933	259,762	277,954	296,258	322,180
46								
47								
48	* The commencing figure for completing this schedule is the most recent ODV value							
49	Note: Additional columns to be added if required							

### Notes to Annual Regulatory Valuation Roll-forward Report

57

58

59

60

61

62

63

64

65

AV1a: Calculation of Revaluation Rate and Indexed Revaluation of System Fixed Assets

CPI as at date of ODV

928

For Year Ended

2005

2006

2007

2008

2009

2010

2011

CPI at CPI reference date

953

985

1010

1044

1075

1097

1146

Revaluation Rate

2.69%

3.36%

2.54%

3.37%

2.97%

2.05%

4.47%

System Fixed Assets: Regulatory Value at End of Previous Year

193,833

210,575

221,825

238,932

259,761

277,953

296,258

Indexed Revaluation of System Fixed Assets

5,222

7,071

5,630

8,043

7,713

5,688

13,233

to FS1, AV1

68

69

70

71

72

AV1b: Input for prior year Acquisitions (Sales) of Assets to (from) another ELB

(\$000)

For Year Ended

2005

2006

2007

2008

2009

2010

2011

Acquisition of System Fixed Assets from another EDB

Sale of System Fixed Assets to another EDB

Net Acquisitions (Sales) of Non-System Fixed Assets from (to) an EDB

**REPORT AV2: REGULATORY VALUATION DISCLOSURE BY ASSET CLASS**  
(for System Fixed Assets)

Electricity Distribution Business: Aurora Energy

For Year Ended: 2011

Subtotals by Asset Class (for System Fixed Assets)

	Subtransmission	Zone Substations	Distribution & LV Lines	Distribution & LV Cables	Distribution Substations and Transformers	Distribution Switchgear	Other System Fixed Assets	Total for System Fixed Assets (per AV1)	
System Fixed Assets									
Regulatory Value of System Fixed Assets (as per most recent ODV)	15,562	28,643	40,514	64,018	29,988	14,042	1,066	193,833	from AV1
Cumulative roll-forward since most recent ODV:									
Asset Additions								121,085	from AV1
Indexed Revaluation (of System Fixed Assets)								52,600	from AV1
less Regulatory Depreciation (of System Fixed Assets)								50,395	from AV1
Net Acquisitions (Sales) of System Fixed Assets from (to) an EDB								-	from AV1
Net Increase (Decrease) Due to Changes in Asset Register Information								5,057	from AV1
Regulatory Value of System Fixed Assets at Year End								322,180	from AV1

## REPORT AV3: SYSTEM FIXED ASSETS REPLACEMENT COST ROLL-FORWARD REPORT

ref	Electricity Distribution Business:	Aurora Energy Limited
5	For Year Ended:	2011
6	<b>System Fixed Assets - Replacement Cost</b>	
7		(\$000)
8	Replacement cost at end of previous year	585,472
9		
10	Asset Additions	21,234 AV3a
11	Indexed Revaluation (of System Fixed Assets)	26,151
12	less Replacement Cost of Assets Decommissioned	4,805
13	Net Acquisitions (Sales) of System Fixed Assets from (to) an EDB	- from AV4
14	Net Increase (Decrease) Due to Changes in Asset Register Information	-
15	<b>Replacement cost of System Fixed Assets at year end</b>	<b>628,052</b>
16		
17		
18	<b>System Fixed Assets - Depreciated Replacement Cost</b>	
19		
20	Depreciated Replacement Cost at end of previous year	301,096
21		
22	Asset Additions	21,234 AV3a
23	Indexed Revaluation (of System Fixed Assets)	13,449
24	less Depreciation of Replacement Cost	8,106
25	less Depreciated Replacement Cost of Assets Decommissioned	439
26	Net Acquisitions (Sales) of System Fixed Assets from (to) an EDB	- from AV4
27	Net Increase (Decrease) Due to Changes in Asset Register Information	-
28	<b>Depreciated replacement cost of System Fixed Assets at year end</b>	<b>327,234</b>

## REPORT AV3: SYSTEM FIXED ASSETS REPLACEMENT COST ROLL-FORWARD REPORT (con

### Notes to Price and Quality Measures

36	<b>AV3a: New Asset Additions</b>	
37		
38	Asset Additions - Depreciated Replacement Cost	21,234 from AV1
39	plus Difference in Replacement Cost and Depreciated Replacement Cost values of Asset Additions	
40		
41	<b>Asset Additions - Replacement Cost</b>	<b>21,234</b>
42		

REPORT AV4: BUSINESS MERGER, ACQUISITION OR SALE - REGULATORY ASSET BASE DISCLOSURE

Electricity Distribution Business: Aurora Energy Limited

Disclosure required? (YES or NIL DISCLOSURE): NO DISCLOSURE REQUIRED

As at (date):  
Proportion of year following transfer of assets 0%

PART 1: Most recent ODV valuation of System Fixed Assets transferred

(\$000)

	Subtransmission	Zone substations	Distribution & LV Lines	Distribution & LV Cables	Distribution substations and transformers	Distribution switchgear	Other System Fixed Assets	Total for System Fixed Assets
Replacement Cost (RC)								-
less Depreciation								-
Depreciated Replacement Cost (DRC)	-	-	-	-	-	-	-	-
less Optimisation adjustment								-
Optimised Depreciated Replacement Cost (ODRC)	-	-	-	-	-	-	-	-
less Economic Value Adjustment (EVA)								-
Most recent ODV value	-	-	-	-	-	-	-	-

PART 2: Valuation disclosure for transferred assets by Asset Class (at transfer date)

(\$000)

	Total for System Fixed Assets	Non-System Fixed Assets	Total RAB value (excl. FDC)
Regulatory Value of System Fixed Assets (as per most recent ODV)	-		
Cumulative roll-forward since most recent ODV:			
Asset Additions			
Indexed Revaluation (of System Fixed Assets)			
less Regulatory Depreciation (of System Fixed Assets)			
Net Acquisitions (Sales) of System Fixed Assets from (to) an EDB			
Net Increase (Decrease) due to Changes in Asset Register Information			
RAB Value of Transferred Assets at Transfer Date	-		-
Acquisition of Assets from Another EDB	-	-	to AV1
Sale of Assets to Another EDB	-	-	to AV1
RAB Value of Transferred Assets at Transfer Date	-		
"p" factor (proportion of year following transfer of assets)	0%		
Adjustment for merger, acquisition or sale to another EDB		-	to FS2

PART 3: Rolled-forward Replacement Cost values for System Fixed Assets transferred

(\$000)

	RC & DRC values of System Fixed Assets at transfer date	RAB value of acquired/(sold) assets	
Net Acquisitions (Sales) of System Fixed Assets from (to) an EDB - RC		-	to AV3
Net Acquisitions (Sales) of System Fixed Assets from (to) an EDB - DRC		-	to AV3

Signed by: Selling Entity

Acquiring Entity

# **E DISCLOSURE RELATING TO FINANCIAL AND EFFICIENCY PERFORMANCE MEASURES (REQUIREMENT 6(1) - TOTAL BUSINESS)**

## **REPORT MP1: NETWORK INFORMATION**

(Separate report required for each Non-Contiguous Network)

ref	Electricity Distribution Business:	Aurora Energy Limited
6		For Year Ended: 2011
7	Network Name:	Total Business (enter "Total Business" or name of network)
9	Disclosure:	Annual Disclosure - Requirement 6(1)
10	<b>Circuit Length by Operating Line Voltage (at year end)</b>	
11		Overhead (km) Underground (km) Total (km)
12	> 66kV	- - -
13	50kV & 66kV	108 1 110
14	33kV	405 94 498
15	SWER (all SWER voltages)	9 - 9
16	22kV (other than SWER)	- - -
17	6.6kV to 11kV (inclusive - other than SWER)	2,332 852 3,185
18	Low Voltage (< 1kV)	1,037 783 1,820
19	<b>Total circuit length (for Supply)</b>	<b>3,891 1,730 5,621</b> to MP2
20		
21	<b>Dedicated Street Lighting Circuit Length</b>	48 157 205
22		
23	<b>Overhead Circuit Length by Terrain (at year end)</b>	(km) (%)
24	Urban (only)	1,097 28%
25	Rural (only)	2,664 68%
26	Remote (only)	- 0%
27	Rugged (only)	- 0%
28	Rural & rugged (only)	131 3%
29	Remote & rugged (only)	- 0%
30	Unallocated overhead lines	- 0%
31	<b>Total overhead length</b>	<b>3,891 100%</b>
32		
33		
34	<b>Transformer capacity (at year end)</b>	
35	Distribution Transformer Capacity (EDB Owned)	815 MVA Previous Year 804
36	Distribution Transformer Capacity (Non-EDB Owned, Estimated)	62 MVA 64
37	<b>Total Distribution Transformer Capacity</b>	877 MVA (to MP2) 868
38		
39	Zone Substation Transformer Capacity	856 MVA 831
40		
41	<b>System Fixed Assets age (at year end)</b>	
42	Average Age of System Fixed Assets	24 Years
43	Average Expected Total Life of System Fixed Assets	51 Years
44	Average Age as a Proportion of Average Expected Total Life	47% %
45		
46	Estimated Proportion of Assets (by Replacement Cost) within 10 years of Total Life	25% %
47		
48		
49		
50	<b>Electricity demand</b>	Maximum coincident system demand (MW) Non-coincident Sum of maximum demands (MW)
51		
52	<b>GXP Demand</b>	233 266
53	plus Embedded Generation Output at HV and Above	41
54	<b>Maximum System Demand</b>	274
55	less Net Transfers to (from) Other EDBs at HV and Above	0
56	<b>Demand on system for supply to customers' Connection Points</b>	274
57	less Subtransmission Customers' Connection Point Demand	- 0
58	<b>Maximum Distribution Transformer Demand</b>	274 to MP2
59		
60	GXP Demand not Supplied at Subtransmission Level	-
61	Embedded Generation Output - Connected to Subtransmission System	41 55
62	Net Transfers to (from) Other EDBs at Subtransmission Level Only	- -
63		
64	<b>Estimated Controlled Load Shed at Time of Maximum System Demand (MW)</b>	10
65		
66	<b>Five-Year System Maximum Demand Growth Forecast</b>	1.1 % p.a.
67		
68		
69	<b>Electricity volumes carried</b>	(GWh)
70	Electricity Supplied from GXPs	1,113
71	less Electricity Exports to GXPs	20
72	plus Electricity Supplied from Embedded Generators	227
73	less Net Electricity Supplied to (from) Other EDBs	- 0
74	<b>Electricity entering system for supply to customers' Connection Points</b>	1,320
75	less Electricity Supplied to Customers' Connection Points	1,238 to MP2
76	<b>Electricity Losses (loss ratio)</b>	82 6.2% %
77		
78	Electricity Supplied to Customers' Connection Points	1,238
79	less Electricity Supplied to Largest 5 Connection Points	54
80	<b>Electricity supplied other than to Largest 5 Connection Points</b>	1,184 96% %
81		
82	<b>Load Factor</b>	55% %
83		
84	<b>Number of Connection Points (at year end)</b>	82,368 ICPs to MP2
85		
86	<b>Intensity of service requirements</b>	
87	Demand Density (Maximum Distribution Transformer Demand / Total circuit length)	49 kW/km
88	Volume Density (Electricity Supplied to Customers' Connection Points / Total circuit length)	220 MWh/km
89	Connection Point Density (ICPs / Total circuit length)	15 ICP/km
90	Energy Intensity (Electricity Supplied to Customers' Connection Points / ICP)	15,034 kWh/ICP

## REPORT MP2: PERFORMANCE MEASURES

ref	Electricity Distribution Business: <b>Aurora Energy Limited</b>				
5	For Year Ended: <b>2011</b>				
6	<b>Performance comparators</b>				
7	<b>Previous Years:</b>				<b>Current Financial Year</b>
8		<b>Current Yr - 3</b>	<b>Current Yr - 2</b>	<b>Current Yr - 1</b>	
9	<b>Operational expenditure ratio</b>				
10	Total Operational Expenditure	18	20	20	19 \$m from FS1
11	Replacement Cost of System Fixed Assets (at year end*)	522	555	585	628 \$m from AV3
12	Ratio (%)	3.48%	3.57%	3.42%	3.03%
13	<b>Capital expenditure ratio</b>				
15	Total Capital Expenditure on System Fixed Assets	18	19	22	22 \$m from FS2
16	Replacement Cost of System Fixed Assets (at year end*)	522	555	585	628 \$m from AV3
17	Ratio (%)	3.47%	3.34%	3.71%	3.55%
18	<b>Capital expenditure growth ratio</b>				
20	Capital Expenditure: Customer Connection and System Growth			17	12 \$m from FS2
21	Change in Total Distribution Transformer Capacity	10	21	8	9 MVA from MP1
22	\$/kVA	-	-	2,211	1,300 \$/kVA
23	<b>Renewal expenditure ratio</b>				
25	Capital & Operational Expenditure: Asset Replacement, Refurbishment and Renewal			4	8 \$m from FS1 & 2
26	Regulatory Depreciation of System Fixed Assets	7	8	8	9 \$m from AV1
27	Ratio (%)	0%	0%	43%	95%
28	<b>Distribution Transformer Capacity Utilisation</b>				
30	Maximum Distribution Transformer Demand	283	275	284	274 MW from MP1
31	Total Distribution Transformer Capacity (at year end*)	840	860	868	877 kVA from MP1
32	Ratio (%)	33.7%	31.9%	32.8%	31.2%
33	<b>Return on Investment</b>				
35	Regulatory Profit / Loss (pre-financing and distributions)	34	34	31	40 \$m from FS1
36	less Interest Tax Shield Adjustment	3	3	2	2 \$m from FS3
37	Adjusted Regulatory Profit	31	32	29	37 \$m
38	Regulatory Investment Value	253	275	295	314 \$m from FS2
39	Ratio (%)	12.40%	11.49%	9.70%	11.93%
40	* If a Merger or Asset Transfer with another EDB was entered into during the year, the denominators are calculated as time-weighted averages.				
41	<b>Expenditure comparison table</b>				
42	<b>Expenditure metrics (\$ per):</b>				
43		<b>Electricity Supplied to Customers' Connection Points (\$/MWh)</b>	<b>Maximum coincident system demand (\$/MW)</b>	<b>Connection Point (\$/ICP)</b>	<b>Distribution Transformer Capacity (EDB-Owned) (\$/MVA)</b>
44		<b>Total circuit length (for Supply) (\$/km)</b>			
45	Capital Expenditure (\$) per	3,966	18	81,340	27,364 from FS2 & MP1
46	Operational Expenditure (\$) per	3,381	15	69,340	23,327 from FS1 & MP1

# REPORT MP3: PRICE & QUALITY MEASURES

(Separate report required for each Non-contiguous Network)

ref

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Electricity Distribution Business:

Aurora Energy Limited

For Year Ended:

2011

Network Name:

Total Business

Disclosure:

Annual Disclosure - Requirement 6(1)

QUALITY

Interruptions

Interruptions by class

Class A	-	planned interruptions by Transpower:
Class B	368	planned interruptions on the network
Class C	490	unplanned interruptions on the network
Class D	-	unplanned interruptions by Transpower
Class E	-	unplanned interruptions of network owned generation
Class F	-	unplanned interruptions of generation (non-network)
Class G	-	unplanned interruptions caused by other electricity industry participant
Class H	-	planned interruptions caused by other electricity industry participant
Total	858	Total of above

Interruption targets for Forecast Year

Class B	2012	Current Financial Year +1
Class C	390	planned interruptions on the network
	470	unplanned interruptions on the network

Average interruption targets for 5 Forecast Years

Class B	2012-2016	Current Financial Year +1 to +5
Class C	385	planned interruptions on the network
	465	unplanned interruptions on the network

Class C interruptions restored within

≤3Hrs	>3hrs
387	103

Faults

Faults per 100 circuit kilometres

The total number of faults for Current Financial Year	10.60	in year	2011
The total number of faults forecast for the Forecast Year	10.60	in year	2012
The average annual number of faults forecast for the 5 Forecast Years	10.50	average over years	2012-2016

Fault Information per 100 circuit kilometres by Voltage and Type

	6.6kV & 11kV non-SWER	22kV non-SWER	SWER	33kV	50kV & 66kV	>66kV
Is this voltage part of the EDB system?	Yes	No	Yes	Yes	Yes	No
Current Financial Year	11.75		11.36	4.70	2.70	
Forecast Year	11.40		11.40	6.50	6.00	
Average annual for 5 Forecast Years	11.30		11.30	6.40	5.90	

Fault Information per 100 circuit kilometres by Voltage and Type

	6.6kV & 11kV non-SWER	22kV non-SWER	SWER	33kV	50kV & 66kV	>66kV
Underground	2.02		NA	1.10	-	
Overhead	15.25		11.36	5.60	2.80	

Reliability

Overall reliability

Based on the total number of interruptions	SAIDI	SAIFI	CAIDI
	111.54	1.48	75.50

Reliability by interruption class

Class B	SAIDI	SAIFI	CAIDI
Class C	16.92	0.12	144.50
	94.62	1.36	69.50

Targets for Forecast Year

Class B	SAIDI	SAIFI	CAIDI
Class C	15.00	0.13	120.00
	71.00	1.29	55.00

Average targets for 5 Forecast Years

Class B	SAIDI	SAIFI	CAIDI
Class C	13.80	0.12	120.00
	69.20	1.25	55.20

PRICES

Price information by Connection Point Class

Connection Point Class

	Small Connection Points	Medium Connection Points	Large Connection Points	Largest 5 Connection Points	Total
Gross line charge income (\$000)	44,422	11,030	15,353	1,311	72,117
Electricity Supplied to Customers' Connection Points (MWh)	618,935	176,500	388,361	54,493	1,238,288
Number of Connection Points (ICPs) at year end	73,656	5,010	3,697	5	82,368
Unit Price (cents/kWh)	7.2	6.2	4.0	2.4	5.8
Relative Unit Price Index	1.00	0.87	0.55	0.34	0.81

from FS1

from MP1

from MP1

## REPORT MP3: PRICE AND QUALITY (cont)

### Notes to Price and Quality Measures

#### MP3a: Connection Point Class breakpoints

Connection Point Class breakpoints methodology kVA based breakpoints

#### kVA based breakpoints - additional disclosure

Breakpoint between small and medium classes 16 kVA

Breakpoint between large and medium classes 70 kVA



# F DISCLOSURE RELATING TO FINANCIAL AND EFFICIENCY PERFORMANCE MEASURES (REQUIREMENT 6(1) - DUNEDIN)

## REPORT MP1: NETWORK INFORMATION

(Separate report required for each Non-Contiguous Network)

ref	Electricity Distribution Business:	Aurora Energy Limited
6	For Year Ended:	2011
7	Network Name:	Dunedin
8	Disclosure:	Annual Disclosure - Requirement 6(1)
9		
10	<b>Circuit Length by Operating Line Voltage (at year end)</b>	
11		
12	> 66kV	-
13	50kV & 66kV	-
14	33kV	144
15	SWER (all SWER voltages)	9
16	22kV (other than SWER)	-
17	6.6kV to 11kV (inclusive - other than SWER)	736
18	Low Voltage (< 1kV)	805
19	<b>Total circuit length (for Supply)</b>	<b>1,694</b>
20		
21	<b>Dedicated Street Lighting Circuit Length</b>	<b>46</b>
22		
23	<b>Overhead Circuit Length by Terrain (at year end)</b>	
24		
25	Urban (only)	887
26	Rural (only)	806
27	Remote (only)	0%
28	Rugged (only)	0%
29	Rural & rugged (only)	0%
30	Remote & rugged (only)	0%
31	Unallocated overhead lines	0%
32	<b>Total overhead length</b>	<b>1,694</b>
33		
34	<b>Transformer capacity (at year end)</b>	
35	Distribution Transformer Capacity (EDB Owned)	474 MVA
36	Distribution Transformer Capacity (Non-EDB Owned, Estimated)	45 MVA
37	<b>Total Distribution Transformer Capacity</b>	<b>519 MVA (to MP2)</b>
38		
39	Zone Substation Transformer Capacity	592 MVA
40		
41	<b>System Fixed Assets age (at year end)</b>	
42	Average Age of System Fixed Assets	32 Years
43	Average Expected Total Life of System Fixed Assets	53 Years
44	Average Age as a Proportion of Average Expected Total Life	60% %
45		
46	Estimated Proportion of Assets (by Replacement Cost) within 10 years of Total Life	35% %
47		
48		
49		
50		
51	<b>Electricity demand</b>	
52		
53	GXP Demand	160
54	plus Embedded Generation Output at HV and Above	32
55	<b>Maximum System Demand</b>	<b>192</b>
56	less Net Transfers to (from) Other EDBs at HV and Above	-
57	<b>Demand on system for supply to customers' Connection Points</b>	<b>192</b>
58	less Subtransmission Customers' Connection Point Demand	-
59	<b>Maximum Distribution Transformer Demand</b>	<b>192</b>
60		
61	GXP Demand not Supplied at Subtransmission Level	-
62	Embedded Generation Output - Connected to Subtransmission System	32
63	Net Transfers to (from) Other EDBs at Subtransmission Level Only	-
64		
65	<b>Estimated Controlled Load Shed at Time of Maximum System Demand (MW)</b>	<b>-</b>
66		
67	<b>Five-Year System Maximum Demand Growth Forecast</b>	<b>0.7 % p.a.</b>
68		
69	<b>Electricity volumes carried</b>	
70		
71	Electricity Supplied from GXPs	790
72	less Electricity Exports to GXPs	0
73	plus Electricity Supplied from Embedded Generators	96
74	less Net Electricity Supplied to (from) Other EDBs	-
75	<b>Electricity entering system for supply to customers' Connection Points</b>	<b>886</b>
76	less Electricity Supplied to Customers' Connection Points	833
77	<b>Electricity Losses (loss ratio)</b>	<b>53 6.0% %</b>
78		
79	Electricity Supplied to Customers' Connection Points	833
80	less Electricity Supplied to Largest 5 Connection Points	54
81	<b>Electricity supplied other than to Largest 5 Connection Points</b>	<b>779 93% %</b>
82		
83	<b>Load Factor</b>	<b>53% %</b>
84		
85	<b>Number of Connection Points (at year end)</b>	<b>53,621 ICPs</b>
86		
87	<b>Intensity of service requirements</b>	
88	Demand Density (Maximum Distribution Transformer Demand / Total circuit length)	84 kW/km
89	Volume Density (Electricity Supplied to Customers' Connection Points / Total circuit length)	364 MWh/km
90	Connection Point Density (ICPs / Total circuit length)	23 ICP/km
91	Energy Intensity (Electricity Supplied to Customers' Connection Points / ICP)	15,537 kWh/ICP

# REPORT MP3: PRICE & QUALITY MEASURES

(Separate report required for each Non-contiguous Network)

ref

Electricity Distribution Business:

Aurora Energy Limited

For Year Ended:

2011

6

Network Name:

Dunedin

7

Disclosure:

Annual Disclosure - Requirement 6(1)

9

QUALITY

11

Interruptions

12

Interruptions by class

13

Class A

-

planned interruptions by Transpower:

14

Class B

7

planned interruptions on the network

15

Class C

175

unplanned interruptions on the network

16

Class D

-

unplanned interruptions by Transpower

17

Class E

-

unplanned interruptions of network owned generation

18

Class F

-

unplanned interruptions of generation (non-network)

19

Class G

-

unplanned interruptions caused by other electricity industry participant

20

Class H

-

planned interruptions caused by other electricity industry participant

21

Total

182

Total of above

23

Interruption targets for Forecast Year

24

Class B

30

planned interruptions on the network

25

Class C

150

unplanned interruptions on the network

27

Average interruption targets for 5 Forecast Years

28

Class B

30

planned interruptions on the network

29

Class C

150

unplanned interruptions on the network

31

Class C interruptions restored within

32

≤3Hrs

>3hrs

33

127

48

35

Faults

36

Faults per 100 circuit kilometres

37

The total number of faults for Current Financial Year

10.52

in year

2011

38

The total number of faults forecast for the Forecast Year

9.30

in year

2012

39

The average annual number of faults forecast for the 5 Forecast Years

9.20

average over years

2012-2016

41

Fault Information per 100 circuit kilometres by Voltage and Type

42

6.6kV & 11kV non-SWER

22kV non-SWER

SWER

33kV

50kV & 66kV

>66kV

43

Is this voltage part of the EDB system?

Yes

No

Yes

Yes

No

No

44

Current Financial Year

11.03

11.36

8.10

45

Forecast Year

9.90

9.90

6.50

46

Average annual for 5 Forecast Years

9.80

9.80

6.40

48

Fault Information per 100 circuit kilometres by Voltage and Type

49

6.6kV & 11kV non-SWER

22kV non-SWER

SWER

33kV

50kV & 66kV

>66kV

50

Underground

1.68

NA

1.30

51

Overhead

14.82

11.36

11.80

53

Reliability

54

Overall reliability

55

Based on the total number of interruptions

SAIDI

SAIFI

CAIDI

56

65.34

0.68

95.50

57

Reliability by interruption class

58

Class B

SAIDI

SAIFI

CAIDI

59

Class C

0.43

0.01

85.60

60

64.92

0.68

95.60

61

Targets for Forecast Year

62

Class B

SAIDI

SAIFI

CAIDI

63

Class C

4.00

0.05

75.00

64

37.00

0.69

54.00

65

Average targets for 5 Forecast Years

66

Class B

SAIDI

SAIFI

CAIDI

67

Class C

4.00

0.05

75.00

68

37.00

0.69

54.00

70

PRICES

72

Price information by Connection Point Class

73

Connection Point Class

74

Small Connection Points

Medium Connection Points

Large Connection Points

Largest 5 Connection Points

Total

75

Gross line charge income (\$000)

24,711

4,443

8,857

1,311

39,321

76

Electricity Supplied to Customers' Connection Points (MWh)

424,591

96,214

257,800

54,493

833,099

77

Number of Connection Points (ICPs) at year end

50,383

2,625

608

5

53,621

78

Unit Price (cents/kWh)

5.8

4.6

3.4

2.4

4.7

79

Relative Unit Price Index

1.00

0.79

0.59

0.41

0.81

80

Error (FS1)

from MP1

81

Error (FS1)

from MP1

## REPORT MP3: PRICE AND QUALITY (cont)

### Notes to Price and Quality Measures

#### MP3a: Connection Point Class breakpoints

Connection Point Class breakpoints methodology kVA based breakpoints

#### kVA based breakpoints - additional disclosure

Breakpoint between small and medium classes 16 kVA

Breakpoint between large and medium classes 70 kVA

# G DISCLOSURE RELATING TO FINANCIAL AND EFFICIENCY PERFORMANCE MEASURES (REQUIREMENT 6(1) – CENTRAL OTAGO)

REPORT MP1: NETWORK INFORMATION			
(Separate report required for each Non-Contiguous Network)			
ref	Electricity Distribution Business: <b>Aurora Energy Limited</b>		
6	For Year Ended: <b>2011</b>		
7	Network Name: <b>Central</b>	(enter "Total Business" or name of network)	
9	Disclosure: <b>Annual Disclosure - Requirement 6(1)</b>		
10	<b>Circuit Length by Operating Line Voltage (at year end)</b>	<b>Overhead (km)</b>	<b>Underground (km)</b>
11			<b>Total (km)</b>
12	> 66kV		-
13	50kV & 66kV	108	1
14	33kV	261	15
15	SWER (all SWER voltages)		-
16	22kV (other than SWER)		-
17	6.6kV to 11kV (inclusive - other than SWER)	1,597	550
18	Low Voltage (< 1kV)	232	563
19	<b>Total circuit length (for Supply)</b>	<b>2,198</b>	<b>1,128</b>
20			<b>3,326</b>
21			to MP2
22	<b>Dedicated Street Lighting Circuit Length</b>	<b>2</b>	<b>59</b>
23			<b>61</b>
24	<b>Overhead Circuit Length by Terrain (at year end)</b>	<b>(km)</b>	<b>(%)</b>
25	Urban (only)	210	10%
26	Rural (only)	1,858	85%
27	Remote (only)		0%
28	Rugged (only)		0%
29	Rural & rugged (only)	131	6%
30	Remote & rugged (only)		0%
31	Unallocated overhead lines		0%
32	<b>Total overhead length</b>	<b>2,198</b>	<b>100%</b>
33			-
34	<b>Transformer capacity (at year end)</b>		<b>Previous Year</b>
35	Distribution Transformer Capacity (EDB Owned)	339 MVA	336
36	Distribution Transformer Capacity (Non-EDB Owned, Estimated)	18 MVA	19
37	<b>Total Distribution Transformer Capacity</b>	<b>357 MVA (to MP2)</b>	<b>355</b>
38			
39	Zone Substation Transformer Capacity	264 MVA	257
40			
41	<b>System Fixed Assets age (at year end)</b>		
42	Average Age of System Fixed Assets	17 Years	
43	Average Expected Total Life of System Fixed Assets	50 Years	
44	Average Age as a Proportion of Average Expected Total Life	35% %	
45			
46	Estimated Proportion of Assets (by Replacement Cost) within 10 years of Total Life	16% %	
47			
48			
49			
50	<b>Electricity demand</b>	<b>Maximum coincident system demand (MW)</b>	<b>Non-coincident Sum of maximum demands (MW)</b>
51			
52	<b>GXP Demand</b>	<b>82</b>	<b>85</b>
53	plus Embedded Generation Output at HV and Above	14	
54	<b>Maximum System Demand</b>	<b>96</b>	
55	less Net Transfers to (from) Other EDBs at HV and Above	-	
56	<b>Demand on system for supply to customers' Connection Points</b>	<b>96</b>	
57	less Subtransmission Customers' Connection Point Demand	-	0
58	<b>Maximum Distribution Transformer Demand</b>	<b>96</b>	
59			to MP2
60			
61	GXP Demand not Supplied at Subtransmission Level	-	
62	Embedded Generation Output - Connected to Subtransmission System	14	24
63	Net Transfers to (from) Other EDBs at Subtransmission Level Only	-	-
64			
65	<b>Estimated Controlled Load Shed at Time of Maximum System Demand (MW)</b>	<b>18</b>	
66			
67	<b>Five-Year System Maximum Demand Growth Forecast</b>	<b>2.0</b> % p.a.	
68			
69	<b>Electricity volumes carried</b>	<b>(GWh)</b>	
70	Electricity Supplied from GXPs	323	
71	less Electricity Exports to GXPs	20	
72	plus Electricity Supplied from Embedded Generators	131	
73	less Net Electricity Supplied to (from) Other EDBs	-	
74	<b>Electricity entering system for supply to customers' Connection Points</b>	<b>434</b>	
75	less Electricity Supplied to Customers' Connection Points	405	
76	<b>Electricity Losses (loss ratio)</b>	<b>29</b>	<b>6.7% %</b>
77			to MP2
78	Electricity Supplied to Customers' Connection Points	405	
79	less Electricity Supplied to Largest 5 Connection Points	14	
80	<b>Electricity supplied other than to Largest 5 Connection Points</b>	<b>391</b>	<b>97% %</b>
81			
82	<b>Load Factor</b>	<b>52% %</b>	
83			
84	<b>Number of Connection Points (at year end)</b>	<b>28,676</b> ICPs	
85			to MP2
86	<b>Intensity of service requirements</b>		
87	Demand Density (Maximum Distribution Transformer Demand / Total circuit length)	29 kW/km	
88	Volume Density (Electricity Supplied to Customers' Connection Points / Total circuit length)	122 MWh/km	
89	Connection Point Density (ICPs / Total circuit length)	9 ICP/km	
90	Energy Intensity (Electricity Supplied to Customers' Connection Points / ICP)	14,116 kWh/ICP	

# REPORT MP3: PRICE & QUALITY MEASURES

(Separate report required for each Non-contiguous Network)

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Electricity Distribution Business:

Aurora Energy Limited

For Year Ended:

2011

Network Name:

Central

Disclosure:

Annual Disclosure - Requirement 6(1)

QUALITY

Interruptions

Interruptions by class

Class A	-	planned interruptions by Transpower:
Class B	361	planned interruptions on the network
Class C	315	unplanned interruptions on the network
Class D	-	unplanned interruptions by Transpower
Class E	-	unplanned interruptions of network owned generation
Class F	-	unplanned interruptions of generation (non-network)
Class G	-	unplanned interruptions caused by other electricity industry participant
Class H	-	planned interruptions caused by other electricity industry participant
Total	676	Total of above

Interruption targets for Forecast Year

Class B	2012	Current Financial Year +1
Class C	360	planned interruptions on the network
	320	unplanned interruptions on the network

Average interruption targets for 5 Forecast Years

Class B	2012-2016	Current Financial Year +1 to +5
Class C	355	planned interruptions on the network
	315	unplanned interruptions on the network

Class C interruptions restored within

≤3Hrs	>3hrs
255	60

Faults

Faults per 100 circuit kilometres

The total number of faults for Current Financial Year	10.60	in year	2011
The total number of faults forecast for the Forecast Year	11.40	in year	2012
The average annual number of faults forecast for the 5 Forecast Years	11.30	average over years	2012-2016

Fault Information per 100 circuit kilometres by Voltage and Type

	6.6kV & 11kV non-SWER	22kV non-SWER	SWER	33kV	50kV & 66kV	>66kV
Is this voltage part of the EDB system?	Yes	No	No	Yes	Yes	No
Current Financial Year	12.10			1.90	2.70	
Forecast Year	12.30			6.50	6.00	
Average annual for 5 Forecast Years	12.20			6.40	5.90	

Fault Information per 100 circuit kilometres by Voltage and Type

	6.6kV & 11kV non-SWER	22kV non-SWER	SWER	33kV	50kV & 66kV	>66kV
Underground	2.21			-	-	
Overhead	15.45			2.00	2.80	

Reliability

Overall reliability

Based on the total number of interruptions	SAIDI	SAIFI	CAIDI
	198.88	2.98	66.80

Reliability by interruption class

Class B	SAIDI	SAIFI	CAIDI
Class C	48.06	0.33	146.20
	150.82	2.65	56.90

Targets for Forecast Year

Class B	SAIDI	SAIFI	CAIDI
Class C	35.43	0.25	140.00
	134.13	2.44	55.00

Average targets for 5 Forecast Years

Class B	SAIDI	SAIFI	CAIDI
Class C	31.27	0.22	140.00
	126.61	2.30	55.00

PRICES

Price information by Connection Point Class

	Connection Point Class				
	Small Connection Points	Medium Connection Points	Large Connection Points	Largest 5 Connection Points	Total
Gross line charge income (\$000)	19,672	6,584	5,726	770	32,753
Electricity Supplied to Customers' Connection Points (MWh)	193,974	80,256	116,453	14,108	404,791
Number of Connection Points (ICPs) at year end	23,204	2,383	3,084	5	28,676
Unit Price (cents/kWh)	10.1	8.2	4.9	5.5	8.1
Relative Unit Price Index	1.00	0.81	0.48	0.54	0.80

Error (FS1)

from MP1

from MP1

## REPORT MP3: PRICE AND QUALITY (cont)

### Notes to Price and Quality Measures

#### MP3a: Connection Point Class breakpoints

Connection Point Class breakpoints methodology kVA based breakpoints

#### kVA based breakpoints - additional disclosure

Breakpoint between small and medium classes 16 kVA

Breakpoint between large and medium classes 70 kVA

## H DISCLOSURE RELATING TO ASSET MANAGEMENT PLANS (REQUIREMENT 7(5))

### REPORT AM1: EXPENDITURE FORECASTS AND RECONCILIATION

ref		Electricity Distribution Business:	Aurora Energy	
5		For Year Ended	2011	
6	A) Five year forecasts of expenditure		(\$000)	
7	From most recent Asset Management Plan			
8		Actual for Current Financial Year	Forecast Years	
9	for year ended	2011	year 1 year 2 year 3 year 4 year 5	
10	Capital Expenditure: Customer Connection	5,776	5,600 6,000 6,400 6,800 7,200	
11	Capital Expenditure: System Growth	5,996	7,090 2,680 10,130 14,180 11,080	
12	Capital Expenditure: Reliability, Safety and Environment	2,041	2,020 1,480 1,130 1,070 1,680	
13	Capital Expenditure: Asset Replacement and Renewal	7,055	8,490 8,140 8,120 4,730 10,030	
14	Capital Expenditure: Asset Relocations	1,426	400 500 600 500 500	
15	Subtotal - Capital Expenditure on asset management	22,294	23,600 18,800 26,380 27,280 30,490	
16				
17	Operational Expenditure: Routine and Preventative Maintenance	3,194	3,540 3,640 3,740 3,850 3,950	
18	Operational Expenditure: Refurbishment and Renewal Maintenance	1,103	1,310 1,340 1,370 1,390 1,430	
19	Operational Expenditure: Fault and Emergency Maintenance	4,155	4,270 4,370 4,470 4,570 4,670	
20	Subtotal - Operational Expenditure on asset management	8,452	9,120 9,350 9,580 9,810 10,050	
21				
22	Total direct expenditure on distribution network	30,746	32,720 28,150 35,960 37,090 40,540	
23				
24	Overhead to Underground Conversion Expenditure	1,204	600 600 600 600 600	
26	The Electricity Distribution Business is to provide the amount of Overhead to Underground Conversion Expenditure included in each of the above Expenditure Categories (explanatory notes can be provided in a separate note if necessary).	\$1,015 of underground conversion expenditure is included in the above Capital Expenditure category - Asset replacement and renewal. A further \$189K is included in the Operational Expenditure category - refurbishment and renewal maintenance.		
27				
28				
30				
32	B) Variance between Previous Forecast for the Current Financial Year, and Actual Expenditure			
33		Actual for Current Financial Year (a)	Previous forecast for Current Financial Year (b) % Variance (a)/(b)-1	
34	Capital Expenditure: Customer Connection	5,776	5,400 7.0%	
35	Capital Expenditure: System Growth	5,996	4,300 39.4%	
36	Capital Expenditure: Reliability, Safety and Environment	2,041	3,750 -45.6%	
37	Capital Expenditure: Asset Replacement and Renewal	7,055	9,960 -29.2%	
38	Capital Expenditure: Asset Relocations	1,426	600 137.7%	
39	Subtotal - Capital Expenditure on asset management	22,294	24,010 -7.1%	
40				
41	Operational Expenditure: Routine and Preventative Maintenance	3,194	3,426 -6.8%	
42	Operational Expenditure: Refurbishment and Renewal Maintenance	1,103	1,782 -38.1%	
43	Operational Expenditure: Fault and Emergency Maintenance	4,155	4,172 -0.4%	
44	Subtotal - Operational Expenditure on asset management	8,452	9,380 -9.9%	
45				
46	Total direct expenditure on distribution network	30,746	33,390 -7.9%	
47				
48				
49	Explanation of variances			
50	Distribution Business must provide a brief explanation for any line item variance of more than 10%			
51				
52	Explanatory notes (can be provided in a separate note if necessary):	Capex - System Growth is above budget due to the early commissioning of the new Cardrona zone substation. It had been budgeted to be commissioned in April 2011.		
53		Capex - Reliability, Safety etc were below budget as NZTA funded projects such as at Frankton (\$1.0m) did not eventuate.		
54		Capex - Asset Replacement was under budget due to delayed commissioning of Dunedin ripple injection equipment (\$2.68m) and reduced expenditure on Undergrounding of Overhead projects.		
55		Capex - Asset Relocations was over budget due to one customer initiated project of \$0.7m.		
56		Opex - Refurbishment and Renewal was under budget due to expenses associated with undergrounding of overhead were less due to the reduced level of projects undertaken.		
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<b>I    CERTIFICATION BY AUDITOR (REQUIREMENT 10)</b>
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**Auditor's independent assurance report****To the readers of Aurora Energy Limited's****Report for the financial year ended 31 March 2011 regarding Aurora Energy Limited's compliance with the Electricity Distribution (Information Disclosure) Requirements 2008**

The Auditor-General is the auditor of Aurora Energy Limited (the company). The Auditor-General has appointed me, Ian Lothian, using the staff and resources of Audit New Zealand, to provide an opinion, on her behalf, on the company's report for the financial year ended 31 March 2011 on pages 3 to 21 regarding compliance with the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008 (the Requirements). In this independent assurance report we refer to the company's report as the "disclosure information".

**Respective responsibilities**

The Board of Directors is responsible for preparing disclosure information that complies with the Requirements.

Clause 10 of the Requirements requires the Auditor-General to provide an opinion on whether the disclosure information prepared by the company complies with and is presented in all material respects in accordance with the Requirements for the financial year ended 31 March 2011.

**Limitations and use of this independent assurance report**

This independent assurance report has been prepared solely to discharge the Auditor-General's responsibilities under the Requirements for the financial year ended 31 March 2011. This independent assurance report is not intended to be used for any purposes, other than that for which it was prepared.

Because of the inherent limitations in evidence gathering procedures, it is possible that fraud, error or non-compliance may occur and not be detected. As the procedures performed for this engagement are not performed continuously throughout the financial year and the procedures performed in respect of the company's compliance with the Requirements are undertaken on a test basis, our engagement cannot be relied on to detect all instances where the company may not have complied with the Requirements. Our opinion has been formed on the above basis.

**Basis of opinion**

The Company's financial statements prepared pursuant to the Electricity Distribution (Information Disclosure) Requirements 2008 for the year ended 31 March 2011 have been subject to audit.

Our work has been planned and performed to obtain all the information and explanations we considered necessary in order to obtain reasonable assurance that the disclosure information complies with and has been presented in all material respects in accordance with the

Requirements. We also included an assessment of the significant estimates and judgements, if any, made by the company in the preparation of the disclosure information.

A matter is material if it would affect a user's overall understanding of the disclosure information prepared by the company.

### **Historical financial and non-financial information**

We conducted the engagement in accordance with the Standard on Assurance Engagements (New Zealand) 3100: Compliance Engagements issued by the New Zealand Institute of Chartered Accountants.

Our work in respect of amounts and disclosures that were audited under the financial statement and default price-quality path compliance statements audits has been limited to agreeing the amounts and disclosures to the underlying records and audited financial statements or default price-quality path compliance statements of the company.

Our work in respect of amounts and disclosures that were not audited under the financial statement and default price-quality path compliance statements audits, has been planned and performed to obtain all the information and explanations we considered necessary in order to obtain reasonable assurance that the disclosure information has been presented in all material respects in accordance with the Requirements.

### **Prospective financial and non-financial information**

Our work on the prospective financial and non-financial information has been limited to assessing whether the information has been presented on a basis consistent with the regulatory accounting or technical measurement requirements used for disclosures for the financial year ended 31 March 2011 and the immediately preceding financial year, and that the information has been calculated based on source data provided by the company. We have not performed audit procedures on the source data.

We acknowledge that it is likely that actual results will vary from those forecasted, since anticipated events frequently do not occur as expected (and those variations may be significant).

### **Independence**

When carrying out the engagement we followed the independence requirements of the Auditor-General, which incorporate the independence requirements of the New Zealand Institute of Chartered Accountants. We also complied with the Independent auditor provisions on independence, as specified in clause 2(1) of the Requirements.

Other than the engagement and the annual audit of the company's financial statements and default price-quality path compliance statements carried out on behalf of the Auditor-General, we have no relationship with or interests in the company.

### **Opinion**

We have obtained all the information and explanations we have required.

In our opinion:



- the company has kept proper records to enable the complete and accurate compilation of required information, in all material respects, as far as appears from our examination of those records; and
- the disclosure information prepared by the company for the financial year ended 31 March 2011 complies with the Requirements.

### **Historical Financial and Non-Financial Information**

In our opinion, the company has:

- presented the historical financial information in reports FS1, FS2, FS3, AV1, AV2, AV3, AV4, MP2, MP3 and AM1 for the financial year ended 31 March 2011 in all material respects in compliance with the Requirements, and
- compiled the historical non-financial information included in reports MP1, MP2 and MP3 in accordance with the guidance (if any) issued pursuant to the Requirements, and has calculated the historical non-financial information based on un-audited source data provided by the company.

### **Prospective Financial and Non-Financial Information**

In our opinion, the company has:

- presented the prospective financial and non-financial information in reports AM1 and MP3 on a basis consistent with the regulatory accounting or technical measurement requirements used for disclosures for the financial year ended 31 March 2011 and the immediately preceding financial year; and
- calculated the prospective financial and non-financial information based on un-audited source data provided by the company.



Ian Lothian  
Audit New Zealand  
On behalf of the Auditor-General  
Christchurch, New Zealand  
27 July 2011