Aurora
ENERGY LIMITED

Information Disclosure

For the year ended 31 March 2014

Pursuant to the Electricity Distribution Information Disclosure Determination 2012

DELTA
THINK.INFRASTRUCTURE

PREPARED FOR AURORA ENERGY LTD
BY DELTA UTILITY SERVICES LTD

TELARC SQI registered
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Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.

sch ref

7 **1(i): Expenditure metrics**

8	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
9 **Operational expenditure**	17,850	266	79,989	3,850	26,663
10 Network	8,937	133	40,050	1,928	13,350
11 Non-network	8,913	133	39,939	1,923	13,313
12					
13 **Expenditure on assets**	12,733	190	57,057	2,747	19,019
14 Network	12,733	190	57,057	2,747	19,019
15 Non-network	-	-	-	-	-

16

17 **1(ii): Revenue metrics**

18	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
19 **Total consumer line charge revenue**	66,472	990
20 Standard consumer line charge revenue	66,472	990
21 Non-standard consumer line charge revenue	-	-

22

23 **1(iii): Service intensity measures**

24

25 Demand density	48	*Maximum coincident system demand per km circuit length (for supply) (kW/km)*
26 Volume density	216	*Total energy delivered to ICPs per km circuit length (for supply) (MWh/km)*
27 Connection point density	14	*Average number of ICPs per km circuit length (for supply) (ICPs/km)*
28 Energy intensity	14,894	*Total energy delivered to ICPs per Average number of ICPs (kWh/ICP)*

29

30

31 **1(iv): Composition of regulatory income**

32	($000)	% of revenue
33 Operational expenditure	22,317	26.17%
34 Pass-through and recoverable costs	29,712	34.85%
35 Total depreciation	11,473	13.46%
36 Total revaluation	4,879	5.72%
37 Regulatory tax allowance	5,574	6.54%
38 Regulatory profit/loss	21,068	24.71%
39 **Total regulatory income**	85,265	

40

41 **1(v): Reliability**

42	Interruptions per 100 circuit km
43 Interruption rate	12.25

Company Name	**Aurora Energy Limited**
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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii). EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

			CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**				
8					
9	**Post tax WACC**		%	%	%
10	**ROI—comparable to a post tax WACC**			6.66%	6.39%
11					
12	**Mid-point estimate of post tax WACC**		6.40%	5.85%	5.43%
13	25th percentile estimate		5.68%	5.13%	4.71%
14	75th percentile estimate		7.11%	6.56%	6.14%
15					
16					
17	**Vanilla WACC**				
18	**ROI—comparable to a vanilla WACC**			7.43%	7.08%
19					
20	**Mid-point estimate of vanilla WACC**		7.22%	6.62%	6.11%
21	25th percentile estimate		6.51%	5.91%	5.39%
22	75th percentile estimate		7.94%	7.34%	6.83%
23					
24	**2(ii): Information Supporting the ROI**			($000)	
25					
26		Total opening RAB value	318,316		
27	*plus*	Opening deferred tax	(2,683)		
28		Opening RIV		315,633	
29					
30		Operating surplus / (deficit)	33,236		
31	*less*	Regulatory tax allowance	5,574		
32	*less*	Assets commissioned	13,374		
33	*plus*	Asset disposals	129		
34		**Notional net cash flows**		14,417	
35					
36		Total closing RAB value	324,967		
37	*less*	Adjustment resulting from asset allocation	0		
38	*less*	Lost and found assets adjustment	-		
39	*plus*	Closing deferred tax	(1,920)		
40		**Closing RIV**		323,047	
41					
42		**ROI—comparable to a vanilla WACC**		7.08%	
43					
44		Leverage (%)		44%	
45		Cost of debt assumption (%)		5.56%	
46		Corporate tax rate (%)		28%	
47					
48		**ROI—comparable to a post tax WACC**		6.39%	

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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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sch ref

56 **2(iii): Information Supporting the Monthly ROI**

57

58 **Cash flows** ($000)

59	Total regulatory income	Expenses	Tax payments	Assets commissioned	Asset disposals	Notional net cash flows
60 April						-
61 May						-
62 June						-
63 July						-
64 August						-
65 September						-
66 October						-
67 November						-
68 December						-
69 January						-
70 February						-
71 March						-
72 **Total**	-	-	-	-	-	-

73

74	Opening / closing RAB	Adjustment resulting from asset allocation	Lost and found assets adjustment	Opening / closing deferred tax	Revenue related working capital	Total
75 Monthly ROI - opening RIV	318,316			(2,683)		315,633
76						
77 Monthly ROI -closing RIV	324,967	0	-	(1,920)	-	323,047
78 Monthly ROI -closing RIV less term credit spread differential allowance						323,047
79 **Monthly ROI—comparable to a vanilla WACC**						N/A
80						
81 **Monthly ROI—comparable to a post-tax WACC**						N/A

82

83 **2(iv): Year-End ROI Rates for Comparison Purposes**

84

85 **Year-end ROI—comparable to a vanilla WACC**	6.54%
86	
87 **Year-end ROI—comparable to a post-tax WACC**	5.85%

88

89 ** these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
Non-exempt EDBs must also complete sections 3(ii) and 3(iii).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

3(i): Regulatory Profit

sch ref			($000)
8		**Income**	
9		Line charge revenue	82,403
10	*plus*	Gains / (losses) on asset disposals	(363)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	3,225
12			
13		**Total regulatory income**	85,265
14		**Expenses**	
15	*less*	Operational expenditure	22,317
17	*less*	Pass-through and recoverable costs	29,712
18			
19		**Operating surplus / (deficit)**	33,236
20			
21	*less*	Total depreciation	11,473
22			
23	*plus*	Total revaluation	4,879
24			
25		**Regulatory profit / (loss) before tax & term credit spread differential allowance**	26,642
26			
27	*less*	Term credit spread differential allowance	-
28			
29		**Regulatory profit / (loss) before tax**	26,642
30			
31	*less*	Regulatory tax allowance	5,574
32			
33		**Regulatory profit / (loss)**	21,068
34			

3(ii): Pass-Through and Recoverable Costs

sch ref		($000)	
36	**Pass-through costs**		
37	Rates	673	
38	Commerce Act levies	162	
	Electricity Authority levies	164	
40	Other specified pass-through costs	1,256	
41	**Recoverable costs**		
42	Net recoverable costs allowed under incremental rolling incentive scheme	-	
43	Non-exempt EDB electricity lines service charge payable to Transpower	20,756	
44	Transpower new investment contract charges	-	
45	System operator services	-	
46	Avoided transmission charge	6,701	
47	Input Methodology claw-back	-	
48	Recoverable customised price-quality path costs	-	
49	**Pass-through and recoverable costs**		29,712

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
Non-exempt EDBs must also complete sections 3(ii) and 3(iii).
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sch ref

57 **3(iii): Incremental Rolling Incentive Scheme**

		($000) CY-1	CY 31 March 2014
58			
59			
60	Allowed controllable opex		
61	Actual controllable opex		
62			
63	Incremental change in year		
64			
65		Previous years' incremental change	Previous years' incremental change adjusted for inflation
66	CY-5 [year]		
67	CY-4 [year]		
68	CY-3 [year]		
69	CY-2 [year]		
70	CY-1 [year]		
71	**Net incremental rolling incentive scheme**		-
72			
73	**Net recoverable costs allowed under incremental rolling incentive scheme**		-

74 **3(iv): Merger and Acquisition Expenditure**

75	Merger and acquisition expenses	N/A
76		
77	Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)	

78 **3(v): Other Disclosures**

79	Self-insurance allowance	N/A

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

4(i): Regulatory Asset Base Value (Rolled Forward)

		RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
	Total opening RAB value	285,613	294,631	307,618	313,820	318,316
less	**Total depreciation**	10,135	10,301	10,796	11,086	11,473
plus	**Total revaluations**	5,845	7,125	4,832	2,696	4,879
plus	**Assets commissioned**	13,308	16,369	12,735	12,886	13,374
less	**Asset disposals**	-	206	569	-	129
plus	**Lost and found assets adjustment**	-				-
plus	**Adjustment resulting from asset allocation**	-				0
	Total closing RAB value	294,631	307,618	313,820	318,316	324,967

4(ii): Unallocated Regulatory Asset Base

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value		318,316		318,316
less					
	Total depreciation		11,473		11,473
plus					
	Total revaluations		4,879		4,879
plus					
	Assets commissioned (other than below)	2,446		2,446	
	Assets acquired from a regulated supplier	-			
	Assets acquired from a related party	10,928		10,928	
	Assets commissioned		13,374		13,374
less					
	Asset disposals (other than below)	129		129	
	Asset disposals to a regulated supplier				
	Asset disposals to a related party				
	Asset disposals		129		129
plus	**Lost and found assets adjustment**				
plus	**Adjustment resulting from asset allocation**				0
	Total closing RAB value		324,967		324,967

** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to non-regulated services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

4(iii): Calculation of Revaluation Rate and Revaluation of Assets

	CPI_4	1,192
	CPI_4^{-4}	1,174
	Revaluation rate (%)	1.53%

		Unallocated RAB *		RAB	
		($000)	($000)	($000)	($000)
	Total opening RAB value	318,316		318,316	
less	Opening RAB value of fully depreciated, disposed and lost assets	129		129	
	Total opening RAB value subject to revaluation	318,187		318,187	
	Total revaluations		4,879		4,879

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year		9,604		9,604
plus	Capital expenditure	11,832		11,832	
less	Assets commissioned	13,374		13,374	
plus	Adjustment resulting from asset allocation				
	Works under construction - current disclosure year		8,062		8,062
	Highest rate of capitalised finance applied				

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	11,473		11,473	
Depreciation - no standard life assets				
Depreciation - modified life assets				
Depreciation - alternative depreciation in accordance with CPP				
Total depreciation		11,473		11,473

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For Year Ended	**31 March 2014**

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

97 **4(vi): Disclosure of Changes to Depreciation Profiles**

($000 unless otherwise specified)

	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
98					
99					
100					
101					
102					
103					
104					
105					
106					

** include additional rows if needed*

107 **4(vii): Disclosure by Asset Category**

108 **($000 unless otherwise specified)**

109			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
110		**Total opening RAB value**	13,835	7,464	52,446	45,067	125,437	50,729	19,702	3,636	-	318,316
111	*less*	Total depreciation	539	318	1,988	2,131	3,697	1,654	940	206	-	11,473
112	*plus*	Total revaluations	212	115	802	691	1,923	778	302	56		4,879
113	*plus*	Assets commissioned	61	2,199	3,563	3,014	1,861	1,194	935	547		13,374
114	*less*	Asset disposals			129							129
115	*plus*	Lost and found assets adjustment										-
116	*plus*	Adjustment resulting from asset allocation										-
117	*plus*	Asset category transfers										-
118		**Total closing RAB value**	13,569	9,460	54,694	46,641	125,524	51,047	19,999	4,033	-	324,967
119												
120		**Asset Life**										
121		Weighted average remaining asset life	25.7	23.5	25.0	21.2	33.9	30.7	21.0	14.1	-	(years)
122		Weighted average expected total asset life	67.5	49.2	40.2	45.8	48.3	50.0	35.8	17.1	-	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5a(i): Regulatory Tax Allowance

sch ref					($000)
8		**Regulatory profit / (loss) before tax**			26,642
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	1,513	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	19	*	
12		Amortisation of initial differences in asset values	3,587		
13		Amortisation of revaluations	746		
14					5,865
15					
16	*less*	Income included in regulatory profit / (loss) before tax but not taxable	4,879	*	
17		Discretionary discounts and consumer rebates	-		
18		Expenditure or loss deductible but not in regulatory profit / (loss) before tax**	-	*	
19		Notional deductible interest	7,722		
20					12,601
21					
22		**Regulatory taxable income**			19,906
23					
24	*less*	Utilised tax losses			
25		Regulatory net taxable income			19,906
26					
27		Corporate tax rate (%)	28%		
28		**Regulatory tax allowance**			5,574
29					

30 * Workings to be provided in Schedule 14
31 ** Excluding discretionary discounts and consumer rebates

5a(ii): Disclosure of Permanent Differences

33 In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).

5a(iii): Amortisation of Initial Difference in Asset Values

sch ref		($000)
35		
36	Opening unamortised initial differences in asset values	98,434
37	Amortisation of initial differences in asset values	3,587
38	Adjustment for unamortised initial differences in assets acquired	(9,013)
39	Adjustment for unamortised initial differences in assets disposed	-
40	Closing unamortised initial differences in asset values	85,834
41		
42	Opening weighted average remaining asset life (years)	27

5a(iv): Amortisation of Revaluations

sch ref		($000)
44		
45	Opening Sum of RAB values without revaluations	299,146
46		
47	Adjusted depreciation	10,727
48	Total depreciation	11,473
49	Amortisation of revaluations	746

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5a(v): Reconciliation of Tax Losses

sch ref				($000)
57				
58				
59		**Opening tax losses**	-	
60	*plus*	Current period tax losses	-	
61	*less*	Utilised tax losses	-	
62		**Closing tax losses**		-

5a(vi): Calculation of Deferred Tax Balance

sch ref				($000)
63				
64				
65		**Opening deferred tax**	(2,683)	
66				
67	*plus*	Tax effect of adjusted depreciation	3,004	
68				
69	*less*	Tax effect of total tax depreciation	4,179	
70				
71	*plus*	Tax effect of other temporary differences*	419	
72				
73	*less*	Tax effect of amortisation of initial differences in asset values	1,004	
74				
75	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	2,524	
76				
77	*less*	Deferred tax balance relating to assets disposed in the disclosure year	-	
78				
79	*plus*	Deferred tax cost allocation adjustment	-	
80				
81		**Closing deferred tax**		(1,920)
82				

5a(vii): Disclosure of Temporary Differences

83 In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary
84 differences).
85

5a(viii): Regulatory Tax Asset Base Roll-Forward

sch ref				($000)
87				
88		**Opening sum of regulatory tax asset values**	163,270	
89	*less*	Tax depreciation	14,927	
90	*plus*	Regulatory tax asset value of assets commissioned	22,387	
91	*less*	Regulatory tax asset value of asset disposals		
92	*plus*	Lost and found assets adjustment		
93	*plus*	Other adjustments to the RAB tax value		
94		**Closing sum of regulatory tax asset values**		170,730

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID determination.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5b(i): Summary—Related Party Transactions

		($000)
8	Total regulatory income	44
9	Operational expenditure	19,184
10	Capital expenditure	14,031
11	Market value of asset disposals	-
12	Other related party transactions	-

5b(ii): Entities Involved in Related Party Transactions

	Name of related party	Related party relationship
15	Delta Utility Services Ltd	Sister Company - Provides Asset Management and Electrical Contracting (Opex and Capex)
16	Dunedin City Holdings Ltd	Dunedin City Holdings holds 100% of the Shares in Aurora Energy Ltd and Delta Utility Services
17	Dunedin City Council	Dunedin City Council holds 100% of the shares in Dunedin City Holding Ltd
18		
19		

20 ** include additional rows if needed*

21 **5b(iii): Related Party Transactions**

22	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
23	Delta Utility Services Ltd	Sales	Recovery of Service Failure Payments	44	
24	Dunedin City Council	Opex	Rates Expense	436	Price Paid as more than 50% of the related parties sales are made to third parties
25	Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies in accordance with Asset Management Agreement	3,996	Price paid as more than 50% of the related parties sales are to third parties
26	Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies - repair of equipment damaged by 3rd parties	896	Price paid as more than 50% of the related parties sales are to third parties
27	Delta Utility Services Ltd	Opex	On going Vegetation Management in accordance with Asset Management Agreement	2,312	Price paid as more than 50% of the related parties sales are to third parties
28	Delta Utility Services Ltd	Opex	On going routine inspection and maintenance work in accordance with Asset Management Agreement	2,475	Price paid as more than 50% of the related parties sales are to third parties
29	Delta Utility Services Ltd	Opex	On going asset replacement and renewal work in accordance with Asset Management Agreement	1,101	Price paid as more than 50% of the related parties sales are to third parties
30	Delta Utility Services Ltd	Opex	Underground conversion costs	351	Price paid as more than 50% of the related parties sales are to third parties
31	Delta Utility Services Ltd	Opex	On going system operation, support and management in accordance with Asset Management Agreement	4,694	Price paid as more than 50% of the related parties sales are to third parties
32	Delta Utility Services Ltd	Opex	On going Business support operations in accordance with Asset Management Agreement	2,209	Price paid as more than 50% of the related parties sales are to third parties
33	Delta Utility Services Ltd	Opex	On going general managment, administration and acountint services in accordance with Administration	523	Price paid as more than 50% of the related parties sales are to third parties
34	Delta Utility Services Ltd	Opex	Miscelanious work associated with processing of easements and ad-hoc advise	146	Price paid as more than 50% of the related parties sales are to third parties
35	Delta Utility Services Ltd	Opex	For lease of CPD metering equipment	45	Price paid as more than 50% of the related parties sales are to third parties
36	Delta Utility Services Ltd	Capex	Installation of New Network Equipment	9,486	Directly attributable costs
37	Delta Utility Services Ltd	Capex	Installation of New Network Equipment	4,546	In accordance with independant valuations undertaken

** include additional rows if needed*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5c(i): Qualifying Debt (may be Commission only)

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Cost of executing an interest rate swap	Debt issue cost readjustment
						-	-	-	-

** include additional rows if needed*

5c(ii): Attribution of Term Credit Spread Differential

Gross term credit spread differential		-
Total book value of interest bearing debt		
Leverage	44%	
Average opening and closing RAB values		
Attribution Rate (%)		-
Term credit spread differential allowance		-

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		4,923			
Not directly attributable				-	
Total attributable to regulated service		4,923			
Vegetation management					
Directly attributable		2,312			
Not directly attributable				-	
Total attributable to regulated service		2,312			
Routine and corrective maintenance and inspection					
Directly attributable		2,475			
Not directly attributable				-	
Total attributable to regulated service		2,475			
Asset replacement and renewal					
Directly attributable		1,464			
Not directly attributable				-	
Total attributable to regulated service		1,464			
System operations and network support					
Directly attributable		4,694			
Not directly attributable				-	
Total attributable to regulated service		4,694			
Business support					
Directly attributable		6,449			
Not directly attributable				-	
Total attributable to regulated service		6,449			
Operating costs directly attributable		22,317			
Operating costs not directly attributable	-	-	-	-	-
Operating expenditure		22,317			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	
Pass through costs	
Directly attributable	2,255
Not directly attributable	
Total attributable to regulated service	2,255
Recoverable costs	
Directly attributable	27,457
Not directly attributable	
Total attributable to regulated service	27,457

5d(iii): Changes in Cost Allocations* †

Change in cost allocation 1

			($000) CY-1	Current Year (CY)
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-

Rationale for change

Change in cost allocation 2

			CY-1	Current Year (CY)
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-

Rationale for change

Change in cost allocation 3

			CY-1	Current Year (CY)
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-

Rationale for change

** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*
† include additional rows if needed

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.
EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any changes in asset allocations. This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5e(i):Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	13569
Not directly attributable	
Total attributable to regulated service	13,569
Subtransmission cables	
Directly attributable	9460
Not directly attributable	
Total attributable to regulated service	9,460
Zone substations	
Directly attributable	54694
Not directly attributable	
Total attributable to regulated service	54,694
Distribution and LV lines	
Directly attributable	46641
Not directly attributable	
Total attributable to regulated service	46,641
Distribution and LV cables	
Directly attributable	125524
Not directly attributable	
Total attributable to regulated service	125,524
Distribution substations and transformers	
Directly attributable	51047
Not directly attributable	
Total attributable to regulated service	51,047
Distribution switchgear	
Directly attributable	19999
Not directly attributable	
Total attributable to regulated service	19,999
Other network assets	
Directly attributable	4033
Not directly attributable	
Total attributable to regulated service	4,033
Non-network assets	
Directly attributable	0
Not directly attributable	
Total attributable to regulated service	-
Regulated service asset value directly attributable	324,967
Regulated service asset value not directly attributable	-
Total closing RAB value	324,967

5e(ii): Changes in Asset Allocations* †

($000)

Change in asset value allocation 1

			CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-

Rationale for change

Change in asset value allocation 2

			CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-

Rationale for change

Change in asset value allocation 3

			CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	-	-

Rationale for change

* a change in asset allocation must be completed for each allocator or component change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.
† include additional rows if needed

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		4,723
9		System growth		350
10		Asset replacement and renewal		7,761
11		Asset relocations		535
12		Reliability, safety and environment:		
13		Quality of supply	2,337	
14		Legislative and regulatory	-	
15		Other reliability, safety and environment	213	
16		**Total reliability, safety and environment**		2,550
17		**Expenditure on network assets**		15,919
18		Non-network assets		-
19				
20		**Expenditure on assets**		15,919
21	*plus*	Cost of financing		-
22	*less*	Value of capital contributions		4,087
23	*plus*	Value of vested assets		-
24				
25		**Capital expenditure**		11,832

			($000)
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**	
27		Energy efficiency and demand side management, reduction of energy losses	-
28		Overhead to underground conversion	247
29		Research and development	-

			($000)	($000)
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**		
32		[EDB consumer type]	4,723	
33		[EDB consumer type]		
34		[EDB consumer type]		
35		[EDB consumer type]		
36		[EDB consumer type]		
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		4,723
39				
40	*less*	Capital contributions funding consumer connection expenditure	2,948	
41		**Consumer connection less capital contributions**		1,775

			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
43				
44				
45		Subtransmission	-	2,069
46		Zone substations	24	2,865
47		Distribution and LV lines	91	1,583
48		Distribution and LV cables	104	468
49		Distribution substations and transformers	71	299
50		Distribution switchgear	34	352
51		Other network assets	26	125
52		**System growth and asset replacement and renewal expenditure**	350	7,761
53	*less*	Capital contributions funding system growth and asset replacement and renewal	64	615
54		**System growth and asset replacement and renewal less capital contributions**	286	7,146
55				

			($000)	($000)
56		**6a(v): Asset Relocations**		
57		*Project or programme**		
58		CFR 7260 -Relocation of part of Frankton substation incl site develop / civil	123	
59		CFR 6705 - Moving works for Trasnspower Fraser Domain, Strode Road	78	
60		CFR 6693 - Moving works NZTA re Caversham SH 1	52	
61		CFR 7267 - Asset Changeovers from relocated Telecom poles	37	
62		CFR 6968 - Customer requested moving of poles and lines	36	
63		** include additional rows if needed*		
64		All other asset relocations projects or programmes	209	
65		**Asset relocations expenditure**		535
66	*less*	Capital contributions funding asset relocations	451	
67		**Asset relocations less capital contributions**		84

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

6a(vi): Quality of Supply

			($000)	($000)
		*Project or programme**		
		CFR 6928 - Half way Bush Feeder 1 Pole replacement program	737	
		CFR 6255 - Roxburgh 5MVA transformer	392	
		Purchase of Freehold land for zone substation	353	
		CFR 6535 - Ab & SDN Scada Upgrade	187	
		[Description of material project or programme]		
		** include additional rows if needed*		
		All other quality of supply projects or programmes	668	
		Quality of supply expenditure		2,337
	less	Capital contributions funding quality of supply	9	
		Quality of supply less capital contributions		2,328

6a(vii): Legislative and Regulatory

			($000)	($000)
		*Project or programme**		
		[Description of material project or programme]		
		[Description of material project or programme]		
		[Description of material project or programme]		
		[Description of material project or programme]		
		[Description of material project or programme]		
		** include additional rows if needed*		
		All other legislative and regulatory projects or programmes		
		Legislative and regulatory expenditure		-
	less	Capital contributions funding legislative and regulatory		
		Legislative and regulatory less capital contributions		-

6a(viii): Other Reliability, Safety and Environment

			($000)	($000)
		*Project or programme**		
		CFR 6143 - Dunorling st, safety clearance issues	58	
		CFR 6791 - Cobham Crescent, safety clearance issues	33	
		CFR 6461 - Wanaka -Mt Aspiring Roads, safety clearance issues	29	
		CFR 6937 - Goldfields Slip, remove OH to reduce risk during rock fall	15	
		CFR 6560 - Blanket Bay transformer replacement	14	
		** include additional rows if needed*		
		All other reliability, safety and environment projects or programmes	64	
		Other reliability, safety and environment expenditure		213
	less	Capital contributions funding other reliability, safety and environment	-	
		Other reliability, safety and environment less capital contributions		213

6a(ix): Non-Network Assets

Routine expenditure

			($000)	($000)
		*Project or programme**		
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		** include additional rows if needed*		
		All other routine expenditure projects or programmes	-	
		Routine expenditure		-

Atypical expenditure

			($000)	($000)
		*Project or programme**		
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		[Description of material project or programme]	-	
		** include additional rows if needed*		
		All other atypical expenditure projects or programmes	-	
		Atypical expenditure		-
		Non-network assets expenditure		-

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of operating expenditure incurred in the disclosure year.
EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operating expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	4,923	
9	Vegetation management	2,312	
10	Routine and corrective maintenance and inspection	2,475	
11	Asset replacement and renewal	1,464	
12	**Network opex**		11,174
13	System operations and network support	4,694	
14	Business support	6,449	
15	**Non-network opex**		11,143
16			
17	**Operational expenditure**		22,317
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		N/A
20	Direct billing*		N/A
21	Research and development		N/A
22	Insurance		192
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.
EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes). This information is part of the audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures.

sch ref

7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	84,580	82,403	(3%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	6,866	4,723	(31%)
11	System growth	7,076	350	(95%)
12	Asset replacement and renewal	7,387	7,761	5%
13	Asset relocations	3,343	535	(84%)
14	Reliability, safety and environment:			
15	Quality of supply	1,793	2,337	30%
16	Legislative and regulatory	-	-	-
17	Other reliability, safety and environment	723	213	(71%)
18	**Total reliability, safety and environment**	2,517	2,550	1%
19	**Expenditure on network assets**	27,189	15,919	(41%)
20	Non-network capex		-	-
21	**Expenditure on assets**	27,189	15,919	(41%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	4,040	4,923	22%
24	Vegetation management	1,312	2,312	76%
25	Routine and corrective maintenance and inspection	3,280	2,475	(25%)
26	Asset replacement and renewal	1,191	1,464	23%
27	**Network opex**	9,822	11,174	14%
28	System operations and network support	585	4,694	702%
29	Business support	315	6,449	1,947%
30	**Non-network opex**	900	11,143	1,138%
31	**Operational expenditure**	10,722	22,317	108%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses		-	-
34	Overhead to underground conversion		247	-
35	Research and development		-	-
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses		N/A	-
39	Direct billing		N/A	-
40	Research and development		N/A	-
41	Insurance		192	-
42				

43 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of the Determination*

44 *2 From the nominal dollar expenditure forecast and disclosed in the second to last AMP as the year CY+1 forecast*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-Network Name	**Total Business**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8 **8(i): Billed Quantities by Price Component**

9
10
11 **Billed quantities by price component**

12 **Price component**

13 **Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
					LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
14															
15 Standard Domestic	Standard domestic	Standard	70,425	565,324	70,425		565,324,812						565,324,812		
15a Load Group 0	Non-domestic	Standard	346	33	346							348			
15b Load Group 0A	Non-domestic	Standard	415	716	415							414			
16 Load Group 1A	Non-domestic	Standard	770	2,405	770			6,171		772				6,171	772
17 Load Group 1	Non-domestic	Standard	5,586	41,249	5,586			83,798		14,210				83,798	14,210
18 Load Group 2	Non-domestic	Standard	5,916	260,522	5,916			315,707		48,328				315,707	48,328
19 Load Group 3	Non-domestic	Standard	193	51,317	193			41,077	644,116	9,564				41,077	9,564
20 Load Group 3A	Non-domestic	Standard	153	80,874	153			51,884	608,945	14,243				51,884	14,243
21 Load Group 4	Non-domestic	Standard	111	170,933	111			88,958	996,011	28,585	68,166			88,958	28,585
22 Load Group 5	Non-domestic	Standard	9	66,853	9			41,608	322,889	11,739	13,225			41,608	11,739
23 Street Lighting	Non-domestic	Standard	11	10,030	10	6,077	2,763,588					2	2,763,588		
24 Distributed Generation	Non-domestic	Standard	10	-	10										
25 *Add extra rows for additional consumer groups or price category codes as necessary*															
26		**Standard consumer totals**	83,945	1,250,257	83,944	6,077	568,088,400	629,203	2,571,961	127,441	81,391	764	568,088,400	629,203	127,441
27		**Non-standard consumer totals**	-	-	-	-	-	-	-	-	-	-	-	-	-
28		**Total for all consumers**	83,945	1,250,257	83,944	6,077	568,088,400	629,203	2,571,961	127,441	81,391	764	568,088,400	629,203	127,441

Add extra columns for additional billed quantities by price component as necessary

29

38 **8(ii): Line Charge Revenues ($000) by Price Component**

39
40 **Line charge revenues ($000) by price component**

41 **Price component**

42 **Rate (eg, $/day, $/kWh, etc.)**

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
							$ / annum	$ / lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
43																	
44 Standard domestic	Standard domestic	Standard	$45,757		$32,737	$13,020	$3,830		$28,908						$13,020		
44a Load Group 0	Non-standard domestic / non domestic	Standard	$72		$51	$22	$51							$22			
44b Load Group 0A	Non-standard domestic / non domestic	Standard	$188		$126	$62	$126							$62			
45 Load Group 1A	Non-standard domestic / non domestic	Standard	$319		$217	$103	$9			$120		$88				$35	$67
46 Load Group 1	Non-standard domestic / non domestic	Standard	$4,661		$3,058	$1,602	$64			$1,469		$1,526				$395	$1,207
47 Load Group 2	Non-standard domestic / non domestic	Standard	$15,356		$11,040	$4,316	$135			$5,764		$5,147	($6)			$323	$3,993
48 Load Group 3	Non-standard domestic / non domestic	Standard	$3,024		$2,115	$909	$86			$1,090	$197	$745	($3)			$132	$777
49 Load Group 3A	Non-standard domestic / non domestic	Standard	$3,939		$2,567	$1,372	$67			$1,297	$188	$1,022	($7)			$192	$1,180
50 Load Group 4	Non-standard domestic / non domestic	Standard	$6,640		$4,076	$2,564	$122			$1,357	$318	$1,723	$556			$258	$2,306
51 Load Group 5	Non-standard domestic / non domestic	Standard	$1,760		$792	$967	$10			$240	$84	$332	$127			$106	$861
52 Street Lighting	Non-standard domestic / non domestic	Standard	$822		$676	$145	$254	$335	$88					$109	$36		
53 Distributed Generation	Distributed generation	Standard	$568		$568	-	$568										
54 *Add extra rows for additional consumer groups or price category codes as necessary*																	
55		**Standard consumer totals**	$83,107	-	$58,024	$25,082	$5,322	$335	$28,996	$11,336	$787	$10,583	$666	$193	$13,056	$1,442	$10,391
56		**Non-standard consumer totals**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57		**Total for all consumers**	$83,107	-	$58,024	$25,082	$5,322	$335	$28,996	$11,336	$787	$10,583	$666	$193	$13,056	$1,442	$10,391

Add extra columns for additional line charge revenues by price component as necessary

58
59 **8(iii): Number of ICPs directly billed** **Check** OK

60 **Number of directly billed ICPs at year end**

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-Network Name	**Dunedin**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8(i): Billed Quantities by Price Component

Billed quantities by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
				Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
				Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Standard Domestic	Standard domestic	Standard	47,023	388,416	47,023		388,416,441						388,416,441		
Load Group 0	Non-domestic	Standard	137	(2)	137							137			
Load Group 0A	Non-domestic	Standard	111	143	111							111			
Load Group 1A	Non-domestic	Standard	395	1,169	395			3,167		407				3,167	407
Load Group 1	Non-domestic	Standard	2,990	21,730	2,990			44,853		7,815				44,853	7,815
Load Group 2	Non-domestic	Standard	3,020	138,822	3,020			159,923		26,864				159,923	26,864
Load Group 3	Non-domestic	Standard	100	30,806	100			20,955	112,753	6,002				20,955	6,002
Load Group 3A	Non-domestic	Standard	87	51,980	87			28,756	157,550	9,392				28,756	9,392
Load Group 4	Non-domestic	Standard	73	114,016	73			61,858	343,037	19,284	49,916			61,858	19,284
Load Group 5	Non-domestic	Standard	8	62,022	8			35,725	246,059	10,719	13,225			35,725	10,719
Street Lighting	Non-domestic	Standard	2	7,234	2							2			
Distributed Generation	Non-domestic	Standard	1	-	1										
Add extra rows for additional consumer groups or price category codes as necessary															
		Standard consumer totals	53,947	816,336	53,947	-	388,416,441	355,237	859,399	80,483	63,141	250	388,416,441	355,237	80,483
		Non-standard consumer totals	-	-	-	-	-	-	-	-	-	-	-	-	-
		Total for all consumers	53,947	816,336	53,947	-	388,416,441	355,237	859,399	80,483	63,141	250	388,416,441	355,237	80,483

Add extra columns for additional billed quantities by price component as necessary

8(ii): Line Charge Revenues ($000) by Price Component

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
						Price component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
						Rate (eg, $/day, $/kWh, etc.)	$ / annum	$ / lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Standard domestic	Standard domestic	Standard	$24,683		$16,250	$8,432	$2,554		$13,696						$8,432		
Load Group 0	Non-standard domestic / non domestic	Standard	$24		$14	$9	$14							$9			
Load Group 0A	Non-standard domestic / non domestic	Standard	$42		$25	$17	$25							$17			
Load Group 1A	Non-standard domestic / non domestic	Standard	$137		$79	$58	$4			$39		$36				$22	$36
Load Group 1	Non-standard domestic / non domestic	Standard	$2,148		$1,196	$952	$30			$481		$685				$263	$689
Load Group 2	Non-standard domestic / non domestic	Standard	$7,114		$4,572	$2,543	$65			$2,188		$2,318				$211	$2,332
Load Group 3	Non-standard domestic / non domestic	Standard	$1,443		$855	$588	$40			$478	$29	$308				$73	$515
Load Group 3A	Non-standard domestic / non domestic	Standard	$2,090		$1,174	$916	$35			$613	$41	$488	($3)			$102	$814
Load Group 4	Non-standard domestic / non domestic	Standard	$4,082		$2,300	$1,782	$75			$815	$87	$922	$400			$189	$1,594
Load Group 5	Non-standard domestic / non domestic	Standard	$1,567		$708	$859	$9			$224	$62	$288	$127			$66	$793
Street Lighting	Non-standard domestic / non domestic	Standard	$617		$508	$109	$254	$254						$109			
Distributed Generation	Distributed generation	Standard	$120		$120	-	$120										
Add extra rows for additional consumer groups or price category codes as necessary																	
		Standard consumer totals	$44,067	-	$27,800	$16,267	$3,224	$254	$13,696	$4,838	$219	$5,045	$524	$136	$8,432	$926	$6,772
		Non-standard consumer totals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Total for all consumers	$44,067	-	$27,800	$16,267	$3,224	$254	$13,696	$4,838	$219	$5,045	$524	$136	$8,432	$926	$6,772

Add extra columns for additional line charge revenues by price component as necessary

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-Network Name	**Central Otago**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8(i): Billed Quantities by Price Component

Billed quantities by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
					Price component										
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
Standard Domestic	Standard domestic	Standard	23,316	176,371		23,316		176,371,049						176,371,049		
Load Group 0	Non-domestic	Standard	209	35		209							209			
Load Group 0A	Non-domestic	Standard	302	569		302							302			
Load Group 1A	Non-domestic	Standard	374	1,232		374			2,996		364				2,996	364
Load Group 1	Non-domestic	Standard	2,596	19,518		2,596			38,940		6,395				38,940	6,395
Load Group 2	Non-domestic	Standard	2,895	121,697		2,895			155,756		21,463				155,756	21,463
Load Group 3	Non-domestic	Standard	93	20,511		93			20,122	531,363	3,562				20,122	3,562
Load Group 3A	Non-domestic	Standard	66	28,894		66			23,128	451,395	4,851				23,128	4,851
Load Group 4	Non-domestic	Standard	38	56,917		38			27,100	652,974	9,301	18,250			27,100	9,301
Load Group 5	Non-domestic	Standard	1	4,831		1			5,883	76,830	1,020				5,883	1,020
Street Lighting	Non-domestic	Standard	8	2,769		8	5,996	2,736,799						2,736,799		
Distributed Generation	Non-domestic	Standard	9			9										
Add extra rows for additional consumer groups or price category codes as necessary																
		Standard consumer totals	29,907	433,346		29,907	5,996	179,107,848	273,925	1,712,562	46,956	18,250	511	179,107,848	273,925	46,956
		Non-standard consumer totals	-	-		-	-	-	-	-	-	-	-	-	-	-
		Total for all consumers	29,907	433,346		29,907	5,996	179,107,848	273,925	1,712,562	46,956	18,250	511	179,107,848	273,925	46,956

Add extra columns for additional billed quantities by price component as necessary

8(ii): Line Charge Revenues ($000) by Price Component

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Perod Demand (Distribution)	Transformer Lease. Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
						Price component											
						Rate (eg, $/day, $/kWh, etc.)	$ / annum	$ / lamp	$ / kWh	$ / kVA	$ / kVA x km	$ / kW	$ / kVA	$ / annum	$ / kWh	$ / kVA	$ / kW
Standard domestic	Standard domestic	Standard	$21,012		$16,441	$4,571	$1,271		$15,170						$4,571		
Load Group 0	Non-standard domestic / non domestic	Standard	$49		$36	$12	$36							$12			
Load Group 0A	Non-standard domestic / non domestic	Standard	$145		$101	$45	$101							$45			
Load Group 1A	Non-standard domestic / non domestic	Standard	$182		$138	$44	$5			$81		$52				$13	$31
Load Group 1	Non-standard domestic / non domestic	Standard	$2,513		$1,862	$650	$34			$988		$841				$132	$519
Load Group 2	Non-standard domestic / non domestic	Standard	$8,241		$6,467	$1,774	$70			$3,575		$2,829	($6)			$112	$1,662
Load Group 3	Non-standard domestic / non domestic	Standard	$1,581		$1,260	$321	$46			$612	$168	$437	($3)			$59	$262
Load Group 3A	Non-standard domestic / non domestic	Standard	$1,848		$1,393	$456	$32			$683	$147	$534	($4)			$90	$365
Load Group 4	Non-standard domestic / non domestic	Standard	$2,558		$1,776	$782	$47			$542	$231	$801	$156			$70	$712
Load Group 5	Non-standard domestic / non domestic	Standard	$192		$84	$108	$1			$17	$22	$44				$40	$68
Street Lighting	Non-standard domestic / non domestic	Standard	$202		$166	$35		$80	$87						$35		
Distributed Generation	Distributed generation	Standard	$449		$449	-	$449										
Add extra rows for additional consumer groups or price category codes as necessary																	
		Standard consumer totals	$38,972	-	$30,173	$8,798	$2,092	$80	$15,257	$6,497	$568	$5,538	$142	$57	$4,607	$516	$3,619
		Non-standard consumer totals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Total for all consumers	$38,972	-	$30,173	$8,798	$2,092	$80	$15,257	$6,497	$568	$5,538	$142	$57	$4,607	$516	$3,619

Add extra columns for additional line charge revenues by price component as necessary

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Total Business**

SCHEDULE 9a: ASSET REGISTER

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy 1–4
9	All	Overhead Line	Concrete poles / steel structure	No.	20,442	20,814	372	4
10	All	Overhead Line	Wood poles	No.	33,346	32,942	(404)	4
11	All	Overhead Line	Other pole types	No.	17	4	(13)	4
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	513	512	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	16	17	1	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	-	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	41	41	-	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	-	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	27	28	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3	3	-	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	203	215	12	4
29	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	-	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	50	53	3	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	339	342	3	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	23	15	(8)	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	66	66	-	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,327	2,324	(3)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	4
37	HV	Distribution Line	SWER conductor	km	9	9	-	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	457	486	29	4
39	HV	Distribution Cable	Distribution UG PILC	km	426	429	3	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	-	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	42	42	-	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	12	12	-	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,323	6,366	43	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	927	947	20	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1,034	1,068	34	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,154	4,156	2	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	2,496	2,575	79	4
48	HV	Distribution Transformer	Voltage regulators	No.	37	39	2	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2,496	2,575	79	4
50	LV	LV Line	LV OH Conductor	km	1,052	1,050	(2)	4
51	LV	LV Cable	LV UG Cable	km	836	855	19	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	218	219	1	4
53	LV	Connections	OH/UG consumer service connections	No.	84,808	85,515	707	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	475	473	(2)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	95	96	1	4
56	All	Capacitor Banks	Capacitors including controls	No	3	3	-	4
57	All	Load Control	Centralised plant	Lot	6	6	-	4
58	All	Load Control	Relays	No	2,183	2,197	14	4
59	All	Civils	Cable Tunnels	km	-	-	-	4

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Dunedin**

SCHEDULE 9a: ASSET REGISTER

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy 1–4
9	All	Overhead Line	Concrete poles / steel structure	No.	13,888	14,015	127	4
10	All	Overhead Line	Wood poles	No.	15,296	15,139	(157)	4
11	All	Overhead Line	Other pole types	No.	13	-	(13)	4
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	144	-	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	1	1	-	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	-	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	41	41	-	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	-	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	18	18	-	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	81	93	12	4
29	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	23	23	-	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	261	261	-	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	35	35	-	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	732	731	(1)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	4
37	HV	Distribution Line	SWER conductor	km	9	9	-	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	28	29	1	4
39	HV	Distribution Cable	Distribution UG PILC	km	278	281	3	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	-	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	11	11	-	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	12	12	-	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,529	2,538	9	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	458	459	1	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	598	613	15	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,706	1,709	3	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	879	894	15	4
48	HV	Distribution Transformer	Voltage regulators	No.	13	13	-	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	879	894	15	4
50	LV	LV Line	LV OH Conductor	km	826	825	(1)	4
51	LV	LV Cable	LV UG Cable	km	238	245	7	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	152	152	-	4
53	LV	Connections	OH/UG consumer service connections	No.	54,494	54,638	144	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	307	307	-	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	38	39	1	4
56	All	Capacitor Banks	Capacitors including controls	No	3	3	-	4
57	All	Load Control	Centralised plant	Lot	3	3	-	4
58	All	Load Control	Relays	No	1,115	1,116	1	4
59	All	Civils	Cable Tunnels	km	-	-	-	4

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Central Otago**

SCHEDULE 9a: ASSET REGISTER

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy 1–4
9	All	Overhead Line	Concrete poles / steel structure	No.	6,554	6,799	245	4
10	All	Overhead Line	Wood poles	No.	18,050	17,803	(247)	4
11	All	Overhead Line	Other pole types	No.	4	4	-	4
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	369	368	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	16	1	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	9	10	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3	3	-	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	122	122	-	4
29	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	-	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	27	30	3	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	78	81	3	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	23	15	(8)	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	31	31	-	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,595	1,593	(2)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	4
37	HV	Distribution Line	SWER conductor	km	-	-	-	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	428	456	28	4
39	HV	Distribution Cable	Distribution UG PILC	km	147	147	-	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	31	31	-	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,794	3,828	34	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	467	486	19	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	434	453	19	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	2,448	2,447	(1)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,612	1,676	64	4
48	HV	Distribution Transformer	Voltage regulators	No.	24	26	2	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1,612	1,676	64	4
50	LV	LV Line	LV OH Conductor	km	226	225	(1)	4
51	LV	LV Cable	LV UG Cable	km	592	604	12	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	65	66	1	4
53	LV	Connections	OH/UG consumer service connections	No.	30,233	30,795	562	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	168	166	(2)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	57	57	-	4
56	All	Capacitor Banks	Capacitors including controls	No	-	-	-	4
57	All	Load Control	Centralised plant	Lot	3	3	-	4
58	All	Load Control	Relays	No	1,063	1,076	13	4
59	All	Civils	Cable Tunnels	km	-	-	-	4

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Total Business**

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	No. with Age unknown	Total assets at year end	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	-	36	1,710	6,215	4,833	3,206	1,853	94	105	204	137	79	118	190	173	218	107	142	233	586	484	91					20,814		3
11	All	Overhead Line	Wood poles	No.	1,324	1,586	2,878	9,449	6,075	3,960	3,398	341	237	407	457	316	278	333	292	323	331	344	349	154	96	14					32,942		3
12	All	Overhead Line	Other pole types	No.	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					4		3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	71	3	74	108	76	27	127	-	-	-	-	-	1	6	-	-	4	4	11	-	-	-					512		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	1	7	-	-	-	-	1	1	-	1	3	1	-	1	1	-	-					17		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	22	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					25		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	6	31	3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					41		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	9	-	-	-	1	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-					11		3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	1	5	3	7	5	4	-	-	-	-	-	-	-	-	-	1	-	1	-	1	-					28		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-					3		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	55	26	4	24	24	-	-	-	6	2	2	-	26	17	2	3	10	1	11	2					215		3
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					6		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	3	4	5	4	7	8	-	-	1	-	-	1	1	2	5	3	-	4	-	3	2					53		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	78	37	80	8	33	-	-	13	17	-	12	1	8	-	17	18	14	2	4	-					342		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	1	5	1	-	-	-	-	3	2	2	-	-	-	-	-	-	-	-	1	-					15		3
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	7	14	15	6	5	-	-	1	4	1	-	-	-	1	2	3	3	3	1	-					66		4
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	78	143	331	431	426	402	343	12	11	14	11	30	12	12	7	11	14	4	16	4	12	-					2,324		3
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
48	HV	Distribution Line	SWER conductor	km	-	-	6	2	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					9		3
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	-	5	13	74	22	23	32	50	37	28	63	38	16	20	13	12	8	27	5					486		3
50	HV	Distribution Cable	Distribution UG PILC	km	-	8	36	54	69	79	69	9	8	12	6	11	11	16	5	8	9	7	5	3	3	1					429		3
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					1		3
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	-	-	1	3	1	-	-	4	3	2	6	5	6	7	1	-	3	-	-					42		3
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	7	-	2	-	-	-	-	-	-	-	2	-	-	-	-	-	1	-	-	-					12		3
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	37	122	782	713	937	1,416	154	166	168	218	161	171	176	166	165	163	219	158	126	127	20					6,366		3
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	10	109	73	82	183	29	27	34	31	42	42	51	40	42	51	22	36	21	19	3					947		3
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	4	95	182	273	28	34	72	28	52	36	26	38	38	32	34	38	18	34	6					1,068		3
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	13	41	354	526	713	1,245	117	114	140	116	82	89	82	84	77	60	61	72	81	75	13					4,156		3
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	3	72	172	210	415	91	102	131	144	189	160	189	145	131	89	77	68	70	103	14					2,575		3
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	2	5	4	4	-	-	-	3	-	3	3	2	4	5	-	-	2	2	-					39		3
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	3	72	172	210	415	91	102	131	144	189	160	189	145	131	89	77	68	70	103	14					2,575		3
61	LV	LV Line	LV OH Conductor	km	56	43	109	264	212	171	153	5	2	5	5	4	3	3	2	2	3	3	1	2	2	-					1,050		3
62	LV	LV Cable	LV UG Cable	km	-	-	2	26	43	174	156	22	23	36	45	55	50	46	45	31	28	14	21	16	18	4					855		3
63	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	5	3	4	12	12	26	102	2	1	2	4	3	5	5	5	3	6	4	4	8	3	-					219		3
64	LV	Connections	OH/UG consumer service connections	No.	13,023	3,696	6,980	8,718	7,028	4,548	22,941	1,003	1,207	1,429	1,482	1,657	1,699	1,596	1,735	1,359	1,081	1,127	913	1,177	894	222					85,515		3
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	3	90	47	87	16	50	1	-	17	26	5	17	8	15	11	27	19	19	5	8	2					473		3
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-	17	-	-	6	10	5	9	1	5	1	5	9	2	6	12	5	3					96		3
67	All	Capacitor Banks	Capacitors including controls	No	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-					3		3
68	All	Load Control	Centralised plant	Lot	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1	-	1	3	-	-					6		4
69	All	Load Control	Relays	No	1	1	12	181	263	262	491	51	45	59	92	150	116	140	104	56	56	30	36	28	22	1					2,197		3
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Dunedin**

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	No. with Age unknown	Total assets at year end	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	-	17	1,621	5,779	2,946	2,148	806	23	11	78	31	11	32	33	23	17	11	30	46	155	159	38					14,015		3
11	All	Overhead Line	Wood poles	No.	1,324	1,545	2,679	3,561	1,265	1,356	1,791	197	128	119	123	93	124	131	114	171	104	92	113	60	47	2					15,139		3
12	All	Overhead Line	Other pole types	No.		-	-	-		-	-			-	-		-	-	-		-	-	-			-					-		3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	62	-	63	14	3	-	2		-	-	-		-	-	-		-	-	-	-		-					144		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-		-	-			-	-		-		-				-								-		3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	-	-		-	-	-		-	-	-	1	-	-	-	-	-	-					1		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	22	3	-		-	-	-		-	-	-		-		-	-	-	-					25		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	6	31	3	1	-		-	-	-		-	-	-		-		-	-	-	-					41		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	9	-	-	-	1		-	-	-	1	-	-	-	-	-	-	-	-	-	-					11		3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	1	5	3	6	2	1		-	-	-		-	-	-		-	-	-	-	-	-					18		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		3
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	41	22	1	-	6		-	-	-		-	-	-		-	2	8	-	11	2					93		3
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-		-	-					-		3
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					-		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	3	-	2	4	-	-		-	1	-		-	1	2	5	-	-	3	-	2	-					23		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	78	37	78	-	13		-	-	17		9		-	-	11	17	-	1	-	-					261		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	-		-	-	-		-		-	-	-	-	-	-	-	-					-		3
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.			6	10	10	2	2								-	1		2	-	2		-					35		4
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2	35	122	251	137	68	64	5	4	6	5	6	5	1	4	6	5	1	2		2						731		3
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-		-	-	-		-	-	-		-		-		-	-					-		3
48	HV	Distribution Line	SWER conductor	km	-	-	6	2	-	1	-		-	-	-		-	-	-		-		-	-	-	-					9		3
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	-	-	-	5	2	2	1	4	2	3	3	2	1	1	1	1	1	-	-					29		3
50	HV	Distribution Cable	Distribution UG PILC	km	-	8	36	54	69	51	29	2	1	1	1	2	3	1	1	3	3	7	3	2	3	1					281		3
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	1	-	-	-	-	-		-	-	-		-	-	-		-	-	-	-	-	-					1		3
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	-	-	-	-	1	-	-	-		1	4	-	-	3	1	-	1	-	-					11		3
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	7	-	2	-	-		-	-	-		2		-		-		1		-	-					12		3
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	23	76	624	461	443	497	14	19	27	42	30	49	44	29	21	33	18	23	29	29	7					2,538		3
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	10	109	73	73	70	5	9	6	12	3	7	3	7	14	13	20	9	14	2	-					459		3
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	4	89	164	183	14	6	16	8	22	14	6	4	14	12	18	12	6	21	-					613		3
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	6	222	272	313	518	39	25	48	32	27	38	33	21	15	21	13	21	22	21	2					1,709		3
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	3	72	156	160	218	11	17	22	18	19	31	29	13	19	22	20	19	20	21	4					894		3
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	2	5	2	4																				13		3
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	3	72	156	160	218	11	17	22	18	19	31	29	13	19	22	20	19	20	21	4					894		3
61	LV	LV Line	LV OH Conductor	km	52	26	70	193	169	151	133	4	2	3	4	3	3	2	2	1	2	2	-	2	1	-					825		3
62	LV	LV Cable	LV UG Cable	km	-	-	2	26	43	38	36	3	4	5	6	8	14	9	9	5	9	5	8	6	7	2					245		3
63	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	5	3	4	11	10	9	90	-	-	-	-	-	1	1	1	2	4	2	2	6	1	-					152		3
64	LV	Connections	OH/UG consumer service connections	No.	13,023	3,696	6,980	8,712	7,022	4,543	4,797	291	269	368	433	502	500	521	557	406	393	461	367	404	336	57					54,638		3
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	3	85	39	84	-	13	1	-	1	17	-	12	5	2	5	14	18	4	2	2	-					307		3
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-	17	-	-	2	-	1	1	-	1	-	-	1	-	1	9	3	3					39		3
67	All	Capacitor Banks	Capacitors including controls	No	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-					3		3
68	All	Load Control	Centralised plant	Lot	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-					3		4
69	All	Load Control	Relays	No	1	1	12	177	244	207	311	14	7	12	8	9	12	14	10	9	18	12	21	12	5	-					1,116		3
70	All	Civils	Cable Tunnels	km			-				-	-			-				-				-								-		3

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Central Otago**

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	No. with Age unknown	Total assets at year end	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	-	19	89	436	1,887	1,058	1,047	71	94	126	106	68	86	157	150	201	96	112	187	431	325	53					6,799		3
11	All	Overhead Line	Wood poles	No.	-	41	199	5,888	4,810	2,604	1,607	144	109	288	334	223	154	202	178	152	227	252	236	94	49	12					17,803		3
12	All	Overhead Line	Other pole types	No.	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					4		3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9	3	12	94	72	27	125	-	-	-	-	-	1	6	-	-	4	4	11	-	-	-					368		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	1	7	-	-	-	-	1	1	-	1	2	1	-	1	1	-	-					16		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	-	-	1	3	3	-	-	-	-	-	-	-	-	-	1	-	1	-	1	-					10		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-					3		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	14	4	3	24	18	-	-	-	6	2	2	-	26	17	2	1	2	1	-	-					122		3
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					6		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	4	3	-	7	8	-	-	-	-	-	1	-	-	-	3	-	1	-	1	2					30		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	-	2	8	20	-	-	13	-	-	3	1	8	-	6	1	14	1	4	-					81		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	1	5	1	-	-	2	2	3	-	-	-	-	-	-	-	-	-	-	1	-					15		3
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	1	4	5	4	3	-	-	1	4	1	-	-	-	-	2	1	3	1	1	-					31		4
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	77	108	210	179	288	334	279	7	7	8	6	25	7	11	3	5	9	2	14	4	10	-					1,593		3
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
48	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	-	5	13	70	20	21	30	46	34	24	61	36	15	19	12	11	7	27	5					456		3
50	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	-	-	27	40	7	7	10	5	9	8	14	4	5	7	1	2	1	-	-					147		3
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	-	-	1	3	-	-	-	4	3	1	2	5	6	4	-	-	2	-	-					31		3
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	14	46	158	252	494	919	140	147	141	176	131	122	132	137	144	130	201	135	97	98	13					3,828		3
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	9	113	24	18	28	19	39	33	48	33	28	38	2	27	7	17	3					486		3
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	-	6	18	90	14	28	56	20	30	20	20	34	24	20	16	26	12	13	6					453		3
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	13	35	132	254	400	727	78	89	92	84	55	51	49	63	62	39	48	51	59	54	11					2,447		3
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	-	-	16	50	197	80	85	109	126	170	124	160	132	112	67	57	49	50	82	10					1,676		3
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	2	-	-	-	-	3	-	3	3	2	4	5	-	-	2	2	-					26		3
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	16	50	197	80	85	109	126	170	124	160	132	112	67	57	49	50	82	10					1,676		3
61	LV	LV Line	LV OH Conductor	km	4	17	40	72	43	22	21	1	-	1	-	1	-	1	-	1	1	-	-	-	-	-					225		3
62	LV	LV Cable	LV UG Cable	km	-	-	-	-	1	137	120	19	18	31	39	46	31	36	36	26	19	9	13	10	10	3					604		3
63	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	-	-	-	1	2	17	12	2	1	2	4	3	3	4	4	1	2	2	2	2	2	-					66		3
64	LV	Connections	OH/UG consumer service connections	No.	-	-	-	6	6	5	18,144	712	938	1,061	1,049	1,155	1,197	1,060	1,162	939	681	653	536	769	557	165					30,795		3
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	5	8	3	16	37	2	2	16	7	3	5	3	13	6	13	1	15	3	6	2					166		3
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-	-	-	-	4	10	4	8	1	4	1	5	8	2	5	3	2	-					57		3
67	All	Capacitor Banks	Capacitors including controls	No	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3
68	All	Load Control	Centralised plant	Lot	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-					3		4
69	All	Load Control	Relays	No	-	-	-	4	19	55	180	37	38	47	84	141	99	126	94	47	38	18	15	16	17	1					1,076		3
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					-		3

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Total Business**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV			-
12	50kV & 66kV	108	1	109
13	33kV	405	96	501
14	SWER (all SWER voltages)	9		9
15	22kV (other than SWER)			-
16	6.6kV to 11kV (inclusive—other than SWER)	2,327	937	3,264
17	Low voltage (< 1kV)	1,052	861	1,913
18	**Total circuit length (for supply)**	3,901	1,895	5,796
19				
20	Dedicated street lighting circuit length (km)	47	157	204
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	1,148	29%	
25	Rural	2,649	68%	
26	Remote only		-	
27	Rugged only	104	3%	
28	Remote and rugged		-	
29	Unallocated overhead lines		-	
30	**Total overhead length**	3,901	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,131	37%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	191	5%	

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Dunedin**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV			-
12	50kV & 66kV			-
13	33kV	144	80	224
14	SWER (all SWER voltages)	9		9
15	22kV (other than SWER)			-
16	6.6kV to 11kV (inclusive—other than SWER)	732	478	1,210
17	Low voltage (< 1kV)	826	247	1,073
18	**Total circuit length (for supply)**	1,711	805	2,516
19				
20	Dedicated street lighting circuit length (km)	44	99	143
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
22				

		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	961	56%
25	Rural	736	43%
26	Remote only		-
27	Rugged only	14	1%
28	Remote and rugged		-
29	Unallocated overhead lines		-
30	**Total overhead length**	1,711	100%
31			

		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,131	85%

		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	91	5%

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Central Otago**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV			-
12	50kV & 66kV	108	1	109
13	33kV	261	16	277
14	SWER (all SWER voltages)			-
15	22kV (other than SWER)			-
16	6.6kV to 11kV (inclusive—other than SWER)	1,595	620	2,215
17	Low voltage (< 1kV)	226	609	835
18	**Total circuit length (for supply)**	2,190	1,246	3,436
19				
20	Dedicated street lighting circuit length (km)	3	57	60
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
22				

		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	187	9%
25	Rural	1,913	87%
26	Remote only		-
27	Rugged only	90	4%
28	Remote and rugged		-
29	Unallocated overhead lines		-
30	**Total overhead length**	2,190	100%
31			

		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)		-

		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	100	5%

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

This schedule requires information concerning embedded networks owned by an EDB that are embedded in another EDB's network or in another embedded network.

sch ref

	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9	Heritage Park Subdivision, Te Anau	94	69
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

26 ** Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network*

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Total Business**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

8 **9e(i): Consumer Connections**

9 *Number of ICPs connected in year by consumer type*

sch ref	Consumer types defined by EDB*	Number of connections (ICPs)
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**
11	Standard domestic (8 and 15kVA variable)	670
11a	Load group 0 (1 kVA un-metered)	14
11b	Load group 0A (2 kVA un-metered)	4
11c	Load group 1A (8 kVA, plus standard domestic 8 kVA)	8
11d	Load group 1 (15 kVA, plus standard domestic 15 kVA)	(86)
11e	Load group 2 (16 - 149 kVA)	78
11f	Load group 3 (150 - 249 kVA)	7
12	Load group 3A (250 - 499 kVA)	(4)
13	Load group 4 (500 - 2,499 kVA)	1
14	Load group 5 (2,500+ kVA)	-
15	Street lighting	-
16	** include additional rows if needed*	
17	**Connections total**	692

18

19 **Distributed generation**

20	Number of connections made in year	73	**connections**
21	Capacity of distributed generation installed in year	4.383	**MVA**

22 **9e(ii): System Demand**

23

24

25	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26	GXP demand	215	
27	*plus* Distributed generation output at HV and above	64	
28	**Maximum coincident system demand**	279	
29	*less* Net transfers to (from) other EDBs at HV and above	-	
30	**Demand on system for supply to consumers' connection points**	279	
31	**Electricity volumes carried**	**Energy (GWh)**	**Energy (GWh)**
32	Electricity supplied from GXPs	1,056	
33	*less* Electricity exports to GXPs	36	
34	*plus* Electricity supplied from distributed generation	300	
35	*less* Net electricity supplied to (from) other EDBs	(1)	
36	**Electricity entering system for supply to consumers' connection points**	1,321	
37	*less* Total energy delivered to ICPs	1,250	
38	**Electricity losses (loss ratio)**	71	5.3%
39			
40	**Load factor**	1	

41 **9e(iii): Transformer Capacity**

42		**(MVA)**
43	Distribution transformer capacity (EDB owned)	837
44	Distribution transformer capacity (Non-EDB owned)	73
45	**Total distribution transformer capacity**	910
46		
47	**Zone substation transformer capacity**	901

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Dunedin**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

8 **9e(i): Consumer Connections**

9 *Number of ICPs connected in year by consumer type*

sch ref	Consumer types defined by EDB*	Number of connections (ICPs)
11	Standard domestic (8 and 15kVA variable)	670
11a	Load group 0 (1 kVA un-metered)	13
11b	Load group 0A (2 kVA un-metered)	4
11c	Load group 1A (8 kVA, plus standard domestic 8 kVA)	(1)
11d	Load group 1 (15 kVA, plus standard domestic 15 kVA)	(96)
11e	Load group 2 (16 - 149 kVA)	(6)
11f	Load group 3 (150 - 249 kVA)	4
12	Load group 3A (250 - 499 kVA)	(5)
13	Load group 4 (500 - 2,499 kVA)	(2)
14	Load group 5 (2,500+ kVA)	-
15	Street lighting	-
16	** include additional rows if needed*	
17	**Connections total**	581

18

19 **Distributed generation**

sch ref			
20	Number of connections made in year	21	**connections**
21	Capacity of distributed generation installed in year	4.079	**MVA**

22 **9e(ii): System Demand**

23

24

25 **Maximum coincident system demand**

sch ref			Demand at time of maximum coincident demand (MW)
26		GXP demand	159
27	*plus*	Distributed generation output at HV and above	36
28		**Maximum coincident system demand**	195
29	*less*	Net transfers to (from) other EDBs at HV and above	-
30		**Demand on system for supply to consumers' connection points**	195

31 **Electricity volumes carried**

sch ref			Energy (GWh)	Energy (GWh)
32		Electricity supplied from GXPs	724	
33	*less*	Electricity exports to GXPs	2	
34	*plus*	Electricity supplied from distributed generation	144	
35	*less*	Net electricity supplied to (from) other EDBs	-	
36		**Electricity entering system for supply to consumers' connection points**	866	
37	*less*	Total energy delivered to ICPs	1,250	
38		**Electricity losses (loss ratio)**	(384)	(44.4%)
39				
40		**Load factor**	1	

41 **9e(iii): Transformer Capacity**

sch ref		(MVA)
43	Distribution transformer capacity (EDB owned)	479
44	Distribution transformer capacity (Non-EDB owned)	49
45	**Total distribution transformer capacity**	528
46		
47	**Zone substation transformer capacity**	610

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Central Otago**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

8 **9e(i): Consumer Connections**

9 *Number of ICPs connected in year by consumer type*

sch ref	Consumer types defined by EDB*	Number of connections (ICPs)
11	Standard domestic (8 and 15kVA variable)	670
11a	Load group 0 (1 kVA un-metered)	1
11b	Load group 0A (2 kVA un-metered)	4
11c	Load group 1A (8 kVA, plus standard domestic 8 kVA)	9
11d	Load group 1 (15 kVA, plus standard domestic 15 kVA)	12
11e	Load group 2 (16 - 149 kVA)	84
11f	Load group 3 (150 - 249 kVA)	3
12	Load group 3A (250 - 499 kVA)	1
13	Load group 4 (500 - 2,499 kVA)	3
14	Load group 5 (2,500+ kVA)	-
15	Street lighting	-
16	** include additional rows if needed*	
17	**Connections total**	787

18

19 **Distributed generation**

20	Number of connections made in year	52	**connections**
21	Capacity of distributed generation installed in year	0.304	**MVA**

22 **9e(ii): System Demand**

23

24

25 **Maximum coincident system demand**

			Demand at time of maximum coincident demand (MW)
26		GXP demand	73
27	*plus*	Distributed generation output at HV and above	24
28		**Maximum coincident system demand**	97
29	*less*	Net transfers to (from) other EDBs at HV and above	-
30		**Demand on system for supply to consumers' connection points**	97

31 **Electricity volumes carried**

			Energy (GWh)	Energy (GWh)
32		Electricity supplied from GXPs	332	
33	*less*	Electricity exports to GXPs	34	
34	*plus*	Electricity supplied from distributed generation	156	
35	*less*	Net electricity supplied to (from) other EDBs	-	
36		**Electricity entering system for supply to consumers' connection points**	454	
37	*less*	Total energy delivered to ICPs	1,250	
38		**Electricity losses (loss ratio)**	(796)	(175.3%)
39				
40		**Load factor**	1	

41 **9e(iii): Transformer Capacity**

		(MVA)
42		
43	Distribution transformer capacity (EDB owned)	357
44	Distribution transformer capacity (Non-EDB owned)	24
45	**Total distribution transformer capacity**	381
46		
47	**Zone substation transformer capacity**	291

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Total Business**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(i): Interruptions**

	Number of interruptions
Interruptions by class	
Class A (planned interruptions by Transpower)	
Class B (planned interruptions on the network)	257
Class C (unplanned interruptions on the network)	453
Class D (unplanned interruptions by Transpower)	
Class E (unplanned interruptions of EDB owned generation)	
Class F (unplanned interruptions of generation owned by others)	
Class G (unplanned interruptions caused by another disclosing entity)	
Class H (planned interruptions caused by another disclosing entity)	
Class I (interruptions caused by parties not included above)	
Total	710

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	440	270

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)		
Class B (planned interruptions on the network)	0.10	22.8
Class C (unplanned interruptions on the network)	1.11	71.7
Class D (unplanned interruptions by Transpower)		
Class E (unplanned interruptions of EDB owned generation)		
Class F (unplanned interruptions of generation owned by others)		
Class G (unplanned interruptions caused by another disclosing entity)		
Class H (planned interruptions caused by another disclosing entity)		
Class I (interruptions caused by parties not included above)		
Total	1.21	94.5

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
Classes B & C (interruptions on the network)	1.21	94.5

Quality path normalised reliability limit	SAIFI reliability limit	SAIDI reliability limit
SAIFI and SAIDI limits applicable to disclosure year*	1.67	98.3

** not applicable to exempt EDBs*

10(ii): Class C Interruptions and Duration by Cause

Cause	SAIFI	SAIDI
Lightning	0.05	2.9
Vegetation	0.23	20.5
Adverse weather	0.11	9.6
Adverse environment	0.02	0.8
Third party interference	0.07	5.8
Wildlife	0.03	1.7
Human error	0.04	1.3
Defective equipment	0.21	18.1
Cause unknown	0.37	13.6

10(iii): Class B Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.2
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	0.09	18.6
Distribution cables (excluding LV)	0.01	2.0
Distribution other (excluding LV)	0.01	2.0

10(iv): Class C Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.13	3.5
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	0.86	55.0
Distribution cables (excluding LV)	0.04	7.2
Distribution other (excluding LV)	0.08	6.1

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	33	513	6.43
Subtransmission cables		97	-
Subtransmission other			
Distribution lines (excluding LV)	586	2,336	25.09
Distribution cables (excluding LV)	56	937	5.98
Distribution other (excluding LV)	112		
Total	787		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Dunedin**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(i): Interruptions**

	Number of interruptions
Interruptions by class	
Class A (planned interruptions by Transpower)	
Class B (planned interruptions on the network)	33
Class C (unplanned interruptions on the network)	133
Class D (unplanned interruptions by Transpower)	
Class E (unplanned interruptions of EDB owned generation)	
Class F (unplanned interruptions of generation owned by others)	
Class G (unplanned interruptions caused by another disclosing entity)	
Class H (planned interruptions caused by another disclosing entity)	
Class I (interruptions caused by parties not included above)	
Total	166

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	101	65

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)		
Class B (planned interruptions on the network)	0.01	1.81
Class C (unplanned interruptions on the network)	0.40	31.3
Class D (unplanned interruptions by Transpower)		
Class E (unplanned interruptions of EDB owned generation)		
Class F (unplanned interruptions of generation owned by others)		
Class G (unplanned interruptions caused by another disclosing entity)		
Class H (planned interruptions caused by another disclosing entity)		
Class I (interruptions caused by parties not included above)		
Total	0.41	33.2

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
Classes B & C (interruptions on the network)	0.41	33.2

Quality path normalised reliability limit	SAIFI reliability limit	SAIDI reliability limit
SAIFI and SAIDI limits applicable to disclosure year*	0.89	49.2

** not applicable to exempt EDBs*

10(ii): Class C Interruptions and Duration by Cause

Cause	SAIFI	SAIDI
Lightning	0.00	0.2
Vegetation	0.13	8.5
Adverse weather	0.06	6.8
Adverse environment	0.00	0.8
Third party interference	0.03	3.3
Wildlife	0.03	2.1
Human error	0.00	0.1
Defective equipment	0.07	5.6
Cause unknown	0.07	3.9

10(iii): Class B Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	-	-
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	0.01	1.2
Distribution cables (excluding LV)	0.00	0.3
Distribution other (excluding LV)	0.00	0.3

10(iv): Class C Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.05	1.6
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	0.30	25.1
Distribution cables (excluding LV)	0.02	2.1
Distribution other (excluding LV)	0.03	2.6

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	4	144	2.78
Subtransmission cables		80	-
Subtransmission other			
Distribution lines (excluding LV)	119	741	16.06
Distribution cables (excluding LV)	16	478	3.35
Distribution other (excluding LV)	31		
Total	170		

Company Name	**Aurora Energy Limited**
For Year Ended	**31 March 2014**
Network / Sub-network Name	**Central Otago**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(i): Interruptions**

	Number of interruptions
Interruptions by class	
Class A (planned interruptions by Transpower)	
Class B (planned interruptions on the network)	224
Class C (unplanned interruptions on the network)	320
Class D (unplanned interruptions by Transpower)	
Class E (unplanned interruptions of EDB owned generation)	
Class F (unplanned interruptions of generation owned by others)	
Class G (unplanned interruptions caused by another disclosing entity)	
Class H (planned interruptions caused by another disclosing entity)	
Class I (interruptions caused by parties not included above)	
Total	544

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	339	205

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)		
Class B (planned interruptions on the network)	0.28	60.7
Class C (unplanned interruptions on the network)	2.39	144.7
Class D (unplanned interruptions by Transpower)		
Class E (unplanned interruptions of EDB owned generation)		
Class F (unplanned interruptions of generation owned by others)		
Class G (unplanned interruptions caused by another disclosing entity)		
Class H (planned interruptions caused by another disclosing entity)		
Class I (interruptions caused by parties not included above)		
Total	2.66	205.4

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
Classes B & C (interruptions on the network)	2.66	205.4

Quality path normalised reliability limit	SAIFI reliability limit	SAIDI reliability limit
SAIFI and SAIDI limits applicable to disclosure year*	3.69	218.3

** not applicable to exempt EDBs*

10(ii): Class C Interruptions and Duration by Cause

Cause	SAIFI	SAIDI
Lightning	0.13	7.8
Vegetation	0.41	42.3
Adverse weather	0.21	14.6
Adverse environment	0.05	0.7
Third party interference	0.14	10.3
Wildlife	0.03	0.9
Human error	0.10	3.5
Defective equipment	0.47	40.7
Cause unknown	0.90	30.9

10(iii): Class B Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.5
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	0.23	50.1
Distribution cables (excluding LV)	0.02	5.0
Distribution other (excluding LV)	0.02	5.0

10(iv): Class C Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.26	6.9
Subtransmission cables	-	-
Subtransmission other	-	-
Distribution lines (excluding LV)	1.87	109.0
Distribution cables (excluding LV)	0.08	16.5
Distribution other (excluding LV)	0.18	12.3

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	29	369	7.86
Subtransmission cables		17	-
Subtransmission other			
Distribution lines (excluding LV)	467	1,595	29.28
Distribution cables (excluding LV)	40	620	6.45
Distribution other (excluding LV)	81		
Total	617		

Company Name	Aurora Energy Limited
For Year Ended	31 March 2014

Schedule 14 Mandatory Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

1. This Schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and 2.5.2.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 12 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

4. In the box below, comment on return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

Box 1: Explanatory comment on return on investment

The 2014 ROI is between the midpoint and the 75th percentile estimate of WACC. There have been no items reclassified in accordance with clause 2.7.1(2)

The 2013 ROI has been restated to reflect:

(a) the correction to the Regulatory Asset Base (RAB) roll-forward for the year 2011 disclosed in schedule 5h of the ID Disclosures where the revaluation rate for year ending 2011 that was disclosed as being 4.47% rather than 2.41%. This error in the CPI being incorrectly applied resulted in Aurora's RAB for year ending 2011 being overstated by $6.024m (1.92%). It also affected Aurora's subsequent RAB roll-forward for 2012 and 2013 disclosed in schedule 4 and 5h.
The changes arising from this restatement were disclosed in the amended 2013 Templates supplied to the Commission on the 4 March 2014.

(b) The correction of the 2013 Regulatory Tax Allowance and Regulatory Profit calculations to remove the $2.684 million of revaluation which should have been excluded / deducted from the Regulatory Tax income by being disclosed in the line Income included in regulatory profit / (loss) before tax but not taxable.

Regulatory Profit (Schedule 3)

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-

   5.1 a description of material items included in 'other regulatory line income' other than gains and losses on asset sales, as disclosed in 3(i) of Schedule 3

   5.2 information on reclassified items in accordance with clause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit

Included in 'other regulatory line income' are the following (all figures in $000's):

- Transmission Rental Rebate Received $1,182
- Transmission Charge Recovered $ 1,537
- Other income incl accident damage $ 506

There have been no items reclassified in accordance with clause 2.7.1(2)

Merger and acquisition expenses (3(iv) of Schedule 3)

6. If the EDB incurred merger and acquisitions expenditure during the disclosure year, provide the following information in the box below-

   6.1 information on reclassified items in accordance with clause 2.7.1(2)

   6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

Box 3: Explanatory comment on merger and acquisition expenditure

There were no merger and acquisition costs incurred.

Value of the Regulatory Asset Base (Schedule 4)

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)

The amounts disclosed in the regulatory asset base calculations as assets commissioned have been reduced by the amount of customer contributions received and have been adjusted in respect of acquisitions sourced from Delta Utility Services Ltd (a related party).

In respect of the 2010 to 2013 regulatory assets bases, related party transactions have been recorded either at:

- Directly attributable cost plus allowance for indirect / overhead expenses incurred by Delta or
- At valuation – in accordance with an independent valuation process under taken in respect of specific larger projects.

Due to time constraints in obtaining market valuations for previous related party transactions, approval had been sought and given to revalue related party transactions retrospectively for prior disclosure years.

During the 2014 year a number of previous capital transactions were independently valued and the opening value of the 2014 regulatory asset base was accordingly adjusted as follows:

Removal of Related Party Deemed Cost

In respect of 2010 Disclosure Additions	(810,088.70)
In respect of 2011 Disclosure Additions	(606,390.79)
In respect of 2012 Disclosure Additions	(1,052,352.11)
In respect of 2013 Disclosure Additions	(457,693.05)
	(2,926,524.65)

Add Back Independent Valuations Now Applied

In respect of 2010 Disclosure Additions	1,354,765.00
In respect of 2011 Disclosure Additions	759,084.00
In respect of 2012 Disclosure Additions	1,814,558.00
In respect of 2013 Disclosure Additions	648,319.00
	4,576,726.00
Net Increase in Related Party Assets Acquired	**1,650,201.35**

These adjustments accordingly impacted upon the values of the regulatory asset base as it rolled forward for the 2010 to 2013 years, explained as follows:

As presented in Amended 2013 Information Disclosure (following correction to 2010 CPI reval)

		RAB 31 Mar 10 ($000)	RAB 31 Mar 11 ($000)	RAB 31 Mar 12 ($000)	RAB 31 Mar 13 ($000)
	Total opening RAB value	285,613	294,086	306,920	312,366
less	**Total depreciation**	10,135	10,288	10,779	11,052
plus	**Total revaluations**	5,845	7,111	4,821	2,684
plus	**Assets commissioned**	12,763	16,217	11,973	12,695
less	**Asset disposals**	-	206	569	-
plus	**Lost and found assets adjustment**	-	-		-
plus	**Adjustment resulting from asset allocation**	-	-		-
	Total closing RAB value	294,086	306,920	312,366	316,693

As restated following retrospective Change in Related Party capital Transactions taken at cost to Independent Valuation

		RAB 31 Mar 10 ($000)	RAB 31 Mar 11 ($000)	RAB 31 Mar 12 ($000)	RAB 31 Mar 13 ($000)
	Total opening RAB value	285,613	294,631	307,618	313,820
less	**Total depreciation**	10,135	10,301	10,796	11,086
plus	**Total revaluations**	5,845	7,125	4,832	2,696
plus	**Assets commissioned**	13,308	16,369	12,735	12,886
less	**Asset disposals**	-	206	569	-
plus	**Lost and found assets adjustment**	-			

plus **Adjustment resulting from asset allocation**	-			
Total closing RAB value	294,631	307,618	313,820	318,316

In respect of the 2014 disclosure year, related party transactions have been recorded either at :

- Directly attributable cost incurred by Delta or
- At valuation – in accordance with an independent valuation process under taken in respect of specific larger projects

The impact of these adjustments are as follows ($000):	2014 Yr
Original Cost (and regulatory tax value)	22,387
Less offset customer contributions	(4,087)
Less margin/ indirect cost on related party capex	(4,321)
Less original cost of assets subject to valuation	(5,151)
Plus assets included at valuation	4,545

Value RAB assets commissioned	13,374

There have been no items reclassified in accordance with clause 2.7.1(2)

Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)

8. In the box below, provide descriptions and workings of the following items, as recorded in the asterisked categories in 5a(i) of Schedule 5a-

   8.1 income not included in regulatory profit / (loss) before tax but taxable;

   8.2 expenditure or loss in regulatory profit / (loss) before tax but not deductible;

   8.3 income included in regulatory profit / (loss) before tax but not taxable;

   8.4 expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences

The figure shown in 'Income not included in regulatory profit / (loss) before tax but taxable' is an adjustment in respect of $1,513,000 of customer contribution that is assessable for income tax purposes in that year.

The figure 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' relates to $19,000 of doubtful debts.

The figure 'income included in regulatory profit / (loss) before tax but not taxable relates to the $4,879,000 from the revaluation of the 2014 regulatory asset base.

Regulatory tax allowance: disclosure of temporary differences (5a(vi) of Schedule 5a)

9. In the box below, provide descriptions and workings of items recorded in the asterisked category 'Tax effect of other temporary differences' in 5a(vi) of Schedule 5a.

Box 6: Temporary differences / Tax effect of other temporary differences (current disclosure year)

The $419,000 shown in the line 'Tax effect of other temporary differences' is ($000):

Value of customer contributions as above	$1,513
Less doubtful debts as above	($19)

Sub-total of differences	$1,494
Tax effect at 28%	$418

Related party transactions: disclosure of related party transactions (Schedule 5b)

10. In the box below, provide descriptions of related party transactions beyond those disclosed on schedule 5b including identification and descriptions as to the nature of directly attributable costs disclosed under clause 2.3.6(1)(b).

Box 7: Related party transactions

Over 50% of sales of goods and service by Aurora's sibling company, Delta Utility Services Limited, are to third parties and third parties may purchase the same or similar goods and services provided to Aurora on substantially the same terms and conditions, including price

Accordingly, related party transactions disclosed in schedule 5b are valued in accordance with clause 2.3.6(1)(c).

Cost allocation (Schedule 5d)

11. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

Box 8: Cost allocation

Operating costs along with pass through and recoverable costs are all directly attributable to the regulated business.

Operating costs include the overhead component of related party capex expenditure.

There have been no items reclassified in accordance with clause 2.7.1(2).

Asset allocation (Schedule 5e)

12. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

Box 9: Commentary on asset allocation

All assets acquired are all directly attributable to the regulated business.

There have been no items reclassified in accordance with clause 2.7.1(2).

Capital Expenditure for the Disclosure Year (Schedule 6a)

13. In the box below, comment on capital expenditure for the disclosure year, as disclosed in Schedule 6a. This comment must include-

    13.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;

    13.2 information on reclassified items in accordance with clause 2.7.1(2),

Box 10: Explanation of capital expenditure for the disclosure year

Consumer connection capital expenditure disclosed in 6a(iii) is all connections. Insufficient data is currently captured to align that expenditure with consumer load groups.

The listed projects are the higher value projects included within the specific reporting categories of 'asset relocations', 'quality of supply', 'other reliability, safety and environment'.

Whilst materiality thresholds of 25% of total spend in those categories have been applied for disclosure purposes, the actual % of transactions disclosed exceeded this.

There have been no items reclassified in accordance with clause 2.7.1(2).

Operational Expenditure for the Disclosure Year (Schedule 6b)

14. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-

    14.1 commentary on assets replaced or renewed with asset replacement and renewal operating expenditure, as reported in 6b(i) of Schedule 6b;

    14.2 information on reclassified items in accordance with clause 2.7.1(2);

    14.3 commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 11: Explanation of operational expenditure for the disclosure year

Expenditure on asset replacement and renewal is relatively minor in nature, generally, applying to asset components and designed to ensure the asset achieves its service life. Typically, such expenditure includes replacement and/or renewal of insulators, fuse links, service and link pillar components, cable terminations, equipment earth grids, transformer and switchgear components, including painting.

There have been no items reclassified in accordance with clause 2.7.1(2).

There are no items of operational expenditure that have been identified as atypical; however expenditure on vegetation management has started to ramp up considerably. As signalled in Aurora's asset management plan.

Variance between forecast and actual expenditure (Schedule 7)

15. In the box below, comment on variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

Box 12: Explanatory comment on variance in actual to forecast expenditure

In general, much of the variance in capital expenditure reflects an inherent difficulty in applying section 2.2.11(5) of the Input Methodologies (asset acquired from related parties). In practice, Aurora is faced with valuing the bulk of its asset additions on the basis of group consolidated cost, or market valuation. It is Aurora's intention to obtain market valuations for all of its asset additions; however, due to the relatively small number of valuers and supporting engineers experienced in infrastructure valuation, it will be several years before valuations will be completed. In the mean-time, asset additions will be valued at group consolidated cost. However, forecasting will continue to be based on market valuation which, in Aurora's experience, is very much closer to the transaction value, and provides a more accurate forecast of long term values.

Capital expenditure on consumer connections reflects increased development activity, mainly within the Central Otago subnetwork. Subdivision projects have noticeably increased, as has irrigation development in the Upper Clutha. However, as noted above, the difference between valuation methodologies applied to forecasting, and used (in the interim) to report additions, masks the trend.

The variance in 'system growth' is largely attributable to the planned major substation development to support the Tarras Water Ltd irrigation scheme being cancelled (this was reported in last year's disclosures as being deferred also). Despite the scheme being cancelled, many farmers have proceeded with their own private scheme, which has necessitated the development of two new rural zone substations. These substations are now scheduled for construction over the next two disclosure years.

Asset relocation activity has been muted, with few requests from developers and territorial authorities. In general, 'Consumer connection', 'system growth' and 'asset relocation' expenditure is generally driven by external factors and less controllable than other categories.

'Asset replacement and renewal' expenditure is close to forecast, and reflects Aurora's increased focus on pole renewals. Aurora is similarly focussed on quality of supply, and this is reflected in total reliability, safety and environment being close to forecast.

Overall maintenance expenditure is up significantly during the disclosure period. This has been driven, predominantly, by greater attention to vegetation management and asset condition, following Aurora's 2012 quality breach. Non-network opex was materially incorrectly stated in the 2013 AMP and associated forecast schedules.

Information relating to revenue and quantities for the disclosure year

16. In the box below provide-

    16.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clauses 2.4.1 and 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

16.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

Box 13: Explanatory comment relating to revenue for the disclosure year

Total delivery revenue budgeted	$84.580 million
Reported – Schedule 8 (Total Business)	$83.107 million
Difference	$1.473 million below target

It is generally expected that total billed line charge revenue for an assessment period will be different from target revenue, due to variation in connection numbers and energy demand. Additionally, Aurora's prices are derived to ensure that allowable notional revenue, as determined under the default price path, is not exceeded.

In the assement period, the volume of energy delivered to standard domestic consumers (the only consumer groups with volume-based pricing) dropped significantly from the prior year (by 6.5%). Energy delivered to standard domestic consumers disclosed in 2012/13 was 605.2GWh, compared to 565.3GWh in this current disclosure.

In the same period, standard domestic connection numbers increased by 0.8%. Standard domestic connection numbers disclosed in 2012/13 were 69,852, compared to 70,425 in this current disclosure.

Accordingly, the average energy use per standard domestic consumer decreased by 7.3%, from 8,664kWh to 8,027kWh.

Network Reliability for the Disclosure Year (Schedule 10)

17. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

Box 14: Commentary on network reliability for the disclosure year

In accordance with Information Disclosure definitions:

- Overhead (subtransmission and distribution) includes poles, stay-wires, crossarms, braces, insulators, conductor (including droppers and connectors), binders and ties
- Underground (subtransmission and distribution) includes cable, mounting brackets, terminations and potheads.
- Other (subtransmission and distribution) includes HV fuses (including fuse operation), lighting arrestors, transformers, switchgear, switching and control errors.
- Faults include unplanned events <1 minute, and events not resulting in loss of supply to a consumer, which would otherwise be excluded from consideration as an interruption.

In accordance with issue 231 of the Issues Register for Electricity and Gas Information Disclosure, Aurora declares that it has derived specific SAIFI and SAIDI boundary values for each sub-network. These values have been derived from the same reference dataset used to devlop the compliance attributed for the total business.

No normalisation for either sub-network was required.

We have predominantly chosen to derive sub-network specific boundary values for internal management and reporting purposes.

Insurance cover

18. In the box below provide details of any insurance cover for the assets used to provide electricity distribution services, including-

    18.1 the EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;

    18.2 in respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 15: Explanation of insurance cover

Insurance cover has been obtained / in place with respect of zone substations, both for the buildings and the plant and equipment contained within them.

The material damage (including flood, earthquake etc.) cover for the zone substations and associated equipment is on a replacement cost basis.

Distribution assets including distribution substations, lines and cables etc. are not currently covered due to the geographical spread, the lower value of the individual assets and the reduced likelihood of significant loss on any less than region wide event. This notwithstanding, Aurora is currently evaluating a proposal to add cover to distribution substations.

Company Name _____

For Year Ended _____

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

1. This Schedule enable EDBs to provide, should they wish to-

   1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.5;

   1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this Schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

There is a $704,000 discrepancy between the total line charge revenue reported in schedule 8, and that recorded in Aurora's financial system. The schedule 8 information has been compiled from a monthly reconciliation model using information derived from Aurora's connection management system. As such, the model may contain contain some wash-up values recorded in the disclosure period, but attributable to events outside the disclosure period. Line charge revenue derived from Aurora's financial system includes accruals for over/under reporting by retailers, calculated with respect to published loss ratios. The variability in retailer reporting can be significant month to month. The line charge revenue stated in schedule 3 (line 9) and schedule 7 (line 8) has been manually entered and reflects the value stated in Aurora's financial system.

SCHEDULE 18

Certification for Year-end Disclosures

Clause 2.9.2 of section 2.9

We, Stuart James McLauchlan and Trevor John Kempton, directors of Aurora Energy Ltd, certify that, having made all reasonable enquiry, to the best of our knowledge -

a. the information prepared for the purposes of clauses 2.3.1 and 2.3.2; and clauses 2.4.21 and 2.4.22; clauses 2.5.1 and 2.5.2; and clauses 2.7.1 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b. the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, 14a and 14b has been properly extracted from the Aurora Energy's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained [and if not, what records and systems were used]; and

c. the forecasts in Schedules 11a, 11b, 12a, 12b and 12c are based on objective and reasonable assumptions which both align with Aurora Energy's corporate vision and strategy and are documented in retained records.

In respect of related party costs and revenues recorded in accordance with clauses 2.3.6(1) (when valued in accordance with clause 2.2.11(5)(h)(ii) of the Electricity Distribution Services Input Methodologies Determination 2010), 2.3.6(2)(f) and 2.3.7(2)(b), we certify that, having made all reasonable enquiry, including enquiries of our related parties, we are satisfied that to the best of our knowledge and belief the costs and revenues recorded for related party transactions reasonably reflect the price or prices that would have been paid or received had these transactions been at arm's-length.

.....

Stuart James McLauchlan

.....

Trevor John Kempton

27 August 2014

Independent Auditor's Report

To the directors of Aurora Energy Limited and to the Commerce Commission

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 whether Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the SAIDI and SAIFI information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 12 in Schedule 14 ("the Disclosure Information") for the disclosure year ended 31 March 2014, have been prepared, in all material respects, in accordance with the Electricity Distribution Information Disclosure Determination 2012 (the "Determination").

Directors' responsibility for the Disclosure Information

The directors of the company are responsible for preparation of the Disclosure Information in accordance with the Determination, and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information that is free from material misstatement.

Auditor's responsibility for the Disclosure Information

Our responsibility is to express an opinion on whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

Basis of opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000: Assurance Engagements Other Than Audits or Reviews of Historical Financial Information issued by the External Reporting Board and the Standard on Assurance Engagements 3100: Compliance Engagements issued by the External Reporting Board.

These standards require that we comply with ethical requirements and plan and perform our audit to provide reasonable assurance (which is also referred to as 'audit' assurance) about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

An audit involves performing procedures to obtain evidence about the amounts and disclosures in the Disclosure Information. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the Disclosure Information, whether due to fraud or error or non-compliance with the Determination. In making those risk assessments, the auditor considers internal control relevant to the company's preparation of the Disclosure Information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control.

An audit also involves evaluating:

- The appropriateness of assumptions used and whether they have been consistently applied; and
- The reasonableness of the significant judgements made by the directors of the company.

Use of this report

This independent auditor's report has been prepared for the directors of the company and for the Commerce Commission for the purpose of providing those parties with independent audit assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company or the Commerce Commission, or for any other purpose than that for which it was prepared.

Scope and inherent limitations

Because of the inherent limitations of an audit engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Disclosure Information nor do we guarantee complete accuracy of the Disclosure Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information.

The opinion expressed in this independent auditor's report has been formed on the above basis.

Independence

When carrying out the engagement we followed the independence requirements of the Auditor-General, which incorporate the independence requirements of the External Reporting Board. We also complied with the independent auditor requirements specified in the Determination.

The Auditor-General, and her employees, and Audit New Zealand and its employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of business, this engagement and the annual audit of the company's financial statements, we have no relationship with or interests in the company.

Opinion

In our opinion:

- As far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;

- The information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records and has been sourced, where appropriate, from the company's financial and non-financial systems; and

- The company has complied with the Determination, in all material respects, in preparing the Disclosure Information.

In forming our opinion, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Ian Lothian
Audit New Zealand
On behalf of the Auditor-General
Dunedin, New Zealand
27 August 2014